# Report

## Blowout Scenario Analysis (BSA)

Blowout Rates and Duration

Wildcat exploration well 6407/1-9 Egyptian Vulture

Rev 0 – 4th January 2021

Ranold.

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# Executive Summary

This report summarizes the blowout rate simulations and corresponding duration evaluations performed for the 6407/1-9 Egyptian Vulture wildcat exploration well in the Norwegian Sea.

The well is to be drilled as a vertical well, exploring for HC in the Lange reservoir. For the evaluations performed in this study, the Lange reservoir is expected to hold oil with a GOR of 177.5 Sm³/Sm³.

The following case is evaluated:

- Case 1: Blowout through 9 ⅝" liner when drilling the Lange reservoir in an 8 ½" section

Blowout rates are calculated for openhole, annulus and drillstring flow paths, with and without restriction, with both seabed and surface release points, and partly and fully penetrated reservoir. The worst-case scenario with respect to oil spill to sea is a blowout through a fully open and unrestricted flow path, exposed to a fully penetrated reservoir with release to surface. Such a blowout will result in a maximum blowout rate of 1050 Sm³/day of oil and 0.19 MSm³/day of gas.

A large number of scenarios have been calculated to span a range of possible outcomes with respect to blowout rates of oil and condensate. The rates are presented and risked according to the Norwegian Oil & Gas (NOROG) Association guidelines and statistical data from the SINTEF offshore blowout database. The most likely, or risked, oil blowout rate is 689 Sm³/day for a surface release point and 696 Sm³/day for a seabed release point. The corresponding risked blowout rates of gas are 0.12 MSm³/day for both a surface release point and a seabed release point.

# Disclaimer

The data forming the basis on this report has been collected by Ranold AS, hereinafter named Ranold. Ranold has gathered the data to the best of our knowledge, ability, and in good faith from sources to be reliable and accurate. Ranold has attempted to ensure the accuracy of the data, though, Ranold makes no representations or warranties as to the accuracy or completeness of the reported information. Ranold assumes no liability or responsibility for any errors or omissions in the information or for any loss or damage resulting from the use of any information contained within this report. This document may set requirements supplemental to applicable laws. However, nothing herein intends to replace, amend, supersede or otherwise depart from any applicable law relating to the subject matter of this document. In the event of any conflict or contradiction between the provision of this document and applicable law as to the implementation and governance of this document, the provision of applicable law shall prevail.

# Revision and Approval Form

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# Table of Contents



# List of Figures

## List of Tables

# Abbreviations

| | |
|---|---|
| ANN | Annulus |
| AOF | Absolute open flow |
| BHA | Bottomhole assembly |
| BHP | Bottomhole pressure |
| BOP | Blowout preventer |
| CGR | Condensate gas ratio |
| DHSV | Down hole safety valve |
| DP | Drillpipe |
| FBHP | Flowing bottomhole pressure |
| GCR | Gas condensate ratio |
| GOR | Gas oil ratio |
| ID | Inner diameter |
| IPR | Inflow performance relationship |
| LPM | Liters per minute |
| MD | Measured depth |
| MSL | Mean sea level |
| NOROG | Norwegian Oil and Gas Association |
| N/G | Net/Gross |
| OD | Outer diameter |
| OH | Open hole |
| OIM | Offshore Installation Manager |
| OWC | Oil water contact |
| PWL | Planned well location |
| RKB | Rotary Kelly bushing |
| sg | Specific gravity |
| TD | Total depth |
| TVD | True vertical depth |
| WBM | Water based mud |

# 1 INTRODUCTION

This study is part of establishing input for required approval and contingency planning purposes as required in NORSOK D-010 in terms of estimating the expected blowout rates and their duration, as well as checking the ability to kill potential blowouts based on defined scenarios and specified input for the 6407/1-9 Egyptian Vulture wildcat exploration well.

Ranold AS, an independent and specialized centre of competence for flow modelling and simulation services, was contacted and asked to perform blowout and dynamic kill analysis for different possible case scenarios during drilling of the well. This report summarizes the blowout simulations and duration evaluations performed.

The primary well objectives are:

1. Confirm reservoir parameters and hydrocarbon filling in line with the technical economical evaluation basis for the calculated minimum economical volumes (MEV).
2. Penetrate defined reservoir package to clarify full volume potential and stratigraphy
3. Confirm Lange reservoir presence and quality to set it into a regional context
4. Determine formation fluid types and HCWC and/or gradients

A geological cross-section for well 6407/1-9 is shown in Figure 1.

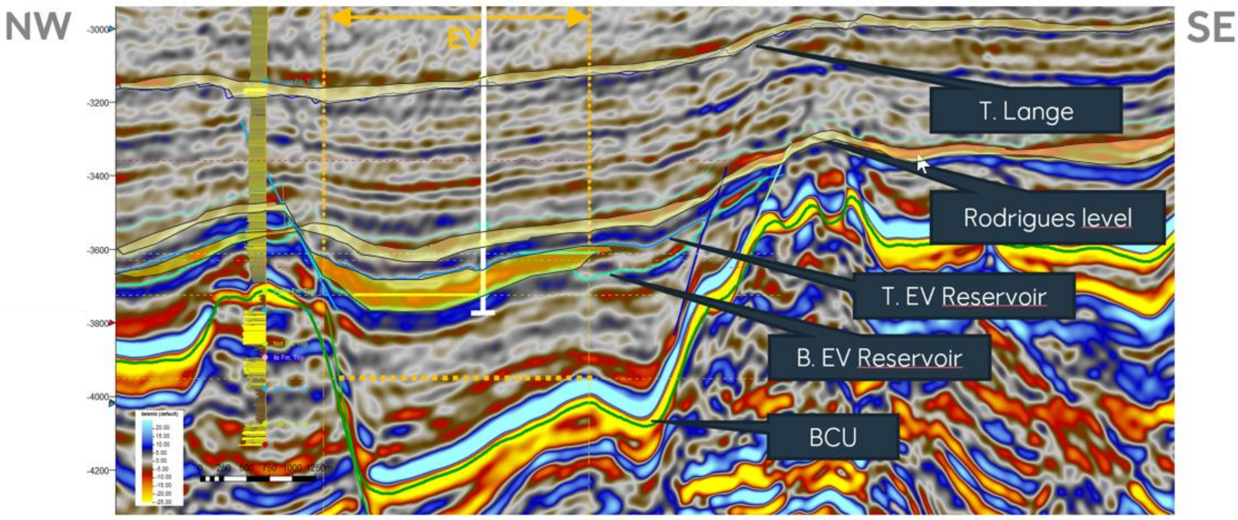



Figure 1: Geological cross-section for the Egyptian Vulture well [6]

# 2 SCOPE

The objectives of this study are:

- Calculate and present an expected range of potential blowout rates for the well, including the worst-case flow rates of oil and gas to surface.
- Estimate flow rate and duration distributions of the blowout rates based on updated historical blowout data and reliable distribution statistics.

The flow rate and duration distributions will be estimated based on the SINTEF Offshore Blowout Database [1][2] and the latest approved evaluation of the SINTEF Database data from Lloyd's Register Consulting [3].

The following main scenarios are evaluated based on Client request in order to span a range of possible outcomes given an incident has occurred:

- Case 1: Blowout through 9 ⅝" liner when drilling the Lange reservoir (oil) with an 8 ½" section
  - Calculate blowout rates
  - Produce flow path distributions
  - Produce duration estimates

Blowout rates will be calculated for partial (5 m MD) and full reservoir exposure, with release to both seabed and surface.

The blowout rates are simulated in Prosper (Petroleum Experts).

# 3 DATA & INFORMATION COLLECTION

## 3.1 Location and water depth

The well will be drilled in block 6407/1-9, northwest of Trondheim. The water depth at location is 301 m. Figure 2 shows the location of block 6407/1 in the Norwegian Sea.

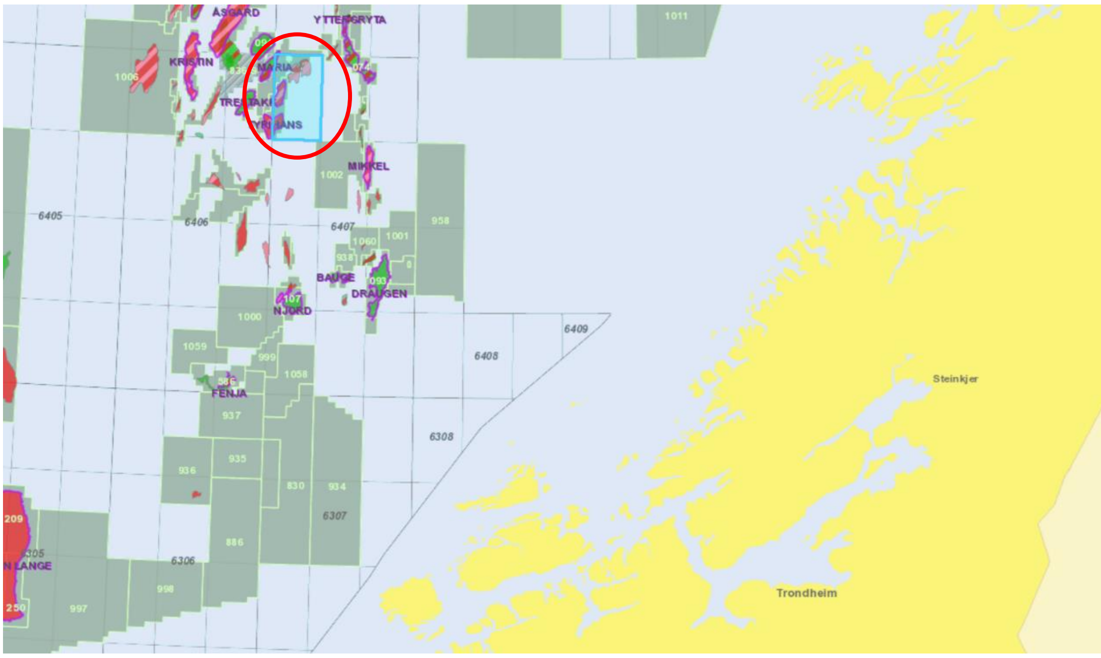



Figure 2: Map showing location of block 6407/1 (Source www.gis.npd.no)

## 3.2 Drilling facilities

The well will be drilled by the semi-submersible drilling rig West Hercules of the GVA 7500 design. West Hercules, which is shown in Figure 3, is a 6th generation ultra-deepwater and harsh environment rig. RKB – MSL is 31 m.

Figure 3: The semi-submersible drilling rig West Hercules (Source www.seadrill.com)

## 3.3 Reservoir properties

The well is to be drilled into the Lange reservoir for investigation of HC potential. For the evaluations performed in this study, Lange is expected to hold oil.

Table 1 shows the reservoir data used in the simulations for the well presented in this report. The PI is provided by Client and verified by Ranold.

In accordance with NORSOK-D10, no mechanical skin is used in the blowout simulations. The partial penetration skin represents the reduction of the IPR for partial exposure of the reservoir (5 m MD net pay). The absolute open flow (AOF) represents the maximum theoretical blowout potential.

Table 1: Reservoir data for well 6407/9-13

| Reservoir property | Unit | Lange |
|---|---|---|
| Top reservoir | m TVD RKB | 3701 |
| Base reservoir | m TVD RKB | 3756 |
| Temperature @ res top | ºC | 139 |
| Pressure | bara | 581 |
| Gross interval depth, total sand | meter | 55 |
| N/G ratio | - | 0.32 |
| Net interval depth, HC layer | meter | 17.6 |
| Porosity | fraction | 0.17 |
| Absolute permeability | mD | 20 |
| Water saturation | fraction | 0.2 |
| Water cut | % | 0 |
| Skin | - | 0 |
| Partial penetration skin | - | 11.8 |
| Productivity index, PI | Sm3/d/bar | 2.36 |
| AOF | $MSm^3/d$ | 1062 |

## 3.4 Reservoir fluid information

The expected properties of the reservoir fluids are listed in Table 2. These properties provided by the Client [6] are based on the reference well/sample 6406/3-8 T2. The fluids are represented by a black-oil model in all simulations presented in this report and tuned according to the data listed in Table 2.

Table 2: Fluid properties for the expected reservoir fluid from well 6407/1-9

| **Standard conditions*** | | **Oil** |
|---|---|---|
| Oil density | kg/Sm³ | 862 |
| Gas density | sg | 0.831 |
| Gas to Oil/Condensate Ratio (GOR, GCR) | Sm³/Sm³ | 177.5 |
| *standard conditions defined as 15˚C / 1.01325 bara | | |

| **Reservoir conditions**** | | **Oil** |
|---|---|---|
| Oil density | kg/m³ | 694.1 |
| Oil viscosity | cP | 0.4394 |
| Bubble point | bar (˚C) | 292.6 |
| Oil formation factor, Bo | Rm³/Sm³ | 1.608 |
| ** reservoir conditions: 139 ˚C / 580.6 bara | | |

## 3.5 Well design

The well is to be drilled as a vertical wildcat exploration well, with the following planned well design:

- 36” conductor pipe set @ 392 m MD/TVD RKB
- 20" surface casing set @ 1439 m MD/TVD RKB
- 13 ⅜” intermediate casing set @ 2349 m MD/TVD RKB
- 9 ⅝” liner set @ 3620 m MD/TVD RKB with TOL @ 2299 m MD/TVD RKB
- An 8 ½” section will be drilled into the Lange reservoir to TD @ 3871 m MD/TVD RKB
- The drillstring comprises a 5 7/8" drillpipe (5.045" ID) and a 150 m long BHA with 6 ½” OD (2.8" ID).

The well schematics are illustrated in Figure 4 and Figure 5.

## 3.6 Inflow Performance Relationship

The productivity index or, more generally, the inflow performance relationship describes how the flowing bottomhole pressure correlates to the flow rate from the reservoir. The result is that the pressure drawdown from reservoir to well increases with increasing flow rate. It is sensitive to parameters such as permeability, fluid viscosity, penetration length, N/G ratio, the productive height of the reservoir as well as mechanical skin, inflow turbulence and skew drainage due to limited penetration.

The productivity index is also a transient parameter that tends to decline shortly after initiation of the production, or as in this case, a blowout. This is caused by the reduction of the near-wellbore pressures.

When calculating the blowout potentials, the blowout rates for the different scenarios are strongly dependent on the reservoir pressure and on the parameters that affect the inflow performance relationship. Simulations are based on the most likely properties, as given in Table 1 - Table 2.

The IPRs for well 6407/1-9 are given in Figure 6. The IPRs shown are for both full and partial penetration according to the scenarios described in Section 2.

Full exposure is modelled by Client provided PI. Partial exposure is modelled by a Darcy model in Prosper, having 5 m net reservoir exposure.

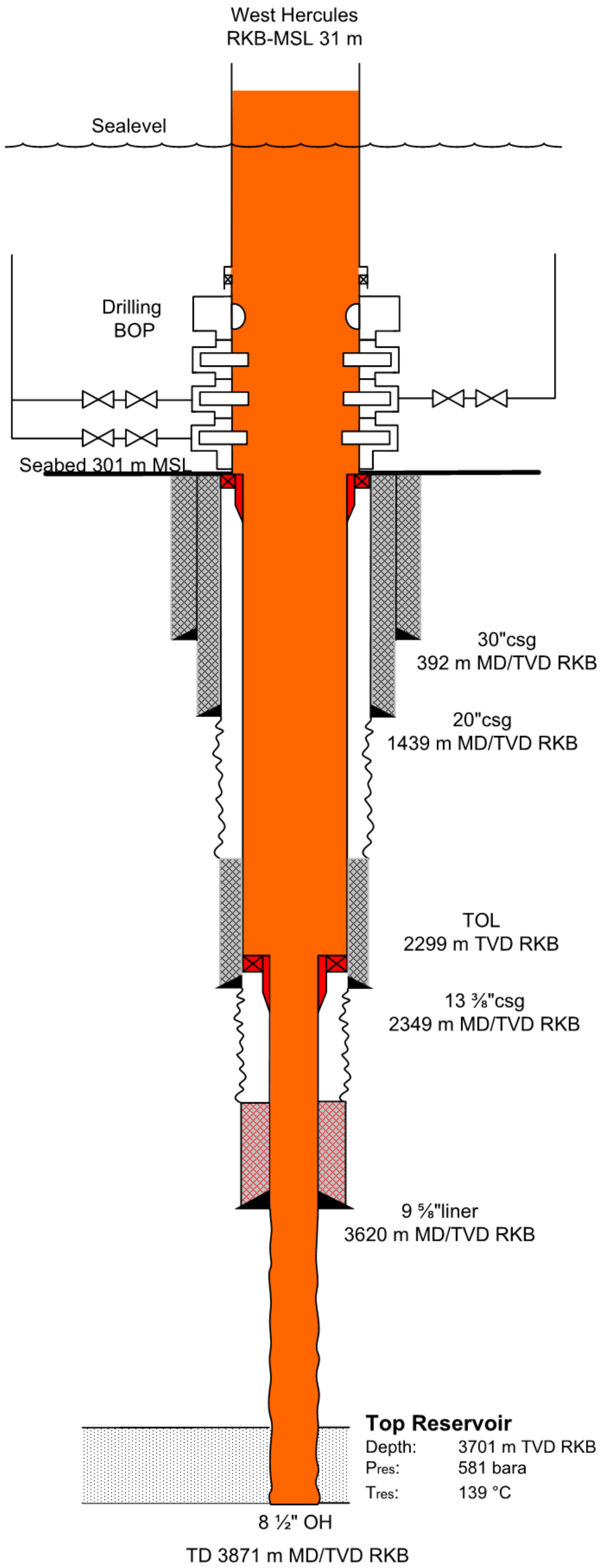
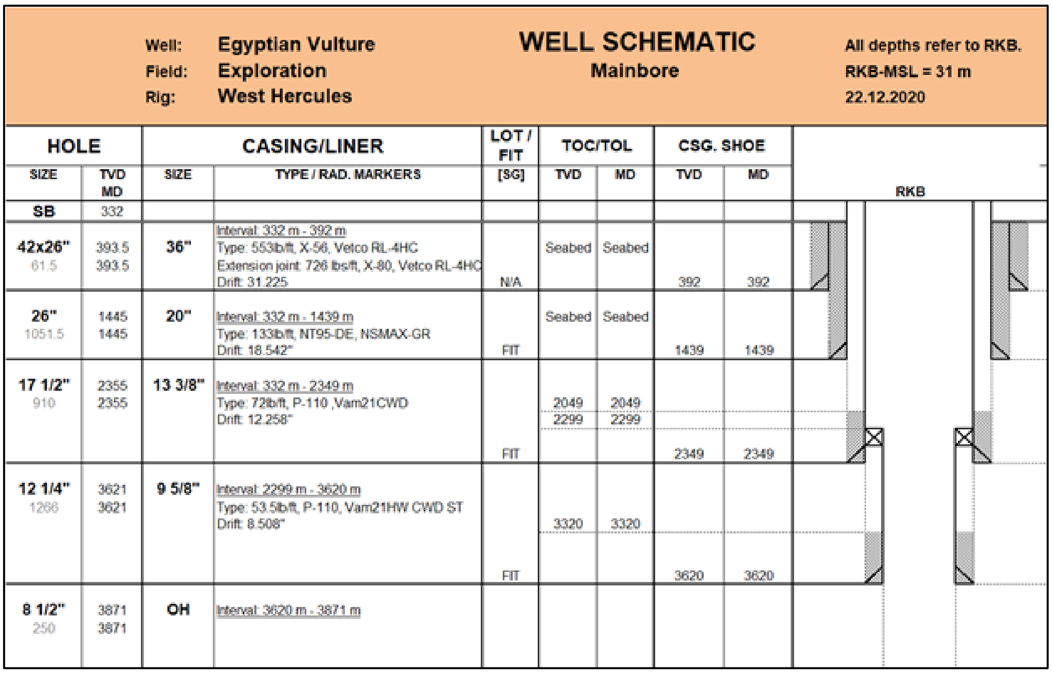



Figure 4: Schematics for well 6407/1-9



Well: **Egyptian Vulture** | Field: **Exploration** | Rig: **West Hercules**

**WELL SCHEMATIC** — **Mainbore**

All depths refer to RKB. RKB-MSL = 31 m. 22.12.2020

| HOLE SIZE | HOLE TVD / MD | CASING/LINER SIZE | TYPE / RAD. MARKERS | LOT / FIT [SG] | TOC/TOL TVD | TOC/TOL MD | CSG. SHOE TVD | CSG. SHOE MD |
|---|---|---|---|---|---|---|---|---|
| SB | 332 | | | | | | | |
| 42x26" 61.5 | 393.5 393.5 | 36" | Interval: 332 m - 392 m Type: 553lb/ft, X-56, Vetco RL-4HC Extension joint: 726 lbs/ft, X-80, Vetco RL-4HC Drift: 31.225 | N/A | Seabed | Seabed | 392 | 392 |
| 26" 1051.5 | 1445 1445 | 20" | Interval: 332 m - 1439 m Type: 133lb/ft, NT95-DE, NSMAX-GR Drift: 18.542" | FIT | Seabed | Seabed | 1439 | 1439 |
| 17 1/2" 910 | 2355 2355 | 13 3/8" | Interval: 332 m - 2349 m Type: 72lb/ft, P-110 ,Vam21CWD Drift: 12.258" | FIT | 2049 2299 | 2049 2299 | 2349 | 2349 |
| 12 1/4" 1266 | 3621 3621 | 9 5/8" | Interval: 2299 m - 3620 m Type: 53.5lb/ft, P-110, Vam21HW CWD ST Drift: 8.508" | FIT | 3320 | 3320 | 3620 | 3620 |
| 8 1/2" 250 | 3871 3871 | OH | Interval: 3620 m - 3871 m | | | | | |

RKB

Figure 5: Well schematics from Client [6] for well 6407/1-9

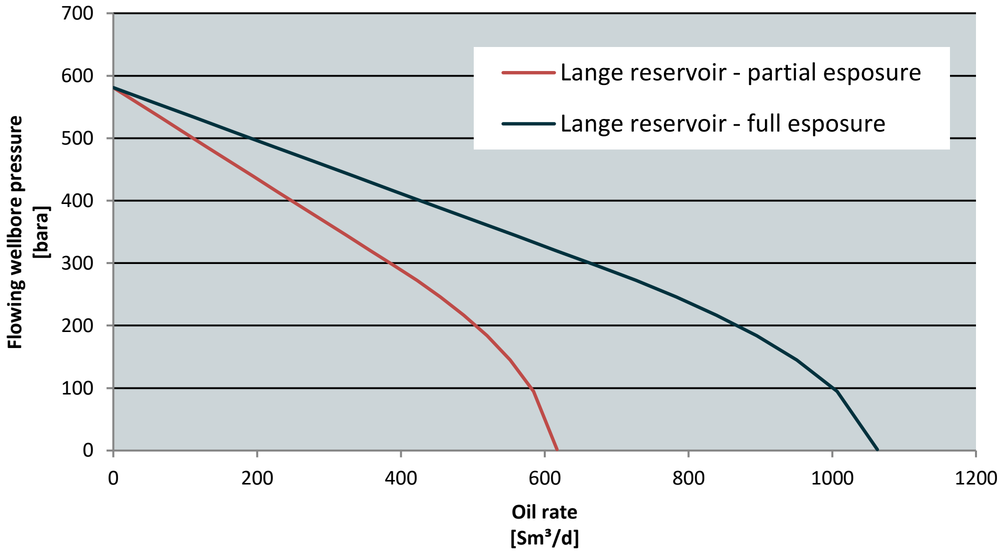



Figure 6: Oil inflow performance – Lange reservoir

## 3.7 Water

Conservatively, no formation water is assumed to enter the well in a blowout situation.

# 4 BLOWOUT POTENTIALS AND DURATION

Blowout potentials are defined as the maximum expected blowout rates for various scenarios. Most likely **expected** parameters are to be used, or a weighted distribution of the same parameters. Whenever necessary, parameters and calculation results should be risked in order to establish the most reliable probability distributions for **expected** rates.

The "NOROG Guidance on calculating blowout rates and duration" [4] are used as basis for all flow rate calculations presented in this report. Distributions of possible flowpaths are given in accordance with data from the SINTEF Offshore Blowout Database [1][2] and the latest evaluation of the SINTEF Database data in the report from LR Consulting [3].

## 4.1 Blowouts in general

A blowout is defined as an unwanted and uncontrolled flow from a subsurface formation which is released at surface, seabed or into a secondary formation, and cannot be closed by the predefined and installed barriers.

For offshore operations, blowouts can be classified in three groups:

- Surface blowouts
- Subsea blowouts
- Underground blowouts

Surface blowouts are characterized by flow of fluid from a permeable formation to the rig floor, where atmospheric conditions exist. For subsea blowouts, the flow typically exits the well at the mudline, where the exit conditions are controlled by the seawater. Surface blowouts have been given the most attention, as they are usually associated with large-scale fires. For subsea blowouts, the plume of the reservoir fluid may cause exposure of HC gas at surface. In deeper water, the plume of oil can be dispersed before reaching the surface or could be carried with the ocean currents to a location away from the rig.

The North Sea Standard requires that two independent barriers shall be present during all drilling and well operations. The drilling fluid that balances the pressure in the well will typically represent the primary barrier, while the casing and the blowout preventer (BOP) typically represents the secondary barrier. In order to make a blowout possible, i.e. to experience total loss of well control, both the primary barrier and the secondary barrier have failed.

Blowout potentials, i.e. the expected rates of oil, water and gas, are highly dependent on the scenario in which the blowout occurs. Lost pipe, junk or complex escape paths for the fluid will result in considerably lower blowout rates than a fully open 9 ⅝" casing all the way from formation to surface.

## 4.2 Blowout potentials

In the following, the methodology for calculation of blowout potentials is presented and implemented on the defined hypothetical wells.

Multiple blowout scenarios are simulated as accurately as possible, and the resulting blowout rates are then used as input to statistical models that provide a complete overview of the sample space for the blowout rates together with the expected value, i.e. the probability-weighted average of the simulated blowout rates.

The probability distribution among all investigated scenarios and associated expected blowout durations are based on the "NOROG Guidance on calculating blowout rates and duration" [4]. Conservative simplifications can be made, as illustrated in Figure 7, where curve A represents a rigorous study with extensive parametric analyses, whereas curve B and C represent conservative simplifications. All scenarios A, B and C are acceptable; alternative A is most work intensive, and alternative C is least work intensive, but most conservative. This study is based on a simplified A (i.e. alternative A without extensive parameter variations). This is in accordance with the requirements in NORSOK D-010.

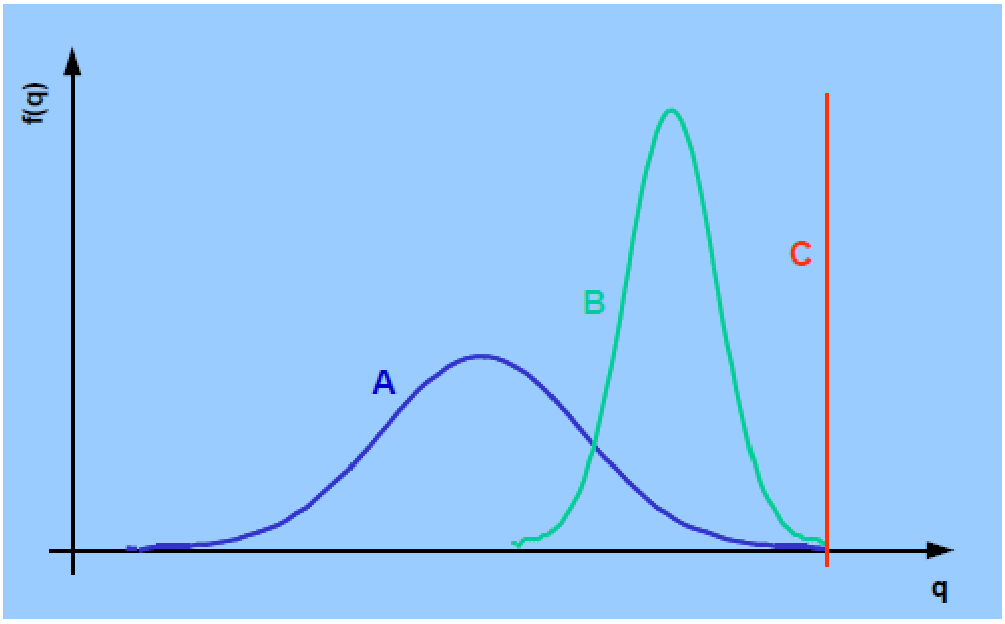



Figure 7: Expectation curves for volume/frequencies and possible simplification strategies

## 4.3 Blowout scenarios

Hypothetical blowout scenarios have been investigated in this study, all relevant for drilling operations. The analyzed scenarios include blowouts through open hole, drill pipe and annulus to drill floor and to seabed. Figure 8 illustrates the possible blowout paths to drill floor. In addition, simulation cases for blowouts through a restriction have also been included representing a partly closed BOP or accidental rupture of piping, valves or hoses connected with the BOP.

The statistical values are found based on the SINTEF Offshore Blowout Database [1][2] and the annual report from LR Consulting [3], which are based upon a more comprehensive analysis of the SINTEF database. Hence, irrelevant cases are removed, and probability distributions are adjusted according to observed trends.

Furthermore, Ranolds operational collaboration with the Acona group of companies, with more than 25 years of relevant experience is implemented in the calculation of the probability distribution. These evaluations and their weighting are discussed in detail below.

In order to limit the number of scenarios to analyse, two main categories of incidents are simulated and are intended to cover all possible scenarios conservatively. These are "*Partly*

*Penetrated*" and "*Fully Penetrated*" reservoir sections, which together are assumed to cover all kick and swab scenarios.

For "*Partly penetrated*" scenarios, a penetration pay of 5 meters is used. In reality, the choice of penetration length into the reservoir, i.e. 5 m, is not of importance when evaluating the probability distribution. In fact, it is the mechanisms leading to the blowout that are important. For the partly penetrated case, the occurrence of a blowout is due to a kick scenario in the well. For the fully penetrated case, a swab scenario leads to the possible blowout. Loss of the primary barrier by swabbing of reservoir fluids when pulling out of hole can be caused by pulling too fast, insufficient compensation of the pumping rates or by a combination of these. Borehole collapse or partial collapse of some strings or formations might increase the risks of swabbing reservoir fluids. Theoretically such swabbing may not be discovered before the BHA is at surface.

Detailed descriptions of each blowout scenario and their associated reservoir exposure were specified in Section 2. Figure 8 illustrates the different flowpaths simulated.

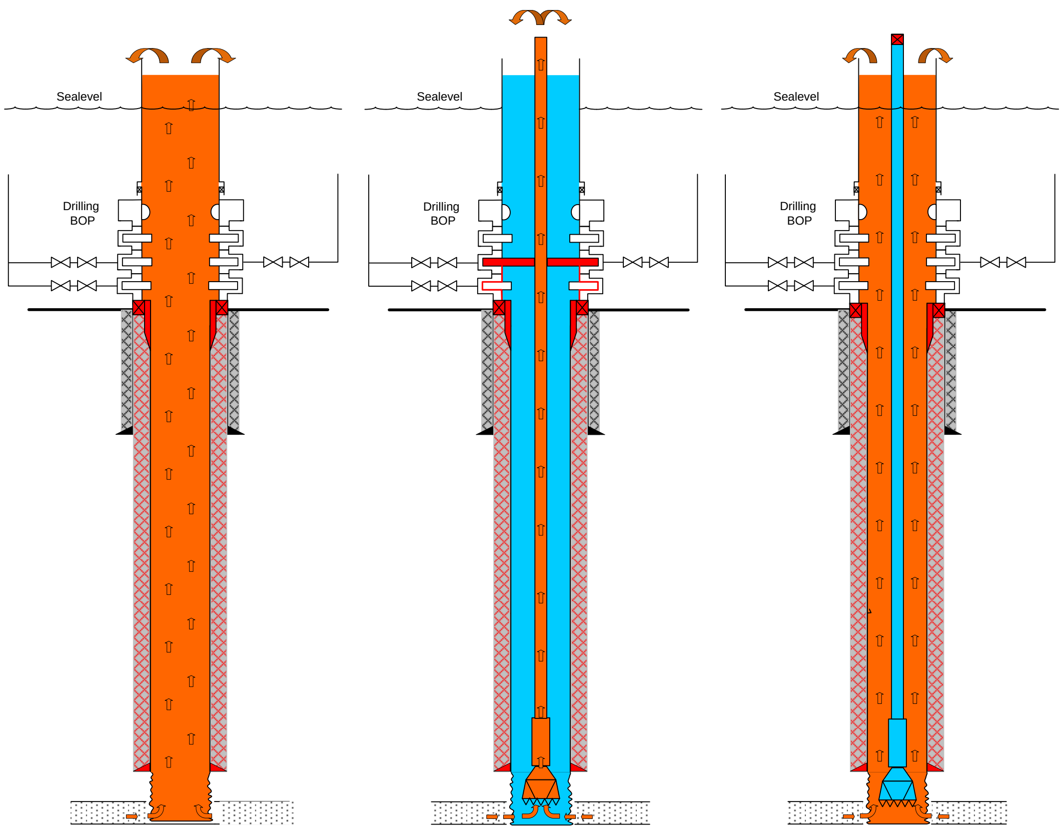



Figure 8: Possible blowout paths for the defined scenarios (illustrative only)
From left to right: Open hole, drill pipe and annulus

The following "Partly penetrated" scenarios have been investigated:

- Blowout through casing/open hole, reservoir partly penetrated
- Blowout through drillpipe, reservoir partly penetrated
- Blowout through annulus, reservoir partly penetrated
- Restricted blowout through a leak, 64/64" choke for each of the above

The following "Fully penetrated" scenarios have been investigated:

- Blowout through casing/open hole, reservoir fully penetrated
- Blowout through drillpipe, reservoir fully penetrated
- Blowout through annulus, reservoir fully penetrated
- Restricted blowout through a leak, 64/64" choke for each of the above

For all the above-mentioned scenarios, the blowout potentials have been modelled, and the results organized.

## 4.4 Statistical modelling of the blowout scenarios

The statistical modelling of flow path distributions is based on the analysis performed by *LR Consulting* [3] of the *SINTEF Offshore Blowout Database* [1][2]. All blowouts in the US Gulf of Mexico and the North Sea since 1980, where equipment has been in accordance with the North Sea standard, form the statistical basis. For completion and workover where the number of blowouts is low, blowouts characterized as "Standard of equipment not relevant" are included with a weight of 0.2 indicating that 20% of the incidents would have happened even if North Sea standard equipment were used. The number of incidents for completion and workover may therefore differ from integers.

Table 3 summarizes relevant statistical findings from drilling, completion and workover activities described in the *LR Consulting* report from March 2020 [3].

Table 3: Probability distribution of flow paths from more than 30 years of historical data

| **Data update: March 2020** | | **Distribution - Floaters** | | | |
|---|---|---|---|---|---|
| | | **Subsea** | | **Topside** | |
| | | Full | Restricted | Full | Restricted |
| **Drilling** (24 incidents) | Outside casing | 20.83% | 4.17% | | |
| | Outer annulus | 25.00% | | | |
| | Annulus | | 29.17% | 8.33% | 4.17% |
| | Open hole | | | | 4.17% |
| | Inside drillstring | | | | |
| | Inside test tubing | | | | 4.17% |
| **Completion** (6.2 incidents) | Annulus | | | 16.13% | 3.23% |
| | Inside drillstring | | | 25.81% | 16.13% |
| | Inside prod tubing | 14.29& | | 6.45% | 16.13% |
| **Workover** (11.6 incidents) | Outside casing | 25.86% | 8.62% | | |
| | Outer annulus | | 8.62% | | |
| | Annulus | | 17.24% | | |
| | Inside drillstring | | | 8.62% | |
| | Inside prod tubing | 8.62% | 8.62% | 10.34% | 3.45% |

When implementing these data for calculation of flow path distribution, the following assumptions and methodology have been used:

Well operations categorized as “dead well”, defined as operations where the fluid column itself is the primary barrier, include the activities:

- Drilling operations
- Work-over operations
- Completion operations

Loss of well control in these operations is initiated by, and limited to:

- Formation kicks or losses caused by unexpected formation properties
- Lack of operational fluid control or swabbing of reservoir fluids from “pulling out of hole” activities
- Lack of heave compensation.

Since all these incidents (kick or loss from/to reservoir, lack of fluid control and swabbing) are also possible from completion and workover operations and the secondary barrier in these operations also includes the drilling BOP, the statistical data from these two groups are included in the statistical summary together with the data from drilling operations.

- In the final distribution used in this work, the outside casing and outer annulus flow paths are combined with the annulus flow path.
- The test tubing flow path is combined with the drill-string flow path due to comparable inner diameter and therefore comparable expected blowout rates.
- The flow through production tubing is interpreted as flow through open hole/casing.

Ranold reviews the statistical values on an annular basis. For data that cannot be derived from statistical sources, operational experience is used. The applied data are thoroughly evaluated, and quality assured by the Ranold review team which consists of Ranold chief engineers within drilling and well control.

### 4.4.1 Statistical distribution

The following probabilities are used between partly and fully penetrated reservoirs when drilling wildcat, exploration and appraisal wells:

| | |
|---|---|
| Blowout initiated when the formation is partly penetrated | 60% |
| Blowout initiated when the formation is fully penetrated | 40% |

For later development wells, more focus and time are used in the reservoir section in order to achieve optimum productivity, or injectivity, for each well. Based on this fact, the values are altered for development wells:

| | |
|---|---|
| Blowout initiated when the formation is partly penetrated | 40% |
| Blowout initiated when the formation is fully penetrated | 60% |

For the partly penetrated scenarios, 5 m penetration is used, with an N/G ratio of 1.0, which is considered conservative.

By implementation of the categorization made above, the flow path probabilities in the top penetration scenario, i.e. a partly penetrated scenario, are given the following values:

| | |
|---|---|
| Blowout through drill pipe has a probability of | 13% |
| Blowout through annulus has a probability of | 87% |
| Blowout through open hole has a probability of | 0% |

**Note**: It is worth to notice that the risk of flowing through open hole (OH), when penetrating top reservoir only, is assumed irrelevant and the probability of this is given a 0.0% value. This is founded upon the fact that the top reservoir cannot be penetrated without having the DP and the bit in the hole.

Similarly, the fully penetrated swab scenario is given the following probability distribution:

| | |
|---|---|
| Blowout through drill pipe has a probability of | 11% |
| Blowout through annulus has a probability of | 72% |
| Blowout through open hole has a probability of | 17% |

In all drilling operations, and most other well operations as well, a Blowout Preventer (BOP) stack of valves and rams defines the secondary barrier against uncontrolled outflow of reservoir fluids. The BOP testing program and its procedures ensure that a BOP stack is experienced as “extremely reliable equipment”. This is further emphasized by the number of independent rams in the BOP and the requirement for accumulator capacity. Based on this, the risk of a total failure of the BOP is assumed to be very low.

Once a blowout has occurred, the BOP has failed or has not been activated. Given such unlikely failures, and based on the “NOROG Guidance on calculating blowout rates and duration” [4], the following distribution has been used for partial or full BOP failure:

| | |
|---|---|
| Restricted flow area has a probability of | 70% |
| No restriction has a probability of | 30% |

The different consequences of a partial failure in the BOP are difficult to predict. In the “NOROG Guidance on calculating blowout rates and duration” [4] it is proposed to model a partial failure as 95% reduction of the available fluid flow area. As restriction in available flow paths also can be caused by pipe in the hole, fish/junk or collapse of the borehole itself, Ranold suggest that modelling of a partial failure is better described with a restriction equivalent to 64/64” flow area for all scenarios. This is justified by the fact that the remaining flow area is now independent of the wellbore design or the size of the drillpipe used.

The release point distribution depends on the location of wellhead and BOP/X-mas tree and therefore on rig type. For a floater, the following statistical distribution is found from the *SINTEF Offshore Blowout database* summarised in Table 3:

- Surface release point 31%
- Subsea release point 69%

When drilling from a floater, anchored or dynamically positioned, the OIM will try to pull the rig off from location shortly after an uncontrollable well integrity issue is unveiled and any surface attempt to stop the flow has not succeeded or has been evaluated as unlikely to succeed.

If the rig is pulled off, the topside blowout release is assumed to change to a subsea blowout release. DNV [5] reports that 75% of the attempts to pull a floater off from location under a blowout have been successful. Accordingly, the following distribution is proposed:

- Surface release point when drilling from a floater: 10%
- Seabed release point when drilling from a floater: 90%

### 4.4.2 Method for risking of blowout potentials

From the detailed analysis presented in the previous section the probabilities for all relevant scenarios were found. According to the “NOROG Guidance on calculating blowout rates and duration" all possible scenarios should be risked, and blowout potentials should be weighted accordingly. The risk methodology breaks down each of the scenarios as illustrated in Figure 9 next.

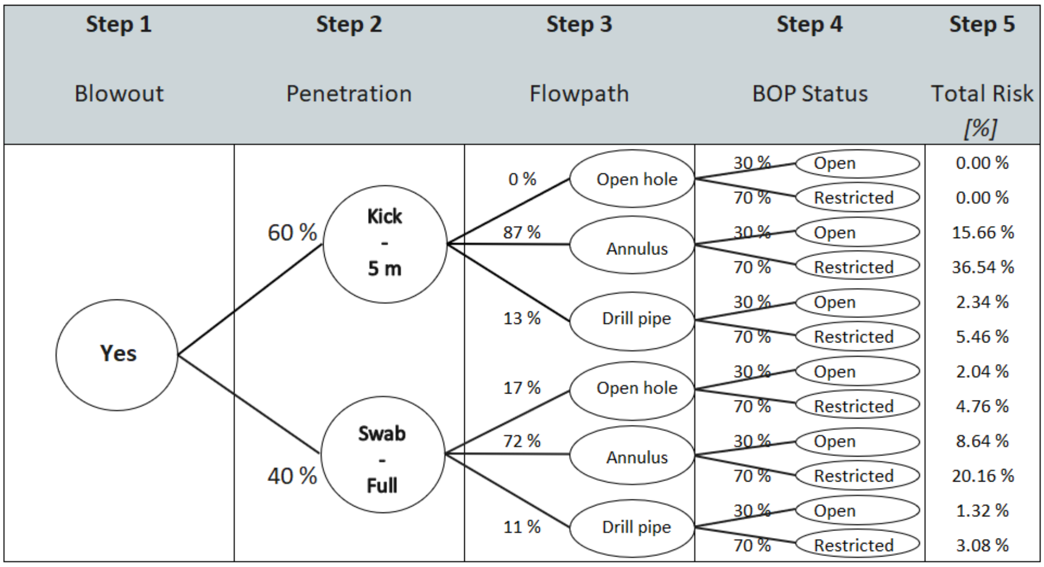



Figure 9: Typical methodology for risking of blowout rates for exploration wells

## 4.5 Method for estimation of most likely blowout duration

### 4.5.1 Remedial actions

A blowout may be stopped by several remedial actions. These can be divided into the following categories:

- Bridging, i.e. collapse of the near-wellbore formation
- Crew intervention
- Subsea installation of a new barrier system (capping)
- Drilling of relief wells with direct intersect of the blowing well
- Other causes

In the following, a more detailed discussion is presented for each of the above categories. In order to be able to model the statistical success for each of the above given actions, these are modelled as if they were the only remedial action imposed to stop the blowout.

#### Bridging

The majority of blowing wells are killed by themselves because of bridging. According to the LR Consulting report approximately 63% of the historical blowouts were stopped by bridging, if this mechanism was the only remedial action imposed. Bridging mechanisms might be:

- Sand or rock accumulates inside the wellbore
- Formation collapses due to high flowing rates and high drawdown pressure
- Formation of hydrates blocking the flow paths

### Crew intervention

Crew intervention is defined as activities possible to perform from the existing installation with equipment, or tools, already available or which can be mobilized on short notice. Typical actions could be repair or replacement of hydraulic components, replacement of control system equipment or similar minor repairs. Prerequisites common to all activities in this group are that there is appropriate working equipment onboard the installation and that people and equipment can be operated safely.

### Subsea capping

Several initiatives have been taken world-wide after the Macondo Blowout in April 2010 for pre-fabrication of capping devices that can be transported by commercial air freight, and that will be possible to assemble on local bases or onboard an offshore rig or supply vessel.

The working principle of most of these devices is that the subsea disconnect feature of the existing subsea BOP is activated and the marine riser is released. The new capping device, often based upon a standard lightweight BOP, is lowered onto the blowing well in open mode. After successful landing, the connection is made up and function tested before the rams are closed and the blowout is stopped.

Typically, these new capping devices shall be possible to mobilize, assemble and send offshore in 10 days. Conservatively 5 – 15 more days installation time should be planned for depending on weather, sea depth, and complexity related to preparation of the existing subsea BOP.

A time estimate for a capping operation is made as follows:

- Collecting and preparing equipment: 10 days
- Start cap and contain operation: 15 days
- Total time for the operation: 25 days

In this work, a capping operation is assumed to have a success rate of 40% in killing the well.

### Drilling of relief wells

In most offshore blowouts, drilling of one or several relief wells will be kicked off immediately after a blowout is confirmed. If one or more relief wells are necessary to regain control of the well, the time needed for mobilization of a drilling rig and the drilling itself may vary. It is assumed that the relief wells can be drilled with the same rate as the exploration well, but in addition, ranging runs are required, e.g. with electromagnetic ranging tools. The time required to run such equipment must be taken into account. The time will depend on drilling intersection depth, rig availability in general and in the specified area and weather conditions.

Time for drilling a relief well down to intersection at the last casing shoe of the blowing well is estimated as follows:

- Decision to drill the relief well: 3 days
- Termination of work, sail to location, anchoring and preparation: 12 days
- Drilling relief well to intersection: 30 days
- Homing in: 10 days
- Total time to kill well: 55 days

Consequently, the assumption is made that the relief well will successfully kill the blowing well after 55 days of blowout.

### Other causes

Other possible mechanisms stopping a blowing well could be:

- Pressure depletion of the blowing reservoir
- Water breakthrough
- Stopping of gas lift, gas- or water injection
- Coning of water or gas into the blowing well

## 4.5.2 Blowout duration distribution

In order to give the best possible distribution estimate, the probability distribution for the different historical incidents must be found. Figure 10 is based on data from March 2020 [3] reported by LR Consulting, and on engineering values for capping and relief well actions. The figure presents the probability that a blowout is still active after a certain number of days based on the use of one single kill mechanism only.

From the statistical data available in the SINTEF Offshore Blowout database and from the latest revision of the LR Consulting report, reliability relations can be derived for each of the remedial actions, as if each of them was the only action imposed. The results from such reliability approach are presented in Figure 10.

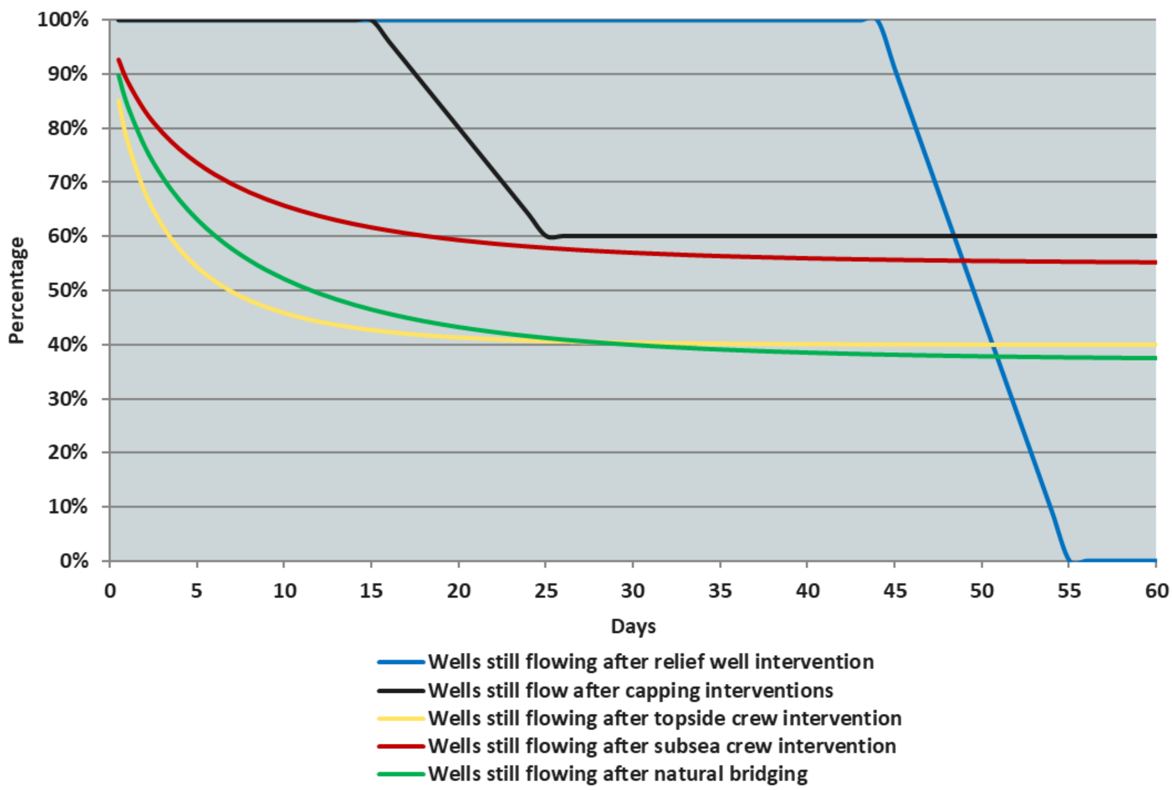



Figure 10: Reliability plots for each of the possible remedial actions

Multiple mechanisms may “work together” in order to stop the blowout. LR Consulting reports [3] that 63% of all blowouts will eventually be stopped by natural bridging (ref the green graph), 60% will eventually be stopped by topside crew intervention (ref the yellow graph) and 45% will eventually be stopped by subsea crew intervention (ref the magenta graph), if each mechanism evaluated is the only mechanism to stop the leak. Furthermore, the installation of a new subsea barrier by cap and contain is assumed to give a uniform distribution with a probability of 40% that the blowout is eventually killed (ref the black graph). The operation starts after 15 days and ends after 25 days.

Drilling a relief well is assumed to give a uniform distribution with a probability of 100% that the blowout is eventually killed. The drilling starts at the latest 12 days after the decision to start drilling has been taken (15 days including decision time) and earliest possible kill attempt can be performed after a successful intersection of the blowing well. In this work, a uniform distribution between 44 days and 55 days is proposed (ref the blue graph).

The probability that either of the kill mechanisms is successful may be derived by assuming that the individual kill mechanisms are not mutually exclusive, but rather independent events.

The results from Figure 10 above can be combined by statistical methods and a combined reliability curve can be presented as if all remedial actions are imposed together in order to stop a possible future blowout.

The combined reliability curve for a seabed release point is presented in Figure 11 next.

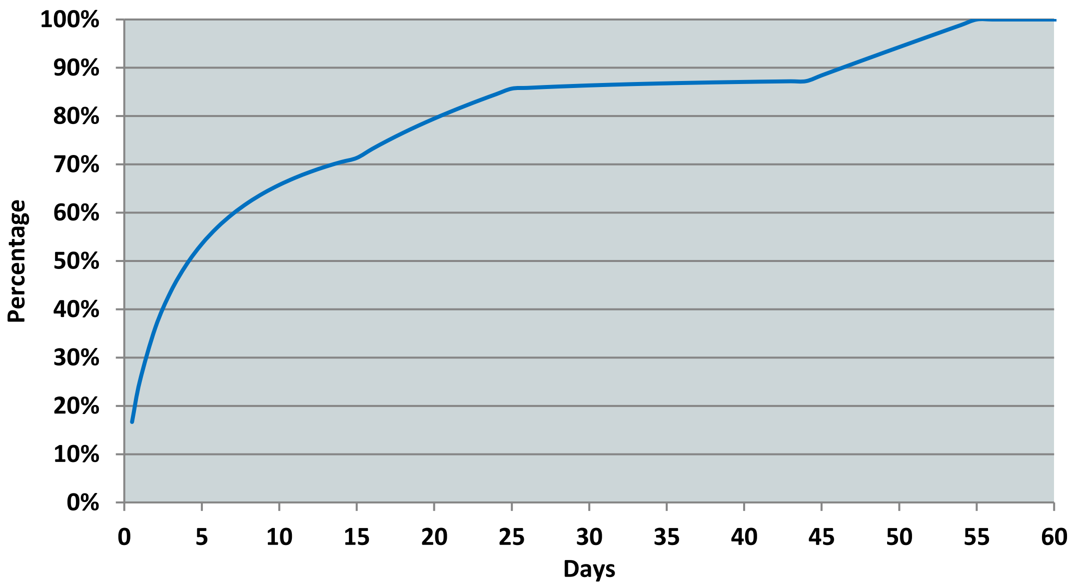



Figure 11: Reliability presentation of all kill actions when combined for a seabed release

Similarly, the same methodology can be used for estimation of blowout duration with a topside release point. The results of this combination are presented in Figure 12.

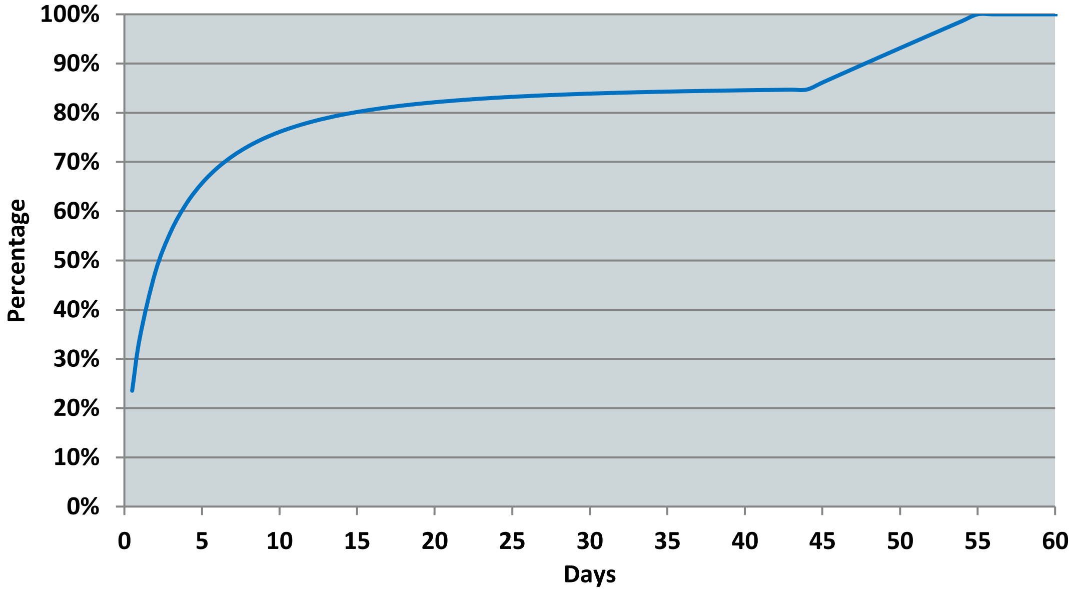



Figure 12: Reliability presentation of all kill actions when combined for a surface release

In order to provide a unique methodology for duration prognosis a simplified discretization is proposed in Table 4. The model represents five different logical stages in a kill operation.

Table 4: Discretization model for duration estimates

| | | |
|---|---|---|
| Risk of a blowout duration of 2 days | $P_2$ | The blowout could be controlled by measures performed from the existing rig |
| Risk of a blowout duration of 5 days | $P_5$ | The blowout could be controlled by use of locally supplied/stored equipment |
| Risk of a blowout duration of 15 days | $P_{15}$ | The blowout could be controlled by bringing in additional equipment |
| Risk of blowout duration of 25 days | $P_{25}$ | The blowout could be controlled by installation of new barrier system |
| Risk of a blowout duration of 55 days | $P_{55}$ | The blowout will have to be killed by drilling a dedicated relief well. |

This discretization methodology makes estimation of possible blowout duration easy to communicate, and the method can be adapted to drilling time estimates shorter or longer than the 55 days used in this work.

When the statistical probabilities are to be found, the incremental value from previous values is to be derived, i.e. the value to be used at day 15 should be found as $P_{15}$- $P_5$.

## 4.6 Blowout duration estimate for Egyptian Vulture

### 4.6.1 Blowout duration with surface release

Based on the discretization proposed above, reliability values can be extracted from Figure 12 above, which leads to the following duration estimate. The figure shows that 47% of the blowouts to surface would be killed in less than 2 days, 65% in less than 5 days, 80% in less than 15 days, 83% in less than 25 days and 100% in less than 55 days.

- Risk of a blowout duration less than 2 days: 47%
- Risk of a blowout duration between 2 days and 5 days (65% - 47%): 18%
- Risk of a blowout duration between 5 days and 15 days (80% - 65%): 15%
- Risk of a blowout duration between 15 days and 25 days (83% - 80%): 3%
- Risk of a blowout duration between 25 days and 55 days (100% - 83%): 17%

Assumptions are made that the relief well will successfully kill the well after 55 days, which means that $P_{55}$ = 0%. A weighted duration can now be calculated in a simplified way and is found to be as follows for a blowout with surface release point:

$$2 * 0.47 + 5 * 0.18 + 15 * 0.15 + 25 * 0.03 + 55 * 0.17 = \mathbf{14.2}\ \boldsymbol{days}$$

### 4.6.2 Blowout duration with seabed release

Based on the discretization proposed above, reliability values can be extracted from Figure 11 above, which leads to the following duration estimate. The figure shows that 36% of the blowouts to seabed would be killed in less than 2 days, 53% in less than 5 days, 71% in less than 15 days, 85% in less than 25 days and 100% in less than 55 days.

- Risk of a blowout duration less than 2 days: 36%
- Risk of a blowout duration between 2 days and 5 days (53% - 36%): 17%
- Risk of a blowout duration between 5 days and 15 days (71% - 53%): 18%
- Risk of a blowout duration between 15 days and 25 days (85% - 71%): 14%
- Risk of a blowout duration between 25 days and 55 days (100% - 85%): 15%

Assumptions are made that the relief well will successfully kill the well after 55 days, which means that $P_{55}$ = 0%. A weighted duration can now be calculated in a simplified way and can be as follows for a blowout with seabed release point:

$$2 * 0.36 + 5 * 0.17 + 15 * 0.18 + 25 * 0.14 + 55 * 0.15 = \mathbf{16.0}\ \boldsymbol{days}$$

### 4.6.3 Overall blowout duration estimate

In section 4.4.1, it was found that for a blowout developing when drilling from a floater, only 10% of the incidents will remain as surface blowout, the rest of the incidents will develop into a blowout with a seabed release point. This gives the following estimate for overall blowout duration:

$$14.2 * 0.1 + 16.0 * 0.9 = 15.8\ \boldsymbol{days}$$

# 5 BLOWOUT RATES

This section lists the findings from the analysis performed with respect to calculating blowout rates of oil to sea. Section 6 takes into account probabilities for different flowpaths, while this section provides a simpler listing of the different scenarios to show the resulting oil, gas and water rates together with flowing bottom hole pressure (FBHP) making basis for the dynamic wellkill simulations. The flowing wellbore pressure (FBHP) is taken at top of the Lange reservoir.

The blowout rates are presented for release of HC to surface and seabed for unrestricted openhole (OH), annulus (ANN) and drillpipe (DP) flowpaths, and for full and partial reservoir exposure. Rates calculated for partial reservoir exposure accounts for 5 m gross exposure of the reservoir, with assumed N/G ratio of 1, resulting in a conservative assumption of 5 m net pay exposure. Full exposure accounts for full exposure of the entire Lange reservoir.

## 5.1 Detailed blowout rates – Case 1

Detailed blowout rates for unrestricted openhole (OH), annulus (ANN) and drillpipe (DP) flowpaths are presented in Table 5 for a surface release point and Table 6 for a seabed release point.

Table 5: Blowout rates – Case 1 – Surface release point

| Release point | Reservoir exposure | Flowpath | Oil rate [Sm$^3$/d] | Gas rate [MSm$^3$/d] | FBHP [bara] |
|---|---|---|---|---|---|
| Surface | Partial exposure (5 m MD) of Lange reservoir | OH | 611 | 0.11 | 22.0 |
| | | ANN | 606 | 0.11 | 35.7 |
| | | DP | 595 | 0.11 | 65.7 |
| | Full exposure of Lange reservoir | OH | 1050 | 0.19 | 24.2 |
| | | ANN | 1037 | 0.18 | 44.4 |
| | | DP | 1008 | 0.18 | 92.1 |

Table 6: Blowout rates – Case 1 – Seabed release point

| Release point | Reservoir exposure | Flowpath | Oil rate [Sm$^3$/d] | Gas rate [MSm$^3$/d] | FBHP [bara] |
|---|---|---|---|---|---|
| Seabed | Partial exposure (5 m MD) of Lange reservoir | OH | 546 | 0.10 | 152.3 |
| | | ANN | 568 | 0.10 | 120.7 |
| | | DP | 565 | 0.10 | 125.8 |
| | Full exposure of Lange reservoir | OH | 979 | 0.17 | 119.8 |
| | | ANN | 980 | 0.17 | 118.5 |
| | | DP | 960 | 0.17 | 136.9 |

The worst-case blowout scenario is an unrestricted openhole to surface with all formations fully exposed. In such an unlikely event, the maximum blowout potential is found to be 1050 Sm$^3$/day of oil/condensate and 0.19 MSm$^3$/day of gas.

# 6 BLOWOUT DISTRIBUTIONS

This section takes into account the statistical data discussed in Section 4.4. From the detailed analysis presented the probabilities for all relevant scenarios were found. According to the *"NOROG Guidance on calculating blowout rates and duration"* [4] all possible scenarios should be risked and blowout potentials should be weighted correspondingly.

The risk process illustrates the most likely expected blowout rates for an uncontrolled blowout while drilling the 6407/1-9 Egyptian Vulture well. These values are risk weighted; therefore, both higher and lower rates may be experienced in a real blowout. The risked values are qualified numbers for likely volumes expected and are to be used when evaluating the possible environmental impact from the well, only. The risked blowout rates shall not be used for evaluating possible kill methods or requirements.

**Note:** The overall probability of finding hydrocarbons in a well, which again introduces a certain risk for a blowout is neglected in this report but could preferably be included in the environmental analysis.

## 6.1 Risked Blowout rates

The risked blowout rate distributions are listed in Table 7 for surface release and Table 8 for seabed release, for a blowout represented by Case 1 properties.

Table 7: Risked blowout rates – Case 1 – Surface release point

| **Scenario** | | **Flowpath** | | **BOP Status** | | **Total Risk** | **Oil blowout potential** | **Risked Oil blowout rate** | **Risked Gas blowout rate** |
|---|---|---|---|---|---|---|---|---|---|
| Prob.% | Exposure | Prob.% | Status | Prob.% | Status | [%] | [Sm$^3$/day] | [Sm$^3$/day] | [MSm$^3$/day] |
| 60 | Partial reservoir exposure | 0 | Open hole | 30 | Open | 0.00 | 611 | 0 | 0.00 |
| | | | | 70 | Restricted | 0.00 | 472 | 0 | 0.00 |
| | | 87 | Annulus | 30 | Open | 15.66 | 606 | 95 | 0.02 |
| | | | | 70 | Restricted | 36.54 | 529 | 193 | 0.03 |
| | | 13 | Drillpipe | 30 | Open | 2.34 | 595 | 14 | 0.00 |
| | | | | 70 | Restricted | 5.46 | 548 | 30 | 0.01 |
| 40 | Full reservoir exposure | 17 | Open hole | 30 | Open | 2.04 | 1050 | 21 | 0.00 |
| | | | | 70 | Restricted | 4.76 | 785 | 37 | 0.01 |
| | | 72 | Annulus | 30 | Open | 8.64 | 1037 | 90 | 0.02 |
| | | | | 70 | Restricted | 20.16 | 837 | 169 | 0.03 |
| | | 11 | Drillpipe | 30 | Open | 1.32 | 1008 | 13 | 0.00 |
| | | | | 70 | Restricted | 3.08 | 852 | 26 | 0.00 |
| | | | | | Total sum: | 100 | | 689 | 0.12 |

Table 8: Risked blowout rates – Case 1 – Seabed release point

| **Scenario** | | **Flowpath** | | **BOP Status** | | **Total Risk** | **Oil blowout potential** | **Risked Oil blowout rate** | **Risked Gas blowout rate** |
|---|---|---|---|---|---|---|---|---|---|
| Prob.% | Exposure | Prob.% | Status | Prob.% | Status | [%] | [Sm$^3$/day] | [Sm$^3$/day] | [MSm$^3$/day] |
| 60 | Partial reservoir exposure | 0 | Open hole | 30 | Open | 0.00 | 546 | 0 | 0.00 |
| | | | | 70 | Restricted | 0.00 | 498 | 0 | 0.00 |
| | | 87 | Annulus | 30 | Open | 15.66 | 568 | 89 | 0.02 |
| | | | | 70 | Restricted | 36.54 | 548 | 200 | 0.04 |
| | | 13 | Drillpipe | 30 | Open | 2.34 | 565 | 13 | 0.00 |
| | | | | 70 | Restricted | 5.46 | 548 | 30 | 0.01 |
| 40 | Full reservoir exposure | 17 | Open hole | 30 | Open | 2.04 | 979 | 20 | 0.00 |
| | | | | 70 | Restricted | 4.76 | 860 | 41 | 0.01 |
| | | 72 | Annulus | 30 | Open | 8.64 | 980 | 85 | 0.02 |
| | | | | 70 | Restricted | 20.16 | 883 | 178 | 0.03 |
| | | 11 | Drillpipe | 30 | Open | 1.32 | 960 | 13 | 0.00 |
| | | | | 70 | Restricted | 3.08 | 876 | 27 | 0.00 |
| | | | | | Total sum: | 100 | | 696 | 0.12 |

The expected oil/condensate blowout rate is 689 Sm$^3$/day for a surface release point and 696 Sm$^3$/day for a seabed release point. The corresponding risked blowout rates of gas are 0.12 MSm$^3$/day for both a surface release point and a seabed release point.

# 7 REFERENCES

1. SINTEF Offshore Blowout Database - 2018 – http://www.sintef.no/en/projects/sintef-offshore-blowout-database/
2. "Blowout and Well Release Characteristics and Frequencies", 2018. SINTEF Report No. 2019:00018, 10th of January 2019.
3. "Blowout and Well Release Frequencies" – Based on SINTEF Offshore Blowout Database 2019, Report, Lloyd's Register Consulting. Report no. 19101001-8/2020/R3, 13.03.2020.
4. "NOROG Guidance on calculating blowout rates and duration for use in environmental risk analyses" – Nilsen, Thomas, January 2017.
5. "Frequencies for accidental oil releases in the Barents Sea". DNV Report No. 2006-0054, 11th of January 2006.
6. Documents from Client:
   a) Input scheme for Blowout Scenario Analysis for NO 6407_1-9 Egyptian Vulture.docx

# Appendix A
# About Ranold AS

## Ranold AS

Since 2006 Ranold AS, formerly known as Acona Flow Technology, has built a unique expert team within flow modelling and simulations services. This group has the capability and the ambition to contribute to increased operational safety, minimization of risks and increased profitability for its clients

### Ranold AS has the mission to:

- Deliver best-in-class services within blowout modelling and well control
- Provide simulation services based on state-of-the-art tools and models
- Offer in-depth understanding and analytical approach to complex flow phenomena
- Serve various industries worldwide, and transfer know-how across industries
- Attract world-class specialists and enthusiastic talents through outstanding reputation

Ranold provides simulations and advisory services to the oil and gas industry within the following areas:

### Blowout contingency planning

- Risk management and contingency documentation through advanced simulations and operational insight
- Simulation services, advisory services, risk management and peer review services

### Wellkill planning and well control advisory

- Transient kill simulations as mandatory documentation of kill capability and to assist well engineering teams

### Emergency response teams

- Trained and IWCF certified teams available to assist planning, preparation and execution of wellkill operations worldwide

### Flow assurance teams

- Skilled seniors with long industrial training available for detailed flow assurance studies related to well and flowline hydraulics, thermal performance, production chemistry or metallurgy
- Complete design-basis engineering studies can be delivered

### Computational Fluid Dynamics

- Advanced CFD experts are available for in-depth analysis of process related flow phenomena and their interaction with structure
- Wind, gas, explosion, spill, separation, settling, erosion, insulation, combustion and radiation are some of many areas to be covered with CFD

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