Report

BSA - Blowout Rates and Duration

Exploration well 35/11-25 S & A – Apodida

Rev 0 – 16th October 2020

Ranold.

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Executive Summary

This report summarizes the blowout rate simulations and corresponding duration evaluations performed for the 35/11-25 S and 35/11-25 A wellbores in the Apodida prospect in the North Sea.

Both wellbores are to be drilled as deviated wells, exploring for HC in the Oxfordian J56 and Etive formations respectively. For these evaluations both reservoirs are expected/assumed to hold oil.

The following cases are evaluated:

- Case 1 (mainbore) – Drilling an 8 ½" section from the 9 5/8" liner through Oxfordian J56 fm
- Case 2 (sidetrack) – Drilling an 8 ½" section from the 9 5/8" liner through the Etive fm

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 represented by Case 2 (sidetrack) through a fully open and unrestricted flowpath, exposed to a fully penetrated reservoir with release to surface. Such a blowout will result in a maximum blowout rate of 15909 Sm^3/day of oil and 4.03 MSm^3/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. The rates are presented and risked according to the Norwegian Oil & Gas (NOROG) Association guidelines and statistical data from the SINTEF offshore blowout database. For Case 2, the most likely, or risked, oil blowout rate is 2710 Sm^3/day for a surface release point and 2713 Sm^3/day for a seabed release point. The corresponding risked blowout rates of gas are 0.33 MSm^3/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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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
GOC	Gas oil contact
GOR	Gas oil ratio
GWC	Gas water contact
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 for the exploration well 35/11-25 S (mainbore) and 35/11-25 A (sidetrack) in the Apodida prospect in the North Sea.

Ranold AS, an independent and specialized center of competence for flow modelling and simulation services, was contacted and asked to perform analysis on blowout rates and duration for different possible case scenarios during drilling of the well.

This report summarizes the blowout simulations and duration evaluations performed. The main objective of the well is to explore for HC potential in the Oxfordian J56 and Etive Fms.

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:

- Case 1 – Mainbore: Drilling an 8 ½" section from the 9 5/8" liner through the Oxfordian formations, with HC potential in the J56 Fm
  - Calculate blowout rates
  - Produce flow rate distributions
  - Produce duration estimates
- Case 2 – Sidetrack: Drilling an 8 ½" section from the 9 5/8" liner, with HC potential in the Etive Fm
  - Calculate blowout rates
  - Produce flow rate 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 have been simulated in Prosper (Petroleum Experts).

3 DATA & INFORMATION COLLECTION

3.1 Location and water depth

The well will be drilled in block 35/11 as part of the Apodida prospect west of Førde and north of the Troll field. The location of block 35/11 in the North Sea is shown in Figure 1. The water depth at location is 352 m.

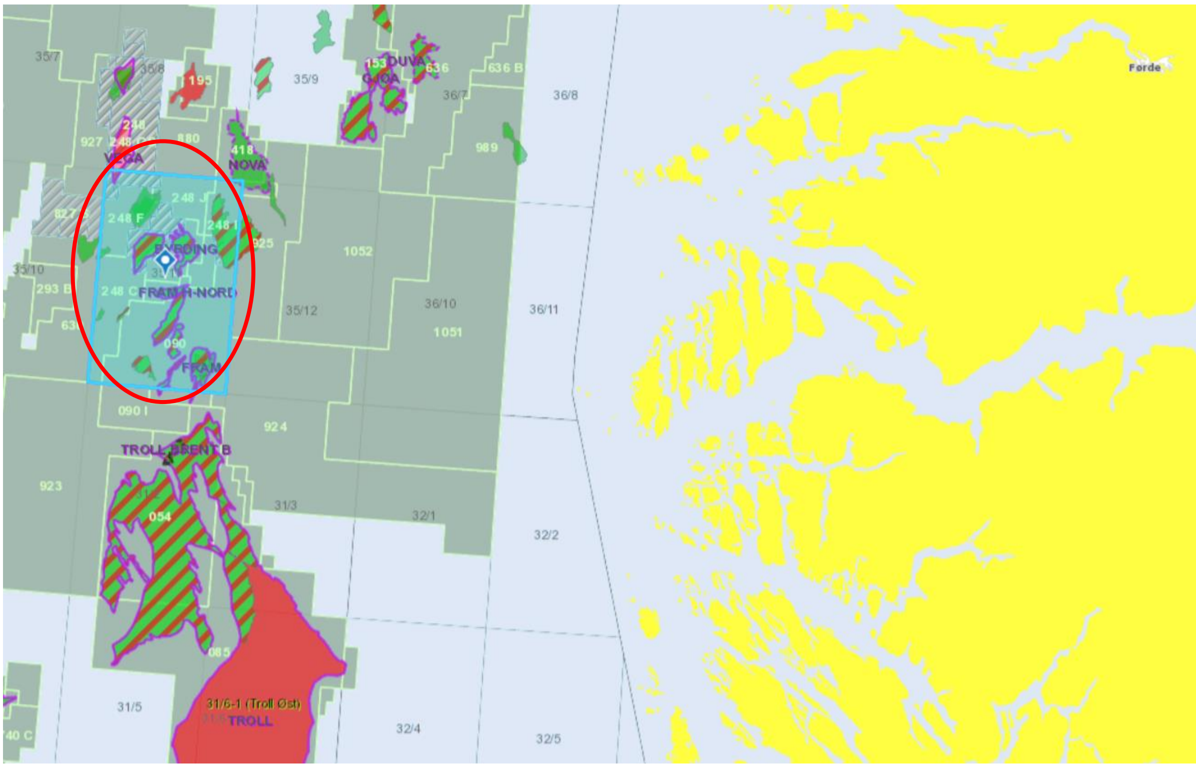


Figure 1: Location of Block 35/11 in the Norwegian Sea (source: www.npd.no)

3.2 Drilling facilities

The well is assumed to be drilled by the semi-submersible drilling rig Deepsea Atlantic, which is a drilling rig of GVA 7500 design, capable of drilling in water depths up to 3000 m. Deepsea Atlantic s is a 6th generation semi-submersible drilling rig. RKB – MSL is 30 m.

3.3 Reservoir properties

The 35/11-25 S is targeting the Oxfordian J56 and J52 within a sweetspot for reservoir presence and quality. The well is expected to hit the OWC within the J56, and the J52 is expected to be water filled.

The 35/11-25 A sidetrack is also expected to penetrate the Oxfordian J56 and J52, but outside the reservoir sweetspot and below the OWC. The main target for the sidetrack is the Etive Fm. The Tarbert and Ness Fms. above is not expected to be of reservoir quality. A thin sand was observed in the Ness Fm. in the offset well 35/11-23 (Echino Sør), but these thin sands are believed to be poorly connected/discontinuous and not contributing to flow. Only the Etive Fm. has been included.

For the Etive Fm. there is a 60/40 distribution between a pure oil case and an oil and gas case. For the BSA, only the oil case has been included.

The Oseberg Fm. is expected to be water filled. Migration is one of the key factors/uncertainties, and few discoveries have been made in the Oseberg Fm. in the area. The properties in the Oseberg Fm. in the 35/11-8 S reference well show poor properties (permeability is a magnitude lower than the Etive Fm.)

Table 1 shows the reservoir data based on customer input [6] used as basis for the well presented in this report.

Table 1: Reservoir data for the Apodida well

Reservoir property	Unit	Mainbore 35/11-25 S J56	Sidetrack 35/11-25 A Etive
Top formation	m TVD RKB	2659	3116
Hydrocarbon Water Contact (HCWC)	m TVD MSL	2670	3185
Net/Gross	ratio	0.73	0.87
Net oil bearing formation thickness along wellpath	m MD	26.6m gross 19.4m net	79.7m gross 69.3m net
Net pay (HC bearing interval – calc from data/line above)	m TVD	14.6	48.2
Porosity	v/v	0.225	0.19
Total permeability	mD	400	150
Reservoir pressure	bar	266.3	329
Reservoir temperature	°C	95.1	111.6
Length along well (X)	m	3000	2050
Width across well (Y)	m	1070	1400
Skin	-	0	0
Partial penetration skin	-	12.3	58.5
AOF - Fully exposed (calculated)	Sm^3/d	9400	23815
AOF - Partial exposure (calculated)	Sm^3/d	3920	3085

3.4 Reservoir fluid information

The expected properties of the reservoir fluids are listed in Table 2. These properties are based on Client input [6]. 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

Standard conditions		Oil J56	Oil Etive
Oil density*	kg/Sm^3	855.3	826.7
Gas density*	sg	0.776	0.865
Gas to Oil/Condensate Ratio (GOR, GCR)	Sm^3/Sm^3	122.6	253.4
*std conditions defined as 15˚C / 1.01325 bara			

Reservoir conditions		Oil	Oil
Oil density**	kg/m^3	716	609
Oil viscosity**	cP	0.4887	0.2101
Bubble point	bar (˚C)	220.7 (95.1)	257.4 (111.6)
Oil formation factor, Bo @ bubble point	Sm^3/Rm^3	1.579	1.855
** res conditions: 266.3 bara / 95.1˚C -- 329 bara / 111.6˚C			

3.5 Well design

Apodida will be drilled with two wellbores, 35/11-25 S and 35/11-25 A. Both the mainbore and sidetrack will be drilled as deviated wells with the following planned well design:

35/11-25 S (mainbore)

- 21" Marine riser
- CapX" set @ 392 m MD/TVD RKB
- 20" casing set @ 763 m MD/TVD RKB
- 13 3/8" casing set @ 1593 m MD/TVD RKB
- 9 5/8" liner set @ 2777/2566 m MD/TVD RKB with TOL @ 1563 m MD/TVD RKB
- An 8 ½" section will be drilled through the reservoirs. The drillstring is modelled according to the data and assumptions in Table 3.

35/11-25 A (sidetrack)

- 21" Marine riser
- CapX" set @ 392 m MD/TVD RKB
- 20" casing set @ 763 m MD/TVD RKB
- 13 3/8" casing set @ 1543 m MD/TVD RKB
- 9 5/8" liner set @ 2886/2606 m MD/TVD RKB with TOL @ 1510 m MD/TVD RKB
- An 8 ½" section will be drilled through the reservoirs. The drillstring is modelled according to the data and assumptions in Table 3.

The well schematics are illustrated in Figure 2 and Figure 3

Table 3: Drillstring model data – mainbore and didetrack

Type	#	Length (m)	OD (in)	ID (in)	Assumption
Bit	-	0.26	8.5		Not accounted for in model
BHA	90.32	19	7	3	
DC	46.29	75	6.5	3	
HWDP		30	5	3	
Jar		12	6.75	3	
HWDP		75	5	3	
DP		580	5	3	
DP	28.96	To surface	5.875	5.513	

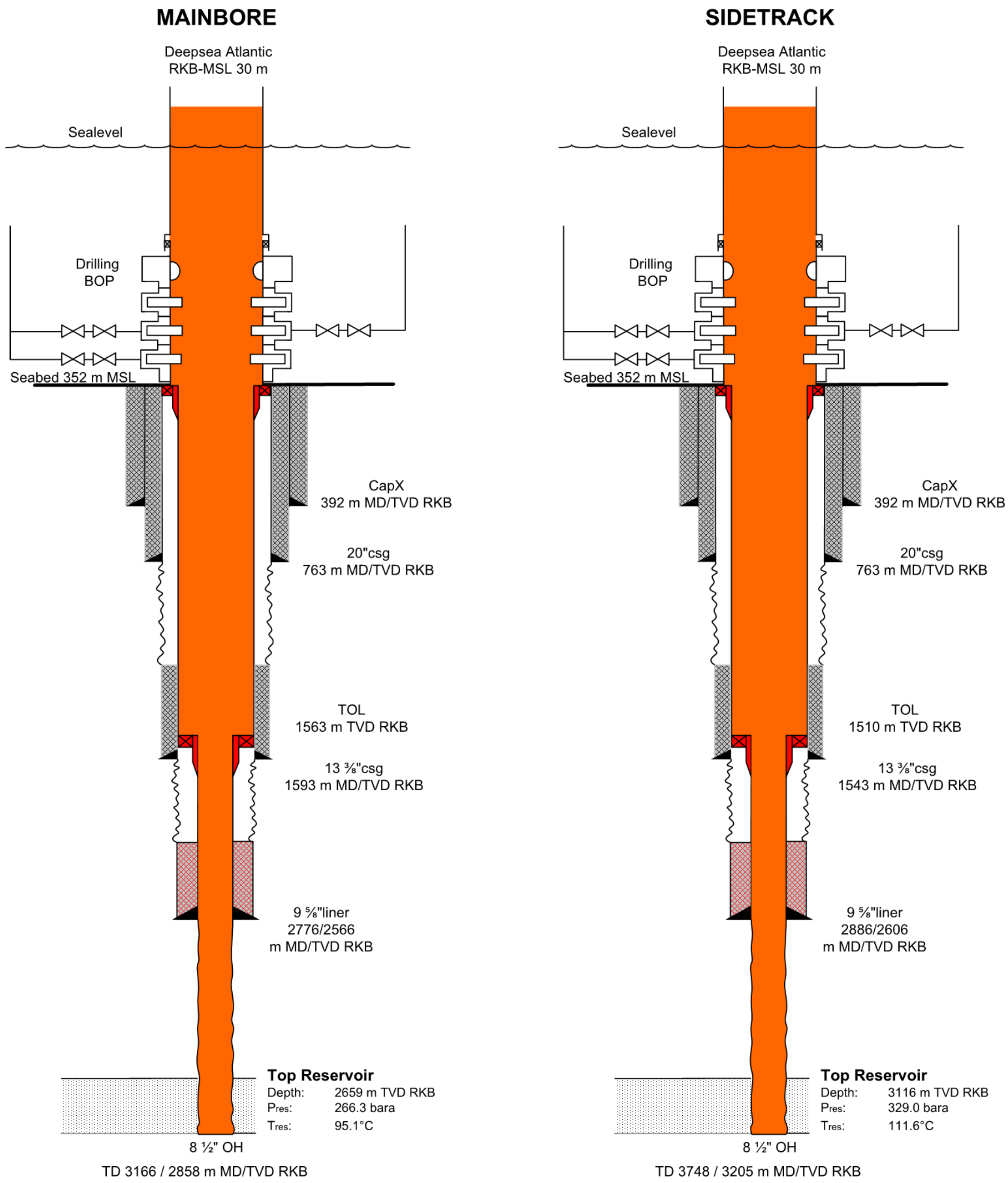


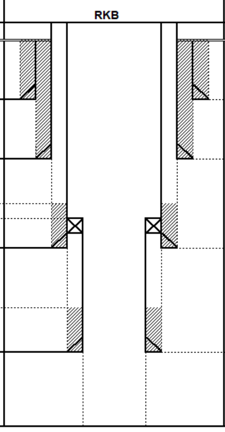
Figure 2: Schematics for the Apodida well

Well: Apodida (35/11-25 S)
Field: Exploration
Rig: Deepsea Atlantic

WELL SCHEMATIC
Mainbore

All depths refer to RKB.
RKB-MSL = 30 m
09.10.2020

HOLE SIZE	HOLE TVD / MD	CASING/LINER SIZE	TYPE / RAD. MARKERS	CENTRALIZERS	LOT / FIT [SG]	TOC/TOL TVD	TOC/TOL MD	CSG. SHOE TVD	CSG. SHOE MD	Max PP [SG]	Min FG [SG]	Fluid [SG]
SB	382											
CapX 10	392 392	Cap-X	Interval: 382 m - 392 m Type: lb/ft, , Drift:		0			392	392			
26" 376	768 768	20"	Interval: 392 m - 763 m Type: 133lb/ft, NT95-DE, NSMAX-GR Drift: 18.542		FIT	Seabed	Seabed	763	763			
17 1/2" 831	1599 1599	13 3/8"	Interval: 768 m - 1593 m Type: 72lb/ft, P-110 ,Vam21CWD Drift: 12.258		FIT	0 1563	0 1563	1593	1593			
12 1/4" 1178	2566 2777	9 5/8"	Interval: 1599 m - 2777 m Type: 53.5lb/ft, P-110, Vam21CWD S Drift: 8.508		FIT	0	0	2566	2776			
8 1/2" 389	2858 3166	OH	Interval: 2777 m - 3166 m					2858	3166			



Well: Apodida sidetrack - 35/11-25 A
Field: Exploration
Rig: Deepsea Atlantic

WELL SCHEMATIC
Sidetrack

All depths refer to RKB.
RKB-MSL = 30 m
09.10.2020

HOLE SIZE	HOLE TVD / MD	CASING/LINER SIZE	TYPE / RAD. MARKERS	CENTRALIZERS	LOT / FIT [SG]	TOC/TOL TVD	TOC/TOL MD	CSG. SHOE TVD	CSG. SHOE MD	Max PP [SG]	Min FG [SG]	Fluid [SG]
SB	382											
CapX 10	392 392	Cap-X	Interval: 382m -392m Type: lb/ft, , Drift:		0			392	392			
26" 376	768 768	20"	Interval: 382m - 763m Type: 133lb/ft, NT95-DE, NSMAX-GR Drift: 18.542		FIT	Seabed	Seabed	763	763			
17 1/2" 831 Side track window in casing	1599 1599	13 3/8"	Interval: 768m -1599m Type: 72lb/ft, P-110 ,Vam21CWD		FIT	0 1510	0 1510	1543	1543			
12 1/4" 1288	2606 2887	9 5/8"	Interval: 1543m -2887m Type: 53.5lb/ft, P-110, Vam21CWD S Drift: 8.508		FIT	0	0	2606	2886			
8 1/2" 861	3205 3748	OH	Interval: 2887m -3748m					3205	3748			

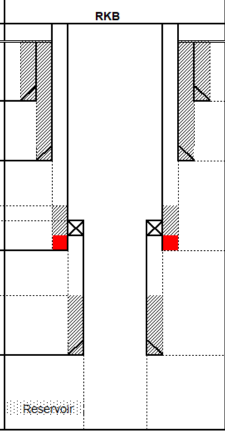


Figure 3: Well schematics (from Client) for mainbore (top) and sidetrack (bottom)

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 and Table 2.

The IPRs for the Apodida well are given in Figure 4. The IPRs shown are for both full and partial penetration according to the scenarios described in Section 2.

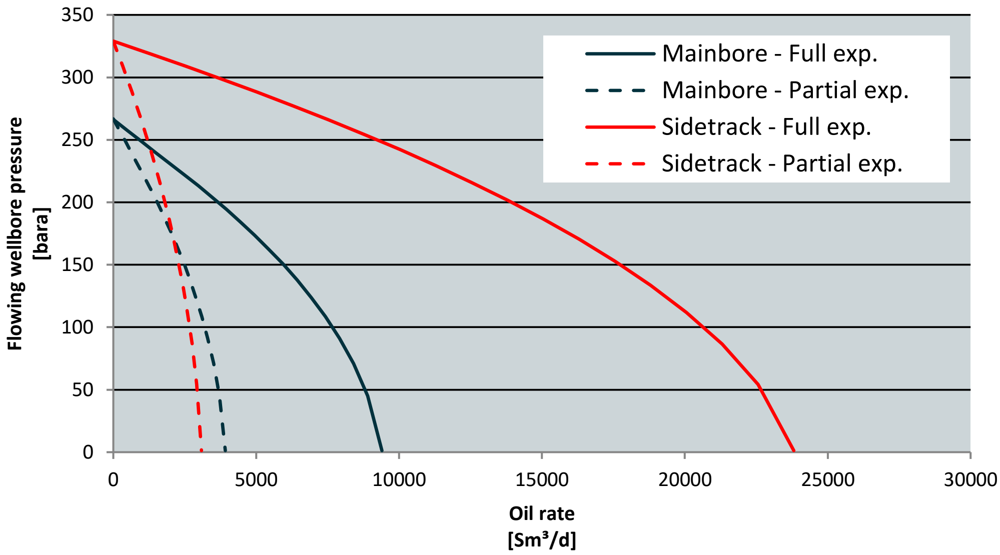


Figure 4: Oil inflow performance

3.7 Water

It is conservatively assumed that no formation water will 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” liner 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 5, 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.

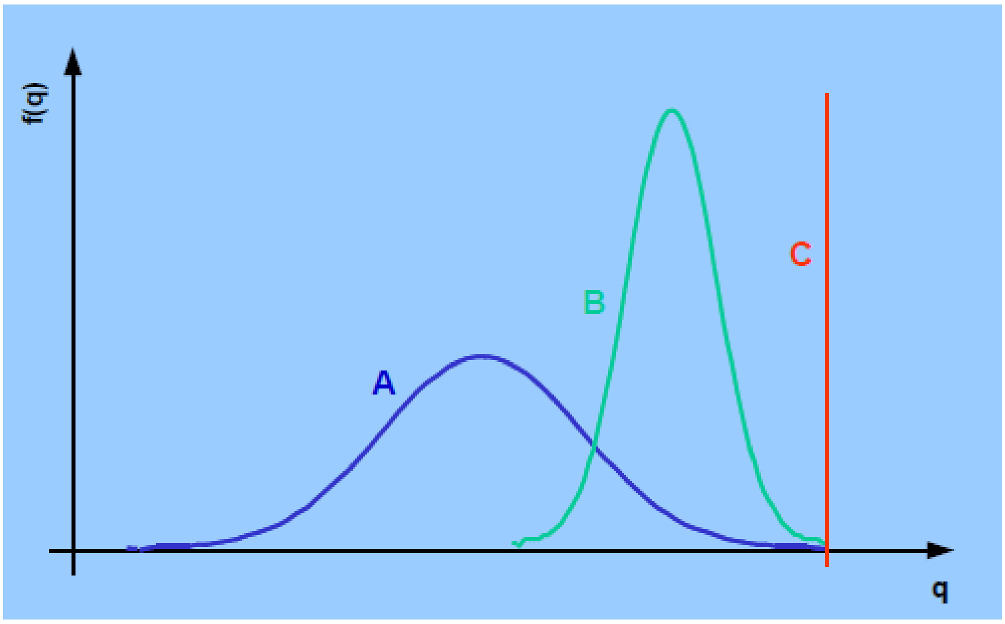


Figure 5: Expectation curves for volume/frequencies and possible simplification strategies

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 6 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 analyze, 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 6 illustrates the different flowpaths simulated.

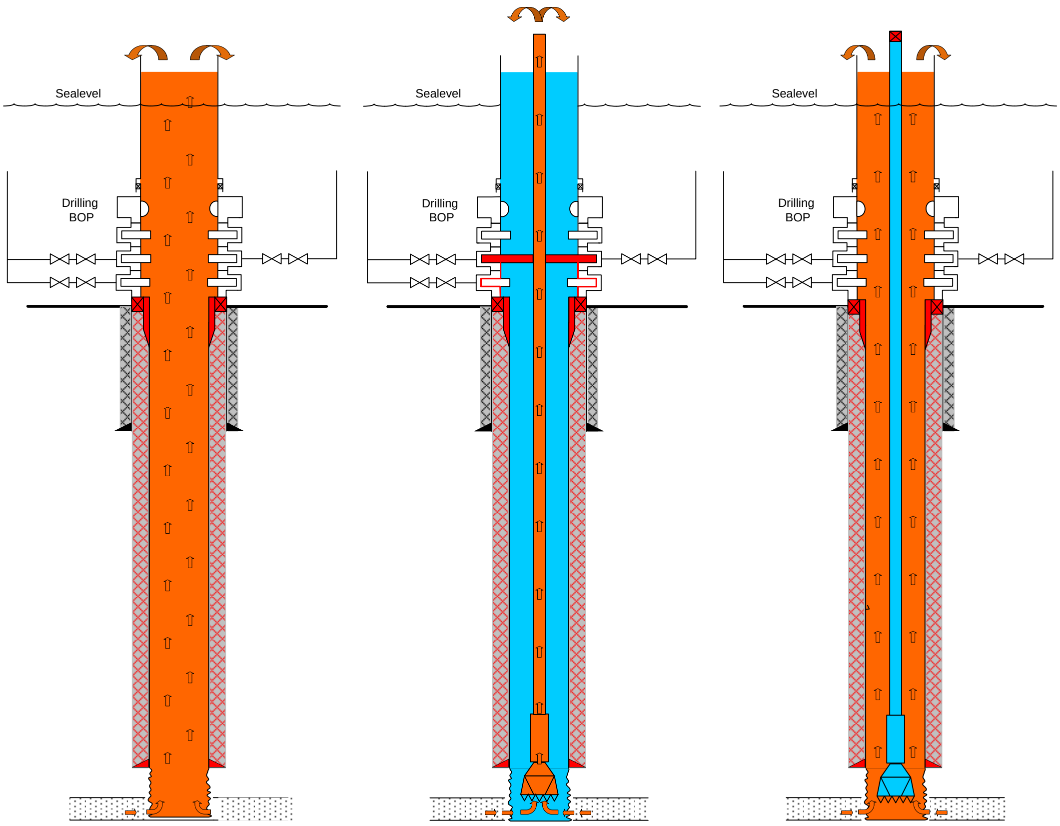


Figure 6: Possible blowout paths for the defined scenarios (illustrative only)
From left to right: Open hole, drill pipe and annulus

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.

Table 4 summarizes relevant statistical findings from drilling, completion and workover activities described in the *LR Consulting* report from March 2020 [3].

Table 4: 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 4:

- 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 7 next.

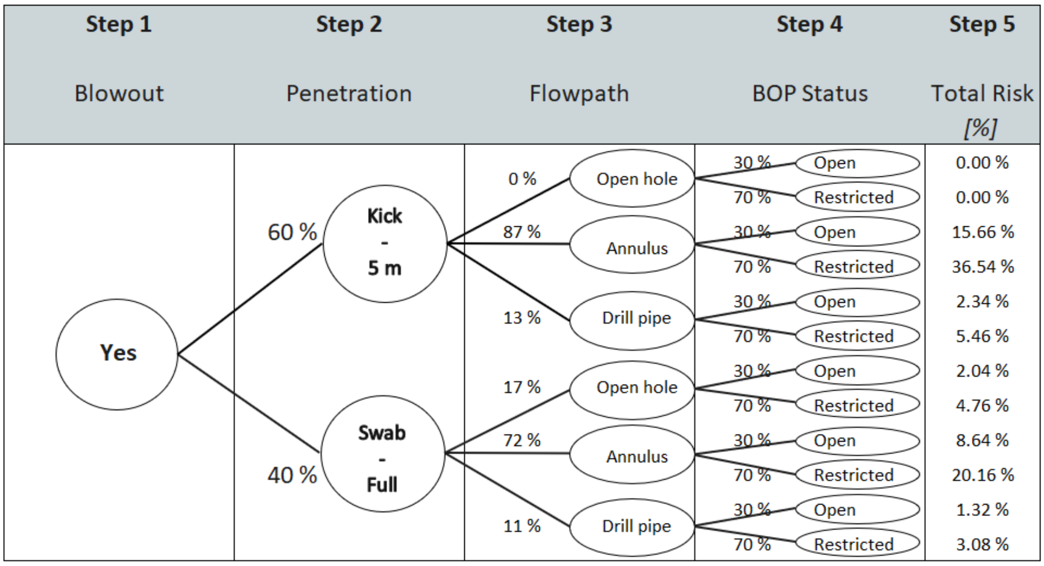


Figure 7: Typical methodology for risking of blowout rates for exploration wells

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: 18 days
- Homing in: 10 days
- Total time to kill well: 43 days

Consequently, the assumption is made that the relief well will successfully kill the blowing well after 43 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 8 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 8.

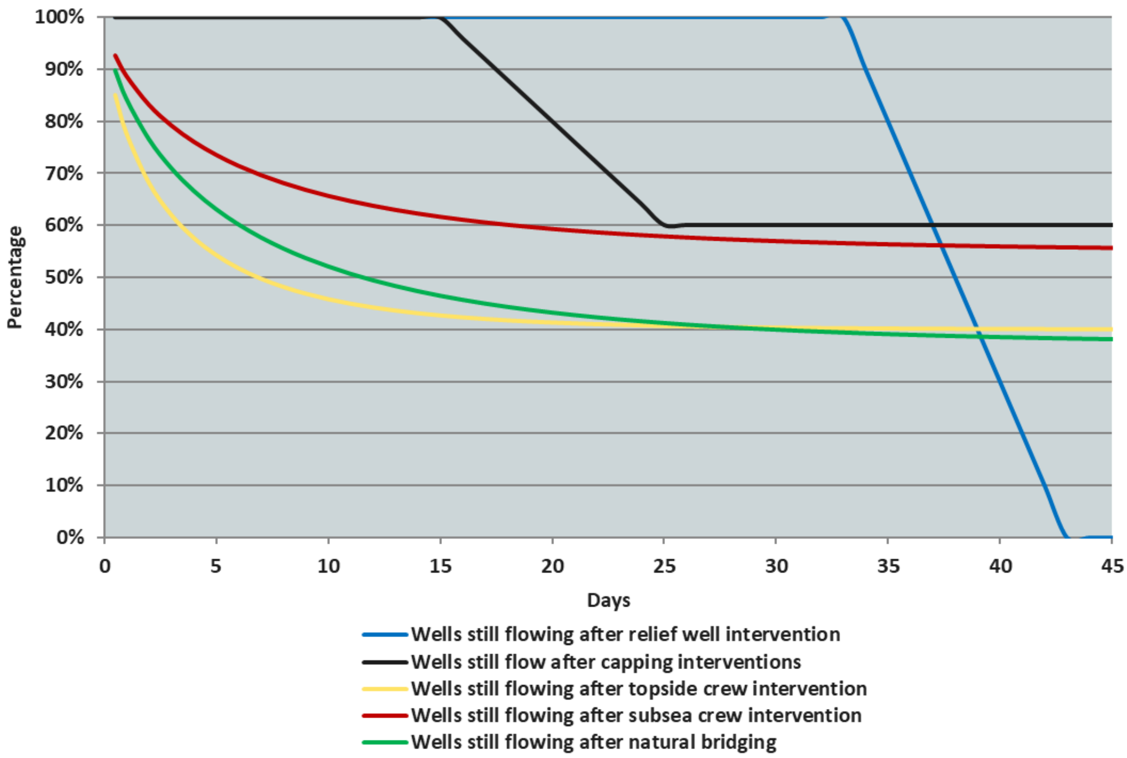


Figure 8: Reliability plots for each of the possible remedial actions

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 33 days and 43 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 8 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 9 next.

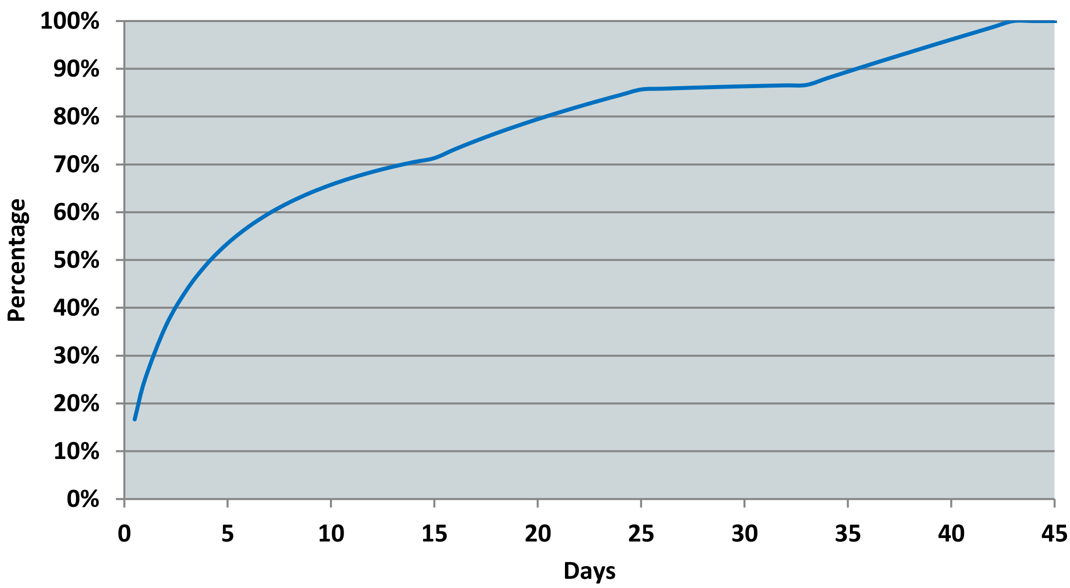


Figure 9: Reliability presentation of all kill actions when combined for a seabed release

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 10.

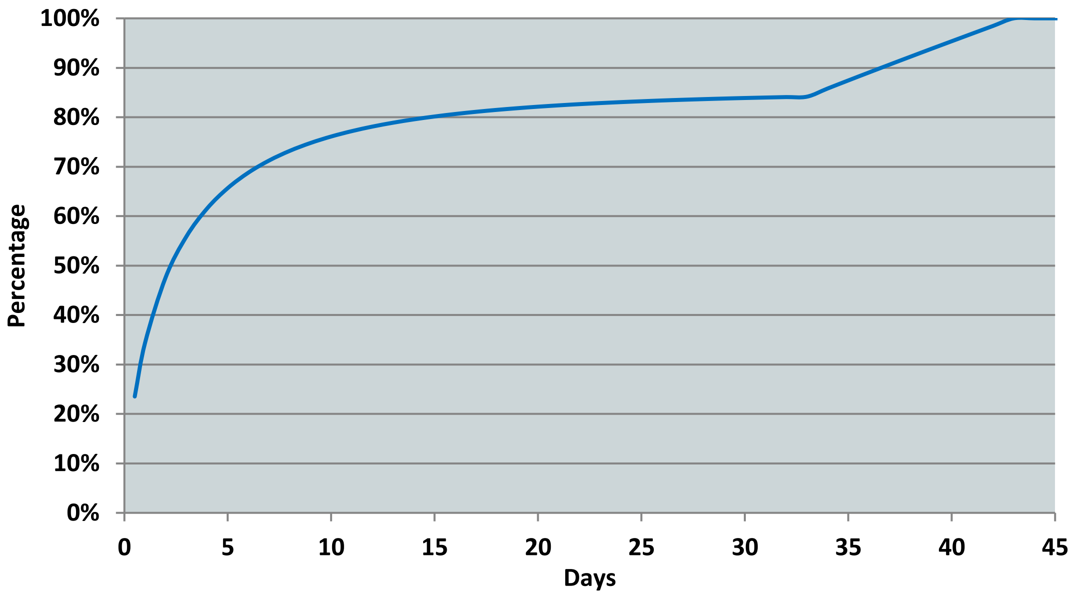


Figure 10: Reliability presentation of all kill actions when combined for a surface release

In order to provide a unique methodology for duration prognosis a simplified discretization is proposed in Table 5. The model represents five different logical stages in a kill operation.

Table 5: 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 43 days	P_{43}	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 43 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 the Apodida well

4.6.1 Blowout duration with surface release

Based on the discretization proposed above, reliability values can be extracted from Figure 10 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 43 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 43 days (100% - 83%): 17%

Assumptions are made that the relief well will successfully kill the well after 43 days, which means that P_{44} = 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:

$$2 * 0.47 + 5 * 0.18 + 15 * 0.15 + 25 * 0.03 + 43 * 0.17 = \mathbf{12.2\ \mathit{days}}$$

4.6.2 Blowout duration with seabed release

Based on the discretization proposed above, reliability values can be extracted from Figure 9 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 43 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 43 days (100% - 85%): 15%

Assumptions are made that the relief well will successfully kill the well after 43 days, which means that P_{44} = 0%. A weighted duration can now be calculated in a simplified way and can be as follows for a blowout with seabed release point:

$$2 * 0.36 + 5 * 0.17 + 15 * 0.18 + 25 * 0.14 + 43 * 0.15 = \mathbf{14.2\ \mathit{days}}$$

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:

$$12.2 * 0.1 + 14.2 * 0.9 = \mathbf{14.0\ \mathit{days}}$$

5 MAXIMUM DISCHARGE 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 and gas rates together with flowing bottom hole pressure (FBHP). The flowing wellbore pressure (FBHP) is taken at top of the producing formation.

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.

5.1 Detailed blowout rates – Case 1 (mainbore)

Detailed blowout rates for unrestricted openhole (OH), annulus (ANN) and drillpipe (DP) flowpaths are presented.

Table 6: 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 net of J56	OH	3776	0.46	31.8
		ANN	3514	0.43	70.1
		DP	2242	0.27	164.1
	Full exposure of J56	OH	8605	1.06	60.9
		ANN	6671	0.82	130.9
		DP	2943	0.36	213.7

Table 7: 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 net of J56	OH	2889	0.35	123.9
		ANN	2754	0.34	133.0
		DP	1951	0.24	179.6
	Full exposure of J56	OH	6748	0.83	128.8
		ANN	5476	0.67	161.5
		DP	2663	0.33	218.8

The worst-case blowout scenario is an unrestricted openhole to surface with J56 fully exposed. In such an unlikely event, the maximum blowout potential is found to be 8605 Sm^3/day of oil and 1.06 MSm^3/day of gas.

5.2 Detailed blowout rates – Case 2 (sidetrack)

Detailed blowout rates for unrestricted openhole (OH), annulus (ANN) and drillpipe (DP) flowpaths are presented.

Table 8: Blowout rates – Case 2 – Surface release point

Release point	Reservoir exposure	Flowpath	Oil rate [Sm³/d]	Gas rate [MSm³/d]	FBHP [bara]
Surface	Partial exposure – 5 m MD net of Etive	OH	2981	0.76	35.1
		ANN	2803	0.71	77.9
		DP	1917	0.49	189.5
	Full exposure of Etive	OH	15909	4.03	175.5
		ANN	8589	2.18	256.1
		DP	3024	0.77	305.0

Table 9: Blowout rates – Case 2 – Seabed release point

Release point	Reservoir exposure	Flowpath	Oil rate [Sm³/d]	Gas rate [MSm³/d]	FBHP [bara]
Seabed	Partial exposure – 5 m MD net of Etive	OH	2709	0.69	94.5
		ANN	2553	0.65	117.9
		DP	1819	0.46	198.7
	Full exposure of Etive	OH	14973	3.79	187.5
		ANN	8059	2.04	261.1
		DP	2964	0.75	305.5

The worst-case blowout scenario is an unrestricted openhole to surface with J56 fully exposed. In such an unlikely event, the maximum blowout potential is found to be 15909 Sm^3/day of oil and 4.03 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 Apodida 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 – Case 1 (mainbore)

The risked blowout rate distributions are listed in Table 10 for surface release and Table 11 for seabed release. J56 is exposed 5 m MD net in the partial reservoir exposure, and the entire J56 is exposed in the full reservoir exposure.

Table 10: 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	[%]	[Sm³/day]	[Sm³/day]	[MSm³/day]
60	Partial reservoir exposure	0	Open hole	30	Open	0.00	3776	0	0.00
				70	Restricted	0.00	1124	0	0.00
		87	Annulus	30	Open	15.66	3514	550	0.07
				70	Restricted	36.54	1220	446	0.05
		13	Drill pipe	30	Open	2.34	2242	52	0.01
				70	Restricted	5.46	1209	66	0.01
40	Full reservoir exposure	17	Open hole	30	Open	2.04	8605	176	0.02
				70	Restricted	4.76	1481	70	0.01
		72	Annulus	30	Open	8.64	6671	576	0.07
				70	Restricted	20.16	1557	314	0.04
		11	Drill pipe	30	Open	1.32	2943	39	0.00
				70	Restricted	3.08	1443	44	0.01
					Total sum:	100		2334	0.29

Table 11: 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	[%]	[Sm³/day]	[Sm³/day]	[MSm³/day]
60	Partial reservoir exposure	0	Open hole	30	Open	0.00	2889	0	0.00
				70	Restricted	0.00	1447	0	0.00
		87	Annulus	30	Open	15.66	2754	431	0.05
				70	Restricted	36.54	1501	549	0.07
		13	Drill pipe	30	Open	2.34	1951	46	0.01
				70	Restricted	5.46	1357	74	0.01
40	Full reservoir exposure	17	Open hole	30	Open	2.04	6748	138	0.02
				70	Restricted	4.76	1895	90	0.01
		72	Annulus	30	Open	8.64	5476	473	0.06
				70	Restricted	20.16	1913	386	0.05
		11	Drill pipe	30	Open	1.32	2663	35	0.00
				70	Restricted	3.08	1641	51	0.01
					Total sum:	100		2272	0.28

The expected oil blowout rate is 2334 Sm³/day for a surface release point and 2272 Sm³/day for a seabed release point. The corresponding risked blowout rates of gas are 0.29 MSm³/day for a surface release point and 0.28 MSm³/d for a seabed release point.

6.2 Risked Blowout rates – Case 2 (mainbore)

The risked blowout rate distributions are listed in Table 12 for surface release and Table 13 for seabed release. Etive is exposed 5 m MD net in the partial reservoir exposure, and the entire Etive is exposed in the full reservoir exposure.

Table 12: Risked blowout rates – Case 2 – 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	2981	0	0.00
				70	Restricted	0.00	1322	0	0.00
		87	Annulus	30	Open	15.66	2803	439	0.05
				70	Restricted	36.54	1319	482	0.06
		13	Drill pipe	30	Open	2.34	1917	45	0.01
				70	Restricted	5.46	1218	67	0.01
40	Full reservoir exposure	17	Open hole	30	Open	2.04	15909	325	0.04
				70	Restricted	4.76	2144	102	0.01
		72	Annulus	30	Open	8.64	8589	742	0.09
				70	Restricted	20.16	2070	417	0.05
		11	Drill pipe	30	Open	1.32	3024	40	0.00
				70	Restricted	3.08	1678	52	0.01
					Total sum:	100		2710	0.33

Table 13: Risked blowout rates – Case 2 – 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	2709	0	0.00
				70	Restricted	0.00	1474	0	0.00
		87	Annulus	30	Open	15.66	2553	400	0.05
				70	Restricted	36.54	1446	529	0.06
		13	Drill pipe	30	Open	2.34	1819	43	0.01
				70	Restricted	5.46	1295	71	0.01
40	Full reservoir exposure	17	Open hole	30	Open	2.04	14973	305	0.04
				70	Restricted	4.76	2384	113	0.01
		72	Annulus	30	Open	8.64	8059	696	0.09
				70	Restricted	20.16	2292	462	0.06
		11	Drill pipe	30	Open	1.32	2964	39	0.00
				70	Restricted	3.08	1804	56	0.01
					Total sum:	100		2713	0.33

The expected oil blowout rate is 2710 Sm^3/day for a surface release point and 2713 Sm^3/day for a seabed release point. The corresponding risked blowout rates of gas are 0.33 MSm^3/day for both a surface release point and seabed release point.

7 REFERENCES

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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

Ranold.

Flow matters

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