Floating Liquefied Gas Terminals

Offshore Technical Guidance OTG-02

March 2011

MANAGING RISK

DNV

Background

DNV has been involved in several studies for floating liquefied gas concepts in order to guide the industry in the detailed phase of designing and building such installations, DNV is issuing this guidance as a means of spreading lessons learned to the industry.

This guideline also describes the various DNV services which can be offered to assist the industry in developing and constructing floating liquefied gas installations in a safe, compliant, and economic way.

This guideline may be used in conjunction with DNV rules, standards and other publications addressing LNG installations.

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1 INTRODUCTION

1.1 Scope

This publication presents a guideline for the design and classification of Floating Installations for handling Liquefied Natural Gas.

The guideline describes principles, procedures and guidance to requirements for classification. It further addresses a number of technical issues considered to be especially relevant for floating LNG installations. This document is intended for guidance only and should be used together with the relevant DNV Rules, DNV OSS 103 *Rules for Classification of Floating LNG/LPG Production, Storage and Loading Units* and the associated DNV Offshore Standards which address specifically the relevant engineering disciplines.. For classification purposes the requirements given in the DNV Rules are to be used.

A prime objective is to address the risks specific to floating liquefied gas concepts and how they can be managed by applying offshore classification systematics.

Much of this document will refer to LNG FPSOs and LNG FSRUs, however many of the principles described and discussed will also be applicable to other offshore gas applications on floating installations. Some of these other applications are described in this document.

1.2 Background

Demand for natural gas continues to increase and it is fast becoming the preferred fossil fuel for a number of applications. A large proportion of the global natural gas reserves are located remote from markets and also in areas where pipeline transport of the gas is impracticable or uneconomic. In other cases natural gas associated with oil production represents a disposal problem when flaring, re-injection, or use for power generation or pipeline to market are not available options. At the same time this associated gas also represents an economic value.

A number of solutions have been proposed to address these issues. These solutions focus on economic processing, storage and transportation of gas, either as a liquid (e.g. LNG, LPG or GTL), as a compressed gas (CNG), or as a product using both compression and liquefaction, and in the case of hydrates, as a solid.

Common to these concepts is that they represent solutions that have not yet been extensively proven in practice. The following issues represent particular challenges:

- a highly complex and compact process plant installed in a limited area
- close proximity of gas processing, LNG and LPG storage, and Living Quarters
- marinising and modularising of land-based technology
- safe handling and storage of hydrocarbons and reactive materials
- cryogenic and/or high pressure gas processes
- cargo transfer in open seas
- simultaneous hazardous operations

DNV has assessed a large number of offshore gas projects and this guidance is intended to provide the industry with some of the generic lessons from such studies and from our own research.

1.3 Organisation of this Guidance

This document is divided into seven main sections:

- Section 1 provides a general introduction and the context of this document
- Section 2 provides presentation of various generic concepts
- Section 3 provides general guidance on structural design
- Section 4 discusses some key technical design issues
- Section 5 discusses conversion of gas carriers to floating LNG applications
- Section 6 discusses maintenance philosophies and inspection in the In-service phase
- Section 7 provides an introduction to class and statutory services

Appendices are provided to describe various useful methodologies and their application and describe some additional consultancy services.

1.4 Objects covered

A floating offshore installation which processes hydrocarbons and refrigerates gas to produce LNG will be termed here an LNG FPSO (LNG floating production, storage and offloading unit) The installation may be fed gas directly from a gas well or a gas network or may process associated gas in conjunction with oil production.

An offshore installation which receives and regasifies LNG to provide gas to an onshore consumer or the market gas grid will be termed here an FSRU (Floating Storage and Regasification Unit). Regasification units may also be located quayside or at a sheltered jetty. Many of the considerations discussed in this guidance will be applicable also to such installations. Reference is also made to DNV Classification Note 61.3 *Regasification Vessels*.

Note that this Guidance addresses floating steel structures. Concrete structures, both floating and bottom fixed have also been proposed for offshore gas applications. For such designs reference is made to DNV Offshore Standard DNV-OS-C503 *Concrete LNG Terminal Structures and Containment Systems.* Relevant parts of this document may also be used as guidance.

Note also that this Guidance addresses offshore terminals, for onshore terminals reference is made to DNV Service Specification DNV-DSS-315 *Verification of Onshore LNG and Gas Facilities.*

1.5 Definitions and Abbreviations

1.5.1 Definitions

Classification: Classification is defined as verification according to DNV rules, where on completion, a DNV Classification Certificate is issued. Classification is always a 3rd party activity. Classification usually implies involvement in all project phases, from design to the operations phase, however this may be specially agreed for an individual contract. The basis of the verification will be DNV Offshore Standards referred to in the DNV Rules for Classification. It should be noted that international codes and standards will normally be used as a supplement to the Offshore Standards and where found equivalent may be permitted to replace them. Classification has been traditionally a prescriptive approach, however for novel technology; existing experience is supplemented with risk assessment.

If desired the Classification approach may adopt a purely risk-based method to define the Classification requirements rather than using the existing prescriptive requirements. This approach is described in DNV-OSS-121 *Classification Based on Performance Criteria Determined from Risk Assessment Methodology*. See also Appendix A of this Guidance which describes the general Risk Assessment methodology.

Risk-Based Verification: Instead of using a Classification approach, project verification requirements may be derived from use of risk assessment technology. Risk Based Verification is a structured, systematic process of using risk analysis and cost-benefit analysis to strike a balance between technical and operational issues and between safety and cost.

The Risk Based Verification methodology involves the following steps:

- Hazard identification
- Risk assessment

- Evaluation of risk-control options
- Recommendations for decision-making
- Development of verification plan
- Performance of verification

This approach is described in DNV-OSS-300 *Risk Based Verification*.

Safety Case Verification: A Safety Case is a structured approach to ensure that there is a documented body of evidence that provides a convincing and valid argument that a system is adequately safe for a given application in a given environment. The term Safety Case is specifically defined in the Shelf State regulations of the UK and of Australia.

Verification within a project involving floating installations may use a combination of Risk-Based Verification and Classification. Most Safety Cases of floating installations essentially use this approach.

Statutory Certification: This is defined as a compliance check against the technical requirements of a third party regulatory body. This will typically be the requirements of the Shelf State where the offshore terminal is located. It may also include requirements of maritime administrations (e.g. Flag State) where floating installations are involved, either during transit or as a supplement to the shelf state when the unit is installed. Statutory Certification will require to be maintained during the life of the installation.

Requirements from authorities may be either mainly prescriptive (e.g. U.S., Canada) or mainly functional and risk based (e.g. U.K., Norway, Australia). In either case the verification approach can be adapted to accommodate the regulatory philosophy.

1.5.2 Abbreviations

CNG – Compressed Natural Gas

DNV - Det Norske Veritas

FLNG – Floating LNG unit both FPSO and FSRU, (though also used solely for LNG FPSO)

FSRU – Floating Storage and Regasification Unit

FPSO – Floating Production Storage and Offloading Unit

GTL – Gas to Liquid

LNG – Liquefied Natural Gas

NGL – Natural Gas Liquids

OCIMF – Oil Companies International Marine Forum

SIGTTO – Society of Gas Tanker and Terminal Operators

SRV – Shuttle Regasification Vessel

OS – DNV Offshore Standard

OSS – DNV Offshore Service Specification

2 FLOATING GAS CONCEPTS

2.1 LNG Regasification Terminals

2.1.1 General

Floating regasification terminals (FSRUs) can provide a flexible and economic alternative to building land-based LNG receiving terminals. The floating installations may either be located near-shore (e.g. alongside a pier, or a jetty) or offshore (permanently moored to the seafloor). Such terminals are supplied with LNG from visiting gas carriers. Depending on their mode of operation (e.g. dry-docking vs. no dry-docking) and local regulation these FSRUs can be considered either as ships or as offshore installations.

Vessels which transport LNG, connect to an offloading buoy, regasify and discharge their cargo, then disconnect and leave to collect a new cargo are termed Shuttle Regasification Vessels (SRV). These are not normally considered as FSRUs and are readily addressed within Maritime Classification (ref DNV Rules for Ships Pt 5 Ch 5 Carriers for Liquefied Gas. Additional requirements for the regasification plant and the additional hazards introduced are given in DNV Classification Note 61.3 Regasification Vessels). SRVs will therefore not normally be engaged in continuous regasification operations and typically will not receive and regasify LNG simultaneously.

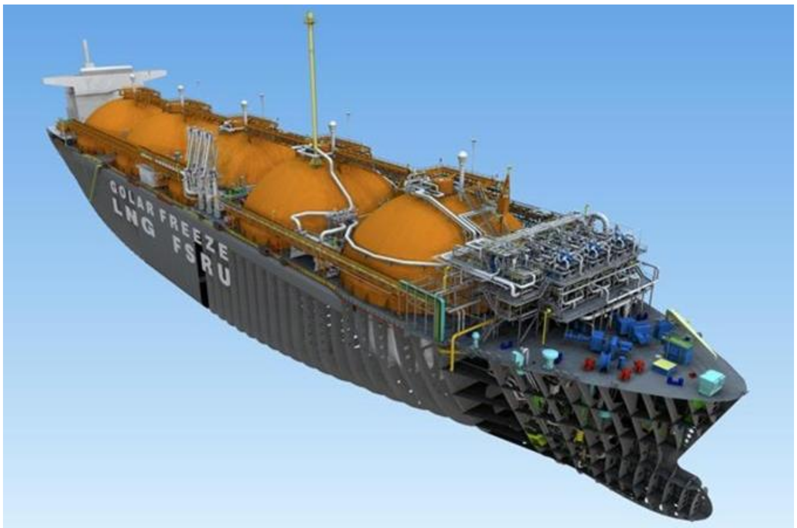


Figure 2-1: Golar Freeze FSRU – Courtesy of Golar LNG

FSRUs may either be purpose built or be converted from existing vessels, typically LNG carriers. Depending on the application the extent of modification to an existing unit will vary, e.g. installation of a turret (internal or external) on an offshore moored FSRUs or location of loading arms on the FSRU or on a jetty for a near-shore FSRU.

2.1.2 Some special considerations for Floating Regasification Terminals

Special issues which will need to be considered for LNG regasification applications will include:

- High pressure gas export systems
- Venting arrangement
- Active and passive fire protection
- Partial filling of LNG containment tanks
- Complex integrated control system
- Ability to inspect, maintain and repair in-situ
- Side by side mooring and LNG transfer

FSRUs have also been proposed for use as floating power stations, where the stored LNG is vaporized and used as fuel for power generation on board the vessel and where this power is then exported by high voltage cable to consumers ashore. This variant can also be accommodated within the Classification system for FSRUs, obviously any hazards associated with the power production and power transmission will also need to be accounted for. Technology which is specially developed for offshore production and transmission may also need to undergo some form of qualification where such is not adequately addressed in existing standards.

Many of the issues discussed in regard to LNG FPSOs will also be relevant for a permanently moored FSRU.

2.2 LNG Liquefaction terminals

2.2.1 General

A typical LNG FPSO design is to base the installation on an LNG carrier hull. The various parts of the process are then located topside and distributed as modules that are installed on the deck. Depending on the intended capacity of the LNG FPSO and the need for treatment of the feed gas composition the topsides may weigh typically from 20 000 tonnes to 50 000 tonnes for medium size units producing 1.5 to 3 MTPA. For very large scale production units (3-5MTPA) this topsides weight may reach 70 000 tonnes or more.

The storage capacity of the FPSO will be related to the processing capacity, the intended offload schedule and the need to store condensate and LPG, which is dependent on the feed gas composition. Current designs for medium size units are being proposed with LNG storage capacity of 180 000 to 190 000 m^3 and LPG and LPG storage capacities of approximately 25 000 m^3 each. For the very large scale units LNG storage capacity of 220 000 m^3 has been proposed together with LPG and Condensate storage in the range of 100 000 m^3 each

Reference is given to the below figure in order to illustrate a typical layout of an LNG FPSO.

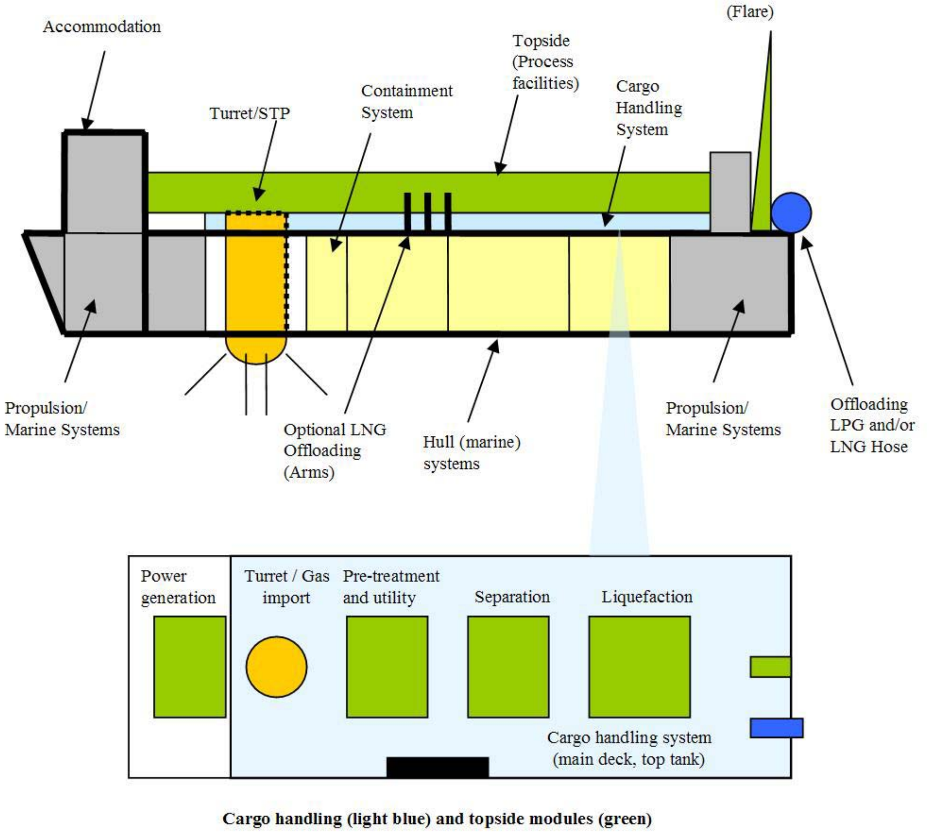


Figure 2-2: Typical system boundaries for LNG FPSO

2.2.2 Some special considerations for Floating Liquefaction Terminals

Special issues which will need to be considered for LNG liquefaction applications will need to include:

- Marinisation of land-based liquefaction technology
- High equipment count and congestion
- Separation of areas of high hazard
- Storage and handling of hydrocarbon fluids used in liquefaction
- Venting arrangement
- Active and passive fire protection
- Partial filling of LNG containment tanks
- Complex integrated control system
- Ability to inspect, maintain and repair in-situ
- Side by side mooring and LNG transfer
- Tandem transfer of LNG
- Cargo management and shuttling of different cargo types

2.3 Other Gas Concepts

2.3.1 LPG Concepts

There are already several LPG FPSOs in operation. With regard to Classification, offshore LPG installations should generally adopt an approach similar to LNG installations, i.e. consider relevant requirements applicable for FPSOs and LPG carriers, and address additional hazards by use of risk assessment.

Reference is therefore made to DNV-OSS-103 *Rules for Classification of Floating LNG/LPG Production, Storage and Loading Units*. These requirements include the carrying out of a HAZID and risk analysis to identify and address issues not covered within standard FPSO design. For assessment of the LPG containment and handling system, the principles used in DNV Rules for Classification of Ships, Part 5 Chapter 5, *Liquefied Gas Carriers,* may be used.

In terms of storage and transfer, LPG units will present fewer problems than equivalent LNG installations. However process plant for LPG production, typically involving high towers (for de-ethanising, de-butanising, and de-propanising), will present some issues with regard to accommodating them structurally and to their sensitivity to motion. A typical solution has been to locate such structures in areas where vessel motion is minimised, e.g. close to a ship centreline.

LPG will also have increased reactivity compared to LNG, with potentially more severe fire and explosion loadings arising after an accidental event. These will need to be quantified in any safety study. In addition dispersion and detection of any leakages will need to consider the actual properties of the LPG, e.g. higher specific gravity compared to methane.

Some special considerations for offshore LPG applications will need to include:

- Support of large process columns
- Stability of the FPSO
- Blowdown and pressure relief of LPG systems
- Fire and explosion hazards associated with LPG

LNG installations may of course also have plant for removal of LPG in their feed gas, and will therefore need to also consider these issues.

2.3.2 CNG Concepts

A number of concepts have been developed for production and storage of compressed natural gas. To date the focus has been primarily on the transportation of the gas, however in theory such concepts might also be used as gas FPSOs.

Concepts currently developed involve storage of compressed gas in horizontal large diameter pipes, in vertical large diameter pipes, in coiled small diameter pipes, in composite pressure vessels and in composite-reinforced steel pressure vessels. Variations include storage at high pressure (over 250 bar) at atmospheric temperature and storage at moderate pressure at reduced temperature (approx -30 degr C).

Sea NG proposes the use of coils made from seamless steel line pipe of 6 inches or more in diameter, called *Coselle (*Figure 2-3*)*. The gas is pressurised to approximately 220 bar. The coils are positioned horizontally within the cargo hold.

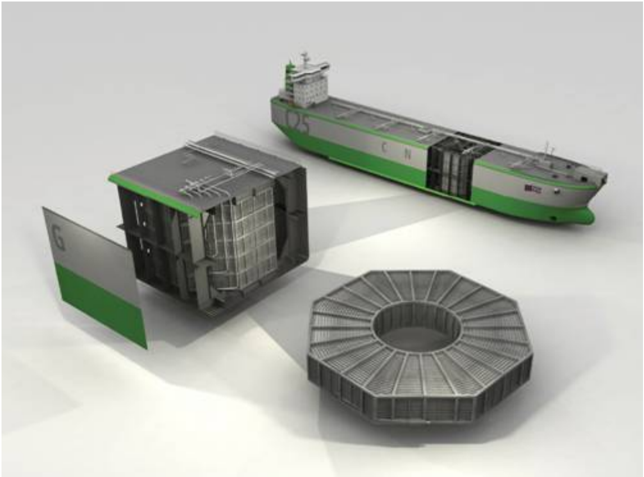


Figure 2-3: Coselle design - Courtesy Sea NG

Knutsen OAS Shipping and **EnerSea Transport LLC** (VOTRANS™) propose the use of large diameter parallel steel pipes with end caps. A solution with vertically oriented pipes is the preferred option, but a horizontally oriented configuration is also possible. This concept uses standard pipes with a diameter of one meter or more, which are fabricated using automatic welding of the longitudinal seam and the seams connecting the end caps. The number of cargo cylinders required is directly proportional to the required cargo capacity ranging from 100 (2 Mscm) to 2,400 (28Mscm) (based on the VOTRANS system).

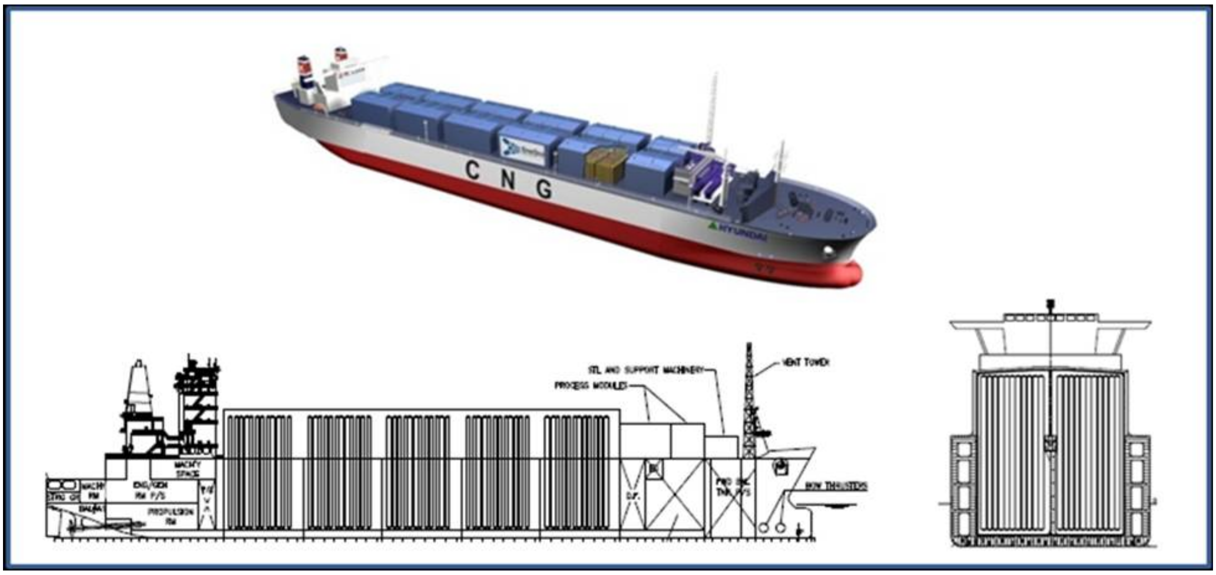


Figure 2-4: EnerSea Transport LLC's design – Courtesy EnerSea

TransCNG proposes using straight pipes (typically 24" to 60" diameter up to 25 m. long) wrapped in a high performance composite material, termed a Gas Transport Module (GTM). They are based upon the Composite Reinforced Line Pipe (CRLP) concept.

CETech (CETech is a fully owned Höegh LNG company) propose use of composite tanks, up to 3 m in diameter and up to 30m length for storage and transport of CNG at 150bar operational pressure.

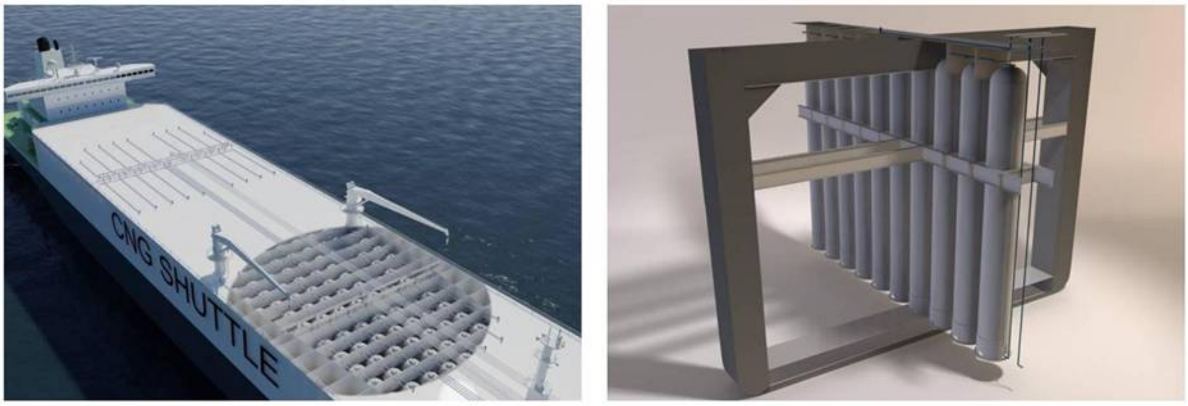


Figure 2-5: CNG Shuttle with vertical composite tanks – Courtesy of CETech

CETech have already developed an FPSO version of their technology.

With regard to Classification, such designs based on CNG, used as FPSOs, may use the general principles applicable for gas FPSOs (i.e. using DNV-OSS-103 *Rules for Classification of Floating LNG/LPG Production, Storage and Loading Units*). These requirements include the carrying out of a HAZID and risk analysis to identify and address issues not covered within standard FPSO design. For assessment of the CNG containment and handling system, the principles used in DNV Rules for Classification of Ships, Part 5 Chapter 15, *Compressed Natural Gas Carriers,* may be used.

Where such concepts involve both production of CNG and its subsequent transportation to shore for offloading then such units would be considered as both FPSOs and trading carriers and would need to be designed and operated to meet both sets of requirements for these operational modes.

Special issues which will need to be considered for offshore CNG applications will need to include:

- Fatigue of containment systems
- Blowdown and pressure relief
- Escalation of a containment system leak
- Fire and explosion hazards

A full listing of special hazards associated with CNG will need to be produced through a HAZID and then will need to be addressed in the design.

2.3.3 Heavy Liquefied Gas (HLG)

Studies have been carried out to assess the feasibility of Heavy Liquefied Gas production and transportation. The technology combines LNG technology and CNG technology and involves condensing pressurized gas at a temperature significantly above the LNG liquefaction temperature. This lessens the cost of liquefaction, and reduces the need to remove feed gas components such as CO_2 and LPGs.

Some key features of HLG technology are as follows:

- Heavy Liquefied Gas (HLG) is natural gas that is condensed at a pressure of 10-20 Bar, corresponding to a temperature of ÷100 to ÷120 °C.
- Heavy hydrocarbons and CO2 that will freeze out in a conventional LNG process will stay in solution because of the higher transport temperature.
- Therefore a minimum of pre-processing is required for HLG compared to LNG.
- The power consumption and topside footprint for production of HLG is significantly less than the equivalent of LNG

Results from technical analyses/simulations indicate that HLG production is technically feasible.

2.3.4 Gas To Liquids (GTL) Concepts

Gas to Liquids technology involves the chemical conversion of natural gas to higher value liquids such as diesel oil and methanol. These liquids can then be more easily stored and transported and marketed as a finished product. While these liquid products are more valuable than LNG, they however require use of more expensive and complex processes to produce them compared to LNG production. There is limited experience with land-based GTL production and marinising this technology especially on an economic scale represents a significant challenge for an offshore GTL installation.

A generic GTL process is illustrated below in Figure 2-.

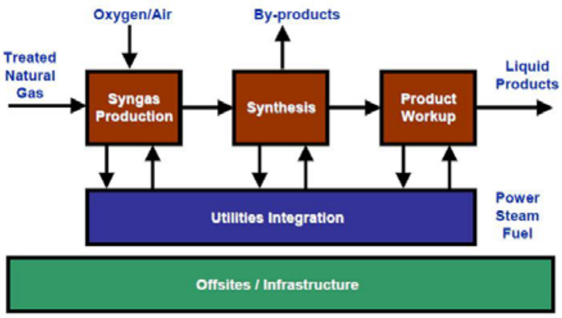


Figure 2-6: Illustration of Gas to Liquids concept

Product workup may typically involve use of the Fischer-Tropsch (F-T) technique to produce diesel or syncrude, or distillation to produce methanol or methanol derivatives. The Fischer-Tropsch (F-T) technique is illustrated in Figure 2-37:

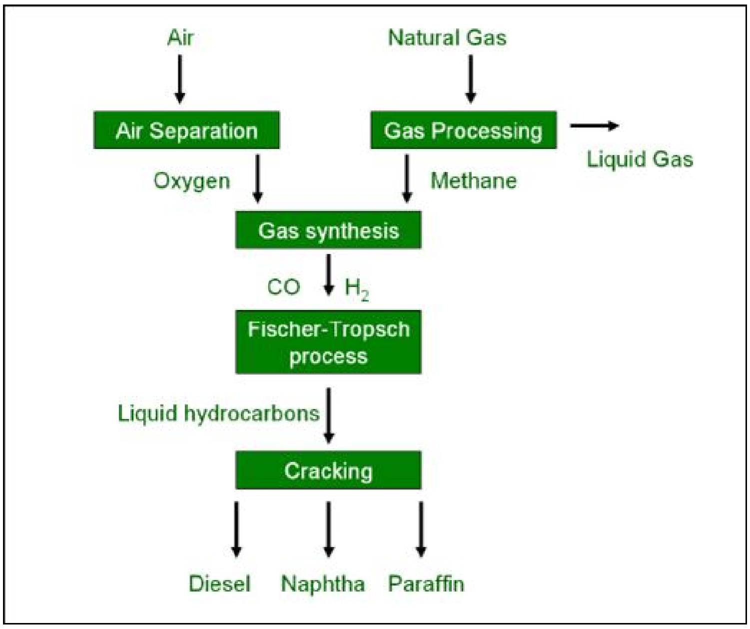


Figure 2-3: The Fischer Tropsch (F-T) technique

With regard to Classification, offshore GTL installations should generally adopt an approach similar to offshore LNG installations, i.e. consider relevant requirements applicable for FPSOs and address additional hazards by use of risk assessment. It will also be useful to consider experience gained in land-based GTL facilities. From a Classification point of view the principles in DNV-OSS-103 may be applied also for GTL FPSOs.

Special issues which will need to be considered for offshore GTL applications will need to include:

- Large process units and columns to be supported
- Presence of Air Separation Units and potential for oxygen leaks

- Storage and potential leakage of liquid oxygen
- Reactive and high temperature processes (syngas and syncrude/methanol production)
- Syngas leakage
- Release of hydrogen
- Auto ignition of hydrogen
- Toxicity of CO
- Additional corrosion issues (from syngas)
- Toxicity of products such as methanol
- Maintenance, inspection and replacement of equipment offshore

A full listing of special hazards associated with GTL will need to be produced through a HAZID and then will need to be addressed in the design.

2.3.5 Natural Gas Hydrates (NGH)

Natural Gas Hydrate is a solid ice-like material which forms naturally in hydrocarbon transport systems at high pressure and low temperature, usually causing operational problems.

However it has been considered to exploit the gas transport potential of hydrates through the development of processes which aim to ship bulk volumes of hydrates from smaller or more remote fields.

Gas hydrates constitute a solid comprised of natural gas and water. Each cubic meter of hydrate contains 160-180 cubic meters of gas. Several alternative methods for storing and transporting hydrates have been proposed, for example, as a solid (crystals) or as a mixture of solid hydrates and oil (slurry).

Gas may be mixed with water at a pressure of 80-100 bar at normal temperatures in order for the gas hydrates to appear.

An oil/hydrate slurry can be produced by mixing the hydrates with oil, and then cooling the mixture to a temperature somewhat below the freezing point of water. The oil/hydrate mixture may consist of up to fifty per cent gas hydrate, the rest being crude oil. The mixture (slurry) is pumped into the storage tanks onboard a floating production unit for subsequent transportation by tanker. The tanker will transport the oil/hydrate mixture to a receiving terminal. At the terminal the mixture will be heated in order to melt the hydrates.

As with any novel concept the particular risks and technical challenges need to be initially identified and then addressed to determine how feasible such an approach is (in addition to considering commercial viability). A recommended approach is therefore:

- Conduct an Approval in Principle (which includes HAZID and Technology Assessment)
- Qualify any new technology (including novel use of existing technology) using the structured approach described in DNV-RP-A203 *Qualification Procedures for New Technology*

An FPSO using this technology may then be classed according to the principles in DNV-OSS-103 *Rules for Classification of Floating LNG/LPG Production, Storage and Loading Units*

3 STRUCTURAL DESIGN OF FLOATING LNG CONCEPTS

3.1 General

Design of ship-shaped floating steel terminals may generally follow the principles of design of steel ships. However as with experience from oil FPSOs and oil tankers which have an apparent initial similarity, the design will have to account for differences in operation and loading between floating offshore gas installations and gas carrying ships. This section will describe additional considerations to be accounted for in offshore ship-shape structure design compared to trading ship design.

Design of containment systems is specifically addressed in Section D.

Some of the critical differences in structural design between standard ship design and offshore installation design will include:

- Environmental loading regime for a fixed location
- Inability to avoid severe weather
- Fatigue design and details for service life
- Partial filling / sloshing loads
- Continuous operation and limited availability and access for inspection and repair
- Increased potential for cryogenic leakage
- Loading in exposed locations
- Scaling up of existing designs
- Increased corrosion considerations
- Increased hazard due to location of gas handling, liquefaction or regasification plant
- Provision of a position mooring system
- Project-specific Design Accidental Loads
- Different regulatory requirements

Requirements for classification of floating gas terminals are given in DNV-OSS-103 *Rules for Classification of Floating LNG/LPG Production, Storage and Loading Units. As per these Rules,* structural design of floating terminals should be in accordance with the principles in this Guidance, DNV-OS-C102 *Structural Design of Offshore Ships*, DNV-OS-C101 *Design Of Offshore Steel Structures* and *DNV Rules for Classification of Ships Pt 5 Ch 5 Liquefied Gas Carriers*, using risk assessment as a means of identifying any gaps and taking account of the topics listed above.

Floating offshore terminals of barge type may be generally designed in accordance with *DNV Rules for Classification of Ships Pt 5 Ch 7 Section 14 Barge*, together with DNV-OS-C102 *Structural Design of Offshore Ships*, DNV-OS-C101 *Design Of Offshore Steel Structures*. Again risk assessment will be used to determine specific hazards and associated design issues related to the particular application as an LNG terminal.

Note that either the Load and Resistance Factor Design methodology (LRFD) or the Working Stress Design methodology (WSD) may be used.

3.2 Design Basis

Offshore operation will typically impose different requirements than those applicable for traditional LNG carrier designs. Some of the requirements will be related to safety while others will arise for reasons of operational optimisation.

Ship design is normally based on worldwide trading operation and regular drydocking and is based on internationally agreed marine safety standards. Offshore design, on the other hand, is based on field-specific operation, usually involving permanently stationed installations and is governed by national regulation and site specific criteria..

Offshore operation will normally imply that the LNG FPSO or FSRU is permanently position-moored. A turret mooring arrangement or a spread mooring arrangement may be used. Being moored to the seabed will mean that wave directions will have dominant headings that will give different motion characteristics to the vessel compared to a trading ship. If the vessel is designed to weathervane, favourable rolling motions may be obtained.

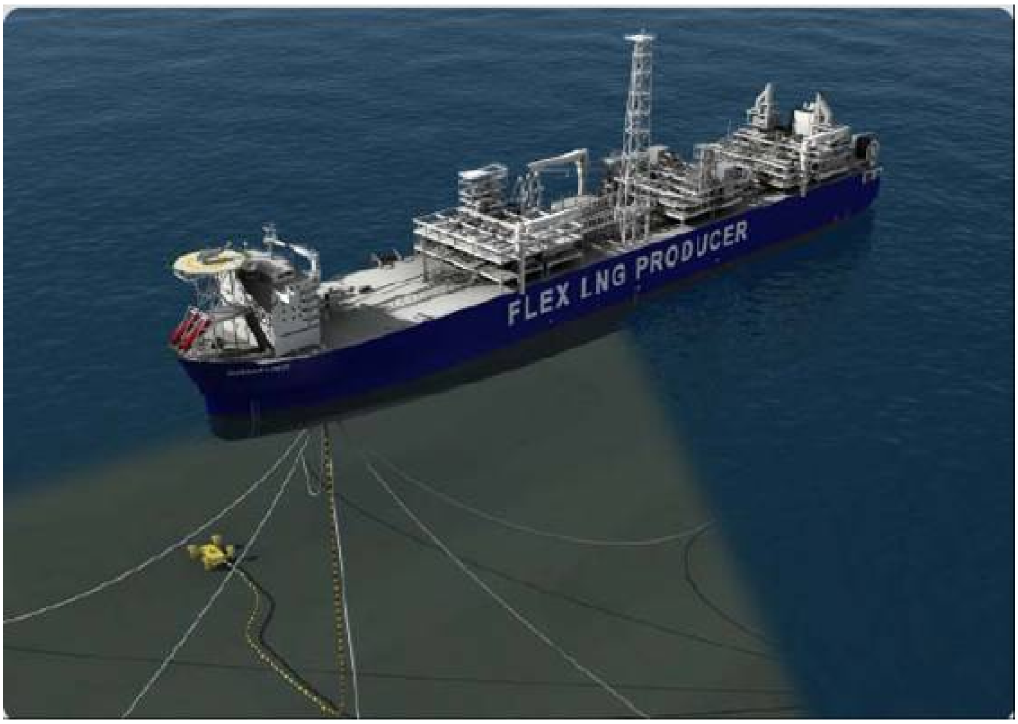


Figure 3-1: Turret-moored LNG FPSO – Courtesy FLEX LNG & Samsung

The wave environment at an offshore location may therefore be considerably different from the design assumptions made for trading carriers. Many of the proposed floating LNG unit designs have to a large degree been planned for areas with a benign wave environment with typical significant wave heights less than 8-9 meters. This is less than the assumptions in the expected wave environment for trading LNG carriers so that the design as a carrier, with respect to global strength, would be conservative. Some designs planned for offshore LNG FPSO or FSRU operation are however intended for harsher environment service, where a standard ship solution may not be satisfactory, at least without further assessment.

LNG operations offshore will impose additional structural loads, for example, arising from topsides loads, sloshing in storage tanks, loads from ship to ship mooring during LNG transfer, and additional design accidental loads arising from activities on board.

Continuous operation offshore, typically without dry-docking, for the life of the gas field will impose the need for increased initial quality in order to avoid the need for in-service repair or replacement. This is particularly relevant for fatigue and corrosion considerations.

To minimize fatigue damage occurring during service, the design fatigue factors for an offshore vessel not intending to dry-dock, will be stricter than for a trading carrier. For oil FPSOs this is addressed with increased safety on submerged and non-inspectable parts as well as increasing the design fatigue factor in general. Such criteria will necessarily need to be applied also to an LNG FPSO or FSRU hull. DNV have developed Class Notations which increase the focus on fatigue cracking during the field life. Reference is made to DNV-RP-C206 *Fatigue Methodology of Offshore Ships.*

Experience from oil FPSOs and offshore vessels in benign areas with high ambient temperature has also shown that there may be a high corrosion rate compared to oil carriers. Oil cargoes are obviously different to gas cargoes; however corrosion may increase in ballast tanks due to more frequent change out of ballast water, where such is necessary during production and offloading of LNG. The corrosion protection system may therefore need to meet a higher standard as there is little possibility to replace any steel due to wastage during service. Possible steel replacements offshore also represent a high cost due to potential downtime if hot work is to be performed. This will normally require a shut down and gas freeing of the exposed areas. Even though novel repair methods exist, such as steel/sandwich composite solutions, repair offshore is not a desirable solution.

Regulatory requirements applicable to offshore installations may also impose some additional structural considerations. For example FPSOs operating in Brazil are normally subjected to IMO MODU Code requirements with respect to stability rather than SOLAS requirements. The load considerations for the MODU Code are more strict than SOLAS.

To summarize, there are a number of important key factors that differentiate a trading ship design from a design suitable for an offshore application.

Ship design

- Design life 20 years with North Atlantic as design criterion
- Fatigue design considering trading service for 20-40 years normally assuming worldwide trade
- Repairs possible during drydocking
- No topsides loads
- No or very limited partial filling operation of the cargo tanks
- All wave directions taken into account
- Prescriptive class rules used for hull structure design
- Accidental loads incorporated into prescriptive requirements

Offshore design

- Design for the intended site of operation including transit to site.
- Design life which is variable: 10-40 years usually depending on field life
- Design based on limit states with the specified probability levels for environmental loads:
- 100 year return period for Ultimate Limit States, ULS
- Fatigue design for design life with increased design fatigue factors, DFFs.
- Limited inspection and repair possibilities
- Increased corrosion protection
- Tank access and gas freeing for inspection
- Additional loads from: topsides, flare, mooring system, risers, cranes, helideck
- Continuous partial filling operation of the cargo tanks
- Different onloading and offloading pattern and berthing loads
- Additional accidental load scenarios to be defined and checked in addition to prescriptive requirements
- Regulatory schemes, shelf states, may have additional requirements

3.3 Fatigue Considerations

Fatigue failures are one of the most important structural defects that need to be assessed in the design of an LNG FPSO or FSRU. Such failures may be a more significant problem in an offshore vessel compared to a trading carrier as the repair may influence the ability to continue production operations. In addition there may be a problem to perform the actual repair as the structural parts may not be accessible for either inspection or repair. As an example, the hull boundary to the containment system in a membrane type unit will have a very low possibility for repair and inspection. This area will then need increased focus in design and construction with a higher design fatigue factor compared to a trading LNG carrier, even though the structural arrangement may be quite similar.

The fatigue evaluation of the LNG FPSO or FSRU should include:

- Evaluation of critical areas: both from experience and fatigue screening
- Assessment of the loads at the intended site of operation
- Calculations of the structural response based on the actual loads

- Accounting for the design life in the calculations
- Fatigue design for design life with increased design fatigue factors (DFFs).
- Internal structure directly welded to submerged part
- External structure not accessible for inspection and repair in dry and clean condition
- Non-accessible areas inside the vessel
- Very limited repair possibilities
- Critical areas in the hull structures will typically include:
    - Topsides areas such as topside supports, riser connections, flare tower supports etc.
    - Ship typical details such as longitudinal end connections, deck attachments
    - LNG/LPG containment system specific details (see containment systems)

These areas should be properly assessed during the design phase. The following figures give an overview of typical areas that need attention.

<table>
<tr><td></td><td>Deck and bottom connections in way of moonpool
Critical deck attachments and pipe penetrations close to the highly stressed areas in the vicinity of the moonpool
Bracket toes
Structural terminations
Erection butt welds
Doubler plates and attachments/pipe penetrations</td></tr>
</table>

<table>
<tr><td>
</td><td>End connections of longitudinals
Longitudinals will need to be addressed as this is the detail that most often cracks in a ship structure.
The critical failure mode is a potential crack through the stiffener web.
Ship side is the area that needs special attention as the dynamic pressure in the ship side causes cyclic loading that may lead to extensive cracking if not taken account of in the design.</td></tr>
<tr><td></td><td>Topside support
Topside supporting structure in general
The critical interface connections between topside and hull are normally highly stressed and needs special attention</td></tr>
</table>

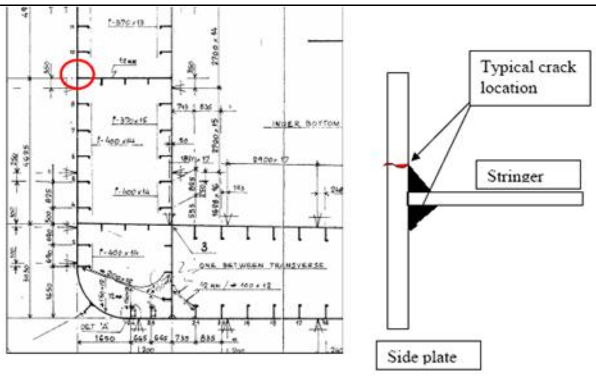
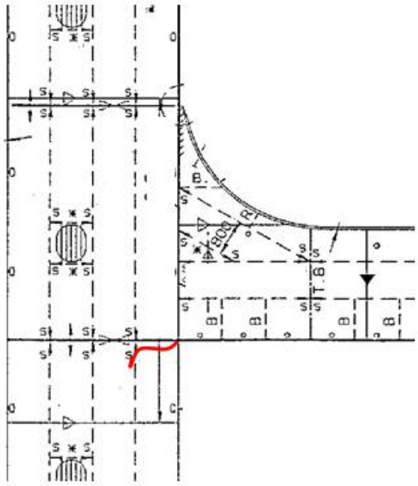
 Detailed drawing of original design	**Side shell plating in ship side** • Thin plating in the ship side may be critical. A potential crack may develop between the longitudinals. • The plate thickness/stiffener span, t/s, should be more than 1/50.
	**Knuckles in hull** • Hopper tank connections • Stringer toes and heels • Knuckle lines • Knuckles have in general high stress concentration factors and will be prone to fatigue cracking

Figure 3-2: Fatigue Sensitive Areas

3.4 Corrosion

3.4.1 General

As with fatigue, corrosion on an LNG FPSO or FSRU carrying out continuous operation and remaining permanently on location without regularly entering drydock will represent a potential serious source of downtime if not handled properly. Frequent change-out of water in ballast tanks to accommodate production and offloading operations and operation in areas with high ambient temperatures and humidity will lead to potential corrosion rates higher than those typically experienced by trading vessels.

3.4.2 Basic aspects of corrosion control

For carbon and low alloy steel LNG FPSO or FSRU hulls there are three principal types of corrosion to be considered :

- General corrosion
- Pitting corrosion, including “in-line pitting attack” and “grooving corrosion”
- Galvanic corrosion (e.g. at welds).

If the ratio of corrosion attack depth to its width is much less than 1 then this is termed general corrosion. Should the depth of the corrosion exceed the width then this is defined as localised corrosion.

When the ratio gets much greater than 1 then this is defined as pitting corrosion. This typically occurs on horizontal surfaces, such as bottom plating. Pitting corrosion can also occur at structural intersections where water collects or flows and may also be termed as “in-line pitting attack” or “grooving corrosion”.

Galvanic corrosion is generated through preferential corrosion of the weld deposit due to galvanic action, e.g. between a weld and the base metal.

3.4.3 Corrosion consequences

There are a number of different consequences for each type of corrosion.

General corrosion can result in fatigue, buckling and leakage at a local or global level. However, the frequency of such failures is low to medium as it is easier to observe during regular inspection intervals. During operation, qualified surveyors and inspectors are able to easily identify whether general corrosion has exceeded the acceptance criteria and if repair is necessary.

Localised corrosion (pitting and groove) can result in leakage of tank contents. Since pitting corrosion rates can be rapid the frequency of occurrence is increased compared to general corrosion. Due to the small surface extension of pits, they can be more difficult to identify compared to general corrosion.

3.4.4 Structural integrity and corrosion control

The structural integrity of the hull, in relation to corrosion, can be achieved through the following:

- Corrosion allowance (for given structural members)
- Corrosion protective coatings
- Cathodic protection (for seawater tanks and for the external hull)

An optimal structural integrity design can be achieved through a combination of these three measures.

3.4.4.1 Design corrosion margins

Corrosion allowances for traditional ship designs are based on 10-year service and are provided in various Classification Society standards, e.g. DNV Rules for Ships.

Typical corrosion allowance for general ballast tank corrosion would be in the range from 1mm to 3.5mm for one sided corrosion exposures.

To apply these corrosion rates to account for corrosion over a 20 year service would result in twice the values for the 10-year service, which is typically an unrealistic approach.

An analytical approach to corrosion control could be as follows:

- Utilize corrosion allowance as a safety factor for critical items,
- Plan and implement a corrosion protection system to avoid corrosion wastage, and
- Develop an appropriate Inspection Maintenance Repair plan to ensure correct and consistent coating maintenance and anode retrofitting.

As indicated above the optimal approach to FPSO maintenance is to ensure adequate corrosion protection and, thereby, avoid corrosion wastage. With this approach a corrosion allowance is not needed. However, a corrosion allowance based on a 10-year service or any arbitrary selected value may be used as a safety factor in the design (e.g. 2mm for a one sided exposure). These may be used as a safety factor for critical structural members.

3.4.4.2 Coating systems

Quality of the coating applied at the newbuilding stage will be the deciding factor for the subsequent maintenance during operation.

A high performance coating will provide a long service life and result in minimum maintenance. The high performance coating will imply high initial costs. However, the benefit will be the optimal life cycle cost for the operation of the LNG FPSO or FSRU. The implication of this is that coating maintenance requires close attention to planning logistics to ensure adequate coating quality.

The repercussions for inadequate coating maintenance work can be an exceedingly short service life of the corrosion protection performance and/or rapidly increasing maintenance/repair costs.

It is important to be aware that coating of a vessel is a very complex process which represents a considerable workload and logistics task in the shipyard. A successful coating application work will require extensive planning before contracting and follow up/inspection during coating work. Normally this is not part of the Classification Society's scope of work, unless specifically requested as a part of the contract or additional class notation, e.g. DNV COAT II (ref Classification of Ships, Pt.3 Ch.1 Sec.15).

Quality control of the surface preparation and application is essential to ensure that the applied coating system will provide the expected performance. A high performance coating can best be ensured by using an experienced third party coating inspector during the vessel fabrication period.

It is important to be aware that a high quality coating can be best achieved at a yard as compared to the quality which can be expected for maintenance on the LNG FPSO or FSRU in service. This is related to the complexities for the working conditions offshore and ability to achieve desirable environmental conditions when carrying out maintenance on an offshore unit in service.

3.4.4.3 Cathodic Protection

Sacrificial anodes provide cathodic protection (CP) in the part of the ballast tanks which are submerged .The design of the CP system is carried out based on providing protection for a given service life. Sacrificial anodes can here be retrofitted during the service life. Optimal corrosion protection can be achieved by combining CP with a coating system.

For the external hull, the protection will be a combination of coating and sacrificial anodes, which is necessary to achieve a 20 year service life. For the external hull there are two alternatives:

- Sacrificial anodes, or
- Impressed current protection.

The industry practice varies; some operators prefer impressed current anodes while others prefer sacrificial anodes.

Cathodic protection of External hull

The external hull can be protected by either sacrificial or impressed current anodes.

The service life of the LNG FPSO or FSRU will imply that the external coating on the hull may experience significant breakdown. This will imply that the cathodic protection current demand will be highest at the end of the service life.

It needs to be established how the sacrificial anodes and/or the impressed current anodes shall be maintained or retrofitted to ensure adequate cathodic protection also at the end of the service life of the unit.

For the external hull, retrofitting anodes can be expected towards the final 5 to 10 years of the service life. Independent of the original installed cathodic protection system, sacrificial or impressed current systems can be applied. The choice will depend on selecting the optimal solution.

Cathodic protection of Internal hull

The ballast tanks of an LNG FPSO or FSRU will be protected by coatings and cathodic protection in the areas submerged in seawater.

For ballast tanks the benefit of replacement of zinc sacrificial anodes needs to be considered at every scheduled point in the maintenance planning.

A combination of coating and cathodic protection can ensure a 20 year corrosion protection service life.

Only sacrificial anodes are permitted in tanks with zinc anodes (typically in ballast tanks).

A high performance coating will reduce the depletion of the anode by a factor of between 10 and 20, which can provide significant weight and inspection savings. A low performance coating system will only achieve a factor of approximately 3 to 5.

The tank bottom of a ballast tank is a critical area for pitting type corrosion. It is important to ensure that anodes are retrofitted in the tank bottoms to ensure full protection during the service life of the unit.

For further information the following documents may be referred to:

- DNV Recommended Practice No. 20 *Corrosion Protection of Ships*
- DNV Classification Note No. 33.1 Corrosion Prevention of Tanks and Holds

3.5 Topside Structure

An area with obvious implications for hull structural design will be the addition of structural appendages to the hull which are normally not present on an LNG carrier. These may include items such as topsides process and power modules, lifting appliances, LNG transfer arrangements, flare or vent stacks, position mooring arrangements, risers, and provision of a helideck.

The principles for designing topside support structure will be the same as for oil FPSOs with the important exception that the loading may also impose deformations on the containment system. Accessibility to the containment tank dome and cargo tank spaces will also be an issue as the presence of the topside may limit crane operations in various areas.

The topside structure on an FLNG unit can be of very significant size and weight. This will obviously vary depending on the intended production capacity of the FLNG, but will typically be in the order of 20 000 to 50 000 tons (for small and medium scale LNG production) and 50 000 to 70 000 tons and more for large scale LNG production units. Accommodating such loads represents a significant challenge.

The topside structure is typically designed with a framing structure supported on locations in the hull with sufficient capacity to accommodate the weight and additional loading given by the topsides structure. The support points are normally arranged in either transverse or longitudinal bulkheads. In addition strong deck girders may be used for support points of the topside structure.

The topside stool is the direct interface with the hull structure and is critical in that respect. (see Figure 3-3 and Figure 3-4). Both ultimate strength and fatigue strength are important in these joints. There are a number of ways to design such supports. Two typical arrangements are:

- Topside module legs with brackets/gusset plates inline with bulkheads below the deck
- Topside module legs with which are resting on elastomeric supports on a topside support stool

The latter solution allows the topside module to slide slightly thus not transferring displacements from the hull structure due to hull girder bending. Figure 3-5 for details.

Figure 3-3: Topside support welded directly to deck

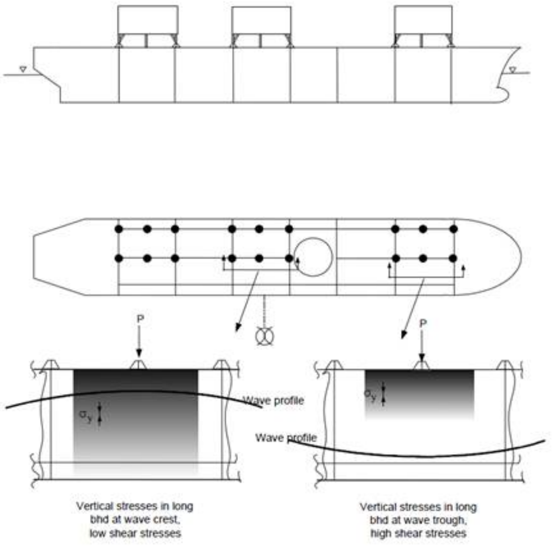


Figure 3-4: Interface topside/hull

Figure 3-5: Topside support on sliding support

The topside structures should be assessed for sufficient capacity to withstand the loading to which they are exposed. These loads may include:

- Static loads from weights of modules and equipment
- Inertia loads due to vessel motion
- Wind loads
- Green sea loads in harsh environment
- Accidental loads, including blast and accident heeling
- Hull deformation loads

In addition there are elements that will be particularly related to FLNG application. LNG-containing equipment and piping may be critical due to the structural hazard of brittle fracture associated with a cryogenic spill. The philosophy for handling cryogenic leakages should be considered for the arrangement and sizing of drip trays for such equipment. Typical equipment would be offloading arms (see Fig 3-6) and cold boxes.

Figure 3-6: LNG Offloading Arms - Courtesy FMC

Use of Passive Fire Protection (PFP) on loadbearing structures is a typical recommendation from Risk Analysis. This is especially applicable to supporting structures in the topsides area. After application of PFP these areas may then become essentially non-inspectable with regard to fatigue design. It is important that such areas are identified as early as possible so that the correct Design Fatigue Factor (DFF) is applied in the design.

Design of the topsides structures should use as basis the DNV Offshore Standard DNV-OS-C101 *Structural Design of Offshore Steel Structures*.

3.6 Mooring Supporting Structure

There are normally two types of mooring arrangements for permanently moored offshore floating production units in use today:

- Spread mooring where the vessel is constrained in one direction
- Turret mooring (internal or external) where the vessel is free to weathervane

Either of the two typical arrangements will involve forces and moments from the mooring system that will have to be taken up by the supporting structure in the hull. A spread mooring system will typically have chain stoppers on main deck level where the mooring loads are taken into the vessel. They may also have fairleads located further down on the hull. In addition the riser connections will typically be connected in a riser balcony above the ship side. For typical arrangements see Figure 3-7.

Induced loads will affect the structure which carries the mooring loads into major load carrying structural elements such as longitudinal and transverse bulkheads. For turret moored units structural analysis is necessary to verify the strength of the hull in the vicinity of the turret and mooring interface structure. Both ultimate strength and fatigue strength must be checked thoroughly. See figures Figure 3-8 to Figure 3-10 for details. Particularly for internal turrets design accidental loads on the ship load bearing structure may be significant.

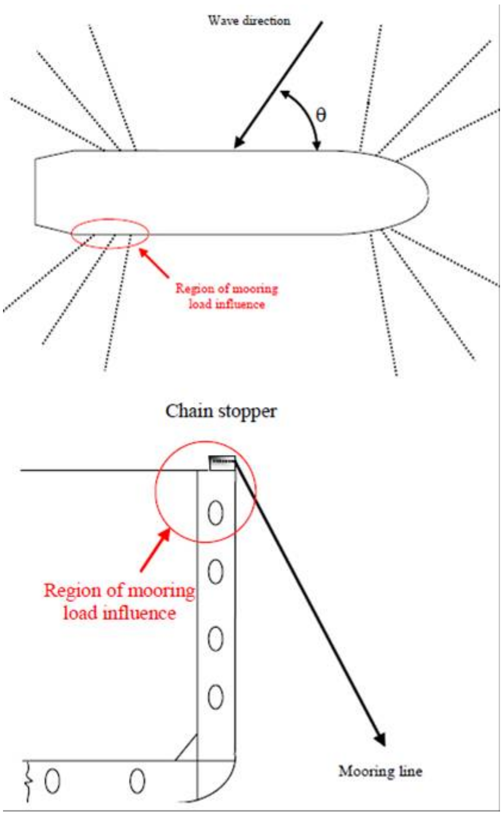


Figure 3-7: Spread mooring and the influenced area on the hull

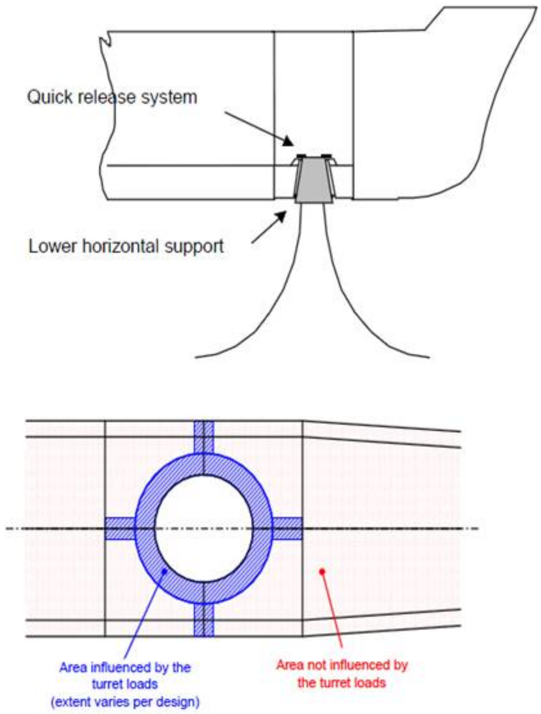


Figure 3-8: Spread mooring and the influenced area on the hull

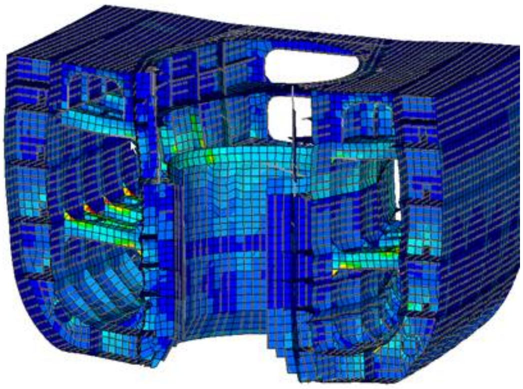


Figure 3-9: Structural analysis of turret interface for internal turret

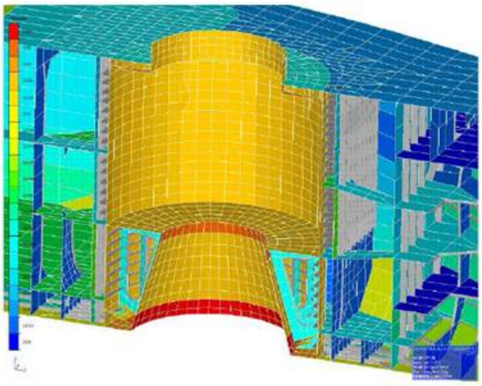


Figure 3-10: Finite element model of turret interface for submerged turret system

Turret loads will need to include the load case of having a shuttle tanker moored alongside and whether the operational philosophy calls for disconnection or remaining on location in severe storm conditions.

Reference is made to the following DNV standards which address the turret interfaces are:

- DNV Offshore Standard OS-C101 *Structural Design of Offshore Steel Structures*
- DNV Offshore Standard OS-C102 *Structural Design of Offshore Ships*
- DNV Offshore Standard OS-E301 *Position Mooring*

3.7 Green Sea Considerations

Although most FLNG concepts are currently being proposed for benign water applications, deployment in harsher environments may also be considered.

An FLNG unit will have more critical topside equipment onboard than a gas carrier. In addition the FLNG does not have the possibility to avoid storms in the same way as a trading ship. This implies that, for those locations where green sea may be experienced (i.e. for harsher environmental applications), it will be more critical than for a normal tanker.

From experience with harsh environment FPSO's, the bow area and also the deck area supporting the topside have been found to be critical with respect to green sea. There are several design measures which may be taken compared to gas carrier design to address this problem. See Figure 3-11 for reference.

In case of accommodation forward: potentially increase the bow height to minimize or eliminate green sea in the bow.

In case of accommodation aft: either increase bow height or protect equipment in the forward deck area by green sea protection panels

For exposure for green sea over the ship side, there are two typical countermeasures:

- Increase the freeboard
- Include green water protection panels along the ship side.

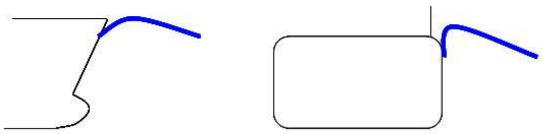


Figure 3-11: Green Sea Cases: Bow & Side

3.8 Material Selection and Fabrication

3.8.1 Materials

The design principles for material selection of hull, topside facilities and topside supporting structure are specified in Table 3-1.

Table 3-1: Design principle for material selection

Design principle for material selection		
Hull structure	If the design temperature is above -10°C based on lowest mean daily average temperature.	Rules for Classification of Ships Pt.3 Ch.1 Sec.2
	In case of lower design temperature than -10°C	Rules for Classification of Ships Pt.5 Ch.1 Sec.7
Topside structure and elements not covered by Rules for Classification of Ships Pt.3 Ch.1	Materials for topside modules, topside supporting structures, foundations and main supporting structures of heavy equipments attached to deck and hull	DNV-OS-C102
Cargo tanks for LNG and LPG	Steel for low temperature service	Rules for Classification of Ships Pt.2 Ch.2 Sec.7

In addition, presence of the cold cargo will give rise to low temperature in parts of the hull steel structure. Therefore, for cargo tanks requiring secondary barriers the temperature calculation for hull structures shall be determined in accordance with DNV Rules for Classification of Ships Pt.5 Ch.5 Sec.2.

Design ambient temperature for the temperature calculation is given in Table 3-2.

Table 3-2: Design ambient temperature for temperature calculation

Design ambient temperature for temperature calculation				
Regulations	Still sea water temperature, ºC	Air temperature, ºC	Speed, knots	Applicable areas
IGC code	0.0	+5,0	0.0	All hull structure in cargo area
USCG requirements, except Alaskan water	0.0	-18.0	5.0	Inner hull and members connected to inner hull in cargo area
USCG requirements, Alaskan water	-2.0	-29.0	5.0	Inner hull and members connected to inner hull in cargo area

Based on the temperature calculation, the material selection of cargo tanks and hull structures shall be determined according to the principles given in Table 3-3.

Table 3-3: Design principle for material selection of cargo tanks and hull structures

Design principle for material selection of cargo tanks and hull structures	
General	The calculation is normally to be based on empty ballast tanks if this assumption will cause the lowest steel temperature.
Material of Cargo Tank	Specification of materials in cargo tank shall be submitted for approval, ref. DNV Rules for Classification of Ships Pt.5 Ch.5 Sec.1 C202. For certain materials, subject to special consideration by the Society, advantage may be taken of enhanced yield strength and tensile strength at design temperatures below -105 °C. ref. DNV Rules for Classification of Ships Pt.5 Ch.5 Sec.5 A401 Materials for cargo tanks and hull structures shall comply with the minimum requirements given in DNV Rules for Classification of Ships Pt.5 Ch.5 Sec.2 D
Outer hull structure	The outer hull structure includes the shell and deck plating of the ship and all stiffeners attached thereto. The material in the outer hull structure is to be in accordance with DNV Rules for Classification of Ships Pt.3 Ch.1 Sec.2, unless the calculated temperature of the material in the design condition is below -5ºC due to the effect of low temperature cargo, in which case the material is to be in accordance with the rules DNV Rules for Classification of Ships Pt.5 Ch.5 Sec.2 assuming the ambient air and sea temperatures of 5ºC and 0ºC respectively. If the design ambient temperature is less than -|10 degrees, the exposed members above the ballast waterline of the vessel shall be complied with Pt.5 Ch.1 Sec.7. In order to travel on US-ports the following requirements to hull plating have to be satisfied along the length of the cargo area. - Deck stringer and sheer strake must be at least Grade E steel - Bilge strake at the turn of the bilge must be of Grade D or Grade E
Inner hull structure	The inner hull structure includes inner bottom plating, longitudinal bulkhead plating, transverse bulkhead plating, floors, webs, stringers and all stiffeners attached thereto. For ships intended for trade in higher or less values of the ambient temperatures, those ambient temperatures may be used for temperature calculation. The load condition giving the lowest draft among load conditions of two tanks empty and the other tanks full may be used for the temperature calculations. For members connecting inner and outer hulls, the mean temperature may be taken for determining the steel grade. Steel grade of load carrying stiffeners (e.g. deck longitudinals or bulkhead stiffeners) shall be as for the plating for which the stiffener is attached. This also applies to structural members where direct loads are not applied. e.g. brackets, top stiffeners, ribs, lugs attached to web frames, floors and girders. For structural members connecting inner and outer hull containing small openings only, the mean temperature may be taken for selection of steel grade as given in DNV Rules for Classification of Ships Pt.5 Ch.5 Sec.2 B501. Engine room temperature of 5^{o}C is normally assumed. It is assumed that heating coil in fuel oil tank is inactive.

The material specification requirement for an LNG FPSO or FSRU with regard to material selection should follow the principles of the offshore standards: DNV-OS-C101 *Design of Offshore Steel Structures* and DNV-OS-C102 *Structural Design of Offshore Ships*.

3.8.2 Fabrication

Fabrication requirements for offshore installations are typically more strict than for normal shipbuilding practice. For instance, NDT (Non Destructive Testing) requirements and typical tolerances are stricter than for a conventional tanker. The fabrication requirements should be in accordance with DNV-OS-C401.

The extent of visual inspection is more or less the same for a tanker and an FPSO. The NDT extent is generally higher for an offshore vessel compared with typical shipbuilding practice. Detailed requirements to visual inspection and NDT can be found in DNV-OS-C401 *Fabrication and Testing of Offshore Structures*.

Areas with no or limited possibility of inspection during operation will require more thorough inspection during fabrication. In addition, areas may be identified, (typically fatigue prone details), where additional inspection of welds will be required. Examples can be bracket toes, brackets in hopper corners inside cargo tanks for condensate, etc. For such areas the need for fit-up inspection should be assessed as a means to improve final quality.

NDT for ships has been tuned towards operation of ships with respect to ship operating philosophy and regular drydock inspection. For traditional ships such a philosophy takes into account that failures may be repairable in the next port of call.

For offshore installations the safety format needs to be tuned to the specific operations philosophy of the installation, which in most cases will call for 20 - 25 years operation on site without dry-docking. Consequently, a greater focus has to be given to the consequences of failures primarily affecting regularity of the unit. Typical ship hull details used on LNG FPSOs or FSRUs should thus be subject to more rigorous fatigue evaluations, and improved upon as deemed necessary, in order to meet appropriate fatigue requirements set forth by the Shelf Regime and Class. From a classification point of view the extent of NDT is closely related to the criticality rating.

For an LNG FPSO or FSRU some critical construction details will typically be around the moonpool, topside support stools, support for cranes, flare tower support etc.

3.9 Guidance on Analysis

3.9.1 Hull modelling and analysis

Modes of operation

All relevant modes of operation shall be considered. Typically, the assessment of the unit should be based on the following operational modes:

- all transit conditions
- all operating conditions, intact and damaged, at the design locations(s)
- all inspection and repair conditions

Changes in the design conditions of a ship-shaped unit are usually accompanied by significant changes in draught, ballast, riser connections, mooring line tension, etc. Limited variation of some of these parameters may be contained within a specific design condition.

The suitability of a ship-shaped unit is dependent on the environmental conditions in the areas of the intended operation. A production unit may be planned to operate at a specific site. Such a site may be harsh environment or benign waters.

Table 3-4: Modes of Operation

Transit & non-operational conditions	Operating conditions	Extreme conditions
For floating production and storage unit which are intended to operate on a specific location for the main part of the design life, wave loads can be based on the actual transit route and season at a return period of 10 years, or on the Rules from a recognised Marine Warranty. Unrestricted transit condition is defined as moving the unit from one geographical location to another, and shall be based on the DNV Rules for Classification of Ships Pt.3 Ch.1. Non-operational conditions such as survey afloat are considered to be covered by DNV Rules for Classification of Ships Pt.3 Ch.1. The stand-by condition is to be established for the safe operation during the installation phases.	Operating conditions are defined as conditions wherein a unit is on location for purposes of production or other similar operations, and combined environmental and operational loadings are within the appropriate design limits established for such operations (including normal operations, survival, and accidental). The operational profile shall be established with specific environmental limiting conditions such as sea state and wind based on site specific representative for the areas in which the units are to operate. The operating condition shall account for the combination of wave effects and wind effects. All the operating limitations used for the design and safe operation shall be stated in the operating manual.	Extreme condition is defined as a condition during which a unit may be subjected to the most severe environmental loadings such as storm, hurricane or typhoon for which the unit is designed. The operation of production plant may have been discontinued due to the severity of the environmental loadings. The unit may be either afloat or supported on the sea bed, or leave the site under its own propulsion or assistance from tugs, as applicable. Survival scenario is to be established, if applicable. For units with disconnectable mooring system e.g. submerged turret, the environmental limiting conditions for disconnection or reconnection of the mooring system are to be specified.

3.9.2 Structural Analysis

Use of finite element methodology for strength analysis of hull and cargo tank structures is primarily in order to obtain a better and complete understanding of the stress response when subject to wave, motion-induced loads as well as other functional loads. In practice, the structural analysis can be performed using several levels of modelling methods. It is particularly important that the level of modelling and associated structural idealization should be based on purpose of the analysis. Normally, four levels of model for finite element analysis are required as follows:

- Three cargo hold model for hull girder longitudinal strength
- Two or three cargo hold model for transverse strength
- Local structural model(s) for local detail stress analysis
- Stress concentration model(s) for fatigue strength

An overview of these four modelling methods is presented in Table 3-5.

Table 3-5: Overview of structural analysis for hull and cargo tanks

Overview of structural analysis for hull and cargo tank				
Model type	Part ship (three cargo hold) model	Part ship (two or three cargo hold) model	Local structural model	Stress concentration model
Objective	ULS (hull girder longitudinal strength) of the main longitudinal members of hull	ULS of the main transverse members of hull and cargo tanks (transverse strength)	ULS of local structural details of hull and cargo tanks	FLS of fatigue sensitive areas of hull and cargo tanks
Mesh size	Standard mesh size equal to or less than the representative spacing of longitudinal stiffeners	Standard mesh size equal to or less than the representative spacing of longitudinal stiffeners	Fine mesh element size of 50x50	t x t element mesh size (t: thickness) in stress concentration areas
Load level	Global and local loads based on direct calculations (wave load analysis) with a 100 year return period	Local loads based on 10-4 probability level	Prescribed deformations or forces from part ship model with local loads	Global and local loads based on 10-4 probability level (recommended)
Acceptance criteria	Nominal stress of main longitudinal members of hull with respect to material yield and buckling capacity	Nominal stress of main transverse girder system with respect to material yield and buckling capacity	Local linear peak stress with respect to material yield	Minimum fatigue life of 20 years with DFFs
Rule/ Standard	DNV-OS-C102	DNV Rules for Classification of Ships Pt.3 Ch.1 and Pt.5 Ch.5	DNV Rules for Classification of Ships Pt.3 Ch.1 and Pt.5 Ch.5	DNV Rules for Classification of Ships Pt.3 Ch.1 and Pt.5 Ch.5

3.9.3 Foundations and Supporting Structure for Hull Equipment

Design principles for foundations and supporting structures of hull equipment and machinery are given in Table 3-6.

Table 3-6: Design principles for foundations and supporting structures of hull equipment and machinery

Design principles for foundations and supporting structures of hull equipment and machinery	
Supporting structures of thruster	Ship Rules Pt.3 Ch.3 Sec.6
Rudders, nozzle and steering gears	Ship Rules Pt.3 Ch.3 Sec.2
Supporting structures of helicopter deck and substructure	DNV-OS-E401
Foundations and supporting structures of temporary mooring equipments (e.g. chain stoppers, windlasses or winches, bollards, chocks, etc)	Ship Rules Pt.3 Ch.3 Sec.5
Supporting structures of position mooring equipments (e.g. turret, etc)	Ship Rules Pt.3 Ch.3 Sec.12
Crane pedestal and supporting structures	DNV-RP-C102
Davits and supporting structures of launching appliances (e.g. life boat, raft, etc)	Ship Rules Pt.3 Ch.3 Sec.5

3.9.4 Side by side mooring analysis

3.9.4.1 General

There are two means of transferring LNG between the LNG FPSO or FSRU (FLNG) and visiting LNG Carriers (LNGC): side-by-side transfer or tandem transfer. This section addresses analysis of the side-by-side mooring of the two vessels to carry out side by side transfer.

The main purpose of the side by side mooring analysis is to determine the berthing forces on the mooring lines and fenders between the FLNG and the LNGCs and the relative motions between the vessels at key points. Similarly the same approach may be used to determine motions and forces between an FLNG and a floating jetty where the FLNG is moored close to shore.

The analysis will need to address:

- Berthing line forces between the FLNG and the LNGCs
- Fender forces between the FLNG and the LNGCs
- Vessel motions, and relative vessel motions

The output of the analysis will provide input to the design of the transfer systems (hoses or loading arms), design of the fixation points (bollards) and berthing lines, dimensioning of the fenders and point loads acting on the ship hull.

General design and operational procedures for the various system components should follow the recommendations of the following internationally recognized codes:

- OCIMF Mooring Equipment Guidelines
- OCIMF / SIGTTO: Ship to Ship Transfer Guide (Liquefied Gases)

3.9.4.2 Typical Methodology

Time-domain simulation of 6 Degree of Freedom large body models of the FLNG and representative gas carriers need to be carried out using recognized and appropriate computer programs. Such programs include WADAM and SIMO.

WADAM is a general analysis program for calculation of wave-structure interaction for fixed and floating structures of arbitrary shape. The analysis capabilities in WADAM comprise calculation of hydrostatic data and inertia properties as well as global hydrodynamic loads and responses. WADAM calculates loads using first and second order 3D potential theory for large volume structures. The 3D potential theory in WADAM is based directly on the WAMIT program developed by MIT. The two floating bodies are solved simultaneously for generating input to the time domain simulation.

SIMO is a computer program for simulation of motions and station-keeping behaviour of a system of floating vessels.

The environmental condition is specified through wave, wind and current parameters:

- Waves are modelled by spectra for irregular waves.
- Wind is modelled by an average wind velocity which is constant and gusts both in propagation and lateral directions.
- Current speed and direction are assumed to be constant with time. A current profile is included by specifying velocity and direction at a set of water levels

WADAM is used to establish hydrodynamic coefficients to be used for the simulation in SIMO:

- 1st order wave exciting forces are described by linear transfer functions between force amplitude and wave amplitude. Time series are obtained by multiplying interpolated transfer functions with the wave spectrum applying a Fast Fourier Transform (FFT) on the result,
- Drift forces are calculated by Newman's approximation based on the 2nd order wave drift force coefficients.
- Frequency-dependent added mass and damping are converted to retardation functions which enter the time domain simulation as convolution integrals. Additional linear and quadratic damping is specified.

Additionally, a number of other force models should be applied

- Wind forces are defined through directional dependent quadratic wind force coefficients.
- Current forces are defined through directional dependent force coefficients.
- Hydrostatic stiffness
- Damping forces expressed by linear and quadratic damping matrices.
- Mooring lines and fenders connect the vessels and are specified by a general force deformation relationship.

The results from the program are presented as time series, statistics and spectral analyses of all forces and motions for all bodies in the analyzed system.

3.9.4.3 Application of Results

The key parameters to be considered are maintaining integrity of mooring lines and remaining within the operating limitations of the transfer system. Failure of either of these two parameters should be related to an agreed probability target (e.g. frequency of occurrence to be less than 10^{-4}). The limitations of components and systems should initially be specified by the manufacturer and follow recognized code requirements where such exist (alternatively these limitations should be determined in a technology qualification program).

It should be borne in mind with regard to transfer between two floating bodies that the entire operation will need to be assessed (from approach to departure and including tug limitations) in order to specify actual operational limits which can be used in any assessment of overall availability.

3.9.5 Fatigue Analysis

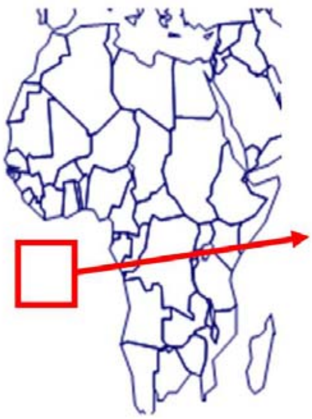
3.9.5.1 Hydrodynamic response

Fatigue calculations are performed using as input environmental action of the waves and wind. Wave actions will induce dynamic loads in the hull. For slender structures in the topsides, vortex shedding from wind loads may also be a fatigue load of importance.

The environmental loads are known to be very different depending on the operating site. Areas considered being "benign" areas, such as West Africa, experience fatigue loads which are relatively small, whereas operating sites in more harsh environments, such as Canada and the North Sea, experience significantly larger fatigue loads. In addition, operating experience from harsh environment projects shows that fatigue is an important design issue.

The wave loads at the operating site are normally described in terms of a scatter diagram showing the relation between the wave heights and wave periods in a specific area. The wave scatter diagram is used as input to the hydrodynamic analysis which will then give the motion and load response of the vessel in the waves.

The arrangement of the mooring system will affect the wave angle towards the waves. A turret moored vessel will have the dominating wave angle at head seas towards the vessel.



Hs \ Tp	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	Sum
0.25		1.8	4.5	1.9	0.6	0.2			9
0.75		26.4	189.2	127.7	46	14.5	4.6	2.3	410.7
1.25		4.1	149.3	181.2	84.5	30.9	10.8	6.1	466.9
1.75			16.5	43.1	28	12.2	4.8	3	107.6
2.25			0.3	1.9	1.9	1	0.5	0.3	5.9
2.75							0.02	0.08	0.1
3.25									0
3.75									0
4.25									0
4.75									0
SUM	0	32.3	359.8	355.8	161	58.8	20.72	11.78	1000.2

Figure 3-12: Typical operation site and scatter diagram

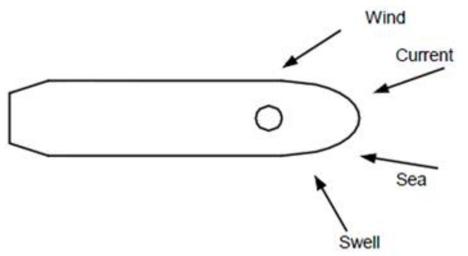


Figure 3-13: Environmental actions affecting the directionality

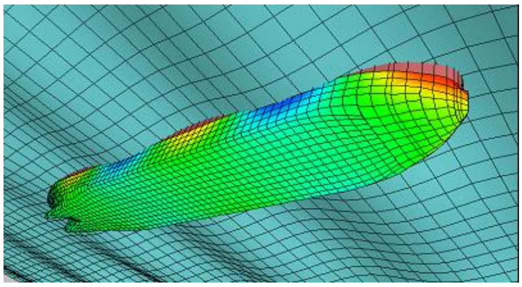


Figure 3-14: Hydrodynamic calculations with 3D panel program

3.9.5.2 Structural response and fatigue damage calculations

To determine the structural response from the environmental loads, it is necessary to utilize finite element models to establish the stress level to be used for the fatigue calculations. The assessment is normally carried out in two steps.

- Coarse model to establish the nominal stress level in the hull
- Fine mesh model to establish stress at the hot spots

Modeling of the structure will typically be refined modelling with a fine mesh (with elements the size of the thickness) at the critical locations. The figures below show typical application areas for such modelling. These include:

- Moonpool areas
- Topside support structures
- Cargo tank supports
- Support of spherical tank skirt and tank cover
- Hull adjacent to membrane tank

The fatigue damage summation is performed by using Miner Palmgrens cumulative damage formula to sum fatigue damages of the different stress blocks. The SN curves give the important relationship between the stress level and the number of cycles before fatigue failure. Different SN curves are used for different welding details and base material. See Figure 3-15 for example of fatigue summations.

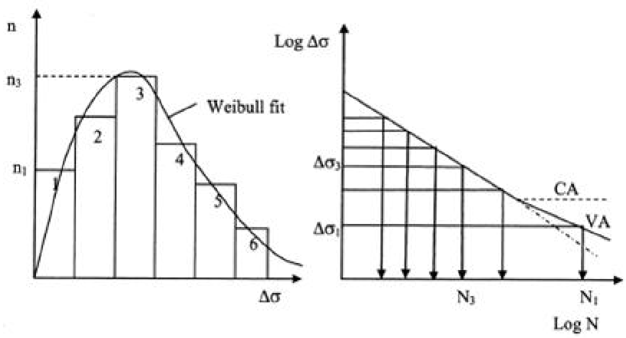


Figure 3-16: Fatigue Summation

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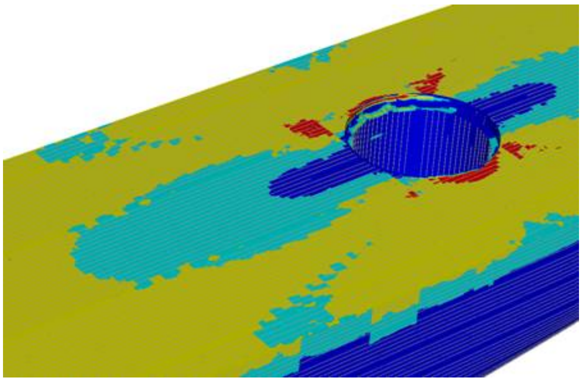


Figure 3-17: Fatigue screening around turret area of a floating unit

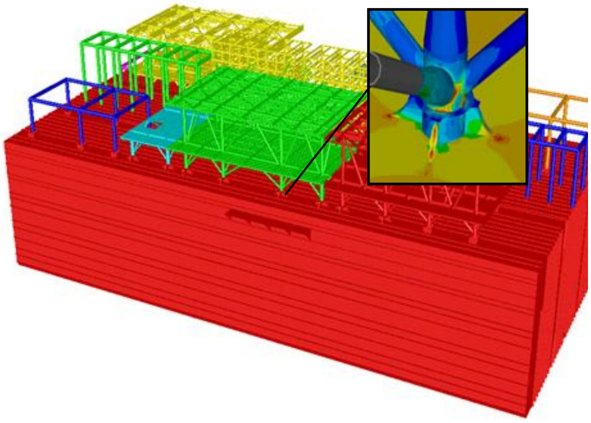


Figure 3-18: Fatigue screening around turret area of a floating unit

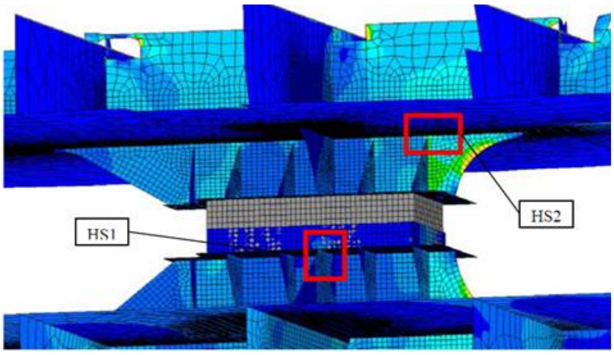


Figure 3-19: Fine mesh fatigue analysis of cargo tank supports of independent tanks

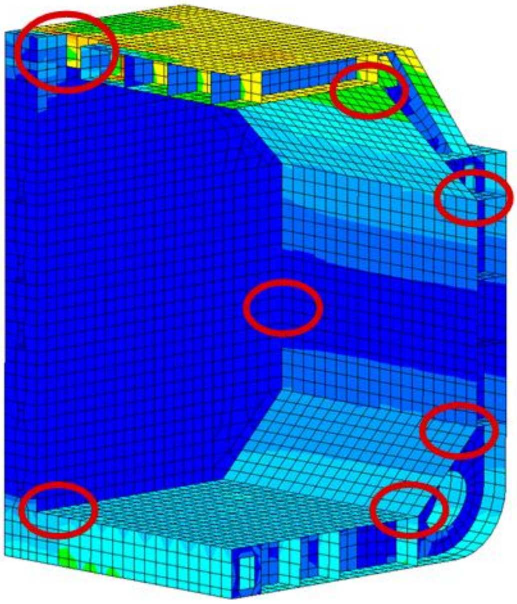
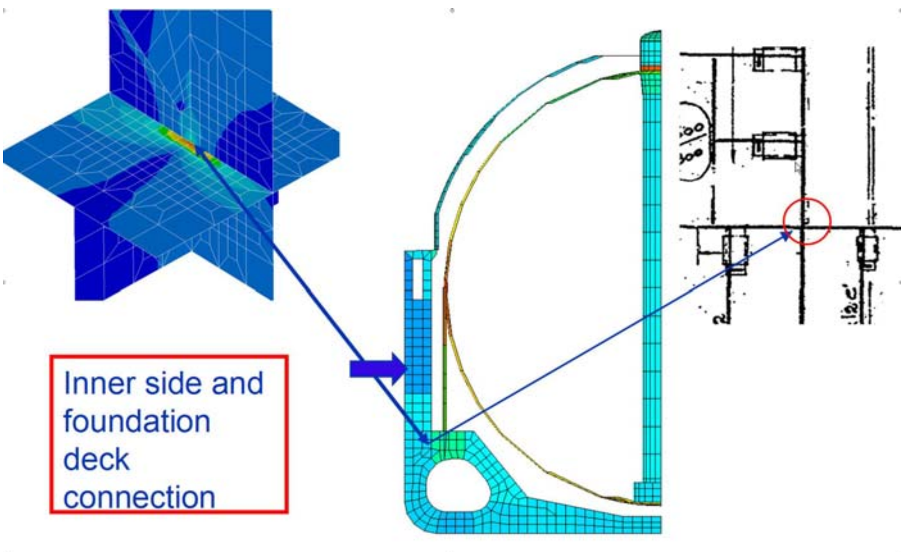


Figure 3-20: Critical fatigue locations of the hull of a membrane vessel



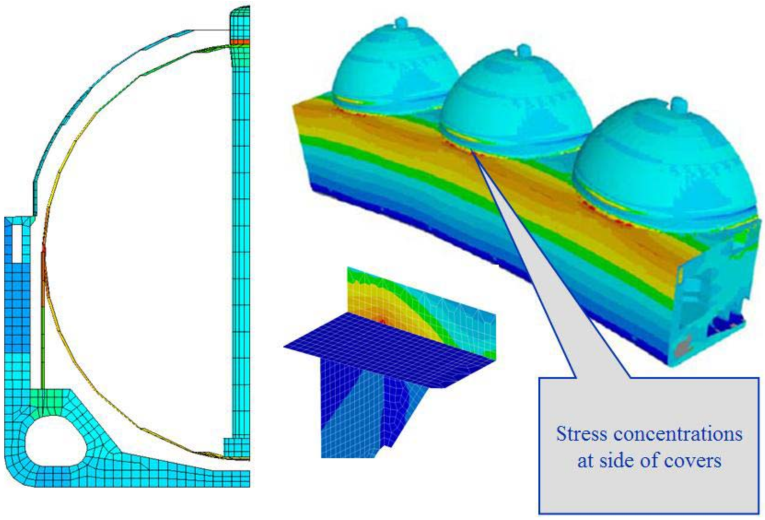


Figure 3-21: Critical fatigue locations of the hull of a Moss type vessel

Further reference is made to the following DNV documents describing the fatigue calculations to be conducted for an FLNG unit:

- DNV Recommended Practice RP-C203 *Fatigue Design of Offshore Steel Structures*
- DNV Recommended Practice RP-C206 *Fatigue Methodology Specification of Offshore Ships*
- Classification Notes 30.7 *Fatigue Assessment of Ship Structures*

3.9.6 Structural Loads defined by Risk Assessment

3.9.6.1 General

Risk Assessment is normally an integral part of the design process for FLNG projects (see Appendix A for recommended approach). The Risk Assessment will result in defining accidental loads which need to be addressed in the structural design. The magnitude of the loads will need to be determined on a case by case basis depending on the detail design and layout of the FLNG and on its area of operation. The following sections discuss the typical structural loads to be incorporated.

3.9.6.2 Collision considerations

The main principle behind the assessment of collision scenarios is that a single failure shall not lead to loss of the vessel. In such an assessment the loads that occur with 10-4 annual probability should be considered.

A frequent offloading scenario with, for example, side by side offloading may indicate a need to assess the risk of collision along the FLNG unit's side. See Figure 3-22 for typical arrangement. Some FLNG concepts consider tandem offloading and there the collision risk may be greater at the stern of the FLNG unit.

Supply vessel impacts are a known hazard to oil FPSOs and this hazard is also likely for an FLNG Unit. In general the collision loads should not lead to loss of hydrocarbon integrity, cryogenic leakages or endanger the vessels floatability. See Figure 3-23 for example of calculations. The likely outcome of such calculations is a recommendation for the sizing of the double side of the unit.

In addition to the above considerations, one should be aware that some of the containment tank concepts are sensitive to inertia loads and loads arising from collisions should be considered in tank design.

Figure 3-22: Side by side offloading (courtesy of Hoegh LNG)

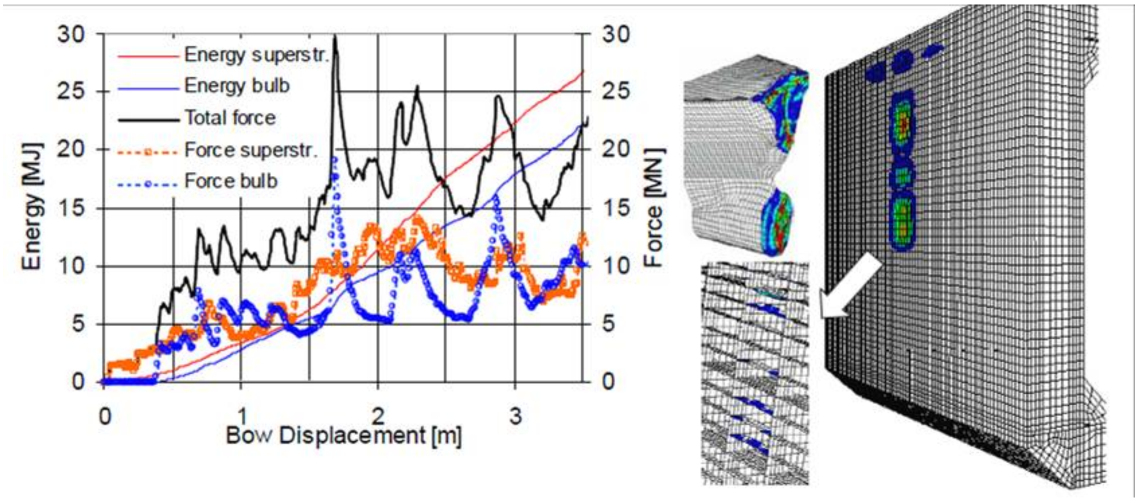


Figure 3-23: Energy absorption in supply ship collision

In general the approach has been to design for low energy impact (<50 MJ) and to eliminate high energy impacts and potential tank rupture through traffic controls.

Detailed guidance on how to assess and design for ship collision loads is provided in DNV Recommended Practice DNV-RP-C204 *Design against Accidental Loads, Section 3.*

3.9.6.3 Dropped Objects

The dropped object load is characterised by a kinetic energy, governed by the mass of the object, including any hydrodynamic added mass, and the velocity of the object at the instant of impact. In most cases the major part of the kinetic energy has to be dissipated as strain energy in the impacted component and, possibly, in the dropped object. Generally, this involves large plastic strains and significant structural damage to the impacted component. The strain energy dissipation is estimated from force-deformation relationships for the component and the object, where the deformations in the component shall comply with ductility and stability requirements. The load bearing function of the installation shall remain intact with the damages imposed by the dropped object load. In addition, damaged condition should be checked if relevant.

From a structural point of view, dropped objects are rarely critical to the global integrity of the installation and will mostly cause local damages. The major threat to global integrity of the floating installation is probably the puncturing of buoyancy tanks, which could impair the hydrostatic stability of the installation. Puncturing of a single tank is normally covered by the general requirements to compartmentalization and watertight integrity given in DNV-OS-C301 *Stability and Watertight Integrity*. More relevant for a ship-shaped structure is the escalation effect of puncturing of a containment tank or release of cryogenic or hydrocarbon fluids.

The structural effects from dropped objects may either be determined by non-linear dynamic finite element analyses or by energy considerations combined with simple elastic-plastic methods.

Detailed guidance on how to assess and design for dropped object loads is provided in DNV Recommended Practice DNV-RP-C204 *Design against Accidental Loads, Section 4.*

3.9.6.4 Fire

The characteristic fire structural load is temperature rise in exposed members. The temporal and spatial variation of temperature depends on the fire intensity, whether or not the structural members are fully or partly engulfed by the flame and to what extent the members are insulated. Structural steel expands at elevated temperatures and internal stresses are developed in redundant structures. These stresses are most often of moderate significance with respect to global integrity. The heating causes also progressive loss of strength and stiffness and is, in redundant structures, accompanied by redistribution of forces from members with low strength to members that retain their load bearing capacity. A substantial loss of load-bearing capacity of individual members and subassemblies may take place, but the load bearing function of the installation shall remain intact during exposure to the fire load.

Detailed guidance on how to assess and design for fire loads is provided in DNV Recommended Practice DNV-RP-C204 *Design against Accidental Loads, Section 5.*

API RP 2FB API Recommended Practice: Design of Offshore Structures against Fire and Explosion Loading also provides useful guidance.

Reference is also made to the publication: LNG Risk Based Safety “Modeling and Consequence Analysis”, by Woodward and Pitblado (Wiley 2010).

3.9.6.5 Explosion

Explosion loads are characterised by temporal and spatial pressure distribution. The most important temporal parameters are rise time, maximum pressure and pulse duration.

For components and sub-structures the explosion pressure shall normally be considered uniformly distributed. On global level the spatial distribution is normally non-uniform both with respect to pressure and duration.

The response to explosion loads may either be determined by non-linear dynamic finite element analysis or by simple calculation models based on Single Degree Of Freedom (SDOF).

Detailed guidance on how to assess and design for explosion overpressures is provided in DNV Recommended Practice DNV-RP-C204 *Design against Accidental Loads, Section 6.* API RP 2FB API Recommended Practice: Design of Offshore Structures against Fire and Explosion Loading also provides useful guidance. Reference is also made to the publication: LNG Risk Based Safety: Modelling and Consequence Analysis, by Woodward and Pitblado. (Wiley 2010).

4 KEY SAFETY AND TECHNOLOGY ISSUES

4.1 Arrangement and Layout

A major contributor to safe design is to ensure that initial arrangement and layout are aimed at arriving at a final design which meets operational requirements and also will be compliant with regulations.
Typically the following principles should be taken into consideration:

- Segregation of accommodation and main working areas from the hydrocarbon processing areas
- Provision of adequate and redundant access and escape ways from normally manned areas
- Ensuring rational flow within the gas and LNG processing system
- Maintenance of availability of lifeboats
- Provision of sufficient access for maintenance and repair and replacement offshore (e.g LNG pumps)
- Permitting the installation and interconnection of modularised units
- Limiting the amount and areal extent of hydrocarbon and cryogenic spills
- Efficient installation of High Voltage cabling
- Limiting congestion and permitting ventilation to reduce explosion potential and effect
- Location of motion sensitive equipment in areas of least motion (e.g. at centreline)
- Orientation of equipment to minimize damage after failure or minimise hull-deflection effects
- Minimising or protecting against flare radiation
- Optimising sizing of fire fighting demand by fire zone design
- Optimising vent and blowdown capacity by segregation
- Limiting escalation after fire or explosion by separation distance or physical barriers (fire and blast divisions and deck coamings)
- Ensuring survivability of safety systems following an accidental event (e.g. redundancy and location of power systems, means of evacuation)
- Location of a turret with respect to safety and thrusters demand
- Meeting material handling demands

Detailing many of these issues will be based on engineering studies and various iterations of Risk Assessment in addition to regulation review.

4.2 Containment System Design

4.2.1 General

Current designs for floating offshore LNG terminals have been generally proposing containment system designs developed for use in marine transportation of LNG. In addition, there are several designs being developed which may be considered as novel, for example Aker's Aluminium Double-barrier Tank design. These also are being considered with regard to compliance with IGC requirements.

For the most part, for the typically specified tank designs, the original design remains essentially unchanged. This applies to the Moss Spherical Tank, the IHI SPB Tank, and the membrane tank designs of GTT (NO 96 and Mk 3).

There are however some special considerations which will need to be made when employing containment system designs originally developed for marine transport applications for offshore LNG applications.

These considerations include issues such as :

- Sufficient deck space to accommodate topside gas treatment and liquefaction plant
- Sufficient strength in the hull to support very large topsides
- Ability to construct and install very large tanks
- Accommodating lack of access for inspection offshore
- Developing means for safe and effective inspection, testing, maintenance and repair offshore

- Changes in load regime with regard to thermal effects, vibration, and fatigue
- Loads due to fluid movement (sloshing)
- Protection of tanks from additional accidental loads such as collision, fires and explosion overpressure
- Safety philosophies/redundancy of bulkheads adjacent to cofferdams with design temperatures based on active heating systems.
- Provision of a common venting arrangement
- Effects of vibration arising from rotating equipment

4.2.2 Containment Tank Types

The International Gas Carrier Code (IGC) designates a number of tank types. This is illustrated in Figure 4-1

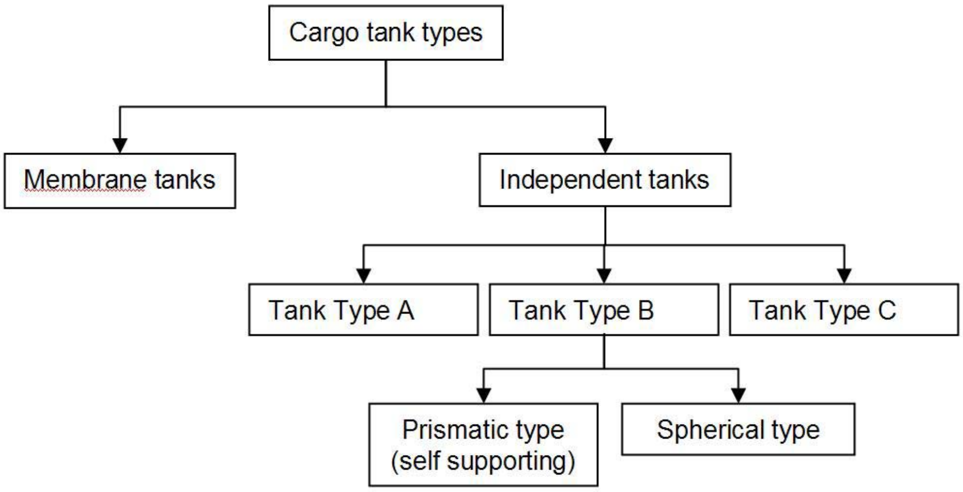


Figure 4-1: Type of cargo tanks for offshore liquefied gas terminal

A key feature which defines containment tank type is the presence and type of secondary barrier. The secondary barrier has the following functions:

- To provide temporary containment of cargo in case of leakage through the primary barrier
- To prevent the hull structure from being cooled to an unsafe level by an envisaged leakage of cargo for a certain period of time

This relates to tank type as follows:

Independent tanks

- Type A - Full secondary barrier
- Type B - Reduced secondary barrier
- Type C - No secondary barrier

Membrane tanks

- Full secondary barrier

The most commonly proposed tank types for use in FLNG applications are the Type B tanks and the Membrane tanks. These are further described below.

4.2.3 Tank type B

General

Independent tanks are self supporting and they do not form part of the ship's hull and are not essential to the hull strength (IGC code). These types of tanks are referred to as type B tanks. Independent tanks of type B are designed using model tests, refined analytical tools and analysis procedures. Where such tanks are primarily constructed of plane surfaces the design vapour pressure shall be less then 0.7 bar.

Prismatic Tank

The main principle of the B-type cargo tank is that the design is based on calculations i.e., all major properties can be verified through theoretical calculations. The quality of workmanship can be directly confirmed by NDT, checking of production tolerances and hydro pneumatic testing. The prismatic B-tank is built up of a single primary barrier, typically of aluminium or stainless steel or 9% nickel steel. The internal structure consists of typical ship hull structural elements in a plate- stiffener – girder system. The primary barrier is surrounded by an insulation system and drip trays (forming a partial secondary barrier) located near the cargo tank supports.

The design is based on detailed stress analysis, documentation of the fatigue life of the critical structural elements of the tank, crack propagation analysis and calculation of leak rates. The design principle of "leak before failure" of the tank is adopted.

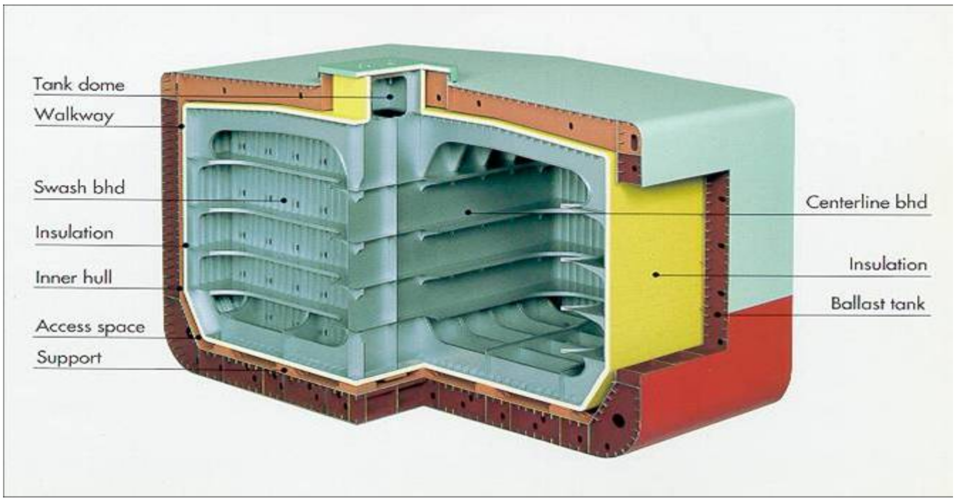


Figure 4-2: Prismatic Tank – Courtesy of IHI Marine United Inc.

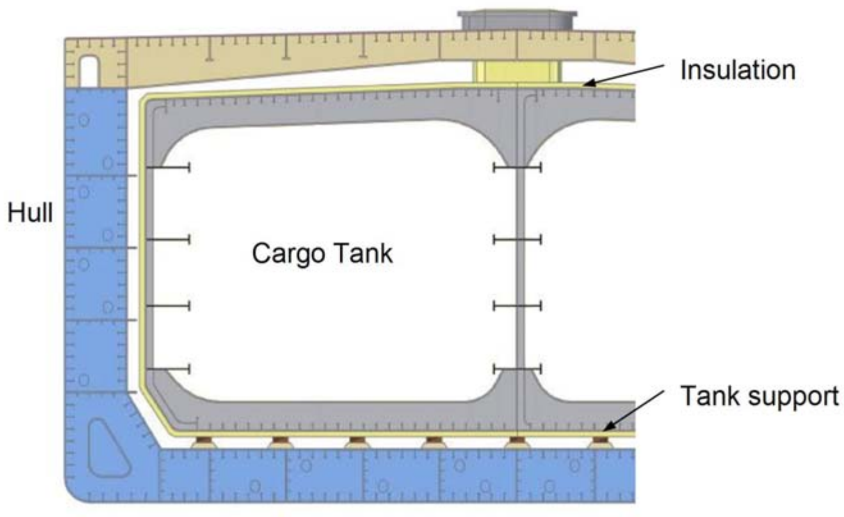


Figure 4-3: Prismatic Tank Construction – Courtesy of IHI Marine United Inc

Spherical Tank

The Spherical cargo tanks ("Moss-type") consist of a primary barrier of aluminium. An insulation system outside the aluminium barrier is installed and a drip tray under the centre of the tank forms the reduced secondary barrier. The cargo pump tower is a cylindrical construction in the centre of the tank. The key areas of the design are the equator profile, the tower with its top and bottom connections, the structural detail forming the transition between the sphere and the hull.

The spherical cargo tank is documented through detailed stress analysis, fatigue life analysis, crack propagation analysis, leak rate assessments. The design principle of "leak before failure" of the tank is adopted.

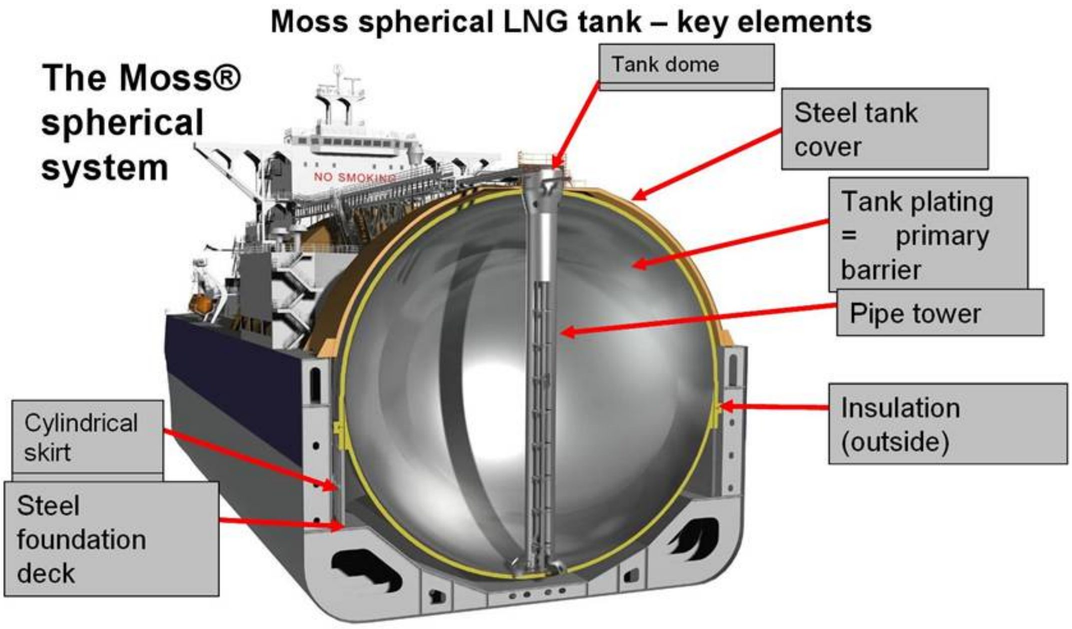


Figure 4-4: Spherical Tank – Courtesy Moss Maritime

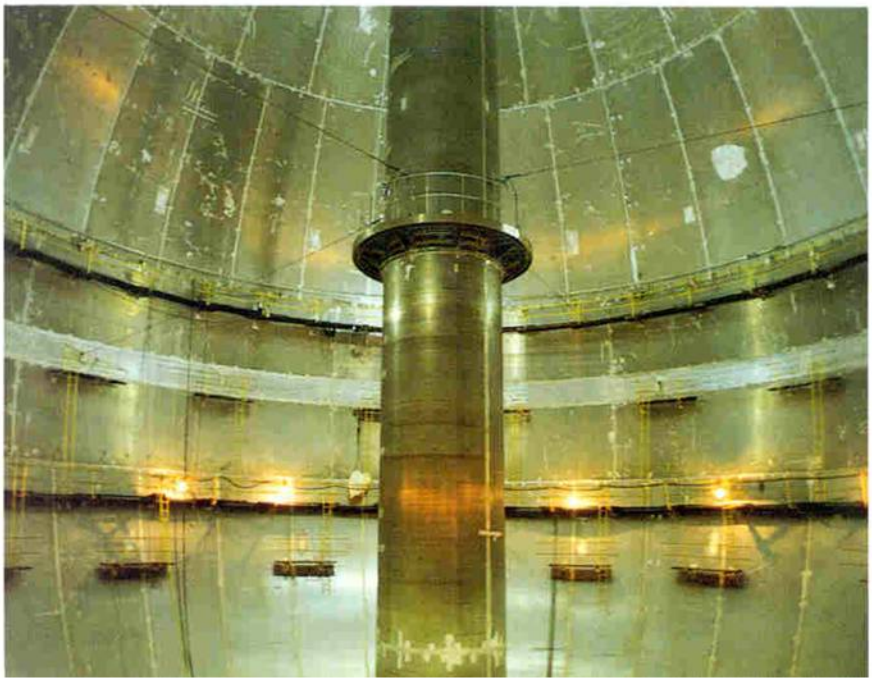


Figure 4-5: Spherical Tank – Pump Tower – Courtesy Moss Maritime

4.2.4 Membrane tanks:

Membrane tanks are non-self supported cargo tanks surrounded by a complete double hull ship structure. The membrane tanks consist of a cryogenic liner composed of primary and secondary membranes. The membrane is designed in such a way that thermal and other expansion or contraction is compensated for without undue stressing of the membrane.

Load bearing cryogenic insulation between the primary and secondary barrier and between the secondary barrier and the inner hull prevents cool down of the hull structure (and heating of the LNG) and ensures load transfer from tank to hull. The membrane cargo containment systems are to a large extent documented through testing rather than direct calculations.

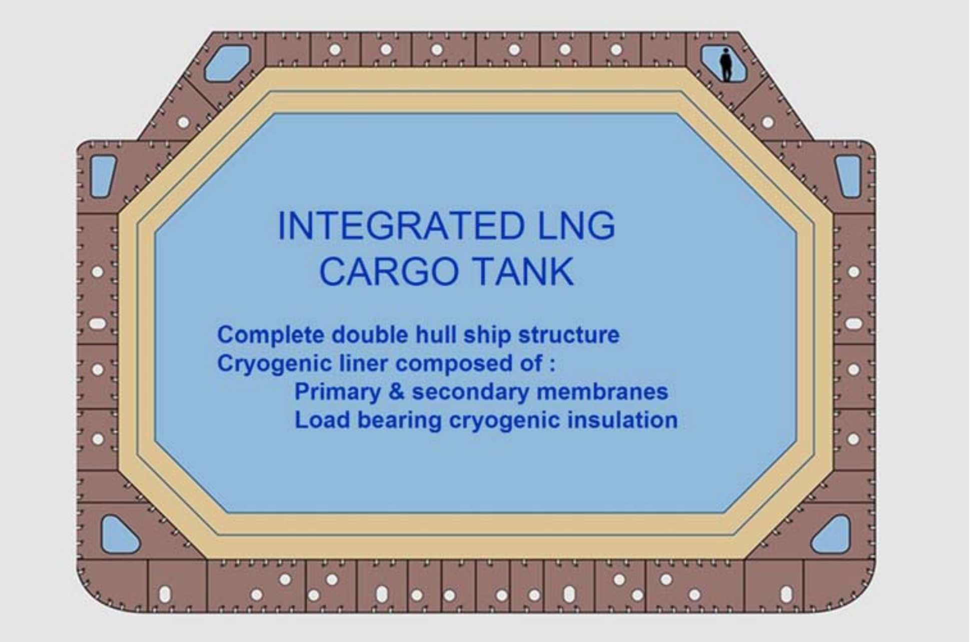


Figure 4-6: Generic Membrane Tank

The most prominent membrane systems are those developed by Gaz Transport and Technigaz (GTT).

NO96 (GTT)

The membrane system NO96 offered by Gaz Transport and Technigaz has primary and secondary membranes of invar steel. The insulation is made of plywood boxes filled with perlite.

Figure 4-7: GTT NO96 – Courtesy GTT

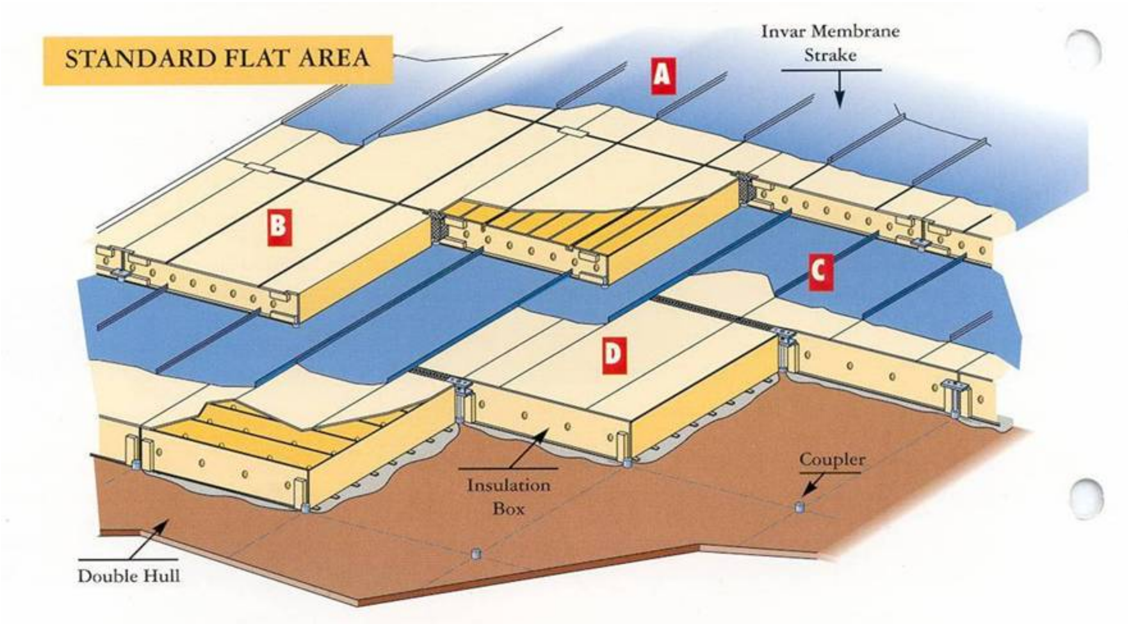


Figure 4-8: GTT NO96 Construction - Courtesy GTT

Mark III (GTT)

The Mark III system offered by GTT has a corrugated stainless steel primary membrane and a triplex secondary membrane. The insulation is reinforced foam.

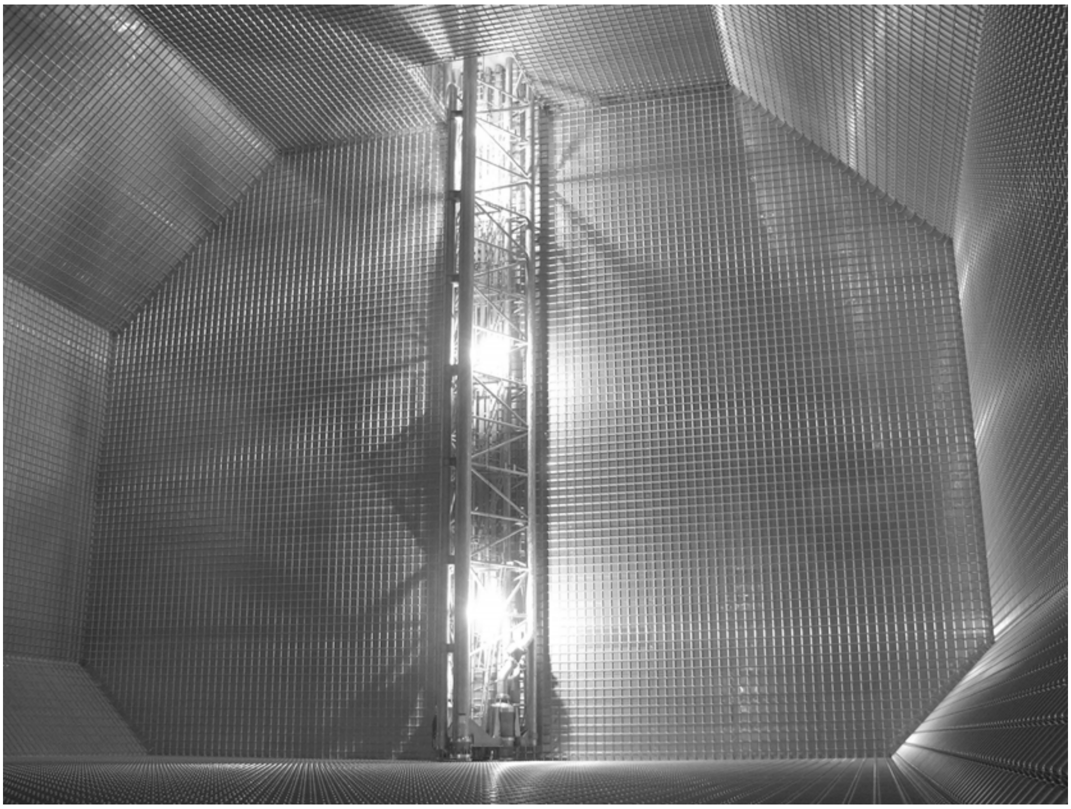


Figure 4-9: GTT Mark III - Courtesy GTT

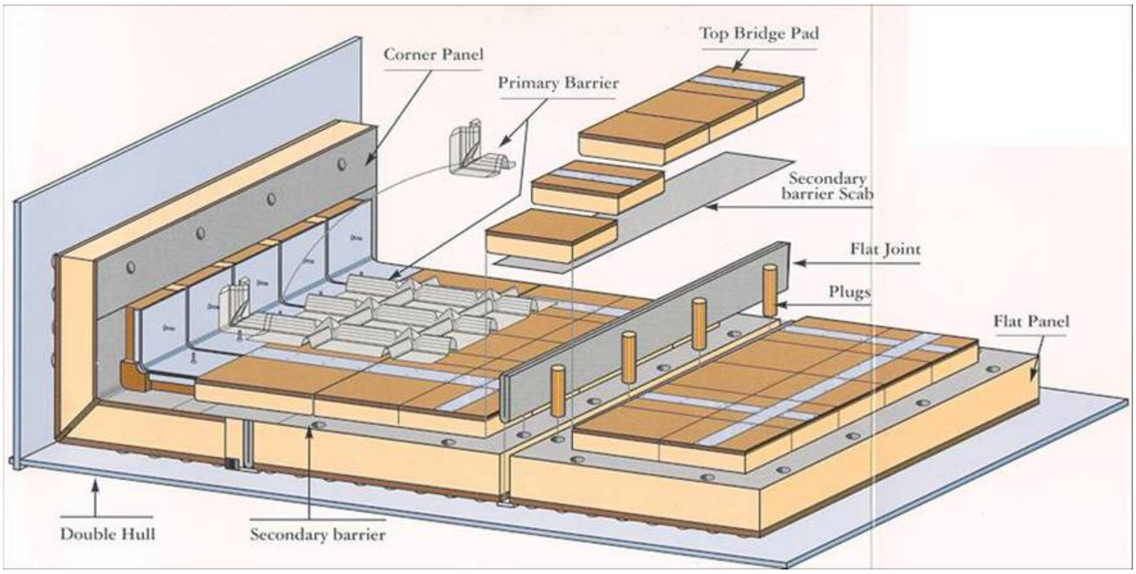


Figure 4-10: GTT Mark III Construction - Courtesy GTT

4.2.5 Classification Requirements to LNG Containment Systems

4.2.5.1 Independent Tanks – Prismatic and Spherical Type

Classification requirements and applicable design standards for the structural elements are given in Table 4-1.

Table 4-1: Classification requirements and applicable design standards

Area	Structural elements and required calculation	Rule/Standard reference
HULL	Local requirements to plates, stiffeners and girders Transverse structures (frames, bulkheads) Structures not affected by longitudinal strength Fore- and aft ship structures Superstructures and deckhouses	Rules for Classification of Ships Pt.3 Ch.1
	Hull girder longitudinal strength (ULS)	DNV-OS-C102
	Transverse strength FE analysis Local strength FE analysis	Rules for Classification of Ships Pt.3 Ch.1
	Fatigue strength of hull	DNV CN No. 30.7 or DNV-OS-C203
	Temperature calculation for material selection of hull due to a cold temperature of LNG and LPG	Rules for Classification of Ships Pt.5 Ch.5 Sec.2 B
TOPSIDE & TOPSIDE SUPPORTING STRUCTURES	Local requirements to plates, stiffeners and girders Global strength of module structures ULS and FLS of topside supporting (hull interface) structures including hull affected by topside modules ULS and FLS of other offshore specific structures (e.g. flare tower, turret, gantry, crane pedestal, etc)	DNV-OS-C102

Area	Structural elements and required calculation	Rule/Standard reference
CARGO TANK AND TANK SUPPORT	Damage stability and cargo tank location Wave load analysis Local requirements to plates, stiffeners and girders of cargo tank (prismatic) ULS and FLS of cargo tanks and tank supports (prismatic) Crack propagation analysis Sloshing analysis Thermal analysis Vibration analysis Reduced secondary barrier (leakage rate calculation) ULS and FLS of pump tower (spherical) ULS and FLS of skirt structures (spherical)	Rules for Classification of Ships Pt.5 Ch.5 IGC Code Classification Note for Type B tank (2011)
LPG CARGO TANKS	Local requirements to plates, stiffeners and girders of cargo tank ULS of cargo tanks and tank supports (vertical, transverse, longitudinal and anti-floating supports) ULS of tank support and hull interface	Rules for Classification of Ships Pt.5 Ch.5 IGC Code Classification Note for Type C tank (2011)
CONDENSATE TANKS (integral)	Local requirements to plates, stiffeners and girders of condensate tank Transverse strength FE analysis Local strength FE analysis Fatigue strength	Rules for Classification of Ships Pt.3 Ch.1

4.2.5.2 Membrane Tanks

Classification requirements and applicable design standards for the structural elements are given in Table 4-2.

Table 4-2: Classification requirements and applicable design standards

Area	Structural elements and required calculation	Rule/Standard reference
HULL	Local requirements to plates, stiffeners and girders Transverse structures (frames, bulkheads) Structures not affected by longitudinal strength Fore- and aft ship structures Superstructures and deckhouses	Rules for Classification of Ships Pt.3 Ch.1
	Hull girder longitudinal strength (ULS)	DNV-OS-C102
	Transverse strength FE analysis Local strength FE analysis	Rules for Classification of Ships Pt.3 Ch.1
	Fatigue strength of hull	DNV CN No. 30.7 or DNV-OS-C203

Area	Structural elements and required calculation	Rule/Standard reference
	Temperature calculation for material selection of hull due to a cold temperature of LNG or LPG	Rules for Classification of Ships Pt.5 Ch.5 Sec.2 B
TOPSIDE & TOPSIDE SUPPORTING STRUCTURES	Local requirements to plates, stiffeners and girders Global strength of module structures ULS and FLS of topside supporting (hull interface) structures including hull affected by topside modules ULS and FLS of other offshore specific structures (e.g. flare tower, turret, gantry, crane pedestal, etc)	DNV-OS-C102
CARGO CONTAINMENT SYSTEM (CCS)	Damage stability and cargo tank location Sloshing analysis ULS of containment system, e.g. insulation box, etc. ULS and FLS analysis Pump tower and pump tower base support Liquid & gas dome area Risk assessment of CCS failure Hull – CCS compatibility requirements, stiffness and strength of hull structure	Rules for Classification of Ships Pt.5 Ch.5 IGC Code DNV CN No.30.9 DNV CN No.31.9 Design requirements given by CCS designer
LPG CARGO TANKS	Local requirements to plates, stiffeners and girders of cargo tank ULS and FLS of cargo tanks and tank supports (vertical, transverse, longitudinal and anti-floating supports) ULS and FLS of tank support - hull interface	Rules for Classification of Ships Pt.5 Ch.5 IGC Code Classification Note for Type C tank (2011)
CONDENSATE TANKS (integral)	Local requirements to plates, stiffeners and girders of condensate tank Transverse strength FE analysis Local strength FE analysis Fatigue strength	Rules for Classification of Ships Pt.3 Ch.1

4.3 Sloshing in Containment Tanks

An issue which is receiving much attention is that of sloshing which becomes more relevant for offshore applications operating at all filling levels, as opposed to marine transportation applications which operate normally with tanks either essentially full or empty.

Liquid sloshing is a design consideration for all cargo tanks designed to carry liquids, and in particular for the large size tanks normally used to carry LNG. The structural design challenges related to liquid sloshing are:

- wave impact on tank walls
- wave impact on internal structure in the tank such as large stringers and girders where relevant
- hydrodynamic drag forces on internal structure in the tank such as pump towers and large stringers/girders

Cargo tanks designed for ship application can generally not be directly applied in offshore LNG units, although the required level of modification varies largely between tank technologies and depends on the operational conditions. This will be discussed in more detail for the main tank technologies considered for offshore LNG application, i.e. Moss type spherical tanks, Mark III and NO96 type membrane tanks, and the IHI prismatic type B independent tank (SPB).

From a sloshing point of view the main difference for a tank onboard an offshore LNG unit compared to one in a ship is the requirement to sustain operation with partial filling. Whereas this is a rare, and for some tank types, a prohibited operational mode for a tank in a gas carrier, it is the normal operational mode for a tank installed in an LNG production or regasification vessel.

A partially filled tank is more exposed to liquid sloshing than a tank that is operated with high filling level. This applies to both prismatic and spherical tanks, and is caused by a combination of a change of the flow phenomena that occur in the tank and more unfavourable relationships between the sloshing resonance periods, the dominating wave periods encountered at sea, and in particular the roll resonance period of the vessel. Figure 4-11 illustrates how the transverse liquid motion resonance period in a typical prismatic tank changes with tank filling height, and how this resonance corresponds to a typical distribution of wave periods encountered on a site. A typical roll resonance period for an LNG carrier with partially filled tanks is also included in the figure for illustration. Similar quantities for a Moss type tank are shown in Figure 4-12.

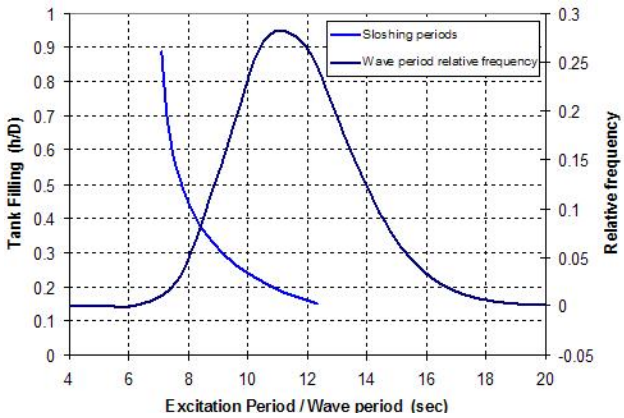


Figure 4-11: Liquid motion resonance period for a prismatic tank as a function of liquid level compared with a probability distribution of wave period content at a typical site

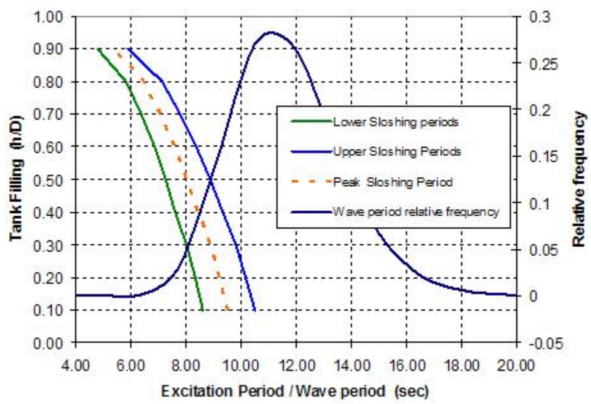


Figure 4-12: Liquid motion resonance period for a 42 meter diameter spherical tank as a function of liquid level compared with the relative wave period frequency at a typical site

Whether or not sloshing is a problem will be influenced by the ship design, the area of operation and the mode of operation. For example application of active measures such as cargo management, heading control, use of a combination of tank types which includes one not sensitive to sloshing, are all measures which can be considered.

Moss Spherical Tanks. From a sloshing point of view the Moss spherical type B cargo tanks are well suited for LNG FPSO or FSRU application. These tanks are approved by DNV for unrestricted filling and navigation on board gas ships. Model tests and numerical simulations show that sloshing can be significant also in these tanks, and in particular for intermediate tank fillings, but sloshing impact pressure is insignificant due to the spherical shape of the tank shell. The cylindrical pump tower in the tank has been designed to sustain the extreme combination of inertia and sloshing loads expected to occur during the operation of the vessel. However, as continuous operation with partially filled tanks has not been anticipated for normal trading carriers, the long term fatigue effect of the combined inertia and sloshing loads acting on the tower during partial filling operation has not been previously specifically considered.

Use of Moss type LNG tanks on LNG FPSO or FSRU newbuilding or conversion will therefore require assessment of the fatigue design of the pump tower and its supports on the tank shell as indicated on Figure 4-13. Locations 1 and 2 should be checked by conventional fatigue analyses as well as fracture mechanics analysis to ensure that a potential through-thickness crack has a stable growth rate during a period required to empty the tank. The length of this period should be determined based on an evaluation of the operation of the vessel. Site specific environmental conditions should be considered.

The implications on the design of the tower and its supports depend on the site specific environmental conditions and the operation of the vessel. Operational parameters that will affect the assessment are:

- Wave heading probability distribution for the vessel
- Tank filling height distribution

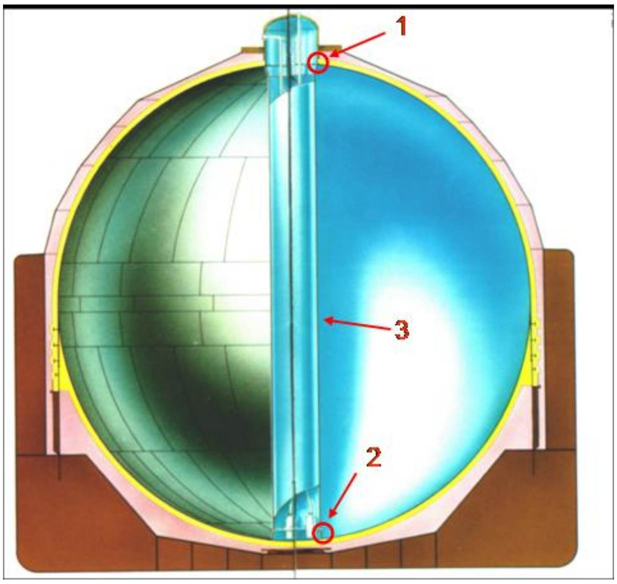


Figure 4-13: Locations in pump tower and pump tower supports that require particular attention for partial fill operation

The fatigue and fracture mechanics analyses required to document compliance with acceptance criteria are well known and used throughout the design of the spherical tanks. The technical challenge is to determine the relevant fatigue load spectrum including the combined effect of inertia and sloshing loads.

As mentioned earlier the environmental conditions on the sites relevant for operation of an offshore LNG unit are often benign and significantly less severe than the ship tank design scenario specified in the IGC Code (IMO 1993). Experience to date for the conversion of Moss type LNG carriers to regasification units is that the partial filling operation has not required any redesign of the cargo tank structure.

Prismatic Type B Tanks

Independent prismatic type B cargo tanks (SPB) are similar in size and shape as membrane tanks, and will experience significant sloshing unless fitted with sufficient internal structure to limit sloshing motion. Peak impact pressure on tank boundaries is not expected to reach the same levels as in membrane tanks as stiffeners and girders will disturb the free surface of the LNG prior to impact. Peak pressures are also generally localised, and are hence not so critical for a stiffened panel structure. However, it is expected that large girders in the tank may experience significant loads. SPB tanks do not have internal pump towers that require particular attention for partial fill operation.

The structural arrangement of an SPB tank is very similar to integral tanks in ships and oil FPSOs, except that such tanks are smaller and/or built with internal swash bulkheads to limit liquid sloshing. There is significant successful experience with partial filling operation of such tanks. Based on this experience DNV considers that SPB-tanks fitted with longitudinal and transverse swash bulkheads and a design according to rule based sloshing loads are suitable for partial fill operation.

For tanks built without swash bulkheads it is considered necessary to carry out dedicated sloshing studies to document the suitability of the tank. This can involve model tests or numerical analysis, depending on the tank configuration, operational conditions, and relevant hazards.

4.3.1 Membrane Tanks.

Membrane tanks are particularly susceptible to liquid sloshing due to their large dimensions and open interior. The smooth surface of these tanks does not significantly disturb the front of an approaching wave prior to impact, and peak impact pressures can therefore reach extremely high levels. This is in particular the case for tank fillings in the range $b/H \sim 0.15$ – $b/H \sim 0.3$ for quartering and beam sea operation of the vessel. The latter is a result of the larger ship motion in beam compared to head waves for the sloshing resonance wave periods.

For the reasons mentioned above the operation of membrane tanks in shipping applications are normally subject to filling restrictions. Ships classed for unrestricted navigation are required to keep tank filling above 70% of tank height or below 10% of tank height. The lower limit has been reduced from 10% of tank length recently due to sloshing related damage incidents.

The sloshing related hazards for membrane LNG tanks are:

- Structural damages to the load carrying insulation caused by sloshing impact potentially causing damage to membranes/loss of liquid tightness and/or loss of insulation efficiency
- Structural damages to the inner hull structure supporting the insulation with potential damage to the liquid tightness of the membranes or ballast water ingress into the insulation space
- Structural damage to pump tower and pump tower supports potentially causing puncturing of membranes (loose objects) or loss of cargo management functionality

Sloshing analyses and damage experience both for Mark III and NO96 membrane systems imply that the applicability of standard size and standard insulation membrane tanks is limited to sites with very limited wave action. Existing or planned regasification units use reinforced versions of the Mark III and NO96 insulation systems to increase the operability of the vessels. Wave height restrictions will still be required on most sites to keep the risk of structural damages due to sloshing within acceptable limits.

Wave height restrictions should be determined based on strength assessment of the cargo containment system. The impact pressure resistance of the insulation system is considered to be the limiting factor in this assessment. Design of pump towers and inner hull structure is more flexible, and can be adapted.

The insulation system strength assessment should be based on the long term distribution of sloshing impact loads in the tanks of the vessel considering the site specific environmental conditions and realistic values of the key operational parameters that affect the sloshing intensity, which are:

- Wave heading probability distribution
- Tank filling probability distribution
- Tank filling/discharge sequence/strategy

Sloshing impact loads should be determined using sloshing model tests. A challenge in model testing has been to determine the scaling factor for pressures measured in model scale to prototype scale. This is still not fully resolved, but investigations of incidents that have led to membrane/insulation damages on Mark III and NO96 LNG carriers have confirmed that the methodology currently used by DNV is reasonable and conservative.

There are currently no accepted suitable numerical simulation methods to solve this problem. CFD tools are not able to accurately predict the sloshing induced impact pressures without a prohibitive computational effort, i.e. it is impractical to conduct the long duration analyses required to establish the long term statistics.

Current experience with FLNG units with conventional tank configuration indicates that they will be subject to wave height restrictions in the range 3-6 meters significant wave height depending on site conditions, type of containment system, and wave heading control. As indicated above, beam sea conditions are severe and the exposure should be limited by using appropriate mooring arrangements and possibly active heading control. Sites exposed to significant swell that are non collinear relative to wind generated waves can be a particular challenge for such vessels as this can lead to situations with beam sea exposure.

The wave height restrictions for a tank normally refer to operation in the most sloshing-critical filling ranges (h/B~0.15 - h/B~0.30). Tanks can sustain more severe conditions in other filling ranges, and the operational limits for the vessel can hence be increased by carefully planned operation and cargo management. This will require that the operational limits of the tanks in other fillings are explored in detail. To increase the robustness of such an approach, vessel and cargo tank designers have proposed to introduce a cargo tank with increased sloshing performance that can be used during encounter of environmental conditions beyond the minimum restrictions of the conventional cargo tanks.

The most efficient measure to reduce sloshing effects and to increase the operability of vessels is to reduce the dimensions of the tanks. Designers of membrane type offshore LNG units have therefore proposed alternative ship arrangements with two parallel rows of cargo tanks as illustrated in Figure 4-14.

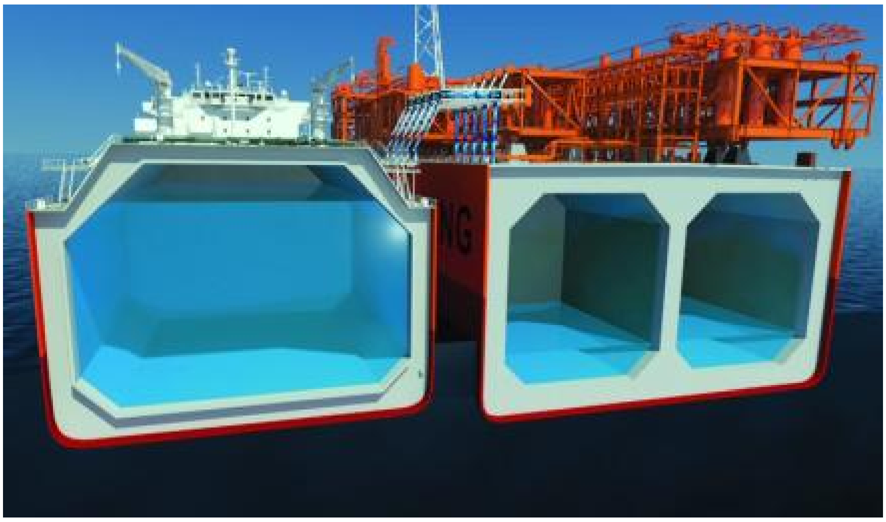


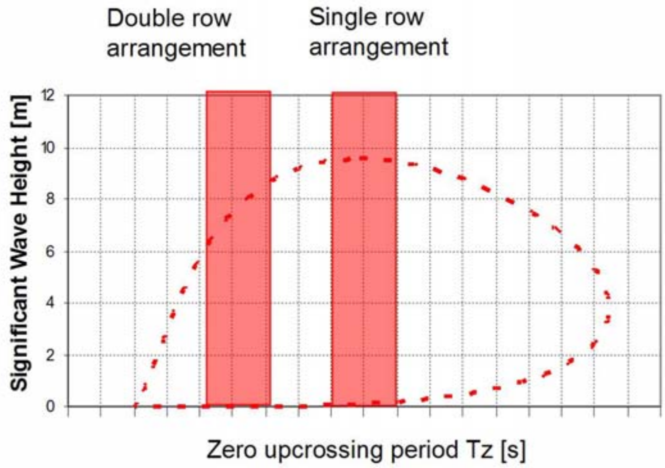
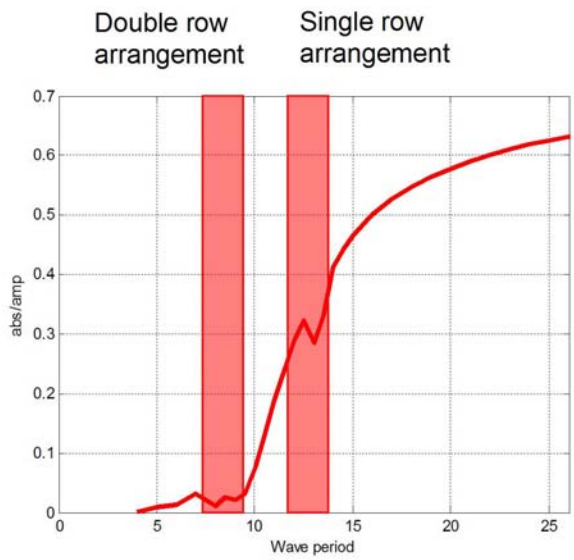
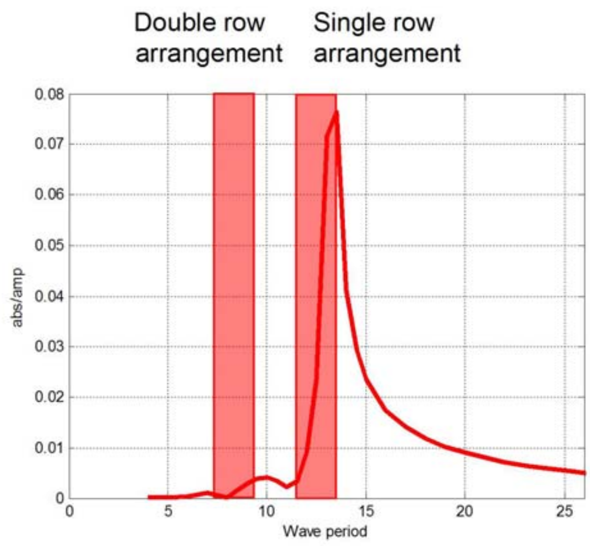
Figure 4-14: Illustration of the two tank row arrangement – Courtesy of Höegh LNG

The smaller tank has three main benefits, all related to the reduced liquid motion resonance period of the tank:

- Reduced probability of resonant wave encounters
- Reduced ship motions with unfavourable motion period content
- Reduced influence of vessel roll

(Note however the design also introduces the possibility of low temperature exposure of the centre longitudinal bulkhead, which will need to be addressed in material specification or equivalent safety measures.)

The positive effects on sloshing are illustrated in Figure 4-15, where diagrams 2 and 3 illustrate sway and roll response amplitude operators for a vessel. DNV has in cooperation with the cargo containment system designer and a ship owner carried out a sloshing assessment of an LNG FPSO based on such a tank arrangement. The assessment did not identify any operational restrictions due to sloshing for any of the considered sites. The site with the most severe environmental conditions had a maximum 20 year return period significant wave height of approximately 10 meters.

1	
2	
3	 **Figure 4-15: Illustration of the beneficial effects of reduced cargo tank dimensions**

Pump towers and inner hull structures supporting the insulation system in membrane type FLNG units must be designed to sustain the sloshing loads encountered during operation within the operational envelope defined by the insulation system.

Pump towers in membrane tanks are designed as truss works, and are therefore different from the towers in spherical tanks. The sloshing load assessment methodology, in particular for the design of the top and bottom supports, will nevertheless be very similar as for a spherical tank. Design load assessments for the local truss members and tubular joints are more complicated and require a somewhat different approach.

Procedures for containment system, pump tower, and inner hull sloshing load and strength assessment for membrane tanks can be found in DNV Classification Note 30.9.

4.4 Regasification Plant

There are a number of different technologies used in order to vaporise LNG.

Land-based technology has typically used vaporization technology based on either water heating or fuel-fired heating.

Open-loop water-based systems (e.g. Open Rack Vaporisers) are typically used as the heating medium where warm water is available in sufficient amounts throughout the year and at locations where discharge of cold water is permitted.

Direct fired heaters, typically using natural gas as a fuel (e.g. Submerged Combustion Vaporisers), have also been used and can be appropriate for locations with cold climates with cold sea water temperatures during some periods of the year.

For offshore installations, especially those proposed for US waters, permitting issues have been raised with regard to these technologies, so that other solutions are typically proposed.

Use of seawater in offshore applications will typically involve large volumes of water and also use of biocides. In addition an open-loop system will release lower temperature water back into the local environment. All of these factors have a potential to impact the marine environment in the short term and also possibly in the long term. Permitting will normally require that these issues are addressed in an environmental study. Measures to address these issues will include controlling water intake velocity and intake mesh size to reduce ingestion of marine organisms, limitations on biocides, and limitations on sea-water temperature drop.

Use of direct-fired vaporisers offshore has been questioned due to the production of CO_2 and air pollutants in the fuel burning process and also due to the amount of energy required in terms of fuel consumption.

Intermediate fluid systems using seawater with glycol, propane or proprietary fluid as intermediate fluid have been developed and are currently in operation on FSRUs. An intermediate vaporizer design using propane is illustrated in Figure 4-16.

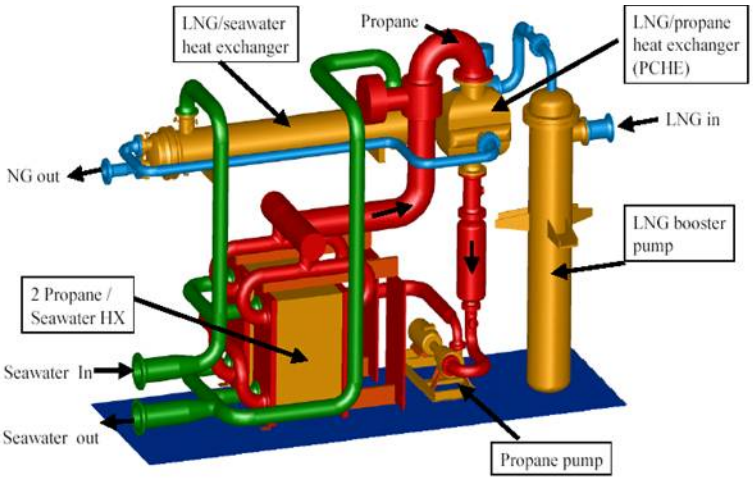


Figure 4-16: Intermediate Fluid Vaporiser – Courtesy Hamworthy Oil and Gas Systems

Air based systems have also been developed and are considered feasible.

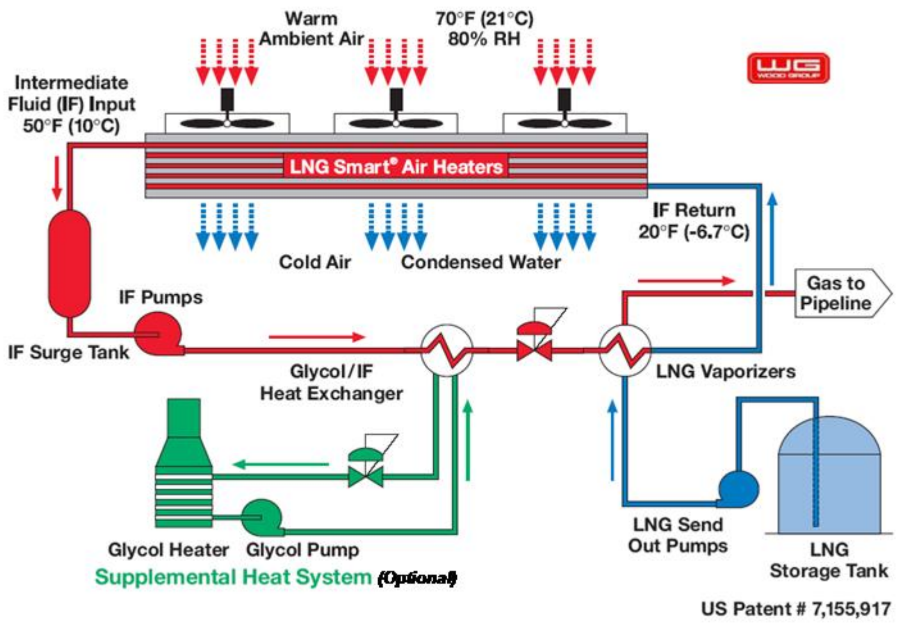


Figure 4-17. Air Intermediate Fluid Vaporiser – Courtesy Wood Group/Mustang Engineering

Typical hazards to be specifically considered with respect to regasification units are release of LNG or gas with subsequent fire or explosion or cryogenic leakage cracking effects.

Requirements to design of regasification plant are given in DNV Classification Note 61.3 *Regasification Vessels*.

4.5 Gas Treatment and Liquefaction Plant

4.5.1 General

The overall purpose of an LNG FPSO is to produce LNG and, depending on feed gas composition, LPG and stable Condensate as by-products. The technology in use on existing Oil FPSOs and LPG FPSOs such as turbines, compressors, towers and separators means that there is already a body of experience for a large number of already proven components that will also be applicable for an offshore LNG FPSO.

The wellstream may entrain solid particles (sand) which will need to be monitored, controlled and removed to limit erosive damage.

Natural gas from an offshore wellstream typically contains water and gas condensate which will need to be removed before processing of the gas. Where these liquids may form slugs the process plant will need to be protected by installation of a specially designed slug catcher at the inlet to the plant. Any liquids will typically be removed in a separator by gravity. Such liquids need to be removed to prevent formation of solid gas hydrates that may block pipeline flow or affect control systems. Water vapour will also need to be removed to prevent later freezing during the liquefaction process. This further removal of water from the wet gas is referred to as dehydration.

Natural gas may also contain sour gases such CO_2, H_2S, CO that may represent a corrosion hazard or hinder the liquefaction processes. Removal of such gases is often referred to as gas sweetening. CO_2 removal is also necessary in avoiding CO_2 freeze out on exchanger surfaces or plugging of lines that may reduce plant efficiency.

For liquefaction processes using aluminium as a material in the process system (typically heat exchangers), limits would also be set for maximum Mercury content (Hg) in the gas. This requires also systems for Mercury removal.

In addition to the above parameters, there are also LNG product specifications that need to be met. These could include Higher Heating Value (HHV) which is related to the percentage NGL products in the gas composition or environmental requirements (max H_2S content etc) set by the end user. The NGL separation would typically apply a fractionation process which gives sharper separation than a series of (horizontal) separator flashes. This would normally be located downstream of the gas sweetening and dehydration plant.

Compared to available liquefaction processes used in onshore LNG plant, offshore alternatives will typically need to be more compact, light and with higher inherent process safety. The additional constraints such as vessel motion due to marine environment also requires a high degree of modularity, ease of operation, low equipment count, quick start-up and high availability. The size of the FLNG and the complexity of the process selected will also have congestion and equipment density issues which will affect safety.

The following guidance divides the gas processing and liquefaction plant into the following main areas:

- Receiving area
- Pre-treatment area
- Gas sweetening
- Dehydration and mercury removal
- Fractionation
- Liquefaction area

Typically, these would be divided either by distance or fire (blast) walls, and process segmenting (ESD, PSD). Reference is made to Figure 4-17.

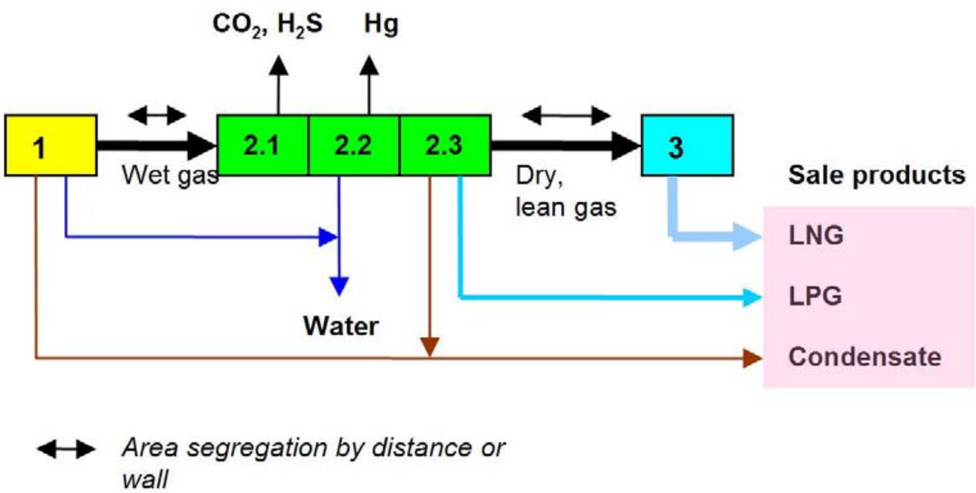


Figure 4-17: Example of a process layout for an LNG FPSO

A typical LNG production flow diagram is presented in Figure 4-18 below.

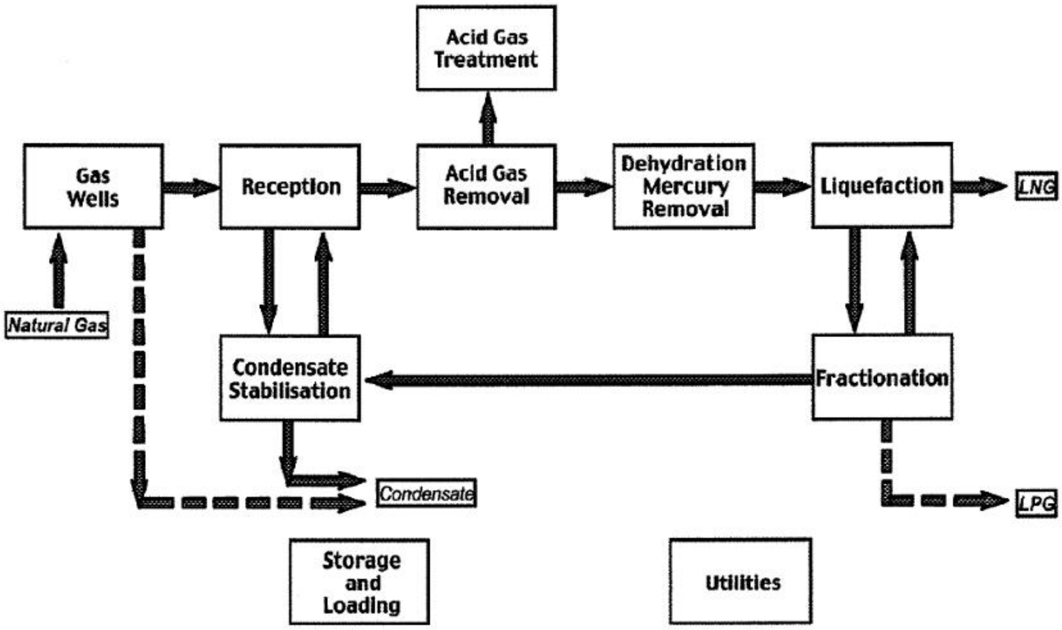


Figure 4-18: Typical LNG Production Flow Diagram

The following sub-sections will give a brief discussion for each of the areas 1, 2 and 3 identified in Figure 4-17.

4.5.2 Receiving area

4.5.2.1 General

The receiving facilities would typically comprise equipment for separation of well fluids into wet gas, condensate and produced water, the relative amount of which will depend on the composition of the well stream. Any class requirements for safety requirements for this system would normally be met by the DNV Offshore Standard DNV-OS-E201 which also applies to equivalent systems on Oil FPSOs.

4.5.2.2 Solids in gas flow

Depending on the reservoir and flow characteristics solids may be produced from the gas well. An assessment will need to be made of the criticality of erosive solids (sand/fines) produced from the reservoir on piping systems and components. Critical components might include Xmas Trees, swivels and piping sections. Erosion will lead to gradual loss of wall thickness due to the erosive character of the produced solids.

The erosion rate will be influenced by factors such as:

- Bulk flow velocity
- Fluid density
- Particle size

An erosion analysis may be performed with reference to the DNV-RP-O501 *Erosive wear in piping systems*.

4.5.3 Gas pre-treatment facilities

4.5.3.1 Sweetening / acid gas removal

The removal of sour gases such as CO_2, H_2S would most typically be based on one of the following concepts:

- Adsorption on a solid (dry process),
- Absorption into a liquid (wet process) or
- Physical Separation (membrane).

There are several factors that may influence the choice of process, however, for the most LNG FPSO concepts with NGL extraction the amine absorption process would be the preferred one. The amine process is well known to the industry and involves a contactor (absorber column) and a stripping cycle where the absorber (amine) is freed from the "recovered" gases, H_2S and CO_2. Target levels of CO_2 would be below 50 ppmv. (Membrane technology is currently considered as not proven and would be subject to technology qualification program for any offshore application).

The application offshore for LNG liquefaction is new, and hence more extensive documentation of equipment and internals may be relevant in any approval process with respect to vessel motion and process upsets. Experience gained with equivalent systems on LPG and oil FPSOs would be a useful reference.

The amount of hydrocarbon remaining in the rich amine stripping cycle would also be subject to assessment with respect to possible leaks and escalation effects especially in congested areas with limited natural ventilation compared to onshore use.

The environmental and any human health issues regarding amine leakage should also be assessed.

In addition the gas composition may mean that quite high concentrations of CO_2 (e.g more than 10% by volume) may need to be accommodated. Disposal of large amounts of CO_2 to the atmosphere may not be desirable or permitted by regulation, so that an adequate arrangement for disposal (e.g. by re-injection) may be necessary.

4.5.3.2 Dehydration (water removal)

Dehydrators are commonly used in LNG liquefaction plants upstream of the cryogenic section to prevent formation of hydrates in the Cold Box.

Whereas the most common dehydration method used on oil FPSOs is use of a glycol contactor (i.e. based on absorption), a more effective means is required for an FLNG as a means to obtain the very low water content (0.5 ppmv or less) that is required for the low temperature processing for NGL extraction and liquefaction of the natural gas. Technology based on adsorption is typically specified.

Solid bed dehydration is seen as the preferred alternative as such units are unaffected by vessel motions and have a relatively small footprint. Typically a molecular sieve is the most common adsorbent technology for LNG plants due to the low outlet water dew point and its effective capacity. Molecular sieves also offer a means of simultaneous dehydration and desulphurisation and may therefore also contribute to the H_2S removal.

As this is a dry desiccant system, with vertical towers, it is not expected to be particularly susceptible to motion offshore, however the internal filling with mol sieve / ceramic balls etc will need to consider the movement of vessel and vibration during offshore service.

4.5.3.3 Mercury Removal

Mercury removal systems are commonly used in LNG liquefaction plants upstream of the cryogenic section to prevent potential corrosion of aluminium Heat Exchangers in the Cold Box.

It is normally specified that such heat exchangers used in the liquefaction process should not be exposed to more than 0.01 microgram/Sm^3 in the dehydrated gas. Typically a mercury bed filter is fitted downstream of the molecular sieve dehydrator for size optimization and bed life purposes.

Such filters need physically to be replaced at certain intervals, and hence the material handling and health and environmental impact due to the mercury content need to be part of a safety assessment.

4.5.3.4 NGL separation (fractionating plant, LPG removal)

The presence or absence of LPG in the feed gas, and its quantity, will be an important factor in the economics of an FLNG project. Since the calorific value of the end product will be an important specification, LPG content will need to be controlled and plant will need to be installed to achieve this. A high LPG content will then be an advantage as a valuable product in sufficient quantity can be produced for sale. LPG may also be used as fuel to create the power to meet the large power demand necessary for the liquefaction process. A low LPG content on the other hand may represent a significant cost to remove but not be of sufficient volume to provide a balancing income.

As previously stated, the preferred separation method for removal of LPGs is fractionation.

Typically, there would be a need to split LPG distillate (C3-C4) from the condensate products (C5+). The fractionating plant would then include a de-ethanizer and a de-propanizer (or fractionator) where inlet gas to the de-ethanizer is pre-cooled by either heat exchange against a sub cycle from the liquefaction refrigeration module or possibly a compressor/expander arrangement. The second alternative increases the effect necessary to recompress the dry gas before liquefaction, while the first method would increase the refrigeration capacity for refrigeration plant. There are however various methods in the market that may optimize this process differently. There is currently experience from a small number of LPG FPSOs in operation.

4.5.4 Gas liquefaction

The liquefaction section is the heart of the topside process. The processes involved in cooling the clean feed gas in succession are usually split into Pre-cooling, Liquefaction and Sub-cooling) to -161 C using mechanical refrigeration. High process efficiency remains an important selection criterion when it comes to choice of liquefaction process. Poor efficiency would for example give rise to need for increased utilities and compressor capacity.

The stages of liquefaction are:

- Pre-cooling
  - Typically -20-50°C
- Liquefaction
  - Typically -70-90°C
- Sub-cooling
  - Typically -150-160°C
- Expansion
  - Storage temperature -160-163°C

For highest efficiency the refrigerant curve should follow that of the natural gas cooling curve as closely as possible, as illustrated in Figure 4-19.

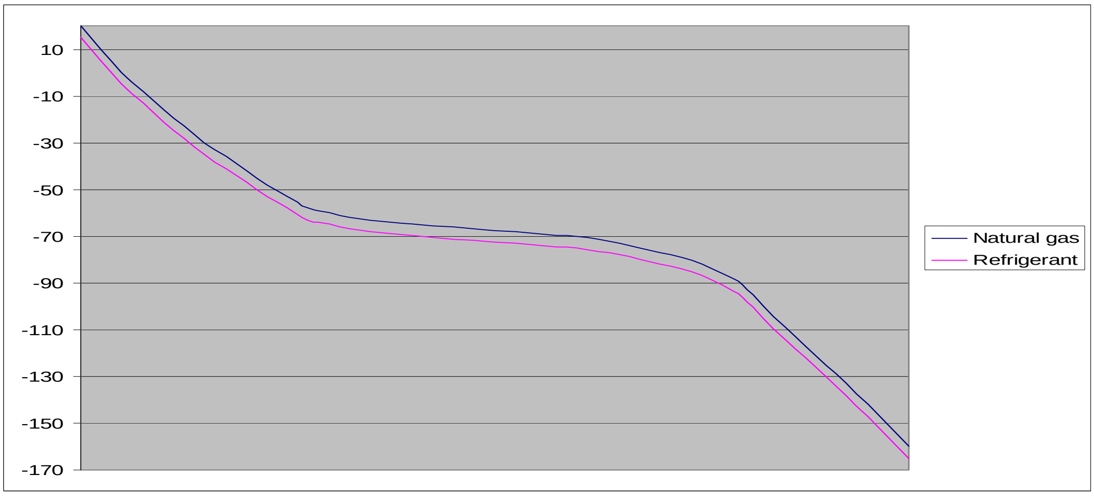


Figure 4-19 Ideal Cooling Curve

The three main liquefaction technologies are:

- Mixed refrigerant processes (MR)
- Cascaded refrigerant processes
- Expander processes

The Mixed-refrigerant cycle

The mixed-refrigerant cycle (MR) uses a single mixed refrigerant, its mixture composition specified so the liquid refrigerant evaporates over a temperature range similar to that of the natural gas being liquefied. A mixture of nitrogen and hydrocarbons (usually in the C1 to C5 range) is normally used to provide optimal refrigeration characteristics (i.e., close matching of composite warming and cooling curves), with small temperature driving forces over the whole temperature range.

The Cascade cycle

In contrast to the mixed-refrigerant cycle, the cascade cycle uses multiple pure refrigerants. The natural gas is cooled, condensed and sub-cooled in heat exchange with propane, ethylene (or ethane) and finally methane in three discrete stages. The three refrigerant circuits generally have multistage refrigerant expansion and compression, each typically operating at three evaporation temperature levels. After compression, propane is condensed with cooling water or air, ethylene is condensed with evaporating propane and methane is condensed with evaporating ethylene.

The Expander cycle

In its simplest form, compression and work-expansion of a single-component gas stream provides process refrigeration. High-pressure cycle gas is cooled in counter-current heat exchange with returning cold cycle gas. At an appropriate temperature, the cycle gas is expanded in a near isentropic manner through an expansion turbine, reducing its temperature to a lower temperature than would be given by expansion through a Joule-Thomson valve. Useful work is generated, which is normally recovered through a booster compressor brake, which supplements the main-cycle compressor.

The cold, low-pressure gas stream from the expander is returned through various stages of heat exchange, where its refrigeration is given up to the incoming natural gas and incoming cycle gas. The main-cycle compressor and booster compressor recompresses the gas. The refrigerant cycle gas used can be methane or nitrogen. Using nitrogen allows sub-cooling to temperatures low enough to eliminate flashing gas when the LNG is let down.

There are a number of variants of these techniques such as : Mixed Fluid Cascade Technology (MFC) used by Statoil on Melkøya, Dual Mixed Refrigerant Technology (DMR) used by Sakhalin LNG, and Propane Pre-cooled Mixed Refrigerant plus Nitrogen Expander Technology, and Pre-cooled Nitrogen expander technology, Dual Nitrogen Expander technology.

There will be special consideration with regard to selection of a technology for offshore application. Such considerations would include :

- Production capacity
- Cost
- Power consumption
- reliability
- Efficiency
- Footprint and available deck space
- Variation in gas composition
- Turndown capability
- Equipment count
- Congestion and confinement
- Performance with vessel motion
- Hydrocarbon inventory in the system
- Storage and handling of coolants and associated hazards

Selection of a particular technology will impact the vessel design in terms of layout, structural support and level of accidental loads to be considered.

Process system safety is addressed in DNV-OS-E201 *Hydrocarbon Processing Plant*.

General safety is addressed in DNV-OS-A101 *Safety and Arrangement*.

4.6 Handling of BOG/Pressure Control

Heat (and other energy) transferred to the LNG in the tanks will cause boil off gas (BOG) or increased liquid temperature and corresponding increased pressure.

The BOG generation will vary significantly during operations as a result of:

- Reduced heat transfer with low wetted surfaces when tank level is low.
- Absorption of kinetic energy during sloshing situations. Partial filled tanks and rough weather.
- Absorption of pump energy due to flow friction during transfer
- Increased heat ingress when the BOG from the shuttle tanker is returned during transfer operations.
- High level of BOG during cool-down during start up.

The high variation in BOG generation needs to be handled to meet the strict requirements to cargo tank pressure control. The tank pressure needs to be positive but within the design limits for the containment system. Negative pressures are normally not acceptably due to implosion of the tank structure and/or ingress of air into the tank.

On an LNG FPSO unit the excess BOG may be fed into the fuel gas system, reinjected into the gas feed or vented.

On an FSRU unit excess gas is typically recondensed by reinjection into a medium pressure liquid stream upstream of the HP pump feeding the vaporiser, used as fuel gas (on a small scale) or vented.

The BOG handling capacity on LNG FPSO's may be limited by the level of variation that can be tolerated by the fuel gas system. The flexibility and capacity of the recondenser on an FSRU is higher, and major challenges due to load variations are not expected.

The vapour handling system including the common vapour header for all tanks, vent systems and off-take of excess vapour gas into the fuel gas system or recycling into the liquefaction process are therefore important control mechanisms to ensure acceptable tank pressures.

The common vapour headers need to transfer large volumes of low pressure gas at a potentially low temperature with a minimum pressure loss. The vapour header needs to connect all tanks and the vapour return system to a common vent mast. The vapour header will use large size piping along the whole cargo area of the vessel. The need to be able to isolate any tank for inspection /maintenance will introduce the need for large size valves and spool pieces.

An alternative to using LNG boil-off gas as fuel in steam boilers, gas turbines or combustion engines is to re-liquefy the vapour and return the LNG to the cargo tanks. A reliquefaction unit is shown in Fig 4-20.

Where a reliquefaction unit is installed a backup Gas Combustion Unit (Thermal Oxidizer) is also typically installed where the boil-off gas is burned and the combustion gas cooled and exhausted to atmosphere. A Gas Combustion Unit is shown in Fig D-12.

Reference is made to DNV Classification Note 61.2 *LNG Boil-off Liquefaction Plants and Gas Combustion Units*.

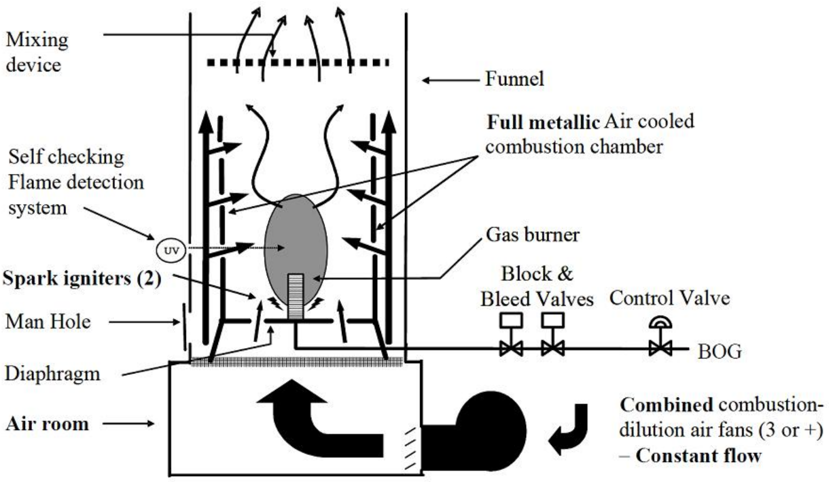


Figure 4-21: Gas Combustion Unit (Courtesy Snecma)

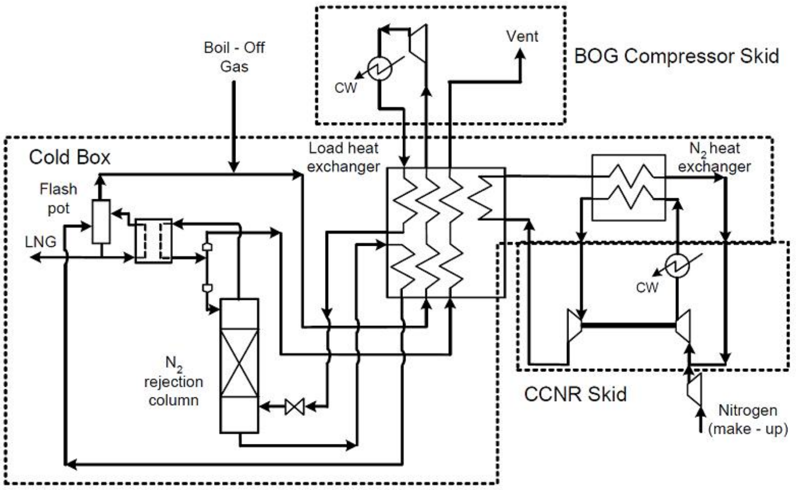


Figure 4-22: Re-Liquefaction System (Courtesy Air Products)

LPG BOG handling may also be included in the fractionating cycle. The interface to the cargo handling system needs to be assessed with respect to requirements for topside safety equipment, versus maritime regulations that would apply for cargo handling BOG systems. Especially with respect to any process upset and how this is isolated from the operation of the LPG cargo system (i.e. handling of BOG during shut down).

4.7 Venting/Flaring

4.7.1 General

Flaring is the controlled burning of natural gas whereas venting is the controlled release of unburned gases directly into the atmosphere. Disposal of gas is necessary during start-up, operation, during maintenance and in the case of an emergency. This disposal is normally achieved by installation of a vent or a flare system.

Both options present advantages and disadvantages in terms of :

- noise and visual effects
- greenhouse gas emissions (CO_2 vs methane)
- efficiency of combustion related to gas composition
- gas dispersion conditions
- flare heat exposure and protection

It will be necessary to carry out dispersion analyses or radiation studies to justify the specific design. Additionally, blowdown studies will need to be carried out to demonstrate the capacity of the depressurization/flare system.

4.7.2 Tank Venting on LNG FPSOs

DNV rules for gas carriers, Rules for Ships Pt.5 Ch.5 Sec.9 and the IGC Code Ch.8 specify requirements for the tank venting system. These rules specify design criteria for venting systems where each pressure relief valve is connected to a dedicated vent mast, or, where relief valves on each tank are combined in separate vent masts. The rules require the vent line to be designed so that the back pressure will not exceed 10% of the gauge pressure at the relief valve inlet when the tank is exposed to an “IMO fire” where $Q = FGA^{0.82}$ (fire on sea)

For LNG FPSO projects, where a process plant will usually be mounted over the storage tanks, the designer would like to avoid gas being vented in the process area since this may result in gas detection and production shutdown and also may endanger personnel working in the area. A common design is thus to tie in the pressure relief lines from all LNG tanks into a common header and locate the vent mast in proximity to the flare tower. As the length of this header is significant (~250 meters) a large diameter pipe will be required to meet the back pressure requirement when a single tank is affected by the fire scenario. However, since all the tanks are connected to the same header it is also conceivable that such a fire scenario can affect two or more tanks simultaneously. For a maritime LNGC project a scenario with fire affecting 2 tanks would be taken as the design basis. However, this is not based on any recognized international standard.

The IMO fire formula above is an empirical approximation derived from fire tests carried out at onshore LNG terminals. In addition the fire exposure factor, F, applied in the IMO fire formula is at present not established for the LNG FPSO containment tank design. Using the IMO fire approach for dimensioning the vent header on a LNG FPSO may therefore be excessively conservative and is likely to result in an extremely large header diameter.

It is thus recommended that the dimensioning vent scenario is based on a fire risk assessment that considers probability of fires, extent of effect, duration, and heat intensity.

4.7.3 Venting from Process Plant

In general the venting arrangement should be designed in accordance with DNV-OS-E201 *Hydrocarbon Production Plant*, which in turn refers to API RP 520 and API RP 521.

It is seen that the NGL extraction includes a large number of segments containing liquid gases (LPG) that may increase fire and explosion loads relative to normal Oil FPSO practice. Hence, blow down of most segments, even for segments containing low volumes (<< 1000 kg), should be assessed to lower the escalation potential during fire. The segment should remain intact until blowdown to a defined threshold has been achieved. Such an assessment may well result in selecting blowdown valves for segment volumes as low as 100 kg.

The venting system will need to account for venting from high pressure and from low pressure segments and from segments with different compositions.

4.7.4 Venting on FSRUs

Since the regasification plant will normally operate at pressures sufficient to ensure pipeline delivery pressure, a high pressure venting system will need to be arranged in addition to the standard (gas carrier) tank venting system. This will typically involve provision of a dedicated high pressure vent mast.

In addition where propane is used in the regasification plant special consideration will need to be given in arranging for its venting.

4.8 LNG Transfer

4.8.1 General

One of the key technologies necessary to support an FLNG operation is the ability to transfer LNG between two floating bodies. The regularity of such a system is important for the economic viability of an FLNG project. Whereas the transfer of fluids such as LPG or condensate does not represent a significant technology challenge, the transfer of LNG offshore is an area where technology is currently still under development. Some technologies are currently available for deployment, others are at various stages of qualification.

The challenges and functional requirements for offshore LNG Transfer are as follows:

- Availability during normal (expected) weather conditions
- Ability to connect between moving vessels
- Ability to stay connected and transfer LNG and vapour return for the required time
- Ability to disconnect safely in normal situations
- Safety
    - Containment of cryogenic and flammable products in a marine environment
    - Safe operation and integration with control systems on both vessels
    - Ability for safe abortion of operation and disconnect
    - Design of handling equipment to ensure safe operations and minimise manual operations and thereby reduce workplace accident
- Operation
    - Procedures and hardware for safe cool-down, ramp-up and shut-down.
    - Responsiveness of control systems to enable safe abortion of operation and disconnect within available time window.
- Maintenance
    - Design enabling necessary maintenance
    - Robustness to achieve acceptable level of maintenance

4.8.2 Transfer System Options

General

There are two main options with regard to transfer of LNG between two floating bodies.

- Side by Side Transfer
- Tandem Transfer

Side-by Side Transfer

Side-by-side transfer involves manoeuvring a shuttle carrier alongside the FLNG, temporarily mooring the two vessels together, separated by fenders, conducting the transfer operation via connection to the carrier's midship manifold, then unmooring the vessels. Manoeuvring would usually involve assistance of tugs. Typical separation of the vessels is then the diameter of the fendering, usually approximately 5 m. The direction of flow will obviously depend on whether the FLNG acts as an FPSO or an FSRU. This operation has similarities with transfer at land based terminals (there is also some relevant experience with transfer at exposed shore sites), and some of the technologies being proposed are marinised versions of technology used at land terminals.

The main side-by-side technologies are:

- Rigid arms with extended envelopes and assisted connection
- Aerial hoses

Figure 4-23: Side by side transfer – Courtesy Höegh LNG

A quite unique technology proposed for side-by-side transfer (currently for regasification applications) is that developed by Torp, and involves a self propelled unit which can connect directly to an LNG shuttle tanker and since it removes the issue of relative motion, land-based transfer arms can be used. Illustration in Figure 4-24. The unit can conduct both transfer and regasification before export of gas via a connected pipeline. A future development may be combination with a cryogenic hose (floating or submerged) to permit use in transfer of LNG from a production unit to a carrier.

Figure 4-24: Torp LNG Transfer system – Courtesy Remora

Tandem Transfer System

The second major technology for LNG transfer is with the shuttle carriers and the FLNG in a tandem configuration. The vessels are connected by hawser line and transfer is from stern of FLNG to bow of shuttle tanker (however floating hose solutions may permit connection to midship manifolds).

The main tandem technologies are :

- Aerial hoses
- Submerged hoses
- Floating hoses
- Motion compensating structures incorporating rigid arms

4.8.3 Side by Side Transfer System vs Tandem Transfer System

Side by side transfer has a number of advantages:

- Allows use of existing manifolds (and therefore non dedicated vessels)
- Technology proven for normal jetty operations including at exposed coastlines
- Ship-to-Ship (STS) operations with tankers well known
- Experience from LPG FPSOs

However there are also a number of challenges:

- More sensitive to sea state than tandem
- Dependent on quality met data
- Complex navigation in open water

Tandem transfer arrangements, in addition to requiring dedicated tankers, will probably require a relatively small separation of the two vessels which will represent a safety challenge. However there is quite extensive experience with tandem oil transfer operations in very harsh environment areas such as the North Sea. Oil. Safe separation distance will need to be justified by risk assessment of the operation. Typical separation for tandem oil transfer using floating hoses is approximately 90-100m. Manoeuvrability may be helped by use of tugs or specification of dynamic positioning capabilities for the shuttle tanker.

Floating hose solutions will permit greater separation of the two vessels and may also permit connection to the shuttle tanker midship manifold. It may however be a challenge for existing manifolds to accommodate weight of such hoses so that strengthening or modification may be required.

Figure 4-25: Aerial Hose Tandem Offloading System – Courtesy FRAMO

4.8.4 Guidelines, codes and standards

Transfer of LNG between gas carriers and land terminals has been carried out for many years so that it is natural to consult codes and standards relevant for such applications for relevant design and operational guidance and adjusting these to address the offshore application.

The following codes/guidelines issued by OCIMF / SIGTTO are relevant:

- Ship to Ship Transfer Guide (Liquefied Gases) Second Edition
- Draft LNG STS Transfer Guidelines (issue scheduled 2011)
- Standardization of Manifold for Refrigerated Liquefied Gas Carriers (LNG)

Additional codes which specifically consider the offshore application have recently been developed via Euronorm, and address offshore transfer systems and components. These are:

- EN1474-1 Installation and equipment for liquefied natural gas. Design and testing of marine transfer systems. Design and testing of transfer arms
- EN1474-2 Requirements for flexible hoses
- EN1474-3 risk based qualification of offshore transfer systems

Transfer Arm Design

EN1474-1 provides detailed requirements for development of transfer arms. The main requirements to a marine loading arm are :

- The fluid conduit shall not carry any structural loads, i.e. the loading arm is constructed by a pipe system fully supported by a supporting structure
- The supporting structure shall not be exposed to cryogenic temperature
- The loading arm shall be free to move within the designated envelope, i.e. the connection head shall be free to move with six degrees of freedom
- The loading arm shall be fully balanced in retracted position when empty

- The arm shall be free to move in six degrees of freedom
- The loading arm shall be equipped with an ERC (Emergency Release Coupling) allowing a quick release with a minimum spill of LNG
- The ESD logic for the loading arms shall have two levels
- ESD1 which stops flow and prepares for disconnect
- ESD 2 releasing the coupling.

The ESD system shall be connected with:

- the ESD logic on the LNGC and on the FLNG
- Motion sensors on the loading arm monitoring the position of the connector in relation to the motion envelope
- Load sensors on mooring lines
- Pushbuttons in the offloading areas

The loading arms are to be designed to meet these requirements and normally comprise:

- A vertical pedestal and inward and outward arm. The structural elements are connected by structural bearings and the fluid connector by cryogenic swivels
- The fluid conduit and the support structure are separated as follows:
    - The fluid conduit is fully supported by the structure. The supporting structure is connected to only at the top of the pedestal and at the end of the outward arm. The connecting points are isolated to prevent low temperatures on the support
    - The supporting structure is carrying all loads and ensures that the system is balanced
    - The outward end of the support structure is free to move in 3 directions
    - The head of the fluid connector is connected to the outward end of the LNG pipe with three additional swivels allowing additional rotation in all directions, i.e. 6 degrees of freedom
    - The connector head ERC comprise a clamped flange connection between two shutdown valves. The operation of the ERC is interlocked so that it is not possible to release the clamps before the valves are closed
    - The fluid conduit is constructed of material suitable for cryogenic service

The structural design of the support shall be carried out according to EN1474-1 and 3 and address:

- Static loads (weights of hardware, ice , LNG)
- Wind loads
- Fatigue reflecting the operation, cool down sequences, motions and accelerations. The effect of fatigue will be more significant on FLNG installations due to higher motions

The design of the containment of LNG shall be in accordance with EN1474-1

Tests and inspections are clearly defined in EN 1474-1. Test protocols are specified in detail. EN 1474-3 should be consulted to identify additional requirements for offshore installations. The normal test program comprise:

- Prototype testing with focus on Swivels, ERS and QCDC
- Manufacturing tests with normal QC (Material control, NDT) and pressure and leak testing
- The FAT (Factory Acceptance Test) demonstrates the functionality of the assembly and that the assembly conforms with the specification

Hose Design

Both for side by side and tandem operations the design of cryogenic hoses is one of the key technologies. EN1474-2 provides detailed requirements for development of such hoses and covers for example:

- Test requirements in EN1474-2
- Suitability of materials
- Prototype hose testing
- Pressure and leak test at ambient and cryogenic temperatures
- Mechanical tests (Cryogenic and ambient)
- Axial
- Bending
- Torsional
- Pressure cycle test
- Burst testing
- External impact
- Fatigue
- Wear testing
- Flow tests
- To determine friction factor and pressure drop
- Noise and noise induced vibrations
- External pressure (for submerged hoses)
- Buoyancy (for submerged hoses)
- Insulation tests
- Electrical tests
- Factory Acceptance test of all hoses
- Leak test
- Electrical test
- Dimensional check
- Cleanliness check
- Marking and identification
- Factory Acceptance test of one hose per order as agreed
- System testing acc. To EN1474-3

EN1474-2 refers to EN1474-1 or EN1474-3 with regard to QCDC and ERC, and system design.

4.8.5 Means of Compliance with EN1474

As a means of ensuring that a particular transfer technology complies with EN 1474, DNV recommend use of a structured approach to qualification of technology. Such an approach is documented in the DNV Recommended Practice DNV-RP-A203 *Qualification of Technology* and has been applied to new technologies applied within the energy industry.

Adopting this approach will provide a structured approach to accepting new technology and a means of complying with EN1474 since :

- EN 1474-3 requires a similar review.

- EN 1474-2 refers to functional and system requirements derived according to the process described in EN 1474-3
- Class requirement specifies Technology qualification for new technology.
- Most NOCs and IOCs have similar requirements as part of their company specifications.

Using such a structured approach has the following advantages :

- Improves the end users confidence in the system
- More efficient use of resources
- Systematically identifies failure modes
- Identifies design changes at an early stage
- Opportunity to improve system design
- Optimize qualification testing and analysis
- Uncovers interface issues between manufacturer and sub-vendors
- Increases the likelihood of delivering on time
- It reduces the Risk cost during operation by reducing uncertainties and increasing reliability
- Provides traceability of qualification efforts
- Allows quicker re-qualification for new operating conditions

Details of the approach are further described in Section 7.3Appendix C - C.1.4 of this document and in DNV Recommended Practice DNV-RP-A203 *Qualification of Technology*.

4.9 Cryogenic Spills

4.9.1 Leakage Handling Philosophy

The drains system should be divided into a closed and an open drains system. The closed system, which is considered as a hazardous drains system, will be used for the controlled removal of liquids from the various vessels and piping systems.

The open drains system should be divided into a hazardous open drains system and a non hazardous drains system. It is essential that the hazardous and non hazardous systems are kept completely separate to prevent hazardous gases entering safe areas.

Design of drains systems must reflect local regulatory requirements as to what can be discharged to sea. The open drains system will need to accommodate rain and washdown as well as leakages from the process system and other hazardous systems. Generally rain and washdown may be directed overboard.

Drains systems should generally follow the principles given in API RP 14C, however special attention will need to be given to containment and handling of cryogenic fluid leakages on floating LNG installations, in view of the personnel hazard and the possibility of provoking brittle fracture in steel structures. This is obviously an issue more critical for floating installations than for land based installations and also possibly more likely to arise on an FLNG (due to increased number of potential leak sources and continuous operation) compared to a gas carrier and therefore it will need to be addressed explicitly in a leakage handling philosophy.

Closed drains of LNG systems will typically be routed back to LNG storage tanks. Drainage may be assisted by nitrogen purging.

4.9.2 Cryogenic Spill handling

The spill handling philosophy should ensure that:

- Spill likelihood is minimized by minimizing potential leak points (e.g flanges)
- Leakages are handled in a controlled way
- Directed overboard
- Collected locally
- Damage to any critical structure is avoided (e.g. by use of polyurethane insulation)
- Injury to personnel is avoided (typically by insulation and spray guards)
- There is no communication between hazardous and non-hazardous areas
- Collection or disposal of any leakage does not lead to escalation of an accidental event

In general smaller spills may be collected locally in drip trays of suitable material (e.g. stainless steel) and allowed to evaporate. It will need to be assessed what the largest collected volume should be with regard to potential fire scenarios, gas dispersion scenarios, ship motion, permitted height of deck bunding for water drainage etc.

Deck areas with normal ship steel should be protected if spillage is possible by specification of low temperature steel or deck covering (e.g. wood or concrete).

Typically areas where larger volumes of cryogenic fluid may leak, disposal overboard should be considered. Such areas might include LNG transfer areas and areas of the liquefaction or regasification plant where larger inventories of LNG are present. Water curtains should also be considered to avoid damage to the hull of the floating installation in areas where cryogenic fluid is disposed of over the side.

Where the cryogenic spill may be of high pressure (e.g. upstream of regasification units) then spray guards should be considered at potential leak sources.

4.10 Position mooring

There are a number of options available for maintaining an FLNG on location. These have been applied previously with oil FPSOs and include:

- Spread mooring

- Internal turret mooring
- External turret mooring
- Turret mooring with thruster assistance
- Dynamic positioning
- Berthing alongside a fixed or floating jetty

Spread mooring with 3-4 mooring lines connected at each corner of the vessel has been applied in benign locations and where there is some directionality to the weather.

Turret moored systems are typically used in areas where environmental conditions are harsher, where there are no prevailing weather directions, and in areas subject to hurricanes or typhoons where disconnection may be desirable.

External turrets have been adopted in a number of projects involving conversion of existing vessels where such modification may be considered less invasive than installation of an internal turret.

In some instances thrusters may be used to support the mooring system. Where they represent an essential element in the mooring system design (i.e. are given credit in determining the design load) then special requirements are applied to ensure their availability. In other cases thrusters may be used to facilitate the offloading operation by maintaining the FPSO or FSRU position relative to a shuttle tanker, but are not given credit in reducing overall mooring loads. Less strict requirements are placed on such thruster arrangements, from a safety point of view.

Especially in very deep water applications Dynamic Positioning may be an option. Given the potential consequences of failure, strict requirements are placed on redundancy and availability of all the critical subsystems.

An option for FSRU or for an FPSO receiving gas from a land source (e.g. Coal Bed Methane well) is to moor the floating unit to a jetty either at shore or close to shore. In such a case the mooring arrangement will need to consider both the jetty design and the berthing lines and fenders attaching the floating unit. In general such mooring arrangements may be designed and constructed in accordance with guidelines issued by OCIMF and SIGTTO.

Relative motion between the floating unit and a floating jetty may need to be assessed in a similar way to relative motion between the FLNG and a visiting gas carrier as described earlier in this document.

Note that all mooring options will need to consider the load case where a shuttle tanker is moored alongside where side-by-side is the selected transfer option. In addition the operational safety philosophy in the event of a partial failure of the mooring system (e.g. loss of an anchor line) should be specified.

It should be noted that some regulators may have more strict requirements than single line failure and that jurisdictions where a Safety Case is used my lead to more strict requirements as part of an ALARP assessment . In areas where the ratio of the 100 year event to the 10 000 year event is relatively high (e.g. NW Shelf of Australia), design based on 100 year return conditions combined with a 10 000 year survival condition for permanently manned non-disconnectable systems has been applied by some Operators.

DNV requirements for Position Mooring systems are specified in DNV-OS-E301 *Position Mooring*.

DNV requirements for Dynamic Positioning systems are specified in DNV Rules for Classification of Ships Pt 6 Ch 7: *Dynamic Positioning Systems.*

Guidance on detail design and fabrication of turrets may also be found in DNV "OTG (2011) *Turrets.*

4.11 Power Supply Options

4.11.1 Power Demand

The Power consumption on a FSRU is relatively limited and the demand can normally be covered by moderate modifications to the standard power generation systems on ships.

The power consumption on an LNG FPSO is, on the other hand, very high mainly due to the power consumption required by compression in the liquefaction process.

A 50 MW compressor will typically deliver 0.9 mtpa in an N_2 expander cycle and 1.5 mtpa with a more effective DMR process. As a result FPSO solutions currently being considered will typically have a power demand ranging from 100 to 250 MW.

In addition the pre-treatment plant on an FPSO needs to supply a significant amount of heat in the form of hot oil or steam for the pre-treatment process.

4.11.2 Power Supply

Gas turbines as direct drives reduce the complexity in the power supply system, but represent layout challenges as they involve large fired units in the process area, and also present challenges for the bearings and support of the rotating machinery.

Electric drives offer more flexibility in the layout and also the possibility of combination with gas turbines and other energy sources. However, effective electricity supply systems for such power level demands normally require very high voltage systems which also represent a challenge.

The heat supply for the pre-treatment process can normally be supplied by Waste Heat Recovery Units in the exhaust gas from gas turbines.

Steam driven systems have been considered and offer significant advantages from a layout point of view and also efficient energy transfer to the drivers. But the thermodynamic efficiency of a steam system is inferior compared to gas turbines.

A hybrid system based on electricity production from gas turbines and steam from waste heat recovery has also been proposed and may be considered.

The power supply options include consideration of use of aeroderivative gas turbines either as direct compressor drives or to drive generators for electricity production.

4.11.3 Aeroderivative Gas Turbines

Today there are a number of installations of gas turbines on floating structures all being used for power generation and these represent significant and valuable experience.

However there are specific differences in the operating load conditions as driver for a compressor compared to a constant speed, power generation unit. These include:

- Variable speed
- Compression surge
- Rapid decelerations due to process upsets such as e.g. emergency shut down(ESD)
- Loading of the machine from start up.

Any application on an FLNG will need to document that these issues have been satisfactorily addressed.

It should also be note that installation of fired units in the cargo area is generally considered as a deviation from IGC Code, however since the code does not explicitly address FLNG and since such an arrangement is similar to use and installation of gas turbines on oil FPSO, it is anticipated that, in so far as it is relevant, this deviation would be accepted by a Flag State.

4.12 Integrated Control Systems

Software and systems used in the energy and maritime environments are becoming increasingly complex as they evolve to meet more demanding customer, regulatory and technological requirements. The energy and maritime industries are also facing greater product innovation with more software embedded systems forming part of the safety and business critical systems. This is especially relevant for an FLNG project with complex processing, simultaneous transfer to shuttle tankers and integrated safety systems.

The software intensive products used in such projects can provide great benefits in terms of functionality, operability and maintainability. However with so much of a systems functionality defined by the software systems, the consequence of a failure of the software system can be catastrophic.

Safe, predictable and profitable operations of these systems depends on

- Development of reliable components
- Successful integration of these components into systems
- Good management and coordination of component and system requirements, development, procurement, testing, validation, integration, commissioning, configuration and operation.

Most system and software defects occur in the early phase of a project and without adequate control of the processes these defects can remain undetected until the later stages of the project. Frequently these defects originate through poor system and component requirements. Research has also shown that it can be up to 100 times more expensive to fix these defects once the system has been delivered than to fix them in earlier phases.

The extent and value of the software installed in a modern integrated system is rarely fully appreciated. The software is a critical component and owners and operators tend to have less control over the software production process than they do over the production of critical mechanical components.

Other industries have successfully managed the transition from mechanical, electrical and hydraulic systems to software intensive integrated systems, most notably the aerospace, nuclear and the automotive industries.

Since these systems have become so complex, it is not practical to fully test them anymore and there was a need for a new approach that can manage the increased complexity for software-embedded systems. Best practices from other industries have been captured and were presented in a set of DNV Recommended Practices for Integrated Software Dependant Systems (ISDS) in 2008. Experiences using this Recommended Practice and a request from a number of rig owners have has led to development of a new DNV class notation ISDS.

When an owner is striving for high production and a safe installation, demands have to be set for the systems that control the installation. So far, the automation industry has mainly focused on connectivity - ensuring the physical integration of the various control systems.

The main challenge for ISDS is how to engineer the various system elements into a single system that meets all the necessary requirements in terms of safety, functionality and reliability. It is not enough simply to select and connect system elements that may individually satisfy the requirements.

The challenge extends to the integration of the system elements and an understanding of each operation within the system. System elements affect each other in order to deliver the emerging properties of the complete system.

The new ISDS notation is a voluntary class notation. If this notation is granted to the system, DNV will provide status reports while the software is being developed giving the status of the software’s readiness with respect to integration and completeness.

Since the ISDS notation looks at the complete lifecycle, it will provide requirements for how to prepare the systems for upgrades and future configurations. The class notation will therefore also prepare for and support configuration management in the operational phase.

For further information reference is made to the following documents :

- DNV-OS-D203 *Integrated Software Dependent System* (Tentative Standard)
- DNV-RP-D201 *Integrated Software Dependent Systems*.

5 CONVERSION OF GAS CARRIERS TO LNG FPSOS OR FSRUS

5.1.1 General

Conversion of existing vessels, normally gas carriers, to offshore LNG units has been proposed. The shorter project time for a conversion and lower cost compared to a newbuilding may make such an approach viable. However it is first necessary to find a specific project which can accommodate any limitations of using an existing hull and the existing storage capacity of a candidate vessel.

DNV's approach to conversion of a gas carrier to an LNG FPSO or FSRU will follow the principles outlined in DNV-OSS-103 Appendix A : *Special Considerations for Conversions*.

In general the assessment of a conversion will involve consideration of:

- new systems and structures installed on board
- modifications to existing structures and systems
- existing structures and systems affected by the new installation and the new function
- additional regulatory requirements for the new application

Existing systems and structures unaffected by the new application will normally be accepted as is. However it will need to be assessed whether such are affected by issues such as different operational modes, modified maintenance schedules and differing accidental loads compared to the initial design.

The existing structure and systems on board will also need to be assessed for the planned service life of the FLNG, especially in the case where the FLNG will remain on location continuously without regular drydocking.

Some of the most important issues relevant for a converted unit are listed and discussed below.

5.1.2 Conversion Gas Carriers to FSRUs

5.1.2.1 Risk Assessment

It is normally required to carry out risk assessment to identify how new systems and operations may affect overall design and safety.

Typically a fire and explosion study will be necessary to quantify additional loads which will need to be addressed in the design.

Typically the following additional hazards would need to be addressed for the converted unit:

- Fire and explosion loads in connection with the regasification plant
- Dropped object over the storage tanks
- Presence of high pressure gas
- Storage of additional hydrocarbons used in the process (e.g. propane)
- release of cryogenic liquids in the regasification plant area
- leakage of LNG onto water and possible Rapid Phase Transition effects
- spread of fire that may threaten storage tank integrity
- relative proximity of LNG process to storage
- hazards associated with venting/flaring
- hazards associated with LNG transfer
- hazards associated with docking of gas carriers
- hazards associated with gas carrier alongside

Such an analysis might, for example, indicate a need for additional passive fire protection, revision of crane procedures, and relocation of means of escape; however such requirements will only be determined following an analysis.

5.1.2.2 Structural Strength

A number of gas carriers have already been converted for use as FSRUs. It has generally been the case that such units are located in benign environment areas. In such cases the structural strength design criteria as a gas carrier will normally be more demanding than those for its operation as an FSRU. Benign environment is as indicated in Figure 5-1below.

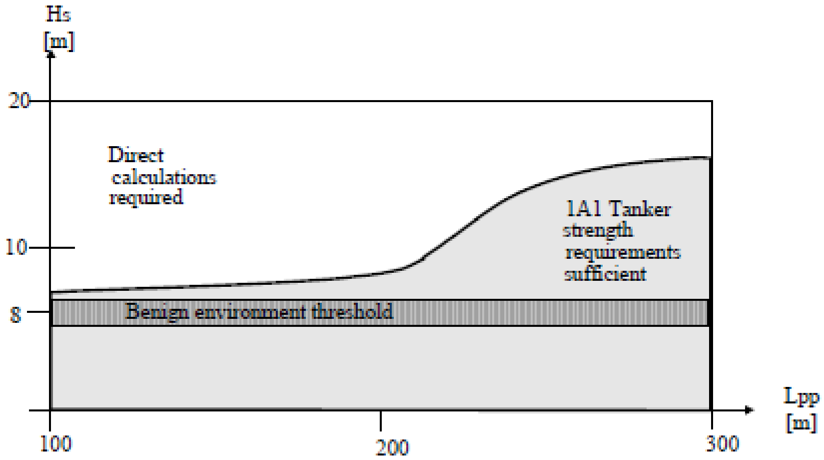


Figure 5-1 Definition of Benign Environmental Conditions

Benign waters is defined as areas where the environmental loads obtained from direct analysis are less or equal to the design wave bending moment obtained from DNV Ship Rules Pt.3 Ch.1. An environment with a significant wave height less than 8.5 m for a probability of occurrence of 10^{-2} (100 years return period) may be considered as benign.

Should it be the case that an FSRU were to be located in a harsher environment area then the structural strength would need to be assessed in detail in accordance with DNV-OS-C102 *Structural Design of Offshore Ships.*

Additional loads imposed by the new mode of operation would also need to be evaluated. These would include:

- Support of regasification skid
- Support of transfer arrangement
- Support of other new items (e.g. vent mast, helideck)
- Additional mooring loads
- Additional fire and blast loads
- Fendering loads
- Sloshing loads
- Fatigue loads

Safety factors associated with loads would need to take account of whether the FSRU intended to drydock or not and the philosophy for repair and replacement.

New structure will need to comply with DNV-OS-C102 *Structural Design of Offshore Ships.*

5.1.2.3 In-service Inspection

Where the FSRU intended to remain on location permanently and conduct all inspections offshore, it would be necessary to make some modifications in order to permit this. This might, for example include provision of closing devices on the ships hull (such as sea chests) to permit inspection while afloat.

In addition repair and replacement may be more problematic on the converted unit since such may affect ability to conduct continuous operation. It should therefore be considered whether systems or equipment, which might directly or indirectly affect availability of the FSRU, should be designed to a higher quality than standard gas carrier quality or should have increased redundancy in order to avoid the need for a shutdown on failure. DNV have recommended for example that some low pressure and non-hazardous piping systems might be subjected to increased inspection from an availability point of view rather than a safety point of view.

5.1.2.4 Regasification Plant

The safety aspects of the regasification plant and its effect on the vessel would be addressed through the REGAS notation which is documented in DNV Classification Note CN 61.3 *Regasification Vessels*.

The process safety aspects of the regasification plant will need to generally follow the principles of API RP 14C and DNV-OS-E201 *Hydrocarbon Production Plant*.

5.1.2.5 General Safety

As a result of continuous processing of gas and increased number of potential leakage sources it would be expected that additional gas detection would need to be provided. Typically this would include the following areas:

- regasification units
- ventilation inlets to accommodation and engine room
- condensate return to engine room (other systems not physically segregated from the gas system)
- export manifold
- turret compartment

Similarly provision of additional fire fighting capacity for water spray would be anticipated to cover for example:

- the regasification units
- metering station
- suction drum
- export manifold
- internal surfaces of the turret compartment
- storage tanks for propane or other flammable fluids, if fitted

Given the continuous nature of the operation and the likelihood of conducting several hazardous operations simultaneously (LNG transfer, LNG regasification, gas export) in the vicinity of a gas carrier, the converted unit would need a more complex Emergency Shutdown System to ensure safe operation. Recommendations on development of ESD systems are given in DNV-OS-A101 *Safety and Arrangement*.

With the installation of a regasification skid on board and an increased need to have manning on deck in connection with its operation and maintenance, the converted unit will need to consider the arrangement for escape and evacuation in light of the new hazards introduced.

5.1.2.6 Position Mooring

The position keeping is a new function for an LNG FSRU compared with a traditional LNG carrier. In the case of an LNG FSRU with an APL buoy, it will be the mooring system for the buoy that shall comply with DNV-OS-E301. However, the interface with the STL buoy must also be covered, e.g. mooring forces from the buoy into the mating ring in the FSRU hull

5.1.2.7 Helicopter Deck

Typically transporting personnel to and from an offshore unit would be by helicopter. DNV's requirements for a helicopter deck are described in DNV-OS-E401. These are voluntary requirements from a classification point of view, since it is the civil aviation authorities who are responsible for controlling such installations.

5.1.2.8 Additional Regulatory Requirements

Aside from classification issues discussed above, the conversion of a gas carrier to an FSRU may well bring the vessel into a new regulatory regime. This will be up to the Shelf State authorities to determine.

5.1.3 Conversion to LNG FPSO

5.1.3.1 General

Conversion of an existing vessel to an LNG FPSO is also a possibility. Converting an existing gas carrier to an FPSO would be a challenge from an economic point of view given the likely size and storage capacity of potential conversion candidates and the need to produce, store and export a certain volume of LNG to justify the investment. However solutions modifying larger ship types (e.g. VLCC) or utilizing additional storage capacity with a second hull have been proposed. Concepts combining the storage capacity of an existing gas carrier with a production plant mounted on a moored barge have also been proposed.

5.1.3.2 Approach to Conversion

In general an approach similar to that proposed for the FSRU conversion would be applied to the vessel for conversion, i.e. that referred to in DNV-OSS-103 Appendix A: *Special Considerations for Conversions.*

A key activity is the risk assessment which will identify project specific hazards and determine the magnitude of the project Design Accidental Loads.

5.1.3.3 Likely implications for conversion vessel

Similar considerations as those listed for the FSRU conversion described in 5.1.2 would apply.

Obviously the impact of the installation of gas handling and liquefaction plant would be significantly greater compared to installation of a regasification skid.

Accommodating the structural loading would be a challenge, depending on the topside weight and the existing containment system design.

The impact of accidental loads on the existing structure would also be more significant than in the FSRU case and it is likely that additional passive fire protection would be required, possibly also on existing structure (e.g., forward bulkhead on Accommodation block).Similarly higher design explosion overpressures might call for additional structural protection of safety systems (e.g. lifeboat area)

Further more comprehensive measures would be needed to accommodate cryogenic spill scenarios.

Fire fighting capacity would need to be upgraded significantly, typically resulting in installation of a large capacity independently driven fire pump, located to ensure availability during and after an accident scenario.

5.1.3.4 Additional Regulatory Requirements

Aside from classification issues discussed above, the conversion of a gas carrier to an LNG FPSO will bring the vessel into a new regulatory regime. This will be up to the Shelf State authorities to determine.

A ship being converted to an FPSO will need to comply with offshore legislation. Offshore legislation may differ in content and format from legislation applicable for a maritime trading vessel (however will usually give credit for compliance with Maritime Certificates).

For example the format of a Safety Case (for units in Australia) requires a formal and structured approach to determining project-specific requirements. However technical requirements derived from a Safety Case approach should not differ significantly from those derived using Classification Rules which include Risk Assessment.

Marine vessels will comply with Statutory Certification developed for shipping applications however, in the case of SOLAS an offshore version has been developed (the IMO MODU Code) which some few Shelf States will require applied to offshore installations. Brazil is an example of such. There are some differences between the two sets of requirements, for example with respect to stability and external communication.

6 CLASS MAINTENANCE AND INSPECTION PHILOSOPHIES

6.1 General Class assumptions

In order to maintain Class status, all classed units and installations are required to undergo periodic Class surveys. The survey objective is to ensure that the condition of the structure, machinery installations, equipment and appliances meet, and will continue to meet, applicable class safety requirements as set forth in Class rules and codes and standards recognized by those rules.

Hull structure surveys are traditionally performed as a combination of visual survey, close visual survey and non-destructive examination (NDE).

The survey focuses on the following failure mechanisms:

- Corrosion/material loss
- Fatigue cracks
- Local damages due to operation of the unit, such as dented and buckled structures
- Damage to any part of the mooring system in cases where the mooring system is part of Class scope
- Damage to the containment system (discussed later in this document)

Surveys of machinery and equipment involve verifying:

- Continued satisfactory operation
- Acceptable wear levels
- Satisfactory safety functions

Annual survey of machinery and equipment typically involves a visual inspection and review of maintenance and inspection records. The renewal survey will be more comprehensive and may involve opening up, non-destructive examination and testing of function and safety features.

6.2 Approaches to Survey

6.2.1 Periodical Survey Approach

The traditional ship approach to verifying continued acceptable standard is by adopting a Periodical Survey approach for both hull and machinery systems. This involves Periodical surveys, annual and renewal (5 yearly).

However this approach would result in a quite extensive survey after a 5 year period and may therefore disrupt an FPSO operation for a significant period, so therefore a less rigid approach is usually adopted for FPSOs.

6.2.2 Survey based on Continuous Survey Arrangement

Another approach permits completion of the renewal survey or part of it distributed throughout the five year cycle in an agreed sequence. Normally some 20% of hull inspections carried out each year, rather than 100% at the 5-yearly renewal survey. This then allows completing the renewal survey in relatively smaller tasks over time.

6.2.3 Survey Based on Owners/Operators Planned Maintenance System

DNV's assessment of the maintained quality of the classed FLNG may typically also be based on the Owners/Operators own maintenance and inspection routines by integrating class requirements with an Operators own Planned Maintenance System. It is DNV's intention that our assessment of the condition of the FLNG should result in as little disruption to the FLNG operation as possible. DNV's activities can be integrated into the Owners/Operators own approach and can take credit for those activities the owner has conducted.

Hull PMS and Machinery PMS are survey arrangements offered as an integral part of classification compliance for the hull structure and the hull machinery systems through the alignment and integration of classification requirements with an approved and implemented planned inspection and maintenance system. The system performance and condition of hull structure and equipment and maintenance work carried out will be verified by DNV during annual survey and in connection with renewal survey of the unit.

An initial survey would need to be carried out onboard the unit in order to verify that the system has been implemented in accordance with the approved documentation and that the system is used as intended. It is required that the planned maintenance system has been operated for at least 6 months before the initial survey is carried out.

6.2.4 Survey using a Risk Based Approach

DNV also permits use of a risk based approach rather than a calendar based approach to inspection and surveys. DNV has an intention to contribute in the development of more modern approaches to maintenance, which can take account of:

- Increased asset complexity and increased cost of down time.
- Equipment manufacturers' standard procedures are replaced by criticality based maintenance programs that are adapted to the operating context of the asset.
- Condition monitoring techniques are replacing calendar based overhauls.

A more detailed description of Risk Centred Maintenance and Risk Based Inspection is provided in Appendix B.

6.3 Inspection and Maintenance of Containment Systems

6.3.1 General

In-service inspection of FLNG is to be in accordance with DNV-OSS-103 Ch.3 which for containment systems build on the Rules for Classification of Ships Pt. 7 Ch. 1.

Integrity of containment systems should be assessed regularly. This can be achieved by activities such as:

- Review of records (e.g. inert gas consumption)
- visual inspection
- pressure/vacuum testing
- leakage monitoring
- temperature monitoring
- sensor and control functioning

From a classification point of view, this assessment is carried out on a yearly basis, with a more stringent assessment being made every 5th year. In general, access to the containment tanks or inerted hold spaces, necessitating gas-freeing / aerating will normally not be necessary more frequently than at 5 yearly intervals, assuming no damage is incurred or suspected within that period.

The requirements listed in this chapter are initially derived from those applied to trading gas carriers and should therefore be considered as minimum requirements with respect to FLNG. Additional issues are discussed later in this section with respect to application as an FLNG.

6.3.2 Annual Inspection

A typical level of class annual inspection would include assessment of:

- Cargo tank, interbarrier space and hold space pressure control
- Cargo level control (indicators and level alarms)
- Temperature control (in tank and adjacent hull structure)
- Leakage monitoring/detection system of hold spaces
- Cargo tank, interbarrier and hold space venting system (pressure and relief valves and alarms)

- Availability of the inert gas system (Tank type A has inert gas in hold spaces. Tank types B and C may have dry air or inert gas in the hold spaces.)

6.3.3 5 Year Inspections

Intermediate survey scope is to be carried out in addition to annual survey requirements and includes testing of cargo handling installations with related automatic control, alarm and safety systems for correct functioning. The ESD system will also be tested.

Below is an indication of the general requirements to inspection with respect to the various containment systems.

6.3.4 Independent Tank Type A

Inspection of Type A cargo tank

All cargo tanks are to be examined internally. The inspection should include the following items:

- Pipe penetrations in dome
- Transverse bulkhead
- Swash bulkhead
- Horizontal stringers
- Web frames
- Longitudinals
- Catwalks and ladders
- Foundations for pumps, ladders, etc.
- Pipe supports and connections to tank shell

Non-destructive testing of highly stressed parts may supplement the visual inspection as deemed necessary.

The following items are considered to have highly stressed parts:

- Cargo tank supports and anti-rolling or anti-pitching devices
- Web frames
- Swash bulkhead boundaries
- Dome and sump connections to tank shell
- Foundations for pumps, ladders etc.
- Pipe connections

The tightness of all cargo tanks shall be verified by an appropriate procedure. Provided that the effectiveness of the ship's gas detection equipment has been confirmed, it is normally acceptable to utilize this equipment for the tightness test.

Inspection of hold spaces

Hold spaces, secondary barriers, tank supporting structures and insulation are to be visually examined. The inspection will typically include the following items:

- Visual examination of the secondary barrier
- Sealing arrangement of the gas dome
- Condition of insulation
- Cargo tank foundations
- Inner hull knuckle points
- Test of bilge arrangement

Special attention is to be given to the cargo tank and insulation in way of chocks, supports and keys as tension stresses will occur in that region and possible cracks may start here. Removal of insulation may be necessary in order to verify the condition of the tank or the insulation itself.

The purpose of the insulation is both to protect the hull structure from low temperature and to reduce the heat flow from the surrounding to the cargo.

Increase of the thermal conductivity of the insulation will increase the heat flow to the tank nearly to the same extent. However, the temperature of the insulation surface will be nearly unchanged (less than 2ºC at 50% increase of the thermal conductivity of the insulation). The result is that it very difficult to discover an overall reduction of the insulation efficiency by visual inspection of the insulation. Local defects of the insulation may create strong convection and may thus decrease the temperate of the near-by hull structure. Even though the hold space normally has a dry atmosphere the dew point is normally higher than the coldest surface temperatures and moisture may condense and freeze on the coldest areas. The tank supports and anti flotation chocks will be normal cold spots.

The thermal conductivity of the insulation will increase with increasing moisture ingress into the insulation. Moisture in the tank atmosphere will tend to flow into the insulation forced by the higher partial pressure of water vapour at higher temperature. To avoid moist insulation the insulation is in most cases equipped with a moisture barrier. Especially at anti-flotation chocks special attention needs to be paid to the moisture barrier to prevent water forming during the warm-up of tanks, which could flow along the nearly flat portions of the tank and fill the insulation with water.

6.3.5 Independent Tank Type B In-service Inspection

Inspection of MOSS type cargo tank

The typical approach to assessing condition of such tanks is to carry out visual inspection and non-destructive testing. The NDT programme aims at detecting cracks propagating from the material surface.

This program may be adjusted based on experience gained but will typically involve assessment of the areas listed in the table below.

Table 6-1: Inspection of Moss Type Cargo Tank

Item	Type and extend of Inspection
Internal inspection of accessible parts of cargo tank, cargo piping, cargo pumps, cables, instrumentation etc.	Visual + DP spot if found necessary
The weld between the dome and the tank shell. Sliding pads and stoppers if fitted	Visual + 25% DP + 25% UT from inside Visual
The welds between the pipe tower foundation and lower hemisphere. The membrane plate welds if fitted. Cross beams in the pump tower support if fitted.	Visual + 100% DP Visual + 10% DP Visual + 10% DP
Structural Transient Joint (STJ). Depth of possible de-lamination is to be measured.	DP at the four locations fore, aft, port and starboard for a length of at least 1m each.
The weld between the equator ring and the skirt plate. The insulation shall be removed.	DP and UT at the four locations fore, aft, port and starboard for a length of at least 1m each.
The upper circumferential weld of the equator ring from outside. The insulation shall be removed	DP and UT at the four locations fore, aft, port and starboard for a length of at least 1m each.

Cargo tanks of type B are continuously monitored for gas tightness. Nitrogen is supplied to the annular space between the tank shell and the insulation. As there are gas detectors in the outlets any leakage from the cargo tank will be detected. Operation records of the nitrogen/gas detection system will confirm gas tightness of the cargo tank.

SPB Tank In-service Inspection

There is currently little industry experience with SPB tanks, however their design is similar to that used for Independent Type A tanks.

The extent and type of inspection would therefore be essentially similar to what is specified for Independent Type A earlier.

The inspection should include following items:

- Pipe penetrations in dome
- Transverse bulkhead
- Swash bulkhead
- Horizontal stringers
- Web frames
- Longitudinals
- Catwalks and ladders
- Foundations for pumps, ladders, etc.
- Pipe supports and connections to tank shell

Non-destructive testing of highly stressed parts may supplement the visual inspection as deemed necessary.

The following items are considered to have highly stressed parts:

- Cargo tank supports and anti-rolling or anti-pitching devices
- Web frames
- Swash bulkhead boundaries
- Dome and sump connections to tank shell
- Foundations for pumps, ladders etc.
- Pipe connections

6.3.6 Independent Tank Type C

Inspection of cargo tank

The cargo tanks are typically examined externally and internally.

Special attention is usually given to the cargo tank and insulation in way of chocks, supports and keys. Removal of insulation may be necessary in order to verify the condition of the tank or the insulation itself.

Non-destructive testing is used to supplement cargo tank inspection with special attention on the integrity of the main structural members, tank shell and highly stressed parts, including welded connections. The following items are normally considered as highly stressed parts:

- Cargo tank supports and anti-rolling/anti-pitching devices.
- Stiffening rings.
- Y-connections between tank shell and a longitudinal bulkhead of bi-lobe tanks.
- Swash bulkhead boundaries.
- Dome and sump connections to the tank shell.

- Foundations for pumps, towers, ladders etc.
- Pipe connections.

At 10 year intervals all cargo tanks are typically subjected to more rigorous examination involving either:

- Hydraulic or hydro-pneumatic testing to 1.25 times MARVS, followed by non-destructive testing as above, or
- A thorough, planned program of non-destructive testing.

This testing is to be carried out in accordance with a program specially prepared for the design. If a special programme does not exist, at least 10% of the length of the welded connections in each of the highly stressed areas given above is to be tested. This testing is to be carried out internally and externally as applicable.

If the pressure testing alternative is selected then care must be taken to ensure complete water removal otherwise this may cause problems through freezing of valves and equipment when the vessel returns to service.

The external inspection of the cargo tanks should especially focus on the tank supports and insulation, i.e.:

- Tank shell and doubler plates at the horns of the saddle. Insulation may have to be removed.
- Compressed wood used in the supports.
- Anti-flotation devices
- Condition of tank outer surface of non-insulated cargo tanks.
- Condition of the insulation with vapour barrier for insulated tanks.

6.3.7 Membrane Tanks

There are a number of membrane tank designs, primarily Gaztransport & Technigaz (GTT) Mark III and NO 96 designs. Inspection and testing will need to be carried out in accordance with programs specially prepared for the actual tank system.

Inspection of membrane cargo tanks

All cargo tanks are to be examined internally. Attention should be given to:

- tank membrane
- Pump tower
- Pump tower support top and bottom. Non-destructive testing may be required.
- tank equipment, pumps, instrumentation, cables, etc

Visual inspection should include checking for, deformation of the primary barrier to discover crushed insulation. As the membranes may be penetrated by falling objects, the internal pumps and pipes and items capable of loosening and falling should be inspected with respect to fixation.

The membrane is installed directly on the inner hull structure with no access to the insulation spaces and the secondary membrane. Hence these tanks have to be inspected from the spaces between outer and inner hull structure. The inspection should especially consider corners of the inner hull and should at least involve visual inspection with respect to cracks, deformations and corrosion.

The primary and secondary barriers of all tanks need to be checked for their effectiveness by means of pressure/vacuum tests or other acceptable methods.

The membrane tightness tests for cargo containment systems of type GTT NO96 and Mark III are described below.

6.3.7.1 Membrane Tightness Testing GTT NO96

Membrane tightness test Procedure

In-service periodical examination of the primary and secondary membranes should be carried out in accordance with GTT External Document No. 1093.

Primary membrane

The primary insulation space is typically provided with a permanently installed gas detection system measuring gas concentrations at intervals not exceeding 30 minutes. Any excessive gas concentration with regard to steady rates would be the indication of primary membrane damage. The primary barrier is, in terms of tightness, continuously monitored and usually considered acceptable provided documented records show that:

- Gas concentration in the primary insulation space is below 30% LEL.
- Nitrogen system is in breathing mode and that nitrogen consumption is normal.

If there is any doubt with respect to the condition of the primary membrane, its integrity should be tested according to the method described for the secondary membrane.

Secondary membrane

In order to check its effectiveness, a global vacuum test of the secondary barrier is carried out.

The pressure in the secondary insulation spaces is normally reduced to 475 mbar absolute and kept stable for 8 hours. The pressure is monitored and recorded for the next 24 hours. The vacuum decay (ΔP in mbar) is selected from the 10 hours continuous period with stable temperature variations in the compartments surrounding the tested membrane. If ΔP is less than 0.8 divided by the thickness (m) of the secondary insulation, the membrane is considered to be gas tight.

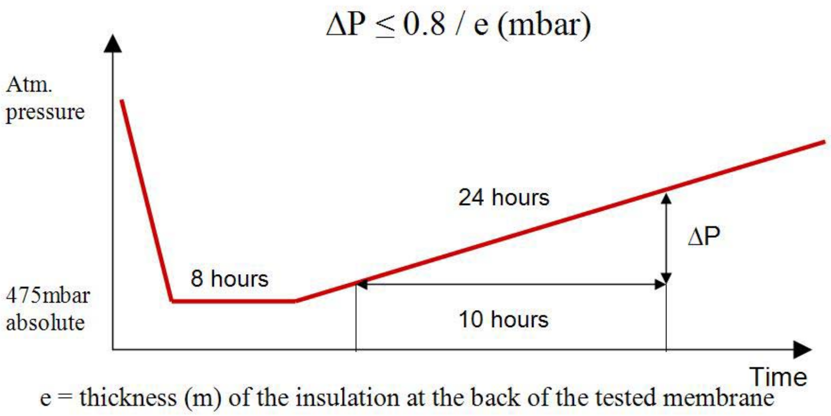


Figure 6-1: Vacuum test of Secondary Membrane

6.3.7.2 Membrane Tightness Testing GTT Mark III

Primary membrane

The primary insulation space is typically provided with a permanently installed gas detection system measuring gas concentrations at intervals not exceeding 30 minutes. Any excessive gas concentration with regard to steady rates would be the indication of primary membrane damage. The primary barrier is continuously monitored for tightness and usually considered acceptable provided documented records show that:

- Gas concentration in the primary insulation space is below 30% LEL.
- Nitrogen system is in breathing mode and that nitrogen consumption is normal.
- If there is any doubt with respect to the condition of the primary membrane, its integrity should be tested according to the method described in the following documents:
- Tightness test of membrane welding, GTT External Document No. 1139

- Primary barrier global test, GTT External Document No. 1138

Secondary membrane

In order to check its effectiveness, a global vacuum test of the secondary barrier is carried out in accordance with GTT External Document No. 1136.

The values obtained are then compared with previous results or results obtained at the new-building stage. If significant differences are observed for each tank or between tanks, further evaluation and additional testing may be necessary.

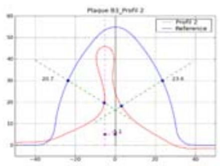
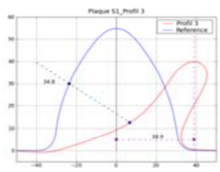
6.3.8 Considerations for FLNG Applications

The generic requirements described above for the various tank types were developed originally for marine containment tank applications. This presupposes that the gas carrier is regularly drydocked and gas freed to permit tank entry.

The FLNG will typically remain on location throughout its service life and may also conduct tank inspection while other tanks and operations continue in to be in operation.

Due to the mode of operation on an FLNG with frequent partial filling levels, the probability of experiencing sloshing loads may also increase (this will need to be assessed from project to project since it will be location specific).

Damage resulting from sloshing loads has already been discovered in membrane tanks. The current recommendations concerning evaluation of deformations in GTT Mark III tanks are shown in the figure below.

Deformation limits (Anywhere in the tank)	Inspection and repair requirements
Symmetric: 0 – 15mm: Acceptable 15 – 20mm: Category 1 >20mm: Category 2  Asymmetric: 0 – 20mm: Acceptable 20 – 30mm: Category 1 >30mm: Category 2  The deformation limits may be re-evaluated based on future experience	Category 1: Close-up inspection, record location and deformation for future reference. Repair if the insulation is damaged. Category 2: Replace membrane and check if insulation is damaged.

3

Figure 6-2 GTT Mark III Primary Barrier Deformations - Recommendations

As discussed earlier, if operations are to continue while tank inspection takes place then the design must ensure that there is acceptable segregation between systems in operation and those out of service for inspection.

In maritime applications the extent of inspection has focused on relatively accessible parts of the tank. Based on experience, especially with membrane tanks, areas which have been shown to be subject to damage will also need to be made accessible.

In general, suitable arrangements (e.g. staging) will need to be provided to provide access to relevant tank sections while the FLNG is on location. This arrangement will need to permit personnel to safely inspect within the planned inspection time window taking account of ship motion. For tanks with no internal structure (such as membrane tanks), gaining access to all areas for visual examination or non-destructive examination for crack detection may be difficult, however inspection booms can be developed attached to pump towers or specially designed scaffolding might also be used.

Figure 6-3 Membrane Tank – Courtesy GTT

Experience to date has not shown damage in Moss tank walls and it is not anticipated that operation as an FLNG would increase likelihood of damage in the tank wall area, so that close visual examination using a boom would not be required by Class.

Tanks which have internal structure, such as SPB tanks, are more easily accessed for inspection.

Carrying out inspection and repairs which previous have been carried out in drydock, while the FLNG is on location will also be a challenge. The industry is working on developing methods and procedures to achieve this. Modification to current drydock methods may be necessary.

A new method for testing of secondary membrane in Mark III tanks is currently being tested out. The method is called “Low Differential Pressure Test procedure” (LDPT) and the principle is to verify the gas tightness of the membrane by applying a small overpressure in the insulation spaces instead of vacuum. Hence the installed nitrogen system onboard could be utilized instead of a portable vacuum pump. It would also be possible to perform the test with loaded cargo tanks. The viability of this method is still being evaluated.

The LDPT procedure is described in GTT External Document No. 3670

Repair offshore is also an area where designers and shipyards are currently developing methods and technology.

7 CLASSIFICATION AND REGULATORY COMPLIANCE

7.1 Classification

7.1.1 General

The classification approach for offshore LNG installations will be based on the experience with classification and risk management of oil and gas carriers and oil producing FPSOs.

DNV's classification rules for Oil FPSOs DNV-OSS-102, *Rules for Classification of Floating Production, Storage and loading Units* and for gas carriers, Rules for Ships, Pt 5 Ch 5 Gas Carriers, reflect DNV experience with these objects.

Classification of gas FPSOs based on this experience from oil and gas carriers and FPSOs has been formalised in DNV-OSS-103, *Rules for Classification of Floating Production, Storage and loading Units*. In addition the additional Class notation PROD(LNG) will also address the gas treatment and liquefaction plant. The design principles outlined in the rules will also be applicable for LPG/GTL installations.

For the ship shaped LNG concepts in question, requirements defined in the IGC Code represent a crucial set of requirements to be complied with. It is, however, important to keep in mind that the IGC Code covers relevant aspects for vessels transporting LNG/LPG and loading/unloading at terminals/jetties. IGC code should be used as far as appropriate but some deviations will be necessary to account for new applications. It will also need to be supplemented with requirements to address the additional hazards from the offshore application.

7.1.2 Offshore Classification Rules and Codes

Class Rules and supporting documents give criteria for design, construction and maintenance of offshore assets. DNV Rules incorporate knowledge and experience acquired over time and provide a consistent set of standards designed to ensure failsafe design and redundancy to prevent a failure from becoming a critical accident. The Rules and supporting documents are subject to regular updating to reflect operational experience and advances in technology.

Documents for Offshore Class consists of a three level document hierarchy:

— Rules for Classification (Offshore Service Specifications); providing principles and procedures of DNV classification services

— Offshore Standards; providing technical requirements and acceptance criteria

— Recommended Practices and Class Notes; providing DNV best practices as well as guidance related to the higher level documents

Current Rules for Classification of Offshore Floating LNG units are:

— DNV-OSS-103: Rules for Classification of LNG/LPG Production and Storage Units

Current Offshore Standards applicable for Offshore Class are:

— DNV-OS-A101 Safety Principles and Arrangement

— DNV-OS-B101 Metallic Materials

— DNV-OS-C101 Design of Offshore Steel Structures, General (LRFD-method)

— DNV-OS-C102 Structural Design of Offshore Ships

— DNV-OS-C103 Structural Design of Column-stabilised Units (LRFD-method)

— DNV-OS-C104 Structural Design of Self-elevating Units (LRFD-method)

— DNV-OS-C105 Structural Design of Tension-leg Platforms (LRFD-method)

— DNV-OS-C106 Structural Design of Deep Draught Floating Units (LRFD-method)

— DNV-OS-C201 Structural Design of Offshore Units (WSD Method)

— DNV-OS-C301 Stability and Watertight Integrity

— DNV-OS-C401 Fabrication and Testing of Offshore Structures

— DNV-OS-D101 Marine & Machinery Systems & Equipment

— DNV-OS-D201 Electrical Installations

— DNV-OS-D202 Instrumentation & Telecommunication Systems

— DNV-OS-D301 Fire Protection

— DNV-OS-E101 Drilling Plant

— DNV-OS-E201 Hydrocarbon Production Plant

— DNV-OS-E301 Position Mooring

— DNV-OS-E401 Helicopter Decks

The hierarchy of DNV rules for an offshore FSRU installation is presented in Figure 7-1below (FSRUs which follow ship classification practice may be designed in accordance with DNV Rules for Classification of Ships together with Classification Note 61.3 Regasification Vessels) :

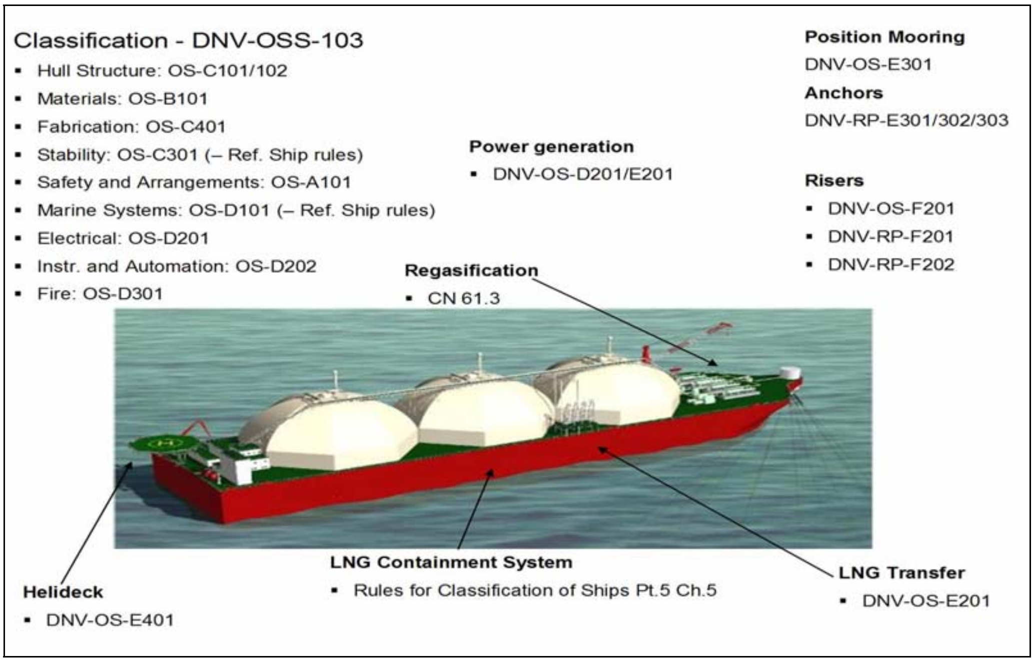


Figure 7-1 DNV Codes for Offshore FSRU

The hierarchy of DNV rules for an offshore LNG FPSO installation is presented in Figure 7-2 below :

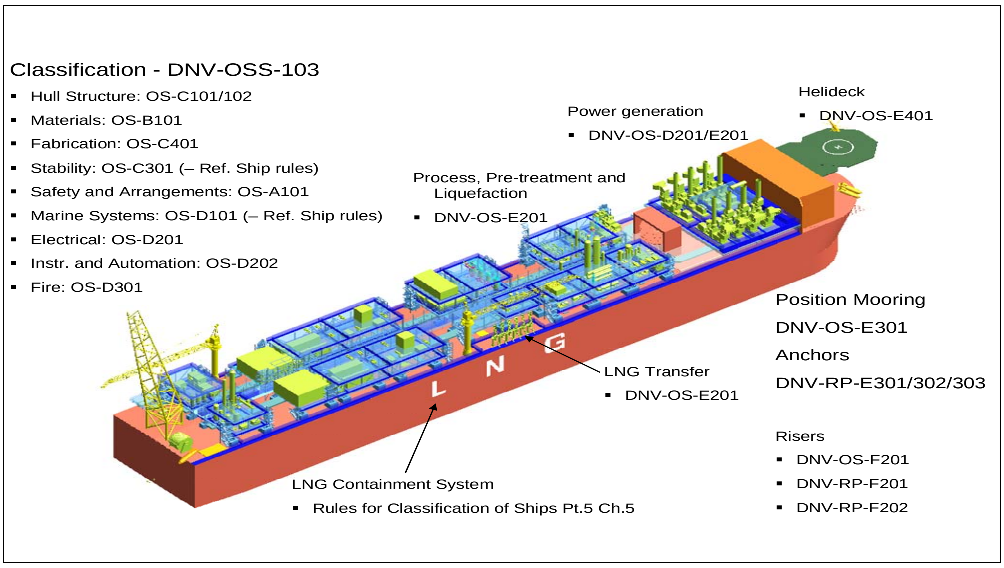


Figure 7-2 DNV Codes for LNG FPSO

7.1.3 Documentation to be submitted

7.1.3.1 General

In this chapter typical documentation to be reviewed in connection with classification of an FLNG (LNG FPSO or LNG FSRU) is described. It is emphasized that the following list is based on a generic FLNG design. The level of detail and areas to be covered will depend on the contractual agreements.

The documents listed include both main class and additional class options, so that the relevant final document list for a project will need to consider whether for example we have an LNG FPSO or an FSRU, whether the process plant is to be included, what sort of mooring arrangement is employed etc.

A detailed list reflecting the type of FLNG and operational mode will therefore need to be established in each case. This specific list of document requirements will normally be established based on a mark-up of the projects own document plan.

It is assumed that critical discrete items of equipment are certified according to recognized codes and standards, or where appropriate subject to technology qualification procedures.

7.1.3.2 Structural Design

The following documentation will typically be required in connection with verification of the design and construction of an FLNG:

Hull Structure

- General arrangement plan
- Plans for spaces and tanks
- Structural design brief
- Design load plan, including design accidental loads
- Structural categorisation plan
- Shell expansion drawing
- Model test documentation
- Loading manual
- Docking arrangement plan
- Fabrication specification, including welding procedures
- Design analyses, both global and local design, including temporary phases such as transit
- Standard details
- Local arrangement plans
- Deck structure in way of topside modules, offloading station, cranes, etc.
- Corrosion protection
- Opening and closing appliances
- Stability including, stability analysis, inclining test procedure, stability manual and watertight integrity plans
- Freeboard plan and list of watertight and weather tight items
- Description of access for inspection and maintenance of the structure
- Topside Structural Design
- Structural plan and design analyses for topside modules
- Structural plan and design analyses for riser balcony

- Cold box structural plan and design analysis
- Deck houses design brief and structural plans
- Explosion wall design brief and structural plan

7.1.3.3 Position keeping

The position keeping system is normally included in the classification of an FLNG. The position keeping system may be based on a position mooring system, a dynamic positioning system, or a combination of the two. The following documentation will typically be submitted:

- Units with Position Mooring System
- Line and anchor pattern
- Type and weight and dimension of all line segments
- Characteristic line strength
- Anchor type, size, weight and material specification
- Arrangement of fairleads ad anchor points/pretensions
- Position and weight of buoyancy elements and weight elements
- Position and type of connection elements, such as Kenter shackles, D-shackles, and triplates
- Windlass, winch and stopper design
- Mooring line tensions in ULS and ALS limit states
- Fatigue calculations of mooring line segments and accessories
- Strength calculations of anchors, windlass components and fairleads
- Corrosion allowance

Furthermore, the environmental data used as basis for the design should be submitted. This should include:

- Waves
- Wind
- Current profile
- Water depths
- Soil conditions
- Marine growth, thickness and specific weight

For FLNGs with thruster assisted mooring systems, the thruster system and thruster control system should also be documented. In addition an FMEA and test program covering failure situations should be included.

Units with Dynamic Positioning (DP) Systems

- DP System Failure Mode and Effect Analysis (FMEA)
- System arrangement plan showing fire and flooding separation
- Cable routing layout drawing
- Environmental Regularity Number (ERN) Calculation
- Details of thrusters, including output and power input curves, response time for thrust changes and direction changes, anticipated thrust reductions due to interaction effects
- Control system philosophy
- Details of main and back-up automatic dynamic positioning control systems
- Details of independent joystick control system
- Details of thruster control mode selection system

- Details of position reference system
- Details of vertical reference, heading reference, wind and other sensor systems
- Power consumption balance
- Power management system FMEA
- Operational manuals

7.1.3.4 Turrets

- General Arrangement drawing
- Design basis
- Materials selection report
- Corrosion protection system deign report
- Equipment list
- Design Accidental Load Specification
- Marine Load summary report
- Operational manual
- Commissioning procedures
- Inspection and maintenance plan
- Buoy pull-in/connect/disconnect & free drop analysis
- Buoy idle motion analysis
- Buoy design drawings, including details, assemblies, bill of materials etc.
- Structural design brief
- Structural plans
- Structural design calculation report
- Fluid transfer system design brief
- Specification of piping, valves and fittings for process and utility systems
- Specification of piping, valves and fittings for hydraulic systems
- Details of swivel including material specification, material and seal properties
- Design-/Calculation report for piping system (including stress isometrics), components and assemblies
- P&IDs and Flow diagrams for process, utility and hydraulic systems
- HAZOP report
- Details of control system including functional description, block diagrams, user interface, power supply arrangement, shutdown logic, description of system response to failure modes, instrument index, etc.
- Details of electrical system including functional description, Ex list, equipment arrangement drawing, single line diagram for geostationary and vessel stationary side, cable routing layout, cable specification, etc.

7.1.3.5 LNG/LPG containment system

The cargo containment system for an FLNG will typically be designed according to the requirements in DNV Rules for Ships, Pt.5 Ch.5 Liquefied Gas Carriers. See the IGC Code for details about tanks type A, B and C. Depending on type of containment system etc. the following documentation will typically be a basis for classification:

Drawing of cargo tanks including information on non-destructive testing of welds and strength and tightness testing of tanks

- Drawings of support and staying of independent tanks
- Drawing of anti-flotation arrangement for independent tanks
- Specification of materials in cargo tanks and cargo piping systems
- Specifications of welding procedures for cargo tanks
- Specification of stress relieving procedures for independent tanks type C (thermal or mechanical)
- Specification of design loads and structural analysis of cargo tanks
- A complete stress analysis is to be submitted for independent tanks, type B and type C
- Detailed analytical calculation of hull and tank system for independent tanks, type B
- Specification of cooling-down procedure for cargo tanks
- Specification of heating-up procedure for cargo tanks (if appropriate)
- Arrangement and specifications of secondary barriers, including method for periodically checking of tightness for membrane tanks and Type A tanks
- Documentation of model tests of primary and secondary barriers of membrane tanks
- Drawings and specifications of tank insulation
- Drawing of marking plate for independent tanks
- Construction and specifications of pressure relief systems for hold spaces, interbarrier spaces and cargo piping if such systems are required
- Calculation of hull steel significant temperature when cargo temperature is below -20°C
- Specification of tightness test of hold spaces for membrane tank system
- Arrangement and specifications of means for maintaining the cargo tank vapour pressure below MARVS – Maximum Allowable Relief Valve Setting (cooling plant, gas burning arrangement, etc.)
- Drawings and specifications of protection of hull steel beneath liquid piping where liquid leakage may be anticipated, such as at shore connections and at pump seals
- Arrangement and specifications of piping systems for gas freeing and purging of cargo tanks
- Arrangement of piping for inerting of inter-barrier and hold spaces
- Location of gas sampling points within cargo tanks
- Bilge and drainage arrangements in cargo pump rooms, cargo compressor rooms, cofferdams, pipe tunnels, hold spaces and inter-barrier spaces
- Sloshing analysis of cargo containment system. The analysis must demonstrate that the containment system, equipment within the cargo tanks, e.g. pump tower, and supporting structure have sufficient resistance for operation at the considered operation sites.
- Facilities for in-service inspection of cargo containment system

7.1.3.6 Gas handling, liquefaction and regasification systems

For the gas processing system typical documentation to be submitted for review is listed below:

- Process system basis of design
- Equipment layout or plot plans
- Heat and mass balance
- Piping and instrument diagrams (P & ID), process flow diagrams (PFD)
- Safety analysis function evaluation (SAFE) charts
- Process isolation philosophy
- Shutdown hierarchy

- Shutdown cause and effect charts
- Flare system design brief giving details of relief systems, i.e. hot-/cold-/high pressure/low pressure relief systems.
- Flare and blow-down system study or report (including relevant calculations for e.g. capacity requirements, back pressure, equipment sizing, depressurising profile, low temperature effects, liquid entrainment etc.)
- Sizing calculations for relief valves, bursting discs and restriction orifices
- Flare radiation calculations and plots
- Cold vent dispersion calculations and plots
- Open and closed drain arrangements
- HAZOP study report
- Piping and valve material specification for process and utility systems (covering relevant data, e.g. maximum or minimum design temperature or pressure, corrosion allowance materials for all components, ratings, dimensions reference standards, branch schedules etc.).
- Line and valve list
- Pipe stress analysis
- Process equipment specification
- Specification of packaged units
- Arrangement showing the location of main electrical components
- "One-line wiring diagrams", cable schedules, equipment schedules, power distribution and main cable layout

In addition, interfaces between the process systems and other utility and/or marine systems should be documented.

7.1.3.7 Offloading System

Document requirements will depend on the type of offloading system used for the project. The below list provides typical document requirements for Offloading Systems:

- Details of ship to ship mooring system including, mooring arrangement, fender loads and quick release system (if applicable)
- Offloading station arrangement plan
- Functional description of offloading system
- FLNG to LNG Carrier interface drawings
- Loading arm general arrangement drawing (if applicable)
- Structural design brief and drawings
- Offloading hose specification (if applicable)
- Transfer hose support and storage arrangement
- Material selection report
- Drawings showing operational envelopes
- Emergency Release System (ERS) drawing showing details of emergency release coupling (ERC) and double block valves
- Failure Mode and Effect Analysis for ERS
- Quick Connect Disconnect system drawing
- Details of swivels and swivel assemblies

- Details of connection targeting system
- P&ID of offloading system showing details of offloading pumps, handling of vapour return, alarms, emergency shutdown arrangements, purging and drain arrangements, etc.
- Interface to FLNG emergency shutdown system
- Details of FLNG to LNG Carrier ESD link
- Electrical equipment list, interconnection diagrams and circuit diagrams
- Cable schedules and routing diagram
- Hydraulic equipment list and circuit diagrams
- Control system logic diagram
- Operation manual

7.1.3.8 Marine and machinery systems

Marine and machinery systems for a floating unit are covered by DNV-OS-D101, *Marine and Machinery System*. Typical systems and document requirements are listed in the following subsections. Documentation for such systems should include:

General

- Tank and capacity plan
- Engine room local arrangement plan and equipment list
- Drain system arrangements and system diagrams
- Line and valve lists for all systems

Propulsion and Steering

- Details of propulsion control and monitoring system
- Propulsion driver arrangements, design analysis, structural drawings, mechanical arrangement drawings
- Propulsion torque and thrust transmission arrangement
- Drawing of propeller shaft including fore and aft connections
- Steering control and monitoring system
- Specification of manoeuvring thrusters including structural drawings, design analysis, piping diagrams and control system

Heating, Ventilation and Air Conditioning (HVAC)

- HVAC philosophy
- HVAC capacity calculations
- HVAC ducting and instrumentation diagrams (D&IDs)
- Plans showing details of HVAC duct penetrations
- Arrangement and specification of Air Handling Units (AHU) and fans
- Electrical schematic drawing showing emergency stop of fans, fail to safe functionality
- Remote operation of valves
- Control diagram for hydraulically operated valves
- Control diagram for pneumatically operated valves

Compressed air

- Compressed air generation unit P&ID
- Working air distribution P&ID

- Instrument air distribution P&ID

Fuel and lubrication

- Fuel and lubrication oil storage arrangement
- Fuel oil system P&IDs
- Quick closing valve arrangement
- Fuel gas piping system diagram showing details of ESD system interface, vent lines from safety relief valves, and arrangement of gas pipes in engine room/non-hazardous areas. (if applicable)
- Lubrication oil system P&ID
- Sludge handling capacity analysis and system P&ID
- Incinerator arrangement plan and system P&ID

Water Systems

- Sea chest arrangement drawings and P&IDs
- Sea water cooling system P&ID
- Fresh water cooling system P&ID
- Fresh water generation system P&ID
- Arrangement of sea connections showing location of sea water intakes, overboard lines and valves.

Bilge & Ballast

- Bilge system capacity analysis
- Bilge system P&ID
- Ballast system P&ID

Sanitation

- Grey water system P&ID
- Black water system P&ID and details of sewage treatment plant
- Garbage disposal arrangement P&ID

Air pipes and sounding

- Air pipes and sounding system P&ID
- Oil discharge control and monitoring system
- Oil discharge control and monitoring (ODM) system P&ID
- Heating system for void spaces, cofferdams (and ballast tanks if appropriate)
- Heat calculation
- System diagram (P&ID)
- Inert gas and gas freeing systems
- P&ID inert gas system showing details of burners, scrubbers, deck water seal, PV valves and breakers
- P&ID for nitrogen plant with connection to the cargo handling system (if applicable)
- P&ID for dry-air plant with connection to the cargo handling system (if applicable)

7.1.3.9 Cargo handling system

- Cargo Handling Safety Philosophy
- Cargo Handling Functional Diagrams

- Cargo Loading/Unloading manual
- P&ID for LNG, LPG, condensate handling system (as applicable)
- P&IDs defining all interfaces, e.g.: Control and Emergency Shutdown Systems, cold vent/cold vent header, PSV vents/PSV vent header, BOG suction drum and BOG compressor, fuel gas system, high duty compressor and heater, LNG process system, metering skid, cargo offloading system, inert gas and gas freeing systems, etc.
- Drawings and specifications of cargo and process piping including vapour piping and vent lines of safety relief valves or similar piping, and relief valves discharging liquid cargo from the cargo piping system
- Drawings and specifications of offsets, loops, bends and mechanical expansion joints, such as bellows, slip joints (only inside tank) or similar means in the cargo piping
- Drawings of flanges and other fittings in the cargo piping system unless in accordance with a recognised standard
- Drawings of valves in the cargo piping system, if of a new type or of an unconventional design
- Complete stress analysis of piping system when design temperature is below -110°C
- Documentation of type tests for expansion components in the cargo piping system
- Specification of materials, welding, post-weld heat treatment and non-destructive testing of cargo piping
- Specification of pressure tests (structural and tightness tests) of cargo and process piping
- Program for functional tests of all piping systems including valves, fittings and associated equipment for handling cargo (liquid or vapour)
- Drawings and specifications of insulation for low temperature piping where such insulation is installed
- Specification of electrical bonding of piping
- Specification of means for removal of liquid contents from cargo loading and discharging crossover headers and or cargo hoses prior to disconnecting the shore connection
- Drawings and specifications for safety relief valves and pressure/vacuum relief valves and associated vent piping

7.1.3.10 Safety and Fire protection

As a general basis for the fire protection and safety systems, a risk analysis should be conducted, where design accidental loads are defined, as well as risk mitigating measures. These loads should cover fire and explosion loads, impact loads from dropped objects and collisions, unintended flooding and loads caused by extreme weather. Based on input from the risk analysis and prescriptive requirements in applicable codes, the following should typically be documented:

General Safety

- HAZID and HAZOP reports
- Risk Assessment including dimensional accidental loads, assumptions and recommendations
- General arrangement of the FLNG
- Specification of dimensional accidental loads
- Emergency shutdown (ESD) philosophy
- ESD hierarchy and Cause and Effect diagrams
- Details of Critical Alarm and Action Panel
- Safety plan
- Escape route plan

- Evacuation Philosophy
- Temporary refuge impairment study
- Cryogenic spill protection philosophy
- Cryogenic spill containment and protection arrangements
- Hazardous area classification and source of release schedule
- PA/GA functional description, arrangement plan showing location of loudspeakers and centrals, data sheets with environmental description, and electrical schematic drawings.
- Decontamination shower and eye washer arrangement
- Emergency towing arrangement
- Operation manual

Fire Safety

- Fire protection philosophy
- Fire and Explosion analysis
- Active fire fighting systems, including pumps and distribution system
- Fire water demand calculation
- Dry powder extinguishing system
- Fixed fire fighting systems in specific areas, e.g. water mist system
- Fire and Gas detection and alarm system
- Fire and Gas Cause and Effect charts
- Passive fire protection arrangement

7.1.3.11 Electrical systems

The verification of the electrical power generation and distribution system on the FLNG will be based on the following typical documentation:

- Overall single line diagram for main and emergency power
- Principal cable routing sketch
- Cable selection philosophy
- Load balance
- Discrimination analysis
- Table of Ex-installation including details of installations in hazardous areas
- Electrical system calculations
- Battery systems

7.1.3.12 Instrumentation and control systems

Typical documentation for instrumentation and control systems is:

- Functional description of control systems
- System block diagrams
- Power supply arrangements
- User interfaces
- Instrumentation and equipment lists

- Arrangement and layouts
- Description of functions covered by software

7.1.3.13 Helicopter Decks

- Helicopter deck design analysis
- Arrangement plan, including markings, safety net, lighting, visual aids and obstacle limitation sectors
- Helicopter deck sub-structure plan
- Helicopter deck structural plan
- Helicopter deck markings plan
- Drainage arrangements

7.1.3.14 Testing and commissioning

- Commissioning procedures
- NDT plans
- In-service inspection plan

7.2 Regulatory compliance / statutory services

7.2.1 General

Floating LNG units will be subject to requirements specified by different regulators depending on the mode of operation and intended area of operation. In this respect the main players will be the Shelf State (in which operations take place) and the Flag State (where a floating installation is registered with such). There may be a difference in regulatory regime between an LNG FPSO and various types of FSRUs.

7.2.2 Flag State Compliance

The FSRU will typically have much in common with a gas carrier when it comes to regulation. Besides complying with Classification rules for ships, LNG carriers, in general, are required to comply with requirements of the flag state in which a vessel is registered. Normally flag state requirements are synonymous with the IMO Conventions, although in some few cases flag states may have some additional requirements. The most important relevant IMO Conventions include:

- Safety of Life at Sea (SOLAS)
- International Convention on Load Lines (ILCC)
- Marine Pollution Convention (MARPOL)
- IGC Code

In addition working conditions onboard ship may be governed by requirements specified by the International Labour Organisation (ILO).

Compliance with the IGC Code is primarily to meet Flag State requirements when an FPSO is flagged. There can be cases where it is not necessary to flag an FPSO, as in Australia, however the scope of issues covered by flag will still need to be addressed to meet the Shelf State regulations and in the absence of other recognised standards the maritime flag requirements would still form the basis of assessment.

The IGC Code however was not specifically written with, for example, a gas FPSO application in mind so that it may not cover some very important issues and necessary design solutions, and also may not be fully appropriate in the areas which it does cover. It may be both too conservative in certain areas and not sufficiently conservative in others. It is DNVs understanding that flag states will expect to see compliance with IGC Code but will accept well justified deviations or arguments for equivalence. It is up to the Flag State to assess such deviations, however that assessment will certainly consider the recommendations and assessment of the Class Society. It is anticipated that future development of the IGC Code will open for more use of Risk Assessment in addressing novel issues. This is further discussed in 7.2.4.

7.2.3 Shelf State Compliance

The significant difference with regard to gas carriers however will be the need for a floating terminal to comply with Shelf State regulations. For a floating offshore terminal the class rules for offshore installation will generally be applicable together with IMO Conventions. In theory Flag State or Class compliance may or may not be required by National Authorities for permanently located units (however the issues addressed by Flag State and Class requirements will still need to be addressed).

Depending on the jurisdiction the Shelf State requirements may be significantly different in form or content from maritime legislation (e.g. Safety Case format) and may address areas not clearly focused on by maritime legislation (e.g. working environment aspects) or may essentially call only for compliance with maritime legislation.

Floating installations permanently located on a continental shelf producing gas from a well (as in the case of an LNG FPSO) would come under the authority of the Shelf State (also referred to as the Coastal State). The Shelf State can specify requirements to such installations on matters which may range from taxation, working environment, management systems to environmental and technical safety. There is no international agreement on which requirements individual Shelf States can specify

Some typical examples would be as follows :

In Australia and LNG FPSO should follow the Safety Case regulations specified by the regulatory authority, NOPSA. For a ship-shaped unit the technical requirements would largely be met by compliance with Classification and flag state requirement for the FPSO combined with risk analysis. The technical solutions would need to be incorporated into the Safety Case format.

In Indonesia, the national regulations for an LNG FPSO can be complied with by use of classification and Flag State compliance. The classification needs of course to be related to operation as an offshore installation.

In Brazil, a similar approach to that described above with use of Classification and Flag State certificates can be applied. However instead of reference to the SOLAS Certificate, offshore units should comply with the IMO MODU Code.

DNV has in-depth knowledge of coastal state safety regimes and offers additional compliance services to assist clients toward fulfilling coastal state requirements, crediting class to the extent possible.

7.2.4 Validity of IGC Code

Below are discussed a number of issues, covered by the IGC Code, which could possibly be subject to consideration with regard to validity and applicability for FLNG projects (this listing is not intended to be comprehensive) :

- **Location of the accommodation block forward**

There are a number of valid safety arguments to support location of living quarters in the bow area of an installation continuously processing gas and which is either non self-propelled or which moves very infrequently. Very many oil FPSOs are designed with this arrangement based on conclusions from Risk Assessment.

- **Use of gas turbines in the cargo storage area**

Many floating terminals with very high energy demands (e.g. for liquefaction) may prefer to generate power locally in the process area by use of gas turbines rather than remotely from an engine room for example. The hazards associated with locating such units have been assessed and found acceptable in many oil FPSO applications.

- **Design of tank venting systems**

Traditional tank vent design on a gas carrier considers individual vents for each storage tank. This may not be practicable in a floating terminal design, particularly those with a large topsides structure above the storage tanks.

Experience with Oil FPSOs and safety studies on terminal concepts has shown that local venting of gas from storage tanks can lead to unnecessary shutdown triggered by gas detectors in the process plant and may also represent a hazard to personnel working within the process area.

The solution usually chosen is to manifold relief lines from the tanks to a single vent line located away from the storage area.

Design of the venting system in accordance with the IGC Code would result in an impracticable solution with regard to piping dimensions. The basis of the IGC design criteria are not made explicit.

It is therefore recommended to base a design on first principles and base fire loading on an assessment of project specific design accidental events.

- **Design of ESD systems**

The control and instrumentation requirements described in the IGC Code and the supplementary guidance provided by SIGTTO for terminal operations reflect the typical operations of a gas carrier in sailing mode and while offloading at a land terminal.

The requirements do not reflect the complex operations required of a floating LNG terminal with continuous gas processing, simultaneous hazardous operations, and configurations involving close proximity and cooperation with respect to visiting shuttle tankers.

Typically therefore a more stringent approach is necessary involving significantly more complexity.

- **Design of gas detection systems**

Trading LNG carriers are fitted with Fire and Gas Detection systems. The hazard scenario on an FLNG is however somewhat different compared to the gas carrier in that the potential for fire and gas release is increased due to the increased complexity and the consequence of such an incident is also potentially greater.

To a large extent fire and gas release on a gas carrier and actions required to tackle such events are relatively uncomplicated in terms of location of such events and likely subsequent development. Traditionally tackling these issues has involved a large degree of human intervention. This also reflects the fact that many of the most hazardous operation on a gas carrier, such as loading and unloading, are of relatively short duration and can be continuously monitored by personnel at a high level of alertness.

Continuous 24/7 operation, involving gas processing on deck, needs to be monitored by a more complex and automated monitoring system. In addition the potential for escalation and the nature of such escalation will be more severe for an FLNG .

Continuous gas detection rather than gas sampling and automatic response to fire and gas alarms rather than human intervention is therefore advisable.

- **Fire safety arrangements/fire divisions**

Prescriptive requirements are given in the IGC Code both concerning active fire protection systems and rating of fire divisions. These should be re-visited in light of fire loads determined through risk assessment and availability of capacity in an accident scenario.

- **Use of LPG as a fuel**

Current requirements only specifically permit methane to be used as a fuel (in Machinery spaces of Category A). However other fuels can be considered acceptable if an equivalent level of safety can be documented compared to using LNG boil-off gas.

- **15-day criterion in tank design**

For a membrane tank, design of the secondary barrier shall be such that it is capable of containing any envisaged leakage of liquid cargo for a period of 15 days, For an independent tank the calculated remaining time to failure, from detection of a leakage to reaching a critical state shall not be less than 15 days. The reasoning behind such a limit is not specified however this period originally related to maximum sailing time to an LNG terminal at which a tank could be emptied. A more appropriate criterion related to actual safety procedures may be considered.

Therefore, for the sake of Flag State compliance, it is recommended to use the IGC Code as a basis and where any areas of deviation exist that these be assessed in light of an engineering study and/or a risk assessment.

7.3 DNV Consulting Services

Further DNV services which might be applicable to offshore LNG projects are described in Appendix D to this document.

APPENDIX A - RISK ASSESSMENT METHODOLOGY

A USE OF RISK ASSESSMENT METHODOLOGY

A.1 General

In recognition of the fact that new concepts, such as offshore terminals, represent elements of novel technology, the generic prescriptive requirements used in Classification Rules are also supplemented by recommendations to use risk assessment to identify and mitigate against hazards associated with novel technology and novel application of existing technology. In addition many hazards and design loads will be specific to individual FLNG design so that it is necessary to assess these specifically from project to project.

Risk assessment is the overall process of risk (hazard) identification, risk analysis and risk evaluation. The results of the assessment identify areas of most significant risk and enable risk reduction measures to be targeted where most effective.

Risk assessment is intended to provide input to design through systematic consideration of: the hazards that can occur, the role and performance of structure and facilities in preventing and protecting against hazards, and the effects of hazards on safety of personnel and the environment.

The risk assessment is intended to be complementary to, and integrated with, the application of recognised design standards. The guidance and requirements of engineering standards will provide the basis for detailed engineering design that can be optimised by the application of, and findings from, the assessment (e.g. establishing optimum dimensioning accidental loads).

The assessment should ideally be performed at concept stage and updated as the design evolves through detailed design and construction.

Preliminary assessment work should aim to ensure that a safe practicable concept is carried forward to detailed design. Matters to be considered include inherent safety through avoiding unnecessary hazards, reducing hazards, optimizing layout etc.

A typical assessment process is shown in Figure A-1. Some stages may require an iterative process as the concept develops and more details are known.

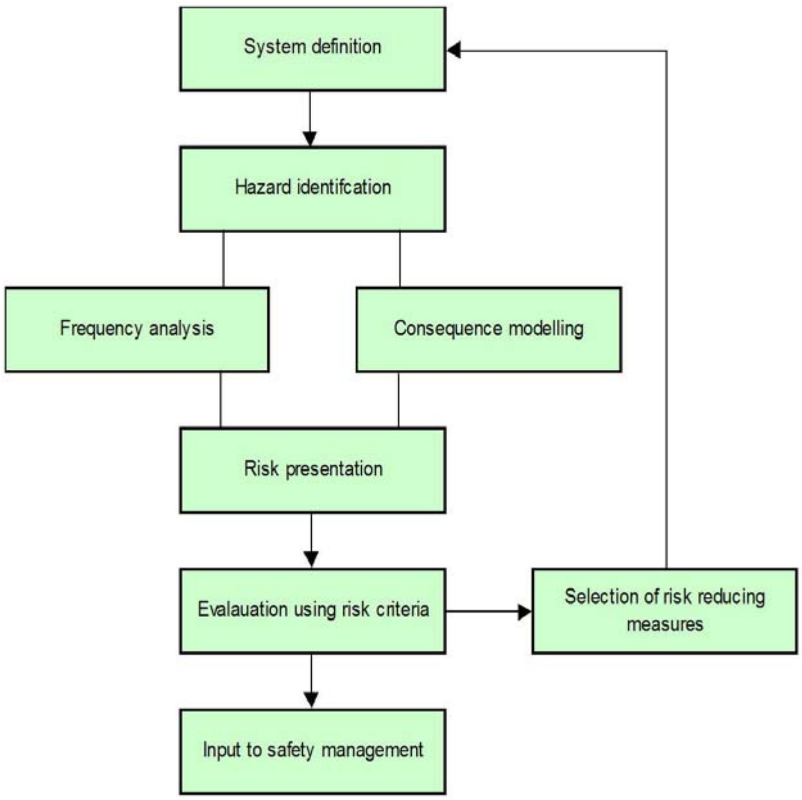


Figure A-1: Flowchart for Safety Assessment

The content of the principal tasks is described in the following sections.

A.2 Hazard identification

Hazard identification should be by means of formal identification techniques, e.g. HAZOPS, HAZID, FMEA etc., by competent personnel from a suitable variety of engineering disciplines, operational and design backgrounds. The identification should, as a minimum, focus on hazards that could directly, or indirectly, result in:

- loss of life
- major fire or explosion
- cryogenic release
- loss of structural integrity or control
- the need for escape or evacuation
- environmental impact

Although not directly related to safety the Operator will usually also consider economic loss and loss of reputation.

A typical, but not necessarily exhaustive, list of hazards for an FLNG would be:

- loss of containment
- Escalation of leakage as a result of cryogenic spill
- gas release into confined space
- release of toxic or other hazardous substances
- fire and explosion
- collisions
- helicopter crash
- structural and/or foundation failure
- dropped objects
- stability and buoyancy failure
- loss of mooring or other position keeping means

A.2.1 Hazard frequency and consequence reduction

Identified hazards should be avoided wherever practicable. This can be achieved by either:

- removal of the source of a hazard (without introducing new sources of hazard), or,
- breaking the sequence of events leading to realization of a hazard.

Where hazards cannot be avoided, design and operation should aim to reduce the risk level by reducing the likelihood of hazards occurring where practicable, for example by:

- reduction in the number of leak sources (flanges, instruments, valves etc.)
- removal or relocation of ignition sources
- simplifying operations, avoiding complex or illogical procedures and inter-relationships between systems
- selection of other materials
- mechanical integrity or protection
- reducing the probability of external initiating events, e.g. lifting operations etc.
- reduction in inventory, pressure, temperature
- use of less hazardous materials, processes or technology

Since the overall level of risk is a product of the likelihood and the consequence, risk may also be reduced by tackling the consequences. The consequences of hazards should be controlled and mitigated with the aim of reducing risk to personnel where practicable, for example through:

- separation of hazardous spaces from less hazardous spaces and each other
- relocation of equipment, improved layout
- provision of physical barriers, distance separation, fire walls etc.
- provision of detection and protection systems
- provision of means to escape and evacuate

As a general principle measures to reduce the frequency should be preferred to measures to reduce consequence.

A.2.2 Hazard evaluation

Identified hazards and potential escalation need to be evaluated based on their effects, consequences and likelihood of occurrence. This evaluation should address the sources and contributors in the chain of events leading to a hazard, including the effect of any prevention and protection measures. The evaluation may be by means of qualitative and/or quantitative analysis as necessary to provide input for comparison with safety targets and safety criteria. Where used, models and data should be appropriate, and from industry recognised sources. Hazards that are commonly considered as not reasonably foreseeable, i.e. extremely unlikely to occur, may be discounted from the evaluation provided that this is clearly indicated and justified in the assessment.

A.2.3 Dimensioning accidental loads

The risk assessment will identify a number of residual risks which must be accounted for in the design. The design needs to be dimensioned for the anticipated loading from these accidental events.

The dimensioning accidental loads for an offshore terminal structure and important safety systems on the terminal shall be identified and included in the evaluation. These are expected to include accidental loads such as:

- toxic or flammable fluids (e.g. smoke, hydrocarbon gas, etc.)
- cryogenic release
- fire
- explosion
- flooding and stability
- collision and impacts
- environmental effects
- and their effect on systems or facilities such as:
- fire and gas detection
- ESD, PSD, and other shutdown systems
- containment system instrumentation
- flare and depressurising system (blowdown/venting)
- fire and explosion protection
- active fire protection systems
- impact protection
- alarm, internal, and external communications
- emergency power systems and UPS
- arrangements for escape and evacuation
- life support at temporary refuge and muster facilities

- structure
- mooring or positioning system
- stability systems

Having identified the design accidental loads, their effects may be assessed by reference to DNV-RP-C204 Design against Accidental Loads (draft).

A.2.4 Safety Criteria

The final selection of dimensioning accidental loads needs to be suitable for the installation to meet the defined safety criteria. Table A-2 shows typical safety targets. Where the safety criteria are exceeded, the initial dimensioning loads may need to be revised.

Table A-2: Typical Safety Targets

No.	Safety target
1.	An escape route shall be available from every work area for sufficient time for personnel to reach the temporary refuge or evacuation facilities.
2.	The temporary refuge shall be capable of providing life support and communications for sufficient time to enable controlled evacuation from the unit or installation.
3.	Evacuation and escape facilities shall be available and reliable for use.
4.	Simultaneous loss of all safety targets shall not occur during the time required to: mitigate an accidental event, or leave the unit or installation.

A.2.5 Assumptions

Any risk assessment will be based on assumptions made with regard to the design, construction and operation of the installation. It is important that these assumptions are recorded and are fed into the projects design, construction and operational phases. It is also important that any change in validity of these assumptions is recorded and assessed for impact on the conclusions of the risk assessment.

A.2.6 Documentation of Safety Level

By following the risk-based approach described above and incorporating specific regulatory requirements, a project should be able to provide a structured and documentable confirmation that the project has achieved the intended level of safety and has met the defined regulatory requirements.

APPENDIX B - RISK BASED MAINTENANCE AND INSPECTION

B RISK BASED APPROACH TO MAINTENANCE AND INSPECTION

B.1 Risk Centred Maintenance

A planned maintenance system based on Risk Centred Maintenance (RCM) may be accepted by DNV. An approved planned maintenance system is a pre-requisite for this survey arrangement. Compliance with the relevant Rule requirements is therefore necessary, with the exception of the requirements related to maintenance intervals.

The RCM system adopted should be based on an internationally recognized standard such as SAE JA1011 or ISO 60300-3-11.

The following information will form the basis for DNV assessment:

The RCM analysis should include the following:

- methodology used for selecting systems
- decision criteria for ranking criticality
- standard used as a baseline (e.g. SAE / ISO)
- details of the participants in the analysis, with qualifications
- The systems and equipment covered by the analysis
- Equipment manufacturers guidelines for minimum maintenance levels
- Details regarding implementation of the RCM analysis into the PM system
- Methodology for continuous improvement / refinement of RCM system

The following seven steps are to be taken into account for machinery systems covered by the RCM philosophy:

- What are the system functions and associated performance standards?
- How can the system fail to fulfil these functions?
- What can cause a functional failure?
- What happens when a failure occurs?
- What effect or consequences will a failure have?
- What can be done to detect and prevent the failure?
- What should be done if a maintenance or proactive task cannot be found?

If condition monitoring of equipment is to be carried out as part of the RCM system, this is to be carried out in accordance with an approved program. See DNV Classification Note 10.2 *Guidance for Condition Monitoring* for further details. Condition monitoring of equipment will normally be approved on an individual equipment basis.

An implementation survey onboard the vessel is required in order to verify that the RCM analysis is properly implemented into the PM system onboard. It is recommended that the system has been implemented and operated for at least 6 months before the implementation survey is carried out.

In order to verify the system and the crew's general knowledge, the implementation survey is to be carried out during normal operation. On a successful implementation survey, a certificate for machinery RCM will be issued stating conditions for the survey arrangement and the machinery included in the arrangement.

To maintain the validity of the survey arrangement machinery RCM, an annual survey of the implemented system is required. This survey replaces the annual and renewal surveys of machinery for components included in the RCM system.

The purpose of this survey is to review and evaluate the previous period's maintenance activities and experience.

The annual survey shall normally consist of examination of:

- Condition monitoring records
- Maintenance records
- Assessment of RCM handling onboard
- Verification that the spares required to be held onboard is in place.
- If found necessary by the surveyor, opening or testing of machinery may be required.
- To prolong the validity of the survey arrangement a renewal survey of the implemented RCM system during normal operation is required. The purpose of this survey is to verify that:
- Procedures for carrying out RCM are followed
- The vessel's crew are familiar with system and handling of results
- Re-evaluation of maintenance schedules as required.

Any modifications to equipment or machinery systems which could impact the RCM system must be documented and forwarded to DNV for approval.

B.2 Risk Based Inspection

B.2.1 General

RBI provides a consistent framework for decision making under uncertainty. The main principle behind the approach is that different inspection strategies are compared in terms of the risk they imply. Risk in this sense is defined as the product between likelihood and consequence of failure. Risk may be assessed for the safety of personnel, environmental impact as well as for monetary costs or any other criterion of relevance for the installation. The RBI approach is a condition based approach by which the inspection effort is adapted to the condition of the item and prioritized in accordance with the:

- Importance of the individual items, and the
- Different deterioration mechanisms.

In order to control the risk level, it is necessary to determine the probability for different failure scenarios over the (extended) service life, both for the individual components in the structure and for the structure as a system. Probabilistic models based on the use of structural reliability methods are required for incorporating these aspects in the determination of the safety level of the structure over the service life. The RBI methodology is now being used for planning in-service inspection of fatigue cracks in jacket structures, semi-submersibles and floating production vessels.

For a ship-shaped unit, fatigue cracking of the hull and the topside structures are generally not considered to be a threat to the safety of personnel and pollution. When the consequences of a failure are limited to economic aspects and only involve negligible risk to personnel or environment, the selection of a target reliability level may be based on a cost optimal solution, i.e. the expected value of the economic consequences are kept at a minimum. These economic consequences may vary for similar details, with the same fatigue lives, in different area of the structure. Therefore, the optimal maximum acceptable annual failure probability (or target failure probability) for these similar details may vary.

A typical RBI project consists of three main activities:

- Collection of available information
- RBI analysis (screening and detailed assessment)
- Preparation and implementation of an In-service Inspection Program (IIP)

A brief description of these activities is given below.

B.2.2 Collection of available information

The RBI analysis is normally based on existing design and/or re-analysis documentation. This reduces the need for additional structural analyses. Inspection and maintenance history, together with fatigue analyses in addition to structural drawings are the most important information.

B.2.3 RBI Analysis

In essence the RBI analysis is performed in two steps:

- Risk screening, and
- Subsequent detailed assessment.

B.2.3.1 Screening Activity

The main objectives for the screening activity are:

- Identify critical connections with respect to the capacity (e.g. low fatigue lives, uncertainties in fatigue lives),
- Identify critical connections with respect to the consequence (production, pollution, human lives),
- Systematisation of inspection, maintenance and repair history, and
- Generate necessary input to the detailed RBI analysis.
- Gap analysis (evaluate if all information necessary to perform the RBI analysis is available)

The risk screening activity is an important tool to collect current information with respect to the likelihood and consequences of deterioration for a given structure. Also, possible strategies for inspection and repair are treated in this process.

A screening meeting is an efficient tool to systemise the necessary input to the RBI analysis from the operator. The following information should be established in such a meeting:

- Consequence of failure e.g. fatigue cracking,
- Inspection methods,
- Inspection costs, repair and failure costs (costs associated with component failure e.g. through thickness cracking)

B.2.3.2 Detailed Assessment

The detailed RBI is normally centred on the inspection planning of structural components subjected to fatigue crack growth. Only the components identified during the risk screening process are considered in the detailed RBI.

In general, acceptable probabilities of failure, or target reliabilities, for the different structural components depend on the consequence of the failure events considered. The evaluation of the consequence of failure is made with respect to personnel risk, environmental risk and economic risk. For components where the risk to personnel or the environment is considered to be high, the acceptance criterion (accumulated target failure probability) is often deduced from requirements to structural strength in storm conditions. When the accumulated probability for failure within a year exceeds the target value for the failure probability, an inspection of the structure for undesirable degradation is to be made, see example in Figure B-1. The inspection plan may be defined based on a specified target failure probability or through the obtained cost-optimal target failure probability.

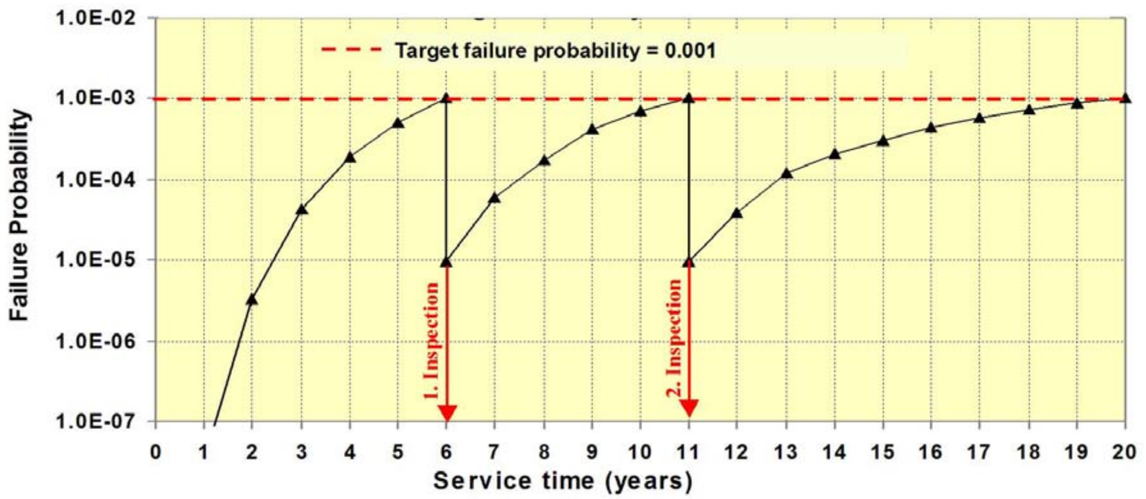


Figure B-1: inspection plan for as-welded butt-weld for target failure probability of 0.001

Normally the development of a (through-plate) crack penetrating a plate will not in itself imply a severe consequence, but rather it may serve as an initiating event, such as explosions or fracture. The conditional probability for a severe event that results from a through-plate crack, needs to be addressed, such as:

- Leakage of hydrocarbons in a floating production vessel may imply a high risk with respect to loss of human lives and/or pollution, or
- Leakage of cryogenic fluid on an FPSO may result in structural damage
- Loss of one member of a flare tower, loss of crane pedestal structural integrity, loss of one member in a drag chain tower and loss of structural strength in non-redundant members in production modules may be defined to have a severe consequence.

To account for various outcomes of the inspections, the detection level of the inspection equipment applied and the uncertainties associated with the sizing of the inspection outcome must be applied. The estimated reliability can be updated during the design life by utilizing the inspection results, where aspects associated with the detection level and measurement accuracy of the inspection and monitoring procedures are included in the updated analysis. Each of these provides information about the condition of the structure, in addition to the information available at the design stage, and will hence reduce the uncertainty associated with the assessment of the structural reliability. The initial models used at the design are then updated and calibrated against accumulated experience by accounting for this information in a rational manner.

B.2.4 Preparation of Inspection plan

The final deliverable from an RBI project is an in-service inspection program (IIP), in which inspection efforts are prioritised from an overall risk perspective. The items to be inspected are collected and grouped into suitable intervals. The IIP describes:

- Where to inspect (which locations/areas),
- What to inspect (which items),
- How to inspect (NDT method, and extent of inspection), and
- When to inspect (inspection time).

The RBI results allow the IIP to be updated. The level of detailing of the NDT inspections on the RBI based plan is usually higher than the traditional IIP, i.e. location of the hot-spots is documented in more detail, as shown in Figure B-2.

Det Norske Veritas	FPSO In-service Inspection Program Framework - Inspection of External Main Deck																						
Fatigue Point	Longit. Number	Frame	Plate	Side	Detail	Fig. No.	HS No.	Req. Basis	2004	2005 RS	2006	2007	2008 IS	2009	2010 RS	2011	2012	2013 IS	2014	2015 RS	2016	2017	2018 IS
MD_ab_WBT5_0	L23-L24	54	MD	P&S	Ballast tank level penetr.	C-2	2	RBI															
MD_ab_WBT5_0	L23-L24	54	MD	P&S	Ballast tank penetr. Gas detection	C-3	2	RBI														EC	
MD_ab_WBT5_0	L23-L24	54	MD	P&S	Sounding on deck	C-7	2	RBI															
MD_ab_WBT5_0	L24-L25	55	MD	P&S	Inert gas to ballast tank	C-9	2	RBI															
MD_ab_WBT5_0	L23-L24	57	MD	P&S	Deck scupper	C-10	2	RBI							EC								
MD_ab_WBT5_0	L24-L25	61	MD	P&S	Ballast tank Vent	C-8	2	RBI															
MD_ab_WBT5_0	L23-L26	55	MD	P&S	Buttweld, t = 22-24mm			RBI															
MD_ab_WBT5_0	L23-L26	57	MD	P&S	Buttweld, t = 24-25mm			RBI															
MD_ab_WBT5_1	L23-L26	60	MD	P&S	Buttweld, t = 25-26mm			RBI															
MD_ab_WBT5_1	L24-L25	54	MD	P&S	Manhole 1100*750 (R1200 / R150)	C-40		RBI													EC		
MD_ab_WBT5_1	L24-L25	56	MD	P&S	Manhole 800*600	C-40		RBI															
MD_ab_WBT5_1	L24-L25	61	MD	P&S	Manhole 800*600	C-40		RBI												EC			
MD_ab_WBT5_1	L1-L23	62	MD	P&S	Doubling plate (assumed 200*200)			RBI												EC			
MD_ab_WBT5_1	L1-L23	62	MD	P&S	Topside support connection			RBI												EC			

Figure B-2:Example Inspection plan with required inspection intervals

B.2.5 Class Approval of the RBI Program

Since the RBI program is to be used as a part of the Class survey process, it is required that it is reviewed and approved by Class. In order to get approval, it is necessary to document the following:

- Analysis methodology applied
- List of assumptions
- Tools / software used
- Input data, including fatigue analysis methodology and results
- List of reference documentation
- Description and maintenance strategies for corrosion protection systems
- Screening findings, including damage types, frequency and consequences
- Description and checklists concerning areas to be inspected, methods to be used and reporting procedures
- Identification of specific NDE procedures or inspection qualifications

An RBI program should be considered as a living document, where the survey results from the Class inspection intervals and owner/operator's own inspections are incorporated into the program for updating and modification, if necessary. Normally the owner/operator maintains and updates the inspection program. However, Class shall be notified when changes are made. The minimum frequency of inspection is pre-determined by unified IACS (International Association of Classification Societies) requirements and international codes, such as SOLAS and MODU Code. All IACS member Class societies are harmonized on this point.

APPENDIX C - ASSESSMENT OF NOVEL CONCEPTS AND TECHNOLOGY

C ASSESSMENT OF NOVEL CONCEPTS AND TECHNOLOGY

C.1 Assessing Novel designs

C.1.1 General

DNV apply several methods of assessing novel designs. For large scale concepts (such as an LNG FPSO design) an approach termed Approval in Principle is typically applied. For more discrete subsystems and components (such as an LNG transfer system or a regasification plant) an approach termed Qualification of Technology is typically applied. Selection of approach will be related to the level of development of the design and the desired statement to be issued at the end of the process. In general the Approval in Principle can be seen as representing a similar level of assessment as the Statement of Feasibility issued in the early stage of a Qualification of Technology process. Both these processes are explained in more detail below.

C.1.2 Approval in Principle

An Approval in Principle (AiP) is an independent assessment of a concept within an agreed requirement framework confirming that a design is feasible and that no insurmountable obstacles ("showstoppers") would prevent the concept being realised.

An AiP is typically carried out at an early stage of a project to confirm its feasibility towards the project team itself, company management, external investors or future regulators. Since it is carried out at an early stage of design it will, of necessity, have to be based on a limited level of engineering detail, and therefore will only focus on the major hazards to a project.

An AiP can be a stand-alone study or it may be a step towards achieving full Classification approval. The AiP will typically identify a number of areas that will need to be addressed during detailed design in order to prepare the design ready for Classification Approval. This is illustrated in Figure C-1.

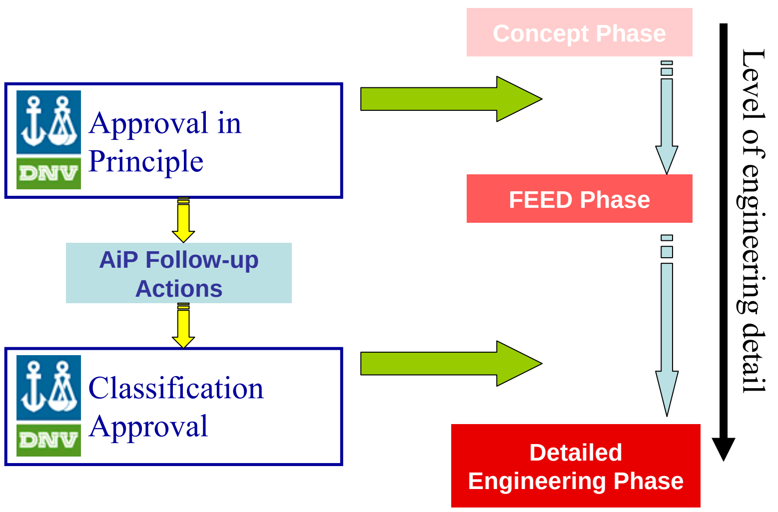


Figure C-1: Approval in Principle - Timing and Context

Approval in Principle is particularly useful to assess novel designs which will not be adequately addressed by existing recognized codes and standards.

The AiP approach is a risk-based approach, which is considered as the most effective means of identifying and addressing hazards associated with a novel concept. Such hazards may arise from use of novel technology (or operation), from a novel application of existing technology and from an interface between novel and existing technology. Identifying these areas is a key part of the AiP process, which will be initially intuitive and then subsequently part of a structured iterative process.

Having identified hazards to be further addressed, the AiP process will assess how the designer has addressed these concerns (typically the designer will carry out risk and engineering studies to document the probability and consequence associated with the hazards and the effects of mitigation measures proposed).

The AiP process will review documentation produced in the risk assessment, will confirm that all considered risks have been adequately addressed and that mitigation measures are considered appropriate. Compliance with relevant prescriptive requirements will also be considered.

It may also be appropriate to consider any regulatory barriers which might impact the design.

In addition, actions to be taken towards full classification (The Path Forward) will be listed. This process is illustrated in Figure C-2.

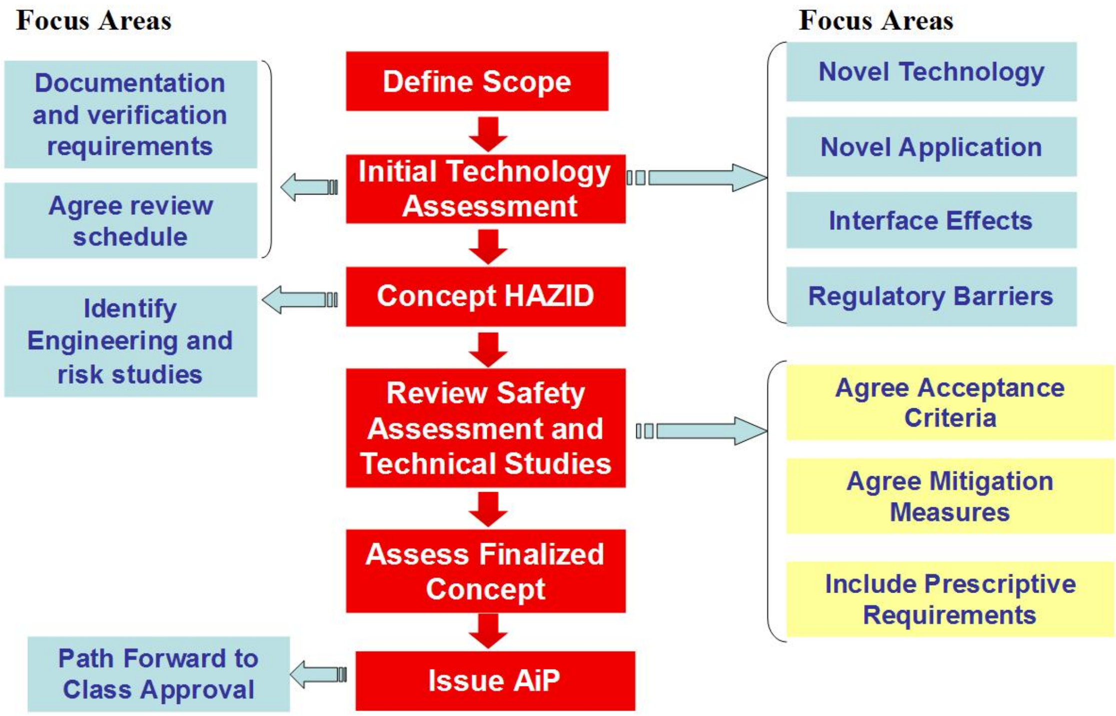


Figure C-2: Approval in Principle Process

C.1.3 Typical Scope for AiP

The Scope of Work for issue of an Approval in Principle includes the following activities which are derived from the flowchart in Figure C-2 .

Define Scope

In order to make the DNV project team familiar with the concept, it is necessary to review available design documentation. This would typically include available Concept Engineering documentation as follows:

- general arrangement and layout drawings,
- design basis or design philosophy documents,
- process descriptions and process flow diagrams,
- operation philosophy
- safety philosophy
- conceptual level design documents addressing :
- material selection
- structural strength

- stability
- safety systems
- emergency shutdown
- electrical systems
- mechanical systems
- constructability
- maintenance, inspection philosophies

In addition it is useful to review any engineering or safety studies previously carried out where any of the key novel aspects are addressed.

Agreeing the plan of assessment and also identifying a schedule for involvement for the AiP process is based on a dialogue between DNV and the Client.

Initial Technology Assessment

The concept is broken down into its key technology elements and these are assessed for degree of novelty. Those areas with a significant degree of novelty will then be the focus of the future work. This assessment methodology is illustrated in .Figure C-3

Operating Condition	Technology Maturity		
	Proven	Limited field history or not used by Company	New or unproven
Previous experience	1	2	3
No experience in Company	2	3	4
No industry experience	3	4	4

Figure C-3: Technology Assessment Matrix

The ratings given in the matrix have the following meaning:

- No new technical uncertainties
- New technical uncertainties
- New technical challenges
- Demanding new technical challenges

This provides an initial listing of areas which need to be addressed in the project (it may be further refined after the HAZID).

Participate in Concept HAZID

In order to fully identify and discuss the key areas on which to focus, a Hazard Identification study (HAZID) must be carried out. This would typically involve a qualified HAZID leader who would facilitate the study, together with a team of Client specialists with details of the design and intended operation.

As part of the AiP process DNV (Classification Unit) would attend the HAZID.

Please note that DNV can also assist in the organisation and running of such HAZIDS by providing personnel from other parts of our organisation who specialise in the methodology of the HAZID.

Review engineering and risk assessment documentation for compliance

DNV will review documentation produced as a result of the risk assessment process and also documentation to address any relevant prescriptive requirements or regulations.

Final concept review

It is anticipated that the process may involve the designers re-visiting certain aspects underway. The Approval in Principle will address these minor modifications for the finalized concept.

Issue AiP statement and project report

On conclusion of the review a statement of Approval in Principle will be issued providing no serious issues are outstanding.

A project report will also be issued summarising the activities carried out and the key findings.

C.1.4 Qualification of Technology

C.1.4.1 General

Design of novel gas development projects may typically identify a number of critical subsystems for which there is no relevant service history. For offshore terminals this might include technology such as LNG transfer systems, some cryogenic components or compact liquefaction systems. These systems may not be adequately described by existing codes or standards. Similar to the Approval in Principle approach described above which is typically applied to concepts, the qualification technique described here may be used to qualify discrete equipment and systems.

The objective of a qualification procedure is to provide a systematic approach to the qualification of new technology, ensuring that the technology functions reliably within specified limits. The approach developed by DNV and described in this section provides a rational qualification philosophy and, by focusing on a balanced use of reliability, ensures a cost effective implementation of technology and an increase in the level of confidence. Sensible input may then be provided to the overall risk assessment of the concept.

Qualification of technology benefits all the major players:

- The manufacturer, who offers the new technology to the market and therefore needs to display a proof of fitness for purpose.
- The company, who integrates the new technology into a larger system, and needs to evaluate the effect on the total system reliability.
- The end-user of the new technology, who must optimise the benefits of his investment through selection between competing technologies and must obtain regulatory compliance for a project incorporating the new technology.

The main features of a qualification approach are described below. (For more detailed information on the procedure, reference should be made *to DNV-RP-A203 "Qualification Procedures for New Technology"*)

C.1.4.2 Basis for the qualification

The qualification must be based on specified performance limits, boundary conditions and interfacing requirements defined in the qualification basis.

C.1.4.3 Qualification process

A risk-based approach should be used to obtain the reliability goals in the qualification. These goals should be specified in the qualification basis. The procedure will specify the philosophies, principles and methods to be used in the qualification process. At each step of the process there is a need for documentation making the process traceable. The qualification process should comprise the following main activities:

- Establish an overall plan for the qualification. This should be a continuous process and needs updating after each step using the available knowledge on the status of the qualification.
- Establish a qualification basis comprising: requirements, specification and description. Define the functionality and limiting parameters for the new technology.
- Screening the technology based on identification of failure modes and their risk, and classification of the technology in degree of novelty to focus the effort where the related uncertainty is most significant.
- Assess maintenance, condition monitoring and possible modification effects to reduce the risk.
- Plan and execute reliability data collection. The data is used to analyze the risk of not meeting the specifications. Data may be obtained through experience, numerical analysis and tests.
- Analyze the reliability of the new technology, and thereby the risk of the failure modes related to the functional requirements of the new technology.

These logical steps in the qualification process are combined and visualized in groups in the figure below. The results from one step are the input to the next step.

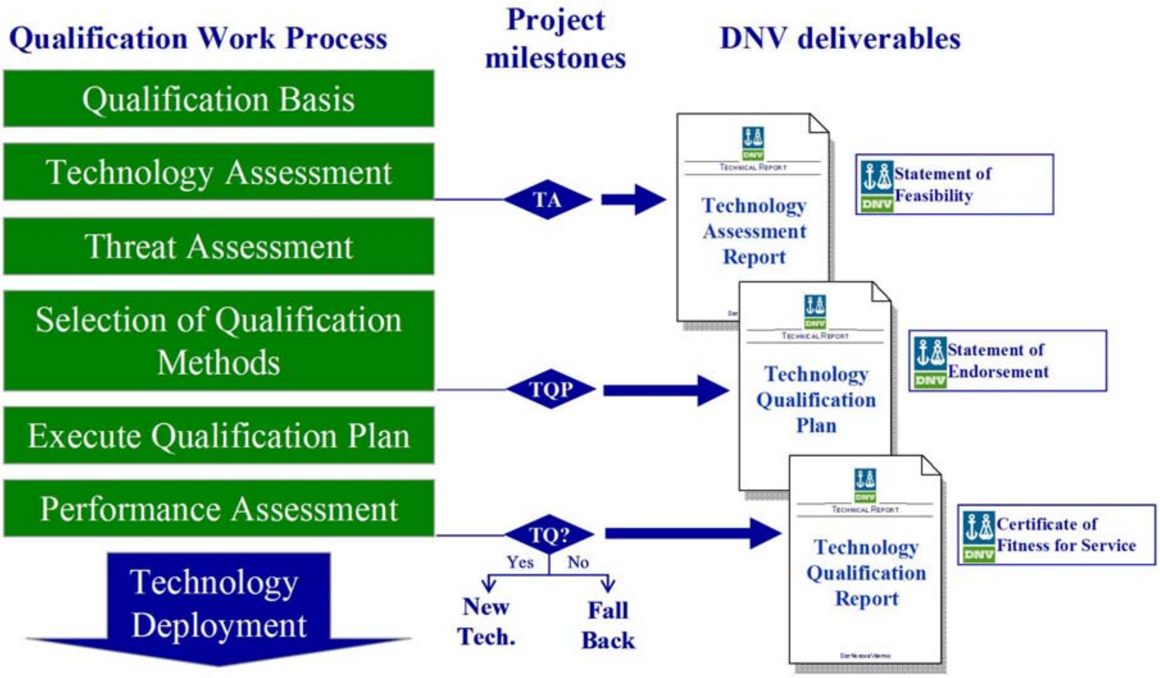


Figure C-4: Qualification Activities

There will be feedback loops between the steps so that results that lie outside the specified limits can lead to a design modification, specification modification or maintenance plan modification.

C.1.4.4 Establishment of reliability

The qualification process can be run throughout the development of the new technology, or be started at any time in the development. Figure C-5 illustrates that the failure probability at the service life target is reduced through the qualification work until a remaining failure probability is reached.

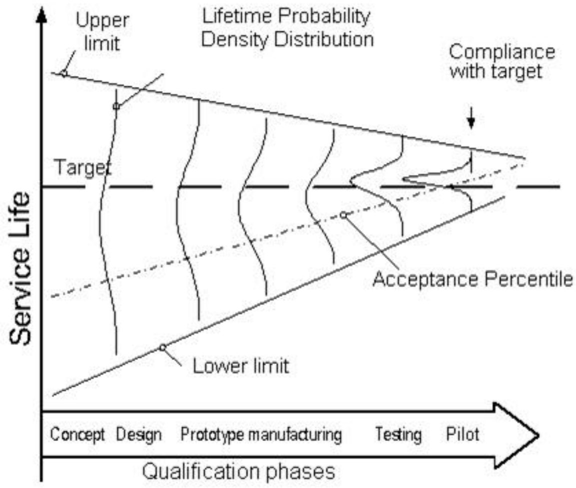


Figure C-5: Illustration of the qualification process

Qualification is considered completed when the acceptance percentile crosses the target level for the service life. A qualitative approach can be practical to use in the early development phase (conceptual phase). Quantitative measures are more relevant in the later development phases.

C.1.4.5 Testing

The analytical approach is supported and complemented by results obtained from testing. Tests as described below are used for materials, components, sub-assemblies and assemblies.

Experiments/ tests are to be planned as part of the qualification in order to:

- Explore novel elements of the technology, and help identify failure modes and mechanisms of relevance
- Provide evidence of functionality and reliability
- Identify or verify the critical parameters and their sensitivities
- Characterise input parameters for models.
- Challenge model predictions or failure mechanisms.
- These qualification tests form the basis for and determine the outcome of the qualification.
- Technology qualification may also specify tests to be performed after qualification is completed as a condition for use of the technology. These tests could be e.g.
    - Quality assurance tests performed during manufacturing that confirm compliance of product with qualification conditions.
    - Factory acceptance tests (FAT) prior to each delivery to reduce the risk that quality errors slip through to service.
    - Pre and post installation tests, of the full assembly verify the soundness prior to and after the completed installation.

Pilot application, represent the first use and can therefore be planned as an advanced test to gain more experience with the system, ensuring that all aspects of a complex system has been taken into account.

Tests to be done as part of maintenance to confirm that the qualification conditions are maintained during service (such as NDT) etc.

An essential part of the qualification process is to specify these tests and the acceptance criteria to be used with them as conditions for use.

C.1.4.6 End Product of the Qualification

The result of the qualification should be documentation of fitness of purpose and should cover the lifetime probability density distribution and/or defined margins against specified failure modes.

C.1.4.7 Use of the results

The qualification results may be used for a number of different purposes:

- as an acceptance for implementation of new technology
- for comparison between alternative technologies
- as input in the evaluation of the reliability of a larger system of which the qualified new technology may be a part
- as part of the concept final risk assessment
- in documenting regulatory compliance

APPENDIX D - CONSULTANCY SERVICES APPLIED TO FLNG

D ADDITIONAL CONSULTING SERVICES

D.1 Enterprise Risk Management

General

Some typical Enterprise Risk Management services which have been employed on FLNG projects would include Project Risk Management and Due Diligence

Project Risk Management

Effective project management demands rapid decisions about uncertain future events, often based on inadequate information. Failure to manage the right variables at the right time during the project may result in overspend, delays and poor delivery. Project risk management seeks to anticipate the development of projects and to implement suitable controls early enough to positively influence the outcome. DNV helps clients manage these project risks.

Due Diligence

Due diligence is an investigation or audit prior to an investment transaction. It confirms that all material facts are correct and therefore reduces the probability of unnecessary harm to either party or entity involved in the transaction. Companies considering acquiring, investing or providing project finance often commission independent expert consultants to provide due diligence services. DNV provides an improved understanding of the risks and risk mitigation measures, thereby contributing to improved investment decisions.

D.2 Safety, Health and Environmental Risk Management

Compliance with legal requirements alone as the basis for SHE performance is no longer sufficient for forward thinking organisations. There is a strong link between SHE requirements and optimum asset performance. DNV assists in achieving real improvements in SHE performance through enhanced design, asset reliability and focused operational controls.

Risk-based Decision Support

DNV offers a full range of services to support clients, ranging from early stage hazard identification, consequence assessment, likelihood estimation, through to advanced risk based decision support, and all the steps in between. These services meet compliance needs and go beyond when necessary to assure appropriate investment and management of hazards protecting staff, the public, the environment, the asset, and the corporate reputation.

Management Systems and performance Measures

Every company has a management system. The challenge is to develop, implement, review and improve systems to enhance business performance. DNV has over 25 years experience helping organisations realise the benefits of an effective management system. We set the standard in helping clients achieve their business objectives.

Environmental Models and Management

All organisations need to effectively manage the environmental and social impact of their operations. Environmentally responsible conduct is now recognised as an essential part of good business. DNV helps deliver experience-based solutions to solve the challenges facing all environmental stakeholders.

Emergency Planning and Accident Investigation

Effective planning for emergencies and other undesired events is an essential part of good business management. Companies need to prepare for situations that could cause potential losses to people, assets, income, company reputation or harm to the environment and society at large. DNV, as an integral part of its risk management services, assists companies in developing and maintaining effective response plans, in order to control their risk exposure.

Advanced simulation and modelling

The energy industry is expanding into new frontiers, often in extreme environments or scale of operations (arctic areas, deep water). Standard analysis methods do not demonstrate the effects of these changes with sufficient resolution and there is a need for accurate simulation able to represent higher complexity and greater detail. This is achieved for fluid flow, fire and explosion analysis by applying Computational Fluid Dynamics integrated with advanced risk models. Dynamic structural response issues are addressed with Finite Element Methods. Fire and explosion modelling related to LNG leaks is an area where DNV have assisted many projects.

Human Factors and safety culture

For controlling risks, preventing accidents, incidents and ill health, important efforts are taken to develop sophisticated management systems and technical solutions. But without addressing the human element and obtaining staff buy-in, the best systems will fail to deliver improvement. DNV works closely with clients helping to design processes and work systems that accommodate people issues carefully and systematically, both through development of positive cultures and through minimization of human error.

Operational Safety

Highly publicized major accidents both onshore and offshore demonstrate that industry successes in improving occupational safety have not been mirrored in major accident performance. Most of these accidents did not result primarily from deficient design; rather it was inadequate operational safety not sufficiently addressing specific threats inherent in the operation. DNV applies the latest techniques to ensure that facilities are aware of all key operational and mechanical integrity requirements and that risks are rigorously controlled.

D.3 Asset Risk Management

Business unit managers and asset managers constantly look for new opportunities to improve operational results and control the risks associated with their operation. Further, ‘Security of Supply’ is of increasing concern, forcing companies and governments worldwide to redefine the management of critical infrastructure. Owners that succeed in making good capital investment decisions and operate their assets more safely, reliably and efficiently than their competitors will be successful in the long run. DNV’s solutions help operators look forward and manage these opportunities by applying a range of qualitative and quantitative methods and techniques combined with advanced software tools, operators obtain maximum value from their facilities, equipment and organisation.

Assessment and benchmarking of asset operations

DNV can assist in assessing real performance, comparing it with industry best practices and identifying improvement opportunities.

Production optimization

The benefits of new technology are often higher revenues, lower CAPEX, reduced OPEX and/or improved SHE performance. DNV helps clients analyse the potential of new technology before significant investments are made.

DNV design processes to manage key uncertainties during the implementation. DNV also works closely with clients to improve production capacities and system regularity in the operations phase.

Maintenance and inspection management

In a challenging business environment, the assets must generate higher return on investments. DNV helps build customised solutions to optimise maintenance and inspection activities to maintain and improve the safety integrity of the assets.

Development of solutions to failures

Materials technology, combined with the understanding of degradation processes in different operating conditions, enables us to design durable constructions and components. Still failures may occur, leading to production loss and threats to life and the environment. DNV can assist in providing highly technical expertise that can reveal root causes and create innovative solutions to reduce risk of material damages with subsequent consequences to business interruptions and economical loss.

D.4 Technology Qualification

Technology Qualification Execution

These advisory services produce qualification evidence. If the technology is new, the scope is specified in the qualification plan produced as part of the Technology Qualification process. For proven technologies, the purpose of these services is to provide the documentation required by the rules/standards that apply.

Technical Analyses and Simulations

In complex projects, it is essential to simulate how a structure or a system responds to certain conditions. To support this, DNV provides a wide range of analyses and simulation tools.

Technical Risk and Reliability Analysis

Today, systems are becoming increasingly complex, followed by a progressive impact on project risk and production availability. It is therefore imperative that the technology's risks and implementation are handled appropriately. To deal with this, DNV offers a wide range of risk and reliability services to manage both technical and project risk.

Materials Technology

Many component or system failures experienced in the energy industry are related to material selection or quality issues. DNV therefore offers a broad range of services within materials technology and laboratory testing worldwide.

Laboratory Testing

DNV supports the global energy and shipping sectors with state of the art laboratory services, offering a wide range of testing capabilities, combined with strong multidisciplinary knowledge and experience.

D.5 Verification

Risk-based verification of field developments

Verification provides the required assurance towards stakeholders and regulatory authorities that projects are implemented right the first time. We provide clients with the ability to focus their verification effort where the contribution is cost effective by employing a risk based verification approach. DNV provide independent and competent appraisals of field developments to provide the required assurance that they are designed, constructed and installed in accordance with project objectives.

Risk-based verification of pipelines, risers

DNV's transparent and fully independent approach to verification on pipeline, riser and subsea facilities will help to reduce and manage risk, thereby ensuring successful subsea projects.

Risk-based verification of process systems

Systems critical to process and safety may also require special attention during the in-service phase. These systems may need to be independently verified to ensure that integrity and/or compliance is continuously maintained.

Product and equipment verification/certification

With process systems or equipment delivered from around the world, it is necessary to verify them against project and regulatory requirements before they arrive at site for subsequent integration or use. Ensuring that equipment and systems arrive on site with the correct specifications and certificates is key to ensuring that unnecessary delays are avoided and that the items are used safely.

Reliability Availability Maintainability (RAM) Analyses

A key to the viability of any FLNG project is its uptime. This may be quantified by structured assessment of those parameters affecting the project uptime. Such an assessment would also identify areas to improve performance.

Marine Operations and warranty Survey

Accidents or unexpected occurrences during temporary phases involving offshore marine operations can have devastating financial and safety consequences. This fact alone emphasises the importance of a well-defined marine operations verification scope, a recognised technical reference, competence and experience, and quality of service. For an FLNG this may be most relevant for the transit and installation phases. Reference is made to DNV Recommended Practice DNV-RP-H103 *Modeling and Analysis of Marine Operations*.

D.6 Marine Consultancy Services

Structural analysis services

Satisfactory structural strength of the hull and containment systems is essential in order to avoid costly damages and fatigue cracks in the hull and tanks during operation. Strength analyses are carried out during concept development or as a feasibility assessment, in order to develop and document strength of new designs, propose design changes, verification of strength or as basis for maintenance plans.

Hull structural services include:

- Design assistance
- Concept development and evaluation
- Feasibility analysis and risk-based assessment
- Assessment of lightweight and composite structures
- Design assessment and verification
- Finite Element Analysis
- Global ship analysis and local fine-mesh analysis
- Linear and non-linear analysis
- Static and dynamic analysis
- Hull strength assessment
- Yield strength assessment
- Buckling strength analysis
- Ultimate hull girder strength analysis
- Fatigue assessment
- Simplified rule-based fatigue analysis
- Advanced fatigue calculations (spectral analysis)
- Crack propagation analysis
- Advanced structural analysis
- Ice load and response calculations
- Collision, grounding, explosions, falling objects, etc.
- Sloshing analysis and assessment
- Hull monitoring and evaluation of measurement data

Stability, wave loads and motions

To ensure adequate fatigue life and ultimate strength of new designs, direct calculation of hydrodynamic hull and tank loads is becoming the industry standard. For this purpose, specialised applications such as Wasim, HydroD (Wadam) and several other in-house solutions as well as Computational Fluid Dynamic (CFD) tools are used.

Hydrodynamic and stability services include:

- Stability analyses, including third-party verification, documentation for approval, wind moment calculations, emergency studies, geometry and stability analyses
- Sea-keeping
- Transfer functions for motions (RAOs)
- Operability studies, e.g. for a given location
- Dynamic stability
- Side-by-side analysis
- Wave loads
- Accelerations, hull girder loads and hull pressures
- Sloshing loads using model tests as well as CFD analysis
- Slamming and whipping
- Green seas
- Model test advice
- Model test specification
- Numerical analysis to complement model test results
- Review of model test results

Noise and Vibration

FLNG, especially LNG FPSOs will typically have a large amount of heavy machinery items installed and a significant number of potential noise and vibration sources.

Vibration may cause situations hazardous to personnel and installations. Elevated levels may cause reduction and even shut down in production. High noise levels may cause human fatigue and increasing the risk for miscommunication and human errors.

DNV offers technical advisory services to assist in the design, building and operational phase providing practical and cost effective solutions. Focus on noise and vibration at the design stage may help avoiding costly re-designs later on.

DNV services include:

- Preparation of noise and vibration specifications
- Review of bids from equipment vendors
- Calculations of noise levels throughout the FLNG vessel
- Analyses of public address (PA) and audible alarm systems
- Development of noise control program
- Detailed design of noise control measures
- Noise and vibration measurements during factory acceptance tests (FAT) and in situ.
- Follow-up during installation and commissioning
- Global and local vibration analysis
- Structural modification analysis of decks, foundations, piping and for instance thrusters
- Noise and vibration verification measurements during technical sea trial as well as during normal operations from a human response point of view.
- Vibration surveys on relevant machinery in order to assure a safe running performance from a vibration point of view.

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