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PROBABILISTIC CORROSION FAILURE ANALYSIS OF A LNG CARRIER LOADING PIPELINE

Erick Miguel Portugal Hidalgo, erickmph@usp.br
Dennis Wilfredo Roldan Silva, dennis.silva@usp.br
Gilberto F. Martha de Souza, gfmsouza@usp.br
Polytechnic School, University of São Paulo, São Paulo, Av. Prof. Mello Moraes, 2231 – Cidade Universitária – São Paulo – SP –Brazil

Abstract. *The rupture of a ship pipeline (part of the manifold or other secondary pipes) used for LNG carrier loading or unloading can cause leakage of the fluid leading not only to the complete stop of the cargo handling operation but also exposing the ship and other terminal facilities to a risk associated with LNG leakage. The paper applies structural reliability concepts to evaluate the probability of failure of a pipeline due to the occurrence of corrosion in the pipe inner wall. The analysis considers the probability of occurrence of yielding associated with the presence of a defect caused by corrosion which is the initiating event for pipe rupture. The limit state function as for yielding analysis is presented, based on ASME B31G standard. The Monte Carlo simulation method is used to calculate the probability of failure. Based on those results, the paper proposes the use of the cause-consequence diagram to evaluate the accident scenarios associated with the pipe failure. The events that appear in the diagram are associated with alarm and control systems that are used as monitoring system for loading and unloading operations. The main analysis result will be the risk profile associated with a pipe yielding failure.*

Keywords: *Reliability, Corrosion, Monte Carlo and Pipeline*

1. INTRODUCTION

Among energy sources consisting of hydrocarbons, natural gas is the cleanest and richest in hydrogen. Being composed primarily of methane, there has been an expanding consumption of natural gas to be used as fuel for thermal power plants based on Rankine or Brayton thermodynamics cycles.

Once the great consumers (concentrated in Asia, Europe and North America) of natural gas are not the great worldwide producers (concentrated in the Middle East, Africa and Central America) the need for transportation of that hydrocarbon has still increased. The most used transport solution for natural gas between continents is the use of ships carrying liquefied natural gas (LNG) once liquefaction reduces the volume of natural gas at about 600 times, making it an economical way for storing and transportation.

The ship moves from a liquefaction terminal, where LNG is loaded, to a storage and regasification terminal. During the travel period the LNG must be kept in cryogenic temperature to avoid vaporization.

The loading and unloading operations of LNG can be considered risky once there are a great number of pieces of equipment that must operate correctly in order to avoid any liquid leakage. The terminal and ship piping systems are important pieces of equipment that in case of failure can cause leakage of LNG.

The present paper focuses on the analysis of the header failure, causing fluid leakage, in LNG carriers aiming at defining the possible accidental scenarios associated with that initial event. The header probability of failure is calculated based on structural reliability concepts considering the corrosion failure. The accidental scenarios are defined with the use of cause-consequence diagram. The consequences of each failure scenario are analyzed based on literature review once, as a preliminary study, once the main objective is to study the barriers and mitigating measures used to avoid an accident.

Although the literature review analyzing accidents with LNG carriers operation, such a reference (IMO, 2007), does not identify failures of the headers, most LNG carriers are achieving operational lives longer than 20 years. The increase in ship operational life can cause an increase in the possibility of piping systems failure, including the header. The last one carries the total volume of LNG handled during loading and unloading operations. Due to great volume of liquid handled by the header, its failure must be analyzed to properly define the risk associated with LNG carriers loading and unloading operations.

2. PROPIERTIES OF LNG

The LNG is a cryogenic fluid that is transported and stored at temperatures as low as -162°C. The main component of the LNG is methane in a quantity of 85 to 95% but other light hydrocarbons are present in the LNG such as ethane, propane, butane and nitrogen. The LNG is about 1/600th the volume of natural gas at standard temperature and pressure. The LNG will neither burn nor explode; it is colorless, odorless, and tasteless.

The methane has a flammability range approximately from 5% to 15% by volume. At a 5 percent concentration of gas in air, LNG vapors are at their lower flammability limit (LFL), this means that below this vapor/air ratio, the cloud is too dilute for ignition and at 15 percent concentration of gas in air, LNG vapors are at their upper flammability limit (UFL). Above this vapor/air ratio, the cloud is too rich in LNG for ignition (ABS Consulting, 2004).

3. HAZARD OF LNG

Contact with Cryogenic Liquid: If there is direct contact with cryogenic liquid, there may be sores on the skin. Steam inhalation for prolonged periods can cause lung damage (Bernatik *et al*, 2010) and (Natacci *et al*, 2010).

Pool Fire: When there is a LNG spill a pool is formed, which spreads and undergoes evaporation simultaneously. The shape and size of the pool depend on variables such as wind, waves and currents (in case of leakage over water), obstacles, etc.

Flash Fire: the leak of LNG forms a cloud that, there being no immediate ignition, grows with the pool vaporization. In case of a leak of LNG unconfined in water, the LNG vaporizes to a high rate, kept constant by the high heat flux from the water. A puddle is formed by leakage on land, in contrast, that has high evaporation rate at the beginning and decays with time. If there is spillage of LNG confined in calm water ice may be formed, causing a decrease in the rate of heat flow and making it similar to the spill on land, (Luketa-Hanlin, 2006) and (Natacci *et al*, 2010).

4. LOADING AND UNLOADING OPERATIONS

In the loading operation, the LNG is loaded through the loading manifold, then is carried by two secondary pipelines to the liquid header line and then to each tank. This operation is completed when all tanks are 98,5% of the total capacity in tank. After the loading operation all components in the system as valves, pipelines, etc. are drained and the fluid directed to a cargo tank avoiding that some quantity of methane are present in the lines. On completion of loading the liquid header line and other pipes are drained to a cargo tank. The liquid remaining in the inclined part of the manifold is pushed into the tank 4 using N2.

During the unloading operations, the LNG is unloaded activating one main cargo pump by each tank which is submerged inside their respective tanks. The main cargo pumps discharge the LNG to the main liquid header and then this fluid is transported to the terminal via the manifold connections. Each tank is normally discharged down to a level of about 0,1m, but the quantity being retained in tanks varies according to the length of ballast voyage. On completion of discharge, the loading arms and pipelines are purged and drained into one cargo tank and the arms are then gas freed and disconnected.

5. METHOD FOR THE ANALYSIS

The safety culture of anticipating hazards rather than waiting for accidents to reveal them has been used in many industries such as nuclear, chemical and aerospace industries. The international ship industry has begun to move from a reactive to a proactive approach to safety through the discussion associated with the proposal of the approach known as Formal Safety Assessment (FSA) by the International Maritime Organization (IMO).

The risk analysis method used in this paper is based on FSA but focuses on the use of the cause-consequence diagram to evaluate failure scenarios associated with an initiating event, which is the failure of the header of a LNG carrier.

5.1 Risk Analysis Concept

Risk analysis is a technique for identifying, characterizing, quantifying, and evaluating the loss from an event. Risk analysis approach integrates probability and consequence analysis at various stages of the analysis and attempts to answer the following questions, (Cheng *et al*, 2009):

- What can go wrong that could lead to a system failure?
- How can it go wrong?
- How likely is its occurrence?
- What would be the consequences if it happens?

In this context, risk can be defined qualitatively/quantitatively as the following set of duplets for a particular failure scenario.

$$Risk = (failure\ probability) \times (consequence\ of\ the\ failure) \quad (1)$$

The risk analysis method aims at the evaluation of the likelihood of occurrence of equipment failures and their consequences for the power plant operation, characterizing a quantitative risk analysis. The output of a quantitative risk assessment will typically be a number, such as cost impact ($) per unit time. The number could be used to prioritize a

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series of items that have been risk assessed. Quantitative risk assessment requires a great deal of data both for the assessment of probabilities and assessment of consequences. The procedure is presented in Fig. 1.

The first step involves the definition of the analysis scope that includes the study of the power plant and equipment operational procedures and federal legislation associated with power generation and distribution. The equipment analysis can be done through the use of functional tree that represents the functional links between the equipment subsystems, (DNV, 2002).

The second step involves the risk quantification that must be executed in two steps: equipment failure probability estimate and failure consequences analysis.

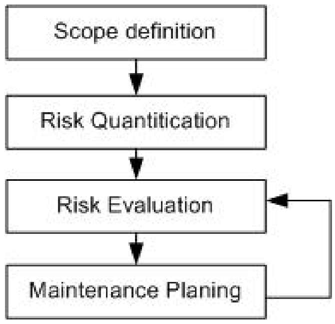

Figure 1. Risk Analysis Method

The equipment failure probability can be estimated based on 'time to failure' database developed by the power plant or even, in case of lack of information, based on equipment reliability database issued by international associations such as RAC (Seyedi *et al*, 2006).

The equipment failure consequences should consider the effects of the occurrence of a given equipment failure mode for the power plant operation according to the scope defined for the analysis. The Cause-Consequence Diagram can be used to qualitatively evaluate the equipment failure consequences. Once the failure modes are identified, they form a basis for defining the initiating events. The suggested methodology transforms these initiating events into risk measures or profiles. The consequence tracing part of the diagram involves taking the initiating event and following the resulting chain of events through the system. At various steps, the chains may branch into multiple paths. The consequence analysis results in a description of all relevant accident scenarios given the occurrence of the initiating event and is used to calculate both the likelihood and the consequences of each accident scenario. Fig. 2 shows the cause-consequence logic.

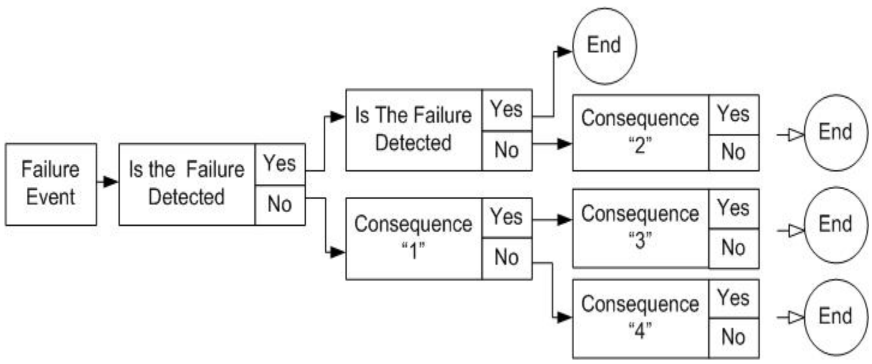

Figure 2. Cause-Consequence Diagram Logical Notation

Once the cause-consequence diagram are developed for the main equipment installed in a power generation plant, the risk analyst can select the most important equipment for plant operation using as prioritization criterion the severity of failure consequences. The higher that severity the higher is the priority of the equipment for maintenance planning.

For that equipment the maintenance planner can select the most feasible maintenance procedures aiming at the reduction of failure probability and consequently aiming at risk minimization.

The main causes of leakage (or main initiating events) are associated with terminal or ship pieces of equipment failures, such as cryogenic transfer arms, piping systems rupture or valves leakage. The paper applies structural reliability concepts to evaluate the probability of failure of a pipeline due to the occurrence of corrosion in the pipe inner wall.

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5.2 Consequence Analysis

To complete the risk analysis, the consequences of equipment failure must be expressed in some quantitative basis. Many aspects have influence on that cost evaluation such as terminal location and configuration, operational pattern and federal legislation. Additionally the costs of maintenance procedures may also be evaluated.

The main consequences associated with any leakage during loading or unloading operations are detailed analyzed in reference (Natacci *et al*, 2010) and (SNL, 2004). The magnitude of the consequences are associated not only with the type of fire (flash or poll fire) but also with atmospheric conditions of the area where the leakage occurs, such as temperature, humidity and wind speed, that affects the vapor cloud formation and dispersion.

5.3 Probabilistic Fracture Mechanics

During service, the remaining strength of pipelines depends on number factors, including the operational conditions, and defects introduced by construction, corrosion, etc. Corrosion is of concern because any loss of the pipe wall thickness means a reduction of pipeline structural intensity and hence an increase in the risk of failure (Li *et al*, 2009).

Corrosion can cause several kinds of defect on pipelines. The reduction of the wall thickness of pipe in a large area is general corrosion, which usually results in a low risk of failure. However, defects due to localized corrosion have a high failure risk to the pressurized pipelines. Generally, a defected pipeline due to corrosion is allowed to operate after the reliability assessment to recalculate its maximum allowable operating pressure. Models have been developed to estimate the remaining strength of pipelines by calculating the failure pressure in the presence of local corrosion defects. The remaining strength of corroded pipelines can be estimated using technique ASME-B31G standard, has been used widely (Qian *et al*, 2011).

For pressurized pipelines, circumferential crack like corrosion defects have little effect on the failure probability compared to longitudinal ones. Hence attention will be given here only to longitudinal surface corrosion defects existing in the wall of a typical pressurized pipeline, as can be seen in Fig. 3. In the figure, t is the pipe wall thickness, d is the defect depth and L is the length of the corroded region projected on the longitudinal axis.

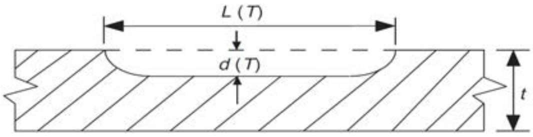

Figure 3. Pipeline wall section with an idealized corrosion defect (Qian *et al*, 2011).

Failure pressure model for pipeline is ASME-B31G (1995) standard. The strength of a corroded pipe is assumed to be function of pipe dimensions and ultimate tensile strength of pipe material. The failure pressure can be expressed as:

$$p_f = \frac{2(\sigma_{ys} + 68.95)t}{D}\left[\frac{1-\frac{d(T)}{t}}{1-\frac{d(T)}{t}M^{-1}}\right] \qquad (2)$$

where p_f is the failure pressure, D the pipe diameter, t the wall thickness, $d(T)$ the time-depended depth of the defect. T is the elapsed time and M is the building factor.

Expressions for the building factor or Folias factor are:

$$M = \sqrt{1+0.6275\frac{L(T)^2}{Dt} - 0.003375\left(\frac{L(T)^2}{Dt}\right)^2}, \qquad \text{if } \frac{L^2}{Dt} \le 50 \qquad (3)$$

$$M = 3.3 + 0.032\frac{L(T)^2}{Dt}, \qquad \text{if } \frac{L^2}{Dt} > 50 \qquad (4)$$

For a quasi-steady corrosion process, the time-dependent depth $d(T)$ and $L(T)$ can be determined by:

$$d(T) = d_0 + V_R(T - T_0) \qquad (5)$$

$$L(T) = L_0 + V_A(T - T_0) \qquad (6)$$

where d_0 is measured depth of the defect at time T_0, L_0 is measured surface length of the defect at time T_0, V_R is the radial corrosion defect growth rate and V_A axial corrosion defect growth rate.

Based on the structural reliability theory, the limit state functions Z is defined by the difference between the pipeline failure pressure p_f and the pipeline operating pressure p_a, given as:

$$Z = p_f - p_a \tag{7}$$

If $Z>0$, the pipeline can operate safely. If $Z<0$, plastic collapse occurs, which defines the failure domain. The failure probability of the pipeline can be written as:

$$P_F = P(z \leq 0) \tag{8}$$

where P_F is failure probability of the pipeline.

To calculate the failure probability the Monte Carlo technique is used because of its generality and easy implementation. Conceptually, Monte Carlo techniques are straightforward to visualize. A value of each input random variable is selected at random from its distribution. The randomly sampled input variables are used to calculate a value of the dependent variable, in the present case, the value of Z. If Z is smaller than 0, the result is a failure. On the contrary, the structure is considered safe. This is repeated many times, and the probability of failure is defined as the relation between the number of trials when $Z < 0$ and the total number of trials (Qian *et al*, 2011).

6. CASE STUDY

The present study analyzes the operation of a LNG carrier in a terminal that can be located onshore or offshore once those operations are not dependent on ship type or terminal location. The failure scenario initiates with the presence of a defect caused by corrosion which is the initiating event for pipe rupture.

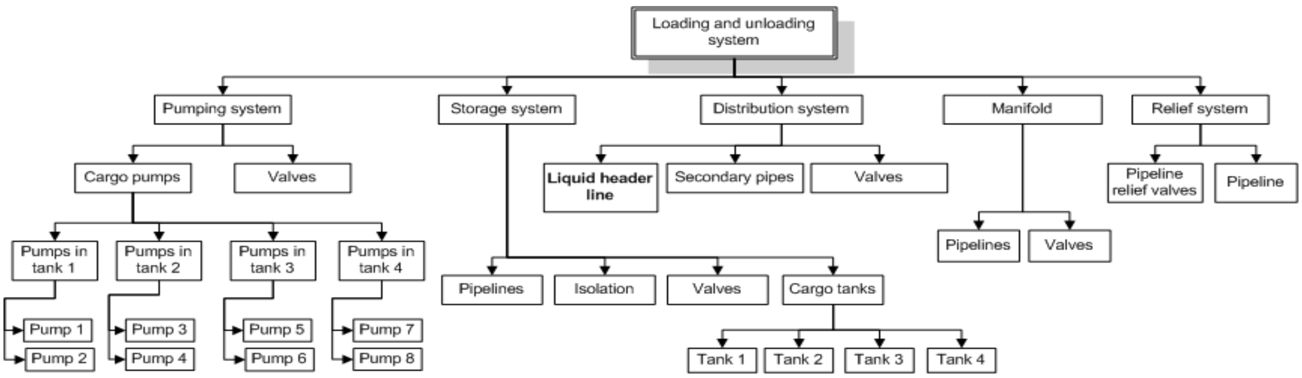

Figure 4. Functional tree for the loading and unloading system

For any LNG carrier, the loading and unloading system is composed by sub-systems as for example: pumping, storage, distribution, relief system and the manifold. Every sub-system has its own components. In this work is analyzed the liquid header line, component that is part of the distribution system and is showed in Fig 5. The Figure 4 presents the functional diagram used to define the functional relations of the components used in the cargo handling system.

The cargo system diagram is showed in the Fig. 5. In the liquid header line are installed two relief valves with set up pressure of 1 MPa. The usual operating pressure of this pipe during loading and unloading is 0,1 MPa. The storage system of the ship under analysis consists of four insulated cargo tanks, separated from each other by transverse cofferdams, and from the outer hull of the vessel by wing and double bottom ballast tanks. Inside these tanks are fitted 2 centrifugal submersed pumps with similar capacity that are use when the LNG is unloaded. These pumps are single stage centrifugal pumps with one inducer stage

All of the cargo piping is welded to reduce the possibility of joint leakage. Flanged connections are electrically bonded by means of straps provided between flanges to ensure that differences in potential, due to static electricity between cargo and other deck piping, tanks, valves and other equipment, are avoided.

All sections of liquid line outside the cargo tanks are insulated with rigid polyurethane foam, covered with a molded protection to act as a tough water and vapor tight barrier.

The liquid header line is the pipe where the liquid LNG coming from all the four tanks discharge. The principal characteristics of this pipe are showed in the Table 1.

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Table 1. Characteristics of the liquid header line.

Item	Description
Material	Stainless steel 304L
Diameter	600 mm
Thickness	6,35 and 9,53 mm
Pressure	0.1 and 1 MPa
Fluid temperature	-162 °C
System	Distribution system

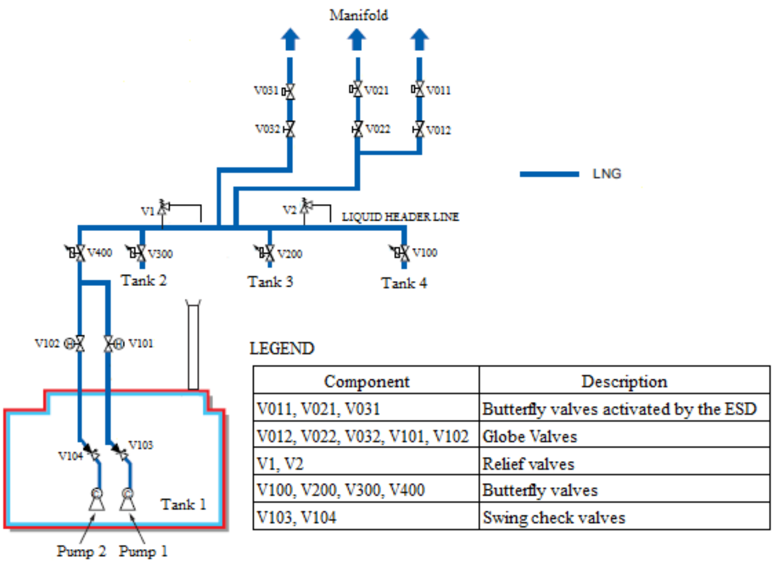

Figure 5. Cargo system diagram

6.1 Probabity of occurrence of the initiating event

The probability of corrosion failure is evaluated for the liquid header line which is used to distribute the liquid to secondary piping system that feeds the storage tanks. The header failure can cause a large leakage once it carries all liquid flow from or to the storage tanks.

The present analysis considers two loading conditions, represented by the header internal pressure, which are: 0.1 MPa and 1MPa. In the second case it is considered the possibility of high pressure acting on the header pipe.

The random variables considered in the analysis are presented in Tab. 2 supposed uncorrelated. The statistical properties of the pipe thickness are based on information provided by manufacturer, such as reference (ASMC, 2011). The normal distribution is used to model thickness variation in accordance with quality control process hypothesis, (Montgomery, 2009).

Table 2. Random variables used in the model.

Parameters of the Random variables	Mean	Cov	Distribution
Thickness (t)	6.35mm	0.05 (1)	Normal
	9.53mm	0.05 (1)	Normal
Operating Pressure (p_a)	0.1 MPa	0.1 (2)	Normal
	1.0 MPa	0.1 (2)	Normal
Initial depth of the defect (d_0)	3 mm	0.1 (3)	Normal
Initial length of the defect (L_0)	200 mm	0.05 (3)	Normal
Diameter (D)	600mm	0.03 (3)	Normal
Yield stress (σ_{ys})	241 MPa	0.067 (1)	Lognormal
Radial corrosion rate (V_R)	1.5 mm/year	0.2 (3)	Normal
Axial corrosion rate (V_A)	1.5 mm/year	0.2 (3)	Normal

Notes: (1) Based on pipe manufacturer catalogue, (ASMC, 2011)
(2) Estimated based on pressure gauge precision and accuracy
(3) Estimated by authors based on reference (Ahammed, 1998)

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The statistical properties of the external loading acting on pipe, represented by internal pressure magnitude, are defined based on the study of precision and accuracy of pressure gauges used to monitor that variable. The composition of those properties defines the repeatability, modeled by normal distribution, and defines the variability of the measurement obtained by the gauge.

The inspection was carried out when the pipeline service life was 10 years (T_0) with a time interval of 5 years. The defect depth (d_0) and the defect length (L_0) were then 3 and 300 mm, respectively, the steady state both radial (V_R) and axial corrosion rate (V_A) was estimated at 0.10 mm/yr.

The reliability analysis used Monte Carlo simulation with 16000 trials to guarantee the convergence of the probability of failure estimate.

The probability of corrosion failure for the thickness of 9.53 mm submitted to the normal operation pressure (0.1 MPa), the failure probability is very small to 0.098 for 60 years. For the same years, but considering the thickness of 6.54mm, the corrosion failure probability is 0.94.

Taking in view that the pipe could be submitted to higher pressure magnitude, equal to 1 MPa, the corrosion failure probability is presented as a function of the exposure periods in Figs. 6 and 7, respectively for pipe thickness of 6.35 mm and 9.53 mm.

The failure probability of the pipeline was evaluated for various values of exposure period (T). This is shown graphically in Fig. 2 and Fig.3. It can be seen from this figure that the failure probability increases with increased exposure period. This is as expected and may be explained in the following way. With increased exposure period, the area of defect increases, resulting in a decrease in net effective area and hence the capability of the pipeline to resist the effect of stresses generated by external loads is also reduced. In other words, this increases the severity of the circumferential stress leading to an increase in failure probability of the pipeline.

Reliability analysis can be used to assess the safety and integrity and also to predict the remaining or remnant life of a corroded pipeline with further corrosion growth. The resulting information can be used to predict safe operating pressures at any time and to adjust the operating pressure accordingly or to prepare effective and economic inspection, repair and replacement operation schedules.

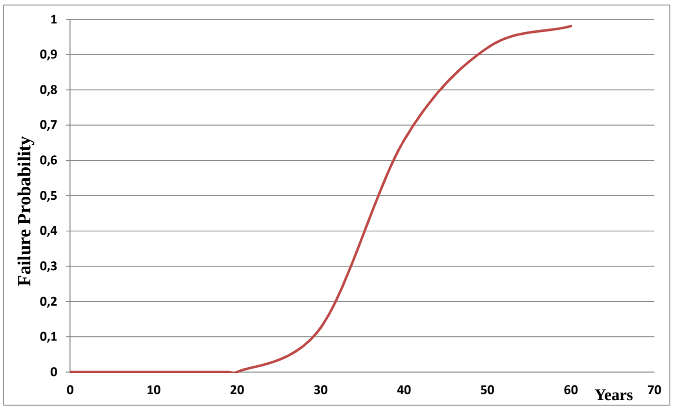

Figure 6. Probability of failure (P_F) versus Exposure periods (T) for 6.35mm pipe thickness

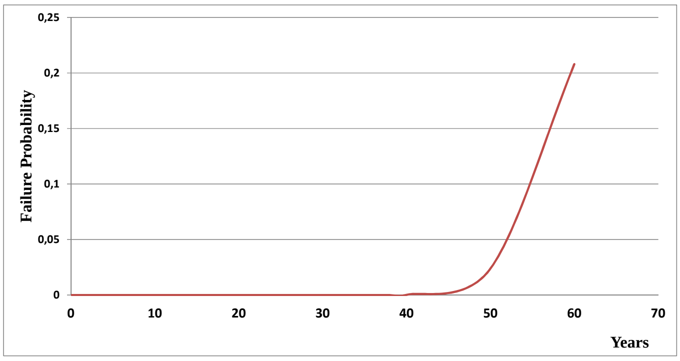

Figure 7. Probability of failure (P_F) versus Exposure periods (T) for 9.53mm pipe thickness

To check the convergence of Monte Carlo simulation process used to estimate failure probability, the number of simulation cycles was varied from 1,000 to 21,000 for the thinner pipe (thickness equal to 6.35 mm). As for example, the result is presented in Fig. 8 for 30 operating years and internal pressure of 1MPa. In those figures it is possible to

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verify that the failure probability estimate converges for more than 17,000 trials that are smaller than the 19,000 trials simulation cycle used in the present analysis, even for small failure probabilities.

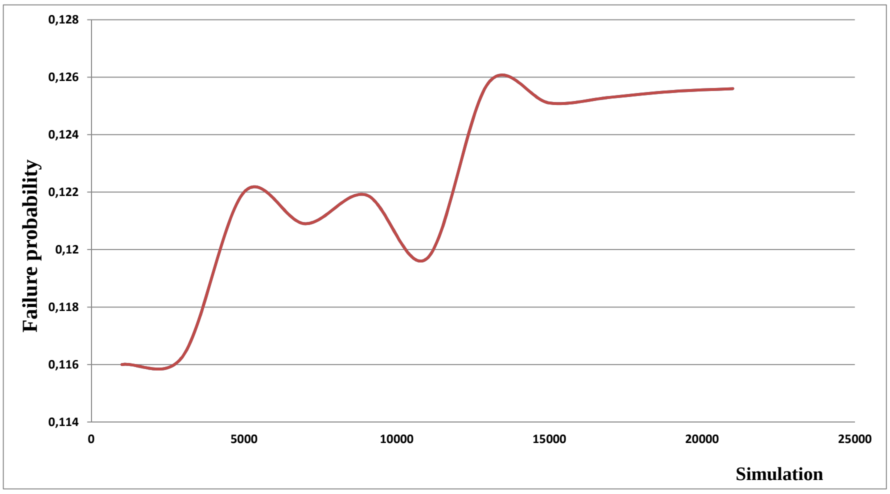

Figure 8. Probability of failure (P_F) as a function of Monte Carlo simulation cycle for 30 operating years

6.2 Cargo control system

The cargo plant is remotely controlled from the Integrated Automation System (IAS) system with control and monitoring performed from the cargo control room. The IAS system is made up of operator and history stations. The operator stations are the main interface between the operator and the processes under the operator's control and the history station is a specific computer on the network which runs the operator station software, it also contains the historical database, storing information regarding the process control parameters.

All major valves such as the mid ship manifold valves, also called ESD Manifold valves, and individual tank loading and discharge valves, are remotely power operated from the IAS, so that all normal cargo operations can be carried out from the cargo control room.

6.3 Gas detection system

The LNG ship has a system that is used to alert the presence of gas, especially in spaces where gas is not normally expected.

Inside the ship there are two completely separate gas monitoring/trip systems. One is the gas sampling system which monitors from sampling points in the hazardous gas zone and the other is the gas detection system which monitors non-hazardous gas zones. In the event of gas being detected, alarms are activated indicating that there is a vapor leakage. There are 34 external sampling points on board. The entire cargo piping system and cargo tanks are also considered gas dangerous areas.

6.4 Emergency shut down

The Emergency Shut Down (ESD) system is used as a safety barrier. The ESD is fitted to protect the ship and terminal in the event of fire risk (Cheng *et al*, 2009). In case of the LNG leakage, the ESD system can be automatically activated to isolate the loading and unloading system or stopping the process by shutting down the primary pumps or closing the ship-side valves located in the manifold V011, V021, V031 in the Fig 2. This system is one of the most important for achieving the security and deserves particular attention because under hazard conditions this system must be activated and it must work.

This emergency system can fail causing severe consequences. According to OREDA (2002) the failure rate of the valves is 54,23x10-6 failure per hour in the case of fail to close on demand. In the case of the centrifugal submersed pumps the failure rate is 1,55x10-6 failure per hour in the case of fail to stop on demand. In the case of power failure the loading or unloading operations is also paralyzed.

As for reliability analysis, for twenty four operational hours (the usual LNG transfer time in terminal), each valve reliability value should be estimated as 99.9963%, modeled with an exponential distribution. That value can be considered a lower bound estimate once all components of the ESD are tested before the loading or unloading operations are started aiming at verifying their availability and guaranteeing the operational safety of ship and terminal equipment.

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6.5 Cause consequence diagram

The consequences of the occurrence of the LNG leakage depend on the reliability of the safety system. The cause-consequence diagram was applied to analyze the sequence of events resulting from the occurrence of an LNG leakage in the liquid header line during loading or unloading operations. This initiating event could develop into a serious consequence or the event is sufficiently controlled by the safety systems. The diagram was not completely developed once the fault tree analysis associated with each “box” in the diagram is still being developed and will be presented in future works.

In the case of the presence of a small defect caused by corrosion which is the initiating event for a small LNG spill. In this particular case there is no formation of pool below the site of the leak because the liquid will quickly vaporize and a cloud close to the leakage point may be observed. The failure scenario will dependent on the operation of the ESD system, on the presence of a ignition source, on the gas concentration and on cloud dispersion dynamics associated with local atmospheric conditions.

In the case of fracture caused by corrosion the amount of liquid spilled is much greater and there will be a formation of a LNG pool close to the failed pipe. The dynamics of the vapor cloud formation will be dependent on the atmospheric conditions but in case of ignition there would be a pool fire that could cause severe consequences for terminal and ship, including operational crew, due to high levels of radiation (Natacci *et al*, 2010).

If the safety systems work successfully, they stop the accident scenario but in the case that the safety systems fail to work, the accident scenario is allowed to progress and is referred to as an aggravating outcome event. These safety systems are the control and monitoring modulus of the cargo control system (IAS) and the gas detection system. Both of them activate the Emergency Shut Down.

The possible sequences of the events caused by the header failure, considering the presence of a defect caused by corrosion are showed in the cause-consequence diagram presented in the Fig. 9.

The first scenario considers the presence of a through thickness crack in the header (without brittle failure) and that the IAS operates normally, not causing important consequences because once the ESD is activated. In this case the pipeline must be isolated and the leakage is controlled and the operation must be stopped.

The second scenario is when after the LNG leakage, the IAS will not detect the variation of the operational parameters such as pressure, temperature and flow. If a variation of these parameters is not detected by the IAS the ship has a gas detection system which works and consequently the ESD is activated, causing the complete stop of the loading or unloading operations.

The third scenario takes place if one of those safety systems does not activated the ESD. In the place where is located the crack is located a vapor cloud can be formed. If the vapor concentration is between the low and upper flammability limit but in the absence of an ignition source the vapor will disperse into the atmosphere without causing effects. This dispersion dilutes the vapors bellow a flammable concentration preventing the ignition. The downwind distance that flammable vapors might reach is a function of the volume of LNG spilled, the rate of the spill, and the weather conditions.

The fourth scenario has the same sequence of the third scenario but the difference is that the flammable vapor cloud is ignited by an energy source that could come to the ship or to the terminal. In this moment the result was an ignition of the flammable vapor-air mixture in open areas and an ignition with explosion in close areas, this happen if the concentration of vapor-air is within the lower and the upper flammability lever. The flame will burn back to the vapor source, and the flammable cloud would not travel a significant distance. The LNG vapors can explode if ignited within a confined space, such as a building or structure (ABS Consulting, 2004).

If the header presents a corrosion fracture failure even if the EDS systems works perfectly there will be a great amount of LNG that will leak from the header. That condition will cause the formation of a cloud and the consequences are similar to those described in the third and fourth scenarios associated with cause consequence diagram presented in Fig. 8.

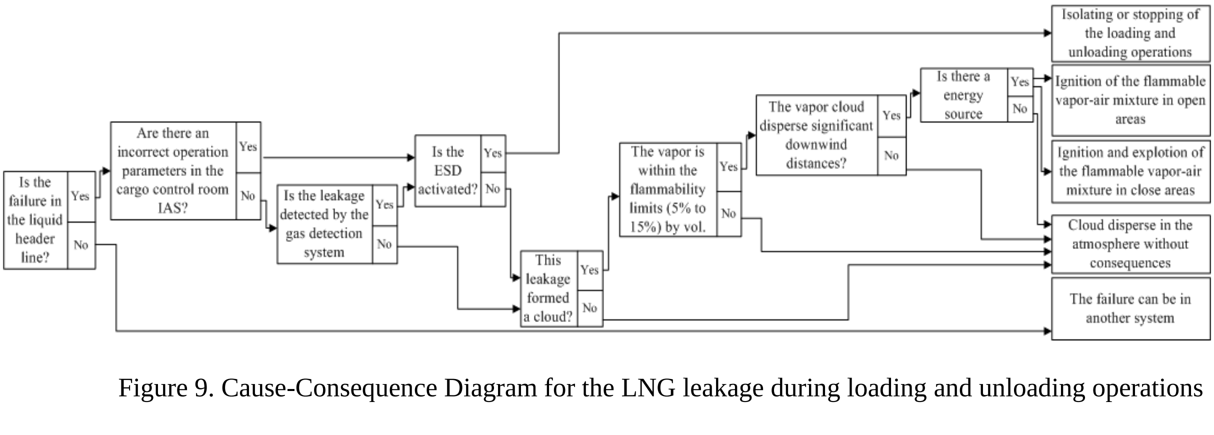

Figure 9. Cause-Consequence Diagram for the LNG leakage during loading and unloading operations

In the case of an ignition, the consequence will be similar to those described in Natacci *et al* (2010), causing pool fire and flash fire which effect will reach distances far from the point of leakage, depending on the amount of liquid spilled. The analysis in that reference is developed for a flow rate of 10000 m^3/h and that the leakage is associated with one minute flow. According to that reference a distance of 510 m and 475 m can be affected by the flash fire and by the pool fire.

Other problem associated with the occurrence of fire is the possibility of collapse of the ship tanks. The severity of consequences increases dramatically in case of rupture of storage tanks, as shown in Natacci *et al* (2010). That severity is measured by the distance from the leakage point affect by fire radiation. In case of a rupture of one tank (with a volume of 26000 m3) the pool fire affected distance can be up to 2600 m.

7. CONCLUSIONS

The study presented in this paper is a first approach for failure scenario modeling associated with a rupture in the header line of LNG carriers.

The failure of a header line during loading or unloading operations of LNG carriers although has small probability of occurrence can cause severe consequences for the ship and for the terminal in case of fire.

Like in any industry which handles hazardous materials, the terminal and ship follows codes and standards that require the elaboration of emergency and contingency planning.

In case of header failure in absence of corrosion fracture, the ESD system plays an important role to minimize the consequences of liquid spill. That system is very sophisticated including gas and low pressure monitoring, heat and fire detectors and cargo-related shutdown devices. The system is capable of stopping the loading or unloading operation in one minute in case of gas or liquid leakage. That system is submitted to a sequence of testing procedure before the LNG transfer between ship and terminal is initiated aiming at checking the existence of hidden failures in control, monitoring and emergency valves systems, not only in the ship but also in the terminal.

Reliability analysis has been presented for the prediction of remaining strength of corroded pressurized pipelines and in particular the prediction of the maximum allowable operating pressure for any future period of such pipelines.

The B31G method was applied to an example corroded pressurized pipeline to evaluate the allowable pressures for different exposure periods and defect length. It was found that the level of allowable pressure is affected significantly by the exposure period, but not much by the defect length.

It has to be emphasized that all results presented in this paper aim at defining the probability of occurrence of an initiating event (header failure) that could cause LNG leakage and the possible failure scenarios associated with that event. However, the estimation of the consequences was not scope of this study, and the analysis is based on other results presented in literature.

8. NOMENCLATURE

t	Thickness
p_a	Operating Pressure
p_f	Failure Pressure
d_o	Initial depth of the defect
L_o	Initial length of the defect
D	Diameter
σ_{ys}	Yield stress
V_R	Radial corrosion rate
V_A	Axial corrosion rate
P_F	Failure probability of the pipeline
Z	Limit state function
M	Folias factor
T	Elapsed time
T_0	Time of last inspection
$d(T)$	Time-dependent depth of the pipeline
$L(T)$	Time-dependent surface length of the pipeline

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