Blowout scenario analysis for the Johan Castberg field

Title:		
Blowout scenario analysis for the Johan Castberg field		
Document no.: **ST-23027**	Contract no.:	Project: **Johan Castberg**

Classification: **Internal**	Distribution:
Expiry date:	Status: **Final**

Distribution date: **06.06.2023**	Rev. no.:	Copy no.:

Author(s)/Source(s): Bente Røiland Stiegler	
Subjects: Blowout scenario analysis, covering rates and frequencies for these events for the Johan Castberg field	
Remarks:	
Valid from:	Updated:
Responsible publisher:	Authority to approve deviations:

Prepared by (Organisation unit / Name): **TDI OG FOS SAPT SAF/ Bente Røiland Stiegler**	Date/Signature: Bente R. Stiegler
Responsible (Organisation unit/ Name):	Date/Signature: X
Recommended (Organisation unit/ Name): **TDI OG FOS SAPT SAF / Mette Roland**	Date/Signature: Mette Roland
Approved by (Organisation unit/ Name):	Date/Signature: X

Summary

This report provides input to the environmental risk analysis for the Johan Castberg field regarding blowout probability, rates, and duration. It presents a quantitative assessment of blowout risk related to the Johan Castberg field for the period 2024 to 2027. Blowout probability, flow rates and duration are quantified for application in the Johan Castberg Field environmental risk analysis (ERA).

For the Johan Castberg field, given as the sum of activity on Skrugard, Havis and Drivis, the year with the highest activity level and corresponding highest blowout probability is year 2025. This includes drilling and completion of Johan Castberg wells. The blowout probability for 2025 as high activity year is 1,84E-03, and 5,09E-04 for year 2026/27 with low activity. The P90 rate for Johan Castberg wells in a high activity year is 3900 Sm^3/d for surface and 4100 Sm^3/d for subsea releases. In a low activity year the P90 rate is 3700Sm^3/d.
The weighted blowout rate for drilling is 3400 Sm^3 for both surface and seabed in a high activity year. Low activity year does not have any drilling activity.

For the Skrugard wells, year 2024 has the highest activity and blowout probability with 1,54E-03. Low activity year is 2026/2027 with blowout probability 2,89E-04. The total P90 rate for Skrugard wells in a high activity year is 4000 for surface and 7600 Sm^3/d for seabed, and for low activity year seabed release is 3800 Sm^3/d.

For the Havis wells, year 2025 has the highest activity and blowout probability with 6,07E-04. Low activity year is 2024 with blowout probability 1,14E-04. The total P90 rate for Havis wells in a high activity year is 4000 Sm^3/d and for low activity year 3800 Sm^3/d.

For the Drivis wells, year 2025 has the highest activity and blowout probability with 5,01E-04. Low activity year is 2024 with blowout probability 3,63E-05. The total P90 rate for Drivis wells in a high activity year is 4100 Sm^3/d and for low activity year 7300 Sm^3/d.

It is found that the duration of a blowout could potentially amount to 70 days with about 1 % probability for surface and seabed releases for drilling/completion/production activities. The weighted blowout durations for blowout scenarios are 5 and 12 days for surface and subsea releases respectively.

Table of Contents

1 Introduction

The purpose of this report is to provide input to the environmental risk analysis for the Johan Castberg field regarding blowout probabilities, rates, and duration. Frequencies are calculated based on all activities in a high and a low activity year. For drilling activities, the blowout frequencies combined with rates give weighted drilling rates. For all activities, the blowout frequency combined with rates that gives P90 which covers 90 % of all blowout scenarios. The blowout duration is based on assessment of historic statistics for different mechanism that have stopped the blowout, and the estimates of the project concerning duration for drilling a relief well or use of capping stack.

2 Abbreviations

BSA	Blowout Scenario Analysis
CT	Coiled tubing
DP	Dynamic Positioning
Drilling WI	Drilling Water injection wells
Drilling GI	Drilling Gas injection wells
ESP	Electrical Submerged Pump
GOR	Gas Oil Ratio
HPHT	High Pressure High Temperature
LPT	Low Permeable/Tight
MLT wells	Mulitlateral wells
P	Probability
P90	The blowout rate that are the same as, or higher, than the blowout rate in 90 % of all blowouts scenarios
WH	Wellhead

3 System description

3.1 General

This blowout scenario analysis (BSA) of blowout frequencies, rates, and duration, are based on GL0498 [2] and the following:

- Statistics for blowout and well leak frequencies [1]
- Input from Johan Castberg, collected in [3]
- Judgements and considerations in TDI OG FOS SAPT SAF and in dialogue with Johan Castberg Field 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, well leaks are not included in the blowout scenario analysis, as these are of short duration and smaller blowout rates than blowouts - thus not causing a major contributor to oil spills or pollution. Also, shallow gas blowouts are excluded due to minimal environmental impact.

3.2 Field Specific Information

The Johan Castberg field is an oil and gas field located in lisence 532 in the Barents Sea. The field is located 240 km northwest of Hammerfest and 100 km north northwest of Snøhvit.
The Johan Castberg field consists of the three reservoir structures Skrugard, Havis and Drivis. Havis is approximately 7 km southwest of Skrugard and Drivis is approximately 7 km south of Havis. The water depths on the field is 360-390 m.

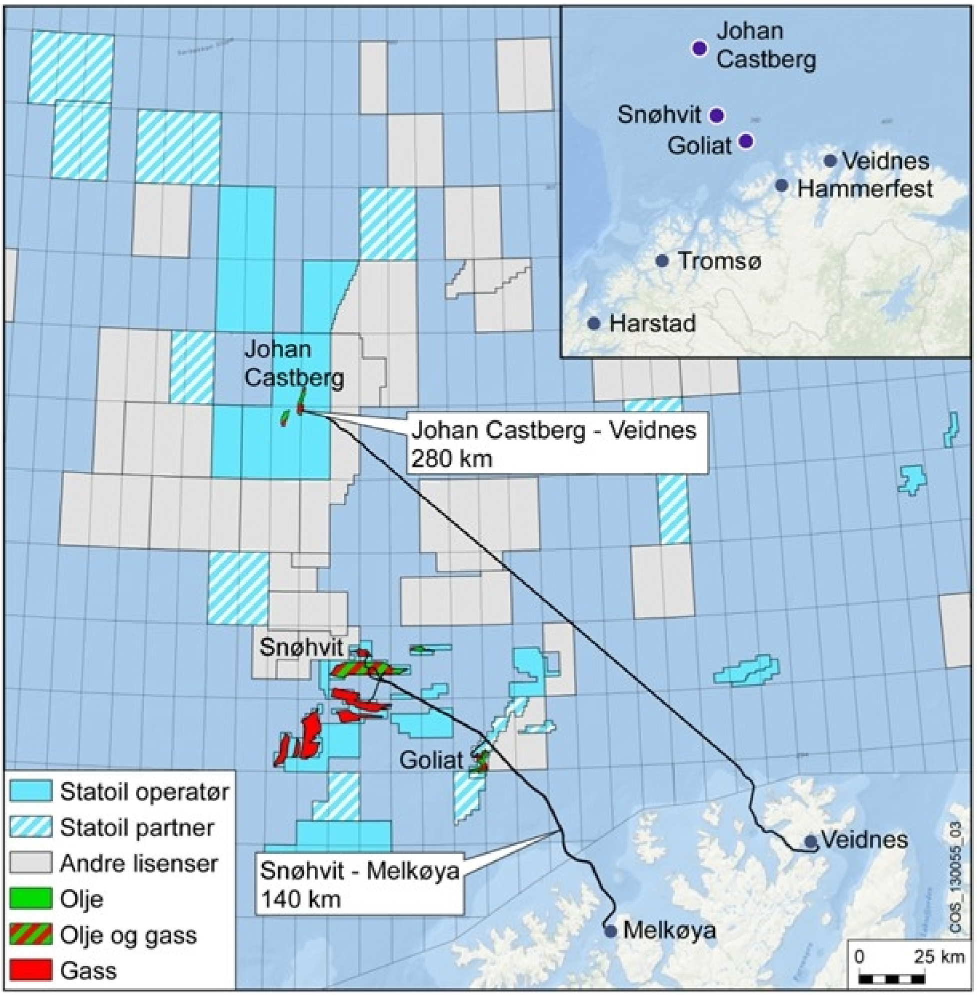


Figure 1 Showing the location of the field in the Northern part of Norway, close to Hammerfest

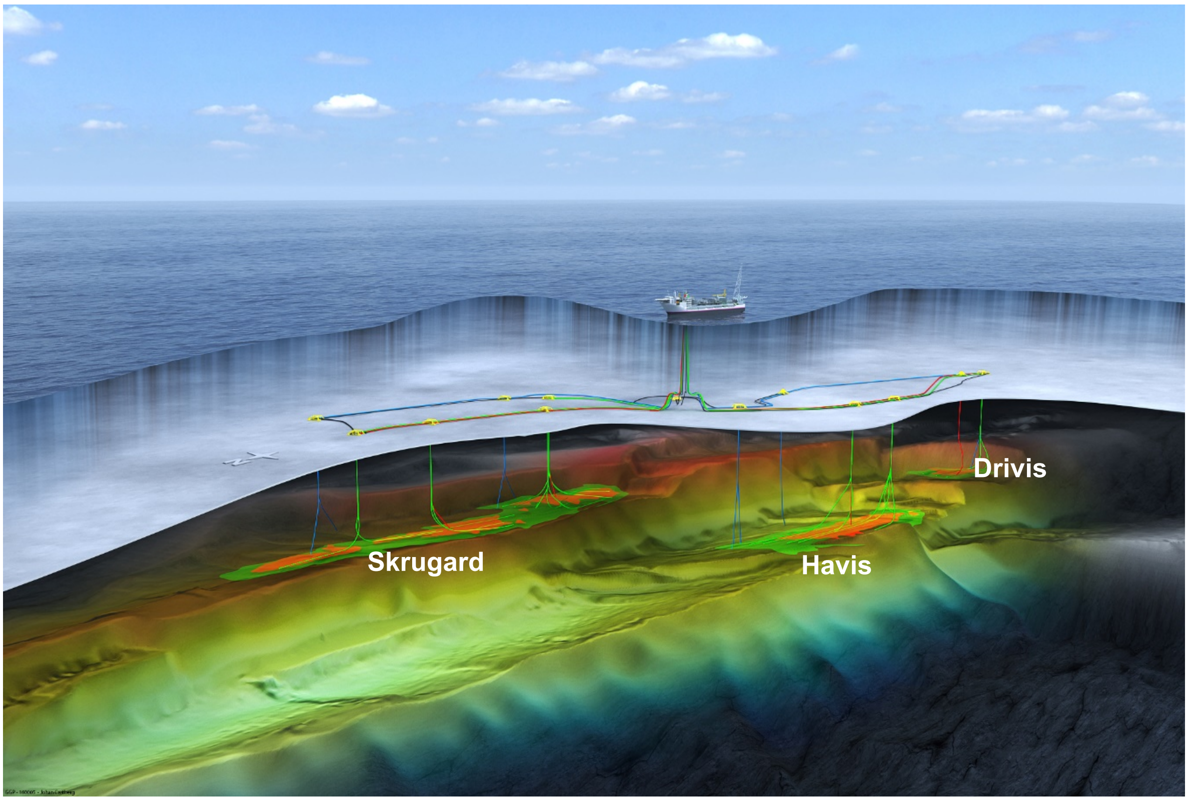


Figure 2 The field layout

This BSA is showing the activities on the Johan Castberg field during the period of 2024 to 2027
The wells to be drilled and studied in this analysis are located at:

- Skrugard
- Havis
- Drivis

All the wells from these different locations are tied in to the FPSO at Castberg.

3.3 Well design

The wells in the Castberg field are to be drilled as producers, gas injectors and water injectors, into the three separate structures.

3.3.1 Oil producers

All the oil producers are horizontal wells and are planned drilled into the reservoir with a 12 ¼'' section. For the multilateral oil producers, the 12 ¼'' section will be drilled 100 m into the top of the reservoir.

For the single oil producers, the 12 ¼'' section will be drilled 5 m into top of the reservoir. All the 9 5/8'' casings will then be cemented into the reservoir before drilling the 8 ½'' section.

The 12 ¼ section drilled into the reservoir will be placed in the poorer Stø4 /3.2 formation at the top of the reservoir

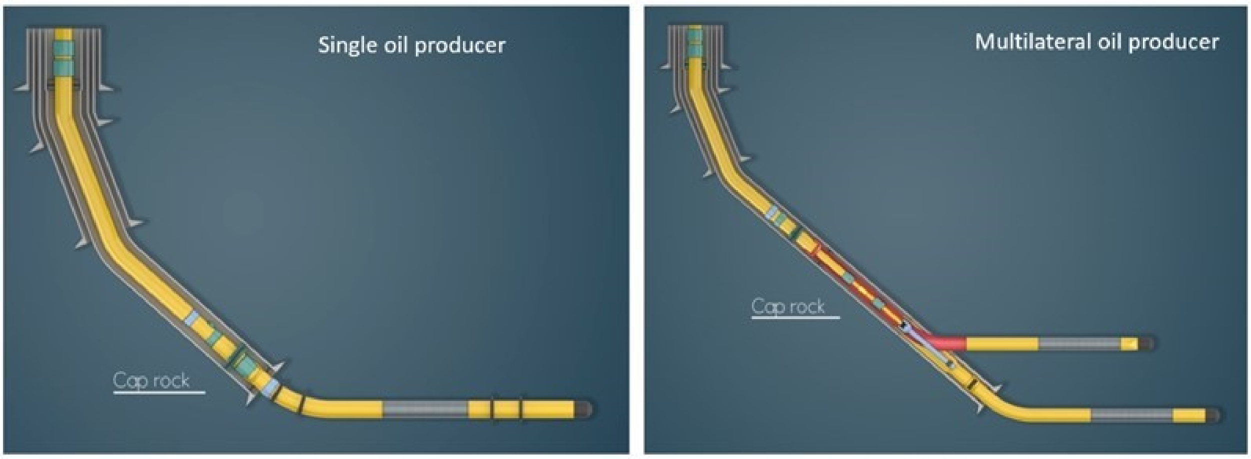


Figure 3 Left hand side - sketch of a single oil producer with 12 ¼'' drilled 5m into top reservoir. 8 ½ '' reservoir section is then drilled to total depth (TD). Right hand side - sketch of multilateral oil producer with 12 ¼'' drilled 100 m into top reservoir. 8 ½'' reservoir sections are then drilled to total depth (TD)

3.3.2 Water injectors

The water injectors on Johan Castberg Field are located down flank on the structure and will be drilled into a water filled reservoir, see Figure 4. However, there are potential hydrocarbon filled sands in the overburden, both in the lower Kolmule formation (possibility of 20 meter sand with a permeability of 50 – 100 mD) and injectite sands in the Hekkingen formation (possibility of 20-35 m sand with a permeability of 40-70 mD). If these sands are present, they will be penetrated by the 12 ¼ section.

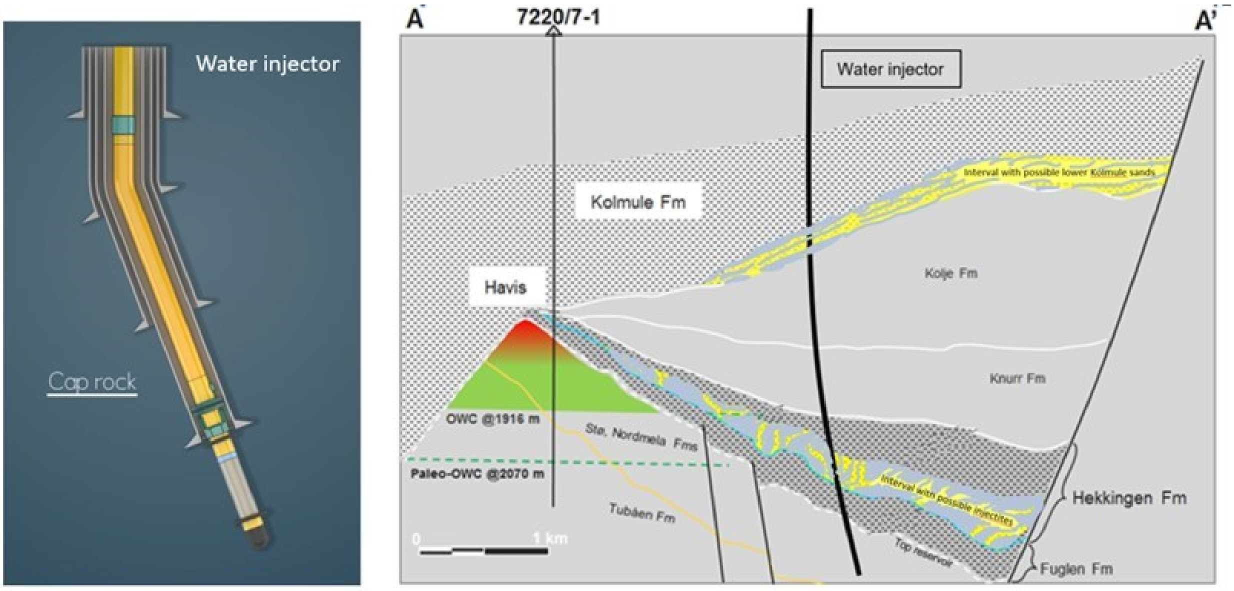


Figure 4 Left hand side - sketch of a water injector with 12 ¼'' drilled into top reservoir. Right hand side – shows that the water injectors are placed down flank, with the possible hydrocarbon filled sands in the overburden. Drawing is not to scale

3.4 Reservoir and fluid properties

The Stø, Nordmela and Tubåen formations provide the reservoirs for the Johan Castberg field. The different formations represent shifting depositional environments, from stacked channels in Tubåen, to prograding mouth bars and bayfills in Nordmela, and deepening shoreface in the Stø formation. Due to the different sedimentary settings, the properties in the different formations varies, see **Error! Reference source not found.**

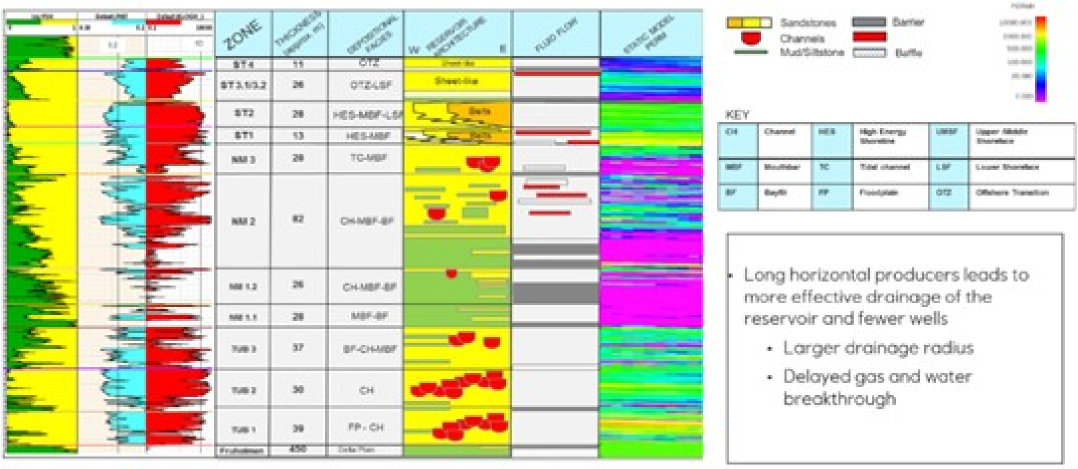


Figure 5 An overview of the different zones on Johan Castberg, depositional facies and permeabilities (static model permeabilities).

The rate simulations for Skrugard, Havis and Drivis were performed by Equinor. The simulations are based on a full reservoir model and is assumed to be the best representation of the dynamic response. The expected reservoir and fluid properties are listed in Table 1 to Table 4.

Table 1 Average properties for Skrugard, Havis and Drivis split by zone

	Average Permeability [mD]			Average porosity		
Formations	Skrugard	Havis	Drivis	Skrugard	Havis	Drivis
Stø 4	104	55	250	0.19	0.17	0.19
Stø 3.2	114	129	582	0.17	0.18	0.22
Stø 3.1	318	156	472	0.22	0.19	0.2
Stø 2	952	725	1056	0.25	0.22	0.23
Stø 1	3186	1483	2799	0.26	0.21	0.23
Nm3	804	240	1262	0.22	0.16	0.21
Nm 2	354	132	365	0.19	0.16	0.2
Nm 1.2	881	424	184	0.17	0.14	0.18
Nm 1.1	443	61	1047	0.18	0.13	0.22
Tubåen 3	2348	675	2101	0.26	0.16	0.25
Tubåen 2	2414	922	-	0.27	0.2	-
Tubååen 1	1298	1205	-	0.23	0.2	-

Table 2 Fluid properties Skrugard

Standard Conditions		Oil	Gas
Oil density	Kg/Sm^3	866.1	-
Gas density	Kg/Sm^3	-	0.724
GOR	$Sm^3/Sm3$	59.8	-
Std conditions defined as 1.01325 bara/15°C			

Reservoir conditions		Oil	Gas
Oil density	Kg/m^3	798.2	-
Oil viscosity	cp	2.7482	-
Bubble point	bar	133.5	-
Oil formation factor, Bo	Rm^3/Sm^3	1.148	-
Reservoir conditions : 134 bara / 37.2°C			

Table 3 Fluid properties Havis

Standard Conditions		Oil	Gas
Oil/condensate density	Kg/Sm^3	850.8	-
Gas density	Kg/Sm^3	-	0.787
GOR	$Sm^3/Sm3$	103.9	-
Std conditions defined as 1.01325 bara/15 °C			

Reservoir conditions		Oil	Gas
Oil/condensate density	Kg/m^3	737.32	-
Oil/condensate viscosity	cp	0.75401	-
Bubble point	bar	184.7	-
Oil formation factor, Bo	Rm^3/Sm^3	1.284	-
Reservoir conditions: 184.7 bara/58.7 °C			

Table 4 Fluid properties Drivis

Standard Conditions		Oil	Gas
Oil/condensate density	Kg/Sm^3	844	-
Gas density	Kg/Sm^3	-	0.743
GOR	$Sm^3/Sm3$	93	-
Std conditions defined as 1.01325 bara/15 °C			

Reservoir conditions		Oil	Gas
Oil/condensate density	Kg/m^3	755	-
Oil/condensate viscosity	cp	0.95	-
Bubble point	bar	146	-
Oil formation factor, Bo	Rm^3/Sm^3	1.23	-
Reservoir conditions: 148.8 bara/ 47.1 °C			

3.6 Assumptions/limitations

The following assumptions are included in the calculations:

- The flow path of blowouts during drilling are assumed to be annular, while for completion it is assumed to be through production tubing.
- Anchored semi submersibles are assumed applied for all activities except production/injection, and for drilling a relief well.
- The use of a capping stack in case of a blowout has been assumed, included the assumption that the topside blowout will transfer to seabed blowout after 28 days.
- The relief well is assumed, in agreement with the project, to be considered as a horizontal relief well.
- For Skrugard, Havis and Drivis, frequencies for "normal" wells are used
- In respect to drilling, the frequencies for all wells are included (drilling of normal wells, water injection wells and gas injection wells)
- In respect to completion and production the gas injection wells are excluded. The reason for this is that these wells shall be located in the gas cap, where no oil content is expected, hence a blowout will not give any oil release.
- In 2024, 2025 and 2026 an LWI ship/vessel will perform a wireline operation with the intention of production start-up of gas injection wells. This operation is assessed as a wireline operation.
- For production on Skrugard it is conservatively assumed that 9 wells are in production in 2024. This is conservative as 5 of these are drilled in 2024, and neither of the will be in production the entire calendar year. Some of the 9 wells were drilled and completed prior to 2023. The same is the case for Havis, and for injection wells.
- Drilling of water injection wells are included with the same frequency as development drilling oil well
- Unrestricted annulus flow where the BOP/XMT has failed entirely.
- As time passes, reservoir pressure will decline, this factor is not accounted for in the analysis.

3.7 Activity level

The activities for the years 2023-2027 are given in the following Table 5.

Table 5 Activity levels, year 2023 to year 2027, Johan Castberg, Skrugard, Havis and Drivis

Activity, seabed wellhead	2023	2024	2025	2026	2027	Note
Drilling, Skrugard	0	3 normal wells 1 water inj. well 1 gas inj. well	1 normal well 1 water inj. well	0	0	Activity pr. year
Drilling, Skrugard (MLT)	0	3	1	0	0	Activity pr. Year
Drilling, Havis	0	0	1 water inj. well	0	0	Activity pr. Year
Drilling, Havis (MLT)	0	0	2	0	0	Activity pr. Year
Drilling, Drivis	0	1 gas inj. well	1 normal well 1 water inj. well	0	0	Activity pr. Year
Drilling, Drivis (MLT)	0	0	1	0	0	Activity pr. Year
Completion, Skrugard	0	8 normal wells 1 water inj. well 1 gas inj. well (not included)	3	0	0	Activity pr. Year
Completion, Havis	0	0	2 normal well 1 water inj. well	0	0	Activity pr. year

Activity, seabed wellhead	2023	2024	2025	2026	2027	Note
Completion, Drivis	0	1 gas inj.well	3 normal wells	0	0	Activity pr. year
Wireline, Skrugard	0	1	1	0	0	Activity pr. year
Wireline, Havis	0	1	0	0	0	Activity pr. year
Wireline, Drivis	0	0	1	0	0	Activity pr. year
Production, Skrugard	0	9 (conservative assumption as 5 of these are drilled in 2024)	11	11	11	Sum of number of wells in production
Production, Havis	0	4	6	6	6	Sum of number of wells in production
Production, Drivis	0	0	2	2	2	Sum of number of wells in production
Water injection, Skrugard	0	3	4	4	4	Activity pr. Year
Water injection, Havis	0	2	3	3	3	Activity pr. Year
Water injection, Drivis	0	0	1	1	1	Activity pr. Year
Gas injection, Skrugard (left out of the analysis)		*1*	*1*	*1*	*1*	Activity pr. Year
Gas injection, Drivis (left out of the analysis)		*1*	*1*	*1*	*1*	Activity pr. Year
TOTAL		38	46	27	27	

Table 5 shows that Johan Castberg Field with Skrugard and Havis/ Drivis has a high activity year in 2025. Johan Castberg field is in a development phase. For year 2023, there is no activity planned as the FPSO is delayed and the activity is postponed to 2024.

4 Blowout scenarios and probabilities

4.1 General

Blowout can be released both on the drilling installation and at the seabed, and the release can be though an open hole (e.g., BOP, blowout preventer, has been blown off), or a restriction (BOP does not close properly).

During a drilling operation a blowout may result if a reservoir is penetrated while well pressure is in under balance with the formation pore pressure (well pressure < reservoir pressure), and a loss of well control follows. Three different scenarios are defined in the guideline [2], and this method is applied for Johan Castberg.

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

Conditional scenario probabilities on well progress are assigned based on historical blowout data, ref /1/ and the planned drilling operation. A review of incidents during drilling showed that 50 % of incidents happened in the intermediate section, ref [1].

Finally, the blowout frequency for blowout during different activities varies. All the above affects the results of the BSA, and data [1] and methods [2] are used to perform the evaluations. The probabilities are discussed below, while rates are handled in ch.5.

4.2 Blowout scenarios and flowpaths

During a drilling operation a blowout may occur if a reservoir is penetrated while well pressure is lower than the formation pore pressure (well pressure < reservoir pressure), and a loss of well control follows. Based on the statistics in [5], an annular flow is assumed for drilling operations.

For completion activities, potential blowout rates have been calculated through production tubing scenario (with no restrictions) by Johan Castberg Petek [3].

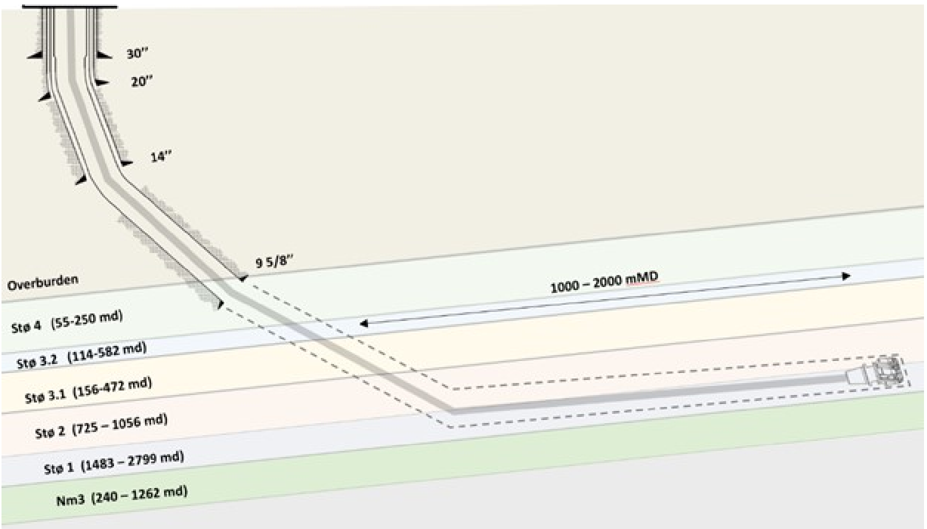
4.2.1 Blowout scenarios based on drilling progress, single path wells

As the single path wells will be drilled into the reservoir with a 12 ¼'' hole and cemented before proceeding with the 8 ½'' section, the conditional probabilities are usually split between the two sections. However, the upper formation layers (Stø 4/3.2) have lower permeability than the deeper layers and are of a shorter interval than the 8 ½'' section. For conservative purposes, the 8 ½'' section is given more weight (80 %), with a 50 / 50 % split between the two 8 ½'' scenarios, and the distribution is thus set to:

Table 6 Drilling blowout scenario probability distribution, single wells

Blowout scenario	**Description**	**Scenario Probability**
Top penetration 12 ¼''	Kick & loss of well control 5 m into reservoir	20 %
Drilling ahead, 8 ½''	Kick & loss of well control 5 m into reservoir	40 %
Tripping, 8 ½''	Kick & loss of well control, 100 % reservoir penetration	40 %
		100 %

Figure 6 Sketch of tripping scenario, 8 ½'' section with 5.5 '' pipe in hole (drawing not to scale). Permeability ranges are averages taken from Table 1



4.2.2 Blowout scenarios based on drilling progress, MLT wells

Drilling multilateral (MLT) wells consists of penetrating the reservoir in two sections (12 ¼'' and 8 ½''). The 100 m long 12 ¼'' section will be cemented and isolated from the reservoir when drilling the 8 ½'' section.

MLT wells are not considered multiple wells as the laterals will be drilled below the barrier envelope inside the reservoir. However, it is found reasonable to separate between the two sections for the scenario definitions due to the length of the sections and the different hole sizes.

A review of incidents during drilling shows that 50 % of the incidents happened in the intermediate section [1]. However, as the permeability in the upper parts of the reservoir and the length of the section is shorter than the 8 ½'' section, the 12 ¼'' is given a 30 % probability and the 8 ½'' section 70 % for conservative purposes. The risks related to reservoir top penetration and tripping out of the well are otherwise considered relevant for both sections. Thus, for drilling MLT wells, four scenarios are defined:

Table 7 Drilling blowout scenario probability distribution, multilateral (MLT) wells

Blowout scenario	**Description**	**Scenario Probability**
Top penetration 12 ¼''	Kick & loss of well control 5 m into reservoir	15 %
Tripping 12 ¼''	Kick & loss of well control, 100 % reservoir penetration	15 %
Top penetration, 8 ½''	Kick & loss of well control 5 m into reservoir	35 %
Tripping, 8 ½''	Kick & loss of well control, 100 % reservoir penetration	35 %
		100 %

Figure 7 Sketch of tripping out of well lateral 12 ¼'' with 5.5 '' pipe in hole (drawing is not to scale). Permeability ranges are averages taken from Table 1.

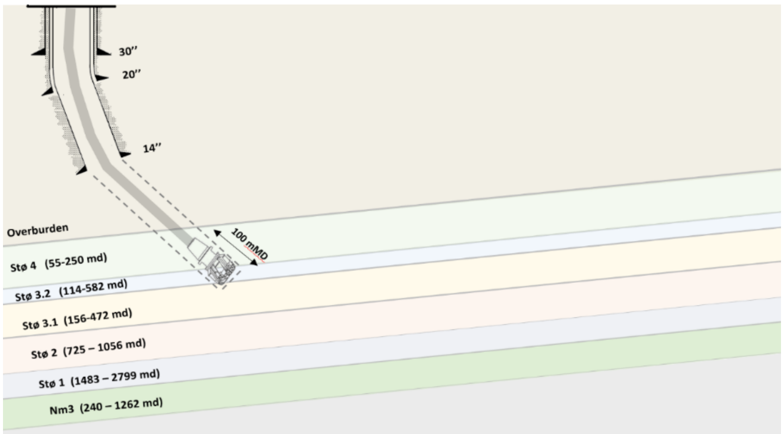
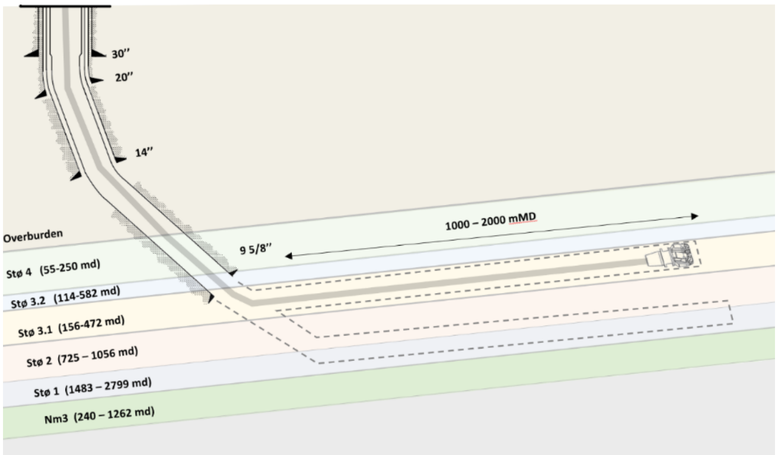


Figure 8 Sketch of tripping out of well lateral 8 ½'' with 5.5 '' pipe in hole (drawing is not to scale). Permeability ranges are averages taken from Table 1.



4.3 Generic blowout frequencies

The Johan Castberg field consists of oil producing wells. Table 8 shows the blowout frequencies.

Table 8 Basic frequencies [1]

Activity	Frequency, oil wells, "normal"	Unit	Description in [1]
Drilling single	3,02E-05	Per well	Development drilling normal oil wells
Drilling MLT	3,02E-05	Per well	Development drilling MLT oil wells
Drilling WI	3,02E-05	Per well	Frequency from Development drilling normal oil wells
Drilling gas injection	3,63E-05	Per well	Development drilling normal gas wells
Completion	1,17E-04	Per operation	
Wireline	4,19E-06	Per operation	
Water injection	9,02E-06	Per well year	Water injection well, average frequency
Production	2,30E-05	Per well year	Production oil well

4.4 Blowout distribution surface and Subsea

The activity specific flow path distributions as recommended given in [1] for floating installations are presented in Table 9. This is based on an overall assessment of scenarios and type of platform. Flow path distributions for floating installations are applicable for the Johan Castberg field.

Table 9 Flow path distribution [1]

	Floating installation, subsea wellhead	
Activity	**Surface**	**Subsea**
Drilling	21 %	79 %
Completion	84 %	16 %
Wireline	20 %	80 %
Production	0	100 %

4.5 Blowout probability

The activity level on Johan Castberg Field is evaluated by the Johan Castberg Field organization [4] and presented in Table 5. Multiplying the total number of wells per activity with the given blowout frequency given in Table 8 and taking the distribution in Table 9 for the same activity gives the total blowout frequency for surface and subsea releases. These values, for high and low activity year respectively, are given in Table 10 to Table 17 for Johan Castberg Field and its satellites.

4.5.1 Blowout probability, Johan Castberg, high activity year, 2025

In a high activity year, 9 wells will be drilled, and 9 wells completed, 2 wells will be wireline, 19 wells will be in production and 8 wells will be water injection. The blowout probability for a high activity year is 1,84E-03 with a distribution of 39 % for surface releases and 61 % for subsea releases.

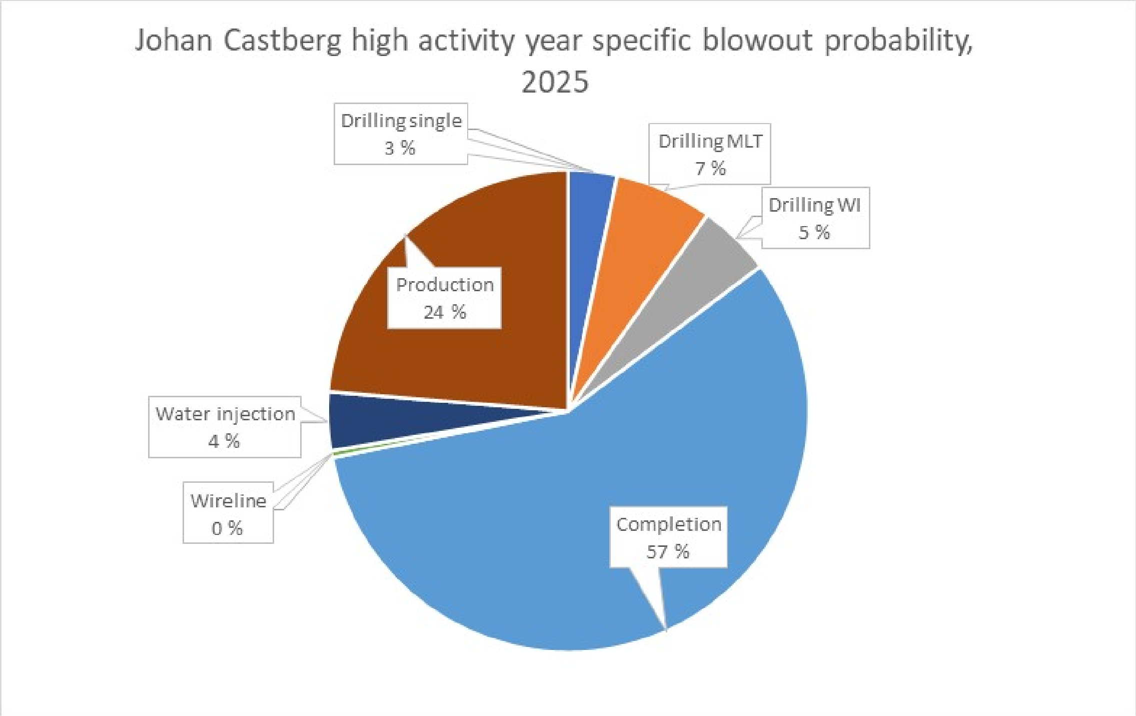


Figure 9 Illustrates the distribution of the blowout probability for the different activities

Table 10 Blowout probability for the high activity year, Johan Castberg field

2025	Seabed WH - Floater				Scenario Probability	Scenario probability for	
Oil wells	**Subsea**	**Per activity**	**Tot prob.**	**Scenario**		**Surface WH**	**Seabed WH**
Drilling single	2	3,02E-05	6,04E-05	5 m	0,20	2,54E-06	9,54E-06
			1,21E-04	50 %	0,40	5,07E-06	1,91E-05
			9,06E-05	100 %	0,40	5,07E-06	1,91E-05
Drilling MLT	4	3,02E-05	0,00E+00 1,53E-03 0,00E+00 7,22E-05	5 m 12.25”	0,15	3,81E-06	1,43E-05
				100% 12.25”	0,15	3,81E-06	1,43E-05
				5 m 8.5”	0,35	8,88E-06	3,34E-05
				100 % 8.5”	0,35	8,88E-06	3,34E-05
Drilling WI	3	3,02E-05	4,37E-04			1,90E-05	7,16E-05
Completion	9	1,17E-04	1,05E-03			6,63E-04	3,90E-04
Wireline	2	4,19E-06	8,38E-06			1,68E-06	6,70E-06
Water injection	8	9,02E-06	7,22E-05				7,22E-05
Production	19	2,30E-05	4,37E-04				4,37E-04
		Sum	1,84E-03			7,22E-04	1,12E-03
		Distribution				**39 %**	**61 %**

4.5.2 Blowout probability, Johan Castberg, low activity year 2026/2027

In a low activity year, there is no drilling or completion. The total blowout probability amounts to 5,09E-04. All releases are subsea.

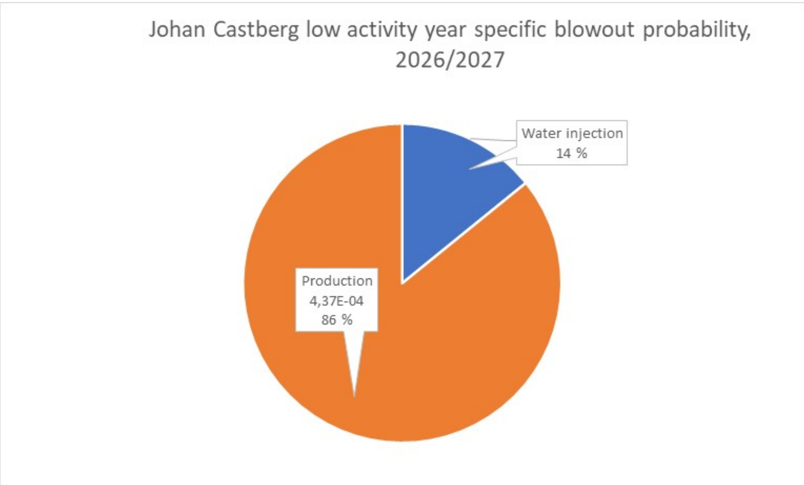


Figure 10 Distribution of the blowout probability for different activities in a low activity year

Table 11 Blowout probability for the low activity year, Johan Castberg field

2026	Seabed WH - Floater			Scenario probability	
Oil wells	**Subsea**	**Per activity**	**Tot prob.**	**Surface WH**	**Seabed WH**
Water injection Johan Castberg	8	9,02E-06	7,22E-05	-	7,22E-05
Production Johan Castberg	19	2,30E-05	4,37E-04	-	4,37E-04
		Sum	5,09E-04	-	5,09E-04
		Distribution		**0 %**	**100 %**

4.5.3 Blowout probability, Skrugard, high activity year, 2024

In the high activity year (2024), 8 wells will be drilled, and 9 wells completed, one wireline operation will be performed, 3 wells will water injection and 9 wells will be in production. The blowout probability for a high activity year is 1,54E-03 with a distribution of 63 % for surface releases and 37 % for subsea releases.

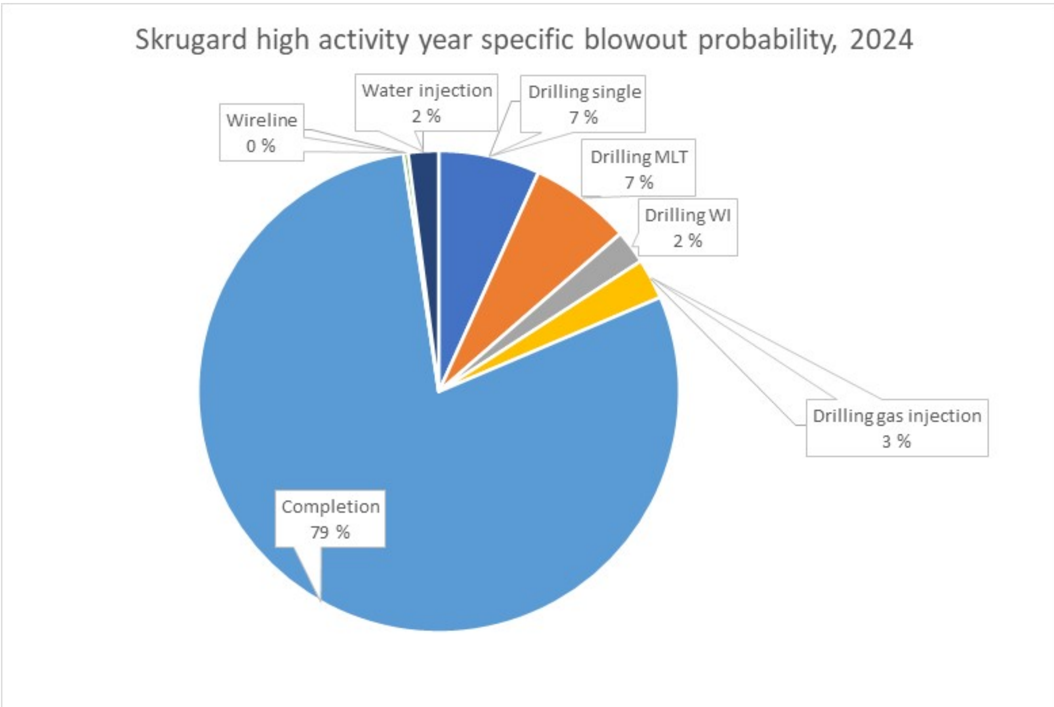


Figure 11 illustrates the distribution of the blowout probability for the different activities

Table 12 Blowout probability for the high activity year, Skrugard

2024	Seabed WH - Floater				Scenario Probability	Scenario probability for	
Oil wells	**Subsea**	**Per activity**	**Tot prob.**	**Scenario**		**Surface WH**	**Seabed WH**
Drilling single	3	3,02E-05	9,06E-05	5 m	0,20	3,81E-06	1,43E-05
				50 %	0,40	7,61E-06	2,86E-05
				100 %	0,40	7,61E-06	2,86E-05
Drilling MLT	3	3,02E-05	9,06E-05	5 m 12.25”	0,15	2,85E-06	1,07E-05
				100% 12.25”	0,15	2,85E-06	1,07E-05
				5 m 8.5”	0,35	6,66E-06	2,51E-05
				100 % 8.5”	0,35	6,66E-06	2,51E-05
Drilling WI	1	3,02E-05	3,02E-05			6,34E-06	2,39E-05
Drilling gas injection	1	3,63E-05	3,63E-05			3,05E-05	5,81E-06
Completion	9	1,17E-04	1,05E-03			8,85E-04	1,68E-04
Wireline	0	4,19E-06					
Water injection	3	9,02E-06	2,71E-05			0,00E+00	2,71E-05
Production	9	2,30E-05	2,07E-04			0,00E+00	2,07E-04
		Sum	1,54E-03			9,60E-04	5,79E-04
		Distribution				**63 %**	**37 %**

4.5.4 Blowout probability Skrugard, low activity year, 2026

In the low activity year, 2026 and 2027, the total blowout probability amounts to 2,89E-04. All releases are subsea releases. The contribution from the different installation/templates are given in Table 13.

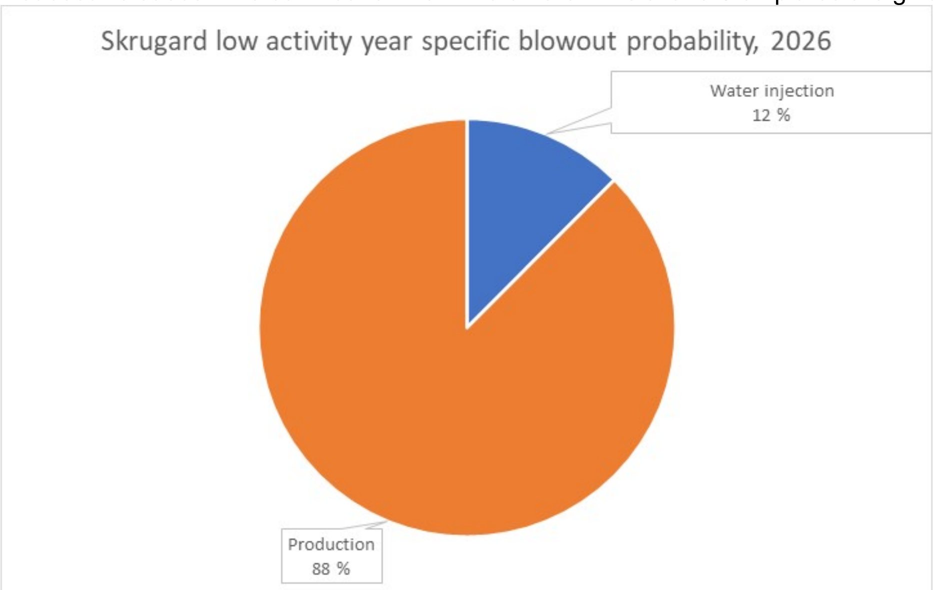


Figure 12 Distribution of the blowout probability for different activities in a low activity year

Table 13 Blowout probability for the low activity year, Skrugard

2026& 2027	Seabed WH - Floater			Scenario probability for	
Oil wells	**Subsea**	**Per activity**	**Tot prob.**	**Surface WH**	**Seabed WH**
Water injection	4	9,02E-06	3,61E-05	0,00E+00	3,61E-05
Production	11	2,30E-05	2,53E-04	0,00E+00	2,53E-04
		Sum	2,89E-04	0,00E+00	2,89E-04
		Distribution		**0 %**	**100 %**

4.5.5 Blowout probability, Havis, high activity year 2025

In a high activity year, 2MLT and 1 water injection wells will be drilled, and 3 wells completed. 6 wells will be in production and 3 wells will be water injection. The blowout probability for a high activity year is 6,07E-04 with a distribution of 15 % for surface releases and 85 % for subsea releases.

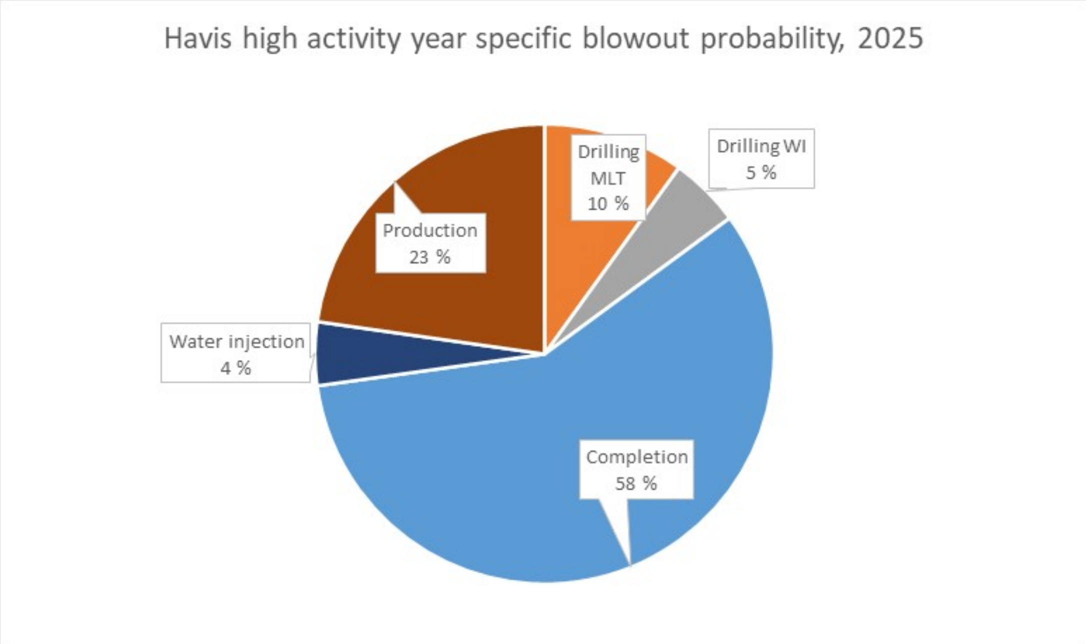


Figure 13 illustrates the distribution of the blowout probability for the different activities

Table 14 Blowout probability for the high activity year, Havis

2025	Seabed WH - Floater				Scenario Probability	Scenario probability for	
Oil wells	**Subsea**	**Per activity**	**Tot prob.**	**Scenario**		**Surface WH**	**Seabed WH**
Drilling MLT	2	3,02E-05	6,04E-05	5 m 12.25”	0,15	1,90E-06	7,16E-06
				100% 12.25”	0,15	1,90E-06	7,16E-06
				5 m 8.5”	0,35	4,44E-06	1,67E-05
				100 % 8.5”	0,35	4,44E-06	1,67E-05
Drilling WI	1	3,02E-05	3,02E-05			6,34E-06	2,39E-05
Completion	3	1,17E-04	3,51E-04			7,37E-05	2,77E-04
Water injection	3	9,02E-06	2,71E-05			0,00E+00	2,71E-05
Production	6	2,30E-05	1,38E-04			0,00E+00	1,38E-04
		Sum	6,07E-04			9,27E-05	5,14E-04
		Distribution				**15 %**	**85 %**

4.5.6 Blowout probability Havis, low activity year, 2024

In the low activity year, 2024, the total blowout probability amounts to 1,14E-04. Alle releases are subsea releases. The contribution from the different installation/templates are given in Table 13.

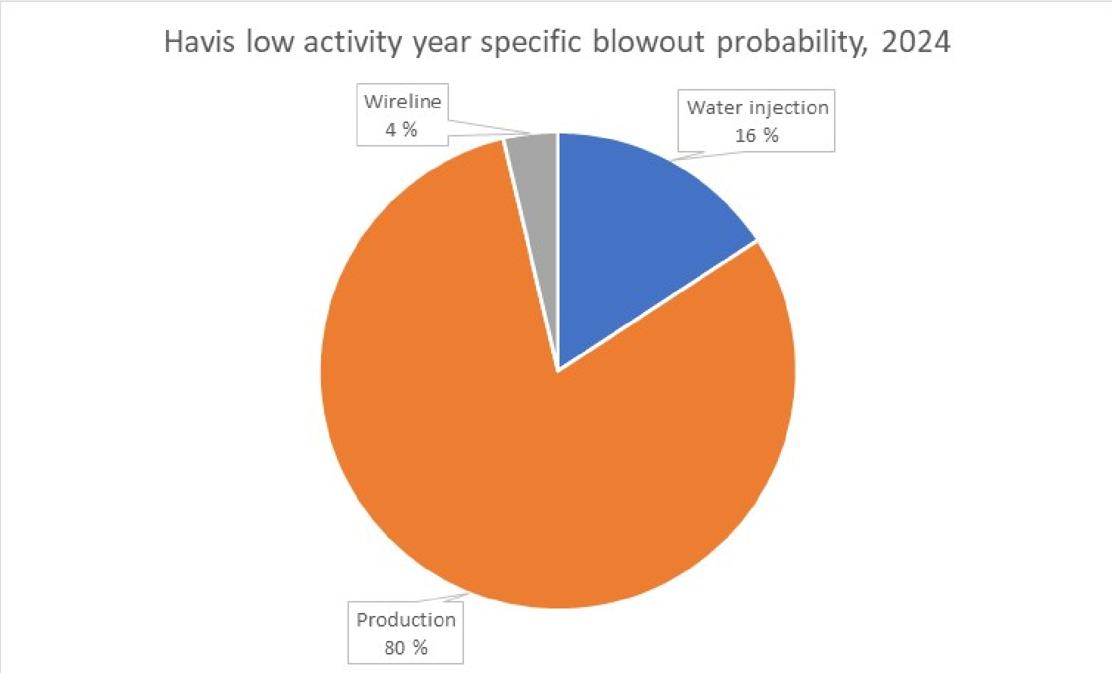


Figure 14 Distribution of the blowout probability for different activities in a low activity year

Table 15 Blowout probability for the low activity year, Havis

2024	**Seabed WH - Floater**			**Scenario probability**	
Oil wells	**Subsea**	**Per activity**	**Tot prob.**	**Surface WH**	**Seabed WH**
Wireline	1	4,19E-06	4,19E-06	8,38E-07	3,35E-06
Water injection Havis	2	9,02E-06	1,80E-05	0,00E+00	1,80E-05
Production Havis	4	2,30E-05	9,20E-05	0,00E+00	9,20E-05
		Sum	**1,14E-04**	8,38E-07	1,13E-04
		Distribution		**1%**	**99%**

4.5.7 Blowout probability, Drivis, high activity year, 2025

In a high activity year, 3 wells will be drilled, and 3 wells completed, 1 well will be water injection and 2 wells will be in production. The blowout probability for a high activity year is 5,01E-04 with a distribution of 63 % for surface releases and 37 % for subsea releases.

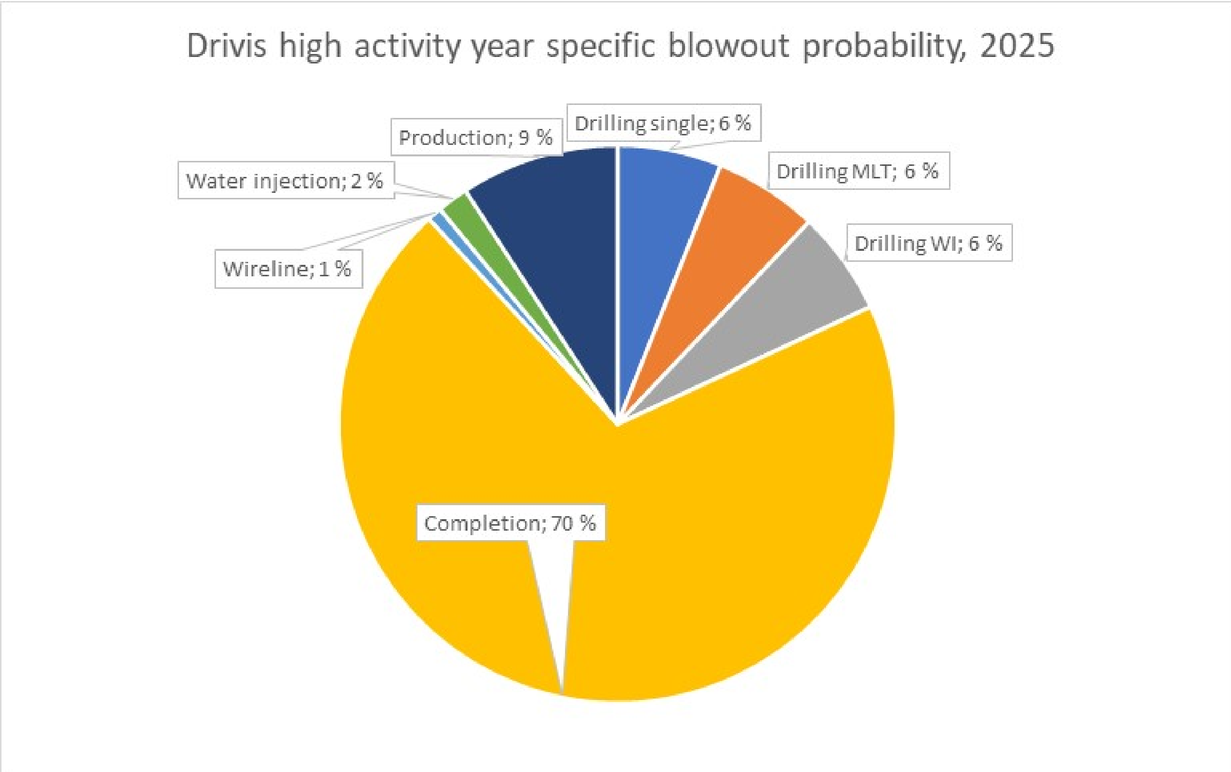


Figure 15 illustrates the distribution of the blowout probability for the different activities

Table 16 Blowout probability for the high activity year 2025, Drivis

2025	Seabed WH - Floater				Scenario	Scenario probability for	
Oil wells	**Subsea**	**Per activity**	**Tot prob.**	**Scenario**	**Probability**	**Surface WH**	**Seabed WH**
Drilling single	1	3,02E-05	3,02E-05	5 m	0,20	1,27E-06	4,77E-06
				50 %	0,40	2,54E-06	9,54E-06
				100 %	0,40	2,54E-06	9,54E-06
Drilling MLT	1	3,02E-05	3,02E-05	5 m 12.25”	0,15	9,51E-07	3,58E-06
				100% 12.25”	0,15	9,51E-07	3,58E-06
				5 m 8.5”	0,35	2,22E-06	8,35E-06
				100 % 8.5”	0,35	2,22E-06	8,35E-06
Drilling WI	1	3,02E-05	3,02E-05			6,34E-06	2,39E-05
Completion	3	1,17E-04	3,51E-04			2,95E-04	5,62E-05
Wireline	1	4,19E-06	4,19E-06			8,38E-07	3,35E-06
Water injection	1	9,02E-06	9,02E-06			0,00E+00	9,02E-06
Production	2	2,30E-05	4,60E-05			0,00E+00	4,60E-05
		Sum	5,01E-04			3,15E-04	1,86E-04
		Distribution				**63 %**	**37 %**

4.5.8 Blowout probability Drivis, low activity year, 2024

In the low activity year, 2024, the total blowout probability amounts to 3,63E-05 due to drilling of a gas injection well. The distribution surface/subsea release in 2024 are represented by surface release with 21 % of the releases while subsea has 79 % of the blowout probability.

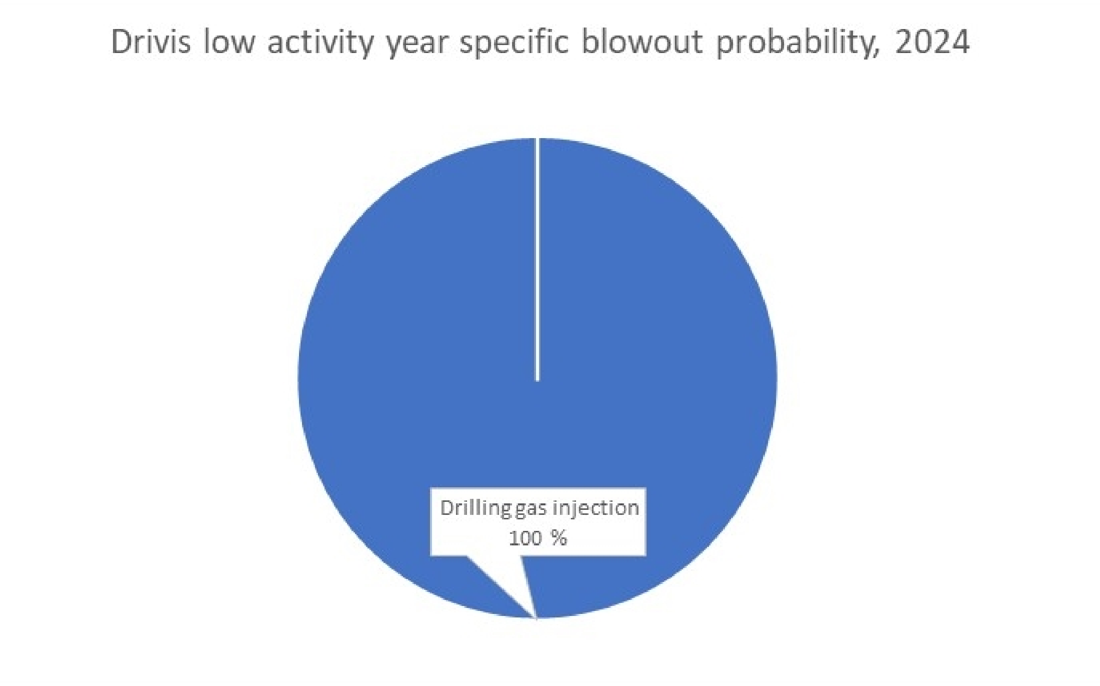


Figure 16 Distribution of the blowout probability for different activities in a low activity year

Table 17 Blowout probability for the low activity year, Drivis

2024	Seabed WH - Floater			Scenario probability	
Oil wells	**Subsea**	**Per activity**	**Tot prob.**	**Surface WH**	**Seabed WH**
Drilling gas injector Drivis	1	3,63E-05	3,63E-05	7,62E-06	2,87E-05
		Sum, oil	3,63E-05	7,62E-06	2,87E-05
		Distribution		**21 %**	**79%**

5 Blowout rates

5.1 General

As mentioned in ch.4.1, the blowout rate will vary with

- Different depths in a well if the blowout occurs during drilling
- Different activities
- Restrictions/no restrictions

In the following calculations are performed which handles these variations. Weighted drilling rates (not including completion) and the P90 values are the results.

5.2 Blowout rates

5.2.1 Johan Castberg Field blowout rates during high activity year, 2025

The probabilities presented in Table 10 are the sum of the activities at Skrugard, Havis and Drivis, and are calculated for the different activities, and different areas. To arrive at a P90 value a distribution of these, probabilities are calculated by taking the blowout probability for the different activities and flow paths (Table 9) and divide on the total blowout probability. The corresponding blowout release rates and distribution according to Table 18, are also required. All these values are later used for the P90 calculation. The rates are not included in the table as these are presented in Skrugard, Havis and Drivis high and low activities chapters. The Total P90 for the total Johan Castberg field is collected in Table 19 and shown in Figure 17 .

Table 18 Flow path distribution for a high activity year at Johan Castberg (Table 8, Table 9 and Table 10)

Johan Castberg	2025	Scenario probability			Probability	
		All	Surface	Seabed	Surface	Seabed
Drilling single	5 m	1,21E-05	2,54E-06	9,54E-06	-	-
	50%	2,42E-05	5,07E-06	1,91E-05	-	0,01
	100%	2,42E-05	5,07E-06	1,91E-05	-	0,01
Drilling MLT	5 m 12.25	1,81E-05	3,81E-06	1,43E-05	-	0,01
	100% 12.25	1,81E-05	3,81E-06	1,43E-05	-	0,01
	5 m 8.5	4,23E-05	8,88E-06	3,34E-05	-	0,01
	100 % 8.5	4,23E-05	8,88E-06	3,34E-05	-	0,01
Drilling WI		9,06E-05	1,90E-05	7,16E-05	0,01	0,03
Drilling GI		-	-	-	-	-
Completion		1,05E-03	6,63E-04	3,90E-04	0,36	0,21
Wireline		8,38E-06	1,68E-06	6,70E-06	0,00	0,00
Water injection		7,22E-05	-	7,22E-05	-	0,03
Production		4,37E-04	-	4,37E-04	-	0,19
SUM		1,84E-03	7,221E-04	1,12E-03	39 %	61 %

Figure 17 show the deduction of the P90 rates for Johan Castberg Field in a high activity year, while the weighted rate for the drilling scenario is based on the methodology described in Table 19. The P90 rate for surface 3900 Sm^3/d and seabed releases is estimated to be 4100 Sm^3/d, giving a total weighted P90 of 4000 Sm^3/day (values rounded off to nearest 100).

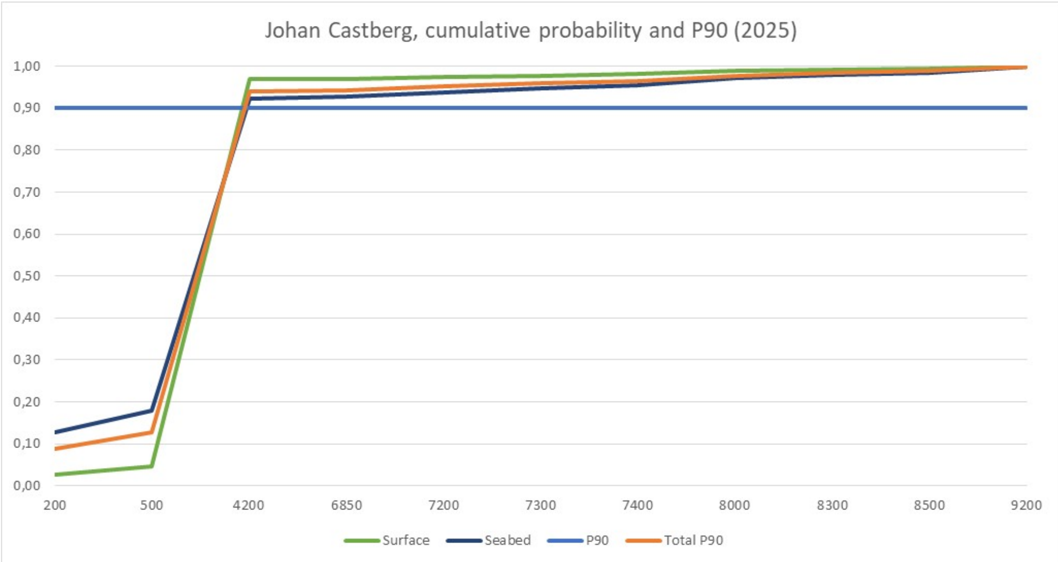


Figure 17 Deduction of 90 blowout rate for high activity year, Johan Castberg Field

Table 19: Weighted rate for drilling scenarios and the total P90, high activity year Johan Castberg

Johan Castberg	2025	Scenario probability	Distribution		Corresponding rate		Contribution to weighted rate		
	Scenario		Surface	Seabed	Surface	Seabed	Surface	Seabed	Total Weighted
Drilling single Skrugard	5 m	20 %	2 %	2 %	500	500	11	11	22
	50%	40 %	4 %	4 %	8000	8000	356	356	711
	100%	40 %	4 %	4 %	8000	8000	356	356	711
Drilling MLT Skrugard	5 m 12.25	15 %	2 %	2 %	500	500	8	8	17
	100% 12.25	15 %	2 %	2 %	7200	7200	120	120	240
	5 m 8.5	35 %	4 %	4 %	500	500	19	19	39
	100 % 8.5	35 %	4 %	4 %	8300	8300	323	323	646
Drilling WI Skrugard		100 %	11 %	11 %	200	200	22	22	44
Drilling GI Skrugard		100 %	0 %	0 %	8000	8000	0	0	0
Drilling MLT Havis	5 m 12.25	15 %	3 %	3 %	500	500	17	17	33
	100% 12.25	15 %	3 %	3 %	8500	8500	283	283	567
	5 m 8.5	35 %	8 %	8 %	500	500	39	39	78
	100 % 8.5	35 %	8 %	8 %	9200	9200	716	716	1431
Drilling WI Havis		100 %	11 %	11 %	200	200	22	22	44
Drilling single Drivis	5 m	20 %	2 %	2 %	500	500	11	11	22
	50%	40 %	4 %	4 %	7200	7200	320	320	640
	100%	40 %	4 %	4 %	7300	7300	324	324	649
Drilling MLT Drivis	5 m 12.25	15 %	2 %	2 %	500	500	8	8	17
	100% 12.25	15 %	2 %	2 %	6850	6850	114	114	228
	5 m 8.5	35 %	4 %	4 %	500	500	19	19	39
	100 % 8.5	35 %	4 %	4 %	7400	7400	288	288	576
Drilling WI Drivis		100 %	11 %	11 %	200	200	22	22	44
Weighted drilling rates (rounded to nearest 100)							3400	3400	3400
P90 rate (rounded to nearest 100)							3900	4100	4000

5.2.2 Johan Castberg Field Blowout rates during a low activity year, 2026/2027

The frequencies presented in Table 20 are based on the different activities for a year of low activity. The frequencies are transferred to a distribution by taking the blowout probability for the different flow paths and divide on the total sum. The corresponding blowout release rates are also listed.

Table 20 Flowpath distribution for a low activity year at Johan Castberg, and the corresponding condensate blowout rates

Johan Castberg 2026/2027	Scenario probability			Probability		Corresponding rate	
	All	Surface	Seabed	Surface	Seabed		
Water injection	7,22E-05	0,00E+00	7,22E-05	0,00	0,14	200	200
Production	4,37E-04	0,00E+00	4,37E-04	0,00	0,86	4200	4200
SUM	5,09E-04	0,00E+00	5,09E-04	0 %	100 %		

Figure 18 show the P90 graphs for a low activity year. The P90 rate for the low activity year is estimated to a total of 3700Sm³/d. This is for seabed releases as no surface release is expected.

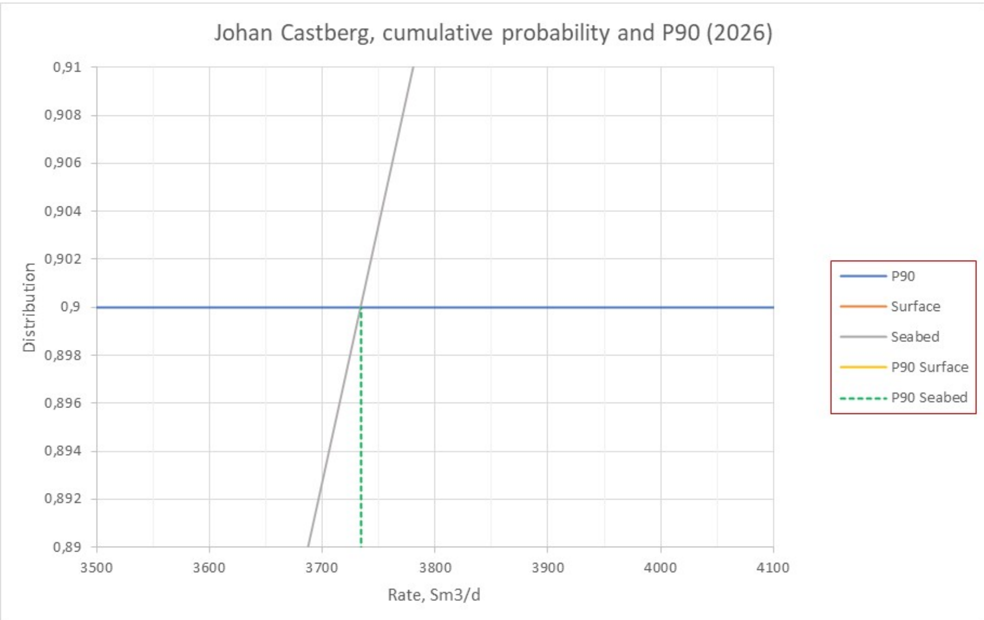


Figure 18 Deduction of 90 blowout rate for low activity year

During the low activity years no drilling activity is planned for at Johan Castberg.

5.2.3 Johan Castberg, summary blowout rates

The blowout rates given by the project have been used in this study to deliver P90 rates and weighted blowout rates.

Table 21 Weighted and P90 blowout rates summarized Johan Castberg, adjusted to nearest 100

Scenarios	Blowout rates, (Sm^3/d), high activity year 2025	Blowout rates, (Sm^3/d), low activity year 2026
Weighted Rate Drilling	3400	-
Weighted P90 rate, surface	3900	-
Weighted P90 rate, Seabed	4100	3700
Weighted P90 rate	4000	3700
Location distribution total, surface/Seabed	39% /61 %	0 /100%

5.2.4 Skrugard blowout rates during high activity year, 2024

The probabilities presented in Table 12 are calculated for the different activities. To arrive at a P90 value, a distribution of these probabilities is calculated by taking the blowout probability for the different activities and flow paths (Table 9) and divide on the total blowout probability. The corresponding blowout release rates and distribution also required. All these values are listed in Table 22 and later used for the P90 calculation.

Table 22 Flow path distribution for a high activity year at Skrugard, and the corresponding blowout rates for oil

Skrugard	2024	Scenario probability			Probability		Corresponding rate	
		All	Surface	Seabed	Surface	Seabed		
Drilling single	**5 m**	1.81E-05	3.81E-06	1.43E-05	0,2 %	0,7 %	500	500
	50%	3.62E-05	7.61E-06	2.86E-05	0,4 %	1,4 %	8000	8000
	100%	3.62E-05	7.61E-06	2.86E-05	0,4 %	1,4 %	8000	8000
Drilling MLT	**5 m 12.25**	1.36E-05	2.85E-06	1.07E-05	0,1 %	0,5 %	500	500
	100% 12.25	1.36E-05	2.85E-06	1.07E-05	0,1 %	0,5 %	7200	7200
	5 m 8.5	3.17E-05	6.66E-06	2.51E-05	0,3 %	1,2 %	500	500
	100 % 8.5	3.17E-05	6.66E-06	2.51E-05	0,3 %	1,2 %	8300	8300
Drilling WI		3.02E-05	6.34E-06	2.39E-05	0,3 %	1,2 %	200	200
Drilling GI		3.63E-05	3.05E-05	5.81E-06	1,5 %	0,3 %	8000	8000
Completion		1,05E-03	8,85E-04	1,68E-04	57,5 %	10,9 %	4200	4200
Wireline		4,19E-06	8,38E-07	3,35E-06	0,1 %	0,2 %	4200	4200
Water injection		2.71E-05	0.00E+00	2.71E-05	0,0 %	1,3 %	200	200
Production		2.07E-04	0.00E+00	2.07E-04	0,0 %	10,3 %	4200	4200
SUM		**1,54E-03**	**9,60E-04**	**5,79E-04**	**62 %**	**38 %**		

Figure 19 show the deduction of the P90 rates for Skrugard in a high activity year. The P90 rate for surface releases is estimated to be 4000 Sm^3/d and 7600 Sm^3/d for a Seabed release, giving a total weighted P90 of 4200 Sm^3/day.

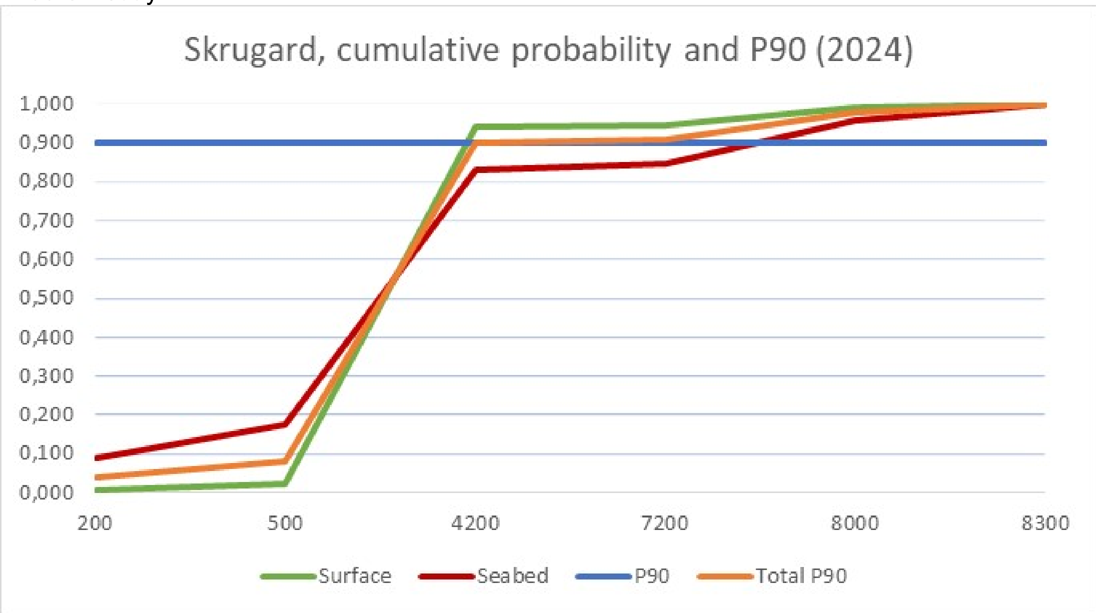


Figure 19 Deduction of 90 blowout rate for high activity year, Skrugard

Table 23: Weighted rate for drilling scenarios and the total P90, high activity year Skrugard

Skrugard	2024	Scenario probability	Distribution		Corresponding rate		Contribution to weighted rate		
	Scenario		Surface	Seabed	Surface	Seabed	Surface	Seabed	Total Weighted
	5 m	20 %	5 %	8 %	500	500	25	41	67
	50%	40 %	10 %	17 %	8000	8000	813	1325	2138
Drilling single	100%	40 %	10 %	17 %	8000	8000	813	1325	2138
	5 m 12.25	15 %	4 %	6 %	500	500	19	31	50
	100% 12.25	15 %	4 %	6 %	7200	7200	274	447	722
	5 m 8.5	35 %	9 %	14 %	500	500	44	72	117
Drilling MLT	100 % 8.5	35 %	9 %	14 %	8300	8300	738	1203	1941
Drilling WI		100 %	8 %	14 %	200	200	17	28	45
Drilling GI		100 %	41 %	3 %	8000	8000	3257	269	3526
Weighted drilling rates (rounded to nearest 100)							6000	4700	5100
P90 rate (rounded to nearest 100)							4000	7600	4200

5.2.5 Skrugard Blowout rates during a low activity year, 2026

The frequencies presented in Table 24 are based on the different activities for a year of low activity. The frequencies are transferred to a distribution by taking the blowout probability for the different flow paths and divide on the total sum. The corresponding blowout release rates are also listed.

Table 24 Flowpath distribution for a low activity year at Skrugard, and the corresponding condensate blowout rates

Skrugard 2026	Scenario probability			Probability		Corresponding rate	
	All	Surface	Seabed	Surface	Seabed		
Water injection	3,61E-05	0,00E+00	3,61E-05	0,00	0,12	200	200
Production	2,53E-04	0,00E+00	2,53E-04	0,00	0,88	4200	4200
SUM	**2,89E-04**	**0**	**2,89-04**	**0**	**100 %**		

Figure 20 show the P90 graph for a low activity year. The total P90 rate for the low activity year is estimated to 3800 Sm³/d which also is the seabed P90 rate as there is not expected any surface release.

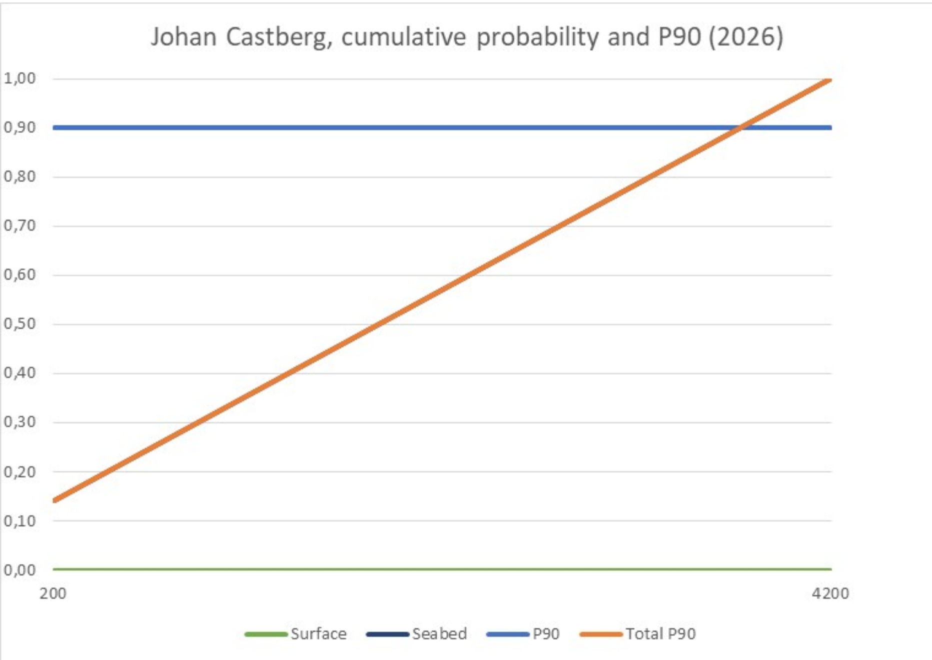


Figure 20 Deduction of 90 blowout rate for low activity year

The weighted drilling rate is not given for the low activity year as there is no drilling planned for this year.

5.2.6 Skrugard, Summary, blowout rates

Several blowout rates have been calculated by the Skrugard project. These have been used in this study to deliver P90 rates and weighted blowout rates, ref. following Table 25

Table 25 Weighted and P90 blowout rates summarized Skrugard, adjusted to nearest 100

Scenarios	Blowout rates, (Sm^3/d), high activity year 2024	Blowout rates, (Sm^3/d), low activity year 2026
Weighted Rate Drilling	5100	-
Weighted P90 rate, surface	4000	-
Weighted P90 rate, Seabed	7600	3800
Weighted P90 rate	4200	3800
Location distribution total, surface/seabed	62% /38 %	0% /100%

5.2.7 Havis blowout rates during high activity year, 2025

The probabilities presented in Table 12 are calculated for the different activities. To arrive at a P90 value, a distribution of these probabilities is calculated by taking the blowout probability for the different activities and flow paths (Table 9) and divide on the total blowout probability. The corresponding blowout release rates and distribution also required. All these values are listed in Table 26 and later used for the P90 calculation.

Table 26 Flow path distribution for a high activity year at Havis, and the corresponding blowout rates for oil

Havis 2025		Scenario probability			Probability		Corresponding rate	
		All	Surface	Seabed	Surface	Seabed		
Drilling MLT	**5 m 12.25**	9,06E-06	1,90E-06	7,16E-06	0,3 %	1,1 %	500	500
	100% 12.25	9,06E-06	1,90E-06	7,16E-06	0,3 %	1,1 %	8500	8500
	5 m 8.5	2,11E-05	4,44E-06	1,67E-05	0,7 %	2,5 %	500	500
	100 % 8.5	2,11E-05	4,44E-06	1,67E-05	0,7 %	2,5 %	9200	9200
Drilling WI		3,02E-05	6,34E-06	2,39E-05	1,0 %	3,6 %	200	200
Completion		3,51E-04	7,37E-05	2,77E-04	14,7 %	55,4 %	4200	4200
Water injection		2,71E-05	0,00E+00	2,71E-05	0,0 %	3,5 %	200	200
Production		1,38E-04	0,00E+00	1,38E-04	0,0 %	18,0 %	4200	4200
SUM		**6,07E-04**	**9,27E-05**	**5,14E-04**	**15 %**	**85 %**		

Figure 21 show the deduction of the P90 rates for Havis in a high activity year. The P90 rate for surface and seabed releases is estimated to be 4000 Sm³/d, giving a total weighted P90 of 4000 Sm³/day.

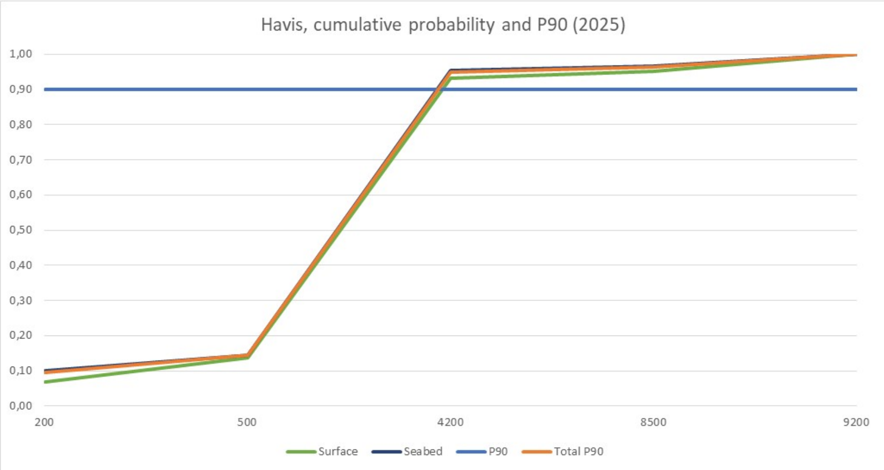


Figure 21 Deduction of 90 blowout rate for high activity year, Havis

Table 27: Weighted rate for drilling scenarios and the total P90, high activity year Havis

Havis	2025	Scenario probability	Distribution		Corresponding rate		Contribution to weighted rate		
	Scenario		Surface	Seabed	Surface	Seabed	Surface	Seabed	Total Weighted
	5 m 12.25	15 %	10 %	10 %	500	500	50	50	100
	100% 12.25	15 %	10 %	10 %	8500	8500	850	850	1700
	5 m 8.5	35 %	23 %	23 %	500	500	117	117	233
Drilling MLT	100 % 8.5	35 %	23 %	23 %	9200	9200	2147	2147	4293
Drilling WI		100 %	33 %	33 %	200	200	67	67	133
Weighted drilling rates (rounded to nearest 100)							**3200**	**3200**	**3200**
P90 rate (rounded to nearest 100)							**4000**	**4000**	**4000**

5.2.8 Havis Blowout rates during a low activity year, 2024

The frequencies presented in Table 28 are based on the different activities for a year of low activity. The frequencies are transferred to a distribution by taking the blowout probability for the different flow paths and divide on the total sum. The corresponding blowout release rates are also listed.

Table 28 Flowpath distribution for a low activity year at Havis, and the corresponding condensate blowout rates

Havis 2024	Scenario probability			Probability		Corresponding rate	
	All	Surface	Seabed	Surface	Seabed		
Wireline	4,19E-06	8,38E-07	3,35E-06	0,01	0,03	4200	4200
Water injection	2.71E-05	0.00E+00	2.71E-05	0,0 %	0,12	200	200
Production	2.07E-04	0.00E+00	2.07E-04	0,0 %	0,88	4200	4200
SUM	**1,14E-04**	**8,38E-07**	**1,13E-04**	**1 %**	**99 %**		

Figure 22 show the P90 graph for a low activity year. The total P90 rate for the low activity year is estimated to 3800 Sm³/d. P90 for surface release is 4200 Sm³/d and for seabed release the rate is 3800 Sm³/d, which is the total.

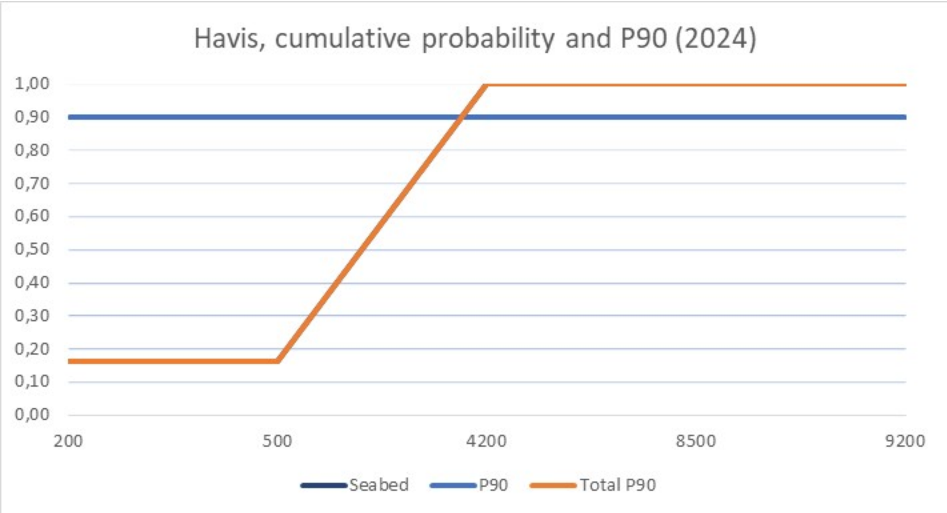


Figure 22 Deduction of 90 blowout rate for low activity year

The weighted drilling rate is not given for the low activity year as there is no drilling planned for this year.

5.2.9 Havis, Summary, blowout rates

Several blowout rates have been calculated by the Havis project. These have been used in this study to deliver P90 rates and weighted blowout rates, ref. following Table 29

Table 29 Weighted and P90 blowout rates summarized Havis, adjusted to nearest 100

Scenarios	Blowout rates, (Sm^3/d), high activity year 2025	Blowout rates, (Sm^3/d), low activity year 2024
Weighted Rate Drilling	3200	-
Weighted P90 rate, surface	4000	4200
Weighted P90 rate, Seabed	4000	3800
Total Weighted P90 rate	4000	3800
Location distribution total, surface/seabed	15% /85 %	1% /99%

5.2.10 Drivis blowout rates during high activity year, 2025

The probabilities presented in Table 30 are calculated for the different activities. To arrive at a P90 value, a distribution of these probabilities is calculated by taking the blowout probability for the different activities and flow paths (Table 9) and divide on the total blowout probability. The corresponding blowout release rates and distribution also required. All these values are listed in Table 30 and later used for the P90 calculation.

Table 30 Flow path distribution for a high activity year at Drivis, and the corresponding blowout rates for oil

Drivis 2025		Scenario probability			Probability		Corresponding rate	
		All	Surface	Seabed	Surface	Seabed		
Drilling single	5 m	6,04E-06	1,27E-06	4,77E-06	0,00	0,01	500	500
	50%	1,21E-05	2,54E-06	9,54E-06	0,01	0,02	7200	7200
	100%	1,21E-05	2,54E-06	9,54E-06	0,01	0,02	7300	7300
Drilling MLT	5 m 12.25	4,53E-06	9,51E-07	3,58E-06	0,00	0,01	500	500
	100% 12.25	4,53E-06	9,51E-07	3,58E-06	0,00	0,01	6850	6850
	5 m 8.5	1,06E-05	2,22E-06	8,35E-06	0,00	0,02	500	500
	100 % 8.5	1,06E-05	2,22E-06	8,35E-06	0,00	0,02	7400	7400
Drilling WI		3,02E-05	6,34E-06	2,39E-05	0,01	0,05	200	200
Drilling GI		0,00E+00	0,00E+00	0,00E+00	0,00	0,00	7300	7300
Completion		3,51E-04	2,95E-04	5,62E-05	0,59	0,11	4200	4200
Wireline		4,19E-06	8,38E-07	3,35E-06	0,00	0,01	4200	4200
Water injection		9,02E-06	0,00E+00	9,02E-06	0,00	0,02	200	200
Production		4,60E-05	0,00E+00	4,60E-05	0,00	0,09	4200	4200
SUM		**5,01E-04**	**3,15E-04**	**1,86E-04**	**63 %**	**37 %**		

Figure 23 show the deduction of the P90 rates for Drivis in a high activity year. The P90 rate for surface releases is estimated to be 3900 Sm^3/d and 7100 Sm^3/d for a Seabed release, giving a total weighted P90 of 4100 Sm^3/day.

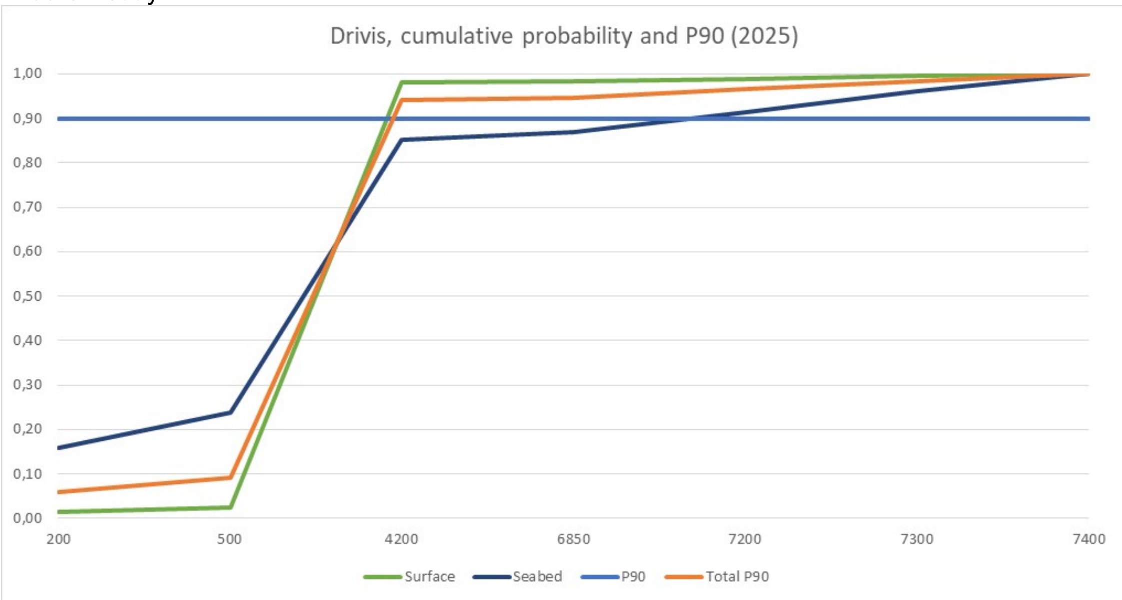


Figure 23 Deduction of 90 blowout rate for high activity year, Drivis

Table 31: Weighted rate for drilling scenarios and the total P90, high activity year Drivis

Drivis	2025		Distribution		Corresponding rate		Contribution to weighted rate		
	Scenario	Scenario probability	Surface	Seabed	Surface	Seabed	Surface	Seabed	Total Weighted
Drilling single	5 m	20 %	7 %	7 %	500	500	33	33	67
	50%	40 %	13 %	13 %	7200	7200	960	960	1920
	100%	40 %	13 %	13 %	7300	7300	973	973	1947
Drilling MLT	5 m 12.25	15 %	5 %	5 %	500	500	25	25	50
	100% 12.25	15 %	5 %	5 %	6850	6850	343	343	685
	5 m 8.5	35 %	12 %	12 %	500	500	58	58	117
	100 % 8.5	35 %	12 %	12 %	7400	7400	863	863	1727
Drilling WI		100 %	33 %	33 %	200	200	67	67	133
Weighted drilling rates (rounded to nearest 100)							3300	3300	3300
P90 rate (rounded to nearest 100)							3900	7200	4100

5.2.11 Drivis Blowout rates during a low activity year, 2024

The frequencies presented in Table 32 [4] are based on the different activities for a year of low activity. The frequencies are transferred to a distribution by taking the blowout probability for the different flow paths and divide on the total sum. The corresponding blowout release rates are also listed.

Table 32 Flowpath distribution for a low activity year at Drivis, and the corresponding condensate blowout rates

Drivis 2024	Scenario probability			Probability		Corresponding rate	
	All	Surface	Seabed	Surface	Seabed		
Drilling gas injection	3,63E-05	7,62E-06	2,87E-05	0,21	0,79	7300	7300
SUM	**3,63E-05**	**7,62E-06**	**2,87E-05**	**21%**	**79%**		

Figure 24 show the P90 graph for a low activity year. The total P90 rate for the low activity year is estimated to 7300 Sm³/d. There is not expected any surface release but for a seabed release the rate is 7300 Sm³/d, which is the total, and this is also the weighted drilling rate for Drivis 2024..

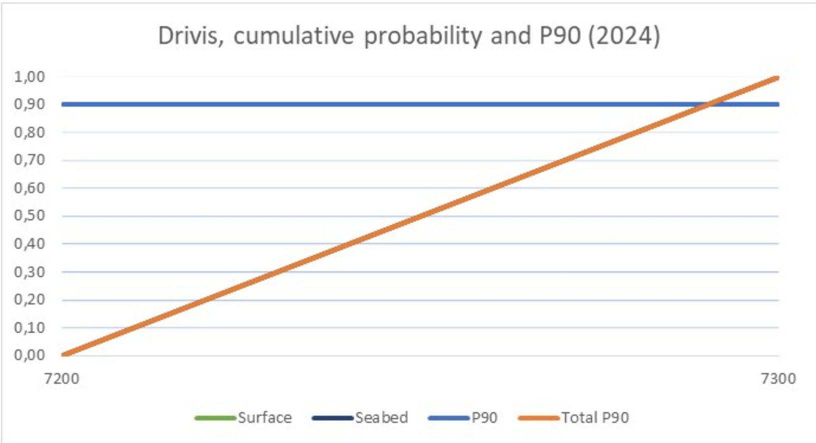


Figure 24 Deduction of 90 blowout rate for low activity year

5.2.12 Drivis, Summary, blowout rates

Several blowout rates have been calculated by the Drivis project. These have been used in this study to deliver P90 rates and weighted blowout rates, ref. following Table 33.

Table 33 Weighted and P90 blowout rates summarized Drivis, adjusted to nearest 100

Scenarios	Blowout rates, (Sm^3/d), high activity year 2025	Blowout rates, (Sm^3/d), low activity year 2024
Weighted Rate Drilling	3300	7300
Weighted P90 rate, surface	3900	7300
Weighted P90 rate, Seabed	7100	7300
Weighted P90 rate	4100	7300
Location distribution total, surface/seabed	63%/37%	21% /79%

6 Blowout duration

6.1 General

Chapter 6 describes stopping mechanisms for blowouts and input data for the duration calculations. The results are presented in tables and graphs.

A blowout can be stopped by:

- Operator actions – mechanical (*capping*)
- Bridging - wellbore collapse and/or rock material plugging the well
- Coning - altered fluid characteristics resulting from *water* or *oil coning* during a blowout
- Drilling a *relief well* and applying kill mud
- Capping stack – only relevant for drilling and completion with use of subsea wellhead

6.2 Blowout stopping mechanisms

Below, the different mechanisms that can stop a blowout is described. Some occur by natural causes; others require human interference of different degrees. The descriptions in sections 6.2.1 to 6.2.4 have [6] as reference, while section 6.2.5 is from the Equinor guideline GL0498 [2].

6.2.1 Operator action

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

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:

- Accumulation of unconsolidated material in the well to block the flow.
- Well collapse

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 because 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

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

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

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 [5] are analysed to give frequencies, distributions and rates. 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 [1] (updated annually):

Table 34 Weibull parameters for calculating duration of blowout

	α	β	Asymptote
Bridge	0,70	6,00	0,63
CapSurface	0,80	2,30	0,62
CapSubsea	0,85	6,00	0,45
ReliefWell	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 (Table 35) and Capping stack, specific input values are used.

6.3.2 Estimation of relief well duration

Well specific input about time to drill a relief well is given by the project and presented in Table 35. 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 35: Time to drill a horizontal relief well (days) [3]

	Min	Most likely	Max	Comments
1- Decision to mobilize	1	1	2	days
2- Mobilization of rig, including: collection of equipment/rearmament, transit, anchoring and preparation	6	12	19	days
3- Drilling down to the specific depth	14	23	30	Days (expected time to drill down to top reservoir)
4- Geo magnetic steering into the well[1]	7	12	30	8 ½" Geomagnetic steering (ranging) into Incident well.
5- Killing of well	1	2	5	days
Sum	29	50	86	days

It is assumed to be a vertical well as the basis in Table 35 is deviated well. The value is conservative as vertical wells have a value of 20 days for maximum number of days for geomagnetic steering into the well.

6.3.3 Duration of drilling a relief well

The required time to drill a relief well and kill a blowout is judged by the project to be between 29 and 86 days. A Monte Carlo simulation has been performed to produce a duration distribution from the well specific input given in Table 35. The statistical expected time for drilling a relief well if not killed by other remedies/occurrences, is 55 days based on assuming all five elements in Table 35 are triangular distributed. Note that this is not the same as the sum of "Most likely" column in Table 35. A probability distribution for the duration is presented in Figure 25 .

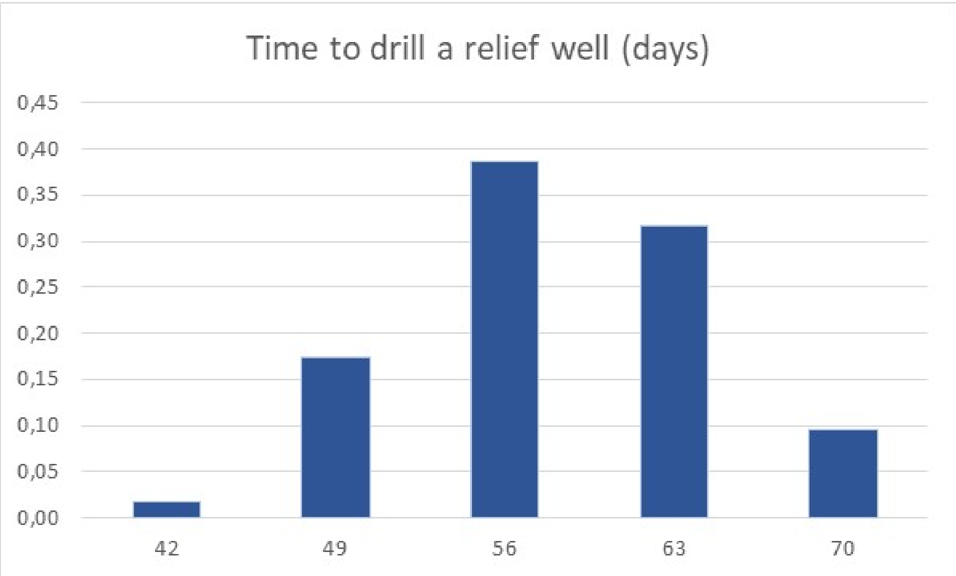


Figure 25 Duration distribution, 'Time to drill a relief well'

[1] 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.

6.3.4 Estimation of blowout duration by use of capping stack

Killing a blowout by means for capping stack is evaluated for Johan Castberg Field.
The probability of successfully stopping the blowout by use of capping stack is assumed to be 44 %. The probability for success is compared with the exploration well Snøfonn/Skavl which is also located in the Barents sea. The probability of use of vertical installation is 60 %, based on water depths around 400m. Note that through several test calculations it has been shown that variations in single values does not affect the total result in a significant way.

Bad weather conditions can lead to delays and increase the probability of success for landing the capping stack. The operational delays are added to the capping stack duration estimate received from the Johan Castberg Field drilling team and compared to the Snøfonn well. The drilling campaign is expected to be an all-year-round activity; hence the probability of operational delays is conservatively set to 10%. Normally P(delay summer) is 1% and P(delay winter) is 10%.

6.3.5 Duration for killing of a blowout

The probability distribution found in Table 36 below, is constructed by combination of the well specific duration distribution for drilling a relief well and the probabilities that a blowout will end by the mechanisms capping and bridging /1/ and use of capping stack. Maximum blowout duration is suggested to be 70 days. The weighted durations are for surface releases is 5 days and for subsea releases 12 days, ref. Table 37.

Table 36 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	36,6 %	23,1 %	42	-	3,1 %
2	14,8 %	11,5 %	49	-	3,4 %
5	18,5 %	18,6 %	56	-	4,6 %
7	10,0 %	6,8 %	63	-	3,7 %
10	9,5 %	6,4 %	70*	-	1,2 %
14	3,4 %	5,8 %	77		
21	3,9 %	9,8 %	84		
28	3,3 %	1,4 %	91		
35	-	0,7 %	98		

*Probabilities in the tail end of the duration distribution (< 0,001) are added to the probability of the preceding duration category.

Table 37 gives the weighted duration in days. The weighted duration is calculated by grouping the durations and their corresponding probabilities in Table 36 into five groups.

Table 37 Weighted duration

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	13,86	28,72 %
3	10 days	10,00	9,51 %	3	28 to 49 days	41,88	8,60 %
4	14 to 21 days	17,77	7,27 %	4	56 days	56,00	4,56 %
5	28 days	28,00	3,26 %	5	63 to 70 days	17,71	4,91 %
Sum weighted surface		**5,44**		**Sum weighted seabed**		**12,39**	

Different probability descriptions of the duration of a seabed or surface blowout are estimated. Possible durations of a seabed or surface blowout are described by probabilities in Figure 26. In Figure 27 blowout duration and 'time to drill a relief well' are described by cumulative probability curves.

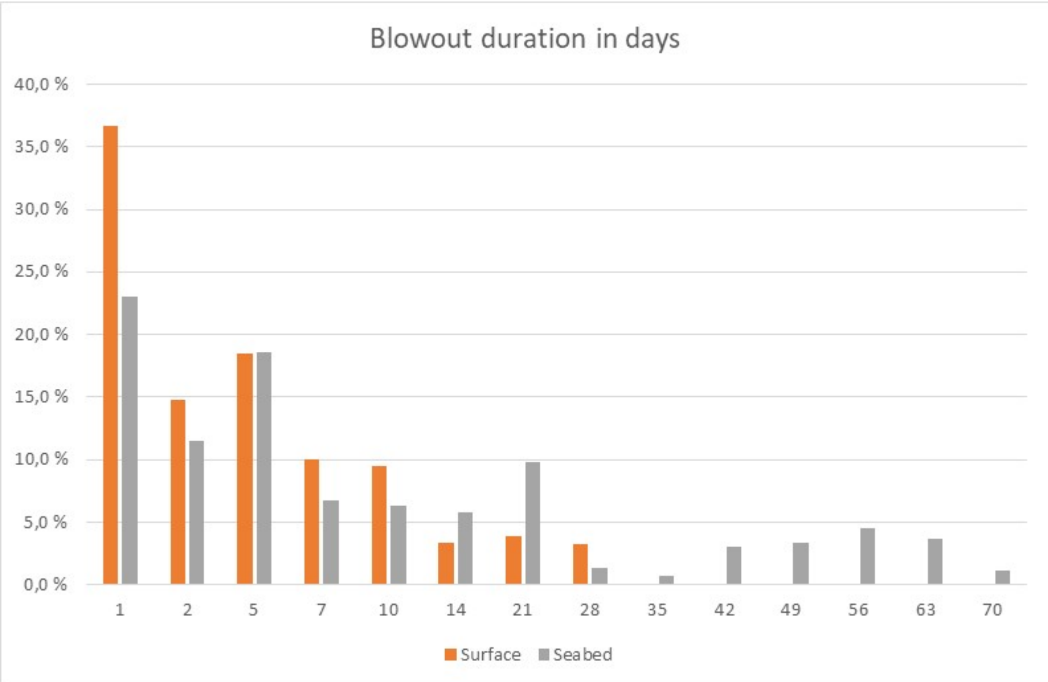


Figure 26 Blowout duration described by probability distributions

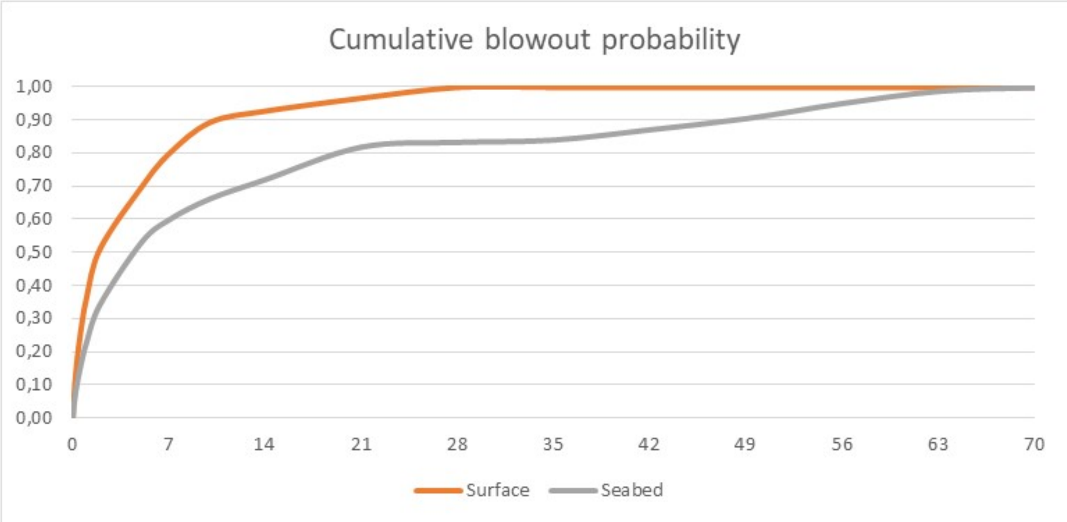


Figure 27 Cumulative Probability distribution for number of days for blowout duration

6.4 Summary, duration of blowouts

The maximum duration of a blowout it estimated to be 70 days included all Blowout stopping mechanisms mentioned in chapter 6.2.

7 Other oil spill scenarios

"Other oil spill scenarios" are assumed unchanged since the last BSSA [13], thus no changes are made.

Table 38 is showing the overview and summary of the other oil spill scenarios at the Johan Castberg Field. These scenarios are shown with a frequency, the expected amount of release and release-point and expected duration of the release.

Table 38: Summary of other oil spill scenarios

Scenario	Annual frequency	Consequence	Release point	Duration
FPSO cargo tank leak	1,29E-05	16700 m^3	Surface	2 days
Shuttle tanker leak	1,75E-07	12000 m^3	Surface	2 days
Risers/pipeline leak	1,12E-02	815 m^3	Seabed	1 day
Offloading hose leak	2,17E-04	1000 m^3	Surface	1 hour

7.1 FPSO cargo tank leaks

The FPSO structure is double hull vessel with ballast tanks between the outer hull and the cargo tanks. A leak due to internal damage to cargo tanks (e.g. corrosion) will not leak directly to sea, and therefore this scenario has not been assessed. The most likely scenario for oil spill to sea from the FPSO cargo tanks is ship collision from visiting tankers, supply vessels or other vessels in the vicinity of the FPSO.

There have been identified three potential scenarios for cargo tank leaks:

- Collision between FPSO and supply vessel or other smaller vessels
- Collision between FPSO and shuttle tanker
- Collision between shuttle tankers and other vessels upon departure from Castberg field

In the following a justification for the resulting frequencies and consequences have been performed.

7.1.1 Collision between FPSO and supply vessels/smaller vessels

The Johan Castberg FPSO can withstand more than 200 MJ impact to the stern without losing stability, and 40 MJ anywhere on the hull to the starboard and port side. Based on structural analyses on a double-hulled FPSO dimensioned for a sideways collision of 14 MJ, it is concluded that a sideways hit with kinetic energy of approximately 70 MJ can result in penetration of cargo tank [7].

However, assessing the different scenarios and consequences from ship collisions requires a more detailed structural evaluation of the FPSO, so for this analysis the following has been conservatively assumed:

- < 40 MJ will lead to local damage (penetration of outer skin, damage to compartments, no oil spill)
- 40-100 MJ will lead to critical damage (penetration of outer and inner skin, oil spill from one cargo tank),
- >100 MJ will lead to global damage (penetration of several compartments and oil spill from all cargo tanks).

For the bow/stern consideration, the energies above are added with a factor 2.

Annual energy exceedance frequencies for supply vessels and other attending vessels are presented in the table below, ref [8].

Table 39: Annual energy exceedance frequencies for supply vessel collisions, ref [8]

		Starboard/port	Bow/stern
Supply vessels	Critical damage	4,3E-06	Negl.
	Global damage	Negl.	Negl.
Attending vessels	Critical damage	4,5E-06	Negl.
	Global damage	Negl.	Negl.
Fishing vessels	Critical damage	1,0E-06	Negl
	Global damage	Negl.	Negl.
Sum		**9,80E-06**	-

Critical damage is defined as oil spill from the largest cargo tank on the FPSO, resulting in the following frequency and consequence for FPSO collision with supply vessel:

Table 40: Summary, FPSO collision with supply vessels

	Frequency	Consequence	Release point
FPSO collision with smaller vessel	9,80E-06	16700 m3*	Surface

*Largest cargo tank at full capacity (98 %) on Johan Castberg (Cargo 3C or 5C), ref.[9]

7.1.2 Shuttle tanker collision with FPSO

The offloading concept is stern offloading with a 100 meters distance to the shuttle tanker which will be operating on DP. In this analysis, it is assumed 81 offloading operations on Johan Castberg (high volume case) per year. Eagle Barents and Eagle Bergen will be used for offloading. Each offloading operation is estimated to last for 18 hours. For this analysis, the following shuttle tanker scenarios has been assessed:

- Phase A: Shuttle tanker collision with FPSO upon approach
- Phase B: Shuttle tanker collision with FPSO while maneuvering within safety zone
- Phase C: Shuttle tanker collision with FPSO during offloading
- Phase D: Shuttle tanker collision with FPSO upon departure

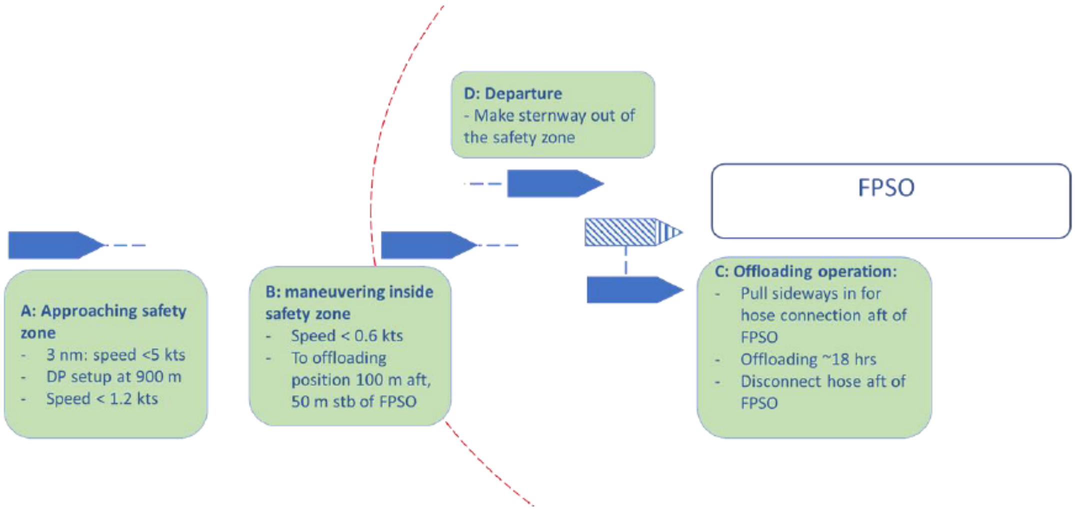


Figure 28: Shuttle tanker operational procedures upon approach, ref [8]

Phase A involves radio contact with the shuttle tanker at 18,5 km and reduction of speed. DP is set up at 900 m distance from the FPSO. Due to the distance from the FPSO and stepwise reduction in speed, the risk contribution from this phase is negligible.

Phase B involves operating in DP mode while maneuvering inside safety zone with low speed. Drift-off and drive-offs in this phase could result in a collision, but the shuttle tanker will approach the FPSO with a 50 m offset from the offloading hose station at starboard side to reduce the probability of collision. Due to the low speed and robust design of the FPSO stern (both regarding collision resistance and the inner layers of the structure), the risk of an impact leading to an oil spill scenario is considered negligible.

Phase C involves the offloading operation with the shuttle tanker located 100 m aft and 50 m port of the offloading station. A drive-off situation is considered the most likely event, with little time for the operator to avoid collision. However, collision energies above 200 MJ are considered to be low. The structure below deck 2 in the aft plane has a strong array of frames that act as a bumper against collisions. Once the bow of the colliding tanker collides with this bumper, high contact forces are needed to deform the structure and large amounts of energy will be dissipated.

Table 41: Annual collision energy exceedance frequencies for Phase C (> 200MJ), ref [8]

		Starboard/port	Bow/stern
Phase C	Critical damage	Negl.	3,1E-06

	Global damage	Negl.	Negl.
Sum		**-**	**3,1E-06**

Phase D involves departure, and the shuttle tanker will back away from the FPSO to a distance of at least 200 m. Hence, the probability of a collision in this phase is considered negligible.

Critical damage is defined as oil spill from the largest cargo tank on the FPSO, resulting in the following frequency and consequence for FPSO collision with shuttle tanker:

Table 42: Summary, FPSO collision with shuttle tanker

	Frequency	**Consequence**	**Release point**	**Duration**
FPSO collision with shuttle tanker	3,1E-06	16700 m3*	Surface	2 days

***Largest cargo tank at full capacity (98 %) on Johan Castberg (Cargo 3C or 5C), ref. [9].

7.1.3 Shuttle tanker collision upon departure

The shuttle tanker will be in ballast mode during approach of the Johan Castberg FPSO, with only bunker spill as a possible environmental release. Thus, only shuttle tanker collision with other vessels upon departure from the Johan Castberg field is assessed (within FPSO safety zone).

Table 43: Annual collision frequency calculation for shuttle tanker collision within safety zone

	Total P(collision) per nautical mile Invalid source specified.	**Nautical miles***	**Annual departures** Invalid source specified.	**Annual collision frequency**
Collision with other vessel	1,2E-07	0,3	81	2,92E-06

* Only collision within 500 m safety zone is considered

Table 44: Probability of oil spill following a collision for double hull oil tankers, ref Invalid source specified.

Hull type	**Zero spill**	**Up to 10 % of cargo**	**> 10 % of cargo**
Double	0,94	0,06	Negl.

The normal offloading volume at Johan Castberg will be approximately 120 000 m3 per operation ref. [8].

Table 45: Summary, shuttle tanker collision with other vessel

	Frequency	**Consequence**	**Release point**	**Duration**
Shuttle tanker collision with other vessel	1,75E-07	12 000 m3	Surface	2 days

7.2 Leaks from offloading operation

Leaks from the offloading system can be caused by equipment failure or operational errors during loading. The full leak frequencies from the offloading system are [8]:

Table 46: Annual leak frequencies for offloading system

	Small (<1,5 kg/s)	**Medium (<12 kg/s)**	**Large (<96 kg/s)**	**Sum**
Annual frequency	1,69E-04	3,25E-05	1,53E-05	**2,17E-04**

No assumptions regarding detection time or activation of barriers have been made.

Table 47: Summary, leaks from offloading system

	Frequency	**Consequence** Invalid source specified.	**Release point**	**Duration**
Leak from offloading system	2,17E-04	1000 m3	Surface	1 hour

7.3 Riser and pipeline leaks

Below the riser data for the Johan Castberg FPSO is presented, ref [8]. The longest pipeline length is chosen for both frequency and consequence evaluation in this assessment.

Table 48: Riser data, Johan Castberg

	Production risers
Number of risers	9
Type riser	Flexible
Type pipeline	Steel
Diameter ID (")	11,5
Riser length (m)	600
Pipeline length (km)	11570
SSIV	No

The following annual frequencies for riser/pipeline leaks have been used, ref. [8]:

Table 49: Annual riser/pipeline leak frequencies distributed by leak size

Hole sizes	Annual frequency (per riser)
Small	7,82E-04
Medium	2,89E-04
Large/rupture	1,70E-04
Sum	**1,24E-03**

Table 50: Johan Castberg riser leak frequencies, all risers

Hole sizes	Total (all risers)
Small	7,04E-03
Medium	2,60E-03
Large/rupture	1,53E-03
Sum	**1,12E-02**

Note that no assumption about detection time and release point has been made in this assessment. It is assumed that the whole content of the riser and pipeline is released to sea. The total oil volume of the riser and pipeline to Drivis is calculated to 815 m3.

Table 51: Summary, riser/pipeline leaks

	Frequency	Consequence	Duration	Release point
Riser/pipeline leaks	1,12E-02	815 m3	1 day	Seabed

8 Uncertainties

There are uncertainties in both the blowout rate input to the BSA and the blowout frequencies (statistics based on low number of incident), thus there will be an inherent uncertainty in the P90 rates and weighted drilling blowout rates. It is not possible to quantify the uncertainty, but the results are considered sufficiently conservative.

9 Summary

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

For the Johan Castberg field, given as the sum of activity on Skrugard, Havis and Drivis, the year with the highest activity level and corresponding highest blowout probability is year 2025. This includes drilling and completion of Johan Castberg wells. The blowout probability for 2025 as high activity year is 1,84E-03, and 5,09E-04 for year 2026/27 with low activity. The P90 rate for Johan Castberg wells in a high activity year is 3900 Sm^3/d for surface and 4100 Sm^3/d for subsea releases. In a low activity year the P90 rate is 3700Sm^3/d. The weighted blowout rate for drilling is 3400 Sm^3 for both surface and seabed in a high activity year. Low activity year does not have any drilling activity.

For the Skrugard wells, year 2024 has the highest activity and blowout probability with 1,54E-03. Low activity year is 2026/2027 with blowout probability 2,89E-04. The total P90 rate for Skrugard wells in a high activity year is 4000 for surface and 7600 Sm^3/d for seabed, and for low activity year seabed release is 3800 Sm^3/d.

For the Havis wells, year 2025 has the highest activity and blowout probability with 6,07E-04. Low activity year is 2024 with blowout probability 1,14E-04. The total P90 rate for Havis wells in a high activity year is 4000 Sm^3/d and for low activity year 3800 Sm^3/d.

For the Drivis wells, year 2025 has the highest activity and blowout probability with 5,01E-04. Low activity year is 2024 with blowout probability 3,63E-05. The total P90 rate for Drivis wells in a high activity year is 4100 Sm^3/d and for low activity year 7300 Sm^3/d.

It is found that the duration of a blowout could potentially amount to 70 days with about 1 % probability for surface and seabed releases for drilling/completion/production activities. The weighted blowout durations for blowout scenarios are 5 and 12 days for surface and subsea releases respectively.

10 References

[1] Vysus: “Blowout and Well Release Frequencies – based on Sintef Offshore Blowout Database 2022”, report 19101001-8/2023/R3, rev Final, March 2023

[2] Equinor: GL0498 “Guideline for Blowout Scenario Analysis as input to Environmental Risk Analysis” rev.2, March 2021

[3] Information from Johan Castberg, collected in “Input Scheme for Blowout Scenario Analysis Johan Castberg Field 2024-2027”, April 2023, Johan Castberg Petek/D&W

[4] Activity overview 2023, received from Erling Grindhaug, Leading Eng., D&W.

[5] SINTEF: "Blowout and Well Release Characteristics and Frequencies, 2020", report no. 2021:00131, January 7th, 2022

[6] NOROG: “Guidance on calculating blowout rates and duration for use in environmental risk analyses”, no report no., 2014

[7] DNV, “Collision analysis and residual hull girder strength of a ship-shaped FPSO,” DNV, 2013.

[8] Lilleaker Consulting, “Johan Castberg FEED TRA,” 2019.

[9] Equinor, Johan Castberg Tank Capacity Plan, rev 05, 2020.

[10] DNV, Appendix B: Accident statistics review and development of base frequencies, DNV, 2012.

[11] PTIL, “Vurderinger av årsaker og medvirkende faktorer som kan resultere i akutt utslipp til sjø fra petroleumsvirksomhet i Barentshavet og havområdene utenfor Lofoten,” PS-0357-RE-03, 2010.

[12] Equinor, Johan Castberg Safety Strategy, 2019.

[13] “Technical Note 2020 Blowout Scenario Analysis Johan Castberg 2020”, K. Apneseth, October 2020

Appendix A Probabilities related to use of capping stack

The table below is the result of a capping stack workshop for Snøfonn/ Skavl which is assessed to be relevant for the Johan Castberg Field Capping stack evaluations, however with justifications for the Johan Castberg field wells. The table 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)		0.4390
P(blowout not through WH/BOP)		0.3
P(outside spec)		0.109
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) *Justification: GOR 60-93, Max Rate ca 9200 Sm3/d, 3-400 m water depth. Rate x GOR =8,56E+05*	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: Like other wells in the Barents Sea*	0.1
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 *Justification: An anchored rig, presumably semi sub*	0.03
P(tilted wellhead)	*Justification: Known area*	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. (*Justification: depth < 500 m = 0,01)*	0.01
P(failed operation)		0.2444
P (Failed operation | vertical)		0.2159
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: Johan Castberg field is almost on the borderline between offset /vertical installation*	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: Assumed small possibility for casing collapse)*	0.2
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)		0.2872
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 are more complex than vertical.	0.1