Bay du Nord Project

Concept Safety Analysis

Equinor Canada Limited

April 2026

IA23-4VER-SA-0002

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Contents

Tables

Figures

Executive Summary

Equinor Canada Ltd. (Equinor) have made multiple oil discoveries in the Flemish Pass area, located approximately 475 km to the northeast of St. John's Newfoundland and 230 km to the north northeast of the Hebron, White Rose, Terra Nova and Hibernia developments.

Equinor is progressing with the development of an initial concept for two of these discoveries, Bay du Nord and Cambriol, with the option of connecting the Cappahayden discovery at a later date. The current production concept is a moored ship-shaped FPSO with a disconnectable turret buoy system, production from subsea wells/templates and tandem offloading to a shuttle tanker at the aft of the vessel. Two similar FPSO Topsides designs were progressed by Equinor as part of a design competition. The concept presented in this Concept Safety Analysis (CSA) is representative of the BW Offshore design which was selected by Equinor following the design competition. The design will be assessed in more detail through the subsequent phases of the Project.

The first step in the CSA was a formal Hazard Identification (HAZID) session that allowed the identification and assessment of the following Major Accident Events (MAE) associated with the proposed development of the Bay du Nord Project:

- MAE1 - LOC of hydrocarbon gas (including 2- phase)
- MAE2 - LOC of hydrocarbon liquid
- MAE3 - Hull tank fire / explosion
- MAE4 - Non-process fires
- MAE5 - Accommodation fire
- MAE6 - Helicopter accident
- MAE7 - Ship collision
- MAE8 - Structural failure
- MAE9 - Dropped/swinging objects
- MAE10 - Loss of mooring.
- MAE11 - Loss of stability and buoyancy
- MAE12 - Iceberg Collision

In addition, the hazards associated with subsea hydrocarbon releases are assessed.

- MAE13 - Hydrocarbon Release Risers and Flowlines Subsea (including blowouts and well releases)

These hazards are assessed quantitatively with the risks presented and compared against Equinor's Target Levels of Safety (TLS). Loss of Mooring (MAE10) has been combined with the Structural Failure (MAE8) in the quantitative assessment. The CSA also qualitatively discusses the risk from Dropped Objects, Turbine Disintegration and Accommodation Fires.

Occupational risk has been based on industry data that provides a Fatal Accident Rate (FAR) for different worker groups. This FAR has been converted into individual risk by applying the time each worker is exposed to the hazard. The occupational risk is reported separately to the above MAEs.

For each of the Major Accident Events listed above, the CSA quantifies the following measures of risk:

- Individual Risk per Annum (IRPA) - Risk to an individual within a specific worker group, based on the amount of time that an individual spends on the installation.
- Potential Loss of Life (PLL) - Societal risk, which is the combined risk for all personnel on the facility, based on continuous occupation and expressed as fatalities per annum.

The CSA presents the IRPA for four representative work groups (admin, maintenance, operations, and LQ crew), taking into account the time spent in different areas of the facility for each worker group.

As well as IRPA and PLL, the impairment of Main Safety Functions has also been assessed, which includes Temporary Refuge, Escape Routes, Evacuation and other identified barriers around the facility. A detailed description of each mechanism that can impair the Main Safety Functions, and the results of the analysis, can be found in Section 5.10 and Section 7.2.

The Bay du Nord Project is currently in the Pre-FEED Phase. There are, therefore, several uncertainties and conservatisms in some of the data used within the risk assessment. In addition, a number of assumptions have been made to develop a full risk profile. Further details of assumptions can be found in Section 3 whilst a table of conservatisms and uncertainties can be found in Section 11.

IRPA and PLL results are summarised next, with more detailed discussion found in Section 7. The weighted average IRPA across all worker groups is shown and expressed as a FAR, which is the number of fatalities per 100 million exposed hours and corresponds to the exposure of 1,000 personnel over their working life.

Table S-1 Average Risk Contribution from MAEs on Bay Du Nord, expressed as a FAR

		Individual Risk (FAR)			
MAE #	**MAE Description**	**Immediate**	**Muster**	**TR Fatalities**	**Evacuation**
1	LOC of hydrocarbon gas (including 2- phase)	0.248	0.121	0.130	0.043
2	LOC of hydrocarbon liquid	0.084	0.009	0.025	0.010
3	Hull tank fire / explosion	0.010		0.000	0.000
4	Non-process fires	0.000		0.002	0.000
5	Accommodation fire				
6	Helicopter accident	1.545		0.001	
7	Ship collision			0.022	0.010
8	Structural failure			0.103	
9	Dropped/swinging objects				
10	Loss of Mooring				
11	Loss of stability and buoyancy				
12	Iceberg Collision			0.001	0.000
13	LOC of hydrocarbon riser			0.004	0.004
	Total (exc Occupational)	1.887	0.130	0.287	0.067
	Occupational	1.604			
	Overall Total	**3.97**			

The Bay du Nord TLS for the average individual risk (FAR) across all worker groups is 10 and therefore it can be seen that the current design meets this target.

Table S-2 PLL Contribution from MAEs on Bay Du Nord

		Potential Loss of Life (fatalities per annum)			
MAE #	**MAE Description**	**Immediate**	**Muster**	**TR Fatalities**	**Evacuation**
1	LOC of hydrocarbon gas (including 2- phase)	1.71E-03	8.39E-04	8.99E-04	2.95E-04
2	LOC of hydrocarbon liquid	5.79E-04	6.23E-05	1.75E-04	6.58E-05
3	Hull tank fire / explosion	6.81E-05		1.81E-06	2.29E-06
4	Non-process fires	6.03E-07		1.24E-05	5.95E-07
5	Accommodation fire				
6	Helicopter accident	1.07E-02		4.89E-06	
7	Ship collision			1.53E-04	6.84E-05
8	Structural failure			7.11E-04	
9	Dropped/swinging objects				
10	Loss of Mooring				
11	Loss of stability and buoyancy				
12	Iceberg Collision			4.13E-06	8.54E-07
13	LOC of hydrocarbon riser			2.46E-05	2.94E-05
	Total (exc Occupational)	1.31E-02	9.01E-04	1.99E-03	4.63E-04
	Occupational	1.11E-02			
	Overall Total	**2.75E-02**			

The assessment of Main Safety Functions, reported in Section 7.2, demonstrated that the current design meets the Project specified TLS.

The following recommendations have been made on the basis of the results of the assessment. The HAZID [1] and ALARP [5] Review documents should also be consulted for details of further recommendations that have been identified during this phase of the project.

1. Asphyxiation from hydrocarbon releases is only expected to be a potential threat within the enclosed lower turret area, and it is expected that breathing equipment will be located within the turret. As such, asphyxiation has not been assessed within the CSA. However, as the design for the turret is developed further, the potential for immediate fatalities from asphyxiation should be reviewed in more detail. If asphyxiation is shown to be a concern in the enclosed area of the turret, or any other enclosed area, the Bay du Nord Operations team should confirm that BA sets will be available and one breath away.
2. An assessment of O_2 depletion and CO_2 build up within the TR should be carried out in later stages of the design, to determine the risk of high heat stress causing impairment of personnel within the LQ.
3. The explosion modelling and escalation rulesets that have been applied are conservative, with uncertainties detailed in Section 11. This will be assessed further in the next phase of the project and it is recommended that this includes a formal escalation review to allow the project team to provide input into the escalation paths captured in the QRA.
4. The protected escape routes, down the port and starboard sides of the FPSO, are essential in allowing personnel to escape back to the LQ in the event of a major incident. However, they may introduce confinement and congestion which could exacerbate the consequences of explosions in the process areas. The analysis has not assessed the potential benefit on explosion overpressures of removing the protected escape routes or relocating them to hang off the process deck. The removal of protected escape routes may reduce the potential for high explosions through increased ventilation. It is recommended that the impact of protected escape routes on explosion overpressures is assessed in more detail in the next phase of the project.

Acronyms

Acronym	Definition
ACH	Air Changes per Hour
AFFF	Aqueous Film-Forming Foam
ALARP	As Low as Reasonably Practicable
ALS	Accidental Limit States
API	American Petroleum Industry
APS	Auxiliary Power Supply
ATA	Auxiliary Thruster Class Notation
BA	Breathing Apparatus
BAT	Best Available Technique
BdN	Bay du Nord
BD	Blowdown
BOP	Blow Out Preventer
CAA	Civil Aviation Authority
CCR	Central Control Room
CDOG	Clarkson Deepwater Oil & Gas
CFD	Computational Fluid Dynamics
CITV	Chemical Injection Throttle Valve
CMPT	Centre for Marine & Petroleum Technology
C-NLOER	Canada-Newfoundland & Labrador Offshore Energy Regulator
CO	Carbon Monoxide
COT	Cargo Oil Tank
CO_2	Carbon Dioxide
CP	Cathodic Protection
CSA	Concept Safety Analysis
CSO	Chief Safety Officer
CSTR	Continuously Stirred Tank Reactor
DNV	Det Norske Veritas
DP	Dynamic Positioning
DSHA	Defined Situations of Hazards & Accidents
DSV	Dive Support Vessel
EDP	Emergency Depressurisation
EER	Escape, Evacuation and Rescue
EERA	Escape, Evacuation and Rescue Assessment
EIS	Environmental Impact Statement
EIT	Electrical, Instrument and Telecommunication
EPA	Emergency Preparedness Analysis
ERRV	Emergency Rescue and Recovery Vessel
ESD	Emergency Shutdown
ESDV	Emergency Shutdown Valve
Ex	Electrically Classified Equipment
FABIG	Fire and Blast Information Group
FAR	Fatal Accident Rates

Acronym	Definition
FCM	Flow Control Module
FEED	Front End Engineering Design
FLACS	Flame Acceleration Simulator
FM	Flow Module
FORRI	Frontier and Offshore Regulatory Renewal Initiative
FPSO	Floating Production, Storage & Offloading
FROG	Lifting basket from ReflexMarine
FSU	Floating Storage Unit
FW	Fire Water
GE	General Electric
GMDSS	Global Maritime Distress Safety System
GRP	Glass Reinforced Plastic
HAZID	Hazard Identification Study
HAZOP	Hazard and Operability
HC	Hydrocarbon
HD	High Definition
HP	High Pressure
HSE	Health & Safety Executive
H_sT_p	Significant Wave Height Peak Period
HVAC	Heating, Ventilation and Air Conditioning
IACS	Industrial Automation and Control Systems
ID	Internal Diameter
IEC	International Electrotechnical Commission
IG	Inert Gas
IMO	International Maritime Organisation
IOGP	International Association of Oil & Gas Producers
IR	Infra-Red
IRPA	Individual Risk Per Annum
ISO	International Standards Organisation
JIP	Joint Industry Project
JOA	Joint Operating Agreement
KO	Knock Out
LEL	Lower Explosive Limit
LER	Local Equipment Room
LFL	Lower Flammable Limit
LP	Low Pressure
LQ	Living Quarters
MAE	Major Accident Event
MCTS	Marine Communications & Traffic Services
MEG	Mono Ethylene Glycol
MES	Marine Evacuation System
MGO	Marine Gas Oil
MJ	Megajoules (unit)
MODU	Mobile Offshore Drilling Unit
MPFM	Multi-Phase Flow Meter
MW	Megawatt (unit)

Acronym	Definition
NAFO	Northwest Atlantic Fisheries Organization
NAP	Normal Atmospheric Pressure
NCS	Norwegian Continental Shelf
NFPA	National Fire Protection Agency
NIST	National Institute of Standards and Technology
NLL	Normal Liquid Level
NORSOK	Norwegian Standards Organisation
NOx	Oxides of Nitrogen
OGP	Oil & Gas Producers
OHS	Occupational Health and Safety
OIR	Offshore Incident Report
PA	Public Address
PARLOC	Pipeline and Riser Loss of Containment
PAU	Process and Utility
PDMS	Plant Design Management System
PFD	Process Flow Diagram
PFP	Passive Fire Protection
PHAST	Process Hazard Analysis Software
PIFL	Pipe Flow (Kent Software)
PLL	Potential Loss of Life
PLOFAM	Process Leak for Offshore Installations Frequency Assessment Mode
POB	Personnel on Board
PPE	Personnel Protective Equipment
PSA	Petroleum Safety Authority
PSV	Pressure Safety Valve
PTW	Permit to Work
PV	Pressure Vacuum
PW	Produced Water
PWRI	Produced Water Reinjection
QCDC	Quick Connect, Dis-Connect
QRA	Quantitative Risk Assessment
RBI	Risk Based Inspection
RIO	Remote Input Output
ROV	Remote Operated Vehicle
SBV	Standby Vessel
SCU	Subsea Control Unit
SDPU	Subsea Data & Processing Unit
SFPE	Society of Fire Protection Engineers
SIMOPs	Simultaneous Operations
SINTEF	Independent Norwegian Research Organisation
SIS	Safety Instrumented System
SOLAS	Safety of Life at Sea
SOR	Statement of Requirements
SPCU	Subsea Power & Communication Unit
SPFM	Single-Phase Flow Meter
SPS	Subsea Production System

Acronym	Definition
SSIV	Subsea Isolation Valve
STP	Submerged Turret Production
SURF	Subsea, Umbilicals, Risers and Flowlines
TEG	Triethylene Glycol
TEMPSC	Totally Enclosed Motor Propelled Survival Craft
THOM	Tubing Hanger Orientation Module
TLS	Target Levels of Safety
TO	Take Off
TR	Temporary Refuge
TRIF	Temporary Refuge Impairment Frequency
UFL	Upper Flammable Limit
UK	United Kingdom
UKOOA	United Kingdom Offshore Operators Association
UPS	Uninterruptible Power Supply
VL	Released Volume
VOC	Volatile Organic Compounds
VXT	Vertical Xmas Tree
WAG	Water Alternating Gas
WEHRA	Working Environment Health Risk Assessment
WI	Water Injection
XMT	Xmas Tree

1. Introduction

1.1. Overview

Equinor Canada Ltd. (Equinor), as operator, on behalf of the project proponents, Equinor and BP Canada Energy Group ULC (BP) is leading the development of the Bay du Nord Project (the Project). The Project is a combination of discovered resources, where hydrocarbons have been proven, and prospects, where there is the potential for hydrocarbons. This Concept Safety Analysis is for the planned development of the Bay du Nord and Cambriol fields, and generally does not assess the deferred developments of the Cappahayden, Harpoon, and Baccalieu fields. The Project is located approximately 475 km offshore Newfoundland and Labrador (NL), in the Flemish Pass Basin, and approximately 230 km from existing offshore infrastructure in the Jeanne d'Arc.

This CSA primarily assesses the risks associated with the FPSO. However, modelling of hydrocarbon releases from risers within 500m of the FPSO is also covered, as these releases may affect personnel working on the FPSO. Risks associated with the subsea wells themselves are outside the scope of this specific assessment but have been assessed by Equinor

Equinor is progressing with the development of a concept for the Bay du Nord and Cambriol fields, through a single processing installation. The concept is still in the early phase of development. This section describes the regulatory requirements that the Project are required to demonstrate have been met, as well as the methods used to identify and assess hazards associated with operation of the facility.

Section 2 provides an outline description of the Bay du Nord FPSO as well as the key safety design features and systems proposed for the inherent safety, prevention, detection, control and mitigation of potential Major Accident Events (MAEs). The facilities described in the CSA are representative of the design that is proposed to be continued to be developed through the next stage of the project. Section 3 further describes inputs and assumptions for the risk assessment including information supplied by Equinor plus industry standard data sources. Where the data source is different to that quoted by NORSOK or Equinor, then context is provided.

Section 4 describes the process followed to identify Major Accident Events for the Project and then how these hazards have been assessed is covered by Section 5. The Target Levels of Safety defined by the Project are described in Section 6, with the results of the assessment shown in Section 7, including the comparison against the Target Levels of Safety. Section 8 then provides a demonstration that risks associated with the current design are As Low as Reasonably Practicable (ALARP), as well as identifying further risk reduction measures that should be considered by the Project in the further stages of design.

1.2. Regulatory Requirements

The *Canada–Newfoundland and Labrador Atlantic Accord Implementation and Offshore Renewable Energy Management Act* and the Canada-Newfoundland and Labrador Atlantic Accord Implementation Newfoundland and Labrador Act (the *Accord Acts*) govern offshore energy activities in the region, and are administered by the Canada-Newfoundland and Labrador Offshore Energy Regulator (C-NLOER). Plans for development projects in the Canada-NL offshore area require approval by the C-NLOER under the *Accord Acts*.

According to Section 24 of the *Canada–Newfoundland and Labrador Offshore Area Petroleum Operations Framework Regulations* (the *Framework Regulations*), an operator is required to submit to the Chief Safety Officer (CSO) a Concept Safety Analysis (CSA) of an installation that considers all components and activities associated with each phase in the life of the production installation. The CSA must include a determination of the frequency of occurrence and potential consequences of potential accidents identified, and details of safety measures designed to protect personnel and the environment from such accidents.

Compliance with the above requirements also ensures that the CSA meets the requirements of the Framework Regulations [2]. The CSA performed within this document fulfils each of the above requirements.

1.3. Objectives and Approach

The objectives of this Concept Safety Analysis (CSA) are to:

- Identify the potential Major Accident Events associated with the development concept.
- Evaluate the identified MAEs in terms of risk to personnel, asset and the environment through Quantitative Risk Assessment (QRA).
- Compare the predicted risks from the QRA with the Equinor Target Levels of Safety (TLS).
- Document results, findings, conclusions and recommendations, as well as key areas of conservatism or uncertainty associated with the assessment at this Phase of design.
- Fulfil the CSA requirements described in Section 24 of the Framework Regulations [2].

This CSA considers all components and activities associated with each phase in the life of the Bay du Nord FPSO, including the construction, installation, operational and removal phases of the installation. The operational phase has been reviewed and assessed quantitatively, whereas the other phases of operation are addressed qualitatively.

Two hazard identification (HAZID) exercises were completed in support of this stage of the project, these being the BWO FPSO HAZID [1] and the SURF System HAZID [3]. In addition, the Buoy Disconnection/Reconnection Process [4] had been assessed in a HAZID previously. The HAZIDs involved the relevant members of the SURF, Upper, Turret and Topsides teams. In all cases, the HAZIDs also included previous experience, knowledge and lessons learned from the existing facilities off the East Coast of Canada.

As required, the risk assessment is quantitative where input data is available in the quantity and quality necessary to demonstrate confidence in results. Where quantitative assessment methods are inappropriate, qualitative methods are employed. Quantitative estimates of risk to personnel and the asset are based on event tree modelling of the following MAEs identified for the proposed installation:

- MAE1 – MAE4 and MAE13 Loss of hydrocarbon containment from risers, topsides processing, oil loading or offloading equipment (resulting in fire, explosion or unignited, potentially toxic, release). Note, Blowouts and well releases (resulting in fire, explosion or unignited, potentially toxic, release) – are not quantified as a risk to personnel on the FPSO as they would occur at some distance from the FPSO. They are addressed separately as an environmental risk.
- MAE6 Transport related accidents
- MAE7 Ship collision
- MAE8 and MAE10 Structural failure
- MAE12 Iceberg collision

The calculated risks have been compared with Equinor's TLS to determine whether risks can be considered acceptable and a formal qualitative ALARP review [5] was completed to provide further assurance to the Project as well as identify additional measures that will be reviewed in future phases.

The level of detail in this assessment reflects the information available at the Pre-FEED Phase. It has been necessary to make a number of assumptions in the development of the QRA, which are recorded in Section 3 with uncertainty and conservatisms recorded in Section 11.

To provide certainty around the assumptions, sensitivity analysis has been performed on a number of these assumptions to ensure that the information used is robust and appropriate at this stage. The results of the sensitivity analysis are shown in Section 7.3.

2. Description of Facilities

2.1. Introduction

The Bay du Nord discovery and adjacent discoveries Cambriol, Cappahayden, Baccalieu, and Harpoon are located approximately 475 km northeast of St John's, Newfoundland in the Flemish Pass Basin, in approximately 600 – 1200 metres of water. This is a basin-opening discovery and as such there is no existing infrastructure in the immediate area. The nearest assets are in the Jeanne d'Arc Basin some 240 km away. This frontier area has harsh environmental conditions which include large sea states, high winds, sea ice and icebergs. The Bay du Nord project License Information and is shown in Table 2-1.

Table 2-1 License Information

License	Owners	Field Reference
SDL 1055	Equinor Canada Ltd (65%, Operator) BP Canada Energy Group ULC (35%)	Bay du Nord
SDL 1060	Equinor Canada Ltd. (60%; operator) BP Canada Energy Group ULC (40%)	Cambriol
SDL 1059	Equinor Canada Ltd. (60%; operator) BP Canada Energy Group ULC (40%)	Deferred development - Cappahayden
SDL 1058	Equinor Canada Ltd. (65%; operator) BP Canada Energy Group ULC (35%)	Deferred development - Harpoon
SDL 1056 and SDL 1057	Equinor Canada Ltd. (65%; operator) BP Canada Energy Group ULC (35%)	Deferred development - Baccalieu

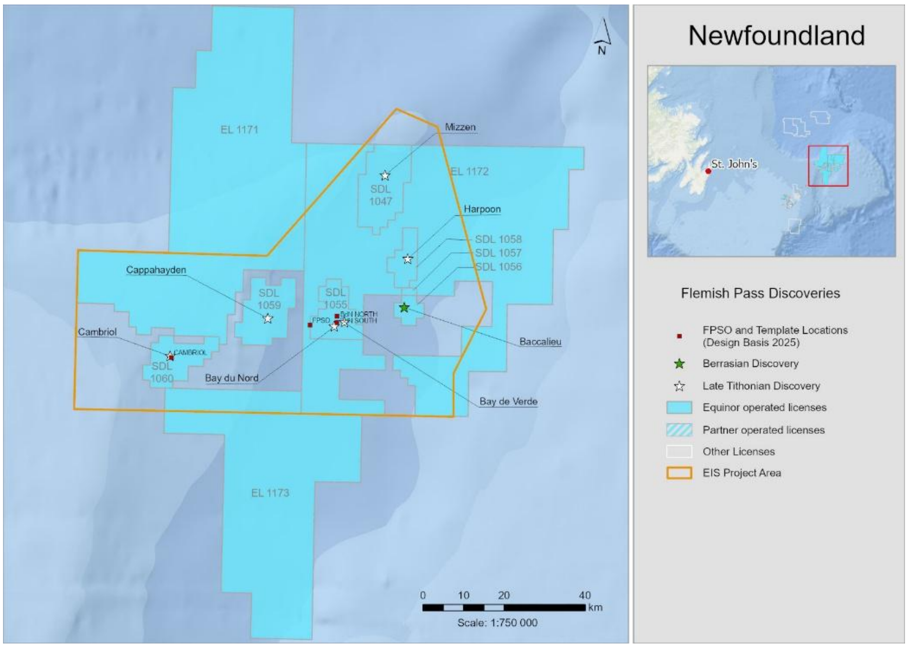


Figure 2-1 Location of Bay du Nord

The Bay du Nord Project comprises development of the Bay du Nord and Cambriol fields. A number of exploration wells have been drilled. Together with multiple seismic surveys this provides a comprehensive dataset over the project area. The current development concept for the fields has approximately 420 MMbbl of light oil produced through 16 subsea wells (8 producers and 8 injectors) to an FPSO shipshape vessel, with offtake to shuttle tankers.

2.2. Facility Development

The Base Case development scenario is a shipshape FPSO with tandem offloading and a disconnectable buoy system with flexible risers and a combination of rigid and flexible flowlines. The design life of the facilities and wells is such that they facilitate 20 years of production. The design life of different elements are to be detailed further in the next phase based on cost benefit considerations towards production profile and future prospects.

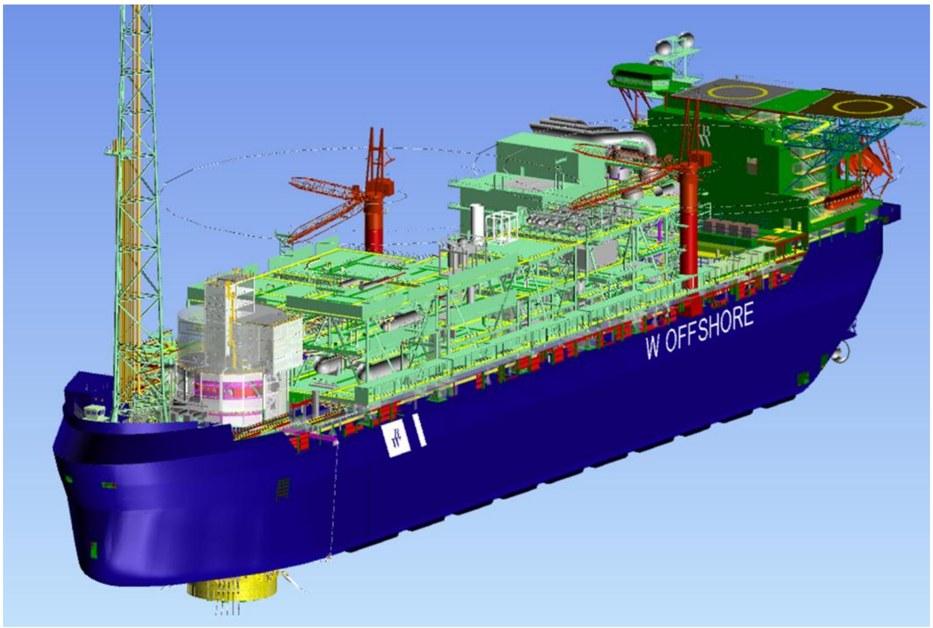


Figure 2-2 Bay du Nord FPSO

With the current topside nameplate production rate of 160 000 bbls/day, the crude oil storage capacity is dimensioned for the FPSO hull size and is approximately 1.2 million barrels. The turret is located at the forward end of the vessel and the FPSO shall have a (quick) disconnectable buoy system complete with mooring and riser system to allow the FPSO to leave the location typically in low probability safety-related situations, such as iceberg threats over a certain collision energy level or ice thickness over a certain threshold level.

2.2.1. Operations

The Bay du Nord operating environment is harsh and remote; some 475km offshore Newfoundland in the North Atlantic Ocean. The operating challenges in this environment include:

- Distance from shore and 250 km from the closest facility offshore Newfoundland
- Icebergs and pack ice may be present in the operating area in the spring / early summer
- Hurricanes are often experienced during the fall months
- Severe fog in the spring and summer provide logistical challenges with helicopter personnel transport

- Severe and frequent storms occur during the fall and winter months.

These elements make logistics challenging, particularly related to personnel movements to and from offshore via helicopter and/or supply vessel. To enable safe and efficient operations in this environment, the future operating model and the facility design will ensure:

- An inherently safe design that ensures that all internal specifications and regulatory requirements are adequately addressed
- An efficient operations organization with a collaborative operating model
- Control System design and architecture that enables highly reliable monitoring and control of the process and subsea systems.

2.2.2. Oil Offtake

For the purposes of this assessment, it is assumed that the FPSO shall offload at the stern to a shuttle tanker from the cargo oil storage tanks via a metering station, adopting a similar approach to other fields Offshore Canada. For the CSA, a "standard" North Sea offtake system is assumed. The offtake will be further evaluated in the next phase as the design develops.

2.3. Safety and Sustainability

Equinor's vision is zero harm for people, the environment, and assets.

The scope relating to Technical Health, Safety and Environment (HSE) for the Bay du Nord FPSO Facilities has had a detailed focus. This has involved addressing major HSE risks and local conditions.

The subjects pertaining to technical safety and working environment relevant for the facilities study scope are:

- Layout, natural ventilation and segregation of areas
- Passive Fire Protection - fire and blast barriers
- Active Fire Protection
- Escape route design
- Noise and vibration control
- Weather protection
- Access and material handling.

Key environmental aspects of facilities design, which are discussed in the Development Plan [6] and or the Environmental Impact Statement (EIS), include:

- Produced Water management
- Drill cuttings management, and
- Energy consumption and emissions

These environmental aspects are not discussed further in the CSA.

2.4. Hull and Living Quarters

2.4.1. General Concept

The FPSO hull and LQ is designed by the experienced FPSO Contractor BW Offshore.

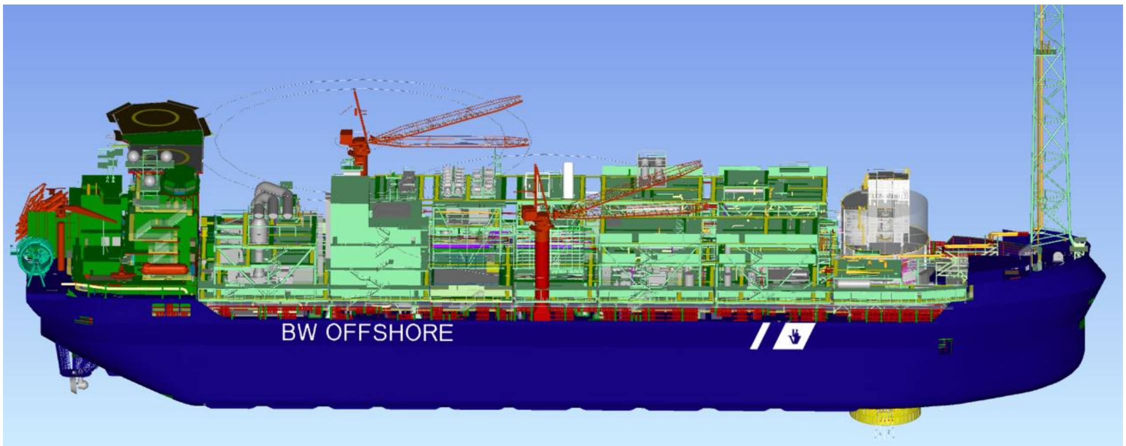


Figure 2-3 View of FPSO (Starboard side)

All the "extraordinary" physical environmental, geographical and metocean features for the location have been considered and have influenced the design of the hull to a large degree:

- Helideck located aft over the port side. This helicopter deck location improves availability of the helicopter deck significantly compared to a forward located helideck. It also improves flight safety compared to forward mounted helicopter decks as wind direction during landing and sight/reference lines are optimal.
- LQ located aft. This improves comfort for crew (reduced accelerations), reduces green sea and slamming issues in the LQ area, reduces collision risk to personnel, improves natural weathervaning and reduces power consumption. It is also easier to achieve aft trim and thus ballast amount may be reduced in fully loaded conditions.
- Turret location is somewhat further forward on the vessel. This improves natural weathervaning capability in some weather combinations, improves layout and improves fabrication installation with regards to structural details around turret.
- Disconnectable unit. This requires that the vessel is equipped to sail as a ship, including navigation bridge, power, propulsion, marine crew, anchor and mooring equipment.
- The hull is ice strengthened to resist sea ice and smaller icebergs up to the established design limits.

2.4.2. Safety Zones

Safety Zones will be established around the production and drilling installation and communicated on nautical charts.

- The safety zone prescribed by the *Framework Regulations* consists of the area within a line enclosing and drawn 500m from the outer edge of the installation or any component of the installations. This also includes moorings, risers, flowlines, and other SURF facilities. Support craft, aircraft, and vessels undertaking work or activity in the field area are prohibited from entering the Safety Zone without the consent of the Offshore Installation Manager (OIM). For external parties (including fishers) the Operator's obligation is to notify them of the Safety Zone's extent via nautical charts, notices to mariners, NAFO, etc.

- The zone prescribed by the UN Convention on the Law of the Sea (UNCLOS) is the area that extends from the outer extremities of the FPSO and fixed structures on the seabed to a distance of 500 metres beyond the boundaries of the anchor pattern of the FPSO, with these being the farthest fixed structures. This safety zone is larger than that prescribed in the Collision Regulations [7] but the Minister of Transport "*may establish a safety zone greater than the prescribed safety zone if it is reasonably related to the nature and function of the exploration or exploitation vessel and is necessary to ensure navigational safety*". In the next phase, Equinor intends to seek approval for the extension of the 'maritime' safety zone. No vessel shall navigate within this safety zone around the FPSO vessel, making it effectively an 'exclusion zone', and a vessel must receive permission from the OIM to enter the safety zone.

2.5. Topside Process Facilities

The Bay du Nord Topsides Facility has focused on a low maintenance, optimized staffing FPSO concept solution for the Bay du Nord Development.

The design philosophy for the Topsides Process has been to create a simple and robust system design.

2.5.1. Process Facilities

The design has a three stage separation process with an electrostatic coalescer, which will ensure good separation with arrival temperatures at 50°C or above. An Inlet heater has not been included for the first stage separator as the arrival temperature is expected to be above 50°C.

The test separator was included due to local regulatory requirements for well cleanup and allocation purposes.

The transfer of crude oil from the coalescer to the storage tanks is done by Oil Booster Pumps supporting the coalescer hydrostatic head of 1.5 barg.

Lower pressure gas from the separation train enters the re-compressors at just above atmospheric pressure and is compressed to around 52 barg via LP and MP gas compression before entering the HP compressors and routed, for gas lift or injection via the turret, at pressures of up to 325 barg.

Produced water will be treated using Best Available Techniques (BAT) and discharged to sea, with the possibility for future produced water reinjection. This is similar to other producing installations operating offshore Newfoundland. A two stage water treatment process has been selected with a hydro cyclone skid and compact flotation units skid. Oil collected is routed to the Oily Water Reject Vessel and gas is routed to LP flare.

Reservoir pressure support strategy is based on Water Alternating Gas (WAG). Produced gas is injected in a designated water injector for a 3-month cycle. Sea water for injection is heated to 35ºC utilizing the low heat source in the gas injection train, oil cooler and produced water coolers. Due to material specifications oxygen is removed from the sea water in a deaerator tower before injection.

It is assumed that barium sulphate scale will not be expected when mixing produced water and sea water as the formation water does not contain barium and has a composition similar to that of sea water. Therefore, sulphate removal has not been planned for. Reservoir souring is expected and will be handled by scavengers and material selection.

An overview of the Bay du Nord process is shown in Figure 2-4.

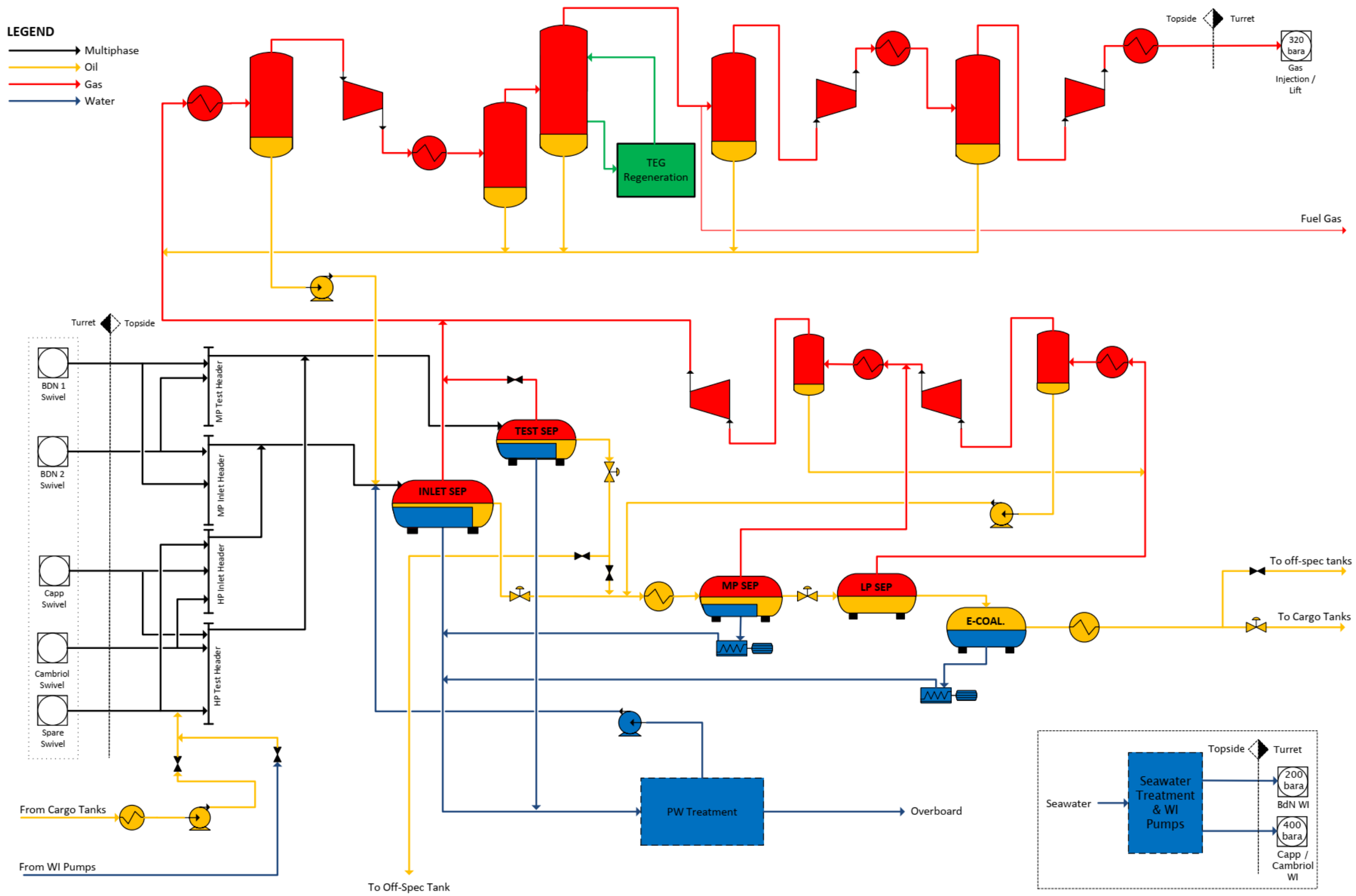


Figure 2-4 Bay du Nord Process Flow Diagram

2.5.2. Technical and Process Safety

2.5.2.1. Layout Arrangement

The FPSO will be arranged with a forward turret which is enclosed and mechanically ventilated up to the process deck but naturally ventilated above that level. The Topsides process and utility decks will be installed on an elevated deck level above the vessel cargo tank deck, with up to three deck levels across the Process & Utility area. Level 1 of the process deck shall be a continuous plated deck to act as a barrier between main deck and topside. The mezzanine and upper decks of topsides are grated except where liquid secondary containment is needed.

The accommodation module is located at the aft of the FPSO along with the offloading hose reel for oil export to the shuttle tanker. The FPSO will weathervane on the turret and thruster assisted heading control will also be provided. The FPSO layout is based around an inherently safe design approach, with higher pressure gas or large un-stabilized oil inventories located at the forward end of the FPSO Topsides, as far as possible from the accommodation.

The helideck is located on the port side, and the current proposed location for W2W gangway landings are at the Galley laydown area M41 and at M90) However, the potential for relocating two W2W gangway landings at the starboard side shall be assessed in the next phase. A protected escape route runs from the forward part of the vessel to the end of M41 on port side and end of M90 on starboard side. The protected escape route has a roof and wall towards the process area, with door openings to allow for escape from the process areas. The primary purpose of the protected escape route is to shield the escape route against radiation and explosion loads from process incidents. Additionally, shielding the escape route from smoke is another benefit of the protected escape route in small/medium fire scenarios.

Figure 2-5 shows the Bay du Nord layout for the topsides concept being considered.

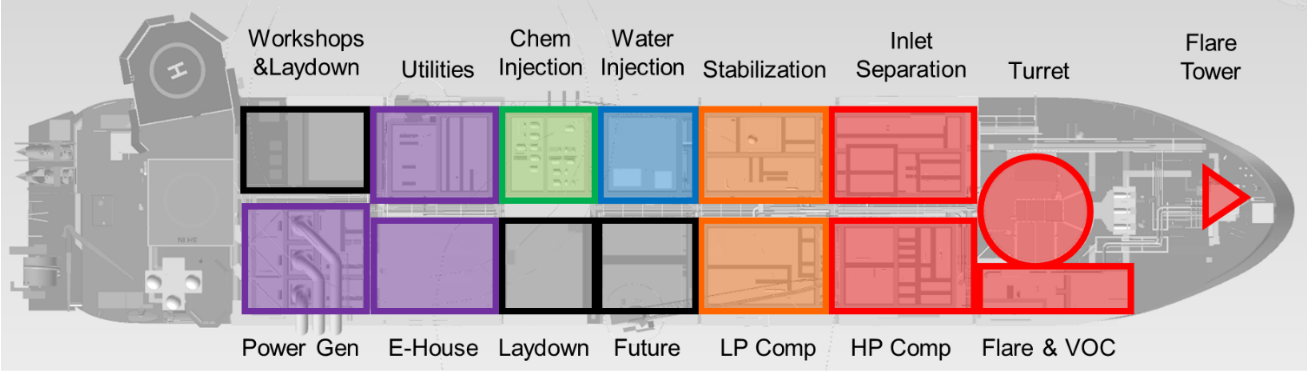


Figure 2-5 Bay du Nord FPSO Layout

The separation system is located port forward on the FPSO in M10 and M11, with the test separator, inlet separator and electrostatic coalescer expected to be on Level 1 (L1) of the Process Deck level and the MP Separator and LP separator expected to be on Level 2 (L2). The Process Deck (L1) is assumed to be plated, with sealed inter-module gaps, and decks L2 and L3 are generally grated, with containment to catch potential liquid releases as required.

The gas compression system is also located towards the forward end of the FPSO, on the Starboard side of M60 and M61. The higher-pressure reinjection compressor package is positioned at the forward end of compression (M61), whereas the lower pressure compressor packages and fuel gas skid are located at the aft end of compression (M60).

The less hazardous utility modules such as water treatment, water injection and the chemical modules are located immediately aft of the separation and compression modules in M50/51 and M71, forming a buffer between the hazardous events in the Process area and the non-hazardous events in the Utility area. A multi-level electrical building (M40) and a laydown area (M42) form an additional buffer. In addition, the Electrical building will form a A-60 fire and blast barrier. The Main Power Generators are located directly forward of the accommodation module, on M90. The dual-fuel gas turbine generators are normally driven by fuel gas, with the pipework routed to minimise the potential inventory of gas at the generators.

2.5.2.2. Passive and Blast Protection

Segregation between the Process and Utility areas on the Topsides is by a combination of buffer modules, barriers and distance, as described above. The accommodation and workshops/stores wall facing the process area is provided with a firewall in accordance with the Framework Regulations [2], which shall be insulated to H-60 standard. The TR and living quarters are designed to be separated from other areas by A-60 rated divisions.

2.5.2.3. Active Fire Protection

Active fire protection will consist of fixed and portable systems applying water, foam, water mist, powder and gaseous extinguishing media. Fixed firefighting systems shall be installed in areas representing a major fire risk. For Machinery spaces Category A (engine power greater than 750 kW), a fixed total flooding system shall be installed.

The firewater system shall be designed to supply firewater to areas affected by the largest credible fire scenario. The 100% firewater demand case shall be determined based on the following supply philosophy:

- Deluge coverage for the module on fire, and
- Simultaneous release of deluge in adjacent modules not segregated by a physical barrier or adequate distance (including diagonal modules), and
- Manual firefighting demand from two (2) fire hoses (taken as 2 × 25 m^3/h).

The firewater demand for all areas shall be assessed, and the performance of the firewater system shall be documented by hydraulic calculations. The dimensional firewater demand shall be documented in the Firewater and Foam Demand Calculation and approved by the Certifying Authority.

Firewater shall be provided from a dedicated firewater ring main of material suitable for the intended duty and for all conditions, including subzero temperatures. The firewater main shall be designed to supply the required volume of firewater with any one section of it inoperative.

The FPSO shall have a central low expansion foam system. The foam system shall provide foam protection to the upper deck and to other areas where pool fires can be predicted. A foam concentrate ring main shall be provided, running adjacent to the firewater ring main. Foam distribution systems shall be designed, installed & maintained in accordance with NFPA 11 and NFPA 16.

A firewater pump set shall consist of a diesel engine driven pump. Lift pumps to be installed when required. Firewater pump configuration is 4 × 50% capacity (two in Aft Firewater Pump Room on engine room floor and two in Forward Firewater Pump Room underneath forecastle deck). The number of pumps to be installed on the FPSO is influenced by the 100 % design firewater demand, and the capacity and reliability of each pump set. The firewater pump system shall maintain a supply capacity of 100% of the anticipated firewater demand under all operational conditions. Firewater pumps shall be certified in accordance with NFPA 20.

The following areas and equipment shall be protected by equipment- and/or area deluge protection as appropriate:

- Turret,
- Hull Cargo Deck,
- Process modules and skids,
- Process equipment on upper module decks (equipment deluge protection only),
- Process piperack (hydrocarbon piping),
- Areas for handling of flammable chemicals,
- Helifuel skids,
- Oxygen and acetylene cylinders

For modules and areas where pool fires may be expected, the deluge system shall be capable of deploying a mixture of water and foam. Deluge systems shall be designed in accordance with NFPA 15

The firewater demand for topside modules is based upon providing enough water to the module in which the fire is detected as well as the surrounding modules, considering any rated divisions. The central pipe rack is provided with deluge in several layers. The firewater demand for the largest credible fire scenario has been estimated in order to size fire water pumps.

2.5.2.4. Fire and Gas Detection

All areas of the facility will be monitored by automatic fire and gas detection systems appropriate to the fire or explosion risk. The systems will provide warnings to control points and, in situations hazardous to personnel, automatically initiate visual and audible alarms. In specific cases, confirmed fire or gas detection will also automatically initiate executive actions, to control and mitigate the consequences of a fire or gas release.

Fire detectors will be installed on the offshore facilities to continuously monitor spaces where the potential for fire exists. Fires will be detected and confirmed by smoke detection, flame detection or heat detection, depending on the nature of the area and the risk. Detectors configuration will be a "voted" system for executive automated action.

The fire detection system will automatically alert all personnel in the event of a fire and relay information about the location and extent of the fire to the designated control point. In designated cases, the fire detection system will initiate executive actions such as:

- Shutdown of process, utility and non-critical electrical systems
- Activation of protection and mitigation systems, such as blowdown and firewater deluge.

Flammable gas detectors will be installed in locations such as: hydrocarbon process and storage areas, ventilation air intakes, barriers between process areas and potential ignition sources in utility areas, gas turbine enclosures, air compressor intakes, gas turbine combustion air intakes and inlets to accommodation.

The flammable gas detection system will indicate in the Control Rooms the location of the detector and the detected concentration of gas. Flammable gas detection warns of a build-up of an explosive atmosphere and, therefore, confirmed detection will initiate executive actions involving process shutdown, blowdown and removal of ignition sources (electrical isolation).

The fire and gas detection systems will be provided with adequate redundancy and protection to ensure, as far as is reasonably practicable, their availability in the event of a major accident.

2.5.2.5. Emergency Shutdown

Emergency shutdown systems will be provided to maintain safe operating conditions and will have defined shutdown levels.

The principal functions of the emergency shutdown (ESD) system will be:

- The protection of personnel and overall safety of the installation
- The minimization of environmental pollution.

The ESD system will be designed to comply with the relevant statutory requirements, codes and standards, and to, as far as reasonably practicable, remain operational in an emergency. It will also be designed so that it can be initiated both manually and automatically.

2.5.2.6. Blowdown and Flare System

The flare tower is located at the forward end of the FPSO. Blowdown of process equipment will be included for pressurised hydrocarbon systems, to dispose of the gaseous inventory under emergency conditions to reduce the duration of an event and the intensity of the fire. The system is expected to blowdown at rates over and above API 521 [8], with a specified minimum of 6.9 barg or half the design pressure, whichever is the lower, within 15 minutes. The preliminary rates for specific systems that have been assessed at this stage of the design and used for the assessment of hydrocarbon consequences and risk levels are shown next. All other systems are assumed to operate as per API 521.

Table 2-2 Current Blowdown Criteria

Blowdown Segment	Blowdown Duration (mins)	Notes
Inlet Separator	4	From 19.92 barg to 6.9 barg
MP Separator	15	From 4.5 barg to 2.25 barg
LP Separator	15	From 2.8 barg to 1.4 barg
Test Separator	4	From 15.88 barg to 6.9 barg
LP Compressor 1st stage	14.5	From 3 barg to 1.5 Barg.
LP Compressor 2nd stage	14.5	From 6.3 barg to 3.15 Barg.
MP Compressor	3.9	From 19.38 barg to 6.9 barg
HP Compressor 1st stage	14.6	From 93.5 barg to 6.9 barg
HP Compressor 2nd stage	14.8	From 146.6 barg to 6.9 barg
TEG Contactor	7	From 52.43 barg to 6.9 barg
Fuel Gas Piping	7	From 52.43 barg to 6.9 barg (as TEG)
Gas Injection Pipework	14.8	From 146.6 barg to 6.9 barg (as 2nd stage HP)

The flare will be sized based on more detailed gas dispersion and thermal radiation assessments that will be completed as the design progresses.

2.5.2.7. Classification of Hazardous Areas

Due to the nature of the hydrocarbon processing to be carried out on the offshore installation, the potential exists for accidental release of hydrocarbons. Hazardous areas of the installation where hydrocarbon gas or vapours may be present will be classified in accordance with internationally recognised standards.

In classified hazardous areas, various measures will be taken to minimize the occurrence of hazards to personnel, including:

- Assurance of adequate natural ventilation or the provision of ventilation to prevent the accumulation of flammable gases or vapours.
- The control of potential ignition points, by selection of appropriate equipment.

Electrical equipment for use in hazardous areas will be selected in compliance with internationally recognised hazardous area equipment standards.

2.5.2.8. Ventilation of Hazardous Areas

Hazardous areas will be ventilated to dilute gas concentration to a certain degree depending of the wind conditions and leak rate, to reduce the likelihood of ignition, and thereby minimize the risk from fire and explosion. In hazardous areas where natural ventilation is not adequate, mechanically-assisted ventilation will be provided.

Natural ventilation studies have been carried out for the topsides, hull and turret of the FPSO to ensure that ventilation in these areas is a minimum of 12 air changes per hour, 95% of the time.

2.5.2.9. EIT /LER Rooms

The Topsides Electrical/Instrument/Telecomms (EIT) "E-House" (M40) is located on the Starboard side, aft of the Water Injection Modules and Laydown area. It has gas detection on the HVAC inlets, that will shut the ventilation to the building in the event of gas being detected at the inlet. Equipment within the room will also be suitably rated and isolated (reasonably gas tight double door entrances and closing of HVAC dampers) if it is required to stay energized after gas detection.

The geostationary Turret module will have a separate Turret Local Equipment Room (TLER) that is located at process deck level in the naturally ventilated upper turret but mechanically ventilated from a source outside the turret.

Equipment housed in the EIT / LER rooms is as follows:

- Power transformers
- Distribution boards (including main, emergency, UPS for escape route lighting)
- Remote Input/Output (RIO)
- Other field cabinets.

2.5.2.10. Ventilation of Non-Hazardous Areas

HVAC applications for non-hazardous areas will include pressurization systems to prevent the migration of gases and smoke from hazardous areas to closed non-hazardous areas. F&G dampers shall close as required upon local detection of gas or smoke. The systems will include, as necessary,

- Fire dampers in ventilation ducts.
- Fire dampers in all main fresh air intakes.
- Fire dampers in penetrations to fire-rated structures and buildings.
- Location of air intakes away from potential sources of hazardous gases or vapours.
- Gas and smoke detectors protecting air intakes, all of which will generate an alarm in the control room and close intake dampers to prevent the ingress of hazardous gases or vapours.

Air handling systems will have automatic detection of system failure, with appropriate alarms to the control room.

2.5.2.11. Temporary Refuge

The prime function of the Temporary Refuge (TR) is to protect all personnel for a predetermined time during an emergency. The TR will be designed to protect and shelter personnel from accidental events for sufficient time (up to 120 minutes) to organize and effect a safe evacuation.

The TR will contain facilities that allow the incident to be investigated, emergency response procedures to be initiated and pre-evacuation planning to be undertaken.

It will therefore provide:

- Shelter for personnel and control points, particularly from fire, smoke, unburned and toxic gases, explosion and thermal radiation.
- Sufficient control facilities to facilitate the evaluation of an incident and, where possible, allow personnel to bring it under control.
- Sufficient means of communication between individuals at the installation and those at other installations, on vessels, aircraft and on shore.

The TR will be designed with overpressure ventilation (50 Pa) to prevent ingress of smoke and gas, and the TR bulkhead facing the topside area, including 3 meters along the side, will be insulated to H-60 standard as minimum.

2.5.2.12. Escape, Evacuation and Rescue (EER)

There are several escape routes along the process deck and cargo deck leading from the fore ship to the accommodation area aft.

- Central escape route on process deck
- Escape route along starboard and port side of the vessel on process deck and cargo deck. On both the port and starboard sides of the FPSO process deck, a protected escape route type design will provide personnel with shelter from events originating in the turret or process areas of the FPSO. There are several stair towers within the escape route shelters connecting the topside and cargo deck levels.

There are three categories of systems for evacuation from the FPSO:

- Primary evacuation system / pre-cautionary down-staffing: helicopter or gangway to support vessel.
- Secondary evacuation system: lifeboats, known as Totally Enclosed Motor Propelled Survival Craft (TEMPSC). This system shall enable quick and controlled evacuation, independent of external assistance when circumstances render the primary method of evacuation unavailable.
- Tertiary evacuation system: Marine Evacuation Systems (MES) comprising escape chutes with life rafts. This system is intended to be used only in circumstances where evacuation by primary and secondary methods is not possible and will often rely considerably on the individual's own actions.

The current TEMPSC arrangements are for two 60-person freefall TEMPSC at the stern of the FPSO and one 60-person davit launched TEMPSC each on the port and the starboard side of the accommodation. The MES are located near the stern and the bow, on both port and starboard sides.

For external threats from unmanageable icebergs the intention is to disconnect the turret buoy and sail away.

There is also intention to install a landing platform for a "walk to work" (W2W) motion-compensated gangway near the accommodation area, The position of the W2W landing is not been finalised, however the preliminary location is on the port side of the Poop Deck. The W2W gangway could be used in suitable situations to transfer non-essential personnel i.e. those personnel not involved in Emergency Response, from the FPSO to the support vessel. In addition, man-riding cranes are available, which can be used to aid down-staffing activities.

2.5.2.13. Telecommunication and Alarms

To operate an FPSO at the Bay du Nord field, there is a need to establish and maintain various highly reliable and cost-effective systems for both:

1. Ship-to-Shore communications, and
2. Ship-to-Ship communications.

The primary Ship-to-Shore communications will be between the Bay du Nord FPSO and an Onshore Support Centre (OSC), which shall be located in Newfoundland. The primary Ship-to-Shore Communication system included in the project's base case is a Satellite-based system.

The primary Ship-to-Ship communications will be between the FPSO and any support vessels, such as standby vessels and tankers; or other installations such as Mobile Offshore Drilling Units (MODUs) at the Bay du Nord field.

A disconnectable FPSO for the Newfoundland offshore area must operate as an ocean-going vessel capable of self-propulsion and navigation, governed by the International Marine Organization (IMO), Safety of Life at Sea (SOLAS) and, if registered in Canada, the regulations specified in the federal law - Canada Shipping Act, 2001 (2001, c. 26). Any time the FPSO is off-station (no longer moored to the sea bottom), it is classified as a ship and therefore must comply with the IMO, SOLAS (GMDSS) and the Canadian Shipping Act regulations for mandatory and minimum on-board communications capabilities. When the FPSO has to disconnect the turret, for any reason, it functions as an ocean-going vessel, therefore, the FPSO must have functioning regulated communications systems (based on the size of the vessel and the oceanic location in which it sails) at all times for distress and hailing monitoring while sailing.

A Public Address and General Alarm (PAGA) system will provide audible speech for the broadcast of routine or emergency messages. In an emergency, the PAGA system will be used to broadcast one of a selection of alarm tones to indicate the nature of the emergency, and to issue instructions to all areas where personnel may be located. The PAGA system shall comply with the requirements of the LSA Code. Alarm signals will be attenuated during the transmission of emergency speech messages.

Two-way communication shall be provided between CCR, the Secondary command centre, muster stations and embarkation stations. The two-way communication system shall be provided for transmission of alarm, instructions and information between those who may require them.

All internal communication equipment, MACs and all internal signals that are required in an emergency shall be available for a period of 18 hours.

Alarms will be generated by the fire and gas system and by manual call points. Fire and gas alarms will be audible and will have a distinct tone. If noise in an area prevents the audible alarm being heard, adequate visible means of alarm shall be provided. Additionally, upon detection of fire or gas, an audible and visual signal will automatically be activated on the fire and gas indicator panel in the CCR along with an indication of the location and extent of the fire or gas.

2.5.2.14. Power Systems

The power system will be reliable and at the same time be as simple and robust as possible. The total need for main, essential and emergency power will be optimized based on electrical load lists.

The electrical system design will be in accordance with class and regulatory requirements.

2.5.2.14.1. Main/Essential Power Supply

The main power generation system (System 80) generates the electric power required to keep the FPSO operating. Main Power Generation shall consist of three gas turbine generator (GTG) units. During normal operation two generators are sufficient to cover all electrical loads, including process, utilities, marine and accommodation.

The generators can be powered by dual fuel, where fuel gas is used for normal operation with the possibility to automatically switch over and utilize diesel fuel when required. During start-up, when fuel gas is unavailable, the GTG's will run on liquid fuel.

Furthermore, there will be two (2) diesel driven power generator sets located in the engine room. These generator sets will be used when the FPSO is disconnected and also as surplus when required.

2.5.2.14.2. Emergency Power Supply

The emergency electrical power supply shall be provided by a diesel generator set of suitable rating. The diesel engine and fuel-supply shall be designed for 18 hours continued operation when all consumers defined by regulations and Class as emergency consumers are connected.

The FPSO will be equipped with Uninterruptible Power Supply (UPS) systems, which shall ensure power to safety critical equipment. UPS sets shall provide emergency and essential consumers like safety systems, control systems, radio and communication systems and escape lights.

2.5.3. Health and Working Environment

Health and working environment considerations in the design of the topsides, hull and turret is based on regulatory requirements and Class and internationally recognized standards, meeting company requirements. To identify potential hazards, evaluate risk and propose future actions for redesign or risk reducing measures, Working Environment Health Risk Assessments (WEHRA) have been performed as a part of the topside and the hull/turret layout studies. The focus during this stage has been to optimise the design to meet area noise requirements, ensure access for maintenance and inspection and reduce the need for winterization measures. Referring to the WEHRA results, the following areas will require close attention in subsequent phases of the design, which would be expected for a FPSO operating in a harsh environment:

- Noise
- Winterization / weather protection
- Access and material handling
- Psychosocial aspects of remote location
- Medical emergency preparedness and response in remote locations.

2.5.4. Heat Generation

Heat generation for process and utility heat is from waste heat recovery units on the three gas driven turbines. There is no fired boiler in the current concept.

2.5.5. Fiscal metering

Fiscal metering is based on an ultrasonic master and duty meter arrangement without a prover loop. This drastically reduces the space and maintenance demand for the metering skid.

The concept of an ultrasonic master meter has been proven on the Cenovus operated SeaRose FPSO, offshore Newfoundland, as well as the Brage platform in the North Sea.

2.5.6. Process utility systems

Utility systems and power generation for topside will mainly be located in topsides utility modules, with emergency generation located in the hull.

2.5.7. Layout and Piping

The overall layout of the FPSO has the offloading and the LQ facilities at the aft end of the vessel with the main laydown areas in front of the LQ (M41) and between the E-House and Water Injection (M42). The turret and the flare tower are located at the forward end of the FPSO. The topside area consists of a utility area, future area, and a process area.

The area allocated to the topside facilities measures approximately 170 x 52 meters.

The process deck (Level 1) is elevated 5.5 meters above the centre line cargo deck and is designed to remain intact in the event of a hydrocarbon fire. The Level 2 process deck is located 10 meters above the process deck, and Level 3 process deck is 6 m above Level 2 on the Port Processing modules and 8 m above Level 2 on the Starboard Processing modules.

The topside has been arranged with a series of modules and pancakes located on either side of a central pipe rack. This arrangement allows for a flexible construction program with the module sizes designed to be comfortably within the lifting capacity of the proposed installation cranes. Larger modules may be arranged to minimize hook-up, if site cranes have sufficient capacity. The main mechanical handling transit route is located at the topside facilities centrally under the pipe rack.

2.5.8. Material Handling

The governing principle for material handling for equipment maintenance of the topside modules is that normal maintenance shall not require the use of the offshore cranes over process modules. Forklift transport along the main transport route is the main means of transporting equipment from modules to workshops or to laydown area for further lifting to shore. Local lifting equipment is provided to remove valves, PSVs or filter cartridges out of the line onto trolleys for transport to goods lift or down to the main transport route.

If major pieces of equipment need to be removed, the offshore cranes will be used, as the process will be shut down and depressurized in such cases. In these circumstances lifting over depressurized process equipment will be allowed.

Containers for galley and laundry will be handled by the offshore crane located at Port side. The material handling between galley laydown area and galley will be carried out by deck trolly.

Similarly tote tanks for chemicals are lifted directly onto tote tank storage above the chemical injection package (level 3).

The turret compartment is provided with hatches providing a vertical lifting corridor. Items will be moved on the relevant decks to this shaft and lifted out of the turret onto the laydown area provided at the port side of the turret on the process deck.

2.6. Subsea Production System

The Subsea Production System (SPS) is defined as the following equipment:

- wellhead
- Xmas tree (XMT)
- flow control module (FCM)
- manifold
- protection structure
- subsea control system
- umbilical containing control and chemical lines

- topside located subsea control system equipment
- production / gas lift / injection flowlines and risers.

Table 2-3 Field Layout

Template	Configuration
BdN North	2 off production, 3 off WAG, 1 spare
BdN South	3 off production, 2 off WAG, 1 spare
Cambriol	3 off production, 3 off WI

The templates are tied into the riser bases with rigid flowlines with spools. The connection between the Bay du Nord North and South templates are by use of either flexible lines (for water injection and production lines) or rigid pipeline (for Gas Injection).

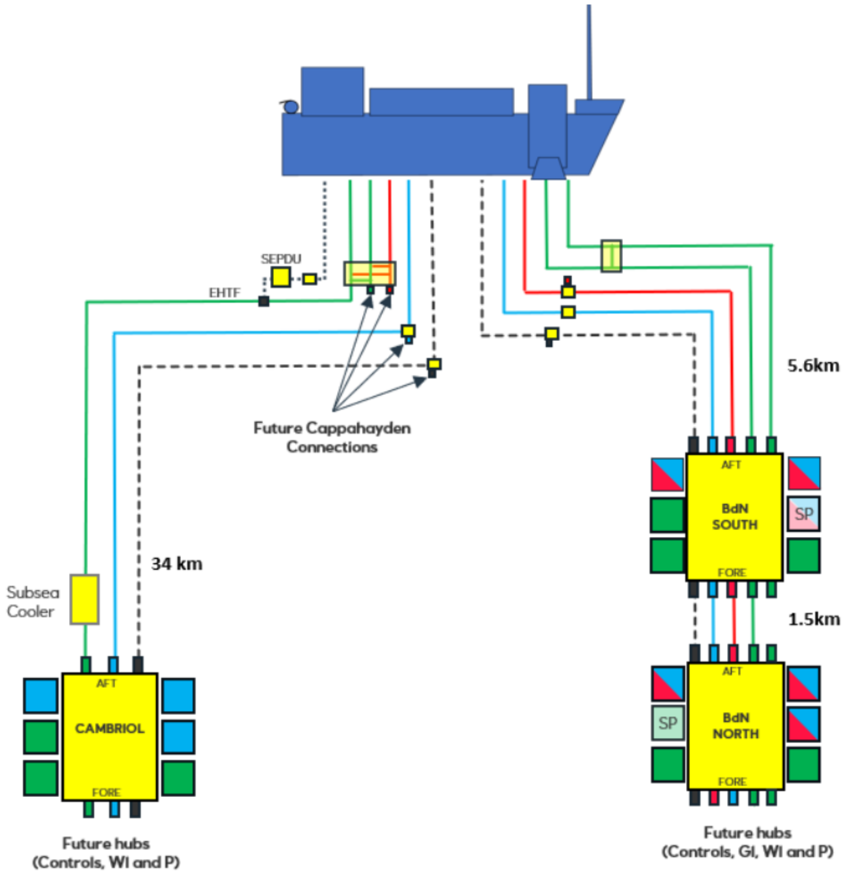


Figure 2-6 Subsea Schematic

2.6.1. Well Protection Structure

Each well bay area is protected from dropped objects and potential trawling impacts by a tubular frame, "Toast Rack". The "Toast Rack" system also protects the neighbouring wells from workover / installation activities. The system also gives free access to all activities at the well.

2.6.2. Sea line Protection Structures

The main function of the Sea Line Protection Structures is to ensure protection of flowlines and umbilicals outside the Template against dropped objects and fishing activities. The SPS will be designed for ROV based tie-in system for flowlines and umbilical. Inspection of the SPS will also be by ROV. The SPS has an open structure and can be inspected from outside the protection frame.

2.6.3. Subsea Manifolds

The Manifold module consist of following main components:

- Structural steel bottom frame
- Guiding system, lock down mechanism and supports to the Template structure
- Top structure and secondary steel for support of piping, cable trays, etc.
- Panels for small bore valves located on the manifold side
- Lifting attachment.

The manifold structure shall support and protect the piping, valves and control system in all phases.

The Manifold roof shall protect all internal manifold equipment against dropped objects and fishing gear as an integrated protection structure. The roof shall also act as a platform for ROV during manifold valve operations and other relevant tasks.

3. Inputs and Assumptions

Wherever possible, the inputs to the risk assessment have been based on information supplied by Equinor and have been referenced as such. However, due to the early stage of the design, as well as the nature of the quantitative risk assessment, some of the inputs have been assumed based on industry data or previous experience, and these assumptions are discussed in the following sections.

A number of the industry standard data sources have also been reviewed and summarized in a series of methodology documents by Kent. The CSA is based upon the most up to date industry standard data sources and where the data source is different to that quoted by NORSOK or Equinor, then a brief description of this is given at the start of the relevant section.

3.1. Processing Conditions (Technical)

The process conditions have been based on the process conditions associated with the maximum oil producing case [9] along with associated P&IDs (for the turret) and PFDs (for topsides) as available [10]. A summary of process conditions for each failure case can be found in Table 4-1.

3.2. Protective Systems Reliability (Technical)

Following a fire or explosion event the performance of critical protective systems can help reduce the size and severity of a major accident event. The benefit of these systems is modelled by means of event tree analysis. The systems with potential to reduce the volume of hydrocarbon released from an accidental breach or to mitigate the effects of the release are:

- Fire & Gas Detection
- Isolation / Emergency Shut Down (ESD) / Blowdown
- TR HVAC
- Active Fire Protection.

For each hydrocarbon event an assessment is made of the ability of these systems to mitigate the consequences of the fire or explosion event. If failure of the protective system increases the probability of escalation or the risk of fatalities, then the reliability of the system to perform its required function is a key input to the analysis.

3.2.1. Fire & Gas Detection

Typically fire and gas detection systems operate using a voting arrangement to reduce the potential for spurious trips. For example, 2oo3 voting in any area is commonly used. Dual redundant fire and gas control panels are also a common arrangement to improve reliability.

The system can fail in essentially 2 ways:

1. Detectors sense the fire or gas cloud, but component failure causes system failure.
2. Detectors fail to detect the fire or gas cloud.

In both causes there is still the opportunity that the event is detected by personnel who could act. This can be an important factor in estimating probability of failure on demand for QRA purposes.

The Probability of Failure on Demand (PFD) for the fire and gas detection function is assumed to be 1%. Based on the analysis of multiple performance standards from offshore installations throughout the world, Kent considers that the probability of failure on demand of 2% is appropriate to be used as a generic value for availability. It is suggested that 1% is used in the base case but that the sensitivity of the risks to the F&G

detection system will be reviewed. It is assumed that, where the fire & gas system fails to automatically initiate the ESD and blowdown system, then manual intervention will be required. This could be from the Control Room (where a release is indicated but automatic ESD has failed) or from an ESD push button local to the release, where the operator can see / hear the release occurring. There is assumed to be a 10% chance that the operator fails to initiate the system correctly [11].

Fire and gas detectors will be distributed across the modules in an effective manner to increase the likelihood of releases being detected. Given the open nature of the majority of the FPSO Topsides, it is reasonable to assume that releases may not be detected due to the gas or smoke being produced if there is wind. The overall F&G detection reliability will also include an effectiveness to detect the release as well as a reliability to perform on demand. In this case, it is expected that a fire and gas detection system will detect 85% of small releases.

Medium and large releases will take up larger module volumes and therefore are more likely to be detected. Values of 95% and 100% are assumed for the effectiveness of the fire and gas system to detect medium and large releases, respectively.

3.2.2. Isolation/Blowdown System

Following a fire or explosion event the performance of critical protective systems can help reduce the size and severity of a major accident event. The benefit of these systems is modelled by means of event tree analysis. The systems with potential to reduce the volume of hydrocarbon released from an accidental breach are:

- Isolation / Emergency Shut Down (ESD)
- Blowdown.

For each hydrocarbon event an assessment is made of the ability of these systems to mitigate the consequences of the fire or explosion event. If failure of the protective system increases the probability of escalation or the risk of fatalities, then the reliability of the system to perform its required function is a key input to the analysis.

The Probability of Failure on Demand (PFD) for an ESD and EDP (Emergency Depressurisation) valve is assumed to be 1.5%. The value is applied to the ESD valves sectioning hydrocarbon inventories on the topsides as well as riser ESDVs.

Based on the analysis of multiple performance standards from offshore installations throughout the world Kent considers that probability of failure on demand of 3% for ESD valves and 1% for EDP valves is appropriate to be used as a generic value for ESD / BD valve availability, hence the proposed value of 1.5% is considered appropriate. A sensitivity with the failure to close on demand probability increased to 3% will also be reviewed in Section 7.3.

The base case design is that SSIVs are not installed on the risers. Where Subsea Isolation Valves (SSIVs) are assumed to be installed, which has been considered as a sensitivity case only at this stage in the design (see section 7.3, then a failure to close on demand probability of 3% is assumed, this is based on the findings from other QRA studies that have shown that SSIVs are typically modelled with a lower reliability figure than the topside valves, based on the environment, testing and maintenance experience.

3.2.3. HVAC

It is assumed that the HVAC for the TR will comprise fans with automatic dampers controlled by redundant voting of smoke and gas detectors at the inlets. Current practice on other harsh environment installation, like those in the North Sea, is to design systems such that the availability of isolation on demand of the HVAC intakes and exhausts will be greater than 99% [12]. In practice this level of availability is difficult to reach and requires a regular, properly implemented, TR HVAC damper testing programme. Considering this and the historic values for TR HVAC damper availability used in performance standards from offshore installations throughout the world, Kent considers that probability of failure on demand of **2%** is more appropriate to be used for the availability of this system. There is currently no PFD quoted in GL0114 for HVAC systems (a failure fraction of 2% for dampers failing to close within the prescribed time is given). Thus, if gas is present at the HVAC inlets in a flammable concentration, there is considered to be a 2% chance that the system will continue to operate and draw this gas into the TR.

3.2.4. Firewater

The firewater system is taken to include firewater pumps through to the water spray devices. Based on the analysis of multiple performance standards from offshore installations throughout the world Kent considers that a probability of failure on demand of **4%** is appropriate to be used as a generic value of firewater / deluge system availability. There is currently no PFD quoted in the Safety Critical Failures document for the firewater system.

The Aft Machinery Space is protected by a high expansion foam system in designated spaces with diesel fuel fire hazard, with two 100% supply pumps and a back-up supply arrangement. Failure of both pumps and the back-up would therefore be required to prevent the system from functioning and whilst there are other components involved in the system that could fail to prevent delivery of water, it is assumed that the overall failure of the system will be dominated by the pumps.

The foam storage capacity shall ensure at least 15 minutes of foam generation for the largest liquid hydrocarbon module (or turret) or 20 minutes of foam generation for main deck, whichever is the greatest.

Based on experience of similar systems in other FPSO designs or operating facilities, which is expected to include a regular i.e. weekly function test of the pumps, an overall availability of the system of 99% is assumed.

Deluge may have an effect in mitigation against jet fires [13] however there is a degree of uncertainty [14] and therefore no credit is taken for deluge in the mitigation of jet fire releases. For pool fires, the deluge effectiveness is assumed based on the fire size and is shown in Table 3-1 and discussed below.

As discussed in [14], activation of deluge can reduce the fire coverage of a pool by 90% in 10 minutes. Areas shielded from deluge but exposed to the fire will receive limited protection from the heat attenuation of the deluge droplets falling between the location of the fire and the location of the equipment. Therefore, the following rulesets are recommended to be applied to deluge effectiveness. Which includes the water mist system in the aft machinery space:

- Small fires (typically less than 3 m diameter) – small (potentially running) pool fires are likely to be controlled by deluge even if the deluge water does not fall onto the fire itself as the volume of water falling onto the deck will act to mitigate against the pool and protect equipment against the effects of a pool fire. There is a low probability that the pool fire could still lead to escalation if the fire was inaccessible to the deluge water. It is therefore assumed that deluge is 95% effective in controlling small fires.
- Medium fires (typically between 3 m and 10 m diameter) – the size of medium pool fires is likely to be reduced to an extent where no further escalation can occur where deluge can reach the pool fire. However, equipment may shield the pool fire from the deluge water in some cases. It is therefore assumed that deluge is 80% effective in controlling medium fires.
- Large fires (typically greater than 10m diameter up to entire module area) – due to the large diameter of these pool fires and the coverage of equipment in modules, even after 10 minutes large pool fires could still have the potential to cause escalation although this will be greatly reduced. In addition, equipment may shield the pool fire from the deluge water in some cases. It is therefore assumed that deluge is 50% effective in controlling large fires.

For the purposes of this CSA, escalation is defined as the fire/explosion having effect on another hydrocarbon-containing area and which could create an unacceptable fire scenario such as causing impairment of escape routes or an uncontrollable fire which eventually leads to the effective loss of the FPSO.

Firefighting foams will be introduced into deluge systems to provide further protection against pool fires. It is expected that the foam system will be able to extinguish all pool fires that may occur in the protected area. Therefore, for the purposes of QRA it has been conservatively assumed that if Foam is applied to a module through the deluge system its effectiveness in preventing escalation from a pool fire is 95% for all pool fire sizes.

Note in cases where the foam is only specified, for say 30 minutes' worth of application, after 30 minutes the foam will be exhausted while the deluge continues to flow. If the fire lasts longer than 30 minutes, then the potential for escalation will be controlled by the deluge and the value for deluge effectiveness should be applied for this type of event.

Table 3-1 Deluge Effectiveness

Initiating Event Fire Type	Percent Effectiveness of Water Only Deluge	Percent Effectiveness of AFF Foam Deluge
Jet fires	-	-
Pool Fire - small	95	95
Pool Fire - medium	80	95
Pool Fire - large	50	95

Deluge may also have a benefit in suppressing explosion overpressures, as described in Annex F of the Z-013 [36]. For small gas clouds, deluge may have the effect of diluting the gas cloud to generate a lower overpressure. For larger gas clouds, deluge may increase the degree of mixing in the cloud resulting in higher overpressures.

Given the Bay du Nord is currently at pre-FEED phase, it is proposed not to model the impact of deluge on explosion overpressures for this phase of the design. This is considered conservative on the basis of the guidance given in Z-013 [36], however will also take account of the fact that explosion overpressures can be underpredicted in earlier phases of design, as the level of complexity and congestion in modules increases in later design.

3.2.5. Riser Buoy Quick-Connect / Dis-Connect (QCDC) System

The disconnectable riser buoy is an important element of the Bay du Nord Ice Management Plan (IMP), where the final step is the ability to shut down, flush and isolate the risers before disconnecting the riser buoy and sailing away from an impending iceberg collision. The availability of the disconnection system to activate, either in a planned or emergency disconnect case, will be high.

For the purposes of the CSA, the availability of the system to operate on demand has been estimated based on the most conservative failure data from a number of sources, as described in [15].

3.2.6. Drainage

The open drain system, in combination with bunded areas surrounded by coaming, is designed for containment of major accidental spills and shall mitigate against the escalation of an accident in case of a large flammable liquid spill. Separate drain systems shall be provided for topside areas classified as hazardous and non-hazardous areas. The hazardous and non-hazardous drain systems shall be fully segregated.

Collected liquids will be drained by gravity or pumped to the open hazardous drain collection tank. In case of deluge release, the excess firewater will be routed directly overboard.

Turret compartment shall have drain pumps to drain out any water leaking into the compartment. The water is collected in a drain well and pumped out to the hazardous open drain system.

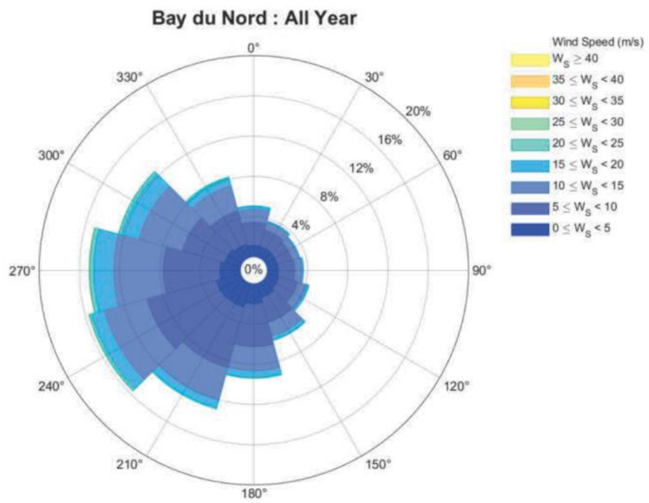
3.3. Consequence Analysis (Technical)

3.3.1. Environmental Data

Climate change may lead to changes in metocean conditions compared to the present basis for the structural design and assessment. An allowance for increases in extreme significant wave height, extreme wind speeds and sea level has been implemented, in line with NORSOK Standard N-003:2017.

3.3.1.1. Wind

The Metocean document [16] provides the following wind velocity distribution for the location of the FPSO, from 1954. This is detailed next with 0 degrees taken to represent true North and the wind blowing from that direction. These are absolute conditions, whereas relative heading with respect to wind is covered in section 3.3.3.



Wind [m/s]	Wind direction												Omni
	0°	**30°**	**60°**	**90°**	**120°**	**150°**	**180°**	**210°**	**240°**	**270°**	**300°**	**330°**	
< 2	0.17	0.18	0.19	0.21	0.21	0.26	0.31	0.37	0.34	0.26	0.24	0.19	**2.93**
< 4	0.73	0.73	0.72	0.75	0.82	0.98	1.27	1.53	1.53	1.27	1.02	0.84	**12.18**
< 6	1.59	1.47	1.39	1.45	1.64	2.01	2.81	3.59	3.80	3.00	2.35	1.93	**27.01**
< 8	2.56	2.18	2.01	2.14	2.48	3.07	4.54	6.17	6.74	5.25	4.05	3.31	**44.49**
< 10	3.42	2.78	2.57	2.70	3.16	3.96	6.24	8.66	9.64	7.65	6.00	4.74	**61.53**
< 12	4.07	3.19	2.94	3.11	3.69	4.73	7.49	10.48	11.90	9.84	7.92	6.02	**75.39**
< 14	4.58	3.47	3.19	3.35	4.03	5.26	8.34	11.60	13.46	11.76	9.71	6.99	**85.73**
< 16	4.81	3.60	3.30	3.47	4.18	5.57	8.87	12.25	14.43	13.21	11.06	7.61	**92.35**
< 18	4.93	3.67	3.36	3.55	4.28	5.75	9.17	12.62	15.02	14.08	11.86	7.95	**96.23**
< 20	5.01	3.71	3.39	3.58	4.33	5.85	9.31	12.82	15.33	14.57	12.27	8.13	**98.29**
< 22	5.05	3.72	3.39	3.60	4.35	5.88	9.38	12.90	15.49	14.81	12.45	8.22	**99.24**
< 24	5.06	3.73	3.40	3.60	4.36	5.89	9.40	12.93	15.58	14.92	12.54	8.26	**99.67**
< 26	5.07	3.73	3.40	3.60	4.36	5.90	9.41	12.94	15.62	14.99	12.58	8.27	**99.87**
< 28	5.07	3.73	3.40			5.90	9.41	12.95	15.64	15.02	12.60	8.28	**99.95**
< 30	5.07	3.73				5.90	9.41	12.95	15.64	15.04	12.60	8.28	**99.98**
< 32								12.95	15.64	15.04	12.60	8.28	**99.99**
< 34								12.95	15.65	15.04	12.60	8.28	**100.00**
< 36								12.95		15.04	12.60		**100.00**
< 38								12.95					**100.00**
Total	**5.07**	**3.73**	**3.40**	**3.60**	**4.36**	**5.90**	**9.41**	**12.95**	**15.65**	**15.04**	**12.60**	**8.28**	**100.00**
Mean	**8.4**	**7.6**	**7.4**	**7.5**	**7.8**	**8.3**	**8.6**	**8.6**	**9.2**	**10.3**	**10.5**	**9.5**	**9.1**
Maximum	**29.8**	**28.6**	**26.8**	**24.2**	**24.7**	**30.0**	**29.0**	**36.8**	**33.7**	**35.6**	**34.1**	**32.4**	**36.8**

Figure 3-1 Annual Directional Non-Exceedance (%) of 1-hour mean Wind Speed

A wind speed exceedance chart is plotted below, and from this the following average, low and high wind speeds are calculated as follows:

- Mean wind (50% exceedance) - 8.6 m/s
- Low wind speed (85% exceedance) - 4.2 m/s
- High wind speed (15% exceedance) - 13.6 m/s

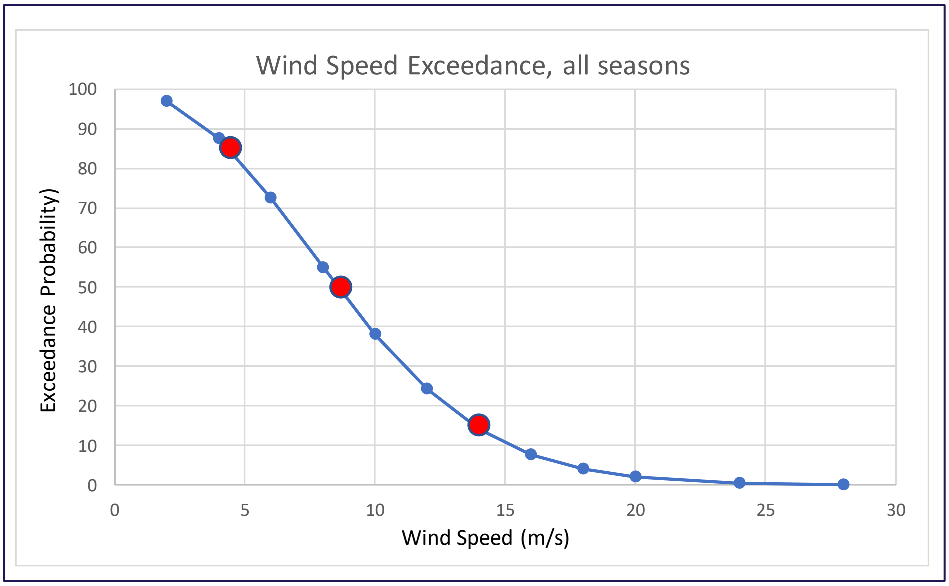


Figure 3-2 Overall Wind Speed Exceedance

These values will be used as representative for wind speeds in the Bay du Nord field when modelling gas or smoke dispersion.

3.3.1.2. Pasquill Stability Class

Neutral stability (class D) boundary layers are used for all wind speeds in this study, since stable (class F) boundary layers are not expected to be credible for the offshore location.

In addition, whilst it is noted that stably stratified conditions may result in reduced dilution rates for high level releases over long distances (due to dampened atmospheric turbulence levels), interest is focussed here on short-distance dispersion either inside or just above the process modules, and so the stability level is not expected to have a significant impact on the consequence modelling results.

3.3.1.3. Temperatures

The sea temperature can be used when considering rescue of personnel in the unlikely event that they enter the sea directly following a MAE on the FPSO. The typical temperature range [16] at 0 m depth is around 2.8-12.6^{o}C; 5^{o}C is chosen as representative.

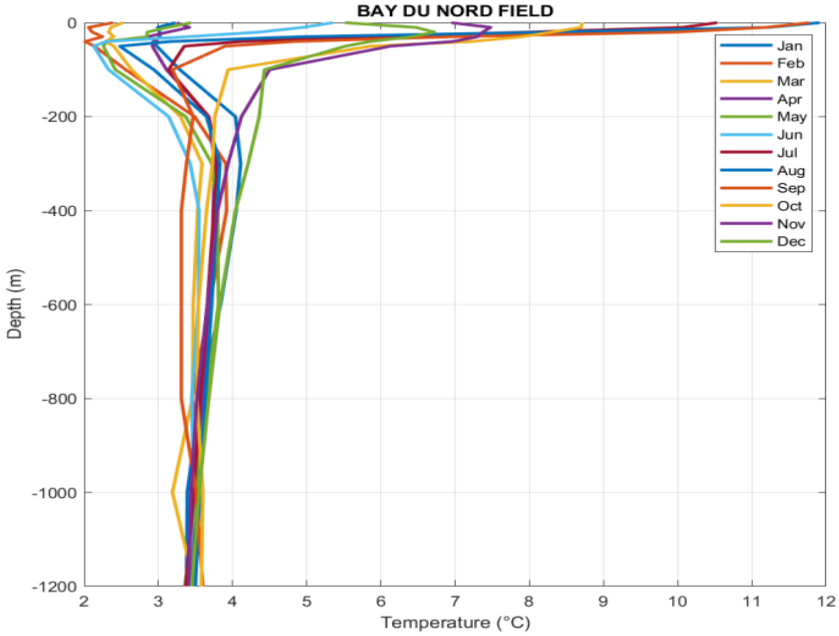


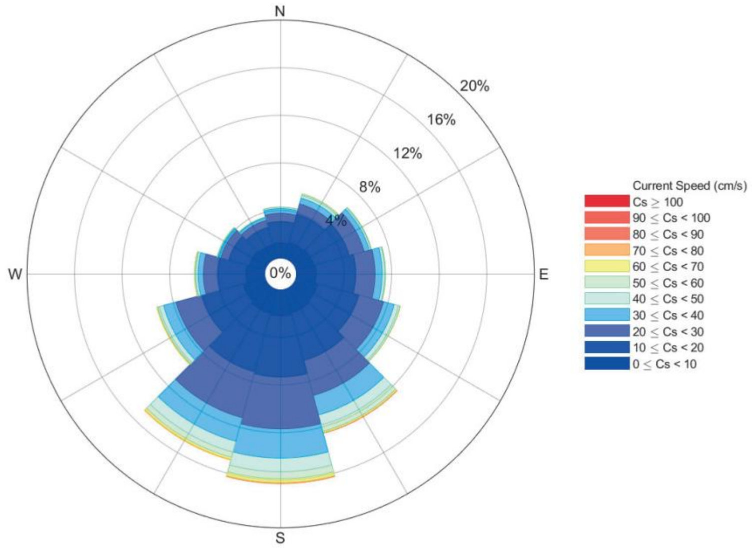
Figure 3-3 Monthly Sea Temperature Conditions

The annual minimum is 2.8°C and the average maximum is 12.7°C.

3.3.2. Sea Depth and Current

The water depth in the area of the Bay du Nord has been taken from the Design Basis [17] as between 613 and 1,170 m. Subsea releases from the flowlines and wells will be based on these water depths.

The current conditions at the Bay du Nord field are important to understand how the FPSO may be positioned relative to the wind direction to determine if plumes of smoke or gas may be blown towards the accommodation at the aft of the vessel (see section 3.3.3).



Current speed [cm/s]	Current direction												Omni
	0°	30°	60°	90°	120°	150°	180°	210°	240°	270°	300°	330°	
< 10	1.27	1.40	1.53	1.65	1.89	2.04	2.18	2.09	1.92	1.58	1.37	1.21	**20.15**
< 20	3.08	3.87	4.63	4.98	5.47	6.18	7.32	7.17	5.56	3.94	3.18	2.72	**58.09**
< 30	3.77	4.77	5.94	6.60	7.63	9.23	11.68	11.17	7.77	5.16	3.87	3.33	**80.93**
< 40	4.15	5.26	6.37	7.21	8.55	10.93	14.14	13.22	8.86	5.61	4.09	3.56	**91.96**
< 50	4.26	5.49	6.51	7.43	8.93	11.80	15.29	14.16	9.23	5.80	4.16	3.61	**96.67**
< 60	4.30	5.61	6.57	7.48	9.07	12.35	15.88	14.61	9.37	5.87	4.19	3.63	**98.95**
< 70		5.65	6.58	7.49	9.09	12.46	16.19	14.79	9.43	5.91	4.21	3.63	**99.74**
< 80				7.49	9.10	12.51	16.25	14.86	9.45	5.92	4.21		**99.94**
< 90					9.10	12.51	16.27		9.46	5.92			**99.98**
< 100						12.53	16.28						**100.00**
Total	**4.30**	**5.65**	**6.58**	**7.49**	**9.10**	**12.53**	**16.28**	**14.86**	**9.46**	**5.92**	**4.21**	**3.63**	**100.00**
Mean	**17**	**18**	**17**	**18**	**19**	**23**	**24**	**23**	**20**	**18**	**16**	**15**	**20**
Maximum	**60**	**69**	**68**	**79**	**84**	**98**	**95**	**80**	**84**	**83**	**76**	**63**	**98**

Figure 3-4 Annual Directional Non-Exceedance (%) of Current Speed (25m Water Depth)

3.3.3. Predominant Wind Direction

It is assumed that the FPSO will weathervane, and as such, the prevailing wind direction can potentially be from the forward to the aft of the vessel. In essence, the prevailing wind would be from the turret to the accommodation. A Heading Control Analysis was prepared and it used hindcast data to predict the statistically likely passive weathervaning heading considering the combinations of wind, waves, and current in the dataset. Figure 3-5 shows the wind rose for *relative wind direction, passive ship*.

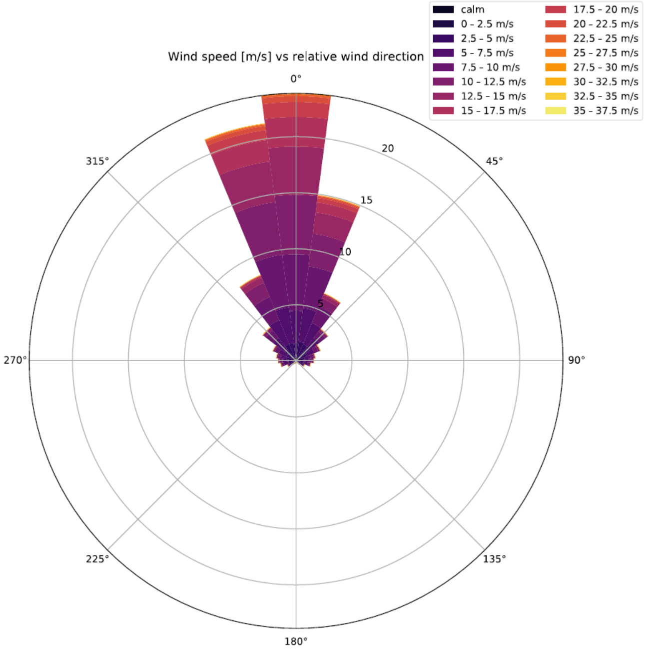


Figure 3-5 Wind Rose for Relative Wind Direction for Passive Ship

When the predominant wind direction is overlaid on the FPSO, it can be concluded that the wind will tend to blow towards the accommodation from the forward end of the FPSO and consequently any gas or smoke produced on the FPSO may be blown towards the accommodation. It should be noted that the FPSO is equipped with air intakes at the aft side of the FPSO for the LQ, which means that the potential for accommodation impairment through smoke or unignited gas ingress should be reduced. If necessary, the intakes can be closed.

The thrusters on the FPSO could be used to angle the vessel against the prevailing wind, although this requires the thrusters to be available following a MAE and may also reduce stability of the FPSO, if orientated less favourably to the wind and wave conditions.

On this basis, it has been assumed that releases from the turret and processing areas will have a high probability of being blown directly towards the accommodation to result in the potential for impairment of the TR. A 0.4 probability is assumed based on the heading analysis [18], whereas for the sensitivity involving a forward accomodation (Section 8.4), the probability of wind being blown towards the accomodation is assumed to be just 0.1.

For releases initiating towards the aft end of the FPSO or pool fires that have accumulated on the cargo deck towards the aft end, the probability that smoke will blow towards the accommodation is taken to be 1.0.

3.3.4. Wave Data and Subsea Releases

The wave conditions must be considered when considering certain types of accidental releases onto the sea surface, in particular sea surface oil fires, as well as the ability to use a Walk to Work vessel.

Table 3-2 Sample of Non-Exceedance (%) of Significant Wave Height

H_S [m]	Month												Year
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
< 1	0.04	1.24	3.50	1.28	1.27	3.54	5.79	4.80	0.80	0.16	0.07	0.00	**1.88**
< 2	1.94	5.45	11.79	20.72	42.06	58.94	71.56	66.03	35.03	15.69	9.96	3.21	**28.68**
< 3	17.43	24.66	39.84	58.91	80.57	89.13	95.38	92.17	74.36	52.66	40.26	23.40	**57.55**
< 4	46.70	54.41	66.84	82.87	93.70	97.33	99.02	97.99	91.14	78.67	67.40	52.01	**77.43**
< 5	69.97	76.13	84.10	92.49	97.81	99.25	99.79	99.33	96.57	91.02	84.19	73.19	**88.70**
< 6	84.25	87.25	92.88	96.77	99.20	99.84	99.99	99.84	98.38	96.30	92.51	86.10	**94.47**
< 7	91.89	93.20	96.79	98.62	99.65	99.93	100.00	99.97	99.24	98.16	96.30	93.07	**97.25**
< 8	95.07	95.93	98.41	99.28	99.83	99.97	100.00	99.99	99.62	99.00	98.11	96.07	**98.45**
< 9	97.13	97.70	99.18	99.65	99.93	99.98		100.00	99.80	99.38	98.93	97.81	**99.13**
< 10	98.52	98.80	99.71	99.92	99.97	99.99			99.87	99.65	99.45	98.97	**99.57**
< 11	99.36	99.45	99.92	100.00	99.98	100.00			99.94	99.89	99.79	99.63	**99.83**
< 12	99.77	99.79	99.96		100.00				100.00	99.97	99.94	99.88	**99.94**
< 13	99.92	99.97	99.99							100.00	100.00	99.96	**99.99**
< 14	99.99	100.00	100.00								100.00	99.98	**100.00**
< 15	100.00											99.99	**100.00**
< 16	100.00											99.99	**100.00**
< 17												100.00	**100.00**
Total	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Mean	4.5	4.1	3.5	3.0	2.4	2.0	1.8	1.9	2.5	3.2	3.6	4.3	3.1
Maximum	15.4	14.0	14.0	11.0	11.6	10.6	7.1	8.6	11.8	12.5	13.2	16.6	16.6

3.3.4.1. Walk to Work Restrictions

The information provided by motion compensated gangway suppliers suggests that the use of the gangway should be restricted for significant wave heights exceeding 4.5 m. This number is specifically for connecting the gangway to a fixed structure and hence the restriction applied to two floating installations, which is the case with the Bay du Nord FPSO, may be different. Applying the restriction of 4.5m suggests a probability that the gangway could not be used of around 17%, on the basis that the wave height is less than 4.5 m around 83% of the time. The gangway would also be restricted in periods of reduced visibility, with 10% restrictions being a typical estimate for other operators off the East Coast of Canada.

The risk assessment has assumed that the W2W operation would be restricted and personnel would not use the gangway in such weather conditions.

3.3.4.2. Subsea Releases

At this stage of the design, a detailed assessment of deep water releases has yet to be calculated. In principle, Computational Fluid Dynamics (CFD) could provide a ready tool for such an analysis, but accurate treatment of gas dissolution, hydrate formation and thermal stratification effects requires the use of empirical models for these effects, and there are currently none that are available to any proven degree of acceptable accuracy.

In the literature, Yappa and co-workers from Clarkson University have developed an empirical model, called the Clarkson Deepwater Oil & Gas (CDOG) model, that has been shown to provide good qualitative performance when compared against the scarce data that was collected during the Deepspill JIP tests [19].

For releases that are deeper than 500m, empirical models such as CDOG predict that all of the gas in the blowout either forms hydrates or dissolves fully in the seawater before reaching the surface. Hence, it is reasonable to assume that there is negligible flammable hazard above the sea surface for these types of releases. This would mean that the maximum boil zone diameter is limited to around 20% of 500m, i.e. 100 m.

Even if the gas is ignited, the flame may not be stable. Kalghatgi [20] presented experimental data for various hydrocarbons that allowed an estimate to be made of the critical crosswind that would cause a burner flame to blow off. This is represented by the equation below where V_{crit} is the critical crosswind velocity and U_{th} is the fuel velocity:

$$V_{crit} = 0.15U_{th}$$

A full-bore rupture of the gas injection riser could produce an initial hydrocarbon release of around 1800 kg/s. The risers exit the hull at the base of the turret and are conveyed in I-tubes away from the FPSO. It is conservatively assumed that in the worst case scenario, a release could occur at a water depth of 100 m, which would produce a gas boil zone of around 20 m diameter. Assuming that the gas injection gas is mainly methane, then the volumetric flowrate of gas through the boil zone would be around 2520 m^3/s. On the basis of a 20m diameter boil zone, the velocity of the gas emerging from the zone is 8 m/s and hence the critical wind velocity would need to be below 0.8 m/s.

The wind rose accompanying Figure 3-1 suggests that wind speeds of less than 2 m/s rarely occur (less than 3% of the time) and therefore a conservative probability that riser fires can be sustained on the sea surface of 0.1 is assumed in the QRA.

3.3.5. Vessel Collisions

As with all offshore facilities, the Bay du Nord FPSO is potentially vulnerable to impact from ships either passing through the region, visiting or attending the FPSO. Those vessels that may visit the FPSO include supply vessels, crew transfer vessels, emergency response/rescue vessels and shuttle tankers.

Typically for FPSOs the size of the Bay du Nord, it is expected that very high impact energies (>200 MJ) would be required to result in a total loss of the vessel. Impact energies in the range of 100-200MJ could be expected to result in Severe Damage. For the purposes of the CSA, it is assumed that there would not be any rupture of the hull as a result of collisions with impact energies less than 30 MJ and therefore impact energies in the 30-100 MJ range are assumed to cause Significant Damage.

The Design Basis for the FPSO hull at the stern includes a collision resistant bulkhead between the thruster maintenance space and the Engine Room. It is assumed that a 200 MJ collision (the high end of the Severe categorization) at the stern does not cause penetration of the Engine Room bulkhead. This bulkhead would prevent flooding of the aft machinery space forward of the thruster maintenance space. No listing of the FPSO would be expected for this case and whilst there may be a need to down-staff the FPSO, this would be expected to be completed through helicopter or boat transfer, rather than precautionary evacuation by lifeboats. Further details on the potential frequency of vessel collisions, and resulting consequences, are presented in Section 5.15.

3.3.6. Iceberg Conditions

The Bay du Nord FPSO is located in an area that can experience icebergs and sea ice conditions. Due to the water depth at the field, the subsea infrastructure on the seabed is not at risk from iceberg scour, however the FPSO itself may need to disconnect as a result of impending iceberg collisions or sea ice.

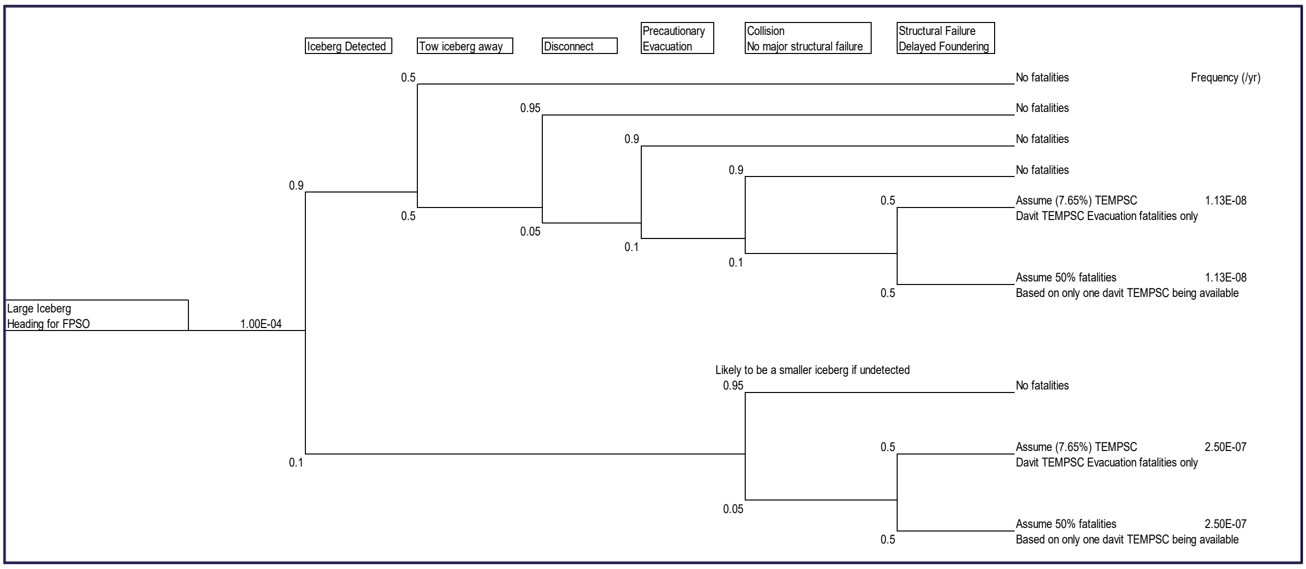
An iceberg load analysis and iceberg design basis studies have been conducted for the Project [21, 27] and the results have been used as input to the CSA. The risk to the FPSO from icebergs has been assumed as shown in the Event Tree in Figure 3-6.

It is worth noting that the evacuation fatality fractions used here relate to the use of davit launched TEMPSC. As described in Section 3.3.9, it may not be possible to use free fall TEMPSCs in certain sea ice conditions and hence only davit launched TEMPSC can be used for that situation. There is a Marine Evacuation system (MES) with life rafts at each side of the accommodation, which could also be used in the event that one of the davit launched TEMPSCs becomes unavailable.

For conservatisms, where foundering or listing occurs rapidly due to iceberg collision then a fatality fraction of 50% is assumed, as only one of the davit launched TEMPSCs may be available and no credit is taken for the life rafts in the QRA for this scenario. In all cases, the risk levels are also calculated on the basis of maximum number of personnel on board for the given phase of operations. In reality, there may be operational restrictions on POB levels for the ice season, meaning that this is likely to be a conservative assumption.

It is very likely that there would not be any major structural damage in the event of an iceberg impact. A conservative value of 0.9 for probability of no significant damage for the case where the iceberg is detected is applied. For the case where the iceberg is not detected (likely a smaller iceberg), then the probability of significant damage will decrease further.

It should be noted that in all Event Trees presented, the upwards branch indicates a positive “yes” response.



Case	Frequency	Fatality Fraction
Impact Delayed Foundering, Evacuation by Davit TEMPSC	2.61E-07	7.65% [22]
Impact Rapid Listing, Evacuation by one Davit TEMPSC	2.61E-07	50%

Figure 3-6 Iceberg Collison Inputs

Frequency of sea ice conditions existing at the FPSO that will limit the ability to launch the TEMPSC are described in Section 3.3.9.

3.3.7. Personnel Distribution (Organisational / Operational)

Risk to life estimates are dependent on the personnel distributions that are used in the analysis. This section presents the overall personnel distribution used in the risk calculations, with two separate staffing scenarios being assessed:

- Maximum Staffing – a POB of 120 represents the maximum staffing level, which occurs during commissioning and start-up operations.
- Normal Staffing – a POB figure of 79 has been used in this analysis, based on a preliminary assessment of the normal core crew staffing for the FPSO.

Further assessment will be carried out during the project phase to determine the necessary operations, maintenance, and emergency response organization. This will be based upon equipment selection, simultaneous operations, and the operating model. An updated risk analysis for the normal POB case will be performed in the Quantitative Risk Assessment during Detailed Design.

For both scenarios, four representative employment categories are used for the individual risk calculation with the offshore occupancy for each worker category based on the typical shift pattern of 3 weeks on and 3 weeks off.

Table 3-3 Representative employment categories

Category	Risk Exposure
Admin	Personnel who spend the majority of their onshift time in the LQ but some of their time in the process modules. They will be exposed to the immediate threats of releases within the modules they are working. Max POB: 13 (plus 1 Equinor representative, allocated to Admin group), Normal Staffing: 7
Maintenance	Personnel who perform maintenance throughout the facility. They will spend time in all areas of the facility and will be exposed to the immediate threats from releases within the area in which they are working. These personnel typically have a high occupational risk as they spend their time working with tools, scaffolding, access at height, etc. Max POB: 59, Normal Staffing: 41
Operations	Personnel who spend the majority of their onshift time in the process modules. They will be exposed to the immediate threats of releases within the modules they are working. These personnel typically have a low occupational risk as they spend their time taking readings and checking equipment. Max POB: 38, Normal Staffing: 22
LQ	Personnel who work within the Living Quarters of the FPSO e.g. chef & domestic support. These personnel typically have a very low occupational risk as they are not considered to spend any time in the process areas and so are not exposed to the immediate effects of any hydrocarbon events. Max POB: 9, Normal Staffing: 9

The average number of hours spent by worker groups in each area of the FPSO is shown next and used to calculate the distribution of personnel in the various worker groups, as well as the total number of workers in each category. The Personnel Distribution for the FPSO was based on information provided by BW Offshore [23].

Table 3-4 Distribution of Worker Groups (Max POB)

Area Description			Area Manning			Area Manning (%)			Worker Group			
Zone #	Area	Module/Area	Day Shift (Sum)	Night Shift (Sum)	Average (Sum)	Day Shift (Sum)	Night Shift (Sum)	Average (Sum)	Admin	Maintenance	Operations	LQ crew
	Living Quarter (LQ), Helideck	Living Quarter	73.43	107.25	90.34	61.7%	90.1%	75.9%	11.39	39.39	30.56	9.00
		Helideck, Helideck Parking area	1.16	0.03	0.60	1.0%	0.0%	0.5%	0.05	0.54	0.01	0.00
		Aft Deck Area inclu. lifeboat embarkation areas	1.45	0.32	0.89	1.2%	0.3%	0.7%	0.06	0.60	0.22	0.00
1		Workshops, Services Spaces, HVAC Room, Emergency Generator and Em Switchb'd Room & Lab	2.34	0.38	1.36	2.0%	0.3%	1.1%	0.07	0.81	0.49	0.00
2	Utility Area	M40 E-house	2.54	0.62	1.58	2.1%	0.5%	1.3%	0.26	1.11	0.21	0.00
		M41 Workshops and Laydown Areas	2.60	0.35	1.47	2.2%	0.3%	1.2%	0.09	1.27	0.12	0.00
		M42 Laydown Areas	1.23	0.36	0.80	1.0%	0.3%	0.7%	0.05	0.63	0.12	0.00
		M70 Utility Areas	2.80	0.84	1.82	2.4%	0.7%	1.5%	0.05	1.17	0.61	0.00
		M71 Chemical Injection	2.50	0.58	1.54	2.1%	0.5%	1.3%	0.07	0.99	0.49	0.00
		M90 Power Generation	2.48	0.46	1.47	2.1%	0.4%	1.2%	0.05	1.26	0.16	0.00
3	Process Modules	M10 Inlet Separation	2.57	0.65	1.61	2.2%	0.5%	1.4%	0.06	1.11	0.44	0.00
		M11 Stabilization	2.58	0.65	1.62	2.2%	0.5%	1.4%	0.07	1.11	0.44	0.00
		M61 HP Compression	3.24	1.12	2.18	2.7%	0.9%	1.8%	0.06	1.44	0.68	0.00
		M60 LP Separation	3.03	1.07	2.05	2.5%	0.9%	1.7%	0.06	1.31	0.68	0.00
		M50/M51 Water Injection	3.03	1.07	2.05	2.5%	0.9%	1.7%	0.06	1.31	0.68	0.00
		M30 Flare Knockout Drums	1.62	0.58	1.10	1.4%	0.5%	0.9%	0.06	0.68	0.36	0.00
4	Main Deck	Main Deck Hull Area	3.46	0.78	2.12	2.9%	0.7%	1.8%	0.08	1.69	0.35	0.00
5	Engine Room	E/R Spaces including Essential Generators, Diesel fire pumps, Cargo pump HPU's, Foam Room & Stores	2.85	0.75	1.80	2.4%	0.6%	1.5%	0.27	1.03	0.50	0.00
6	*Hull Space*	*Cargo Tanks, Slop Tanks, Ballast Tanks, Chemical Storage Tanks. - No manning*	*0.00*	*0.00*	*0.00*	*0.0%*	*0.0%*	*0.0%*	*0.00*	*0.00*	*0.00*	0.00
7	Forward Spaces	Forward Electrical Equipment Room, Turret HPU Room, Firewater Pump Room and Forward Escape to Sea Point.	1.21	0.31	0.76	1.0%	0.3%	0.6%	0.08	0.50	0.18	0.00
8	Turret	Turret compartment, TLER and all decks of the turret	2.88	0.84	1.86	2.4%	0.7%	1.6%	0.06	1.09	0.71	0.00
		Totals:	*119.0*	*119.0*	*119.0*	*100%*	*100%*	*100%*	*13.0*	*59.0*	*38.0*	*9.0*

Table 3-5 Distribution of Worker Groups (Normal POB)

Area Description			Area Manning			Area Manning (%)			Worker Group			
Zone #	Area	Module/Area	Day Shift (Sum)	Night Shift (Sum)	Average (Sum)	Day Shift (Sum)	Night Shift (Sum)	Average (Sum)	Admin	Maintenance	Operations	LQ crew
	Living Quarter (LQ), Helideck	Living Quarter	42.12	74.48	58.30	53.3%	94.3%	73.8%	5.71	27.19	16.40	9.00
		Helideck, Helideck Parking area	1.15	0.00	0.58	1.5%	0.0%	0.7%	0.03	0.54	0.01	0.00
		Aft Deck Area inclu. lifeboat embarkation areas	1.16	0.11	0.64	1.5%	0.1%	0.8%	0.05	0.44	0.14	0.00
1		Workshops, Services Spaces, HVAC Room, Emergency Generator and Em Switchb'd Room & Lab	2.38	0.30	1.34	3.0%	0.4%	1.7%	0.05	0.81	0.49	0.00
2	Utility Area	M40 E-house	2.53	0.12	1.33	3.2%	0.2%	1.7%	0.07	1.11	0.15	0.00
		M41 Workshops and Laydown Areas	2.23	0.06	1.15	2.8%	0.1%	1.4%	0.08	0.95	0.12	0.00
		M42 Laydown Areas	0.82	0.10	0.46	1.0%	0.1%	0.6%	0.03	0.31	0.12	0.00
		M70 Utility Areas	2.41	0.45	1.43	3.1%	0.6%	1.8%	0.06	0.85	0.53	0.00
		M71 Chemical Injection	1.98	0.27	1.13	2.5%	0.3%	1.4%	0.05	0.67	0.41	0.00
		M90 Power Generation	2.06	0.02	1.04	2.6%	0.0%	1.3%	0.04	0.94	0.06	0.00
3	Process Modules	M10 Inlet Separation	1.98	0.25	1.11	2.5%	0.3%	1.4%	0.04	0.79	0.28	0.00
		M11 Stabilization	2.02	0.25	1.13	2.6%	0.3%	1.4%	0.06	0.79	0.28	0.00
		M61 HP Compression	2.49	0.45	1.47	3.2%	0.6%	1.9%	0.07	0.92	0.48	0.00
		M60 LP Separation	2.24	0.45	1.35	2.8%	0.6%	1.7%	0.07	0.79	0.48	0.00
		M50/M51 Water Injection	2.24	0.45	1.34	2.8%	0.6%	1.7%	0.07	0.79	0.48	0.00
		M30 Flare Knockout Drums	1.13	0.25	0.69	1.4%	0.3%	0.9%	0.05	0.36	0.28	0.00
4	Main Deck	Main Deck Hull Area	2.71	0.22	1.46	3.4%	0.3%	1.9%	0.07	1.05	0.35	0.00
5	Engine Room	E/R Spaces including Essential Generators, Diesel fire pumps, Cargo pump HPU's, Foam Room & Stores	2.49	0.38	1.43	3.1%	0.5%	1.8%	0.27	0.71	0.46	0.00
6	*Hull Space*	*Cargo Tanks, Slop Tanks, Ballast Tanks, Chemical Storage Tanks. - No manning*	*0.00*	*0.00*	*0.00*	0.0%	0.0%	0.0%	*0.00*	*0.00*	*0.00*	*0.00*
7	Forward Spaces	Forward Electrical Equipment Room, Turret HPU Room, Firewater Pump Room and Forward Escape to Sea Point.	1.03	0.14	0.59	1.3%	0.2%	0.7%	0.07	0.34	0.18	0.00
8	Turret	Turret compartment, TLER and all decks of the turret	1.86	0.26	1.06	2.3%	0.3%	1.3%	0.06	0.69	0.31	0.00
		Totals:	*79.0*	*79.0*	*79.0*	*100%*	*100%*	*100%*	*7.0*	*41.0*	*22.0*	*9.0*

3.3.8. Transport Risks

Transfer of personnel to the FPSO will normally be by helicopter, although the FPSO will also have facilities fitted to allow for transfer of personnel by FROG or by motion compensated gangways and a walk to work (W2W) vessel. Based on information from other operators, it has been assumed that 88% of transfers will be via helicopter and 12% via boat and gangway/FROG. During high staffing phases it is anticipated that boat transfers would be the preferred option to allow transfer of higher number of personnel and reduce helicopter flights.

The number of return trips to the facility will depend on the offshore shift pattern for the category of worker.

For helicopter transport, the following assumptions are taken to apply when calculating the risk levels, taken from the Kent Method Statement 21 [24], which is based on Oil & Gas Producers (OGP) data:

- Journey time from shore to FPSO – 2 hours 45 minutes
- Take-Off & landing crash frequency – 4.54E-06 per TO/L
- Probability of crash being fatal – 33.3%
- Take-Off & Landing fatality fraction – 60%
- Cruise Crash Frequency – 5.68E-06 per hour
- Probability of crash being fatal – 16.7%
- Cruise fatality fraction – 100%
- Number of passengers per helicopter journey – 5.

For transfer of personnel by boat, it is assumed that such transfers will only be planned when the conditions offshore allow for safe transfer of personnel to the FPSO. Hence, the sea state is taken to be less than a significant wave height of 4.5m, which is the typical height above which gangway manufacturers recommend that transfers are restricted.

The transfer process itself is taken to be by a Crew Transfer Type vessel to the FPSO and then motion compensated gangway to the FPSO or via FROG. The calculation of risk is based on the following:

- 25 passengers per boat journey
- Gangway Accident Frequency - there is limited data available which relates to this operation. An accident rate of 2.65E-07 per passenger transfer stage is however quoted in CMPT [25]. A stage is defined as a complete round trip i.e. boarding the vessel and disembarking at shore (or back onto the platform if personnel do not return to shore).
- FROG Accident Frequency: 2.65E-07 (as above for gangway accident frequency)
- Boat Transit Accident Frequency: 3.05E-07 per hour, from OGP data [26]
- Time from shore to FPSO: 23 hours (based on a speed of 12knots and distance of 500kms)
- 95% of transfers from crew boat to FPSO will be via gangway and 5% will be via FROG (assumption based on similar operators in the region).

The data relating to marine transport and transfer is taken from OGP 434-10 [26], where there have been no historical fatalities from crew transport vessels. The frequency of the vessel sinking whilst transporting personnel is therefore low and a conservative assumption adopted that all personnel on board will be lost.

3.3.9. Escape, Evacuation and Rescue

All escape routes lead to the accommodation with at least two routes provided from all locations on the topsides, turret compartment and machinery space. Fires that lead to a heat flux of greater than $6.3kW/m^2$ on exposed sections of plant will block escape routes, as this heat flux is defined as "Pain within approximately 10 seconds; rapid escape only is possible". This is based on the criteria from API RP 521, which is referenced in GL0282 [37] based on flare radiation.

Fires also generate large volumes of smoke which can obscure the escape ways. Within reference [37], it is stated that that visibility of below 4m would also result in impairment of an escape route. An escape route is also considered to be impaired if it is engulfed by gas at a concentration of 50% or more of its lower flammable limit.

The current TEMPSC arrangements are:

- 2 x 60-person freefall TEMPSC at the stern and designated as the primary lifeboats.
- 1 x 60-person davit launched TEMPSC port side of Accommodation.
- 1 x 60-person davit launched TEMPSC starboard side of Accommodation.

The primary lifeboats are confirmed to meet the regulations of the flag state (Transport Canada / SOLAS) for a vessel of this type. The davit-launched lifeboats are installed to meet the additional requirements in Framework Regulations and for the rare occasions when there is sea ice in the area, as described below.

There is no lifeboat at the bow area. It is acknowledged that the other NL FPSO with aft LQ (SeaRose) has a forward lifeboat. The forward lifeboat on SeaRose was initially installed in response to the regulatory requirement (Installations Regulations) that half the lifeboats be close to the accommodations and half be located "on the other side of the installation." This placement is understood to have been reconsidered during that project's development, resulting in an approved RQF which would have allowed the forward lifeboat to be removed. However, during the early years of SeaRose operations, all NL facilities had their evacuation systems de-rated when instruction was given that equipment would need to allow for passengers weighing 100 kg. Following this de-rating, the forward lifeboat was required in order to meet the aggregate lifeboat capacity requirement, and the forward lifeboat was retained. All evacuation systems on the Bay du Nord FPSO are rated for persons weighing 100 kg.

A sensitivity has been conducted as reported in Section 7.3.5, with 4 x 60-person davit TEMPSCs, two on each side of the TR. A sensitivity has also been conducted regarding suitable evacuation for personnel located in the bow area who are unable to perform egress to the aft TR (Section 7.3.10).

When considering launching of TEMPSC, sea ice must also be considered as it could potentially impair the ability for the TEMPSC to be launched safely. Sea ice is described by the area it covers, its thickness, its age, and its movement with the winds and ocean currents. Concentration is a unitless term that describes the relative amount of area covered by ice, compared to a reference area, typically a 25 km by 25 km box. The Equinor approach is to describe the concentration in tenths (0/10 to 10/10).

The following is currently assumed by Equinor:

- Greater than 0/10ths coverage i.e. any sea ice in the water, freefall TEMPSC cannot be used
- Greater than 6/10ths coverage, assumed to be problematic for davit launched TEMPSC unless other active measures (such as clearing by standby vessel) are employed.

The iceberg and pack ice design basis [27] for the Bay du Nord states that 0.61% of the time the area will experience some level of sea ice. Sea ice with greater than 6/10ths coverage is also reported as being present for 30% of the time when ice is in the area. On the basis of the above, the freefall TEMPSC will not be available for use 0.61% of the time and that davit launched TEMPSC will be unavailable for launch 0.18% of the time. Where both types of lifeboat are unavailable for evacuation and TR impairment has occurred, then the 62% fatality rate described in Section 5.9.3 is assumed.

This also means that 70% of the time when ice coverage occurs, it will be less than 6/10ths and hence even when the freefall TEMPSC are unavailable for use the davit launched TEMPSC will be available.

Excluding the sea ice, the probability of fatality associated with use of such lifeboats is based on the Kent Method Statement 25 [28], which in turn uses the Norwegian Offshore Directorate (previously Norwegian Petroleum Directorate) [29] recommended values. The overall probability is taken to be 4% based on the tables below and the weather conditions for the region, which is based on the wind speeds shown in Figure 3-1.

Secondary evacuation is provided via life rafts with MES chutes, with an associated fatality rate of 8.65%. Life rafts are assumed to be able to be launched in the same ice conditions as Davit launched lifeboats.

Table 3-6 Evacuation Recovery Fatality Rates

Weather State	Beaufort Force	Probability of Beaufort Force	Recovery Fatality Rate [28]
Calm	0 - 3	20.0%	0.000
Moderate	4 - 6	65.95%	0.000
Severe	7 - 9	14.05%	0.260
Weather Averaged	**All**		**0.0365**

Table 3-7 Overall Evacuation Fatality Rates

Evacuation Means		Fatality Rate [28]		
		Evacuation	Rescue	Overall
Primary	Freefall TEMPSC	0.35%	3.65%	4.00%
Primary	Davit Launched TEMPSC	4.0%	3.65%	7.65%
Secondary	Chute Based with Life rafts	5.0%	3.65%	8.65%
Secondary	Throw Over Life rafts	13.9%	3.65%	17.55%

For the QRA, a single fatality fraction is used which also takes account of the sea ice hazard mentioned above. Taking the ability to launch the various lifeboats into account with the sea ice hazard results in an overall fatality fraction of 4.12%.

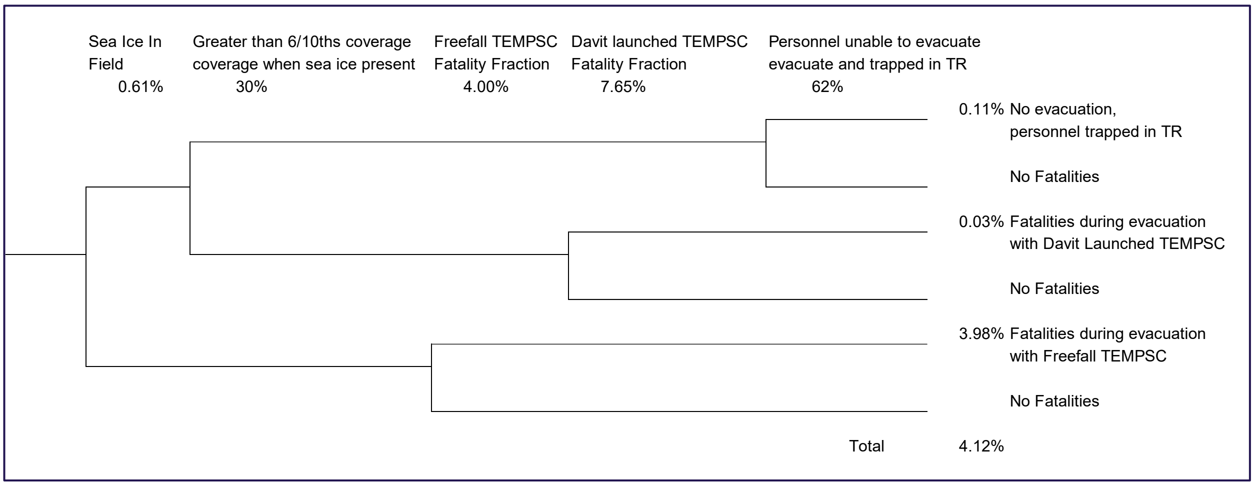


Figure 3-7 Evacuation Fatality Fraction including Sea Ice Risk

A sensitivity has been added with no freefall TEMPSC, but with 4 x 60-person davit launched TEMPSC, 2 each located on the port and starboard side of the accommodation. In this case, the overall evacuation fatality fraction is 7.75%.

3.3.9.1. Escape Routes

An Escape, Temporary Refuge, Evacuation and Rescue Analysis [30] has been carried out in support of the Bay du Nord Project. The purpose of escape routes is:

- To ensure that personnel always have access to at least one safe route of escape.
- To enable personnel to safely reach the assigned mustering area from any position on the FPSO they are likely to occupy.
- To ensure that personnel may evacuate from a point of muster to a point of evacuation.
- To enable personnel to safely reach the forward escape to sea point where the main escape to TR is unavailable.
- To enable rescue/medical teams to safely bring injured personnel to areas where medical treatment can be given

There shall be at least two means of escape from all locations and decks in exterior and interior locations on the FPSO with an escape length more than 5 m on the facility, including the turret. The exceptions are for small access platforms, rooms with low vulnerability and cabins, where a single exit is acceptable. Design, arrangement and construction of the Escape routes shall comply with SOLAS requirements and DNV-OS-A101.

The motion time calculations are performed for three scenarios. The following are the key outcomes from the assessment:

1. Escape from top level of module M10 via starboard bus shelter:- The calculated motion time from the top level of module M10 to the primary mustering area in TR, i.e., Mess room, is estimated to be 5.8 minutes.
2. Escape from top deck of Turret via starboard Main deck escape way:- The calculated motion time from the top deck of Turret the Mess room (primary mustering area) is estimated to be 7.9 minutes.
3. Escape from central Main deck area via Forward and central escape routes on Process deck level:- The calculated motion time from central Main deck to Mess room (primary mustering area) via escape to forward stair and central escape ways on Process deck level is estimated to be 8.0 minutes.

The maximum anticipated time to fully evacuate the FPSO from "event time 0" is 38.6 minutes. This estimate is based on the longest estimated escape time (escape route 3).

It is therefore concluded that there will be sufficient time for evacuating the FPSO within 60 minutes.

In a situation with a stranded helicopter, the maximum POB that would ever be on the FPSO is assumed to be 127 (120 Max POB + 7 additional personnel from helicopter). The two primary lifeboats will have the capacity to evacuate a total of 120 persons. This means that in situations with 127 persons on the FPSO, the secondary lifeboats will have to supplement the primary lifeboats.

The two secondary lifeboats will have total capacity for 120 persons. The secondary lifeboats are located on B deck, one on each side of the LQ, i.e., closer to the Mess room than the primary lifeboats. The secondary lifeboats are lowered to sea by davits. By assuming that the secondary lifeboats are prepared and lowered in parallel with the primary lifeboats, the total evacuation time is not expected to increase significantly. It is assessed that the evacuation time will not exceed 60 minutes.

4. Hazard Identification and MAEs

4.1. HAZID Workshop

A Hazard Identification (HAZID) exercise [1] was conducted along with Equinor at the BWO offices in April 2025. The HAZID covered the normal operations of the FPSO, as well as the potential hazards that may be experienced during the Installation, Offshore Construction, Decommissioning and Abandonment phases. The FPSO was in pre-FEED phase although the level of detail available was sufficient for a robust HAZID to be completed. An additional HAZID was carried out virtually with the SURF team.

The objectives of the HAZID study were:

- Identification of potential hazards associated with Normal Operations on the Bay du Nord FPSO
- Identification of potential hazards associated with Installation, Offshore Operations, Decommissioning and Abandonment of the Bay du Nord Field
- Evaluation of the associated consequences and risks, considering potential effects on personnel, assets, the environment and production loss
- Identification of additional safeguards that may be required to prevent the realisation of the hazard or operability issue and mitigate against the consequences.

The key hazards that were identified, as well as safeguards in place to prevent, control, mitigate and provide emergency response against the hazards, have been brought forward into the CSA to assess the risks to personnel, the Temporary Refuge, escape and evacuation provisions, plus the environment and assets

The primary focus of the HAZID was on the operational phase of the Bay du Nord FPSO, whilst the construction, installation and decommissioning phases were discussed during the HAZID, it was at a high level only, due to the early stages of the project and, therefore, lack of information.

Following assessment of the risk levels at the concept stage, an ALARP Review Workshop was completed to determine if any additional measures should be considered to reduce the risks further. The findings of the ALARP review [5] are discussed in more detail in Section 8.

4.2. Hydrocarbon Events

Releases from the facilities at the Bay du Nord field can lead to a variety of different consequences including:

- Hydrocarbon containing systems that have the potential to result in fires and explosions on the FPSO
- Releases subsea and in the vicinity of the FPSO from the risers and flowlines
- Releases from the subsea wells or blowouts that are remote from the FPSO but may impact on mobile drilling units or vessels that are operating in the area.

The risks associated with releases from the subsea wells are not assessed as part of this Concept Safety Analysis, with the focus being on risks to personnel working on the FPSO.

The analysis of hazardous events is undertaken by dividing the process plant (and other inventories) into identifiable sections isolatable by emergency shutdown valves and by defining representative release events for each inventory. In doing so, the locations and actions of ESD valves and blowdown valves are taken into account. A full list of hydrocarbon isolatable sections is shown in Table 4-1.

Within any QRA, hydrocarbon releases can lead to the following undesirable outcomes:

- Causing casualties amongst personnel in the vicinity of the incident
- Preventing personnel from evacuating the installation.

Death, injury or incapacitation of personnel may arise from high thermal radiation levels, blast overpressures, cryogenic threats or the toxic or heat effects of smoke. Personnel may be prevented from reaching the muster area by structural collapse of the evacuation routes due to explosions, high thermal radiation levels or from smoke/gas which may hinder personnel movement by obscuring routes, or subjecting personnel to toxic effects.

In addition, escalation within the process modules may lead to catastrophic damage to the FPSO and widespread damage before personnel have had sufficient time to leave the FPSO. This may lead to further fatalities amongst those evacuating from the FPSO.

The potential consequences of each failure case are assessed to determine which, if any, of the above outcomes could occur. Those that are identified are then quantified in the CSA.

Table 4-1 shows the estimated hydrocarbon inventory for each of the isolatable sections on the FPSO, based on the available topsides PFDs [10] and the Heat and Material Balance [9].

Table 4-1 Bay du Nord Topsides Failure Cases, Masses & Volumes and Operating Conditions

Failure Case Description	Event ID	Physical Properties of Inventory - Mass					Modelling Parameters - Oil		Modelling Parameters - Gas	
		Total Oil Mass in Inventory (kg)	Maximum Oil Mass Released (kg)	Total Free Gas Mass (kg)	Total Flash Gas Mass (kg)	Total Gas Released (kg)	Oil Density (kg/m^3)	Vessel Pressure (barg)	Operating P (Barg)	Operating T (°C)
BdN Production Flowline 1 and 2 (ESV to XSV) - Two Phase Release at Turret Lower Deck	P01-M-TRTL	28,215	29,853	119	3,123	3,242	-	-	15	70
MP Inlet and Test Manifolds - Two Phase Release at Piperack	P01-M-PRK	28,215	29,853	119	3,123	3,242	-	-	15	70
MP Inlet and Test Manifolds - Two Phase Release at M10 Process Deck Level 1	P01-M-M10L1	28,215	29,853	119	3,123	3,242	-	-	15	70
MP Inlet and Test Manifolds - Two Phase Release at Turret Upper Deck	P01-M-TRTU	28,215	29,853	119	3,123	3,242	-	-	15	70
HP Inlet and Test Manifolds - Two Phase Release at Turret Upper Deck	P02-M-TRTU	31,381	31,381	125	3,474	3,599	-	-	15	70
HP Inlet and Test Manifolds - Two Phase Release at Piperack	P02-M-PRK	31,381	31,381	125	3,474	3,599	-	-	15	70
HP Inlet and Test Manifolds - Two Phase Release at M10 Process Deck Level 1	P02-M-M10L1	31,381	31,381	125	3,474	3,599	-	-	15	70
HP Spare, Cambriol and Circulation Production Flowline (ESV to XSV) - Two Phase Release at Turret Lower Deck	P02-M-TRTL	31,381	31,381	125	3,474	3,599	-	-	15	70
Test Separator (20-VA-1004) - Two Phase Release at M10 Process Deck Level 1	P03-M-M10L1	53,346	49,427	2,616	4,863	7,479	-	-	15	67
Test Separator (20-VA-1004) - Gas Release at M10 Process Deck Level 1	P03-G-M10L1	53,346	49,427	2,616	4,863	7,479	-	-	15	67
Test Separator (20-VA-1004) - Liquid Release at M10 Process Deck Level 1	P03-L-M10L1	53,346	49,427	2,616	4,863	7,479	788	15	-	-
Inlet Separator (20-VA-1001) - Two Phase Release at M10 Process Deck Level 1	P04-M-M10L1	59,185	55,469	3,064	5,389	8,453	-	-	15	70
Inlet Separator (20-VA-1001) - Gas Release at M10 Process Deck Level 1	P04-G-M10L1	59,185	55,469	3,064	5,389	8,453	-	-	15	67
Inlet Separator (20-VA-1001) - Gas Release at Piperack	P04-G-PRK	59,185	55,469	3,064	5,389	8,453	-	-	15	67
Inlet Separator (20-VA-1001) - Liquid Release at M10 Process Deck Level 1	P04-L-M10L1	59,185	55,469	3,064	5,389	8,453	788	15	-	-
LP Separator (20-VA-1002) - Two Phase Release at M11 Process Deck Level 2	P05-M-M11L2	80,334	77,175	380	3,149	3,529	-	-	2.5	61
LP Separator (20-VA-1002) - Gas Release at M11 Process Deck Level 2	P05-G-M11L2	80,334	77,175	380	3,149	3,529	-	-	1.3	86
LP Separator (20-VA-1002) - Liquid Release at M11 Process Deck Level 2	P05-L-M11L2	80,334	77,175	380	3,149	3,529	792	1.5	-	-
1st Stage LP Compressor Scrubber Pumps (23-PA-6001A/B) - Two Phase Release at M60 Process Deck Level 1	P05-M-M60L1	80,334	77,175	380	3,149	3,529	-	-	1.5	86
Electrostatic Coalescer (20-VJ-1003) & Oil Booster Pump (20-PA-1001A/B) & Crude Oil Coolers (20-HB-1002A/B) - Liquid Release at M11 Process Deck Level 1	P06-L-M11L1	198,473	198,473	-	4,933	4,933	792	1.5	-	-
Crude Oil Loading Header - Liquid Release at M11 Process Deck Level 1	P07-L-M11L1	23,199	23,199	-	571	571	840	0	-	-
Crude Oil Loading Header - Liquid Release at Piperack	P07-L-PRK	23,199	23,199	-	571	571	840	0	-	-
Crude Oil Loading Header - Liquid Release on Hull	P07-L-HULL	23,199	23,199	-	571	571	840	0	-	-
Cargo Tank - Liquid Release on Hull	P08-L-HULL	9,284,805	9,284,805	-	-	-	840	0	-	-
Off-Spec Fluid Tank - Liquid Release on Hull	P09-L-HULL	9,285,812	9,285,812	-	25	25	840	0	-	-
Off-Spec Fluid Tank - Liquid Release at Piperack	P09-L-PRK	1,007	1,007	-	25	25	840	0	-	-
Crude Oil Transfer Header - Liquid Release on Hull	P10-L-HULL	11,528	11,528	-	284	284	840	14	-	-
Crude Oil Offloading Header - Liquid Release at Piperack	P10-L-PRK	11,528	11,528	-	284	284	840	14	-	-
Crude Oil Offloading Header - Liquid Release at M10 Process Deck Level 1	P10-L-M10L1	11,528	11,528	-	284	284	840	14	-	-
Crude Oil Offloading Header - Liquid Release on Hull	P11-L-HULL	15,454	15,454	-	380	380	840	14	-	-
Crude Oil Offloading Reel - Liquid Release on Hull	P12-L-HULL	4,194	4,194	-	103	103	840	14	-	-
Crude Oil Offloading Reel - Liquid Release at Offloading Reel	P12-L-OFF	4,194	4,194	-	103	103	840	14	-	-
COT Gas Blanketing - Gas Release on Hull	P13-G-HULL	-	-	13	-	13	-	-	0	78
COT Gas Blanketing - Gas Release at Piperack	P13-G-PRK	-	-	13	-	13	-	-	0	78
COT Gas Blanketing - Gas Release at M30 Process Deck Level 1	P13-G-M30L1	-	-	13	-	13	-	-	0	78
1st Stage LP Gas Compression Suction Cooler (23-HB-6001) - Two Phase Release at M60 Process Deck Level 2	P14-M-M60L2	6,686	6,686	222	-0	222	-	-	0.8	30
1st Stage LP Gas Compression - Gas Release at M60 Process Deck Level 1	P14-G-M60L1	6,686	6,686	222	-0	222	-	-	0.7	30
1st Stage LP Gas Suction Scrubber (23-VG-6001) - Liquid Release at M60 Process Deck Level 1	P14-L-M60L1	6,686	6,686	222	-0	222	677	0.8	-	-
1st Stage Recompression to Flare KO Drum (43-VD-3001) - Gas Release at Piperack	P14-G-PRK	6,686	6,686	222	-0	222	-	-	5	86
2nd Stage LP Gas Compression Suction Cooler (23-HB-6002) - Two Phase Release at M60 Process Deck Level 2	P15-M-M60L2	3,004	3,004	229	-	229	-	-	4	30
2nd Stage LP Gas Compression - Gas Release at M60 Process Deck Level 1	P15-G-M60L1	3,004	3,004	229	-	229	-	-	6	30
2nd Stage LP Gas Compressor Suction Scrubber (23-VG-6002) - Liquid Release at M60 Process Deck Level 1	P15-L-M60L1	3,004	3,004	229	-	229	593	4	-	-

* Note that the inventory reported for the Cargo Tank and Off-spec fluid tank events (P8-L-HULL and P9-L-HULL) is conservatively assumed to be the entire full inventory of a storage tank

Failure Case Description	Event ID	Physical Properties of Inventory - Mass					Modelling Parameters - Oil		Modelling Parameters - Gas	
		Total Oil Mass in Inventory (kg)	Maximum Oil Mass Released (kg)	Total Free Gas Mass (kg)	Total Flash Gas Mass (kg)	Total Gas Released (kg)	Oil Density (kg/m^3)	Vessel Pressure (barg)	Operating P (Barg)	Operating T (°C)
MP Gas Compression - Gas Release at Piperack	P16-G-PRK	8,139	8,139	1,192	870	2,062	-	-	49	30
MP Gas Compression Suction Cooler (23-HA-6003) - Two Phase Release at M60 Process Deck Level 2	P16-M-M60L2	8,139	8,139	1,192	870	2,062	-	-	13	30
MP Gas Compression - Gas Release at M60 Process Deck Level 1	P16-G-M60L1	8,139	8,139	1,192	870	2,062	-	-	49	30
MP Gas Compression Suction Scrubber (23-VG-6003) - Liquid Release at M60 Process Deck Level 1	P16-L-M60L1	8,139	8,139	1,192	870	2,062	622	13	-	-
Gas Dehydration Inlet Cooler (24-HG-6601) - Two Phase Release at M60 Process Deck Level 2	P17-M-M60L2	3,050	3,050	5,014	-	5,014	-	-	49	35
Gas Dehydration System - Two Phase Release at Piperack	P17-M-PRK	3,050	3,050	5,014	-	5,014	-	-	49	35
Gas Dehydration Inlet Scrubber (24-VG-6601) - Two Phase Release at M61 Process Deck Level 1	P17-M-M61L1	3,050	3,050	5,014	-	5,014	-	-	50	35
Gas Dehydration Inlet Scrubber (24-VG-6001) & TEG Contactor (24-VB-6602) & 1st Stage HP Gas Compressor Suction Scrubber (23-VG-6004) - Gas Release at M61 Process Deck Level 1	P17-G-M61L1	3,050	3,050	5,014	-	5,014	-	-	77	35
Gas Dehydration & 1st Stage HP Gas Compression - Gas Release at Piperack	P17-G-PRK	3,050	3,050	5,014	-	5,014	-	-	77	35
Gas Dehydration Inlet Scrubber (24-VG-6601) - Liquid Release at M61 Process Deck Level 1	P17-L-M61L1	3,050	3,050	5,014	-	5,014	470	49	-	-
1st Stage HP Gas Compressor Discharge Cooler (23-HG-6004) at M61 Process Deck Level 2	P17-G-M61L2	-	-	1,683	-	1,683	-	-	77	35
2nd Stage HP Gas Compressor & Suction Scrubber (23-VG-6005) - Gas Release at M61 Process Deck Level 1	P18-G-M61L1	-	-	5,626	-	5,626	-	-	194	30
1st & 2nd Stage HP Gas Compressor Discharge Coolers (23-HG-6004 & 23-HG-6005) - Gas Release at M61 Process Deck Level 2	P18-G-M61L2	-	-	5,626	-	5,626	-	-	194	30
HP Gas Compression / Injection Pipework - Gas Release at M61 Process Deck Level 2	P19-G-M61L2	-	-	1,683	-	1,683	-	-	319	60
HP Gas Compression / Injection Pipework - Gas Release at Piperack	P19-G-PRK	-	-	1,683	-	1,683	-	-	319	60
HP Gas Compression / Injection Pipework and Flowlines - Gas Release at Turret Upper Deck	P19-G-TRTU	-	-	1,683	-	1,683	-	-	319	60
Gas Injection/Lift 1 BDN & Gas Lift 2 Cambriol/Circulation Flowline (XSV to ESV) - Gas Release at Turret Lower Deck	P19-G-TRTL	-	-	1,683	-	1,683	-	-	319	60
Fuel Gas System - Gas Release	P20-G-M61L1	3,301	3,301	1,511	1,250	2,761	-	-	48	34
Fuel Gas System - Liquid Release	P20-L-M61L1	3,301	3,301	1,511	1,250	2,761	473	48	-	-
Fuel Gas Superheaters, Metering Skid & Filter Package - Gas Release	P20-G-M61L2	3,301	3,301	1,511	1,250	2,761	-	-	48	34
Fuel Gas to Turbines - Gas Release	P21-G-M61L2	-	-	218	-	218	-	-	46	63
Fuel Gas to Turbines - Gas Release	P21-G-PRK	-	-	218	-	218	-	-	46	63
Fuel Gas to Turbines - Gas Release	P21-G-M90L1	-	-	218	-	218	-	-	46	63
LP Fuel Gas to Consumers - Gas Release	P22-G-M61L2	-	-	49	-	49	-	-	46	63
LP Fuel Gas to Consumers - Gas Release	P22-G-PRK	-	-	49	-	49	-	-	46	63
LP Fuel Gas to Consumers - Gas Release	P22-G-M11L2	-	-	49	-	49	-	-	46	63
Reject Vessel (44-VD-1003) - Two Phase Release at M11 Process Deck Level 3	P23-M-M11L3	2,722	2,722	11	-	11	-	-	0	86
Reject Vessel (44-VD-1003) - Gas Release at M11 Process Deck Level 3	P23-G-M11L3	2,722	2,722	11	-	11	-	-	0	86
Reject Vessel (44-VD-1003) - Liquid Release at M11 Process Deck Level 3	P23-L-M11L3	2,722	2,722	11	-	11	804	0	-	-
VOC Compression - Gas Release at Piperack	P24-G-PRK	-	-	1	-	1	-	-	1.5	146
VOC Compression - Gas Release at M30 Process Deck Level 1	P24-G-M30L1	-	-	1	-	1	-	-	1.5	146
Pig receiver - Two Phase Release at Turret Lower Deck	P25-M-TRTL	1,719	1,719	7	190	197	-	-	15	70
Pig launcher - Two Phase Release at Turret Lower Deck	P26-M-TRTL	1,719	1,719	7	190	197	-	-	15	70
BdN Production Riser 1 Subsea	R01-G-SS	247,758	247,758	987	27,424	28,411	-	-	15	70
BdN Production Riser 2 Subsea	R02-G-SS	247,758	247,758	987	27,424	28,411	-	-	15	70
Cambriol Riser Subsea	R05-G-SS	756,999	756,999	3,016	83,792	86,808	-	-	15	70
Gas Injection/Gas Lift Riser Subsea	R06-G-SS	-	-	58,059	-	58,059	-	-	324	60
Helifuel Skid - Liquid Release	H01-L-HELI	-	-	-	-	-	841	10	-	-
MP Separator - Two Phase Release at Piperack	P35-M-PRK	25,326	25,326	24	1,205	1,230	-	-	4.5	61
MP Separator - Two Phase Release at M11 Process Deck Level 2	P35-M-M11L2	25,326	25,326	24	1,205	1,230	-	-	4.5	61
MP Separator - Gas Release at M11 Process Deck Level 2	P35-G-M11L2	25,326	25,326	24	1,205	1,230	-	-	4.5	61
MP Separator - Liquid Release at M11 Process Deck Level 2	P35-L-M11L2	25,326	25,326	24	1,205	1,230	796	4.5	-	-

4.3. Non-Process Events

A number of non-hydrocarbon or non-process related events have been identified that have the potential to cause human injury/loss or damage to assets. Some may be significant risk contributors and hence require consideration, whilst others may be screened out as not having the potential to lead to fatalities. A brief description of these hazards, and whether they have been assessed further in the CSA, is given next.

- Helicopter Travel/Crash - The preferred means of transport to the FPSO is from St John's airport by helicopter. Helicopter travel to and from offshore installations has historically been a major risk contributor. Historically, casualties have been associated with helicopter occupants and these are the fatalities considered in the QRA, however loss of control of the helicopter in close proximity to the FPSO, or during take-off and landing, may result in the helicopter crashing into the FPSO. This has also been considered further in the CSA.
- Boat Transfer - As offshore facilities located off the East Coast of Canada can be more prone to fog, the secondary means of transporting personnel to the FPSO is by boat and motion compensated gangway. Historically, boat transfer has been a lower risk option to helicopter travel, however the journey time is significantly longer. This type of transport is also considered in the CSA.
- Occupational - A significant number of fatalities have occurred offshore due to workplace accidents such as falls, dropped objects, electrocution, man-overboard, fatalities during confined space entry, flooding of ballast tanks/pump rooms during man entry, etc. These are considered as occupational fatalities for the purpose of the CSA.
- Structural - The structural failure rate of Hull or other critical load bearing structures is considered in the risk assessment. Structural failure may result from design faults, loading failures, external impacts (ship collision, iceberg collision, loss of position, extreme weather etc) as well as fire or explosion loads. The potential for global structural failure is assessed in more detail within the CSA, with some of the other contributing factors described in more detail within this section.
- Ship Collision - The Bay du Nord FPSO will be located almost 500km from the coast of Newfoundland. As such the FPSO may be positioned close to a number of third-party vessels, A ship collision assessment has been performed [51] which assesses the risk from passing as well as attendant vessels.
- Iceberg Collision - As the FPSO will be located off the coast of Newfoundland, there is the possibility of the vessel being struck by an iceberg. A study [21] identified the frequency of such collisions and assessed the potential consequences of iceberg collision, which have been assessed further in the CSA.
- Iceberg scour - The water depth at which SURF facilities are placed on the seabed (i.e. flowlines, templates, riser bases, subsea cooler, etc) is such that the risk of iceberg scour has been discounted. There are indications of ancient post-glacial scours when sea level was understood to be much lower than today
- Seismic Activity - Seismic risks are not included within this CSA. Although earthquakes on the seabed may result in disruption to the wellheads, they are taken to be at a sufficient distance not to result in a significant threat to the FPSO.
- Dropped Objects - Any lifted load is a hazard as it has the potential to fall and cause a hydrocarbon release from the process, or to cause a direct fatality by striking nearby personnel. The potential for dropped objects leading to breaches in the process equipment is generally included in the generic breach frequencies used to model each event and threats to personnel are incorporated within the occupational risk. Equipment is lifted onto the FPSO via cranes onto laydown areas located well away from the processing modules, hence there is no reason to make any modifications to historical topsides leak frequency data. Dropped loads overboard may impact on risers or subsea flowlines. See section 5.17 for the discussion regarding impacts on risers subsea.
- Man Overboard - Although there is a small possibility of personnel being lost overboard during severe weather, this is mitigated against by restricting personnel movements during periods of high wind and

storms. It is assumed that adequate controls on the hazard will limit the risk levels to that already accounted for in the occupational risk levels and hence this is not assessed further in the CSA.

- Loss of Position / Stability - Loss of position resulting in the FPSO drifting off station can result from mooring system failure, which could be accompanied by severe or extreme weather, making evacuation of the FPSO difficult. Loss of buoyancy or stability may occur as a result of ballast system failure or during oil loading / offloading from the COTs. External events such as ship collision or extreme weather may also result in loss of buoyancy or stability but were captured previously under Ship Collision or Structural Failure.
- Flaring - The Bay du Nord uses a hydrocarbon gas blanket with Flare Gas Recovery Unit and hence the flare is not used for normal operations. In the event that the flare is required then this may introduce hazards associated with hydrocarbon gas slumping down to staffed areas, from the flare tip or from the cargo vents that are currently intended to be on the flare stack, or in the event of an ignited flare, liquid carry over resulting in a fire on the ships deck of the FPSO. These hazards have been identified and will be reviewed in more detail in the next phase of the study.
- Electrical Fires - Faults in electrical equipment or transformers throughout the installation could lead to fires. These should not lead to any additional fatalities, as personnel would be able to leave the room in which they occur. Transformers associated with the Power Generation facilities in the Topsides Utility area are dry transformers rather than oil filled, hence the potential consequences of a transformer fire are much reduced. These have not been assessed further in the CSA.
- Accommodation Fires - Fires within the accommodation may occur as a result of galley fires, laundry fire or electrical fires. These have been reviewed qualitatively in Section 5.20 of the CSA.
- Asphyxiation - A number of non-process areas on the FPSO will include a water mist extinguishing system for controlling fires. There are plans for gaseous extinguishing systems, but not using poisonous agents. Systems based on INERGEN or Argonite may be used to cover the switchboard rooms, electrical equipment rooms, emergency generator room, paint store and chemical stores. CO_2, halocarbon, or other noxious and poisonous gases will not be used." Hence the potential for asphyxiation incidents is reduced. The open nature of the topsides area and ships deck mean that the potential for personnel to be asphyxiated from hydrocarbon releases is also limited. The HAZID identified the enclosed turret as being a potential asphyxiation risk to personnel as a result of large, high pressure releases rapidly filling the turret area. The conclusion from the HAZID was that breathing equipment would likely be positioned in the turret and, on this basis, the hazards have not been assessed further in the CSA but will be reviewed as the design progresses to ensure that measures proposed are implemented.
- Turbine Disintegration - Although it is possible for the blades or disc within the power turbines / compressors to fracture and cause high energy missiles, it is assumed that the turbine casing and housing will be designed to contain fragments generated and these will not pose a significant threat to personnel. This hazard is therefore not considered further in the CSA.
- Sabotage, Threats, etc. - Acts of malicious damage could present a threat to the installation and personnel on board, particularly as the vessel is located in International Waters. Threats may also result as a result of weaknesses in Cyber Security, that could allow a third party to take control of the process or marine functions on the FPSO. Whilst such threats cannot be ruled out, controls are in place to prevent or mitigate possible malicious acts, particularly those involving the release of hydrocarbons.

Compliance to CyberSecure class notation and the IEC 62443 [31] series of standards will increase requirements for multiple levels of network security, access to critical parts of the system being restricted and increased security at integrated operation centre.Equinor and the Contractor are currently developing specification for a digitalisation philosophy which includes cybersecurity.

Vendors will have to comply with Equinor's and the Contractor's cybersecurity requirements.

As cybersecurity is a relatively new potential threat, to offshore facilities throughout the world, further details on the approach to addressing this potential threat is given in Section 8.5.

4.4. MAEs

The hazards associated with hydrocarbon containing items of equipment, as well as non-process sources, have been considered with the Major Accident Events (MAEs) shown and considered as potentially presenting a risk to personnel on the vessel. The following MAEs have been assessed further in the CSA:

Major Accident Event	Description
MAE1: LOC of hydrocarbon gas (including 2- phase)	Release of hydrocarbon gas (including 2-phase) on the FPSO (inboard and inclusive of the RESDVs) from turret swivel, process systems, piping or vessels. Release of hydrocarbon gas in main power generator enclosure.
MAE2: LOC of hydrocarbon liquid	Release of hydrocarbon liquids on board the FPSO from process systems, piping, vessels or equipment. Release of hydrocarbon liquids from the hull tanks. Release of hydrocarbon liquids from the offloading system.
MAE3: Hull tank fire / explosion	Explosive atmosphere in crude storage tanks with the potential for fire or explosion if ignited. Presence of hydrocarbon blanket gas in an adjacent ballast or void tank with the potential for fire or explosion if ignited.
MAE4: Non-process fires	Ignited release of helifuel from helifuel storage or distribution (including on helideck during refuelling). Ignited release of MGO within the hull & machinery spaces.
MAE5: Accommodation fire	Fire and/or smoke in the accommodation with the potential to impact personnel.
MAE6: Helicopter accident	Helicopter crash onto the FPSO or into the sea (note that this also covers transportation risks from boats).
MAE7: Ship collision	Collision between an errant vessel, in-field supply/support vessel or offtake tankers with the FPSO.
MAE8: Structural failure	Structural failure of hull, topsides primary & secondary structure, modules, and equipment/pipe supports/foundations due to functional, environmental, or accidental loads with the potential to impact personnel or hydrocarbon containing equipment.
MAE9: Dropped /swinging objects	Dropped/swinging loads with the potential to impact multiple personnel or hydrocarbon containing equipment. Failure of major winch lines under tension with the potential to impact multiple personnel. Dropped personnel transfer device during personnel transfers using pedestal cranes certified for man-riding. Dropped fast rescue craft during manned launch or recovery, including during drills. Failure of LQ elevator.
MAE10: Loss of mooring.	Loss of position of the FPSO with the potential to result in loss of containment from risers.
MAE11: Loss of stability and buoyancy	Accidental condition resulting in loss of stability or buoyancy of the FPSO.
MAE12: Iceberg Collision	This Major Accident Event covers the encroachment of an iceberg or sea ice into the field that could result in a collision of the FPSO or damage to the risers / mooring lines.
MAE13: Hydrocarbon Release Risers and Flowlines Subsea	This Major Accident Event covers a release from any of the hydrocarbon risers or flowlines subsea that could result in an accumulation of oil or gas on the sea surface that, if ignited, could cause sea fires in close proximity to the hull. Blowouts and well releases are also covered as these are pollution-causing events.

5. Hazard Assessment Process

The hazards that were identified in Sections 4.2 and 4.3, classified as per the MAEs described in Section 4.4, are now assessed using the approach described in this Section.

5.1. Introduction

The approach has been broken down into a number of clearly definable stages. These are as follows:

Hydrocarbon Risks:

1. Identify inventories and calculate outflow rates from representative leaks
2. Calculate fire sizes that may result from releases
3. Assess explosion consequences in a quantified manner using the most appropriate, industry recognised assessment tools
4. Assess how failure of protective systems (blowdown, ESD) may influence the severity of consequences
5. Calculate the frequency of initiating events and the probability of combinations of associated protective systems failure
6. Consider whether events may escalate by involving further process inventory, either in the incident area or beyond, by considering the effects of fire walls, bunding and drainage systems
7. Calculate the level of fatality resulting from the immediate effects of the incident
8. Consider whether personnel can be trapped, i.e. are unable to access the evacuation routes to the embarkation station
9. Consider whether personnel may become fatalities if an event escalates before they can leave the FPSO
10. Express fatality levels as a function of incident type, frequency and number of personnel involved.

Other Risks:

11. Identify other hazards not associated with process hydrocarbon releases (structural, iceberg, transport, ship collision, etc.)
12. Calculate the frequency of occurrence, the ultimate consequence and the probability of fatalities arising
13. Calculate fatality levels.

Summary of Risks

14. Summarise all risks to personnel and compare against Target Levels of Safety for the project
15. Identify major contributors and ensure that the design is ALARP.

In order to estimate risk levels, and in particular those due to the immediate effects of fires and explosions, it is necessary to estimate the likelihood that an individual would be at a specific location at any time. This is achieved by sub-dividing the installation into a number of areas and estimating the number of persons within each work group who are likely to be in that area at any time.

The basis for the personnel categories and the personnel distribution was shown in Section 3.3.7. This has been analysed to determine how many personnel on average would be in each area during normal operations.

5.2. Hydrocarbon Risk Analysis

5.2.1. Representative Inventory

The volumes of hydrocarbon within vessels, heat exchangers, compressors, pipework, etc. are calculated based on the detailed rules presented in the Kent "Inventories" Methodology [32], which follows a standard industry approach, as well as equipment dimensions [33], sectionalisation diagrams [10] and operating conditions [9].

The hydrocarbon inventories include an assessment of oil, free gas and dissolved gas within the pressurised oil inventory.

Pipe volumes have been estimated by summing the difference in location between connected equipment in the x, y and z directions, and then doubling the total to allow for complex routing. This has been shown on a FPSO design as being reasonably accurate, with some conservatism. If the pipework runs through the pipe rack, then the direct length of the routing will be estimated without doubling this distance. All pipework diameters have been included as this also determines the leak frequency category that the pipe lengths feed into.

5.2.2. Fire Modelling Methodology

5.2.2.1. Outflow Rate and Fire Size Modelling

The first step within the Fire Hazard Assessment is to identify the type of release that is being modelled. This will be one of the following types:

- Pure Gas (e.g. gas line from the top of a separator to compression train)
- Two Phase (e.g. mixed incoming fluids in the production header)
- Pure Liquid (e.g. liquid line from a liquid filled vessel)
- Liquid Followed by Gas (e.g. release from below the interface level in a separator)
- Gas Supported by Flashing Liquid (e.g. release from above the interface level in a separator)
- Riser Release.

Each of these requires a specific approach with a unique set of calculations. An explanation of how the outflows are calculated for each of the identified release types is outlined in the following sections. For each case, the outflow will be modelled for up to four combinations of the ESD and blowdown system operating:

- Base Case – Safety Systems operate as intended
- Blowdown Fails – There is no opportunity to remove any inventory to the flare, hence all inventory has the potential to come out of the breach
- Isolation Fails – A single isolation valve fails, linking the inventory to the largest adjacent inventory. In this case, the blowdown on the source and adjacent inventories is assumed to still operate, giving the inventory two routes to the flare system.
- Isolation and Blowdown Fails - As above, but now there are no routes to the flare, hence all of the volume from both inventories has the potential to be released from the breach.

Note that, for all cases (gas, two phase and liquid) where isolation fails, the properties of the initial release are used in the release calculation, with the mass from the adjacent inventory being converted to the conditions of the initial release.

In all cases, the duration of the release is calculated up to the point where the jet fire drops to 3m in length. It is assumed that these fires can be dealt with using fixed or portable firefighting equipment and present a very low probability of escalation or additional risk to personnel. Note that in some cases this may cause the results to indicate a shorter fire duration for releases from smaller hole sizes than larger ones.

Further details on the fire modelling methodology can be found in Appendix B.

5.2.3. Explosion Modelling

CFD modelling was carried out using the FLACS CFD code, which is an industry standard application for this type of analysis. The first stage of the explosion analysis agreed the targets at which blast loads will be gathered (e.g. turret, living quarters, process modules). A range of explosion cases were modelled. These comprised of simulations of different cloud sizes, cloud locations and ignition point locations. Explosions were modelled in the topsides modules and the cargo deck (note explosions in the turret are excluded since these results are provided by the turret designers APL [34]).

The blast loads at the targets of interest were reported. Contours of overpressure were produced to show the loads experienced by particular structures and in areas such as corners formed between the fire wall and protected escape routes. The main targets or areas of interest were the process modules, the forward face of the electrical building and the area of the turret closest to the process modules.

Leak frequencies, ignition probabilities and metocean data were combined with the dispersion and blast results to generate exceedance curves and DiALs for each target. Frequency based Design accident loads (DiALs) were extracted from the exceedance curves at frequencies of 10^{-4} and 10^{-5}.

Further details on the use of the explosion loads to determine DiALs, through the development of exceedance curves, is described in Section 5.8.

5.3. Dispersion Modelling

CFD simulations Representative dispersion scenarios were used for modelling using the CCM+ CFD code. A range of simulations were carried out to allow for modelling releases from different topsides/cargo deck locations. Each location was modelled with 3 representative leak rates, in the prevailing wind conditions. The simulations were processed to determine the flammable gas cloud sizes and locations in the topsides and cargo deck areas.

5.3.1. Leak Modelling

5.3.1.1. Leak type and composition

Leaks are classified as one of the following:

- Vapour release – treated as a choked, sonic vapour release.
- Flashing release – treated as a liquid release, to calculate the release rate. Note that the post-flash jet may still contain liquid content. As discussed below, it will conservatively be assumed that this liquid all evaporates as the droplet spray passes through the module or boils off when the liquid droplets impact on pipework, structure and equipment in the module. The full stream release rate is therefore used as a high momentum vapour source, with an appropriate flashing jet source term.
- Liquid release – non-flashing liquid releases. It is assumed that there is negligible evaporation of the liquid and that there is therefore negligible vapour production.

A representative gas composition is chosen for each leak location and is used to calculate a gas molecular weight and flammability limits. Flashing and evaporating liquid leaks are treated separately from vapour leaks, since they have significantly different material properties and source terms.

5.3.1.2. Leak events

The FPSO topsides currently includes a number of modules containing hydrocarbons – Turret, Separation, Compression and fuel gas to the Power Generator Turbines. The Upper Deck space also contain hydrocarbon release sources associated with loading and offloading oil, with the HC Gas Blanket pipework also being located on the Upper Deck.

Leaks will conservatively be directed into the module block containing the leak source. This maximises the gas build-up within the module block, since it is reasoned that a leak directed across a large open gap would generate two smaller clouds, with a total smaller than the volume of the single cloud from a leak directed into the module block.

Furthermore, it is assumed that:

- There is a 1-in-6 chance that a topside leak will be directed off the side of the FPSO and therefore will not contribute to any significant gas cloud formation within the congested region.
- Releases with the Process Deck that are orientated upwards could result in gas accumulation in the Upper Deck area, as the boundary between these two levels could be a mixture of plated and grated decks (to be confirmed during FEED).
- Releases within the Upper Deck are likely to disperse upwards and away from the FPSO, due to the predominantly buoyant nature of the gas.

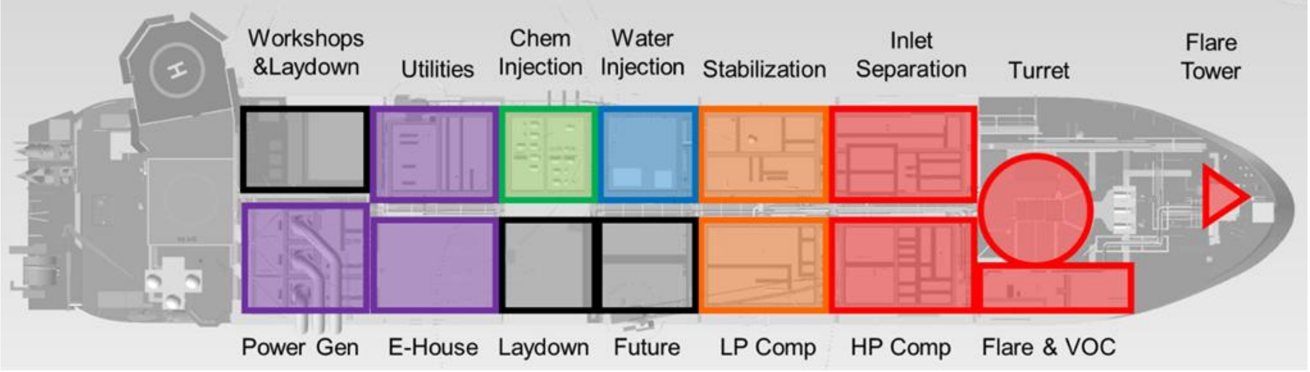


Figure 5-1 FPSO Layout and Location of Modules

5.4. Fire and Explosion Modelling Results

5.4.1. Initial Release Rates, Fires Sizes and Durations

The initial release rates, fire sizes and fire durations calculated for each topsides and riser events are summarised in the tables below. For all topsides releases, breach sizes of 10mm, 50mm and 100mm have been modelled. For riser releases, full-bore releases have been modelled instead of 100mm releases, due to the nature of the available data on riser releases from OGP.

Initial release rates and fire sizes are shown in the tables below. A summary of release durations for various combinations of isolation and blowdown are shown in Appendix B.

Table 5-1 Initial Release Rates for Topsides and Riser Events

Failure Case Description	Event ID	Initial Fire Type	Initial Release Rate (kg/s)		
			Small (10mm)	Medium (50mm)	Large (100mm)
BdN Production Flowline 1 and 2 (ESV to XSV) - Two Phase Release at Turret Lower Deck	P01-M-TRTL	Gas Jet	0.52	12.97	51.88
MP Inlet and Test Manifolds - Two Phase Release at Piperack	P01-M-PRK	Gas Jet	0.52	12.97	51.88
MP Inlet and Test Manifolds - Two Phase Release at M10 Process Deck Level 1	P01-M-M10L1	Gas Jet	0.52	12.97	51.88
MP Inlet and Test Manifolds - Two Phase Release at Turret Upper Deck	P01-M-TRTU	Gas Jet	0.52	12.97	51.88
HP Inlet and Test Manifolds - Two Phase Release at Turret Upper Deck	P02-M-TRTU	Gas Jet	0.52	12.97	51.88
HP Inlet and Test Manifolds - Two Phase Release at Piperack	P02-M-PRK	Gas Jet	0.52	12.97	51.88
HP Inlet and Test Manifolds - Two Phase Release at M10 Process Deck Level 1	P02-M-M10L1	Gas Jet	0.52	12.97	51.88
HP Spare, Cambriol and Circulation Production Flowline (ESV to XSV) - Two Phase Release at Turret Lower Deck	P02-M-TRTL	Gas Jet	0.52	12.97	51.88
Test Separator (20-VA-1004) - Two Phase Release at M10 Process Deck Level 1	P03-M-M10L1	Gas Jet	0.52	12.88	51.53
Test Separator (20-VA-1004) - Gas Release at M10 Process Deck Level 1	P03-G-M10L1	Gas Jet	0.19	4.80	19.21
Test Separator (20-VA-1004) - Liquid Release at M10 Process Deck Level 1	P03-L-M10L1	Liquid Spray	2.31	57.85	231.39
Inlet Separator (20-VA-1001) - Two Phase Release at M10 Process Deck Level 1	P04-M-M10L1	Gas Jet	0.52	12.88	51.53
Inlet Separator (20-VA-1001) - Gas Release at M10 Process Deck Level 1	P04-G-M10L1	Gas Jet	0.19	4.80	19.21
Inlet Separator (20-VA-1001) - Gas Release at Piperack	P04-G-PRK	Gas Jet	0.19	4.80	19.21
Inlet Separator (20-VA-1001) - Liquid Release at M10 Process Deck Level 1	P04-L-M10L1	Liquid Spray	0.99	24.68	98.74
LP Separator (20-VA-1002) - Two Phase Release at M11 Process Deck Level 2	P05-M-M11L2	Gas Jet	0.31	7.77	31.08
LP Separator (20-VA-1002) - Gas Release at M11 Process Deck Level 2	P05-G-M11L2	Gas Jet	0.02	0.52	2.09
LP Separator (20-VA-1002) - Liquid Release at M11 Process Deck Level 2	P05-L-M11L2	Liquid Pool	0.72	17.98	71.92
1st Stage LP Compressor Scrubber Pumps (23-PA-6001A/B) - Two Phase Release at M60 Process Deck Level 1	P05-M-M60L1	Gas Jet	0.31	7.77	31.08
Electrostatic Coalescer (20-VJ-1003) & Oil Booster Pump (20-PA-1001A/B) & Crude Oil Coolers (20-HB-1002A/B) - Liquid Release at M11 Process Deck Level 1	P06-L-M11L1	Liquid Spray	1.23	30.87	123.48
Crude Oil Loading Header - Liquid Release at M11 Process Deck Level 1	P07-L-M11L1	Liquid Pool	0.42	10.41	41.64
Crude Oil Loading Header - Liquid Release at Piperack	P07-L-PRK	Liquid Pool	0.42	10.41	41.64
Crude Oil Loading Header - Liquid Release on Hull	P07-L-HULL	Liquid Pool	0.50	12.43	49.72
Cargo Tank - Liquid Release on Hull	P08-L-HULL	Liquid Pool	0.42	10.41	41.64
Off-Spec Fluid Tank - Liquid Release on Hull	P09-L-HULL	Liquid Pool	0.42	10.41	41.64
Off-Spec Fluid Tank - Liquid Release at Piperack	P09-L-PRK	Liquid Pool	0.42	10.41	41.64
Crude Oil Transfer Header - Liquid Release on Hull	P10-L-HULL	Liquid Spray	2.30	57.47	229.88
Crude Oil Offloading Header - Liquid Release at Piperack	P10-L-PRK	Liquid Spray	2.30	57.47	229.88
Crude Oil Offloading Header - Liquid Release at M10 Process Deck Level 1	P10-L-M10L1	Liquid Spray	2.30	57.47	229.88
Crude Oil Offloading Header - Liquid Release on Hull	P11-L-HULL	Liquid Spray	2.30	57.47	229.88
Crude Oil Offloading Reel - Liquid Release on Hull	P12-L-HULL	Liquid Spray	2.30	57.47	229.88
Crude Oil Offloading Reel - Liquid Release at Offloading Reel	P12-L-OFF	Liquid Spray	2.30	57.47	229.88
COT Gas Blanketing - Gas Release on Hull	P13-G-HULL	Gas Jet	0.00	0.03	0.12
COT Gas Blanketing - Gas Release at Piperack	P13-G-PRK	Gas Jet	0.00	0.03	0.12
COT Gas Blanketing - Gas Release at M30 Process Deck Level 1	P13-G-M30L1	Gas Jet	0.00	0.03	0.12
1st Stage LP Gas Compression Suction Cooler (23-HB-6001) - Two Phase Release at M60 Process Deck Level 2	P14-M-M60L2	Gas Jet	0.04	0.96	3.85
1st Stage LP Gas Compression - Gas Release at M60 Process Deck Level 1	P14-G-M60L1	Gas Jet	0.08	2.06	8.23
1st Stage LP Gas Suction Scrubber (23-VG-6001) - Liquid Release at M60 Process Deck Level 1	P14-L-M60L1	Liquid Spray	1.32	32.96	131.83
1st Stage Recompression to Flare KO Drum (43-VD-3001) - Gas Release at Piperack	P14-G-PRK	Gas Jet	0.08	2.06	8.23
2nd Stage LP Gas Compression Suction Cooler (23-HB-6002) - Two Phase Release at M60 Process Deck Level 2	P15-M-M60L2	Gas Jet	0.11	2.79	11.18
2nd Stage LP Gas Compression - Gas Release at M60 Process Deck Level 1	P15-G-M60L1	Gas Jet	0.11	2.67	10.66
2nd Stage LP Gas Compressor Suction Scrubber (23-VG-6002) - Liquid Release at M60 Process Deck Level 1	P15-L-M60L1	Liquid Spray	1.29	32.27	129.07
MP Gas Compression - Gas Release at Piperack	P16-G-PRK	Gas Jet	0.70	17.46	69.85
MP Gas Compression Suction Cooler (23-HA-6003) - Two Phase Release at M60 Process Deck Level 2	P16-M-M60L2	Gas Jet	0.23	5.66	22.65
MP Gas Compression - Gas Release at M60 Process Deck Level 1	P16-G-M60L1	Gas Jet	0.70	17.46	69.85
MP Gas Compression Suction Scrubber (23-VG-6003) - Liquid Release at M60 Process Deck Level 1	P16-L-M60L1	Liquid Spray	3.83	95.76	383.04

Failure Case Description	Event ID	Initial Fire Type	Initial Release Rate (kg/s)		
			Small (10mm)	Medium (50mm)	Large (100mm)
Gas Dehydration Inlet Cooler (24-HG-6601) - Two Phase Release at M60 Process Deck Level 2	P17-M-M60L2	Gas Jet	0.89	22.32	89.28
Gas Dehydration System - Two Phase Release at Piperack	P17-M-PRK	Gas Jet	0.89	22.32	89.28
Gas Dehydration Inlet Scrubber (24-VG-6601) - Two Phase Release at M61 Process Deck Level 1	P17-M-M61L1	Gas Jet	0.89	22.32	89.28
Gas Dehydration Inlet Scrubber (24-VG-6001) & TEG Contactor (24-VB-6602) & 1st Stage HP Gas Compressor Suction Scrubber (23-VG-6004) - Gas Release at M61 Process Deck Level 1	P17-G-M61L1	Gas Jet	1.06	26.42	105.67
Gas Dehydration & 1st Stage HP Gas Compression - Gas Release at Piperack	P17-G-PRK	Gas Jet	1.06	26.42	105.67
Gas Dehydration Inlet Scrubber (24-VG-6601) - Liquid Release at M61 Process Deck Level 1	P17-L-M61L1	Liquid Spray	4.01	100.25	400.99
1st Stage HP Gas Compressor Discharge Cooler (23-HG-6004) at M61 Process Deck Level 2	P17-G-M61L2	Gas Jet	1.06	26.42	105.67
2nd Stage HP Gas Compressor & Suction Scrubber (23-VG-6005) - Gas Release at M61 Process Deck Level 1	P18-G-M61L1	Gas Jet	2.69	67.33	269.32
1st & 2nd Stage HP Gas Compressor Discharge Coolers (23-HG-6004 & 23-HG-6005) - Gas Release at M61 Process Deck Level 2	P18-G-M61L2	Gas Jet	2.69	67.33	269.32
HP Gas Compression / Injection Pipework - Gas Release at M61 Process Deck Level 2	P19-G-M61L2	Gas Jet	4.46	111.56	446.22
HP Gas Compression / Injection Pipework - Gas Release at Piperack	P19-G-PRK	Gas Jet	4.46	111.56	446.22
HP Gas Compression / Injection Pipework and Flowlines - Gas Release at Turret Upper Deck	P19-G-TRTU	Gas Jet	4.46	111.56	446.22
Gas Injection/Lift 1 BDN & Gas Lift 2 Cambriol/Circulation Flowline (XSV to ESV) - Gas Release at Turret Lower Deck	P19-G-TRTL	Gas Jet	4.46	111.56	446.22
Fuel Gas System - Gas Release	P20-G-M61L1	Gas Jet	0.73	18.13	72.53
Fuel Gas System - Liquid Release	P20-L-M61L1	Liquid Spray	2.33	58.28	233.11
Fuel Gas Superheaters, Metering Skid & Filter Package - Gas Release	P20-G-M61L2	Gas Jet	0.73	18.13	72.53
Fuel Gas to Turbines - Gas Release	P21-G-M61L2	Gas Jet	0.69	17.13	68.53
Fuel Gas to Turbines - Gas Release	P21-G-PRK	Gas Jet	0.69	17.13	68.53
Fuel Gas to Turbines - Gas Release	P21-G-M90L1	Gas Jet	0.69	17.13	68.53
LP Fuel Gas to Consumers - Gas Release	P22-G-M61L2	Gas Jet	0.07	1.67	6.68
LP Fuel Gas to Consumers - Gas Release	P22-G-PRK	Gas Jet	0.07	1.67	6.68
LP Fuel Gas to Consumers - Gas Release	P22-G-M11L2	Gas Jet	0.07	1.67	6.68
Reject Vessel (44-VD-1003) - Two Phase Release at M11 Process Deck Level 3	P23-M-M11L3	Gas Jet	0.01	0.25	1.00
Reject Vessel (44-VD-1003) - Gas Release at M11 Process Deck Level 3	P23-G-M11L3	Gas Jet	0.01	0.36	1.42
Reject Vessel (44-VD-1003) - Liquid Release at M11 Process Deck Level 3	P23-L-M11L3	Liquid Spray	0.30	7.57	30.29
VOC Compression - Gas Release at Piperack	P24-G-PRK	Gas Jet	0.02	0.41	1.65
VOC Compression - Gas Release at M30 Process Deck Level 1	P24-G-M30L1	Gas Jet	0.02	0.41	1.65
Pig receiver - Two Phase Release at Turret Lower Deck	P25-M-TRTL	Gas Jet	0.52	12.97	51.88
Pig launcher - Two Phase Release at Turret Lower Deck	P26-M-TRTL	Gas Jet	0.52	12.97	51.88
BdN Production Riser 1 Subsea	R01-G-SS	Sea Surface Pool	1.56	38.94	1332.82
BdN Production Riser 2 Subsea	R02-G-SS	Sea Surface Pool	1.56	38.94	1332.82
Cambriol Riser Subsea	R05-G-SS	Sea Surface Pool	1.40	35.01	1087.79
Gas Injection/Gas Lift Riser Subsea	R06-G-SS	Gas Boil Zone	5.47	136.82	1922.29
Helifuel Skid - Liquid Release	H01-L-HELI	Liquid Spray	0.25	6.25	24.99
MP Separator - Two Phase Release at Piperack	P35-M-PRK	Gas Jet	0.33	8.13	32.53
MP Separator - Two Phase Release at M11 Process Deck Level 2	P35-M-M11L2	Gas Jet	0.33	8.13	32.53
MP Separator - Gas Release at M11 Process Deck Level 2	P35-G-M11L2	Gas Jet	0.06	1.46	5.84
MP Separator - Liquid Release at M11 Process Deck Level 2	P35-L-M11L2	Liquid Spray	0.55	13.63	54.52

Table 5-2 Initial Fire Sizes for Topsides Events

Failure Case Description	Event ID	Initial Fire Type	Initial Flame Length/Pool Diameter (m)		
			Small (10mm)	Medium (50mm)	Large (100mm)
BdN Production Flowline 1 and 2 (ESV to XSV) - Two Phase Release at Turret Lower Deck	P01-M-TRTL	Gas Jet	9.2	33.4	58.2
MP Inlet and Test Manifolds - Two Phase Release at Piperack	P01-M-PRK	Gas Jet	9.2	33.4	58.2
MP Inlet and Test Manifolds - Two Phase Release at M10 Process Deck Level 1	P01-M-M10L1	Gas Jet	9.2	33.4	58.2
MP Inlet and Test Manifolds - Two Phase Release at Turret Upper Deck	P01-M-TRTU	Gas Jet	9.2	33.4	58.2
HP Inlet and Test Manifolds - Two Phase Release at Turret Upper Deck	P02-M-TRTU	Gas Jet	9.2	33.4	58.2
HP Inlet and Test Manifolds - Two Phase Release at Piperack	P02-M-PRK	Gas Jet	9.2	33.4	58.2
HP Inlet and Test Manifolds - Two Phase Release at M10 Process Deck Level 1	P02-M-M10L1	Gas Jet	9.2	33.4	58.2
HP Spare, Cambriol and Circulation Production Flowline (ESV to XSV) - Two Phase Release at Turret Lower Deck	P02-M-TRTL	Gas Jet	9.2	33.4	58.2
Test Separator (20-VA-1004) - Two Phase Release at M10 Process Deck Level 1	P03-M-M10L1	Gas Jet	9.2	33.4	58.1
Test Separator (20-VA-1004) - Gas Release at M10 Process Deck Level 1	P03-G-M10L1	Gas Jet	6.2	22.5	39.1
Test Separator (20-VA-1004) - Liquid Release at M10 Process Deck Level 1	P03-L-M10L1	Liquid Spray	16.8	60.8	105.9
Inlet Separator (20-VA-1001) - Two Phase Release at M10 Process Deck Level 1	P04-M-M10L1	Gas Jet	9.2	33.4	58.1
Inlet Separator (20-VA-1001) - Gas Release at M10 Process Deck Level 1	P04-G-M10L1	Gas Jet	6.2	22.5	39.1
Inlet Separator (20-VA-1001) - Gas Release at Piperack	P04-G-PRK	Gas Jet	6.2	22.5	39.1
Inlet Separator (20-VA-1001) - Liquid Release at M10 Process Deck Level 1	P04-L-M10L1	Liquid Spray	11.9	29.2	29.2
LP Separator (20-VA-1002) - Two Phase Release at M11 Process Deck Level 2	P05-M-M11L2	Gas Jet	7.5	27.3	47.4
LP Separator (20-VA-1002) - Gas Release at M11 Process Deck Level 2	P05-G-M11L2	Gas Jet	2.6	9.3	16.1
LP Separator (20-VA-1002) - Liquid Release at M11 Process Deck Level 2	P05-L-M11L2	Liquid Pool	3.4	17.2	29.2
1st Stage LP Compressor Scrubber Pumps (23-PA-6001A/B) - Two Phase Release at M60 Process Deck Level 1	P05-M-M60L1	Gas Jet	7.5	27.3	47.4
Electrostatic Coalescer (20-VJ-1003) & Oil Booster Pump (20-PA-1001A/B) & Crude Oil Coolers (20-HB-1002A/B) - Liquid Release at M11 Process Deck Level 1	P06-L-M11L1	Liquid Spray	13.1	22.6	29.2
Crude Oil Loading Header - Liquid Release at M11 Process Deck Level 1	P07-L-M11L1	Liquid Pool	2.6	12.8	25.6
Crude Oil Loading Header - Liquid Release at Piperack	P07-L-PRK	Liquid Pool	2.6	12.8	25.6
Crude Oil Loading Header - Liquid Release on Hull	P07-L-HULL	Liquid Pool	2.8	14.0	27.9
Cargo Tank - Liquid Release on Hull	P08-L-HULL	Liquid Pool	2.6	12.8	25.6
Off-Spec Fluid Tank - Liquid Release on Hull	P09-L-HULL	Liquid Pool	2.6	12.8	25.6
Off-Spec Fluid Tank - Liquid Release at Piperack	P09-L-PRK	Liquid Pool	2.6	12.8	25.6
Crude Oil Transfer Header - Liquid Release on Hull	P10-L-HULL	Liquid Spray	16.7	60.7	105.6
Crude Oil Offloading Header - Liquid Release at Piperack	P10-L-PRK	Liquid Spray	16.7	60.7	105.6
Crude Oil Offloading Header - Liquid Release at M10 Process Deck Level 1	P10-L-M10L1	Liquid Spray	16.7	60.7	105.6
Crude Oil Offloading Header - Liquid Release on Hull	P11-L-HULL	Liquid Spray	16.7	60.7	105.6
Crude Oil Offloading Reel - Liquid Release on Hull	P12-L-HULL	Liquid Spray	16.7	60.7	105.6
Crude Oil Offloading Reel - Liquid Release at Offloading Reel	P12-L-OFF	Liquid Spray	16.7	60.7	105.6
COT Gas Blanketing - Gas Release on Hull	P13-G-HULL	Gas Jet	0.0	3.0	5.2
COT Gas Blanketing - Gas Release at Piperack	P13-G-PRK	Gas Jet	0.0	3.0	5.2
COT Gas Blanketing - Gas Release at M30 Process Deck Level 1	P13-G-M30L1	Gas Jet	0.0	3.0	5.2
1st Stage LP Gas Compression Suction Cooler (23-HB-6001) - Two Phase Release at M60 Process Deck Level 2	P14-M-M60L2	Gas Jet	3.3	11.8	20.6
1st Stage LP Gas Compression - Gas Release at M60 Process Deck Level 1	P14-G-M60L1	Gas Jet	4.4	16.0	27.9
1st Stage LP Gas Suction Scrubber (23-VG-6001) - Liquid Release at M60 Process Deck Level 1	P14-L-M60L1	Liquid Spray	13.4	48.6	29.2
1st Stage Recompression to Flare KO Drum (43-VD-3001) - Gas Release at Piperack	P14-G-PRK	Gas Jet	4.4	16.0	27.9
2nd Stage LP Gas Compression Suction Cooler (23-HB-6002) - Two Phase Release at M60 Process Deck Level 2	P15-M-M60L2	Gas Jet	5.0	18.1	31.5
2nd Stage LP Gas Compression - Gas Release at M60 Process Deck Level 1	P15-G-M60L1	Gas Jet	4.9	17.8	30.9
2nd Stage LP Gas Compressor Suction Scrubber (23-VG-6002) - Liquid Release at M60 Process Deck Level 1	P15-L-M60L1	Liquid Spray	13.3	22.4	29.2
MP Gas Compression - Gas Release at Piperack	P16-G-PRK	Gas Jet	10.4	37.7	65.6
MP Gas Compression Suction Cooler (23-HA-6003) - Two Phase Release at M60 Process Deck Level 2	P16-M-M60L2	Gas Jet	6.6	24.0	41.8
MP Gas Compression - Gas Release at M60 Process Deck Level 1	P16-G-M60L1	Gas Jet	10.4	37.7	65.6
MP Gas Compression Suction Scrubber (23-VG-6003) - Liquid Release at M60 Process Deck Level 1	P16-L-M60L1	Liquid Spray	20.5	74.4	129.6

Failure Case Description	Event ID	Initial Fire Type	Initial Flame Length/Pool Diameter (m)		
			Small (10mm)	Medium (50mm)	Large (100mm)
Gas Dehydration Inlet Cooler (24-HG-6601) - Two Phase Release at M60 Process Deck Level 2	P17-M-M60L2	Gas Jet	11.5	41.6	72.4
Gas Dehydration System - Two Phase Release at Piperack	P17-M-PRK	Gas Jet	11.5	41.6	72.4
Gas Dehydration Inlet Scrubber (24-VG-6601) - Two Phase Release at M61 Process Deck Level 1	P17-M-M61L1	Gas Jet	11.5	41.6	72.4
Gas Dehydration Inlet Scrubber (24-VG-6001) & TEG Contactor (24-VB-6602) & 1st Stage HP Gas Compressor Suction Scrubber (23-VG-6004) - Gas Release at M61 Process Deck Level 1	P17-G-M61L1	Gas Jet	12.3	44.5	77.4
Gas Dehydration & 1st Stage HP Gas Compression - Gas Release at Piperack	P17-G-PRK	Gas Jet	12.3	44.5	77.4
Gas Dehydration Inlet Scrubber (24-VG-6601) - Liquid Release at M61 Process Deck Level 1	P17-L-M61L1	Liquid Spray	20.9	75.8	132.0
1st Stage HP Gas Compressor Discharge Cooler (23-HG-6004) at M61 Process Deck Level 2	P17-G-M61L2	Gas Jet	12.3	44.5	77.4
2nd Stage HP Gas Compressor & Suction Scrubber (23-VG-6005) - Gas Release at M61 Process Deck Level 1	P18-G-M61L1	Gas Jet	17.8	64.6	112.5
1st & 2nd Stage HP Gas Compressor Discharge Coolers (23-HG-6004 & 23-HG-6005) - Gas Release at M61 Process Deck Level 2	P18-G-M61L2	Gas Jet	17.8	64.6	112.5
HP Gas Compression / Injection Pipework - Gas Release at M61 Process Deck Level 2	P19-G-M61L2	Gas Jet	21.8	79.1	137.7
HP Gas Compression / Injection Pipework - Gas Release at Piperack	P19-G-PRK	Gas Jet	21.8	79.1	137.7
HP Gas Compression / Injection Pipework and Flowlines - Gas Release at Turret Upper Deck	P19-G-TRTU	Gas Jet	21.8	79.1	137.7
Gas Injection/Lift 1 BDN & Gas Lift 2 Cambriol/Circulation Flowline (XSV to ESV) - Gas Release at Turret Lower Deck	P19-G-TRTL	Gas Jet	21.8	79.1	137.7
Fuel Gas System - Gas Release	P20-G-M61L1	Gas Jet	10.6	38.2	66.6
Fuel Gas System - Liquid Release	P20-L-M61L1	Liquid Spray	16.8	27.5	29.2
Fuel Gas Superheaters, Metering Skid & Filter Package - Gas Release	P20-G-M61L2	Gas Jet	10.6	38.2	66.6
Fuel Gas to Turbines - Gas Release	P21-G-M61L2	Gas Jet	10.3	37.4	65.1
Fuel Gas to Turbines - Gas Release	P21-G-PRK	Gas Jet	10.3	37.4	65.1
Fuel Gas to Turbines - Gas Release	P21-G-M90L1	Gas Jet	10.3	37.4	65.1
LP Fuel Gas to Consumers - Gas Release	P22-G-M61L2	Gas Jet	4.1	14.7	25.6
LP Fuel Gas to Consumers - Gas Release	P22-G-PRK	Gas Jet	4.1	14.7	25.6
LP Fuel Gas to Consumers - Gas Release	P22-G-M11L2	Gas Jet	4.1	14.7	25.6
Reject Vessel (44-VD-1003) - Two Phase Release at M11 Process Deck Level 3	P23-M-M11L3	Gas Jet	0.0	6.9	12.0
Reject Vessel (44-VD-1003) - Gas Release at M11 Process Deck Level 3	P23-G-M11L3	Gas Jet	2.2	7.9	13.8
Reject Vessel (44-VD-1003) - Liquid Release at M11 Process Deck Level 3	P23-L-M11L3	Liquid Spray	7.4	11.1	22.2
VOC Compression - Gas Release at Piperack	P24-G-PRK	Gas Jet	2.3	8.4	14.7
VOC Compression - Gas Release at M30 Process Deck Level 1	P24-G-M30L1	Gas Jet	2.3	8.4	14.7
Pig receiver - Two Phase Release at Turret Lower Deck	P25-M-TRTL	Gas Jet	9.2	33.4	58.2
Pig launcher - Two Phase Release at Turret Lower Deck	P26-M-TRTL	Gas Jet	9.2	33.4	58.2
BdN Production Riser 1 Subsea	R01-G-SS	Sea Surface Pool	N/A	20.0	20.0
BdN Production Riser 2 Subsea	R02-G-SS	Sea Surface Pool	N/A	20.0	20.0
Cambriol Riser Subsea	R05-G-SS	Sea Surface Pool	N/A	20.0	20.0
Gas Injection/Gas Lift Riser Subsea	R06-G-SS	Gas Boil Zone	20.0	20.0	20.0
Helifuel Skid - Liquid Release	H01-L-HELI	Liquid Spray	7.4	11.1	22.2
MP Separator - Two Phase Release at Piperack	P35-M-PRK	Gas Jet	7.7	27.8	48.3
MP Separator - Two Phase Release at M11 Process Deck Level 2	P35-M-M11L2	Gas Jet	7.7	27.8	48.3
MP Separator - Gas Release at M11 Process Deck Level 2	P35-G-M11L2	Gas Jet	3.9	14.0	24.3
MP Separator - Liquid Release at M11 Process Deck Level 2	P35-L-M11L2	Liquid Spray	9.4	29.2	29.2

Denotes pool fire diameter

Denotes sea surface pool fire or gas boil zone

Table 5-3 Riser Release Durations

Failure Case Description	Event ID	Initial Fire Type	Total Release Duration (min)			Sustainable Sea Surface Fire Duration (min)		
			Small (10mm)	Medium (50mm)	Large (100mm)	Small (10mm)	Medium (50mm)	Large (100mm)
BdN Production Riser 1 Subsea	R01-G-SS	Sea Surface Pool	>120	60.0	6.0	N/A	10.0	5.0
BdN Production Riser 2 Subsea	R02-G-SS	Sea Surface Pool	>120	60.0	6.0	N/A	10.0	5.0
Cambriol Riser Subsea	R05-G-SS	Sea Surface Pool	>120	6.0	2.0	N/A	5.0	1.0
Gas Injection/Gas Lift Riser Subsea	R06-G-SS	Gas Boil Zone	>120	60.0	36.0	60.0	40.0	30.0

5.4.2. Event Analysis

The analysis of each hydrocarbon event takes place in several stages and is based on the event trees shown in Figure 5-2 and Figure 5-3.

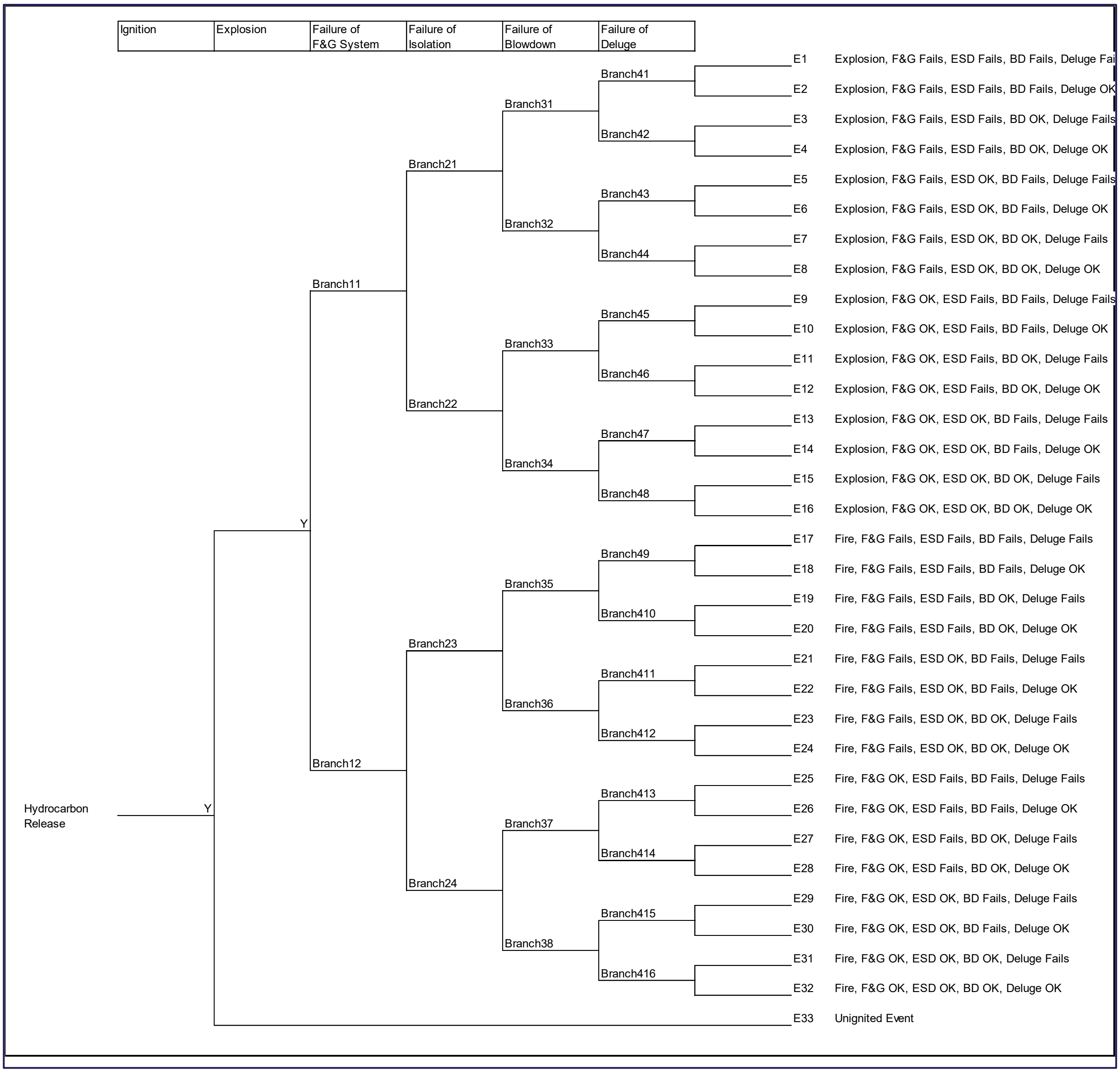


Figure 5-2 Hydrocarbon Release Event Tree

The event tree in Figure 5-2 combines the base event frequency with a probabilistic analysis to produce the frequency of thirty-three possible outcomes (E1 to E33) for each breach size. It is not intended to represent the action of each safety system in chronological order from left to right across the event tree, e.g. the fire and gas detection system will have an effect on the outcome of an explosion event by acting to send a signal to close ESDVs and operate blowdown and therefore limit the size of gas cloud which could build up prior to ignition.

However, presenting the event tree in this way allows explosion events to be the top 16 branches and fire events to be the next 16 branches, for a total of 32 ignited events

The event trees for each accident event are located in the calculation engine, with the branch probabilities for each event being stored in an input data sheet which contains all the event specific data required to perform the risk calculations.

An input sheet is used for each of the hydrocarbon accident events. Muster, TEMPSC and TR impairment probabilities are assigned for each breach size and are entered into each event tree input sheet. TEMPSC and TR impairments are entered separately for different mechanisms of impairment.

Where the fire and gas system fail to detect the release or fails to operate then it is assumed that manual intervention is required to initiate the ESD and blowdown systems. A 10% chance that the operator fails to initiate the system is built into the analysis, as described previously in Section 3.2.1. The consequences of these outcomes (E1 to E33) are then assessed to determine the probability of:

- Immediate fatalities
- Muster fatalities
- Fatalities in the Temporary Refuge when evacuation is not possible
- Fatalities during evacuation when the Temporary Refuge is impaired.

The immediate fatalities caused at the site of the event are estimated for each end outcome of the event tree according to the type and size of the event and the typical numbers of exposed personnel. The probabilities of the event impairing escape routes to muster are estimated and additional casualties as a result of failing to muster are calculated.

Figure 5-3 shows the post-muster event tree. The event tree illustrates the possible outcomes given that personnel have succeeded in reaching the Temporary Refuge. The TR impairment mechanisms TR1, TR2, TR3 etc may be different for the various hydrocarbon events. The impairment mechanisms are ordered in chronological order, therefore the mechanisms that results in rapid impairment will be TR1 whereas those mechanisms that take longer to cause impairment will be TR5 or TR6.

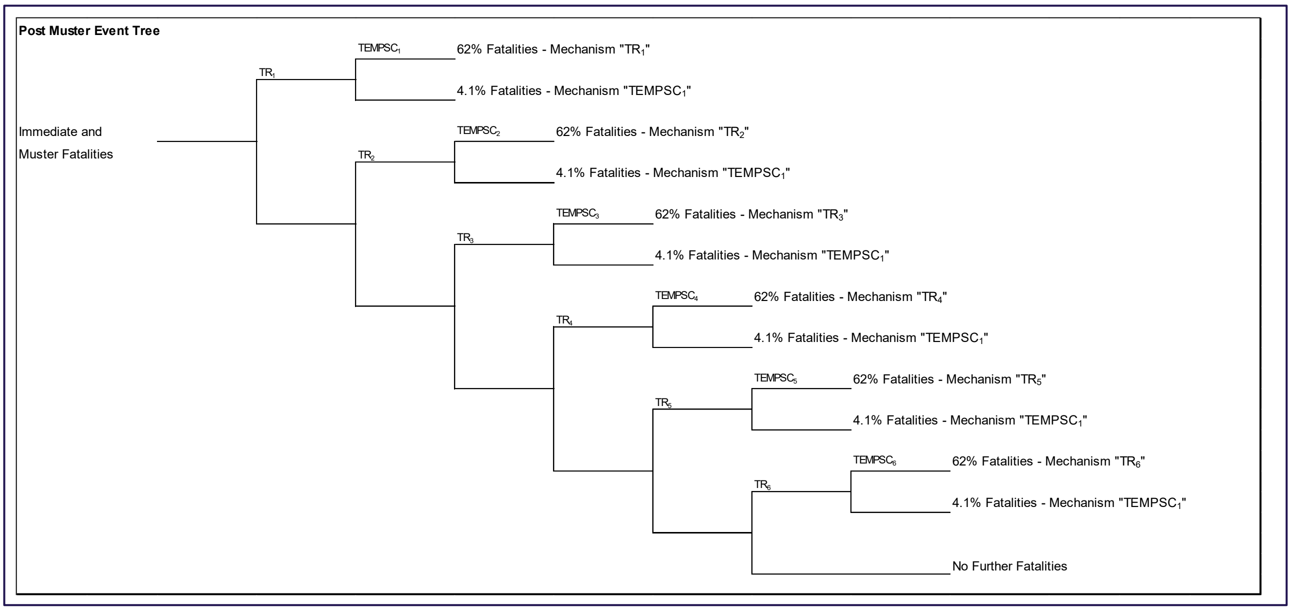


Figure 5-3 Post Muster Event Tree

These are grouped under three headings when considering further fatalities:

- Temporary Refuge Fatalities: The Temporary Refuge is impaired and evacuation facilities are impaired. In such circumstances it is assumed that 62% of the personnel remaining on the installation will be unable to successfully evacuate and become fatalities. This reasoning behind this fatality fraction is described below.
- Evacuation Fatalities: The Temporary Refuge is impaired, but evacuation facilities are available. An average of 4.1% fatality amongst personnel evacuating by TEMPSC is assumed [28] (the freefall TEMPSC has a 4% fatality fraction and the davit launched life boat uses a 7.65% fatality fraction). This is based on historical evidence of TEMPSC usage during major incidents and is independent of the time to rescue by ERRV.
- No Further Fatalities: The Temporary Refuge is not impaired, and personnel do not evacuate the installation.

It should be noted that there is an inherently optimistic assumption here. This is that the installation is only evacuated if the Temporary Refuge is threatened. In reality, the decision to evacuate may be taken before the Temporary Refuge is actually impaired. This evacuation may not have been necessary.

The 62% fatality fraction, for personnel trapped in the TR, was developed on the basis that for any given hydrocarbon event scenario which impaired the TR and TEMPSC facilities, a range of numbers of fatalities was possible. This is described in more detail in Section 5.9.3. This fatality fraction is applied consistently to those events that impair both the TR and TEMPSC. There are no catastrophic events that happen so quickly as to justify a higher fatality fraction, which is primarily due to the layout and design of the FPSO.

The equations used to calculate these different fatality types are presented in the methodology [28]. Each stage of the risk analysis process is discussed in more detail below.

5.5. Hydrocarbon Event Release Frequencies

5.5.1. Release Sizes

Inventory release sizes for the consequence modelling will be based on representative hole sizes, for each failure case. The background for choosing the hole sizes is presented in [35]. The figures below can be used as guidance for selecting a lower limit for hole sizes to be included in the release frequency.

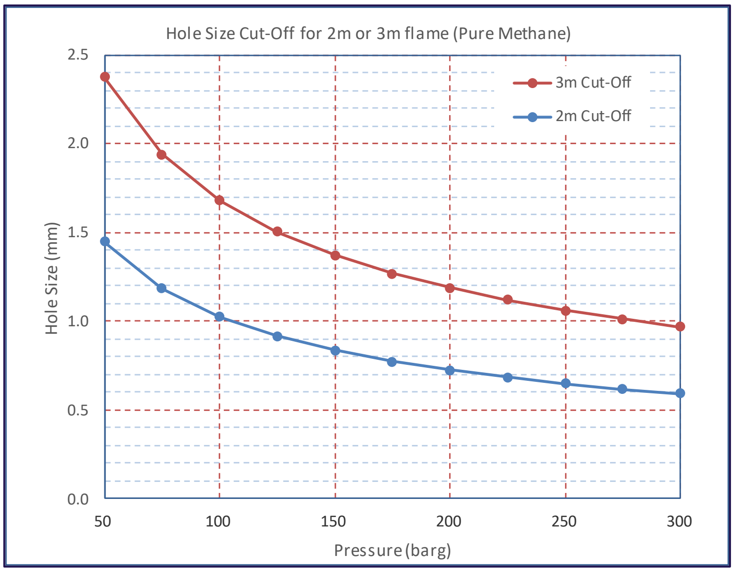


Figure 5-4 Hole Size Cut-off for 2m or 3m flame

At the highest pressure in the plant (around 300barg), a 1mm breach would generate an outflow rate of around 0.05 kg/s, which corresponds to a 3m jet fire. This flame length is considered borderline in terms of escalation potential and presents a limited immediate threat to personnel. The release rate is also below the 0.1 kg/s cut-off specified in GL0282 [37] and therefore hole sizes less than 1mm will not be included within the frequency analysis. Based on the ranges below, representative hole sizes can be calculated from the weighted average of the hole sizes within the supporting database across the hole size range. It is suggested that all releases above 100 mm should be modelled as 100 mm and that full-bore releases are reserved for risers.

Table 5-4 Representative Hole Sizes

Representative Hole Size	Hole Size Range (mm)
Not included	≤ 1
10mm	1-22.5
50mm	22.5-70.7
100mm	>70.7
Full Bore (risers only)	Rupture

5.5.2. Equipment Counts Procedure

The hydrocarbon hazards are defined according to the isolatable section of plant from which a release could occur. These sections are based on the plant contained within isolation valves. Isolation points have been assumed based on the latest sectionalisation drawings [10] for the process and have been discussed with the project team. A count of equipment packages has been completed based on the PFDs e.g. an event may contain a separator package, pump package and heat exchanger package. The more detailed items of equipment associated with a particular package are based on detailed parts counts completed by Kent on other Offshore facilities and are recorded in [35]. In the next phase of the project, the QRA will be further developed using P&IDs. In order to establish inventories and failure cases, shutdown valves were identified as isolation points. For each failure case, a package count has been carried out, using the following packages:

- Vessel Package – Gas Side
- Vessel Package – Liquid Side
- Separator Package – Gas Side
- Separator Package – Liquid Side
- Pump (Centrifugal – Single Seal) Package
- Compressor Accessories (per stage)
- Metering
- Heat Exchanger Package (accessories only).

Where a failure case includes a compressor or heat exchanger, the package count accounts for accessories only and compressors / heat exchangers will be counted separately.

When completing a count, the following assumptions have been made:

- In addition to the package count, a blowdown valve has been included in the count for gas inventories and shutdown valves have been included as per the assumptions made on the PFD. Associated flanges will be counted for both blowdown and shutdown valves.

- It is assumed that each stage of a compressor should be counted separately as a "compressor". This is a conservative assumption as it is not known exactly how the population of compressors across the North Sea was recorded.
- Pumps on the FPSO have been counted as single seal type, which have a higher historical leak frequency than double seal types.
- The compressor packages are based on centrifugal type compressors, which historically have a lower leak frequency than reciprocating types.
- Pipework is assumed to be routed through piperacks for module / deck changes.

Piping lengths have been estimated by using the same approach as for piping volume estimation (see Section 5.2.1 – i.e. by summing the difference in location between connected equipment in the x, y and z directions, and then doubling the total to allow for complex routing. Estimates of pipework lengths for small diameter pipework will also be made as these can have a significant effect on the overall leak frequency.

An example package count sheet for one event is shown below. The "offset" column represents the frequency of releases 1mm and below that has been removed from the analysis, as described earlier in Section 5.5.1.

Table 5-5 Sample Failure Rate Input Sheet

Event Name	P3L-P11		Frequency Count					
Event Location	P11							
Equipment Description		Number of Components	Total	Offset	Small (10mm)	Medium (50mm)	Large (100mm)	XLarge
Centrifugal Compressors								
Reciprocating Compressors								
Reciprocating Pump								
Centrifugal Pump (double seal)								
Centrifugal Pump (Single seal)								
Shell & Tube Heat Exchangers	Shell							
Shell & Tube Heat Exchangers	Tubing	2	1.76E-03	3.01E-03	1.58E-03	1.58E-05	1.58E-04	
Plate								
Fin Fan Coolers								
Dual Fuel Turbines								
Gas Turbines								
Expanders								
Pressure Vessels								
Pig Receivers & Launchers	All Sizes							
Wellheads / Xmas Tree (Press. < 5000 psi)								
Wellheads / Xmas Tree (Press. > 5000 psi)								
Crude Oil Storage Tank								
Filters								
Instruments								
Flanges	D ≤ 3"							
Flanges	3" < D ≤ 11"	2	2.81E-05	4.10E-05	2.69E-05	7.29E-07	4.60E-07	
Flanges	D > 11"							
ESD Valves	D ≤ 3"							
ESD Valves	D > 3"	1	1.19E-04	1.88E-04	1.09E-04	7.97E-06	2.53E-06	
Other Actuated Valves	D ≤ 3"							
Other Actuated Valves	D > 3"							
Manual Valves	D ≤ 3"							
Manual Valves	3" < D ≤ 11"							
Manual Valves	D > 11"							
Steel Piping (/ metre)	D ≤ 3"							
Steel Piping (/ metre)	3" < D ≤ 11"	193.48	4.43E-03	4.05E-03	4.16E-03	2.41E-04	3.32E-05	
Steel Piping (/ metre)	D > 11"							
Flexible Piping (All sizes / metre)	All Sizes							
Packages								
Vessel Package - Gas Side								
Vessel Package - Liquid Side								
Separator Package - Gas Side								
Separator Package - Liquid Side		1	4.93E-03		4.66E-03	2.05E-04	6.84E-05	
Pump (Centrifugal - Single seal) Package		2	1.35E-02		1.31E-02	3.69E-04	5.64E-05	
Compressor Accessories (per stage)								
Metering								
Heat Exchanger Package (accessories only)		2	3.43E-03		3.30E-03	9.68E-05	3.10E-05	
Flowline								
Production Swivel**								
Loading Arm (quantity - 1) ***								
Loading Arm (quantity - 2) ***								
Total Leak Frequency (/yr) for Isolated Section			2.82E-02		2.70E-02	9.35E-04	3.50E-04	

Note: "Offset" refers to the frequency count associated with 1mm and below releases

5.5.3. Generic Component Failure Rate Data

As discussed previously in Section 3, the release frequency is calculated based on Kents interpretation of the UK HSE release database available online [35]. This covers all releases from the UK continental shelf in the period from 1992 to 2015. This is in line with NORSOK [36] Annex D, which references the UK HSE data (OIR 12), and supersedes the 2008 UK HSE data that is used in the DNV reference in Section A.3 of GL0282 [37]. It is also understood that the leak frequencies in the OIR12 database give much higher frequencies than would be the case with the alternative PLOFAM [38] database and hence provide a more conservative estimate of the risks.

5.5.4. Riser Failure Rates

Risers on the Bay du Nord FPSO shall be flexible risers.

Releases from sections of the riser outboard of the riser ESDV, the riser beneath the FPSO and flowline up to the 500m Safety Zone, will be modelled using the PARLOC database referenced in the Kent Riser Leak Frequency 03 Method Statement [39]. The PARLOC data covers releases from flexible and steel risers in the period 2001 – 2012, within the UK Continental Shelf of the North Sea.

The use of the PARLOC database is in line with Annex D of NORSOK [36] and also supersedes the DNV 2009 pipeline and riser data referred to in GL0282 [37] Section A3.

The PARLOC database provides leak frequencies for rigid steel and flexible risers. The base case assumes that all risers are flexible.

Table 5-6 Riser Release Frequencies

Release Source	Flexible	Rigid Steel
Riser – Above Sea (/yr)	3.10E-03	8.50E-04
Riser – Below Sea (/yr)	3.10E-03	8.09E-04
Safety Zone – Near (/yr)	7.30E-04	7.59E-04
Safety Zone – Far (/yr)	6.79E-04	4.92E-04
Midline (/km-yr)	2.49E-03	2.51E-04

Mooring failure has been identified as potentially resulting in loss of position of the FPSO, to the extent where riser failure may occur. The safeguards in place to prevent this occurring include the number of mooring line clusters in place, the system being designed for survival of 2-line failures, the ability of the FPSO to maintain position using thrusters and the risers being designed for an excursion distance of 160m. As such, mooring line failure has not been included as an additional riser failure mechanism at this stage in the design but will continue to be reviewed as the design progresses.

The potential for overboard dropped objects to impact the risers is discussed in more detail in Section 5.17.

Table 5-7 shows the total release frequencies for the production and gas injection risers, including valves, fittings, etc. The release frequency for the risers is based on 3 production risers and 1 gas injection riser.

5.5.5. Blowout Frequencies

Blowouts from the subsea wells will not directly impact on the FPSO and therefore are not included in the calculation of risk to personnel on the Bay du Nord. The potential impact of blowouts on the surrounding environment will be assessed and considered further in the Environmental Impact Statement (EIS). In subsequent phases of the Project, where risks to Mobile Offshore Drilling Unit (MODU) personnel is required, then the blowout frequencies provided in the Kent Method Statement 04 [40] could be used, which is based on the SINTEF database [41].

5.5.6. Overall Hydrocarbon Release Frequencies

The overall hydrocarbon release frequency for the Bay du Nord FPSO has been calculated as 5.92E-01, this is equal to a leak every 1.69 years on the installation. Leak frequency per event is shown in Table 5-7.

The inlet manifolds (inventories P01 and P02) contribute 11.0% of the total leak frequency.

The separation equipment (inventories P3 to P6 and P35) contribute 34.2% of the total leak frequency.

The oil export header, metering, offloading and offloading reel events have had their release frequency modified to reflect the fact that their system is only used intermittently and drained and flushed when not in use. Offloads are assumed to occur every 6 days and for a 24-hour period. Despite the fact that not all of the equipment is used continuously, the oil loading, offloading and metering equipment (P7 to P12) contribute 5.8% to the leak frequency.

The recompression and reinjection equipment and fuel gas system (inventories P14-18 and P20-P23) contributes 36.1% of the FPSO leak frequency.

Releases associated with the VOC compression (P24) and hydrocarbon gas blanket system (P13) contribute 6.1% in total, which is primarily a result of the large amount of pipework associated with these inventories. They are either fed by a number of gas inventories or provide gas to a number of COTs, although the operating pressure of the equipment is low and therefore, they would not be expected to be high contributors to risk on the FPSO.

Gas injection flowlines (P19) in the turret and riser events (R01, R02, R05, R06) only contribute 3.4% of the total leak frequency.

Table 5-7 Summary of Base Case Release Frequencies (per Annum)

Failure Case Description	Event ID	Location	Leak Frequency (/yr)			Total	%
			Small (10mm)	Medium (50mm)	Large (100mm)		
BdN Production Flowline 1 and 2 (ESV to XSV) - Two Phase Release at Turret Lower Deck	P01-M-TRTL	TRTL	8.07E-03	2.79E-04	1.63E-04	8.51E-03	1.44%
MP Inlet and Test Manifolds - Two Phase Release at Piperack	P01-M-PRK	PRK	2.78E-03	7.85E-05	7.85E-05	2.94E-03	0.50%
MP Inlet and Test Manifolds - Two Phase Release at M10 Process Deck Level 1	P01-M-M10L1	M10L1	1.55E-02	5.53E-04	2.32E-04	1.62E-02	2.75%
MP Inlet and Test Manifolds - Two Phase Release at Turret Upper Deck	P01-M-TRTU	TRTU	3.58E-03	1.35E-04	4.46E-05	3.76E-03	0.64%
HP Inlet and Test Manifolds - Two Phase Release at Turret Upper Deck	P02-M-TRTU	TRTU	1.12E-02	3.88E-04	1.95E-04	1.18E-02	2.00%
HP Inlet and Test Manifolds - Two Phase Release at Piperack	P02-M-PRK	PRK	2.78E-03	7.85E-05	7.85E-05	2.94E-03	0.50%
HP Inlet and Test Manifolds - Two Phase Release at M10 Process Deck Level 1	P02-M-M10L1	M10L1	1.66E-02	5.65E-04	2.42E-04	1.74E-02	2.94%
HP Spare, Cambriol and Circulation Production Flowline (ESV to XSV) - Two Phase Release at Turret Lower Deck	P02-M-TRTL	TRTL	1.24E-03	5.54E-05	1.80E-05	1.32E-03	0.22%
Test Separator (20-VA-1004) - Two Phase Release at M10 Process Deck Level 1	P03-M-M10L1	M10L1	1.93E-02	8.51E-04	1.27E-04	2.03E-02	3.43%
Test Separator (20-VA-1004) - Gas Release at M10 Process Deck Level 1	P03-G-M10L1	M10L1	9.44E-03	3.61E-04	1.32E-04	9.94E-03	1.68%
Test Separator (20-VA-1004) - Liquid Release at M10 Process Deck Level 1	P03-L-M10L1	M10L1	7.76E-03	3.61E-04	7.21E-05	8.19E-03	1.38%
Inlet Separator (20-VA-1001) - Two Phase Release at M10 Process Deck Level 1	P04-M-M10L1	M10L1	1.01E-02	6.70E-04	1.60E-04	1.09E-02	1.85%
Inlet Separator (20-VA-1001) - Gas Release at M10 Process Deck Level 1	P04-G-M10L1	M10L1	9.87E-03	3.84E-04	1.39E-04	1.04E-02	1.76%
Inlet Separator (20-VA-1001) - Gas Release at Piperack	P04-G-PRK	PRK	4.80E-03	2.04E-04	1.83E-05	5.02E-03	0.85%
Inlet Separator (20-VA-1001) - Liquid Release at M10 Process Deck Level 1	P04-L-M10L1	M10L1	1.63E-02	7.30E-04	3.58E-04	1.74E-02	2.95%
LP Separator (20-VA-1002) - Two Phase Release at M11 Process Deck Level 2	P05-M-M11L2	M11L2	2.08E-02	9.26E-04	4.41E-04	2.21E-02	3.74%
LP Separator (20-VA-1002) - Gas Release at M11 Process Deck Level 2	P05-G-M11L2	M11L2	3.14E-03	1.54E-04	6.33E-05	3.36E-03	0.57%
LP Separator (20-VA-1002) - Liquid Release at M11 Process Deck Level 2	P05-L-M11L2	M11L2	4.29E-03	1.37E-04	5.71E-05	4.48E-03	0.76%
1st Stage LP Compressor Scrubber Pumps (23-PA-6001A/B) - Two Phase Release at M60 Process Deck Level 1	P05-M-M60L1	M60L1	2.57E-02	9.57E-04	1.81E-04	2.68E-02	4.53%
Electrostatic Coalescer (20-VJ-1003) & Oil Booster Pump (20-PA-1001A/B) & Crude Oil Coolers (20-HB-1002A/B) - Liquid Release at M11 Process Deck Level 1	P06-L-M11L1	M11L1	2.84E-02	1.30E-03	2.68E-04	2.99E-02	5.06%
Crude Oil Loading Header - Liquid Release at M11 Process Deck Level 1	P07-L-M11L1	M11L1	5.41E-04	1.84E-05	1.57E-05	5.75E-04	0.10%
Crude Oil Loading Header - Liquid Release at Piperack	P07-L-PRK	PRK	6.37E-04	1.80E-05	1.80E-05	6.73E-04	0.11%
Crude Oil Loading Header - Liquid Release on Hull	P07-L-HULL	HULL	8.58E-03	4.89E-04	7.83E-05	9.14E-03	1.55%
Cargo Tank - Liquid Release on Hull	P08-L-HULL	HULL	2.39E-03	1.02E-03	6.29E-04	4.04E-03	0.68%
Off-Spec Fluid Tank - Liquid Release on Hull	P09-L-HULL	HULL	2.61E-03	1.03E-03	6.35E-04	4.28E-03	0.72%
Off-Spec Fluid Tank - Liquid Release at Piperack	P09-L-PRK	PRK	3.45E-03	2.01E-04	3.15E-05	3.68E-03	0.62%
Crude Oil Transfer Header - Liquid Release on Hull	P10-L-HULL	HULL	9.00E-03	5.08E-04	8.79E-05	9.59E-03	1.62%
Crude Oil Offloading Header - Liquid Release at Piperack	P10-L-PRK	PRK	1.18E-04	6.84E-06	9.44E-07	1.26E-04	0.02%
Crude Oil Offloading Header - Liquid Release at M10 Process Deck Level 1	P10-L-M10L1	M10L1	1.09E-04	6.50E-06	9.45E-07	1.17E-04	0.02%
Crude Oil Offloading Header - Liquid Release on Hull	P11-L-HULL	HULL	5.04E-04	2.68E-05	6.61E-06	5.38E-04	0.09%
Crude Oil Offloading Reel - Liquid Release on Hull	P12-L-HULL	HULL	1.27E-03	6.46E-05	2.02E-05	1.36E-03	0.23%
Crude Oil Offloading Reel - Liquid Release at Offloading Reel	P12-L-OFF	OFF	7.47E-07	2.02E-08	1.28E-08	7.80E-07	0.00%
COT Gas Blanketing - Gas Release on Hull	P13-G-HULL	HULL	9.32E-03	5.63E-04	7.16E-05	9.95E-03	1.68%
COT Gas Blanketing - Gas Release at Piperack	P13-G-PRK	PRK	7.09E-04	4.10E-05	5.66E-06	7.56E-04	0.13%
COT Gas Blanketing - Gas Release at M30 Process Deck Level 1	P13-G-M30L1	M30L1	6.78E-03	2.89E-04	2.68E-05	7.09E-03	1.20%
1st Stage LP Gas Compression Suction Cooler (23-HB-6001) - Two Phase Release at M60 Process Deck Level 2	P14-M-M60L2	M60L2	5.58E-03	2.57E-04	6.88E-05	5.90E-03	1.00%
1st Stage LP Gas Compression - Gas Release at M60 Process Deck Level 1	P14-G-M60L1	M60L1	1.92E-02	5.65E-04	1.84E-04	2.00E-02	3.37%
1st Stage LP Gas Suction Scrubber (23-VG-6001) - Liquid Release at M60 Process Deck Level 1	P14-L-M60L1	M60L1	3.37E-03	1.69E-04	5.99E-05	3.60E-03	0.61%
1st Stage Recompression to Flare KO Drum (43-VD-3001) - Gas Release at Piperack	P14-G-PRK	PRK	2.18E-03	1.28E-04	1.88E-05	2.33E-03	0.39%
2nd Stage LP Gas Compression Suction Cooler (23-HB-6002) - Two Phase Release at M60 Process Deck Level 2	P15-M-M60L2	M60L2	5.28E-03	2.37E-04	6.23E-05	5.58E-03	0.94%
2nd Stage LP Gas Compression - Gas Release at M60 Process Deck Level 1	P15-G-M60L1	M60L1	1.60E-02	5.08E-04	1.62E-04	1.67E-02	2.83%
2nd Stage LP Gas Compressor Suction Scrubber (23-VG-6002) - Liquid Release at M60 Process Deck Level 1	P15-L-M60L1	M60L1	2.36E-03	1.13E-04	3.72E-05	2.51E-03	0.42%
MP Gas Compression - Gas Release at Piperack	P16-G-PRK	PRK	4.91E-03	1.77E-04	8.69E-05	5.17E-03	0.87%
MP Gas Compression Suction Cooler (23-HA-6003) - Two Phase Release at M60 Process Deck Level 2	P16-M-M60L2	M60L2	5.49E-03	2.43E-04	6.83E-05	5.80E-03	0.98%
MP Gas Compression - Gas Release at M60 Process Deck Level 1	P16-G-M60L1	M60L1	1.70E-02	5.54E-04	1.89E-04	1.78E-02	3.00%
MP Gas Compression Suction Scrubber (23-VG-6003) - Liquid Release at M60 Process Deck Level 1	P16-L-M60L1	M60L1	2.24E-03	1.07E-04	3.42E-05	2.38E-03	0.40%
Gas Dehydration Inlet Cooler (24-HG-6601) - Two Phase Release at M60 Process Deck Level 2	P17-M-M60L2	M60L2	5.13E-03	2.45E-04	2.54E-05	5.40E-03	0.91%
Gas Dehydration System - Two Phase Release at Piperack	P17-M-PRK	PRK	2.58E-04	1.49E-05	2.06E-06	2.75E-04	0.05%
Gas Dehydration Inlet Scrubber (24-VG-6601) - Two Phase Release at M61 Process Deck Level 1	P17-M-M61L1	M61L1	5.59E-04	3.23E-05	4.46E-06	5.95E-04	0.10%
Gas Dehydration Inlet Scrubber (24-VG-6001) & TEG Contactor (24-VB-6602) & 1st Stage HP Gas Compressor Suction Scrubber (23-VG-6004) - Gas Release at M61 Process Deck Level 1	P17-G-M61L1	M61L1	3.21E-02	1.22E-03	4.42E-04	3.37E-02	5.70%
Gas Dehydration & 1st Stage HP Gas Compression - Gas Release at Piperack	P17-G-PRK	M61L1	5.50E-04	1.55E-05	1.55E-05	5.81E-04	0.10%
Gas Dehydration Inlet Scrubber (24-VG-6601) - Liquid Release at M61 Process Deck Level 1	P17-L-M61L1	M61L1	2.33E-03	1.14E-04	3.57E-05	2.47E-03	0.42%
1st Stage HP Gas Compressor Discharge Cooler (23-HG-6004) at M61 Process Deck Level 2	P17-G-M61L2	M60L2	6.22E-03	3.36E-04	2.86E-05	6.59E-03	1.11%

Failure Case Description	Event ID	Location	Leak Frequency (/yr)			Total	%
			Small (10mm)	Medium (50mm)	Large (100mm)		
2nd Stage HP Gas Compressor & Suction Scrubber (23-VG-6005) - Gas Release at M61 Process Deck Level 1	P18-G-M61L1	M61L1	1.89E-02	6.62E-04	1.69E-04	1.97E-02	3.33%
1st & 2nd Stage HP Gas Compressor Discharge Coolers (23-HG-6004 & 23-HG-6005) - Gas Release at M61 Process Deck Level 2	P18-G-M61L2	M61L2	6.22E-03	3.36E-04	2.86E-05	6.59E-03	1.11%
HP Gas Compression / Injection Pipework - Gas Release at M61 Process Deck Level 2	P19-G-M61L2	M61L2	2.22E-03	1.32E-04	2.39E-05	2.38E-03	0.40%
HP Gas Compression / Injection Pipework - Gas Release at Piperack	P19-G-PRK	PRK	1.59E-03	9.20E-05	1.27E-05	1.69E-03	0.29%
HP Gas Compression / Injection Pipework and Flowlines - Gas Release at Turret Upper Deck	P19-G-TRTU	TRTU	6.37E-03	2.87E-04	7.04E-05	6.72E-03	1.14%
Gas Injection/Lift 1 BDN & Gas Lift 2 Cambriol/Circulation Flowline (XSV to ESV) - Gas Release at Turret Lower Deck	P19-G-TRTL	TRTL	1.33E-03	3.51E-05	1.56E-05	1.38E-03	0.23%
Fuel Gas System - Gas Release	P20-G-M61L1	M61L1	3.00E-03	2.19E-04	5.01E-05	3.27E-03	0.55%
Fuel Gas System - Liquid Release	P20-L-M61L1	M61L1	1.42E-03	1.09E-04	3.07E-05	1.56E-03	0.26%
Fuel Gas Superheaters, Metering Skid & Filter Package - Gas Release	P20-G-M61L2	M61L2	1.45E-02	8.13E-04	1.65E-04	1.54E-02	2.61%
Fuel Gas to Turbines - Gas Release	P21-G-M61L2	M61L2	1.40E-03	8.14E-05	1.21E-05	1.49E-03	0.25%
Fuel Gas to Turbines - Gas Release	P21-G-PRK	PRK	2.90E-03	1.68E-04	2.32E-05	3.09E-03	0.52%
Fuel Gas to Turbines - Gas Release	P21-G-M90L1	M90L1	1.07E-03	6.22E-05	8.58E-06	1.15E-03	0.19%
LP Fuel Gas to Consumers - Gas Release	P22-G-M61L2	M61L2	1.10E-03	6.40E-05	9.73E-06	1.17E-03	0.20%
LP Fuel Gas to Consumers - Gas Release	P22-G-PRK	PRK	8.06E-04	4.66E-05	6.43E-06	8.59E-04	0.15%
LP Fuel Gas to Consumers - Gas Release	P22-G-M11L2	M11L2	9.24E-04	5.57E-05	8.25E-06	9.88E-04	0.17%
Reject Vessel (44-VD-1003) - Two Phase Release at M11 Process Deck Level 3	P23-M-M11L3	M11L3	9.35E-04	4.56E-05	8.33E-06	9.89E-04	0.17%
Reject Vessel (44-VD-1003) - Gas Release at M11 Process Deck Level 3	P23-G-M11L3	M11L3	2.38E-03	1.54E-04	3.69E-05	2.58E-03	0.44%
Reject Vessel (44-VD-1003) - Liquid Release at M11 Process Deck Level 3	P23-L-M11L3	M11L3	5.91E-03	2.88E-04	9.42E-05	6.29E-03	1.06%
VOC Compression - Gas Release at Piperack	P24-G-PRK	PRK	7.88E-03	3.35E-04	2.96E-05	8.24E-03	1.39%
VOC Compression - Gas Release at M30 Process Deck Level 1	P24-G-M30L1	M30L1	1.00E-02	2.52E-04	3.63E-05	1.03E-02	1.74%
Pig receiver - Two Phase Release at Turret Lower Deck	P25-M-TRTL	TRTL	3.26E-04	1.81E-05	1.33E-05	3.57E-04	0.06%
Pig launcher - Two Phase Release at Turret Lower Deck	P26-M-TRTL	TRTL	3.20E-04	1.77E-05	1.32E-05	3.51E-04	0.06%
BdN Production Riser 1 Subsea	R01-G-SS	SS	1.02E-03	3.54E-04	5.81E-04	1.95E-03	0.33%
BdN Production Riser 2 Subsea	R02-G-SS	SS	1.02E-03	3.54E-04	5.81E-04	1.95E-03	0.33%
Cambriol Riser Subsea	R05-G-SS	SS	1.02E-03	3.54E-04	5.73E-04	1.95E-03	0.33%
Gas Injection/Gas Lift Riser Subsea	R06-G-SS	SS	1.02E-03	3.54E-04	5.81E-04	1.95E-03	0.33%
Helifuel Skid - Liquid Release	H01-L-HELI	HELI	9.80E-04	4.88E-05	5.36E-06	1.03E-03	0.17%
Diesel / Fuel Oil Release Machinery Space - Liquid Release	D01-L-MCH	MCH	1.77E-02	4.30E-04	1.23E-04	1.83E-02	3.09%
MP Separator - Two Phase Release at Piperack	P35-M-PRK	PRK	3.62E-03	1.71E-04	5.46E-05	3.84E-03	0.65%
MP Separator - Two Phase Release at M11 Process Deck Level 2	P35-M-M11L2	M11L2	3.11E-02	1.55E-03	4.72E-04	3.31E-02	5.60%
MP Separator - Gas Release at M11 Process Deck Level 2	P35-G-M11L2	M11L2	3.14E-03	1.54E-04	6.33E-05	3.36E-03	0.57%
MP Separator - Liquid Release at M11 Process Deck Level 2	P35-L-M11L2	M11L2	4.29E-03	1.37E-04	5.71E-05	4.48E-03	0.76%
Topsides Total			5.51E-01	2.53E-02	7.86E-03	5.84E-01	98.68%
Riser Total			4.08E-03	1.42E-03	2.32E-03	7.81E-03	1.32%
Total			5.55E-01	2.67E-02	1.02E-02	5.92E-01	100.00%

5.6. Ignition & Explosion Probabilities

The overall ignition probability was calculated using Kent's standard methodology, which is based on the UKOOA/HSE/Energy Institute [42] for the calculation of ignition probabilities for accidental releases within process facilities. The UKOOA method is referenced in the NORSOK Z-013 [36] guidance through the link to the OGP Ignition Probabilities Risk Assessment Data Directory [43].

This study has shown that for a given scenario, the ignition probability varies with the mass flow rate, and that this relationship can be represented by a relatively simple correlation. 'Look-up' tables or correlations for a range of representative scenarios have been developed to provide an easy to use reference for ignition probabilities for use in QRA. These tables / correlations are supported by guidance on how to select a suitable representative scenario, interpret and apply the data, consider sensitivities, etc. For this facility, the following correlations have been used:

- **Correlation 23 - Offshore Riser**

  Releases from offshore installation risers in the air gap area where there is little chance of a release entering process areas on the installation (e.g. solid deck, wind walls). This remains relevant for Bay du Nord, as releases within the Lower Turret have solid walls towards Topsides and Cargo Deck that mean that the potential for a release migrating to the process area remains limited.

- **Correlation 27 - Offshore Engulf (Riser)**

  Full bore release from risers where the release could engulf the entire installation and reach process areas.
- **Correlation 24 - Offshore FPSO Gas (gas release from typical offshore FPSO process module)**

  Release of flammable gases, vapour or liquids significantly above their normal (NAP) boiling point within offshore process modules or decks on FPSO that have the potential to reach the utilities modules.
- **Correlation 26 - Offshore FPSO Liquid (liquid release from a typical offshore FPSO process module)**

  Release of flammable liquids that do not have any sufficient flash fraction (10% or less) if released from within offshore process modules or decks on the FPSOs.

A graph of the relationship between outflow rate and ignition probability for each of these correlations can be seen in the graphs presented next.

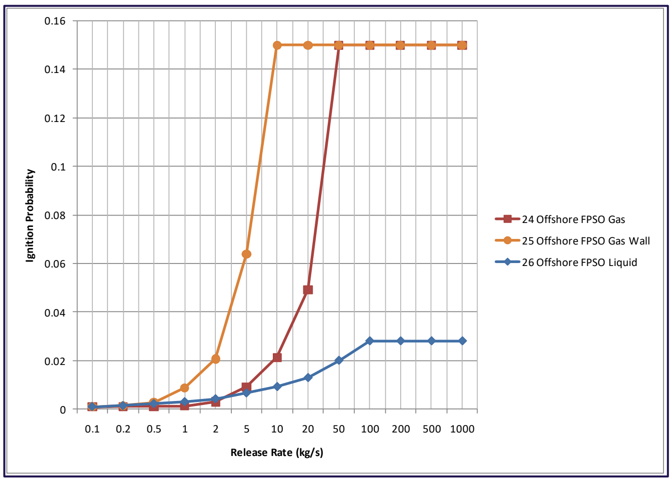


Figure 5-5 Plot of the UKOOA Ignition Correlations (24, 25 and 26)

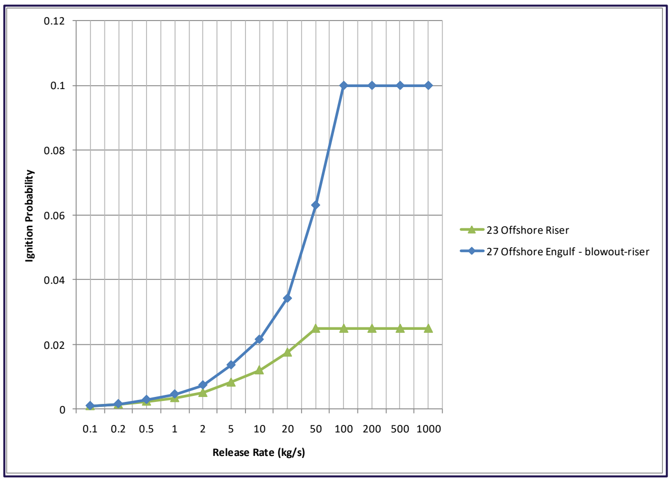


Figure 5-6 Plot of the UKOOA Ignition Correlations (23 and 27)

A minimum ignition probability of 0.1% has been applied on the basis of analysis of events where the release was considered to ignite immediately. No other minimum value was considered necessary to apply. Ignition probabilities for all of the hydrocarbon events on the FPSO are shown next.

Table 5-8 Ignition Probabilities

Failure Case Description	Event ID	Location	Ignition Probabilities		
			Small (10mm)	Medium (50mm)	Large (100mm)
BdN Production Flowline 1 and 2 (ESV to XSV) - Two Phase Release at Turret Lower Deck	P01-M-TRTL	TRTL	0.001	0.029	0.150
MP Inlet and Test Manifolds - Two Phase Release at Piperack	P01-M-PRK	PRK	0.001	0.029	0.150
MP Inlet and Test Manifolds - Two Phase Release at M10 Process Deck Level 1	P01-M-M10L1	M10L1	0.001	0.029	0.150
MP Inlet and Test Manifolds - Two Phase Release at Turret Upper Deck	P01-M-TRTU	TRTU	0.001	0.029	0.150
HP Inlet and Test Manifolds - Two Phase Release at Turret Upper Deck	P02-M-TRTU	TRTU	0.001	0.029	0.150
HP Inlet and Test Manifolds - Two Phase Release at Piperack	P02-M-PRK	PRK	0.001	0.029	0.150
HP Inlet and Test Manifolds - Two Phase Release at M10 Process Deck Level 1	P02-M-M10L1	M10L1	0.001	0.029	0.150
HP Spare, Cambriol and Circulation Production Flowline (ESV to XSV) - Two Phase Release at Turret Lower Deck	P02-M-TRTL	TRTL	0.001	0.029	0.150
Test Separator (20-VA-1004) - Two Phase Release at M10 Process Deck Level 1	P03-M-M10L1	M10L1	0.001	0.029	0.150
Test Separator (20-VA-1004) - Gas Release at M10 Process Deck Level 1	P03-G-M10L1	M10L1	0.001	0.009	0.047
Test Separator (20-VA-1004) - Liquid Release at M10 Process Deck Level 1	P03-L-M10L1	M10L1	0.005	0.022	0.028
Inlet Separator (20-VA-1001) - Two Phase Release at M10 Process Deck Level 1	P04-M-M10L1	M10L1	0.001	0.029	0.150
Inlet Separator (20-VA-1001) - Gas Release at M10 Process Deck Level 1	P04-G-M10L1	M10L1	0.001	0.009	0.047
Inlet Separator (20-VA-1001) - Gas Release at Piperack	P04-G-PRK	PRK	0.001	0.009	0.047
Inlet Separator (20-VA-1001) - Liquid Release at M10 Process Deck Level 1	P04-L-M10L1	M10L1	0.003	0.015	0.028
LP Separator (20-VA-1002) - Two Phase Release at M11 Process Deck Level 2	P05-M-M11L2	M11L2	0.001	0.016	0.084
LP Separator (20-VA-1002) - Gas Release at M11 Process Deck Level 2	P05-G-M11L2	M11L2	0.001	0.001	0.003
LP Separator (20-VA-1002) - Liquid Release at M11 Process Deck Level 2	P05-L-M11L2	M11L2	0.003	0.013	0.024
1st Stage LP Compressor Scrubber Pumps (23-PA-6001A/B) - Two Phase Release at M60 Process Deck Level 1	P05-M-M60L1	M60L1	0.001	0.016	0.084
Electrostatic Coalescer (20-VJ-1003) & Oil Booster Pump (20-PA-1001A/B) & Crude Oil Coolers (20-HB-1002A/B) - Liquid Release at M11 Process Deck Level 1	P06-L-M11L1	M11L1	0.004	0.016	0.028
Crude Oil Loading Header - Liquid Release at M11 Process Deck Level 1	P07-L-M11L1	M11L1	0.002	0.010	0.019
Crude Oil Loading Header - Liquid Release at Piperack	P07-L-PRK	PRK	0.002	0.010	0.019
Crude Oil Loading Header - Liquid Release on Hull	P07-L-HULL	HULL	0.002	0.011	0.020
Cargo Tank - Liquid Release on Hull	P08-L-HULL	HULL	0.002	0.010	0.019
Off-Spec Fluid Tank - Liquid Release on Hull	P09-L-HULL	HULL	0.002	0.010	0.019
Off-Spec Fluid Tank - Liquid Release at Piperack	P09-L-PRK	PRK	0.002	0.010	0.019
Crude Oil Transfer Header - Liquid Release on Hull	P10-L-HULL	HULL	0.005	0.022	0.028
Crude Oil Offloading Header - Liquid Release at Piperack	P10-L-PRK	PRK	0.005	0.022	0.028
Crude Oil Offloading Header - Liquid Release at M10 Process Deck Level 1	P10-L-M10L1	M10L1	0.005	0.022	0.028
Crude Oil Offloading Header - Liquid Release on Hull	P11-L-HULL	HULL	0.005	0.022	0.028
Crude Oil Offloading Reel - Liquid Release on Hull	P12-L-HULL	HULL	0.005	0.022	0.028
Crude Oil Offloading Reel - Liquid Release at Offloading Reel	P12-L-OFF	OFF	0.005	0.022	0.028
COT Gas Blanketing - Gas Release on Hull	P13-G-HULL	HULL	0.001	0.001	0.001
COT Gas Blanketing - Gas Release at Piperack	P13-G-PRK	PRK	0.001	0.001	0.001
COT Gas Blanketing - Gas Release at M30 Process Deck Level 1	P13-G-M30L1	M30L1	0.001	0.001	0.001
1st Stage LP Gas Compression Suction Cooler (23-HB-6001) - Two Phase Release at M60 Process Deck Level 2	P14-M-M60L2	M60L2	0.001	0.001	0.007
1st Stage LP Gas Compression - Gas Release at M60 Process Deck Level 1	P14-G-M60L1	M60L1	0.001	0.003	0.017
1st Stage LP Gas Suction Scrubber (23-VG-6001) - Liquid Release at M60 Process Deck Level 1	P14-L-M60L1	M60L1	0.004	0.017	0.028
1st Stage Recompression to Flare KO Drum (43-VD-3001) - Gas Release at Piperack	P14-G-PRK	PRK	0.001	0.003	0.017
2nd Stage LP Gas Compression Suction Cooler (23-HB-6002) - Two Phase Release at M60 Process Deck Level 2	P15-M-M60L2	M60L2	0.001	0.005	0.024
2nd Stage LP Gas Compression - Gas Release at M60 Process Deck Level 1	P15-G-M60L1	M60L1	0.001	0.004	0.023
2nd Stage LP Gas Compressor Suction Scrubber (23-VG-6002) - Liquid Release at M60 Process Deck Level 1	P15-L-M60L1	M60L1	0.004	0.016	0.028
MP Gas Compression - Gas Release at Piperack	P16-G-PRK	PRK	0.001	0.042	0.150
MP Gas Compression Suction Cooler (23-HA-6003) - Two Phase Release at M60 Process Deck Level 2	P16-M-M60L2	M60L2	0.001	0.011	0.057
MP Gas Compression - Gas Release at M60 Process Deck Level 1	P16-G-M60L1	M60L1	0.001	0.042	0.150
MP Gas Compression Suction Scrubber (23-VG-6003) - Liquid Release at M60 Process Deck Level 1	P16-L-M60L1	M60L1	0.006	0.027	0.028
Gas Dehydration Inlet Cooler (24-HG-6601) - Two Phase Release at M60 Process Deck Level 2	P17-M-M60L2	M60L2	0.001	0.056	0.150
Gas Dehydration System - Two Phase Release at Piperack	P17-M-PRK	PRK	0.001	0.056	0.150
Gas Dehydration Inlet Scrubber (24-VG-6601) - Two Phase Release at M61 Process Deck Level 1	P17-M-M61L1	M61L1	0.001	0.056	0.150
Gas Dehydration Inlet Scrubber (24-VG-6001) & TEG Contactor (24-VB-6602) & 1st Stage HP Gas Compressor Suction Scrubber (23-VG-6004) - Gas Release at M61 Process Deck Level 1	P17-G-M61L1	M61L1	0.001	0.069	0.150
Gas Dehydration & 1st Stage HP Gas Compression - Gas Release at Piperack	P17-G-PRK	M61L1	0.001	0.069	0.150
Gas Dehydration Inlet Scrubber (24-VG-6601) - Liquid Release at M61 Process Deck Level 1	P17-L-M61L1	M61L1	0.006	0.028	0.028
1st Stage HP Gas Compressor Discharge Cooler (23-HG-6004) at M61 Process Deck Level 2	P17-G-M61L2	M60L2	0.001	0.069	0.150

Failure Case Description	Event ID	Location	Ignition Probabilities		
			Small (10mm)	Medium (50mm)	Large (100mm)
2nd Stage HP Gas Compressor & Suction Scrubber (23-VG-6005) - Gas Release at M61 Process Deck Level 1	P18-G-M61L1	M61L1	0.004	0.150	0.150
1st & 2nd Stage HP Gas Compressor Discharge Coolers (23-HG-6004 & 23-HG-6005) - Gas Release at M61 Process Deck Level 2	P18-G-M61L2	M61L2	0.004	0.150	0.150
HP Gas Compression / Injection Pipework - Gas Release at M61 Process Deck Level 2	P19-G-M61L2	M61L2	0.008	0.150	0.150
HP Gas Compression / Injection Pipework - Gas Release at Piperack	P19-G-PRK	PRK	0.008	0.150	0.150
HP Gas Compression / Injection Pipework and Flowlines - Gas Release at Turret Upper Deck	P19-G-TRTU	TRTU	0.008	0.150	0.150
Gas Injection/Lift 1 BDN & Gas Lift 2 Cambriol/Circulation Flowline (XSV to ESV) - Gas Release at Turret Lower Deck	P19-G-TRTL	TRTL	0.008	0.150	0.150
Fuel Gas System - Gas Release	P20-G-M61L1	M61L1	0.001	0.044	0.150
Fuel Gas System - Liquid Release	P20-L-M61L1	M61L1	0.005	0.022	0.028
Fuel Gas Superheaters, Metering Skid & Filter Package - Gas Release	P20-G-M61L2	M61L2	0.001	0.044	0.150
Fuel Gas to Turbines - Gas Release	P21-G-M61L2	M61L2	0.001	0.041	0.150
Fuel Gas to Turbines - Gas Release	P21-G-PRK	PRK	0.001	0.041	0.150
Fuel Gas to Turbines - Gas Release	P21-G-M90L1	M90L1	0.001	0.041	0.150
LP Fuel Gas to Consumers - Gas Release	P22-G-M61L2	M61L2	0.001	0.002	0.013
LP Fuel Gas to Consumers - Gas Release	P22-G-PRK	PRK	0.001	0.002	0.013
LP Fuel Gas to Consumers - Gas Release	P22-G-M11L2	M11L2	0.001	0.002	0.013
Reject Vessel (44-VD-1003) - Two Phase Release at M11 Process Deck Level 3	P23-M-M11L3	M11L3	0.001	0.001	0.001
Reject Vessel (44-VD-1003) - Gas Release at M11 Process Deck Level 3	P23-G-M11L3	M11L3	0.001	0.001	0.002
Reject Vessel (44-VD-1003) - Liquid Release at M11 Process Deck Level 3	P23-L-M11L3	M11L3	0.002	0.008	0.016
VOC Compression - Gas Release at Piperack	P24-G-PRK	PRK	0.001	0.001	0.002
VOC Compression - Gas Release at M30 Process Deck Level 1	P24-G-M30L1	M30L1	0.001	0.001	0.002
Pig receiver - Two Phase Release at Turret Lower Deck	P25-M-TRTL	TRTL	0.003	0.014	0.025
Pig launcher - Two Phase Release at Turret Lower Deck	P26-M-TRTL	TRTL	0.003	0.014	0.025
BdN Production Riser 1 Subsea	R01-G-SS	SS	0.005	0.025	0.025
BdN Production Riser 2 Subsea	R02-G-SS	SS	0.005	0.025	0.025
Cambriol Riser Subsea	R05-G-SS	SS	0.004	0.024	0.025
Gas Injection/Gas Lift Riser Subsea	R06-G-SS	SS	0.009	0.025	0.025
Helifuel Skid - Liquid Release	H01-L-HELI	HELI	0.001	0.001	0.002
Diesel / Fuel Oil Release Machinery Space - Liquid Release	D01-L-MCH	MCH	0.001	0.001	0.001
MP Separator - Two Phase Release at Piperack	P35-M-PRK	PRK	0.001	0.017	0.089
MP Separator - Two Phase Release at M11 Process Deck Level 2	P35-M-M11L2	M11L2	0.001	0.017	0.089
MP Separator - Gas Release at M11 Process Deck Level 2	P35-G-M11L2	M11L2	0.001	0.002	0.011
MP Separator - Liquid Release at M11 Process Deck Level 2	P35-L-M11L2	M11L2	0.002	0.011	0.021

5.7. Overall Ignited Event Frequency

By combining the hydrocarbon release frequencies with the ignition probabilities, the overall ignited event frequency for the installation is calculated to be 0.00249 per annum, i.e. approximately one ignited event every 401 years of operation. A summary of ignited event frequency per event is shown in Table 5-9.

In a similar manner to the release frequencies, higher pressure events associated with gas compression / injection are the highest contributors to the ignited event frequencies as well as manifold events that have a number of potential leak sources from instruments, valves and flanges. Cargo Oil Tank fires are also a high contributor but are based on generic, historical events.

Table 5-9 Topsides and Riser Ignited Event Frequencies

Failure Case Description	Event ID	Location	Ignited Event Frequency			Total	%
			Small (10mm)	Medium (50mm)	Large (100mm)		
BdN Production Flowline 1 and 2 (ESV to XSV) - Two Phase Release at Turret Lower Deck	P01-M-TRTL	TRTL	1.00E-05	8.13E-06	2.44E-05	4.25E-05	1.71%
MP Inlet and Test Manifolds - Two Phase Release at Piperack	P01-M-PRK	PRK	3.45E-06	2.29E-06	1.18E-05	1.75E-05	0.70%
MP Inlet and Test Manifolds - Two Phase Release at M10 Process Deck Level 1	P01-M-M10L1	M10L1	1.92E-05	1.61E-05	3.47E-05	7.00E-05	2.81%
MP Inlet and Test Manifolds - Two Phase Release at Turret Upper Deck	P01-M-TRTU	TRTU	4.44E-06	3.94E-06	6.69E-06	1.51E-05	0.60%
HP Inlet and Test Manifolds - Two Phase Release at Turret Upper Deck	P02-M-TRTU	TRTU	1.39E-05	1.13E-05	2.93E-05	5.46E-05	2.19%
HP Inlet and Test Manifolds - Two Phase Release at Piperack	P02-M-PRK	PRK	3.45E-06	2.29E-06	1.18E-05	1.75E-05	0.70%
HP Inlet and Test Manifolds - Two Phase Release at M10 Process Deck Level 1	P02-M-M10L1	M10L1	2.06E-05	1.65E-05	3.62E-05	7.33E-05	2.94%
HP Spare, Cambriol and Circulation Production Flowline (ESV to XSV) - Two Phase Release at Turret Lower Deck	P02-M-TRTL	TRTL	1.54E-06	1.62E-06	2.71E-06	5.86E-06	0.23%
Test Separator (20-VA-1004) - Two Phase Release at M10 Process Deck Level 1	P03-M-M10L1	M10L1	2.39E-05	2.46E-05	1.90E-05	6.75E-05	2.71%
Test Separator (20-VA-1004) - Gas Release at M10 Process Deck Level 1	P03-G-M10L1	M10L1	1.09E-05	3.15E-06	6.18E-06	2.02E-05	0.81%
Test Separator (20-VA-1004) - Liquid Release at M10 Process Deck Level 1	P03-L-M10L1	M10L1	3.72E-05	7.82E-06	2.02E-06	4.70E-05	1.88%
Inlet Separator (20-VA-1001) - Two Phase Release at M10 Process Deck Level 1	P04-M-M10L1	M10L1	1.25E-05	1.94E-05	2.41E-05	5.59E-05	2.24%
Inlet Separator (20-VA-1001) - Gas Release at M10 Process Deck Level 1	P04-G-M10L1	M10L1	1.14E-05	3.36E-06	6.55E-06	2.13E-05	0.85%
Inlet Separator (20-VA-1001) - Gas Release at Piperack	P04-G-PRK	PRK	5.53E-06	1.79E-06	8.59E-07	8.18E-06	0.33%
Inlet Separator (20-VA-1001) - Liquid Release at M10 Process Deck Level 1	P04-L-M10L1	M10L1	5.26E-05	1.06E-05	9.96E-06	7.31E-05	2.93%
LP Separator (20-VA-1002) - Two Phase Release at M11 Process Deck Level 2	P05-M-M11L2	M11L2	2.48E-05	1.45E-05	3.72E-05	7.65E-05	3.07%
LP Separator (20-VA-1002) - Gas Release at M11 Process Deck Level 2	P05-G-M11L2	M11L2	3.14E-06	1.91E-07	2.01E-07	3.53E-06	0.14%
LP Separator (20-VA-1002) - Liquid Release at M11 Process Deck Level 2	P05-L-M11L2	M11L2	1.19E-05	1.71E-06	1.37E-06	1.50E-05	0.60%
1st Stage LP Compressor Scrubber Pumps (23-PA-6001A/B) - Two Phase Release at M60 Process Deck Level 1	P05-M-M60L1	M60L1	3.07E-05	1.50E-05	1.53E-05	6.09E-05	2.44%
Electrostatic Coalescer (20-VJ-1003) & Oil Booster Pump (20-PA-1001A/B) & Crude Oil Coolers (20-HB-1002A/B) - Liquid Release at M11 Process Deck Level 1	P06-L-M11L1	M11L1	1.01E-04	2.10E-05	7.51E-06	1.30E-04	5.20%
Crude Oil Loading Header - Liquid Release at M11 Process Deck Level 1	P07-L-M11L1	M11L1	1.16E-06	1.79E-07	2.92E-07	1.63E-06	0.07%
Crude Oil Loading Header - Liquid Release at Piperack	P07-L-PRK	PRK	1.37E-06	1.74E-07	3.34E-07	1.88E-06	0.08%
Crude Oil Loading Header - Liquid Release on Hull	P07-L-HULL	HULL	2.00E-05	5.15E-06	1.58E-06	2.67E-05	1.07%
Cargo Tank - Liquid Release on Hull	P08-L-HULL	HULL	5.12E-06	9.88E-06	1.17E-05	2.67E-05	1.07%
Off-Spec Fluid Tank - Liquid Release on Hull	P09-L-HULL	HULL	5.60E-06	1.00E-05	1.18E-05	2.74E-05	1.10%
Off-Spec Fluid Tank - Liquid Release at Piperack	P09-L-PRK	PRK	7.40E-06	1.95E-06	5.84E-07	9.93E-06	0.40%
Crude Oil Transfer Header - Liquid Release on Hull	P10-L-HULL	HULL	4.30E-05	1.10E-05	2.46E-06	5.64E-05	2.26%
Crude Oil Offloading Header - Liquid Release at Piperack	P10-L-PRK	PRK	5.65E-07	1.48E-07	2.64E-08	7.39E-07	0.03%
Crude Oil Offloading Header - Liquid Release at M10 Process Deck Level 1	P10-L-M10L1	M10L1	5.22E-07	1.40E-07	2.65E-08	6.89E-07	0.03%
Crude Oil Offloading Header - Liquid Release on Hull	P11-L-HULL	HULL	2.41E-06	5.80E-07	1.85E-07	3.17E-06	0.13%
Crude Oil Offloading Reel - Liquid Release on Hull	P12-L-HULL	HULL	6.08E-06	1.39E-06	5.65E-07	8.04E-06	0.32%
Crude Oil Offloading Reel - Liquid Release at Offloading Reel	P12-L-OFF	OFF	3.57E-09	4.37E-10	3.58E-10	4.37E-09	0.00%
COT Gas Blanketing - Gas Release on Hull	P13-G-HULL	HULL	9.32E-06	5.69E-07	7.99E-08	9.97E-06	0.40%
COT Gas Blanketing - Gas Release at Piperack	P13-G-PRK	PRK	7.09E-07	4.14E-08	6.32E-09	7.57E-07	0.03%
COT Gas Blanketing - Gas Release at M30 Process Deck Level 1	P13-G-M30L1	M30L1	6.78E-06	2.91E-07	2.99E-08	7.10E-06	0.28%
1st Stage LP Gas Compression Suction Cooler (23-HB-6001) - Two Phase Release at M60 Process Deck Level 2	P14-M-M60L2	M60L2	5.72E-06	3.34E-07	4.59E-07	6.52E-06	0.26%
1st Stage LP Gas Compression - Gas Release at M60 Process Deck Level 1	P14-G-M60L1	M60L1	2.08E-05	1.76E-06	3.08E-06	2.57E-05	1.03%
1st Stage LP Gas Suction Scrubber (23-VG-6001) - Liquid Release at M60 Process Deck Level 1	P14-L-M60L1	M60L1	1.24E-05	2.82E-06	1.68E-06	1.69E-05	0.68%
1st Stage Recompression to Flare KO Drum (43-VD-3001) - Gas Release at Piperack	P14-G-PRK	PRK	2.37E-06	3.99E-07	3.16E-07	3.08E-06	0.12%
2nd Stage LP Gas Compression Suction Cooler (23-HB-6002) - Two Phase Release at M60 Process Deck Level 2	P15-M-M60L2	M60L2	5.85E-06	1.07E-06	1.52E-06	8.44E-06	0.34%
2nd Stage LP Gas Compression - Gas Release at M60 Process Deck Level 1	P15-G-M60L1	M60L1	1.77E-05	2.17E-06	3.72E-06	2.36E-05	0.95%
2nd Stage LP Gas Compressor Suction Scrubber (23-VG-6002) - Liquid Release at M60 Process Deck Level 1	P15-L-M60L1	M60L1	8.61E-06	1.87E-06	1.04E-06	1.15E-05	0.46%
MP Gas Compression - Gas Release at Piperack	P16-G-PRK	PRK	6.22E-06	7.39E-06	1.30E-05	2.66E-05	1.07%
MP Gas Compression Suction Cooler (23-HA-6003) - Two Phase Release at M60 Process Deck Level 2	P16-M-M60L2	M60L2	6.41E-06	2.59E-06	3.92E-06	1.29E-05	0.52%
MP Gas Compression - Gas Release at M60 Process Deck Level 1	P16-G-M60L1	M60L1	2.15E-05	2.32E-05	2.83E-05	7.31E-05	2.93%
MP Gas Compression Suction Scrubber (23-VG-6003) - Liquid Release at M60 Process Deck Level 1	P16-L-M60L1	M60L1	1.36E-05	2.95E-06	9.59E-07	1.75E-05	0.70%
Gas Dehydration Inlet Cooler (24-HG-6601) - Two Phase Release at M60 Process Deck Level 2	P17-M-M60L2	M60L2	6.61E-06	1.38E-05	3.81E-06	2.42E-05	0.97%
Gas Dehydration System - Two Phase Release at Piperack	P17-M-PRK	PRK	3.32E-07	8.41E-07	3.09E-07	1.48E-06	0.06%
Gas Dehydration Inlet Scrubber (24-VG-6601) - Two Phase Release at M61 Process Deck Level 1	P17-M-M61L1	M61L1	7.20E-07	1.82E-06	6.69E-07	3.21E-06	0.13%
Gas Dehydration Inlet Scrubber (24-VG-6001) & TEG Contactor (24-VB-6602) & 1st Stage HP Gas Compressor Suction Scrubber (23-VG-6004) - Gas Release at M61 Process Deck Level 1	P17-G-M61L1	M61L1	4.46E-05	8.42E-05	6.63E-05	1.95E-04	7.82%
Gas Dehydration & 1st Stage HP Gas Compression - Gas Release at Piperack	P17-G-PRK	M61L1	7.65E-07	1.07E-06	2.33E-06	4.17E-06	0.17%
Gas Dehydration Inlet Scrubber (24-VG-6601) - Liquid Release at M61 Process Deck Level 1	P17-L-M61L1	M61L1	1.44E-05	3.19E-06	1.00E-06	1.86E-05	0.75%
1st Stage HP Gas Compressor Discharge Cooler (23-HG-6004) at M61 Process Deck Level 2	P17-G-M61L2	M60L2	8.65E-06	2.33E-05	4.29E-06	3.62E-05	1.45%

Failure Case Description	Event ID	Location	Ignited Event Frequency			Total	%
			Small (10mm)	Medium (50mm)	Large (100mm)		
2nd Stage HP Gas Compressor & Suction Scrubber (23-VG-6005) - Gas Release at M61 Process Deck Level 1	P18-G-M61L1	M61L1	8.16E-05	9.93E-05	2.53E-05	2.06E-04	8.27%
1st & 2nd Stage HP Gas Compressor Discharge Coolers (23-HG-6004 & 23-HG-6005) - Gas Release at M61 Process Deck Level 2	P18-G-M61L2	M61L2	2.69E-05	5.04E-05	4.29E-06	8.16E-05	3.27%
HP Gas Compression / Injection Pipework - Gas Release at M61 Process Deck Level 2	P19-G-M61L2	M61L2	1.77E-05	1.98E-05	3.58E-06	4.12E-05	1.65%
HP Gas Compression / Injection Pipework - Gas Release at Piperack	P19-G-PRK	PRK	1.27E-05	1.38E-05	1.90E-06	2.84E-05	1.14%
HP Gas Compression / Injection Pipework and Flowlines - Gas Release at Turret Upper Deck	P19-G-TRTU	TRTU	5.08E-05	4.31E-05	1.06E-05	1.04E-04	4.19%
Gas Injection/Lift 1 BDN & Gas Lift 2 Cambriol/Circulation Flowline (XSV to ESV) - Gas Release at Turret Lower Deck	P19-G-TRTL	TRTL	1.06E-05	5.26E-06	2.33E-06	1.82E-05	0.73%
Fuel Gas System - Gas Release	P20-G-M61L1	M61L1	3.82E-06	9.61E-06	7.52E-06	2.09E-05	0.84%
Fuel Gas System - Liquid Release	P20-L-M61L1	M61L1	6.84E-06	2.36E-06	8.60E-07	1.01E-05	0.40%
Fuel Gas Superheaters, Metering Skid & Filter Package - Gas Release	P20-G-M61L2	M61L2	1.84E-05	3.56E-05	2.47E-05	7.87E-05	3.15%
Fuel Gas to Turbines - Gas Release	P21-G-M61L2	M61L2	1.77E-06	3.33E-06	1.82E-06	6.92E-06	0.28%
Fuel Gas to Turbines - Gas Release	P21-G-PRK	PRK	3.67E-06	6.86E-06	3.47E-06	1.40E-05	0.56%
Fuel Gas to Turbines - Gas Release	P21-G-M90L1	M90L1	1.36E-06	2.54E-06	1.29E-06	5.19E-06	0.21%
LP Fuel Gas to Consumers - Gas Release	P22-G-M61L2	M61L2	1.17E-06	1.55E-07	1.27E-07	1.46E-06	0.06%
LP Fuel Gas to Consumers - Gas Release	P22-G-PRK	PRK	8.61E-07	1.13E-07	8.38E-08	1.06E-06	0.04%
LP Fuel Gas to Consumers - Gas Release	P22-G-M11L2	M11L2	9.87E-07	1.35E-07	1.08E-07	1.23E-06	0.05%
Reject Vessel (44-VD-1003) - Two Phase Release at M11 Process Deck Level 3	P23-M-M11L3	M11L3	9.35E-07	5.36E-08	1.08E-08	9.99E-07	0.04%
Reject Vessel (44-VD-1003) - Gas Release at M11 Process Deck Level 3	P23-G-M11L3	M11L3	2.38E-06	1.86E-07	7.37E-08	2.64E-06	0.11%
Reject Vessel (44-VD-1003) - Liquid Release at M11 Process Deck Level 3	P23-L-M11L3	M11L3	1.09E-05	2.41E-06	1.51E-06	1.48E-05	0.59%
VOC Compression - Gas Release at Piperack	P24-G-PRK	PRK	7.88E-06	4.08E-07	7.08E-08	8.36E-06	0.33%
VOC Compression - Gas Release at M30 Process Deck Level 1	P24-G-M30L1	M30L1	1.00E-05	3.07E-07	8.69E-08	1.04E-05	0.42%
Pig receiver - Two Phase Release at Turret Lower Deck	P25-M-TRTL	TRTL	8.50E-07	2.56E-07	3.32E-07	1.44E-06	0.06%
Pig launcher - Two Phase Release at Turret Lower Deck	P26-M-TRTL	TRTL	8.36E-07	2.50E-07	3.31E-07	1.42E-06	0.06%
BdN Production Riser 1 Subsea	R01-G-SS	SS	4.75E-06	8.85E-06	1.45E-05	2.81E-05	1.13%
BdN Production Riser 2 Subsea	R02-G-SS	SS	4.75E-06	8.85E-06	1.45E-05	2.81E-05	1.13%
Cambriol Riser Subsea	R05-G-SS	SS	4.49E-06	8.45E-06	1.43E-05	2.73E-05	1.09%
Gas Injection/Gas Lift Riser Subsea	R06-G-SS	SS	9.18E-06	8.85E-06	1.45E-05	3.26E-05	1.30%
Helifuel Skid - Liquid Release	H01-L-HELI	HELI	9.80E-07	4.88E-08	1.07E-08	1.04E-06	0.04%
Diesel / Fuel Oil Release Machinery Space - Liquid Release	D01-L-MCH	MCH	1.77E-05	4.30E-07	1.23E-07	1.83E-05	0.73%
MP Separator - Two Phase Release at Piperack	P35-M-PRK	PRK	4.33E-06	2.83E-06	4.86E-06	1.20E-05	0.48%
MP Separator - Two Phase Release at M11 Process Deck Level 2	P35-M-M11L2	M11L2	3.73E-05	2.57E-05	4.21E-05	1.05E-04	4.21%
MP Separator - Gas Release at M11 Process Deck Level 2	P35-G-M11L2	M11L2	3.32E-06	3.17E-07	7.02E-07	4.34E-06	0.17%
MP Separator - Liquid Release at M11 Process Deck Level 2	P35-L-M11L2	M11L2	1.04E-05	1.51E-06	1.20E-06	1.31E-05	0.53%

5.8. Dimensioning Accidental Loads (DiALs)

The approach to determining DiALs is similar for both fire and explosion hazards.

As the design is currently in the Pre-FEED Phase a simplified approach has been followed, as outlined in NORSOK Z-013 [36] as well as GL2082 [37]. A more detailed assessment, based on CFD analysis, would be expected for subsequent stages of design and therefore this simplified approach has introduced necessary conservatisms, to account for the detail currently available in the design.

The DiALs have been determined based on an exceedance approach for both fire and explosion loads. The loads themselves have been calculated for a number of targets on the FPSO. These targets, which are shown in Table 5-10, have been selected based on the Target Levels of Safety criteria discussed in Section 6, which require an assessment of impairment of Main Safety Functions such as the Turret, Escape Route, TR, module boundaries etc such that the frequency for loss of integrity to the installation's key safety functions from any Single Major Accident Event should not exceed 1E-04 per annum.

The fire DiALs are based on physical flame impingement and the explosion pulse durations shown in the table are those for the overpressure that corresponds with the 1E-04 DiAL. As mentioned above, a more detailed assessment is expected for subsequent phases of design that will include assessment of DiALs for different types of fire i.e. jet fire or pool fire.

Table 5-10 Preliminary Fire and Explosion DiALs

Target	Fire DiAL (min)		Explosion DiAL	
	1E-04/yr	1E-05/yr	1E-04/yr (bar)	1E-05/yr (bar)
LQ Forward Wall (above Hull Deck Level)	N/A	N/A	0.11	0.43
Turret – Aft Wall	3	31	0.36	2.07
Escape Route – Port side M10	4	120	0.36	4.71
Escape Route – Port side M11	2	21	0.74	5.67
Escape Route – Port side M50	N/A	5	0.42	2.56
Escape Route – Port side M71	N/A	1	0.26	1.01
Escape Route – Stbd side M61	2	6	0.38	3.17
Escape Route – Stbd side M60	2	5	0.72	4.47
Escape Route – Stbd side M51	N/A	3	0.34	1.70
Escape Route – Stbd side M42	N/A	1	0.19	0.71
Process Module M10 Level 1	5	>120	0.41	1.98
Process Module M10 Level 2	4	50	0.35	1.83
Process Module M11 Level 1	2	43	0.61	2.51
Process Module M11 Level 2	3	70	0.41	1.91
Process Module M61 Level 1	8	18	0.43	1.55
Process Module M61 Level 2	6	17	0.35	1.52
Process Module M60 Level 1	4	62	0.59	1.81
Process Module M60 Level 2	3	24	0.49	1.68
Hull Deck / Supports Beneath M10	4	>120	0.44	2.55
Hull Deck / supports beneath M61	6	14	0.42	2.46
Hull Deck / Supports Beneath M11	2	25	0.57	2.19
Hull Deck / Supports Beneath M60	3	30	0.57	2.30
Flare Knock Out Drum HP	2	21	0.37	2.24
Forward Crane Pedestal (Stbd side M51) Hull Deck	N/A	4	0.14	0.54
Utility Module M50 Level 1	1	9	0.36	1.40
Utility Module M51 Level 1	1	6	0.33	1.05
Utility Module M71 Level 1	N/A	1	0.22	0.73
Utility Module M42 Laydown Plating	N/A	2	0.71	4.43
Utility Module M70 Level 1	N/A	N/A	0.16	0.80
Forward wall of E House M40	N/A	1	0.24	0.73

Table 5-11 Assumed PFP Ratings

Critical Location / Structure	PFP Rating
LQ Forward Wall	H60
Turret – Critical Internal Structure	J120
Riser ESDVs	J120
Forecastle aft wall	H60

5.9. Risk Calculations

In the QRA, the predicted level of risk has been calculated for four different categories of fatalities that could occur following a hydrocarbon release. Each is discussed in more detail below.

5.9.1. Immediate Fatalities

These are defined as the fatalities occurring in the vicinity of the hydrocarbon release immediately after ignition.

The personnel exposed to this risk are generally considered to be those located in the incident area at the time of ignition. However, this is not always the case. Immediate fatalities may occur in adjacent areas if the release is particularly large, for example due to a riser release. The actual number of fatalities is based on a rule set regarding the size and type of event. The calculations take account of the expected average number of persons in the incident area at any time.

5.9.1.1. Asphyxiation

Air normally contains about 21% Oxygen with the remainder consisting mostly of nitrogen. Individuals exposed to reduced-oxygen atmospheres may suffer a variety of harmful effects. The table below contains a list of some of these effects and the sea level oxygen concentrations at which they occur.

If exposure to reduced oxygen is terminated early enough, effects are generally reversible. If not, permanent central nervous system damage or lethality results. Major effects hindering escape from the vicinity of an oxygen deficient atmosphere are disorientation and unconsciousness.

In general, the intensities of the effects increase rapidly with falling oxygen concentration and longer exposure duration: reduced abilities, then unconsciousness, then death. It can be concluded that any exposure to an atmosphere containing less than 17% oxygen presents a risk.

The effects of oxygen depletion are outlined in Table 5-12.

Table 5-12 Effects of Oxygen Depletion on Humans

% Oxygen in Air	Symptoms
21-20	Normal
18	Night vision begins to be impaired
17	Respiration volume increases, muscular coordination diminishes, attention and thinking clearly requires more effort
12 to 15	Shortness of breath, headache, dizziness, quickened pulse, effort fatigues quickly, muscular coordination for skilled movement lost
10 to 12	Nausea and vomiting, exertion impossible, paralysis of motion
6 to 8	Collapse and unconsciousness occur
6 or below	Death in 6 to 8 minutes

The Offshore Area OHS Regulations [44] states that oxygen levels should be above 19.5% in confined spaces.

A release of unignited gas may displace oxygen in the atmosphere and as such has the potential to cause harm to personnel, including fatalities. However, it must be noted that asphyxiation will only apply to enclosed modules. For modules which are open on 3 or more sides, it is assumed that any gas release will disperse such that asphyxiation will not be an issue.

On the Bay du Nord FPSO, only accidental releases within the semi-enclosed areas of the turret have the potential to cause asphyxiation. However, entry into the semi-enclosed turret would be done under a permit to work system with personnel either carrying BA sets or being one breath away from such apparatus. As such, asphyxiation has not been considered further in the CSA.

Recommendation 1 – Asphyxiation from hydrocarbon releases is only expected to be a potential threat within the enclosed lower turret area, and it is expected that breathing equipment will be located within the turret. As such, asphyxiation has not been assessed within the CSA. However, as the design for the turret is developed further, the potential for immediate fatalities from asphyxiation should be reviewed in more detail. In addition to hydrocarbon releases, inert gas releases in hull spaces may also pose an asphyxiation threat. If asphyxiation is shown to be a concern in the enclosed area of the turret, or any other enclosed area, the Bay du Nord Operations team should confirm that BA sets will be available and one breath away.

5.9.1.2. Jet Fires

The quantification of fatalities as a result of exposure to the thermal effects of jet fires is calculated to take account for the reduction in thermal radiation as personnel move away from the fire event. It has been assumed that it will take personnel 30 seconds to move to a safe location, away from the effects of the thermal radiation.

The standard Equinor approach in GL0282 [37] has been applied, which is that personnel exposed to a thermal radiation level of 12.5 kW/m^2 or above will have a 100% likelihood of immediate fatalities from jet and liquid spray fires. The fire analysis calculated the distance to this radiation contour for all initial gas and liquid jet fire events. Assuming that the radiation contours would behave in a similar manner to an ellipse, the area of volume of the radiation contour can be calculated.

The proportion of the initial release module that could be occupied by these levels of radiation was found and the fatality fractions were applied to this to calculate an overall fatality fraction for each fire event.

The potential to cause fatalities in adjacent modules was also examined, in this case, if the contour volume fills the entire source module, the same methodology as above is applied to the adjacent module to determine immediate fatalities.

At the high outflow rates produced by failure of a high-pressure riser the predicted jet fire lengths are extremely large. The jet fire flame length correlations are not validated up to the higher outflow rates predicted here, therefore there is some uncertainty in their use for the high outflow rates predicted from large breaches in risers. Furthermore, such releases are very likely to impinge on nearby structures due to the high level of congestion within the turret whereupon they will lose their momentum.

5.9.1.3. Pool Fires

The pool fire immediate fatalities have been calculated in a similar manner to the jet fire immediate fatalities, using information from the Fire analysis.

5.9.1.4. Subsea Release

Subsea releases from the risers and flowlines may occur some distance from the FPSO due to the departure angle of the risers and weathervaning nature of the FPSO. In addition, any fire that formed would not be able to cause significant levels of heat flux on the Cargo Deck. It has been assumed that there will be no immediate fatalities for subsea releases.

5.9.1.5. Explosions

Explosion is perhaps the most hazardous occurrence and is likely to lead to 100% fatalities amongst those exposed to the overpressure, but any delay in ignition will have allowed personnel to escape. However, on the subject of escape, personnel, especially production operators, are as likely to investigate a leakage as to leave the area, thereby reducing their survival rates.

The maximum explosion overpressures can be calculated for each hydrocarbon event, and leak size, using the methodology described earlier in Section 5.2.3. The fatality fractions for the areas on the Bay du Nord FPSO where explosions occur are obtained using the overpressures calculated for each failure case as well as information provided by the HSE, as discussed in [28].

Table 5-13 Fatality Level for Various Explosion Overpressures

Overpressure	Immediate Fatality Fraction
<0.25 barg	0%
0.25 – 0.5 barg	50%
>0.5 barg	100%

It is assumed that personnel in adjacent modules may have an improved chance of escape due to the greater separation and therefore a maximum 50% fatality fraction is applied for such personnel.

The CSA has also taken account of the fire following the explosion which may result in fatalities from thermal radiation if the overpressure is low but followed by a severe fire.

5.9.1.6. Fatality Calculations

The immediate fatalities have been calculated for each end event for each breach size using the following formula:

Immediate fatality = frequency of end event x ([number of personnel in the area x conditional probability of immediate fatality in immediate area] + [number of personnel in adjacent areas x conditional probability of immediate fatality in adjacent areas])

To accurately calculate the immediate fatality risk levels, it is necessary to develop a picture of the spread of personnel or individuals around the installation at any time and assign a probability that they are at a specific location when an event occurs. This influences their risk of becoming a fatality. This is achieved by dividing the installation into a number of areas and using information about the workforce's occupations and duties to derive a realistic distribution of personnel around the installation. This is presented Section 3.3.7.

5.9.2. Muster Fatalities

Muster fatalities are defined as those fatalities resulting from personnel being unable to muster because the escapeways back to the Temporary Refuge are impaired and conditions on the FPSO are life-threatening.

All escape routes on the Bay du Nord FPSO lead to the temporary refuge. At least 2 routes are provided from all locations of the topsides, turret and machinery space. In addition, a bus shelter type escape route is provided along both the port and starboard sides of the FPSO. Personnel can also escape along the upper deck.

The provision of two bus shelter type escape routes means that, in the event of a fire, personnel who do not become immediate fatalities should not be prevented from reaching the TR as it is not expected that both the port and starboard side escape routes can be impaired by the same fire event. As such, personnel will be able to use the unimpaired escape routes to reach the TR.

For muster fatalities due to explosions, the explosion analysis and exceedance curves have been used to determine the possibility of exceeding the design load of the escape routes and, as a result, damaging the escape routes and preventing personnel from mustering.

The fatality fraction for personnel who are unable to return to the Temporary Refuge due to the escape routes being impaired has then been calculated. This takes into account the possibility of trapped personnel evacuating the installation by tertiary methods, e.g. life rafts, or through directly entering the sea. Fatalities that arise from personnel who are prevented from mustering, but who evacuate the platform via tertiary means are still classed as muster fatalities.

The muster fatalities have been calculated for each end event for each breach size using the following formula:

Muster fatality = frequency of end event x [number of personnel on plant - immediate fatalities] x probability of escape route impairment x muster fatality factor

5.9.3. Post Muster Fatality Event Tree

Post muster, the risk calculations are based on the event tree logic shown in Figure 5-3, if the Temporary Refuge, which is considered to be the whole of the accommodation block, maintains its integrity no further fatalities are assumed to occur. If the Temporary Refuge is impaired through a first mechanism e.g. direct explosion impairment, then the possibility of evacuation is considered. If installation evacuation is achieved, it is assumed that there are no fatalities in the Temporary Refuge and that 4.12% of the remaining installation POB becomes fatalities during the evacuation process using the free fall lifeboats [28]. However, if the Temporary Refuge is impaired and installation evacuation cannot be achieved, then in such circumstances it is assumed that 62% of the personnel remaining on the installation will be unable to successfully evacuate and become fatalities. This was developed on the basis that for any given hydrocarbon event scenario which impaired the TR and TEMPSC facilities, a range of numbers of fatalities was possible. The range of possible fatality fractions and estimated probabilities of these was estimated to be as follows:

- 0.3 Probability of 90% POB becoming fatalities
- 0.3 Probability of 70% POB becoming fatalities
- 0.2 Probability of 50% POB becoming fatalities
- 0.1 Probability of 30% POB becoming fatalities
- 0.1 Probability of 10% POB becoming fatalities.

The weighted aggregation results in an average fatality rate of 0.62. The only solid data for such an event can be taken from The Piper Alpha incident [45], where the integrity of the TR was lost due to smoke ingress. At the time of the disaster 226 people were on the platform; 165 died and 61 survived. Two men from the Standby Vessel Sandhaven were also killed. These figures correspond to a fatality rate of 73% amongst those on board.

Following this, other Temporary Refuge impairment mechanisms that may happen during the later stages of an event, e.g. progressive collapse or smoke logging, are considered in turn, together with their effects on the TEMPSC availability.

An assessment of the likely effects of the hydrocarbon events on the Temporary Refuge and EER facilities has been performed and is used when calculating the impairment probabilities of the Temporary Refuge / EER facilities. The results are presented on an event-by-event basis in Appendix A.

Before calculating the risks associated with Temporary Refuge and EER impairment it is necessary to identify the potential mechanisms by which the Temporary Refuge can be impaired. These are discussed below.

5.9.3.1. Smoke Ingress

The smoke ingress analysis considers the likely build-up of carbon monoxide (CO) in the Temporary Refuge by leakage through door seals, open doors, penetrations, etc.

The calculation of smoke impairment of the TR is based on the Kent Methodology Statement 13 [46] in conjunction with the Smoke and Gas Dispersion Analysis [47] and is based on Carbon Monoxide (CO) being the limiting factor associated with TR impairment from smoke.

Once the smoke concentrations (CO) outside of the TR are known, then the accumulation within the building can be calculated. The key inputs for determining ingress into the TR are:

- Air Change Rate per Hour (ACH)
- External CO Concentration.

The air changes per hour value represents the number of times that the entire volume of the TR building is replaced within one hour based on air flow transfer. For new build TRs, the ACH tends to be in the region of 0.1 – 0.2 ACH or lower. However, the effects of HVAC fans and dampers closing down as well as external doors being opened during the muster process must also be taken into account.

The accommodation air change rate with HVAC operating is taken to be 6 ACH and it is assumed that it will take 30 seconds from smoke or gas detection to the HVAC being shut down, which is considered conservative. The muster process is taken to occur for 5 minutes and during this time the external doors will be in use resulting in an assumed ACH of 3. Once the doors are closed, the TR is taken to be sealed with an air change rate of 0.1 ACH.

Over the two-hour period, taking the above phases into account, the average ACH of the TR is taken to be 0.25 ACH.

The CO concentration within the TR is used to determine the potential to impair personnel, through the build-up of carboxyhaemoglobin (COHb) within the bloodstream of personnel in the TR. Loss of integrity of the TR is taken to occur when personnel COHb levels reach 10% [48].

The time over which smoke leakage will lead to the Temporary Refuge becoming uninhabitable has been calculated for each event and compared with the durations of the incidents to determine the events that may result in impairment of the TR, as shown in Appendix A.

5.9.3.2. Structural Failure of the LQ due to High Heat Loads or Overpressure

This aspect is considered on an event-by-event basis in Appendix A where the probability of the Temporary Refuge external fire divisions failing due to direct flame impingement, high thermal radiation levels or impact damage is calculated. The separation provided between the Temporary Refuge and the process/riser areas means that the majority of process events do not have the potential to cause direct structural failure of the Temporary Refuge shell. However, escalation to other larger inventories e.g. cargo tanks, could result in Temporary Refuge impairment. If Temporary Refuge impairment occurs quickly then there would be little time to evacuate and a high level of fatalities would be expected. If the event took a long time to affect the Temporary Refuge (e.g. through escalation to the cargo tanks) then there would be adequate time for personnel to escape and there would be a lower fatality rate. This is assessed on an event-by-event basis.

5.9.3.3. Gas Ingress

A high level, free field dispersion analysis has been completed for the CSA [47]. This assessment has determined the flammable range of all releases on the FPSO and has been used in the CSA to determine whether unignited events on the FPSO can result in impairment of the TR.

The results of the dispersion analysis show that there are a small number of release cases that may produce flammable gas at the TR. Releases from some MP and HP compression events may produce a concentration of gas around 50% of LFL (which is 2.5% methane concentration) at the TR. Some large riser releases have also been considered to produce 50% LFL at the front face of the TR.

A concentration of 50% of LFL within the TR is taken to result in impairment and may result in an explosion inside of the TR. Using the TR air change rates quoted in Section 5.9.3.1, it would take over 2 hours for flammable gas to build up inside the TR if a gas concentration of 5% methane (which is 100% LFL) was outside of the TR. For such events, it is expected that personnel would have sufficient time to muster and evacuate from the FPSO by TEMPSC.

In the unlikely event that the HVAC system fails to shut down and 50% of LFL gas is present outside of the TR then it is assumed that impairment occurs rapidly. For such a scenario it is assumed ignition of the gas inside the TR occurs, preventing personnel from evacuating in an orderly manner.

The potential for each hydrocarbon event to cause TR impairment through gas increase, coincident with failure of the HVAC system to shut down is assessed on a case-by-case basis in Appendix A.

5.9.3.4. O_2 Depletion / CO_2 Build Up / Heat Stress

Low levels of oxygen are unlikely to represent a major threat as even with the HVAC system shutdown the capacity of the Temporary Refuge is such that a survivable atmosphere will be maintained for the endurance time of the Temporary Refuge. Due to the separation between the fires and the Temporary Refuge, the heat loads on the Temporary Refuge shell are not expected to represent a major threat in terms of heat stress.

The risk of an external fire (heat stress) or a smoke event leading to high accumulations of CO_2 causing impairment of personnel inside the LQ and the eventual fatalities has not been specifically assessed at this stage. As stated above, heat stress should not be an issue due to the separation between potential fires and the LQ. However, the potential for impairment of personnel from effects of CO_2 build up and O_2 depletion should be assessed in the next phase of design.

Recommendation 2 - An assessment of O_2 depletion and CO_2 build-up has not been assessed at this stage in the design but should be assessed in later stages of the design.

5.9.3.5. Evolution of Toxic Fumes

The Temporary Refuge will be constructed and furnished with materials which do not produce toxic fumes when subjected to external heating. This impairment mechanism has not been considered any further in this analysis.

5.9.4. Temporary Refuge Fatalities

These fatalities occur as a result of the Temporary Refuge and the TEMPSC being coincidentally impaired such that personnel become fatalities within the Temporary Refuge.

The calculation for each end event is detailed below:

Temporary Refuge fatality = end event frequency x [total POB – immediate fatalities – number of personnel prevented from mustering in the Temporary Refuge] x Temporary Refuge impairment probability x conditional TEMPSC impairment probability x Temporary Refuge fatality factor

The Temporary Refuge and EER impairment probabilities are derived on an event-by-event basis in Appendix A. As mentioned in Section 5.9.3, a TR fatality fraction of 0.62 is used for those persons who are trapped in the Temporary Refuge when evacuation by TEMPSC is not possible. This allows for some personnel to take independent action to evacuate by tertiary methods and be rescued safely.

5.9.5. Evacuation Fatalities

Evacuation fatalities are defined as those occurring during the evacuation if access to the TEMPSC is possible and the TEMPSC are still available. Evacuation route unavailability may arise through smoke or thermal radiation effects. Alternatively, there may be insufficient time to implement an orderly evacuation before impairment occurs.

In an emergency situation, there may be insufficient time to organise an evacuation to a standby vessel (if available) and therefore the only evacuation route considered in the analysis is by TEMPSC. Helicopter evacuation is generally considered to be too slow and too prone to smoke effects, etc. to be a realistic means of evacuation from a major incident.

The current TEMPSC arrangements are taken to be:

- 2 x 60-person freefall TEMPSC at the stern and designated as the primary lifeboats
- 1 x 60-person davit launched TEMPSC port side of Accommodation
- 1 x 60-person davit launched TEMPSC starboard side of Accommodation.

The weather averaged fatality rate of 4.12% during TEMPSC launch allows for the potential loss of the TEMPSC during the launch process and movement away from the vessel. It does not allow for fatalities during the rescue process of personnel from the TEMPSC. It is assumed that this will not be attempted unless conditions are such that the risk of fatality is low.

5.10. TR Impairment Mechanisms

A description of the mechanisms that may result in impairment of the TR is given here.

5.10.1. Cargo Tank Fire

Loss of the FPSO may be possible following a cargo tank explosion or overpressure failure that initiates from within the COTs. Events that may escalate to the tanks from process or riser events are covered separately through the 'Turret Collapse' or 'Process Module Collapse' mechanisms. Fires initiating from the COTs are assumed to result in TR impairment between 1 and 2 hours after the initiating event, resulting in precautionary evacuation of the FPSO.

5.10.2. Direct Impairment

An explosion or fire within the process modules that can directly impact on and then subsequently impair the Temporary Refuge. For Bay du Nord this is considered to be either from explosion events or pool fires during cargo offloading that may cause impairment within the TR endurance time.

5.10.3. Flare Tower Collapse

Collapse of the flare tower due to high thermal exposure, leading to cargo tank fire and eventual foundering of the FPSO. The position of the Flare Tower at the very forward end of the semi-enclosed bow means that the potential for events to impinge on the tower are limited. As such, impairment of the TR through flare tower collapse has not been considered further at this stage of the design.

5.10.4. Machinery Space Explosion

An explosion in the machinery space may result in rapid impairment of the TR (note: fires that occur in the machinery space of the FPSO and, in particular the engine room, result in flames or smoke at the TR are included within the Smoke Impairment mechanism and are likely to cause impairment more slowly).

5.10.5. Process Module Collapse

Fires or explosions that initiate in the Process Deck or Cargo Deck and result in direct collapse of the process deck or escalate to result in collapse of the deck, damage to the cargo tanks and subsequent loss of the FPSO. Explosions that can directly fail the process deck and escalate to the COTs are considered to result in impairment in around 60 minutes, resulting in precautionary evacuation of the FPSO. All other fire mechanisms are also considered to cause impairment between 65-70 minutes as there is no PFP applied to the structures associated with the process modules in the current proposed design.

5.10.6. Sea Fires

Subsea riser events may form a hydrocarbon accumulation at the sea surface close to the FPSO. Ignition may result in a sea fire that could cause damage to the FPSO hull and eventual loss of the vessel. However, the time for escalation to the cargo tanks and subsequent foundering of the FPSO will not be within the TR endurance period. Precautionary evacuation would occur.

5.10.7. Smoke – HVAC Fails

This mechanism represents a fire event producing smoke at the TR coincident with the HVAC dampers failing to shut-down on demand, rapidly drawing smoke into the Temporary Refuge and causing impairment within 5 minutes.

5.10.8. Smoke – HVAC OK

HVAC Dampers successfully close but smoke leakage through the sealed TR still occurs to result in impairment of the TR. This will happen over a longer period of time than for the same event where the dampers failed to close. The time to impairment will depend on the external smoke concentrations and event duration.

5.10.9. Turret Collapse / Escalation

Riser fire and subsequent inter-riser escalation or un-isolated fires that escalates to other risers leading to structural impairment of the turret due to high thermal loading are captured by this mechanism. Fire escalation is not assumed to result in impairment within the 2-hour endurance period. Large explosions in the turret may rapidly lead to loss of integrity of the turret and escalation to the COTs if the surrounding cofferdams are also breached, with the impairment of the TR within between 1 to 2 hours, necessitating a precautionary evacuation.

5.10.10. Unignited Gas Ingress

HVAC dampers fail to shut down on demand, rapidly drawing unignited flammable gas into the Temporary Refuge. Ignition of the gas inside the TR could result in a high number of fatalities as well as impairment of the Temporary Refuge. Events that can produce gas concentrations above 50% LFL are taken to result in impairment through rapid gas ingress.

5.10.11. Helicopter Crash

Impact of a helicopter onto the processing area of the FPSO to result in a fire or smoke events that causes impairment of the TR.

5.11. Non-Hydrocarbon Risk Analysis

To form a complete picture of the risks associated with the operation of the installation, non-hydrocarbon hazards have been identified and assessed for their potential to lead to fatalities. Each category of non-hydrocarbon hazard identified in Section 4.3 is discussed below and the risk levels calculated where the hazard is assessed to be significant.

The risk calculations used for the non-hydrocarbon events are much simpler than those required for the hydrocarbon events. They generally take the following forms:

- IRPA = frequency of hazardous events x fatality fraction x fraction of year exposed to hazard (/yr)
- PLL = frequency of hazardous event x fatality fraction x POB (per annum)

The risks from transport and occupational hazards are treated in a different way as discussed in the following sections.

5.12. Transport

Transport of personnel to the FPSO will be via helicopter or crew boat and gangway/FROG. It has been assumed that 88% of personnel transfers will be via helicopter and 12% via crew boat. This ratio is based on detailed analysis statistics for another operator in the region. During high staffing phases it is anticipated that boat transfers would be the preferred option to allow transfer of higher number of personnel and reduce helicopter flights. As helicopter transfer is historically considered to be a higher risk mode of transport than boat transfer, the current assessment is conservative.

5.12.1. Transportation Risks

Helicopter movements can be considered to generate two potential hazards. Firstly, the risk to personnel on board the helicopter if it crashes and secondly the risk to the installation if the helicopter impacts on it. Historically, helicopter risks have been dominated by fatalities amongst those on board the helicopter.

Helicopter risk, for the normal POB case (79), is calculated based on direct helicopter flights to or from shore. It is expected that there will be 5 people onboard the helicopter and flight time between shore and the Bay du Nord FPSO is 2.75 hours.

For this analysis, helicopter risk data has been based on risk levels taken from the Kent Method Statement 21 [24] which is based on OGP data. The frequency of fatal helicopter crash for each stage of a helicopter trip is presented in Table 5-14.

Table 5-14 Helicopter Fatality Rate Data

Flight Stage	Crash Frequency	Probability of a Fatal Crash
Cruise	5.68E-06 per flight hr	0.167
Take Off/Landing	4.54E-06 per TO&L	0.20

The risk to life from helicopter transportation accidents is calculated based on personnel working 3 weeks on, 3 weeks off shift pattern and each person making a maximum of 15 helicopter journeys year (other journeys being boat transfer operations).

As discussed previously, for transfer of personnel by boat, it is assumed that such transfers will only be planned when the conditions offshore allow for safe transfer of personnel to the FPSO.

FPSO crew boat transfer risk is calculated based on each FPSO crew member undertaking 2 boat transfers per year (with other transfers assumed to be by helicopter). It is expected that there will be 25 people on board the boat and travel time between shore and the Bay du Nord FPSO is 23 hours.

There is very little data on accident records for the transfer of personnel by supply boat and basket. CMPT data [25] shows that in a total of 2.3 million passenger transfer hours and 2.6 million transfer stages, no fatalities have been reported. Where no accidents have occurred, the frequency may be estimated using statistical techniques based on the Poisson distribution. The most likely frequency is equivalent to assuming that 0.7 accidents have occurred to date, i.e. that the operation is 70% of the way to its first accident. The confidence interval on this value is of course very wide.

Since accidents in transit (such as boat sinking) arise from different mechanisms than accidents in transfer (such as crew members being crushed while transferring), it may be appropriate to assume that both parts of the operation are independent and 70% of the way to an accident. This is thought to be a conservative assumption.

Using the above approach, the following frequencies of fatalities during boat and basket transfer have been used:

- Risk of fatality, per transfer hour (boat transfer): 3.05E-07
- Risk of fatality, per transfer hour (gangway or basket transfer): 2.65E-07

5.12.2. Helicopter Crash on FPSO

There is a potential hazard associated with the collision of a helicopter on to the Bay du Nord FPSO.

Based on the accident rates described previously for helicopter take-off and landing and predicted flight frequencies, the results of the frequency analysis indicated that, assuming a helicopter flight frequency of 5.7 flights onto or from the helideck per week (during normal operations), the crash frequency on the FPSO would be 1.99E-03 per annum.

Helicopter crashes on to other areas of the FPSO are considered unlikely as the helideck is located to the aft of the FPSO and is cantilevered over the port side. As the FPSO weathervanes freely around the turret, located at the front of the FPSO, it is likely that the approach/departure sector for helicopters will extend to the aft of the vessel, thus avoiding flying over the live process facilities. In addition, due to the location of the flare tower and turret plus the location and procedures for crane operations during helicopter activity, there are no moving or elevated obstacles within the expected helicopter approach and take-off paths.

In the unlikely event that the helicopter crashed onto the processing area then there is the possibility of some process escalation to result in a fire. The QRA has assumed that there is a 10% likelihood of the helicopter crashing onto the process area of the FPSO. The QRA risk results, presented later in this report, show that the average probability of TR impairment from ignited process events is low, around 1%. If it is conservatively assumed that a helicopter crash onto the processing area of the FPSO may result in subsequent TR impairment, then the likelihood of loss of the TR integrity occurring during Normal Operations is calculated to be 1.99E-06 per year.

It is concluded that the risk to personnel on the FPSO from helicopter operations is very low. There is clearly a risk to personnel on incoming and departing helicopters, but this is taken account of in their transport risks, as discussed in Section 5.12.1.

5.13. Occupational Risk

The occupational risks relate to the hazards associated with performing work offshore, e.g. hazards such as falls, crushing mechanical impacts, electrocution, etc. The Fatal Accident Rates (FARs) used in the QRA are based on information published by the UK HSE over a period from 1991 – 2024 and summarised in [49]. The FAR values are converted to individual risk per annum (IRPA) by taking into account the actual time each year that members of each employment category are exposed to the hazards at the workplace.

Conversion of the FARs into IRPA values is based upon the work pattern for the representative individual within each employment category. For all employment categories, it is assumed that each individual spends 50% of their time at the workplace.

Table 5-15 Occupational FARs

Worker Group	Occupational FAR
Admin	0.4
Maintenance	5.9
Operations	0.4
LQ Crew	-

Note: The LQ Crew category does not have an associated FAR for the period assessed. The value of zero has been used in order to remain consistent with the data for the other categories. This does not suggest that there is no occupational risk associated with the LQ Crew, only that there have been no fatal accidents recorded since 1991.

5.14. Structural Failures

5.14.1. Hull, Deck Structures & Superstructures

Circumstances leading to major structural failure and subsequent loss of life on a vessel can be divided into three principal categories:

- Occasions where extremes of weather conditions exceed the vessel's design criteria. In these cases, it may not be possible to distinguish whether foundering is from structural failure or from loss of stability or buoyancy.
- Design or construction faults where failure occurs within design criteria.
- Failure of key load bearing members after a period of deterioration not detected by inspection or not corrected before failure.

To reduce the possibility of environmental loadings exceeding the vessel's design capabilities, it is important to have a reliable understanding of the worst sets of reasonably foreseeable conditions which can occur and their return period. Detailed static and dynamic structural analysis would then be required to ensure that the vessel could withstand the conditions and to determine the fatigue life of key structures. Unlike the offloading tanker, the FPSO, being permanently moored, will be unable to avoid the worst weather conditions and therefore may be exposed more frequently to such conditions and suffer greater fatigue. However, as a weathervaning vessel, it should avoid the peak bending moments of a vessel making way through crossing seas.

Reduction of failures resulting from design and construction faults can only be achieved through tight quality controls during design, construction, testing and certification. Similarly, prevention of failures of deteriorating members depends upon having meaningful inspection schedules and programmes conscientiously applied. It should be a requirement of the integrity management process to impose controls during design, construction and operation which will minimise the risk of structural failure.

A further source of excess loadings which could, in bad weather, contribute to structural failure is poor ballast and weight control on board.

Whatever the causes of structural failures, they are most likely to occur in storm conditions when structural loadings are high, enhancing the probability of high resulting casualties.

A known hazard for FPSOs is the potential occurrence of unbroken waves (green water) landing on deck that can cause structural damage. This phenomenon has been seen over the past few years on a number of FPSOs in both Canadian, UK and Norwegian waters. As a result of this, the bow will be designed to take this into account and green water screens are expected to be incorporated along the length of the upper deck to prevent such an occurrence.

Installation-specific estimates of major structural failure rates cannot be made by this study and indeed it is debatable whether this can reliably be made for any installation. It is indicated in [50] that major structural failures during the useful life (approximately 20-25 years) of a 300m tanker could occur at a frequency of about 10^{-5} to 10^{-8} per annum. There is a significant amount of uncertainty in this data and therefore a conservative estimate of the frequency of major structural damage leading to loss of the vessel is taken to be $1x10^{-5}$ per annum.

Such an incident would most probably occur quickly with little warning and is most likely during severe loading conditions such as in a storm. On this basis, there would a high level of fatalities, assumed to be 90% of the POB.

5.14.2. Process Structures & Primary Steel

Failures of process structures or their primary steel could occur from the three principal causes discussed above. The immediate outcome is likely to be hydrocarbon releases and escapeway impairment. These events could escalate as discussed under the hydrocarbon events risk calculations. It is assumed that a small part of the generic failure rate for hydrocarbon systems is due to these types of failures.

5.15. Ship Collision

A detailed Ship Collision Study has been conducted for the Bay du Nord FPSO [51], taking into account infield attendant vessel activities as well as passing shipping traffic for the region:

Passing	Accidental contact between offshore unit and/or passing marine vessel when at least one of them is propelled or under tow. Examples include tankers, cargo ships and fishing vessels. Also included are collisions with vessels engaged in oil and gas activity on FPSOs / platforms other than the FPSO in question (i.e. supply ship or offloading tanker from nearby field) and collisions from drifting vessels.
Infield	Collisions or accidental contacts between vessels engaged in the oil and gas activity on the unit affected. Examples include support vessels, supply boats, and offloading tankers.

In addition, the degree of damage that has occurred is classified according to the severity and extent of the damage to primary structures and topside equipment. These classifications are explained as follows:

Total Loss	Total loss of the unit including constructive total loss from an insurance point of view. Unit may however be repaired and put into operation again.
Severe Damage	Severe damage to one or more modules on the unit, large/medium damage to load bearing structures or major damage to essential equipment.

Significant Damage	Significant/serious damage to single module and local area of unit, minor damage to load bearing structures, significant damage to single essential equipment or damage to more essential equipment.
Minor Damage	Minor damage to single essential equipment, damage to more non-essential equipment or damage to non-load bearing structures.
Insignificant Damage	Insignificant or no damage, some damage to parts of essential equipment or damage to towline, thrusters, generators or drives.

Typically for FPSOs the size of the Bay du Nord, it is expected that very high impact energies (>200MJ) would be required to result in a total loss of the vessel. Impact energies in the range of 100-200MJ could be expected to result in Severe Damage. The Bay du Nord FPSO hull design for ship impact will be based on the more detailed ship collision study. For the purposes of the CSA, it is assumed that there would not be any rupture of the hull as a result of collisions with impact energies less than 30MJ and therefore impact energies in the 30-100MJ range are assumed to cause Significant Damage.

The initial oil production rate for the Bay du Nord field is taken to be 160,000 bopd and with a COT capacity of 1 million barrels then this will require offloading operations to take place every 6 days for a period of 24 hours.

The ship collision frequencies shown in Table 5-16 are sourced from the Ship Collision study [51] for Bay du Nord.

Table 5-16 Ship Collision Frequencies

Impact Energy (MJ)	Classification	Annual Collision Frequency		
		Passing Vessels	Infield / Visiting Vessels	Shuttle Tanker
0-30	Minor or Insignificant	3.48E-07	4.59E-03	1.44E-03
30-100	Significant	1.20E-06	1.08E-04	5.12E-04
100-200	Severe	9.91E-07	1.92E-05	4.17E-05
>200	Total Loss	-	-	1.03E-05
Total		**2.54E-06**	**4.71E-03**	**2.00E-03**

The number of fatalities that may occur as a result of a ship collision is dependent on the severity of the collision, the weather conditions and whether or not sufficient advance warning is received to allow personnel to perform a controlled evacuation prior to the collision occurring.

Infield vessel collisions, including supply and Walk-to-Work vessels, are likely to occur without significant warning, as the vessels are expected visitors and therefore no alarm would be raised due to them being within the safety zone or heading towards the FPSO. Infield vessel collisions are likely to occur at much lower speeds and therefore result in lower impact energies and less significant levels of damage.

Passing or drifting vessels are likely to be detected as they head towards the FPSO; in good weather, it is assumed that there is a 95% chance that an impending collision will be detected with sufficient time to muster and allow the next steps of action to be determined. However, in heavy weather or poor visibility, detection capability of ship monitoring systems diminishes – it has been assumed that the 95% chance reduces to 75%. Data shown in Table 3-2 for the Bay du Nord field shows that wave heights exceed 5m approximately 11% of the year. Visibility can be reduced to less than 1km, due to fog, for considerable periods of time, assumed to be around

20%, and therefore in up 30% of cases, the weather conditions would reduce the potential for early detection of an impending collision.

Collisions resulting in total loss are taken to occur rapidly and therefore a fatality fraction of 90% is assumed where no warning is received. Where early warning is received, this is reduced to 10% - which would be a combination of a small number of immediate fatalities plus any fatalities associated with evacuation.

Collisions resulting in severe damage are assumed to result in far fewer fatalities. In many cases, the collision would not require evacuation of the FPSO; a fatality fraction of 1% is applied to cases where early warning is received, representing that evacuation may be required in some circumstances. Where no advance warning is received, a higher (5%) fraction is applied as personnel may not have mustered and therefore could be more vulnerable to the effects of a collision.

Significant damage category collisions are assumed not to require immediate evacuation from the vessel and therefore no fatalities are assumed to occur. Any evacuation carried out would most likely be precautionary by helicopter.

Shuttle Tanker collisions could occur as a result of drive-off. An impending collision would be unlikely to go unnoticed and although the time to react would be limited, it is expected that personnel who were involved in offloading activities would be able to remove themselves from the area prior to a collision occurring. The immediate consequences of a collision would most likely be limited to the stern of the FPSO and the potential for significant hull damage would be lower than for a collision with the side of the FPSO. It should be noted that an analysis of DP shuttle tanker tandem offloading incident data for the 5-year period 1996 to 2000 found that there were 61 incidents in the North Sea, both in the UK and Norwegian sector. Of these incidents, there were 9 recorded drive-offs, 7 of which were in a forward direction (2 were astern). Of the 7 drive-offs forward, 4 resulted in collisions and 3 were near-misses.

The frequency of collisions with the potential to cause fatalities is estimated at 6.04E-04 per annum. The overall fatality fractions used for each collision type are summarised in Table 5-17.

Table 5-17 Ship Collision Fatality Fractions

Impact Energy Category	Collision Fatality Fraction		
	Passing Vessels	Infield / Visiting Vessels	Shuttle Tanker
Severe Damage	0.014	0.014	0.003 (immediate) 0.0765 (evacuation)
Total Loss	N/A	N/A	0.188

5.16. MODU Collisions

In recent years, a number of high-profile mooring failures have emphasised the high-risk nature of the mooring capabilities of a floating structure. Semi-submersible mobile offshore drilling units (MODUs) operating in the harsh North Sea environment have experienced approximately three mooring failures every two years; this is based on an average population of 34 units.

However, the 1,200m water depth at Bay du Nord means that MODU's operating at the field maintain their position through a redundant DP system.

There is expected to be frequent MODU activity in the field, approximately 2 - 12 km from the FPSO. The probability of a collision between a MODU operating in the field and the BdN FPSO has not been assessed for this stage of the development, however MODU collision assessments in nearby fields have determined that the likelihood of failure of the MODU to maintain its position leading to a collision with another installation is low. This is due to the range of systems in place to provide early warning, the ability of both the MODU and FPSO to power themselves to avoid a collision and simply the low chance that the wind / current conditions align such that the MODU follows the exact path required to hit a relatively small target (small compared to the expanse of open sea).

5.17. Dropped Objects

Information relating to lift paths and objects to be lifted has been assessed within the Dropped Object Study [52] for the FPSO for dropped objects both subsea and topsides.

For the purposes of the CSA, the impact from dropped objects on topside equipment is taken to be included in the generic topside release frequencies and direct impact with personnel is taken to be included in the Occupational risks. Objects lifted by the FPSO cranes are not expected to be lifted over the process modules.

Impacts on the risers have been added to the PARLOC release frequency data. Leak frequencies from dropped objects onto the risers are 1.15E-05 leaks/yr on the Bay du Nord North and South Production risers and the Gas Injection riser, and 3.43E-06 leaks/yr on the Cambriol Production riser.

5.18. Turbine Disintegration

The potential exists for a turbine disc or blade to disintegrate resulting in missiles, leading to direct fatalities or releases of hydrocarbons which may lead to impairment of the TR.

The three power generation turbines are to be located on the topside Utility area, directly forward of the accommodation on the starboard side. The potential for direct blade impact with the TR, should the blade penetrate through the turbine enclosure, is extremely low based on historical operation of such turbines and the orientation of the equipment. As the turbines are located some distance from processing equipment then the potential to cause TR impairment through escalation to other equipment is also low, with failure of diesel or fuel gas being the only credible scenarios. Releases from this equipment is already considered within the CSA.

Turbine failure is therefore not included further in the CSA.

5.19. Loss of Position

Loss of position resulting in the FPSO drifting off station can result from mooring system failure, which would have to be accompanied by severe or extreme weather.

The FPSO has been provided with a mooring system with the turret as close to the bow as practicable. Moorings design has high redundancy and integrity, with 3x5 mooring line clusters designed for the 2-line failure case. Risers are designed for 160m excursion distances. The design includes three corridors for moorings and separate corridors for risers with large separation distances. This is inherently more reliable than a mooring configuration which is dependent upon DP systems to ensure vessel heading and position. The frequency of loss of position occurring is therefore likely to be very low.

In the event of the mooring system failing, the associated hazards would be:

- Colliding with another installation.
- Foundering or capsizing as a result of the vessel turning beam-on to the seas.
- Loss of containment from the risers that would be ruptured as a result of the FPSO losing position. It is unlikely that loss of position would occur instantaneously. It is more likely that there would be partial failure with perhaps one of the mooring lines being lost first. If this occurred, the subsea lines would all be isolated, and the lines blown down to reduce inventory in the risers.

However, due to the excursion distance required to cause failure and the long length of the risers, loss of position of the FPSO has been deemed unlikely and is, therefore, not included further in the CSA.

5.19.1. Loss of Buoyancy / Stability

Loss of buoyancy may occur as a result of ballast system failure or during oil loading / offloading from the COTs. External events such as ship collision or extreme weather may also result in loss of buoyancy or stability but were captured previously under Ship Collision or Structural Failure.

The consequences depend on location and nature of failure, but could include:

- FPSO list angle depending on the number of ballast tanks and/or cargo tanks affected.
- Loss of FPSO under extreme circumstances.
- Difficulty in launching lifeboats due to list angle.

The hull tanks have been optimised to ensure stability in all intact and damaged cases. The ballast system will comply with requirements in IMO, Transport Canada and Class rules.

On the basis of the above, the potential for loss of buoyancy or stability has not been assessed further within the QRA, with the exception of Ship Collision or Extreme weather events leading to Structural failures.

5.20. Accommodation Fires

Fires within the accommodation fall into one of the following categories:

- Galley fires (galley hood extinguishing system is fitted)
- Fires within living quarters (including laundry)
- Electrical fires.

There is the potential for multiple fatalities due to fires in the accommodation modules. The main threat is smoke, though in some instance's personnel could become trapped in their cabins due to the location of a fire.

From inspection of the current design and expected boundary protection, it is concluded that a fire in the accommodation is very unlikely to escalate outside the accommodation. Hence, provided personnel can escape out of the accommodation, they should not be further threatened. This scenario has therefore not been considered as threatening the integrity of the Living Quarters.

There is the potential for individuals to become fatalities before making their escape from accommodation fires. Historically this has been a low risk.

With regards to the provision of a fixed fire suppression system in the LQ. It is reasonable to assume that a fixed fire suppression system would reduce the risk to personnel, but the magnitude of this risk is difficult to determine, as there is a dearth of data associated with fatalities from fires which originate in offshore accommodation (which means that any reduction in risk would certainly be very small as the original risk is very small).

Table 5-18 Summary of Accommodation Fire Control Measures

No	Control Measure
Cabins	
1	Control of ignition sources: smoking, electrical equipment. No smoking policy except in designated recreation areas.
2	Fuel; Cabins shall have sufficient storage to ensure absence of clutter. Soft furnishings to be fire retardant
3	Detection and alarm. Smoke detector in each cabin which would raise an addressable alarm and give location of fire.
4	Segregation and ventilation control. Ventilation dampers will be provided as per class requirements.
5	Electrical shutdown. There is emergency lighting throughout the accommodation, which is powered from the emergency generator.
6	Fire Team. The fire team shall train on accommodation fire scenarios including Cabin, Galley and Laundry fires
7	Manual firefighting equipment. manual firefighting equipment available at the Accommodations.
8	Inspection/maintenance shall be carried out to ensure control measures, detection, partitions, dampers, alarms are functional
9	Training with cabin fire emergency scenarios shall be carried out
Galley: The Galley fuel sources include cooking oil and grease, which can be ignited by heat. Good Practice in relation to Galley fire management is:	
10	Training – Galley staff shall always be present when operating equipment and shall be given specific training in relation to development of and fighting galley fires
11	Galley Hood – automatic fire suppression systems shall be installed in galley hoods to extinguish the fire and prevent its spread
12	Preventative maintenance routines shall be implemented for galley equipment
Laundry: Laundry fires have occurred offshore, with the main cause being build up and ignition of lint. Good practice is to ensure that:	
13	Lint filters in tumble dryers are cleaned before use and that lint build-up is avoided. Lint is removed.
14	The 'cool down' cycle of the tumble dryer is adequate to reduce the temperature of the items. Cool down cycle is applied.
15	Items (e.g. catering cloths, PPE) contaminated with combustible substances such as solvents, grease, oils, fats etc. are soaked in detergent prior to washing. Heavily soiled items are washed separately with additional detergent and at a high temperature wash. Coveralls are washed separately and aggressively to remove contaminants Coveralls are hung after drying
Corridors	
16	Corridors to be unobstructed.

6. Target Levels of Safety

6.1. Requirements

Equinor has specified Target Levels of Safety (TLS), see Section 6.2, that must be met at the conceptual and design stages of the Bay du Nord Project to ensure that the risks associated with Major Accident Events are acceptable. This is in accordance with the Framework Regulations [2], section 24.2.

Equinor must subsequently demonstrate that the risks to personnel and the environment are as low as reasonably practicable (ALARP) by implementing risk reduction measures, if required. In the case of the Bay du Nord Project, this has been demonstrated through the completion of a Quantitative Risk Assessment (QRA), along with a formal ALARP Workshop [5], the findings of which are reported in Section 8.

Risk to personnel can be expressed in terms of Individual Risk (IR), which is a quantitative measure of the fatality rate per individual per annum. Such a measure can also be expressed as a function of the amount of time that an individual spends on the installation. The TLS stipulated for Equinor contain both risk-based and impairment-based criteria. The risk-based criteria are further sub-divided into the following categories:

- Individual Risk
- Group Risk.

The impairment-based criteria stipulate criteria for the following installation Safety Functions:

- the installation's primary structure
- the temporary refuge (TR)
- the escape routes back to the TR
- the availability of the evacuation systems from the FPSO to a place of safety.

For risks to individuals, the IR criteria, developed as part of the risk-based criteria, are the overriding criteria and must be met by the final design. Installation staffing levels are required to quantitatively assess the IR associated with a facility and a comparison made with the stipulated criteria to determine the significance of the risk.

The remaining criteria, that is, the Group Risk and impairment-based criteria, are provided to allow the assessment of the design when staffing levels have not been defined or are uncertain, or when the overall risk assessment is still at a preliminary stage. Such criteria are used for design guidance only, specified to allow design of the facility to proceed as the project progresses. Impairment-based criteria can be used during the concept and design phase to distinguish between possible accidental events which have the potential to cause high-fatality accidents, and those which do not. Provided the impairment-based criteria are not exceeded, the accident can be considered to have low potential for preventing the escape of personnel away from the accident; or for threatening the integrity of the installation, the safe refuge or the means of evacuation within a time period that is long enough to safely evacuate personnel. Meeting impairment-based criteria may not guarantee that the IR criteria are met, it will, however, make it more likely. Risks to the environment are also assessed by Equinor and detailed further in the Bay du Nord Environmental Impact Statement.

6.2. Project Specific TLS

The risk criteria that is applied to the Bay du Nord design will be based on the Equinor DPN Risk Analyses and Risk Tolerance Criteria document [53]. The criteria for personnel are based on the definition of 1st person i.e. an individual or group who are involved in work at Equinor's installation.

6.2.1. Individual Risk

The average individual risk, expressed by fatal accident rate (FAR), is calculated for people at work. For offshore facilities, "at work" means all the time a person is on the installation as well as during transport to an installation or between installations.

The risk shall meet the following criteria:

- A FAR of less than 10, calculated as an average for all personnel on the installation. This is equivalent to an IRPA of 4.4E-04 per annum for a worker who spends 50% of their time offshore i.e. (10 / 1E+08) x 8760 x 0.5.
- A FAR of less than 25 for particularly exposed groups on the installation, which corresponds to an IRPA of 1E-03 per annum for a worker who spends 50% of their time offshore i.e. (25 / 1E+08) x 8760 x 0.5.

6.2.2. Group Risk

Group risk has been presented as Potential Loss of Life, based on the number of fatalities per annum. There is no specified criteria or TLS for PLL, with the primary risk target being for Individual Risk.

6.2.3. Loss of Main Safety Functions

High-fatality accidents can occur if the following criteria are not met:

- at least one escape route from any position, which may be subject to an accident, to an area of shelter, shall remain intact
- TR shall remain intact until safe evacuation is possible
- the main supporting structure must maintain the load carrying capacity for a specified time, until safe evacuation is possible
- evacuation systems remain useable.

As such, the Bay du Nord project consider main safety functions to include key escape routes and particularly the shelter type that run down the port and starboard side of the FPSO, TR and evacuation facilities but also partitions between main areas. From the above, the following were identified as the installation's key Safety Functions for which the impairment-based criteria were applied:

- Primary Structures (the Process and Upper Deck supports have been considered in this phase of design in terms of the frequency assessment due to the criticality of these to prevent rapid escalation to the COTs and TR)
- Temporary Refuge
- the sheltered escape routes (from any position which may be subject to an accident) to the TR
- the availability of the evacuation systems, with the TEMPSC being taken as the primary means of evacuation.
- the boundary of the Turret
- Process Deck (Separation and Compression Areas only)

For the above functions the impairment-based criterion that has been applied is that the frequency for loss of integrity to the installation's key safety functions from any Single Major Accident Event should not exceed 1E-04 per annum.

7. Risk Assessment

One of the primary Target Levels of Safety relates to IRPA, which is presented for the 4 worker groups on the FPSO as well as a weighted average of the number of workers in each group. The Individual risk figures are calculated taking into account:

- The proportion of time individuals spend in each location, based on the personnel distributions given in Table 3-4.
- The predicted frequency of hazardous events to which individuals are exposed in each location
- The impact of those hazardous events, in terms of predicted fatality rates.

The average IRPA is presented as a FAR, which is equivalent to the number of fatalities per 100 million exposed hours. This is based on the definition of exposed hours given in GL0282 [37].

Table 7-1 Average Individual Risk (FAR) Contribution from MAEs on Bay Du Nord

		Individual Risk (FAR)			
MAE #	**MAE Description**	**Immediate**	**Muster**	**TR Fatalities**	**Evacuation**
1	LOC of hydrocarbon gas (including 2- phase)	0.248	0.121	0.130	0.043
2	LOC of hydrocarbon liquid	0.084	0.009	0.025	0.010
3	Hull tank fire / explosion	0.010		0.000	0.000
4	Non-process fires	0.000		0.002	0.000
5	Accommodation fire				
6	Helicopter accident	1.545		0.001	
7	Ship collision			0.022	0.010
8	Structural failure			0.103	
9	Dropped/swinging objects				
10	Loss of Mooring				
11	Loss of stability and buoyancy				
12	Iceberg Collision			0.001	0.000
13	LOC of hydrocarbon riser			0.004	0.004
	Total (exc Occupational)	1.887	0.130	0.287	0.067
	Occupational	1.604			
	Overall Total	**3.97**			

It should be noted that the occupational FAR calculated in Table 7-1 is half of the FAR used in Section 5.13. This is because the historical FAR data is based on the exposed hours at the worksite, whereas the FAR presented in 5.13 includes offshift time as well as onshift. As the offshift time is assumed to be 12 hours per day, then the overall FAR is half the FAR based on onshift time alone.

It can be seen that the overall average FAR of 3.97 is below the TLS set by Equinor of 10. The highest contributors to the FAR are transportation, either by helicopter or boat and occupational hazards associated with slips, trips, falls, electrocution, etc.

The Individual Risk for the four different worker groups on Bay du Nord is presented next.

Table 7-2 Individual Risk (FAR) per Worker Group on Bay Du Nord

Individual Risk - FAR	Admin	Maintenance	Operations	LQ Crew
Immediate	0.18	0.43	0.36	-
Muster	0.09	0.17	0.12	-
TR Fatalities	0.16	0.16	0.16	0.16
Evacuation Fatalities	0.06	0.06	0.06	0.06
Transport	1.54	1.54	1.54	1.54
Occupational	0.20	2.95	0.20	-
Ship Collision	0.03	0.03	0.03	0.03
Structural	0.10	0.10	0.10	0.10
Toxic Gas	-	-	-	-
Iceberg Collision	0.001	0.001	0.001	0.001
Helicopter Crash	0.005	0.01	0.01	0.001
Total	2.38	5.45	2.59	1.90

It can be seen that the FAR for each the worker groups is below the TLS set by Equinor of 25, indicating that the current design of the FPSO is in the ALARP region. Transport to and from the FPSO, iceberg collision as well as global structural failure are the same for each of the worker groups. Occupational risk is highest for the Maintenance worker group but is zero for the LQ Crew, where the historical occupational FAR associated with their activities, based entirely in the LQ, is negligible.

The worker group with the highest FAR is the Maintenance Crew, which is predominantly as a result of their higher historical occupational risks, associated with performing maintenance activities on process, electrical and mechanical equipment. A breakdown of the individual risk for an average Maintenance Worker is shown in Figure 7-1.

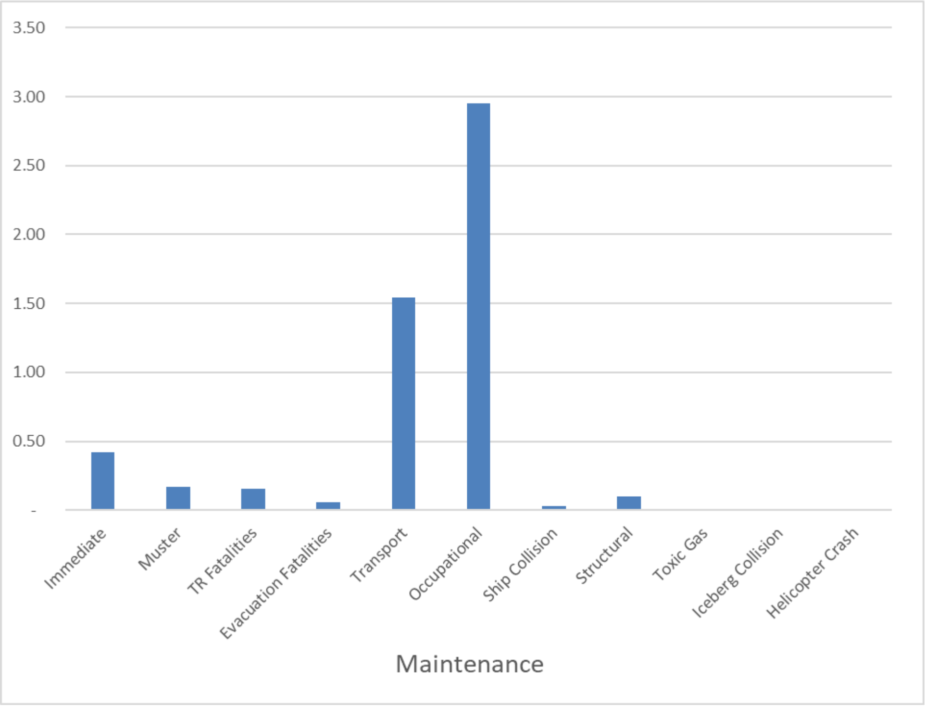


Figure 7-1 Breakdown of Maintenance Worker Individual Risk (FAR)

7.1. Potential Loss of Life (PLL)

The overall risk to life on the facility, or societal risk, is presented next for each MAE on the FPSO. The PLL is presented as average potential fatalities per annum and, as the FPSO is an offshore facility, assumes continuous exposure to the hazards as the installation will be staffed 365 days per year, 24 hours per day.

Hydrocarbon hazards are presented on the basis of the immediate effects of the event, fatalities that may occur during the muster process, whilst mustered in the TR or during the evacuation process. The other contributors are either only immediate, for example occupational and transport incidents, or they are global events where the total number of final fatalities is considered, such as ship collision, structural failure, iceberg collision, etc within the TR or whilst evacuating the FPSO.

Table 7-3 PLL Contribution from MAEs on Bay Du Nord

		Potential Loss of Life (fatalities per annum)			
MAE #	**MAE Description**	**Immediate**	**Muster**	**TR Fatalities**	**Evacuation**
1	LOC of hydrocarbon gas (including 2- phase)	1.71E-03	8.39E-04	8.99E-04	2.95E-04
2	LOC of hydrocarbon liquid	5.79E-04	6.23E-05	1.75E-04	6.58E-05
3	Hull tank fire / explosion	6.81E-05		1.81E-06	2.29E-06
4	Non-process fires	6.03E-07		1.24E-05	5.95E-07
5	Accommodation fire				
6	Helicopter accident	1.07E-02		4.89E-06	
7	Ship collision			1.53E-04	6.84E-05
8	Structural failure			7.11E-04	
9	Dropped/swinging objects				
10	Loss of Mooring				
11	Loss of stability and buoyancy				
12	Iceberg Collision			4.13E-06	8.54E-07
13	LOC of hydrocarbon riser			2.46E-05	2.94E-05
	Total (exc Occupational)	1.31E-02	9.01E-04	1.99E-03	4.63E-04
	Occupational	1.11E-02			
	Overall Total	**2.75E-02**			

The overall risk to life, for a POB of 79, has been assessed to be 2.75E-02 fatalities per year, or one fatality every 36.4 years. In a similar manner to Individual Risk, transportation to and from the FPSO, and occupational hazards are the key contributors to risk to life, with approximately 79% of the total.

Risks to personnel in the immediate vicinity of a hydrocarbon release make up approximately 8.6% of the overall risk to life, whilst the delayed effects of a release, either during muster, within the TR or during evacuation, contribute 8.6% to the overall risk to life. This is due to the protected escape routes, design and separation of the TR from the majority of MAEs and redundancy in TEMPSC provisions.

There is currently no TLS for Group Risk to compare the Bay du Nord assessed PLL against.

7.2. Main Safety Functions

The potential for each of the identified MAEs to result in failure of the Main Safety Functions, described previously in Section 6.2.3, is presented in Table 7-4.

Table 7-4 Contribution of MAEs to Main Safety Functions

MAE#	MAE Description	Hull (/annum)			Temporary Refuge (/annum)					Escape Routes		Evacuation (/annum)		Prevent Escalation	
		Fire	Explosion	Impact	Fire / Heat	Explosion	Smoke	Gas	Impact	Fire	Explosion	Fire	Explosion	Fire	Explosion
1	LOC of hydrocarbon gas (including 2- phase)	7.96E-05	2.41E-05		5.64E-05	4.06E-06	4.47E-05	4.76E-06		0.00E+00	5.70E-05	7.31E-07	1.33E-05	1.31E-05	3.03E-05
2	LOC of hydrocarbon liquid	2.08E-05	4.67E-07		1.18E-05	8.87E-07	1.16E-05	0.00E+00		0.00E+00	4.28E-06	7.97E-07	2.88E-06	2.84E-06	1.70E-05
3	Hull tank fire / explosion	7.63E-07	1.09E-06		5.72E-07	0.00E+00	1.91E-07	0.00E+00		0.00E+00	0.00E+00	1.91E-08	1.91E-08	0.00E+00	0.00E+00
4	Non-process fires	0.00E+00	0.00E+00		3.71E-08	0.00E+00	3.61E-07	0.00E+00		0.00E+00	0.00E+00	1.27E-07	1.27E-07	0.00E+00	0.00E+00
5	Accommodation fire								no data available						
6	Helicopter accident								1.99E-06						
7	Ship collision			7.22E-05											
8	Structural failure			1.00E-05											
9	Dropped/swinging objects								included in MAE 13 (subsea riser impacts)						
10	Loss of mooring.			included in MAE 8											
11	Loss of stability and buoyancy			included in MAE 8											
12	Iceberg Collision			5.23E-07											
13	LOC of hydrocarbon riser	0.00E+00	0.00E+00		0.00E+00	0.00E+00	5.02E-07	0.00E+00		0.00E+00	0.00E+00	5.02E-07	0.00E+00	0.00E+00	0.00E+00
	Overall Total	1.01E-04	2.57E-05	8.27E-05	6.88E-05	4.95E-06	5.74E-05	4.76E-06	1.99E-06	0.00E+00	6.13E-05	2.18E-06	1.63E-05	1.60E-05	4.73E-05

The results in Table 7-4 show that the Main Safety Functions generally meet the requirements of the TLS, and that only a single MAE exceeds the function with a frequency greater than 1E-04 per year (the hull impairment frequency is 1.01E-04 per annum). It should be noted that the escalation rulesets and explosion modelling around process releases leading to hull impairment are relatively conservative in nature, and it is expected that the risk to the hull will reduce in subsequent phases of the design as more detail becomes available and conservatisms around the modelling for the design can be removed.

The key hydrocarbon events that contribute to TR impairment, within the two-hour endurance period, are shown next for those events that contribute more than 2% to the overall total. It should be noted that the TRIF presented in the following tables does not include the following:

- MAE5 - Accommodation fire
- MAE6 - Helicopter accident
- MAE7 - Ship collision
- MAE8 - Structural failure
- MAE9 - Dropped/swinging objects
- MAE10 - Loss of mooring.
- MAE11 - Loss of stability and buoyancy
- MAE12 - Iceberg Collision

These MAEs are not included in the TRIF numbers as the TR would not normally be expected to be designed for these types of MAE.

Table 7-5 Ranked Contribution to TR Impairment within 2 hours

Event ID	Description	Total TRIF	%
P19-G-TRTU	HP Gas Compression / Injection Pipework and Flowlines - Gas Release at Turret Upper Deck	2.66E-05	18.2%
P02-M-TRTU	HP Inlet and Test Manifolds - Two Phase Release at Turret Upper Deck	1.24E-05	8.5%
P17-G-M61L1	Gas Dehydration Inlet Scrubber (24-VG-6001) & TEG Contactor (24-VB-6602) & 1st Stage HP Gas Compressor Suction Scrubber (23-VG-6004) - Gas Release at M61 Process Deck Level 1	1.16E-05	7.9%
P18-G-M61L1	2nd Stage HP Gas Compressor & Suction Scrubber (23-VG-6005) - Gas Release at M61 Process Deck Level 1	1.06E-05	7.2%
P01-M-TRTL	BdN Production Flowline 1 and 2 (ESV to XSV) - Two Phase Release at Turret Lower Deck	9.76E-06	6.7%
P04-L-M10L1	Inlet Separator (20-VA-1001) - Liquid Release at M10 Process Deck Level 1	5.63E-06	3.9%
P06-L-M11L1	Electrostatic Coalescer (20-VJ-1003) & Oil Booster Pump (20-PA-1001A/B) & Crude Oil Coolers (20-HB-1002A/B) - Liquid Release at M11 Process Deck Level 1	5.03E-06	3.4%
P19-G-TRTL	Gas Injection/Lift 1 BDN & Gas Lift 2 Cambriol/Circulation Flowline (XSV to ESV) - Gas Release at Turret Lower Deck	4.63E-06	3.2%
P18-G-M61L2	1st & 2nd Stage HP Gas Compressor Discharge Coolers (23-HG-6004 & 23-HG-6005) - Gas Release at M61 Process Deck Level 2	4.19E-06	2.9%
P03-L-M10L1	Test Separator (20-VA-1004) - Liquid Release at M10 Process Deck Level 1	4.04E-06	2.8%
R06-G-SS	Gas Injection/Gas Lift Riser Subsea	3.83E-06	2.6%
P01-M-TRTU	MP Inlet and Test Manifolds - Two Phase Release at Turret Upper Deck	3.38E-06	2.3%

Releases from large hydrocarbon inventories or high-pressure process equipment can produce high explosion overpressures that may either fail the process deck or escalate to large liquid inventories and spill onto the ships deck below. Explosions may also result in failure of the PFP that is assumed to be fitted to the stools supporting the process and utility decks, causing collapse of the process deck into the COTs and impairment of the TR within 2 hours. This is assumed to result in an evacuation of the FPSO.

There is some known conservatism in the escalation rule sets to cause TR impairment through escalation to the COTs. This has been raised as an area of uncertainty in Section 11 and will be assessed in more detail in the next phase of the Project. This should include a formal escalation review to allow the project team to provide input into the escalation paths captured in the QRA.

7.3. Sensitivity Analysis

Due to the relatively early stage of the Bay du Nord design, there are a number of areas of uncertainty or assumptions that the risk levels may be particularly sensitive to that were identified as described next.

- Flexible risers – the production risers are currently modelled as flexible risers and the gas riser is rigid, but a sensitivity with production risers as rigid risers is assessed here.
- Safety System Sensitivities – the assumptions around F&G, firewater, ESD, blowdown and HVAC reliability are assessed here.
- POB – the base case is presented for a total number of personnel on board of 79. However, the anticipated maximum POB for the FPSO is 120 and this sensitivity assesses the risks associated with a POB of 120.
- Subsea actuated valves on the risers – the base case currently does not take credit for the actuated valves installed at the base of each of the risers. This sensitivity examines the change in risks if these were taken credit for to act as subsea isolation valves.
- TEMPSC – the current arrangement is for a combination of freefall and davit launched lifeboats. This sensitivity examines the impact on risks if all lifeboats were considered to be davit-launched only.
- No protected escape routes – the base case design includes shelter type protection along the port and starboard escape routes. However, if this protection was not provided then the potential impact on risks is examined in this sensitivity.
- Forward LQ - The positioning of the LQ forward of the turret is assessed to determine whether there is a significant reduction in risk from relocating the LQ.
- PFP on module supports – there is currently no PFP applied in the process modules of the FPSO. This sensitivity assesses the change in risk from applying H120 PFP to the module supports of the process modules.
- Forward Muster Area Means of Evacuation – one of the objectives of the FPSO design is to ensure that suitable evacuation means are provided in the bow area for personnel who are unable to perform egress to the aft TR. This sensitivity looks at the different options which are available.

These sensitivities are examined in more detail next, along with the potential impact on risks.

7.3.1. Flexible Risers

The base case models releases from the risers based on the historical data for steel risers for the gas riser and flexible risers for the production risers. This sensitivity assesses the impact on risk in the case where production risers were instead supplied as steel risers, which have a lower release frequency. The results are shown in Table 7-6.

Table 7-6 Riser Release Frequency Sensitivity

Risk Parameter		Base Case	Sensitivity	% change
TRIF (/year)	Within 2 hours	1.38E-04	1.38E-04	-0.1%
	Overall	1.48E-04	1.45E-04	-2.1%
Potential Loss of Life	Hydrocarbon	4.77E-03	4.75E-03	-0.4%
(fatalities/year)	Non-Hydrocarbon	2.27E-02	2.27E-02	0.0%
	Total	2.75E-02	2.75E-02	-0.1%
IRPA (FAR)	Hydrocarbon	0.69	0.69	-0.4%
Average	Non-Hydrocarbon	3.29	3.29	0.0%
	Total	3.97	3.97	-0.1%

The TR impairment frequency and hydrocarbon IRPA decreases by 0.1% and 0.4% respectively by adopting the steel riser failure frequencies for riser releases. The decrease in impairment of the TR within the 2 hours is due a reduction in smoke and unignited gas impairment from sea surface fires. As mentioned previously, the assessment of smoke and gas dispersion towards the TR is believed to be conservative and will be reviewed in more detail in subsequent phases of the design.

The decrease in risk to TR integrity and personnel on the FPSO is entirely due to the lower historical frequency associated with steel risers.

7.3.2. Safety System Sensitivities

The key safety systems previously identified for the Bay du Nord FPSO include Fire & Gas detection, firewater, ESD, blowdown and TR HVAC. The reliability of these systems is based on known system reliabilities calculated for operational assets. The sensitivity of the risks to changes in assumed reliability has been reviewed for the systems next.

Table 7-7 Fire & Gas Detection Sensitivity – 99% Base Case v 97% Reliability

Risk Parameter		Base Case	Sensitivity	% change
TRIF (/year)	Within 2 hours	1.38E-04	1.38E-04	0.08%
	Overall	1.48E-04	1.48E-04	0.14%
Potential Loss of Life	Hydrocarbon	4.77E-03	4.77E-03	0.076%
(fatalities/year)	Non-Hydrocarbon	2.27E-02	2.27E-02	0%
	Total	2.75E-02	2.75E-02	0.013%
IRPA (FAR)	Hydrocarbon	0.69	0.69	0.076%
Average	Non-Hydrocarbon	3.29	3.29	0%
	Total	3.97	3.98	0.013%

Table 7-8 ESD and Blowdown Sensitivity – 98.5% Base Case v 97% Reliability

Risk Parameter		Base Case	Sensitivity	% change
TRIF (/year)	Within 2 hours	1.38E-04	1.38E-04	0.05%
	Overall	1.48E-04	1.48E-04	0.09%
Potential Loss of Life	Hydrocarbon	4.77E-03	4.77E-03	0.02%
(fatalities/year)	Non-Hydrocarbon	2.27E-02	2.27E-02	0%
	Total	2.75E-02	2.75E-02	0.004%
IRPA (FAR)	Hydrocarbon	0.69	0.69	0.02%
Average	Non-Hydrocarbon	3.29	3.29	0%
	Total	3.97	3.98	0.004%

Table 7-9 Deluge Sensitivity – 96% Base Case v 90% Reliability

Risk Parameter		Base Case	Sensitivity	% change
TRIF (/year)	Within 2 hours	1.38E-04	1.39E-04	0.6%
	Overall	1.48E-04	1.49E-04	0.8%
Potential Loss of Life	Hydrocarbon	4.77E-03	4.77E-03	0.08%
(fatalities/year)	Non-Hydrocarbon	2.27E-02	2.27E-02	0%
	Total	2.75E-02	2.75E-02	0.01%
IRPA (FAR)	Hydrocarbon	0.69	0.69	0.08%
Average	Non-Hydrocarbon	3.29	3.29	0%
	Total	3.97	3.98	0.01%

Table 7-10 QCDC System Sensitivity – 95% Base Case v 98% Reliability

Risk Parameter		Base Case	Sensitivity	% change
TRIF (/year)	Within 2 hours	1.38E-04	1.38E-04	0%
	Overall	1.48E-04	1.48E-04	0%
Potential Loss of Life	Hydrocarbon	4.77E-03	4.77E-03	0%
(fatalities/year)	Non-Hydrocarbon	2.27E-02	2.27E-02	-0.0006%
	Total	2.75E-02	2.75E-02	-0.0005%
IRPA (FAR)	Hydrocarbon	0.69	0.69	0%
Average	Non-Hydrocarbon	3.29	3.29	-0.0006%
	Total	3.97	3.97	-0.0005%

The results indicate that the primary risk criteria of IRPA and TRIF are relatively insensitive to changes in safety system reliability, within the bounds of the reasonable reliability figures presented here. Part of the reason for this is that the explosion analysis completed for this phase of the CSA is based on isolated and blown down releases only, therefore does not take into account the impact of ESD and blowdown on gas cloud sizes. Modifying the reliability of the ESD and blowdown system would not, therefore, have any impact on explosion risks. It is recommended that the effects of non-isolation and blowdown failure are taken into account when modelling gas cloud volumes for the next phase of the Project. Larger variations in system reliability would, of course, also introduce greater changes in risks but would mean that the systems are operating with an unrealistically low level of reliability and hence unlikely to meet Performance Standard expectations.

7.3.3. Personnel on Board

The base case risks are presented for a POB of 79 personnel, which represents the normal occupancy for the FPSO. It is anticipated that the maximum POB shall be 120, which would be bounded by the occupancy of the free-fall lifeboats. This is consistent with the operating model established for other similar newbuild harsh environment FPSOs, taking into account a higher degree of digitalization for the Bay du Nord installation.

The POB of 79 personnel used in this analysis is based on a preliminary assessment of the steady state, core crew staffing with some contractors onboard. Further analysis will be carried out during the project to determine the necessary operations, maintenance, and emergency response organization. This will be based upon equipment selection, simultaneous operations, and the operating model. An updated risk analysis for the normal and maximum POB case will be performed in the Quantitative Risk Assessment during Detailed Design. The numbers of worker in each category, for both staffing levels, is shown below.

Table 7-11 Number of Workers for Staffing Cases

Worker Category	120 POB (Maximum Case)	79 POB (Normal Operations)
Admin Crew	13 + 1 Equinor rep	7
Maintenance Crew	59	41
Operations Crew	38	22
LQ Crew	9	9

The distribution of workers around the FPSO as follows.

- The Admin crew work mainly within the TR but are also occasionally out in the operational areas of the FPSO.
- The Maintenance crew are evenly spread through the processing, turret, utility and other areas of the FPSO.
- The Operations crew will spend a higher proportion of their time in the Process and Turret areas of the FPSO
- The LQ crew continue to spend all of their offshore time in the living quarters.

A comparison of the key risk levels is presented next for the two staffing cases.

Table 7-12 Comparison of Key Risk Parameters for Maximum POB

Risk Parameter		Normal POB	Max POB	% change
TRIF (/year)	Within 2 hours	1.38E-04	1.39E-04	0.5%
	Overall	1.48E-04	1.49E-04	0.5%
Potential Loss of Life	Hydrocarbon	4.77E-03	7.08E-03	48.4%
(fatalities/year)	Non-Hydrocarbon	2.27E-02	3.39E-02	48.9%
	Total	2.75E-02	4.09E-02	48.8%
IRPA (FAR)	Hydrocarbon	0.69	0.67	-2.3%
Average	Non-Hydrocarbon	3.29	3.22	-2.0%
	Total	3.97	3.89	-2.1%

The overall PLL has increased by approximately 49%, which aligns well with the increase in number of persons on board. The TRIF has increased slightly with the higher POB due to the increased number of helicopter flights that would be required for 120 personnel. Whilst a low contributor to TRIF, helicopter crashes onto the process area of the FPSO have been assessed as having the potential to result in a large fire that could escalate to the TR.

The Average IRPA has slightly changed with the higher POB. This is due to the difference in the number of personnel within each worker group and slightly changed personnel distribution. (The average FAR for each worker group is still below the TLS of 10.

7.3.4. Riser Subsea Actuated Valves

The base case currently does not include actuated valves located subsea on each of the risers (SSIVs). This sensitivity shows the impact on the risk profile for the FPSO in the event that these SSIVs were installed on the production and gas risers. The sensitivity assumes that the valves are installed at the base of the risers, on the seabed, and would close, following actuation of the ESD, within 1 minute. The results of this sensitivity are presented next.

Table 7-13 Comparison of Risk Results with SSIVs installed on Risers

Risk Parameter		Base Case	Sensitivity	% change
TRIF (/year)	Within 2 hours	1.38E-04	1.38E-04	-0.22%
	Overall	1.48E-04	1.48E-04	-0.21%
Potential Loss of Life	Hydrocarbon	4.77E-03	4.75E-03	-0.31%
(fatalities/year)	Non-Hydrocarbon	2.27E-02	2.27E-02	0%
	Total	2.75E-02	2.75E-02	-0.05%
IRPA (FAR)	Hydrocarbon	0.69	0.69	-0.31%
Average	Non-Hydrocarbon	3.29	3.29	0%
	Total	3.97	3.97	-0.05%

It can be seen that the introduction of SSIVs on the risers does not result in a significant reduction in risks. This is primarily due to the sea depth in the region meaning that the inventory within the isolated riser section is still significant. It should be noted that the SSIVs are also unlikely to provide any additional benefit against explosion overpressures, due to the large inventory in the risers which would still have the potential to create large gas clouds in the turret. The introduction of SSIVs would not reduce the explosion risk.

7.3.5. TEMPSCs

The base case design includes a 60-person davit launched TEMPSC on both the port and starboard side of the FPSO, as well as two 60-person free fall TEMPSC at the aft side of the accommodation. This provides additional redundancy against sea ice formation, as the davit lifeboats can be launched in conditions that the freefall TEMPSC would not be used, with an overall TEMPSC launch success rate of 95.86%. The sensitivity has examined an alternative lifeboat configuration where the free-fall lifeboats could not be utilised and only the davit-launched lifeboats were available. For this scenario, a TEMPSC successful launch rate of 92.23% has been calculated.

Referring to the event tree in Section 5.2 allows the likelihood of successful evacuation to be calculated, as shown above, along with the corresponding risks to personnel, which are shown in the table next.

Table 7-14 All Davit Launched TEMPSC

Risk Parameter		Base Case	Sensitivity	% change
TRIF (/year)	Within 2 hours	1.38E-04	1.38E-04	0%
	Overall	1.48E-04	1.48E-04	0%
Potential Loss of Life (fatalities/year)	Hydrocarbon	4.77E-03	5.11E-03	7.24%
	Non-Hydrocarbon	2.27E-02	2.27E-02	0.022%
	Total	2.75E-02	2.79E-02	1.27%
IRPA (FAR) Average	Hydrocarbon	0.69	0.74	7.24%
	Non-Hydrocarbon	3.29	3.29	0.022%
	Total	3.97	4.03	1.27%

It can be seen from the tables above that the risk levels for the freefall TEMPSC option does confirm that the proposed arrangement in the base case produces the lowest level of risk. This is because the proposed approach offers the full POB the option to evacuate by either freefall or davit options, including when sea ice is present. Historically free fall TEMPSC have a higher launch success rate than davit launched TEMPSC, although this would be prevented when sea ice was present. The overall likelihood of sea ice being in the vicinity of the FPSO does not reduce the success probability of freefall TEMPSC below the historical level for davit launched TEMPSC and hence freefall is still the preferred option.

7.3.6. Escape Routes

The base case design includes protected escape routes along the full length of the port and starboard to provide a measure of protection against fire events, explosions and smoke. This sensitivity considers how risks may be different if the routes were not protected.

In the event that personnel are now unable to escape back to the TR at the aft of the FPSO, as a result of the escape route shelter being removed, then they are assumed to move to the forward end of the FPSO and evacuate using the tertiary means if necessary. The potential impact on risks is examined for this sensitivity.

Table 7-15 Comparison of Risks with no protected Escape Routes

Risk Parameter		Base Case	Sensitivity	% change
TRIF (/year)	Within 2 hours	1.38E-04	1.38E-04	0%
	Overall	1.48E-04	1.48E-04	0%
Potential Loss of Life (fatalities/year)	Hydrocarbon	4.77E-03	5.30E-03	11.1%
	Non-Hydrocarbon	2.27E-02	2.27E-02	0%
	Total	2.75E-02	2.80E-02	1.9%
IRPA (FAR) Average	Hydrocarbon	0.69	0.77	11.1%
	Non-Hydrocarbon	3.29	3.29	0%
	Total	3.97	4.05	1.9%

It can be seen from the table that removal of the protected escape routes results in a significant increase in risk to life. The increase in risk to life from hydrocarbon events is over 11% higher with the protected routes removed.

The protection of escape routes is considered to be a key safety benefit and is included in the design of many other FPSOs. It should also be noted that this sensitivity has not assessed the impact on explosions originating in the process area from removal of the protected escape routes, which may reduce the potential for high overpressure explosions through increased ventilation and reduced confinement. The effect of protected escape routes on explosion overpressures shall be assessed in more detail in the next stage of the project.

7.3.7. Forward LQ

The current concept is based on the accommodation being located at the aft of the FPSO. An assessment of the proposed aft location of the accommodation on the Bay du Nord FPSO, compared to a forward location has been carried out in this sensitivity. A copy of the Bay du Nord risk model was prepared that reflected an FPSO with forward accommodation. Similar parameters were used in the model but where appropriate these parameters were adjusted due to distances/proximity and arrangements with respect to the predominant FPSO heading.

The notional FPSO layout utilized in the calculation of the risks associated with a forward accommodation is shown in Figure 7-2. It is considered reasonable given the systems/modules for BDN plus the layout of other similar FPSOs.

Figure 7-2 Forward Accommodation Hypothetical Layout

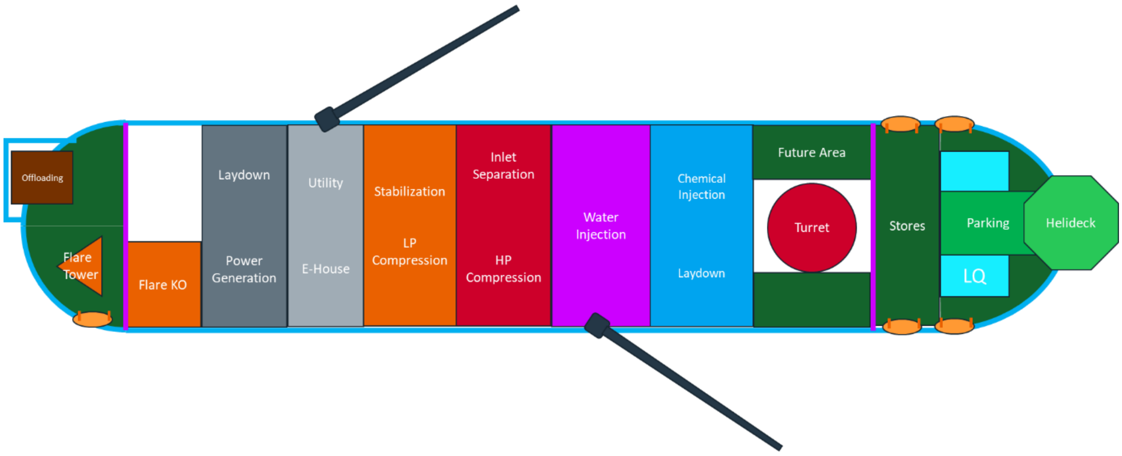


Table 7-16 Comparison of Risk with Forward v Aft Accommodation

Risk Parameter		Aft	Forward	% change
TRIF (/year)	Within 2 hours	1.38E-04	1.31E-04	-5.1%
	Overall	1.48E-04	1.34E-04	-9.3%
Potential Loss of Life	Hydrocarbon	4.77E-03	4.77E-03	-0.03%
(fatalities/year)	Non-Hydrocarbon	2.27E-02	2.27E-02	0.02%
	Total	2.75E-02	2.75E-02	0.01%
IRPA (FAR)	Hydrocarbon	0.69	0.69	-0.03%
Average	Non-Hydrocarbon	3.29	3.29	0.02%
	Total	3.97	3.98	0.01%

The risk profile shows that a forward accommodation leads to a slightly decreased TRIF and IRPA over the aft accommodation as smoke and unignited events are more likely to be directed towards the LQ when in the aft configuration. The advantages and disadvantages of forward versus aft accommodation is discussed qualitatively in Section 8.4.

7.3.8. PFP Applied in Process Areas

The current base case is that there is no specific PFP applied to the module structure or major equipment items in the process modules of the FPSO. The philosophy is to ensure robustness of the structure to improve its resistance to fire and explosion. This sensitivity calculates the risk reduction associated with applying H120 PFP to the module structure for the process level, thus ensuring that escalation from the process deck to the main deck (and cargo tanks) is delayed.

Table 7-17 Comparson of Risks with PFP Applied in Process Areas

Risk Parameter		Base Case	Sensitivity	% change
TRIF (/year)	Within 2 hours	1.38E-04	1.15E-04	-16.3%
	Overall	1.48E-04	1.45E-04	-1.8%
Potential Loss of Life	Hydrocarbon	4.77E-03	4.76E-03	-0.2%
(fatalities/year)	Non-Hydrocarbon	2.27E-02	2.27E-02	0.00%
	Total	2.75E-02	2.75E-02	-0.03%
IRPA (FAR)	Hydrocarbon	0.69	0.69	-0.2%
Average	Non-Hydrocarbon	3.29	3.29	0.00%
	Total	3.97	3.97	-0.03%

The effect of adding PFP to the module structure is to ensure that escalated process fires tend to lead to TR impairment at an impairment time of greater than 2 hours, whereas in the base case (where no PFP is applied), the TR impairment frequency is concentrated in the '<2 hour' category. In effect, the application of PFP leads to the TR impairment from process module escalation to be largely shifted to the '>2 hour' category. The effect on individual risk is small, as immediate fatalities from fires is unchanged, and there is assumed to be only a small chance of evacuation fatalities occurring for process fires which impair the TR in less than 2 hours.

7.3.9. Helicopter Transport Risk Dataset

Transportation risk is a major component of the overall risk to personnel. The transport risk contributes 38.9% of the total risk to personnel. OGP data regarding helicopter risk is divided between different datasets. The base case for this CSA uses the output from the worldwide dataset. This sensitivity calculates the risk reduction associated with applying the North Sea (UKCS) data to the helicopter risks for personnel working on the FPSO.

Table 7-18 Use of UKCS helicopter risk data in Bay Du Nor Project

Risk Parameter		Base Case	Sensitivity	% change
TRIF (/year)	Within 2 hours	1.38E-04	1.38E-04	0.00%
	Overall	1.48E-04	1.48E-04	0.00%
Potential Loss of Life	Hydrocarbon	4.77E-03	4.77E-03	0.00%
(fatalities/year)	Non-Hydrocarbon	2.27E-02	2.07E-02	-9.17%
	Total	2.75E-02	2.54E-02	-7.58%
IRPA (FAR)	Hydrocarbon	0.69	0.69	0.00%
Average	Non-Hydrocarbon	3.29	2.98	-9.17%
	Total	3.97	3.67	-7.58%

The effect of utilising UK Continental Shelf data regarding helicopter transportation risk to the CSA is that the overall calculated risk to personnel reduces by 7.6%.

7.3.10. Forward Muster Area Means of Evacuation

One of the objectives of the FPSO design is to ensure that suitable evacuation means are provided in the bow area for personnel who are unable to perform egress to the aft TR. This objective is in line with SOLAS code requirements.

The CSA base case assumes that personnel who are prevented from mustering at the aft TR due to a fire or explosion which impairs both bus shelter routes would attempt to independently escape to sea by whatever means are available. The FPSO design includes provision for MES life raft evacuation at the bow, but the CSA base case assessment does not take credit for this. The fatality rate for personnel who fail to muster at the TR and escape to sea is conservatively assumed to be 80%. This value is in line with the Piper Alpha incident, where the integrity of the TR was lost due to smoke ingress. At the time of the disaster 226 people were on the platform; 165 died and 61 survived. Two men from the Standby Vessel Sandhaven were also killed. These figures correspond to a fatality rate of 73% amongst those on board.

The main contributing events concerning inability to muster at the TR, which contribute over 5% of the total muster PLL, are listed in the table below:

Table 7-19 Main Hydrocarbon Events Contributing to Muster Fatalities

Description	Contribution to Muster PLL
Gas Dehydration Inlet Scrubber (24-VG-6001) & TEG Contactor (24-VB-6602) & 1st Stage HP Gas Compressor Suction Scrubber (23-VG-6004) - Gas Release at M61 Process Deck Level 1	18.1%
2nd Stage HP Gas Compressor & Suction Scrubber (23-VG-6005) - Gas Release at M61 Process Deck Level 1	15.0%
MP Gas Compression - Gas Release at M60 Process Deck Level 1	11.3%
Fuel Gas Superheaters, Metering Skid & Filter Package - Gas Release	5.7%
1st Stage HP Gas Compressor Discharge Cooler (23-HG-6004) at M61 Process Deck Level 2	5.5%
1st & 2nd Stage HP Gas Compressor Discharge Coolers (23-HG-6004 & 23-HG-6005) - Gas Release at M61 Process Deck Level 2	5.2%

The Bay du Nord design includes a bow muster area, which is protected by a fire division and is equipped with chute-based evacuation to a life raft, on both port and starboard sides of the bow. It may also be possible to equip the forward muster area with a davit-launched lifeboat. The provision of a free fall lifeboat at the side of the FPSO may be difficult to implement considering the support structure needed, and requires an approved deviation to SOLAS (which requires freefall lifeboats to be installed at the stern). This assessment calculates the risk profile for all types of means of escape to sea that are listed in Table 3-7.

In the event that personnel are able to muster at the forward muster area and carry out an orderly evacuation, then depending on the configuration and extent of escape shelters and means of evacuation, the following risk reduction can be achieved:

Table 7-20 Forward Means of Evacuation Cases

Scenario	Protected Escape	Fwd Evac Means	Notes	Muster PLL	Hydrocarbon PLL	Total PLL
1	No	N/A	See sensitivity 7.3.6	1.43E-03	5.31E-03	2.80E-02
2	Yes, full length	N/A	CSA base case (this document)	9.01E-04	4.77E-03	2.75E-02
3	No	Throwover Life raft		3.15E-04	4.17E-03	2.69E-02
4	Yes, full length	Throwover Life raft		1.98E-04	4.05E-03	2.68E-02
5	Yes, full length	MES Life Raft	BdN reference design	9.75E-05	3.95E-03	2.67E-02
6	Partial (gap from Topsides to Fo'csle)	Davit Lifeboat	Similar to SeaRose FPSO Design	8.92E-05	3.94E-03	2.67E-02
7	Yes, full length	Davit Lifeboat		8.62E-05	3.94E-03	2.67E-02
8	Yes, full length	Freefall lifeboat		4.51E-05	3.90E-03	2.66E-02

It should be noted that it is mandatory by SOLAS code for a hull of this length to have liferafts at the bow end and that the most basic rafts would meet the code requirements. So "N/A" isn't realistic with regards to evacuation means from the bow. They are instead conservative, unmitigated risk calculations used to bound the realistic risks which are assessed in scenarios 3-7. Scenario 8 is also discounted as the provision of a free fall lifeboat at the side of the FPSO may be difficult to implement considering the support structure needed, and requires an approved deviation to SOLAS (which requires freefall lifeboats to be installed at the stern).

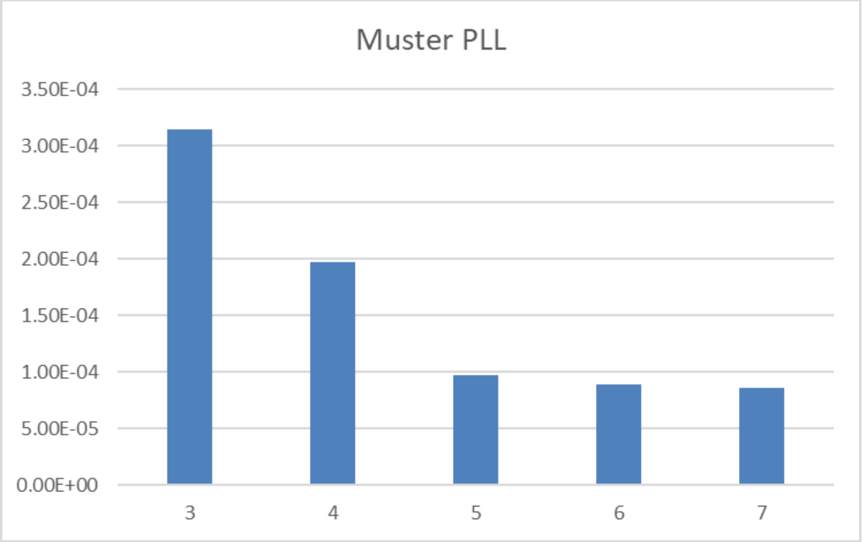


Figure 7-3 Muster PLL for each Realistic Scenario

The reduction in muster risk from the implementation of protected escape routes and the provision of a means of escape forward of the turret is shown in the Figure 7-3. As would be expected, the introduction of protected means of escape is highly beneficial, as is the provision of a forward-located means of escape, with chute-based life rafts being notably superior to throwover rafts. The Bay du Nord scenarios where protected escape route are in place and there is an MES liferaft (scenario 5) or a lifeboat installed at the bow (scenario 7) lead to similar overall reductions in the overall PLL.

It should be noted that the muster risk is only a very small component of the overall risk for the FPSO, as shown in Figure 7-4 below.

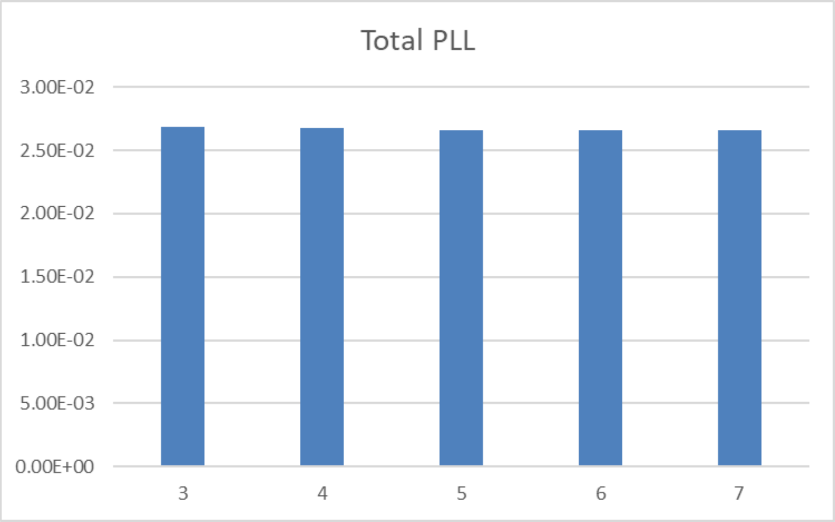


Figure 7-4 Total PLL for each Realistic Scenario

Where a lifeboat is installed, there would be a requirement to ensure that a trained coxswain is available to pilot the lifeboat whenever any personnel are working in the process areas of the FPSO. With regards to the different types of lifeboat available and their relative capabilities regarding successful launching from the bow of a vessel, a review of industry data has found limited information relating to the success or failure of evacuations using the different types of lifeboat designs available. Some anecdotal evidence and simulation modelling exists to show that systems classed as 'enhanced' (i.e. perpendicular to the FPSO hull) may provide some additional benefit, even if this deviates from SOLAS. However, there is no statistical evidence that could be used in a quantitative assessment with any authority. It was however found that the importance of coxswain training and action may have a greater importance with regards to successful outcomes for evacuation by lifeboat. In practical terms, the lifeboat can collide with the launch platform if there is insufficient clearance between the launch target and the platform. While the environmental conditions at the time an evacuation are outside the control of evacuees, the timing of the launch is not. Timing a launch requires that the coxswain can see or otherwise sense the approaching waves and has enough familiarity with the lifeboat controls to perform the launch operation within the narrow time window required for a successful launch on a crest.

Conclusion

The provision of a protected escape route for the full length of the FPSO vessel, plus the use of chute-based MES with liferafts, provides a meaningful reduction in muster & evacuation risk compared to not having these features. The incremental cost and layout impact of adding a davit-launched lifeboat may be seen as disproportionate to the incremental risk reduction that could be achieved.

8. ALARP Demonstration

8.1. Introduction

The results presented in Section 7 indicate that the current risk levels assessed for the Bay du Nord FPSO fall into the ALARP region, when reviewed against the project specified TLS.

In order to further review the measures that are included within the design, or additional measures that may reasonably help to reduce the risks further, an ALARP Workshop was held with the design team in August 2025 [5].

Ensuring that a risk has been reduced to ALARP is about weighing the risk against the sacrifice needed to further reduce it. The decision is weighted in favour of health, safety and the environment because the presumption is that the operator should implement the risk reduction measure. To avoid having to make this sacrifice, the operator must be able to show that it would be grossly disproportionate to the benefits of risk reduction that would be achieved. Thus, the process is not one of balancing the costs and benefits of measures but, rather, of adopting measures except where they are ruled out because they involve grossly disproportionate sacrifices. As discussed in GL0139, gross disproportionality has not been precisely defined in most cases where the principle has been used, but normally one is expected to spend more on risk reduction the closer the risk is to the intolerable level [54].

As depicted below, ALARP is applied when the risks are in the tolerable region.

Whilst not directly relevant to offshore Newfoundland, Equinor note that under Norwegian Havtil jurisdiction, no lower level is defined, this means that the risk must be ALARP, no matter how low the risk level is.

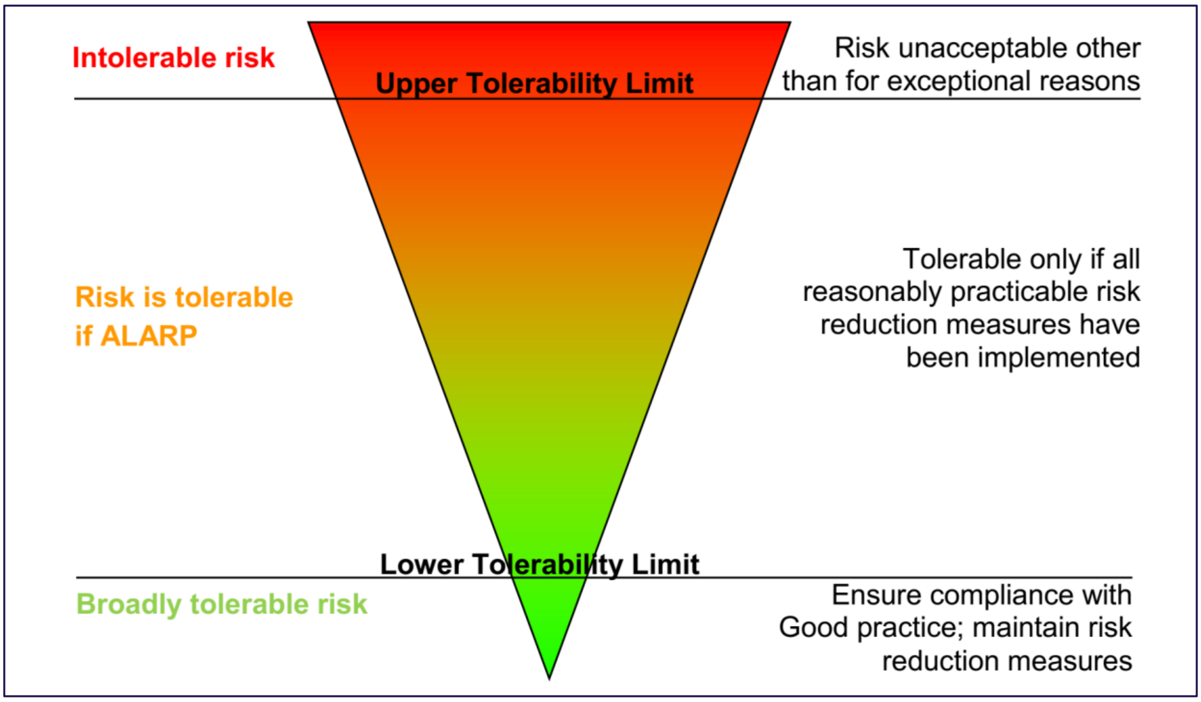


Figure 8-1 ALARP Region

The decision-making process adopted during the ALARP review was based on a structured approach against which the process of judging proposed risk reduction measures can be performed. Where different options exist, this approach also assists in providing context against which these can be judged.

The approach is based on three different decision contexts (A, B and C):

- For a type A decision, where the risk is relatively well understood, in general the decision will be determined by the application of recognised good practice. In cases where good practice may not be sufficiently well-defined, engineering risk assessment may be required to guide the decision.
- For a type B decision, involving greater uncertainty or complexity, the decision will not be made entirely by established good practice. Thus, while any applicable good practice will have to be met, there will also be a need for engineering risk assessment to support the decision and ensure that the risk is ALARP.
- A type C decision will typically involve sufficient complexity, uncertainty or stakeholder interest to require a precautionary approach. In this case, relevant good practice will still have to be met and detailed engineering risk assessment will be used to support the decision.

8.2. Existing Measures

Any identified safeguards or safety features were mapped against the relevant BW Performance standards [55]. These are listed next:

P-01 Structural Integrity Hull

P-02 Structural Integrity Turret, Topsides, Marine Structures

P-03 Hydrocarbon Containment Topsides and Turret (*see note)

P-04 Hydrocarbon Containment Hull

P-06 STP Buoy and Mooring System

P-08 Inert Gas, Vapour Recovery and Purge Gas Systems

P-09 Collision Prevention and Nav Aids (Marine/Aviation)

P-10 Lifting Appliances and Dropped/Swinging Object Protection

P-12 Electrical Protection

P-14 Cyber Security

D-01 Fire and Gas Detection System

C-01 Ignition Source Control

C-02 Emergency Shutdown System

C-03 Flare and Blowdown

C-04 Bilge and Ballast Systems

C-05 Human Machine Interface and Alarm Management

M-01 Open Drains

M-02 HVAC Systems

M-03 Passive Fire Protection

M-04 Layout and Explosion Mitigation

M-05 Active Fire Protection

M-06 Helideck Facilities

E-01 Temporary Refuge and Muster

E-02 Escape Routes

E-03 Lifeboats

E-04 Escape to Sea Systems

E-06 Rescue and Personal Safety Equipment

E-07 PAGA and Emergency Communication

E-08 Central Battery System (Lighting)

E-09 Emergency Power

(*note) Related to P-03, a Performance Standard for "*Hydrocarbon Containment Subsea and Pipeline*" will be developed in the next phase by Equinor and the FPSO/SURF Contractors.

8.2.1. Inherent Safety

Inherent safety mitigation measures are concerned with the removal or reduction of a hazard at source. Table 8-1 lists inherently safe mitigation measures applied to the proposed FPSO design.

Table 8-1 Inherent Safety Measures

Standard	Inherently Safe Measures
P-03, P-04	Minimised flanges through predominantly welded topsides piping, fully welded offloading pipework, welded cargo and vent piping, corrosion resistant subsea systems design, presence of two independent shutdown valves on the gas injection riser.
M-02	Upper turret and utility areas naturally ventilated.
D-01	Design includes gas tight doors, EX rated equipment, Hazardous Area Classification.
P-08	Chemical treatment to prevent toxic gas accumulation, a near atmospheric gas blanket system.
E-09	Robust generator configuration and back up essential power generation.
M-04	Design includes separate corridors for risers and moorings to allow for adequate separation distance, location of TR with maximum separation from turret, location of helideck to improve pilot visibility, gas tight process deck, separation by distance of oil metering system and LQ, no lifting over live/pressurised HC process systems.
P-10	No lifting over pressurised equipment and lifting rails.
P-06	Anchors/ substructures are designed to stay in position, tried and tested mooring and riser anchor design, multiple ballast tanks, designed for 2-line mooring failure, ballast system compliant with IMO requirements.
P-09	Standby vessel does not normally approach close to the FPSO, the field location is highlighted on navigational charts and has a Safety Zone.
P-01, P-02	Structural design accounts for vessel impact, the hull is designed to ALS and serviceability criteria and also for hogging and sagging load conditions, there are no sizeable gaps in the steel deck, fatigue analysis of riser joints will be conducted, redundancy in stiffened plate structural design and designed to class.

8.2.2. Prevention

Prevention measures are intended to prevent the initiation of a sequence of events that could lead to a major accident. They can be designed to prevent the failure of equipment or human error and include individual activities aimed at preventing specific failures. Table 8-2 lists examples of preventative mitigation measures that apply to the proposed FPSO design.

Table 8-2 Prevention Measures

Standard	Prevention Measures
P-03, P-04	Riser disconnect procedure, piping and equipment is designed for fluid type and operating pressure. Flowline trawl protection, over trawlable subsea structures and well templates, flowline rock installation, riser arrangement for easy replacement. Low trawling frequency near FPSO, fishing exclusion zone, trenching of flowlines, well and manifold GRP covers, SURF facilities are designed for seismic accelerations in the area. Swinging load protection.
M-02	Mechanically ventilated machinery room and lower turret with fire/blast wall. Process (naturally vented).
C-01	Electrical equipment is rated for hazardous areas, ignition source isolation upon gas detection, a cargo tank HC blanketing and inert gas systems.
C-03	The blowdown system design achieves blowdown rates superior to those required by API 521.
E-08, E-09	Emergency generator and separate essential power.
M-04	No manned rooms in aft of machinery space vulnerable to impact (also PS20), restricted areas, the flare location prevents impingent from process and riser events.
P-10	Lifting procedures, safe lifting zones for MODU over SURF facilities, crane operating procedures, competent and trained crane operators, lifting and maintenance plans.
P-06	Marine procedures, ice management plan, multiple thrusters for position control.
P-09	Safety zones around infrastructure, supply boat / W2W / standby vessel personnel competency, shuttle tanker will be DP class 2, DP2 fitted vessels and DP trials.
P-01, P-02	Flexible joint ROV inspection, external surfaces coating and cathodic protection, there is a steel deck between process and deck.

8.2.3. Detection and Control

Detection and Control measures are intended to prevent a hazardous event from escalating into a major accident. They include measures directed at preventing or limiting small releases, which have the potential to escalate into a major accident. Control measures should be independent from the cause of the initiating hazardous event and associated systems so as not to fail as a direct result of the event. Table 8-3 lists design and control mitigation measures applied to the proposed FPSO design.

Table 8-3 Detection and Control Measures

Standard	Detection and Control Measures
P-03	Bunding around the offloading reel area, electrically controlled production wing valve, the downhole safety valves fail closed. PTW system.
M-02	HVAC system in the lower turret.
D-01	Leak detection on Xmas trees, ships deck fire and gas detection system, air intake inlets have gas detectors, fire and gas detection with ignition source control, toxic gas detection alarms.
C-02	Well shutdown when umbilical is damaged, ESD system, emergency shutdown and inventory isolation for topsides, risers and utilities, emergency disconnect of the riser buoy.
C-01	All electrical equipment is earthed, hazardous area classifications.
C-03	The blowdown system design achieves blowdown rates superior to those required by API 521.
M-05	Two aft and two forward firewater pumps for redundancy.
P-04	Tank inspection and design.
C-05	Class approved loading computer for ballast tanks, RBI and hull monitoring.
C-01, P-10	Classified areas, design loads for dropped objects in lifting corridors to be established.
P-10	Crane selection from approved vendors.
E-09	Thrusters are supplied by emergency power.
P-09	Standby vessel.
C-05	Remote operation of offloading equipment.

8.2.4. Mitigation / EER

Mitigation measures, including emergency response, are those that are taken to reduce the consequences of a major accident once it has occurred. Table 8-4 lists relevant examples in this design.

Table 8-4 Mitigation / EER Measures

Standard	Mitigation / EER Measures
M-02	Naturally ventilated process areas and upper turret, which offers superior capabilities over mechanical ventilation with regards to the removal of any gas build-up and hence lowered potential explosion overpressures. Position and redundancy in LQ HVAC.
D-01	Portable gas detectors and BA sets.
M-03, M-05	Active fire protection including general area deluge in processing areas, offloading area fire water monitor, cargo deck fire protection and deluge system, firewall between lifeboats and offloading hose reel, H60 fire rated LQ wall, water mist system, manual firefighting equipment and helicopter DIFF system.
M-03	PFP optimisation study to be carried out to determine PFP levels to ensure that DiALs are met. Turret PFP.
E-02, E-03, E-04, E-06	Protected and diverse escape routes, escape trunk in turret, shielded lifeboats and muster location, tank entering PPE, alternative davit launched lifeboat available, enclosed escape stairwells, plated process deck, smoke hood cabinets, life rafts and survival suits.
M-04, E-01	Process equipment is in bunded areas, fire and blast rated barriers in turret, protected escape routes and Temporary Refuge.

8.3. Selected and Potential Improvements

The ALARP workshop [5] identified some improvements which shall be implemented in the design and operation of the FPSO:

- Implementation of active weathervaning using thrusters to maintain wind direction at 20–30 degrees off the bow during emergency scenarios, to ensure that the risk from smoke or unignited gases is minimised. The use of thrusters during emergency scenarios shall be included in the emergency response plan.
- Assess whether engineering openings in the process deck architecture would lead to the prevention of the ingress of heavy gas into the cargo deck area during a release. This measure aims to reduce the risk of gas accumulation in lower deck levels, thereby improving personnel safety and maintaining escape route integrity in the event of a hydrocarbon release.
- Helicopters in the vicinity of any hydrocarbon gas release above 10% LEL in the helicopter operating area should be immediately advised to stay clear. This applies to flare flame-out scenarios. This requirement will be incorporated into the operating procedures.

In addition, the following topics were identified as requiring further development at the next phase of the design

- In order to combat the potential fire and smoke spread between Process Modules and the Turret, a firewall shall be assessed to determine whether the benefit of the firewall regarding smoke and fire events is greater than the potential detrimental impact from impeded ventilation patterns and explosion overpressures.
- Consider installing a firewall between the Process Modules and the Utility Modules (A4), specifically facing the laydown area, to eliminate the potential risk of immediate fatality from a process fire. This must consider the potential impact on natural ventilation and explosion overpressure.

- Consider closing the bus shelter on all sides to prevent ingress of smoke and impairment of all escape routes from forward areas towards LQ. While the existing open-sided design provides adequate shielding from heat radiation, several scenarios indicate that both port and starboard shelters may be simultaneously compromised due to smoke-induced low visibility. This could prevent personnel in forward areas from escaping to the Living Quarters, particularly if internal escape routes are also blocked by smoke or heat.
- Consider elevating the bus shelters or introducing gaps beneath sections of the structures to facilitate dispersion of heavy gas from the process deck, thus reducing the accumulation of hazardous gas in the shelter area during a release event (specifically at Modules M60 and M11).
- Investigate the potential to implement traffic surveillance performed by Marine Traffic Control (MTC) in order to reduce the risk from for ship collisions.
- Develop a move-off procedure for the FPSO in the event of a vessel on a collision course.
- Ensure sufficient capacity at the Forward Escape to Sea Point, including its EER arrangement, to at least account for the personnel working in Utility modules, Process modules, Turret, Forward area and Main deck, i.e., 38 personnel to account for the number of personnel who could potentially be working in these areas during day shift.
- Evaluate the need for passive fire protection (PFP) on the main load-bearing structures in the process module and for the supports of the large hydrocarbon-containing vessels.
- Carry out an evaluation to determine whether an isolation valve is required on the outlet of the production and test manifold.
- Carry out an evaluation to determine what the procedure would be to handle potential gas leakages in void spaces.
- Carry out an evaluation to determine whether there is appreciable benefit to be gained from supplying accommodation sprinkler systems.
- Consider including the propulsion system as a safety-critical element (SCE) against MAE10, MAE12 and MAE13 as the propulsion may be required both before and after an emergency disconnect. Current requirements specify post-disconnect use, but practical needs indicate that pre-disconnect capability is also important. Propulsion system for existing FPSOs in basin are designated as SCE. Note that the list of specific SCEs for the identified PSs shall be updated as the project develops.

8.4. Forward vs Aft Accommodation

The current concept is based on the accommodation being located at the aft of the FPSO. The current FPSOs Terra Nova and SeaRose operating in the region are equally split between forward and aft accommodation. It is also noted that all of FPSOs in the Norwegian sector have forward accommodations, whereas a majority in other jurisdictions have aft accommodations.

An assessment of the proposed aft location of the accommodation on the Bay du Nord FPSO, compared to a forward location has been carried out. The assessment has been both qualitative and quantitative (using the QRA risk model, as already presented in Section 7.

The issues relating to the integrity of the accommodation and evacuation provisions have been evaluated. A number of other safety and operability issues have also been considered.

Equinor has assumed that an FPSO with forward LQ in NL waters would have only conventional davit launched lifeboats, with enhanced position and steering capabilities (e.g. PrOD or bow thrusters) similar to other NL installations. If freefall lifeboats were located at the sides of the LQ, then two (2) of these boats would be required on each side to meet the LSA Code. It would not be feasible to locate two freefall boats, plus a conventional lifeboat (for sea ice season), plus life raft arrangements for 120 POB each side. Making space for this equipment would likely require the turret to be located even farther aft, thereby degrading the ability to naturally weathervane. Therefore a significant advantage of the aft LQ design is that it enables the placement of freefall lifeboats at the stern and close to the LQ.

The initial observation is that the aft accommodation layout has a simple distinction between hazardous and non-hazardous areas, with the highest hazard areas located furthest from the LQ and the most highly populated modules (e.g. power generation) located closest to the LQ, improving the potential for safe and effective muster of maximum personnel in the event of an emergency. This is contrasted with the forward accommodation layout, where there is a mix of hazardous and non-hazardous modules along the FPSO; this reduces the separation between the LQ and potential high hazard incidents and, in the event of a process or riser emergency situation, requires relatively high numbers of personnel to travel towards the hazard from the utility areas in order to reach the safety of the TR / LQ muster area.

The aft accommodation concept offers a significant benefit in respect of achieving a reliable passive mooring system. It also affords maximum protection from turret events through physical separation. Generally, given the number of risers required and the significant pressure and inventory within some of the risers, the turret is seen as a relatively high-risk area. A forward located accommodation and associated evacuation provisions would be more exposed to turret events.

The aft accommodation, including helideck is, however, likely to be more at risk from smoke impairment. It is estimated that approximately 40% of the time, wind would be directed towards an aft accommodation, whereas in a forward accommodation, the wind would be directed towards the accommodation only 10% of the time.

The aft accommodation is also more exposed to the effects of smoke from cargo tank and offloading fires and is also at greater risk from shuttle tanker collision, but these risks can be managed to a low level.

The aft located accommodation offers a number of advantages in terms of TEMPSC launchability, primarily concerning sea state and the lower potential for sea ice obstructing launch. The aft accommodation is also considered advantageous in terms of routine helicopter operations, due to reduced heave motions. Aft TEMPSCs are more inherently safe from a launch and sail away perspective, however, as for the TR, aft TEMPSCs may be at a higher risk of smoke impairment.

A forward accommodation would likely mean an aft flare and vent stack. This is more inherently safe as any burning liquid carryover/drop out or flammable gas or flare radiation would be directed aft of the FPSO rather than over the process area. Falling ice from the flare tower or any other elevated areas would be less likely to impact on exposed areas, equipment, personnel or escape routes.

Aft accommodations are regarded as preferable in terms of the physiological and mental wellbeing of the crew, due to reduced motions and effects from wave or ice impacts on the bow of the vessel. Greenwater impacts on the area surrounding the accommodation, including the potential for damage to lifeboats and other equipment, would also be lower for at the aft. Reduced spray would also lead to less icing of the helideck and TEMPSCs if located at the aft.

In summary, a number of hazards have been identified where the resulting risk will vary, depending upon whether the accommodation is forward or aft. It can be seen from the summary in Table 8-5 that there are more advantages relating to an aft accommodation for regular or continuous operations, whereas for infrequent or major accident events, there is a more even split between advantages for forward or aft accommodation.

Both the forward and aft accommodation concepts would be expected to meet, through design, Equinor's impairment-based criteria for the TR.

Table 8-5 Forward v Aft Accommodation Advantages Summary

	Aft Accommodation Advantage	**Forward Accommodation Advantage**
Regular/ Continuous Operations	• Superior weather-vaning • Lower energy consumption (passive heading) • Physiological wellness of crew (motions) • Distance to workplaces, main machinery • Routine helicopter operations safety • Visibility of offloading operations	• HVAC for LQ upwind of process and riser areas
Frequent Occurrences	• Walk-to-work facilities placement • Less Green water damage to TEMPSC/ lifeboats/decks or equipment • Less Helideck icing due to spray • Less Lifeboats icing due to spray	• Flare & vent system hazards
Infrequent Occurrences /Major Accident Events	• Superior lifeboat launch positions • Escape to muster areas (fewer trapped) • Turret events (fires and explosions close to LQ) • Lifeboat launch and sail or drift away • Loss of Heading Control less severe consequences	• Topsides or riser events (smoke / gas) • Cargo deck events (smoke) • Offloading area events (smoke/radiation) • Shuttle tanker impact

It is apparent that neither concept offers an insurmountable disadvantage over the other. The quantitative assessment in Section 7.3 showed that in both cases, Equinor's target levels of safety are easily met.

It is therefore concluded that the risk associated with the aft accommodation concept selected is ALARP for this stage of the project.

8.5. Defined Situations of Hazards and Accidents (DSHAs)

At this stage in the project design, the DSHA are identified and linked to the MAEs that have been assessed through the HAZID and QRA.

This information, in combination with knowledge of operations, will provide a list of DSHAs specific for the location or facility. During the next phase of the Bay du Nord Project, more detailed assessment will be carried out using the results of risk analysis, the QRA, and focused working groups. The DSHA will be an input into the Emergency Preparedness Analysis (EPA), which is the basis of the emergency response plans.

DSHAs should be considered in the following areas:

- Process related accidents (leaks, fire, explosion, other hazardous exposure)
- Non-process related fires
- Structural accidents
- Occupational accidents
- Acute medical cases
- Threats and criminal acts, including cyber security
- Transportation
- External loads (incl. weather)
- Man over board (offshore).

The MAEs that have been identified for the Bay du Nord FPSO are shown next and previously highlighted in Section 4.4.

- MAE1 - LOC of hydrocarbon gas (including 2- phase)
- MAE2 - LOC of hydrocarbon liquid
- MAE3 - Hull tank fire / explosion
- MAE4 - Non-process fires
- MAE5 - Accommodation fire
- MAE6 - Helicopter accident
- MAE7 - Ship collision
- MAE8 - Structural failure
- MAE9 - Dropped/swinging objects
- MAE10 - Loss of mooring.
- MAE11 - Loss of stability and buoyancy
- MAE12 - Iceberg Collision
- MAE13 – LOC of hydrocarbons risers and flowlines

A more detailed list of anticipated DSHAs is given in the following table, along with the MAEs that has been used to determine the potential hazard, consequences and risks. For those scenarios where a fatality may not be expected, then a description of how the DSHA has been assessed is also given.

Table 8-6 Defined Situations of Hazards and Accidents (DSHA) for Bay du Nord FPSO

DSHA Number	DSHA Title
DSHA01	Oil and/or gas leakage Unignited releases covered through MAE1 to MAE4 and MAE13
DSHA02	Oil spill These have been assessed through MAEs 2, MAE3 and MAE13
DSHA03a	Fire and/or explosion – Hydrocarbon The potential for fire and explosion has been assessed through MAE1 to MAE4 and MAE13.
DSHA03b	Fire and/or explosion - Machinery and utility areas Releases and fires / explosions in the machinery space has been assessed in MAE4.
DSHA03c	Fire and/or explosion - Living quarter Accommodation fires have been assessed in MAE5 and qualitatively discussed in Section 5.20.
DSHA05	Dropped object Objects that are dropped during lifting or crane operations, as well as through fatigue from failure of supports, are assessed as part of Occupational Risk, if the object has the potential to strike an individual, or through MAEs 1 – 4 and 13 if it has the potential to fail hydrocarbon equipment.
DSHA06	Personal injury or acute illness Occupational hazards leading to fatality of an individual are assessed within the CSA, however they are not defined as a MAE. The assessment is based on historical industry data, rather than Equinor or asset specific data at this stage.
DSHA07	Man over board This has not been assessed further for the CSA at this stage but is addressed qualitatively in Section 4.3.

DSHA Number	DSHA Title
DSHA08	Cyber-attack or other incident in technical network / office network Criminal acts, including cyber security, may lead to some of the other identified DSHAs, such as power failure, production halt, loss of safety systems etc. Contingency plans will be developed that cover the scenarios and outcomes associated with criminal acts, including cyber security.
DSHA09	Loss of stability / Damage to main support structure Critical global structural failure of the hull is covered by MAE8.
DSHA10	Loss of position Mooring line failure is covered by MAE10.
DSHA11	Radioactive source out of control Procedures for handling or use of radioactive material will be developed that should minimise the potential for such incidents to occur. This has not been assessed further at this stage in the CSA.
DSHA12a	Collision risk Passing, attendant and shuttle tanker collisions have been assessed in MAE7.
DSHA12b	Collision risk - Icebergs and pack ice Collision of an iceberg with the FPSO has been covered as part of MAE12. Ice Management Plans will also be developed to reduce the potential for iceberg collision to occur.
DSHA13a	Helicopter accident - Crash on installation Transport to and from the FPSO, either by helicopter or boat are covered under MAE6.
DSHA13b	Helicopter accident - Crash in sea Transport to and from the FPSO, either by helicopter or boat are covered under MAE6.

DSHA Number	DSHA Title
DSHA14	Physical security incident (a) Attack on personnel, site and/or asset), b) Bomb threat or suspicious item, c) Activism Criminal acts may lead to some of the other identified DSHAs, such as power failure, production halt, loss of safety systems etc. Contingency plans will be developed that cover the scenarios and outcomes associated with criminal acts.
DSHA15	Extreme weather conditions Critical global structural failure of the hull is covered by MAE 8. Mooring line failure is covered by MAE 10. Loss of stability/buoyancy is covered by MAE 11.
DSHA16	Evacuation All MAEs consider the requirement to evacuate the FPSO, as well as the potential hazards and risks associated with this.
DSHA17	Loss of power The power generation arrangements provided for in the current design should reduce the potential for total power failure. Nevertheless, contingency plans will be developed that cover this scenario, either accidentally or through deliberate acts such as a cyber-attack.

The DSHAs will continue to be reviewed and developed as the Project progresses.

9. Future CSA Considerations and Recommendations

The following sections contains future CSA considerations and recommendations. Future CSA considerations are aspects that will be developed further during later stages of the design and may impact risk assessment results. Recommendations are based specifically on risk assessment results.

9.1. Recommendations

The following recommendations have been made on the basis of the results and assessment completed in the CSA document. The HAZID [1] and ALARP Review [5] documents should also be consulted for further actions and recommendations that have been identified. In addition, an ALARP workshop is planned for the FEED stage after the initial draft production of the (preliminary) TRA.

1. Asphyxiation from hydrocarbon releases is only expected to be a potential threat within the enclosed lower turret area, and it is expected that breathing equipment will be located within the turret. As such, asphyxiation has not been assessed within the CSA. However, as the design for the turret is developed further, the potential for immediate fatalities from asphyxiation should be reviewed in more detail. If asphyxiation is shown to be a concern in the enclosed area of the turret, or any other enclosed area, the Bay du Nord Operations team should confirm that BA sets will be available and one breath away.
2. An assessment of O_2 depletion and CO_2 build up within the TR should be carried out in later stages of the design, to determine the risk of high heat stress causing impairment of personnel within the LQ.
3. The explosion modelling and escalation rulesets that have been applied are conservative, with uncertainties detailed in Section 11. This will be assessed further in the next phase of the project and it is recommended that this includes a formal escalation review to allow the project team to provide input into the escalation paths captured in the QRA.
4. The protected escape routes, down the port and starboard sides of the FPSO, are essential in allowing personnel to escape back to the LQ in the event of a major incident. However, they may introduce confinement and congestion which could exacerbate the consequences of explosions in the process areas. The analysis has not assessed the potential benefit on explosion overpressures of removing the protected escape routes or relocating them to hang off the process deck. The removal of protected escape routes may reduce the potential for high explosions through increased ventilation. It is recommended that the impact of protected escape routes on explosion overpressures is assessed in more detail in the next phase of the project.

10. Future Updates of the CSA

This CSA is the initial document that quantifies the risk to personnel and the environment due to operation of the FPSO and is prepared and maintained during the concept stage of the Bay du Nord Project. The purpose of the CSA is to demonstrate that the FPSO design is capable of meeting Equinor's Target Levels of Safety and to support the Bay du Nord development application.

However, during the further stages of design, the Bay du Nord FPSO and associated subsea infrastructure will be subject to a formal program of safety assessment studies. These studies will be reflected in an updated Quantitative Risk Assessment (QRA), which provides a more substantive assessment of risks and safety, being based on more detailed design information, than does the CSA, which the QRA will supersede. The QRA and associated studies will also be primary inputs into the Basis of Safe Operations for the FPSO that will be included as part of the Safety Plan.

Equinor and the Contractor will maintain the QRA, the associated safety studies and the Basis of Safe Operations throughout the life of the FPSO, and these documents will be reviewed to reflect changes or new knowledge in operating conditions or equipment on the FPSO. The Framework Regulations require that the QRA is updated at an interval of no more than 5 years.

In addition, where any proposed operational changes or FPSO plant or equipment modifications are considered to be substantial, in that the Basis of Safe Operations is materially different to that submitted to the C-NLOER, then Equinor commit to revise the QRA and Basis of Safe Operations.

A change may be considered substantial if:

- The modification or introduction of new structures, plant, equipment or activities to the installation (or within the safety zone) would result in the exposure of personnel to additional major accident events.
- Permanent or long-term (of a year's duration or more) modification of structure, plant, equipment or activity is planned that may be detrimental to the functionality, reliability, availability or survivability of safety critical elements.
- New safety systems are introduced either to manage additional hazards or to replace existing arrangements to prevent, control or mitigate major accident hazards (e.g. blast walls).
- Significant changes are to be made in the functions of the installation management or the management system.

Due regard will be paid to the cumulative effect of any series of minor changes when considering whether any change constitutes a material change and hence requires revision of the QRA and Basis of Safe Operations.

11. Summary of Significant Conservatisms and Uncertainties

Risk Category	Type	Description	Comment
Release Frequency - Process	Uncertainty	Use of package parts counts to determine topsides hydrocarbon release frequency.	As mature P&IDs are not currently available for the topsides process, a detailed parts count cannot be performed. Use of package counts may underestimate the total release frequency for the topsides hydrocarbon process. **Perform parts count when approved P&IDs are available and update Risk Assessment accordingly.**
Fire and Explosion Escalation Rulesets	Uncertainty	The potential for fire and explosion hazards to escalate to result in impairment of the TR are based on rulesets adopted for similar FPSOs or as a standalone desktop exercise.	A facilitated workshop, involving key members of the Project team, would allow more certainty around the escalation rule sets, especially with respect to the time to cause impairment of the TR from escalation to the COTs.
Transport Risk	Uncertainty	Lack of available data on Fatal Accident Rates from use of the gangway. FAR of FROG 2.65E-07 has been applied for both.	No other data currently available. Would be possible to use Poisson distribution as per CMPT to estimate.
Fire Modelling	Uncertainty	Correlations used for calculating flame lengths have been based on industry standard equations (PHAST modelling was carried out on selected events with standard equations giving more conservative results).	As stated, although PHAST modelling was carried out, using industry standard correlations gave more conservative results for flame lengths. **PHAST analysis for a wider range of events may be carried out at a later stage but this is unlikely to have a significant impact on overall results.**

12. References

[1] Project Document – HAZID/ENVID Report – Safety Studies + HSE Workshops, 4531-SAF-S-RA-00007_B, April 2025.

[2] Canada–Newfoundland and Labrador Offshore Area Petroleum Operations Framework Regulations SOR/2024-25

[3] SURF System HAZID Report 4504447111-SURF-ENG-006, Rev 01, April 2025

[4] Disconnection and Reconnection HAZID Report, 5205575-SA-REP-002, Rev A3, August 2022

[5] Project Document - Bay du Nord ALARP Report, 4531-SAF-S-RA-00006

[6] Reference: Equinor Canada Ltd. (2025). Bay du Nord Project Development Plan.

[7] Collision Regulations, CRC, c1416 (Canada Shipping Act 2001)

[8] Industry Practice - Pressure Relieving and Depressuring Systems, API Standard 521, Sixth Edition, January 2014

[9] Project Document - Heat and Material Balance H&MB 4531-BWO-P-RA-00001_C

[10] Project Document – Topsides PFDs - 4531-BWO-P-XA-00001, 00002, 13001, 13002, 20001, 20002, 23001, 23002, 23003, 24001, 27001, 29001, 29002. March 2025. Turret PFDs A01-APL-P-XA-0001-01 and -0002-01.

[11] Industry Practice - Human Reliability Estimates within Offshore Safety Cases, J.N. Edmonson, Issue 1, 12 November 1993, JWP/FRD/74.

[12] Industry Practice - Testing regime for offshore TR-HVAC fire dampers & TR pressurisation requirements, HSE, OIS 1/2006, January 2007.

[13] Industry Practice - Review of the Response of Pressurised Process Vessels and Equipment to Fire Attack, HSE, OTO 2000 051, June 2000.

[14] Industry Practice - Oil and Gas UK Fire and Explosion Guidance, Issue 1, May 2007.

[15] 4531-APL-H-CA-00001 STP Disconnect System Reliability Analysis

[16] Project Document - Bay du Nord Metocean Design Basis, RE-PM539-00016 MAD-RE-2017-002 Ref 05.

[17] Project Document - Design Basis Bay du Nord Development, PM539-PMS-050-004_05, Rev 05.

[18] Heading analysis reference TBC

[19] Industry Practice - "Behaviour of oil & gas from deepwater blowouts", PD. Yapa & F. Chen, J. Hydraulic Engineering, 2004.

[20] Industry Practice - "Blow-out stability of gaseous jet diffusion flames, Part II: effect of cross wind", G. Kalghatgi, Comb, Sci. & Tech., vol 26, 1981.

[21] Project Document – Bay du Nord Iceberg Load Analysis, C-CORE, R-22-009-271662

[22] NPD and Norwegian Oil Industry Association, "Evacuation And Rescue Means –Strengths Weaknesses And Operational Constraints", Report No. 98-5601, Rev 3

[23] Project Document - Personnel Distribution for Safety Studies 4531-BWO-S-CA-00001, rev C

[24] "Methodology Statement 21 – Personnel Transport Risk", Kent Internal Document, Rev 4, April 2020.

[25] Industry Practice - A Guide to Quantitative Risk Assessment for Offshore Installations, CMPT, 1999

[26] Industry Practice - Water Transport Accident Statistics, OGP Risk Assessment Data Directory, Report No. 434 – 10, March 2010

[27] Project Document – Bay du Nord Pack Ice and Iceberg Design Basis, C-CORE Report R-22-001-1661 Vol2.

[28] "Methodology Statement 25 – Fatality Probability for QRA", Kent Internal Document, Rev 4, April 2020.

[29] Regulatory Document or Guidance - NPD and Norwegian Oil Industry Association, "Evacuation And Rescue Means –Strengths Weaknesses And Operational Constraints", Report No. 98-5601, Rev 3

[30] Escape, Temporary Refuge, Evacuation and Rescue Analysis, 4531-SAF-S-CA-00006, rev A, July 2025

[31] Industry Practice – IEC 62443 Series: Industrial Communication Networks – Network and System Security
[32] "Methodology Statement 10 - Inventories", Kent Internal Document, Rev 3, April 2020.
[33] Project Document - 4531-BWO-M-LA-00001 Master Equipment List.
[34] Project Document - 2185-APL-D-CA-0001 Gexcon explosion analysis open vs enclosed turret compartment.
[35] "Methodology Statement 02 - Topsides Leak Frequency", Kent Internal Document, Rev 6, April 2020.
[36] Regulatory Document or Guidance - Risk and Emergency Preparedness Assessment, NORSOK Z-013, Edition 3, October 2010.
[37] Equinor Standards & Guidance - Equinor, Risk Analysis, GL0282, Version 4.03, 2024.
[38] Industry Practice - Process Leak for Offshore Installations Frequency Assessment Model (PLOFAM), Main Report, Lloyd's Consulting Register for Statoil, 105586/R1, 18th March 2016
[39] "Methodology Statement 03 - Riser Leak Frequency", Kent Internal Document, Rev 1, April 2020.
[40] "Methodology Statement 04 – Blowout Frequencies", Kent Internal Document, Rev 5, June 2020.
[41] Industry Practice - SINTEF F27447 Report, blowout and Well Release Characteristics and Frequencies 2015, SINTEF Technology and Society, January 2016
[42] Industry Practice - Ignition Probability Review, Model Development and Look-up Correlations", IP/UKOAA/HSE, Energy Institute, Ed. January 2006.
[43] Industry Practice - International Oil and Gas Producers, Risk Assessment Data Directory, 434-6.1, March 2010.
[44] Regulation - Canada–Newfoundland and Labrador Offshore Area Occupational Health and Safety Regulations, SOR/2021-247
[45] Industry Practice - Cullen, L. (1990). The Public Inquiry into the Piper Alpha Disaster.
[46] "Methodology Statement 13 – Smoke Dispersion and TR Impairment", Kent Internal Document, Rev 2, June 2020.
[47] Smoke and Gas Dispersion Analysis 4531-SAF-S-CA-00012 rev A, July 2025
[48] Industry Practice - Indicative Human Vulnerability to the Hazardous Agents Present Offshore for Application in Risk Assessment of Major Accidents", SPC/Tech/OSD/30, Health and Safety Executive (including annex - Methods of approximation and determination of human vulnerability for offshore major accident hazard assessment).
[49] "Methodology Statement 22 - Occupational Risk", Kent Internal Document, Rev 11, September 2024.
[50] Industry Practice - "Towards a Unified Approach to Ship Structure Safety", Faulkner and Saddam, RINA, 1978
[51] Ship Collision Study 4531-SAF-S-CA-00011, rev A, June 2025
52] Dropped Objects Study, 4531-SAF-S-CA-00004 rev A, June 2025
[53] Equinor Standards & Guidance - TR2076 DPN Risk Analyses and Risk Tolerance Criteria, Version 3.01, 2022.
[54] Equinor Standards & Guidance - Guideline GL0139, ALARP Principles, Equinor, Version 4.02, 2023.
[55] BW Offshore Safety Critical Element (SCE) Identification Report 4531-BWO-S-RA-00002_C, June 2025

Appendices

Appendix A. TR Impairment

The following tables show those hydrocarbon events that can result in impairment of the TR through the various impairment mechanisms that were discussed in Section 5.10. Only those events that can result in impairment for a particular mechanism are shown in the table.

Table A-1 Events Causing TR Impairment due to Unignited Gas Ingress

Failure Case Description	Event ID	Location	Potential for TRI		
			Small (10mm)	Medium (50mm)	Large (100mm)
Gas Dehydration Inlet Scrubber (24-VG-6001) & TEG Contactor (24-VB-6602) & 1st Stage HP Gas Compressor Suction Scrubber (23-VG-6004) - Gas Release at M61 Process Deck Level 1	P17-G-M61L1	M61L1			X
Gas Dehydration & 1st Stage HP Gas Compression - Gas Release at Piperack	P17-G-PRK	M61L1			X
Gas Dehydration Inlet Scrubber (24-VG-6601) - Liquid Release at M61 Process Deck Level 1	P17-L-M61L1	M61L1			
1st Stage HP Gas Compressor Discharge Cooler (23-HG-6004) at M61 Process Deck Level 2	P17-G-M61L2	M60L2			X
2nd Stage HP Gas Compressor & Suction Scrubber (23-VG-6005) - Gas Release at M61 Process Deck Level 1	P18-G-M61L1	M61L1			X
1st & 2nd Stage HP Gas Compressor Discharge Coolers (23-HG-6004 & 23-HG-6005) - Gas Release at M61 Process Deck Level 2	P18-G-M61L2	M61L2			X
HP Gas Compression / Injection Pipework - Gas Release at M61 Process Deck Level 2	P19-G-M61L2	M61L2		X	
HP Gas Compression / Injection Pipework - Gas Release at Piperack	P19-G-PRK	PRK		X	
HP Gas Compression / Injection Pipework and Flowlines - Gas Release at Turret Upper Deck	P19-G-TRTU	TRTU		X	
Gas Injection/Lift 1 BDN & Gas Lift 2 Cambriol/Circulation Flowline (XSV to ESV) - Gas Release at Turret Lower Deck	P19-G-TRTL	TRTL		X	
BdN Production Riser 1 Subsea	R01-G-SS	SS			X
BdN Production Riser 2 Subsea	R02-G-SS	SS			X
Gas Injection/Gas Lift Riser Subsea	R06-G-SS	SS		X	X

Table A-2 Events Causing TR Impairment due to Smoke (TR HVAC System Operates Successfully)

Failure Case Description	Event ID	Location	Potential for TRI (ISO BD)			Potential for TRI (ISO NOBD)			Potential for TRI (NOISO BD)			Potential for TRI (NOISO NOBD)		
			Small (10mm)	Medium (50mm)	Large (100mm)	Small (10mm)	Medium (50mm)	Large (100mm)	Small (10mm)	Medium (50mm)	Large (100mm)	Small (10mm)	Medium (50mm)	Large (100mm)
Electrostatic Coalescer (20-VJ-1003) & Oil Booster Pump (20-PA-1001A/B) & Crude Oil Coolers (20-HB-1002A/B) - Liquid Release at M11 Process Deck Level 1	P06-L-M11L1	M11L1			X			X			X			X
Crude Oil Offloading Reel - Liquid Release at Offloading Reel	P12-L-OFF	OFF	X			X			X	X		X	X	
Gas Dehydration Inlet Cooler (24-HG-6601) - Two Phase Release at M60 Process Deck Level 2	P17-M-M60L2	M60L2												X
1st & 2nd Stage HP Gas Compressor Discharge Coolers (23-HG-6004 & 23-HG-6005) - Gas Release at M61 Process Deck Level 2	P18-G-M61L2	M61L2											X	
BdN Production Riser 1 Subsea	R01-G-SS	SS	X			X			X			X		
BdN Production Riser 2 Subsea	R02-G-SS	SS	X			X			X			X		
Cambriol Riser Subsea	R05-G-SS	SS	X			X			X			X		
Gas Injection/Gas Lift Riser Subsea	R06-G-SS	SS	X			X			X			X		
Diesel / Fuel Oil Release Machinery Space - Liquid Release	D01-L-MCH	MCH		X	X		X	X		X	X		X	X

Table A-3 Events Causing TR Impairment due to Smoke (TR HVAC System Fails to Shut Down)

Failure Case Description	Event ID	Location	Potential for TRI (ISO BD)			Potential for TRI (ISO NOBD)			Potential for TRI (NOISO BD)			Potential for TRI (NOISO NOBD)		
			Small (10mm)	Medium (50mm)	Large (100mm)	Small (10mm)	Medium (50mm)	Large (100mm)	Small (10mm)	Medium (50mm)	Large (100mm)	Small (10mm)	Medium (50mm)	Large (100mm)
Test Separator (20-VA-1004) - Liquid Release at M10 Process Deck Level 1	P03-L-M10L1	M10L1			X			X			X			X
Electrostatic Coalescer (20-VJ-1003) & Oil Booster Pump (20-PA-1001A/B) & Crude Oil Coolers (20-HB-1002A/B) - Liquid Release at M11 Process Deck Level 1	P06-L-M11L1	M11L1			X			X			X			X
Crude Oil Offloading Header - Liquid Release at M10 Process Deck Level 1	P10-L-M10L1	M10L1			X			X			X			X
Crude Oil Offloading Reel - Liquid Release at Offloading Reel	P12-L-OFF	OFF	X	X		X	X		X	X	X	X	X	X
1st Stage LP Gas Suction Scrubber (23-VG-6001) - Liquid Release at M60 Process Deck Level 1	P14-L-M60L1	M60L1									X			X
Gas Dehydration Inlet Cooler (24-HG-6601) - Two Phase Release at M60 Process Deck Level 2	P17-M-M60L2	M60L2			X			X			X			X
Gas Dehydration Inlet Scrubber (24-VG-6001) & TEG Contactor (24-VB-6602) & 1st Stage HP Gas Compressor Suction Scrubber (23-VG-6004) - Gas Release at M61 Process Deck Level 1	P17-G-M61L1	M61L1			X			X			X			X
Gas Dehydration & 1st Stage HP Gas Compression - Gas Release at Piperack	P17-G-PRK	M61L1			X			X			X			X
1st Stage HP Gas Compressor Discharge Cooler (23-HG-6004) at M61 Process Deck Level 2	P17-G-M61L2	M60L2			X			X			X			X
2nd Stage HP Gas Compressor & Suction Scrubber (23-VG-6005) - Gas Release at M61 Process Deck Level 1	P18-G-M61L1	M61L1			X			X			X			X
1st & 2nd Stage HP Gas Compressor Discharge Coolers (23-HG-6004 & 23-HG-6005) - Gas Release at M61 Process Deck Level 2	P18-G-M61L2	M61L2		X	X		X	X		X	X		X	X
HP Gas Compression / Injection Pipework - Gas Release at M61 Process Deck Level 2	P19-G-M61L2	M61L2					X			X			X	
Fuel Gas Superheaters, Metering Skid & Filter Package - Gas Release	P20-G-M61L2	M61L2			X			X			X			X
Fuel Gas to Turbines - Gas Release	P21-G-M61L2	M61L2									X			X
BdN Production Riser 1 Subsea	R01-G-SS	SS	X			X			X	X		X	X	
BdN Production Riser 2 Subsea	R02-G-SS	SS	X			X			X	X		X	X	
Cambriol Riser Subsea	R05-G-SS	SS	X			X			X			X		
Gas Injection/Gas Lift Riser Subsea	R06-G-SS	SS	X			X			X	X	X	X	X	X
Diesel / Fuel Oil Release Machinery Space - Liquid Release	D01-L-MCH	MCH	X	X	X	X	X	X	X	X	X	X	X	X

Table A-4 Events Causing TR Impairment due to Direct Impairment (Fire)

Failure Case Description	Event ID	Location	Potential for TRI (ISO BD)			Potential for TRI (ISO NOBD)			Potential for TRI (NOISO BD)			Potential for TRI (NOISO NOBD)		
			Small (10mm)	Medium (50mm)	Large (100mm)	Small (10mm)	Medium (50mm)	Large (100mm)	Small (10mm)	Medium (50mm)	Large (100mm)	Small (10mm)	Medium (50mm)	Large (100mm)
Crude Oil Loading Header - Liquid Release on Hull	P07-L-HULL	HULL								X	X		X	X
Cargo Tank - Liquid Release on Hull	P08-L-HULL	HULL		X	X		X	X		X	X		X	X
Off-Spec Fluid Tank - Liquid Release on Hull	P09-L-HULL	HULL		X	X		X	X		X	X		X	X
Fuel Gas to Turbines - Gas Release	P21-G-M90L1	M90L1										X		

Table A-5 Events Causing TR Impairment due to Direct Impairment (Explosion, Fire following Explosion)

Failure Case Description	Event ID	Location	Potential for TRI (ISO BD)			Potential for TRI (ISO NOBD)			Potential for TRI (NOISO BD)			Potential for TRI (NOISO NOBD)		
			Small (10mm)	Medium (50mm)	Large (100mm)	Small (10mm)	Medium (50mm)	Large (100mm)	Small (10mm)	Medium (50mm)	Large (100mm)	Small (10mm)	Medium (50mm)	Large (100mm)
Test Separator (20-VA-1004) - Liquid Release at M10 Process Deck Level 1	P03-L-M10L1	M10L1			X			X			X			X
Crude Oil Loading Header - Liquid Release on Hull	P07-L-HULL	HULL								X	X		X	X
Cargo Tank - Liquid Release on Hull	P08-L-HULL	HULL		X	X		X	X		X	X		X	X
Off-Spec Fluid Tank - Liquid Release on Hull	P09-L-HULL	HULL		X	X		X	X		X	X		X	X
1st Stage LP Gas Suction Scrubber (23-VG-6001) - Liquid Release at M60 Process Deck Level 1	P14-L-M60L1	M60L1		X	X		X	X		X	X		X	X
MP Gas Compression - Gas Release at Piperack	P16-G-PRK	PRK		X	X		X	X		X	X		X	X
MP Gas Compression - Gas Release at M60 Process Deck Level 1	P16-G-M60L1	M60L1			X			X			X			X
MP Gas Compression Suction Scrubber (23-VG-6003) - Liquid Release at M60 Process Deck Level 1	P16-L-M60L1	M60L1		X	X		X	X		X	X		X	X
Gas Dehydration Inlet Cooler (24-HG-6601) - Two Phase Release at M60 Process Deck Level 2	P17-M-M60L2	M60L2			X			X			X			X
Gas Dehydration System - Two Phase Release at Piperack	P17-M-PRK	PRK			X			X			X			X
Gas Dehydration Inlet Scrubber (24-VG-6601) - Two Phase Release at M61 Process Deck Level 1	P17-M-M61L1	M61L1			X			X			X			X
Gas Dehydration Inlet Scrubber (24-VG-6001) & TEG Contactor (24-VB-6602) & 1st Stage HP Gas Compressor Suction Scrubber (23-VG-6004) - Gas Release at M61 Process Deck Level 1	P17-G-M61L1	M61L1			X			X			X			X
Gas Dehydration & 1st Stage HP Gas Compression - Gas Release at Piperack	P17-G-PRK	M61L1		X	X		X	X		X	X		X	X
Gas Dehydration Inlet Scrubber (24-VG-6601) - Liquid Release at M61 Process Deck Level 1	P17-L-M61L1	M61L1		X	X		X	X		X	X		X	X
2nd Stage HP Gas Compressor & Suction Scrubber (23-VG-6005) - Gas Release at M61 Process Deck Level 1	P18-G-M61L1	M61L1		X	X		X	X		X	X		X	X
1st & 2nd Stage HP Gas Compressor Discharge Coolers (23-HG-6004 & 23-HG-6005) - Gas Release at M61 Process Deck Level 2	P18-G-M61L2	M61L2		X	X		X	X		X	X		X	X
HP Gas Compression / Injection Pipework - Gas Release at M61 Process Deck Level 2	P19-G-M61L2	M61L2		X	X		X	X		X	X		X	X
HP Gas Compression / Injection Pipework - Gas Release at Piperack	P19-G-PRK	PRK		X	X		X	X		X	X		X	X
HP Gas Compression / Injection Pipework and Flowlines - Gas Release at Turret Upper Deck	P19-G-TRTU	TRTU		X	X		X	X		X	X		X	X
Gas Injection/Lift 1 BDN & Gas Lift 2 Cambriol/Circulation Flowline (XSV to ESV) - Gas Release at Turret Lower Deck	P19-G-TRTL	TRTL		X	X		X	X		X	X		X	X
Fuel Gas to Turbines - Gas Release	P21-G-M90L1	M90L1										X		

Table A-6 Events Causing TR Impairment due to Sea Fires

There are no cases of a sea fire leading to impairment of the TR. This is due to the fact that any release which has sufficient mass flow rate to lead to a sustainable sea fire will tend to use up all of its inventory before the effects of the sea fire can lead to TR impairment through smoke or unignited gas release.

Table A-7 Events Causing TR Impairment due to Process Module Collapse (Fire)

Failure Case Description	Event ID	Location	Potential for TRI (ISO BD)			Potential for TRI (ISO NOBD)			Potential for TRI (NOISO BD)			Potential for TRI (NOISO NOBD)		
			Small (10mm)	Medium (50mm)	Large (100mm)	Small (10mm)	Medium (50mm)	Large (100mm)	Small (10mm)	Medium (50mm)	Large (100mm)	Small (10mm)	Medium (50mm)	Large (100mm)
MP Inlet and Test Manifolds - Two Phase Release at Piperack	P01-M-PRK	PRK	X	X	X	X	X	X	X	X	X	X	X	X
MP Inlet and Test Manifolds - Two Phase Release at M10 Process Deck Level 1	P01-M-M10L1	M10L1	X	X	X	X	X	X	X	X	X	X	X	X
HP Inlet and Test Manifolds - Two Phase Release at Turret Upper Deck	P02-M-TRTU	TRTU												
HP Inlet and Test Manifolds - Two Phase Release at Piperack	P02-M-PRK	PRK	X	X	X	X	X	X	X	X	X	X	X	X
HP Inlet and Test Manifolds - Two Phase Release at M10 Process Deck Level 1	P02-M-M10L1	M10L1	X	X	X	X	X	X	X	X	X	X	X	X
Test Separator (20-VA-1004) - Two Phase Release at M10 Process Deck Level 1	P03-M-M10L1	M10L1	X	X	X	X	X	X	X	X	X	X	X	X
Test Separator (20-VA-1004) - Gas Release at M10 Process Deck Level 1	P03-G-M10L1	M10L1		X	X	X	X	X	X	X	X	X	X	X
Test Separator (20-VA-1004) - Liquid Release at M10 Process Deck Level 1	P03-L-M10L1	M10L1	X	X	X	X	X	X	X	X	X	X	X	X
Inlet Separator (20-VA-1001) - Two Phase Release at M10 Process Deck Level 1	P04-M-M10L1	M10L1	X	X	X	X	X	X	X	X	X	X	X	X
Inlet Separator (20-VA-1001) - Gas Release at M10 Process Deck Level 1	P04-G-M10L1	M10L1		X	X	X	X	X	X	X	X	X	X	X
Inlet Separator (20-VA-1001) - Gas Release at Piperack	P04-G-PRK	PRK		X	X	X	X	X	X	X	X	X	X	X
Inlet Separator (20-VA-1001) - Liquid Release at M10 Process Deck Level 1	P04-L-M10L1	M10L1	X	X	X	X	X	X	X	X	X	X	X	X
LP Separator (20-VA-1002) - Two Phase Release at Piperack	P05-M-PRK	PRK	X	X	X	X	X	X	X	X	X	X	X	X
LP Separator (20-VA-1002) - Two Phase Release at M11 Process Deck Level 2	P05-M-M11L2	M11L2	X	X	X	X	X	X	X	X	X	X	X	X
LP Separator (20-VA-1002) - Gas Release at M11 Process Deck Level 2	P05-G-M11L2	M11L2		X	X		X	X		X	X		X	X
LP Separator (20-VA-1002) - Liquid Release at M11 Process Deck Level 2	P05-L-M11L2	M11L2		X	X		X	X		X	X		X	X
1st Stage LP Compressor Scrubber Pumps (23-PA-6001A/B) - Two Phase Release at M60 Process Deck Level 1	P05-M-M60L1	M60L1	X	X	X	X	X	X	X	X	X	X	X	X
Electrostatic Coalescer (20-VJ-1003) & Oil Booster Pump (20-PA-1001A/B) & Crude Oil Coolers (20-HB-1002A/B) - Liquid Release at M11 Process Deck Level 1	P06-L-M11L1	M11L1		X	X		X	X		X	X		X	X
Crude Oil Loading Header - Liquid Release at M11 Process Deck Level 1	P07-L-M11L1	M11L1		X	X		X	X		X	X		X	X
Crude Oil Loading Header - Liquid Release at Piperack	P07-L-PRK	PRK		X	X		X	X		X	X		X	X
Crude Oil Loading Header - Liquid Release on Hull	P07-L-HULL	HULL		X	X		X	X		X	X		X	X
Cargo Tank - Liquid Release on Hull	P08-L-HULL	HULL		X	X		X	X		X	X		X	X
Off-Spec Fluid Tank - Liquid Release on Hull	P09-L-HULL	HULL		X	X		X	X		X	X		X	X
Off-Spec Fluid Tank - Liquid Release at Piperack	P09-L-PRK	PRK		X	X		X	X		X	X		X	X
Crude Oil Transfer Header - Liquid Release on Hull	P10-L-HULL	HULL		X	X		X	X		X	X		X	X
Crude Oil Offloading Header - Liquid Release at Piperack	P10-L-PRK	PRK		X	X		X	X		X	X		X	X
Crude Oil Offloading Header - Liquid Release at M10 Process Deck Level 1	P10-L-M10L1	M10L1		X	X		X	X		X	X		X	X
Crude Oil Offloading Header - Liquid Release on Hull	P11-L-HULL	HULL		X	X		X	X		X	X		X	X
Crude Oil Offloading Reel - Liquid Release on Hull	P12-L-HULL	HULL		X			X			X	X		X	X
1st Stage LP Gas Compression Suction Cooler (23-HB-6001) - Two Phase Release at M60 Process Deck Level 2	P14-M-M60L2	M60L2		X	X		X	X		X	X		X	X
1st Stage LP Gas Compression - Gas Release at M60 Process Deck Level 1	P14-G-M60L1	M60L1		X	X		X	X		X	X		X	X
1st Stage LP Gas Suction Scrubber (23-VG-6001) - Liquid Release at M60 Process Deck Level 1	P14-L-M60L1	M60L1	X			X			X	X	X	X	X	X
1st Stage Recompression to Flare KO Drum (43-VD-3001) - Gas Release at Piperack	P14-G-PRK	PRK		X			X			X			X	
2nd Stage LP Gas Compression Suction Cooler (23-HB-6002) - Two Phase Release at M60 Process Deck Level 2	P15-M-M60L2	M60L2		X			X			X	X		X	X
2nd Stage LP Gas Compression - Gas Release at M60 Process Deck Level 1	P15-G-M60L1	M60L1		X			X			X	X		X	X
2nd Stage LP Gas Compressor Suction Scrubber (23-VG-6002) - Liquid Release at M60 Process Deck Level 1	P15-L-M60L1	M60L1	X			X			X			X		
MP Gas Compression - Gas Release at Piperack	P16-G-PRK	PRK		X	X	X	X	X	X	X	X	X	X	X
MP Gas Compression Suction Cooler (23-HA-6003) - Two Phase Release at M60 Process Deck Level 2	P16-M-M60L2	M60L2		X	X	X	X	X			X	X	X	X
MP Gas Compression - Gas Release at M60 Process Deck Level 1	P16-G-M60L1	M60L1	X	X	X	X	X	X	X	X	X	X	X	X
MP Gas Compression Suction Scrubber (23-VG-6003) - Liquid Release at M60 Process Deck Level 1	P16-L-M60L1	M60L1	X			X			X	X		X	X	

Failure Case Description	Event ID	Location	Potential for TRI (ISO BD)			Potential for TRI (ISO NOBD)			Potential for TRI (NOISO BD)			Potential for TRI (NOISO NOBD)		
			Small (10mm)	Medium (50mm)	Large (100mm)	Small (10mm)	Medium (50mm)	Large (100mm)	Small (10mm)	Medium (50mm)	Large (100mm)	Small (10mm)	Medium (50mm)	Large (100mm)
Gas Dehydration Inlet Cooler (24-HG-6601) - Two Phase Release at M60 Process Deck Level 2	P17-M-M60L2	M60L2	X	X	X	X	X	X		X	X	X	X	X
Gas Dehydration System - Two Phase Release at Piperack	P17-M-PRK	PRK	X	X	X	X	X	X		X	X	X	X	X
Gas Dehydration Inlet Scrubber (24-VG-6601) - Two Phase Release at M61 Process Deck Level 1	P17-M-M61L1	M61L1	X	X	X	X	X	X		X	X	X	X	X
Gas Dehydration Inlet Scrubber (24-VG-6001) & TEG Contactor (24-VB-6602) & 1st Stage HP Gas Compressor Suction Scrubber (23-VG-6004) - Gas Release at M61 Process Deck Level 1	P17-G-M61L1	M61L1	X	X	X	X	X	X	X	X	X	X	X	X
Gas Dehydration & 1st Stage HP Gas Compression - Gas Release at Piperack	P17-G-PRK	M61L1	X	X	X	X	X	X	X	X	X	X	X	X
Gas Dehydration Inlet Scrubber (24-VG-6601) - Liquid Release at M61 Process Deck Level 1	P17-L-M61L1	M61L1	X			X						X		
1st Stage HP Gas Compressor Discharge Cooler (23-HG-6004) at M61 Process Deck Level 2	P17-G-M61L2	M60L2	X	X		X	X	X	X	X	X	X	X	X
2nd Stage HP Gas Compressor & Suction Scrubber (23-VG-6005) - Gas Release at M61 Process Deck Level 1	P18-G-M61L1	M61L1	X	X		X	X		X	X	X	X	X	X
1st & 2nd Stage HP Gas Compressor Discharge Coolers (23-HG-6004 & 23-HG-6005) - Gas Release at M61 Process Deck Level 2	P18-G-M61L2	M61L2	X	X		X	X		X	X	X	X	X	X
HP Gas Compression / Injection Pipework - Gas Release at M61 Process Deck Level 2	P19-G-M61L2	M61L2	X			X			X	X		X	X	
HP Gas Compression / Injection Pipework - Gas Release at Piperack	P19-G-PRK	PRK	X			X			X	X		X	X	
Fuel Gas System - Gas Release	P20-G-M61L1	M61L1	X	X		X	X		X	X		X	X	
Fuel Gas System - Liquid Release	P20-L-M61L1	M61L1							X			X		
Fuel Gas Superheaters, Metering Skid & Filter Package - Gas Release	P20-G-M61L2	M61L2	X	X		X	X		X	X		X	X	
Fuel Gas to Turbines - Gas Release	P21-G-M61L2	M61L2				X			X	X		X	X	
Fuel Gas to Turbines - Gas Release	P21-G-PRK	PRK				X			X	X		X	X	
LP Fuel Gas to Consumers - Gas Release	P22-G-M61L2	M61L2											X	
LP Fuel Gas to Consumers - Gas Release	P22-G-PRK	PRK											X	X
LP Fuel Gas to Consumers - Gas Release	P22-G-M11L2	M11L2											X	X
Reject Vessel (44-VD-1003) - Two Phase Release at M11 Process Deck Level 3	P23-M-M11L3	M11L3			X			X			X			X
Reject Vessel (44-VD-1003) - Gas Release at M11 Process Deck Level 3	P23-G-M11L3	M11L3												X
MP Separator - Two Phase Release at Piperack	P35-M-PRK	PRK	X	X		X	X		X	X		X	X	X
MP Separator - Two Phase Release at M11 Process Deck Level 2	P35-M-M11L2	M11L2	X	X		X	X		X	X		X	X	X
MP Separator - Gas Release at M11 Process Deck Level 2	P35-G-M11L2	M11L2		X			X			X	X		X	X
MP Separator - Liquid Release at M11 Process Deck Level 2	P35-L-M11L2	M11L2	X	X		X	X		X	X	X	X	X	

Table A-8 Events Causing TR Impairment due to Process Module Collapse (Explosion, Fire following Explosion)

Failure Case Description	Event ID	Location	Potential for TRI (ISO BD)			Potential for TRI (ISO NOBD)			Potential for TRI (NOISO BD)			Potential for TRI (NOISO NOBD)		
			Small (10mm)	Medium (50mm)	Large (100mm)	Small (10mm)	Medium (50mm)	Large (100mm)	Small (10mm)	Medium (50mm)	Large (100mm)	Small (10mm)	Medium (50mm)	Large (100mm)
MP Inlet and Test Manifolds - Two Phase Release at Piperack	P01-M-PRK	PRK	X	X	X	X	X	X	X	X	X	X	X	X
MP Inlet and Test Manifolds - Two Phase Release at M10 Process Deck Level 1	P01-M-M10L1	M10L1	X	X	X	X	X	X	X	X	X	X	X	X
HP Inlet and Test Manifolds - Two Phase Release at Piperack	P02-M-PRK	PRK	X	X	X	X	X	X	X	X	X	X	X	X
HP Inlet and Test Manifolds - Two Phase Release at M10 Process Deck Level 1	P02-M-M10L1	M10L1	X	X	X	X	X	X	X	X	X	X	X	X
Test Separator (20-VA-1004) - Two Phase Release at M10 Process Deck Level 1	P03-M-M10L1	M10L1	X	X	X	X	X	X	X	X	X	X	X	X
Test Separator (20-VA-1004) - Gas Release at M10 Process Deck Level 1	P03-G-M10L1	M10L1		X	X	X	X	X	X	X	X	X	X	X
Test Separator (20-VA-1004) - Liquid Release at M10 Process Deck Level 1	P03-L-M10L1	M10L1	X	X	X	X	X	X	X	X	X	X	X	X
Inlet Separator (20-VA-1001) - Two Phase Release at M10 Process Deck Level 1	P04-M-M10L1	M10L1	X	X	X	X	X	X	X	X	X	X	X	X
Inlet Separator (20-VA-1001) - Gas Release at M10 Process Deck Level 1	P04-G-M10L1	M10L1		X	X	X	X	X	X	X	X	X	X	X
Inlet Separator (20-VA-1001) - Gas Release at Piperack	P04-G-PRK	PRK		X	X	X	X	X	X	X	X	X	X	X
Inlet Separator (20-VA-1001) - Liquid Release at M10 Process Deck Level 1	P04-L-M10L1	M10L1	X	X	X	X	X	X	X	X	X	X	X	X
LP Separator (20-VA-1002) - Two Phase Release at Piperack	P05-M-PRK	PRK	X	X	X	X	X	X	X	X	X	X	X	X
LP Separator (20-VA-1002) - Two Phase Release at M11 Process Deck Level 2	P05-M-M11L2	M11L2	X	X	X	X	X	X	X	X	X	X	X	X
LP Separator (20-VA-1002) - Gas Release at M11 Process Deck Level 2	P05-G-M11L2	M11L2		X	X		X	X		X	X		X	X
LP Separator (20-VA-1002) - Liquid Release at M11 Process Deck Level 2	P05-L-M11L2	M11L2		X	X		X	X		X	X		X	X
1st Stage LP Compressor Scrubber Pumps (23-PA-6001A/B) - Two Phase Release at M60 Process Deck Level 1	P05-M-M60L1	M60L1	X	X	X	X	X	X	X	X	X	X	X	X
Electrostatic Coalescer (20-VJ-1003) & Oil Booster Pump (20-PA-1001A/B) & Crude Oil Coolers (20-HB-1002A/B) - Liquid Release at M11 Process Deck Level 1	P06-L-M11L1	M11L1		X	X		X	X		X	X		X	X
Crude Oil Loading Header - Liquid Release at M11 Process Deck Level 1	P07-L-M11L1	M11L1		X	X		X	X		X	X		X	X
Crude Oil Loading Header - Liquid Release at Piperack	P07-L-PRK	PRK		X	X		X	X		X	X		X	X
Crude Oil Loading Header - Liquid Release on Hull	P07-L-HULL	HULL		X	X		X	X		X	X		X	X
Cargo Tank - Liquid Release on Hull	P08-L-HULL	HULL		X	X		X	X		X	X		X	X
Off-Spec Fluid Tank - Liquid Release on Hull	P09-L-HULL	HULL		X	X		X	X		X	X		X	X
Off-Spec Fluid Tank - Liquid Release at Piperack	P09-L-PRK	PRK												
Crude Oil Transfer Header - Liquid Release on Hull	P10-L-HULL	HULL		X	X		X	X		X	X		X	X
Crude Oil Offloading Header - Liquid Release at Piperack	P10-L-PRK	PRK		X	X		X	X		X	X		X	X
Crude Oil Offloading Header - Liquid Release at M10 Process Deck Level 1	P10-L-M10L1	M10L1		X	X		X	X		X	X		X	X
Crude Oil Offloading Header - Liquid Release on Hull	P11-L-HULL	HULL		X	X		X	X		X	X		X	X
Crude Oil Offloading Reel - Liquid Release on Hull	P12-L-HULL	HULL		X			X			X	X		X	X
1st Stage LP Gas Compression Suction Cooler (23-HB-6001) - Two Phase Release at M60 Process Deck Level 2	P14-M-M60L2	M60L2		X	X		X	X		X	X		X	X
1st Stage LP Gas Compression - Gas Release at M60 Process Deck Level 1	P14-G-M60L1	M60L1		X	X		X	X		X	X		X	X
1st Stage LP Gas Suction Scrubber (23-VG-6001) - Liquid Release at M60 Process Deck Level 1	P14-L-M60L1	M60L1	X	X	X	X	X	X	X	X	X	X	X	X
1st Stage Recompression to Flare KO Drum (43-VD-3001) - Gas Release at Piperack	P14-G-PRK	PRK		X			X			X			X	
2nd Stage LP Gas Compression Suction Cooler (23-HB-6002) - Two Phase Release at M60 Process Deck Level 2	P15-M-M60L2	M60L2		X	X		X	X		X	X		X	X
2nd Stage LP Gas Compression - Gas Release at M60 Process Deck Level 1	P15-G-M60L1	M60L1		X	X		X	X		X	X		X	X
2nd Stage LP Gas Compressor Suction Scrubber (23-VG-6002) - Liquid Release at M60 Process Deck Level 1	P15-L-M60L1	M60L1	X			X			X			X		
MP Gas Compression - Gas Release at Piperack	P16-G-PRK	PRK		X	X	X	X	X	X	X	X	X	X	X
MP Gas Compression Suction Cooler (23-HA-6003) - Two Phase Release at M60 Process Deck Level 2	P16-M-M60L2	M60L2		X	X	X	X	X			X	X	X	X
MP Gas Compression - Gas Release at M60 Process Deck Level 1	P16-G-M60L1	M60L1	X	X	X	X	X	X	X	X	X	X	X	X
MP Gas Compression Suction Scrubber (23-VG-6003) - Liquid Release at M60 Process Deck Level 1	P16-L-M60L1	M60L1	X	X	X	X	X	X	X	X	X	X	X	X

Failure Case Description	Event ID	Location	Potential for TRI (ISO BD)			Potential for TRI (ISO NOBD)			Potential for TRI (NOISO BD)			Potential for TRI (NOISO NOBD)		
			Small (10mm)	Medium (50mm)	Large (100mm)	Small (10mm)	Medium (50mm)	Large (100mm)	Small (10mm)	Medium (50mm)	Large (100mm)	Small (10mm)	Medium (50mm)	Large (100mm)
Gas Dehydration Inlet Cooler (24-HG-6601) - Two Phase Release at M60 Process Deck Level 2	P17-M-M60L2	M60L2	X	X	X	X	X	X		X	X	X	X	X
Gas Dehydration System - Two Phase Release at Piperack	P17-M-PRK	PRK	X	X	X	X	X	X		X	X	X	X	X
Gas Dehydration Inlet Scrubber (24-VG-6601) - Two Phase Release at M61 Process Deck Level 1	P17-M-M61L1	M61L1	X	X	X	X	X	X		X	X	X	X	X
Gas Dehydration Inlet Scrubber (24-VG-6001) & TEG Contactor (24-VB-6602) & 1st Stage HP Gas Compressor Suction Scrubber (23-VG-6004) - Gas Release at M61 Process Deck Level 1	P17-G-M61L1	M61L1	X	X	X	X	X	X	X	X	X	X	X	X
Gas Dehydration & 1st Stage HP Gas Compression - Gas Release at Piperack	P17-G-PRK	M61L1	X	X	X	X	X	X	X	X	X	X	X	X
Gas Dehydration Inlet Scrubber (24-VG-6601) - Liquid Release at M61 Process Deck Level 1	P17-L-M61L1	M61L1	X	X	X	X	X	X		X	X	X	X	X
1st Stage HP Gas Compressor Discharge Cooler (23-HG-6004) at M61 Process Deck Level 2	P17-G-M61L2	M60L2	X	X	X	X	X	X	X	X	X	X	X	X
2nd Stage HP Gas Compressor & Suction Scrubber (23-VG-6005) - Gas Release at M61 Process Deck Level 1	P18-G-M61L1	M61L1	X	X	X	X	X	X	X	X	X	X	X	X
1st & 2nd Stage HP Gas Compressor Discharge Coolers (23-HG-6004 & 23-HG-6005) - Gas Release at M61 Process Deck Level 2	P18-G-M61L2	M61L2	X	X	X	X	X	X	X	X	X	X	X	X
HP Gas Compression / Injection Pipework - Gas Release at M61 Process Deck Level 2	P19-G-M61L2	M61L2	X	X	X	X	X	X	X	X	X	X	X	X
HP Gas Compression / Injection Pipework - Gas Release at Piperack	P19-G-PRK	PRK	X	X	X	X	X	X	X	X	X	X	X	X
Fuel Gas System - Gas Release	P20-G-M61L1	M61L1	X	X	X	X	X	X	X	X	X	X	X	X
Fuel Gas System - Liquid Release	P20-L-M61L1	M61L1							X			X		
Fuel Gas Superheaters, Metering Skid & Filter Package - Gas Release	P20-G-M61L2	M61L2	X	X	X	X	X	X	X	X	X	X	X	X
Fuel Gas to Turbines - Gas Release	P21-G-M61L2	M61L2				X			X	X		X	X	
Fuel Gas to Turbines - Gas Release	P21-G-PRK	PRK				X			X	X		X	X	
LP Fuel Gas to Consumers - Gas Release	P22-G-M61L2	M61L2											X	
LP Fuel Gas to Consumers - Gas Release	P22-G-PRK	PRK											X	X
LP Fuel Gas to Consumers - Gas Release	P22-G-M11L2	M11L2											X	X
Reject Vessel (44-VD-1003) - Two Phase Release at M11 Process Deck Level 3	P23-M-M11L3	M11L3			X			X			X			X
Reject Vessel (44-VD-1003) - Gas Release at M11 Process Deck Level 3	P23-G-M11L3	M11L3												X
MP Separator - Two Phase Release at Piperack	P35-M-PRK	PRK	X	X		X	X		X	X		X	X	X
MP Separator - Two Phase Release at M11 Process Deck Level 2	P35-M-M11L2	M11L2	X	X		X	X		X	X		X	X	X
MP Separator - Gas Release at M11 Process Deck Level 2	P35-G-M11L2	M11L2		X			X			X	X		X	X
MP Separator - Liquid Release at M11 Process Deck Level 2	P35-L-M11L2	M11L2	X	X	X	X	X	X	X	X	X	X	X	X

Table A-9 Events Causing TR Impairment due to Turret Collapse (Fire Only)

Failure Case Description	Event ID	Location	Potential for TRI (ISO BD)			Potential for TRI (ISO NOBD)			Potential for TRI (NOISO BD)			Potential for TRI (NOISO NOBD)		
			Small (10mm)	Medium (50mm)	Large (100mm)	Small (10mm)	Medium (50mm)	Large (100mm)	Small (10mm)	Medium (50mm)	Large (100mm)	Small (10mm)	Medium (50mm)	Large (100mm)
BdN Production Flowline 1 and 2 (ESV to XSV) - Two Phase Release at Turret Lower Deck	P01-M-TRTU	TRTU	X			X			X	X	X	X	X	X
MP Inlet and Test Manifolds - Two Phase Release at Turret Upper Deck	P01-M-TRTL	TRTL	X			X			X	X	X	X	X	X
HP Inlet and Test Manifolds - Two Phase Release at Turret Upper Deck	P02-M-TRTU	TRTU	X	X		X	X		X	X	X	X	X	X
HP Spare, Cambriol and Circulation Production Flowline (ESV to XSV) - Two Phase Release at Turret Lower Deck	P02-M-TRTL	TRTL	X	X		X	X		X	X	X	X	X	X
Pig receiver - Two Phase Release at Turret Lower Deck	P25-M-TRTL	TRTL							X	X		X	X	
Pig launcher - Two Phase Release at Turret Lower Deck	P26-M-TRTL	TRTL							X	X		X	X	

Table A-10 Events Causing TR Impairment due to Turret Collapse (Explosion and Fire following Explosion)

Failure Case Description	Event ID	Location	Potential for TRI (ISO BD)			Potential for TRI (ISO NOBD)			Potential for TRI (NOISO BD)			Potential for TRI (NOISO NOBD)		
			Small (10mm)	Medium (50mm)	Large (100mm)	Small (10mm)	Medium (50mm)	Large (100mm)	Small (10mm)	Medium (50mm)	Large (100mm)	Small (10mm)	Medium (50mm)	Large (100mm)
BdN Production Flowline 1 and 2 (ESV to XSV) - Two Phase Release at Turret Lower Deck	P01-M-TRTU	TRTU	X	X	X	X	X	X	X	X	X	X	X	X
MP Inlet and Test Manifolds - Two Phase Release at Turret Upper Deck	P01-M-TRTL	TRTL	X	X	X	X	X	X	X	X	X	X	X	X
HP Inlet and Test Manifolds - Two Phase Release at Turret Upper Deck	P02-M-TRTU	TRTU	X	X	X	X	X	X	X	X	X	X	X	X
HP Spare, Cambriol and Circulation Production Flowline (ESV to XSV) - Two Phase Release at Turret Lower Deck	P02-M-TRTL	TRTL	X	X	X	X	X	X	X	X	X	X	X	X
HP Gas Compression / Injection Pipework and Flowlines - Gas Release at Turret Upper Deck	P19-G-TRTU	TRTU	X	X	X	X	X	X	X	X	X	X	X	X
Gas Injection/Lift 1 BDN & Gas Lift 2 Cambriol/Circulation Flowline (XSV to ESV) - Gas Release at Turret Lower Deck	P19-G-TRTL	TRTL	X	X	X	X	X	X	X	X	X	X	X	X
Pig receiver - Two Phase Release at Turret Lower Deck	P25-M-TRTL	TRTL							X	X	X	X	X	X
Pig launcher - Two Phase Release at Turret Lower Deck	P26-M-TRTL	TRTL							X	X	X	X	X	X

Appendix B. Fire Modelling Methodology and Results

B.1. Gas Outflow Rates

Vapor phase release rates from process equipment are calculated using a standard form of the equation for sonic gas through a sharp-edged orifice [25]. For topsides process inventories, the methodology assumes no frictional losses and therefore provides an overestimation of the leak rate, particularly for small pipes rather than pressure vessels.

$$\dot{m} = P_t . A_{breach} . C_d . k$$

Where: $\dot{m}$ is the mass flowrate at time t (kg/s)

P_t is the supply pressure at time t (Pascal)

A_{breach} is the breach flow area (m^2)

C_d is the flow coefficient

M is the molecular weight (kg/kmol)

R is the gas constant, 8,314 (J/kmolK)

T is the supply temperature (K)

γ is the ratio of specific heats, C_p/C_v

k is a coefficient that is equal to $\sqrt{\frac{M\gamma}{RT}\left(\frac{2}{\gamma+1}\right)^{\left(\frac{\gamma+1}{\gamma-1}\right)}}$.

The pressure decay over time is extremely important in the fire modelling process as this is used to calculate how the outflow rate and thus the fire size changes over time. The pressure at any stage of the release is modelled as an exponential decay, calculated using:

$$P_t = P_0 . e^{\left(\frac{-kC_d A_{total} P_0 t}{V \rho_0}\right)}$$

Where: P_0 is the initial source absolute pressure (Pascal)

A_{total} is the total flow area through both the breach and the blowdown valve (m^2)

t is the time (seconds)

V is the Volume of the inventory(m^3)

ρ_0 is the gas density (kg/m^3)

The outflow rates and fire sizes are calculated for 1-minute time intervals, from t=0 mins to t=120 mins.

The jet flame length associated with each release flowrate is calculated using the following equation (from the latest FABIG guidance from Technical Note 13 in 2014 [56], based on a large range of experimental data for a range of fuels):

$L=12 \times Q^{0.4}$

Where L is the flame length, (m)

Q is the release rate (kg/s)

B.2. Two Phase Outflow Rates

Two-phase releases are treated in the same way as gas releases, but the outflow rates are factored by the initial two-phase outflow rate. The initial two-phase outflow rate is calculated using the Fauske equation which uses an equivalent density of the two-phase mixture.

$$G = 0.85\sqrt{2\rho_m(P_o - P_c)}$$

where G is the mass velocity, (kg/m^{2}s)

ρ_m is the mixture density, (kg/m^3)

P_o is the upstream pressure, (Pa)

P_c is the critical pressure, (Pa).

The critical pressure is calculated:

$$\frac{P_C}{P_o} = 0.55(1 - e^{-l/3d})$$

where *l* is the length of the vessel, (m)

d is the diameter of the vessel, (m)

B.3. Liquid Spray Outflow Rates

Liquid spray releases can occur under the following circumstances:

1. When liquid released from a vessel has a higher pressure than the "spray transition pressure" (i.e. the pressure at which the liquid jet release breaks up into droplets, through aerodynamic instability). In this case, release rate calculations take account of vessel blowdown in order to estimate release outflow rates. At the point where the vessel pressure falls below the transition pressure, if there is any liquid remaining, a pool fire will ensue with consequences that are estimated based on the pure liquid methodology described below.
2. When liquid is released from a liquid inventory where the saturated vapor pressure exceeds the transition pressure. In these cases, it is assumed that following the initial release phase (prior to pump shutdown where applicable, pipework relaxation and density change), the pressure in the pipeline will fall to the saturated vapor pressure at which point gas will evolve from the liquid. For these cases it has been assumed that this mechanism effectively keeps the inventory above the transition pressure for the duration of the release.

The transition pressure for liquid events has been calculated based on liquid properties including surface tension, viscosity, density as well as release size.

The outflow rate for spray fires is defined as:

$$Q_t = Cd.A.\rho\sqrt{\frac{2\Delta P}{\rho}}$$

Where:	Cd	is the Discharge coefficient
	Area	is the hole area (m^2)
	ρ	is the Density of liquid released (kg/m^3)
	ΔP	is the Differential pressure (N/m^2)

The differential pressure equation takes into account both the process pressure and the liquid head inside the equipment which contributes to the differential.

$$Q_t = Cd.A.\rho\sqrt{2\left(\frac{P_1 - P_2}{\rho} + Zg\right)}$$

Where:	P_1	is the liquid storage pressure (N/m^2)
	P_2	is the ambient pressure (N/m^2)
	g	is the acceleration due to gravity (9.81 m/s^2)
	Z	is the static head of liquid (m)

The spray fire flame length is calculated using the same equation as for gas jet fires.

Spray fire durations are determined based on the time for the inventory to reach the transition pressure. For vessel spray releases, where blowdown operates successfully then the vessel depressurisation curve is used to determine the time before the spray transition pressure is reached. Below this pressure, any remaining liquid inventory is modelled as a pool fire release as outlined in the methodology in Section B.3.

In cases where blowdown fails to operate, and the vessel pressure is above the transition pressure to begin with, then this pressure remains constant throughout the release duration and the entire liquid inventory burns as a spray fire. Note that there is a necessarily conservative assumption here in that the release is assumed to occur from a location whereby the entire liquid inventory can be released.

Finally, if the liquid release is exhausted before the associated gas inventory has fully blown down (or if blowdown fails) then the liquid release could be followed by a gas jet fire.

B.3.1. Pure Liquid Outflow Rates

Pure liquid releases are those, normally trapped in pipework, which do not have a gas cap to drive them out. It is assumed that up until the point where the isolation valve closes the liquid will be driven out of the release by operating pressure in the line. From current industry practices, the release of a liquid from a process vessel, storage tank or other hydrocarbon containing vessel can be represented by a form of the Bernoulli equation:

$$Q_t = Cd.A.\rho\sqrt{2\left(\frac{P_1 - P_2}{\rho} + Zg\right)}$$

Where: C_d is the discharge coefficient

A is the release area (m^2)

ρ is the liquid density (kg/m^3)

P_1 is the liquid storage pressure (N/m^2)

P_2 is the ambient pressure (N/m^2)

g is the acceleration due to gravity (9.81 m/s^2)

Z is the static head of liquid (m).

For simplicity, the flowrate is assumed to remain constant at the initial rate until the inventory has been discharged. Constant pressure is assumed, due to the vapor above liquid in a vessel and the liquid's vapor pressure.

For predominantly liquid filled vessels or equipment with low vapor content i.e. dead crude, diesel etc, the vapor pressure of the fluid is used to model the release rate. For such conditions, the liquid head of the fluid will be more influential on the release conditions and for the purposes of this assessment an average liquid head, between the vessel being full and empty, is used.

Pool fires resulting from liquid spills are divided into two categories: those where containment is provided by bunds around the fire area and those where no bunds exist, or the spillage is too small to reach the sides of the bunds. For bunded pool fires, the fire duration is related to the depth of the pool and the mass burning rate according to equation:

$$m = y\rho$$

where m is the mass burning flux in kg/m^2s

y is the regression rate in m/s

ρ is the fuel density in kg/m^3.

A typical value for y of 4mm/min (6.67×10^{-5} m/s) will be used [57].

The use of such an expression for prediction of fire duration must be used with care. It is highly probable that fuel will be removed from the pool by drainage as well as burning, thereby reducing fire durations. The activation of a deluge system or monitors will also tend to wash oil away from the pool on the surface of the applied water. The fire behaviour will be now more akin to that of a running pool fire. Consideration should be given as to whether the oil remains a hazard as it is swept into other areas.

Unbounded pool fires form when oil burns as it spreads across a surface. If the oil release is from a large inventory, and therefore of long duration, the fire spreads (ideally to form a circular fire) until the mass burning rate is equivalent to the release rate from the vessel. The maximum (steady state) fire diameter is as follows:

$$d = 2\left[\frac{Q}{\pi \cdot m}\right]^{1/2}$$

where d is the diameter (m)

Q is the oil release rate (kgs^{-1})

m is the oil burning flux ($kgm^{-2}s^{-1}$).

For uncontained pool fires it is necessary to establish whether the release is treated as instantaneous or continuous, thus the parameter t_{cr} is calculated as follows:

$$t_{cr} = \frac{t_s\, y}{V_L}$$

where t_s is the spill duration, (sec.)

V_L is the released volume, (m^3).

For values of t_{cr} less than 2 x 10^{-3} the release is modelled as instantaneous. For higher values the release is modelled as continuous. For continuous releases the fire duration is taken as equalling the release duration.

For instantaneous releases the pool diameter (maximum) is calculated as:

$$d_m = 2\left[\frac{V_L^3\, g}{y^2}\right]^{0.125}$$

t_m, the fire duration in seconds is calculated as:

$$t_m = 0.67\left[\frac{V_L}{gy^2}\right]^{0.25}$$

where g is the acceleration due to gravity = 9.81 m/s^2.

Once the diameter of a fire is determined, the height of the flames is found by Thomas' correlation:

$$H/d = 42\left[\frac{m}{\rho_a\sqrt{gd}}\right]^{0.61}$$

where H, is the flame height (m)

d, is the pool fire diameter (m)

m, is the mass burning rate (kgm^{-2} s^{-1})

ρ_a, is the ambient air density (kgm^{-3})

g, is the gravitational constant (ms^{-2}).

The engulfed heat transfer rate is taken to be 150 kW/m^2 for pool fires. This is considered to be an upper limit, with 100 kW/m^2 being a more typical value.

Releases from the oil export pipework are calculated in a similar manner, but with some important differences. Firstly, the exported oil is effectively dead crude, hence the assumption above, that the initial outflow rate remains constant, is not true, as this is based on a combination of vapour above a liquid in a vessel and the vapour pressure of the liquid. In the case of the dead crude, both these effects are removed. For releases from this pipework, there will be a very short duration initial spike of liquid released, followed by a release driven by the export pumps.

B.4. Riser Releases

For riser releases, two different release scenarios with different associated fire hazards are considered:

1. Above Sea – a topsides release resulting in a fire or explosion within the turret
2. Subsea – a subsea release from the riser below the FPSO and flowline up to the 500m Safety Zone, leading to a sea surface fire.

Any releases further from the facility will not pose a risk to the facility and are not assessed further.

The methodology used to model riser releases is detailed below

B.4.1. Gas / Two-Phase Releases

Outflow from a large or full-bore release is dominated by the effects of pipe wall friction and pipe inventory decay. When a pipeline is ruptured, a depressurisation front is formed at the open end and then rapidly travels away from the open end along the length of the pipe. As the front moves away from the open end the wall friction head loss increases and so the flowrate decreases.

Choked ideal gas mass flow rate is calculated from:

Equation 1

$$m_0 = C_d A_0 \sqrt{P_2 \rho_2 \gamma (\frac{2}{\gamma + 1})^{\frac{\gamma+1}{\gamma-1}}}$$

Where m_0 = mass flow rate through rupture (kg/s)

C_d = discharge co-efficient (1 for full bore ruptures [58], 0.85 [see explanation in [59]] sharp edged ruptures less than full bore)

A_0 = exit hole cross sectional area (m^2)

P_2 = gas pressure at ruptured end (N/m^2)

ρ_2 = gas density at ruptured end (kg/m^3)

γ = ratio of specific heat capacities

The initial rupture mass flow rate (at time t=0) is calculated by setting the pipe pressure at the rupture P_2 as the initial pipeline pressure P_0

After a time, t, the depressurisation front will have moved a distance x away from the rupture. The mass flow rate due to the pressure drop over distance x can be calculated using the following equation:

Equation 2 [60]

$$m_{pipe} = \sqrt{(P_1^2 - P_2^2)\frac{D_p}{4fx}\frac{A_p^2}{RT_0}}$$

Where D_p = pipe diameter (m)

f = Fanning friction factor (a factor of 0.005 can be used, i.e. fully turbulent flow in a steel pipe)

x = distance between pressure front and pipe rupture

A_p = pipe cross-sectional area (m^2)

P_1 = pressure at depressurisation front, initially equal to P_0 (N/m^2)

P_2 = pressure at ruptured end (N/m^2)

m_{pipe} = mass flowrate along pipe (kg/s)

R = gas constant (J/kmolK)

T_0 = initial gas temperature (K)

The mass flowrate along the pipe must equate to the mass flowrate out of the ruptured end of the pipe, enabling the values of P_2 and m_{pipe} to be found.

The distance x is calculated by equating the reduction in gas inventory over time t to the mass that has flowed out of the ruptured pipe end. This is done by calculating the mean density for the gas in the pipe between the pressure front and the exit orifice using a pressure profile based on equation 2. If the pressure front reaches the opposite end of the pipe, then x remains constant while the value of P_1 decays from its initial value of P_0.

As the pipe depressurises there is a point where the flow from the rupture changes from choked to subsonic conditions. The transition to subsonic flow occurs when the flowing condition is no longer satisfied.

Equation 3

$$\frac{P_2}{P_3} > \left(\frac{\gamma + 1}{2}\right)^{\frac{\gamma}{\gamma - 1}}$$

Where P_3 = external pressure (N/m^2)

For example, if the pipe contained methane (γ=1.3) then subsonic flow would occur if the pressure dropped to less than 1.8 times the atmospheric pressure.

The exit mass flow rate is then calculated using:

Equation 4

$$m_0 = C_d A_0 \sqrt{2\, P_2 \rho_2 \frac{\gamma}{\gamma - 1}\left(W^{\frac{2}{\gamma}} - W^{\frac{\gamma+1}{\gamma}}\right)}$$

Where $W = P_3 / P_2$

It should be noted that the initial pipe pressure may be low enough to cause the initial flow to be subsonic and the above equation will thus be used from the start of the depressurisation.

In the calculations, it has been assumed that isothermal conditions exist within the pipe (i.e. the pipe absorbs enough heat from the atmosphere, ground or sea to maintain a constant temperature). In the early stages of the rupture, the flow is more likely to be adiabatic. However, this situation will only last for a matter of seconds and once the flowrate has reduced the assumption of isothermal flow is justified.

For two-phase risers and flowlines, the initial two-phase discharge rate is calculated using the Fauske two phase outflow equation below:

Equation 5

$$m_0 = C_d A_0 \sqrt{2\, \rho_m\, (P_2 - P_3)}$$

Where ρ_m = density of two-phase mixture at initial pipe conditions (kg/m^3)

Other variables have the same designations as detailed in section 2, however with regards to the discharge co-efficient, the issue is complicated in that there is a range of compositions which are considered to be two-phase in nature.

C_d = discharge co-efficient. 1 for full bore ruptures [58], 0.85 sharp edged gaseous (liquid mass fraction < 80%) ruptures less than full bore, 0.6 for sharp edged liquid (liquid mass fraction > 80%) ruptures less than full bore [59].

Due to the uncertainties surrounding two phase gas releases, the approach taken is to utilise the Fauske two phase outflow equation in order to determine initial conditions, then use the gas phase of the release as the starting point for determining the outflow decay rate over time, suitably modified by the mass factor detailed in below.

In order to calculate the decay rate of the release however, an additional step is included, this being the calculation of an equivalent pipe length. The PIFL calculation uses the pipeline length in order to determine the decay rate of a gas release, so in order to model a 2-phase release, an equivalent length of pipe is calculated in order for PIFL to operate in a reasonable fashion.

It is necessary to calculate the total amount of free gas combined with the dissolved gas in the liquids and convert this to an equivalent volume at the same initial operating conditions. It is advised to use HYSIS to calculate the flash fraction of gas that would be released from the liquid.

The equivalent pipeline length is calculated as follows

Equation 6

$$L_{eq} = \frac{m_g}{MW_g} RTP_2/A_p$$

Where L_{eq} = equivalent pipeline length (m).

m_g = mass of gas in pipe (kg) (free gas **plus** dissolved gas)

MW_g = molecular weight of gas in pipeline

R = ideal gas constant J/kmolK

T = Temperature of release (K)

For two phase releases, the equivalent pipeline length replaces the pipeline length in all subsequent release calculations.

B.5. Fire Results

The fire durations for the hydrocarbon inventories modelled in the CSA are shown next. These are shown for the following combination of Isolation and Blowdown function:

- Iso BD Isolation and Blowdown both function correctly
- Iso No-BD Isolation functions correctly but Blowdown fails to operate
- No-Iso BD Isolation fails to operate but Blowdown functions correctly
- No-Iso No- BD Neither Isolation nor blowdown operate correctly.

Failure Case Description	Event ID	Release Durations											
		Isolated, Blow Down			Isolated, no Blowdown			No Isolation, Blow down			No Isolation, no Blowdown		
		small	medium	large	small	medium	large	small	medium	large	small	medium	large
BdN Production Flowline 1 and 2 (ESV to XSV) - Two Phase Release at Turret Lower Deck	P01-M-TRTL	>120	>120	75	>120	>120	75	>120	>120	>120	>120	>120	>120
MP Inlet and Test Manifolds - Two Phase Release at Piperack	P01-M-PRK	>120	>120	75	>120	>120	75	>120	>120	>120	>120	>120	>120
MP Inlet and Test Manifolds - Two Phase Release at M10 Process Deck Level 1	P01-M-M10L1	>120	>120	75	>120	>120	75	>120	>120	>120	>120	>120	>120
MP Inlet and Test Manifolds - Two Phase Release at Turret Upper Deck	P01-M-TRTU	>120	>120	75	>120	>120	75	>120	>120	>120	>120	>120	>120
HP Inlet and Test Manifolds - Two Phase Release at Turret Upper Deck	P02-M-TRTU	>120	>120	83	>120	>120	83	>120	>120	>120	>120	>120	>120
HP Inlet and Test Manifolds - Two Phase Release at Piperack	P02-M-PRK	>120	>120	83	>120	>120	83	>120	>120	>120	>120	>120	>120
HP Inlet and Test Manifolds - Two Phase Release at M10 Process Deck Level 1	P02-M-M10L1	>120	>120	83	>120	>120	83	>120	>120	>120	>120	>120	>120
HP Spare, Cambriol and Circulation Production Flowline (ESV to XSV) - Two Phase Release at Turret Lower Deck	P02-M-TRTL	>120	>120	83	>120	>120	83	>120	>120	>120	>120	>120	>120
Test Separator (20-VA-1004) - Two Phase Release at M10 Process Deck Level 1	P03-M-M10L1	18	33	34	>120	>120	>120	77	>120	>120	>120	>120	>120
Test Separator (20-VA-1004) - Gas Release at M10 Process Deck Level 1	P03-G-M10L1	16	27	22	>120	>120	49	66	118	96	>120	>120	>120
Test Separator (20-VA-1004) - Liquid Release at M10 Process Deck Level 1	P03-L-M10L1	61	49	5	61	15	5	61	44	9	61	30	9
Inlet Separator (20-VA-1001) - Two Phase Release at M10 Process Deck Level 1	P04-M-M10L1	18	33	35	>120	>120	>120	68	>120	>120	>120	>120	>120
Inlet Separator (20-VA-1001) - Gas Release at M10 Process Deck Level 1	P04-G-M10L1	16	28	24	>120	>120	55	60	109	92	>120	>120	>120
Inlet Separator (20-VA-1001) - Gas Release at Piperack	P04-G-PRK	16	28	24	>120	>120	55	60	109	92	>120	>120	>120
Inlet Separator (20-VA-1001) - Liquid Release at M10 Process Deck Level 1	P04-L-M10L1	61	21	4	61	11	4	61	61	14	61	47	13
LP Separator (20-VA-1002) - Two Phase Release at Piperack	P05-M-PRK	41	>120	>120	>120	>120	>120	44	>120	>120	>120	>120	>120
LP Separator (20-VA-1002) - Two Phase Release at M11 Process Deck Level 2	P05-M-M11L2	41	>120	>120	>120	>120	>120	44	>120	>120	>120	>120	>120
LP Separator (20-VA-1002) - Gas Release at M11 Process Deck Level 2	P05-G-M11L2	14	71	65	>120	>120	>120	14	72	68	>120	>120	>120
LP Separator (20-VA-1002) - Liquid Release at M11 Process Deck Level 2	P05-L-M11L2	61	61	23	61	61	19	61	61	25	61	61	20
1st Stage LP Compressor Scrubber Pumps (23-PA-6001A/B) - Two Phase Release at M60 Process Deck Level 1	P05-M-M60L1	40	117	>120	>120	>120	>120	42	>120	>120	>120	>120	>120
Electrostatic Coalescer (20-VJ-1003) & Oil Booster Pump (20-PA-1001A/B) & Crude Oil Coolers (20-HB-1002A/B) - Liquid Release at M11 Process Deck Level 1	P06-L-M11L1	>120	>120	>120	>120	>120	>120	>120	>120	>120	>120	>120	>120
Crude Oil Loading Header - Liquid Release at M11 Process Deck Level 1	P07-L-M11L1	>120	>120	29	>120	>120	29	>120	>120	>120	>120	>120	>120
Crude Oil Loading Header - Liquid Release at Piperack	P07-L-PRK	>120	>120	29	>120	>120	29	>120	>120	>120	>120	>120	>120
Crude Oil Loading Header - Liquid Release on Hull	P07-L-HULL	>120	82	19	>120	82	19	>120	>120	>120	>120	>120	>120
Cargo Tank - Liquid Release on Hull	P08-L-HULL	>120	>120	>120	>120	>120	>120	>120	>120	>120	>120	>120	>120
Off-Spec Fluid Tank - Liquid Release on Hull	P09-L-HULL	>120	>120	>120	>120	>120	>120	>120	>120	>120	>120	>120	>120
Off-Spec Fluid Tank - Liquid Release at Piperack	P09-L-PRK	>120	5	2	>120	5	2	>120	5	2	>120	5	2
Crude Oil Transfer Header - Liquid Release on Hull	P10-L-HULL	>120	60	14	>120	60	14	>120	60	14	>120	60	14
Crude Oil Offloading Header - Liquid Release at Piperack	P10-L-PRK	>120	60	14	>120	60	14	>120	60	14	>120	60	14
Crude Oil Offloading Header - Liquid Release at M10 Process Deck Level 1	P10-L-M10L1	>120	60	14	>120	60	14	>120	60	14	>120	60	14
Crude Oil Offloading Header - Liquid Release on Hull	P11-L-HULL	>120	81	19	>120	81	19	>120	81	19	>120	81	19
Crude Oil Offloading Reel - Liquid Release on Hull	P12-L-HULL	>120	21	5	>120	21	5	>120	103	24	>120	103	24
Crude Oil Offloading Reel - Liquid Release at Offloading Reel	P12-L-OFF	>120	21	5	>120	21	5	>120	103	24	>120	103	24
COT Gas Blanketing - Gas Release on Hull	P13-G-HULL	-	8	5	-	8	5	-	9	6	-	9	6
COT Gas Blanketing - Gas Release at Piperack	P13-G-PRK	-	8	5	-	8	5	-	9	6	-	9	6
COT Gas Blanketing - Gas Release at M30 Process Deck Level 1	P13-G-M30L1	-	8	5	-	8	5	-	9	6	-	9	6

Failure Case Description	Event ID	Release Durations											
		Isolated, Blow Down			Isolated, no Blowdown			No Isolation, Blow down			No Isolation, no Blowdown		
		small	medium	large	small	medium	large	small	medium	large	small	medium	large
1st Stage LP Gas Compression Suction Cooler (23-HB-6001) - Two Phase Release at M60 Process Deck Level 2	P14-M-M60L2	5	30	15	73	49	18	1	14	18	>120	>120	>120
1st Stage LP Gas Compression - Gas Release at M60 Process Deck Level 1	P14-G-M60L1	38	24	9	>120	29	10	39	29	12	>120	39	13
1st Stage LP Gas Suction Scrubber (23-VG-6001) - Liquid Release at M60 Process Deck Level 1	P14-L-M60L1	61	4	1	61	4	1	61	61	12	61	42	11
1st Stage Recompression to Flare KO Drum (43-VD-3001) - Gas Release at Piperack	P14-G-PRK	30	9	4	89	10	4	15	12	6	>120	17	6
2nd Stage LP Gas Compression Suction Cooler (23-HB-6002) - Two Phase Release at M60 Process Deck Level 2	P15-M-M60L2	32	14	6	>120	16	6	48	40	17	>120	56	18
2nd Stage LP Gas Compression - Gas Release at M60 Process Deck Level 1	P15-G-M60L1	31	8	3	81	9	3	47	31	13	>120	41	14
2nd Stage LP Gas Compressor Suction Scrubber (23-VG-6002) - Liquid Release at M60 Process Deck Level 1	P15-L-M60L1	48	2	1	30	2	1	61	10	3	61	9	3
MP Gas Compression - Gas Release at Piperack	P16-G-PRK	9	8	10	>120	15	13	25	39	33	>120	>120	87
MP Gas Compression Suction Cooler (23-HA-6003) - Two Phase Release at M60 Process Deck Level 2	P16-M-M60L2	17	21	12	>120	48	15	3	7	8	>120	>120	94
MP Gas Compression - Gas Release at M60 Process Deck Level 1	P16-G-M60L1	28	12	12	>120	15	13	28	43	36	>120	>120	87
MP Gas Compression Suction Scrubber (23-VG-6003) - Liquid Release at M60 Process Deck Level 1	P16-L-M60L1	61	2	1	32	2	1	61	53	4	61	15	4
Gas Dehydration Inlet Cooler (24-HG-6601) - Two Phase Release at M60 Process Deck Level 2	P17-M-M60L2	15	17	14	>120	39	19	8	14	15	>120	>120	103
Gas Dehydration System - Two Phase Release at Piperack	P17-M-PRK	15	17	14	>120	39	19	8	14	15	>120	>120	103
Gas Dehydration Inlet Scrubber (24-VG-6601) - Two Phase Release at M61 Process Deck Level 1	P17-M-M61L1	15	16	13	>120	39	18	8	14	15	>120	>120	103
Gas Dehydration Inlet Scrubber (24-VG-6001) & TEG Contactor (24-VB-6602) & 1st Stage HP Gas Compressor Suction Scrubber (23-VG-6004) - Gas Release at M61 Process Deck Level 1	P17-G-M61L1	14	13	9	>120	26	12	16	18	11	>120	41	17
Gas Dehydration & 1st Stage HP Gas Compression - Gas Release at Piperack	P17-G-PRK	14	13	9	>120	26	12	16	18	11	>120	41	17
Gas Dehydration Inlet Scrubber (24-VG-6601) - Liquid Release at M61 Process Deck Level 1	P17-L-M61L1	61	1	1	13	1	1	61	4	1	61	3	1
1st Stage HP Gas Compressor Discharge Cooler (23-HG-6004) at M61 Process Deck Level 2	P17-G-M61L2	13	7	7	>120	9	7	11	17	9	>120	25	12
2nd Stage HP Gas Compressor & Suction Scrubber (23-VG-6005) - Gas Release at M61 Process Deck Level 1	P18-G-M61L1	23	14	5	>120	19	5	25	23	12	>120	56	16
1st & 2nd Stage HP Gas Compressor Discharge Coolers (23-HG-6004 & 23-HG-6005) - Gas Release at M61 Process Deck Level 2	P18-G-M61L2	23	14	5	>120	19	5	25	23	12	>120	56	16
HP Gas Compression / Injection Pipework - Gas Release at M61 Process Deck Level 2	P19-G-M61L2	15	5	2	39	5	2	19	9	3	>120	12	3
HP Gas Compression / Injection Pipework - Gas Release at Piperack	P19-G-PRK	15	5	2	39	5	2	19	9	3	>120	12	3
HP Gas Compression / Injection Pipework and Flowlines - Gas Release at Turret Upper Deck	P19-G-TRTU	15	5	2	39	5	2	19	9	3	>120	12	3
Gas Injection/Lift 1 BDN & Gas Lift 2 Cambriol/Circulation Flowline (XSV to ESV) - Gas Release at Turret Lower Deck	P19-G-TRTL	15	5	2	39	5	2	19	9	3	>120	12	3

Failure Case Description	Event ID	Release Durations											
		Isolated, Blow Down			Isolated, no Blowdown			No Isolation, Blow down			No Isolation, no Blowdown		
		small	medium	large	small	medium	large	small	medium	large	small	medium	large
Fuel Gas System - Gas Release	P20-G-M61L1	15	12	5	>120	20	6	15	12	5	>120	22	7
Fuel Gas System - Liquid Release	P20-L-M61L1	8	1	1	8	1	1	46	1	1	46	1	1
Fuel Gas Superheaters, Metering Skid & Filter Package - Gas Release	P20-G-M61L2	15	12	5	>120	20	6	15	12	6	>120	22	7
Fuel Gas to Turbines - Gas Release	P21-G-M61L2	10	4	1	24	4	1	14	11	5	>120	20	6
Fuel Gas to Turbines - Gas Release	P21-G-PRK	10	4	1	24	4	1	14	11	5	>120	20	6
Fuel Gas to Turbines - Gas Release	P21-G-M90L1	10	4	1	24	4	1	14	11	5	>120	20	6
LP Fuel Gas to Consumers - Gas Release	P22-G-M61L2	3	1	0	3	1	0	6	8	4	116	14	5
LP Fuel Gas to Consumers - Gas Release	P22-G-PRK	3	1	0	3	1	0	1	4	4	>120	>120	63
LP Fuel Gas to Consumers - Gas Release	P22-G-M11L2	3	1	0	3	1	0	1	4	4	>120	>120	63
Reject Vessel (44-VD-1003) - Two Phase Release at M11 Process Deck Level 3	P23-M-M11L3	-	>120	>120	-	>120	>120	-	>120	>120	-	>120	>120
Reject Vessel (44-VD-1003) - Gas Release at M11 Process Deck Level 3	P23-G-M11L3	4	3	1	4	3	1	1	10	12	>120	>120	77
Reject Vessel (44-VD-1003) - Liquid Release at M11 Process Deck Level 3	P23-L-M11L3	>120	7	1	>120	7	1	>120	7	1	>120	7	1
VOC Compression - Gas Release at Piperack	P24-G-PRK	1	1	3	1	1	3	6	6	5	16	7	5
VOC Compression - Gas Release at M30 Process Deck Level 1	P24-G-M30L1	1	1	3	1	1	3	6	6	5	16	7	5
Pig receiver - Two Phase Release at Turret Lower Deck	P25-M-TRTL	>120	18	6	>120	18	6	>120	>120	102	>120	>120	102
Pig launcher - Two Phase Release at Turret Lower Deck	P26-M-TRTL	>120	18	6	>120	18	6	>120	>120	102	>120	>120	102
Helifuel Skid - Liquid Release	H01-L-HELI	>120	14	2									
1st Stage HP Gas Compressor Discharge Cooler (23-HG-6004) at M61 Process Deck Level 2	P17-G-M61L2	13	7	7	>120	9	7	11	17	9	>120	25	12
MP Separator - Two Phase Release at Piperack	P35-M-PRK	27	7	3	64	7	3	10	11	6	>120	18	6
MP Separator - Two Phase Release at M11 Process Deck Level 2	P35-M-M11L2	27	7	3	64	7	3	10	11	6	>120	18	6
MP Separator - Gas Release at M11 Process Deck Level 2	P35-G-M11L2	25	9	4	78	10	4	23	19	8	>120	25	9
MP Separator - Liquid Release at M11 Process Deck Level 2	P35-L-M11L2	61	51	9	61	31	8	61	61	12	61	40	10

Appendix References

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[60] Perry R.H. and Green D., Perry's Chemical Engineers Handbook.

Christopher Hammond
Kent Energies UK Ltd
9 George Square
Glasgow
G2 1DY

Email: Christopher.Hammond@kentplc.com