NTNU – Trondheim
Norwegian University of
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Offshore Field Development in Cold Climate

with Emphasis on Terminals

Isabel Jimenez-Puente

Coastal and Marine Civil Engineering
Submission date: June 2013
Supervisor: Ove Tobias Gudmestad, BAT

Norwegian University of Science and Technology
Department of Civil and Transport Engineering

ERASMUS MUNDUS MSC PROGRAMME

COASTAL AND MARINE ENGINEERING AND MANAGEMENT
COMEM

OFFSHORE FIELD DEVELOPMENT IN COLD CLIMATE

with Emphasis on Terminals

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17th June 2013

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Faculty of Civil Engineering and geosciences
P.O. Box 5048
2600 GA Delft
The Netherlands

NORWEGIAN UNIVERSITY OF SCIENCE AND TECHNOLOGY
DEPARTMENT OF CIVIL AND TRANSPORT ENGINEERING

Report Title: Offshore Field Development in Cold Climate - with emphasis on terminals -	**Date:** 17th June 2013			
	Master Thesis	x	Project Work	
Student: Isabel Jiménez Puente				
Professor in charge/supervisor: Professor Ove Tobias Gudmestad				

Abstract:

It is estimated that 25% of the remaining oil and gas reserves worldwide are held in Arctic regions. The combined effects of a global resource depletion, climate change and technological progress, mean that this natural resource area is now increasingly interesting and commercially attractive. However, numerous challenges are present when it comes to hydrocarbon production in cold climate, not only related to suitable technology, but also to social and environmental issues. Any hydrocarbon development in the Arctic represents, thus, a balance between opportunity and risk.

This thesis analyzes a broad range of aspects influencing **offshore hydrocarbon field development scenarios in cold climate, emphasizing on terminals as a major building block necessary in the development of a petroleum field.**

Feasible, safe and cost effective terminal concepts for cold climate areas, face challenges that need specific assessment of technical solutions and operational aspects. Many of these challenges can be managed, though at additional cost, through the application of customised solutions.

After having presented and gained the necessary knowledge and insight in the main issues influencing a cold climate terminal, an assessment of different development schemes is carried out, using for this purpose three case studies located in the Barents Sea: Johan Castberg, Snøhvit and Goliat fields.
In this context, a quantitative assessment of breakwater stability in cold climate environments has been an important part of the discussions.

Finally, given the complex and often unique risk challenges present in cold climate regions, risk assessment arise as an important part of the decision making process, and thus, has been used to understand the sensitivity of different development schemes.

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The Master thesis, therefore, provides an insight in the following aspects:

- Aspects influencing offshore hydrocarbon field development scenarios in cold climate.
- Technical issues influencing a cold climate terminal, with a thorough quantitative discussion of breakwater stability and design in cold climate.
- Operational issues influencing a cold climate terminal.
- Assessment of the sensitivity of different schemes through case studies analysis.
- Risk assessment for identification and evaluation of the main risks involved, applied to the case studies.

Keywords:

1. Cold climate
2. Oil and gas
3. Terminal
4. Breakwater
5. Risk assessment

Faculty of Engineering Science and Technology
Department of Civil and Transport Engineering

MASTER THESIS

(TBA4920 marine Civil Engineering, master thesis)

Spring 2013
for
Isabel Jiménez Puente

OFFSHORE FIELD DEVELOPMENT IN COLD CLIMATE
- with emphasis on terminals -

BACKGROUND

It is estimated that about 25% of the remaining oil and gas reserves worldwide are held in Arctic regions. The combined effects of a global resource depletion, climate change and technological progress, mean that this natural resource area is now increasingly interesting and commercially attractive. However, any oil and gas development in the Arctic represents a balance between opportunity and risk. The Arctic offers numerous challenges when it comes to oil and gas production because of the remoteness, darkness, cold climate, impairments from ice offshore and permafrost on land. Challenges are not only related to suitable technology, but also to social and environmental issues.

TASK DESCRIPTION

This thesis will analyze **Offshore Field Developments in Cold Climate, with focus on terminals, as a major building block in the development of a petroleum field.**

Onshore terminals as part of the oil and gas production process are dedicated harbor facilities with different functions associated such as: export, import, transshipment, storage or processing. The need for processing is essential to obtain the products that can be sold and transported. Other facilities, for instance concrete platforms, production ships or offshore storage tanks, can provide terminal functions. The parameters for an onshore terminal choice will be safety, reliability and costs, taking into account aspects such as accessibility due to climate aspects, maintenance, future extensions, structural design etc.

Specific issues are relevant to establish an onshore terminal project in an Arctic region. Operational and structural aspects of arctic terminals must be studied in detail and will be discussed through case scenarios in this context.

- <u>Technical aspects of terminals</u>
  - Pipeline design specific issues
  - Breakwater design specific issues
  - Harbour oscillations
- <u>Operational aspects of terminals</u>
  - Terminal arrangement
  - Ice management
  - Spilled oil
  - Tanker operations

Many of these challenges can be managed, though at additional cost, through the application of existing technologies, through specific design and build specifications, or with adapted processes and additional infrastructure. A justification of investment and economical assessment is of great importance to decide over the different options.

Finally, the given complex and often unique risk challenges of the Arctic, arise the specific need for improved knowledge, risk assessment and risk management in the Arctic context. Risk analysis and selection of safety levels are an important part of the decision making process.

The Master thesis, therefore, will provide an insight in the following aspects:

- Aspects influencing offshore hydrocarbon field development scenarios in cold climate.
- Technical issues influencing a cold climate terminal.
- Operational issues influencing a cold climate terminal.
- Assessment of the sensitivity of different schemes through case study analysis.
- Risk analysis for identification and evaluation of the main risks involved

Initial references:

- O. T. Gudmestad, A. Zolotukhin, and E. Jarlsby. *Petroleum Resources with Emphasis on Offshore Fields*. WIT Press, Southampton, 2010.

- O. T. Gudmestad, S. Løset, A. I. Alhimenko, K.N.Shkhinek, A. Tørum, and A. Jensen. *Engineering Aspects Related to Arctic Offshore Developments*. LAN, St. Petersburg, 2007.

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The text for the master thesis is meant as a framework for the work of the candidate. Adjustments might be done as the work progresses. Tentative changes must be done in cooperation and agreement with the professor in charge at the Department.

The reporting of the work should be academic anchored and well described with respect to the theoretical and scientific basis so that the work could be implemented in the field of international research.

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The report shall include:

- Standard report front page (from DAIM, http://daim.idi.ntnu.no/)
- Title page with abstract and keywords.(template on: http://www.ntnu.no/bat/skjemabank)
- Preface
- Summary and acknowledgement. The summary shall include the objectives of the work, explain how the work has been conducted, present the main results achieved and give the main conclusions of the work.
- Table of content including list of figures, tables, enclosures and appendices.
- If useful and applicable a list explaining important terms and abbreviations should be included.
- The main text.
- Clear and complete references to material used, both in text and figures/tables. This also applies for personal and/or oral communication and information.
- Text of the Thesis (these pages) signed by professor in charge as Attachment 1..
- The report musts have a complete page numbering.

Advice and guidelines for writing of the report is given in: “Writing Reports” by Øivind Arntsen. Additional information on report writing is found in “Råd og retningslinjer for rapportskriving ved prosjekt og masteroppgave ved Institutt for bygg, anlegg og transport” (In Norwegian). Both are posted on http://www.ntnu.no/bat/skjemabank

Submission procedure

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Printing of the thesis is ordered through DAIM directly to Skipnes Printing delivering the printed paper to the department office 2-4 days later. The department will pay for 3 copies, of which the institute retains two copies. Additional copies must be paid for by the candidate.

On submission of the thesis the candidate shall submit a CD with the paper in digital form in pdf and Word version, the underlying material (such as data collection) in digital form. Students must submit the submission form (from DAIM) where both the Ark-Bibl in SBI and Public Services (Building Safety) of SB II has signed the form. The submission form including the appropriate signatures must be signed by the department office before the form is delivered Faculty Office.

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Start and submission deadlines
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The thesis report as described above shall be submitted digitally in DAIM at the latest: 24th June 2013 at 3pm.

Professor in charge: Ove Tobias Gudmestad

Trondheim, 28.01.2013

Ove T Gudmestad

Professor in charge

Preface

It is estimated that 25% of the remaining oil and gas reserves worldwide are held in Arctic regions. The combined effects of a global resource depletion, climate change and technological progress, mean that this natural resource area is now increasingly interesting and commercially attractive. However, numerous challenges are present when it comes to hydrocarbon production in cold climate, not only related to suitable technology, but also to social and environmental issues. Any hydrocarbon development in the Arctic represents, thus, a balance between opportunity and risk.

The present thesis focuses on aspects related to offshore hydrocarbon field development in cold climate. Emphasis is made on terminals as a major building block necessary in the development of a petroleum field. Feasible, safe and cost effective terminal concepts for cold climate areas, face challenges that need specific assesment of technical solutions and operational aspects. Many of these challenges can be managed, though at additional cost, through the application of customised solutions. Finally, given the complex and often unique risk challenges present in cold climate regions, risk assessment arise as an important part of the decision making process.

This thesis is my final work within the Erasmus Mundus Master Course in Coastal and Marine Engineering and Management (CoMEM), after two years of studies at the Norwegian University of Science and Technology (NTNU, Norway), Delft University of Technology (TU Delft, The Netherlands), and the University of Southampton (United Kingdom).

The thesis work has been carried out at NTNU during the spring of 2013 under the supervision of professor Ove Tobias Gudmestad.

Trondheim, 17th June 2013

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I would like to express sincere thanks to professor Ove Tobias Gudmestad for his contributions as my supervisor. I appreciate his extensive knowledge and teaching methodology, which struck me from the first lecture at NTNU, where he catched our attention by explaining the need to stabilize oil for ship transport by using a soda drink.

Thanks to professor Alf Tørum for his useful insights and willingness to help.

Moreover, I would like to acknowledge the contribution made by Statoil providing information as support to this thesis work.

Finally, I would like to appreciate the three polytechnic universities (NTNU, TU Delft and Southampton University) in which I have had the opportunity to study during these two years.

I.J.P

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Acronyms

ALARP As Low As Reasonably Practicable.

ALS accidental/damage condition.

API American Petroleum Institute.

atm standard atmosphere, unit of pressure.

bar bar, unit of pressure.

bbl oil barrel.

cm centimeters, unit of longitude.

DR Design Review.

dwt dead weigth tonnage.

EER Escape, Evacuation and Rescue.

FLIR Forward Infrared.

FMECA Failure Modes, Effects and Critically Analysis.

FPSDO Floating Production, Storage, Drilling and Offloading.

FPSO Floating Production, Storage and Offloading.

FSU Floating Storage Unit.

GOR Gas to Oil Ratio.

GPR Ground Penetreting Radar.

ha hectares, unit of area.

HAZID Hazard Identification Analysis.

HAZOP Hazard and Operability Analysis.

kdwt kilo dead weigth tonnage.

km kilometers, unit of longitude.

kN kiloNewton, unit of force.

LNG Liquified Natural Gas.

LPG Liquified Petroleum Gas.

m meters, unit of longitude.

MEG Mono Ethylen Glycol.

mm milimeters, unit of longitude.

MN MegaNewton, unit of force.

MW MegaWatio, unit of power.

N Newton, unit of force.

NGL Natural Gas Liquid.

NPD Norwegian Petroleum Directorate.

NTNU Norwegian University of Science and Technology.

OCDI Overseas Coastal Area Development Institute of Japan.

OCIFM Oil Companies International Marine Forum.

ppm parts per million.

s seconds, unit of time.

SAL Moored Single Anchor Loading.

SBM Offshore Single Buoy Mooring.

SIB Shoulder Ice Barrier.

SLAR Side Looking Airbone Radar.

SPAR Floating Production, Storage and Offloading.

SPM Single Point Mooring.

SQRA Semi Quantitative Risk Analysis.

STL Submerged Turret Loading.

t tonnes, unit of mass.

TEG Tetraethylene glycol.

TLP Tension Leg Platform.

UK United Kingdom.

ULCC Ultra Large Crude Carrier.

ULS Ultimate Limit State.

US United States.

USGS United States Geological Survey.

VLCC Very Large Crude Carrier.

Symbols

%	percentage.
$	dollard.
°	degree.
℃	degree Celsius.
D_{50}	median armour stone diameter.
H_0	stability number.
H_0T_0	period stability number.
H_D	design wave height.
H_S	significant wave height.
$H_{S,100}$	significant wave height for 100 year return period.
T_p	peak wave period.
T_z	mean wave period.
W_{50}	median armour stone mass.
H_2S	hydrogen sulfide.
CO_2	carbon dioxide.
CH_4	methane.
C_2H_6	ethane.
C_3H_8	propane.
C_4H_{10}	butane.
α	front slope angle of a breakwater.
β	wave attack angle.
γ	specific gravity of oil with respect to water.

ρ_s	stone density.
ρ_w	water density.
ξ_z	Iribarren number.

Part I

Introduction

Chapter 1

Background

1.1 Oil and Gas Opportunities and Risks in the Arctic

The Arctic has for over two centuries been known to hold oil and gas reserves. In 1923, a petroleum storage was established in northern Alaska for the United States (US) Navy [1]. However, commercial activities started more recently, in the late 1960s in the US and Canadian Arctic and in the early 1980s in both the Norwegian and Russian Arctic. According to the United States Geological Survey (USGS) estimations [1], approximately one quarter of the global undiscovered oil and gas reserves may remain to be found in the Arctic. More specifically, the USGS estimations are that the Arctic contains: *90 billion oil barrel (bbl), 1,669 trillion cubic feet of natural gas, and 44 billion barrels of natural gas liquids* [2]. Figure 1.1 shows the potential areas of hydrocarbon resources in the Arctic region.

In the next 25 years, the global consumption of natural gas is expected to increase by 50%, while the oil consumption is expected to increase at a lower rate, with a predicted increase of about 20% [3]. The combined effects of a global resource depletion and growing global energy demand, make sustainable oil and gas production in the Arctic an important contributor for securing energy supply. In addition, the key factors that sharpen the interest in this natural resource area are as given below; these factors being interrelated and reinforcing themselves.

- *Feasibility*: technological progress makes projects technically and economically viable.
- *Commercial attractiveness*: high oil prices, for instance reaching 147US$ per barrel in the summer of 2008, coupled with fears about not being able to meet future demands from rising powers such as India, China or Brazil, were making potential Arctic projects attractive to investors [3].

[1] The USGS estimates do not include non-conventional hydrocarbons, such as heavy oil and gas hydrates.

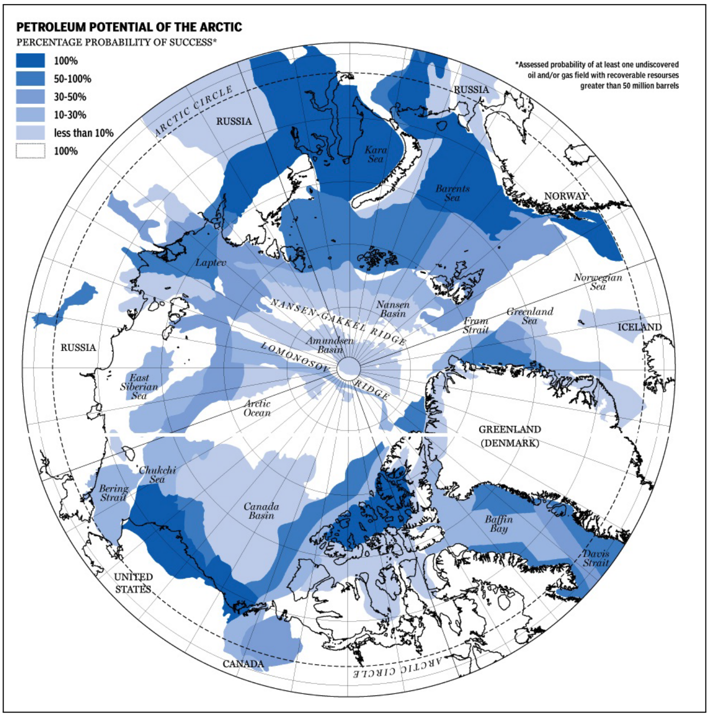

Figure 1.1: Oil and gas potential in the Arctic. *Source: USGS*

– *Accessibility*: improving access to the Arctic region due to climate change and substantial ice melting, consequently a trend towards more ice-free areas of the Arctic Ocean and longer ice-free periods.

Although at the present moment there is considerable oil and gas activities in the Arctic (Canada, US, Norway and Russia), and the resources in these areas already have been under consideration for over 30 years, the challenging environment of the Arctic has put a threshold on these developments. Some of the numerous challenges when it comes to oil and gas production, are due to the extreme climate conditions, for instance: darkness, low temperatures and ice, polar low pressures, remoteness and impairments from ice offshore and permafrost on land. Challenges are not only related to lack of qualified technology, but also to social and environmental issues, due to the resilience of the Arctic´s ecosystems being weak in terms of response to risk events, and high political and public sensitivity to a disaster.

The Arctic is therefore a complex risk environment and any hydrocarbon development in this area, represents a balance between opportunity and risk.

1.2 The Arctic Region

The Arctic region extends across northern North America, northern Europe and northern Asia, including eight countries (Canada, Denmark (Greenland), Russia, US, Iceland, Norway, Sweden and Finland), and the oceans and seas in between: Barents, Beaufort, Chukchi, East Siberian, Greenland, Kara, Laptev, White Sea and Bays of Hudson and Baffin) [4], [5]. See Figure 1.2.

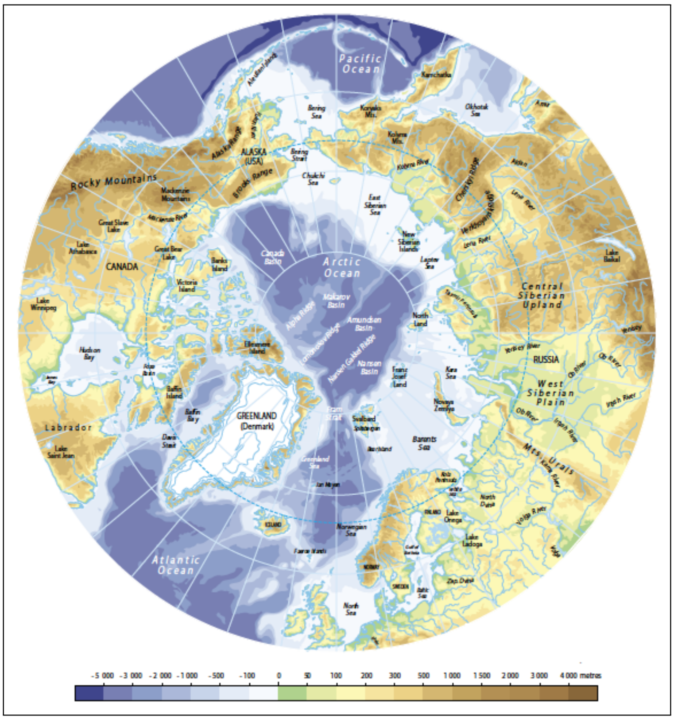

Figure 1.2: Topography and bathymetry of the Arctic. *Source: GRID-ARENDAL*

Several definitions of the Arctic as a region exist, and are all extensively used. The more simplistic definition, delimits the Arctic by the Arctic Circle ($66\,^{\circ}33'N$) (see Figure 1.3), which marks the southern limit where the sun is above (polar day) and below (polar night) the horizon for 24 hours at least once a year. However, the variations in temperature, distribution of water bodies, ice conditions or differences in permafrost occurrence can give rise to more complex definitions. For instance, based on temperature, the Arctic is defined as the area to the north of the 10 ℃ July isoterm (see Figure 1.3). This isotherm encloses the Arctic Ocean, Greenland, Svalbard, most of Iceland and the northern coasts of Russia, Canada and Alaska. West of Norway, the North Atlantic Current (Gulf Stream) deflects the isotherm

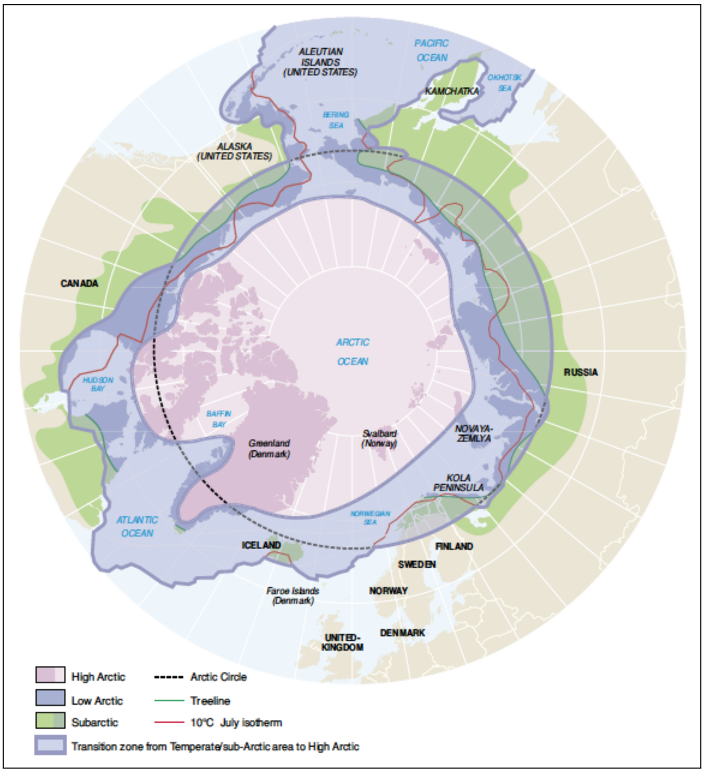

Figure 1.3: Boundaries of the Arctic for different definitions. *Source: GRID-ARENDAL*

northward including therefore only the northernmost parts of Scandinavia [6]. Ice conditions also vary within the region, and therefore, the following areas and corresponding characteristics can be distinguished:

– **Arctic areas with sea ice**
  - Freezing water
  - Drifting ice
  - Icebergs
– **Cold temperature areas**
  - Cold winters
  - Sea water freezes on vessels
  - Freezing rain

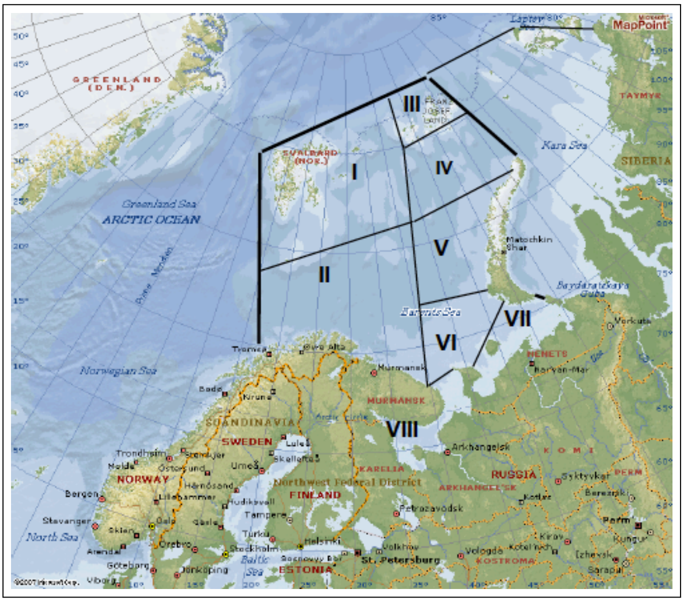

Figure 1.4: Barents Sea ice conditions. *Source: Barents 2020, DNV*

1.2.1 The Barents Sea

The Barents Sea is not uniform with respect to ice and meteocean conditions. In the Barents 2020 project [7], the Norwegian part of the Barents Sea is divided in 8 subareas (Figure 1.4). Conditions are somewhat uniform within each subarea. Subarea II is generally ice free. I, III, IV, VII and VIII usually have ice every winter. V and VI are in between. The subareas with uniform ice conditions are the following:

I Spitsbergen
II Norwegian
III Franz Josef Land
IV Kara
V Novozemelsky
VI Kola
VII Pechora
VIII White Sea

Chapter 2
Purpose and Extent of the Study

The interest for exploration of cold climate oil and gas resources has undergone a considerable increase over the last years due to some key factors sharpening the interest such as an increased demand, technological progress and accessibility. Cold climate regions, however, represent a complex risk environment for any hydrocarbon field development. The present thesis analyzes aspects that influence offshore hydrocarbon field development scenarios in cold climate, emphasizing on terminals as a major building block necessary in the development of a petroleum field.

Firstly, the need for processing and terminals needs to be identified, and thereafter, the main challenges influencing the development of a safe and cost effective terminal concept, need to be studied in detail. Some of the technical and operational issues that will need assessment are related to pipeline design, harbour layout, ice management, oil spills and tanker operations. Specifically, a thorough discussion of breakwaters in cold climate environments will be necessary, in which the different options for breakwater design need to be evaluated, with the inclussion of some quantitative discussions regarding this issue.

After having presented and gained the necessary knowledge and insight in the main issues influencing a cold climate terminal, an assessment of different development schemes will be carried out, using for this purpose three case studies located in the Barents Sea. Johan Castberg, Snøhvit and Goliat fields will be studied in detail, describing the field development and background of choice first, and focussing on the terminal concept afterwards for each development. In this context, a quantitative assessment of the breakwaters stability and design will be an important part of the discussions.

Finally, in order to understand the sensitivity of the different development schemes, and given the complex and often unique risk challenges present in cold climate regions, arises the need for risk assessment as an important part of the decision making process.

Summarizing, the Master thesis will provide an insight in the following aspects:

- Aspects influencing offshore hydrocarbon field development scenarios in cold climate.
- Technical issues influencing a cold climate terminal, with a thorough quantitative discussion of breakwater stability and design in cold climate.
- Operational issues influencing a cold climate terminal.
- Assessment of the sensitivity of different schemes through a case studies analysis.
- Risk assessment for identification and evaluation of the main risks involved, applied to the case studies.

Chapter 3
Structure of the Report

This thesis is divided into 13 chapters structured within four main parts.

– **Part I: INTRODUCTION**

  This introductory part intends to give a clear formulation of the task, providing the background for the topic (Chapter 1), the purpose and extent of the study (Chapter 2), and finally explaining how is the report structured in the present chapter.

  - Chapter 1: Background
  - Chapter 2: Purpose and Extent
  - Chapter 3: Structure of the report

– **Part II: OFFSHORE FIELD DEVELOPMENT IN COLD CLIMATE WITH EMPHASIS ON TERMINALS**

  The second part of the thesis starts discussing the main building blocks for offshore hydrocarbon field developments (Chapter 4). Emphasis is made on the terminals, and thus, Chapters 5 and 6 will give an insight into the needs for processing and terminals, including the main transport schemes. In addition, this second part of the thesis deals with the specific challenges regarding offshore field development in cold climate regions (Chapter 7), with special attention to oil spills in cold climate (Chapter 8). Finally, chapters 9 and 10 focus on specific technical and operational issues regarding cold climate terminals.

  - Chapter 4: Field Development Building Blocks
  - Chapter 5: Needs for Processing and Transport Schemes
  - Chapter 6: Needs for Oil and Gas Onshore Terminals

- Chapter 7: Arctic Specific Issues
- Chapter 8: Oil Spills in Cold Climate
- Chapter 9: Technical aspects for pipelines and harbours
- Chapter 10: Operational aspects of terminals

– **Part III: CASE STUDIES**

The third part of the thesis discusses three different development schemes in the Barents Sea: Johan Castberg, Snøhvit and Goliat. Chapter 11 presents the field developments, discusses the background for the chosen solution, and goes into the detail of the terminal for each case. Chapter 12 discusses and applies risk analysis tools to the three case studies in order to identify and evaluate the main risks involved.

- Chapter 11: Three Fields, Three Solutions
- Chapter 12: Risk Assessment

– **Part IV: CONCLUSIONS**

The final chapter of the thesis presents and outlook of the work carried out, and some concluding remarks.

- Chapter 13: Concluding Remarks

Part II

Offshore Field Development in Cold Climate with Emphasis on Terminals

Chapter 4

Offshore Field Development Building Blocks

The development of an offshore hydrocarbon field, is a complex project which includes many kinds of equipment and installations in order to cover all the required functions of oil and gas production.

A number of issues need to be addressed, such as:

– gathering the well stream
– where and how to treat produced fluids
– how to transport and store products once processed

For addressing these issues, most developments can be broken down into different building blocks. The main building blocks used in the development of a petroleum field, can be classified as follows:

- **Wells**
  - *Wellhead platform*
  - *Subsea equipment*: templates, manifolds and flowlines
- **Offshore production facilities**
  - *Production platform*: fixed or floating
  - *Risers*
- **Transportation systems**
  - *Pipelines*
  - *Tankers*
- **Onshore processing**
  - *Terminals*
  - *Refineries*

The offshore field development layout will vary depending on the well pattern and the export product specifications [8], and in most cases, will involve the combination of several building blocks. Some of the typical field layouts might include:

- wellhead, process and quarters adjacent platforms
- integrated production platform
- floating production system
- subsea production system: *connecting to a fixed platform, to a floating platform, to a ship unit or directly to an onshore facility.*

Several examples of different field layout scenarios can be given from the Norwegian Continental Shelf. Figure 4.1 shows an example of a field development layout in the Norwegian Sea. In that case, the Norne field has been developed through a production and storage ship tied to subsea tempates. The ship has a processing plant on deck and storage tanks for stabilised oil, and flexible risers carry the wellstream to the ship, which is able to rotate around a turret moored to the seabed to head up against the wave direction [9].

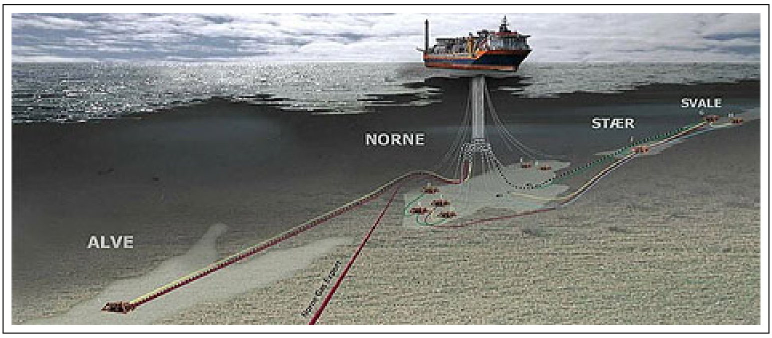

Figure 4.1: Norne field development. *Source: Statoil*

Although the different developments tend to be characterised by the production facility used, the design of the project usually starts taking into consideration the processing required to handle the reservoir wellstream [10]. The different processing requirements for a production facility, need to be studied in detail for an optimum design. Usually, due to the large costs of offshore processing, only minimum processing is carried out offshore, for instance removal of water, separation of oil and gas, and oil stabilization. The final processing is, in most cases, carried out at an onshore terminal [11].

In addition, the transportation system as a building block, can involve offshore loading of stable oil to tankers, oil transport by pipeline to shore and/or gas export pipelines.

Offshore topside and subsea facilities will be further discussed in this chapter, while the need for processing and onshore terminals in addition to transport schemes will be studied in detail on chapters 5 and 6.

4.1 Topside

Offshore platforms can be classified *a grosso modo* in two categories: fixed and floating installations. The selection of the suitable platform type (if any) is mainly based on the water depth and the number of wells.

4.1.1 Fixed platforms

Fixed platforms (Figure 4.2) can be further classified in:

- Steel jacket platform
- Gravity-based platform

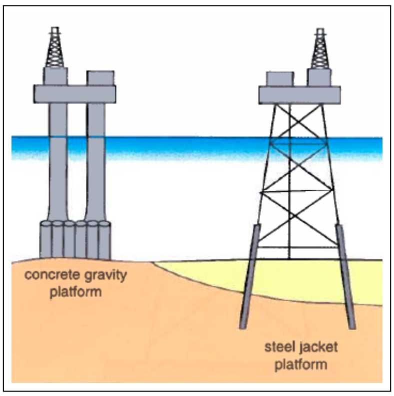

Figure 4.2: Fixed production platforms. *Source: F. Jahn et al., 2008*

The *steel piled jacket* type of platform is a well-established technology, probably the most common. It is used as a wellhead platform with no storage for limited water depths up to 150m, and in a broad range of sea conditions [10]. Built from welded steel pipes, the platform is constructed onshore and then floated out on a barge to the corresponding offshore location. In addition, offshore installation of topsides for processing equipment, drilling, living quarters etc., is required.

Concrete or steel *gravity-based* platforms are used for similar water depths as the steel piled jacket type. The main advantage in this case is that the need for piling in hard seabeds is eliminated since they rely on their own weight. The concrete type is the most common, and it offers the possibility of temporary oil storage on their hollow concrete legs [10]. The use of a barge is not necessary for floating the platform out, furthermore on-shore installation of topsides is possible.

The Oseberg Field in the North Sea (Figure 4.3), provides an example of a development which includes both types of fixed platforms with different functions. Three platforms (Oseberg A, B and D) are located in the south part of the field, connected by bridges, in addition to a fourth platform (Oseberg C) lying 14 km north of the field centre. Oseberg A is a concrete base platform with process equipment, oil storage and living quarters, while Oseberg B is a steel jacket which has drilling, production and injection equipment. Oseberg D is a steel platform with gas processing and export equipment. Finally, Oseberg C is an integrated drilling, accommodation and production unit on a steel jacket [9].

Figure 4.3: Concrete based and steel jacket platforms in the Oseberg field in the North Sea. *Source: Statoil*

4.1.2 Floating platforms

Floating platforms (Figure 4.4) can be categorised into the following types:

- Tension Leg Platform (TLP)
- Semi-submersible units
- Floating Production, Storage and Offloading (FPSO)
- Spar platforms

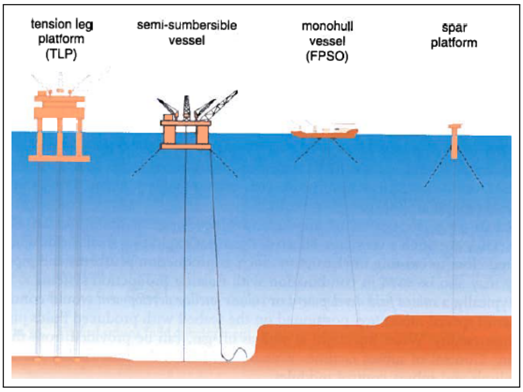

Figure 4.4: Floating production platforms. *Source: F. Jahn et al., 2008*

Floating platforms are common in deep water fields where a fixed platform scheme is not technically or economically feasible, or in the case of small fields for which the cost of a fixed system is not justified.

TLP are suitable for deep water, and although this is a well-know technology, their dynamic behaviour is complex [8]. A TLP rig is tied to the bottom through jointed legs kept in tension. Oil storage is not possible.

The *semi submersible* concept is also suitable for deep water and can include a drilling rig or subsea wells. The new build semi submersible platforms have been designed for an increased topside weight in order to accommodate production facilities, and to support heavy steel risers [10]. This concept is moored with additional mooring lines and anchors.

Ship-shaped units are mainly FPSOs vessels with some variants, for instance a Floating Production, Storage, Drilling and Offloading (FPSDO) or a Floating Storage Unit (FSU). This concept includes subsea wells and flexible risers from the sea bottom to the floating unit. Complex mooring systems and connection to the wellheads are required to accommodate rotation and movement towards the direction of the wind and currents (weathervaning).

The first *Spar platforms* were developed for offshore loading and as oil storage facilities, for instance in the Brent Field in the North Sea [10]. More recent concepts incorporate drilling and some production, although the deck area is limited. The complex dynamic behavior is significant if large currents are present [8].

The Snorre field (Figure 4.5) in the Norwegian North Sea, is an example of a field in which two of these concepts are employed. Snorre A as an integrated production, drilling and quarters unit consisting of a TLP moored to the sea bottom by steel tethers; and Snorre B, a semi submersible platform located about 7 km north of the A platform.

Figure 4.5: Semi-submersible platform at Snorre field in the North Sea. *Source: Oil Rig Photos*

4.2 Subsea

Subsea production systems are an alternative option for development of an offshore field.

These production systems operated on the seabed, represent a cost-effective solution for the development of small size reservoirs, which otherwise alone do not justify a complete development including a platform. In this case, subsea systems can be conected directly to a nearby existing production platform which is not close enough to allow wells to be drilled from the platform directly.

The use of subsea systems for deeper waters, can also lead to lower costs of the developments. In this case, a possible solution is their use in combination with a floating production system such as a production ship. Subsea-to-shore is another solution which conects directly the subsea wells with an onshore processing facility or terminal.

The main components of a subsea system are the well and the production and pipeline systems. The basic installation is a *single subsea wellhead* with subsea tree[1] connected to the corresponding production facility by pipelines and umbilicals[2].

[1]Subsea tree: assembly of valves and gauges located at the top of the well.

[2]Umbilicals may consist of control electric, hydraulic or optical cables, and chemical lines for injection of fluids into the well.

Figure 4.6: Subsea template with four wells tied to the fixed platform at Gullfaks C in the Norwegian North Sea. *Source: Statoil*

Another configuration is a *subsea production template* (Figure 4.6), where several wells are drilled at a certain location. The wells are located directly below the tubular structure, allowing drilling and completion from a single location. The third component is a *manifold*, which is a tubular structure similar to a template. The different subsea trees installed on the seabed are tied back to the central manifold through flow lines and umbilicals. A single set of pipelines and umbilicals is then required to connect the manifold with the production facility.

Ormen Lange field, in the Norwegian Sea, is an example of an offshore field development in which the full wellstream is transferred directly to an onshore facility (Nyhamna) for processing and exporting of gas, with no need of topside installations (Figure 4.7).

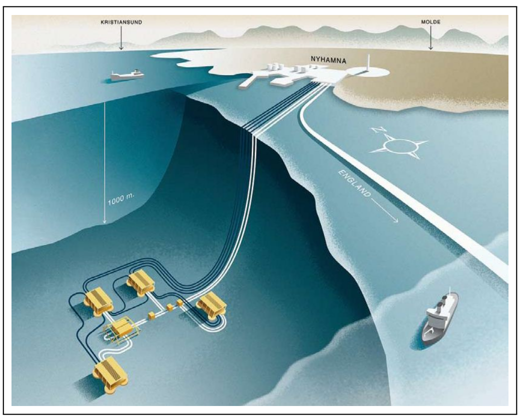

Figure 4.7: Subsea development at Ormen Lange field. *Source: Subsea World News*

4.3 Building Blocks for Arctic Developments

Specific considerations need to be taken when treating offshore exploration of oil and gas fields in the Arctic. The main issues influencing an Arctic field development will be addressed in Chapter 7. However, this section will present some cases in which, under Arctic conditions, different solutions have been used for each of the main building blocks already presented in this chapter.

Production Facilities

Physical environmental conditions (metereological and marine) and site specific conditions (soil, geotechnical, bathymetric, permafrost etc.) in addition to the wave and ice actions on the selected platform to be placed at the location, are key parameters in order to develop a safe design. In the Arctic, the uncertainties in the estimate of the design ice conditions are specially large. Moreover, the uncertainties in the ice properties are also important when determining the ice actions [12].

Subsea installations in Arctic conditions present challenges related to the use of the facilities under ice covered waters. Regarding drilling and maintenance of the wells, specific technology to avoid the ice is required. In addition, the possibility of ice interaction with the templates in shallow water is another concern. Ice strengthened steel templates and trenching of pipelines are required. Moreover, the well stream flow in Arctic pipelines represents an extra challenge, due to the more probable hydrate formation [3] at low temperatures [11].

Two examples of production facilities in the Arctic are presented here:

- The Prirazlomnoye field located on the Pechora Sea shelf in nothern Russia, is at 60km from the shore, at a water depth of about 20m. This field development is designed with a single gravity based platform in the center of the field. The Prirazlomnoye platform (Figure 4.8) is an Arctic ice-resistant oil-producing platform. Well drilling, oil production, storage and offloading are planned to be carried out[4]. Its main features are resistance to strong ice loads and year-round operability.
- The White Rose field (Figure 4.9) is located on the Grand Banks, Canada, in water depths of around 120m. The field has been developed using a FPSO vessel. The subsea wells are located in excavated *glory holes*[5] to protect the subsea equipment from possible iceberg scour. The subsea wells are connected

[3] See section 5.4.1 for more details

[4] Start up of the production is delayed (as per June 2013) due to problems with topsides commissioning.

[5] Protection measure for subsea equipment. The top of the equipment has a minimum clearance of 2 to 3m below the seabed level. This is due to the measured scour depths in the area of 1m.

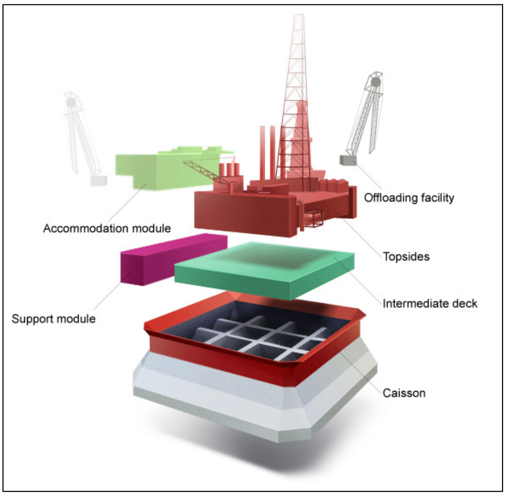

Figure 4.8: Prirazlomnoye Arctic ice-resistant platform. *Source: Gazprom*

through flexible flow lines and risers to the ship-shaped floating facility. The FPSO's turret system is designed to allow the facility to disconnect from the subsea installations and move in the event of an emergency such as an approaching iceberg.

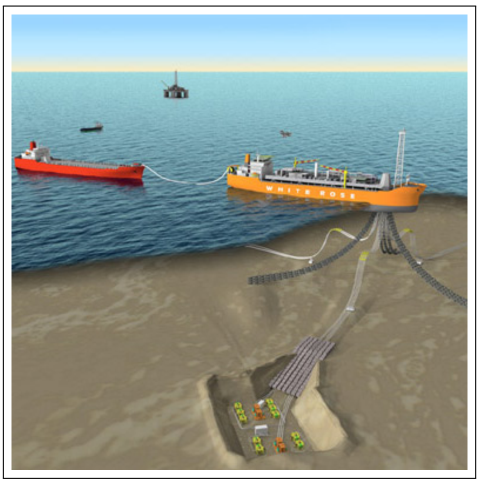

Figure 4.9: White Rose field development on the Grand Banks, Canada. *Source: Husky Energy*

Onshore Processing and Transport Schemes

Hydrocarbon transport from Arctic offshore fields entails large challenges, whether pipeline or ship transport is selected. In addition, the very long distances to the oil and gas markets, are translated into substantial capital and operational costs [12].

Establishing an onshore terminal in an Arctic region involves operational and technical challenges that will usually involve a comprehensive economical and risk assessment. The feasibility of this type of project and associated issues, will be the focus of this thesis report from Chapter 9.

A good example of an Arctic innovative project involving subsea installations, wellstream, pipeline transport and an Arctic terminal, is Snøhvit (Figure 4.10). This is the first offshore development in the Barents Sea and presents no surface installations. The full wellstream is transported directly to the processing plant on the Melkøya island, using a 143km long pipeline. The transport of the unprocessed wellstream, through a long seabed pipeline like that, presents several challenges itself. Due to the high pressure and the low temperature on the seabed, ice plugs (hydrates) will tend to form in the pipeline. This is avoided by adding Mono Ethylen Glycol (MEG) at the wellheads, or by heating up the pipeline electrically as required [9].

Other Arctic considerations for the offshore subsea facilities and the onshore plant are very important, with aspects such as sudden changes in weather conditions due to the Polar Low Pressures, icing of equipment and facilities, working environment under low temperatures, safe ship transportation of Liquified Natural Gas (LNG) to the market or offshore maintenance as some of the main issues. In addition, special measures need to be taken in order to limit discharges to the sensitive Arctic environment.

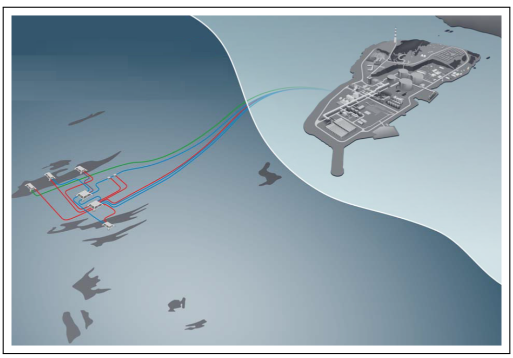

Figure 4.10: Snøhvit field layout in the Barents Sea. *Source: Statoil*

Chapter 5

Needs for Processing and Transport Schemes

Processing is a key part of a hydrocarbon development. The wellstream from a reservoir is normally not suitable for transport or marketing. Processing of the wellstream is necessary to obtain products that can be transferred to land for further processing and to obtain commercially suitable products (Figure 5.1).

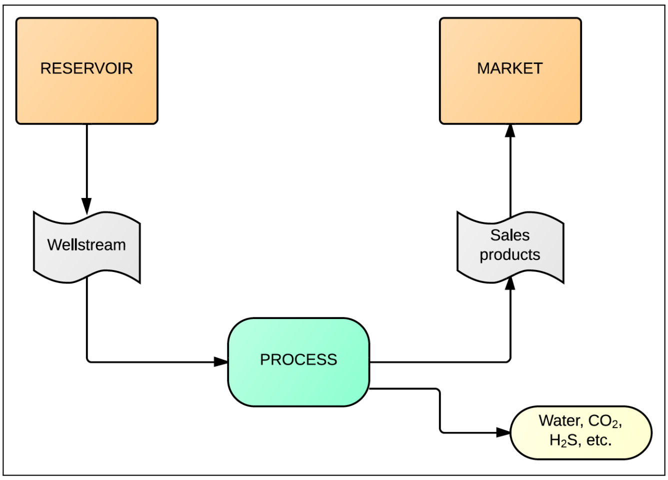

Figure 5.1: Need for processing.

The ultimate purpose of the required processing is the transformation of the well flow into marketable products with the required qualities before the delivery to customers is carried out. However, another important determinant of the need for processing, is to generate products that can be transported and/or stored. For instance, to be able to transport oil or condensate by ships, these must be stabilised[1], which leads to the removal of the water and most of the gas components from the crude oil [8]. Another transport processing requirement, has to do with the fact that

[1]See Section 5.2.2

non processed oil or gas transported by pipeline to shore, might lead to hydrate formation, which could cause partial or complete plugging of the pipeline. In this case, the use of chemicals or heat is necessary to avoid it.

The needs for processing as a key part of a field development, and the main transport schemes will be addressed in this chapter.

5.1 Well Stream

The needs for processing of the wellstream will vary depending on several factors regarding the composition of the wellstream and its properties. Therefore, the knowledge of the basic physical and chemical properties of the wellstream is essential for the design of the process facilities and moreover to determine the sales products that can be obtained.

The wellstream is a complex mixture of organic compounds, mostly hydrocarbons (molecules composed of hydrogen and carbon atoms), some water and may also include sulphur, nitrogen, oxygen, sand and metal compounds. Typically the carbon element represents around 85%, the hydrogen element 11-14% and the other elements usually less than 1%. The non-hydrocarbon components are small in volume percent, but of particular importance, especially if H_2S or CO_2 are present. Their influence on the quality and the processing requirements is notable, for instance causing corrosion in combination with free water, in addition to the toxicity.

Wellstream fluids are very diverse, varying from gases, to clear or almost solid liquids (Extra Heavy Crude). The different types of wellstream can then be classified depending on the fluid composition, but also using easily measurable properties in the field, such as:

- *Oil gravity*: usually expressed in degrees API [2]
- *Gas to Oil Ratio (GOR)*: volumetric ratio of the gas/oil produced at standard conditions of temperature and pressure (25°C, 1 atm).

Table 5.1 shows the main types in which the wellstream can be classified, taking into account its oil gravity and gas to oil ratio [10].

[2] American Petroleum Institute (API).

$$API = 141.5/\gamma - 131.5$$

where γ is the specific gravity of the oil with respect to water

Table 5.1: Types of reservoir fluid

	Dry Gas	Wet Gas	Gas Condensate	Volatile Oil	Black Oil
Degrees API	-	60-70	50-70	40-50	<40
GOR (Sm^3/Sm^3)	No liquids	>15000	3000-15000	2500-3000	100-2500

Wellstreams with different gas to oil ratio will have different needs in terms of processing. High GOR oil, for instance, will need large processing facilities to stabilize the oil. As the API number, expressed as degrees API, goes up, the less dense (lighter and thiner) is the crude. The different density will influence, for instance, the production of refined products. The water content can also influence the type of processing required for the wellstream. In these cases, gas drying is needed, and if the amount of water to handle is large, special facilities for this purpose may be needed. As it was mentioned before, it is of great importance to identify the presence of H_2S, CO_2 and radioactive or corrosive substances as early as possible, to enable the appropriate choice of processing facilities and the selection of materials [8].

The composition of the wellstream (hydrocarbon, acid gas, other contaminants or water content) and its properties (particularly the GOR, oil density and fluid viscosity) will determine the basis for the design of the process facilities. Therefore, accurate measurements of flow and compositional data are required in order to determine the initial volumes of fluid and the flow properties, at an early stage of the development.

5.2 Processing of Oil and Gas

As it was pointed out in the introduction of the chapter, the wellstream from a reservoir is normally not suitable for transport or marketing. Usually the well stream consists of a full range of hydrocarbons from gas (methane, butane, propane, etc.), condensates (medium density hydrocarbons) to crude oil. In addition, components such as water, carbon dioxide, sulfur or sand are usually present. Processing of oil and gas, therefore, comprises a number of complex procedures and facilities to obtain products suitable for transport and sales. The main processes are outlined in Figure 5.2.

5.2.1 Separation

As described before, the well stream consists of gas, oil, water and various contaminants. The function of the separators is to split the flow into the desirable fractions.

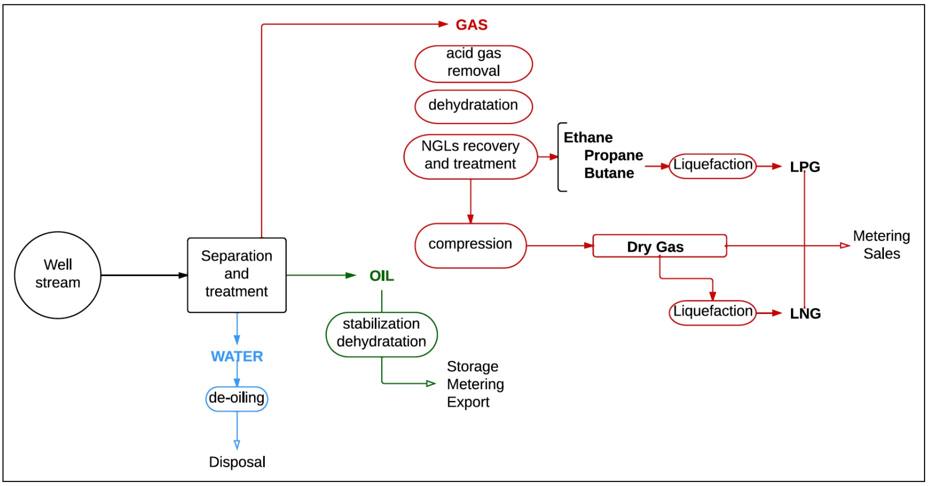

Figure 5.2: Processing schematic diagram. *Modified from F. Jahn et al., 2008*

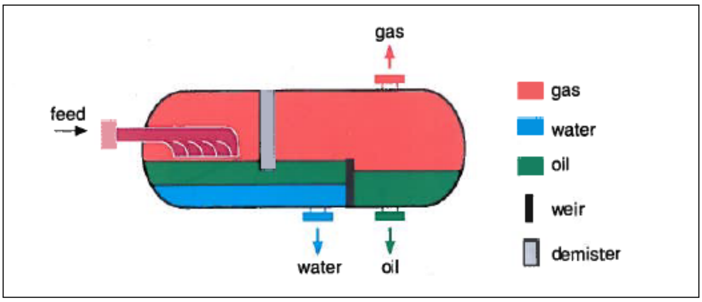

Figure 5.3: Three phase separator. *Source: F. Jahn et al., 2008*

Separation might be carried out at a single or multiple stage separator. Usually multistage separation at different pressures is employed to achieve maximum liquid recovery. The retention period is typically 5 minutes to allow the gas to bubble out, water to settle at the bottom and oil to be extracted in the middle [13]. An example of a basic three-phase separator is shown in Figure 5.3.

5.2.2 Oil stabilization and water handling

Even after separation, the oil/condensate still contains gas and water. Crude oil or condensate needs to be stabilised to minimise gas evolution during transportation by tanker. This process generates stable liquids with a vapour pressure lower than 0.8 bar at ambient temperature by removing the volatile components, usually through a fractionation column [8].

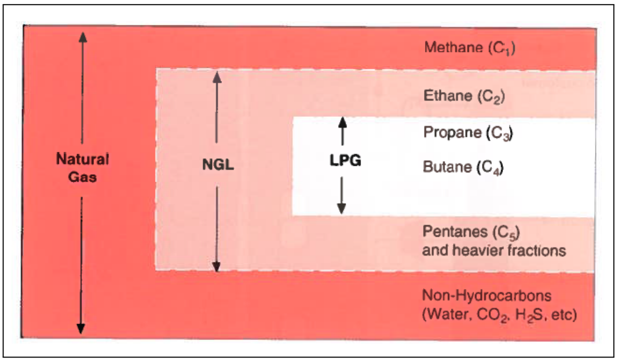

Figure 5.4: Natural gas composition and terminology. *Source: F. Jahn et al., 2008*

Usually a large amount of water with different chemical compositions is produced from petroleum production. The separated water from the wellstream can be reinjected into the reservoir or treated. Water treatment systems before disposal to sea are required to meet the corresponding environmental regulations. Standars range between 10 and 100 parts per million (ppm) of oil in water. In most regulations, 40ppm of oil in water is the legal requirement [10].

5.2.3 Gas processing

Natural gas processing consists of separating all of the various hydrocarbons and fluids from the natural gas (Figure 5.4), to produce dry natural gas with the required transport and sales specifications. Sales gas (dry gas), mainly consists of methane (CH_4), but also contains other hydrocarbons such as ethane, butane and propane.

Gas processing comprises, therefore, several stages. Firstly, to prepare gas prior to transportation by pipeline, it is necessary to extract or inhibit any component which could cause corrosion or blockage (water vapour, heavy hydrocarbons and contaminants such as carbon dioxide and hydrogen sulphide). Before delivery to the users, further processing is carried out, usually Natural Gas Liquid (NGL) recovery, compression and possibly liquefaction of natural gas (LNG) or propane and butane (Liquified Petroleum Gas (LPG)) for easier storage and transport.

- **Acid gas removal**

  The main acid gases in produced gas are carbon dioxide (CO_2) and hydrogen sulphide (H_2S). The acid gas removal is needed mainly due to corrosion and toxicity (H_2S). Removal can be carried out by absorption, adsorption or gas permeation [8].

- **Gas dehydratation**

  In case the gas contains water vapour, it might be necessary to dry it (dehydratation). Water condensation could lead to hydrate formation, causing blockage of the pipeline or process equipment. Dehydratation can be performed by several methods: cooling, absorption or adsorption. Absorption using solvent tetraethylene glycol (TEG) is the most common method [10].

- **NGLs recovery**

  Once natural gas has been separated from crude oil (in case this is present), it usually contains other hydrocarbons, mainly ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}), and pentanes. These are known as NGLs. These are usually recovered by a fractionation plant, in which the stream passes through a series of distillation columns called de-ethaniser, de-propaniser and de-butaniser, to extract ethane, propane and butane respectively and leave a residual stream of pentane and higher hydrocarbons [10].

- **Compression**

  Gas from a pure natural gas wellhead, may have enough pressure to enter directly a pipeline transport system. However, gas from separators usually loose so much pressure that it must be recompressed for transportation [13]. There are several types of compressors used, the main types the reciprocating and centrifugal compressors. Compression facilities are generally the most expensive in the gas process faciliy [10].

- **Liquefaction of gases**

  Liquefaction of gases may be carried out for easier transport or storage. For instance, if the distance to the user is very large, gas might be shipped as a liquid. Natural dry gas is liquefied (LNG) by refrigeration at -162 ℃ at atmospheric pressure. The volume is reduced to 1/600th of the original volume by this process. In a receiving terminal, the LNG is unloaded and can be converted back to gaseous phase before distribution to users.

  Propane and butane are relatively heavy gases which can be also liquefied for transportation and storage purposes. The liquefied mixture is called LPG, and is usually liquefied by refrigeration at a temperature of -50℃ and atmospheric pressure. It can also be liquefied by pressurization at ambient temperature.

  Figure 5.5 shows the relation between temperature and minimum pressure required to liquefy different gases.

5.3 Sales products

As a summary, Table 5.2 presents an overview of the different trade products, their composition and primary use in the market.

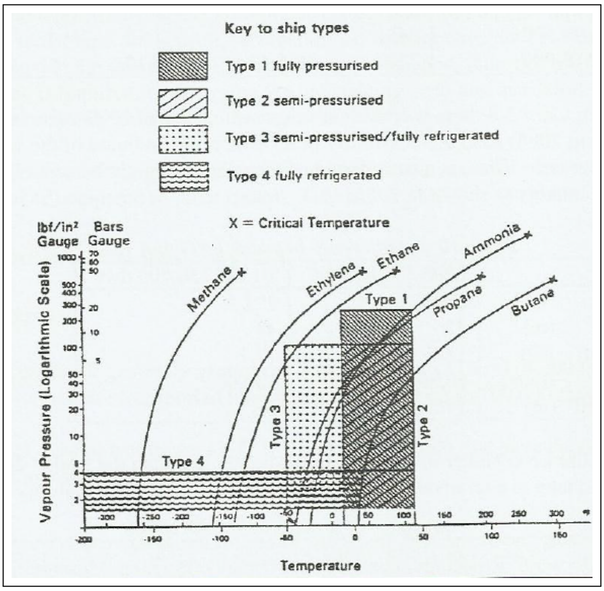

Figure 5.5: Temperature-vapour pressure relationship of different gases. *Source: H. Ligperingen, 2009*

Table 5.2: Products from oil and gas production

Type of Product	Description	Main use
Crude oil and condensate	Complex mixture of hydrocarbon molecules in different combination/concentration	Converted to refined products in oil refineries
Refined products	Gasoline, gasoil, naphtha, kerosene, jet fuel, asphalt, etc.	Mainly transportation and industrial sector
Natural Gas Liquids (NGLs)	Ethane (C_2H_6), propane (C_3H_8) and butane (C_4H_{10}) LPG (Liquefied butane and propane by refrigeration (-50 ℃) or pressure)	Transportation, residential, industrial and commertial sectors
Natural Gas		Industrial purposes,
Dry gas	Mainly methane (CH_4), but with limited quantities of heavier gases	residential heating and cooking, electricity
LNG	Liquefied Natural Gas by refrigeration at -162 ℃. Mainly methane (CH_4)	generation at a gas power plant

5.4 Transport Schemes

Once oil and gas have been processed to obtain commertially suitable products, these need to be transported to the users. The main transport methods are pipelines and ships. Distance, volume, product specification and the capacity of the processing facility are some of the parameters determining the transport scheme.

The transport method usually varies depending on the nature of the products. Table 5.3 summarizes the different trading products and their corresponding method of transport.

Table 5.3: Types of products and transport schemes

Type of Product		Transport Scheme
Crude oil and condensates	Stable	Oil tanker
	Non-stable	Pipeline
Refined products	Gasoline, gasoil, naphtha, kerosene, etc.	Product tanker
Natural Gas Liquids (NGLs)	Ethane, LPG	Liquid gas carrier
Natural Gas	Dry gas	Pipeline
	LNG	Liquid gas carrier

In terms of distances and volumes, the most common solution for natural gas is pipeline transport, whereas oil transportation varies between pipeline or ship, noticing that only stable oil can be transported on ships due to safety reasons. 90% of the natural gas is transported by pipeline, although ship transportation of natural gas as liquefied gas (LNG) is increasingly used, especially for long distances, where pipeline construction is not economically or technically feasible. Pipeline transport for more than 2000km is not a common solution [8], except in the absence of suitable maritime access. Pipeline transport is therefore favoured over ships as an export solution in case of smaller distances to the market or large volumes.

Therefore, different parameters (distance, volume, product specification and capacity of the processing facility), determine the costs of the different transport schemes, making pipeline or ship transport the most suitable method in each case.

5.4.1 Pipeline transport

Oil and gas transport through pipelines has several advantages as well as disadvantages. The main advantages of oil and gas pipelines as a transport scheme are [8]:

- *Small operation and maintenance costs*: although large capital investments are required, the costs afterwards are relatively low.
- *Long lifetime*: usually over 50 years if the conditions are optimal.

The main disadvantage is the lack of flexibility; when installed, there is little margin for modification.

The pipeline system on the Norwegian continental shelf is the largest of its kind in the world. It comprises 8100km of oil and gas pipelines connecting fields with processing facilities on the Norwegian coast along with connexion points in France, Germany, Belgium and UK. Figure 5.6 shows the existing and projected oil and gas pipelines for Norwegian exports to Europe.

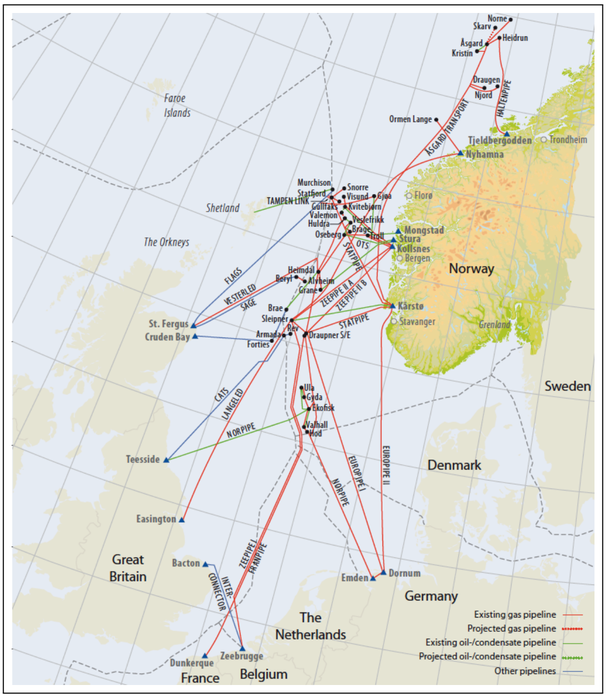

Figure 5.6: Existing and projected pipelines on the Norwegian Continental Shelf. *Source: The Norwegian Petroleum Directorate*

The pipeline design requirements, will be determined by the product specification, the flow rates and the pressure conditions. For gas pipelines, for instance, a high content of CO_2 and elevated temperatures may corrode carbon steel, necessitating the use of a corrosion inhibitor to protect the carbon steel or the use of corrosion-resistant steel. For oil pipelines, for instance, very viscous oils may need upstream processing or some treatment along the pipeline such as heating, pigging or special insulation. In addition, a multiphase flow will require measures to avoid hydrates[3]. In pipelines carrying gas with large contents of condensate and NGLs, pressure must be managed to prevent separation of the liquids from the gas. The pressure accepted at the receiving terminal is also of importance [11].

5.4.2 Maritime transport

Ship transportation is competitive for very long distances where pipeline construction is not economically feasible. In addition, an important advantage is its flexibility when compared to pipeline transport, as most oil and gas tankers are able to call at almost any port or refinery around the world [8].

The type of liquid bulk carrier used, depends on the product being carried. Table 5.4 gives an overview of the different liquid bulk carrier types depending on the product handled [14].

Table 5.4: Liquid bulk carrier types

Type of Product	Type of bulk carrier	Capacity range (1000 dwt)	Length L_{OA} (m)	Fully loaded draught (m)
Crude oil	Crude oil tanker	20-400	175-380	9.2-24
Refined products	Product tanker	3-50	90-210	6-12.6
LNG	LNG gas carrier	60-90	202-245	11.8-12.7
LPG	LPG gas carrier	0.5-70	138-220	7-11.5

i *Oil tankers*

There are several types of crude oil tankers (Figure 5.7) from the *Panamax* tanker between 50 and 80 dwt of capacity to the Ultra Large Crude Carrier (ULCC) of up to 550000 dwt. Even if the size of the tankers has seen an important increase through the years, nowadays the intermediate size tanker (50 to 200 kdwt) has become more important since bigger tankers can only call at few ports in the world due to their deep draught (*i.e. up to 24m*) [14].

[3] Hydrates may be generated when hydrocarbon molecules are in contact with water at high pressures and temperatures below 15-25°C

Figure 5.7: VLCC "Alexander The Great", 297456 dwt. *Source: Capital Ship Management*

ii *Liquid gas carriers* (see Figure 5.8)

The gas is transported at high pressure or at low temperature. The products involved include:

- LPG: mixture of propane and butane
- LNG: maily consisting of methane
- Other liquefied gases: amonia, ethylene etc.

The gas is mostly transported at atmospheric pressure and refrigerated (LPG: -50℃; LNG: -162℃) in liquid form. Some small LPG tankers carry the gas pressurised (at about 7bar). It is not possible to liquefy the LNG by pressurisation at temperatures above -80 ℃. In addition, it is not possible to carry pressurised LPG in big vessels, since it would require too thick walls for the tanks. The biggest advantage is that the volume of the liquid form of natural gas is reduced to 1/600 of its original gas volume.

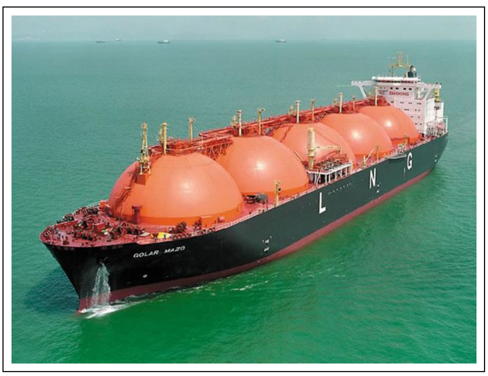

Figure 5.8: LNG gas carrier "Golar Mazo", 76210 dwt. *Source: LNG World News*

Chapter 6

Needs for Oil and Gas Onshore Terminals

Oil and gas onshore terminals (Figure 6.1), are dedicated harbour facilities with different functions such as: export, import, transshipment, storage and processing of oil and/or gas. The reasons why these terminals are dedicated, and therefore separated from other port facilities, have to do with:

- Safety aspects
- Security aspects
- Size of the ships
- Special layout for the quays
- The land facilities are restricted areas

Figure 6.1: Kårstø gas terminal, Norway. *Source: Offshore Energy Today*

6.1 Onshore versus Offshore Terminals

There are several activities carried out at an onshore terminal. The main function of the terminals is to receive the incoming oil or gas, in some cases process it, and make it ready for export into pipelines, by ships or to refineries. As it has been reviewed in the previous chapter, the processing requirements of an onshore terminal are characterised by whether they are handling oil, gas or both.

Some of the activities carried out at an onshore terminal, could be accomplished on offshore facilities such as concrete platforms, production ships or offshore storage tanks [8]; including loading and shipment of oil and gas.

The most important parameters for the choice between an onshore or offshore scheme are:

- **Costs**
  The cost assessment needs to take into account the following aspects:
  - Accessibility due to waves, wind, currents, ice, visibility etc.
  - Maintenance (*e.g. dredging*)
  - Future extensions (if expected)
- **Safety**
- **Reliability**

In terms of loading and storage, different marine facilities can be distinguished [14, 15]:

i *Conventional sheltered port with storage and/or processing areas (onshore terminal).*

   The berthing area usually consists of a jetty, a loading platform, breasting and mooring dolphins, and the corresponding breast and spring lines [16]. The most typical berth arrangement, following the Oil Companies International Marine Forum (OCIFM) Guidelines [17], is shown in Figure 6.2.
   If the harbour is located in an exposed area, it needs to be protected by breakwaters; their dimensions and location depends on the depth and the local wave and ice conditions in the harbour area. (More about breakwater design in Chapter 9).

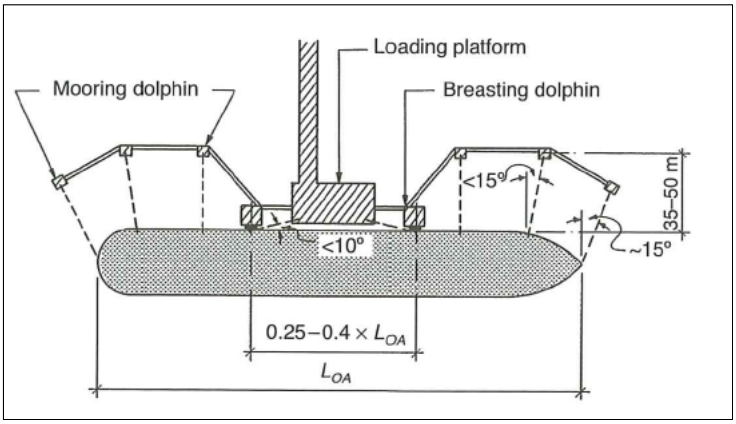

Figure 6.2: Typical berthing arrangement for tankers. *Source: Thoresen, 2010*

ii *Single Buoy Mooring*

The system consists of a Single Point Mooring (SPM) with submarine pipelines to shore where storage takes place. In some situations, it may be economically attractive to carry out the unloading at an offshore single point mooring (see Figure 6.3), for instance in the case of large ships and insufficient water depth near the shore, in order to avoid excesive dredging of an approaching channel and basin, or the construction of a jetty for big tankers.

Figure 6.3: Single buoy mooring. *Source: BMT Scientific Marine Services*

For the feasibility of this option, waves and currents are decisive parameters. Table 6.1 shows the limiting wave heights for jetties and SBMs [14].

Table 6.1: Limiting significant wave heights for jetties and SBMs

	During berthing without swell (m)	During berthing with swell (m)	During loading or discharging (m)
Jetty	1.5-2.0	1.0-1.5	2.0-3.0
SBM	2.0-3.0	2.0-3.0	4.0-6.0

Winds and currents have also a large influence. Berthing with wind speeds higher than $12.5m/s$ to $15m/s$ is not allowed due to safety reasons. The advantages of this SBM configuration are the low capital costs, flexibility (for instance in case of replacement), and high operability (up to $H_s = 2 - 3m$). The main disadvantages have to do with high operational and maintenance costs and low pump capacity. It is therefore economical for small to medium throughputs (up to 5-6 million tons per year) or at very deep water. For bigger throughputs, this solution becomes less attractive due to the lower unloading rate when compared with a jetty on an onshore terminal, bigger delays and greater threat of pollution [14].

iii *Offshore terminals with floating storage*

This scheme can be economically attractive when dealing with small or remote fields. It consists of a SBM with a permanently moored storage vessel, which supplies tankers (see Figure 6.4).

Figure 6.4: The Peregrino FPSO. *Source: Statoil*

In general, loading and unloading of liquified gases, is mostly done at protected harbours. Some exceptions are for instance, a floating LPG import facility in

Lebanon and an offshore LNG loading terminal in Brunei [14].

Apart from the loading/unloading activity, one of the most important functions and, as it was shown in the previous chapter, essential part of the development, is processing. The costs of an offshore processing are usually very high due to the installations and offshore work needed. Weight and space restrictions make offshore processing and storage non-viable in the majority of the situations [10].

Summarizing, some of the terminal functions (loading and small storage), under specific situations, can be feasible and economically more attractive to carry out offshore. However, in the majority of cases, the final processing of the product is carried out at an onshore terminal. The costs of offshore processing are usually very high, that is why normally, only minimum processing is performed offshore in order to get products that can be transported onshore for final processing and larger storage.

An onshore terminal is therefore a major buliding block necessary in the development of a hydrocarbon field.

6.2 Types and Functions of Onshore Terminals

The shape, dimensions, location and arrangement of terminals depends on their function. The functional classification of onshore terminals can be summarized as:

- Export/Import terminal
- Storage and transhipment terminal
- Processing plant
- Industrial terminal (*refinery/power plant*)

In the majority of the situations, a combination of different functions takes place. For instance, the facility comprises an oil terminal associated with a refinery or the facility includes some type of processing, storage and transhipment.

The variety of products handled needs to be taken into account. Simulation models establish the requirements for berths, loading/unloading and storage capacity.

6.2.1 Onshore facilities in Norway

The Norwegian coast offers good examples of different types of terminals related to oil and gas production in which different activities are carried out (Figure 6.5).

Figure 6.5: Onshore facilities on the Norwegian coast.

Table 6.2 [1] shows the main onshore terminals on the Norwegian coastline, their location and main purpose. A variety of functions are involved, for instance receiving and exporting harbours, refinery, as well as different treatment and storage plants.

Table 6.2: Main onshore oil and gas facilities on the Norwegian coastline

Onshore facility	Location	Functions
Kårstø terminal	Rogaland	Treatment of gas up to 88 million m^3/day. Stabilisation and fractionation of unprocessed condensate. NGL fractionation plant and Ethane separation plant. Export of dry gas.
Kollsnes gas processing plant	Hordaland	Gas treatment up to 143 million m^3/day. NGL separation plant with capacity for 26 million m^3/day. NGL transport to refinery.
Sture terminal	Hordaland	Export terminal for crude oil. Comprises two jetties to berth tankers up to 300000 dwt. Storage of crude oil and LPG.
Mongstad onshore facility	Hordaland	The complex comprises a refinery, a NGL fractionation plant, a crude oil terminal and a combined heat and power plant.
Nyhamna onshore facility	Møre and Romsdal	Gas treatment for export to UK. Stabilisation of condensate, storage and export by tankers.
Tjeldbergodden industrial complex	Møre and Romsdal	Gas receiving terminal, processing plants for methanol, air separation and gas liquefaction
Melkøya onshore facility	Finnmark	Production, storage and transport of LNG from processed well stream transported through a 143km pipeline.
Future Veidnes terminal	Finnmark	Oil storage facility in two mountain caverns. Export quay for transportation by tankers (50-100 crude tankers/year estimated).

[1]Information retrieved from Statoil and Norwegian Petroleum Directorate (NPD)

Chapter 7
Arctic Specific Issues

Field developments in the Arctic have been under consideration for over 40 years now. The first developments took place on the North Slope of Alaska in the late 1960s, exploration was extended to Greenland in 1976-1977, and the first exploration activities in the European Arctic took place in the early 1980s in both the Norwegian and Russian Arctic, with a number of oil and gas finds, including Snøhvit, Shokman and Prirazlomnoye [1]. However, the challenging environment has established a threshold on this type of developments.

The Arctic is a frontier operating environment where conditions are especially challenging and often unpredictable. The additional challenges vary depending on the Arctic region, but are mainly caused by low temperatures, ice and icing, darkness, remoteness and a vulnerable environment. In addition, Arctic conditions make the consequences of incidents more severe in terms of economic, personal or environmental damages or losses.

The main issues influencing an Arctic field development will be addressed in this chapter.

7.1 Physical Environment

The climate in the Arctic is harsh with strong and fast changing winds and low temperatures. The weather can change very suddenly in the Arctic due to the Polar Low Pressure phenomenon; changing wind direction and increasing wind speed from 2 to 4 in the Beaufort scale within a few hours. In addition, weather forecasts are usually more uncertain due to satellite constraints.

7.1.1 Surface air temperature

Low air temperatures are a typical characteristic of the Arctic region. However the differences are apparent when comparing temperatures among stations at similar

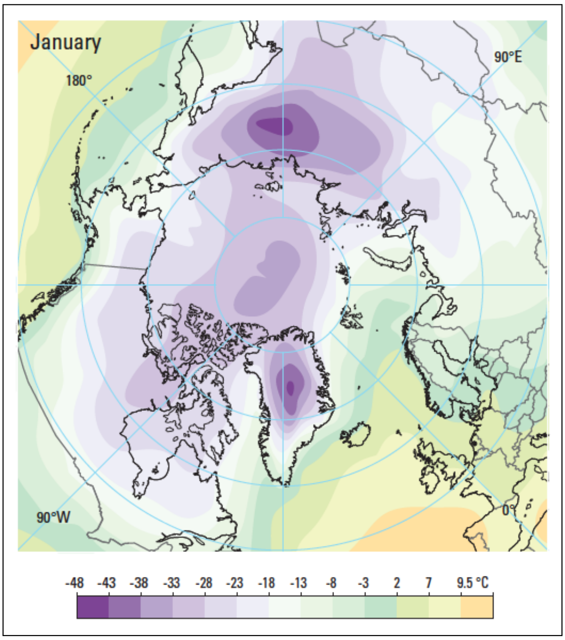

Figure 7.1: Mean January surface air temperature (°C) in the Arctic. *Source: AMAP*

latitudes. For instance, the average temperature of January in the Canadian Arctic being approximately -20°C lower than that in the same latitude on Svalvard [6]. See Figure 7.1.

Icing

Icing is a serious threat for Arctic shipping or offshore structures, and it is also a major issue for coastal infrastructure, particularly if there is exposure to sea spray and storms. For example the Melkøya LNG plant, outside Hammerfest in Norway (Figure 7.2), has reported a number of technical problems due to temperature and heavy icing, with more than 5cm of accumulated ice thickness being expected in February and March [18].

The rate of icing depends on precipitation type, wind speed, air temperature and sea surface temperature.

- *Precipitation Types*: types of precipitation in the Arctic that can cause icing include:
  - . Freezing rain: not a major hazard.

Figure 7.2: Melkøya LNG Plant, Norway. *Source: Reuters/Haakon Mosvold Larsen*

- Arctic frost smoke: when the air temperature is below 0 ℃ and at least 9 ℃ colder than the sea
- Freezing spray: the most dangerous form of icing; when the air temperature is below the freezing temperature of the sea water (-2 ℃), the spray freezes creating clear ice of glaze.

– *Wind*: sea spray depends on the wave conditions, and therefore on the wind duration, speed and fetch. For critical temperature ranges (for instance lower than -2 ℃), freezing ice appears for wind speeds higher than $9m/s$. In general, the lower the temperature and stronger the wind, more rapid ice accumulation taking place.
– *Air temperature*: the critical range goes from -18 ℃ to 0 ℃. At temperatures below -18 ℃, dry ice crystals form.
– *Sea temperature*: the critical range goes from -2.2 ℃ to 8.9 ℃, being -2.2 ℃ the freezing point for seawater of common salinity.

Icing, therefore, results in sea spray freezing on the structure or vessel, causing machinery to seize up and/or loss of vessel stability [19].

Cold conditions

Cold temperatures affect both, people and materials. Materials exposed to cold temperatures change their thermo-mechanical properties. Steel is more exposed to brittle fracture under these conditions. Sensitive equipment needs to be designed to resist freezing temperatures. In addition, fluids in cold temperature change their properties. For instance, oil viscosity increases with lower temperatures. Application of specific low temperature lubricating oil can improve the performance of machines exposed to this climate. Insulation, antifreeze liquids, heating or circulation of the fluids are some of the methods used to combat the effects of low temperatures in fluids other than oil.

7.1.2 Ice conditions

Ice conditions differ significantly depending on the regions of the Arctic Ocean. The main reason is the influx of warm water from the Norwegian Atlantic current which causes an open ice edge in the southern part of the Barents Sea, even in winter. The predominate forms of ice in the Barents Sea are winter and young ice, with some polar ice in the area between Franz Josef Land and Spitsbergen.

Thickness, size and concentration of ice are the most relevant and restrictive factors. In the Barents Sea, the ice reaches its greatest extent in March and April (up to 1.5-4.5m height), melting taking place rapidly between May and August, after which freezing starts again. Sea ice is problematic where low temperatures cause the sea surface to freeze into level ice which can cause large loads on the structure, and be a complicating factor in rescue operations and oil spill response. Ice ridges and icebergs may also cause problems due to large impact loads in case of collision or scoring of pipelines and structures at the sea bottom in shallow areas. An effective ice management is crucial [20].

7.1.3 Climate change factors

The current trend towards more ice free areas and longer periods is likely to continue [21]. Access to some regions in the Arctic will improve as a result of the melting ice. However, in other areas the accessibility may decrease for this same reason, for instance melting permafrost on land could reduce accessibility.

7.2 Remoteness

Geographic isolation brings specific operational challenges, which entail substantial costs and amplify the potential consequences of risk events [1]. Infrastructure and capability to react against an emergency situation can be distant or unavailable. If an installation is situated far from land, it will need to be selfsufficient when needed. This applies for emergency, evacuation and oil spill response systems. Safe and reponsible operations in Arctic regions can involve, therefore, important additional costs.

7.3 Visibility

Visibility can be an important operational issue in the Arctic.

The Arctic Circle, located at $66\,^{\circ}33\,'N$, marks the southern limit where the sun is above (polar day) and below (polar night) the horizon for 24 hours at least once a year, being the effect prolonged in higher latitudes. During late autumn, winter and early spring, limitations on visibility will occur due to the number of hours in darkness. That season implies also the worst temperature and weather conditions, making any operation much more complex. In addition, strain and effort on personnel can increase due to darkness [7].

Other limitations to visibility are mainly blowing snow and fog. One of the Arctic weather features is fog. It is usual to have more than 100 days/year with fog in some areas. In summer, warm air moves in overlying cold ice and cold water, condensing water, which forms thick fog fields, with peaks in relative humidity in August. In winter 'sea smoke' may form over open water. Another condition found in Arctic climates is ice fog, composed of ice crystals, which occurs mainly for temperatures between -30 °C and -45 °C. Visual observation of drifting ice can be hard under these situations [6].

7.4 Human Factors

Arctic environmental conditions have a strong influence on the working environment and technical safety of offshore operations. Design requirements need to be considered in order to ensure the facility´s integrity and operability requirements under these conditions. Human factors are a major contributor to operational safety and optimization of the performance. Arctic operations expose personnel to cold, windy and wet conditions, which can cause different adverse effects on human health and performance: thermal discomfort, increased strain, decreased performance and cold related diseases and injuries [7]. A set of management practices and methods is needed for work in cold environments, for instance cold and wind chill exposure limits, winterization of facilities, clothing and personal protection equipment and work, warm-up and rehabilitation regimes.

In ice-covered regions, safe Escape, Evacuation and Rescue (EER) approaches must be capable of accommodating a full spectrum of ice or open water situations, which are often complicated by many other environmental and logistical factors. Some of the major EER risks include:

- Traditional EER methods may not be appropriate for most part of the year

– Long distances from the potential emergency site to the support bases and other facilities
– Limited amount of time available to react to particular emergency situations
– Lack of qualified medical support
– Difficulties caused by communication due to high latitude and lack of satellite coverage
– Full range of ice conditions, including icebergs and sea ice, combined with cold, wind or other weather conditions

The EER risks are directly related to the installation type, function, location and distance from rescue bases and resources. Arctic Evacuation Methods and Emergency Response Vessel are important components within the total EER system.

The Barents 2020 Project [7], following the initiative of the Norwegian Ministry of Foreign Affairs, provides concrete guidance for safe exploration, production and transportation of oil and gas in the Barents Sea.

7.5 Environmental Hazards

The Arctic environment can be described as highly vulnerable to pollution. The Arctic, largely remains an unspoiled environment due to its remote location, low population and historical absence of industry, making therefore an important contribution to global biodiversity.

The probability of a hazardous event such an oil spill is not higher in the Arctic, however the potential consequences, difficulties and costs of recovery, are likely to be significantly greater.

There are many ways in which an ecosystem may be disturbed. Any development will cause an ecosystem disturbance as it would be the case for any other area. For instance the construction of pipelines, the noise pollution from drilling or increased maritime traffic, disturbance of the seabed, or break-up of sea ice. However, even if the potential pollution sources are broad and the probability of a risk event such an oil spill is not higher in the Arctic, the risk of an oil spill is probably the most relevant since it represents the greater potential environmental and economical consequences. If a damaging event occurs in the Arctic region, it is likely to have long term impacts due to the limited resilience of the natural environment, making the environmental recovery process much harder to achieve. In addition, the response to an oil spill in the Arctic is likely to be complicated by several factors [22]:

- Gaps in knowledge related to oil spill response (containment, dispersants and clean-up) in Arctic waters.
- Limited accessibility and available time in some areas due to remoteness and vast distances from infrastructure and services required to cope with such a pollution event.
- Lower rate of natural evaporation and biodegradation of spilled oil due to the lower Arctic temperatures.

This particular issue will be treated in detail in a separate chapter (Chapter 8), since the environment is of particular importance in a cold climate or Arctic region, where risk reduction should be the main driver for all work carried out.

Chapter 8

Oil Spills in Cold Climate

When moving oil production to cold climate areas, the risks of accidental oil spills grow substantially due to more severe environmental conditions, remoteness and lack of infrastructure. The same accident scenarios are valid as in temperate areas, however, the consequences of accidents are likely to be more fatal, since the resilience of the Arctic's ecosystems in terms of withstanding risk events is weak. Moreover, the extra challenges presented under cold climate conditions will require of a different response. In other words, the probability of an oil spill in cold climate is as in more temperate areas, however, its consequences might be more severe, therefore, improved mitigating measures are needed.

Other hazardous and noxious substances might be released into Arctic waters during the hydrocarbon production and transport, however, the focus of this chapter is the spreading of oil, and the response techniques to oil spills in cold-water environments.

8.1 Spill Risks

Oil spills may occur during any phase of oil exploration, production, transportation or storage. The major potential sources of oil spills include:

- Well blowouts during exploration or production
- Releases during off-loading operations
- Leaks from subsea pipelines
- Spills from storage tanks
- Spills from vessels during transportation

Oil spills can be the result of a variety of factors, for instance human errors or structural and mechanical failures. Arctic environmental conditions such as sea ice, low temperatures, darkness, high winds, and extreme storms increase the probability of an accident or error that could cause a spill.

8.1.1 Spill risks from exploration and production

Well blowouts are the worst case of potential discharge during production. The potential spilled volume from a blowout equals the volume of the reservoir that could flow to the surface until the well is controlled [23]. Although well blowouts are infrequent, they represent a threat during exploration and production, especially if the reservoir size is large, and the pressure of the reservoir is particularly high.

A well blowout can occur at the surface, or on the sea bottom, which involves an underwater release of oil travelling through the water column before reaching the surface. Depending on the ice conditions, the oil may be trapped below the ice, spread within the ice floes, or be incorporated into new forming ice [23].

In Arctic waters, oil spills from exploration and production activities have been rare, however, the volume of exploration and production has been far less in Arctic regions up to date. The largest blowout in the North Sea occurred at the Ekofisk B platform in 1977, due to an incorrectly installed safety valve, which led to a 202000 bbl spill (Figure 8.1).

Figure 8.1: Ekofisk blowout in the Norwegian North Sea, 1977. *Source: Aftenbladet*

8.1.2 Spill risks from transportation

Oil spill risks from transportation come from the main two transport schemes: pipelines and tankers.

A subsea pipeline transporting oil from production units to onshore facilities could suffer different release mechanisms: a sudden breach which may result in a rapid discharge, or a leak, which can be very damaging if it remains undetected for a long period of time or if there is a problem to shut down the pressure in the pipeline. The various causes for an offshore Arctic pipeline oil spill, may include ice gouging, scour, permafrost thaw settlement, thermal loads and/or corrosion. Significant amounts of oil were spilled due to an undetected pipeline leak in Alaska during March 2006. Between 750-1000m^3 of oil were leaked due to corrosion in the pipeline during transport from the Prudhoe Bay oil field. Approximately 30% of the spilled oil was recovered [24].

Oil tankers pose spill risks due to loading operations and while in transit. The potential spilled volume varies, therefore, from a small spill during transfer operations to a complete loss of cargo. The potential spill may be located above or below the surface; in addition, the response involves additional challenges since the spill could occur at any place in the transportation route. The Exxon Valdez spill in 1989 (Figure 8.2), is a relevant example of oil spill in cold environment. The tanker ran aground in Alaska while travelling outside normal shipping lanes to avoid ice [24]. The vessel gashed its hull releasing 37000 tons of oil within six hours of the grounding.

Figure 8.2: Exxon Valdez oil spill in Alaska, March 1989. *Source: USGS*

Spill prevention measures for pipelines installed in ice covered waters include the use of double walls, protection against corrosion and ice scouring and pre-scheduled maintenance, inspection and repair programs due to the difficulty of access during most part of the year. Prevention measures for tankers may include double hulls and bottoms, ice or monitor weather, engineered systems for leak detection and navigational safety programs [23].

8.1.3 Spill risks from storage and loading

The main risks of oil spill from storage come from storage tanks, facility piping or manifold valve systems on offshore platforms, and from onshore storage tanks in terminals or refineries. The worst scenario is the spill of the whole volume stored in the tank, or the volume of oil being transferred during loading operations. Spills from offshore storage or loading, may flow directly to the water or ice surface, since these facilities usually do not count with additional containment measures. Onshore storage tanks in terminals, typically have a secondary containment around the tanks. Each tank has to be surrounded by a concrete or earth wall at such distance and of such height that in the event of the collapse of a full tank, the oil can be contained within the bund [14].

According to a study of 242 tank accidents over the last 40 years [25], 48% of the accidents occurred at oil refineries, 26% happened at terminals and during loading operations, 13% occurred at petrochemical plants and only around 3% happened at offshore storage tanks.

8.2 Behaviour of Oil Spilled in Cold-Water Environment

Both the behaviour of spilled oil in regions with sea ice and the vulnerabilities of the Arctic ecosystem to spilled oil, need to be taken into account in any oil and gas operation in an Arctic area.

The type of oil, temperature of the oil and the water, wind, currents, tides and presence of sea ice, are some of the factors that will affect the behaviour, movement and weathering[1] processes. Table 8.1 shows the oil weathering processes which are affected by the presence of sea ice *(modified from [23])*.

The type of ice present, their internal structure, and the timing of the release relevant for the ice formation, will influence to a large extent the behaviour of the spilled oil into ice-infested waters. Figure 8.3 shows the different oil-ice interactions depending on the type of ice present.

In general, oil spills in ice spread much slower and occupy a smaller area than a similar spill in open water. However, the oil could spread over a large distance if it moves trapped within pieces of ice. The weathering process is slower in ice, which might be an advantage for the response effectiveness in some scenarios [26]. On the other hand, degradation is slower in coldwater areas than in temperate regions, since the oil tends to move to a more viscous form, not evaporating as quickly,

[1] Weathering of oil: term used to describe the combination of processes that change the properties of spilled oil with increasing time on the sea surface

Table 8.1: Physical processes affected by the presence of sea ice

Process	Open water	Severe cold or ice
Spreading	A thick layer of oil becomes thinner, covering a larger area of water	Ice acts as a physical barrier or retardant, slowing the spreading and dispersion process
Drift	Oil movement with wind and currents	Separate drift from the ice for <30% ice coverage, or drift with ice for 60-70% ice coverage
Evaporation	Relatively fast for thin oil films	Slowed by cold weather. Might be completely arrested if oil is buried in snow or ice
Emulsification	Depending on the type of oil. Higher when breaking waves.	Might be lower due to the reduced wave activity.

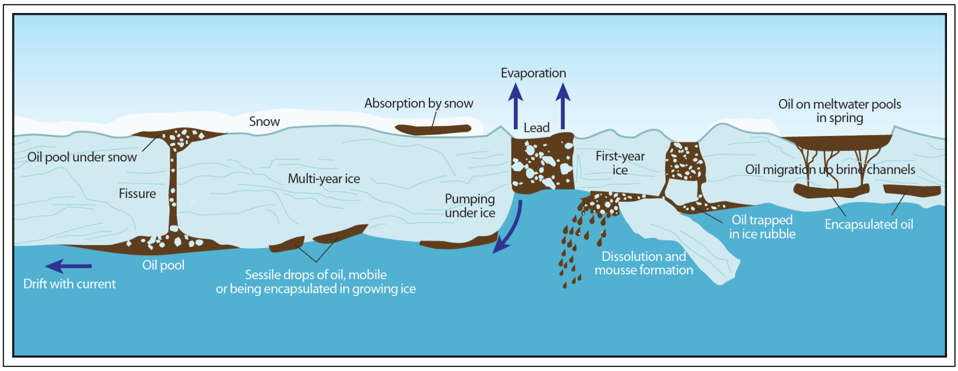

Figure 8.3: Possible distribution of spilled oil in ice-infested waters. *Source: AMAP*

and making it less accessible to bacteria, which should slowly degrade petroleum hydrocarbons spilled in the marine environment [23].

8.3 Response Techniques to Oil Spills

The Arctic is one of the most challenging areas for oil spill response. Sea ice, low visibility, high winds, rough seas and cold temperatures complicate every aspect of a spill response, from stopping a well blowout to predicting or mapping the movement of an oil spill under sea ice. In addition, the different cleanup technologies face operational limits due to wind speed, wave height, ice conditions and visibility [23]. Once the limit is reached for one or a combination of these factors, a spill response operation might be slowed or shut down for periods of time varying from days to months. On the other hand, the presence of sea ice may assist in the oil spill response operations, by acting as a natural containtment barrier under certain situations.

Effective oil spill recovery require advanced planning. The selection of the best response option depends on site specific conditions such as sensitivity of the receiving environment, ice coverage, weather, ice drift forecasts, etc.; and the assessment of the environmental impact from applying the different response options [23].

– **Mechanical recovery**

  This solution involves the physical containment of the oil by the use of booms, and its subsequent removal from the surface by the use of skimmers. The efficiency of the available technology varies depending on the type of ice and its concentration. It is difficult to use booms (typical mechanical recovery in open waters) when the ice coverage exceeds 15-30%, while in case the ice coverage is higher, the ice itself may act as a boom confining the oil. A skimmer in ice covered waters needs to deflect the ice in order to access the oil. It is also necessary to deal with low temperatures, and freezing or icing of the equipment [26]. Oil can be recovered with similar efficiency to that of open water conditions in open leads and pockets between large ice floes, however, reduced efficiency is expected in the presence of smaller ice floes and slush ice [26].

  SINTEF through the Joint Industry Program in Oil Spill Contingency for Arctic and Ice Covered Waters [27], developed two prototipes of skimmers for ice conditions which were tested in the Barents Sea during field experiments in 2009 (Figure 8.4). The results showed that brush type skimmers represent a good solution for ice processing and oil recovery. Moreover, skimmers with thrusters showed an improved capability to recover oil in ice.

– **In-situ burning**

  In-situ burning (Figure 8.5) can be used for oil on open water, on ice and broken ice, if the adequate oil thickness to sustain burning is achieved (1 to 3mm for fresh crude, more than 3mm thick for weathered crude oil [23]). As in mechanical recovery, ice may aid in the use of this technique by providing natural containtment. For ice coverage up to 30%, the use of fire resistant booms or chemical herding agents is generally required for achieving the adequate thickness.

Figure 8.4: Skimmer prototype "Framo" during field testing in the Barents Sea in 2009. *Source: SINTEF*

The window of opportunity for the use of in situ burning in ice covered waters, is under some circumstances larger than in open sea. The presence of cold water and ice can limit the spread of oil and slow the weathering processes [28].

This technique has been proven and established as part of the oil spill contingency plans in many Arctic areas. According to several field experiments performed in the US, Canada and Norway, efficiencies over 90% have been verified [27], showing this technique as one with the greater effectiveness in the removal of both free floating oil in ice and oil collected in fire resistant booms. Some of the factors influencing the success of the burning are slick thickness, oil emulsification, igniter temperature, swell/waves and wind conditions.

Figure 8.5: Controlled in-situ burning for JIP Project. *Source: SINTEF*

– **Dispersants**

Chemical dispersion can be used to enhance the formation of oil droplets in order to accelerate the natural biodegradation of spilled oil.

The weathering processes are slowed down in the presence of ice and cold temperatures, enabling a larger window of opportunity for chemical dispersion of oil. Some oils spilled in ice, remain dispersible over a period of several days [27]. However, mixing energy is required for the application of this technique. Breaking waves in open water provide this mixing potential, however, in ice covered waters, adding extra mixing energy is required to enhance the dispersion process. An extra challenge is the lower salinity of cold waters, which generally reduces the effectiveness of chemical dispersants. This option presents extra concerns due to the little information about dispersant toxicity to Arctic organisms and environments, which might be slower to recover from exposure to toxic chemicals [23].

– **Remote Sensing**

Oil spill detection and mapping is important under cold climate conditions, as oil may be hidden under snow and ice during periods of almost total darkness. The combination of sensors operating from aircraft, helicopters, vessels, satellites and the ice surface is recommended for Arctic oil spill emergency preparedness [27]. An ideal system has the capability of determining if oil is present and map the boundaries of potential contamination. Some of the most useful remote sensors and systems applicable to Arctic spills are: Side Looking Airbone Radar (SLAR); aircraft and vessel-based Forward Infrared (FLIR); trained dogs; and Ground Penetreting Radar (GPR) operated from helicopters or from the ice surface [27].

Figure 8.6 summarizes the accepted response limits for mechanical recovery (with and without ice management) and in-situ burning, for different climatic limiting factors such as ice coverage, wind, sea state and visibility[2]. The green cells represent favourable conditions for the response technique. The yellow cells represent impediments in the response operation, while the red cells indicate that the reponse option is not possible under that specific situation. It is important to notice that not only a red cell can shut down a response, but a combination of yellow cells may have a cumulative impact on the response.

[2]Chemical dispersion is not included in this matrix due to the immaturity of the technology under cold climate conditions, not being an authorized response method in some areas, for instance the US Arctic Ocean.

Figure 8.6: Oil spill response limits matrix. *Source: U.S. Arctic Program*

8.4 Knowledge Gaps and R&D Priorities

Significant gaps exist in knowledge, planning, and oversight in the areas of oil spill risks, impacts and response capabilities. In addition, baseline science for Arctic marine environments is improving but is still limited. There is, therefore, a research need to better understand the behaviour and impact of oil spilled in a seasonal ice environment and specific technology priorities.

- Arctic Oil Spill Impacts

  Most of the existing knowledge in oil toxicity and chemical interaction comes from temperate climate studies. Oil spills impacts in cold locations might be significant and long lasting. The 2008 Arctic Oil and Gas Assessment Scientific Findings and Recommendations (AMAP Assessment [24]) emphasizes that the current state of knowledge regarding Arctic oil spill impacts and oil toxicity to Arctic species is extremely limited. In the Norwegian Barents Sea, research carried out by SINTEF [28], has added knowledge on the sensitivity of Arctic species to dispersed oil and other contaminants.

- Arctic Oil Spill Trajectory Models

  Better trajectory modeling is needed to develop realistic oil spill planning scenarios. Existing models are not able to accurately predict how oil and ice interactions will affect oil movement under ice carried by currents and oil drifting with the sea ice [24].

- Other Research and Technology Priorities

  - Solutions and technologies adapted to be used in cold climate (including ice), seasonal darkness and remote locations.
  - Reliable surveillance and monitoring (subsea and on surface) technologies, including automatic detection of spills and leakages.
  - Standardized methods for efficiency testing of oil spill response equipment and techniques.

Chapter 9

Technical Aspects for Pipelines and Harbours

Feasible and cost effective terminal concepts for cold climate areas need specific assessments of technical solutions and design parameters. It has already been pointed out that environmental issues are of critical importance in cold climate areas, which makes safety and reliability of structures even more significant, requiring redundancy and backup solutions for safe operations. This chapter focus on technical considerations to take into account under cold climate scenarios, related to pipeline, breakwater and harbour design.

9.1 Pipeline Design Specific Issues

Due to climate conditions and ice coverage, the design and installation of pipelines in cold climate areas, imposes certain challenges that do not apply elsewhere. These include the evaluation of environmental and geotechnical data, specific design according to those conditions, and construction and installation limited by harsh environmental conditions.

9.1.1 Environmental loading

Some of the main considerations with respect to pipeline design for cold climate areas include ice gouging, thaw settlement of permafrost, upheaval buckling and strudel scour. These loading conditions on subsea pipelines will be presented separately here, however, assessment of interaction situations will usually be required for a specific project.

– **Ice Gouging**

  Ice gouging represents one of the main threats to submarine pipelines in the Arctic, being therefore among the key design issues in both pipeline design and route selection. The phenomenon is caused by ice masses running aground in shallow waters. The ice bodies are mainly icebergs or ice ridges which have

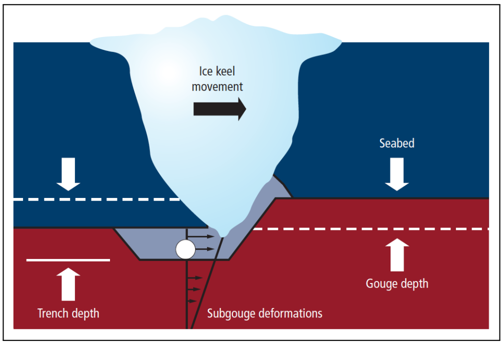

Figure 9.1: Simplified scheme of an ice keel-seabed interaction. *Source: Touch Briefings*

a keel extending below the water surface, cutting deep gouges into the seabed (Figure 9.1). For a safe design, the soil displacement induced at the pipeline depth, and the resulting pipe strains must be assessed and checked against design limits.

Ice ridge gouging often increases with depth outside the fast ice zone, with the maximum gouges found between 20 and 40m. This phenomenon has been observed in many Arctic locations such as the Canadian Arctic Islands, offshore Sakhalin, the north area of the Caspian and the Beaufort Sea, with dimensions of around 80m wide and up to 5m deep [29].

The loads generated on the seabed by a gouging ice body might be between 10 and 100MN [30]. It is thus, impractical to design a pipe which can withstand those loads. Therefore, a protective measure needs to be approached. The main alternatives are: ice management, shielding and trenching-burial (Figure 9.2).

- *Ice management*: deviating the drifting of ice features threatening the structure through the use of ice management is a possible approach for specific situations. However, this may not be an optimum solution when considering protection of the whole length of a pipeline against ice gouging, due to the resources that would be required for ice detection and management. Furthermore, this is not an adequate solution in the shore approach zone.
- *Shielding*: construction of a protective structure which absorbs the energy delivered by a potential ice body impact, might be a solution, for instance, adopted for the pipeline´s shore approach. However, it would not be a cost-effective technique to be applied over longer stretches of pipeline.

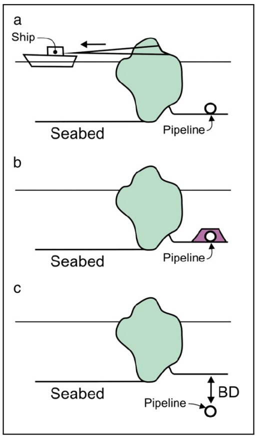

Figure 9.2: Protection against ice gouging: a)ice management; b) shielding with a structure; c) burial at a burial depth BD. *Source: P. Barrette, 2011*

- *Trenching and burial*: this is the common approach for protection against ice gouging, which in addition presents advantages in terms of protection against loading from waves and currents, thermal insulation and buckling, for instance [31].

  The main issue to be addressed is the optimization of a safe and economic burial depth given the length of this type of pipelines. Gouging by an ice keel results in large sub-scour horizontal and vertical deformations [32], not guaranteeing the safety of a pipeline buried below the maximum scour depth predicted. To make this option economically feasible, ice management can be used in combination with a trenching approach, reducing the probability of an encounter.

  A new approach suggests the use of a weak layer above the pipeline in order to reduce forces and soil displacements transmitted downwards [31], which could be translated in a reduction of pipe burial depth. This has been shown recently by a study on protection of subsea pipelines against ice ridge gouging [33], which suggests to trench the pipeline right below the possible gouge with the subsequent backfilling by very soft clay on top of the pipeline, and with the insitu sand to the original seabed level. This was shown to minimize the scour depth allowing clay to flow around the pipeline, without substantial resistance [33].

– **Thaw Settlement**

Thaw settlement is an important issue for pipeline design in cold climate areas. Transport of oil or gas from an offshore field to an onshore terminal, may involve a buried pipeline crossing permafrost. In the nearshore area

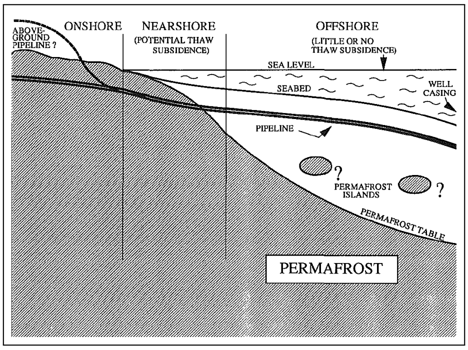

Figure 9.3: Offshore to onshore permafrost section. *Source: J.F. Nixon, 1991*

(Figure 9.3), when the pipeline is in operation, temperatures above the melting point of the surrounding permafrost might cause thaw, reducing the carrying capacity of the soil, and therefore, causing settlements beneath the pipeline.

The effects are worsened if differential thaw settlement occurs. That is the case in areas of low thaw settlement, such as sands and gravels, adjacent to areas of high sensitivity to settlement such as silts and clays. These differential settlements would result in curvatures and bending strains in the pipe.

According to an analysis on thaw subsidence effects on pipelines in the Beaufort Sea [34], a buried offshore pipeline under the range of soils considered in the study, was able to accomodate up to 1m of thaw settlement if the permafrost layer was located 3 to 4m below the pipeline. However, when the permafrost layer is closer to the pipe base, a mitigation solution is required to reduce the possible damages in the pipeline.

Some of the techniques to minimize settlements of thawing permafrost may be the use of a thaw-stable bed of gravel beneath the pipeline or the use of a foam sheet insulation around the pipe [29].

– **Upheaval Buckling**

A buried steel pipeline may suffer thermal expansion during operation, when the temperature and pressure are higher than the ones experienced during installation. Expansion is restrained by the surrounding soil, and in that case, an axial compressive force develops (Figure 9.4), which will tend to move the pipe upwards. The pipeline response might be unacceptable in case of excessive vertical displacements or plastic yield deformations [35].

Although this issue is not unique to cold climate environments, pipes in such conditions are installed at lower temperatures, experiencing therefore a larger temperature gradient when operation starts. In addition, the pipeline could become exposed, increasing the risks of ice keel impacts [29].

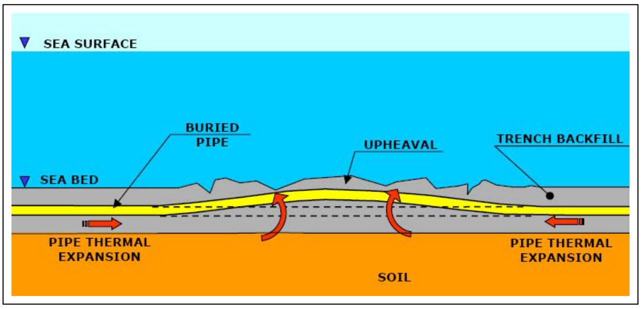

Figure 9.4: Upheaval buckling illustration. *Source: B. Abdalla et al., 2008*

The design should take into account the minimum backfill thickness to be placed on top of the pipeline to hold it into the installed position, and the maximum permissible vertical displacement of the installed pipe.

Since this mechanism is very sensitive to imperfections or points of residual vertical curvature in the pipeline, the main way to minimize the risk of buckling is the use of additional backfill weight over these imperfection points.

– **Strudel Scour**

Strudel scour is possible in cold climate areas in the presence of a stream flowing over the surface of an ice sheet in the nearshore zone. The overflowing water drains through cracks in the ice sheets, being able to scour the seabed depending on the resulting velocities and volumes of water (Figure 9.5). This phenomenon has been observed in some pipelines in Arctic projects. At the Beaufort Sea, in the Northstar development, a strudel scour of 30 meters wide was documented, having a maximum depth measured of 1.7 meters [36].

The probability of a strudel scour should be evaluated prior to designing for such phenomena.

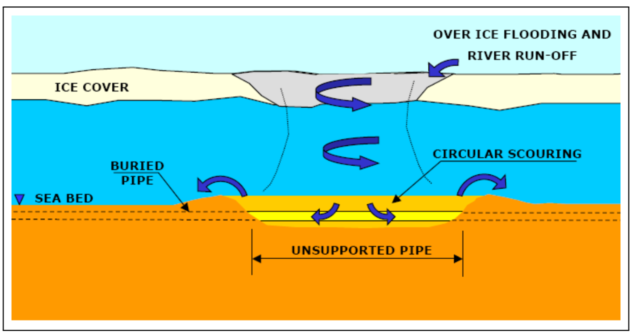

Figure 9.5: Strudel scour illustration. *Source: B. Abdalla et al., 2008*

9.1.2 Shore approach protection solutions

A pipeline shore approach is defined as the section from where the pipeline enters the breaking wave zone to the point where it reaches shore [37].

The analysis and design of the pipeline shore approach, presents unique demanding issues that are not present in deep water pipeline sections. Particularly in cold climate areas, designing shore approaches is often more problematic due to coastal erosion and pipeline interaction with nearshore permafrost.

Among the shoreline protection solutions are the following:

- *Tunneling*

  If continuous permafrost is present in the area, a tunnel may be an appropriate solution for the nearshore area. For this solution to be feasible, the permafrost temperature in the area must be sufficiently low for drilling and mantaining the tunnel without artificial refrigeration [11].

  This method has been already applied in several field developments in the Norwegian coast. For instance, tunnels have been the design chosen for the wet gas pipelines from the Troll and Kvitebjørn fields arriving at the Kollsnes gas processing plant.

  The pipelines arriving from the North Sea at the Kårstø processing plant, are placed in 600m concrete tunnel, consisting of 5 bridge elements, at the shore approach [38].

- *Retaining structures*

  Retaining walls may be built in order to protect the shoreline from erosion, preventing the potential degradation at the crossing point. The different structures can be sheet pile walls, concrete retaining structures, and cellular sheet pile walls. The last one offers several advantages, although is the more expensive option [11]. The cells are filled with site material, which is stable while is frozen. Refrigerating systems such as thermosyphons may be installed inside the cells for that purpose.

Some Arctic projects such as the PanArctic Drake and Pioneer Oooguruk projects in the Canadian and US Arctic, have explored innovative mehods to protect and install pipelines in extreme environmental conditions.

The Drake field pipeline was the first arctic subsea pipeline transporting gas (1978) to a production facility onshore at Melville Island, Canada. The shore approach solution (Figure 9.6), involved placing the pipeline in a shallow trench,

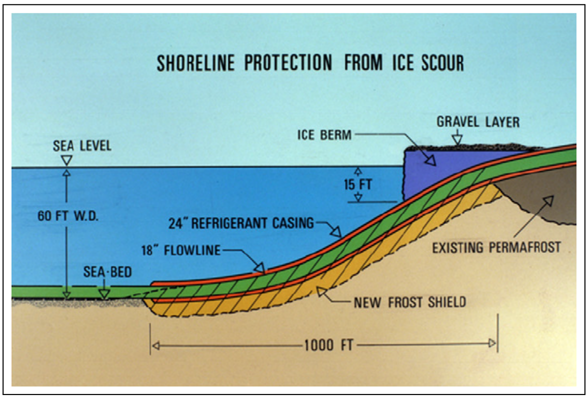

Figure 9.6: Shore approach for the Drake pipeline. *Source: SNAME*

1.5m deep, back filling the trench with gravel and freezing the soil around the pipe, forming a strong cyllinder of artificial permafrost [39]. This artificial permafrost system extends from 15m onshore to 280m offshore, where there is a water depth of 20m. An increased protection was given in the shallow water area by constructing a grounded ice berm of 2.1m thick, which was built using ice platform construction techniques[1].

For the Oooguruk oil field in Alaska, produced fluids are transported to shore by a multiphase pipe-in-pipe system. The shore crossing consists of a narrow beach and an eroding bluff of approximately 2.5m. The shore crossing (Figure 9.7), was set back 60m from the bluff line to accommodate predicted shoreline erosion and potential for ice over riding. In addition, the shore approach design included a thaw stable gravel bedding beneath the pipe and a short length foam sheet insulation. This thermal design was chosen to keep the thaw-unstable permafrost frozen and to keep the pipelines from settling [40].

Finally, an option that might be also considered, is to set an acceptable shoreline degradation. In this case, there are no shoreline protection measures, but a level of permanent degradation, based on the present erosion rate is accepted. Aspects such as erosion rate and design lifetime of the pipeline must be taken into account to assess the profile of the pipeline at the crossing point. In case the level of erosion increases unexpectedly, it is possible to proceed protecting the shore crossing, for instance through a concrete protection [11].

[1]This technique consists of flooding and natural freezing of the ice in layers, up to the desired thickness.

Figure 9.7: Oooguruk shore crossing aerial photograph. *Source: G. Lanan et al., 2008*

9.2 Breakwater Design Specific Issues

Terminals need to be protected from environmental conditions to achieve safe tanker operations. Breakwaters are built for that purpose. The main difference in the design of breakwaters in cold climate, is that they are subjected to ice actions in addition to wave forces.

Recent developments in cold climate breakwater design, for instance in Norway or Iceland, favour the use of berm type breakwaters. The main advantages for the use of this type of breakwater in cold climate harbours will be reviewed in the following sections. However, these type of structures require good quality rock access. The caisson type breakwater is usually a good alternative for cold environments, in case that suitable rocks are not available at the site [32].

9.2.1 Berm breakwaters as protection for cold climate harbours

Berm breakwaters (Figure 9.8), present several advantages as harbour protection in Arctic areas compared to a conventional rubble mound breakwater [32], [41], [42]:

- Less mass of the individual armour stones is required than for a classical rubble mound breakwater.
- Limits the ride up events if ice is present and thus, limits the possibility of ice floes overtopping the crest of the breakwater.
- The piling up of ice on the berm may have a consolidation effect on the breakwater, limiting potential global failures.

– Greater acceptance tolerances with respect to placement accuracy.

– Readily available and less specialized construction equipment and labor compared to the construction of a conventional rubble mound.

– Increases navigational safety for narrow entrances with heavy breaking waves due to decreased reflection, compared to conventional breakwaters.

– Low overtopping potential, which benefits the protection of cold climate harbours, due to potential icing from spray in the berths behind the breakwaters.

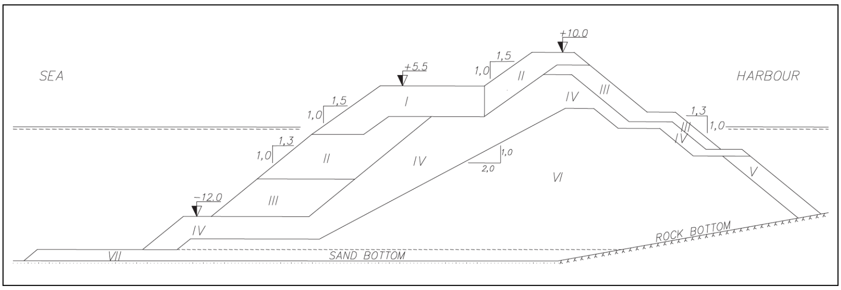

Figure 9.8: Cross section of the Sirevåg berm breakwater. $H_{S,100} = 7.0m$; $T_Z = 10.6s$; $H_0T_0 = 48$. Berm: 20m wide. *Source: A. Tørum et al., 2011*

Some experiences of breakwater design in cold climate regions, confirm the efficiency of berm breakwaters against extreme environmental actions, including ice.

The North Bay area in Ontario, Canada, presents an interesting case in which two breakwaters, a conventional rubble mound and a berm breakwater, are located closed to each other. The behaviour of these two breakwaters after the winter season in 1988, showed that while the rubble mound suffered severe damage by ice, the berm breakwater suffered almost no damage in the same event. The berm reduces the likelihood of rock movement by ice. Moreover, the presence of ice between rocks, may act as a cement to help resist external ice forces [43].

The berm breakwater in Sirevåg, Norway (Figure 9.8), was hit by a severe storm in 2002. The maximum recording during the storm was $H_S = 9.75m$, and the wave height exceeded $H_S = 8.5m$ for a duration of 3 hours [44], well above the design wave of $H_{S,100} = 7m$. The breakwater survived the storm without any reshaping, and only a few stones were moved from the original location (Figure 9.9). Moreover, an analysis of the probability of failure regarding recession on the Sirevåg berm breakwater carried out by A. Tørum et al. in 2011, using Monte Carlo simulations, showed that the breakwater is extremely strong, which in general should favour the berm breakwater designs [41].

Figure 9.9: The Sirevåg berm breakwater after the storm in January 2002. *Source: P. Bruun, 2006*

9.2.2 Icelandic type berm breakwater

Berm breakwaters have different stability criteria, and may be divided in three categories:

- Reshaped static stable berm breakwater, *i.e. the profile is reshaped into a profile which is stable and where the individual stones are stable too.*
- Reshaped dynamic stable berm breakwater, *i.e. the profile is reshaped into a stable profile, but the individual stones may move up and down the slope.*
- Non-reshaped static stable berm breakwater (Icelandic type), *i.e. only few stones are allowed to move.*

Traditionally, berm breakwaters have been able to reshape statically or dinamically. A modification of the original berm breakwater has been developed in Iceland as a statically stable berm breakwater (*Icelandic type*). The structure is more stable and at the same time involves less volume [44]. This is the case of the Sirevåg breakwater presented in the previous section.

The Icelandic type breakwater uses several narrowly graded armour classes. The larger armour classes are placed at the most exposed locations within the cross section. These armour classes, have a higher porosity than wider graded armours, and thus higher permeability, which increases the stability of the structure and decreases both the overtopping and reflection from the structure.

An Islandic type breakwater, was chosen to protect the Melkøya LNG terminal in Norway (Figure 9.10). Since the terminal is located in a cold climate area at

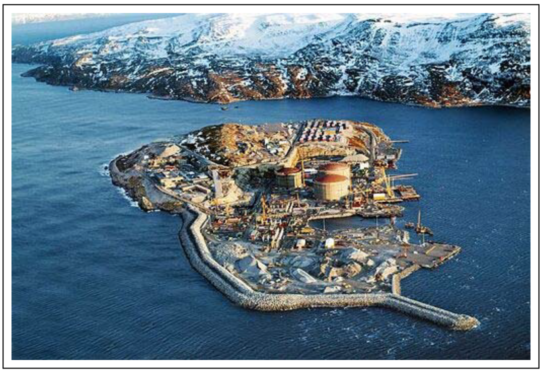

Figure 9.10: Icelandic type berm breakwater protecting Melkøya terminal, Norway. *Source: Statoil*

$70\,^{\circ}N$, icing from frozen sea spray is an important issue, and represents significant difficulties for the terminal operations. One of the main reasons for using an Icelandic berm breakwater as harbour protection in this case, was therefore the potential reduction of wave overtopping, in order to avoid icing issues in the terminal.

9.2.3 Caisson type breakwater

Other proposed designs for cold climate harbour protection, are caisson type breakwaters. This is an option in case suitable rock material is not available. Knowledge on ice forces from other type of structures used in the oil industry, have been applied to some extent to the caisson type breakwater [42].

The design of caisson breakwaters to withstand wave and ice loads, usually implies a larger height than the normally used for a conventional caisson breakwater. The reason is mainly protection against ice pile-up. Although different ice load codes give significantly different values, the given ice loads are, in general, larger than the wave loads, requiring therefore a much wider and heavier caisson design. According to A. Tørum (2011), a caisson with a slopping front may be an attractive solution [42].

Most caisson type breakwaters are built with rectangular shaped caissons. However, circular caissons have been used in some harbours, *i.e. Hanstholm, Denmark*. According to a recent study on wave forces on a composite breakwater with circular caissons [45], this type of breakwater may be an option in feasibility studies for high risk breakwaters. This breakwater concept has been studied for a breakwater under planning for protection of a LNG terminal in Teriberka, Russia, which is planned to process and export the gas coming from the Shtokman field (Figure 9.11).

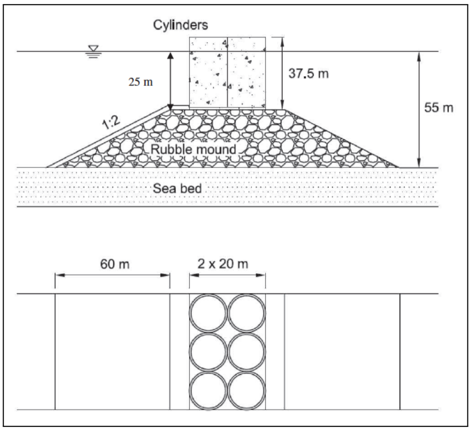

Figure 9.11: Composite breakwater with circular caissons used for model tests by A. Tørum et al., 2012. *Source: A. Tørum et al., 2012*

The breakwater dimensions are 1150m long at a maximum water depth of 55m. The design wave for the Ultimate Limit State (ULS) is $H_D = 16m$ and $T_p = 15.8s$. The results show a significant reduction on horizontal wave forces compared with the forces obtained in a vertical straight wall. Even with an overprediction of 10% for the Goda formula (see Appendix A), the results still indicate a reduction between 10-15% for high waves by using circular caissons instead of plain wall vertical caissons [45].

9.2.4 Shoulder ice barrier

A new concept for ice barrier structures, is the Shoulder Ice Barrier (SIB) (Figure 9.12). The main modification to traditional ice barriers, is the shoulder section, which aims to collect smaller ice pieces and to avoid ice overriding [46].

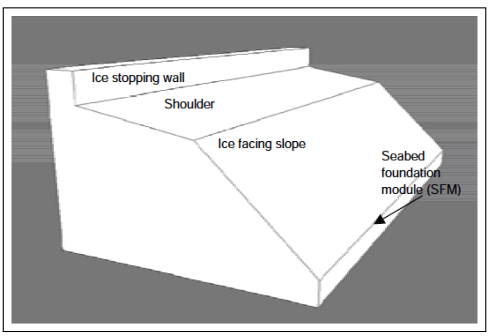

Figure 9.12: Shoulder ice barrier illustration. *Source: A. Gurtner, 2009*

The idea behind the shoulder section has been developed from the design of static stable berm breakwaters. The SIB concept, is designed as a gravity based caisson structure with the so called "shoulder section". The main purpose of this design is that the ice can potentially override the inclined surface and stabilize on top of the shoulder section. The generation of the ice rubble, and consequently the extra weight placed on top of the structure, provides extra sliding resistance (Figure 9.13).

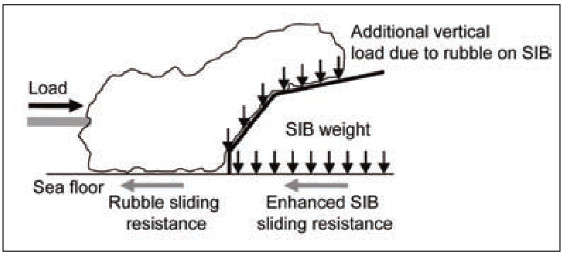

Figure 9.13: Enhanced barrier sliding resistance. *Source: A. Gurtner, 2009*

Model tests of the SIB concept were carried out at the Hamburg Ship Model Basin, Germany, during 2007. The results showed that the shoulder section performed its function satisfactorily, breaking the ice in smaller pieces and avoiding ice overriding [47].

Although the main purpose of ice barriers is protection of offshore structures against drifting ice and against significant loads exerted by the ice-structure interaction, the SIB concept may also be used as a breakwater at ice infested harbour locations. In that case, the wave forces may govern the stability and therefore the design of the structure. Thus, a modified version of SIB for 16m water depth was tested in a wave flume at the Norwegian University of Science and Technology (NTNU), in 2007. The results of the measured wave forces and overturning moments showed, that the wave forces are significantly reduced compared to the results obtained applying the Goda formula (see Appendix A) for vertical wall caissons [48].

9.2.5 Theoretical formalisms

A quantitative discussion regarding berm and caisson breakwaters is presented in this section. For berm breakwaters, the stone size has been determined as a function of wave height and period. For the caisson breakwater type, the maximum horizontal force on the vertical wall has been determined as a function of wave height and period. Two Excel programs have been set up for this purpose. The detailed formulations, parameters employed, and generation of curves can be seen in Appendix A.

1. **Berm Breakwater**

Several threshold criteria are defined to prevent the movement of rock (Table 9.1). If the hydraulic load exceeds the mobility threshold, instability of the armour layer occurs, and the stones move. The most used parameters to evaluate the stability of the armour layer are the stability number H_0 (A.1), and the period stability number, H_0T_0 (A.2).

Table 9.1: Mobility criteria

Category	H_0 (A.1)	H_0T_0 (A.2)
Non-reshaping	<2	<40
Reshaping, static stable	<2.7	40-70
Reshaping, dynamic stable	>2.7	>70

Both numbers can be used as stability criteria for the armour layer. If H_0 is used, only the effect of wave height is being taken into account. If H_0T_0 is used, wave height and period are combined with the same exponent[2].

An Excel program has been set up in order to calculate the dependency of the armour size on wave height and wave period. Reference is made to Appendix A for the detailed explanations on the generation of curves. Figure 9.14 shows the results obtained for the Icelandic berm breakwater, by using the stability number as mobility criteria. Thus, only the effect of the wave height is taken into account.

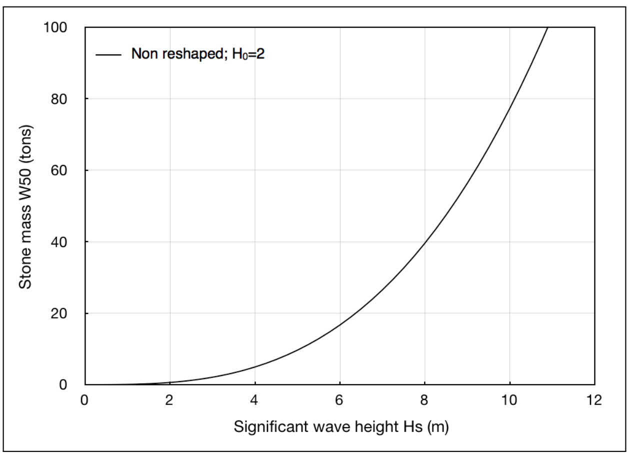

Figure 9.14: Stone size as a function of significant wave height by using H_0 as mobility criteria for non-reshaping breakwater.

[2]The criteria presented is for an angle of attack $\beta = \pm 20\,^\circ$, and depends on stone gradiation.

It can be observed that, for instance, a significant wave height of $H_S = 8m$ would mean a requirement of approximately $W_{50} = 40t$ for the largest armour class.

If the period stability number is used as mobility criteria, then the effect of wave period is included in the calculation of the armour size. Figure 9.15 shows the results obtained for the non-reshaped static stable case for five different wave heights.

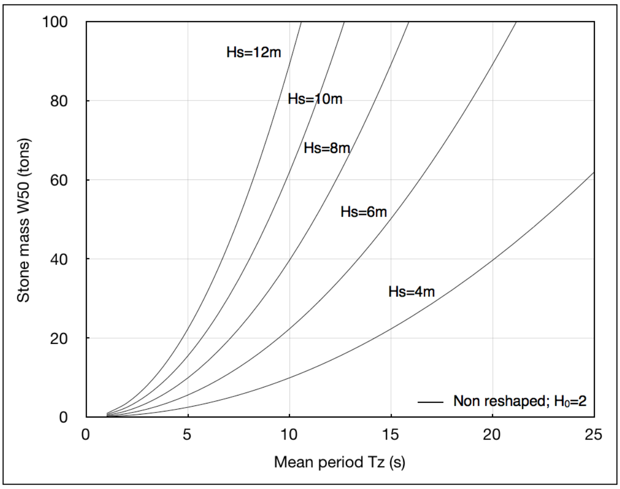

Figure 9.15: Stone size as a function of significant wave height and mean period by using H_0T_0 as mobility criteria for non-reshaping breakwater.

It can be observed that the curves get steeper with increasing wave height. That means that a change in mean period from $T_z = 5s$ to $T_z = 10s$ represents a stone mass requirement of 2.5 tons to 10 tons approximately for a significant wave height of $H_S = 4m$. However, if the wave height is $H_S = 12m$, the difference in period involves a large difference in rock size requirement, going from 20t for the 5s period up to 90t for the 10s period.

Moreover, both graphs (Figures 9.14 and 9.15) can be compared for the same wave height, for instance $H_S = 8m$. The use of the stability number as mobility criteria gives us a stone size requirement of 40t (Figure 9.16). If the period stability number is used as mobility criteria, for the same wave height $H_S = 8m$, the $W_{50} = 40t$ mass of the largest armour layer corresponds with a mean period of $T_z = 10s$. However, this value may vary significantly in case the actual wave period does not correspond to that exact value. For instance, for the same wave height of $H_S = 8m$, an increased period of $T_z = 13s$ would give a requirement of $W_{50} = 63t$ by using this criteria (Figure 9.17).

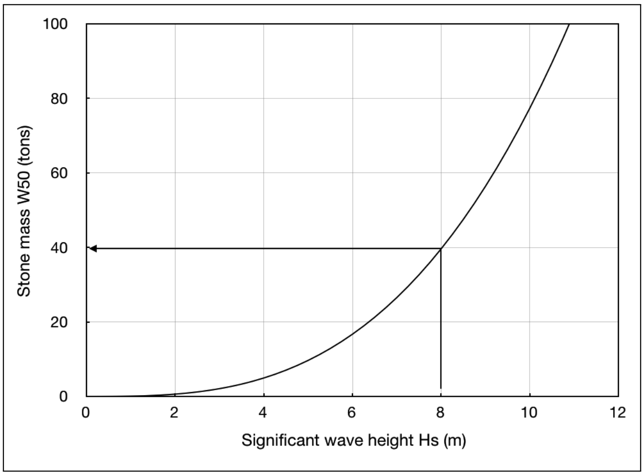

Figure 9.16: Stone size dependence on wave parameters by using different mobility criteria. Use of stability number.

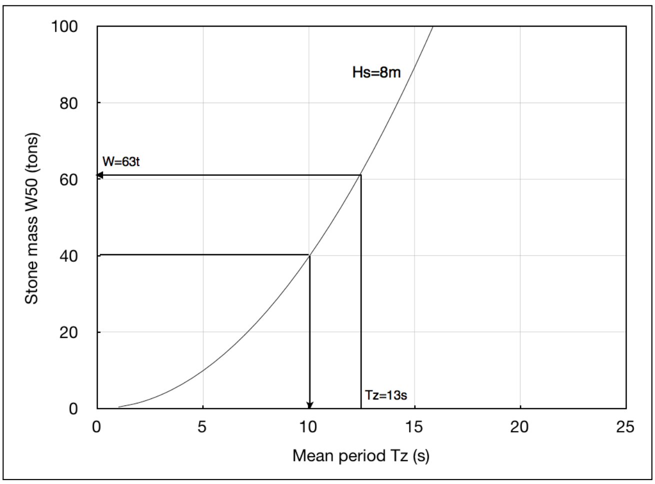

Figure 9.17: Stone size dependence on wave parameters by using different mobility criteria. Use of period stability number.

For a comparison of results for non-reshaped and reshaped static stable berm breakwaters, see Appendix A.

2. **Caisson Breakwater**

   The maximum horizontal force on the vertical wall of a caisson breakwater has been calculated, using Goda formulation, as a function of wave parameters such as design wave height (H_D) and peak period (T_p). An Excel program has been set up for this purpose. Appendix A, presents the detailed formulations, caisson configuration and parameters used for the calculations.

Figure 9.18 shows the results obtained for the maximum horizontal force on the vertical wall of a caisson as a function of the design wave height and for four different wave peak periods. Notice the geometry of the caisson used for the calculations, Figure A.4.

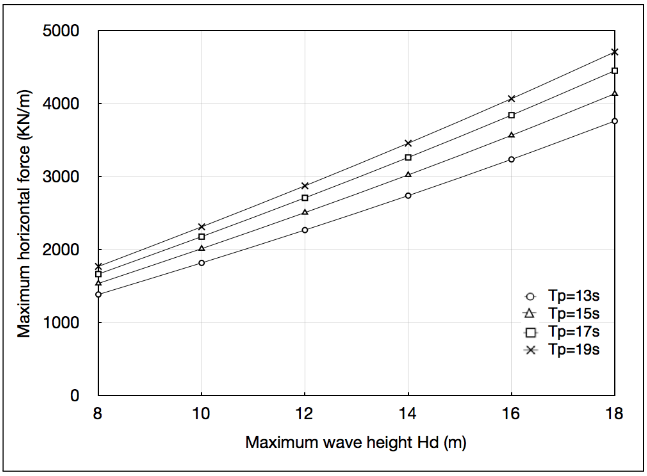

Figure 9.18: Maximum horizontal force on the vertical wall as a function of wave height and period

The results show an approximately linear trend incrementing around $500kN/m$ for a variation of 2m in the maximum wave height. The wave period in this case does not influence extremely the maximum horizontal force. The difference between a wave peak period of $T_p = 13s$ and $T_p = 19s$ for the same wave height, shows a variation of around $300kN/m$.

9.3 Harbour Oscillations

Harbour oscillations are wave motions of long periods that may cause damaging surge and disruption in harbour activities. The oscillations are caused by standing waves with periods between 30 seconds and 10 minutes. This type of long period waves may be free long waves generated out in the ocean, or bound long waves associated with groups of storm waves.

Even relatively small vertical motions can be accompanied by large horizontal motions. Factors influencing the characteristics of the oscillations are generally controlled by basin shape, size and water depth [49]. The situation is more damaging if the incoming period matches the natural period of oscillation of the harbour.

If the characteristic length of the harbour is of the same order of magnitude as the wave length associated with an important mode of oscillation, large resonant motions may result. The phenomenon is also referred to as harbour resonance.

In addition, moored ships may have the same range of periods as harbour oscillations, so these can create dangerous issues regarding high mooring forces, fender system problems, vessel collisions and delays in loading operations at the harbour.

Harbour oscillations are usually initiated by forcing through the harbour entrance, thus, they can not be considered closed basins. Harbour oscillations differ from long period standing oscillations in closed water bodies in the main following ways [50]:

- Harbour oscillations are usually initiated by forcing water through the harbour entrance from the open sea. The main forcing mechanisms include infragravity waves, currents moving past the entrance and generating eddies, and tsunamis or local seismic activity.
- Energy losses of harbour oscillation are mainly due to radiation through the harbour entrance.
- A harbour basin can resonate in a specific fundamental mode referred as Helmholtz resonance. This mode is absent in closed basins.

In harbours of simple geometry, modes of oscillation may be predicted from the shape of the basin. In those cases, the response characteristics can be determined based on analytic solutions, approximating the geometry of the harbour by an idealized, simple shape such as a rectangle.

A harbour basin generally has several modes of oscillation with corresponding natural resonant periods and harmonics. The most important mode is the fundamental or lowest mode (n=0). For the simplest case, a rectangular basin with uniform depth, the fundamental mode of resonance occurs when the wavelength of the wave is equal to four times the length of the harbour (Figure 9.19).

The general expression for the free oscillation period is:

$$T_n = \frac{4l_b}{(1+2n)\sqrt{gd}} \tag{9.1}$$

where:

T_n: natural free oscillation period

n: number of nodes along the basin axis

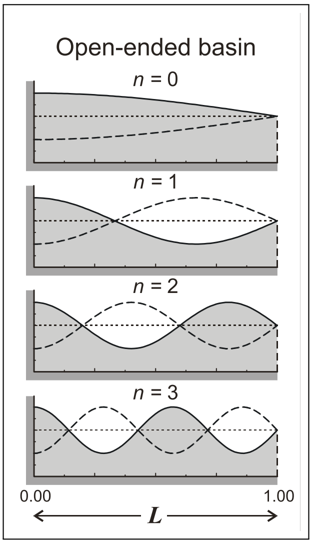

Figure 9.19: Surface profiles for the first four oscillating modes in open rectangular basins of uniform depth. *Source: A. B. Rabinovich, 2008*

l_b: basin length along the axis

g: acceleration of gravity

d: water depth

Of important concern for harbour operations and ships, are the strong currents associated with the standing waves. The maximum horizontal velocities occur at the nodes. Therefore, the locations in the vicinity of the nodes are the potentially more risky and unsafed areas [50]. The maximum current can be estimated as:

$$V_{max} = \frac{H}{2}\sqrt{\frac{g}{d}} \tag{9.2}$$

where:

V_{max}: is the maximum horizontal velocity at the node

H: is the standing wave height

Figure 9.20 shows a practical graph for evaluation of resonant length and amplification factor[3] of rectangular harbours with symmetric entrance.

[3]The amplification factor is defined as the ratio of wave height along the back wall of the harbour to standing wave height along a straight coastline (twice the incident wave height).

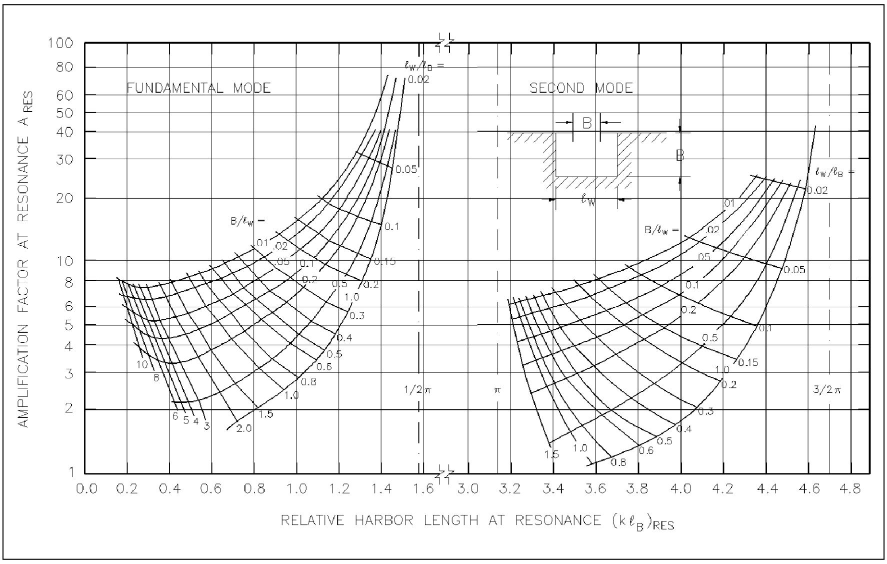

Figure 9.20: Resonant length and amplification factor of symmetrical rectangular harbours. *Source: Coastal Engineering Manual*

For reading the graph, it is important to define the relative harbour length kl_b, where $k = 2\pi/L$ is the wave number, and l_b is the basin length. The kl_b values (x-axis) can be converted to resonant periods by the following expression [49]:

$$T = \frac{2\pi l_b}{\sqrt{gd}} \frac{1}{kl_b} \tag{9.3}$$

The curves represent a range of basin aspect ratios l_w/l_b, which relates the width of the basin (l_w) with its length (l_b); and relative entrance withds B/l_w, in which B is the width of the mouth. As it can be observed, the character of the natural oscillation in the harbour depends strongly on the relative aperture. The smaller the width of the entrance, and thus the ratio B/l_w, the slower the entrance of water penetrating from open sea into the basin. By narrowing the harbour entrance, the amplification factor increases, and therefore the arriving wave is amplified. The operational impact of harbour oscillations is defined by the amplification factor (y-axis). An amplification factor $A > 5$ will cause some problems, while a factor $A > 10$ will mean major operational problems [49].

The ratio between the natural period of the harbour and the incoming wave period (T_N/T), determines the degree of amplification. The greatest amplification occurs when $T_N/T = 1$. The amplification factor decreases at each successive higher order mode, therefore, simple analysis methods usually focus only on the lowest order modes [49].

The worst case scenarios, which involve low modes of resonance and the greatest amplification ($T_N/T = 1$), have been represented in Figures 9.21 and 9.22 applying (9.1) for different water depths and simplified rectangular harbour basin lengths, resulting in the different wave periods that would cause harbour resonance for each configuration.

For the selection of the water depths used in the analysis, reference is made to the information contained in Chapter 5, section 5.4.2, where the main dimensions of liquid bulk carriers where presented, including their fully loaded draught. It can be seen that the bigger crude oil tankers might have a deep draught (*i.e. up to 24m*), while the LNG gas carriers and intermediate size oil tankers are in the range of 12m. Based on that, depths of 15m (Figure 9.21) and 25m (Figure 9.22) have been plotted.

It can be observed from the resulting graphs, that deeper harbours are more prone to harbour oscillation concerns. Focusing the attention on the fundamental mode of resonance (n=0), it can be observed that the differences between the 15m depth port and the 25m depth port, are significant. For instance, a deepwater port accomodating large crude oil tankers (Figure 9.22), with a rectangular basin of around 200m, will result in a resonance situation for waves with periods around 16s, which is not an uncommon situation. As it will be seen later on in this report, peak periods for the 100 year return period are of the order of 15s for both Melkøya and the future Veidnes terminal for Johan Castberg field. It is therefore of great importance to take into account the resonance phenomena inside the harbour during design, specially for deepwater harbours with the intention of accommodating large draught oil tankers.

In the majority of situations, the harbour will differ significantly from a simple shape. For these cases, physical and numerical model tools can be effectively applied for accurate results regarding the wave conditions and behaviour in the harbour.

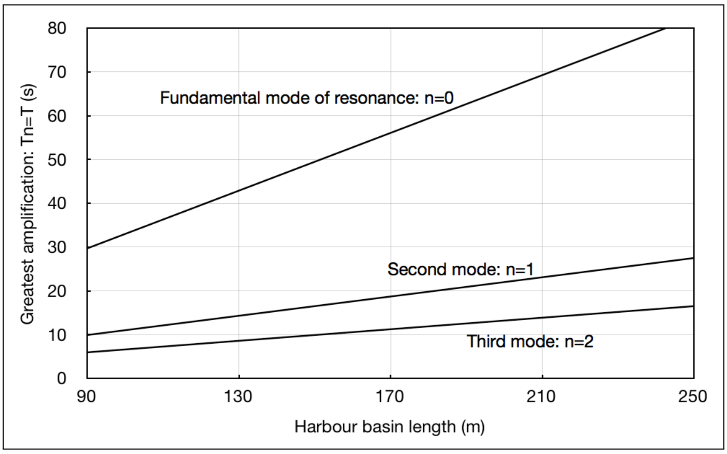

Figure 9.21: Resonance in a 15m water depth harbour for low resonance modes.

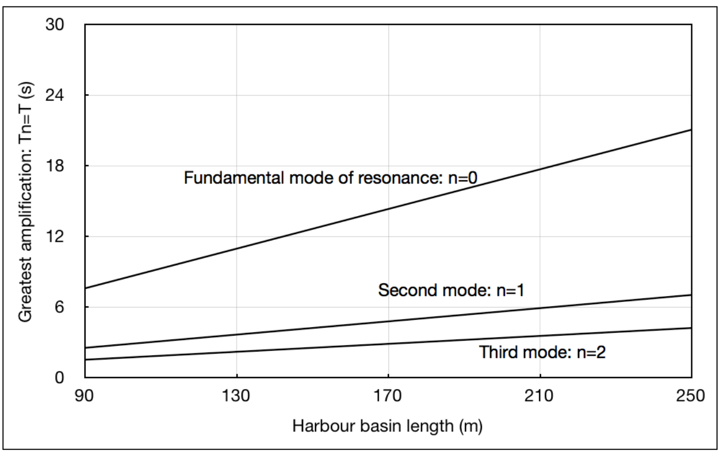

Figure 9.22: Resonance in a 25m water depth harbour for low resonance modes.

Chapter 10
Operational Aspects of Terminals

Specific issues are relevant to develop a terminal project in a cold climate or Arctic region. This chapter will address some of the main operational aspects to take into account when dealing with Arctic terminals.

10.1 Terminal Arrangement

10.1.1 Harbour layout

Oil and gas terminal layout in cold climate environments does not differ substantially from the design basis for temperate harbours.

The location of the terminal berth should pursue the following principles [16]:

- Oil and gas berths are separated from other port facilities for safety reasons. No other shipping should be allowed inside the harbour basin.
- The berth shall be fugitive, if possible. This means that the ship could stay at berth under all weather conditions. This is particularly interesting for liquid gas tankers, as these can only sail with the tanks either full or empty, since contrary to oil tankers, gas carriers have no partitions in their cargo tanks. When in open sea, if partially filled, a rupture of the tank wall and loss of stability of the ship may occur due to sloshing of fluid in the tank.
- The orientation of the berth, if possible, should be such that the mooring loads are minimized. Usually this is achieved by aligning the berth axis with the current direction. In case the current is weak, it is advised to orient it parallel to the prevailing wind direction.

The type of structure used for oil and gas berths varies from quays to jetties (Figure 10.1). Table 10.1 shows the main advantages and disadvantages of the two types of structure.

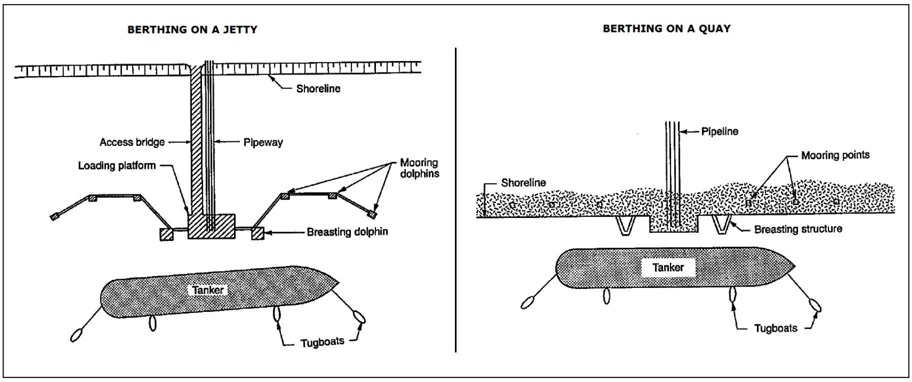

Figure 10.1: Comparison between a quay and jetty layout for berthing. *Source: modified from Thoresen, 2010*

Table 10.1: Comparison between structures for oil and gas berths

Type of Structure	Advantages	Disadvantages
Jetty	Flexible structure	Vulnerable for abnormal berthing
	Prefabrication	Vulnerable for ice loads
	General low costs	Low flexibility in range of vessels
	Easy construction	Maintenance costs
Quay wall	Stability of the structure	Higher costs
	Reduction on berthing energy	Difficulties in construction
	Easier spill response	for deeper water
	Safer escape routes	One vessel moored at the time

It can be observed, that for a non-Arctic harbour, jetties would usually be the preferred option due to its flexibility, prefabrication and in general relatively low costs. However, for cold climate terminals, jetties present several disadvantages compared to a straight quay wall, particularly due to ice loads and difficulties in oil spill response.

10.1.2 Offshore oil loading concepts

In cold climate areas, and in the presence of ice covered waters, the action of sea ice may cause large loads, globally or locally, making not feasible the use of a conventional loading system used in open waters. The different loading systems used for export from an offshore terminal (Figure 10.2), in ice covered waters, can be divided in two categories:

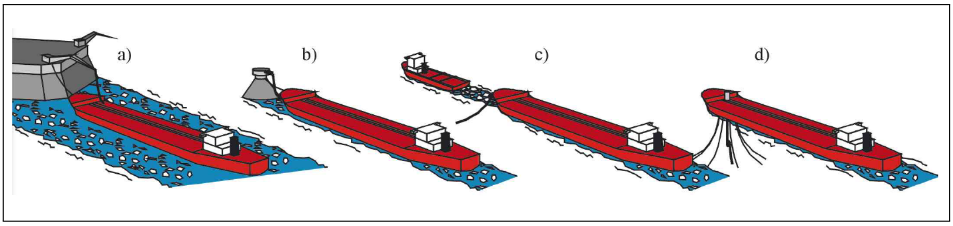

Figure 10.2: Arctic offshore loading concepts. *a) Platform corner loading; b) Tower loading; c) Single Anchor Loading (SAL); d) Submerged Turret Loading (STL). Source: INTSOK*

1. **Mooring and loading in the wake of a structure**

   – ***Direct platform loading*** *(i.e. Prirazlomnoye, Russia)*
   The loading takes places directly at the production platform through loading arms located at the corners of the structure (Figure 10.3). The tanker is then moored at a fixed point and has limited manoeuvrability range to stay in the platform lee without disconnecting in case of direction changes in ice drift [51]. This represents an economical option but suffers of operational risks related to impacts between tanker and structure.

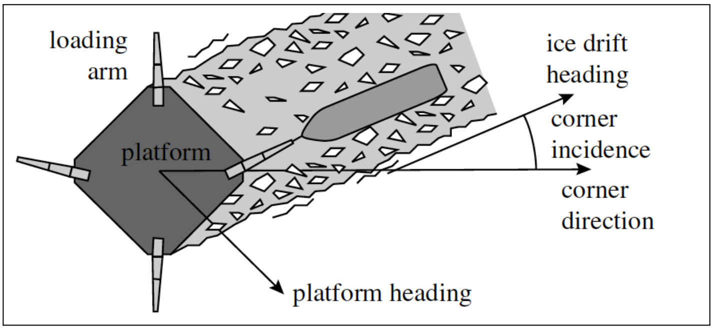

Figure 10.3: Platform corner loading concept top view. *Source: B Bonnemaire, 2006*

   – ***Loading tower*** *(i.e. Varandey, Russia)*
   Loading is carried out behind a loading tower with a swivel. This option improves the direct loading efficiency due to a reduction in the need for repositioning, since a full circle swivel-loading arm and mooring platform can be installed [32]. Might be an expensive solution in areas with severe ice conditions, since the tower design should be able to withstand the ice loads.

2. **Subsea designs** (Figure 10.4)

   - ***Moored Single Anchor Loading (SAL)***

     The tanker moors on a single line coupled with the loading hose connected to a single anchor on the seabed [11]. This concept has a limited capability to resist ice loads, and an effective ice management is absolutely necessary for its operatibity in severe ice conditions.

   - ***Submerged Turret Loading (STL)***

     For this concept, the tanker is outfilled with an internal turret. The STL system protects the top of the loading riser interacting with the ice from being damaged by moving ice travelling under the hull of the vessel. The solution minimizes, therefore, the interaction between ice and riser, and thus the damage risk.

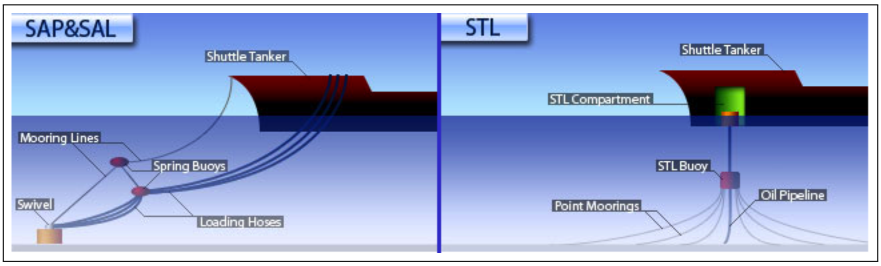

Figure 10.4: Subsea offloading concepts for cold climate conditions. *Source: Oil Spill Solutions*

A study comparing the different offloading concepts for the Prirazlomnoye location, in the Pechora Sea [51], suggests that the different terminal solutions will have different operational risks associated, presenting the qualitative risk analysis as in Figure 10.5.

It can be observed that, the armoured STL will present the lowest probability of accident from all of of the available concepts for cold climate offshore loading[1]. The emergency disconnection would avoid hazards in most cases using this concept. On the other hand, with the use of the wake type solutions, an emergency disconnection does not reduce the collision hazard with the structure. Moreover, the SAL concept is extremely vulnerable without an effective and permanent ice management.

[1] The arrows represent the reduction in risk with a permanent ice management.

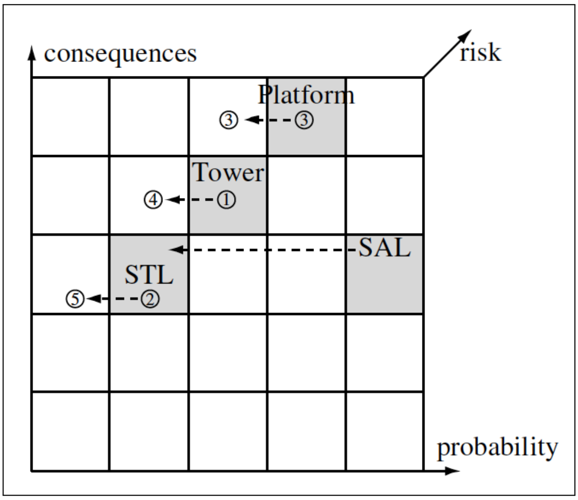

Figure 10.5: Qualitative risk analysis of the loading concepts for cold climate offshore terminals. *Source: B Bonnemaire, 2006*

10.2 Ice Management

Ice management concerns all activities which objective is to reduce or avoid actions from any kind of ice features. Ice management issues are remarkable for a marine terminal in a northern location. The identification of potential solutions and the selection of a feasible ice management approach are essential to ensure safe year-round operations.

10.2.1 Onshore terminals

Ice may freeze in the quays and structures, or be piled up in front of the terminal due to the influence of winds, tides and currents, or the action of the berthing vessel itself. Moreover, uneven accumulations of ice may cause difficulties in maneuvring if the vessel berthing is unassisted. In addition, the ice growth is accelerated with the exposure to open water caused by repeated ship passages, compared to an undisturbed situation [52].

Terminals must remain relatively clear of large floe ice at all times so that vessels can manoeuvre to the berth. An effective port ice management is, therefore, essential to ensure safe berthing and loading operations all year round.

The potential ice management schemes for a harbour facility, can be classified as follows [52]:

– **Ice suppression techniques**: *inhibiting the formation of ice (Table 10.2).*

Table 10.2: Ice suppression techniques

Management Technique	Description	Reliability and Effectiveness
Thermal Discharge	Warm seawater discharged to the berth side or turning area, to avoid ice growth	Low cost; technology proven to be very reliable; minimum expected environmental effects
Insulation	Presence of a snow cover or an artificial insulating cover	Has not been used extensively; problems with life and application
Bubbler Systems	Release of air bubbles at depth to create an upward circulation of the warmer water layer	Some benefit in delaying ice formation if applied during the early part of the ice season
Enclosure	All-weather terminal concept with covered berths to avoid freezing temperatures	Effective in limiting ice growth and planning harbour operations; high costs; not proven in Arctic

For the LNG terminal proposed at Melville Island in the 1980's, as part of the Arctic Pilot Project in the Canadian Arctic, it was concluded that the use of waste heat in the form of thermal discharge from the liquefaction process, was the most effective and reliable way to manage the ice near the terminal [52].

– **Ice breaking techniques**: *breaking of ice by bending, crushing or shearing, to improve vessel access and reduce ice actions on the tanker and berths.*

The most common and proven technique for ice management is the use of icebreaking vessels (Figure 10.6). The icebreaking vessels assist in managing the ice in the harbour area to facilitate berthing operations, reducing therefore the possible downtime of the terminal, increasing its regularity. In addition, the ice actions on the tanker and berths decrease, since the ice floes are reduced in size. Deflection of moving ice to avoid collision with the loading tanker, is another important objective of icebreaking vessels in the harbour area.

It is a well proven concept for ice management with high reliabilities [52]. The main drawback is generally the high capital, operating and maintenance costs associated.

Figure 10.6: Canadian icebreaker "Louis S.st Laurent" at Port Alfred, Canada. *Source: Canadian Coast Guard*

The ice management level at a specific harbour, depends mainly on the ice conditions, but also on the required redundancy and regularity required. The following classification can be used for the different levels of ice management [11]:

- *Sporadic ice management*: management needed for specific short term operations.
- *Permanent mild ice management*: one icebreaker manages the ice to assist with the loading operations, however the vessel safety at the terminal should be guaranteed even if the icebreaker stops assisting due to any unpredicted reason.
- *Permanent extensive ice management*: two or more icebreakers work assisting the tanker operations.

In addition to breaking the ice upfront the terminal, ice watch is an important task for icebreakers. For a reliable ice watching system, automated monitoring of the ice and meteocean conditions is required in addition to ice observers on board.

- **Ice removal techniques**: *displacement of ice to reduce the interference in the terminal area (Table 10.3).*

Table 10.3: Ice removal techniques

Management Technique	Description	Reliability and Effectiveness
Towing or Pushing	Ice floes can be towed or pushed away by tug/barges	Little precedents; requirement for tugs; disposal problems
Dredges & Hopper Barges	Removal by dredges and transport away from the site by barges	Little precedents; requirement for tugs; disposal problems
Flow Developers	Local high velocity flow by floating units; keep open pools of water and broken ice away from berths	Reliable but minimal local application; small scale only
Mechanical Transport	Conveyors are used to transport ice away from the terminal area	Not reliable due to freezing and breakdown problems
Crushing & Melting	Crushed ice is dumped into a holding tank of warm water	Effective for ice disposal; no precedents

10.2.2 Offshore terminals

For an offshore loading concept in ice-infested waters to be operative all year-round, a proper ice management is essential. The use of icebreakers in support of ice offshore operations, enables stationary operations in ice. The management necessary for such ice offshore operations, is substantially different and more demanding than the traditional ice transit operations or port operations in ice-infested harbours and terminals [53]. Some of the objectives of ice breakers at offshore terminals are:

- Channeling and assisstance to the tanker in maneouvring, mooring and loading operations at the terminal.
- Reduction of the actions on the tanker: the incoming ice floes are broken and therefore reduced in size, turning into rubble.
- Prevention against collision between the loading tanker and large multi-year ice ridges.
- Reduction of lateral stresses on the tanker by breaking the ice against the loading tanker.

Although there are several examples of hydrocarbon transfer in ice-infested waters, the only experience in year-round offshore loading operations with heavy ice conditions, is the offshore Varandey terminal in the Pechora Sea [11]. The number of days with freezing temperatures down to -48℃ is of approximately 240 days per year; the average duration of ice cover around 247 days, with an ice thickness between 1.25 and 1.8m [54].

The ice management approach (Figure 10.7) includes a dedicated icebreaker, *Varandey*, capable of operating independently in ice conditions, and an icebreaking standby/supply vessel, *Toboy*, capable of year-round operation within the area of the offshore terminal. The functions of the special-purpose vessel *Varandey*, include ice channeling for tankers; assisstance in maneuvring, mooring and loading operations at the offshore terminal; rescue and standby functions; firefighting capability; oil spill response operations; fulfilling supply functions; and performing underwater engineering and towing operations in the prevailing ice conditions [55].

Figure 10.7: Tanker approaching Varandey terminal assisted by icebreakers. *Source: Lukoil*

The most important development in the physical ice management technology for ice offshore operations, has been the azimuth thrusters. These can be more powerful in terms of breaking ice than the hull of an icebreaker. Clearing of the ice in a highly efficient manner, is an additional benefit. The full potential of using the azimuth thrusters could be developed by designing and installing them onto ice offshore platforms, for the purpose of not only propulsion or turning the vessel, but also for self ice management, increasing therefore the operational efficiency and safety [53].

10.3 Spills

Oil harbours and terminals present the threat of accidental releases from storage, loading operations and potential discharge from pipelines (see Chapter 8 for oil spill risks, behaviour in cold water environments and response techniques).

To ilustrate the volumes of hydrocarbons stored from examples in cold climate areas, in the US Arctic, the major oil terminal in Valdez, Alaska, has a current holding capacity of 8.78 millions bbl in 18 crude oil tanks and two functional loading berths (Figure 10.8). The crude oil arrives to the terminal through the Trans-Alaska Pipeline. In Russia, there are crude oil storage facilities at Arkhangelsk and

Figure 10.8: Storage tanks at Valdez terminal, Alaska. *Source: Reuters*

Mursmansk. Unique to the region is the Varandey terminal in the Pechora Sea. The Varandey facility includes an onshore tank farm with a capacity of 325000 m^3, and the fixed ice-resistant oil terminal 22km offshore, with a height of 64m. In Norway, oil from the Skrugard field in the Barents Sea is planned to be brought ashore at Veidnes terminal in Finnmark. The oil will be transported through a 280km pipeline from Skrugard to the onshore terminal. The production is estimated at almost 200000 barrels of oil equivalent per day; 50 to 100 crude oil tankers calling at the terminal per year.

10.3.1 Onshore terminals

Oil and gas terminals are located in separate harbour basins, not accessible to other traffic and which can be closed off by floating booms rapidly in case of an accident. For safety reasons, the surroundings of an onshore terminal or refinery, need to be protected. Thus, for terminal planning purposes, different safety distances need to be taken into account.

In case of oil tanks, the spacing between them is determined by bunds at such distance that in case of a collapse of the full tank, the oil can be contained within the bund. Liquid gas storage is more dangerous than oil storage and requires special need for space due to safety reasons. As a guideline, a LNG terminal with a throughput of 6 millions m^3/year requires, 15 to 20ha for storage, for instance in 4 tanks of 60000 to 80000 m^3 [14].

Special precautions have to be taken when dealing with possible oil spills at harbours during loading/unloading, since any spill would occur in the midst of broken ice, presenting a more difficult clean-up task. Additional safety measures may include the restriction of loading rates to limit the size of a spill from a rupture in the loading arms. For major accidents such a main storage tank failure, the best defence is to take precautions in planning, design and in operational procedures, in order to reduce the probability of occurrance to a minimum level.

10.3.2 Offshore terminals

Prevention systems for offshore storage tanks and piping may include use of double-walled piping, double-walled storage tanks and improved containment structures to capture and pump recovered fluids before they reach the sea surface [23].

Ice breaking vessels carrying out ice management functions, may also provide first aid oil spill response. As an example, the *Varandey* icebreaker, managing the ice at Varandey offshore terminal, is fitted with a workboat for oil spill response readiness, which is able to tow an oil boom. The icebreaker has storage for 500 m^3 of recovered fluids and is also provided with $20m^3$ of chemical dispersants to be applied via spray systems from both sides [55].

The implementation of the future oil spill preparedness for the Goliat offshore terminal in the Barents Sea (Figure 10.9), will include NOFO2009[2] systems consisting of a new contingency vessel, *Esvagt Aurora*, with tank capacity of 1000-2000m^3, 400m of heavy offshore boom and skimmer. Oil detecting radar and infrared cameras will provide the vessel with the ability to operate regardless of darkness conditions. In addition, a coastal barrier will be implemented with the use of permanent contingency formed by fishing vessels from Finnmark area. The Goliat oil spill contingency will also include the capability to use ship based dispersant systems [56].

[2]Most recent oil spill contingency standards from the Norwegian Clean Seas Association for Operating Companies

Figure 10.9: Simulation of oil spill contingency plan for Goliat field in the Barents Sea, Norway. *Source: Eninorge*

10.4 Tanker Operations

The main tanker operations and corresponding limitations are discussed here, including berthing and (off)loading operations.

10.4.1 Onshore terminals

The complete navigation operation, which ranges from arrival to departure of the tanker at the terminal, can be divided as follows [16]:

- Arrival at the outer harbour basin
- Berthing: including turning, pre-berthing and mooring operations
- Loading/unloading operations
- Unberthing
- Departure from the harbour basin

Safe vessel approaching and berthing at the terminal, as well as cargo-handling operations, are essential for the operational availability of the harbour or the berth.

- **Visibility and wind restrictions**
  In addition to ice formation, which needs to be managed at the terminal as it was reviewed in a previous section, other environmental factors limit the operability of the tanker berthing and loading at a cold climate harbour.
  - *Visibility*
    Fog, heavy rain and snow can cause poor visibility (Figure 10.10). Visibility of more than 2000m can be acceptable for manoeuvring and berthing

operations inside an oil or gas terminal. However, for reduced visibility conditions (less than 1000m), it is advised that oil and gas tankers use tugboat assisstance within the terminal area . As a rule of thumb, most oil and gas terminals would not be operative for arrival, berthing/unberthing and departure of tankers if the visibility is less than 1000m [16].

Figure 10.10: Poor visibility conditions near Melkøya gas terminal, Norway. *Source: Espen Ørud Photography 2012*

- *Wind restrictions*

  The following limits for wind velocities (Table 10.4[3]), are commonly used in the evaluation of the mooring system and horizontal forces during berthing/unberthing of oil tankers and gas carriers at terminals.

Table 10.4: Operational wind limits for oil and gas terminals

Situation	Oil terminal	Gas terminal
Berthing	10m/s (>150000dwt) 15m/s (< 60000dwt)	10m/s (LPG >80000m^3 or LNG >137000m^3) 12m/s (< 70000dwt)
Loading	20m/s	17m/s
Loading arms disconnection	23m/s	20 m/s
At berth	< 26m/s	< 24m/s
Tanker shall leave the berth	>26m/s	>24m/s

[3]Information retrieved from C. Thoresen, 2010

The risk when taking a gas carrier in ballasted condition to a berth, is higher than that for an oil tanker. Gas carriers usually have a bigger freeboard than oil tankers, being therefore more affected by the wind, with more strict limits applying in those cases. It is recommended to have instrumentation continuously measuring wind velocities in the vicinity of oil and gas berths.

– **Acceptable wave heights and ship movements**
The tanker at berth, may be exposed to different wave directions, and to a combination of long and short waves as shown in Figure 10.11.

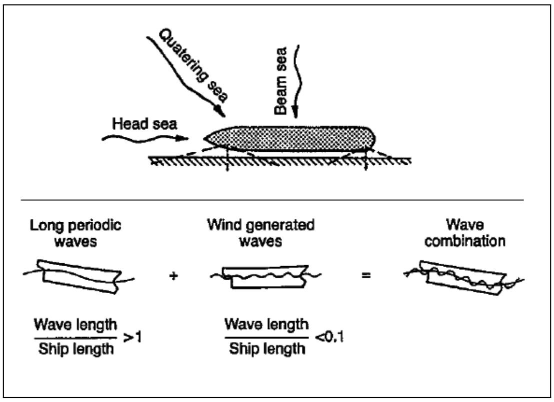

Figure 10.11: Wave combination and directions for a tanker at berth. *Source: C. Thoresen, 2010*

The wave configuration is the main responsible for unacceptable ship movements and forces in the mooring system. For large ships such as oil and gas tankers, the longer periodic waves ($T > 20s$, $5000 < L(m) < 8000$) might cause serious movements and forces. This introduces the risk of resonance inside the harbour basin, with long periodic waves having periods of the same magnitude as the natural period of the moored tankers. If this is the situation, the ship movement can increase significantly.

The acceptable wave heights and movements of a tanker at a berth will depend on the elastic properties of the fenders, the type of vessel, the mooring system of the ship, the method used for loading/unloading, the orientation of the berth with repect to currents and waves, the wave period and the natural period of oscillation of the tanker. According to PIANC recommendations [16], the limiting significant wave heights for different wave directions are shown in Table 10.5. For higher waves, loading and unloading operations have to be stopped.

Table 10.5: Maximum significant wave height at berth

Size of tanker	Limiting wave height H_s (m) 0° (head on or sted on)	Limiting wave height H_s (m) 45° - 90°
< 30 kdwt	1.5	0.8 - 1
30-200 kdwt	1.5 - 2.5	1 - 1.2
> 200 kdwt	2.5 - 3.5	1 - 1.5

These figures, should be always checked against the acceptable ship movements by the loading/unloading systems. Table 10.6[4] presents the ranges for maximum allowable movements at berth during loading operations.

Table 10.6: Range for maximum acceptable movements at berth during loading

Type of ship	Surge (m)	Sway (m)	Heave (m)	Yaw (°)
Oil tanker	±2	+ 0.5	+0.5	1
Gas carrier	±0.2	+0.1	±0.1	0.5

It can be noticed, that the limits beyond which loading operation is not longer efficient or safe, vary significantly between an oil tanker and a gas carrier. For loading/unloading of gas carriers, the movements considered acceptable are much lower than those for oil tankers.

The evaluation of the ship mooring layout, in charge of safely secure the tanker to the berth structure, will need to take into account the most severe combination of wind, waves, currents and ice forces acting on the ship.

10.4.2 Offshore terminals

The loading operation is the most vulnerable marine operation, particularly under cold climate conditions. The main concerns regarding the operatibity of the terminal are harsh seas during summer, and ice drift during winter. When operating in ice covered waters, the offshore terminal is exposed to variable conditions (ice thickness and varying ice drift and direction), which can pose hazards on the tanker when connected to the terminal. The worst risk scenarios might be collision between the tanker and the structure for platform or tower loading, or the rupture of the mooring or loading line for SAL or STL concepts due to excessive mooring loads [51]. Thus, the offloading option chosen, as reviewed in section 10.1.2, should be able to cope with the harsh environmental conditions in a cold climate or Arctic area. Ice management is likely to be used during all these phases in order to reduce global and local ice design actions.

[4]Information retrieved from C. Thoresen, 2010

The parameters influencing the tanker operatibity at the offshore terminal, include the tanker design, type of terminal, ice management and ice conditions, being ice drift the governing parameter in terms of potential downtime at the terminal. According to the analysis of ice drift measurements at the Prirazlomnoye location, in the Pechora Sea [51], the different concepts present different vulnerabilities to ice drift events, downtime rates varying from 6 to 72% depending on the concept chosen. Figure 10.12 presents the downtime curves for the different offloading concepts, depending on the minimum loading window necessary for connection to the terminal, for a full ice management situation.

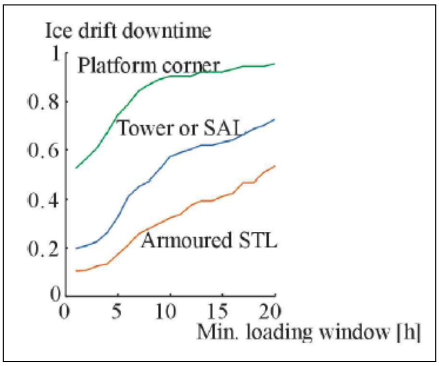

Figure 10.12: Downtime due to ice drift for different offloading concepts and full ice management. *Source: A. Jensen et al., modified from B. Bonnemaire, 2006*

The time needed to load a tanker is approximately 10 hours. It can be observed that the downtimes associated with loading windows of around 10 hours are substantial (40 to 70% on average); the loading will be therefore carried out usually in shorter windows in order to get a good operability rate during winter [51]. The results show that, under full ice management conditions, direct platform loading has the lowest performance, the STL concept reaching the best one.

An important requirement for a tanker loading on an offshore loading terminal, is the possibility of disconnection when operations are foreseen to be unsafed in the short term. This situation takes place when moving ice becomes stationary. Ice might start drifting in any direction, increasing rapidly the risks of collision with the structure and the ice actions. If extremely reliable ice forecasting is performed at the site, disconnection may not be necessary.

According to a study using North American, Baltic and Russian ship operational data from vessel approach and mooring at Arctic loading terminals [57], the analytical models developed concluded that mooring and loading operations are feasible in both pack ice and landfast ice conditions all year-round with the proper equipment, ice management and planning.

Part III

Case Studies

Chapter 11

Three Fields, Three Solutions

This chapter discusses three different development schemes in the Barents Sea: Snøhvit, Goliat and Johan Castberg[1]. The three fields are located nearby (see Figure 11.1), however, they present three different development solutions. In particular, emphasis will be made on the three offtake solutions and terminals.

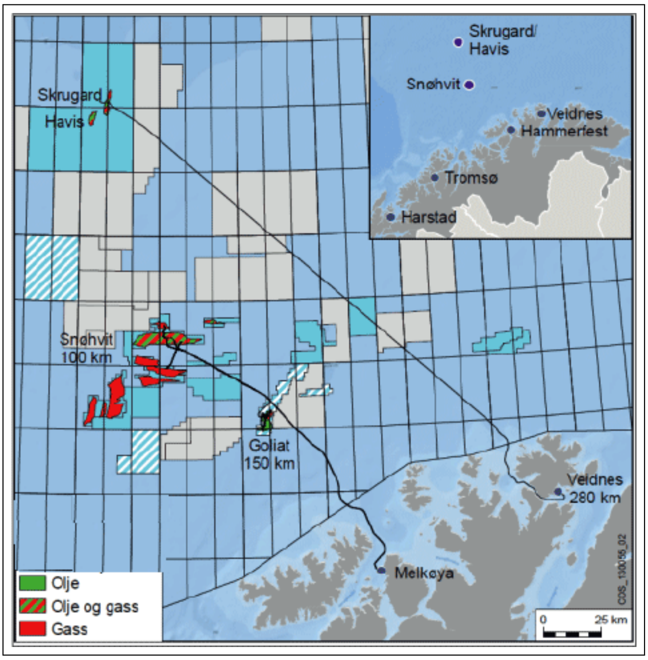

Figure 11.1: Location of the three fields considered for the case study analysis. *Source: Statoil*

[1] Former Skrugard Field. Renamed by the Norwegian Ministry of Petroleum and Energy on 22nd April 2013

11.1 Johan Castberg Field Development

11.1.1 Field description and background for choice

The Johan Castberg field is located in the Barents Sea (blocks 7219/9 and 7220/4,5,7). The location is about 100km north of Snøhvit and 150km north of Goliat (Figure 11.1). The water depth varies between 360-390m depth. The development, at the moment, includes Skrugard and Havis, two independent structures within the same licence located 7km one from another. This is a prospective area, with four new prospects being explored at the moment (Figure 11.2): Nunatak, Skavl, Iskrystall and a fouth prospect not yet announced (as per May 2013).

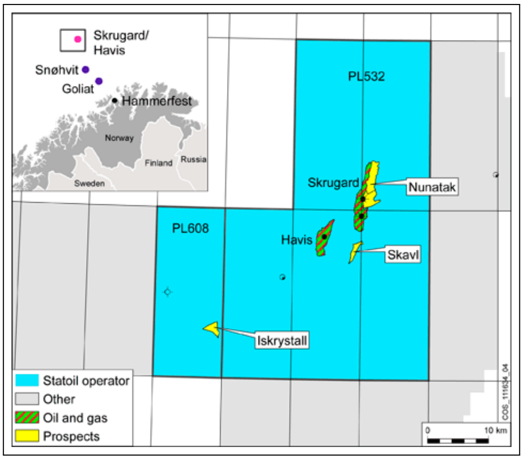

Figure 11.2: Johan Castberg field area. *Source: Statoil*

Johan Castberg is an oil field with some gas. The exploratory drilling results proved a gas column of 33m and an oil column of 90m for the Skrugard prospect (7220/8-1), and a 48m gas colum and 128m oil column for the Havis prospect (7220/7-1) [58]. The total preliminary estimated volumes for these two oil discoveries are in the range of 400-600 million bbl, with the field scheduled to come on stream in 2018 [9].

1. **Physical Environment**

   The location of the field, high north between $72-73\,^{\circ}N$, presents special considerations to take into account in terms of harsh climatic conditions and the special challenges associated. Aspects such as low temperatures, polar lows, ice, darkness, vulnerable environment and remoteness are specially aggravated compared to Snøhvit or Goliat, since the location is even more to the north.

Figure 11.3 shows the location of the field in relation to the marine icing risk. The field is located in an area with strongly aggravating gradient of sea spray icing.

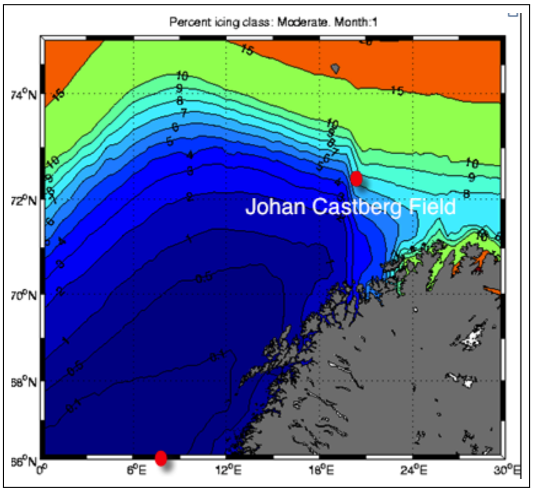

Figure 11.3: Marine icing at the field location. *Source: Statoil*

Figure 11.4 shows the location of the field in a sea ice probability map. Sea ice is considered as an accidental/damage condition (ALS), therefore within the probability 10^{-4} (red line). The green line, which lies over the field in the map, corresponds to the 100 year probability of occurrance (10^{-2}).

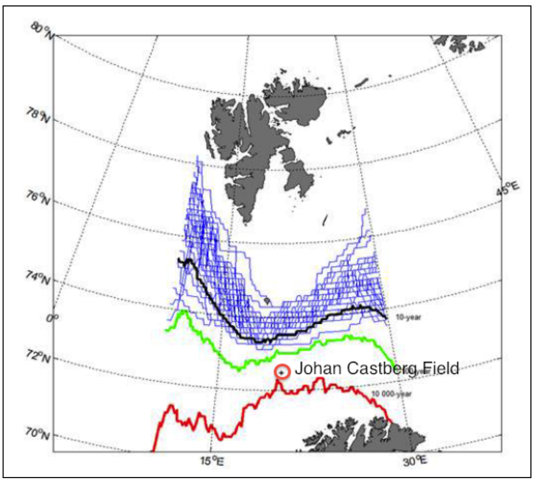

Figure 11.4: Sea ice at the field location. *Source: Statoil*

Regions where collision between icebergs and an installation can occur with an annual probability of exceedance of 10^{-2} and 10^{-4} in the Barents Sea, are shown in Figure 11.5. Both limits, the 100 year and 10000 year limits for the likelihood of southward penetration by icebergs have been estimated in the Norsok N-003 industry standard [59]. The Johan Castberg field lies within the 10000 year limit, probability of occurrance 10^{-4} (dotted line). The solid line shows the limit for the probability of exceedance of 10^{-2}.

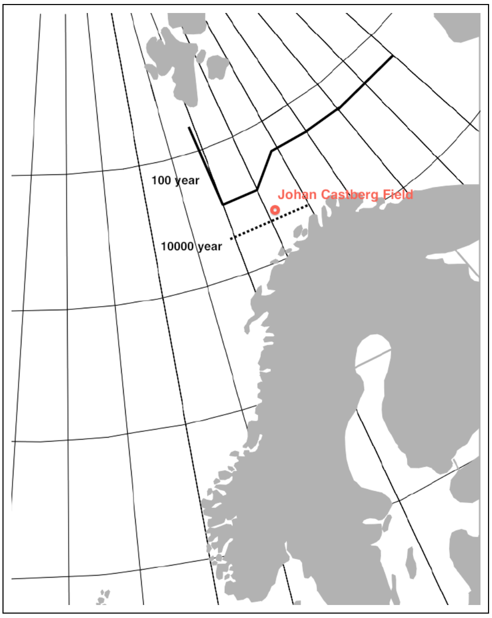

Figure 11.5: Limit for collision with icebergs at the field location. *Source: Modified from NORSOK N-003*

It can be observed that the field location is placed at low level probability for both sea ice and iceberg collision. The ALS requirement governs the design, corresponding with an annual exceedance probability for both events set to 10^{-4}. The consequences of sea ice and icebergs at low level probability, depend on the concept chosen. The structural layout should be selected so as to limit the consequences. For instance, particular attention should be paid to protecting critical components such as risers [59]. As it would be explained later on, the concept chosen includes a subsea production system tied in to a floating installation. These elements should be, thus, designed to account for the ALS requirement for impact events.

2. **Alternative Concepts for the Development**

   The alternatives considered for the field development (see Figure 11.6), include:

- **Floater Alternatives**: subsea production system on the seabed and processing of the well stream carried out at a floating platform (FPSO platform or vessel). The oil would be exported to market using tankers which would be loaded at the offshore platform (solution as chosen for Goliat).
- **Oil pipeline to shore**: subsea production system on the seabed tied up to a floating production unit with first stage separation and with a pipeline to an onshore terminal where final processing and storage of the oil are held. The oil is then shiped to the market by tankers loaded at the harbour.

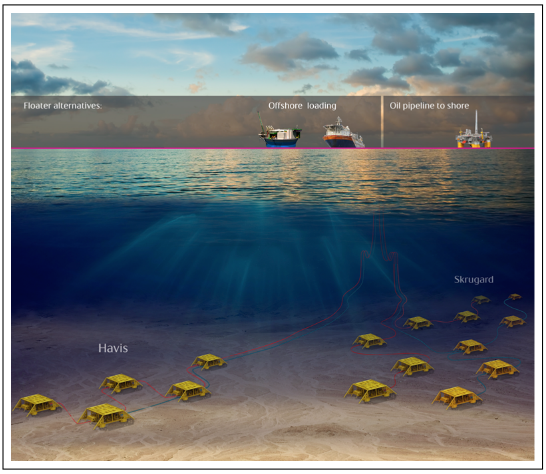

Figure 11.6: Johan Castberg field development alternatives. *Source: Statoil*

3. **Final Development Solution**

   The development concept chosen for the area, is the oil pipeline to shore option (Figure 11.7). The infraestructure is common for Skrugard and Havis, and possibly for new prospects in the area, and includes the following elements [9]:

   - Subsea production system located at 380m of water depth and tied in to a floating installation.
   - Floating installation consisting of a semi-submersible floating unit. Water will be processed out and gas reinjected.
   - Pipeline of 280km length transporting oil from the field to an onshore terminal.
   - Onshore terminal at Veidnes, Finnmark, where the oil will be processed and stored in two mountain caverns.

– Transportation to the market by tankers arriving at the terminal harbour for loading. 50 to 100 crude tankers are estimated to call at the terminal each year.

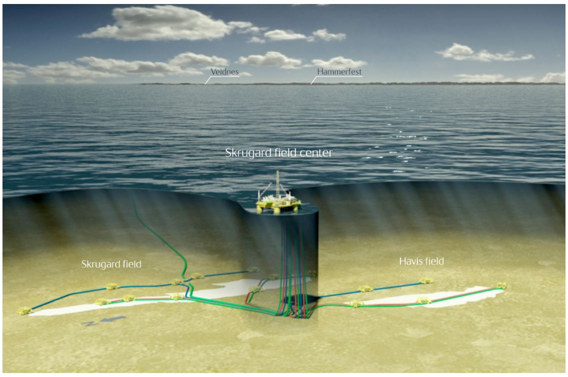

Figure 11.7: Development concept chosen for Johan Castberg field. *Source: Statoil*

The reasons for this concept choice are related mainly to the location of the field at a very high latitude, and also to the possibility of further exploration and future discoveries in the area.

– *High Latitude Location* ($72 - 73\,°N$)
The location of the field, further north than Goliat or Snøhvit, accentuates the challenges that are imposed due to the climatic conditions. Colder environment, potentially considerably more icing and sea ice risk, darkness, remoteness etc., increase the technical and operational risks, especially offshore. The concept chosen, avoids offshore storage and offloading, therefore decreasing the technical risk and the production downtime. Economically, the offshore costs are reduced, which is of extreme importance in cold climate locations, on the other hand, an investment in the terminal is added in this case.

– *Further exploration and future discoveries*
Due to the high potential of future discoveries in the area, this concept facilitates further exploration and helps make future discoveries profitable in the area due to its flexibility to include prospecive resources. Future new discoveries in the area could be tied in to the Veidnes oil terminal.

11.1.2 Terminal concept and breakwater assessment

The project for the planned onshore terminal operated by Statoil, as part of the Skrugard field development, is in a relatively early stage at the moment (as per

June 2013). Information from the screening study for the site selection process of the terminal has been provided, Courtesy of Statoil, as support for this part of the Master thesis.

The alternative locations for the terminal, included five different locations in Finnmark area (see Figure 11.8), including the current plant at Melkøya.

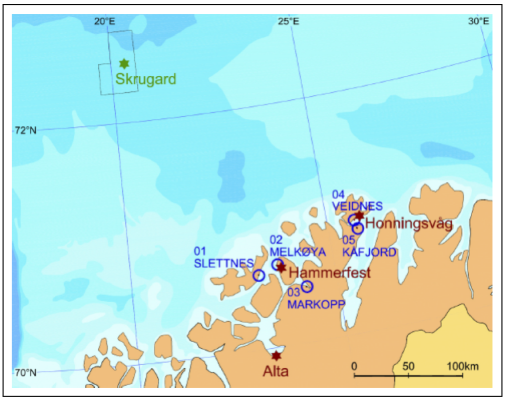

Figure 11.8: Alternative locations for the onshore terminal for the Johan Castberg field. *Source: Courtesy of Statoil*

The final location for the terminal will be Veidnes, outside Honningsvåg. Figure 11.9 shows the exact location of the terminal area. Meteocean information (100 year return period) for Veidnes area, is included in Appendix B (Figure B.3). It can be observed that the location chosen is well sheltered from waves, with a 100 year return period significant wave height from wind waves of $H_S = 2.2m$ and peak period $T_p = 6.2s$. It is important to notice that although sea ice is not likely to occur, there is a high/extreme icing risk at Veidnes.

An assessment has been carried out for the stability of a potential breakwater protecting the onshore terminal at Veidnes. The required armour stone mass for a conventional rubble mound and a berm breakwater has been calculated using different formulations available. A comparison of the different armour unit masses is presented here. The detailed formulations, meteocean data and calculations carried out, are presented in Appendix B.

i **Rubble mound breakwater**

For the stability of a conventional rubble mound breakwater, Hudson (B.1) and Van der Meer (B.2), (B.3) formulations have been used. The parameters

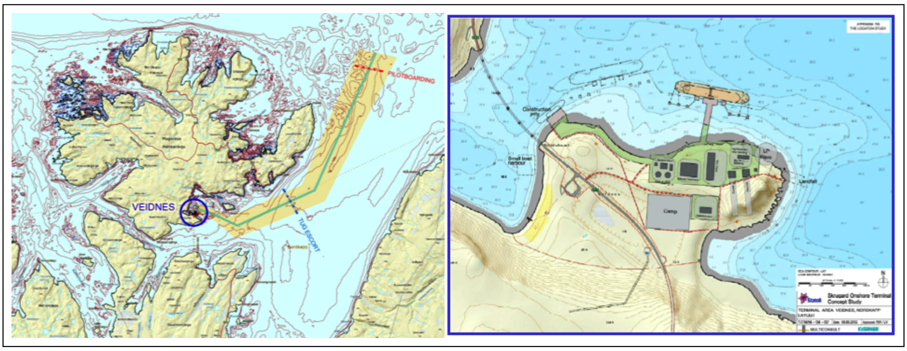

Figure 11.9: Onshore terminal location and preliminary layout. *Source: Courtesy of Statoil*

employed in the calculations and their justification are presented in Appendix B.

Table 11.1 shows the required stone mass and size for a rubble mound breakwater concept, after calculations using Hudson and Van der Meer formulations.

Table 11.1: Required armour stone mass for a rubble mound breakwater concept at Veidnes, using Hudson and Van der Meer formulations. $H_S = 2.24m$, $T_z = 8.06s$, slope 1:1.5.

Formulation	W_{50} (tons)	D_{50} (m)
Hudson (B.1)	1.2	0.80
Van der Meer (B.2), (B.3) start of damage $S = 2$	3.2	1.1
Van der Meer (B.2), (B.3) near failure $S = 6$	1.6	0.85

Here W_{50} and D_{50} represent median armour stone mass and diameter respectively. S represents the damage level.

Hudson formulation is still used for conceptual design due to its simplicity. However, important parameters, for instance the wave period, are not taken into account. In addition to the parameters in the Hudson formula, Van der Meer formulation takes into account the storm duration, the wave period, the damage level, the permeability and the type of breaking. However, the formulation is based on curve fitting, with no other physical meaning than the stability number (H_0), which can be recognized in formulas (B.2) and (B.3).

The necessary armour stone mass has been plotted as a function of the Iribarren number (see Appendix B for formulation). The Iribarren number varies with the slope angle and the wave period. The results can be represented for different wave periods, and therefore, Hudson and Van der Meer results can be compared (Figures B.4, B.5).

For the mean wave period caculated at the location $T_z = 8.06s$ (Appendix B), the Iribarren number is $\xi_z = 4.5$, which corresponds with the surging wave case (see Figure 11.10, red line). For that Iribarren number, Van der Meer formulation gives a required armour stone mass $W_{50} = 3.2t$, while Hudson formula, for $K_D = 4$ (K_D is a coefficient obtained from model tests of the required W_{50}) and $H = H_S$, gives $W_{50} = 1.2t$, as summarized in Table 11.1.

The results show a difference of around 2 tons depending on the formulation employed. However, it is important to notice that the evaluation of the mean wave period introduces some uncertainty. Therefore, a range should be defined for the expected mean wave period. In this case, a range between $T_z = 6 - 10s$ has been defined. In that case, the Iribarren number (Appendix B, equation (B.3)) would be in the range of $\xi_z = 3.4 - 5.5$, varying between the plunging and surging cases. The required stone mass would be approximately $W_{50} = 2.5t$ for a period $T_z = 10s$ or $W_{50} = 2.2t$ for a period $T_z = 6s$ (see Figure 11.11).

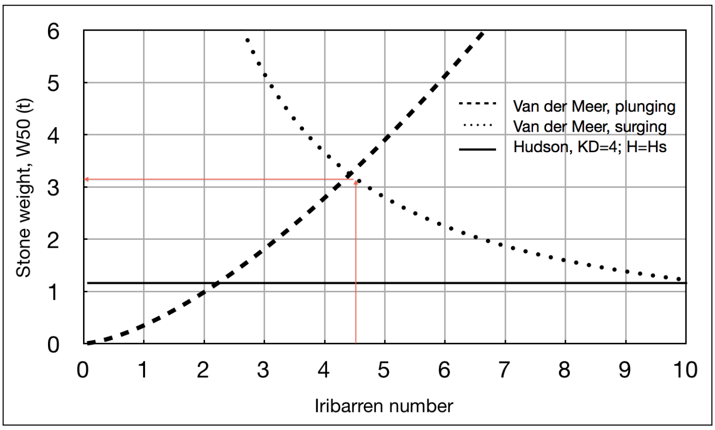

Figure 11.10: Necessary armour stone mass vs Iribarren number for a damage level $S = 2$; slope 1:1.5; permeability coefficient $P = 0.4$; non-breaking waves; $H_S = 2.24m$; $N = 3000$ (corresponding to ca. 9 hours sea state), $T_z = 8.06s$.

The results for a higher damage level ($S = 6$) are presented in Appendix B.

It can be concluded that due to the protected location of the harbour, and the relatively low wave heights at the site, the required armour stone mass for these given conditions and a conventional rubble mound breakwater, is relatively small; stone size that should be accessible from rock quarries in the area.

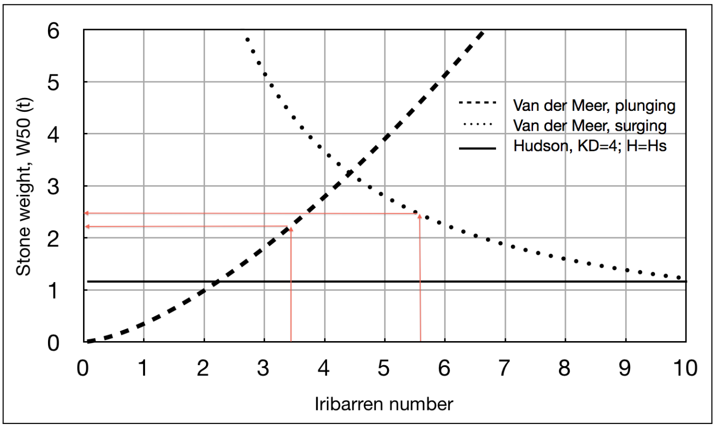

Figure 11.11: Necessary armour stone mass vs Iribarren number for a damage level $S = 2$; slope 1:1.5; permeability coefficient $P = 0.4$; non-breaking waves; $H_S = 2.24m$; $N = 3000$; $T_z = 6 - 10s$.

ii **Berm breakwater**

The stability of a berm breakwater concept has also been assessed. In this case, the stability number (H_0) and the period stability number (H_0T_0) have been used as mobility criteria for the calculation of the required armour stone mass. The values obtained, correspond to the main armour class, the rocks that would only be placed in the most exposed part of the cross section. See Appendix B for detailed calculations.

The maximum stone size calculated from the stability number (Table B.1) and from the period stability number (Table B.2) are compared to obtain the upper limits that are selected as final requirement for the maximum stone size for a berm breakwater concept at Veidnes. Table 11.2 shows the final requirements to the stone size.

Table 11.2: Final requirement for maximum stone size for a berm breakwater concept at Veidnes. $H_S = 2.24m$; $T_z = 8.06s$

Category	W_{50} (tons)	D_{50} (m)
Non-reshaping	≈ 1.1	0.75
Reshaping, static stable	≈ 0.70	0.65

Although both types, non-reshaping and reshaping static stable types are presented, the reshaping type in this case would not be a safe option to take into account since the stone size is already very small, and the reshaping could potentially cause an unsafe situation.

It can be observed that the required mass for the main armour class is in this case $W_{50} = 1.1t$ for the Icelandic type, which is very close to the $W_{50} = 1.2t$ required for the conventional rubble mound calculated by using Hudson formula.

Sea ice has not been considered in any of the calculations since the meteocean information shows that it is not likely to occur at the site (Figure B.3).

Summarizing, the location chosen for the onshore terminal at Veidnes, is well protected and sheltered, presenting relatively mild wave conditions, with a design significant wave height of $H_S = 2.24m$ and a peak period $T_p = 6.2s$. For low wave heights, $H_S < 3m$, usually conventional rubble mound breakwaters are chosen as design option [44], and a berm breakwater would probably not be the most economic solution in a case like this.

11.2 Snøhvit Field Development

11.2.1 Field description and background for choice

The Snøhvit field is the first offshore project in the Barents Sea, without surface installations, and also comprises the first LNG production and export facility in Europe. The field is located on the Norwegian Continental Shelf at $71\,^{\circ}N$, in the Barents Sea (blocks 7120 and 7121). The location is approximately 150km offshore, where the water depth varies between 310-340m (Figure 11.12). The area includes three different fields: Askeladd, Albatros and Snøhvit, all of them parts of the Snøhvit LNG field development project. There is a total of 20 wells, one injection well for CO_2 and 19 production wells which are producing gas from those three fields. Snøhvit and Albatros wells came on stream in 2007. The Askeladd field of the development is due to come on stream in 2014-2015 [9], [58].

Snøhvit is a gas field with condensate and an underlying oil zone. The reservoirs contain gas, condensate and oil in Lower and Middle Jurasic sandstones of the Stø and Nordmela Formations. The reservoir depth is approximately 2300m. The recovery strategy is pressure depletion, not including recovery of the oil zone. The original recoverable reserves include 176.7 billion Sm^3 of gas, 6.4 million tonnes of NGL and 22.6 million Sm^3 of condensate [58].

The alternative concepts considered for the field development included:

i Processing out the water on a platform and sending the rich gas to shore.
ii Full wellstream sent to shore and gas treatment at an onshore terminal.
iii Subsea processing and rich gas sent to shore. This option is not yet technically available, but it will possibly be a feasible option from 2015.

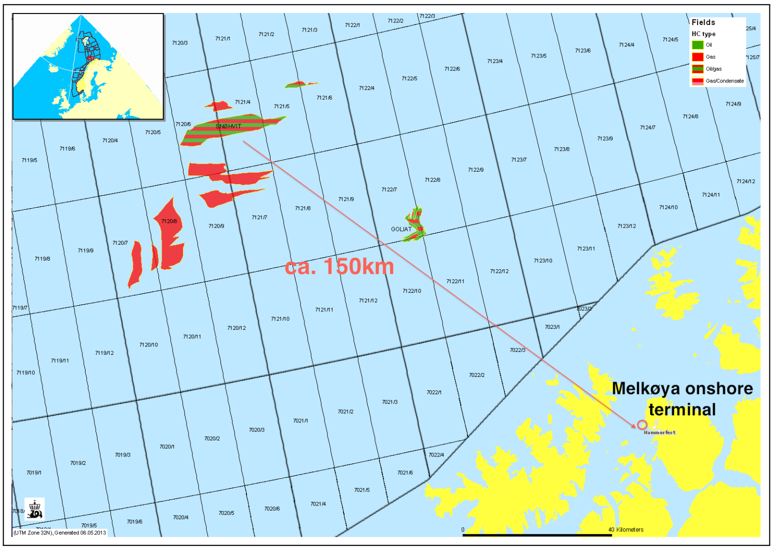

Figure 11.12: Snøhvit field area. *Source: Modified from Norwegian Petroleum Directorate*

The final development concept chosen for the area was the option of a full unprocessed wellstream to shore through a 143km long pipeline to the onshore terminal at Melkøya for processing and export (Figure 11.13):

- Remotely-operated subsea installation located at 340m of water depth.
- Pipeline transport to the onshore facility at Melkøya through a 143km multiphase flow line.
- 153km pipeline for CO_2 reinjection from the Hammerfest LNG plant back to the Snøhvit field.
- LNG plant and terminal at Melkøya island, Hammerfest, where the gas is liquified and shipped out mainly to Europe and US.
- Transportation of LNG, LPG and condensate to the market by tankers arriving at the terminal harbour for loading. Around 70 LNG carriers and 10 LPG carriers call at the terminal each year.

Some of the main challenges related to the development chosen for the Snøhvit field include:

- *Nothern Location (70°N)*

  The climatic factors associated with the nothern location of the field represent several challenges for the design, construction and operating lifetime of the

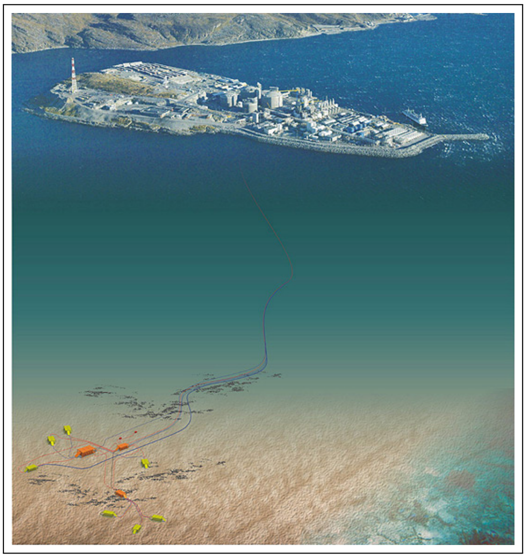

Figure 11.13: Development concept chosen for Snøhvit field. *Source: Statoil*

development. Although the Gulf Stream keeps the sea free of ice year round, polar low pressures represent one of the main issues since they could change the weather suddenly, causing operation disruptions. As an example, the frequency of polar lows passing Melkøya during the last 20 years has been approximately one polar low every second year, suddenly increasing the mean wind speed to more than $25m/s$ [60]. In addition, high waves caused by winter storms make surface installations diffcult to operate in these conditions. The main advantage of a complete subsea installation on the seabed for this type of cold climate is that it allows a steady and stable production, unaffected by the temperature and conditions on the surface.

Moreover, the ambient conditions on the onshore terminal are very important during the plant operation. One of the main issues affecting the onshore facilities at Melkøya is the extreme risk of icing of equipment and facilities at the LNG plant. The plant suffered heavy icing during the winter of 2002 (Figure 11.14), with an ice growth rate in the order of 30cm in an area 25m away from the shoreline during 48 hours [60].

– *Transport challenges*

The transport of unprocessed wellstream, through such a long seabed pipeline, poses several challenges. Due to low temperature and high pressure on the seabed, ice plugs tend to form in the pipeline. Hydrate control is therefore of extreme importance in this type of development. Various hydrate control solutions exist. The selection of hydrate control scheme is normally based on

Figure 11.14: Icing of facilities at Melkøya during winter 2002. *Source: M. A. Drage et al. 2003 [59]*

a life cycle cost comparison between different solutions. In this case, hydrate formation is avoided by continuous MEG injection and heating up of the pipeline electrically when required [9].

11.2.2 Terminal concept and breakwater assessment

The island of Melkøya was the selected location for the construction of the LNG plant for the Snøhvit gas field. The function of the plant is to liquify gas from the Snøhvit gas field for export by LNG and LPG gas carriers to Europe and US.

Firstly, a slug catcher links the offshore and onshore systems by taking the fluid from the pipe. Then the gas must be dried by removing water, MEG and condensate. In addition, the Snøhvit gas contains 5-6% CO_2 which freezes at a higher temperature than natural gas, so it must be also removed before the gas is cooled into LNG. This carbon dioxide removed from the wellstream is returned offshore and reinjected into the reservoir. Then methane is converted to LNG by cooling it down to -163℃. Moreover, propane and butane are also liquefied by refrigeration at -50℃ to get LPG, which is stored in dedicated tanks before shipment. Figure 11.15 shows the detailed diagram for the processing at the plant.

The plant is protected by a berm breakwater with a top level of $+12m$. The initial design was a dynamically stable berm breakwater, design that was changed afterwards for the final Icelandic berm breakwater. The breakwater is therefore designed as a statically stable non-reshaping berm structure for the 100 years return period, significant wave height $H_S = 7.5m$ and peak wave period $T_p = 15.6s$. The design should also withstand a 1000 years return period wave without structural damage ($H_S = 8.5m$, $T_p = 17s$) [61].

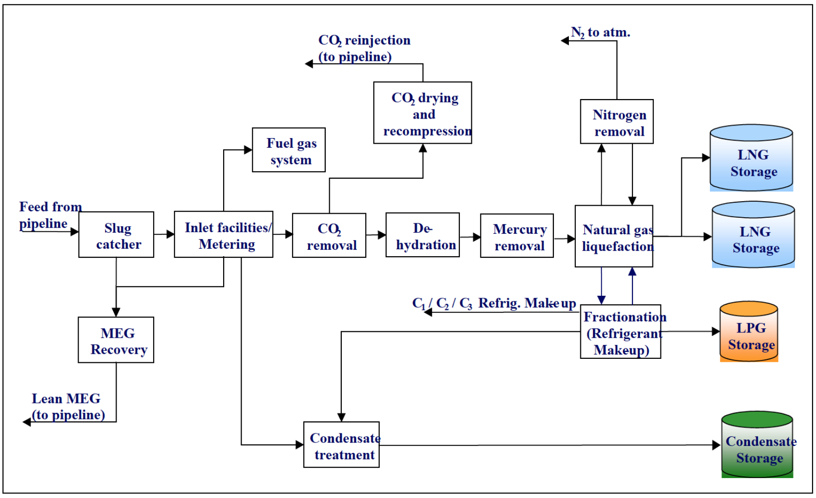

Figure 11.15: Block flow diagram of processing at Melkøya. *Source: Statoil*

The cross section of the most exposed part of the breakwater protecting the LNG plant, and the stone classes used are presented in Figure 11.16. It can be observed that the armour stone mass goes up to 35 tonnes at the most exposed locations.

Stone Class	W_{min}-W_{max} (tonnes)	W_{mean} (tonnes)	W_{max}/W_{min}	d_{max}/d_{min}
Class I	20 – 35	23.3	1.5	1.14
Class II	10 – 20	13.3	2.0	1.26
Class III	4 – 10	6.0	2.5	1.36
Class IV	1.5 – 4	2.0	4.0	1.59
Class V	0.5 – 1.5	0.8	3.0	1.44

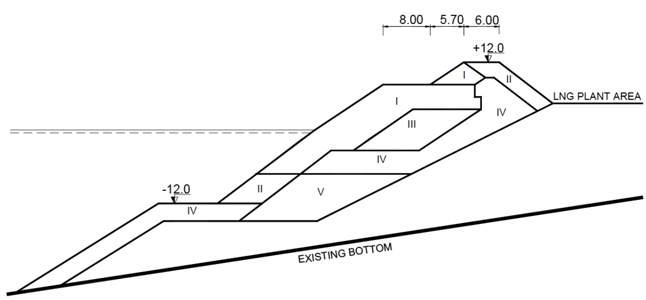

Figure 11.16: Cross section of the most exposed part of the Melkøya breakwater and corresponding stone classes. *Source: S. Sigurdarson et al., 2005*

The reasons for choosing an Icelandic design aimed to optimize the structure with respect to wave load, usage of rock yield and construction equipment. Moreover, during stability tests of the preliminary dynamically stable design, heavy green water overtopping occurred, and large rocks from the armour layer were carried over the top to the industrial area, a situation clearly unacceptable. The design was therefore modified to an Icelandic type aiming to reduce overtopping and increase stability using a less voluminous structure. Taking into account the nothern location of the breakwater where icing from accumulation of frozen sea spray may represent significant difficulties for the plant structures and facilities, wave overtopping reduction was an important factor in the choice of this type of structure.

As an exercise, the necessary armour stone mass has been calculated for a conventional rubble mound breakwater at the site, using Hudson and Van der Meer formulations for a slope 1:1.5. See Appendix B for the detailed parameters used in the calculations. The results are shown in Figure 11.17, in which the necessary armour mass has been plotted as a function of the Iribarren number for a damage level $S = 2$, start of damage (see Appendix B for a higher damage level of $S = 6$).

For a mean wave period of $T_z = 20.3s$, the Iribarren number is $\xi_z = 6.1$. For this Iribarren number, the Van der Meer formula gives a required armour stone mass $W_{50} \approx 83t$, while the Hudson formula gives a required stone mass $W_{50} \approx 44t$.

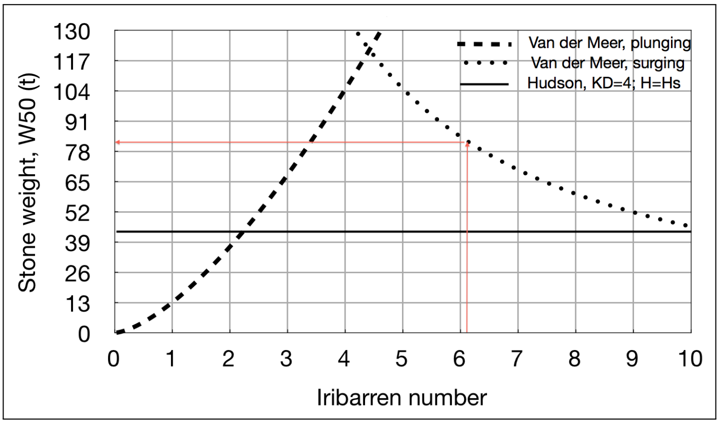

Figure 11.17: Necessary armour stone mass vs Iribarren number for a damage level $S = 2$; slope 1:1.5; permeability coefficient $P = 0.4$; non-breaking waves; $H_S = 7.5m$; $N = 3000$, $T_z = 20.3s$.

If the mean wave period is expected to be in the range of $T_z = 18 - 22s$, the Iribarren number varies in the range of $\xi_z = 5.5 - 6.7$, still in the surging wave case.

In general, the required armour stone mass for these conditions is so large that it would not be possible to obtain large enough stones from rock quarries. In this case, alternatives such as concrete armour units or the actual chosen berm breakwater concept with rock units are good alternative solutions.

Table 11.3 shows a summary of the results for the required armour unit mass of the actual Melkøya berm breakwater in addition to the required mass for a conventional two layer rubble mound breakwater using rock, cubes and tetrapods, slope 1:1.5 and a start of damage level $S = 2$. See Appendix B for details.

Table 11.3: Comparison of armour unit masses for different concepts at Melkøya breakwater. $H_S = 7.5m$; $T_z = 20.3s$; slope 1:1.5; two layer armour stones for the different rubble mounds.

	Berm breakwater	Rubble Mound rocks Hudson	rocks Van der Meer	concrete cubes	tetrapods
$\approx W_{50}$ (t)	13 ($H_0 = 2.7$) 33 ($H_0 = 2$)	44	83	30	15

The results presented in Table 11.3 indicate that it would have not been possible to build a conventional rubble mound breakwater at Melkøya, with a reasonable slope, from quarried stone for the wave conditions at the site. If a conventional rubble mound would have been still required, concrete armour units may have been used. However, the mass of the concrete elements needs to be larger than the mass of the rock units in the berm breakwater [2]. Thus, if good quality rocks of the required size are available, the berm breakwater concept would be the preferred option, as it was the actual final design built at Melkøya.

11.3 Goliat Field Development

11.3.1 Field description and background for choice

The Goliat field is located on the Norwegian Continental Shelf at $71\,^{\circ}N$, in the Barents Sea (block 7122/7,8,10,11). The location is approximately 50km southeast of the Snøhvit field. The water depth varies between 360-420m (Figure 11.18), and the area includes two separate main reservoirs: the Kobbe and Realgrunnen formations [62], [58].

The Goliat reservoirs contain oil and thin gas caps. The reservoir depth is 1100 to 1800m in a complex and segmented structure. The pressure in the reservoirs is low (123bar for Realgrunnen and 192bar for Kobbe). The recovery strategy consists

[2] Notice that the upper stability criteria for reshaped static stable ($H_0 = 2.7$) needs to be used in order to compare the different types of breakwaters. The non-reshaped threshold ($H_0 = 2$) would define only the larger stone class. However, the weighted stability number for all stone classes of the most exposed cross section, results in a statically stable structure.

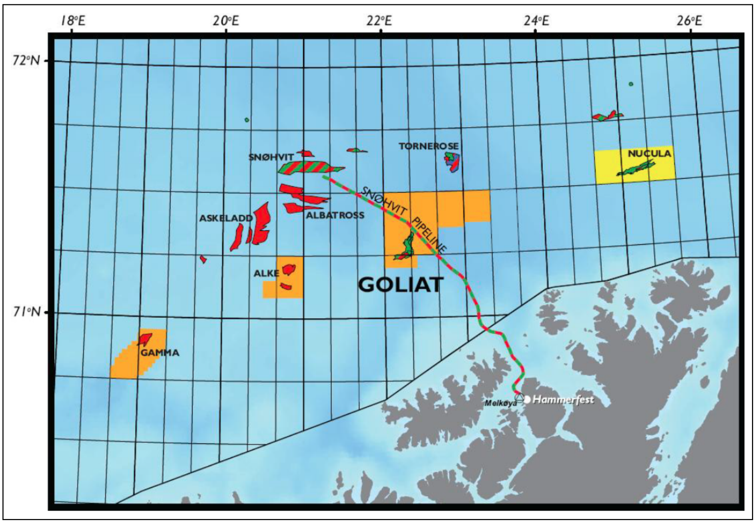

Figure 11.18: Goliat field area. *Source: Eni Norge*

on using water injection as pressure support. Associated gas will be reinjected back until a possible export solution for the gas is available, for instance through the Snøhvit pipeline to Melkøya. The original recoverable reserves include 30.2 million Sm^3 of oil, 7.3 billion Sm^3 of gas and 0.3 million tonnes of NGL [58].

The alternative concepts considered (Figure 11.19) for the field development included [63]:

– **Offshore processing and oil storage**: subsea production system and processing of the well stream carried out at a floating platform (in addition to a standard FPSO, SEMO[3] and Sevan[4] designs have been evaluated). The oil is exported to the market using tankers which are loaded at the offshore platform.
– **Offshore processing and onshore oil storage**: subsea production system tied up to a semisubmersible unit with first stage separation and with a pipeline to an onshore terminal where final processing and storage of the oil are held. The oil is then shiped to the market by tankers loaded at the harbour.
– **Onshore processing and storage**: full well stream sent to shore for processing at an onshore terminal. Gas and water pipelines back to the field from the onshore terminal for reinjection into the reservoirs.

[3]Monofloater design, geostationary FPSO.
[4]FPSO design with a cylindrical hull. The hull is used for cargo storage and segregated ballast tanks, as well as for marine and utility systems.

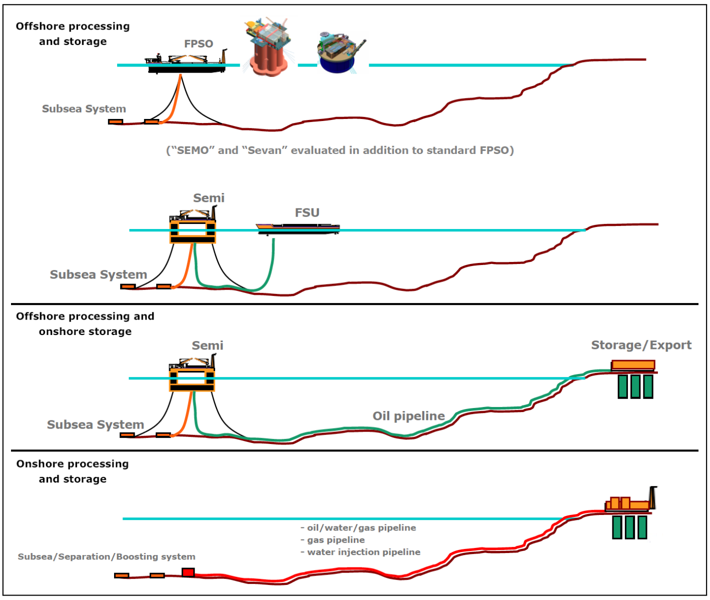

Figure 11.19: Goliat field development alternatives. *Source: Eni Norge*

The final development concept chosen for the area is offshore processing, storage and offloading (Figure 11.20). The infraestructure includes the following elements [62]:

- Subsea installation located at 350-400m water depth. It includes 22 subsea wells in 8 of 4-slot templates. Eleven of these wells will be producers, 9 water injectors and 2 gas injectors. The southernmost template is located approximately 7km from the FPSO.
- Cylindrical production facility (Sevan 1000 FPSO). At the floating platform, the wellstream will be processed and the oil will be stored and offloaded to tankers. The platform counts on winterization systems to operate under the subarctic conditions at the location. The offloading from the FPSO to the shuttle tankers can be carried out around the entire circumference of the platform (see next section for details of the solution).
- Reinjection of produced gas in addition to sea water in order to attain the total pressure drive necessary to achieve optimal production. Later gas export is being evaluated.
- Power supplied from land via a subsea electric cable, combined with an onboard power generation system
- Transportation of oil through shuttle tankers that will call at Goliat on a weekly basis to collect 850000 bbl from the FPSO.

– Operation of a contingency vessel on permanent station in the area equipped for mechanical oil recovery and dispersal operations. The vessel is provided with winterization systems, oil detecting radar and infrared cameras for operation under cold and dark conditons.

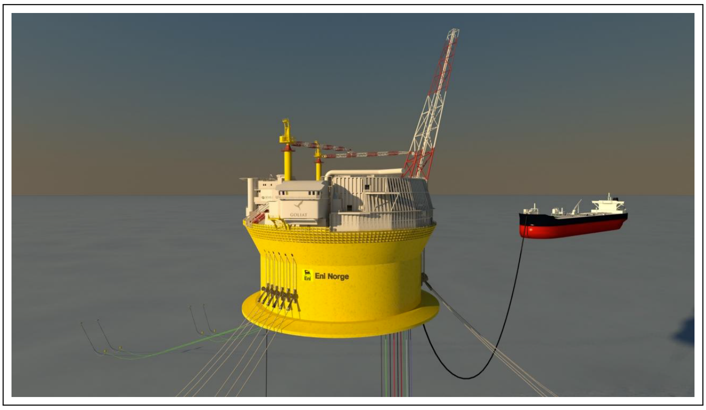

Figure 11.20: Development concept chosen for Goliat field. *Source: Eni Norge*

In this case, taking into account the location of the field, further south than Johan Castberg, the challenges imposed due to the climatic conditions are lowered, which potentially decreases the technical and operational offshore risks at the location, making offshore processing, storage and offloading a feasible and less expensive solution, for instance avoiding investment in a terminal or providing opportunity for tie-ins in case of other discoveries in the area.

However, the severe climate conditions and sensitivity of the environment due to the nothern and relatively close to shore location of the field, make oil spill protection and contingency measures of extreme importance in order to minimize the environmental risks. The location of the Goliat field means that any oil spill might potentially affect the coast. In order to prevent accidents in severe climate conditions during oil and gas production, it is necessary to develop specific technical and emergency reponse systems [11]. Some of the special requirements and new solutions that will be applied to the Goliat preparedness system are as follows [64]:

– Sensors on subsea templates combined with inspections using a remotely operated vehicle in order to ensure an early warning in case of any error.
– Standby vessel stationed by the production unit. The vessel has been optimized for cold climate and winter conditions.
– FPSO design to reduce the probability of acute pollution (see next section). The production unit will have sensors and flow meters monitoring the discharge

points. In addition, it will count with onboard infrared cameras to detect and monitor any oil spill independent of lighting conditions.

- Infrared radar surveillance of the area integrated into helicopters, aircraft and other vessels participating in the emergency response plan.
- Permanent preparedness organization in cooperation with regional fishermans and NOFO. Fishing vessels from Finnmark will carry light and medium weight boom systems.

11.3.2 Terminal concept and offshore loading

The offshore solution chosen for the Goilat field, is based on a cylindrical FPSO. This type of geostationary FPSO, presents some differences compared to a shipshaped FPSO or a semisubmersible unit, making it a potentially advantageous offshore option when the harsh and subarctic environment at the field location is taken into account [65], [62].

- The main difference between the geostationary FPSO and ordinary production vessels, is that it faces the environment with the same shape in all directions, therefore, there is no need to rotate and thus avoids the often costly turret and swivel system. This implies also less maintenance costs and risk of downtime. Moreover, the floating cylindrical structure has no bow or stern. This enhances the safety zone around the unit because it is not turned by the sea or wind, potentially reducing the environmental risks.

- Due to the global stresses on the hull, the bending stresses are insignificant [65], eliminating typical wave induced fatigue loads and deflections between modules (Figure 11.21). This results in stability under harsh water conditions.

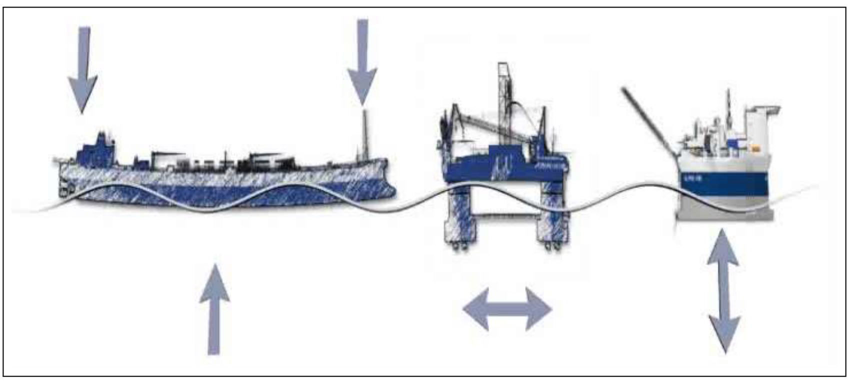

Figure 11.21: Comparison of hull stresses for different platform types. *Source: Sevan Marine*

– Low heave and roll/pitch motions allow a high operability.

– Accomodates a large number of risers, and the posibility for future tie-ins through low investment costs.

– The processing carried out at the platform includes the following modules: manifold and pigging, separation, gas compression/recompression and water system chemical injection. The total liquid processing capacity is 17500 Sm^3/day.

– Winterization is required. The winterization strategy includes a protective shielding of exposed areas, safe areas fully enclosed as far as possible, heat tracing on relevant surfaces, process area covered by a protective wall with overlapping plates and a fully enclosed roof structure. Specifically, the process area is protected by winterization panels, which are transparent allowing sufficient air flow to satisfy natural ventilation of the process area [65].

– The FPSO unit is constructed with double base and hull.

– Electricity will be supplied from land via a subsea electric cable (108km, 75MW), combined with energy generated onboard the facility (additional 20-30MW) to ensure operability in case of problems with electricity supply from land.

Table 11.4 shows the main dimensions of the FPSO for the Goliat field.

Table 11.4: Main dimensions Goliat FPSO.

Storage (bbl)	Displacement (mt)	Diameter (m)			Deck area (m^2)		Topside weight (tons)
		Hull	Main deck	Process deck	Tanktop deck	Process deck	
1000000	180000	90	102	107	8170	8990	25000-30000

Offloading system

A new, improved concept will be used for offloading oil from the Goliat FPSO and loading onto tankers. The new system makes it possible for a potentially safer and efficient offloading by introducing an extended loading positioning sector for tankers loading from the cylindrical FPSO. The reduced offloading risk is mainly due to [65]:

– Significant reduced collision risk compared to a conventional offloading from a weathervaning FPSO.
– The geostationary hull presents favourable motion characteristics and mooring safety, leading to less motion interference with the tanker.
– Larger operational window.

Having a look at the North Sea experience, there have been several collisions during offloading operations in the past. In the last 15 years, tanker collision in tandem offloading has occurred on Emerald FSU, Gryphon FPSO, Norne FPSO, Njord FSU and Captain FPSO [65]. This shows the high risk of the offshore loading activity. The goal of this new offloading system is the reduction of collision risk by an improved system in which the operation envelope and separation distance have been increased.

The governing criteria for the tanker loading is the distance from the floating unit and heading away from the FPSO (Figure 11.22).

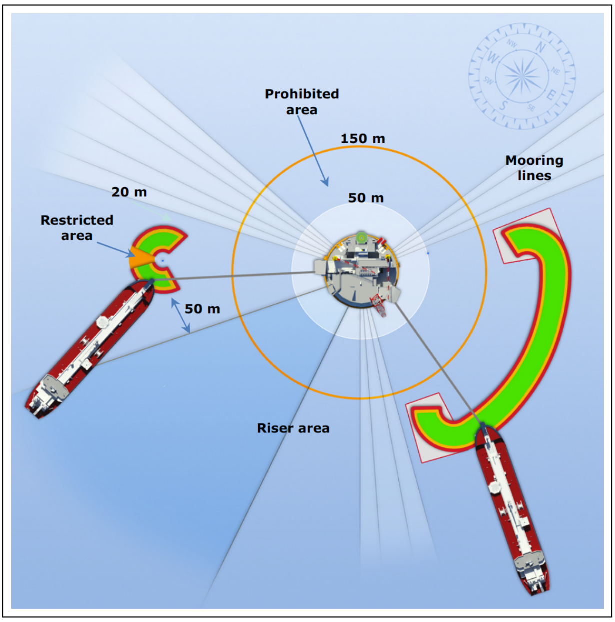

Figure 11.22: Tanker positioning requirements and limitations. *Source: Eni Norge*

The following requirements and limitations apply [63]:

– The shuttle tanker should usually operate with 50m heading offset to the FPSO.
– The tanker should not head towards the FPSO when connected. Heading toward the FPSO is only allowed during change of the tanker´s heading from one side of the FPSO to the other.
– Typical operating distance between the shuttle tanker bow and the FPSO is approximately 250m
– Minimum distance between the shuttle tanker and the FPSO is 150m.
– Minimum distances between the tanker bow manifold and the closest riser and mooring line are 50m and 20m respectively.
– A restricted operation area in the secondary offloading station.
– Tankers are equiped with a dedicated Dynamically Positioned system in continuous operation.

The operating sector is therefore 240+190 degrees (overlapping sectors), through a primary and secondary offloading stations. The wave height limit for tanker hook up and loading is $H_S = 4.5 - 5.5m$. Figure 11.23 shows the significant wave height data at the FPSO location. It can be observed that the main direction of incidence is west-southwest.

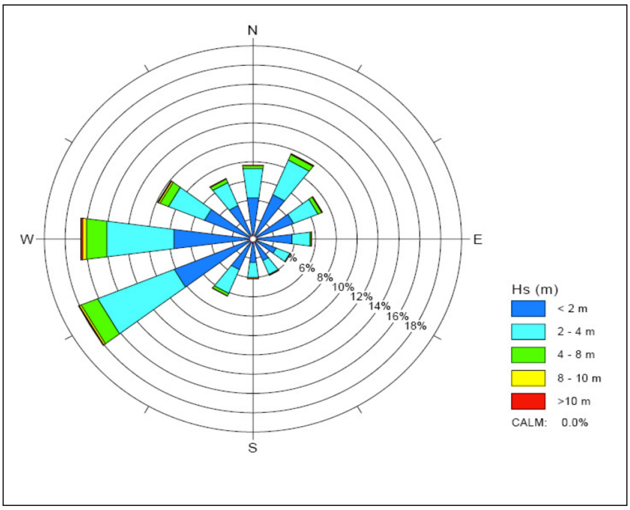

Figure 11.23: Significant wave height data at Goliat field. *Source: Eni Norge*

According to a risk assessment on collision and accidental drive off carried out by Scandpower and Sevan [66], the collision risk with the cylindrical FPSO is shown to be reduced by a factor of 250 compared to traditional tandem offloading. The main contributors are the increased stability of the geostationary hull and the tanker bow not pointing at the FPSO.

Figure 11.24 shows the collision risk comparison between direct offloading from a geostationary FPSO and tandem offloading from a shipshaped FPSO.

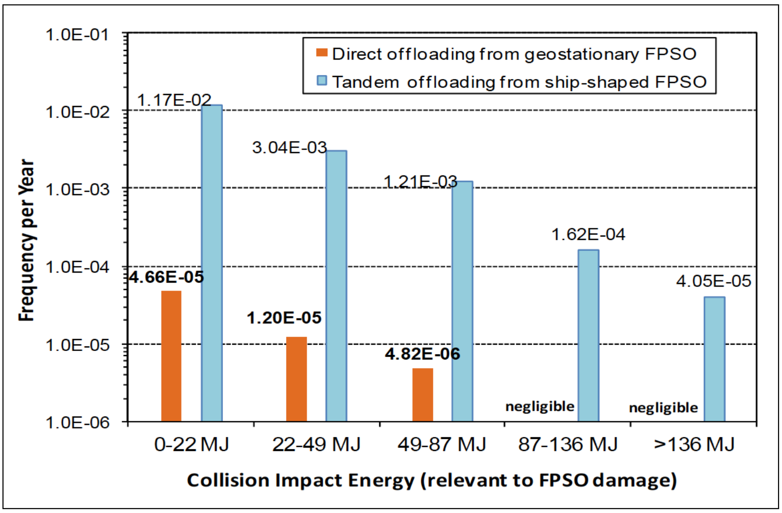

Figure 11.24: Collision risk comparison of tandem vs direct offloading. *Source: Sevan*

Chapter 12
Risk Assessment

This chapter discusses qualitative risk analysis tools for use during assessment of hydrocarbon field developments. Generally, a qualitative analysis is carried out before any quantitative, more sophisticated analysis is employed.

The methodology described here, will be applied to the three case studies: Johan Castberg, Snøhvit and Goliat field developments, for identification and evaluation of the main risks involved.

The risk concept is used as a measure of safety, and can be defined as the product of probability and consequence of a potential undesired event (Figure 12.1).

$$Risk = Probability \times Consequence$$

- Probability: likelihood of a potential event. Expressed in the range of 0 to 1, zero meaning the certainty that the event will not occur, and 1 means the certainty that the event will occur.
- Consequence: severity of negative impact if the unwanted event occurs.

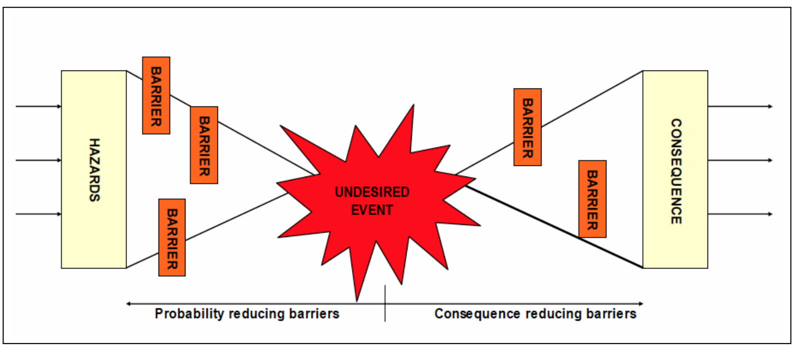

Figure 12.1: Hazard bow-tie diagram. *Source: Aker Kværner*

Generally, a risk assessment comprises the following steps [67], [68]:

- **Risk acceptance criteria:** sets the criteria before carrying out the assessment.
- **Identification of the potential hazards:** factors such as properties of the substances being handled, arrangement of the equipment, operating and maintenance procedures, processing conditions, leakages and explosions, extreme environmental conditions, ship collision, etc. are considered at this first stage.
- **Assessment of the risk:** evaluates the probabilities and consequences of such hazards taking into account their tolerability to personnel, the infrastructure or the environment.
- **Acceptability of the risk:** evaluates the estimated risks against the risk acceptance criteria appropriate to the situation, which should be defined prior to the risk analysis.

12.1 Acceptance Criteria and Qualitative Risk Matrix

The acceptance criteria expresses the risk level that is considered tolerable for the activity in question. The definition of the acceptable risk levels should be decided prior to the risk analysis, and it is usually determined as regulatory requirements, company policy, public opinion, customer requirements and satisfying economic constraints [67].

The most common framework used for risk criteria, widely adopted in marine risk assessments, divides the risks into three categories [69], [70]. See Figure 12.2.

- **Unacceptable:** risks are intolerable except in extraordinary circumstances, whatever their benefits. Risk reduction measures need to be implemented, otherwise the operation shall not be carried out.
- **Tolerable:** risks that are tolerated to secure the benefits generated. The As Low As Reasonably Practicable (ALARP)[1] principle is applied. Risk reducing measures are required to ensure performance of the operations within an acceptable risk level. The risk is tolerable only if reduction cost exceeds improvement achieved or is disproportionate to the benefits gained.
- **Broadly acceptable:** risks considered insignificant by the majority, and therefore regarded as acceptable. Action to reduce those risks is usually not required, however, the ALARP principle can be applied to ensure that the risk remains at this level and/or reduced further if reasonably practical. Usually,

[1]The ALARP principle is that the residual risk should be As Low As Reasonably Practicable. Risk reducing measures are feasible and their costs are not larger than the benefits.

for the definition of the negligible risk level, below wich the risk is considered acceptable, cost-benefit anlysis are used to evaluate the effect of risk reducing measures.

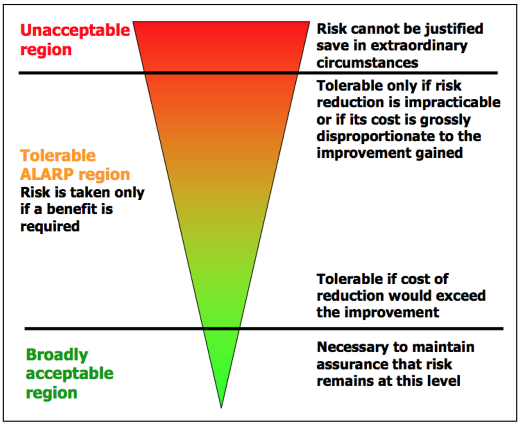

Figure 12.2: Tolerability of risk framework. *Source: HSE*

For qualitative assessments, is possible to use a risk matrix to compare options and the value of risk reducing measures. The results are expressed in the form of a two dimensional matrix, with the probability of occurrence on one axis and the consequences on the other. This arrangement may be a suitable expression of risk, specially for early project phases. The matrix is usually divided into three categories, which can be compared to the acceptance criteria previously defined.

- **Low risk - Acceptable (A):** risk management for continued improvement.
- **Medium risk - Satisfactory (S):** risk reduction based on ALARP principle.
- **High risk - Unacceptable (U):** risk reduction, high management attention and detailed assessment is necessary.

For ranking and evaluation of the risks, a 5x5 risk matrix has been defined (Figure 12.3) for this analysis, taking as indication the risk matrix presented in the International Standard ISO 17776 [68], the assessment criteria used for oil companies in Norway, adopted from the OLF MIRA [2] guideline, and the recommended practice by Det Norske Veritas for risk management of marine and subsea operations [70].

The consequences have been defined to apply to four categories: people, environment, assets and company reputation. The red color shows the high risk situations,

[2] The Norwegian Oil Industry Association. Method for Environmental Risk Analysis

which correspond with an unacceptable risk (U); yellow cells show the medium risk situations, which correspond to a satisfactory risk level (S); green cells show the low or acceptable risk situations (A).

Consequence					Probability				
	People	Environment	Assets	Reputation	Improbable (A) Very unlikely. It may never be experienced	Remote (B) Rarely has occurred in industry	Occasional (C) Has occurred in operating company	Likely (D) Occurred several times a year in operating company	Frequent (E) Occurred several times a year in location
5) Extensive	Fatalities	Global or national effect. Restoration time >10 years	Project/ production consequence costs >10M USD	International impact/ negative exposure	A5=S	B5=S	C5=U	D5=U	E5=U
4) Severe	Major injury	Restoration time >1yr. Restoration cost >1M USD	Project/ production consequence costs >1M USD	Extensive National impact	A4=A	B4=S	C4=S	D4=U	E4=U
3) Moderate	Moderate injury	Restoration time >1month. Restoration cost > 1K USD	Project/ production consequence costs >100K USD	Limited National Impact	A3=A	B3=A	C3=S	D3=S	E3=U
2) Minor	Illness or minor injury	Restoration time <1month. Restoration cost <1K USD	Project/ production consequence costs >1K USD	Local impact	A2=A	B2=A	C2=A	D2=S	E2=S
1) Negligible	Zero or slight injury	Zero or slight effect	Zero or slight damage	Zero or slight impact	A1=A	B1=A	C1=A	D1=A	E1=A

Figure 12.3: Risk matrix used for the analysis.

12.2 Hazard Identification and Risks Reduction

A hazard can be defined as a potential source of harm. Several methods are available for the identification of hazards, some of them are briefly described below [70], [71].

- **Hazard Identification Analysis (HAZID)**
  This technique is used to identify and evaluate hazards early in a project. The method is used as a tool for assessing the potential risks the operation initially represents.
- **Hazard and Operability Analysis (HAZOP)**
  It is an interdisciplinary, systematic approach to identify risky operations and weaknesses in procedures.
- **Design Review (DR)**
  It is a systematic approach to review a particular design solution and is used to reveal weaknesses in the design of a particular system, structure or component.
- **Failure Modes, Effects and Critically Analysis (FMECA)**
  This method is used to identify potential failure modes of each functional block in a system, and to study the effects those failures might have on the system.

- **Semi Quantitative Risk Analysis (SQRA)**
  The main purpose of the SQRA is to subjectively assess the risk and criticality of operations in order to identify the most critical activities. A semi-quantitative risk assessment, may be used in combination or as a part of other of the previously defined hazard review techniques (HAZID, HAZOP, FMECA, etc.).

As an initial tool, a HAZID can be used to identify the main areas of concern and what are the typical design drivers. Here, brief HAZIDs have been prepared for each of the three case studies (see next section).

After the potential hazards have been identified and the risks estimated, the evaluation of risk reducing measures is carried out. Risk reduction measures should include those to prevent incidents (i.e. reduce the probability of occurrence), to control incidents (i.e. limit the extent and duration of a hazardous situation) and to mitigate the effects (i.e. reduce the consequences). The general hierarchy for risk reducing measures is as follows:

i Prevention to avoid the hazard
ii Elimination of the cause of the hazard
iii Technical action to reduce the probability of the hazard.
iv Technical action to reduce the consequences of the hazard
v Operational actions to reduce the hazard

12.3 Case Studies Application

In this section, the main potential hazards and their effects have been identified for each of the three case studies. Figures 12.4, 12.5 and 12.6 show the HAZIDs generated for Johan Castberg, Snøhvit and Goliat respectively. For the identification of the main hazards and assessment of possible effects, the hazards checklist provided by the International Standard ISO 17776 [68] has been used. The probability and consequence upon the four categories (people, environment, assets and reputation) have been estimated and ranked, i.e. describing the risk as low, medium or high, following the criteria explained in the previous section.

After the identification of hazards and the estimation of risks, the higher risk activities have been placed in the 5x5 risk matrix (Figure 12.7).

The Goliat field presents several hazardous situations related to offshore storage and offloading of hydrocarbons, especially if the northern location of the field and the proximity to the coast are taken into account. Comparing the chosen solution

JOHAN CASTBERG FIELD						
HAZARD ID	**IDENTIFIED HAZARD**	**HAZARD SOURCES**	**CONSEQUENCES**	**UPON**	**PROBABILITY**	**RISK RATING**
1. Subsea Production System						
J 1.1	Subsea hydrocarbon release	Equipment failure Structural damage Human error	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low
J 1.2	Production stop	Extreme weather conditions Equipment failure Well maintenance required	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low
2. Semisubmersible Floating Unit						
J 2.1	Gas release under pressure	Equipment failure Mechanical failure Human error	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low
J 2.2	Separation failure	Equipment failure Mechanical failure Human error Extreme weather conditions	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low
3. 280km Oil Pipeline						
J 3.1	Oil release	Pipeline failure Structural damage Human error Corrosion	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low
J 3.2	Production stop	Pipeline blockage Human error	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low
4. Onshore Terminal						
J 4.1	Breakwater failure	Extreme weather conditions Structural failure/ damage Human error in design, construction	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low
J 4.2	Oil spill during loading operation	Mechanical failure Human error Extreme weather conditions Harbour oscillations Overloading	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low
J 4.3	Oil spill from storage tank	Mechanical failure Human error Structural damage	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low
J 4.4	Production stop	Mechanical failure Human error Structural damage Extreme weather conditions	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low
5. Oil Tankers						
J 5.1	Grounding/collision with other ships or facilities	Extreme weather conditions Ice presence Equipment failure Human error Excessive forces, mooring damage Harbour oscillations	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low
J 5.2	Oil leakage from tanker	Extreme weather conditions Equipment failure Human error Structural damage Overloading	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low

Figure 12.4: HAZID for Johan Castberg field.

SNØHVIT FIELD						
HAZARD ID	**IDENTIFIED HAZARD**	**HAZARD SOURCES**	**CONSEQUENCES**	**UPON**	**PROBABILITY**	**RISK RATING**
1. Subsea Production System						
S 1.1	Subsea oil release	Equipment failure Structural damage Human error	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low
S 1.2	Production stop	Extreme weather conditions Equipment failure Well maintenance required	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low
2. 143km Multiphase Subsea Pipeline						
S 2.1	Pipeline leakage	Pipeline failure Structural damage Human error Corrosion	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low
S 2.2	Pipeline blockage	Hydrate formation Human error Extreme weather conditions	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low
3. Onshore LNG Terminal						
S 3.1	Breakwater failure	Extreme weather conditions Structural failure/damage Human error in design, construction	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low
S 3.2	LNG release during loading operations	Mechanical failure Human error Extreme weather conditions Harbour oscillations Overloading	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low
S 3.3	LNG release from storage tank failure	Mechanical failure Human error Structural damage	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low
S 3.4	LNG ignition at the plant or terminal	Mechanical failure Human error Structural defects	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low
S 3.5	Production stop	Mechanical failure Human error Structural damage Extreme weather conditions	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low
4. LNG/LPG Tankers						
S 4.1	Grounding/collision with other ships or facilities	Extreme weather conditions Ice presence Equipment failure Human error Excessive forces, mooring damage Harbour oscillations	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low
S 4.2	LNG leakage from tanker	Extreme weather conditions Equipment failure Human error Structural damage Overloading	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low

Figure 12.5: HAZID for Snøhvit field.

GOILAT FIELD						
HAZARD ID	**IDENTIFIED HAZARD**	**HAZARD SOURCES**	**CONSEQUENCES**	**UPON**	**PROBABILITY**	**RISK RATING**
1. Subsea Production System						
G1.1	Subsea hydrocarbon release	Equipment failure Structural damage Human error	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low
G 1.2	Production stop	Extreme weather conditions Equipment failure Well maintenance required	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low
2. Cylindrical FPSO unit						
G 2.1	Oil release	Equipment failure Mechanical failure Human error Structural damage	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low
G 2.2	Gas leakage	Equipment failure Mechanical failure Human error Structural damage	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low
G 2.3	Offshore loading failure	Extreme weather conditions Equipment failure Mechanical failure Human error	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low
G 2.4	Not enough oil storage capacity	Extreme weather conditions, tanker delays Mechanical failure Human error	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low
G 2.5	Separation failure	Mechanical failure Human error	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low
G 2.6	Production stop	Extreme weather conditions, tanker delays Mechanical failure Human error Structural error	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low
3. Electrification System						
G 3.1	Electricity shutdown	Subsea cable failure Onboard generator failure Onshore facilities failure Human error	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low
4. Oil Tankers						
G 4.1	Grounding/collision with other vessels (standby vessels)	Extreme weather conditions Ice presence Equipment failure Human error	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low
G 4.2	Collision with FPSO	Extreme weather conditions Ice presence Human error Equipment failure	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low
G 4.3	Oil leakage from tanker	Equipment failure Human error Structural damage Overloading	Extensive	People	Frequent	High
			Severe	Environment	Likely	Medium
			Moderate		Occasional	
			Minor	Assets	Remote	
			Negligible	Reputation	Improbable	Low

Figure 12.6: HAZID for Goliat field.

Consequence						Probability			
	People	Environment	Assets	Reputation	Improbable (A) Very unlikely. It may never be experienced	Remote (B) Rarely has occurred in industry	Occasional (C) Has occurred in operating company	Likely (D) Occurred several times a year in operating company	Frequent (E) Occurred several times a year in location
5) Extensive	Fatalities	Global or national effect. Restoration time >10 years	Project/ production consequence costs >10M USD	International impact/ negative exposure			S 2.1 J 3.1 J 5.1	G 4.2	
4) Severe	Major injury	Restoration time >1yr. Restoration cost >1M USD	Project/ production consequence costs >1M USD	Extensive National impact				G 2.3	
3) Moderate	Moderate injury	Restoration time >1month. Restoration cost > 1K USD	Project/ production consequence costs >100K USD	Limited National Impact					
2) Minor	Illness or minor injury	Restoration time <1month. Restoration cost <1K USD	Project/ production consequence costs >1K USD	Local impact					
1) Negligible	Zero or slight injury	Zero or slight effect	Zero or slight damage	Zero or slight impact					

Figure 12.7: Higher risk hazards located in the defined 5x5 qualitative risk matrix before the application of risk reducing measures.

for Johan Castberg in terms of risks with an offshore processing and oil storage solution (as chosen for Goliat), it can be observed that mainly due to the high latitude location (150km to the north from Goliat), which accentuates the climatic challenges, the concept chosen reduces the technical risk, the production downtime and a potential emergency response (oil spill and/or rescue operations). For the Snøhvit field, one of the main risks appears in the subsea multiphase transport during 143km under low temperatures and harsh climatic conditions. In addition it presents some different hazards due to the handling of LNG as compared to the other two fields.

Summarizing, it can be observed from the resulting matrix, that the higher risk activities identified for the different fields are related to:

i **Johan Castberg:** oil pipeline transport from the field to the terminal; tanker operations especially under extreme weather conditions.
ii **Snøhvit:** multiphase pipeline transport from the field to the terminal.
iii **Goliat:** tanker operations in the proximity of the FPSO under harsh climatic conditions, specifically the offloading from the FPSO unit onto tankers; offshore storage and processing of hydrocarbons.

Part IV

Conclusions

Chapter 13
Concluding Remarks

The present thesis provides with an insight on a broad range of aspects influencing offshore hydrocarbon field development in cold climate. Special emphasis has been made on terminals as a major building block necessary in the development of a petroleum field. Quantitative assessments of breakwater stability in cold climate environments have been an important part of the discussions.

Moreover, three different development schemes in the Barents Sea: Johan Castberg, Snøhvit and Goliat, have been used to carry out a practical case study analysis, through which the knowledge gained during the first part of the thesis work could be applied to different development solutions and terminal concepts in cold climate. Furthermore, given the complex and unique risk challenges present in cold climate regions, risk assessment arises as an important part of the decision making process, and thus, has been used to understand the sensitivity of the different development schemes.

i **On offshore field development in cold climate:**

- Cold climate oil and gas production, represents a potential contributor for securing energy supply in the next 25 years, with key factors such as an increased demand, technological progress and accesibility sharpening the interest.
- Cold climate regions are complex risk environments, and therefore, any hydrocarbon development in these areas, represents a balance between opportunity and risk.
- The probability of an oil spill in cold climate is as in more temperate areas, however, its consequences might be more severe, therefore, improved mitigating measures are needed.
- Processing is a key part of a hydrocarbon development in order to obtain products that can be transported, stored and marketed.

- A terminal is a major building block necessary in the development of a hydrocarbon field. High costs and weight and space restrictions of offshore processing, make onshore terminals and important part of a petroleum development.

ii **On cold climate terminals:**

- Recent developments in cold climate breakwater design, favour the use of berm breakwaters. The *Icelandic type* berm breakwater, increases the stability of the structure and decreases both overtopping and reflection from the structure due to the use of several narrowly graded armour classes.
- The analysis on the dependency of the armour size on wave height and wave period for berm breakwaters, shows that usually, the stability number (H_0) is employed as stability criteria, however, doing so, only the effect of the wave height is taken into account. If the period stability number (H_0T_0) is used as mobility criteria, the effect of the wave period is included in the calculation of the armour size.
- The accountability of the harbour resonance phenomena is of great importance, specifically in the case of deepwater ports, which have been shown to be more prone to harbour oscillation concerns.
- Offshore loading is the most vulnerable marine operation, particularly under cold climate conditions. Thus, the offloading option chosen should ensure the ability to cope with the harsh environmental conditions at the location.

iii **On the case studies analysis:**

- The location chosen for the Johan Castberg terminal at Veidnes, is well protected and sheltered, presenting relatively mild wave conditions. A berm breakwater, although in general recommended for cold climate harbours, would probably not be the most economic solution in this case. The required armour stone mass for a conventional rubble mound breakwater, is relatively small, being therefore a more plausible solution for this location.
- The results of the comparison of necessary armour unit masses for different breakwater concepts, carried out for the terminal at Melkøya, indicate that it would not have been possible to build a conventional rubble mound breakwater, with a reasonable slope, from quarried stone for the wave conditions at the site. Concrete armour units may have been used, however, if good quality rock of the required size is available, the berm breakwater concept would be the preferred option, as it was the actual final design build at Melkøya.

- The location of Johan Castberg, further north than Goliat or Snøhvit, accentuates the challenges imposed due to climatic conditions, which increase the technical and operational risks, specially offshore. The concept chosen, avoids offshore storage and offloading, therefore decreasing the technical risks, the production downtime and potential emergency response. The location of Goliat, further south, makes in that case offshore processing, storage and offloading a feasible and less expensive solution.
- The results of the risk assessment carried out, show that Goliat presents several hazardous situations related to offshore storage and offloading of hydrocarbons, specially if the northern location of the field and the proximity to the coast are taken into account. Special procedures will be implemented to reduce the risk during offloading. Comparing the chosen solution for Johan Castberg in terms of risks with an offshore processing and oil storage solution, mainly due to the high latitude location, the concept chosen reduces the technical and operational risks. For Snøhvit, one of the main risks appears due to the subsea multiphase transport.

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Appendix A
Breakwater design: quantitative discussion

This appendix presents the main design rules and formulations for berm and caisson breakwaters. In addition, the extended calculations for the results of the quantitative discussion carried out in Chapter 9 are presented here.

A.1 Berm Breakwaters

The main guidelines for the design of berm breakwaters can be found in the 2003 PIANC report *State of the Art of Designing and Constructing Berm Breakwaters* [72]. The main formulations, design rules and generation of curves used in the main body of the thesis are presented here.

A.1.1 Stability criteria

Several threshold criteria are defined to prevent the movement of rock. If the hydraulic load exceeds the mobility threshold, instability of the armour layer occurs. The most used parameters to evaluate the stability of the armour layer are a combination of hydraulic and material parameters.

Stability number

$$H_0 = \frac{H_S}{\Delta D_{50}} \tag{A.1}$$

Period stability number

$$H_0 T_0 = \frac{H_S}{\Delta D_{50}} \sqrt{\frac{g}{D_{50}}} T_z \tag{A.2}$$

where:

H_S, significant wave height

$\Delta = \frac{\rho_s}{\rho_w} - 1$

ρ_s, density of stone

ρ_w, density of water

$D_{50} = (\frac{W_{50}}{\rho_s})^{1/3}$

W_{50}, median stone weight

T_z, mean wave period

g, acceleration of gravity

A.1.2 Conceptual design rules for Icelandic-type breakwater

The design of an Icelandic berm breakwater involves the use of the non-reshaping stability criteria and the use of several narrowly graded stone classes, the larger armour classes placed at the most exposed locations.

The most common designs involve a non-reshaping statically stable structure for the 100 years storm, which can be able, in addition, to withstand a wave height with 1000 years return period without structural damage.

- Two layers of rocks are placed on the upper layer of the berm, and extend down the slope to mean sea level.
- The larger armour class is calculated by: $H_S/\Delta D_{50} = 2$, which corresponds with the non-reshaping stability criteria.
- Recommended slopes below and above the berm are 1:1.5
- Berm width: $3.5H_S$
- Berm level: $0.65H_S$ above design water level
- Crest height: $R_C/H_S s_{op}^{1/3}$
- The second class of armour stones is determined as: $D_{N50II} = 0.8D_{50I}$

A.1.3 Quantitative discussion: dependency of stone size on wave height and period

The dependency of the armour size on wave height and wave period for berm breakwaters has been assessed on Chapter 9. With this purpose, an Excel program has been set up using the threshold criteria and parameters presented on Table 9.1.

The use of the stability number (H_0) or the period stability number (H_0T_0) as mobility criteria, involve taking only the effect of the wave height into account or wave height and period respectively.

Firstly, the stone weight for the larger armour class has been calculated as a function of the significant wave height (H_S) by using the stability number as mobility criteria. The expression for the stability number (A.1), is derived taking into account that the measure used for the stone dimension is $D_{50} = \left(\frac{W_{50}}{\rho_s}\right)^{1/3}$, where D_{50} is an equivalent to the edge of a cube with the same mass as the stone of mass W_{50}.

$$H_0 = \frac{H_S}{\Delta D_{50}} \Longrightarrow D_{50} = \frac{H_S}{\Delta H_0} \tag{A.3}$$

$$W_{50} = \rho_s \left(\frac{H_S}{\Delta H_0}\right)^3 \tag{A.4}$$

where:

$$H_0 = \begin{cases} 2 & \text{for non-reshaping condition} \\ 2.7 & \text{for reshaping stable condition} \end{cases}$$

This expression for the armour mass as a function of the significant wave height has been plotted and is shown in Figure A.1 for both, non-reshaping and reshaping static stable breakwaters.

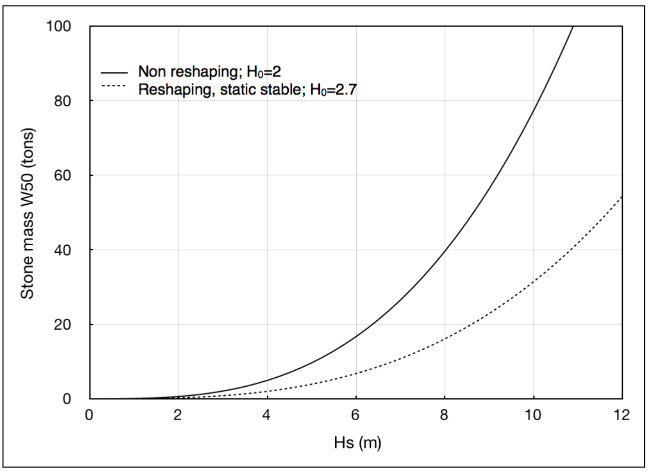

Figure A.1: Stone size as a function of significant wave height by using H_0 as mobility criteria.

In addition, the stone weight for the larger armour class has been also calculated as a function of the significant wave height (H_S) and the mean wave period (T_z). For taking into account both effects, the period stability number has been used in this case as mobility criteria. The expression for the period stability number (A.2), is derived to obtain the stone mass as a function of wave height and period.

$$H_0T_0 = \frac{H_S}{\Delta D_{50}}\sqrt{\frac{g}{D_{50}}}T_z \Longrightarrow D_{50} = \left(\frac{H_ST_z}{\Delta H_0T_0}\right)^{2/3} g^{1/3} \qquad \text{(A.5)}$$

taking again into account the measure for the stone dimension $D_{50} = \left(\frac{W_{50}}{\rho_s}\right)^{1/3}$,

$$W_{50} = \left(\frac{H_ST_z}{\Delta H_0T_0}\right)^2 g\rho_s \qquad \text{(A.6)}$$

where:

$$H_0T_0 = \begin{cases} 40 & \text{for non-reshaping condition} \\ 70 & \text{for reshaping stable condition} \end{cases}$$

Figure A.2 shows the results of plotting this expression for both, the non-reshaping and the reshaping static stable conditions.

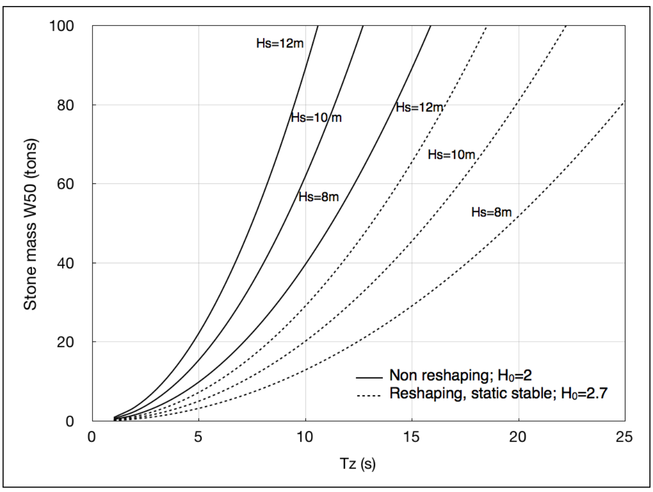

Figure A.2: Stone size as a function of significant wave height and mean period by using H_0T_0 as mobility criteria.

In this case, three significant wave heights have been represented: $H_S = 8m$, $H_S = 10m$ and $H_S = 12m$, for mean periods varying up to 25s.

For the calculations, gravity has been set to $g = 9.81m/s^2$, water density $\rho_w = 1025kg/m^3$ and stone density $\rho_s = 2700kg/m^3$. It is important to notice that the density of the rock depends on the quarry available, and may influence the stability criteria.

In both cases, it can be seen the large difference in the required weight size by using the non-reshaping or the reshaping stability criteria. For instance, for a wave height of $H_S = 8m$, the Icelandic type breakwater would require a median stone of approximately $40t$. On the other hand, if the breakwater is designed as a reshaping static stable breakwater, the larger armour needed would be of around $16t$, half the size needed for the non-reshaping type.

A.2 Caisson Breakwaters

The main guidelines for the design of caisson breakwaters can be found in the 2009 Overseas Coastal Area Development Institute of Japan (OCDI) report *Technical Standards and Commentaries for Port and Harbour Facilities in Japan.* The main formulations and design rules used in the main body of the thesis are presented here.

A.2.1 Goda formulation for wave actions on a caisson breakwater

The wave height used for the design, H_D, is the highest wave height taken as $H_D = 1.8H_S$, when the breaker is outside the surfzone. The wave period used to calculate the wave length, is the significant period of the design wave, which is equal to $0.9T_p$ or $1.2T_z$, where T_p is the peak period and T_z is the mean period.

Figure A.3 shows the linear distribution of wave pressures acting on a caisson type breakwater.

Elevation to which the wave pressure is exerted:

$$\eta^* = 0.75(1 + cos\beta)\lambda_1 H_D \tag{A.7}$$

where β is the angle between the wave approach and the line normal to the vertical wall.

Pressure intensities:

$$p_1 = 0.5(1 + cos\beta)(\alpha_1\lambda_1 + \alpha_2\lambda_2 cos^2\beta)\rho_w g H_D \tag{A.8}$$

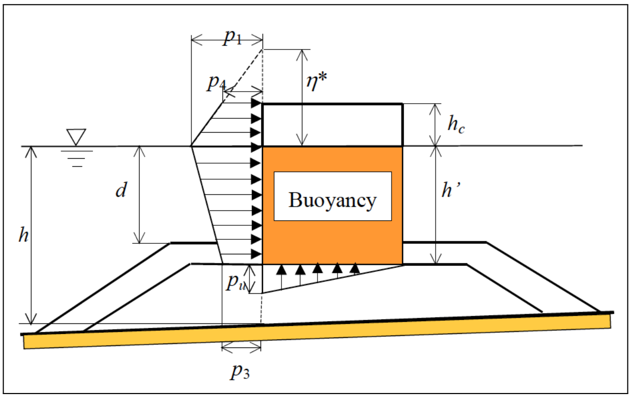

Figure A.3: Wave pressure distribution on a caisson breakwater. *Source: A. Tørum, 2011*

$$p_3 = \alpha_3 p_1 \tag{A.9}$$

$$p_4 = \begin{cases} p_1(1 - \frac{h_c}{\eta^*}) : \eta^* > h_c \\ 0 : \eta^* \leq h_c \end{cases} \tag{A.10}$$

where λ_1 and λ_2 are pressure modification factors (1 is the standar value for composite breakwaters); h_c is the crest height of the vertical wall above SWL; g is the acceleration of gravity; ρ_w is the water density. The coefficients α_1, α_2 and α_3 are defined as follows:

$$\alpha_1 = 0.6 + 0.5 \left[\frac{4\pi h/L}{sinh(4\pi h/L)} \right]^2 \tag{A.11}$$

$$\alpha_2 = min \left[\left(\frac{h_b - d}{3h_b} \right) \left(\frac{H_D}{d} \right)^2 ; \frac{2d}{H_D} \right] \tag{A.12}$$

$$\alpha_3 = 1 - \frac{h'}{h} \left[1 - \frac{1}{cosh(2\pi h/L)} \right] \tag{A.13}$$

where h, h' and d are the corresponding water depths shown in Figure A.1; h_b is the water depth at an offshore distance of 5 times the significant wave height; and L is the wave length at water depth h.

Uplift pressure:

$$p_u = 0.5(1 + cos\beta)\alpha_1\alpha_3\lambda_3\rho_w g H_D \tag{A.14}$$

The Goda formula tends to overestimate the total wave loading by about 10% [11]. It is important, thus, to take this uncertainty into account in probabilistic design of caisson breakwaters. Moreover, if it is necessary to take into account impulsive breaking wave pressures, the modificated formulation by Takahashi et al. 1994, needs to be used.

A.2.2 Quantitative discussion: dependency of maximum horizontal force on wave height and period

The dependency of the maximum horizontal wave force against the vertical wall of the caisson, on wave height and period, has been evaluated. An Excel program has been set up using the Goda formulations, presented on the previous section, for the calculation of forces. The total horizontal force on the caisson is calculated based on the pressures intensities, for different wave heights and periods.

Figure A.4 shows the caisson configuration used here as an example, to carry out the calculations.

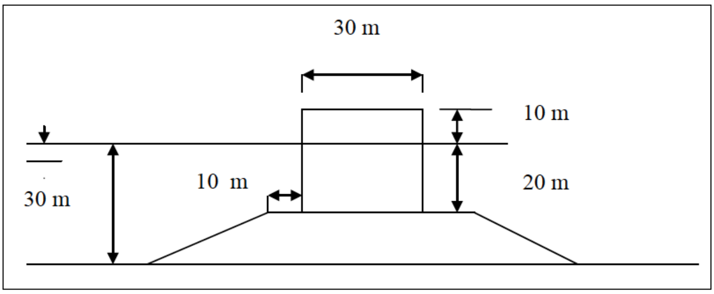

Figure A.4: Example of caisson breakwater used for the analysis

Gravity has been set up to $g = 9.81 m/s^2$ and water density $\rho_w = 1030 kg/m^3$. The design wave height (H_D) has been varied from 8m to 18m. The maximum horizontal force as a function of the wave height has been represented in this case for peak periods varying from 13s to 19s. Figure A.5 shows an example of the results obtained.

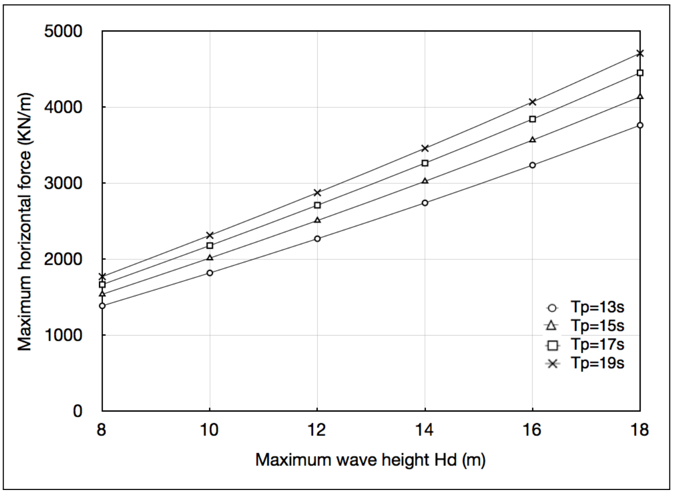

Figure A.5: Maximum horizontal force on the vertical wall as a function of wave height and period

Appendix B
Case Studies: Breakwater Stability

This appendix presents the main formulations and detailed calculations carried out for the comparison of armour unit masses presented in Chapter 11 for a potential breakwater at Veidnes terminal, part of the Johan Castberg field; as well as the assessment carried out for the Melkøya terminal, part of the Snøhvit field.

B.1 Formulations

The main formulations for the stability assessment of rubble mound breakwaters using rocks or concrete units as armour layer are presented here. For the formulation needed for berm breakwaters, reference is made to Appendix A, (A.1) and (A.2).

B.1.1 Hudson formulation, rock armour

Necessary median armour stone mass according to Hudson formula [73]:

$$W_{50} = \frac{\rho_s H^3}{K_D \left(\frac{\rho_s}{\rho_w} - 1 \right)^3 cotg\alpha} \tag{B.1}$$

where:

W_{50}, median stone weight

$H = H_s$, for slope angles $1.5 \leq cotg\alpha \leq 3$

ρ_s, density of stone

ρ_w, density of water

α, front slope angle of the breakwater

K_D, coefficient obtained from model tests

From the Coastal Engineering Manual [49], the coefficient K_D can be obtained from Figure B.1.

Stone shape	Stone placement	Damage[4]			
		0 – 3%		5-10%	10-15%
		Breaking waves[1]	Non-breaking waves[2]	Non-breaking waves[2]	Non-breaking waves[2]
Smooth, rounded	Random	2.1	2.4	3.0	3.6
Rough, angular	Random	3.5	4.0	4.9	6.6
Rough, angular	Special[3]	4.8	5.5		

Figure B.1: K_D values for $H = H_s$, slope angles $1.5 \leq cotg\alpha \leq 3$. *Source: Coastal Engineering Manual*

B.1.2 Van der Meer formulation, rock armour

Necessary median armour stone mass according to Van der Meer formula [74]:

Plunging waves:

$$\frac{H_S}{\Delta D_{50}} = 6.2 C_H P^{0.18} \left(\frac{S}{\sqrt{N}}\right)^{0.2} \xi_z^{-0.5} \tag{B.2}$$

Surging waves:

$$\frac{H_S}{\Delta D_{50}} = 1.0 C_H P^{-0.13} \left(\frac{S}{\sqrt{N}}\right)^{0.2} \xi_z^{P} \sqrt{cotg\alpha} \tag{B.3}$$

where:

$D_{50} = \left(\frac{W_{50}}{\rho_s}\right)^{1/3}$

$\Delta = \frac{\rho_s}{\rho_w} - 1$

$C_H = 1.4/(H_{1/20}/H_{1/3})$, modification factor due to random wave breaking, takes a value of 1 outside the surfzone.

$\xi_z = \frac{tan\alpha}{\sqrt{\frac{2\pi H_S}{g T_z^2}}}$, Iribarren number

T_z, mean wave period

$S = A_c/D_{50}^2$, damage level

N, number of waves

P, permeability coefficient

The permeability coefficient is taken as $P = 0.4$ for a cross section with armour layer, filter and core, as in Figure B.2.

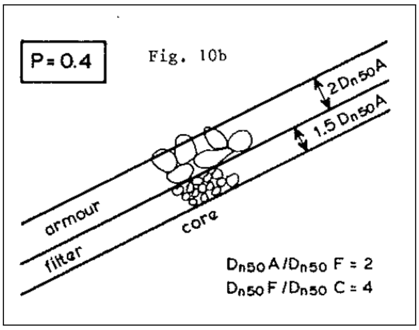

Figure B.2: Breakwater cross section for permeability coefficient $P = 0.4$. *Source: Van der Meer Consulting*

B.1.3 Van der Meer formulation, concrete cubes

For concrete cubes in two layers on slope 1:1.5 to 1:1.2:

$$\frac{H_S}{\Delta D_{50}} = \left(6.7\frac{N_{od}^{0.4}}{N^{0.3}} + 1\right) s_{om}^{-0.1} \tag{B.4}$$

where:

$N_{od} = 0.5N$, actual number of units displayed related to a width

N, number of waves

$s_{om} = 2\pi H_S/gT_m^2$, wave steepness

B.1.4 Van der Meer formulation, concrete tetrapodes

For concrete tetrapods in two layers on slope 1:1.5 to 1:1.2:

$$\frac{H_S}{\Delta D_{50}} = \left(3.75\sqrt{\frac{N_{od}}{\sqrt{N}}} + 0.85\right) s_{om}^{-0.2} \tag{B.5}$$

B.2 Breakwater Stability Assessment: Veidnes Terminal

B.2.1 Meteocean parameters at Veidnes

Figure B.3 shows the preliminary meteocean parameters at Veidnes for 100 years return period. This information is part of the screening studies for the terminal site selection process for the Johan Castberg (Skrugard) field development, Courtesy of Statoil.

The significant wave height is calculated using both wind and swell wave data as follows:

$$H_s^2 = H_{s,wind}^2 + H_{s,swell}^2 \tag{B.6}$$

where $H_{s,wind} = 2.2m$ and $H_{s,swell} = 0.4m$, are values taken from the meteocean information shown in Figure B.3. The final value for the significant wave height to be used in the calculations is thus $H_s = 2.24m$, after applying (B.6).

The mean period is calculated from the peak period which is provided for the 100 years return period in Figure B.3.

$$T_z = 1.3T_p \tag{B.7}$$

where $T_p = 6.2s$, taken from the meteocean information shown in Figure B.1. The final value for the mean wave period to be used in the calculations is, thus, $T_z = 8.06s$, after applying (B.7).

B.2.2 Stability of armour layer for a rubble mound breakwater concept

For the calculation of the necessary mass of individual armour units on a straight slope, Hudson (B.1) and Van der Meer (B.2), (B.3) formulations have been used. These formulations are the most used for conceptual design. For using them, the wave direction is taken perpendicular to the longitudinal breakwater axis. A deviation of the wave direction of, $10 - 20\,^\circ$ from the normal, is considered to have a minor effect on the breakwater stability [42]. It is assumed a two layer rock armour, since single layer placement is more vulnerable to damage by removing only one stone, therefore exposing the filter layer.

1. **Hudson**

   From the Coastal Engineering Manual [49], the coefficient K_D has been taken as $K_D = 4$ (see Figure B.1), for non-breaking waves, rough angular stone shape and random placement; value corresponding to a percentage

Preliminary metocean parameters at Veidnes					**Comments**
Wind	RP100	34 m/s from W to NW			*2 / *3
	Wind speed >10 m/s	5 % of time			*2 / *3
	Wind speed > 15 m/s	1 % of time			*2
	Prevailing direction(s)	From SW – NW on a yearly basis, seasonal dependent			*2 / *3
	Fall winds	Possibly from SE – SW			*1
Wind waves	RP100	H_s	T_p	Direction from	
		2.2 m	6.2 s	105°	*1 / *4
	H_s > 0.4 m	15 % of time			*2 / *4
	H_s > 0.8 m	2 % of time			*2 / *4
	Prevailing direction(s)	From E – SE			*2 / *4
Ocean swell	RP100	H_s	T_p	Direction from	
		0.4 m	14.9 s	111°	*4
	H_s > 0.1 m	1.3 % of the time			*4 / *5
	Prevailing direction(s)	From E			*4 / *5
Current speed	RP100 (at the jetty)	0.4 m/s			*3
Temperature	Minimum monthly average	-3.9°C in February (Honningsvåg)			*2
Wind chill	Maximum monthly average	1300 Wm^2 / h in February (Slettnes fyr)			*2
Precipitation	Annual average	603 mm (Repvåg)			*2
Ice	High / Extreme icing risk	On average 1.2 events/year			*2
	Sea ice	Not likely			
Snow drift	Average annual cold precipitation	176 mm			*2
	Average wind speeds during/after snow fall > 10 m/s	5 % of precipitation time			*2
	Average wind speeds during/after snow fall > 15 m/s	0.1 % of precipitation time			*2
	Prevailing directions(s)	From SW – NW			*2 / *3
*1	based on NS-EN 1991-1-4				
*2	based on long-term time series from nearby meteorological station				
*3	based on approx. 6 months of local measurements				
*4	based on simulation of wave propagation and generation				
*5	based on hindcast data				

Figure B.3: Meteocean parameters at Veidnes. Return period 100 years. *Source: Courtesy of Statoil* damage $D = 0 - 3\%$. The rest of the values for the calculations are taken as $H = H_s = 2.24m$; $\rho_s = 2700kg/m^3$; $\rho_w = 1025kg/m^3$; slope 1:1.5.

The necessary armour stone mass by using Hudson formulation (B.1) is therefore:

$$W_{50} = 1160kg \approx W_{50} = 1.2t \tag{B.8}$$

The stone dimension D_{50} is considered equivalent to the edge of a cube with the same mass as the stone of mass W_{50}:

$$D_{50} = \left(\frac{W_{50}}{\rho_s}\right)^{1/3} \Longrightarrow D_{50} \approx 0.80m \tag{B.9}$$

2. **Van der Meer**

The following values are taken for the calculations: $T_z = 8.06s$, from (B.7); damage levels $S = 2$ and $S = 6$, which correspond to start of damage and almost failure for a slope angle of $cot\alpha = 1.5$; $N = 3000$, which corresponds to approximately 9 hours sea state duration;

The necessary armour stone mass by using Van der Meer formulation (B.2), (B.3) has been plotted in Figures B.4 and B.5 as a function of the Iribarren number.

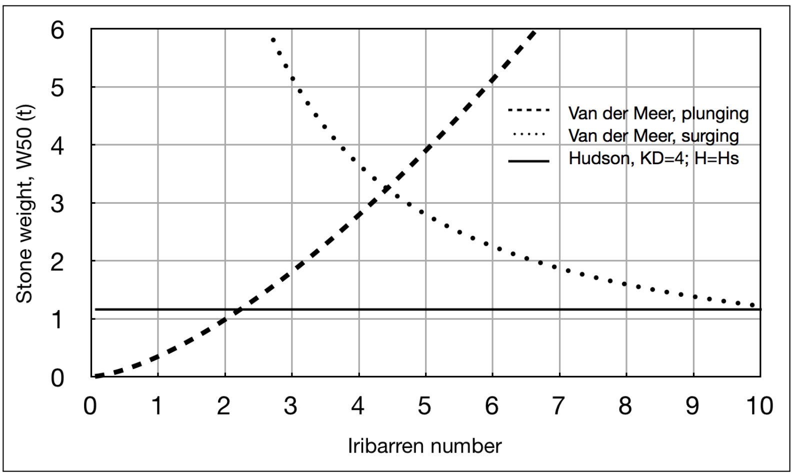

Figure B.4: Necessary armour stone mass vs Iribarren number for a damage level $S = 2$; slope 1:1.5; permeability coefficient $P = 0.4$; non-breaking waves; $H_S = 2.24m$; $N = 3000$

The Iribarren number is the only parameter in which the wave period is involved in Van der Meer formulation. Since Hudson formulation does not take into account the wave period, the formulation gives results indifferent to the wave period or Iribarren number. Figure B.4 shows the results for a damage level $S = 2$, which corresponds to start of damage. Figure B.5 has been calcultated for a damage level $S = 6$, which represents almost the failure situation for a slope $cot\alpha = 1.5$.

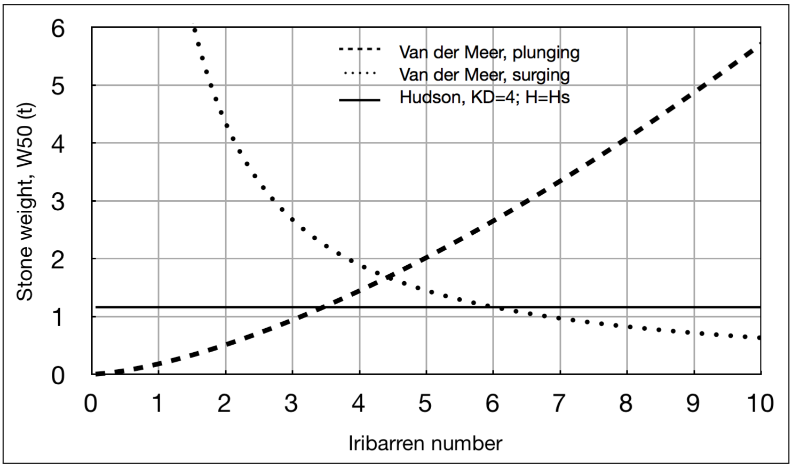

Figure B.5: Necessary armour stone mass vs Iribarren number for a damage level $S = 6$; slope 1:1.5; permeability coefficient $P = 0.4$; non-breaking waves; $H_S = 2.24m$; $N = 3000$

It can be observed that the change from plunging to surging occurs for an Iribarren number around $\xi_z = 4.4$. The mean wave period calculated, $T_z = 8.06s$, corresponds therefore to the surging condition. However, there is always some uncertainty on the determination of the mean wave period, and thus, a range for the mean wave period can be defined between $T_z = 6 - 10s$, which would lead to Iribarren numbers between $\xi_z = 3.4 - 5.56$, varying from plunging to surging.

The calculations have been carried out only for rocks, since the results show a relatively small stone size, which presumably would be easy to find in the site. Thus, concrete armour units not being required.

B.2.3 Stability of armour layer for a berm breakwater concept

A berm breakwater concept as an alternative to the uniform slope has been also calculated. The stability number and the period stability number have been used for calculating the necessary armour stone mass.

1. **Stability Number**

   The use of the stability number (H_0) as mobility criteria, involves taking only the effect of the wave height into account. The expression of the armour stone mass as a function of the significant wave height was derived in Appendix A. The calculations for the main armour stone mass have been carried out for the Icelandic type breakwater or non-reshaping ($H_0 = 2$), and the reshaping static stable type ($H_0 = 2.7$)[1].

$$W_{50} = \rho_s \left(\frac{H_S}{\Delta H_0} \right)^3 \tag{B.10}$$

   Table B.1 shows the results for the required maximum stone mass, by using the stability number as mobility criteria.

Table B.1: Required maximum stone size for a berm breakwater concept at Veidnes using stability number as mobility criteria; $H_S = 2.24m$.

Category	H_0	W_{50} (kg)
Non-reshaping	2	870
Reshaping, static stable	2.7	350

2. **Period Stability Number**

   The use of the period stability number (H_0T_0) as mobility criteria, includes the effect of the wave period in addition to the wave height. The expression of the armour stone mass as a function of the significant wave height and period was derived in Appendix A. The calculations for the main armour stone mass have been carried out for the Icelandic type breakwater or non-reshaping and reshaping static stable types. The results obtained by using the period stability number threshold criteria recommended by PIANC, show large disagreement with the results obtained using the stability number. Thus, the calculations have also been carried out following professor's A. Tørum recommendation for threshold criteria in non-reshaping berm breakwaters [42].

$$W_{50} = \left(\frac{H_S T_z}{\Delta H_0 T_0} \right)^2 g \rho_s \tag{B.11}$$

   Table B.2 shows the results for the required maximum stone mass, by using the stability number as mobility criteria.

[1] Threshold criteria defined by PIANC and shown in Table 11.1

Table B.2: Required maximum stone size for a berm breakwater concept at Veidnes using period stability number as mobility criteria; $H_S = 2.24m$, $T_z = 8.06s$.

Category	H_0T_0	W_{50} (kg)
Non-reshaping (PIANC guidelines)	40	2021
Non-reshaping (Prof. Tørum recommendation)	55	1069
Reshaping, static stable	70	660

Finally, comparing tables B.1 and B.2, the upper limits are selected as final requirement for the maximum stone size in a berm breakwater concept for Veidnes. However, for the non-reshaping case, the result obtained by using professor A. Tørum threshold has been selected, since it provides a result closer to the one obtained by using the stability number. This means that the threshold by PIANC probably overpredicts the stone size. The results are shown in Table B.3.

Table B.3: Final requirement for maximum stone size for a berm breakwater concept at Veidnes; $H_S = 2.24m$, $T_z = 8.06s$.

Category	W_{50} (tons)	D_{50} (m)
Non-reshaping	≈ 1.1	0.75
Reshaping, static stable	≈ 0.70	0.65

B.3 Breakwater Stability Assessment: Melkøya Terminal

B.3.1 Meteocean parameters at Melkøya

The wave data[2] for the 100 years return period at the Melkøya location correponds with a significant wave height $H_S = 7.5m$ and a peak period $T_p = 15.6s$. Applying equation (B.6) to calculate the mean wave period, the value obtained is $T_z = 20.3s$.

B.3.2 Stability of armour layer for a rubble mound breakwater concept

For the necessary mass of individual armour units on a straight slope, Hudson (B.1) and Van der Meer (B.2), (B.3) formulations have been used for the required rock armour. In addition, the required concrete armour units have been calculated for cubes and tetrapods assuming a two layer armour, and applying Van der Meer formulas.

[2] Wave data retrieved from S. Sigurdarson et al., 2005 [61]

1. **Hudson**

   From the Coastal Engineering Manual [49], the coefficient K_D has been taken as $K_D = 4$ (see Figure B.1), for non-breaking waves, rough angular stone shape and random placement; value corresponding to a percentage damage $D = 0 - 3\%$. The rest of the values for the calculations are taken as $H = H_s = 7.5m$; $\rho_s = 2700kg/m^3$; $\rho_w = 1025kg/m^3$; slope 1:1.5.

   The necessary armour stone mass by using Hudson formulation (B.1) is therefore:

$$W_{50} \approx W_{50} = 44t \tag{B.12}$$

   The stone dimension D_{50} is considered equivalent to the edge of a cube with the same mass as the stone of mass W_{50}:

$$D_{50} = \left(\frac{W_{50}}{\rho_s}\right)^{1/3} \Longrightarrow D_{50} \approx 2.5m \tag{B.13}$$

2. **Van der Meer, rock armour**

   The following values are taken for the calculations: $T_z = 20.3s$, from (B.7) and a peak period $T_p = 15.6s$; damage levels $S = 2$ and $S = 6$, which correspond to start of damage and almost failure for a slope angle of $cot\alpha = 1.5$; $N = 3000$, which corresponds to approximately 9 hours sea state duration;

   The necessary armour stone mass by using Van der Meer formulation (B.2), (B.3) has been plotted in Figures B.6 and B.7 as a function of the Iribarren number.

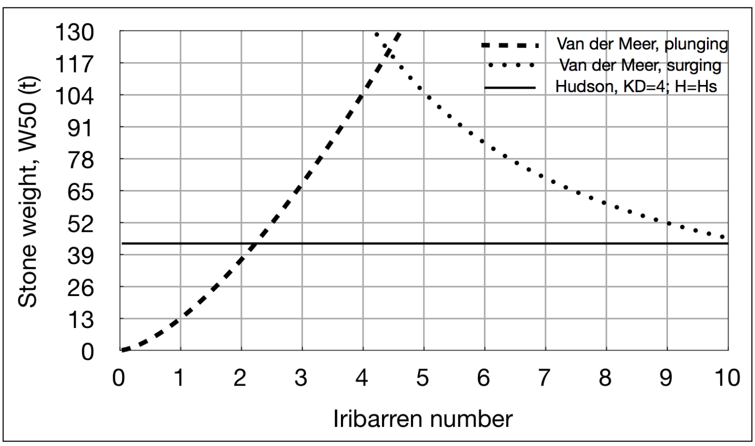

Figure B.6: Necessary armour stone mass vs Iribarren number for a damage level $S = 2$; slope 1:1.5; permeability coefficient $P = 0.4$; non-breaking waves; $H_S = 7.5m$; $N = 3000$

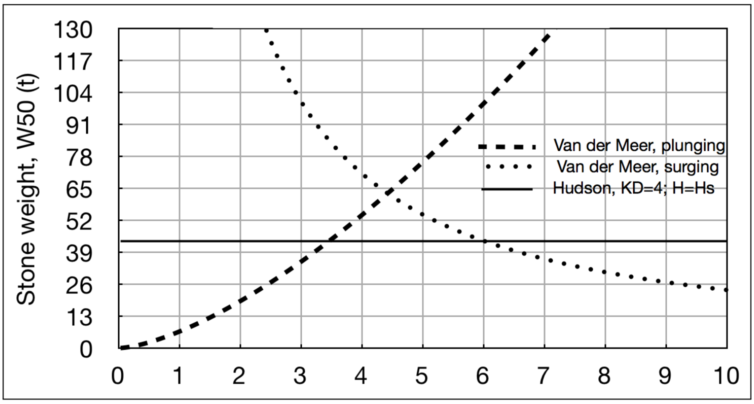

Figure B.7: Necessary armour stone mass vs Iribarren number for a damage level $S = 6$; slope 1:1.5; permeability coefficient $P = 0.4$; non-breaking waves; $H_S = 7.5m$; $N = 3000$

For a mean wave period of $T_z = 20.3s$, the Iribarren number is $\xi_z = 6.1$. For this Iribarren number the Van der Meer formula gives a required armour stone mass $W_{50} \approx 83t$, while the Hudson formula gives a required stone mass $W_{50} \approx 44t$.

3. **Van der Meer, concrete cubes**

After applying equation (B.4) for $H_S = 7.5$; $\rho_s = 2700kg/m^3$; $N = 3000$; $N_{od} = 0.5N = 0.2$; wave steepness $s_{om} = 0.012$ for a mean wave period $T_z = 20.3s$, the required mass of the armour unit using concrete cubes is:

$$W_{50} = \rho_s \left(\frac{H_S}{\Delta \left(6.7 \frac{N_{od}^{0.4}}{N^{0.3}} + 1 \right) s_{om}^{-0.1}} \right)^3 \Longrightarrow W_{50} \approx 30t \qquad \text{(B.14)}$$

4. **Van der Meer, concrete tetrapodes**

After applying equation (B.5) for $H_S = 7.5$; $\rho_s = 2700kg/m^3$; $N = 3000$; $N_{od} = 0.5N = 0.2$; wave steepness $s_{om} = 0.012$ for a mean wave period $T_z = 20.3s$, the required mass of the armour unit using concrete cubes is:

$$W_{50} = \rho_s \left(\frac{H_S}{\Delta \left(3.75 \sqrt{\frac{N_{od}}{\sqrt{N}}} + 0.85 \right) s_{om}^{-0.2}} \right)^3 \Longrightarrow W_{50} \approx 15t \qquad \text{(B.15)}$$