Blowout Scenario Analysis
34/6-9 S/A Avbitertang/Hekksaks

Summary

This report presents the assessment of blowout frequency, rate, and duration for the Avbitertang/ Hekksaks normal HT well. The analysis is based on input from the project, available blowout statistics, and internal guidelines.

Blowout frequency, rates and durations are calculated, and estimates are given.

The maximum probable duration is estimated at 63 days, with a probability of 1,64%. The weighted duration of a blowout is estimated at 5 days for surface releases and 14 days for seabed releases.

To ensure a flexible and conservative approach in the environmental risk assessment, calculations have been conducted for both operational scenarios: rig on dynamic positioning (DP) and rig on anchor.

The weighted blowout rate for surface is 6900 Sm3/d and for seabed it is 6400 Sm3/d.

Using the distribution 10% / 90 % for surface / seabed releases for a rig on DP, the total weighted rate is estimated to 6500 Sm3/d. Using the distribution 25 % / 75 % for surface /seabed releases for a rig on anchor, the total weighted rate is estimated to 6500 Sm3/d.

The blowout frequency is expected to be 2 x 1.07 × 10^{-4} = 2,14E-04 per year for drilling of this normal HT well, including sidetrack.

Contents

1 Introduction

To verify whether the existing local Environmental Impact Statement (EIS) is valid for the 34/6-9 S/A Avbitertang/Hekksaks normal HT well, detailed information regarding blowout duration, rates, and frequencies is required. This document discusses the blowout frequency, rates, and possible duration of a blowout and provides relevant results.

2 Abbreviations

BSA	Blowout Scenario Analysis
BOP	Blowout preventer
DMA	Dead-man anchor
DP	Dynamic positioning system
EIS	Environmental Impact Statement
GOR	Gas Oil Ratio
GCR	Gas Condensate Ratio
LMRP	Lower Marine Riser Package
MSL	Mean Sea Level
NCS	Norwegian Continental Shelf
ROV	Remotely Operated Vehicle

3 System description

3.1 General

This blowout scenario analysis (BSA) of blowout frequencies, rates and duration is based on GL0498 [3] and the following input:

- Statistics for blowout and well leak frequencies [1]
- Input from 34/6-9 S/A Avbitertang/Hekksaks project, collected in [4]
- Judgements and considerations in TDI OG FOS SAPT ST and in dialogue with 34/6-9 S/A Avbitertang/Hekksaks organization

Only wells producing oil to some extents are relevant for inclusion in the BSAs, as the primary purpose of the BSA is to support oil spill preparedness and environmental risk analysis. Consequently, shallow gas and other well releases are excluded due to their minimal environmental impact.

3.2 Well Specific Information

The 34/6-9 S/A Avbitertang/Hekksaks is in the North Sea, with surface location, coordinates and water depth given in table below. For the drilling, a semi-sub rig is assumed. The GOR is estimated to 70 Sm^3/Sm^3, hence an oil well. Further essential details are found in Table 1. See App.B for further details.

Table 1 Essential BSA Information

Expected positioning system (DP/anchored)	Anchored / DP
Type of rig (jack up/semi-sub)	Semi-sub
Type of well - HPHT/normal	Normal
" - normal HT/appraisal*)	Normal exploration HT well
Well trajectory (vertical/horizontal)	Inclined J-Shaped
Number of reservoir zones	2
Single well/ well with side-track	Sidetrack Hekksaks
Casing collapse study performed (Yes/ No)	Stresscheck ongoing
Probability for Casing Collapse (small/medium/large)	Small
GOR (Sm3/Sm3)	70

Table 2 Relevant data for ERA/oil spill preparedness, 34/6-9 S/A Avbitertang/Hekksaks

Parameter	**Value**
Surface location (coordinates in ED50 datum)	485592.88 mE, 6836554.50 mN
Distance to shore (km)	107 km
Name of oil (with valid weathering study)	Garantiana
Expected oil density at surface conditions (kg/m3)	871.6
Gas density/gravity (sg)	0.926
Casing or liner design	liner
ID of surface casing (in) i.e., ID of dimensioning casing if blowout	8.535
OD of drill string (in)	5.875
Water depth (m)	387 m
Estimated time for drilling (month)	September-November
Reference wells/ previous normal HT wells in area (last 5 years)? Distances (km)?	Distance to 34/6-5 S/ST2: ~6.6 km

3.3 Assumptions/limitations

- It has not yet been definitively decided whether the rig will operate while anchored or using dynamic positioning (DP). To ensure a flexible and conservative approach in the environmental risk assessment, calculations are therefore conducted for both operational scenarios: anchored and DP-based.
- The probability has included a sidetrack.
- The GOR and rates are identical for all reservoirs.
- There are two reservoirs, hence the scenario distribution is 30% for blowout during top penetration, 30% for drilling ahead for two of the contributing reservoirs and 40% for tripping.

4 Blowout probabilities and scenarios

Frequency

The well is assessed to be a “normal pressure well”, as well as a normal HT well. As the GOR is below 1000 Sm^3/Sm^3, the well is defined as an oil well. The statistics in [2] gives this type of well a blowout frequency of 1.07×10^{-4} per year.

Rig on DP Scenario

Based on information in [2] and an overall evaluation of different scenarios and type of vessel from the database [1], a probability distribution between surface and seabed release scenarios is set to 10% and 90% in order of appearance. This results in the following probabilities:

- P (blowout with surface release) = 2 x 0.10 · $1.07 \times 10^{-4} = 2.14 \times 10^{-5}$
- P (blowout with seabed release) = 2 x 0.90 · $1.07 \times 10^{-4} = 1.93 \times 10^{-4}$

Rig on anchor Scenario

Based on information in [2] and an overall evaluation of different scenarios and types of vessel from the database [1], a probability distribution between surface and seabed release scenarios is set to 25% and 75% in order of appearance. This results in the following probabilities:

- P (blowout with surface release) = 2 x 0,25 · $1.07 \times 10^{-4} = 5.35 \times 10^{-5}$
- P (blowout with seabed release) = 2 x 0,75 · $1.07 \times 10^{-4} = 1.61 \times 10^{-4}$

Location of incident

During a drilling operation, a blowout may occur if a reservoir is penetrated while well pressure is in underbalance with the formation pore pressure, and a loss of well control follows. Three different scenarios for normal HT drilling are defined:

- Top penetration: Kick and loss of well control after 5 m into the reservoir, typically due to higher reservoir pressure than expected.
- Drilling ahead: Kick and loss of well control after penetration of half the pay zone depth. Represents various causes of underbalance while drilling ahead.
- Tripping: Kick and loss of well control after full reservoir penetration, typically due to swabbing during tripping.

As per 3, the following probabilities are recommended:

- P (5m into reservoir| blowout) = 0,30
- P (50% into reservoir)= 0,40
- P (100% reservoir penetration)| blowout) = 0,30

Flow path scenarios

Annulus flow path only is recommended for a basic analysis, for a more detailed analysis of blowout scenarios, the following flow path scenarios and probabilities can be applied for all depths, ref. [3]:

- Open hole 10 %
- Annulus 80 %
- Drill pipe 10 %

The present BSA is carried out on a basic level, i.e. all blowouts are considered having flow through annulus.

Flow restriction scenarios

A significant number of recorded blowouts experienced varying degree of restrictions such as:

- Almost closed BOP (pipe ram or blind/shear ram)
- Solids blocking the open hole section due to sand aggregation or formation collapse
- Deformed tubulars, including riser, BOP, casing, drill string

Based on ref. [3] a 60/40 % distribution between full and restricted flow is recommended. The flow restriction is modelled as a circular disc on top of the wellhead with the following hole sizes:

- Open hole 2''
- Annulus 1,5''
- Drill pipe 1''

5 Blowout rates

In the table below, relevant distribution parameters and the originally calculated blowout rates [4] are given, in addition to the weighted blowout rate, for the well. The values are given for surface and seabed releases.

Table 3 Blowout rates – initial and weighted for the well

Scenario distributio n	Scenario	Restriction	Restriction distributio n	Total distribution	Surface		Seabed	
					Initial rates (Sm³/d)	Weighted blowout rate (Sm³/d)	Initial rates (Sm³/d)	Weighted blowout rate (Sm³/d)
30%	Top Penetration	Open	60 %	0,18	1302	234	846	152
		95 % restr	40 %	0,12	1180	142	825	99
30%	Drilling ahead	Open	60 %	0,18	8226	1481	6734	1212
		95 % restr						
		Open	40 %	0,12	5279	633	5720	686
		95 % restr						
40 %	Tripping	Open	60%	0,24	12824	3078	11582	2780
		95 % restr	40%	0,16	8326	1332	9233	1477
				Total		**6900**		**6407**

The weighted blowout rate for surface is 6900 Sm³/d and for seabed is 6400 Sm³/d.

Using the distribution 10 % / 90 % for surface /seabed releases for a rig on DP (ch.4), the total weighted rate is estimated and rounded up to 6500 Sm³/d.

Using the distribution 25 % / 75 % for surface /seabed releases for a rig on anchor (ch.4), the total weighted rate is estimated and rounded down to 6500 Sm³/d.

6 Blowout duration, 34/6-9 S/A Avbitertang/Hekksaks normal normal HT well

6.1 General

An oil blowout can be stopped by:

- Operator actions – mechanical (*capping*)
- Wellbore collapse and/or rock material plugging the well – (*bridging*)
- Altered fluid characteristics resulting from *water* or *oil coning* during a blowout
- Drilling a *relief well* and pumping kill mud
- For drilling and completion on Central template – use of capping stack

6.2 Blowout stopping mechanisms

6.2.1 Operator action [5]

Capping (without capping stack) is an operator action involving closing off the flow from the wellbore at the mudline, rather than downhole, using equipment available on the installation. This is either a mechanical shut-in of the well or killing the well with various types of mud and cement.

Depending on the type of operation, capping can involve closing one or more valves in the well's permanent barrier system, such as:

- one of the BOP valves
- valves in the Xmas tree
- valves in the drill or operation string
- downhole valves. This could be a possibility, for example, if one of the causes of the blowout was a failure in the valve's control system which subsequently proves to be repairable.

The ability to run a work string or having one already in place is a precondition for pumping mud down the well. A distinction can be made between hydraulic or dynamic killing. In the first case, a heavy mud is used which provides sufficient hydrostatic pressure to stop the flow from the reservoir. Dynamic killing involves circulating mud in the well at high pumping rates, so that the frictional pressure loss makes a substantial contribution to the counterpressure against the reservoir. A killing operation can also be a combination of these two methods.

Bullheading is another approach. In principle, this involves pumping liquid at high rates and under high pressure through the BOP's choke and kill lines. That presses the formation fluid back into the formation and eventually fills the well with sufficiently heavy kill mud. This method consequently again requires the ability to pump with sufficient rates and pressure to drive more mud into the well. Cement can be used in a kill process either by filling all or part of the well with this material, in the same way as with a kill mud, or by driving cement slurry into the formation.

6.2.2 Bridging [5]

Bridging is a natural mechanism which cause the wellbore to collapse, or the well is plugged or filled up with produced sand, unconsolidated material or formation fragments.
Bridging is a collective term for mechanisms which alter downhole conditions so that the flow ceases. The following can be distinguished:

1. Accumulation of unconsolidated material in the well to block the flow.
2. Well collapse
3. Formation of a hydrate plug in the flow path.

Unconsolidated materials can derive from sand accompanying formation fluid out of the reservoir (sand production) or be loosened from the well walls by the production flow or as a result of stress changes in the formation surrounding the well. Relatively unconsolidated sandstone reservoirs with good permeability can give rise to substantial sand production. Depending on flow rates, the sand can accumulate over time in the well to restrict and eventually halt the flow. If blowout rates are high, however, the sand will accompany the oil stream out of the well. A combination of a brittle formation, friction from the fluid flow along the well wall and stress changes in the well wall could cause formation fragments large and small to flake off and plug the well. Should the drainage of formation fluid during a blowout cause formation pressure to fall to a level below the formation's collapse gradient, the well may collapse or implode. The flow will then be sharply reduced or cease completely. Factors which could contribute to well collapse include:

- high flow rates which yield rapid drainage of the reservoir and pressure drop
- a small reservoir or poor communication between various reservoir areas, which gives rapid pressure drop per unit volume of liquid drained
- a high collapse gradient (loosely consolidated formation).

6.2.3 Coning [5]

If gas or water coning is a relevant mechanism in a well, this phenomenon could convert a blowout which initially conducts oil to the surface into a pure gas and/or water discharge. Three phases lie one above the other in the reservoir – gas on the top, water at the bottom and oil in between. The thickness of these layers and the extent to which all are present vary from reservoir to reservoir. When producing from the oil layer, a local pressure reduction arises in that part of this zone which is closest to the well. Depending on such factors as:

- thickness of the oil layer
- viscosity of the oil
- reservoir flow properties horizontally compared with vertically
- production rate, the interface between the three fluid layers during production will differ from the original in the vicinity of the well.

The water phase is pulled up and the gas phase down. With vertical wells, these changes form cones centred in the well. That increases water and/or gas cuts during oil production. Concern about water/gas coning could govern the design of the well path for producers and subsequently the actual production process. Production from an oil layer could convert entirely in this way to water or gas output. Water and gas coning could thereby be a mechanism which halts uncontrolled oil flow during a blowout.

6.2.4 Drilling a relief well [5]

A relief well will be spudded where it is difficult for various reasons to conduct effective kill measures from the rig. This is drilled in towards the bottom of the blowing well. If effective communication can be established between the two wells, control could be restored over the blowout with the aid of dynamic and hydraulic kill methods.

6.2.5 Capping stack [3]

A capping stack can be considered as a contingency BOP which is launched from one or more vessels, lowered, and installed on the BOP or wellhead of the blowing well. Clearance operations to remove equipment and debris from the BOP or wellhead may be necessary before the installation. When the capping stack is successfully installed, the capping stack blind rams are closed to stop the blowout.

Depending on the scenario, two installation methods may be used: vertical or offset installation. Vertical installation is comparable to installation of a subsea BOP. An important difference is that when installing the capping stack, the marine operation and closure of the BOP is disturbed by the flowing well, both at the wellhead and on the surface. Vertical installation is carried out using one vessel positioned directly above the well. Conditions that may challenge vertical installation include shallow waters, high gas rate, limited sea current.

If dictated by the scenario, in particular disturbance from the blowout plume, offset installation will be applied. Offset installation is carried out using the offset installation carrier to position the capping stack on the blowing well. This is done in combination with two vessels towing the carrier with the capping stack subsea on tensioned wires from both vessels and additional equipment used to manoeuvre the stack in position, including concrete dead man's DPs (DMAs). Offset installation is generally considered more complex and time consuming than vertical installation of the capping stack.

6.3 Background for Duration Calculations

6.3.1 Historical data

In [1], the Sintef database for blowouts are treated statistically. In addition to frequencies, also durations are collected and treated. The results of this are used for the following duration calculations.

The probability distribution of the duration of a possible blowout is derived by way of the approach utilised in [2]. Water and oil coning are not considered in the assessment. Historical data for establishing distributions for stop mechanisms active measures from rig and bridging are found in tab.4 in [2] (updated annually):

Table 4 Weibull parameters for calculating duration of blowout

	α	β	Asymptote
Bridge	0,70	6,00	0,63
CapTopside	0,80	2,30	0,62
CapSubsea	0,85	6,00	0,45
ReliefWell[1]	15	80	1

$T_{Reliefwell}$ is uniformly distributed between α and β, while T_{bridge}/$T_{capping\ surface}$/$T_{capping\ Subsea}$ has Weibull distributions. Note that for Relief well and Capping stack, specific input values are used (Table 5 and 6.4.2).

6.4 Duration of the blowout

6.4.1 Estimation of relief well duration

Well specific input about time to drill a relief well is given by the project and presented in Table 5. Please note that it is a requirement in NORSOK D-010, chapter 4.8.2 that initiation of relief well drilling should start no later than twelve days after the decision to drill relief wells, i.e. the expected time in step 2 should not be higher than 12 days for operations on NCS.

Table 5: Time to drill a relief well (days)

	Min	Most likely	Max	Comments
1- Decision to mobilize	0.5	1	2	
2- Mobilization of rig, including: collection of equipment/rearmament, transit, anchoring and preparation	4	8	12	
3- Drilling down to the specific depth	23	27	32	
4- Geo magnetic steering into the well	7	12	20	
5- Killing of well	1	2	5	
Sum	35.5	50	71	

6.4.2 Capping stack input

Based on the information provided by the project ([4] and App. A) and the methodology presented in App. A in [3], the probability of successfully stopping the blowout by use of capping stack is 48%.

Neither number of days nor the probabilities listed in App. A are exact values but a best estimate. Since several factors are added to give a statistical distribution, inaccuracies in single value do not affect the total result in a significant way.

Bad weather conditions can lead to delays and decrease the probability of success for landing the capping stack. Water depth and sea current also affects the success.

The probability for success of capping stack is described in Appendix A.

6.4.3 Calculated blowout duration (including capping stack)

The probability distribution in Table 6 is constructed by a combination of the well specific input on capping stack installation and relief well drilling together with probabilities that a blowout will end by the mechanisms capping and bridging.

Table 6 Probability distribution for a blowout to end as a function of time (days)

Duration (days)	Surface blowout	Seabed blowout
1	36,65 %	23,07 %
2	14,80 %	11,50 %
5	18,48 %	18,64 %
7	10,04 %	6,76 %
10	9,51 %	6,38 %
14	3,35 %	6,25 %
21	3,92 %	8,75 %
28	3,26 %	1,47 %
35		3,14 %
42		2,79 %
49		2,80 %
56		6,80 %
63		1,64 %

**Contribution from 70 days is 0,01%, which have been added to the group above – 63 days.*

Table 7 Weighted duration, including capping stack

Surface				Seabed			
Group no	**Duration group**	**Grouped weighted duration**	**Grouped weighted probability**	**Group no**	**Duration group**	**Grouped weighted duration**	**Grouped weighted probability**
1	1 to 2 days	1,29	51,45 %	1	1 to 5 days	2,62	53,22 %
2	5 to7 days	5,70	28,51 %	2	7 to 21 days	13,59	28,13 %
3	10 days	10,00	9,51 %	3	28 to 49 days	39,75	10,20 %
4	14 to 21 days	12,27	7,27 %	4	56 days	56,00	6,80 %
5	28 days	28,00	3,26 %	5	63 to 77 days	63,04	1,64 %
Sum weighted surface			**5,44**	**Sum weighted seabed**			**14,12**

As presented in Table 6, the maximum blowout duration is 28 days for surface release with a probability of 3,26% and 63 days for seabed release with a probability of 1,64%. The weighted duration of a blowout for surface is 5 days and seabed releases are 14 days. In Figure 1 and Figure 2 the blowout probabilities and duration are illustrated.

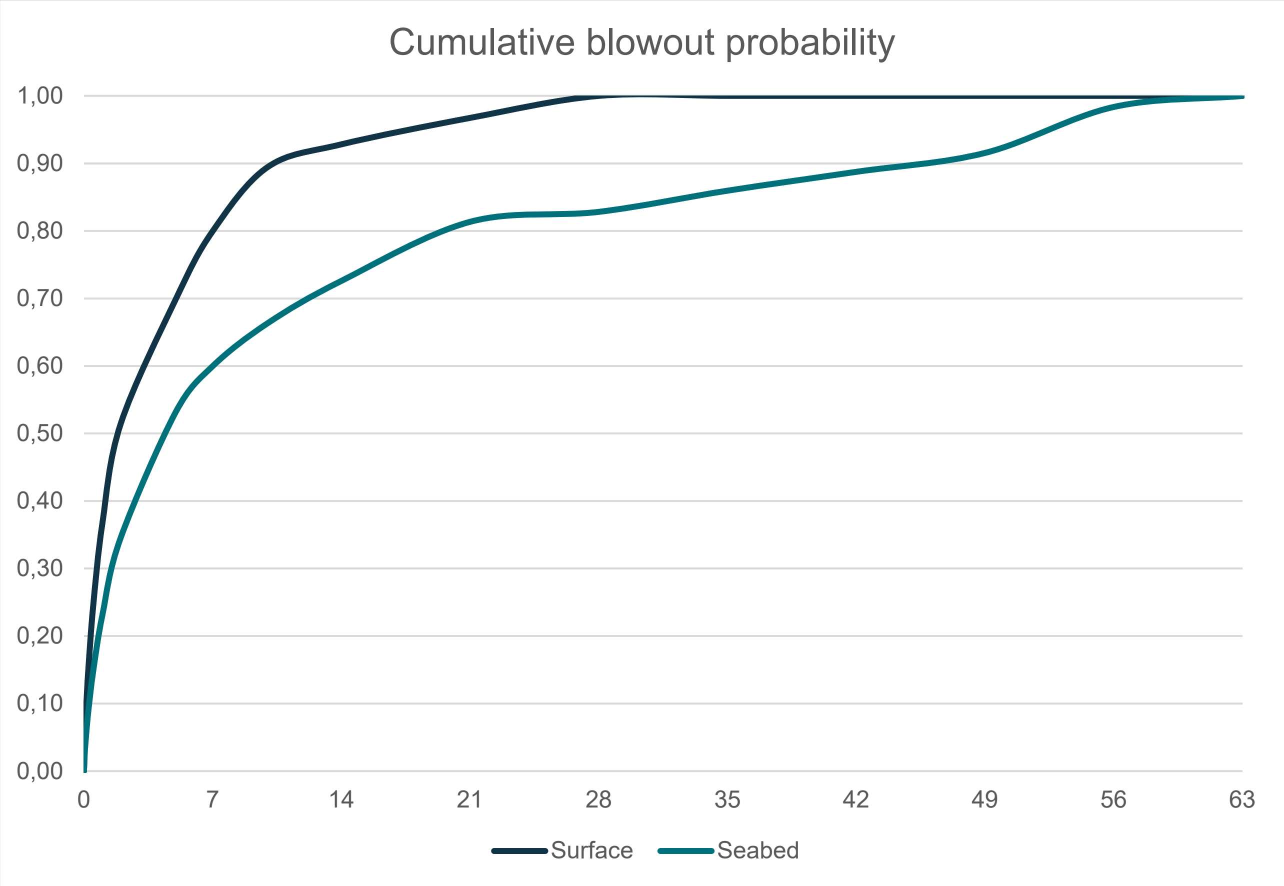


Figure 1 Blowout duration described by cumulative distributions, including capping stack

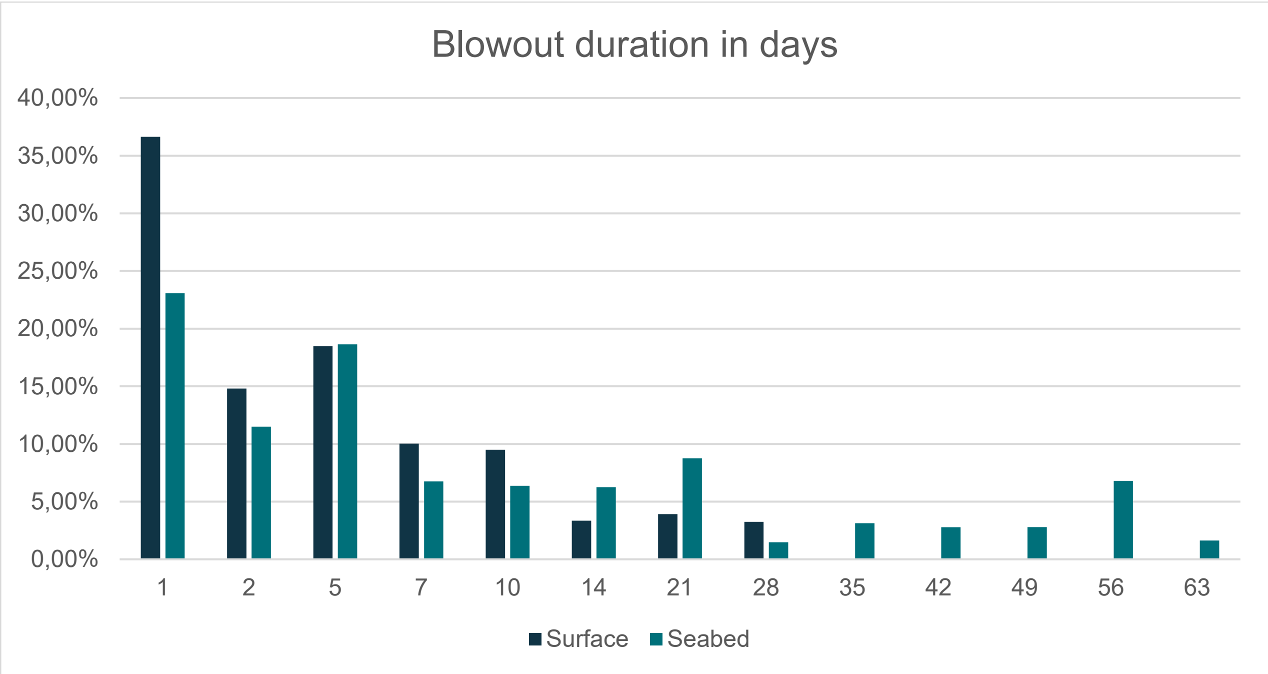


Figure 2 Blowout duration described by probability distributions, including capping stack

7 Uncertainties

This report is based on statistical values from [1]. These values are studies and treated in [2]. The blowout frequency is thus a statistical value but assumed to give a rather correct range of the expected blowout frequency.

Rate calculations are assumed correct based on present knowledge. All values are calculated and verified by Petek personnel, and the uncertainty in the final result due to assumptions made in the rate calculations is considered small.

8 Summary

Blowout frequency, rates and durations are calculated, and estimates are given.

The maximum probable duration is estimated at 63 days, with a probability of 1,64%. The weighted duration of a blowout is estimated at 5 days for surface releases and 14 days for seabed releases.

To ensure a flexible and conservative approach in the environmental risk assessment, calculations have been conducted for both operational scenarios: rig on dynamic positioning (DP) and rig on anchor.

The weighted blowout rate for surface is 6900 Sm3/d and for seabed it is 6400 Sm3/d.
Using the distribution 10% / 90 % for surface / seabed releases for a rig on DP, the total weighted rate is estimated to 6500 Sm3/d.
Using the distribution 25 % / 75 % for surface /seabed releases for a rig on anchor, the total weighted rate is estimated to 6500 Sm3/d.

The blowout frequency is expected to be 2 x 1.07×10^{-4} = 2,14E-04 per year for drilling of this normal HT well, including sidetrack.

9 References

1. SINTEF: "Blowout and Well Release Characteristics and Frequencies, 2024", Report no.: 2024:01538, 13 January 2025.
2. Vysus: “Blowout and Well Release Frequencies – based on Sintef Offshore Blowout Database 2025”, report RMC0500833-/2024/R0, rev Final, Feb. 2025
3. Equinor: GL0498 “Guideline for Blowout Scenario Analysis as input to Environmental Risk Analysis” rev.2
4. Information from the 34/6-9 S/A Avbitertang/Hekksaks project in “Normal HT input scheme 34/6-9 S/A Avbitertang/Hekksaks BSA and ERA input”
5. NOROG: “Guidance on calculating blowout rates and duration for use in environmental risk analyses”, 2014
6. Blowout simulation report for MRABA NO 34/6-9 S/A Avbitertang/Hekksaks

Appendix A Probabilities related to use of capping stack.

In the period 2019- 2023 the methodology for use of capping stack has been specified and calculated pr. location for drilling operations where semi- submersible rigs are used. The rig needs to move- off location for the ship to install a capping stack in case of a blowout. The values are now standardised based on the wells given in Table 8. These wells are selected based on their location and on the lowest and highest probability of success of stopping the blowout with the use of a capping stack.

The purpose of the capping stack evaluation is to identify the Surface and Seabed duration of a potential blowout.

For Surface releases the duration of the blowout is not affected using capping stack, as this duration is linked to the "rig move-off location".

For seabed releases the duration changes from 19 to 20 days for Rosebank which has the biggest change in duration with the new standardised probabilities, ref. Table 8. All other wells have less change in duration, and the new standardised probabilities are assessed to be acceptable considering all assumptions and following uncertainties in these blowout duration assessments.

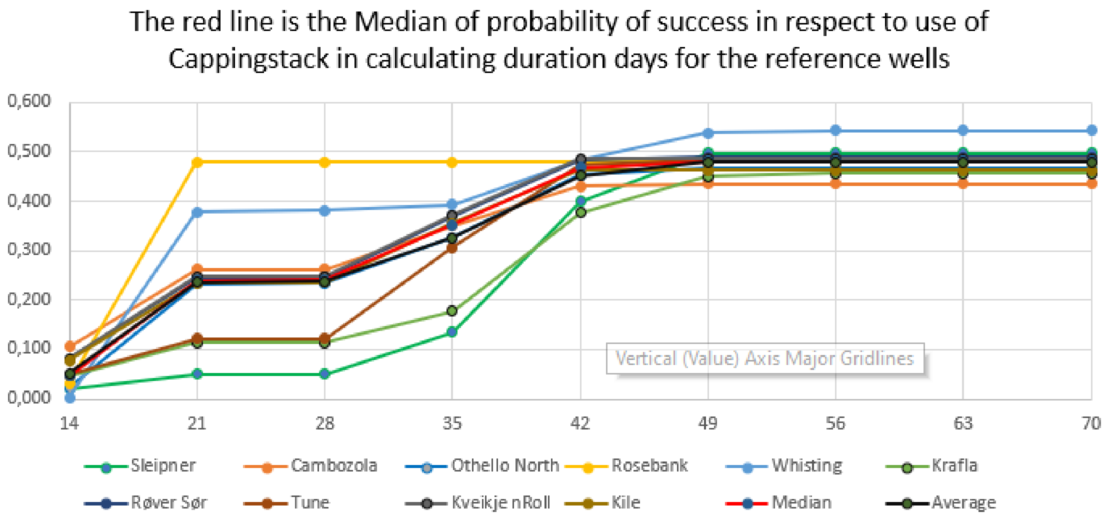
The detailed calculations performed for the capping stack may be found in the BSA reports for the wells referred to in Table 8.

Table 8 showing new recommended probabilities of successful use of capping stack in the column to the right

Duration	Sleipner	Cambozola	Othello North	Rosebank	Whisting	Krafla	Røver Sør	Tune	Kveikje n'Roll	Kile	Median/ recommended probabilities to be used
14	0,021	0,105	0,023	0,031	0,002	0,046	0,081	0,049	0,082	0,078	**0,047**
21	0,050	0,262	0,233	0,478	0,377	0,114	0,245	0,121	0,247	0,235	**0,240**
28	0,051	0,262	0,234	0,478	0,381	0,114	0,246	0,123	0,248	0,236	**0,241**
35	0,135	0,350	0,326	0,478	0,393	0,178	0,369	0,305	0,372	0,355	**0,352**
42	0,399	0,430	0,453	0,478	0,482	0,377	0,482	0,472	0,485	0,462	**0,467**
49	0,497	0,435	0,466	0,478	0,538	0,451	0,489	0,484	0,485	0,462	**0,481**
56	0,497	0,435	0,466	0,478	0,543	0,456	0,489	0,484	0,485	0,462	**0,481**
63	0,497	0,435	0,466	0,478	0,543	0,457	0,489	0,484	0,485	0,462	**0,481**
70	0,497	0,435	0,466	0,478	0,543	0,457	0,489	0,484	0,485	0,462	**0,481**

The table above shows that the highest probability of successful use of capping stack to shut in a blowout is about **48%**. This will be reached after 49 days and is shown in Figure 3 to be similar for all the wells that are used as reference.

Figure 3 is showing the median line for the probability of successful use of capping stack for the wells



Appendix B Parameters for blowout simulations Ref. 6

Table B-1 Reservoir parameters

Reservoir data	Unit	Avbitertang 34/6-9 S		Hekksaks N 34/6-9 A		GeoX mean? Y/N	Comment
		Cook 6	Cook 1-5	Cook 6	Cook 1-5		
GeoX ID		814795	814794	814748	814750		
Geo prognosis		28.01.25 for R03		28.01.25 for R01			
Trajectory (Compass name)		34/6-9 S R03		34/6-9 A R01			
Deviation through reservoir	°	20		12.93			
Hole size	in	8.5		8.5			
Top reservoir	mTVD MSL	**3881**	**3924**	**3890**	**3934**		<At well penetration point (not apex)>
Base reservoir	mTVD MSL	**3924**	3968	**3934**	3969		
Gas Oil Contact (GOC)	mTVD MSL	N/A	N/A	N/A	N/A		<At well location>
Oil Water Contact (OWC)	mTVD MSL	3964	**3964**	3950	**3950**	Y	(Mean contact)
Gas Water Contact (GWC)	mTVD MSL	N/A	N/A	N/A	N/A		
Net/Gross	ratio	0.5	0.65	0.5	0.65	Y	<In the HC-bearing interval>
Net pay	mTVD	**21.5**	**26**	**22**	**10.4**		
Net pay	mMD	**22.5**	**27.90**	**22.5**	**10.72**		
Porosity	v/v	0.205	0.21	0.205	0.21	Y	<In the HC-bearing interval>
Absolute permeability	mD	280	250	280	250	Y	<In net pay interval.>
Effective permeability	mD	246.4	212.5	246.4	212.5		Used 12% & 15% reduction
Sw, Water saturation	fraction	0.22	0.25	0.22	0.25	Y	<In the HC-bearing interval>
Kv/Kh	ratio	0.1	0.1	0.1	0.1		<Default value 0.1>
Reservoir pressure	bar	630.5		629			<at the OWC>
246.4Reservoir temperature	°C	154		153			Temperature at the OWC
Radius (r_e) (if X&Y not given)	m						<Drainage area (HC-filled reservoir)>
Length along well (X)	m	800		1100			<Rectangular outline of reservoir drainage area (HC-filled only)>
Width across well (Y)	m	1500		980			
Position of well within reservoir (X_1)	m	228		300			
Position of well within reservoir (Y_1)	m	615		530			

Fluid Parameters

A calculated, uncontaminated oil sample from well Garantiana West (NO 34/6-5 ST2), SPMC-T-093, was used as input for the BO calculations by adjusting it to the prognosed reservoir conditions for Avbitertang (done by PVTSim). Fluid properties at standard conditions, and the simulated fluid properties at reservoir conditions can be found in the following table:

Table B-2 Fluid parameters used as input to kill simulations

Fluid data	Unit	Avbitertang		Hekksaks		
		Cook 6	**Cook 5**	**Cook 6**	**Cook 5**	
Reference field/well for fluid properties (PVT)		Garantiana West (NO 34/6-5 ST2): SPMC-T-093				
Reference fluid properties at surface conditions (15 deg C and 1 bar)						
Gas gravity (air=1)	sg	0.928		0.928		
Oil density	kg/m3	871.6		871.6		
GOR	Sm3/Sm3	69.9		69.9		
Calculated fluid properties at initial reservoir conditions (at top reservoir depth)						
Reservoir pressure	bar	**631**		**629**		<at the contact>
Reservoir temperature	°C	**154**		**153**		<at the contact>
Reservoir fluid density	g/cc	0.7876		0.7878		Oil density at Pb: Avbitertang/Hekksaks: 0.7370
Gas density	g/cc	N/A		N/A		
Bubble point	bar	162.8		162.4		<Recalculated>
Viscosity 2)	cP	1.254		1.259		Corrected Visc at Pb & reservoir temp.: 0.68 (valid for both, Avbitertang & Hekksaks)
Formation Volume Factor, Bo 1)	Rm^3/Sm^3	1.292		1.291		At Pb
CO_2	mol%	2.317		2.317		
N2	mol%	0.968		0.968		
H_2S	mol%	0		0		

Table B-3 Oil composition from Blowout and Kill simulations report

Component	Mol %	Molecular weight	Liquid density (g/cm^3)
N_2	0.968	28.014	
CO_2	2.317	44.010	
C1	28.076	16.043	
C2	6.409	30.070	
C3	6.559	44.097	
iC4	1.426	58.124	
nC4	3.046	58.124	
iC5	1.062	72.151	
nC5	1.136	72.151	
C6	1.307	86.178	0.6640
C7+	47.694	281	0.8795