

## **Blowout scenario analysis, Mistral Sør**

Doc. No.

Valid from:

Rev. no.

---

## Summary

This memo presents a quantitative assessment of blowout risk related to drilling of the exploration well Mistral Sør (6406/6-7). The analysis is based on input from the Mistral Sør project, available blowout statistics and internal guidelines.

Maximum probable duration is 63 days with a 4,4 % probability. The weighted duration of a blowout for surface is 5 days and seabed releases are 15 days. The weighted blowout rate is 7500 Sm<sup>3</sup>/d, assuming use of anchored rig.

The blowout frequency is expected to be  $1.09 \times 10^{-4}$  per year, due to drilling of a normal exploration oil well.

## Contents

<b>1</b>	<b>Introduction</b> .....	<b>5</b>
<b>2</b>	<b>Abbreviations</b> .....	<b>5</b>
<b>3</b>	<b>System description</b> .....	<b>5</b>
3.1	General .....	5
3.2	Well specific information .....	5
3.3	Assumptions/limitations .....	6
<b>4</b>	<b>Blowout probabilities and scenarios</b> .....	<b>6</b>
<b>5</b>	<b>Blowout rates</b> .....	<b>8</b>
<b>6</b>	<b>Blowout duration, Mistral Sør wells (6406/6-7)</b> .....	<b>8</b>
6.1	General .....	8
6.2	Blowout stopping mechanisms .....	9
6.2.1	Operator action /6/ .....	9
6.2.2	Bridging /6/ .....	9
6.2.3	Coning /6/ .....	10
6.2.4	Drilling a relief well /6/ .....	10
6.2.5	Capping stack /3/ .....	10
6.3	Background for duration calculations .....	11
6.3.1	Historical data .....	11
6.4	Duration of the blowout .....	11
6.4.1	Estimation of relief well duration .....	11
6.4.2	Capping stack input .....	12
6.4.3	Calculated blowout duration (including capping stack) .....	12
<b>7</b>	<b>Uncertainties</b> .....	<b>14</b>
<b>8</b>	<b>Summary</b> .....	<b>14</b>
<b>9</b>	<b>References</b> .....	<b>15</b>
	<b>Appendix A Probabilities related to use of capping stack</b> .....	<b>16</b>
	<b>Appendix B Reservoir and fluid parameters</b> .....	<b>18</b>

## 1 Introduction

To verify whether existing local Environmental Impact Statement (EIS) is valid for the Mistral Sør exploration well, information regarding blowout duration, rates and frequencies for this well is required. In this document, the blowout frequency, rates and possible duration of a blowout is discussed, and results given.

## 2 Abbreviations

BSA	Blowout Scenario Analysis
BOP	Blowout preventer
DMA	Dead-man anchor
DP	Dynamic positioning system
EIS	Environmental Impact Statement
ERA	Environmental Risk Analysis
GOR	Gas Oil Ratio
MSL	Mean Sea Level
NCS	Norwegian Continental Shelf
OSPA	Oil Spill Preparedness Analysis

## 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:

- Blowout and well leak frequencies /2/
- Input scheme for blowout scenario analyses from project /4/
- Judgements and considerations in TDI OG FOS SAPT SAF

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 Mistral Sør well (6406/6-7) is planned to be drilled in late fall 2024. The location is in the Norwegian Sea, with surface coordinates of 64° 39' 53.9" N and 6° 51' 55.28" E. For the drilling, a semi-sub rig on anchor is planned. Water depth is about 260 m. The GCR is estimated to 963 Sm<sup>3</sup>/Sm<sup>3</sup>. See App.B for further details on reservoir and fluid properties.

**Table 1 Relevant data for ERA/oil spill preparedness, Mistral Sør /4/**

<b>Surface location (coordinates in ED50 datum)</b>	64° 39' 53.9 N 6° 51' 55.28 E	Affects ERA and OSPA
<b>Distance to shore (km)</b>	~118 km (small islands by Frøya/Froan)	Closer than 100 km the well should be considered environmental sensitive
<b>Name of oil (with valid weathering study)</b>	Smørbukk condensate (2003)	Affects ERA and OSPA
<b>Expected oil density at surface conditions (kg/m<sup>3</sup>)</b>	823.4	Affects ERA and OSPA
<b>Gas density/gravity (sg)</b>	0.758	Affects ERA
<b>Casing or liner design</b>	Casing design	Affects blowout rates and ERA/OSPA
<b>ID of dimensioning casing (if blowout) (inches)</b>	8.553 (9 7/8" casing)	Affects ERA
<b>OD of drill string (inches)</b>	5"OD drill pipe and 6.75" OD BHA (~160m at the bottom)	Affects ERA
<b>Water depth (m)</b>	260	Affects ERA cont'd.
<b>Estimated time for drilling (month)</b>	October/ November	Affects ERA and OSPA
<b>Reference wells/ previous exploration wells in area (last 5 years)? Distances (km)?</b>	6406/5-2 ST2 Tott West (19.3 km) 6406/6-6 S Jasper (7.7 km)	Affects ERA

### 3.3 Assumptions/limitations

- It is assumed a rig on anchor for this study.
- The well is assumed to be drilled during late fall (October/November).
- The Mistral Sør well is planned as a single, normal, exploration well, with two similar reservoir zones.

## 4 Blowout probabilities and scenarios

### Frequency

The Mistral Sør wells are assessed to be a normal well, as well as an exploration. As the GCR is 963 Sm<sup>3</sup>/d, the well is defined as an oil well. The statistics in /2/ gives this type of well a blowout frequency of 1.09 x 10<sup>-4</sup> per year.

A rig on anchor 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:

$$P(\text{blowout with seabed release}) = 0.75 \times 1.09 \cdot 10^{-4} = 8.18 \cdot 10^{-5}$$

$$P(\text{blowout with surface release}) = 0.25 \times 1.09 \cdot 10^{-3} = 2.73 \cdot 10^{-5}$$

Doc. No.

Valid from:

Rev. no.

### 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.

The overview of blowout causes given in /1/ combined with assumptions of annular flow do, in our opinion, justify the following probabilities:

$$P(\text{Top penetration} \mid \text{blowout}) = 0,20$$

$$P(\text{Tripping} \mid \text{blowout}) = 0,40$$

Given the above definition of scenarios:

$$P(\text{Drilling ahead} \mid \text{blowout}) = 1 - P(\text{Top penetration or tripping} \mid \text{blowout}) = 0,40$$

As per /3/, the following probabilities are recommended:

- Top penetration: 5 m into reservoir – 30 %
- Drilling ahead: 50 % into reservoir (Garn/Ile HC column)- 40 %
- Tripping: fully penetrated reservoir – 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"

These hole sizes represent a restriction of ca. 95 %.

## 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, and the rates are rather similar.

**Table 2 Blowout rates – initial and weighted blowout rates**

Scenario distribution	Scenario	Restriction	Restriction distribution	Total distribution	Surface		Seabed	
					Initial rates (Sm <sup>3</sup> /d)	Weighted blowout rate (Sm <sup>3</sup> /d)	Initial rates (Sm <sup>3</sup> /d)	Weighted blowout rate (Sm <sup>3</sup> /d)
30%	Top penetration	Open	60%	0.18	6264	1128	6251	1125
		95 % restr	40%	0.12	5036	604	5036	604
40%	Drilling ahead	Open	60%	0.24	9126	2190	9116	2188
		95 % restr	40%	0.16	6824	1092	6824	1092
30%	Tripping	Open	60%	0.18	9455	1702	9444	1700
		95 % restr	40%	0.12	7014	842	7016	842
					<b>Weighted rate</b>		<b>7500</b>	<b>7500</b>
					<b>Total weighted rate</b>		<b>7500</b>	

Thus, the weighted rate for surface and seabed blowouts are both 7500 Sm<sup>3</sup>/d, thus weighted blowout rate is also 7500 Sm<sup>3</sup>/d.

## 6 Blowout duration, Mistral Sør wells (6406/6-7)

### 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 /6/

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 /6/

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 /6/

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 /6/

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 3 Weibull parameters for calculating duration of blowout**

	$\alpha$	$\beta$	Asymptote
Bridge	0,70	6,00	0,63
CapTopside	0,80	2,30	0,62
CapSubsea	0,85	6,00	0,45
ReliefWell <sup>1</sup>	15	80	1

$T_{\text{Reliefwell}}$  is uniformly distributed between  $\alpha$  and  $\beta$ , while  $T_{\text{bridge}}/T_{\text{capping surface}}/T_{\text{capping Subsea}}$  has Weibull distributions. Note that for Relief well and Capping stack, specific input values are used (Table 4 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 4. 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 vertical well. Need for a second relief well would require a re-evaluation.

**Table 4: Time to drill a relief well (days)**

	Min <sup>*)</sup>	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	5	8	12	
3- Drilling down to the specific depth	25	30	36	
4- Geo magnetic steering into the well <sup>2</sup>	7	12	20	Assumed vertical well.
5- Killing of well	1	2	5	
Sum	38,5	53	75	

#### 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%. The background for this probability for success with use of capping stack is described in Appendix A.

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.

#### 6.4.3 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)**

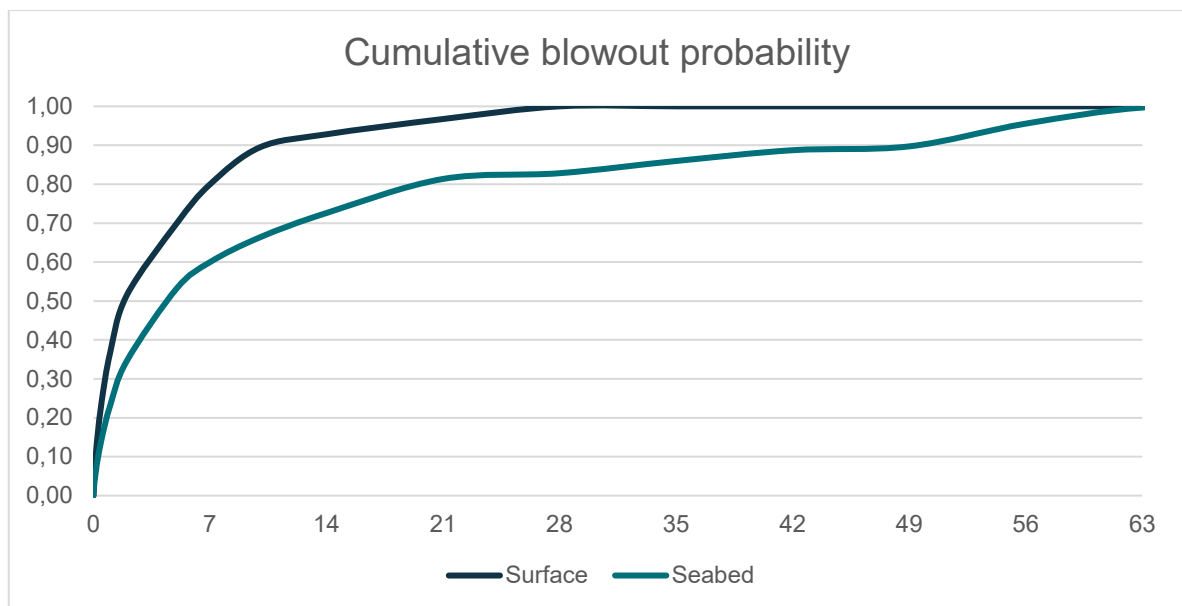
Duration (days)	Surface blowout	Seabed blowout	Duration (days)	Surface blowout	Seabed blowout
1	36.65%	23.07%	42	0.00%	2.77%
2	14.80%	11.50%	49	0.00%	0.99%
5	18.48%	18.64%	56	0.00%	5.85%
7	10.04%	6.76%	63	0.00%	4.40%
10	9.51%	6.38%			
14	3.35%	6.25%			
21	3.92%	8.75%			
28	3.26%	1.47%			
35	0.00%	3.14%			

<sup>2</sup> 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.

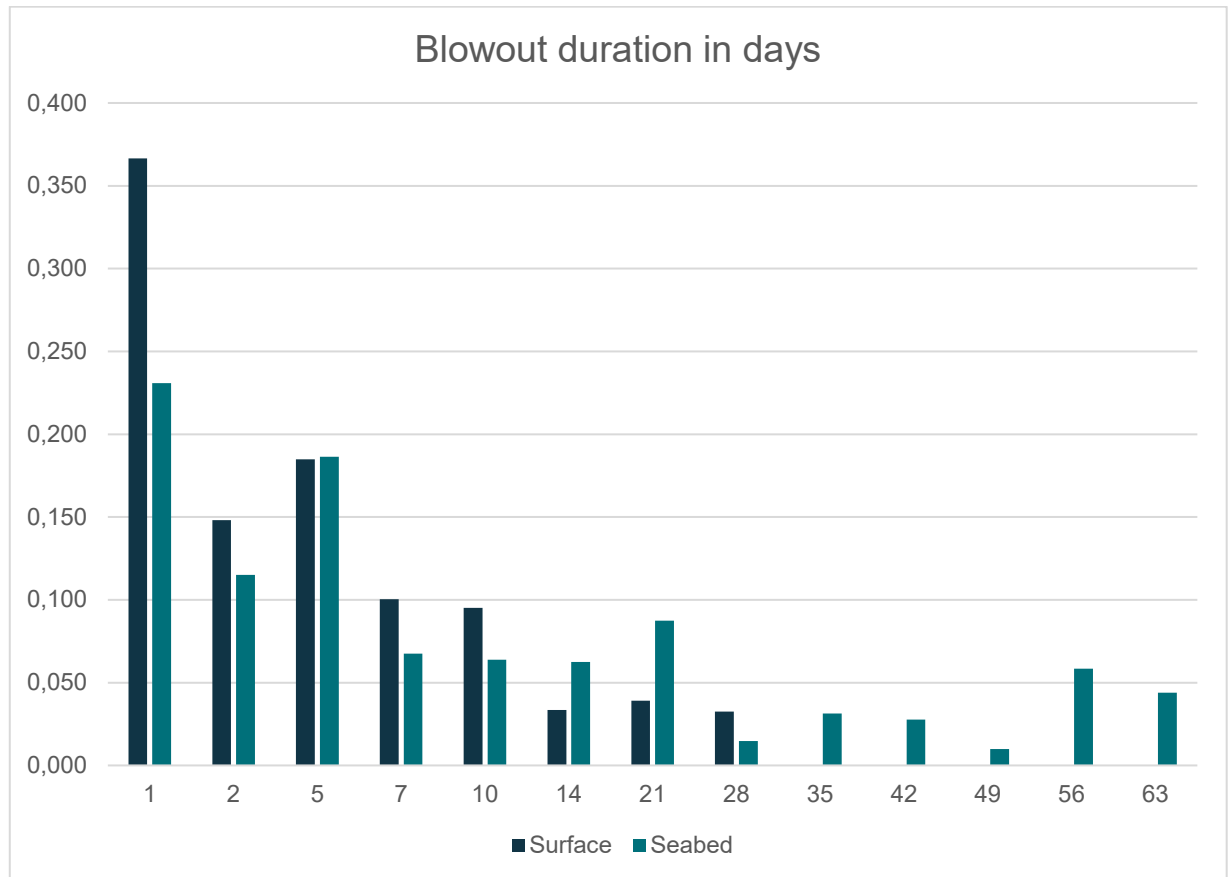
**Table 6 Weighted duration, including capping stack**

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%	1	1 to 5 days	2.6	53%
2	5 to 7 days	5.70	29%	2	7 to 21 days	13.6	28%
3	10 days	10.00	10%	3	28 to 49 days	37.7	8%
4	14 to 21 days	17.77	7%	4	56 days	56.0	6%
5	28 days	28.00	3%	5	63 days	63.5	5%
<b>Sum weighted surface</b>			<b>5.44</b>	<b>Sum weighted seabed</b>			<b>14.65</b>

As presented in Table 5, the maximum blowout duration is 63 days for seabed release with a probability of up to 4.4 %. The weighted duration of a blowout for surface is 5 days and seabed releases is 15 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 Subsurface 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. For Mistral Sør normal exploration well, the blowout frequency is judged to be  $1,09 \times 10^4$  per year. The weighted blowout rate is calculated to 7500 Sm<sup>3</sup>/d.

Maximum probable duration is 63 days with a 4.4 % probability. The weighted duration of a blowout for surface is 5 days and seabed releases is 15 days.

Doc. No.

Valid from:

Rev. no.

---

## 9 References

1. Sintef: "Blowout and Well Release Characteristics and Frequencies, 2023", Dok.nr. Report no.: 2023:01489, December 2023
2. Vysus: "2024 version of Blowout and Well Release Frequencies based on Sintef Offshore Blowout Database 2023", doc.ref. RMC0500833, rev Final, February 2024
3. Equinor: GL0498 "Guideline for Blowout Scenario Analysis as input to Environmental Risk Analysis" rev.2
4. "Exploration input scheme for blowout scenario analyses", May 21st, 2024
5. Blowout simulation report for MRABA NO\_6406/6-7, Mistral Sør, May 2024
6. NOROG: "Guidance on calculating blowout rates and duration for use in environmental risk analyses", 2014

## 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 cappingstack 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 (calculated elsewhere) 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.

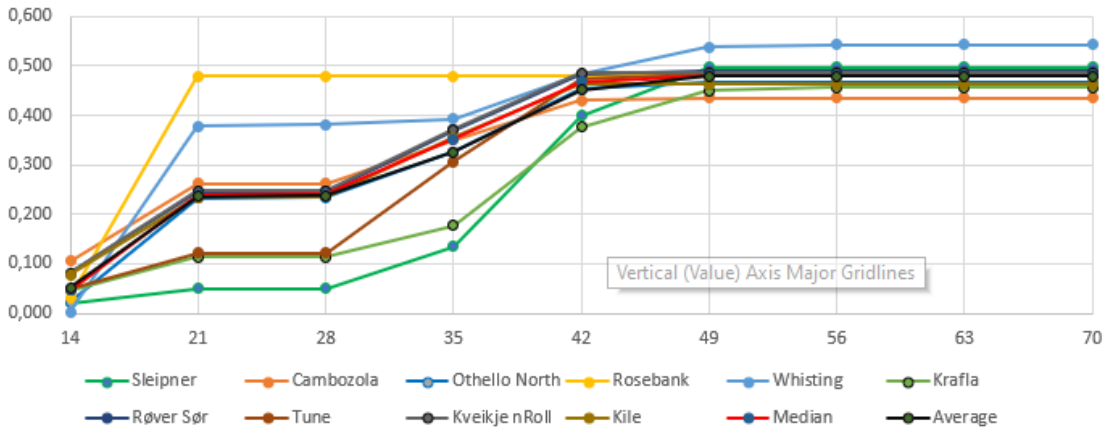
**Table 7 showing new recommended probabilities of successful use of cappingstack in the column to the right**

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	<b>0,047</b>
21	0,050	0,262	0,233	0,478	0,377	0,114	0,245	0,121	0,247	0,235	<b>0,240</b>
28	0,051	0,262	0,234	0,478	0,381	0,114	0,246	0,123	0,248	0,236	<b>0,241</b>
35	0,135	0,350	0,326	0,478	0,393	0,178	0,369	0,305	0,372	0,355	<b>0,352</b>
42	0,399	0,430	0,453	0,478	0,482	0,377	0,482	0,472	0,485	0,462	<b>0,467</b>
49	0,497	0,435	0,466	0,478	0,538	0,451	0,489	0,484	0,485	0,462	<b>0,481</b>
56	0,497	0,435	0,466	0,478	0,543	0,456	0,489	0,484	0,485	0,462	<b>0,481</b>
63	0,497	0,435	0,466	0,478	0,543	0,457	0,489	0,484	0,485	0,462	<b>0,481</b>
70	0,497	0,435	0,466	0,478	0,543	0,457	0,489	0,484	0,485	0,462	<b>0,481</b>

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

The red line is the Median of probability of success in respect to use of Cappingstack in calculating duration days for the reference wells



## Appendix B Reservoir and fluid parameters

Table B-1 Reservoir parameters

Reservoir data	Unit	Garn Formation	Ile Formation	GeoX mean? Y/N	Comment
GeoX ID			785686		
Geo prognosis					
Trajectory (Compass name)					
Deviation through reservoir		0	0		
Hole size		8.5"	8.5"		
Top reservoir	mTVD MSL	3743.1	3879.6	N/A	
Base reservoir	mTVD MSL	3824.5	3959.3	N/A	
Gas Oil Contact (GOC)	mTVD MSL	N/A	N/A		<At well location>
Oil Water Contact (OWC)	mTVD MSL	N/A	N/A		
Gas Water Contact (GWC)	mTVD MSL	3813.0	3885.0		
Net/Gross	ratio	0.86	1		Value for the Ile Formation based on good sand in the uppermost Ile Formation in the nearest 6406/6-4 S well. Not representative if having a deeper filling in the Ile Formation in 6406/6-7 Mistral Sør.
Net pay	mTVD	60.1	5.4		
Net pay	mMD	60.1	5.4		<b>60.1 + 0.68 = 60.78m net for Garn</b>
Porosity	v/v	0.17	0.18	Res 1: Y Res 2: Y	<In the HC-bearing interval>
Absolute permeability	mD	221	28		See comment for the Ile Formation under "Net/Gross".
Effective permeability		198.9	25.2		<>
Sw, Water saturation	fraction	0.2	0.2		In the HC-bearing interval. See comment for the Ile Formation under "Net/Gross". No reduction in permeability for the first 0.1 v/v. 1% reduction in permeability for each 0.01 v/v step from 0.1 – 0.3 v/v water saturation.
Kv/Kh	ratio	0.1	0.1		
Reservoir pressure	bar	676.937	686.109	N/A	At top reservoir.
Reservoir temperature	°C	135.38	140.40	N/A	Temperature at top reservoir.
Radius (r <sub>e</sub> ) (if X&Y not given)	m	750	750	N/A	Radius of 750m.

**Table B-2 Fluid parameters**

Fluid data	Unit	Garn Fm.	Ile Fm.	GeoX mean? Y/N	Comment
Reference field/well for fluid properties (PVT)		NO 6406/6-4 S Tvillingen Sør Sample 2247- EA	NO 6406/6-4 S Tvillingen Sør Sample 2247- EA		
Reference fluid properties at surface conditions (15°C and 1 bar)					
Oil density	kg/m <sup>3</sup>	n/a	n/a	n/a	
Gas gravity (air=1)	sg	0.758	0.758	n/a	
Condensate density	kg/m <sup>3</sup>	0.8234	0.8234	n/a	
GOR	Sm <sup>3</sup> /Sm <sup>3</sup>	n/a	n/a		
GCR	Sm <sup>3</sup> /Sm <sup>3</sup>	962.6	962.6		
Calculated fluid properties at initial reservoir conditions (at top reservoir depth)					
Reservoir pressure	bar	676.937	686.109		
Reservoir temperature	°C	135.38	140.40		
Gas density	g/cc	0.4673	0.4654		
Dew point	bar	475.66	476.67		Recalculated in PVT-sim.
Viscosity at reservoir pressure	cP	0.091417	0.090428		
Formation Volume Factor, B <sub>g</sub> at reservoir pressure.	Rm <sup>3</sup> /Sm <sup>3</sup>	0.003825	0.003841		
CO <sub>2</sub>	mol%	3.259	3.259		
N <sub>2</sub>	mol%	0.226	0.226		
H <sub>2</sub> S	mol%	6.2 / 5.7	7.5 / 6.5		H <sub>2</sub> S calculator based on an SPE paper 50763 using temperature and CO <sub>2</sub> content as input.