Blowout scenario analysis, 6610/7-3 Arkenstone well

Summary
This note presents the assessment of blowout frequency, rate, and duration for the 6610/7-3 Arkenstone wildcat well. The analysis is based on input from the 6610/7-3 Arkenstone project, available blowout statistics and internal guidelines.

Blowout frequency, rates and durations are calculated, and estimates are given. For 6610/7-3 Arkenstone wildcat well, the blowout frequency is judged to $1{,}18 \times 10^{-4}$ per year. The weighted blowout rate for the well is 1900 Sm^3/d.

Maximum probable duration is 63 days with a 3 % probability, while the weighted duration of a blowout with release on surface is 5 days and for seabed releases it is 13 days.

1 Introduction

In this document, the blowout frequency, rates and possible duration of a blowout during drilling is discussed, and results given for the 6610/7-3 Arkenstone well. This is performed as input to the Environmental Risk Analysis and the oil spill analysis.

2 Abbreviations

BSA	Blowout Scenario Analysis
BOP	Blowout preventer
DMA	Dead-man anchor
GOR	Gas Oil 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, are based on GL0498 [3] and the following:

- Statistics for blowout and well leak frequencies [1]
- Input from 6610/7-3 Arkenstone project, collected in [4]
- Judgements and considerations in TDI OG FOS SAPT SAF and in dialogue with 6610/7-3 Arkenstone organisation

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

The Arkenstone well is in the Norwegian Sea, with ED50 coordinates 66° 27’ 11.95” N, 10° 11’ 35.08 ” E (block 6610/7-3). For the drilling, a semi-sub rig on anchors is assumed. Water depth is about 230m. The GOR is estimated to 51,8 Sm^3/Sm^3.

Table 1 Relevant data for ERA/oil spill preparedness, 6610/7-3 Arkenstone

Parameter	Value
Surface location (coordinates in ED50 datum)	66° 27' 11.95" N 10° 11' 35.08 " E
Distance to shore (km)	~80 km
Name of oil (with valid weathering study)	Svale
Expected condensate density at surface conditions (kg/m3)	892
Gas density/gravity (sg)	0.667
Casing or liner design	Liner design (9 5/8" liner)
ID of surface casing (in)	13 3/8" casing
OD of drill string (in)	5.875
Water depth (m)	230 m
Estimated time for drilling (month)	July
Reference wells/ previous exploration wells in area (last 5 years)? Distances (km)?	Toutatis, ~53 km (north-east)

3.3 Assumptions/limitations

It is assumed a rig on anchors for this study.
For the rig on anchor, it is assumed that the rig will be disconnected at least after 28 days, which is the same assumption as for a rig on DP.
The Arkenstone well is planned as one main- bore well drilling into the reservoir.
This is a 2-reservoir zone well, and the scenario distribution is assumed split as a multi reservoir well. . In this study the scenarios are analysed in respect to the Tilje formation as the Åre formation will be drilled above the hydrocarbon/water contact. The scenario distribution is described in Table 2

Table 2 The scenario distribution for the different reservoir zones

Scenario distribution	Scenario	Penetration Reservoir Zones
30 %	Top penetration	Tilje
40 %	Drilling ahead	Tilje
30 %	Tripping	Tilje

4 Blowout probabilities and scenarios

Frequency
The 6610/7-3 Arkenstone well is assumed by the project to be a "normal well" (i.e. not HPHT), as well as an wildcat well, with a one single track. As the GOR is 51.8Sm^3/Sm^3, the well is defined as an oil well. The statistics in [2] gives this type of well a blowout frequency of 1,18x10^{-4} per year.

A rig on anchors will be used for drilling the well. 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) = $0,25 \cdot 1,18 \cdot 10^{-4} = 2,95 \cdot 10^{-5}$

- P(blowout with seabed release) = $0{,}75 \cdot 1{,}18 \cdot 10^{-4} = 8{,}85 \cdot 10^{-5}$

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 3, the following probabilities are recommended:

- P(Top penetration | blowout) = 0,30
- P(Tripping | blowout) = 0,30

Given the above definition of scenarios:

- P(Drilling ahead | blowout) = 1 – P(Top penetration | blowout) – P(Tripping | blowout) = 0,40

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

Table 3 Blowout rates – initial and weighted rates 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 penetration	Open	60 %	0,18	717	129	335	60
		95 % restr	40 %	0,12	630	76	332	40
40 %	Drilling ahead	Open	60 %	0,24	3294	791	1788	429
		95 % restr	40 %	0,16	1775	284	1483	237
30 %	Tripping	Open	60 %	0,18	5575	1004	3434	618
		95 % restr	40 %	0,12	2392	287	2251	270
				Total		2570		1655

The weighted surface blowout rate is 2600 Sm^3/d and seabed blowout rate is 1700 Sm^3/d (rounded to the nearest 100). Using the distribution 25 % / 75 % for surface /seabed releases for a rig on anchors (ch.4), the total weighted rate is calculated to 1900 Sm^3/d.

6 Blowout duration, Arkenstone wildcat 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 anchors (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 0).

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. One assumption in the assessment of blowout duration is that one relief well is sufficient to kill the well. Also, the relief well is assumed to drill into a horizontal well. Need for a second relief well would require a re-evaluation.

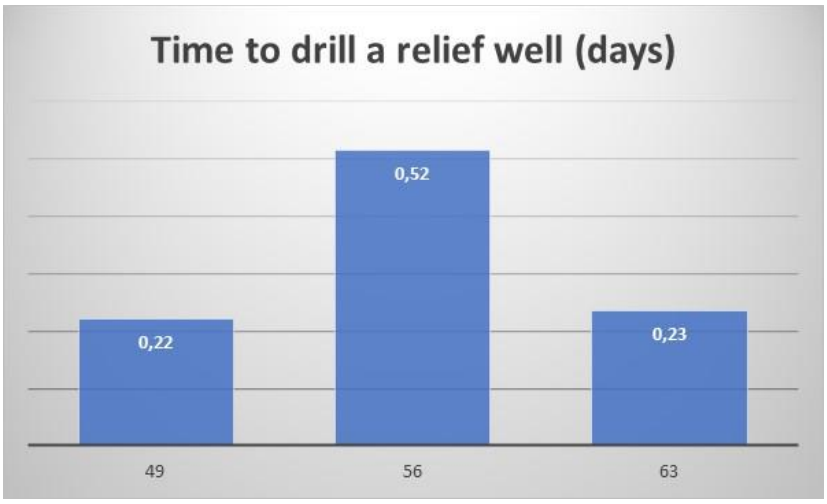
Table 5: Time to drill a relief well (days)

	Min*)	Most likely	Max	Comments
1- Decision to mobilize	1	1	2	
2- Mobilization of rig, including: collection of equipment/rearmament, transit, anchoring and preparation	9	12	25	
3- Drilling down to the specific depth	16	21	25	Drilling top hole and 12 ¼" section
4- Geo magnetic steering into the well[2]	7	12	20	Vertical well
5- Killing of well	1	2	5	
Sum	34	48	77	

A Monte Carlo simulation is performed to produce a duration distribution from the well specific input in Table 5. The statistical expected time for drilling a relief well when other well kill scenarios has not succeeded/occurred, is estimated to 52 days. A probability distribution is presented in Figure 1.

[2] 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.

Figure 1 is showing the time to drill a relief well and the probability of success



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 47 %.

The duration of the different parts of a vertical capping stack installation for the 6610/7-3 Arkenstone operations are given in the tables below. The Othello North well is used as reference well for Arkenstone as the Othello North well is located in the same area in the North Sea (Othello North in Nordland 2 close to Norne and Arkenstone to the northeast in the Nordland 1 area) and the GOR and blowout rates are comparable, and the water depths are in the same range between 200-300m. Grey cells are default values (as in App. A), and these are based on expert judgement from the discipline ladder and several capping stack workshops for exploration wells. 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 of vertical installation, P(vertical) is based on well specific evaluations and expert judgements, and set to 0,6 for the 6610/7-3 Arkenstone well, ref. Appendix A.

Table 6 Vertical capping stack - duration for the different time steps for the different activities related to the cap&contain operation. Grey values are assumed well independent and based on North Sea wells. Values from Othello North, applied for Arkenstone

		Vertical lowering – in days			
Part	**Description**	**P(delay)**	**Min**	**Mean**	**Max**
Decision	Time lost before mobilization is started		1	1	1
Mobilization	Equipment and resource set-up, parts and personnel transportation, ready for deployment from shore *Justification: Typical values for NCS*		8	10	14
Deployment	Time to deploy equipment to site and get ready for operation (typically, 1-3 days for the NCS). *Justification: Typical values for NCS. The area is in the North Sea*		2	3	4
Additional time for debris clearance	Time necessary for debris (pipe, items from the rig etc.) clearance beyond the time of decision, mobilization, and deployment (LMRP disconnect successful). *Justification: Typical values for NCS*	P(add time) = 2 %	2	2	2
Stack installation	Transit carrier with capping stack to WH/BOP and install stack on the blowing well • Transit stack to WH/BOP • Connect • Shut in well *Justification: Typical values for NCS for this water depth*		Hours a) 8 b) 1 c) 8	Hours a) 12 b) 1,5 c) 8	Hours a) 24 b) 2 c) 8
Operational delays	Delays throughout operation, not covered by above factors, e.g., mobilization and fabrication, weather, vessel availability, position control and coordination/collaboration during subsea mooring, equipment failure (ROV, carrier, mooring wires, air supply systems, debris), operational failures (communication, sim ops 2+ vessels) *Justification of probability: Well will be drilled during summer/ period*	P(delay summer) = 1 %	2	3	7

Table 7 Offset capping stack - duration for the different time steps for the different activities related to the cap&contain operation. Grey values are assumed well independent and based on North Sea wells. Values from Othello North, applied for Arkenstone

		Offset lowering – in days			
Part	**Description**	**P(delay)**	**Min**	**Mean**	**Max**
Decision	Time lost before mobilization is started		1	1	1
Mobilization	Equipment and resource set-up, parts and personnel transportation, ready for deployment from shore		14	18	28
Deployment	Time to deploy equipment to site and get ready for operation (typically, 4-6 days for the NCS)		3	5	7
Prepare offset installation system	Plan subsea layout, establish wet storage area (mooring corridors, dead man anchors etc.), typically 15 runs. Restrict to additional time beyond mobilization and deployment.		2	3	4
Set up offset installation system	Deploy equipment in wet storage area and set up offset installation system (3 x DMA installations, air systems using wires/tug lines between two boats). Sensitive weather conditions (through splash zone).		3	4	8
Additional time for debris clearance	Time necessary for debris (pipe, items from the rig etc.) clearance beyond the time of decision, mobilization, and deployment (LMRP disconnect successful).	P(add time) = 2 %	2	3	4
Stack installation	Transit carrier with capping stack to WH/BOP and install stack on the blowing well • 7a. Transit stack to WH/BOP • 7b. Connect • 7c. Shut in well		a) 24 hrs b) 8 hrs c) 8 hrs	a) 27 hrs b) 12 hrs c) 8 hrs	a) 36 hrs b) 24 hrs c) 8 hrs
Operational delays	Delays throughout operation, not covered by above factors, e.g. mobilization and fabrication, weather, vessel availability, position control and coordination/collaboration during subsea mooring, equipment failure (ROV, carrier, mooring wires, air supply systems, debris), operational failures (communication, sim ops 2+ vessels)	P(delay summer) = 2 %	2	5	20

6.4.3 Calculated blowout duration (including capping stack)

The probability distribution in Table 8 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 8 Probability distribution for a blowout to end as a function of time (days)

Duration (days)	Surface blowout	Seabed blowout	Duration (days)	Surface blowout	Seabed blowout
1	36,65 %	23,07 %	**42**	0,00 %	0,35 %
2	14,80 %	11,50 %	**49**	0,00 %	2,62 %
5	18,48 %	18,64 %	**56**	0,00 %	5,77 %
7	10,04 %	8,03 %	**63***	0,00 %	2,59 %
10	9,51 %	14,54 %			
14	3,35 %	3,53 %			
21	3,92 %	3,04 %			
28	3,26 %	4,18 %			
35	0,00 %	1,88 %			

** For blowout duration exceeding 63 days the probability less than 0,3% is added to 63 days duration.*

Table 9 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	10,80	29,14 %
3	10 to 14 days	11,04	12,86 %	**3**	28 to 49 days	36,09	9,03 %
4	21 days	21,00	3,92 %	**4**	56 days	56,00	5,77 %
5	28 days	28,00	3,26 %	**5**	63 days	63,62	2,85 %
Sum weighted surface			**5,44**				**12,84**

** For blowout duration exceeding 63 days the probability less than 0,3% is added to 63 days duration.*

As presented in Table 8, the maximum blowout duration is 63 days for seabed release, while Table 9 indicates a weighted duration of 5 and 13 days for surface and seabed releases respectively. In

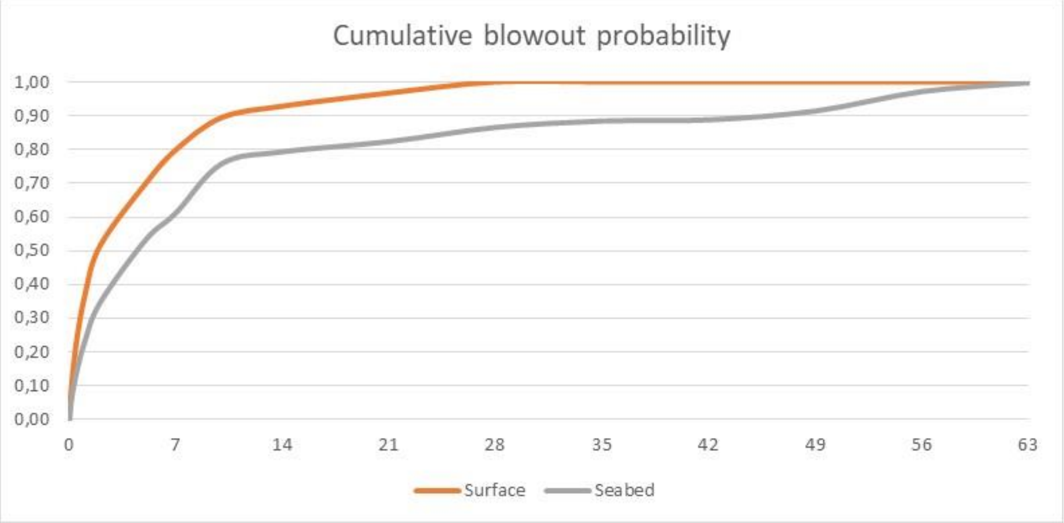


Figure 2 and Figure 3 the blowout probabilities and duration are illustrated.

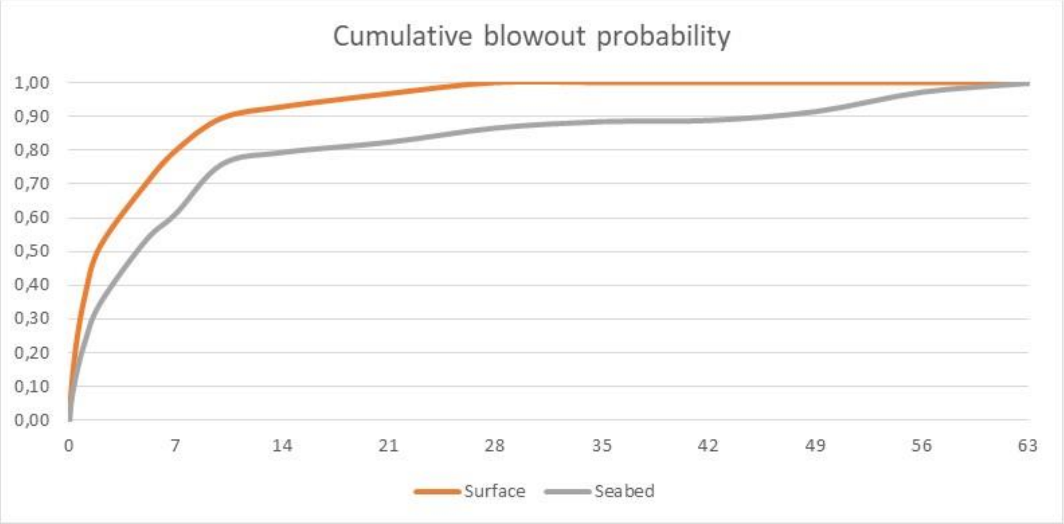


Figure 2 Blowout duration described by cumulative distributions, including capping stack

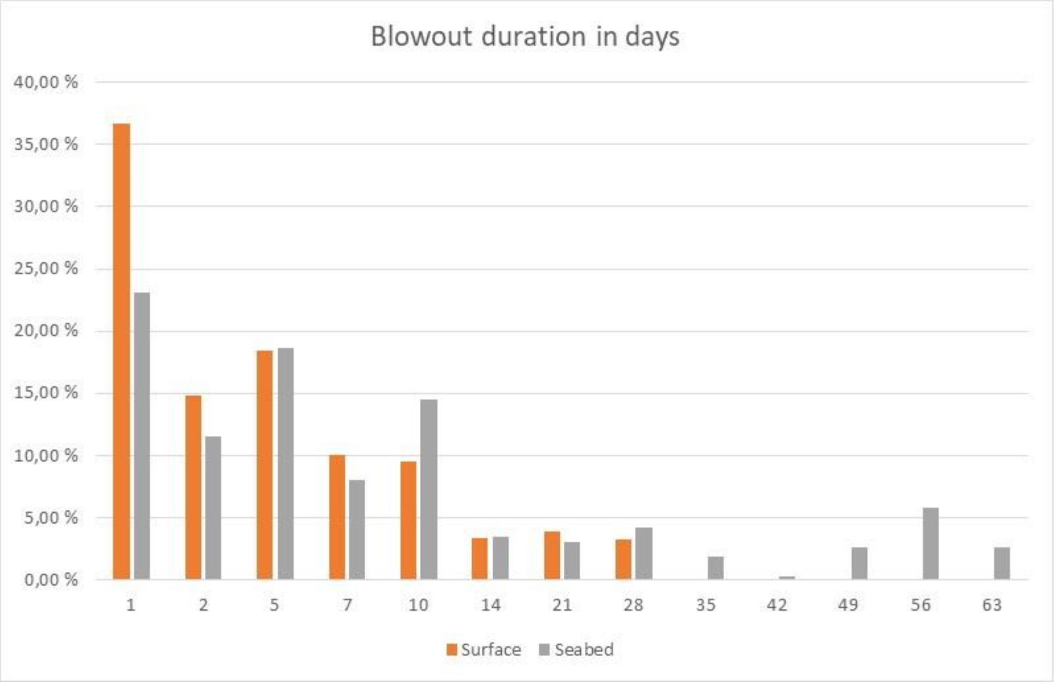


Figure 3 Blowout duration described by probability distributions, including capping stack

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. Some values are estimated values and the uncertainty in the final result due to these estimates is considered small.

8 Summary

Blowout frequency, rates and durations are calculated, and estimates are given. For 6610/7-3 Arkenstone wildcat well, the blowout frequency is judged to $1,18 \times 10^{-4}$ per year. The weighted blowout rate for the well is 1900 Sm^3/d.

Maximum probable duration is 63 days with a 3 % probability, while the weighted duration of a blowout with release on surface is 5 days and for seabed releases it is 13 days.

9 References

1. Sintef: “Blowout and Well Release Characteristics and Frequencies, 2022”, Dok.nr. 2021:00131, Final rev., Jan 2022
2. Vysus: “Blowout and Well Release Frequencies – based on Sintef Offshore Blowout Database 2022”, report 19101001-8/2023/R3, rev Final, April 2023
3. Equinor: GL0498 “Guideline for Blowout Scenario Analysis as input to Environmental Risk Analysis” rev.2
4. Information from the 6610/7-3 Arkenstone project in “Exploration input scheme 6610/7-3 Arkenstone BSA and ERA input”
5. NOROG: “Guidance on calculating blowout rates and duration for use in environmental risk analyses”, 2014

Appendix A Probabilities related to use of capping stack. Values from Othello North, applied for Arkenstone

The table below is the result of a capping stack workshop with mainly relevant project personnel and the discipline ladder. It shows the probability for the different aspects of the use of capping stack. Grey cells are set default values for capping stack operations. Blue and green cells are calculated values. The value in the green cell is used as input in the duration calculation.

Success, P(capping stack)		0.4664
P(blowout not through WH/BOP)		0.3
P(outside spec)		0.1585
P(outside technical spec)	The technical spec has limitations like - water depth > 12500 ft/3810 m - max wellhead pressure (15K psi / ca 1000 bar) - GOR (liquid rate 15900 Sm3/d with GOR 356)	0.01
P(outside operational window)	Capping operation not undertaken due to restrictions related to environmental conditions, blowout rate and medium (uplift forces from flowing well) and vessel capabilities. E.g., · Water depth · Weather · Sea current · Vessel condition · Blowout flow rate · Blowout medium composition (GOR) *(Justification of value: generic value of 0,1 for NCS)*	0.15
P(Landing point not available)		0.0685
P(damaged landing points)	Most likely cause is failure of emergency disconnect to LMRP in case of loss of position	0.03
P(tilted wellhead)		0.03
P(no access)	The probability of this scenario is low and could be excluded if there are not specific conditions that suggest otherwise (e.g. subsea installations) makes installation impossible even after debris clearance.	0.01
P(failed operation)		0.1500
P (Failed operation | vertical)		0.1179
P(vertical)	The probability of vertical installation, P(vertical) should be based on well specific evaluations on the most probable installation method based on e.g. surface conditions (plume, induced currents, water depth). *(Justification of value: well is at 230m water depth)*	0.6
P(inflict critical damage to landing point | vertical)	The probability of damaging landing point (connectors, wellhead/BOP) during the deployment and installation phase is dependent on the type of installation method. The probability of this occurring during vertical installation is low and comparable to BOP installation.	0.01
P(failed well integrity)	The probability of failed well integrity during the capping stack installation (i.e. blowout outside casing) is studied in the well planning phase (casing collapse study) and should be based on well specific input. *(Justification of value: Not HPHT well, standard design, assumed casing collapse probability low)*	0.1
P(capping blind shear ram not sealing)	Given inside spec, the probability of the blind shear ram not sealing is low and is not accounted for in the model.	0.01
P (Failed operation | offset)		0.1981
P(offset)	(max water depth 600 m)	0.4
P(inflict critical damage to landing point | offset)	The probability for damaging the landing point during offset installation is less compared to vertical installation method. However, overall operations prior to landing capping stack is more complex than vertical.	0.1