Case Study 5: Drilling from a Semi-sub in the Arctic

Submitted to
The Bureau of Safety and Environmental Enforcement (BSEE)

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ABBREVIATION	EXPLANATION
BOEM	Bureau of Ocean Energy Management
BOP	Blowout Preventer
BSEE	Bureau of Safety and Environmental Enforcement
C	Celsius
CS	Capping Stack
DP	Dynamic Positioning
DWOP	Deepwater Operations Plan
ERA	Environmental Risk Analysis
FMECA	Failure Mode, Effects and Criticality Analysis
GOR	Gas to Oil Ratio
HAZID	Hazard Identification
HVAC	Heating Ventilation Air Conditioning
LMRP	Lower Marine Riser Package
MAH	Major Accident Hazard
MLC	Mud line Cellar
MMbbl	Millions of barrels
nm	Nautical miles
OCS	Outer Continental Shelf
ROV	Remotely Operated Vehicle
SINTEF	Stiftelsen for Industriell og Teknisk Forskning (Norwegian research institute)

1. Introduction

1.1 Background

As part of the Bureau of Safety and Environmental Enforcement (BSEE) Emergent Technologies project, a risk assessment framework was developed to qualify new technology applications submitted to BSEE. To provide the better understanding of the risk assessment framework, ABSG Consulting Inc. (ABS Consulting) selected the following five scenarios to test the proposed framework. The results of the five risk assessment scenarios will guide BSEE during the review of new technology applications using the proposed methodology.

- Scenario 1: Ultra-deepwater drilling
- Scenario 2: Floating production installation with a surface BOP (SBOP)
- Scenario 3: Managed Pressure Drilling
- Scenario 4: Production in High Pressure High Temperature (HPHT) and Sour Environment
- Scenario 5: Drilling from a Semi-sub in the Arctic

It is important to consider when reviewing this document, that the subject scenario background information and risk assessment were developed and tested based on publicly available information. Therefore, due to this limitation, the provided studies or assessments do not reflect actual real-life projects and the studies performed for real-life projects will be more comprehensive than those provided in this document.

This document provides information on the Scenario 5: Drilling from a Semi-sub in the Arctic.

2. Scenario Development

To perform the new technology evaluation, the following information will have to be made available.

In general terms, the information may be grouped into three main categories:

- Technical description/documentation of the installation and equipment that are to be the subject of the assessment. An overall description of the main characteristics and capacities of the installation will be required in order to establish the framework for the assessment. As the assessment goes into details on the technical side, an increased level of technical information will likely be required, including details on any reliability assessments, as well as details of the safety systems.
- Description of the conditions where the installation is to operate. This includes metrological and environmental data, reservoir and well stream data as well as other activities in the area that may affect the installation. This is important input to the risk assessment as it tells under which conditions the installation and equipment shall operate. Different assessments will require different types of information.
- Description of the operations that will take place. This defines the operations and activities that will take place with the installation and its equipment in the actual conditions. The assessment will also require information about the different operations that will take place (e.g., number and type of wells to be drilled) as well as which of the operations that will go on in parallel (e.g., if there will be large maintenance activities going on at the same time as production is running).

This scenario stems from publicly available information tailored to provide the information required to do the assessments as part of these scenario example assessments. In real life, other information, as well as more comprehensive information, will be available and may be required based on the actual situation to be considered in the risk assessments

2.1 Scenario Description

This Scenario covers the case of moving a rig (‘Arctic Conqueror’) that is older, but still winterized, to a new remote and harsh location. The location is the Chukchi Sea north of Alaska.

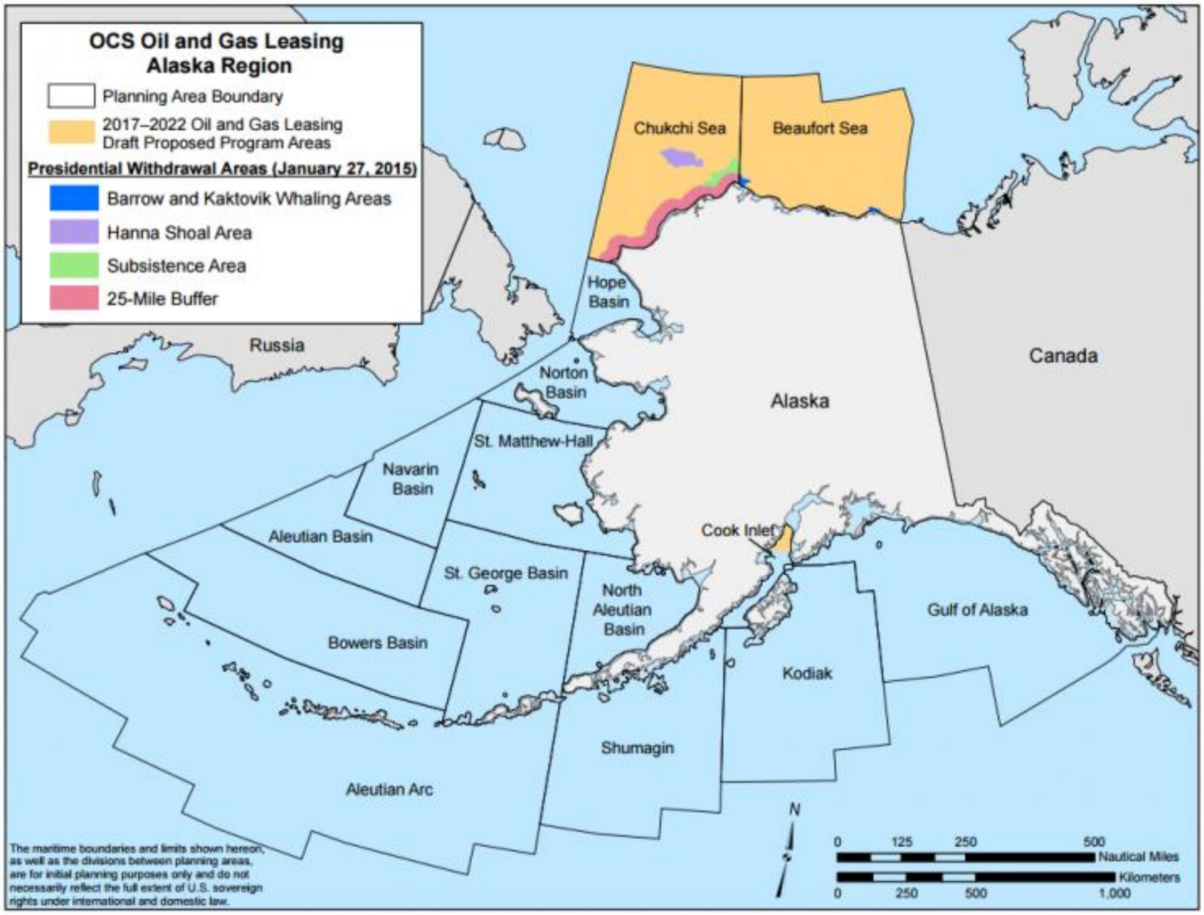

Figure 1. Alaska Outer Continental Shelf[1]

The Chukchi Sea (Figure 1) is extremely remote and prone to icy waters, major storms, and waves that can reach 50 feet high. In the event of a spill or accident, the closest Coast Guard resource with the necessary equipment is more than 1,000 miles (approx. 1610 km) away. The community in closest proximity to the planned exploration activities is Wainwright, roughly over 60 miles to the southeast. The stretch of Alaskan coast near the drilling area has no roads leading to major cities or ports for hundreds of miles. In addition, the calendar window for drilling is extremely narrow: just a few months during the summer.

These leases are located on the relatively shallow continental shelf of the Chukchi Sea. The seafloor near each proposed well is largely flat, nearly featureless, and predominately composed of sandy mud. The sea depth is approximately 150 ft. (45m) mean water depth.

[1] http://www.ibtimes.com/arctic-drilling-2015-shell-advances-plans-drill-alaskan-arctic-despite-low-oil-prices-1918968 [02.07.2015]

2.2 Meteorology[1]

The Alaska North Slope, adjacent to the Chukchi Sea, is a polar climate characterized by moderate winds and cold temperatures during the winter, cool temperatures in the summer, and little annual precipitation (less than 7 inches (17.8 centimeters (cm) a year near Wainwright, Alaska) (Ahrens 2013). Subfreezing temperatures dominate the region for most of the year, and ice almost totally covers the Chukchi Sea from early December to mid-May. During the summer, fog occurs frequently as warmer air moves over the colder water, which is sometimes covered with ice. Because of the fog, low visibility of one-half mile or less can occur, most commonly during June, July, and August. During October, temperatures remain below freezing, ranging from 12.2°F to 23.0°F, (-11 to -5°C) and rarely drop below zero (-17.8°C). The daily average wind speed in early October is 15 mph (24 km/h), occasionally reaching near 20 mph (32 km/h).

There are three general forms of sea ice in the project area (including the shore base and areas where oil spill response could occur):

- Landfast ice, which is attached to the shore, is relatively immobile, and extends variable distances offshore
- Stamukhi ice, which is grounded and ridged ice
- Pack ice, which includes first-year and multiyear ice and moves under the influence of winds and currents.

Real time ice and weather forecasting will be from the Arctic Conqueror Ice and Weather Advisory Center.

The proposed drilling activities are planned for the Arctic summer "open-water" season. The proposed drill sites are far seaward of the typical extent of landfast ice during the time of operations. Landfast ice could occur in areas near the Kotzebue Sound mooring, the shorebase, and oil spill response locations. The end of the season represented by the formation of ice is always difficult to predict and will always pose a great source of uncertainty to the operation and risk picture. The ability to either shut down the operation or to withstand that first period of ice will be crucial to the operational risk.

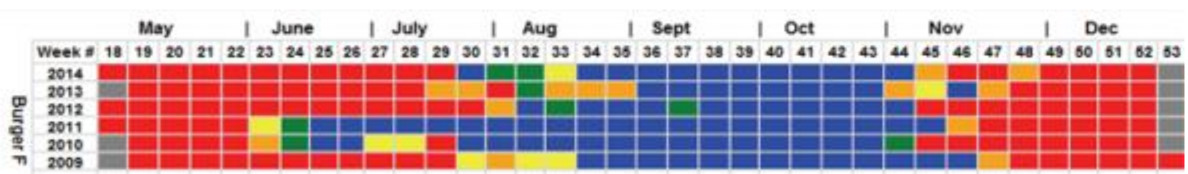

Figure 2. Weekly Minimum Sea Ice Concentration Adjacent to the Proposed Action Area.

Figure 2 illustrates the minimum bi-weekly sea ice concentrations within a 30-kilometer radius of proposed Burger exploration well sites between May and December.

2.2.1 Currents

Little is known about the currents, but the shallow sea depth in the area will most likely present heavy currents.

2.2.2 Wave Conditions

Development of waves depends on wind speed and direction, presence and distribution of ice, and the sea depth. Strong winds are relatively rare in July and August, which hinders wave development. Waves of maximum magnitude usually develop in September and October.

Area	Start - End Date	Dominant		Average	Maximum		Reference
		Significant Wave Height	Peak Period	Significant Wave Height	Significant Wave Height	Peak Period	
Burger	10/12/2008-10/7/2009	0-1.5 m	5-7 s	1.2 m	3.6 m	10.5 s	Mudge et al., 2010
Burger	10/07/2009-7/28/2010	0.5-1.5 m	4-7 s	1.2 m	5.1 m	10.1 s	Fissel et al., 2011
Site 1	7/26/2010-7/27/2011	0.5-1.5 m	4-8 s	1.34 m	4.3 m	10.8 s	Mudge et al., 2011
Chukchi	08/18/2010-11/07/2010 05/12/2011-08/25/2011	< 2.0	4-8 s	1-2 m	3.8 m	na	Weingartner et al., 2013

Figure 3. Wave Heights for Development Area

2.3 "Arctic Conqueror"

The rig that will be moved to the Chukchi Sea is the Arctic Conqueror. The rig has undergone extensive modifications in recent years to perform drilling operations in the Arctic and under similar circumstances during the summer period.

The Arctic Conqueror is a semi-submersible drilling rig designed for drilling and completion for operation between 45-600m water depth and a maximum drilling depth of 7000m.

Generally, physical divisions (fire division, solid deck, solid roofs etc.) and escape way layout make up the area division. Areas with similar or almost similar expected risks are merged into one area to restrict the number of areas. The rig is divided into areas like drilling (incl. moon pool area, mud-, cement- and testing area), laydown areas, living quarters, and utility area and engine rooms.

Arctic Conqueror, when completed in 1986, was originally built to operate at temperatures as low as -20°C (-4°F).

Arctic Conqueror has maintained class with American Bureau of Shipping since the unit its construction.

Arctic Conqueror is a fourth generation semi-submersible drilling rig. The accommodation capacity is 110 beds. The evacuation means are davit launched lifeboats and life rafts. There are four conventional lifeboats, each with the capacity of 70 persons.

2.4 Technology Descriptions

2.4.1 Status

Arctic drilling operations have existed for decades. Many different areas around the Arctic have been explored from onshore, ice islands and shallow water to deep water exploration. Operations take place mostly in the summer season when the ice conditions are the lightest, but drilling in heavy ice conditions during summertime has also been performed. Year round offshore exploration is rare in this area.

2.4.2 Technical and Operational Description

In Arctic drilling operations, numerous external factors influence the risk and risk contribution. In most cases, the harsh environment will increase risk. However, some environmental factors may actually mitigate the risk. For example, the presence of sea ice will reduce waves and wave propagation.

When it comes to barriers in the arctic, there will be a heightened need for redundancy and protective measures implemented for identified barriers to retain their function. There may also be a need to introduce new barriers. These may be dependent on new technology or they may be simple known solutions that are already tested and known, but the operational environment is new. High interest in Arctic operations in recent years has brought about an increased focus on arctic technology and development. This will be important for the development of more robust barriers for Arctic operations. Based on where the drilling will take place there will most likely be a need for some kind of upgrade to ensure safe operations. Typical need for upgrades can be seen from the modifications done to the Arctic Conqueror.

To ensure safe operations in the Arctic, the Arctic Conqueror was modified, including numerous winterization measures:

- Enhanced Subsea Shut-In Device
- Extra weather cladding on drill floor
- Heat tracing (extensive upgrades and additions) including extra power generation to handle the extra loads
- Anti-icing/De-icing measures
- Offshore ”walk to work” gangway (due to inability to use helicopter)
- Net for riser protection from ice actions
- Extensive Ice Defense Plan
- More focus on wind chill and outdoor operations
- New anchor arrangement for quick move-off
- Escape, Evacuation and Rescue equipment (escape ways, lifeboats [including launch mechanisms], rafts, chutes, survival gear, etc.) has to be operational under all operating conditions
- New fuel regime for use of “arctic” diesel
- Helicopter operation and evacuation
- Environmental impact must be taken into consideration since there is a high focus on the fragile arctic environment
- Communication with local entities critical for the exploration and impact

- Operation logistics and entities involved on-site and in direct operational support

Table 1 shows what the main operation will include of logistics and entities involved in the drilling campaign.

Table 1. Logistics and Entities Involved in Drilling Campaign

Drilling Units	Drillship X and Arctic Conqueror
Mud line Cellar (MLC) Construction	Drillship X and Arctic Conqueror, MLC remotely operated vehicle (ROV) system
Support Vessels	Drilling Support Vessel includes a number of vessels for ice management, anchor handling, supply tugs and barges, Offshore Standby Vessel, MLC ROV system vessel, science vessel, shallow water and oil spill containment vessels.
Aircraft	Helicopters All Weather Search and Rescue, etc. for crew change. Fixed wing aircrafts for Protected Species Observer, ice monitoring and crew change.
Aircraft Flights	Helicopter and fixed wing aircrafts are available for crew change/resupply and ice monitoring/environmental observations.
BOP Test Frequency	Pressure test every 14 days as per BSEE regulation
Shorebase	Camp for staff with utilities and helicopter space. Primary site or secondary site must house emergency response equipment.
Secondary Relief Well Unit for the Discover	Drillship X will serve as secondary relief well unit for Arctic Conqueror, and Arctic Conqueror will serve as secondary relief well unit for Drillship X

When drilling in the Arctic, if the well cannot be contained and equipment like the blowout preventer (BOP) fails to shut in the well as intended, a containment measure called Capping Stack (CS) should be available to “cap” the well. A containment dome shall also be available for gathering and removing the oil with minimal release to the environment if the capping operation fails. The design and availability of such Source Control and Containment Equipment is extremely important for the environmentally sensitive areas in the Arctic.

In this scenario, the focus will be on the capping stack as a new technology used to seal the well in case of a blowout. The equipment that is crucial to install and seal the well together with the CS is included, and associated operational and physical tasks are defined. All critical functions, elements and attributes for arctic application will be included to highlight the unique operating conditions. The capping stack is specialized subsea equipment with limited winterization requirements and unique elements related to the success of the operation. Adapting to arctic requirements and specifications will be more visible in the attributes developed for each of these elements.

2.5 Risk and Barrier Assessment Workflow

As there is limited experience with drilling operations in an arctic environment on the Outer Continental Shelf (OCS) and there are environmental challenges as described in Section 2.2, the operation in question is considered to be in a different or unknown environment in comparison to the areas where the rig has previously been used for drilling operations.

The CS is a containment system designed for placement on top of a wellhead or BOP to seal and contain an incident well when the BOP or other preventive measures have failed to stop the flow of hydrocarbons. Note that capping stacks have not been excessively used in actual blowout scenarios. The CS, as a concept and product, was first developed in 2010 in the aftermath of the Deep Water Horizon blowout, to seal the well and reduce the environmental consequences. Since then the need for capping stacks to be available (i.e., on standby or ready for use) have been a top priority for both regulators and Operators. Many commercial consortiums have been formed which store and maintain capping stacks in key locations around the globe to support response efforts. Hence, many capping stacks have been developed but the technology has not been applied in an arctic environment yet.

Taking all the above aspects into consideration, the proposal of a capping stack in the arctic environment is deemed a suitable candidate for the new technology evaluation process. The new technology risk assessment framework requires guidance that depends on the novelty of the combination of the technology and the applied conditions, as presented in Figure 4.

The proposed scenario represents a borderline case between WF2 and WF4. As it can be argued that the technology is new due to its limited usage, it would be best to do a more detailed assessment using Workflow WF4 – New Technology in Different or Unknown Conditions. The risk assessment step will focus on the identification of Major Accident Hazards (MAHs) and associated consequences. As part to the risk assessment, the team will identify the barrier critical systems that can prevent MAHs, or provide mitigation against the consequence resulting from MAHs.

Operation in different or unknown condition using the barrier critical system would require a greater focus on the consequence effects from the identified MAHs. In addition, failure of the barrier critical system due to potential incompatibility or inadequate design for the different or unknown conditions could lead to the realization of a MAH. A barrier analysis to identify the critical success attributes for the barrier elements that constitute the barrier critical system is of extreme significance.

The HAZID carried out as part of the risk assessment helps in identifying the MAHs and affected barrier functions. Section 3 covers the risk assessment for this scenario and related findings. Section 4 covers the barrier analysis involving the review of the barrier critical system (Capping Stack) to understand what needs to succeed in order for it to perform its barrier function(s). For this purpose, a barrier model is developed and analyzed to determine the ways in which the barrier critical system can succeed, in performing its function. A good understanding of the success logic is critical in determining the requirements and related activities for ensuring the integrity of the barrier critical system.

The application of the barrier model also provides insight about other barrier critical system(s)/barrier element(s) that interface with the proposed barrier critical system and contribute to the realization of the barrier function(s). The barrier model begins with the identification of the barrier function and contributing barrier critical systems. The model then identifies the required barrier critical system function(s) for each barrier critical system and relevant barrier elements. For each barrier element, physical and operational tasks are identified that enable the barrier critical system function. Performance influencing factors and attributes along with the relevant success criteria can be derived at this stage for the barrier element to perform its intended physical/operational tasks thereby realizing the barrier function.

Note: For further detail on Barrier Analysis, refer to the "Barrier Analysis for New Technologies in OCS", deliverable #3 of this contract.

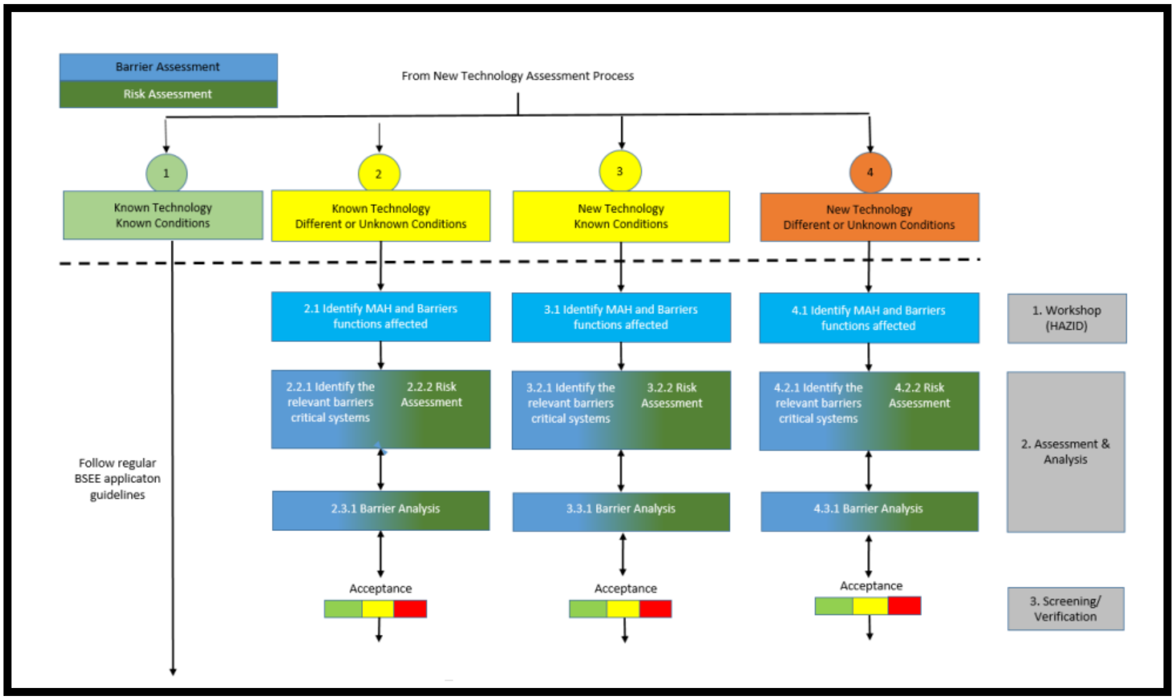

Figure 4. New Technology Assessment Framework

ABS Consulting

3. Scenario Risk Assessment

3.1 HAZID

3.1.1 Purpose

As part of the Deepwater Operations Plan (DWOP) verification procedure, a Hazard Identification (HAZID) is performed. The HAZID tool identifies MAHs or barriers from new technology and/or changed conditions as identified in technology assessment. The focus is to identify any impact on barriers in place to control the actual MAH and possible changes in consequences from the same hazards.

3.1.2 General

This section documents the HAZID performed for the Arctic Conqueror's drilling program in the Chukchi Sea north of Alaska. It contains the guidewords and findings from the HAZID.

The following questions should be answered during the HAZID related to *New Conditions* and *New technology*:

1. Do the <u>changed/new conditions</u> directly impair, weaken, or increase demand on any barrier function(s) in place to control the MAH in question? Are any new barriers introduced?
2. Do the <u>changed/new conditions</u> give potential for increased or new consequences related to the MAH in question?
3. Does the <u>new technology</u> directly impair, weaken, or increase demand on any barrier function(s) in place to control the MAH in question? Are any new barriers introduced?
4. Does the <u>new technology</u> give potential for increased or new consequences from the MAH in question?

The risk and barrier assessments that follow the HAZID may vary in size and scope, depending on the complexity of the assessed equipment or systems.

3.1.3 Guidewords

The tables below contain the guidewords used during the HAZID. The relevance of each of the guidewords were decided in the session. The focus was on how the accidental events are affected by introduction of:

- Changed/new conditions
- New technology

As a basis for the HAZID, a generic list of MAHs is established. The HAZID procedure was conducted for each of the MAHs that are not deemed *not relevant* for the operations in question.

Table 2. General Guidewords

General (Affected by Conditions/Technology)	Check List to Evaluate Any Major Accidental Hazards
Loss of Evacuation and escape	• Are escape and evacuation functions affected? • Are new escape/evacuation functions introduced?
Marine operations	• Are marine operations are affected/introduced? • Collision hazards?
Marine/other	• Anchoring /tethers/ DP • Loss of stability • Loss of buoyancy • Water depth • Environmental forces (wind/waves/cold/visibility) affecting operations? • Traffic surveillance/ control
Material handling	• Is material handling affected? • Were lifts over subsea equipment/pipelines performed? • Falling/ swinging load potential affected
Other events	• Helicopter crash • Power (main/emergency) • Blackout • Other?
Requirements	• Authorities • Standards • Deviations

Table 3. Area Specific Accidental Events

Area Specific (Affected by Conditions/Technology)	Check List used to Identify Major Accident Hazards per Area

Major accident hazards (MAH) (Hydrocarbon)	• Loss of containment
	  ○ Process equipment
	  ○ Loss of well control
	• Ignition sources
	• Ventilation conditions
	• Ignition (fire/explosion):
	  ○ Process equipment
	  ○ Well (fire in shale shake /mud system/Discharge Elimination System)
	  ○ Engine room
	• Escalation potential (source/target)

Other inflammable materials and fluids	• Methanol, diesel, lube oil, seal oil, hydraulic oil, glycol, electrical fires, etc. • Hot fluids • Cold fluids • Bottles (gas cylinders) with pressurized gas?

Area Specific (Affected by Conditions/Technology)	Check List used to Identify Major Accident Hazards per Area
Toxic gas/other effects	• Toxic releases • Anoxic effect • Hot / cold fluids • H2S, N2, CO2, SO2 etc. • Vents • Inerting systems • Hazardous atmospheres (CO, CO2 etc.) • Biocide • Inhibitors (scale, corrosion, etc.) • Antifoam • Emulsion breaker • Oxygen Scavenger

Table 4. Area Specific Barriers

Area Specific (Affected by Conditions/Technology)	Check List Used to Identify Barriers Area by Area
Fire and explosion barriers	• Are physical barriers (walls/decks) with respect to fire and explosion defined? (A/H – rated)
Escape routes / Evacuation	• Are escape routes affected? • Has the area direct access to evacuation means?
Area classification/Heating, Ventilation, and Air Conditioning (HVAC)	• Are main principles for area classification established/affected? • HVAC - location of in/outlets and philosophy (actions upon gas exposure)?
Gas/ fire detection	• Is automatic gas and fire detection implemented in all relevant areas – need for more detectors? • Alarms and/or automatic actions? • Voting principles and set levels?
Isolation and blowdown	• Are segments isolatable by ESVs or XVs, also between main areas? (automatic/manual) • Are ESVs / BOP to be protected against fires and explosions? • Blowdown? (automatic/manual/time) • Flare or diverter system affected? • Power/signal dependency (fail safe?)
Active fire protection	• Is active fire suppression (deluge) to be implemented? • Philosophy for when deluge/monitors is released? • Fire water capacity (one or more areas simultaneously?) • Foam?
Passive fire protection	• Philosophy? • On structural elements? • On process equipment? • On main safety critical elements (e.g., RESVs etc.)? • On risers/riser tensioning system? • On flare system/stack?
Other Barriers	• Emergency power affected? • Drain affected? • Heat tracing – on what barriers?

3.1.4 Summary and Conclusion

A key focus of Arctic exploration in the public eye will invariably be environmental concerns due to the fragility of many Arctic coastal areas – including the Chukchi Sea and the northern Alaskan coast. This is a very important aspect and will be explored further in risk and barrier analyses.

However, there are also other important concerns, such as personnel risk in a cold and potentially hostile environment concerning temperatures and weather conditions. Additionally, the remoteness of the location means that there are fewer emergency preparedness resources close by – although this is somewhat mitigated by resources located on standby vessels nearby.

In the HAZID worksheets, the rightmost column includes recommended studies to address the concerns raised by the HAZID findings. A summary is shown in Table 5.

Table 5. Overview of Recommended Risk Assessment Studies

Study	HAZID Reference No.	Covers Risk Related to
EERA	1, 24	Personnel
Dropped objects study	8	Personnel, assets
Collision risk assessment	3, 6	Personnel, assets
Helicopter risk assessment	7, 12	Personnel, assets
Blowout risk assessment	9, 14, 15	Personnel, assets, environment
Well test risk assessment	13, 15	Personnel, assets
WCI/Unavailability study	19	Personnel
Diesel fire assessment	21	Personnel, assets, environment
FMECA for the capping stack	22	Environment
Environmental Risk Analysis (ERA)	22	Environment
Explosion risk assessment	23	Personnel, assets
FMECA for the power systems	29, 30	Personnel, assets

Of the studies shown in Table 6, the Environmental Risk Analysis (ERA), with input from the Failure Mode, Effects and Criticality Analysis (FMECA) for the capping stack, mainly addresses environmental concerns. The criticality of environmental issues in the Arctic therefore naturally provides input to the DWOP process. The risk and barrier assessments that follow the HAZID may vary in size and scope, depending on the complexity of the assessed systems and equipment. On the barrier side, it is recommended that the capping stack in particular be treated with a separate barrier model.

The following aspects are the main outcome from this HAZID and should be used as basis for the further risk assessment work:

- This is an environmentally vulnerable area accordingly all possible measures to mitigate environmental hazards should be identified and implemented.
- Many of the safety barriers may be vulnerable to the meteorological conditions in the area.
- The remote location adds additional challenges with regard to emergency preparedness.

Scenario 5 example focus on the environmental risk in an ERA focusing on well events, and the capping stack as a consequence-reducing barrier.

3.1.5 General Guidewords

ID No	Guideword	Hazard/Accident	Existing Risk Reducing Measures	Observations	Action/Recommendation	Recommended Assessment
1	Loss of evacuation and escape	Harsh environment - waves, ice and low visibility	Monitoring, heat tracing, upgraded evacuation means.	There is an impairment risk related to sea spray. Properly dimension evacuation means. Use of heat tracing as chemicals are generally not approved.	To be addressed in Risk assessment	Escape, Evacuation and Rescue Assessment (**EERA**).
2	Lifting operations	Dropped objects during material handling	Operational requirements. DP on supply vessel.	Operational issues due to fog. Drilling will take place in the summer season, when fog is the largest issue. Operational envelope may require extension due to limited time for operations. De-icing of cranes is not common, mechanical removal is more common. There will be storage of a lot of equipment on vessels in close proximity to the rig.	To be addressed in Risk assessment	**Dropped objects study** according to e.g., DNV RP F107, using lifting information and rig layout.
3	Marine operations	Collision	Radar, visual, radio communication, procedures.	A large number of marine operations and vessels involved. There are small operational windows and fog may be a problem for visiting vessels. Issues with fog may lead to personnel change using vessels. This may increase collision risk.	To be addressed in Risk assessment	Probabilistic **collision risk assessment** based on AIS data for passing vessels and information about vessel activity and behavior for visiting vessels. The study should also consider ice movement and the effect of fog.
4	Marine operations	Collision	Standby vessels, radar	There will be less passing vessels, causing lower risk related to passing vessel collisions.	Measures to ensure control of approaching vessels for assessment.	
5	Marine operations	Collision	Radar, visual, radio communication, procedures.	Wave and fog causes less visibility and increase potential for misunderstanding and collisions.	Measures to ensure appropriate communication in all conditions.	
6	Material handling	Frequency of visiting vessels affects the collision risk.	Radar, visual, radio communication, procedures.	Not a large distance from shore. Manual handling of materials in frigid icy conditions increases personnel risk.	Supply vessels with respect to operational windows, etc., should be studied in risk assessment.	Included as part of **collision risk assessment** recommended in ID 3.
7	Other events	Helicopter crash	Operational procedures related to weather.	Fog and unstable conditions may cause problems with taking off helicopters, leading to delays in personnel change and hence fatigue etc. The supply base onshore is in a remote location, there might also be issues concerning shuttling people in and out of the supply base location.	Info	Discussed as part of a **helicopter risk assessment** where both transit and landings/take-off are included.

ID No	Guideword	Hazard/Accident	Existing Risk Reducing Measures	Observations	Action/Recommendation	Recommended Assessment
				There will be additional risk to personnel if crew change has to occur with baskets,		
8	Marine/other	Stability	Ballasting system, Anchor handling.	May be more stability issues due to weather. The waves are higher in the summer than the winter, due to the dampening effect when there is a considerable amount of sea ice. The size of the waves is, however, not considered a large issue in itself, but may cause icing which can be a stability issue. Can cause other issues related to material handling. May increase swinging load potential.	Info	Swinging load potential to be discussed as part of **dropped objects study**.
9	Marine/other	Buoyancy	Ballasting system, Anchor handling.	Shallow water, gas blowout can lead to tilting of rig. Not considered a critical issue based on knowledge available today. The shallow water may however cause it to be a larger problem than in deeper waters.	To be addressed in risk assessment and stability calculations.	Lack of stability during gas blowout to be covered in **blowout risk assessment** for non-ignited events.
10	Marine/other	Ice collisions	Ice monitoring. Ice handling vessel.	There should be a system with daily fly-bys and buoys to monitor ice, as well as vessels such as ice breakers.	There should be an ice management plan, as well as plans given that vessels will be preoccupied in case of other incidents (e.g., collisions).	
11	Marine operations	Collision	The integrity of hull should be able to withstand some impacts.	Older rig. Uncertainty of impact integrity.	As this is an older rig, it should be checked the collision energies the rig can withstand.	
12	Other events	Helicopter crash	Man over board boat, other nearby vessels.	Helicopter crashes may have less survival potential due to conditions. Need quick salvage from sea.	To be addressed in Risk assessment. The Norwegian Barents Sea uses a different survival suit than the North Sea. Similarly, modified survival suits with additional protection from the cold should be used.	Discussed as part of the **helicopter risk assessment**

3.1.6 Area Specific Accidental Events

ID NO	GUIDEWORD	HAZARD/ACCIDENT	EXISTING RISK REDUCING MEASURES	OBSERVATIONS	ACTION/RECOMMENDATION	RECOMMENDED ASSESSMENT
13	MAH hydrocarbon	Process equipment event	Containment of hydrocarbons. Inspection of equipment.	Winterization/cladding of an older rig may increase probability of corrosion below the cladding, as it is not designed for this from the start.	To be addressed in risk assessment. There should be a corrosion monitoring system in place. Physical inspection is necessary; the maintenance program needs to account for this.	To be covered in **risk assessment for well test equipment** by increasing frequency for loss of containment compared to historical data.
14	MAH hydrocarbon	Loss of well control	BOP, diverter system	Very short time from a blowout until exposure of the rig due to shallow waters. This can reduce the effect of move-off when it comes to avoiding ignition, as there may already be a gas cloud when anchors are being dropped – a potential ignition source.	To be addressed in risk assessment.	Taken into account in the probability for successful move-off in the **blowout risk assessment.**
15	MAH hydrocarbon	Ignition sources	Ignition control.	There will be more ignition sources due to increased heat tracing.	To be addressed in risk assessment.	To be covered in **blowout risk assessment** and **risk assessment for well test equipment**.
16	MAH hydrocarbon	Loss of well control	BOP and casing	There will be more tear on the casing, drill string and BOP due to adverse weather conditions and low water depth. This can increase the blowout frequency.	The effect of the fact that the rig is used at its limit with respect to water depth should be checked.	
17	MAH hydrocarbon	Loss of well control	Reservoir analyses, drilling program.	During production, there might be other migration paths due to soil conditions, but not necessarily relevant during drilling.	Info	
18	MAH hydrocarbon	Iceberg gouging	Ice monitoring.	Icebergs may scour the seabed and harm subsea equipment. If an event occurs and the well is capped, the capping stack will be left on the seabed and can be exposed to iceberg gouging.	Should be checked whether subsea structures (during production) should be protected from iceberg gouging. Not relevant for drilling, but relevant after a blowout or when the well is abandoned or plugged after a find. The use of "glory holes" should be applied to lessen the risk of damage from iceberg gouging.	
19	MAH hydrocarbon	Ventilation conditions	Weather cladding for improved working environment and avoiding icing.	Need to fit more equipment and cladding, will decrease ventilation conditions. Should	To be addressed in risk assessment. Should check design loads if they are sufficient. Should check requirements for working environment and ventilation conditions.	**Wind Chill Index (WCI)/Unavailability study** to find the necessary amount of cladding in order to sustain a good work environment that has a high percentage of availability.

ID NO	GUIDEWORD	HAZARD/ACCIDENT	EXISTING RISK REDUCING MEASURES	OBSERVATIONS	ACTION/RECOMMENDATION	RECOMMENDED ASSESSMENT
20	MAH hydrocarbon	Ventilation conditions	Weather cladding for working improved environment and avoiding icing.	May be more demand for HVAC etc. HVAC inlets may introduce gas to ignition sources. Additional gas monitoring/detectors to be introduced.	To be addressed in risk assessment.	
21	Other inflammable materials and fluids	Diesel fire	Containment of diesel, leakage monitoring.	Winterized diesel with lower ignition point is used.	To be addressed in risk assessment.	Increasing diesel ignition probability compared to historical data in the **diesel fire assessment.**
22	MAH hydrocarbon	Loss of well control	BOP, mud, diverter system, casing, summer drilling season	Spills to the environment can have particularly damaging consequences due, but not limited, to: - Presence of endangered or threatened species of wildlife - Special aquatic sites including marine sanctuaries, national seashores, coral reefs - Fishing as an important and integral part of commercial and recreational activities in the area. - Difficulty in cleaning up spill if it reaches ice	To be addressed in risk assessment. A capping stack is important to have in close proximity, for fast deployment given a loss of well control event.	**FMECA** of capping stack deployment. **ERA** Separate **barrier model** for capping stack

3.1.7 Area Specific Barriers

ID NO	GUIDEWORD	HAZARD/ACCIDENT	EXISTING MITIGATION/BARRIER	OBSERVATIONS	ACTION/RECOMMENDATION	RECOMMENDED RISK ASSESSMENT STUDY
23	Fire and explosion barriers	Ignited well events (fire/explosion)	Drill floor, main deck, hull are rigid structures, and act as barriers.	Normally no defined explosion barriers on such older rigs. However, rig is now much more enclosed (increased amount of cladding), which can increase explosion loads.	To be addressed in risk assessment	**Explosion risk assessment** with frequency input from blowout risk assessment and ventilation/explosion simulations
24	Escape routes/evacuation	Blocked / redirected escape ways.	-	May be affected by enclosures, etc., but assumed that escape way principles are maintained.	Info	This should be verified in the **EERA.**
25	Area classification/HVAC	Well events	-	There are different philosophies regarding area classification, which will have to be updated when cladding is introduced.	Should be a focus on area classification and HVAC requirements in risk/barrier assessment. Should be a thorough mapping of the winterization actions performed on the rig, and the risk or barrier elements affected by the actions.	
26	Gas/fire detection	Wind, fog, ice may reduce effectiveness of gas detection	Gas (and fire) detection system	Weather will affect the ability to detect fire and gas leakages. Line detectors may have problems with line of sight. Icing/ packing of snow blocking gas detectors. Anti-icing measures should be evaluated.	Should be a study regarding detection.	
27	Falling ice	Falling ice may damage equipment or harm personnel	Heat tracing - ice protection.	Falling ice in general, can cause harm. Should be assessed together with ice accretion risk and location.	There should be an evaluation of locations where ice can fall etc.	
28	Active fire protection	Reduced functionality due to icing	Fire dampers to avoid spreading of smoke.	Functionality during given conditions to be addressed.	To be addressed in barrier analysis	
29	Power systems	Harsh environment or electrical failures causing blackout.	-	Blackout can be a particular problem in the arctic conditions. Consequences and duration should be assessed. Blackout will most likely lead to evacuation.	To be addressed in risk/barrier assessment.	**FMECA** of power systems
30	Power systems	Harsh environment or electrical failures causing blackout.	-	If only emergency power is available for a limited time, it might be critical to life due to low temperatures.	To be addressed in risk/barrier assessment	See 29
31	Active fire protection	Blocking/freezing of water piping and	-	May cause limited functionality of fire water system.	Active Fire Protection should be heat traced. Water monitor philosophy	

ID NO	GUIDEWORD	HAZARD/ACCIDENT	EXISTING MITIGATION/BARRIER	OBSERVATIONS	ACTION/RECOMMENDATION	RECOMMENDED RISK ASSESSMENT STUDY
		nozzles.			should be evaluated.	
32	Drain system	May freeze due to cold conditions	Drain lines, closed drain	Freezing may cause overflow during leaks. Critical drains should be heat traced.	To be addressed in risk/barrier assessment	
33	Passive fire protection	Exposure of critical equipment during fire	-	Heat traced equipment could at the same time be passive fire protected with the same dual functionality protection.	Info. Practicality of dual protection could be addressed.	
34	Heat tracing	May freeze due to cold conditions	-	In general, all safety critical equipment should be heat traced.	To be evaluated in barrier assessment	
35	Isolation	Well events	Subsea BOP	The BOP should be standard. Operation down to sea temperature of min. -2 C	May be possible to have other temperature requirements. Need to ensure functionality in relevant conditions.	
36	Heat tracing	-	-	Heat tracing can be considered part of the barrier system in its own right.	All barriers should be reviewed and see which will be vulnerable to temperature and require heat tracing. Must ensure proper control of the heat tracing.	
37	Heat tracing	-	-	-	It should be decided whether heat tracing is a barrier in its own right or an attribute of existing barriers.	

3.2 Environmental Risk Assessment – Arctic Scenario

3.2.1 Purpose

The purpose of this Environmental Risk Analysis, as recommended in the HAZID in Section 3.1, is to evaluate the environmental risk, and to use results and conclusions as inputs to the environmental risk management plans. The Assessment also aims to ensure that requirements and expectations from the authorities and social expectations are met, as well as to provide the basis for a spill response operation in case of an event.

Although spills to the environment may occur from diesel tanks, well testing equipment or from containers of chemicals stored on the rig, the main potential for spills will be from events with loss of well control. Hence, the focus of this document will be blowouts and well releases.

3.2.2 General

This section documents an ERA for the planned drilling program for the Arctic Conqueror semi-submersible drilling rig in the Chukchi Sea. The drilling program includes four drilled wells.

Using predicted frequencies, release rates and durations, a distribution of releases within different consequence categories is calculated. When categorized according to severity in terms of numbers of tons of oil released, the frequency is by far larger in the lower consequence categories. While the frequency in the 0-10 ton category suggest a release every 338 years, a release in the highest category of >100,000 tons is estimated to take place every 26,667 years on average.

Despite frequencies that suggest that the probability of a significant loss of well control event is small, the consequences can potentially have a severe impact on the environment. The Bureau of Ocean Energy Management (BOEM) has defined a very large oil spill at 300,000 tons. The following groups of wildlife such as polar bears, seals, brant, murres, puffins, kittiwakes, auklets, and shearwaters would be at risk if such an event occurs

With the 150 kg/s and 35 kg/s blowout rates used herein for the Arctic Conqueror, there are 8% and 0.5 % probabilities of releases of 300,000 tons given that a blowout has occurred. Lesser releases, which can also have serious consequences on the environment, have higher probabilities.

Due to the potentially severe consequences for wildlife given a blowout, it is vital that measures to limit the consequences are available. The primary measure is rapid deployment of a capping stack.

3.2.3 Definitions

The definitions applied in this document are as shown in Table 6 are based on the Stiftelsen for Industriell og Teknisk Forskning (SINTEF) report, "Blowout and Well release Characteristics and Frequencies" (Reference 2).

Table 6. Blowout and Well Release Definitions

TERM	Definition
Blowout	A blowout is an incident where formation fluid flows out of the well or between formation layers after all the predefined technical well barriers or the activation of the same has failed. Drilling blowouts may occur at nearly all well depths. Historically, shallow gas pockets have been observed in some wells. In terms of well control, shallow gas blowouts are different from blowouts stemming from deeper zones of the well. Drilling blowout can therefore be divided in two main types: - Shallow gas blowouts - "Deep" blowouts The drilling blowouts not regarded as shallow gas blowouts, are regarded as "deep" blowouts in the analysis.
Gas blowout	In this report, the term gas blowout refers to a mainly gas blowout medium.
Gas well	A well where the well stream has a Gas to Oil Ratio (GOR) > 1000.
Oil blowout	In this report, the term oil blowout refers to a mainly oil blowout medium.
Oil well	A well where the well stream has a GOR < 1000.
Average well	Term applied for a well where the GOR is uncertain, and where average frequencies for blowouts are applied (number of total blowouts / number of total wells drilled).
Shallow gas	Any gas zone penetrated before the installation of the blowout preventer (BOP). Any zone penetrated after installation of the BOP is not shallow gas.
Well release	The reported incident is classified as a well release if oil or gas flowed from the well from some point where flow was not intended, and the flow was stopped by use of the barrier system that was available on the well at the time the incident started.
Well kick	Inflow of formation fluid from the reservoir. A well kick may generate a blowout if well control action is not taken.

3.2.4 System Description

3.2.4.1 Field and Facility Description

Figure 5 gives an overview of the Alaska OCS region, where the Cook Inlet, Chukchi Sea and Beaufort Sea are shown in yellow due to their status as locations up for leasing consideration in the 2012-2017 Program.

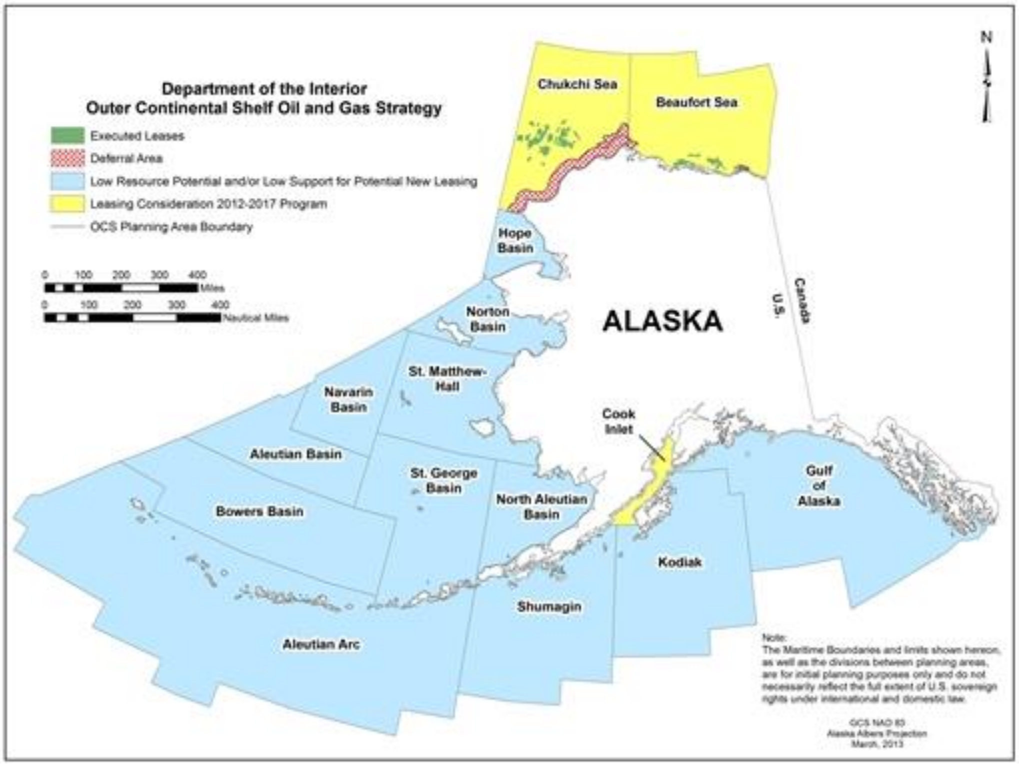

Figure 5. Alaska Outer Continental Shelf (Reference 3)

The water depth on location is approximately 150 ft., or 45m. The wells to be drilled are located 75 miles off the coast of northern Alaska, in the Chukchi Sea.

The Arctic Conqueror semi-submersible drilling rig is from 1986 and has been through winterization modifications in order to operate in Arctic environments.

3.2.5 Barriers

The Arctic Conqueror contains a number of barriers to prevent a major accident and reduce the consequences if a release to the environment takes place. Figure 6 depicts some of the main barriers to prevent events from taking place.

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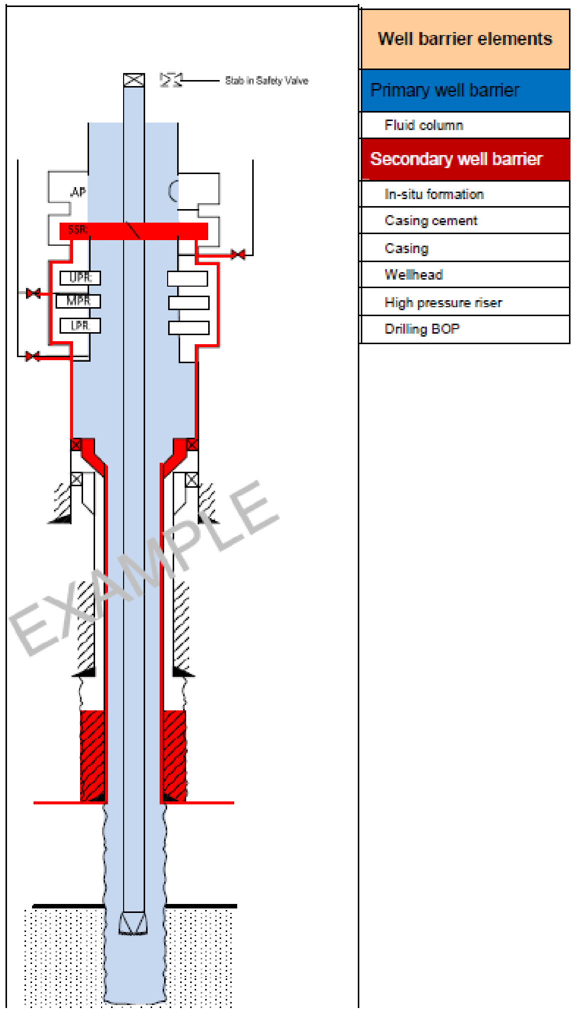

Figure 6. Illustration of Main Barriers to Prevent Blowouts and Well Releases (Reference 3)

The listing includes the in-situ formation, i.e., the formation that has been drilled through, found adjacent to the outer casing annulus. This is not discussed below; only barriers controllable by the Arctic Conqueror are included – it is hence assumed that a site with suitable formation properties has been selected. Additionally, the Arctic Conqueror will not contain a high pressure riser. This is also not discussed below.

Of the barriers that help to reduce consequences given that a loss of well control event has taken place and the BOP and other barriers are unable to keep formation fluids from escaping, a capping stack is considered to be the primary barrier, as described in Section 3.2.11. Other spill containment measures such as booms, skimmer vessels and in-situ burning are not covered here.

3.2.6 Drilling Mud

The drilling mud, a mixture of water, clay and chemicals, has a number of applications. It cools and lubricates the drill bit, transports drill cuttings up to the surface, controls viscosity, helps to limit corrosion, helps avoid formation damage and enhances the rate of penetration. It also functions as an important barrier by providing hydrostatic pressure to prevent formation fluids from entering the wellbore. It is vital that the mud is the correct type and has the right weight in order for it to fulfil these requirements.

3.2.7 Casing Cement

The casings are cemented in place, with cement in the annulus between the casing strings or between casing/liner and the formation. The cement provides a seal to prevent flow of formation fluids, to resist pressures and to provide structural support to casing and liner strings.

3.2.8 Casing

The casing acts as a barrier that prevents formation fluids from leaking to the environment. Several strings of casing are run, partially within each other and with smaller and smaller diameters.

3.2.9 Wellhead

The wellhead includes the wellhead body with annulus access ports and valves, as well as seals and casing/tubing hangers with seal assemblies. It provides support for casing and tubing strings and as hook-up for the Blowout Preventer (BOP). It prevents flow from the bore and annuli to the formation and the environment.

3.2.10 Blowout Preventer (BOP)

The Blowout Preventer is fastened onto the wellhead directly above the sea floor. A subsea BOP stack has some defined requirements in the Code of Federal Regulations, §250.442:

- Four remote-controlled, hydraulically operated preventers: one annular preventer, two pipe rams and one blind-shear ram. The shear ram must be able of shearing drill pipe including work string and tubing under maximum anticipated surface pressures.
- Operable dual-pod control to ensure proper and independent operation of the BOP system.
- An accumulator system to provide fast closure of components and to operate all critical functions in case of loss of power.
- ROV intervention capability, where the ROV should be able to close at least one set of pipe rams, one set of blind-shear rams and unlatching the Lower Marine Riser Package (LMRP).
- Have an ROV with trained crew on the drilling rig from BOP deployment until its recovery to the surface.
- Auto shear and dead man systems for rigs using dynamical positioning (DP).
- Operational/physical barrier(s) on BOP control panels to prevent accidental disconnect.
- Clearly labelled control panels for the BOP control system.
- Management system for operating the BOP system, including the prevention of accidental or unplanned disconnects of the system.
- Personnel authorized to operate critical BOP equipment must have training in deepwater control theory and practice and a comprehensive knowledge of BOP hardware and control systems.

In addition to the components in the list above, the BOP stack will also have one or more kill and choke lines (typically two) used to reduce fluid pressure during well-control operations. The kill and choke lines run from the subsea BOP up to the surface. The BOP system is hence considered a redundant and reliable safety system.

The elements of a BOP stack are shown in Figure 7.

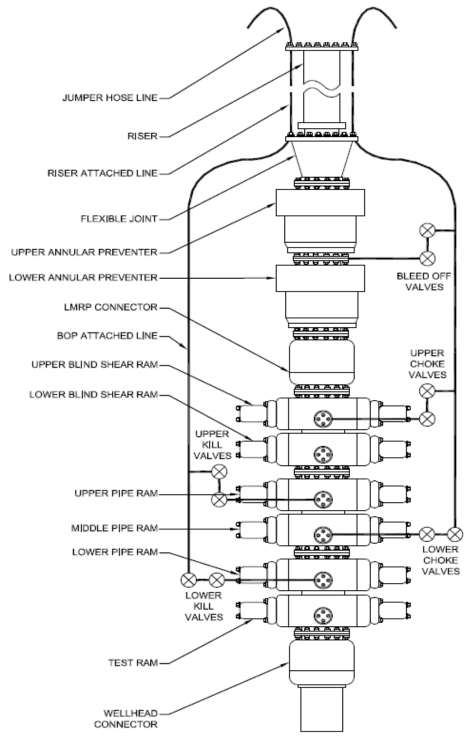

Figure 7. Illustration of a Subsea BOP stack

3.2.11 Capping Stack

3.2.11.1 Introduction

In the event of a loss of well control incident where the subsea BOP fails to isolate the well, a capping stack provides a secondary option. Stored elsewhere, it is transported to the site of the incident and is deployed by using a heave compensated crane, using the A-frame of an anchor handling vessel or lowered from the rig using drill pipe.

For Arctic exploration drilling, BSEE requires a capping stack to be readily deployable within 24 hours.

Due to the criticality of the capping stack as a barrier in an Arctic environment, a barrier analysis has been performed for the capping stack of the Arctic Conqueror (Sections 4 - 7).

3.2.11.2 Configuration

The CS configuration will be either cap or cap and flow, Categories 1 and 2 respectively. Category 1 configurations should have the ability to:

- Connect to a flowing well
- Shut in the well
- Temporarily divert wellbore fluids in order to facilitate closure of the main bore
- Interface to pumping equipment for kill fluid injection into the wellbore

Category 2 is used for circumstances where the wellbore may lose pressure integrity during shut-in. These stacks should additionally have the ability to control the rate of flow through the diversion outlet(s) with a choking device, and the diversion of fluids may be more than temporary.

Figure 8 illustrates the two configurations.

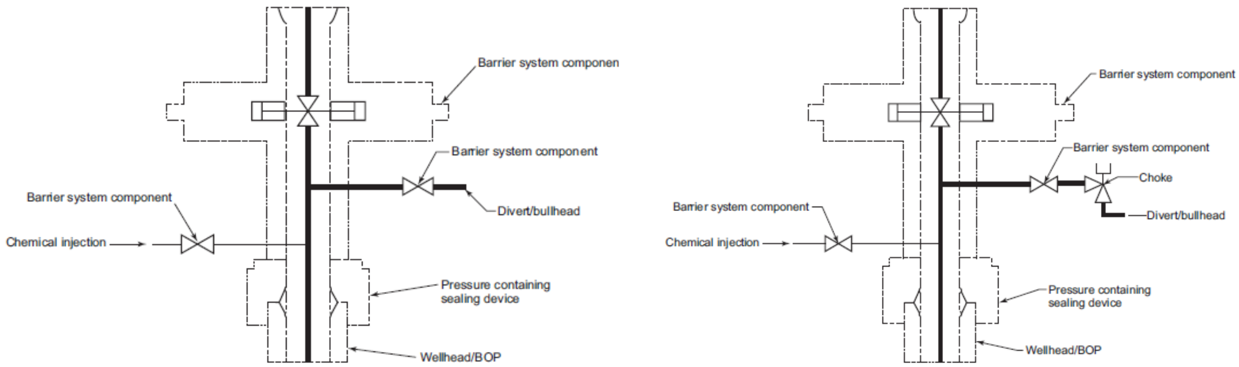

Figure 1—Category 1 (Cap) Figure 2—Category 2 (Cap and Flow)

Figure 8. Illustrations of Capping Stacks in the "Cap" and "Cap and Flow" Configurations (Reference 3)

3.2.11.3 Interface

The preferred interface point is the BOP mandrel profile where the LMRP connector attaches (Reference 5). The intention is to leave the lower BOP in place, which may reduce the overall volume of hydrocarbons released into the environment by:

- Reducing preparation time required to deploy a subsea capping stack;
- Reducing the well discharge rate because of any partially closed elements in the lower BOP.

The secondary connection point is the subsea wellhead/tree, given no BOP and an inadequate pressure rating of or damage to the primary connection point. The contingency connection point is the riser adapter above the lower flex joint of the LMRP after removal of the attached riser. This option is not available if the LMRP has already been disconnected as part of the initial rig emergency response to the blowout condition.

3.2.11.4 Example Procedure for Operating a Capping Stack

The following is a typical list of procedures to be performed for a capping stack in the Category 2 configuration discussed in Section 3.2.11.2.

1. Function open and/or confirm all diverter valves, and any associated diverter line chokes, in the full open position with ROV.
2. Close lower main bore element via ROV panel.
3. Monitor well pressure and compare with expected pressure response.
4. Progressively close chokes (or sequentially close diverter valves) on the diverter lines with ROV.
5. Monitor well pressure and compare with expected pressure response.
6. Move ROV to safe standby position; observe for leaks.

7. If any leaks observed from closed main bore element, close additional main bore element(s) if possible.
8. Monitor well pressure and compare with expected pressure response.
9. If available, run and latch a pressure cap on the capping stack main bore and, if possible, pressure caps on all the side outlet diverter lines.

3.2.12 Blowout and Well Release Scenarios

In order to analyze the risk to the environment posed by blowouts and well releases, it is necessary to establish the scenarios that have a realistic potential to occur and to cause spills to sea. The establishment of scenarios stems from several factors, such as:

- Well activities to take place;
- Possible release locations;
- Release type: Blowout or well release;
- Possible release rates;
- Release medium – oil and gas, only gas or only oil;
- Release before/after installation of BOP;
- Deck type on rig - grid or plate;
- Geometry – layout of actual release location.

The established scenarios will then be assigned frequencies according to historical data as presented by SINTEF and Lloyd's Register Consulting (References 2 and 3).

3.2.13 Scenario Definition

3.2.13.1 Release Locations

Possible release locations for blowouts and well releases have been assessed based on experience data as summarized by SINTEF (Reference 2), where the release location for each included blowout or well release has been registered. A distribution between the following experienced release points has been established: BOP, diverter, drill floor, drill module / skid deck, mud room, shale shaker, wellhead, and subsea.

Based on the Arctic Conqueror area definition an allocation of release points as defined in the SINTEF report to areas on the rig has been carried out and is shown in Table 7.

Table 7. Location of Possible Well Event Release Points

Release Point	Relevant Location on Arctic Conqueror	Main Area on Arctic Conqueror
BOP	Subsea	Subsea
Diverter	Moonpool	MA3 – Drilling areas and Open Decks
Drill floor	Drill floor	MA3 – Drilling areas and Open Decks

Release Point	Relevant Location on Arctic Conqueror	Main Area on Arctic Conqueror
Drill module /skid deck	Drill floor	MA3 – Drilling areas and Open Decks
Mud Room	Mud Treatment Room	MA4 – Aft
Shale Shaker	Shale Shaker Room	MA4 – Aft
Well head	Subsea	Subsea
Subsea	Subsea	Subsea

3.2.13.2 Predicted Release Rates

The release rate of a blowout or a well release is dependent of several parameters, with some main parameters listed below.

- Reservoir Characteristics: Volume, shape, pressure, permeability, porosity, fluid viscosity and fluid density;
- Flow path: Size and shape of influx area, hydrostatic pressure, length, diameter and surface roughness of flow path, local obstructions;
- Release Orifice: size of orifice, shape and pressure outside.

The establishment of two release rate categories for the risk analysis:

- Restricted flow;
- Full flow.

Table 8 presents the representative release rates for the two release categories, for the three release types considered in the analysis (shallow gas blowouts, deep blowouts and well releases). Releases in the "restricted flow" category are considered more likely than releases in the "full flow" category. Blowout rates have been poorly documented in the experience data, and a distribution between different release rates is generally not easily available. The table presents assumed probabilities of distribution for different release types.

Table 8. Representative Release Rates, Total Flow and Gas Content

Release Type	Restricted Flow		Full Flow	
	Flow Rate [kg/s]	Probability	Flow Rate [kg/s]	Probability
Shallow gas blowout	35	90 %	150	10 %
Blowout	35	90 %	150	10 %
Well release	35	90 %	150	10 %

3.2.13.3 Predicted Durations

A distribution of durations from blowouts and well releases is calculated based on the Lloyd's Register Consulting report "Blowout and well release frequencies based on SINTEF offshore blowout database 2014" (Reference 2). Figure 9 and Figure 10 presents the duration distributions for blowouts and well releases, respectively.

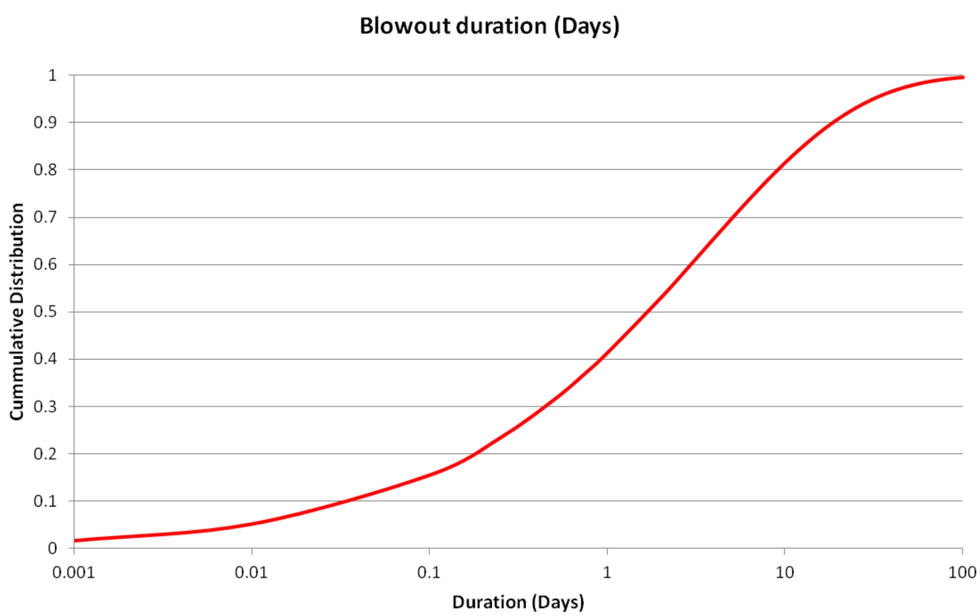

Figure 9. Distribution of Blowout Duration, Based on Reference 2

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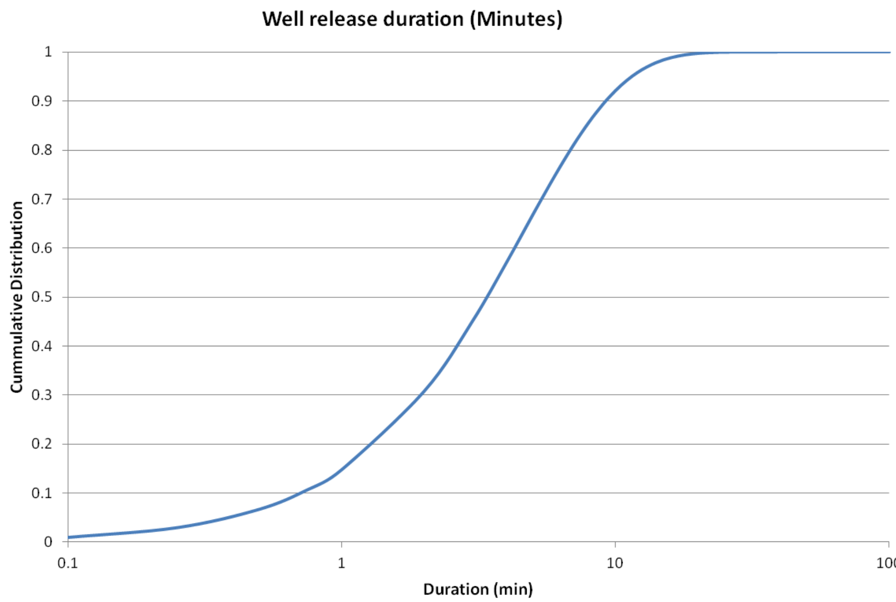

Figure 10. Distribution of Well Release Duration, Based on (References 2 and 3).

Well releases generally take place for a shorter duration than blowouts due to the definitions of a blowout and a well release. Well releases are brought under control by the barrier system available at the time of the incident, whereas blowouts are not. Thus, blowouts can last for days and months, while most well releases are brought under control within minutes. For manned installations in the North Sea and the Gulf of Mexico, reported well releases have been controlled within 15 minutes after the initial release (Reference 2).

3.2.14 Drilling Program

The basis for the blowout and well release frequencies for the Arctic Conqueror is the drilling program shown in Table 9.

Table 9. Planned Annual Activity Level

Activity	Number of Operations per Year
Exploration drilling, deep, Normal well	4 (1 gas well and 3 oil wells)
Exploration drilling, Shallow gas	1
Completion	**4** **(1 gas well and 3 oil wells)**

Shallow gas is relevant for drilling activities, for the top hole prior to installation of the BOP. These sections of the well have large diameters and it is possible to meet gas-bearing zones here that are too small to show up on seismic surveys. For the Arctic Conqueror, the top hole is assumed to be drilled with a marine riser. A shallow gas blowout will potentially result in a spill onto both the sea floor and topside

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on the rig. It is assumed that shallow gas will only be a possibility for one out of the four wells drilled in the annual program.

3.2.15 Frequencies

Frequencies are generated based on the possible release locations, rates and drilling program presented in Sections 3.2.13 and 3.2.14 as well as the historical data in the SINTEF and Lloyd's Register Consulting reports (References 2 and 3).

The Lloyd’s Register Consulting report (Reference 3) presents base event frequencies for blowouts and well releases from different well operations based on experience data. Combined with the assumed number of annual operations presented in Table 10, the tables and figures below present annual release frequencies.

Table 10. Annual Frequencies for Blowouts and Well Releases on Arctic Conqueror

<table>
<tr><th>Operation</th><th>Medium</th><th># Wells per Year</th><th>Type</th><th>Annual Frequency</th></tr>
<tr><td rowspan="4">Exploration Drilling, Deep, Normal Well</td><td rowspan="2">Gas</td><td rowspan="2">1</td><td>Blowout</td><td>1.51E-04</td></tr>
<tr><td>Well release</td><td>1.55E-03</td></tr>
<tr><td rowspan="2">Oil</td><td rowspan="2">3</td><td>Blowout</td><td>4.09E-04</td></tr>
<tr><td>Well release</td><td>4.21E-03</td></tr>
<tr><td>Exploration Drilling</td><td>Shallow Gas</td><td>1</td><td>Blowout</td><td>3.29E-03</td></tr>
<tr><td rowspan="4">Completion</td><td rowspan="2">Gas</td><td rowspan="2">1</td><td>Blowout</td><td>2.31E-04</td></tr>
<tr><td>Well release</td><td>4.48E-04</td></tr>
<tr><td rowspan="2">Oil</td><td rowspan="2">3</td><td>Blowout</td><td>2.89E-04</td></tr>
<tr><td>Well release</td><td>5.61E-04</td></tr>
</table>

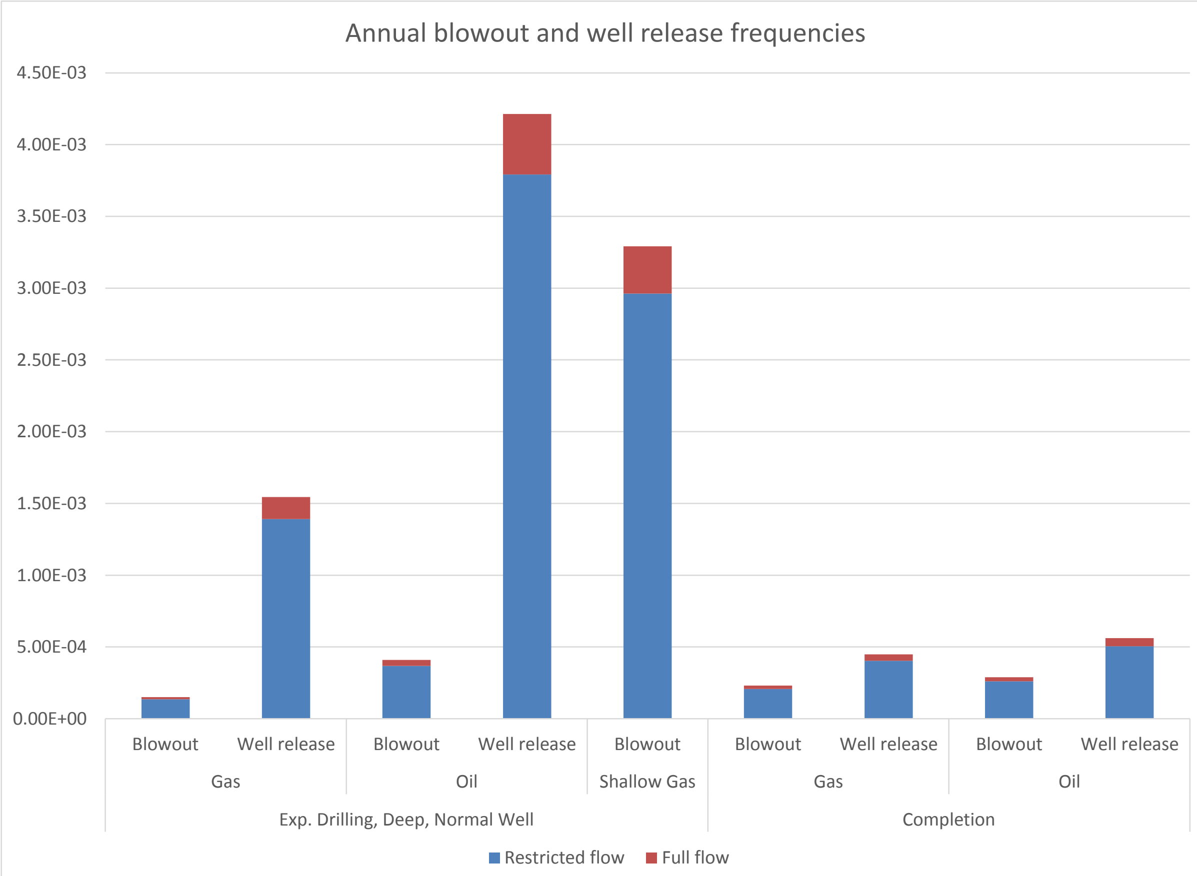

Figure 11. Annual Blowout and Well Release Frequencies per Operation Type, Flow Size and Release Medium

Table 11 shows the annual frequencies, split between operation, release type, location and medium.

Table 11. Annual Blowout and Well Release Frequencies per Operation Type, Release Type, Location and Medium

		SUBSEA		MOONPOOL		DRILL FLOOR		MUD TREATMENT ROOM		SHALE SHAKER ROOM	
OPERATION	MEDIUM	Blow out	Well release	Blow out	Well release	Blow out	Well release	Blow out	Well release	Blow out	Well release
Exploration drilling, shallow gas	Average	1.53E-03	3.29E-04	1.06E-03	2.28E-04	1.18E-04	2.53E-05	0	0	0	0
Exploration drilling, deep (normal wells)	Gas	1.16E-04	0	5.03E-06	1.93E-04	3.02E-05	1.35E-03	0	0	5.03E-06	0
Completion	Gas	2.31E-05	0	0	4.48E-05	1.85E-04	3.58E-04	2.31E-05	0	0	4.48E-05
Exploration drilling, deep (normal wells)	Oil	3.14E-04	0	1.36E-05	5.25E-04	8.19E-05	3.68E-03	0	0	1.36E-05	0
Completion	Oil	2.89E-05	0	0	5.61E-05	2.31E-04	4.49E-04	2.89E-05	0	0	5.61E-05

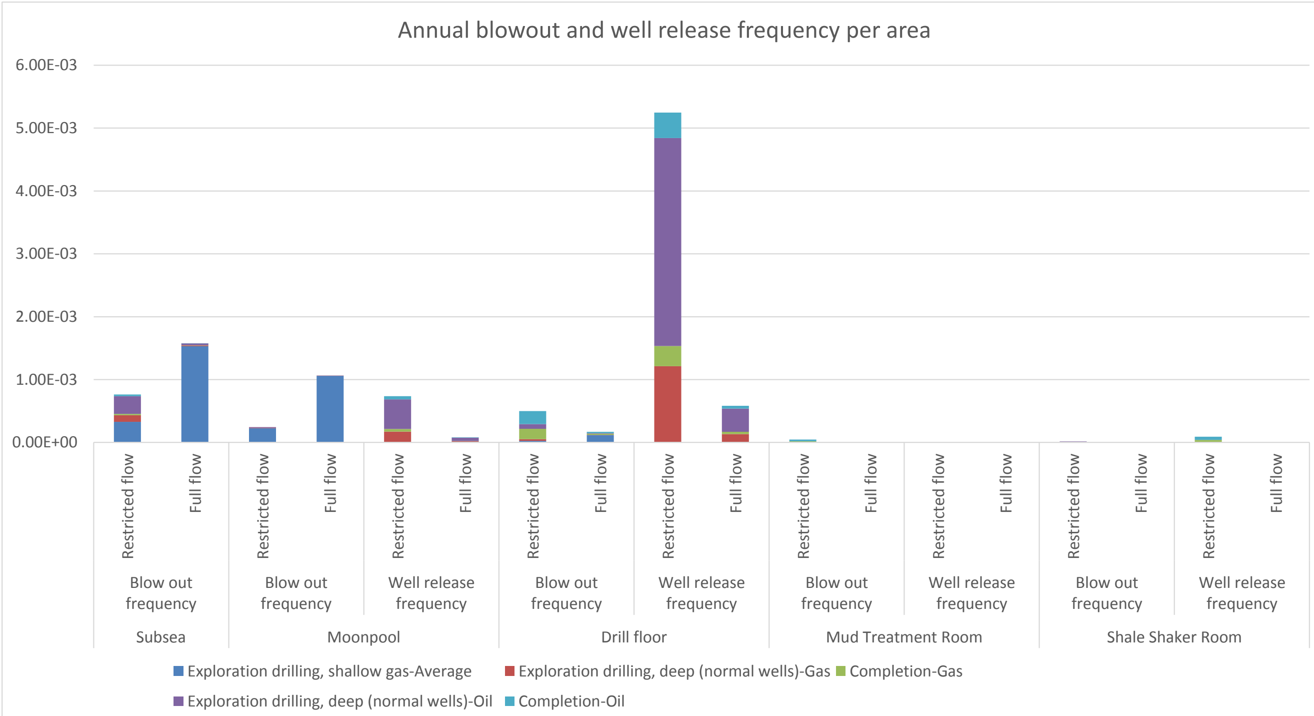

Figure 12. Frequencies per Area, Split between Restricted and Unrestricted Blowouts and Well Releases

Table 11 and Figure 12 show that the highest total release frequencies take place at the Drill floor. The main parts of these releases consist of restricted flow well releases, i.e., releases in the order of 35 kg/s for a maximum of 30 minutes (according to historical data). These releases will have a considerable potential for causing injury to personnel and damage to equipment, but will not necessarily be large contributors to personnel risk due to the limited release rate and duration. The shallow gas incidents are the largest contributors to full flow blowouts, as seen in the frequency subsea and in the moon pool.

3.3 Detailed Risk Assessment

3.3.1.1 Description of Potential Releases

In DNV-RP-F107 (Reference 4), the following categorization is used for the oil Spill of different sizes:

Table 12. Environmental Impact from Oil Spills of Different Sizes

Category	Description	Amount of Release
1 (low)	None, small or insignificant on the environment. Either due to no release of internal medium or only insignificant release.	~0
2	Minor release of polluting media. The released media will decompose or neutralize rapidly by air or seawater.	<1,000 tons
3 (medium)	Moderate release of polluting medium. The released media will use some time to decompose or neutralize by air or seawater, or can easily be removed.	<10,000 tons
4	Large release of polluting medium, which can be removed, or will after some time decompose or be neutralized by air or seawater.	<100,000 tons
5 (high)	Large release of high polluting medium, which cannot be removed and will use long time to decompose or be neutralized by air or seawater.	>100,000 tons

3.3.1.2 Development of an oil spill

The prevailing wind in the area is between east-northeast and east, meaning that an oil spill trajectory would be likely to be towards the southwest. This would lead the spill towards land. Assuming a speed of around 0.2 nm/hr and a distance to closest shore point southeast at 150 nm, the spill would take around 30 days to reach shore. Before this time, a large amount of measures should have taken place in order to limit the effect of the spill.

Within 24 hours, a capping stack must be available for deployment. If such a capping stack is assumed deployed at 24 hours after the spill, it would have been limited to approximately 3,000 tons given a 35 kg/s blowout and 13,000 tons or around 100,000 barrels given the extreme 150 kg/s blowout.

By combining the assumed release rates with the predicted blowout durations based on historical data shown in Section 3.2.13.2, producing Figure 13.

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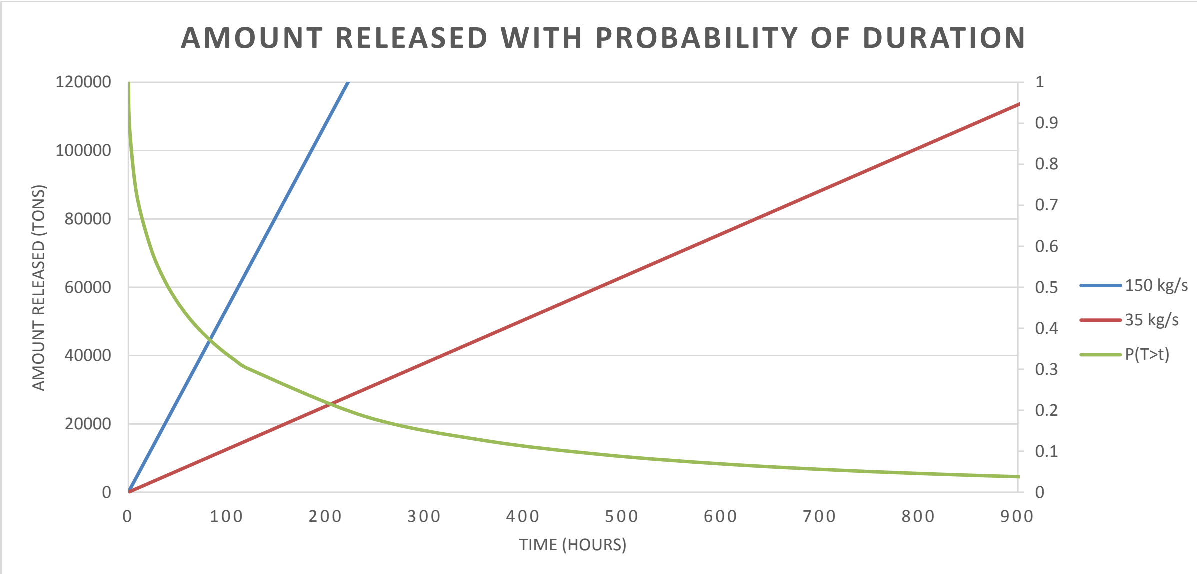

Figure 13. Amount Released Given 35 and 150 kg/s Blowouts Given Releases Lasting between 0 and 900 Hours (37.5 days), with Probability of Equal or Longer Durations on the Second Axis

Figure 13 shows the amount released given constant 35 and 150 kg/s blowouts from 0 to 900 hours – about 38 days. The second axis shows the probability that a blowout lasts for at least as long as the value on the x axis, e.g., historical data from the North Sea and U.S. Gulf of Mexico indicates there is an approximately 30% probability that if you have a blowout, then it will last for at least 120 hours or five days. This blowout would then, given a constant[2] blowout rate from beginning to end, release about 65,000 tons for the large blowout rate and about 15,000 tons for the smaller rate.

The Figure 13 shows that to reach 100,000 tons released – category 5, a 150 kg/s blowout would have to continue for at least 8 days – for which there is a duration probability of 23%. A 35 kg/s blowout would have to last at least 33 days; this has a duration probability of a bit less than 5 %.

Figure 13 also illustrates the necessity of rapid utilization of measures to limit the oil spill. Deploying a capping stack within 2 and 8 hours for the 150 kg/s and 35 kg/s blowouts would keep the release within category 2 as defined in Table 12 – where the environmental impact is insignificant or minor. Such rapid deployment must be considered relatively unlikely, particularly the two hours required for the large blowout: a takeaway from this is that *given a blowout, the environmental consequences will not be insignificant even if measures such as a capping stack are used successfully*.

In order to keep the release within Category 3, or 10,000 tons, the capping stack must fully deploy within 19 hours for the large blowout and 80 hours for the small blowout. This should be possible, but could be hindered due to technical issues with the capping stack, the vessel on which it is located,

[2] Constant rates is not a likely scenario; the rate will likely increase at first (first hours or perhaps days) and then decline as the reservoir near the wellbore is depressurized. One way of considering the 35 and 150 kg/s rates is instead as averages over the duration of the blowout. Either way, constant rates will suffice as an assumption for this analysis, where no detailed calculations have been performed.

unfavorable weather conditions or parameters for the leaking well that hinder deployment of the stack. The FMECA investigates the possible modes of failure for the capping stack (Reference to FMECA as provided in the Section 3.4).

3.3.2 Effect on Wildlife

The full impact of an oil spill on wildlife and flora should be treated in a separate environmental assessment as part of the DWOP application procedure. The sections below discuss some main points regarding the effect on wildlife.

The Chukchi Sea is home to around 50% of the polar bears in America (Reference 5), at around 2,000 bears. Along with other mammals such as walrus, seals and gray whales, they use the ice edges for activities such as calving, feeding and hunting. The Chukchi walrus population constitutes most of the Pacific walrus population in the summer months.

Fin, humpback and gray whales also use the Chukchi, along with a large number of threatened birds.

According to BOEM, a very large oil spill in the Chukchi Sea could (Reference 6):

- Result in the deaths of large numbers of polar bears,
- Result in many thousands of seals, especially ringed seal pups, dying from oil exposure;
- Decimate bird populations and result in population-level effects for most marine and coastal bird species that would take more than three generations to recover;
- Kill up to 60,000 brant and have major impacts on the pacific flyway brant population;
- Result in "large-scale mortality" for murres, puffins, kittiwakes, auklets, and shearwaters.

The very large oil spill scenario is defined in the BOEM report as a release with a maximum 61,000 bbl/day, or around 100 kg/s, declining to 20,500 bbl/day (32 kg/s) at day 40 and lasting 74 days in total – a total spill of 2,2 MMbbl or 300,000 tons.

With the rates of 150 kg/s and 35 kg/s applied in this document, it would require 23 and 99 days, respectively, to reach 300,000 tons released. According to Figure 6, there is historically an 8% probability that given a 150 kg/s blowout will have such a duration, and a 0.5 % probability for the 35 kg/s blowout.

The main results from this Environmental Risk Assessment are:

- The return period for a blowout with a total release of less than 10 tons is assessed to be 338 years while the return period for a release of more than 100 000 tons is assessed to be more than 26 000 years.
- A blowout with a release rate of 35 kg/s may last for 99 days before it reach a total amount of 300 000 tons, while a release of 150 kg/s may last for 23 days before the same amount is released to the environment
- A capping stack is a consequence-mitigating barrier that will stop the release to the environment as soon as it is successfully deployed.
- Given the potential for very severe environmental damage in this geographical area, a capping stack is considered an effective barrier if good reliability deployment plans can be ensured under the given conditions.

3.4 FMECA – Capping Stack

3.4.1 Purpose

The purpose of this FMECA type assessment is to identify and assess likelihood and consequences for failures that may impair the successful deployment of the capping stack in case of a subsea blowout. The results from the assessment should then be used as a basis and as input to the verification of the capping stack design and installation plans, with implementation of additional measures as deemed necessary.

3.4.2 General

This high level assessment is based on the barrier model (Section 4) developed as part of the barrier analysis. Each part of the process from bringing the capping stack to the field and into position until the flow is successfully stopped by the capping stack is evaluated, with aim to identify the risk potential in each step of the operation.

This is done by identifying, on a high level, the possible failure modes during each step of the installation process and the consequences from these failures, both direct, local consequences and consequences on system level, if the failure occurs.

As this study is kept on a high level there is no detailed assessment of the different technical systems. Instead each system is considered as a "unit" and the consequences if this fails – so that the intended action cannot be completed – is assessed. For example, the hydraulic control system is considered as one such 'unit'. The hydraulic control system has a function in several of the necessary steps to successfully close the flow by use of the capping stack. The probability for and the consequences from a hydraulic control system failure is assessed without looking into which technical cause that could be the reason for the failure.

The assessment is limited to environmental risk, expressed as duration of a release, and the risk for personnel injury or fatalities.

The consequences are grouped into four categories each for environmental and personnel risk:

Environmental risk:

Cat1 – Release continue less than 1 day
Cat.2 – Release continue more than one day
Cat.3 – Release continue more than one week
Cat.4 – Release continue more than one month

This should be understood as the delay in stopping the release (by use of capping stack or other) in case the actual failure occurs.

Personnel risk:

Cat.1 – No or very minor injury
Cat.2 – Personnel injury
Cat.3 – Severe injury or fatality
Cat.4 – Multiple fatalities

The probability is grouped into four categories.

Cat.1 – Less than 1% of deployments
Cat.2 – More than 1% of deployments
Cat.3 – More than 10% of deployments
Cat.4 – More than 50% of deployments

This should be understood as the likelihood that the actual failure will occur given that a well event requiring the capping stack to be deployed has occurred.

The risks are placed in risk matrixes as shown below, where the following three risk categories are shown with different colours.

Color	Code	Description
	3	High risk
	2	Medium risk
	1	Low risk

Environment

Cause probability (Failure rate score)		Effect severity (Consequence score) 1	2	3	4
	Description	Release continue less than one day	Release continue more than 1 day	Release continue more than 1 week	Release continue more than 1 month
4	More than 50% of deployments	2	3	3	3
3	More than 10% of deployments	2	2	3	3
2	More than 1% of deployments	1	2	2	3
1	Less than 1% of deployments	1	1	2	2

Personnel safety

Cause probability (Failure rate score)		Effect severity (Consequence score) 1	2	3	4
	Description	No or very minor injury	Personnel injury	Severe injury or single fatality	Multiple fatalities
4	More than 50% of deployments	2	3	3	3
3	More than 10% of deployments	2	2	3	3
2	More than 1% of deployments	1	2	2	3
1	Less than 1% of deployments	1	1	2	2

Figure 14. Sample Risk Matrixes

It should be noted that the risk categories are given only to present a relative ranking of the identified risks, not saying anything about the acceptability of the risk level.

3.4.3 FMECA Worksheet

With use of the methodology described above the assessment is done and presented in the table below.

Description of Step			Description of Failure		Effect of Failure		Frequency Category	Environment		Personnel Safety		Comment
Assessment Item No.	Assessment Item Name	Function	Failure Mode	Failure Cause	Local Effect	System Effect		Consequence Category	Risk	Con-sequence category	Risk	
1	Capping stack transport to location	Bring capping stack to field for deployment	Fail to transport capping stack.	Suitable vessel not available.	Capping stack not transported to field.	Delayed deployment of capping stack.	More than 1% of deployments	Release continue more than 1 day	4	No or very minor injury	2	Assumed suitable vessel will be in location within one week.
2	Capping stack transport to location	Bring capping stack to field for deployment	Fail to transport capping stack.	Bad weather conditions (including ice on location).	Capping stack not transported to field.	Delayed deployment of capping stack.	More than 1% of deployments	Release continue more than 1 day	4	No or very minor injury	2	Assumed weather conditions will improve within one week.
3	Capping stack positioning for deployment	Bring capping stack into position for deployment	Unable to position vessel in correct position.	Surfacing gas/ wellstream from subsea BOP/well-head.	Capping stack not positioned for deployment.	Delayed deployment of capping stack.	More than 1% of deployments	Release continue more than 1 month	8	No or very minor injury	2	With 45 meter water depth horizontal offset for surfacing well flow may be small.
4	Capping stack positioning for deployment	Bring capping stack into position for deployment	Large Hydrocarbons fire alongside/ engulfing vessel	Surfacing gas/ wellstream ignited by vessel/equipment or activities on board.	Injury to personnel and damage to equipment	Delayed deployment of capping stack.	Less than 1% of deployments	Release continue more than 1 month	4	Multiple fatalities	4	Assuming vessel will not be brought into a position with possible gas concentration above LEL.
5	Lower capping stack onto connection hub.	Bring capping stack onto the top of the BOP/well-head.	Not able to land the capping stack in correct position.	Crane / lifting appliances failure, including Operator error.	Capping stack not landed.	Delayed landing of capping stack.	Less than 1% of deployments	Release continue more than 1 day	2	No or very minor injury	1	Assuming cranes may be repaired within one week.
6	Lower capping stack onto connection hub.	Bring capping stack onto the top of the BOP/well-head.	Not able to land the capping stack in correct position.	Vessel/ vessel positioning failure, including Operator error.	Capping stack not landed.	Delayed landing of capping stack.	Less than 1% of deployments	Release continue more than 1 week	3	No or very minor injury	1	Assuming more than 1 week to repair or replace vessel.

Description of Step			Description of Failure		Effect of Failure		Frequency Category	Environment		Personnel Safety		Comment
Assessment Item No.	Assessment Item Name	Function	Failure Mode	Failure Cause	Local Effect	System Effect		Consequence Category	Risk	Con-sequence category	Risk	
7	Lower capping stack onto connection hub.	Bring capping stack onto the top of the BOP/well-head.	Not able to land the capping stack in correct position.	ROV / ROV videofeed failure, including Operator error and/or visibility problems.	Capping stack not landed.	Delayed landing of capping stack.	More than 1% of deployments	Release continue less than one day	2	No or very minor injury	2	Assumed back-up ROV being present on field and that visibility problems are solved within one day.
8	Lower capping stack onto connection hub.	Bring capping stack onto the top of the BOP/well-head.	Hard impact between BOP/wellhead and capping stack.	Crane / lifting appliances failure.	Damage to connection assemblies.	Delayed connection of capping stack.	Less than 1% of deployments	Release continue more than 1 day	2	No or very minor injury	1	Assumed repairs can be made within 1 week.
9	Lower capping stack onto connection hub.	Bring capping stack onto the top of the BOP/well-head.	Hard impact between BOP/wellhead and capping stack.	Vessel/ vessel positioning failure, including Operator error.	Damage to connection assemblies.	Delayed connection of capping stack.	Less than 1% of deployments	Release continue more than 1 day	2	No or very minor injury	1	Assumed repairs can be made within 1 week. For the event of more severe failure of vessel / vessel DP system this is covered in Item 6.
10	Seal capping stack connector on mantling hub.	Seal connection between capping stack and mantling hub	Fail to seal	Failure in BOP/well-head mantling hub.	Fail to seal.	Delayed connection of capping stack.	Less than 1% of deployments	Release continue more than 1 week	3	No or very minor injury	1	Assumed there will take more than 1 week to solve problem if the cause is damage on the BOP/wellhead side.
11	Seal capping stack connector on mantling hub.	Seal connection between capping stack and mantling hub	Fail to seal	Failure in capping stack connector.	Fail to seal.	Delayed connection of capping stack.	Less than 1% of deployments	Release continue more than 1 day	2	No or very minor injury	1	Assumed capping stack can be brought to surface and repaired within 1 week. If recovering capping stack includes re-entry of vessel to position above BOP/wellhead the risk reflected in Assessment items 3 and 4 applies.
12	Seal capping stack connector	Seal connection between	Fail to seal	ROV / ROV videofeed failure,	Fail to seal.	Delayed connection of capping	More than 1% of deployments	Release continue less than one day	2	No or very minor injury	2	Assumed back-up ROV being present on field and that visibility

Description of Step			Description of Failure		Effect of Failure		Frequency Category	Environment		Personnel Safety		Comment
Assessment Item No.	Assessment Item Name	Function	Failure Mode	Failure Cause	Local Effect	System Effect		Consequence Category	Risk	Con-sequence category	Risk	
	on mantling hub.	capping stack and mantling hub		including Operator error and/or visibility problems.		stack.						problems are solved within one day.
13	Seal capping stack connector on mantling hub.	Seal connection between capping stack and mantling hub	Fail to seal	Failure in capping stack's hydraulic control system	Fail to seal.	Delayed connection of capping stack.	Less than 1% of deployments	Release continue more than 1 day	2	No or very minor injury	1	Assuming capping stack can be brought to surface and hydraulics repaired within 1 week. If recovering capping stack includes re-entry of vessel to position above BOP/wellhead the risk reflected in Assessment items 3 and 4 applies.
14	Divert flow	Enable closure of main bore	Not able to divert flow.	Failure in capping stack's hydraulic control system	Fail to divert flow	Delayed activation of capping stack.	Less than 1% of deployments	Release continue more than 1 day	2	No or very minor injury	1	Assuming capping stack can be brought to surface and hydraulics repaired within 1 week. If recovering capping stack includes re-entry of vessel to position above BOP/wellhead the risk reflected in Assessment items 3 and 4 applies.
15	Divert flow	Enable closure of main bore	Not able to divert flow.	ROV / ROV videofeed failure, including Operator error and/or visibility problems.	Fail to divert flow	Delayed activation of capping stack.	More than 1% of deployments	Release continue less than one day	2	No or very minor injury	2	Assumed back-up ROV being present on field and that visibility problems are solved within one day.
16	Divert flow	Enable closing of main bore	Not able to divert flow.	Mechanical failure in diverters	Fail to divert flow	Delayed activation of capping stack.	Less than 1% of deployments	Release continue more than 1 day	2	No or very minor injury	1	Assuming capping stack can be brought to surface and diverters repaired within 1 week. If recovering capping stack includes re-entry of vessel to position above BOP/wellhead

Description of Step			Description of Failure		Effect of Failure		Frequency Category	Environment		Personnel Safety		Comment
Assessment Item No.	Assessment Item Name	Function	Failure Mode	Failure Cause	Local Effect	System Effect		Consequence Category	Risk	Con-sequence category	Risk	
												the risk reflected in Assessment items 3 and 4 applies.
17	Close the bore	Close stream through main bore	Not able to close the bore	Failure in capping stack's hydraulic control system	Fail to close bore	Delayed activation of capping stack.	Less than 1% of deployments	Release continue more than 1 day	2	No or very minor injury	1	Assuming capping stack can be brought to surface and hydraulics repaired within 1 week. If recovering capping stack includes re-entry of vessel to position above BOP/wellhead the risk reflected in Assessment items 3 and 4 applies.
18	Close the bore	Close stream through main bore	Not able to close the bore	ROV / ROV videofeed failure, including Operator error and/or visibility problems.	Fail to close bore	Delayed activation of capping stack.	More than 1% of deployments	Release continue less than one day	2	No or very minor injury	2	Assumed back-up ROV being present on field and that visibility problems are solved within one day.
19	Close the bore	Close stream through main bore	Not able to close the bore	ROV control panel failure	Fail to close bore	Delayed activation of capping stack.	Less than 1% of deployments	Release continue less than one day	1	No or very minor injury	1	Assuming capping stack can be brought to surface and ROV control panel repaired within 1 week. If recovering capping stack includes re-entry of vessel to position above BOP/wellhead the risk reflected in Assessment items 3 and 4 applies.
20	Close the bore	Close stream through main bore	Not able to close the bore with two blind rams.	Failure in one of the two blind rams.	Only one blind ram closed	Less reliable closure of main bore.	More than 1% of deployments	Release continue less than one day	2	No or very minor injury	2	Assumed that operation will continue even if one of the two blind rams fail to close.
21	Close the bore	Close stream through main bore	Not able to close the bore	Failures in both of the two blind rams.	Fail to close bore	Delayed activation of capping stack.	Less than 1% of deployments	Release continue more than 1 day	2	Personnel injury	2	Assuming capping stack can be brought to surface and the two blind rams repaired

Description of Step			Description of Failure		Effect of Failure		Frequency Category	Environment		Personnel Safety		Comment
Assessment Item No.	Assessment Item Name	Function	Failure Mode	Failure Cause	Local Effect	System Effect		Consequence Category	Risk	Con-sequence category	Risk	
												within 1 week. If recovering capping stack includes re-entry of vessel to position above BOP/wellhead the risk reflected in Assessment items 3 and 4 applies.
22	Seal the bore	Close flow from diverters	Fail to choke flow from one or more diverter	Failure of retrievable chokes	Fail to choke flow	Delayed activation of capping stack or situation with continued release with limited rate through one or more chokes.	Less than 1% of deployments	Release continue more than 1 day	2	No or very minor injury	1	Assuming capping stack can be brought to surface and the choke repaired within 1 week. If recovering capping stack includes re-entry of vessel to position above BOP/wellhead the risk reflected in Assessment items 3 and 4 applies. If this occurs there need to be decided if capping stack shall be brought to surface for repair of choke, opening up for full release to sea, or if the operation shall continue with limited flow from one or more of the diverters.
23	Seal the bore	Close flow from diverters	Fail to close one or more gate valve.	Mechanical failure in valve	Fail to completely close flow from diverter.	Delayed activation of capping stack or situation with continued release with limited rate through one or more chokes.	Less than 1% of deployments	Release continue more than 1 day	2	No or very minor injury	1	Assuming capping stack can be brought to surface and the gate valve repaired within 1 week. If recovering capping stack includes re-entry of vessel to position above BOP/wellhead the risk reflected in Assessment items 3 and 4 applies. If this occurs there need to be decided if capping stack shall be brought

Description of Step			Description of Failure		Effect of Failure		Frequency Category	Environment		Personnel Safety		Comment
Assessment Item No.	Assessment Item Name	Function	Failure Mode	Failure Cause	Local Effect	System Effect		Consequence Category	Risk	Con-sequence category	Risk	
												to surface for repair of choke, opening up for full release to sea, or if the operation shall continue with limited flow from one or more of the diverters.
24	Seal the bore	Close flow from diverters	Fail to choke or close diverter.	ROV / ROV video feed failure, including Operator error and/or visibility problems.	Fail to choke or completely close flow from diverter.	Delayed activation of capping stack or situation with continued release with limited rate through one or more chokes.	More than 1% of deployments	Release continue less than one day	2	No or very minor injury	2	Assumed back-up ROV being present on field and that visibility problems are solved within one day.
25	Seal the bore	Close flow from diverters	Fail to choke flow from one or more diverter	ROV control panel failure	Fail to choke flow	Delayed activation of capping stack or situation with continued release with limited rate through one or more chokes.	Less than 1% of deployments	Release continue more than 1 day	2	No or very minor injury	1	Assuming capping stack can be brought to surface and the ROV control panel repaired within 1 week. If recovering capping stack includes re-entry of vessel to position above BOP/wellhead the risk reflected in Assessment items 3 and 4 applies. If this occurs there need to be decided if capping stack shall be brought to surface for repair of choke, opening up for full release to sea, or if the operation shall continue with limited flow from one or more of the diverters.

Description of Step			Description of Failure		Effect of Failure		Frequency Category	Environment		Personnel Safety		Comment
Assessment Item No.	Assessment Item Name	Function	Failure Mode	Failure Cause	Local Effect	System Effect		Consequence Category	Risk	Con-sequence category	Risk	
26	Install blind caps	Secure the sealing of the main bore.	Fail to install top blind caps.	Mechanical failure / debris	Fail to install top blind cap.	Less reliable closure of main bore.	Less than 1% of deployments	Release continue less than one day	1	No or very minor injury	1	Assumed that operation will continue even if installation of top blind cap fails.
27	Install blind caps	Secure the sealing of the main bore.	Fail to install diverter blind caps.	Mechanical failure / debris	Fail to install one or more diverter blind caps.	Less reliable closure of diverter outlet.	Less than 1% of deployments	Release continue less than one day	1	No or very minor injury	1	Assumed that operation will continue even if installation of diverter blind caps fail.
28	Install blind caps	Secure the sealing of the main bore and the diverter outlets.	Fail to install blind caps.	ROV / ROV videofeed failure, including Operator error and/or visibility problems.	Fail to install one or more blind caps.	Less reliable closure of main bore and diverter outlets.	More than 1% of deployments	Release continue less than one day	2	No or very minor injury	2	Assumed back-up ROV being present on field and that operation will continue even if installation of blind caps fail.
29	Activate chemical injection into well flow	Allow influx of chemicals into well flow to prevent hydrate formation.	Fail to initiate chemical injection	Failure in chemical injection system (lines, valves or control)	Fail to inject chemicals and possible hydrates formation.	Not able to complete operation.	Less than 1% of deployments	Release continue more than 1 day	2	No or very minor injury	1	Assuming capping stack can be brought to surface and the chemical injection repaired within 1 week. If recovering capping stack includes re-entry of vessel to position above BOP the risk reflected in Assessment items 3 and 4 applies.

3.4.4 *Results, Conclusions and Recommendations*

3.4.4.1 *Results*

A total of 29 risks are identified and assessed. These are placed in the risk matrixes for Environmental and Personnel risk as shown below.

Environment

Cause probability (Failure rate score)	Description	Effect severity (Consequence score) 1: Release continue less than one day	2: Release continue more than 1 day	3: Release continue more than 1 week	4: Release continue more than 1 month
4	More than 50% of deployments				
3	More than 10% of deployments				
2	More than 1% of deployments	7, 12, 15, 18, 20, 24, 28	1, 2		3
1	Less than 1% of deployments	19, 26, 27	5, 8, 9, 11, 13, 14, 16, 17, 21, 22, 23, 25, 29	6, 10	4

Personnel safety

Cause probability (Failure rate score)	Description	Effect severity (Consequence score) 1: No or very minor injury	2: Personnel injury	3: Severe injury or single fatality	4: Multiple fatalities
4	More than 50% of deployments				
3	More than 10% of deployments				
2	More than 1% of deployments	1, 2, 3, 7, 12, 15, 18, 20, 24, 28			
1	Less than 1% of deployments	5, 6, 8, 9, 10, 11, 13, 14, 16, 17, 19, 22, 23, 25, 26, 27, 29	21		4

Figure 15.Samples of Risk Matrixes for Environmental and Personnel Risk

Of these only one is assessed to be in the high risk zone. This is risk of the vessel not being able to get into position to lower the capping stack due to large amount of gas surfacing on the location (No. 3). This is considered to be a possible scenario due to the relatively shallow water depth (45 meter) with possibly very little horizontal offset between the release position and the position where the release reaches the surface. This risk is classified as high risk for environment only as there is assumed that a vessel will not be brought into a position where it is known to be surfacing well flow.

There are a total of 5 risks classified as medium, of which one relates to both environmental and personnel risk and the remaining 4 to environmental risk only. The one that relates to both environmental and personnel risk (No. 4) is an escalation of the high risk discussed above (No. 3) where the vessel is brought into a position with gas concentration above LEL causing a fire that potentially can engulf the vessel with multiple fatalities as result. This is considered to be a low probability event but is classified as medium risk due to the severe consequences.

Two of the medium risk events are related to delay in transporting the capping stack into position due to lack of suitable vessel (No. 1) and bad weather (No. 2). Both these situations are assessed to cause more than 1 day of delay.

Also No. 6 is related to availability of suitable vessels. If there is a vessel failure during the operation it is assumed to take more than one week to repair or replace with another suitable vessel. This is a low probability event but ranked as medium risk due to the consequence class.

The last medium ranked risk (No. 10) is not being able to seal due to failure on the BOP side. The BOP can obviously not be brought to surface for repair and it is assessed that such situation may cause a delay of more than one week.

For details on the 23 risks ranked as low reference is made to the assessment tables.

3.4.4.2 Conclusions and Recommendations

The highest risk identified in this assessment is not being able to bring the capping stack into position for deployment due to gas surfacing on the location straight above the subsea release.

It is recommended that this risk is evaluated more in detail with regard to how much gas can be anticipated in a situation where the capping stack is required and were this gas is likely to surface. This information should be used to plan for the situation with regard to how the site shall be approached and if taking this situation into account will place additional requirements on the vessel to be used.

Clear criteria and procedures should be established for situations when a vessel cannot approach the location due to risk of ignition from surfacing gas.

Further, as several of the medium classified risks are related to availability of vessel (either initially or in case of vessel failure), preparations should be made to ensure a suitable vessel are present at all time when there is a potential for a blowout and that replacement vessels, in case of a vessel failure, are identified and located within reasonable distance. Due consideration should be given to the possible weather conditions in the area during the drilling season, taking this into account in the specification of suitable vessels in order to limit the probability of delay due to weather conditions as much as possible.

In this assessment it is assumed that the capping stack can be recovered to the surface and repaired within a week at any time if a failure should occur during the deployment process. Due consideration should be given to spare parts, tools and facilities required on the field for this to be valid.

The reliability of the capping stack with subsystems and the operations required to install it should be verified in detail as part of the design and verification of the capping stack in order to avoid built in weaknesses or operations with a high probability for failure that could increase the probability that the capping stack could not fulfil its function on demand.

It should be noted that ROV is critical for several steps of the process. It is hence recommended to ensure there is a back-up ROV with correct specifications present on the field and that the competence and experience of the ROV Operator is given high priority. Specific training for capping stack installation operations should be provided. It is considered that visibility by use of ROV within the mud-line cellar may be a problem that may delay or complicate the operation.

The main conclusions from the risk assessment, which is in the form of an FMECA-type assessment of the capping stack installation are:

- Not being able to bring the capping stack into position for deployment due to surfacing gas is the event identified as the highest risk factor with respect to failure to deploy the capping stack when needed.
- Poor visibility may delay or prevent installation of the capping stack during use of ROVs to do operations in the mud line cellar.
- The installation of the capping stack should be verified by developing a detailed barrier model covering operational as well as technical aspects.

As capping stack is an important barrier critical system and requires to be further analysed by barrier analysis as detailed in Section 4.

4. Barrier Function and Barrier Critical Systems

4.1 Barrier Function Description in Relation to Major Accident Hazard

The MAH of concern in this scenario is a blowout that has occurred while drilling in the Arctic. This implies that the BOP, or any other means present on the rig has failed to seal the well and there is an uncontrolled flow from the well.

Given this MAH has occurred, the barrier functions that are in place will be strictly consequence reducing.

The barrier function selected for this example is **"Limit Environmental Consequences of Blowout".** The main focus here will be on trying to reduce the environmental impact of the blowout on the environmentally sensitive Arctic region by sealing the uncontrolled well using a Capping Stack.

4.2 Relevant Barrier Critical Systems and Brief Summary of Their Role in Realizing the Barrier Function

For the barrier function "Limit Environmental Consequences of Blowout", the identified barrier critical systems consist of the following:

1. Mud Line Cellar – A hole dug in the sea floor, in which the Wellhead and BOP are placed, in order to better protect them from iceberg scraping.
2. Chemical Injection System – The topside system, that delivers hydrate inhibitors to the Capping Stack.
3. Remote Operated Vehicle (ROV) – ROV is considered an essential Barrier Critical System since most of the operations in order to seal an incident well is performed by the ROV.
4. Lowering Crane System – The crane system that lowers structures down onto the sea floor, for use by both the Capping Stack and the Containment Dome.
5. Casing/Cement – The integrity of the casing and cementing is crucial to prevent more than the existing flow paths. It provides stability and structural support for the well to avoid cratering which would make the containment of the well flow harder.
6. Wellhead/BOP – The wellhead and the BOP need to maintain its mechanical integrity to allow for an attachment point to connect the CS to the incident well. The BOP can be removed if damaged and the wellhead used as an attachment point. Any cracks or other leak points on the wellhead would cause the leak to continue even if a CS is in place.
7. Capping Stack – It is an arrangement of valves and/or rams placed on top of the failed BOP or the wellhead after the removal of the BOP to shut in and seal the incident well.
8. Containment Dome – The Containment Dome is an intermediate system that will collect hydrocarbon flow from an uncontrolled well before pressure relief from a relief well is in place, and if a CS is unable to completely seal the well.
9. Mud/Circulation/Cement – Can be used to kill the well, using a topside system connected to the Capping Stack (the Capping Stack would be a barrier element for this Barrier Critical System).

10. Oil Spill Response Systems – This includes a combination of different emergency response elements such as use of dispersants, oil filter booms, which can contain the spill within a restricted area, and prevent the oil from reaching areas of ice, or the shore. Oil spill detection and surveillance would also be integral for this barrier critical system.
11. Relief Well – Drilling a relief well would be required to stop the flow from an uncontrolled well and kill it in most cases.

5. Selected Barrier Critical System - The Capping Stack

5.1 System Description and Basis of Design

For this example, the Barrier Critical System to be assessed is the CS. The operation in question for the described scenario is a drilling operation, and the CS helps realize the barrier function “Limit Environmental Consequences of Blowout”. The CS operation for the incident well is considered “cap only”, i.e., the barrier model does not consider regaining control of the well. It is assumed that the wellbore is capable of maintaining pressure integrity during and after shut in of the well. It is however relevant to mention that the CS used for arctic drilling operations has to be of a “cap-and-flow” configuration, but the system and process until the well is sealed is considered the same.

The CS is a consequence reducing measure that is typically stored offsite and brought to any location where a blowout has occurred. The specific requirement by BSEE in the case of Arctic exploratory drilling is that a CS shall be available in the Arctic region and the related mobilization time shall be less than 24 hours.

Multiple options exist for lowering the CS on to the planned attachment point: (1) using the drill string on the rig through the moon pool, (2) over the side of the rig or vessel using a heave compensated crane, or (3) by an anchoring vessel or barge with required capabilities.

The system description stems from a generic example of a CS, and not an actual design. The barrier elements, listed in Table 13, are considered critical for the barrier critical system to perform its intended function, as part of the Capping Stack.

Table 13. Barrier Elements Part of the Capping stack

Barrier Element	Description
First and Second Blind Ram	There are two independent blind rams that can close to seal the main bore
Retrievable Chokes	Diverter choke valves with the physical task of choking the flow in the diverter lines.
Diverter and Diverter Gate Valves	Outlets for diverting flow from the main vertical bore. Diverter closing valves, diverter lines and diverter gate valves, with physical tasks that include opening and sealing of diverter lines.
Capping stack connector	Hydraulic connector to latch and seal to the planned subsea attachment such as the BOP or wellhead.
ROV Control Panels	The interface on the Capping stack for ROV intervention.
Subsea Hydraulic Accumulator	Delivers sufficient hydraulic power and flow to perform the required Capping Stack functions.
Umbilical	Supplies electric power to the Capping Stack, and transmits sensor and camera output to topside. Additional function is also hydraulic resupply or recharging of the subsea hydraulic accumulator module.
Acoustic modems w/power supply	Part of the Capping Stack control system. Transmits sensor

Barrier Element	Description
	readouts from the capping stack to the topside control panel.
Sensors	Measure critical wellbore parameters such as pressure, flow and temperature readouts from the Capping Stack
Cameras	Installed on the capping stack and provides live feed of the capping stack position in relation to the attachment point (wellhead or BOP) and provide confirmation of latch and seal
Lowering Arrangement	Connectors and deployment system to enable lowering and landing of the CS onto the subsea attachment point
Topside Control Panel	Part of the Capping Stack control system and displays information on flow, temperature and pressure during all stages. From an operational standpoint it will also include monitoring activities of these parameters

Additional barrier elements relevant for the CS functions and part of other Barrier Critical Systems are listed in Table 14 below.

Table 14. Barrier Elements Part of other Barrier Critical Systems

Barrier Element	Description
ROV	Free-swimming or tethered submersible craft used to interact with the CS subsea in order to shut in the incident well. The ROV is considered a separate Barrier Critical system
ROV tools / manipulators	ROV tools/manipulators are part of the ROV Barrier Critical System and interact with the Capping Stack in order to perform the required functions.
ROV pilot station	The topside system from which the ROV pilot controls the ROV and views the video feed from the ROV. It is part of the ROV Barrier Critical System.
Subsea Attachment Point	The point of attachment, either on the Wellhead or the BOP in order to interface with the incident well. It is part of the Wellhead/BOP Barrier Critical System.
Seal ring	Provides a seal between Capping Stack and Subsea Attachment Point. Considered as part of the Wellhead/BOP Barrier Critical System
Chemical Injection Lines	Lines connecting the Capping Stack to the Barrier Critical system Chemical Injection System (located topside) for the supply of hydrate inhibitors and dispersants as relevant.

6. Barrier Model for CS

6.1 Barrier Model Scope (Interfaces and Barrier Elements) and Key Assumptions

6.1.1 Barrier Critical System Functions

The Barrier Critical System Functions (BCSFs) identified as necessary for the CS to realize its barrier function include the following:

- Connect to the incident well at a planned attachment point (BOP mandrel/hub or wellhead) (BCSF1)
- Divert flow to enable closure of main bore (BCSF2)
- Close on open hole (BCSF3)
- Cap the main bore (BCSF4)

Read the contents of the subsequent sections in conjunction to the Barrier Model (presented in 6.2 below).

Connect to the incident well at a planned attachment point (BOP mandrel/hub or wellhead) (BCSF1)

This function includes lowering and landing the capping stack from topsides onto the incident well by means of the lowering arrangement. The CS Connector latches and seals upon landing on to the planned subsea attachment point (BOP mandrel/hub or wellhead). The CS connector latch function is activated by the ROV via the ROV hot stab. An alternate option for activating the latch function is to use the ROV Control Panel where hydraulic power for latching is provided by the subsea hydraulic accumulator module. A secondary ROV control panel is also available on the seafloor for the latch function as a redundant measure. Hydrate inhibitors are continuously provided through chemical injection lines to an injection point on the CS connector. This prevents hydrates from forming in the connector locking elements during the installation of the CS onto the incident well.

Cameras installed on the CS transmit live video feed to help with the landing and to confirm latch and seal. When this operation is finished, the capping stack is connected to the well and well fluids are flowing through the capping stack main bore. Throughout the process, sensors measure critical wellbore parameters and transmit their output to the topside control panel.

Divert flow to enable closure of main bore (BCSF2)

Diverter valves are in the closed position when the capping stack is lowered and connected to the incident well ensuring that the well flow is redirected through the main bore only. This step precedes the closure of the main bore using the main bore vertical closure device (blind shear rams) and involves opening the four diverter gate valves present on the CS so that flow is diverted though both the diverter lines and main bore. Keeping the diverter valves open helps to (a) minimize the erosion of the sealing surfaces of the first closure device, and (b) minimize effects of water hammer on the well and CS. The diverter valves can be activated open by the ROV hot stab or via the ROV Control Panel.

Close on open hole (BCSF3)

This function includes closing the first and second blind shear rams in sequence. Typically, the lowermost blind shear closes first, followed by the second blind shear ram. This operation seals the main bore and ensures that all flow occurs only through the four open diverter lines. The blind shear rams are activated by the ROV via the ROV Control Panel, and uses the subsea hydraulic accumulator module for supply of power fluid for the BOP close function.

Cap the main bore (BCSF4)

This function includes a stepwise sealing of the diverter lines, which is carried out as per written procedures. First, the choke valve on the diverter line closes before the upstream gate valve is closed. A seal test is performed following the gate valve closure. This procedure repeats until all four diverter lines are sealed. Once flow is stopped, the secondary caps are mounted by the ROV. This includes a main bore pressure cap on the main bore and diverter outlet pressure caps mounted after the choke valves are removed from each of the diverter lines.

6.1.2 Assumptions

CSs can vary in design and configuration. Note that the barrier model for the capping stack is **an example** developed to illustrate how the barrier model template can be applied to a generic capping stack and **should not** be considered as representative of all capping stack configurations. The barrier model has been developed by the project team from ABS Consulting and verified through a review workshop with industry Subject Matter Experts and BSEE personnel.

For the purpose of this example, Table 15 represents the main assumptions considered regarding the different barrier elements of the CS.

Table 15. Capping Stack Scenario Assumptions – Barrier Elements

Assumption	Barrier Element
Since the capping stack is mainly a subsea system it is assumed that the winterization measures are limited to a barrier element basis and will be more visible as part its attributes. The limited exposure of the CS to the arctic environment relates to pre-deployment phases involving storage and running the CS.	All systems
The lowering arrangement is assumed to be the equipment directly attached to the capping stack and associated lifting equipment. Crane and topside equipment is included in the Lowering crane system on the Barrier Critical System level.	Lowering arrangement

Assumption	Barrier Element
- The latch and seal of the hydraulic CS connector on to the subsea attachment point is assumed to be primarily activated by the ROV hot stab. A subsea hydraulic accumulator is also included to provide secondary means of activating the latch through the ROV control panel if necessary. - It is assumed that hydraulic connector on capping stack is self-locking upon latching. Hence, loss of hydraulic supply does not cause the unlatching of the connector from the attachment point. - It is assumed that the flowmeters installed can provide accurate confirmation about the sealing integrity of the capping stack connector. This can also be confirmed visually by the cameras on the capping stack and the ROV.	Capping stack connector
The Chemical Injection Lines are assumed to run from topsides through the Capping Stack and distribute chemicals close to the Capping Stack connector. Chemical Injection is assumed to be required in this scenario to avoid hydrate formation and is assumed to be performed throughout the process, i.e., from landing the capping stack and until the well is securely shut in. Pumps topsides feed the chemical injection lines. This line also has a normally open shut off valve which is ROV operated and located on the capping stack.	Chemical Injection Lines
It is assumed that the capping stack has an integrated hydraulic accumulator module which is pre-charged and having sufficient capacity to perform all required CS functions.	Subsea Hydraulic accumulator
- Valve actuation is assumed to be performed by the ROV interfacing with the ROV Control Panel, for systems not using hot stab. - The main rams are assumed to require the subsea accumulators and hence activated using the ROV Control Panel.	ROV and ROV Control Panel
- Closure of the main bore is assumed to be accomplished via two blind rams. The rams are assumed to be ROV actuated via the ROV Control Panel. The subsea hydraulic accumulator module supplies the power fluid for the ram closure. - The rams may be closed by the hot stab, but due to demands for closing time/response time requirements, hot stab is not considered to be an adequate solution. - It is assumed that the main bore of the CS has a nominal diameter of 18 3/4'' same as the two blind rams installed.	First and Second Blind Rams
It is assumed that the attachment point is either the BOP mandrel/hub or the wellhead based on Source Control and Containment plans/procedures. LMRP is assumed as not being a suitable option. The condition of the site is uncertain and plans must be made to ensure a successful capping operation (e.g., debris removal).	Subsea attachment point

Assumption	Barrier Element
- The gate valves are assumed to be actuated and powered via ROV hot stab. - The scenario and Capping Stack setup assumes that during landing of the CS, the diverter lines are required to be closed and so the diverter gate valves are in closed position. - It is assumed that the capping stack is of a cap and flow design as required in the proposed Requirements for Exploratory Drilling on the Arctic Outer Continental Shelf BSEE-2013-0017. By using this, the diverter lines are assumed to follow requirements in standards addressing choke/kill lines. - Primary means of activation is the ROV hot stab. Secondary means of activation is via the ROV Control Panel.	Diverter and Diverter Gate Valves
- The choke valves are assumed to be powered via the hydraulic accumulators and actuated by the ROV via the ROV Control Panel. - Choke valves are assumed to be in open position during landing of the CS - Primary means of activation is via the ROV Control Panel. Secondary means of activation is by ROV hot stab.	Retrievable Chokes
The secondary pressure caps, both on the main bore and the diverter lines are assumed to be actuated via ROV hot stab.	Secondary Caps
An umbilical is added in addition to the acoustic modems w/ power supply. The umbilical will have power supply and fibre-optic cables for transfer of video to the surface. In addition to this the umbilical has hydraulic lines to resupply/recharge the hydraulic accumulators. This is assumed not to be a primary function as the design shall have adequate volumes for the ram and valve operations. The use of umbilical is considered an easy solution in such shallow water depth.	Umbilical
The hot stab function is considered to be the primary way of closing and opening valves except the blind rams and chokes. The use of the control panels and hydraulic accumulator is considered to be secondary.	Hot Stab and valves
It is assumed that the capping operation is managed by a command staff that has visual control of the ROV and capping stack video feed and all relevant parameters. They are not necessarily located close to the ROV Pilot, but constant communication is maintained.	ROV Pilot Station
Redundancy is added by assuming that a secondary ROV control panel is installed in the vicinity of the capping stack. This is assumed to be connected by a hydraulic lead to the capping stack.	Secondary ROV control panel on seafloor

6.2 Barrier Model

The following Figure 16 - Figure 22 shows the developed barrier model for the Capping Stack.

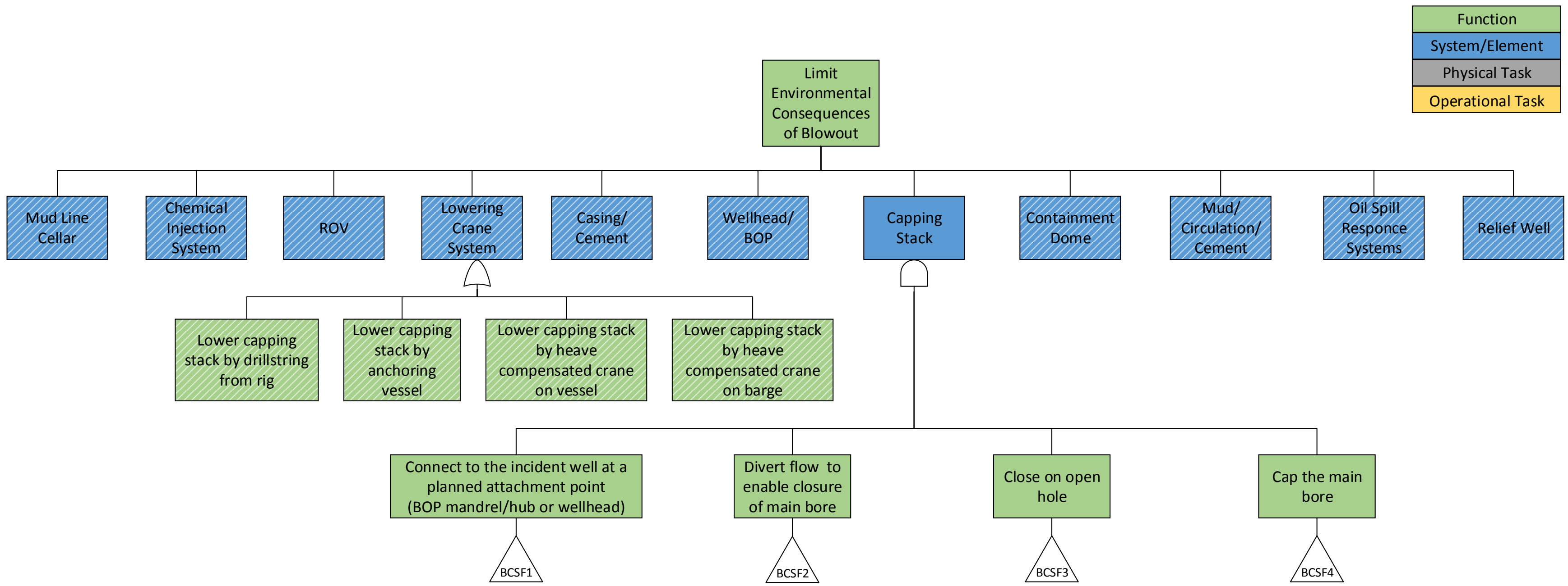

Figure 16 Barrier Function, Barrier Critical Systems and Barrier Critical System Functions

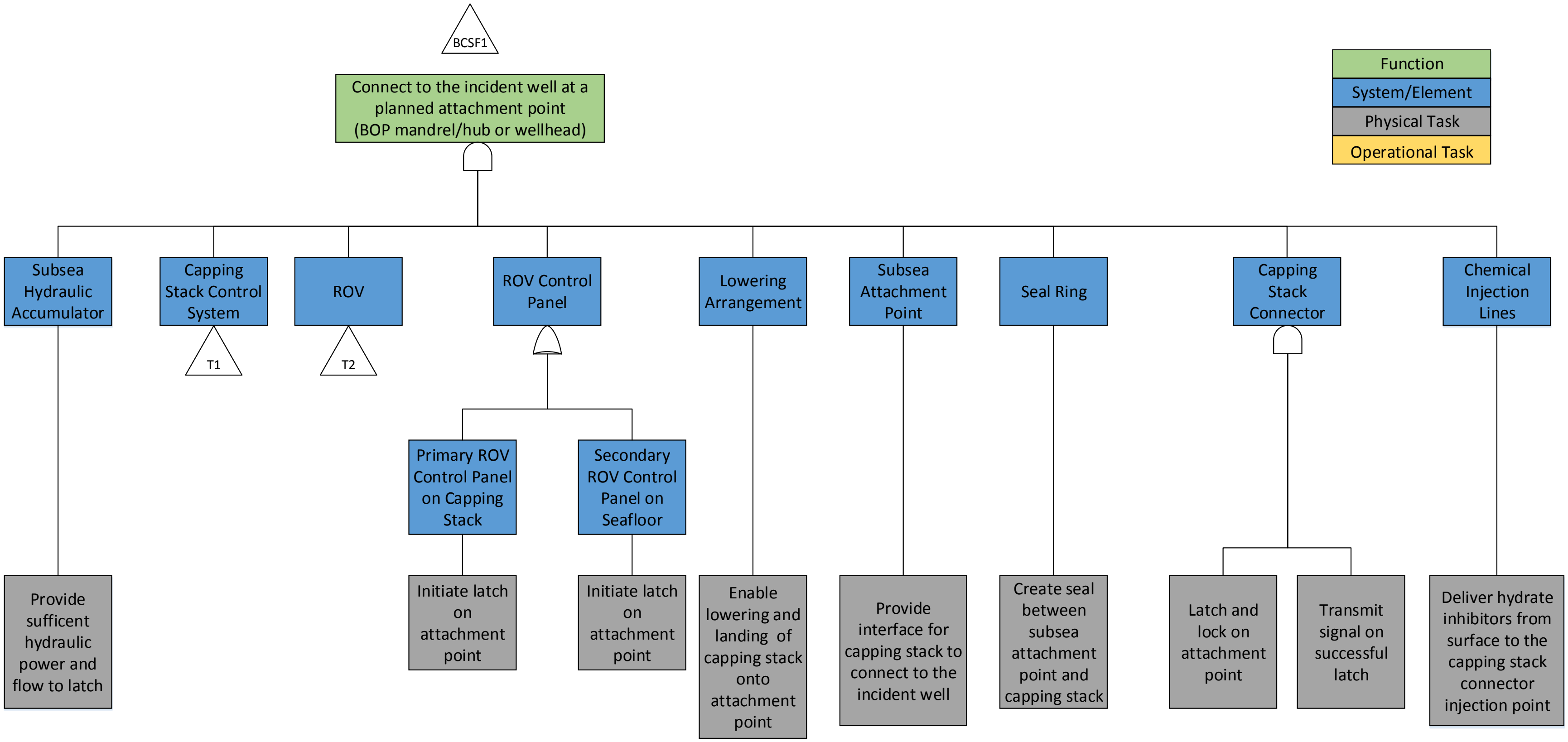

Figure 17 Barrier Critical System Function 1 – Connect to Wellhead/BOP and Seal on Hub – Part 1

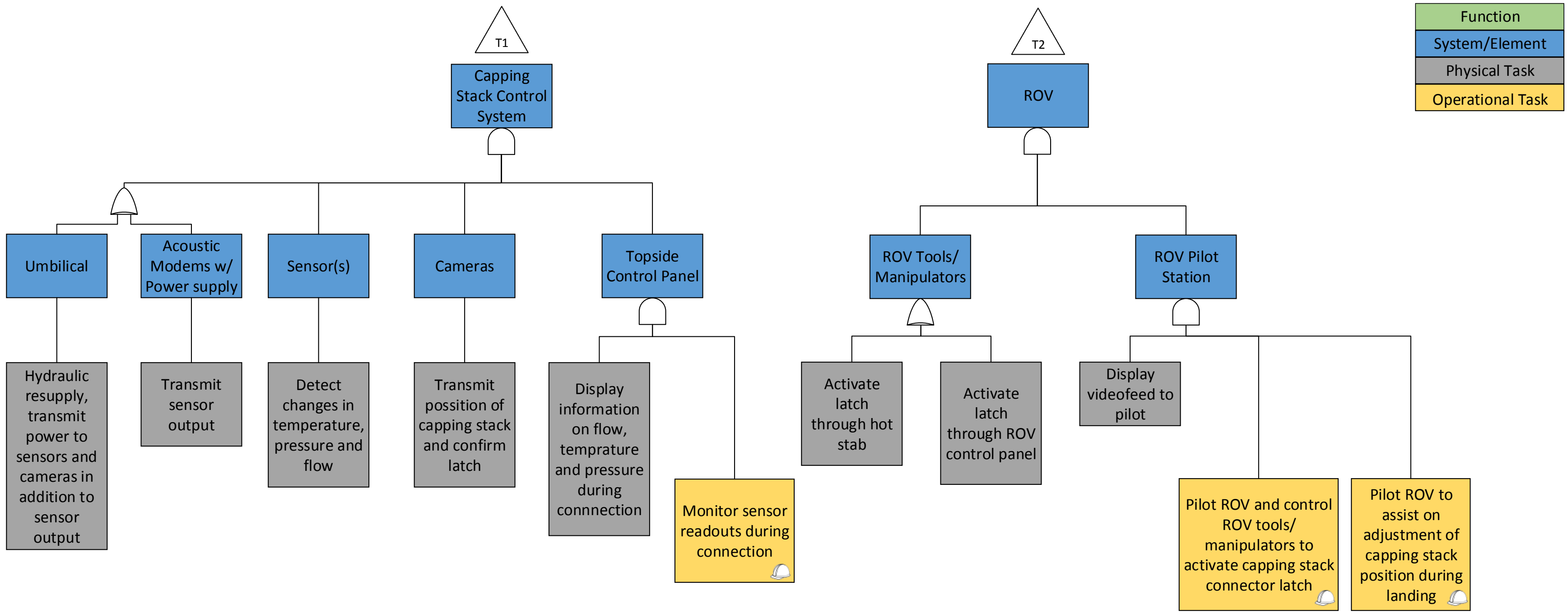

Figure 18 Barrier Critical System Function 1 – Connect to Wellhead/BOP and Seal on Hub – Part 2

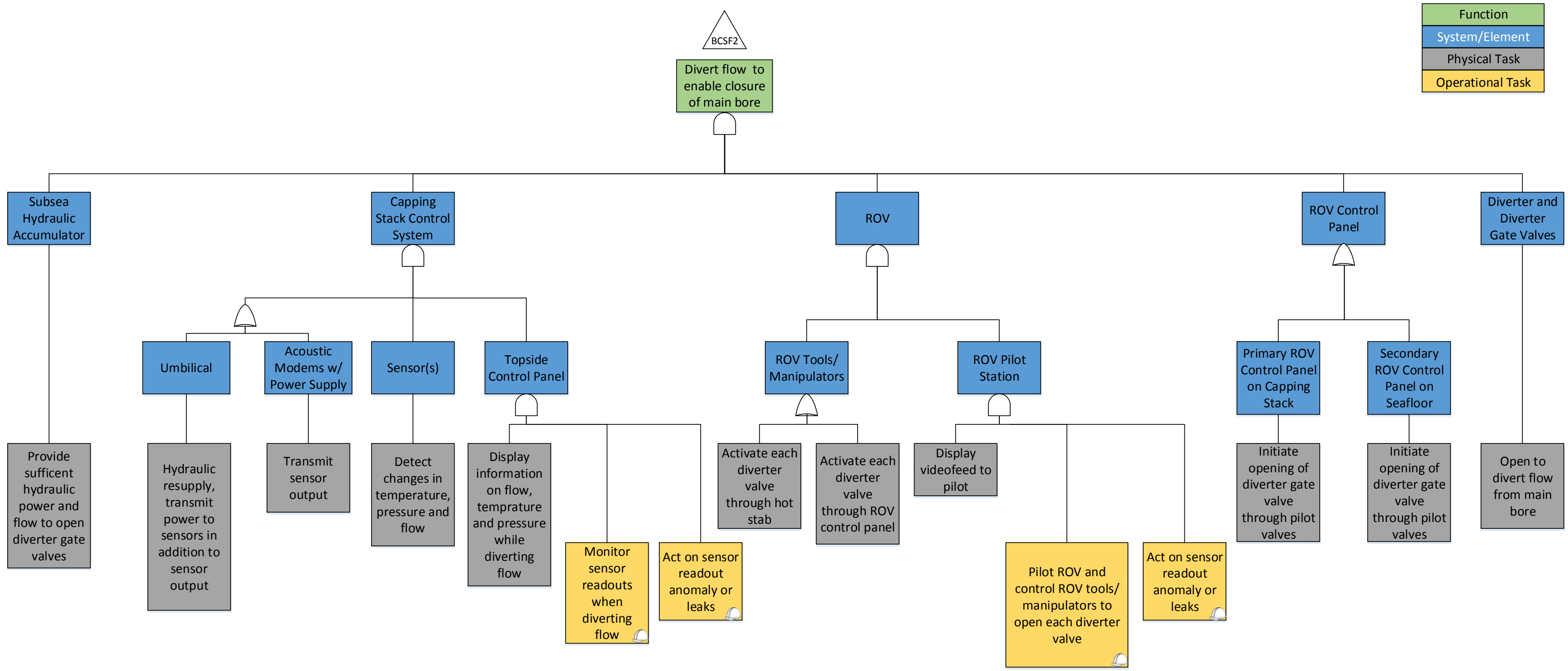

Figure 19 Barrier Critical System Function 2 – Divert flow to Enable Closure of Main Bore

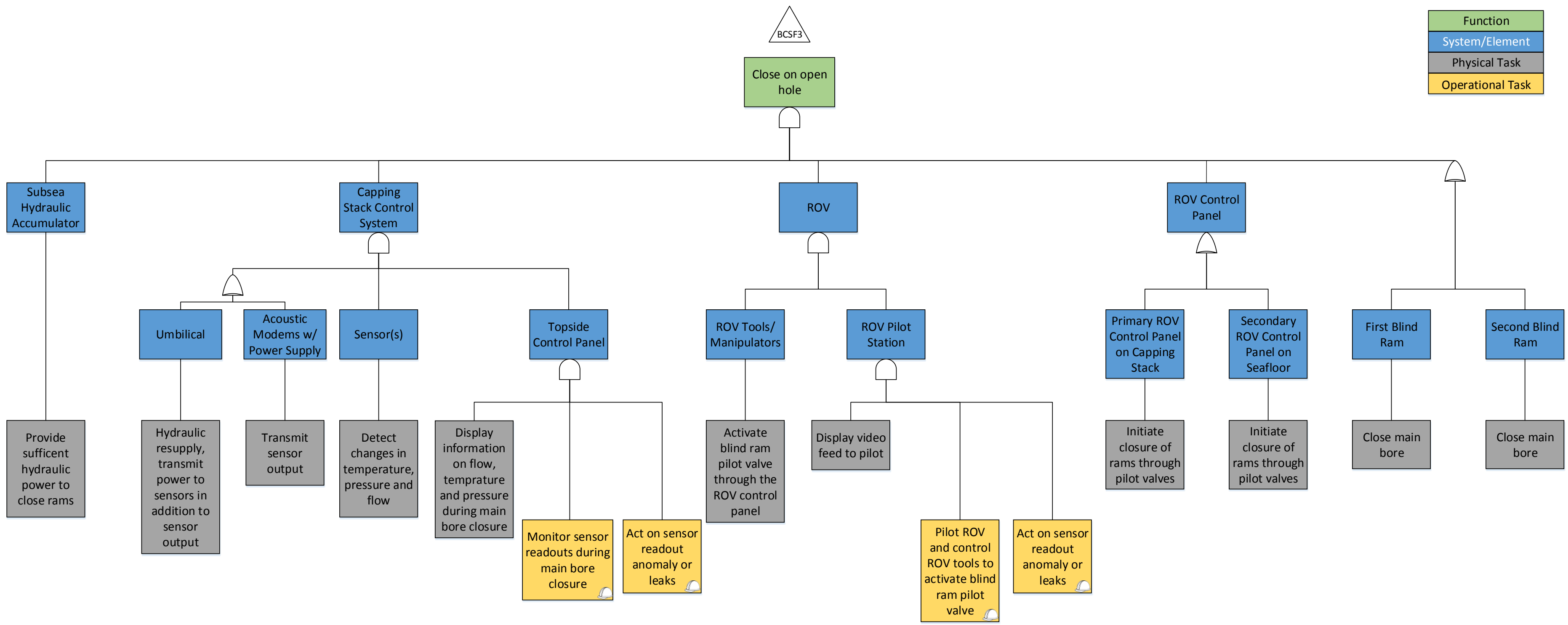

Figure 20 Barrier Critical System Function 3 – Close on Open Hole

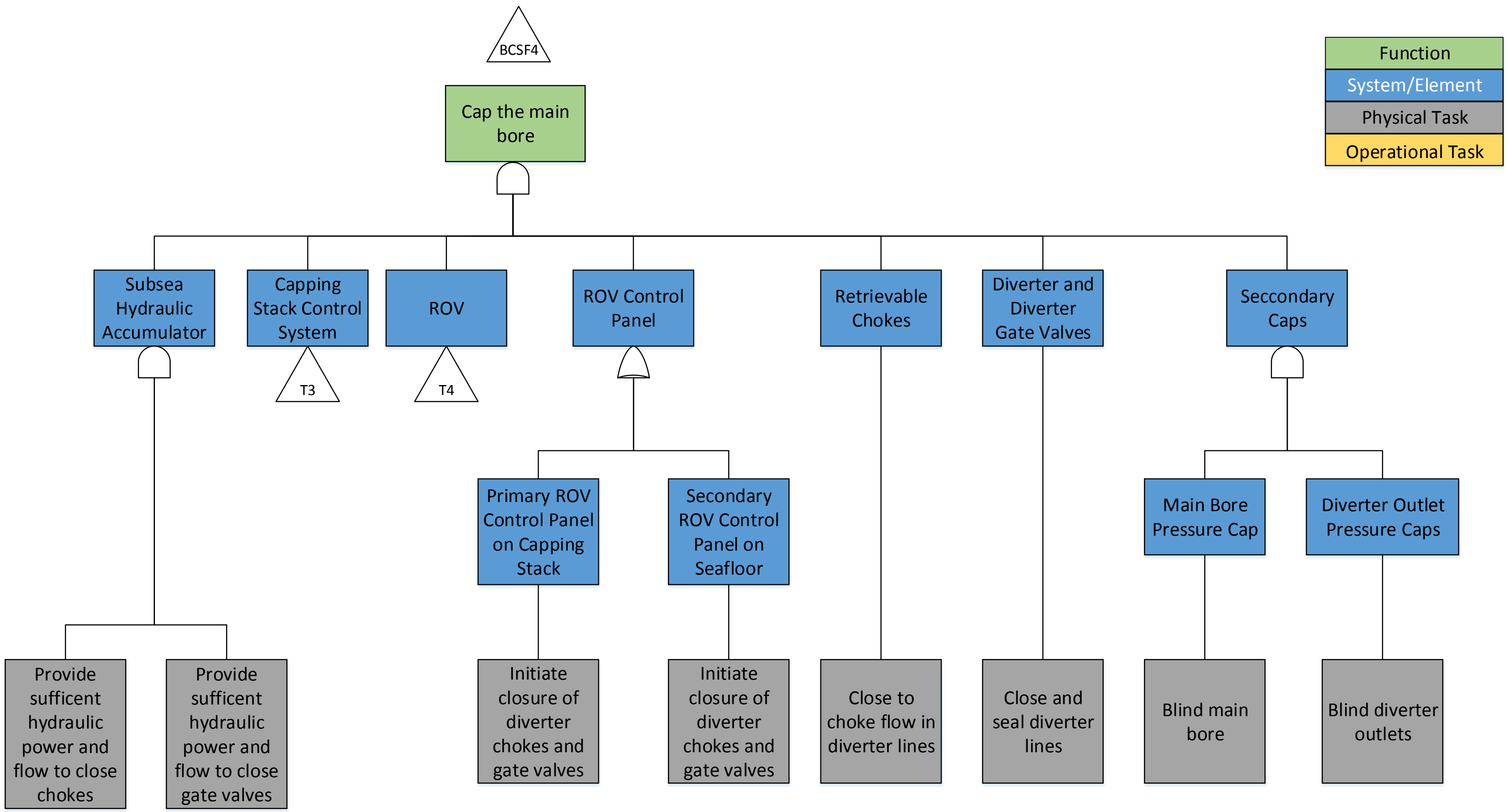

Figure 21 Barrier Critical System Function 4 – Seal the Bore – Part 1

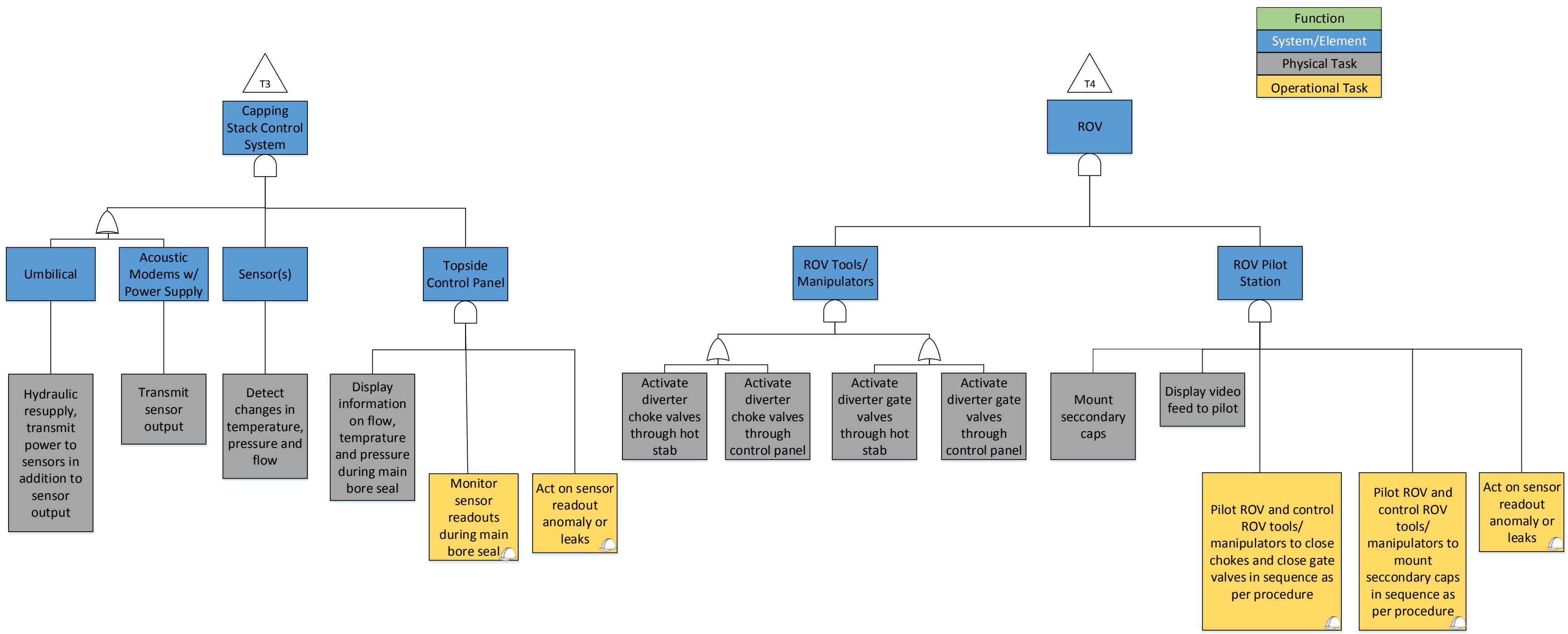

Figure 22 Barrier Critical System Function 4 – Seal the Bore – Part 2

7. Barrier Element Attribute Checklist

Checklists highlighting attributes and related success criteria for the barrier elements have been developed to ensure that they can perform the required physical/operational task(s) to meet their intended barrier critical system function(s). The checklists exist as MS Excel workbooks. Each checklist contains three tiers of the attributes influencing the performance of the barrier elements:

- Tier I – Covers the life cycle phases that need to be assessed
  - Design;
  - Fabrication and Testing;
  - Installation and Commissioning;
  - Operation and Maintenance;
  - Decommissioning and Removal.

  These are indicated by the worksheet labels.

- Tier II – Specific aspects that are required to be assessed as part of each lifecycle phase.

  As an example, corresponding to the Tier I Design worksheet, there are four Tier II attributes indicated by headers in green with each worksheet:

  - Design Parameters
  - Interactions/Interdependencies
  - Layout
  - Material

- Tier III – Provides specific detail and consideration for the BSEE reviewer to assess and validate.

These are developed in rows under each corresponding Tier II header.

It is important to note that the success attributes provided for the barrier elements are **<u>only examples</u>** to illustrate the development of typical attributes based on available design standards/codes and **<u>should not</u>** be interpreted as prescriptive requirements to be complied with. For each proposed new technology attributes will have to be developed based on the barrier model by the Operator in conjunction with relevant parties such as the equipment manufacturers.

Table 16 summarizes the barrier elements and the attribute checklists developed for the CS. Each barrier element checklist developed is provided as an individual MS Excel workbook, which can be accessed by clicking on the icon within the table.

Table 16. Barrier Element Attribute Checklist

Barrier Element	Checklist Provided? (Y/N)	Attribute Checklist (Click to open in MS Excel)
ROV		
- ROV tools/manipulators	Y	CS_ROV tools_manipulators.
- ROV pilot station	Y	CS_ROV_Pilot_Station.xlsx
Topside Control System		
- Sensor(s)	Y	CS_Sensors.xlsx
- Cameras	N	NA
- Umbilical	N	NA
- Acoustic modems w/ power supply	Y	CS_Acoustic System.xlsx
- Topside control panel	Y	CS_Topside_control_panel.xlsx
ROV control panel	Y	CS_ROV_Control_Panel.xlsx
Lowering arrangement	Y	CS_lowering_arrangement.xlsx
Chemical injection lines	Y	CS_Chemical Injection Line.xlsx
Subsea hydraulic accumulator	Y	CS_Hydraulic accumulator.xlsx

Barrier Element	Checklist Provided? (Y/N)	Attribute Checklist (Click to open in MS Excel)
Subsea attachment point	Y	CS_Subsea attachment point.xls
Capping Stack Connector	Y	CS_CS Connector.xlsx
Blind Ram	Y	CS_Blind Ram.xlsx
Diverter and diverter gate valves	Y	CS_Diverter_and_gate_Valve.xlsx
Retrievable chokes	Y	CS_Retrievable Chokes.xlsx
Main bore pressure cap	Y	CS_Main Bore_Pres_Cap.xlsx
Diverter outlet pressure caps	Y	CS_DO_Pres_Cap.xlsx
Seal Ring	N	NA

8. References

1 Bureau of Ocean Energy Management , Shell Gulf of Mexico, Inc. Revised Outer Continental Shelf Lease Exploration Plan Chukchi Sea, Alaska, Environmental Assessment

2 SINTEF; Blowout and Well Release Characteristics and Frequencies 2014, Doc. No. SINTEF F26576, 30 Dec 2014

3 Lloyd's Register Consulting: Blowout and well release frequencies based on SINTEF offshore blowout database 2014, Report no. 19101001-8/2015/R3,Final, 17 Mar 2015

4 DNV; Risk Assessment of Pipeline Protection, DNV-RP-F107, October 2010

5 National Audubon Society Inc.; http://ak.audubon.org/chukchi-sea , retrieved on 22 Aug 2015

6 Bureau of Ocean Energy Management; Chukchi Sea Planning Area – Final Second Supplemental Environmental Impact Statement, BOEM 2014-669, February 2015