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MASTER'S THESIS

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Abstract

The maritime delimitation in the former disputed area between Norway and Russia was agreed upon in 2011. It is therefore probable that the area will be opened for petroleum exploration in the near future. A blowout represents one of the most severe threats associated with petroleum exploration. This thesis has investigated the risk involved with such an activity through a case study, by considering geology and well specific conditions for this area. Currently, no wells have been drilled in the nearby area. Therefore, there is a lot of uncertainty related to reservoir and well conditions.

The blowout risk was determined in a well specific manner by employing several computer modeling tools. Determination of blowout probability, flow rate and duration was emphasized. This thesis also assessed the associated environmental risk through a methodological study. The main objective of this thesis was to investigate how available computer modeling tools allowed the uncertainty to propagate throughout an environmental risk assessment. This is done by observing how the applied tools could communicate probabilistic elements.

The blowout probability was determined through two different approaches. Both methods applied statistics as basis. A pure statistical approach attempted to reduce the historical blowout probability by considering recent trends in kick statistics. The computer modeling tool BlowFAM adjusted the historical probability by considering reservoir and well characteristics, and through an evaluation of a wide range of risk elements. The latter was also used to identify certain risk reducing measures. BlowFAM was considered to yield the most well specific result of the two approaches, and was therefore chosen as the most appropriate model for this case study. BlowFAM has yielded a blowout probability of 7.58×10^{-5}.

BlowFlow is a computer modeling tool used to determine flow rate and duration of a potential blowout in a probabilistic manner. This tool determines flow rate based on a consideration of reservoir and well conditions. The duration is a function of different types of blowout killing mechanisms. BlowFlow considers the uncertainty in input parameters, and reflect these uncertainties in the final results. The results are presented by means of probability distributions for several different scenarios. BlowFlow has yielded a mean flow rate of 1 200 m^3/d, and a mean duration of 10 days. The implications of several risk reducing measures was also investigated.

OPERAto is a computer based tool used to determine the environmental risk related to a possible blowout. The risk is determined based on the area of influence, and presence of specific valued ecosystem components (VECs). The model does currently not include data collected from the former disputed area of the Barents Sea. Oil drift simulations and environmental data have been collected from Norne; an oil field in the northern part of the Norwegian Sea. Consequently, the environmental risk presented will not be correct for this case study. OPERAto was applied as a methodological study to determine the compatibility between the different modeling tools, and their ability to reflect uncertainty in input parameters. Also, the effect of implementing risk reducing measures was observed.

Through the methods applied it was possible to determine blowout probability, flow rate and duration in a well specific manner. However, it was not possible to determine the environmental risk in a relevant manner, within the frames of this thesis. Still it was possible to study how these tools communicated, and how the uncertainty was allowed to propagate through the environmental risk

assessment. It was concluded that the tools were able to communicate some probabilistic elements, but that there is still a lot of work to be done before a unified probabilistic methodology exists.

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Last but not least I would like to thank my boyfriend Runar, my family and friends for their help and support throughout the work with this thesis.

Table of contents

List of figures

List of tables

Abbreviations and terminology

ALARP	- As low as reasonably practicable.
Annulus	- The ring-shaped space between the outside of the drill pipe and the wellbore.
Bbl	- A barrel is a common unit of expressing oil volume, and corresponds to 0.159 m^3.
BOP	- Blowout Preventer.
CECS	- Canada East Continental Shelf
DNV	- Det Norske Veritas.
EMW	- Equivalent mud weight.
GLR	- Gas/liquid ratio.
GOR	- Gas/oil ratio. When oil is produced and brought to the surface, gas will come out of the solution as pressure and temperature is reduced. GOR is the ratio of the volume of gas that comes out of solution, to the volume of oil at standard conditions in Sm^3/Sm^3.
HPHT	- High pressure and high temperature.
IPR	- Inflow performance relationship.
IRIS	- International Research Institute of Stavanger.
LNG	- Liquefied Natural Gas. It consists mainly of methane and some ethane cooled below its condensing temperature. The volume is reduced by a factor of 600, thus it can be transported or stored effectively.
Ma	- Million years ago.
MIRA	- Method for Environmental Risk analysis.
MSm^3	- Million cubic meters at standard conditions.
NCS	- Norwegian continental shelf.
NPD	- Norwegian Petroleum Directorate.
OLF	- The Norwegian Oil Industry Association.
Open hole	- Well bore were the drill string has been withdrawn.
OSPRAG	- Oil Spill Prevention and Response Advisory Group.
OSRL	- Oil Spill Response Limited.
Permeability	- A measure of the ease with which fluids will flow though a porous rock, sediment, or soil.

Porosity	- The ratio of the volume of openings (voids) to the total volume of material. Porosity represents the storage capacity of the geologic material.
PSA	- Petroleum Safety Authority.
PVT	- Pressure-Volume-Temperature.
RT	- Rotary table.
Scf	- Standard cubic feet, or cubic feet at standard conditions. A cubic feet correspond to 0.0283 m^3 in volume.
SG	- Specific gravity refers to the ratio of the density of a substance to the density of a reference substance. Air is used as the reference substance for gas, while water is used as reference substance for oil or mud.
Shale	- A fine-grained, usually laminated, clastic rock of compacted clay or mud particles.
Sm^3	- Cubic meters at standard conditions.
STB	- Stock tank barrel. A barrel of oil that has expanded to standard conditions. It contains less dissolved gas than oil at reservoir conditions.
SWRP	- Subsea Well Response Project.
TVD MSL	- True vertical depth to mean sea level.
TVD RT	- True vertical depth from rotary table.
UKCS	- British Continental Shelf.
US GoM OCS	- United States Gulf of Mexico Outer Continental shelf.
VEC	- Valued ecosystem components.
VLP	- Vertical lift performance.

1. Introduction

This thesis aims to analyze the blowout risk related to exploration drilling in the former disputed area southeast in the Norwegian part of the Barents Sea. This is done in a probabilistic manner, where the uncertainty related to different parameters is emphasized. The blowout risk is determined in a well specific manner by employing several computer modeling tools. Determination of blowout probability, flow rate and duration is emphasized. This thesis will also assess the associated environmental risk through a methodological study. The main objective is to investigate how available computer modeling tools allow the uncertainty to propagate throughout an environmental risk assessment. This is done by observing how the applied tools can communicate probabilistic elements. A high level of detail is important to provide a good basis for making sound risk management decisions. Thus, the applicability of these models as decision support tools in risk management is investigated.

1.1 Background

The maritime delimitation in the former disputed area between Norway and Russia was agreed upon in 2011. It is therefore likely that this area will be opened for petroleum exploration in the near future. The southeastern Barents Sea has not yet been thoroughly explored for hydrocarbon resources. As of today, there are no wells drilled in this area. Collection of geologic data through seismic surveys have been initiated, and will be continued in 2012 (Nyland et al., 2011). If the processed data indicate that there might be recoverable hydrocarbons, it is likely that on ore more exploration wells will be drilled.

A blowout represents one of the most severe threats associated with petroleum exploration. Even though much effort is put into describing how a blowout occurs and how to prevent it, the risk of a blowout remains a threat to the industry. To enlighten the risk involved with the drilling activity, an environmental risk assessment can be performed. This is especially important in environmentally vulnerable areas, where the potential consequences are high and oil spill contingency planning require extra attention (Arild et al., 2008). Since there are currently no wells drilled in the former disputed area, there is limited information available about geological conditions. Whether this region contains any recoverable oil or gas resources is still uncertain. Preliminary data indicate that it may be primarily a gas province. If there are oil reservoirs present, these are likely to be characterized by poor reservoir conditions. The Barents Sea is generally governed by low pressures (pers. comm. Høy). Due to these factors, it is crucial to take well specific conditions into consideration, to present a reasonable risk level.

As of today, ERAs are commonly based on statistics and experience data, rather on conditions of the well or field in question. Through such an approach, it becomes difficult to incorporate the uniqueness of each well into the analysis. It is also common to use conservative estimates in an ERA, due to the limited ability of different methods to reflect uncertainty. Today's environmental focus has generated a need for improved cross disciplinary tools within blowout risk management. As a result, risk assessment tools have become more sophisticated (Arild et al., 2008). The Norwegian Oil Industry Association (OLF) has developed a "Method for Environmental Risk Assessment" (MIRA) (Brude, 2007). It presents standardized guidelines on how to perform an ERA. Fig. 1 shows a simplified summary of the ERA process.

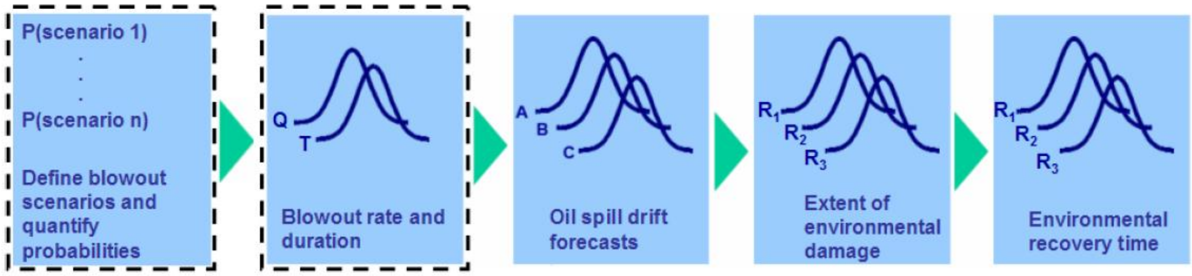

Figure 1: Environmental risk assessment process and propagation of uncertainty (Arild et al., 2008, Brude, 2007).

A blowout probability assessment is one of the main activities in quantifying the risk related to drilling and well operations. Determination of blowout probability has often been based on statistics. However, this does not reflect recent trends in statistics. Nor does it include recent technological or operational improvements. The blowout probability might be considerably reduced in recent years, compared to the early records of historical databases. The probability will also vary greatly from well to well, due to well specific characteristics. This is not reflected in statistical probabilities.

As of today, there is no common standardized methodology among oil companies for the calculation of blowout rate and duration. Today's practice still varies greatly with respect to level of detail, handling of uncertainty, terminology, level of documentation and traceability. OLF has produced guidelines on how to calculate flow rates and durations for use in an ERA (Nilsen et al., 2004). According to the OLF guidelines the results should be presented in a probabilistic manner, to reflect uncertainty. It is important to be able to reflect uncertainty throughout the ERA process. Otherwise, the uncertainty will not be reflected in the final results, and the level of detail will be compromised. A higher level of detail will yield more accurate result. It is therefore necessary to communicate these probabilistic elements through the different steps of the ERA, as illustrated in Fig. 1.

1.2 Goals

This thesis will investigate the blowout risk related to drilling of an exploration well in the former disputed area of the Barents Sea. It will attempt to determine the risk in a probabilistic manner, by considering uncertainty in different parameters such as geological conditions. Several computer modeling tools are applied in this assessment. Some tools will incorporate the uncertainty of input parameters in the analysis, while others only allow use of deterministic data. The ability of each tool to reflect uncertainty will be discussed. The uncertainty in one step of an ERA should ideally be allowed to propagate and be reflected in each of the following steps. This is illustrated in Fig. 1, where the environmental risk and recovery times are presented as a probability distribution. Ideally, each step should reflect the same level of detail, and the same amount of uncertainty as the previous. The main objective of this thesis is to investigate whether available computer modeling tools allow propagation of uncertainty throughout an ERA.

A complete environmental risk assessment will not be performed in this case study, as there is limited time and resources available. Determination of blowout probability, flow rate and duration is emphasized in this thesis. One could say that the focus is on the *upstream* aspects of the blowout. This means that assessing the probability and dimensions of a possible blowout is of priority, rather than the environmental consequences. This is illustrated in Fig. 1, where the first two steps of the ERA have been highlighted. It is desirable to be able to assess these parameters in a more mechanistic way, which is specific to each case analyzed. Therefore, it will be attempted to incorporate the uniqueness of the well in question into the analysis. To determine whether these tools are able to reflect well specific conditions is an important aspect of this thesis.

Two different blowout probability assessment methods will be investigated. This constitutes the 1st step of the ERA process in Fig. 1. The 1st method is a purely statistical approach that adjusts the historical blowout probability to reflect recent trends in kick statistics. The 2nd method involves the computer tool BlowFAM, which is developed by Scandpower. This model also has a statistical basis. Here the blowout probability is adjusted by considering well configuration and reservoir conditions, and through an evaluation of equipment, management and procedures. This tool allows to identify which parameters contribute to an increased risk through a sensitivity study. It can also identify possible risk reducing measures through an evaluation of risk elements. The two different approaches will be compared with respect to the resulting blowout probability, incorporation of well specific conditions, and their applicability as risk management tools. Their (in)ability to reflect uncertainty will also be assessed.

BlowFlow is a tool developed by IRIS which will be used to assess the flow rate and duration of a potential blowout. These values will be presented as probability distributions, to reflect uncertainty in input parameters. The flow rate is presented for a range of different blowout scenarios. This tool constitutes the 2nd step of the ERA process and Fig. 1. It is desirable to include a high reflection of uncertainty in the analysis to achieve a high level of detail. BlowFlow allows a detailed reflection of uncertainty. Therefore, it is important to allow these probabilistic elements to propagate through the following steps of the ERA. By altering input parameters through a sensitivity study the tool can reveal which factors contribute most to an increased risk. Measures that will reduce the duration of a blowout can be initiated, to mitigate the environmental consequences of potential blowout.

DNV's computer model OPERAto is used to determine the environmental risk associated with a possible blowout. This is done by assessing environmental damage and recovery time for specific valued ecosystem components (VEC). Due to the time restrictions of this thesis, environmental consequences have received limited attention. OPERAto is run based on oil drift forecasts and environmental resources present in a given area. Since this is only a case study, oil drift forecasts and collection of environmental data will not be performed. A worksheet run for Statoil's field Norne will therefore be applied in this thesis. This means that the resulting environmental risk will not reflect the conditions of specific for this case study. The tool will be applied as a methodological study to determine the ability of these tools to allow the uncertainty to propagate. The compatibility of the different tools applied is assessed. This thesis will investigate how these tools can communicate probabilistic elements. OPERAto's ability to reflect uncertainty in parameters is the main focus of this thesis. This is determined by investigating how applicable the results from the previous models are as input in OPERAto.

It is important to incorporate risk management in the ERA. OPERAto can demonstrate the effect of implementing different risk reducing measures. This is done by observing the relative implications on the environmental risk, when altering input parameters. Different measures will be identified through both BlowFAM and BlowFlow. The blowout risk is defined as a function of both probability and consequences of a blowout. Measures identified through BlowFAM will work to reduce the probability of a blowout occurring. These are referred to as preventive measures. Measures identified through BlowFlow can reduce the duration of a blowout, and thus mitigate the environmental consequences. The implication of both preventive and consequence mitigating measures on the environmental risk will be investigated through OPERAto. An objective of this thesis is to evaluate the ability of these tools to aid decision making in a risk management process. Does the combined use of these tools provide a common platform for risk based decision making? But the main objective is to investigate the reflection of uncertainty through the entire assessment, and also through the implementation of risk reducing measures.

1.3 Structure

Chapter 2 includes a theoretical background that gives the reader basic knowledge about the subjects addressed. It introduces different aspects of a blowout. Definitions regarding risk and environmental risk are discussed shortly. This section also presents information about the activity in the Barents Sea, as well as physical conditions of the former disputed area southeast in the Norwegian part of the Barents Sea.

Chapter 3 includes a methodology description of the three different computer modeling tools applied in this thesis. It introduces input categories and some basic calculations.

Chapter 4 presents the case study, which is a short description of the activity, location, focus of the thesis, as well as different assumptions made.

Chapter 5 presents two different approaches to determine blowout probability. A statistical approach attempts to reduce the probability by considering recent kick statistics. The computer modeling tool BlowFAM attempts to adjusts the risk by considering reservoir and well characteristics, and through an evaluation of a wide range of risk elements. Both approaches are used to assess which blowout scenarios are possible. BlowFAM is also used to identify certain risk reducing measures.

In chapter 6, BlowFlow is used to determine oil spill scenarios by means of flow rate and duration, in a probabilistic manner. The sensitivity of the flow rate to uncertainty in input parameters is investigated. The tool is also used to identify risk reducing measures that can reduce the duration of a blowout.

In chapter 7, OPERAto is used to address the environmental risk as a function of blowout probability, flow rate and duration through a methodological study. The effects of the identified risk reducing measures on environmental risk are also investigated.

Chapter 8 includes a discussion of the results from the chapter 5, 6 and 7. It also investigates the compatibility of these models, and the propagation of uncertainty. Chapter 9 presents the conclusion which can be drawn from the discussion.

2. Theoretical background

During the last decade there has been an increased interest in the relatively unexplored areas in the North, from the oil and gas industry. The Barents Sea has proven to contain producible amounts of hydrocarbons, and there are now several fields in the planning and development stages. Optimistic estimates suggest that 24 % of the world's undiscovered petroleum resources are located in the Arctic (Ahlbrandt et al., 2000). The delimitation between Norway and Russia in the southeastern part of the Barents Sea was agreed upon in 2011. Therefore, this area is believed to be opened for petroleum activity in the near future. It is still high uncertainty related to whether this new region contains any producible oil resources. Seismic surveys have been initiated to map possible resources. If these findings indicate that hydrocarbons may be present, exploration drilling will follow (Nyland et al., 2011).

There is always some risk associated with exploratory activity. If an exploration well is to be drilled an environmental risk assessment must be performed. There are several reasons for this (Brude, 2007):

- To comply with national regulations
- Evaluate if the operators acceptance criteria will be met
- Manage and reduce the environmental risk
- Internal and external decision support
- Form a basis for choosing risk reducing measures, such as dimensioning oil spill response and preparedness

Petroleum resources are complex mixtures of hydrocarbons. They are found in geologic formations beneath the Earth's surface. Hydrocarbons are formed by degradation of organic material. If clay and minerals are deposited with 5 % or more organics to form shale, a hydrocarbon source rock can be formed. The organics will be degraded as new layers form on top. Oil maturation requires high temperatures (60 -120 °C) and high pressures, which is represented by an “oil window”. Formation of gas has a corresponding “gas window”. If the conditions of the rock layers reach this window, the organics can mature into hydrocarbons. This maturation takes millions of years (Selley, 1998).

As most hydrocarbons are lighter than rock or water, they will eventually leak from the source rock and migrate upward. Some of these resources can be captured in closed structures called hydrocarbon traps. A trap is a geologic structure capable of retaining hydrocarbons. The hydrocarbons are contained in porous and permeable structures (mostly sand- or limestone) called reservoirs. For the hydrocarbons to be retained, they must be trapped beneath an impermeable cap rock (typically shale and/or salt structures). When hydrocarbons are concentrated in a trap, an oil and/or gas field is formed. These resources can be extracted by drilling a well (Selley, 1998).

A blowout is among the most serious incidents that can occur during exploration drilling. Even though much effort is put into describing how a blowout occurs and how to prevent it, the risk of a blowout remains a threat to the industry (Arild et al., 2008). Therefore, the risk related to a blowout will be investigated in this thesis.

2.1 Blowouts

A **blowout** can be defined as an uncontrolled release of reservoir fluid to the surroundings. A blowout occurs when all defined technical barriers or operation of these has failed. It can consist of crude oil, natural gas and/or water. Such events can occur in both complex HPHT wells and simple shallow wells. A blowout is considered to be the most harmful event that can occur during exploration or production of petroleum resources. It has the potential to severely damage equipment, people or the environment. It might also lead to huge financial losses and cause damage to the responsible company's reputation (Arild et al., 2008). A blowout can occur during drilling, well testing, completion, production, or workover operations. Blowouts during exploration drilling are according to statistics the most frequent (Haugsvold, 2011, Holand, 2010), and will be focused on in this thesis. There is always a risk that a blowout can be ignited. This can happen through sparks from rocks exiting the well, or by heat generated by friction (Adams and Kuhlman, 1994).

In addition to a blowout, there are several other incidents that can lead to release of reservoir fluids to the surroundings. A **well release** can be defined as unintended flow of oil or gas from the well, which was stopped by use of the barrier system. This barrier system used must have been available on the well at the time the incident started. In other words, it is a blowout that was successfully diverted by use of well barriers. Well releases are therefore associated with smaller volumes than blowouts. A well release incident is however much more probable than a blowout (Holand, 2010). The overall risk related to well releases might therefore be higher than for blowouts. Smaller and more frequent events might pose a bigger threat to the environment. If addressing risk related to oil spills in a broader sense, well releases would be of interest. However, with respect to single events a blowout yields a higher risk and will therefore be the focus of this study.

A **shallow gas** blowout can occur if a gas zone is penetrated prior to installation of the BOP. Drilling before setting of the BOP usually involves drilling of the top hole with water or water based mud, which can be directly discharged to sea. During this initial drilling process it is possible to encounter an unexpected gas pocket (Murray et al., 1995). The only difference between a shallow gas blowout and a shallow gas well release is that well releases are per definition successfully diverted. These are the typical Norwegian classifications and might now be correct in other countries. The term "deep" is often used when referring to well operations performed after the BOP is installed (Holand, 2010). Since shallow gas pockets contain lighter hydrocarbon components, it is not as harmful as an oil blowout. Shallow gas will therefore not be discussed in further detail.

2.1.1 Well control

To prevent a blowout from occurring, the well is equipped with pressure control equipment and barriers. According to North Sea standards, the well must at all time be equipped with two independent well barriers during drilling or other well operations (Vestre, 1995). In order for a blowout to occur, both well barriers must fail at the same time. This situation can be expressed in a fault tree, as shown in Fig. 2.

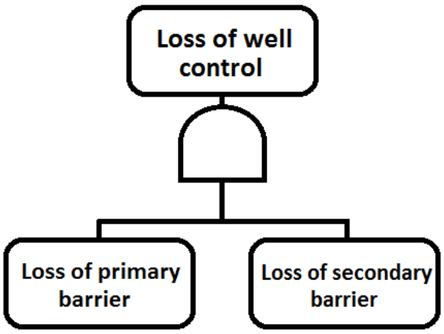

Figure 2: Fault tree for loss of well control (Brandt et al., 2010).

The primary barrier in a drilling operation is the hydrostatic pressure of the drilling mud inside the well. The hydrostatic pressure can be defined as the pressure exerted by a column of fluid. Sometimes there is also a pressure contribution from pumping of mud into the well, called equivalent circulating pressure. The pressure in the well must never be lower than the pressure of the pores in the reservoir. Otherwise, an influx might result. An influx is the flow of reservoir fluids into the well. This is often referred to as a kick. The density of the drilling fluid is used to obtain the appropriate well pressure. The density is controlled by varying the concentration of high specific gravity solids within the fluid, such as barite. Reliable mud monitoring equipment is necessary to prevent kicks from occurring (Adams and Kuhlman, 1994).

The well pressure must always be higher than the pore pressure of the formation. In addition, it must be sufficient to prevent a collapse of the well bore. However, the collapse pressure is usually lower than the pore pressure, thus an influx would occur before well collapse. But at the same time, the well pressure must be lower than the fracture pressure. A too high mud weight might fracture the reservoir. This can result in loss of well fluids to the formations, which in turn can cause a kick. The overburden (lithostatic) pressure is the pressure exerted by the weight of overlying formation. This pressure must not be exceeded. However, this is usually higher than the fracture pressure. These curves are commonly presented in a pore-pressure plot as shown in Fig 3. The curves are given as specific gravity (SG) or pressure gradients, as a function of depth. This plot is used to determine the appropriate mud weight at each depth. In this simplified model, the collapse pressure is not included (Jincai, 2011).

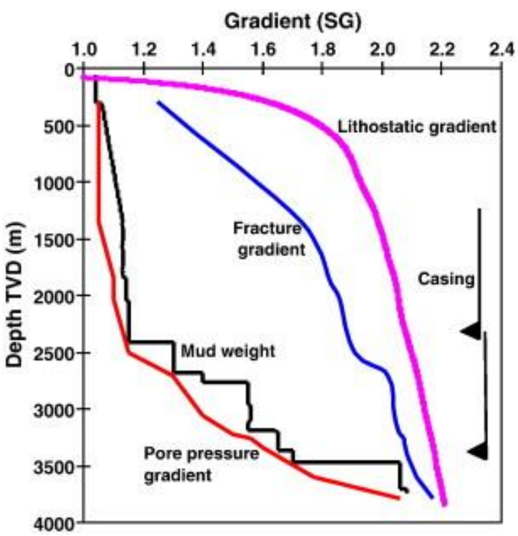

Figure 3: Pore pressure plot presenting specific gravity gradient as a function of depth (Jincai, 2011).

An essential part of well control is to maintain the appropriate mud weight throughout the drilling process. If the pore pressure of the formation increases, the mud density must be increased accordingly, to keep the well in balance. An imbalanced well can result in an influx, potentially leading to a blowout. The mud weight must be kept between the pore pressure and fracture pressure gradients at all time. The window between the pore pressure and fracture pressure gradient is often referred to as the drilling window. The mud weight must be altered and monitored continuously as the well is drilled. As the casings are set, the overlying formations are secured from collapse or fracture, and the mud weight can be increased.

A more detailed loss of well control scenario is shown in the fault tree diagram below. It shows the correlation between different initiating events, as well as the different constituents of the secondary barrier. The diagram is significantly simplified with respect to initiating events. These will be further discussed in next section. If the primary barrier is lost, it is crucial that the secondary barrier is functioning and can seal the well. If not, a kick can easily escalate into a blowout where reservoir fluids flow from the well and into the surrounding sea. The secondary barrier always consists of a blowout preventer (BOP), casings, cement and wellhead seals. The casing and cement seal the well from the outer well bore, preventing well collapse or fracture of overlying formations. The wellhead connections seal the well from the surface, along with the BOP.

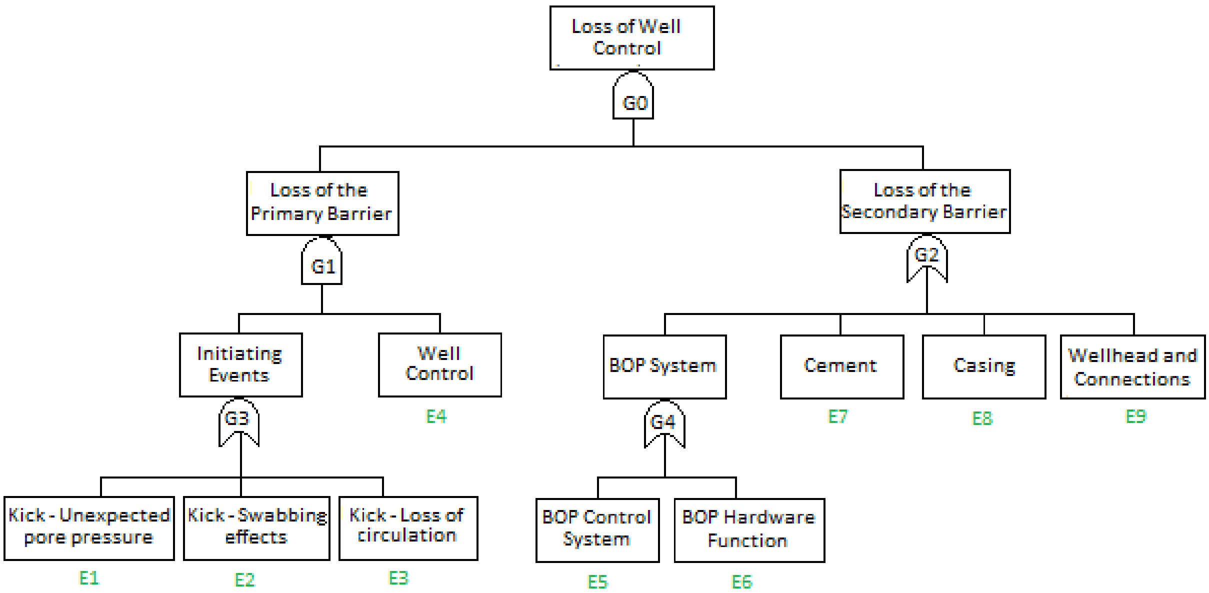

Figure 4: Fault Tree model – Loss of Well Control (Brandt et al., 2010).

On a subsea well, the BOP is located at the seabed, between the wellhead and the riser. During a drilling operation, the BOP will close immediately if an influx is detected. The device is designed to be a failsafe device. When the BOP is closed, the drilling mud density can be increased to restore well balance. After well control has been retrieved, the BOP can be reopened. BOPs must be tested at regular intervals depending on local practice, legal requirements and the probability of well control problems of the specific well. Testing intervals can vary from daily on critical wells, to monthly, or even less frequent. BOPs come in a variety of sizes and pressure ratings. The BOP stack includes several types of individual BOPs, either annular or ram preventers. A ram preventer consist of two steel plates (rams) fitted with packers, that are forced together to seal the well. There are several types of ram preventers (Adams and Kuhlman, 1994):

- Blind rams is the simplest type that is used to seal the well above the open well bore.
- Pipe rams will seal the well around the drill pipe, to prevent fluids from flowing through annulus. It does not however, prevent flow through the drill pipe.
- Variable bore rams are applicable for a wider range of pipe and tubing diameters than pipe rams.
- Shear rams are equipped with a steel-cutting surface, that enables them to completely shear through the drill pipe and/or casing.
- Blind shear rams are designed to seal the well while shearing the drill pipe in the process.

Annular preventers consist of a donut-shaped rubber packing that is squeezed inward to seal the well. It has the ability to close around a wide range of pipe diameters. It can also seal the open wellbore, but is generally not as effective as ram preventers at maintaining a seal on the open hole. The rubber packing it is then subject to high stresses, and this can result in a shortening in the lifetime of the preventer. Annular preventers are positioned above ram preventers, since they are not typically rated to working pressures as high as those of the ram preventers. A BOP stack typically includes 2 (dual) annular preventers installed above 4 or more ram preventers (Adams and Kuhlman, 1994). The BOP system also includes kill and choke lines, with hydraulically operated valves (McCrae, 2003). A simplified sketch is shown in Fig. 5.

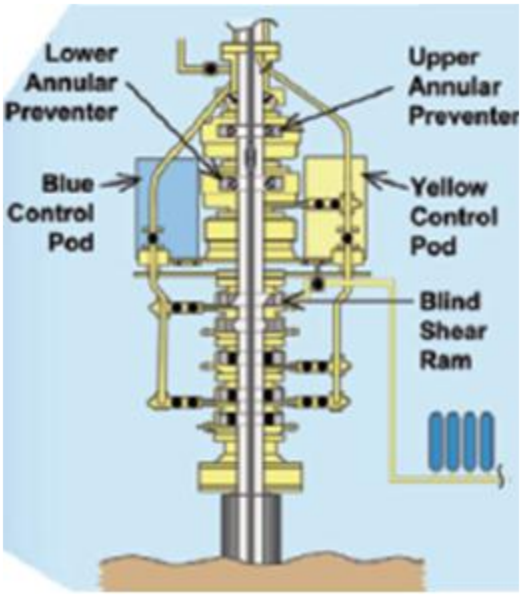

Figure 5: Blowout preventer schematic (McAndrews, 2011).

2.1.2 Causes

A blowout can occur if both the primary and secondary barrier is lost, as the fault tree diagrams in Fig. 2 and 4 show. A blowout can also be caused by human error or external causes, such as storms or collisions. According to the SINTEF offshore blowout database, incidents related to external causes are associated with production. Since this thesis addresses an exploration wells, external causes will not be discussed further. A kick is often the initiating event of a blowout. The SINTEF database includes detailed information about common causes of a kick. Blowout causes for deep exploration drilling are listed below in ranked order of occurrence (Holand, 2010):

- Annular losses (4)
- While cement setting (4)

- Too low mud weight (3)
- Gas cut mud (2)
- Improper fill up (2)
- Swabbing (2)
- Unexpected high well pressure (2)
- Unknown (2)
- Disconnected riser (1)
- Trapped gas (1)
- Reservoir depth uncertainty (1)
- Poor cement (1)
- Packer leakage (1)

Annular losses involve loss of well fluids to surrounding formations. This can lead to a reduced hydrostatic head of the mud column, and a kick can result. A high gas-cut in the mud will only cause small reductions in bottomhole pressure. But the gas expands as it moves toward the surface. The effective weight of the fluid can then be reduced, resulting in a reduced well pressure. If an unexpected pressure zone is encountered, the well pressure might become too low compared to the reservoir pressure. Improper fill up can lead to a temporarily reduced well pressure, and cause a kick. Swabbing is a result of failure to keep the hole full when withdrawing well equipment. Withdrawal of the drill string is referred to as a tripping operation. If the volume of the withdrawn equipment is not filled fast enough, a kick can result. If an influx occurs, the well pressure can be reduced even further as the reservoir fluids typically have a lower density than the mud. When a kick is detected, heavier mud must be circulated into the well in order to regain pressure control (Adams and Kuhlman, 1994). To avoid kicks, thorough well monitoring is necessary (Grace and Cudd, 2003).

2.1.3 Release points

Loss of well control can result in a blowout of several different scenarios. For one thing, the reservoir fluids flowing from the well can have several different release points. The most common release points are **topside blowouts** and **subsea blowouts**. At fixed platforms the wellhead and pressure control equipment is located at the platform above the sea surface. For such platforms a blowout will in most cases be a topside blowout, through the well head. A subsea well on the other hand has its wellhead on the seabed. Then the blowout can either be topside or subsea. For a subsea well, it is also possible for a topside blowout escalate into a subsea blowout. An example is the Macondo accident, where the entire rig sank and the riser was bent (McAndrews, 2011). If possible, the riser might be disconnected and the floating rig moved to a secure location. The well would then continue to flow at the seabed, rather than at the sea surface. It can be difficult to retrieve control over deep subsea wells, because of limited accessibility from the surface. There is limited experience with such events. Whether the oil is ignited or not is of great significance to the consequences.

Underground blowouts can also occur, but these are less common. It can be a result of a failed casing, due to high pressures in the well. During an underground blowout the reservoir fluids will typically flow from a high pressure deep zone, to a more shallow formation of lower pressure. These blowouts do not necessarily reach the sea or the surface, but they can be difficult to get control over. If the blowout is not stopped it might eventually reach the surface (Holand, 2010).

2.1.4 Flow paths

A blowout can flow through several different flow paths. The flow path of the blowout will partly depend on the equipment present in the well. If a drill string is present, the blowout can flow through **annulus**, the **drill string** or both. To be able to flow through the drill string, there would have to be an influx from the reservoir at the same time as the drill float valve fails. The drill string float valve is supposed to prevent back-flow of fluids into the drill pipe. This is also less likely since the drill string constantly is filled with mud. The annulus typically has much less resistance. Thus an annulus blowout is the predominant flow path, especially for topside blowouts (Holand, 2010).

If the drill string has been withdrawn, the blowout would be an **open hole** blowout. This could be the case if an entire section has been drilled, where the drill pipe has been removed before setting and cementing of the casing. However, it is unlikely that such a blowout should occur if the mud weight is maintained.

It is also possible to have a blowout **outside the casing**. This can occur if there is a failure of the cement or casing. Such a blowout will flow outside the casing wall and through the formations toward the surface. The fault tree above shows that if the casing or cement fails, the blowout cannot be stopped by a BOP because other constituents of the secondary barrier have failed. This is a more common flow path for subsea blowouts (Holand, 2010).

2.1.5 Duration

The duration of a potential blowout is among the most crucial factors regarding the amount of reservoir fluids released, and hence the degree of environmental damage. The blowout duration will be a function how long it takes to kill the well. Different killing mechanisms are discussed in appendix A. Some mechanisms are naturally occurring. Examples are **natural depletion**, **coning** and **bridging**. These occur as a result of pressure changes in the vicinity of the well bore. Other mechanisms are active measures which are initiated by crew. Examples of crew interventions are **capping** and **relief well drilling**.

There are several factors and challenges that can complicate a killing operation. If the well is on fire, it might have to be extinguished to regain access. It might also be necessary to clear the debris before a killing operation can be initiated. At the same time, extinguishing the fire can lead to build-up of flammable gases and H_2S. For some cases, the blowout might even be ignited to avoid an explosion, or exposure to H_2S. Fire and explosion can affect the time necessary to perform a killing operation, but will not be assessed in further detail here.

Emergency preparedness is crucial if a blowout should occur. Keeping equipment for a killing operation available near the well can reduce the mobilization time. If drilling a relief well, a drilling rig will have to be mobilized. If deploying a capping device, the device and an appropriate lifting crane is necessary. Whether this equipment is available near the field or not, will have a great impact on the time it takes to perform the operation.

2.2 Risk

Risk is defined as a combination of the probability of a specific hazardous event and the severity of the consequences of the event. The formula shown below can be used to calculate the risk quantitatively, by summing all potential accident sequences (Vinnem, 2007).

$$R = \sum_{i}^{Accidents} (p_i \cdot C_i)$$

Where:

R = Risk
p = Probability of an accident occurring
C = Consequence of the accident
i = Accident sequence

Though it is not possible to completely eliminate risk, it is desirable to reduce it as much as possible. This is stated in the Framework Regulations (2010). The term ALARP (As Low As Reasonably Practicable) is often used when discussing whether a risk level is acceptable or not. The Framework Regulations state that the ALARP principle is required in order to reduce risk. The regulations also state that risk reduction shall follow the cost-benefit principle. The cost of risk mitigating measures must be carefully considered to find a balance in a cost-risk-benefit manner. The responsible party shall choose the technical, operational and organizational solutions that offer the best results provided the costs are not significantly disproportionate to the risk reduction achieved.

2.2.1 Environmental risk assessment

Environmental risk is potential threat that a specific activity poses to living organisms, populations, habitats, etc. This is commonly investigated by means of an environmental risk assessment. The different steps in an environmental risk assessment were shown schematically in Fig. 1. Fig. 6 presents a more detailed overview of an ERA. The probability of a blowout must first be determined, and distributed between different scenarios. Flow rates and duration must be determined, and used as input to the oil drift forecasts. The oil drift simulations determine the area of influence by consideration of wind and current conditions at the release point. Data on vulnerable recourses is collected to determine the abundance in the area of influence. Consequently, the environmental damage and restitution time of exposed resources can be determined.

An ERA includes the identification of risks, and evaluating these against the environmental risk acceptance criteria of the operator. It might also include examining and implementing risk reducing measures. Accordingly, it contains both risk analysis and management (Brude, 2007). Whether risk reducing measures should be implemented should be evaluated with respect to cost and benefits. If the risk constitutes more than 50 % of acceptance criteria, risk reducing measures should be considered. This is often referred to as the "ALARP region". However, this region can vary from company to company (Brude, 2007).

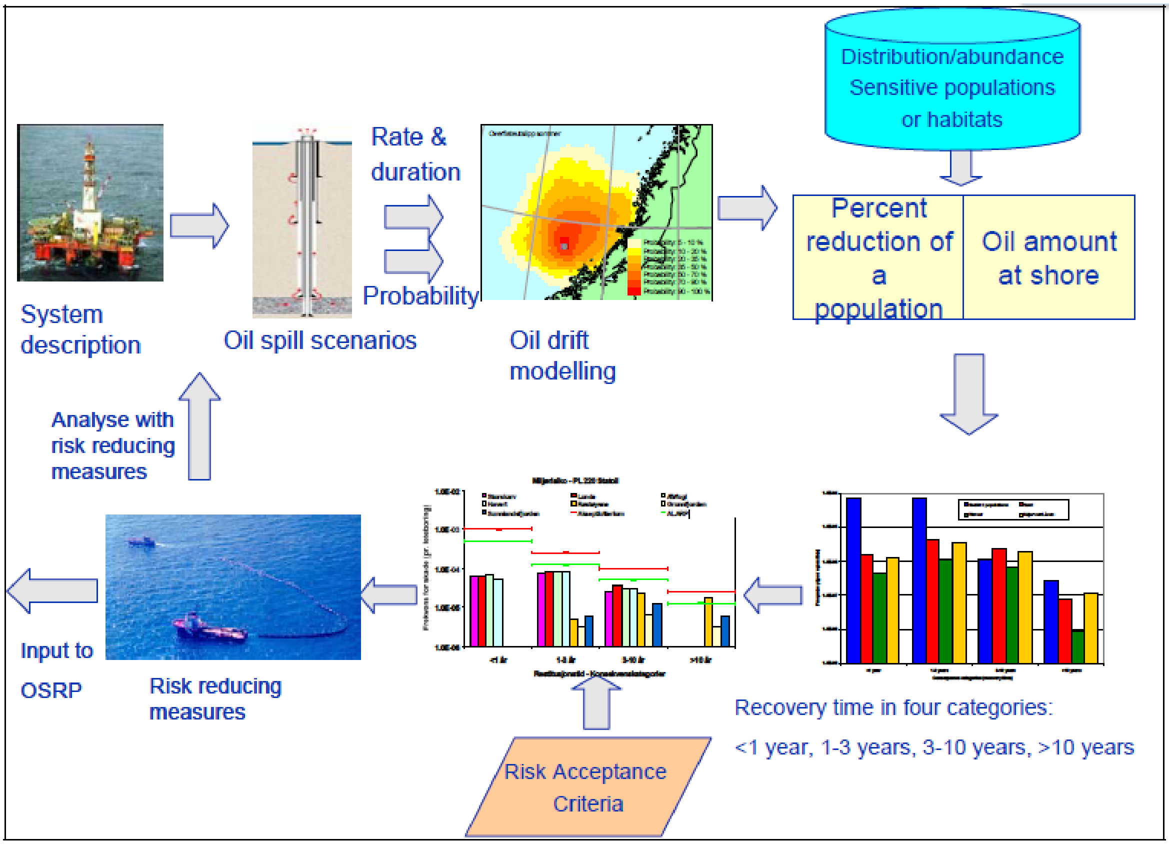

Figure 6: Schematic overview of an environmental risk assessment process (Brandt et al., 2010).

2.2.2 Acceptance criteria

Acceptance criteria are used to define an acceptable level of risk. The Norwegian Petroleum Directorate has issued a regulation related to risk analysis in the petroleum industry (The Norwegian Petroleum Directorate, 1995). It states that the operator must define the acceptance criteria based on company environmental policy and goals, before performing a risk analysis. These criteria should comply with governmental regulations. When evaluated against the overall risk, they are used as a decision support in risk mitigating measures.

According to the "Integrated Management Plan for the Lofoten-Barents Sea Area", human intervention and activities should not harm the function, structure, productivity or dynamics of the ecosystem (The Ministry of the Environment, 2011). Common acceptance criteria for an environmental risk assessment are shown in Table 1 below (Aaserød et al., 2011). The degree of environmental damage is categorized in 4 different levels of severity, with respect to recovery time of the environmental resource. The acceptance criteria define the highest acceptable risk level for each of these categories. The criteria in Table 1 are used as basis for many operators, such as GDF Suez and Statoil (Bjørnbom et al., 2008, Aaserød et al., 2011). They are determined based on the policy: "The recovery time after environmental damage for the most vulnerable resource should be negligible compared to the expected time between such events" (Brude, 2007). A high environmental vulnerability will lead to a longer recovery time. To meet the acceptance criteria for a more vulnerable area, the risk per operation must be correspondingly lower. All of the given criteria must be met simultaneously.

Table 1: Environmental risk acceptance criteria for petroleum activity (Aaserød et al., 2011).

Degree of environmental damage	Recovery time	Field specific risk per year	Installation specific risk per year	Operational specific risk per operation
Minor	(< 1 year)	$< 2.0 \times 10^{-2}$	$< 1.0 \times 10^{-2}$	$< 1.0 \times 10^{-3}$
Moderate	(1-3 years)	$< 5.0 \times 10^{-3}$	$< 2.5 \times 10^{-3}$	$< 2.5 \times 10^{-4}$
Considerable	(3-10 years)	$< 2.0 \times 10^{-3}$	$< 1.0 \times 10^{-3}$	$< 1.0 \times 10^{-4}$
Severe	(>10 years)	$< 5.0 \times 10^{-4}$	$< 2.5 \times 10^{-4}$	$< 2.5 \times 10^{-5}$

2.3 Petroleum activity in the Norwegian Barents Sea

The Norwegian part of the Barents Sea was first opened for petroleum exploration in 1980. From 1980 to 2001 a total of 61 exploration wells were drilled, and 21 discoveries were made. In 2001 there was a sudden halt in the exploration activity, as the "Impact Assessment for Year-Round Petroleum-related Activity in the Lofoten-Barents Sea" was executed. In 2004 the Barents Sea was reopened for year-round petroleum production, with exceptions of areas considered especially vulnerable to oil spills (Hasle et al., 2009). These areas are shown in Fig. 7.

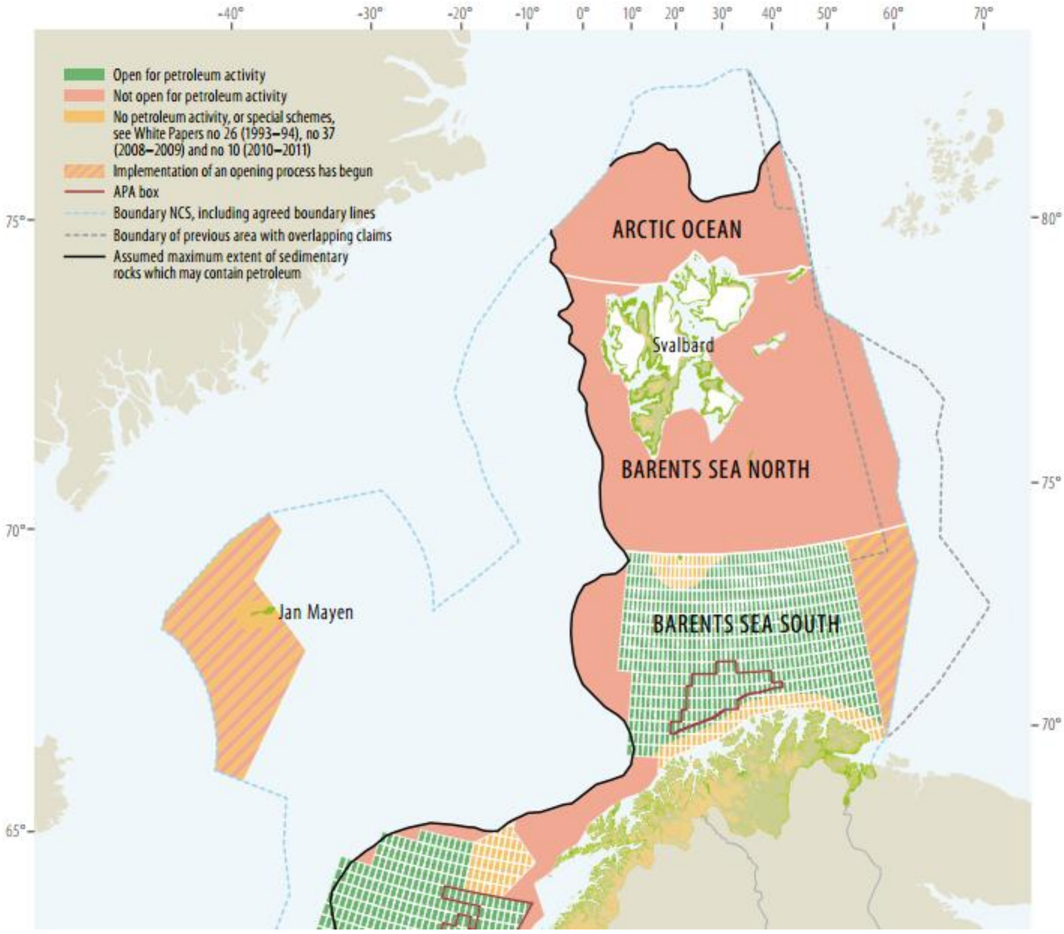

Figure 7: Overview of geographical restrictions on petroleum activity on the NCS outside Northern Norway (Nyland et al., 2011).

The Snøhvit gas field was discovered in 1981, and given development permission by the Norwegian Government in 2002. The development was subject to political debate, both since the development was the first one in the Barents Sea and because the LNG facilities were powered by gas turbines. In 2007 the first gas was piped from the subsea facilities offshore to the LNG processing plant onshore. The Goliat field was discovered in 2000 (Ulfsnes et al., 2010). When it starts producing in 2014 it will be the first oil producing field in the Barents Sea (Bjørnbom et al., 2010, Hasle et al., 2009).

In 2011 several promising new discoveries were made in the Barents Sea. Among them are Norvarg, Skrugard and Havis. Statoil has described the Skrugard-Havis finding as a breakthrough in the Barents Sea and one of the most important events on the Norwegian Continental Shelf (NCS) during the past decade. This, even though the recent Johan Sverdrup discovery in the North Sea may contain as much as twelve times the reserves of Skrugard. These new discoveries lead to an increased optimism in the North, which will have large implications on the development of infrastructure. It puts the Barents Sea region on the map as a future large scale energy basin (Offerdal, 2011).

The maritime delimitation between Norway and Russia in the Barents Sea and Arctic Sea have been subject to negotiation for roughly 40 years. In April 2010 an agreement was finally reached. The treaty was signed in Murmansk in September 2010, ratified in June 2011 in Oslo, and finally took effect at July 7th 2011. This allowed for cooperation and the possibility of opening the area for future petroleum exploration and production. If oil or gas deposits were to extend across the boundary line, the treaty specifies detailed rules and procedures aimed at ensuring their responsible and cost-effective administration. The treaty divided the former disputed area into two roughly equal parts. The area is shown in Fig. 7 above by a grey dash line, while the new boundary is shown by the blue dash line representing the boundary line for the NCS. The NPD regards this new area as interesting with respect to petroleum discoveries. Hopes are raised by the fact that petroleum resources have been found both to the east and west of this area. Geological data in this area have been very limited. Seismic surveys are initiated by the Norwegian Petroleum Directorate in the new Norwegian part of the Barents Sea. These were conducted from July 8th to September 13th 2011. The collection of seismic data is planned to continue the summer of 2012. This is assumed to provide sufficient information to be able to map hydrocarbon resources in the area (Nyland et al., 2011). A preliminary map of possible resources is shown in Fig. 8.

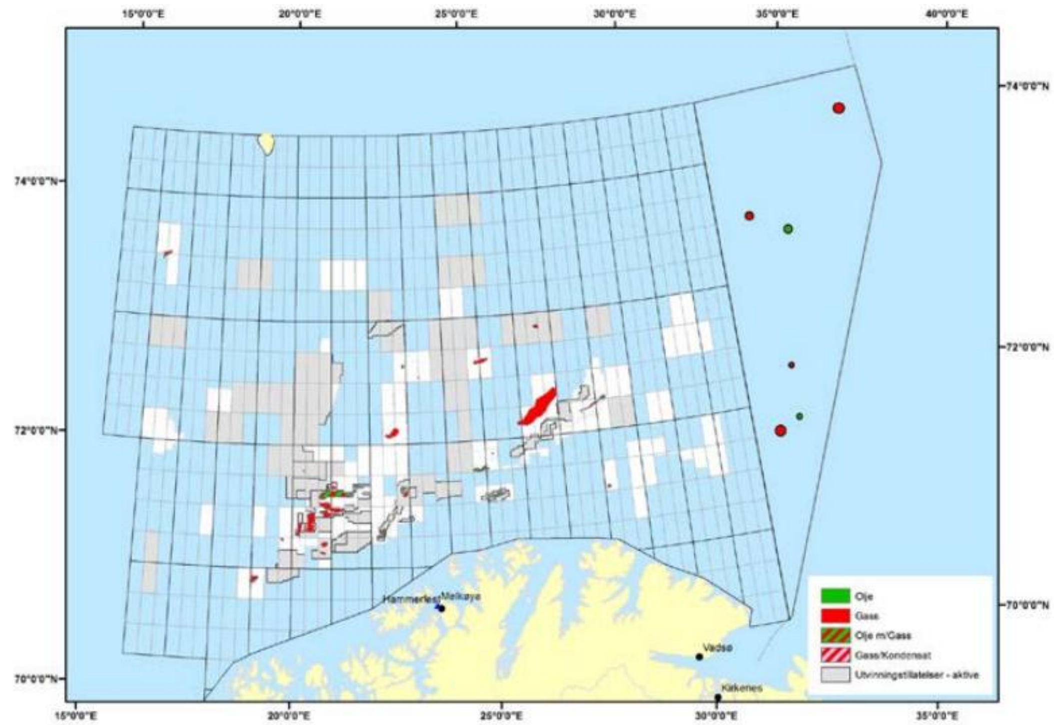

Figure 8: Overview of Barents Sea geography, with possible findings in the former disputed area (Moe, 2011).

When updating the “Integrated Management Plan for the Lofoten-Barents Sea Area”, it was decided to initiate an impact assessment for opening of the former disputed area in the Barents Sea South for petroleum activity (Ministry of the The Ministry of the Environment, 2011). One aim of this assessment is to award production licenses. The opening of this area for petroleum exploration and production will be up for discussion in the Parliament in the spring 2013 at the earliest (Nyland et al., 2011).

2.4 Physical conditions

Whether an accidental oil spill will be more serious in the Arctic region compared to further south, is a much discussed topic. The main differences in physical conditions include (Rekdal, 1987):

- Proximity of the sea ice
- Relatively frequent formations of polar lows
- Risk of sea spray and atmospheric icing
- Reduced visibility and long dark winters
- Remoteness and limited infrastructure
- Vulnerable marine and coastal environment

These conditions might complicate different types of operations, or oil spill preparedness. In relation to environmental resources, the Barents Sea has a low species diversity. But these species have a high abundance, and the biomass production is high. Conditions such as oceanography and geology of the southeastern part of the Barents Sea are discussed briefly below.

2.4.1 Oceanography

There is no significant difference in wind, wave or current conditions in the Barents Sea, compared to further south on the NCS. But the wave height in the eastern Barents Sea, is significantly lower than in the west. The most prospective areas of the Barents Sea are located at water a depth of 200 - 400 m. The seabed is characterized by a number of iceberg plough marks. However, certain areas are still relatively unexplored (Rekdal, 1987).

The dominating currents along the coast are the North Atlantic Current and the Norwegian Coastal Current. The NAC splits in two at the entrance to the Barents Sea, one entering the Barents Sea and one continuing northwards. The NCC follows the Norwegian continental shelf northward along the coast (Hjermann et al., 2007).

2.4.2 Geology

There is little data available on geological structures and possible hydrocarbon resources in the southeastern part of the Norwegian Barents Sea. The NPD has commissioned collection of seismic data, which will be completed in 2012. Preliminary data indicate a predominance of gas in possible hydrocarbon traps. The bedrock beneath the Barents Sea is a complex mixture of sedimentary rocks deposited through the Mesozoic (251.0 – 65.5 Ma) and early Cenozoic era (65.5 – 2.6 Ma). The Mesozoic era can be further divided into the geological periods Triassic (250.0 – 200.0 Ma), Jurassic (200 – 145.5 Ma) and Cretaceous (145.5 – 65.0 Ma). Due to glacial periods in more recent time, the bedrock has been significantly eroded, and has experienced uplift (Faleide et al., 1993).

Recoverable hydrocarbons are typically found in Jurassic or Triassic sediment layers. Jurassic layers are often characterized by good reservoir properties, with a high porosity and permeability. However, there is great uncertainty to whether Jurassic shale layers in this area are buried deep enough for oil maturation to take place. These structures have also been significantly eroded through glacial periods, thus any recoverable resources might have leaked out. Possible hydrocarbon reservoirs in this area are therefore believed to be contained in Triassic rocks or deeper layers. However, these structures typically have poorer reservoir quality. They are characterized by a low porosity and permeability. It is not uncommon for oil reservoirs to be trapped beneath a salt structure (pers. comm. Høy), as shown in Fig. 9. These structures might penetrate and deform surrounding sediments, and form traps able to retain hydrocarbons (Dore, 1995). Gas is shown as a red column within the Triassic reservoirs, while oil are smaller green columns beneath the gas.

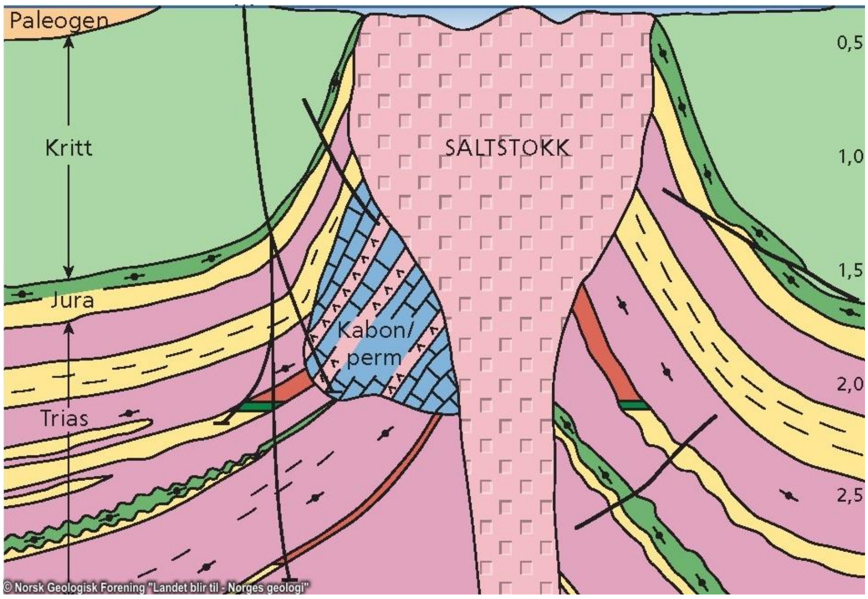

Figure 9: Schematic representation of hydrocarbon reservoirs beneath a salt structure (Ramberg et al., 2008).

3. Methodology

Today's practice in ERAs varies greatly with respect to level of detail, handling of uncertainty, terminology, level of documentation and traceability. Different companies use different approaches. There is an increasing number of computer models available for determining risk related to a blowout. This is a result of increased focus on environmental concerns, especially as the oil industry is moving further north. There is an increased interest in such models, and more and more companies employ them in ERAs.

Several different computer models have been applied in this thesis to predict the risk related to a blowout. This thesis emphasizes determination of blowout probability, flow rate and duration. It will also investigate the effect of these parameters on the overall environmental risk. It is desirable to be able to assess these parameters in a more mechanistic way, which is specific to each case analyzed. When performing environmental risk assessments, these are commonly based on statistics and experience data and not on conditions of the specific well or field in question. BlowFAM will be used to determine the blowout probability. BlowFlow is used to determine flow rate and duration. These models are both mechanistic, which means that they can determine the risk based on well specific conditions. OPERAto is used to determine the environmental risk based on input from these models, through a methodological study. This thesis will also evaluate how well these models can communicate with each other, where the main focus is on their ability to allow the uncertainty to propagate through the steps of an ERA.

3.1 BlowFAM

The Blowout Frequency Assessment Model (BlowFAM) is a tool used to assess the blowout probability related to specific activities. If performing an ERA, it is necessary to determine the blowout probability. The different steps in an ERA are shown in Fig. 1, where BlowFAM constitutes the 1st part of the process. The computer tool was developed by Scandpower in 1995 in cooperation with several oil companies (Statoil, BP, etc). It is based on historical data from the SINTEF database. The historical blowout probability is adjusted through several steps by considering well configuration, reservoir characteristics, crew, procedures and equipment. A high number of risk elements are evaluated. It determines blowout probability for activities such as drilling, production and well interventions for a well or field. BlowFlow also presents well release and shallow gas probabilities. BlowFAM can be applied during the design phase of a platform, or for future well operations on existing units. This can help aid the identification of risk reducing measures prior to development.

By defining specific flow rates for the different scenarios, BlowFAM can present duration and oil spill quantities. This will not be applied in this thesis as BlowFAM includes a higher number of scenarios, compared to BlowFlow. Thus, BlowFAM would require more detailed input on flow rate than what is supplied by BlowFlow.

3.1.1 General information

The general information includes the type and number of wells or operations. The possible activities are listed below. Drilling before the BOP is set refers to shallow drilling, where a possible blowout will lead to a shallow gas incident. Drilling after setting of the BOP refers to deep drilling.

- Drilling before the BOP is set
- Drilling after the BOP is set
- Completion
- Production
- Workover
- Wireline

Drilling activity can further be categorized as exploration or developmental drilling. Whether the well is a HPHT or a normal well is crucial to the related risk, since a HPTH well involves a higher risk. A HPHT well typically has a small drilling window, which makes it difficult to maintain the appropriate mud density (see section 2.1.1). The well can contain either oil or gas. The installation can be classified as a floating, fixed or tension leg platform (TLP). This will result in a basic blowout probability specific for the type of well, fluid and installation. This is done by excluding irrelevant accidents based on input data. I.e. for a normal well, HPHT incidents can be excluded.

3.1.2 Reservoir and well design

Formation properties and well design are important contributors to the blowout probability. Implications of these factors can be assessed by evaluating different blowout causes. The blowout probability is divided between different blowout causes. The cause distribution from the SINTEF database is used as a starting point. This distribution is given in Table 12, as the historical fraction. Different reservoir and well characteristics will affect the chance of a specific blowout cause to occur. For instance, a narrow drilling window will increase the risk of annular losses. A range of parameters related to formation characteristics, pressure profiles and well design must be defined and entered in the model:

- Water depth
- Well depth
- Reservoir temperature
- Pore pressure
- Drilling window
- Mud weight
- Length of horizontal section
- Height of drill floor above sea
- Drill pipe diameter
- Open hole diameter
- Casing inner diameter
- Gas/oil ratio (GOR)
- Mud circulation rate
- Seawater density

The well must also be classified with regards to several other reservoir and well characteristics. This includes:

- Risk related to drilling too deep
- Well testing to be performed
- Risk of drilling into neighboring wells
- Gas cap above the oil
- Reservoir segmentation
- Reservoir productivity

Some elements may be excluded if they are not applicable for the specific activity. If parameters are classified as normal or unknown, the risk level will be left unchanged. Otherwise, the classification of each of these parameters can either increase or reduce the risk. A high reservoir productivity will for example yield a higher risk. If the casing shoe is close to the reservoir, there is a risk of drilling too deep. The cap rock beneath the reservoir might have a higher pressure than the reservoir. If so, the mud weight can become too low, and a kick might result. A high reservoir segmentation indicates poor pressure communication between zones of the reservoir. If the communication is poor, this increases the chance of encountering an unexpected pressure zone. If gas is injected into the reservoir, this risk is especially high.

The listed parameters are compared to the average well. Based on experience from blowout studies, the implication of different parameters on each blowout cause can be assessed. The sum of the historical cause distribution is equal to 1, per operational phase (drilling, production, etc.). When input is entered into the model, the cause distribution is adjusted according to algorithms built into the model. An adjustment is determined for each specific blowout cause. This adjustment is multiplied with the historical fraction of each cause (see Table 12). The sum of the adjusted cause contributions is equal to the adjustment factor. This is referred to as adjustment factor 1, and can either be higher or lower than 1. This factor is applied to the basic blowout probability. An adjustment factor greater than 1 yields a higher risk, and opposite.

3.1.3 Risk elements

This is the main part of BlowFAM and comprises an evaluation of risk elements associated with equipment, crew and procedures. The database consists of more than 300 risk elements that contributes more or less to the blowout risk. These elements are distributed in several different categories (Dervo and Blom-Jensen, 2004), as listed below. Some of them are explained in further detail in Fig. 10.

- Production
- Wireline
- Completion
- Drilling management
- Frame conditions
- Operational procedures
- Drilling
- HPHT

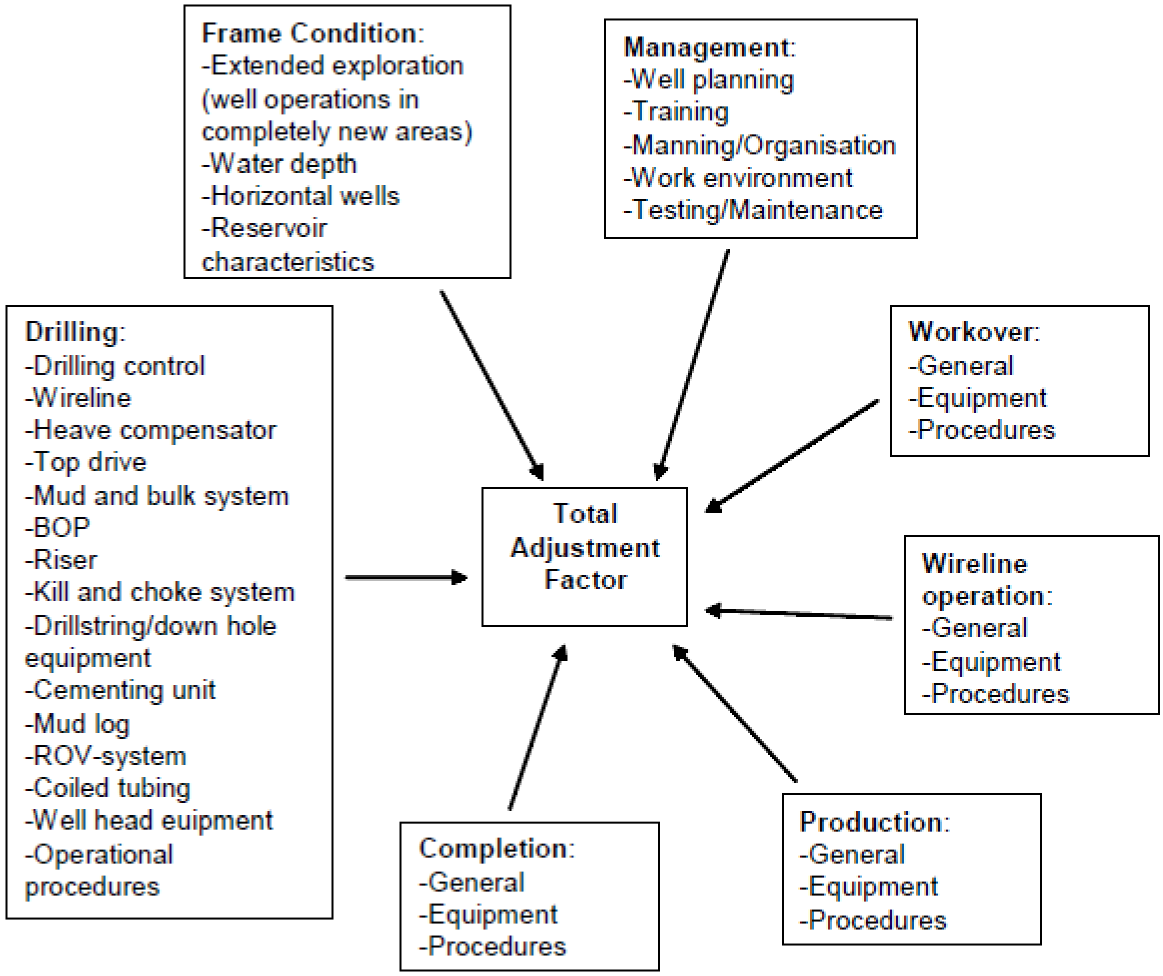

Figure 10: Sketch of elements contributing to the blowout risk (Dervo and Blom-Jensen, 2004).

Which risk elements are relevant will depend on the activity. For deep zone operations elements related to shallow gas can be disregarded. If performing only drilling activity, production, wireline and completion can be disregarded and so on. Elements considered irrelevant for the specific well can be excluded, and set to not applicable. The user chooses which elements that are considered to be applicable for the specific well or operation. All the applicable risk elements are then evaluated to determine whether they pose an increased or reduced risk. Risk elements that increase the risk are assigned a negative score, while risk *reducing* elements are assigned a positive score. Elements that are not considered to yield any change in risk compared to an average well are left unchanged. Guidance for each element is available in the tool to aid the evaluation process. All elements have a default value or a maximum score. If the maximum score is 3, the score can vary between -3 and 3. An explanation for the dedicated score should be given for each element. The implication of all the applicable elements on the blowout risk is calculated by the following formula, to find adjustment factor 2:

$$Adjustment\ factor\ 2 = \frac{\sum X + \sum W - \sum B}{\sum X}$$

Where:
∑X = Total number of applicable risk elements.
∑W = Worse; added up score of all the risk elements contributing to an increased risk.
∑B = Better; added up score of all the risk elements contributing to a reduced risk.

These figures are given as absolute (positive) values. The adjustment factor will be a function of the total score of modified risk elements, as well as the total number of applicable risk elements. This means that the number of applicable elements will influence the relative importance of each element. If only a few elements are applicable for the activity, then a higher score for one of them will give a greater impact on the blowout probability than if there were many applicable elements. It is therefore important to exclude elements that are not applicable. The adjustment factor calculated from the formula above is applied to the basic blowout probability, resulting in a new probability for the specific well or activity.

3.2 BlowFlow

Assessing blowout rate and duration is an important part of an environmental risk assessment (ERA). However, there is no standardized method for calculations of these values which can easily be communicated and compared between different parties. BlowFlow is a tool that evaluates blowout scenarios by enabling a risk-based quantification of blowout rates and duration. It allows for comparing of results from field to field, as well as communication among geologists, drilling- and HSE engineers (Arild et al., 2008). It is developed by IRIS and builds on the OLF guidelines for calculation of flow rates and duration for use in environmental risk assessment (Nilsen et al., 2004). The different steps in an ERA are shown in Fig. 1, where the BlowFlow model constitutes the 2nd part of the process.

The model uses a wide range of defined blowout scenarios as a basis for the analysis. The sequence of events following a blowout is described in a probabilistic manner, where the uncertainty related to the blowout rate, duration and volume is described by means of probability distributions. The BlowFlow model constitutes three different phases; determining input parameters, computer modeling and evaluating the result (output) (Arild et al., 2008). The three processes are represented in Fig. 11, and discussed in further detail below.

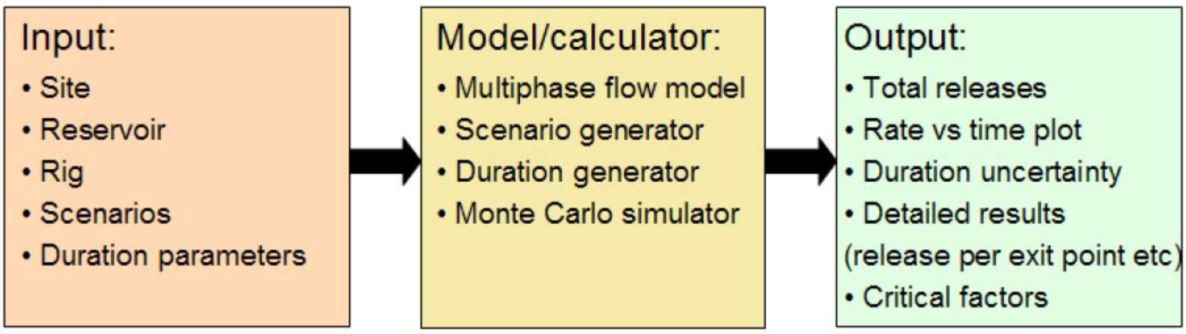

Figure 11: BlowFlow work process (Arild et al., 2008).

The first phase of the work process is finding and determining accurate input parameters, which is the most time-consuming part of the analysis. Here, parameters such as well geometry, reservoir parameters, killing mechanisms and probabilities of different blowout scenarios must be assessed. Table 2 gives an overview of the different input parameter categories. These data must be carefully considered to achieve as accurate results as possible. Blowout killing mechanisms can be a result of natural processes or human intervention. Pre-defined mechanisms covered by the model are capping, coning, bridging and relief well drilling.

Table 2: Input parameter categories (Arild et al., 2008).

Category	Sub-category	Input parameters related to
Reservoir input	Fluid	Type of fluid Impurities Temperature GOR Gravity
	Influx data	Permeability Skin Well location
Well design	Platform	Depth references Wellhead
	Architecture	Riser BOP Casings Open hole section
	Drill string	Drill string run Drill string description Drill string element description
	Survey	Trajectory
Duration	Active measures	Capping
	Relief well	Relief well
	Bridging	Bridging
	Natural cessation	Coning
Scenario	Release point	Topside probabilities Subsea probabilities
	Scenario	Flow path Penetration depth BOP opening

Each input category will not be discussed in further detail here, due to the large amounts of input. Parameters with high uncertainty can be presented by means of probability distributions. The different distributions available in the model are depicted in section 3.2.1, and further described in appendix B. PVT models and multiphase flow correlations are models within BlowFlow used to calculate PVT data and predict multiphase flow in wells. They are discussed further in section 3.2.2 and 3.2.3, respectively.

After entering all input, it is simply a matter of clicking "run". A pre-defined number of blowout scenarios are simulated, and what happens in each scenario is recorded. The number of simulations can be chosen depending on the required accuracy. 10 000 simulations is considered to be sufficient in most cases. Such a large number of simulated scenarios are often referred to as a Monte Carlo simulation. The Monte Carlo simulation combined with a fast steady-state solver for the calculations, is the underlying engine for propagating uncertainty in input parameters to the end results in BlowFlow. Flow rates are determined by pre-generating IPR and VLP curves, and interpolating between these curves. Interpolation gives more accurate results, but can only be used for single reservoir zone cases. IPR and VLP curves are explained further in section 3.2.4.

3.2.1 Probability distributions

Parameters with high uncertainty, such as reservoir pressure, should be presented by means of probability distribution. Uncertainty can then be expressed on a relatively detailed level, thereby easing the probability assessment process. These uncertainties will propagate and be reflected in the final results of BlowFlow. There are a number of different distributions available in the model for uncertain input values. These distributions are depicted in Fig. 12. Each distribution described in further detail in appendix B.

Figure 12: Sketches of single value, uniform, triangular, piecewise linear, discrete, generic, Gaussian, exponential, Weibull, trapezium and tailed triangular distributions, respectively, from BlowFlow.

3.2.2 PVT models

Reservoir fluids expand as they leave the reservoir, and approach the surface. Both pressure and temperature will typically decrease, while the volume increases. Parameters related to pressure, volume and temperature (PVT) must be determined, to be able to predict flow rate. Ideally, PVT properties are measured experimentally in the laboratory. When such direct measurements are not possible, these physical properties can be estimated from a PVT correlation from literature. There are a number of available PVT correlations (Zahaby et al., 2012). In BlowFlow, such PVT correlations are used to predict several different properties of the well fluid. These properties are bubble point pressure (P_b), solution gas-oil ratio (R_s), oil formation volume factor (B_o), oil viscosity (μ_o) and gas viscosity (μ_g). Six correlations are included in BlowFlow, and these will be further described in appendix C, along with definitions of relevant PVT properties.

The accuracy of the results will depend on using each correlation within the specified range of applicability. Thus, which model should be used will depend on reservoir and fluid properties such as temperature, gravity and pressure. The gathering of data used to develop the PVT models should be performed in an area similar to the area in question.

3.2.3 Multiphase flow

It presents a challenge to accurately determine pressure drops and flow patterns of multiphase flow in wells. The well stream from an oil well typically contains oil, gas and water. There are a number of models or correlations available to predict multiphase flow and pressure profiles in the wellbore. 4 such models are included in the BlowFlow. The applicability of these models depend on several factors such as tubing diameter, inclination, oil gravity, gas-liquid ratio and water content (Pucknell et al., 1993). The 4 available models are discussed briefly in appendix D.

3.2.4 Reservoir productivity

Productivity index (PI) is a mathematical means of expressing the ability of a reservoir to produce fluids to the wellbore. It is given in m^3/bar·d, which means volumetric flow (q_o) per drawdown pressure. The drawdown pressure is the difference between the reservoir pressure (P_r) and the flowing bottomhole pressure (P_{wf}). This relation is expressed in the formula below. The productivity will depend on reservoir parameters, but also on the degree of formation damage (skin) in vicinity of the wellbore. If the formation has been severely damaged during drilling, this can result in a lower productivity.

$$PI = \frac{q_o}{(P_r - P_{wf})}$$

The BlowFlow tool has 4 different models available for the determination of the productivity index:

- Oil – Basic
- Oil – Fractured well
- Gas – Deliverability
- Explicit

The different methods are applicable for different types of fluids and reservoir characteristics. The explicit method involves entering the reservoir productivity directly, without calculation. The other methods use different reservoir parameters to calculate the productivity. The calculations will not be explained in further detail.

The **inflow performance relationship** (IPR) expresses the flow rate into the well as a function of flowing bottomhole pressure. It is a function of the mean values for productivity index, pressure, thickness (net pay) and bubble point pressure. IPR curves are necessary to predict the flow rate of a potential blowout, and are therefore a crucial part of BlowFlow. Based on input data, the tool constructs IPR curves for three different reservoir penetration depths; 5 m, 50 % and 100 %. As the penetration depth increases more of the reservoir is exposed, which leads to an increased flow rate to the wellbore. Since the IPR curve is a function of the bottomhole pressure, it is independent on flow path or release point (Liao and Stein, 2002).

The **vertical lift performance** (VLP) is the ability of a well to produce fluids at a given bottom hole pressure. A VLP curve is often constructed to predict the pressure drop of the well. The pressure drop is caused by several different factors, such as hydrostatic and frictional pressure loss as the fluid flow up the well bore. The VLP curve will vary with different release points and flow paths. This is because it depends on friction and vertical distance. It also depends on the gas-liquid ratio (GLR), as high amounts of gas tend to change the flow regime and generally increase flow.

The IPR and VLP curves are constructed to determine the flow rate of a well. One can say that the IPR curve represents well inflow (from reservoir to the bottom of the well), while the VLP curve represent well outflow (from the bottom of the well to the release point). The intersection point between the IPR and VLP curve represents an equilibrium condition, which determines the actual flow rate (Liao and Stein, 2002). This relation can be seen in section 6.4.1.

3.3 OPERAto

OPERAto (Operational Environmental Risk Analysis tool) is a computer based tool developed by DNV to assess the blowout risk related to a specific activity. It is an excel worksheet that presents environmental risk based on input from the customer. Fig. 13 presents the chain of events embedded in OPERAto. For simplicity, the uncertainty is presented as normal distributions. The environmental risk is determined by assessing the consequences of a blowout to valued ecosystem components (VECs). The risk is compared to acceptance criteria for several different severity levels. Each severity has a given restitution time. OPERAto can be used for a range of activities such as drilling, completion, workover, wireline, production and water injection.

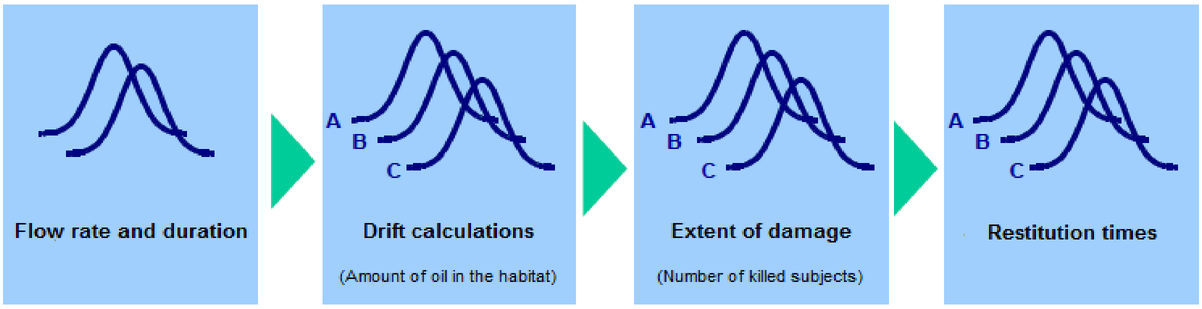

Figure 13: Propagation of uncertainty in the chain of events of an ERA (Nilsen et al., 2004).

The tool is also able to quantify effects of risk reducing measures. This can be done by varying input such as blowout probability, flow rate or duration, and observing the effect this has on the overall environmental risk. It can also include consequence mitigating measures, such as oil spill preparedness (Brandt et al., 2010). Oil spill preparedness will not be considered here as probability, flow rate and duration is in focus.

The worksheet used in this thesis based on Statoil's field, Norne. Since input data are specific for the Norne field, the resulting risk level will not reflect the correct environmental risk for the former disputed area. The objective is to investigate the compatibility between different computer models, and investigate the environmental risk on a relative level. OPERAto's ability to reflect uncertainty is the main focus.

3.3.1 Flow rate and duration

A number of flow rates and duration are determined as a result of calculations performed by Statoil, for the Norne field. The 7 different rates and 6 different durations used in the simulations are presented in Table 3. The flow rate and duration can be distributed between these values for each considered activity (drilling, production, etc.).

Table 3: Flow rates and duration used in the OPERAto simulations.

Flow rates (m^3/d)	Durations (days)
200	0.5
600	2.0
1 200	5.0
2 300	14.0
5 000	28.0
8 000	84.0
12 000	

3.3.2 Oil drift simulation

OPERAto includes data from oil drift simulations. It is assumed that the gas evaporates, and does not contribute to any particular damage to seabirds. When constructing the specific worksheet for the Norne field, OS3D was employed to calculate the oil drift simulations. The influence area is a function of several factors:

- Flow rate
- Duration
- Oil type
- Wind and current systems
- Release point
- The season in which the activity is carried out

The released volume is a function of the flow rate and duration. The oil gravity and composition will determine how the oil spill dissipates. These factors, as well as wind and currents systems will be of great importance to oil drift. Wind and current patterns will vary throughout the year, depending on the season. Whether the oil is released at the sea surface or seabed will also be of relevance. Based on this, OS3D determines the area of influence. The open sea influence area is presented as a probability function. It is given by the total number of grid cells (10 x 10 km) with ≥ 5 % probability of being hit by ≥ 1 ton of oil. The area is divided into several probability ranges. For beach exposure, it presents the time of beaching and amount of stranded oil, both as probability functions.

3.3.3 Environmental risk

The extent of damage is determined as a function the environmental resources present in the area of influence. Environmental data from the Norne field is collected and entered into OPERAto. For this field, seabirds are considered the most valued ecosystem components (VECs). Based on the environmental data, a given number of seabirds are assumed to be present in the influence area. The number of seabirds present will vary with different seasons. The oil type, amount of oil, and number of individuals present in the habitat determines how many seabirds that will be harmed or die from the exposure. The extent of damage is determined for 3 different habitats: open sea, coastal and beach.

The restitution time of a seabird population will depend on the number of harmed/killed individuals, as well as the population dynamic. The severity of an incident is characterized according to installation specific acceptance criteria, based on the restitution time. As can be seen from Table 1, an incident with a restitution time of less than a year is characterized as minor. A restitution time of 1 – 3 years is characterized as moderate, 3 – 10 years as considerable and more than 10 years as severe. The environmental risk is presented as a percentage of the acceptance criteria, for each of these severity levels.

The risk is also presented as an environmental risk index. This index is a function of the percentages in each severity level. It is calculated as follows:

$$Environmental\ risk\ index = \frac{(P_{minor} + P_{moderate} \times 4 + P_{considerable} \times 10 + P_{severe} \times 40)}{55} \times 100$$

The more severe categories are weighted more as they have greater environmental consequences. Since it gives on absolute number, rather than 4 percentages, it can be a good means of comparison. This index is often used to compare the risk from case to case or field to field.

3.3.4 Variable input of OPERAto

The OPERAto worksheet is constructed based on the simulation results from the Norne field. Results from the oil drift simulations and collection of data on environmental resources are included in the model as basis for the calculations. These parameters therefore cannot be altered in the OPERAto worksheet. However, probabilistic data and activity level can still be defined by the user.

The blowout probability must be established for each type activity. The release point distribution must also be specified, with given probabilities for both subsea and topside blowouts. The activity level is set by means of number of operations or wells per season. The activity can also last through several seasons. An activity can be excluded if it is not relevant for the assessment.

Flow rate and duration is presented as probability distributions, where each flow rate and duration have a given probability. Since oil drift simulations have been performed based on given rates and durations, these cannot be altered. However, the probability distribution between these given values can be changed. The distributions for flow rate and duration can be different for a subsea scenario than for a topside scenario. However, OPERAto does not distinguish between different flow paths.

4. Case study

This thesis will determine the blowout risk related to exploration drilling in the former disputed area in the southeastern part of the Norwegian Barents Sea. This is done in a probabilistic and well specific manner, where uncertainty is emphasized. Ideally the probabilistic elements should be reflected in each step of an ERA, following the calculations of flow rate and duration, as illustrated in Fig. 1. A high level of detail is important to provide a good basis for making sound risk management decisions. This thesis will investigate the ability of available computer modeling tools to allow the uncertainty to propagate through an ERA. Their ability to manage risk and work as a decision support tools will be investigated.

There is an increasing number of computer models available for determining the risk related to a blowout. As a means of assessing the risk related to a blowout, a variety of computer models have been employed. These all have different purposes, and will here be used together to yield the final results. All these models are developed by different suppliers, and therefore might have limited compatibility. Results from one model might be used as input in another. This might present a problem if the results from one model are presented as a probability distribution, while another model needs a deterministic value as input. In such cases the level of detail might have to be comprised. This study will investigate the ability of these models to allow the uncertainty to propagated through the chain of events/models.

Some of these models have the possibility to assess which parameters contribute most to the risk. By altering input parameters, the effects on the end results can be observed. Thus, these models might serve as a tool to determine risk reducing measures. Some of the models present the results as deterministic values, while others present probability distributions. The compatibility of the results will be investigated, and the effect of using deterministic values instead of probabilistic is observed. The main objective of this thesis is to examine how the uncertainty propagates through the chain in the different approaches taken.

There are several different types of wells, which might pose a risk of a blowout. These wells can be drilled for developmental or exploration purposes. Developmental drilling is performed to produce recoverable hydrocarbons through a production well. Exploration wells are drilled for exploratory purposes, to collect information in a new area. There are several different types of exploration wells. A wildcat well is drilled to find out whether a prospect, where seismic surveys have indicated a presence of recoverable hydrocarbon resources, contains oil or gas. It is drilled outside of, and not in the vicinity of any known fields. An appraisal well on the other hand, is drilled to determine the extent and size of a petroleum deposit that has already been discovered by a wildcat well. This is the NPD's definition and may not apply everywhere (The Norwegian Petreoleum Directorate, 2012). When determining blowout frequencies, wildcat and appraisal wells will for simplicity not be distinguished between. They will simply be referred to as exploration wells.

According to historical data, exploration wells involve a greater blowout risk than production wells (Haugsvold, 2011, Holand, 2010). This is mainly due to the fact that there is more uncertainty with respect to pressure profiles and possible hydrocarbon traps for an exploration well. When a developmental well is drilled, both a wildcat and an appraisal well have usually been drilled beforehand to collect information. The blowout risk for an exploration well will be assessed in this study. Since the former disputed area have not yet been opened for petroleum activity, and no wells have been drilled to date, an exploration well will be the first type of well to be drilled.

The exploration well of the case study will be drilled from a semisubmersible drilling rig. Thus, the well will be a subsea well. There are several winterized rigs available for such activity. Transocean Arctic is an example of a semi-submersible drilling rig capable of drilling in harsh environments, and water depths up to 500 meters. This rig was used for drilling the first exploration well at the Goliat field. It can withstand the wave heights up to 32 m (pers. comm. Holen). Because a blowout from deep drilling (after setting of the BOP) is the most environmentally harmful (see section 2.1), this is chosen as the study objective. Both shallow gas and well release will be disregarded as they have limited environmental consequences for a single incident compared to a blowout from deep drilling.

It has been questioned whether the former disputed area is merely a gas province, or if it also contains recoverable oil reserves. The NPD has recently collected large amounts of seismic data within this area. The seismic acquisitions will supposedly be continued in the summer of 2012. These data have yet to be processed, thus there is still insufficient information available to be able to predict possible hydrocarbon traps. However, preliminary data have indicated that there might be several fields containing oil, though gas discoveries are most likely. Possible oil and gas reservoirs are shown in Fig. 8. This risk assessment is based on a blowout release point located, according to this map, at coordinates 73.4 °N 34.1 °E. From Fig. 8 this point can be seen as the largest green dot, representing an oil field. It located is approximately 300 km from shore.

There is little knowledge available about the geology and reservoir conditions in the area. Thus, data have to some degree been based on assumptions. However, these assumptions have been discussed with several experts to be able to predict conditions as accurately as possible. According to senior geologist Tore Høy at the Norwegian Petroleum Directorate, a possible oil reservoir in this region is believed to be relatively shallow with poor reservoir conditions. The Barents Sea is generally recognized by its low pressures. This low pressure and the poor reservoir quality will result in a less productive reservoir, accompanied by a lower risk (pers. comm. Høy).

5. Blowout probability

There are number of approaches commonly used for determining the blowout probability related to drilling. Many are based on historical data from the SINTEF database and Scandpower report. Blowout probabilities from this historical data may be applied directly in a quantitative analysis, without further adjustments. But this approach presents and average blowout probability and does not consider recent technological and operational improvements. The most commonly used method in the industry today is a statistical approach that evaluates recent improvements to assess whether the basic blowout probability can be reduced. This can include evaluating recent kick statistics, BOP reliability or other technological or operational improvements. A typical blowout probability assessment process is shown in Fig. 14.

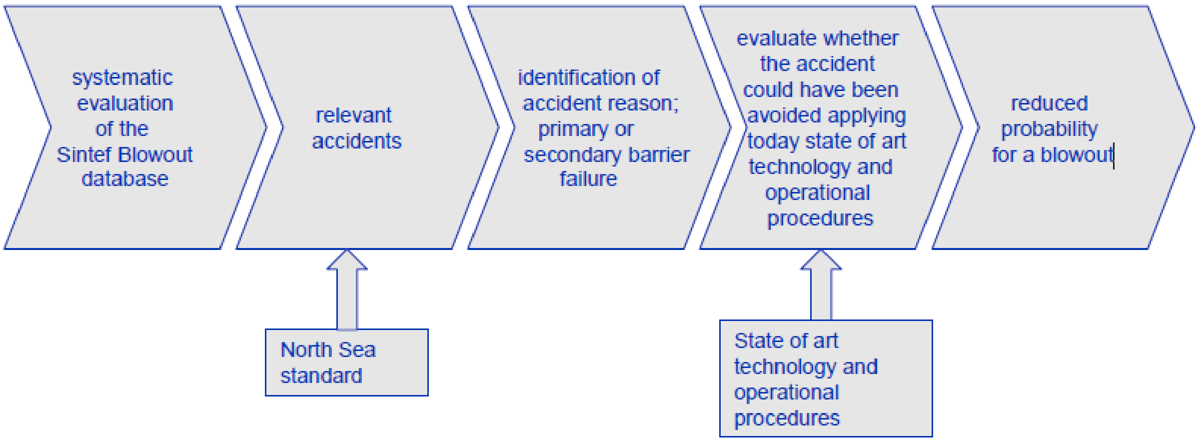

Figure 14: Schematic overview of the evaluation of risk reduction (Brandt et al., 2010).

A statistical approach is applied in this thesis that attempts to adjust the basic blowout probability to reflect recent improvements. Due to time restrictions and limited availability of reliable information, technological or operational advances have not been given any credit here. However, this method will incorporate an evaluation of recent trends in kick statistics. Since a kick is often the initiating event of a blowout, a reduced kick frequency is considered to reduce the blowout probability.

BlowFAM is a blowout frequency assessment model developed by Scandpower in close cooperation with drilling and well engineers from several oil companies. This is also based on statistics, but takes well specific conditions into consideration. This includes equipment, well configuration, operating procedures, planning/organization and formation properties. However, this model requires an understanding of risk elements, as well as competence in drilling and completion, to obtain detailed input data and accurate results (Dervo and Blom-Jensen, 2004). This tool can also aid the risk management process by identifying possible risk reducing measures. These are preventive measures that can reduce the probability of a blowout occurring.

The blowout probability can be distributed for different blowout scenarios. Both subsea and topside releases are possible for a subsea well. In addition these release points can be further divided into different flow paths.

The ability of both these approaches to reflect conditions of the specific well in question will be assessed. Limitations and advantages of each will also be discussed, along with their (in)ability to reflect uncertainty.

5.1 Statistical approach

This statistical approach is based on historical data from the SINTEF database and Scandpower report. Technological and operational improvements will not be quantified in this approach, due to both time restrictions and the limited availability of reliable data. However, recent trends in kick statistics will be taken into consideration, to assess whether this can yield a reduced blowout probability. The kick frequency is directly related to the ability to control the primary barrier. Thus, improved mud control will manifest itself in the kick frequency.

5.1.1 SINTEF Offshore Blowout Database

The SINTEF database publishes historical data on blowout and well release frequencies annually. Per December 2010 the SINTEF database includes information on 584 offshore blowouts and well releases that have occurred world-wide since 1955. It contains 51 different fields describing each blowout and well release. The fields are categorized in six different groups (Holand, 2010):

- Category and location
- Well description
- Present operation
- Blowout causes
- Blowout characteristics
- Other

The database also includes drilling and production *exposure data* from various areas, as shown in Table 4.

Table 4: Overview of exposure data included in the SINTEF database (Holand, 2010).

Country	Drilling exposure data	Production exposure data
Norway	Yes	Yes
United Kingdom	Yes	Yes
US GoM OCS	Yes	Yes
The Netherlands	Yes	No
Canada East Coast	Yes	No
Australia	Yes	No
US Pacific	Yes	Yes
Denmark	Yes	No

With the SINTEF database as a basis, relevant and irrelevant accidents are evaluated. For risk analysis on the NCS, only incidents from the deep-water areas in the US Gulf of Mexico Outer Continental Shelf (US GoM OCS), the Netherlands, the NCS and British Continental Shelf (UKCS) are considered. This is because in these areas, North Sea standards are required, which means that two well barriers must be present during all drilling operations. Thus, only incidents reported in these areas are considered. The SINTEF database is searchable with respect to different fields and criteria. Based on an evaluation of relevant incidents, the blowout probability can be found.

5.1.2 Scandpower report

Scandpower annually releases a report presenting blowout and well release probabilities based on the records in the SINTEF database. The latest report presents frequencies based on data from the areas of US GoM OCS, Canada East Continental Shelf (CECS) and the North Sea (British, Dutch and

Norwegian sector) in the period of 01.01.89 – 31.12.08. All these areas fulfill the North Sea standard requirements. Thus, Scandpower report is widely used by the industry when performing risk assessment on the NCS. An overview of blowout probabilities for exploration drilling collected from the Scandpower report is shown in Table 5. It represent average probabilities from 1989 to 2009, which can be used as basis values for risk assessments of well operations of North Sea standards.

Table 5: Summary of blowout and well release probabilities (Haugsvold, 2011).

Operation	Probability, average well	Probability, gas well	Probability, oil well	Unit
Exploration drilling, deep (normal wells)	1.12×10^{-4}	1.02×10^{-4}	1.23×10^{-4}	Per well
Exploration drilling, deep (HPHT)	6.92×10^{-4}	6.32×10^{-4}	7.65×10^{-4}	Per well

These numbers will be used as basis when determining blowout probability of the well in question. As can be seen from Table 5, the risk related to HPHT wells is significantly higher than for a normal well. The geology in the Barents Sea indicates reservoirs with pressure and temperature well within the limits of a normal reservoir. This has been supported by more than 80 drilled wells so far (Brandt et al., 2010). It is therefore unlikely to find HPHT reservoirs in this area. Based on the table, the basic probability for an oil blowout from an exploration well with normal reservoir pressure and temperature is $1.23 \cdot 10^{-4}$ per well drilled (Haugsvold, 2011). That is equal to one blowout per 8 130 drilled wells.

Both well characteristics and technical solutions will affect the blowout probability related to drilling of an exploration well. The type and reliability of the applied technology is detrimental, as well as the number of safety barriers. One of the most important improvements over the last decade is the increased ability to control the primary barrier. The BOP reliability has also been significantly improved in recent years. Most of these improvements are difficult to quantify for a hypothetical situation. It is obvious that better contingency planning, more knowledge and awareness, higher BOP reliability, etc. has had a significant impact on blowout probability. Such recent improvements are not reflected in historical data. There is little reliable information about what kind of effects these improvements have had on the blowout probability. A thorough evaluation of these factors would also be time-consuming, and due to the limitations of this thesis these factors will not be given any attention in this approach.

5.1.3 Kick statistics

In this example the only improvement that will be quantified in the blowout probability assessment is the kick frequency. There is a clear correlation between the kick frequency and the probability of a blowout. A kick will usually be the initial trigger that potentially can result in a blowout. Several of the previously mentioned technological advances has directly manifested itself in the kick frequency. Some examples are better control of the primary barrier and more up-front information about e.g. pore pressure. The reduced kick frequency can here be justified based on available data. Despite more difficult drilling operations, such as deepwater drilling and HPHT wells, the kick frequency has been significantly reduced in the last decade (Brandt et al., 2010).

According to SINTEF's report "Deepwater kicks and BOP performance", the average kick frequency of an exploration well in the North Sea was approximately 25 kicks per 100 in the period 1984 - 1996

(Holand and Skalle, 2001, p. 22). This frequency includes both normal and HPHT wells. As discussed earlier, the kick frequency is significantly lower for a normal well than a HPHT well. This is evident in the historical data on kick frequencies (Holand and Skalle, 2001). HPHT wells typically have a much smaller drilling window than normal wells (see section 2.1.1). If the drilling window is less than 0.12 SG, which is the case for HPHT wells, there is a high risk of both well influx and reservoir fracture. The well in question is within the normal range.

There is a considerable amount of data on kick frequencies collected each year. As mentioned, recent kick statistics show a much reduced kick frequency. The Petroleum Safety Authority's (PSA) annual report on "Risk level in the petroleum activity" present the number of well control incidents (kicks) per year. It analyzes incidents that possibly could have lead to a blowout if the secondary barrier were to fail. The latest report include frequencies from 1996 – 2010 for both exploration and production wells (Årstad et al., 2011, p. 60). The kick frequency from 1996 - 2010 for *exploration* drilling is presented as a bar chart in Fig. 15. The average value for 1984 - 1996 is also included (Holand and Skalle, 2001). Despite more complex drilling operations in later years, the trend of the diagram indicates a reduced kick frequency. However, the kick frequency increased in 2010 compared to previous years. As for the SINTEF report, these recent kick frequencies comprise both HPHT and normal wells. As both reports are based on same type of wells, the frequencies are assumed to be comparable.

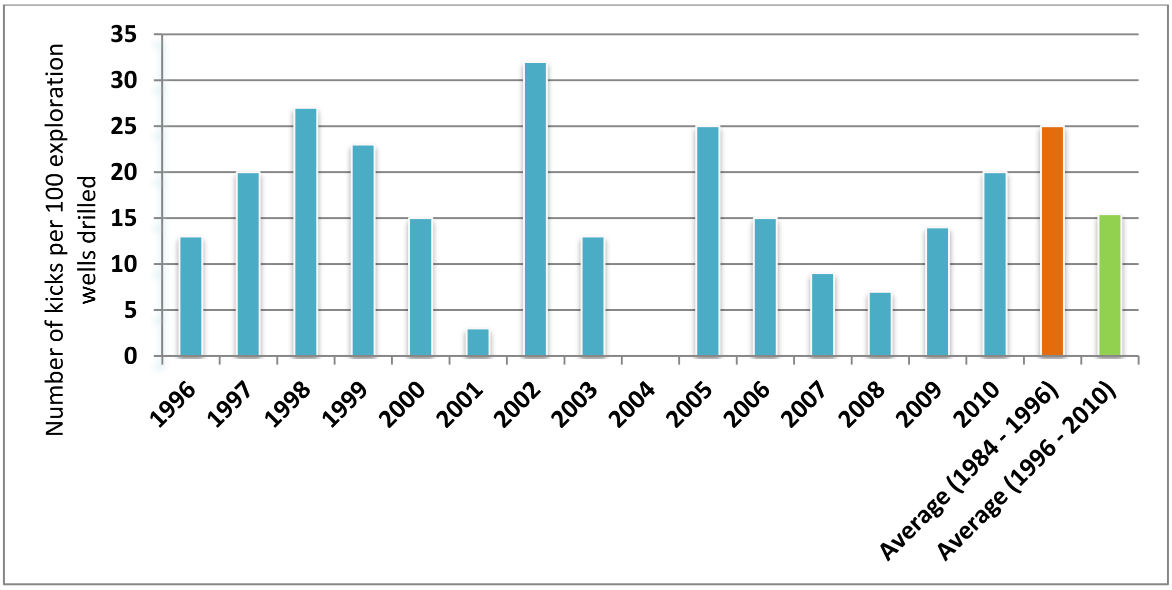

Figure 15: Well incidents for exploration drilling 1996 – 2010 (Årstad et al., 2011, Holand and Skalle, 2001).

5.1.4 Results

The average kick frequency over the past 15 years is approximately 15.3 per 100 drilled wells. This can be seen from the diagram shown above. In this assessment, a frequency of 20 kicks per 100 exploration wells drilled will be used as a slightly conservative approximation. It is also taken into consideration that the kick frequency in 2010 was 20 kicks per 100 exploration wells drilled (see above). 15 is only a mean value, and using this could yield and underestimated risk. Still, the kick frequency has been reduced from 25 to 20 kicks per 100 exploration wells drilled, which is a 20 % reduction. It is assumed that the kick frequency will be directly correlated to the blowout probability. Thus, the 20 % reduction in kick frequency can be directly applied to the generic blowout probability found from the Scandpower report. Since kick frequency is the only factor quantified in this study, this yields a 20 % reduction in blowout probability. The modified blowout probability becomes 9.84 × 10^{-5}. The basic and modified probabilities are summarized in Table 6.

Table 6: Summary of resulting blowout probabilities.

Basis	Blowout probability
Scandpower data	1.23×10^{-4}
Modified kick statistics	9.84×10^{-5}

The modified blowout probability does not involve a considerable risk reduction. If an evaluation of BOP reliability, technology, human and organizational factors were conducted, the risk could potentially have been reduced even further.

5.1.5 Scenarios

Historical data can also be used to find release point and flow path distributions. Table 7 presents historical data on release points and flow paths for deep exploration drilling, collected from the SINTEF database. These data are based on blowout data from US GoM OCS, UKCS and NCS in the period 1980-2008. The SINTEF data does not include open hole as a possible flow path (Holand, 2010, p. 27). As the study objective is a subsea well, releases from the wellhead or BOP have in Table 7 been categorized as subsea incidents. The data have been converted to express probability distributions rather than number of incidents. The BlowFlow tool used to calculate flow rate and duration does not include all the flow paths from the historical data. Therefore, the flow paths inside drill string and inside test tubing are merged into one category in the below table. This is also done for the flow paths annulus and outer annulus. This is seen as reasonable, since these flow paths are closely related.

Table 7: Flow path and release point distribution for exploration drilling (Holand, 2010, p. 27).

Flow path	Release point	
	Subsea	Topside
Outside casing	26.1 %	4.3 %
Annulus	52.2 %	8.7 %
Inside drill string	0.0 %	8.7 %
Total	78.3 %	21.7 %

Table 8 presents historical data on release points, flow paths and flow restrictions for subsea wells, collected from the Scandpower report. It is based on blowout data from the US GoM OCS and NCS in the period 1980 - 2008. Because this database is collected from a slightly different area, it might contain fewer blowout incidents. The Scandpower data does not differentiate between exploration and developmental drilling (Haugsvold, 2011, p. 44-45). The data in Table 8 are converted to express a probability distribution rather than frequencies.

Table 8: Flow path and release point distribution for drilling activity for floaters (Haugsvold, 2011, p. 44-45).

Flow path	**Subsea**		**Topside**	
	Fully open BOP	**Partially closed BOP**	**Fully open BOP**	**Partially closed BOP**
Outside casing	22.3 %	4.9 %	0.0 %	0.0 %
Annulus	17.4 %	35.8 %	4.9 %	4.9 %
Open hole	0.0 %	0.0 %	0.0 %	4.9 %
Inside drill string	0.0 %	0.0 %	0.0 %	4.9 %
Total	39.7 %	40.7 %	4.9 %	14.7 %
		80.4 %		19.6 %

Based on these historical data, it is concluded to use a release point distribution with a 80 % chance of a subsea blowout, and 20 % chance of a topside blowout. This distribution corresponds well to both tables, and is listed in Table 9 below.

As can be seen from Table 7 and 8, there is a considerable difference in the flow path distribution depending on whether the release point is subsea or topside. For subsea blowouts, a considerable amount of blowout data is related to flow at the outside of the casing. However, this flow path is not included in BlowFlow, and will therefore be excluded from the flow path distribution. Thus, incidents related to flow outside the casing are instead considered to flow through annulus. There is no subsea blowout data related to flow through the drill string or open hole. This leaves annulus flow as the only possible flow path. Consequently, subsea blowout will have a 100 % chance of flow through annulus. This yields an overall probability of 80 % of a subsea annulus blowout, as shown in Table 9.

Table 7 and 8 indicate that all the different flow paths are possible for a topside blowout. Here, there are some deviations between the SINTEF and Scandpower data. The flow paths included will be the ones included in BlowFlow. These are drill string, annulus and open hole. Since the SINTEF data does not include flow through open hole, the Scandpower data have received most focus. An evaluation of the historical data has resulted in a flow path distribution as shown in Table 9. The scenario distributions found here will be used as input in BlowFlow. Table 8 also includes data on BOP opening distribution, which will be further discussed in section 6.2.4.

Table 9: Flow path and release point distribution as input to BlowFlow.

Release point	**Distribution**	**Flow Path**	**Distribution**
Topside	20 %	Drill string blowout	5 %
		Annulus blowout	10 %
		Open hole blowout	5 %
Subsea	80 %	Drill string blowout	0 %
		Annulus blowout	80 %
		Open hole blowout	0 %

5.2 BlowFAM

BlowFAM is used to determine the blowout probability related to a specific activity. This can be done for several different operations such as drilling, completion, production, workover or wireline. BlowFAM differs from the more traditional statistic approach in several ways. The basic frequency can here be modified by defining well configuration and reservoir parameters, and evaluating a wide range of risk elements. This tool can also easily be used as a risk reduction tool, by identifying risk reducing measures from the list of risk elements. Consequently it can be used as decision support in risk management.

5.2.1 General information

The study objective is, as described in chapter 4, a single exploration well drilled from a semisubmersible rig. It can therefore be characterized as a floating platform. When drilling before setting of the BOP, there is a chance that shallow gas can be encountered. However, shallow gas will be disregarded in this assessment (see section 2.1). The objective is to determine the blowout probability related to deep exploration drilling. Thus, activities such as completion, production, workover and wireline operations will also be disregarded.

The reservoir of this case study is assumed to contain oil, with an adjacent gas cap. As mentioned, it might look like this area is mainly a gas province. But there is also a chance that oil reservoirs can be found. Since an oil blowout is most detrimental to the environment, and thus of most concern, it is chosen as the study objective. Oilfields with adjacent gas caps are common in the western parts of the Barents Sea, and are assumed possible also in the east. These decisions are based on recommendations from Tore Høy (pers. comm. Høy). The reservoir is assumed to have pressures and temperatures well within the normal range. Thus, the well is not HPHT. The well classifications can be summarized as follows:

- Exploration well
- Oil well
- Floating platform
- Not HPHT well

This information has resulted in a basic blowout frequency of 2.1×10^{-4}. The Scandpower report yields a basic blowout frequency of 1.23×10^{-4} for an exploratory oil well. This deviation is caused lack of updated statistics in BlowFAM. This inconsistency will be further discussed in section 5.2.4.

5.2.2 Reservoir and well design

In this section, well design and reservoir characteristics are used as a basis to determine whether the blowout risk is higher or lower than for an average well. This results in a blowout frequency adjustment factor, which is referred to as adjustment factor 1. Reservoir parameters have been determined based on discussion with Tore Høy, and through comparison with other fields. Goliat will be the first oil producing field in the Barents Sea, and is therefore considered to be the most appropriate field for comparison (pers. comm. Høy). Data from this field have been obtained from published reports, and through communication with Lasse Holen, working for Eni Norge with Goliat subsurface. Well design and diameters of drill pipes and casings have been determined through discussion with drilling professor at the University of Stavanger, Kjell Kåre Fjelde.

The water depth in the area of our case study has been determined through a consideration of seismic data. Travel time of seismic waves have indicated a water depth of approximately 330 m (pers. comm. Høy). However, the seismic data have not yet been interpreted to give detailed information on possible reservoir depths. By a consideration of the geology in the area, it is concluded that a possible oil reservoir is most likely to be found in Triassic layers, at a well depth of approximately 2000 m. Such a reservoir could be hidden beneath a salt structure (pers. comm. Høy). The Kobbe reservoir of the Goliat field is also found in Triassic layers, and is located at a depth of 1 800 m (pers. comm. Holen).

Common temperatures at the seabed in the southeastern Barents Sea is approximately 2.0 - 3.0 °C (pers. comm. Høy). The temperature for this specific area has been set to 2.5 °C. The reservoir temperature can be calculated based on the geothermal gradient. For the Barents Sea, this is typically in the range of 25.0 - 30.0 °C/km. For the well in question a gradient of 30.0 °C/km is assumed (pers. comm. Høy). The reservoir temperature is calculated from the following formula:

$$T = T_{seabed} + \frac{\partial T}{\partial h} \times \partial h = 2.5^oC + \frac{0.030^oC}{m} \times (2000 - 330)m = 52.5^oC$$

Where:
T = Temperature, °C
$\frac{\partial T}{\partial h}$ = Temperature gradient, 0.030 °C/m
∂h = Vertical distance from the seabed to the reservoir, m

This results in a reservoir temperature of 52.5 °C. This is quite close to the temperature of the Kobbe reservoir at the Goliat field, which is 48.0 °C (pers. comm. Holen).

The formation pressure tends to increase with depth according to the hydrostatic pressure gradient. However, hydrocarbon traps usually have an elevated pore pressure compared to the hydrostatic gradient. The Kobbe reservoir at the Goliat field has a pore pressure gradient of 1.1 SG (pers. comm. Holen). The pressure gradient varies from reservoir to reservoir, and the pore pressure is therefore associated with some uncertainty. Since BlowFAM input must be given as single values, it does not reflect the uncertainty of input parameters. Thus, a pressure gradient of 1.2 is seen as reasonable to avoid underestimating the risk involved. This is slightly conservative, compared to the Kobbe reservoir. The pore pressure in BlowFAM is given by specific gravity (relative to water density), rather than bar (see Fig. 3). This corresponds to the equivalent mud weight (EMW).

As explained in section 2.1.1, the drilling window is the difference between the pore pressure and fracture pressure gradient. The Kobbe reservoir at the Goilat field has a fracture pressure gradient of 2.0 SG, and consequently a drilling window of 0.9 (pers. comm. Holen). As there is little knowledge available on pressure profiles in this former disputed area, the drilling window is difficult to predict. The drilling window is set to 0.8 SG, which corresponds to a fracture pressure gradient equal to that of Kobbe (pers. comm. Fjelde). This is considered to be sufficiently conservative to cover the uncertainty related to this parameter. The mud density must always be within the drilling window (between the pore pressure and fracture pressure gradient). For a narrow drilling window, it can be difficult to obtain the right mud weight throughout the drilling process. The drilling window is therefore a crucial parameter with respect to blowout risk. A mud weight of 1.55 SG is here considered appropriate, seeing that it is in the middle of the range.

On an exploration well, the inclination is usually small or negligible (pers. comm. Fjelde). The objective is then to explore for any recoverable resources, and not to drain the reservoir. Thus, for simplicity the well trajectory is assumed to be vertical, with a horizontal section of 0 m. Rigs used for arctic drilling typically have a drill floor height of 25 m. Drill pipe diameter, open hole diameter, and casing diameter have been set to 5.0, 8.5 and 9.6 inches, respectively (pers. comm. Fjelde).

The GOR at Kobbe is 215 (Bjørnbom et al., 2008). The GOR of this reservoir is for simplicity set to be 200. This is considered a slightly conservative measure, seeing that an oil spill containing more oil and less gas is much more environmentally hazardous. The mud circulation rate and seawater density are assumed equal to the BlowFAM default values. All these reservoir and well data are summarized in Table 10.

Table 10: Reservoir and well design characteristics for case input to BlowFAM (pers. comm. Høy, pers. comm. Fjelde).

Variable	Value
Water depth	330 m
Well depth to TVD	2000 m
Reservoir temperature	52.5 °C
Pore pressure (EMW)	1.20 SG
Drilling window (EMW)	0.80 SG
Mud weight	1.55 SG
Length of horizontal section	0.00 m
Height of drill floor above sea	25.0 m
Drill pipe diameter	5.00 in
Open hole diameter	8.50
Casing inner diameter	9.62
GOR	200
Mud circulation rate	0.0500 m^3/s
Seawater density	1.03 kg/dm^3

Several other factors related to the reservoir and drilling activity will also affect the risk in BlowFAM. This includes reservoir productivity, segmentation, neighboring wells and presence of gas cap. It will also depend on whether there is a risk of drilling too deep, or whether well testing is to be performed. The well is classified according to the state of the well in Table 11.

Table 11: State of formation/well, as case specifications in BlowFAM

State of well	Classification	Comment
Risk related to drilling too deep	Possible	Little knowledge of reservoir and drilling program
Well testing to be performed	Yes	Well testing is performed to determine characteristics of the reservoir
Risk of drilling into neighboring wells	No	No wells in the area
Gas cap above the oil	Yes	Oil with adjacent gas cap
Reservoir segmentation	Unknown	Little knowledge of reservoir
Reservoir productivity	Low	Poor flow conditions

This data on reservoir and well design will adjust the historical blowout cause distribution collected from the SINTEF database. Some blowout causes might be excluded. Others might be given higher or lower probabilities, while some are left unchanged. This results in a new cause distribution and an adjustment factor, as shown in Table 12.

5.2.3 Risk elements

BlowFAM consist of almost 300 risk elements that is evaluated to enlighten their effect on the risk level. Based in this evaluation, an adjustment factor for the blowout frequency is determined. This is called adjustment factor 2. Only elements related to deep drilling (after setting of the BOP) is included in this evaluation, since a blowout from deep exploration drilling is the study objective. The risk elements considered applicable are listed in appendix E, under risk elements and evaluations. Elements that are considered not applicable for this specific case can be excluded, and are labeled “NA”.

Elements considered to increase the risk level are given a negative implication in appendix E. These are mostly related to challenges of arctic drilling and limited geological information. Risk elements considered to reduce the risk are given a positive implication. These are to a large degree related to recent technological improvements. Elements that are not considered to have any increased or reduced implication to the overall risk are left unchanged. Many of the elements are difficult to assess due to limited available information. Ideally, the BlowFAM analysis should be performed in cooperation with operators and drilling experts. Adjustment factor 2 is calculated in the next section.

5.2.4 Results

Based on the conditions given in section 5.2.2, the blowout cause distribution is adjusted to reflect field characteristics. Both the historical and the adjusted blowout cause distribution is shown in Table 12. The historical cause distribution is collected from the SINTEF database from 2003, and will therefore deviate from the cause distribution given in section 2.1.2. It should be noted that the distributions concern drilling activity only. Cause distributions for production, completion, workover or wireline are not presented, since an exploration well is the study objective.

Table 12: Blowout cause distribution for drilling activity from case analysis in BlowFAM.

Cause	Historical fraction	Factor	Adjusted fraction	New fraction
Annular losses	0.087	0.127	0.011	0.014
Drilling into neighboring well	0.011	0.000	0.000	0.000
Gas cut mud	0.051	0.972	0.050	0.062
Improper fill-up	0.025	1.000	0.025	0.031
Poor cement	0.120	0.984	0.118	0.147
Swabbing	0.076	0.053	0.004	0.005
Too low mud weight	0.214	0.915	0.196	0.244
Trapped gas behind casing	0.025	1.000	0.025	0.031
Tubing plug failure during well test	0.011	0.800	0.009	0.011
Unexpected high well pressure	0.134	0.890	0.119	0.149
Well test string failure	0.047	1.200	0.056	0.070
Unknown	0.199	0.955	0.190	0.237
Total/adjustment factor	1.000		**0.803**	1.000

Each historical fraction is multiplied with the adjusted probabilities in the column "Factor", and the products listed in the column "Adjusted fractions". The sum of all these adjusted fractions yields an adjustment factor of 0.803. This is called adjustment factor 1, and is applied to the basic frequency in Table 13. A new cause distribution is found by dividing each of the adjusted fractions by the adjustment factor. This new distribution is shown in the rightmost column, and has a sum of 1.

An adjustment factor of 0.803 is smaller than 1 and will therefore contribute to a reduced the blowout risk. The blowout probability is reduced by almost 20 %, as a result of the defined reservoir and well conditions. This seems reasonable, as the reservoir is assumed to have a low productivity. If more knowledge was available it might be possible to reduce the risk even further. Input parameters such as pore pressure and drilling window are set slightly conservative, due to lack of knowledge and a high uncertainty. If a risk assessment were performed in cooperation with operators and drilling experts, prior to drilling of the well, more detailed information would assumingly have been available. By gaining more knowledge, the uncertainty can be reduced. This could yield a lower adjustment factor, and consequently a lower blowout probability. As BlowFAM does not reflect uncertainty, the adjustment factor becomes a result of several assumptions. This is further discussed in the section 5.2.8. The effects of varying different parameters are shown in Table 15 in section 5.2.6, through a sensitivity study.

The adjustment factor resulting from Table 12 should be equal to the one supplied by BlowFAM. However, BlowFAM states that adjustment factor 1 is 0.613. This is presumably due to a bug in the calculation. BlowFAM has not included the last blowout cause "unknown" in the calculation. This error will be further discussed in section 5.2.8. The adjustment factor of 0.803 found from the table will be used from now on.

To find adjustment factor 2, the total number of applicable risk elements is counted from the list in appendix E. This yields a total of 163. The total positive score, B (better), is found by adding up all the positive elements. This yields a score of 47. The same is done for the negative score, W (worse). This results in a (absolute) score of 9. Adjustment factor 2 is then found from the following formula:

$$Adjustment\ factor\ 2 = \frac{\sum X + \sum W - \sum B}{\sum X} = \frac{163 + 9 - 47}{163} = 0.767$$

This calculation results in an adjustment factor of 0.767. By applying this to the basic blowout probability, it can be reduced by approximately 23 %. This is a considerable risk reduction. But if more knowledge was available, and relevant experts were included in the evaluation, it might be possible to reduce the risk even further. BlowFAM states that adjustment factor 2 is 0.749, which again does not correspond to the calculated value. This is discussed further in section 5.2.8. The number calculated from the formula will be used from now on, and is applied to the basic frequency in Table 13.

It is also possible to adjust the frequency manually in BlowFAM. This can be desirable if there are known changes in the frequency which are not implemented in the model; i.e. if there are technological improvements that has not been accounted for. In this study the manual adjustment is used to reflect recent changes in blowout statistics, which have not yet been included in the model. Since the BlowFAM worksheet is based on blowout data from 2003, there are considerable changes to the basic frequency. According to Table 5, the basic blowout probability for an exploratory oil well is 1.23×10^{-4}. This is much lower than the basic blowout probability of 2.1×10^{-4}, given by BlowFAM. To account for these recent changes, a manual adjustment factor is implemented.

$$Manual\ adjustment = \frac{Basic\ frequency\ 2010}{Basic\ frequency\ BlowFAM} = \frac{1.23\times10^{-4}}{2.10\times10^{-4}} = 0.586$$

This manual adjustment is applied to the basic blowout frequency in Table 13. The table presents the adjustment factors and blowout frequencies. The basic frequency is the statistic blowout frequency for a well with the given classifications, found in section 5.2.1. The different adjustments are applied to the basic frequency to determine the final blowout frequency. Adjustment factor 1 reflects well design and reservoir characteristics. Adjustment factor 2 reflects the evaluation of risk elements.

Table 13: Blowout frequency per 10 000 drilled wells and adjustments applied.

Category	Result
Basic frequency	2.100
Adjustment factor 1	0.803
Adjustment factor 2	0.767
Manual adjustment	0.586
Frequency	0.758

This yields a final blowout frequency of less than 1 per 10 000 drilled exploration wells, or a probability of 7.58×10^{-5}. This probability is considerably smaller than 9.84×10^{-5}, which resulted from the statistical approach in section 5.1. The overall risk reduction is achieved is considerable. But this is mainly due to lack of reliable information, which tends to result in conservative estimates. For a hypothetical situation in this unexplored area, knowledge is limited. It is difficult to predict reservoir conditions, and improvements related to equipment, procedures, etc. By involving experts in the BlowFAM assessment process, the risk might be reduced to a lower level. The risk can also be reduced by implementing risk reducing measures. BlowFAM allows identifying risk reducing measures through the evaluation of risk elements. This is further discussed in section 5.2.7.

The blowout probability determined through BlowFAM is considered to yield the most well specific result, compared to the statistical approach. This case study attempts to determine the blowout risk in a mechanistic manner, by evaluating specific conditions at the well location. Therefore, the blowout probability resulting from the BlowFAM assessment is considered to be the most appropriate. It is also the most interesting in relation to possible identification of risk reducing measures.

5.2.5 Scenarios

Table 14 presents the flow path, release point and BOP opening distribution for a subsea exploration well. These data are collected from the BlowFAM worksheet. It resembles the Scandpower data in Table 8. But in Table 8 subsea, wellhead and BOP releases have been merged into one (subsea) category. Also, the flow paths tubing and outer annulus have been included in similar categories in Table 8. However, since BlowFAM is based on older statistics, the values will deviate from the more recent Scandpower data. As these distributions are not thoroughly updated, scenario evaluations will be based on section 5.1.5. Flow path and release point distributions are shown graphically in Fig. 16.

Table 14: Flow path and release point distribution for a floating platform, collected from the BlowFAM worksheet.

Flow path	Subsea		Wellhead		BOP/X-mas tree		Drill floor	
	Full	Choked	Full	Choked	Full	Choked	Full	Choked
Outside casing	24 %	5 %	0 %	0 %	0 %	0 %	0 %	0 %
Outer annulus	0 %	0 %	24 %	0 %	0 %	0 %	0 %	0 %
Annulus	0 %	0 %	0 %	18 %	0 %	5 %	0 %	14 %
Open hole	0 %	0 %	0 %	0 %	0 %	0 %	0 %	5 %
Tubing	0 %	0 %	0 %	0 %	0 %	0 %	0 %	5 %

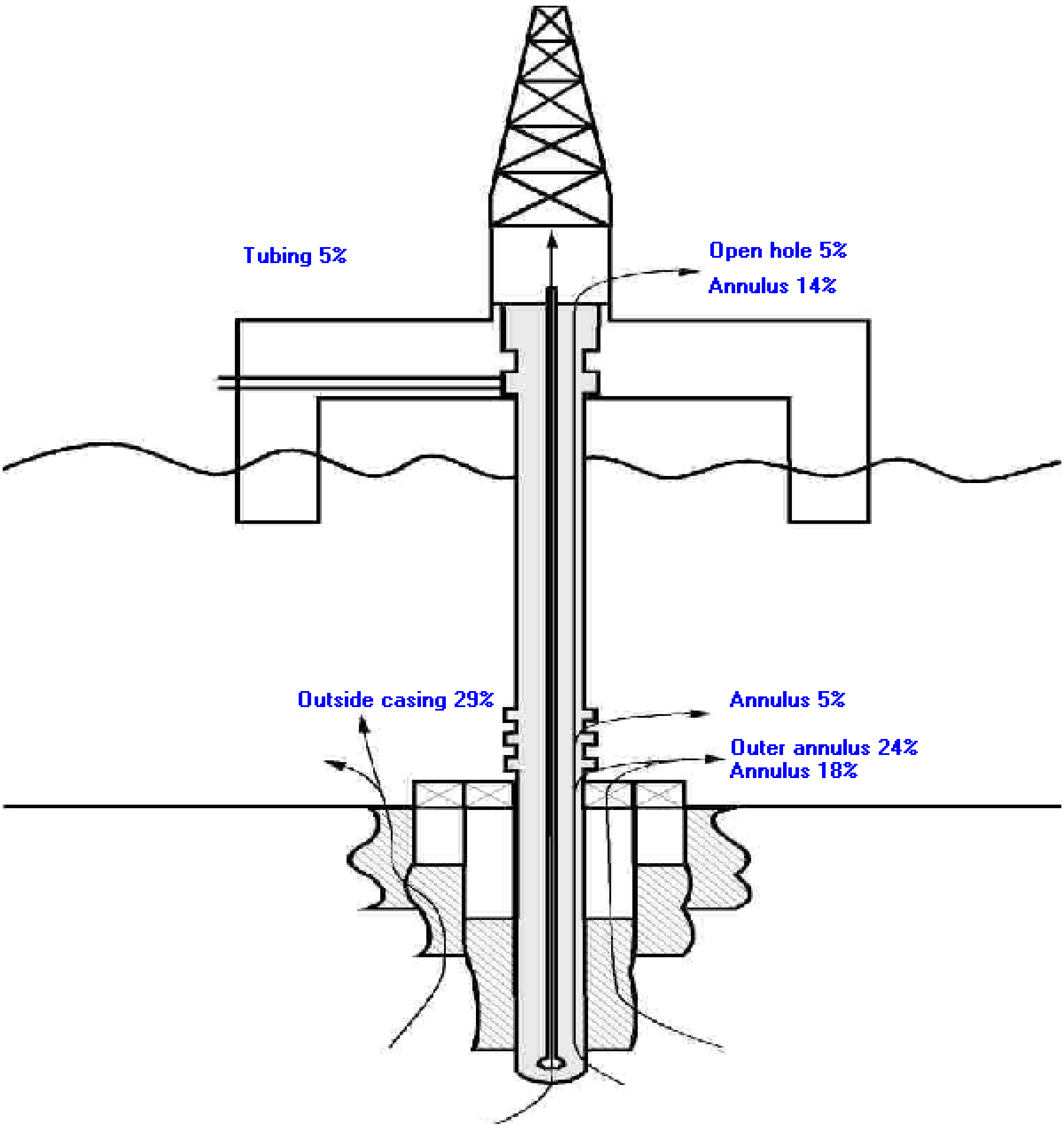

Figure 16: Illustration of flow path and release point distribution for a floating platform from BlowFAM.

5.2.6 Sensitivity study

This section will investigate the effect of varying input parameters on adjustment factor 1. There is high uncertainty related to several reservoir parameters. Adjustment factor 1 is highly sensitive to some of these. The sensitivity to some different parameters is investigated and shown in Table 15. This is done by observing the implication of changing a single parameter, while other parameters are kept constant. But when changing input such as drilling window or pore pressure, the mud weight (MW) must also be changed to obtain an appropriate mud density within the drilling window. The values used in the base case are also included in the "Default" column. These yield an adjustment factor of 0.803.

Table 15: Sensitivity of adjustment factor 1 to various input parameters in the BlowFAM case analysis.

Variable	Default	Value	Adjustment factor 1
Base case			0.803
Drilling window (EMW SG)	0.80 (mw 1.60)	0.40 (mw 1.40)	1.309
		0.60 (mw 1.50)	0.959
		1.00 (mw 1.70)	0.712
Pore pressure	1.20 (mw 1.60)	1.10 (mw 1.50)	0.784
		1.30 (mw 1.70)	0.860
Risk of drilling too deep	Possible	No	0.751
		Yes	0.933
Well testing	Yes	No	0.756
Reservoir segmentation	Unknown	No	0.683
		Yes	1.299
Reservoir productivity	Low	Unknown/average	0.937
		High	1.207
Gas cap	Yes	No	0.803
GOR	200	400	0.803

As can be seen from the Table 15, adjustment factor 1 is highly sensitive to the drilling window. Seeing that there is little data available on pressure profiles in this area, it becomes difficult to determine such values accurately. Consequently, there is a high uncertainty related to this value. Since BlowFAM does not allow presenting input parameters as probability distribution, it must be given as a single value. Therefore, it is specified slightly conservative. The pore pressure also has some uncertainty related to it. But as can be determined from Table 15, variations in this parameter will not be as important for the blowout risk (as long as the drilling window is kept constant). Whether there is a gas cap present or not, has a negligible effect on the blowout risk. For low risk levels, the effect is not noticeable. This is also the case for changes in GOR.

5.2.7 Risk management

BlowFAM has the possibility to identify risk reducing measures, through the evaluation or risk elements. It can enlighten weak areas and work as a decision support tool in risk management. Risk reducing measures identified through BlowFAM will affect the risk by reducing the probability of a blowout occurring in the first place. It identifies measures that can be initiated to try to prevent a blowout. Many of the risk elements are procedures and technology improvements that can be implemented as a means of reducing the risk. Risk reducing measures will here be identified to provide an example of how BlowFAM can be used as a decision support tool.

In appendix E.3, a number of risk reducing measures have been identified. These are mostly related to human factors, procedures and the BOP reliability. Risk related to human errors can be reduced by an increased frequency and quality of training courses, especially courses related to well control. A qualification feedback system can help reveal lack of experience in some areas. Procedures can be improved by better mud control and more differentiated contingency plans. Mud control can be improved by careful monitoring of mud volumes, e.g. between trips. High rate mixing and an increased number of mud pumps available can ensure fast mud supply during a critical situation. Checking cement quality before permitting to drill ahead can also reduce the risk. Use of a more reliable BOP, and frequent testing can further reduce the blowout risk.

Each of the identified elements have been given a maximum positive score. The additional positive score from section E.3 is added up, and found to be 39 points higher than for the base case. The new adjustment factor 2 can then be calculated from the same formula as in 5.2.4:

$$Adjustment\ factor = \frac{\sum X + \sum W - \sum B}{\sum X} = \frac{163 + 9 - (47 + 39)}{163} = 0.528$$

If comparing this to the adjustment factor from the base case of 0.767, it can be seen that the blowout frequency is reduced with approximately 31 % by implementing these measures. This would result in a blowout probability of 5.22×10^{-5}. In this way, BlowFAM can quantify the effects of different risk reducing measures on blowout probability.

5.2.8 Limitations

Based on the use of BlowFAM for this case study, it was experienced some shortcomings. Both statistics and risk elements in BlowFAM have not been thoroughly updated since 2003. Historical data from the most recent SINTEF database must be included to reflect present day blowout probabilities. This lack of updates is also reflected in the historical blowout cause distribution in Table 12. This cause distribution changes each year, as new incidents are included in the blowout database. The flow path, release point and BOP opening distributions given in Table 14 (and Fig. 16) are also collected from statistics from 2003. Since these data are not updated, these distributions will not be used as basis in this case study. The scenario distributions found in section 5.1.5 are considered to be more accurate.

The implications of different well configuration and reservoir characteristics should also be re-evaluated. By evaluating recent blowout incidents, trends can be identified which reflects the implications of e.g. a different drilling windows.

There is a high number of risk elements included in BlowFAM. These elements have not been updated since the model was developed in 1995. Thus, these elements need a thorough review to determine whether they are still relevant with today's technology and equipment. Many of the elements might concern types of equipment and procedures which are not in use today. Safety requirements have grown stricter in this period. Therefore, all the risk elements should be re-evaluated to reflect issues regarding present day equipment and safety levels.

There are also several bugs in the BlowFAM calculations. Adjustment factor 1 supplied by the BlowFAM tool does not match the one calculated from the cause distribution in Table 12. The last cause "unknown" is not included in BlowFAM's adjustment factor. Thus, the model yields an adjustment factor which is too low.

Adjustment factor 2 supplied by BlowFAM does not match the adjustment factor calculated from the given formula. The explanation seems to be that some of the risk elements with a negative score has not been excluded in the calculations. The total negative score was found from section E.2 to be 9. BlowFAM's adjustment factor of 0.749 would correspond to a total negative score of 6, assuming the other numbers are constant. This can explain the lower adjustment factor given by BlowFAM. The elements related to drilling before BOP are supposed to be automatically excluded when choosing deep drilling. However, several of these elements are included in the calculations of adjustment factor 2 for deep drilling. Thus, there seems to be an error in the command telling BlowFAM which elements to include. As elements related to drilling before setting of the BOP have not been altered in this assessment, it has not affected the adjustment factor here. The tool is currently being modified to exclude these bugs (pers. comm. Giljarhus).

It can be added as this student's subjective opinion that the layout of the risk element evaluation has room for improvement. Relevant risk elements are automatically screened and highlighted, depending on whether they relate to production, drilling (before or after BOP), etc. Instead of highlighting relevant elements, irrelevant elements could be removed. The screening process should be more thorough and also differentiate between deepwater, HPHT and normal wells. It should also be possible to categorize elements according to type of equipment or procedure they related to. Elements related to cement, casing, BOP and so on could be combined to ease the evaluation process, or at least unified in the same section.

BlowFAM does not allow presenting input parameters as probability distributions. The model only allows single value input. Thus, parameters that are uncertain must be assumed relatively conservative to ensure that the risk is not underestimated. If input is presented as probability distributions, this would also yield results presented as probability distributions. If the model were to include uncertainty, this would require an entirely different calculation engine. As of today, blowout probability is commonly given by single values. This is also the case in the presentation given in Fig. 1.

BlowFAM is not a mechanistically based approach, as it is based on statistics and not on calculations of well specific conditions. Also, it consists of a high number of assessment factors. These are evaluated and given credit according to the opinion of the user, which gives it a subjective and not necessarily scientific basis.

6. BlowFlow - Blowout scenarios

Assessing blowout rate and duration is an important part of an environmental risk assessment (ERA). However, there is no standardized method for calculations of these values which can easily be communicated and compared between different parties. MIRA states that a sufficient number of probable flow rates and duration should be established, for use in an environmental risk assessment (Brude, 2007). The approaches used to determine these values typically vary from company to company. It is unclear which approach gives the best prediction, whether uncertainty is handled properly and how applicable one methodology is to a given situation.

Due to the high variations from analysis to analysis, OLF has produced guidelines on how to determine flow rate and duration in a more detailed manner. According to these guidelines, flow rate and duration should be presented as probability distributions to reflect uncertainty in input parameters. BlowFlow is a computer tool used to calculate flow rate and duration of a blowout that builds on these OLF guidelines (Nilsen et al., 2004). It is a mechanistic model developed by IRIS (Arild et al., 2008). BlowFlow is still in the development phase, and is being continuously tested against field data at Statoil (pers. comm. Ford).

The different steps of an ERA are shown in Fig. 1, where BlowFlow constitutes the 2nd step of the process. The blowout rate and duration are detrimental with respect to environmental consequences, and therefore to the result of an ERA. BlowFlow will be used here to assess flow rate and duration in a probabilistic manner for a range of different blowout scenarios. The tool allows assessing the uncertainty of parameters. This facilitates a way to assess uncertainties, where the uncertainty in input parameters is reflected in the probability distributions of flow rate and duration. This uncertainty should be allowed to propagate as in Fig. 1, to ensure that the level of detail is not compromised.

A sensitivity study will be performed to assess which parameters are the most crucial to the uncertainty of the flow rate. This can reveal which parameters that contribute most to an increased risk. This chapter will also investigate the effects of neglecting uncertainty, and choosing a more conservative approach. Such an approach resembles a more traditional conservative approach. This will also demonstrate how the probabilistic flow rate and duration distributions are a function of uncertainty in input parameters.

BlowFlow can aid the risk management process by providing a common platform for identifying risk mitigating measures. This is done by observing the effects of varying input parameters. BlowFlow can also help dimension oil spill preparedness, as it predicts possible flow rates and durations.

6.1 Well input

This section presents basic input on type of fluid, reservoir characteristics and well design. These properties must be carefully considered to be able to predict the possible blowout rate accurately. As in section 5.2.2, reservoir parameters have been determined based on discussion with Tore Høy, and through comparison with data from the Goliat field. Well design, drill pipe and casing diameters have been discussed with Kjell Kåre Fjelde.

6.1.1 Platform

The water depth in the area has been set to 330 m, with a seabed temperature of 2.5 °C, as discussed in section 5.2.2. The platform is a semi-submersible drilling rig. A rotary table (RT) elevation of 25 meters is considered adequate (pers. comm. Fjelde). This is more than sufficient with respect to wave height in the former disputed area (pers. comm. Høy). Fig. 17 shows a schematic representation of the platform and water depth.

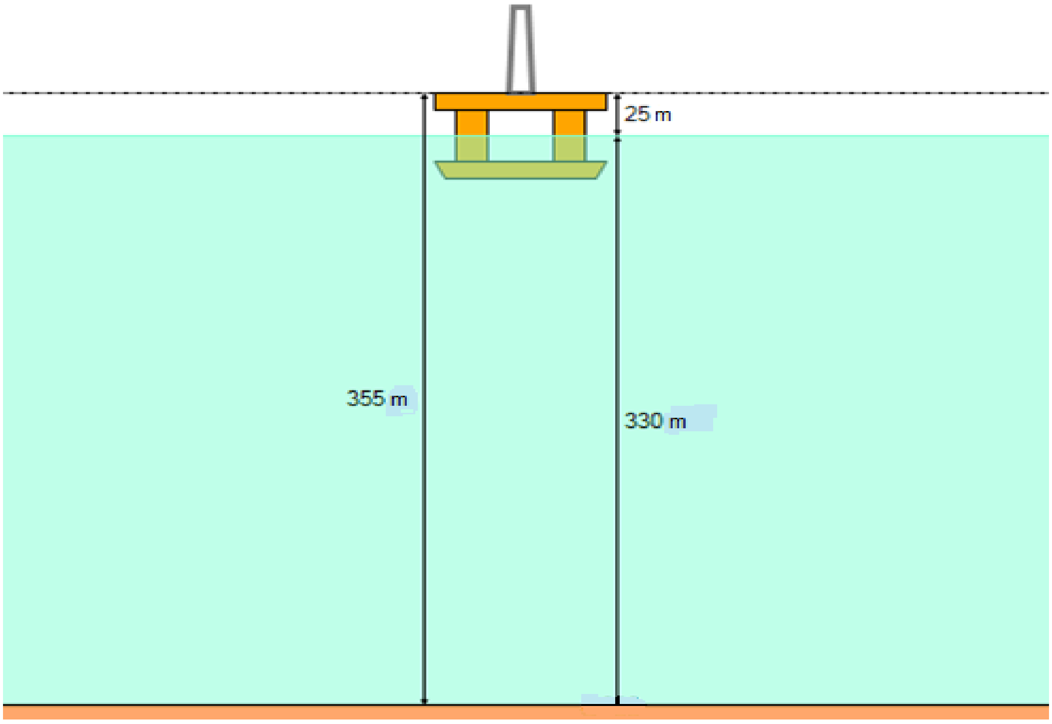

Figure 17: Topside schematic.

6.1.2 Architecture

The casing program is crucial for the well diameter, and thus for the potential flow rate from the well. The suspensions depths and outer and inner diameters of the casings are listed in Table 16. Each casing is suspended from the seabed. The casing program is also shown schematically in Fig. 18. As discussed in section 5.2.2, the inclination of an exploration well is usually small. Thus, for simplicity the well trajectory is assumed to be vertical. Table 16 also includes length and diameters of the open hole section, riser and BOP. These details have set based on discussion with Kjell Kåre Fjelde (pers. comm. Fjelde). The bit location has been assumed equal to the BlowFlow default settings, which is at the bottom of the well.

Table 16: Casing program, open hole, riser and BOP design used as input in BlowFlow (pers. comm. Fjelde).

Section	Suspension depth (m)	Shoe depth (m)	OD (in)	ID (in)
Casing program	355	500	30.0	29.0
	355	890	20.0	19.0
	355	1500	13.4	12.3
	355	1880	9.63	8.62

	Length (m)	OD (in)	ID (in)
Open hole	120	8.50	
Riser	355	21.0	19.0
BOP	2.00	20.0	

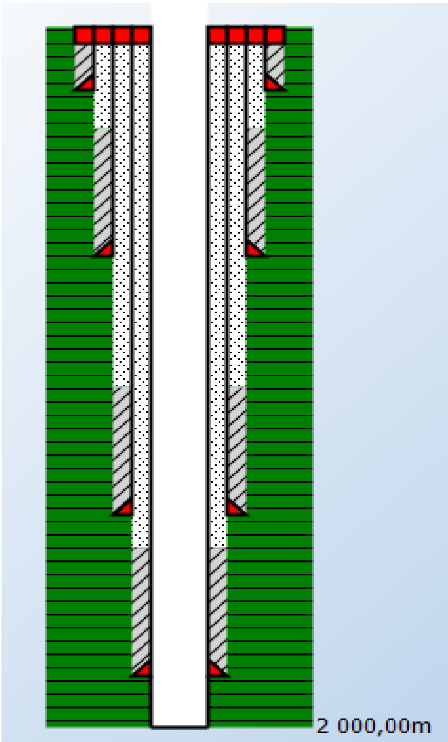

Figure 18: Wellbore schematic showing casing program and open hole section.

BlowFlow has many different material selection possibilities for casings and other well equipment. For this specific well, stainless/stretched steel is chosen as the best alternative. This is the most commonly used steel type, and is considered sufficient to prevent erosion and different types of corrosion damage. This is also the default steel type in BlowFlow, with a given roughness height of 15 µm. This was selected through discussion with Kjell Kåre Fjelde (pers. comm. Fjelde).

6.1.3 Drill string

Dimensions of drill string components are presented in Table 17, and schematically in Fig. 19. All components are assumed to be made of stainless steel. The drill bit diameter is set to 8.5 inches which corresponds to the open hole diameter (pers. comm. Fjelde). Drill-collar and drill string sizes are set according to the BlowFlow default values.

Table 17: Drill string description used as input in BlowFlow.

Type	Number	Length	OD (in)	ID (in)
Bit	1	3.00 in	8.50	
Drill-collar	10	9.14 m	6.75	3.00
Drill string	1	1910 m	5.00	4.28

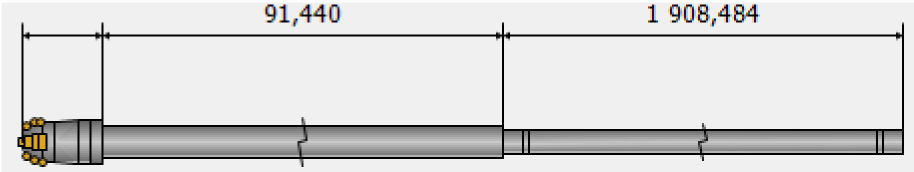

Figure 19: Drill string overview.

6.1.4 Fluid

As described in section 5.2.1, the case study reservoir is assumed to contain oil with an adjacent gas cap. BlowFlow estimates specific flow rates for both oil and gas. The relative amount of each will depend on the gas-oil ratio (GOR). Flow rate of oil will be in focus in this case study. Gas typically evaporates relatively quickly, and is therefore considered to have limited environmental effects. A typical ERA methodology includes only oil flow when assessing environmental consequences, as this represents the highest environmental hazard.

Impurities in the reservoir, such as CO_2, H_2S and N_2, are for simplicity assumed to be negligible (pers. comm. Høy). Presence of small amounts of such gases will not have any noticeable implications on the flow rate of oil.

6.1.5 Reservoir properties

A possible oil reservoir is according to Tore Høy most likely to be found at a depth of 2 000 m, in Triassic layers. The reservoir temperature was calculated to be 52.5 °C in section 5.2.2. The net thickness of the flowing reservoir is set to 15 m (pers. comm. Høy), which also corresponds to the thickness of the Goliat reservoirs (pers. comm. Holen). The total thickness of the zone is set to 160 m (pers. comm. Høy). The net/gross ratio is the relation between the hydrocarbon thickness of the zone and the total thickness of the zone, including shale/sand, etc. This yields a net/gross ratio of 9.4 %. The top depth is set to 1 985 m. The GOR has been set to 200, as in section 5.2.2. It is possible to present the thickness and GOR as probability distributions in BlowFlow. However, there is not considered to be a sufficient basis to present these parameters as such distributions. They are therefore represented as single values.

The gravity of the Kobbe oil of the Goliat field is 796 kg/m^3 (Bjørnbom et al., 2008). As there is some uncertainty related to this parameter, it has been set to 800 kg/m^3 for the well in question. This is chosen based on recommendations from Tore Høy (pers. comm. Høy). The Kobbe gas gravity is 0.800 SG (pers. comm. Holen). It is chosen to use this as input in this case study. Oil gravity is the density of the oil at standard conditions (pers. comm. Høy). Gas gravity is the gas density at standard conditions, relative to air density. These input parameters are summarized in Table 18.

Table 18: Reservoir zone properties, represented by single values as BlowFlow input (pers. comm. Høy).

Variable	**Value**
Reservoir temperature	52.5 °C
Reservoir thickness (net pay)	15.0 m
Net/gross ratio	9.4 %
Top reservoir depth (TVD RT)	1985 m
Oil gravity	800 kg/m^3
Gas gravity	0.800 SG
GOR	200

Some of the input values with a high uncertainty related to them are presented by probability distributions. There is assumed to be a high degree of uncertainty related to the reservoir pressure. The pressure gradient was given in section 5.2.2 to be 1.2. The reservoir pressure can be calculated from the pressure gradient by using the below formula.

$$P = \rho_f \times g \times h = \nabla P \times \rho_w \times g \times h = 1.20 \times 1000 kg/m^3 \times 9.81 m/s^2 \times 2000 m = 235 \times 10^5 Pa$$

Where:
P = Pressure, Pa
ρ_f= Formation density, kg/m^3
∇P = Pressure gradient, SG
ρ_w = Water density, kg/m^3
g = Gravitational constant, 9.81 m/s^2
h = Well depth, m

This results in a reservoir pressure of 235 bars. However, the pressure varies greatly from reservoir to reservoir. Since there is high uncertainty related to this value, but without statistical basis for representing the reservoir pressure as a probability function, it was decided to present it as a triangular distribution. A pressure gradient of 1.2 is assumed to be slightly conservative, as the Goliat pressure gradient is 1.1 (pers. comm. Holen). A pressure gradient of 1.1 would correspond to a pressure of 216 bars. The assumed minimum pressure is set to 210 bar, most likely pressure to 220 bar, and the maximum pressure to 240 bar (pers. comm. Høy). This triangular distribution is presented in Fig. 20, where the pressure is plotted against probability.

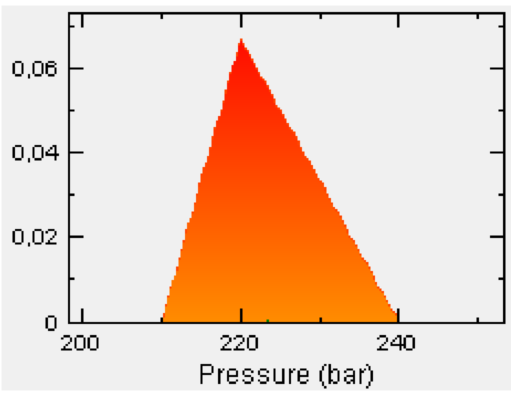

Figure 20: Reservoir pressure represented by a triangular probability distribution.

6.1.6 Productivity index

For this specific well the inflow model "Oil – Basic" is chosen. This is the preferred model to determine the productivity index for vertical and deviated wells with rectangular drainage areas. The necessary input values for this model are listed in Table 19. The reservoir area is of limited importance to the flow rate, as long as the well is located close to the middle. Therefore, it is assumed equal to the BlowFlow default values, as listed in the table. The vertical well location is the reservoir penetration depth. As this must be set as a single value, the well location is assumed to be in the middle of the flowing reservoir zone, at 7.5 m (pers. comm. Fjelde). The oil formation volume factor (B_o) and oil viscosity (μ_o) are calculated from the PVT models (appendix C).

Permeability and skin factor are both crucial parameters with respect to reservoir productivity. The skin factor (well damage) typically varies from -6 for a productive fractured reservoir, to 100 or more for a poorly executed gravel pack. A skin factor of 0 corresponds to no damage. In BlowFlow it must be set by a single value. For a vertical well the skin factor is usually quite small. Due to the high uncertainty it is set to 0, to avoid underestimating this parameter (pers. comm. Fjelde). This is also the value recommended to use in the BlowFlow user manual (Ford, 2012).

According to Tore Høy, a reservoir in this area will have quite poor reservoir conditions. The horizontal permeability for such a reservoir is likely to vary between 2 – 150 mD, with 100 mD as the assumed most probable value. (pers. comm. Høy). Thus, it is represented by a triangular distribution, as listed in Table 19. By experimenting with these values one can see how the flow rate is affected (see section 6.5 for sensitivity study). The vertical-horizontal permeability (kV/kH) is set to 0.1, which is the value recommended in BlowFlow.

Table 19: Input to the "Oil – Simple" inflow model in BlowFlow (pers. comm. Høy, pers. comm. Fjelde).

Variable	Value
Reservoir length along well (x_e)	1000 m
Reservoir with across well (y_e)	500 m
Well location along reservoir (x_w)	1000 m
Well location across reservoir (y_w)	500 m
Well location (z_w)	7.50 m
Oil formation volume factor (B_o)	1.58
Oil viscosity (μ_o)	0.386 cP
Skin along well (damage)	0
Horizontal permeability (mD)	2 - 100 - 150 mD
kV/kH	0.100

BlowFlow calculates the productivity index of the reservoir, based on these input data. This yields the volumetric flow rate per drawdown pressure. The drawdown pressure is the difference between the pore pressure and flowing bottomhole pressure. The mean productivity index is plotted for three different reservoir penetration depths in Fig. 21; 5 m, 50 % and 100 % It can be seen that the productivity is strongly dependent on the penetration depth.

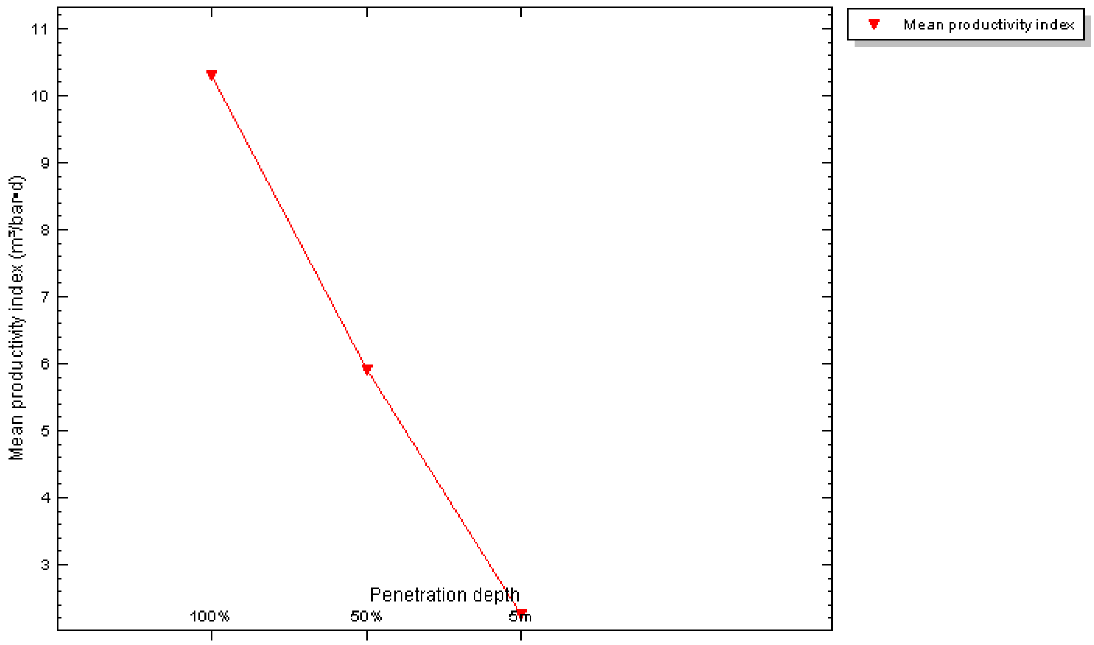

Figure 21: Mean productivity index for 5 m, 50 % and 100 % reservoir penetration.

6.2 Scenario input

The type of blowout scenario will be important for the severity of a blowout. Scenarios that can vary from blowout to blowout include:

- Release point
- Flow path
- Penetration depth
- BOP opening

These scenarios must be defined as probability distributions in BlowFlow. The probabilities have been determined based on an evaluation of statistics. In addition, OLF's guidelines on calculation of flow rate and duration have been considered (Nilsen et al., 2004). For a more mechanistic approach, these values can be based on a detailed kick analysis (Arild et al., 2008). However, this is very time consuming and requires expert judgment. Thus, it will not be performed in this case study. Each different scenario will have a specific flow rate. The probability of each scenario will therefore be important to the overall mean flow rate and discharge volume.

6.2.1 Release point

As discussed in section 2.1.3, a blowout from a subsea well mainly has two possible release points; subsea and topside. Underground blowouts will the disregarded here, seeing that they are not included in BlowFlow. The release point distribution found in section 5.1.5 will be used as input in BlowFlow. This distribution is based on updated statistics (Haugsvold, 2011, Holand, 2010). It is shown as a sector diagram in Fig. 23.

6.2.2 Flow path

The blowout scenarios are also characterized by different flow paths, which were discussed in section 2.1.4. There are three possible flow paths included in BlowFlow:

- Through the drill string
- Through annulus, between the casing and drill string
- Through the open hole, without a drill string in the well

Both the SINTEF database and Scandpower report show that a significant amount of blowout data is related to blowouts outside the casing. At present, this flow path is not part of the BlowFlow tool. Therefore, incidents related to outside casing flow are considered to flow through annulus. The flow path distribution between the 3 possible flow paths was found in section 5.1.5. This distribution is used as input in BlowFlow. Both release point and flow path distribution is shown graphically in the sector diagram in Fig. 22.

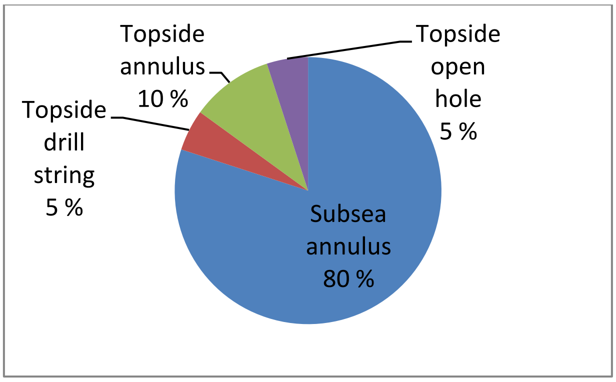

Figure 22: Sector diagram of release point and flow path distribution.

6.2.3 Penetration depth

The reservoir penetration depth is related to the proportion of the reservoir that is exposed to the well. As can be seen from Fig. 21, this is crucial for the flow rate. It is difficult to predict at what penetration depth a blowout is most likely to occur. It will vary depending on the type of well. For an exploration well, it is more likely to encounter an unexpected pressure zone, compared to a developmental well. This is because much less information is available about the reservoir and pressure profile. This would typically occur right after the reservoir has been penetrated, at about 5 m penetration depth. A blowout can occur at 100 % penetration depth if swabbing (see section 2.1.2) is experienced during tripping (withdrawal of the drill string). With respect to other blowout causes, these can occur at all different penetration depths.

The OLF guidelines proposes a penetration depth distribution as presented in Table 20 (Nilsen et al., 2004). A 5 m penetration is assumed to be the least probable, with 20 % probability. This might be a little conservative for an exploration well, where unexpected pressure zones are encountered more often. Penetration depths of 50 % and 100 % are given equal probabilities of 40 %. It is concluded to use the OLF recommendations as BlowFlow input (Nilsen et al., 2004).

Table 20: Reservoir penetration depth distribution as input in BlowFlow.

Reservoir penetration depth		Probability
5 m	17 %	20 %
15 m	50 %	40 %
30 m	100 %	40 %

6.2.4 BOP opening

The BOP opening will also affect the flow rate of a potential blowout. The BOP stack is a reliable system, and a fully open BOP is therefore less likely. Two possible BOP openings are commonly included in ERAs: fully open and partially closed (5 % opening). OLF's guidelines proposes a distribution with a 30 % chance of full flow and 70 % chance of choked flow (Nilsen et al., 2004). According to the statistics of Table 8, 51 % of subsea blowouts occur with restricted flow, and 75 % of topside blowouts (Haugsvold, 2011). However, the BOP seal might be disintegrated over time. Then, the flow restriction could decrease quickly, and the restricted flow escalate into full flow. This is especially the case for high flow rates. Statoil and IRIS commonly apply a fully open BOP as a conservative implication is BlowFlow (pers. comm. Ford). It is chosen to use full flow as basis in the case study.

6.3 Duration input

There are several different well kill mechanisms included in BlowFlow. These are capping, coning bridging and relief well drilling. Each of these killing mechanisms are described in appendix A. The effect of the different mechanisms on the blowout duration will depend on 3 factors:

- Degree of flow reduction
- Probability of success
- Duration

Not all of these mechanisms will make the well completely seize to flow. Coning can e.g. reduce the flow of oil due to water or gas coning. For such cases, the flow reduction is given as a percentage decline in oil flow. Bridging also has the ability to restrict the flow, but is here assumed to be 100 % effective. Each mechanism has a different duration, and will therefore take place at different times in the blowout lapse. Some might be initiated almost immediately, while others need a longer period of time to be deployed. Probabilities, effects and durations of the different mechanisms have been based on both statistics and expert judgment.

6.3.1 Coning

The probability of coning has been set to 50 %, with a flow reduction of 50 %. In reality, the probability and effect of both water and gas coning will depend on the reservoir penetration depth. However, they cannot be specified specifically for different scenarios in BlowFlow. If coning is to occur, it typically happens quite quickly. The time for coning to take place is therefore set to 1 day (pers. comm. Fjelde). The probability, duration and effect of coning is shown in Table 21.

Table 21: Implications of coning.

Variable	Value
Coning probability	50 %
Coning duration	1 day
Coning effect	50 %

If coning where considered to be 100 % effective, it would have implications on the duration of the blowout. If coning is set to have a smaller effect than 100 %, it cannot be considered as a killing mechanism. It will then only influence the flow rate after the given time, and thus the total discharge volume. If coning occurs, the flow rate will be reduced by 50 % from day 1.

6.3.2 Bridging

Bridging will normally take place relatively early in the blowout lapse. According to the Scandpower report on blowout statistics from 2009, as much as 77 % of the registered blowouts have been stopped due to bridging (Haugsvold, 2010). According to more recent historical data, the time for bridging to take place can be presented by a Weibull distribution, with a shape (α) of 0.6 and a scale (β) of 3.8 days (Haugsvold, 2011). BlowFlow does not construct a curve for the bridging duration. But with a shape of 0.6, it resembles an exponential distribution. BlowFlow yields a mean duration of 5.7 days. It is chosen to use this probability and duration as input in BlowFlow. Probability and distribution values for the bridging duration are listed in Table 22.

Table 22: Probability and duration of bridging (Haugsvold, 2010, Haugsvold, 2011).

Probability	Duration (Weibull distribution)	
	Shape (α)	Scale (β)
77 %	0.6	3.8 days

6.3.3 Crew interventions (capping)

The mechanism capping will here be referred to as crew interventions to avoid confusing these operations with the new capping technology described in appendix A.4.1. Currently the only active measure included in BlowFlow is capping. Thus, capping is commonly applied by Statoil and IRIS to include all types of crew interventions (other than well caps and relief wells). Therefore, this mechanism in BlowFlow will from now on be referred to as crew interventions. This will be further discussed in section 6.7. The default probabilities and durations are set according to historical data from the Scandpower report. The complexity of a crew intervention will depend on preparedness and the physical conditions at the release point. Crew interventions are split into subsea and topside, since the duration and success probability of a crew intervention has been evaluated to vary with different release points (Haugsvold, 2011).

According the blowout statistics from 2009, there is a high probability that a blowout is killed by a crew intervention. The historical data indicate that crew interventions have a success probability of 70 % for topside incidents, and 43 % for subsea incidents (Haugsvold, 2010). The time to perform these operations also deviate between topside and subsea releases. According to more recent historical data, the durations can be constructed as Weibull distributions. With a shape (α) of 0.6 for topside and 0.5 for subsea interventions, both durations resemble an exponential distribution. The scale is given to be 1.8 days and 6.3 days, respectively. BlowFlow does not construct curves for these durations, but yields mean durations of 2.7 and 12.6 days, respectively. It is considered more difficult to regain access of a subsea well, since these interventions are more complex. Therefore subsea interventions are more time consuming. It has been concluded to use these values as input in BlowFlow. Success probabilities and distributions values are listed in Table 23. These probabilities might be a bit conservative because of the low flow rates of the well of this case study. It is generally easier to kill a well with a smaller flow rate through crew interventions. On the other hand, equipment mobilization might be more time consuming due to the remote locations. For simplicity, these factors have not been given any credit here due to lack of reliable information.

Table 23: Probability and duration of topside and subsea crew interventions, entered as input in the capping mechanism in BlowFlow.

Crew interventions	Probability	Duration (Weibull distribution)	
		Shape (α)	Scale (β)
Topside	70 %	0.6	1.8 days
Subsea	43 %	0.5	6.3 days

Well caps are currently not available for deployment on the NCS. But in light of the Macondo accident, development of several types of subsea capping devices has been initiated. The SWRP is currently working on developing capping stacks that will be applicable on the NCS. It is therefore not unlikely that a well cap will become available in the near future, possibly before any exploration wells will be drilled in the former disputed area. A well cap is not included as a killing mechanism in the base case, since the technology is not yet qualified and implemented. It will however be considered in section 6.6, as a risk reducing measure.

6.3.4 Relief well

The probability of a relief well to be successful is set to 100 %. This is based on the fact that two relief wells will always be prepared, which significantly increases the probability of successfully intersecting the uncontrolled flowing well. If the first attempt fails, then the other well is ready for deployment. The time it takes to drill a relief well depend on several different factors: The decision time, rig mobilization time, drilling time, intersection time and killing time. An operator must always have a relief well contingency plan before start of drilling, in case of a blowout. Therefore the decision time is set to 0. The rig mobilization is assumed to take two weeks, due to the remote location (pers. comm. Fjelde).

The time it takes to drill a relief well is difficult to determine accurately. This will depend on several different factors, such as the accessibility to the uncontrolled blowing well. To account for the uncertainty related to the drilling process, the drilling time is represented by a triangular probability distribution, as listed in Table 24. Due to the low to moderate reservoir depth, it might be difficult to accurately steer the relief well into the bottom of the wellbore. Well intersection might require several attempts. Due to some uncertainty in the time necessary to intersect the well, this is also presented as a triangular distribution. It is assumed to vary between 1 to 5 days, with 3 days as the most likely duration. The time to kill the blowing well from the relief well after intersection is represented by a exponential distribution, with mean durations of 1 day (pers. comm. Fjelde). These durations are summarized in Table 24. The killing time is also presented graphically in Fig. 23, where the number of days is plotted against probability.

Table 24: Probability and duration of drilling a successful relief well.

Activity	Duration (days)
Decision time	0
New rig mobilization time	14
Drilling time	25 – 36 – 54
Time to steer/control relief well into main well	1 – 3 – 5
Killing time (mean value)	1

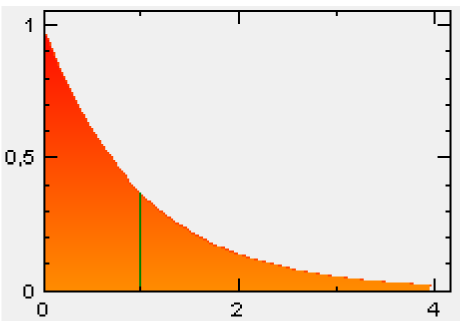

Figure 23: Exponential distribution of killing duration from a relief well, in days versus probability.

6.4 Results

The output section presents a summary of the results from each simulated blowout case. This is expressed through probability distributions of flow rate, duration and volume (Arild et al., 2008). Flow rate and duration has here received most focus, as these are commonly applied to the ERA. The probability distributions are presented as density curves, where each value has an associated probability. Each density curve has associated distribution values. The different distribution values are defined in appendix B.4.

6.4.1 IPR / VLP

An IPR curve gives bottomhole pressure as a function of flow rate *into* the well. It is a function of the reservoir productivity. The VLP curve represents the bottomhole pressure as a function of flow rate *out* of the well. In other words, VLP curves present the bottom hole pressure necessary to produce fluids out of the well at a specific rate. The intersection point between the IPR curves and the VLP curve, determines the mean flow rate for each penetration depth. Flow rates are determined by pre-generating IPR and VLP curves, and interpolating between them. Interpolation gives more accurate results, but can only be used for single reservoir zone cases.

Fig. 25 presents the mean IPR curves for three different reservoir penetration depths; 5 m, 50 % and 100 %. Since IPR curves are a function of flow *into* the well, they are independent of release point, flow path and BOP opening. IPR curves will only vary with penetration depth. A deeper reservoir penetration corresponds to a higher reservoir exposure. This will yield a higher productivity, and consequently a higher flow rate. A penetration depth of 5 m would significantly limit influx, compared to 50 % or 100 % reservoir penetration. This correlation is seen from Fig. 24 below.

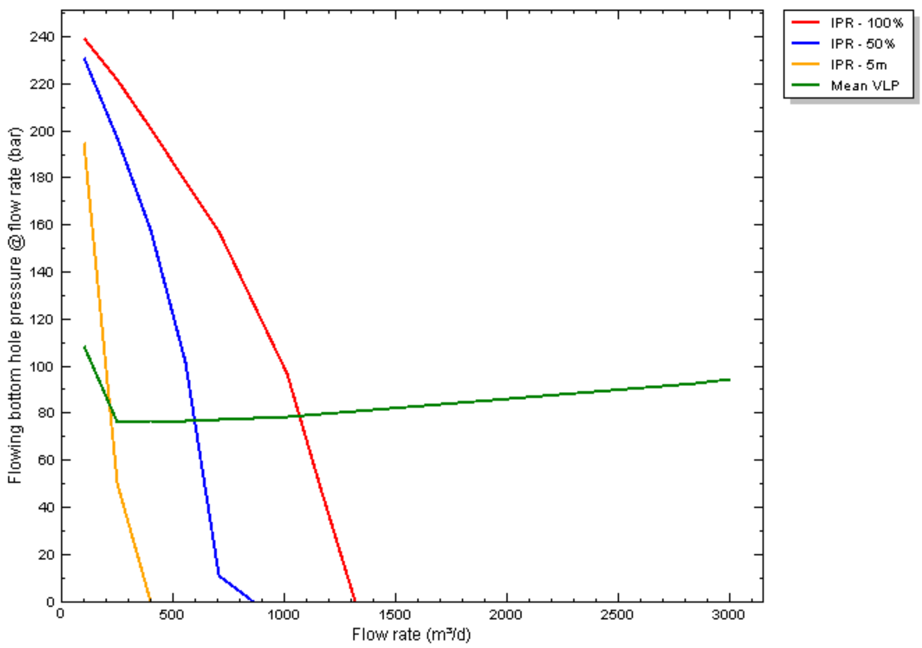

Figure 24: IPR and VLP curves for a subsea annulus blowout.

Fig. 24 also presents an example of a mean VLP curve, for a subsea annulus blowout. As explained in section 3.2.4, the VLP curve varies with different release points, flow paths and BOP openings. As a result, the flow rate will also vary with these scenarios. The vertical travel distance the fluid travels is higher for a topside blowout, than for a subsea blowout. One might assume that this would yield a higher flow rate for a subsea release. However, this is not the case here. The pressure profile is similar from the reservoir to the seabed for both cases. But the pressure difference along the riser (from seabed to the platform) can deviate from the hydrostatic head of the seawater. If the fluid density is lower than for seawater this can yield a lower pressure drop in the riser, compared to outside. A lower pressure drop would yield a lower VLP curve; with an associated higher flow rate (see Fig. 24). The pressure profile in the riser will also depend on friction.

The flow rate will also vary with flow path. This is mainly a result of frictional pressure loss. A smaller flow area will generally yield a higher frictional pressure loss. The fluid is most inhibited near the well wall or pipe. Thus, friction is high for smaller flow diameters. Higher flow restrictions would yield a higher VLP curve; with an associated lower flow rate (see Fig. 24). Therefore, the open hole flow path has the highest flow rate, while the drill pipe has the lowest. A partially closed BOP would also inhibit flow and cause a large pressure drop across the wellhead. Higher flow restriction yields a higher VLP curve, with an associated lower flow rate. A fully open BOP is assumed for all cases in this study. This results in slightly more conservative flow rates. The effect of a partially closed BOP is assessed in section 6.5.

The IPR and VLP curves in Fig. 24 indicate that in order reduce the flow rate; the flowing bottomhole pressure must be increased. A higher bottomhole pressure would result in a reduced drawdown pressure. This principle is used when employing a dynamic kill from a relief well. In a production well, the intention is rather to maximize flow.

6.4.2 Flow rate

The flow rate is a function of a wide range of parameters. Reservoir conditions, well design and penetration depth are important factors when determining the flow rate. Which parameters are the most crucial will be assessed in the sensitivity study of section 6.5. The flow rate is represented by a density curve, where the probability is plotted against flow rate in m^3/d. The graph consists of 98 cells, forming columns of different heights representing the probability for each specific flow rate. The flow rate varies with release point, flow path, reservoir penetration depth, type of fluid and with time. One curve is presented for each scenario. Due to the large amounts of data, each curve will not be presented. BlowFlow also presents a probabilistic flow rate distribution, which is the weighted mean distribution between the different scenarios. Fig. 25 shows this probabilistic flow rate distribution for oil at day 0.

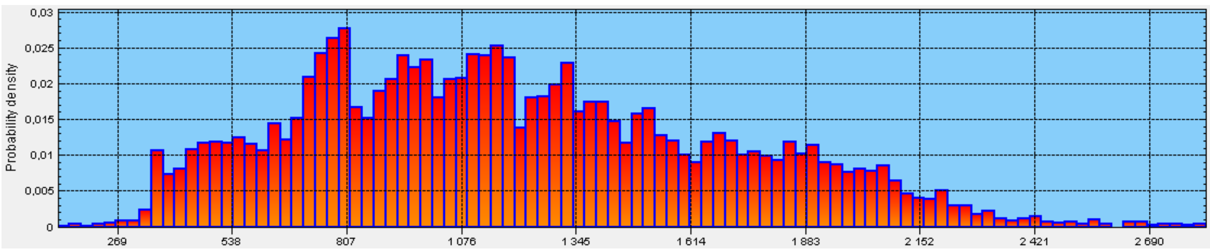

Figure 25: Probabilistic flow rate distribution at day 0, in m^3/d.

The distribution values corresponding to this curve are given in Table 25, along with distribution values for different release points and flow paths. Subsea blowouts through the drill string or open hole are excluded as these are not seen as possible scenarios (see section 5.1.5). The flow rate ranges from a minimum of 114 m^3/d to a maximum of 3 377 m^3/d. The flow rate can be any value within this range. Each flow rate is given a specific probability. The flow rate can be estimated for a single scenario, or as the weighted for a probabilistic scenario. This allows representing uncertainty on a detailed level. The probabilistic flow rate for a topside blowout can be calculated to be 1 333 m^3/d, based on the flow path distribution from Table 9, and mean flow rates from Table 24. The mean subsea flow rate can be read directly from the table to be 1 196 m^3/d. The probabilistic mean flow rate (subsea and topside) is given by BlowFlow to be 1 200 m^3/d.

Table 25: Flow rate distribution values for oil at day 0 for different release points and flow paths.

Distribution values	Flow rate oil (m^3/d)				
	Topside			Subsea	Probabilistic
	Drill string	Annulus	Open hole	Annulus	
Minimum	114	151	148	129	129
P10	654	709	742	583	591
P50	1 187	1 267	1 307	1 135	1 144
P90	1 892	2 124	2 255	1 904	1 901
Maximum	2 586	3 188	3 377	2 822	2 822
Mean	**1 236**	**1 344**	**1 406**	**1 196**	**1 200**
St. dev.	458	542	584	494	486

In BlowFlow, the flow rate *distribution* will decrease quickly with time. One flow rate curve is given for each day. The flow rate approaches 0 as it comes closer to the maximum duration, which is 72 days (see below). This is a reflection of the probability and duration of each killing mechanism. In reality, the flow rate is constant if none of the killing mechanisms have occurred. Therefore, the flow rate at day 0 will be used as basis further in this case study. However, this will exclude the effect of coning. If coning occurs, it will reduce the flow rate by 50 % after 1 day. Using the flow rate at day 1 however would also include effects of bridging and crew interventions. This would be unrealistic, as these mechanisms are considered to kill the blowout, rather than reducing the flow rate. In reality, bridging might be able to reduce the flow, but this is not quantified in BlowFlow. These mechanisms will only increases the probability that the blowout has been killed, and thus that the flow rate is 0 m^3/d. The flow rate over time is discussed further in appendix F.

The flow rates resulting from this study are quite low compared to an average field on the NCS, and to fields further west in the Barents Sea (Aspholm et al., 2007). The low flow rates are due to the poor reservoir conditions in the area. According to Tore Høy, an oil reservoir in the southeastern Barents Sea is likely to have a poor productivity (pers. comm. Høy). Flow rates in this area have also been predicted by the NPD. These have currently not been published, but according to Tore Høy, they are as follows (pers. comm. Høy):

- P95: 239 m^3/d
- P50: 717 m^3/d
- P05: 1592 m^3/d

The flow rates predicted by the NPD are lower than the ones supplied by BlowFlow. This is most likely due to a difference in the input parameters applied in the analysis. In this case study, the oil gravity of 800 kg/m^3 was set based on the density of the Kobbe reservoir. This was chosen based on recommendations from Tore Høy. The NPD have applied a density of 857 kg/m^3 in their calculations (pers. comm. Høy), which is equal to the density of the Realgrunnen reservoir of the Goliat field.

6.4.3 Duration

The duration is a function of the different killing mechanisms. It will depend on the time of occurrence, and the probability of a mechanism to successfully kill the well. For this case, 3 different killing mechanisms are considered:

- The blowout stops due to bridging.
- The blowout stops due to successful drilling of a relief well.
- The blowout is stopped by crew interventions (other than capping and relief well drilling).

The duration curve is presented as a probability distribution in Fig. 26, which reflects the uncertainty of the different killing mechanisms. The attending distribution values are given in Table 26.

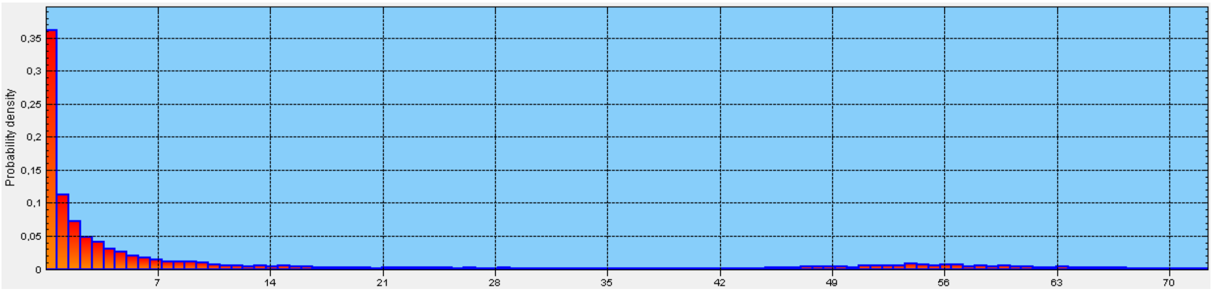

Figure 26: Probabilistic blowout duration distribution, in days.

Table 26: Distribution values for the duration density function.

Distribution values	Duration (days)
Minimum	0
P10	0
P50	2
P90	51
Maximum	72
Mean	**10**
St. dev.	19

The curve in Fig. 26 has several peaks because of the different killing mechanisms that interfere at different times. The 1st peak is a function of the implications bridging and crew interventions combined, as these mechanisms overlap in duration. Both durations are presented as exponential distributions. The 1st peak of the duration curve has a similar shape, with a steep inclination during the first few days. There is a 77 % chance that the blowout will be stopped due to bridging within the early phase of the blowout. The success probability and duration of a crew intervention will vary depending on release point (see section 6.3.3). Crew interventions are generally considered to be effective within a period of 14 days, but can also have a longer duration. Topside crew interventions have a 70 % success probability, while subsea crew interventions have a 43 % success probability. This leaves a small residual probability that the well is killed by a relief well. The 2nd (much lower) peak is caused by a dynamic kill from a relief well. The duration of this operation is a function of the mobilization time, drilling time, intersection time and killing time. These are represented by several probability distributions. The time to kill a blowout from a relief well is considered to vary between 40 and 72 days. The maximum duration is therefore 72 days.

The duration is here independent of probabilistic scenarios such as release point, flow path, penetration depth and BOP opening. Consequently, it is represented by a single curve. However, it includes different durations for topside and subsea capping. The probabilistic duration is then calculated from the release point distribution. For some cases it might be beneficial to construct different blowout durations for different release points. This will be discussed further in section 6.7.

The mean duration resulting from this case study is 10 days. This blowout duration correspond quite well to other ERAs in the area. The mean duration for the Goliat exploration well was estimated to be 9 days (Aspholm et al., 2007). Due to the remoteness of the well of this case study, this deviation seems reasonable.

6.4.4 Volume

The volume is a function of the probabilistic distributions of both blowout flow rate and duration. Consequently, the volume is also given as a probability distribution. The volume will vary with type of fluid, release point, flow path and penetration depth. Each scenario has a probability distribution for total discharge volume. This results in a high amount of data, which will not be presented here. Fig. 27 shows an example of the probabilistic total discharge volume of oil. The associated distribution values are given in Table 27. This table also includes oil discharge volume for other relevant release points and flow paths.

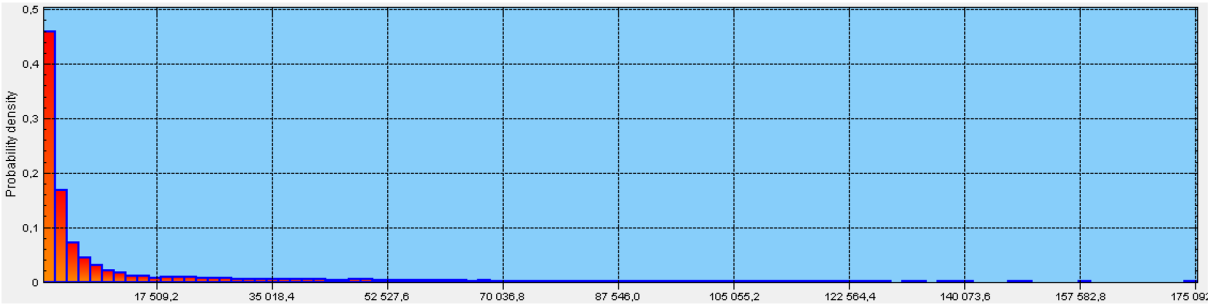

Figure 27: Probabilistic total discharged volume distribution of oil, in m^3.

Table 27: Volume distribution values for both oil and gas for different scenarios.

Distribution values	Volume oil (m³)				
	Topside			Subsea	Probabilistic
	Drill string	Annulus	Open hole	Annulus	
Minimum	0	0	0	0	165
P10	795	795	839	694	707
P50	2 105	2 369	2 476	2 049	2 036
P90	33 651	25 310	36 725	31 507	31 573
Maximum	155 601	195 748	195 419	175 257	175 257
Mean	**10 285**	**11 149**	**11 634**	**9 693**	**10 195**
St. dev.	19 653	21 668	22 592	18 874	19 416

Since the volume is a function of the flow rate and the duration distributions, it reflects uncertainty related to reservoir and well input, as well as uncertainty related to different killing mechanisms. The volume also reflects the flow rate over time. Thus, the effects of coning is here taken into account.

6.4.5 Summary

BlowFlow presents flow rate, duration and volume as probability distributions. These are curves composed of 98 or 100 columns, where the value of each column has an associated probability. Table 28 presents the mean values for flow rate, volume and duration for both oil and gas, for different release points and flow paths. A probabilistically weighted mean value is also shown to the right. The flow rate and volume will vary with type of fluid and scenario, while the duration remains constant. The flow rates and durations are typically applied as input to the ERA, through oil drift simulations. However, in this thesis oil drift simulations will not be performed.

Table 28: Summary of mean values of flow rate, duration and volume for different release points and flow paths, for the mean reservoir penetration.

Mean values at different scenarios	Topside			Subsea	Probabilistic
	Drill string	Annulus	Open hole	Annulus	
Flow rate oil (m^3/d)	1 236	1 344	1 406	1 196	1 200
Flow rate gas (m^3/d)	247 288	268 820	281 241	239 191	240 056
Duration (days)	10	10	10	10	10
Volume oil (m^3)	10 285	11 149	11 634	9 693	9 792
Volume gas (Mm^3)	2.1	2.2	2.3	1.9	2.0

6.5 Sensitivity study

A sensitivity study should be performed to reveal which parameters contribute most to an increased risk. This involves investigate how uncertainty in input parameters is reflected in the final results. It also involves assessing how changes in one parameter is reflected in the final results. What would happen to the results if all input parameters were presented by single values? If uncertainty is not included in the analysis, it is more common to chose conservative approximations. A sensitivity study is here performed to enlighten the effect of varying input parameters such as reservoir conditions and well diameter. The sensitivity study emphasizes the effect on flow rate. It would also be possible to investigate the effect of altering duration input. However, the sensitivity to duration input will be assessed when identifying risk reducing measures in the following section.

The flow rate is a function of reservoir conditions, well design and scenario. Fig. 28 shows which reservoir parameters' uncertainty is most crucial to the flow rate distribution. Permeability and pressure are both parameters with high associated uncertainties. This will be strongly reflected in the probabilistic flow rate curve. Fig. 28 shows that the flow rate distribution is sensitive to uncertainty in both permeability and pressure. The flow rate is more sensitive to permeability, as the pressure has a more narrow triangular distribution. BOP opening, bit location, thickness and GOR have here been set as single values. Consequently, they do not contribute to uncertainty in the probabilistic flow rate curve. The productivity index is a function of permeability, and otherwise single value input.

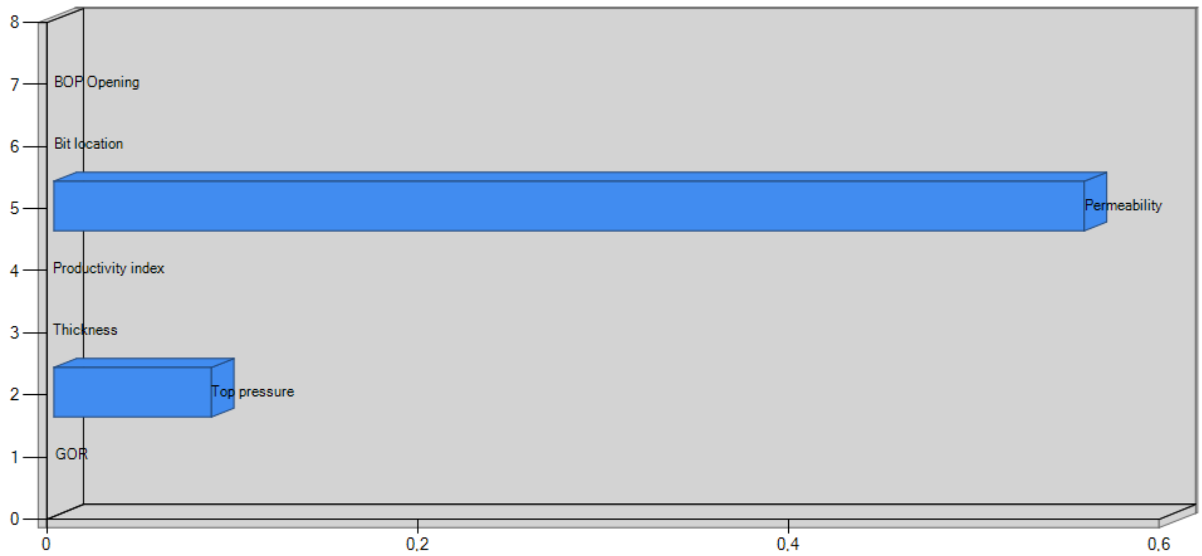

Figure 28: Flow rate sensitivity to uncertain input parameters in BlowFlow.

Table 29 shows the effect of altering different input parameters on oil flow rate. The base case values are included in the "Default" column. The table shows how the mean flow rate varies when entering input as single values rather than probability distributions. BlowFlow does not allow all parameters to be given by probability distributions. Some of these parameters have a lot of uncertainty related to them. The table shows how increasing or decreasing these values will affect the mean flow rate. It can be seen that both skin factor and permeability are crucial parameters to the flow rate. Consequently, it might be beneficial to allow the skin factor to be presented as a probability distribution. Otherwise, the flow rate becomes a result of a conservative assumption. The skin factor has been set to 0 in the base case, which is relatively conservative. The GOR, reservoir thickness and oil and gas gravities are also important parameters. A partially closed BOP is seen to have a negligible effect on flow rate.

Table 29: Sensitivity of the mean flow rate to reservoir parameters and well diameter.

Variable (other parameters constant)	Default	Value	Mean flow rate oil (m^3/d)
Base case			**1 200**
Permeability (mD)	2-100-150	50	667
		125	1 635
		300	3 590
Pressure (bar)	210-220-240	216	1 110
		235	1 287
		260	1500
Skin	0.0	5.0	696
		10.0	517
Net thickness (m)	15.0	30.0	1 900
GOR	200	100	1 043
		300	1 214
Oil gravity (kg/m^3)	800	820	969
		850	703
Gas gravity (SG)	0.800	0.700	1 132
		0.900	1 250
Well diameter (inches)	8 ½	12 ¼	1 284
Penetration depth	20 %	5 m	797
	40 %	50 %	1 033
	40 %	100 %	1 525
BOP opening	100 %	5 %	1 192

If uncertainty were neglected, a more conservative approach would have to be taken. A alternative case will here be presented to enlighten the effects of choosing conservative single values, rather than using probability distributions. As discussed above, the uncertainty in flow rate is a function of uncertainty in pressure and permeability. The uncertainty in the blowout duration is a function of the uncertainty in the time frames of the different killing mechanisms. In the example below, a simplified conservative case is presented. The reservoir parameters and durations applied are listed in Table 30.

Table 30: Reservoir parameters and durations presented as conservative single values.

Flow rate		**Reservoir parameter**
Pressure		235 bar
Permeability		125 mD
Duration		**Time frames**
Time for bridging to occur		8 days
Crew interventions	Topside	4 days
	Subsea	10 days
Relief well	Drilling time	40 days
	Intersection time	4 days
	Killing time	2 days

BlowFlow was run based on the single value input listed in Table 30. The results are presented in Table 31. The weighted mean topside flow rates have been calculated from the three possible flow paths, as a function of the flow path distribution of Table 9.

Table 31: Distributions for flow rate and duration where all inputs are presented as single values.

Flow rate (m^3/d)		Distribution
Topside	Subsea	
1 380	1 231	20.5 %
1 779	1 631	40.1 %
2 608	2 393	39.4 %
Duration (days)		**Distribution**
(topside crew interventions)	4	13.9 %
(bridging)	8	66.4 %
(subsea crew interventions)	10	7.8 %
(drilling of relief well)	62	11.9 %

If all these input values were represented by single values, the flow rate and duration curves would be considerably simplified. Excluding the uncertainty in input parameters will also exclude the uncertainty in the results. The flow rate presented in Table 31 is given by 3 columns; one for each penetration depth. The lowest flow rate corresponds to a 5 m reservoir penetration, etc. Thus, the flow rate distribution has been simplified to yield one flow rate for each scenario. The percentage distribution in Table 31 correspond to the penetration depth distribution of Table 20. There are some minor deviations in the percentages, as BlowFlow includes a limited number of simulations. The duration in Table 31 is presented by 4 columns; one for each killing mechanism.

These distributions have been subject to a major simplification, when excluding the uncertainty. In the base case they were represented by smooth curves composed of 98 to 100 columns. Since input values are chosen conservatively, the results will be correspondingly higher. The environmental risk resulting from the more conservative flow rates and durations is investigated in section 7.3.

6.6 Risk management

A high flow rate or a long duration will result in a greater oil spill volume, and hence a potential for greater consequences. As discussed in section 2.2, the risk is a function of both probability and consequences of a blowout. BlowFlow can be used to identify measures that can mitigate the consequences of a blowout. This is done through observing the effects of altering input parameters. Reservoir conditions cannot be changed at will, and is therefore unsuitable for identification of risk reducing measures. Parameters related to well design can also affect the flow rate. I.e. the well diameter will affect flow restrictions and the pressure profile of the well. As can be seen from Table 29, changes in well diameter will not have any major effect on flow rate. Thus, this will not be applied as a risk mitigating measure in this case.

The duration is a function of the different killing mechanisms. Since the duration is a probabilistic curve, changing one of the mechanisms will alter the curve. By evaluating the probability and time frame of each mechanism, risk mitigating measures can be identified. Coning and bridging are naturally occurring events that cannot be influenced by human activity. But capping and relief well drilling are active measures that can be affected by risk mitigating measures. Decreasing the time necessary to perform a killing operation can reduce the blowout duration. Increasing the probability of a killing mechanism to be successful can have a similar effect.

The maximum blowout duration is set by the maximum time it takes to drill a relief well. Thus, reducing relief well drilling time will reduce the maximum duration. A contingency plan is required before drilling is initiated. This is especially important due to the remote location. There are mainly two identified risk mitigating measures with respect to relief well drilling:

- Improved emergency preparedness by making sure relief well drilling rigs are available at a reasonable distance.
- Detailed planning and an increased number of training courses to prepare drilling experts for an emergency situation.

Keeping a relief well drilling rig available nearby will reduce the rig mobilization time significantly. It would be preferable to have two rigs available, as two relief wells should be drilled simultaneously. Initiating such a measure is assumed to yield a rig mobilization time of 6 days, compared to 14 for the base case. Detailed planning and an increased number of training courses is assumed to reduce the time to intersect the well, as it can increase the chance of successful intersection at the first attempt. The reduced intersection time is assumed to vary (uniformly) between 1 to 2 days. The drilling time is mostly a function of the rate of penetration. But through detailed planning it might be possible to choose a more appropriate well location and drilling path. Thus, it has been concluded that the drilling time can be reduced slightly. The new drilling time is presented as a triangular distribution (23 – 33 – 52 days). These new time frames are listed in Table 32 (pers. comm. Fjelde). The killing time is here kept constant.

In light of the Macondo accident, development of capping devices was initiated by several different companies. SWRP is currently working on developing subsea capping devices deployable around the world. When the development is completed, these devices are to be located at strategic locations. They will be available on the NCS for operators that have signed a contract with Oil Spill Response Limited (OSRL). For well cap deployment, it would be necessary to have access to a vessel or rig able to deploy the device. This vessel must include a crane with a high enough lifting capacity. Rough seas and harsh weather conditions can be an obstacle, as lifting cranes often have a maximum wave working height. Keeping both vessel and well cap available at a reasonable distance will improve emergency preparedness, and reduce the time necessary to deploy the device. Emergency equipment delivered by SWRP can also increase the chance of manually overruling the BOP. This can increase the chance of a short blowout duration (typically 2 days). For the time being, this has not been embedded in the BlowFlow analysis due to lack of quantitative data.

If a capping device is made available this could reduce the probability of a long-term blowout considerably. It can therefore be considered a major risk mitigating measure. For the purpose of investigating the effects of this risk reducing measure, it is assumed that this device becomes available prior to drilling of the case study well. However, the time to deploy this well cap is difficult to estimate, as these devices are not yet commissioned. It will depend on:

- The decision time of the operator
- Delivery time of equipment
- Deployment time
- Killing time

There are no appropriate killing mechanisms available for simulating this in BlowFlow, as the capping mechanism is used to simulate more traditional crew interventions (see section 6.3.3). Since this section only addresses implications on blowout duration, it is chosen to simulate a well cap through the coning mechanism. Coning will only affect flow rate over time in this study. Thus, coning will not have any implications on the duration. If the effect of coning is set to 100 %, it can resemble the same kind of mechanism as capping. However, this will not allow presenting different input for subsea and topside blowouts. This new capping technology involves only subsea equipment. Therefore, the effect of capping will be slightly overestimated.

Whether a blowout can be killed by a well cap will depend on condition at the release point. This will depend on the condition of the wellhead, whether the well is on fire, etc. According to Tormod Slåtsveen it is likely that a well cap can be deployed and kill the well within a time span of 10 to 18 days after blowout initiation (pers. comm. Slåtsveen). It is chosen to present the deploying time as a Gaussian distribution as shown in Table 32 and Fig. 29. However, this is assuming that the well is "capable". According to Tormod Slåtsveen, as many as 90 % of all subsea wells worldwide are considered to be "capable" (pers. comm. Slåtsveen). Since the well is assumed to have a 80 % probability of a subsea blowout, the success probability of the well cap is set to 72 %, to achieve the correct effect on the probabilistic duration curve.

Table 32: Altered duration input after implementation of risk reducing measures.

<table>
<tr><th>Killing mechanism</th><th>Probability of success</th><th colspan="7">Duration (days)</th></tr>
<tr><td rowspan="5">Relief well</td><td rowspan="5">100 %</td><td>Mobilization time</td><td colspan="6">6</td></tr>
<tr><td rowspan="2">Drilling time</td><td colspan="2">Minimum</td><td colspan="2">Most likely</td><td colspan="2">Maximum</td></tr>
<tr><td colspan="2">23</td><td colspan="2">33</td><td colspan="2">52</td></tr>
<tr><td rowspan="2">Intersection time</td><td colspan="3">Minimum</td><td colspan="3">Maximum</td></tr>
<tr><td colspan="3">1</td><td colspan="3">2</td></tr>
<tr><td rowspan="2">Well cap</td><td rowspan="2">72 %</td><td rowspan="2">Time to deploy</td><td colspan="3">Mean</td><td colspan="3">Standard deviation</td></tr>
<tr><td colspan="3">13</td><td colspan="3">1,3</td></tr>
</table>

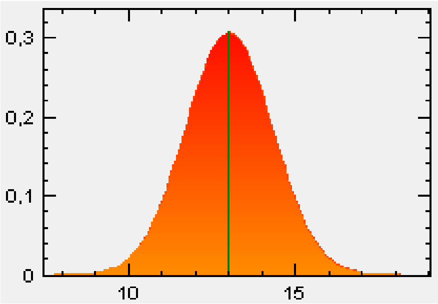

Figure 29: Gaussian distribution of well cap deployment time, in days versus probability.

BlowFlow was run with this new duration input, and the resulting probability curve is shown in Fig. 30, with associated distribution values in Table 33. The effects of risk mitigating measures related to relief well drilling and well cap deployment on the blowout duration are shown both separately and simultaneously in Table 33.

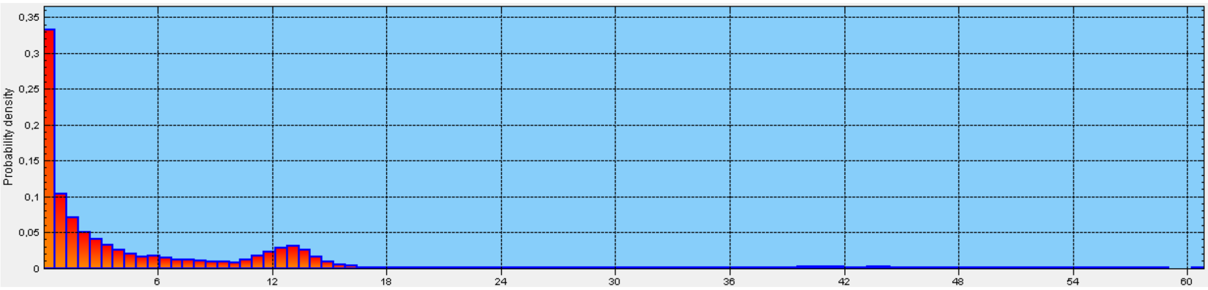

Figure 30: Probabilistic blowout duration distribution after implementation of risk reducing measures, in days.

Table 33: Distribution values for the duration after implementation of risk reducing measures.

Distribution values	Duration (days)			
	Base case	Capping	Relief well	Both
Minimum	0	0	0	0
P10	0	0	0	0
P50	2	2	2	2
P90	51	13	40	14
Maximum	72	69	62	61
Mean	**10**	**6**	**9**	**6**
St. dev.	19	11	15	9

Development of capping device applicable on the NCS will have a great implication on the blowout duration. It can be seen from Fig. 30 that the well cap shifts the curve to the left. Since capping has a high success probability, the residual probability that the blowout is killed by a relief well becomes much smaller. By comparing the columns “Capping” and “Relief well kill” of the Table 33, it can be seen that a well cap has a much greater implication on the duration, compared to the reduced drilling time of a relief well. The well cap reduces the duration distribution significantly. The mean duration is reduced from 10 to 6 days. But it will not influence the maximum duration, as this is still set by the maximum time to drill a relief well. The difference in the maximum duration with and without a well cap in the table is only a result of the limited number of simulations in BlowFlow.

6.7 Limitations

The BlowFlow tool is still under development and is subject to continuous improvement. Simulation errors are continuously being excluded. Through this case study, it was experienced some shortcomings. The latest version seems to have overcome most of these problems. However, there still seems to be some limitations where there is room for improvement.

There are several common flow paths that are not included in BlowFlow. Blowout data from the SINTEF database and Scandpower report indicate that there is a considerable amount of blowout data related to flow both outside the casing, especially for subsea blowouts. It would therefore be of benefit if the model included these flow paths in future upgrades. The flow path outside casing is planned to be included in the model through the next project phase (pers. comm. Ford). Lack of the outside casing flow path is assumed to have a conservative implication, since there is likely to be more flow resistance outside the casing than inside the relatively open annulus. For the present study, all subsea blowouts are assumed to flow through the annulus.

The BOP opening distribution is set independently of flow path. It will therefore be equal for flow through the drill string, annulus or open hole. According to historical data in Table 8, the BOP opening distribution will vary with different flow paths (Haugsvold, 2011). Therefore, this would be an advantage to include in future upgrades. For an outside casing blowout, the BOP might be unable to restrict the flow. However, it can be seen from Table 29 that a partially closed BOP will only have a negligible effect on flow rate.

Reservoir depletion is currently not part of the BlowFlow tool. Fig. 35 in appendix A indicates that 9 % of well incidents in the GoM OCS was stopped due to depletion. However, these data are based on incidents from 1960 – 1996. The distribution might look different if considering the last 16 years. In addition this article does not differentiate between blowout and well releases. Therefore, these data will not be weighted in this study. But it indicates that blowouts are sometimes stopped by natural depletion. In BlowFlow the reservoir pressure or hydrocarbon reserves are assumed constant. If the reservoir is drained, it can result in a decrease in flow rate. If the pressure is significantly reduced as a result of reservoir draining, the well might also seize to flow. The reservoir pressure can be maintained even though reserves diminish, due to a rise of the oil water contact. For the reservoir to be depleted during a blowout, the reservoir must either be small or have poor communication between zones.

Currently, capping is the only active measure included in BlowFlow (other than relief wells). BlowFlow does not differentiate between capping and other crew interventions. The capping mechanism in BlowFlow is often used to simulate more traditional crew interventions. The default settings are therefore based on statistics on crew interventions from the Scandpower report (Haugsvold, 2011). This may be less appropriate since the well cap technology under development is referred to as capping. This can lead to confusion. These new capping devices will also have a different duration than other crew interventions. Therefore, it might be beneficial to include a separate mechanism to simulate crew interventions. As there are currently not enough appropriate mechanisms to simulate both, capping had to be simulated through the coning mechanism. This will yield a slightly underestimated duration since the coning mechanism cannot be specified for subsea operations only.

The duration in BlowFlow is given by a single probabilistic curve. It might beneficial to calculate separate durations for topside and subsea releases. This is commonly done in ERAs today. The complexity of a crew intervention will depend on whether the operation is performed subsea or topside. Subsea interventions are more complex, and might be more time-consuming than a topside intervention. The complexity will also depend on the water depth. But as mentioned, a topside blowout can sometimes escalate into a subsea blowout. As a result it might be difficult to estimate the difference in duration for these different release points.

BlowFlow allows presenting input parameters as probability distributions of different forms. However, there are several input parameters that cannot be entered as distributions. Examples are skin factor (well damage) and oil and gas gravities. All these parameters are important for the flow rate of a potential blowout. Table 29 shows the changes in flow rate when altering these parameters. It would require a more complicated and time-consuming calculation process, but it should be possible to present these input values as distributions. This would allow expressing uncertainty on a more detailed level, rather than using conservative approximations.

7. OPERAto - Environmental risk

In this thesis, OPERAto is used to analyze the environmental risk related to drilling of an exploration well in the former disputed area. Based on result from BlowFAM and BlowFlow, it is used investigate the consequences of a blowout to selected valued ecosystem components (VECs). This yields an overall environmental risk, which is compared to given acceptance criteria. It is also possible to study the effect of risk reducing measures. Since data are not available to apply OPERAto on a well in the former disputed area, the model applied for the Norne field is chosen as an example. Several conditions have been fixed in this model, and cannot be altered to reflect field specific conditions for the former disputed area. Therefore the resulting environmental risk will not be field specific. This is further discussed in section 7.5.

To be able to reflect field specific conditions, the OPERAto worksheet would have to be re-developed. This would require performing new oil drift simulations. This is a time-consuming process which would require employing professionals. Environmental data would also have to be changed to reflect VECs present in the southeastern Barents Sea. It was therefore not practically possible to construct a new worksheet for this case study.

Even though the resulting environmental risk will be incorrect for a well in the former disputed area, the tool can still be used to perform a methodological study. The worksheet applied for the Norne field can indicate the functionality and purpose of this methodology. The objective is to determine the compatibility between the different computer modeling tools used in this thesis. This involves assessing how the results from BlowFAM and BlowFlow fit into OPERAto. Assessing blowout probability, flow rate and duration is the main focus in this thesis. This chapter will examine the tools ability to reflect uncertainty in input parameters, such as flow rate and duration. The main focus is to investigate the ability of OPERAto to allow the uncertainty to propagate, and be reflected in the final results.

The effects of neglecting uncertainty and taking a more conservative approach on the environmental risk will be observed in section 7.3. The ability of OPERAto to work as a risk management tool is investigated in section 7.4. This is done by observing the implications of different risk reducing measures on the environmental risk. OPERAto can reflect how changes in input parameters influence the overall environmental risk. The reflection of uncertainty through the conservative approach and through the implementation of risk reducing measures will be assessed.

7.1 Input

As explained earlier, certain data in OPERAto are fixed and cannot be changed. Values that can be changed are related to activity level, blowout probability and probability distributions for release point, flow rate and duration. OPERAto will use results from BlowFAM as input on blowout probability, while BlowFlow results are used to determine distributions for flow rate and duration.

7.1.1 Blowout probability

The blowout probability used in OPERAto is collected from the BlowFAM results. This is considered to yield the most well specific results, of the two approaches assessed chapter 5. BlowFAM yields an adjusted blowout probability of 7.58×10^{-5}.

7.1.2 Flow rate

7 flow rates are given in OPERAto. These cannot be altered, as they were used as basis when the oil drift simulations were performed. However, the probability for each of these can be changed. The results from BlowFlow are used as basis when determining the flow rate distribution between these 7 rates. The flow rate will vary with different scenarios. OPERAto can present different probability distributions for topside and subsea releases. The release point distribution used here is the one derived in section 5.1.5, with a 20 % chance of a topside release and 80 % chance of a subsea release. This is seen as the most appropriate since the BlowFAM release point distribution has not been adjusted according to recent statistics. OPERAto does not however, differentiate between different flow paths.

BlowFlow presents the flow rate as a probability curve, as seen in Fig. 25. It consists of 98 columns, where each represents a flow rate with an associated probability. To be able to use this as input in OPERAto, it has to be converted to a discrete distribution. The 7 given flow rates for Norne are listed in column 1 of Table 34 below. Each of these rates must be given a specific probability. However, the maximum flow rate for Norne is set to 12 000 m^3/d, while the maximum flow rate of the case study is 3 377 m^3/d. The flow rate is therefore distributed between the 5 lowest rates (200 – 5 000 m^3/d).

To find a probability for each of these 5 rates, the density curve from BlowFlow is re-distributed. This is done by dividing each of the 98 flow rates in BlowFlow, between the 2 closest rates of these 5. The 98 flow rates with associated probabilities are read from the curve, and entered into an excel sheet. This had to be done for each of the 4 possible scenarios; subsea annulus, topside drill string, topside annulus and topside open hole. The flow rates that are lower than the smallest flow rate of OPERAto is considered to contribute 100 % to the lowest rate. For flow rates in between 2 values, the following formula was used:

$$Q_1 \times x + Q_2 \times (1 - x) = Q_{BlowFlow}$$

Where:

Q_1 = The closest lower flow rate in OPERAto, m^3/d

Q_2 = The closest higher flow rate in OPERAto, m^3/d

x = Probability contribution to the lower flow rate

$Q_{BlowFlow}$ = Flow rate of a given column in BlowFlow, m^3/d

The equation is solved with respect to x, to determine the distribution between the lower and higher flow rate. This includes a high number of calculations, as it had to be performed for all 98 flow rates, for 4 different scenarios. Thus, only one example will be included here. For a subsea blowout, one of the 98 columns has a flow rate of 726 m^3/d, with an associated probability of 2.6 %. The closest lower flow rate in OPERAto is 600 m^3/d, and the higher flow rate 1 200 m^3/d. This is entered in the above formula, which is solved with respect to x:

$$600x + 1200(1-x) = 726 \quad \rightarrow \quad x = 0.790 \quad \rightarrow \quad 1-x = 0.210$$

A distribution with a 79 % probability for flow rate 600 m^3/d and 21 % for flow rate and 1 200 m^3/d, correspond to the flow rate of 726 m^3/d. These two probabilities are multiplied with the flow rate's associated probability in BlowFlow.

$$P_{200} = x \times P_{BlowFlow} = 0.790 \times 0.027 = 0.021$$

$$P_{600} = (1-x) \times P_{BlowFlow} = 0.210 \times 0.027 = 0.06$$

This means that this specific column yields a percentage contribution of 2.1 % to the lower flow rate of 600 m^3/d, and 0.6 % to the higher flow rate of 1 200 m^3/d.

The probability for each rate can then be found by adding up the percentage contributions from each of the 98 flow rates. This must be done for both topside and subsea rates. As OPERAto does not differentiate between flow paths, the weighted mean flow between possible topside flow paths is applied. The flow path distribution in Table 9 is used as basis to calculate the weighted mean percentage contribution to each of the 5 applicable flow rates. As annulus is considered to be the only possible flow path for a subsea blowout, the distribution is found directly from the sum of each contribution. The total percentage contributions for both topside and subsea flow rates are listed in Table 34, and shown graphically in Fig. 31.

Table 34: Discrete probability distribution of flow rate for subsea and topside blowouts used in the OPERAto base case analysis.

Flow rate (m^3/d)	Distribution	
	Topside	Subsea
200	1.6 %	4.0 %
600	22.6 %	28.2 %
1 200	51.2 %	50.2 %
2 300	24.1 %	17.5 %
5 000	0.5 %	0.1 %
8 000	0.0 %	0.0 %
12 000	0.0 %	0.0 %

These distributions result in an overall mean flow rate of 1 216 m^3/d. This is close to the mean flow rate of 1 200 m^3/d given by BlowFlow. However, this new flow rate distribution is a major simplification compared to the flow rate curve in Fig. 25. Thus, the level of detail is compromised, and this limits the ability to reflect uncertainty.

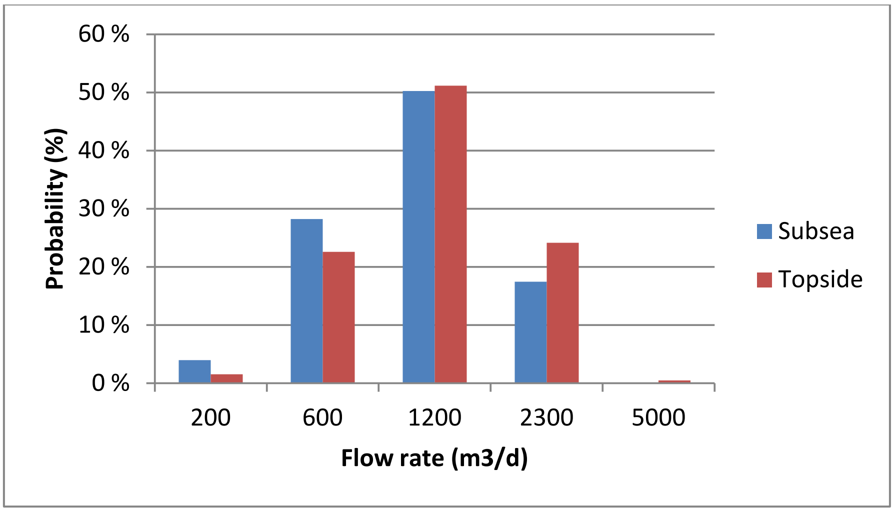

Figure 31: Bar chart of blowout rate distribution for both subsea and topside used in OPERAto.

7.1.3 Duration

The 6 durations available in OPERAto are listed in Table 35. BlowFlow results are used as basis when determining the distribution between the given duration. The BlowFlow duration curve in Fig. 26, had to be converted to a discrete distribution, to fit into OPERAto. The durations and associated probabilities are read from the curve in Fig. 26, and entered in an excel sheet. The percentage contribution to each of the 6 given durations is calculated in the same manner as explained above. The results are presented in Table 35, and graphically in Fig. 32. This gives a weighted mean duration of 10 days, which is the same as the mean duration from BlowFlow. However, this re-distribution also implies a major simplification that limits the ability to allow the uncertainty to propagate.

Table 35: Discrete probability distribution of blowout duration used in the OPERAto base case analysis.

Duration (days)	Distribution
0.5	44.0 %
2.0	18.5 %
5.0	14.7 %
14.0	6.7 %
28.0	9.6 %
84.0	6.5 %

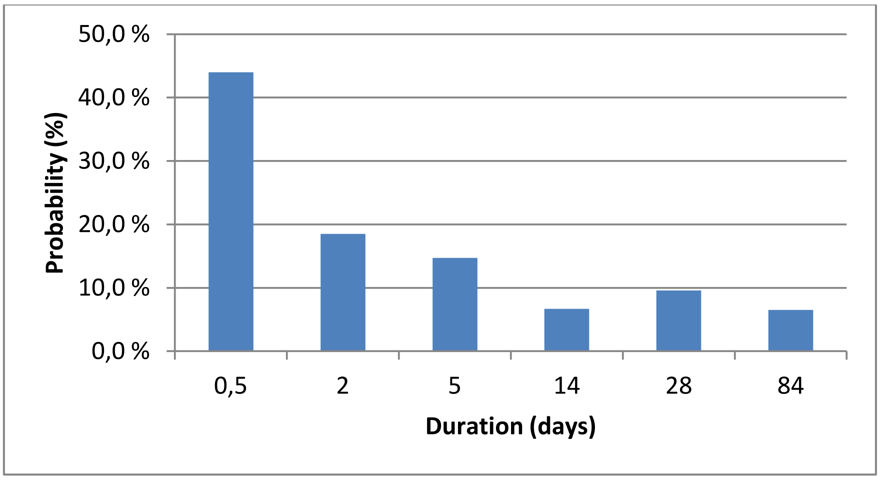

Figure 32: Histogram of blowout duration distributions used in OPERAto.

7.2 Results

This section presents the environmental risk resulting from the base case input on blowout probability, flow rate and duration. It is important to emphasize that the results presented through this chapter does not represent the actual risk of the case study. The objective is to investigate the compatibility between the computer models, and how the uncertainty is reflected through OPERAto.

Fig. 33 shows the risk contribution from drilling of an exploration well, in different seasons for open sea VECs. It includes both topside and subsea release for each season. The risk is presented as damage frequency per season, for each of 4 severity levels; minor, moderate, considerable and severe. These results can help to evaluate in which season the drilling activity poses the highest risk. If one season has a much higher risk, it can be concluded that drilling should not be performed in this season. Fig. 33 shows that drilling in the autumn poses a slightly higher risk than in other seasons. But this is not necessarily relevant for our case study, seeing that other resources are present at different times of the year in the former disputed area, compared to the Norne field. For coastal and beach VECs, this chart looks quite different. But due to the long distance to shore from the well of the case study, environmental risk in open sea areas will receive most focus. It is chosen to investigate the environmental risk associated with drilling of an exploration well in the autumn in the further study.

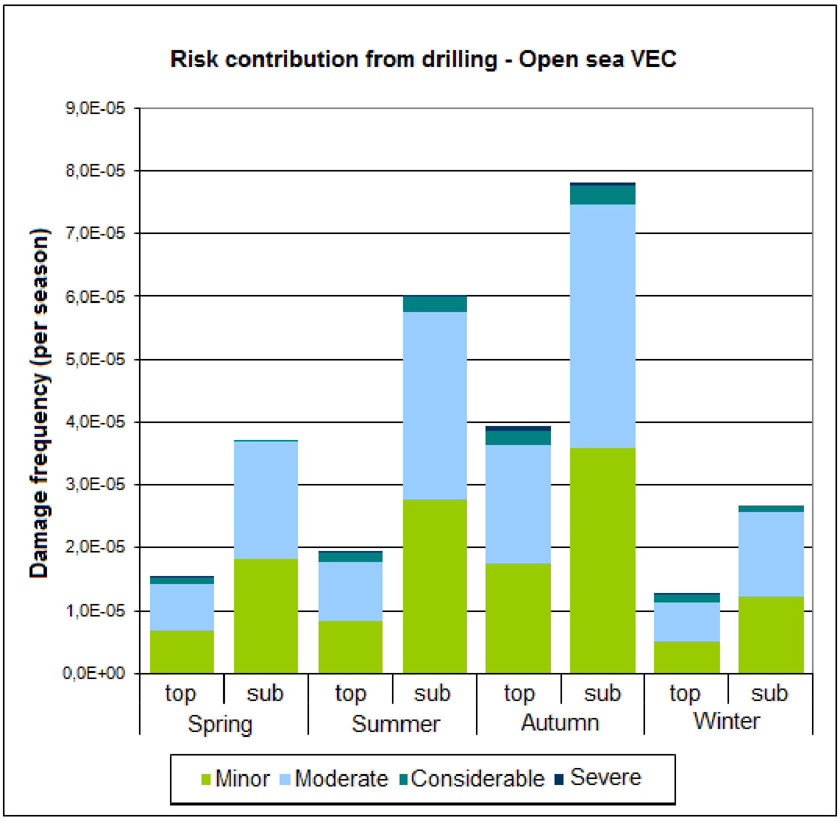

Figure 33: Risk contribution from drilling of an exploration well in different seasons estimated by OPERAto.

Fig. 34 presents the environmental risk to VECs at the open sea as a percentage of the acceptance criteria. It shows the risk for each of the 4 severity levels, and for each type of operation. Since drilling is the only operation that is performed in this study, the only risk is related to drilling. The percentages presented in this diagram are commonly used as decision support, to determine whether an activity poses an acceptable risk or not. The environmental risk presented in Fig. 34 is considered low, as it constitutes less than 3 % of the acceptance criteria.

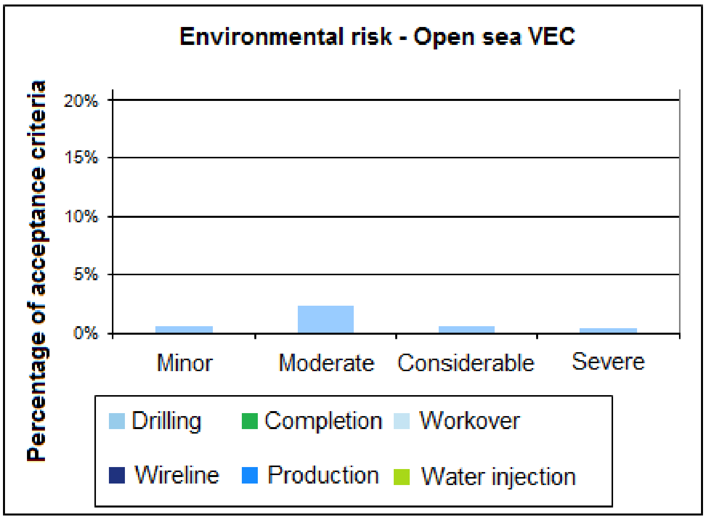

Figure 34: Environmental risk as percentage of acceptance criteria, for 4 severity levels estimated by OPERAto.

Table 36 lists the environmental risk to VECs related to drilling for the 3 different habitats: Open sea, coastal and beach. As for Fig. 34, the associated environmental risk low. The highest risk is related to a moderately serious incident for open sea VECs. The environmental risk here constitutes 2.3 % of the defined acceptance criteria. This moderately serious incident involves an incident with a restitution time of 1 to 3 years. Table 36 also presents the environmental risk *index*. This index is a function of the risk contribution from each of the 4 severity levels. The calculation of this index is shown in section 3.3.3. As the environmental risk index is an absolute value, it is a good means of comparing the risk between different cases or fields. The table shows that a blowout poses a greater risk for VECs in the open sea, compared to in coastal and beach habitats. The reason is the low probability of oil beaching.

Table 36: Environmental risk as a percentage of acceptance criteria, for 3 different habitats.

Severity level	Environmental risk as % of acceptance criteria		
	For open sea VECs	For coastal VECs	For beach VECs
Minor	0.5 %	0.1 %	0.1 %
Moderate	2.3 %	0.3 %	0.1 %
Considerable	0.5 %	0.2 %	0.0 %
Severe	0.4 %	0.1 %	0.0 %
Environmental risk index	0.59	0.12	0.01

The uncertainty that has been allowed to propagate is reflected in the distribution between the 4 severity levels. A higher or lower level of uncertainty can result in a change in the severity level distribution. I.e. a higher flow rate or a longer duration would yield a greater risk contribution in the severe categories. Since the level of detail is considerably compromised in this example, the severity level distribution might not be completely accurate. Some alternative ways of presenting input is investigated in the next section.

7.3 Sensitivity study

This section will investigate the implications of a conservative case on the environmental risk to open sea VECs. In this conservative case the uncertainty has been neglected in BlowFlow, and more conservative data has been chosen as input. If the methodology does not incorporate uncertainty in the analysis, or if there is limited data available, it is common to use conservative approximations. In section 6.5, relatively conservative single values have been chosen for reservoir conditions and duration input in BlowFlow. This has resulted in highly simplified distributions for flow rate and duration. This section will investigate the environmental risk associated with such an approach. The simplified distributions given in Table 31 must be re-distributed to be applicable in OPERAto. This is done in the same manner as above. The new distribution is listed in the Table 37.

Table 37: New distribution for more conservative values without uncertainty, as input to alternative OPERAto analysis.

Flow rate (m^3/d)	Distribution	
	Topside	Subsea
1 200	43.8 %	35.7 %
2 300	54.8 %	59.7 %
5 000	1.4 %	4.6 %
Duration (days)	**Distribution**	
2.0	5.0 %	
5.0	57.0 %	
14.0	26.0 %	
28.0	4.7 %	
84.0	7.3 %	

The re-distribution of the simplified BlowFlow data does not involve any major simplification. Thus, the simplified conservative case of BlowFlow corresponds better to the level of detail incorporated in OPERAto. The data from Table 37 is applied as input in OPERAto through an alternative case. The resulting environmental risk is shown in the column "Conservative case" of Table 38. The risk is here compared to the risk of the base case.

Table 38: Environmental risk to open sea VEC for a simplified and conservative case, estimated by OPERAto.

Severity level	Environmental risk as % of acceptance criteria	
	Base case	Conservative case
Minor	0.5 %	0.8 %
Moderate	2.3 %	3.4 %
Considerable	0.5 %	0.7 %
Severe	0.4 %	0.4 %
Environmental risk index	0.59	0.65

Table 38 yields an environmental risk which is considerably higher than for the base case. The environmental risk index has increase from 0.59 to 0.65, which corresponds to an increase of 10 %. The conservative case generally increases the risk in all severity levels, especially in the lower categories. When uncertainty is neglected, the severity level is shifted. This is a result of the much lower level of detail.

7.4 Risk management

It is important to incorporate risk management into an ERA. OPERAto determines whether the risk is acceptable or not, by comparing the environmental risk against acceptance criteria. If the risk is too high, risk reducing measures should be considered. OPERAto can investigate the effects of different risk reducing measures by observing the relative effect on the environmental risk. Risk reduction and risk management has been incorporated in this case study regardless of the resulting environmental risk. This is to investigate the ability of the applied methodology to provide a basis for choosing and implementing risk reducing measures. The level of detail and reflection of uncertainty through the risk management process is also investigated.

Possible risk reducing measures have been identified both through BlowFAM and BlowFlow. These measures were identified and implemented in section 5.2.7 and 6.6, respectively. The blowout risk is defined as a function of both probability and consequences of a blowout. Risk reducing measures identified in BlowFAM are preventive measures, which will reduce the probability of a blowout occurring. Risk reducing measures identified in BlowFlow will reduce the duration of a blowout, and can therefore mitigate the consequences. This section will investigate the effect of both preventive and risk mitigating measures on the environmental risk.

If the risk reducing measures identified through BlowFAM are implemented, this will result in a blowout probability of 5.22×10^{-5}. This is a 31 % reduction compared to the base case probability. The reduced probability can be entered directly in OPERAto, without any simplification. The environmental effect of this reduced probability alone can be seen in the column "BlowFAM" of Table 40.

If the risk mitigating measures identified by BlowFlow are implemented, this will result in a duration distribution as shown in Fig. 30. The weighted mean duration is here 6 days, compared to the base case duration of 10 days. The reduced duration curve must be simplified and re-distributed to be applicable as OPERAto input. This is done in the same manner as above. The simplified duration distribution entered in OPERAto is listed in Table 39. This simplification will, as in the previous sections, result in a compromised level of detail.

Table 39: Durations distribution after implementation of risk reducing measures from BlowFlow.

Duration (days)	Distribution
0.5	43.0 %
2.0	18.4 %
5.0	16.3 %
14.0	17.4 %
28.0	3.8 %
84.0	1.1 %

The environmental effect of implementing the risk mitigating measures identified in BlowFlow is shown in the column "BlowFlow" of Table 40. The column "Both" present the environmental risk resulting from implementing risk reducing measures identified in both BlowFAM and BlowFlow simultaneously.

Table 40: Environmental risk to open sea VEC after implementing all risk reducing measures.

Severity level	Environmental risk as% of acceptance criteria			
	Base case	BlowFAM	BlowFlow	Both
Minor	0.5 %	0.4 %	0.6 %	0.4 %
Moderate	2.3 %	1.6 %	2.3 %	1.6 %
Considerable	0.5 %	0.4 %	0.3 %	0.2 %
Severe	0.4 %	0.3 %	0.2 %	0.1 %
Environmental risk index	0.59	0.41	0.35	0.24

Both preventive and consequence mitigating measures are seen to have a considerable effect on the environmental risk. The 31 % reduction in blowout probability has lead to corresponding 31 % reduction in the environmental risk index. The relative reduction in each severity level is relatively similar. One could say that the absolute risk is reduced. The relative reduction in the environmental risk as assumed to present an accurate result, as there is no simplification in the implementation preventive measures.

The reduced blowout duration will also reduce the environmental risk index, and thus the overall risk. But the reduced duration will changed the distribution between the different severity levels. This is a result of the reduced probability of a long-term blowout. The risk of severe and considerable damage has been considerably reduced, relative to the lower severity levels. The risk in the lower severity levels are kept relatively constant. The accuracy of these measures is questionable, due to the considerable simplification in the duration distribution. However, it is assumed to yield a good indication of the relative risk reduction.

7.5 Limitations

The OPERAto worksheet applied in this thesis was originally constructed for the Norne field. This has resulted in several limitations. The oil type used in OPERAto is the Norne oil. The case study oil type resembles the Goliat oil from Kobbe, which has a slightly different density and composition (pers. comm. Aas). The oil type will be important to oil persistence and dispersion characteristics, and therefore also to the oil drift simulations. As a result it will yield inaccurate results in relation to the area of influence, and the extent of damage to VECs.

The Norne field is located approximately 150 km off the coast, in the northern part of the Norwegian Sea. The case study well, on the other hand, is located approximately 300 km off the coast of Finnmark in the southeastern Barents Sea. Since Norne has an entirely different location, the wind and current systems will be completely different. The prevailing wind and current conditions used in the oil drift simulations are from the northern Norwegian Sea. As a result, the oil drift simulations used in OPERAto will not be representative for the case study. The influence area, and also the risk level, will therefore be incorrect for the area in question.

OPERAto is based on input on environmental resources present in the northern part of the Norwegian Sea. Seabirds are considered the most important VECs here, and are therefore used as the study object. However, the type and number of seabirds present in the southeastern Barents Sea may be different. OPERAto presents the risk as a percentage of these acceptance criteria. Seeing that neither the area of influence nor the number of seabirds killed is relevant for the case study well, the resulting environmental risk will be incorrect. The area of influence from Norne stretches beyond the Lofoten area. This area is highly productive and might contain a lot of valuable natural resources. Therefore, the environmental risk might be considerably overestimated, and not numerically relevant for the southeastern Barents Sea. This is emphasized in order to avoid any possible misunderstandings regarding environmental risk in the former disputed area, based on calculations made in this study.

The given flow rates and durations cannot be altered, since these have been used when performing the oil drift simulation. As a result, these values may not be the most representative for this case study. The wells at the Norne field are considered to be far more productive than the well of the case study. I.e. the maximum flow rate at Norne is set to 12 000 m^3/d, while the maximum flow rate given by BlowFlow 3 377 m^3/d. Flow rate 6 and 7 from Table 3 are much higher than the BlowFlow values. The flow rate distribution must therefore be divided between the 5 lowest rates in OPERAto. This limits the models ability to reflect uncertainty. Flow rate 1 is a bit higher than the minimum flow rate from BlowFlow. This will yield results that are a bit conservative, as everything below 200 m^3/d is included in this rate.

The flow rate and duration curves in Fig. 25 and 26 from BlowFlow must be considerable simplified to be applied as input in OPERAto. By comparing these curves with the diagrams given in Fig. 31 and 32, it can be seen that the level of detail has been severely compromised. This limits the ability to reflect uncertainty on a detailed level, as was proposed in Fig. 1. OPERAto does not differentiate between different flow paths. Thus, the weighted mean flow rate from different flow paths must be calculated for BlowFlow results to be applicable in OPERAto. This will also compromises the level of detail. However, it is less common to include different flow rates for different flow paths in ERAs today (Aspholm et al., 2007).

8. Discussion

The Barents Sea is an area of increasing interest from oil and gas operators. The oil production on the NCS is declining, thus the industry must move further north to explore new prospects. The areas off Lofoten and the Barents Sea are rich in environmental resources like fish, seabirds, sea mammals and special coastal areas. Whether these areas should be opened for exploration and year-round petroleum activity have been subject to political debate for many years. In 2004 it was agreed to open the Barents Sea, with the exception of some areas (Hasle et al., 2009).

There are several factors related to physical conditions that makes the Barents Sea more challenging for offshore petroleum activity, compared to further south (Allen, 2011, Sutyagin et al., 2007):

- Proximity of the sea ice
- Rough seas and harsh weather
- Relatively frequent formations of polar lows
- Risk of sea spray and atmospheric icing
- Reduced visibility
- Long dark winters
- Remoteness and limited infrastructure

These factors might complicate design, oil spill preparedness, rescue operations and attempts to kill a blowout. As the industry moves north-eastwards the offshore developments become even more challenging due remoteness and lack of infra structure. As a result of these factors, the consequences of a accident may be more serious in the Arctic region compared to warmer areas. Enhanced system integrity and operational certainty will be of increasing importance (Allen, 2011).

The Barents Sea contains important spawning areas for several specimens of fish, such as capelin. Cod and herring spawning areas are typically located further south. During spawning season large portions of a specific specie is gathered in a smaller area. Eggs and larvae are much more susceptible to damage from external stress factors than adult fish. Unlike adult fish, they are normally not able to escape polluted areas. Therefore, most spawning areas are closed for drilling activities, either year-round or certain times of the year. However, in case of a large-scale oil spill in areas nearby, it is still possible that these areas can be exposed (Hjermann et al., 2007). Seabirds are among the most vulnerable species, because they cannot easily avoid an oil spill. If a larger area is polluted it could kill a large portion of a seabird population. Seabirds are considered to be the most valued ecosystem component for the Norne field in OPERAto. Thus, seabirds will be considered for determination of the environmental risk in this study. What type of species this includes will not be discussed in further detail.

After agreement of the maritime delimitations between Norway and Russia, it is likely that the formed disputed area will be opened for petroleum exploration in the near future. Whether any recoverable oil resources will be found in the southeastern Barents Sea is uncertain. Geologic history indicates that hydrocarbon resources might have leaked out due to high erosion and uplift through several ice ages. Seismic surveys indicate that the remaining resources are most likely gas. However, it might be possible that an oil reservoir could be trapped beneath a salt structure (pers. comm. Høy).

The risk of a blowout in this area has been determined, assuming that an oil reservoir was discovered at a depth of 2 000 m. This involves determining blowout probability, flow rate and duration. Due to variations in geological conditions, well configuration, location and organizational factors, the risk will vary from well to well. Therefore, this case study has attempted to determine these parameters in a well specific manner. Two different approaches have been used to determine the blowout probability. The results and limitations of these approaches will be further discussed in section 8.1. BlowFlow was used to determine flow rate and duration of a potential blowout in a probabilistic manner. This will be further discussed in section 8.2.

OPERAto yields the environmental risk as a function of blowout probability, flow rate and duration. However, the resulting risk is not correct with respect to the well of the case study. The OPERAto worksheet is based on oil drift simulations, oil type and environmental data for the Norne field. OPERAto is only used to perform a methodological study. The compatibility between the different models, and the ability of OPERAto to reflect uncertainty is discussed in section 8.3. The sensitivity of the environmental risk to different risk mitigating measures will also be investigated, to assess the tools' applicability in risk management.

8.1 Blowout probability

There is currently a wide range of different approaches used to determine blowout probability for a specific well or operation. Many of these approaches are based on statistics, such as historical blowout data from the SINTEF database and Scandpower report (Haugsvold, 2011, Holand, 2010). Statistical probabilities are often adjusted to reflect recent technological and operational improvements, as shown in Fig. 14. To reflect recent improvements and well specific conditions it is necessary to consider formation properties, well configuration, equipment, procedures and management. There are also several models developed to determine the blowout probability in a more mechanistic, well specific manner. In this thesis two different approaches to determine blowout probability will be evaluated. A brief comparison is included at the end of this chapter.

8.1.1 Statistical approach

The first method is a statistical approach that adjusts the basic blowout probability by consideration of recent trends in kick statistics. For a hypothetical case, as in this case study, it is difficult to assess factors like BOP reliability, procedures and technology quantitatively. This would also be a time-consuming process, and due to the limitations of this thesis these factors have not be given any credit here. Scandpower states that the basic blowout probability is 1.23×10^{-4} for an exploratory oil well (Haugsvold, 2011). However, this basic probability presents an industry average, and does not reflect recent trends in statistics.

The kick frequency has been considerably reduced during the past decades. According to Fig. 15, the average kick frequency has been reduced by 40 % in more recent time. The kick frequency varies from year to year, and using the mean value as basis could lead to an underestimation of the blowout risk. It is also taken into consideration that the kick frequency in 2010 was relatively high. There is a relatively high uncertainty related to the annual kick frequency. Thus, a relatively conservative reduction of 20 % is used as an approximation. The kick frequency is assumed to be directly correlated to the blowout frequency, as a kick is often the initiating event of a blowout, Thus, this 20 % reduction is directly applied to the basic blowout probability. This results in a blowout probability of 9.84×10^{-4}.

The modified blowout probability does not involve a considerable risk reduction, compared to other fields on the NCS (Brandt et al., 2010). But compared to the ERA for the Goliat exploration well, where the historical blowout probability has been applied directly, this approach involves a reduced risk. If an evaluation of BOP reliability, equipment, human errors and organizational factors were conducted, the risk could potentially have been reduced even further. If the assessment was performed related to a specific operator or organization, some of these improvements could have been given credit.

Release point and flow path distribution have also been determined based on the SINTEF database and Scandpower report. For a subsea exploration well, a subsea release point is seen as the most probable. Common flow paths for a subsea release are through annulus and outside casing (Holand, 2010, Haugsvold, 2011). As flow on the outside of the casing is not included in BlowFlow, it will be disregarded in the flow path distribution. Annulus is therefore seen as the only possible flow path for a subsea release. For a topside release the possible flow paths are through the drill string, annulus or open hole. The Scandpower data in Table 8 indicate that annulus flow is the more probable flow path for a topside release (Haugsvold, 2011).

This statistical blowout probability assessment cannot be considered as mechanistic, as it is purely based on statistics and recent trends. It does not incorporate well specific conditions in the assessment. This is not a good basis for evaluating whether the risk is acceptable or not (Arild et al., 2008). It does not provide any basis for making risk management decisions, as it is not applicable for identifying risk reducing measures. Neither well specific conditions nor uncertainty in different parameters have been included in this assessment.

8.1.2 BlowFAM

The second approach used in this thesis is Scandpower's computer model BlowFAM. This has been developed to adjust statistic blowout probabilities through a consideration of well specific conditions such as well configuration, operating procedures, planning/organization and formation properties. It determines a basic blowout probability for a given activity, based on statistics from the SINTEF database (Holand, 2010). For deep drilling of an oil containing exploration, BlowFAM yields a basic blowout probability of 2.1×10^{-4}. This does not correspond to the basic blowout probability given by the Scandpower report, which is 1.23×10^{-4}. This deviation is caused by the lack of updated statistics in the computer model. It is based on statistics from 2003. The tool is now subject to modification. But for the time being, the basic blowout probability must be corrected by a manual adjustment.

The basic blowout probability is adjusted through several steps. In the first part of BlowFAM, relevant blowout causes are adjusted through an evaluation of well configuration and formation properties. An adjustment factor of 0.803 has resulted from the given input. This adjustment is applied to the basic blowout probability, and has resulted in a risk reduction of almost 20 %. This means that well and reservoir characteristics yield a blowout probability lower than that of an average well. Seeing that a reservoir in the present case study is considered to have a low productivity, this seems reasonable. The risk reduction might be higher if less conservative input had been applied. As Table 15 shows, a wider drilling window would reduce the risk considerably. But as there is limited knowledge of pressure profiles in the area, the uncertainty related to such parameters is high.

In the second part of BlowFAM, 300 risk elements related to frame conditions, management, equipment and procedures are evaluated to determine a second adjustment factor. There is limited knowledge with respect to many of the risk elements. It is for example difficult to say anything about the risk related to organizational factors for a hypothetical situation. Ideally, a BlowFAM analysis should be performed through close cooperation with the operator and drilling professionals. The risk elements considered to contribute to a reduced or increased risk in this case study are mostly related to physical conditions at the location and recent technological and operational improvements. Through the evaluation of risk elements an adjustment factor of 0.767 has resulted. This involves a 23 % reduction of the blowout probability. If more knowledge is available, and operators and drilling professionals are included in the assessment, it might be possible to reduce the risk further.

The final blowout probability, after applying each adjustment factor, becomes 7.58×10^{-5}. This involves an overall reduction of 38 %, compared to the basic blowout probability. This is considered to be a moderate risk reduction (Brandt et al., 2010).

BlowFAM also presents release points, flow paths and BOP opening distribution. This is shown in Table 14 and Fig. 16. These data resemble the historical data given in Table 8. However, there are deviations between the given distributions. This is because the statistics in BlowFAM have not been updated since 2003. Table 8 reflects historical data up to 2008. BlowFAM is currently being updated with respect to recent statistics.

BlowFAM allows identifying risk reducing measures directly, by evaluating different risk elements in the second part of BlowFAM. A number of these elements has the possibility to reduce the probability of a blowout occurring. Such measures are therefore referred to as preventive. Through the evaluation of risk contributing elements, weak areas can be detected (Dervo and Blom-Jensen, 2004). Several possible preventive measures are identified and listed in appendix E.3. If these are implemented, it will lead to a 31 % reduction in the blowout probability. The blowout probability after this risk reduction becomes 5.22×10^{-5}. Consequently, it can be concluded that BlowFAM can serve as a tool to aid decision making, through a risk management process.

Whether all these risk reducing measures are economical, or even necessary in reality must be assessed according to the ALARP principle. If the risk is more than half of the environmental risk acceptance criteria, risk reduction should be considered. The cost of each measure should not be disproportionate to the benefit gained. Considering the risk elements in a cost-benefit manner will help identify which elements yield the highest risk reduction per cost. Risk reducing measures should be implemented until it is no longer economically feasible. Thus, it might not be necessary to implement all the risk elements identified. It might not be necessary to implement any at all, as it will depend on the resulting risk level and the cost of the different risk elements.

BlowFAM is supposed to be updated each year with respect to historical blowout data, according to changes in the annual SINTEF report. However, this has not been done since 2003. Thus, the basic probabilities embedded in the model do not correspond to the most recent blowout data. A manual adjustment has been implemented to adjust the basic blowout probability to reflect today's risk level. The lack of recent modifications is not only reflected in the basic blowout probability. The historical cause distribution shown in table 12 will continuously change as incidents are added or removed from the database. This is also the case for release point, flow path and BOP opening distributions. The distributions presented by BlowFlow are all based on data from 2003.

The list of risk elements should also be reviewed regularly. These elements have not been thoroughly updated after development of the model. As a result, many of the elements may not be relevant at all. There have been significant improvements in technology since 1995, and other types of equipment may be used. This list should therefore be re-evaluated, to add new risk elements and remove those that are no longer applicable.

BlowFAM does not allow reflecting uncertainty in input parameters. Parameters such as drilling window and pore pressure are associated with a high uncertainty. The drilling window is especially crucial to the blowout risk. Since the model does not allow any uncertainty in input parameters, the blowout probability becomes a result of an assumption; in this case that the drilling window is 0.8 SG. Allowing input parameters in BlowFAM to be presented as probability distributions would be difficult, as this would require an entirely different calculating engine. If uncertainty in input parameters were allowed, the final probability would also have to be presented as probability distributions. As of today, the blowout probability is commonly presented as a single value. This is also seen in Fig. 1. A sensitivity study was conducted in section 5.2.6 to enlighten the effects of varying input parameters. This can enlighten which parameters contribute most to an increased risk. This might initiate a discussion about the reasoning behind crucial parameters. By gaining more detailed knowledge form e.g. seismic surveys, the uncertainty could be reduced. This could eliminate the need for conservative assumptions.

8.1.3 Comparison

There is a deviation between the results of the two different blowout probability assessment approaches. The statistical approach yields a blowout probability of 9.84×10^{-5}, while BlowFAM yields a probability of 7.58×10^{-5}. Even though both models are based on statistics, they consider very different aspects. BlowFAM has several advantages compared to the more traditional statistical approach. If the computer model was updated with respect to both recent statistics and the risk elements included, it could work as a flexible tool able to predict blowout risk in a well specific manner. BlowFAM also eases the risk management process. Through the risk element evaluation it can help detect weak areas. However, this model requires an understanding of risk elements, as well as competence in drilling and completion, to obtain detailed input data and accurate results. It is therefore preferable to involve experts, operators and/or contractors in the blowout probability assessment (Dervo and Blom-Jensen, 2004).

The more traditional statistical approach does not require this level of competence, as it is based on publications. Basic blowout probabilities collected from statistics present an industry average. Consequently, it does not consider the specific properties of the well in question. The uniqueness of each drilling operation becomes difficult to incorporate into the analysis. Moreover, it does not consider typical risk contributors such as pressure margins, procedures and equipment. Possible risk reducing measures will relate to these factors. If they are not reflected in the analysis it is difficult to identify and evaluate possible risk reducing measures. Thus, it is not a good basis for making sound risk management decision. But the results are relatively easy to communicate (Arild et al., 2008).

Seeing that BlowFAM is considered to yield more well specific results than the more statistical approach, this blowout probability was used further in the study. The blowout probability of the case study is therefore set to 7.58×10^{-5}. But due to the lack of updated release point, flow path and BOP opening distributions in BlowFAM, it was concluded to use the scenario distributions from the 1st approach. The distributions from the 1st approach are summarized in Table 9 of section 5.1.5.

None of these models can be defined as mechanistically based approaches, as they are both based on statistics rather than calculations based on driving mechanisms. BlowFAM also involves a high number of assessment factors. Each element is evaluated by the user. How much each element is weighted becomes a result of the opinion of the analyst. A positive or negative score given for each element becomes an assumption, rather than a number collected from seismic data or the drilling program. This results in a subjective and not necessarily a scientific basis. Neither of them allow to reflect any uncertainty. Both input and results are given as single values. Due to these factors the two blowout probability assessment models deviate from the mechanistic approach of BlowFlow.

KickRisk is another tool used to evaluate blowout risk and possible scenarios in a more mechanistic manner. This tool is a predecessor of BlowFlow, and these tools are often used in combination. A KickRisk simulation is time-consuming, and relies on expert judgment when assessing input parameters. This tool have therefore not been employed in this thesis.

8.2 BlowFlow - Blowout scenarios

As of today, there is no common standardized methodology among oil companies for calculation of blowout rate and duration. MIRA states that a sufficient number of probable flow rates and duration should be established, for use in an environmental risk assessment (Brude, 2007). Today's practice varies greatly from company to company. The reasoning behind a selected methodology might be difficult to access, and the calculations hard to track. As a result, it might be hard to compare flow rates and durations from field to field (Arild et al., 2008). OLF has produces guidelines on how to determine flow rate and duration, for use in an ERA, in a probabilistic manner (Nilsen et al., 2004).

Traditionally, flow rates and duration have often been determined based on statistical or conservative values. A purely statistical approach calculates the blowout rate and duration based on historical data. This limits the ability to incorporate the uniqueness of each well in the assessment. If a more conservative approach is taken, this would yield worst-case scenarios. A major disadvantage of this approach is that the results may be unrealistic. Risk reducing measures will then be over-dimensioned. Neither of these approaches handles uncertainty properly. Consequently, they do not provide the framework necessary for making sound risk management decisions (Arild et al., 2008).

BlowFlow is a computer tool developed by IRIS to determine blowout rate and duration in a probabilistic and well specific manner. It is a mechanistic approach that simulates a high number of scenarios, by enabling risk based quantification. The simulations are based on a wide range of input parameters related to reservoir conditions, well design, killing mechanisms and scenario distributions. The uncertainty in input parameters is allowed to propagate and be reflected in the end result. It allows the user to assess uncertainty on a detailed level, by understanding how the uncertainty of each parameter propagates to the overall uncertainty picture. It is necessary to communicate these probabilistic elements through the different steps of the analysis.

BlowFlow can aid the risk management process by providing a common platform for communication between geologists, HSE-engineers and drilling engineers. This involves identifying risk reducing measures, by observing the effects of varying input parameters. BlowFlow can also help to dimension oil spill preparedness, as it predicts possible flow rates and durations.

8.2.1 Flow rate

In this study focus has been on oil flow rate. BlowFlow presents flow rate for both oil and gas, for each single scenario. However, gas is considered to be less harmful with respect to VECs, as it typically evaporates relatively quickly. When performing oil drift simulations, these are typically based on oil flow rate. Thus, oil flow rate has been in focus in this study.

The flow rate varies for different types of scenarios such as release point, flow path and penetration depth. This is a result of the flow restrictions and pressure profiles of the well. A flow rate curve is presented for each combination of release point and flow path. Fig. 25 presents the probabilistic flow rate distribution, which is the weighted mean between the different scenarios. Each flow rate curve is presented as a probability distribution. The flow rate ranges from a minimum of 114 m^3/d to a maximum of 3 377 m^3/d. The flow rate can be any value within this range. The flow rates can be estimated for a single scenario, or as the weighted mean value from different scenarios. This allows representing uncertainty on a detailed level. If more detailed data on reservoir conditions were collected, this might indicate that the flow rate lies in the upper range of the distribution.

The flow rate is a function of wide range of reservoir parameters, well design and scenario distributions. Which input parameters that contribute most to an increased flow rate was investigated through a sensitivity study in section 6.5. This can help establish a discussion between analyst and decision makers, in terms of how to reduce the impact of a blowout. The reasoning behind the assessed figures is evaluated. This gives a good background for discussing the benefits of for example a revised will design or for collecting more subsurface information (Arild et al., 2008). Table 29 indicates that permeability, pressure, skin factor (well damage) and gravity are important parameters. Permeability and pressure are both parameters with high associated uncertainties. Their uncertainty is strongly reflected in the probabilistic flow rate curve in Fig. 25. This can easily be seen from Table 30, where the uncertainty in these parameters has been neglected.

BlowFlow allows presenting input parameters as probability distributions of different forms. However, there are certain input parameters that cannot be entered as distributions. Examples are skin factor (well damage) and oil and gas gravities. Table 29 demonstrates that these parameters are important for the flow rate of a potential blowout. Consequently, it might be beneficial to present these input values as distributions. Otherwise, conservative approximations might have to be chosen. Due to a high uncertainty, the skin factor is assumed relatively conservative. This will also have a conservative implication on the flow rate. Presenting this parameter as a distribution, would allow expressing uncertainty on a more detailed level, rather than using conservative approximations.

In BlowFlow the flow rate distribution decreases rapidly with time. One curve is given for each day, for each scenario. This is a reflection of the different killing mechanisms. In reality, the flow rate is constant if none of the killing mechanisms have occurred. Therefore, the flow rate at day 0 has been used as basis in this case study. Using the flow rate at day 0 will however excluded the effects of coning. But if using the flow rate at day 1, this would include a reduced flow as a result of bridging and crew interventions. This would be unrealistic, as the flow rate is not really reduced by these mechanisms. They will only increase the probability that the blowout has been killed, and that the flow rate is 0 m^3/d.

According to historical data, a significant amount of subsea incidents are related to blowouts outside the casing (Holand, 2010, Haugsvold, 2011). At present, this flow path is not included in BlowFlow. But in light of the Macondo accident, there has been an increased focus on outside casing blowouts. Thus, this flow path is planned to be included in the model in near future. However, it might be difficult to predict flow patterns and friction on the outside of the casing. It is considered reasonable to assume that the outside casing flow is small, compared to flow through the relatively open annulus. Excluding flow outside the casing, in favor of annulus flow, will therefore result in a higher overall flow rate. However, it is desirable to achieve as realistic results as possible. A higher degree of conservatism results in a lower overall accuracy.

The overall mean flow rate resulting from the BlowFlow assessment is 1 200 m^3/d. This is quite low compared to other fields on the NCS, and further west in the Barents Sea. This is in spite of the above mentioned limitations regarding the skin factor and outside casing flow. The flow rates estimated in the ERA for the Goliat exploration well provides an example. The Kobbe reservoir has a weighted mean flow rate of 3 288 m^3/d (Aspholm et al., 2007). This is considerably higher than for well of this case study. The low flow rates are caused by the poor reservoir conditions in the area. According to Tore Høy, an oil reservoir at the given depth is likely to have a poor productivity (pers. comm. Høy). It might be possible to find fields with higher productivity in this new area. It might also prove to be merely a gas province.

Flow rates in the southeastern Barents Sea have been predicted by the NPD. These have currently not been published, but according to Tore Høy they are as follows (pers. comm. Høy):

- P95: 239 m^3/d
- P50: 717 m^3/d
- P05: 1592 m^3/d

The flow rates predicted by the NPD are lower compared to those given by BlowFlow. This is presumably due to a difference in certain input parameters applied in the analysis. In this case study, the oil gravity was based on the gravity of the Kobbe reservoir of the Goliat field (800 kg/m^3). This was chosen based on recommendations from Tore Høy. The NPD have applied an oil gravity of 857 kg/m^3 in their calculations (pers. comm. Høy). As can be seen from Table 29, a density of 850 kg/m^3 in BlowFlow would yield a mean flow rate of 703 m^3/d. This correspond better the flow rates predicted by the NPD.

8.2.2 Duration

The duration is a function of the different killing mechanisms, and the release point distribution. It will depend on the time of occurrence, and the probability of a mechanism to successfully kill the well. There are several different killing mechanisms considered in the base case. Some are naturally occurring, while others are active measures initiated by the crew. The duration curve is presented as a probability distribution that reflects the uncertainty of the different killing mechanisms (see Fig. 26). This allows a detailed reflection of uncertainty, and a high level of detail.

The duration in BlowFlow is presented as a single probabilistic curve. This means that it is given independently of release point, flow path, penetration depth and BOP opening. However, BlowFlow differentiates between the duration of crew interventions for topside and subsea releases. The duration is currently found by weighting the mean duration of different release points. It might be desirable to present a probabilistic duration curve for each release point. A subsea intervention is typically more complex, and might be more time-consuming than a topside intervention. Subsea blowouts typically have a longer duration than topside blowouts. In ERAs today, it is common to present one duration for each release point. This is also embedded in OPERAto. If BlowFlow presented one curve for each release point, a higher level of detail could be maintained through the analysis.

Currently, capping is the only active measure included in BlowFlow. Seeing that well caps are not available at the NCS today, they are not included as a killing mechanism in the base case of this study. The capping mechanism in BlowFlow is commonly used to apply more traditional types of crew interventions. The default settings of this mechanism are based on statistics on crew interventions from the Scandpower report (Haugsvold, 2011). This may lead to confusion since the well cap technology is under development. These new capping devices will also have a different duration than the traditional crew interventions. Therefore, it might be beneficial to include a separate mechanism to simulate crew interventions in the future.

The duration found from BlowFlow in this case study seems reasonable, compared to other fields on the NCS. The mean duration estimated for the exploration well at the Goliat field was 9 days (Aspholm et al., 2007). This corresponds well to the duration of 10 days found in this case study. The location of the well of this case study is further from shore. Due to remoteness, a slightly longer duration seems reasonable.

8.2.3 Uncertainty

Through BlowFlow, the flow rates and duration can be determined on a detailed level, with a high reflection of uncertainty. Uncertainty in input parameters has here been allowed to propagate and be reflected in the probabilistic curves of the final results. By allowing input to be presented as probability distributions, one can avoid over-estimating the risk. If only single values were used as input, this would typically include more conservative estimations. Conservative assumptions are commonly used to account for uncertainty. An example is shown in section 6.5, where uncertain parameters have been set to conservative single values. This has resulted in much simplified and more conservative results. The major drawback of such an approach is that the scenarios generated may be unrealistic, thus over-dimensioning risk reducing measures. This conservative approach does not provide the framework necessary for making sound risk management decisions (Arild et al., 2008).

By including a high degree of uncertainty in the analysis, as in BlowFlow, detailed and realistic results can be achieved. This uncertainty should be allowed to propagate in the ERA, to obtain the same level of detail in the following steps and in the resulting environmental risk. Fig. 1 presents such an assessment, where the environmental risk and recovery time is presented as probability distributions. To utilize the full potential of BlowFlow to perform detailed assessments, the level of detail must be maintained throughout the ERA.

8.2.4 Risk management

BlowFlow can be applied as a decision support tool, to assess which input parameters contribute most to an increased risk. Decision-makers can be informed about potential outcomes, driving forces and mechanisms affecting the blowout risk. The analysis is detailed with respect to which factors that contributes to a high flow rate and duration. As it helps improve communication between geologists, HSE-engineers and drilling engineers, it provides a common platform for risk informed decision making (Arild et al., 2008).

Risk mitigating measures have been identified in section 6.6. The implications of a risk mitigating measures can be investigated by observing the effects of altering input parameters. As reservoir parameters cannot be changed at will, these cannot be used to identify such measures. Risk mitigating measures implemented in this case study are related to killing mechanisms and blowout duration. The identified measures involve minimizing the time necessary drill a relief well, and investigating implications of the new capping technology.

There are currently no capping devices available on the NCS. But in light of the Macondo accident, development of several different capping devices has been initiated by the SWRP. During 2013 these are to be placed at strategic location. The aim of this development is to reduce the environmental consequences of a subsea blowout, by reducing the possibility of a long-term blowout. This will enhance the industry’s ability to respond quickly and efficiently to a subsea well control incident. Compared to a relief well, a capping device has a considerably shorter time of deployment (Lewis, 2012). As a well cap may have great implications on the blowout duration, it can be considered as a major risk mitigating measure. Opening of the former disputed area for petroleum exploration and production will be up for governmental discussion in the spring 2013 at the earliest. It is therefore not unlikely that a well cap will be available before start of drilling.

The effect of implementing risk mitigating measures related to relief well drilling and well cap development was investigated in section 6.6. Table 33 shows that the blowout duration was considerably reduced. This can also be observed by comparing the duration curves of Fig. 26 and 30. The mean duration has been reduced from 10 to 6 days, after implementation of these risk mitigating measures. The maximum duration is reduced from 72 days to 62 days, as a result of the reduced relief well killing time.

Development of a capping device applicable on the NCS would no doubt have a considerably reducing effect on the probability distribution of the blowout duration. It can be seen from Fig. 30 that the well cap shifts the curve to the left, by creating a new “peak”. Since capping has a high success probability (72 %), the residual probability that the blowout is killed by a relief well becomes much smaller. By comparing the columns “Capping” and “Relief well” of Table 33, it can be seen that well cap development has had a much greater implication on the duration distribution, compared to the reduced killing time of a relief well. The latter has limited effect because of the small residual probability that the well is killed by a relief well. A well cap will not influence the maximum duration, as this is still governed by the maximum time to drill a relief well.

Through an evaluation of risk mitigating measures, it has been concluded that BlowFlow can be applied as a risk management tool to identify of such measures. It is considered a good platform for risk informed decision making. Due to the high level of detail it yields realistic scenarios, which is a good basis for making risk management decisions.

8.3 OPERAto - Environmental risk

OPERAto is an excel worksheet model developed by DNV to determine the environmental risk related to a blowout. The risk is calculated based on the number of harmed VECs, and their recovery time. As there is currently no OPERAto model applicable for the former disputed area, the worksheet run for the Norne field has been applied in this case study. Even though the environmental risk resulting from the assessment does not present a realistic risk picture for the well of the case study, OPERAto can still be used to assess the functionality and purpose of this methodology. The objective of this case study is to investigate the compatibility of the different models, and the propagation of uncertainty through the different steps of an ERA. Both flow rate and duration are associated with a considerable amount of uncertainty. The ability of OPERAto to reflect uncertainty in input parameters is here the main focus.

OPERAto serves as a tool to aid the risk management process. It has the ability to reflect changes in blowout probability, flow rate and duration. The relative effect of risk reducing measures on the environmental risk has been observed. However, the relative risk might not provide an accurate and correct picture as it is based on data from another area.

8.3.1 Environmental risk

The environmental risk in OPERAto is given as a percentage of acceptance criteria for 4 different severity levels. These numbers can be used to determine whether the risk level is acceptable or not. It will also help determine whether risk reduction is necessary. The severity of an incident will depend on the flow rate and duration of a potential blowout. According to Table 36, the environmental risk resulting from this case study is quite low compared to the acceptance criteria. It is also low compared to other wells on the NCS (Aspholm et al., 2007). This is mainly a result of relatively low flow rates. It is important to emphasize that these results are not necessarily correct with respect to the well of the present case study in the eastern Barents Sea. As the Norne field is located quite close to the productive area around Lofoten, the environmental risk might be even lower for the case study. To determine this with certainty, oil drift simulations and collection of regional data on environmental resources would be necessary.

OPERAto can be used to asses in which season an operation poses the highest and lowest risk. If drilling in one season poses a higher risk, it can be concluded not to perform the drilling operation in that specific season. Fig. 33 shows the risk contribution from drilling of a well in each of the 4 seasons. For this case study, drilling in the autumn yields the highest overall risk contribution. As the environmental resources, wind and currents vary from field to field, the risk contributions might be different if well specific data were included.

The location of an exploration well will be of great importance to the environmental consequences. It will be decisive for the distance to shore or ice edge, the abundance of environmental resources, and the prevailing direction of oil drift. The location will also be of importance for oil spill response capability, and to some degree the rate of natural weathering. If the blowout point is close to the coast or the ice edge the consequences can be much more severe than in the open ocean. Both coastal and ice edge environments are generally considered more sensitive to oil spills. Due to oil penetration in landmasses, accumulation under ice sheets etc., the natural oil degradation is significantly prolonged and pollution may persist much longer, compared to in a pelagic environment. The oil can persist in the ice or landmasses for many years, and this may have a negative effect on biological growth and marine organisms (Blumer and Sass, 1972, Doerffer, 1992).

OPERAto can also indicate in which habitat the risk is highest. Table 36 shows that the highest risk contribution in the present study was related to open sea VECs, rather than coastal or beach VECs. This is mostly because beaching is considered less likely for an accidental oil spill at Norne. The Norne field is located approximately 150 km off shore, while the present case study well is located approximately 300 km off the coast. This is considered to be quite far off shore. However, the prevailing direction of oil drift in the areas is crucial to whether an oil spill will reach shore or not. Whether an oil spill from the well of this case study is likely to reach the ice edge should also be assessed. Oil drift simulations have been performed by DNV through OS3D, at a nearby location. The results are presented in a Master's thesis written by Sigve Evensønn Rasmussen. The results indicate that it is less likely that the oil reaches shore or the ice edge, even at moderate to high flow rates (Rasmussen, 2011).

8.3.2 Risk management

The environmental risk is here a function of both the probability and consequences of a blowout. If an area is particularly vulnerable, this could yield more severe consequences compared to a less vulnerable area. To achieve the same level of risk for a vulnerable area, risk reducing measures might have to be implemented. But whether the environment in the Arctic region is more vulnerable than further south on the NCS is not included in the scope of this study. In principle, the risk can be reduced by reducing the probability and/or mitigating the consequences of a potential accident.

It is important to incorporate risk management into an ERA. OPERAto can be used to determine whether the risk related to a specific activity is acceptable or not, by comparing the environmental risk against acceptance criteria. If the risk is too high, risk reducing measures should be considered. Possible risk reducing measures have been investigated here, regardless of the resulting risk level. This was done to evaluate the ability of the applied methodology to provide a basis for choosing and implementing risk reducing measures. Possible risk reducing measures was identified both through BlowFAM and BlowFlow. OPERAto investigated the effects of these risk reducing measures, by observing the relative effect on the environmental risk.

Both preventive and consequence mitigating measures are seen to have a considerable impact on the risk level in Table 40. BlowFAM identified risk reducing measures able to prevent a blowout from occurring in the first place. Such measures are therefore be referred to as preventive. A reduced blowout probability led to a corresponding reduction in the environmental risk index. The relative risk reduction in each severity level was relatively similar. One could say that the absolute risk level was reduced. The relative reduction in the environmental risk is assumed to be representative, as there is no data lost when implementing these preventive measures. The level of detail is presumably maintained throughout the evaluation.

The risk reducing measures identified in BlowFlow are categorized as consequence mitigating measures. These are related to reducing the duration of a blowout. The shorter blowout duration has led to a reduced environmental risk index, and thus a reduced overall risk. It has also led to a change in the distribution between the different severity levels. This is caused by the much lower probability of a long-term blowout. The risk of severe and considerable damage has been considerably reduced, relative to the lower severity levels. The reduced probabilistic duration had to be simplified and re-distributed to be applicable as input in OPERAto. Consequently, the environmental effects of these measures may not be completely accurate. The accuracy may also be compromised by the fact that the worksheet is not based on well specific conditions. However, OPERAto is assumed to yield a good indication of the relative effects of these consequence mitigating measures on the environmental risk.

By combining these tools in a risk management process, it provides a common platform to make sound risk management decisions. Decision-makers can be informed about potential outcomes, driving forces and mechanisms affecting the blowout risk. The analysis is detailed with respect to which factors that contribute to a high risk level. By pointing out major risk contributors, the most appropriate measures can be chosen. Together these tool can aid the risk management process by evaluating whether risks should be avoided, transferred, mitigated or accepted (Arild et al., 2008). It provides a good means of assessing the effects of different risk reducing measures. It can also be used as basis to plan emergency preparedness and oil spill response (Roald, 2000).

The preventive measures identified through BlowFAM were reflected directly an accurately in the environmental risk of OPERAto. This is due to the good compatibility between these models. However, the level of detail is compromised when changes in blowout duration propagates through the analysis, to the environmental risk. OPERAto does not allow maintaining the high level of detail in the duration distribution. Thus, the detailed reflection of uncertainty related to the identified consequence mitigating measures was not reflected in the final results. If the OPERAto worksheet allowed reflecting uncertainty on a more detailed level, risk management could be performed with improved precision.

8.3.3 Level of detail / uncertainty

In this study, blowout probability, flow rate and duration were the main variables. Blowout probability is commonly given as a single value in ERAs today. This is also the form in which it is entered in OPERAto. As both blowout probability assessment methods applied in this thesis present a single value for blowout probability, there is a good compatibility between these methods and OPERAto. Due to the good compatibility between input and output, no data is lost in this step. However, there is uncertainty related to certain BlowFAM input. As it does not allow presenting any input as distributions, this uncertainty is eliminated from the assessment. If a model was developed to present blowout probability in a probabilistic manner, this would also require changes in the following steps of an ERA, and consequently in OPERAto.

As both flow rate and duration involves a high uncertainty, this uncertainty should ideally be allowed to propagate throughout the assessment, as illustrated in Fig. 1. Each of the steps following the calculations of flow rate and duration should ideally be presented as probability distributions. This includes presenting possible outcomes in environmental recovery time as probability distributions (Arild et al., 2008).

In the OPERAto worksheet applied in this case study, there are 7 possible flow rates and 6 possible durations. BlowFlow on the other hand, presents these parameters as density curves of 98 - 100 columns (Fig. 25 and 26). Consequently, these distributions had to be considerably simplified to be applicable as input in OPERAto. In addition, the flow rates given in OPERAto were not the most suitable for the case study, considering that the worksheet was tailored for the Norne field. Only the 5 lowest flow rates were applicable. As a result of these factors, the level of detail that BlowFlow allowed to work with was severely compromised. This limited the possibility to reflect the uncertainty related to these parameters in the resulting environmental risk. Consequently, the environmental risk and recovery times will not present the same accuracy as the one presented by BlowFlow. It is not possible to assess how the compromised level of detail affected the overall risk.

If running a new OPERAto worksheet for this specific well, it would be possible to tailor the flow rates and durations. As only 5 of 7 flow rates in the current worksheet were applicable, this would improve the tool's ability to reflect uncertainty. Unfortunately, it is not possible to investigate the effects of applying more appropriate flow rates on the environmental risk, as the flow rates are fixed in OPERAto. As an example, mean values for flow rate (1 200 m^3/d) and duration (10 days) from BlowFlow can be entered in OPERAto, rather than distributions. This yields an environmental risk index of 0.46, compared to 0.59 for the base case. This demonstrates that a major simplification can result in an incorrect risk. It can therefore be concluded that a higher level of detail maintained throughout the analysis can affect the risk considerably.

A conservative case was presented in section 7.3, were the uncertainty related to reservoir conditions and killing mechanisms was neglected. Conservative single values were applied as input to BlowFlow, rather than probability distribution. Table 38 shows that it led to an increase in the environmental risk index (from 0.59 to 0.64). Through this simplified conservative case the BlowFlow results could be reflected with better accuracy in OPERAto. This is to be expected, as the uncertainty has been eliminated. The ability of BlowFlow to present detailed results with a high reflection of uncertainty has not been utilized. The major drawback of such an approach is that the scenarios generated may be unrealistic, thus over-dimensioning risk reducing measures. It does not provide the framework necessary for making sound risk management decisions (Arild et al., 2008). For the risk to be as accurate as possible, it is important to maintain a high level of detail. This will lead to a better reflection of uncertainty, and provide a better basis for decisions related to risk management.

By modeling with different blowout probabilities, flow rates and durations in section 7.4, the following could be concluded: The blowout probability affects the overall risk level. Flow rate and duration will affect the overall risk, but also influence the distribution between the different levels of severity. It is the flow rate and duration that determines the area of influence, and consequently the severity of a blowout. A high flow rate with a long duration would yield a high risk contribution in the severe category. A shorter duration will reduce the probability of a long-term blowout, and thus reduce the risk of having an incident with severe consequences. This demonstrates that the uncertainty in OPERAto is reflected in the severity level distribution, and that this can vary with different input values from BlowFlow. It means that the tools can communicate variable blowout probabilities, flow rates and durations and maintain a certain level of detail through the analysis. This can be utilized to achieve a better reflection of uncertainty.

From the above, it seems clear that if OPERAto was developed based on a higher number of flow rates and durations, this would allow the model to reflect uncertainty in greater detail. This is assumingly easy to include in the calculations of the OPERAto worksheet. However, this would require performing a high number of oil drift simulations. Whether this is necessary would have to be considered for each specific case. If the risk is in an ALARP area, it might be helpful to use such an approach. If the risk is close to or above the risk acceptance criteria, a more detailed analysis can be crucial with respect to the final decisions. It is clear that there is still a lot of work to be done before a unified methodology exists, that can allow maintaining a high level of detail throughout an ERA.

9. Conclusion

The objective of this thesis was to determine the blowout risk in a probabilistic manner, where the uncertainty related to different parameters was emphasized. This was done by applying several different computer modeling tools. It was attempted to determine blowout probability, flow rate and duration in a well specific manner, to reflect the uniqueness of the well in question. The environmental risk was determined through a methodological study, to investigate the ability of the applied tools to communicate probabilistic elements throughout an environmental risk assessment. It is important to maintain a high level of detail to provide a good basis for making sound risk management decisions.

Two approaches were applied for determining blowout probability. Neither of these methods can be defined as mechanistic as they both are based on statistics, rather than on calculations based on driving mechanisms. BlowFAM also consists of a high number of assessment factors. These are evaluated and given credit according to the opinion of the user, which gives it a subjective and not necessarily genuine scientific basis. However, BlowFAM has several advantages compared to more traditional statistical approach. This model is considered to yield the most well specific result of the two approaches, and was therefore chosen as the most appropriate for this case study. BlowFAM yielded a blowout probability of 7.58×10^{-5}. The key to moving toward a more mechanistic approach is modeling conditions that govern whether a blowout is likely to occur or not, e.g. through a detailed kick analysis.

The blowout probability is commonly given as a single value in ERAs today, as provided by both of the above probability assessment methods. This is also the form in which the blowout probability is entered in OPERAto. Consequently, it can be concluded that there is a good compatibility between both blowout probability assessment approaches and OPERAto. Due to the good compatibility between input and output, no data is lost in this step. However, there is uncertainty related to certain BlowFAM input. As it does not allow presenting any input as distributions, this uncertainty is eliminated from the assessment.

Through BlowFlow, the blowout rates and duration can be determined on a detailed level, with a high reflection of uncertainty. Uncertainty in input parameters has been allowed to propagate and be reflected in the probabilistic curves of the final results. Since the results are calculated based on well driving mechanisms it can be considered a mechanistic approach. The uncertainty should ideally be allowed to propagate throughout an ERA, as illustrated in Fig. 1. Each of the steps following the calculations of flow rate and duration should be presented as probability distributions, to obtain the same level of detail in the resulting environmental risk. This includes presenting possible outcomes in environmental recovery time as probability distributions.

The flow rates given by BlowFlow for this case study are quite low compared to typical wells on the NCS. The overall mean flow rate from BlowFlow is 1 200 m^3/d. This is a result of the poor reservoir conditions in the southeastern Barents Sea. The duration resulting from BlowFlow seems reasonable compared to estimated durations from ERAs in nearby areas. The mean duration from the case study is 10 days.

OPERAto allows entering the flow rate and duration as simplified probability distributions divided between 6 and 7 values, respectively. This distribution is significantly simplified, compared to the probabilistic curves given by BlowFlow. The level of detail is therefore compromised. This limits the ability to reflect the level of uncertainty that BlowFlow allows to work with.

Through the methods applied it can be concluded that it was possible to determine blowout probability, flow rate and duration in a well specific manner. However, it was not possible to determine the environmental risk in a relevant manner, within the frames of this thesis. Still it was possible to study how these tools communicated, and how the uncertainty was allowed to propagate through the environmental risk assessment.

Another objective of this thesis was to investigate if, and how these tools could be operated in combination to improve the overall environmental risk assessment through risk informed decision making. The ability of these tools to aid the risk management process was investigated. OPERAto can be used to determine whether the risk is acceptable or not, and whether risk reduction is necessary. This model can also observe the environmental effects of implementing different risk reducing measures. Both preventive and consequence mitigating measures have proven able to reduce the environmental risk considerably.

By combining these tools in a risk management process, it provides a common platform to make sound risk management decisions. Decision-makers can be informed about potential outcomes, driving forces and mechanisms affecting the blowout risk. The analysis is detailed with respect to which factors that contribute to a high risk level. Together these tools can aid the risk management process by evaluating whether risks should be avoided, transferred, mitigated or accepted. However, certain limitation emerge when the consequence mitigating measures identified by BlowFlow propagates through the assessment. Due to the limited compatibility between BlowFlow and OPERAto, the level of detail is compromised. A high level of detail is important to provide a good basis for making sound risk management decisions. If OPERAto allowed reflecting uncertainty on a more detailed level, risk management could be performed with improved precision. Accordingly, one could avoid over- or under-estimating risk reducing measures.

The main objective of this thesis was to investigate how a combined use of these tools handles uncertainty throughout the analysis. By modeling with different blowout probabilities, flow rates and durations, the following could be concluded: A reduced blowout probability led to a corresponding reduction in the overall environmental risk. Flow rate and duration affected the overall environmental risk, but also the distribution between the different levels of severity. It is the flow rate and duration that determines the area of influence, and consequently the severity of a blowout. This demonstrates that the uncertainty in OPERAto is reflected in the severity level distribution. This means that the tools can communicate variable blowout probabilities, flow rates and durations and maintain a certain level of detail through the analysis. This can be utilized to achieve a better reflection of uncertainty. For the risks in the different severity level to be as accurate as possible, it is important to maintain a high level of detail.

It seems clear that if OPERAto was developed based on a higher number of flow rates and durations, this would allow the model to reflect uncertainty in greater detail. This is assumingly easy to include in the calculations of the OPERAto worksheet. However, this would require performing a high number of oil drift simulations. Whether this is necessary would have to be considered for each specific case. If the risk is close to or above the risk acceptance criteria, a more detailed analysis can be crucial with respect to the final decisions.

As to the questions asked, the conclusion can be summarized as follows: The methodology investigated allows handling the uncertainty of some elements by probability distributions. These are allowed to propagate to some degree through the analysis, and be reflected in the severity levels of the environmental risk assessment tool. It was also demonstrated that this can be important and make a difference as to which decisions should be taken to reduce the risk. However, it is also clear that the potential for improvement is large. There is still much modeling work to be done before a unified methodology exists. A unified ERA methodology should allow the inclusion of both preventive and consequence mitigating measures, where endpoints are in targeted environmental resources, and where uncertainties can be included in a probabilistic manner.

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Appendix A – Killing mechanisms

The blowout duration depends on how long it takes to kill the uncontrolled blowing well. Some common killing mechanisms are discussed in this appendix. It includes both passive and active measures. Fig. 35 presents an overview of the most common killing methods applied in the GoM from 1960 to 1996. However, the distribution might look different if considering the last 16 years. Also, this article does not differentiate between blowouts and well releases (Skalle et al., 1999).

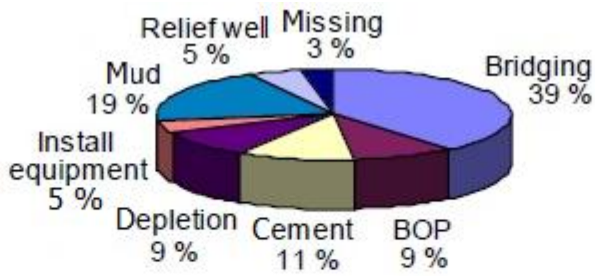


Figure 35: Kill methods applied to the GoM OCS from 1960 to 1996 (Skalle et al., 1999).

A.1 Natural depletion

There is a theoretical possibility that the reservoir can deplete naturally. This means that the pressure is reduced as a result of the reservoir emptying out. This might be the case for very small reservoirs or reservoirs with poor communication between zones. When the reservoir pressure approaches the pressure of the bottomhole pressure, the well will cease to flow. However, for most wells it would take a long time before the blowout rate is even reduced due to depletion. Normally, the reservoir pressure is maintained even though reserves diminish, due to a rise of the oil water contact.

A.2 Coning

Coning is a type of natural cessation that refers to the event were the water level beneath the oil may rise, or the gas level above the oil may sink, in proximity of the well. As the oil flows out of the well at high flow rates, the reservoir area close to the well will be drained, and therefore experience a reduced pressure. Due to the lower pressure close to the well, the gas-oil contact and the oil-water contact will be drawn towards the well opening. The smaller the distance to the well, the larger the drawdown pressure will be. As the oil-water contact rises (or gas-oil contact sinks) in proximity of the well, it forms a conical shape as is shown in Fig. 36. The extent to which coning takes place will depend on the drawdown pressure, the vertical and horizontal permeability (K_v/K_r), as well as the vertical distance (z) from the perforations to the gas-oil or oil-water contact (Wheatley, 1985).

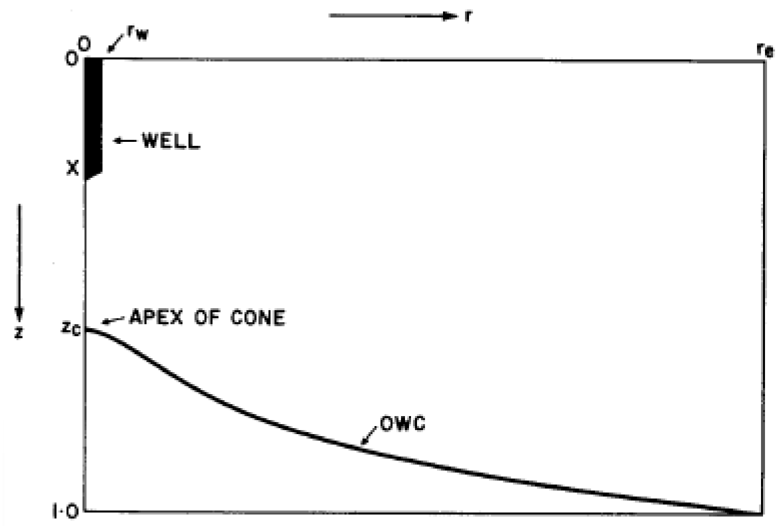


Figure 36: Schematic of oil/water coning system, where radial and vertical distance from the well is shown on the x- and y-axis, respectively (Wheatley, 1985).

To avoid coning in a producing well, it is crucial not to perforate the well too close to the gas-oil contact or oil-water contact. If the gas or water breaks through, it will lead to a high gas or water production, and an equivalent reduction in oil production. This will reduce revenue and lead to fill up of production and processing equipment. For mature fields, the water production can make out as much as 95 % or more of the total produced volume. In case of a blowout, a gas or water breakthrough will reduce the amount of oil flowing out of the well significantly. Coning can therefore be considered a killing mechanism. However, it will not stop oil completely from flowing; the degree of prevention will vary greatly.

A.3 Bridging

Bridging is a naturally occurring mechanism, which blocks the well and prevents the fluid from flowing. It can either stop or reduce flow. It is considered a passive mechanism because it is affected by formation characteristics, and generally not by attempts to kill the well. The term "bridging" includes several natural mechanisms that change the conditions inside the wellbore, and lead to stop of influx (Adams and Kuhlman, 1991):

- Accumulation of formation debris that block fluid flow.
- Collapse of open hole wellbore
- Formations of gas hydrates

Formation debris can consist of sand that is produced along with the reservoir fluids, or fragments torn of the well wall. Solids accumulation can be substantial in poorly consolidated sandstone reservoirs with great permeability. A high flow rate can then cause rapid accumulation. However, if the flow rate is too high, the solids might follow the fluids out of the well and bridging will not occur. If the well pressure drops below the collapse pressure of the formation, this can lead to collapse of the open hole well bore which will reduce or stop the flow. This can be a result of high influx rates, rapid pressure drops, high collapse gradient, or a combination of these. If the borehole is cased and perforated, this will prevent well collapse. Nor do deepwater wells with high hydrostatic heads tend to collapse. Plugging of the well can occur with severe hydrate formation. This originates if the fluid contains methane and water at low temperatures and high pressures (Adams and Kuhlman, 1991).

If bridging occurs, this typically happens within the first 24 hours (Adams et al., 1991). The drawdown pressure near the wellbore will be most significant in this initial period. Also, formation disturbance and washout will normally occur a few hours after the blowout initiation. If the formation holds stable through this first period, it is unlikely that bridging will occur (Adams and Kuhlman, 1991). According to the Scandpower blowout database, as much as 77 % of blowouts are killed by bridging (Haugsvold, 2010). This is a very desirable event if a blowout should occur. It requires no work, and there are only financial losses due to the oil spill itself.

A.4 Active measures

An active measure is an intervention activated by the crew to stop an uncontrolled blowout. Normally, the operator attempts to regain access to the well by manually closing/overriding the BOP and/or by restoring the primary barrier (through e.g. bullheading or snubbing). I.e. an ROV can be deployed to regain access, and seal the wellhead at the seabed. Crew interventions related to the primary and secondary barrier will not be discussed further here. They can be studied in detail in the SINTEF database, which includes information of how each registered blowout incident has been killed (Holand, 2010). Capping will be discussed in further detail below, along with different methods to circulate mud into the well (Vallejo-Arrieta, 2002).

A.4.1 Capping

Capping serves to stop the uncontrolled flow by closing it in at the release point. It is a mechanical shut-in of the well. A capping stack commonly consist of a pipe fitted with one or more valves or BOPs, as well as kill and choke lines. This mechanism requires access to the well. Thus, any debris or damage structures might have to be removed prior to well cap deployment. It may be necessary to cut valves, risers or the entire wellhead before attaching the cap. Alternatively, the existing wellhead equipment might be repaired or replaced. If the wellhead has been cut, the pipe of the capping stack must be anchored into the well remains. If the well is on fire, this can complicate a capping operation, as the fire must be distinguished for most cases. If the well is cratered, capping is not possible (Vallejo-Arrieta, 2002).

When deploying a well cap, the valves are first left open to let the well flow while the assembly is properly anchored. The wellhead pressure is sometimes reduced by diverting well fluids, before closing it. This operation is shown in Fig. 37. After shut-in, the well must be killed by circulating heavy mud through the capping device by e.g. bullheading or snubbing. When pressure control has been retrieved, it is often sealed by cementing, either directly through the well cap or through a relief well (Grace and Cudd, 2003, Schubert et al., 2004).

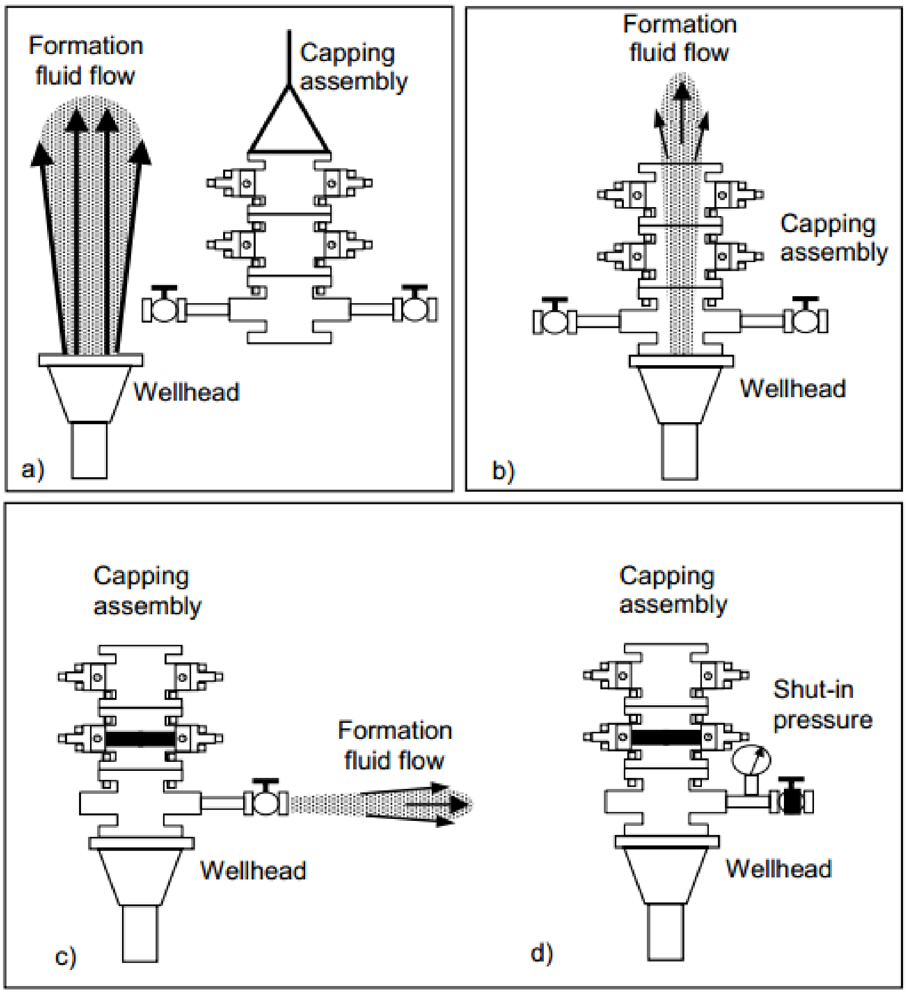


Figure 37: Typical capping operation (Vallejo-Arrieta, 2002).

When the Deepwater Horizon blowout started, on April 20th 2010, there were no existing capping equipment able to shut in the well. Such equipment had not yet been developed for deepwater, HPHT wells with such high blowout rates. At these conditions, drilling of a relief well would take months. BP immediately started its attempts to contain the leaks and shut in the well. Development of capping devices was initiated, to be able to stop the blowout. By July 15th, a three ram capping device "Top Hat" was finally in place, and the well ceased to flow. On August 4th a pressure test showed that the well had reached static conditions. The casing was plugged by cement, and the well could finally be declared shut-in. The operations was complicated by the fact that the riser had to be cut before the cap could be deployed, because it was still attached to the BOP and had been bent when the platform sank. The well cap was then placed on top of the original wellhead. At September 17th a relief well was completed to seal the well permanently (Yeo et al., 2010-2011, McAndrews, 2011).

This event initiated reviews of potential response options, and development of several new capping devices. Oil and Gas UK established the Oil Spill Prevention and Response Advisory Group (OSPRAG) for review at UK sector. This resulted in OSPRAG developing its own capping device which have become available on the UK continental shelf, for met-ocean conditions. It can be deployed quite rapidly using a wide range of vessels or rigs, due to its relatively low weight. This device is currently only available on British sector (Kinkead, 2011). The Subsea Well Response Project was established by 9 oil companies to enhance the industry's capability to respond to a subsea well incident around the world. 4 capping stacks capable of handling a variety of scenarios are to be prepared. During 2013 capping stacks and dispersant equipment will be placed at strategic locations in South America, Europe, Africa and Australasia. From there, the devices can be transported by sea or air to blowout locations around the world (Lewis, 2012).

A.4.2 Bullheading

Bullheading involves pumping of kill fluid to displace any influx fluids back down the well and into the reservoir or other subsurface formations. The kill fluid must be circulated at a momentum greater than the flow of formation fluid coming up the wellbore. The mud can be injected through the kill and choke lines by e.g. a capping device. However, bullheading challenges the integrity of the wellhead and casings. As kill fluids are pumped into the well at high pressure, the design pressure of the casing or wellhead might be exceeded. If the casing is severely damaged it might result in an underground blowout. Also, if the fracture gradient is exceeded, the reservoir below the casing may fracture and mud will be lost to the formation. Bullheading can therefore lead to further deterioration of the blowout conditions. Thus, inappropriate bullheading can lead to a longer blowout duration since well control might be delayed, or other kill methods eliminated (Vallejo-Arrieta, 2002).

A.4.3 Snubbing

Snubbing is a vertical intervention that involves running the bottom hole assembly (BHA) on a pipe string into the uncontrolled flowing well. The pipe is made up and broken down while running in and pulling out. A snubbing operation allows killing a blowout by injection of killing mud through the drill string. Alternatively, this operation can be performed through wireline or coiled tubing (Vallejo-Arrieta, 2002).

A.5 Relief well

If none of the above methods can kill the blowout successfully, a relief well will have to be drilled. This is a worst-case scenario, seeing that relief well drilling is a time-consuming operation. Relief wells are typically used to gain control of a blowing well where a direct surface intervention is impossible. This involves drilling of a new well to intersect the original one, to regain pressure control. Planning of two relief wells is typically initiated early on. If the first relief well is unsuccessful in intersecting the blowing well, the second one can be used. The well should be intersected at the bottom, as close to the flowing zone as possible as shown in Fig. 38. When the relief well hits the blowing well, communication is established. The BOP can then be closed and killing mud pumped down through both the kill and choke line. There are several methods for killing a blowout through a relief well; Dynamic kill, static kill and flooding. Dynamic kill is the most commonly used, and will be in focus here (Maehs et al., 2008).

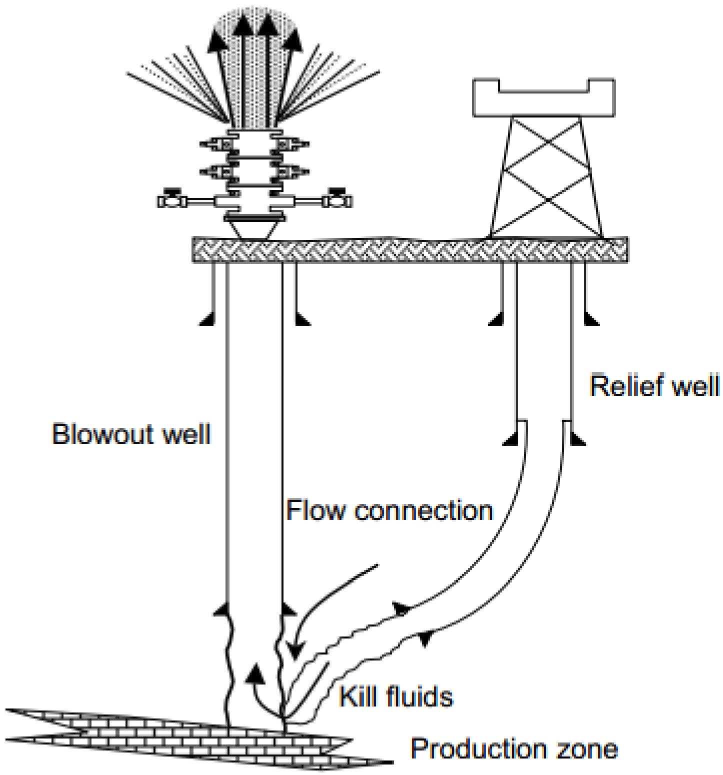


Figure 38: Relief well intervention (Vallejo-Arrieta, 2002).

A dynamic kill involves circulating kill fluids from the relief well, and into the bottom of the blowing well. Seawater is often used as the initial kill fluid, since it is easily accessible. The water in itself does not have a sufficient hydrostatic head to stop influx. But as the fluid is pumped down into the annulus at high rates it creates a high frictional pressure. This frictional pressure combined with the hydrostatic head of the fluid column make out the equivalent circulating pressure. As the pump pressure is increased the equivalent circulating pressure eventually overcomes the flowing well pressure and influx of formation fluids is stopped (Adams and Kuhlman, 1994).

As the well ceases to flow, frictional pressure is neglected and the hydrostatic pressure of the kill fluid alone must exceed the formation pore pressure. The pump rate must then be sustained until the seawater can be replaced by a heavier kill mud. The mud is circulated down through the annulus of the relief well, and up through the annulus of the original well. The hydrostatic head of the mud must be sufficient to prevent inflow, consequently higher than the static formation pressure (Adams and Kuhlman, 1994). If the formation is fractured, the pump rate can be decreased to reduce mud loss. A thick, viscous mud can help reduce the chance of fracturing. If a heavy mud was injected initially, instead of water, it would be difficult to avoid fracturing the formation (Noynaert and Schubert, 2005).

Appendix B – Probability distributions and distribution values

Below some different probability distributions are explained briefly. A graphical representation is shown Fig. 12. These are the distribution available in BlowFlow for uncertain input values. Only some of them will be included in this assignment.

B.1 Common distributions

- A **single value** or deterministic value is used if there is little or no uncertainty related to the variable.
- A **uniform distribution** is specified by a minimum value and a maximum value. All values in between have a constant probability of 1 / (max – min). This means that all values in the interval have the same probability, while those below or above have a probability of zero.
- A **triangular distribution** is specified by its minimum value, most probable value (peak value) and maximum value. The probability increases linearly from zero at the minimum value, to a maximum probability at the peak value, and then decreases linearly to zero at the maximum value. It does not necessarily need to be symmetric.
- A **piecewise linear distribution** is specified by a minimum value, lower percentile value, most probable value, upper percentile value and a maximum value. Here, the increase or decrease in probability is constant between each of these values, and it allows a "tail" effect. Like for a triangular distribution, it does not have to be symmetric.
- A **discrete distribution** is defined by a set of values with associated probabilities. Each value is given with a specific probability, and the sum of all these probabilities must be equal to 1. It is often presented as a histogram (Walpole et al., 2012).

B.2 Advanced distributions

- A **generic distribution** is built up of a *set* of data. Based on a number of input values, a histogram is formed. The distribution curve is a "smoothing" curve with the same shape as the histogram. This type of distribution is suitable if there is historical data available, and it is difficult to find an appropriate distribution.
- A normal distribution, or **Gaussian distribution**, is defined by a mean (expectation) value and a standard deviation. It is has a symmetrical bell shaped curve. It has the highest probabilities near the mean value, and decreases on either side. Here the total probabilities within one standard deviation is 0.68, and 0.95 the within two standard deviations.
- An **exponential distribution** is given by a mean value, where the probability decreases exponentially with increasing values. This model is used to model the behavior of units with a constant failure rate that does not degrade with time. It is a special case of the Weibull distribution, where the variable k is set to 1.
- A **Weibull distribution** is set by a shape parameter (α), and scale parameter (β), both positive. It is often used to measure the failure rate of a unit, due to its flexibility. It can mimic a normal distribution or an exponential distribution. If α is less than 1, the curve is decreasing over time. I.e. if k is set to 0.5, the failure rate decreases exponentially. If α is higher than 1, this suggests an increases over time. The latter can mimic a normal distribution (Walpole et al., 2012).

B.3 Special case distributions

- A **trapezium distribution** is represented by a minimum, left peak, right peak and maximum value. The probability increases linearly from the minimum value to the left peak, is uniform from the left to the right peak, and decreases linearly from the right peak to the maximum value. It will then form a trapeze.
- A **tailed triangular distribution** is like a triangular distribution given by a minimum, peak and maximum value. However, one side is represented by a tail that has an exponential slope. This tail can be either on the left or the right side of the peak. The opposite side has a linear slope.

B.4 Distribution values

Results are often presented as distribution values. Some common ones that are used in this thesis are defined below.

- Minimum value
- P10, 10 % percentile
- P50, 50 % percentile
- P90, 90 % percentile
- Maximum value
- Mean value
- Standard deviation

The 10 % percentile expresses the value, where there is a 10 % chance that the results will be lower or equal to this value. Accordingly, there is a 90 % chance that the results will be higher than the given value. Likewise, there is a 50 % and 90 % chance that the results will be lower than the P50 and P90 values, respectively. The standard deviation is measure of variation or "dispersion" from mean value. A low standard deviation indicates that the data points tend to be very close to the mean, whereas a high standard deviation indicates that the data points are spread out over a larger range of values (Walpole et al., 2012).

Appendix C – PVT properties and correlation

This section defines different PVT properties that are necessary to calculate in BlowFlow. It also describes different correlation available in the tool used to determine these values.

C.1 Definitions of PVT properties

The **bubble point pressure** (P_b) is the pressure at which the first bubble of gas is formed when decreasing the pressure of a fluid. The **solution gas-oil ratio** (R_s) is the amount of gas dissolved in the oil at a given pressure in scf/stb. R_s increases linearly with pressure as it approaches B_p, after which it is constant. The oil is said to be under-saturated with gas above B_p, because there is no more free gas available to dissolve in the solution. R_s is also a function of the oil and gas composition. The solution gas-oil ratio is often the most significant component of the PVT correlations. It has a strong impact on oil viscosity and the formation volume factors (Danesh, 1998). Fig. 39 shows how the solution gas-oil ratio changes with pressure below and above the bubble point pressure.

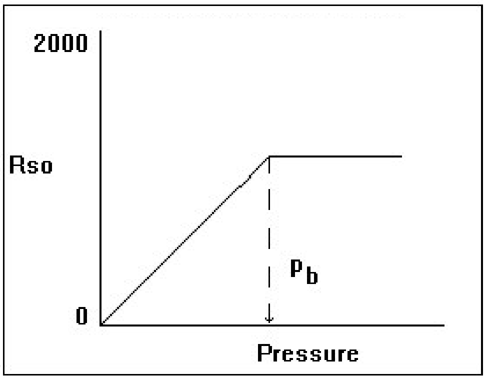


Figure 39: Solution gas oil ration as a function of pressure (Danesh, 1998).

The **oil formation volume factor** (B_o) is the volume of oil and dissolved gas at reservoir conditions divided by the volume of oil standard conditions. Since the oil flow rate is normally measured at standard conditions, it must be converted to reservoir conditions by multiplying with B_o. This value is usually higher than 1, because the oil contains dissolved gas at reservoir conditions. As for R_s, it increases linearly with pressure as it approaches the bubble point pressure. This is because more gas goes into solution. Above B_p however, there is no more gas to enter the solution, and the oil is compressed (England et al., 1987, Danesh, 1998). Fig. 40 shows how the oil formation volume factor changes with pressure below and above the bubble point pressure.

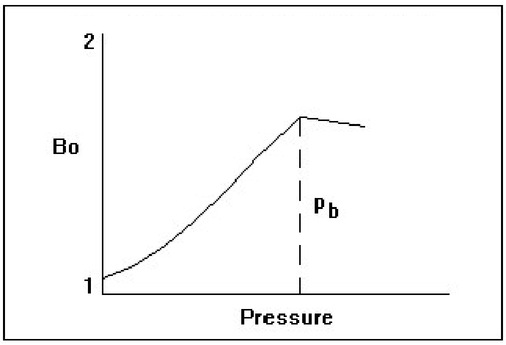


Figure 40: Oil formation volume factor as a function of pressure (Danesh, 1998).

The **viscosity** can be defined as “thickness” or “internal friction” of a fluid. Water has a viscosity of 1 cP at 20 °C, and a higher viscosity corresponds to higher flow resistance (Danesh, 1998).

C.2 PVT correlations

Several models are available in BlowFlow to correlated PVT properties. Different methods may be applied for determining the different parameters mentioned above. These models are presented shortly below, along with the a conclusion of which model is the most appropriate for the case study. Information about errors and applicability is given in the BlowFlow tool.

C.2.1 Vasquez-Beggs

The Vasquez-Beggs correlation from 1978 is based on approximately 6000 measured data points at various temperatures and pressures. This data is gathered from more than 600 crude oil systems. There will be various degrees of error when using PVT correlation An average error of ±8 % has been reported for the Vasquez-Beggs correlation. This model is applicable for determining P_b, R_s, B_o and μ_o.

C.2.2 Standing

The Standing model is based on 105 experimentally determined data points, which is gathered from 22 different oil-gas mixtures in the United States. It is valid for oil gravities of 0.770 - 0.970 SG and reservoir temperatures of 38 - 109 °C (Shokir et al., 2004). As for the Vasquez-Beggs it is applicable to find P_b, R_s, B_o and μ_o.

C.2.3 De Ghetto

The De Ghetto model can be used to determine P_b, R_s, B_o and μ_o. Data on the first three parameters are collected worldwide, while data on the latter is collected from the Mediterranean Basin, Africa and the Persian Gulf. It is optimized to handle both heavy oils (0.92 - 1.00 SG) and extra-heavy oils (gravities greater than 1.00 SG). However, it may also be used for lighter oils. For saturated and under-saturated oil viscosity prediction, the average absolute errors were reported to be 12 % and 6 %, respectively.

C.2.4 Egbogah

The Egbogah correlation is especially developed to determine oil viscosity for heavy oils. It is applicable for oil gravities 0.75 - 1.04 SG and reservoir temperatures of 15 - 80 °C.

C.2.5 Lee

The Lee model is applicable to determine gas viscosity for reservoir temperatures within 38 - 171 °C and pressures of 7 - 552 bars. Average reported error is 2 – 4 %. For high gas viscosities the model is known to under-predict the viscosity.

C.2.6 Modified Lee

The modified Lee model is also used to determine gas viscosity. It is reported to have an average absolute error of 2.3 percent, and is based on a wider range of data, compared to the traditional Lee model.

C.2.7 Case study

For determination of bubble point pressure (P_b), solutions gas-oil ratio (R_s), oil formation volume factor (B_o), and oil viscosity (μ_o) in the case study, the Vasquez-Beggs correlation will be employed. This is chosen because this model is based on large amounts of data collected worldwide. The Standing model is based on much smaller database, which is collected in California. Thus, the Vasquez-Beggs is more applicable on the Norwegian Continental Shelf. De Ghetto and Egbogah on the other hand, are more complex models applicable for heavy oils.

The gas viscosity (μ_g) is determined by the modified Lee model, since this has a lower average error rate than the traditional Lee model.

Appendix D – Multiphase flow models

This section describes the different multiphase flow models available in BlowFlow, and their applicability. Limitations of each model are described in the BlowFlow tool. This section also includes a conclusion of which model is the most applicable for the case study.

D.1 Hagedorn-Brown

The Hagedorn-Brown correlation is one of the multiphase flow models used in the BlowFlow tool. When developing this correlation, a 450 meter deep well was used to obtain experimental pressure profiles at different flow rates. Pressures were measured for flow in tubes ranging from 1 ¼ to 2 7/8 in outer diameter. Since it was developed for vertical flow in oil wells, it has limited accuracy for horizontal or deviated wells. The effects of liquid viscosity were studied by using water and oil as the liquid phase. The oil used had viscosities of 10, 35 and 110 cP at stock tank conditions. Also, a wide range of gas/liquid ratios were included in the study. The model gives the best results for liquids with a moderate to high gas fractions, and high mixture velocities. The correlation provides good results over a wide range of well conditions an flow regimes and is among the most widely used multiphase flow models. However, the model has several limitations (Hagedorn and Brown, 1965):

- Over predicts pressure losses for high API gravities.
- Under predicts pressure losses for low API gravities.
- Over predicts pressure drop for large pipe/tubing sizes.
- Poor accuracy for deviated or horizontal wells.

D.2 Beggs & Brill

The Beggs & Brill model is developed for tubing strings in inclined wells and pipelines for hilly terrain. It can be used to model flow in vertical, horizontal and inclined wellbores. The elevation pressure gradient in a pipeline with a small upward inclination from horizontal can be much higher than the frictional pressure gradient. When gas flows at a greater linear velocity than the liquid, slippage takes place and liquid holdup occurs. Therefore, in order to predict the pressure drop, the liquid holdup must be accurately predicted. The Beggs & Brill model has resulted from experiments using air and water as test fluids over a wide range of parameters, as given below (Beggs and Brill, 1973):

- Gas flow rate 0.00 - 8.50 Mscm/d
- Liquid flow rate 0 - 164 Scm/d
- Average system pressure 2.00 - 6.50 bar
- Pipe diameter 1.00 - 1.50 in.
- Liquid holdup 0.000-0.870
- Pressure gradient 0.000 - 0.180 bar/m
- Inclinations angle -90.0° to +90.0° also horizontal flow patterns

As for the Hagedorn-Brown correlation, it is known to over predict pressure losses at large diameters and for high GOR values (especially for GOR > 890). Also, it yields better results for oil at intermediate API gravities (Beggs and Brill, 1973).

D.3 Orkiszewski

The Orkiszewski correlation is applicable for assessing pressure drops for two-phase flow in vertical wells. It can be used for high-velocity flow ranges and gas condensate wells in addition to oil wells, and has proven accuracy. Some known limitations are given below (Orkiszewski, 1967):

- Over predicts pressure losses for tubing sizes > 2.00 inches
- At low oil gravities (13.0 – 30.0 °API) the pressure profile is over predicted
- Errors become large (> 20 %) for GOR > 890

D.4 Gray

The Gray correlation is one of the most commonly used methods for gas-condensate well pressure profile prediction. It provides accurate results of pressure drops for gas wells experiencing liquid loadings. The correlation notes that caution should be used for the following conditions (Gray, 1955):

- Flow velocities < 15.0 m/s
- Tubing sizes < 3.50 in
- Roughness height < 8.44 μm

There is no single method that gives the most accurate predictions for all types of wells. Models developed for predicting pressure drops in oil fields, might give poor results for gas wells. The Orkiszewski and Hagedorn-Brown correlations are considered to perform satisfactorily for engineering purposes for vertical oil wells with or without water-cut. They are applicable for the same types of wells, and are considered equally accurate for most cases. The Beggs & Brill model is considered to be the best method available for inclined/deviated wells, with or without water-cut. However, the model can also be used for vertical and horizontal wells. The Gray correlation is also a much used model, and is considered to give the best results for vertical gas or condensate wells. Several of these models have been modified recently to be able to predict a larger range of flow conditions and well designs (Pucknell et al., 1993).

D.5 Case study

The multiphase flow model used for this case study is the Hagedorn-Brown correlation. Several of the available models can be used for vertical oil and gas wells, but The Hagedorn-Brown is developed for a wider range of flow diameters. Thus, it gives better accuracy for larger pipes. The Beggs &Brill and Orkiszewski both over predict pressure losses in large tubes. This is unfortunate since it gives smaller flow rates. The Gray model is better for gas wells.

Appendix E – BlowFAM report

This section presents the report generated from the BlowFAM tool. It includes general information about the well, activity level, results in the form of frequencies and adjustments, and a list of all the risk elements considered to contribute the blowout risk for the specific well. Risk elements that are not considered to yield a higher or lower risk for this specific well is also included, since these will also affect the final blowout frequency.

E.1 General information

Water depth (m): 330 m

BlowFAM session date: 07.05.2012

Drilling before the BOP is set (number of wells): 0

Drilling after the BOP is set (number of wells): 1

Completion (number of operations): 0

Production (number of operations): 0

Workover (number of operations): 0

Wireline (number of operations): 0

Exploration well

Type of well: Oil

Type of installation: Floater

E.2 Risk elements and evaluations

The Table 41 present all the risk elements related to drilling after setting of the BOP. Elements related to other activities have for simplicity been excluded. The total number of risk elements included is 171. 8 of these elements are set to not applicable (NA) for the well in question. Thus, the total number of applicable elements is 163. The sum of all positive scores is B = 47, and the sum of all negative scores is W = 9.

Table 41: Risk element evaluation for the base case.

ID	Risk element	Max	Score	Comment
F	**Frame Conditions**			
F01-01	Areas with low hole (well) density	3	0	
F01-02	Drilling in northern areas	3	-3	The area is in northern areas with Arctic climate.
F01-03	Collisions with icebergs	1	-1	Possibility for iceberg collision in this area.
F01-04	Fields with H2S	2	0	
F01-05	Slimhole drilling	3	0	
F02-01	Difficult to use riser margins in deep water	3	1	The water depth is 330 meters, and not considered deep water.

F02-02	Booster line on marine riser	2	0	
F02-03	Possible hydrate formation during flow, circulation out	3	0	
F02-04	More complex operation systems for subsea BOP	3	1	More advanced technology in recent years, and high safety demands in the area.
F02-05	Circulate small amount of gas through choke line	3	0	
F02-06	Establish guidelines for deepwater operations	3	NA	Not deepwater.
F03-01	Drilling into neighbouring well	2	NA	No other wells in the area.
F03-02	Generally good knowledge about reservoirs and shallow gas	5	-1	Limited knowledge since there a currently no wells in the area.
F03-03	Increased number of possible leak paths between different well slots	2	NA	No other wells in the area.
F04-01	Use of heavy mud to prevent hole collapse	2	NA	No horizontal section.
F04-02	Easy to get stuck pipe after rotation stop or if the well is closed in	2	0	
F04-03	Increased time of reservoir exposure	3	NA	No horizontal section.
F04-04	Difficult to circulate out gas from horizontal sections	3	NA	No horizontal section.
F04-05	Possible swabbing during e.g. hole cleaning	2	0	
M	**Drilling Management**			
M01-01	Seismic of 3-D	4	2	Better seismic surveys have improved the quality of seismic data.
M01-02	Too much trust on seismics	2	0	
M01-03	Change of location due to expected shallow gas	0	0	
M01-04	Improved casing program	3	3	More reliable data has lead to improved casing programs and flexibility in the casing setting depths.
M01-05	Experience data available	5	-2	Little data available in this area.
M01-06	Risk analysis prior to drilling	4	1	Thorough analysis is demanded.
M01-07	Prespud meetings	3	2	Better communication and awareness.
M01-08	Systemizing of all drilling documentation	2	0	
M01-09	H2S preparedness when drilling wells in new area	3	0	
M01-10	Kick-off meetings prior to critical	3	2	Better communication and

	drilling phases			awareness.
M01-11	Improved geological information	4	-2	Little information about geology available.
M01-12	Special shallow gas seismic survey	0	NA	Shallow gas not considered.
M01-13	Analysis of difficult wells postdrilling	4	0	
M01-14	Establishing of Safety Management System (SMS)	3	3	Safety management will be of high priority.
M01-15	Safe Job Analysis	2	0	
M01-16	Risk analysis of new equipment	2	0	
M01-17	System for experience transfer into procedures	3	0	
M01-18	Improved quality of weather forecast	2	2	Weather forecasts significantly improved in recent years.
M01-19	Use of rig which can withstand rough weather	3	3	In northern areas weather resistant rigs are required.
M01-20	Earlier start of well planning	1	1	Thorough planning required.
M01-21	Use of special contractor if possibilities for H2S in well	2	0	
M01-22	Developed flow chart for the planning	2	0	
M02-01	Simulation tools	3	0	
M02-02	Introduction of new equipment/systems	3	0	
M02-03	Increased training frequency of courses in general	3	0	
M02-04	Qualification feedback system	3	0	
M02-05	Well control (BOP) courses for drilling supervisors	5	0	
M02-06	Internal courses that emphasize well control and other critical aspects	3	0	
M02-07	Regularly kick handling tests (kick drill/pit drill)	4	0	
M02-08	More experience and better understanding of well conditions and parameters	3	0	
M02-09	Use of rig on normal well prior to use on difficult well	1	0	
M02-10	Expert system gives possible explanations to symptoms which have occurred	1	0	
M02-11	Full scale training facilities	4	0	
M03-01	Too much time spent on meetings, reporting etc.	1	0	
M03-02	More stress for some personnel due to reduced manning	1	0	
M03-03	The shift arrangement may result in lost experience among some	2	0	

	personnel			
M03-04	New meeting/information structure (team work)	1	0	
M03-05	Establishing of competent well control team	2	0	
M03-06	Independent mud volume control by mud log company	4	0	
M03-07	Too much trust on mud loggers attention	1	0	
M03-08	Transfer of responsibility to contractor leads to higher understanding of operations	3	0	
M03-09	All information onshore/offshore channelled through one person offshore	2	0	
M03-10	Engineer who has prepared drilling programs is present and follows-up offshore	4	0	
M04-01	Improved physical and psychosocial work environment	2	0	
M04-02	Improved man-machine interface ergonomics	2	0	
M04-03	Improved communication	2	0	
M04-04	Encouraging more team work between operator and contractors	1	0	
M04-05	Policy change in companies towards safety	3	3	High safety requirements.
M04-06	Better control routines for logging overtime	1	0	
M04-07	Stress on contractor personnel	1	0	
M05-01	Improved pressure/functional testing	4	0	
M05-02	System for introduction of new and unproven equipment	2	0	
M06-01	Increased maintenance level	3	0	
M06-02	Reduced manning in some areas	1	0	
M06-03	Tailoring maintenance programs to suit each case	1	0	
M06-04	Contractors evaluated on maintenance philosophy	1	0	
E	**Drilling**			
E01-01	MWD/AWD/LWD	4	0	
E01-02	Sensors for pit level control	3	0	
E01-03	Control/display equipment	2	0	
E01-04	Long response time after stop of mud pumps	1	0	
E01-05	Real time surveillance	3	0	
E01-06	Pore pressure tools	3	0	

E01-07	Gammaray MWD	3	0	
E01-08	Ultra sonic pit level indicator	1	0	
E01-09	Number of flow meters in mud system	4	0	
E02-01	Slick line	2	0	
E03-01	Top heave compensator (hydraulic lock)	2	0	
E03-02	Active heave compensator system	2	0	
E04-01	Number of connections	3	0	
E04-02	Possible to circulate mud while tripping	4	0	
E04-03	Remotely operated IBOP	3	0	
E04-04	Rotary table as back-up	1	0	
E04-05	Stab the IBOP	3	0	
E04-06	Soft torque system (topdrive and rotary table)	1	0	
E04-07	Dropped objects from topdrive	1	0	
E04-08	Frequent use of IBOP gives more wear and lower reliability	1	0	
E04-09	Reliability of top drive	2	0	
E05-01	Mud quality/properties	4	0	
E05-02	High rate mixing	2	0	
E05-03	Number of mud pumps	1	0	
E05-04	Drilling fluid contingency	3	0	
E05-05	Back-up to the gas sensor in the gas trap	3	0	
E05-06	Closed system to handle gas while circulating out	4	0	
E05-07	Location of individual equipment	1	0	
E05-08	TAM packers beneath top drive	3	0	
E05-09	Closed pits obstruct visual detection of pit level	2	0	
E05-10	Water based mud gives more sticking	1	0	
E05-11	Oil based mud: Gas in solution	3	0	
E06-01	Acoustic back-up control	1	0	
E06-02	Variable bore ram (VBR)	3	3	Commonly used today,
E06-03	Reliability of subsea BOP	4	0	
E06-04	Accumulator capacity, subsea BOP	1	0	
E06-05	Elastomer in pipe ram	3	3	Pipe rams commonly include elastomers today.
E06-06	Upgrade of annular preventer	4	4	Improved equipment reilability
E06-07	Nitrogen bottle on annular preventer	3	0	
E06-08	Automatic locking of rams on surface BOP	1	NA	Surface BOP not included.
E06-09	Use of one-stack instead of two-	3	0	

	stack system			
E07-01	Booster line on Marine Riser	2	0	
E07-02	Segmented hubs for riser and BOP connection	1	0	
E08-01	Improved surveillance and registration of K/C system. (Temperature and pressure)	2	0	
E08-02	More reliable flexible hoses especially with respect to fatigue	3	0	
E08-03	More K/C inlets on BOP	3	0	
E08-04	Internal pressure equalizing of kill/choke valves	1	0	
E09-01	Improved certification and quality in general	3	0	
E09-02	Removal of side entry hubs on drill string	1	0	
E09-03	Float in drill tool (1)	2	0	
E09-04	Float in drill tool (2)	1	0	
E09-05	Dart/circulation sub	2	0	
E09-06	H2S and CO2 resistant equipment	3	0	
E09-07	Drill bits	3	0	
E09-08	Use of drill pipes with larger diameter	2	0	
E09-09	Sensors for monitoring of drill string vibrations	1	0	
E09-10	Equipment for monitoring of condition of downhole tubulars	3	0	
E10-01	Cement quality and cementing of casing	3	2	Better cement quality and procedures.
E10-02	Automatic cementing unit	2	0	
E11-01	Continuously improved equipment	3	3	Better mud logging equipment has lead to improved kick detection.
E13-01	Use of coiled tubing	3	0	
E13-02	Significantly increased quality of equipment	3	0	
E14-01	Wellhead gasket	3	0	
E14-02	Use of fire resistant well heads	1	0	
E15-01	Kinetic energy system	1	0	
E15-02	System to localise travelling block	1	0	
P	**Operational Procedures**			
P01-02	More focus on pore pressure, mud weight and formation strength in general	5	2	Recent increased focus in these parameters.
P01-04	Special procedures when drilling H2S contaminated wells	3	0	
P01-07	Use of 2 tested independent barriers	4	4	Two independent barriers are required according to North Sea standards.

P01-08	Shut-in at kick detection	4	0	
P01-09	Less possibilities for individual decisions	3	0	
P01-10	Software for recalculation of well design	1	0	
P03-01	Circulate mud and rotate during back-reaming	2	0	
P03-02	Circulate during POOH of the open hole section	4	0	
P03-03	Improved procedures for monitoring of mud return	3	2	Increased focus on kick detection.
P03-04	Circulate bottom up and flow check before tripping	5	0	
P03-05	Higher awareness to procedures during tripping in general	3	0	
P03-06	Perform short trip to check well conditions	4	0	
P03-08	Recording of mud volumes to compare between trips	3	0	
P03-09	Use of software to decide pulling/running speed	3	0	
P04-02	2-Step cementing procedure	2	0	
P04-03	Improved quality check of cementing	2	0	
P04-04	Use float	3	0	
P04-05	Procedure for checking quality of cement job before permit to drill ahead	2	0	
P04-06	Continuous monitoring of swab/surge pressures during running casing	2	0	
P04-07	Surveying of make-up torque of casings	1	0	
P04-08	Rotate or reciprocate string during cementing	2	0	
P04-09	Circulate down casing	1	0	
P04-10	Monitor annulus during/after cementing	3	0	
P04-11	Fitting of correct sized piperams	4	0	
P04-12	Have circulation sub available on deck	3	0	
P05-01	Improved requirements to quality of test equipment	4	0	
P05-02	Use of special production test string	3	0	
P05-03	Safety valve below seabed in test string	3	0	
P06-01	Monitoring of trip tank	3	0	
P06-02	Closing of blind rams	3	0	

E.3 Risk reduction

Table 42 includes an evaluation of possible relevant risk reducing elements from Table 41. Each of the implemented elements is given a maximum positive score. This has resulted in an overall additional positive score of 39.

Table 42: List of risk reducing elements implemented in BlowFAM.

ID	Risk element	Max	Score	Comment
M02-03	Increased training frequency of courses in general	3	3	An increased number and quality of training courses can help reduce risk.
M02-04	Qualification feedback system	3	3	A qualification feedback system may reveal lack of experience or training in some areas.
M02-05	Well control (BOP) courses for drilling supervisors	5	5	Annual refreshing courses for drilling supervisors can help reduce risk.
M02-06	Internal courses that emphasize well control and other critical aspects	3	3	A higher number of such courses can help reduce the risk.
E05-02	High rate mixing	2	2	High rate mixing will provide fast mud supply during critical situations.
E05-03	Number of mud pumps	1	1	A higher number of mud pumps will ensure sufficient mud supply during critical situations.
E05-04	Drilling fluid contingency	3	3	Detailed contingency plans can enhance emergency preparedness.
E06-03	Reliability of subsea BOP	4	4	A more reliable subsea BOP will reduce risk.
P03-05	Higher awareness to procedures during tripping in general	3	3	Higher awareness can help reduce the risk.
P03-06	Perform short trip to check well conditions	4	4	Can check if the pulling speed is too high and will lead to swabbing.
P03-08	Recording of mud volumes to compare between trips	3	3	Can make it easier to detect abnormalities
P04-05	Procedure for checking quality of cement job before permit to drill ahead	2	2	Squeezing will reveal indications of poor cement.
P04-10	Monitor annulus during/after cementing	3	3	Thorough monitoring can reduce the risk.

E.4 Frequencies and adjustments

Table 43 present the results from BlowFAM based on the base case. The frequencies that contained errors have here been corrected based on the calculated frequencies. Table 44 presents the frequencies resulting after implementation of the risk reducing measures identified in Table 42.

Table 43: Blowout frequency and adjustments for the base case.

Phase	Activity level	Basic blowout frequency	Adjustment factor 1	Adjustment factor 2	Manual adjustment	Blowout frequency
Drilling before BOP	0.00	22.8	1.00	1.00	1.00	0.00
Drilling after BOP	1.00	2.10	0.98	0.77	0.59	0.92
Completion	0.00	0.73	0.66	0.86	1.00	0.00
Production	0.00	0.07	0.88	0.77	1.00	0.00
Workover	0.00	1.40	0.95	0.86	1.00	0.00
Wireline	0.00	0.06	0.95	0.86	1.00	0.00
						0.69

Table 44: Blowout frequency and adjustments after risk reduction.

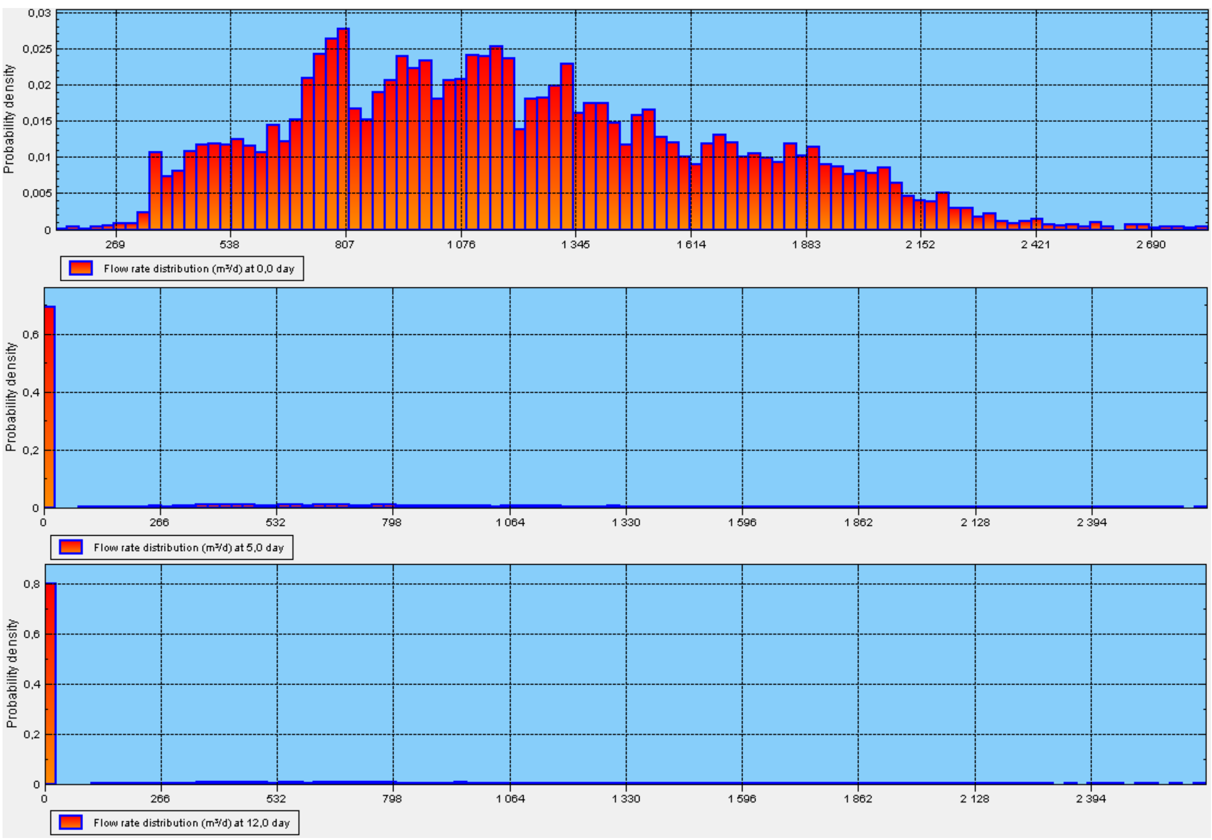
Phase	Activity level	Basic blowout frequency	Adjustment factor 1	Adjustment factor 2	Manual adjustment	Blowout frequency
Drilling before BOP	0.00	22.8	1.00	1.00	1.00	0.00
Drilling after BOP	1.00	2.10	0.98	0.53	0.59	0.64
Completion	0.00	0.73	0.66	0.86	1.00	0.00
Production	0.00	0.07	0.88	0.77	1.00	0.00
Workover	0.00	1.40	0.95	0.86	1.00	0.00
Wireline	0.00	0.06	0.95	0.86	1.00	0.00
						0.69

Appendix F – Flow rate over time

This section presents the oil flow rate distribution over time given by BlowFlow. The decrease in flow rate over time is a function of the different killing mechanisms. Each killing mechanism has a different duration, and will therefore take effect at different times. Seeing that the flow rate is a density distribution, it reflects each of the killing mechanisms. Table 45 present probabilistic (weighted mean) flow rate distribution values for a selection of days; 0, 5, 12, 35, 55 and 72. The corresponding curves are shown in Fig. 41.

Table 45: Oil flow rate distribution values for a probabilistic blowout scenario at day 0, 5, 12, 35, 55 and 75, respectively.

Distribution values		Flow rate oil (m^3/d)				
	Day 0	Day 5	Day 12	Day 35	Day 55	Day 72
Minimum	129	0	0	0	0	0
P10	591	0	0	0	0	0
P50	1 144	0	0	0	0	0
P90	1 901	993	757	523	0	0
Maximum	2 822	2 822	2 822	2 822	2 822	0
Mean	**1 200**	**266**	**171**	**118**	**63**	**0**
St. dev.	486	475	402	344	256	0



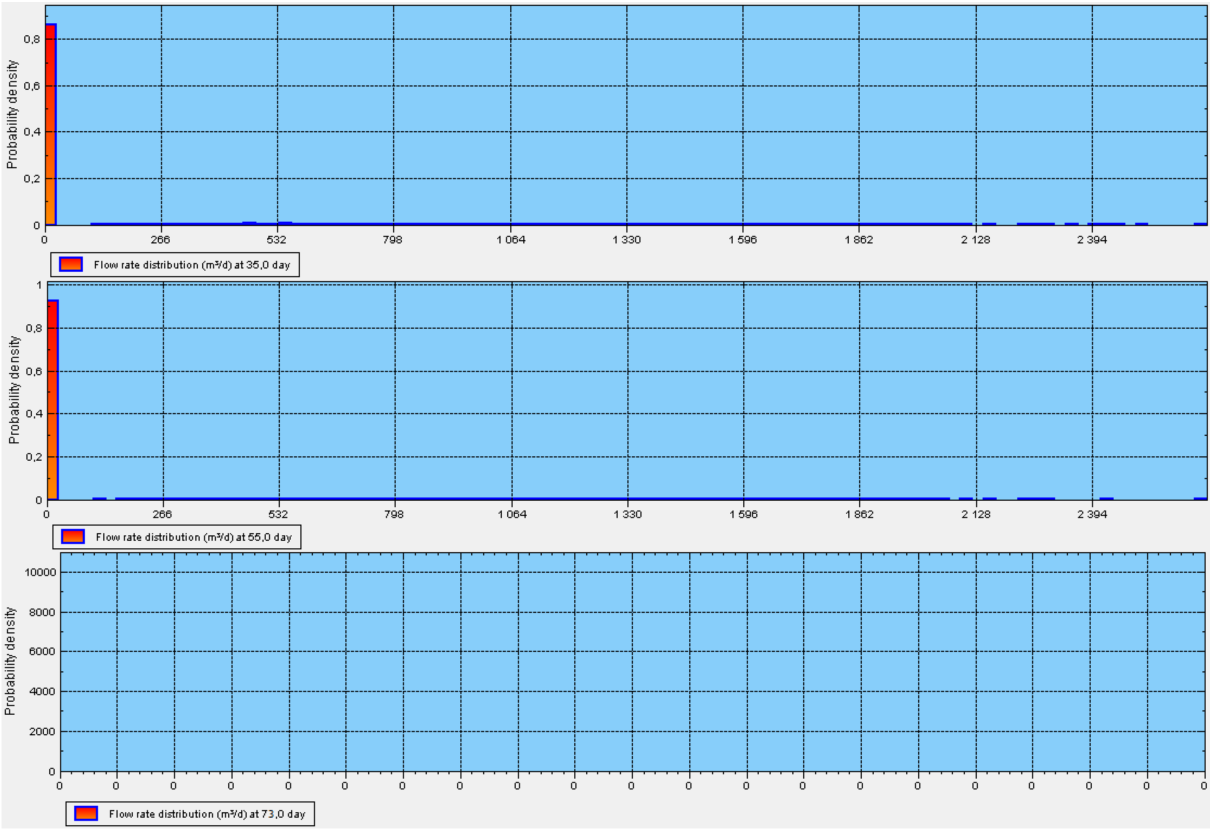


Figure 41: Probabilistic flow rate distribution of oil at day 0, 5, 12, 35, 55 and 72, respectively.

At day 0, none of the killing mechanisms will have occurred. In reality, the flow rate will remain constant (equal to the flow at day 0), if it is not killed or reduced by a killing mechanism. This can be seen from the more or less constant maximum flow rate in Table 45. But the probability that the well has been killed increases with time. This affects the flow rate distribution, and increases the probability of having a flow rate of 0 m^3/d. Coning, bridging and crew interventions will often occur within the early phase of a blowout. Coning has a 50 % chance of reducing the oil flow rate by 50 %. Bridging on the other hand has a 77 % chance of killing the well. Crew interventions will have a 70 % and 43 % chance of killing topside and subsea releases, respectively. Drilling of a relief well is considered to have a 100 % probability of success, and will kill the well after a longer period of time. As a result, the mean flow rate is reduced over time. Fig. 42 presents a curve of the mean flow rate over time (for each day), from start of influx to the maximum blowout duration for a probabilistic (mean) scenario.

The mean flow rate will have a rapid initial decrease as a result of coning, bridging and crew interventions. Bridging and crew interventions will be more crucial to flow than coning, as these mechanisms involve a greater flow reduction. Bridging and crew interventions have an exponentially distributed time of occurrence, which gives the flow rate a similar initial decrease. Drilling of a relief well will reduce the flow rate distribution from day 40 to 72. 72 days is the maximum time to drill a relief well, at which the flow rate is 0.

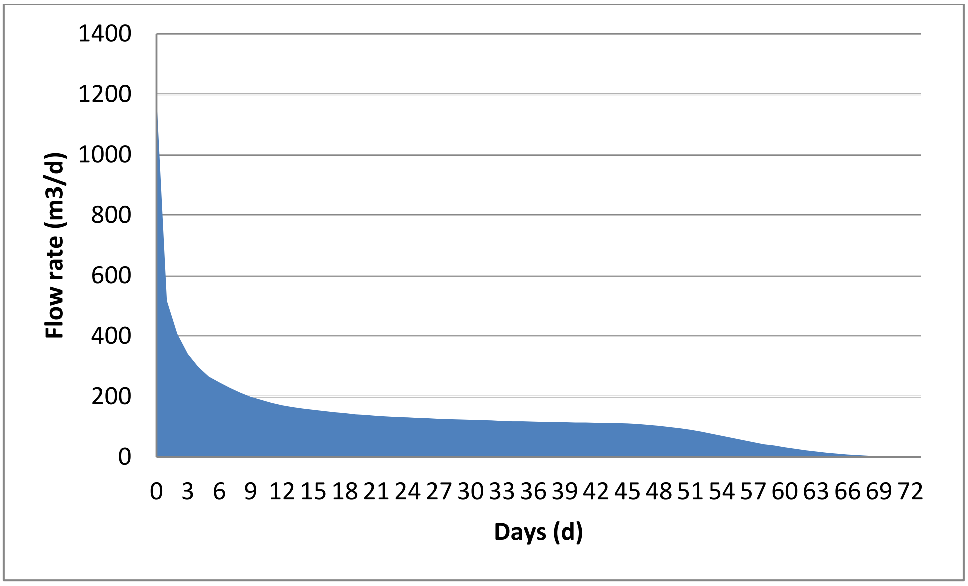


Figure 42: Mean probabilistic flow rate over time.