Blowout Scenario Analysis
25/7-13 Linga

Summary

This note presents the assessment of blowout frequency, rate, and duration for the 25/7-13 Linga high pressure, high temperature exploration well. The analysis is based on input from the project, available blowout statistics and internal guidelines.

Blowout frequency, rates and durations have been calculated, and estimates are provided.

The maximum probable duration is 84 days with a probability of 2,44%. The weighted duration of a blowout is estimated at 5 days for surface releases and 16 days for seabed releases. The weighted blowout rate is 4000 Sm³/d, assuming use of a rig on anchor system.

The blowout frequency is expected to be 2 x 6,65E-04 = 1,33 x10-3 per year for drilling of this HPHT exploration well, included sidetrack.

Contents

1 Introduction

To verify whether the existing local Environmental Impact Statement (EIS) is valid for the well, detailed information regarding blowout duration, rates and frequencies is required. This document discusses the blowout frequency, rates and possible duration of a blowout an 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 25/7-13 Linga project, collected in [4]
Judgements and considerations in TDI OG FOS SAPT ST and in dialogue with 25/7-13 Linga organization

Only wells producing some extents of oil are relevant to include in the BSAs as the sole purpose of the BSA is to be input to oil spill preparedness and environmental risk analysis. For the same reason, shallow gas and well releases are excluded, due to minimal environmental impact.

3.2 Well Specific Information

Table 1 Essential BSA Information

Expected positioning system (DP/anchored)	Anchor	Affects blowout probability and duration of surface release
Type of rig (jack up/semi-sub)	Semi-sub	Affects blowout probability
Type of well - HPHT/normal	HPHT	Affects blowout probability
Normal exploration / wildcat/appraisal*	Normal exploration	Affects blowout probability
Well trajectory (vertical/horizontal)	Mainbore: Vertical Sidetrack: Deviated (~43°)	Affects blowout duration
Number of reservoir zones	1	Affects blowout probability and scenario definition
Single well/ well with side-track	Well with optional sidetrack	Affects blowout probability
Casing collapse study performed (Yes/ No)	Yes	Affects blowout duration
Probability for Casing Collapse (small/medium/large)	Small (9 7/8" casing)	Affects blowout probability and duration
GOR (Sm3/Sm3) / GCR (Sm3/Sm3)	587.8 / 0.0017	Affects blowout probability

Table 2 Relevant data for ERA/oil Spill Preparedness

Surface location (coordinates in ED50 datum)	6578485.9m N, 455922.6m E	Affects ERA and OSPA
Distance to shore (km)	150 (Utsira)	Closer than 100 km the well should be considered environmental sensitive
Name of oil (with valid weathering study)	Gudrun 2019/Gudrun 2012	Affects ERA and OSPA
Expected oil density at surface conditions (kg/m3)	811 kg/m3	Affects ERA and OSPA
Gas density/gravity (sg)	0.812	Affects ERA
Casing or liner design	9 7/8" casing	Affects blowout rates and ERA/OSPA
ID of dimensioning casing (if blowout) (inches)	8.553	Affects ERA
OD of drill string (inches)	5 7/8	Affects ERA
Water depth (m)	126	Affects ERA cont'd.
Estimated time for drilling (month)	Mar-Apr	Affects ERA and OSPA
Reference wells/ previous exploration wells in area (last 5 years)? Distances (km)?	25/7-7 Busta: 2.9 km 25/7-11 S Norma: 9.6 km 25/7-10 Lamba: 13.6 km	Affects ERA

3.3 Assumptions/limitations

- It is assumed a rig on Anchor for this study.
- The probability has included sidetrack, since optional sidetrack may be used.

4 Blowout probabilities

The well is assessed to be a high pressure, high temperature exploration well. As the GOR is below 1000 Sm3/Sm3, it is defined as an oil well. The statistics in [2] gives this type of well a blowout frequency of 6.65E-04 per year.

A rig on Anchor will be used for drilling the well with optional sidetrack. Based on information in [2] and an overall evaluation of different scenarios and sort 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 · 0,25 · 6,65E-04 = $3{,}33 \times 10^{-4}$
P (blowout with seabed release) = 2 · 0,75 · 6,65E-04 = $9{,}98 \times 10^{-4}$

5 Blowout rates

In the tables 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 distribution	**Scenario**	**Restriction**	**Restriction distribution**	**Total distribution**	**Surface**		**Seabed**	
					Initial rates (Sm^3/d)	**Weighted blowout rate (Sm^3/d)**	**Initial rates (Sm^3/d)**	**Weighted blowout rate (Sm^3/d)**
30 %	Top (5m)	Open	60 %	0,18	2995	539	2988	538
		95 % restr	40 %	0,12	2407	289	2407	289
40 %	Drilling ahead (50%)	Open	60 %	0,24	4939	1185	4928	1183
		95 % restr	40 %	0,16	3580	573	3578	572
30 %	Tripping (100%)	Open	60%	0,18	5280	950	5435	978
		95 % restr	40%	0,12	3868	464	3869	464
				Total		4001		4024

The weighted blowout rate for surface is 4001 and seabed is 4024 Sm^3/d. Using the distribution 25 % / 75 % for surface /seabed releases for a rig on Anchor (ch.4), the total weighted rate is estimated to 4000 Sm^3/d.

6 Blowout duration

6.1 Estimation of relief well duration

Well specific input about time to drill a relief well is given by the project and presented in **Error! Reference source not found.**. One assumption in the assessment of blowout duration is that one relief well is sufficient to kill the well. Need for a second relief well would require a re-evaluation.

Table 4: 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	35	43	55	Drilling 4 sections in overburden and 8 ½" section for killing operation.
4	Geomagnetic steering into the well	7	12	30	*Default values for horizontal/vertical wells (in order of appearance) are provided based on expert judgement.* *An argument must be provided for alterations in these numbers.*
5	Killing of well	1	2	5	

6.2 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.

6.3 Calculated blowout duration (including capping stack)

The probability distribution in Table 5 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 5 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		2,77 %
49		0,45 %
56		0,11 %
63		0,83 %
70		3,24 %
77		4,19 %
84		2,44%

Note: As the probability for 91 days (0,45%) days and 98 days (0,03%) was below 1% it has been added to the probability for 84% days.

Table 6 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 70 days	47,86	12,02 %
4	14 to 21 days	17,77	7,27 %	**4**	77 days	77,00	4,19 %
5	28 days	28,00	3,26 %	**5**	84 to 98 days	85,45	2,44 %
Sum weighted surface			**5,44**	**Sum weighted seabed**			**16,28**

As presented in Table 5, the maximum blowout duration is 28 days for surface release with a probability of 3,26%, and 84 days for seabed release with a probability of 2,44%. The weighted duration of a blowout is 5 days for surface and 16 days for seabed. In Figure 1 and Figure 2 the blowout probabilities and duration are illustrated.

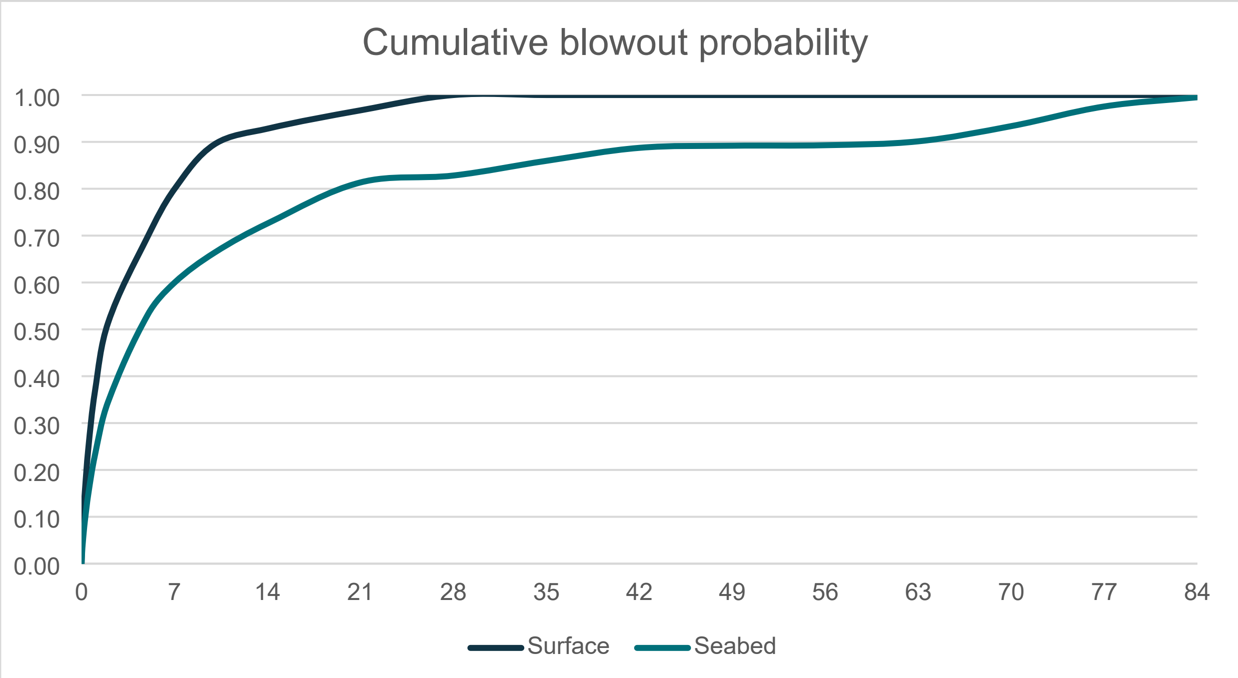


Figure 1 Blowout duration described by cumulative distributions, including capping stack

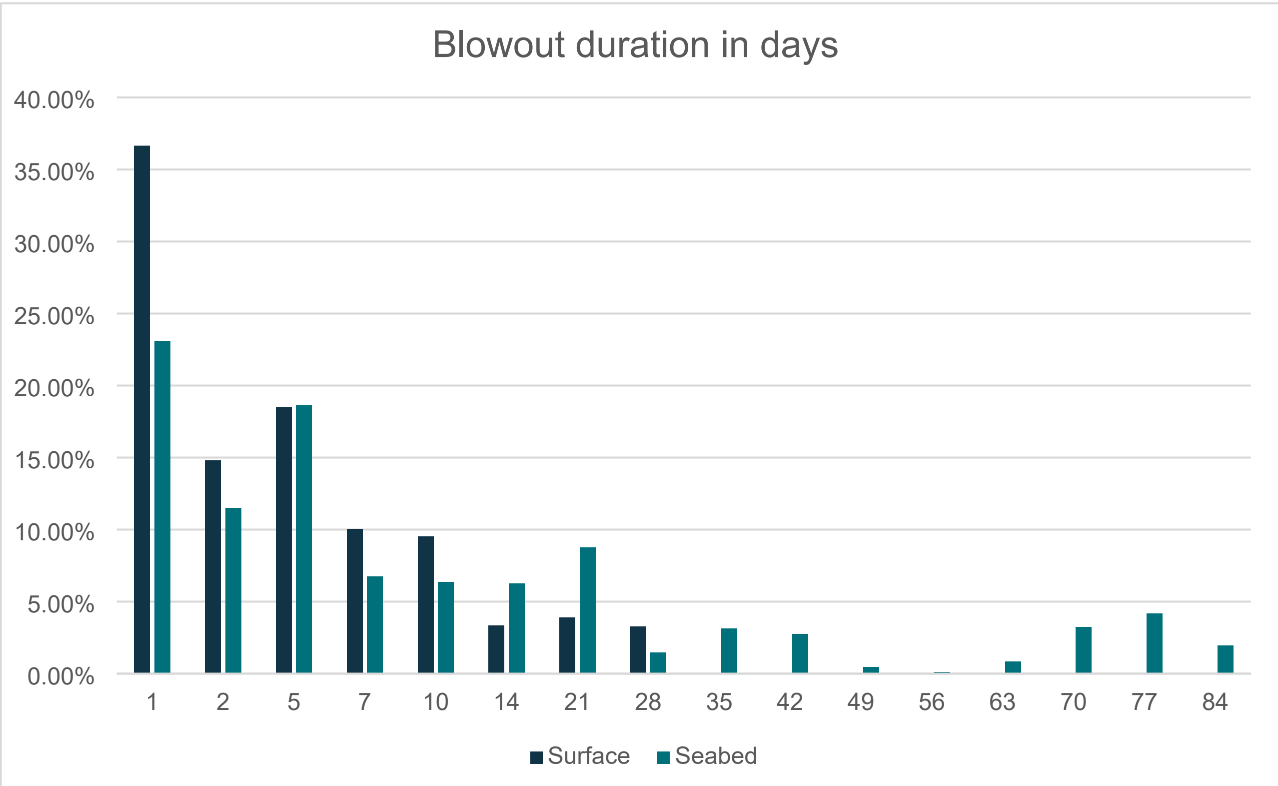


Figure 2 Blowout duration described by probability distributions, including capping stack

7 Uncertainties

This report is based on statistical values from [1]. These values are studies and treated in [**Error! Reference source not found.**]. 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 result due to assumptions made in the rate calculations is considered small.

8 Summary

Blowout frequency, rates and durations have been calculated, and estimates are provided.

The maximum probable duration is 84 with a probability of 2,44%. The weighted duration of a blowout is estimated at 5 days for surface releases and 16 days for seabed releases. The weighted blowout rate is 4000 Sm³/d, assuming use of a rig on anchor system.

The blowout frequency is expected to be 2 x 6,65E-04 = 1,33 x10-3 per year for drilling of this HPHT exploration well, included sidetrack.

9 References

1. SINTEF: "Blowout and Well Release Characteristics and Frequencies, 2023", Report no.: 2023:01489, 21 December 2023 “
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 25/7-13 Linga project in “Exploration input scheme 25/7-13 Linga BSA and ERA input”
5. NOROG: “Guidance on calculating blowout rates and duration for use in environmental risk analyses”, 2014

10 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 7. 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 7. 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.

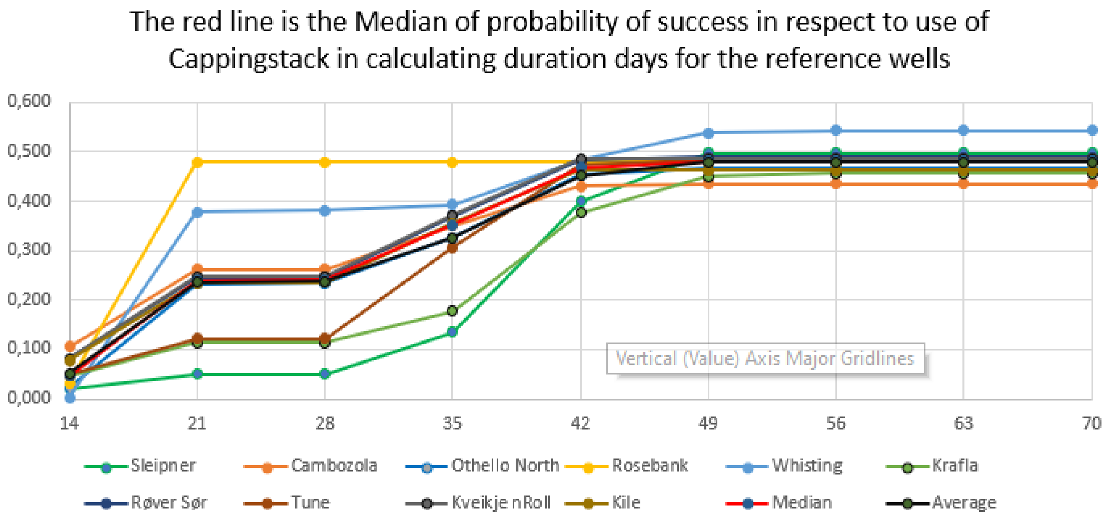
The detailed calculations performed for the capping stack may be found in the BSA reports for the wells referred to in Table 7.

Table 7 showing new recommended probabilities of successful use of cappingstack 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



11 Appendix B Parameters for blowout and kill simulations

11.1 Reservoir parameter

Table B-1 Reservoir parameters

Reservoir data	Unit	Brae Fm.	GeoX mean? Y/N	Comment
GeoX ID		731240		
Geo prognosis				
Trajectory (Compass name)		25/7-13 R00		
Deviation through reservoir		0		
Hole size		8.5''		
Top reservoir	mTVD MSL	4285	N/A	<At well penetration point (not apex)>
Base reservoir	mTVD MSL	4487	N/A	
Gas Oil Contact (GOC)	mTVD MSL	n/a		
Oil Water Contact (OWC)	mTVD MSL	4514		At well location – O/GDT
Gas Water Contact (GWC)	mTVD MSL	4514		
Net/Gross	ratio	0.19	Y	
Net pay	mTVD	38	n	At wellbore intersection
Net pay	mMD	38	n	At wellbore intersection
Porosity	v/v	0.195	Y	
Absolute permeability	mD	27.5	Y	Mean arithmetic permeability
Effective permeability	-			
Sw, Water saturation	fraction	0.15	Y	Initial water saturation
Kv/Kh	ratio			<Default value 0.1>
Reservoir pressure	bar	802.4	N/A	<At top reservoir> Add comment: PP version
Depleted pressure	bar	n/a	N/A	<State how many days depletion>
Reservoir temperature	°C	142	N/A	At top reservoir depth
Radius (r_e) (if X&Y not given)	m	-	N/A	<Drainage area (HC-filled reservoir)>
Length along well (X)	m	1500	N/A	<Rectangular outline of reservoir drainage area (HC-filled only)>
Width across well (Y)	m	575	N/A	
Position of well within reservoir (X_1)	m	250	N/A	
Position of well within reservoir (Y_1)	m	500	N/A	

11.2 Fluid Parameters

Fluid properties at standard conditions, and the simulated fluid properties at reservoir conditions

Fluid data	Unit	Brae Fm.	GeoX mean? Y/N	Comment
Reference field/well for fluid properties (PVT)	Brae Fm	NO 25/7-7 Busta		
Reference fluid properties at surface conditions (15°C and 1 bar)				
Gas density	kg/m3	1	n/a	
Gas gravity (air=1)	sg	0.792	n/a	
Condensate density	kg/m3	810.9	n/a	
GOR	Sm3/Sm3	n/a		
GCR	Sm3/Sm3	810.6		
Calculated fluid properties at initial reservoir conditions (at top reservoir depth)				
Reservoir pressure	bar	802.4		
Reservoir temperature	°C	142		At top reservoir
Reservoir fluid density	g/cc	0.5111		
Gas density	g/cc	-		
Dew point	bar	377.0		Recalculated at Res. Cond.
Viscosity	cP	0.1053		Recalculated at Res. Cond.
Formation Volume Factor, Bo/Bg [1)]	Rm^3/Sm^3	0.003864		[1)] At dew point.
CO_2	mol%	2.19		
N2	mol%	0.234		
H_2S	ppm	5-7		From empirical correlation

12 Appendix C BSA Methodology- Scenario Distribution and Blowout duration

Blowout scenarios

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 exploration 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 **Error! Reference source not found.**, 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’’

Blowout duration, exploration wells

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

Blowout stopping mechanisms:

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.

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).

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.

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.

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.

Background for duration calculations

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 C-1 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 4 and 6.2).