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Environmental Risk Assessment of Exploration Drilling in Nordland VI

Oljeindustriens Landsforening

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CONCLUSIVE SUMMARY

DNV has, on assignment from OLF, conducted an environmental risk analysis for a hypothetical exploration drilling operation in Nordland VI. The analysis has been conducted for a "base case" which has been developed using conventional analysis methodology and for an "alternative case" which takes into account risk reducing measures. In cooperation with drilling and well integrity experts DNV has conducted an evaluation of various risk mitigating measures including new technological solutions and operational improvements. The aim of the evaluation has been to illustrate to which extent recent improvements in the drilling industry have contributed to risk reduction. The results clearly demonstrate that significant risk reduction may be achieved when taking into account the recent improvements in the industry, compared purely basing the risk analysis on the historic data.

Objective

The objective for performing this study of a hypothetical exploration well operation in Nordland VI is to provide a more realistic environmental risk exposure for possible accidental oil spill related to such an operation, when considering the recent improvements in the industry related to state-of-the-art drilling technology, barriers with improved technical integrity and better operating procedures. The objective is also to raise the awareness of risk reducing measures related to environmentally safe drilling operations, thereby moving the attention from conservative, outdated scenarios to focusing on aspects of a realistic modern operation.

Well data

To make the analysis specific, a well from the Norwegian Sea was selected as the basis for the model. This selected well is a Statoil exploration well called Bjørk that was drilled using the semi-submersible drilling vessel Ocean Vanguard at 337 meter water depth. It was located in PL 352 north of the Norne field. For this study this particular well was placed in Nordland VI at the same location as one used for the impact assessments related to the updating of the Lofoten – Barents Sea Management plan.

The seismic and geology data for the shelf outside of Lofoten and in the southern part of the Barents Sea indicate that one may expect conventional wells with normal pressure margins. This has also been supported by the more than 80 wells drilled in the southern part of the Barents Sea so far.

Historical accident data

This study has carried out a detailed assessment of the blowouts and well control incidents recorded in the SINTEF Offshore Blowout Database. From this data, only one blowout has been recorded in the North Sea in the past 20 year's period (1987-2007) which is the data that forms the basis for the recommended blowout frequency. This blowout occurred in 1988 in the UK sector, and was a high pressure and high temperature (HPHT) well that was drilled without the specific HPHT procedures.

Further, the conclusion from a review of all of the 23 relevant blowout incidents which have been reported in other regions of the world over the same period was that these events to a large extent can be eliminated when considering the specific requirements and operating procedures in the North Sea.

The annual Scandpower report on blowout and well release frequencies provides the basis for conventional risk assessments. This report is based on a detailed analysis of the same blowout database discussed above considering trends and other factors in the data material. For North Sea operations the single blowout which occurred in the UK sector is therefore the basis and the additional events from other parts of the world is used to define the factors that distinguish the exploration drilling operations from development drilling.

When exploring the trend the past 10 years, based on the annual Scandpower reports, the blowout frequency from an exploration well has been reduced by a factor of more than 3.5, from $5,5*10^{-4}$ to $1.54*10^{-4}$. While the frequency of a blowout has been reduced, this historical blowout data does not reflect the latest improvements in the drilling industry. The fact that this data is based on information collected over the last 20 years, it should be considered a lagging indicator. Consequently, this analysis has conducted a more detailed evaluation of the factors that contribute to a blowout in order to provide a more realistic prediction of the blowout probability.

Technological and operational improvements

The most important risk reducing measures identified and considered in this study are divided into the following main categories:

1) BOP reliability
    a. Less trips due to better materials
    b. Improved shear-seal ram (SSR) functions
    c. Dual annular preventers
    d. Better testing procedures
2) Procedures
    a. Better fluid and pressure control
    b. More differentiated contingency plans
    c. Improved procedures to avoid influx
    d. More systematic risk assessment procedures
3) Technology
    a. Better and more reliable up-front reservoir predictions and information
    b. Real time data related to the primary barrier in terms of bottom hole pressure and below bit formation changes
        i. Measurement while drilling (MWD)
        ii. Vertical seismic profile (VSP) like a Look-Ahead VSP
    c. Improved cementing
4) Human Factors
    a. Training and systematic knowledge transfer
    b. More experience with difficult wells

c. Integrated operations (IO) enhances utilization of the technical experts in an organization

Estimation of risk reduction

In order to quantify the impact of the recent improvements within drilling operations, a model was developed which links the different areas evaluated and how they contribute to the overall reliability of the well barriers and how they contribute in preventing a blowout. Based on the identified improvements related to the drilling operations and well barrier technology, i.e. improved reliability and better procedures, DNV argues that the blowout probability is significantly lower than the historical figures which are normally used in environmental risk analyses.

While many of the elements indentified in this study may be difficult to quantify specifically, recent data collected in the North Sea confirms that the kick frequency has been reduced significantly over the last decade. Improved up front information from better seismic data, better operating procedures and fluid quality have therefore clearly had an impact on the probability of losing the primary well barrier. Based on this kick data, it was concluded that the probability of blowout could be reduced by 50 %. In the table below the base case probability and the alternative case probability taking into account the primary well barrier improvements are shown.

Case	Probability of a blowout
Base case	1.5×10^{-4}
Alternative case	7.7×10^{-5}

It should be noted that no further risk reducing measures, i.e. giving credit to the improvements in secondary barriers or operational operations, have been taken into acount in these quantitative predictions. DNV does however consider some of these improvements to be significant, and therefore recommend that these issues are evaluated in more details in further analysis.

In addition to estimating the probability of a blowout, this study has also assessed the probability distribution between various flow paths related to a blowout, its related blowout rates and durations. The assessment has been based on the historical blowout data and results from Scandpowers BlowFam report. For the alternative case it is split between the probability for less than 12 hours duration and less than 2 days duration of a blowout. The probability of a flow path outside casing has also been included and the split between the various flow paths is altered based on more recent information.

The environmental risk is analysed based on the oil drift and weathering properties of the Balder oil, which is one of the most persistent oil's at the NCS. This oil type is applied because it is the same that is used in the environmental risk assessments for the Management Plan for the Barents Sea and Lofoten area. However, the risk is also analysed based on the oil drift and weathering properties of Goliat oil and Huldra condensate, two other highly relevant oil types for the region.

The change in risk is expressed as the relative reduction of the risk index for the "alternative case" compared to the "base case", calculated for seabird/sea mammal, shoreline and fish.

Figure 1 shows that the risk reduction between the "base case" and the "alternative case" is approximate 65 percentage points for seabirds, sea mammals and shoreline habitats. The risk reduction is approximate than 75 percentage points for fish eggs and larva.

The contribution of the probability reduction for a blowout counts for approximate 60 % of the risk reduction. While the change in flow path and flow duration probability counts for approximate 40 % of the risk reduction. This is for seabird/sea mammals and shoreline. For fish the contribution is highest from change in flow path and flow duration, counting for approximate 63 % of the risk reduction. The probability reduction for a blowout counts for 37 % of the risk reduction.

Comparing the environmental risk analysed with the "base case" with environmental risk analysed for other exploration wells shows that the environmental risk from exploration drilling at Nordland VI has approximate the same level as from exploration drilling in the central part of the North Sea. Based on the environmental risk analysis methodologies applied in the industry today.

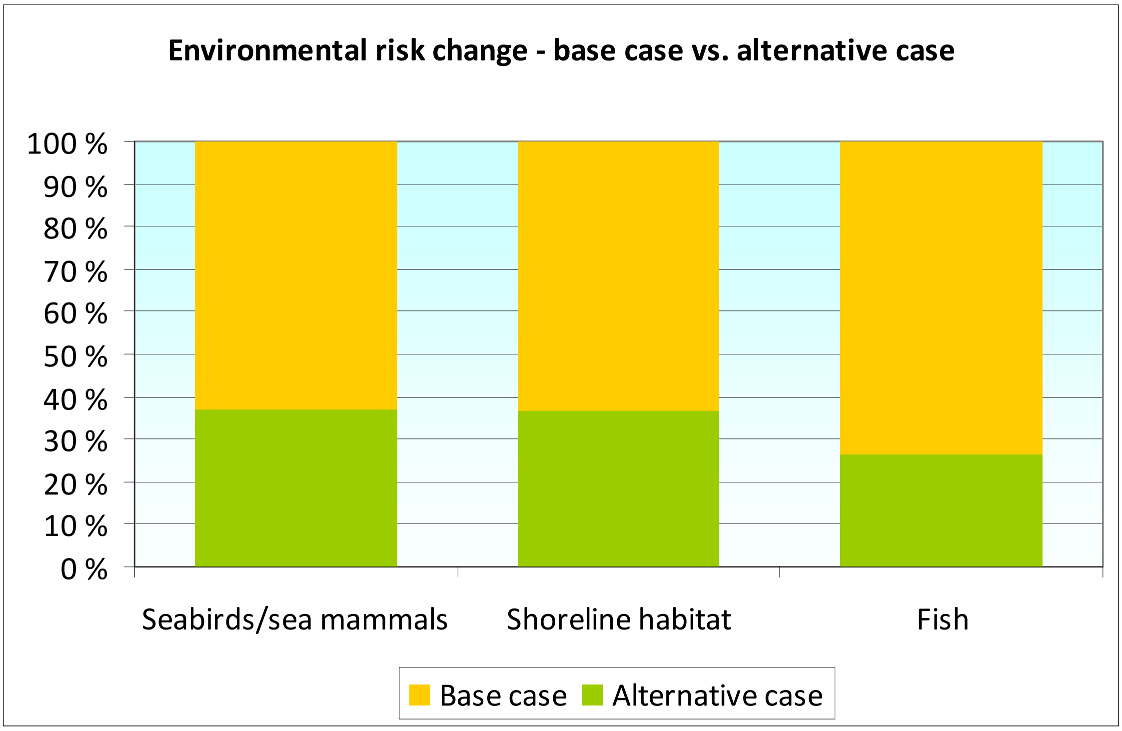


Figure 1 Relative changes in environmental risk between the "base case" and the "alternative case" with use of Balder oil. The relative risk is shown for all four seasons and for the seabird/sea mammal populations, coastal areas and fish populations with highest risk for damage.

Environmental risk from a potential oil blowout strongly varies with the oil type of the reservoir. There is little data available concerning the oil types present in the Nordland VI area. The impact assessments that form the basis for the updated Management plan for Lofoten and the Barents Sea are all based on the Balder oil. As previously mentioned, due to its weathering properties, Balder oil is a very conservative oil for use in environmental risk assessments. The environmental risk is also analysed for two other oil types in this report; the Goliat oil and the Huldra condensate. The risk to seabirds is approximately 20 % lower with Goliat oil compared to Balder oil. The risk to shoreline habitats is more than 30 % lower with Goliat oil. While the risk for harming fish eggs and larvae is slightly higher (7 %) for the Goliat oil compared to the Balder oil. The risk caused by the Huldra oil is approximately 90 % lower than the risk caused by the Balder oil, except for fish. The risk for fish is approximately 65 % lower.

Conclusion

This analysis clearly demonstrates that risk reducing measures implemented in the oil and gas industry the last years within technology, equipment reliability and operational procedures have a significant impact on the environmental risk level. The improvements and learning process in the industry the past years have lead to more environmentally safe drilling operations and thus reduced the environmental risk significantly.

SAMMENDRAG

DNV har på oppdrag fra OLF utarbeidet en miljørisikoanalyse for en hypotetisk leteboring i Nordland VI. Analysen tar for seg to ulike scenarier, et ”base case” der tradisjonell analysemetode er benyttet og et ”alternativt case” hvor man implementerer gevinsten av risikoreduserende tiltak. DNV har i samarbeid med spesialister innen boring og brønnintegritet gjennomført en evaluering av ulike risikoreduserende tiltak som omfatter både tekniske og operasjonelle områder. Hensikten med analysen er å vurdere i hvilken grad disse tiltakene bidrar til en redusert risiko. Evalueringen viser at man kan påvise en betydelig reduksjon i miljørisiko sammenlignet med basisnivået, når tiltak industrien har gjennomført det siste tiåret blir tatt hensyn til.

Hensikt

Formålet med å utføre dette studiet for en hypotetisk letebrønn i Nordland VI er å fremstille en mer realistisk miljørisikoanalyse enn det som normalt blir lagt til grunn i grunnlagsundersøkelser for konsekvensutredninger. Dette gjøres ved å synliggjøre risikoreduserende tiltak i en kvalitativ og kvantitativ analyse, med fokus på uhellsutslipp. Studien har også hatt til hensikt å belyse etablerte risikoreduserende tiltak for å gjennomføre boreoperasjoner på en sikker måte. Dette gjøres med det mål for øyet å flytte fokus fra konservative og utdaterte scenarier over til en mer moderne og realistisk tilnærming.

Brønndata

For å gjøre analysen realistisk ble en tidligere boret brønn fra Nordsjøen, Statoils letebrønn Bjørk, valgt som utgangspunkt. Brønnen er fra PL 352, nord for Norne-feltet, og ble boret med enhalvt nedsenkbart (semisubmersible) borerigg, Ocean Vanguard, på 337 meter vanndyp i 2007. I denne studien har Bjørk-brønnen blitt plassert i Nordland VI på nøyaktig samme lokasjon som konsekvensanalysen for oppdateringen av Forvaltningsplanen for Lofoten og Barentshavet benyttet.

Seismiske og geologiske data fra sokkelen utenfor Lofoten og sørlige deler av Barentshavet indikerer at en eventuell brønn kan forventes å være en tradisjonell brønn med normale trykkmarginer. Dette støttes så langt av mer enn 80 borede brønner i de sørlige delene av Barentshavet.

Historiske utblåsningsdata

Denne analyses inkluderer en detaljert gjennomgang av registrerte utblåsninger fra SINTEF Offshore Blowout Database. En gjennomgang av 23 registrerte hendelser i løpet av de siste 20 årene (1987 – 2007) fra relevante deler av verden, viser at de fleste hendelser ikke ville inntreffe på norsk sektor, grunnet spesifikke krav og prosedyrer som forhindrer slike hendelser her. Blant de registrerte hendelsene er det kun en enkelt utblåsning fra boreoperasjoner i Nordsjøen. Hendelsen inntraff i 1988 på Britisk sektor, og var en HPHT brønn som ble boret før det ble innført spesifikke HPHT prosedyrer.

Scandpower utgir årlig en rapport som angir frekvenser for utblåsninger og brønnlekkasjer, og disse benyttes normalt i miljørisikoanalyser. Rapporten vurderer hendelsesforløp og aktivitetsnivået for relevante deler av verden de siste 20 årene, sammen med tidstrender og andre faktorer av betydning. Den ene hendelsen fra 1988 danner frekvensgrunnlaget for utblåsninger fra boreoperasjoner på norsk sektor, og det er ikke tatt hensyn til utvikling over tid. Denne frekvensen er derfor svært konservativ.

Ser man på trendene de siste 10 årene ser man at basisfrekvensen for utblåsninger fra leteboringer, ihht Scandpowers årlige rapporter, har gått ned fra $5{,}5 \cdot 10^{-4}$ per brønn i 2000, til $1{,}5 \cdot 10^{-4}$ per brønn i 2009, med andre ord en reduksjon på en faktor ca. 3,5. Imidlertid vil ikke et gjennomsnitt for de siste 20 årene reflektere denne forbedringen i tilstrekkelig grad. Det er derfor valgt å gjennomføre en analyse for å beregne gevinsten av risikoreduserende tiltak de seneste årene.

Teknologiske og operasjonelle forbedringer

Rapporten presenterer de viktigste risikoreduserende tiltakene som er identifisert i dette studiet. Tiltakene er delt inn i fire hovedkategorier, og de viktigste forbedringene er:

5) BOP pålitelighet
    a. Færre svikt grunnet bedre materialer
    b. Forbedret kutteventil (shear-seal ram, SSR) funksjon
    c. Doble ringromsventiler
    d. Bedre testprosedyrer
6) Prosedyrer
    a. Bedret væske- og trykkontroll
    b. Mer differensierte planer for uventede situasjoner
    c. Forbedrede prosedyrer for å forhindre brønninnstrømning
    d. Mer systematisk risikostyring
7) Teknologi
    a. Bedre og mer pålitelige prediksjoner og modeller om reservoarforhold
    b. Sanntidsdata relatert til primærbarrieren med tanke på bunnhullstrykk og formasjonsendringer under borekronen
        i. Målinger under boring (Measurement while drilling (MWD))
        ii. Vertikal seismikk profil (Vertical seismic profile (VSP) som f.eks Look-Ahead VSP)
    c. Forbedrede sementoperasjoner
8) Menneskelige faktorer
    a. Systematisk opplæring og kompetanseoverføring
    b. Mer erfaringsgrunnlag med vanskelige brønner

c. Integrerte operasjoner (IO) fremmer bruk av tekniske spesialister i hele organisasjonen

Beregning av endret risiko

Denne analysen har som mål å kvantifisere forbedringstiltakene som er identifisert for å forhindre utblåsninger fra boreoperasjoner. DNV har derfor utviklet en modell der de ulike hovedkategoriene (vist ovenfor) kobles sammen for å illustrere den samlede påliteligheten av brønnbarrierene. Basert på de identifiserte forbedringstiltakene for boring og barriereteknologi, pålitelighet og operasjonelle prosedyrer, argumenterer DNV for at utblåsningssannsynligheten kan reduseres betraktelig sammenlignet med historiske tall som vanligvis benyttes i miljørisikoanalyser. Hvis man ser på pålitelighetsdata for primærbarrieren (brønnsparkfrekvens) bidrar den alene med å redusere sannsynligheten for utblåsning med 50 prosent.

I tabellen under vises sannsynligheten for utblåsning for ”base case” og ”alternative case”. Den ”alternative casen” tar hensyn til de forbedringene som er nevnt for primærbarrieren.

Case	Sannsynlighet for utblåsning
Base case	1.5×10^{-4}
Alternativ case	7.7×10^{-5}

Det understrekes at ingen risikoreduserende tiltak for sekundær barrieren eller operasjonelle rutiner er tatt i beregning av sannsynligheten for den ”alternative casen”. DNV mener at dette er helt klart områder som også har gjennomgått betydelige forbedringer og vil kunne bidra til en videre risikoreduksjon.

I tillegg til å vurdere sannsynligheten for en utblåsning, har studien også evaluert hendelsesforløpet gitt utblåsninger, som ulike strømningsveier, utblåsningsrater og utblåsningsvarigheter. Studien er basert på historiske utblåsningsdata fra SINTEF Offshore Blowout Database . For den ”alternative casen” er det splittet mellom sannsynligheten for mindre enn 12 timers varighet og mindre enn 2 dagers varighet for en utblåsning, noe som vanligvis ikke legges til grunn. Strømningsveier på utsiden av selve brønnen er også ivaretatt, og sannsynlighetsfordelingen mellom ulike strømningsveier er endret sammenlignet med base case, basert på beste tilgjengelige informasjon.

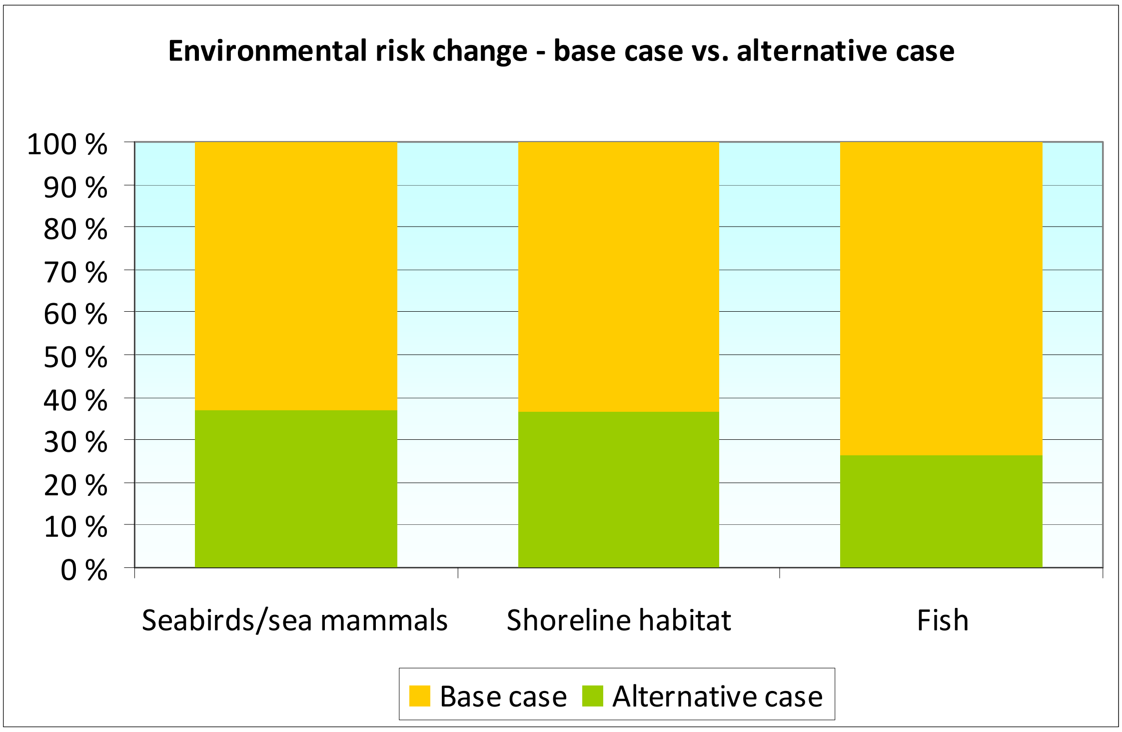
Spredningsberegningene i miljørisikoanalysen benytter seg av Balderoljen? Balder oljen er relativt tung og har lang levetid på havoverflaten gitt et utslipp. Denne type olje er valgt fordi den også er benyttet i risikoanalysen for Forvaltningsplanen for Barentshavet og Lofoten. For å illustrere i hvilken grad valg av oljetype påvirker risikobildet er det også gjennomført spredningsberegninger og tilhørende miljørisikoanalyse for Goliatolje og Huldra-kondensat.

Endringen i miljørisiko, beregnet for sjøfugl/sjøpattedyr, strandhabitater og fisk, er uttrykt som relativ reduksjon i risiko for ”alternative case” sammenlignet med ”base case”, ved bruk av alle oljetypene.

Figur 1 viser at risikoreduksjonen mellom “base case” og “alternative case” for Balderoljen er tilnærmet 65 prosent for sjøfugl, sjøpattedyr og strandhabitater. Risiko reduksjonen er ca 75 prosent for fiskeegg og larver.

Analysen viser at det er frekvensreduksjonen som i størst grad bidrar til det reduserte risikobildet, med ca 60 prosent av den totale risikoreduksjonen. For fisk har derimot endringene i strømningsveiene og/eller utblåsningsvarigheten størst effekt med omtrent 63 % av risikoreduksjonen.

Sammenligning av miljørisikoen for “base case” med andre letebrønner, som er analysert med identiske forutsetninger, viser at leteboring i Nordland VI har anslagsvis det samme risikonivået som de fleste brønner boret på norsk sokkel.



Figur 1 Relativ endring av miljørisiko for “base case” og “alternative case” ved bruk av Balder olje. Den relative risikoen er illustrert, alle årstider inkludert, for sjøfugl/sjøpattedyr, kystlinje habitater og fisk med høyest sannsynlighet for skade.

Miljørisiko som følge av en utblåsning varierer kraftig med reservoarets oljetype. Det er lite data tilgjengelig om hva slags type olje det er forventet å finne i Nordland VI. Konsekvensutredningen som ligger til grunn for Forvaltningsplanen for Lofoten og Barentshavet benytter seg av Balder olje. Balder oljen er, som tidligere nevnt, ansett som en svært konservative oljetype å benytte i miljørisikoanalyser på grunn av sine forvitringsegenskaper. DNV har derfor utført risikoberegninger for to andre hydrokarbontyper, Goliat Blend olje og Huldra kondensat. Analysen viser at risiko for skade på sjøfugl en rundt 20 prosent lavere ved utslipp av Goliat olje sammenlignet med Balder olje. Risikoen for strandhabitater er mer enn 30 prosent lavere med Goliat olje. Risikoen for å skade fiskeegg og larver er noe høyere (7 prosent poeng høyere) med Goliat oljen enn med Balder oljen, gitt ellers like utslippsbetingelser. Miljørisikoen knyttet til utslipp av Huldra kondensat er omtrent 90 prosent lavere enn utslipp av Balder oljen, bortsett fra for fisk. Miljørisikoen for fisk er kun 65 prosent lavere.

Konklusjon

Denne analysen viser tydelig at risikoreduserende tiltak innen teknologi, pålitelighet av utstyr og operasjonelle prosedyrer innført i olje- og gassindustrien i løpet av de siste 10 årene har hatt en betydelig effekt for risikobildet. Industriens mange forbedringer og evne til å benytte seg av lærdom og erfaring de siste årene har bidratt til en sikrere borevirksomhet med redusert risiko for store utslipp.

1 INTRODUCTION

1.1 Background

In accordance with the Management regulations § 16 an environmental risk analysis and an oil spill contingency analysis shall be prepared for any exploration drilling, field development and field operation. This is one of the bases for granting operation permits within Norwegian regulation.

The Framework regulations state that the ALARP principle (As Low as Reasonably Possible) is required in order to reduce risk. The Framework regulations also state that risk reduction shall follow the cost- benefit principle.

The environmental risk assessments conducted for accidental oil spills on the NCS relies mainly on historical data to estimate the probability of an accident. Few realistic risk reducing measures are incorporated in the environmental risk analysis. The consequence reducing effect of oil spill recovery is to some extent included in some risk assessments, but it is not fully incorporated. Probability reducing measures are usually not included in the analyses at all. This reduces the ability to visualize the effect on environmental risk reduction due to specific risk reducing measures incorporated into the operation. It is thus likely to have the impression that there does not exist any management of environmental risk in oil and gas exploration and production. This is not correct. A wide range of technical and operational improvements have been developed in the industry in recent years, and more are expected to come. The probability of having a blowout today is calculated from historical data including accidents that occurred more than 20 years ago. The industry has learned from previous accidents and from incidents during more than 40 years of offshore oil and gas production. This is clearly indicated in safety and reliability risk assessments, but up to now not indicated in environmental risk assessments.

The effect of risk mitigating measures has to be included in the environmental risk assessments to be able to maintain focus on such measures. As a result of this, DNV have developed an environmental risk analysis tool called OPERAto (Operational Environmental Risk Analysis tool) that can include and quantify effects of both probability and consequence reducing measures into the environmental risk analysis. This report will present results from the application of OPERAto to analyse the environmental risk related to a potential exploration drilling in Nordland VI.

1.2 Objective

The objective for conducting an operational environmental risk analysis for Nordland VI is to illustrate a more realistic environmental risk for accidental oil spill taking into account the risk reduction due to use of state-of-the-art technology and barriers with high technical integrity.

The analysis shall apply the Operational Environmental Risk Analysis Tool (OPERAto) combined with a thorough analysis of blowout probabilities and blowout rates given application of best available technology and barrier philosophy. The analysis will take into account:

- type of technology applied and its reliability
- specific barriers applied and their reliability

- Potential human factors that can influence the risk level
- Time of year that the exploration drilling is carried out

1.3 The Basis Well

To have a specific well for this analysis a previously drilled well from the Norwegian Sea was selected as a basis well. The well is a Statoil exploration well called Bjørk which was drilled with the rig Ocean Vanguard at 337 meter water depth. It was drilled within PL 352, north of Norne, in 2007 \15\. The well has reservoir and hydrocarbon parameters that give quite high flow rates, but the well is similar to most other wells on the Norwegian continental shelf (NCS). The well location was then moved to Nordland VI at the same location as the one used for impact assessment in the updating of the Lofoten – Barents Sea Management plan (Figure 1-1). The well properties that are applicable for this analysis are described in section 7.1.

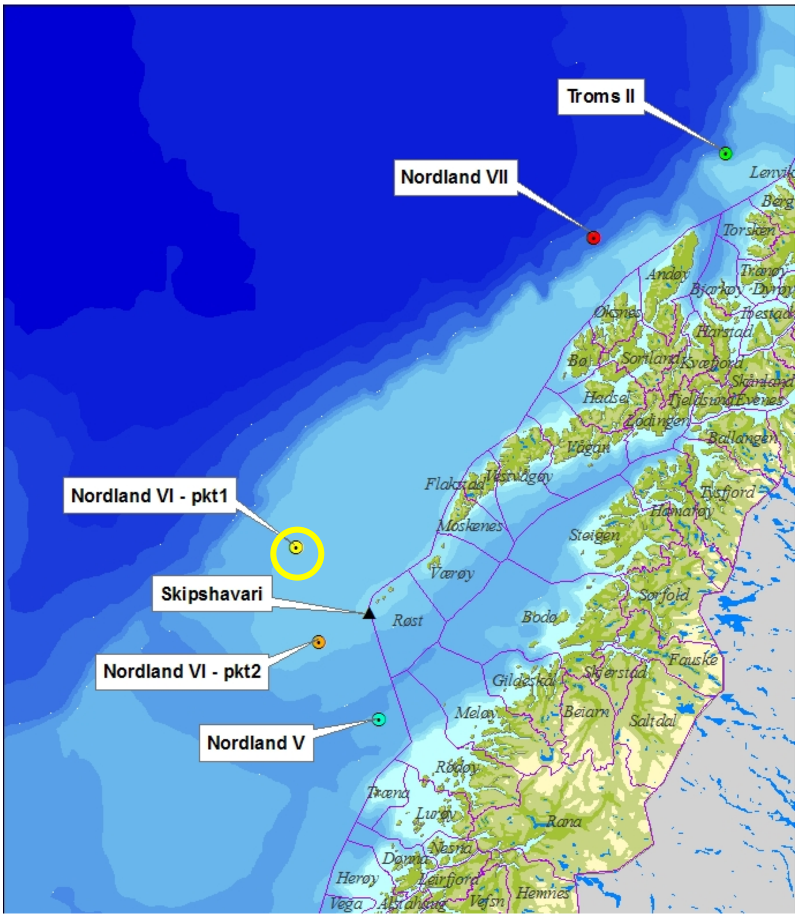


Figure 1-1 Location of the hypothetical exploration well used in this analysis is the same as Nordland VI pkt1 that was used as a potential field development site in the impact assessment for the updated Management plan, see the yellow ring in the map.

2 METHODOLOGY

2.1 OPERAto work process

Figure 2-1 provides an overview and a diagram of the main work process and activities. A more detailed approach to the activities explained in the subsequent sections.

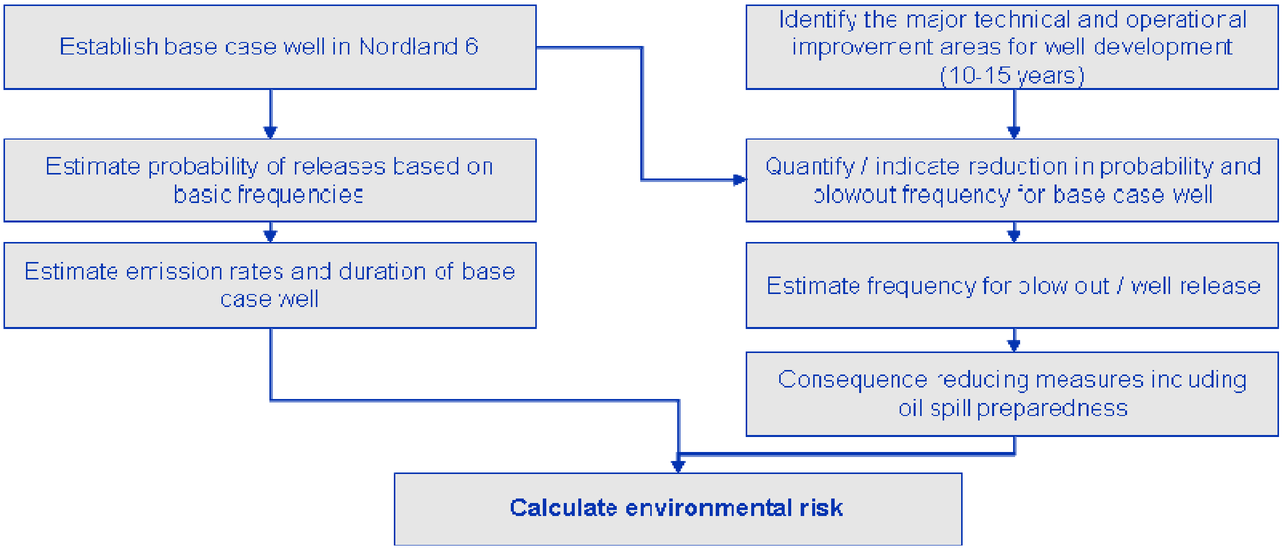


Figure 2-1 The OPERAto work process

2.2 Method for quantifying reduction in blowout probability

The methodology for quantifying reduction in blowout probability due to improvement of technology, equipment reliability and operating procedures is schematically shown in Figure 2-2.

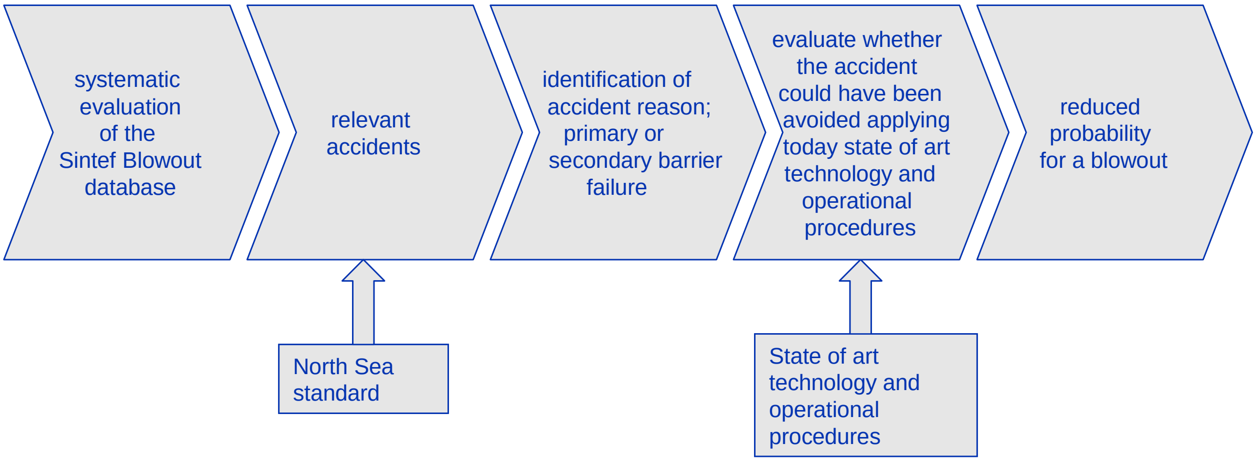


Figure 2-2 Schematic overview of the evaluation of risk reduction

2.2.1 Identification of technical and operational improvements

A brainstorming workshop, similar to a HAZID session, was conducted with participation from the technical experts from both Statoil and Shell to identify technical improvements with respect to drilling operations. This exercise is covered in detail in an own section, see Chapter 5.2.

2.2.2 Blowout probability for the base case

The frequency for blowouts and well releases for the base case is based on the historical data from the SINTEF Offshore Blowout Database (ref, \3\). The SINTEF Database is a comprehensive event database for blowouts. The database includes information on 544 offshore blowouts and well releases that have occurred world-wide since 1955 and overall exposure data from the US Gulf of Mexico, Outer Continental Shelf and the North Sea. The blowouts/well releases are categorized using several parameters, with the main emphasis on blowout causes and descriptions of the event.

The database contains 51 different fields describing each blowout/well release. In addition, the database allows for attachment of any electronic file(s) to the blowout description. The various fields are grouped in six different groups:

1. Category and location
2. Well description
3. Present operation
4. Blowout causes
5. Blowout characteristics
6. Other

The database also covers the overall offshore drilling and production exposure data for the US GoM OCS, Norwegian, and UK waters since January 1980. In addition, drilling exposure data for the Dutch Continental Shelf, the east Coast of Canada, Australian waters, Danish waters and the US OCS Pacific are included.

Scandpower is contracted to establish and yearly update blowout and well release frequencies based on the records in the SINTEF Blowout Database. The most recent Scandpower report (\2\) presents blowout frequencies based on data from the areas of US Golf of Mexico Outer Continental Shelf and North Sea in the period of 01.01.87 – 31.12.06. The frequencies are industry recognised to be applied as basis values in risk analysis on operations of the North Sea standard in terms of practice and equipment.

For the Nordland VI base case, the frequencies and data from the Scandpower report and SINTEF Blowout Database have been used as a basis for the analysis. A generic fault tree was then developed to highlight the contributing factors to this blowout frequency. Results and conclusions for the base case are presented in section 4.1.

2.2.3 Estimate blowout probability for exploration drilling in Nordland VI based on state of the art technology, the "alternative case".

The output of the activity described in the previous section is a given probability for blowout applicable for the study basis for Nordland VI, based only on historical data. The probability is calculated from a subset of incidents extracted for the SINTEF Blowout Database. These subsets of incidents combined with the output of the Improved Technology Review, see section 2.2.1, are used as input for estimating an altered blowout frequency for modern drilling operations.

For estimating the blowout frequency when considering the improved technologies over the last 10 years, two different approaches were undertaken.

1. *Bottom – up approach:* For the Bottom – up approach the starting point is the dataset that formed the base case frequency. Each of the incidents is reviewed in detail by DNV subject matter experts. The objective of the exercise is to reduce or eliminate the occurrences from the sample data set by applying the study basis for Nordland VI, i.e. location, type of installation and drilling program. From this new reduced subset, a blowout probability for a modern drilling operation is to be calculated.
2. *Top – down approach:* For the top – down approach the starting point is the list of Improved Technologies. The Improved Technology is divided into four main categories; Equipment Reliability, Procedures, Technology and Human Factors. Within these categories the areas which play the most significant part in improving the primary barrier, secondary barrier and/or well control are identified. This was done by looking at company recognition, external credibility, barrier impact and implementation success. These areas are quantified by using new research, experience and expert judgement.

For the base case Nordland VI, the blowout probability is based on the historical data combined with the recognised industry technology improvements. A fault tree is developed to justify the future case frequency to highlight the driving components contributing to failures, also showing the improvements from the base case.

Results and conclusions for the base case are presented in section 4.1.4.

2.3 Environmental risk analysis methodology

The environmental risk analysis methodology follows the OLF guidelines \7\ and \16\. Figure 2-3 shows a schematic overview of the steps in the analysis.

- The system description gives the description of the well, its location and the type of drilling equipment and procedures applied. The type of drilling equipment and procedures applied is normally very generically described. However this is an important part of the OPERAto as this defines the applied equipment and procedures and makes room for evaluation of improved technology or procedures.
- The oil spill scenarios is calculated based on well and reservoir specific parameters. The flow rate of hydrocarbons in the blowout is analysed using OLGA. The duration of a potential blowout is calculated based on the Sintef offshore blowout database. While the probability of each blowout scenario (rate and duration) is calculated based on the methods described in section 2.2.

- Oil drift modelling is conducted for all the various oil spill scenarios applying the OS3D model. The model is closer described in Appendix 6.
- The mortality of specific sensitive environmental resources is calculated as population reduction in percentage of the total population based on the overlap between sensitive resources and oil pollution. For shoreline habitats it is the oil amount polluting the shoreline that is applied. This is closer described in Appendix 5.
- The environmental impact is calculated as the recovery time for a sensitive resource. This means the time it takes for a population or a habitat to recover to the state it was prior to an oil pollution incident. This is related to the percentage of population loss for seabirds, sea mammals and fish. For shoreline habitats is is related to the oil amount at shore. The recovery time is expressed in four categories with increasing severity; less than 1 year recovery, 1 – 3 years recovery, 3 – 10 years recovery and more than 10 years recovery. This is closer described in Appendix 5.
- The probability of having an environmental impact related to the four consequence categories is calculated and compared with company specific acceptance criteria. The comparison with acceptance criteria is not conducted in this work as the focus is on risk reduction and not only the risk value. This is closer described in Appendix 5.
- The last step of the ERA methodology is to evaluate need for further risk reducing measures and re-calculate the risk based on the effect of the risk reducing measures.

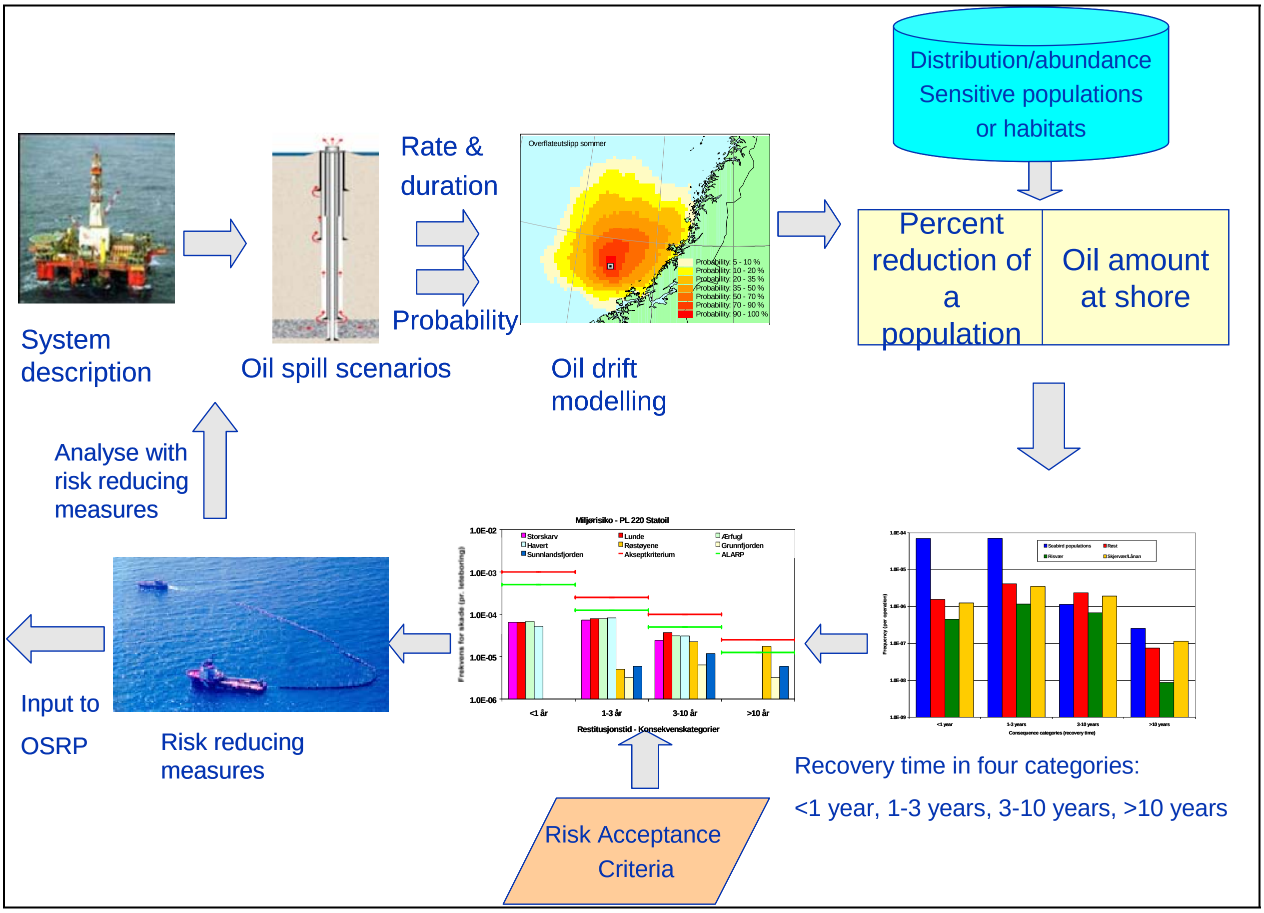


Figure 2-3 Schematic overview of the environmental risk analysis methodology.

3 STUDY BASIS

3.1 Introduction

In this analysis a realistic potential exploration drilling operation in Nordland VI has been evaluated. Such a drilling operation would most likely be drilled from a semi-submersible drilling rig which would be moored to keep the position during the entire drilling operation. Figure 3-1 provides an illustration of a drilling rig.

Figure 3-1: Semi-submersible drilling rig – Typically used in Norwegian waters

3.2 Exploration Drilling

Oil drilling is the process of perforating the earth's surface and rock layers to extract fossil fuels, or oil, for energy production. Exploration drilling is performed to explore and gather data related to a possible prospect which can then be used to evaluate the commercial value and consider a site location for future development wells.

3.2.1 Well Design

Well planning is a fundamental part of the drilling operation. Geologists, drilling engineers and geophysics are gathering information in order to predict the formation pressures and the fracture gradient which is used in the well planning. The casing setting depths will be set based on this information. Figure 3-2 provides an illustration of how the estimated pore pressure and fracture pressure in a well is used to determine the mud weight for a drilling operation.

The curves in Figure 3-2 are the most important tool for the drilling engineer when planning a drilling operation. Based on these curves, the drilling fluid density (mud weight) is determined and the casing setting depths defined. Too high mud weight will fracture the formation which will lead to loss of drilling fluid into the formation. Too low mud weight will lead to influx of formation fluids into the wellbore (kick) and/or collapse of the borehole. Consequently the mud weight is selected to provide a balance between the pore pressure and fracture pressures in the formations as illustrated in the figure.

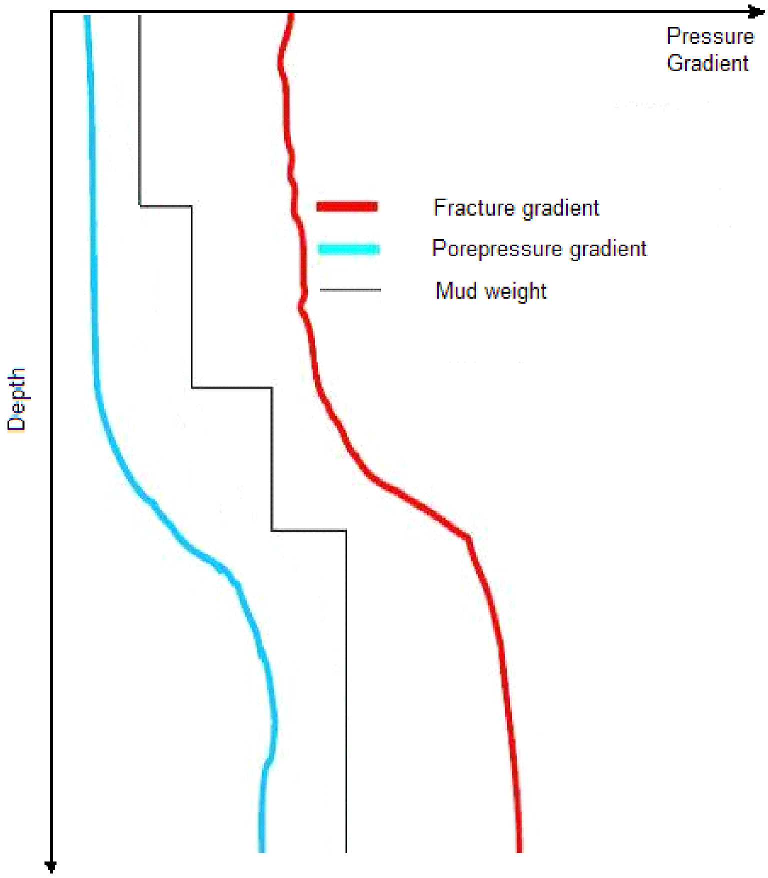


Figure 3-2: Pressure prognosis including pore pressure, collapse pressure and fracture pressure for the formations and planned mud weight.

3.2.2 Hole Sections

As indicated in Figure 3-2 the well is build up as a step function defined by the pore pressure and fracture gradient. The main steps in a typical well program are illustrated in Figure 3-3, and can be summarized as:

- *Conductor Pipe* - Typically, a wide conductor pipe, usually 30” in diameter is used to stabilise the top section of the well. The conductor pipe is typically set 50 to 120m below the sea bed.
- *Top Hole (18 5/8” Casing)* - This section is drilled from bottom of the 30” conductor and normally down to just above where the pressure starts to build up on the pore pressure curve. Offshore floating rigs will drill this hole section ‘open’ allowing the seawater to act as the drilling fluid and return the drilled cutting to the seabed, thus it is normally drilled without a BOP.
- *Intermediate Hole (13 5/8” Casing)* - In general, the BOP stack will be installed once the top hole casing has been set. When drilling the intermediate hole a riser will then be connected to

return drilling mud and cuttings to the surface. In the case of offshore floating rigs, the BOP stack is installed on the seabed where the casing strings terminate. The marine riser will link the BOP stack to the rig completing the closed system. A diverter is always installed as part of the surface flowline system, so that, if the well is not able to be controlled by the BOP's, and returns are reaching surface, gas can be directed safely away from the rig.

- *Production Casing (10 ¾" Casing)* – The production casing is the final casing which will be set before drilling into the reservoir. Similar to the intermediate hole section this section will be drilled with the BOP and marine riser installed.
- *Reservoir Drilling (8 ½" hole)* – When drilling into the reservoir a drill bit which drills an 8 ½" hole is typically used. Drilling mud is pumped through the drill pipe and returned fluids with drill cuttings is being returned up through the annulus between the drill pipe and the production casing wall.

Figure 3-3 provides an illustration of a typical well plan.

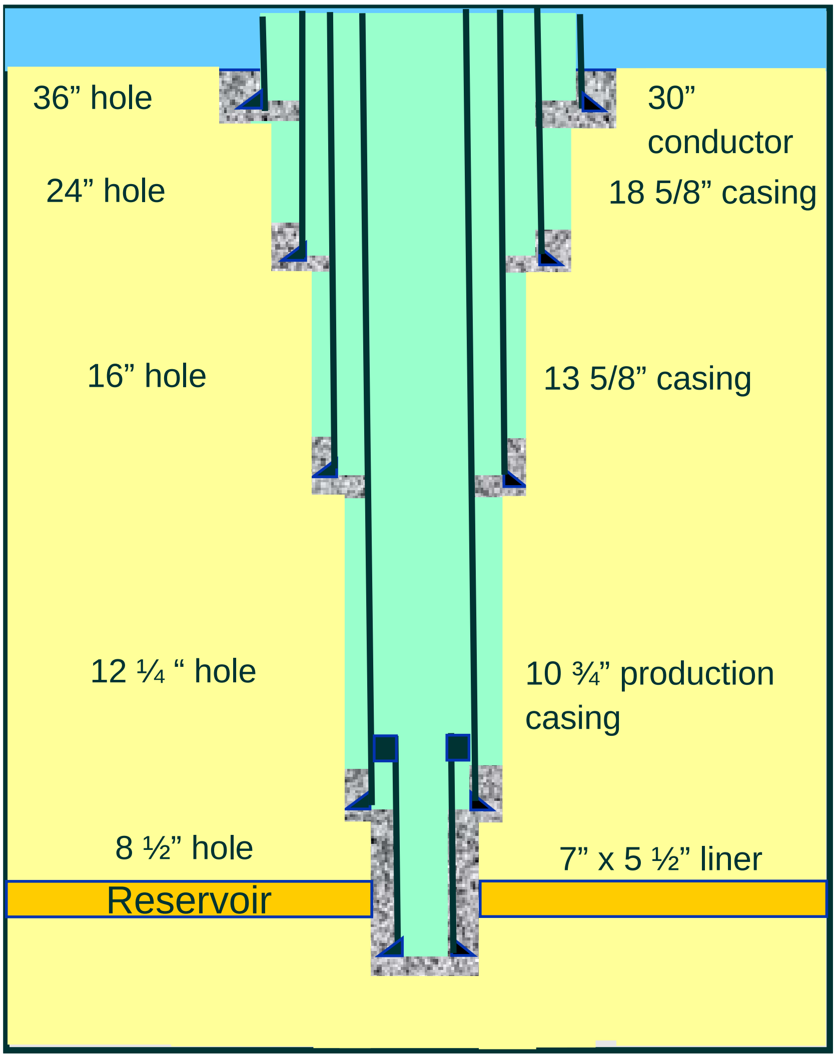
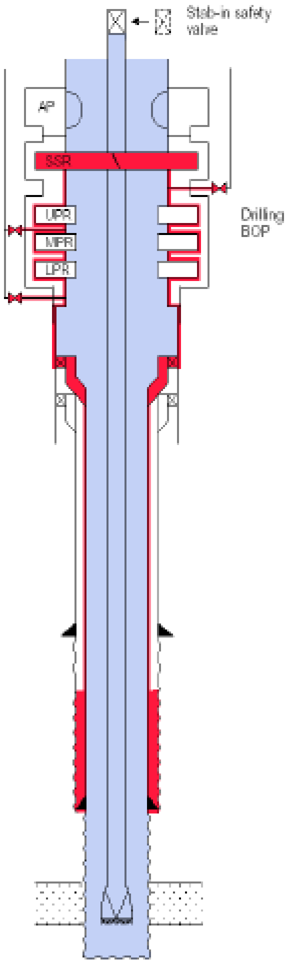


Figure 3-3: Illustration of a typical well

3.3 Well Barriers

In all well operations two tested and independent well barriers are in place at all times. Each barrier is in itself intended to prevent uncontrolled flow of reservoir fluid to the surroundings (blowout). A blowout may only occur when both well barriers fail, i.e. both the primary barrier represented by the drilling fluid column and the secondary barriers represented by the blowout preventer (BOP), wellhead, cement and surface casings. This is illustrated in Figure 3-5 in the form of a Fault Tree model, where loss of well control is a result of both (and-gate) loss of the primary and the secondary well control barrier.

5.8.1 Drilling, coring and tripping with shearable drill string



Well barrier elements	See Table	Comments
Primary well barrier		
1. Fluid column	1	
Secondary well barrier		
1. Casing cement	22	
2. Casing	2	Last casing set.
3. Wellhead	5	
4. High pressure riser	26	If installed.
5. Drilling BOP	4	

Note

None

Figure 3-4. Illustration of a well barrier schematic for a typical drilling phase. Primary barrier (drilling fluid column) is illustrated in blue, the secondary barriers are illustrated in red. Figure is taken from NORSOK D-010.

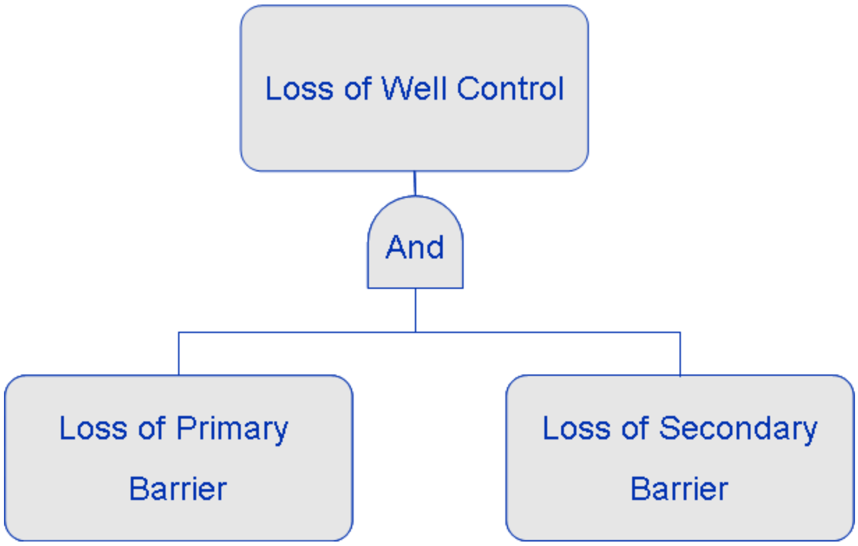


Figure 3-5: Fault Tree representation of loss of well control

When loss of primary well barrier occurs, commonly called a kick, formation fluids begin to flow into the wellbore. If the well is not shut in, a kick can quickly escalate into a blowout when the formation fluids reach the surface, especially when the fluid contains gas which rapidly expands as it flows up the wellbore. Blowouts can cause significant damage to drilling rigs, injuries or fatalities to rig personnel, as well as polluting the environment.

3.3.1 Primary Barrier

During the drilling operations, the drilling fluid (mud) column represents the primary well control barrier. The density of the drilling mud is normally set to provide an over-balance compared to the reservoir pressure (pore pressure), thus the hydrostatic pressure represented by the mud column prevents the well from flowing. In conventional drilling, loss of the primary barrier therefore implies loss of the hydrostatic pressure represented by the mud column. This hydrostatic pressure may be lost as a result of:

- Kicks: Flow of reservoir fluids into the wellbore during the drilling operations, due to insufficient pressure on the formation. Kicks may also be triggered by the operator, i.e. influx may be caused as a result of swabbing effects when pulling out of the hole, so called tripping operations.
- Lost Circulation: Reduced or total loss of the returned fluids in the annulus. In the worst case part of the hydrostatic column in the wellbore may also be lost, resulting in an immediate underbalanced situation.

While lost circulation could be challenging, it does not by itself necessarily result in a hydrocarbon influx. If the operating procedures are followed, the drilling operator should be able to prevent an influx as a result of a fluid loss.

The essential part of well control during the drilling operation is therefore to maintain the appropriate mud density, or mud weight. If the formation pressure increases, mud density should also be increased, using barite or other weighting agents, to balance the pressure and keep the wellbore stable. Unbalanced formation pressures will cause an influx into the wellbore potentially leading to a blowout of formation fluids. If the mud weight is too high the mud will fracture the formation and the fluids will be lost. This could in turn result in an influx if the overbalance is lost.

3.3.2 Secondary Barrier

The secondary well control barrier includes the blowout prevention equipment, such as the BOP rams, kill/choke lines, wellhead seals, casing and cement. A blowout preventer (BOP) is a large block with valves, the so called ram blocks, which can seal off the wellbore. During the drilling operation the BOP rams or annular preventers may close in the event of an influx. By closing the BOP (usually operated remotely via hydraulic or electric actuators), the drilling crew can prevent an uncontrolled blowout. Once the well is shut-in, the drilling mud density can be increased until adequate fluid pressure is being placed on the influx zone, the BOP can be opened and the drilling operations resumed.

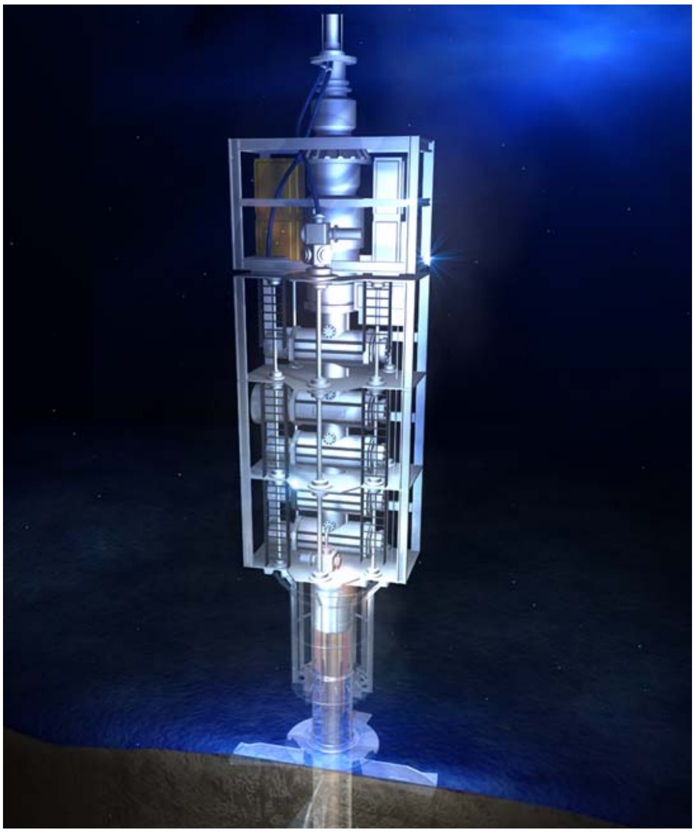


Figure 3-6: Subsea Blowout Preventer (BOP)

3.3.3 The Well Control

In addition to the physical well barriers, well control is an important element of preventing an uncontrolled blowout. Well control is the procedure and process related to regaining control of a well in the event of failure or defect in one of the physical well barriers. Well control includes the process of circulating heavier drilling mud into the well in order to regain the pressure control. During a well control situation the secondary barrier will always be important to prevent the uncontrolled flow of hydrocarbons.

4 BASE CASE DATA FOR BLOWOUT PROBABILITY

4.1 Historical Data

Referencing section 2.2.2, the SINTEF Offshore Blowout Database and Scandpower report, ref /3/ and /2/ are used as basis and starting point for calculating the probability of a blowout.

4.1.1 SINTEF Offshore Blowout Database

The SINTEF Offshore Blowout Database includes information on 544 offshore blowouts/well releases that have occurred world-wide since 1955.

The data base is searchable with respect to all the fields of the data base. The following was applied as the basis for the Nordland VI well:

- Blowout (restricted to surface flow)
- US GoM OCS, UK, Norway, the Netherlands
- North Sea standard (implies two barriers throughout all well operations)
- Normal well (shut in wellhead pressure below 690 bar and/or bottom hole temperature below 150°C)
- Exploration drilling
- Semisubmersible rig
- No shallow gas incidents
- From 01.01.1987 and onwards

The search with the above Nordland VI input parameters returned no reported blowout or well releases amongst the 11 358 drilled wells categorised as exploration wells for this period, hence no such incident similar to the study basis has occurred in the given period of time. However, if ignoring the normal well parameter, the database returns one reported incident; a blowout in the British sector on a HPHT well in 1988. The same number of wells were included in this search due to that the exposure database does not filter on normal vs. HPHT wells.

For risk analysis on the NCS, only incidents from the Norwegian and British continental shelf, the Netherlands and deepwater areas in the Golf of Mexico are of interest. This because in these locations are required to have what is called North Sea standard, two barriers present during all drilling operations. Thus, only these locations are applicable for the Nordland VI project.

4.1.2 Scandpower Report – Blowout and Well release probabilities

Scandpower annually releases a report with blowout and well release probabilities based on the records in the SINTEF Blowout Database. Ref /2/, the latest report presents frequencies based on data from the areas of US Golf of Mexico Outer Continental Shelf and North Sea in the period of 01.01.87 – 31.12.06. The Scandpower report is well known in the industry and is widely used in risk assessment work done for the NCS activities.

Table 4-1 Summary of blowout and well release probabilities extract from ref /2/

Operation	Category	Probability, average well	Probability, gas well	Probability, oil well	Unit
Exploration drilling, deep (normal wells)	Blowout	**$1.54 \cdot 10^{-4}$**	$1.47 \cdot 10^{-4}$	$1.63 \cdot 10^{-4}$	Per well
Exploration drilling, deep (HPHT)	Blowout	$9.55 \cdot 10^{-4}$	$9.12 \cdot 10^{-4}$	$1.01 \cdot 10^{-3}$	Per well
Wildcat drilling, deep (normal wells)	Blowout	$1.38 \cdot 10^{-4}$	$1.32 \cdot 10^{-4}$	$1.46 \cdot 10^{-4}$	Per well
Wildcat drilling, deep (HPHT wells)	Blowout	$8.56 \cdot 10^{-4}$	$8.17 \cdot 10^{-4}$	$9.03 \cdot 10^{-4}$	Per well
Appraisal drilling, deep (normal wells)	Blowout	$1.72 \cdot 10^{-4}$	$1.64 \cdot 10^{-4}$	$1.81 \cdot 10^{-4}$	Per well
Appraisal drilling, deep (HPHT wells)	Blowout	$1.06 \cdot 10^{-3}$	$1.02 \cdot 10^{-3}$	$1.12 \cdot 10^{-3}$	Per well

Based on the Scandpower report, Table 4-1, the blowout probability for an exploration well with normal reservoir pressure and temperature is $1.54 \cdot 10^{-4}$ per well. The geology in the Nordland VI area indicates reservoirs with pressure and temperature well within the limits of a "normal reservoir" (based on communication with Statoil). It is not expected to find HTHP reservoirs in the area. Thus the basis probability of having a blowout from an exploration well in Nordland VI is $1.54 \cdot 10^{-4}$. That is equal to one blowout per 6 493 drilled well. The blowout scenario, however, will vary from a short to long durations and small to large flow rates. The probability of the various scenarios is calculated in chapter 7.

To obtain the probability in Table 4-1, Scandpower has based the calculations on one incident in the North Sea and additionally an evaluation of other relevant incidents to differentiate between, amongst others;

- Development Drilling versus Exploration Drilling
- Normal wells versus HPHT wells

The one (1) incident reported in the North Sea, which is a blowout from 1988 in the British sector on a HPHT well, founds the basis frequency of 1.0×10^{-4} blowouts/well drilled. This incident concerned a semisubmersible installation. During the same period a total of 9 868 wells were drilled. The number of wells includes all drilled wells, exploration and development, in the North Sea UK, Norway and the Netherlands for all types of installations.

To calculate a distinct probability for development and exploration drilling, incidents for both blowouts and well releases during the same period and areas were used. These calculations implied that the blowout probability for exploration wells is 4.1 factor higher than development wells. Scandpower has done a similar exercise to distinguish between Normal and HPHT wells, giving a 6.2 factor higher frequency for blowouts for HPHT wells. These factors gives the probability of $1.54 \cdot 10^{-4}$ blowouts/well from the basis frequency of 1.0×10^{-4} blowouts/drilled well.

4.1.3 Trends in Scandpowers recommended blowout probability

The base probability represents an average blowout probability from the past 20 years (1987-2007). The single event that forms the basis for the frequency for 2010 occurred in 1988. When exploring the trend the past 10 years, based on the annual Scandpower reports, the base probability for an exploration well has been reduced by a factor of more than 3.5, from $5,5 \cdot 10^{-4}$ to $1.54 \cdot 10^{-4}$.

4.1.4 Review of Events

For the Nordland VI project this one incident on a HPHT well was considered as a too small sample to further conduct any further analysis on. It was decided to work on a list of 23 relevant incidents which the Scandpower report uses as basis for their main class. These incidents are reported blowouts during deep exploration and development drilling in the period 01.01.87 – 31.12.06, mostly from the US Gulf of Mexico Outer Continental Shelf (US GoM OCS).

The sample includes 23 blowout incidents and exposure data for about a total of 30 000 wells, 20 000 operations in the GoM and 10 000 in the North Sea. It can be derived that 96% of the incidents are from US GoM OCS, while the North Sea includes 4% of the incidents. This indicates a blowout frequency for the GoM which is approximately 9 times higher than in the North Sea. Even though it two barriers against formation fluids is required for well operation at both locations, it is justly assumed that the quality of the barriers is lower in the GoM.

These 23 incidents are extracted from the database using the following parameters:

- Blowout (underground flow or surface flow)
- US / GoM OCS, UK, Norway and the Netherlands
- Normal well (shut in wellhead pressure below 690 bar and/or bottom hole temperature below 150°C)
- Exploration drilling and Development Drilling
- From 01.01.1987 and onwards

The data set includes 22 blowouts in the US GoM and 1 in the North Sea.

The parameters are chosen to give a number of events to conduct further work on, as well as they are used in the Scandpower report which is industry recognised.

Each of the 23 reported incidents were reviewed in detail by DNV subject matter experts, investigating the cause and characteristics of the blowout and the loss of barriers.

Table 4-1 Example of the individual incident review

ID	Installation type	Main Category	Loss of barrier 1	Primary	Loss of barrier 2	Secondary	Well Control	North sea standard	Improved Technology	Nordland VII relevant	Comments
524	Jacket	Blowout (surface flow)	A9.TOO LOW HYD. HEAD - RESERVOIR DEPTH UNCERTAINTY (unexpected shallow zone above top of cement)	X X X	C5.INNER CASING FAILED	X	X X	Yes	1.1 Blowout preventer equipment improvements. 3.7 Direct pore pressure measurement during drilling operations. 3.17 Improved pore and fracture pressure prediction 3.24 Pore pressure evaluation	Yes	Better seismic. Logging of well. Equipement reliability.
570	Semisubmersible	Blowout (surface flow)	A15.TOO LOW HYD. HEAD - UNKNOWN WHY		B13.DRILLING WITHOUT RISER			Yes		No	Before installing the drilling riser (26"). Shallow gas.

For **each incident** the cause and characteristics of the blowout and loss of barriers were compared to the technical and operational improvements list, see example in Table 4-1 above.

Focus for the session was to:

- understand what went wrong during each incident.
- consider if the incident could occur given todays technology and experience in the North Sea and the Nordland VI well.
- assess if the incident could be avoided or consequence reduced with the technical and operational progress we have had in the industry.
- asses if the potential improvements applies to the primary barrier, secondary barrier or well control operations.

Findings from the sessions were that all the 23 incidents could either be eliminated or the probability reduced due to required North Sea standards and drilling program and procedures and / or improved equipment and technologies.

The following summaries the major findings (blowout database id is referenced):

- 3 (288, 460, 478) of the 23 incidents would not occur with a semisubmersible with the BOP located subsea. These incidents include for leaks below the BOP.
- 7 (311, 324, 390, 420, 425, 448, 476) of the 23 incidents would not occur since it is required to have two barriers in place at all times throughout well operations. The 7 incidents did all occur while the BOP or diverter was not in place or removed.
- 6 (471, 476, 479, 507, 518, 570) of the 23 incidents included shallow gas problems and were not considered relevant for this analysis. The search did not explicitly include shallow gas incidents, but some show up in the search due to that they are categorised different in the database, i.e. blowout with totally uncontrolled flow from a shallow zone.
- Approximately a quarter of the incidents occurred during cementing or while cement setting. It is generally recognised that the industry has improved pressure control during cementing and improved cement quality which will improve the primary barrier.

A complete review of the incidents can be found in Appendix 4.

The survey shows that applying Norwegian operational requirements and standards significantly reduces the frequency related to incidents from other offshore sectors. It is not possible however, to quantify the exact benefit in risk reduction for Norwegian operations given these evaluations.

5 TECHNOLOGY EVALUATION

5.1 Methodology

Based on the historical data for blowouts, a list of predefined issues, or areas of concern, which could impact the probability of a blowout was systematically reviewed. Major technological improvements, including organizational elements, were systematically identified as they related to the main topics being discussed. The main topics considered in these review meetings, included:

9) BOP reliability

10) Procedures

11) Technology

12) Human Factors

The technology evaluation was reviewed over two workshop meetings; the first workshop was conducted at Gardermoen on the 4th of December 2009 and the second at Statoil's facilities in Stavanger on the 12th of February 2010. Most of the technical content and details was however provided by the technical experts in the participating operating companies and was populated outside these review sessions.

The objective with the first session was to establish the framework and the basis for the assessment and evaluation of technological improvements. A structure and format was established, and the topics listed above were reviewed to identify initial ideas with respect to technologies and processes used during drilling operations which could impact the loss of well control. This material was then distributed to the technical experts in the different operating companies involved where more details and specific information related to the various technologies was added.

Focus of the second review workshop was to review and rank the different technologies and areas of improvements which had been proposed, and to highlight the main contributors which could reduce the probability of a blowout. In order to easier evaluate the impact of the technologies, or areas of improvement, each topic was evaluated with respect to how it would improve the reliability of the drilling operation. Thus, a qualitative ranking was provided to indicate the improvement related to the primary and the secondary well barrier, and finally also the impact on well control procedures.

The format of the spreadsheet that was used in this process is given in Figure 5-1. For each of the main topics identified to possibly have an impact on reducing the probability of a blowout, relevant issues or technological improvements were identified and described. Further, the spreadsheet includes a ranking of the improvements identified into Low, Medium and High as they relate to the primary well barrier, the secondary well barrier or the well control operations. Thus, for each of the improvements a ranking was given to highlight the improvements which were considered to have a high impact on the blowout probabilities, medium and low.

ID	Description	Effects/Impacts	Primary Barrier	2ndary Barrier	Well Control	Comments
1	Equipment Reliability					
1.1	Blowout preventer (BOP) equipment improvements	Improved reliability of control systems		M		Lessons learned from more advanced technology related to deep water and HPHT drilling operations. Statoil has performed BOP campaign with good results. New monitoring plan are in progress.
1.2		Improved reliability of ram blocks and lock mechanisms		M	M	
1.3		More robust BOP stack setup with double annular preventer, minimum 3 pipe rams and shear ram. Improved closure reliability and operability		M	M	Two annular preventers is not yet fully standard in the North Sea
1.4		New shear RAM developed and is more likely to make a successful cut, i.e. Improved closure reliability when string/cable cut is required.		M	L	Can cut cable ect. Cameron and Shaffer has the new shear ram. Hydril will soon perform test.
1.5		Extra BOP pressure rating safety margin due to high design pressure on the exploration rigs.		M	?	In general the rig equipment spec is higher than the well design.
1.6	Improved testing, management and maintenance of BOPs.	Better knowledge and understanding on optimal testing frequencies – more testing does not necessarily make the system more reliable. The maintenance procedures have improved.		M		The reliability management on the component level has improved. It is recommended to use rigs with proven track record. Statoil has performed BOP campaign with good results. New monitoring plans are in progress.
2	Procedures					
2.1	Improved operating procedures	The drilling procedures have improved in general with respect to pressure control and well control focus. Particular improvements within HPHT and operations with smaller margins.	H		H(M)	Improved focus as a result of the experience related to HPHT, depleted reservoirs and deep well operations.
2.2	More comprehensive risk assessment processes	Drilling procedures are more systematically subjected to quality reviews and risk assessment.	H	H	M	

Figure 5-1: The Technology Review Spreadsheet

5.2 Technological Improvements

In this section of the report, the main areas of improvements identified during the technology and improvement review evaluation are highlighted and explained in more detail. The complete spreadsheet which was populated during this review session is included in Appendix 2.

5.2.1 BOP reliability

Recent studies (Ref /5/, and /10/) indicate that the reliability of the BOP system have improved over the last decade. These improvements have primarily been related to the hardware of the system, and the focus has been to improve the operational performance of this equipment in order to avoid unnecessary downtime, i.e. non-productive time. The benefits however, are also seen towards reliability of the system in emergency situations.

In theory, a modern subsea BOP stack should be able to stop any type of influx whether the flow is through the drill string, the annulus or an open hole, even if one or more of the BOP components have failed. Many of the previous problems related to the BOP stacks, i.e. leaks in the shear RAM after cutting and failure to keep closed, have essentially been eliminated with design improvements over the last years.

The specifications and requirements for the BOP systems have increased. Today's recommendations in high risk well operations are double operating barriers, i.e. two annular preventers. This improvement increases the operational flexibility in the event of a kick, and will increase the reliability of the well control system during critical operations.

Further, recent developments in high pressure high temperature (HPHT) drilling has also resulted in improved drill pipe and BHA (Bottom Hole Assembly) properties. Improved material strength and ductility of drill pipe have reduced the number of trips required when drilling the well. Further, these harder materials have also increased the requirements in force for shearing a drill pipe (Ref /11/). Today, every operator needs to be able to operate the shear-seal rams (SSR), the ultimate rig floor defense against blowouts, and seal the well in a reliable way after having cut the drill pipe. Recent design improvements for the SSR have overcome some of the difficulties related to sealing after cutting the drill pipe and have resulted in more reliable well control equipment. This is an example where more demanding field operations (i.e. HPHT-operations) have helped the industry by providing better and more reliable systems which are now also applied in regular drilling operations.

Finally, better testing procedures has helped to improve the reliability of the BOP system even further. The test interval criteria applied today take more into account what operations are being performed, thus making sure critical functions are properly tested before they may be required for well control purposes.

To summarize, it may be argued that the reliability of the BOP system has improved as a consequence of:

1) Less trips due to better materials
2) Improved shear-seal ram (SSR) functions
3) Dual annular preventers
4) Better testing procedures

It could be argued that the increased use of aged drilling rigs and equipment compromise these latest improvements; however even on the older drilling rigs the new well control equipment will be applied. Further, international organizations are currently adjusting their requirements and the standards related to life extension of equipment are becoming much more stringent, requiring detailed re-qualification and evaluations.

5.2.2 Procedures

As a result of more systematic risk assessment processes in the planning phase of drilling a well, the operating procedures have also improved. The topic of risk assessments is discussed in more detail in Section 5.2.4 which covers human factors and organizational improvements related to drilling operations. When evaluating these, it was recognized that several key areas have improved over the lasts decade, including:

1) Better fluid and pressure control
2) Defined contingency plans
3) Improved procedures to avoid influx

Based on discussions with experts within the participating companies supporting this JIP project, examples from previous drilling operations into difficult reservoir conditions were used as examples to illustrate how improved procedures and control of fluid properties have significantly reduced the number of kicks. For the first HPHT wells drilled, the kick frequency was close to one in every two well drilled. This kick frequency has been reduced significantly even for these difficult wells.

Procedures are being developed to reduce and eliminate many of the drilling risks, i.e. stop criteria are used to avoid drilling into high pressure zones or the reservoir unintentionally. Further, the procedures related to fluid control and always maintain the hydrostatic mud balance has had an impact on the kick frequency. The kick frequency is discussed in more detail in Section 5.2.3 which covers the technological improvements which is very focused on control of the primary well control barrier.

Another key area which has improved over the last years is the development of detailed contingency plans. Specific procedures are developed to manage difficult situations and avoid escalation of critical events. Thus, risks and possible difficulties are to a much larger extent identified and evaluated in the planning phase.

5.2.3 Technology

When reviewing the technological advances related to the drilling operation, two main topics were discussed in detail:

1) Better and more reliable up-front reservoir predictions and information

2) Real time data related the primary barrier and the pore pressure

Some of the key technological improvements which were evaluated and considered to have had significantly impact on the reliability of the well control system are explained briefly in the sections below:

5.2.3.1 Measurement while drilling (MWD)

Measurement while drilling (MWD) is a system which performs downhole measurements and transmits information to the surface supported by developments in fiber optics, advance sensors, and mud pulse telemetry in real time in every step of drilling. MWD tools are conveyed downhole as part of the bottom hole assembly (BHA). MWD systems today can cover several parameters typically enclosed previously in logging, like natural gamma ray, borehole pressure, temperature etc. Some of the latest advances in MWD provide the opportunity to have real time measures of formation pressures, vibrations, shock, torque etc. The measured information is transmitted digitally to surface using mud pulsar telemetry through the mud or other advanced technology.

MWD tools provide accurate downhole measurement of equivalent circulating density (ECD) which results in better kick detection, including shallow water flows. Also, MWD provides better control of swab/surge pressure while tripping and reaming crucial for avoiding the more usual kicks. Other applications of MWD which helps in well control are: monitoring of hole cleaning, accurate downhole measurement of hydrostatic pressure and effective mud weight. In addition, MWD provides critical information in challenging drilling environments where a narrow window exists between pore pressure and formation fracture gradient, allowing for better fluid control in difficult operations like deep-water drilling operations.

5.2.3.2 VSP look ahead

Current methods of predicting pore pressure of formations penetrated by the drill bit, rely on velocities derived from surface seismic data or detailed surface geological models. The use of new technologies of vertical seismic profile (VSP) like a Look-Ahead VSP has proven to be helpful and increases the accuracy in predicting pore pressures when drilling exploration wells /12/. The look ahead VSP surveys provide reliable information on seismic information below current drilling depth of the well to help locate a suspected pressurized zone, faults, drill bit location and any other useful structural or stratigraphic characteristic that may be predicted by seismic methods /13/.

5.2.3.3 3D seismic

3D seismic data provide detailed information about fault systems and subsurface structures. Computer-based interpretation and display of 3D seismic data allow for more thorough analysis than 2D seismic data. 3D data provides the information in the planning phase leading to safer well construction and better well control procedures.

5.2.3.4 Cementing

Cementing is used for sealing the well. The latest advances in cement slurries and in new equipment used in cementing show improvements. Some of the improvements nowadays are tailor-made cement slurries for each specific field and increasing the solids content of the slurries. More solids in the cement mean greater compressive strength, reduced permeability and greater resistance to corrosive fluids. Such cement jobs reduce the risk of shallow flow and shorten the waiting-on-cement time compared with conventional cement technology.

5.2.4 Organizational and Human Factors

Organizational changes have contributed to more reliable well operations. Active use of knowledge exchange and building on previous experience when planning new drilling and well operations has improved significantly over the last decade. More extensive training of everyone involved in the drilling and well operations has resulted in organizations with better knowledge and understanding of well integrity and the risks involved with the specific operations. Personnel involved in drilling and well operations are continuously followed-up and regular well control training for all operational personnel on the drilling rig is now a requirement.

The better knowledge and understanding of well integrity issues has reduced the operational risks involved. Systematic use of risk assessment processes secures a better planning process which results in more reliable well operations. As was discussed in Section 5.2.2, risks are clearly identified in the plan phase and contingency measures are developed to address these risks. A manifest of the impact of these changes is the significant reduction in kicks and other well control incidents which were experienced in the initial HPHT drilling operations in the 1990s. Similarly, the longer and more complicated drilling operations performed today have not resulted in more incidents; the general trend has been a reduction in incidents despite more complicated and difficult operations.

In addition to the improved knowledge and increased focus on risk assessment processes, there has been a major change in the way the drilling operations are performed today. The amount of information which is now available both to the drilling operator on the rig and to the technical discipline experts in the support organization on land, is significant. As discussed in the previous section, Section 5.2.3, real-time measurements of the mud weight and pore pressure provide the operator with a much better tool to always control the primary barrier.

It may be argued that Integrated Operations primarily was introduced to reduce the costs and move technical experts from the drilling rig to the support organization on land. However, these new technologies and the way of working together as an integrated team provide a unique opportunity to better utilize more of the technical experts in an organization. They now have continuous information about the operations, and can update modes and predictions almost in real-time. Access to other technical experts in the support organization will also be a significant advantage.

There are several methods and techniques to quantify human factors and organizational behavior. In the BlowFAM tool developed by Scandpower there are a number of questions related to the organization which is used to rate the organization and provide a modified blowout probability. The assessment is conducted similar to an audit, where the organization is evaluated on a set of parameters and given a score based on a set of predefined criteria. Other techniques which can be used to evaluate the organizational elements include the Human Error Assessment and Reduction Technique, HEART. HEART is a recognized method for quantifying human factors and the probability of successfully performing a defined task. This assessment is also based on audits which address the organizational elements. The assessment is based on the following two important assumptions:

- Human reliability is dependent on the “generic nature” of the task to be performed. This generic nature gives a nominal reliability that will be achieved if working conditions are “perfect”. (Optimistic Value)
- There is a set of “Error-Producing Conditions” (EPC) that will reduce the reliability of the human to successfully perform the defined tasks. The reliability will depend on the extent to which these EPC apply. (Conservative Value)

HEART defines classes of generic task descriptions with assigned failure probabilities. Further, there are a number of conditions, typically related to an organization which could impact the ability to successfully performed a given task, i.e. stress, fatigue, lack of communication, ownership and responsibility etc. HEART identifies 38 such error-producing conditions (EPC), which should be assessed as part of an audit.

By using either the BlowFAM or the HEART method on a drilling organization, it can relatively easily be demonstrated that there could be a difference of a factor 2 between the blowout probabilities for an organization with certain identified deficiencies compared to an organization which scores well on all the defined criteria. Experience from other industries suggests that this difference could be significant. Experience and statistics from the airline industry indicates that there could be a difference of as much as an order of magnitude between the best and the worst organizations, and this for an industry where the operations and the maintenance is very strictly driven by regulatory requirements which all the airlines would have to comply with. Thus, organizational and human factors could have a significant impact on the blowout probability.

5.3 Conclusions

In this chapter a significant number of improvements in the drilling industry have been discussed and evaluated. It is difficult to quantify the impact of many of these improvements, particularly for a concept evaluation of a drilling operation. For this analysis, there is limited data available for the specific well conditions, i.e. the operating window, and the organization which will be responsible for drilling the particular well, and it is therefore difficult to give credit for some of these elements.

For BOP reliability data, there is an extensive amount of reliability data available based on a series of reliability studies which were conducted by SINTEF for the Minerals Management Services (MMS) in the late 1990-ties, Ref /4/. However, there is limited information available to compare this data with data for equipment which is used in the drilling industry today. It is therefore difficult to quantify the effects of the latest advances and improvements in the technologies. Many operators have collected data from their BOP function tests in internal databases; however, this information is not available in any of the public databases like OREDA. While it is obvious that the improvements made to the BOP system will have had an impact on the reliability of the system, no credit has been given to this in this quantitative evaluation.

Similar, this quantitative analysis has not given any credit to the organizational improvements, which also is related to the improved operating procedures. While experience from difficult well operations have demonstrated significant improvements, which only can be contributed from the organizational factors and better procedures, these effects have not been quantified in this analysis. As explained in the previous section, this is a conceptual evaluation and in order to provide a realistic quantification of these effects, the organization should be known and an audit be conducted, or at least the organization reviewed.

Technological and operational improvements which contribute to a reduced kick frequency is the only improvement which can be justified based on available data. There is significant amount of kick data collected every year, and as will be explained in the next section the kick frequency has reduced significantly over the last decade compared to the experience from the years before, and this despite more difficult well operations.

6 PROBABILITY OF A BLOWOUT

6.1 Introduction

In order to quantify the impact of the technological improvements discussed in the previous sections, a model has been developed which links the different areas evaluated and how they contribute to the overall reliability of the drilling operation. As defined in Section 3.3, loss of well control (blowout) implies loss of both the primary and the secondary well barrier, and a Fault Tree was presented in Figure 3-5.

In this section of the report, the technologies evaluated in the previous section are evaluated and quantified based on relevant information available. In this evaluation credit has only been given to the factors that can be clearly justified based on the data and information available. Further, a generic model which considers the main contributors and the relationships which could result in loss of well control has been developed. The objective has been to develop a base case model which represents the historical blowout data and a modified model which accounts for some of the main technological improvements discussed in the previous section which can be justified based on quantitative data.

6.2 Kick Statistics

It is difficult to quantify the effect of many of the improvements identified in the previous section, the effects may vary greatly with the conditions for a specific well and as such are difficult to quantify in a generic case. The most obvious technological improvement over the last decade is related to the ability to better control the primary well barrier. Better up-front information allows the drillers to develop a more reliable well program, i.e. the risk of encountering unexpected pressure zones has been significantly reduced. This has also manifested itself in the kick frequency.

Based on historical data from 1984-1996, Ref /5/, the kick frequency in the North Sea was in the range of 25-30 kicks per 100 exploration drilling operations. It should be noted that the kick frequency in the North Sea was significantly lower than the kick frequency experienced in the Gulf of Mexico in the same period; the difference is very similar to the difference also found when considering the blowout data. It is clear that there is a logical relationship between the increased probability of a blowout and the kick frequency. This relationship is also the basis for the reliability calculations conducted in this analysis. The Fault Tree presented in Figure 3-5 provides a simplified illustration of the relationship been the kick frequency and the probability of a blowout. A kick will usually be the initial trigger which potentially could result in a blowout if not successfully controlled.

The following scenarios may result in a blowout:

1) A kick which is not successfully shut-in. It is essential that the BOP closes in the event of a kick, i.e. a failure of the secondary well barrier (like the BOP stack or the control system) while taking a kick could result in a blowout.
2) Failure of the casing / cement may also result in loss of the primary barrier and could therefore initiate an influx.
3) A failure when in a well control situation, i.e. a leak in the choke and kill manifold or a leak through the BOP blocks when trying to get the well under control. There is also a risk related

to potential human errors or other unexpected situations (equipment failures or weather conditions) which could be challenging when combating the kick.

If evaluating the more recent kick statistics, 2000 – 2008, it can be concluded that the kick frequency is reduced significantly during the last decade, Ref /1/. Only three years have resulted in kick frequencies on the same level as the average data representative for the period represented by the historical data. With the exception of 2002 and 2005, it can be argued that the kick frequency for exploration drilling has been reduced to between 10 and 15 kicks per 100 drilling operations. It should also be noted that the average kick frequency over the last ten years is lower than ten. It has not been possible to extract and identify all the specific wells drilled in 2002 and 2005, but it is reason to believe that these years involved drilling in high pressure, high temperature reservoirs (HPHT). Information provided by one of the operating companies indicate that there may have been some drilling in HPHT wells in these particular years, which could explain the deviations compared to the other years. There are unique challenges related to drilling in HPHT reservoirs, and it is not anticipated that the wells to be encountered in Nordland VI will have these characteristics.

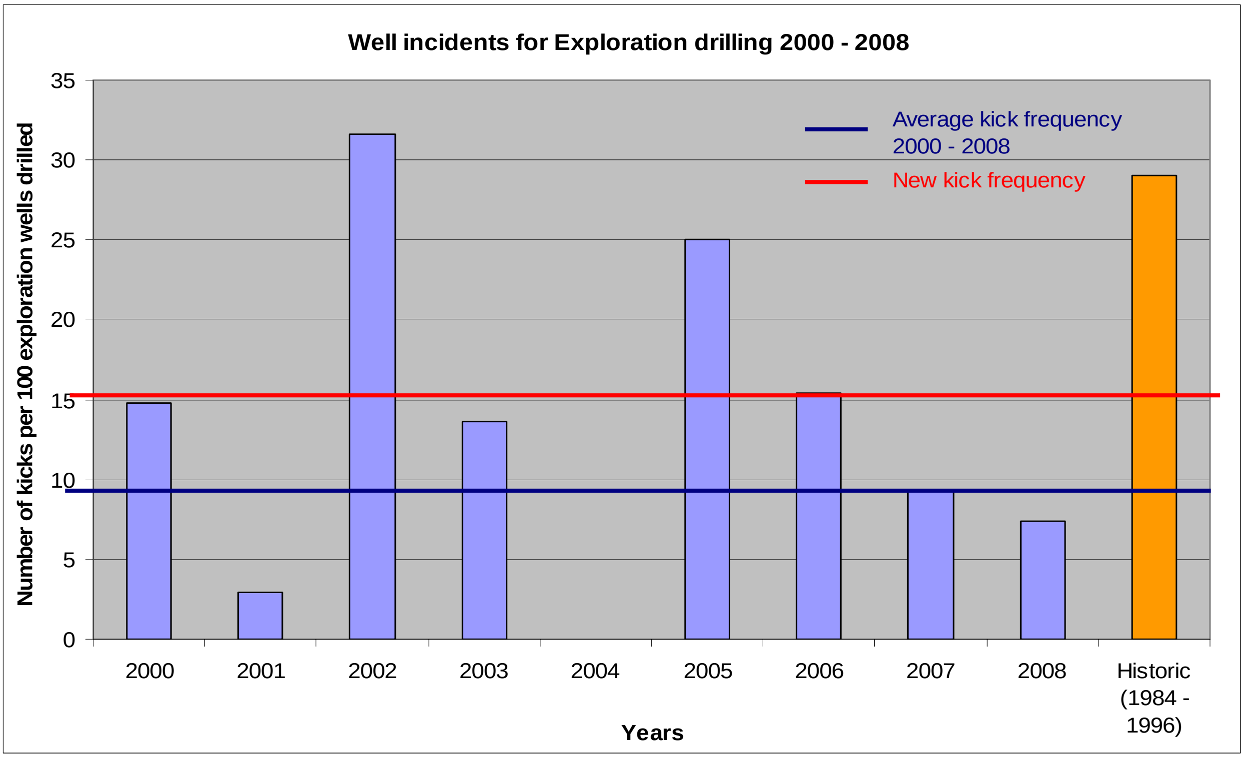


Figure 6-1: Number of kicks for development and exploration drilling

When reviewing this kick data with the technical experts from the participating companies in this JIP, it was concluded that the kick frequency is very dependent on the specific well operation. The operating margin, i.e. the window between the pore pressure and the fracture pressure gradient, is essential when determining the kick frequency. This trend is also supported in the kick data from the historical data material, which indicates that there is a significant increase in the kick frequency for the wells where the operating margin has been less than 0.12 s.g. (1 ppg). You then risk going from a situation where you would be taking influx, to a situation where you would be fracturing the reservoir and take mud losses into the reservoir (drilling above fracturing pressure of the reservoir).

Based on the expert input from the operators, it was concluded that the kick frequency can be categorized into a typical value depending on the operational window in the specific well operation. For a normally pressured well, with a relatively good operating margin, the kick frequency would typically be in the range from one to five kicks per 100 well operations. For wells with a narrow operating window, including the HPHT wells, the kick frequency would be in the range from 10 to 25 kicks per 100 well operations.

It should further be noted that from the blowout data, the frequency of a blowout from a high pressure well is 6.3 times higher than a normal pressured well.

6.2.1 Reliability Model

When developing the generic model to estimate the probability of losing of well control (blowout), historical data for kicks and the reliability for the BOP equipment has been used as a basis. From the historical data for kick in the North Sea, Ref /5/ a kick frequency between 25-30 kicks per 100 well operations has been used as the basis. This data is based on the number of kicks that were report on the Norwegian Continental Shelf in the period 1984 until 1996. Thus, in a similar time period as the blowout statistics.

The kick data could be split into the following categories, or contributors to a kick:

1) Unexpected pore pressure (70%)
2) Swabbing effects (20%)
3) Lost circulation (10%)

In this definition unexpected pore pressure has become the main category which has been defined to include events where the mud weight was too low, gas cut reduced the mud weight and influx was experienced during the cementing operation.

This split was used the basis when constructing the generic reliability model. A summary of the kick data which has been used when generating the generic reliability model is given in Table 6-1. It should be highlighted that the kick frequency used in thus study is an average kick frequency, which also includes experience from HPHT wells. As noted in Section 6.2, the kick frequency is significantly higher in an HPHT well comported to a normally pressured well.

Table 6-1: Summary of the historical data used in the generic model

Well Barrier	Description of scenario	Frequency
Primary Barrier	Kick - Unexpected pore pressure	1.9×10^{-1}
	Kick - Swabbing effects	5.4×10^{-2}
	Kick - Loss of circulation	2.7×10^{-2}

The kick frequency will be directly linked to the probability of a blowout for a particular well operation. As reflected earlier in this chapter, a blowout could emerge when encountering a kick if failures occur during the well control operation or if there is a failure in the secondary barrier, i.e. the BOP system, the cement, casing and wellhead when closing the well. Figure 6-2 provides the generic Fault Tree model which has been developed for the base case model. The kick data is reflected in the initiating events, all the other parameters in the model has been adjusted to generate the historical blowout frequency.

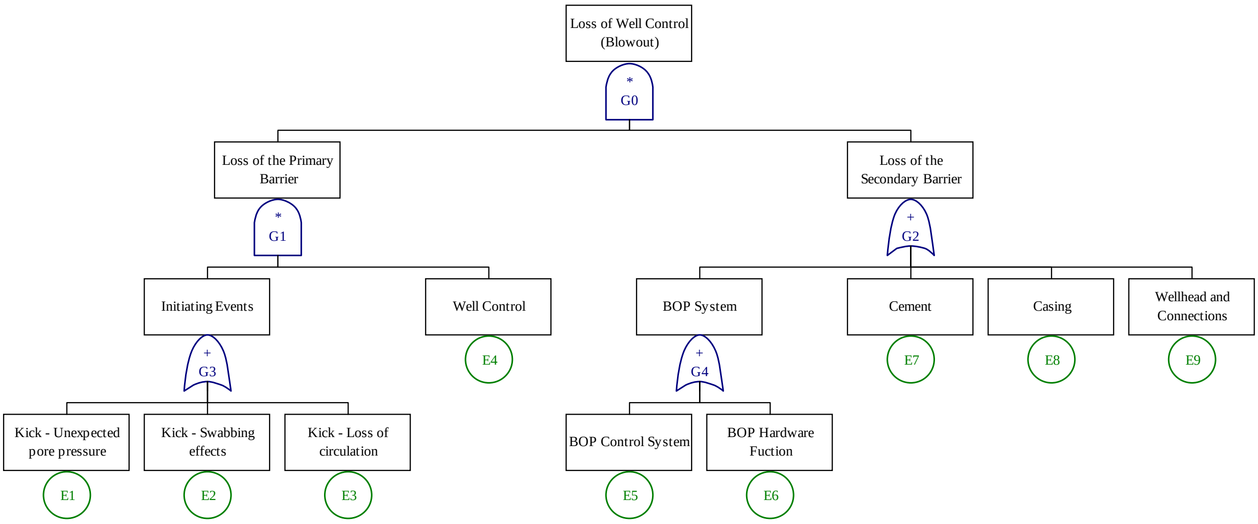


Figure 6-2: Fault Tree model – Loss of Well Control Base Case Model (Historical Data)

With the generic model being developed which now links the kick frequency to the probability of a blowout, the impact of the improvements identified in the workshops and evaluated in detail in the previous sections can now be quantified. The main areas for which have been quantified in this evaluation include:

- Equipment reliability
- Technology improvements
- Human factors / procedures

Based on the evaluation in the previous section, improved equipment reliability has resulted in improved hardware reliability. The use of multiple annular preventers, improved shear-seal ram design and multiple shear-seal rams, i.e. both casing and blind shear rams, which are now typically used, will impact the system reliability. Further, it is recognised that the industry has improved pressure control during cementing and improved cement quality which will also contribute to improve the primary barrier. While these improvements will have impacted the system reliability, no specific credit has been given to these improvements in this quantitative evaluation.

From the detailed kick information reviewed, it can be concluded that some of the major improvements in the drilling industry has resulted in better kick pressure control. The improved predictions from 3D seismic and sophisticated reservoir models provide more reliable predictions of the pore pressure and fracture pressure gradient. Further, real-time monitoring and better fluid quality has significantly improved the control when drilling the well. Experience data indicates that there has been a significant improvement with respect to the number of kick experienced during exploration drilling operations. As concluded in the previous section in this chapter, for normally pressurized reservoirs with a good pressure margin the kick frequency has almost been eliminated, i.e. 1-5 kicks per 100 wells drilled. In this quantitative evaluation it has conservatively been assumed that the kick frequency has been reduced by approximately 50%, resulting in a kick frequency in the range of 14 kicks per 100 well operations. When comparing this kick frequency with the experience data from the last years, Figure 6-1, only two years had an annual kick frequency which was higher. The average kick frequency for this period (2000-2008) was however significantly lower; with approximately 8-9 kicks per 100 exploration drilling operations.

The effect of more thorough planning processes and stringent well control training requirements are difficult to quantify. It is obvious that better knowledge and awareness has had a significant impact on the risk related to drilling. Particularly the planning phase of drilling operations and the development of detailed operating procedures including contingency plans has changed significantly over the years. In this quantitative evaluation these improvements have however not been given any credit beyond the adjustment in the kick frequency. If evaluating the data in more detail, it may however be possible to give some additional credit to the risk related to swabbing, i.e. better procedures relating to tripping and continuously filling up the hole will have some impact on the risk of swabbing.

In this analysis, the reduced kick frequency is therefore the only element which has been given credit in the quantitative analysis. The kick frequency will be directly related to the probability of a blowout as indicated in the Fault Tree structure presented in Figure 6-2 in Figure 6-3 this element of the Fault Tree model has been highlighted with the historical data included.

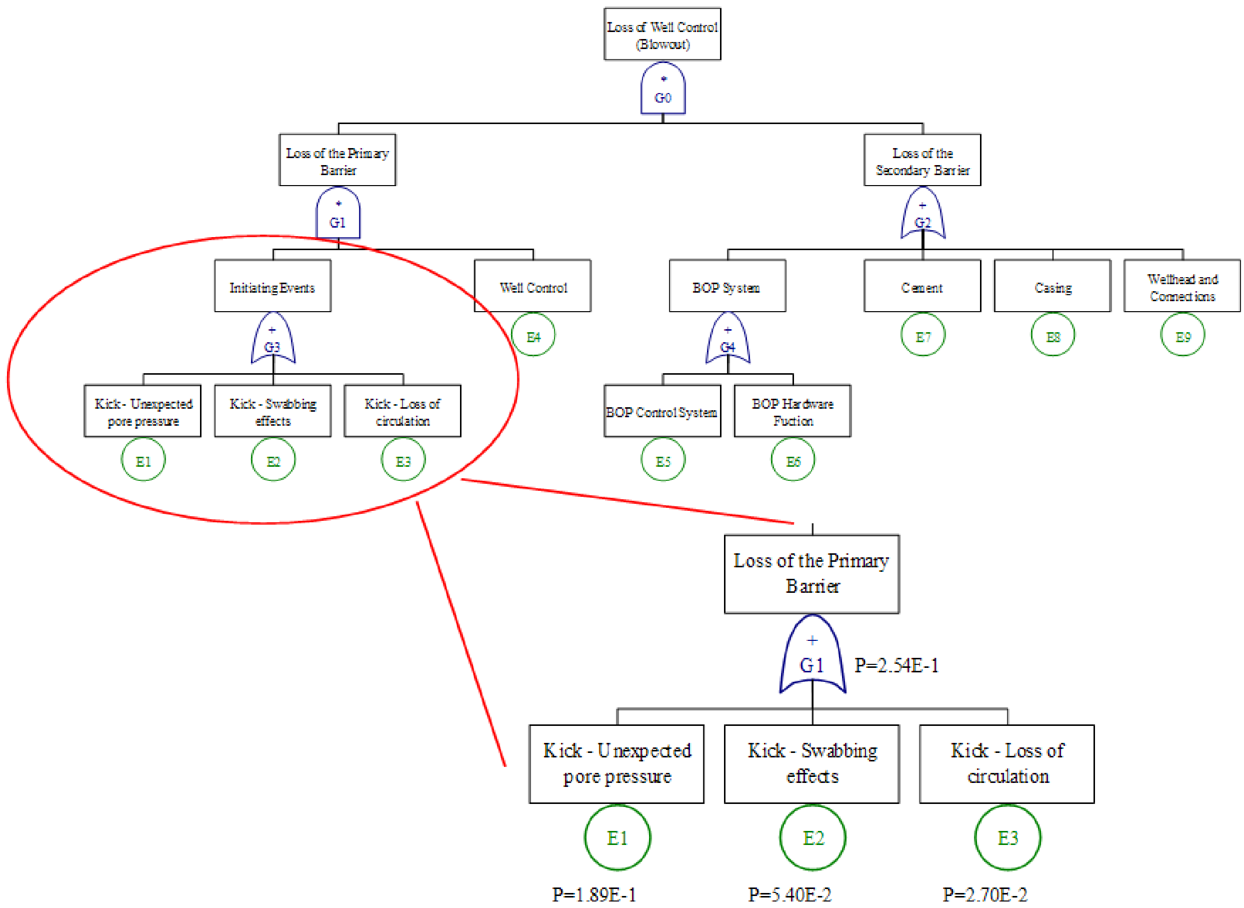


Figure 6-3: Fault Tree model – Loss of Well Control Base Case

When considering the more recent kick data, it was concluded that the kick frequency can be reduced by 50%. With these improvements included, the Fault model was updated and the new probability of a blowout was estimated. The new input to the model is reflected in the Fault Tree model in Figure 6-4.

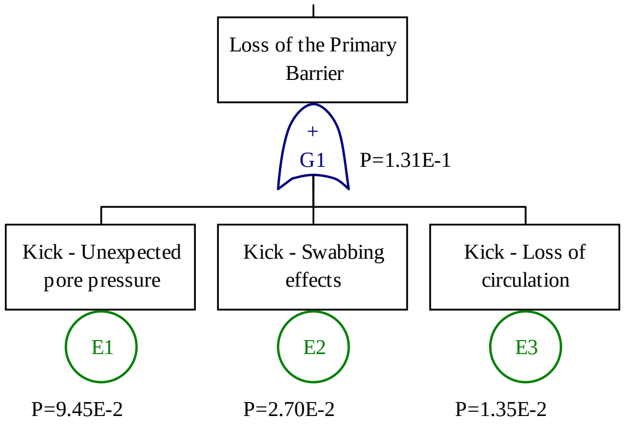


Figure 6-4: Fault Tree model – Loss of Well Control Modified (Improved Data)

With all the other data the same, the probability of a blowout was estimated to be 7.7 x 10^{-5}. Thus, by considering the more recent kick data, the probability of a blowout has been reduced by a factor of two. It should be highlighted that this quantified in improvement has been justified on the basis of real experience data related to the kick frequency. No credit has been given to any of the other factors which also could have a significant impact on the probability of a blowout. In Table 6-2 the results for the base case, which is based on the historical blowout data, and the modified case which account for the improvements which are evident in the new kick data have been summarised.

Table 6-2: Summary of the Blowout Probability

Case	Probability of Blowout
Base Case – Scandpower data	1.5 x 10^{-4}
Alternative Case – New modified data	7.7 x 10^{-5}

7 OIL SPILL SCENARIOS

7.1 Flow Modelling

7.1.1 Input data to modelling of flow rates

The Bjørk well (6608/8-2) is chosen as a model well. Statoil has previously performed blow out simulations on two cases for the well, and the input data from these calculations were applied in the blowout simulations performed here. Statoil had applied the software "Maurer Eng's Promod1" for their simulations, while DNV applies OLGA 5.3. The blowout rates from the two applications matched within 10% on the blowout rates. The difference is probably due to differences in the implementation of two-phase flow and the phase envelope.

The following data apply:

Sea depth: 337 m

Height of rig above sea level: 22m

Norne oil is applied as reservoir fluid, the composition received from Statoil /9/. Data on the Norne oil is given in Table 7-1.

Table 7-1 Reservoir composition applied in the simulations. Norne oil is chosen as representative fluid.

	mole%
Nitrogen	0.28
Carbon dioxide	1.07
Methane	46.93
Ethane	3.93
Propane	2.11
i-Butane	0.43
n-Butane	0.87
i-Pentane	0.41
n-Pentane	0.46
Hexanes	0.82
Heptanes	2.35
Octanes	3.82
Nonanes	2.83
Decanes plus	33.69
Sum	100.00
C10+ MW	276
C10+ Density (g/cm^3)	0.876

The composition in Table 7-1 was applied as input to PVTSim in order to create the fluid for the OLGA simulations. For Bjørk, the fluid was split in an oil and a gas part and recombined with a GOR of 100 Sm^3/Sm^3. This results in a phase envelope as shown in Figure 7-1. The gas density at standard conditions was 0.83 kg/m^3, the oil density at standard condition was 861 kg/m^3.

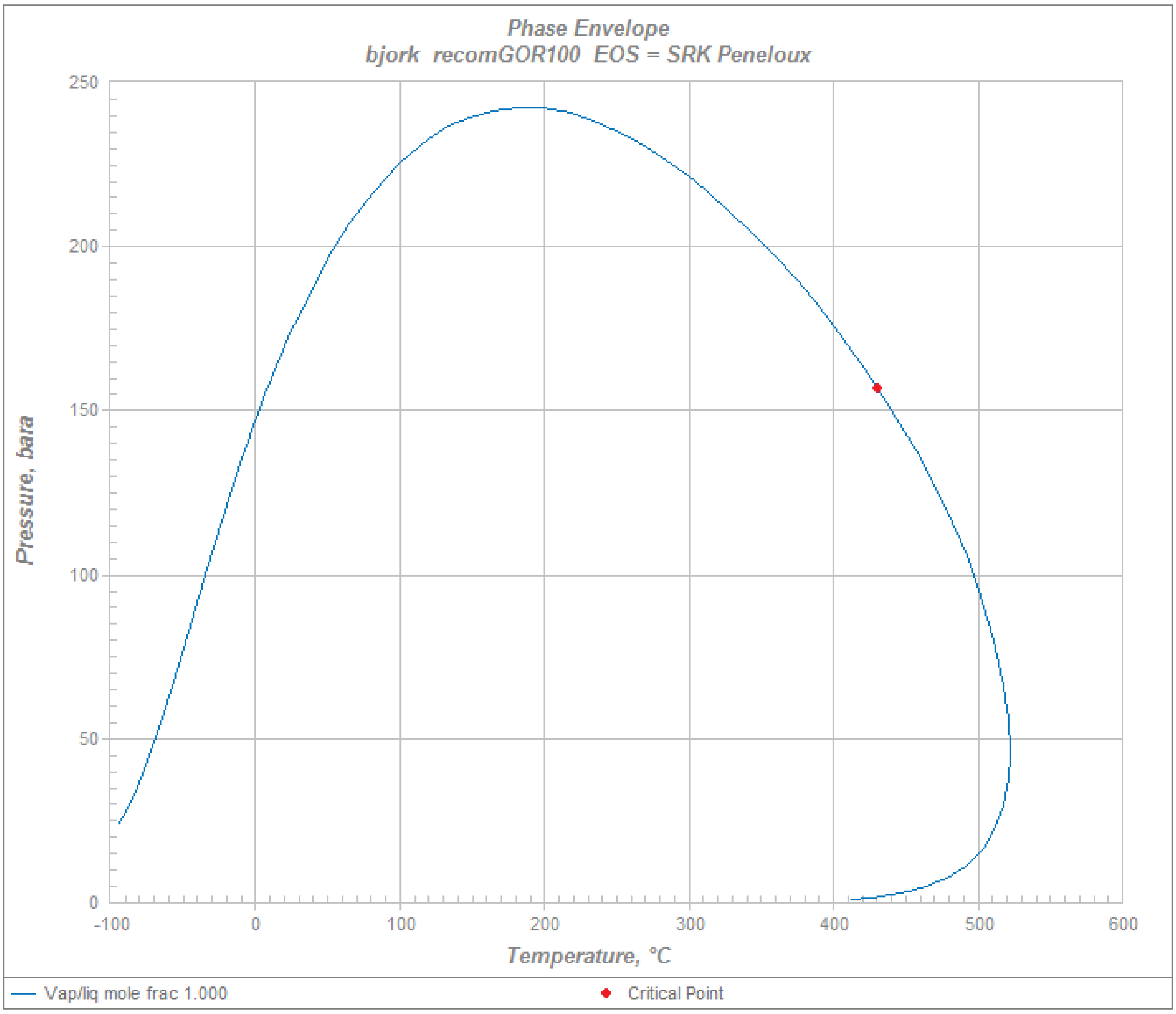


Figure 7-1 The phase envelope for the recombined fluid for Bjørk

Information on the Bjørk reservoir is found in Table 7-2. The information on PI (Productivity Index), inflow correlations etc. was delivered by Statoil /8/ The inflow correlation is based upon Vogels equation with AOF (Absolute open flow) =PI*Reservoir Pressure/1.8. Graphs illustrating the inflow as a function of bottom hole pressure is shown in Figure 7-2.

Table 7-2 Reservoir properties

Reservoir depth (TVD m)	2 545
Reservoir pressure (bar)	370
Reservoir temperature (^{o}C)	98
PI (penetration of the whole reservoir)	72
PI (from half of the reservoir)	36
PI (from penetration of the first 5 meters of the eservoir)	3.8
Inflow correlation	Vogels equation

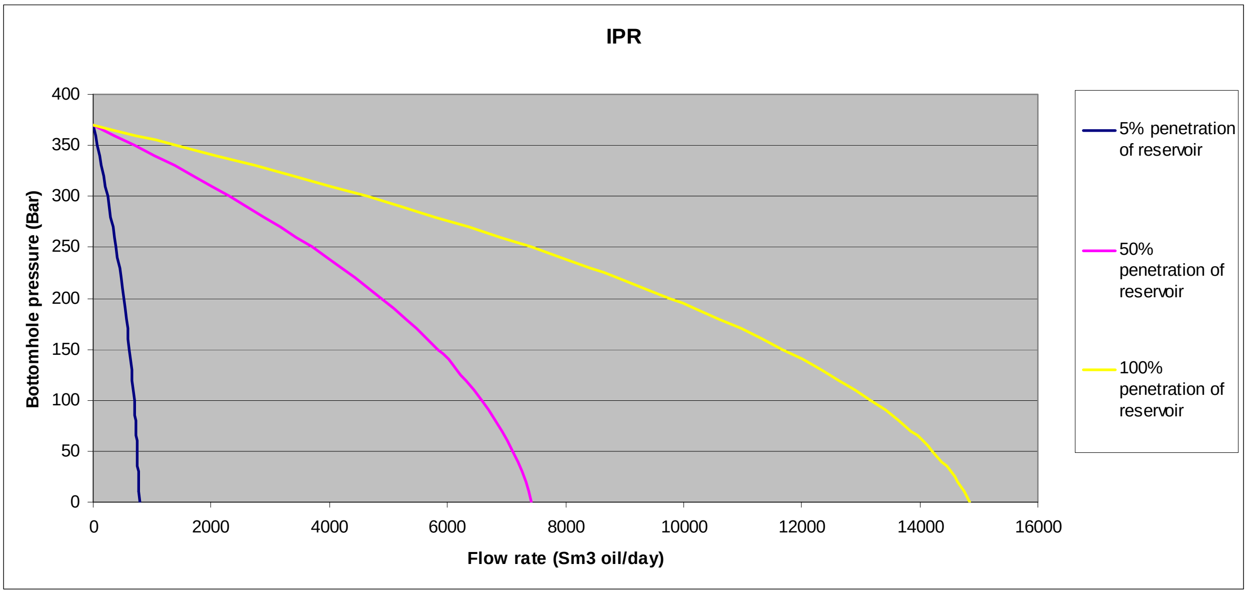


Figure 7-2 The inflow performance relationships for Bjørk when Vogels equation is applied.

The casings for Bjørk is described in Table 7-3 together with the corresponding figures which have been applied in the OLGA simulations. The Rigfloor is located at TVD=0, Sealevel at TVD 22 and the Seabed at TVD 359.

Table 7-3 Description of casings for Bjørk

From TVD	To TVD	Description	Inner diameter casing/riser (Outer diameter annulus) (m)	Outer diameter drillstring (Inner diameter annulus) (m)	Inner diameter drillstring (m)
0	359	Marine riser	0.48	0.127	0.108
359	2495 1507	9 5/8" casing	0.226	0.127	0.108
2495	2545	8.5" Hole	0.216	0.127	0.108

7.1.2 Methodology for estimation of flow rates

The simulation tool used in the study is OLGA 5.3. It is a dynamic multiphase flow simulator which is also designed for well flow applications where the reservoir properties and the inflow relationships play an important role when modelling the flow scenarios. The reservoir performance is specified through permeability, extension of the reservoir, fluid properties, etc. or from inflow performance relationships as has been done here.

The boundary conditions define the interface between the simulated systems (typical wells) and their surroundings. For blowout simulations performed by this study, well inflow condition has been used at the well's inlet and atmospheric conditions at well's outlet for the blowouts simulated with exit point at surface/ drill floor. For subsea releases the outlet pressure is the seabed pressure of 34 bar.

The reservoir fluid is in dense phase at reservoir pressure and gas typically starts to come out of solution at 200 – 240 bar, dependent on the temperature. Flow at outlet is sonic, governed by the conditions in well (outlet pressure p_{out} and outlet temperature T_{out}) and outlet area.

7.1.3 Flow rates

The flow rates in case of a blowout were found for three different types of flowpaths:

- Through annulus
- Through open hole
- Through drillstring

The following types of blowout scenarios were simulated

- to seabed and to topside,
- with no flow restriction in the BOP and with flow restriction corresponding to only 5% of flow area open in BOP
- With flow from the entire reservoir, 50% of the reservoir and 5% of the reservoir

The results are given in Table 7-4 and illustrated in Figure 7-3 - Figure 7-6

Table 7-4 Flow rate for the specified scenarios

Release location	Flow path	Reservoir penetration	BOP opening	Flow rate (Sm^3 oil/day)
Topside	Drill pipe	top (5%)	100% open	717.1
			5% open	661.1
		50 %	100% open	3801.6
			5% open	2626.6
		100 %	100% open	4752.0
			5% open	3136.3
	Annulus	top (5%)	100% open	760.3
			5% open	722.3
		50 %	100% open	6082.6
			5% open	4639.7
		100 %	100% open	9936.0
			5% open	6696.0
	Open hole	100 %	100% open	12787.2
			5% open	8475.8
Seabed	Drill pipe	top (5%)	100% open	647.1
			5% open	622.1
		50 %	100% open	4043.5
			5% open	2626.6
		100 %	100% open	5287.7
			5% open	3145.0
	Annulus	top (5%)	100% open	622.1
			5% open	619.1
		50 %	100% open	5572.8
			5% open	4631.0
		100 %	100% open	9331.2
			5% open	6687.4
			5% open	5313.6
	Open hole	100 %	100% open	11664.0
			5% open	8467.2
	Outside casing	top (5%)	100% open	647.1
			5% open	622.1
		50 %	100% open	4043.5
			5% open	2626.6
		100 %	100% open	5287.7
			5% open	3145.0

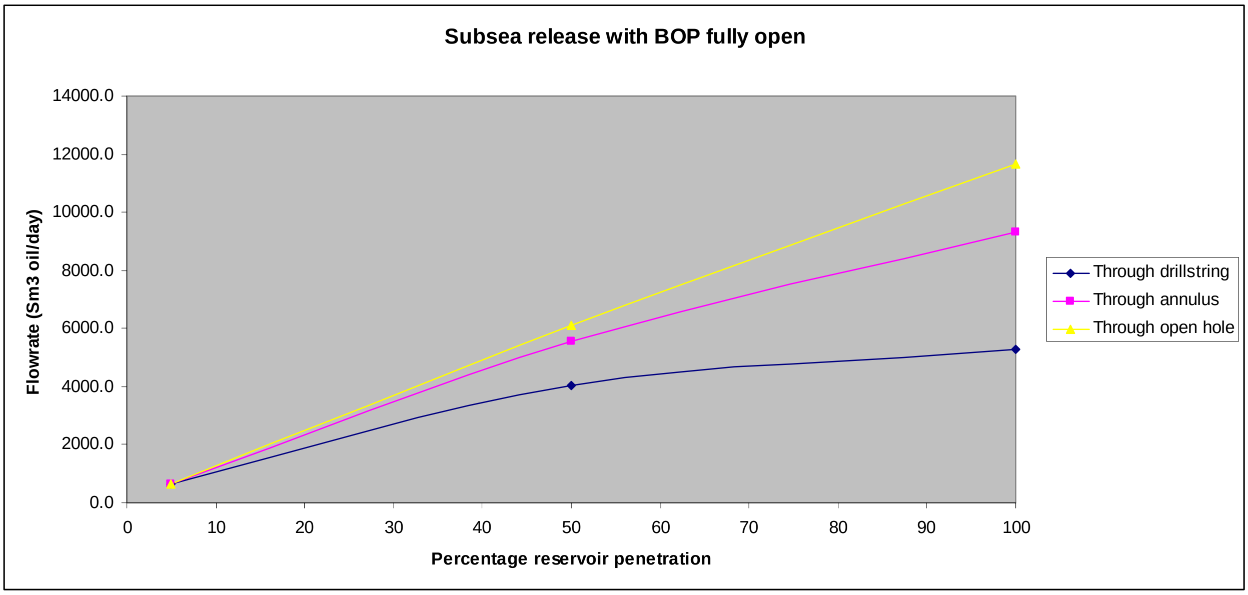


Figure 7-3 Release rates as a function of percentage penetration of reservoir for subsea releases with the BOP fully open.

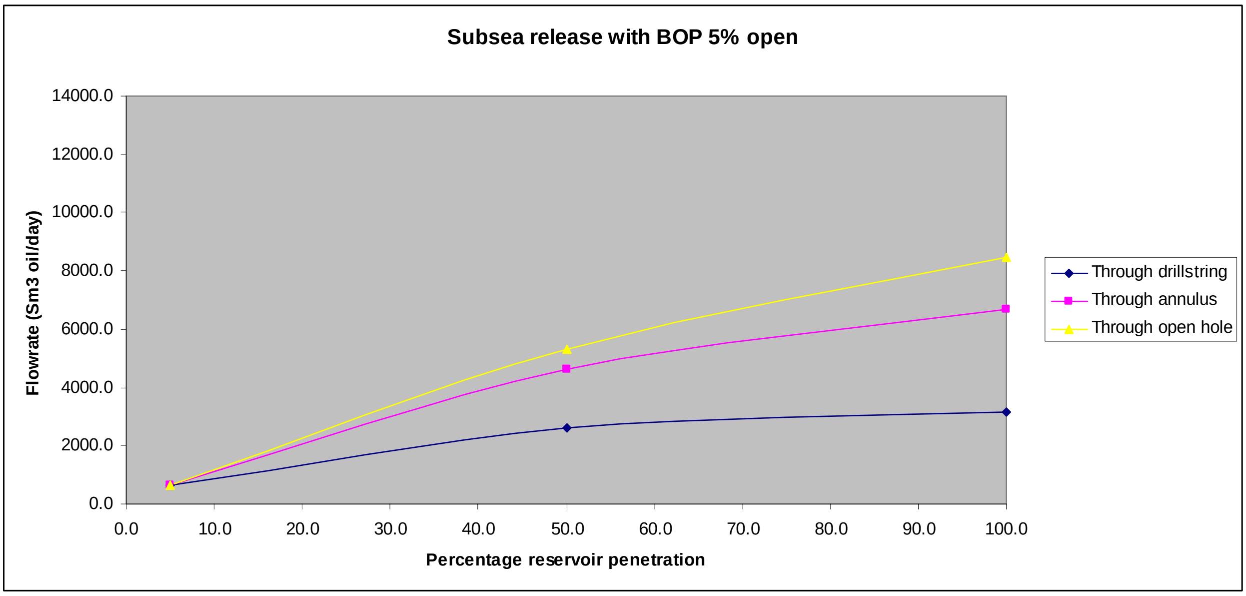


Figure 7-4 Release rates as a function of percentage penetration of reservoir for subsea releases with the BOP 5% open.

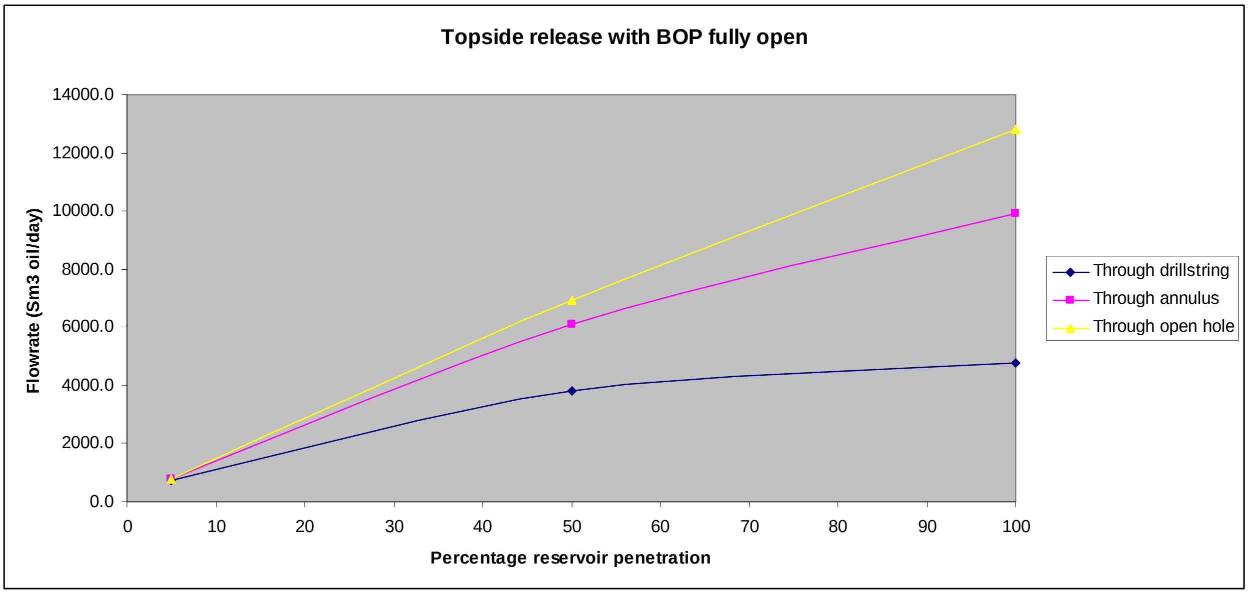


Figure 7-5 Release rates as a function of percentage penetration of reservoir for topside releases with the BOP fully open.

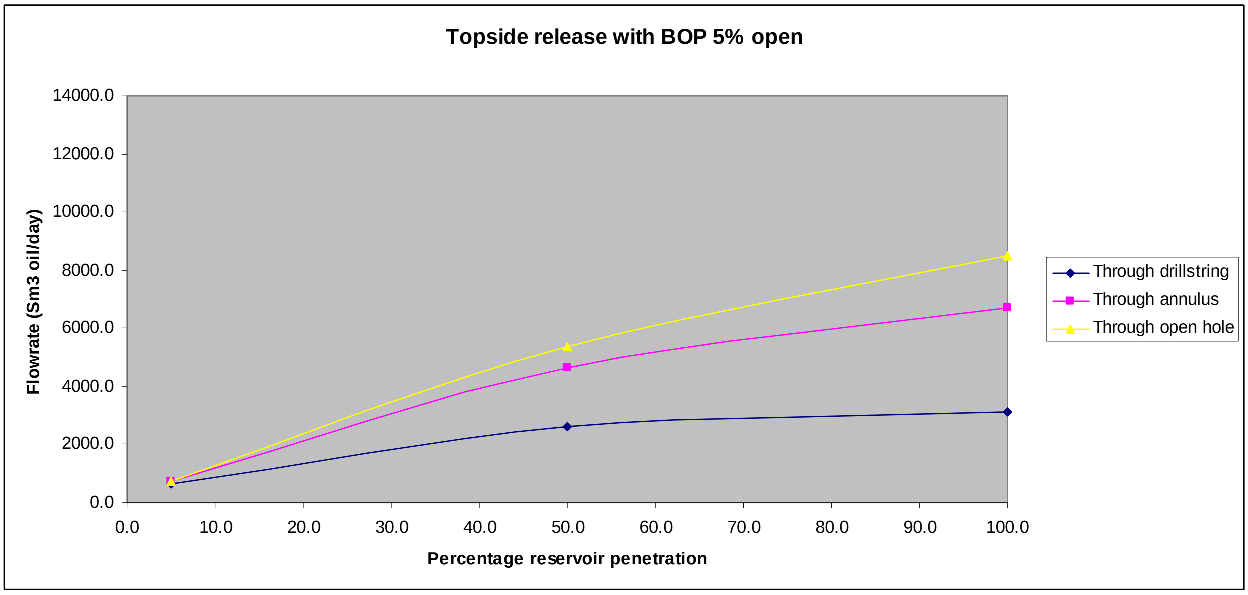


Figure 7-6 Release rates as a function of percentage penetration of reservoir for topside releases with the BOP 5% open.

7.2 Flow Path Distribution

Before the consequences of a blowout can be predicted, it is necessary to specify the blowout scenario, defining parameters, such as:

- Location of the blowout
- Flow rate of fluid from the well
- Duration of the blowout

Depending on the particular blowout scenario, there are a number of possible flow paths for the emerging influx/flow. The release may be topside or subsea, through the drill pipe or annulus and the flow may be restricted or unrestricted depending on the particular scenario for a given blowout. The associated flow rate for each of these scenarios will be different and it is therefore important to understand the appropriate split between each of these possible outcomes. In this evaluation two different cases have been considered, a base case which has been developed based on the typical assumptions made when conducting a general risk assessment and the alternative case which is based on a more detailed review which also considered the most recent information.

Kicks may occur any time during the drilling operation, a 50% open reservoir section has been assumed on average when considering these kicks which may occur any time during the drilling operation. From experience data kicks frequently occur relatively quickly after penetrating the reservoir, thus in the very top part of the reservoir section. Further, many kicks occur as a result of swabbing, i.e. when tripping out of the hole, for these events it has been assumed that the entire hole section could be exposed.

Based on experience data approximately 20% of the kicks in exploration drilling occurs quickly after drilling into the reservoir. For the other two scenarios it has been assumed an equal split. A summary of the basis for the kicks is given in Table 7-5. The amount of reservoir exposed will have an impact on the flow calculations.

Table 7-5: Depth drilled into the reservoir when a kick occurs

Drilling depth into the reservoir	Probability
Top of the reservoir (5 meters)	20%
Half of the reservoir exposed	40%
Full reservoir exposed (drilled to TD)	40%

In the next sections the relevant assumptions related to the split between the different blowout scenarios for the base case and the alternative case are presented.

7.2.1 Base Case

The flow path distribution which has been applied for the base case model corresponds to what is typically applied when conducting risk assessment in the industry. This split originates from a review of the blowout statistics which was conducted several years ago, and has, without further consideration, been adopted as an industry best practice, Ref /14/. While the data was based on historical records from the blowout database, it does not consider the most recent information and the data in this report was never intended to be used as a basis in all future environmental risk assessments. Further, there are some questions related to how the data is applied in the risk assessment, which will be discussed when establishing the basis for the alternative case.

In addition to the split between topside and subsea, traditionally risk assessments make the following split between the possible blowout flow scenarios:

- Blowout through the drill pipe
- Blowout through the annulus
- Blowout through open hole

For the drill pipe scenario, there would first have to be an influx through the drill pipe. This implies that there is an influx from the reservoir, and at the same time that the drill float valve, which is suppose to prevent back flow in the drill pipe, has failed. Further, it is very unlikely that the influx will flow through the drill pipe as the drill pipe is constantly filled with drilling mud during the drilling operation. If the well control equipment has failed, i.e. the pipe RAM or the drill float, the influx will tend to emerge up the flow path of least resistance, thus the annulus between the drill pipe and the production casing.

The most likely blowout flow scenario to topside is through the annulus when the drill pipe is in the hole. When drilling into the reservoir, high pressure zones of hydrocarbons may be encountered, these high pressure zones may compromise the primary barrier and result in an influx. Further, there may be swabbing effects from the reservoir when pulling the drill pipe and BHA out of the hole, the so called tripping operation.

If there is no drill pipe in the hole when a possible influx occurs, we may have an open hole blowout scenario. This could happen if there is an influx after the drill pipe has been pulled out, i.e. after drilling a hole section and before running and cementing the casing. Provided that the mud weight is maintained, it is however very unlikely that an influx should be initiated when there is no drill pipe in the hole. Further, there will also be the possibility to kill the well and bullhead to prevent the influx.

Table 7-6 provides a summary of the split in flow path scenarios which has been used for the base case model. As emphasised earlier this split is based on the typical assumptions which are used when developing a risk assessment.

Table 7-6: Flow path distribution for the base case

Scenario	Probability	Flow Path	Probability
Topside	25%	Drill pipe	11%
		Annulus	78%
		Open hole	11%
Subsea / Seabed	75%	Drill pipe	11%
		Annulus	78%
		Open hole	11%

Based on the data recommended practice for evaluation of blowout rates for environmental risk assessments, Ref /14/, the probability of the BOP to fail totally open in the event of a blowout is estimated to be 30%. Thus, the probability of a restricted flow, i.e. the BOP closes partly or leaks, has been set to 70%. It is further noted in the report, Ref /14/, that this split applies for all scenarios and that it is considered to be a conservative estimate.

Table 7-7: BOP closure in the event of a blowout for the base case

BOP Closure	Probability
BOP fully open (100%) / no restriction	70%
BOP partly closed (95% restriction)	30%

7.2.2 Updated data

For the alternative case, the latest blowout data from the SINTEF database has been evaluated in detail. The two main modifications compared to the base case assumptions, are:

1) There is a significant difference in the flow path split depending on whether the relate is subsea or topside. In the base case the same split has been used for a subsea blowout and a topside blowout
2) A significant amount of the blowout data is related to blowouts on the outside of the casing or through the outer annulus. In the base case these events have been excluded when making the splits.

Based on the most recent blowout data, Ref /3/, a large proportion of seabed incidents is related to flow on the outside of the casing. These incidents are caused by flow through cracks in the cement and formation rocks outside the casing program. It is difficult to calculate and predict the flow rate for these scenarios as the flow path conditions are uncertain, it is however reasonable to assume that these flow rates are relatively small compared to the flow through the annulus up the *"clean"* wellbore. In this analysis the outside casing flow rates have therefore been assumed to be equal to the unrestricted flow through the drill string. Table 7-8 shows the flow path distribution which has been applied for the alternative case in this analysis.

Table 7-8: Flow path distribution for the alternative case

Scenario	Probability	Flow Path	Probability
Topside	20%	Drill pipe	30%
		Annulus	55%
		Open hole	15%
Subsea / Seabed	80%	Drill pipe	0%
		Open hole	0%
		Annulus	40%
		Outside casing	60%

When further evaluating the blowout data, Ref /3/, to determine the split between restricted and non-restricted flow through the BOP, there is a significant difference between the specific scenarios. Thus, the assumption that this split is the same for all scenarios is not reflected in the historical data. Table 7-9 provides a summary of the split between restricted and non-restricted flow through the BOP for the different scenarios.

Table 7-9: BOP closure in the event of a blowout for the alternative case

Scenario	Flow Path	Restricted (95% closure)	Full Flow (100% open)
Topside	Drill pipe	95%	5%
	Annulus	50%	50%

Scenario	Flow Path	Restricted (95% closure)	Full Flow (100% open)
	Open hole	95%	5%
Subsea / Seabed	Annulus	95%	5%
	Outside casing[1]	N/A	

7.3 Duration of the Blowout

In the environmental risk assessment, the duration of the blowout is essential when calculating the consequences. The probability distribution between the blowout durations is calculated based on the SINTEF blowout database. A conservative approach is most often taken, when calculating the probability distribution, because the split between 12 hours duration and 2 days are most often ignored and the whole probability is distributed to 2 days distribution. Further, the duration is divided into categories with a range of durations, but the longest duration is applied in the oil spill modeling. Table 7-10 shows the probability split applied in the “base case”.

Scandpower is making a more detailed analysis of the blowout duration distribution, based on the same blowout data, but further analysed applying the BlowFAM. These data is applied in the “alternative case” and is including the 12 hours duration (Table 7-11) as well as differentiating between topside and subsea blowouts. A subsea blowout has a higher probability for long blowout durations than a topside blowout.

Table 7-10: Probability distribution of blowout durations as applied in the “base case”

Duration range (days)		< 2	2-5	5-14	>14
Representative duration (days)		2	5	14	50
probability	topside	0.58	0.2	0.16	0.06
	subsea	0.58	0.2	0.16	0.06

Table 7-11: Probability distribution of blowout durations as applied in the “alternative case”

Duration range (days)		<0.5	0.5-2	2-5	5-14	>14
Representative duration (days)		0.5	2	5	14	50
probability	topside	0.49	0.19	0.12	0.13	0.07
	subsea	0.33	0.2	0.14	0.16	0.17

[1] For the outside casing scenarios, it has been assumed that an unrestricted flow through the drill pipe is representative. Further, this split between restricted and non-restricted flow is not relevant for the scenario.

7.4 Blowout rate – duration matrixes

Table 7-12 at the next page shows the probability distribution for blowout rates and flow paths used for environmental risk assessment in the “base case”. The probability distribution of blowout durations is shown in Table 7-10 and is applicable for all the rates.

Table 7-13 at shows the probability distribution for blowout rates and flow paths used for environmental risk assessment in the “alternative case”. The probability distribution of blowout durations is shown in Table 7-11 and is applicable for all the rates for topside and subsea blowout, respectively.

Table 7-12 Probability distributions for blowout rates and flow paths used for environmental risk assessment in the "base case"

occurance	probability	flow path	probability	penetration depth	probability	BOP opening	probability	Rate (Sm^3/døgn)	probability
topside	0.25	Drill string	0.11	topp (5%)	0.2	100% open	0.3	717.1	0.0066
						5% open	0.7	661.1	0.0154
				50 %	0.4	100% open	0.3	3801.6	0.0132
						5% open	0.7	2626.6	0.0308
				100 %	0.4	100% open	0.3	4752.0	0.0132
						5% open	0.7	3136.3	0.0308
		Annulus	0.78	topp (5%)	0.2	100% open	0.3	760.3	0.0468
						5% open	0.7	722.3	0.1092
				50 %	0.4	100% open	0.3	6082.6	0.0936
						5% open	0.7	4639.7	0.2184
				100 %	0.4	100% open	0.3	9936.0	0.0936
						5% open	0.7	6696.0	0.2184
		Open hole	0.11	100 %	1	100% open	0.3	12787.2	0.033
						5% open	0.7	8475.8	0.077

	probability	flow path	probability	penetration depth	probability	BOP opening	probability	Rate (Sm^3/døgn)	probability
subsea	0.75	Drill string	0.11	topp (5%)	0.2	100% open	0.3	647.1	0.0066
						5% open	0.7	622.1	0.0154
				50 %	0.4	100% open	0.3	4043.5	0.0132
						5% open	0.7	2626.6	0.0308
				100 %	0.4	100% open	0.3	5287.7	0.0132
						5% open	0.7	3145.0	0.0308
		Annulus	0.78	topp (5%)	0.2	100% open	0.3	622.1	0.0468
						5% open	0.7	619.1	0.1092
				50 %	0.4	100% open	0.3	5572.8	0.0936
						5% open	0.7	4631.0	0.2184
				100 %	0.4	100% open	0.3	9331.2	0.0936
						5% open	0.7	6687.4	0.2184
		Open hole	0.11	100 %	1	100% open	0.3	11664.0	0.033
						5% open	0.7	8467.2	0.077

Table 7-13 Probability distributions for blowout rates and flow paths used for environmental risk assessment in the "alternative case"

occurance	probability	flow path	probability	penetration depth	probability	BOP opening	probability	Rate (Sm^3/døgn)	probability
topside	0.2	Drill string	0.3	topp (5%)	0.2	100% open	0.05	717	0.003
						5% open	0.95	661	0.057
				50 %	0.4	100% open	0.05	3801	0.006
						5% open	0.95	2626	0.114
				100 %	0.4	100% open	0.05	4752	0.006
						5% open	0.95	3136	0.114
		Annulus	0.55	topp (5%)	0.2	100% open	0.5	760	0.055
						5% open	0.5	722	0.055
				50 %	0.4	100% open	0.5	6082	0.11
						5% open	0.5	4639	0.11
				100 %	0.4	100% open	0.5	9936	0.11
						5% open	0.5	6696	0.11
		Open hole	0.15	100 %	1	100% open	0.05	12787	0.0075
						5% open	0.95	8475	0.1425
subsea	0.8	Outside casing and outer casing	0.6	topp (5%)	0.2	100% open	0.8	647	0.096
						5% open	0.2	622	0.024
				50 %	0.4	100% open	0.8	4043	0.192
						5% open	0.2	2626	0.048
				100 %	0.4	100% open	0.8	5287	0.192
						5% open	0.2	3145	0.048
		Annulus	0.4	topp (5%)	0.2	100% open	0.05	622	0.004
						5% open	0.95	619	0.076
				50 %	0.4	100% open	0.05	5572.8	0.008
						5% open	0.95	4631.0	0.152
				100 %	0.4	100% open	0.05	9331.2	0.008
						5% open	0.95	6687.4	0.152

8 OIL DRIFT SIMULATIONS

8.1 Oil types

The environmental risk is analysed based on the oil drift properties of two different oil types and one condensate type; Balder oil, Goliat oil and Huldra condensate. This is done to show the sensitivity in environmental risk due to oil type. This chapter shows some of the modelling results while Appendix 6 gives all the modelling results. The main physical oil properties for Balder oil, Goliat Blend oil and Huldra condensate are shown in Table 8-1.

Balder oil has the highest density of all Norwegian crudes (916 kg/m^3) with moderately low wax content. The viscosity and the asphaltene content are very high. Balder crude contains relatively low proportion of volatile components and the extent of evaporative loss will therefore be low, see Figure 8-1.

The Goliat Blend oil contains 70% Goliat Kobbe and 30% Goliat Realgrunnen oil. Goliat Kobbe is categorised among the paraffinic crude, with low content of asphaltenes while Goliat Realgrunnen is categorised as a naphtenic oil, but also exhibit characteristics of both paraffinic and waxy oils at rough weather at sea (Figure 8-2).

Huldra condensate is a typical paraffinic condensate and has a relatively high density. The wax content is high compared to other Norwegian condensates. The asphaltene content is moderate. Huldra has a relatively high density compared to other condensates, but low compared to the most crude oils.

Table 8-1 Physical oil properties for Balder oil, Goliat Blend oil and Huldra condensate

Oil type	Density (kg/m^3)	Viscosity 13 °C (cP)	Wax (wt%)	Asphaltene content (wt%)	Max water content (%)	Evaporate loss at wind speed 10 m/s and 15 °C after 1 day at sea (%)
Balder	916	132	2,1	2,3	80	15
Goliat Blend	822	95,2	3,6	0,08	80	40
Huldra	809	4	5,2	0,13	40	47

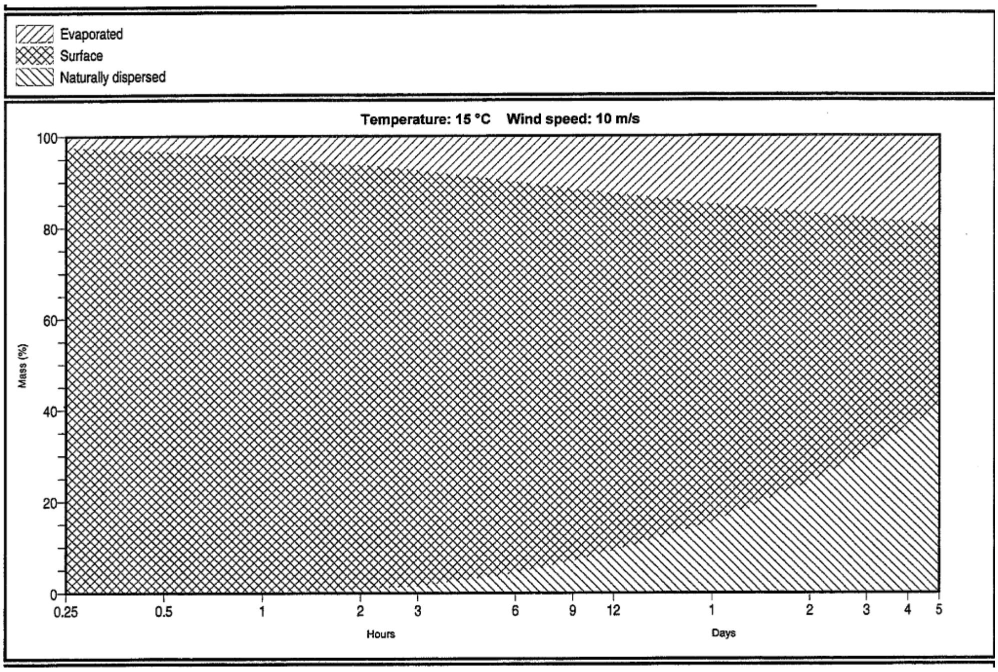


Figure 8-1 Mass balance for Balder oil

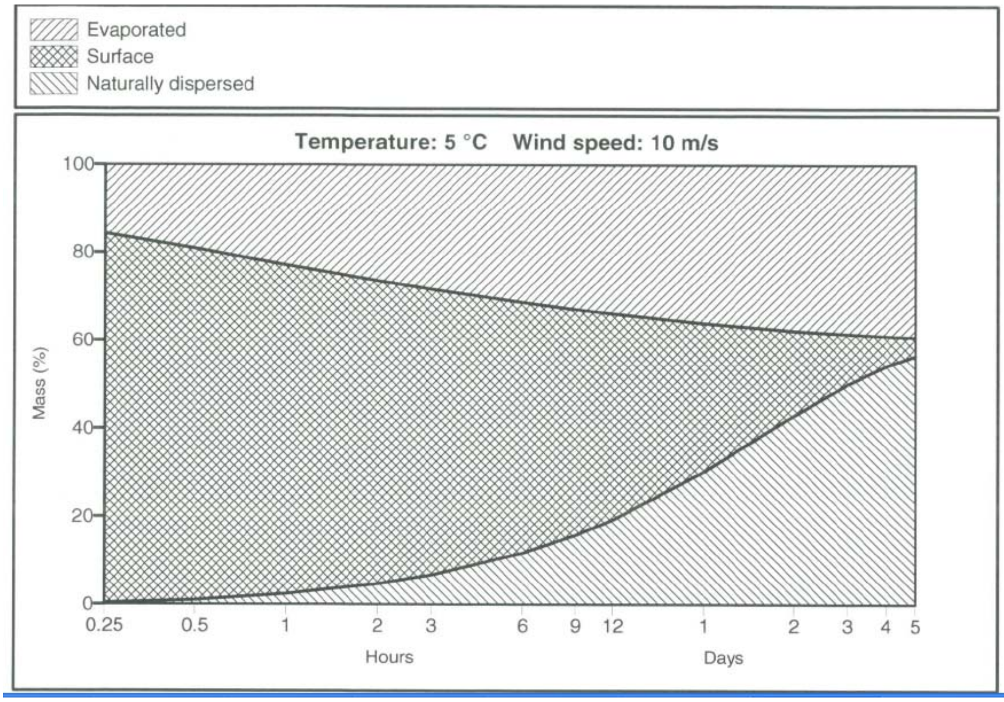
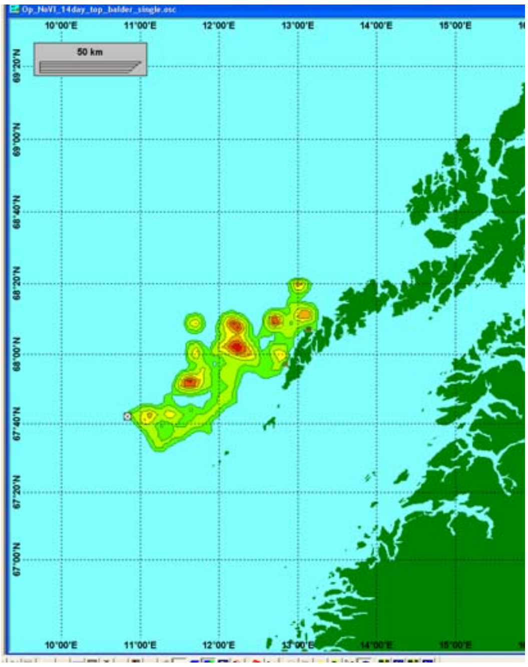


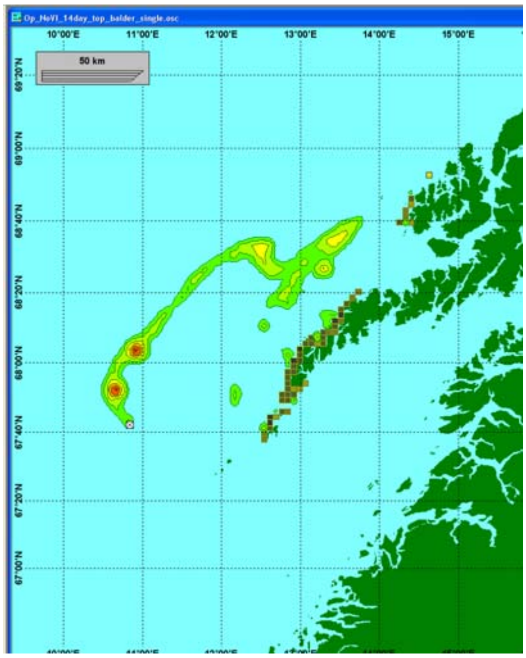
Figure 8-2 Mass balance for Goliat Blend oil

8.2 Model results – single scenarios

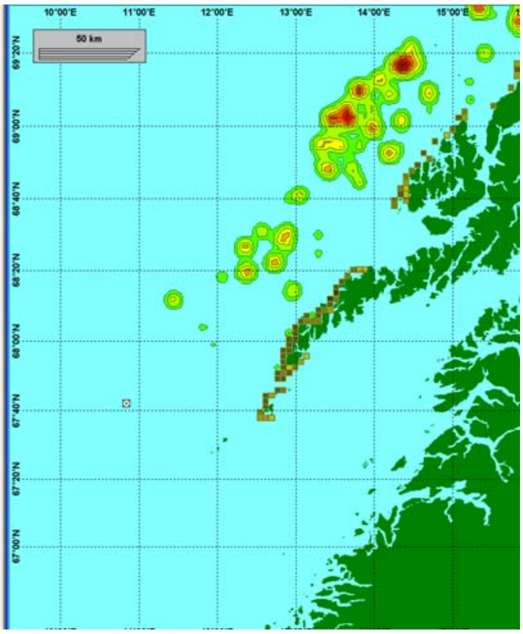
Three single scenarios based on both the expected (50 percentile of the stranding simulations) amounts of oil on shore and the expected drift time to land are presented. Time development and mass balance for a top side release 4500 tons/day and 14 days release duration for Balder oil, Goliat oil and Huldra condensate are presented in Figure 8-3, Figure 8-4, Figure 8-5 and Figure 8-7, Figure 8-8, Figure 8-9 respectively.



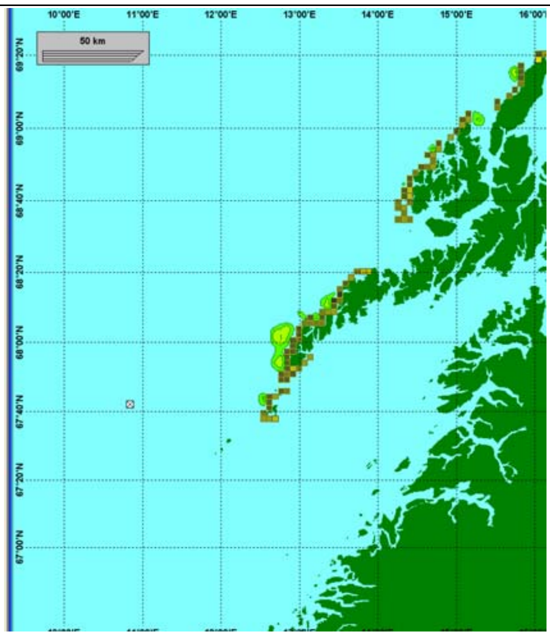
After 6 days



After 12 days

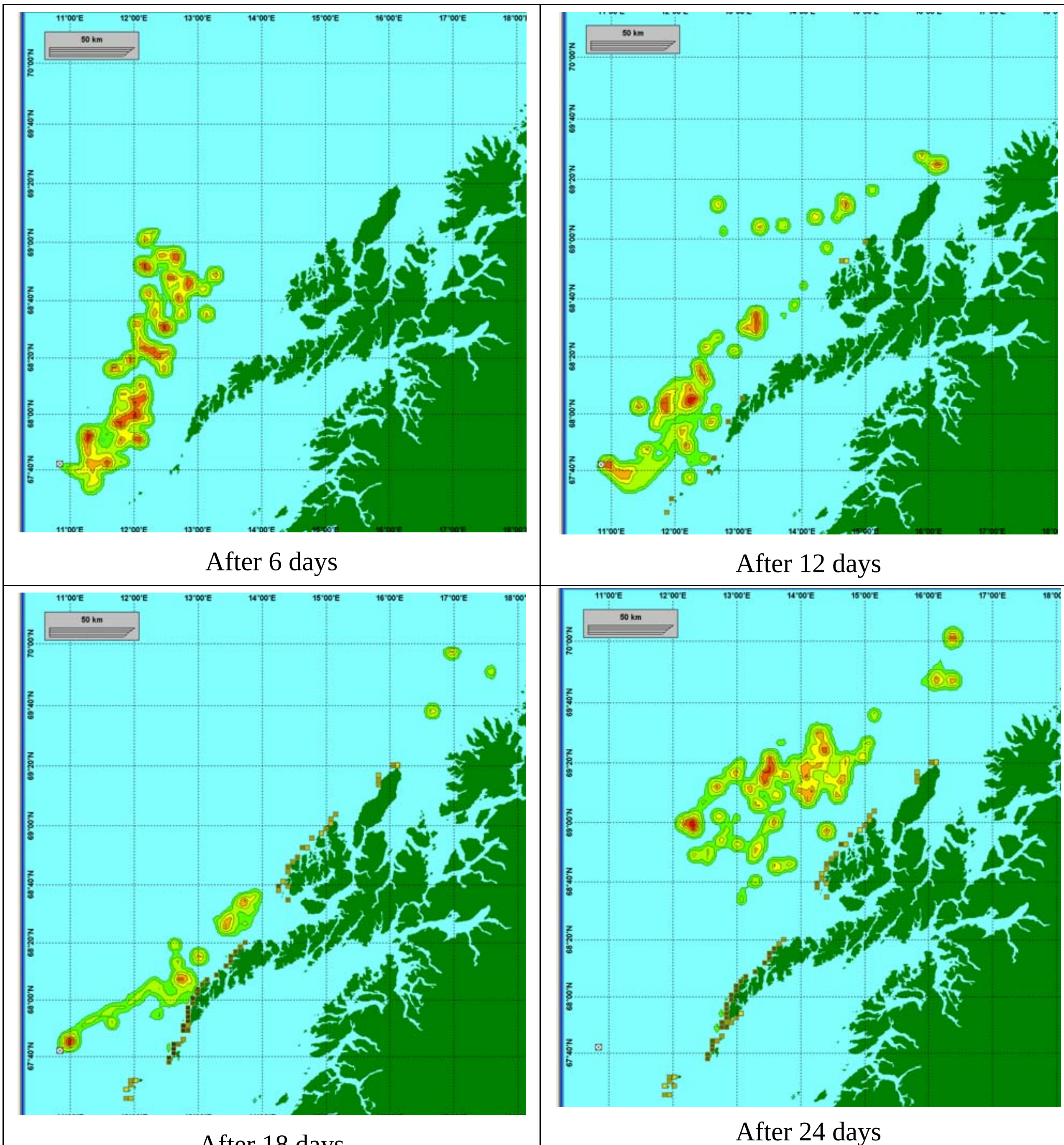


After 18 days



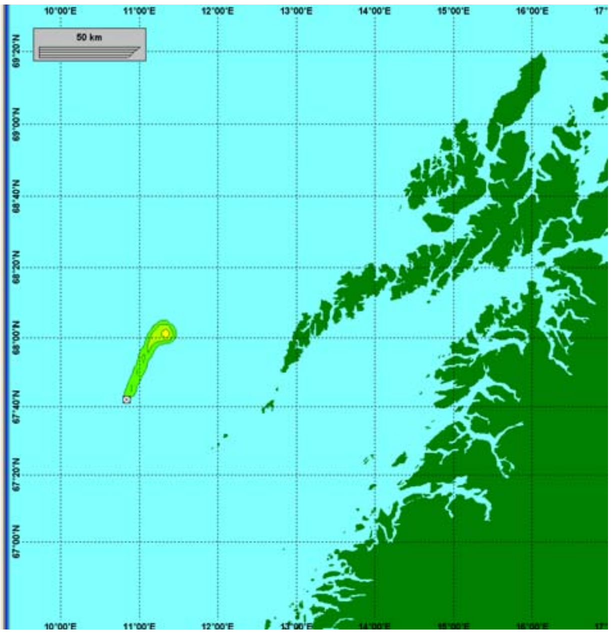
After 24 days

Figure 8-3 Time development for a single scenario top-side release of Balder oil with start date 1995-08-02. The figures show oil coverage at the surface. 3951 tons of oil has stranded after 5,5 days.

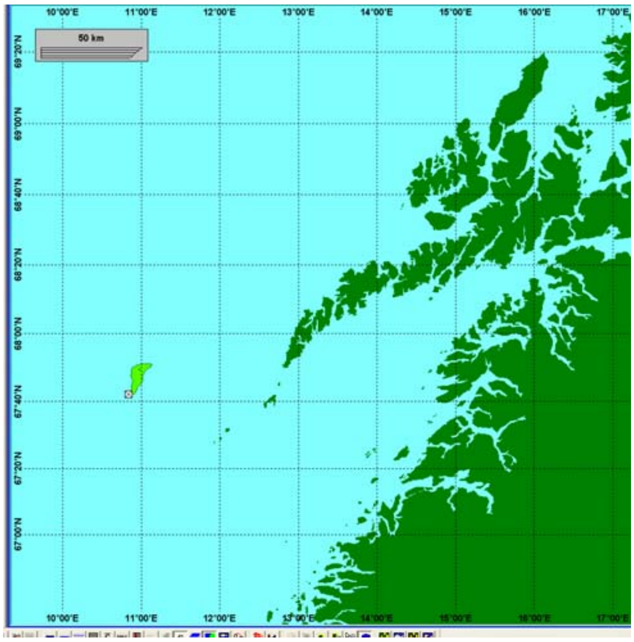


After 6 days | After 12 days | After 18 days | After 24 days

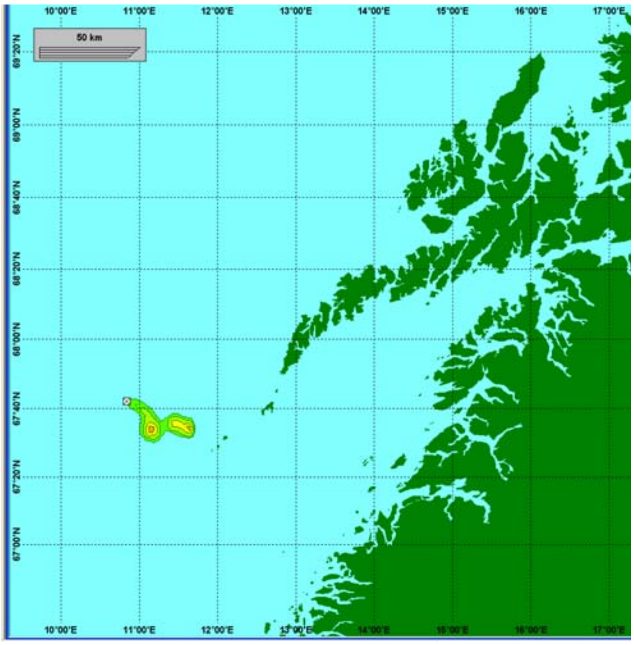
Figure 8-4 Time development for a single scenario top-side release of Goliat oil with start date 1996-02-23. The figures show oil coverage at the surface. 2170 tons of oil has stranded after 9,4 days.



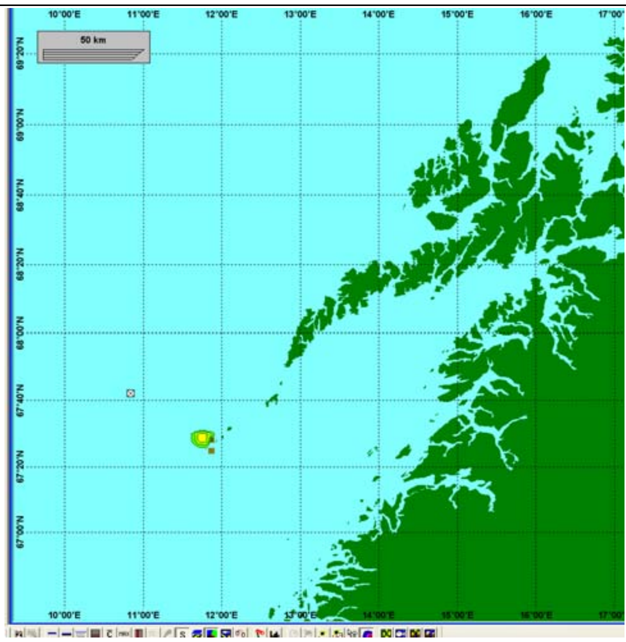
After 6 days



After 12 days



After 18 days



After 24 days

Figure 8-5 8-6 Time development for a single scenario top-side release of Huldra condensate with start date 1994-09-16. The figures show oil coverage at the surface. 120 tons of condensate has stranded at Røst after 16,3 days.

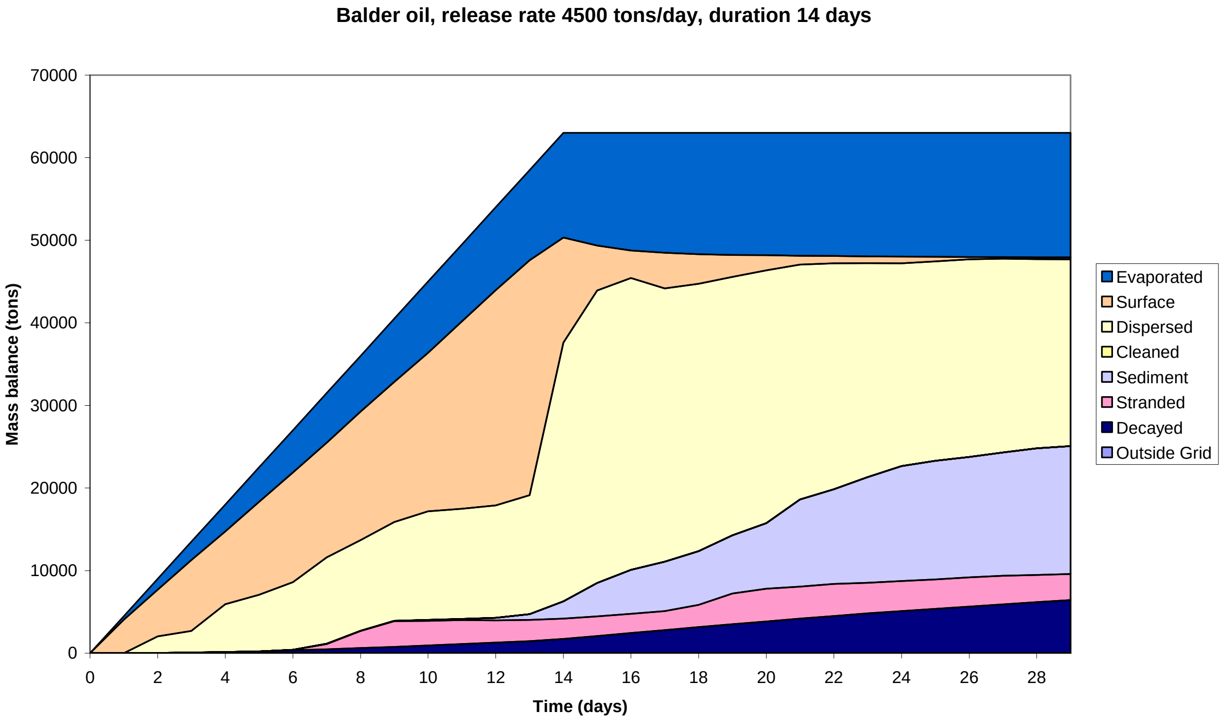


Figure 8-7 Mass balance for a single scenario top-side release of Balder oil with start date 1995-08-02.

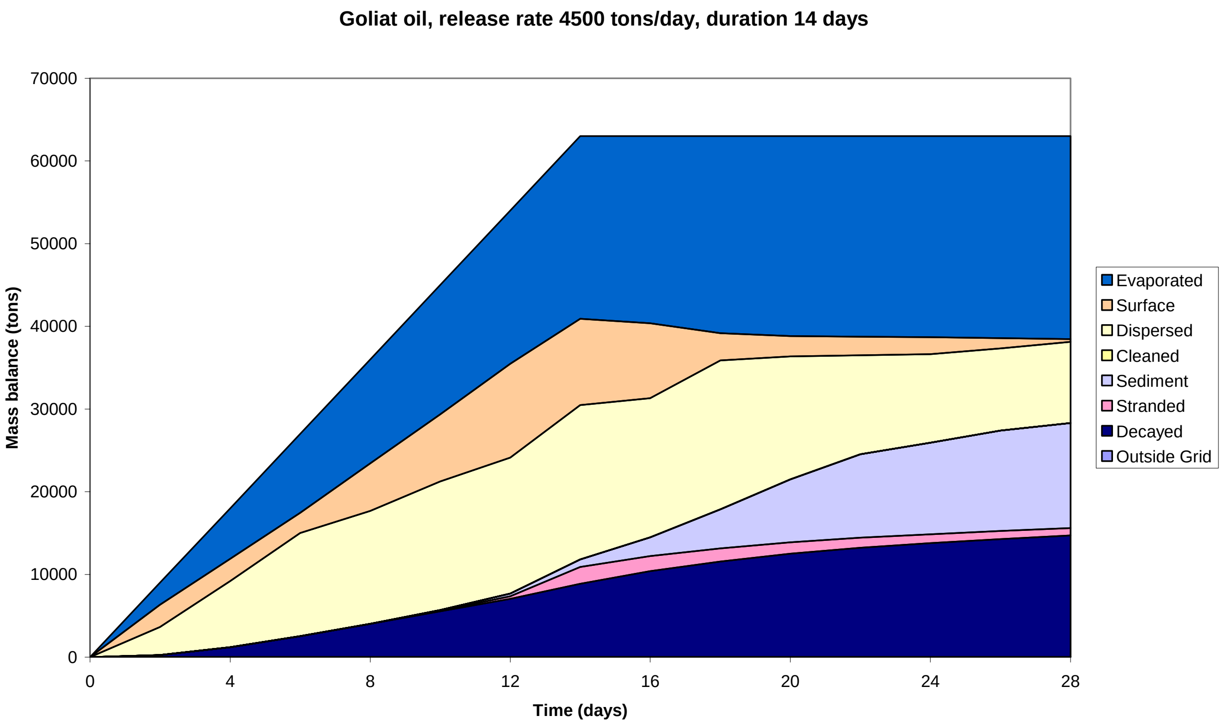


Figure 8-8 Mass balance for a single scenario top-side release of Goliat oil with start date 1996-02-23.

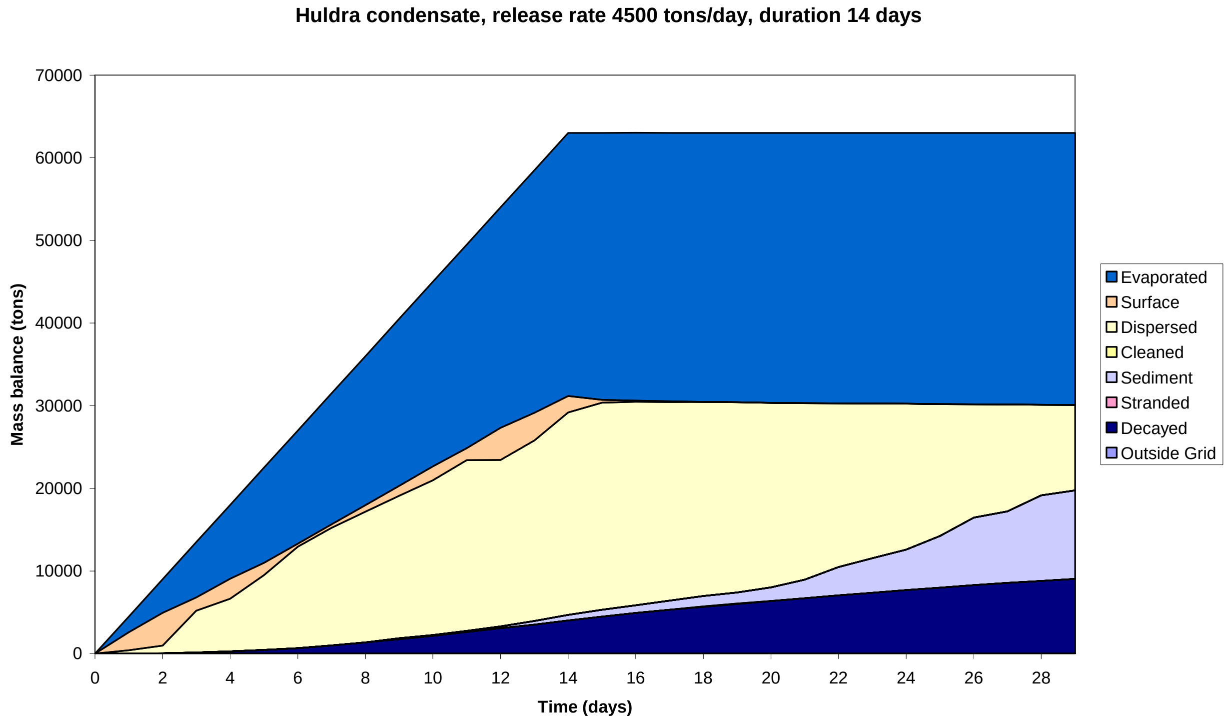


Figure 8-9 Mass balance for a single scenario top-side release of Huldra condensate with start date 1994-09-16.

8.3 Model results - stochastic modelling

Selected results from the oil drift modelling of the different oil spill scenarios are shown in Figure 8-10 through Figure 8-13. The first blowout scenario shown is a two day blowout with eight different blowout rates; 100 tons/day, 200 tons/day, 500 tons/day, 1000 tons/day, 4500 tons/day, 8500 tons/day and 10600 tons/day. Figure 8-10 shows the results for a topside blowout, while Figure 8-11 shows the result from a subsea blowout. The graphs show the number of 10 x 10 km grid cells with probability for hits of 1-100 tons of oil, 100-500 tons of oil, 500-1000 tons of oil and > 1000 tons of oil given the scenario.

Figure 8-12 and Figure 8-13 show the number of grid cells affected by oil given a blowout of 4500 tons/day with various blowout durations; 0.5 days, 2 days, 5 days, 14 days and 50 days. Figure 8-12 is given a topside blowout while Figure 8-13 is given a subsea blowout.

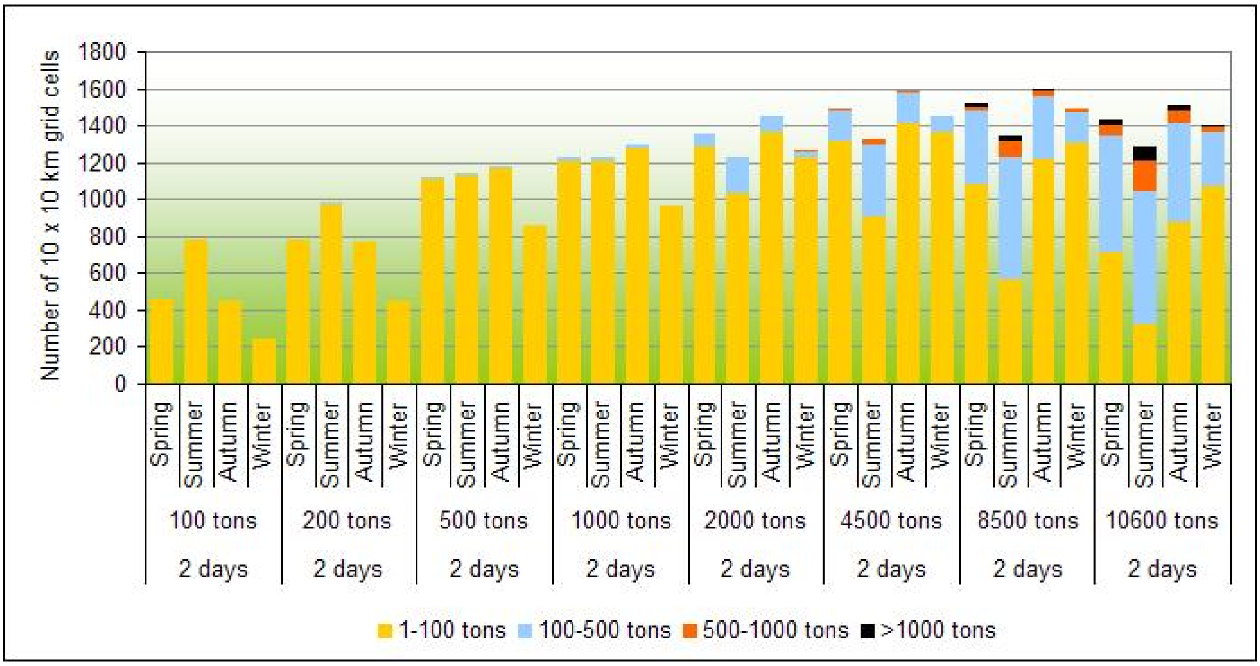


Figure 8-10 Number of 10 x 10 km open sea grid cells with respectively 1-100 tons of oil, 100-500 tons of oil, 500-1000 tons of oil and > 1000 tons of oil given oil spill scenario 2 days duration and various rates or a top side release with Balder oil

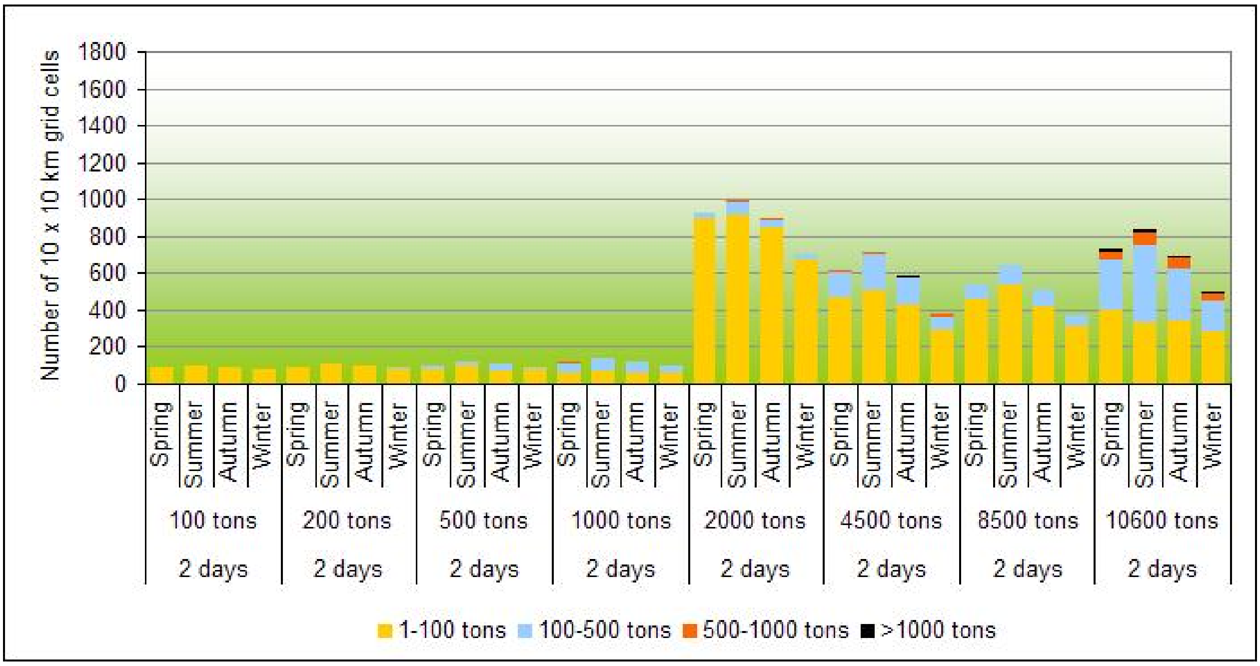


Figure 8-11 Number of 10 x 10 km open sea grid cells with respectively 1-100 tons of oil, 100-500 tons of oil, 500-1000 tons of oil and > 1000 tons of oil given oil spill scenario 2 days duration and various rates for a subsea release with Balder oil

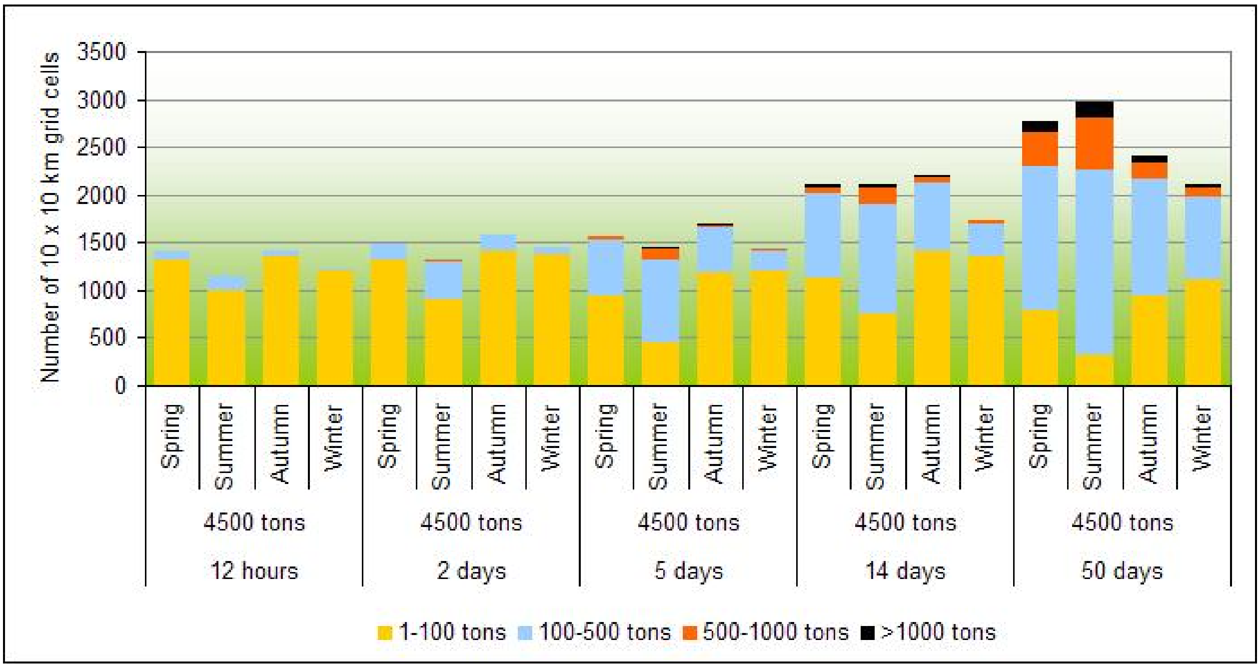


Figure 8-12 Number of 10 x 10 km open sea grid cells with respectively 1-100 tons of oil, 100-500 tons of oil, 500-1000 tons of oil and > 1000 tons of oil given oil spill scenario for release rate 4500 tons/day and 12 hours, 2 – 5 – 14 - 50 days duration for a top side release with Balder oil

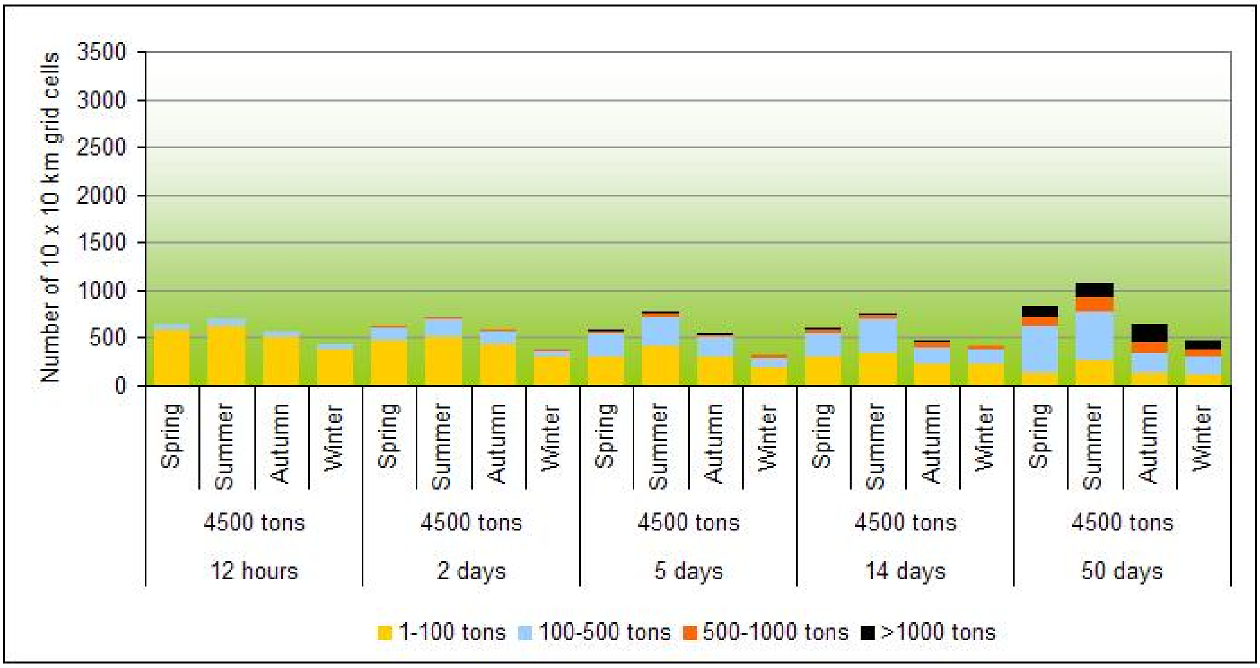


Figure 8-13 Number of 10 x 10 km open sea grid cells with respectively 1-100 tons of oil, 100-500 tons of oil, 500-1000 tons of oil and > 1000 tons of oil given oil spill scenario for release rate 4500 tons/day and 12 hours, 2 – 5 – 14 - 50 days duration for a subsea release with Balder oil

9 ENVIRONMENTAL RISK

9.1 Environmental resources

The environmental resources that have been basis for this environmental risk analysis is the same resources as those analysed for in the environmental consequence and risk assessment that forms the basis for the updated Management plan for the Barents Sea and Lofoten area. Maps with temporal and spatial distribution of the resources are showed in Appendix 7.

9.2 Change in environmental risk due to risk mitigation

The environmental risk is analysed based on the oil drift and weathering properties of the Balder oil, which is one of the most persistent oil's at the NCS. It is analysed for the "base case", which is without taking into consideration the risk mitigation from the operational and technological improvements that have been made in the oil industry. The risk is also analysed for the "alternative case" which includes the effect of risk mitigating measures. Detailed environmental risk results are shown in section 9.4 for the Balder oil. This section shows the relative changes in environmental risk due to risk mitigation.

The relative change in risk is expressed by calculating the risk index (see Appendix 4 for explanation of the risk index) for all risk indicators; seabird/sea mammal, shoreline and fish. The change in risk is then expressed as the difference between the risk index for the "base case" and for the "alternative case".

Figure 9-1 shows that the risk reduction between the "base case" and the "alternative case" using Balder oil is approximate 65 % for seabirds/sea mammals and shoreline habitats, while approximate 75 % for fish.

The contribution of the probability reduction for a blowout counts for approximate 60 % of the risk reduction. While the change in flow path and flow duration probability counts for approximate 40 % of the risk reduction. This is for seabird/sea mammals and shoreline. For fish is the contribution highest from change in flow path and flow duration, counting for approximate 63 % of the risk reduction. The probability reduction for a blowout counts for 37 % of the risk reduction.

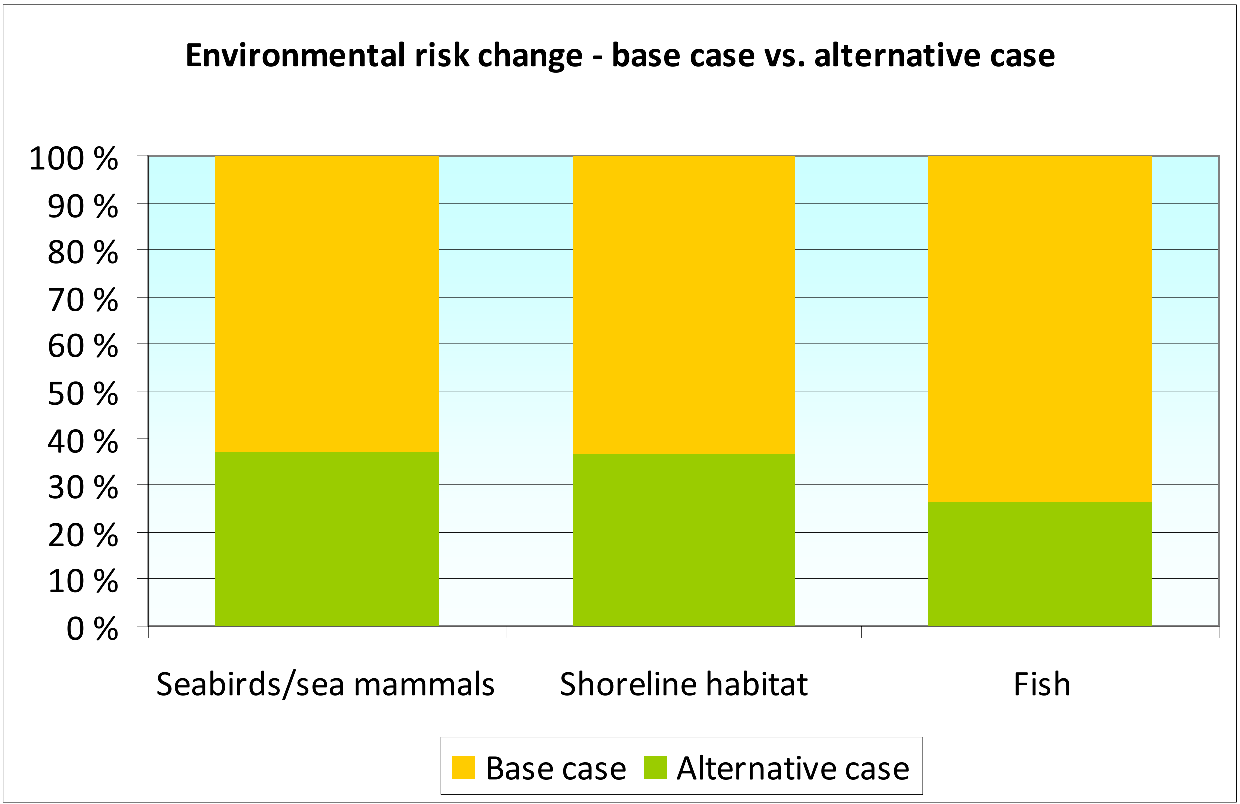


Figure 9-1 Relative changes in environmental risk between the "base case" and the "alternative case" with use of Balder oil. The relative risk is shown for all four seasons and for the seabird/sea mammal populations, coastal areas and fish populations with highest risk for damage.

9.3 Change in environmental risk due to oil type

Environmental risk from a potential oil blowout varies strongly with the oil type released. There is little data available about oil types expected to be found in the Nordland VI area. The environmental risk assessments that forms the basis for the updated Management plan for the Barents Sea and Lofoten area are based on modelling using Balder oil.

To indicate the variation in environmental risk between different oil types, the environmental risk is also analysed for two other oil types; the Goliat oil and the Huldra condensate. The detailed results from these analyses are shown in Appendix 3. This section shows the relative changes in the risk compared to the Balder oil.

Figure 9-2 shows that the risk for seabirds is approximate 20 % lower with Goliat oil compared to Balder oil. The risk for shoreline habitats is more than 30 % lower with Goliat oil. While the risk for harming fish eggs and larvae is slightly higher (7 % points higher) for the Goliat oil compared to the Balder oil. The reason for this is that more of the Goliat oil is mixed down in the water column. However, the detailed results show that the risk for harming fish eggs and larva is very low for the "base case" as well as for the "alternative case" with Balder and Goliat oil (see chapter 9.4 and Appendix 2).

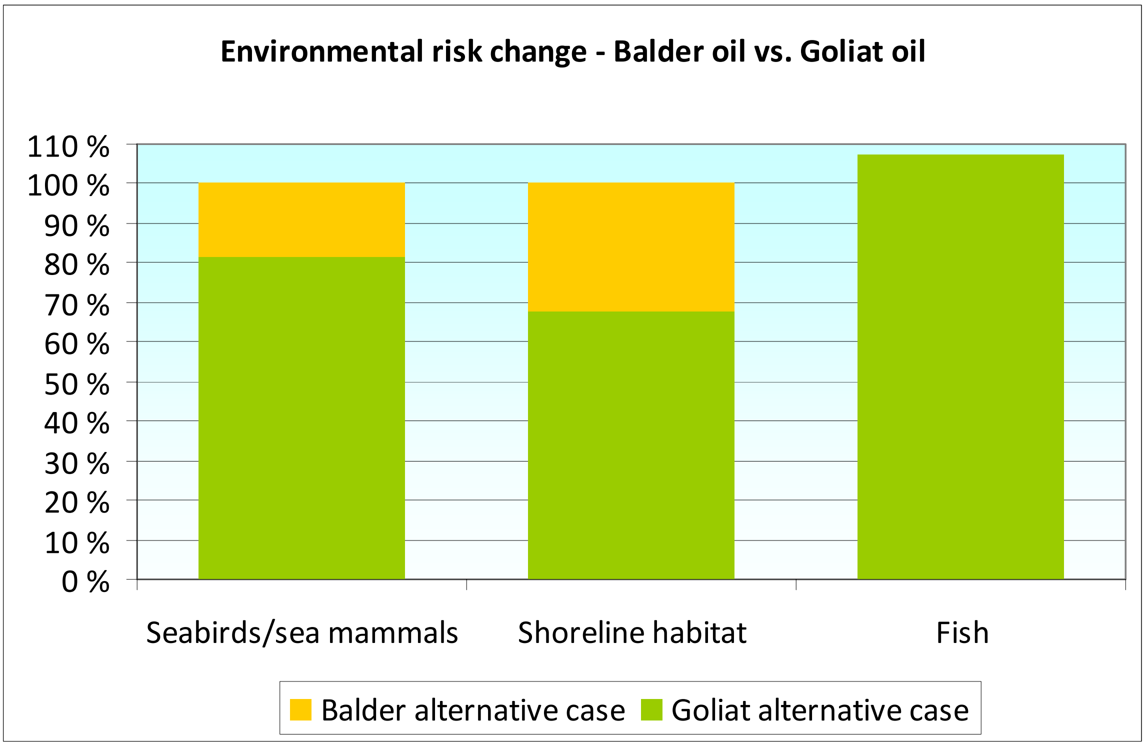


Figure 9-2 Relative changes in the environmental risk, comparison between the "alternative case" for Balder oil and the "alternative case" for Goliat oil (Realgrunnen). The relative risk is shown for all four seasons and for the seabird/sea mammal populations, coastal areas and fish populations with highest risk for damage.

Figure 9-3 shows that the risk caused by the Huldra condensate is approximate 90 % lower than the risk caused by the Balder oil, except for fish. The risk for fish is approximate 65 % lower. The reason for this large reduction in risk between the two oil types is the rapid evaporation of the Huldra condensate. The oil drift model also calculates hydrocarbon drift in the water column, both from hydrocarbons dissolved in the water column during a subsea blowout and from hydrocarbons mixed down from oil slicks at the surface. See Appendix 3 for detailed results of the environmental risk analysis using the Huldra condensate.

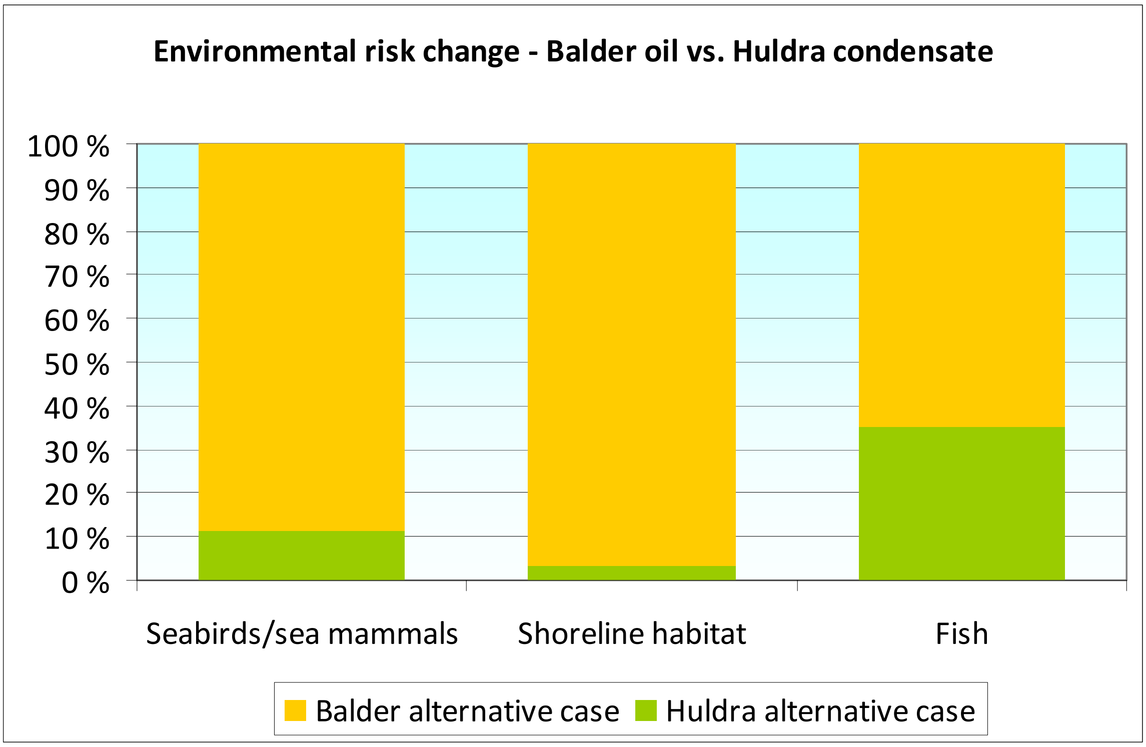


Figure 9-3 Relative changes in the environmental risk, comparison between the "alternative case" for Balder oil and the "alternative case" for Huldra condensate. The relative risk is shown for all four seasons and for the seabird/sea mammal populations, coastal areas and fish populations with highest risk for damage.

9.4 Detailed environmental risk results based on the Balder oil

This section shows a comparison between the overall environmental risk for the "base case" and the "alternative case" analysed with Balder oil. The environmental risk is expressed as the probability of an environmental damage per drilling operation. The environmental damage is divided into four consequence categories in accordance with the OLF guideline for ERA (Ref //11/). The consequence categories express the severity of the environmental damage that is calculated as the theoretically recovery time for the environmental resource. The categorisation is as follows:

- Low damage: less than 1 year recovery time
- Minor damage: 1 – 3 years recovery time
- Considerable damage: 3 – 10 years recovery time
- Serious damage: more than 10 years recovery time

Figure 9-5 to Figure 9-7 shows that the risk for environmental damage is less than 1 x 10^{-4}. The highest risk is for seabirds in the summer season in the "base case", i.e. without considering the risk reducing measures. A probability less than $1x10^{-4}$ is the same as the probability that this can happen less than once per 10.000 operations.

For comparison 1;

In a safety risk assessment the probability of defined main safety functions being impaired (damaged), is calculated in order to ensure that the platform design does not imply unacceptably high risk. The acceptability level for the impairment of each main safety function is the annual probability of 1 x 10^{-4} for each type of accidental loads.

Looking into the various consequence categories shows that more than 90 % of the probability of damage is related to the two lowest consequence categories (<1 year and 1-3 years recovery time).

The results show that the risk is considerably reduced for all seasons and all environmental resources when the effect of technology improvement is taken into consideration see the section above.

For comparison 2;

The environmental risk from exploration drilling at Nordland VI has the same level as the environmental risk from exploration drilling in the central part of the North Sea based on the environmental risk analysis methodologies applied in the industry today. Figure 9-4 *shows the total environmental risk level from eight randomly selected exploration wells in the North Sea and from the exploration well in Nordland VI without taking into consideration the risk mitigating measures. The highest total risk is selected for the Nordland VI case.*

The basis probability from the annual Scandpower reports has changed during the last years, and these analyses are from the last four years. Thus some of the wells would have slightly lower damage probability if they were analysed today. The well with highest damage probability is close to shore in the North Sea.

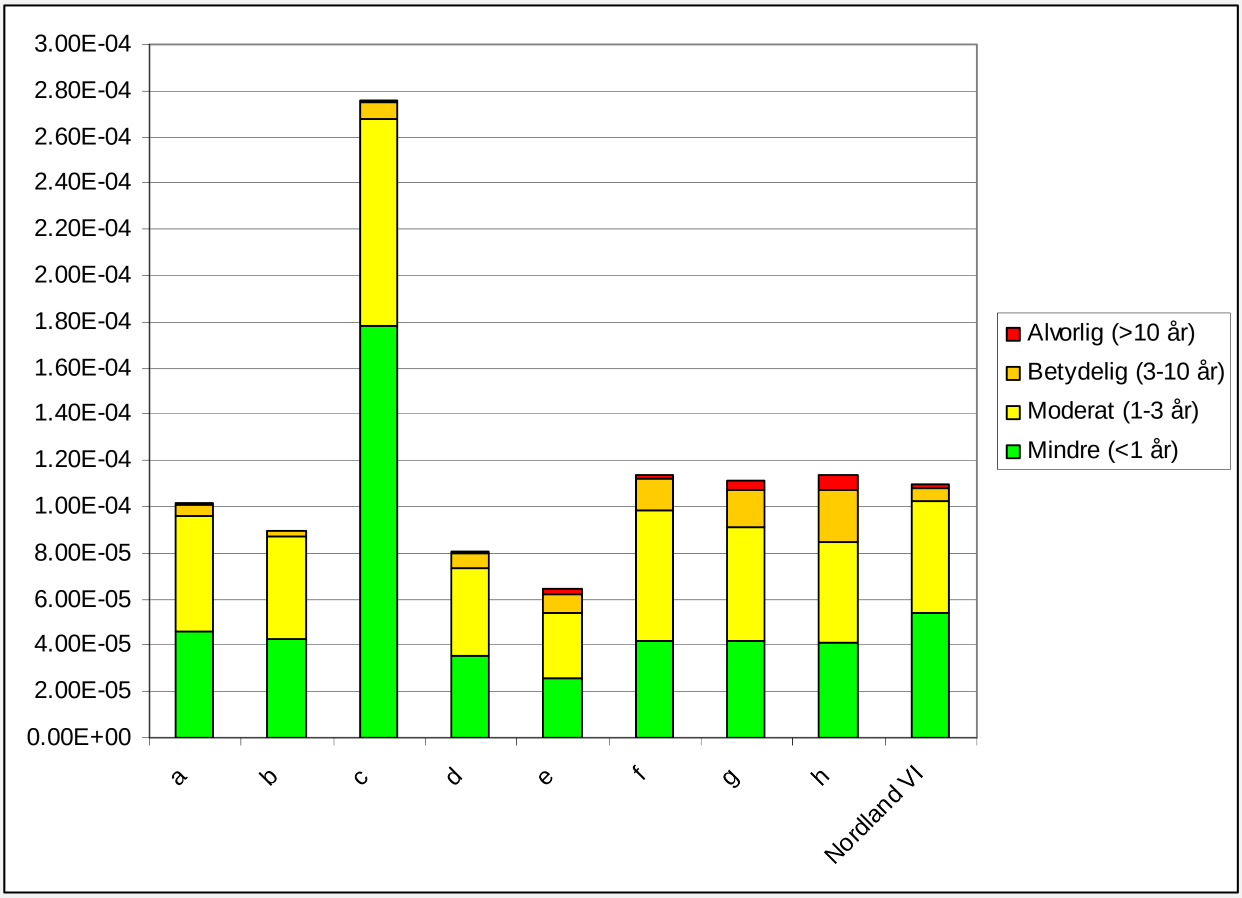


Figure 9-4 Environmental risk from exploration drilling at two randomly selected wells in the central part of the North Sea. The environmental resources with highest risk are selected.

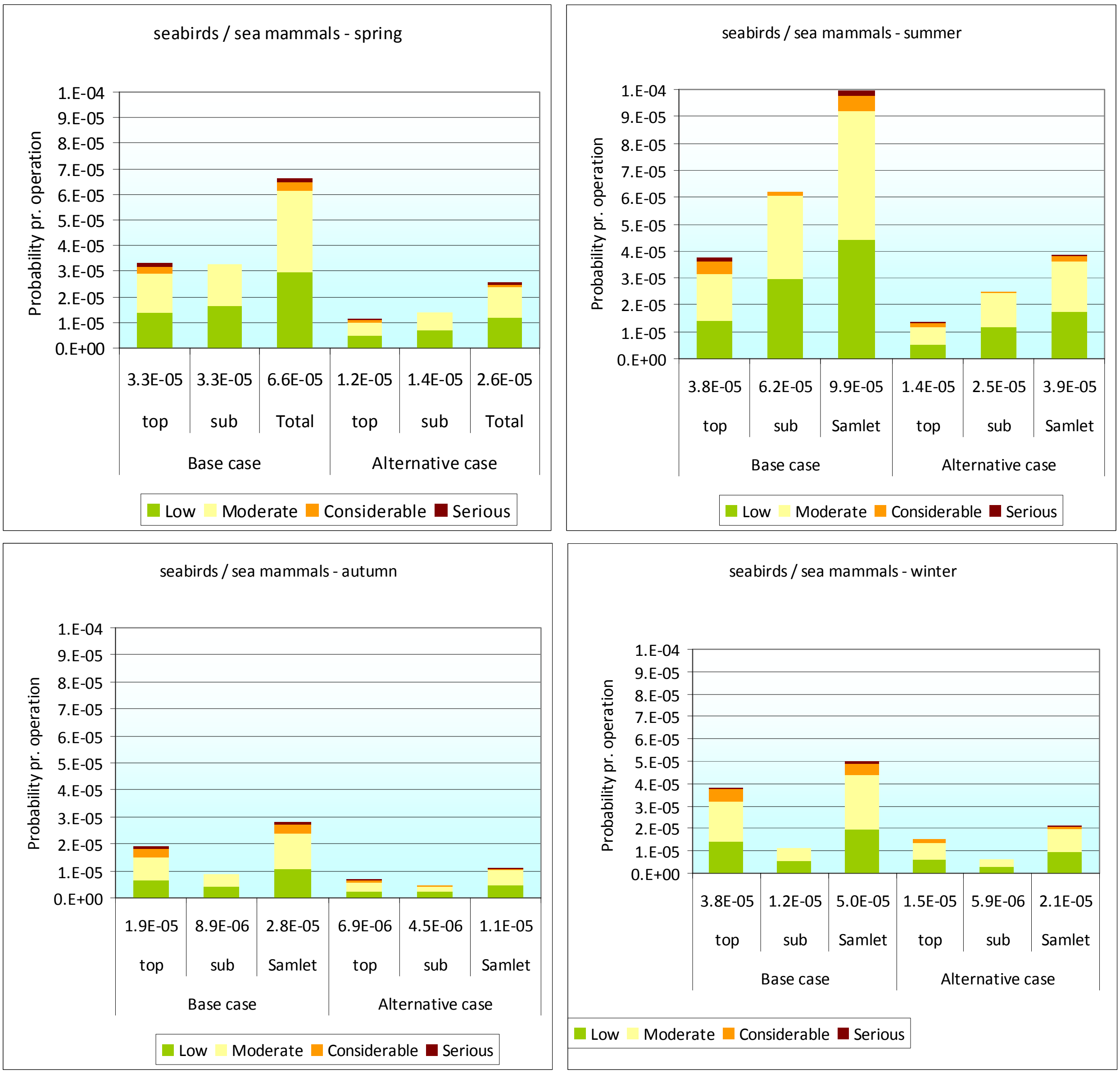


Figure 9-5 Environmental risk to seabirds or sea mammals, expressed as the probability of environmental damage, per drilling operation. The environmental damage is divided into four damage categories with increasing severity; low, moderate, considerable and serious damage. The probability of environmental damage is divided between subsea and topside blowout and is also showed as the sum between those two. The environmental risk is shown for the "base case" at the left in the figure and for the "alternative case" at the right in the figure.   The four different graphs show the risk for each of the seasons.

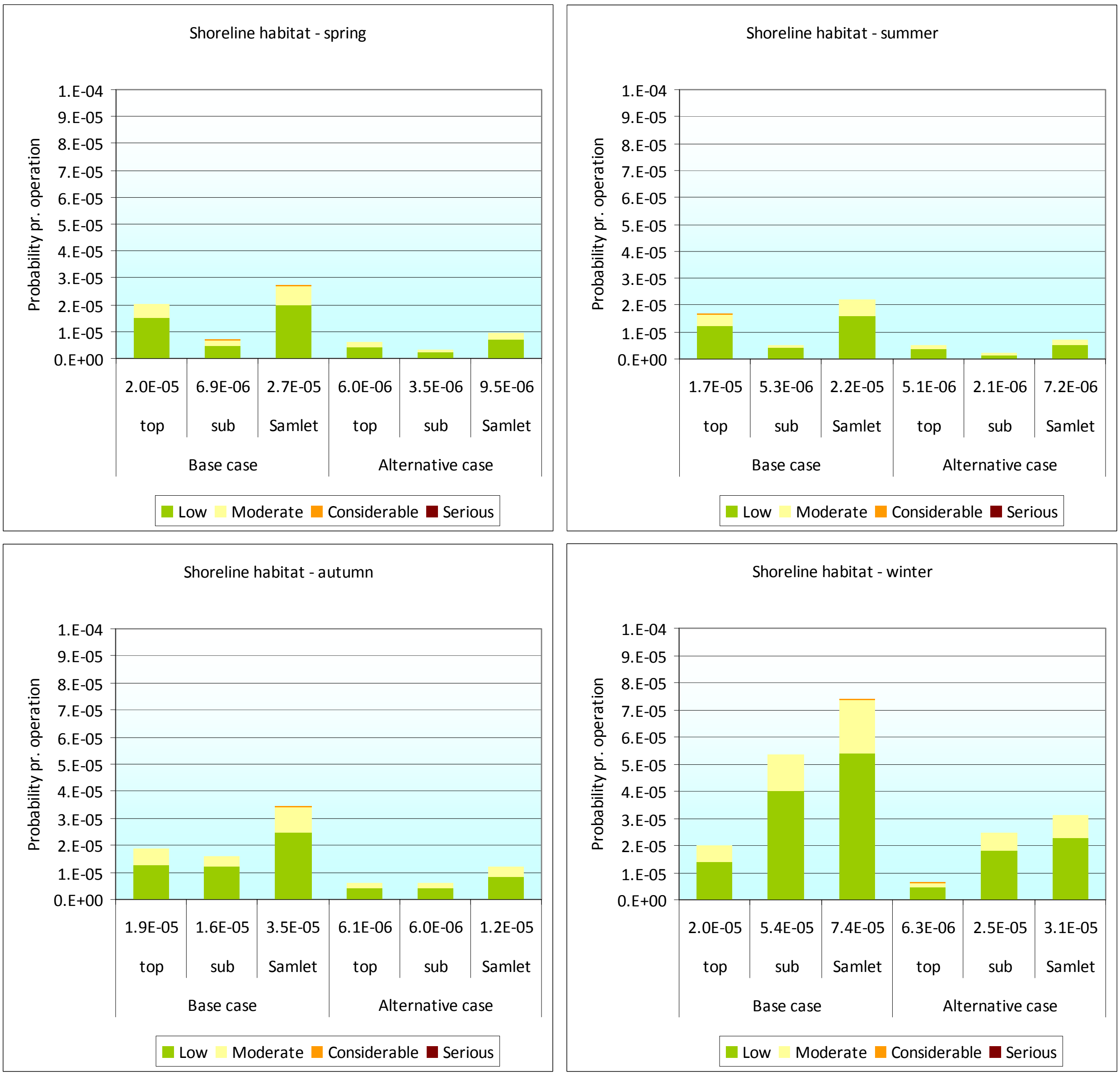


Figure 9-6 Environmental risk to shoreline habitats, expressed as the probability of environmental damage, per drilling operation. The environmental damage is divided into four damage categories with increasing severity; low, moderate, considerable and serious damage. The probability of environmental damage is divided between subsea and topside blowout and is also showed as the sum between those two. The environmental risk is shown for the "base case" at the left in the figure and for the "alternative case" at the right in the figure.   The four different graphs show the risk for each of the seasons.

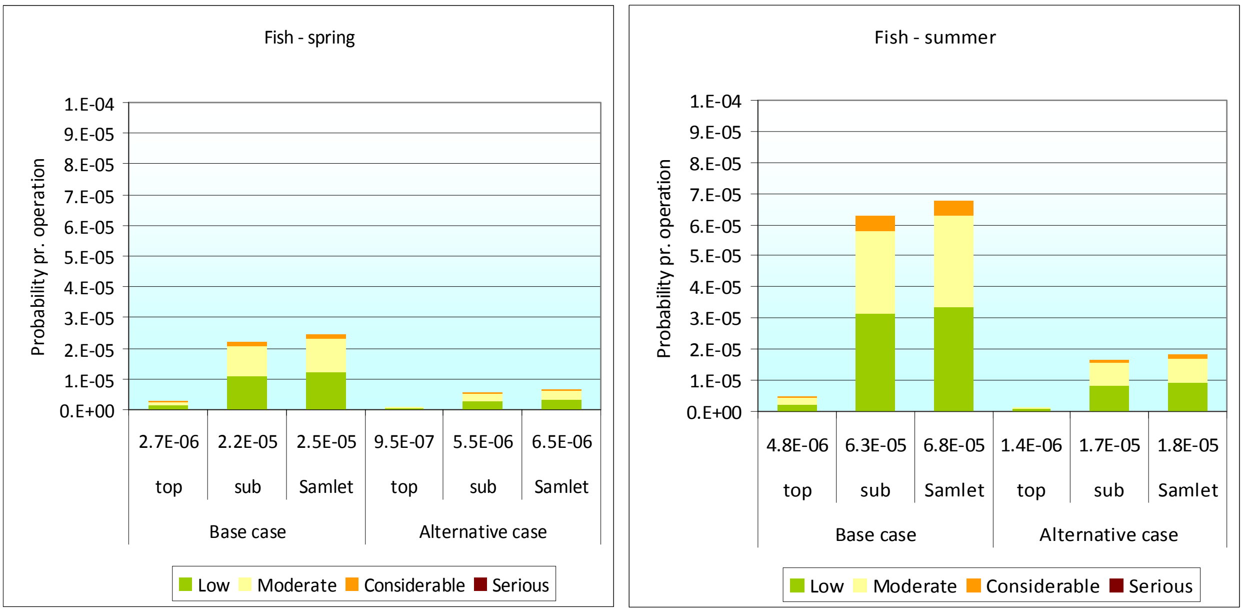


Figure 9-7 Environmental risk to fish, expressed as the probability of environmental damage, per drilling operation. The environmental damage is divided into four damage categories with increasing severity; low, moderate, considerable and serious damage. The probability of environmental damage is divided between subsea and topside blowout and is also showed as the sum between those two. The environmental risk is shown for the "base case" at the left in the figure and for the "alternative case" at the right in the figure. The risk is shown for the spring season in the left graph and for the summer season in the right graph, the risk in the autumn and winter season is analysed as zero.

10 CONCLUSIONS

This analysis has shown that the technology, the equipment reliability and the operating procedures that are applied in the oil and gas industry today have a clear impact on the environmental risk level. The improvements and learning in the industry have lead to more environmentally safe drilling operations and thus reduced the environmental and operational risk significantly. This is not reflected in the baseline parameters used for conventional risk characterisation, and thus, the risk is overestimated for many or most operations. The analysis also shows how important it is to include risk mitigating measures in the environmental risk analysis.

This analysis also shows that, based on the industry standard for environmental risk analysis oil drift modelling; the environmental risk level from exploration drilling in Nordland VI is similar to the risk in the North Sea.

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APPENDIX

1
TECHNOLOGY REVIEW

ID	Description	Effects/Impacts	Primary Barrier	2ndary Barrier	Well Control	Implementation	Comments	external credibility	WC External credibility	comments to impact
1	Equipment Reliability									
1.1	Blowout preventer (BOP) equipment improvements	Improved reliability of control systems		M		Yes	Lessons learned from more advanced technology related to deep water and HPHT drilling operations. Statoil has performed BOP campaign with good results. New monitoring plan are in progress.	M		There is statistics of the results of well testing that can be used for the reliability
1.2		Improved reliability of ram blocks and lock mechanisms		M	?	Yes		M		
1.3		More robust BOP stack setup with double annular preventer, minimum 3 pipe rams and shear ram. Improved closure reliability and operability		M	M	Yes	Two annular preventers is not yet fully standard in the North Sea	M		quantify the increased redundancy **WC** Some simpler operations. Possibility to release drill string through BOP.
1.4		New shear RAM developed and is more likely to make a successful cut, i.e. Improved closure reliability when string/cable cut is required.		M	L	Yes	Can cut cable ect. Cameron and Shaffer has the new shear ram. Hydril will soon perform test.	M		**WC** Tight shut-off.
1.5		Extra BOP pressure rating safety margin due to high design pressure on the exploration rigs.		M	?	Yes	In general the rig equipment spec is higher than the well design.	M		

ID	Description	Effects/Impacts	Primary Barrier	2ndary Barrier	Well Control	Implementation	Comments	external credibility	WC External credibility	comments to impact
1.6	Improved testing, management and maintenance of BOPs.	Better knowledge and understanding on optimal testing frequencies – more testing does not necessarily make the system more reliable. The maintenance procedures have improved.		M		Yes	The reliability management on the component level has improved. It is recommended to use rigs with proven track record. Statoil has performed BOP campaign with good results. New monitoring plans are in progress.	M		improved the practices and procedures for testing of BOP equipment
2	Procedures									
2.1	Improved operating procedures	The drilling procedures have improved in general with respect to pressure control and well control focus. Particular improvements within HPHT and operations with smaller margins.	H		H(M)	Yes	Improved focus as a result of the experience related to HPHT, depleted reservoirs and deep well operations.	M/L		**WC** More contingency plans developed. Experience.
2.2	More comprehensive risk assessment processes	Drilling procedures are more systematically subjected to quality reviews and risk assessment.	H	H	M			M		Improved procedures and well design, improved understanding of risk **WC** Identify worse case sceanrios upfront.
2.3	Stop criteria and contingencies better defined.	Smart procedures increase the ability to act safely before hazards unfold and to get out of hazardous situations in a prepared manner	M			Yes	Preparedness plan and hard-stop criteria now base on risk assessment.	M		output of risk assessment

ID	Description	Effects/Impacts	Primary Barrier	2ndary Barrier	Well Control	Implementation	Comments	external credibility	WC External credibility	comments to impact
2.4	Better control with fluid properties	Fluid technology and surface processes has improved. The ability to achieve stable fluid quality has resulted in a more reliable primary well control barrier. (quality and stability of fluid)	M			Yes	More use of WBM resulting in reduced risk of gas mixing with the drilling mud. Use of premixed mud from onshore.	L		less exposed to human error in mud preparation
2.5	Methods for reducing potential blowout rate	Reduced consequence of a blow out by reducing potential blow out rate related to drilling too far, e.g. in a permeable reservoir.			M	Yes	Logging of reservoir while drilling and considering setting extra casings if required. Avoid multiple reservoirs if possible.			**WC** Increased control on where to set casing (better formation strength etc.). Increased operational window during well control (asess if to drill one or two sections).
2.6	Improved specification, definition and communication of barriers.	More specific and demanding requirements with regards to qualification of drilling and well components serving as well barrier elements. Better definitions on how to use barriers.	M	M		Yes	More systematic use of barrier documentation. Step change in barrier thinking after Snorre A.	L		most relevant for secondary barriers
2.7	Early kick detection	Use of systems developed for early detection of kicks, fingerprinting procedures, reduces expected kick volume and the risk of challenging well control operations.			H	Partly	Improved surface equipment for volume control. Improved data processing. Reduced risk of loosing well control. Used in challenging wells.			**WC** Increased control of buttomhole pressure. Before the pressure was calculated, now measured directly.
3	Technology improvement									

ID	Description	Effects/Impacts	Primary Barrier	2ndary Barrier	Well Control	Implementation	Comments	external credibility	WC External credibility	comments to impact
3.1	Developments within drilling fluids	Enables maintenance of intended mud properties through various conditions, better control bottom hole pressure and operate safely within more narrow margins	H			Yes	Brine based system without the risk of decreasing mud weight due to settling. Premixed mud from onshore more used today.	H		difficult wells or during disconnect
3.2	Measurement while drilling (MWD)	More and more reliable data, instantly. - verify down hole pressure and ECD - instant feedback on formation changes - Improved control and adjustment of mud weight	H		M (H)	Yes	Pressure while drilling. Resistivity at bit.	H		**WC** Increased control of buttomhole pressure. Before the pressure was calculated, now measured directly.
3.3	Improved reliability of well control equipment including surface equipment.	Improved precision and reliability in well control situations.			M	Yes	Upgraded choke manifold, gauges, lines and up lining.			**WC** Precision and reliability matter.
3.4	Improved well control equipment for hazardous environments.	Operationally improved barriers from new equipment. Improved equipment especially for rough/cold environments has improved based on experience.			M	Yes	Lessons learned from more advanced technology related to deep water and HPHT drilling operations. Improved equipment for Arctic environment.			Related to well control (check the relevance?) **WC** Are we in an hazardous environment? Relating to maintenance, awarened of use of glykol (MEG) injections.

ID	Description	Effects/Impacts	Primary Barrier	2ndary Barrier	Well Control	Implementation	Comments	external credibility	WC External credibility	comments to impact
3.5	Improved quallity of casing and casing connections	More robust secondary barrier. Reduced risk of leak through casings.		M		Yes	Premium threads only used today. Torque turn computer is standard. Improved control of casing material.	M		Improved qualification, design and fabrication as well as make up
3.6	Wired data transfer (Acoustic back-up)	Better data transfer, wider such that more data can be transferred more reliably.	L		SJEKK	Partly	New tech – qualified but not implemented as a standard.	M		linked to measurement while drilling, improves utilization of measurement/logging, faster and more reliable transfer NT **WC** Continoius data transfer. To what extent is this implemented for a well control scenario?
3.7	Direct pore pressure measurement during drilling operations.	Drastically reduces uncertainty in pressure margins and improves the ability to keep the pressure within the safe drilling window	H		L (M)	Yes	Technology based on sonic and resistivity real time data. Requires short interruption of drilling operation	H		not given that we would like to sell this, could have an impact on tripping and understanding the tripping margin NT **WC** Aware of margins to act according too.
3.8	VSP look ahead	Reduced risk of drilling into reservoir section unintentionally and drilling into high pressure zones.	H			Yes	Reduced risk of drilling into hazard zones unintentionally. Better stratigraphic control. Required stop in operation.	H		dedicated wireline run (logging tool)

ID	Description	Effects/Impacts	Primary Barrier	2ndary Barrier	Well Control	Implementation	Comments	external credibility	WC External credibility	comments to impact
3.9	Seismic while drilling	Reduced probability of drilling into reservoirs by reducing seismic uncertainty.	H			Emerg-ing		H		Continuous updating, improved data in connection with VSP, only relevant were it is uncertainty on the horizont
3.10	3-D seismic	Better information in the planning phase leading to less uncertainty	H			Yes	3-D seismic has resulted in improved reliability in the early predictions	H		
3.11	Improved pressure control during cementing and better cement quality.	Avoid influx while cementing and leaks past the cement shoes (gas tight and foam cement). Better control of the cementing process. Improved chemicals and types available. Improved cement logs.	H	H		Yes	improvement in 2 areas: improved cement quality improved pressure control while pumping cement, avoids fracturing and loss/gain	H		most credible for secondary barriers
3.12	Improved data gathering on rig	Improved data collection regarding gas in mud, volume and flowrates on the rig	H			Yes	Higher accuracy with regards to trending data and handling larger amounts of data, pre kick detection	L		continuous sampling of data
3.13	Flow meter technology	Early kick detection system	M		H (M)	Emerg-ing	primarily for WBM at present	L		NT, technology needs to be developed **WC** Not implementes, if in use, maybe H / M. Related to early kicks detection.

ID	Description	Effects/Impacts	Primary Barrier	2ndary Barrier	Well Control	Implementation	Comments	external credibility	WC External credibility	comments to impact
3.14	Managed pressure drilling	Pressure control philosophy which enhances the ability to operate within small margins.	L			Yes	Might be appropriate when experiencing tight margins and high probability of kicks. Not yet performed on floaters and typically not in exploration.	L		Not a technology used in exploration drilling. We will not want to evaluate this tech.
3.15	Pressure and temperature sensors in BOP	Improved well control and reduced risk of hydrates.			M	Yes	Often used in deep water.			**WC** Possible to measure temperature and pressure.
3.16	Improved well control and kill calculation models.	Improved well design with regards to kill rate and casing design.			M	Yes	Improved base for design of bull heading ect. Dynamic models developed. Consequence reducing measure.			
3.17	Improved pore and fracture pressure prediction	Reduces probability of loosing primary well barrier or fracturing formations.	H			Yes	Increased understanding and improved models for pore and fracture pressure prediction	L		industry is better at understanding the 3D data with regards to fracture pressure, ability to keep within a window, linked to 3D
3.18	Improved surge/swab data	Technology can significantly reduce operational risk.	M		M	Emerg-ing?	Technology not available.	L		NT , related to MWD **WC** Relevant for Well Control, early kick detection?
	Improved hydrolic modelling	better prediction of buttom hole pressure given mud weight in dynsmic conditiond (surge/swab and ECD)	H					L/M		most relevant for difficult wells

ID	Description	Effects/Impacts	Primary Barrier	2ndary Barrier	Well Control	Implementation	Comments	external credibility	WC External credibility	comments to impact
3.19	Increased knowledge of wellhead fatigue	Improved wellhead design. Improved connections and casing connections on surface casings. More robust design with regards to fatigue. Quality control of wellhead and connectors. Rigid lock down.		L		Yes	larger drilling rigs might increase the risk of blowout, well head fatigue knowledge and awarenes reduces the risk.	L		Use of larger drilling rigs and more heavy equipment may lead to increased fatigue. More an issue for production wells
3.20	Improved directional control.	Improved procedures and better control of well path and less uncertainty. Improves the ability to efficiently intersect a blowing well when drilling a relief well. Avoid known geo-hazards, position controll on the top reservoir	M		?	Yes	Consequence-reducing. (relief well drilling)	M/L		most of the exploration wells are vertical **WC** Scenario when already loss of well control. Effect on duration (one or 3 days extra).
3.21	Magnetising casing	Increased probability to efficiently intersect with relief well.			?	Partly	Consequence-reducing. Can be used if required by special conditions. Used on PEON well			
3.22	Reduced casing wear due to less mechanical exposure.	Improved ROP and less bit trips resulting in less worn casing.		L		Yes	Less exposure due to less rotation and tripping. Use of motor to reduce RMP. Casing designed to handle casing wear.	L		vertical wells and limited wear cycling in exploration drilling

ID	Description	Effects/Impacts	Primary Barrier	2ndary Barrier	Well Control	Implementation	Comments	external credibility	WC External credibility	comments to impact
3.23	Reduced number of bit trips and less exposure to swabbing	Reduced number of trips gives less exposure of surge/swab and reduced kick probability.	H		M	Yes	tripping is main cause to kicks	H		improved reliability of bottom hole assembly **WC** Increased number of kicks / well control incidents will occur drill near the string in the well.
3.24	Pore pressure evaluation	- Improvements in software and more consistent and efficient work processes for real time evaluation. - Better utilization of seismic interval velocities for pore pressure prognosis. - Basin pressure modelling software development (Sintef)	H		L (M)	Yes	Use real time LWD data, i.e. sonic, density and resistivity.	H		check overlap with previous parameters **WC** Better knowledge of pressure winndow resulting in better conditions for well control.
3.25	Reduced need for wireline logging, increased quality and functionality of LWD	Open-hole time is reduced. Less possibilities for complications linked to hole stability, fishing and cut wire.	H		M (L)	Yes	Reduce response time in well control situation during wireline logging. Reduced fishing.	H		linked to the quality of equipment, less tripping, avoids open hole flow scenarios **WC** Reduced response time related to well control. Increased time with drill string in wel.

ID	Description	Effects/Impacts	Primary Barrier	2ndary Barrier	Well Control	Implementation	Comments	external credibility	WC External credibility	comments to impact
3.26	Formation Testing While Tripping (FTWT)	Will increase applications of WFT testing and reduce the need for DST, resulting in reduced risk.	H		M (L)	Emerg-ing	Statoil patent. Emerging technology.	H		NT - eliminate the need for doing a separate well testing operation **WC** Ref above. Simpler operation - see primary barrier. Ref above. Simpler operation - see primary barrier.
3.27	Smartest	Well testing without produced hydrocarbons to surface	H		M (L)	Emerg-ing	Partial Statoil patent. Emerging technology.	M		NT - eliminate the need for doing a separate well testing operation **WC** Ref above. Simpler operation - see primary barrier.
5.5	Reduced well testing in exploration wells	New technology has replaced the requirement for full scale well testing. Reduced operational risk.			M (L)	Yes	Wireline Formation Testing produces less hydrocarbons, take less time, and reduces overall exposure. No need to produce or burn hydrocarbons.			ref- 3.28 and 3.29 (this is proven tech, not NT) **WC** Ref above. Simpler operation - see primary barrier.
3.28	MWD downhole gas (methane) detection/measure-ments	Early warning of HC influx to the well by downhole MWD sensor measuring in real-time while drilling gas content of mud. Reduce kick probability (?) and reduce risk of loosing well control in the case of a kick.	H		M	Emerg-ing	Concept, possible but might need active support. Emerging technology. improvement of the gas detection to detect kick risk at an early stage (pre-kick)	L		NT **WC** Eliminate uncertanty during operation (keep above pore pressure). Early kick detection.

ID	Description	Effects/Impacts	Primary Barrier	2ndary Barrier	Well Control	Implementation	Comments	external credibility	WC External credibility	comments to impact
4	Human factor & organisation									
4.1	Experience gained with drilling difficult/challenging wells.	The systematic risk assessment process and procedures developed as part of HPHT well operations have increased the safety focus and level of planning and operational sophistication	H	H	H	Yes	A more thorough and detailed process in the planning phase. More comprehensive and precautious procedures	M		Look at the kick records for early HPHT wells. Improved description of procedures and organisation related to drilling of difficult wells. 2nd: Hardware modifications (pressure and temp gauges, glycol injection points, rubber qualifications, compatible fluid systems) **WC** See på 2.1.
4.2	Training and knowledge.	Better awareness and understanding of well integrity issues. Statoil have arranged yearly well integrity seminars. Qualification requirements has in increased in Norway.	H	H	M	Yes	Awareness of control barriers for personnel. Barrier and well integrity focus drastically improved after the Snorre incident.	M		compare with other industry (aviation, process industry, nuclear, military). 2nd: More well, rig, and operations specific including simulator training. **WC** Focus and awareness.

ID	Description	Effects/Impacts	Primary Barrier	2ndary Barrier	Well Control	Implementation	Comments	external credibility	WC External credibility	comments to impact
4.3	Processes for internal independent verification. (Procedures?)		H	H	M	Yes	Internal asurance on well delivery and geo-hazards	L		
	Processes for external independent verification. (Procedures?)	Increased BOP availability. Prevents pulling and maintenance of BOPs.		H			More use of external verification and audits	H		More use of external equipment verification
4.4	Improved competence, knowledge and procedures with mud weight in HPHT wells	Improved control with bottom hole pressure. Pressure While Drilling (PWD) is used to verify the mud weight models. Ref: Lars Tore input from Thomas Nilsen on this experience (technology).	H			Yes	Improved models for simulation of downhole pressure with regards to pressure and temperature effects. Step change in HPHT.			ref-4.1, 2.4 and 3.1 (better control of fluid properties)
4.5	Improved work processes	Continouos improvement in work processes in D&W	X	X	M	Yes	Industry development and experience transfer			ref section 2 **WC** Consistency between projects, lists are developed and followed.
4.6	Better understanding of well integrity	Well integrity developed as discipline. Systematic work and increased corporate competence.	X	X	M	Yes	More focus and step change after incidents.			ref- 4.2
5	General									

ID	Description	Effects/Impacts	Primary Barrier	2ndary Barrier	Well Control	Implementation	Comments	external credibility	WC External credibility	comments to impact
5.1	Better weather prediction.	Reduced risk related to station keeping incidents. Improved documentation to stop critical operations.	M	M	M	Yes	More and more reliable data available	H		More predictable conditions for disconnect **WC** Avoid critical situations and handling of incident during poor working conditions.
5.2	Integrated operations (offshore vs. onshore)	The improved communication and better data to the onshore personnel results in better understanding of potential risks. Operation centre onshore to support the offshore operation.	H	H	H	Yes	The quality of data available onshore provides opportunities for more detailed evaluations	M		Experts have real time access to information, and improved co-operation between experts. **WC** This is really important when need of operational support. Risk assessement and decision support.
5.3	Increased reliability of anchors.	Reduced risk of incidents with regards to drift off. GPS and station keeping. More control with anchors. Anchor analysis has been improved.	M	M		Yes	Requirements have changed last 10-15 years. Survey program is improved (CPT).	M		
5.4	Better control with vendors	Audits, better control and qualification of vendors. Improved QA/QC. Contractor included.	H	H		Yes	Better QA/QC at vendors. Typical focus on the up-time of the rig and not quality of the well.	L		Link to 4.3+4.
5.6	Ships collision.	Radar technology and communication systems has improved.	L	L	L	Partly		M		
5.7	Improved barriers	ISO 14310 V1/V0 testing of barrier equipment	M	M			More robust temporary P&A design.	L		

ID	Description	Effects/Impacts	Primary Barrier	2ndary Barrier	Well Control	Implementation	Comments	external credibility	WC External credibility	comments to impact
		implemented.								
NOTE	Number of kicks? PTIL collect data on kicks – is it increasing.	Type of kick. Use of statistics.					NPD report (PTIL).			

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APPENDIX
2
ENVIRONMENTAL RISK RESULTS

Environmental risk results with the Goliat Realgrunnen oil

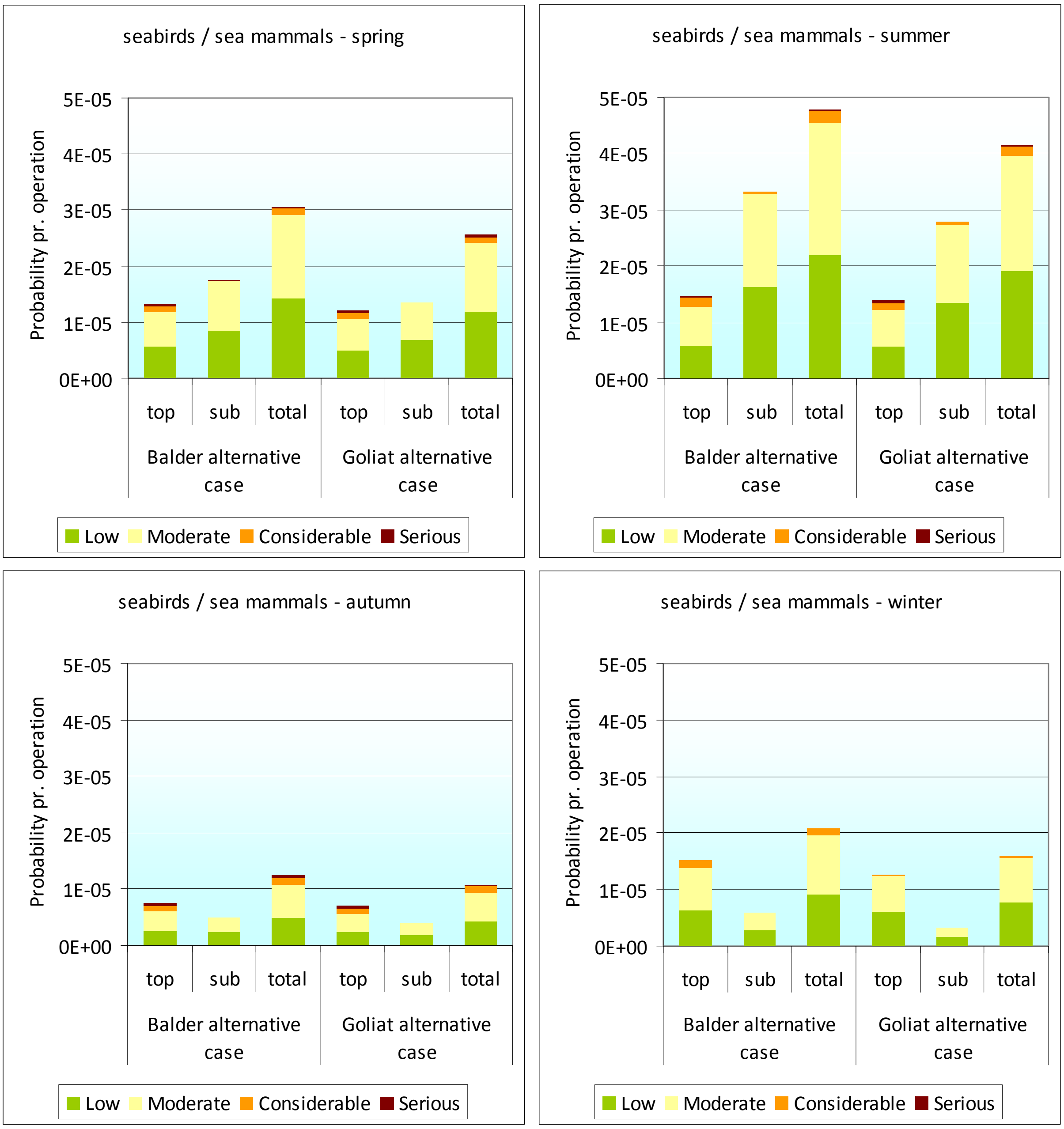

Figure 1 Environmental risk to seabirds or sea mammals, expressed as the probability of environmental damage, per drilling operation. The environmental damage is divided into four damage categories with increasing severity; low, moderate, considerable and serious damage. The probability of environmental damage is divided between subsea and topside blowout and is also showed as the sum between those two. The environmental risk is shown for the "alternative case" with Balder oil at the left in the figure and for the "alternative case" with Goliat oil at the right in the figure. The four different graphs show the risk for each of the seasons.

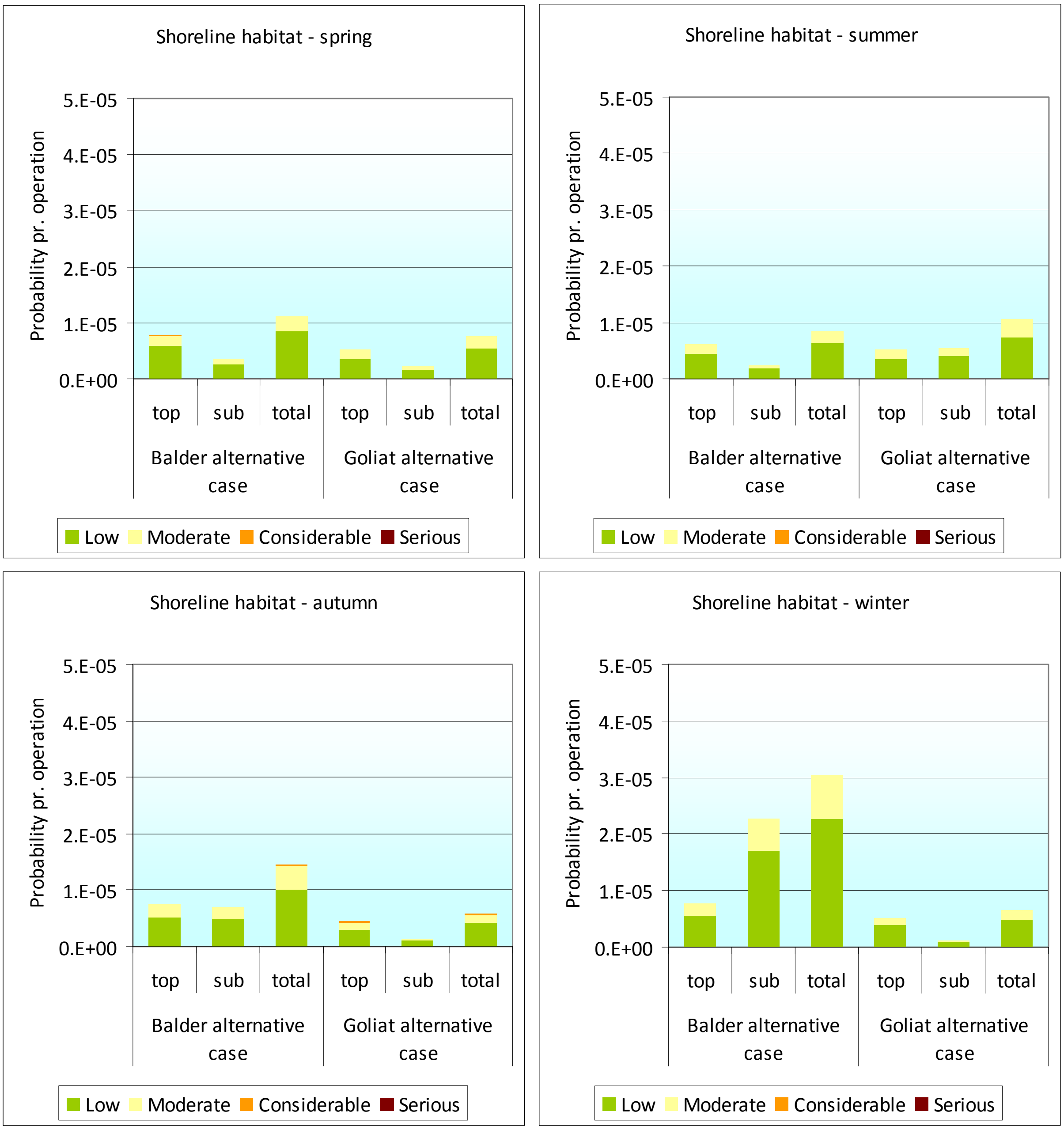

Figure 2 Environmental risk to shoreline habitats, expressed as the probability of environmental damage, per drilling operation. The environmental damage is divided into four damage categories with increasing severity; low, moderate, considerable and serious damage. The probability of environmental damage is divided between subsea and topside blowout and is also showed as the sum between those two. The environmental risk is shown for the "alternative case" with Balder oil at the left in the figure and for the "alternative case" with Goliat oil at the right in the figure. The four different graphs show the risk for each of the seasons.

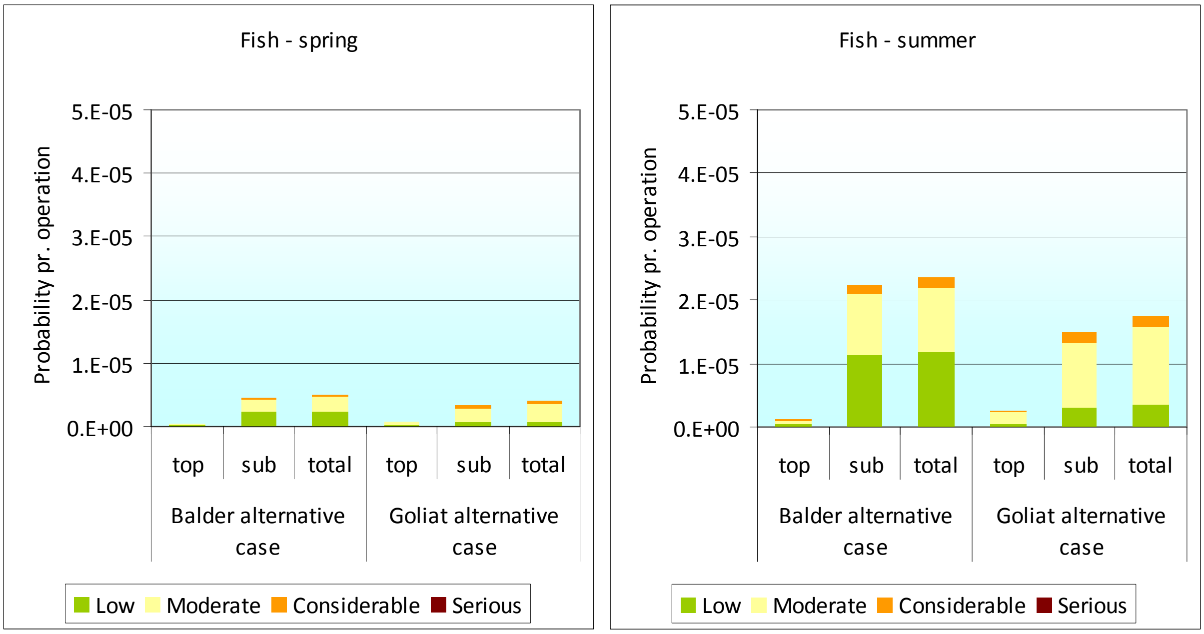

Figure 3 Environmental risk to fish, expressed as the probability of environmental damage, per drilling operation. The environmental damage is divided into four damage categories with increasing severity; low, moderate, considerable and serious damage. The probability of environmental damage is divided between subsea and topside blowout and is also showed as the sum between those two. The environmental risk is shown for the "alternative case" with Balder oil at the left in the figure and for the "alternative case" with Goliat oil at the right in the figure. The risk is shown for the spring season in the left graph and for the summer season in the right graph, the risk in the autumn and winter season is analysed as zero.

Environmental risk results with the Huldra condensate

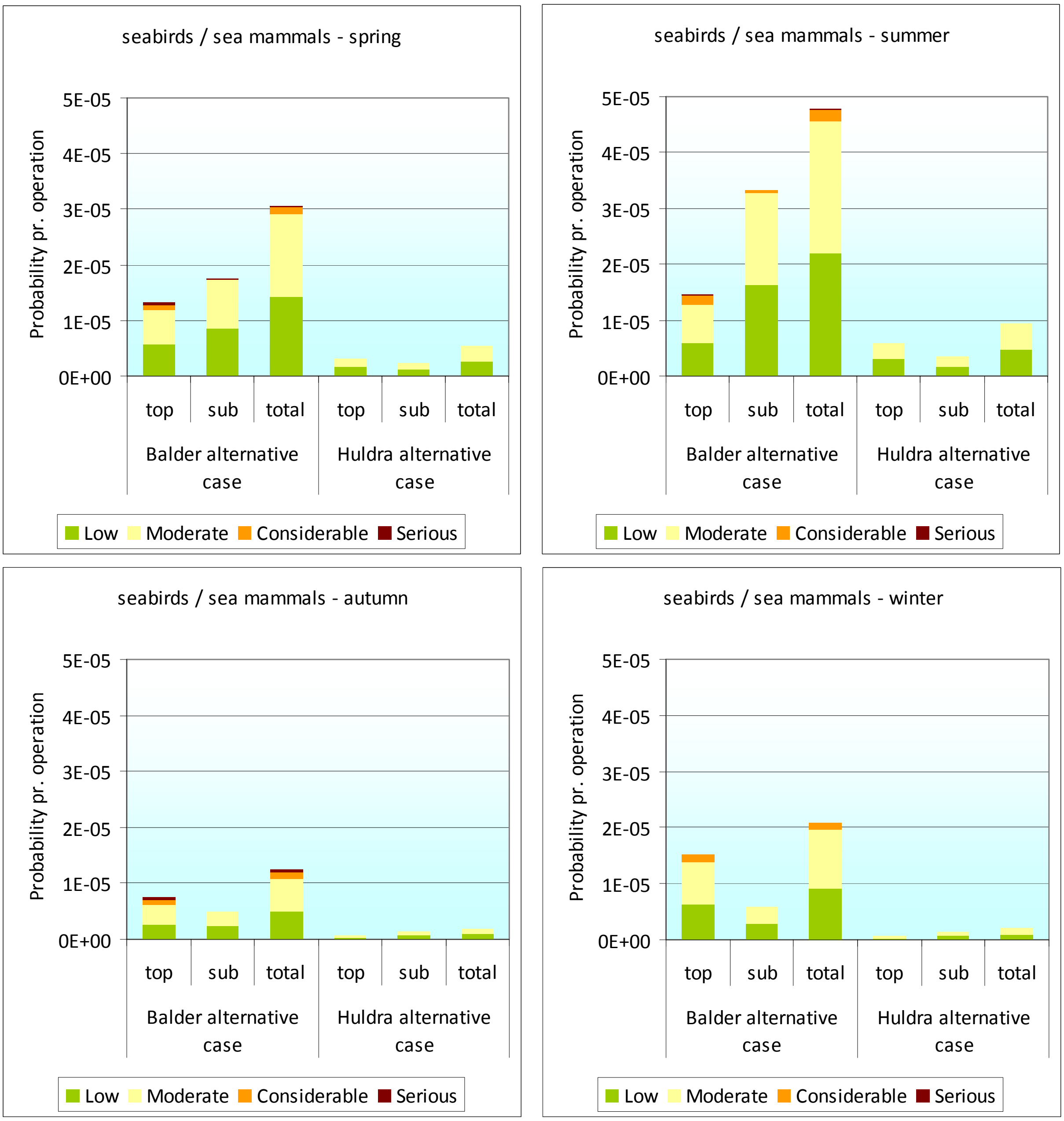

Figure 4 Environmental risk to seabirds or sea mammals, expressed as the probability of environmental damage, per drilling operation. The environmental damage is divided into four damage categories with increasing severity; low, moderate, considerable and serious damage. The probability of environmental damage is divided between subsea and topside blowout and is also showed as the sum between those two. The environmental risk is shown for the "alternative case" with Balder oil at the left in the figure and for the "alternative case" with Huldra condensate at the right in the figure. The four different graphs show the risk for each of the seasons.

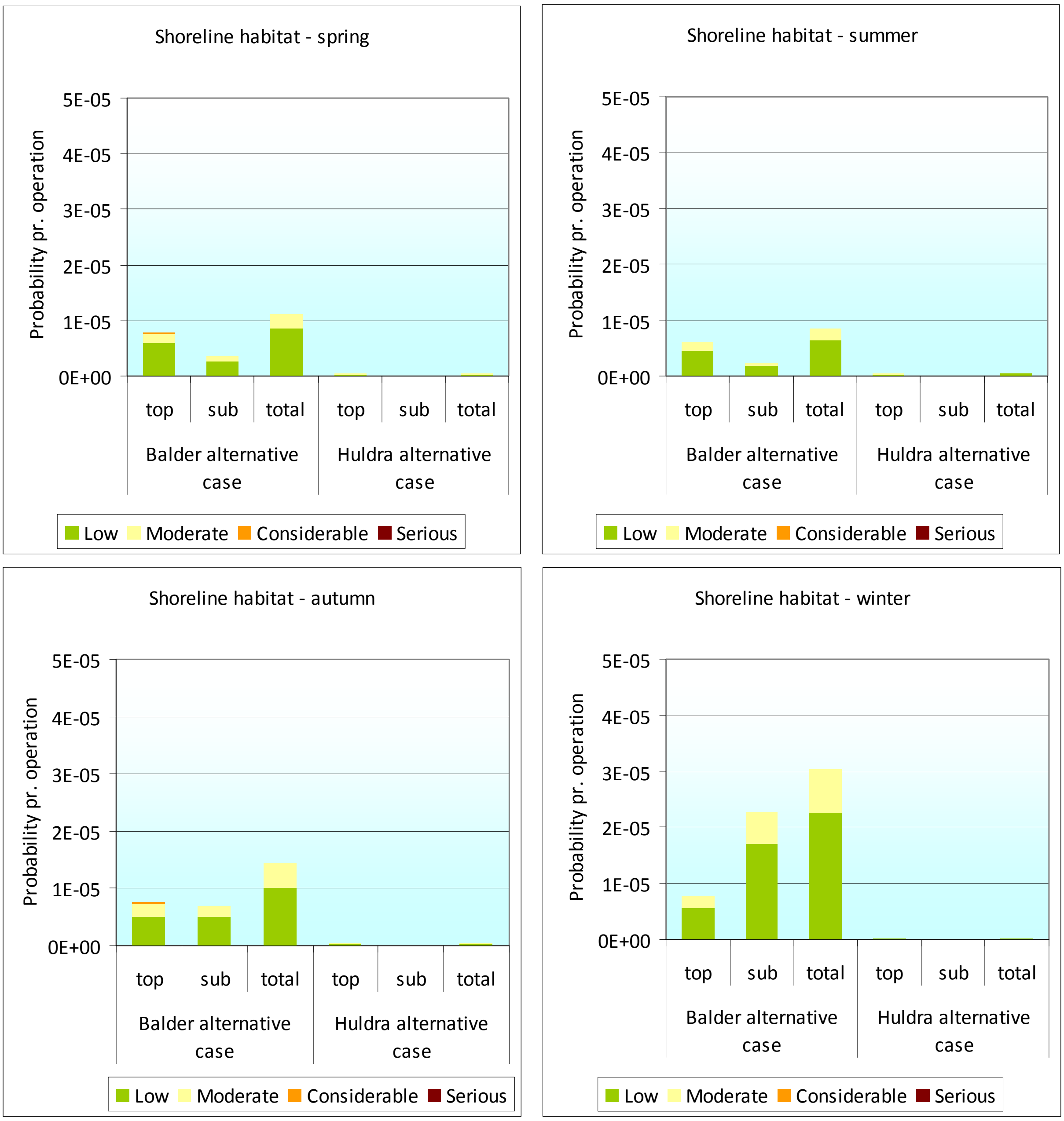

Figure 5 Environmental risk to shoreline habitats, expressed as the probability of environmental damage, per drilling operation. The environmental damage is divided into four damage categories with increasing severity; low, moderate, considerable and serious damage. The probability of environmental damage is divided between subsea and topside blowout and is also showed as the sum between those two. The environmental risk is shown for the "alternative case" with Balder oil at the left in the figure and for the "alternative case" with Huldra condensate at the right in the figure. The four different graphs show the risk for each of the seasons.

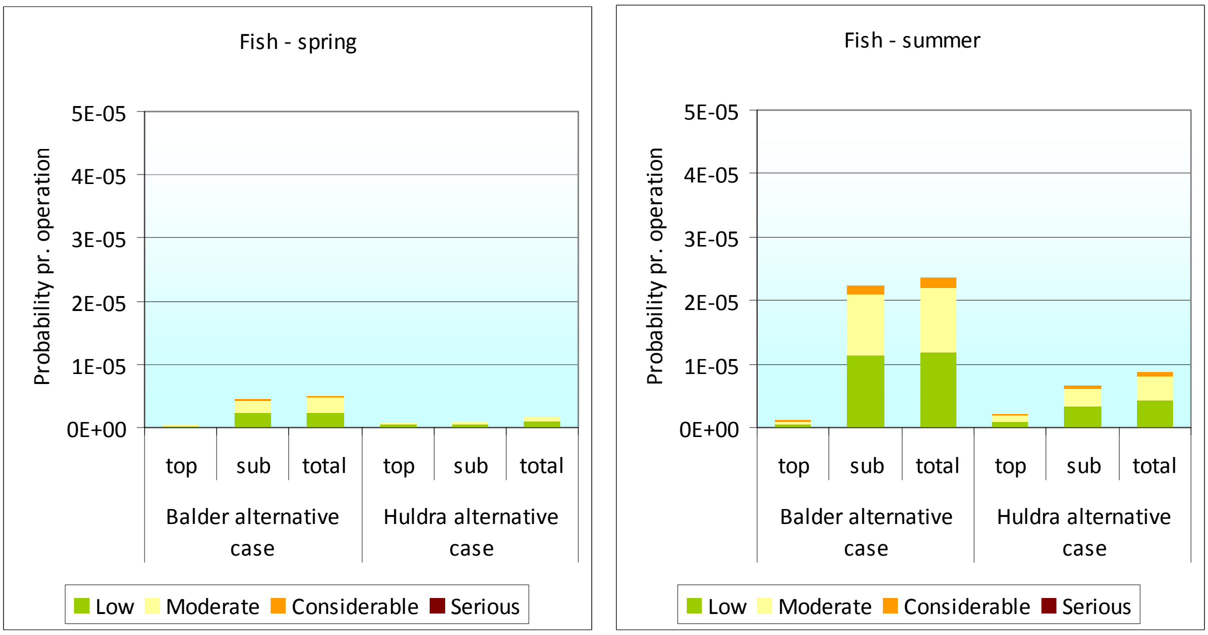

Figure 6 Environmental risk to fish, expressed as the probability of environmental damage, per drilling operation. The environmental damage is divided into four damage categories with increasing severity; low, moderate, considerable and serious damage. The probability of environmental damage is divided between subsea and topside blowout and is also showed as the sum between those two. The environmental risk is shown for the "alternative case" with Balder oil at the left in the figure and for the "alternative case" with Huldra condensate at the right in the figure. The risk is shown for the spring season in the left graph and for the summer season in the right graph, the risk in the autumn and winter season is analysed as zero.

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APPENDIX

3

BLOWOUT INCIDENTS REVIEW

ID	Installation type	Main Category	Loss of barrier 1	Primary	Loss of barrier 2	Secondary	Well Control	North sea standard	**Improved Technology**	**Nordland VII relevant**	**Comments**
288	Jacket / Jack - up	Blowout (surface flow)	C6.WELL TEST STRING BARRIER FAILURE (STRING SPLIT) TRIED TO LOOSEN FLOWLINE TO TEST SEPARATOR-CAUSED DRILL PIPE TO FAIL	X X	B1.FAILED TO CLOSE BOP (Flowline fell on HRC valve and caused loss of accumulator pressure)	X X	X X	No, no shear ram	2.2 More Comprehensive Risk Assessement Process 4.2 Training and Knowledge	No	Incident with dropped object, statistics show high improvement. Assumed unlikely if dropped from rig to hit the subsea BOP. Better awarenes on safety incidents.
311	Jacket	Blowout (surface flow)	A11.TOO LOW HYD. HEAD - WHILE CEMENT SETTING		B3.BOP/DIVERTER NOT IN PLACE (beeing removed)			Sometimes not relevant, BOP removed to install casing		No	Inflow test before removing BOP. Better procedures and following up of human error. No activity is done without the BOP.
324	Satellite / Jacket	Blowout (surface flow)	A11.TOO LOW HYD. HEAD - WHILE CEMENT SETTING	X X	B3.BOP/DIVERTER NOT IN PLACE		X	Yes	3.9 Seismic while drilling 3.10 3-D Seismic	No	Better 3D seismic.
331	Jacket / Jack - up	Blowout (surface flow)	C13.TUBING PLUG FAILURE (PLUG HAD NOT SET IN 2 7/8" TUBING)		B2.BOP FAILED AFTER CLOSURE (S/R leaked after closure) A SERIES OF TOPSIDE EQUIPMENT FAILURES OCCURED	X		Yes	1.1 Blowout preventer equipment improved.	Yes	Better reliability of plugs / remote valve? Subsurface valves covered by standards now.
336	Jackup	Blowout (surface flow)	A2.TOO LOW HYD. HEAD - SWABBING (ASSUMED)	X	Not relevant		X	Yes	2.1 Improved operating procedures.	Yes	General concern to operators that swabbing might occur. Today considered in procedures.

ID	Installation type	Main Category	Loss of barrier 1	Primary	Loss of barrier 2	Secondary	Well Control	North sea standard	**Improved Technology**	**Nordland VII relevant**	**Comments**
357	Jacket	Blowout (underground flow)	A11.TOO LOW HYD. HEAD - WHILE CEMENT SETTING		B10.DIVERTED - NO PROBLEM, D1.FRACTURE AT CSG SHOE			Yes		Yes	Cement quality improved, but no better performance.
390	Jacket / Jack - up	Blowout (surface flow)	A11.TOO LOW HYD. HEAD - WHILE CEMENT SETTING (7 HOURS AFTER CEMENTING)		B3.BOP/DIVERTER NOT IN PLACE (JUST BEEN REMOVED)			Sometimes not relevant, BOP removed to install casing	3.11 Improved pressure control during cementing and better cement quality	No	Cement quality? Following procedures. For this operation, probably not remove BOP before activity is finished.
420	Jacket	Blowout (surface flow)	A11.TOO LOW HYD. HEAD - WHILE CEMENT SETTING		B3.BOP/DIVERTER NOT IN PLACE			Sometimes not relevant, BOP removed to install casing		No	For this operation, probably not remove BOP before activity is finished.
425	Jacket / Jack - up	Blowout (surface flow)	A10.TOO LOW HYD. HEAD - ANNULAR LOSSES (could also be waiting on cmt., see remarks)		B3.BOP/DIVERTER NOT IN PLACE			Yes		No	At this depth in the drilling program, probably not removed the BOP.
444	Jackup	Blowout (underground flow)	A8.TOO LOW HYD. HEAD - UNEXPECTED HIGH WELL PRESSURE	X X X	D1.FRACTURE AT CSG SHOE			Yes	3.7 Direct pore pressure measurement during drilling operations. 3.17 Improved pore and fracture pressure prediction 3.24 Pore pressure evaluation	Yes	IN wells were there is a small margin between pore fracture gradient you would considered casing while drilling techniques. Need a certain kick margin before start drilling.

ID	Installation type	Main Category	Loss of barrier 1	Primary	Loss of barrier 2	Secondary	Well Control	North sea standard	**Improved Technology**	**Nordland VII relevant**	**Comments**
447	Semisubmersible	Blowout (underground flow)	A1.TOO LOW HYD. HEAD - TOO LOW MUD WEIGHT		D3.FORMATION BREAKDOWN			Yes		-	? Actually a blowout?
448	Jackup	Blowout (surface flow)	A11.TOO LOW HYD. HEAD - WHILE CEMENT SETTING		C1.POOR CEMENT			Yes		No	At this depth in the drilling program, we would probably not removed the BOP. Not really a north sea standard event, 18,5" BOP commony used in north sea..
452	Semisubmersible	Blowout (surface flow)	A10.TOO LOW HYD. HEAD - ANNULAR LOSSES		D3.FORMATION BREAKDOWN			Yes	Casing while drilling	Yes	Blowout? No release of hydrocarbons. Cement quality - still can get such challenges/problems.
460	Jackup	Blowout (surface flow)	A11.TOO LOW HYD. HEAD - WHILE CEMENT SETTING	X	B3.BOP/DIVERTER NOT IN PLACE	X X		Yes	1.1 Blowout preventer equipment improved. 3.11 Better cement quality	No	Leaks below BOP, still a concern. But this is a jackup with BOP on floor, with subsea BOPs it will be subsurface flow. Should be addressed - braking wellheads (foundation from well). Improved cementing, better equipment (leakage flange/valve).
471	Jacup	Blowout (surface flow)	A1.TOO LOW HYD. HEAD - TOO LOW MUD WEIGHT	X X X X	B13.DRILLING WITHOUT RISER	X X		Yes	3.7 Direct pore pressure measurement during drilling operations. 3.17 Improved pore and fracture pressure prediction 3.24 Pore pressure evaluation 3.14 Managed pressure drilling.	No	Shallow gas before setting BOP. Better seismic. Find a way to drill shallow zone with pressure control.

ID	Installation type	Main Category	Loss of barrier 1	Primary	Loss of barrier 2	Secondary	Well Control	North sea standard	Improved Technology	Nordland VII relevant	Comments
473	Jacket	Blowout (surface flow)	A11.TOO LOW HYD. HEAD - WHILE CEMENT SETTING	X	C1.POOR CEMENT, D2.CASING LEAKAGE (cut hole in 30" casing on pupose to clean)	X X		Yes	3.11 Improved pressure control during cementing and better cement quality.	No	Cement quality imroved. Not applicable for subsea BOP. Don't clean the annulus for subsea drilling/development (seabottom BOP).
476	Jacket / Jack - up	Blowout (surface flow)	A11.TOO LOW HYD. HEAD - WHILE CEMENT SETTING	X	B3.BOP/DIVERTER NOT IN PLACE	X		Yes	3.11 Improved pressure control during cementing and better cement quality.	No	Wrong cement applied for the shallow zone. Shallow gas incident.
479	Jacket / Jack - up	Blowout (surface flow)	A11.TOO LOW HYD. HEAD - WHILE CEMENT SETTING	X	D3.FORMATION BREAKDOWN	X		Yes	3.11 Improved pressure control during cementing and better cement quality.	No	Poor cement. Shallow gas.
494	Semisubmersible	Blowout (surface flow)	A15.TOO LOW HYD. HEAD - UNKNOWN WHY		NOT RELEVANT - ONLY ONE BARRIER PRESENT			Yes		No	Before setting the BOP (Spudding). Shallow gas incident.
507	Jackup	Blowout (surface flow)	A2.TOO LOW HYD. HEAD - SWABBING	 X X X	B12.DIVERTER FAILED AFTER CLOSURE	X X X	X	Yes	1.1 Blowout preventer equipment improvements. 3.7 Direct pore pressure measurement during drilling operations. 3.17 Improved pore and fracture pressure prediction 3.24 Pore pressure evaluation	No	Shallow gas. Equipment reliability and cabling and equipment that can cause fires / EX equipment (no sparks, source for fires and explosions. Better seismic.
518	Jacket / Jack - up	Blowout (surface flow)	A11.TOO LOW HYD. HEAD - WHILE CEMENT SETTING	 X	B12.DIVERTER FAILED AFTER CLOSURE	X X		Yes	1.1 Blowout preventer equipment improvements. 3.11 Improved pressure control during cementing and better cement quality.	No	Shallow gas. Equipment reliability. Cement jobs.

ID	Installation type	Main Category	Loss of barrier 1	Primary	Loss of barrier 2	Secondary	Well Control	North sea standard	**Improved Technology**	**Nordland VII relevant**	**Comments**
524	Jacket	Blowout (surface flow)	A9.TOO LOW HYD. HEAD - RESERVOIR DEPTH UNCERTAINTY (unexpected shallow zone above top of cement)	X X X	C5.INNER CASING FAILED	X	X X	Yes	1.1 Blowout preventer equipment improvements. 3.7 Direct pore pressure measurement during drilling operations. 3.17 Improved pore and fracture pressure prediction 3.24 Pore pressure evaluation	Yes	Better seismic. Logging of well. Equipement reliability.
570	Semisubmersible	Blowout (surface flow)	A15.TOO LOW HYD. HEAD - UNKNOWN WHY		B13.DRILLING WITHOUT RISER			Yes		No	Before installing the drilling riser (26"). Shallow gas.
580	Unknown	Blowout (underground flow)	Unknown		Unknown			Yes		_	..

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APPENDIX

4
ENVIRONMENTAL RISK ANALYSIS METHODOLOGY

Method for Environmental Risk Analysis

The environmental risk analysis for seabirds, marine mammals, shoreline and fish is performed based on OLF's guideline for environmental risk analysis (OLF, 2007 and OLF 2008).

Fish

Quantification and evaluation of possible effects on fish following an accidental spill of oil from the petroleum industry is based on exposure to hydrocarbons in the water column. Fish eggs and larvae are considered most vulnerable to such exposure, as adult fish tend to sense oil pollution and leave the area (on a temporary basis). The effects that oil-pollution induced mortality of fish eggs and larvae may have on the annual recruitment to the stock is what is initially assessed. However, the primarily interest of the analysis is how recruitment losses affect future spawning populations.

Mortality of eggs- and larvae caused by an oil spill is analyzed statistically using a large number of oil drift simulations based on historical weather and wind conditions, combined with a large number of possible distributions of fish larvae from observed historical spawning patterns. Exposure is a result of overlap between larvae in the water column and the total hydrocarbon concentration in the water column exceeding a level giving mortality or reduced survival. The effect level of acute mortality is set to a hydrocarbon concentration of 375 ppb (dispersed and dissolved oil), based on recent calculations for Balder crude oil (DNV 2010).

Based on the acute mortality of fish eggs/larva the probability for losses in annual recruitment is calculated based on Table 11-1.

Table 11-1 Probability distribution of losses in yearly recruitment to the stock associated with losses of eggs and larvae (cod) (OLF 2008, DNV 2010).

Losses in annual recruitment	**Mortality of egg/larvae**						
	1 %	**2 %**	**5 %**	**10 %**	**20 %**	**30 %**	**50 %**
<1 %	50 %	10 %					
1 %	30 %	20 %	10 %				
2 %	15 %	40 %	20 %	10 %			
5 %	5 %	20 %	40 %	20 %	10 %	5 %	
10 %		10 %	20 %	40 %	20 %	10 %	5 %
20 %			10 %	15 %	40 %	15 %	10
30 %				10 %	15 %	40 %	15
50 %				5 %	10 %	20 %	40 %
100 %					5 %	10 %	30 %

Further on the restitution time according to the Ugland model, as illustrated in Figure 11-1. This is a simple model that predicts how losses in yearly recruitment to the stock will inflict on population dynamics (i.e., restitution time for spawning stock). Depending on whether the yearly recruitment which is subject to an oil-pollution induced loss is assumed to belong to a strong recruitment year (good general survival) or a weak recruitment year (poor general survival), the calculated restitution time will fall within a certain range.

Herring (“NVG Sild”) possesses a larger variation in the strength of individual recruitment years than cod, and the difference between the strongest and weakest recruitment years for herring in the period 1980 to 2004 is about 500.

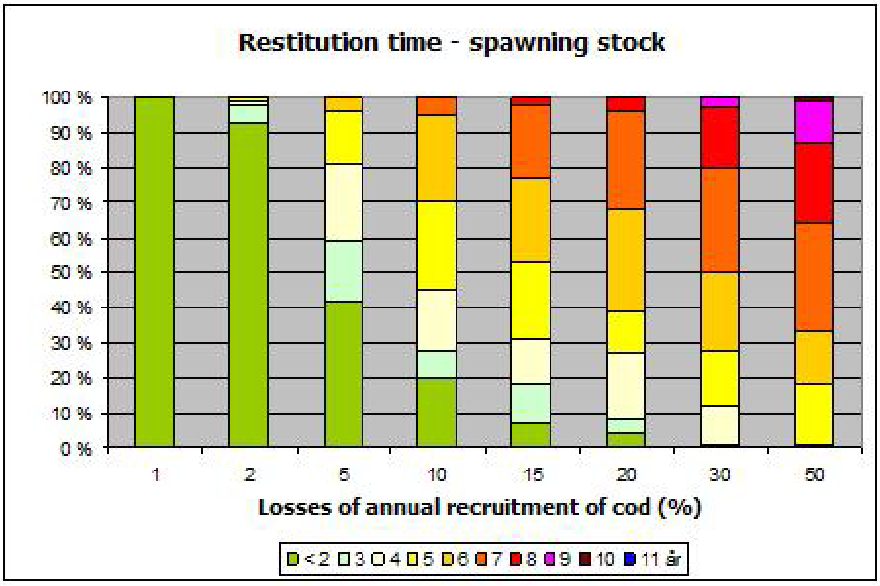

Figure 11-1 Calculated restitution time for the spawning stock of cod given the variation in annual recruitment caused by acute mortality of eggs/larvae following an oil spill.

Seabirds and marine mammals

The Operational Environmental Risk Analysis tool is based on methodology for environmental risk analysis in accordance to OLF’s guideline for environmental risk analysis (OLF 2007). A short description of the method is given in the following, but it is referred to the guideline for more supplementary information.

Environmental damage for stocks of e.g. seabirds is estimated by calculating damage to the stock by how large part of the stock that can be killed by a possible oil spill. This is done by connecting the geographical distribution of seabirds, spread in 10 × 10 km grid cells, with the probability for oil masses in the corresponding grid cells. The share of dead birds in each grid cell is estimated in accordance to the effect key shown in Table 11-2 (marine birds) and Table 11-3 (marine mammals). The effect keys take into account the individual vulnerability seabirds and marine mammals have to oil pollution. Each species is given vulnerability index S1, S2 or S3, where S1 is least vulnerable and S3 is most vulnerable. One species can have varying vulnerability index throughout the year.

Table 11-2 Effect key for estimating acute mortality of birds within a 10 x 10 km grid cell, when exposed to an oil spill (distributed in four mass categories).

Oil rate (ton) in 10 x 10 km grid cell	Effect key – mortality		
	Individual vulnerability for VEC seabird		
	S1	S2	S3
1-100 ton	5 %	10 %	20 %
100-500 ton	10 %	20 %	40 %
500-1000 ton	20 %	40 %	60 %
≥1000 ton	40 %	60 %	80 %

Table 11-3 Effect key for estimating acute mortality of marine mammals within a 10 x 10 km grid cell, when exposed to an oil spill (distributed in four mass categories).

Oil rate (ton) in 10 x 10 km grid cell	Effect key – mortality		
	Individual vulnerability for VEC marine mammal		
	S1	S2	S3
1-100 ton	5 %	15 %	20 %
100-500 ton	10 %	20 %	35 %
500-1000 ton	15 %	30 %	50 %
≥1000 ton	20 %	40 %	65 %

The lost share of the stock is further used to characterize the seriousness of the environmental damage in four consequence categories. Each consequence category is given a theoretical restitution time:

minor *< 1 year theoretical restitution time*
moderate *1 - 3 year theoretical restitution time*
considerable *3 - 10 year theoretical restitution time*
serious *> 10 year theoretical restitution time*

The damage key (Table 11-1) is based on information about the species population dynamic characteristics and on modelling of restitution time for species with low reproduction potential (OLF, 2007). Guillemot does in addition to low reproduction also have a negative population trend. For this species it is used a separate damage key shown in Table 11-2.

Given a population with negative population trend there is two possibilities: The stock is recovered more slowly because it is under stress, or the stock is recovered more rapidly because it causes less competition in the population and the time to get back to the descending stock line is shorter. It is conservatively chosen the first of these theories in the following analysis.

For each of the oil drift simulation it is estimated the damage in each grid cell in accordance to the reduction of the stock and the prescribed damage key. The damage for all the grid cells is then added up to total damage on the stocks in accordance to the key for restitution time.

Table 11-1 Damage key for the probability distribution of theoretical restitution time by acute reduction of seabird- and marine mammal stocks with low restitution potential (S3) (OLF, 2007).

Acute reduction of the stocks	Consequence category – environmental damage Theoretical restitution time in year			
	Minor <1 year	Moderate 1-3 year	Considerable 3-10 year	Serious >10 year
1-5 %	50 %	50 %		
5-10 %	25 %	50 %	25 %	
10-20 %		25 %	50 %	25 %
20-30 %			50 %	50 %
≥ 30 %				100 %

Table 11-2 Damage key for the probability distribution of theoretical restitution time by acute reduction of seabird stocks with negative population trend in addition to low restitution potential (S4).

Acute reduction of the stocks	Consequence category – environmental damage Theoretical restitution time in year			
	Minor <1 year	Moderate 1-3 year	Considerable 3-10 year	Serious >10 year
1-5 %	40 %	50 %	10 %	
5-10 %	10 %	50 %	30 %	10 %
10-20 %		10 %	50 %	40 %
20-30 %			20 %	80 %
≥ 30 %				100 %

Shoreline

Environmental risk for coast line is performed in accordance with the VEC- habitat method (OLF, 2007). For VEC-habitat the environmental damage is estimated directly from the oil drift statistics in an area (e.g. a grid cell), and the vulnerability for the habitat in question (vulnerability on habitat/society level). The environmental damage is expressed by restitution time. Restitution is achieved when the original plant- and animal life in the affected society is back on same level as before the spill (natural variation is taken into consideration), and the biological processes works normally.

In the VEC habitat method the probability for damage on coast for all 10 x 10 km grid cells within the influence area from a oil spill is estimated. The probability is estimated from degree of exposure and composition of coast types and their vulnerability (Table 11-3).

Table 11-3 Vulnerability index for coast types for exposed and protected coast (DNV, 2006).

Coast type	Degree of vulnerability	
	Exposed	Protected
Bare rock	1	1
Cliff	1	1
Boulder beach	1	2
Sand beach	2	3
Rocky beach	1	3
Clay	2	3
Not data	2	3
Man made	1	1
Sand dune	2	3

For each grid cell it exist information on type of coast and the length of each coast type. Each coast type gets a vulnerability index S1, S2 or S3. The vulnerability indexes are given for exposed coast and protected coast, and also in accordance to type of substrate.

Coast habitat with vulnerability S1, S2 and S3 is estimated for each coastal grid cell. In early versions of the guideline the consequences was estimated from the coast type with the highest vulnerability in the grid cell, independent of the fact that only a small part of the total coastline in the grid cell had this vulnerability. From now on the probability for damage in each vulnerability category is estimated in each grid cell.

The contribution from each vulnerability category is equal to the relative distribution of vulnerability categories within the grid cell. The probability for damage on coast within each vulnerability index is then a product of probability for oil in the four different oil mass categories, the part of the coast with vulnerability index 1,2 or 3 and the respectively probability distribution for the consequence categories shown in Table 11-4. The total probability for damage in each grid cell is indicated by adding up the probability for each consequence category for the three different vulnerability indexes.

Table 11-4 Damage key for estimation of the probability for damage to coast (DNV, 2006).

Damage key for coast		**Damage category Theoretical restitution time**			
Vulnerability	**oil masses**	**Minor <1 year**	**Moderate 1-3 year**	**Considerable 3-10 year**	**Serious >10 year**
High (S3)	1-100 t	20 %	50 %	30 %	
	100-500 t	10 %	60 %	20 %	10 %
	500-1000 t		20 %	50 %	30 %
	>1000 t			40 %	60 %
Moderate (S2)	1-100 t	60 %	40 %		
	100-500 t	30 %	60 %	10 %	
	500-1000 t	10 %	60 %	30 %	
	>1000 t		40 %	50 %	10 %
Low (S1)	1-100 t	80 %	20 %		
	100-500 t	60 %	40 %		
	500-1000 t	40 %	50 %	10 %	
	>1000 t	20 %	40 %	40 %	

Selection of most severely affected population of seabirds or marine mammals, and shoreline area

For each spill scenario the possible consequences and probabilities for restitutions time of various lengths for every population of marine mammals and seabirds, and for every affected 10 × 10 km grid cell along the shore, are calculated according to the method as described above. In the OPERAto however only the population and the 10 × 10 km grid cell expected to be affected the most are considered. The environmental risk for each population and grid cell is calculated with seasonal resolution. This means that the most severely affected population and grid cell may differ in the different seasons. In each season a “damage index” is calculated for each population and grid cell. The damage index scales the probabilities for *minor*, *moderate*, *considerable* and *serious* damage, as possible effects causing *serious* damage is worse than *minor* damage. The damage categories are scaled according to the most commonly used acceptance criteria for each damage category, stating that it is 4 times worse to have moderate damage (1-3 years restitution time), 10 times worse to have considerable damage (3-10 years restitution time) and 40 times worse to have serious damage (> 10 years restitution time), than to have minor damage (< 1 years restitution time). The damage index is thereby calculated as given in Formula 3.1.

The results for the population with the highest damage index in each season is extracted and used in OPERAto.

Formula 11.1

$$Damageindex = p[\mathrm{Minor}]\times 1 + p[\mathrm{Moderate}]\times 4 + p[\mathrm{Considerable}]\times 10 + p[\mathrm{Serious}]\times 40$$

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APPENDIX
5
OIL DRIFT MODELLING METHODOLOGY

Method for oil spill simulation

The model used for simulations of oil drift is OS3D which is based on the SINTEF Oil Spill Contingency And Response (OSCAR) model. OS3D is a 3-dimensional Oil Spill Contingency And Response model system that calculates and records the distribution (as mass and concentrations) of contaminants on the water surface, on shorelines, in the water column, and in sediments. The model allows multiple release sites, each with a specified beginning and end to the release. For subsurface releases (e.g. blowouts or pipeline leaks), the near field part of the simulation is conducted with a multi-component integral plume model that is embedded in the OSCAR model. The near field model accounts for buoyancy effects of oil and gas, as well as effects of ambient stratification and cross flow on the dilution and rise time of the plume.

The model output is recorded in three physical dimensions plus time. The model databases supply values for water depth, sediment type, ecological habitat, and shoreline type. The system has an oil physical-chemical database that supplies physical and chemical parameters required by the model.

The model is run both in stochastic and single spill modus. In the stochastic simulations, a specified number of scenarios are simulated subsequently in one run. In order to provide data for computing oil drift statistics, certain oil drift parameters are accumulated for each scenario in each impacted 10 x 10 km grid cell. These results are in the end used to calculate probabilities for impact in a given cell – defined in terms of exceeding certain threshold values for oil concentrations. The results are presented as probability maps for the different environmental compartments (sea surface, water masses or shoreline).
In order to illustrate the temporal development of an oil spill, single scenario runs are made. Such runs are limited to certain selected cases, here as the case with expeceted drift time to shore and expected amounts of stranded oil. The results from such simulations are used to produce snapshots of the distribution of surface oil (coverage), stranded oil (oil mass per unit area)

In the present study, monthly mean climatologic current data provided by The Norwegian Meteorological Institute in 20 x 20 km resolution are combined with gridded hindcast wind data from the same source in 20 x 20 km resolution at 3 hours intervals for the period from 1980 to 2007. One statistical run will comprise a large number of spills with a specified spill rate and duration with spill start distributed evenly within the period of years with available wind data. The number of spills to be simulated in one statistical run must be large enough to provide a basis for reliable oil drift statistics on a seasonal basis (winter, spring, summer and autumn), but the actual number required depends on the duration of each spill: In order to cover the total variability in wind and current data within the period with wind data, more simulations will be required for spills with short durations than for spills with long durations.

Post processing and generation of statistical parameters

Based on the OS3D simulation results, statistical parameters such as surface hit probability and total hydrocarbon concentration in 10 x 10 km grid cells are generated in a post processor.

Oil drift statistics for the open sea are given here as mean values for the actual parameters. The model area is divided into grid cells; each cell covers an area of 10 x 10 km. Each time an oil particle (slick) enters a new cell the pertinent parameters and counters for that cell will be updated. When all release scenarios are simulated the appropriate statistics for each cell, stranding area and influence area are computed.

The statistical parameters computed in each grid cell and used here are:

- Hit probability which is defined as the relative number of simulations in which a particle , representing surface oil, has hit the cell
- Total hydrocarbon concentration which is defined as the mean over all simulations of the maximum THC concentration in each cell from each spill simulation

Average amounts of oil in each 10 x 10 km grid cell, categorized in 1-100 tons, 100-500 tons, 500-1000 tons and > 1000 tons of oil.

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APPENDIX

6
OIL DRIFT MODELLING RESULTS

Model results – stochastic scenarios

Selected results from the oil drift modelling of the different scenarios are summed up in Figure 11-2 through Figure 11-25. The figures show the area (in 10 x 10 km grid cells) within the influence area with probability for hits of 1-100 tons of oil, 100-500 tons of oil, 500-1000 tons of oil and > 1000 tons of oil given the scenario 2 days for each of the 8 release rates. In addition results from the scenarios 4500 tons/day for each of the release duration are presented. These results are shown for open sea and shoreline for four seasons for three different hydro carbon compositions, Balder oil, Goliat Realgrunnen oil and Huldra condensate. Total hydrocarbon concentrations of 50-200 ppb, 200-500 ppb, 500-1000 ppb and > 1000 ppb are also presented.

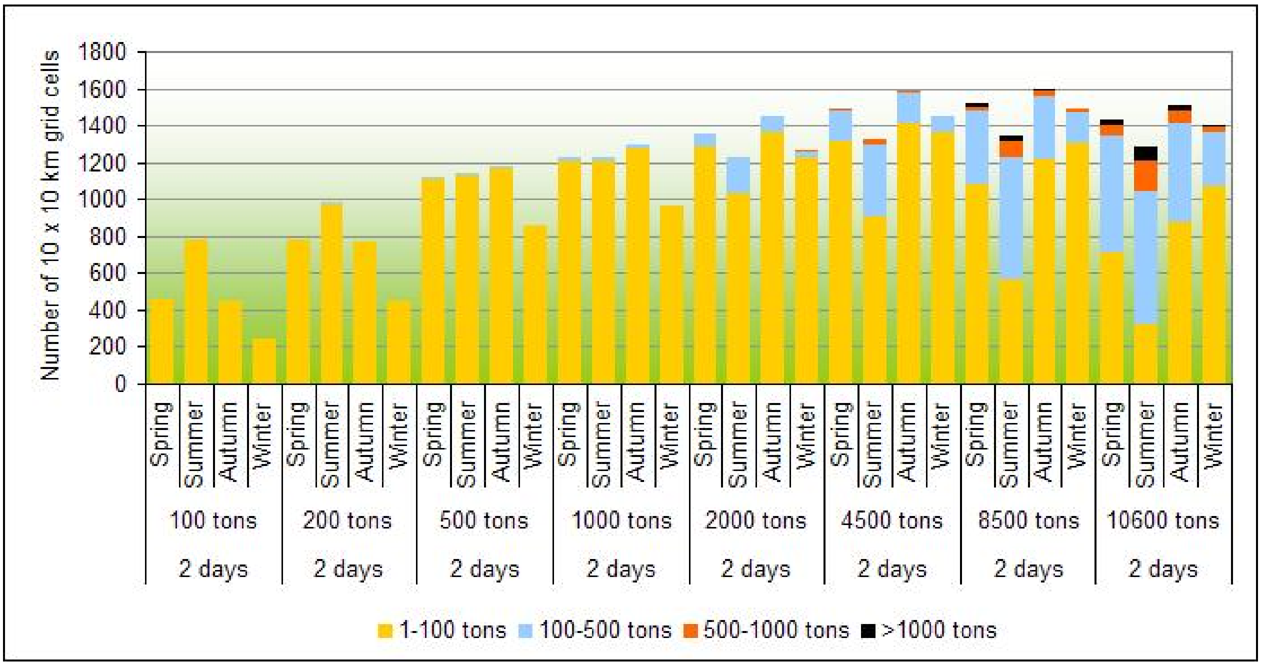

Figure 11-2 Number of 10 x 10 km open sea grid cells with respectively 1-100 tons of oil, 100-500 tons of oil, 500-1000 tons of oil and > 1000 tons of oil given oil spill scenario 2 days duration and various rates for a top side release with Balder oil

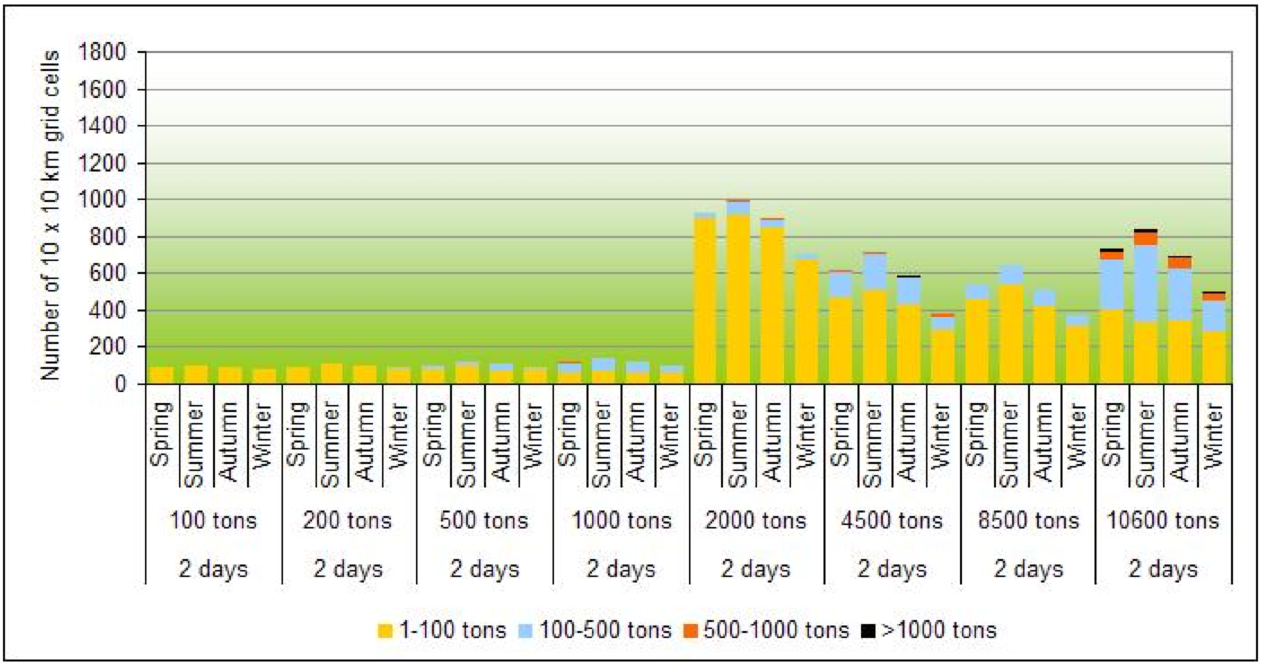

Figure 11-3 Number of 10 x 10 km open sea grid cells with respectively 1-100 tons of oil, 100-500 tons of oil, 500-1000 tons of oil and > 1000 tons of oil given oil spill scenario 2 days duration and various rates for a subsea release with Balder oil

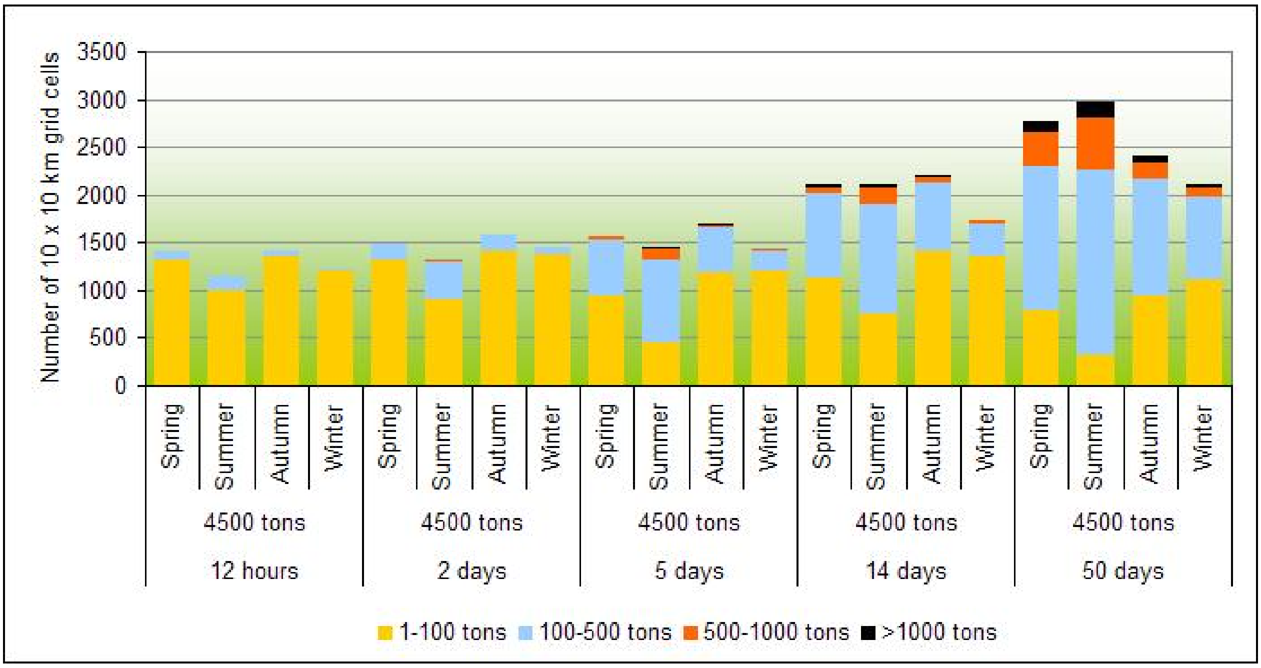

Figure 11-4 Number of 10 x 10 km open sea grid cells with respectively 1-100 tons of oil, 100-500 tons of oil, 500-1000 tons of oil and > 1000 tons of oil given oil spill scenario for release rate 4500 tons/day and 12 hours, 2 – 5 – 14 - 50 days duration for a top side release with Balder oil

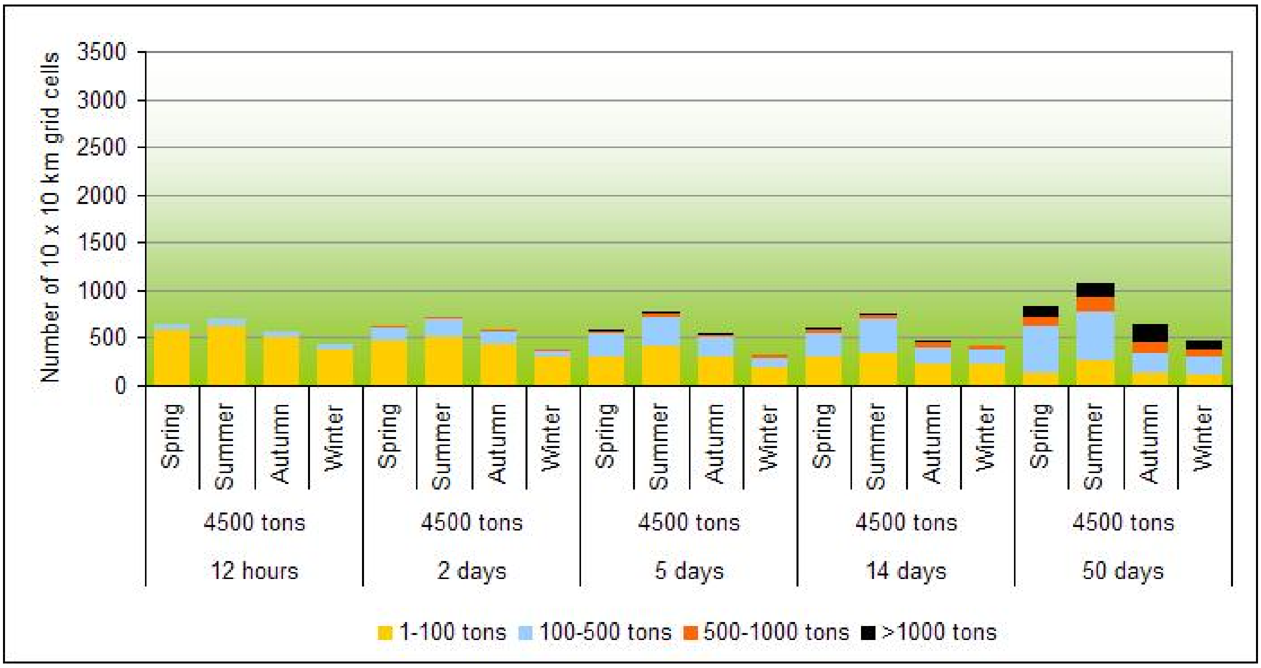

Figure 11-5 Number of 10 x 10 km open sea grid cells with respectively 1-100 tons of oil, 100-500 tons of oil, 500-1000 tons of oil and > 1000 tons of oil given oil spill scenario for release rate 4500 tons/day and 12 hours, 2 – 5 – 14 - 50 days duration for a subsea release with Balder oil

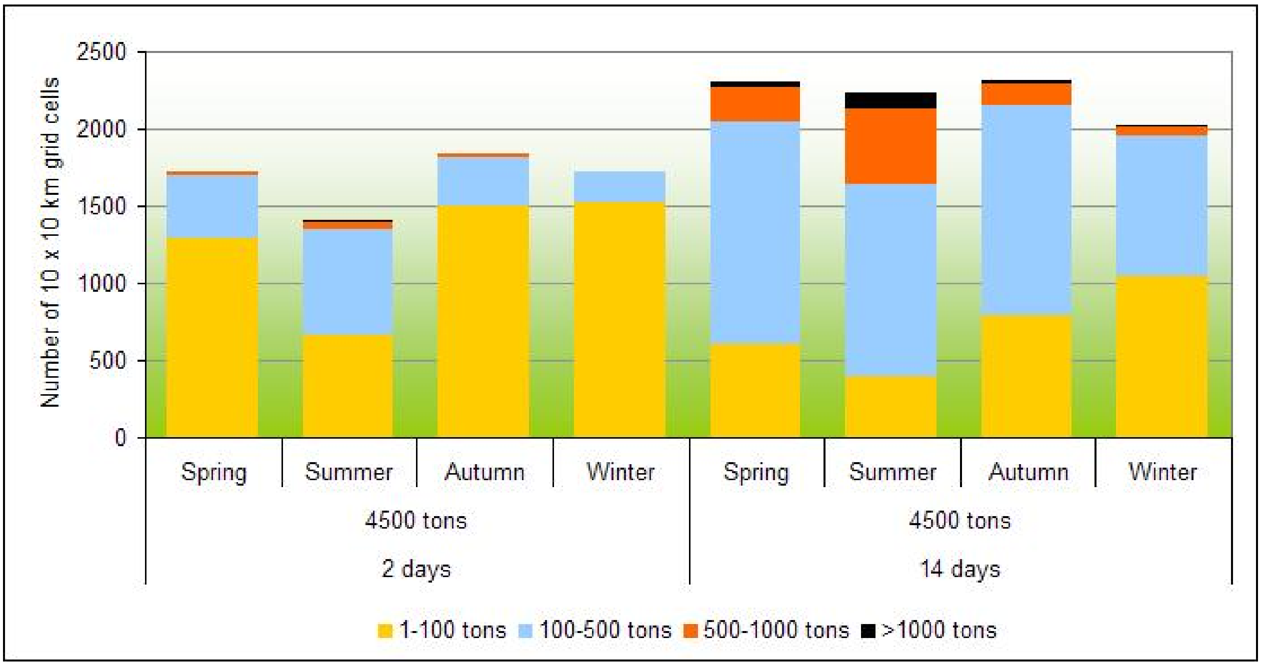

Figure 11-6 Number of 10 x 10 km open sea grid cells with respectively 1-100 tons of oil, 100-500 tons of oil, 500-1000 tons of oil and > 1000 tons of oil given oil spill scenario for release rate 4500 tons/day and 2 and 14 days duration for a top side release with Goliat oil

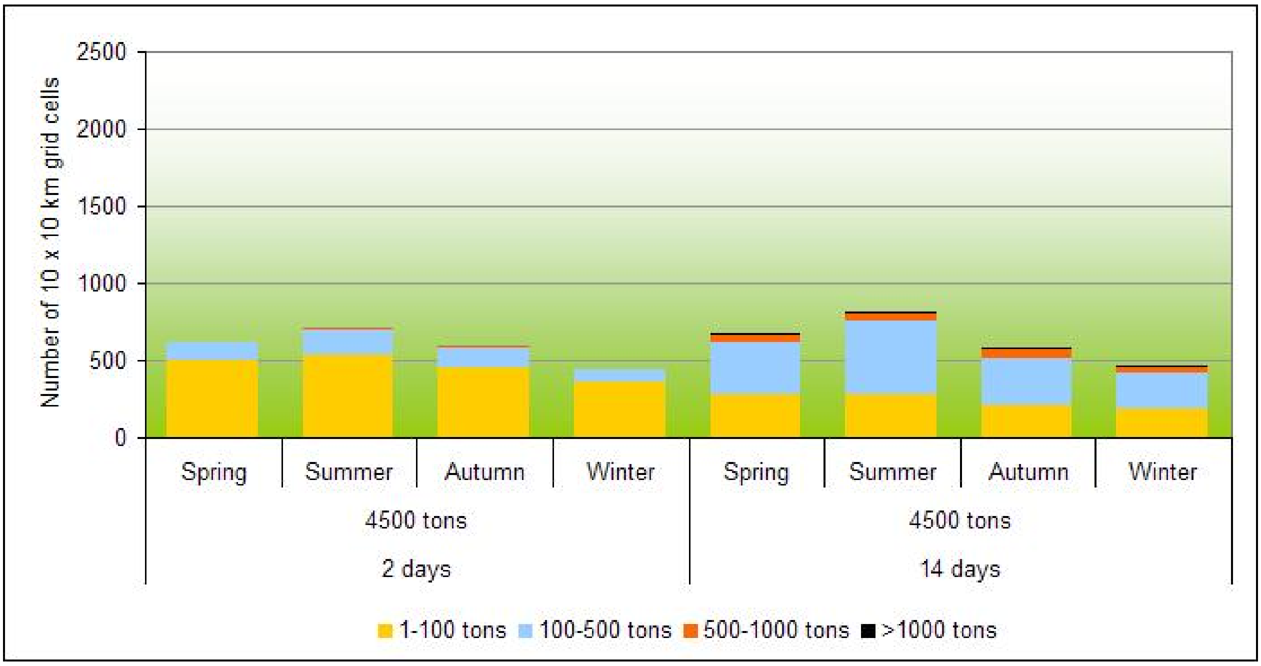

Figure 11-7 Number of 10 x 10 km open sea grid cells with respectively 1-100 tons of oil, 100-500 tons of oil, 500-1000 tons of oil and > 1000 tons of oil given oil spill scenario for release rate 4500 tons/day and 2 and 14 days duration for a subsea release with Goliat oil

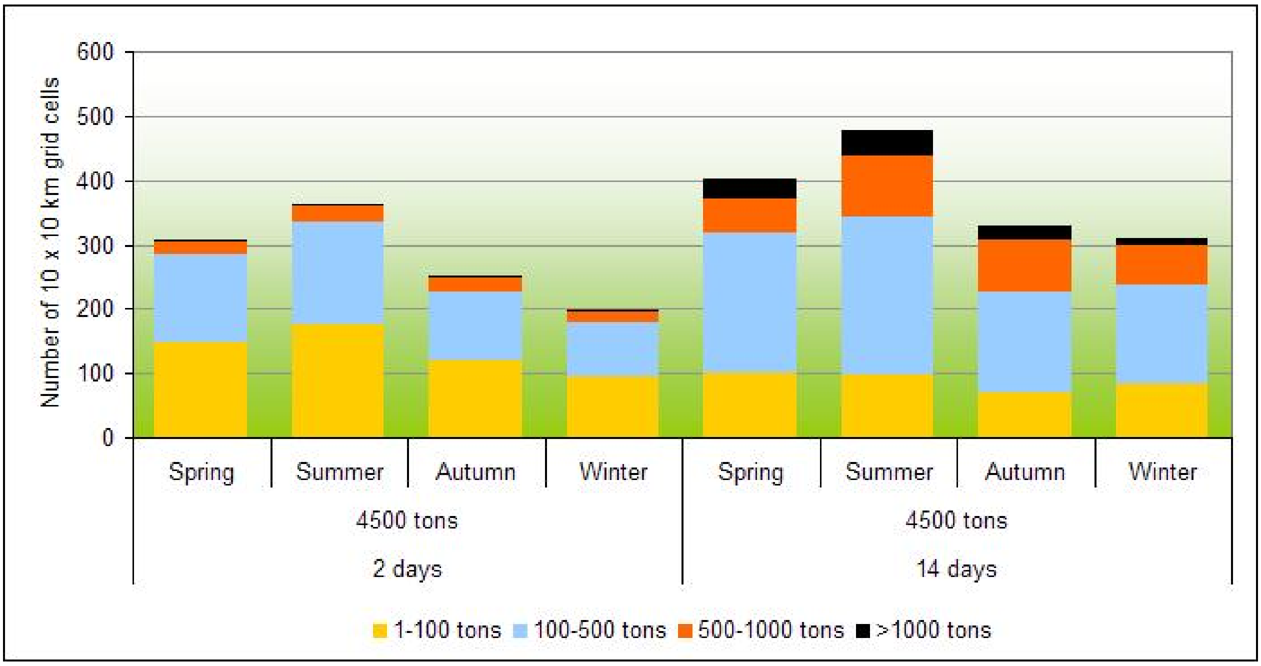

Figure 11-8 Number of 10 x 10 km open sea grid cells with respectively 1-100 tons of oil, 100-500 tons of oil, 500-1000 tons of oil and > 1000 tons of oil given oil spill scenario for release rate 4500 tons/day and 2 and 14 days duration for a top side release with Huldra oil

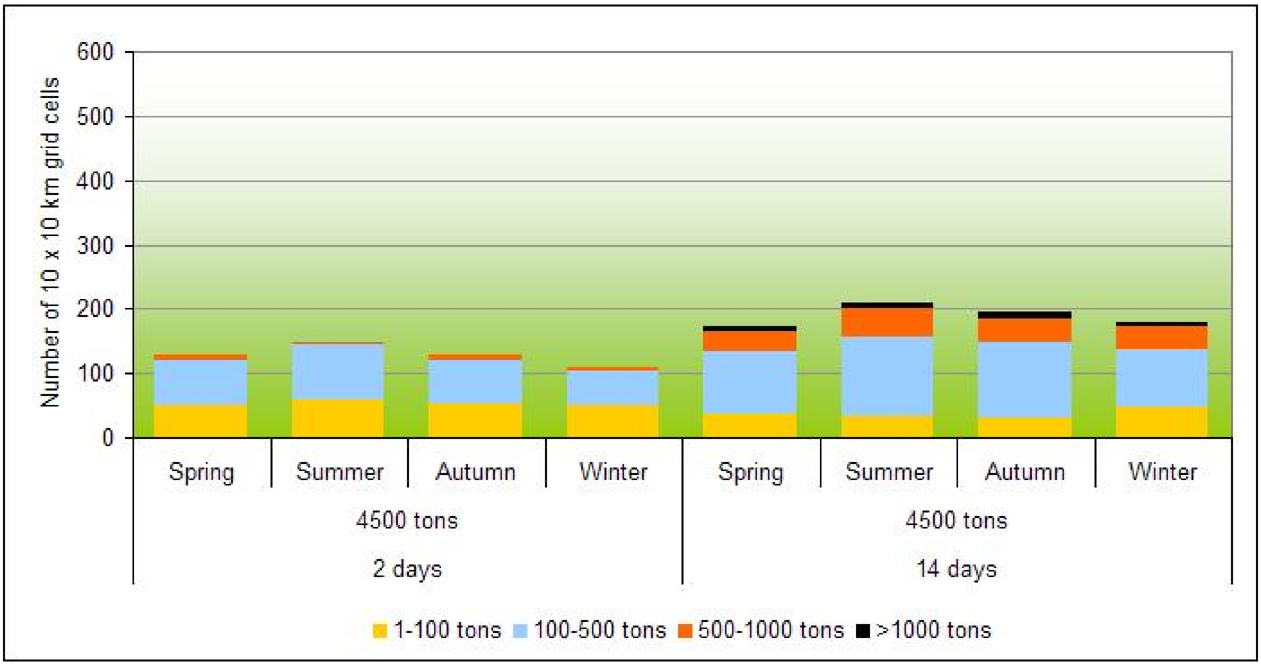

Figure 11-9 Number of 10 x 10 km open sea grid cells with respectively 1-100 tons of oil, 100-500 tons of oil, 500-1000 tons of oil and > 1000 tons of oil given oil spill scenario for release rate 4500 tons/day and 2 and 14 days duration for a subsea release with Huldra oil

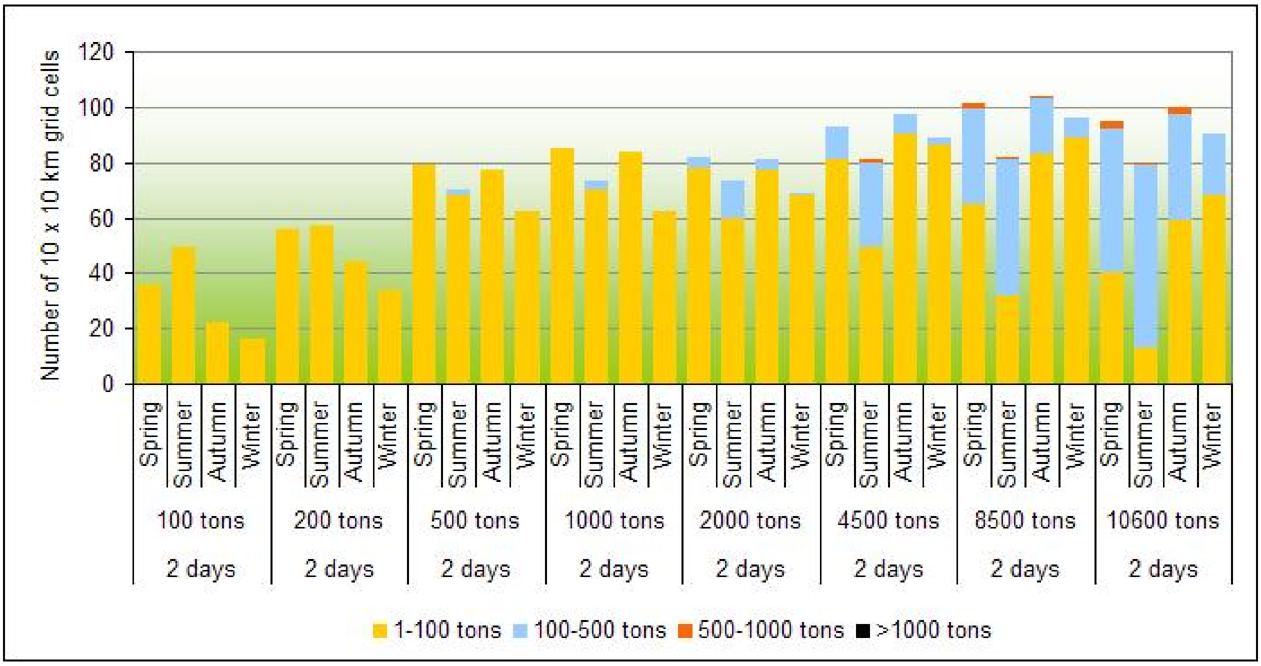

Figure 11-10 Number of 10 x 10 km strand grid cells with respectively 1-100 tons of oil, 100-500 tons of oil, 500-1000 tons of oil and > 1000 tons of oil given oil spill scenario 2 days duration and various rates for a top side release with Balder oil

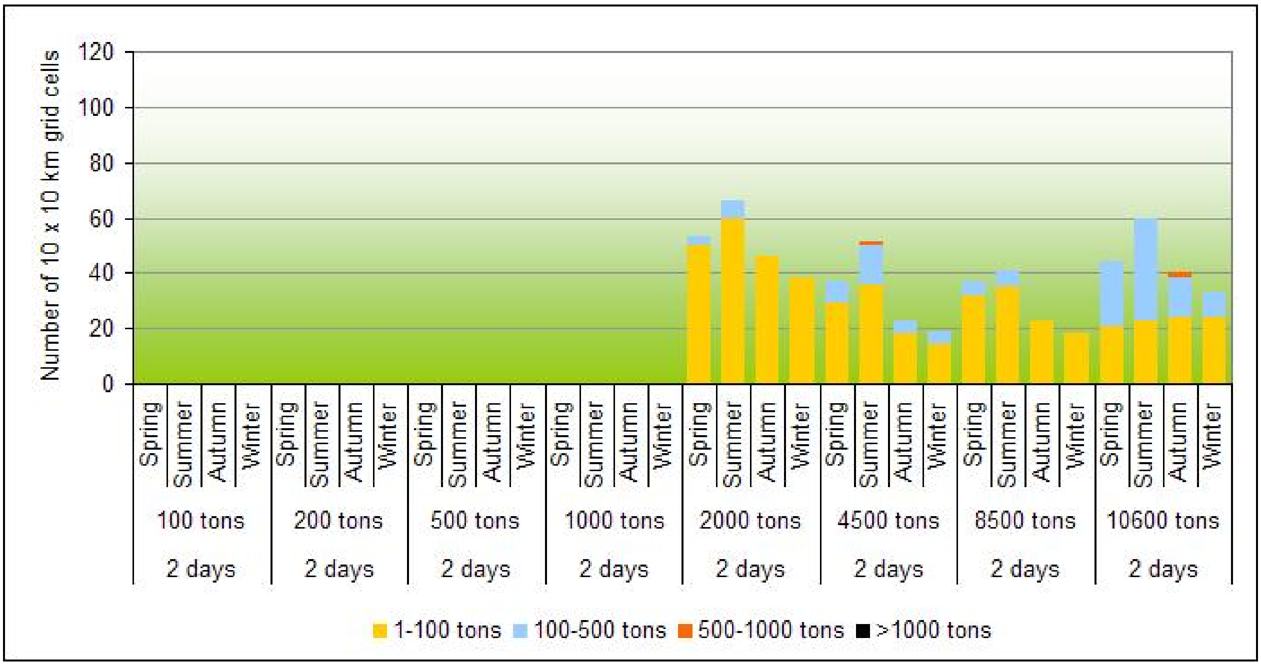

Figure 11-11 Number of 10 x 10 km strand grid cells with respectively 1-100 tons of oil, 100-500 tons of oil, 500-1000 tons of oil and > 1000 tons of oil given oil spill scenario 2 days duration and various rates for a subsea release with Balder oil

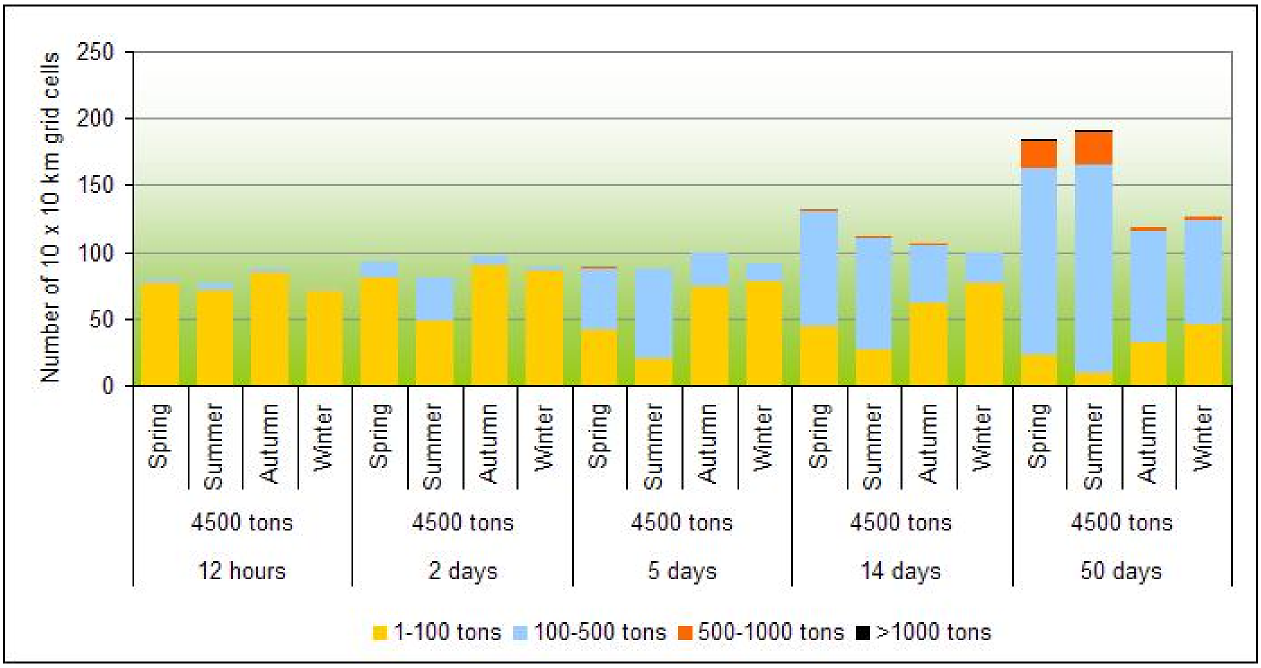

Figure 11-12 Number of 10 x 10 km strand grid cells with respectively 1-100 tons of oil, 100-500 tons of oil, 500-1000 tons of oil and > 1000 tons of oil given oil spill scenario for release rate 4500 tons/day and 12 hours, 2 – 5 – 14 - 50 days duration for a top side release with Balder oil

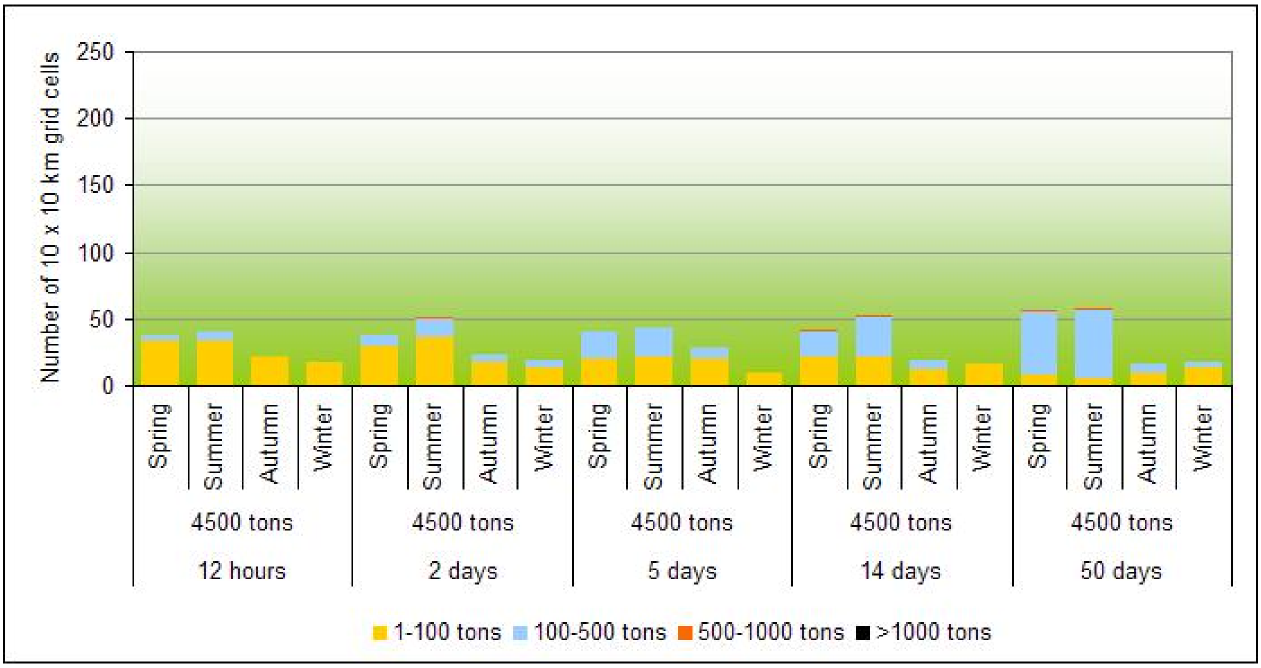

Figure 11-13 Number of 10 x 10 km strand grid cells with respectively 1-100 tons of oil, 100-500 tons of oil, 500-1000 tons of oil and > 1000 tons of oil given oil spill scenario for release rate 4500 tons/day and 12 hours, 2 – 5 – 14 - 50 days duration for a subsea release with Balder oil

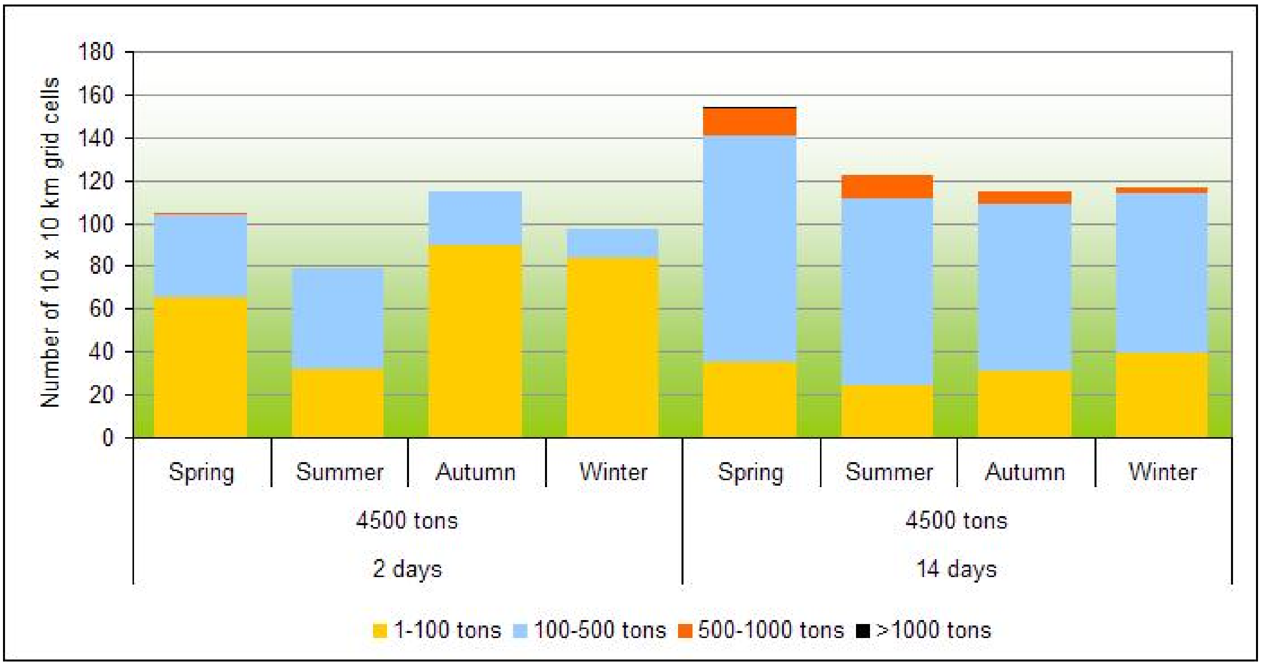

Figure 11-14 Number of 10 x 10 km strand grid cells with respectively 1-100 tons of oil, 100-500 tons of oil, 500-1000 tons of oil and > 1000 tons of oil given oil spill scenario for release rate 4500 tons/day and 2 and 14 days duration for a top side release with Goliat oil

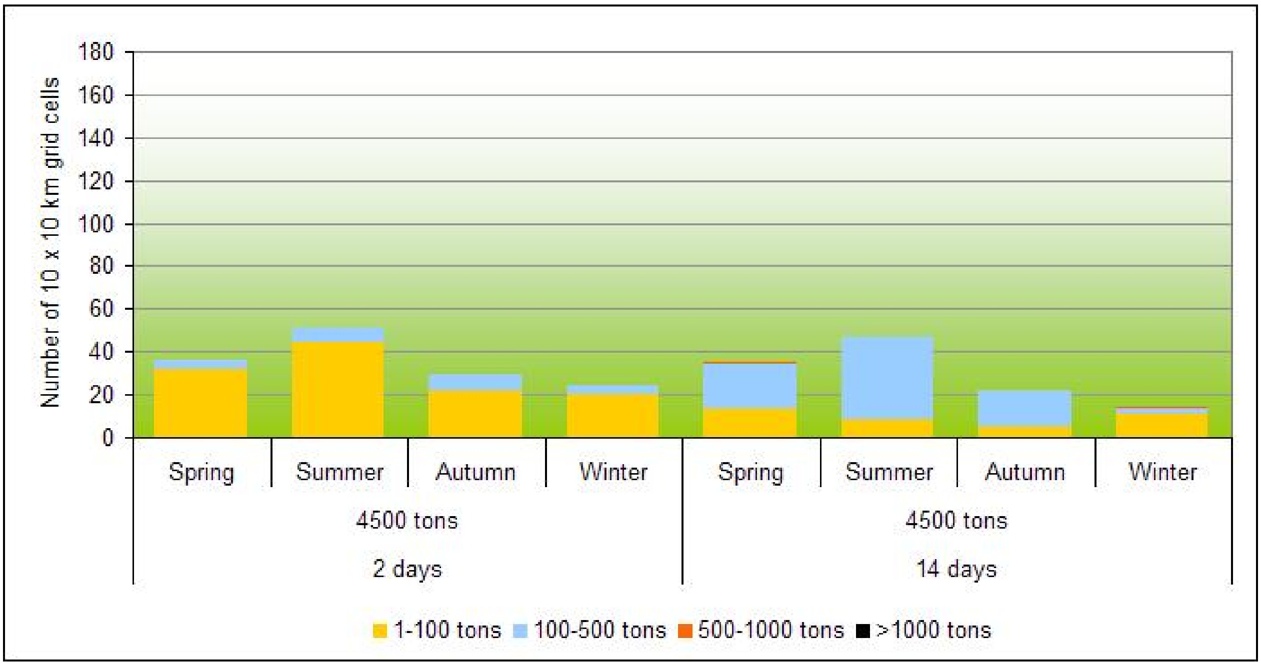

Figure 11-15 Number of 10 x 10 km strand grid cells with respectively 1-100 tons of oil, 100-500 tons of oil, 500-1000 tons of oil and > 1000 tons of oil given oil spill scenario for release rate 4500 tons/day and 2 and 14 days duration for a subsea release with Goliat oil

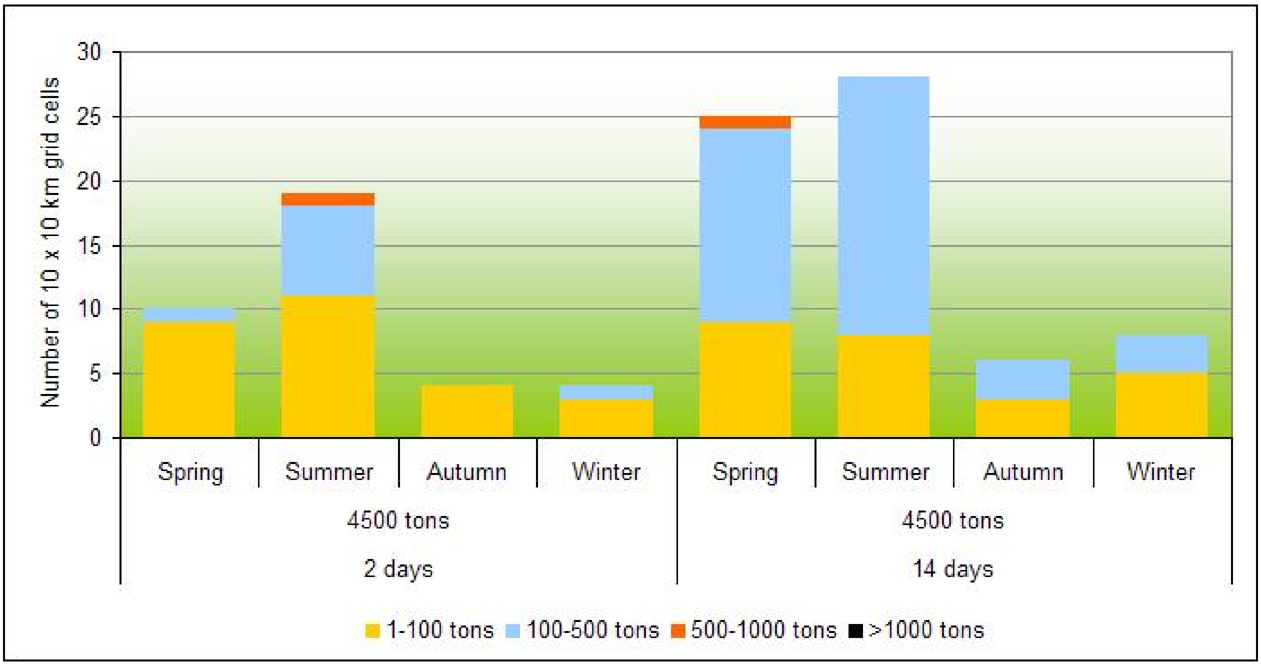

Figure 11-16 Number of 10 x 10 km strand grid cells with respectively 1-100 tons of oil, 100-500 tons of oil, 500-1000 tons of oil and > 1000 tons of oil given oil spill scenario for release rate 4500 tons/day and 2 and 14 days duration for a top side release with Huldra oil

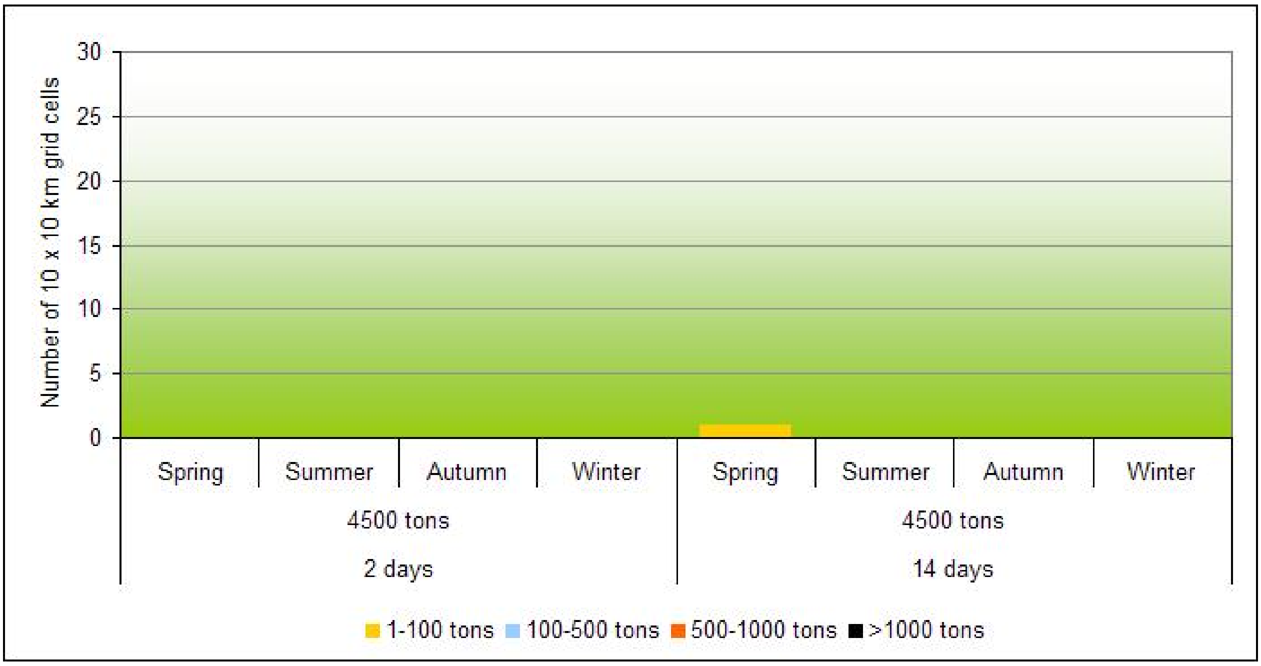

Figure 11-17 Number of 10 x 10 km strand grid cells with respectively 1-100 tons of oil, 100-500 tons of oil, 500-1000 tons of oil and > 1000 tons of oil given oil spill scenario for release rate 4500 tons/day and 2 and 14 days duration for a subsea release with Huldra oil

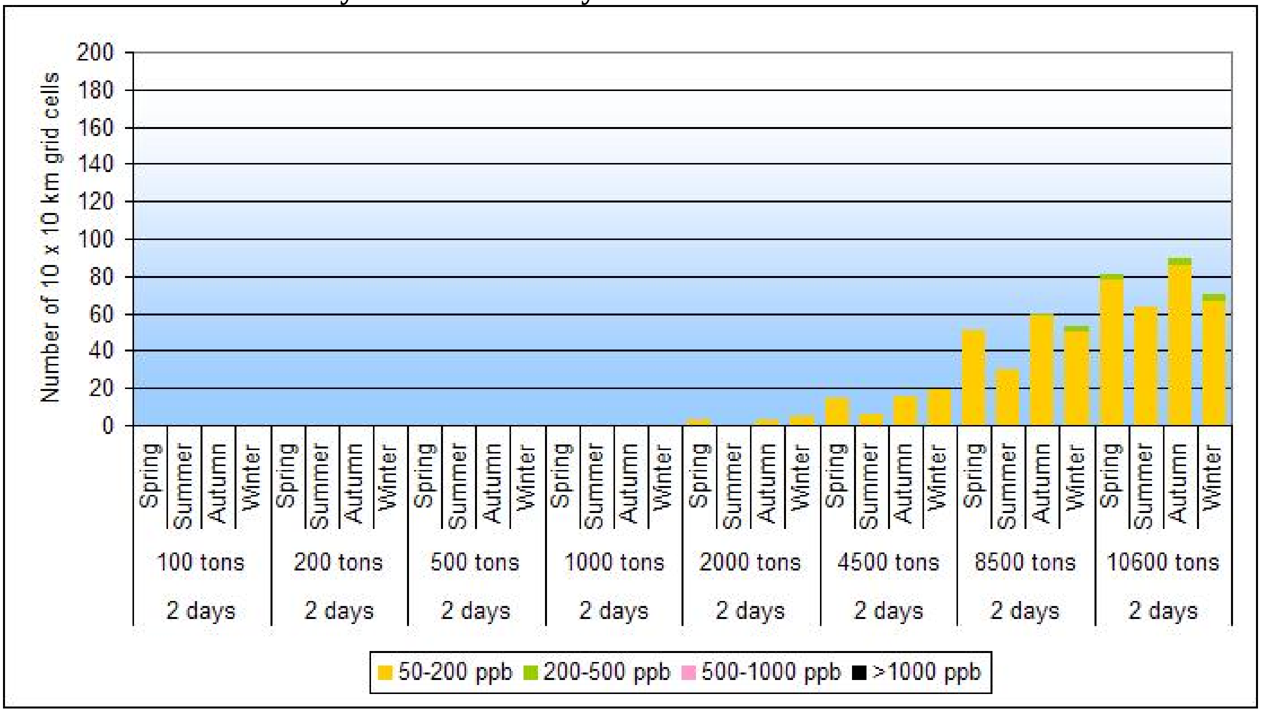

Figure 11-18 Number of 10 x 10 km open sea grid cells with a total hydrocarbon concentration in the water column of respectively 50-200 ppb, 200-500 ppb, 500-1000 ppb and > 1000 ppb, given oil spill scenario 2 days duration and various rates for a top side release with Balder oil

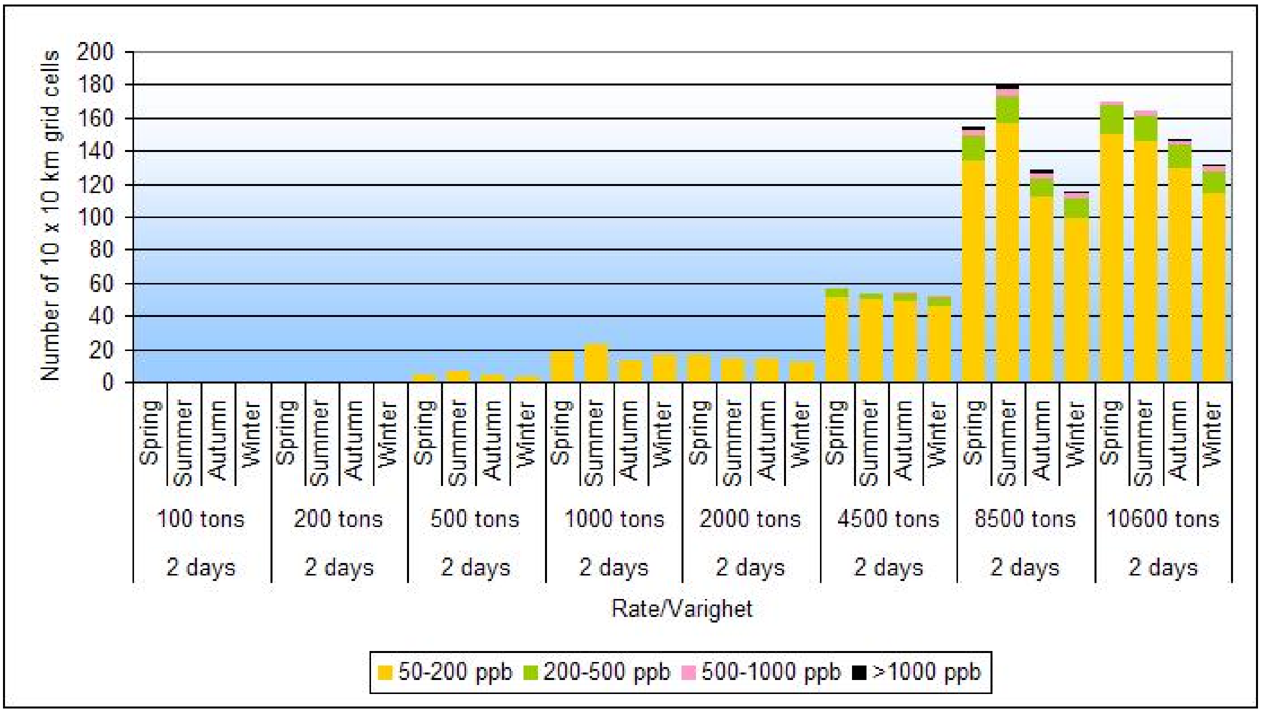

Figure 11-19 Number of 10 x 10 km open sea grid cells with a total hydrocarbon concentration in the water column of respectively 50-200 ppb, 200-500 ppb, 500-1000 ppb and > 1000 ppb, given oil spill scenario 2 days duration and various rates for a subsea release with Balder oil

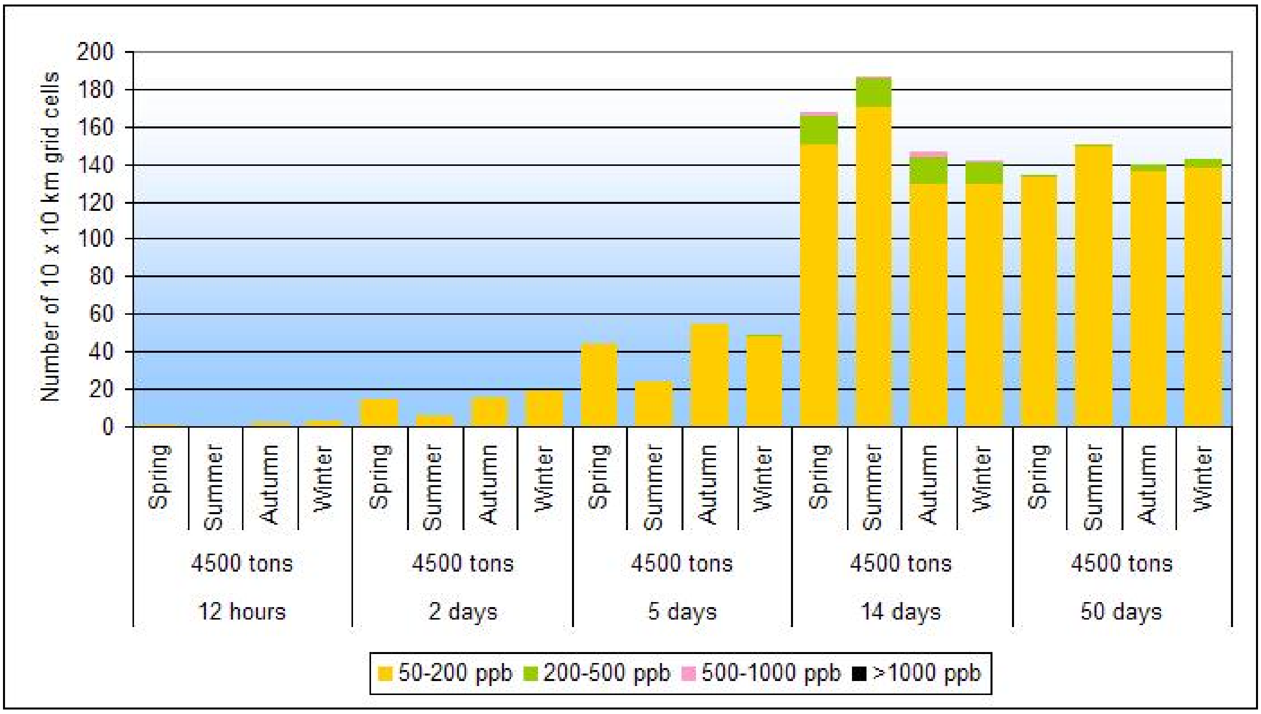

Figure 11-20 Number of 10 x 10 km open sea grid cells with a total hydrocarbon concentration in the water column of respectively 50-200 ppb, 200-500 ppb, 500-1000 ppb and > 1000 ppb, given oil spill scenario for release rate 4500 tons/day and 12 hours, 2 – 5 – 14 - 50 days duration for a top side release with Balder oil

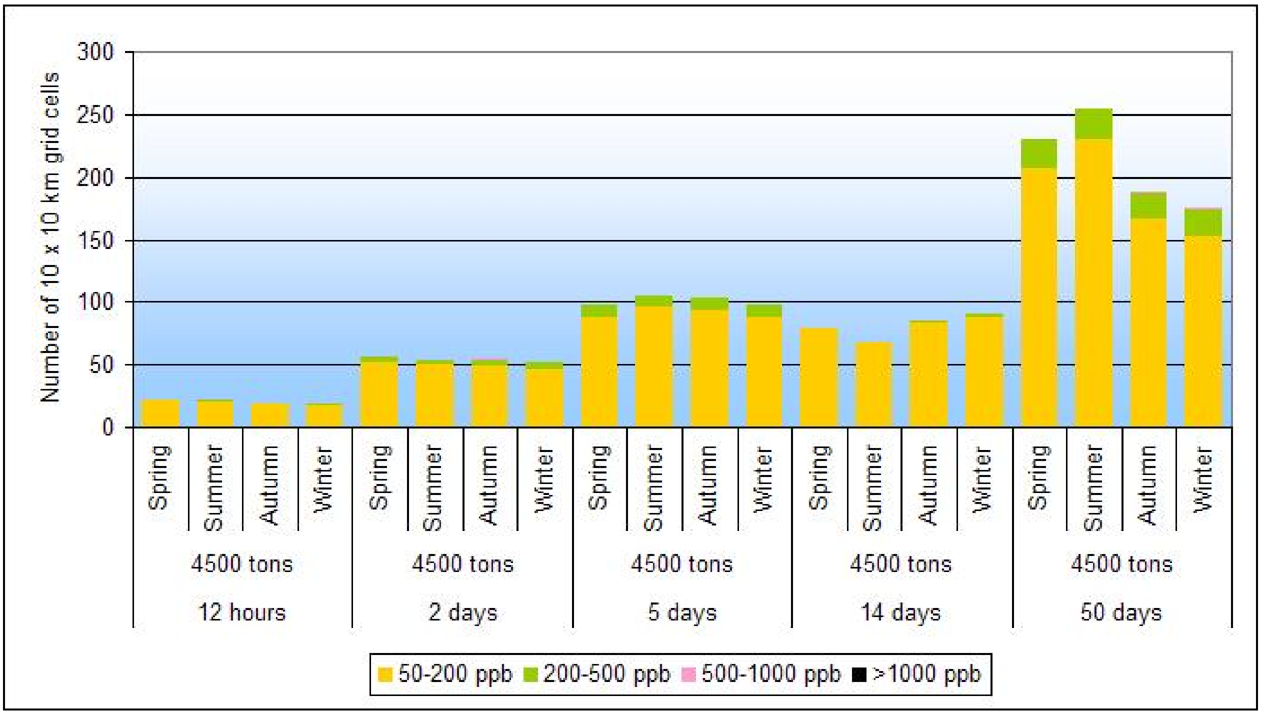

Figure 11-21 Number of 10 x 10 km open sea grid cells with a total hydrocarbon concentration in the water column of respectively 50-200 ppb, 200-500 ppb, 500-1000 ppb and > 1000 ppb, given oil spill scenario for release rate 4500 tons/day and 12 hours, 2 – 5 – 14 - 50 days duration for a subsea release with Balder oil

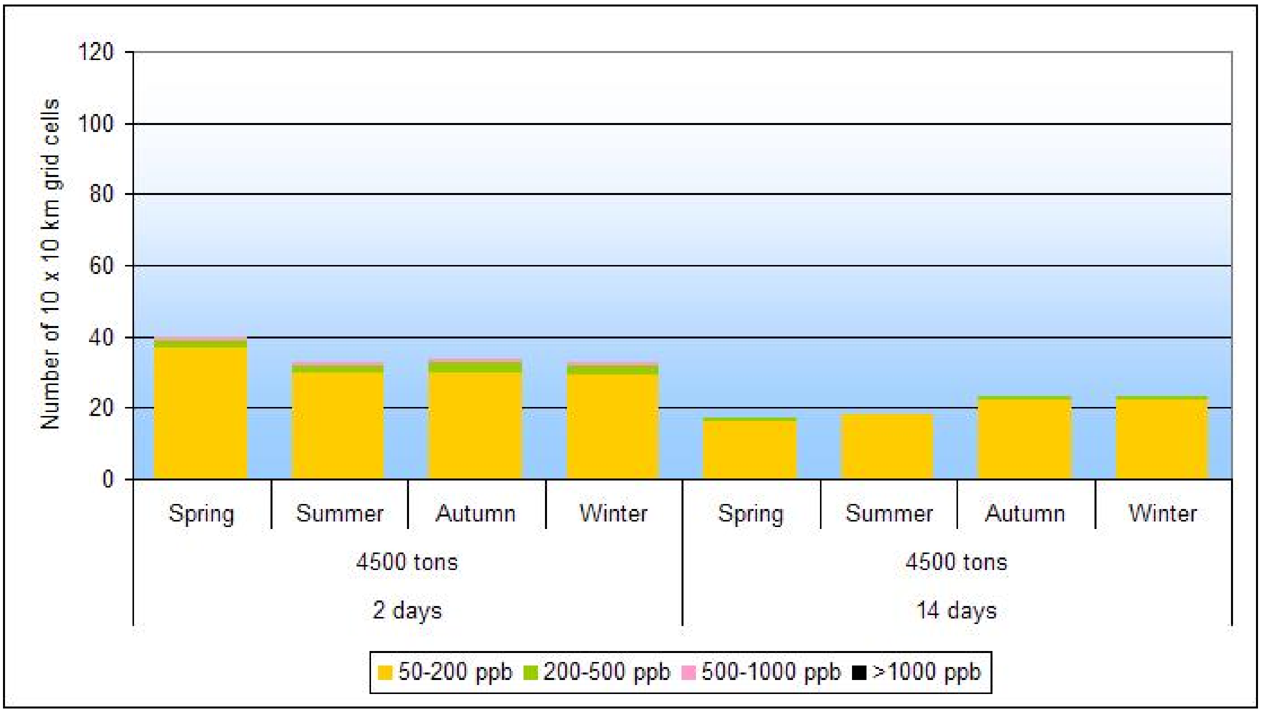

Figure 11-22 Number of 10 x 10 km open sea grid cells with a total hydrocarbon concentration in the water column of respectively 50-200 ppb, 200-500 ppb, 500-1000 ppb and > 1000 ppb, given oil spill scenario for release rate 4500 tons/day and 2 and 14 days duration for a top side release with Goliat oil

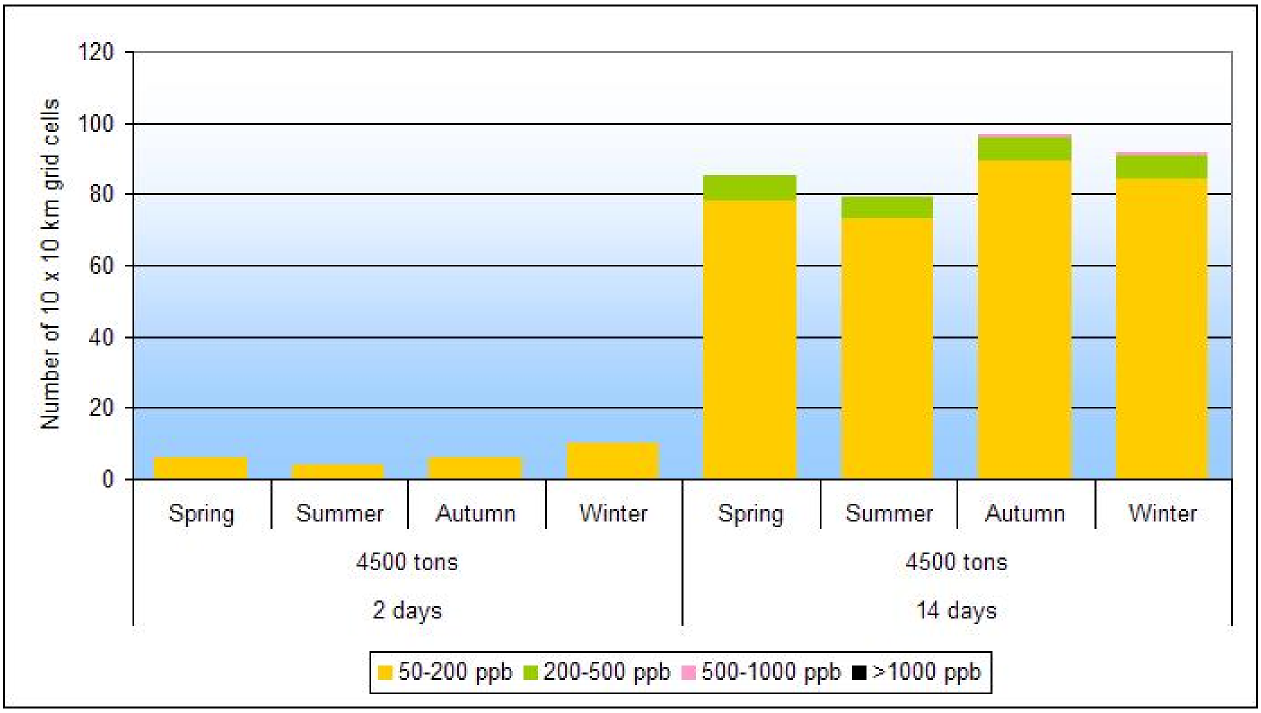

Figure 11-23 Number of 10 x 10 km open sea grid cells with a total hydrocarbon concentration in the water column of respectively 50-200 ppb, 200-500 ppb, 500-1000 ppb and > 1000 ppb, given oil spill scenario for release rate 4500 tons/day and 2 and 14 days duration for a subsea release with Goliat oil

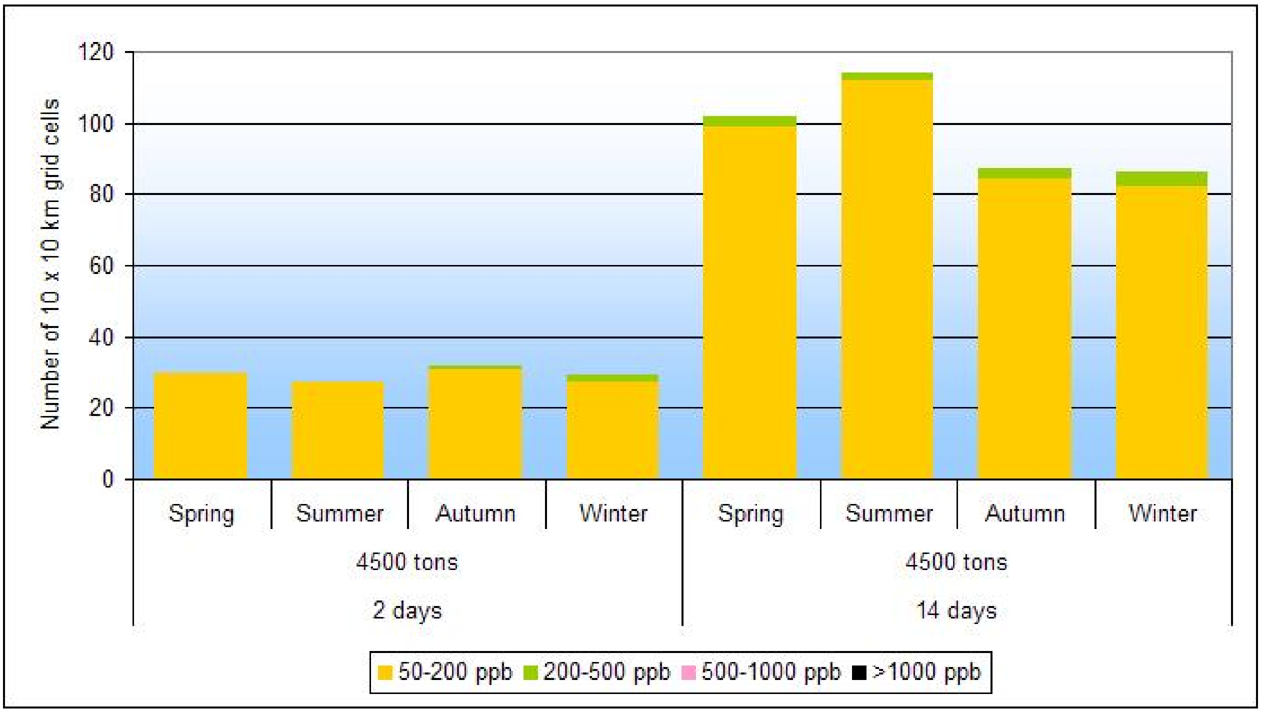

Figure 11-24 Number of 10 x 10 km open sea grid cells with a total hydrocarbon concentration in the water column of respectively 50-200 ppb, 200-500 ppb, 500-1000 ppb and > 1000 ppb, given oil spill scenario for release rate 4500 tons/day and 2 and 14 days duration for a top side release with Huldra oil

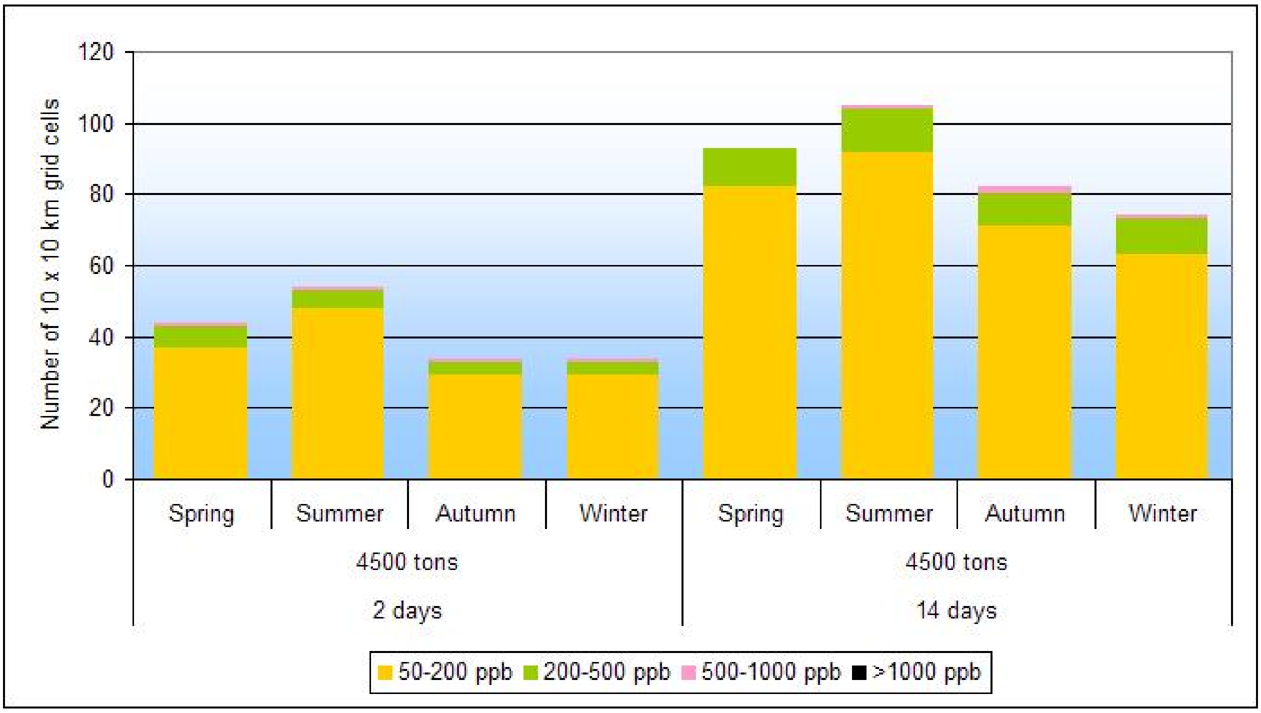

Figure 11-25 Number of 10 x 10 km open sea grid cells with a total hydrocarbon concentration in the water column of respectively 50-200 ppb, 200-500 ppb, 500-1000 ppb and > 1000 ppb, given oil spill scenario for release rate 4500 tons/day and 2 and 14 days duration for a subsea release with Huldra oil

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APPENDIX

7
ENVIRONMENTAL RESOURCES

The figures below show the temporal and spatial distribution of the environmental resources that is analysed for in the environmental risk analysis.

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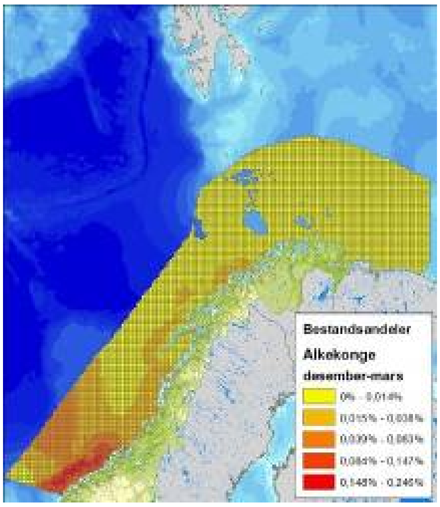
<td>
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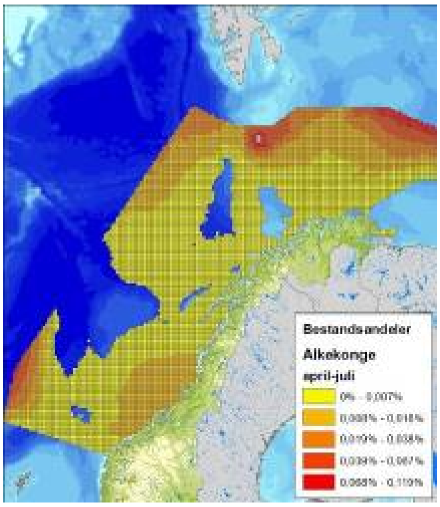
<td>
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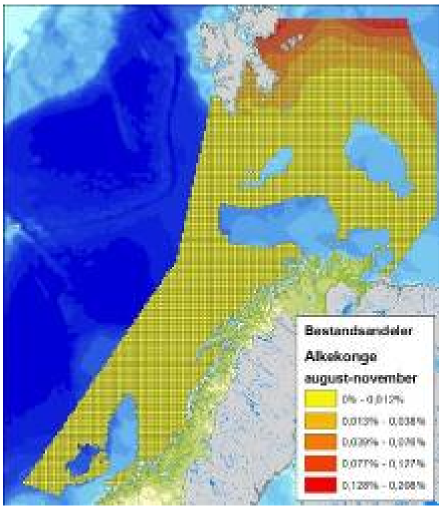
<td>
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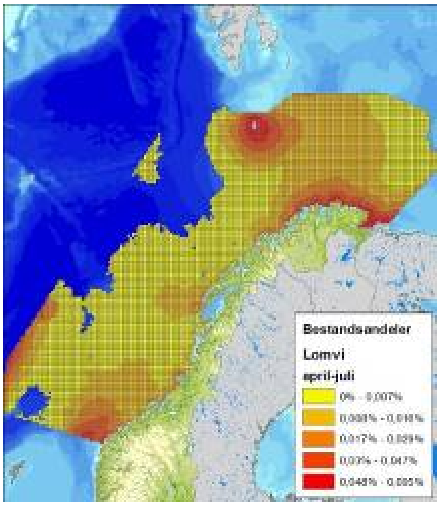
<td>
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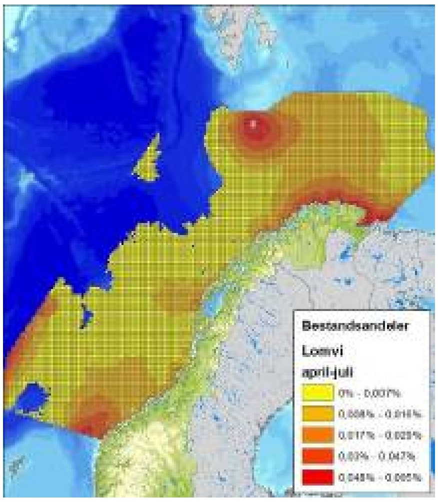
<td>
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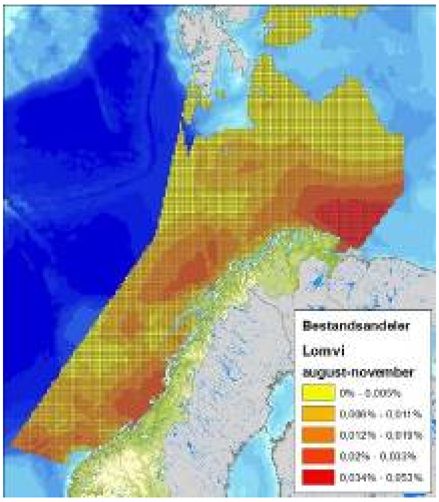
<td>
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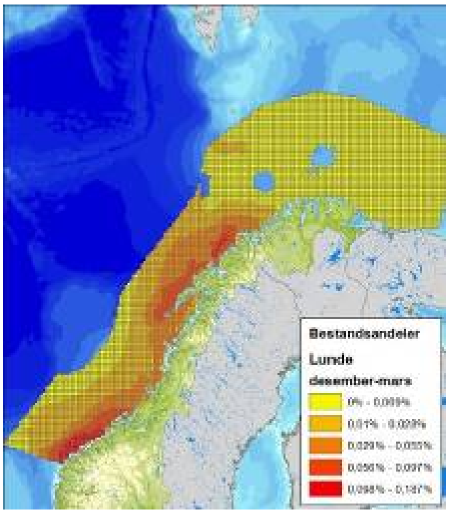
<td>
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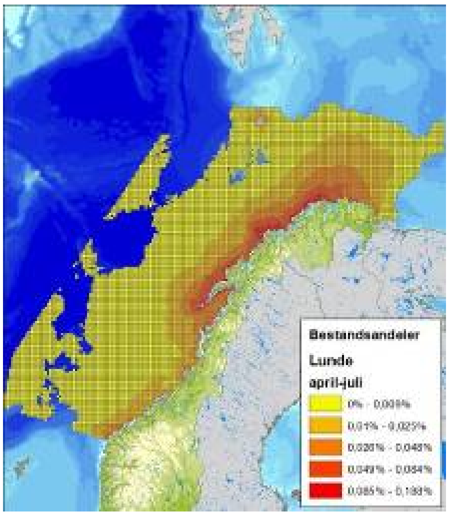
<td>
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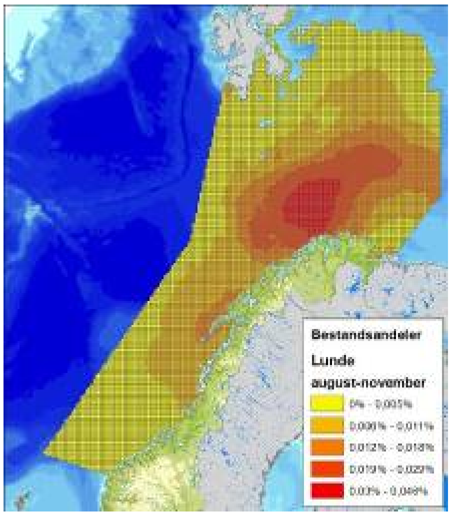
<td>
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<tr><th>Brünnich's Guillemot – December – March</th><th>Brünnich's Guillemot – April – July</th><th>Brünnich's Guillemot – August – November</th></tr>
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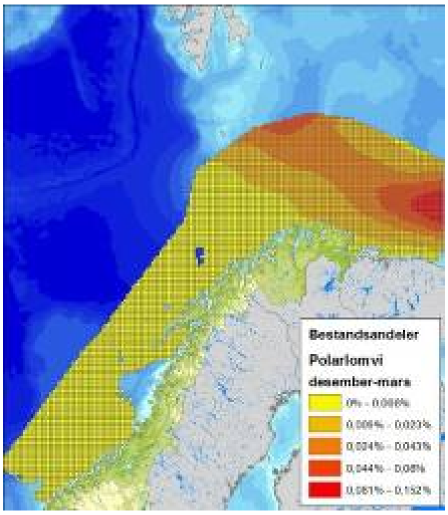
<td>
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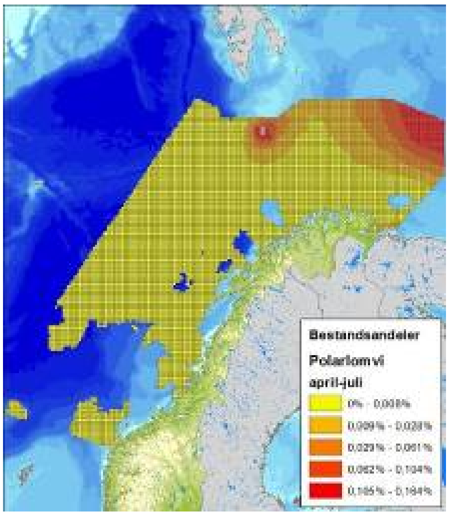
<td>
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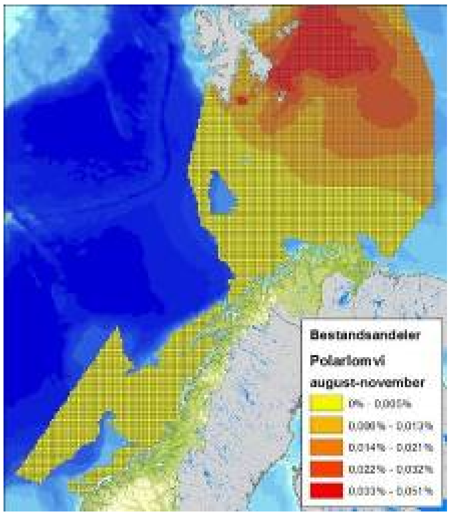
<td>
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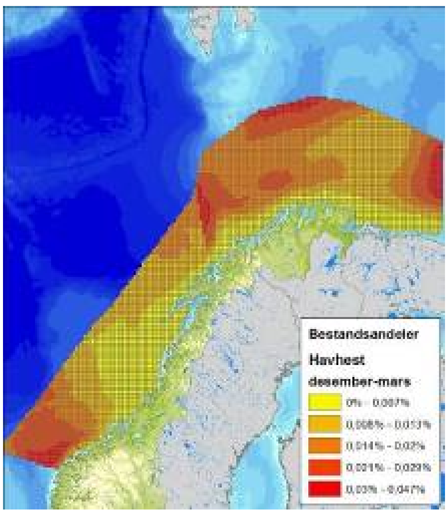
<td>
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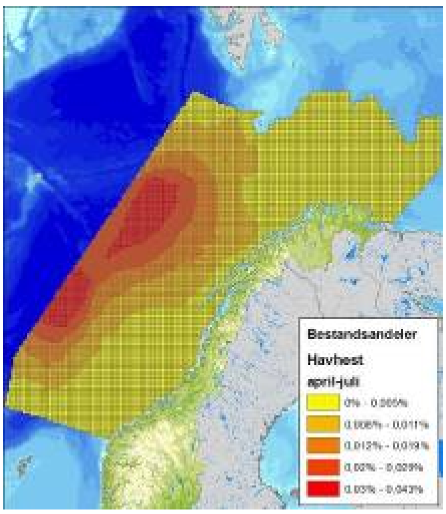
<td>
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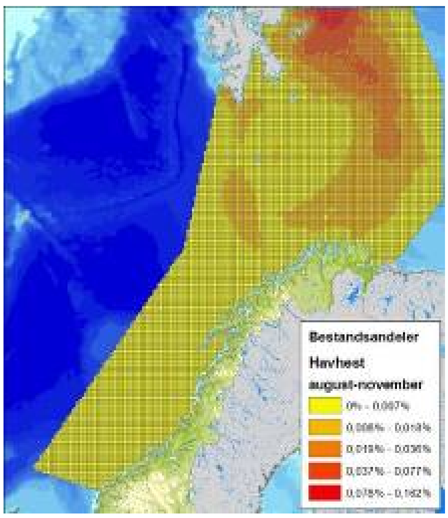
<td>
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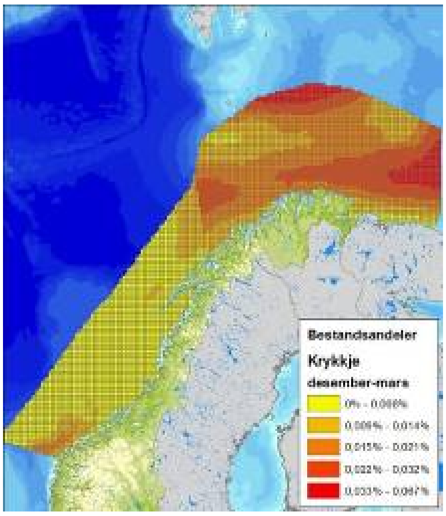
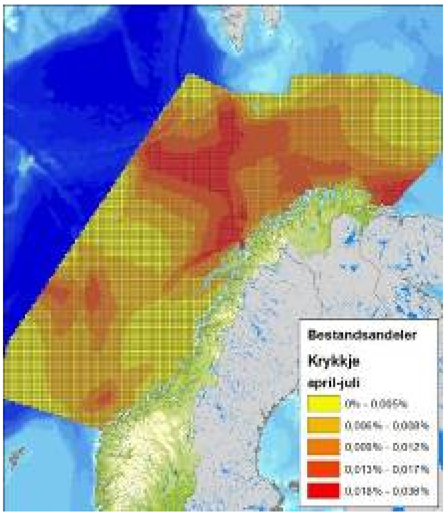
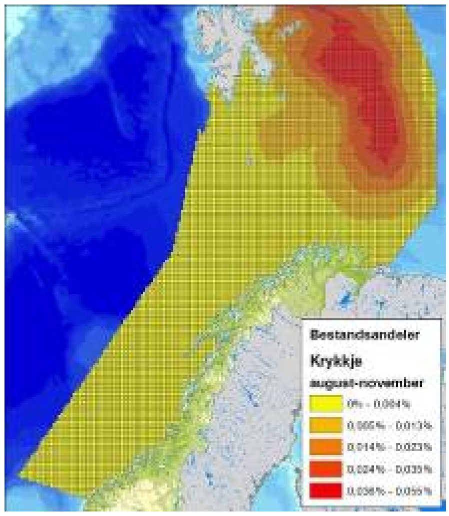
<tr><td>Kittiwake – December – March</td><td>Kittiwake – April – July</td><td>Kittiwake – August - November</td></tr>
<tr><td>
</td><td>
</td><td>
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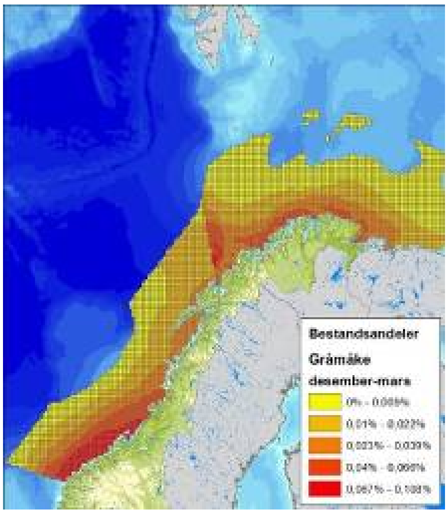
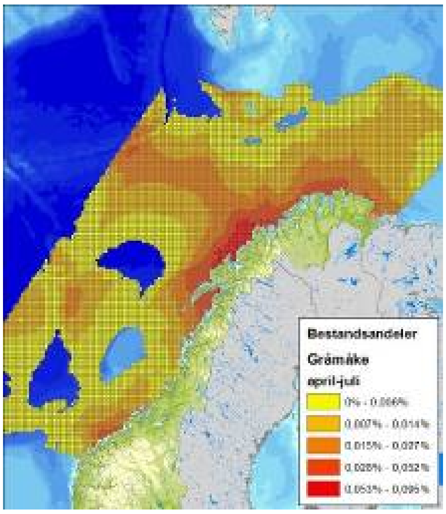
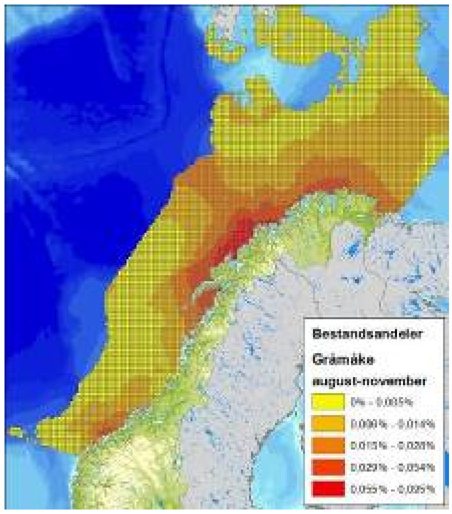
<tr><td>
</td><td>
</td><td>
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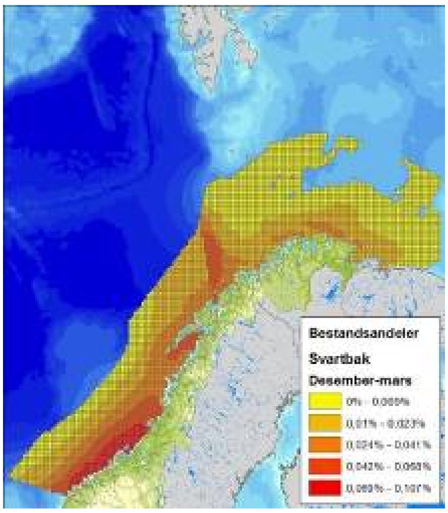
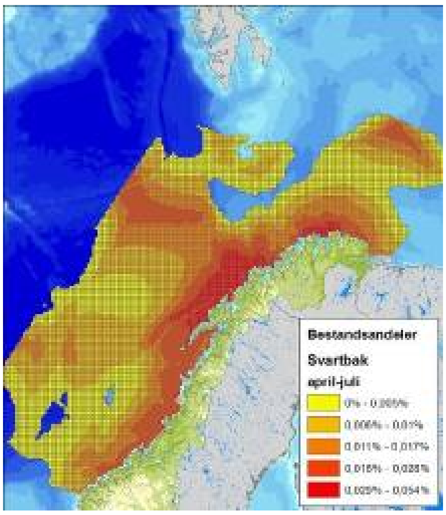
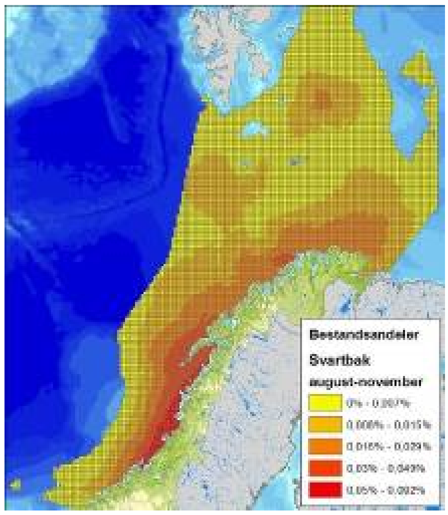
<tr><td>Great Black-backed Gull – December – March</td><td>Great Black-backed Gull – April – July</td><td>Great Black-backed Gull – August – November</td></tr>
<tr><td>
</td><td>
</td><td>
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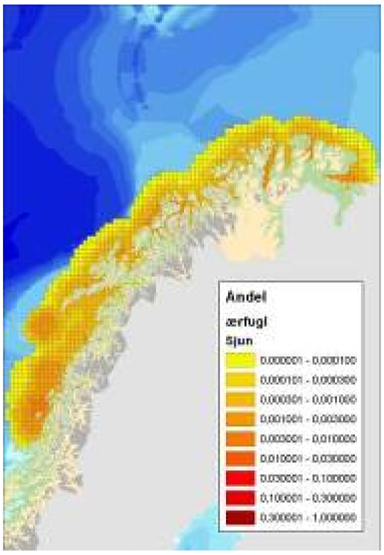
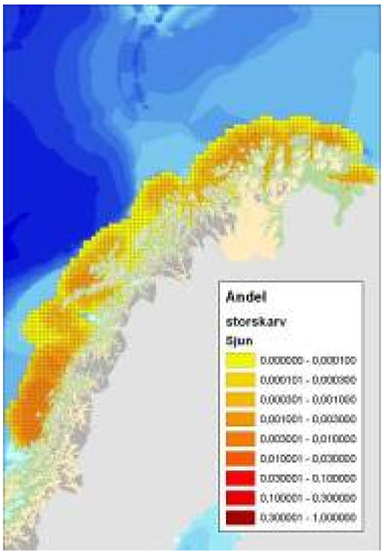
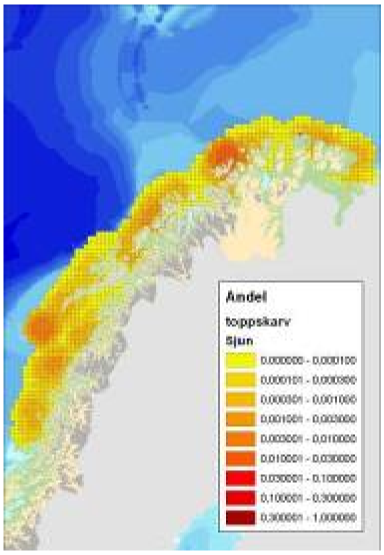
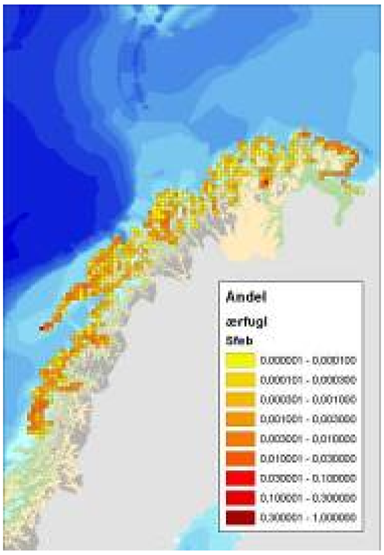
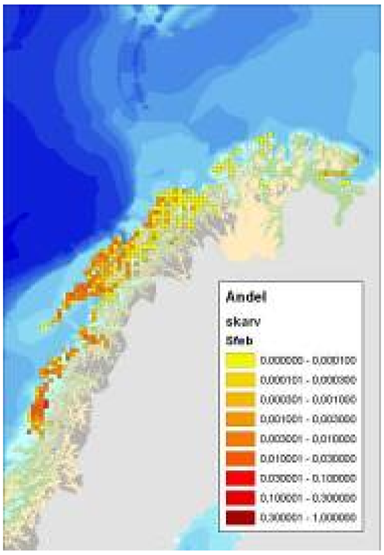
Common Eider – nesting season (summer)	**Great Cormorant – nesting season (summer)**	**Shag – nesting season (summer)**
		
Common Eider – Winter	**Cormorant – Winter**	
		

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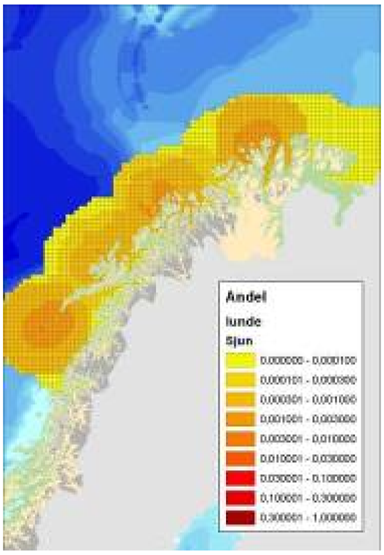
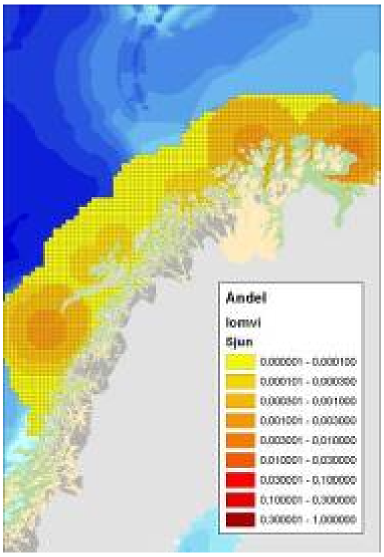
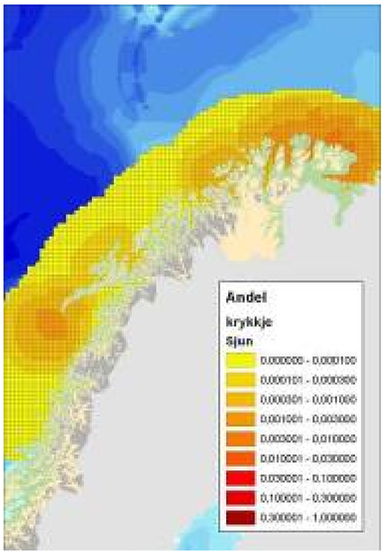
<tr><td>
</td><td>
</td><td>
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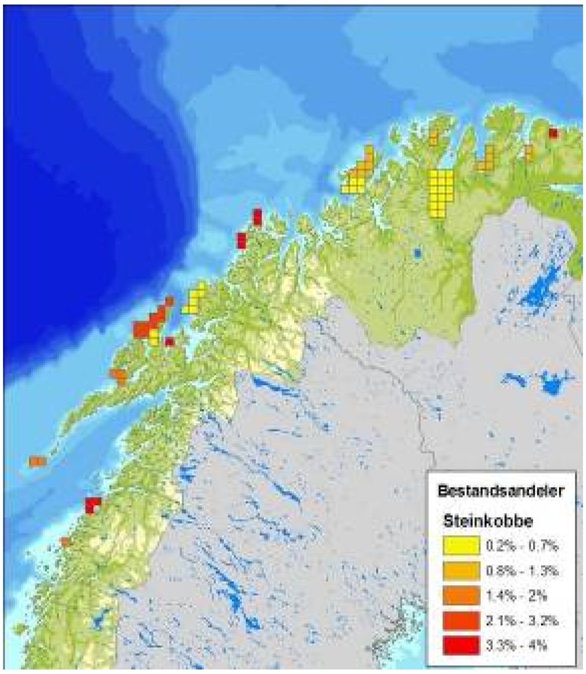
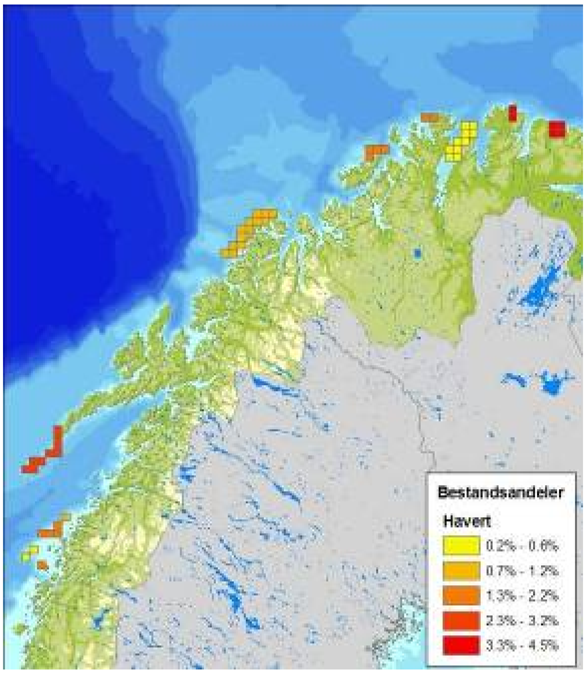
<tr><th>Harbour Seal</th><th>Grey Seal</th></tr>
<tr><td>
</td><td>
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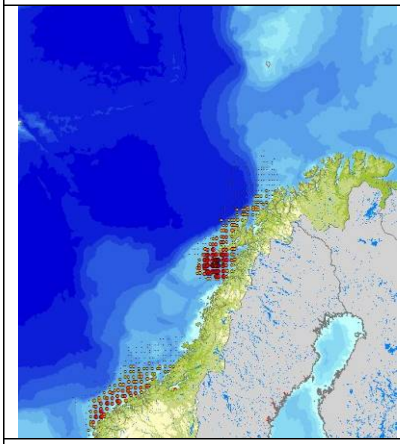
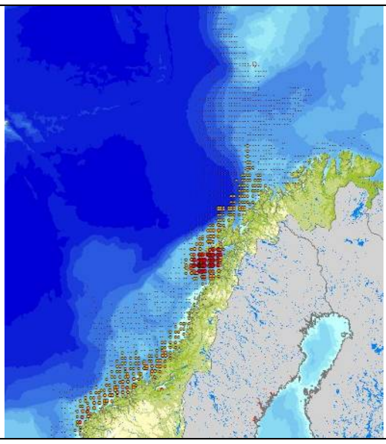
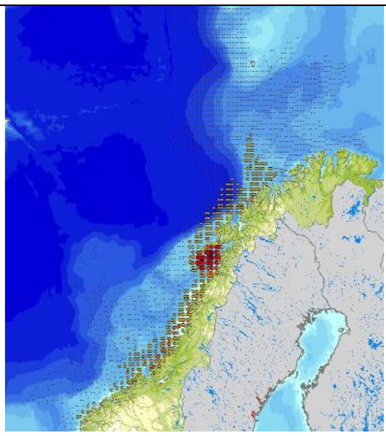
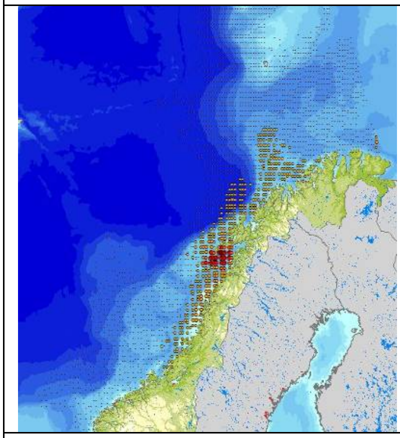
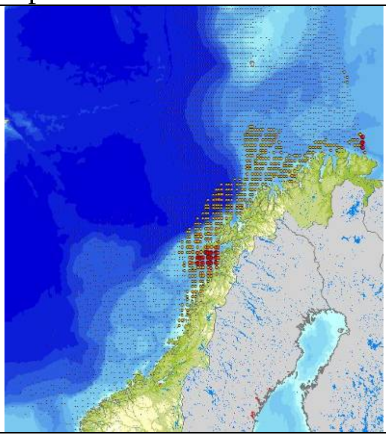
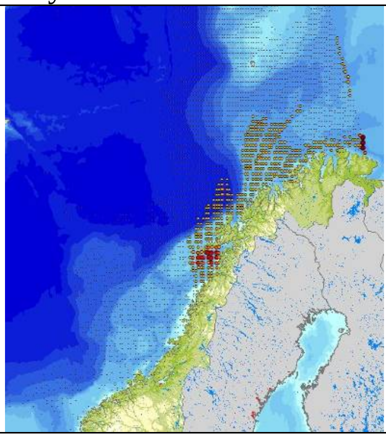
Average spatial and temporal distribution of cod egg and larvae based on modelling of monitoring data from 1980 until 2004 (Source: Marine Resource Institute)

COD EGG AND LARAVAE		
		
March	April	May
		
June	July	August

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