**POLITECNICO DI TORINO**
Master of Science in Energy and Nuclear Engineering:
Innovation in the Energy Production

Master's thesis

# PRELIMINARY RISK ANALYSIS FOR A FLOATING LIQUEFIED NATURAL GAS SYSTEM

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# Abstract

This work, entitled "Preliminary risk analysis for a floating liquefied natural gas system" presents a preliminary risk analysis of an actual industrial case study, performed during my internship at RAMS&E.srl, and a series of investigations and considerations developed consequently to the study. Its goal is to verify the effectiveness of the preliminary risk assessment in guiding the decision-making process in the oil and gas field.

Oil and Gas companies involved in the construction of new facilities (such as those for the exploitation of hydrocarbon reservoirs) have become even more interested in performing suitable risk evaluations. The operational context and the competitive environment in which these corporations operate enforce monetary investments and an important level of certainty in decisions. Therefore, a proper decision-making process, followed by a phase of design and implementation of the system, is necessary to avoid weakening the economic reality of the company or even its failure. Nowadays, the quantitative risk assessment (QRA) is a suggested study to guide the decision-making processes during the design of hazardous systems.

The preliminary risk assessment has been performed on behalf of a Contractor, who has been assigned to develop the conceptual design of a FLNG (Floating Liquefied Natural Gas) technology for the extraction, processing and liquefaction of the natural gas of an offshore reservoir, exploring different potential layouts. For each configuration, the objective of this study was to evaluate the consequences of accidental fires and explosions on the integrity and functionality of structural elements and process equipment, to highlight potential criticalities from a safety point of view and to provide recommendations to be implemented in the successive design phases. In order to fulfil this aim, a Fire and Explosion Risk Analysis (FERA) has been implemented.

The studied facilities consist of two traditional offshore platforms, called Well - Head Platforms (WHP), and a floating liquefied natural gas system, called FLNG. In particular, two configurations were analysed. The WHPs were the same for both the arrangements, while the adopted FLNGs are different: in the first case, the FLNG is a newly built system, while in the second case the FLNG is obtained from the conversion of an LNG carrier. After the analysis of the process systems, layouts and present hazardous fluids, a fire risk map

for each deck of the facilities has been produced through the superposition of fire damage areas generated by all the analysed accidental scenarios potentially impacting on the deck under consideration. The resistance to load and drags, which should be provided to the structural elements of the facilities has been evaluated through a procedure described in the document DNVGL-OS-A101. It would be essential to allow the systems to resist overpressure generated by accidental explosions. Then, analysing the frequencies of the cumulative maps in the turret zones, the necessity of subsea isolation valves installation has been in-depth studied.

The specific methodology and the relative hypothesis adopted to perform the FERA had been provided by the Contractor. They have been further analysed to understand their correctness, their points of weakness and to interpret the results of the analysis as impartially as possible. Several investigations have been done. The influence on the risk distribution produced by the ESV/SDV failure and the exclusion of flash fire and VCE by the hypothetical release consequences have been examined. Justifications concerning the chosen asset vulnerability, the weather conditions and the exclusion of the full-bore rupture have been produced. Then, an analysis concerning the uncertainty produced by the preliminary fire risk analysis has been carried out. Toward the end, some calculations have been done to define the effectiveness of the explosion risk assessment result, while a general disquisition has been performed to identify the reason which pushed Contractors to analyse the necessity to install SSIVs (subsea isolation valve).

*I would like to dedicate this thesis to my loving parents*

# Contents

# INTRODUCTION

*"A day without risk is a not lived day"* can be read in the Italian national fire department prayer. A phrase full of meaning to celebrate brave men but characterized by an intrinsic error. As taught during some university courses, lives are branded by "elements" which cannot be eliminated at all. The risk is one of these. Every day, just sleeping in a bed, people are subjected to risk which is going to increase by making the commonest routine actions, such as driving a car or extinguishing a fire. Fortunately, the busy lives do not allow to spend much time reflecting and the largest part of people live a carefree life.
However, dwelling on this topic, it is possible to identify a lot of different things which people unknowingly use or are parts of the modern lifestyle. In my opinion, hydrocarbons are surely some of the most important.
The words "risk" and "hydrocarbon substance" are frequently associated. They were strongly used together in Italy in 2016, when a referendum regarding offshore facilities took place. In particular, it concerned the repeal of the law for the extending the concessions to extract hydrocarbons in sea areas placed within 12 nautical miles from the coast. The result obtained was not relevant, as the minimum quorum was not reached. Nevertheless, it may be interesting to analyse a very common thought leading people to vote against the further exploitation of the platforms. The will to move towards renewable energy sources and the fear that possible accidents would cause environmental damages are surely the crucial motivations. The consciousness of the increasing pollution levels and the great disaster produced in the past by famous offshore platforms and oil tanker ships, but also of the important role played by hydrocarbons in our society, it not possible to state if their decision was wrong or not. Nevertheless, it makes me question regard my own level of knowledge of safety in the oil and gas industry. This is the personal reason that pushed me in facing the analysis described hereinafter.
A working experience, which can be considered the "foundation" for this writing, allowed me to learn more about the cited topic. However, safety is a too large theme to be treated in a single thesis. Indeed, the main subject will be the QRA (Quantitative Risk Assessment) study, a useful instrument guiding oil and gas companies in the decisional processes for dangerous facilities. The objective of my work was to analyse the results of a preliminary QRA performed on the behalf of a Contractor, who was interested in comparing two floating liquefied natural gas (FLNG) configurations. In particular, the applied

methodology, the hypothesis and the results obtained during the analysis will be explained. Indeed, the lack of a well-defined system layout might affect the reliability of the results, making the preliminary risk assessment not suitable to guide the decision-making process.

The thesis is articulated in six chapters. At first, the chapter one, which is an introducing section concerning the QRA study, will present the importance of this assessment in the framework of the oil and gas field, giving a generic definition and describing its role along the different phases of the design. Then, in chapter two, we are going to focus on a generic pre-feed phase of a design process. The state of art of configurations generally analysed during this phase is briefly described, together with inputs and criticalities which can be faced. These two initial chapters will be essential to justify decisions and methods that are used for the Case study, which will be introduced in the third chapter.

Inside the chapter three, key information to perform the risk assessment is presented. The two FLNG configurations, the purpose and the methodology will be described in depth. In particular, according the methodology, the analysis will be divided into three parts. The first one concerns the analysis of fire scenarios, the second regards the explosion, the last one discusses the necessity of the installation of subsurface isolation valves. Chapter four will contain all the important hypothesis are going to be assumed to complete the methodology and perform the study. A look at the developed data for the different analysis is going to be provided. Finally, the results are contained in the fifth chapter.

The analysis will be further integrated with other investigations. Chapter six will contain final considerations and calculations regarding the methodology and the analysis requested by the Contractor. This section will be a good instrument for analysing hypothetical weaknesses of the methodology and verifying the effectiveness of the procedures suggested by the Contractor, which may differ from the ones typically adopted in a feed phase analysis. The thesis is completed by annexes reporting some technical data and the complete set of obtained results.

Before moving into the heart of the writing, I would like to thank RAMS&E.srl for the great opportunity. The data and layouts here reported have been accurately modified to produce a realistic study without diffusing sensible information concerning Contractor’s facilities.

# Chapter 1

# QRA in an asset project

## 1.1. Introduction to decision making process instruments

Oil and gas production involves some of the most ambitious engineering projects of the contemporary world and can be a major source of revenue for many companies and countries [17]. However, the operational context and the competitive environment in which these corporations operate enforce monetary investments and an important level of certainty in decisions. Therefore, a proper decision-making process followed by a phase of design and implementation of the system is necessary to avoid weakening the economic reality of the company or even its failure.

During the design of a system for the exploitation of hydrocarbon, a crucial moment is the identification of the technically feasible concepts with the best economic option revenue for a given investment. These economic evaluations mainly based on the use of indexes, such as the utility index, the net present value and the net present investment value might be effective but also complicated; forecasted factors, such as initial production and price of the produced substances, vary randomly during the life of the system. Nevertheless, the screening of the potential exploitation configurations based only on economic aspects connected to the hydrocarbon production sale is not enough; it does not take into account other features, which can affect the economic field of the system during the operational life. The procedures previously cited cannot consider elements such us operability, reliability, constructability, schedule and future expansions. Therefore, further analyses are necessary to define a proper decision-making process [17].

As a drawback, instead of producing benefits to its owner, operators and country, the oil and gas installation can become the scenario of a major accident. It happened several times during history. Some remarkable events are the explosion of the production platform Piper Alpha, the sinking of the Norwegian gravity base structure Sleipner A and the capsizes Canadian semi-submersible drilling rig Ocean Ranger [17]. Major accidents can cause sickness, injury or death of workers, damage to properties and investments, degradation of the physical and biological environment and also interruption of oil and gas production, economic losses and reputation damage. Hence, it is necessary to find a compromise between the cost of safety and the economic returns of oil and gas production. As a result, the risk assessment becomes fundamental in fields involving hazardous scenarios and, in particular, in the oil and gas branch. In European counties, risk analyses are a legislative requirement for all new and existing installations in the exploitation of hydrocarbon substances. Quantitative risk assessment (QRA) is a technique, worldwide used, which can be employed to reach this objective [17].

## 1.2. QRA definition

The risk assessment is the practise for identification and analysis of risk and it can be carried out through different procedures, such as the quantitative risk assessment (QRA). The QRA, also called "probabilistic risk assessment" or "probabilistic safety analysis" allows to perform a systematic examination of the risk caused by hazardous activities, and to establish a rational evaluation of their significance, in order to offer inputs to a decision-making process. QRA is a quite new technique, nevertheless, it is one of the most complete. It is useful for studying the risk of accidents and providing guidance on appropriate methods for minimising it. There is not a single approach to perform a QRA, but it is possible to choose the ones more appropriate to the case study [17].

The most common structure of a risk assessment, applicable also to a QRA, is divided in two parts according to the nature of procedure applied during the different phases of the analysis. The first one is called "risk analysis", while the second "risk assessment" [17].

The **risk analysis** is constituted by purely technical processes, which can be summarized in the following steps [17].

1. <u>System definition</u>: definition of battery limits of the analysis, i.e. the identification of the included activities and the considered phases of the installation's life.
2. <u>Hazard identification</u>: qualitative evaluation of accidents that may occur. In this phase, it is requested to use information obtained by previous accident experiences.
3. <u>Frequency analysis</u>: estimation of occurrence frequency for the accidents identified in the previous step through the analysis of prior accidents experience or statistical methods.
4. <u>Consequence modelling</u>: evaluation of the possible effects, which may follow the accidents occurrence, and their impacts on different targets, such us workers, environment and structures. These evaluations are usually carried out by computer modelling or by using the experience obtained during the happening of previous major accidents.
5. <u>Risk evaluation</u>: results obtained by the simulations of each accidental scenario are summed up in order to evaluate the overall risk.

During **risk assessment**, it becomes necessary to introduce criteria, which are the indexes to verify whether the overall risks are acceptable, or if new studies and or additional preventive/mitigative measures are requested. In order to perform that step, non-technical and decision-making issues should be introduced. This part of the study can be articulated in the following steps [17].

6. Risk check: the overall risk is compared to international standards and to the criteria stated according to the thresholds of the company, which allocates the study and construction of the system.
7. Risk reduction study: if the overall risk identified is higher than the fixed threshold, some risk reduction measures (concerning the maintenance, the design implementation and the management of the facility and its processes) may be necessary. In order to evaluate the benefits from these measures, the entire risk assessment study/QRA should be repeated. An iterative loop is introduced inside the process.

Despite the risk is an important matter in our culture, the economic field is the one considered by investors. Indeed, the quantitative risk assessment should not be the only source of information to guide a decision-making process.

## 1.3. QRA in the asset project and system life

The QRA should not be treated as an isolated study but as a part of the risk management process. Moreover, it ought to be an on-going activity during the entire life of the installation. In fact, during the different stages of installation's life, the QRA is performed several times with a level of detail consistent to the available information. Indeed, the study tends to become more complex as the design advances. The typical phases when a QRA is required or restructured are explained below [17].

1. Feasibility studies and concept selection stage
   At the beginning of a design process, different project options are usually considered and through simplified QRAs, due to the absence of details, risks are usually estimated. These studies allow to state the feasibility of the different system configurations and to choose which one is the best option through the comparison of the obtained results.

2. Concept definition phase (PRE-FEED)
   During this phase, a reasonably detailed study is performed thanks to the availability of a good amount of information. This is one of the most important stages for a QRA, since a structured study can avoid negative impacts on the project schedule and costs. It should assist the final major decisions of the project with respect to design possibilities and provide a source for further design optimization during completion of the conceptual engineering. QRA shall confirm that risk criteria will be achieved and address the identification of all risk reduction actions. In this phase, the design is still elastic enough to be influenced by the QRA conclusions.

3. Detailed design/ Execution phase (FEED)
   During the execution phase, at the end of the detailed engineering, when the optimization of the chosen design has been completed, a total risk assessment is usually applied. It is intended to prove and verify that all risk reduction actions identified during the previous step have been implemented and the risk criteria have been achieved. It is also used to develop operating and emergency procedures.

4. <u>Operation</u>

   For existing facilities, the full QRA of the final design should be revised after significant changes caused by new installations or just to consider the “as built” state of the system after 3-5 years. The additional or revalidated QRA shall prove that the modifications comply with risk criteria and that new recommendations have been identified for the risk reduction strategy. The procedure is addressed both on new and existing facilities, reflecting on proved leaks, emergency exercises and other phenomena experimented during the system’s life. In conclusion, a QRA should address risk over the entire life of the system, from the start of construction to the final disposal.

## 1.4. Purpose of the QRA

QRA can be executed to evaluate or obtain different information concerning the system. The most important QRA purposes are listed below [17].

- Assessing risk levels and weighing their significance, in order to choose whether the risks need to be reduced.
- Detecting the main contributors to the risk. It is useful to understand the nature of the hazard and to suggest risk reduction potentialities.
- Defining design accident scenarios. They represent the bases for the design and implementation of fire protection systems, emergency evacuation equipment and/or for emergency planning and training.
- Comparing design options. This gives inputs on risk issues for the selection of a design.
- Estimating risk reduction measures. QRA can be performed in parallel to a cost-benefit analysis, to identify the most cost-effective ways of mitigating the risk.
- Demonstrating risk acceptability to regulators and the workforce. QRA can show whether the risk is “as low as reasonably practicable”.
- Recognizing safety-critical procedures and equipment. These ones need special attention during operation for minimizing risks.
- Detecting accident precursors, which may be examined during operation to provide warning of adverse trends in incidents.

## 1.5. Considerations

QRA is a complex procedure, which can be performed in a lot of different ways and with different purposes. It is surely an effective practise for monitoring risk and providing a guidance for a decision-making process about safety. In particular, in the following chapter, we will focus the attention on offshore systems and, in particular, on an FLNG unit pre-feed risk assessment. Further information concerning the theory of the QRA and its development can be found in specialized guides concerning this theme. An example is the book “A Guide To Quantitative Risk Assessment for Offshore Installations” [17].

## 1.6. The objectives

At the end of this short chapter, it is indispensable to remember that this thesis is not intended as a complete disquisition concerning the QRA, but a means to assess the effectiveness of the preliminary risk assessment in guiding the decision-making process in the oil and gas field. Indeed, the lack of a well-defined system layout might affect the reliability of the results. A real case study will be used to achieve this intention. A preliminary risk assessment will be performed on behalf of a Contractor. That company has been assigned to develop the conceptual engineering (PRE-FEED) of a floating liquefied natural gas (FLNG) unit and two similar configurations were considered feasible for that purpose. The study will be used to identify the best configuration according to fire risk distributions and risk reduction measures will be suggested to reduce the identified criticalities. Then the methodology adopted in the analysis will be investigated. Hypothesis and results obtained will be verified by means of theoretical researches and calculations. These investigations will define the effectiveness of the methodology and the possibility to use the preliminary risk assessment to guide the implementation of the configurations during the feed phase. Toward the end, a general disquisition will be performed to identify the reason which pushed Contractors to analyse the necessity to install SSIVs (subsea isolation valve).

# Chapter 2

# Pre-Feed phase in a FLNG system

## 2.1. Relationship between parts

When a company is interested in the exploitation of an offshore hydrocarbon reservoir, after having obtained rights to extraction by the local authorities, it shall develop a proper technology for the monetization of the reserves. Oil companies, usually not specialized in the design and construction of such systems, rely on other companies, also called contractor, to perform this task for them. At the same time, the contractor may engage a Third Party, who will perform some activities on his behalf. The contribution of these third parties to the project becomes relevant especially during the pre-feed phase, also known as the concept selection procedure.

Pre-feed analysis are complex procedures, which have important consequences in the future development of the system. Analysts must consider different options in order to identify the best configuration. The initial different design configurations should be analysed from the process and the economic point of view. After those studies, risks assessment can support the decision: it should confirm the feasibility of the layouts and/or suggest some changes, which can affect consequently the design and its cost.

Thus, the most important preliminary analyses are the economic forecast, the layout and process configuration study and the risk evaluation. In particular, the complexity of preliminary analysis states in the mutual influence played by all these fields; a small variation applied in order to make the system competitive in one of the cited branches, can make the others not any more practicable. Nevertheless, the contractor can strongly benefit from this phase. The preliminary evaluation, and specifically the risk assessment, can provide a source of information for further design optimizations during the completion of the conceptual engineering. At the end of this phase, the Contractor can easily exclude the unfeasible or more expensive configurations and choose the least risky one from the list of possible structures.

I was involved in a preliminary risk assessment, which will be analysed in the following chapters. In particular, it was necessary to help a Contractor in the development of the conceptual engineering for the exploitation of offshore fields using FLNG technology. To better comprehend how this risk assessment has been performed, it is necessary to recognize which are the inputs, that the Contactor shall provide, which could be the major criticalities can be faced, and, above all, how to identify major risk sources in the pre-feed risk analysis of a FLNG configuration.

## 2.2. Inputs for a preliminary risk assessment

Contractors request to the Third Party to develop studies with a level of detail appropriate to the information available based on the current design phase. During the concept selection, specific details essential for an in-depth risk assessment may not be available; consequently, comparative coarse analysis may be done in order to compare risk assessment of the different project configurations under study.
In order to perform the preliminary risk assessment, the following minimum input data shall be used [3][17]:

- All available preliminary layouts and system descriptions of the facility;
- All available preliminary PFDs (process flow diagrams);
- Available data on similar projects (information can be used to formulate realistic hypothesis concerning missing data for the system in analysis);
- Production profiles (tables showing the forecasted flows which will be produced by the system);
- Cause and effects charts (diagrams describing the evolution of accidental events);
- Descriptions of operational procedures and intervention times in case of accident;
- HAZID (hazard identification) study;
- Available streams characteristics (composition, pressure, temperature, flow);
- Weather conditions (site wind rose and wind velocities distribution);
- Sea conditions (water depth, currents velocities and distributions, sea temperatures).

It may happen that contractors do not provide some of the previously listed information. There could be multiple reasons justifying this behaviour. Two of them have been experienced during my working experience at RAMS&E. Firstly, contractors may rely on the third party for the evaluation or the development of missing information and it may be necessary to wait for their reports. For example, RAMS&E was delegated to perform the HAZID study on behalf of the Contractor. Secondly, some Oil and Gas companies are not inclined to provide a complete set of information because of their sensitivity to the issue of information leakage. Then, in many cases, it may happen that useful design information cannot be available due to the early phase and the absence of a detailed design. In these cases, it is necessary to make realistic hypothesis, for example concerning instruments and components, to continue with the study. Specifically, I had to suppose, in accordance with the working team, the position of pipelines and pipe racks and the future location of drip pans necessary to contain liquid releases. In order to avoid the explained criticalities, it is necessary to develop a close collaboration between parts and be aware that the analysis can provide results not completely precise. Simplified procedures, compared to the ones performed during a feed phase, may be necessary. This topic will be the subject of a chapter 6.

## 2.3. Criticalities in an FLNG configuration

In a QRA, hazard identification is a qualitative examination of possible accidents that may arise, in order to select failure cases for quantitative modelling. In particular, the simplest form of hazard identification is the division of possible accidents into hazard categories. The most important ones in a FLNG, or offshore facilities in general, are [17]:

- Blowouts;
- Risers/pipelines leaks;
- Process leaks;
- Collisions;
- Structural and marine events;
- Non-process fires;
- Transport accidents;
- Personal accidents.

For consequences modelling purpose, each category can be split in failure cases, which are represented in a more detailed way by accident scenarios. Each accidental scenario, after being characterized by specific parameters, can be simulated by means of a software. The outcomes produced by computing procedures provide the data necessary to evaluate risk distributions of hazard categories.

Different groups of hazard categories can be analysed in QRA studies for offshore systems. Therefore, QRA of FLNG installations may take many different forms, that can suit or not the situation, according to the installation, budget and project phase under consideration. The main QRA typologies are listed below [17].

- <u>Fatality Risk Assessment</u>: it is probably the most common type of QRA. Its goal is to determine the individual and group risk of death and produce an assessment using fatality risk criteria. A cost-benefit analysis is then used to select risk reduction measures [17].
- <u>Concept Safety Evaluation</u>: it is adopted to evaluate the risk of impairment of safety functions, which are usually identify as escape routes, shelter areas and support structures of the platform [17].
- <u>Total Risk Assessment</u>: it is used to evaluate all kinds of risk. In particular, it considers risks to life and environment, the risks of business interruption and the risks to safety functions and properties [17].
- <u>Lifetime Risk Assessment</u>: it is used at the concept selection phase to evaluate the fatality risks. It is based on a simple methodology which consists on adding generic risks for various types of workers [17].
- <u>Fire and Explosion Analysis</u>: a specific risk assessment applied only to fires and explosions [17].
- <u>Evacuation, Escape and Rescue Analysis</u>: it is performed only to escape, evacuation and rescue systems and procedures used during accidental scenarios [17].

For more information, regarding the different hazard categories and QRA typologies, it is suggested to refer to a proper manual, such as “A Guide To Quantitative Risk Assessment for Offshore Installations” [17].

Before starting with the case study risk analysis, it is suggested to spend some time understanding the hazard categories, the failure cases and the targets, which shall be the objective of a preliminary analysis.
As we have previously stated, information in a pre-feed phase are limited; during the previous phases of the system design, companies will usually focus the attention on production schemes design and their performances, while they will not define in a complete way the analysis concerning human occupation, displacement of loads, naval movements and other fields. According to the produced material, it is possible to identify as main causes of risk the “risers/pipeline leak” and the “process leaks” [3].
Dispersions surely represent the most important source of risk. Hydrocarbon leaks can produce fires and explosions, which can involve a simple production stop or also worst consequences, such as domino effects, losses of life and in extremis the total destruction of the system. In order to identify frequencies and the risk concerning hydrocarbon leaks, a fire and explosion risk analysis, focus on the consequences of accidental fire scenarios on structures, can be performed. Analyses are used to produce recommendations to verify the feasibility of the system or develop a safer one, considering that the configuration is an offshore system therefore some variations may not be feasible. It will be a Contractor’s task to implement those layout variations verifying if the configuration will be still economically sustainable.
However, in the pre-feed phase, performing a total risk assessment concerning all the risk issues is not forbidden but highly not recommended; the lack of information and the successive modifications of the system will probably make the study useless and surely expensive in terms of money and time. It is necessary to focus the attention only on the major criticalities with a level of detail sufficient to improve or confirm the validity of the design [3].

# Chapter 3

# Methodology and case study description

## 3.1. Introduction to the study

The Contractor has been assigned to develop the conceptual engineering (PRE-FEED) of a FLNG technology for the exploitation of offshore fields and the monetization of reserves. In this particular case study, the activities performed by the Contractor for the system design will include two different configurations:

- New design FLNG + wellhead platforms (WHP1 and WHP2);
- Converted FLNG + wellhead platforms (WHP1 and WHP2).

A Fire and Explosion Risk Analysis (FERA) and SSIV criticalities study has been developed for each kind of installation with a level of detail appropriate to the information available in the current design phase.

A document [3] produced by the Contractor and following line basis fixed in previous contracts have been used to fix the scope of the study, the boundaries of the systems and the Contractor duties toward FERA developer. In particular, the Contractor declared to commit to cooperate closely with RAMS&E, provide all necessary design input, evaluate and include risk reducing and ALARP recommendation in its own design.

Now the scope of the preliminary FERA, the procedures and the hypothesis, which have been essential to perform the main steps of the risk assessment, will be described. Finally, a description of each configuration analysed inside the case study will be provided focusing at first on the production chain and then on the layout.

## 3.2. Scope of the study

The objective of the preliminary FERA (Fire and Explosion Risk Assessment) was the quantification of the effects and frequencies of fire scenarios, which develop as results of accidental losses of containment, in order to avoid an intolerable risk of scenario escalation. Through the fire risk assessment, the effects produced by fires should be evaluated in terms of impact areas and frequency of occurrence, considering only the accidental scenarios that might affect the integrity and functionality of structural elements or equipment. An explosion hazard assessment should complete the fire risk assessment. It should be performed to define a first attempt identification of the structural strength, which will be provided by those elements of the installation required to afford good resistance to blast and drag loads, as part of the MA hazard management strategy (e.g. structure (primary and secondary), boundaries (floors, walls, ceilings) to the area involved in an explosion, escape routes, TR, and evacuation facilities ). During the PRE-FEED phase, the typical input information needed to perform the complete explosion hazard analysis might be not available or not sufficiently consolidated. As a consequence, only a preliminary explosion hazard assessment should be performed. Furthermore, the evaluation of the need for subsea isolation should be part of the pre-feed study of the system.

Preliminary FERA outputs might be used to identify risk reduction actions useful to prevent or mitigate major hazards events affecting the asset.

The activity should include the analysis of two WHPs (WHP1 and WHP2), the new design FLNG and the converted design FLNG. The FERA study ought to cover the only normal operations and deal with accidental fire scenarios occurring in each installation systems and sub-systems except for the following ones:

- FLNG utility modules;
- Hull and associated equipment including mooring lines;
- Hull tanks;
- Risers and subsea equipment.

The fire and explosion risk analysis (FERA) should be developed for each kind of installation with a level of detail appropriate to the information available in the current design phase. Furthermore, procedures and assumptions should be in accordance to the best engineering practices generally adopted in FERA's assessments in "Oil & Gas Industry" and in particular to the methodology [3], explained in the 3.3 paragraph.

## 3.3. Methodology

The methodology adopted during the study was defined by a document produced by the Contractor in compliance with goal fixed for the pre-feed scope of work. In case of criticalities, the methodology suggested was changed in accordance to the best engineering practices generally adopted in FERA's assessments in the Oil & Gas Industry.

In the following sections, the methodology adopted for analysis is explained in detail. At first, the procedures and the assumptions for the fire risk analysis will be described; then the ones for the explosion assessment will be defined. Finally, the methodology and the assumptions for the subsea isolation evaluation are going to be explicated.

### 3.3.1 Methodology and assumptions of fire risk analysis

The fire risk analysis (FRA) starts from the identification of credible major accidental events and associated scenarios.

The major accidental events identified and analyzed within this FRA are fundamentally originated by loss of containment events, which are events occurring after an unexpected rupture and/or release from piping/equipment due to defect, wearing, corrosion or other unforeseeable problems [3]. Release scenarios deriving from the loss of containment events and potentially leading to release of hazardous material are identified according to best practice criteria, based on available project documentation (Heat and Material Balance, PFDs and Equipment List). By means of these documents, the representative sections of the process and the possible release locations are identified, and the associated loss of containment scenarios is analyzed.

The fire risk assessment continues following the steps below [3]:

1 Identification of the isolatable sections in the systems' layouts and their characterization in terms of operating conditions and inventories;

2 Evaluation of the frequency of release associated to the identified isolatable sections;

3 Conservative characterization of the realistic release points within each identified isolatable section and determination of the potential accidental fire scenarios deriving from the credible accidental releases (accidental events);

4 Modelling of consequences which might be produced by the identified accidental fire scenarios and evaluation of their frequency of occurrence;

5 Fire risk mapping.


*Figure 3-1: block diagram summarizing the main FERA phases*

The assumptions and methodology used for these steps are specifically described in the following paragraphs.

Before moving on is important reflect on the word "credible". A release scenario is assumed "credible" only if the release frequency associated to the domain is sufficiently high. In the oil and gas field 1E10-7 ev/year is the breaking point between "credible" or "not credible".

### *3.3.1.1 Isolatable Sections definition*

Isolatable sections should be identified on the PFDs, pointing out the process sections that can be automatically isolated during an emergency following a shutdown. As a general rule, an isolatable section is defined as a process installation "segment", that the protection systems can isolate from the rest of the process by automatic isolation valves (SDV or ESDV) and/or normally closed isolation valves [3]. The generic automatic control valves are not considered adequate sections boundaries. It is assumed that the mentioned valves performing a safety function cannot fail, a hypothesis which may not be adopted by other Contractors asking for in-depth analysis. In those cases, the frequency concerning the "valve failure when requested" is evaluated and implemented. Further considerations will be made at the end of the analysis (see Chapter 6).

In this analysis, isolatable sections are identified considering a preliminary position of SDVs/ESDVs on PFDs, based on previous projects and Contractor experience.

For each isolatable section, the total hold-up is estimated considering the contribution of the main process equipment identified on PFDs and piping. The equipment volumes are evaluated by means of the preliminary data reported on the equipment list if they are already available and sufficiently consolidated in the current design phase. To evaluate the liquid and/or vapor inventories contained in each process equipment, the available project data are considered. Other considerations and assumptions concerning specific process equipment are deliberated by the Contractor. For example, the inventory volume for compressors, expanders and pumps is assumed equal to 1 $m^3$ while the inventory volume for filters is set equal to 5 $m^3$.

The piping hold-up is calculated as follows:

- The piping system that connects the equipment in the same module (intra-module pipe) is considered applying a factor equal to 2 (200%) to the inventory calculated taking into account only the equipment included in the section [3];
- Volume for main inter-module pipe runs and interconnecting pipes is evaluated considering the expected piping length, estimated by the plot plan layout, and conservatively increasing this value by 50%. This procedure allows considering the contribution to the section inventory provided by vertical piping sections and branches [3].

Further volume data and the liquid fraction of those components not listed inside the equipment list and considered essential or useful, have been directly asked to the Contractor during the analysis.

Other inventories should be considered infinite. These dominions are usually characterized by long pipelines or big tanks, which can contain a large hold-up. It is not possible that following to an incidental event those inventories can discharge their content in a sufficiently small amount of time. They may take hours or even more to have a full discharge. As a consequence, they are defined "infinite" because of their long release time. The infinite inventories are listed below [3].

- The risers to WHPs wellheads;
- The sealine starting from the WHPs and arriving on the FLNG;
- The LNG storages;
- The condensate tanks;
- The export pipelines.

As a general rule, the final inventory of flammable substance (in kg) in liquid and/vapor phase contained in each identified isolatable section, is calculated multiplying the volume of the section, estimated as described above, by the average process fluid density. Phase properties of each representative stream (the same adopted for the consequence modelling exercise), is derived from the project "Heat & Mass Balance" document.

### *3.3.1.2 Frequencies Evaluation*

In order to evaluate the frequency of occurrence of a fire scenario, two different kinds of frequency should be evaluated. The first one is the "Release Frequency", the frequency that an accidental release from an isolatable section can take place; the second one is the "Ignition Probability", the probability that a released substance starts burning. These data are essential to evaluate the "Fire Scenarios Frequency", which is evaluated through the product of the "Release Frequency" and the "Ignition Probability".

Now, the procedures and hypothesis to evaluate the cited frequencies will be explained.

#### *3.3.1.2.1 Release Frequencies Evaluation*

In case of loss of containment events, historical failure data are used to assess the frequency of occurrence of item and equipment ruptures leading to a release scenario. For this project, historical failure data from the standard reference OGP Report No. 434-1 [12] are assumed as basic failure data to assess a preliminary frequency of occurrence of the release events [3].

Release frequencies are evaluated considering the following representative hole sizes, typically used for risk assessment evaluation [3]:

- Small rupture: 5 mm;
- Significant rupture: 20 mm;
- Large rupture: 65 mm.

To adjust OGP statistics to the representative hole sizes that will be implemented into the analysis, the following correspondences are defined for the case study [3]:

- 5 mm leak size frequency is evaluated considering the frequency data for leak of hole diameter range 1 to 3 mm and of hole diameter range from 3 to 10 mm reported on OGP;
- 20 mm leak size frequency is estimated considering the frequency data for leak of hole diameter range 10 to 50mm reported on OGP;
- 65 mm leak size frequency is assessed considering the frequency data for leak of hole diameter range 50 to 150mm reported on OGP.

Releases from hole diameter higher than 150 mm are disregarded for this preliminary study as the proportion of the total leak frequency associated to this hole class is limited. Specifically, the leak frequency of the holes characterized by diameter higher than 150 mm is about 1,7E-07 ev/year for a 12'' pipe or a larger one. Its contribution to the total leak frequency is about 0.5%. In terms of consequences, most of the time, the depletion of the inventory with a full-bore release is very quick, lasting less than 5 minutes, so less than the fire damage criteria considered here in the study (see 3.3.1.4) [3]. Moreover, the depressurization from the leak itself leads to low pressure in a short period of time, reducing the effects' distances. For these reasons, it is useless to consider full bore releases, because they will be not substantial for the overall fire risk assessment. Further consideration about this topic will be done in Chapter 6.

The data for piping and equipment from OGP [12] standard are reported in the Table 3-1. The table contains the release frequencies listed as function of hole dimension ranges and item typologies.

*Table 3-1: release frequencies taken from OGP [12] standard.*

| Main Item from OGP Standard | | Frequency of Release (ev/year) (1) | | |
|---|---|---|---|---|
| | | **Small release 5mm hole diam. (1 to 10mm)** | **Medium release 20mm hole diam. (10 to 50mm)** | **Significant release 65mm hole diam. (50 to 150mm)** |
| Pumps (centrifugal) (2) | | 4.4E-03 | 2.9E-04 | 3.9E-05 |
| Compressors (centrifugal) (2) | | 4.08E-03 | 1.3E-04 | 1.0E-05 |
| Heat exchanger: Plate | | 5.9E-03 | 1.1E-03 | 3.2E-04 |
| Heat exchanger: S&T, Shell side (2) | | 1.61E-03 | 1.4E-04 | 2.4E-05 |
| Heat exchanger: S&T, Tube side (2) | | 1.2E-03 | 1.8E-04 | 4.3E-05 |
| Process (pressure) vessels (2) | | 5.9E-04 | 1.0E-04 | 2.7E-05 |
| Filters (2) | | 1.81E-03 | 1.9E-04 | 3.5E-05 |
| Steel process pipes | 24" DIA | 3.04E-05 | 2.4E-06 | 3.6E-07 |
| | 18" DIA | 3.05E-05 | 2.4E-06 | 3.6E-07 |
| | 12" DIA | 3.06E-05 | 2.4E-06 | 3.7E-07 |
| | 6" DIA | 3.45E-05 | 2.7E-06 | 6.0E-07 |
| | 2" DIA | 7.3E-05 | 7.0E-06 | 0.0E+00 |
| Flanged joints | 24" DIA | 1.42E-04 | 8.8E-06 | 1.1E-06 |
| | 18" DIA | 1.07E-04 | 6.6E-06 | 8.7E-07 |
| | 12" DIA | 7.6E-05 | 4.7E-06 | 6.1E-07 |
| | 6" DIA | 4.8E-05 | 3.0E-06 | 2.0E-06 |
| | 2" DIA | 3.36E-05 | 4.0E-06 | 0.0E+00 |
| Manual valves | 24" DIA | 8.6E-05 | 9.4E-06 | 1.8E-06 |
| | 18" DIA | 7.4E-05 | 8.0E-06 | 1.5E-06 |
| | 12" DIA | 6.0E-05 | 6.5E-06 | 1.2E-06 |
| | 6" DIA | 4.32E-05 | 4.7E-06 | 2.4E-06 |
| | 2" DIA | 2.77E-05 | 4.9E-06 | 0.0E+00 |
| Actuated valves | 24" DIA | 2.59E-04 | 1.7E-05 | 2.2E-06 |
| | 18" DIA | 2.6E-04 | 1.7E-05 | 2.3E-06 |
| | 18" DIA | 2.73E-04 | 1.8E-05 | 2.4E-06 |
| | 6" DIA | 2.86E-04 | 1.9E-05 | 8.6E-06 |
| | 2" DIA | 3.13E-04 | 3.0E-05 | 0.0E+00 |
| Instrument connections | | 2.84E-04 | 2.5E-05 | 0.0E+00 |

Notes:

(1) According to OGP definitions, Full Releases values are considered for leak frequencies evaluation.

(2) Release frequency for main equipment is related to the items with inlet size > 150mm. In case of inlet size is lower than 150mm, frequency associated to significant release (65mm hole size) is assumed equal to 0.

For preliminary FRA purposes, the release frequency of each isolatable section is calculated considering the release frequency of the main equipment plus the release frequency of a fixed number of items (pipes, automatic and manual valves, flanged joints, instrument connections) associated with them [3]. In order to perform this procedure, a part count is necessary. However, according to the leak of a detailed configuration design, only a simplified part count can be done. Table 3-2 shows, as an example, the number of typical items associated with a pump [3]. Numbers have been obtained by means of the part counts of similar facilities. The same information, obtained through the part counts of similar projects, was provided for compressors, pressure vessels, filters and heat exchangers by the methodology.

In addition, for each ESDV/SDV, one flanged joint and half-actuated valve are considered in the overall release frequency for each isolatable section. Those elements are chosen of the maximum size foreseen for the section. This procedure is done to consider only half ESDV/SDV at each boundary of the isolatable section associated with the respective inventory.

*Table 3-2: items associated to a pump [3].*

| Item identified in Isolatable Section | Associated main equipment (from OGP list) | Steel process pipes connected to the equipment | Flanged joints (qty.) | Manual valves (qty.) | Actuated valves (qty.) | Instrum. connect. (qty.) |
|---|---|---|---|---|---|---|
| Pumps | Pumps (centrifugal) | Suction line of 25m | 15 | 1 | 0 | 4 |
| | | Discharge line of 25m | 15 | 2 | 1 | 4 |

The size of the lines and associated sub-items (i.e. valves and flanges) are assumed through project information and data found in similar projects. With respect to the sealine, starting from the WHPs and arriving on the FLNG, only the above water part is taken into account for the frequency evaluation. For the FLNG, the arriving ESDVs are on the process deck, in the proximity of the swirling turret. The above-water portion of the sealine is evaluated equal to 35 m according to the Contractor's recommendation provided [3]. On the other hand, the above-water portion of the export pipeline is evaluated equal to 5m.

With respect to redundant components (pumps, compressors, filters, etc.); if there are three components in parallel, only two are considered in operation, while if only two components are in parallel, one is working. Only the plate heat exchangers upstream and downstream the demethanizer produce an exception. All of them are considered in operation [3].

To compile correctly the part count, further assumption for peculiar components and pipelines have been stated by the Contractor. Some examples are presented below [3].

- All the expanders should be modelled as compressors.
- Each of the plate heat exchangers in the liquefaction system should be modelled as:
  - 1 plate heat exchanger for the warmer fluid (methane);
  - 1 plate heat exchanger for the colder fluid (methane);
- The diameter of the sealines starting on the WHPs and arriving to the FLNG is set equal to 14'';
- The diameter of LNG offloading header is set equal to 30'';
- The diameter of the offloaging arms is set equal to 26'';

- The diameter of the thermal package incinerator is set equal to 3'';
- The length of the pipelines from WHP2 to the FLNG is about 20 km;
- The length of the pipelines from WHP1 to the FLNG is about 10 km;
- The length of the export pipeline is about 40 km.

For wells, which are treated in a separate technical legislation, the release frequency is estimated in accordance with OGP Report n°434-4 [13]. In particular, the selected release frequency is 9,10E-04 ev/y for well. The frequency is then divided for the set of holes according to the frequency distribution reported in Table 3-3, which is based on the recommended hole size distributions for risers and pipelines reported in the above mentioned OGP. Furthermore, it is also considered the release location distribution for risers, fixed by the OGP [13] (see Table 3-4).

*Table 3-3: Release hole size distribution for risers (the table is taken from OGP Report n°434-4 [13])*

| **Frequency distribution for holes** | |
|---|---|
| 5 mm | 35.00% |
| 20 mm | 25.00% |
| 65 mm | 15.00% |
| 150 mm | 25.00% |

*Table 3-4: Release location distribution for risers (the table is taken from OGP Report n°434-4 [13])*

| **Release Location** | **Distribution** |
|---|---|
| Above Water | 20.00% |
| Splash Zone | 50.00% |
| Subsea | 30.00% |

Even if the hole bigger than 150 mm are not analyzed in this preliminary study, their occurrence probability is reported in Table 3-3.

In order to evaluate the release frequency, only the "Above Water" and "Splash Zone" contributions are considered (Table 3-4). The final frequency for release point representing the well inventories is identified multiplying the obtained value by the number of wells, and then dividing it by the number of the involved decks [3].

##### *3.3.1.1.1 Ignition probabilities*

The ignition probability represents the probability that a released substance starts burning. They are usually evaluated by means of the statistics and mathematical models.

It is necessary to select the proper values to be used. The original UKOOA (United Kingdom Offshore Operators Association) model for ignition is selected for this study. This model was developed to relate the ignition probabilities in the air to the release rates for typical offshore scenarios, resulting particularly adapt for our case study. OGP standards (OGP Report n°. 434-6 [11]) provides a wide range of curve, based on UKOOA model, which are defined according to the different applicability scenario. The ignition probability curve n°24 (Offshore FPSO Gas for gas and two-phase release) is used for the evaluation of fire scenarios frequency from gas or liquefied gas releases. For any stabilized liquid, UKOOA ignition probability of curve n°26 is selected. These curves are the most appropriate according to the offshore scenario under evaluation and the fluid properties. A generic repartition of 50% for immediate ignition and 50% for delayed ignition is considered [3].

###### *3.3.1.1.2 Evaluation of Fire Scenarios Frequency*

The accidental scenarios are the "final outcome" in which the accidental events could develop. According to the type of release, the nature of the substance, the applicable external parameters (presence of ignition sources, meteorological conditions, etc.) and the characteristics of the event itself in general, the consequences can vary. In the FRA, hazardous consequences evaluation is performed only for the credible fire scenarios. In order to produce a proper outcomes evaluation, it is necessary to focus the attention on the "Event tree analysis".

The identifications of the various accidental scenarios, following a loss of containment, together with their expected frequency of occurrence evaluations, are performed by means of the "Event Tree Analysis (ETA)". The event tree is a visual representation of all the possible events, which can occur following the random rupture in a system. In this case study, the starting point (called initiating event) is always the undesired accidental event. The "trees" display the sequences of events involving success and/or failure of the components and all the different phenomena which can take place. Then they quantify each possible final scenario on a probabilistic basis, considering all different possibilities, such as the ignition type (immediate, delayed or no ignition), weather conditions, etc. Each branch of the event tree represents a separate accident sequence, or rather a defined set of functional relationships between the initiating event and the subsequent events [17].
General event trees are developed for the case study considering as representative initiating events concerning the gaseous or liquid releases in the plant. They are reported in Figure 3-2 and Figure 3-3 [3]. The probability values relating to each of the different branches of the event trees are evaluated according to standard literature data and international references. The following event trees are used for each failure case in order to provide the foreseen of final scenarios.

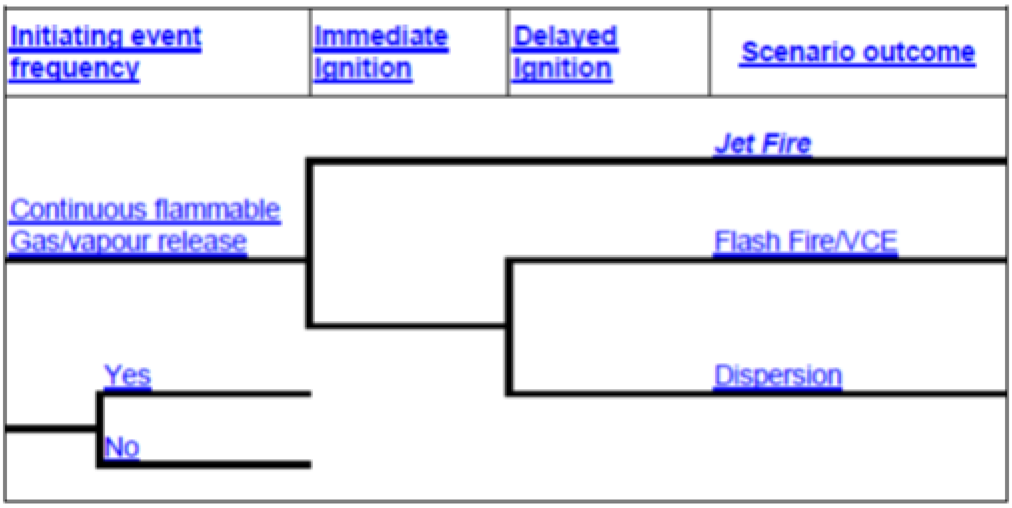



*Figure 3-2: the figure shows the event tree adopted for vapour/gas release [3].*

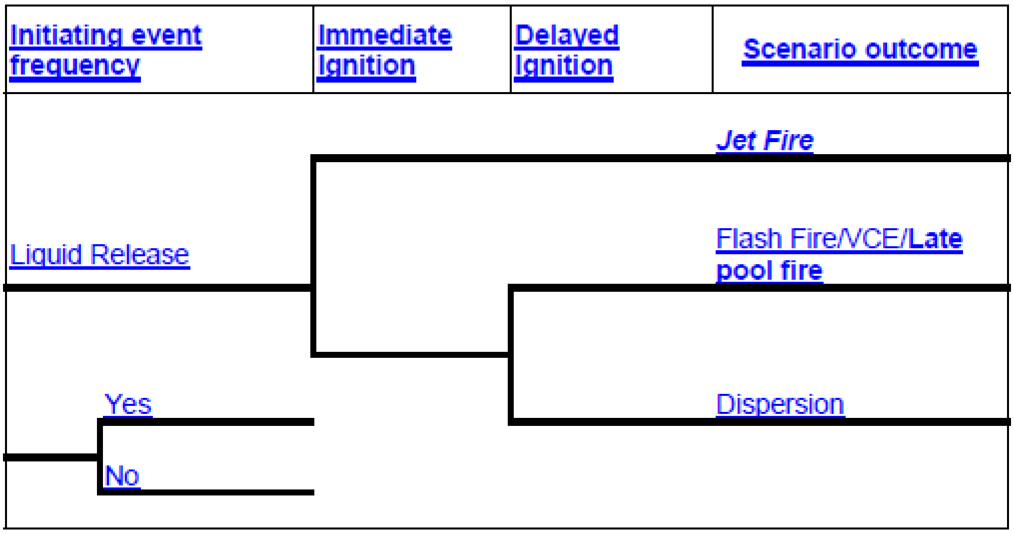



*Figure 3-3: the figure shows the event tree adopted for liquified gas release [3].*

Depending on substance characteristics and process release conditions, a fire scenario can develop as a jet fire in case of immediate ignition and pool fire in case of delayed ignition (just for a liquid release). Indeed, for the purpose of the analysis, only jet fire and pool fire are evaluated as possible consequences in the fire risk analysis. This approach may be considered not completely correct. Phenomena such as flash fire and VCE are not taken into account. Although, it can be justified making reference to the vulnerability asset considered in the preliminary risk assessment (see 3.3.1.4) and the methodology adopted for the explosion analysis. A further explanation will be produced in Chapter 6, when all the cited hypothesis will be explained.

#### *3.3.1.2 Modelling of Fire Scenarios*

Accidental fire scenarios shall be modelled by the use of a specific software and DNV PHAST 8.21 is chosen for the consequence evaluation in this assessment. The use of DNV PHAST 8.21 was directly requested by the Contractor [3]. This software is strongly requested by Contractors looking for Third Part, who want to perform risk analysis on their behalf. Some references to PHAST are found in technical manual concerning QRA.

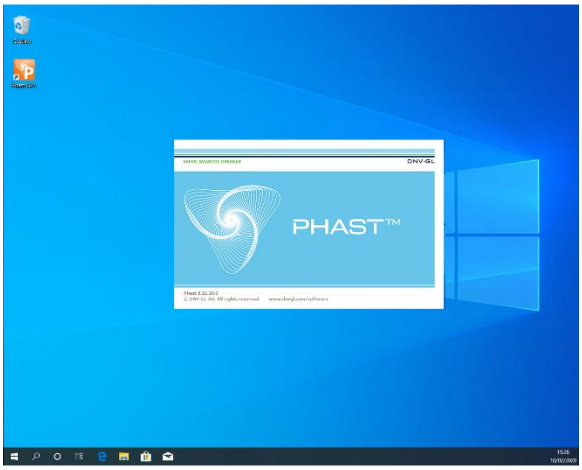



*Figure 3-4: Opening windows of DNV PHAST 8.21*

While working on a software for the evaluation of the consequence, it becomes essential to set correctly models and parameters to implement simulations. Below some important parameters and hypothesis will be described.

##### *3.3.1.2.1 Pseudo Component and Multi Component Modelling*

Different substances should be replicated in PHAST by means of commonest chemical substance in the Oil and Gas industry and the flux molar compositions provided by the Contractor inside the "Heat & Material balance" document. As per DNV GL Technical documentation, the "Multi Component (MC)" extension allows to model the release of mixtures accurately, being based on a calculation of mixture properties and phase equilibria. Therefore, MC modelling is used to replicate gas or two-phase releases, while the "Pseudo Component (PC)" is adopted in modelling the liquid releases [3].

##### *3.3.1.2.2 Weather Conditions*

According to preliminary analysis performed by the Contractor (a geotechnical, geophysical, metocean and earthquake risk analysis) on the future site of installation of the system, weather conditions has been identified (see Table 3-5) [3]. The table shows the weather conditions to implement in PHAST. These are the most common ones according the wide range of weather circumstances detected by the Contractor in that location.

*Table 3-5: the weather conditions to implement in PHAST.*

| **Parameter** | |
|---|---|
| Atmospheric humidity | 80 % |
| Average ambient temperature | 25° C |
| Solar radiation | 0,99 kW/m² |

As a consequence, it is proposed to use the atmospheric conditions D3 and D6 for the calculation of consequences in PHAST [3]. The letter designates the Pasquill atmospheric stability class, while the number indicates the wind speed (m/s) associated with this atmospheric stability class. Pasquill stability class D means neutral, or rather little sun and high wind or overcast/windy night. The D parameter represents the most common condition for a majority of weather conditions. Some consideration according the chosen weather conditions will be made in Chapter 6.

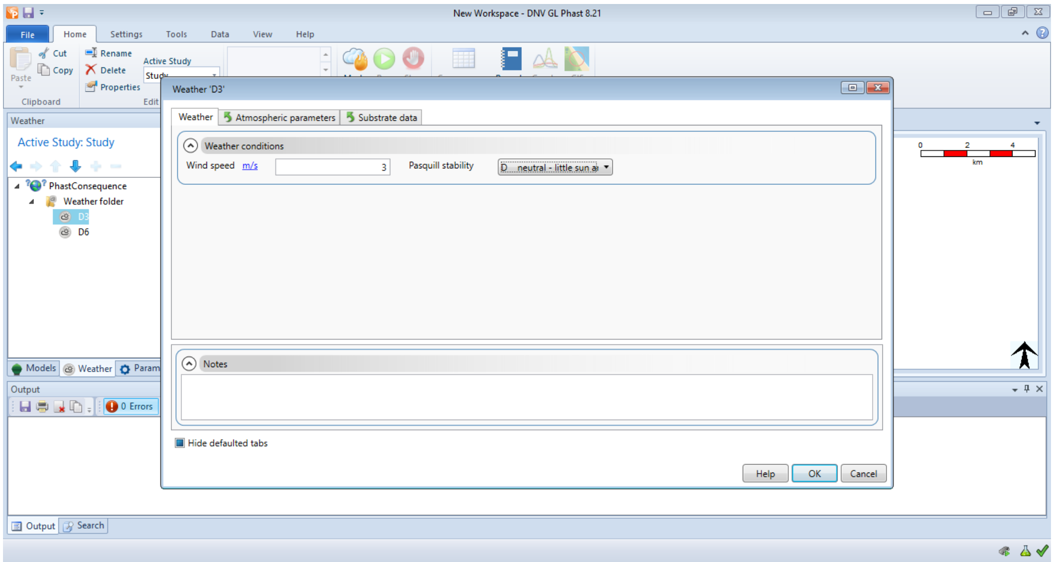



*Figure 3-5: PHAST windows used to choose the Pasquill atmospheric stability class.*

#### 3.3.1.2.3 Release direction

The horizontal impingement release model in PHAST is considered in the analysis both for gas/two-phase and liquid phase releases, due to the congested and confined nature of the overall FLNG design [3].

In case of gas or two-phase releases, based on event tree shown in Figure 3-2, only jet fire scenario is analysed in the FRA. For liquid releases (liquefied gas releases as LNG and NGL in this facility), based on Event Tree at Figure 3-3, both jet fire and late pool fire scenarios are analyzed. Pool fire scenario is assumed centered below the hole of release.

It is to be noted that the flame length calculated with PHAST for a horizontal impingement release is conservative since the flame length is evaluated by PHAST as a horizontal un-impinged release. Moreover, the distances to radiations calculated by PHAST are lower for an impinged release than for an un-impinged release. Therefore, in case of escalation criteria based on flame length, this leads to conservative results.

The directivity of jet fires has been considered in the fire risk mapping. A jet fire cannot be directed in all the 360° directions at the same time. Hence, the width of the jet fire (provided by PHAST as "jet frustrum tip width") for a horizontal release is determined with PHAST in order to divide the jet in several directions. The number of directions depends on the jet width and therefore, is different for each failure case and each hole size. Finally, the frequency of the jet fire occurrence is divided by the number of directions previously determined [3].

#### 3.3.1.2.4 Various parameters within PHAST

The following parameters are assumed for complete the setting of the models within PHAST [3]:

- Surface roughness: 0,5 m corresponding to PHAST default for "numerous obstacles";
- Release elevation/ Height for reporting results: they are considered equal to 1 m above the deck. Those elevations are imposed by the Contractor and they are affected by the target of interest.
- Solar radiation flux: included in fire radiation calculations;
- Consequence Models:
  - Jet Fire: modelled by means of the "Cone Model" (DNV recommended);
  - Bund: pool fire dimensions are limited to the bund area when applicable;
- PHAST Default discharge coefficient are used:
  - For liquid, the discharge coefficient is assumed equal to 0,6, the typical value for incompressible fluids;
  - For compressible fluids, the discharge coefficient is calculated by PHAST.

##### *3.3.1.2.5 Detection and Isolation time*

The leak duration depends on the time to detect the release, to isolate the section and to initiate the blowdown. Because blowdown starts automatically, it is assumed to occur at the same time as isolation. The time taken for a release to be automatically detected and isolated is assumed to be 2 minutes according international standards.

##### *3.3.1.2.6 Time of Interest and Decay of Release rate*

For this case study, in order to evaluate the damages on assets, the consequences of fire scenarios due to accidental releases are modelled considering the fire effects as follows [3]:

- at 5 minutes of release for jet fire scenarios;
- at 10 minutes of release for pool fire scenarios.

Release flowrates at 5 and 10 minutes are evaluated taking into account the effects of the section isolation. The blowdown effects are not considered due to the lack of information concerning that procedure. PHAST time-varying model is only used to implement the decreasing rate release with time in gas inventories. It is not considered for liquid releases. The time of interest chosen to model fire consequences, which was directly imposed by the Contractor, can be explained making reference to the section 3.3.1.4. They depend on the vulnerability associated to the target.

#### *3.3.1.3 Release points identification*

The number and position of failure cases are selected for each identified isolatable section, based on their location, the handled fluid, the contained gas/liquid inventories, their associated process conditions and the expected fire consequences in case of accidental release. If an isolatable section encompasses several equipment with process pressure varying significantly (for example over a compression train), the section can be split into different failure cases or the worst failure case in terms of fire scenario can be selected.

For each failure case, depending on the location of the equipment on the layout, a single or multiple release sources can be considered. For some specific events, specified during the analysis, related to isolatable sections covering a wide area on plant (e.g. isolatable section which include the transfer lines, if these latter run for a long way of the longitudinal section of the FLNG), the failure cases can be discretized into five release locations [3].

#### *3.3.1.4 Fire Risk Mapping*

The assessment of the vulnerability to the asset integrity due to fire, escalation and structural impairment hazards is usually evaluated on the following basis:

- Hazard intensity levels
- Duration of hazard level
- Escalation potential

In this preliminary phase of the project, a simplified approach has been used, therefore a target is assumed to fail if exposed directly to a fire (jet fire flame length or pool fire diameter) for a time greater than those reported in Table 3-6 [3]. Some consideration according the approach goodness will be presented in Chapter 6.

*Table 3-6: Representative escalation times for fires*

| Target | Gas or Two-Phase Jet Fire | Pool Fire |
|---|---|---|
| Failure of process equipment, structure, piping or equipment supports | 5 minutes | 10 minutes |

The overall fire risk mappings have been obtained from the combination of every credible fire scenarios (small, significant and large) with their corresponding frequencies. Three different maps will be produced.

1. Cumulative frequency jet fire impact areas for flame length at each process deck elevation. Consequences at 5 min (escalation time) are represented;
2. Cumulative frequency pool fire impact areas for pool diameter at each process deck elevations. Consequences at 10 min (escalation time) are represented;
3. Cumulative frequency jet fire impact areas at 5 min + pool fire impact areas at 10 min at each process deck elevations.

### 3.3.2 Methodology and assumptions of preliminary explosion risk analysis

From FEED phase, an explosion hazard analysis shall be performed using analysis tools to develop the design accidental loads (overpressure and drag) for structure, equipment and piping systems. During the PRE-FEED, not all the typical input information needed to perform the explosion hazard analysis are available and sufficiently consolidated. Consequently, only a preliminary explosion hazard assessment shall be performed to define a first attempt identification of the structural strength to be provided by those elements of the installation required to provide resistance to blast and drag loads.

This activity has been performed following the indications presented in the document “DNVGL-OS-A101, Safety principles and arrangements“ [5]. Specifically, in chapter 2, section 1, paragraph 3.6 it is possible to find the following Figure 3-6 and Table 3-7. They will be used to evaluate the hypothetical overpressure to be endured by the above-mentioned targets. The table shows the categorization of naturally ventilated offshore oil and gas areas according to their characteristics. Different kinds of zone are linked to different letters. These letters are reported in the figure, where they are used to distinguish the curves showing the DAL pressures as a function of the congested area volume and the explosion volume.

*Table 3-7: Categorization of naturally ventilated offshore oil and gas areas according their features. (from "DNVGL-OS-A101, Safety principles and arrangements" [5]).*

| *Congestion /density level* | *Operation* | *Confinement by blastwalls and solid decks* | | *Typical unit type* | *DAL on* | *Weather cladding* | *Curve no.* |
|---|---|---|---|---|---|---|---|
| | | *Confinement level* | *Blastwalls and solid decks* | | | | |
| High to normal | Production | Confined | 1 or 2 blastwalls, open or solid deck 6 m or more above | FPSO, FLNG, Semi sub, fixed | Blastwall (s) | Windwalls more than 50% | A |
| | | | | | | No windwalls | B |
| | | Open | No blastwalls open or deck above (FPSO, FLNG) | FPSO, FLNG, Turrets | Deck | Windwalls more than 50% | B |
| | | | | | | No windwalls | D |
| Less congested | Drilling | Confined | 1 or 2 blastwalls, open or solid deck 6 m or more above | Drilling rig, Integrated prod/drill | Blastwall (s) | Windwalls more than 50% | B |
| | | | | | | No windwalls | C |
| | | Open | No blastwalls open or deck above | Drilling rig | Deck | Windwalls more than 50% | C |
| | | | | | | No windwalls | E |
| Less congested | Tank deck/ crude piping area or similar | Confined | 1 or 2 blastwalls, and plated deck above | Tank decks (FPSO, FLNG) | Blastwall (s) | Windwalls more than 50% | E |
| | | | | | | No windwalls | F |
| | | Open | No blastwalls, plated deck above | Open area on tank deck | deck | Windwalls more than 50% | F |
| | | | | | | No windwalls | G |

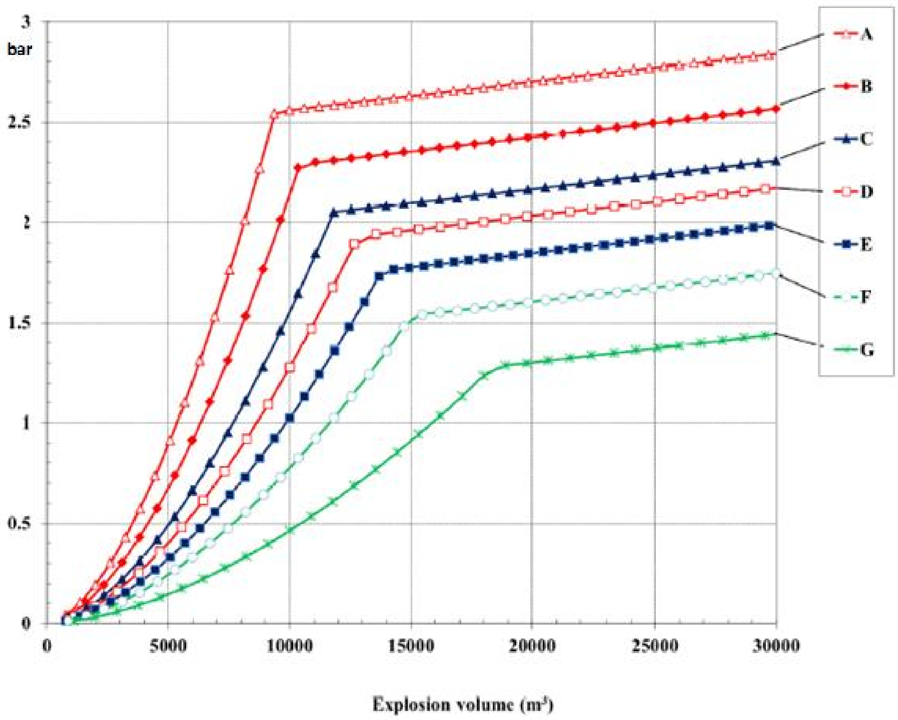



*Figure 3-6: DAL pressures as a function of the congested area volume and the explosion volume. (from "DNVGL-OS-A101, Safety principles and arrangements" [5])*

This explosion hazard analysis requires the identification of an explosion volume and then, according to its characteristics, the evaluation, by means of Table 3-7, of the proper curve to represent the area in the Figure 3-6.
In order to further verify information collected by the previously explained procedure, explosion simulations have been performed using DNV PHAST version 8.21.

### 3.3.3 Methodology and assumptions of subsea isolation evaluation

In addition to the previous analyses, the need of introducing additional sub surface isolation valves (SSIVs) has been investigated. The procedure has been developed with reference to the content of the section 2.3.2 LOSS OF CONTAINMENT – PIPELINES category HS5 "Subsea Isolation Valves (SSIVs)" contained in the document "Offshore safety cases - GASCET (Guidance for the topic assessment of the major accident hazard aspects of safety cases)" [8].

The criteria adopted in order to establish the requirement of the SSIVs at the early stage concern the amount of released gas. More in depth, a SSIV is required if a pipeline inventory without that valve causes a release of significant quantities of gas at the host facility FLNG for more than 30 minutes [3]. That verification was performed by the Contractor, selecting the following isolatable sections as the base cases to estimate the inventory in each pipeline:

- Single infield pipeline from WHP1 to FLNG (from WHP1 riser ESDV to FLNG riser ESDV);
- Single infield pipeline from WHP2 to FLNG (from WHP2 riser ESDV to FLNG riser ESDV);
- Export pipeline from FLNG riser ESDV to the pipeline tie-in point connecting the system with the onshore system: the minimum inventory is estimated.

For each isolatable section, the release rates from different release hole sizes are evaluated with and without SSIVs. The results of this study are analysed and compared with the FRA results in order to verify the necessity for SSIV installations.

## 3.4. Systems description

The oil and gas company, which is the instigator of the design and further construction of one of the systems under analysis, intends to develop two blocks under the license of the local government for the exploitation of methane reservoirs. The two configurations are designed to work in an offshore site and to exploit contemporary two different natural gas sources located in that "place". Both the systems, that will be studied with two different analyses (Case A and Case B), are characterized by two wellhead platforms (the same for both layouts), which are linked by pipelines and risers to a central FLNG unit; a new design FLNG in Case A and a converted FLNG in Case B. Platforms' aim is to host the wells while the methane will be processed in the FLNG system.

In particular, the development shall consist of 7 wells at the first block and 8 wells at the second block, each flowing to a dedicated, unmanned wellhead platform, which we call WHP1 and WHP2 respectively, in a phased production scenario. Initial production starts from WHP1 until the point of pressure decline. At this point, production begins also from

WHP2 to maintain a fixed rate of production. Production flows from each wellhead platform to an infield FLNG by rigid flow lines with flexible risers. On the FLNG, the natural gas is processed, liquefied, stored or eventually offloaded in auxiliary ships, which are not part of this investigation. In addition, there is a requirement for a 20% royalty gas payment, which should be exported from the FLNG by means of a flexible riser into a rigid flow line to tie-in to a pipeline directly linked to onshore systems belonging to the government.

Figure 3-7 shows a schematic representation of a hypothetical field development of the wells, wellhead platform, FLNG and export route respectively (dotted green line).

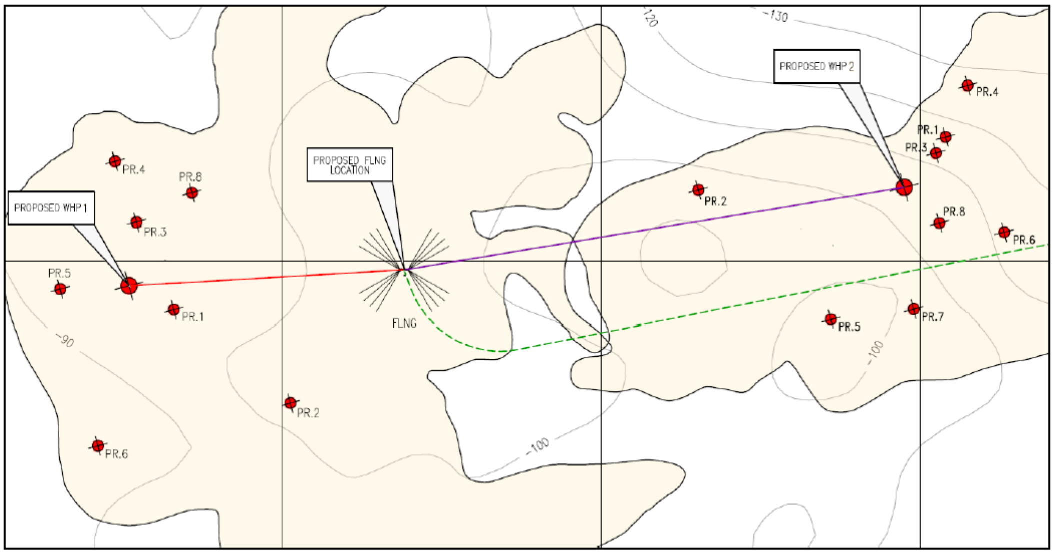



*Figure 3-7: an example of an hypothetical field development schematic of the system.*

### 3.4.1. WHP

The well head platforms used in Case A and Case B are the same. During the analysis, these two systems are considered equal according to the fact that exclusively the geographical position and the number of wells distinguish them; WHP1 has seven wells while WHP2 has one more tanh WHP1. Now they will be described from the process and structural layouts.

The task of these structures is to receive and combine the different fluxes of gas extracted by the different dislocated wells (box n°2 in Figure 3-13). Before putting the gas fluxes together inside the production manifold (box n°4 in Figure 3-13), a test separator (n°3 in Figure 3-13) is used to study randomly the composition of one of that. Then, two subsea flowlines receive the gas from the manifold (n°4 in Figure 3-13) and finally they send it to the FLNG system (n°5 in Figure 3-13), where it will be properly cleaned and liquefied.
These two platforms are pretty simple and they are not characterized by a large amount of process components. However, five different decks characterize them, which are respectively placed at +6, +12, +16, +19 and +24 meters over the sea levels. A simplified representation of these elements is shown below. However, before moving on the representations of the decks, it is necessary to explain briefly symbols and general rules adopted to represent in a simplified way the AutoCAD files provided by the Contractor.

The following rules will be also adopted for the illustrations of FLNG layouts. The pictures are characterized by these specific elements:

- An orange cross which is a spatial reference;
- Double continue red lines used to represent grated floors;
- Continue black lines used to indicate plated zones.
- Coloured circles are used to indicate the placement of the main components.

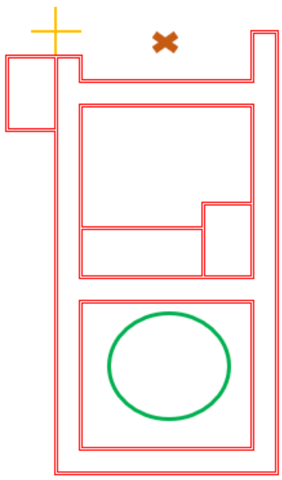


*Figure 3-8: +6 deck representation.*

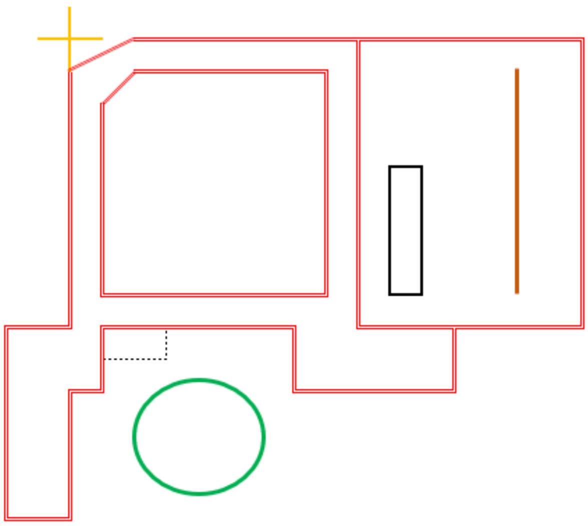


*Figure 3-9: +12 deck.*

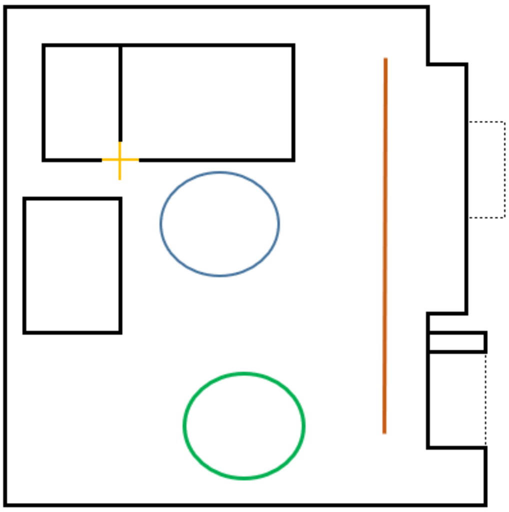


*Figure 3-10: +16 deck.*

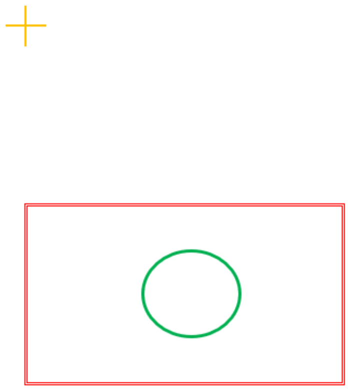


*Figure 3-11: +19 deck.*

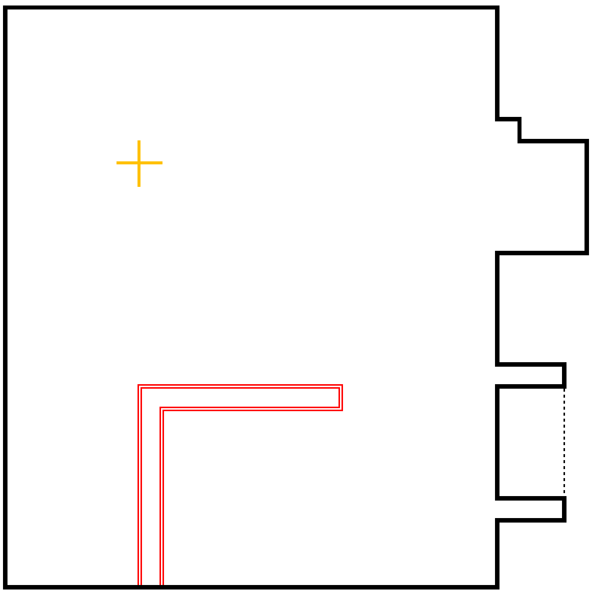


*Figure 3-12: +24 deck.*

The green circles indicate the position of the production wellheads. Christmas trees are placed in the +16 deck (Figure 3-10), risers cross the decks below, while in the +19 floor (Figure 3-11) are placed the chokes valves. The test separator is placed at the +16 deck and a blue circle identifies it. The production manifold (red line), starting at +16, crosses the +16 and +12 floors (Figure 3-12) in the right from the lower to the upper part of the structure. Then it goes vertically down to the +6 deck (Figure 3-8), where it goes down again until the sea level (orange cross).

### 3.4.2. FLNG

The FLNG facilities have the task to clean, liquefied and then store the produced liquefied gas until a shuttle tanker will take it away. Life for that kind of facilities is estimated about 25 years long. As already explained in paragraph 3.2, we are interested only in normal operations and specifically, in the process equipment placed over the main decks (below the hull deck). Only fewer information has been provided about the FLNG utility modules. The hull and associated equipment were not described at all by the Contractor, being out of the FERA boundaries. No indications have been provided about the protection systems, except for ESDV/SDV locations, while an in-depth description has been given about the process layouts.

In the following parts, the descriptions of the FLNG process chain is presented. It will be followed by an elucidation about the FLNG layouts. Indeed, the location of process components and the shape of the FLNG units are different.

#### *3.3.3.1 FLNG process chain*

The first and the last parts of the process chain are in common to both configurations. They are characterized by similar process design, except for the liquefaction and the storage facilities. These process parts will be described separately for each structure.

The feed gas, after being introduced in the subsea flowlines, is delivered through the turret to the FLNG topside. The process gas is fed to the FLNG from a total of four flowlines: two coming from WHP1 and two coming from WHP2. Each flowline is provided with a pig launcher/receiver station in order to allow the maintenance by means of loop pigging operations from the FLNG.
The receiving units are located inside the turret. They mainly consist of two topside umbilical termination units, for the supply of hydraulic, electric power and the chemical injection (to WHP1 and WHP2), one topside umbilical termination unit, for the supply of hydraulic power to the section valves of the export pipeline, four pig launchers/receivers and one leak recuperation system.

Two inlets receiving separator (box n°5 in Figure 3-13) units receive, separate and finally measure independently the production fluids coming from WHP1 and WHP2 fields. The most important components located in these sections are the feed gas and condensate metering systems and the verticals three-phase separators. This section should separate the feed gas from the liquids (hydrocarbon and/or water), provide enough volume to avoid pressure fluctuations at the plant inlet and finally accommodate liquid slugs in order to ensure a stable flow to the downstream facilities. In particular, the inlet separators (box n°5 in Figure 3-13), designed as a three-phase vertical separator, should separate the

gaseous streams from the aqueous and liquid condensate ones, which are then sent to dedicated treatment units (box n°6 in Figure 3-13) where water and hydrocarbon separation is achieved. The produced water is sent to the water treatment unit (box n°7 in Figure 3-13) before being discharged to the sea (box n°8 in Figure 3-13). On the other hand, the liquid hydrocarbons collected are sent to the condensate stabilization unit (box n°9 in Figure 3-13). Here, the condensates are produced at the condensate stabilizer bottom and sent to condensate storages (box n°10 in Figure 3-13), which is located in the hull. The recovered flashed gas is sent to LP fuel gas system (box n°11 in Figure 3-13).
A dedicated offloading header ((box n°16 in Figure 3-13) is installed to transfer condensate from the FLNG to the carrier. Before the condensate is sent to the offloading hose, its flow is metered by one metering system. One off-spec condensate storage tank is provided as well to collect off-spec condensate coming from the treatment unit. This stored fluid is then pumped back to a condensate pre-flash drum for reprocessing.

A future feed gas boosting compression unit is foreseen to overcome the rapid wellhead pressure depletion observed in both WHP1 and WHP2 fields. The configuration identified at this stage of the study consists of 2 parallel compression trains. This configuration is to be confirmed during FEED study based on updated production profiles provided by Company. When pressure level in the inlet receiving separator falls below a specific target, gas shall be routed to the feed gas boosting compressors in order to maintain the minimum required pressure at the inlet of the gas treatment units.

The gas stream from the inlet separator is sent to the following gas pre-treatment units (box n°12 in Figure 3-13). It goes through the acid gas removal unit to remove $CO_2$ and meet the $CO_2$ and the sulfur content specifications. Then it goes through the gas dehydration unit to remove $H_2O$. Finally, it moves through a mercury removal unit to remove Hg.
The acid gas removal is carried out by a regenerative chemical absorption process using an activated amine aqueous solution. This process includes three main sections, which are the absorption section, an amine regeneration section and finally an acid gas treatment unit.
Then the gas dehydration is performed using the molecular sieves technology. The selected process is regenerative; the water is retained by adsorption on the molecular sieves until they are saturated with water. Then, the molecular sieves must be regenerated (water desorption) by hot regeneration gas. There are three molecular sieve gas driers and during normal operation, two of them are in adsorption while the third bed is in stand-by or in regeneration. Dry gas from the gas driers is then routed to the gas driers after filter which removes the entrained dust from the molecular sieve beds before the gas is routed to the mercury removal section. The purpose of the mercury removal section is to reduce the mercury content in the dry sweet gas down to the required level. This measure is required in order not to damage the aluminium equipment used in the downstream cryogenic units. The feed gas from the dehydration section flows downwards through a mercury adsorber, which consists of a single non-regenerative bed. The gas is then routed to the mercury adsorber after filters to remove particles entrained from the mercury adsorbent beds.

A portion of gas corresponding to 20% of the FLNG incoming feed flow, coming from the downstream mercury removal unit, is processed to the required gas specification and sent to the local state (box n°18 in Figure 3-13) as gas royalty. The remaining part of the sweet dried gas is fed to the gas liquefaction unit (box n°13 in Figure 3-13), which design differs according to the configuration under study. It is also necessary to make distinction regarding the storage system.

Inside the Case A, "New design FLNG configuration", the dry gas is cooled down inside a warm box and then liquefied passing through a cold box, which could be considered as big vessels working as a heat exchanger. The refrigerating power is provided by a solution of heavy hydrocarbons circulating inside two refrigeration cycles, one feeding the warm box and one the cold box. These cycles are both characterized by a double compression unit and the one providing the cold to the cold box uses the warm box as condenser. The produced LNG is stored inside tanks (box n°15 in Figure 3-13) placed inside the hull.

In the Case B, Converted FLNG configuration, the dry gas after pre-treatment and boosting is routed to four liquefaction trains operating in parallel. The gas liquefaction technology is articulated around a triple expander refrigeration scheme which includes two semi-open natural gas cycles, that perform NGL extraction and use the expanded gas to provide the main refrigeration duty for natural gas cooling. Then a closed nitrogen cycle for natural gas ends the refrigeration. This process includes turbo-expanders, processing natural gas and processing nitrogen units. However, the central equipment of the liquefaction system is the cold box that includes the plate-fin heat exchangers, the connecting piping and manifolds, the LNG flashing valves and the end flash drum. The produced gas goes through this component several times, until it reaches proper condition and it is almost fully liquefied. Thus, the LNG exiting from the bottom of the end flash drum is pumped by the LNG rundown pumps and routed to the existing LNG tanks (box n°15 in Figure 3-13) through the LNG rundown header. Five LNG tanks are installed on the central zone of the FLNG and they are spherical type and are thermally insulated. Each tank is fitted with the following equipment. Two submerged type LNG offloading pumps are used for offloading and tank to tank transfer, an existing spray nozzle system which has been designed to allow tank progressive cooldown by LNG spraying and finally one submerged type LNG spray.

The remaining components and process equipment are again similar in both configurations.
A debutanizer (box n°14 in Figure 3-13) receives a liquid cut of ethane and heavier components from the bottom of the NGL separator of the liquefaction unit. The overhead gas from debutanizer is sent to LP Fuel gas system (box n°11 in Figure 3-13). The stripping vapor for the column is generated in a debutanizer reboiler. The bottom liquid from the debutanizer is routed to the condensate storage tank (box n°10 in Figure 3-13) after being cooled with water in a condensate cooler.

The offloading system (box n°16 in Figure 3-13) is designed to safely accommodate typical LNG carriers (LNGC) (box n°17 in Figure 3-13). LNG offloading is carried out through two offloading arms. The fourth arm is a vapor return arm provided to allow flash gas return from the LNGC to the FLNG. A hybrid liquid/vapor arm is provided as spare for liquid or vapor service. Dedicated offloading header is installed to transfer LNG from the relevant storage tanks (box n°15 in Figure 3-13) to the LNG offloading arms (box n°16 in Figure 3-13). Once the LNGC is moored, the offloading arms are connected to the LNGC loading system manifold. When the connection is completed, the tightness of the connection is tested with nitrogen and the proper operation of the offloading ESD system is checked. Cool-down of the offloading arms and loading line is then started from the FLNG. Cool-down is carried out by routing a small flow of LNG from the spray header into the liquid offloading arms by a small bypass valve. After cooling down a cold offloading ESD test may be carried out. The LNG transfer rate is then gradually increased by starting cargo pumps in sequence until the design offloading rate is reached. At the end of offloading, the LNG transfer rate is gradually decreased down to zero. The arms are then purged with nitrogen before the disconnection. LNG which is purged out of the arms is returned to the FLNG spray header and to the LNGC cargo manifold.

The LNG tanks normally operate at a fixed pressure, but BOG is continuously generated inside the tank. In addition, during offloading, the LNGC will return vapor to the fuel gas compressor through the vapor return arm. So, it is necessary to control the tank pressure. In holding and offloading mode, FLNG tank pressure is controlled by adjusting the capacity of the fuel gas compressor with the possibility to recycle back any excess to the inlet of the liquefaction. In the emergency scenario event of excessive pressure in the FLNG tanks, gas from the fuel gas compressor suction line will be routed to the cold LLP flare by a pressure control valve.

Steam turbine generators are installed. While one of them is in operation, another one is in stand-by and the last one is in maintenance. So, the rated power of the single steam turbine generator is selected to meet the maximum power demand during offloading. An emergency generator is also installed and it is designed to guarantee the power supply to the safety related systems. The diesel engine generator is installed for the emergency power generation to cover black start operation, the safe shutdown of the FLNG plant and to maintain minimum life support services for the personnel on board.

In order to supply fuel gas to all users, the plant fuel gas system is based on two different pressures fuel gas networks. The HP (high pressure) system is connected to the end flash drum and BOG systems and it feeds the HP fuel gas consumers, while the LP (low pressure) system fed directly by the HP fuel gas header is connected to LP fuel gas consumers.

Other process systems are present inside the FLNG configurations, but according to the methodology 3.3, we are not interested in them. These systems are:

- The seawater and produced water treatment units;
- The chemicals treatment unit;
- The service and instruments air production systems;
- The nitrogen processing system;

A simplified block diagram is presented in the following page in order to resume the main point of the complex production system.

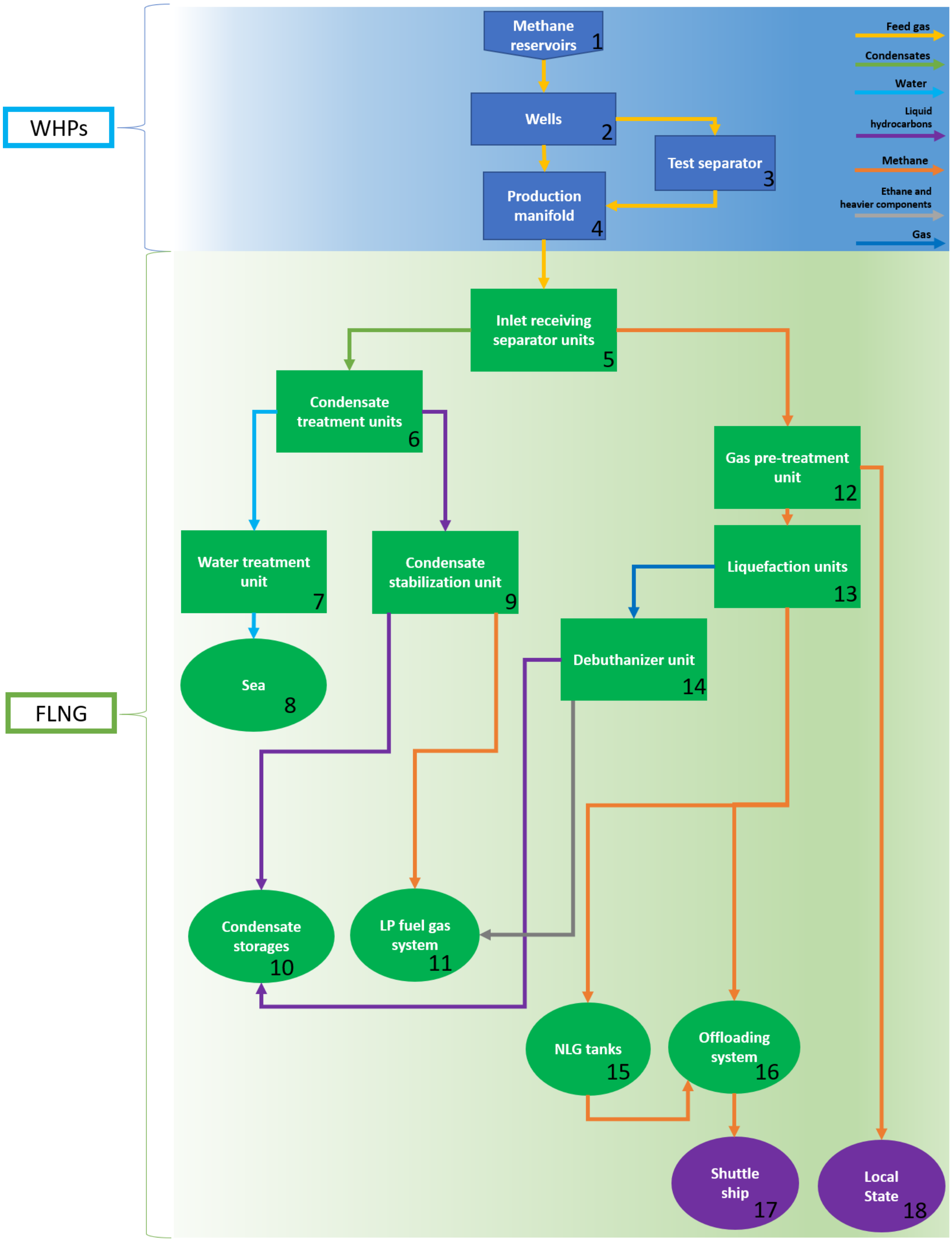



*Figure 3-13: simplified block diagram resuming the main points in the "feed gas to NLG" production chain*

#### 3.4.2.1. Case A: new design FLNG

The new design FLNG is about 60 m width, 440 long and 50 m high from the sea level. It will be made up by the hull level, where different storages are situated, and seven different decks where all previously cited process components will be placed (see 3.4.2). Each deck is divided in modules. They are developed in vertical; their location over all the different decks is always the same. Figure 3-14 and Table 3-8 are used to display the position of those sections over a simplified representation of the process deck.

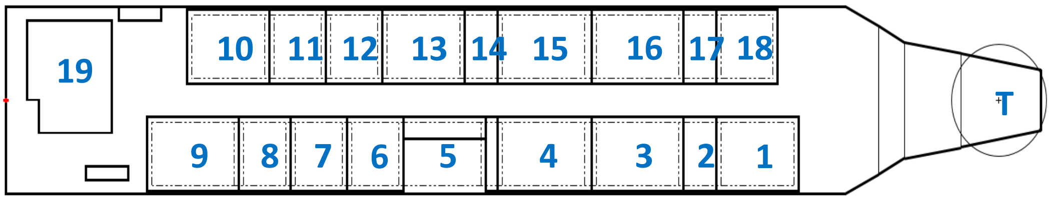



*Figure 3-14: Case A modules division.*

*Table 3-8: Legend for Figure 3-14 (Case A).*

| ZONE | INSTRUMENTS |
|---|---|
| T | Turret:<br>receiving facilities |
| 1 | Inlet separator and metering,<br>Condensate stabilization unit, Gas cleaning unit |
| 2 | Safety Gap |
| 3 | Second refrigeration cycle:<br>compression and refrigeration units |
| 4 | Second refrigeration cycle:<br>compression and refrigeration units |
| 5 | Offloading zone |
| 6 | Compression unit |
| 7 | Gas boosting unit |
| 8 | Gas cleaning unit |
| 9 | Power generation units |
| 10 | Water, chemical and heat process units |
| 11 | Compression unit |
| 12 | Compression unit |
| 13 | Condensate stabilization unit, Gas cleaning unit |
| 14 | Safety Gap |
| 15 | First refrigeration cycle:<br>compression and refrigeration units |
| 16 | First refrigeration cycle:<br>compression and refrigeration units |
| 17 | Safety Gap |
| 18 | Gas cleaning unit |

| ZONE | INSTRUMENTS |
|---|---|
| *19* | *Living quarter area* |

In this FLNG facility it is possible to identify areas which are not designed for process purposes. The main ones are the safety gaps, which are used in order to outdistance particularly hazardous zones, the living quarter where the staff lives when not in duty.

Following, simplified representations of three different decks are presented. In these pictures black thick lines are used to indicate plated zones, while the double red lines are for grated ones. The red cross placed in the left part of the structure is a geographical reference in order to have a common indication on all different decks.

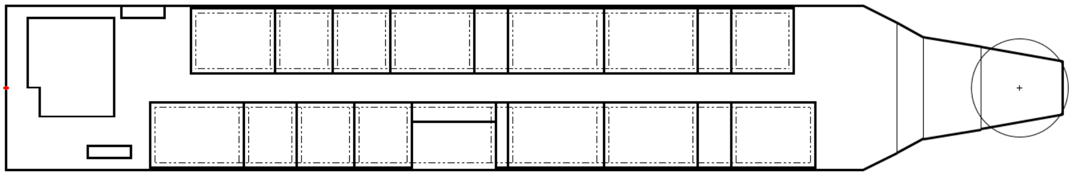


*Figure 3-15: Process Deck, Deck A +109.*

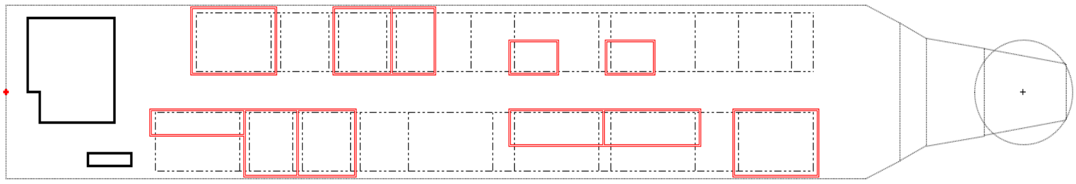


*Figure 3-16: Deck B +114.*

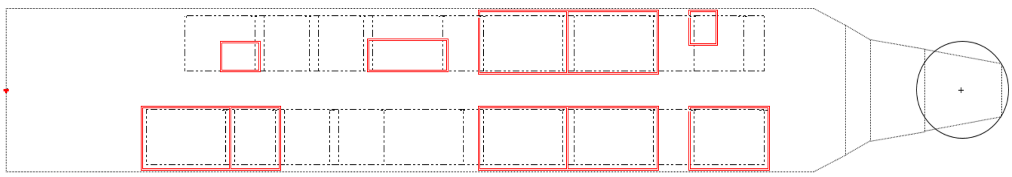


*Figure 3-17: Deck E +132.*

The Deck A (+109 m) (see Figure 3-15) is completely plated and all the different modules can be identified. However, different decks are characterized by a different module's layout. For example, only half of the modules "4" and "3" can be identified on Deck B (see Figure 3-16), while the module "11" is not present. Moreover, all the modules are now grated except for the living quarter area. Besides, since Deck E (+132 m) (see Figure 3-17), the living quarter is not present anymore. The structure is not sufficiently high to reach the +132 m level.
All the maps are characterized by a circle on the right. It represents the turret.

#### 3.4.2.2. *Case B: converted FLNG*

The converted FLNG is about 50 m width, 350 m long and 56 m high from the sea level. The decks are divided in modules. Their position over the facilities is the same in all the different decks they reach, since the process components will develop in vertical. Figure 3-18 is used to represent the position of those sections over the process deck, while in Table 3-9, the process unit included in each single zone are listed. Modules have been identified with numbers.

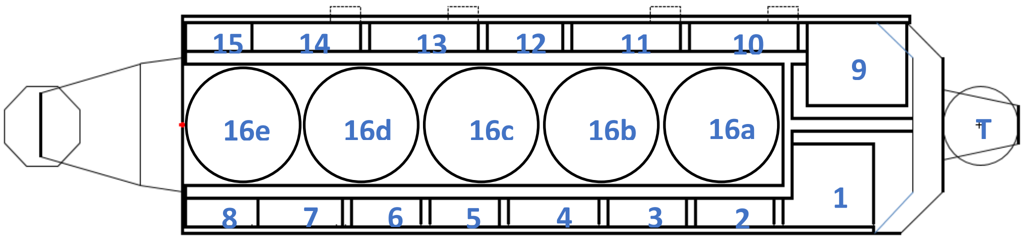



*Figure 3-18: Case B, modules division.*

*Table 3-9: Case B, legend for Figure 3-18.*

| ***ZONE*** | ***INSTRUMENTS*** |
|---|---|
| *T* | *Turret:*<br>*receiving facilities* |
| *1* | *Inlet separator and metering,*<br>*Condensate stabilization unit* |
| *2* | *Compression unit* |
| *3* | *Compression unit* |
| *4* | *Offloading zone* |
| *5* | *Compression unit* |
| *6* | *Compression unit* |
| *7* | *Water, chemical and heat process units* |
| *8* | *Laydown area* |
| *9* | *Gas cleaning units* |
| *10* | *Liquefaction unit* |
| *11* | *Liquefaction unit* |
| *12* | *Royalty gas conditioning* |
| *13* | *Liquefaction unit* |
| *14* | *Liquefaction unit* |
| *15* | *Laydown area* |
| *16a, b, c, d, e* | *Storage tanks* |

The following pictures show three schematic illustrations of the Case B FLNG facility. Each deck is represented using the generic rules already adopted for the WHPs and Case A FLNG (black thick lines are used to indicate plated zones, double red lines are for grated floors, the red cross is a geographical reference).

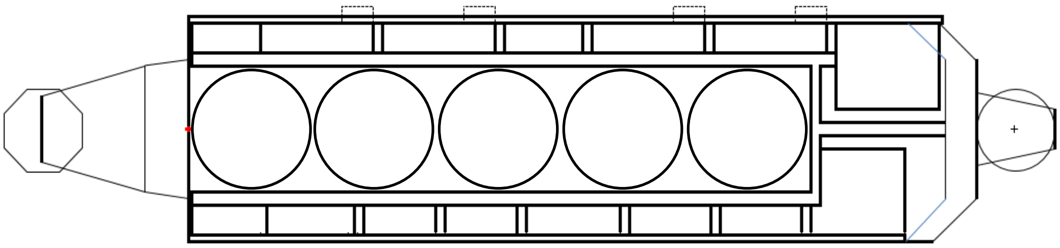


*Figure 3-19: Process deck, Deck A' +25.*

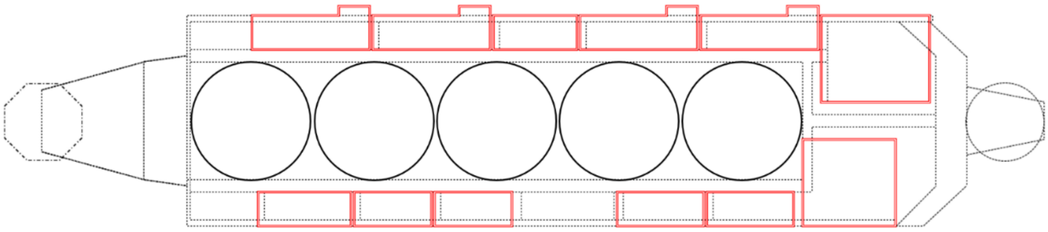


*Figure 3-20: Deck B' +34.*

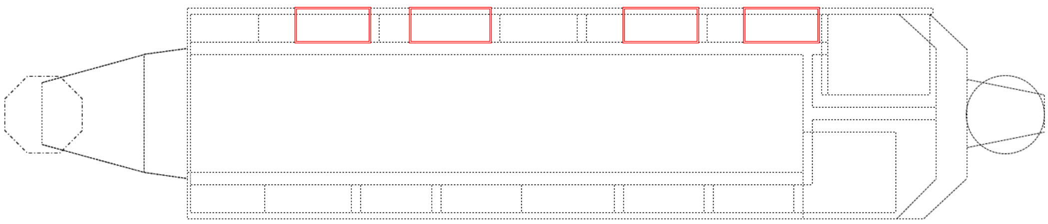


*Figure 3-21: Deck E' +56*

In Case B, different decks are characterized again by a different module's layout. The Deck A' (+25 m) (see Figure 3-19) is completely plated and all the different modules can be identified, while, for example, in deck E' (Figure 3-21) only the liquefaction units are present. The decks placed above the Process deck (i.e. Deck B'- Figure 3-20) are made up of grated modules. Besides, since Deck C' (+41 m), the spherical storages are not present anymore. These structures are not sufficiently high to reach the +41 m level.
The circle on the right represents the turret, while the octagon on the left is the helicopter landing pat.

# Chapter 4

# Assumptions adopted during the risk assessment

Deep knowledge of the case study is necessary to perform a risk assessment of the system. Indeed, the analysis of the material provided by the Contractor should be performed at the beginning of the study. This phase can be considered foregone by readers, but it is so essential that its importance and its role shall be remarked. The purpose of this stage is to understand the methodology, identify possible criticalities and consequently state the main assumptions to solve problems. The continuous relationship with the Contractor, where a large number of experts in the process and design configuration of the system work, was the "tool" that allowed a rapid resolution of criticalities. Now for each analysis requested by the Contractor, the main criticalities and the assumptions adopted to solve these problems will be explained. Then also the developed data obtained during the analysis will be explained below.

## 4.1. Fire risk analysis

### 4.1.1. Assumptions for the analysis

The lack of information caused by the absence of a well-defined system design strongly affects the fire risk analysis. The solutions to the criticalities encountered during the different phases of the fire risk analysis will be described below.

The first problem has arisen by the analysis of the "Heat & Material" balance documents, where the real future productions of each structure of the system are defined. The initial production starts, in the first year, from WHP1, while in the tenth year, when the point of pressure decline, WHP2 starts working. Its production becomes necessary to maintain a constant annual average rate. Only at the fifteenth year, WHP2 will be the only wellhead platform producing gas. Moreover, as already explained in the system description of the case study, the number of wells owned by the two platforms is not the same; WHP1 has seven wells while WHP2 eight. Therefore, it has been necessary to choose the conditions and the years, which should become objects of the study. The aim was to be as conservative as possible. The decision should also reduce the economical effort and time spent on the analysis. For the purposes of this analysis, WHP1 has been considered. Even if WHP1 contains 7 wellheads while 8 wells will be installed on WHP2, the first one has been chosen. In fact, WHP1 production is maximum at the year n°1 when the pressure is the highest reached by the reservoirs, while the WHP2 production reaches its maximum only at year n°15 when the pressure has already been strongly reduced due to the previous extractions. On the other hand, the worst conditions of the FLNG systems are obtained while it receives flow from both the WHPs. A higher number of inventories and structure are used increasing the possibility to have accidental scenarios. The WHP configuration was considered in the first year, while the FLNG configurations at the fifteen.

Stated the boundary conditions, the study of the process should be performed. In order to divide the system into inventories and sub-inventories, it is requested to know the temperature and the pressure of each flow together with the position of components on the facilities. Moreover, it is necessary to understand the dimensions of pipes and pipelines and where they are placed. The length of extra-module pipes in the WHPs and FLNGs has been detected using plot plans, while their diameters, if not specified in the provided documents, have been hypothesized with reference to a similar project made available by the Contractor. Plot plans have been used in order to state where pipelines will be probably placed. In accordance with the Contractor, we have stated that the extra-module pipes run on the floor of the process deck; in the newly built configuration, they are placed at the centre of the FLNG, while in the converted ones they are abreast or over the spherical storages. By means of hull's plot plans, the position and length of the tubes going from the top sites to storages have been decided.

Some clarifications about the position of process components have been requested. During the initial study of configurations, we have noticed that some vessels change abnormally their position over different decks, or they were not represented in plots plan. In particular, ESDVs and SDVs are never designed in preliminary plot plans; the position of those components has been forecast by the use of PFDs or directly requested to the Contractor.

Indeed, it is fundamental to identify the position of the SDVs/ESDVs and storage tanks, in order to correctly define the isolatable sections. Main useful hypothesis used are listed below:

- For the sealines starting on the WHPs and arriving on the FLNG, the starting ESDVs are located on the WHP +12 and +16 decks, while in FLNG configurations they are placed on the process deck near the turret;
- On the FLNG the HIPPSes are located near the field separator;
- The LNG storage tanks are in the hull. Only the LNG offloading header and the correspondent ESDVs are located on the topside;
- The condensate storage tanks are in the hull. Only two lines and the correspondent ESDVs are located on the topside;

- The ethane and butane storage tanks are in the hull. The pipeline going to the boat landing is not used in continuous; therefore, a release from these components is not considered able to affect the topside;

Another query concerns the modelling of heat exchangers inside the part. At first, it was not known when considering a shell and when a tube heat exchanger.

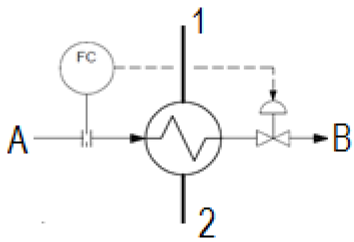



*Figure 4-1: typical representation of a shell/tube heat exchanger in a plot plan*

The solution to this problem was the following one. The fluid flowing from A to B, or vice versa, has been modelled as moving inside the tube side of the component, while the one going from 1 to 2 (and vice versa) in the shell side.

Moving on the substance definition for simulation, the physical state and the composition of the HC (hydrocarbon) fluids have been modelled according to the data from the "Heat and Material balances". In the case of gas release, only the gaseous jet fire formation has been considered, according to the methodology. In case of presence of liquid and gas in the same subsection, for example in separators and columns, the probability of having a gas release has been considered equal to 50%. Consequently, the probability of having a liquid release from the same component has been fixed 50% as well. The gas release is supposed to occur on the top of the vessels. In case of liquid release, both for subsections containing only liquid and subsections containing liquid and gas at the same time, the probability of a pool fire formation with a release down to the ground has been estimated equal to 50%; the probability of a horizontal liquid jet fire formation is equally estimated to 50%. These hypothesis are coherent with the methodology. The only exception is constituted by the linear liquid inventories, which have been considered able to produce only liquid jet fire. Furthermore, for a correct simulation of liquid release causing pool fire, the speculation of drip pans (Figure 4-2) presence and dimensions have been necessary. They have been placed around the main components characterized by liquid content and during PHAST simulations they have been considered not able to fail (it has been suggested the presence of a proper system to bring away hazardous liquids directly connected with drip pans). Their dimensions have been stated by means of proportions.

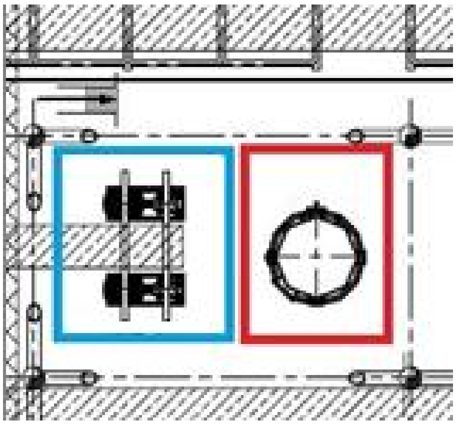


*Figure 4-2: Examples of drip pan representation.*

Finally, there is have the risk mapping. Different issues took place during that phase. The first one concerns the definition of the release points. Being in a preliminary design phase, important information such as the definition of pipes layers are not already defined. Thanks to RAMS&E previous experiences in a similar case, the placement of those points has been speculated, building up a conservative analysis.
A particular case concerns the number of release point used for the WHPs' wellheads. It has been chosen to conservatively consider one barycentric release point, instead of 7/8 release points (one for each wellhead) with lower singular frequencies.
Another difficulty we have faced during the analysis concerns the influence played by fires on neighbour decks, which directly depends on flooring (plated/grated). The WHPs flooring was specified in plot plans, so fire risk maps have been developed considering that plated decks are able to ensure the protection of steel beams (flames are not able to by-pass a large and solid surface) and other targets which are not immediately underneath of them. For example, the +24 deck of the WHP is plated, therefore, the equipment and structures on this deck can not be impacted by the flames originated in the +16 deck, except for a small grated escape route. It has been considered that grated decks do not protect the upper elements; targets, placed on decks different from the one where the initiating event occurred, are supposed to be damaged if they are reached by the flames for enough time (see Table 3-6). In particular, for each deck the contribution of fires to the cumulative maps, developed in all the levels of the WHP, has been evaluated and considered only if the flame dimensions were sufficient to reach the considered deck. On the other hand, since the flooring of the FLNG decks were not known, the method used for the WHP was not adoptable. Thus, we propose to apply a 50% probability to the possibility that the fires may affect the neighbouring deck. This hypothesis has changed when the Contractor specified that only the FLNG process deck would be plated. Since the WHP method could be used again. In conclusion, because all the FLNG floors are grated, except for the Process deck, we assume a 100% probability that fires can impact the other decks, both upper and lower, if the flame can reach them as a consequence of its dimensions.

### 4.1.2. Developed data

In this section, the results of the FERA study processes are reported and described.

According to methodology and hypothesis, only hydrocarbons isolatable inventories have been considered. For the “WHPs + New built FLNG” configuration, we have identified n° 24 HC isolatable sections and n° 57 subsections. They are divided as follows.

- Subsections on the WHP: n° 5;
- Subsections on the FLNG: n° 52.

On the other hand, for the “WHPs + Concerted FLNG” configuration, n° 18 HC isolatable sections and n° 73 subsections have been identified. They have been allocated as following explained.

- Subsections on the WHP: n° 5;
- Subsections on the FLNG: n° 68.

In both Case A and Case B, 3 isolatable sections are located on the WHP, 1 is shared between the facilities while the remaining are located on the FLNG. In particular, the one divided between the WHPs and the FLNG has been further split into 2 subsections; the first part is situated on the WHPs while the other one on the FLNG.
More information, concerning the isolatable section divisions developed and the technical data adopted to perform simulations, are presented in the ANNEX 1.

## 4.2. Explosion risk analysis

Now, the assumptions produced for each studied facility during the explosion risk analysis will be explained.

### 4.2.1. Assumptions for WHPs

According to WHP structure and design, it is not assumed that explosions can take place in these facilities. Each deck is vented and the amount of inventory is low. Although this hypothesis can be used only because we are in a preliminary phase and the Contractor is not very interested in changing or choosing the WHP design. These structures will be surely analysed in-depth during the feed phase when a wider range of information is going to be available.

### 4.2.2. Assumptions for the Case A, New design FLNG

For the purpose of the preliminary explosion evaluation, a representative explosion site (PES 1) has been identified and it is reported in Figure 4-3 and Figure 4-4. The PES 1 corresponds to part of modules “4” and “3” (see Figure 3-14), where the second circle of the liquefaction is situated. It is limited downwards by plates, upward by the grated ceiling, on the left and on the right by safety gaps, while the other directions are assumed without obstacles. It is in the core of the liquefaction process, in an area where the fire risk has been found to be the highest (that assumption has been done before having obtained the total cumulative risk maps).


*Figure 4-3: graphical representation of PES 1 location on the Process Deck.*

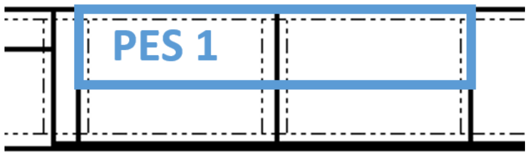



*Figure 4-4: PES 1 detail.*

According to its characteristics (position, geometry and process performed inside the zone), PES 1 have been speculated as represented in Figure 3-6 by the curve D. Other PES characteristics are summarized in Table 4-1. The PES volume is going to be used to identify the overpressure.

*Table 4-1: PES 1 dimensions.*

| PES | x [m] | y [m] | H [m] | PES Volume [m$^3$] |
|---|---|---|---|---|
| 1 | 75 | 13.7 | 6 | 5791.74 |

### 4.2.3. Assumptions for the Case B, Converted FLNG

Emulating procedures adopted in Case A, a representative explosion site (PES 2) has been identified for the Case B. PES 2 has been situated in the process deck, and in particular in module "14" (see Figure 3-18), where one of the liquefaction train will be installed. This area has been chosen consequently to preliminary fire analysis results, according to the fact that it is an area where the fire risk has been found to be high. As PES 1, it is limited downwards by a plated floor, upward by the grated ceiling, on the left and on the right by safety gaps, while the other directions are assumed without obstacles. Figure 4-5 and Figure 4-6 represents in detail PES 2 positioning.

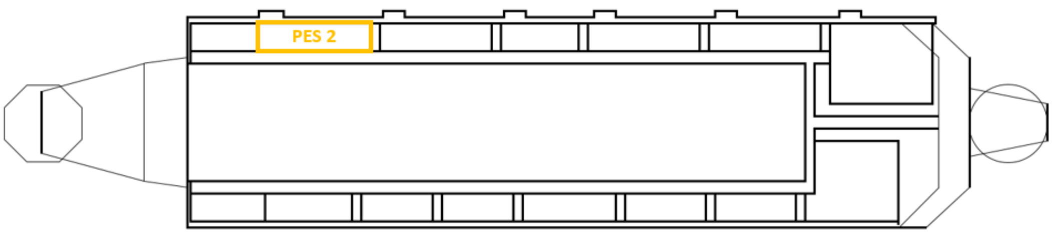



*Figure 4-5: PES 2 location on the process deck.*

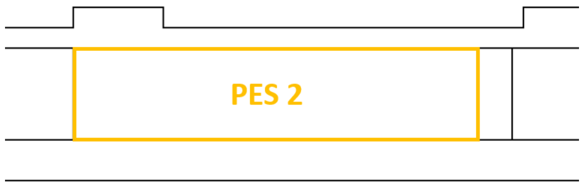



*Figure 4-6: PES 2 zoom*

According to PES 2 features, it is represented in Figure 3-6 by the curve D. The other PES characteristics are summarized in Table 4-2.

*Table 4-2: PES 2 characteristics.*

| PES | x [m] | y [m] | H [m] | PES Volume [m$^3$] |
|---|---|---|---|---|
| 1 | 36 | 8,5 | 9 | 2754 |

## 4.3. SSIV analysis

According to legislation and verifications performed on different floating units, in general, the major part of operating offshore facilities are designed to provide a temporary refuge (TR). Their means of evacuation and structures will withstand the effects of a major accident event for at least 30 to 60 minutes.

Although, while the TR may be able to withstand fire for more than 60 minutes, it is unlikely that the primary and secondary structures or lifeboats would survive much longer. The evacuation would be necessary after major accident events if the consequences will last more than a fixed amount of time.

The Contractor has performed an initial study on his facilities in order to verify if the subsea isolation will be necessary according to the information previously stated. Consequently, to establish the requirement of those safety systems at the early stage, the following criterion has been stated for the study.

*"A proper SSIV should be installed if the inventory of a pipeline without a SSIV causes a release of significant quantities of gas at the host FLNG facility for more than 30 minutes." [3]*

Inside this study, the following isolatable sections were selected as the base cases to estimate the inventory in each pipeline.

- A single pipeline from WHP1 to FLNG: from WHP1 riser ESDV to FLNG riser ESDV;
- A single pipeline from WHP2 to FLNG: from WHP2 riser ESDV to FLNG riser ESDV;
- The export pipeline: from FLNG riser ESDV to the export pipeline tie-in point.

That study was performed on the assumption that the risers ESDV(s) and SSIV(s) (if required) will be closed in the event of a hydrocarbon release. The total mass of fluid, which can be released from a pipeline, depends on the flowrate of the released gas when the pressure decreases. For the purpose of SSIV assessment, it was conservatively assumed that the entire gas inventory in the isolated sections will be released, in case of accidental scenario.

Typically, as underlined inside "Cullen, H. L. (1990). *The Public Inquiry into the Piper Alpha Disaster"* [4], SSIV will be located within a 500 m safety zone of the host FLNG facility. The following reasons are further used to optimize the location.

1. The SSIV should be far enough away to be out of dropped object radius;
2. The SSIV should be far enough away to mitigate the risk of gas cloud blowing back over the host facility;
3. The SSIV should be near enough to minimize inventory between SSIV and riser.

Because the exact location of the SSIV was not finalized during this phase of the project, the inventories of pipelines with SSIVs were estimated 500 m long, the maximum SSIV distance allowed from the host facility. This decision maximizes the inventory to be isolated between the SSIVs and the riser ESDVs. It was assumed that riser ESDVs and SSIVs (if required) will be successfully closed in the event of riser or pipeline failure; hence, the inventory will be isolated within every single pipeline.

For the FLNG development option, two cases have been analysed and they referred respectively to the infield pipelines from WHP1 and WHP2 to FLNG. The predicted release rate from different release hole sizes has been studied and for each pipeline, the cases with and without SSIVs has been considered.

The results have shown that the 20 mm hole release rate is not relevant; in fact, it involves a long duration but always a small magnitude release. The full-bore release (FBR) has a very high initial release rate which rapidly decreases (within 5 minutes). Therefore, the effects of the installation of an SSIV are not significant for a 20 mm hole and the full-bore releases. This is true both for WHP1 and WHP2.
For the WHP1 infield pipeline, considering a release after 30 minutes without a SSIV, both 50 mm and 100 mm holes' releases are still relatively high (more than 20kg/s). Moreover, a release from the 50 mm hole is reduced to 15kg/s after 60 minutes, while all other holes' releases decrease to a relatively low rate after 60 minutes.
For the WHP2 infield pipelines, only the 50 mm hole has a release rate higher than 15kg/s after 30 minutes, due to lower pressure and inventory than the WHP1 pipelines. Considering the installation of the SSIVs in the infield production system, the release rates from all the hole sizes drop off very quickly within 5 minutes.
In conclusion, the benefit of SSIVs to infield pipelines is to reduce the duration and release rates from these medium hole sizes (predominantly 50mm) to allow safe evacuation from the host facility FLNG [3].

For the export pipeline, the same study has been performed. The predicted release rates from different release hole sizes have been compared between the case with and without a SSIV.
Similarly, to the infield pipelines, the effect of a SSIV to 20 mm hole and FBR releases are not significant. The results show that most hole sizes release rates are still high without a SSIV after 30 minutes except the 20mm and FBR hole size releases. Moreover, the effect of a SSIV is to significantly reduce the releases to a low rate within 5 minutes for all hole sizes [3].

The results show that SSIVs for infield pipelines would have the benefit of mitigating the releases from medium holes. However, the medium size releases only contribute to about 15% of the overall release frequencies from risers and pipelines according to the statistical data from OGP [13]. Hence, the SSIV benefit for infield pipelines is considered limited.
For the export pipeline, the results indicate that there is a substantial benefit to the FLNG in including a SSIV, as the releases are significantly reduced for all the hole sizes within 5 minutes. Taking into consideration that the inventory within the pipeline could also backflow to the export pipeline in the event of loss of containment, the benefit of SSIV would be even greater than the base case. In addition, a non-return valve (NRV) is recommended to be installed at the export pipeline tie-in point to reduce the risk that the large inventory after this point backflows and it may impact on the FLNG. The NRV has the advantages of being a self-contained operation and of rapid closure in the event of a pipeline rupture.
Conclusions are summarized in the following table.

*Table 4-3: Summary of SSIV requirements*

| ***Inventory considered*** | ***SSIV Requirement*** |
|---|---|
| Pipeline from WHP1 to FLNG | Marginal |
| Pipeline from WHP2 to FLNG | Marginal |
| Export pipeline | Required |

The results obtained by this study are relevant for the SSIV analysis. They are the basis for further consideration which will be obtained with the risk assessment. In the case study, the risk analysis can verify the goodness of the conclusions stated by the Contractor in order to help them in the decision process to install the SSIV influencing the turret zone.

# Chapter 5

# Results and considerations

In this section of the thesis, preliminary risk assessment results will be reported according the methodology. Using the numerical outcomes, some technical recommendations and other suggestions have been proposed. The Contractor could implement them in order to reduce the risk level of the facilities or to guide the decisional process.

## 5.1. Fire Risk Results

In this preliminary phase of the project, process equipment, structure, piping or equipment supports are considered targets. They are assumed to fail if exposed directly to a fire for a time greater than 5 minutes for jet fires and 10 minutes for pool fires.

The overall fire risk maps are obtained from the combination of every credible fire scenarios (small, significant and large) with their corresponding frequencies. Three different cumulative maps should be obtained according the methodology. Indeed, for each process deck a cumulative frequency map, representing the jet fire consequences at 5 min, a cumulative frequency of pool fire impact, showing the consequences generated by pool fires at 10 min and finally total cumulative frequency map, which sums up jet fire impact areas at 5 min and pool fire impact areas at 10 min, should be produced.

Figure 5-1 shows the risk tolerability criteria chosen by the Contractor and the colours adopted in the fire risk mapping procedure. The different probability [ev/y] ranges have been associated with a specific colour in order to uniquely identify zones of the cumulative maps characterized by the same frequency magnitude.

| |
|---|
| P > 1E-05 |
| 1E-06 < P < 1E-05 |
| P < 1E-06 |

*Figure 5-1: The risk tolerability criteria chosen by the Contractor.*

### 5.1.1. WHP

Since only gaseous inventories are present in WHPs, the overall fire risk maps involve only the jet fire scenarios while pool scenarios are not considered. Moreover, the jet fire scenarios, because of their flame dimensions, interfere only with the adjacent decks. So, each fire generated in a deck can affect only the immediately upper and lower decks. Thus, we are interested only in the cumulative map presenting the total frequency of jet fire at 5 min.

The WHPs fire risk maps obtained as results of the analysis are presented below.

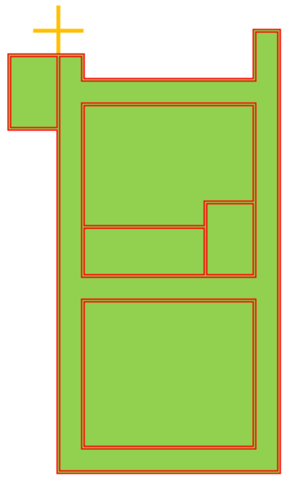


*Figure 5-2: Cumulate +6 deck*

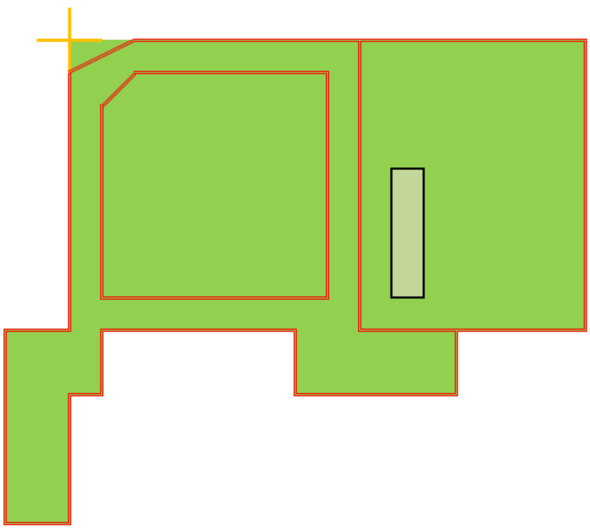


*Figure 5-3: Cumulate +12 deck.*

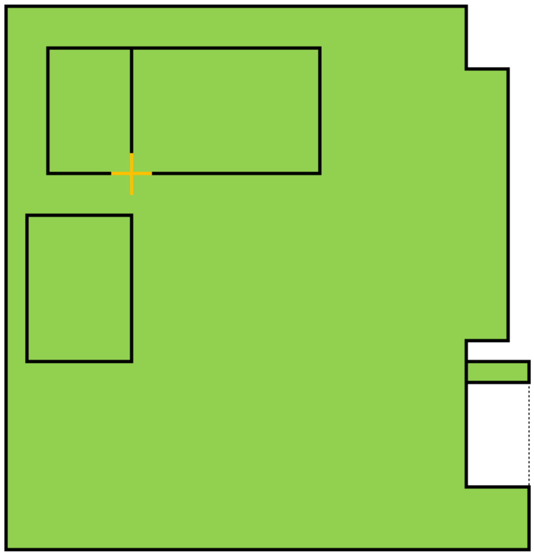


*Figure 5-4: Cumulate +16 deck*

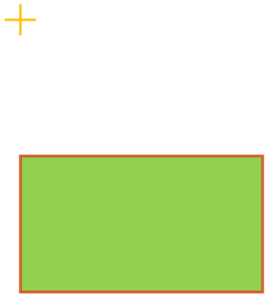


*Figure 5-5: Cumulate +19 deck*

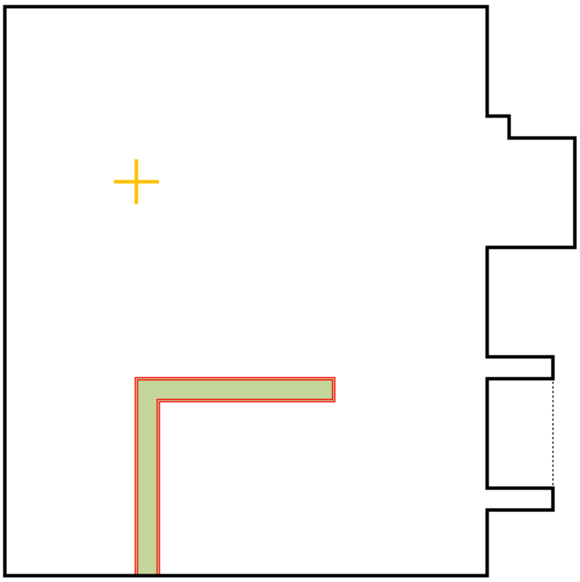


*Figure 5-6: Cumulate +24 deck.*

As it is possible to understand by the previous maps, the cumulative frequency falls mostly in the "$1\mathrm{E}-06 < \mathrm{P} < 1\mathrm{E}-05$" interval (Figure 5-1). Moreover, the cumulative frequency falls in the "$\mathrm{P} < 1\mathrm{E}-06$" range (Figure 5-1) only in two small zones. The first one is in the +12 deck (see Figure 5-3) and it refers to a portion of the deck that is plated, while the second one is in the +24 deck (see Figure 5-6). In this deck (+24), no release points have been identified, therefore the calculated frequency derives from events occurring in the lower deck. Moreover, the deck is plated, except for a grated walkway escape route (the light green area in Figure 5-6). The plated part is considered not affected by the other decks' scenarios, so it is fixed a null value, while the grated part's frequency of this deck is always lower than 10-6 ev/y.

In the following Table 5-1, the maximum frequency calculated on each deck is reported.

*Table 5-1: Maximum frequency calculated on each WHP deck*

| Deck | Maximum frequency on the deck [ev/y] |
|---|---|
| +6 deck | 1,13 E-06 |
| +12 deck | 1,13 E-06 |
| +16 deck | 1,40 E-06 |
| +19 deck | 1,35 E-06 |
| +24 deck | 4,30 E-07 |

It can be observed that the cumulative frequency assumes very similar values on all the decks, except for the +24 deck, where it is about an order of magnitude lower.

From the analysis, specific criticalities have not been highlighted. The maximum calculated risk is equal to 1.40E-06 ev/y. This maximum value is registered on the +16 deck and it is given by the superposition of the frequencies of releases from the wellheads and from the test separator. The most critical area is identified by a red circle and it is represented in Figure 5-7.

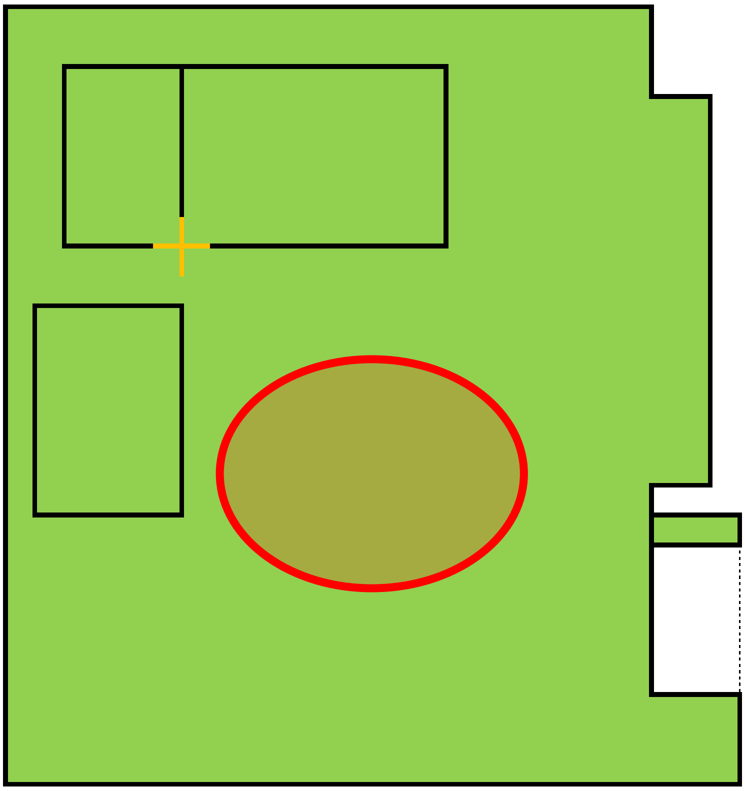


*Figure 5-7: The most critical area identified on WHP.*

In conclusion, according the numerical value obtained, the risk can be considered tolerable. In the end, it is necessary to highlight that the contribution of a fire fighting system has not been measured. It will surely produce a reduction of the calculated values.

### 5.1.2. Case A, new design FLNG

For the FLNG, release scenarios can give rise to gaseous jet fires or liquid jet fires and pool fires. Thus, for both FLNGs, the Contractor was interested in all the three different kind of cumulative maps (see the paragraph 3.3.1.4). They are represented in the following figures. For each deck, the overall risk map, including gaseous and liquid jet fires, the one produced by pool fires and finally the one, considering both jet fires and pool fires, are respectively presented.

As already explained in the Chapter 4, since all the FLNG decks are grated except for the process deck, the flammable pools are all located in the process deck, where the drip pans have been supposed. Nonetheless, the flames generated by a pool fire affect all the higher decks.

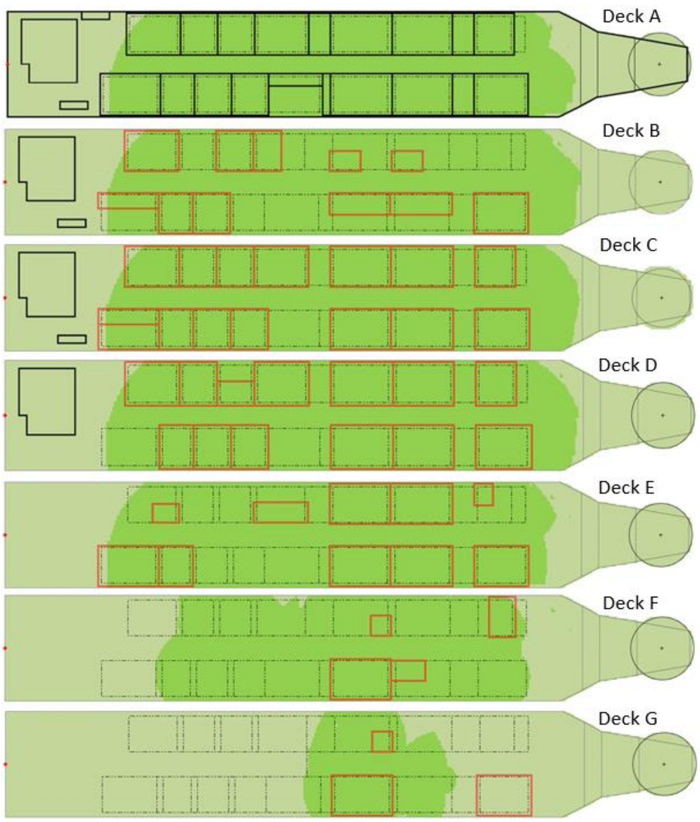



*Figure 5-8: Cumulates jet fire at 5 min*

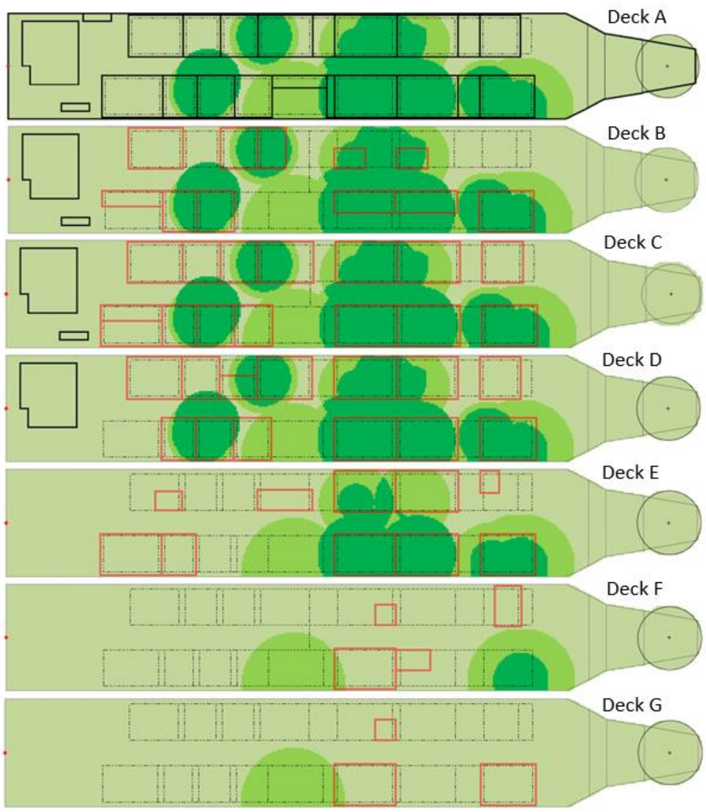



*Figure 5-9: Cumulates pool fire at 10 min.*

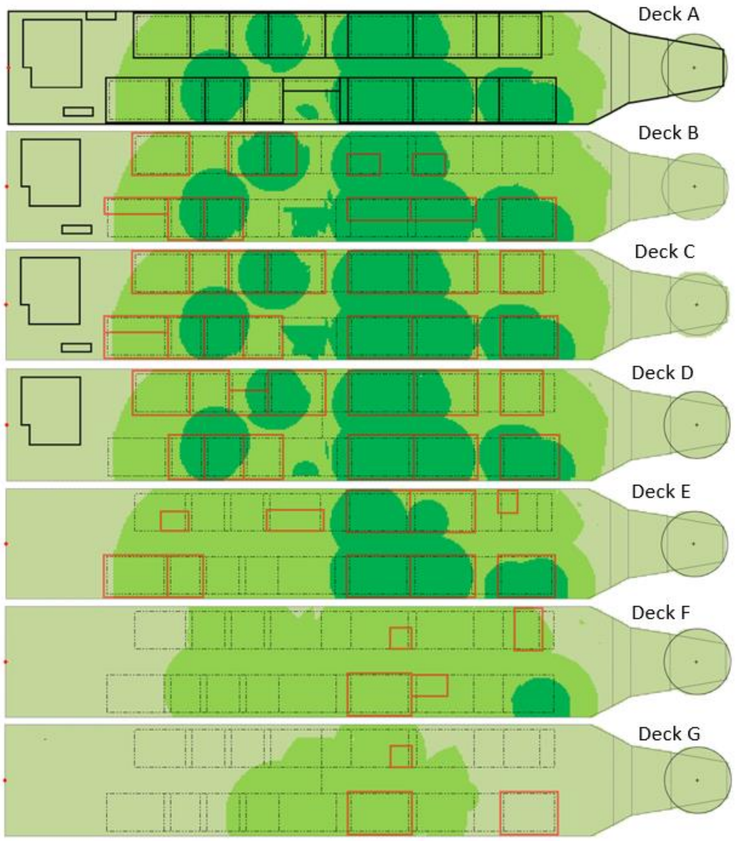



*Figure 5-10: Total Cumulates.*

The highest contribution to the overall risk is due to the pool fires. Indeed, the final shape of the cumulative risk spatial distribution (Figure 5-10) follows the shape of the pool fire risk one (Figure 5-9), except for the module hosting the LNG offloading systems (number 5 in Figure 3-14). For this module, the cumulative frequency falls in the "$1\mathrm{E}-06\ \mathrm{ev/y} < \mathrm{P} < 1\mathrm{E}-05\ \mathrm{ev/y}$" range (see Figure 5-1) if only the jet fire (Figure 5-8) or only the pool fire scenario (Figure 5-9) is considered. When the contribution to the frequency of the different scenarios is cumulated, this zone becomes dark green, according to the frequency interval presented in Figure 5-1. The pool contribution is so relevant since all the release scenarios from isolatable sections producing pool are cumulated on the process deck and because the largest part of pools affects until the deck E.

In this analysis the Contractor was very interested in the swirling turret zone, because the presence of several infinite inventory could produce a high-risk zone. This topic will be developed better in the explanation of results concerning the SSIV analysis (Section 5.3 “SSIV analysis result”).
On the other hand, the living quarter area (number 19 in Figure 3-14) was not considered as target according to the methodology (Chapter 3.3). However, being the risk on people surely analysed in future studies, it can be useful making some consideration according this area, if it does not involve time expenditure. The cumulative frequency in those zones (turret and living quarter) always falls in the “$\mathrm{P} < 1\mathrm{E}-06\ \mathrm{ev/y}$” interval of frequencies.

In the following Table 5-2, the maximum frequency calculated on each deck is reported.

*Table 5-2: the table shows the maximum frequency evaluated on each FLNG deck*

| Deck | Maximum cumulative frequency on the deck [ev/y] |
|---|---|
| Process deck, deck A (+119) | 1,16 E-04 |
| Deck B (+114m) | 1,18 E-04 |
| Deck C (+120m) | 1,17 E-04 |
| Deck D (+126m) | 1,16 E-04 |
| Deck E (+132m) | 1,12 E-04 |
| Deck F (+138m) | 5,43 E-06 |
| Deck G (+144m) | 3,94 E-06 |

The maximum calculated risk is equal to 1,18E-04 ev/y. This value is registered on the Deck B (+114m) in sector "4" (see Figure 3-14), where the second refrigerant cycle is located. The worst pool fires involve the second refrigerant cycle (module "4" and "3", which are characterised by the maximum cumulative frequency above mentioned), the first refrigerant loop (module "15" and part of module "16", characterised by a maximum cumulative frequency equal to 6.6E-05 ev/y) and the field facilities (module "1", characterised by a maximum cumulative frequency equal to 3,7 E-05 ev/y).
It is important to notice that for each deck, the maximum cumulative frequency always corresponds to the module "4", in correspondence of the second refrigerant loop. It is necessary to underline that the calculated frequency spatial distribution strongly depends on the park count methodology and on the assumptions used to model specific components. For example, the module "4" contains the cold box, that has been modelled as four tube heat exchangers, two shell heat exchangers and a wide range of connected equipment defined by the methodology. This assumption may result conservative if it increases the final cumulative frequency value, or just a summative guideline if it reduces the wanted values. A more detailed analysis should achieve a more precise risk evaluation, but it should be carried out in the next project phase, when all the layouts information will be available. However this would be the topic of the chapter 6.6 "Uncertainty produced by the preliminary fire risk analysis", where some calculation will help to define the accuracy of the part count methodology used.

In the end, it is necessary to highlight that the contribution of a fire fighting system has not been taken into account.

### 5.1.3. Case B, converted FLNG

The hypothesis and shrewdness used to produce cumulative maps for the Case B are the same adopted for the Case A analysis. In Case B FLNG facility, release scenarios can develop in gaseous or liquid jet fires and pool fires. Thus, all the three different kinds of cumulative maps have been produced for each deck.
As already explained in the Assumptions adopted during the risk assessment 4, since all the FLNG decks are grated, the flammable pools are located in the process deck, where drip pans have been supposed. Nonetheless, the flames generated by a pool fire can affect all the higher decks.

After having studied the influences produced by each fire scenarios on the other decks, the following cumulative maps has been obtained.

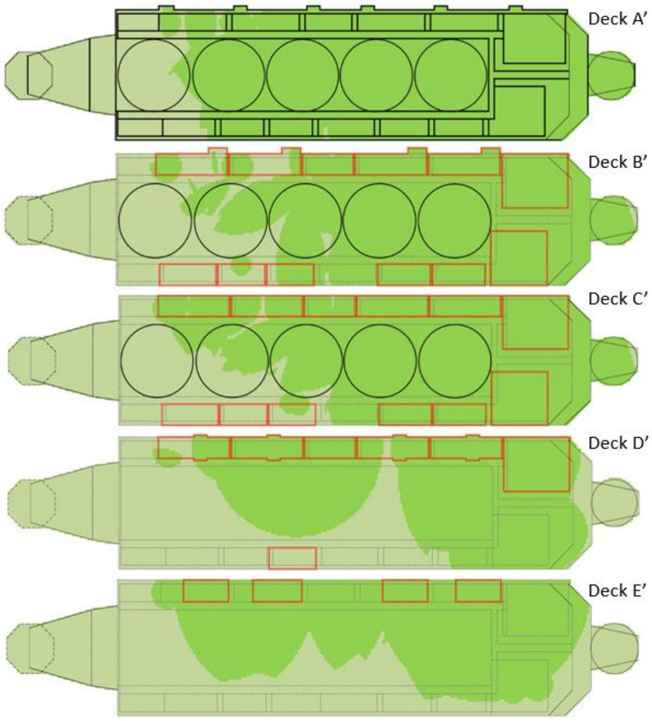



*Figure 5-11: Cumulates jet fire at 5 min.*

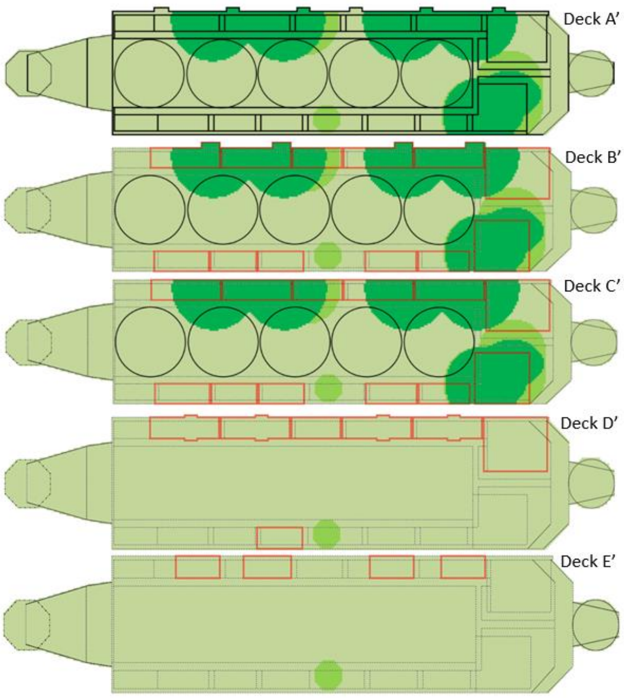



*Figure 5-12: Cumulates pool fire at 10 min.*

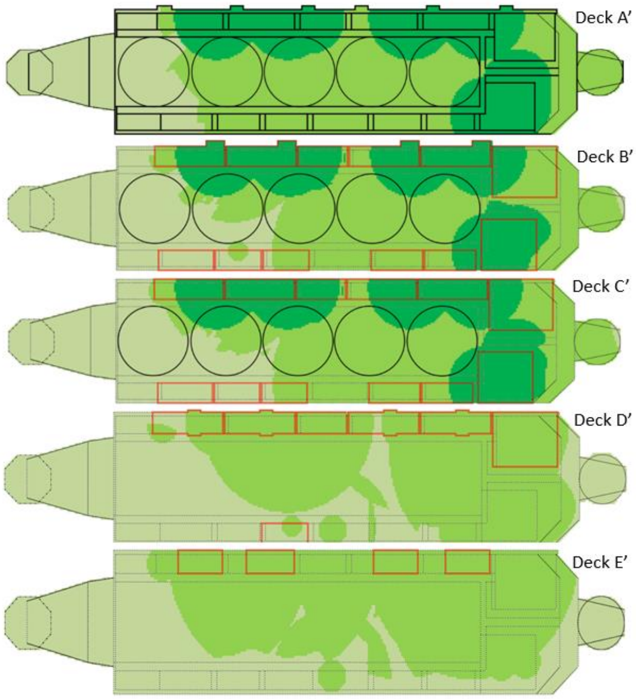



*Figure 5-13: Total Cumulates.*

In the following Table 5-3, the maximum frequency calculated on each deck is reported.

*Table 5-3: Maximum frequency calculated on each deck*

| Deck | Maximum cumulative frequency on the deck [ev/y] |
|---|---|
| Process deck (+24.994m) | 9,03 E-05 |
| Deck (+33.994m) | 8,97 E-05 |
| Deck (+40.994m) | 9,06 E-05 |
| Deck (+49.994m) | 6,36 E-06 |
| Deck (+55.994m) | 5,08E-06 |

Looking Figure 5-11, Figure 5-12 and Figure 5-13 it is possible to notice that the highest contribution to the overall risk is produced by pool fires (see Figure 5-12), phenomena already registered in Case A. In fact, the final shape of the cumulative risk spatial distribution follows the shape of the pool fire risk map. It is important to notice that for each deck, the maximum cumulative frequency always corresponds to the liquefaction units, which are placed in modules situated in the upper part of each deck. In particular the most critical areas, in general, are the liquefaction and the gas cleaning units, where the cumulative frequency falls in the interval $\mathrm{P} \geq 1\mathrm{E}-05$ ev/y (dark green according Figure 5-1). The pool contribution is so relevant since all the frequency contributions from isolatable sections able to produce a pool are cumulated on the process deck. The rest of the cumulative frequency falls in the interval $1\mathrm{E}-06 < \mathrm{P} < 1\mathrm{E}-05$ [ev/y] or in the lower one.

The maximum calculated risk is equal to 9,06E-05 ev/y. This value is registered on the deck C' (+41 m) (see Figure 5-12)in between modules 10 and 11 (see Figure 3-18), which contain two out of four liquefaction trains. The worst pool fires involve the four trains of the liquefaction unit, and the gas cleaning unit (module 9, characterised by a maximum cumulative frequency equal to 6,5E-05 ev/y).

In addition, it is important to notice that the maximum risk in the living quarter area is 4.57E-07, while for the swirling turret refer to Section 5.3 “SSIV analysis result”.

It is necessary to underline that, also in this case, the calculated frequency spatial distribution strongly depends on the park count methodology and on the assumptions adopted to model the components. These conventions may result conservative only if they increase the final cumulative frequency value. A in depth analysis will be made in the feed phase.

In conclusion, it is necessary to highlight that the contribution of the action of a fire fighting system has not been taken into account.

### 5.1.4. FRA conclusions

In conclusion, the FRA analysis does not identify any criticalities. The converted configuration seems to be the best one according to the lower risk registered.

Now, the risk distributions identified should be used to address the design in the concept definition phase. In particular, the implementation of proper protections and mitigation systems is strongly recommended. In both cases, the highest contribution to the overall risk is due to the pool fire. Indeed, the final shape of the cumulative risk spatial distributions follows the shape of the pool fire risk maps, while the maximum cumulative frequency always corresponds to the liquefaction unit. Consequently, specific attention should be given to the following points:

- Reduce as much as possible drip pan dimension to minimize the risk linked to the pools.
- Implement a firefighting system that can reduce the risk due to pool fires.

## 5.2. Explosion Risk Result

### 5.2.1. Case A, new design FLNG

According to the explosive volumes reported in Table 4-1 and PES categorization reported in Table 3-7, Figure 3-6 has been used to estimate the potential overpressures. For PES 1, characterized by a PES volume of 6165 $m^3$, an overpressure of about 0.6 bar has been identified on curve D.

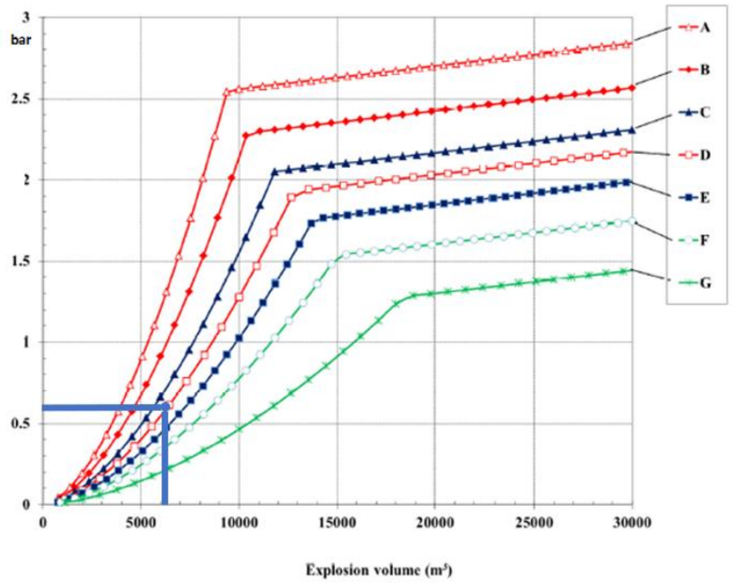



*Figure 5-14: Identification of PES 1 overpressure*

### 5.2.2. Case B, converted FLNG

Figure 5-15 shows the correspondence between PES 2 volume, presented in Table 4-2 and the researched overpressure. According to PES categorization reported in Table 3-7, an explosion taking place in PES 2, which is characterized by a volume of 2754 $m^3$, can cause an hypothetical overpressure of about 0.2 bar.

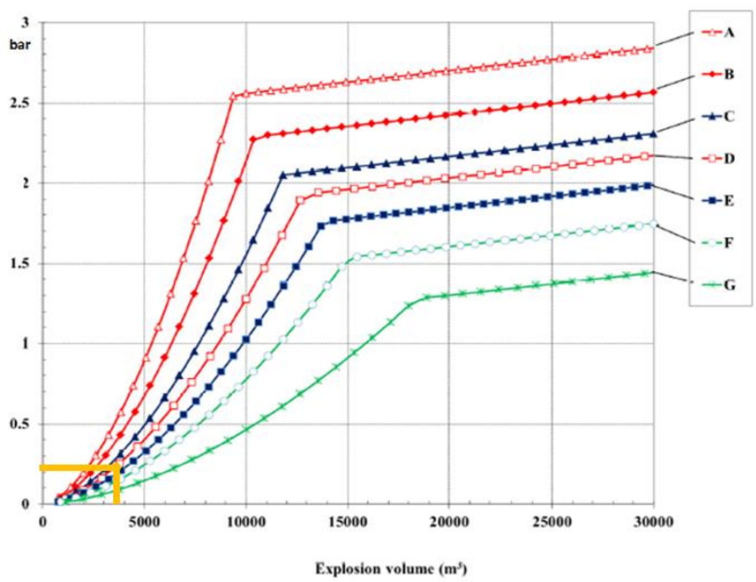



*Figure 5-15: Identification of PES 2 overpressure*

### 5.2.3. Further considerations concerning ERA results

The procedure suggested by the Contractor for the identification of the structural strength is not the one usually adopted in a QRA/FERA analysis. It has produced realistic results, but they might be imprecise. Some explosion simulations will be performed using

PHAST 8.21 (see Chapter 6.7). The results provided by the software will be used to verify the goodness the information collected from DNVGL-OS-A101.

## 5.3. SSIV analysis result

According to methodology (3.3), if the risk assessment shows non-compliance with criteria, risk reducing measures are needed. In particular, a SSIV shall be installed if it is the most relevant measure in order to comply with established safety or environmental risk tolerance criteria. This last situation can eventually not be satisfied in the turret zone, where the risers keeping the gas from WHPs and the one for the export, are placed. These infinite systems can produce a fire scenario sufficiently long to damage the turrets and stop the production.

The study summarized in the chapter 4.3 states the necessity to install a SSIV on the export pipeline. In case of hypothetical malfunctions, it is an efficient solution to isolate the FLNG facilities from the Third part receiving the royalties. On the other hand, SSIVs for the subsea pipelines connecting the FLNGs and the WHPs have been further studied with the risk assessment. In both cases, values taken from the total cumulative maps of the process deck have been analysed. Indeed, firstly the inventories placed inside the turrets and the ones connecting modules to the risers have been associated to the process deck. Secondly, the highest risk values in the turret zones have been registered in the process deck. The following results have been obtained considering the contribution to the frequency due to all the different accidental fire scenarios able to produce a possible impact on that building block. Specifically, the most important are the two risers of the pipelines coming from WHP1, the two risers of the pipelines coming from WHP2 and the riser of the export pipeline.

### 5.3.1. Case A, new design FLNG

From the analysis, specific criticalities have not been highlighted. In particular for the turret area, the cumulative frequency falls in the $\mathrm{P} \leq 1\mathrm{E}-06\ \mathrm{ev/y}$ interval (lightest green according Figure 5-1). The maximum calculated frequency is equal to 9,49E-07 ev/y. Figure 5-16 shows the zoom of the total cumulative on the FLNG bow, where the turret is placed.

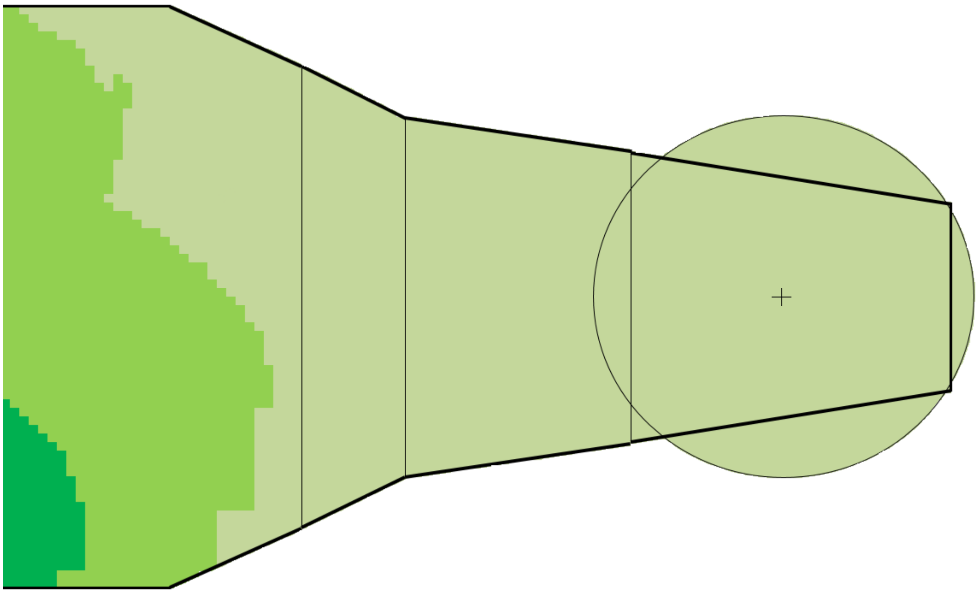


*Figure 5-16: Case A, turret detail of the process deck total cumulative.*

### 5.3.2. Case B, converted FLNG

Moving on Case B, the cumulative frequency in the turret zone falls in the $1E-06\ ev/y < P < 1E-05$ ev/y interval (see Figure 5-1). In particular, the maximum calculated frequency is equal to 3,05E-06 ev/y (see Figure 5-17).

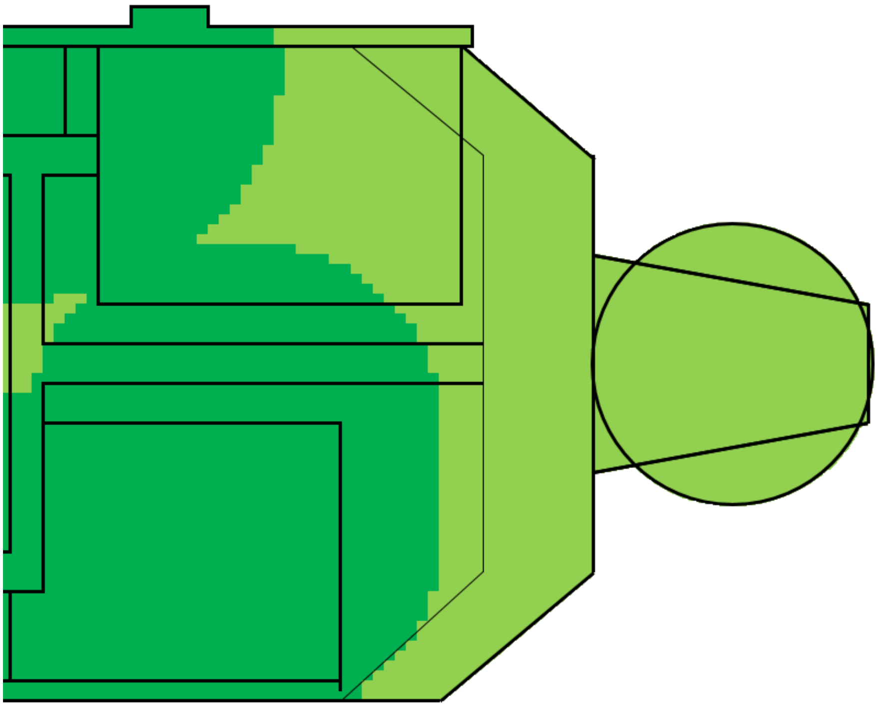


*Figure 5-17: Case B, turret detail of the process deck total cumulative.*

### 5.3.3. Further considerations

The results produced according the risk assessment for the turret zones are summarized in the following Table 5-4.

*Table 5-4: Frequencies identified in the turret zones*

| CASE | Maximum frequency in the turret zone [ev/y] |
|---|---|
| A, New built FLNG | 9,49E-07 |
| B, Converted FLNG | 3,05E-06 |

The difference between the values indicated above may be considered negligible in a lot of different technical fields, being these frequency assessments very small. However, it is very important focus the attention on their order of magnitude, underlining that the frequency identified in the Converted FLNG is one order of magnitude bigger than the one in the New built configuration. In the risk assessment this variation may be crucial. Furthermore, being the two systems equal according the process equipment placed in the turret zones, such variation should be studied. Figure 5-1 may be a good example to shortly explain reasons behind this topic. Risk assessments are based on a frequency classification depending on the order of magnitude. Contractors, according to their field of origin and the legislation in force, define a proper frequency classification, such as the one shown in Figure 5-1. This arrangement defines if a system is considered ALARP or should be further implemented until agreeing a proper safety level. For the reason above explained, a simple variation such as the one identified in the case study may be relevant and it can produce a system not in accordance with Contractor guidelines.

The initial hypothesis to justify this phenomenon was find in the position of release scenarios affecting the turret but not placed inside its zone. Comparing Figure 5-16 and Figure 5-17 it is possible to notice that in the Converted FLNG facility the modules 1 and 9 are nearer to the turret zone than the corresponding New built configuration's modules 1 and 18. It has been supposed that the simulated consequence scenarios placed in module 1 and 9 can affect and consequently increase the frequency of the Case B turret. It has been verified working on the release scenarios maps placed in those modules and observing the changes in the total cumulative map of that case. In particular, jet fires coming from the gas cleaning area and the condensate stabilization unit directly impact on the turret. Without the presence of these additional jet fires, the risk in the turret area would falls in the low risk interval (P < 1E-06 ev/year), becoming in accordance with the "New Built FLNG" FRA analysis.

In conclusion, it is advisable to install protection systems, such as firewalls, in order to reduce the risk in the turret zone. They will minimize the possibility to produce a domino effect affecting the turret zone.

# Chapter 6

# Weaknesses of the methodology and verifications

The Contractor has requested to perform the analysis following his methodology. However, it is necessary to make some consideration concerning the procedures adopted. Each job should be an opportunity to deepen knowledge, learn about new topics and improve the procedures usually adopted. Thus, it becomes necessary to analyse possible weaknesses of the procedures adopted, which differ from the ones usually adopted by "Oil & Gas" companies.

Different topics have been identified:

- The failure of ESVs/SDVs;
- Considerations concerning the assessment of vulnerability to the asset;
- Considerations about the chosen weather conditions;
- Exclusion of flash fire and VCE by the hypothetical release consequences;
- Reasons to exclude the full-bore rupture from a risk analysis;
- Uncertainty between a preliminary fire risk analysis and the assessment performed during the feed phase;
- Verifications of the results obtained by the adopted explosion risk assessment;
- Importance of the subsea isolation evaluation;

## 6.1. The failure of ESV/SDV

Isolatable sections have been identified as process installation portions, which can be isolated from the rest of the system by automatic isolation valves (SDV or ESDV) and/or normally-closed isolation valves (generic automatic control valves are not considered as adequate sections boundaries). In the FRA, the valves have been assumed as always able to perform their safety function when requested [3].

However, some Contractors ask for more in-depth risk assessment. It becomes necessary to evaluate the unavailability (*Q(t)*) of that valve, or rather the probability that the component is not available when requested (*t*).

ESV/SDV valves can be assumed as components "reparable when tested". The unavailability of components belonging to that class is evaluated with the following formula (1), where:

- "λ" is the failure rate;
- "τ" is the time necessary to perform the test and to restore the component if failed;
- "θ" is the period of operation between two tests.

$$Q = \frac{1}{2}\lambda\theta + \frac{\tau}{\tau + \theta} \tag{1}$$

Since τ << θ the last addendum of the equation is negligible, so the equation can be approximated (2).

$$Q = \frac{1}{2}\lambda\theta \tag{2}$$

The failure rate has been identified by means of the OREDA book [1], where its mean value for a generic ESDV valve is 0,65 event per $10^6$ hours. Therefore, using formula (2), the unavailability is estimated equal to 2,85E-03 ev/year, setting θ equal to 8760 hours.

Implementing the unavailability for a generic ESDV inside the inventories identified during the FRA, new release frequencies have been obtained. The frequency of an accidental release from an inventory together with the failure of an ESDV is now analyzed. The new values obtained were characterized by an order of magnitude equal to 1E-06 or even lower (1E-07 or 1E-08). This strong reduction in the release frequencies has affected the fire initial and the fire cumulative frequencies of each scenario. The last ones decrease until reaching 1E-09 or even lower values.

In conclusion, the fire cumulative frequencies obtained considering the unavailability of the ESDV/SDV are two orders of magnitude lower than the ones adopted in the FRA. Indeed, these new scenarios will produce little or negligible variations in the total cumulative frequency distribution. Therefore, being in a preliminary risk analysis aimed to identify main criticalities in the facilities, considering the ESDV/SDV failure will be useless and too much expensive according to time expenditure.

## 6.2. Considerations concerning the assessment of vulnerability to asset

The preliminary risk analysis performed was based on the hypothesis that a target invested by a fire scenario is assumed to fail only if exposed directly to a jet fire for a time greater than five minutes for a jet fire and ten minutes for a pool fire [3]. That kind of assumption strongly affects the results obtained. It states which data should be extracted by PHAST reports and consequently the areas interested by the accidental fire scenarios. For example, assuming that a possible target will fail if hit by a fixed heat flux, jet fire flame length or pool fire diameter will lose their importance as data, while an evaluation concerning the evolution of the heat flux magnitude, as a function of the distance from the source will be performed. This procedure is used in QRA, when the risk on people is evaluated.

Some bibliographical references have been identified concerning this topic. The documents titled “Vulnerability of Plant/Structure” by OGP Directory [14], “Development of methods to assess the significance of domino effects from major hazards sites” [7] and “Fire and Explosion Guidance” by HSE [18] are indicated in different methodologies as sources of information for the identification of the fire escalation times. However, the in-depth analysis identifying five and ten minutes as the proper time values has not been found. It is supposed that these data have been identified for the first time by HSE company. Although, the fire escalation and maximum exposure times have been detected by means of statistical studies on the vulnerability of different targets. So, material properties and their evolution under fire accidental scenarios or heat fluxes are the discriminants data for assessing the failure time for process systems, building supports and structures in general.

However, the exposure times suggested by the Contractor’s methodology are the ones proposed by the international standards [3]. Therefore, the procedure adopted may be considered suitable for a conservative evaluation of the risk on buildings and process components, which are the main target for the analysis performed. Indeed, this approach is adopted by several contractors interested in FERA.

## 6.3. Considerations about the chosen weather conditions

Paragraph 3.3.1.2.2 has been used to specify the weather conditions implemented in PHAST simulations. According to Contractor’s analysis, D3 and D6 were the optimal classes to be used. They are the ones able to represent the wider range of conditions which can take place in the future system location [3]. The methodology specifies to use both the weather conditions and then implement in the fire risk mapping phase only the “worst” (the one characterized by the largest area of impact) [3].

Although a doubt may arise. The weather conditions implemented can be the most frequent but are the ones producing the worst consequences? A verification has been performed.

Some PHAST simulations have been implemented setting weather conditions equal to “F2”, and the impact produced by the atmospheric class definition on the characteristics of fire scenarios has been checked. Discharge rates, jet fire lengths and widths, pool fire flame lengths and the angles between pool fire axis and vertical have been checked.

Relevant variations have not been found. Discharge rates are independent by weather condition as expected. Consequently, they are not varied. Moving on jet fires, worst conditions appeared in D6 conditions when the highest flame lengths took place. Jet fire widths did not present relevant deviations.

Pool fires have presented the most important discrepancy. F2 conditions caused an increment in the flame length and a reduction of the angle between the pool fire axis and the vertical, producing consequently a higher pool fire. However, this phenomenon might not present relevant criticalities in the risk assessment. The higher decks are the ones affected by the lower number of accidental scenarios and consequently, they are characterized by the lower risk values. Even if a higher number of pool fires is be able to affect those decks, risk will not reach a value considered critical.

On the other hand, weather conditions became relevant in analysis considering flash fires scenarios, explosions and dispersions of toxic substances. In particular, the wind can move the clouds made up by the dangerous released substances. At this point, the cloud can be dispersed in the atmosphere or, in worst cases, congested inside different areas of the system. Thus, explosions can take place. Future QRA on the FLNGs systems may require better analysis concerning the atmospheric classes, that will be chosen in PHAST simulations. They are essential while evaluating the risk on people.

## 6.4. Exclusion of flash fire and VCE by the hypothetical release consequences

The asset vulnerability, which has been chosen to perform the analysis, states that a target (a structure or a process component) is assumed to fail if exposed directly to a for a time greater than those reported in Table 3-6. Jet fires and pool fires have been considered, while flash fires and VCE have been excluded.

In the worst cases considered a structure should be invested by a flame for at least five minutes, a duration which can not be reached by a flash fire. Indeed, flash fires are characterized by short or quite instantaneous durations and by high radiation levels compared to human vulnerability. As a consequence, because of the short exposure time which they can produce, flash fires are usually not considered in a FERA, while became relevant in a QRA, when risk on people is evaluated.

On the other hand, the VCE are not evaluated as a hypothetical fire accidental scenario because of the lack of information concerning the system layouts. PES can not be identified properly and a detailed risk analysis considering explosion will be useless in term of result accuracy. It will be too much expensive in time and economical efforts.

However, in order to avoid an underestimation in the frequency evaluation for delayed fire scenarios, occurrence frequencies of flash fires and VCE have been associated with the pool fire one (see Figure 3-2, Figure 3-3) [3].

## 6.5. Full bore rupture inside a risk analysis

As already explained in section 3.3.1.2.1, release frequencies have been evaluated considering the following representative hole sizes, typically used for risk assessment evaluation [3]:

- Small rupture: 5 mm;
- Significant rupture: 20 mm;
- Large rupture: 65 mm.

To adapt OGP statistics to the representative hole sizes considered in the analysis, the following correspondences were defined for the project [3]:

- 5 mm leak size frequency were estimated considering the frequency data for the leak of hole diameter range 1 to 3 mm and data for the leak of hole diameter range 3 to 10 mm reported on OGP;
- 20 mm leak size frequency were estimated considering the frequency data for the leak of hole diameter range 10 to 50 mm reported on OGP;
- 65 mm leak size frequency were estimated considering the frequency data for the leak of hole diameter range 50 to 150 mm reported on OGP.

Releases from hole diameter higher than 150 mm were disregarded for this preliminary study as the proportion of the total leak frequency from releases higher than 150 mm was very limited. In terms of consequences, the depletion of the inventory with a full-bore release was very quick, lasting less than 5 minutes. Moreover, the depressurization from the leak itself will lead to a low pressure in a short period of time, reducing the effect distances. For these reasons, it was considered that full bore releases were not significant to the fire risk assessment [3]. However, these data are not enough to state the real duration of a fire scenario. The duration of a large pool fire generated by a release lasting less than 10 min, can eventually be longer than the fire damage criteria adopted.

Despite everything, this trend is commonly adopted in safety reports concerning floating systems for methane treatment. The full-bore rupture is usually excluded by the analysis or at least only partially implemented putting inside another rupture class its small contribution to the release frequency.
It may be interesting understand the motivations which involve the use of this strategy.

After some researches, the study of rupture mechanisms affecting pipelines have been shown as a possible starting point. An excellent source of information regarding the issue of breakages and rupture mechanism is the "EGIG" report [6], which is also cited by the “OGP 434” [12]. EGIG studies have been carried out on onshore pipelines. Being interested in offshore structures, this source might be considered not suitable for our analysis. However, difficulties in finding database concerning ruptures in offshore facilities and the trend of using onshore databases to increment the reliability of offshore RAMS studies, make the EGIG report an excellent starting point to better explain the rupture mechanisms affecting the methane-carrying pipes.

The following tables and graphs are extracted by the EGIG document [6], where an assessment concerning their pipelines is reported.

EGIG [6] conducts an analysis based on the division of pipe breaks according to their size. We can distinguish 3 different groups.

- Pinhole/Crack: break diameter ≤ 20 mm.
- Hole: 20 mm ≤ hole diameter ≤ tube diameter.
- Breakage/Rupture: hole diameter> tube diameter.

EGIG has outlined the trend of breakages and their frequency over time and as a function of the nominal diameters of the pipes [6]. The cited trends are shown in the graphs below.

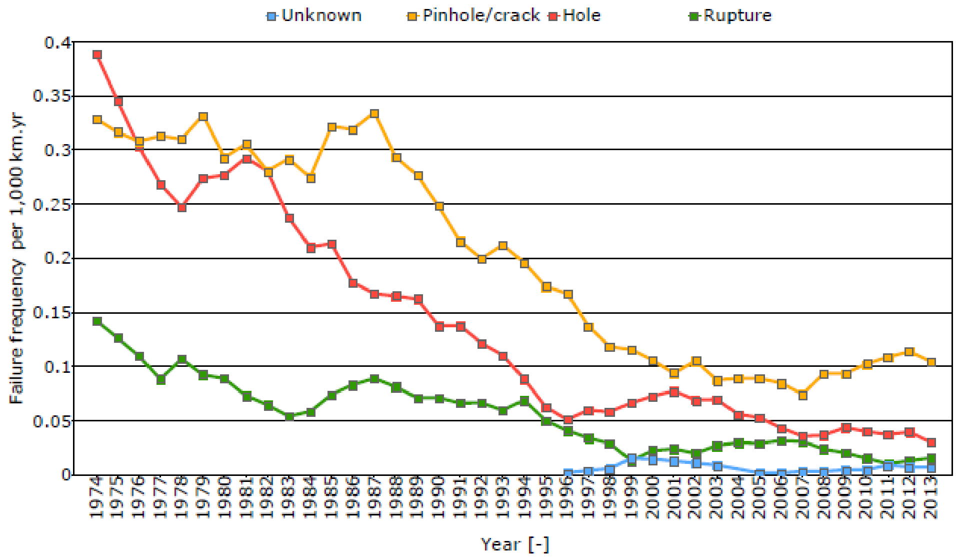



*Figure 6-1: Trends of breakages and their frequencies over time (figure extracted by EGIG report [6]).*

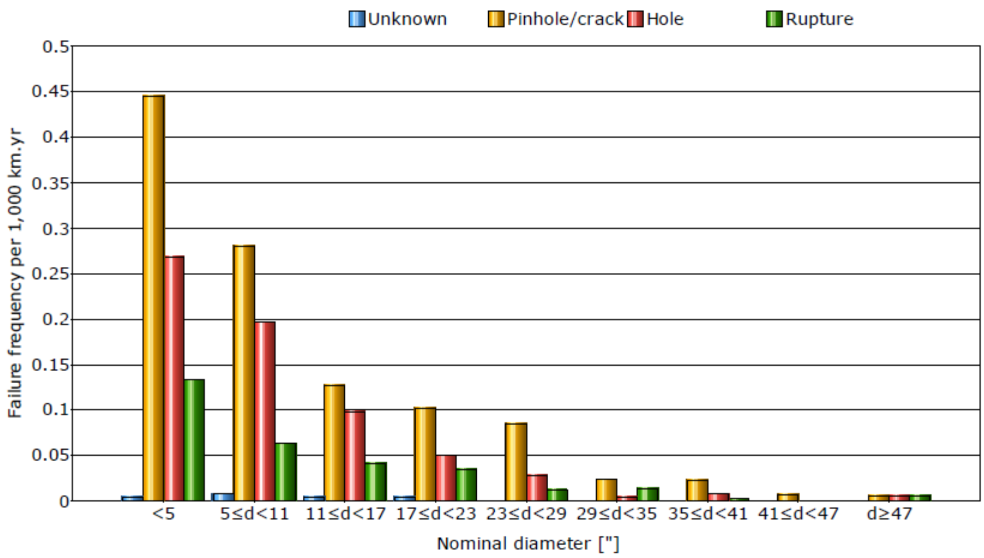



*Figure 6-2: Trends and frequencies of breakages according to the nominal diameters of the pipe (figure extracted by EGIG report [6]).*

As can be seen from the graphs (Figure 6-1 and Figure 6-2), the frequency of breakages over time has undergone a progressive reduction until 1999/2000, from which the reduction rate has decreased or cancelled [6]. Figure 6-2 shows how the frequency of "failure" tends to decrease with an increment in the pipe diameter. The formation of medium and small holes is much more frequent than the total breakage of the pipe, a phenomenon that occurs mainly in the smallest [6]. A summary of the values shown in Figure 6-1 is presented in the following Table 6-1.

*Table 6-1: Failure frequency as a function of the nominal diameters of pipelines (table extracted by EGIG report [6]).*

| Nominal diameter | System exposure $\cdot 10^6$ km·yr | Primary failure frequency per 1,000 km·yr | | | |
|---|---|---|---|---|---|
| | | Unknown | Pinhole/crack | Hole | Rupture |
| diameter < 5" | 0.436 | 0.005 | 0.445 | 0.268 | 0.133 |
| 5" ≤ diameter < 11" | 1.066 | 0.008 | 0.280 | 0.197 | 0.064 |
| 11" ≤ diameter < 17" | 0.714 | 0.004 | 0.127 | 0.098 | 0.041 |
| 17" ≤ diameter < 23" | 0.442 | 0.005 | 0.102 | 0.050 | 0.034 |
| 23" ≤ diameter < 29" | 0.401 | 0.000 | 0.085 | 0.027 | 0.012 |
| 29" ≤ diameter < 35" | 0.214 | 0.000 | 0.023 | 0.005 | 0.014 |
| 35" ≤ diameter < 41" | 0.389 | 0.000 | 0.023 | 0.008 | 0.003 |
| 41" ≤ diameter < 47" | 0.146 | 0.000 | 0.007 | 0.000 | 0.000 |
| diameter ≥ 47" | 0.170 | 0.000 | 0.006 | 0.006 | 0.006 |

The mechanisms, identified by EGIG [6], producing the creation of holes or breaks in pipes are the following ones:

- External interference;
- Corrosion;
- Construction defects or defects in the material;
- Ground movements;
- Hot Tap;
- Others.

The frequencies of these mechanisms in producing pipe holes have also decreased over time [6]. This trend has been reported in Figure 6-3 and Table 6-2, and it might be caused by the technological development in pipes protection systems, construction materials and technics.

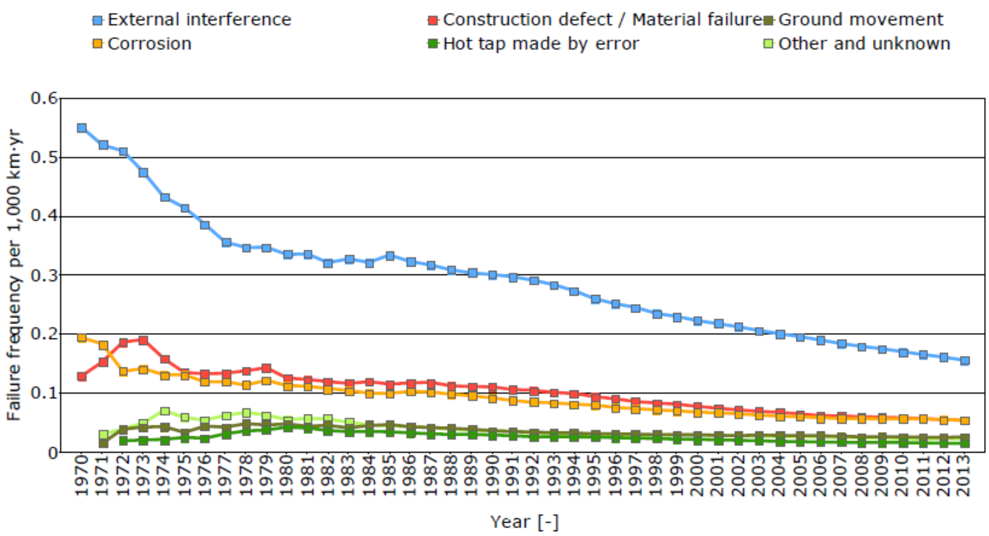



*Figure 6-3: Frequency of mechanisms in producing pipe holes (figure extracted by EGIG report [6]).*

*Table 6-2: Frequency of mechanisms in producing pipe holes (table extracted by EGIG report [6]).*

| Cause | Primary Failure frequency | | |
|---|---|---|---|
| | 1970-2013 per 1,000 km·yr | 2004-2013 per 1,000 km·yr | 2009-2013 per 1,000 km·yr |
| External interference | 0.156 | 0.055 | 0.044 |
| Corrosion | 0.055 | 0.038 | 0.042 |
| Construction defect / Material failure | 0.055 | 0.025 | 0.026 |
| Hot tap made by error | 0.015 | 0.006 | 0.009 |
| Ground movement | 0.026 | 0.020 | 0.024 |

Although the breaking frequency has decreased over time, the trend in the distribution of holes remains the same. While the holes and ruptures are mainly caused by external interferences, pinholes and cracks are mainly caused by corrosion [6]. The distributions are presented in the following figures (Figure 6-4 and Figure 6-5).

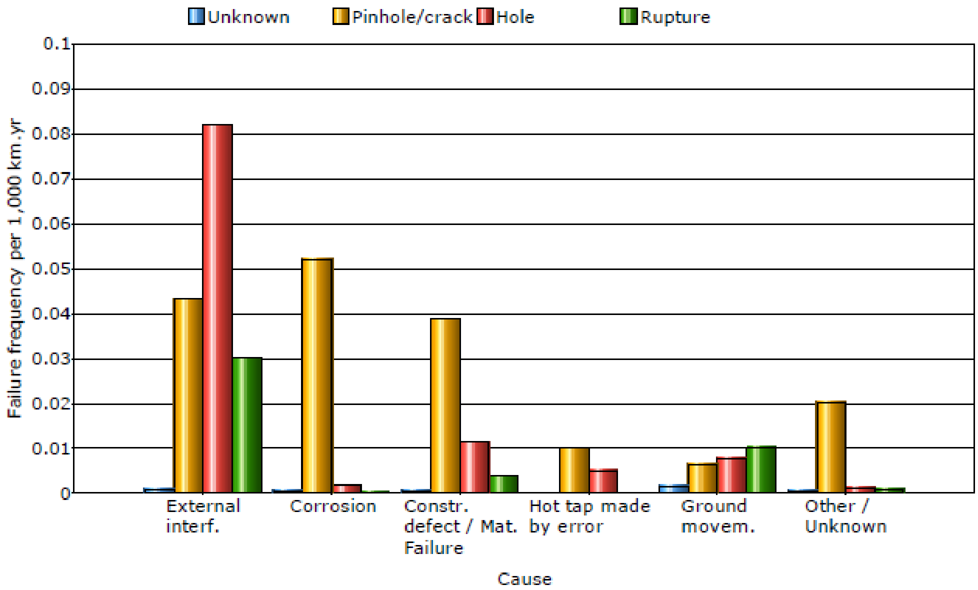



*Figure 6-4: Breaking frequency as a function of cause and breaking dimension (1970-2014) (Figure extracted by EGIG report [6]).*

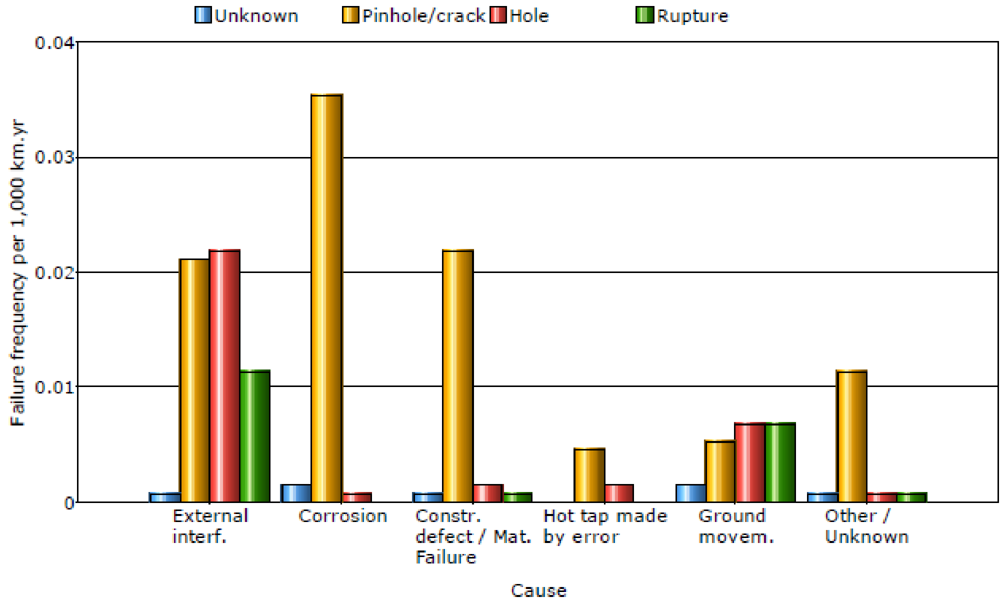



*Figure 6-5: Breaking frequency as a function of cause and hole classification (2003-2014) (the figure is extracted by EGIG report [6]).*

*Table 6-3: Breaking frequency as a function of cause and hole classification (the table is extracted by EGIG report [6])*

| Leak size | failure frequency per 1,000 km·year | | | | | |
|---|---|---|---|---|---|---|
| | External interference | Corrosion | Construction defect / Mat. Failure | Hot tap made by error | Ground movement | Other and unknown |
| Unknown | 0.001 | 0.002 | 0.001 | 0 | 0.002 | 0.001 |
| Pinhole/Crack | 0.021 | 0.035 | 0.022 | 0.005 | 0.005 | 0.011 |
| Hole | 0.022 | 0.001 | 0.002 | 0.002 | 0.007 | 0.001 |
| Rupture | 0.011 | 0 | 0.001 | 0 | 0.007 | 0.001 |

According to information contained in the EGIG [6] report, the full-bore rupture might be mainly produced by external interferences, construction defects, ground movements and unknown elements. However, some of the cited mechanisms must be excluded due to the nature of the system under analysis.

First, it is possible to omit the corrosion mechanism. On the FLNG systems analyzed, corrosive materials are not treated and countermeasures have been taken to avoid corrosion caused by external events. Moreover, the extracted natural gas is usually characterized by a lower amount of substances, which can produce corrosion, compared to the oil. The cleaning processes performed in the FLNGs were studied to further reduce those substances. Thus, it is possible to state that the corrosion mechanism can be excluded from the analysis.

Then, the system cannot undergo structural movements comparable to those of the ground. This phenomenon must also be excluded.

The most relevant causes producing holes in FLNG pipes and are the following ones:

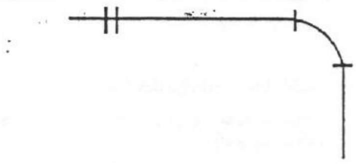
- External interference;
- Construction defects;
- Unknown elements;

Among the aforementioned elements, according to Figure 6-5, the most relevant is surely the “external interference”. In particular, the main external interference, that can cause a pipe break in a FLNG or offshore system in general is the impact with moving elements, (i.e. falling loads or moving machinery). This aspect is always studied through an appropriate "Dropped Object Study", which is usually performed during the FEED phase. This study will produce the recommendations to install suitable protection systems against possible dropped objects and develop procedures for the loading and unloading of materials without producing an increased risk of impact with critical systems.

Another important rupture mechanism should be considered. It is the cryogenic embrittlement of materials. That phenomenon may take place in FLNG systems and it should be avoided by means of proper precautions in the system construction. Pipes, tanks and process systems dealing with cold fluids, which can reach temperatures lower than -160°C, ought to be made of metals which can not be affected by the cryogenic embrittlement. Some examples are the austenitic stainless steels, the aluminium alloys and the nickel-based materials. However, other protection systems should be further adopted. Great large changes in temperature must be avoided through cooling systems, progressive increases in flow and spraying systems. Those precautions are used in the offloading systems and in the NLG tanks.

An additional guideline to state the necessity to consider the full-bore rupture is the document titled “Attività a rischio di incidente rilevante – Guida alla lettura, all’analisi e alla valutazione dei rapporti di sicurezza” [10], which was produced by the Italian Ministry of the Interior. Making reference to the table shown in the figure below (Figure 6-6), taken from the chapter III, sub-chapter C, section 3 of the cited document, it is possible to understand the minimum breakage dimension which should be considered on a system according to the legislation.

TAB. 3 TUBAZIONI



CAMPO DI APPLICAZIONE:
Tubi, flange, curve, manichette, bracci di carico.

| ROTTURE TIPICHE | DIMENSIONI DELLE FRATTURE |
|---|---|
| Perdita al tubo o a saldature di collegamento | 100% del diametro per diametri sino a 200 mm<br>20% del diametro per diametri superiori a 200 mm |
| Perdita alla flangia | 20% del diametro del tubo |
| Perdita da manichetta | 100% del diametro del tubo |

Nota: Per i bracci di carico occorre prendere in considerazione il distacco intempestivo del sistema di collegamento al mezzo mobile

*Figure 6-6: Italian legislation about hole dimension in a fluid leakage scenario (taken from document [10]).*

The table in Figure 6-6 shows that analysing scenarios simulating fluid leakage from a pipe, the maximum hole dimension should be equal to the diameter of the pipe only if the pipeline is characterized by a diameter up to 200 mm. On the other hand, considering the 20% of the diameter for dimensions greater than 200 mm is sufficient [10].

Moving again on the case study, the upper limit considered in hole dimensions is 150 mm. This value is almost sufficient to satisfy the Italian legislation. To support this claim, in the following paragraphs the study performed on a safety report is reported. The analysis was developed for an offshore regasification facility, which design looks very similar to the Case B converted FLNG. In particular, in terms of pipelines dimensions, the inventories of this system can be easily assimilated to the ones installed in the FLNGs.

In this new study concerning the safety report for the regasification unit, the Contractor was interested in clarification about the exclusion of the full-bore rupture from the risk assessment. The scenarios considered for the analysis were the following ones [15].

- EIR 1 – LNG loss from a pipe which sends the flow to the storage tanks;
- EIR 2 – LNG loss from the manifold connecting the loading arms to storage tanks;
- EIR 3 – LNG loss from the manifold connecting the storage tanks to the recondenser;
- EIR 4 – LNG loss from the piping downstream of the booster unit;
- EIR 5 – loss of LNG from the BOG collector connecting the storages with the recondenser;
- EIR 6A – loss of LNG from the piping downstream of the vaporizers in the regasification area;
- EIR 6B - LNG loss from the swival, especially on the coupling between the pipe and the risers;
- EIR 8 – loss of natural gas due to the breakage of the supply pipe of auxiliary generators.

Each scenario was described in detail concerning the dimension of pipes. Indeed, the annexes of the safety report provided information about the division of pipes into classes, which have been set according to the diameter of tubes [15]. To identify the most representative size of pipe hole within each individual scenario, the weighted average, as a function of pipe length and breakdown areas has been carried out. Then from the value of the averaged value, the diameter size was newly obtained. The relative surfaces for each individual pipe classes have been obtained in compliance with the indication provided by the legislation, (see Figure 6-6). Two tables are shown below. Table 6-4 contains the main formulas adopted, while Table 6-5 contains the obtained results.

*Table 6-4: Adopted formulas*

| ***SCENARIO*** | ***Pipe diameter*** | ***Pipe length [m]*** | ***Hole dimesion for legislation [mm]*** | ***Hole surface [mm2]*** | ***Hole diameter [mm] (Weighted average as function of the pipe length)*** |
|---|---|---|---|---|---|
| EIR XX | dd | ll | dl | $Al = \pi * \left(dl/_2\right)^2$ | $d = 2 * \sqrt{\frac{\left(\frac{Al * ll + AL * LL}{ll + LL}\right)}{\pi}}$ |
| | DD | LL | DL | $AL = \pi * \left(Dl/_2\right)^2$ | |

*Table 6-5: Obtained results*

| SCENARIO | Pipe diameter | | Pipe length [m] | Hole dimesion for legislation [mm] | Hole surface [$mm^2$] | Hole diameter [mm] (Weighted average as function of the pipe length) |
|---|---|---|---|---|---|---|
| | Inch | mm | | | | |
| EIR 1 | 16 | 406,4 | - | 81,28 | 5188,68 | 81,28 |
| EIR 2 | 8 | 203,2 | 250,00 | 40,64 | 1297,17 | 90,87 |
| | 24 | 609,6 | 250,00 | 121,92 | 11674,54 | |
| EIR 3 | 8 | 203,2 | 50,00 | 40,64 | 1297,17 | 68,06 |
| | 14 | 355,6 | 350,00 | 71,12 | 3972,59 | |
| EIR 4 | 10 | 254,0 | 78,00 | 50,80 | 2026,83 | 65,97 |
| | 12 | 304,8 | 47,00 | 60,96 | 2918,64 | |
| | 4 | 101,6 | 30,00 | 101,60 | 8107,32 | |
| | 3 | 76,20 | 35,00 | 76,20 | 4560,37 | |
| | 2 | 50,80 | 35,00 | 50,80 | 2026,83 | |
| EIR 5 | 8 | 203,2 | 11,00 | 40,64 | 1297,17 | 120,33 |
| | 24 | 609,6 | 366,00 | 121,92 | 11674,54 | |
| EIR 6A | 24 | 609,6 | 155,00 | 121,92 | 11674,54 | 121,92 |
| EIR 6B | 14 | 355,6 | 372,00 | 71,12 | 3972,59 | 71,67 |
| | 16 | 406,4 | 20,00 | 81,28 | 5188,68 | |
| EIR 8 | 12 | 304,8 | 87,50 | 60,96 | 2918,64 | 60,96 |

The Table 6-5 shows that the upper limit concerning the hole dimension imposed by legislation should be equal to 122 mm, the maximum value obtained (in EIR 5). This result may be used to confirm the conservativeness of the procedure adopted in the case study. 150 mm is almost sufficient to satisfy the Italian legislation considering the dimensions of pipelines in those offshore facilities.

## 6.6. Uncertainty produced by the preliminary fire risk analysis

As already explained inside the Chapters 1 and 2, the precision which could be obtained in a QRA/FERA study highly depends on the design phase. Results gained in a preliminary assessment, because of the lack of information characterizing the pre-feed phase, are usually considered a guideline. More precise evaluations are obtained through a "FEED" study. Indeed, the level of detail requested in a feed phase will provide information useful to achieve the implementation of the system making its risk as low as reasonably possible. Therefore, the preliminary risk analysis developed for the case study is surely affected by a level of uncertainty. That value can be obtained comparing the results obtained and the ones that will be found through the risk assessment performed during the feed phase. However, it is not possible due to lack of time at disposal. A new strategy has been formulated to solve this problem. A comparison between the case study and another facility, which was studied during its feed phase by RAMS&E and that is called WHP3, has been used to evaluate the uncertainty affecting the case study analysis.

WHP3 is a wellhead platform for the exploitation of a natural gas reservoir. It was designed and built to host workers and process components for the production of gaseous methane. The components and layout of this system can appear different from the WHPs' ones analysed in our case study. However, their functions are enough similar to obtain acceptable results by means of a comparison.

Understanding the criticalities in a preliminary feed analysis is essential to produce a valuable study. The lack of information concerning the design and the use of PFDs is surely the most relevant one and it affects different procedures, such as the part count. Indeed, the bigger difference between the risk assessment performed for the case study and the one made up for WHP3 is the part count methodology adopted. This phase is fundamental for the evaluation of release frequencies and consequently for the final risk.
In an advanced risk assessment phase, the part count is performed by means of P&Is, where the design of the system is well specified and represented. All different kind of valves, auxiliary devices and pipes are exactly identifiable and countable. On the other hand, as described in the Chapter 3.3, the case study procedure was based on a simplified methodology directly produced by the Contractor and not verified by the legislation. This one may be the main weakness.

For a good verification concerning the part count was necessary to identify common process structures between WHP1 and WHP3. Through an initial analysis of the P&Is and PFDs, a test separator has been identified in both configurations.

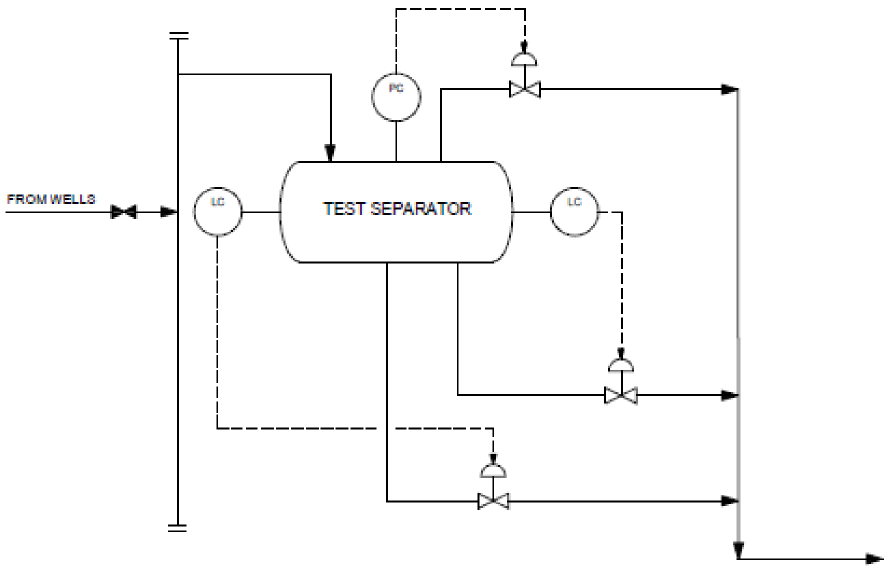



*Figure 6-7: an example of test separator configuration taken from a generic PFD.*

Their part count can be used to identify the uncertainty concerning release frequencies. Two different comparisons have been performed as a consequence of the information found in the WHP3 configuration. It was possible to associate to the test manifold a set of valves additional to the ones owned by the vessel itself. I have decided to compare the WHP1's test separator to the WHP3's one, at first without the valve set and then with it.
In the following tables, the part counts and the resulting release frequencies are reported.

*Table 6-6: Part count of WHP3's test separator.*

| | N° for diameter 2 | 6 | 12 | 18 | 24 | 36 | Tot. |
|---|---|---|---|---|---|---|---|
| **Process pipes [m]** | | 23 | | | | | 23 |
| **Flanges** | 2 | 51 | | | | | 53 |
| **Actuated Valves** | | 3 | | | | | 3 |
| **Manual Valves** | 5 | 26 | | | | | 31 |

| | 2 to 6 | > 6 | Tot. |
|---|---|---|---|
| **Process Vessels** | 1 | | 1 |
| **Filters** | | | 0 |
| **Centrifugal Compressors** | | | 0 |
| **Reciprocating Compressors** | | | 0 |
| **Fin Fan Heat Exchangers** | | | 0 |
| **Pig Trap** | | | 0 |
| **Tube Side Heath Exchanger** | | | 0 |
| **Plate Heath Exchanger** | | | 0 |
| **Shell Side Heath Exchanger** | | | 0 |
| **Centrifugal Pump** | | | 0 |
| **Reciprocating Pump** | | | 0 |

| | < 2 | Tot. |
|---|---|---|
| **Small Bore Fittings: instrument connections** | 12 | 12 |

*Table 6-7: Release frequencies, WHP3's test separator*

| Isolatable Inventory Tot | | |
|---|---|---|
| **Leak frequency** | 1-10 mm | 1,66E-02 |
| | 10-50 mm | 2,25E-03 |
| | 50-150 mm | 9,18E-04 |

*Table 6-8: Part count WHP3's test separator + valve set*

| | N° for diameter 2 | 6 | 12 | 18 | 24 | 36 | Tot. |
|---|---|---|---|---|---|---|---|
| **Process pipes [m]** | | 28 | | | | | 28 |
| **Flanges** | 3 | 58 | | | | | 61 |
| **Actuated Valves** | | 4 | | | | | 4 |
| **Manual Valves** | 6 | 30 | | | | | 36 |

| | 2 to 6 | > 6 | Tot. |
|---|---|---|---|
| **Process Vessels** | 1 | | 1 |
| **Filters** | | | 0 |
| **Centrifugal Compressors** | | | 0 |
| **Reciprocating Compressors** | | | 0 |
| **Fin Fan Heat Exchangers** | | | 0 |
| **Pig Trap** | | | 0 |
| **Tube Side Heath Exchanger** | | | 0 |

| | | | |
|---|---|---|---|
| **Plate Heath Exchanger** | | | 0 |
| **Shell Side Heath Exchanger** | | | 0 |
| **Centrifugal Pump** | | | 0 |
| **Reciprocating Pump** | | | 0 |

| | **< 2** | **Tot.** |
|---|---|---|
| **Small Bore Fittings: instrument connections** | 12 | 12 |

*Table 6-9: Release frequencies, WHP3's test separator + valve set*

| **Isolatable Inventory Tot** | | |
|---|---|---|
| **Leak frequency** | 1-10 mm | 1,83E-02 |
| | 10-50 mm | 2,49E-03 |
| | 50-150 mm | 1,06E-03 |

*Table 6-10: WHP1's test separator*

| | N° for diameter | | | | | | Tot. |
|---|---|---|---|---|---|---|---|
| | 2 | 6 | 12 | 18 | 24 | 36 | |
| **Process pipes [m]** | | | | 50 | 40 | | 90 |
| **Flanges** | | | | 12 | 9 | | 21 |
| **Actuated Valves** | | | | 2 | 1 | | 3 |
| **Manual Valves** | | | | 1 | 1 | | 2 |

| | 2 to 6 | > 6 | Tot. |
|---|---|---|---|
| **Process Vessels** | 1 | | 1 |
| **Filters** | | | 0 |
| **Centrifugal Compressors** | | | 0 |
| **Reciprocating Compressors** | | | 0 |
| **Fin Fan Heat Exchangers** | | | 0 |
| **Pig Trap** | | | 0 |
| **Tube Side Heath Exchanger** | | | 0 |
| **Plate Heath Exchanger** | | | 0 |
| **Shell Side Heath Exchanger** | | | 0 |
| **Centrifugal Pump** | | | 0 |
| **Reciprocating Pump** | | | 0 |

| | < 2 | Tot. |
|---|---|---|
| **Small Bore Fittings: instrument connections** | 9 | 9 |

*Table 6-11: Release frequencies, WHP1's test separator*

| Isolatable Inventory Tot | | |
|---|---|---|
| **Leak frequency** | 1-10 mm | 8,95E-03 |
| | 10-50 mm | 7,85E-04 |
| | 50-150 mm | 9,21E-05 |

At this point, some calculations concerning the release frequencies have been produced. The aim was to evaluate the relative error concerning the total frequency. The release frequency obtained by each hole class have been summed up and then those sums, also called total release frequencies, have been used to evaluate the relative error as the ratio between the absolute error and the average of WHP3's and WHP1's sums itself. Results are showed in Table 6-12 and Table 6-13.

*Table 6-12: Calculations, WHP1's test separator vs WHP3's test separator*

| | | WHP3 | WHP1 | Absolute error | Average | Relative error |
|---|---|---|---|---|---|---|
| Leak frequency | 1-10 mm | 1,66E-02 | 8,95E-03 | 3,81E-03 | 1,28E-02 | 29,87% |
| | 10-50 mm | 2,25E-03 | 7,85E-04 | 7,32E-04 | 1,52E-03 | 48,26% |
| | 50-150 mm | 9,18E-04 | 9,21E-05 | 4,13E-04 | 5,05E-04 | 81,76% |
| | **TOTAL** | **1,97E-02** | **9,82E-03** | **4,96E-03** | **1,48E-02** | **33,53%** |

*Table 6-13: Calculations, WHP1's test separator vs WHP3's test separator + valve set*

| | | WHP3 | WHP1 | Absolute error | Average | Relative error |
|---|---|---|---|---|---|---|
| Leak frequency | 1-10 mm | 1,83E-02 | 8,95E-03 | 4,70E-03 | 1,36E-02 | 34,43% |
| | 10-50 mm | 2,49E-03 | 7,85E-04 | 8,51E-04 | 1,64E-03 | 52,01% |
| | 50-150 mm | 1,06E-03 | 9,21E-05 | 4,82E-04 | 5,74E-04 | 83,95% |
| | **TOTAL** | **2,19E-02** | **9,82E-03** | **6,03E-03** | **1,59E-02** | **38,04%** |

The final relative errors obtained were:

- 33,53% for WHP1's test separator vs WHP3's test separator
- 38,04% for WHP1's test separator vs WHP3's test separator + Valve set

The final relative error obtained, as average, was about 35%. WHP1 release frequencies appeared highly underestimated and consequently the methodology adopted for the case study might be considered not precise at all. However, a further verification has been carried out in order to verify if the error evaluated had been suitably mitigated by the following calculation and corrective parameters adopted to produce the risk maps.

It was necessary to compare WHP1 and WHP3 cumulative risk maps to complete this task. In order to reduce the result deviation that could be produced by the different layout design between WHP1 and WHP3, WHP3 inventories have been revised. Only the inventories and decks for the production of methane have been considered and, in particular, the following changes have been produced. The number of wells and their dispositions have been aligned to that of WHP1, while inventories for the treatment of chemicals have been eliminated. They have not been analysed in the case study.

The following cumulative maps, considering gaseous and liquid jet fires consequences together with pool fires ones, have been obtained for the WHP3 case. For the graphical representation refer to the rules shown in the Chapter 5.

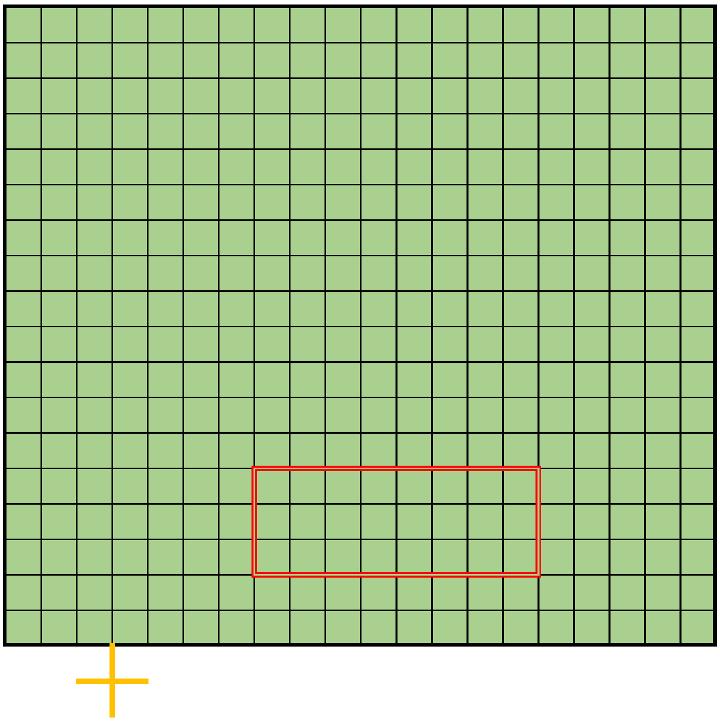


*Figure 6-8: WHP3 Cumulative map, Deck 1*

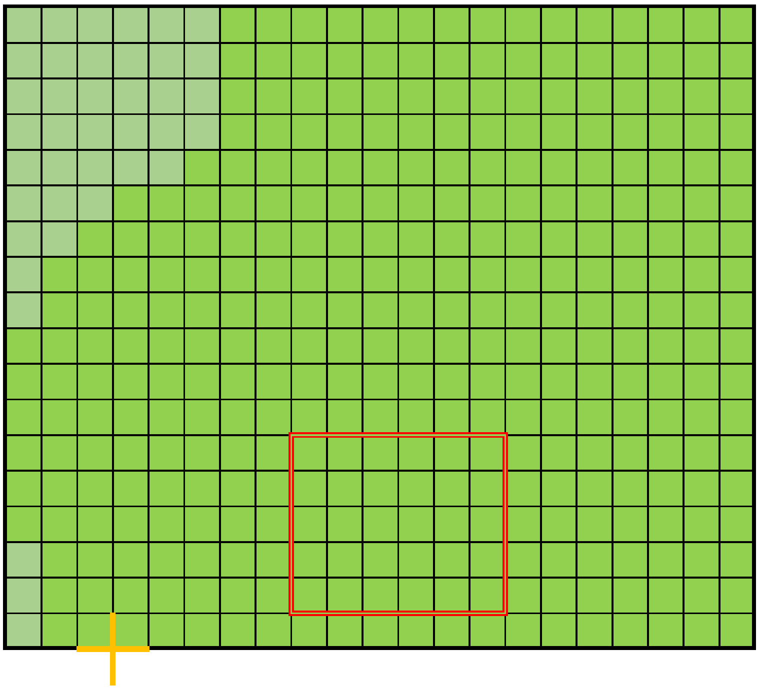


*Figure 6-9: WHP3 Cumulative map, Deck 2*

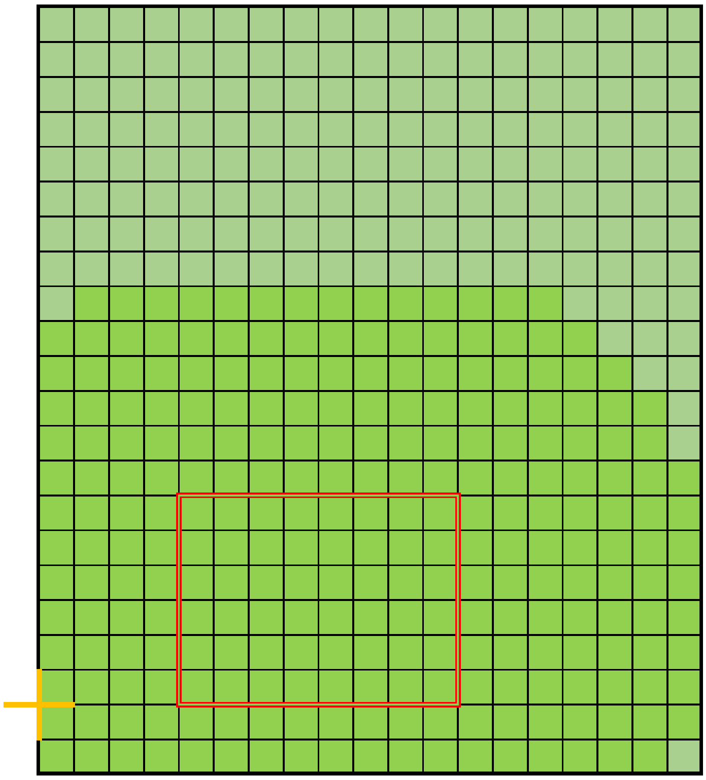


*Figure 6-10: WHP3 Cumulative map, Deck 3*

The maximum frequency obtained by the WHP3's cumulative maps are reported in the Table 6-14.

*Table 6-14: the table shows the maximum frequency identified on each WHP3 deck*

| Deck | Maximum frequency on the deck [ev/y] |
|---|---|
| Deck 1 | 7,14E-07 |
| Deck 2 | 6,33E-06 |
| Deck 3 | 8,11E-06 |

If we compare these value with the ones obtained in our case study (Table 5-1), it is possible to state the order of magnitude of the evaluated risks is the same. While the maximum frequency level in WHP3 is 8,11 E-06 ev/y, WHP1 is characterized by a value of 1,40 E-06 ev/y.
This evaluation has confirmed that the methodology adopted for the case study produces underrate of cumulative risk but, at the same time, it is enough precise to be adopted in a preliminary risk assessment.
This short study can be the starting point for further verification, maybe producing a direct comparison between the case study preliminary risk assessment and the ones produced during the FLNG's feed phase.

## 6.7. Explosion risk verifications

The methodology suggested to perform the explosion risk analysis was not the conventional one usually adopted in a feed phase. Not all the typical input information needed for a meticulous explosion hazard analysis were available and sufficiently consolidated. Therefore, a preliminary explosion hazard assessment has been performed to define a first attempt identification of the structural strength, that should be provided to the structures.

However, the company policy requires to carry out jobs accurately, respecting a fixed quality standard. Further verification of the performed explosion analysis were necessary.

In order to further verify information collected from DNVGL-OS-A101 [5], explosion simulations have been performed using PHAST 8.21. The standard procedure adopted during the feed phase for a FERA has been emulated.

According to the inventories placed in the PES 1 and PES 2 zones, the characteristics to implement inside the software have been chosen. They are summarized in Table 6-15.

*Table 6-15: PES 1 and PES 2 characteristics for PHAST simulation*

| PES | Flame expansion | Obstacle density | Gas reactivity | Ground reflection coefficient | x [m] | y [m] | H [m] | Notes | PES Volume [m^3] | Exploding mass 100% |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2 | Medium | Low | 1 | 75 | 13,7 | 6 | Area on Process deck: modules 3 and 4 | 6165 | 350 |
| 2 | 2 | Medium | Low | 1 | 36 | 8,5 | 9 | Area on Process deck: module 14 | 2754 | 160 |

In both cases, the considered substance was methane, whose reactivity has been modelled as “Low”. According to the modules’ configurations containing PES 1 and PES 2, the obstacle densities were modelled as “Medium” and the methane was supposed to completely fill the space inside the PES under consideration. These parameters have been chosen in order to build up a conservative simulation of the phenomena. The results obtained are shown in Annex 2.

The results obtained for PES 1, adopting the information by DNVGL-OS-A101 [5], has underlined an overpressure of about 0,6 bar, while PHAST has provided a maximum overpressure value of 0,335 bar. It is characterized by an impulse of 1902 $N \cdot s/m^2$.

Moving on PES 2, an overpressure of about 0.2 bar has been identified using the procedure specified inside the methodology. This value has been confirmed by PHAST which has provided a maximum value of overpressure equal to 0,335 bar with an impulse of 1430 $N \cdot s/m^2$.

Results obtained adopting the standard procedure are slightly bigger than the ones provided by using the methodology. However, being the order of magnitude respected and considering that the lack of information affects also the new simulations, results by PHAST could confirm the ones gotten by the procedure presented in the methodology.

In conclusion, the methodology suggested by the Contractor has provided results sufficiently precise for a pre-feed phase, but further analysis are essential for the following design phases of the system. Indeed, a better PES identification based on the dispersion of gaseous substances over the FLNG is necessary to produce indisputable and correct results.

## 6.8. Importance of SSIV evaluation

Producing a further analysis regarding the "SSIV evaluation" topic has been particularly difficult. Some researches were made on the websites, but the results obtained were not appropriate at the study. The largest parts of those sites belong to SSIV producers, who present their products with some captivating description but without technical or useful information for my thesis. Libraries were not provided of technical books concerning the topic too.

However, researches led me to some titles, which allow to understand the importance of a SSIV analysis. These books contain some technical information concerning the building structure of the valves, their reliability and development of the subsea pipeline security. On the other hand, the economic aspects were only briefly mentioned inside the documents. Nothing provides tangible values concerning the real costs for the purchase of these systems, their maintenance and their installation and dismissing. Little economic data has been directly provided by the Contractor.
Another hypothetical source of data may be the document titled "Subsea Isolation System (SSIS) Cost Reduction Study" by Andrew Palmer & Associates [2]. It might be a starting point for further verifications, but unfortunately, I didn't manage to find it.

The Piper Alpha accident was surely a breaking point in the development of stronger procedures and design configuration increasing the safety in the oil and gas field [4] [16]. In particular, the cited calamity was in-depth analysed by Lord Cullen publishing "*The Public Inquiry into the Piper Alpha Disaster"* [4], a document containing recomendations for future offshore facilities. Inside this writing, as underlined inside *"Subtech '91 – Back to the future" [16], "…, the Cullen report does not make it mandatory to install SSIVs into the pipeline system but their need should be investigated during the Formal Safety Audit and preparation of the Safety Case."* Lord Cullen has underlined the importance of a specific analysis concerning the implementation of safety sistem for subsea pipelines, but he was conscious of the economic effort that companies should make to implement offshore structure in general.

Therefore, a proper study allows the Contractor to be in accordance with the legislation and at the same time, it can avoid "wrong" decisions moved by short term economic motivations. Indeed, the purchase of a SSIV could be quite expensive. Their cost will vary according to their dimensions, their building materials and their rating. It is possible to define an order of magnitude of cast thanks to the information provided by the Conctractor, who has bought two of them in the last years. In particular, for a 26'" SSIV they have spent 500.000/600.000 euros, while for a 18" they paid 300.000/400.000 euros. However, these prices do not take into account cost concerning the installation and the maintenance. The installation should be performed by a ship equipped with a crane with high lifting capacity and underwater support to properly connect the systems to the pipelines. A few million euros are needed for these operations. However, the costs may further increase. The SSIVs are usually designed as maintenance free-structures. Nevertheless, corrective maintenance may be needed or a fault can take place. In these cases, according to the water depth, different kind of ships are needed to perform operations and it directly affects the procedure costs. In worst cases, when the system is placed in deep-water, the ship equipped with a crane with high lifting capacity is required again. This would probably cost other few millions of euros, while, when the position corresponds to a site characterized by shallow-water, a multi-supply vessel and a ROV can be used. In this situation, the procedure results to be cheaper than the one performed in deep-water.

As a consequence, it is possible to state that the maintenance of the SSIV is an expensive exercise. It is necessary that the design of those valves is as simple as possible and in particular their components should be designed to require minimum maintenance [16]. A major problem linked to this practise is the cost involved in the offshore spread and in particular the loss of production due to the time it takes to carry out the procedures. These concerns push to gradually improve the valve design and to perform comprehensive testing on land before installing the system.

More information about the topic can be found in the article *"Installation and Maintenance of Subsea Isolation Valves"* by R. K. Jain contained inside the Subtech '91 [16]. It provides recommendation guiding the system building project. On the other hand, data concerning the reliability are shown in *"OTH 94 445, Reliability study into subsea isolation systems"* by *M Humphreys* [9].

If the SSIV valve is needed, a proper study concerning its positioning should be accurately done. After taking the decision to invest several million to instal the safety system, its fundamental to guarantee its integrity [16].

Subtech '91 suggests the following criteria to dictate the location of a SSIV. The guidelines are [16]:

- The SSIV should be placed outside the effective radiation area of expected fire;
- The location should provide a good SSIV protection;
- Installation, inspection, testing, maintenance and repair should be performed much easier as possible;
- The SSIV position should guarantee the minimum time for the entrapped inventory evacuation.

These conditions are translated in the following recommendation directly extracted by the cited book [16]:

*"SSIVs should be installed as close to the platform as possible but outside the pool radiation area or where falling debris from a platform can pose a threat to the SSIVs or the pipeline outside of the SSIVs. It is therefore considered that SSIVs should be within 500 meters of the Statutory platform safety zone, with the preferred distance being between 150 and 350 meters."*

Both the SSIV and the umbilical must be protected from damage. The commonest way to reach this goal is to cover the umbilical with rocks to shield them from possible dropped objects or other subsea activities. On the other hand, the valves and the control systems must be preserved by suitable protection housing, that allows the entree for the inspection and the maintenance [16].

In conclusion economic reasons are the ones with lead the Contractor to be strongly interested in the SSIV study. Before starting the final procedure to design the final configuration, it is necessary to states which would be the best solution to guarantee the FLNG safeguarding, spending as little money as possible and reducing the future capital required to make a proper maintenance. SSIV could be a good solution but they may lead to a possible economic risk.

# Conclusions

At this point is necessary to draw the conclusions of the work. This thesis was not intended as a complete disquisition concerning the QRA, but a means to assess the effectiveness of the preliminary risk assessment in guiding the decision-making process in the oil and gas field. Indeed, the lack of a well-defined system layout might affect the reliability of the results. A real case study has been performed and analysed to achieve this intention.

The preliminary risk assessment has been done on behalf of a Contractor, who has been assigned to develop the conceptual engineering (PRE-FEED) of a floating liquefied natural gas (FLNG) unit. The target of the study was to identify, according to the risk distributions, the best configuration out of the two systems that were considered feasible. Risk reduction measures to minimize the identified criticalities should be suggested.

The methodology adopted should also be investigated to confirm the possibility to use the preliminary risk assessment results to guide the implementation of the configurations during the feed phase of design. Hypothesis and results obtained from the risk assessment should be verified by means of theoretical researches and calculations. Then, a general disquisition should be performed to identify the reason which pushed Contractors to analyse the necessity to install SSIVs (subsea isolation valves).

Although the criticalities encountered, the prefixed objectives have been achieved. The FERA analysis has been the more challenging ones. The lack of information, produced by the “early” design phase and the absence of well-defined system layouts, has affected the “resources” spent for each phase of the analysis. A lot of time has been spent in analysing facility configurations, process layouts, components position and formulation of hypothesis to “replace” the missing information. However, the methodology adopted has resulted suitable in obtaining sufficiently detailed results according to the asset project phase under consideration.

The fire risk assessment has identified an interesting trend affecting both analysed configurations. The highest contribution to the overall risk is due to the pool fire. Indeed, the final shape of the cumulative risk spatial distributions follows the shape of the pool fire risk maps. Moreover, the maximum cumulative frequency always corresponds to the liquefaction unit.

Nevertheless, it has been verified that the calculated frequency spatial distribution strongly depends on the park count methodology and assumptions adopted to model components. A lot of hypothesis have been made to represent process components situated in the liquefaction units. These assumptions could have generated inaccuracies affecting the risk evaluation in these areas.

However, the order of magnitude identified through the cumulative risk distributions can be considered appropriate and acceptable if compared to the ones obtained during the feed phase. Indeed, the error produced in the leak frequencies evaluation has been mitigated by the other hypothesis made.

In-depth analysis ought to be performed during the future design phases. Indeed, the targets of the FERA were the structures and the process systems. Consequently, the carefully chosen simplifications adopted during the preliminary risk assessment, such as the asset vulnerability and the weathers conditions, have resulted suitable. However, they will not be acceptable for an evaluation of risk affecting people working on these facilities.

Releases from hole diameter higher than 150 mm have not been investigated. They are usually disregarded for preliminary study as the proportion of the total leak frequency from releases higher than 150 mm is very limited. The development of a “Dropped object study” is suggested during the next design phases. Measures to further minimize their occurrence frequency shall be implemented. Indeed, the impact with moving elements, such as falling loads or moving machinery, has been identified as the main cause of the full-bore rupture creation in a pipeline.

In conclusion, the preliminary risk assessment can be defined as a useful instrument to guide the decision-making process in the oil and gas field. The analysis performed does not identify any criticalities, while the procedure and hypothesis adopted are suitable to the analysis. Despite a certain level of uncertainty of the results, the recommendations provided can be used to implement the safety level of the system analysed. It will ensure monetary and time savings in the subsequent design phases.

## 19.1. WHP

*Table 8-1: WHP's isolatable section and subsections*

| Isolatable subsection n° | Section typology (punctual /linear) | Section description | SDV / Equipment Section starting | SDV / Equipment Section ending | SDV / Equipment Sub-section starting | SDV / Equipment Subsection ending | Deck |
|---|---|---|---|---|---|---|---|
| **1A** | L | Line from the production well to the production manifold | SCSSV | WV | SCSSV | Before christmas tree | +16 deck<br>+12 deck<br>+6 deck |
| **1B** | P | Line from the production well to the production manifold | SCSSV | WV | From christmas tree | WV | +19 deck |
| **2** | L | Production manifold on WHP | WV | ESDV11;<br>ESDV421; | - | - | +16 deck<br>+12 deck |
| **3** | P | Test manifold and separator on WHP | Valve on prod. manifold | Valve on prod. manifold | - | - | +16 deck |
| **4A** | L | Pipeline to FLNG | ESDV11;<br>ESDV421; | ESDV21;<br>ESDV21b;<br>ESDV431;<br>ESDV431b; | ESDV11;<br>ESDV421; | Subsea pipeline | +16 deck<br>+12 deck<br>+6 deck |

*Table 8-2: Operative conditions and hold up for each WHP's subsections*

| Isolatable subsection n° | Type of fluid (G - L -G/L) | Gas pressure [barg] | Liquid pressure [barg] | Gas temperature [°C] | Liquid temperature [°C] | Gas density [kg/m$^3$] | Liquid density [kg/m$^3$] | Isolatable section mass | | | PHAST fluid name |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | Gas mass isolatable section TOTAL [kg] | Liquid mass isolatable section TOTAL [kg] | Total mass [kg] | |
| **1A** | G | 190 | - | 80 | - | 120 | - | INFINITE | 0 | INFINITE | CH4 |
| **1B** | G | 190 | - | 80 | - | 120 | - | INFINITE | 0 | INFINITE | CH4 |
| **2** | G | 91 | - | 60 | - | 60 | - | 480 | 0 | 480 | CH4 |
| **3** | G | 110 | - | 60 | - | 5 | - | 22200 | 0 | 22200 | CH4 |
| **4A** | G | 91 | - | 60 | - | 60 | - | INFINITE | 0 | INFINITE | CH4 |

*Table 8-3: HC Composition (Molar amount) for WHP's subsections*

| PHAST Fluid Name | METHANE | ETHANE | PROPANE | BUTANE | C5 | C6 | C7 | C8 | C9 | H2O |
|---|---|---|---|---|---|---|---|---|---|---|
| **CH4** | 100% | - | - | - | - | - | - | - | - | - |

## 19.2. FLNG Case A

*Table 8-4: Case A FLNG's isolatable section and subsections*

| Isolatable subsection n° | Section typology (punctual/linear) | Section description | SDV / Equipment Section starting | SDV / Equipment Section ending | SDV / Equipment Sub-section starting | SDV / Equipment Subsection ending | Deck |
|---|---|---|---|---|---|---|---|
| **4B** | L | Pipeline to FLNG | ESDV11; ESDV421; | ESDV21; ESDV21b; ESDV431; ESDV431b; | Subsea pipeline | ESDV21; ESDV21b; ESDV431; ESDV431b; | Deck A (+109); |
| **5A** | L | WHP1 field separator inlet | ESDV21b; ESDV21; | HIPS; | - | - | Deck A (+109); |
| **5B** | P | WHP1 field separator | HIPS; | ESDV31; ESDV41; ESDV51; | - | - | Deck A (+109); Deck B (+114); Deck C (+120); |
| **6A** | L | WHP2 field separator inlet | ESDV431; ESDV431b; | HIPS; | - | - | Deck A (+109); |
| **6B** | P | WHP2 field separator | HIPS; | ESDV71; ESDV81; ESDV91; | - | - | Deck A (+109); Deck B (+114); Deck C (+120); |
| **7A** | P | Condensate preflash drum | ESDV41; ESDV81; Compressor suction scrubber; | ESDV101; ESDV111; ESDV121; | ESDV41; ESDV81; | ESDV101; ESDV111; ESDV121; | Deck C (+120); |
| **7B** | L | Condensate preflash drum | ESDV41; ESDV81; Compressor suction scrubber; | ESDV101; ESDV111; ESDV121; | Compressor suction scrubber; | Condensate preflash drum; | Deck A (+109); |
| **8A** | L | Gas treatment unit | ESDV51; ESDV91; | Molecular sieve gas drier; ESDV151; ESDV161; ESDV171; | ESDV51; ESDV91; Compressor after cooler; | Compressor suction scrubber; Feed gas coalescer; | Deck A (+109); Deck B (+114); |
| **8B** | P | Gas treatment unit | ESDV51; ESDV91; | Molecular sieve gas drier; ESDV151; ESDV161; ESDV171; | Compressor suction scrubber; | Compressor after cooler; | Deck A (+109); Deck B (+114); Deck D (+126); |
| **8C** | P | Gas treatment unit | ESDV51; ESDV91; | Molecular sieve gas drier; ESDV151; ESDV161; ESDV171; | Compressor suction scrubber; | Compressor after cooler; | Deck A (+109); Deck B (+114); Deck D (+126); |

| Isolatable subsection n° | Section typology (punctual/linear) | Section description | SDV / Equipment Section starting | SDV / Equipment Section ending | SDV / Equipment Sub-section starting | SDV / Equipment Subsection ending | Deck |
|---|---|---|---|---|---|---|---|
| **8D** | P | Gas treatment unit | ESDV51; ESDV91; | Molecular sieve gas drier; ESDV151; ESDV161; ESDV171; | Compressor suction scrubber; | Compressor after cooler; | Deck A (+109); Deck B (+114); Deck D (+126); |
| **8E** | P | Gas treatment unit | ESDV51; ESDV91; | Molecular sieve gas drier; ESDV151; ESDV161; ESDV171; | Feed gas coalescer; | ESDV161; ESDV171; KO drum; | Deck A (+109); Deck B (+114); Deck C (+120); Deck D (+126); Deck E (+132); Deck G (+144); |
| **8F** | P | Gas treatment unit | ESDV51; ESDV91; | Molecular sieve gas drier; ESDV151; ESDV161; ESDV171; | KO drum; | Molecular sieve gas drier; ESDV151; | Deck A (+109); Deck B (+114); Deck C (+120); Deck D (+126); Deck E (+132); |
| **9A** | P | Condensate stabilization unit | ESDV111; ESDV121; | ESDV181; ESDV191; SDV451; | ESDV111; | Condensate water pump; | Deck A (+109); |
| **9B** | L | Condensate stabilization unit | ESDV11; ESDV121; | ESDV181; ESDV191; SDV451; | Condensate water pump; | Condensate pre-filter; | Deck A (+109); |
| **9C** | P | Condensate stabilization unit | ESDV111; ESDV121; | ESDV181; ESDV191; SDV451; | Condensate pre-filter; | ESDV181; ESDV191; SDV451; | Deck A (+109); Deck B (+114); Deck C (+120); Deck D (+126); |
| **10A** | L | Feed gas heat exchanger, separator and compander | ESDV151 | ESDV211; ESDV221; ESDV231; SDV461; SDV471; | ESDV151; | Heat exchanger; | Deck A (+109); |
| **10B** | P | Feed gas heat exchanger, separator and compander | ESDV151 | ESDV211; ESDV221; ESDV231; SDV461; SDV471; | Heat exchanger; | Separator; | Deck B (+114); Deck C (+120); Deck D (+126); Deck E (+132); |

| **Isolatable subsection n°** | **Section typology (punctual/linear)** | **Section description** | **SDV / Equipment Section starting** | **SDV / Equipment Section ending** | **SDV / Equipment Sub-section starting** | **SDV / Equipment Subsection ending** | **Deck** |
|---|---|---|---|---|---|---|---|
| **10C** | P | Demethanizer Column | ESDV151; | ESDV211; ESDV221; ESDV231; SDV461; SDV471; | Separator; | Heat exchanger; | Deck A (+109); Deck B (+114); Deck C (+120); Deck D (+126); Deck E (+132); Deck F (+138); Deck G (+144); |
| **10D** | P | Debutanizer Column | ESDV151; | ESDV211; ESDV221; ESDV231; SDV461; SDV471; | Separator; | Butane reinjection pump; ESDV211; | Deck A (+109); Deck B (+114); Deck C (+120); Deck D (+126); |
| **10E** | P | Lean gas boosting | ESDV151; | ESDV211; ESDV221; ESDV231; SDV461; SDV471; | Feed gas compander; | ESDV221; SDV461; SDV471; Royal gas metering skid; | Deck A (+109); Deck B (+114); Deck C (+120); |
| **10F** | L | Lean gas boosting | ESDV151; | ESDV211; ESDV221; ESDV231; SDV461; SDV471; | Royal gas metering skid; | | Deck A (+109); |
| **11** | P | Regeneration unit | ESDV141; Molecular sieve gas drier valve; | ESDV131; ESDV201; | - | - | Deck A (+109); Deck B (+114); Deck C (+120); Deck D (+126); |
| **12A** | L | Pipeline of lean gas to warm box | ESDV221; | ESDV241; | - | - | Deck A (+109); |
| **13A** | P | Liquefaction unit | ESDV241; | ESDV251; ESDV261; ESDV401; | ESDV241; | Cold box | Deck A (+109); Deck B (+114); Deck C (+120); Deck D (+126); Deck E (+132); Deck F (+138); |

| Isolatable subsection n° | Section typology (punctual/linear) | Section description | SDV / Equipment Section starting | SDV / Equipment Section ending | SDV / Equipment Sub-section starting | SDV / Equipment Subsection ending | Deck |
|---|---|---|---|---|---|---|---|
| **13B** | P | Liquefaction unit | ESDV241; | ESDV251; ESDV261; ESDV401; | Cold box | Lng liquid turbine; | Deck A (+109); Deck B (+114); Deck C (+120); Deck D (+126); Deck E (+132); Deck F (+138); |
| **13C** | P | Liquefaction unit | ESDV241; | ESDV251; ESDV261; ESDV401; | Lng liquid turbine; | ESDV251; ESDV261; ESDV401; | Deck A (+109); Deck B (+114); Deck C (+120); Deck D (+126); |
| **14A** | P | Warm box | - | - | Inlet warm box; | Outlet warm box | Deck A (+109); Deck B (+114); Deck C (+120); Deck D (+126); Deck E (+132); Deck F (+138); |
| **14B** | P | Compressing unit of the MR1 refrigeration cycle | - | - | Outlet warm box; | Inlet of the MR1 accumulator | Deck A (+109); Deck B (+114); Deck C (+120); Deck D (+126); Deck G (+144); |
| **14C** | P | Compressing unit of the MR1 refrigeration cycle | - | - | Outlet warm box; | Inlet of the MR1 accumulator | Deck A (+109); Deck B (+114); Deck C (+120); Deck D (+126); Deck E (+132); Deck G (+144); |

| Isolatable subsection n° | Section typology (punctual/linear) | Section description | SDV / Equipment Section starting | SDV / Equipment Section ending | SDV / Equipment Sub-section starting | SDV / Equipment Subsection ending | Deck |
|---|---|---|---|---|---|---|---|
| **14D** | P | Condenser of the MR1 refrigeration cycle | - | - | Inlet of the MR1 accumulator | Inlet of the warm box | Deck A (+109); Deck C (+120); Deck D (+126); Deck E (+132); Deck F (+138); Deck G (+144); |
| **15A** | P | Cold box | - | - | Inlet cold box; | Outlet cold box; | Deck A (+109); Deck B (+114); Deck C (+120); Deck D (+126); Deck E (+132); Deck F (+138); |
| **15B** | P | Compressing unit of the MR2 refrigeration cycle | - | - | Outlet cold box; | MR2 compressor after cooler; | Deck A (+109); Deck B (+114); Deck C (+120); Deck D (+126); |
| **15C** | P | Compressing unit of the MR2 refrigeration cycle | - | - | Outlet cold box; | MR2 compressor after cooler; | Deck A (+109); Deck B (+114); Deck C (+120); |
| **15D** | L | Condenser of the MR2 refrigeration cycle | - | - | MR2 compressor after coolers; | Inlet of the warm box; | Deck A (+109); |
| **15E** | L | Condenser of the MR2 refrigeration cycle | - | - | Inlet of the warm box; | Outlet of the warm box; | Deck A (+109); Deck D (+126); Deck E (+132); Deck F (+138); |
| **15F** | P | Condenser of the MR2 refrigeration cycle | - | - | Outlet of the warm box; | Inlet of the cold box; | Deck A (+109); Deck B (+114); Deck C (+120); Deck D (+126); |

| Isolatable subsection n° | Section typology (punctual/linear) | Section description | SDV / Equipment Section starting | SDV / Equipment Section ending | SDV / Equipment Sub-section starting | SDV / Equipment Subsection ending | Deck |
|---|---|---|---|---|---|---|---|
| **16** | L | LNG storage | ESDV261; ESDV311; ESDV411; | ESDV271; ESDV281; ESDV291; ESDV301; ESDV321; | - | - | Deck A (+109); |
| **17** | P | Offloading | ESDV271; ESDV281; ESDV291; ESDV301; | - | - | - | Deck A (+109); |
| **18** | L | Condensate storage | ESDV181; ESDV211; | ESDV331; | - | - | Deck A (+109); |
| **19A** | P | Ethane storage | - | ESDV341; ESDV351; ESDV361; ESDV461; | - | ESDV341; ESDV351; ESDV461; | Hull |
| **19B** | P | Butane storage | - | ESDV341; ESDV351; ESDV361; ESDV461; | - | ESDV361; | hull |
| **20** | L | Regeneration gas inlet line | ESDV371; | ESDV141; | - | - | Deck A (+109); |
| **21** | L | Regeneration gas outlet line | ESDV131; | ESDV381; | - | - | Deck A (+109); |
| **22A** | L | Fuel gas ko drum | SDV481; ESDV321; ESDV381; ESDV191; ESDV251; | ESDV371; ESDV311; ESDV391; ESDV411; SDV471; FG inlet of thermal incinerator package; FG inlet for hot oil boiler and gas turbine generator WHRU; | ESDV251; | KO drum; | Deck A (+109); |
| **22B** | P | Fuel gas ko drum | SDV481; ESDV321; ESDV381; ESDV191; ESDV251; | ESDV371; ESDV311; ESDV391; ESDV411; SDV471; FG inlet of thermal incinerator package; FG inlet for hot oil boiler and gas turbine generator WHRU; | ESDV321; | KO drum; ESDV31; | Deck C (+120); Deck D (+126); Deck E (+132); |

| Isolatable subsection n° | Section typology (punctual/linear) | Section description | SDV / Equipment Section starting | SDV / Equipment Section ending | SDV / Equipment Sub-section starting | SDV / Equipment Subsection ending | Deck |
|---|---|---|---|---|---|---|---|
| **22C** | P | Fuel gas compression line and HP distribution | SDV481; ESDV321; ESDV381; ESDV191; ESDV251; | ESDV371; ESDV311; ESDV391; ESDV411; SDV471; Inlet of thermal incinerator package; Inlet for hot oil boiler and gas turbine generator; | KO drum; ESDV381; PY011; | ESDV371; ESDV391; PC011; PC021; ESDV411; | Deck A (+119); Deck B (+114); Deck C (+120); Deck D (+126); |
| **22D** | L | Fuel gas compression line and HP distribution | SDV481; ESDV321; ESDV381; ESDV191; ESDV251; | ESDV37; ESDV31; ESDV39; ESDV41; SDV47; Inlet of thermal incinerator package; Inlet for hot oil boiler and gas turbine generator; | SDV481; PC021; | PY011; SDV471; | Deck A (+119); |
| **22E** | P | Fuel gas LP distribution | SDV481; ESDV321; ESDV381; ESDV191; ESDV251; | ESDV371; ESDV311; ESDV391; ESDV411; SDV471; Inlet of thermal incinerator package; Inlet for hot oil boiler and gas turbine generator; | PC011; ESDV191; | ESDV41; lines to incinerator and hot oil heater and gas turbine generator; | Deck D (+126); |
| **22F** | L | Fuel gas LP distribution | SDV481; ESDV321; ESDV381; ESDV191; ESDV251; | ESDV371; ESDV311; ESDV391; ESDV411; SDV471; Inlet of thermal incinerator package; Inlet for hot oil boiler and gas turbine generator; | LP fuel gas electric heater | ESDV311; ESDV411; Inlet of thermal incinerator package; Inlet for hot oil boiler and gas turbine generator; | Deck A (+119); |
| **23** | L | Gas distribution | ESDV391; | Gas turbine of the diesel generator; SDV451; Refrigerator cycle gas turbines; | - | - | Deck A (+119); |

| Isolatable subsection n° | Section typology (punctual/linear) | Section description | SDV / Equipment Section starting | SDV / Equipment Section ending | SDV / Equipment Sub-section starting | SDV / Equipment Subsection ending | Deck |
|---|---|---|---|---|---|---|---|
| **24** | P | Lean gas boosting | ESDV231; | Export pipeline | - | - | Deck A (+119); |

*Table 8-5: Operative conditions and hold up for each Case A FLNG's subsections*

| Isolatable subsection n° | Type of fluid (G - L - G/L) | Gas pressure [barg] | Liquid press-ure [barg] | Gas temperature [°C] | Liquid temperature [°C] | Gas density [kg/m$^3$] | Liquid density [kg/m$^3$] | Isolatable section mass | | | PHAST Fluid Name | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | Gas mass isolatable section TOTAL [kg] | Liquid mass isolatable section TOTAL [kg] | Total mass [kg] | Gas | Liquid |
| **4B** | G | 90 | - | 60 | - | 60 | - | INFINITE | - | INFINITE | CH4 | - |
| **5A** | G | 70 | - | 20 | - | 60 | - | 2960 | - | 2960 | CH4 | - |
| **5B** | G/L | 70 | 10 | 20 | 30 | 60 | 730 | 10220 | 14550 | 24770 | CH4 | LIQ SEP IN |
| **6A** | G | 30 | 30 | 20 | 20 | 20 | 720 | 980 | 15 | 995 | CH4 | - |
| **6B** | G/L | 30 | 10 | 20 | 30 | 20 | 730 | 3280 | 14550 | 17830 | CH4 | LIQ SEP IN |
| **7A** | G/L | 10 | 10 | 20 | 30 | 5 | 730 | 580 | 52740 | 53320 | CH4 | LIQ FLAS Ha |
| **7B** | L | 10 | 10 | 20 | 20 | 5 | 730 | 580 | 52740 | 53320 | - | LIQ SEP IN |
| **8A** | G | 70 | - | 30 | - | 50 | - | 103480 | - | 103480 | CH4 | - |
| **8B** | G | 70 | - | 30 | - | 50 | - | 103480 | - | 103480 | CH4 | - |
| **8C** | G | 70 | - | 30 | - | 50 | - | 103480 | - | 103480 | CH4 | - |
| **8D** | G | 70 | - | 30 | - | 50 | - | 103480 | - | 103480 | CH4 | - |
| **8E** | G | 70 | - | 30 | - | 50 | - | 103480 | - | 103480 | CH4 | - |
| **8F** | G | 70 | - | 30 | - | 50 | - | 103480 | - | 103480 | CH4 | - |
| **9A** | L | - | 10 | - | 30 | - | 730 | 110 | 34270 | 34380 | - | LIQ FLASH |
| **9B** | L | - | 10 | - | 30 | - | 730 | 5 | 34270 | 34275 | - | LIQ FLASH |
| **9C** | G/L | 10 | 10 | 30 | 30 | 5 | 730 | 5 | 34270 | 34275 | CH4 | LIQ FLASH |
| **10A** | G | 60 | - | 30 | - | 50 | - | 65760 | 118030 | 183790 | CH4 | - |
| **10B** | G | 60 | 60 | -40 | -40 | 80 | 650 | 65760 | 118030 | 183790 | CH4 | - |
| **10C** | G/L | 40 | 10 | -80 | 100 | 60 | 580 | 65760 | 118030 | 183790 | CH4 | LIQ DEM |

| Isolatable subsection n° | Type of fluid (G - L - G/L) | Gas pressure [barg] | Liquid press-ure [barg] | Gas temperature [°C] | Liquid temperature [°C] | Gas density [kg/m$^3$] | Liquid density [kg/m$^3$] | Isolatable section mass | | | PHAST Fluid Name | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | Gas mass isolatable section TOTAL [kg] | Liquid mass isolatable section TOTAL [kg] | Total mass [kg] | Gas | Liquid |
| **10D** | G/L | 10 | 10 | 70 | 170 | 30 | 500 | 65760 | 118030 | 183790 | GAS DEB | LIQ DEB |
| **10E** | G | 110 | - | 60 | - | 70 | - | 65760 | 118030 | 183790 | CH4 | - |
| **10F** | G | 110 | - | 60 | - | 70 | - | 65760 | 118030 | 183790 | CH4 | - |
| **11** | G | 50 | - | 130 | - | 20 | - | 250 | - | 250 | CH4 | - |
| **12A** | G | 80 | - | 30 | - | 60 | - | 153 | - | 153 | CH4 | - |
| **13A** | G | 80 | - | 30 | - | 60 | - | 680 | 182500 | 183180 | CH4 | - |
| **13B** | L | - | 60 | - | -150 | - | 420 | 680 | 182500 | 183180 | | CH4 |
| **13C** | L | - | 10 | - | -150 | - | 410 | 680 | 182500 | 183180 | | CH4 |
| **14A** | G/L | 10 | 50 | 30 | 30 | 10 | 350 | 105360 | 185460 | 290820 | MR1 W | MR1 W |
| **14B** | G/L | 50 | 50 | 80 | 30 | 70 | 350 | 105360 | 185460 | 290820 | MR1 CG | MR1 W |
| **14C** | G/L | 50 | 50 | 80 | 30 | 70 | 350 | 105360 | 185460 | 290820 | MR1 CG | MR1 W |
| **14D** | G/L | 50 | 50 | 30 | 30 | 80 | 350 | 105360 | 185460 | 290820 | MR1 S | MR1 W |
| **15A** | G/L | 5 | 50 | -50 | -50 | 5 | 400 | 40670 | 86510 | 127180 | MR2 CG | MR2 CL |
| **15B** | G | 50 | - | 30 | - | 60 | - | 40670 | 86510 | 127180 | MR2 CG | - |
| **15C** | G | 50 | - | 30 | - | 60 | - | 40670 | 86510 | 127180 | MR2 CG | - |
| **15D** | G | 50 | - | 30 | - | 60 | - | 40670 | 86510 | 127180 | MR2 CG | - |
| **15E** | G/L | 50 | 50 | -50 | -50 | 80 | 400 | 40670 | 86510 | 127180 | MR2 CG | MR2 CG |
| **15F** | G/L | 50 | 50 | -50 | -50 | 70 | 400 | 40670 | 86510 | 127180 | MR2 S | MR2 S |
| **16** | L | - | 5 | - | -160 | - | 410 | - | INFINITE | INFINITE | - | CH4 |
| **17** | L | - | 5 | - | -160 | - | 410 | - | 300 | 300 | - | CH4 |
| **18** | L | - | 10 | - | 40 | - | 660 | - | INFINITE | INFINITE | - | LIQ DEB |
| **19A** | L | - | - | - | - | - | - | - | - | - | - | C2H6 |
| **19B** | L | - | - | - | - | - | - | - | - | - | - | C4H10 |
| **20** | G | 50 | - | 30 | - | 40 | - | 30 | - | 30 | CH4 | - |
| **21** | G | 50 | - | 40 | - | 30 | - | 25 | - | 25 | CH4 | - |
| **22A** | G | 5 | - | -160 | - | 5 | - | 7760 | - | 7760 | CH4 | - |
| **22B** | G | 5 | - | -160 | - | 5 | - | 7760 | - | 7760 | CH4 | - |
| **22C** | G | 50 | - | 30 | - | 40 | - | 7760 | - | 7760 | CH4 | - |
| **22D** | G | 80 | - | 30 | - | 60 | - | 7760 | - | 7760 | CH4 | - |

| Isolatable subsection n° | Type of fluid (G - L - G/L) | Gas pressure [barg] | Liquid press-ure [barg] | Gas temperature [°C] | Liquid temperature [°C] | Gas density [kg/m$^3$] | Liquid density [kg/m$^3$] | Isolatable section mass | | | PHAST Fluid Name | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | Gas mass isolatable section TOTAL [kg] | Liquid mass isolatable section TOTAL [kg] | Total mass [kg] | Gas | Liquid |
| **22E** | G | 5 | - | 30 | - | 5 | | 7760 | - | 7760 | CH4 | - |
| **22F** | G | 5 | - | 30 | - | 5 | | 7760 | - | 7760 | CH4 | - |
| **23** | G | 40 | - | 60 | - | 30 | - | 170 | - | 170 | CH4 | - |
| **24** | G | 110 | - | 60 | - | 70 | - | INFINITE | - | INFINITE | CH4 | - |

*Table 8-6: HC Composition (Molar amount) for Case A FLNG's subsections*

| PHAST Fluid Name | METHANE | ETHANE | PROPANE | BUTANE | C5 | C6 | C7 | C8 | C9 | H2O |
|---|---|---|---|---|---|---|---|---|---|---|
| **CH4** | 100% | | | | | | | | | |
| **LIQ SEP IN** | 2% | | | | | 14% | 40% | 24% | 20% | |
| **LIQ FLASH** | 1% | | | | 3% | 18% | 27% | 26% | 25% | |
| **LIQ FLASHA** | 1% | | | | 3% | 15% | 30% | 26% | 25% | |
| **LIQ DEM** | | | 10% | 14% | | 42% | 13% | | 10% | |
| **GAS DEB** | 33% | | 24% | 30% | 13% | | | | | |
| **LIQ DEB** | | | | 12% | 16% | 40% | 17% | | 15% | |
| **MR1 W** | 11% | 67% | 4% | 18% | | | | | | |
| **MR1 CG** | 13% | 71% | 4% | 12% | | | | | | |
| **MR1 S** | 26% | 67% | 2% | 5% | | | | | | |
| **MR2 CL** | 43% | 54% | 3% | | | | | | | |
| **MR2 CG** | 56% | 41% | 3% | | | | | | | |
| **MR2 CL** | 43% | 54% | 3% | | | | | | | |
| **MR2 S** | 85% | 15% | | | | | | | | |
| **C2H6** | | 100% | | | | | | | | |
| **C4H10** | | | | 100% | | | | | | |

## 19.3. FLNG Case B

*Table 8-7: Case B FLNG's isolatable section and subsections*

| Isolatable subsection n° | Section typology (punctual/linear) | Section description | SDV / Equipment Section starting | SDV / Equipment Section ending | SDV / Equipment Sub-section starting | SDV / Equipment Subsection ending | Deck |
|---|---|---|---|---|---|---|---|
| **4'B** | L | Receiving facilities | Subsea pipeline | ESDV21; ESDV21b; ESDV431; ESDV431b; | Subsea pipeline | ESDV21; ESDV21b; ESDV431; ESDV431b; | Deck A' (+25); |
| **5'** | L | WHP1 field separator inlet | ESDV21b; ESDV21; | HIPS; | - | - | Deck A' (+25); |
| **6'** | L | WHP2 field separator inlet | ESDV431; ESDV431b ; | HIPS; | - | - | Deck A' (+25); |
| **7'** | P | WHP1 field separator | HIPS; | ESDV32; ESDV42; ESDV52; | - | - | Deck A' (+25); Deck B' (+34); Deck C' (+41); |
| **8'** | P | WHP2 field separator | HIPS; | ESDV72; ESDV82; ESDV92; | - | - | Deck A' (+25); Deck B' (+34); Deck C' (+41); |
| **9'A** | P | Condensate preflash drum | ESDV42; ESDV82; compresso r suction scrubber; | ESDV102; ESDV112; ESDV122; | ESDV42; ESDV82; | ESDV102; ESDV112; ESDV122; | Deck C' (+41); |
| **9'B** | L | Condensate preflash drum | ESDV42; ESDV82; compresso r suction scrubber; | ESDV102; ESDV112; ESDV122; | Compressor suction scrubber; | Condensate preflash drum; | Deck A' (+25); |
| **10'A** | L | Gas treatment unit | ESDV52; ESDV92; | Feed gas coalescer; ESDV152; ESDV162; ESDV172; ESDV212; | ESDV52; ESDV92; Compressor suction scrubbers; | Compressor suction scrubber; feed gas heater; | Deck A' (+25); |
| **10'B** | P | Gas treatment unit | ESDV52; ESDV92; | Feed gas coalescer; ESDV152; ESDV162; ESDV172; ESDV212; | Compressor suction scrubber; | Feed gas compressor after cooler; | Deck A' (+25); Deck B' (+34); Deck C' (+41); |

| Isolatable subsection n° | Section typology (punctual/linear) | Section description | SDV / Equipment Section starting | SDV / Equipment Section ending | SDV / Equipment Sub-section starting | SDV / Equipment Subsection ending | Deck |
|---|---|---|---|---|---|---|---|
| **10'C** | P | Gas treatment unit | ESDV52; ESDV92; | Feed gas coalescer; ESDV152; ESDV162; ESDV172; ESDV212; | Compressor suction scrubber; | Feed gas compressor after cooler; | Deck A' (+25); Deck B' (+34); Deck C' (+41); |
| **10'D** | P | Gas treatment unit | ESDV52; ESDV92; | Feed gas coalescer; ESDV152; ESDV162; ESDV172; ESDV212; | Feed gas heater; | Feed gas coalescer; | Deck A' (+25); Deck B' (+34); |
| **10'E** | P | Gas treatment unit | ESDV52; ESDV92; | Feed gas coalescer; ESDV152; ESDV162; ESDV172; ESDV212; | Feed gas coalescer; | Molecular gas drier; ESDV152; ESDV162; ESDV172; ESDV212; | Deck A' (+25); Deck B' (+34); Deck C' (+41); Deck D' (+50); |
| **11'A** | P | Condensate stabilization unit | ESDV112; ESDV122; | ESDV182; ESDV192; SDV452; | ESDV112; | Condensate coalescer filter; | Deck A' (+25); Deck B' (+34); |
| **11'B** | P | Condensate stabilization unit | ESDV112; ESDV122; | ESDV182; ESDV192; SDV452; | Condensate coalescer filter; ESDV122; | ESDV182; ESDV192; SDV452; | Deck B' (+34); Deck C' (+41); |
| **11'C** | L | Condensate stabilization unit | ESDV112; ESDV122; | ESDV182; ESDV192; SDV452; | ESDV122; | ESDV192; | Deck A' (+25); |
| **12'** | P | Regeneratio n unit | ESDV142; Molecular gas drier; | ESDV132; ESDV202; | - | - | Deck A' (+25); Deck B' (+34); Deck C' (+41); Deck D' (+50); |
| **13'T1_A** | L | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | ESDV152; | Warm turbo expander; | Deck A' (+25); |

| Isolatable subsection n° | Section typology (punctual/linear) | Section description | SDV / Equipment Section starting | SDV / Equipment Section ending | SDV / Equipment Sub-section starting | SDV / Equipment Subsection ending | Deck |
|---|---|---|---|---|---|---|---|
| **13'T1_B** | P | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | Warm turbo expander | Warm turbo compressor; Warm turbo compressor; | Deck A' (+25); |
| **13'T1_C** | P | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | Warm turbo compressor; Warm turbo compressor; | Natural gas refrigerant compressor | Deck C' (+41); |
| **13'T1_D** | P | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | Natural gas refrigerant compressor | Middle turbo expander; | Deck A' (+25); Deck E' (+56); |
| **13'T1_E** | P | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | Cold box; | Middle turbo expander; | Deck B' (+34); |
| **13'T1_F** | P | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | Cold box | Lng rundown pumps; SDV292; | Deck D' (+50); Deck E' (+56); |
| **13'T1_G** | P | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | Lng rundown pumps; SDV272; | SDV232; | Deck C' (+41); |

| Isolatable subsection n° | Section typology (punctual/linear) | Section description | SDV / Equipment Section starting | SDV / Equipment Section ending | SDV / Equipment Sub-section starting | SDV / Equipment Subsection ending | Deck |
|---|---|---|---|---|---|---|---|
| **13'T1_H** | L | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | NLG Separator | SDV222; | Deck A' (+25); |
| **13'T1_I** | P | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | NGL separator | NGL separator | Deck D' (+50); Deck E' (+56); |
| **13'T2_B** | P | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | Warm turbo expander | Warm turbo compressor; Warm turbo compressor; | Deck A' (+25); |
| **13'T2_C** | P | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | Warm turbo compressor; Warm turbo compressor; | Natural gas refrigerant compressor; | Deck C' (+41); |
| **13'T2_D** | P | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | Natural gas refrigerant compressor | Middle turbo expander; | Deck A' (+25); Deck E' (+56); |
| **13'T2_E** | P | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | Cold box; | Middle turbo expander; | Deck B' (+34); |

| Isolatable subsection n° | Section typology (punctual/linear) | Section description | SDV / Equipment Section starting | SDV / Equipment Section ending | SDV / Equipment Sub-section starting | SDV / Equipment Subsection ending | Deck |
|---|---|---|---|---|---|---|---|
| **13'T2_F** | P | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | Cold box; | Lng rundown pumps; SDV342; | Deck D' (+50); Deck E' (+56); |
| **13'T2_G** | P | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | Lng rundown pumps; SDV272; | SDV24; | Deck C' (+41); |
| **13'T2_H** | L | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | NLG Separator | SDV222; | Deck A' (+25); |
| **13'T2_I** | P | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | NGL separator | NGL separator | Deck D' (+50); Deck E' (+56); |
| **13'T3_B** | P | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | Warm turbo expander | Warm turbo compressor; Warm turbo compressor; | Deck A' (+25); |
| **13'T3_C** | P | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | Warm turbo compressor; Warm turbo compressor; | Natural gas refrigerant compressor; | Deck C' (+41); |

| Isolatable subsection n° | Section typology (punctual/linear) | Section description | SDV / Equipment Section starting | SDV / Equipment Section ending | SDV / Equipment Sub-section starting | SDV / Equipment Subsection ending | Deck |
|---|---|---|---|---|---|---|---|
| **13'T3_D** | P | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | Natural gas refrigerant compressor | Middle turbo expander; | Deck A' (+25); Deck E' (+56); |
| **13'T3_E** | P | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | Cold box; | Middle turbo expander; | Deck B' (+34); |
| **13'T3_F** | P | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | Cold box | Lng rundown pumps; SDV352; | Deck D' (+50); Deck E' (+56); |
| **13'T3_G** | P | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | Lng rundown pumps; SDV272; | SDV252; | Deck C' (+41); |
| **13'T3_H** | L | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | NLG Separator; | SDV222; | Deck A' (+25); |
| **13'T3_I** | P | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | NGL separator; | NGL separator; | Deck D' (+50); Deck E' (+56); |

| Isolatable subsection n° | Section typology (punctual/linear) | Section description | SDV / Equipment Section starting | SDV / Equipment Section ending | SDV / Equipment Sub-section starting | SDV / Equipment Subsection ending | Deck |
|---|---|---|---|---|---|---|---|
| **13'T4_B** | P | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | Warm turbo expander | Warm turbo compressor; Warm turbo compressor; | Deck A' (+25); |
| **13'T4_C** | P | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | Warm turbo compressor; Warm turbo compressor; | Natural gas refrigerant compressor; | Deck C' (+41); |
| **13'T4_D** | P | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | Natural gas refrigerant compressor | Middle turbo expander; | Deck A' (+25); Deck E' (+56); |
| **13'T4_E** | P | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | Cold box; | Middle turbo expander; | Deck B' (+34); |
| **13'T4_F** | P | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | Cold box | Lng rundown pumps; SDV362; | Deck D' (+50); Deck E' (+56); |
| **13'T4_G** | P | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | Lng rundown pumps; SDV272; | SDV262; | Deck C' (+41); |

| Isolatable subsection n° | Section typology (punctual/linear) | Section description | SDV / Equipment Section starting | SDV / Equipment Section ending | SDV / Equipment Sub-section starting | SDV / Equipment Subsection ending | Deck |
|---|---|---|---|---|---|---|---|
| **13'T4_H** | L | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | NLG Separator; | SDV222; | Deck A' (+25); |
| **13'T4_I** | P | Liquefaction unit | ESDV152; SDV272; | SDV222; SDV292; SDV232; SDV242; SDV252; SDV262; SDV342; SDV352; SDV362; | NGL separator; | NGL separator; | Deck D' (+50); Deck E' (+56); |
| **14'A** | P | NGL fractionatio n unit | ESDV282; SDV222; | ESDV62; SDV302; | SDV282; SDV222; | ESDV62; debutanizer column; | Deck B' (+34); Deck C' (+41); Deck D' (+50); |
| **14'B** | L | NGL fractionatio n unit | ESDV282; SDV222; | ESDV62; SDV302; | Debutanizer column; | SDV302; | Deck C' (+41); |
| **15'A** | L | Fuel gas compressio n | ESDV322; SDV292; SDV342; SDV352; SDV362; ESDV382; ESDV402; SDV302; ESDV192; | ESDV372; SDV332A/B/ C/D; ESDV412; incinerator package; ESDV392; | SDV292; SDV342; SDV352; SDV362; ESDV322; | KO drum; | Deck C' (+41); |
| **15'B** | P | Fuel gas compressio n | ESDV322; SDV292; SDV342; SDV352; SDV362; ESDV382; ESDV402; SDV302; ESDV192; | ESDV372; SDV332A/B/ C/D; ESDV412; incinerator package; ESDV392; | KO drum; ESDV382; SDV302; ESDV192; | ESDV372; ESDV412; fuel gas compressor; fuel gas HP mixing drum; incinerator package; ESDV392; | Deck A' (+25); Deck B' (+34); Deck C' (+41); Deck D' (+50); |
| **15'C** | P | Fuel gas compressio n | ESDV322; SDV292; SDV342; SDV352; SDV362; ESDV382; ESDV402; SDV302; ESDV192; | ESDV372; SDV332A/B/ C/D; ESDV412; incinerator package; ESDV392; | KO drum; ESDV402; | Fuel gas compressor discharge cooler; ESDV392; | Deck A' (+25); Deck B' (+34); |

| Isolatable subsection n° | Section typology (punctual/linear) | Section description | SDV / Equipment Section starting | SDV / Equipment Section ending | SDV / Equipment Sub-section starting | SDV / Equipment Subsection ending | Deck |
|---|---|---|---|---|---|---|---|
| **15'D** | L | Fuel gas compression | ESDV322; SDV292; SDV342; SDV352; SDV362; ESDV382; ESDV402; SDV302; ESDV192; | ESDV372; SDV332A/B/C/D; ESDV412; incinerator package; ESDV392; | Fuel gas compressor discharge coolers; | SDV332A/B/C/D; | Deck C' (+41); |
| **16'A** | L | LNG storage | SDV232; SDV242; SDV252; SDV262; | ESDV312; ESDV322; ESDV422; ESDV432; ESDV442; ESDV452; SDV272; | SDV232; SDV242; SDV252; SDV262; | LNG tanks; | Deck C' (+41); |
| **16'B** | L | LNG storage | SDV232; SDV242; SDV252; SDV262; | ESDV312; ESDV322; ESDV422; ESDV432; ESDV442; ESDV452; SDV272; | LNG tanks; | ESDV322; | Deck C' (+41); |
| **16'C** | L | LNG storage | SDV232; SDV242; SDV252; SDV262; | ESDV312; ESDV322; ESDV422; ESDV432; ESDV442; ESDV452; SDV272; | LNG tanks; | ESDV422; ESDV432; ESDV442; ESDV452; | Deck C' (+41); |
| **16'DT1** | P | LNG storage | SDV232; SDV242; SDV252; SDV262; | ESDV312; ESDV322; ESDV422; ESDV432; ESDV442; ESDV452; SDV272; | LNG tank 1; | LNG tank 1; | Deck C' (+41); |
| **16'DT2** | P | LNG storage | SDV232; SDV242; SDV252; SDV262; | ESDV312; ESDV322; ESDV422; ESDV432; ESDV442; ESDV452; SDV272; | LNG tank 2; | LNG tank 2; | Deck C' (+41); |
| **16'DT3** | P | LNG storage | SDV232; SDV242; SDV252; SDV262; | ESDV312; ESDV322; ESDV422; ESDV432; ESDV442; ESDV452; SDV272; | LNG tank 3; | LNG tank 3; | Deck C' (+41); |

| Isolatable subsection n° | Section typology (punctual/linear) | Section description | SDV / Equipment Section starting | SDV / Equipment Section ending | SDV / Equipment Sub-section starting | SDV / Equipment Subsection ending | Deck |
|---|---|---|---|---|---|---|---|
| **16'DT4** | P | LNG storage | SDV232; SDV242; SDV252; SDV262; | ESDV312; ESDV322; ESDV422; ESDV432; ESDV442; ESDV452; SDV272; | LNG tank 4; | LNG tank 4; | Deck C' (+41); |
| **16'DT5** | P | LNG storage | SDV232; SDV242; SDV252; SDV262; | ESDV312; ESDV322; ESDV422; ESDV432; ESDV442; ESDV452; SDV272; | LNG tank 5; | LNG tank 5; | Deck C' (+41); |
| **17'A** | L | Fuel gas distribution | ESDV392; | Inlet of natural gas turbines; inlet of feed gas compressor gas turbine; | ESDV392; | Inlet of natural gas turbines; | Deck C' (+41); |
| **17'B** | L | Fuel gas distribution | ESDV39; | Inlet of natural gas turbines; inlet of feed gas compressor gas turbine; | ESDV392; | Inlet of feed gas compressor gas turbine; | Deck A' (+25); |
| **18'A** | L | Export gas conditioning | ESDV212; | SDV282; ESDV462; | ESDV212; | Export gas turbo expander; | Deck A' (+25); |
| **18'B** | P | Export gas conditioning | ESDV212; | SDV282; ESDV462; | Export gas turbo expander; | SDV282; export gas booster compressor; | Deck A' (+25); Deck B' (+34); |
| **18'C** | L | Export gas conditioning | ESDV212; | SDV282; ESDV462; | Export gas booster compressor; | ESDV462; | Deck C' (+41); |
| **19'** | L | Lean gas boosting | ESDV462; | Export pipeline | - | - | Deck A' (+25); |
| **20'A** | L | Line to condensate storage | ESDV62; ESDV182; | Hull deck; | ESDV62; | Hull deck; | Deck A' (+25); Deck B' (+34); |

| Isolatable subsection n° | Section typology (punctual/linear) | Section description | SDV / Equipment Section starting | SDV / Equipment Section ending | SDV / Equipment Sub-section starting | SDV / Equipment Subsection ending | Deck |
|---|---|---|---|---|---|---|---|
| **20'B** | L | Line to condensate storage | ESDV62; ESDV182; | Hull deck; | ESDV182; | Hull deck; | Deck A' (+25); Deck B' (+34); |
| **21'** | P | Offloading | ESDV422; ESDV432; ESDV442; ESDV452; | LNG offloading and BOG return arms; | - | - | Deck A' (+25); |
| **22'** | L | | ESDV132; ESDV372; | ESD382; ESDV142; | - | - | Deck C' (+41); |

*Table 8-8: Operative conditions and hold up for each Case B FLNG's subsections*

| Isolatable subsection n° | Type of fluid (G - L -G/L) | Gas pressure [barg] | Liquid pressure [barg] | Gas temperature [°C] | Liquid temperature [°C] | Gas density [kg/m³] | Liquid density [kg/m³] | Isolatable section mass | | | PHAST Fluid Name | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | Gas mass isolatable section TOTAL [kg] | Liquid mass isolatable section TOTAL [kg] | Total mass [kg] | Gas | Liquid |
| **4'B** | G | 90 | - | 60 | - | 60 | - | INFINITE | - | INFINITE | CH4 | - |
| **5'** | G | 80 | - | 20 | - | 60 | - | 1910 | - | 1910 | CH4 | - |
| **6'** | G | 30 | - | 20 | - | 20 | - | 560 | - | 560 | CH4 | - |
| **7'** | G/L | 80 | 10 | 20 | 20 | 60 | 750 | 11480 | 14990 | 26470 | CH4 | LIQ SEP IN |
| **8'** | G/L | 25 | 10 | 20 | 20 | 20 | 750 | 3280 | 14990 | 18270 | CH4 | LIQ SEP IN |
| **9'A** | G/L | 10 | 10 | 20 | 20 | 5 | 750 | 540 | 54100 | 54640 | CH4 | LIQ FLASH |
| **9'B** | L | - | 10 | - | 20 | - | 750 | 540 | 54100 | 54640 | - | LIQ SEP IN |
| **10'A** | G | 80 | - | 20 | - | 60 | - | 73890 | - | 73890 | CH4 | - |
| **10'B** | G | 80 | - | 30 | - | 60 | - | 73890 | - | 73890 | CH4 | - |
| **10'C** | G | 80 | - | 30 | - | 60 | - | 73890 | - | 73890 | CH4 | - |
| **10'D** | G | 80 | - | 30 | - | 60 | - | 73890 | - | 73890 | CH4 | - |
| **10'E** | G | 80 | - | 30 | - | 60 | - | 73890 | - | 73890 | CH4 | - |
| **11'A** | L | - | 10 | - | 20 | - | 750 | 110 | 26526,78 | 26636,78 | - | LIQ FLASH |
| **11'B** | G/L | 5 | 10 | 20 | 170 | 5 | 610 | 110 | 26526,78 | 26636,78 | CH4 | LIQ FLASH |
| **11'C** | G | 5 | - | 20 | - | 5 | - | 110 | 26526,78 | 26636,78 | CH4 | - |
| **12'** | G | 50 | - | 270 | - | 20 | - | 3500 | - | 3500 | CH4 | - |
| **13'T1_A** | G | 80 | - | 30 | - | 60 | - | 9150 | 2566600 | 2575750 | CH4 | - |

| Isolatable subsectio n n° | Type of fluid (G - L -G/L) | Gas pressure [barg] | Liquid pressure [barg] | Gas temperature [°C] | Liquid temperature [°C] | Gas density [kg/m³] | Liquid density [kg/m³] | Isolatable section mass | | | PHAST Fluid Name | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | Gas mass isolatable section TOTAL [kg] | Liquid mass isolatable section TOTAL [kg] | Total mass [kg] | Gas | Liquid |
| 13'T1_B | G | 15 | - | 30 | - | 10 | - | 9150 | 2566600 | 2575750 | CH4 | - |
| 13'T1_C | G | 30 | - | 30 | - | 20 | - | 9150 | 2566600 | 2575750 | CH4 | - |
| 13'T1_D | G | 80 | - | 80 | - | 50 | - | 9150 | 2566600 | 2575750 | CH4 | - |
| 13'T1_E | G | 20 | - | 30 | - | 15 | - | 9150 | 2566600 | 2575750 | CH4 | - |
| 13'T1_F | G/L | 1 | 80 | -100 | -140 | 5 | 420 | 9150 | 2566600 | 2575750 | CH4 | CH4 |
| 13'T1_G | L | - | 2 | - | -160 | - | 420 | 9150 | 2566600 | 2575750 | - | CH4 |
| 13'T1_H | L | - | 15 | - | 15 | - | 690 | 9150 | 2566600 | 2575750 | - | DEB |
| 13'T1_I | L | - | 15 | - | -60 | - | 740 | 9150 | 2566600 | 2575750 | - | NLG |
| 13'T2_B | G | 15 | - | 30 | - | 10 | - | 9150 | 2566600 | 2575750 | CH4 | - |
| 13'T2_C | G | 30 | - | 30 | - | 20 | - | 9150 | 2566600 | 2575750 | CH4 | - |
| 13'T2_D | G | 80 | - | 80 | - | 50 | - | 9150 | 2566600 | 2575750 | CH4 | - |
| 13'T2_E | G | 20 | - | 30 | - | 15 | - | 9150 | 2566600 | 2575750 | CH4 | - |
| 13'T2_F | G/L | 1 | 80 | -100 | -140 | 5 | 420 | 9150 | 2566600 | 2575750 | CH4 | CH4 |
| 13'T2_G | L | - | 2 | - | -160 | - | 420 | 9150 | 2566600 | 2575750 | - | CH4 |
| 13'T2_H | L | - | 15 | - | 15 | - | 690 | 9150 | 2566600 | 2575750 | - | DEB |
| 13'T2_I | L | - | 15 | - | -60 | - | 740 | 9150 | 2566600 | 2575750 | - | NLG |
| 13'T3_B | G | 15 | - | 30 | - | 10 | - | 9150 | 2566600 | 2575750 | CH4 | - |
| 13'T3_C | G | 30 | - | 30 | - | 20 | - | 9150 | 2566600 | 2575750 | CH4 | - |
| 13'T3_D | G | 80 | - | 80 | - | 50 | - | 9150 | 2566600 | 2575750 | CH4 | - |
| 13'T3_E | G | 20 | - | 30 | - | 15 | - | 9150 | 2566600 | 2575750 | CH4 | - |
| 13'T3_F | G/L | 1 | 80 | -100 | -140 | 5 | 420 | 9150 | 2566600 | 2575750 | CH4 | CH4 |
| 13'T3_G | L | - | 2 | - | -160 | - | 420 | 9150 | 2566600 | 2575750 | - | CH4 |
| 13'T3_H | L | - | 15 | - | 15 | - | 690 | 9150 | 2566600 | 2575750 | - | DEB |
| 13'T3_I | L | - | 15 | - | -60 | - | 740 | 9150 | 2566600 | 2575750 | - | NLG |
| 13'T4_B | G | 15 | - | 30 | - | 10 | - | 9150 | 2566600 | 2575750 | CH4 | - |
| 13'T4_C | G | 30 | - | 30 | - | 20 | - | 9150 | 2566600 | 2575750 | CH4 | - |
| 13'T4_D | G | 80 | - | 80 | - | 50 | - | 9150 | 2566600 | 2575750 | CH4 | - |

| Isolatable subsection n° | Type of fluid (G - L -G/L) | Gas pressure [barg] | Liquid pressure [barg] | Gas temperature [°C] | Liquid temperature [°C] | Gas density [kg/m³] | Liquid density [kg/m³] | Isolatable section mass | | | PHAST Fluid Name | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | Gas mass isolatable section TOTAL [kg] | Liquid mass isolatable section TOTAL [kg] | Total mass [kg] | Gas | Liquid |
| **13'T4_E** | G | 20 | - | 30 | - | 15 | - | 9150 | 2566600 | 2575750 | CH4 | - |
| **13'T4_F** | G/L | 1 | 80 | -100 | -140 | 5 | 420 | 9150 | 2566600 | 2575750 | CH4 | CH4 |
| **13'T4_G** | L | - | 2 | - | -160 | - | 420 | 9150 | 2566600 | 2575750 | - | CH4 |
| **13'T4_H** | L | - | 15 | - | 15 | - | 690 | 9150 | 2566600 | 2575750 | - | DEB |
| **13'T4_I** | L | - | 15 | - | -60 | - | 740 | 9150 | 2566600 | 2575750 | - | NLG |
| **14'A** | G/L | 5 | 5 | 50 | 120 | 10 | 600 | 150 | 1600 | 1750 | GAS DEB | LIQ DEB |
| **14'B** | G | 5 | - | 50 | - | 10 | - | 150 | 1600 | 1750 | GAS DEB | - |
| **15'A** | G | 1 | - | -120 | - | 5 | - | 11640 | - | 11640 | CH4 | - |
| **15'B** | G | 50 | - | 40 | - | 40 | - | 11640 | - | 11640 | CH4 | - |
| **15'C** | G | 50 | - | 40 | - | 40 | - | 11640 | - | 11640 | CH4 | - |
| **15'D** | G | 50 | - | 40 | - | 40 | - | 11640 | - | 11640 | CH4 | - |
| **16'A** | L | - | 5 | - | -160 | - | 420 | INFINITE | INFINITE | INFINITE | - | CH4 |
| **16'B** | G | 1 | - | -160 | - | 5 | - | INFINITE | INFINITE | INFINITE | CH4 | - |
| **16'C** | L | - | 5 | - | -160 | - | 420 | INFINITE | INFINITE | INFINITE | - | CH4 |
| **16'DT1** | L | - | 5 | - | -160 | - | 420 | INFINITE | INFINITE | INFINITE | - | CH4 |
| **16'DT2** | L | - | 5 | - | -160 | - | 420 | INFINITE | INFINITE | INFINITE | - | CH4 |
| **16'DT3** | L | - | 5 | - | -160 | - | 420 | INFINITE | INFINITE | INFINITE | - | CH4 |
| **16'DT4** | L | - | 5 | - | -160 | - | 420 | INFINITE | INFINITE | INFINITE | - | CH4 |
| **16'DT5** | L | - | 5 | - | -160 | - | 420 | INFINITE | INFINITE | INFINITE | - | CH4 |
| **17'A** | G | 40 | - | 70 | - | 30 | - | 280 | - | 280 | CH4 | - |
| **17'B** | G | 40 | - | 70 | - | 30 | - | 280 | - | 280 | CH4 | - |
| **18'A** | G | 80 | - | 30 | - | 60 | - | 5060 | - | 5060 | CH4 | - |
| **18'B** | G | 70 | - | 30 | - | 50 | - | 5060 | - | 5060 | CH4 | - |
| **18'C** | G | 100 | - | 70 | - | 70 | - | 5060 | - | 5060 | CH4 | - |
| **19'** | G | 100 | - | 70 | - | 70 | - | INFINITE | - | INFINITE | CH4 | - |
| **20'A** | L | - | 5 | - | 40 | - | 740 | - | INFINITE | INFINITE | - | LIQ DEB |
| **20'B** | L | - | 5 | - | 40 | - | 740 | - | INFINITE | INFINITE | - | LIQ DEB |
| **21'** | L | - | 5 | - | -160 | - | 420 | - | 7400 | 7400 | - | CH4 |
| **22'** | G | 40 | - | 40 | - | 30 | - | 290 | - | 290 | CH4 | - |

*Table 8-9: HC Composition (Molar amount) for Case B FLNG's subsections*

| PHAST Fluid Name | METHANE | ETHANE | PROPANE | BUTANE | C5 | C6 | C7 | C8 | C9 | H2O |
|---|---|---|---|---|---|---|---|---|---|---|
| **CH4** | 100% | | | | | | | | | |
| **LIQ SEP IN** | 12% | | | | | 18% | 19% | 18% | 33% | |
| **LIQ FLASH** | | | | 5% | 18% | 20% | 20% | 37% | | |
| **GAS DEB** | 40% | 4% | 26% | 20% | 4% | 3% | 3% | | | |
| **LIQ DEB** | | | | 2% | 15% | 35% | 24% | 9% | 15% | |
| **DEB** | | | | 23% | 12% | 36% | 19% | 10% | | |
| **NGL** | 15% | | | 16% | 11% | 32% | 16% | 6% | 4% | |

# Annex 2

*Table 20-1: Explosion results for PES 1 by PHAST 8.21*

| Distance [m] | Overpressure [bar] | Impulse [N.s/m2] |
|---|---|---|
| 0 | 0,3273 | 3153,8 |
| 0,5 | 0,3273 | 3153,8 |
| 1 | 0,3273 | 3172 |
| 1,5 | 0,3273 | 3068,9 |
| 2 | 0,3273 | 3020,1 |
| 2,5 | 0,3273 | 2994,2 |
| 3 | 0,3273 | 2969,1 |
| 3,5 | 0,3273 | 2936,4 |
| 4 | 0,3273 | 2894,1 |
| 4,5 | 0,3273 | 2842,8 |
| 5 | 0,3273 | 2784 |
| 5,5 | 0,3273 | 2719,5 |
| 6 | 0,3273 | 2651,1 |
| 6,5 | 0,3273 | 2580 |
| 7 | 0,3273 | 2507,7 |
| 7,5 | 0,3273 | 2435 |
| 8 | 0,3273 | 2362,7 |
| 8,5 | 0,3273 | 2291,4 |
| 9 | 0,3277 | 2221,5 |
| 9,5 | 0,3293 | 2153,4 |
| 10 | 0,3308 | 2087,3 |
| 10,5 | 0,3322 | 2023,3 |
| 11 | 0,3337 | 1961,5 |
| 11,5 | 0,3348 | 1902 |
| 12 | 0,3353 | 1844,8 |
| 12,5 | 0,3353 | 1789,8 |
| 13 | 0,3348 | 1737,1 |
| 13,5 | 0,3339 | 1686,5 |
| 14 | 0,3325 | 1638,1 |
| 14,5 | 0,3308 | 1591,7 |
| 15 | 0,3288 | 1547,3 |
| 15,5 | 0,3264 | 1504,8 |
| 16 | 0,3238 | 1464,1 |
| 16,5 | 0,321 | 1425,1 |
| 17 | 0,318 | 1387,8 |
| 17,5 | 0,3148 | 1352,1 |
| 18 | 0,3115 | 1317,8 |
| 18,5 | 0,3081 | 1285,1 |
| 19 | 0,3047 | 1253,7 |

| Distance [m] | Overpressure [bar] | Impulse [N.s/m2] |
|---|---|---|
| 19,5 | 0,3011 | 1223,5 |
| 20 | 0,2975 | 1194,7 |
| 20,5 | 0,2939 | 1167 |
| 21 | 0,2902 | 1140,4 |
| 21,5 | 0,2866 | 1114,9 |
| 22 | 0,2829 | 1090,4 |
| 22,5 | 0,2793 | 1066,9 |
| 23 | 0,2757 | 1044,3 |
| 23,5 | 0,2721 | 1022,6 |
| 24 | 0,2685 | 1001,7 |
| 24,5 | 0,265 | 981,55 |
| 25 | 0,2615 | 962,2 |
| 25,5 | 0,2581 | 943,56 |
| 26 | 0,2547 | 925,6 |
| 26,5 | 0,2514 | 908,3 |
| 27 | 0,2481 | 891,62 |
| 27,5 | 0,2449 | 875,53 |
| 28 | 0,2418 | 860,01 |
| 28,5 | 0,2387 | 845,03 |
| 29 | 0,2356 | 830,56 |
| 29,5 | 0,2326 | 816,58 |
| 30 | 0,2297 | 803,08 |
| 30,5 | 0,2269 | 790,02 |
| 31 | 0,224 | 777,39 |
| 31,5 | 0,2213 | 765,18 |
| 32 | 0,2186 | 753,36 |
| 32,5 | 0,2159 | 741,91 |
| 33 | 0,2133 | 730,83 |
| 33,5 | 0,2108 | 720,09 |
| 34 | 0,2083 | 709,68 |
| 34,5 | 0,2059 | 699,59 |
| 35 | 0,2035 | 689,8 |
| 35,5 | 0,2012 | 680,3 |
| 36 | 0,1989 | 671,09 |
| 36,5 | 0,1967 | 662,14 |
| 37 | 0,1945 | 653,46 |
| 37,5 | 0,1923 | 645,02 |
| 38 | 0,1902 | 636,82 |
| 38,5 | 0,1882 | 628,85 |
| 39 | 0,1862 | 621,1 |
| 39,5 | 0,1842 | 613,56 |
| 40 | 0,1822 | 606,22 |
| 40,5 | 0,1803 | 599,09 |
| 41 | 0,1785 | 592,14 |

| Distance [m] | Overpressure [bar] | Impulse [N.s/m2] |
|---|---|---|
| 41,5 | 0,1767 | 585,37 |
| 42 | 0,1749 | 578,78 |
| 42,5 | 0,1731 | 572,36 |
| 43 | 0,1714 | 566,1 |
| 43,5 | 0,1697 | 560 |
| 44 | 0,1681 | 554,05 |
| 44,5 | 0,1665 | 548,25 |
| 45 | 0,1649 | 542,59 |
| 45,5 | 0,1633 | 537,06 |
| 46 | 0,1618 | 531,67 |
| 46,5 | 0,1603 | 526,41 |
| 47 | 0,1588 | 521,26 |
| 47,5 | 0,1574 | 516,24 |
| 48 | 0,156 | 511,33 |
| 48,5 | 0,1546 | 506,53 |
| 49 | 0,1532 | 501,84 |
| 49,5 | 0,1519 | 497,26 |
| 50 | 0,1505 | 492,77 |
| 50,5 | 0,1493 | 488,38 |
| 51 | 0,148 | 484,09 |
| 51,5 | 0,1467 | 479,89 |
| 52 | 0,1455 | 475,77 |
| 52,5 | 0,1443 | 471,75 |
| 53 | 0,1431 | 467,8 |
| 53,5 | 0,1419 | 463,94 |
| 54 | 0,1408 | 460,15 |
| 54,5 | 0,1396 | 456,44 |
| 55 | 0,1385 | 452,8 |
| 55,5 | 0,1374 | 449,23 |
| 56 | 0,1363 | 445,68 |
| 56,5 | 0,1353 | 441,8 |
| 57 | 0,1342 | 437,99 |
| 57,5 | 0,1332 | 434,24 |
| 58 | 0,1322 | 430,55 |
| 58,5 | 0,1312 | 426,92 |
| 59 | 0,1302 | 423,34 |
| 59,5 | 0,1292 | 419,82 |
| 60 | 0,1283 | 416,36 |
| 60,5 | 0,1273 | 412,95 |
| 61 | 0,1264 | 409,59 |
| 61,5 | 0,1255 | 406,27 |
| 62 | 0,1246 | 403,01 |
| 62,5 | 0,1237 | 399,79 |
| 63 | 0,1228 | 396,62 |

| Distance [m] | Overpressure [bar] | Impulse [N.s/m2] |
|---|---|---|
| 63,5 | 0,1219 | 393,5 |
| 64 | 0,1211 | 390,41 |
| 64,5 | 0,1202 | 387,37 |
| 65 | 0,1194 | 384,38 |
| 65,5 | 0,1186 | 381,42 |
| 66 | 0,1178 | 378,5 |
| 66,5 | 0,117 | 375,62 |
| 67 | 0,1162 | 372,77 |
| 67,5 | 0,1154 | 369,97 |
| 68 | 0,1146 | 367,2 |
| 68,5 | 0,1139 | 364,46 |
| 69 | 0,1131 | 361,76 |
| 69,5 | 0,1124 | 359,09 |
| 70 | 0,1117 | 356,45 |

*Table 20-2: Explosion results for PES 2 by PHAST 8.21*

| Distance [m] | Overpressure [bar] | Impulse [N.s/m2] |
|---|---|---|
| 0 | 0,327 | 2410,9 |
| 0,5 | 0,327 | 2410,9 |
| 1 | 0,327 | 2371,0 |
| 1,5 | 0,327 | 2310,6 |
| 2 | 0,327 | 2284,7 |
| 2,5 | 0,327 | 2257,1 |
| 3 | 0,327 | 2217,7 |
| 3,5 | 0,327 | 2166,4 |
| 4 | 0,327 | 2105,7 |
| 4,5 | 0,327 | 2038,6 |
| 5 | 0,327 | 1967,8 |
| 5,5 | 0,327 | 1895,3 |
| 6 | 0,327 | 1822,8 |
| 6,5 | 0,327 | 1751,3 |
| 7 | 0,328 | 1681,7 |
| 7,5 | 0,33 | 1614,5 |
| 8 | 0,332 | 1550,0 |
| 8,5 | 0,334 | 1488,4 |
| 9 | 0,335 | 1429,8 |
| 9,5 | 0,335 | 1374,2 |
| 10 | 0,335 | 1321,5 |
| 10,5 | 0,333 | 1271,6 |
| 11 | 0,331 | 1224,4 |
| 11,5 | 0,329 | 1179,9 |
| 12 | 0,325 | 1137,8 |
| 12,5 | 0,322 | 1098,1 |
| 13 | 0,318 | 1060,5 |
| 13,5 | 0,314 | 1025,1 |
| 14 | 0,309 | 991,5 |
| 14,5 | 0,305 | 959,8 |
| 15 | 0,3 | 929,8 |
| 15,5 | 0,295 | 901,4 |
| 16 | 0,291 | 874,5 |
| 16,5 | 0,286 | 849,0 |
| 17 | 0,281 | 824,9 |
| 17,5 | 0,276 | 801,9 |
| 18 | 0,272 | 780,1 |
| 18,5 | 0,267 | 759,4 |
| 19 | 0,263 | 739,8 |
| 19,5 | 0,258 | 721,0 |
| 20 | 0,254 | 703,2 |
| 20,5 | 0,249 | 686,2 |

| Distance [m] | Overpressure [bar] | Impulse [N.s/m2] |
|---|---|---|
| 21 | 0,245 | 670,0 |
| 21,5 | 0,241 | 654,5 |
| 22 | 0,237 | 639,7 |
| 22,5 | 0,233 | 625,6 |
| 23 | 0,229 | 612,1 |
| 23,5 | 0,225 | 599,2 |
| 24 | 0,222 | 586,8 |
| 24,5 | 0,218 | 575,0 |
| 25 | 0,215 | 563,6 |
| 25,5 | 0,212 | 552,8 |
| 26 | 0,208 | 542,3 |
| 26,5 | 0,205 | 532,3 |
| 27 | 0,202 | 522,6 |
| 27,5 | 0,199 | 513,4 |
| 28 | 0,196 | 504,4 |
| 28,5 | 0,193 | 495,9 |
| 29 | 0,19 | 487,6 |
| 29,5 | 0,188 | 479,6 |
| 30 | 0,185 | 471,9 |
| 30,5 | 0,183 | 464,5 |
| 31 | 0,18 | 457,4 |
| 31,5 | 0,178 | 450,5 |
| 32 | 0,175 | 443,8 |
| 32,5 | 0,173 | 437,4 |
| 33 | 0,171 | 431,2 |
| 33,5 | 0,169 | 425,1 |
| 34 | 0,167 | 419,3 |
| 34,5 | 0,164 | 413,6 |
| 35 | 0,162 | 408,2 |
| 35,5 | 0,16 | 402,9 |
| 36 | 0,159 | 397,7 |
| 36,5 | 0,157 | 392,8 |
| 37 | 0,155 | 387,9 |
| 37,5 | 0,153 | 383,2 |
| 38 | 0,151 | 378,7 |
| 38,5 | 0,15 | 374,2 |
| 39 | 0,148 | 369,9 |
| 39,5 | 0,146 | 365,7 |
| 40 | 0,145 | 361,7 |
| 40,5 | 0,143 | 357,7 |
| 41 | 0,142 | 353,9 |
| 41,5 | 0,14 | 350,1 |
| 42 | 0,139 | 346,4 |
| 42,5 | 0,137 | 342,9 |

| Distance [m] | Overpressure [bar] | Impulse [N.s/m2] |
|---|---|---|
| 43 | 0,136 | 339,2 |
| 43,5 | 0,134 | 335,4 |
| 44 | 0,133 | 331,6 |
| 44,5 | 0,132 | 327,9 |
| 45 | 0,13 | 324,3 |
| 45,5 | 0,129 | 320,8 |
| 46 | 0,128 | 317,4 |
| 46,5 | 0,127 | 314,0 |
| 47 | 0,126 | 310,6 |
| 47,5 | 0,124 | 307,4 |
| 48 | 0,123 | 304,2 |
| 48,5 | 0,122 | 301,1 |
| 49 | 0,121 | 298,0 |
| 49,5 | 0,12 | 295,0 |
| 50 | 0,119 | 292,0 |
| 50,5 | 0,118 | 289,1 |
| 51 | 0,117 | 286,2 |
| 51,5 | 0,116 | 283,4 |
| 52 | 0,115 | 280,6 |
| 52,5 | 0,114 | 277,9 |
| 53 | 0,113 | 275,2 |
| 53,5 | 0,112 | 272,5 |
| 54 | 0,111 | 269,9 |
| 54,5 | 0,11 | 267,4 |
| 55 | 0,109 | 264,8 |
| 55,5 | 0,108 | 262,4 |
| 56 | 0,107 | 259,9 |
| 56,5 | 0,106 | 257,5 |
| 57 | 0,105 | 255,1 |
| 57,5 | 0,105 | 252,8 |
| 58 | 0,104 | 250,5 |
| 58,5 | 0,103 | 248,4 |
| 59 | 0,102 | 246,2 |
| 59,5 | 0,101 | 244,2 |
| 60 | 0,1 | 242,1 |
| 60,5 | 0,1 | 240,1 |
| 61 | 0,099 | 238,2 |
| 61,5 | 0,098 | 236,2 |
| 62 | 0,097 | 234,3 |
| 62,5 | 0,097 | 232,4 |
| 63 | 0,096 | 230,6 |
| 63,5 | 0,095 | 228,8 |
| 64 | 0,094 | 227,0 |
| 64,5 | 0,094 | 225,2 |

| Distance [m] | Overpressure [bar] | Impulse [N.s/m2] |
|---|---|---|
| 65 | 0,093 | 223,5 |
| 65,5 | 0,092 | 221,8 |
| 66 | 0,092 | 220,1 |
| 66,5 | 0,091 | 218,5 |
| 67 | 0,09 | 216,8 |
| 67,5 | 0,09 | 215,2 |
| 68 | 0,089 | 213,6 |
| 68,5 | 0,088 | 212,1 |
| 69 | 0,088 | 210,5 |
| 69,5 | 0,087 | 209,0 |
| 70 | 0,087 | 207,5 |

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[1] A generic reference has been used for this document. This precautionary measure is necessary to avoid diffusing sensible information concerning Contractor's facilities.

[2] A generic reference has been used for this document. This precautionary measure is necessary to avoid diffusing sensible information concerning Contractor's facilities.