BACHELOR THESIS & COLLOQUIUM – ME184841

INSPECTION PROGRAM PLANNING OF PROCESS GAS PIPING USING RISK BASED INSPECTION API 581 IN MUARA KARANG PEAKER GAS METER

ADE RATIH ANGGRAINI
NRP. 04211641000008

SUPERVISOR :
Ir. Dwi Priyanta, M.SE.
Nurhadi Siswantoro, S.T, M.T.

DOUBLE DEGREE PROGRAM OF
DEPARTEMENT OF MARINE ENGINEERING
FACULTY OF MARINE TECHNOLOGY
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APPROVAL SHEET

INSPECTION PROGRAM PLANNING OF PROCESS GAS PIPING USING RISK BASED INSPECTION API 581 IN MUARA KARANG PEAKER GAS METER

BACHELOR THESIS

Submitted to Comply One of the Requirement to Obtain a Bachelor Engineering Degree
on
Laboratory of Marine Operational and Maintenance (MOM)
Bachelor Program Department of Marine Engineering
Faculty of Marine Technology
Institut Teknologi Sepuluh Nopember

Prepared By :
ADE RATIH ANGGRAINI
NRP. 0421641000008

Approved by Academic Supervisor:

Ir. Dwi Priyanta,M.SE.
NIP. 196807031994021001 ( )

Nurhadi Siswantoro,ST.,MT.
NIP. 1992201711049 ( )

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Prepared By :
ADE RATIH ANGGRAINI
NRP. 0421641000008

Approved by
Head of Marine Engineering Department

Beny Cahyono, S.T., M.T., Ph.D
197903192008011008

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DECLARATION OF HONOR

I hereby who signed below declare that:

This final project has written and developed independently without any plagiarism act. All contents and ideas drawn directly from internal and external sources are indicated such as cited sources, literatures and other professional sources.

Name	:	Ade Ratih Anggraini
Student Number	:	04211641000008
Final Project Title	:	Inspection Program Planning of Process Gas Piping Using Risk Based Inspection API 581 in Muara Karang Peaker Gas Meter
Departement	:	Marine Engineering

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Surabaya, January 2020

Ade Ratih Anggraini

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INSPECTION PROGRAM PLANNING OF PROCESS GAS PIPING USING RISK BASED INSPECTION API 581 IN MUARA KARANG PEAKER GAS METER

Name : **Ade Ratih Anggraini**
NRP : **04211641000008**
Department : **Marine Engineering FTK – ITS**
Supervisors : **Ir. Dwi Priyanta, M.SE.**
Nurhadi Siswantoro, ST., MT.

ABSTRACT

Nowdays, theusage of natural gas is very popular in the power plant industry compared to coal and oil. In 2016, natural gas-fired generators accounted for 42% of the operating electricity generating capacity in the United States. The use of natural gas is considered to be environmentally safe than coal and oil. Natural gas emits 50 to 60 percent less carbon dioxide (CO_2) when combusted in a new, efficient natural gas power plant compared with emissions from a typical new coal plant. Besides, the natural gas power plant has an efficiency of 53% when combined.

PT Nusantara Regas has an Onshore Receiving Facility (ORF) to flow the gas produced from the regasification process in the Floating Storage and Regasification Unit (FSRU) to three Power plants. One of them is PLTGU Muara Karang which capacity of 630 psi and 350 psi. In 2017, PLTGU Muara Karang will increase electricity capacity through Muara Karang Peaker MKP) which is planned to be operational in March 2020. One of the equipment at MKP that used to fluida is piping. When operating, and there is a failure in the piping that can effect in a gas explosion or flammable, this is caused by corrosion, over pressure or other errors that can damage the facility to shutdown the plant.

Based on the Regulation of Minister of Energy and Mineral Resources Republic Indonesi No.18, 2018 that every company engaged in the oil and gas processing industry must inspect on any equipment in the plan, which has a level of risk or failure that can affect the overall system performance. An accurate inspection and scheduling program is needed to guarantee the life of each equipment, ensuring the plant is safe and safe for workers. Therefore it is necessary to conduct a risk evaluation for Process Gas Piping equipment using the Risk Based Inspection (RBI) method that refers to API 581. RBI is a systematic approach to inspection management on static equipment according to the level of risk. The acceptable risk level is then made as a reference to determine the next inspection. Whereas for unacceptable risks mitigation efforts must be made.

In determining the risk ranking and inspections plan, the risk value is required, which is a function of the probability of failure and the consequences of failure, also requires risk targets from the company to determine when the next inspection will be carried out. The risk value based on the calculation of pipe 12" – PG – 06251 – C is 0,412162146 ft^2/year and for pipe 2" – PG – 06255 – C is 0,412173420 ft^2/year. Both of the pipes don't exceed the risk target and for the inspection carried out on March 24^{th}, 2023.

Key words - API 581, Peaker, Process Gas Piping, Risk - Based Inspection

PENJADWALAN PROGRAM INSPEKSI PADA PIPA GAS PROSES MENGGUNAKAN METODE RISK BASED INSPECTION API 581 PADA MUARA KARANG PEAKER GAS METER

Nama	**: Ade Ratih Anggraini**
NRP	**: 04211641000008**
Departemen	**: Teknik Sistem Perkapalan, FTK – ITS**
Dosen Pembimbing	**: Ir. Dwi Priyanta, M.SE.**
	Nurhadi Siswantoro, ST., MT.

ABSTRAK

Saat ini, penggunaan gas alam sangat populer di industri Power Plan dibandingkan dengan batu bara dan minyak bumi. Pada tahun 2016, sebanyak 42% generator berbahan bakar gas alam menyumbang 42% dari kapasitas pembangkit listrik yang beroperasi di Amerika Serikat. Penggunaan gas alam dianggap lebih ramah lingkungan dibandingkan dengan batu bara dan minyak. Pembangkit yang menggunakan gas alam menghasilkan 50% - 60% emisi karbon dioksida (CO_2) lebih sedikit dibandingkan dengan pembangkit batu bara ketika baru beroperasi. Selain itu, pembangkit listrik dengan gas alam memiliki efisiensi hingga 53% ketika digabungkan.

PT Nusanatara Regas mempunyai fasilitas Onshore Receiving Facility (ORF) yang digunakan untuk menyalurkan gas dari proses regasifikasi pada kapal Floating Storage and Regasification Unit (FSRU) ke tiga pembangkit. Salah satu pembangkit tersebut adalah PLTGU Muara Karang dengan kapasitas 630 psi and 350 psi. Pada tahun 2017, PLTGU Muara Karang berencana untuk menambah kapasitas listrik dengan menyalurkan ke Muara Karang Peaker (MKP) yang berencana akan beroperasi pada Maret 2020. Salah satu alat yang digunakan pada peaker adalah pipa. Ketika beroperasi dan terdapat kegagalan pada pipa dapat mengakibatkan ledakan gas atau kebakaran, hal ini dapat disebabkan oleh beberapa faktor yaitu korosi, overpressure dan faktor lain yang dapat menyebabkan fasilitas pada Plan tidak dapat bekerja.

Berdasarkan peraturan Menteri Energi dan Sumber Daya Mineral Republik Indonesia No. 18 Tahun 2018, bahwa setiap perusahaan yang bergerak di bidang industri pengelolaan minyak dan gas harus melakukan inspeksi terhadap setiap peralatan bertekanan yang memiliki tingkat risiko atau kegagalan yang dapat mempengaruhi kinerja sistem secara keseluruhan. Diperlukan program inspeksi dan penjadwalan yang akurat untuk menjamin umur masing-masing peralatan, memastikan instalasi aman terhadap Plan maupun bagi pekerja. Oleh karena itu perlu dilakukan evaluasi risiko untuk peralatan Pipa Gas menggunakan metode Risk Based Inspection (RBI) yang mengacu pada API 581. RBI adalah pendekatan sistematis untuk manajemen inspeksi pada peralatan statis sesuai dengan tingkat risikonya. Tingkat risiko yang dapat diterima kemudian dijadikan referensi untuk menentukan pemeriksaan selanjutnya. Sedangkan untuk upaya mitigasi risiko yang tidak dapat diterima harus dilakukan.

Dalam menentukan rangking risiko dan penjadwalan inspeksi berikutnya diperlulan nilai risiko, yaitu fungsi dari kemugkinan kegagalan dan konsekuensi kegagalan dan juga diperlukan risk target dari perusahaaan untuk menentukan kapan dilakukan inspeksi berikutnya. Nilai risk berdasarkan dari perhitungan pipa 12” – PG – 06251 – C adalah 0,412162146 ft^2/tahun dan untuk pipa 2” – PG – 06255 – C adalah 0,412173420 ft^2/tahun. Kedua pipa tersebut tidak melebihi risk target dan untuk pelaksanaan inspeksi berikutnya dilakukan pada 24 Maret 2023.

Kata kunci - API 581, Peaker, Process Gas Piping, Risk - Based Inspection

PREFACE

Praise be to God Almighty, for His blessings, the authors can finish "Final Project Proposal" of reports in accordance with a predetermined time. The final Project entitled "Inspection Program Planning of Process Gas Piping Using Risk Based Inspection API 581 in Muara Karang Peaker Gas Meter" is submitted as one of the graduation requirements for the bachelor program in Department of Marine Engineering, Faculty of Marine Technology, Sepuluh Nopember Institut of Technology Surabaya. The authors hope this report can be useful for readers and writers so that they can understand what considerations are used as a reference in making statements about the final project research and data collecting in a particular gas company.

In writing this bachelor thesis,the authors received support from several parties, and also thanks to the parties who have helped in completing the preparation of this report so that it can be realized include :

1. Allah SWT, the lord of the worlds, for the gracious mercy and tremendous blessing and the great lord of the Prophet Muhammad who gave us directions to the right path,
2. Beloved parents, for prayers and support both morally and materially so that this report is completed properly,
3. Beny Cahyono, S.T., M.T., Ph.D, as the head of Marine Engineering Department FTK – ITS,
4. Ir. Dwi Priyanta, M.Sc., as lecturer supervising the subjects of Bachelor Thesis that has taken the time to give guidance and direction in every workmanship.
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8. Pradnya Sasmita Andaka and Aditya Wicaksana, as alumnus of ITS who have assit the authors to complete the final project,
9. Shafira Rosyada, Madina Nur Pratiwi, Dzilfia Qurrotul'Aini, who supports and accomodate the author so this report is completed properly,
10. MOM Laboratory friends who given supports and guidance on the complete final project,
11. Other parties who play a role in completing this final project.

The author realize that many obstacles and limitations of science and insight, makes the final project imperfect. Therefore, constructive suggestions and criticism are expected for better writing in the future. The author also apologizes if in the process of carrying out this final project there are many intentional or unintentional mistakes. The author hopes that by writing of the Final Project can be useful and provide information to the reader.

Suaranaya, January 2020

Author

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CHAPTER I
INTRODUCTION

1.1 Background

To supply the demand for the electricity, especially in Jakarta, PLN cooperates with PT Nusantara Regas by providing gas to the power plant. Gas distributed to three power plants in Jakarta, UP PJB Muara Karang, UP PJB Muara Tawar and IP Tanjung Priok. Gas for supplying three power plants comes from LNG, which taken from PT Badak LNG then has passed the regsification process at FSRU (Floating Storage Regasification Unit). After the regasification process, gas flowed to ORF (Onshore Receiving Facility) in Figure 1.1 by 15 km subsea pipeline for metering. Gas distributes to three power plant after the metering process. The most significant gas distributes to PJB UP Muara Karang, with pressure 650 psi and 350 psi.

In 2017, PT PLN as the customer, request addition the amount of gas capacity which is planned to flow through Muara Karang Peaker (MKP) with maximum capacity is 500 MW. MKP planned, it would be operating at the beginning of 2020 [1]. To keep the performance of the gas supply, it is necessary to inspect equipment in each equipment, which one is piping.

Piping is one of the pressurised equipment used to drain fluid. A pressurised equipment has a different level of risk, risks that generally occur in power plants are gas leakage, fire and explosion. To prevent these risks, inspections are needed to reduce these risks.

Every company engaged in gas processing industry have an inspection on any equipment so as per rules and regulations implemented in Indonesia like Peraturan Pemerintah No. 11 Tahun 1979 which controls the work safety on the residential and processing of oil and gas has to be obeyed. Furthermore, based on the Peraturan Menteri Energy dan Sumber Daya Mineral (ESDM) No. 18 Tahun 2018 showing that the equipment installed in a gas plant must conduct an inspection either time-based or preventive inspection. According to the latest revision of Pedoman Tata Kerja (PTK)-041 SKK Migas Indonesia about the maintenance of oil and gas production facilities by implementing the scheduled inspection and planned maintenance.

The purpose of the inspection itself to ensure safety workmanship and workplace. In this case, the author offers a solution for doing an inspection schedule procurement using Risk-based Inspection based on API 581. Those inspection planning program chain is essential in order the risks of each equipment owned by the company can be prevented and run until the predetermined time.

Figure 1. 1 ORF PT Nusantara Regas[1]

1.2 Problem Statements

In the description above, we can determine the main issues that will be discussing more, as mentioned below :

1. How to calculate the Probability of Failure (POF) of Gas Process Piping using Risk Based Inspection (RBI)?
2. How to calculate the Consequence of Failure (COF) of Gas Process Piping using Risk Based Inspection (RBI)?
3. How to determine Risk Analysis of Gas Process Piping in Muara Karang Peaker Gas Meter?
4. How to determine the right inspection interval planning for the Process Gas Piping on the condition level using RBI method?

1.3 Scope Problems

1. Analysed Gas Process Piping in this research belong to Muara Karang Peaker, PT Nusantara Regas
2. The analysis of Gas Process Piping reliability based on American Petroleum Institution (API) 580 and 581.
3. In this calculation not including a particular cost calculation inside this inspection/research when applying the Risk Based Inspection.

1.4 Objectives

The author goals of doing this final project in Muara Karang Peaker Gas Meter, PT Nusantara Regas are as follows:

---

[1] Author’s Documentation

1. To determine the Probability of Failure (POF) and Consequence of Failure (COF) based on Risk-Based Inspection (RBI).
3. To assess the risk of Gas Process Piping in Muara Karang Peaker, PT Nusantara Regas using Risk-Based Inspection method.
4. To determine the right inspection plan and methodology using Risk Based Inspection based on American Petroleum Institution (API) 581

1.5 Benefits

This result of the research can be used as a reference for the company to implement the right type of inspection program and interval schedule of the inspection for Gas Process Piping in Muara Karang Peaker Gas Meter, PT Nusantara Regas.

1.6 Output

The output from this final project result ari spreadsheet modelling, each equipment risk level, and inspection plan.

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CHAPTER II
LITERATURE STUDY

2.1. Problem Overview

Nowdays, the usage of natural gas more efficient than coal or oil. Natural gas generates electricity by burning natural gas as their fuel. Natural gas emits 50 to 60 percent less carbon dioxide (CO_2) when combusted in a new, efficient natural gas power plant compared with emissions from a typical new coal plant [2]. Cleaner burning than other fossil fuels, the combustion of natural gas produces negligible amounts of sulfur, mercury, and particulates. Burning natural gas does produce nitrogen oxides (NOx), which are precursors to smog, but at lower levels than gasoline and diesel used for motor vehicles.

Besides the lower emissions, natural gas power plants have high thermodynamic efficiencies compared to other power plants. In 2016, natural gas-fired generators accounted for 42% of the operating electricity generating capacity in the United States. Natural gas provided 34% of total electricity generation in 2016, surpassing coal to become the leading generation source. The increase in the natural gas generation since 2005 is primarily a result of the continued cost-competitiveness of natural gas relative to coal[2].

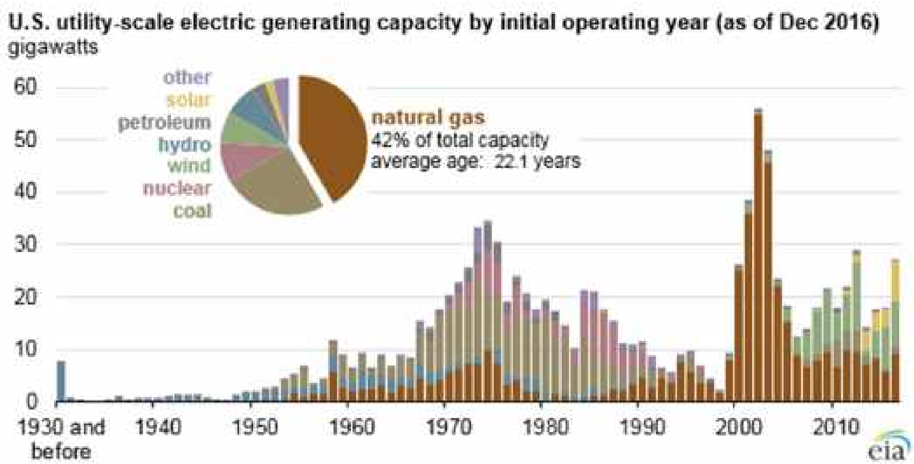

Figure 2. 1 Graphic of Types Power Plant Efficiency[3]

Based on the Regulation of Minister of Energy and Mineral Resources Republic Indonesia No. 01 Tahun 2013, the government limits the use of fuel oil, especially in power plants to reduce emissions. Therefore, there are currently many power plants that

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[2] Source : https://www.eia.gov/todayinenergy/detail.php?id=34172
[3] Source : U.S. Energy Information Administration

use natural gas as combustion. One of them is PLTGU Muara Karang, which operated since 1978. Starting from 2013, PLTGU Muara Karang Recive gas from the FSRU Jawa Barat managed by PT Nusantara Regas.

Besides to supply the PLTGU Muara Karang, PT Nusantara Regas also provides gas to the PLTGU Muara Tawar and PLTGU Tanjung Priok. The most significant gas distributed to PLTGU Muara Karang with pressure 620 psi and 350 psi. In 2017, PT PLN as the customer request addition the amount of gas capacity which is planned to flow through Muara Karang Peaker (MKP) with maximum capacity was 500 MW[4]. MKP proposed it will be operating in the March 2020.

Although not yet operational, it is necessary to schedule an inspection for the future, especially on piping equipment because the pipe has an important role which is to flow the fluids. Determining the correct inspection can reduce the level of probability of failure.

According to data record by Pipeline and Hazardous Materials Safety Administration (PHMSA), since 2010, there ave been 4,215 pipeline incidents resulting in 100 reported fatalities, 470 injuries, and property damage exceeding $3.4 billion. Rates exceeding 1.9 incidents per day in 2014 and 2015 have brought the average rate up to 1.7 incidents per day, and in 2016, incidents have been a bit less frequent [3].

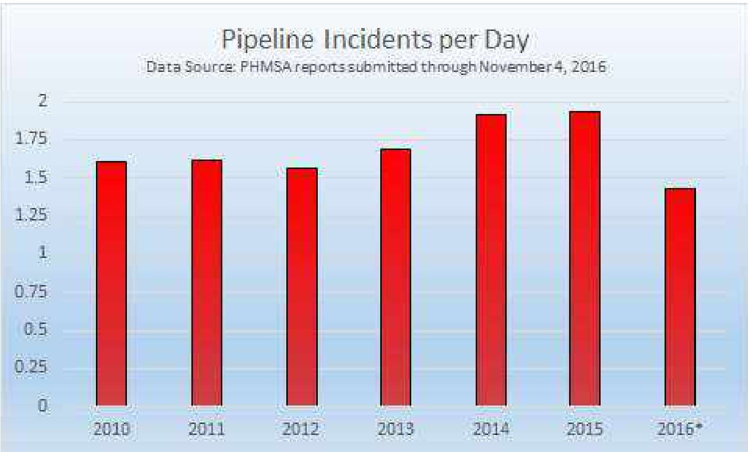

Figure 2. 2 Pipeline Incidents per Day

There was an incident that was caused by an inspection eror. The incident of natural gas pipeline happened on December 11, 2012, at 12.41 p.m eastern standard time. A pipeline owned and opererated by Columbia Gas Transmission Coorporation with 20 inch diameter was ruptured near a sparsely populated area in Sissonville, West Virginia. The effect of this accident, three houses were destroyed, and the fire ignited

[4] Source : https://finance.detik.com/energi/d-4646934/satu-unit-pembangkit-500-mw-dibangun-di-pltgu-muara-karang

approximately 76 million standard cubic feet of high-pressure natural gas, which was released and burned an area 820 feet wide and 1,100 feet along the pipeline right-of-way. The costs were spent on pipeline repair about $8.4 million, and for the damage, cost caused release gas about $8.4 million [4]..

The primary source of this inccident was external corrosion of the pipe wall due to deteriorated coating and ineffective cathodic protection, and the pipeline was not inspected since 1988. The responsible of the employee about inspection and maintenance was questionable and capable of influencing the perception of the stakeholders[5].

Another incident happened in April 2016, in Honglian south community of Haidian District. The natural gas pipeline was ruptures, the flammable gas spread around and leading to gas explosion due to maintenance staff misread the construction drawings because of this incident, one person was kiled, and two were injured [5]**.**. The last incident happened in July 30, 2004. In Ghislenghien, Belgium, the underground gas pipeline was leakage and explosion due to external corrosion. The consequences Five employees kiled and 132 injured [6].

Figure 2. 3 Ruptured Pipe *[7]* **.**

According to data reported by PHMSA, there are several cause of pipelines incidents; Equipment failure is the first cause, and the second is corrosion failure. And several incidents in above because of corrosion. In the figure, 2.4 containts the cause of pipeline incidents [8] .

To prevent damage mechanism such as corrosion and cracking, effective inspection planning needs to be done to reduce the existing risk. Previously the inspection applied to the MKP facility was Time Based Inspection, because it is less effective then

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[5] National Transportation Safety Board, Columbia Gas Transmission Corporation Pipeline Rupture

another inspection is needed, namely Risk Based Inspection (RBI). There are literature studies that explain the successful implementation of RBI.

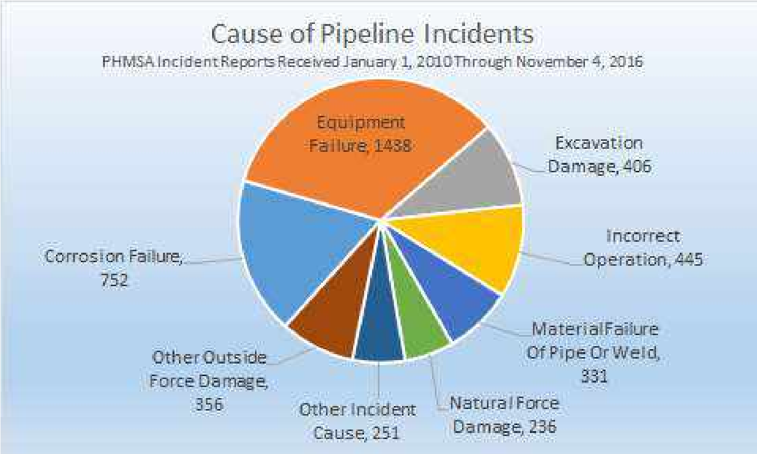

Figure 2. 4 Cause of Pipeline Incidents[6]

The Illinois Refining Division (IRD) of Marathon Petroleum Company LP, started a new mechanical inspection in 2009. The goal of the RBI was to suplement the existing time based inspection intervals defined in API 510 and focus their inspection efforts. Over three years, RBI analysis has been complete on the majority of process units at the facility. Through training, planning and scheduling, the RBI program at IRD has had a successful implementation. The RBI program is believed to have reduced operating risk, optimised inspection activities, and created a forum for information sharing as the API 581 methodology has been applied at IRD [9].

Based on the success story above, the implementation of RBI is beneficial to apply. RBI has been used to the previous facility, which is piping which flows fluid to Muara Karang. However, at the MKP facility, because it is still a new facility and has not yet operated, it is necessary to analyse the inspection for the future.

Implementation of Risk-Based Inspection method has several benefits to be able to increase the inspection effectiveness. Efficiencies such as a more-cost effective alternative to traditional inspection, usually using Non-Destructive Test (NDT). The output of an RBI assessment, identifies risk driver, inspection interval, and risk mitigation.

RBI would not eliminate risks. So that, probabilities and risk consequences of the equipment will always be included. RBI is useful to help manage and control risks to an acceptable level by prioritising resources to equipment which has high risk and worse subsequent impact.

[6] Source : https://www.fractracker.org/2016/11/updated-pipeline-incidents/

2.2. Gas Process

PT Nusantara Regas is a company running mainly on LNG (Liquified Naural Gas) regasification and gas sales business. Its primary customer is PT. PLN, which is the most significant national company responsible for national electric power. The whole business is a development of the government's intention to switch energy source in term of power generation, especially for the Jakarta region. Before this project was commencing, the energy source for power generation in Jakarta used diesel oil. The escalating price of diesel oil and environmental issue due to its usage led the government to search for a new and cleaner energy source. Natural gas was dee as a suitable substitution to the diesel oil.

The business process of PT. Nusantara Regas starting from buying LNG in PT Pertamina, then take it from Badak LNG, Tangguh or Donggi Senoro, after that is transport to FSRU(Floating Storage Regasification Unit) Nusantara Regas Satu by LNG carrier for regasification process. The end of regasification proceess in FSRU, gas transferred to the ORF (Onshore Receiving Facilities) via 15 km subsea pipeline, then from ORF will be transmitt to customer and metering for pay gas bill. The process of LNG regasification gas selling describes in Figure 2.5.

Figure 2. 5 LNG Regasification Gas Selling[7]

2.3. Regasification Process

Regasification is a process of converting LNG at -160ºC temperature back to natural gas at atmospheric temperature. Regasification process in the FSRU Nusantara Regas Satu divided in to three operations, LNG loop, propane loop and seawater loop, in Figure 2.6 show the regasification system and Figure 2.7 – 2.9 there will describe three processes of regasification.

2.4. LNG Loop

Figure 2. 6 LNG Loop

[7] Source : Company's Database

In LNG loop, the process starting from liquid LNG that processed from suction drum until the natural gas flowed to shore. In Table 2.1 below will describe the LNG loop process

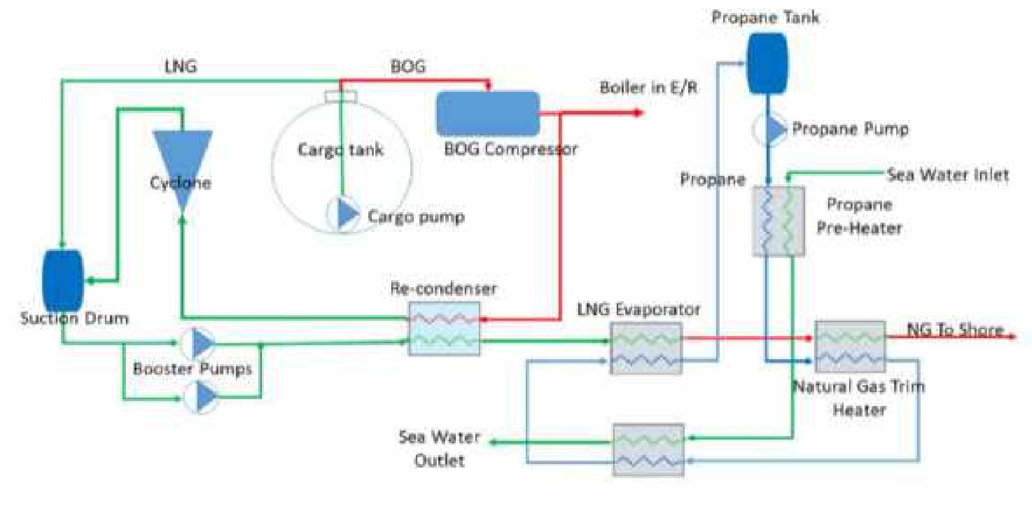

Figure 2. 7 Regasification Sytem[8]

2.5. Propane Loop

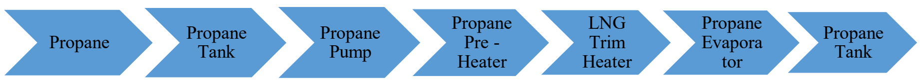

Figure 2. 8 Propane Loop

The propane system is a closed loop circulation where propane used as an intermediate heating medium between seawater and LNG. The volume of the propane tank is 4.4 m^3 and the temperature design of the propane tank between 45^{O}C - 65^{O}C. Propane tanks equipped with temperature, pressure and level transmitter which provide input to control the propane circulation rate. The description of propane loop, available on Table 2.2.

2.6. Sea Water Loop

Figure 2. 9 Sea Water Loop

[8] Company Database

The seawater supplied to the regasification plant at a pressure of about 2.2 bar. The seawater system has no control loop, but utilise the seawater at whatever temperature it has. The seawater flows in parallel to the propane evaporators and the propane pre-heater. The detail description of sea water loop shown in the Table 2.3

Table 2. 1 LNG Loop Description

No.	Process Name	Description
1.	LNG	Processed of natural gas to remove impurities and heavy fraction hydrocarbons then condensed into liquid on atmospheric pressure by cooling into -160ºC. LNG from Badak NGL carried out by LNG carrier, after that by ship to ship method LNG transfered to FSRU cargo tank.
2.	Cargo Tank	LNG is transfered from FSRU cargo tank number 1,2 and 3 using production pump. This transported liquid is then momentarily stored in a suction drum.
3.	Suction Drum	The suction drum is a tank device with the primary purpose as a buffer for LNG stock to regas skid. It also has a vapor-liquid separation function which is useful for pump performance. The buffered LNG is then sucked out from the bottom of the suction drum by a booster pump.
4.	Booster Pump	The booster pump is an in-tank cryogenic centrifugal pump whose purpose is to give pressure to the LNG to obtain absolute gas pressure at the end of the regas skid. LNG is pumped by booster pump to re-condenser
5.	Recondenser	Re-condenser is a typical heat exchanger that exchanges heat between liquid LNG and Boil Off Gas (BOG) from tanks or suction drum. The BOG will revert to liquid form as it passes this heat exchanger.
6.	LNG Vaporizer	LNG from the booster pump pass through recondenser to LNG evaporator and change into natural gas. Temperature inlet : -160 ^{O}C and outlet: -20 ^{O}C. Pressure outlet: 54- 64 barg.
7.	NG Trim Heater	Natural gas from LNG evaporator will be reheat in NG trim heater with propne. Pressure outlet: 45-64 barg. Temperature outlet 30 ^{O}C
8.	NG to Shore	Gas from NG trim heater flowed into manifold sent out and flowed to ORF by riser and subsea pipeline.

Table 2. 2 Propane Loop Description

No.	Process Name	Description
1.	Propane	Propane is heating, evaporating and superheating LNG of temperature - 160°C to NG of temperate of 17.5°C in the LNG evaporator and the NG trim heater.
2.	Propane Pump	When the flow rate in LNG evaporator increased, flow thermo – siphon propane will be low automatically, and propane pump will be turned on. Propane pump as equipment for propane circulation at closed loop system.
3.	Propane Pre - Heater	Every train in FSRU consists of one propane pre– heater. Pressure design in 125 bar and temperature design - 45°C until 70°C.
4.	LNG Trim Heater	In NG trim heater, gas from LNG evaporator/vaporiser will be heating by propane. The inlet temperature is -20^{O}C and outlet 27^{O}C. Pressure design in LNG 118 bar and propane 25 bar.
5.	Propane Evaporator	In LNG evaporator, propane exchanges heat with LNG. Because of the exchange with LNG, propane condensed into liquid and re-entered the propane tank.
6.	Propane Tank	Propane that condensed due to exchanging heat with LNG in the LNG Evaporator flows back to the propane tank.

Table 2. 3 Sea Water Loop Description

No.	Process Name	Description
1.	Sea Water	Sea water supplied to regasification with pressure 2.2 bar. Sea water system doesn't have loop control, so using sea water temperature at that time. Seawater heat is used to heat propane in the propane pre-heater and the propane evaporator.
2.	Sea Chest	Sea water flow through sea chest (port and starboard) in the FSRU engine room.
3.	Sea Water Line	Sea water flows to regasification system through the sea water line.
4.	Propane Pre-Heater	Sea water heating propane in propane preheater.
5.	Propane Evaporator	Sea water reheats propane in propane evaporator
6.	Outlet	Sea water flows to the outlet and flows to the sea

2.7. Muara Karang Peaker (MKP) :

Located in Muara Karang, Jakarta Utara, ORF of PT Nusantara Regas distribute the most significant gas to PJB UP Muara Krang with pressure 620 psi and 350 psi. In 2017, PT PLN as the customer request addition the amount of gas capacity which is planned to flow through Muara Karang Peaker with maximum capacity was 500 MW[9]. MKP designed will be operating at the beginning of 2020. While peaker is power plants that generally run when there is a high demand for electricity [10]**.** There are several types of peaker :

A. Gas Turbine :

Typically using natural gas as combustion, but several of peaker using biogas or liquid petroleum such as diesel oil and jet fuel. Comparing with biogas or petroleum, natural gas more low capital cost and relatively high fuel costs, which means they are most cost-effective as peaking power plants that run only intermittently. But, gas turbine tends to be natural gas fired smaller units, which adjust quickly and efficiently to changing loads. Historically, both steam and gas-turbine plants have had similar efficiencies, typically in the low 30% range [10].

B. Pumped Storage Hydroelectricity :

Storage energy in the form of the potential power of water that pumped from a lower reservoir to a higher level reservoir. Providing the most significant capacity of energy, usually used when electricity in off peak time and categorised as cost electric power. During the periods of high power demand, the stored water is released through hydro turbines to produce electric power. Typical of pumped storage hydroelectricity is wind and solar photovoltaic power options for transferring water from lower to the upper reservoir. The technique is currently the most cost-effective means of storing large amounts of electrical energy, but capital costs and the presence of appropriate geography are critical, decisive factors [11].**.**

C. Batteries :

Used in several conditions, to avoid increasing high power during peaking loads, also as a backup during operation in the hybrid configuration in the turbine. The battery is the fastest in responding power plant, and it can react to the grid in milisecond timescales. But, battery considered caused some losses because it does not have a permanent source of energy[11].

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[9] Source : https://finance.detik.com/energi/d-4646934/satu-unit-pembangkit-500-mw-dibangun-di-pltgu-muara-karang

[10] Source : Masters, G. M., 2004. *Renewable and Efficient Electric Power System.* Canada: JOHN WILEY & SONS, INC., PUBLICATION

[11] Source : Masters, G. M., 2004. Renewable and Efficient Electric Power System. Canada: JOHN WILEY & SONS, INC., PUBLICATION

From several types of peaker above, Muara Karang Peaker is a gas turbine type because of using natural gas as combustion. This peaker designed with operational pressure 46 barg, temperature 23,6 oC and maximum capacity is 135 MMSCFD (Million Standard Cubic Feet per Day). Piping is one of the essential equipment in peaker. Piping delivers gas from ORF to peaker when the high demand for electricity. During the operation, if there are problems cause shut down of the plant, certainly causing huge losses.

2.8. Piping

Generally, piping used in oil and gas plant for the production process. Piping is one of pressure vessel which has a function flowing the fluid with diffrent pressure in every point. There are several types of piping, such as galvanise and stainless stell. The usage of piping type based on the fluid and the requirement of every plant. In MKP, using galvanise as a piping type with 40 in the schedule. While pressure in piping is ten barg and the operational temperature is 50°C.

As essential equipment, piping has a function for flowing fluid in different pressure and temperature in every plant. Every plant has a different characteristic of gas composition. The gas composition can influence the piping condition in the future. If in the gas composition, there are ingredients caused damage mechanisms such as corrosion and scaling, this damage needs to be aware to prevent the plant stopped operation. The composition of gas from every refinery that flowed to PJB Muara Karang described in Table 2.4 – 2.5[12] :

Table 2. 4 Gas composition in every refinery

Composition	PT Badak (% mol)	Tangguh (% mol)	PT DSLNG (% mol)
Methane	91,49	96,93	91,99
Ethane	4,98	2,32	4,42
Propane	2,41	0,38	2,03
Iso – butane	0,55	0,07	0,52
N – butane	0,53	0,05	0,63
Iso - pentane	0,00	0,01	0,03
N – pentane	0,00	0,00	0,00
Nitrogen	0,03	0,24	0,38
Total	100,00	100,00	100,00

[12] Source : Company's Database

Table 2. 5 Gas Composition in PJB Muara Karang

Gas Composition % Mol	
Methane	92,3802
Nitrogen	0,0047
CO_2	3,1479
Ethane	2,5964
Propane	1,1551
i - Butane	0,3174
n- Butane	0,3596
i - Pentane	0,0267
n - Pentane	0,0072
n - Hexane	0,0012
% Total	99,996

2.9. Mechanical Failures

The first mechanical failure is corrosion, and corrosion is an electrochemical process which occurs when four elements are present; an anode which gives up electrons, a cathode which receives electrons, an electrolyte (which is usually an aqueous solution of acids, bases, or salts) and a metallic current path.

The rate at which corrosion occurs depends on the electric potential between the anodic and cathodic areas, the pH of the electrolyte, the temperature, the water and oxygen available for chemical reactions [12] . Factors that affect the corrosion rate:

1. Dissolved Gas Factor

A. Oxygen :

The presence of dissolved oxygen, causing corrosion in metals such as the corrosion rate in mild stell alloys be increased by increasing oxygen content. Generally, the chemical reaction on iron due to dissolved oxygen described as follows:

Anode reaction : $Fe(s) \leftrightarrow Fe^{2+}(aq) + 2e$

Cathodic reaction : $O_2(g) + 2\ H_2O(l) + 4\ e– \leftrightarrow 4\ OH^{-}(aq)$

B. Carbondioxide :

The reaction of carbondioxide in dissolved water will form carbonic acid (H_2CO_2) which can reduce the pH of the water and increasing corrosiveness, usually the form of corrosion is in the form of pitting which in general the reaction is:

$$CO_2 + H_2O \leftrightarrow H_2CO_3$$

$$Fe + H_2CO_3 \leftrightarrow FeCO_3 + H_2$$

$FeCO_3$ is a corrosion product as known as sweet corrosion

2. **Temperature**

   In general, the addition of temperature will be increasing the corrosion rate. Despite the oxygen, solubility decreases with increasing the temperature. If the metal at a non – uniform temperature, corrosion will most likely be formed.

3. **pH**

   Neutal pH is 7, while pH < 7 is acidic and corrosion, and pH > 7 is base and corrosion. For iron, the corrosion rate is low at pH between 7 and 13. The corrosion rate will increase at pH < 7 and at pH > 13.

4. **Environment**

   The location of metal or pipe, in a wet or dry, tropis or winter area, on the surface or underground. Every site has poterntial of the chemical causing corrosion. And the pipe or metal condition if there are stress, fatigue, erosion, and cavitation potential.

In the description above, several factors causing corrosion rates have been descrive. The impact of corrosion in piping, causing the high cost of maintenance. The widespread problem in the oil and gas industry counting for as much as 80% of all pipe maintenance costs. As an example, a study carried out between 1999 and 2001 detailed the direct cost of corrosion in the United States was estimated to be 276 billion dollars a year, i.e., about 3% of the gross domestic product. One hundred twenty-one billion dollars spent on preventing corrosion and 88.3% spent on organic coatings [13] .

And the others mechanical failure is fouling. Fouling is an adverse effect on heat transfer by increasing heat transfer resistance, due to various operating conditions and is mainly a function of fuid velocity and heat transfer surface temperature and also the growth of animals and plants on the surface or biological fouling [14].

The optimisation technique for piping problem based on the Second Law of Thermodynamic proposed by Sahin [15] [16]**.** In this method, the total entropy generation due to heat transfer and fluid friction formulated. Since entropy generation is proportional to the destruction of energy, an optimum configuration generates minimum irreversible losses

2.10. Regulation of Oil and Gas Processing in Indonesia

Oil and gas company, mandatory for implementation safety regulation for each process, which refers to Indonesin Goverment, the regulation maker, and ensuring the that everything goes well in the track and under controlled. Every labor shall be entitled to get protection and safety in every detail of the work. Therefore, the implementation of each regulation that refers to occupational safety and health, its necessary to prevent failure or accident in each operation.

1. **Regulation No. 1, 1970**

   This regulation provides for safety reason. As we can see in Chapter III, Article 3, paragraph 1, explained that to realise the work safety, we need to[13] :

   A. Prevent and reduce accidents possibility
   B. Prevent, reduce, and extinguish fires
   C. Prevent and reduce the danger of explosion

2. **Goverment Regulation No.11, 1979**

   This regulation controls working safety in oil and gas purification process. It consists of 31 chapters and 58 articles governing the administration and supervision of work safety on the purification process of oil and gas industry, the authority and responsibility of the mining of minister, and in the execution of supervision submitted to the General Director (Dirjen) with substitution rights while the duties and supervisory work are carried out by the head of the inspection and mine inspectors.

   According to Chapter IV Articles, 14 and 15 discuss the usage and inspection programs to be undertaken to prevent possible hazards that may occur during petroleum processing[14].

3. **Regulation of Minister of Energy and Mineral Resources Republic Indonesia No. 38, 2017**

   This rule stipulates the regulation of The Minister of Energy and Mineral Resources concerning the inspection of the safety installations and equipment in the oil and gas industry business. Several related articles include:

   A. Article 5 Section 1

   For a guarantee of the design, construction, operation and maintenance, testing, inspection and implementation of installations and equipment, each facility and equipment used in oil and gas business activities must inspect and well-checked.

[13] Undang – Undang Nomer 1 Tahun 1970
[14] Peraturan Pemerintah No. 11 tahun 1979

B. Article 11 Section 2

Safety check and inspection on intallations and equipment operated can be carried out periodically based on:

1. Specific period or time
2. Results of risk analysis

C. Article 17 Section 1 and 3

Approval of the use of periodically safety checks based on a specific period valid for a maximum of four years or less than that period if the installations and equipment change or is doubtful of its ability.

Approval of the use of safety checks based on the results of the risk analysis has a validity period based on the results of the risk analysis for the remainder of life.

4. Regulation of Minister of Energy and Mineral Resources Republic Indonesia No. 18, 2018

This Minister Energy and Mineral Resources Regulation stipulates any rules and laws about safety inspection of installations and equipment engaged in oil and gas activity related to the previous Peraturan Menteri Energi dan Sumber Daya Mineral No. 38 Tahun 2017. The specific contents of this regulation are more likely to lead to procedures on how to carry out safety inspection and parties who take in charge of carrying out these inspections, as mentioned below:

a. Chapter III Article 6 Section 1 dan 2

1 Every installation or equipment used in the oil and gas industry must carry out inspection and safety check.

2 Types of equipment engaged in oil and gas industry that must includ on the inspection consist of pressure vessel, rotating equipments (pump and compressor), power generator, power transformer, distribution panel, atmospheric tank, etc.

b. Chapter III Article 10 Section 1 dan 2

1 The Chief of Engineering is uing information on the inspection results.

5. Work Order Guidelines 041 SKK MIGAS

SKK Migas is an institution established by the government of Republic Indonesia through Presidential Regulation (Perpres) No. 9 of 2013 which concerns in the implementation of management in the oil and gas activities. SKK Migas is a task with carrying out the administration of upstream oil and gas business under a cooperation contract and also issuing regulation and procedures as Pedoman Tata

Kerja (PTK). One of PTK that have to be concerned by the oil and gas company in Indonesia is about “Maintenance of Oil and Production Facilities”. According to PTK-041/SKKMA000/2018/S0, Chapter II “ Maintenance Management Principles”, Every data and documents related to maintenane program are regularly checked by KKKS and stored in a data management system that can be updated and accessed at any time. Data and documents related to the maintenance program include Data integrity and reliability, including Risk Based Inspection (RBI).

2.11. Risk Based Inspection (RBI)

RBI is the process of developing a scheme of inspection based on knowledge of the risk of failure. The essential process is risk analysis. The combination of an assessment of the Probability of Failure (POF) due to flaws damage, deterioration or degradation with an evaluation of the Consequences of Failure (COF) [17] .

RBI program identifies the type of damage that may be present, the location of damage occurs, the rate of damage might evolve, and the failure location would give rise to danger. RBI applied in any industry sector, mostly in the power plant and petrochemical sector. The implementation of RBI method by compromised the equipment’s hazard, and risk. The leveling of risk by systematically prioritised the equipment on high risk level to get the first inspection program.

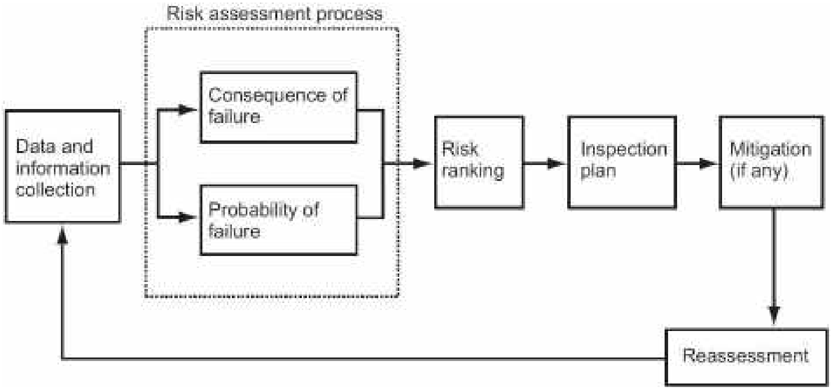

Figure 2. 10 Risk based inspection planning method[15]

Figure 2.10 shows the planning process of RBI. Starting from collect data about the equipment and inspected, such as material characteristic, failure history, current conditions and others data. Then, the probability of failure and the consequence of failure calculated. Both of them can determine the level risk of each component. After knowing the risk, the inspection planning and mitigation (if any) defined. Risk mitigation such as changes the material construction changes the operating fluids and condition, and the usage of corrosion inhibitor.

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[15] API Recommended Practice 580, Risk Based Inspection, 3rd Edition, Washington, D.C: API Publishing Services, 2016.

2.11.1. Probability of Failure (POF)

According to the standard of American Petroleum Institute (API) Recommended Practice 581 for calcualting Risk Based Inspection, there is two main part for calculating RBI which are Probability of Failure (POF) and Consequence of Failure (COF). In the below there is following equation for determining POF :

$$P_f\ (t) = gff.D_f\ (t).F_{MS} \tag{2.1}$$

Where :

$P_f\ (t)$ = Probability of Failure

gff = Total Generic Failure Frequency

$D_f\ (t)$ = Damage Factor

F_{MS} = Management System Factor

2.11.1.1. Generic Failure Frequency

Generic Failure Frequency as a representtive value from refining data and different components types of failure. GFF used for failure frequency before failure occured, caused by the environment to the component's operation.

2.11.1.2. Damage Factor

Damage factor as a factor determined from detorioration (corrosion, cracking, etc.) which proportional to maintenance. According to API RP 581 [18], there are 21 types of damage factors:

1. Thinning Damage Factor
2. Component Lining Damage Factor
3. SCC Damage Factor – Caustic Cracking
4. SCC Damage Factor – Amine Cracking
5. SCC Damage Factor – Sulfide Stress Cracking
6. SCC Damage Factor – HIC / SOHIC – H2S
7. SCC Damage Factor – Alkaline Carbonate Cracking
8. SCC Damage Factor – PTA Cracking
9. SCC Damage Factor – CLSCC
10. SCC Damage Factor – HSC-HF
11. SCC Damage Factor – HIC / SOHIC – HF
12. External Corrosion Damage Factor – Ferritic Component
13. External CLSCC Damage Factor Austenitic Component
14. CUI Damage Factor – Ferritic Component
15. External CUI CLSCC Damage Factor – Austenitic Component
16. HTHA Damage Factor
17. Brittle Damage Factor
18. Temper Embrittlement Damage Factor

19. Embrittlement Damage Factor
20. Sigma Phase Embrittlement Damage Factor
21. Piping Mechanical Fatigue Damage Factor.

The twenty-one damage factors have their criteria. Starting the calculation of the probability of failure on a particular component, by doing screening damage factor, the damage occurs in these components will be known, the screening through component data and on-site observations.

Table 2. 6 Damage Factor Screening Criteria

<table>
<tr><th>No</th><th>Damage Factor</th><th colspan="3">Screening Criteria</th><th>Yes/No</th></tr>
<tr><td>1.</td><td>Thining</td><td colspan="3">All component should be checked for thining</td><td>Yes</td></tr>
<tr><td>2.</td><td>Component Lining</td><td colspan="3">If the component has organic or inorganic lining, then the component should be evaluated for lining damage</td><td>No</td></tr>
<tr><td>3.</td><td>SCC Damage Factor-Caustic Cracking</td><td colspan="3">If the component's material of construction is carbon or low alloy steel and the process environment contains caustic in any concentration, then the component should be evaluated for susceptibility to caustic cracking.</td><td>No</td></tr>
<tr><td rowspan="3">4.</td><td rowspan="3">Piping Mechanical Fatigue Damage Factor</td><td colspan="3">If <u>BOTH</u> of the following are true, then the component should be evaluated for susceptibiity to mechanical fatigue:</td><td rowspan="3">Yes</td></tr>
<tr><td>a.</td><td>The component is pipe</td><td>Y</td></tr>
<tr><td>b.</td><td>There have been past fatigue failure in this piping system or there is visible/audibble shaking in this piping system or there is a source of cyclic vibration within approximately 15.24 meters (50 feet) and connected to the piping (directly or indirectly via structure). Shaking and source of shaking can be continuous or intermittent.Transient conditions often cause intermittent virbration.</td><td>Y</td></tr>
</table>

Table 2. 7 Damage Factor Screening Criteria

<table>
<tr><td rowspan="11">5.</td><td rowspan="11">External Corrosion Damage Factor</td><td colspan="3">If the component is un-insulated and subject to any of the following , then the component should be evaluated for external damage from corrosion.</td><td rowspan="11">Yes</td></tr>
<tr><td>a.</td><td>Areas exposed to mist overspray from cooling towers.</td><td>N</td></tr>
<tr><td>b.</td><td>Areas exposed to steam vents</td><td>N</td></tr>
<tr><td>c.</td><td>Areas exposed to deluge system</td><td>N</td></tr>
<tr><td>d.</td><td>Areas subject to process spills, ingress of moisture, or acid vapors.</td><td>N</td></tr>
<tr><td rowspan="2">e.</td><td>Carbon steel system, operatinng between -12°C and 177°C (10°F and 350°F). External corrosion is particulartly aggressive where operating temperatures cause frequent or continuous condensation and re-evaporation of atmospheric moisture.</td><td rowspan="2">N</td></tr>
<tr><td>Operating temperature 100°C (212°F)</td></tr>
<tr><td>f.</td><td>Systems that do not operating in normally temperature between -12°C and 177°C (10°F and 350°F) but cool or heat into this range intermitterntly or are subjected to frequent outages.</td><td>Y</td></tr>
<tr><td>g.</td><td>Systems with deteoriated coating and/or wrappings</td><td>N</td></tr>
<tr><td>h.</td><td>Cold service equipment consistently operating below the atmospheric dew point.</td><td>N</td></tr>
<tr><td>i.</td><td>Un-insulated nozzles or other prostrusions components of insulated equipment in cold service conditions.</td><td>N</td></tr>
</table>

2.11.1.2.1. Thinning Damage

All kind of components should be checked and assessed for thinning damage factor that can possibly cause both general or local thinning. In this calculation section has a very close relation with corrosion rate. As we know that corrosion rate is constant degradation material of construction growing over time. To determine corrosion rate in the thinning damage factor, we should consider several scenarios based on the available data and the atmosphere of the plant itself. These below steps should be used to determine the DF for thinning as follows:

1 Determining the furnished thickness, t, and age for the component from the installation date.

2 Determining the corrosion rate for base material, Cr_{bm}, based on the material construction and environment, and the cladding/overlay corrosion rate, Cr_{cm}. To determine corrosion rate in the thinning damage factor, we should consider several scenarios based on the available data and the atmosphere of the plant itself such as:
- Corrosion rate calculation based on RLA from the company
- Corrosion rate calculation based on the API RP 581 Annex 2B

3 Determining the time in-service, age_{tk}, since the last known inspection, t_{rdi}.

4 For cladding/weld overlay pressure vessel components, calculate the age from the date starting thickness from STEP 3 required to corrode away the cladding/weld overlay material, age_{rc}, using equation below:

$$age_{rc} = \max\left[\left(\frac{t_{rdi} - tbm}{C_{r\,cm}}\right), 0.0\right] \tag{2.1}$$

Piping installed in a company's plant is not including into cladding/weld overlay because the stream flows through the pressure vessel is not too much corrosive.

5 Determine the minimum thickness of the component's wall, t_{min}. [19]

$$t_m = t + c$$

$$t = \frac{PD}{2(SE + PY)} \tag{2.2}$$

6 Determine the A_{rt} parameter
For component without cladding/weld overlay then use equation below:

$$A_{rt} = \frac{Cr_{b,m} .\ age_{tk}}{t_{rdi}} \tag{2.3}$$

7 Calculate the Flow Stress, FS^{thin}, using the equation (4.4) below.

$$FS^{Thin} = \frac{(YS+TS)}{2}. \text{E.1,1} \tag{2.4}$$

8 Calculate the strength ratio parameter, SR^{thin}, using the appropriate equation below.

$$SR_P^{Thin} = \frac{S.E}{FS^{Thin}} . \frac{Max\,(t_{min}, t_c)}{FS^{Thin}} \tag{2.5}$$

9 Determine the number of inspections for each of the corresponding inspection effectiveness. Piping in Muara Karang Peaker will be operate in March 2020, also this equipment never be inspection. So, the Inspection effectiveness level D based on the Table 2.7.

$$N_A^{Thin} = 0$$
$$N_B^{Thin} = 0$$
$$N_C^{Thin} = 0$$
$$N_D^{Thin} = 0 \tag{2.6}$$

Table 2. 8 Inspection Effectiveness

Inspection effectiveness category	Ispection effectiveness description	Description
A	Highly effective	The inspection methods will correctly identify the true damage state in nearly every case (or 80-100% confidence)
B	Usually effective	The inspection methods will correctly identify the true damage state most of the time case (or 60-80% confidence)
C	Fairly effective	The inspection methods will correctly identify the true damage state about half of the time (or 40-60% confidence)
D	Poorly effective	The inspection methods will provide little information to correctly identify the true damage state (or 20-40% confidence)
E	Ineffective	The inspection method will provide no or almost no information that will correctly identify the true damage state and are considered ineffective for detecting the specific damage mechanism (less than 20% confidence)

10 Calculate the inspection effectiveness factor, $I_1^{Thin}, I_2^{Thin}, I_3^{Thin}$, using equation below, and the prior probabilities, $Pr_{p1}^{Thin}, Pr_{p2}^{Thin}, Pr_{p3}^{Thin}$, from Table 4.5 and 4.6 from API RP 581 Part 2 of POF based on the number of inspection, $N_A^{Thin}, N_B^{Thin}, N_C^{Thin}, N_D^{Thin}$, from the STEP 9.

$$I_1^{Thin} = Pr_{P1}^{Thin}(Co_{P1}^{ThinA})^{N_A^{Thin}}(Co_{P1}^{ThinB})^{N_B^{Thin}}(Co_{P1}^{ThinC})^{N_C^{Thin}}(Co_{P1}^{ThinD})^{N_D^{Thin}}$$

$$I_2^{Thin} = Pr_{P2}^{Thin}(Co_{P2}^{ThinA})^{N_A^{Thin}}(Co_{P2}^{ThinB})^{N_B^{Thin}}(Co_{P2}^{ThinC})^{N_C^{Thin}}(Co_{P2}^{ThinD})^{N_A^{Thin}}$$

$$I_3^{Thin} = Pr_{P3}^{Thin}(Co_{P3}^{ThinA})^{N_A^{Thin}}(Co_{P3}^{ThinB})^{N_B^{Thin}}(Co_{P3}^{ThinC})^{N_C^{Thin}}(Co_{P3}^{ThinD})^{N_A^{Thin}} \quad (2.7)$$

For the value of the probability conditional, see Table 2.8

Table 2. 9 Probability Conditional

Conditional probability of inspection	E	D	C	B	A
Co_{P1}^{Thin}	0.33	0.4	0.5	0.7	0.9
Co_{P2}^{Thin}	0.33	0.33	0.3	0.2	0.09
Co_{P3}^{Thin}	0.33	0.27	0.2	0.1	0.01

11 Calculate the Posterior Probability, $Po_{p1}^{Thin}, Po_{p2}^{Thin}, Po_{p3}^{Thin}$, using equation below.

$$Po_{p1}^{Thin} = \frac{I_1^{Thin}}{I_1^{Thin} + I_2^{Thin} + I_3^{Thin}} \quad (2.8)$$

$$Po_{p2}^{Thin} = \frac{I_2^{Thin}}{I_1^{Thin} + I_2^{Thin} + I_3^{Thin}} \quad (2.9)$$

$$Po_{p3}^{Thin} = \frac{I_3^{Thin}}{I_1^{Thin} + I_2^{Thin} + I_3^{Thin}} \quad (2.10)$$

12 Calculate the parameters, $ß_1^{Thin}, ß_2^{Thin}, ß_3^{Thin}$, using equation (2.11), (4.13), and (4.14) within assigning $COV_{\Delta t} = 0.2$, $COV_{sf} = 0.2$, and $COV_P = 0.05$.

$$ß_1^{Thin} = \frac{1-D_{S1} \, . \, A_{rt}-SR_P^{Thin}}{\sqrt{D_{S1}{}^2 . \, A_{rt}{}^2 . \, COV_{\Delta t}{}^2+(1-D_{S1}.A_{rt})^2 . COV_{sf}{}^2+(SR_P^{Thin})^2 . (COV_P)^2}} \quad (2.11)$$

$$ß_2^{Thin} = \frac{1-D_{S2} \, . \, A_{rt}-SR_P^{Thin}}{\sqrt{D_{S2}{}^2 . \, A_{rt}{}^2 . \, COV_{\Delta t}{}^2+(1-D_{S2}.A_{rt})^2 . COV_{sf}{}^2+(SR_P^{Thin})^2 . (COV_P)^2}} \quad (2.12)$$

$$ß_3^{Thin} = \frac{1-D_{S3} \, . \, A_{rt}-SR_P^{Thin}}{\sqrt{D_{S3}{}^2 . \, A_{rt}{}^2 . \, COV_{\Delta t}{}^2+(1-D_{S3}.A_{rt})^2 . COV_{sf}{}^2+(SR_P^{Thin})^2 . (COV_P)^2}} \quad (2.13)$$

13 For tank bottom components, determine the base damage factor for thinning using Table 4.8 and calculated A_{rt} parameter from STEP 6. Because the component asses in this case is piping, then this calculation chapter can be skipped.

14 Calculate the base damage factor, D_{fB}^{Thin}, for the piping using equation (2.14).

$$D_{fb}^{Thin} = [\frac{\left(Po_{P1}^{Thin}\Phi(-\beta_1^{Thin})\right)+\left(Po_{P2}^{Thin}\Phi(-\beta_2^{Thin})\right)+\left(Po_{P3}^{Thin}\Phi(-\beta_3^{Thin})\right)}{1.56E-0.4} \quad (2.14)$$

15 Determine the DF for thinning, D_f^{Thin}.

$$D_f^{Thin} = \mathrm{Max}[(\frac{(D_{fb}^{Thin} \cdot F_{IP} \cdot F_{DL} \cdot F_{WD} \cdot F_{AM} \cdot F_{SM})}{F_{OM}}),0.1] \quad (2.15)$$

2.11.1.2.2. Mechanical Fatigue

Fatigue failures of piping systems present a very real hazard under certain conditions. Properly designed and installed piping systems should not be subject to such failures, but prediction of vibration in piping systems at the design stage is very difficult, especially if there are mechanical sources of cyclic stresses such as reciprocating pumps and compressors. In addition, even if a piping systems are not subject to mechanical fatigue in the as-built condition, changing conditions such as failure of pipe supports, increased vibration from out of balance machinery, chattering of relief valves during process upsets, changes in flow and pressure cycles or adding weight to unsupported branch connections (pendulum effect) can render a piping system susceptible to failure. Awareness of these influences incorporated into a management of change program can reduce the POF. The following procedure below may be used to determine the DF for mechanical fatigue:

1. Determining the number of previous failures that have occurred, and determine the base DF D_{fB}^{PF} based on the following criteria.

   1. None $D_{fB}^{PF} = 1$
   2. One - $D_{fB}^{PF} = 50$
   3. Greater than one - $D_{fB}^{PF} = 500$ (2.16)

2. Determine the the amount of visible / audible shaking or audible noise occuring in the pipe, and determine the base DF D_{fB}^{AS} based on the following criteria.
   1. Minor $D_{fB}^{AS} = 1$
   2. Moderate - $D_{fB}^{AS} = 50$
   3. Severe - $D_{fB}^{AS} = 500$ (2.17)

3. Determine the adjustment factor for visible / audible shaking based on the following criteria. This adjustment is based on observation that some piping system may endure visible shaking for years. A repeated stress with a cycle of only 1 hertz (1/s) result in over 30 million cycles in years. Most system, if they were subject to failure by mechanical fatigue would be expected to fail before reaching tens or hundreds of million cycles. One should note that intermitten cycles are cumulative.
   1. Shaking less than 2 weeks - $D_{fB}^{AS} = 1$
   2. Shaking between 2 and 13 weeks - $D_{fB}^{AS} = 0.2$
   3. Shaking between 13 and 52 weeks - - $D_{fB}^{AS} = 0.02$ (2.18)

4. Determine the type of cyclic loading connected directly or indirectly within approximately 15.24 meters (50 feet) of the pipe, and determine the base DF D_{fB}^{CF} based on the following criteria.
   1. Reciprocating machinery- $D_{fB}^{CF} = 50$
   2. PRV Chatter - $D_{fB}^{CF} = 25$
   3. Valve with high pressure drop - $D_{fB}^{CF} = 10$
   4. None - $D_{fB}^{CF} = 1$ (2.19)

2.11.1.2.3. External Corrosion Damage Factor

The external corrosion damage and factor associated with thinning damage factor. Once thinning damage factor is calculated, then, the external corrosion must also be considered. Mitigation of external corrosion damage is accomplished through proper painting. There are several level of coating or painting either poor/low or medium or high. A regular program of inspection for paint deterioration and re-painting will prevent most of external corrosion. The following step is how to calculate the damage factor caused by the external corrosion such:

1. Determining the furnished thickness, t, and age for the component from the installation date.

2. Determining the base corrosion rate, C_{rB} based on the driver and operating temperature using table 2.9.

Table 2. 10 Corrosion Rates for Calculation of the Damage Factor

Operating Temperature (oC)	Corrosion Rate as a Function of Driver (1) (mmpy)			
	Marine / Cooling	Temperat	Arid / Dry	Severe
-12	0	0	0	0
-8	0,025	0	0	0
6	0,127	0,076	0,025	0,254
32	0,127	0,076	0,025	1,254
71	0,127	0,051	0,025	2,254
107	0,025	0	0	0,051
121	0	0	0	0

3. Calculate the final corrosion rate, Cr, using equation below.

$$C_r = C_{rB} \,.\max[(F_{EQ}, F_{IF})] \quad (2.20)$$

F_{EQ} = Adjustment for equation design or fabrication

F_{IF} = Adjustment fo interface

4. Determine the time in service, age_{tk}, since the last known inspection, t_{rde}. The t_{rde} is the starting thickness with respect to wall loss associated with external corrosion. If no measured thickness is available, set t_{rde} = t and age_{tk} = age

5. Determine the time in-service, age_{coat}, since the coating has been installed using equation 2.21 below.

$$age_{coat} = Calculation\ Date - Coating\ Installation\ Date \quad (2.21)$$

6. Determine coating adjustment, coatadj using one of below equations

If $Age_{tk} \geq Age_{coat}$ (2.22)

$Coat_{adj} = 0$ If No or Poor Coating Quality

$Coat_{adj} = \min[5, age_{coat}]$ If Medium Coating Quality

$Coat_{adj} = \min[15, age_{coat}]$ If High Coating Quality

If $Age_{tk} < Age_{coat}$

$Coat_{adj} = 0$ No / poor

$Coat_{adj} = \min[5, age_{coat}] - \min[5, age_{coat} - age_{tk}]$ Medium

$Coat_{adj} = \min[15, age_{coat}] - \min[15, age_{coat} - age_{tk}]$ High

7. Determine the in - service time, age, over which external corrosion may have occured using equation 2.23

$$age = age_{tk} - Coat_{adj} \quad (2.23)$$

8. Determine the allowable stress, S, weld joint efficiency, E, and minimum required thickness, t_{min}, per the original construction code or ASME B.31.3

9. Determine the A_{rt} Parameter
   For component without clading/weld overlay then use the equation 2.24 below.

$$A_{rt} = \frac{Cr\,.\,agetk}{t_{rde}} \quad (2.24)$$

10. Calculate the Flow Stress, $FS^{extecor}$, using E from STEP 5 and equation (2.25).

$$FS^{extcorr} = \frac{(YS+TS)}{2}.\ \mathrm{E.1,1} \quad (2.25)$$

11. Calculate the strength ratio parameter, SR_P^{Thin}, using the appropriate equation.

$$SR_P^{Thin} = \frac{S.E}{FS^{Thin}}.\frac{Max\,(t_{min}, t_C)}{t_{rdi}} \quad (2.26)$$

12. Determine the number of inspection , $N_A^{extcorr}$, $N_B^{extcorr}$, $N_C^{extcorr}$, $N_D^{extcorr}$ and the corresponding inspection effectiveness category using Table 2.10 inspection effectiveness for past inspections performed during the in - service time.

13. Determine the inspection effectiveness factors, $I_1^{extcorr}$, $I_2^{extcorr}$, $I_3^{extcorr}$ using equation below, prior probabilities, $Pr_{p1}^{extcorr}$, $Pr_{p2}^{extcorr}$, $Pr_{p3}^{extcorr}$, from Table 2.11. Conditional Probabilities (for each inspection effectiveness $Co_{p1}^{extcorr}$, $Co_{p2}^{extcorr}$, $Co_{p3}^{extcorr}$ level) , from Table 2.12, and the number of inspection, $N_A^{extcorr}$, $N_B^{extcorr}$, $N_C^{extcorr}$, $N_D^{extcorr}$

, in each effectiveness level from STEP 12.

$$
\begin{aligned}
I_1^{extcorr} &= Pr_{P1}^{extcorr}\left(Co_{P1}^{extcorrA}\right)^{N_A^{extcorr}}\left(Co_{P1}^{extcorrB}\right)^{N_B^{extcorr}}\left(Co_{P1}^{extcorrC}\right)^{N_C^{extcorr}}\left(Co_{P1}^{extcorrD}\right)^{N_D^{extcott}}\\
I_2^{extcorr} &= Pr_{P2}^{extcorr}\left(Co_{P2}^{extcorrA}\right)^{N_A^{extcorr}}\left(Co_{P2}^{extcorrB}\right)^{N_B^{extcorr}}\left(Co_{P2}^{extcorrC}\right)^{N_C^{extcorr}}\left(Co_{P2}^{extcorrD}\right)^{N_D^{extcott}}\\
I_3^{extcorr} &= Pr_{P3}^{extcorr}\left(Co_{P3}^{extcorrA}\right)^{N_A^{extcorr}}\left(Co_{P3}^{extcorrB}\right)^{N_B^{extcorr}}\left(Co_{P3}^{extcorrC}\right)^{N_C^{extcorr}}\left(Co_{P3}^{extcorrD}\right)^{N_D^{extcott}}
\end{aligned}
\tag{2.27}
$$

Table 2. 11 Inspection Effectiveness for External

Inspection effectiveness category	Ispection effectiveness description	Description
A	Highly effective	Visual Inspection of > 95% of the exposedsurface area with follow uap by UT< RT or bit gauge as required.
B	Usually effective	Visual Inspection of > 60% of the exposedsurface area with follow uap by UT< RT or bit gauge as required.
C	Fairly effective	Visual Inspection of > 30% of the exposedsurface area with follow uap by UT< RT or bit gauge as required.
D	Poorly effective	Visual Inspection of > 5% of the exposedsurface area with follow uap by UT< RT or bit gauge as required.
E	Ineffective	Ineffective Inspection technique Plan bas utilized

Table 2. 12 Prior Probability for Thinning Corrosion Rate

Damage State	Low Confidance Data	Medium Conf. Data	High Conf.Data
Pr_{P1}^{Thin}	0,5	0,7	0,8
Pr_{P2}^{Thin}	0,3	0,2	0,15
Pr_{P3}^{Thin}	0,2	0,1	0,05

Table 2. 13 Conditional Probability for Inspection Effectiveness

Conditional P. of Inspection	**E-None or Ineffective**	**D-Poorly Effective**	**C-Fairly Effective**	**B-Usually Effective**	**A-Highly Effective**
Co_{P1}^{Thin}	0,33	0,4	0,5	0,7	0,9
Co_{P2}^{Thin}	0,33	0,33	0,3	0,2	0,09
Co_{P3}^{Thin}	0,33	0,27	0,2	0,1	0,01

14. Calculate the Posteroir Probability, $Po_{p1}^{extcorr}$, $Po_{p2}^{extcorr}$, $Po_{p3}^{extcorr}$, using equations 2.28.

$$Po_{p1}^{extcorr} = \frac{I_1^{extcorr}}{I_1^{extcorr} + I_2^{extcorr} + I_3^{extcorr}}$$
$$Po_{p2}^{extcorr} = \frac{I_2^{extcorr}}{I_1^{extcorr} + I_2^{extcorr} + I_3^{extcorr}}$$
$$Po_{p3}^{extcorr} = \frac{I_3^{extcorr}}{I_1^{extcorr} + I_2^{extcorr} + I_3^{extcorr}} \quad (2.28)$$

15.Calculate the parameters, ß$_1$, ß$_2$, and ß$_3$ using equation 2.29 and also assigning COV$_{\Delta t}$ = 0.20, COV$_{sf}$ = 0.20, and CO$_{VP}$ = 0.05.

$$ß_1^{extcorr} = \frac{1-D_{S1} \cdot A_{rt}-SR_P^{extcorr}}{\sqrt{D_{S1}{}^2 \cdot A_{rt}{}^2 \cdot COV_{\Delta t}{}^2+(1-D_{S1} \cdot A_{rt})^2 \cdot COV_{sf}{}^2+(SR_P^{extcorr})^2 \cdot (COV_P)^2}}$$

$$ß_2^{extcorr} = \frac{1-D_{S2} \cdot A_{rt}-SR_P^{extcorr}}{\sqrt{D_{S2}{}^2 \cdot A_{rt}{}^2 \cdot COV_{\Delta t}{}^2+(1-D_{S2} \cdot A_{rt})^2 \cdot COV_{sf}{}^2+(SR_P^{extcorr})^2 \cdot (COV_P)^2}}$$

$$ß_3^{extcorr} = \frac{1-D_{S3} \cdot A_{rt}-SR_P^{extcorr}}{\sqrt{D_{S3}{}^2 \cdot A_{rt}{}^2 \cdot COV_{\Delta t}{}^2+(1-D_{S3} \cdot A_{rt})^2 \cdot COV_{sf}{}^2+(SR_P^{extcorr})^2 \cdot (COV_P)^2}} \quad (2.29)$$

16. Calculate $D_f^{extcorr}$ using equation 2.30

$$D_f^{extcor} = [\frac{\left(Po_{P1}^{extcorr}\Phi(-\beta_1^{extcorr})\right)+\left(Po_{P2}^{extcorr}\Phi(-\beta_2^{extcorr})\right)+\left(Po_{P3}^{extcorr}\Phi(-\beta_3^{extcorr})\right)}{1.56E-0.4} \quad (2.30)$$

2.11.1.2.4. Total Damage Factor

In the case of multiple damage mechanisms, the combination of those damage mechanims is explained in section 3.4.2 API RP 581 Part 2 3rd Edition. Total DF, Df-total - If more than one damage mechanism is present, the following rules are used to combine the DFs. The total DF is given by Equation 2.31, when the external and/or thinning damage are classified as local and therefore, unlikely to occur at the same location.

$$D_{f-total} = max\left[D_{f-gov}^{thin}, D_{f-gov}^{extd}\right] + D_{f-gov}^{scc} + D_f^{htha} + D_{f-gov}^{brit} + D_f^{mfat} \quad (2.31)$$

If the external and thinning damage are general, then damage is likely to occur at the same location and the total DF is given by Equation 2.32.

$$D_{f-total} = D_{f-gov}^{thin} + D_{f-gov}^{extd} + D_{f-gov}^{scc} + D_{f}^{htha} + D_{f-gov}^{brit} + D_{f}^{mfat} \tag{2.32}$$

2.11.1.3. Management Syatem Factor

The effectiveness of a company's process safety management system can have a pronounced effect on mechanical integrity. The methodology includes an evaluation tool to assess the portions of the facility's management system that most directly impact the POF of a component.

2.11.2. Consequence of Failure (COF)

The Consequence of Failure (COF) methodology presented in Part 3 of American Petroleum Institution Recommended Practice 581 (API RP 581) which later on will combine with Probability of Failure (POF) calculation to provide a risk ranking and inspection plan for a component subject to process and environmental conditions typically found in refining, petrochemical and exploration, and production industries. The COF methodology is to perform to aid in establishing a ranking of equipment items based on risk and also intended to be used for establishing priorities for inspection programs[16]. As listed in the API Recommended Practice 581, there are two kinds of COF levels, namely Level 1 and Level 2, which has a different application of fluid characteristics one and another. A Level 1 COF methodology used for a defined list of hazardous fluids. A Level 2 COF methodology is intended to be more rigorous and applied to a broader range of hazardous fluids.

2.11.2.1. Consequence Categories

The major consequence categories are analyzed using different techniques as mentioned below :

A. Flammable and Explosive Consequence

Flammable and explosive consequence is calculated using event tress to determine the probabilities of various outcomes (i.e. pool fires, flash fires, vapor cloud explosions), combined with computer modeling to determine

[16] API RP 581, Risk Based Inspection Methodology, 3rd Edition, Washington D.C: API Publishing Service, 2016.

the magnitude of the consequence. Consequence area can be determined based on serious personnel injuries and component damage from thermal radiation and explosions. Financial losses are determined based on the area affected by the release.

B. Toxic Consequence

Toxic consequence is calculated is calculated using computer modelling to determine the magnitude of the consequence area as a result of overexposure to personnel to toxic concentration within a vapor cloud. Where the fluids are flammable and toxic, the toxic event probability assumes that is the release is ignited, the toxic consequence is negligible (i.e. toxic is consumed in the fire). Financial losses are determined based on the area affected by the release.

C. Non-Flammable, Non-Toxic Consequence

Non-flammable, non-toxic releases are considered since they can still in serious consequences. Consequence from chemical splashes and high temperature steam burns are determined based on serious injuries to personnel. Physical explosion and Boiling Liquid Expanding Vapor Explosions (BLEVE) can also cause serious personnel injuries and component damage.

D. Financial Consequence

Financial consequence includes losses due to business interruption and costs associated with environmental releases. Business interruption consequences is estimated as a function of the flammable and non-flammable consequence area results. Environmental consequence is determine directly from the mass available for release or from the release rate.

2.11.2.2. Calculating Consequence of Failure (COF)

The methodology for calculating the Consequence of Failure (COF) for piping are covered in Recommended Practice API 581 Part 3 (according to the Table 3.1. Steps in Consequence Analysis and Figure 3.1. Level of COF Methodology). The COF methodology is performed to aid in establishing a ranking of equipment items on the basis of risk and also intended to be used for establishing priorities for inspection programs. For the consequence of failure analysis step shows in the Table 2.13.

Table 2. 14 consequence of failure analysis step

Step	Description
1	Determine the released fluid and its properties, including the release phase.
2	Select a set of release hole sizes to determine the possible range of consequence in the risk calculation
3	Calculate the theoritical release rate
4	Estimate the total amount of fluid available for release
5	Determine the type of release, continuous or instantaneous, to determine the method used for modelling the dispersion and consequence
6	Estimate the impact of detection and isolation systems on release magnitude.
7	Determine the release rate and mass for the consequence analysis
8	Calculate flammable/explosive consequence
9	Calculate toxic consequence
10	Calculate non-flammable, non-toxic consequence
11	Determine the final probability weighted component damage and personnel injury consequence areas
12	Calculate financial consequence

Here are the 11 steps of determining the Consequence Area of Piping without any considerable of Financial Consequence as follows:

1. **Determining the release fluid and its properties, including its release phase.**
   1.1. Selecting the representative fluid group from the Table 4.1 from the API RP 581 Part 3
   In selecting the representative fluid from the Table provided by the API RP 581 is affected by the dominant fluid contained inside the piping. So, based on the Heat Material Balance (HMB) data, the major fluids in this pressure vessel are called methane and ethane, which is included into a chemical hydrocarbon group of C_1-C_2.
   1.2. Determining the stored fluid phase, it can be either liquid or vapor. That is why, there are two major fluid constituents such gas and liquid. Then, to determine the stored fluid phase is assumed with gaseous fluid, because the gaseous constituent is dominant.
   1.3. Determining the stored fluid properties
   Because the major constituent fluid inside the piping is gas or vapor. Then, the properties are dependent on these parameters such as:
   - MW : Molecular Weight (kg/kg-mol)
   - k : Ideal gas specific heat ratio
   - AIT : Auto-ignition Temperature (K(°R))

All of above parameter can be estimated from Table 4.2 which is provided by API RP 581 Part 3.

1.4. Determine the steady state phase of the fluid after release to the atmosphere and the phase of fluid stored in the equipment as determined in STEP 1.2.

Because of the representative fluid (methane and ethane) is stored in the piping is modeled as gas, and when it releases to the ambient temperature is still phased in gas. So, the determination of final of consequence calculation is modeled as gas-gas.

2. **Select a set of release hole sizes to determine the possible range of consequence in the risk calculation.**

2.1. Calculate of release hole sizes by determining each diameter (d_n)

Based on the API RP 581 Part 3 Annex 3A shows that for the equipment of pressure vessel, that the standard four release hole sizes are assumed for all size and all pressure vessel types. So, starting from the small release hole size, medium release hole size, large release hole size, and until rupture release hole size must be calculated each.

2.2. Determining the gff_n, for the n^{th} release hole sizes.

This step can be done by following the Table 3.2 of API RP 581 Part 2.

3. **Calculate the theoretical release rate**

3.1. Selecting the appropriate release rate equation based on the fluid phase as determined in STEP 1.2.

Because of the fluid phase that has been determined in STEP 1.2. is gas or vapor within the storage pressure of the equipment P_s is greater than the transition pressure P_{trans}. So, the used theoretical release rate equation is below.

$$W_n = \frac{Cd}{C2} \; x \; An \; \text{x} \; Ps \sqrt{\left(\frac{k \; x \; MW \; x \; gc}{R \; x \; Ts}\right)\left(\frac{2}{k+1}\right)^{\frac{k+1}{k-1}}} \quad (2.33)$$

3.2. Calculating the release hole size area, A_n, for each release hole size using the equation below.

$$An = \frac{\pi dn^2}{4} \quad (2.34)$$

3.3. For liquid releases, for each release hole size, calculate the viscosity correction factor ($K_{v,n}$)

Because the release phase of the fluid in this case is gaseous or vapour. Then, this step is no needed to be calculated.

3.4. For each hole size, calculate the release rate, Wn , for each release area An

Calculate the theoretical release rate (W_n) for each release hole size based on the release hole size area (A_n) that has been determined I the STEP 3.2.

4. **Calculating the Inventory Mass**

4.1. Determining the group components and equipment items into inventory groups.
API RP 581 gives any description for the Consequence of Failure (COF) for a equipment items assessed is to combine with the other component that can contribute to add the release mass of inventory.

4.2. Calculating the fluid mass, $mass_{comp}$, in the component being evaluated using equation below.

$$Mass_{comp} = \rho \text{ x } 50\% \text{ x } V \quad (2.35)$$

In this case is using 50% because the equipment evaluated in this case is two-phase Production Separator which is assumed having 50% liquid content and 50% gaseous content.

4.3. Calculating the fluid mass in each of other components that are included in the inventory group, $mass_{comp,i}$.

4.4. Calculating the fluid mass in the inventory group, $mass_{inv}$, using this equation below.

$$\sum mass_{inv} = \sum_{i=1}^{n} mass_{comp,i} \quad (2.36)$$

4.5. Calculate the flow rate from a 203 mm (8 inch) diameter hole, W_{max}
Calculate the flow rate from a 203 mm (8 inch) diameter hole, Wmax8, using the equation 5 as applicable with An = A8 = 32.450 mm2 (50.3 inch2). This is the maximum flow rate that can be added to the equipment fluid mass from the surrounding equipment in the inventory group.

$$W_{max8} = \frac{Cd}{C2}\ x\ An \text{ x Ps} \sqrt{\left(\frac{k\ x\ MW\ x\ gc}{R\ x\ Ts}\right)\left(\frac{2}{k+1}\right)^{\frac{k+1}{k-1}}} \quad (2.37)$$

4.6. Calculating the added fluid mass $mass_{add,n}$ for each release hole size
Determining the additional fluid mass for each release hole size resulting from three minutes of flow from the inventory group using this below equation below.

$$Mass_{add\ n} = 180.\left[W_n, W_{maxB}\right] \quad (2.38)$$

4.7. Calculate the available mass for release for each hole size
For each release hole size, calculate the available mass for release using this below equation below.

$$\text{Mass}_{avail\ n} = min.\left[\{\text{Mass}_{comp} + \text{Mass}_{add,n}\}, \text{Mass}_{inv}\right] \qquad (2.39)$$

5. **Determining the release type which can be either continuous or instantaneous to model the dispersion and consequence**.
INSTATANEOUS RELEASE
An instantaneous or puff release is one that occurs so rapidly that the fluid disperses as a single large cloud or pool.

CONTINOUS RELEASE
a continuous or plume release is one that occurs over a longer period of time, allowing the fluid to disperse in the shape of elongated ellipse (depending in the weather conditions).

5.1. Calculate the time required to release 4536 kgs (10000 lbs) of fluid for each hole size
To determine the time required to release 4536 kgs (10000 lbs) of fluid for each hole size can be adopted from the equation below.

$$t_n = \frac{C3}{W_n} \qquad (2.40)$$

5.2. Determining if the release type is instantaneous or continuous using this following criteria.
- If the release hole size is 6.35 mm (0.25 inch) or less, then the release type is automatically continuous.
- If $t_n \leq 180$ sec and the release mass is greater than 4536 kgs (10000 lbs.), then the release is instantaneous; otherwise, the release is continuous.

6. **Estimating the impact of detection and isolation system on release Magnitude**
Every oil and gas, petrochemical, and refining industries commonly have such as detection system, isolation system, and also mitigation system designed to decrease the magnitude possibility from the dangerous compositions or fluids. Based on Table 4.5 of API RP 581 Part 3 listed about the detection and isolation systems scenarios that might be belonged to a particular oil and gas company as its safety system whenever the magnitude occurs.

6.1. Determining the detection and isolation systems present in the unit
Type of safety support that available in the unit is SDV which is functioned to detect any pressure changes, both overpressure or leakage. In the other hand, the isolation system is activated directly

from process instrumentations with detectors, with no operator intervention.

6.2. Selecting the appropriate classification (A, B, or C) for the detection system using Table 2.14

Table 2. 15 Type clasification of detection system

Type of Detection System	**Det. Classification**
Instrumentation designed specifically to detect material losses by changes in operating conditions (i.e. loss of pressure or flow) in the system	A
Suitably located detectors to determine when the material is present outside the pressure-containing envelope	B
Visual detection, cameras, or detectors with marginal coverage	C

6.3. Selecting the appropriate classification (A, B, or C) for the isolation system using Table 2.15

Table 2. 16 Type classification of isolation system

Type of Isolation System	**Iso. Classification**
Isolation or shutdown systems activated directly from process instrumentation or detectors, with no operator intervention	A
Isolation or shutdown systems activated by operators in the control room or other suitable location remote from the leak	B
Isolation dependent on manually operated valves	C

6.4. Determine the release reduction factor, $fact_{di}$, using the Table 4.6 and classification from table 4.5 as chosen in the STEP 6.2 and 6.3.

Table 2. 17 Adjustment to release based on detection and isolation system

System Classification		Release Magnitude Adjustment	Reduction Factor, $fact_{di}$
Detection	Isolation		
A	A	Reduce release rate or mass by 25%	0,25
A	B	Reduce release rate or mass by 20%	0,20

A or B	C	Reduce release rate or mass by 10%	0,10
B	B	Reduce release rate or mass by 15%	0,15
C	C	No adjustment to release rate or mass	0,00

6.5. Determining the total leak duration for each selected release hole sizes, $ld_{max,n}$, using Table 4.7 and the classification from STEP 6.2 and 6.3.

Table 2. 18 Leak Durations Based on detection and Isolation Systems

Detection System Rating	**Isolation System Rating**	**Maximum Leak Duration,** ld_{max}
A	A	20 minutes for 1/4 inch leaks
		10 minutes for 1 inch leaks
		5 minutes for 4 inch leaks
A	B	30 minutes for 1/4 inch leaks
		20 minutes for 1 inch leaks
		10 minutes for 4 inch leaks
A	C	40 minutes for 1/4 inch leaks
		30 minutes for 1 inch leaks
		20 minutes for 4 inch leaks
B	A or B	40 minutes for 1/4 inch leaks
		30 minutes for 1 inch leaks
		20 minutes for 4 inch leaks
B	C	1 hour for 1/4 inch leaks
		30 minutes for 1 inch leaks
		20 minutes for 4 inch leaks
C	A, B, or C	1 hour for 1/4 inch leaks
		40 minutes for 1 inch leaks
		20 minutes for 4 inch leaks

7. **Determine the release rate and mass for consequence of failure CONTINOUS RELEASE RATE**

For continuous releases, the release is modeled as a steady state plume: therefore, the release rate is used as an input to the consequence analysis. The release rate that is used in the analysis is the theoretical release adjusted for the presence of unit detection and isolations as formulated in the equation below:

$$Rate_n = W_n (1 - fact_{di}) \tag{2.41}$$

INSTATANEOUS RELEASE RATE

For transient instantaneous puff releases, the release mass is required to perform the analysis. The available release mass for each hole size, $mass_{avail,n}$, is used as an upper bound for the release mass, $mass_n$, as shown in the equation below:

$$Mass_n = min.\left[\{Rate_n \cdot ld_n\}, Mass_{avail,n}\right] \quad (2.42)$$

7.1. Calculating the adjusted release rate, $rate_n$, using equation above.

7.2. Calculating the leak duration, ld_n, for each release hole size using equation below.

$$ld_n = min.\left[\left\{\frac{Mass_{avail,n}}{Rate_n}\right\}, \{60 \cdot ld_{max,n}\}\right] \quad (2.43)$$

7.3. Calculate the release mass, $mass_n$, for each release hole size

For each release hole size, calculate the release mass, $mass_n$, using equation 13 above based on the release rate, $rate_n$, the leak duration, Id_n, and the available mass, $mass_{avail,n}$.

8. **Determining the flammable and explosive consequences**

Consequence of Area (CA) is estimated by using the release rate ($Rate_n$) for the continuous release type and Mass rate ($Mass_n$) for the instantaneous release type.

8.1. Selecting the consequence area mitigation reduction factor, $fact_{mit}$, from Table 4.10

8.2. Calculate the energy efficiency, $eneff_n$, for each hole size using equation mentioned below.

$$eneff_4 = 4. log_{10}\left[C_4 \cdot mass_n\right] - 15 \quad (2.44)$$

The equation above is just applied for the instantaneous release type, so, for the continuous release type is no need to be considered.

8.3. Determine the fluid type, either TYPE 0 or TYPE 1 based on the Table 4.1

In this case, the representative fluid as mentioned in previous STEP 1.1 are methane and ethane (C_1 and C_2). So, it is included to the TYPE 0 of fluids.

8.4. For each release hole size, calculate the component damage consequence areas for Auto-Ignition Not Likely, Continuous Release (AINT-CONT), $CA^{AINL-CONT}$.

Consequence area for Component Damage Auto-Ignition Not Likely for the continuous release can be calculated by using this equation below:

$$CA_{cmd,n}^{AINL-CONT} = \alpha(rate_n)^b \ . \ (1 - fact_{mit}) \tag{2.45}$$

8.5. For each release hole size, calculate the component damage consequence areas for Auto-Ignition Likely, Continuous Release (AIT-CONT), $CA^{AIL\text{-}CONT}$.

Consequence area for Component Damage Auto-Ignition Likely for the continuous release can be calculated by using this equation below:

$$CA_{cmd,n}^{AIL-CONT} = \alpha(rate_n)^b \ . \ (1 - fact_{mit}) \tag{2.46}$$

8.6. For each release hole size, calculate the component damage consequence areas for Auto-Ignition Not Likely, Instantaneous Release (AINT-INST), $CA^{AINL\text{-}INST}$.

Consequence area for Component Damage Auto-Ignition Not Likely for the instantaneous release can be calculated by using this equation below:

$$CA_{cmd,n}^{AINL-INST} = \alpha(mass_n)^b \ . \ \left(\frac{1-fact_{mit}}{eneff_n}\right) \tag{2.47}$$

8.7. For each release hole size, calculate the component damage consequence areas for Auto-Ignition Likely, Instantaneous Release (AIT-INST), $CA^{AIL\text{-}INST}$.

Consequence area for Component Damage Auto-Ignition Not Likely for the instantaneous release can be calculated by using this equation below:

$$CA_{cmd,n}^{AIL-INST} = \alpha(mass_n)^b \ . \ \left(\frac{1-fact_{mit}}{eneff_n}\right) \tag{2.48}$$

8.8. For each release hole size, calculate the personnel injury consequence areas for Auto-Ignition Not Likely, Continuous Release (AINL-CONT), $CA^{AINL\text{-}CONT}$.

Consequence area for Personnel Injury Auto-Ignition Not Likely for the continuous release can be calculated by using this equation below:

$$CA_{inj,n}^{AINL-CONT} = [\alpha.(rate_n^{AINL-CONT})^b].(1 - fact_{mit}) \tag{2.49}$$

8.9. For each release hole size, calculate the personnel injury consequence areas for Auto-Ignition Likely, Continuous Release (AIT-CONT), $CA^{AIL\text{-}CONT}$.

Consequence area for Personnel Injury Auto-Ignition Not Likely for the continuous release can be calculated by using this equation below:

$$CA_{inj,n}^{AIL-CONT} = [\alpha.(rate_n^{AIL-CONT})^b].(1 - fact_{mit}) \tag{2.50}$$

8.10. For each release hole size, calculate the personnel injury consequence areas for Auto-Ignition Not Likely, Instantaneous Release (AINL-INST), $CA^{AINL-INST}$.

Consequence area for Personnel Injury Auto-Ignition Not Likely for the instantaneous release can be calculated by using this equation below:

$$CA_{inj,n}^{AINL-INST} = [\alpha.(mass_n^{AINL-INST})^b].\left(\frac{1-fact_{mit}}{eneff_n}\right) \quad (2.51)$$

8.11. For each release hole size, calculate the personnel injury consequence areas for Auto-Ignition Likely, Instantaneous Release (AIL-INST), $CA^{AIL-INST}$.

Consequence area for Personnel Injury Auto-Ignition Likely for the instantaneous release can be calculated by using this equation below:

$$CA_{inj,n}^{AIL-INST} = [\alpha.(mass_n^{AIL-INST})^b].\left(\frac{1-fact_{mit}}{eneff_n}\right) \quad (2.52)$$

8.12. Calculating the instantaneous/continuous blending factor, $fact_n$, for each release hole size using the equation as applicable for instantaneous or continuous release type for each release hole size.

a. For continuous release type

$$fact_n^{IC} = \min\left[\left\{\frac{rate_n}{C_5}\right\}, 1.0\right] \quad (2.53)$$

b. For instantaneous release type

For instantaneous releases, the blending factor is not required. Since the definition of instantaneous release is one with an adjusted release rate, $rate_n$,, greater than 25.2 kg/s (55.6 lbs.) (4356 kg/s (10000 lbs.) in 3 minutes), the blending factor is equal to 1.0. (2.54)

8.13. Calculating the AIT blending factor, $fact^{AIT}$, using equation (2.55), (2.56), or (2.57) as applicable.

$$fact_n^{IC} = 1.0$$

$$fact^{AIT} = 0 \quad \text{if } T_s + C_6 \leq AIT \quad (2.55)$$

$$fact^{AIT} = \frac{(T_s - AIT + C_6)}{2\,x\,C_6} \quad \text{if } T_s + C_6 > AIT > T_s - C_6 \quad (2.56)$$

$$fact^{AIT} = 1 \quad \text{if } T_s - C_6 \geq AIT \quad (2.57)$$

Where:

T_s = 100°C

T_s = 212°F

T_s = 373.15 K

C_6 = 55.6 K

AIT = 557,78°C

AIT = 830.78 K

8.14. Calculating the continuous/instantaneous blended consequence area for the component using equation (2.58) through (2.61) based on the consequence area that have been calculated in the previous steps.

$$CA^{AIL}_{cmd,n} = CA^{AIL-INST}_{cmd,n} x\, fact^{IC}_{n} + CA^{AIL-CONT}_{cmd,n} x\, (1 - fact^{IC}_{n}) \tag{2.58}$$

$$CA^{AINL}_{cmd,n} = CA^{AINL-INST}_{cmd,n} x\, fact^{IC}_{n} + CA^{AINL-CONT}_{cmd,n} x\, (1 - fact^{IC}_{n}) \tag{2.59}$$

$$CA^{AIL}_{inj,n} = CA^{AIL-INST}_{inj,n} x\, fact^{IC}_{n} + CA^{AIL-CONT}_{inj,n} x\, (1 - fact^{IC}_{n}) \tag{2.60}$$

$$CA^{AINL}_{inj,n} = CA^{AINL-INST}_{inj,n} x\, fact^{IC}_{n} + CA^{AINL-CON}_{inj,n}\, x\, (1 - fact^{IC}_{n}) \tag{2,61}$$

8.15. Calculating the AIT blended consequence areas for the component using equation (2.62) and (2.63).

$$CA^{flam}_{cmd,n} = CA^{AIL}_{cmd,n}\, x\, fact^{AIT} + CA^{AINL}_{cmd,n} x\, (1 - fact^{AIT}) \tag{2.62}$$

$$CA^{flam}_{inj,n} = CA^{flam-AIL}_{inj,n}\, x\, fact^{AIT} + CA^{AINL}_{inj,n} x\, (1 - fact^{AIT}) \tag{2.63}$$

8.16. Determining the final consequence areas (probability weighted on release hole sizes) for component damage and personnel injury using equation (2.64) and (2.65).

$$CA^{flam}_{cmd} = \left(\frac{\sum gff_n \cdot CA^{flam}_{cmd,n}}{gff_{total}} \right) \tag{2.64}$$

$$CA^{flam}_{inj} = \left(\frac{\sum gff_n \cdot CA^{flam}_{inj,n}}{gff_{total}} \right) \tag{2.65}$$

9. Calculating the toxic consequence area

Because of no toxic chemical composition, so this step not calculate

10. Calculating the Non-flammable and Non-toxic consequence area

Because this piping containing gas constituents, so, the vapor or stream from the liquid is included into the non-flammable and non-toxic consequence that should be calculated using these following steps.

10.1. For each release hole size, calculate the non-flammable and non-toxic consequence are using equation (2.66) and (2.69)

For caustics/acids that have splash type consequences. Acid or caustic leaks do not result in a component damage consequence. The consequence area was defined at the 180° semi-circular area covered by the liquid spray or rainout. Modeling was performed at three pressures; 103.4 kPa, 206.8 kPa, and 413.7 kPa (15 psig, 30 psig, and 60 psig) for four release hole sizes (see Table 4.4). The results were analyzed to obtain a correlation between release rate and consequence area, and were divided by 5 since it is believed that serious injuries to personnel are only likely to occur within about 20% of the total splash area as calculated by the above method

a. For continuous release type

$$CA_{inj,n}^{CONT} = 0.2 \cdot C_8 \cdot g\left(C_4 \cdot rate_n\right)^h \tag{2.66}$$

$$g = 2696 - 21.9 \cdot C_{11}\,(P_S - P_{atm}) + 1.474\,[C_{11}(P_S - P_{atm})]^2 \tag{2.67}$$

$$h = 0.31 - 0.00032\,\left[C_{11}\left(P_S - P_{atm}\right) - 40\right]^2 \tag{2.68}$$

b. For instantaneous release type

$$CA_{inj,n}^{INST} = 0 \tag{2.69}$$

10.2. For each release hole size, calculate the continuous/instantaneous blending factor, $fact_{id}$, for acid.

10.3. For each release hole size , compute the blended non-flammable , non-toxic personnel injury consequence area for steam or acid leaks using equation based on the consequence are from step 10.1 and the blending factor from step 10.2 note that there is no need to calculate component damage area for the level 1 non-flammable release (steam or acid/caustic)

$$CA_{cmd,n}^{leak} = 0 \tag{2.70}$$

$$CA_{inj,n}^{leak} = CA_{inj,n}^{INST} \cdot fact_n^{IC} + CA_{inj,n}^{CONT} \cdot \left(1 - fact_n^{IC}\right) \tag{2.71}$$

10.4. Determining the final non-flammable, non-toxic consequence areas for personnel injury using equation (2.72)

$$CA_{inj}^{nfnt} = \left(\frac{\sum gff_n \cdot CA_{inj,n}^{leak}}{gff_{total}}\right)$$

(2.72)

11. Calculating the final consequence area

11.1. Calculate the final component damage consequence area, CA_{cmd}, using equation (2.73)

$$CA_{cmd} = CA_{cmd}^{flam} \quad (2.73)$$

11.2. Calculate the final personnel injury consequence area, CA_{inj}, using equation (2.74)

$$CA_{inj} = \max\left[CA_{inj}^{flam},\ CA_{inj}^{tox},\ CA_{inj}^{nfnt}\right] \quad (2.74)$$

11.3. Calculate the final consequence rea, CA, using equation (2.75)

$$CA = \max\left[CA_{cmd}, CA_{inj}\right] \quad (2.75)$$

2.11.3. Risk

Risk define as the combination between the probability of failure in certain time and the consequence (usually negative) from the event. Every system consist of several component and their risk. Because of this component part of the system, so the failure will be impact to the systm. The probability from the component risk must be hold out in the acceptable level by doing testing or inspection.

Risk definition

$$Risk = P_{f(t)} . C_{f(t)} \quad (2.76)$$

Where $P_f\ (t)$ is probability of falure, $C_f\ (t)$ and consequence of failure. From this equation it can be concluded that an effective risk assessment must be rational, logical, structured and contain:

- How significant the impact of these risks.
- Whether the risk is acceptable.
- How high is the probability that the risk will occur.

2.11.4. Risk Matrix

Risk matrix is a way to determine the level of risk from the related components. Red indicates high risk, orange indicates medium-high level of risk, yellow indicates that the risk of failure of the component is at medium level, green indicates risk at low level. An example of a risk matrix is shown in Figure 2.11 below.

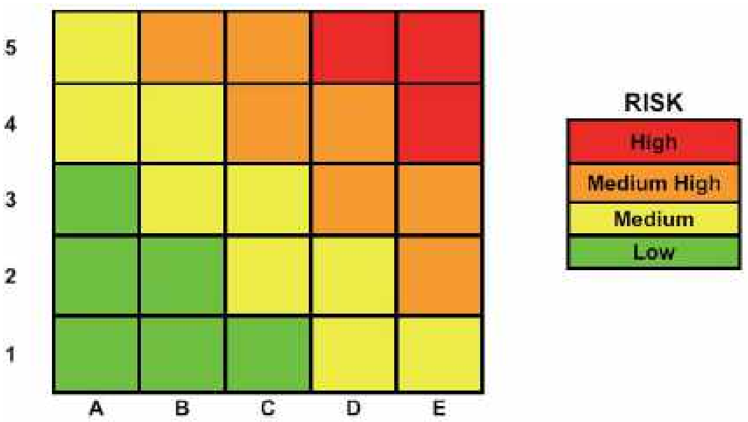

Figure 2. 11 Risk Matrix

In Figure 2.11, the horizontal axis is the level of consequence of failure or damage factor, and the vertical axis is the level of probability of failure or damage factor. For the classification of values can be seen in the following table which is an excerpt from table 4.1M in API RP 581, Part 1.

Table 2. 19 Numerical value associated with POF and COF categories

Category	Probability Category		Consequence Category	
	Probability range	Damage factor range	Category	Range (m^2)
1	$P_f(t, I_E) \leq$ 3.06E-05	$D_{f-total} \leq 1$	A	CA≤9.29
2	3.06E-05 < $P_f(t, I_E) \leq$3.06E-	$1 < D_{f-total} \leq 10$	B	9.29<CA≤92.9
3	3.06E-04 < $P_f(t, I_E) \leq$3.06E-	$10 < D_{f-total} \leq 100$	C	92.9<CA≤929
4	3.06E-03 < $P_f(t, I_E) \leq$3.06E-	$100 < D_{f-total} \leq 1000$	D	929<CA≤9290
5	$P_f(t, I_E) >$ 3.06E-02	$D_{f-total} > 1000$	E	CA>9290

2.11.5. Inspection Plan

Inspections are designed based on the risk level of an equipment according to the risk analysis using RBI. Equipment with a higher level of risk will be prioritized for inspection. Inspections are carried out when the risk or condition of the equipment has exceeded the target set by the company. Targets that can be determined by the RBI for mitigation actions are :

- Risk Target - the minimum risk level for planning an inspection. Can be a unit area (m2 / year) or financial ($ / year).
- PoF Target - The maximum limit of frequency of failures / leaks that are acceptable (# / year) or can trigger inspection planning.

- DF Target - The maximum damage value (a factor of PoF) that can be accepted or can trigger inspection planning.
- CoF target - Unacceptable level of consequence area (CA) or financial consequence (FA).
- Target Thickness - The minimum thickness that is acceptable or can trigger inspection planning.
- Target Interval - The maximum interval for the time of inspection

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CHAPTER III
METHODOLOGY

3.1 General Overview

Bachelor Thesis in the third chapter contains a flowchart, which becomes the summary for determining every process for doing calculation and risk analysis to raise the risk level and inspection program. In figure 3.1. Show the flowchart of the methodology.

3.2 Literarure Study

A literature study is being done to make a summary of fundamental theory both generally and specifically. Conducting a literature review means of demonstrating the author's knowledge about a particular field of study, in this case, is about the gas industry, including vocabularies, theories, key variables and phenomena, and its additional method or working principles. This literature Study, by reading and summarise the journal, handbook, textbook, company database, the other well-done thesis, and even from the internet surfing about everything related to the author's thesis. The discussion between the author-company supervisor, and author-thesis supervisor also included as an effort to get more additional information to fulfill the literature study in order the author can provide several points of view and perspective to the readers. Table 3.1. Show the literature study by the author.

3.3 Collecting Data

Collecting data on the research component was carried out at PT Nusantara Regas, Jakarta Pusat. Data required in this Bachelor Thesis research as followed below:

- PID and PFD of Process Gas Piping
- Data Sheet about Process Gas Piping
- Heat material Balance (HMB) for the Process Gas Piping
- Safety Plan of the gas plant
- Corrosion study report
- pH report for the Process Gas Piping
- Chemical Composition Data for the Process Gas Piping

The collected data next will be processed as it meant to be to determine the probability of failure and consequence of failure in order the inspection program cam appropriately done and the scheduling of inspection planning can be run in the right time before the plant is shutdown.

Table 3. 1 Literature Study Result

References	Result
Company Database about the Process Gas Piping, and previous pressure vessel inspection	Used as a fundamental reference of researching this Bachelor Thesis which help to conduct the background theory, study literature, and reference.
Textbook: International Journal of Chemical Industry	Additional reference to order the background theory, and literature study.
Guidelines : API 580 API 581	Recommended Practice (RP) which provides guidelines to order minimum program requirements to qualify for establishing inspection intervals based on Risk-Based Inspection (RBI) analysis and provides additional suggested guidelines on risk analysis to develop an effective inspection plan.
Internet Reference	Provide the information about the definition and working principle of pressure vessel, Process Gas Piping and Corrosion
Discussion with the company supervisor	Process Gas Piping in Muara Karang Peaker Gas Meter is owned by PT Nusantara Regas which functioned to drain the gas from ORF to the power plant.
Discussion with the bachelor thesis supervisor	The analysis of Process Gas Piping tends to be a corrosive pressure vessel because of its function and direct gas inlet connection.

3.4 Data Processing

All of data processing, based on Recommended Practice API 581 which provides a basis for managing risk by making an informed decision on inspection frequency level of detail and types of Non-Destructive Examination (NDE). The calculation needed is consisted of POF calculation, COF calculation, and risk analysis. So, the inspection planning program can be determined.

3.5 Calculating Probability of Failure (POF)

The methods for calculating the Probability of Failure (POF) for pressure vessel (Piping) are covered in Recommended Practice API 581 Part 2 (according to the Table 1.1)**Invalid source specified.**. The POF is based on the component type and damage mechanisms present referred on:

- The process fluid characteristics
- Design conditions
- Materials of construction
- And the original construction code

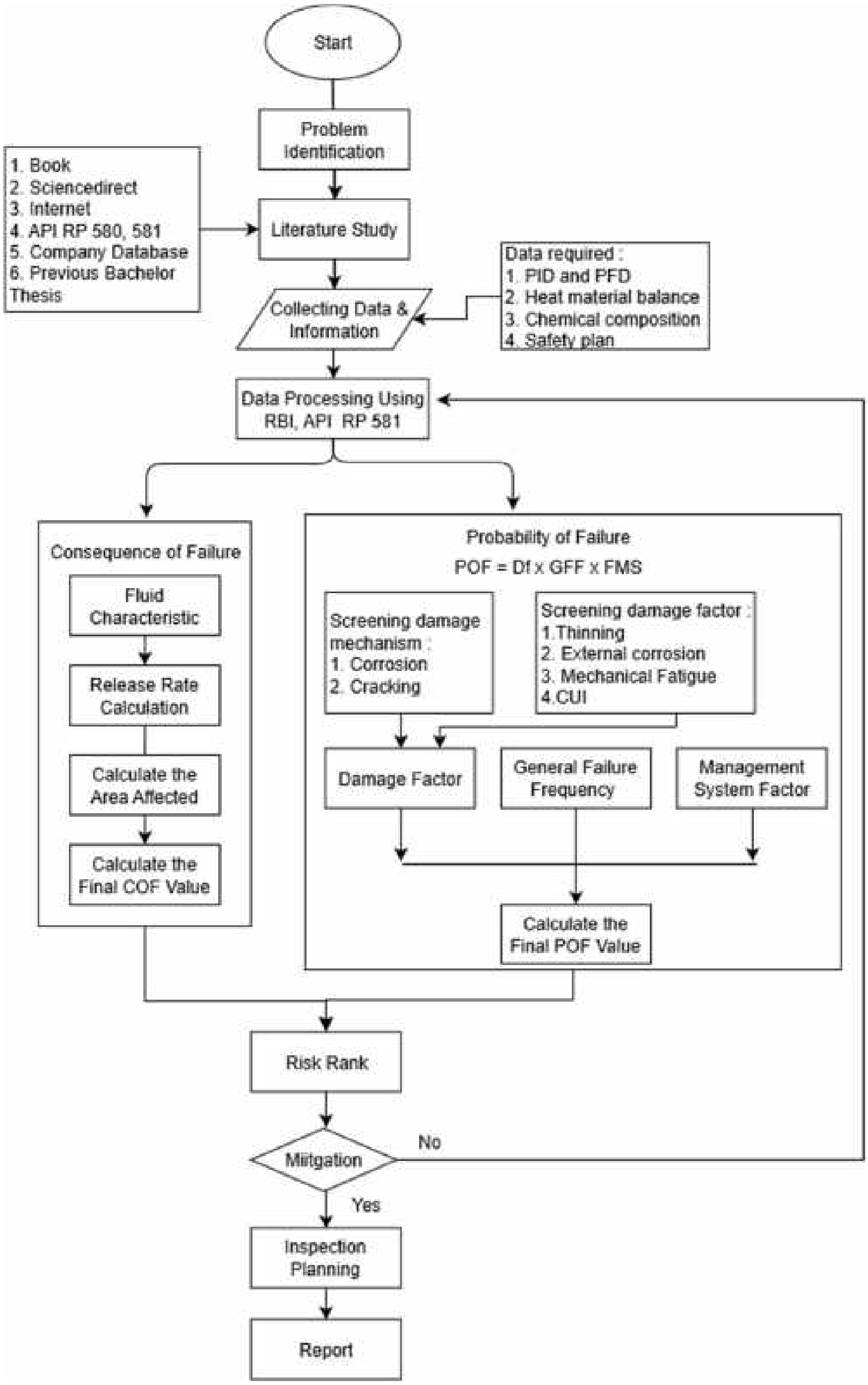

Figure 3. 1 Flowchart Methodology

POF is as a function of time and inspection effectiveness is determined using a generic failure frequency, factor management system, and DFs for the applicable active damage mechanisms, which can be mathematically formulated as follows:

$$P_f\ (t) = gff.D_f\ (t).F_{MS} \quad \text{...} \ (3.1)$$

3.6 Calculating Consequence of Failure (COF)

The methodology for calculating the Consequence of Failure (COF) for pressure vessel (Piping) are covered in Recommended Practice API 581 Part 3 (according to the Table 3.1. Steps in Consequence Analysis and Figure 3.1. Level of COF Methodology). The COF methodology is performed to aid in establishing a ranking of equipment items on the basis of risk and also intended to be used for establishing priorities for inspection programs. In this RBI case, the author has implemented the calculation consequence area procedure of pressure vessel or piping in a particular gas plant owned by PT Nusantara Regas. As described in the API Recommended Practice 581, there are two kinds of COF levels namely Level 1 and Level 2 which has different application of fluid characteristics one and another. In this Consequence Area calculation of Process Gas Piping is used Level 1 of COF because the major fluids contain inside the pressure vessel has been defined in a list of representative fluids provides by the API RP 581 itself.

3.7 Risk Rank

Among the POF and COF calculation are inseparable to determine the risk analysis and inspection planning program. Once, the particular risk of the equipment is defined, then, it can be inspected by a suitable treatment to prevent any damage or plant shutdown. So that, it can keep the equipment's lifetime and reduce any damage for the personnel, equipment, plant, and even the environment.

3.8 Result

After calculating both of Probability of Failure (POF) and Consequence of Failure (COF), the result can be determined. If the result is accepted, the we can continue to do the inspection planning using the right methodology of maintenance. In the other hand, if the result is denied, so, we have to do some mitigation step which requires to re-calculate both POF and COF until result is entirely accepted.

3.9 Inspection Plan

After calculating both of Probability of Failure (POF) and Consequence of Failure (COF), the result can be determined. If the result is accepted, the we can continue to do the inspection planning using the right methodology of maintenance. In the other hand, if the result is denied, so, we have to do some mitigation step which requires to re-calculate both POF and COF until result is entirely accepted.

1. Type of the Damage
   This type of damage can be seen in Recommended Practice API 581
2. The opportunity for Non-Destructive Evaluation (NDE) methods to identify the damage
3. Maximum interval as specified in the code and standards

3.10 Finish

The final stage is decision making from the result of comparative inspections that have been applied to the relevant company. In the last step, conclusion will be drawn from this final project analysis. At this stage comment and suggestion can be formulated and used as references for further decision making.

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CHAPTER IV
DATA ANALYSIS AND DISCUSSION

4.1 Process Gas Piping Data

Conducting the Risk-Based Inspection (RBI) calculation needs several bundles of data based on the American Petroleum Institution (API) 580 Chapter 7 which are design and construction of the Process Gas Piping (PFD and P&ID), Process Gas Piping operating conditions, Heat Material Balance (HMB), Chemical Composition Data of the Process Gas Piping, Safety Plan of the equipment, and many more. Those data will be processed and referred to the steps and formulation contained in the API 581 both for Probability of Failure (POF) and Consequence of Failure (COF). Here are the detail explanation about analyzed data:

4.1.1 General Data

General Data is the data containing basic information and general specification about the Process gas Piping starting from its Tag Number, Quantity, Service, Serial Number, Manufacturer, Type of the pressure Vessel, and the Code of the Process Gas piping which is referred to the ASME B.31.3, 2018 Edition. General specification of piping shows in Table 4.1

4.1.2 Data Quality

This equipment will be operate in March 2020, so there is no caorrosion rate, and the value of corrosion rate assume based on API 510 "The general corrosion rate of a vessel is known to be less than 0.005 in. (0.125 mm) per year". For thinning, the corrosion rate based on the CO_2 corrosion rate, and the value is 0,0079703 mm/year. For external corrosion rate based on the enivironment and temperature, the location of Muara Karang Peaker near the sea, so its categorized as marine environtment with corrosion rate 0,127 mm/year.

The volume inventory in the calculation Consequence of Failure (COF) based on the the biggest volume of gas from FSRU which flow to ORF. Based on the daily report on 26th May 2019, the volume is 117.586,101 m^3. Heat Materail Balance (HMB) and gas composition data for this calculation based on the existing data.

4.1.3 Design Condition

This type of data is showing the design condition and characteristic of the Process Gas Piping when it was designed by the manufacturer such as the information about the design pressure and design temperature.

Table 4. 1 General Specification of Piping

GENERAL SPECIFICATION OF PRESSURE VESSEL				
Tag Number		:	306 - JY - 09	
Quantity		:	1	
Service		:	Process Gas piping	
Serial No.		:	12" - PG - 06251 - C	
Code		:	ASME B.31.3	
Design Pressure	(P)	:	95	barg
		:	1363,35	psig
		:	9,4	MPa
Design Temperature	(T)	:	65	°C
		:	149	°F
Outer Diameter	(OD)	:	323,8	mm
		:	12	inch
Operating Pressure		:	46	barg
		:	667,174	psig
Operating Temperature		:	18,83	°C
		:	65,894	°F
Flow Rate		:	135	mmscfd
Efficiency	(Ef)	:	1	
Corrosion Allowance	(CA)	:	1,6	mm
		:	0,062992	inch
Minimum Thickness	(t)	:	15,29	mm
		:	0,6	inch
Corrosion Rate	(CR)	:	0,125	mm/years
		:	0,0049	inch/years
Allowable Stress	(S)	:	23300	psig
		:	1606,479	bar
		:	160,6479	Mpa
Year Built		:	2017	
Material		:	A 106 GR, SMLS, SCH 80, BE	
Last Inspection		:	-	

4.1.4 Operating Condition

Operating conditions are set of conditions for operating a particular system or process, in this case the will be reach when the Process Gas Piping is being operated. This set of data is containing operating pressure, operating temperature, Maximum Allowable Working Pressure (MAWP), Corrosion Allowance, Jont Efficiency, Vessel

Volume, and so on. In this case, the operating condition is explained deeper both in the shell and head of the Process Gas Piping.

4.1.5 Materials

Material is the basic component metal ingredients used to build the Piping based on the several factors and considerations. In Muara Karang Peaker Gas Meter owned by PT Nusantara Regas, the ingredients for making the Process Gas Piping is A 106 GR, SMLS, SCH 80, BE (Carbon Steel).

4.2 Fluid Properties

Fluid composition or containment processed inside the Process Gas Piping of pressure vessel can be seen in table of Heat Material Balance (HMB) below. As we know that Heat Material Balance (HMB) is one of the basic process engineering document produced by process design engineers while an initial designing of process plant. The HMB document includes operating conditions, chemical compositions, and key physical properties of every major process stream on the Process Flow Diagram (PFD).

Table 4. 2 Chemical Composition

Gas Composition % Mol	
Methane	92,3802
Nitrogen	0,0047
CO2	3,1479
Ethane	2,5964
Propane	1,1551
i - Butane	0,3174
n- Butane	0,3596
i - Pentane	0,0267
n - Pentane	0,0072
n - Hexane	0,0012
% Total	99,996

4.3 Piping

There are 8 pipes, 5 pipes with diameter 12 inch and 3 pipes with diameter 2 inch, because the same of operating temperature, operating pressure, type of fluid, and environment so the calculations take the sample from pipes 12" - PG - 06251 – C and 2" – PG – 06255 – C based on the diffrent diameter. The pipes are :

- 12” – PG – 06247 – C
- 12” – PG – 06249 – C
- 12” – PG – 06250 – C
- 12” – PG – 06251 – C
- 12” – PG – 06252 – C
- 2” – PG – 06253 – C
- 2” – PG – 06254 – C
- 2” – PG – 06255 – C

4.3.1 Probabiliy of Failure

There are two pipes calculation, with diffrent diameter. Pipe 12” – PG – 06251 – C, pipe with diameter 12 inch and the other 2” – PG – 06255- C with diameter 2 inch.

Probability of Failure (POF) is calculated by the value of the total Damage Factor (DF), generic failure frequency, and factor management system from the company. Damage Factor can be identifying by screening criteria, can be seen in ATTACHMENT 2A and 3A: DAMAGE FACTOR SCREENING QUESTION PROCESS GAS PIPING. Damage factor for this equpment are thinning, mechanical fatigue, and external corrosion.

Step how to determine the Probability of Failure of the piping in Muara Karang Peaker as mentioned below:

1. **Thinning**

   Thinning - is a degradation of the metal due to its environment which results in thinning of the thickness of the metal. To find out the value of damage factor thinning, it requires data on the material corrosion rate. The data is obtained from the last inspection or corrosion lane calculation based on the thinning mechanism in Annex 2.B API RP 581. Thinning can occur due to several mechanisms. For this case, the thinning mechanism that matches the API RP 581 corrosion rate screening criteria is CO2 corrosion. For detail calculation on ATTACHMENT 2B : PROBABILITY OF FAILURE (POF) CALCULATION OF RISK BASED INSPECTION API 581. The result of thinning calculation for damage factor in Pipe 12” – PG – 06251 -C is 0,24092090927 for RBI date and 0,2409196704 for palnned date. The result of thinning calculation for damage factor in Pipe 2” – PG – 06255 -C is 0,24094067523 for RBI date and 0,2409374389for palnned date.

2. **Mechanical Fatigue**

   Fatigue failures of piping systems present a very real hazard under certain conditions. Properly designed and installed piping systems should not be subject to such failures, but prediction of vibration in piping systems at the design stage is very difficult, especially if there are mechanical sources of cyclic stresses such as reciprocating pumps and compressors. In addition, even if a piping systems are not subject to mechanical fatigue in the as-built condition, changing conditions such as failure of pipe supports, increased vibration from out of balance machinery, chattering of relief valves during process upsets, changes in flow and pressure cycles or adding weight to unsupported branch connections (pendulum effect) can render a piping system susceptible to failure. Awareness of these influences incorporated into a management of change program can reduce the POF. For detail calculation on ATTACHMENT 2B and 3B : PROBABILITY OF FAILURE (POF) CALCULATION OF RISK BASED INSPECTION API 581. The result of mechanical fatigue calculation for damage factor is 0,0111

3. **External Corrosion**

As a general rule, plants located in areas with high annual rainfalls or warmer, marine locations are more prone to external corrosion than plants located in cooler, drier, mid-continent locations. Regardless of the climate, units located near cooling towers and steam vents are highly susceptible to external corrosion, as are units whose operating temperatures cycle through the dew point on a regular basis. Mitigation of external corrosion is accomplished through proper painting. A regular program of inspection for paint deterioration and repainting will prevent most occurrences of external corrosion. For detail calculation on ATTACHMENT 2B : PROBABILITY OF FAILURE (POF) CALCULATION OF RISK BASED INSPECTION API 581. The result of external corrosion calculation for damage factor Pipe 12" – PG – 06251 - C is 0,86192004 for RBI date and 0,86187933 for plan date. The result of external corrosion calculation for damage factor in Pipe 2" – PG – 06255 -C is 0,86193075 for RBI date and 0,86131798 for plan date.

4. **Probability of Failure**

Probability of failure is the possibility of failure on the component. The value is a function of damage factor, generic failure frequency (gff) and factor management system (fms). The value of gff is determined based on the type of equipment (piping) with the value 3,06 x 10-5, the value of fms determined by doing screening to the company management or by comply to the API RP 581, with the total value of screening is 500 the the result of fms is 1. Total damage factor is the combination of 3 damage factors. Table 4.3 describes the result of damage factor and POF.

Table 4. 3 Total Damage Factor and POF

Tag Number	RBI Date		Plan Date	
	DF	POF	DF	POF
12” – PG – 06247 – C 12” – PG – 06249 – C 12” – PG – 06250 – C 12” – PG – 06251 – C 12” – PG – 06252 – C	1,113952065	3,40869 x 10^{-5}	1,113910112	3,4085 x 10^{-5}
2” – PG – 06253 – C 2” – PG – 06254 – C 2” – PG – 06255 – C	1,113982536	3,40878 x 10^{-5}	1,113366525	3,4069 x 10^{-5}

4.3.2 Consequence of Failure

There are 11 steps for determine the Consequence of Area from Process Gas Piping :

<u>Step 1: Determine the representative fluid and associated properties</u>

The representative fluid is the dominant fluid in the system which is used as a reference calculation if there is a leak in the piping. Generally, representative fluids are compounds with the most moles in the fluid. In the Muara Karamh Peaker the representative fluid is Methane, and when the equipment operates the output is gas phase. For detail calculation see ATTACHMENT 2D and 3D : CONSEQUENCE OF FAILURE (POF) CALCULATION OF RISK BASED INSPECTION API 581

<u>Step 2 : Select a set of release hole size to determine the possible range of consequence the risk</u>

A descrete set of release events or release hole sizes are used since it would be impractical to perform the consequence analysis for a continous spectrum of release hole sizes. Limiting the number of of release hole sizes allows for an analysis that is manageable, yet still reflects the range of possible outcomes.

The following steps are repeated of each release hole size, typically four hole sizes are evaluated. According to Annex 3.A of API 581 Chapter 3.2.3 committs that the standard four release hole sizes are assumed for all sizes in pressure vessel type.

Table 4. 4 Release hole size and area

Release Hole Number	Release Hole Sizes	Range of Hole Diameter (mm)	Release Hole Diameter; d_n (inch)
1	Small	0 - 1/4	$d_1 = 0{,}25$
2	Medium	> 1/4 - 2	$d_2 = 1$
3	Large	> 2 - 6	$d_3 = 4$
4	Rupture	> 6	$d_4 = \min [D,16]$

Step 3 : Calculate theoritical release rate

Theoritical release rate (Wn) calculate in every hole size to get the release rate. The value of Wn will be describe in Table 4.5. The greater release rate means the greater the impact that can be generated because it is related to the total mass of methane released at any time.

Table 4. 5 Theoritical release rate

12"- PG - 06251 - C			2"- PG - 06255 - C		
W_{n1}	8590,291246	kg/s	W_{n1}	8590,2912	kg/s
W_{n2}	137444,66	kg/s	W_{n2}	0	kg/s
W_{n3}	2199114,6	kg/s	W_{n3}	0	kg/s
W_{n4}	19792031	kg/s	W_{n4}	549778,64	kg/s

Step 4: Estimate the total amount of fluid inventory available for release

Total mass fluid estimate from the company data is $Mass_{inv}$ 78547,5155 kg. Then estimate the total inventory added with inventory of additional components that can provide additional mass. For the additional mass itself, API 581 estimates that there is a mass limit, because within 3 minutes there will be an intervention from the operator on leakage. Total fluid that can be removed in each output hole ($mass_{avail,\ n}$) shows in Table 4.6. For detail calculation see ATTACHMENT 2D and 3D : CONSEQUENCE OF FAILURE (POF) CALCULATION OF RISK BASED INSPECTION API 581

Table 4. 6 Mass add

12"- PG - 06251 - C			2"- PG - 06255 - C		
$Mass_{add1}$	1584,86	kgs	$Mass_{add1}$	1584,86	kgs
$Mass_{add2}$	1584,86	kgs	$Mass_{add2}$	0	kgs
$Mass_{add3}$	1584,86	kgs	$Mass_{add3}$	0	kgs
$Mass_{add4}$	1584,86	kgs	$Mass_{add4}$	1584,86	kgs

Step 5 : Determine the release type (continous or isntantaneous)

The release is modeled as one of these two following types : An instataneous or puff release is one that occurs so rapidly that the fluid disperses as a single large cloud or pool. A continous or plume release is one that occurs over a longer period of time, allowing the fluid to dispers in the shape of elongated ellipse (dependening in the weather conditions). The output condition is instantaneous if it can release a mass of 4536 kg in less than 180 seconds. Calculations are carried out to see the duration of removing a mass of 4536 kg of fluid in each hole size.

Table 4. 7 Time release rate

12"- PG - 06251 - C			2"- PG - 06255 - C		
t_1	0,528039	kgs	t_1	0,528039	kgs
t_2	0,033002	kgs	t_2	0	kgs
t_3	0,002063	kgs	t_3	0	kgs
t_4	0,000229	kgs	t_4	0,00825059	kgs

Step 6: Estimate the impact of detection and isolation system on release magnitude

Estimate the impact from detection system and isolation system to output. In this peaker the deection system is suitably located detectors to determine when the material is present outside the pressure-containing envelope, classification as B. For type isolation in peaker is isolation or shutdown systems activated by operators in the control room or other suitable location remote from the leak, classified as B. SO, maksimum time for each hole is in Table 4.8:

Table 4. 8 Maximum leaks duration

12"- PG - 06251 - C		2"- PG - 06255 - C	
Id_{max1}	40 minutes for1/4 inch	Id_{max1}	40 minutes for1/4 inch
Id_{max2}	30 minutes for 1 inch	Id_{max2}	30 minutes for 1 inch
Id_{max3}	20 minutes for 4 inch	Id_{max3}	20 minutes for 4 inch
Id_{max4}	20 minutes for 4inch	Id_{max4}	20 minutes for 4inch

The maximum leak time here includes the time to detect leakage, the time to analyze the incident and determine the corrective action, and the time to carry out the corrective action.

Step 7: Determine release rate and mass for consequence analysis

For continous type output. the output is described as coming out stable at a certain rate. The rate is obtained from the theoretical release rate value in step 3. The result on Table 4.9 :

Table 4. 9 Release Rate

12"- PG - 06251 - C			2"- PG - 06255 - C		
$Rate_1$	7301,74756	kg/s	$Rate_1$	7301,74756	kg/s
$Rate_2$	116827,990	kg/s	$Rate_2$	0	kg/s
$Rate_3$	1869247,38	kg/s	$Rate_3$	0	kg/s
$Rate_4$	1682322	kg/s	$Rate_4$	467311,844	kg/s

In addition to the release rate, the mass rate must also be calculated as a consideration for spontaneous output that is temporary.The result on Table 4.10 :

Table 4. 10 Mass release

12"- PG - 06251 - C			2"- PG - 06255 - C		
$Mass_1$	78547,52	kgs	$Mass_1$	78547,52	kgs
$Mass_2$	78547,52	kgs	$Mass_2$	0	kgs
$Mass_3$	78547,52	kgs	$Mass_3$	0	kgs
$Mass_4$	78547,52	kgs	$Mass_4$	78547,52	kgs

Step 8 : Calculate flammable /explosive consequence

Using the release rate and mass rate values in step 7, the calculation of step 8 is carried out to determine the consequence area for components and personnel using equations 2.37 to 2.58. In these equations there are constants a and b whose value can be determined from tables 4.6 and 4.7 in section 4.4. Here are the results of the consequences of flammability for components)Pipe 12’’ – PG – 06251 - C and 2’’ – PG – 06255 - C):

CA_{cmd}^{flam}= 583,22 m^2

The results of the consequences of flammability for personnel (Pipe 12’’ – PG – 06251 - C and 2’’ – PG – 06255 - C):

CA_{inj}^{flam}= 1123, 3 m^2

Step 9 : Calculate toxic consequence

Because this fluid no toxic, so this step not calculate.

Step 10 : Calculate the non flammable, non toxic consequence area

There are two categorized for type of liquid, for steam and for acid/caustic. The fluid in this equipment is acid. For caustics/acids that have splash type consequences. Acid or caustic leaks do not result in a component damage consequence. The consequence area was defined at the 180° semi-circular area covered by the liquid spray or rainout. Modeling was performed at three pressures; 103.4 kPa, 206.8 kPa, and 413.7 kPa (15 psig, 30 psig, and 60 psig) for four release hole sizes (see Table 4.4). The results were analyzed to obtain a correlation between release rate and consequence area, and were divided by 5 since it is believed that serious injuries to personnel are only likely to occur within about 15% of the total splash area as calculated by the above method. The results of the non-flammable, non toxic consequence area for (Pipe 12'' – PG – 06251 - C and 2'' – PG – 06255 - C):

CA_{inj}^{nfnt}= 0 m^2

Step 11 : Calculation of fianl consequence area

Final consequence area is the final component damage consequence area plus the final personnel injury consequence area:

CA =1123,3382 m^2

Both of pipes calculation have same value in consequence of area. For detail calculation see ATTACHMENT 2C and 3C : CONSEQUENCE OF FAILURE CALCULATION OF RISK BASED INSPECTION API 581

Table 4. 11 POF and COF Result

Piping	RBI date		Plan date		COF (m^2)
	DF	POF	DF	POF	
12" – PG – 06247 – C 12" – PG – 06249 – C 12" – PG – 06250 – C 12" – PG – 06251 – C 12" – PG – 06252 – C	1,113952	3,408693E-05	1,1139101	3,40856E-05	1.123,33
2" – PG – 06253 – C 2" – PG – 06254 – C 2" – PG – 06255 – C	1,113982	3,40878E-05	1,1133665	3,406906E-05	1.123,33

4.3.3 Inspection Plan

Inspection plan based on the target from company. No target from the company, but based on API 581 the risk target on scale 5 – 50 ft /year. The author use 10 ft/year for risk target.

Table 4. 12 RBI date to Risk Target For Pipe 12”- PG – 06251 - C

	Time	Risk (ft^2/year)	Risk target (ft^2/year)
Last insp. date	15/11/2018	0	10
RBI date	20/08/2019	0,412162146	10
Plan date	11/11/2022	0,412146624	10
Target	24/03/2023	10	10

Table 4. 13 RBI date to Risk Target for Pipe 2”- PG – 06255 - C

	Time	Risk (ft^2/year)	Risk target (ft^2/year)
Last insp. date	15/11/2018	0	10
RBI date	20/08/2019	0,412173420	10
Plan date	11/11/2022	0,411945496	10
Target	24/03/2023	10	10

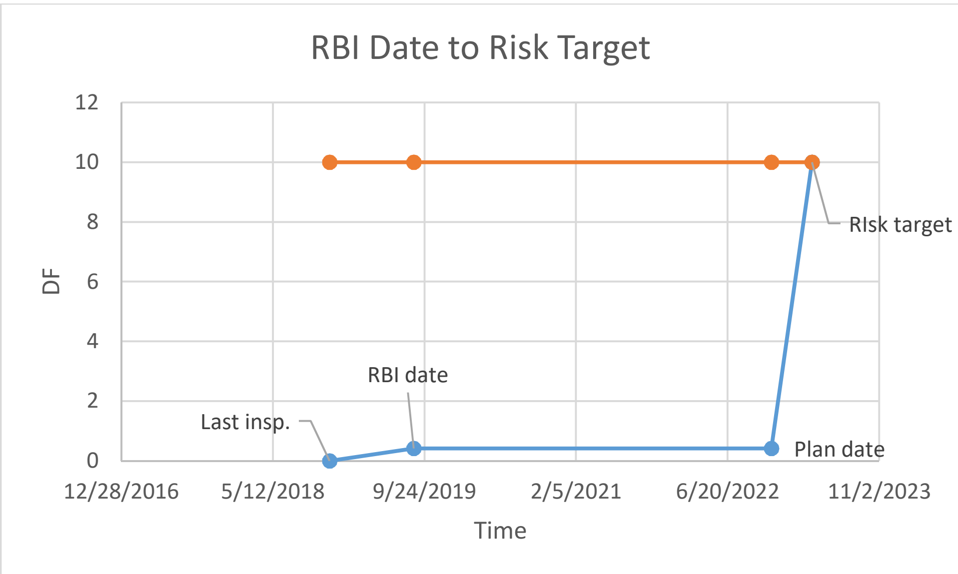

Figure 4. 1 RBI date to Risk Target for Pipe 12’’ – PG – 06251 - C

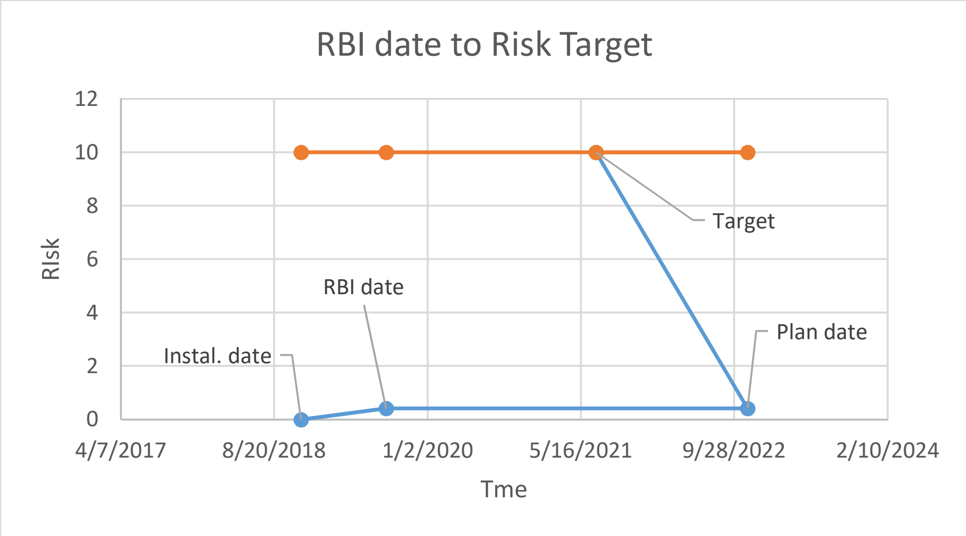

Figure 4. 2 RBI date to Risk Target for Pipe 2'' – PG – 06255 - C

For the risk rangking, it categorize as medium, shown in Figure 4.3.

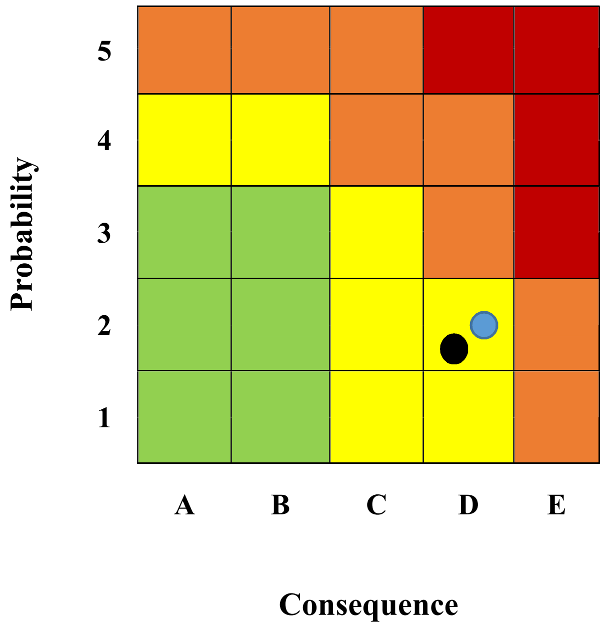

Figure 4. 3 Risk rangking

● Pipe 12" – PG – 06251 - C
● Pipe 2" – PG – 06255 - C

CHAPTER V
CONCLUSION AND SUGGESTION

5.1. Conclusion

1. The value Probability of Failure (POF) and Consequence of Failure (COF) shows in Table below :

Piping	RBI date		Plan date		COF (m^2)
	DF	POF	DF	POF	
12” – PG – 06247 – C 12” – PG – 06249 – C 12” – PG – 06250 – C 12” – PG – 06251 – C 12” – PG – 06252 – C	1,113952	3,40869E-05	1,113910	3,40856E-05	1.123,3
2” – PG – 06253 – C 2” – PG – 06254 – C 2” – PG – 06255 – C	1,113982	3,40878E-05	1,113366	3,40690E-05	1.123,3

2. Risk value of this calculation shows in table below. Both of the pipes have risk in medium category.

Piping	Risk (ft^2/year)		Risk (m^2/year)	
	RBI Date	Plan Date	RBI Date	Plan Date
12” – PG – 06247 – C 12” – PG – 06249 – C 12” – PG – 06250 – C 12” – PG – 06251 – C 12” – PG – 06252 – C	0,41216214	0,4214662	0,0382911	0,03828971
2” – PG – 06253 – C 2” – PG – 06254 – C 2” – PG – 06255 – C	0,41217342	0,4119454	0,0382922	0,0382710

3. Inspection planning and type of inspection for both of the pipe shows in the table below :

	Thinning	Mechanical Fatigue	External Corrosion
Effectiveness	D	-	D
Due Date	26/09/2023	01/05/2026	06/09/2022
Description **12" – PG – 06247 – C** **12" – PG – 06249 – C** **12" – PG – 06250 – C** **12" – PG – 06251 – C** **12" – PG – 06252 – C**	For the total surface area;>20% ultrasonic scanning or profile radiography.	Visual examination	Visual inspection of >5% of the exposed surface area with follow up by Ultrasonic Test, Radiography Test or pit gauge as required

	Thinning	Mechanical Fatigue	External Corrosion
Effectiveness			
Due Date	26/09/2023	01/05/2026	06/09/2022
Description 2" – PG – 06253 – C 2" – PG – 06254 – C 2" – PG – 06255 – C	For the total surface area;>20% ultrasonic scanning or profile radiography.	Visual examination	Visual inspection of >5% of the exposed surface area with follow up by Ultrasonic Test, Radiography Test or pit gauge as required

5.2. Suggestion

1. There is no data about corrosion rate. The maximum corrosion rate, according to API 510 is 0.125 mm/year. In this calculation, using comparison between the corrosion rate from API 510 and from API 581 Annex 2B. After several years the Peaker operation, should calculate the risk based on the recent corrosion rate.
2. Risk target for this calculation is 10 ft^2/year according to API 581. For the next calculation, company should detemine the risk target.

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ATTACHMENT

AUTHOR BIOGRAPHY

The author was born in Surabaya on August 4th 1998, named Ade Ratih Anggraini. She is the first bord of two siblings. The author has taken formal education in SDN Sambikerep II/480 Surabaya (2006 – 2010), SMP Negeri 6 Surabaya (2010 – 2013), SMA Negeri 2 Surabaya (2013 - 2016).

In 2016, the author accepted as a college student by Sepuluh Nopember Institute of Technology in Department of Marine Engineering which is familiar as Departemen Teknik Sistem Perkapalan. As a registered student of Double-Degree Program, the author has a chance to experience any curriculum courses from both Indonesia and German, because the Department of Marine Engineering itself has been cooperating with the Wismar Hochschule German.

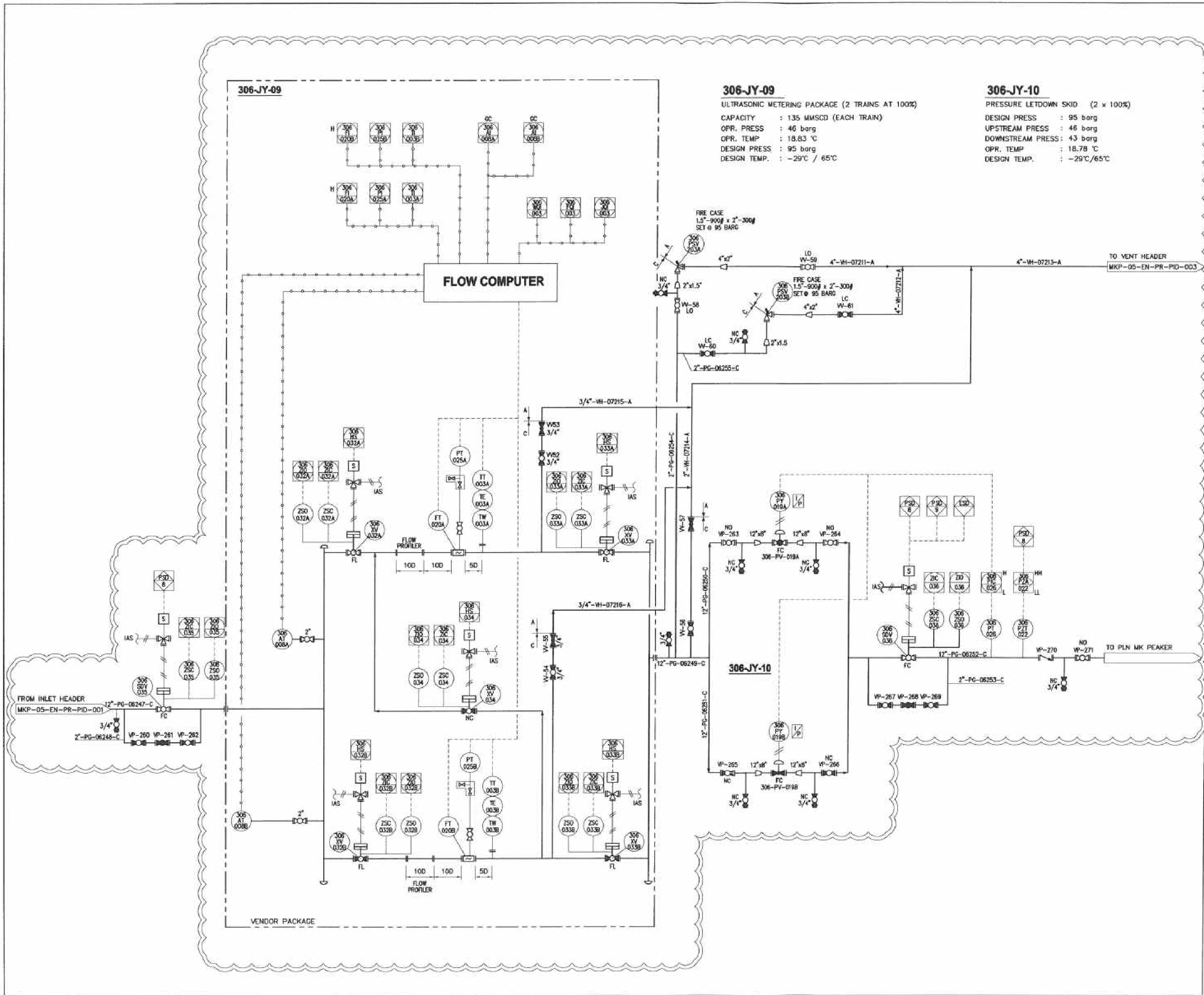
During college period, the author has been active following several organizations which were being External Staff of Volleyball UKM - ITS 2017,Secretary of Department Biro Seni dan Olahraga (BSO) HIMASISKAL 2018, voluntary activities, and so on. The author decides to take the field of Inspection for the Bachelor Thesis using Risk Based Inspection (RBI) API 581 Method. The author can be contacted via the following email : aderatiha@gmail.com.

	INSPECTION PROGRAM PLANNING OF PROCESS GAS PIPING USING RISK BASED INSPECTION API 581 IN MUARA KARANG PEAKER GAS METER

ATTACHMENT 1A :

P&ID OF PROCESS GAS PIPING

Rev	Tanggal	Keterangan	Disusun Oleh:		Disetujui Oleh:	
			Nama	Paraf	Pembimbing	Paraf
			Ade Ratih Anggraini		Ir. Dwi Priyanta, M.SE	
			No. Registration :		Nurhadi Siswantoro,ST.,MT.	
			04211641000008			



NOTES :

1. METERING INSTALLATION REFERS TO AGA 9.
2. DETAIL DRAWING FOR METERING PACKAGE WILL BE PROVIDED BY VENDOR

LEGEND

: SCOPE OF WORK MUARA KARANG PEAKER GAS METER PROJECT

FOR CONSTRUCTION

REV	DATE	DESCRIPTION	DSGN	CHKD	APVD	APVD
			HR			
0	13/09/2017	ISSUED FOR CONSTRUCTION	HR	DNG	CSW	
C	11/09/2017	ISSUED FOR APPROVAL	HR	DNG	CSW	
B	11/09/2017	ISSUED FOR APPROVAL	HR	DNG	SBK	
A	08/09/2017	ISSUED FOR REVIEW	HR	DNG	SBK	
			ELNUSA			NR

REVISIONS TABLE

CLIENT : NUSANTARA REGAS

CONTRACTOR : elnusa

PROJECT : MUARA KARANG PEAKER GAS METER

TITLE : PIPING & INSTRUMENT DIAGRAM
METERING SKID AND PRESSURE LETDOWN
(PLN MUARA KARANG PEAKER)

SCALE	CONTRACT NO	
NTS	00800/NR/D000/P/2017 068/EN/KTR/001D/2017	A3
SHEET	DRAWING NO:	REV NO.
1 OF 1	MKP-05-EN-PR-PID-002	0

	INSPECTION PROGRAM PLANNING OF PROCESS GAS PIPING USING RISK BASED INSPECTION API 581 IN MUARA KARANG PEAKER GAS METER

ATTACHMENT 1B :

CHEMICAL GAS COMPOSITION OF PROCESS GAS PIPING

Rev	Tanggal	Keterangan	Disusun Oleh:		Disetujui Oleh:	
			Nama	Paraf	Pembimbing	Paraf
			Ade Ratih Anggraini		Ir. Dwi Priyanta, M.SE	
			No. Registration :		Nurhadi Siswantoro,ST.,MT.	
			04211641000008			

Table 1. Gas Composition

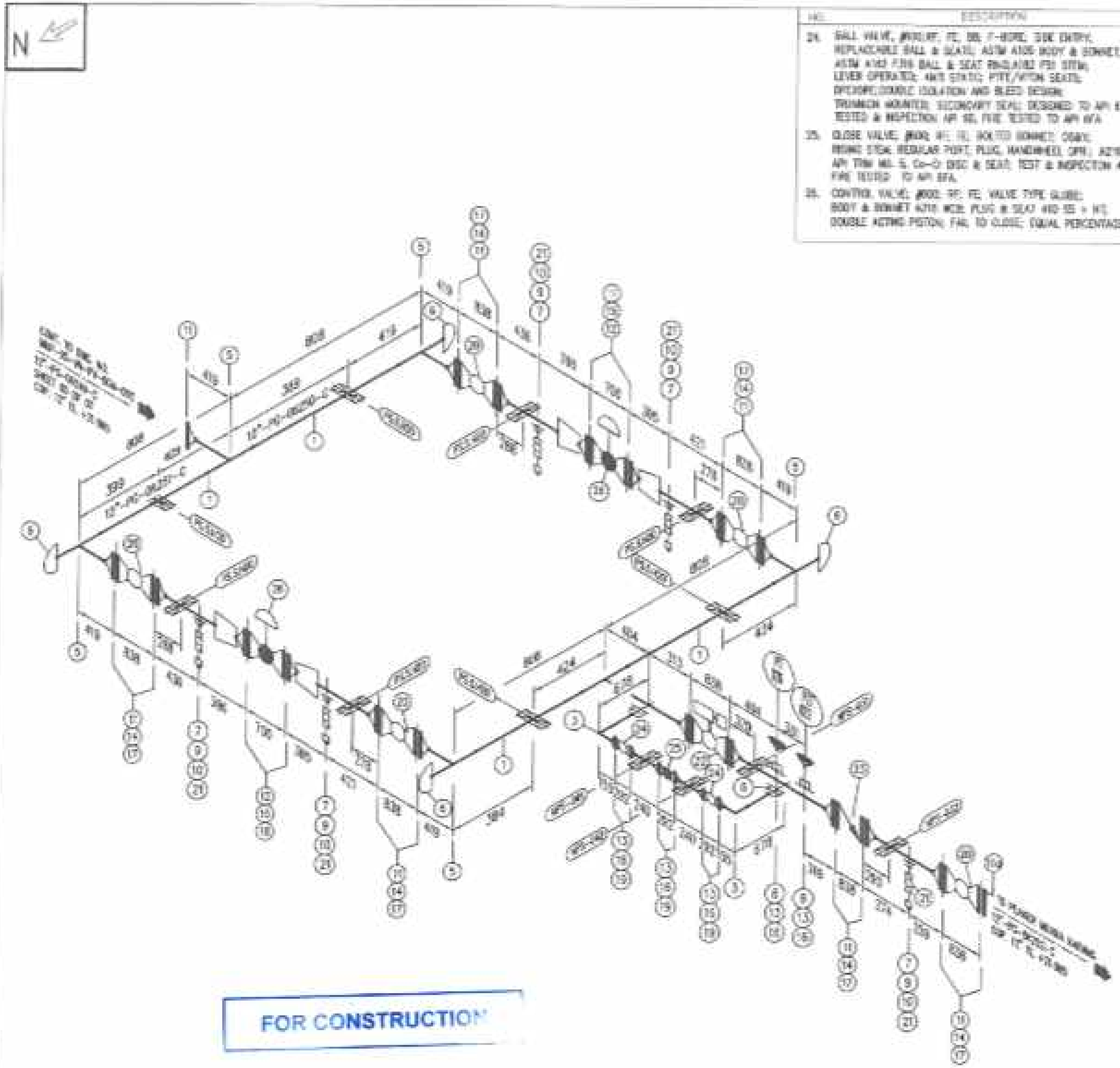
Gas Composition % Mol	
Methane	92,3802
Nitrogen	0,0047
CO_2	3,1479
Ethane	2,5964
Propane	1,1551
i - Butane	0,3174
n - Butane	0,3596
i - Pentane	0,0267
n - Pentane	0,0072
n - Hexane	0,0012
% Total	99,9964

	INSPECTION PROGRAM PLANNING OF PROCESS GAS PIPING USING RISK BASED INSPECTION API 581 IN MUARA KARANG PEAKER GAS METER

ATTACHMENT 1C :

ISOMETRIC DIAGRAM OF:
12" - PG - 06249 - C
12" - PG - 06250 - C
12" - PG - 06251 - C
12" - PG - 06252 - C
2" - PG - 06253 - C

Rev	Tanggal	Keterangan	Disusun Oleh:		Disetujui Oleh:	
			Nama	Paraf	Pembimbing	Paraf
			Ade Ratih Anggraini		Ir. Dwi Priyanta, M.SE	
			No. Registration :		Nurhadi Siswantoro,ST.,MT.	
			04211641000008			



FOR CONSTRUCTION

NO.	DESCRIPTION	SIZE	Q'TY
24.	BALL VALVE, #800,RF, FE, BB, F-BORE, SIDE ENTRY, REPLACEABLE BALL & SEATS; ASTM A105 BODY & BONNET, ASTM A182 F316 BALL & SEAT ENP,A182 F51 STEM; LEVER OPERATED; ANTI STATIC; PTFE/VITON SEATS; DPE/DIPE;DOUBLE ISOLATION AND BLEED DESIGN; TRUNNION MOUNTED; SECONDARY SEAL; DESIGNED TO API 6D; TESTED & INSPECTION API 6D, FIRE TESTED TO API 6FA	2"	2 EA
25.	GLOBE VALVE, #800, RF, FE, BOLTED BONNET, OS&Y, RISING STEM, REGULAR PORT, PLUG, HANDWHEEL OPR.; A216 WCB BODY, API TRIM NO. 5, Co-Cr DISC & SEAT, TEST & INSPECTION API 598, FIRE TESTED TO API 6FA	2"	1 EA
26.	CONTROL VALVE, #600, RF, FE, VALVE TYPE GLOBE; BODY & BONNET A216 WCB, PLUG & SEAT 410 SS + NT, DOUBLE ACTING PISTON, FAIL TO CLOSE; EQUAL PERCENTAGE	8"	2 EA

NO.	DESCRIPTION	SIZE	Q'TY
1.	PIPE, A106-B, SMLS, SCH 80, BE, ASME B36.10	12"	2690 MM
2.	PIPE, A106-B, SMLS, SCH 80, BE, ASME B36.10	2"	735 MM
3.	90 DEG. ELBOW, A234-WPB, SMLS, LR, SCH 80, BW, ASME B16.9	2"	2 EA
4.	CONCENTRIC REDUCER, A234-WPB, SMLS, SCH 80, BW, ASME B16.9	12"x8"	2 EA
5.	TEE EQUAL, A234-WPB, SMLS, SCH 80, BW, ASME B16.9	12"	8 EA
6.	CAP, A234-WPB, SCH 80, BW, ASME B16.9	12"	4 EA
7.	COUPLING, CS, A105, CL 3000, 3/4 - THD NPT, ASME B16.11	3/4"	5 EA
8.	WELDOLET, A105, SCH 80, BW, ASME B16.11	2"	4 EA
9.	SOCKOLET, CS, A105, CL 3000, MSS, SP-97	3/4"	5 EA
10.	PLUG, CS, A105, CL 3000, HEX-HEAD NPT, ASME B16.11	3/4"	5 EA
11.	FLANGE, A105, WN, SCH 80, ANSI CL.600 RF-SERRATED-F, ASME B16.5	12"	14 EA
11a.	BLIND FLANGE, A105, ANSI CL.600 RF-SERRATED-F, ASME B16.5	12"	1 EA
12.	FLANGE, A105, WN, SCH 80, ANSI CL.600 RF-SERRATED-F, ASME B16.5	8"	2 EA
13.	FLANGE, A105, WN, SCH 80, ANSI CL.600 RF-SERRATED-F, ASME B16.5	2"	8 EA
14.	GASKET, SPWD, HOOP 304 SS, MICA GRAPHITE FILLER (FLEXITALIC FLEXITE SUPER or EQUIVALENT), CS CENTERING RING AND 304SS INNER RING, THK=4.5 MM, CL.600, RF, ASME B16.5, ASME B16.20	12"	14 EA
15.	GASKET, SPWD, HOOP 304 SS, MICA GRAPHITE FILLER (FLEXITALIC FLEXITE SUPER or EQUIVALENT), CS CENTERING RING AND 304SS INNER RING, THK=4.5 MM, CL.600, RF, ASME B16.5, ASME B16.20	8"	4 EA
16.	GASKET, SPWD, HOOP 304 SS, MICA GRAPHITE FILLER (FLEXITALIC FLEXITE SUPER or EQUIVALENT), CS CENTERING RING AND 304SS INNER RING, THK=4.5 MM, CL.600, RF, ASME B16.5, ASME B16.20	2"	8 EA
17.	BOLT & NUT, A193-B7 M / A194-2H HVY-HEX-NUT FULL-THD SEM-FN 8-UN CL 2A/2B (ASME B1.1 / B18.2.2 & 1), FLOURO CARBON COATED MIN.THK. 35 MICRON	1 1/4" x 240	283 EA
18.	BOLT & NUT, A193-B7 M / A194-2H HVY-HEX-NUT FULL-THD SEM-FN 8-UN CL 2A/2B (ASME B1.1 / B18.2.2 & 1), FLOURO CARBON COATED MIN.THK. 35 MICRON	1 1/8" x 205	48 EA
19.	BOLT & NUT, A193-B7 M / A194-2H HVY-HEX-NUT FULL-THD SEM-FN 8-UN CL 2A/2B (ASME B1.1 / B18.2.2 & 1), FLOURO CARBON COATED MIN.THK. 35 MICRON	5/8"ø x 110	72 EA
20.	BALL VALVE, #600,RF; FE' BB; F-BORE,SIDE ENTRY; REPLACEABLE BALL & SEATS; ASTM A105 BODY & BONNET ASTM A105+3 Mils ENP BALL & SEAT,AISI 4140+ENP STEM; GEAR OPERATED; ANTI STATIC; PTFE/VITON SEATS; DPE/DIPE;DOUBLE ISOLATION AND BLEED DESIGN; TRUNNION MOUNTED; SECONDARY SEAL; DESIGNED TO API 6D; TESTED & INSPECTION API 6D, FIRE TESTED TO API 6FA	12"	3 EA
21.	BALL VALVE, #800,MIN. SEAT RATING 1500# CWP, REDUCE PORT; FLOATING BAL; SW FxOD; BB; REPLACEABLE BALL & SEATS; ASTM A105 BODY & BONNET; ASTM A182 316SS BLL & STEM; LO; PTFE/VITON SEATS; DESIGN TO API 608, TESTED & INSPECTED TO API 598, FIRE TESTED TO API 607; WITH PIPE PIECE LENGTH 100MM	3/4"	5 EA
22.	SHUTDOWN VALVE; PNEUMATIC SPRING RETURN PISTON,SINGLE ACTING; ACTUATOR ORIENTATION IN-LINE WITH PIPE; FAIL TO CLOSED BALL VALVE, #600; BB,F-BORE,SIDE ENTRY; REPLACEABLE BALL & SEATS; ASTM A105 BODY & BONNET, ASTM A105+3 Mils ENP BALL & SEAT, AISI 4140+ENP STEM,ANTI STATIC; PTFE/VITON SEATS; DPE/DIPE; DOUBLE ISOLATION AND BLEED DESIGN; TRUNNION MOUNTED; SECONDARY SEAL; DESIGNED TO API 6D; TESTED & INSPECTION API 6D, FIRE TESTED TO API 6FA	12"	1 EA
23.	CHECK VALVE, #600, BOLTED COVER, FULL BORE, SWING TYPE, FE, RF, ASTM A216 WCB BODY, HINGE ASTM A216WCB, HINGE PIN ASTM A276-304, API TRIM NO. 5 Co-Cr DISC & SEAT TEST & INSPECTION API6D	12"	1 EA

NOTE :
1. ALL DIMENSIONS ARE IN MILLIMETER OTHERWISE NOTED
2. SEE DOCUMENT NO. MKP-05-EN-PV-SPC-007 (SPECIFICATION FOR PROTECTIVE COATING)

CLIENT : NUSANTARA REGAS

CONTRACTOR : elnusa

VENDOR :

PROJECT : MUARA KARANG PEAKER GAS METER PROJECT

ISOMETRIC DRAWING METERING PRESSURE LETDOWN SECTION

CONTRACT NO. : [illegible] | SCALE : NONE

SHEET NO.	DRAWING NO.	REV.
06 OF 07	MKP-05-VN-PV-DSA-002	0

PWHT	☐ YES	☒ NO
OP. PRESS	40.81	Barg
OP. TEMP	19.83	°C
DESIGN PRESS	85	Barg
DESIGN TEMP	65	°C
HYDROTEST/PN	100%	
TEST MEDIA	WATER	
TEST PRESS	142.5	Barg
SERVICE	PROCESS GAS	
CODE	ASME B31.3	
INSULATION	NO	
COAT SPEC	NOTE 2	

REV.	DATE	DESCRIPTION	DRAWN	CHK'D	APP'D	APP'D
0	13/05/18	ISSUED FOR CONSTRUCTION	FN	SBK	AP	
E	15/05/18	ISSUED FOR APPROVAL	FN	SBK	AP	
D	08/05/18	ISSUED FOR APPROVAL	FN	SBK	CDN	
C	26/03/18	ISSUED FOR APPROVAL	FN	SBK	CDN	
B	07/03/18	ISSUED FOR APPROVAL	FN	SBK	CDN	
A	15/01/18	ISSUED FOR REVIEW	FN	SBK	CDN	
		REVISION	VENDOR	ELNUSA		NR

DWG.NO.	REV.	TITLE
MKP-05-VN-PV-DSG-001	0	METERING ARRANGEMENT LAYOUT

REFERENCE DRAWING

	INSPECTION PROGRAM PLANNING OF PROCESS GAS PIPING USING RISK BASED INSPECTION API 581 IN MUARA KARANG PEAKER GAS METER

ATTACHMENT 1D :

ISOMETRIC DIAGRAM OF:
2" - PG - 06254 - C
2" - PG - 06255 - C

<table>
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<tr><td></td><td></td><td></td><td>Nama</td><td>Paraf</td><td>Pembimbing</td><td>Paraf</td></tr>
<tr><td></td><td></td><td></td><td rowspan="2">Ade Ratih Anggraini</td><td rowspan="2"></td><td rowspan="2">Ir. Dwi Priyanta, M.SE</td><td rowspan="2"></td></tr>
<tr><td></td><td></td><td></td></tr>
<tr><td></td><td></td><td></td><td colspan="2">No. Registration :</td><td rowspan="2">Nurhadi Siswantoro,ST.,MT.</td><td rowspan="2"></td></tr>
<tr><td></td><td></td><td></td><td colspan="2">04211641000008</td></tr>
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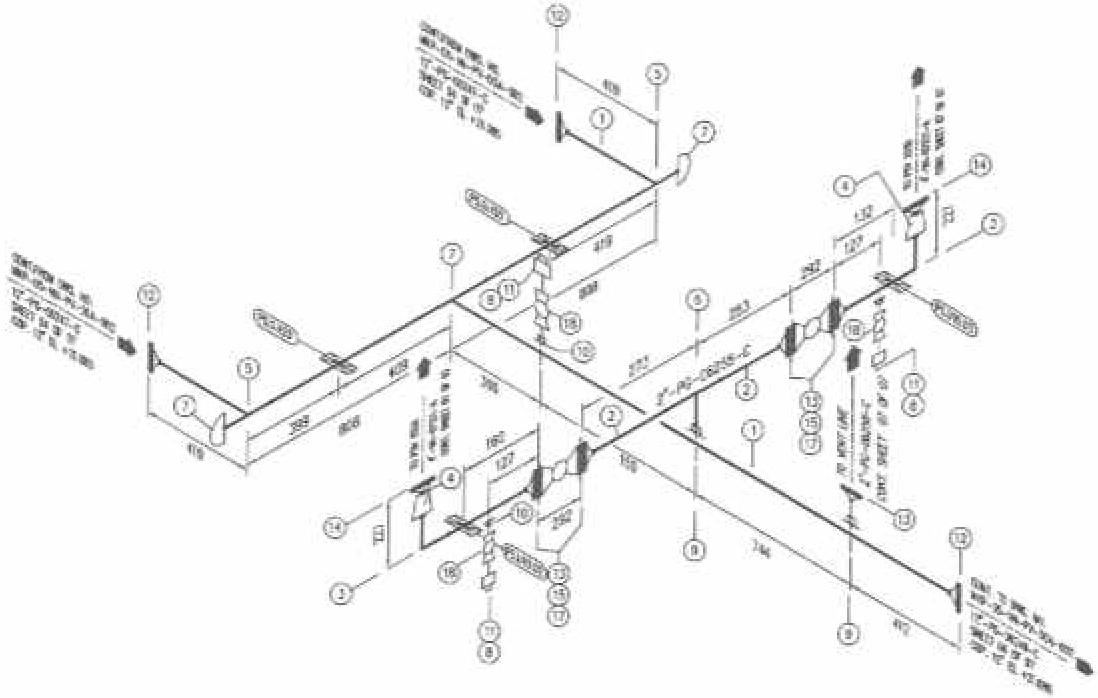


FOR CONSTRUCTION

NO.	DESCRIPTION	SIZE	QTY
1.	PIPE, A106-B, SMLS, SCH 80, BE, ASME B36.10	12"	1993 MM
2.	PIPE, A106-B, SMLS, SCH 80, BE, ASME B36.10	2"	847 MM
3.	90 DEG. ELBOW, A234-WPB, SMLS, LR, SCH 80, BW, ASME B16.9	2"	2 EA
4.	CONCENTRIC REDUCER, A234-WPB, SMLS, SCH 80, BW, ASME B16.9	2"x1.5"	2 EA
5.	TEE EQUAL, A234-WPB, SMLS, SCH 80, BW, ASME B16.9	12"	3 EA
6.	TEE EQUAL, A234-WPB, SMLS, SCH 80, BW, ASME B16.9	2"	1 EA
7.	CAP, A234-WPB, SCH 80, BW, ASME B16.9	12"	2 EA
8.	COUPLING, CS, A105, CL. 3000, SW - THD NPT, ASME B16.11	3/4"	3 EA
9.	WELDOLET, A105, SCH 80, BW, ASME B16.11	2"	2 EA
10.	SOCKOLET, CS, A105, CL. 3000, MSS, SP-97	3/4"	3 EA
11.	PLUG, CS, A105, CL. 3000, HEX-HEAD NPT, ASME B16.11	3/4"	3 EA
12.	FLANGE, A105, WN, SCH 80, ANSI CL.600 RF-SERRATED-F, ASME B16.5	12"	3 EA
13.	FLANGE, A105, WN, SCH 80, ANSI CL.600 RF-SERRATED-F, ASME B16.5	2"	5 EA
14.	FLANGE, A105, SW, ANSI CL.600 RF-SERRATED-F, ASME B16.5	1.5"	2 EA
15.	GASKET, SPWD, HOOP 304 SS, MICCA GRAPHITE FILLER (FLEXITALIC FLEXITE SUPER or EQUIVALENT), CS CENTERING RING AND 304SS INNER RING, THK=4.5 MM, CL.600, RF, ASME B16.5, ASME B16.20	2"	4 EA
16.	BOLT & NUT, A193-B7 W / A194-2H HVY-HEX-NUT FULL-THD SEMI-FN 8-UN CL 2A/A2 (ASME B1.1 / B18.2.2 & 1), FLOURO CARBON COATED MIN.THK. 35 MICRON	5/8"ø x 110	32 EA
17.	BALL VALVE, #600,RF; FE; BB; T-BORE; SIDE ENTRY; REPLACEABLE BALL & SEATS; ASTM A105 BODY & BONNET; ASTM A182 F316 BALL & SEAT RING;A182 F51 STEM; LEVER OPERATED; ANTI STATIC; PTFE/VITON SEATS; DPE/DIPE;DOUBLE ISOLATION AND BLEED DESIGN; TRUNNION MOUNTED; SECONDARY SEAL; DESIGNED TO API 6D; TESTED & INSPECTION API 6D; FIRE TESTED TO API 6FA	2"	2 EA
18.	BALL VALVE, #800,WN; SEAT RATING 1500# CWP; REDUCE PORT; FLOATING BALL; SW ENDS; BB; REPLACEABLE BALL & SEATS; ASTM A105 BODY & BONNET; ASTM A182 316 BLL & STEM; LO; PTFE/VITON SEATS; DESIGN TO API 608; TESTED & INSPECTED TO API 598; FIRE TESTED TO API 607; WITH PIPE PIECE LENGTH 100MM.	3/4"	3 EA

NOTE :

1. ALL DIMENSIONS ARE IN MILLIMETER OTHERWISE NOTED
2. SEE DOCUMENT NO. MKP-05-EN-PV-SPC-003 (SPECIFICATION FOR PROTECTIVE COATING)

CLIENT :

NUSANTARA REGAS

CONTRACTOR :

elnusa

VENDOR :

			F	[illegible]	ISSUED FOR CONSTRUCTION	FN	[illegible]	AP
			E	[illegible]	ISSUED FOR APPROVAL	FN	[illegible]	AP
			D	[illegible]	ISSUED FOR APPROVAL	FN	[illegible]	CDW
			C	[illegible]	ISSUED FOR APPROVAL	FN	[illegible]	CDW
			B	[illegible]	ISSUED FOR APPROVAL	FN	[illegible]	CDW
MKP-05-VN-PV-004-001	3	METERING ARRANGEMENT LAYOUT	A	[illegible]	ISSUED FOR REVIEW	FN	[illegible]	CDW
DWG.NO.	REV.	TITLE	REV.	DATE	DESCRIPTION	DSGN	CHKD	APPD
REFERENCE DRAWING			REVISION			VENDOR		

PAINT	YES	NO
OP PRESS	40.37	Barg
OP TEMP	10.83	°C
DESIGN PRESS	95	Barg
DESIGN TEMP	65	°C
RADIOGRAPH	100%	
TEST MEDIA	WATER	
TEST PRESS	142.5	Barg
SERVICE	PROCESS GAS	
CODE	ASME B31.3	
INSULATION	NO	
PAINT SPEC	NOTE 2	

PROJECT :

MUARA KARANG PEAKER GAS METER PROJECT

TITLE :

ISOMETRIC DRAWING METERING
OUTLET METERING

CONTRACT NO. : [illegible]

SCALE : NONE

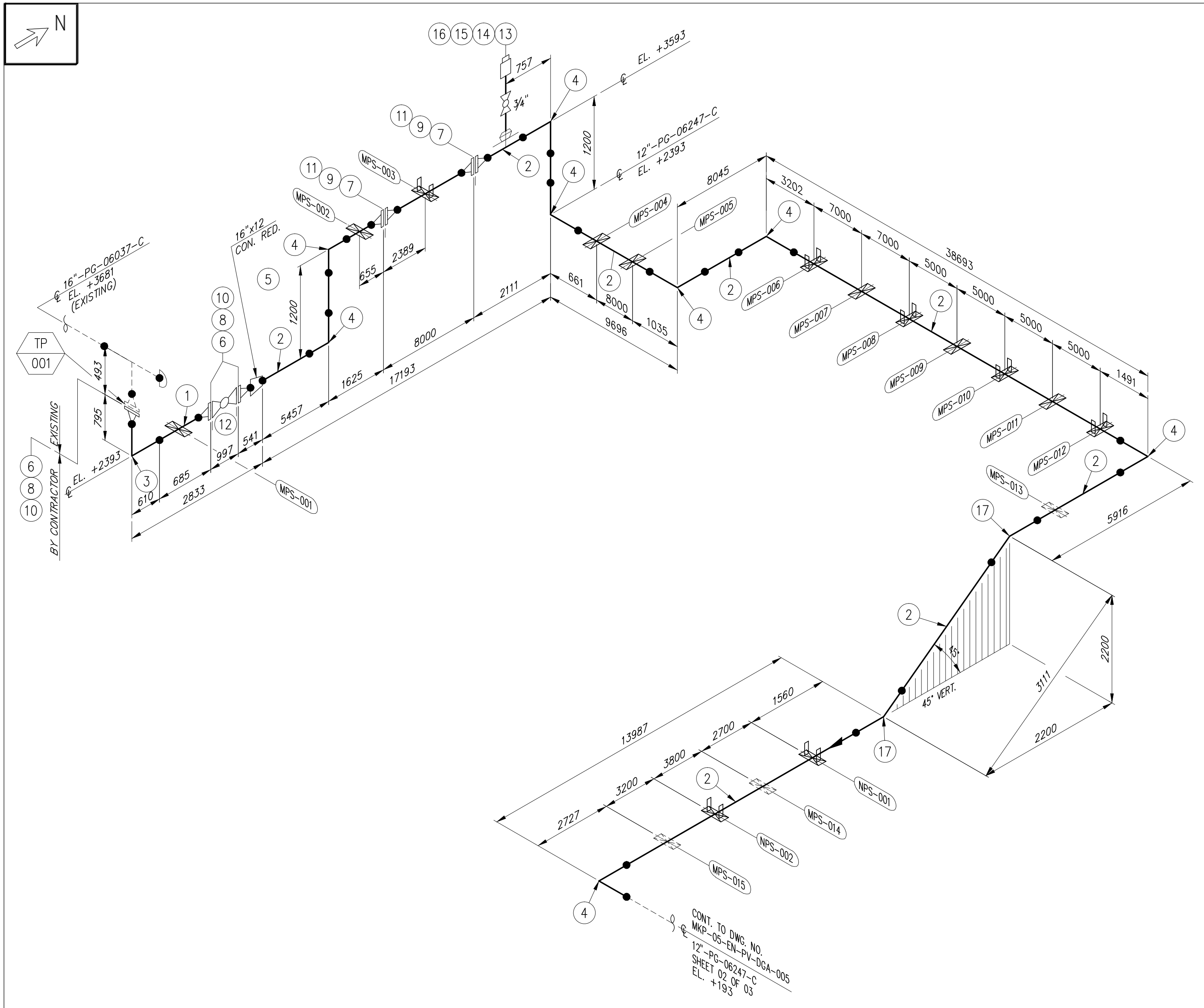
SHEET NO.	DRAWING NO.	REV
05 OF 07	MKP-05-VN-PV-004-002	F

	INSPECTION PROGRAM PLANNING OF PROCESS GAS PIPING USING RISK BASED INSPECTION API 581 IN MUARA KARANG PEAKER GAS METER

ATTACHMENT 1E :

ISOMETRIC DIAGRAM OF 12" - PG - 06247 - C

Rev	Tanggal	Keterangan	Disusun Oleh:		Disetujui Oleh:	
			Nama	Paraf	Pembimbing	Paraf
			Ade Ratih Anggraini		Ir. Dwi Priyanta, M.SE	
			No. Registration :		Nurhadi Siswantoro,ST.,MT.	
			04211641000008			



NO.	DESCRIPTION	SIZE	Q'TY
1.	PIPE, A106-B, SMLS, SCH 80, BE, ASME B36.10	16"	600 MM
2.	PIPE, A106-B, SMLS, SCH 80, BE, ASME B36.10	12"	99000 MM
3.	90 DEG. ELBOW, A234-WPB, SMLS, LR, SCH 80, BW, ASME B16.9	16"	1 EA
4.	90 DEG. ELBOW, A234-WPB, SMLS, LR, SCH 80, BW, ASME B16.9	12"	8 EA
5.	CONCENTRIC REDUCER 16"x12" BOTTOM FLAT, A234-WPB, SMLS, LR, SCH 80, BW, ASME B16.9	12"	1 EA
6.	FLANGE, A105, WN, SCH 80, ANSI CL.600 RF-SERRATED-F, ASME B16.5	16"	3 EA
7.	FLANGE, A105, WN, SCH 80, ANSI CL.600 RF-SERRATED-F, ASME B16.5	12"	4 EA
8.	GASKET, SPWD, HOOP 304 SS, MICCA GRAPHITE FILLER (FLEXITALIC FLEXITE SUPER or EQUIVALENT), CS CENTERING RING AND 304SS INNER RING, THK=4.5 MM, CL.600, RF, ASME B16.5, ASME B16.20	16"	3 EA
9.	GASKET, SPWD, HOOP 304 SS, MICCA GRAPHITE FILLER (FLEXITALIC FLEXITE SUPER or EQUIVALENT), CS CENTERING RING AND 304SS INNER RING, THK=4.5 MM, CL.600, RF, ASME B16.5, ASME B16.20	12"	2 EA
10.	BOLT AND NUTS, A193 Gr B7 / A194 Gr 2H HVY-HEX-NUT FULL-THD SEMI-FN UNC CL.2A/2B ,FLUORO CARBON COATED MIN THK 35 MICRON	1½"ø x 275	60 EA
11.	BOLT AND NUTS, A193 Gr B7 / A194 Gr 2H HVY-HEX-NUT FULL-THD SEMI-FN UNC CL.2A/2B ,FLUORO CARBON COATED MIN THK 35 MICRON	1¼"ø x 240	40 EA
12.	BALL VALVE, #600, RF FLG ASME16.5, TRUNNION, FIRE SAFE, A105 + 3 mils ENP, BODY SEAL: TFE/GRAPHITE, SEAT: PTFE/NYLON/VITON, DPE X DPE, GEAR OPR	16"	1 EA
13	SOCKOLET, CS, ASTM A105, CL. 3000, MSS, SP-97	12" x ¾"	1 EA
14	BALL VALVE, 800#; MIN. SEAT RATING 1500# CWP; REGULAR PORT; FLOATING BALL; SW ENDS; BB; REPLACEABLE BALL & SEATS; ASTM A105/ASTM A350 LF2 BODY & BONNET; ASTM A182 316SS BALL & STEM; LO; PTFE/VITON SEATS; DESIGN TO API 608; TESTED & INSPECTED TO API 598; FIRE TESTED TO API 607, WITH PIPE PIECE LENGTH 100 MM	¾"	1 EA
15	COUPLING, CS, A105, CL. 3000, SW - THD NPT, ASME B16.11	¾"	1 EA
16	PLUG, CS, A105, CL. 3000, HEX-HEAD NPT, ASME B16.11	¾"	1 EA
17.	45 DEG. ELBOW, A234-WPB, SMLS, LR, SCH 80, BW, ASME B16.9	12"	2 EA

NOTE :

1. ALL DIMENSIONS ARE IN MILLIMETER OTHERWISE NOTED
2. TP / XXX = TIE-IN POINT
3. SEE DOCUMENT NO. MKP-05-EN-PV-SPC-003 (SPECIFICATION FOR PROTECTIVE COATING).

CLIENT : NUSANTARA REGAS

a joint venture company between PERTAMINA & PGN

CONTRACTOR : elnusa

PROJECT : MUARA KARANG PEAKER GAS METER

TITLE : ISOMETRIC DRAWING FOR PROCESS SYSTEM INLET METERING AND VENTING LINE 12"-PG-06247-C

PROJECT NO : -

CONTRACT NO : 00800/NR/D000/P/2017 068/EN/KTR/001D/2017

SCALE : NONE

SHEET NO.	DRAWING NO.	REV.
01 OF 03	MKP-05-EN-PV-DGA-005	0

REFERENCE DRAWING

DWG.NO	REV.	TITTLE
MKP-05-EN-PR-PID-001	0	P&ID FOR INDIRECT FIRED WATER BATH HEATER
MKP-05-EN-PV-DGA-004	0	PIPING PLAN MUARA KARANG PEAKER GAS METER

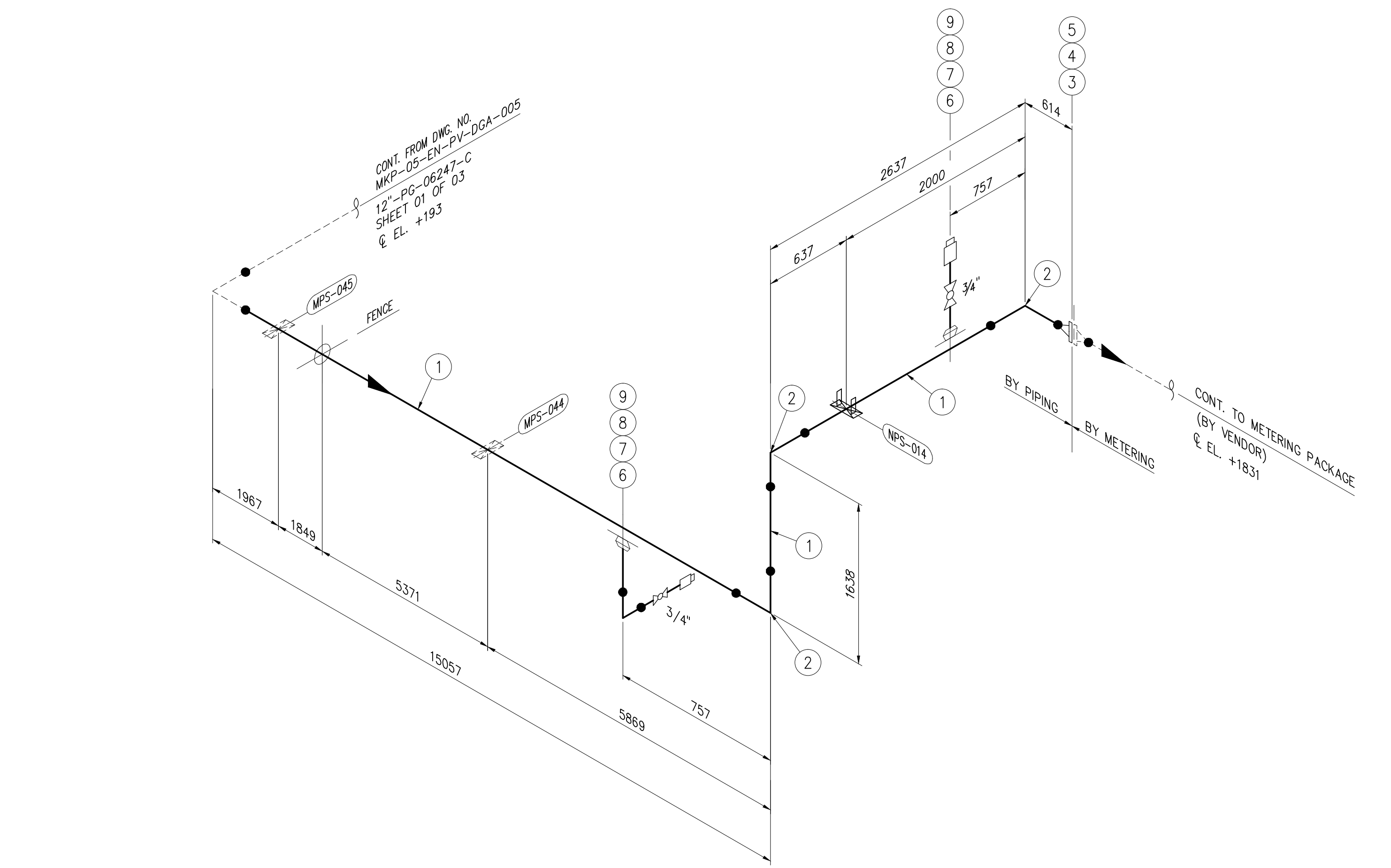
REVISION

REV.	DESCRIPTION	DRAWN	CHKD	APVD	APVD	DATE
0	ISSUED FOR CONSTRUCTION	DED	SBK	CSW		14/09/17
C	ISSUED FOR APPROVAL	DED	SBK	CSW		14/09/17
B	ISSUED FOR REVIEW	DED	SBK	CSW		13/09/17
A	ISSUED FOR REVIEW	LT	SBK	CSW		04/09/17
		ELNUSA			NR	

	BY	DATE
DRAWN		
DSGN		
CHKD		
CLIENT APPROVED		
ISSUED FOR CONSTRUCTION		
PT. ELNUSA		

PWHT	:	☒ YES ☐ NO	
OP PRESS	:	45.91	Barg
OP TEMP	:	18.83	°C
DESGN PRESS	:	95	Barg
DESGN TEMP	:	65	°C
RADIOGRAPH	:	100%	
TEST MEDIA	:	WATER	
TEST PRESS	:	142.5	Barg
SERVICE	:	PROCESS GAS	
CODE	:	ASME B31.3	
INSUL	:	NO	
COAT SPEC.	:	NOTE 3	

D:/MKP-05-EN-PV-DGA-005-SHT-01 - Isometric Drwing For Process System_IFC



NO.	DESCRIPTION	SIZE	Q'TY
1.	PIPE, A106-B, SMLS, SCH 80, BE, ASME B36.10 M	12"	20000 MM
2.	90 DEG. ELBOW, A234-WPB, SMLS, LR, SCH 80, BW, ASME B36.20 M	12"	3 EA
3.	FLANGE, A105, WN, SCH 80, ANSI CL.600 RF-SERRATED-F, ASME B16.5	12"	1 EA
4.	GASKET, SPWD, HOOP 304 SS, MICCA GRAPHITE FILLER (FLEXITALIC FLEXITE SUPER or EQUIVALENT), CS CENTERING RING AND 304SS INNER RING, THK=4.5 MM, CL.600, RF, ASME B16.5, ASME B16.20	12"	1 EA
5.	BOLT AND NUTS, A193 Gr B7 / A194 Gr 2H HVY-HEX-NUT FULL-THD SEMI-FN UNC CL.2A/2B ,FLUORO CARBON COATED MIN THK 35 MICRON	1¼"ø x 240	20 EA
6.	SOCKOLET, CS, A105, CL. 3000, MSS, SP-97	12" x ¾"	2 EA
7.	BALL VALVE, 800#; MIN. SEAT RATING 1500# CWP; REGULAR PORT; FLOATING BALL; SW ENDS; BB; REPLACEABLE BALL & SEATS; ASTM A105/ASTM A350 LF2 BODY & BONNET; ASTM A182 316SS BALL & STEM; LO; PTFE/VITON SEATS; DESIGN TO API 608; TESTED & INSPECTED TO API 598; FIRE TESTED TO API 607, WITH PIPE PIECE LENGTH 100 MM	¾"	2 EA
8.	COUPLING, CS, A105, CL. 3000, SW - THD NPT, ASME B16.11	¾"	2 EA
9.	PLUG, CS, A105, CL. 3000, HEX-HEAD NPT, ASME B16.11	¾"	2 EA

NOTE :

1. ALL DIMENSIONS ARE IN MILLIMETER OTHERWISE NOTED
2. TP/XXX = TIE-IN POINT
3. SEE DOCUMENT NO. MKP-05-EN-PV-SPC-003 (SPECIFICATION FOR PROTECTIVE COATING).

CLIENT : NUSANTARA REGAS
a joint venture company between PERTAMINA & PGN

CONTRACTOR : elnusa

PROJECT : MUARA KARANG PEAKER GAS METER

TITLE : ISOMETRIC DRAWING FOR PROCESS SYSTEM
INLET METERING AND VENTING LINE
12"-PG-06247-C

PROJECT NO : -	CONTRACT NO : 00800/NR/D000/P/2017 068/EN/KTR/001D/2017	SCALE : NONE
SHEET NO.	DRAWING NO.	REV.
02 OF 03	MKP-05-EN-PV-DGA-005	0

DWG.NO	REV.	TITTLE	REV.	DESCRIPTION	DRAWN	CKHD	APVD	APVD	DATE
			0	ISSUED FOR CONSTRUCTION	DED	SBK	CSW		14/09/17
			C	ISSUED FOR APPROVAL	DED	SBK	CSW		14/09/17
MKP-05-EN-PR-PID-001	0	P&ID FOR INDIRECT FIRED WATER BATH HEATER	B	ISSUED FOR REVIEW	DED	SBK	CSW		13/09/17
MKP-05-EN-PV-DGA-004	0	PIPING PLAN MUARA KARANG PEAKER GAS METER	A	ISSUED FOR REVIEW	LT	SBK	CSW		04/09/17
REFERENCES			REVISION		ELNUSA			NR	

	BY	DATE
DRAWN		
DSGN		
CHKD		
CLIENT APPROVED		
ISSUED FOR CONSTRUCTION		
PT. ELNUSA		

PWHT	:	☒ YES ☐ NO
OP PRESS	:	45.91 Barg
OP TEMP	:	18.83 °C
DESGN PRESS	:	95 Barg
DESGN TEMP	:	65 °C
RADIOGRAPH	:	100%
TEST MEDIA	:	WATER
TEST PRESS	:	142.5 Barg
SERVICE	:	PROCESS GAS
CODE	:	ASME B31.3
INSUL	:	NO
COAT SPEC.	:	NOTE 3

D:/MKP-05-EN-PV-DGA-005-SHT-02 - Isometric Drwing For Process System_IFC

	INSPECTION PROGRAM PLANNING OF PROCESS GAS PIPING USING RISK BASED INSPECTION API 581 IN MUARA KARANG PEAKER GAS METER

ATTACHMENT 2 :

GENERAL SPECIFICATION PROCESS GAS PIPING

12" - PG - 06251 - C

Rev	Tanggal	Keterangan	Disusun Oleh:		Disetujui Oleh:	
			Nama	Paraf	Pembimbing	Paraf
			Ade Ratih Anggraini		Ir. Dwi Priyanta, M.SE	
			No. Registration :		Nurhadi Siswantoro,ST.,MT.	
			04211641000008			

1 GENERAL SPECIFICATION OF PRESSURE VESSEL

Tag Number		:	306 - JY - 09	
Quantity		:	1	
Service		:	Process Gas piping	
Serial No.		:	12" - PG - 06251 - C	
Code		:	ASME B.31.3	
Design Pressure	(P)	:	95	barg
		:	1363,35	psig
		:	9,4	MPa
Design Temperature	(T)	:	65	°C
		:	149	°F
Outer Diameter	(OD)	:	323,8	mm
		:	12	inch
Operating Pressure		:	46	barg
		:	667,174	psig
Operating Temperature		:	18,83	°C
		:	65,894	°F
Flow Rate		:	135	mmscfd
Efficiency	(Ef)	:	1	
Corrosion Allowance	(CA)	:	1,6	mm
		:	0,062992	inch
Thickness	(t)	:	17,48	mm
		:	0,7	inch
Corrosion Rate	(CR)	:	0,125	mm/years
		:	0,0049	inch/years
Allowable Stress	(S)	:	23300	psig
		:	1606,479	bar
		:	160,6479	Mpa
Year Built		:	2017	
Material		:	A 106 GR, SMLS, SCH 80	
Last Inspection		:	-	

TABLE OF CONVERSION

1	$inch^2$	=	0,00065	m^2
1	m2	=	6,29	BBLS
1	psi	=	6,895	Kpa
1	lb/ft^3	=	16,018	kg/m^3

THICKNESS AND MAWP CALCULATION

$$t\ req = \frac{P\ X\ (\frac{OD}{2})}{((S\ X\ E) + (0.4P))}$$

$$= \frac{1363{,}35\ X\ (\frac{304{,}8}{2})}{((23300\ X\ 1) + (0.4\ X 1363{,}35))}$$

$$= \frac{1363{,}35\ X\ 152{,}4}{(23300) + 545{,}34}$$

$$= \frac{207774{,}54}{23845{,}34}$$

$= 9{,}25658$ mm (ACCEPTED)

(t > t req)

$$MAWP = \frac{(S\ X\ E)(t - (2\ x\ 3\ x\ CR))}{((\frac{OD}{2}) - (0.4\ X\ (t - (2\ X\ 3\ X\ CR))))}$$

$$= \frac{(23300\ X\ 1)(17{,}48) - (6x\ 0.125))}{((\frac{304{,}8}{2}) - (0.4\ X\ (17{,}48 - (6X\ 0.125))))}$$

$$= \frac{23300\ X\ 16{,}73}{152{,}4 - 6{,}692}$$

$$= \frac{389809}{145{,}708}$$

$= 2511{,}53$ psig (ACCEPTED)

(MAWP > P)

	INSPECTION PROGRAM PLANNING OF PROCESS GAS PIPING USING RISK BASED INSPECTION API 581 IN MUARA KARANG PEAKER GAS METER

ATTACHMENT 2A :

DAMAGE FACTOR SCREENING QUESTION PROCESS GAS PIPING

12" - PG - 062521 - C

Rev	Tanggal	Keterangan	Disusun Oleh:		Disetujui Oleh:	
			Nama	Paraf	Pembimbing	Paraf
			Ade Ratih Anggraini		Ir. Dwi Priyanta, M.SE	
			No. Registration :		Nurhadi Siswantoro,ST.,MT.	
			04211641000008			

DAMAGE FACTOR SCREENING QUESTION

DETERMINATION OF PROBABILITY OF FAILURE

API 581 PART 2

I. DAMAGE FACTOR

Damage Factor(s) provides a screening tool to determine inspection priorities and optimize inspection. The basic function of the DF is to statistically evaluate the amount of damage that may be present as a function of time in service and the effectiveness of an inspection activity. DFs are calculated based on the 3 different techniques as mentioned below, but are not intended to reflect the actual POF for the purposes of reliability analysis. DFs reflect a relative level of concern about the component based on the stated assumptions in each of the applicable sectiion of the document.

a. Structural reliability modes

b. Statistical models based on generic data

c. Expert judgement

Table of Damage Factor Screening Questions

No	Damage Factor	Screening Criteria	Yes/No
1.	Thining	All component should be checked for thining	Yes
2.	Component Lining	If the component has organic or inorganic lining, then the component should be evaluated for lining damage	No
3.	SCC Damage Factor-Caustic Cracking	If the component's material of construction is carbon or low alloy steel and the process environment contains caustic in any concentration, then the component should be evaluated for susceptibility to caustic cracking.	No
4.	SCC Damage Factor-Amine Cracking	If the component's material of construction is carbon or low alloy steel and process environment contains acid gas treating amines (MEA, DEA, DIPA, MDEA, etc.) in any concentration, then the component should be evaluated for susceptibility to amine cracking.	No
5.	SCC Damage Factor-Sulfide Stress Cracking	If the component's material of construction contains is carbon or low alloy steel and the process environment contains water and H_2S in any concentration, then the component should be evaluated to Sulfide Ctress Cracking (SCC). Concentration of H_2S is 0.00 mg/L	No

No	Damage Factor	Screening Criteria	Yes/No
6.	SCC Damage Factor HIC/SOHIC-H_2S	If the component's material of construction contains is carbon or low alloy steel and the process environment contains water and H_2S in any concentration, then the component should be evaluated to HIC/SOHIC-H_2S cracking.	No
7.	SCC Damage Factor-Alkaline Carbonate Stress Corrosion Cracking	If the component's material of construction is carbon or low alloy steel and the process environment contains alkaline water at pH>7.5 in any concentration, the the component should be evaluated to ACSCC.	No
		Another trigger would be changes in FCCU feed sulfurr and nitrogen contents particularly when feed changes have reduced sulfur (low sulfur feeds or hydroprocessed feeds) or increased nitrogen.	
8.	SCC Damage Factor-Polythionic Acid Stress Corrosion Cracking	If the component's material of construction is an austenitic stainless steel or nickel based alloys and the components is wxposed to sulfur bearing compunds, then the component should be evaluated for susceptibility to PASCC	No
9.	SCC Damage Factor-Chloride Stress Corrosion Cracking	If **<u>ALL</u>** of the following are true, then the component should evaluated for suscepibility to CLSCC cracking:	No
		a. The component's material of construction is an austenitic stainless steel.	
		b. The component is exposed or potentially exposed to chlorides and water also considering upsets and hydrotest water remaining in component, and cooling tower drift (consider both under insulation and process conditions).	
		c. The operating temperature is above 38^o (100^{o}F)	
		Chlorine concentration 4.14% mg/L	
10.	SCC Damage Factor-Hydrogen Stress Cracking-HF	If the component's material of construction is ccarbon or low alloy steel and the component is exposed too hydrofluoric acid in any concentration, then the component should be evaluated for susceptibility to HSC-HF.	No

No	Damage Factor	Screening Criteria			Yes/No
11.	SCC Damage Factor HIC/SOHIC-HF	If the component's material of construction is ccarbon or low alloy steel and the component is exposed too hydrofluoric acid in any concentration, then the component should be evaluated for susceptibility to HIC/SOHIC-HF.			No
12.	External Corrosion Damage Factor	If the component is un-insulated and subject to any of the following , then the component should be evaluated for external damage from corrosion.			Yes
		a.	Areas exposed to mist overspray from cooling towers.	N	
		b.	Areas exposed to steam vents	N	
		c.	Areas exposed to deluge system	N	
		d.	Areas subject to process spills, ingress of moisture, or acid vapors.	N	
		e.	Carbon steel system, operatinng between -12^{o}C and 177^{o}C (10^{o}F and 350^{o}F). External corrosion is particulartly aggressive where operating temperatures cause frequent or continuous condensation and re-evaporation of atmospheric moisture.	N	
			Operating temperature 100^{o}C (212^{o}F)		
		f.	Systems that do not operating in normally temperature between -12^{o} and 177^{o}C (10^{o}F and 350^{o}F) but cool or heat into this range intermitterntly or are subjected to frequent outages.	Y	
		g.	Systems with deteoriated coating and/or wrappings	N	
		h.	Cold service equipment consistently operating below the atmospheric dew point.	N	
		i.	Un-insulated nozzles or other prostrusions components of insulated equipment in cold service conditions.	N	

<table>
<tr><th>No</th><th>Damage Factor</th><th colspan="3">Screening Criteria</th><th>Yes/No</th></tr>
<tr><td>13.</td><td>Corrosion Under Insulation Damage Factor-Ferritic Commponent</td><td colspan="3">The criteria can be seen at the API 581 Part 2 of POF Section 16.3</td><td>No</td></tr>
<tr><td rowspan="4">14.</td><td rowspan="4">External Chloride Stress Corrosion Cracking Damage Factor-Austenitic Component</td><td colspan="3">If <u>ALL</u> of the following are true, then the component should evaluated for susceptibility to CLSCC:</td><td rowspan="4">No</td></tr>
<tr><td>a.</td><td>The component's material of construction is an austenitic stainless steel.</td><td>N</td></tr>
<tr><td>b.</td><td>The component external surface is exposed to chloride containing fluids, mists, or solids.</td><td>N</td></tr>
<tr><td>c.</td><td>The operating temperature is between 50°C and 150°C (120°F and 300°F) , or the system heats or cools into this range intermittently.</td><td>N</td></tr>
<tr><td rowspan="5">15.</td><td rowspan="5">External Chloride Stress Corrosion Cracking Under Insulation Damage Factor-Austenitic Component</td><td colspan="3">If <u>ALL</u> of the following are true, then the component should be evaluated for susceptibiity to CUI CLSCC:</td><td rowspan="5">No</td></tr>
<tr><td>a.</td><td>The component's material of construction is an austenitic stainless steel.</td><td>N</td></tr>
<tr><td>b.</td><td>The component is insulated</td><td>N</td></tr>
<tr><td>c.</td><td>The component external surface is exposed to chloride containing fluids, mists, or solids.</td><td>N</td></tr>
<tr><td>d.</td><td>The operating temperature is between 50°C and 150°C (120°F and 300°F) , or the system heats or cools into this range intermittently.</td><td>N</td></tr>
<tr><td rowspan="3">16</td><td rowspan="3">Low Alloy Steel Embrittlement Damage Factor</td><td colspan="3">If <u>ALL</u> of the following are true, then the component should be evaluated for susceptibiity to low alloy steel embrittlement:</td><td rowspan="3">No</td></tr>
<tr><td>a.</td><td>The material is 1Cr--0.5Mo, 1.25Cr-0.5Mo, or 3Cr-1Mo low alloy steel.</td><td>N</td></tr>
<tr><td>b.</td><td>The operating temperature is between 343°C and 577°C (650°F and 1070°F).</td><td>N</td></tr>
</table>

No	Damage Factor	Screening Criteria			Yes/No
17	High Temperature Hydrogen Attack Damage Factor	If **ALL** of the following are true, then the component should be evaluated for susceptibiity to HTHA:			No
		a.	The material is carbon steel, C-$^1/_2$Mo, or a CrMo low alloy steel (such as $^1/_2$Cr-$^1/_2$Mo, 1Cr-$^1/_2$Mo, 1$^1/_4$Cr-$^1/$2Mo, 2$^1/_4$Cr-1Mo, 3Cr-1Mo, 5Cr-1Mo, 7Cr-1Mo, 9Cr-1Mo).	Y	
		b.	The operating temperature is greater than 177°C (350°F).	N	
			Operating temperature 100°C (212°F)		
		c.	The operating hydrogen partial presssure is greater than 0.345 Mpa (50 psia).	N	
			There is no hydrogen content		
18	Brittle Fracture Damage Factor	If **BOTH** of the following are true, then the component should be evaluated for susceptibiity to brittle fracture:			
		a.	The material is carbon steel or low alloy steel (see Table 20.1).	Y	
		b.	If Minimum Design Metal Temperature (MDMT), T_{MDMT}, or Minimum Allowable Metal Temperature (MAT), T_{MAT}, is unknown, or the component is known to operate at below MDMT or MAT under normal or upset conditions.		
19.	885°F Embrittlement Damage Factor	If **BOTH** of the following are true, then the component should be evaluated for susceptibiity to 885°F embrittlemet:			No
		a.	The material is high chromium (>12% Cr) ferritic steel	N	
		b.	The operating temperature is between 371°C and 566°C (700°F and 1050°F).	N	
		If **BOTH** of the following are true, then the component should be evaluated for susceptibiity to sigma phase embrittlemet:			

<table>
<tr><th>No</th><th>Damage Factor</th><th colspan="3">Screening Criteria</th><th>Yes/No</th></tr>
<tr><td rowspan="2">20</td><td rowspan="2">Sigma Phase Embrittlement Damage Factor</td><td>a.</td><td>The component's material of construction is an austenitic stainless steel.</td><td>N</td><td rowspan="2">No</td></tr>
<tr><td>b.</td><td>The operating temperature is between 593°C and 927°C (1100°F and 1700°F).</td><td>N</td></tr>
<tr><td rowspan="3">21.</td><td rowspan="3">Piping Mechanical Fatigue Damage Factor</td><td colspan="3">If <u>BOTH</u> of the following are true, then the component should be evaluated for susceptibiity to mechanical fatigue:</td><td rowspan="3">Yes</td></tr>
<tr><td>a.</td><td>The component is pipe</td><td>Y</td></tr>
<tr><td>b.</td><td>There have been past fatigue failure in this piping system or there is visible/audibble shaking in this piping system or there is a source of cyclic vibration within approximately 15.24 meters (50 feet) and connected to the piping (directly or indirectly via structure). Shaking and source of shaking can be continuous or intermittent.Transient conditions often cause intermittent virbration.</td><td>Y</td></tr>
</table>

THINNING DAMAGE FACTOR CALCULATION

1. RLA DATA

REQUIRED DATA

The basic component data required for analysis is given in Table 4.1. Component types and geometry data are shown in Tables 4.2 and 4.3, respectively. The data required for determination of the thinning DF is provided in Table 4.4.

Table 4.1. Basic Component Data Required for Analysis

Basic Data	Value	Unit	Comments
Start Date	16/03/2020		The date the component was placed in service.
Thickness	17,48	mm	The thickness used for DF calculation that is either the furnished thickness or the measured thickness.
Corrosion Allowance	1,60	mm	The corrosion allowance is the specified design or actual corrosion allowance upon being placed in the current servicce.
Design Tempearture	65	^{o}C	The design temperature for process gas piping
Design Pressure	9399,97	Kpa	The design pressure for process gas piping
Operating Tempearture	18,83	^{o}C	The highest expected operating temperature expected during operation including normal and unusual operating conditions process gas piping
Operating Pressure	4500	Kpa	The highest expected operating pressure expected during operation including normal and unusual operating conditions.
Design Code	ASME B.31.3		The designing of the component containing the component.
Equipment Type	Piping		The type of equipment.
Component Type	Pipe		The type of component.
Material Specification	A106 Gr.B		The specification of the material of construction, the ASTM A106 Grade B, specification for piping components. Data entry is based on the material specification, grade, year, UNS Number, class/condition/temper/size/thickness; this data is readdily available in the ASTM Code.
Yield Strength	241000	Kpa	The design yield strength of the material based on material specification.
Tensile Strength	414000	Kpa	The design tensile strength of the material based on material specification.

Weld Joint Efficiency	1		Weld joint efficiency per the Code of construction.
Heat Tracing	No		Is the component heat traced? (Yes or No)

STEP 1 Determining the furnished thickness, t, and age for the component from the installation date.

t	=	0,6882	inch	
	=	17,48	mm	(Assumed on 16 March 2020)
age	=	0	years	

STEP 2 Determining the corrosion rate for base material, $C_{r,bm}$ based on the material construction and environment, and cladding/weld overlay corrosion rate, $C_{r,cm}$.

Based on the explanation from Section 4.5.2 that the corrosion rate is **CALCULATED** using the approach of Annex 2B. Then, first of all, the corrosion screening question must be done as follows:

Table 2.B.1.1-Screening Questions for Corrosion Rate Calculations

No.	Type of Corrosion		Screening Question	Yes/No	Action
1.	Hydrochloric Acid (HCl) Corrosion	1.	Does the process contain HCl?	N	No
		2.	Is free water present in the process stream (including initial condensing condition)?	Y	
		3.	Is the pH < 7.0?	Y	
2.	High Temperature Sulfidic/Naphtenic Acid Corrosion	1.	Does the process contain oil with sulfur compounds?	N	No
		2.	Is the operating temperature > 204°C (400°F)?	N	
			The operating temperature is 18,3°C.		
3.	Sulfuric Acid Corrosion	1.	Does the process contain H_2SO_4	N	No
4.	High Temperature H_2S/H_2 Corrosion	1.	Does the process contain H_2 and Hydrogen?	N	No
		2.	Is the operating temperature > 204°C (400°F)?	N	
			The operating temperature is 18,3°C.		
5.	Hydrifluoric Corrosion	1.	Does the process contain HF?	N	No
6.	Sour Water Corrsion	1.	Is free water with H_2S present?	N	No

7.	Amine Corrosion	1.	Is equipment exposed to acid gas treaating amines (MEA, DEA, DIPA, or MDEA)?	N	No
8.	High Temperature Oxidation Corrosion	1.	Is the temperature ≥ 482^{o}C (900^{o}F)?	N	No
			The operating temperature is 18,3^{o}C.		
		2.	Is the oxygen present?	N	
9.	Acid Sour Water Corrosion	1.	Is free water with H_2S present and pH < 7.0?	Y	No
		2.	Does the proocess contain < 50 ppm chlorides?	N	
10.	Cooling Water	1.	Is equipment in cooling water service?	N	No
11.	Soil Side Corrosion	1.	Is equipment in contact with soil (buried or partially buried)?	N	No
		2.	Is the material of construction carbon steel?	Y	
12.	CO_2 Corrosion	1.	Is the free water with CO_2 present (including consideration for dew point	Y	Yes
		2.	Is the material of construction carbon steel or < 13% Cr?	Y	
			Carboon Steel		
13.	AST Bottom	1.	Is the equipment item an AST tank bottom?	N	No

1. Corrosion Rate (Cr) from the RLA data

   Cr = 0,004921 inch/year

   = 0,125 mm/year

2.a. Corrosion Rate (Cr) based on the Annex 2B CO_2 Corrosion Calculation

CR = $CR_B . \min[F_{glycol}, F_{inhib}]$ .... (Equation 1)

Base Corrosion Rate

CR_B = f(T,pH) . $f_{CO2}^{0.62} . (\frac{S}{19})^{0.146+0.0324\, fco2}$................................ (Equation 2)

Where ;

CR_B = Base corrosion rate (mm/y)

f(T,pH) = Temperature-pH function tabulated in Table 2.B.13.2

f_{CO2} = CO_2 fugacity

S = Shear stress yo calculate the flow velocity (Pa)

a. Determine the calculated pH

$pH = 2{,}8686 + 0{,}7931.log_{10}[T] - 0{,}57.log_{10}[p_{CO2}]$.......... (Equation 3)

T = 18,83 °C

= 65,894 °F

= 291,83 K

mole% of CO2 in gas = 3,1497 %

P_{CO2} = 141,74 kPa

= 20,557 psi

= 1,4174 bar

$pH = 2{,}8686 + 0{,}7931.log_{10}[T] - 0{,}57.log_{10}[p_{CO2}]$

= 2,8686 + 0,7931. $\log_{10}$ [65,89 F] - 0,57. $\log_{10}$ [20,56 psi]

= 3,56273791

b. Determine the CO_2 fugacity

$log_{10}\,[f_{CO2}] = log_{10}[p_{CO2}] + \min[250, p_{CO2}].(0.0031-\frac{1.4}{T+273})$(Equation 4)

$log_{10}\,[f_{CO2}] = log_{10}[20{,}56] + \min[250, 20{,}56].(0.0031-\frac{1.4}{18{,}3+273})$

= 0,05

c. Determine the flow velocity

To determine the flow velocity, the API 581 reffers to the NORSOK M-506. and both of the Recommended Practice use the fluid flow shear stress, S, to model the effect of flow velocity n the base corrosion rate.

$S = \frac{f.\rho m.um^2}{2}$ .... (Equation 5)

In the calculation for the corrosion rate, the shear stress need not exceed 150 Pa.

Where;

f = Friction factor

ρ_m = Mixture mass density kg/m^3

= 0,668 kg/m^3

u_m = Mixture flow velocity m/s

= 1,8 m/s

$f = 0.001375$ [1+ $(20000(\frac{e}{D}) + (\frac{10^6}{Re})^{0.33}]$......................... (Equation 6)

$\frac{\varepsilon}{D}$ = Relative roughness of the material

0,035

Based on the Table below that for the Carbon Steel (A106 Gr.B) material of construction which is assumed as new carbonsteel is approximately ranging from 0.02 - 0.05.

Material	Absolute Roughness (mm)
Copper, Lead, Brass, Aluminum (new)	0.001 - 0.002
PVC and Plastic Pipes	0.0015 - 0.007
Flexible Rubber Tubing - Smooth	0.006-0.07
Stainless Steel	0.0015
Steel Commercial Pipe	0.045 - 0.09
Weld Steel	0.045
Carbon Steel (New)	0.02-0.05
Carbon Steel (Slightly Corroded)	0.05-0.15
Carbon Steel (Moderately Corroded)	0.15-1
Carbon Steel (Badly Corroded)	1-3
Asphalted Cast Iron	0.1-1
New Cast Iron	0.25 - 0.8
Worn Cast Iron	0.8 - 1.5
Rusty Cast Iron	1.5 - 2.5
Galvanized Iron	0.025-0.15
Wood Stave	0.18-0.91
Wood Stave, used	0.25-1
Smoothed Cement	0.3
Ordinary Concrete	0.3 - 1
Concrete – Rough, Form Marks	0.8-3

Source by: https://www.nuclear-power.net/nuclear-engineering/fluid-dynamics/major-head-loss-friction-loss/relative-roughness-of-pipe/

$$Re = \frac{D.\rho m.um}{\mu m} \quad \text{(Equation 7)}$$

Re = Reynolds number

D = Diameter

= 323,8 mm

= 0,3238 m

µm = Viscosity of the mixture cp

= 0,35 Cp

= 0,0004 Pa s

$$Re = \frac{D.\rho m.um}{\mu m}$$

= 1112,3918

$$f = 0.001375\,[\,1 + (20000(\tfrac{e}{D}) + (\tfrac{10^6}{Re})^{0.33}]$$

$$= 0.001375\,[\,1 + (20000(\,0{,}035) + (\tfrac{10^6}{1112{,}392})^{0.33}]$$

= 0,013

After the value of relative roughness, Reynolds number, and the friction factor have been determines. Then, the value of the flow velocity can be calculated.

$$S = \frac{f.\rho m.um^2}{2}$$

= 0,0143954 Pa

Those calculated pH, CO_2 fugacity, and also flow velocity have been known. So, the value of Base Corrosion Rate (Cr_{base}) can be determined.

CR_B = f(T,pH) . $f_{CO2}^{\ 0.62}$. $(\frac{S}{19})^{0.146+0.0324\ fco2}$

Where;

f(T,pH) = Temperature-pH function tabulated in Table 2.B.13.2

= 5,45

Cr_{base} = 5,45 x $(0{,}05)^{0{,}62}$ x $(0{,}014395/19)^{0{,}146+(0{,}0324 \text{ x } 0{,}05)}$

= 0,3137906 mpy

= 0,0079703 mm/y

Because there is no any mixture for glycol and the other inhibitors inside the piping, then, Cr is equal to Cr_{base}. The glycol or inhibitor is placed in another equipment not being process in the Piping itself.

Where;

CR = $CR_B . \min[F_{glycol}, F_{inhib}]$

<u>CR</u> = Cr_{base}

= 0,0079703 mm/y

<u>Calculated corrosion rate =</u> 0,00797 mm/year

STEP 3 Determine the time in service, age_{tk}, since the last known inspection, t_{rdi}.

• t_{rdi}	=	0,6882 inch		Last inspection is on:	15/11/2018
	=	17,48 mm		RBI Date is on:	20/08/2019
• t_{pd}	=	0,6872 inch		Planned Date is on:	11/11/2022
		17,45 mm			

age_{tk} = 0,761 years (Construction was on November 2018)

age_{PD} = 3,23 years

STEP 4 For cladding/weld overlay piping components, calculate the age from the date starting thickness from STEP 3 required to corrode away the cladding/weld overlay material, age_{rc}, using equation below:

$$age_{rc} = \max\left[\left(\frac{t_{rdi}-tbm}{C_{r\,cm}}\right), 0.0\right] \text{ .... (Equation 8)}$$

Because the piping is not cladding/weld overlay. Then, the equation above does not need to be considered.

STEP 5 Determine the t_{min}

Actually there are 4 methods used to determine the minimum thickness of the equipment (t_{min}). Based on the condition, the method used by the author is the first method which is for cylindrical, spherical, or head components, determine the allowable Stress, S, weld joint efficiency, E, and the minimum thickness, t_{min}.

$$t_m = t + c \quad \text{(Equation 9)}$$

$$t = \frac{PD}{2(SE + PY)}$$

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Where,

tm	:	Minimum required thickness, including mechanical, corrosion, and erosion allowances (mm)
t	:	Pressure design thickness
c	:	The sum of mechanical allowance (groove depth and threading) plus allowance for corrosion and erosion (mm)
E	:	Joint efficiency
P	:	Design pressure (MPa)
D	:	Outside diameter of pipe (mm)
S	:	Allowable stresses for pipe material (Mpa)
Y	:	Temperature factor, per Table 304.1.1 in ASME B31.3 (Normally 0,4)

Table S301.3.1 Generic Pipe Stress Model Input

Term	Value
Operating conditions:	
Internal pressure, P_1	3 450 kPa (500 psi)
maximum metal temp., T_1	260°C (500°F)
minimum metal temp., T_2	−1°C (30°F)
Installation temperature	21°C (70°F)
Line size	DN 400 (NPS 16)
Pipe	Schedule 30/STD, 9.53 mm (0.375 in.)
Mechanical allowance, c	1.59 mm (0.063 in.)
Mill tolerance	12.5%
Elbows	Long radius
Fluid specific gravity	1.0
Insulation thickness	127 mm (5 in.)
Insulation density	176 kg/m^3 (11.0 lbm/ft^3)
Pipe material	ASTM A106 Grade B
Pipe density	7 833.4 kg/m^3 (0.283 lbm/in.^{3})
Total weight	7 439 kg (16,400 lbm)
Unit weight	248.3 kg/m (166.9 lbm/ft)

Source : ASME B31.3, Table S301.3.1 Generic Pipe Stress Model Input, Edition 2016

Table 304.1.1 Values of Coefficient Y for $t < D/6$

Material	Temperature, °C (°F)					
	482 (900) and Below	510 (950)	538 (1,000)	566 (1,050)	593 (1,100)	621 (1,150)
Ferritic steels	0.4	0.5	0.7	0.7	0.7	0.7
Austenitic steels	0.4	0.4	0.4	0.4	0.5	0.7
Nickel alloys UNS Nos. N06617, N08800, N08810, and N08825	0.4	0.4	0.4	0.4	0.4	0.4
Gray iron	0.0	...	...	...	...	...
Other ductile metals	0.4	0.4	0.4	0.4	0.4	0.4

Source : ASME B31.3, Table 304.1.1 Value of Coeeficient Y, Edition 2016

$$t = \frac{PD}{2(SE + PY)}$$

$$t = \frac{(9{,}4\ MPa)\ x\ (323{,}8\ mm)}{2((160{,}648\ MPa\ x\ 1) + (9{,}4\ MPa\ x\ 0{,}4))}$$

= 9,3637 mm

$$t_m = t + c$$

= 9,3637 mm + 1,59 mm

= 10,95 mm

= 0,43125 inch

STEP 6 Determine the A_{rt} Parameter

For component without clading/weld overlay then use the equation following.

$$A_{rt} = \frac{Cr_{b,m}.\,age_{tk}}{t_{rdi}} \quad \text{...} \quad (\text{Equation 10})$$

Where,

$Cr_{b.m}$: Corrosion base material

age_{tk} : Component in-service time since the last inspection

t_{rdi} : Furnished thickness since last inspection

A_{rt} on RBI Date:

$$A_{rt} = \frac{Cr_{b,m}.\,age_{tk}}{t_{rdi}} = \frac{0{,}00797\ \left(\frac{mm}{year}\right).\,0{,}761 year}{17{,}48\ mm}$$

= 0,000347 **(Annex 2B)**

$$A_{rt} = \frac{Cr.\,age_{tk}}{t_{rdi}} = \frac{0{,}125\ \left(\frac{mm}{year}\right).\,0{,}761 year}{17{,}48\ mm}$$

= 0,0054428 **(RLA data)**

A_{rt} on Plan Date:

$$A_{rt} = \frac{Cr_{b,m}.\,age_{pd}}{t_{pd}} = \frac{0{,}00797\ \left(\frac{mm}{year}\right).\,3{,}23 year}{17{,}45\ mm}$$

= 0,001474 **(Annex 2B)**

$$A_{rt} = \frac{Cr\ .\,age_{pd}}{t_{pd}} = \frac{0{,}125\ \left(\frac{mm}{year}\right).\,3{,}23 year}{17{,}45\ mm}$$

= 0,0231170 **(RLA data)**

STEP 7 Calculate the Flow Stress, FS^{Thin} , using E from STEP 5 and equation below.

$$FS^{Thin} = \frac{(YS+TS)}{2}.\,E.1{,}1 \quad \text{...} \quad (\text{Equation 11})$$

Where;

YS = 241000 KPa

TS = 414000 KPa

E = 1

Source : ASME B31.3 - Table A -1M Basic Allowable Stresses in Tension for Metal Page 220. Edition 2016

$$FS^{Thin} = \frac{(241000+414000)}{2}.\,E.1{,}1$$

= 360250

STEP 8 Calculate the strength ratio parameter, SR_P^{Thin}, using the appropriate equation.

$$SR_P^{Thin} = \frac{S.E}{FS^{Thin}} \cdot \frac{Max\,(t_{min},t_c)}{t_{rdi}} \quad \text{(Equation 12)}$$

Where;

t_c = is the minimum structural thickness of the component base material

= 0,4312474 inch

= 10,9537 mm

$$SR_P^{Thin} = \frac{160648\ x\ 1}{360250} \cdot \frac{Max\,(10{,}9537\,;10{,}9537)}{10{,}9537}$$

= 0,27944084

STEP 9 Determine the number of inspections for each of the correspondesing inspection effectiveness, $N_A^{Thin}, N_B^{Thin}, N_C^{Thin}, N_D^{Thin}$, using Section 4.5.6 of the API RP 581 Part 2 for past inspections performed during in-service time.

N_A^{Thin} = 0

N_B^{Thin} = 0

N_C^{Thin} = 0

N_D^{Thin} = 0

STEP 10 Calculate the inspection effectiveness factors, $I_1^{Thin}, I_2^{Thin}, I_3^{Thin}$,using equation below, prior probabilities, $Pr_{p1}^{Thin}, Pr_{p2}^{Thin}, Pr_{p3}^{Thin}$ from Table 4.5. The Conditional Probabilities (for each inspection effectiveness level), $Co_{p1}^{Thin}, Co_{p2}^{Thin}$ Co_{p3}^{Thin} from Table 4.6, and the number of inspection, $N_A^{Thin}, N_B^{Thin}, N_C^{Thin}, N_D^{Thin}$ in each effectiveness level from STEP 9.

$$I_1^{Thin} = Pr_{P1}^{Thin}(Co_{P1}^{ThinA})^{N_A^{Thin}}(Co_{P1}^{ThinB})^{N_B^{Thin}}(Co_{P1}^{ThinC})^{N_C^{Thin}}(Co_{P1}^{ThinD})^{N_D^{Thin}}$$

$$I_2^{Thin} = Pr_{P2}^{Thin}(Co_{P2}^{ThinA})^{N_A^{Thin}}(Co_{P2}^{ThinB})^{N_B^{Thin}}(Co_{P2}^{ThinC})^{N_C^{Thin}}(Co_{P2}^{ThinD})^{N_D^{Thin}}$$

$$I_3^{Thin} = Pr_{P3}^{Thin}(Co_{P3}^{ThinA})^{N_A^{Thin}}(Co_{P3}^{ThinB})^{N_B^{Thin}}(Co_{P3}^{ThinC})^{N_C^{Thin}}(Co_{P3}^{ThinD})^{N_D^{Thin}}$$

(Equation 13)

Table 4.5 - Prior Probability for Thinning Corrosion Rate

Damage State	Low Confidence Data	Medium Confidence	High Conf. Data
Pr_{P1}^{Thin}	0,5	0,7	0,8
Pr_{P2}^{Thin}	0,3	0,2	0,15
Pr_{P3}^{Thin}	0,2	0,1	0,05

Table 4.6 - Conditional Probability for Inspection Effectiveness

Conditional of Inspection	E-None or Ineffective	D-Poorly Effective	C-Fairly Effective	B Usually Effective	A-Highly Effective
Co_{P1}^{Thin}	0,33	0,4	0,5	0,7	0,9
Co_{P2}^{Thin}	0,33	0,33	0,3	0,2	0,09
Co_{P3}^{Thin}	0,33	0,27	0,2	0,1	0,01

$$I_1^{Thin} = Pr_{P1}^{Thin}(Co_{P1}^{ThinA})^{N_A^{Thin}}(Co_{P1}^{ThinB})^{N_B^{Thin}}(Co_{P1}^{ThinC})^{N_C^{Thin}}(Co_{P1}^{ThinD})^{N_D^{Thin}}$$

$= 0,5\ (0,4)^0 \times (0,4)^0 \times (0,4)^0 \times (0,4)^0$

$= 0,5$

$$I_2^{Thin} = Pr_{P2}^{Thin}(Co_{P2}^{ThinA})^{N_A^{Thin}}(Co_{P2}^{ThinB})^{N_B^{Thin}}(Co_{P2}^{ThinC})^{N_C^{Thin}}(Co_{P2}^{ThinD})^{N_D^{Thin}}$$

$= 0,3\ (0,33)^0 \times (0,33)^0 \times (0,33)^0 \times (0,33)^0$

$= 0,3$

$$I_3^{Thin} = Pr_{P3}^{Thin}(Co_{P3}^{ThinA})^{N_A^{Thin}}(Co_{P3}^{ThinB})^{N_B^{Thin}}(Co_{P3}^{ThinC})^{N_C^{Thin}}(Co_{P3}^{ThinD})^{N_D^{Thin}}$$

$= 0,2\ (0,33)^0 \times (0,33)^0 \times (0,33)^0 \times (0,33)^0$

$= 0,20$

STEP 11 Calculate the Posteroir Probability, $Po_{p1}^{Thin}, Po_{p2}^{Thin}, Po_{p3}^{Thin}$, using equations:

$$Po_{p1}^{Thin} = \frac{I_1^{Thin}}{I_1^{Thin} + I_2^{Thin} + I_3^{Thin}} \qquad \text{.. (Equation 14)}$$

$$= \frac{0,5}{0,5 + 0,3 + 0,2}$$

$= 0,5$ f

$$Po_{p2}^{Thin} = \frac{I_2^{Thin}}{I_1^{Thin} + I_2^{Thin} + I_3^{Thin}}$$

$$= \frac{0,3}{0,5 + 0,3 + 0,2}$$

$= 0,3$

$$Po_{p3}^{Thin} = \frac{I_3^{Thin}}{I_1^{Thin} + I_2^{Thin} + I_3^{Thin}}$$

$$= \frac{0,2}{0,5 + 0,3 + 0,2}$$

$= 0,2$

STEP 12 Calculate the parameters, ß$_1$, ß$_2$, and ß$_3$ using equation below and also assigning $COV_{\Delta t} = 0.20$, $COV_{sf} = 0.20$, and $COV_P = 0.05$.

$$ß_1^{Thin} = \frac{1-D_{S1}.A_{rt}-SR_P^{Thin}}{\sqrt{D_{S1}{}^2.A_{rt}{}^2.COV_{\Delta t}{}^2+(1-D_{S1}.A_{rt})^2.COV_{sf}{}^2+(SR_P^{Thin})^2.(COV_P)^2}} \qquad \text{............. (Equation 15)}$$

$$ß_2^{Thin} = \frac{1-D_{S2}.A_{rt}-SR_P^{Thin}}{\sqrt{D_{S2}{}^2.A_{rt}{}^2.COV_{\Delta t}{}^2+(1-D_{S2}.A_{rt})^2.COV_{sf}{}^2+(SR_P^{Thin})^2.(COV_P)^2}}$$

$$ß_3^{Thin} = \frac{1-D_{S3}.A_{rt}-SR_P^{Thin}}{\sqrt{D_{S3}{}^2.A_{rt}{}^2.COV_{\Delta t}{}^2+(1-D_{S3}.A_{rt})^2.COV_{sf}{}^2+(SR_P^{Thin})^2.(COV_P)^2}}$$

Where;

$COV_{\Delta t}$ = The thinning coefficient of variance ranging from $0.1 \leq COV_{\Delta t} \leq 0.2$

= 0,2

COV_{sf}	=	The flow stress coefficient of variance
	=	0,2
COV_P	=	Pressure coeffficient of variance
	=	0,05
D_{s1}	=	Damage State 1
	=	1
D_{s2}	=	Damage State 2
	=	2
D_{s3}	=	Damage State 3
	=	4

RBI DATE:

<u>BASED ON CORROSION RATE FROM RLA DATA</u>

$$ß_1^{Thin} = \frac{1-1\ x\ 0{,}0054428-0{,}27944084}{\sqrt{(1)^2\ x\ (0{,}0054428)^2\ x\ (0{,}2)^2+(1-(1\ x0{,}0054428))^2\ x\ (0{,}2)^2+(0{,}27944084)^2.(0{,}05)^2}}$$

$ß_1^{Thin}$ = 3,586259

$$ß_2^{Thin} = \frac{1-2\ x\ 0{,}0054428-0{,}27944084}{\sqrt{(2)^2\ x\ (0{,}0054428)^2\ x\ (0{,}2)^2+(1-(2\ x0{,}0054428))^2\ x\ (0{,}2)^2+(0{,}27944084)^2.(0{,}05)^2}}$$

$ß_2^{Thin}$ = 3,578289

$$ß_3^{Thin} = \frac{1-3\ x\ 0{,}0054428-0{,}27944084}{\sqrt{(3)^2\ x\ (0{,}0054428)^2\ x\ (0{,}2)^2+(1-(3\ x0{,}0054428))^2\ x\ (0{,}2)^2+(0{,}27944084)^2.(0{,}05)^2}}$$

$ß_3^{Thin}$ = 3,561749

<u>BASED ON CORROSION RATE FROM ANNEX 2B</u>

$$ß_1^{Thin} = \frac{1-1\ x\ 0{,}000347-0{,}27944084}{\sqrt{(1)^2\ x\ (0{,}000347)^2\ x\ (0{,}2)^2+(1-(1\ x0{,}000347))^2\ x\ (0{,}2)^2+(0{,}27944084)^2.(0{,}05)^2}}$$

$ß_1^{Thin}$ = 3,5935461

$$ß_2^{Thin} = \frac{1-2\ x\ 0{,}000347-0{,}27944084}{\sqrt{(2)^2\ x\ (0{,}000347)^2\ x\ (0{,}2)^2+(1-(2\ x0{,}000347))^2\ x\ (0{,}2)^2+(0{,}27944084)^2.(0{,}05)^2}}$$

$ß_2^{Thin}$ = 3,5930552

$$ß_3^{Thin} = \frac{1-3\ x0{,}000347-0{,}27944084}{\sqrt{(3)^2\ x\ (0{,}000347^2\ x\ (0{,}2)^2+(1-(3\ x0{,}000347))^2\ x\ (0{,}2)^2+(0{,}27944084)^2.(0{,}05)^2}}$$

$ß_3^{Thin}$ = 3,5920710

PLANNED DATE:

<u>BASED ON CORROSION RATE FROM RLA DATA</u>

$$ß_1^{Thin} = \frac{1-1\ x\ 0{,}023117-0{,}27944084}{\sqrt{(1)^2\ x\ (0{,}023117)^2\ x\ (0{,}2)^2+(1-(1\ x0{,}023117))^2\ x\ (0{,}2)^2+(0{,}27944084)^2.(0{,}05)^2}}$$

$ß_1^{Thin}$ = 3,5596476

$$ß_2^{Thin} = \frac{1-2\ x\ 0{,}023117-0{,}27944084}{\sqrt{(2)^2\ x\ (0{,}023117)^2\ x\ (0{,}2)^2+(1-(2\ x0{,}023117))^2\ x\ (0{,}2)^2+(0{,}27944084)^2.(0{,}05)^2}}$$

$ß_2^{Thin}$ = 3,5215080

$$ß_3^{Thin} = \frac{1-3\ x\ 0{,}023117-0{,}27944084}{\sqrt{(3)^2\ x\ (0{,}023117)^2\ x\ (0{,}2)^2+(1-(3\ x0{,}023117))^2\ x\ (0{,}2)^2+(0{,}27944084)^2.(0{,}05)^2}}$$

$ß_3^{Thin}$ = 3,4325608

<u>BASED ON CORROSION RATE FROM ANNEX 2B</u>

$$ß_1^{Thin} = \frac{1-1\ x\ 0{,}001474-0{,}27944084}{\sqrt{(1)^2\ x\ (0{,}001474)^2\ x\ (0{,}2)^2+(1-(1\ x0{,}001474))^2\ x\ (0{,}2)^2+(0{,}27944084)^2.(0{,}05)^2}}$$

$ß_1^{Thin}$ = 3,5919491

$$ß_2^{Thin} = \frac{1-2\ x0{,}001474-0{,}27944084}{\sqrt{(2)^2\ x\ (0{,}001474)^2\ x\ (0{,}2)^2+(1-(2\ x0{,}001474))^2\ x\ (0{,}2)^2+(0{,}27944084)^2.(0{,}05)^2}}$$

$ß_2^{Thin}$ = 3,5898479

$$ß_3^{Thin} = \frac{1-3\ x\ 0{,}001474-0{,}27944084}{\sqrt{(3)^2\ x\ (0{,}001474)^2\ x\ (0{,}2)^2+(1-(3\ x0{,}001474))^2\ x\ (0{,}2)^2+(0{,}27944084)^2.(0{,}05)^2}}$$

$ß_3^{Thin}$ = 3,5856033

STEP 13 For tank bottom components, determine the base damage factor for thining using Table 4.8. and based on A_{rt} parameter from STEP 6.

Because component observed in this case of analysis is including into piping, then this step of calculation can be skipped.

STEP 14 For all components (excluding tank bottoms covered in STEP 13), calculate the base damage factor, . D_{fb}^{Thin}

$$D_{fb}^{Thin} = [\frac{\left(Po_{P1}^{Thin}\Phi(-\beta_1^{Thin})\right)+\left(Po_{P2}^{Thin}\Phi(-\beta_2^{Thin})\right)+\left(Po_{P3}^{Thin}\Phi(-\beta_3^{Thin})\right)}{1.56E-0.4} \text{....} \quad \text{(Equation 16)}$$

RBI DATE:

<u>BASED ON CORROSION RATE FROM RLA DATA</u>

$$D_{fb}^{Thin} = [\frac{\left(0{,}5\ \Phi(-3{,}586259)\right)+\left(03\ \Phi(-3{,}78289)\right)+\left(0{,}2\Phi(-3{,}561749)\right)}{1.56(1)-0.4}]$$

D_{fb}^{Thin} = 0,24091501238

BASED ON CORROSION RATE FROM ANNEX 2B

D_{fb}^{Thin} = $[\frac{(0{,}5\ \Phi(-3{,}5935461))+(0{,}3\ \Phi(-3{,}5930522))+(0{,}2\Phi(-3{,}5920710))}{1.56(1)\ -0.4}]$

D_{fb}^{Thin} = 0,24092090927

PLANNED DATE:

BASED ON CORROSION RATE FROM RLA DATA

D_{fb}^{Thin} = $[\frac{(0{,}5\ \Phi(-3{,}5596476))+(0{,}3\ \Phi(-3{,}5215080))+(0{,}2\Phi(-3{,}4325608))}{1.56(1)\ -0.4}]$

D_{fb}^{Thin} = 0,24088654222

BASED ON CORROSION RATE FROM ANNEX 2B

D_{fb}^{Thin} = $[\frac{(0{,}5\ \Phi(-3{,}5919491))+(0{,}3\ \Phi(-3{,}5898479))+(0{,}2\Phi(-3{,}5856033))}{1.56(1)\ -0.4}]$

D_{fb}^{Thin} = 0,24091967043

STEP 15 Determine the DF for thinning, D_f^{Thin} using equation equation below.

D_f^{Thin} = Max$[(\frac{(D_{fb}^{Thin}.\ F_{IP}\ .\ F_{DL}\ .F_{WD}.F_{AM}\ .F_{SM})}{F_{OM}}),0.1]$ .... (Equation 17)

Where;

F_{IP} = DF adjustent for injection points (for piping circuit)
= 1

F_{DL} = DF adjustment for dead legs (for piping only used to intermittent service)
= 1

F_{WD} = DF adjustment for welding construction (for only AST Bottom)
= 0

F_{AM} = DF adjustment for AST maintenance per API STD 653 (for only AST)
= 0

F_{SM} = DF adjustment for settlement (for only AST Bottom)
= 0

F_{OM} = DF adjustment for online monitoring based on Table 4.9
= 1

RBI DATE:

BASED ON CORROSION RATE FROM RLA DATA

D_f^{Thin} = Max$[(\frac{(0{,}24091501238x\ 1\ x\ 1}{1}),0.1]$

D_f^{Thin} = 0,24091501238

BASED ON CORROSION RATE FROM ANNEX 2B

D_f^{Thin} = Max[($\frac{(0{,}24092090927 x\ 1\ x\ 1}{1}$),0.1]

D_f^{Thin} = 0,24092090927

PLANNED DATE:

BASED ON CORROSION RATE FROM RLA DATA

D_f^{Thin} = Max[($\frac{(0{,}24088654222\ x\ 1\ x\ 1}{1}$),0.1]

D_f^{Thin} = 0,24088654222

BASED ON CORROSION RATE FROM ANNEX 2B

D_f^{Thin} = Max[($\frac{(0{,}24091967043 x\ 1\ x\ 1}{1}$),0.1]

D_f^{Thin} = 0,24091967043

DAMAGE FACTOR FOR THINNING

The governing thinning DF is determined based on the presence of an internal liner using equation below.

D_{f-gov}^{Thin} = min[D_f^{Thin}, D_f^{elin}] When internal liner is present

$D_{f-gov}^{Thin} = D_f^{Thin}$ When internal liner is not present

According to above calculaton, there is no any presence of liner, then, we can consider to use the second governing thinning DF calculation.

$D_{f-gov}^{Thin} = D_f^{Thin}$

RBI DATE:

Based on RLA Data

D_{f-gov}^{Thin} = 0,24091501238

Based on Corrosion Rate from Annex 2B

D_{f-gov}^{Thin} = 0,24092090927

PLANNED DATE:

Based on RLA Data

D_{f-gov}^{Thin} = 0,24088654222

Based on Corrosion Rate from Annex 2B

D_{f-gov}^{Thin} = 0,2409196704

<u>TYPE OF THINNING</u>

The type of thinning (wheter it is local or general) can be determined from table 2.B.1.2 from API RP 581 3rd Edition Part 2 - Annex 2.B, as follow:

Table 2.B.1.2 Type of Thinning

Thinning Mechanism	Condition	Type of Thinning
Hydrochloric Acid (HCl) Corrosion	—	Local
High Temperature Sulfidic/Naphthenic Acid Corrosion	TAN ≤ 0.5	General
	TAN > 0.5	Local
High Temperature H_2S/H_2 Corrosion	—	General
Sulfuric Acid (H_2SO_4) Corrosion	Low Velocity ≤ 0.61 m/s (2 ft/s) for carbon steel, ≤ 1.22 m/s (4 ft/s) for SS, and ≤ 1.83 m/s (6 ft/s) for higher alloys	General
	High Velocity ≥ 0.61 m/s (2 ft/s) for carbon steel, ≥ 1.22 m/s (4 ft/s) for SS, and ≥ 1.83 m/s (6 ft/s) for higher alloys	Local
Hydrofluoric Acid (HF) Corrosion	—	Local
Sour Water Corrosion	Low Velocity: ≤ 6.1 m/s (20 ft/s)	General
	High Velocity: > 6.1 m/s (20 ft/s)	Local
Amine Corrosion	Low Velocity < 1.5 m/s (5 ft/s) rich amine < 6.1 m/s (20 ft/s) lean amine	General
	High Velocity > 1.5 m/s (5 ft/s) rich amine > 6.1 m/s (20 ft/s) lean amine	Local
High Temperature Oxidation	—	General
Acid Sour Water Corrosion	< 1.83 m/s (6 ft/s) ≥ 1.83 m/s (6 ft/s)	General Local
Cooling Water Corrosion	≤ 0.91 m/s (3 ft/s) 0.91-2.74 m/s (3-9 ft/s) > 2.74 m/s (9 ft/s)	Local General Local
Soil Side Corrosion	—	Local
CO_2 Corrosion	—	Local
AST Bottom	Product Side Soil Side	Local Local

The thinning mechanisms is CO_2 corrosion.

CO2 corrosion is localized thinning mechanisms. The type of thinning designated will be used to determine the effectiveness of inspection performed.

So, the thinning damage is designated as <u>localized</u>

MECHANICAL FATIGUE DAMAGE FACTOR CALCULATION

STEP 1 Determine the number of previous failures that have occured, and determine the base D_{fB}^{PF} based on the following criteria.

1) None - D_{fB}^{PF} = 1
2) One - D_{fB}^{PF} = 50
3) Greater than one - D_{fB}^{PF} = 500

Because this equipment still new and no failures occurs, so the value D_{fB}^{PF} = 1

STEP 2 Determine the amount of visible / audible shaking or audible noise occuring in the pipe, and determine the base D_{fB}^{AS} based on the following criteria.

1) Minor - D_{fB}^{AS} = 1
2) Moderate - D_{fB}^{AS} = 50
3) Severe - D_{fB}^{AS} = 500

This equipment not yet operation, so it can be categorized as Minor- = 1

STEP 3 Determine the adjustment factor for visible / audible shaking based on the following criteria. This adjustment is based on observation that some piping system may endure visible shaking for years. A repeated stress with a cycle of only 1 hertz (1/s) result in over 30 million cycles in years. Most system, if they were subject to failure by mechanical fatigue would be expected to fail before reaching tens or hundreds of million cycles. One should note that intermitten cycles are cumulative.

1) Shaking less than 2 weeks - D_{fB}^{AS} = 1
2) Shaking between 2 and 13 weeks - D_{fB}^{AS} = 0.2
3) Shaking between 13 and 52 weeks - D_{fB}^{AS} = 0.02

This equipment not yet operation, so the shaking less than 2 weeks - = 1

STEP 4 Determine the type of cyclic loading connected directly or indirectly within approximately 15.24 meters (50 feet) of the pipe, and determine the base DF D_{fB}^{CF} based on the following criteria.

1) Reciprocating machinery - D_{fB}^{CF} = 50
2) PRV Chatter - D_{fB}^{CF} = 25
3) Valve with high pressure drop - D_{fB}^{CF} = 10
4) None - D_{fB}^{CF} = 1

This equipment is process gas piping, so the value of is 1

STEP 5 Determine the base DF using this equation

$$D_{fB}^{mfat} = \max\left[D_{fB}^{PF}, \left(D_{fB}^{AS} . F_{fB}^{AS}\right), D_{fB}^{CF}\right]$$

$$D_{fB}^{mfat} = \quad 1$$

STEP 6 Determine the final value of the DF using this equation

$$D_{f}^{mfat} = D_{fb}^{mfat}\ x\ F_{CA}\ x\ F_{PC} x\ F_{JB}\ x\ F_{BD}$$

The adjustment factor are determined as follows.

1) Adjustment for corrective action, F_{CA} - Established based on the following criteria.
    - □ Modification based on complete engineering analysis - = 0.002
    - □ Modification based on experience - F_{CA} = 0.2
    - □ No modification - F_{CA} = 2

    No modification for this piping so, the value of = 2

2) Adjustment for pipe complexity, F_{PC} - Established based on the following criteria.
    - □ 0 to 5 total pipe fittings - F_{PC} = 0.5
    - □ 6 to 10 total pipe fittings - F_{PC} = 1
    - □ Greater than 10 total pipe fittings - F_{PC} = 2

    The total fittings are 15, so the F_{CA} = 2

3) Adjustment for condition of pipe, - F_{CP} Established based on the following criteria.
    - □ Missing or damaged supports, improper support - F_{CP} = 2
    - □ Broken gussets, gussets welded directly to the pipe - = 2
    - □ Good condition - F_{CP} = 1

    The piping condition is good because not yet operation = 1

4) Adjustment for joint type or branch design, F_{JB} - Established based on the following criteria.
    - □ Threaded, socketweld, saddle on - F_{JB} = 2
    - □ Saddle in fittings - F_{JB} = 1
    - □ Piping tee, Weldolets - F_{JB} = 0.2
    - □ Sweepolets - F_{JB} = 0.02

    The joint type for this piping is threaded, so the value of = 2

5) Adjustment for branch diameter, F_{BD}- Established based on the following criteria.

- □ All branches less than or equal to 2 NPS - F_{BD} = 1
- □ Any branches greater than 2 NPS - F_{BD} = 0.02

The branches greater than 2 NPS, so the value of = 0.02

$D_f^{mfat} = D_{fb}^{mfat} \; x \; F_{CA} \; x \; F_{PC} x \; F_{JB} \; x \; F_{BD}$ .... (Equation 18)

$D_f^{mfat} = 0{,}0111$

EXTERNAL CORROSION DAMAGE FACTOR CALCULATION

1. RLA DATA

REQUIRED DATA

The basic component data required for analysis is given in Table 4.1. and the specific data required for determination of the DF for external corrosion is provided Table 15.1 in API RP 581 Part 2 of POF.

Table 4.1. Basic Component Data Required for Analysis

Basic Data	Value	Unit	Comments
Start Date	16/03/2020		The date the component was placed in service.
Thickness	17,48	mm	The thickness used for DF calculation that is either the furnished thickness or the measured thickness.
Corrosion Allowance	1,60	mm	The corrosion allowance is the specified design or actual corrosion allowance upon being placed in the current servicce.
Design Tempearture	65	^{o}C	The design temperature for process gas piping
Design Pressure	9399,97	Kpa	The design pressure for process gas piping
Operating Tempearture	18,83	^{o}C	The highest expected operating temperature expected during operation including normal and unusual operating conditions process gas piping
Operating Pressure	4500	Kpa	The highest expected operating pressure expected during operation including normal and unusual operating conditions.
Design Code	ASME B.31.3		The designing of the component containing the component.
Equipment Type	Piping		The type of equipment.
Component Type	Pipe		The type of component.
Geometry Data			Component geometry data depending on the type of component.
Material Specification	A106 Gr.B		The specification of the material of construction, the ASTM A106 Grade B, specification for pressure vessel components or piping and tankage components. Data entry is based on the material specification, grade, year, UNS Number, class/condition/temper/size/thickness; this data is readdily available in the ASTM Code.

Yield Strength	241000	Kpa	The design yield strength of the material based on material specification.
Tensile Strength	414000	Kpa	The design tensile strength of the material based on material specification.
Weld Joint Efficiency	1,00		Weld joint efficiency per the Code of construction.
Heat Tracing	No		Is the component heat traced? (Yes or No)

STEP 1 Determining the furnished thickness, t, and age for the component from the installation date.

t = 0,6882 inch

= 17,480 mm (Assumed on 16 March 2020)

age = 0 years

STEP 2 Determining the base corrosion rate, CrB based on the driver and operating temperature using Table 15.2.

Table 15.2M - Corrosion Rates for Calculation of the Damage Factor-External Corrosion

Operating Temperature (oC)	Corrosion Rate as a Function of Driver (1) (mmpy)			
	Marine / Cooling	Temperat	Arid / Dry	Severe
-12	0	0	0	0
-8	0,025	0	0	0
6	0,127	0,076	0,025	0,254
32	0,127	0,076	0,025	1,254
71	0,127	0,051	0,025	2,254
107	0,025	0	0	0,051
121	0	0	0	0

t = Operating temperature

= 18,83 ^{o}C

= 118,83 K

mmpy 1 = 0,127 mm/y

Because the operating temperature is normally 18,83^{o}C, and there is no list of such that temperature. But, it does list values for 6^{o}C and 32^{o}C. Both of them have same value on arid / dry condition.

So C_{rB} = 0,127

STEP 3 Calculate the final corrosion rate, Cr, using equation below.

$$C_r = C_{rB} . \max[(F_{EQ}, F_{IF})] \quad \text{..} \quad (\text{ Equation 19})$$

F_{EQ} = Adjustment for equation design or fabrication

= 1

F_{IF} = Adjustment fo interface

= 1

$$C_r = C_{rB} . \max[(F_{EQ}, F_{IF})]$$

= 0,127 . max [(1;1)]

= 0,127

STEP 4 Determine the time in service, age_{tk}, since the last known inspection, t_{rde}. The t_{rde} is the starting thickness with respect to wall loss associated with external corrosion. If no measured thickness is available, set t_{rde} = t and age_{tk} = age

t_{rde}	=	0,6882	inch			
	=	17,48	mm		Last inspection is on:	15/11/2018
t_{pd}	=	0,672	inch		RBI Date is on:	20/08/2019
		17,07	mm		Planned Date is on:	11/11/2022
age_{tk}	=	0,761	years	(Construction was on November 2018)		
age_{pd}	=	3,23	years			

STEP 5 Determine the time in-service, age_{coat}, since the coating has been installed using equation below.

$$age_{coat} = Calculation\ Date - Coating\ Installation\ Date \quad (\text{ Equation 20})$$

Calculation Date = 20/08/2019

Coating installation Date = 15/11/2018

$$age_{coat} = Calculation\ Date - Coating\ Installation\ Date$$

= 0,761 years

STEP 6 Determine coating adjustment, $coat_{adj}$ using one of below equations

If $Age_{tk} \geq Age_{coat}$

$Coat_{adj} = 0$ If No or Poor Coating Quality

$Coat_{adj} = \min[5, age_{coat}]$ If Medium Coating Quality

$Coat_{adj} = \min[15, age_{coat}]$ If High Coating Quality

If $Age_{tk} < Age_{coat}$

$Coat_{adj} = 0$ No / poor

$Coat_{adj}$ $= \min[5, age_{coat}] - \min[5, age_{coat} - age_{tk}]$ Medium

$Coat_{adj}$ $= \min[15, age_{coat}] - \min[15, age_{coat} - age_{tk}]$ High

It is assumed that the coating of the company has ever had is categorized as Medium coating. The type of coating just in external, and the installation on 2018. So the most suitable equation for calculating step 6 is in equation below.

$Coat_{adj} = \min[5, age_{coat}] - \min[5, age_{coat} - age_{tk}]$.... (Equation 21)

$= \min [5 ; 0{,}761] - \min [5 ; 0{,}761 - 0{,}761]$

$= 0{,}761$

STEP 7 Determine the in - service time, age, over which external corrosion may have occured uing equation below

$age = age_{tk} - Coat_{adj}$.. (Equation 22)

$= 0{,}761 - 0{,}761$

$= 0$

STEP 8 Determine the allowable stress, S, weld joint efficiency, E, and minimum required thickness, t_{min}, per the original construction code or ASME B.31.3

t_{min}	=	0,4312	inch
	=	10,954	mm
S	=	23300	psig
	=	160647908	Pa
	=	160647,908	Kpa
E	=	1	

STEP 9 Determine the A_{rt} Parameter

For component without clading/weld overlay then use the equation below.

<u>RBI DATE</u>

$$A_{rt} = \frac{Cr.agetk}{t_{rde}}$$ .... (Equation 23)

$$= \frac{0{,}127 . 0{,}761}{17{,}48}$$

$= 0{,}00552989$ (For calculated corrosion rate based on STEP 3)

$$A_{rt} = \frac{Cr.age}{t_{rde}}$$ .... (Equation 24)

$$= \frac{0{,}125 .\ 0,{,}761}{17{,}48}$$

$= 0{,}00544281$ (For corrosion rate based on RLA Data)

PLAN DATE

$$A_{rt} = \frac{Cr.agepd}{t_{pd}} \quad \text{...} \quad \text{(Equation 25)}$$

$$= \frac{0{,}127\ .\ 3{,}23}{17{,}07}$$

= 0,02401554 (For calculated corrosion rate based on STEP 3)

$$A_{rt} = \frac{Cr.age}{t_{pd}} \quad \text{..} \quad \text{(Equation 26)}$$

$$= \frac{0{,}125\ .\ 3{,}23}{17{,}07}$$

= 0,02363735 (For corrosion rate based on RLA Data)

STEP 10 Calculate the Flow Stress, $FS^{extector}$, using E from STEP 5 and equation below.

$$FS^{extcorr} = \frac{(YS+TS)}{2}.\ \mathrm{E}.1{,}1 \quad \text{..} \quad \text{(Equation 27)}$$

Where;

YS = 241000

TS = 414000

E = 1

$$FS^{extcorr} = \frac{(YS+TS)}{2}.\ \mathrm{E}.1{,}1$$

$$= \frac{(241000 + 414000)}{2}.\ (1)\ .1{,}1$$

= 360250

STEP 11 Calculate the strength ratio parameter, SR_P^{Thin} , using the appropriate equation.

$$SR_P^{Thin} = \frac{S.E}{FS^{Thin}}.\frac{Max\ (t_{min}, t_c)}{t_{rdi}} \quad \text{...} \quad \text{(Equation 28)}$$

Where ;

t_c = is the minimum structural thickness of the component base material

= 0,4312 inch

= 10,954 mm

$$SR_P^{extcorr} = \frac{160647{,}908\ .\ 1}{360250}.\frac{Max\ (10{,}954\ )}{17{,}48}$$

= 0,27944084

STEP 12 Determine the number of inspection , $N_A^{extcorr}, N_B^{extcorr}, N_C^{extcorr}, N_D^{extcorr}$, and the corresponding inspection effectiveness category using Section 15.6. 2 for past inspections performed during the in - service time.

$N_A^{extcorr}$ = 0

$N_B^{extcorr}$ = 0

$N_C^{extcorr}$ = 0

$N_D^{extcorr}$ = 0

Table 2.C.10.1 - LoIE Example for External Damage

Inspection Category	Inspection Effectiveness Category	Inspection[1]
A	Highly Effective	Visual inspection of >95% of the exposed surface area with follow-up by UT, RT or pit gauge as required
B	Usually Effective	Visual inspection of >60% of the exposed surface area with follow-up by UT, RT or pit gauge as required
C	Fairly Effective	Visual inspection of >30% of the exposed surface area with follow-up by UT, RT or pit gauge as required
D	Poorly Effective	Visual inspection of >5% of the exposed surface area with follow-up by UT, RT or pit gauge as required
E	Ineffective	Ineffective inspection technique/plan was utilized
Note: 1. Inspection quality is high		

STEP 13 Determine the inspection effectiveness factors, $I_1^{extcorr}, I_2^{extcorr}, I_3^{extcorr}$, using equation below, prior probabilities, $Pr_{p1}^{extcorr}, Pr_{p2}^{extcorr}, Pr_{p3}^{extcorr}$, from Table 4.5. Conditional Probabilities (for each inspection effectiveness level) , $Co_{p1}^{extcorr}, Co_{p2}^{extcorr}, Co_{p3}^{extcorr}$ fromTable 4.6, and the number of inspection, $N_A^{extcorr}, N_B^{extcorr}, N_C^{extcorr}, N_D^{extcorr}$ in each effectiveness level from STEP 12.

$$I_1^{extcorr} = Pr_{P1}^{extcorr}(Co_{P1}^{extcorrA})^{N_A^{extcorr}}(Co_{P1}^{extcorrB})^{N_B^{extcorr}}(Co_{P1}^{extcorrC})^{N_C^{extcorr}}(Co_{P1}^{extcorrD})^{N_D^{extcorr}}$$

$$I_2^{extcorr} = Pr_{P2}^{extcorr}(Co_{P2}^{extcorrA})^{N_A^{extcorr}}(Co_{P2}^{extcorrB})^{N_B^{extcorr}}(Co_{P2}^{extcorrC})^{N_C^{extcorr}}(Co_{P2}^{extcorrD})^{N_D^{extcorr}}$$

$$I_3^{extcorr} = Pr_{P3}^{extcorr}(Co_{P3}^{extcorrA})^{N_A^{extcorr}}(Co_{P3}^{extcorrB})^{N_B^{extcorr}}(Co_{P3}^{extcorrC})^{N_C^{extcorr}}(Co_{P3}^{extcorrD})^{N_D^{extcorr}}$$

(Equation 29)

Table 4.5 - Prior Probability for Thinning Corrosion Rate

Damage State	Low Confidence Data	Medium Confidence	High Conf. Data
Pr_{P1}^{Thin}	0,5	0,7	0,8
Pr_{P2}^{Thin}	0,3	0,2	0,15
Pr_{P3}^{Thin}	0,2	0,1	0,05

Table 4.6 - Conditional Probability for Inspection Effectiveness

Conditional P. of Inspection	E-None or Ineffective	D-Poorly Effective	C-Fairly Effective	B-Usually Effective	A-Highly Effective
Co_{P1}^{Thin}	0,33	0,4	0,5	0,7	0,9
Co_{P2}^{Thin}	0,33	0,33	0,3	0,2	0,09
Co_{P3}^{Thin}	0,33	0,27	0,2	0,1	0,01

$$I_1^{extcorr} = Pr_{P1}^{extcorr}(Co_{P1}^{extcorrA})^{N_A^{extcorr}}(Co_{P1}^{extcorrB})^{N_B^{extcorr}}(Co_{P1}^{extcorrC})^{N_C^{extcorr}}(Co_{P1}^{extcorrD})^{N_D^{extcorr}}$$

$= 0,5\ (0,4)^0 \times (0,4)^0 \times (0,4)^0 \times (0,4)^0$

$= 0,50$

$$I_2^{extcorr} = Pr_{P2}^{extcorr}(Co_{P2}^{extcorrA})^{N_A^{extcorr}}(Co_{P2}^{extcorrB})^{N_B^{extcorr}}(Co_{P2}^{extcorrC})^{N_C^{extcorr}}(Co_{P2}^{extcorrD})^{N_D^{extcorr}}$$

$= 0,3\ (0,33)^0 \times (0,33)^0 \times (0,33)^0 \times (0,33)^0$

$= 0,30$

$$I_3^{extcorr} = Pr_{P3}^{extcorr}(Co_{P3}^{extcorrA})^{N_A^{extcorr}}(Co_{P3}^{extcorrB})^{N_B^{extcorr}}(Co_{P3}^{extcorrC})^{N_C^{extcorr}}(Co_{P3}^{extcorrD})^{N_D^{extcorr}}$$

$= 0,2\ (0,27)^0 \times (0,27)^0 \times (0,27)^0 \times (0,27)^0$

$= 0,20$

STEP 14 Calculate the Posteroir Probability $Po_{p1}^{extcorr}, Po_{p2}^{extcorr}, Po_{p3}^{extcorr}$, using equations

$$Po_{p1}^{extcorr} = \frac{I_1^{extcorr}}{I_1^{extcorr} + I_2^{extcorr} + I_3^{extcorr}}$$

$= 0,5$

$$Po_{p2}^{extcorr} = \frac{I_2^{extcorr}}{I_1^{extcorr} + I_2^{extcorr} + I_3^{extcorr}}$$

$= 0,3$

$$Po_{p3}^{extcorr} = \frac{I_3^{extcorr}}{I_1^{extcorr} + I_2^{extcorr} + I_3^{extcorr}}$$

$= 0,2$

STEP 15 Calculate the parameters, $ß_1$, $ß_2$, and $ß_3$ using equation below and also assigning $COV_{\Delta t} = 0.20$, $COV_{sf} = 0.20$, and $COV_P = 0.05$.

$$ß_1^{extcorr} = \frac{1-D_{S1}.A_{rt}-SR_P^{extcorr}}{\sqrt{D_{S1}^2.A_{rt}^2.COV_{\Delta t}^2+(1-D_{S1}.A_{rt})^2.COV_{sf}^2+(SR_P^{extcorr})^2.(COV_P)^2}}$$

$$ß_2^{extcorr} = \frac{1-D_{S2}.A_{rt}-SR_P^{extcorr}}{\sqrt{D_{S2}^2.A_{rt}^2.COV_{\Delta t}^2+(1-D_{S2}.A_{rt})^2.COV_{sf}^2+(SR_P^{extcorr})^2.(COV_P)^2}}$$

$$ß_3^{extcorr} = \frac{1-D_{S3}.A_{rt}-SR_P^{extcorr}}{\sqrt{D_{S3}^2.A_{rt}^2.COV_{\Delta t}^2+(1-D_{S3}.A_{rt})^2.COV_{sf}^2+(SR_P^{extcorr})^2.(COV_P)^2}}$$

Where;

$COV_{\Delta t}$ = The thinning coefficient of variance ranging from $0.1 \leq COV_{\Delta t} \leq 0.2$

= 0,2

COV_{sf} = The flow stress coefficient of variance

= 0,2

COV_P = Pressure coeffficient of variance

= 0,05

D_{s1} = Damage State 1

= 1

D_{s2} = Damage State 2

= 2

D_{s3} = Damage State 3

= 4

RBI DATE

BASED ON CORROSION RATE FROM STEP 3

$ß_1^{extcor}$ = 3,5861

$ß_2^{extcor}$= 3,5780

$ß_3^{extcor}$ = 3,5612

BASED ON CORROSION RATE FROM RLA

$ß_1^{extcor}$ = 3,5863

$ß_2^{extcor}$= 3,5783

$ß_3^{extcor}$= 3,5617

PLAN DATE

BASED ON CORROSION RATE FROM STEP 3

$ß_1^{extcor}$ = 3,5582

$ß_2^{extcor}$= 3,5184

$ß_3^{extcor}$ = 3,4249

BASED ON CORROSION RATE FROM RLA

$ß_1^{extcor}$ = 3,5588

$ß_2^{extcor}$= 3,5197

$ß_3^{extco}$ = 3,4467

STEP 16 Calculate $D_f^{extcorr}$ using equation below

RBI DATE

$$D_f^{extcor} = [\frac{\left(Po_{P1}^{extcorr}\Phi\left(-\beta_1^{extcorr}\right)\right)+\left(Po_{P2}^{extcorr}\Phi\left(-\beta_2^{extcorr}\right)\right)+\left(Po_{P3}^{extcorr}\Phi\left(-\beta_3^{extcorr}\right)\right)}{1.56E-0.4}$$

= 0,86192004 **BASED ON CORROSION RATE FROM STEP 3**

$$D_f^{extcor} = [\frac{\left(Po_{P1}^{extcorr}\Phi\left(-\beta_1^{extcorr}\right)\right)+\left(Po_{P2}^{extcorr}\Phi\left(-\beta_2^{extcorr}\right)\right)+\left(Po_{P3}^{extcorr}\Phi\left(-\beta_3^{extcorr}\right)\right)}{1.56E-0.4}$$

= 0,86192019 **BASED ON CORROSION RATE FROM RLA**

PLAN DATE

$$D_f^{extcor} = [\frac{\left(Po_{P1}^{extcorr}\Phi\left(-\beta_1^{extcorr}\right)\right)+\left(Po_{P2}^{extcorr}\Phi\left(-\beta_2^{extcorr}\right)\right)+\left(Po_{P3}^{extcorr}\Phi\left(-\beta_3^{extcorr}\right)\right)}{1.56E-0.4}$$

= 0,86187933 **BASED ON CORROSION RATE FROM STEP 3**

$$D_f^{extcor} = [\frac{\left(Po_{P1}^{extcorr}\Phi\left(-\beta_1^{extcorr}\right)\right)+\left(Po_{P2}^{extcorr}\Phi\left(-\beta_2^{extcorr}\right)\right)+\left(Po_{P3}^{extcorr}\Phi\left(-\beta_3^{extcorr}\right)\right)}{1.56E-0.4}$$

= 0,86188389 **BASED ON CORROSION RATE FROM RLA**

PROBABILITY OF FAILURE

The probability of failure can be calculated using the equation of;

Pf (t) = gff . Fms . D f (t)

Where,

pf (t)	=	The PoF as a function of time
gff	=	General failure frequency
Fms	=	Management system factor
Df (t)	=	Total damage factor

DETERMINING DAMAGE FACTOR (Df)

In the case of multiple damage mechanisms, the combination of those damage mechanims is explained in section 3.4.2 API RP 581 Part 2 3rd Edition. Total DF, $D_{f\text{-total}}$ - If more than one damage mechanism is present, the following rules are used to combine the DFs. The total DF is given by Equation below, when the external and/or thinning damage are classified as local and therefore, unlikely to occur at the same location.

$$D_{f-total} = max\left[D_{f-gov}^{thin}, D_{f-gov}^{extd}\right] + D_{f-gov}^{scc} + D_{f}^{htha} + D_{f-gov}^{brit} + D_{f}^{mfat}$$

If the external and thinning damage are general, then damage is likely to occur at the same location and the total DF is given by Equation below.

$$D_{f-total} = D_{f-gov}^{thin} + D_{f-gov}^{extd} + D_{f-gov}^{scc} + D_{f}^{htha} + D_{f-gov}^{brit} + D_{f}^{mfat}$$

Note that the summation of DFs can be less than or equal to 1.0. This means that the component can have a POF less than the generic failure frequency.

Acccording to the observation of Piping equipment is categorized as local thinning and also it does not likely occur at the same location. So, we used equation correlated to local thinning.

1 DETERMINGING THE GOVERNING THINNING DF

The governing thinning DF is determined based on the presence of an internal liner using equation

$D_{f\ -gov}^{Thin} = \min\left[D_{f}^{Thin}, D_{f}^{elin}\right]$ When an internal linear is present

$D_{f\ -gov}^{Thin} = D_{f}^{Thin}$ When an internal linear is not present

According to above calculaton, there is no any presence of liner, then, we can consider to use the second governing thinning DF calculation

RBI DATE:

$D_{f-gov}^{Thin} = D_f^{Thin}$

= 0,24091501238 (Based on RLA Data)

= 0,24092090927 (Based on Annex 2B Calculation)

PLAN DATE:

$D_{f-gov}^{Thin} = D_f^{Thin}$

= 0,24088654222 (Based on RLA Data)

= 0,24091967043 (Based on Annex 2B Calculation)

2 DETERMINGING THE MECHANICAL FATIGUE DF

D_f^{mfat} = 0,01111

3 DETERMING THE GOVERNING EXTERNAL DF

$$D_{f-gov}^{extd} = \max\left[D_f^{extf}, D_f^{CUIF}, D_f^{SSC}, D_f^{extd-CLSCC}, D_f^{CUI-CLSCC}\right]$$

Based on the DFs screening tool above, type of external DF that likely appears is only external corrosion. So, the other damage factor of external damage mechanism can be ignored.

RBI DATE:

$D_{f-gov}^{extd} = D_f^{extf}$

= 0,8619201891 (Based on RLA Data)

= 0,8619200442 (Based on the calculation on the STEP 3 of External Corrosion)

PLAN DATE:

$D_{f-gov}^{extd} = D_f^{extf}$

= 0,861883887 (Based on RLA Data)

= 0,861879331 (Based on the calculation on the STEP 3 of External Corrosion)

4 CALCULATE THE TOTAL DF

If more than one damage mechanism is present, the following adjustment are used to combine the Damafe Factors (DFs). There some different formula to use accordding to the type of the thinning itself, either it is localized thinning or general thinning.

a. GENERAL THINNING

If the external and thinning damage are general, then damage is likely to occur at the same location and the total DF is given by Equation below.

$$D_{f-total} = D_{f-gov}^{thin} + D_{f-gov}^{extd} + D_{f-gov}^{scc} + D_{f}^{htha} + D_{f-gov}^{brit} + D_{f}^{mfat}$$

b. LOCAL THINNING

$$D_{f-total} = max\left[D_{f-gov}^{thin}, D_{f-gov}^{extd}\right] + D_{f-gov}^{scc} + D_{f}^{htha} + D_{f-gov}^{brit} + D_{f}^{mfat}$$

Based on the thinning calculation its categorized as localized thinning, because the fluids contains carbon dioxide.

RBI DATE:

$$D_{f-total} = max\left[D_{f-gov}^{thin}, D_{f-gov}^{extd}\right] + D_{f-gov}^{scc} + D_{f}^{htha} + D_{f-gov}^{brit} + D_{f}^{mfat}$$

= 1,1139463125 **(Based on RLA Data)**

$$D_{f-total} = max\left[D_{f-gov}^{thin}, D_{f-gov}^{extd}\right] + D_{f-gov}^{scc} + D_{f}^{htha} + D_{f-gov}^{brit} + D_{f}^{mfat}$$

= 1,1139520646 **(Based on the calculation of corrosion rate)**

PLAN DATE:

$$D_{f-total} = max\left[D_{f-gov}^{thin}, D_{f-gov}^{extd}\right] + D_{f-gov}^{scc} + D_{f}^{htha} + D_{f-gov}^{brit} + D_{f}^{mfat}$$

= 1,113881541 **(Based on RLA Data)**

$$D_{f-total} = max\left[D_{f-gov}^{thin}, D_{f-gov}^{extd}\right] + D_{f-gov}^{scc} + D_{f}^{htha} + D_{f-gov}^{brit} + D_{f}^{mfat}$$

= 1,113910112 **(Based on the calculation of corrosion rate)**

DETERMINING GENERAL FAILURE FREQUENCY (gff)

To determine the value of gff, we can use the recommended list from table 3.1 of API RBI 581

Table 3.1 – Suggested Component Generic Failure Frequencies

Equipment Type	Component Type	*gff* as a Function of Hole Size (failures/yr)				gff_{total} (failures/yr)
		Small	Medium	Large	Rupture	
Compressor	COMPC	8.00E-06	2.00E-05	2.00E-06	0	3.00E-05
Compressor	COMPR	8.00E-06	2.00E-05	2.00E-06	6.00E-07	3.06E-05
Heat Exchanger	HEXSS. HEXTS,	8.00E-06	2.00E-05	2.00E-06	6.00E-07	3.06E-05
Pipe	PIPE-1, PIPE-2	2.80E-05	0	0	2.60E-06	3.06E-05
Pipe	PIPE-4,	8.00E-06	2.00E-05	0	2.60E-06	3.06E-05

	PIPE-6					
Pipe	PIPE-8, PIPE-10, PIPE-12, PIPE-16, PIPEGT16	8.00E-06	2.00E-05	2.00E-06	6.00E-07	3.06E-05

gff = 0,0000306

DETERMINING MANAGEMENT SYSTEM FACTOR (fms)

To determine the value of Fms, use a series of question and survey given by API RBI 581 to determine Fms value. But in this calculation the score is 500 from 1000

$$pscore = \frac{Score}{1000}\ x\ 100\ [unit\ is\ 100\ \%]$$

From the equation above, the $pscore$ is = 50 %

To determine the value of Fms we can use the equation:

$$Fms = 10^{(-0.02\ .pscore+1)}$$

$$Fms = 1$$

DETERMINING THE PROBABILITY OF FAILURE

There are two main calculation to conduct an RBI for all type of equipment which are POF and COF. And the Probability of Failure (POF) is computed from equation below.

$$\boldsymbol{P_f(t) = gff_{total}\,.\,D_f(t).F_{MS}}$$

Where :

$P_f(t)$ = Probabilitty of Failure (POF)

gff_{total} = Generic Failure Frequency

$D_f(t)$ = Total Damage Factors

F_{MS} = Management System Factors

RBI DATE:

Based on Corrosion Rate from RLA Data

- ***Pf (t) = 3,06 x 10^-5 . 1. 1,1139463125***

Pf (t) = 3,40867572E-05

Based on the calculated corrosion rate

- ***Pf (t) = 3,06 x 10^-5 . 1 . 1,1139520646***

Pf (t) = 3,4086933,E-05

PLANNED DATE:

Based on Corrosion Rate from RLA Data

- ***Pf (t) = 3,06 x 10^-5 . 0,171 . 1,113881541***

  Pf (t) = 3,4084775E-05

Based on the calculated corrosion rate

- ***Pf (t) = 3,06 x 10^-5 . 0,171 . 1,113910112***

  Pf (t) = 3,4085649,E-05

	INSPECTION PROGRAM PLAN+A1:U31NING OF PROCESS GAS PIPING USING RISK BASED INSPECTION API 581 IN MUARA KARANG PEAKER GAS METER

ATTACHMENT 2D :

CONSEQUENCE OF FAILURE (COF) CALCULATION OF RISK BASED INSPECTION API 581

12" - PG - 06251 - C

Rev	Tanggal	Keterangan	Disusun Oleh:		Disetujui Oleh:	
			Nama	Paraf	Pembimbing	Paraf
			Ade Ratih Anggraini		Ir. Dwi Priyanta, M.SE	
			No. Registration :		Nurhadi Siswantoro,ST.,MT.	
			04211641000008			

PART 1 : DETERMINE THE REPRESENTATIVE FLUID AND ASSOCIATED PROPERTIES

1.1 Representative Fluids

A representative fluid that most closely matches the fluid contained pressurized system being evaluated is selected from the representative fluids table shown in Table 4.1 API 581 Part 3 of COF.

1.2 Fluid Properties

The required fluid properties estimated for each of the representative fluids as provided in Table 4.2 are dependent on the stored phase of the fluid below:

a) Stored Liquid

1. Normal Boiling Point *(NBP)*
2. Density (ρ_l)
3. Auto-Ignition Temperature *(AIT)*

b) Stored Vapor or Gas	
1. Normal Boiling Point	*(NBP)*
2. Molecular Weight	*(MW)*
3. Ideal Gas Specific Heat Capacity Ratio	*(k)*
4. Constant Pressure Specific Heat	(C_p)
5. Auto - Ignition Temperature	*(AIT)*

1.3 Release Phase

The dispersion characteristics of fluids and probability of consequence outcomes (events) after release are strongly dependent on the phase (gas, liquid, or two-phase) of the fluid after it is released into the environment. Guidelines for determining the phase of the released fluid can be seen on Table 4.3 API 581 Part 3 of COF. For this, the release phase is gas/vapor.

STEP 1.1 Select the representative fluid group from Table 4.1 Annex 3.A

Gas Composition % Mol	
Methane	92,3802
Nitrogen	0,0047
CO_2	3,1479
Ethane	2,5964
Propane	1,1551
i - Butane	0,3174
n- Butane	0,3596
i - Pentane	0,0267
n - Pentane	0,0072
n - Hexane	0,0012
% Total	99,996

Note : Those value are average of the value sample taken on June 2019. This data based on gas composition in ORF

The representative fluid is gas, there are some consideration of representative fluid in API RP 581 - Annex 3.A Section 3.A.3.1.2. Choice of representative fluids of mixture ststed in the following paragraph.

If a mixture contains inert materials such as CO2 or water, the choice of representative fluid should be based on the flammable/toxic materials of concern, excluding these materials. This is a conservative assumption that will result in higher COF results, but it is sufficient for risk prioritization.

Table 4.1 – List of Representative Fluids Available for Level 1 Consequence Analysis

Representative Fluid	Fluid TYPE (see Section 4.1.5)	Examples of Applicable Materials
$C_1 - C_2$	TYPE 0	Methane, Ethane, Ethylene, LNG, Fuel Gas
$C_3 - C_4$	TYPE 0	Propane, Butane, Isobutane, LPG
C_5	TYPE 0	Pentane
$C_6 - C_8$	TYPE 0	Gasoline, Naphtha, Light Straight Run, Heptane
$C_9 - C_{12}$	TYPE 0	Diesel, Kerosene
$C_{13} - C_{16}$	TYPE 0	Jet Fuel, Kerosene, Atmospheric Gas Oil

The representative fluid is methane and CO_2

STEP 1.2 Determine the stored fluid phase

Liquid or vapor. If stored fluid is two - phase, use the conservative assumption of liquid. Alternatively, a level 2 consequence analysis can be performed.

Muara Karang Peaker is vapor stored fluid properties

STEP 1.3 Determine the stored fluid phase

Table 4.2 – Properties of the Representative Fluids Used in Level 1 Consequence Analysis

Fluid	MW	Liquid Density (lb/ft^3)	NBP (°F)	Ambient State	Ideal Gas Specific Heat Eq.	C_p Ideal Gas Constant *A*	Ideal Gas Constant *B*	Ideal Gas Constant *C*	Ideal Gas Constant *D*	Ideal Gas Constant *E*	Auto-Ignition Temp. (°F)
C1-C2	23	15.639	-193	Gas	Note 1	12.3	1.150E-01	-2.87E-05	-1.30E-09	N/A	1036

For a stored vapor, the properties are dependent on these parameters such as:

1. Molecular Weight (MW), kg / kg - mol (lb / lb - mol)
   The stored vapor Molecular Weight (MW) can be estimated from Table 4.2
   MW = 23 (kg / kg - mol)

2. Ideal Gas Specific Heat Ratio (k)
   Can be estimated using Equation 2, and the C_p values determined using Table 4.2

Cp_A = 12,3 J/kmol-K

Cp_B = 0,115 J/kmol-K

Cp_C = -0,0000287 J/kmol-K

Cp_D = -1,3E-09 J/kmol-K

T = 18,83 °C

T = 65,894 °F

T = 291,83 K

R = 8,314 J/kg-mol-K

$$C_p = A + BT + CT^2 + DT^3 \quad \text{.....................................} \quad (\text{ Equation 1})$$

$$= 12{,}3 + (0{,}115 \times 291{,}83) + (-0{,}0000287 \times 291{,}83)^2 + (-1{,}3 \times 10^{-9} \times 291{,}83)^3$$

$$= 45{,}861 \text{ J/kmol-K}$$

$$k = \frac{C_p}{C_p - R} \quad \text{..} \quad (\text{ Equation 2})$$

$$k = \frac{45{,}861}{45{,}861 - 8{,}314}$$

$$k = 1{,}2214$$

3. Auto - Ignition Temperature, K

   The stored liquid Auto-Ignition Temperature (AIT) can be estimated from Table 4.2 of API 581 Part 3 of COF.

   AIT = 1036 °F

   = 557,78 °C

   = 830,78 K

STEP 1.4 Determine the steady state phase of the fluid after release to the atm

Determine the steady state phase of the fluid after release to the atmosphare can be adopted from the Table 4.3 API 581 Part 3 of COF shown below :

Phase of Fluid at Normal Operating (Storage) Conditions	Phase of Fluid at Ambient (after release) Conditions	Determination of Final Phase of Consequence Calculation
Gas	Gas	Model as Gas
Gas	Liquid	Model as Gas
Liquid	Gas	Model as gas unless the fluid boiling point at ambient conditions is greater than 80^oF, then model as a liquid
Liquid	Liquid	Model as Liquid

SUMMARY of STEP 1 :

1 methane and CO2 which has the percentage of 92,3802% and 3,1479% of all.

2 The fluid stored in the piping is gas

3 Fluid properties id based on the STEP 1.3 which has been adjusted by using Table 4.2 in API RP 581 Part 3 of COF

MW	=	23	(kg / kg - mol)
AIT	=	830,78	K
T	=	291,83	K
C_p	=	45,861	J/kmol-K
k	=	1,2214	

4 The steady state phase after release to the atmoshpere is gaseous type.

PART 2 : SELECT A SET OF RELEASE HPLE SIZES TO DETERMINE THE POSSIBLE RANGE OF CONSEQUENCE THE RISK

2.1 Release Hole Size Selection

A descrete set of release events or release hole sizes are used since it would be impractical to perform the consequence analysis for a continous spectrum of release hole sizes. Limiting the number of of release hole sizes allows for an analysis that is manageable, yet still reflects the range of possible outcomes.

STEP 2.1 Calculate of release hole sizes by determining each diameter (d_n)

The following steps are repeated of each release hole size, typically four hole sizes are evaluated.

According to Annex 3.A of API 581 Chapter 3.2.3 committs that the standard four release hole sizes are assumed for all sizes in pressure vessel type.

Table 4.4. Release Hole Sizes and Areas Used in Level 1 and 2 Consequences Analysis

Release Hole Number	Release Hole Sizes	Range of Hole Diameter (mm)	Release Hole Diameter; d_n (inch)
1	Small	0 - 1/4	$d_1 = 0{,}25$
2	Medium	> 1/4 - 2	$d_2 = 1$
3	Large	> 2 - 6	$d_3 = 4$
4	Rupture	> 6	$d_4 = \min\,[D\,,16]$

STEP 2.2 Determine the generic failure frequency, gff_n , for the n^{th} release hole size from API 581 Part 2, Table 3.1 , and the total generic failure frequency from this table or from Equation 3

Table 3.1. Suggested Component Generic Failure Frequency

Table 3.1 – Suggested Component Generic Failure Frequencies

Equipment Type	Component Type	gff as a Function of Hole Size (failures/yr)				gff_{total} (failures/yr)
		Small	Medium	Large	Rupture	
Compressor	COMPC	8.00E-06	2.00E-05	2.00E-06	0	3.00E-05
Compressor	COMPR	8.00E-06	2.00E-05	2.00E-06	6.00E-07	3.06E-05
Heat Exchanger	HEXSS. HEXTS,	8.00E-06	2.00E-05	2.00E-06	6.00E-07	3.06E-05
Pipe	PIPE-1, PIPE-2	2.80E-05	0	0	2.60E-06	3.06E-05
Pipe	PIPE-4, PIPE-6	8.00E-06	2.00E-05	0	2.60E-06	3.06E-05
Pipe	PIPE-8, PIPE-10, PIPE-12, PIPE-16, PIPEGT16	8.00E-06	2.00E-05	2.00E-06	6.00E-07	3.06E-05

Because the total vallue of generic failure frequency has been availabled from the table. So, we can directly put the value from the table into the calculation.

$$gff_{total} = \sum_{n=1}^{4} gffn \quad \text{...} \quad \text{(Equation 3)}$$

Because the total vallue of generic failure frequency has been availabled from the table. So, we can directly put the value from the table into the calculation.

gff_{total}	=	0,0000306	failures / year
gff_{small}	=	0,000008	failures / year
gff_{medium}	=	0,00002	failures / year
gff_{large}	=	0,000002	failures / year
$gff_{rupture}$	=	0,0000006	failures / year

SUMMARY of STEP 2 :

1 According the Annex 3.A Part 3 of API RP 581 commits that for pipe, all of model of release hole size must be assumed.

2 The total generic failure frequency per years for every type of pipe has been adjusted by the Table 3.1 in Part 2 of API RP 581.

gff_{total}	=	0,0000306	failures / year
gff_{small}	=	0,000008	failures / year
gff_{medium}	=	0,00002	failures / year
gff_{large}	=	0,000002	failures / year
$gff_{rupture}$	=	0,0000006	failures / year

PART 3: CALCULATE THE THEORITICAL RELEASE RATE

3.1 Release Rate

Release rate has a close correlation within the physical properties of the material, the initial phase, the process operating conditions, and the assigned release hole sizes. As we know that initial phase is the phase of the stored fluid prior contacting to the atmosphere. for special case, two-phases systems which contain gaseos and liquid containmment inside the pressure vessel, so, according t the API 581 Part 3, choosing liquid as the initial state inside the equipment is more conservative and may be preferred.

3.2 Vapor Release Rate Equations

There are two regimes for flow gases through an orifice: sonic (choked) for higher internal pressure, and subsonic flow for lower pressure (nominally 15 psig (103.4 kPa) or less). The transition pressure at which the flow regime changes from sonic to subsonic is determined using below equation.

P_{atm} = 14,696 psi

k = 1,2214

$$P_{trans} = P_{atm}\left(\frac{k+1}{2}\right)^{\frac{k}{k-1}} \quad \text{.. (Equation 4)}$$

$$P_{trans} = 14{,}696\left(\frac{1{,}22143+1}{2}\right)^{\frac{1{,}22143}{1{,}22143-1}}$$

= 26,227 psi

STEP 3.1 Select the appropriate release rate equation

Because of the phase inside the pipe is gaseous phase and the storage pressure (P_s) within the equipment item is greater than the transition pressure (P_{trans}), so the equation chosen is shown below:

$$W_n = \frac{C_d}{C_2}\; x\; A_n\; x\; P_s \sqrt{\left(\frac{k\; x\; MW\; x\; g_c}{R\; x\; T_s}\right)\left(\frac{2}{k+1}\right)^{\frac{k+1}{k-1}}} \quad \text{.................. (Equation 5)}$$

Abbreviation list :

C_d	=	Discharge coefficient, for turbulent liquid flow from the sharp-edge orifices in the range of $0.85 \le C_d \le 1.00$			
A_n	=	Release hole sized area			
P_s	=	Storage operating pressure	=	676	psi
P_{atm}	=	Atmosphere pressure	=	14,7	psi
k	=	Ideal gas specific heat capacity ratio	=	1,221	
MW	=	Molecular weight	=	23	(kg / kg - mol)

g_c = Gravitational constant = 9,8 m/s^2

R = Universal gas constant = 8,314 J/(kg-mol-K)

T_s = Storage operating temperature = 18,83 °C

= 65,89 °F

= 291,8 K

STEP 3.2 For every release hole size, calculate the release hole size area based on d_n

Release Hole Number	Release Hole Sizes	Range of Hole Diameter (mm)	Release Hole Diameter; d_n (inch)
1	Small	0 - 1/4	$d_1 = 0,25$
2	Medium	> 1/4 - 2	$d_2 = 1$
3	Large	> 2 - 6	$d_3 = 4$
4	Rupture	> 6	$d_4 = \min[D, 16]$

The release hole size area can be determined by formulating below equation :

$$A_n = \frac{\pi\, d_n^2}{4} \quad \text{...} \quad \text{(Equation 6)}$$

1. **SMAL RELEASE HOLE SIZE AREA**

d_1 = 0,25 inch

= 0,0064 m

π = 3,14

$$A_n = \frac{3{,}14\ x 0{,}0064^2}{4}$$

= 31,65 m^2

2. **MEDIUM RELEASE HOLE SIZE AREA**

d_2 = 1 inch

= 0,0254 m

π = 3,14

$$A_n = \frac{3{,}14\ x 0{,}0254^2}{4}$$

= 506,45 m^2

3. **LARGE RELEASE HOLE SIZE AREA**

d_3 = 4 inch

= 0,1016 m

π = 3,14

$$A_n = \frac{3{,}14\ x 0{,}1016^2}{4}$$

= 8.103,21 m^2

4. RUPTURE RELEASE HOLE SIZE AREA

d_4 = 12 inch

= 0,3048 m

π = 3,14

$$A_n = \frac{3{,}14\ x 0{,}3048^2}{4}$$

= 72.928,89 m^2

STEP 3.3 For liquid release, for each release hole size, calculate the viscosity correction factor ($K_{v,n}$)

Viscosity Correction Factor ($K_{v,n}$) can be determined using both equation 4 of graph below, which have been printed from API Standard 520 Part 1. Another option, the conservative value of viscosity correction factor may be used the value of 1.0

$$K_{v,n} = \left(0{,}9935 + \frac{2{,}878}{Ren^{0{,}5}} + \frac{342{,}75}{Ren^{1{,}5}}\right)^{-1}$$

Because the store fluid phase determined in STEP 1.2 is gaseous or vapor phase, then, this step is no neeed to be considered.

STEP 3.4 For each hole size, calculate the release eate, W_n , for each release area A_n

$$W_n = \frac{C_d}{C_2}\ x\ A_n\ x\ P_s \sqrt{\left(\frac{k\ x\ MW\ x\ g_c}{R\ x\ T_s}\right)\left(\frac{2}{k+1}\right)^{\frac{k+1}{k-1}}}$$

Abbreviation list :

C_d	=	0,9	
A_{n1}	=	31,65	m^2
A_{n2}	=	506,45	m^2
A_{n3}	=	8.103,21	m^2
A_{n4}	=	72.928,89	m^2
P_s	=	4500	kPa
P_{atm}	=	101,3	kPa
k	=	1,22	
MW	=	23	(kg / kg - mol)
g_c	=	9,8	m/s^2
R	=	8,314	J/(kg-mol-K)
T_s	=	291,83	K
C_2	=	1	

1. **SMAL RELEASE HOLE SIZE AREA**

$$W_n = \frac{C_d}{C_2}\ x\ A_{n1}\ x\ P_s \sqrt{\left(\frac{k\ x\ MW\ x\ g_c}{R\ x\ T_s}\right)\left(\frac{2}{k+1}\right)^{\frac{k+1}{k-1}}}$$

$$W_n = \frac{0{,}9}{1} x\ (31{,}65)\ x4500 \sqrt{\left(\frac{1{,}22\ x\ 23\ x\ 9{,}8}{8{,}314\ x\ 291{,}83}\right)\left(\frac{2}{1{,}22+1}\right)^{\frac{1{,}22+1}{1{,}22-1}}}$$

= 8590,29125 kg/s

2. **MEDIUM RELEASE HOLE SIZE AREA**

$$W_n = \frac{C_d}{C_2}\ x\ A_{n2}\ x\ P_s \sqrt{\left(\frac{k\ x\ MW\ x\ g_c}{R\ x\ T_s}\right)\left(\frac{2}{k+1}\right)^{\frac{k+1}{k-1}}}$$

$$W_n = \frac{0{,}9}{1} x\ (506{,}45)\ x4500 \sqrt{\left(\frac{1{,}22\ x\ 23\ x\ 9{,}8}{8{,}314\ x\ 291{,}83}\right)\left(\frac{2}{1{,}22+1}\right)^{\frac{1{,}22+1}{1{,}22-1}}}$$

= 137444,66 kg/s

3. **LARGE RELEASE HOLE SIZE AREA**

$$W_n = \frac{C_d}{C_2}\ x\ A_{n3}\ x\ P_s \sqrt{\left(\frac{k\ x\ MW\ x\ g_c}{R\ x\ T_s}\right)\left(\frac{2}{k+1}\right)^{\frac{k+1}{k-1}}}$$

$$W_n = \frac{0{,}9}{1} x\ (8103{,}21)\ x4500 \sqrt{\left(\frac{1{,}22\ x\ 23\ x\ 9{,}8}{8{,}314\ x\ 291{,}83}\right)\left(\frac{2}{1{,}22+1}\right)^{\frac{1{,}22+1}{1{,}22-1}}}$$

= 2199114,56 kg/s

4. **RUPTURE RELEASE HOLE SIZE AREA**

$$W_n = \frac{C_d}{C_2}\ x\ A_{n4}\ x\ P_s \sqrt{\left(\frac{k\ x\ MW\ x\ g_c}{R\ x\ T_s}\right)\left(\frac{2}{k+1}\right)^{\frac{k+1}{k-1}}}$$

$$W_n = \frac{0{,}9}{1} x\ (7298{,}89\ )\ x4500 \sqrt{\left(\frac{1{,}22\ x\ 23\ x\ 9{,}8}{8{,}314\ x\ 291{,}83}\right)\left(\frac{2}{1{,}22+1}\right)^{\frac{1{,}22+1}{1{,}22-1}}}$$

= 19792031 kg/s

SUMMARY of STEP 3 :

1 The chosen equation for determining the theoretical release rate (W_n) is using equation below because, the release fluid is modeled as gas-gas and the storage pressure is greater than the transition pressure.

$$W_n = \frac{C_d}{C_2} \, x \, A_n \, x \, P_s \sqrt{\left(\frac{k \, x \, MW \, x \, g_c}{R \, x \, T_s}\right)\left(\frac{2}{k+1}\right)^{\frac{k+1}{k-1}}}$$

2 For calculating the release hole size area (A_n), all of assumed size of release hole for piping must be considered to determine theoretical release rate.

3 It is no need to calculate the viscosity correction factor because the release fluid is modeled as gas-gas. The voscosity correction factor calculation is adjusted for only the liquid phase.

4 After determining each release hole size are from the small until the rupture, then, the theoretical release rate can be calculated.

W_{n1} = 8590,2912 kg/s
W_{n2} = 137444,66 kg/s
W_{n3} = 2199114,6 kg/s
W_{n4} = 19792031 kg/s

PART 4 : ESTIMATE THE TOTAL AMOUNT OF FLUID INVENTORY AVAILABLE FOR RELEASE

4.1 Release Rate

The leaking component's inventory is combined with inventory with the other attached components that can contribute fluid mass.

Table 3.A.3.2 -– Assumptions Used When Calculating Liquid Inventories Within Equipment

Equipment Description	Component Type	Examples	Default Liquid Volume Percent
Piping	PIPE-xx		100% full, calculated for Level 2 methodology

4.2 Maximum Mass Available for Release

The available mass for release is estimated for each release hole size as the lesser of two quantities:

Inventory Mass

The component being evaluated is part of a larger group of components that can be expected to provide fluid inventory to the release. The inventory calculation as presented here is used as an upper-limit and does not indicate that this amount of fluid would be released in all leak scenarios. The inventory group mass can be calculated using this below equation:

$$Mass_{inv} = \sum_{i=1}^{N} \left(Mass_{comp,i}\right) \quad \text{...} \quad \text{(Equation 7)}$$

Component Mass

It is assumed that for large leaks and above, operator intervention will occur within 3 minutes, thereby limiting the amount of release material. Therefore, the amount of available mass for the release is limmited to the mass of the component plus an additional mass, $mass_{add,n}$, that is calculated based on three minutes of leakage from the component's inventory group.

STEP 4.1 Group components and equipment items into inventory groups

This step of determining the group components and equipment items can be referred to API 581 Part 3 Annex 3.A.3.3 says that when a component or equipment type is evaluated, the inventory of the component is combined with inventory from associated equipment that can contribute fluid mass to the leaking components. Theoritically, the total amount of fluid that can be released is the amount that is held within pressure containing equiment between isolation valves that can be quickly closed.

STEP 4.2 Calculate the fluid masss, $mass_{comp}$, in the component being evaluated

ID	=	306,32	mm
V_{tot}	=	117586,101	m^3
	=	4152513,97	ft^3
ρ_{gas}	=	0,668	kg/m^3
	=	0,04170188	lb/ft^3
L	=	6418	mm
$Mass_{comp}$	=	78547,5155	kg

STEP 4.3 Calculate the fluid masss in each of the other component that are included in the inventory group mass

Based on the design of the gas plant, there is no other component or equipment type that can be combined to contribute the fluid mass to the leaking components.

STEP 4.4 Calculate the fluid mass in the inventory group, $mass_{mv}$

$$Mass_{inv} = \sum_{i=1}^{N} \left(Mass_{comp,i}\right)$$

Abbreviation list :

$Mass_{comp}$ = is the inventory fluid mass for the component or piece of equipment being evaluated, kgs [lbs]

$Mass_{inv}$ = is the inventory group fluid mass, kgs [lbs]

= 78547,5155 kg

STEP 4.5 Calculate the flow rate from a 203 mm (8 inch) diameter hole, W_{max8}

Calculate the flow rate from a 203 mm (8 inch) diameter hole, Wmax8, using the equation 8 as applicable with $A_n = A_8 = 32.450\ mm^2$ ($50.3\ inch^2$). This is the maximum flow rate that can be added to the equipment fluid mass from the surrounding equipment in the inventory group.

$$W_{max8} = \frac{C_d}{C_2}\ x\ A_n\ x\ P_s \sqrt{\left(\frac{k\ x\ MW\ x\ g_c}{R\ x\ T_s}\right)\left(\frac{2}{k+1}\right)^{\frac{k+1}{k-1}}} \quad \text{............... (Equation 8)}$$

Abbreviation list :

C_d = Discharge coefficient, for turbulent liquid flow from the sharp-edge orifices in the range of $0.85 \leq C_d \leq 1.00$

= 0,9

A_n = Release hole sized area = 50,3 $inch^2$

= 0,0324 m^2

P_s = Storage operating pressure = 676 psi

			=	4500	kPa
P_{atm}	=	Atmosphere pressure	=	15	psi
k	=	Ideal gas specific heat capacity ratio	=	1,22	
MW	=	Molecular weight	=	23	(kg / kg - mol)
g_c	=	Gravitational constant	=	9,8	m/s^2
R	=	Universal gas constant	=	8,314	J/(kg-mol-K)
T_s	=	Storage operating temperature	=	18,83	°C
			=	65,89	°F
			=	291,8	K
C_2	=	SI customary conversion factors	=	1	

So,

$$W_{max8} = \frac{C_d}{C_2} \; x \; A_n \; x \; P_s \sqrt{\left(\frac{k \; x \; MW \; x \; g_c}{R \; x \; T_s}\right)\left(\frac{2}{k+1}\right)^{\frac{k+1}{k-1}}}$$

$$W_{max8} = \frac{0,9}{1} x \; (0,0324) \; x 4500 \sqrt{\left(\frac{1,22 \; x \; 23 \; x \; 9,8}{8,314 \; x \; 291,83}\right)\left(\frac{2}{1,22+1}\right)^{\frac{1,22+1}{1,22-1}}}$$

= 8,80477943 kg/s

STEP 4.6 Calculate the added fluid mass, $mass_{add,n}$ for each release hole size

Determining the additional fluid mass for each release hole size resulting from three minutes of flow from the inventory group using equation 9:

$$mass_{add,n} = 180.\min[W_n, W_{max8}]$$ .... (Equation 9)

1. **SMAL RELEASE HOLE SIZE AREA**

$$mass_{add,n} = 180.\min[W_n; W_{max8}]$$

$$mass_{add,1} = 180.\min[8590,2912; 8,80477943]$$

= 1584,9 kgs

2. **MEDIUM RELEASE HOLE SIZE AREA**

$$mass_{add,n} = 180.\min[W_n; W_{max8}]$$

$$mass_{add,2} = 180.\min[137444,66; 8,80477943]$$

= 1584,9 kgs

3. **LARGE RELEASE HOLE SIZE AREA**

$$mass_{add,n} = 180.\min[W_n; W_{max8}]$$

$$mass_{add,3} = 180.\min[2{,}99114{,}6; 8{,}80477943]$$

= 1584,9 kgs

4. **RUPTURE RELEASE HOLE SIZE AREA**

$$mass_{add,n} = 180.\min[W_n; W_{max8}]$$

$$mass_{add,4} = 180.\min[19792031; 8{,}80477943]$$

= 1584,9 kgs

STEP 4.7 Calculate the mass for release for each hole size

For each release hole size, calculate the available mass for release using equation

$Mass_{avail,n} = \min.\left[\left\{Mass_{comp} + Mass_{add,n}\right\}, Mass_{inv}\right]$........... (Equation 10)

1. **SMAL RELEASE HOLE SIZE AREA**

$$Mass_{avail,n} = \min.\left[\left\{Mass_{comp} + Mass_{add,1}\right\}, Mass_{inv}\right]$$
$$Mass_{avail,1} = \min.[\{ 78547{,}5155 + 1{,}5463\}, 78547{,}5155]$$

= 78547,52 kgs

2. **MEDIUM RELEASE HOLE SIZE AREA**

$$Mass_{avail,n} = \min.\left[\left\{Mass_{comp} + Mass_{add,2}\right\}, Mass_{inv}\right]$$
$$Mass_{avail,2} = \min.[\{ 78547{,}5155 + 24{,}74\}, 78547{,}5155]$$

= 78547,52 kgs

3. **LARGE RELEASE HOLE SIZE AREA**

$$Mass_{avail,n} = \min.\left[\left\{Mass_{comp} + Mass_{add,3}\right\}, Mass_{inv}\right]$$
$$Mass_{avail,3} = \min.[\{ 78547{,}5155 + 395{,}84\}, 78547{,}5155]$$

= 78547,52 kgs

4. **RUPTURE RELEASE HOLE SIZE AREA**

$$Mass_{avail,n} = \min.\left[\left\{Mass_{comp} + Mass_{add,4}\right\}, Mass_{inv}\right]$$
$$Mass_{avail,4} = \min.[\{ 78547{,}5155 + 1584{,}9\}, 78547{,}5155]$$

= 78547,52 kgs

SUMMARY of STEP 4 :

1 For group inventory, theoritically, the total amount of fluid that can be released is the amount that is held within pressure containing equiment between isolation valves that can be quickly closed.

2 Calculating the fluid mass and the mass of component to determine the mass inventory.

3 There is no other components contributing the mass of the equipment evaluated.

4 $Mass_{inv}$ = 78548 kg

5 Determining the maximum flow rate of a hole size within the diameter of 203 mm (8 inch) with the hole size area of 32.450 mm^2 (50.3 $inch^2$).

W_{max8} = 8,80477943 kg/s

6 Determining the additional fluid mass for release hole size starting for the small release hole size until the rupture release hole size.

$Mass_{add1}$ = 1584,86 kgs

$Mass_{add2}$ = 1584,86 kgs

$Mass_{add3}$ = 1584,86 kgs

$Mass_{add4}$ = 1584,86 kgs

7 Determining the available mass for each release hole size

$Mass_{avail1}$ = 78547,52 kgs

$Mass_{avail2}$ = 78547,52 kgs

$Mass_{avail3}$ = 78547,52 kgs

$Mass_{avail4}$ = 78547,52 kgs

PART 5 : DETERMINE THE RELEASE TYPE (CONTINOUS OR

5.1 Release Type

The release is modeled as one of these two followinng types:

A). Instantaneous Release

An instataneous or puff release is one that occurs so rapidly that the fluid disperses as a single large cloud or pool.

B). Continous Release

A continous or plume release is one that occurs over a longer period of time, allowing the fluid to dispers in the shape of elongated ellipse (dependening in the weather conditions).

The process for determining the appropriate type for release to model requires to determine the time required to release 4536 kgs (10000 lbs) of fluid, t_n, through each release hole size.

STEP 5.1 Calculate the time required to release 4536 kgs (10000 lbs) of fluid for each hole size.

To determine the time required to release 4536 kgs (10000 lbs) of fluid for each hole size can be adopted from the equation below:

$$t_n = \frac{C_3}{W_n} \qquad \text{(Equation 11)}$$

Abbreviation list :

t_n = time required to release 4536 kgs (10000 lbs) of fluid

C_3 = SI and US customary conversion factors

= 4536 kgs

= 10000 lbs

W_n = Theoretical release rate associated with the n^{th} release hole size, kg/s

W_1 = 8590,29125 kg/s

W_2 = 137444,66 kg/s

W_3 = 2199114,56 kg/s

W_4 = 19792031 kg/s

1. **SMAL RELEASE HOLE SIZE AREA**

$$t_n = \frac{C_3}{W_n}$$

$$t_1 = \frac{4536}{8590{,}291}$$

$$= 0{,}52803798 \text{ s}$$

2. **MEDIUM RELEASE HOLE SIZE AREA**

$$t_n = \frac{C_3}{W_n}$$

$$t_2 = \frac{4536}{137444{,}7}$$

$$= 0{,}03300237 \text{ s}$$

3. **LARGE RELEASE HOLE SIZE AREA**

$$t_n = \frac{C_3}{W_n}$$

$$t_3 = \frac{4536}{2199115}$$

$$= 0{,}00206265 \text{ s}$$

4. **RUPTURE RELEASE HOLE SIZE AREA**

$$t_n = \frac{C_3}{W_n}$$

$$t_4 = \frac{4536}{19792031}$$

$$= 0{,}00022918 \text{ s}$$

STEP 5.2 Determine the release type for each release hole size.

For each release hole size, determine the release type either instataneous or continous using this following criteria:

a. If the release hole size is 6.35 mm(0.25 inch) or less, then the release type is continous
b. b. If t_n<180 sec and the releaase mass is gretaer than 4536 kgs (100000 lbs), then the release is instataneous: otherwise the release is continous

1. **SMAL RELEASE HOLE SIZE AREA**

d_1 = 0,25 inch

t_1 = 0,52803798 s (Instantaneous)

2. **MEDIUM RELEASE HOLE SIZE AREA**

d_2 = 1 inch

t_2 = 0,03300237 s (Instantaneous)

3. **LARGE RELEASE HOLE SIZE AREA**

d_3 = 4 inch

t_3 = 0,00206265 s (Instantaneous)

4. RUPTURE RELEASE HOLE SIZE AREA

d_4 = 12 inch

t_4 = 0,00022918 s (Instantaneous)

SUMMARY of STEP 5 :

1 Calculating the time required to release 4536 kgs (10000 lbs) of fluid for each hole size, starting for the small until the rupture release hole size.

t_1 = 0,52803798 s

t_2 = 0,03300237 s

t_3 = 0,00206265 s

t_4 = 0,00022918 s

2 Based on the characteristic that if the release hole size is 0.25 inch or less, then, automatically including into the continuous release type. And the other hand, if t_n<180 sec and the release mass is gretaer than 4356 kgs (10000 lbs), it is including into instantaneous release type.

PART 6 : ESTIMATE THE IMPACT OF DETECTION AND ISOLATION SYSTEMS ON RELEASE MAGNITUDE

STEP 6.1 Determine the detection and isolation systems present in the unit using Table 4.5 and 4.6 API 581 Part 3

Table 4.5- Detection and Isolation System Rating Guide

Type of Detection System	**Det. Classification**
Instrumentation designed specifically to detect material losses by changes in operating conditions (i.e. loss of pressure or flow) in the system	A
Suitably located detectors to determine when the material is present outside the pressure-containing envelope	B
Visual detection, cameras, or detectors with marginal	C
Type of Isolation System	**Iso. Classification**
Isolation or shutdown systems activated directly from process instrumentation or detectors, with no operator intervention	A
Isolation or shutdown systems activated by operators in the control room or other suitable location remote from the leak	B
Isolation dependent on manually operated valves	C

Table 4.6-Adjustment to Release Based on Detection and Isolation Systems

System Classification		Release Magnitude Adjustment	Reduction Factor, $fact_{di}$
Detection	Isolation		
A	A	Reduce release rate or mass by 25%	0,25
A	B	Reduce release rate or mass by 20%	0,20
A or B	C	Reduce release rate or mass by 10%	0,10
B	B	Reduce release rate or mass by 15%	0,15
C	C	No adjustment to release rate or mass	0,00

STEP 6.2 Type of detection system = Suitably located detectors to determine when the material is present outside the pressure-containing envelope *

Detection Classification = B

STEP 6.3 Type of isolation system = Isolation or shutdown systems activated by operators in the control room or other suitable location remote from the leak *

Isolation Classification = B

STEP 6.4 Determine the release reduction factor *$fact_{di}$* using Table 4.6

Release Magnitude Adjustment	=	Reduce release rate or mass by 15%
Reduction Factor, $fact_{di}$	=	**0,15**

STEP 6.5 Determine the total leak durations for each release hole sizes using Table 4.7

Table 4.7 - Leak Durations Based on detection and Isolation Systems

Detection System Rating	Isolation System Rating	Maximum Leak Duration, ld_{max}
A	A	20 minutes for 1/4 inch leaks
		10 minutes for 1 inch leaks
		5 minutes for 4 inch leaks
A	B	30 minutes for 1/4 inch leaks
		20 minutes for 1 inch leaks
		10 minutes for 4 inch leaks
A	C	40 minutes for 1/4 inch leaks
		30 minutes for 1 inch leaks
		20 minutes for 4 inch leaks
B	A or B	40 minutes for 1/4 inch leaks
		30 minutes for 1 inch leaks
		20 minutes for 4 inch leaks
B	C	1 hour for 1/4 inch leaks
		30 minutes for 1 inch leaks
		20 minutes for 4 inch leaks
C	A, B, or C	1 hour for 1/4 inch leaks
		40 minutes for 1 inch leaks
		20 minutes for 4 inch leaks

1. **SMAL RELEASE HOLE SIZE AREA**

d_1 = 0,25 inch

t_1 = 0,528 s (Continous)

$ld_{max,1}$ = 40 minutes for 1/4 inch leaks

2. **MEDIUM RELEASE HOLE SIZE AREA**

d_2 = 1 inch

t_2 = 0,033 s (Instantaneous)

$ld_{max,2}$ = 30 minutes for 1 inch leaks

3. **LARGE RELEASE HOLE SIZE AREA**

d_3 = 4 inch

t_3 = 0,0021 s (Instantaneous)

$ld_{max,3}$ = 20 minutes for 4 inch leaks

4. RUPTURE RELEASE HOLE SIZE AREA

d_4 = 12 inch

t_4 = 0,0002 s (Instantaneous)

$ld_{max,4}$ = 20 minutes for 4 inch leaks

SUMMARY of STEP 6 :

1. Detection and isolation system of process gas piping which ones of the following options provided by the API RP 581 suits them better.

2. Type detection system of process gas piping in Muara Karang Peaker classified as "B" detection, which mean : Suitably located detectors to determine when the material is present outside the pressure-containing envelope

3. Type isolation system of process gas piping in Muara Karang Peaker classified as "B" isolation, which mean : Isolation or shutdown systems activated by operators in the control room or other suitable location remote from the leak

4. Based on the category both of detection and isolation system, then we could determine the percentage of the release factor magnitude ($fact_{di}$) of the whole piping safety plan. From the result above, the release factor magnitude ($fact_{di}$) is 15% because of both detection and isolation system are including into Category B.

5. Based on the Category B of both detection and isolation systems, the maximum leaks duration can be known.

   $Id_{max,1}$ = 40 minutes for 1/4 inch leaks

   $Id_{max,2}$ = 30 minutes for 1 inch leaks

   $Id_{max,3}$ = 20 minutes for 4 inch leaks

   $Id_{max,4}$ = 20 minutes for 4 inch leaks

PART 7 : DETERMINE THE RELEASE RATE AND MASS FOR CONSEQUENCE OF FAILURE

7.1 Continous Release Rate

For continous releases, the release is modeled as a steady state plume: therefore, the release rate is used as an input to the consequence analysis. The release rate that is used in the analysis is the theoretical release adjusted for the presence of unit detection and isolations as formulated in the equation below:

$$Rate_n = W_n (1 - fact_{di})$$ .... (Equation 12)

7.2 Instaneous Release Rate

For transient instataneous puff releases, the release mass is required to perform the analysis. The available release mass for each hole size, $mass_{avail,n}$, is used ass an upper bound for the release mass, $mass_n$, as shown in the equation below:

$$Mass_n = min . [\{Rate_n . ld_n\}, Mass_{avail,n}]$$ .... (Equation 13)

STEP 7.1 Calculate the adjusted release rate, $rate_n$ for each release hole size

For each release hole size, determine the adjusted release rate, $rate_n$, using equation 12 above where the theoreical release rate, W_n, and also note that the release reduction factor, $fact_{di}$, account for any detection and isolation systemss that are present.

Reduction Factor, $fact_{di}$ = 0,15

W_{n1} = 8590,29125 kg/s

W_{n2} = 137444,66 kg/s

W_{n3} = 2199114,56 kg/s

W_{n4} = 19792031 kg/s

1. **SMALL RELEASE HOLE SIZE AREA**

$$Rate_1 = W_n (1 - fact_{di})$$
$$Rate_1 = 8590{,}2912(1 - 0{,}15)$$
$$= 7301{,}75 \text{ kg/s}$$

2. **MEDIUM RELEASE HOLE SIZE AREA**

$$Rate_2 = W_n (1 - fact_{di})$$
$$Rate_2 = 137444{,}66(1 - 0{,}15)$$
$$= 116.828 \text{ kg/s}$$

3. **LARGE RELEASE HOLE SIZE AREA**

$$Rate_3 = W_n (1 - fact_{di})$$
$$Rate_3 = 2199114{,}6 (1 - 0{,}15)$$
$$= 1869247{,}38 \text{ kg/s}$$

4. **RUPTURE RELEASE HOLE SIZE AREA**

$$Rate_4 = W_n (1 - fact_{di})$$

$$Rate_4 = 19792031 (1 - 0{,}15)$$

$$= 16823226{,}4 \text{ kg/s}$$

STEP 7.2 Calculate the leak duration, ld_n, for each release hole size

For each release hole size, calculate the leak duration, ld_n, of the release using this equation below, ,. Note that the leak duration cannot exceed the maximum duration $ld_{max,n}$.

$$ld_n = min . [\{\frac{Mass_{avail,n}}{Rate_n}\},\{60 . ld_{max,n}]$$ .... (Equation 14)

$ld_{max,1}$	=	40 minutes for 1/4 inch leaks	40	$Mass_{avail,1}$	=	78547,52	kgs
$ld_{max,2}$	=	30 minutes for 1 inch leaks	30	$Mass_{avail,2}$	=	78547,52	kgs
$ld_{max,3}$	=	20 minutes for 4 inch leaks	20	$Mass_{avail,3}$	=	78547,52	kgs
$ld_{max,4}$	=	20 minutes for 4 inch leaks	20	$Mass_{avail,4}$	=	78547,52	kgs

1. **SMALL RELEASE HOLE SIZE AREA**

$$ld_1 = min . [\{\frac{Mass_{avail,n}}{Rate_1}\},\{60 . ld_{max,1}]$$

$$ld_1 = min . [\{\frac{78547{,}52}{7301{,}75}\},\{60 . 40\}]$$

$$= 10{,}757 \text{ s}$$

2. **MEDIUM RELEASE HOLE SIZE AREA**

$$ld_2 = min . [\{\frac{Mass_{avail,n}}{Rate_2}\},\{60 . ld_{max,2}]$$

$$ld_2 = min . [\{\frac{78547{,}52}{116{,}828}\},\{60 . 30\}]$$

$$= 0{,}672 \text{ s}$$

3. **LARGE RELEASE HOLE SIZE AREA**

$$ld_3 = min . [\{\frac{Mass_{avail,n}}{Rate_3}\},\{60 . ld_{max,3}]$$

$$ld_3 = min . [\{\frac{78547{,}52}{1869247{,}38}\},\{60 . 20\}]$$

$$= 0{,}042 \text{ s}$$

4. **RUPTURE RELEASE HOLE SIZE AREA**

$$ld_4 = min . [\{\frac{Mass_{avail,n}}{Rate_4}\},\{60 . ld_{max,4}]$$

$$ld_4 = min . [\{\frac{78547{,}52}{16823226{,}4}\},\{60 . 20\}]$$

$$= 0{,}0047 \text{ s}$$

STEP 7.3 Calculate the release mass, $mass_n$, for each release hole size

For each release hole size, calculate the release mass, $mass_n$, using equation in section 7.2 above based on the release rate, $rate_{n,}$ the leak duration, Id_n, and the available mass, $mass_{avail,n}$.

1. **SMALL RELEASE HOLE SIZE AREA**

$$Mass_1 = min\,.\,[\{Rate_1\,.\,Id_1\},Mass_{avail,1}]$$

$$Mass_1 = min\,.\,[\{7301{,}75.\ 10{,}757\},\ 78547{,}52]$$

$= 78547{,}5155$ kgs

2. **MEDIUM RELEASE HOLE SIZE AREA**

$$Mass_2 = min\,.\,[\{Rate_2\,.\,Id_2\},Mass_{avail,n}]$$

$$Mass_2 = min\,.\,[\{116{,}828\,.\,0{,}672\},\ 78547{,}52]$$

$= 78547{,}5155$ kgs

3. **LARGE RELEASE HOLE SIZE AREA**

$$Mass_3 = min\,.\,[\{Rate_3\,.\,Id_3\},Mass_{avail,n}]$$

$$Mass_3 = min\,.\,[\{1869247{,}38.\ 0{,}0042\},78547{,}52]$$

$= 78547{,}5155$ kgs

4. **RUPTURE RELEASE HOLE SIZE AREA**

$$Mass_4 = min\,.\,[\{Rate_4\,.\,Id_4\},Mass_{avail,n}]$$

$$Mass_4 = min\,.\,[\{16823226{,}4.\ 0{,}0047\},78547{,}52]$$

$= 78547{,}5155$ kgs

SUMMARY of STEP 7:

1 Determining the adjusted release rate, $rate_n$, for each release hole size. This adjusted release rate is quite different with the theoretical release rate, W_n because the adjusted release rate is based on the real condition with the theoretical release rate referrence. Otherwise, the theoretical release rate, $W_{n,}$ is purely based on the theory and approching equationg provided by API RP 581.

$Rate_1$	=	7301,74756 kg/s
$Rate_2$	=	116827,961 kg/s
$Rate_3$	=	1869247,38 kg/s
$Rate_4$	=	16823226,4 kg/s

2 Determining the leak duration, ld_n, for each release hole size.

ld_1	=	10,757	s
ld_2	=	0,672	s
ld_3	=	0,042	s
ld_4	=	0,0047	s

3 Determining the release mass for each release hole size based on the release rate, leak duration, and available mass for each release hole size.

$Mass_1$	=	78547,52	kgs
$Mass_2$	=	78547,52	kgs
$Mass_3$	=	78547,52	kgs
$Mass_4$	=	78547,52	kgs

PART 8 : DETERMINE FLAMMABLE AND EXPLOSIVE CONSEQUENCE

8.1 Consequence Area Equations

The following equations are used to determine the flammable consequence areas for comoponent damage and personnel injury. There are two kind of equantions explained based on its type of release, either continous release or instataneous release as mentioned below:

1. **Continous Release** $(CA_n^{CONT} = a(rate_n)^b)$ .... (Equation 15)

2. **Instataneous Release** $(CA_n^{INST} = a(mass_n)^b)$ .... (Equation 16)

The coefficients for those equations for component damage areas and personel injury are provided in Table 4.8 and 4.9 in API RP 581 Part 3 of COF.

STEP 8.1 Select the consequence area mitigation reduction factor, factmit, from Table 4.10

Table 4.10 - Adjustment to Flammable Consequence for Mitigation Systems

Mitigation System	Consequence Area Adjustment	Consequence Area Reduction Factor, $fact_{mit}$
Inventory blowdown, couple with isolation system classification B or higher	Reduce consequence area by 25 %	0,25
Fire water deluge system and monitors	Reduce consequence area by 20%	0,2
Fire water monitor only	Reduce consequence area by 5%	0,05
Foam spray system	Reduce consequence area by 15%	0,15

Mitigation Systen = Inventory blowdown, couple with isolation system classification B or higher

Consequence Area = Reduce consequence area by 15%

$fact_{mit}$ = 0,15

STEP 8.2 Calculate the energy efficiency, $eneff_n$, for each hole size using equation mentioned below.

$$eneff_n = 4\,.\,log_{10}\,[C_{4A}\,.\,mass_n] - 15 \quad \text{....................................} \quad (\text{ Equation 17})$$

This correction is made for instantaneous events exceeding a release mass of 4,536 kgs (10,000 Ibs). Comparison of calculated consequence with those of actual historical releases indicates that there is need to correct large instantaneous releases for energy efficiency.

C_{4A} = 2205 1/kg

1. **SMALL RELEASE HOLE SIZE AREA**

$$eneff_1 = 4\,.\,log_{10}\,[C_{4A}\,.\,mass_1] - 15$$
$$eneff_1 = 4\,.\,log_{10}\,[2205\,.\,78547{,}5155] - 15$$
$$eneff_1 = 17{,}954164$$

2. **MEDIUM RELEASE HOLE SIZE AREA**

$$eneff_2 = 4\,.\,log_{10}\,[C_{4A}\,.\,mass_2] - 15$$
$$eneff_2 = 4\,.\,log_{10}\,[2205\,.\,78547{,}5155] - 15$$
$$eneff_2 = 17{,}954164$$

3. **LARGE RELEASE HOLE SIZE AREA**

$$eneff_3 = 4\,.\,log_{10}\,[C_{4A}\,.\,mass_3] - 15$$
$$eneff_3 = 4\,.\,log_{10}\,[2205\,.\,78547{,}5155] - 15$$
$$eneff_3 = 17{,}954164$$

4. **RUPTURE RELEASE HOLE SIZE AREA**

$$eneff_4 = 4\,.\,log_{10}\,[C_{4A}\,.\,mass_4] - 15$$
$$eneff_4 = 4\,.\,log_{10}\,[2205\,.\,78547{,}5155] - 15$$
$$eneff_4 = 17{,}95416$$

STEP 8.3 Determine the Fluid Type

Determine the fluid type, either TYPE 0 or TYPE 1 based on Table 4.1 of API RP 581 Part 3 of COF.

Table 4.1 – List of Representative Fluids Available for Level 1 Consequence Analysis

Representative Fluid	Fluid TYPE (see Section 4.1.5)	Examples of Applicable Materials
$C_1 - C_2$	TYPE 0	Methane, Ethane, Ethylene, LNG, Fuel Gas

LNG (Methane)	=	TYPE 0	T	=	18,83 °C
MW	=	23 (kg / kg - mol)	T	=	65,89 °F
AIT	=	557,8 °C	T	=	291,8 K
AIT	=	830,8 K			

STEP 8.4 For each release hole size, calculate the component damage consequence areas for Auto-Ignition Not Likely, Continous Release (AINT-CONT), $CA^{AINL\text{-}CONT}$

1. Determine the appropriate constant a and b from the Table 4.8

Table 4.8M - Component Damage Flammable Consequence Equation Constants

Fluid	Continuous Release Constant								nstantaneous Release Constan							
	Auto Ignition Not Likely (CAINL)				Auto Ignition Likely (CAIL)				Auto-Ignition Not Likely (IAINL)				Auto-Ignition Likely (IAIL)			
	Gas		Liquid		Gas		Liquid		Gas		Liquid		Gas		Liquid	
	α	b	α	b	α	b	α	b	α	b	α	b	α	b	α	b
Methane (LNG)	8,67	0,98			55,13	0,95			6,469	0,67			163,7	0,62		

α = $\alpha_{cmd,n}^{AINL-CONT}$ = 8,67   b = $b_{cmd,n}^{AINL-CONT}$ = 0,98

2. Calculate the consequence of area using equation 18

Rate1	=	7301,75	kg/s
Rate2	=	116827,96	kg/s
Rate3	=	1869247,38	kg/s
Rate4	=	16823226,38	kg/s

$$CA_{cmd,n}^{AINL-CONT} = \alpha\,(rate_n)^b.(1 - fact_{mit})$$ .... (Equation 18)

A. SMALL RELEASE HOLE SIZE AREA

$$CA_{cmd,1}^{AINL-CONT} = \alpha\,(rate_1)^b.(1 - fact_{mit})$$

$$CA_{cmd,1}^{AINL-CONT} = 8{,}67\,(7301{,}75)^{0{,}98}.(1 - 0{,}15)$$

$$CA_{cmd,1}^{AINL-CONT} = 45034{,}59 \text{ m}^2$$

B. MEDIUM RELEASE HOLE SIZE AREA

$$CA_{cmd,2}^{AINL-CONT} = \alpha\,(rate_2)^b.(1 - fact_{mit})$$

$$CA_{cmd,2}^{AINL-CONT} = 8{,}67\,(116827{,}96)^{0{,}98}.(1 - 0{,}15)$$

$$CA_{cmd,2}^{AINL-CONT} = 681685{,}1 \text{ m}^2$$

C. LARGE RELEASE HOLE SIZE AREA

$$CA_{cmd,3}^{AINL-CONT} = \alpha\,(rate_3)^b.(1 - fact_{mit})$$

$$CA_{cmd,3}^{AINL-CONT} = 8{,}67\,(1869247{,}38)^{0{,}98}.(1 - 0{,}15)$$

$$CA_{cmd,3}^{AINL-CONT} = 10318614 \text{ m}^2$$

D. RUPTURE RELEASE HOLE SIZE AREA

$$CA_{cmd,4}^{AINL-CONT} = \alpha\,(rate_4)^b.(1 - fact_{mit})$$

$$CA_{cmd,4}^{AINL-CONT} = 8{,}67\,(16823226{,}38)^{0{,}98}.(1 - 0{,}15)$$

$$CA_{cmd,4}^{AINL-CONT} = 88874880{,}91 \text{ m}^2$$

STEP 8.5 **For each release hole size, calculate the component damage consequence areas for Auto-Ignition Likely, Continous Release (AIL-CONT), $CA^{AIL\text{-}CONT}$**

1. **Determine the appropriate constant a and b from the Table 4.8**

α = $\alpha_{cmd,n}^{AIL-CONT}$ = 55,13 b = $b_{cmd,n}^{AIL-CONT}$ = 0,95

2. **Calculate the consequence of area using equation 19**

$$CA_{cmd,n}^{AIL-CONT} = \alpha\,(rate_n)^b.(1 - fact_{mit}) \qquad \text{(Equation 19)}$$

A. SMALL RELEASE HOLE SIZE AREA

$$CA_{cmd,1}^{AIL-CONT} = \alpha\,(rate_1)^b.(1 - fact_{mit})$$

$$CA_{cmd,1}^{AIL-CONT} = 55{,}13\,(7301{,}75)^{0{,}95}.(1 - 0{,}15)$$

$$CA_{cmd,1}^{AIL-CONT} = 219312 \text{ m}^2$$

B. MEDIUM RELEASE HOLE SIZE AREA

$$CA_{cmd,2}^{AIL-CONT} = \alpha\,(rate_2)^b.(1 - fact_{mit})$$

$$CA_{cmd,2}^{AIL-CONT} = 55{,}13\,(116827{,}96)^{0{,}95}.(1 - 0{,}15)$$

$$CA_{cmd,2}^{AIL-CONT} = 3054754{,}9 \text{ m}^2$$

C. LARGE RELEASE HOLE SIZE AREA

$$CA_{cmd,3}^{AIL-CONT} = \alpha\,(rate_3)^b.(1 - fact_{mit})$$

$$CA_{cmd,3}^{AIL-CONT} = 55{,}13\,(1869247{,}38)^{0{,}95}.(1 - 0{,}15)$$

$$CA_{cmd,3}^{AIL-CONT} = 42549098{,}08 \text{ m}^2$$

D. RUPTURE RELEASE HOLE SIZE AREA

$$CA_{cmd,4}^{AIL-CONT} = \alpha\,(rate_4)^b.(1 - fact_{mit})$$

$$CA_{cmd,4}^{AIL-CONT} = 55{,}13\,(16823226{,}38)^{0{,}95}.(1 - 0{,}15)$$

$$CA_{cmd,4}^{AIL-CONT} = 343100019{,}4 \text{ m}^2$$

STEP 8.6 For each release hole size, calculate the component damage consequence areas for Auto-Ignition Not Likely, Instantaneous Release (AINL-CONT), $CA^{AINL\text{-}INST}$

1. **Determine the appropriate constant a and b from the Table 4.8**

α = $\alpha_{cmd,n}^{AINL-INST}$ = 6,469 b = $b_{cmd,n}^{AINL-INST}$ = 0,67

2. **Calculate the consequence of area using equation 20**

$$CA_{cmd,n}^{AINL-INST} = \alpha\,(mass_n)^b.\left(\frac{1-fact_{mit}}{eneff_n}\right) \quad \text{.................. (Equation 20)}$$

From step 7, know that :

$Mass_1$	=	78547,51547	kgs
$Mass_2$	=	78547,51547	kgs
$Mass_3$	=	78547,51547	kgs
$Mass_4$	=	78547,51547	kgs

A. SMALL RELEASE HOLE SIZE AREA

$$CA_{cmd,1}^{AINL-INST} = \alpha\,(mass_1)^b.\left(\frac{1-fact_{mit}}{eneff_1}\right)$$

$$CA_{cmd,1}^{AINL-INST} = 6{,}469\,(78547{,}51547)^{0,67}.\left(\frac{1-0{,}15}{17{,}95416}\right)$$

$$CA_{cmd,1}^{AINL-INST} = 583{,}22\ \text{m}^2$$

B. MEDIUM RELEASE HOLE SIZE AREA

$$CA_{cmd,2}^{AINL-INST} = \alpha\,(mass_2)^b.\left(\frac{1-fact_{mit}}{eneff_2}\right)$$

$$CA_{cmd,2}^{AINL-INST} = 6{,}469(78547{,}51547)^{0,67}.\left(\frac{1-0{,}15}{17{,}95416}\right)$$

$$CA_{cmd,2}^{AINL-INST} = 583{,}22\ \text{m}^2$$

C. LARGE RELEASE HOLE SIZE AREA

$$CA_{cmd,3}^{AINL-INST} = \alpha\,(mass_3)^b.\left(\frac{1-fact_{mit}}{eneff_3}\right)$$

$$CA_{cmd,3}^{AINL-INST} = 6{,}469\,(78547{,}51547)^{0,67}.\left(\frac{1-0{,}15}{17{,}95416}\right)$$

$$CA_{cmd,3}^{AINL-INST} = 583{,}22\ \text{m}^2$$

D. RUPTURE RELEASE HOLE SIZE AREA

$$CA_{cmd,3}^{AINL-INST} = \alpha\,(mass_4)^b.\left(\frac{1-fact_{mit}}{eneff_4}\right)$$

$$CA_{cmd,4}^{AINL-INST} = 6{,}469\,(78547{,}51547)^{0,67}.\left(\frac{1-0{,}15}{17{,}95416}\right)$$

$$CA_{cmd,4}^{AINL-INST} = 583{,}22\ \text{m}^2$$

STEP 8.7 For each release hole size, calculate the component damage consequence areas for Auto-Ignition Likely, Instantaneous Release (AIL-CONT), $CA^{AIL-INST}$

1. **Determine the appropriate constant a and b from the Table 4.8**

$\alpha = \alpha_{cmd,n}^{AIL-INST} = 163{,}7$ $\quad$ $b = b_{cmd,n}^{AIL-INST} = 0{,}62$

2. **Calculate the consequence of area using equation 21**

$$CA_{cmd,n}^{AIL-INST} = \alpha\,(mass_n)^b.\left(\frac{1-fact_{mit}}{eneff_n}\right) \quad \text{.................. (Equation 21)}$$

From step 7, know that :

$Mass_1$	=	78547,51547	kgs
$Mass_2$	=	78547,51547	kgs
$Mass_3$	=	78547,51547	kgs
$Mass_4$	=	78547,51547	kgs

A. SMALL RELEASE HOLE SIZE AREA

$$CA_{cmd,1}^{AIL-INST} = \alpha\,(mass_1)^b.\left(\frac{1-fact_{mit}}{eneff_1}\right)$$

$$CA_{cmd,1}^{AIL-INST} = 163{,}7\,(78547{,}51547)^{0{,}62}.\left(\frac{1-0{,}15}{17{,}95416}\right)$$

$$CA_{cmd,1}^{AIL-INST} = 8400{,}1\ \text{m}^2$$

B. MEDIUM RELEASE HOLE SIZE AREA

$$CA_{cmd,2}^{AIL-INST} = \alpha\,(mass_2)^b.\left(\frac{1-fact_{mit}}{eneff_2}\right)$$

$$CA_{cmd,2}^{AIL-INST} = 163{,}7(78547{,}51547)^{0{,}62}.\left(\frac{1-0{,}15}{17{,}95416}\right)$$

$$CA_{cmd,2}^{AIL-INST} = 8400{,}1\ \text{m}^2$$

C. LARGE RELEASE HOLE SIZE AREA

$$CA_{cmd,3}^{AIL-INST} = \alpha\,(mass_3)^b.\left(\frac{1-fact_{mit}}{eneff_3}\right)$$

$$CA_{cmd,3}^{AIL-INST} = 163{,}7(78547{,}51547)^{0{,}62}.\left(\frac{1-0{,}15}{17{,}95416}\right)$$

$$CA_{cmd,3}^{AIL-INST} = 8400{,}1\ \text{m}^2$$

D. RUPTURE RELEASE HOLE SIZE AREA

$$CA_{cmd,3}^{AIL-INST} = \alpha\,(mass_4)^b.\left(\frac{1-fact_{mit}}{eneff_4}\right)$$

$$CA_{cmd,4}^{AIL-INST} = 163{,}7\,(78547{,}51547)^{0{,}62}.\left(\frac{1-0{,}15}{17{,}95416}\right)$$

$$CA_{cmd,4}^{AIL-INST} = 8400{,}1\ \text{m}^2$$

STEP 8.8 **For each release hole size, calculate the personnel injury consequence areas for Auto-Ignition Not Likely, Continous Release (AINL-CONT), $CA^{AINL-CONT}$**

1. **Determine the appropriate constant a and b from the Table 4.9**

Table 4.9 - Personnel Injury Flammable Consequence Equation Constant

Fluid	Continuous Release Constant								Instantaneous Release Constant							
	Auto Ignition Not Likely (CAINL)				Auto Ignition Likely (CAIL)				Auto-Ignition Not Likely (IAINL)				Auto-Ignition Likely (IAIL)			
	Gas		Liquid		Gas		Liquid		Gas		Liquid		Gas		Liquid	
	α	b	α	b	α	b	α	b	α	b	α	b	α	b	α	b
Methane (LNG)	21,83	0,96			143,2	0,92			12,46	0,67			473,9	0,63		

$\alpha = \alpha_{inj,n}^{AINL-CONT} = 21{,}83$ $\quad b = b_{inj,n}^{AINL-CONT} = 0{,}96$

2. **Calculate the consequence of area using equation 22**

$$CA_{inj,n}^{AINL-CONT} = [a\,.(rate_n^{AINL-CONT})^b]\,.(1-fact_{mit}) \quad \text{(Equation 22)}$$

A. SMALL RELEASE HOLE SIZE AREA

$$CA_{inj,1}^{AINL-CONT} = \left[a\,.\left(rate_1^{AINL-CONT}\right)^b\right].(1-fact_{mit})$$
$$CA_{inj,1}^{AINL-CONT} = [21{,}83\,.(7301{,}75)^{0{,}96}]\,.(1-0{,}15)$$
$$CA_{inj,1}^{AINL-CONT} = 94921{,}02 \quad m^2$$

B. MEDIUM RELEASE HOLE SIZE AREA

$$CA_{inj,2}^{AINL-CONT} = \left[a\,.\left(rate_2^{AINL-CONT}\right)^b\right].(1-fact_{mit})$$
$$CA_{inj,2}^{AINL-CONT} = [21{,}83\,.(116827{,}96)^{0{,}96}]\,.(1-0{,}15)$$
$$CA_{inj,2}^{AINL-CONT} = 1359307{,}1 \quad m^2$$

C. LARGE RELEASE HOLE SIZE AREA

$$CA_{inj,3}^{AINL-CONT} = \left[a\,.\left(rate_3^{AINL-CONT}\right)^b\right].(1-fact_{mit})$$
$$CA_{inj,3}^{AINL-CONT} = [21{,}83\,.(1869247{,}38)^{0{,}96}]\,.(1-0{,}15)$$
$$CA_{inj,3}^{AINL-CONT} = 19465822{,}98 \quad m^2$$

D. RUPTURE RELEASE HOLE SIZE AREA

$$CA_{inj,4}^{AINL-CONT} = \left[a\,.\left(rate_3^{AINL-CONT}\right)^b\right].(1-fact_{mit})$$
$$CA_{inj,4}^{AINL-CONT} = [21{,}83\,.(16823226{,}38)^{0{,}96}]\,.(1-0{,}15)$$
$$CA_{inj,4}^{AINL-CONT} = 160452164 \quad m^2$$

STEP 8.9 For each release hole size, calculate the personal injury consequence areas for Auto-Ignition Likely, Continous Release (AIL-CONT), $CA^{AIL\text{-}CONT}$

1. **Determine the appropriate constant a and b from the Table 4.9**

$\alpha = \alpha_{inj,n}^{AIL-CONT} = 143{,}2 \qquad b = b_{cinj,n}^{AIL-CONT} = 0{,}92$

2. **Calculate the consequence of area using equation 23**

$$CA_{inj,n}^{AIL-CONT} = [a\,.(rate_n^{AIL-CONT})^b]\,.(1 - fact_{mit}) \ldots\ldots \text{(Equation 23)}$$

A. SMALL RELEASE HOLE SIZE AREA

$$CA_{inj,1}^{AIL-CONT} = \left[a\,.\left(rate_1^{AIL-CONT}\right)^b\right].(1 - fact_{mit})$$
$$CA_{inj,1}^{AIL-CONT} = [143{,}2\,.(7301{,}75)^{0{,}92}]\,.(1 - 0{,}15)$$
$$CA_{inj,1}^{AIL-CONT} = 436229{,}08 \quad m^2$$

B. MEDIUM RELEASE HOLE SIZE AREA

$$CA_{inj,2}^{AIL-CONT} = \left[a\,.\left(rate_2^{AIL-CONT}\right)^b\right].(1 - fact_{mit})$$
$$CA_{inj,2}^{AIL-CONT} = [143{,}2\,.(116827{,}96)^{0{,}92}]\,.(1 - 0{,}15)$$
$$CA_{inj,2}^{AIL-CONT} = 5591199{,}6 \quad m^2$$

C. LARGE RELEASE HOLE SIZE AREA

$$CA_{inj,3}^{AIL-CONT} = \left[a\,.\left(rate_3^{AIL-CONT}\right)^b\right].(1 - fact_{mit})$$
$$CA_{inj,3}^{AIL-CONT} = [143{,}2\,.(1869247{,}38)^{0{,}92}]\,.(1 - 0{,}15)$$
$$CA_{inj,3}^{AIL-CONT} = 71663065{,}3 \quad m^2$$

D. RUPTURE RELEASE HOLE SIZE AREA

$$CA_{inj,4}^{AIL-CONT} = \left[a\,.\left(rate_4^{AIL-CONT}\right)^b\right].(1 - fact_{mit})$$
$$CA_{inj,4}^{AIL-CONT} = [143{,}2\,.(16823226{,}38)^{0{,}92}]\,.(1 - 0{,}15)$$
$$CA_{inj,4}^{AIL-CONT} = 541001525{,}2 \quad m^2$$

STEP 8.10 For each release hole size, calculate the component damage consequence areas for Auto-Ignition Not Likely, Instantaneous Release (AINL-INST), $CA^{AINL\text{-}INST}$

1. **Determine the appropriate constant a and b from the Table 4.9**

$\alpha = \alpha_{inj,n}^{AINL-INST} = 12{,}46 \qquad b = b_{inj,n}^{AINL-INST} = 0{,}67$

2. **Calculate the consequence of area using equation 24**

$$CA_{inj,n}^{AINL-INST} = [a\,.(mass_n^{AINL-INST})^b].\left(\frac{1 - fact_{mit}}{eneff_n}\right) \quad \text{(Equation 24)}$$

A. SMALL RELEASE HOLE SIZE AREA

$$CA_{inj,1}^{AINL-INST} = \left[a\,.\left(mass_1^{AINL-INST}\right)^b\right].\left(\frac{1-fact_{mit}}{eneff_1}\right)$$

$$CA_{inj,1}^{AINL-INST} = [12{,}46\,.\,(78547{,}51547\,)^{0{,}67}].\left(\frac{1-0{,}15}{17{,}95416}\right)$$

$$CA_{inj,1}^{AINL-INST} = 1123{,}34\ m^2$$

B. MEDIUM RELEASE HOLE SIZE AREA

$$CA_{inj,2}^{AINL-INST} = \left[a\,.\left(mass_2^{AINL-INST}\right)^b\right].\left(\frac{1-fact_{mit}}{eneff_2}\right)$$

$$CA_{inj,2}^{AINL-INST} = [12{,}46\,.\,(78547{,}51547\,)^{0{,}67}].\left(\frac{1-0{,}15}{17{,}95416}\right)$$

$$CA_{inj,2}^{AINL-INST} = 1123{,}34\ m^2$$

C. LARGE RELEASE HOLE SIZE AREA

$$CA_{inj,3}^{AINL-INST} = \left[a\,.\left(mass_3^{AINL-INST}\right)^b\right].\left(\frac{1-fact_{mit}}{eneff_3}\right)$$

$$CA_{inj,3}^{AINL-INST} = [12{,}46\,.\,(78547{,}51547\,)^{0{,}67}].\left(\frac{1-0{,}15}{17{,}95416}\right)$$

$$CA_{inj,3}^{AINL-INST} = 1123{,}34\ m^2$$

D. RUPTURE RELEASE HOLE SIZE AREA

$$CA_{inj,4}^{AINL-INST} = \left[a\,.\left(mass_4^{AINL-INST}\right)^b\right].\left(\frac{1-fact_{mit}}{eneff_4}\right)$$

$$CA_{inj,4}^{AINL-INST} = [12{,}46\,.\,(78547{,}51547\,)^{0{,}67}].\left(\frac{1-0{,}15}{17{,}95416}\right)$$

$$CA_{inj,4}^{AINL-INST} = 1123{,}34\ m^2$$

STEP 8.11 **For each release hole size, calculate the component damage consequence areas for Auto-Ignition Likely, Instantaneous Release (AIL-INST), $CA^{AIL-INST}$**

1. Determine the appropriate constant a and b from the Table 4.9

$\alpha = \alpha_{inj,n}^{AIL-INST} = 473{,}9$ b $= b_{inj,n}^{AIL-INST} = 0{,}63$

2. Calculate the consequence of area using equation 25

$$CA_{inj,n}^{AIL-INST} = [a\,.\,(mass_n^{AIL-INST})^b].\left(\frac{1-fact_{mit}}{eneff_n}\right) \quad \text{(Equation 25)}$$

A. SMALL RELEASE HOLE SIZE AREA

$$CA_{inj,1}^{AIL-INST} = \left[a\,.\left(mass_1^{AIL-INST}\right)^b\right].\left(\frac{1-fact_{mit}}{eneff_1}\right)$$

$$CA_{inj,1}^{AIL-INST} = [473{,}9\,.\,(78547{,}51547\,)^{0,63}].\left(\frac{1-0{,}15}{17{,}95416}\right)$$

$$CA_{inj,1}^{AIL-INST} = 27219{,}11 \quad \mathrm{m}^2$$

B. MEDIUM RELEASE HOLE SIZE AREA

$$CA_{inj,2}^{AIL-INST} = \left[a\,.\left(mass_2^{AIL-INST}\right)^b\right].\left(\frac{1-fact_{mit}}{eneff_2}\right)$$

$$CA_{inj,2}^{AIL-INST} = [473{,}9\,.\,(78547{,}51547\,)^{0,63}].\left(\frac{1-0{,}15}{17{,}95416}\right)$$

$$CA_{inj,2}^{AIL-INST} = 27219{,}11 \quad \mathrm{m}^2$$

C. LARGE RELEASE HOLE SIZE AREA

$$CA_{inj,3}^{AIL-INST} = \left[a\,.\left(mass_3^{AIL-INST}\right)^b\right].\left(\frac{1-fact_{mit}}{eneff_3}\right)$$

$$CA_{inj,3}^{AIL-INST} = [473{,}9\,.\,(78547{,}51547\,)^{0,63}].\left(\frac{1-0{,}15}{17{,}95416}\right)$$

$$CA_{inj,3}^{AIL-INST} = 27219{,}11 \quad \mathrm{m}^2$$

D. RUPTURE RELEASE HOLE SIZE AREA

$$CA_{inj,4}^{AIL-INST} = \left[a\,.\left(mass_4^{AIL-INST}\right)^b\right].\left(\frac{1-fact_{mit}}{eneff_4}\right)$$

$$CA_{inj,4}^{AIL-INST} = [473{,}9\,.\,(78547{,}51547\,)^{0,63}].\left(\frac{1-0{,}15}{17{,}95416}\right)$$

$$CA_{inj,4}^{AIL-INST} = 27219{,}11 \quad \mathrm{m}^2$$

STEP 8.12 **For each release hole size, calculate the instantaneous / continous blending factor, $fact_n^{ic}$**

1. FOR CONTINOUS RELEASE

$$fact_n^{IC} = \min\left[\left\{\frac{rate_n}{C_5}\right\}, 1.0\right] \quad \text{.. (Equation 26)}$$

C_5 = 25,2 kg/s

A. SMALL RELEASE HOLE SIZE AREA

$$fact_1^{IC} = \min\left[\left\{\frac{rate_1}{C_5}\right\}, 1.0\right]$$

$$fact_1^{IC} = \min\left[\left\{\frac{17{,}95416}{25{,}2}\right\}, 1.0\right]$$

$$fact_1^{IC} = 1$$

B. MEDIUM RELEASE HOLE SIZE AREA

$$fact_2^{IC} = \min\left[\left\{\frac{rate_2}{C_5}\right\}, 1.0\right]$$

$$fact_2^{IC} = \min\left[\left\{\frac{116827{,}96}{25{,}2}\right\}, 1.0\right]$$

$$fact_1^{IC} = 1$$

C. LARGE RELEASE HOLE SIZE AREA

$$fact_3^{IC} = \min\left[\left\{\frac{rate_3}{C_5}\right\}, 1.0\right]$$

$$fact_3^{IC} = \min\left[\left\{\frac{1869247{,}38}{25{,}2}\right\}, 1.0\right]$$

$$fact_3^{IC} = 1$$

D. RUPTURE RELEASE HOLE SIZE AREA

$$fact_4^{IC} = \min\left[\left\{\frac{rate_4}{C_5}\right\}, 1.0\right]$$

$$fact_4^{IC} = \min\left[\left\{\frac{16823226{,}38}{25{,}2}\right\}, 1.0\right]$$

$$fact_4^{IC} = 1$$

2. FOR INSTATANEOUS RELEASE

$$fact_n^{IC} = 1$$

STEP 8.13 **Calculate the AIT blending factor, $fact^{AIT}$, using the optional equation below**

$$fact^{AIT} = 0 \qquad \text{for,} \quad T_S + C_6 \le AIT$$

$$fact^{AIT} = \frac{(T_S - AIT + C_6)}{2 \, . \, C_6} \qquad \text{for,} \quad T_S + C_6 > AIT > T_S - C_6$$

$$fact^{AIT} = 1 \qquad \text{for,} \quad T_S + C_6 \ge AIT$$

T_S	=	18,83	°C	AIT	=	558	°C
T_S	=	65,89	°F	AIT	=	831	K
T_S	=	291,83	K	C_6	=	55,6	K

$T_S + C_6$	=	347,43	K
$T_S - C_6$	=	236,23	K

So, $fact^{AIT} = 0$

STEP 8.14 **Calculate the continuous/instantaneous blended consequence area for the component using equation (3.53) through (3.56) based on the consequence areas calculated in previous steps**

$$CA_{cmd,n}^{AIL} = CA_{cmd,n}^{AIL-INST} . fact_n^{IC} + CA_{cmd,n}^{AIL-CONT} . (1 - fact_n^{IC}) \text{......} \quad \text{(Equation 27)}$$

A. SMALL RELEASE HOLE SIZE AREA

$CA_{cmd,1}^{AIL-INST}$ = 8400,1015 m² $fact_1^{IC}$ = 1

$fact_1^{IC}$ = 1

$CA_{cmd,1}^{AIL-CONT}$ = 219312 m²

$CA_{cmd,1}^{AIL}$ = 8400,1015 m²

B. MEDIUM RELEASE HOLE SIZE AREA

$CA_{cmd,2}^{AIL-INST}$ = 8400,1015 m² $fact_2^{IC}$ = 1

$fact_2^{IC}$ = 1

$CA_{cmd,2}^{AIL-CONT}$ = 3054754,9 m²

$CA_{cmd,2}^{AIL}$ = 8400,1015 m²

C. LARGE RELEASE HOLE SIZE AREA

$CA_{cmd,3}^{AIL-INST}$ = 8400,1015 m² $fact_3^{IC}$ = 1

$fact_3^{IC}$ = 1

$CA_{cmd,3}^{AIL-CONT}$ = 42549098 m²

$CA_{cmd,3}^{AIL}$ = 8400,1015 m²

D. RUPTURE RELEASE HOLE SIZE AREA

$CA_{cmd,4}^{AIL-INST}$ = 8400,101 m² $fact_4^{IC}$ = 1

$fact_4^{IC}$ = 1

$CA_{cmd,4}^{AIL-CONT}$ = 343100019,4 m²

$CA_{cmd,4}^{AIL}$ = 8400,1015 m²

$$CA_{inj,n}^{AIL} = CA_{inj,n}^{AIL-INST} . fact_n^{IC} + CA_{inj,n}^{AIL-CONT} . (1 - fact_n^{IC}) \; ......$$ (Equation 28)

A. SMALL RELEASE HOLE SIZE AREA

$CA_{inj,1}^{AIL-INST}$ = 27219,11 m^2 $fact_1^{IC}$ = 1

$fact_1^{IC}$ = 1

$CA_{inj,1}^{AIL-CONT}$ = 436229,08 m^2

$CA_{inj,1}^{AIL}$ = 27219,108 m^2

B. MEDIUM RELEASE HOLE SIZE AREA

$CA_{inj,2}^{AIL-INST}$ = 27219,11 m^2 $fact_2^{IC}$ = 1

$fact_2^{IC}$ = 1

$CA_{inj,2}^{AIL-CONT}$ = 5591199,6 m^2

$CA_{inj,2}^{AIL}$ = 27219,108 m^2

C. LARGE RELEASE HOLE SIZE AREA

$CA_{inj,3}^{AIL-INST}$ = 27219,108 m^2 $fact_3^{IC}$ = 1

$fact_3^{IC}$ = 1

$CA_{inj,3}^{AIL-CONT}$ = 71663065,3 m^2

$CA_{inj,3}^{AIL}$ = 27219,108 m^2

D. RUPTURE RELEASE HOLE SIZE AREA

$CA_{inj,4}^{AIL-INST}$ = 27219,108 m^2 $fact_4^{IC}$ = 1

$fact_4^{IC}$ = 1

$CA_{inj,4}^{AIL-CONT}$ = 541001525,2 m^2

$CA_{inj,4}^{AIL}$ = 27219,108 m^2

$$CA_{cmd,n}^{AINL} = CA_{cmd,n}^{AINL-INST} . fact_n^{IC} + CA_{cmd,n}^{AINL-CONT} . (1 - fact_n^{IC}...)$$ (Equation 29)

A. SMALL RELEASE HOLE SIZE AREA

$CA_{cmd,1}^{AINL-INST}$ = 583,21627 m^2 $fact_1^{IC}$ = 1

$fact_1^{IC}$ = 1

$CA_{cmd,1}^{AINL-CONT}$ = 45034,59 m^2

$CA_{cmd,1}^{AINL}$ = 583,21627 m^2

B. MEDIUM RELEASE HOLE SIZE AREA

$CA_{cmd,2}^{AINL-INST}$ = 583,21627 m^2 $fact_2^{IC}$ = 1

$fact_2^{IC}$ = 1

$CA_{cmd,2}^{AINL-CONT}$ = 681685,1 m^2

$CA_{cmd,2}^{AINL}$ = 583,21627 m^2

C. LARGE RELEASE HOLE SIZE AREA

$CA_{cmd,3}^{AINL-INST}$ = 583,21627 m^2 $fact_3^{IC}$ = 1

$fact_3^{IC}$ = 1

$CA_{cmd,3}^{AINL-CONT}$ = 10318614 m^2

$CA_{cmd,3}^{AINL}$ = 583,21627 m^2

D. RUPTURE RELEASE HOLE SIZE AREA

$CA_{cmd,4}^{AINL-INST}$ = 583,2163 m^2 $fact_4^{IC}$ = 1

$fact_4^{IC}$ = 1

$CA_{cmd,4}^{AINL-CONT}$ = 88874880,91 m^2

$CA_{cmd,4}^{AINL}$ = 583,21627 m^2

$$CA_{inj,n}^{AINL} = CA_{inj,n}^{AINL-INST} . fact_n^{IC} + CA_{inj,n}^{AINL-CONT} . (1 - fact_n^{IC})$$ (Equation 30)

A. SMALL RELEASE HOLE SIZE AREA

$CA_{inj,1}^{AINL-INST}$ = 1123,338 m^2 $fact_1^{IC}$ = 1

$fact_1^{IC}$ = 1

$CA_{inj,1}^{AINL-CONT}$ = 94921,02 m^2

$CA_{inj,1}^{AINL}$ = 1123,3382 m^2

B. MEDIUM RELEASE HOLE SIZE AREA

$CA_{inj,2}^{AINL-INST}$ = 1123,338 m^2 $fact_2^{IC}$ = 1

$fact_2^{IC}$ = 1

$CA_{inj,2}^{AINL-CONT}$ = 1359307,1 m^2

$CA_{inj,2}^{AINL}$ = 1123,3382 m^2

C. LARGE RELEASE HOLE SIZE AREA

$CA_{inj,3}^{AINL-INST}$ = 1123,338 m^2 $fact_3^{IC}$ = 1

$fact_3^{IC}$ = 1

$CA_{inj,3}^{AINL-CONT}$ = 19465822,98 m^2

$CA_{inj,3}^{AINL}$ = 1123,3382 m^2

D. RUPTURE RELEASE HOLE SIZE AREA

$CA_{inj,4}^{AINL-INST}$ = 1123,3382 m^2 $fact_4^{IC}$ = 1

$fact_4^{IC}$ = 1

$CA_{inj,4}^{AINL-CONT}$ = 160452164 m^2

$CA_{inj,4}^{AINL}$ = 1123,3382 m^2

STEP 8.15 **Calculate the AIT blended consequence areas for the component using equations (31) and (32) based on the consequence areas determined in step 8.14 and the AIT blending factors, $fact^{AIT}$, calculate in step 8.13. the resulting consequence areas are the component damage and personnel injury flammable consequence areas, $CA^{flam}_{cmd,n}$ and $CA^{flam}_{inj,n}$ for each release hole size selected in step 2.2**

$$CA_{cmd,n}^{flam} = CA_{cmd,n}^{AIL} \cdot fact^{AIT} + CA_{cmd,n}^{AINL} \cdot (1 - fact^{AIT})$$ (Equation 31)

A. SMALL RELEASE HOLE SIZE AREA

$CA_{cmd,1}^{AIL}$ = 8400,1 m^2

$fact^{AIT}$ = 0

$CA_{cmd,1}^{AINL}$ = 583,2163 m^2

$CA_{cmd,1}^{flam}$ = 583,21627 m^2

B. MEDIUM RELEASE HOLE SIZE AREA

$CA_{cmd,2}^{AIL}$ = 8400,1 m^2

$fact^{AIT}$ = 0

$CA_{cmd,2}^{AINL}$ = 583,2163 m^2

$CA_{cmd,2}^{flam}$ = 583,21627 m^2

C. LARGE RELEASE HOLE SIZE AREA

$CA_{cmd,3}^{AIL}$ = 8400,1 m^2

$fact^{AIT}$ = 0

$CA_{cmd,3}^{AINL}$ = 583,2163 m^2

$CA_{cmd,3}^{flam}$ = 583,21627 m^2

D. RUPTURE RELEASE HOLE SIZE AREA

$CA_{cmd,4}^{AIL}$ = 8400,1 m^2

$fact^{AIT}$ = 0

$CA_{cmd,4}^{AINL}$ = 583,2163 m^2

$CA_{cmd,4}^{flam}$ = 583,21627 m^2

$$CA_{inj,n}^{flam} = CA_{inj,n}^{flam-AIL} . fact^{AIT} + CA_{inj,n}^{AINL} . (1 - fact^{AIT}) \quad \text{(Equation 32)}$$

A. SMALL RELEASE HOLE SIZE AREA

$CA_{inj,1}^{flam-AIL}$ = 27219,11 m^2

$fact^{AIT}$ = 0

$CA_{inj,1}^{AINL}$ = 1123,338 m^2

$CA_{inj,1}^{flam}$ = 1123,3382 m^2

B. MEDIUM RELEASE HOLE SIZE AREA

$CA_{inj,2}^{flam-AIL}$ = 27219,11 m^2

$fact^{AIT}$ = 0

$CA_{inj,2}^{AINL}$ = 1123,338 m^2

$CA_{inj,2}^{flam}$ = 1123,3382 m^2

C. LARGE RELEASE HOLE SIZE AREA

$CA_{inj,3}^{flam-AIL}$ = 27219,11 m^2

$fact^{AIT}$ = 0

$CA_{inj,3}^{AINL}$ = 1123,338 m^2

$CA_{inj,3}^{flam}$ = 1123,3382 m^2

D. RUPTURE RELEASE HOLE SIZE AREA

$CA_{inj,4}^{flam-AIL}$ = 27219,108 m^2

$fact^{AIT}$ = 0

$CA_{inj,4}^{AINL}$ = 1123,338 m^2

$CA_{inj,4}^{flam}$ = 1123,3382 m^2

STEP 8.16 **Determine the final consequence areas (probability weighted on release hole size) for component damage and personnel injury using Equations (33) and (34) based on the consequence areas from STEP 8.15.**

Equipment Type	Component Type	*gff* as a Functional of Hole Size				*gff* total (failure/yr
		Small	Medium	Large	Rupture	
Pipe	Pipe 8"	8E-06	0,00002	2E-06	6E-07	0,0000306
	Pipe10"					
	Pipe 12"					
	Pipe 16"					

CONSEQUENCE AREA FOR COMPONENT DAMAGE

$$CA_{cmd}^{flam} = \left(\frac{\sum gff_n \,.\, CA_{cmd.n}^{flam}}{gff_{total}}\right)$$ .... (Equation 33)

$$CA_{cmd}^{flam} = \left(\frac{gff_1 . CA_{cmd,1}^{flam} + gff_2 \,.\, CA_{cmd,2}^{flam} + gff_3 \,.\, CA_{cmd,3}^{flam} + gff_4 \,.\, CA_{cmd,}^{flam}}{gff_{total}}\right)$$

$$CA_{cmd}^{flam} = \left(\frac{8.10^{-6}.583{,}216 + 2.10^{-5}.583{,}216 + 2.10^{-6}.583{,}216 + 6.10^{-7}.583{,}216}{3{,}06.10^{-5}.}\right)$$

CA_{cmd}^{flam} = 583,216 m^2

CONSEQUENCE AREA FOR PERSONEL INJURY

$$CA_{inj}^{flam} = \left(\frac{\sum gff_n \, . CA_{cmd.n}^{flam}}{gff_{total}}\right)$$ .... (Equation 34)

$$CA_{inj}^{flam} = \left(\frac{gff_1 . CA_{inj,1}^{flam} + gff_2 \, . CA_{inj,2}^{flam} + gff_3 \, . CA_{inj,3}^{flam} + gff_4 \, . CA_{inj,4}^{flam}}{gff_{total}}\right)$$

$$CA_{inj}^{flam} = \left(\frac{8.10^{-6}.1123{,}34 + 2.10^{-5}.1123{,}34 + 2.10^{-6}.1123{,}34 + 6.10^{-7}.1123{,}34}{3{,}06.10^{-5}.}\right)$$

CA_{inj}^{flam} = 1123,34 m^2

PART 9: CALCULATE THE TOXIC CONSEQUENCE

STEP 9.1 For each release hole size selected in STEP 2.2, calculate the effective duration of the toxic release using equation 35.

Table 4.13 – Continuous Gas and Liquid Release Toxic Consequence Equation Constants for Miscellaneous Chemicals

Chemical	Release Duration (Minutes)	Gas Release Constants		Liquid Release Constants	
		e	*f*	*e*	*f*
Aluminum Chloride (AlCl3)	All	17.663	0.9411	N/A	N/A
Carbon Monoxide (CO)	3	41.412	1.15	N/A	N/A
	5	279.79	1.06	N/A	N/A
	10	834.48	1.13	N/A	N/A
	20	2,915.9	1.11	N/A	N/A
	40	5,346.8	1.17	N/A	N/A
	60	6,293.7	1.21	N/A	N/A
Hydrogen Chloride (HCL)	3	215.48	1.09	N/A	N/A
	5	536.28	1.15	N/A	N/A
	10	2,397.5	1.10	N/A	N/A
	20	4,027.0	1.18	N/A	N/A
	40	7,534.5	1.20	N/A	N/A
	60	8,625.1	1.23	N/A	N/A
Nitric Acid	3	53,013	1.25	5,110.0	1.08
	5	68,700	1.25	9,640.8	1.02
	10	96,325	1.24	12,453	1.06
	20	126,942	1.23	19,149	1.06
	40	146,941	1.22	31,145	1.06
	60	156,345	1.22	41,999	1.12
Nitrogen Dioxide (NO_2)	3	6,633.1	0.70	21,32.9	0.98
	5	9,221.4	0.68	2,887.0	1.04
	10	11,965	0.68	6,194.4	1.07
	20	14,248	0.72	13,843	1.08
	40	22,411	0.70	27,134	1.12
	60	24,994	0.71	41,657	1.13
Phosgene	3	12,902	1.20	3,414.8	1.06
	5	22,976	1.29	6,857.1	1.10
	10	48,985	1.24	21,215	1.12
	20	108,298	1.27	63,361	1.16
	40	244,670	1.30	178,841	1.20
	60	367,877	1.31	314,608	1.23
Toluene Diisocyanate (TDI)	3	N/A	N/A	3,692.5	1.06
	5	N/A	N/A	3,849.2	1.09
	10	N/A	N/A	4,564.9	1.10
	20	N/A	N/A	4,777.5	1.06
	40	N/A	N/A	4,953.2	1.06
	60	N/A	N/A	5,972.1	1.03
Ethylene Glycol Monoethyl Ether (EE)	1.5	3.819	1.171	N/A	N/A
	3	7.438	1.181	N/A	N/A
	5	17.735	1.122	N/A	N/A
	10	33.721	1.111	3.081	1.105
	20	122.68	0.971	16.877	1.065
	40	153.03	0.995	43.292	1.132
	60	315.57	0.899	105.74	1.104

Because of no chemical toxic in this equipment, so this step not calculate.

PART 10 : CALCULATE THE NON - FLAMMABLE, NON TOXIC CONSEQUENCE AREA

STEP 10.1 **For each release hole size,calculate the non - flammable, non - toxic consequence**

1) FOR STEAM

For Steam - Calculate $CA_{inj,n}^{CONT}$ using Equation (3.69) and $CA_{inj,n}^{INST}$ using Equation (3.70)

This piping process is not steam. So, thus value is 0

2) FOR ACID OR CAUSTICS

Calculate $CA_{inj,n}^{CONT}$ using Equation 36, 37. Note that data is not provided for an instantaneous release; therefore, $CA_{inj,n}^{INST}$ = 0

For caustics/acids that have splash type consequences. Acid or caustic leaks do not result in a component damage consequence. The consequence area was defined at the 180° semi-circular area covered by the liquid spray or rainout. Modeling was performed at three pressures; 103.4 kPa, 206.8 kPa, and 413.7 kPa (15 psig, 30 psig, and 60 psig) for four release hole sizes (see Table 4.4). The results were analyzed to obtain a correlation between release rate and consequence area, and were divided by 5 since it is believed that serious injuries to personnel are only likely to occur within about 20% of the total splash area as calculated by the above method

The resulting consequence area for non-flammable releases of acids and caustics is calculated using Equations (36) and (37)

$$CA_{inj,n}^{CONT} = 0.2 \cdot C_8 \cdot g(C_4 \cdot rate_n)^h \quad \text{(Equation 36)}$$

$$CA_{inj,n}^{INST} = 0 \quad \text{(Equation 37)}$$

The constants g and h shown in Equation (36),are functions of pressure and can be calculated using Equations (38) and (39), respectively.

$$g = 2696 - 21.9 \cdot C_{11}(P_S - P_{atm}) + 1.474\,[C_{11}(P_S - P_{atm})]^2 \quad \text{(Equation 38)}$$

$$h = 0.31 - 0.00032\,[C_{11}(P_S - P_{atm}) - 40]^2 \quad \text{(Equation 39)}$$

$Rate_1$	=	7301,747559 kg/s		C_8	=	0,0929	$m^2.s$
$Rate_2$	=	116827,9609 kg/s		C_4	=	2,205	s/kg
$Rate_3$	=	1869247,375 kg/s		C_{11}	=	0,145	1/kPa
$Rate_4$	=	16823226,38 kg/s				0,00145	1/bar
				P_S	=	4500	kPa
						45	bar
				P_{atm}	=	101,33	kPa
						1,01	bar

$$g = 2696 - 21.9 \cdot C_{11}\,(P_S - P_{atm}) + 1.474\,[C_{11}(P_S - P_{atm})]^2$$
$$g = 2696 - 21.9 \cdot 0{,}145\,(45 - 101{,}33) + 1.474\,[0{,}00145(4500 - 1{,}01)]^2$$
$$g = 2694{,}609197$$

$$h = 0.31 - 0.00032\,[C_{11}(P_S - P_{atm}) - 40]^2$$
$$h = 0.31 - 0.00032\,[0{,}00145(45 - 1{,}01) - 40]^2$$
$$h = -0{,}2$$

A. SMALL RELEASE HOLE SIZE AREA

$$CA_{inj,1}^{CONT} = 0.2 \cdot C_8 \cdot g(C_4 \cdot rate_1)^h$$
$$CA_{inj,1}^{CONT} = 0.2 \cdot 0{,}0929 \cdot 2694{,}6092(2{,}205 \cdot 7301{,}75)^{-0{,}2}$$
$$CA_{inj,1}^{CONT} = 7{,}1883 \quad m^2$$

B. MEDIUM RELEASE HOLE SIZE AREA

$$CA_{inj,2}^{CONT} = 0.2 \cdot C_8 \cdot g(C_4 \cdot rate_2)^h$$
$$CA_{inj,2}^{CONT} = 0.2 \cdot 0{,}0929 \cdot 2694{,}6092(2{,}205 \cdot 116827{,}96)^{-0{,}2}$$
$$CA_{inj,2}^{CONT} = 4{,}1244 \quad m^2$$

C. LARGE RELEASE HOLE SIZE AREA

$$CA_{inj,3}^{CONT} = 0.2 \cdot C_8 \cdot g(C_4 \cdot rate_3)^h$$
$$CA_{inj,3}^{CONT} = 0.2 \cdot 0{,}0929 \cdot 2694{,}6092(2{,}205 \cdot 1869247{,}38)^{-0{,}2}$$
$$CA_{inj,3}^{CONT} = 2{,}3664 \quad m^2$$

D. RUPTURE RELEASE HOLE SIZE AREA

$$CA_{inj,3}^{CONT} = 0.2 \cdot C_8 \cdot g(C_4 \cdot rate_4)^h$$
$$CA_{inj,3}^{CONT} = 0.2 \cdot 0{,}0929 \cdot 2694{,}6092(2{,}205 \cdot 6823226{,}38)^{-0{,}2}$$
$$CA_{inj,3}^{CONT} = 1{,}5237 \quad m^2$$

STEP 10.2 **For each release hole size,calculate the instantaneous / continous blending factor $fact_n^{IC}$. For steam, use Equation (3.71). For Acids or Caustics, $fact_n^{IC}$ = 0**

Because its acid, so : $fact_n^{IC} = 0$

STEP 10.3 **For each release hole size, calculate the blended non - flammable, non-toxic personal injury consequence area for steam or acid leaks, $CA_{inj,n}^{IC}$, using Equation 41 based on the consequencw areas from STEP 10.1 and the blending factor, $fact_n^{IC}$, From STEP 10.2. Note that there is no need to calculate area component damage area for the Level 1 non - flammable releases (steam or acid/ caustic):**

$$CA_{inj,n}^{IC} = 0 \text{ m}^2 \quad \text{(Equation 40)}$$

$$CA_{inj,n}^{leak} = CA_{inj,n}^{INST} \cdot fact_n^{IC} + CA_{inj,n}^{CONT} \cdot (1 - fact_n^{IC}) \quad \text{(Equation 41)}$$

$fact_1^{IC} = 1$
$fact_2^{IC} = 1$
$fact_3^{IC} = 1$
$fact_3^{IC} = 1$

A. SMALL RELEASE HOLE SIZE AREA

$$CA_{inj,1}^{leak} = CA_{inj,1}^{INST} \cdot fact_1^{IC} + CA_{inj,1}^{CONT} \cdot \left(1 - fact_1^{IC}\right)$$
$$CA_{inj,1}^{leak} = 0 \cdot 1 + 7{,}1883 \cdot (1 - 1)$$
$$CA_{inj,1}^{leak} = 0 \text{ m}^2$$

B. MEDIUM RELEASE HOLE SIZE AREA

$$CA_{inj,2}^{leak} = CA_{inj,2}^{INST} \cdot fact_2^{IC} + CA_{inj,2}^{CONT} \cdot \left(1 - fact_2^{IC}\right)$$
$$CA_{inj,2}^{leak} = 0 \cdot 1 + 4{,}1244 \cdot (1 - 1)$$
$$CA_{inj,2}^{leak} = 0 \text{ m}^2$$

C. LARGE RELEASE HOLE SIZE AREA

$$CA_{inj,3}^{leak} = CA_{inj,3}^{INST} \cdot fact_1^{IC} + CA_{inj,3}^{CONT} \cdot \left(1 - fact_3^{IC}\right)$$
$$CA_{inj,3}^{leak} = 0 \cdot 1 + 2{,}3664 \cdot (1 - 1)$$
$$CA_{inj,3}^{leak} = 0 \text{ m}^2$$

D. RUPTURE RELEASE HOLE SIZE AREA

$$CA_{inj,3}^{leak} = CA_{inj,3}^{INST} \cdot fact_1^{IC} + CA_{inj,3}^{CONT} \cdot \left(1 - fact_3^{IC}\right)$$
$$CA_{inj,3}^{leak} = 0 \cdot 1 + 1{,}5237 \cdot (1 - 1)$$
$$CA_{inj,3}^{leak} = 0 \text{ m}^2$$

STEP 10.4 **Determine the final non-flammable, non toxic consequence areas for personnil injury, $CA_{inj,n}^{nfnt}$ using Equation 42 based on consequence area calculated for each release hole size in Step 10.3. Note that there is no need to calculate a final - flammable, non-toxic consequence area for component damage area for the Level 1 non-flammble relese (steam or acid/caustic) :**

$$CA_{inj,n}^{infnt} = 0 \quad m^2$$

$$CA_{inj}^{nfnt} = \left(\frac{\sum gff_n \cdot CA_{inj,n}^{leak}}{gff_{total}} \right) \quad \text{...} \quad \text{(Equation 42)}$$

Equipment Type	Component Type	*gff* as a Functional of Hole Size				*gff* total (failure/yr
		Small	Medium	Large	Rupture	
Pipe	Pipe 8"	8E-06	0,00002	2E-06	6E-07	0,0000306
	Pipe10"					
	Pipe 12"					
	Pipe 16"					

$$CA_{inj}^{nfnt} = \left(\frac{\sum gff_n \cdot CA_{inj,n}^{leak}}{gff_{total}} \right)$$

$$CA_{inj}^{nfnt} = \left(\frac{\left(gff_1 \cdot CA_{inj,1}^{leak}\right) + \left(gff_2 \cdot CA_{inj,2}^{leak}\right) + \left(gff_3 \cdot CA_{inj,3}^{leak}\right) + \left(gff_4 \cdot CA_{inj,4}^{leak}\right)}{gff_{total}} \right)$$

$$CA_{inj}^{nfnt} = \left(\frac{(8 \cdot 10^{-6} \cdot 0) + (2 \cdot 10^{-5} \cdot 0) + (2 \cdot 10^{-6} \cdot 0) + (6 \cdot 10^{-7} \cdot 0)}{3{,}06 \cdot 10^{-5}} \right)$$

$$= 0 \quad m^2$$

PART 11 : CALCULATION OF FINAL CONSEQUENCE AREA

STEP 11.1 **Calculate the final component damage consequences area CA_{cmd}**

Note that since the component damage consequence areas for toxic releases, CA_{cmd}^{tox}, and non-flammable, non-toxic releases, CA_{cmd}^{nfnt}, are both equal to zero. Then, the final component damage consequence area is equal to the consequence area calculated for flammable releases, CA_{cmd}^{flam}.

$$CA_{cmd} = CA_{cmd}^{flam}$$
$$= 583{,}216 \text{ m}^2$$

STEP 11.2 **Calculate the final personnel injury consequences area CA_{inj}**

$$CA_{inj} = max\left[CA_{inj}^{flam}, CA_{inj}^{tox}, CA_{inj}^{nfnt}\right] \quad \text{(Equation 43)}$$

$$CA_{inj}^{flam} = 1123{,}3382 \text{ m}^2$$

$$CA_{inj}^{tox} = 0 \text{ m}^2$$

$$CA_{inj}^{nfnt} = 0 \text{ m}^2$$

$$CA_{inj} = max\left[CA_{inj}^{flam}, CA_{inj}^{tox}, CA_{inj}^{nfnt}\right]$$
$$CA_{inj} = max[1123{,}3382; 0; 0]$$
$$CA_{inj} = 1123{,}3382$$

STEP 11.3 **Calculate the final consequences area CA, using Equation 44**

$$CA = max\left[CA_{cmd}, CA_{inj}\right] \quad \text{(Equation 44)}$$
$$CA = max[583{,}216; 1123{,}3382]$$
$$= 1123{,}338177 \text{ m}^2$$

DETERMINE THE RISK

A. Last Inspection Date

Last known inspection date is November 15rd 2018

B. RBI Date

RBI date is the date when the Risk - Based Inspection is conducted. In this case, the RBI date is set on default date September 20th 2019.

$$R_{RBI} = POF_{RBI} \times COF_{RBI}$$

Where ;

POF_{RBI} = 3,408676E-05 (Based on RLA data)

= 3,408693E-05 (Based on the corrosion rate calculation)

COF_{RBI} = 1123,338177 m^2

So,

R_{RBI} = $POF_{RBI} \times COF_{RBI}$

= 3,8290956E-02 m^2/year (Based on RLA data)

= 3,8291153E-02 m^2/year (Based on the corrosion rate calculation)

= 4,1216215E-01 ft^2/year

C. Plan Date

The plan date is 3,23 years, starting from the installation date on a plant was on 15^{rth} November 2018, until the plan date 11st November 2022.

$$R_{PD} = POF_{PD} \times COF_{PD}$$

Where ;

POF_{PD} = 3,408478E-05 (Based on RLA data)

= 3,408565E-05 (Based on the corrosion rate calculation)

COF_{PD} = 1123,338177 m^2

So,

R_{PD} = $POF_{PD} \times COF_{PD}$

= 3,828873E-02 m^2/year (Based on RLA data)

= 3,828971E-02 m^2/year (Based on the corrosion rate calculation)

= 4,121466E-01 ft^2/year

INSPECTION PLAN

A. PIPE SPECIFICATION

Tag Number	= 12"-PG-062451-C
Diameter (inch)	= 12
Material	= A 106 GR, SMLS, SCH 80
Min. Wall Thickness Design (mm)	= 10,95
Fluid Handle	= C1 - C2
Operating Pressure (barg)	= 46
Operating Temperature (^{O}C)	= 18,78
PID	= MKP-05-EN-PR-PID-002

B. RBI SUMMARY

a. Probability Assessment

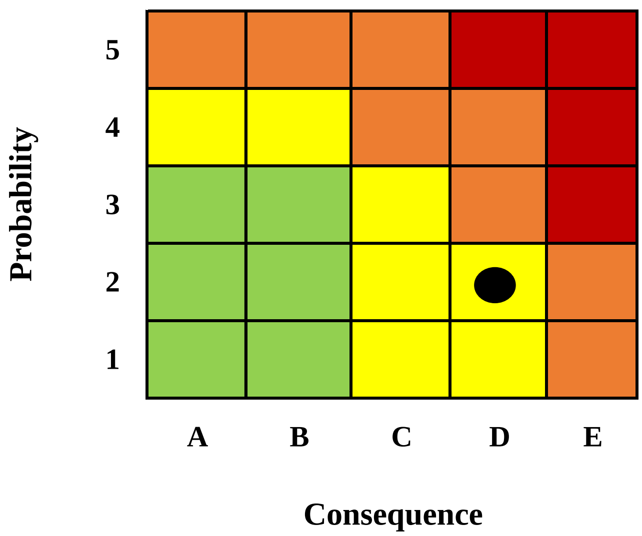
Total Damage Factor	= 1,113952065
Probability	= 3,40869E-05
Probability Category	= 2
Active Damage Mechanism	= Thinning Damage Factor, Mechanical Fatigue Damage Factor, External Corrosion Damage Factor

b. Consequence Assessment

Fluid Representative	= C1 - C2
Fluid Phase	= Gas
Consequence Area (m^2)	= 1123,338177
Consequence Category	= D

c. Risk Ranking

Probability Category	= 2
Consequence Category	= D
Risk Ranking	= Medium
Area Risk (m^2)	= 3,8291153E-02
Risk Category	= Acceptable



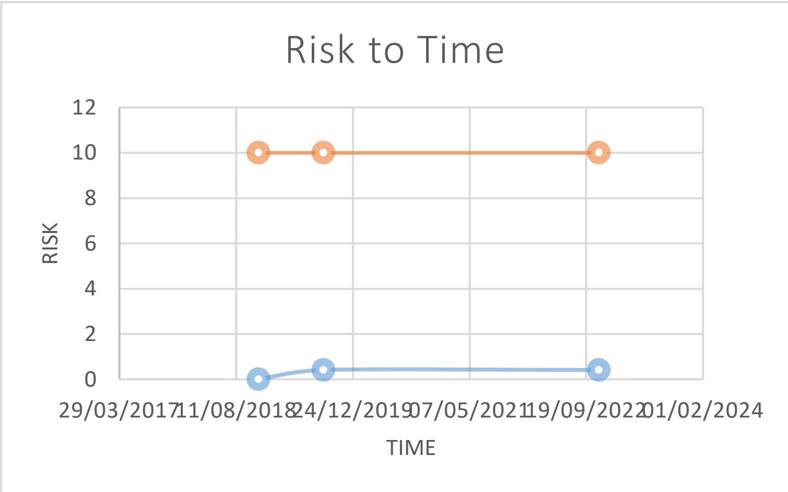
d. Recommendation

	Thinning	Mechanical Fatigue	External Corrosion
Effectiveness	D	-	D
Due Date	26/09/2023	01/05/2026	06/09/2022
Description	For the total surface area;>20% ultrasonic scanning or profile radiography.	Visual examination	Visual inspection of >5% of the exposed surface area with follow up by Ultrasonic Test, Radiography Test or pit gauge as required

RISK PLOTTING

RBI Date - Risk Target

	Time	Risk (ft^2/year)	Risk target (ft^2/year)
Last insp. date	15/11/2018	0	10
RBI date	20/08/2019	0,412162146	10
Plan date	11/11/2022	0,412146624	10



Risk Target = (RBI Date) . (Time Plan Date - RBI Date) $^{n-1}$

10 = (0,412162146) . (3,23) $^{n-1}$

24,263 = (3,23) $^{n-1}$

Interpolation

X_1	3	Y_1	10,42
X	x	Y	24,263
X_2	4	Y_2	33,63

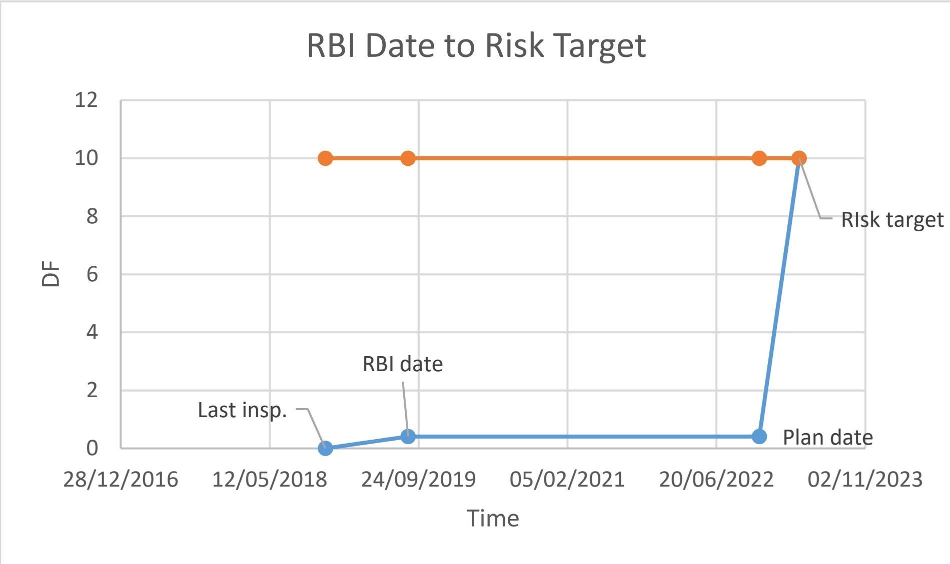
$$X = X_1 + \left(\frac{Y - Y_1}{Y_2 - Y_1}\right)(X_2 - X_1)$$

$$X = 3 + \left(\frac{24{,}263 - 10{,}42}{33{,}63 - 10{,}42}\right)(2 - 1)$$

= 3,596354275 Year

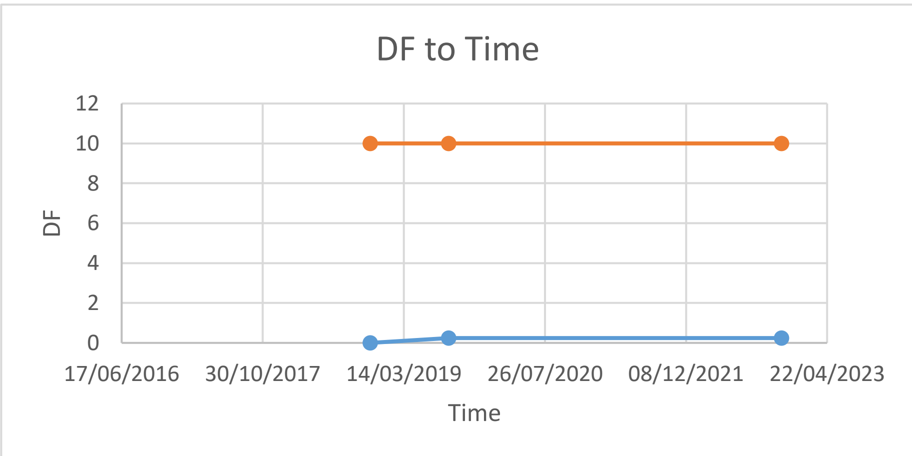
So, time to risk target is on 24/03/2023

	Time	Risk (ft^2/year)	Risk target (ft^2/year)
Last insp. date	15/11/2018	0	10
RBI date	20/08/2019	0,412162146	10
Plan date	11/11/2022	0,412146624	10
Target	24/03/2023	10	10



Thinning

	Time	DF	DF target
Last insp. date	15/11/2018	0	10
RBI date	20/08/2019	0,240920909	10
Plan date	11/11/2022	0,24091967	10



DF Target = (DF RBI Date) . (Time Plan Date - RBI Date) $^{n-1}$

10 = (0,240920909) . (3,23) $^{n-1}$

41,5074 = (3,23) $^{n-1}$

Interpolation			
X_1	4	Y_1	33,63
X	x	Y	41,5074
X_2	5	Y_2	108,57

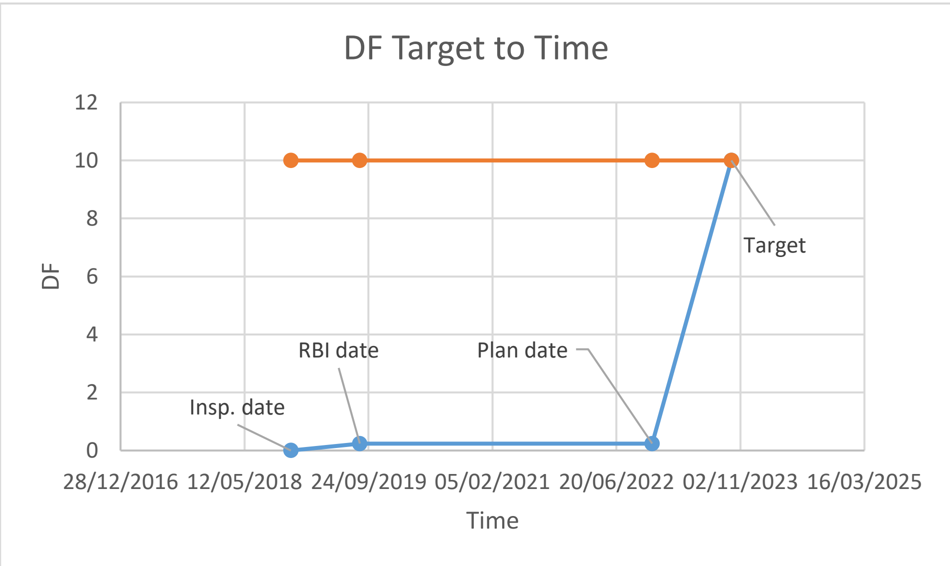
$$X = X_1 + \left(\frac{Y - Y_1}{Y_2 - Y_1}\right)(X_2 - X_1)$$

$$X = 3 + \left(\frac{41{,}5074 - 33{,}63}{108{,}57 - 33{,}63}\right)(4 - 3)$$

= 4,105080928 Year

So, time to risk target is on 26/09/2023

	Time	DF	DF target
Last insp. date	15/11/2018	0	10
RBI date	20/08/2019	0,240920909	10
Plan date	11/11/2022	0,240919670	10
Target	26/09/2023	10	10



Mechanical Fatigue

	Time	DF	DF target
Last insp. date	15/11/2018	0	10
RBI date	20/08/2019	0,011111111	10
Plan date	11/11/2022	0,011111111	10

DF Target = (DF RBI Date) . (Time Plan Date - RBI Date) $^{n-1}$

10 = (0,24087829) . (3,23) $^{n-1}$

900 = (3,23) $^{n-1}$

Interpolation

X_1	6	Y_1	350,44
X	x	Y	900
X_2	7	Y_2	1131,21

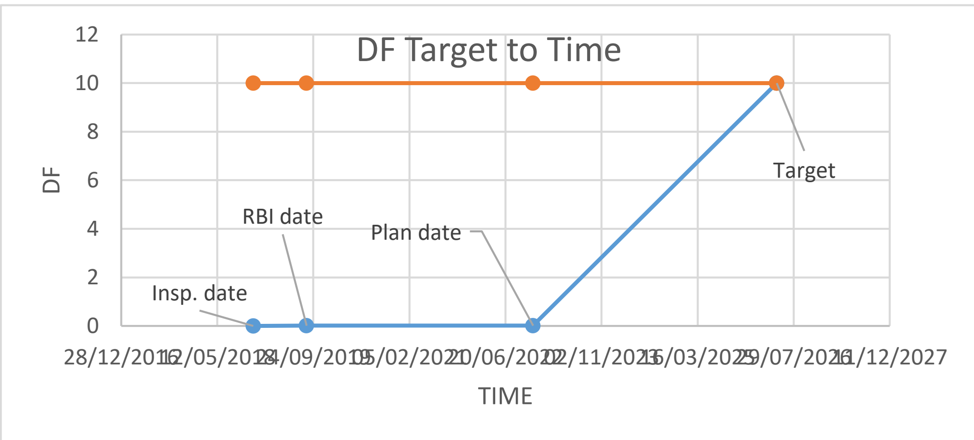
$$X = X_1 + \left(\frac{Y - Y_1}{Y_2 - Y_1}\right)(X_2 - X_1)$$

$$X = 6 + \left(\frac{900 - 350{,}44}{1131{,}21 - 350{,}44}\right)(5 - 4)$$

= 6,703872078 Year

So, time to risk target is on 01/05/2026

	Time	DF	DF target
Last insp. date	15/11/2018	0	10
RBI date	20/08/2019	0,011111111	10
Plan date	11/11/2022	0,011111111	10
Target	01/05/2026	10	10



External Corrosion

	Time	DF	DF target
Last insp. date	15/11/2018	0	10
RBI date	20/08/2019	0,861920044	10
Plan date	11/11/2022	0,861879331	10

DF Target $= (\text{DF RBI Date}) \cdot (\text{Time Plan Date - RBI Date})^{n-1}$

$10 = (0{,}861920044) \cdot (3{,}23)^{n-1}$

$11{,}602 = (3{,}23)^{n-1}$

Interpolation

X_1	3	Y_1	10,42
X	x	Y	11,60200
X_2	4	Y_2	33,63

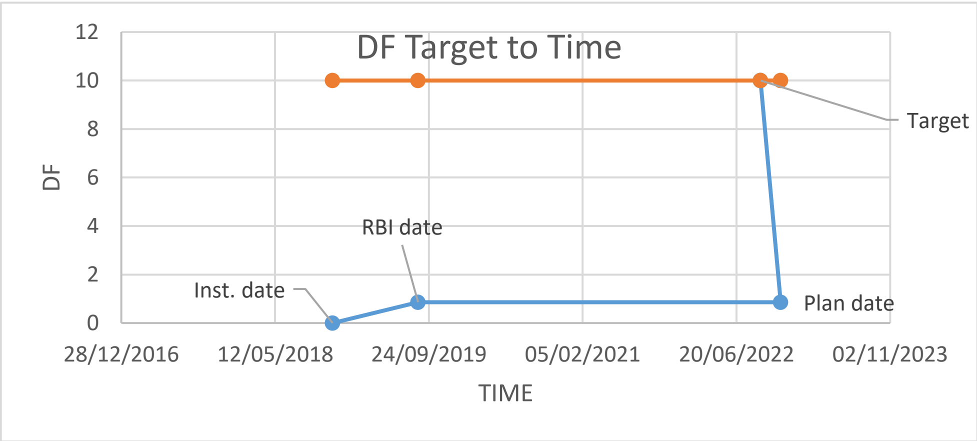
$$X = X_1 + \left(\frac{Y - Y_1}{Y_2 - Y_1}\right)(X_2 - X_1)$$

$$X = 3 + \left(\frac{11{,}60200 - 10{,}42}{33{,}63 - 10{,}42}\right)(2 - 1)$$

$= 3{,}050939219$ Year

So, time to risk target is on 06/09/2022

	Time	DF	DF target
Last insp. date	15/11/2018	0	10
RBI date	20/08/2019	0,861920044	10
Plan date	11/11/2022	0,861879331	10
Target	06/09/2022	10	10



	INSPECTION PROGRAM PLANNING OF PROCESS GAS PIPING USING RISK BASED INSPECTION API 581 IN MUARA KARANG PEAKER GAS METER

ATTACHMENT 3 :

GENERAL SPECIFICATION PROCESS GAS PIPING

2" - PG - 06255 - C

Rev	Tanggal	Keterangan	Disusun Oleh:		Disetujui Oleh:	
			Nama	Paraf	Pembimbing	Paraf
			Ade Ratih Anggraini		Ir. Dwi Priyanta, M.SE	
			No. Registration :		Nurhadi Siswantoro,ST.,MT.	
			04211641000008			

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1 GENERAL SPECIFICATION OF PRESSURE VESSEL

Tag Number		:	306 - JY - 09	
Quantity		:	1	
Service		:	Process Gas piping	
Serial No.		:	2" - PG - 06255 - C	
Code		:	ASME B.31.3	
Design Pressure	(P)	:	95	barg
		:	1363,35	psig
		:	9,4	MPa
Design Temperature	(T)	:	65	°C
		:	149	°F
Outer Diameter	(OD)	:	60,3	mm
		:	2	inch
Operating Pressure		:	46	barg
		:	667,174	psig
Operating Temperature		:	18,83	°C
		:	65,894	°F
Flow Rate		:	135	mmscfd
Efficiency	(Ef)	:	1	
Corrosion Allowance	(CA)	:	1,6	mm
		:	0,062992	inch
Thickness	(t)	:	5,54	mm
		:	0,2	inch
Corrosion Rate	(CR)	:	0,125	mm/years
		:	0,0049	inch/years
Allowable Stress	(S)	:	23300	psig
		:	1606,479	bar
		:	160,6479	Mpa
Year Built		:	2017	
Material		:	A 106 GR, SMLS, SCH 80	
Last Inspection		:	-	

TABLE OF CONVERSION

1	$inch^2$	=	0,00065	m^2
1	m2	=	6,29	BBLS
1	psi	=	6,895	Kpa
1	lb/ft^3	=	16,018	kg/m^3

THICKNESS AND MAWP CALCULATION

t req $= \dfrac{P\ X\ (\frac{OD}{2})}{((S\ X\ E) + (0.4P))}$

$= \dfrac{1363{,}35\ X\ (\frac{60{,}3}{2})}{((23300\ X\ 1) + (0.4\ X 1363{,}35))}$

$= \dfrac{1363{,}35\ X\ 30{,}15}{(23300) + 545{,}34}$

$= \dfrac{41105{,}0025}{23845{,}34}$

= 1,72382 mm (ACCEPTED)
(t > t req)

MAWP $= \dfrac{(S\ X\ E)(t - (2\ x\ 3\ x\ CR))}{((\frac{OD}{2}) - (0.4\ X\ (t - (2\ X\ 3\ X\ CR)))}$

$= \dfrac{(23300\ X\ 1)(5{,}54) - (6x\ 0.125))}{((\frac{60{,}3}{2}) - (0.4\ X\ (5{,}54 - (6X\ 0.125)))}$

$= \dfrac{23300\ X\ 4{,}79}{30{,}15 - 1{,}916}$

$= \dfrac{``111607}{28{,}234}$

= 3952,93 psig (ACCEPTED)
(MAWP > P)

	INSPECTION PROGRAM PLANNING OF PROCESS GAS PIPING USING RISK BASED INSPECTION API 581 IN MUARA KARANG PEAKER GAS METER

ATTACHMENT 3A :

DAMAGE FACTOR SCREENING QUESTION PROCESS GAS PIPING

2" - PG - 06255 - C

Rev	Tanggal	Keterangan	Disusun Oleh:		Disetujui Oleh:	
			Nama	Paraf	Pembimbing	Paraf
			Ade Ratih Anggraini		Ir. Dwi Priyanta, M.SE	
			No. Registration :		Nurhadi Siswantoro,ST.,MT.	
			04211641000008			

DAMAGE FACTOR SCREENING QUESTION

DETERMINATION OF PROBABILITY OF FAILURE

API 581 PART 2

I. DAMAGE FACTOR

Damage Factor(s) provides a screening tool to determine inspection priorities and optimize inspection. The basic function of the DF is to statistically evaluate the amount of damage that may be present as a function of time in service and the effectiveness of an inspection activity. DFs are calculated based on the 3 different techniques as mentioned below, but are not intended to reflect the actual POF for the purposes of reliability analysis. DFs reflect a relative level of concern about the component based on the stated assumptions in each of the applicable sectiion of the document.

a. Structural reliability modes

b. Statistical models based on generic data

c. Expert judgement

Table of Damage Factor Screening Questions

No	Damage Factor	Screening Criteria	Yes/No
1.	Thining	All component should be checked for thining	Yes
2.	Component Lining	If the component has organic or inorganic lining, then the component should be evaluated for lining damage	No
3.	SCC Damage Factor-Caustic Cracking	If the component's material of construction is carbon or low alloy steel and the process environment contains caustic in any concentration, then the component should be evaluated for susceptibility to caustic cracking.	No
4.	SCC Damage Factor-Amine Cracking	If the component's material of construction is carbon or low alloy steel and process environment contains acid gas treating amines (MEA, DEA, DIPA, MDEA, etc.) in any concentration, then the component should be evaluated for susceptibility to amine cracking.	No
5.	SCC Damage Factor-Sulfide Stress Cracking	If the component's material of construction contains is carbon or low alloy steel and the process environment contains water and H_2S in any concentration, then the component should be evaluated to Sulfide Ctress Cracking (SCC). Concentration of H_2S is 0.00 mg/L	No

No	Damage Factor	Screening Criteria		Yes/No
6.	SCC Damage Factor HIC/SOHIC-H_2S	If the component's material of construction contains is carbon or low alloy steel and the process environment contains water and H_2S in any concentration, then the component should be evaluated to HIC/SOHIC-H_2S cracking.		No
7.	SCC Damage Factor-Alkaline Carbonate Stress Corrosion Cracking	If the component's material of construction is carbon or low alloy steel and the process environment contains alkaline water at pH>7.5 in any concentration, the the component should be evaluated to ACSCC.		No
		Another trigger would be changes in FCCU feed sulfurr and nitrogen contents particularly when feed changes have reduced sulfur (low sulfur feeds or hydroprocessed feeds) or increased nitrogen.		
8.	SCC Damage Factor-Polythionic Acid Stress Corrosion Cracking	If the component's material of construction is an austenitic stainless steel or nickel based alloys and the components is wxposed to sulfur bearing compunds, then the component should be evaluated for susceptibility to PASCC		No
9.	SCC Damage Factor-Chloride Stress Corrosion Cracking	If **<u>ALL</u>** of the following are true, then the component should evaluated for suscepibility to CLSCC cracking:		No
		a.	The component's material of construction is an austenitic stainless steel.	
		b.	The component is exposed or potentially exposed to chlorides and water also considering upsets and hydrotest water remaining in component, and cooling tower drift (consider both under insulation and process conditions).	
		c.	The operating temperature is above 38^{o} (100^{o}F)	
		Chlorine concentration 4.14% mg/L		
10.	SCC Damage Factor-Hydrogen Stress Cracking-HF	If the component's material of construction is ccarbon or low alloy steel and the component is exposed too hydrofluoric acid in any concentration, then the component should be evaluated for susceptibility to HSC-HF.		No

<table>
<tr><th>No</th><th>Damage Factor</th><th colspan="3">Screening Criteria</th><th>Yes/No</th></tr>
<tr><td>11.</td><td>SCC Damage Factor HIC/SOHIC-HF</td><td colspan="3">If the component's material of construction is ccarbon or low alloy steel and the component is exposed too hydrofluoric acid in any concentration, then the component should be evaluated for susceptibility to HIC/SOHIC-HF.</td><td>No</td></tr>
<tr><td rowspan="12">12.</td><td rowspan="12">External Corrosion Damage Factor</td><td colspan="3">If the component is un-insulated and subject to any of the following , then the component should be evaluated for external damage from corrosion.</td><td rowspan="12">Yes</td></tr>
<tr><td>a.</td><td>Areas exposed to mist overspray from cooling towers.</td><td>N</td></tr>
<tr><td>b.</td><td>Areas exposed to steam vents</td><td>N</td></tr>
<tr><td>c.</td><td>Areas exposed to deluge system</td><td>N</td></tr>
<tr><td>d.</td><td>Areas subject to process spills, ingress of moisture, or acid vapors.</td><td>N</td></tr>
<tr><td rowspan="2">e.</td><td>Carbon steel system, operatinng between -12^{o}C and 177^{o}C (10^{o}F and 350^{o}F). External corrosion is particulartly aggressive where operating temperatures cause frequent or continuous condensation and re-evaporation of atmospheric moisture.</td><td rowspan="2">N</td></tr>
<tr><td>Operating temperature 100^{o}C (212^{o}F)</td></tr>
<tr><td>f.</td><td>Systems that do not operating in normally temperature between -12^{o} and 177^{o}C (10^{o}F and 350^{o}F) but cool or heat into this range intermitterntly or are subjected to frequent outages.</td><td>Y</td></tr>
<tr><td>g.</td><td>Systems with deteoriated coating and/or wrappings</td><td>N</td></tr>
<tr><td>h.</td><td>Cold service equipment consistently operating below the atmospheric dew point.</td><td>N</td></tr>
<tr><td>i.</td><td>Un-insulated nozzles or other prostrusions components of insulated equipment in cold service conditions.</td><td>N</td></tr>
</table>

<table>
<tr><th>No</th><th>Damage Factor</th><th colspan="3">Screening Criteria</th><th>Yes/No</th></tr>
<tr><td>13.</td><td>Corrosion Under Insulation Damage Factor-Ferritic Commponent</td><td colspan="3">The criteria can be seen at the API 581 Part 2 of POF Section 16.3</td><td>No</td></tr>
<tr><td rowspan="4">14.</td><td rowspan="4">External Chloride Stress Corrosion Cracking Damage Factor-Austenitic Component</td><td colspan="3">If <u>ALL</u> of the following are true, then the component should evaluated for suscepibility to CLSCC:</td><td rowspan="4">No</td></tr>
<tr><td>a.</td><td>The component's material of construction is an austenitic stainless steel.</td><td>N</td></tr>
<tr><td>b.</td><td>The component external surface is exposed to chloride containing fluids, mists, or solids.</td><td>N</td></tr>
<tr><td>c.</td><td>The operating temperature is between 50°C and 150°C (120°F and 300°F) , or the system heats or cools into this range intermittently.</td><td>N</td></tr>
<tr><td rowspan="5">15.</td><td rowspan="5">External Chloride Stress Corrosion Cracking Under Insulation Damage Factor-Austenitic Component</td><td colspan="3">If <u>ALL</u> of the following are true, then the component should be evaluated for susceptibiity to CUI CLSCC:</td><td rowspan="5">No</td></tr>
<tr><td>a.</td><td>The component's material of construction is an austenitic stainless steel.</td><td>N</td></tr>
<tr><td>b.</td><td>The component is insulated</td><td>N</td></tr>
<tr><td>c.</td><td>The component external surface is exposed to chloride containing fluids, mists, or solids.</td><td>N</td></tr>
<tr><td>d.</td><td>The operating temperature is between 50°C and 150°C (120°F and 300°F) , or the system heats or cools into this range intermittently.</td><td>N</td></tr>
<tr><td rowspan="3">16</td><td rowspan="3">Low Alloy Steel Embrittlement Damage Factor</td><td colspan="3">If <u>ALL</u> of the following are true, then the component should be evaluated for susceptibiity to low alloy steel embrittlement:</td><td rowspan="3">No</td></tr>
<tr><td>a.</td><td>The material is 1Cr--0.5Mo, 1.25Cr-0.5Mo, or 3Cr-1Mo low alloy steel.</td><td>N</td></tr>
<tr><td>b.</td><td>The operating temperature is between 343°C and 577°C (650°F and 1070°F).</td><td>N</td></tr>
</table>

<table>
<tr><th>No</th><th>Damage Factor</th><th colspan="3">Screening Criteria</th><th>Yes/No</th></tr>
<tr><td rowspan="6">17</td><td rowspan="6">High Temperature Hydrogen Attack Damage Factor</td><td colspan="3">If <u>ALL</u> of the following are true, then the component should be evaluated for susceptibiity to HTHA:</td><td rowspan="6">No</td></tr>
<tr><td>a.</td><td>The material is carbon steel, C-$^1/_2$Mo, or a CrMo low alloy steel (such as $^1/_2$Cr-$^1/_2$Mo, 1Cr-$^1/_2$Mo, 1$^1/_4$Cr-^{1}/2Mo, 2$^1/_4$Cr-1Mo, 3Cr-1Mo, 5Cr-1Mo, 7Cr-1Mo, 9Cr-1Mo).</td><td>Y</td></tr>
<tr><td rowspan="2">b.</td><td>The operating temperature is greater than 177^{o}C (350^{o}F).</td><td rowspan="2">N</td></tr>
<tr><td>Operating temperature 100^{o}C (212^{o}F)</td></tr>
<tr><td rowspan="2">c.</td><td>The operating hydrogen partial presssure is greater than 0.345 Mpa (50 psia).</td><td rowspan="2">N</td></tr>
<tr><td>There is no hydrogen content</td></tr>
<tr><td rowspan="3">18</td><td rowspan="3">Brittle Fracture Damage Factor</td><td colspan="3">If <u>BOTH</u> of the following are true, then the component should be evaluated for susceptibiity to brittle fracture:</td><td rowspan="3"></td></tr>
<tr><td>a.</td><td>The material is carbon steel or low alloy steel (see Table 20.1).</td><td>Y</td></tr>
<tr><td>b.</td><td>If Minimum Design Metal Temperature (MDMT), T_{MDMT}, or Minimum Allowable Metal Temperature (MAT), T_{MAT}, is unknown, or the component is known to operate at below MDMT or MAT under normal or upset conditions.</td><td></td></tr>
<tr><td rowspan="3">19.</td><td rowspan="3">885^{o}F Embrittlement Damage Factor</td><td colspan="3">If <u>BOTH</u> of the following are true, then the component should be evaluated for susceptibiity to 885^{o}F embrittlemet:</td><td rowspan="3">No</td></tr>
<tr><td>a.</td><td>The material is high chromium (>12% Cr) ferritic steel</td><td>N</td></tr>
<tr><td>b.</td><td>The operating temperature is between 371^{o}C and 566^{o}C (700^{o}F and 1050^{o}F).</td><td>N</td></tr>
<tr><td></td><td></td><td colspan="3">If <u>BOTH</u> of the following are true, then the component should be evaluated for susceptibiity to sigma phase embrittlemet:</td><td></td></tr>
</table>

No	Damage Factor	Screening Criteria			Yes/No
20	Sigma Phase Embrittlement Damage Factor	a.	The component's material of construction is an austenitic stainless steel.	N	No
		b.	The operating temperature is between 593°C and 927°C (1100°F and 1700°F).	N	
21.	Piping Mechanical Fatigue Damage Factor	If **BOTH** of the following are true, then the component should be evaluated for susceptibiity to mechanical fatigue:			Yes
		a.	The component is pipe	Y	
		b.	There have been past fatigue failure in this piping system or there is visible/audibble shaking in this piping system or there is a source of cyclic vibration within approximately 15.24 meters (50 feet) and connected to the piping (directly or indirectly via structure). Shaking and source of shaking can be continuous or intermittent.Transient conditions often cause intermittent virbration.	Y	

	INSPECTION PROGRAM PLANNING OF PROCESS GAS PIPING USING RISK BASED INSPECTION API 581 IN MUARA KARANG PEAKER GAS METER

ATTACHMENT 3B :

PROBABILITY OF FAILURE (POF) CALCULATION OF RISK BASED INSPECTION API 581

2" - PG - 06255 - C

Rev	Tanggal	Keterangan	Disusun Oleh:		Disetujui Oleh:	
			Nama	Paraf	Pembimbing	Paraf
			Ade Ratih Anggraini		Ir. Dwi Priyanta, M.SE	
			No. Registration :		Nurhadi Siswantoro,ST.,MT.	
			04211641000008			

THINNING DAMAGE FACTOR CALCULATION

1. RLA DATA

REQUIRED DATA

The basic component data required for analysis is given in Table 4.1. Component types and geometry data are shown in Tables 4.2 and 4.3, respectively. The data required for determination of the thinning DF is provided in Table 4.4.

Table 4.1. Basic Component Data Required for Analysis

Basic Data	Value	Unit	Comments
Start Date	16/03/2020		The date the component was placed in service.
Thickness	5,54	mm	The thickness used for DF calculation that is either the furnished thickness or the measured thickness.
Corrosion Allowance	1,60	mm	The corrosion allowance is the specified design or actual corrosion allowance upon being placed in the current servicce.
Design Tempearture	65	^{o}C	The design temperature for process gas piping
Design Pressure	9399,97	Kpa	The design pressure for process gas piping
Operating Tempearture	18,83	^{o}C	The highest expected operating temperature expected during operation including normal and unusual operating conditions process gas piping
Operating Pressure	4500	Kpa	The highest expected operating pressure expected during operation including normal and unusual operating conditions.
Design Code	ASME B.31.3		The designing of the component containing the component.
Equipment Type	Piping		The type of equipment.
Component Type	Pipe		The type of component.
Material Specification	A106 Gr.B		The specification of the material of construction, the ASTM A106 Grade B, specification for piping components. Data entry is based on the material specification, grade, year, UNS Number, class/condition/temper/size/thickness; this data is readdily available in the ASTM Code.
Yield Strength	241000	Kpa	The design yield strength of the material based on material specification.
Tensile Strength	414000	Kpa	The design tensile strength of the material based on material specification.

Weld Joint Efficiency	1		Weld joint efficiency per the Code of construction.
Heat Tracing	No		Is the component heat traced? (Yes or No)

STEP 1 Determining the furnished thickness, t, and age for the component from the installation date.

t	=	0,2181	inch
	=	5,54	mm (Assumed on 16 March 2020)
age	=	0	years

STEP 2 Determining the corrosion rate for base material, $C_{r,bm}$ based on the material construction and environment, and cladding/weld overlay corrosion rate, $C_{r,cm}$.

Based on the explanation from Section 4.5.2 that the corrosion rate is **CALCULATED** using the approach of Annex 2B. Then, first of all, the corrosion screening question must be done as follows:

Table 2.B.1.1-Screening Questions for Corrosion Rate Calculations

No.	Type of Corrosion	Screening Question		Yes/No	Action
1.	Hydrochloric Acid (HCl) Corrosion	1.	Does the process contain HCl?	N	No
		2.	Is free water present in the process stream (including initial condensing condition)?	Y	
		3.	Is the pH < 7.0?	Y	
2.	High Temperature Sulfidic/Naphtenic Acid Corrosion	1.	Does the process contain oil with sulfur compounds?	N	No
		2.	Is the operating temperature > 204°C (400°F)? The operating temperature is 18,3°C.	N	
3.	Sulfuric Acid Corrosion	1.	Does the process contain H_2SO_4	N	No
4.	High Temperature H_2S/H_2 Corrosion	1.	Does the process contain H_2 and Hydrogen?	N	No
		2.	Is the operating temperature > 204°C (400°F)? The operating temperature is 18,3°C.	N	
5.	Hydrifluoric Corrosion	1.	Does the process contain HF?	N	No
6.	Sour Water Corrsion	1.	Is free water with H_2S present?	N	No

7.	Amine Corrosion	1.	Is equipment exposed to acid gas treaating amines (MEA, DEA, DIPA, or MDEA)?	N	No
8.	High Temperature Oxidation Corrosion	1.	Is the temperature ≥ 482°C (900°F)?	N	No
			The operating temperature is 18,3°C.		
		2.	Is the oxygen present?	N	
9.	Acid Sour Water Corrosion	1.	Is free water with H_2S present and pH < 7.0?	Y	No
		2.	Does the proocess contain < 50 ppm chlorides?	N	
10.	Cooling Water	1.	Is equipment in cooling water service?	N	No
11.	Soil Side Corrosion	1.	Is equipment in contact with soil (buried or partially buried)?	N	No
		2.	Is the material of construction carbon steel?	Y	
12.	CO_2 Corrosion	1.	Is the free water with CO_2 present (including consideration for dew point	Y	Yes
		2.	Is the material of construction carbon steel or < 13% Cr?	Y	
			Carboon Steel		
13.	AST Bottom	1.	Is the equipment item an AST tank bottom?	N	No

1. Corrosion Rate (Cr) from the RLA data

   Cr = 0,004921 inch/year

   = 0,125 mm/year

2.a. Corrosion Rate (Cr) based on the Annex 2B CO_2 Corrosion Calculation

$$CR = CR_B . \min[F_{glycol}, F_{inhib}] \qquad \text{(Equation 1)}$$

<u>Base Corrosion Rate</u>

$$CR_B = f(T,pH) . f_{CO2}^{0.62} . \left(\frac{S}{19}\right)^{0.146+0.0324\, fco2} \qquad \text{(Equation 2)}$$

Where ;

CR_B	=	Base corrosion rate (mm/y)
f(T,pH)	=	Temperature-pH function tabulated in Table 2.B.13.2
f_{CO2}	=	CO_2 fugacity
S	=	Shear stress yo calculate the flow velocity (Pa)

a. Determine the calculated pH

$pH = 2{,}8686 + 0{,}7931.log_{10}[T] - 0{,}57.log_{10}[p_{CO2}]$.......... (Equation 3)

T = 18,83 °C

= 65,894 °F

= 291,83 K

mole% of CO2 in gas = 3,1497 %

P_{CO2} = 141,74 kPa

= 20,557 psi

= 1,4174 bar

$pH = 2{,}8686 + 0{,}7931.log_{10}[T] - 0{,}57.log_{10}[p_{CO2}]$

= 2,8686 + 0,7931. $\log_{10}$ [65,89 F] - 0,57. $\log_{10}$ [20,56 psi]

= 3,56273791

b. Determine the CO_2 fugacity

$log_{10}\,[f_{CO2}] = log_{10}[p_{CO2}] + \min[250, p_{CO2}].(0.0031 - \frac{1.4}{T+273})$ (Equation 4)

$log_{10}\,[f_{CO2}] = log_{10}[20{,}56] + \min[250, 20{,}56].(0.0031 - \frac{1.4}{18{,}3+273})$

= 0,05

c. Determine the flow velocity

To determine the flow velocity, the API 581 reffers to the NORSOK M-506. and both of the Recommended Practice use the fluid flow shear stress, S, to model the effect of flow velocity n the base corrosion rate.

$S = \frac{f.\rho m.um^2}{2}$ .... (Equation 5)

In the calculation for the corrosion rate, the shear stress need not exceed 150 Pa.

Where;

f = Friction factor

ρ_m = Mixture mass density kg/m^3

= 0,668 kg/m^3

u_m = Mixture flow velocity m/s

= 1,8 m/s

$f = 0.001375\,[\,1 + (20000(\frac{e}{D}) + (\frac{10^6}{Re})^{0.33}]$......................... (Equation 6)

$\frac{\varepsilon}{D}$ = Relative roughness of the material

0,035

Based on the Table below that for the Carbon Steel (A106 Gr.B) material of construction which is assumed as new carbonsteel is approximately ranging from 0.02 - 0.05.

Material	Absolute Roughness (mm)
Copper, Lead, Brass, Aluminum (new)	0.001 - 0.002
PVC and Plastic Pipes	0.0015 - 0.007
Flexible Rubber Tubing - Smooth	0.006-0.07
Stainless Steel	0.0015
Steel Commercial Pipe	0.045 - 0.09
Weld Steel	0.045
Carbon Steel (New)	0.02-0.05
Carbon Steel (Slightly Corroded)	0.05-0.15
Carbon Steel (Moderately Corroded)	0.15-1
Carbon Steel (Badly Corroded)	1-3
Asphalted Cast Iron	0.1-1
New Cast Iron	0.25 - 0.8
Worn Cast Iron	0.8 - 1.5
Rusty Cast Iron	1.5 - 2.5
Galvanized Iron	0.025-0.15
Wood Stave	0.18-0.91
Wood Stave, used	0.25-1
Smoothed Cement	0.3
Ordinary Concrete	0.3 - 1
Concrete – Rough, Form Marks	0.8-3

Source by: https://www.nuclear-power.net/nuclear-engineering/fluid-dynamics/major-head-loss-friction-loss/relative-roughness-of-pipe/

$$Re = \frac{D.\rho m.um}{\mu m}$$ .... (Equation 7)

Re = Reynolds number

D = Diameter

= 323,8 mm

= 0,3238 m

µm = Viscosity of the mixture cp

= 0,35 Cp

= 0,0004 Pa s

$$Re = \frac{D.\rho m.um}{\mu m}$$

= 1112,3918

$$f = 0.001375 \, [\, 1+ (20000(\tfrac{e}{D}) + (\tfrac{10^6}{Re})^{0.33}]$$

$$= 0.001375 \, [\, 1+ (20000(\, 0{,}035) + (\tfrac{10^6}{1112{,}392})^{0.33}]$$

= 0,013

After the value of relative roughness, Reynolds number, and the friction factor have been determines. Then, the value of the flow velocity can be calculated.

$$S = \frac{f.\rho m.um^2}{2}$$

= 0,0143954 Pa

Those calculated pH, CO_2 fugacity, and also flow velocity have been known. So, the value of Base Corrosion Rate (Cr_{base}) can be determined.

$$CR_B = f(T,pH) \cdot f_{CO2}^{\ 0.62} \cdot \left(\frac{S}{19}\right)^{0.146+0.0324\, fco2}$$

Where;

f(T,pH) = Temperature-pH function tabulated in Table 2.B.13.2
= 5,45

Cr_{base} = $5,45 \times (0,05)^{0,62} \times (0,014395/19)^{0,146+(0,0324 \times 0,05)}$
= 0,3137906 mpy
= 0,0079703 mm/y

Because there is no any mixture for glycol and the other inhibitors inside the piping, then, Cr is equal to Cr_{base}. The glycol or inhibitor is placed in another equipment not being process in the Piping itself.

Where;

CR = $CR_B . \min[F_{glycol}, F_{inhib}]$

<u>CR</u> = Cr_{base}
= 0,0079703 mm/y

<u>Calculated corrosion rate =</u> 0,00797 mm/year

STEP 3 Determine the time in service, age_{tk}, since the last known inspection, t_{rdi}.

- t_{rdi} = 0,2181 inch Last inspection is on: 15/11/2018
  = 5,54 mm RBI Date is on: 20/08/2019
- t_{pd} = 0,2171 inch Planned Date is on: 11/11/2022
  5,51 mm

age_{tk} = 0,761 years (Construction was on November 2018)

age_{PD} = 3,23 years

STEP 4 For cladding/weld overlay piping components, calculate the age from the date starting thickness from STEP 3 required to corrode away the cladding/weld overlay material, age_{rc}, using equation below:

$$age_{rc} = \max\left[\left(\frac{t_{rdi}-tbm}{C_{r\,cm}}\right), 0.0\right] \quad \text{..} \quad \text{(Equation 8)}$$

Because the piping is not cladding/weld overlay. Then, the equation above does not need to be considered.

STEP 5 Determine the t_{min}

Actually there are 4 methods used to determine the minimum thickness of the equipment (t_{min}). Based on the condition, the method used by the author is the first method which is for cylindrical, spherical, or head components, determine the allowable Stress, S, weld joint efficiency, E, and the minimum thickness, t_{min}.

$$t_m = t + c \quad \text{(Equation 9)}$$

$$t = \frac{PD}{2(SE + PY)}$$

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Where,

tm : Minimum required thickness, including mechanical, corrosion, and erosion allowances (mm)

t : Pressure design thickness

c : The sum of mechanical allowance (groove depth and threading) plus allowance for corrosion and erosion (mm)

E : Joint efficiency

P : Design pressure (MPa)

D : Outside diameter of pipe (mm)

S : Allowable stresses for pipe material (Mpa)

Y : Temperature factor, per Table 304.1.1 in ASME B31.3 (Normally 0,4)

Table S301.3.1 Generic Pipe Stress Model Input

Term	Value
Operating conditions:	
internal pressure, P_1	3 450 kPa (500 psi)
maximum metal temp., T_1	260°C (500°F)
minimum metal temp., T_2	−1°C (30°F)
installation temperature	21°C (70°F)
Line size	DN 400 (NPS 16)
Pipe	Schedule 30/STD, 9.53 mm (0.375 in.)
Mechanical allowance, c	1.59 mm (0.063 in.)
Mill tolerance	12.5%
Elbows	Long radius
Fluid specific gravity	1.0
Insulation thickness	127 mm (5 in.)
Insulation density	176 kg/m^3 (11.0 lbm/ft^3)
Pipe material	ASTM A106 Grade B
Pipe density	7 833.4 kg/m^3 (0.283 lbm/in.^{3})
Total weight	7 439 kg (16,400 lbm)
Unit weight	248.3 kg/m (166.9 lbm/ft)

Source : ASME B31.3, Table S301.3.1 Generic Pipe Stress Model Input, Edition 2016

Table 304.1.1 Values of Coefficient Y for $t < D/6$

Material	Temperature, °C (°F)					
	482 (900) and Below	510 (950)	538 (1,000)	566 (1,050)	593 (1,100)	621 (1,150)
Ferritic steels	0.4	0.5	0.7	0.7	0.7	0.7
Austenitic steels	0.4	0.4	0.4	0.4	0.5	0.7
Nickel alloys UNS Nos. N06617, N08800, N08810, and N08825	0.4	0.4	0.4	0.4	0.4	0.4
Gray iron	0.0	...	...	...	...	...
Other ductile metals	0.4	0.4	0.4	0.4	0.4	0.4

Source : ASME B31.3, Table 304.1.1 Value of Coeeficient Y, Edition 2016

$$t = \frac{PD}{2(SE + PY)}$$

$$t = \frac{(9{,}4\ MPa)\ x\ (60{,}3\ mm)}{2((160{,}648\ MPa\ x\ 1) + (9{,}4\ MPa\ x\ 0{,}4))}$$

= 1,7438 mm

$$t_m = t + c$$

= 1,748 mm + 1,59 mm

= 3,33 mm

= 0,13125 inch

STEP 6 Determine the A_{rt} Parameter

For component without clading/weld overlay then use the equation following.

$$A_{rt} = \frac{Cr_{b,m}.age_{tk}}{t_{rdi}} \quad \text{(Equation 10)}$$

Where,

$Cr_{b.m}$: Corrosion base material

age_{tk} : Component in-service time since the last inspection

t_{rdi} : Furnished thickness since last inspection

A_{rt} on RBI Date:

$$A_{rt} = \frac{Cr_{b,m}.age_{tk}}{t_{rdi}} = \frac{0{,}00797\left(\frac{mm}{year}\right).0{,}761year}{5{,}54\ mm}$$

= 0,001095 **(Annex 2B)**

$$A_{rt} = \frac{Cr.age_{tk}}{t_{rdi}} = \frac{0{,}125\left(\frac{mm}{year}\right).0{,}761year}{5{,}54\ mm}$$

= 0,0171733 **(RLA data)**

A_{rt} on Plan Date:

$$A_{rt} = \frac{Cr_{b,m}.age_{pd}}{t_{pd}} = \frac{0{,}00797\left(\frac{mm}{year}\right).3{,}23year}{5{,}51\ mm}$$

= 0,004666 **(Annex 2B)**

$$A_{rt} = \frac{Cr\ .age_{pd}}{t_{pd}} = \frac{0{,}125\left(\frac{mm}{year}\right).3{,}23year}{5{,}51\ mm}$$

= 0,0731721 **(RLA data)**

STEP 7 Calculate the Flow Stress, FS^{Thin} , using E from STEP 5 and equation below.

$$FS^{Thin} = \frac{(YS+TS)}{2}.\ E.1{,}1 \quad \text{(Equation 11)}$$

Where;

YS = 241000 KPa

TS = 414000 KPa

E = 1

Source : ASME B31.3 - Table A -1M Basic Allowable Stresses in Tension for Metal Page 220. Edition 2016

$$FS^{Thin} = \frac{(241000+414000)}{2}.\ E.1{,}1$$

= 360250

STEP 8 Calculate the strength ratio parameter, SR_P^{Thin}, using the appropriate equation.

$$SR_P^{Thin} = \frac{S.E}{FS^{Thin}} \cdot \frac{Max\ (t_{min},t_c)}{t_{rdi}} \quad \text{(Equation 12)}$$

Where;

t_c = is the minimum structural thickness of the component base material

= 0,1312505 inch

= 3,3338 mm

$$SR_P^{Thin} = \frac{160648\ x\ 1}{360250} \cdot \frac{Max\ (10{,}9537\ ;10{,}9537)}{10{,}9537}$$

= 0,26834649

STEP 9 Determine the number of inspections for each of the correspondesing inspection effectiveness, $N_A^{Thin}, N_B^{Thin}, N_C^{Thin}, N_D^{Thin}$, using Section 4.5.6 of the API RP 581 Part 2 for past inspections performed during in-service time.

N_A^{Thin} = 0

N_B^{Thin} = 0

N_C^{Thin} = 0

N_D^{Thin} = 0

STEP 10 Calculate the inspection effectiveness factors, $I_1^{Thin}, I_2^{Thin}, I_3^{Thin}$,using equation below, prior probabilities, $Pr_{p1}^{Thin}, Pr_{p2}^{Thin}, Pr_{p3}^{Thin}$ from Table 4.5. The Conditional Probabilities (for each inspection effectiveness level), $Co_{p1}^{Thin}, Co_{p2}^{Thin}$ Co_{p3}^{Thin} from Table 4.6, and the number of inspection, $N_A^{Thin}, N_B^{Thin}, N_C^{Thin}, N_D^{Thin}$ in each effectiveness level from STEP 9.

$$I_1^{Thin} = Pr_{P1}^{Thin}(Co_{P1}^{ThinA})^{N_A^{Thin}}(Co_{P1}^{ThinB})^{N_B^{Thin}}(Co_{P1}^{ThinC})^{N_C^{Thin}}(Co_{P1}^{ThinD})^{N_D^{Thin}}$$

$$I_2^{Thin} = Pr_{P2}^{Thin}(Co_{P2}^{ThinA})^{N_A^{Thin}}(Co_{P2}^{ThinB})^{N_B^{Thin}}(Co_{P2}^{ThinC})^{N_C^{Thin}}(Co_{P2}^{ThinD})^{N_D^{Thin}}$$

$$I_3^{Thin} = Pr_{P3}^{Thin}(Co_{P3}^{ThinA})^{N_A^{Thin}}(Co_{P3}^{ThinB})^{N_B^{Thin}}(Co_{P3}^{ThinC})^{N_C^{Thin}}(Co_{P3}^{ThinD})^{N_D^{Thin}}$$

(Equation 13)

Table 4.5 - Prior Probability for Thinning Corrosion Rate

Damage State	Low Confidence Data	Medium Confidence	High Conf. Data
Pr_{P1}^{Thin}	0,5	0,7	0,8
Pr_{P2}^{Thin}	0,3	0,2	0,15
Pr_{P3}^{Thin}	0,2	0,1	0,05

Table 4.6 - Conditional Probability for Inspection Effectiveness

Conditional of Inspection	E-None or Ineffective	D-Poorly Effective	C-Fairly Effective	B Usually Effective	A-Highly Effective
Co_{P1}^{Thin}	0,33	0,4	0,5	0,7	0,9
Co_{P2}^{Thin}	0,33	0,33	0,3	0,2	0,09
Co_{P3}^{Thin}	0,33	0,27	0,2	0,1	0,01

$$I_1^{Thin} = Pr_{P1}^{Thin}(Co_{P1}^{ThinA})^{N_A^{Thin}}(Co_{P1}^{ThinB})^{N_B^{Thin}}(Co_{P1}^{ThinC})^{N_C^{Thin}}(Co_{P1}^{ThinD})^{N_D^{Thin}}$$

= 0,5 $(0,4)^0$ x $(0,4)^0$ x $(0,4)^0$ x $(0,4)^0$

= 0,5

$$I_2^{Thin} = Pr_{P2}^{Thin}(Co_{P2}^{ThinA})^{N_A^{Thin}}(Co_{P2}^{ThinB})^{N_B^{Thin}}(Co_{P2}^{ThinC})^{N_C^{Thin}}(Co_{P2}^{ThinD})^{N_D^{Thin}}$$

= 0,3 $(0,33)^0$ x $(0,33)^0$ x $(0,33)^0$ x $(0,33)^0$

= 0,3

$$I_3^{Thin} = Pr_{P3}^{Thin}(Co_{P3}^{ThinA})^{N_A^{Thin}}(Co_{P3}^{ThinB})^{N_B^{Thin}}(Co_{P3}^{ThinC})^{N_C^{Thin}}(Co_{P3}^{ThinD})^{N_D^{Thin}}$$

= 0,2 $(0,33)^0$ x $(0,33)^0$ x $(0,33)^0$ x $(0,33)^0$

= 0,20

STEP 11 Calculate the Posteroir Probability, $Po_{p1}^{Thin}, Po_{p2}^{Thin}, Po_{p3}^{Thin}$, using equations:

$$Po_{p1}^{Thin} = \frac{I_1^{Thin}}{I_1^{Thin} + I_2^{Thin} + I_3^{Thin}} \quad \text{.. (Equation 14)}$$

$$= \frac{0,5}{0,5 + 0,3 + 0,2}$$

= 0,5

$$Po_{p2}^{Thin} = \frac{I_2^{Thin}}{I_1^{Thin} + I_2^{Thin} + I_3^{Thin}}$$

$$= \frac{0,3}{0,5 + 0,3 + 0,2}$$

= 0,3

$$Po_{p3}^{Thin} = \frac{I_3^{Thin}}{I_1^{Thin} + I_2^{Thin} + I_3^{Thin}}$$

$$= \frac{0,2}{0,5 + 0,3 + 0,2}$$

= 0,2

STEP 12 Calculate the parameters, $ß_1$, $ß_2$, and $ß_3$ using equation below and also assigning $COV_{\Delta t}$ = 0.20, COV_{sf} = 0.20, and COV_P = 0.05.

$$ß_1^{Thin} = \frac{1-D_{S1}.A_{rt}-SR_P^{Thin}}{\sqrt{D_{S1}{}^2.A_{rt}{}^2.COV_{\Delta t}{}^2+(1-D_{S1}.A_{rt})^2.COV_{sf}{}^2+(SR_P^{Thin})^2.(COV_P)^2}} \quad \text{............. (Equation 15)}$$

$$ß_2^{Thin} = \frac{1-D_{S2}.A_{rt}-SR_P^{Thin}}{\sqrt{D_{S2}{}^2.A_{rt}{}^2.COV_{\Delta t}{}^2+(1-D_{S2}.A_{rt})^2.COV_{sf}{}^2+(SR_P^{Thin})^2.(COV_P)^2}}$$

$$ß_3^{Thin} = \frac{1-D_{S3}.A_{rt}-SR_P^{Thin}}{\sqrt{D_{S3}{}^2.A_{rt}{}^2.COV_{\Delta t}{}^2+(1-D_{S3}.A_{rt})^2.COV_{sf}{}^2+(SR_P^{Thin})^2.(COV_P)^2}}$$

Where;

$COV_{\Delta t}$ = The thinning coefficient of variance ranging from $0.1 \le COV_{\Delta t} \le 0.2$

= 0,2

COV_{sf}	=	The flow stress coefficient of variance
	=	0,2
COV_P	=	Pressure coeffficient of variance
	=	0,05
D_{s1}	=	Damage State 1
	=	1
D_{s2}	=	Damage State 2
	=	2
D_{s3}	=	Damage State 3
	=	4

RBI DATE:

BASED ON CORROSION RATE FROM RLA DATA

$ß_1^{Thin}$ = 3,625834

$ß_2^{Thin}$ = 3,599597

$ß_3^{Thin}$ = 3,540534

BASED ON CORROSION RATE FROM ANNEX 2B

$ß_1^{Thin}$ = 3,6485754

$ß_2^{Thin}$ = 3,6470801

$ß_3^{Thin}$ = 3,6440664

PLANNED DATE:

BASED ON CORROSION RATE FROM RLA DATA

$ß_1^{Thin}$ = 3,5321362

$ß_2^{Thin}$ = 3,3688678

$ß_3^{Thin}$ = 2,8563144

BASED ON CORROSION RATE FROM ANNEX 2B

$ß_1^{Thin}$ = 3,6436712

$ß_2^{Thin}$ = 3,6371386

$ß_3^{Thin}$ = 3,6236401

STEP 13 For tank bottom components, determine the base damage factor for thining using Table 4.8. and based on A_{rt} parameter from STEP 6.

Because component observed in this case of analysis is including into piping, then this step of calculation can be skipped.

STEP 14 For all components (excluding tank bottoms covered in STEP 13), calculate the base damage factor, . D_{fb}^{Thin}

$$D_{fb}^{Thin} = [\frac{\left(Po_{P1}^{Thin}\Phi(-\beta_1^{Thin})\right)+\left(Po_{P2}^{Thin}\Phi(-\beta_2^{Thin})\right)+\left(Po_{P3}^{Thin}\Phi(-\beta_3^{Thin})\right)}{1.56E-0.4} \text{....}$$ (Equation 16)

RBI DATE:

<u>BASED ON CORROSION RATE FROM RLA DATA</u>

D_{fb}^{Thin} = 0,24092323968

<u>BASED ON CORROSION RATE FROM ANNEX 2B</u>

D_{fb}^{Thin} = 0,24094067523

PLANNED DATE:

<u>BASED ON CORROSION RATE FROM RLA DATA</u>

D_{fb}^{Thin} = 0,24061226847

<u>BASED ON CORROSION RATE FROM ANNEX 2B</u>

D_{fb}^{Thin} = 0,24093743891

STEP 15 Determine the DF for thinning, D_f^{Thin} using equation equation below.

$$D_f^{Thin} = \mathrm{Max}[(\frac{(D_{fb}^{Thin} . F_{IP} . F_{DL} .F_{WD}.F_{AM} .F_{SM})}{F_{OM}}),0.1]$$ .... (Equation 17)

Where;

F_{IP} = DF adjustent for injection points (for piping circuit)

= 1

F_{DL} = DF adjustment for dead legs (for piping only used to intermittent service)

= 1

F_{WD} = DF adjustment for welding construction (for only AST Bottom)

= 0

F_{AM} = DF adjustment for AST maintenance per API STD 653 (for only AST)

= 0

F_{SM} = DF adjustment for settlement (for only AST Bottom)

= 0

F_{OM} = DF adjustment for online monitoring based on Table 4.9

= 1

RBI DATE:

BASED ON CORROSION RATE FROM RLA DATA

D_f^{Thin} = Max[($\frac{(0,24092323968x\ 1\ x\ 1}{1}$),0.1]

D_f^{Thin} = 0,24092323968

BASED ON CORROSION RATE FROM ANNEX 2B

D_f^{Thin} = Max[($\frac{(0,24094067523x\ 1\ x\ 1}{1}$),0.1]

D_f^{Thin} = 0,24094067523

PLANNED DATE:

BASED ON CORROSION RATE FROM RLA DATA

D_f^{Thin} = Max[($\frac{(0,24061226847x\ 1\ x\ 1}{1}$),0.1]

D_f^{Thin} = 0,24061226847

BASED ON CORROSION RATE FROM ANNEX 2B

D_f^{Thin} = Max[($\frac{(0,24093743891x\ 1\ x\ 1}{1}$),0.1]

D_f^{Thin} = 0,24093743891

DAMAGE FACTOR FOR THINNING

The governing thinning DF is determined based on the presence of an internal liner using equation below.

D_{f-gov}^{Thin} = min[D_f^{Thin}, D_f^{elin}] When internal liner is present

$D_{f-gov}^{Thin} = D_f^{Thin}$ When internal liner is not present

According to above calculaton, there is no any presence of liner, then, we can consider to use the second governing thinning DF calculation.

$D_{f-gov}^{Thin} = D_f^{Thin}$

RBI DATE:

Based on RLA Data

D_{f-gov}^{Thin} = 0,24092323968

Based on Corrosion Rate from Annex 2B

D_{f-gov}^{Thin} = 0,24094067523

PLANNED DATE:

Based on RLA Data

D_{f-gov}^{Thin} = 0,24061226847

Based on Corrosion Rate from Annex 2B

D_{f-gov}^{Thin} = 0,2409374389

<u>TYPE OF THINNING</u>

The type of thinning (wheter it is local or general) can be determined from table 2.B.1.2 from API RP 581 3rd Edition Part 2 - Annex 2.B, as follow:

Table 2.B.1.2 Type of Thinning

Thinning Mechanism	Condition	Type of Thinning
Hydrochloric Acid (HCl) Corrosion	—	Local
High Temperature Sulfidic/Naphthenic Acid Corrosion	TAN ≤ 0.5	General
	TAN > 0.5	Local
High Temperature H_2S/H_2 Corrosion	—	General
Sulfuric Acid (H_2SO_4) Corrosion	Low Velocity ≤ 0.61 m/s (2 ft/s) for carbon steel, ≤ 1.22 m/s (4 ft/s) for SS, and ≤ 1.83 m/s (6 ft/s) for higher alloys	General
	High Velocity ≥ 0.61 m/s (2 ft/s) for carbon steel, ≥ 1.22 m/s (4 ft/s) for SS, and ≥ 1.83 m/s (6 ft/s) for higher alloys	Local
Hydrofluoric Acid (HF) Corrosion	—	Local
Sour Water Corrosion	Low Velocity: ≤ 6.1 m/s (20 ft/s)	General
	High Velocity: > 6.1 m/s (20 ft/s)	Local
Amine Corrosion	Low Velocity < 1.5 m/s (5 ft/s) rich amine < 6.1 m/s (20 ft/s) lean amine	General
	High Velocity > 1.5 m/s (5 ft/s) rich amine > 6.1 m/s (20 ft/s) lean amine	Local
High Temperature Oxidation	—	General
Acid Sour Water Corrosion	< 1.83 m/s (6 ft/s) ≥ 1.83 m/s (6 ft/s)	General Local
Cooling Water Corrosion	≤ 0.91 m/s (3 ft/s) 0.91-2.74 m/s (3-9 ft/s) > 2.74 m/s (9 ft/s)	Local General Local
Soil Side Corrosion	—	Local
CO_2 Corrosion	—	Local
AST Bottom	Product Side Soil Side	Local Local

The thinning mechanisms is CO_2 corrosion.

CO2 corrosion is localized thinning mechanisms. The type of thinning designated will be used to determine the effectiveness of inspection performed.

So, the thinning damage is designated as localized

MECHANICAL FATIGUE DAMAGE FACTOR CALCULATION

STEP 1 Determine the number of previous failures that have occured, and determine the base D_{fB}^{PF} based on the following criteria.

1) None - D_{fB}^{PF} = 1
2) One - D_{fB}^{PF} = 50
3) Greater than one - D_{fB}^{PF} = 500

Because this equipment still new and no failures occurs, so the value D_{fB}^{PF} = 1

STEP 2 Determine the amount of visible / audible shaking or audible noise occuring in the pipe, and determine the base D_{fB}^{AS} based on the following criteria.

1) Minor - D_{fB}^{AS} = 1
2) Moderate - D_{fB}^{AS} = 50
3) Severe - D_{fB}^{AS} = 500

This equipment not yet operation, so it can be categorized as Minor- D_{fB}^{AS} 1

STEP 3 Determine the adjustment factor for visible / audible shaking based on the following criteria. This adjustment is based on observation that some piping system may endure visible shaking for years. A repeated stress with a cycle of only 1 hertz (1/s) result in over 30 million cycles in years. Most system, if they were subject to failure by mechanical fatigue would be expected to fail before reaching tens or hundreds of million cycles. One should note that intermitten cycles are cumulative.

1) Shaking less than 2 weeks - D_{fB}^{AS} = 1
2) Shaking between 2 and 13 weeks - D_{fB}^{AS} = 0.2
3) Shaking between 13 and 52 weeks - D_{fB}^{AS} = 0.02

This equipment not yet operation, so the shaking less than 2 weeks - = 1

STEP 4 Determine the type of cyclic loading connected directly or indirectly within approximately 15.24 meters (50 feet) of the pipe, and determine the base DF D_{fB}^{CF} based on the following criteria.

1) Reciprocating machinery - D_{fB}^{CF} = 50
2) PRV Chatter - D_{fB}^{CF} = 25
3) Valve with high pressure drop - D_{fB}^{CF} = 10
4) None - D_{fB}^{CF} = 1

This equipment is process gas piping, so the value of is 1

STEP 5 Determine the base DF using this equation

$$D_{fB}^{mfat} = \max\left[D_{fB}^{PF}, \left(D_{fB}^{AS} . F_{fB}^{AS}\right), D_{fB}^{CF}\right]$$

$$D_{fB}^{mfat} = 1$$

STEP 6 Determine the final value of the DF using this equation

$$D_{f}^{mfat} = D_{fb}^{mfat}\ x\ F_{CA}\ x\ F_{PC} x\ F_{JB}\ x\ F_{BD}$$

The adjustment factor are determined as follows.

1) Adjustment for corrective action, F_{CA} - Established based on the following criteria.
   - Modification based on complete engineering analysis - = 0.002
   - Modification based on experience - F_{CA} = 0.2
   - No modification - F_{CA} = 2

   No modification for this piping so, the value of = 2

2) Adjustment for pipe complexity, F_{PC} - Established based on the following criteria.
   - 0 to 5 total pipe fittings - F_{PC} = 0.5
   - 6 to 10 total pipe fittings - F_{PC} = 1
   - Greater than 10 total pipe fittings - F_{PC} = 2

   The total fittings are 15, so the F_{CA} = 2

3) Adjustment for condition of pipe, F_{CP} - Established based on the following criteria.
   - Missing or damaged supports, improper support - F_{CP} = 2
   - Broken gussets, gussets welded directly to the pipe - F_{CP} = 2
   - Good condition - F_{CP} = 1

   The piping condition is good because not yet operation = 1

4) Adjustment for joint type or branch design, F_{JB} - Established based on the following criteria.
   - Threaded, socketweld, saddle on - F_{JB} = 2
   - Saddle in fittings - F_{JB} = 1
   - Piping tee, Weldolets - F_{JB} = 0.2
   - Sweepolets - F_{JB} = 0.02

   The joint type for this piping is threaded, so the value of = 2

5) Adjustment for branch diameter, F_{BD}- Established based on the following criteria.

- All branches less than or equal to 2 NPS - F_{BD} = 1
- Any branches greater than 2 NPS - F_{BD} = 0.02

The branches greater than 2 NPS, so the value of = 0.02

$D_{f}^{mfat} = D_{fb}^{mfat} \; x \; F_{CA} \; x \; F_{PC} x \; F_{JB} \; x \; F_{BD}$ .... (Equation 18)

$D_{f}^{mfat} = 0{,}0111$

EXTERNAL CORROSION DAMAGE FACTOR CALCULATION

1. RLA DATA

REQUIRED DATA

The basic component data required for analysis is given in Table 4.1. and the specific data required for determination of the DF for external corrosion is provided Table 15.1 in API RP 581 Part 2 of POF.

Table 4.1. Basic Component Data Required for Analysis

Basic Data	Value	Unit	Comments
Start Date	16/03/2020		The date the component was placed in service.
Thickness	5,54	mm	The thickness used for DF calculation that is either the furnished thickness or the measured thickness.
Corrosion Allowance	1,60	mm	The corrosion allowance is the specified design or actual corrosion allowance upon being placed in the current servicce.
Design Tempearture	65	^{o}C	The design temperature for process gas piping
Design Pressure	9399,97	Kpa	The design pressure for process gas piping
Operating Tempearture	18,83	^{o}C	The highest expected operating temperature expected during operation including normal and unusual operating conditions process gas piping
Operating Pressure	4500	Kpa	The highest expected operating pressure expected during operation including normal and unusual operating conditions.
Design Code	ASME B.31.3		The designing of the component containing the component.
Equipment Type	Piping		The type of equipment.
Component Type	Pipe		The type of component.
Geometry Data			Component geometry data depending on the type of component.
Material Specification	A106 Gr.B		The specification of the material of construction, the ASTM A106 Grade B, specification for pressure vessel components or piping and tankage components. Data entry is based on the material specification, grade, year, UNS Number, class/condition/temper/size/thickness; this data is readdily available in the ASTM Code.

Yield Strength	241000	Kpa	The design yield strength of the material based on material specification.
Tensile Strength	414000	Kpa	The design tensile strength of the material based on material specification.
Weld Joint Efficiency	1,00		Weld joint efficiency per the Code of construction.
Heat Tracing	No		Is the component heat traced? (Yes or No)

STEP 1 Determining the furnished thickness, t, and age for the component from the installation date.

t = 0,2181 inch

= 5,540 mm (Assumed on 16 March 2020)

age = 0 years

STEP 2 Determining the base corrosion rate, CrB based on the driver and operating temperature using Table 15.2.

Table 15.2M - Corrosion Rates for Calculation of the Damage Factor-External Corrosion

Operating Temperature (oC)	Corrosion Rate as a Function of Driver (1) (mmpy)			
	Marine / Cooling	Temperat	Arid / Dry	Severe
-12	0	0	0	0
-8	0,025	0	0	0
6	0,127	0,076	0,025	0,254
32	0,127	0,076	0,025	1,254
71	0,127	0,051	0,025	2,254
107	0,025	0	0	0,051
121	0	0	0	0

t = Operating temperature

= 18,83 ^{o}C

= 118,83 K

mmpy 1 = 0,127 mm/y

Because the operating temperature is normally 18,83^{o}C, and there is no list of such that temperature. But, it does list values for 6^{o}C and 32^{o}C. Both of them have same value on arid / dry condition.

So C_{rB} = 0,127

STEP 3 Calculate the final corrosion rate, Cr, using equation below.

$$C_r = C_{rB} \,.\, \max[(F_{EQ}, F_{IF})] \quad \text{..} \quad (\text{ Equation } 19)$$

F_{EQ} = Adjustment for equation design or fabrication

= 1

F_{IF} = Adjustment fo interface

= 1

$$C_r = C_{rB} \,.\, \max[(F_{EQ}, F_{IF})]$$

= 0,127 . max [(1;1)]

= 0,127

STEP 4 Determine the time in service, age_{tk}, since the last known inspection, t_{rde}. The t_{rde} is the starting thickness with respect to wall loss associated with external corrosion. If no measured thickness is available, set t_{rde} = t and age_{tk} = age

t_{rde}	=	0,2181	inch		
	=	5,54	mm	Last inspection is on:	15/11/2018
t_{pd}	=	0,202	inch	RBI Date is on:	20/08/2019
		5,13	mm	Planned Date is on:	11/11/2022

age_{tk} = 0,761 years (Construction was on November 2018)

age_{pd} = 3,23 years

STEP 5 Determine the time in-service, age_{coat}, since the coating has been installed using equation below.

$$age_{coat} = Calculation\ Date - Coating\ Installation\ Date \quad (\text{ Equation } 20)$$

Calculation Date = 20/08/2019

Coating installation Date = 15/11/2018

$$age_{coat} = Calculation\ Date - Coating\ Installation\ Date$$

= 0,761 years

STEP 6 Determine coating adjustment, $coat_{adj}$ using one of below equations

If $Age_{tk} \geq Age_{coat}$

$Coat_{adj} = 0$ If No or Poor Coating Quality

$Coat_{adj} = \min[5, age_{coat}]$ If Medium Coating Quality

$Coat_{adj} = \min[15, age_{coat}]$ If High Coating Quality

If $Age_{tk} < Age_{coat}$

$Coat_{adj} = 0$ No / poor

$$Coat_{adj} = \min[5, age_{coat}] - \min[5, age_{coat} - age_{tk}] \qquad \text{Medium}$$
$$Coat_{adj} = \min[15, age_{coat}] - \min[15, age_{coat} - age_{tk}] \qquad \text{High}$$

It is assumed that the coating of the company has ever had is categorized as Medium coating. The type of coating just in external, and the installation on 2018. So the most suitable equation for calculating step 6 is in equation below.

$$Coat_{adj} = \min[5, age_{coat}] - \min[5, age_{coat} - age_{tk}] \text{....} \qquad \text{(Equation 21)}$$
$$= \min[5 ; 0{,}761] - \min[5 ; 0{,}761 - 0{,}761]$$
$$= 0{,}761$$

STEP 7 Determine the in - service time, age, over which external corrosion may have occured uing equation below

$$age = age_{tk} - Coat_{adj} \text{...} \qquad \text{(Equation 22)}$$
$$= 0{,}761 - 0{,}761$$
$$= 0$$

STEP 8 Determine the allowable stress, S, weld joint efficiency, E, and minimum required thickness, t_{min}, per the original construction code or ASME B.31.3

t_{min}	=	0,1313 inch
	=	3,334 mm
S	=	23300 psig
	=	160647908 Pa
	=	160647,908 Kpa
E	=	1

STEP 9 Determine the A_{rt} Parameter

For component without clading/weld overlay then use the equation below.

RBI DATE

$$A_{rt} = \frac{Cr.agetk}{t_{rde}} \text{...} \qquad \text{(Equation 23)}$$
$$= \frac{0{,}127 \,.\, 0{,}761}{5{,}54}$$
$$= 0{,}01744812 \qquad \text{(For calculated corrosion rate based on STEP 3)}$$

$$A_{rt} = \frac{Cr.age}{t_{rde}} \text{...} \qquad \text{(Equation 24)}$$
$$= \frac{0{,}125 \,.\, 0{,}{,}761}{5{,}54}$$
$$= 0{,}01717334 \qquad \text{(For corrosion rate based on RLA Data)}$$

PLAN DATE

$$A_{rt} = \frac{Cr.agepd}{t_{pd}}$$ .... (Equation 25)

$$= \frac{0{,}127\,.\,3{,}23}{5{,}513}$$

= 0,07991079 (For calculated corrosion rate based on STEP 3)

$$A_{rt} = \frac{Cr.age}{t_{pd}}$$ .... (Equation 26)

$$= \frac{0{,}125\,.\,3{,}23}{5{,}513}$$

= 0,07865235 (For corrosion rate based on RLA Data)

STEP 10 Calculate the Flow Stress, $FS^{extector}$, using E from STEP 5 and equation below.

$$FS^{extcorr} = \frac{(YS+TS)}{2}.\,\mathrm{E}.1{,}1$$ .... (Equation 27)

Where;

YS = 241000

TS = 414000

E = 1

$$FS^{extcorr} = \frac{(YS+TS)}{2}.\,\mathrm{E}.1{,}1$$

$$= \frac{(241000+414000)}{2}.\ (1)\,.1{,}1$$

= 360250

STEP 11 Calculate the strength ratio parameter, SR_P^{Thin} , using the appropriate equation.

$$SR_P^{Thin} = \frac{S.E}{FS^{Thin}}.\frac{Max\,(t_{min},t_c)}{t_{rdi}}$$ .... (Equation 28)

Where ;

t_c = is the minimum structural thickness of the component base material

= 0,1313 inch

= 3,334 mm

$$SR_P^{extcorr} = \frac{160647{,}908\,.\,1}{360250}.\frac{Max\,(10{,}954\,)}{17{,}48}$$

= 0,26834649

STEP 12 Determine the number of inspection , $N_A^{extcorr}, N_B^{extcorr}, N_C^{extcorr}, N_D^{extcorr}$, and the corresponding inspection effectiveness category using Section 15.6. 2 for past inspections performed during the in - service time.

$N_A^{extcorr}$ = 0

$N_B^{extcorr}$ = 0

$N_C^{extcorr}$ = 0

$N_D^{extcorr}$ = 0

Table 2.C.10.1 - LoIE Example for External Damage

Inspection Category	Inspection Effectiveness Category	Inspection[1]
A	Highly Effective	Visual inspection of >95% of the exposed surface area with follow-up by UT, RT or pit gauge as required
B	Usually Effective	Visual inspection of >60% of the exposed surface area with follow-up by UT, RT or pit gauge as required
C	Fairly Effective	Visual inspection of >30% of the exposed surface area with follow-up by UT, RT or pit gauge as required
D	Poorly Effective	Visual inspection of >5% of the exposed surface area with follow-up by UT, RT or pit gauge as required
E	Ineffective	Ineffective inspection technique/plan was utilized

Note:
1. Inspection quality is high

STEP 13 Determine the inspection effectiveness factors, $I_1^{extcorr}, I_2^{extcorr}, I_3^{extcorr}$, using equation below, prior probabilities, $Pr_{p1}^{extcorr}, Pr_{p2}^{extcorr}, Pr_{p3}^{extcorr}$, from Table 4.5. Conditional Probabilities (for each inspection effectiveness level) , $Co_{p1}^{extcorr}, Co_{p2}^{extcorr}, Co_{p3}^{extcorr}$ fromTable 4.6, and the number of inspection, $N_A^{extcorr}, N_B^{extcorr}, N_C^{extcorr}, N_D^{extcorr}$ in each effectiveness level from STEP 12.

$$I_1^{extcorr} = Pr_{P1}^{extcorr}\left(Co_{P1}^{extcorrA}\right)^{N_A^{extcorr}}\left(Co_{P1}^{extcorrB}\right)^{N_B^{extcorr}}\left(Co_{P1}^{extcorrC}\right)^{N_C^{extcorr}}\left(Co_{P1}^{extcorrD}\right)^{N_D^{extcorr}}$$

$$I_2^{extcorr} = Pr_{P2}^{extcorr}\left(Co_{P2}^{extcorrA}\right)^{N_A^{extcorr}}\left(Co_{P2}^{extcorrB}\right)^{N_B^{extcorr}}\left(Co_{P2}^{extcorrC}\right)^{N_C^{extcorr}}\left(Co_{P2}^{extcorrD}\right)^{N_D^{extcorr}}$$

$$I_3^{extcorr} = Pr_{P3}^{extcorr}\left(Co_{P3}^{extcorrA}\right)^{N_A^{extcorr}}\left(Co_{P3}^{extcorrB}\right)^{N_B^{extcorr}}\left(Co_{P3}^{extcorrC}\right)^{N_C^{extcorr}}\left(Co_{P3}^{extcorrD}\right)^{N_D^{extcorr}}$$

(Equation 29)

Table 4.5 - Prior Probability for Thinning Corrosion Rate

Damage State	Low Confidence Data	Medium Confidence	High Conf. Data
Pr_{P1}^{Thin}	0,5	0,7	0,8
Pr_{P2}^{Thin}	0,3	0,2	0,15
Pr_{P3}^{Thin}	0,2	0,1	0,05

Table 4.6 - Conditional Probability for Inspection Effectiveness

Conditional P. of Inspection	E-None or Ineffective	D-Poorly Effective	C-Fairly Effective	B-Usually Effective	A-Highly Effective
Co_{P1}^{Thin}	0,33	0,4	0,5	0,7	0,9
Co_{P2}^{Thin}	0,33	0,33	0,3	0,2	0,09
Co_{P3}^{Thin}	0,33	0,27	0,2	0,1	0,01

$$I_1^{extcorr} = Pr_{P1}^{extcorr}(Co_{P1}^{extcorrA})^{N_A^{extcorr}}(Co_{P1}^{extcorrB})^{N_B^{extcorr}}(Co_{P1}^{extcorrC})^{N_C^{extcorr}}(Co_{P1}^{extcorrD})^{N_D^{extcot}}$$
$$= 0{,}5\ (0{,}4)^0 \text{ x } (0{,}4)^0 \text{ x } (0{,}4)^0 \text{ x } (0{,}4)^0$$
$$= 0{,}50$$

$$I_2^{extcorr} = Pr_{P2}^{extcorr}(Co_{P2}^{extcorrA})^{N_A^{extcorr}}(Co_{P2}^{extcorrB})^{N_B^{extcorr}}(Co_{P2}^{extcorrC})^{N_C^{extcorr}}(Co_{P2}^{extcorrD})^{N_D^{extcot}}$$
$$= 0{,}3\ (0{,}33)^0 \text{ x } (0{,}33)^0 \text{ x } (0{,}33)^0 \text{ x } (0{,}33)^0$$
$$= 0{,}30$$

$$I_3^{extcorr} = Pr_{P3}^{extcorr}(Co_{P3}^{extcorrA})^{N_A^{extcorr}}(Co_{P3}^{extcorrB})^{N_B^{extcorr}}(Co_{P3}^{extcorrC})^{N_C^{extcorr}}(Co_{P3}^{extcorrD})^{N_D^{extcot}}$$
$$= 0{,}2\ (0{,}27)^0 \text{ x } (0{,}27)^0 \text{ x } (0{,}27)^0 \text{ x } (0{,}27)^0$$
$$= 0{,}20$$

STEP 14 Calculate the Posteroir Probability $Po_{p1}^{extcorr}, Po_{p2}^{extcorr}, Po_{p3}^{extcorr}$, using equations

$$Po_{p1}^{extcorr} = \frac{I_1^{extcorr}}{I_1^{extcorr} + I_2^{extcorr} + I_3^{extcorr}}$$
$$= 0{,}5$$
$$Po_{p2}^{extcorr} = \frac{I_2^{extcorr}}{I_1^{extcorr} + I_2^{extcorr} + I_3^{extcorr}}$$
$$= 0{,}3$$
$$Po_{p3}^{extcorr} = \frac{I_3^{extcorr}}{I_1^{extcorr} + I_2^{extcorr} + I_3^{extcorr}}$$
$$= 0{,}2$$

STEP 15 Calculate the parameters, $ß_1$, $ß_2$, and $ß_3$ using equation below and also assigning $COV_{\Delta t} = 0.20$, $COV_{sf} = 0.20$, and $COV_P = 0.05$.

$$ß_1^{extcorr} = \frac{1 - D_{S1}.A_{rt} - SR_P^{extcorr}}{\sqrt{D_{S1}{}^2.A_{rt}{}^2.COV_{\Delta t}{}^2 + (1 - D_{S1}.A_{rt})^2.COV_{sf}{}^2 + (SR_P^{extcorr})^2.(COV_P)^2}}$$

$$ß_2^{extcorr} = \frac{1 - D_{S2}.A_{rt} - SR_P^{extcorr}}{\sqrt{D_{S2}{}^2.A_{rt}{}^2.COV_{\Delta t}{}^2 + (1 - D_{S2}.A_{rt})^2.COV_{sf}{}^2 + (SR_P^{extcorr})^2.(COV_P)^2}}$$

$$ß_3^{extcorr} = \frac{1 - D_{S3}.A_{rt} - SR_P^{extcorr}}{\sqrt{D_{S3}{}^2.A_{rt}{}^2.COV_{\Delta t}{}^2 + (1 - D_{S3}.A_{rt})^2.COV_{sf}{}^2 + (SR_P^{extcorr})^2.(COV_P)^2}}$$

Where;

$COV_{\Delta t}$ = The thinning coefficient of variance ranging from $0.1 \leq COV_{\Delta t} \leq 0.2$

= 0,2

COV_{sf} = The flow stress coefficient of variance

= 0,2

COV_P = Pressure coeffficient of variance

= 0,05

D_{s1} = Damage State 1

= 1

D_{s2} = Damage State 2

= 2

D_{s3} = Damage State 3

= 4

RBI DATE

BASED ON CORROSION RATE FROM STEP 3

$ß_1^{extcor}$ = 3,6254

$ß_2^{extcor}$ = 3,5987

$ß_3^{extcor}$ = 3,5385

BASED ON CORROSION RATE FROM RLA

$ß_1^{extcor}$ = 3,6258

$ß_2^{extcor}$ = 3,5996

$ß_3^{extcor}$ = 3,5405

PLAN DATE

BASED ON CORROSION RATE FROM STEP 3

$ß_1^{extcor}$ = 3,5192

$ß_2^{extcor}$ = 3,3329

$ß_3^{extcor}$ = 2,7297

BASED ON CORROSION RATE FROM RLA

$ß_1^{extcor}$ = 3,5216

$ß_2^{extcor}$= 3,3397

$ß_3^{extcor}$ = 3,0279

STEP 16 Calculate $D_f^{extcorr}$ using equation below

RBI DATE

$$D_f^{extcor} = [\frac{\left(Po_{P1}^{extcorr}\Phi(-\beta_1^{extcorr})\right)+\left(Po_{P2}^{extcorr}\Phi(-\beta_2^{extcorr})\right)+\left(Po_{P3}^{extcorr}\Phi(-\beta_3^{extcorr})\right)}{1.56E-0.4}$$

= 0,86193075 **BASED ON CORROSION RATE FROM STEP 3**

$$D_f^{extcor} = [\frac{\left(Po_{P1}^{extcorr}\Phi(-\beta_1^{extcorr})\right)+\left(Po_{P2}^{extcorr}\Phi(-\beta_2^{extcorr})\right)+\left(Po_{P3}^{extcorr}\Phi(-\beta_3^{extcorr})\right)}{1.56E-0.4}$$

= 0,86193125 **BASED ON CORROSION RATE FROM RLA**

PLAN DATE

$$D_f^{extcor} = [\frac{\left(Po_{P1}^{extcorr}\Phi(-\beta_1^{extcorr})\right)+\left(Po_{P2}^{extcorr}\Phi(-\beta_2^{extcorr})\right)+\left(Po_{P3}^{extcorr}\Phi(-\beta_3^{extcorr})\right)}{1.56E-0.4}$$

= 0,86131798 **BASED ON CORROSION RATE FROM STEP 3**

$$D_f^{extcor} = [\frac{\left(Po_{P1}^{extcorr}\Phi(-\beta_1^{extcorr})\right)+\left(Po_{P2}^{extcorr}\Phi(-\beta_2^{extcorr})\right)+\left(Po_{P3}^{extcorr}\Phi(-\beta_3^{extcorr})\right)}{1.56E-0.4}$$

= 0,86165581 **BASED ON CORROSION RATE FROM RLA**

PROBABILITY OF FAILURE

The probability of failure can be calculated using the equation of;

Pf (t) = gff . Fms . D f (t)

Where,

pf (t)	=	The PoF as a function of time
gff	=	General failure frequency
Fms	=	Management system factor
Df (t)	=	Total damage factor

DETERMINING DAMAGE FACTOR (Df)

In the case of multiple damage mechanisms, the combination of those damage mechanims is explained in section 3.4.2 API RP 581 Part 2 3rd Edition. Total DF, $D_{f\text{-total}}$ - If more than one damage mechanism is present, the following rules are used to combine the DFs. The total DF is given by Equation below, when the external and/or thinning damage are classified as local and therefore, unlikely to occur at the same location.

$$D_{f-total} = max\left[D_{f-gov}^{thin}, D_{f-gov}^{extd}\right] + D_{f-gov}^{scc} + D_{f}^{htha} + D_{f-gov}^{brit} + D_{f}^{mfat}$$

If the external and thinning damage are general, then damage is likely to occur at the same location and the total DF is given by Equation below.

$$D_{f-total} = D_{f-gov}^{thin} + D_{f-gov}^{extd} + D_{f-gov}^{scc} + D_{f}^{htha} + D_{f-gov}^{brit} + D_{f}^{mfat}$$

Note that the summation of DFs can be less than or equal to 1.0. This means that the component can have a POF less than the generic failure frequency.

Acccording to the observation of Piping equipment is categorized as local thinning and also it does not likely occur at the same location. So, we used equation correlated to local thinning.

1 DETERMINGING THE GOVERNING THINNING DF

The governing thinning DF is determined based on the presence of an internal liner using equation

$$D_{f\ -gov}^{Thin} = \min\left[D_{f}^{Thin}, D_{f}^{elin}\right]$$ When an internal linear is present

$$D_{f\ -gov}^{Thin} = D_{f}^{Thin}$$ When an internal linear is not present

According to above calculaton, there is no any presence of liner, then, we can consider to use the second governing thinning DF calculation

RBI DATE:

$D_{f-gov}^{Thin} = D_f^{Thin}$

= 0,24092323968 (Based on RLA Data)

= 0,24094067523 (Based on Annex 2B Calculation)

PLAN DATE:

$D_{f-gov}^{Thin} = D_f^{Thin}$

= 0,24061226847 (Based on RLA Data)

= 0,24093743891 (Based on Annex 2B Calculation)

2 DETERMINGING THE MECHANICAL FATIGUE DF

D_f^{mfat} = 0,01111

3 DETERMING THE GOVERNING EXTERNAL DF

$$D_{f-gov}^{extd} = \max\left[D_f^{extf}, D_f^{CUIF}, D_f^{SSC}, D_f^{extd-CLSCC}, D_f^{CUI-CLSCC}\right]$$

Based on the DFs screening tool above, type of external DF that likely appears is only external corrosion. So, the other damage factor of external damage mechanism can be ignored.

RBI DATE:

$D_{f-gov}^{extd} = D_f^{extf}$

= 0,8619312534 (Based on RLA Data)

= 0,8619307498 (Based on the calculation on the STEP 3 of External Corrosion)

PLAN DATE:

$D_{f-gov}^{extd} = D_f^{extf}$

= 0,861655807 (Based on RLA Data)

= 0,861317975 (Based on the calculation on the STEP 3 of External Corrosion)

4 CALCULATE THE TOTAL DF

If more than one damage mechanism is present, the following adjustment are used to combine the Damafe Factors (DFs). There some different formula to use accordding to the type of the thinning itself, either it is localized thinning or general thinning.

a. GENERAL THINNING

If the external and thinning damage are general, then damage is likely to occur at the same location and the total DF is given by Equation below.

$$D_{f-total} = D_{f-gov}^{thin} + D_{f-gov}^{extd} + D_{f-gov}^{scc} + D_{f}^{htha} + D_{f-gov}^{brit} + D_{f}^{mfat}$$

b. LOCAL THINNING

$$D_{f-total} = max\left[D_{f-gov}^{thin}, D_{f-gov}^{extd}\right] + D_{f-gov}^{scc} + D_{f}^{htha} + D_{f-gov}^{brit} + D_{f}^{mfat}$$

Based on the thinning calculation its categorized as localized thinning, because the fluids contains carbon dioxide.

<u>RBI DATE:</u>

$$D_{f-total} = max\left[D_{f-gov}^{thin}, D_{f-gov}^{extd}\right] + D_{f-gov}^{scc} + D_{f}^{htha} + D_{f-gov}^{brit} + D_{f}^{mfat}$$

= 1,1139656041 **<u>(Based on RLA Data)</u>**

$$D_{f-total} = max\left[D_{f-gov}^{thin}, D_{f-gov}^{extd}\right] + D_{f-gov}^{scc} + D_{f}^{htha} + D_{f-gov}^{brit} + D_{f}^{mfat}$$

= 1,1139825361 **<u>(Based on the calculation of corrosion rate)</u>**

<u>PLAN DATE:</u>

$$D_{f-total} = max\left[D_{f-gov}^{thin}, D_{f-gov}^{extd}\right] + D_{f-gov}^{scc} + D_{f}^{htha} + D_{f-gov}^{brit} + D_{f}^{mfat}$$

= 1,113379187 **<u>(Based on RLA Data)</u>**

$$D_{f-total} = max\left[D_{f-gov}^{thin}, D_{f-gov}^{extd}\right] + D_{f-gov}^{scc} + D_{f}^{htha} + D_{f-gov}^{brit} + D_{f}^{mfat}$$

= 1,113366525 **<u>(Based on the calculation of corrosion rate)</u>**

<u>DETERMINING GENERAL FAILURE FREQUENCY (gff)</u>

To determine the value of gff, we can use the recommended list from table 3.1 of API RBI 581

Table 3.1 – Suggested Component Generic Failure Frequencies

Equipment Type	Component Type	*gff* as a Function of Hole Size (failures/yr)				gff_{total} (failures/yr)
		Small	Medium	Large	Rupture	
Compressor	COMPC	8.00E-06	2.00E-05	2.00E-06	0	3.00E-05
Compressor	COMPR	8.00E-06	2.00E-05	2.00E-06	6.00E-07	3.06E-05
Heat Exchanger	HEXSS. HEXTS,	8.00E-06	2.00E-05	2.00E-06	6.00E-07	3.06E-05
Pipe	PIPE-1, PIPE-2	2.80E-05	0	0	2.60E-06	3.06E-05
Pipe	PIPE-4,	8.00E-06	2.00E-05	0	2.60E-06	3.06E-05

	PIPE-6					
Pipe	PIPE-8, PIPE-10, PIPE-12, PIPE-16, PIPEGT16	8.00E-06	2.00E-05	2.00E-06	6.00E-07	3.06E-05

gff = 0,0000306

DETERMINING MANAGEMENT SYSTEM FACTOR (fms)

To determine the value of Fms, use a series of question and survey given by API RBI 581 to determine Fms value. But in this calculation the score is 500 from 1000

$$pscore = \frac{Score}{1000}\ x\ 100\ [unit\ is\ 100\ \%]$$

From the equation above, the $pscore$ is = 50 %

To determine the value of Fms we can use the equation:

$$Fms = 10^{(-0.02\,.pscore+1)}$$

Fms = 1

DETERMINING THE PROBABILITY OF FAILURE

There are two main calculation to conduct an RBI for all type of equipment which are POF and COF. And the Probability of Failure (POF) is computed from equation below.

$$\boldsymbol{P_f(t) = gff_{total}\,.\,D_f(t).F_{MS}}$$

Where :

$P_f(t)$ = Probabilitty of Failure (POF)
gff_{total} = Generic Failure Frequency
$D_f(t)$ = Total Damage Factors
F_{MS} = Management System Factors

RBI DATE:

Based on Corrosion Rate from RLA Data

- ***Pf (t) = 3,06 x 10^-5 . 1. 1,1139656041***

Pf (t) = 3,40873475E-05

Based on the calculated corrosion rate

- ***Pf (t) = 3,06 x 10^-5 . 1 . 1,1139825361***

Pf (t) = 3,4087866,E-05

PLANNED DATE:

Based on Corrosion Rate from RLA Data

- ***Pf (t) = 3,06 x 10^-5 . 0,171 . 1,113379187***

Pf (t) = 3,4069403E-05

Based on the calculated corrosion rate

- ***Pf (t) = 3,06 x 10^-5 . 0,171 . 1,113366525***

Pf (t) = 3,4069016,E-05

	INSPECTION PROGRAM PLANNING OF PROCESS GAS PIPING USING RISK BASED INSPECTION API 581 IN MUARA KARANG PEAKER GAS METER

ATTACHMENT 3C :

CONSEQUENCE OF FAILURE (COF) CALCULATION OF RISK BASED INSPECTION API 581

2" - PG - 06255 - C

Rev	Tanggal	Keterangan	Disusun Oleh:		Disetujui Oleh:	
			Nama	Paraf	Pembimbing	Paraf
			Ade Ratih Anggraini		Ir. Dwi Priyanta, M.SE	
			No. Registration :		Nurhadi Siswantoro,ST.,MT.	#NAME?
			04211641000008			

PART 1 : DETERMINE THE REPRESENTATIVE FLUID AND ASSOCIATED PROPERTIES

1.1 Representative Fluids

A representative fluid that most closely matches the fluid contained pressurized system being evaluated is selected from the representative fluids table shown in Table 4.1 API 581 Part 3 of COF.

1.2 Fluid Properties

The required fluid properties estimated for each of the representative fluids as provided in Table 4.2 are dependent on the stored phase of the fluid below:

a) Stored Liquid

1. Normal Boiling Point *(NBP)*
2. Density (ρ_l)
3. Auto-Ignition Temperature *(AIT)*

b) Stored Vapor or Gas	
1. Normal Boiling Point	*(NBP)*
2. Molecular Weight	*(MW)*
3. Ideal Gas Specific Heat Capacity Ratio	*(k)*
4. Constant Pressure Specific Heat	(C_p)
5. Auto - Ignition Temperature	*(AIT)*

1.3 Release Phase

The dispersion characteristics of fluids and probability of consequence outcomes (events) after release are strongly dependent on the phase (gas, liquid, or two-phase) of the fluid after it is released into the environment. Guidelines for determining the phase of the released fluid can be seen on Table 4.3 API 581 Part 3 of COF. For this, the release phase is gas/vapor.

STEP 1.1 Select the representative fluid group from Table 4.1 Annex 3.A

Gas Composition % Mol	
Methane	92,3802
Nitrogen	0,0047
CO_2	3,1479
Ethane	2,5964
Propane	1,1551
i - Butane	0,3174
n- Butane	0,3596
i - Pentane	0,0267
n - Pentane	0,0072
n - Hexane	0,0012
% Total	99,996

Note : Those value are average of the value sample taken on June 2019. This data based on gas composition in ORF

The representative fluid is gas, there are some consideration of representative fluid in API RP 581 - Annex 3.A Section 3.A.3.1.2. Choice of representative fluids of mixture ststed in the following paragraph.

If a mixture contains inert materials such as CO2 or water, the choice of representative fluid should be based on the flammable/toxic materials of concern, excluding these materials. This is a conservative assumption that will result in higher COF results, but it is sufficient for risk prioritization.

Table 4.1 – List of Representative Fluids Available for Level 1 Consequence Analysis

Representative Fluid	Fluid TYPE (see Section 4.1.5)	Examples of Applicable Materials
$C_1 - C_2$	TYPE 0	Methane, Ethane, Ethylene, LNG, Fuel Gas
$C_3 - C_4$	TYPE 0	Propane, Butane, Isobutane, LPG
C_5	TYPE 0	Pentane
$C_6 - C_8$	TYPE 0	Gasoline, Naphtha, Light Straight Run, Heptane
$C_9 - C_{12}$	TYPE 0	Diesel, Kerosene
$C_{13} - C_{16}$	TYPE 0	Jet Fuel, Kerosene, Atmospheric Gas Oil

The representative fluid is methane and CO_2

STEP 1.2 Determine the stored fluid phase

Liquid or vapor. If stored fluid is two - phase, use the conservative assumption of liquid. Alternatively, a level 2 consequence analysis can be performed.

Muara Karang Peaker is vapor stored fluid properties

STEP 1.3 Determine the stored fluid phase

Table 4.2 – Properties of the Representative Fluids Used in Level 1 Consequence Analysis

Fluid	MW	Liquid Density (lb/ft^3)	NBP (°F)	Ambient State	Ideal Gas Specific Heat Eq.	C_p Ideal Gas Constant *A*	Ideal Gas Constant *B*	Ideal Gas Constant *C*	Ideal Gas Constant *D*	Ideal Gas Constant *E*	Auto-Ignition Temp. (°F)
C1-C2	23	15.639	-193	Gas	Note 1	12.3	1.150E-01	-2.87E-05	-1.30E-09	N/A	1036

For a stored vapor, the properties are dependent on these parameters such as:

1. Molecular Weight (MW), kg / kg - mol (lb / lb - mol)
   The stored vapor Molecular Weight (MW) can be estimated from Table 4.2
   MW = 23 (kg / kg - mol)

2. Ideal Gas Specific Heat Ratio (k)
   Can be estimated using Equation 2, and the C_p values determined using Table 4.2

Cp_A	=	12,3	J/kmol-K
Cp_B	=	0,115	J/kmol-K
Cp_C	=	-0,0000287	J/kmol-K
Cp_D	=	-1,3E-09	J/kmol-K
T	=	18,83	°C
T	=	65,894	°F
T	=	291,83	K
R	=	8,314	J/kg-mol-K

$$C_p = A + BT + CT^2 + DT^3 \quad \text{.......................................} \quad \text{(Equation 1)}$$

$$= 12{,}3 + (0{,}115 \times 291{,}83) + (-0{,}0000287 \times 291{,}83)^2 + (-1{,}3 \times 10^{-9} \times 291{,}83)^3$$

$$= 45{,}861 \ \text{J/kmol-K}$$

$$k = \frac{C_p}{C_p - R} \quad \text{..} \quad \text{(Equation 2)}$$

$$k = \frac{45{,}861}{45{,}861 - 8{,}314}$$

$$k = 1{,}2214$$

3. Auto - Ignition Temperature, K

   The stored liquid Auto-Ignition Temperature (AIT) can be estimated from Table 4.2 of API 581 Part 3 of COF.

AIT	=	1036	°F
	=	557,78	°C
	=	830,78	K

STEP 1.4 Determine the steady state phase of the fluid after release to the atm

Determine the steady state phase of the fluid after release to the atmosphare can be adopted from the Table 4.3 API 581 Part 3 of COF shown below :

Phase of Fluid at Normal Operating (Storage) Conditions	Phase of Fluid at Ambient (after release) Conditions	Determination of Final Phase of Consequence Calculation
Gas	Gas	Model as Gas
Gas	Liquid	Model as Gas
Liquid	Gas	Model as gas unless the fluid boiling point at ambient conditions is greater than 80°F, then model as a liquid
Liquid	Liquid	Model as Liquid

SUMMARY of STEP 1 :

1 methane and CO_2 which has the percentage of 92,3802% and 3,1479% of all.

2 The fluid stored in the piping is gas

3 Fluid properties id based on the STEP 1.3 which has been adjusted by using Table 4.2 in API RP 581 Part 3 of COF

MW	=	23	(kg / kg - mol)
AIT	=	830,78	K
T	=	291,83	K
C_p	=	45,861	J/kmol-K
k	=	1,2214	

4 The steady state phase after release to the atmoshpere is gaseous type.

PART 2 : SELECT A SET OF RELEASE HPLE SIZES TO DETERMINE THE POSSIBLE RANGE OF CONSEQUENCE THE RISK

2.1 Release Hole Size Selection

A descrete set of release events or release hole sizes are used since it would be impractical to perform the consequence analysis for a continous spectrum of release hole sizes. Limiting the number of of release hole sizes allows for an analysis that is manageable, yet still reflects the range of possible outcomes.

STEP 2.1 Calculate of release hole sizes by determining each diameter (d_n)

The following steps are repeated of each release hole size, typically four hole sizes are evaluated.

According to Annex 3.A of API 581 Chapter 3.2.3 committs that the standard four release hole sizes are assumed for all sizes in pressure vessel type.

Table 4.4. Release Hole Sizes and Areas Used in Level 1 and 2 Consequences Analysis

Release Hole Number	Release Hole Sizes	Range of Hole Diameter (mm)	Release Hole Diameter; d_n (inch)
1	Small	0 - 1/4	d_1 = 0,25
2	Medium	> 1/4 - 2	d_2 = 1
3	Large	> 2 - 6	d_3 = 4
4	Rupture	> 6	d_4 = min [D ,16]

STEP 2.2 Determine the generic failure frequency, gff_n , for the n^{th} release hole size from API 581 Part 2, Table 3.1 , and the total generic failure frequency from this table or from Equation 3

Table 3.1. Suggested Component Generic Failure Frequency

Table 3.1 – Suggested Component Generic Failure Frequencies

Equipment Type	Component Type	gff as a Function of Hole Size (failures/yr)				gff_{total} (failures/yr)
		Small	Medium	Large	Rupture	
Compressor	COMPC	8.00E-06	2.00E-05	2.00E-06	0	3.00E-05
Compressor	COMPR	8.00E-06	2.00E-05	2.00E-06	6.00E-07	3.06E-05
Heat Exchanger	HEXSS. HEXTS,	8.00E-06	2.00E-05	2.00E-06	6.00E-07	3.06E-05
Pipe	PIPE-1, PIPE-2	2.80E-05	0	0	2.60E-06	3.06E-05
Pipe	PIPE-4, PIPE-6	8.00E-06	2.00E-05	0	2.60E-06	3.06E-05
Pipe	PIPE-8, PIPE-10, PIPE-12, PIPE-16, PIPEGT16	8.00E-06	2.00E-05	2.00E-06	6.00E-07	3.06E-05

Because the total vallue of generic failure frequency has been availabled from the table. So, we can directly put the value from the table into the calculation.

$$gff_{total} = \sum_{n=1}^{4} gffn \quad \text{...} \quad (\text{ Equation 3})$$

Because the total vallue of generic failure frequency has been availabled from the table. So, we can directly put the value from the table into the calculation.

gff_{total}	=	0,0000306	failures / year
gff_{small}	=	0,000028	failures / year
gff_{medium}	=	0	failures / year
gff_{large}	=	0	failures / year
$gff_{rupture}$	=	0,0000026	failures / year

SUMMARY of STEP 2 :

1 According the Annex 3.A Part 3 of API RP 581 commits that for pipe, all of model of release hole size must be assumed.

2 The total generic failure frequency per years for every type of pipe has been adjusted by the Table 3.1 in Part 2 of API RP 581.

gff_{total}	=	0,0000306	failures / year
gff_{small}	=	0,000028	failures / year
gff_{medium}	=	0	failures / year
gff_{large}	=	0	failures / year
$gff_{rupture}$	=	0,0000026	failures / year

PART 3: CALCULATE THE THEORITICAL RELEASE RATE

3.1 Release Rate

Release rate has a close correlation within the physical properties of the material, the initial phase, the process operating conditions, and the assigned release hole sizes. As we know that initial phase is the phase of the stored fluid prior contacting to the atmosphere. for special case, two-phases systems which contain gaseos and liquid containmment inside the pressure vessel, so, according t the API 581 Part 3, choosing liquid as the initial state inside the equipment is more conservative and may be preferred.

3.2 Vapor Release Rate Equations

There are two regimes for flow gases through an orifice: sonic (choked) for higher internal pressure, and subsonic flow for lower pressure (nominally 15 psig (103.4 kPa) or less). The transition pressure at which the flow regime changes from sonic to subsonic is determined using below equation.

P_{atm} = 14,696 psi

k = 1,2214

$$P_{trans} = P_{atm} \left(\frac{k+1}{2}\right)^{\frac{k}{k-1}} \quad \text{..} \quad \text{(Equation 4)}$$

$$P_{trans} = 14{,}696 \left(\frac{1{,}22143+1}{2}\right)^{\frac{1{,}22143}{1{,}22143-1}}$$

= 26,227 psi

STEP 3.1 Select the appropriate release rate equation

Because of the phase inside the pipe is gaseous phase and the storage pressure (P_s) within the equipment item is greater than the transition pressure (P_{trans}), so the equation chosen is shown below:

$$W_n = \frac{C_d}{C_2}\; x\; A_n\; x\; P_s \sqrt{\left(\frac{k\; x\; MW\; x\; g_c}{R\; x\; T_s}\right)\left(\frac{2}{k+1}\right)^{\frac{k+1}{k-1}}} \quad \text{..................} \quad \text{(Equation 5)}$$

Abbreviation list :

C_d	=	Discharge coefficient, for turbulent liquid flow from the sharp-edge orifices in the range of $0.85 \leq C_d \leq 1.00$			
A_n	=	Release hole sized area			
P_s	=	Storage operating pressure	=	676	psi
P_{atm}	=	Atmosphere pressure	=	14,7	psi
k	=	Ideal gas specific heat capacity ratio	=	1,221	
MW	=	Molecular weight	=	23	(kg / kg - mol)

g_c	=	Gravitational constant	=	9,8	m/s^2
R	=	Universal gas constant	=	8,314	J/(kg-mol-K)
T_s	=	Storage operating temperature	=	18,83	°C
			=	65,89	°F
			=	291,8	K

STEP 3.2 For every release hole size, calculate the release hole size area based on d_n

Release Hole Number	Release Hole Sizes	Range of Hole Diameter (mm)	Release Hole Diameter; d_n (inch)
1	Small	0 - 1/4	$d_1 = 0,25$
2	Medium	> 1/4 - 2	$d_2 = 1$
3	Large	> 2 - 6	$d_3 = 4$
4	Rupture	> 6	$d_4 = \min[D, 16]$

The release hole size area can be determined by formulating below equation :

$$A_n = \frac{\pi\, d_n^2}{4} \quad \text{..........} \quad \text{(Equation 6)}$$

1. **SMAL RELEASE HOLE SIZE AREA**

d_1 = 0,25 inch

= 0,0064 m

π = 3,14

$$A_n = \frac{3{,}14\, x 0{,}0064^2}{4}$$

= 31,65 m^2

2. **MEDIUM RELEASE HOLE SIZE AREA**

d_2 = 0 inch

= 0 m

π = 3,14

$$A_n = \frac{3{,}14\, x 0^2}{4}$$

= - m^2

3. **LARGE RELEASE HOLE SIZE AREA**

d_3 = 0 inch

= 0 m

π = 3,14

$$A_n = \frac{3{,}14\, x 0}{4}$$

= - m^2

4. RUPTURE RELEASE HOLE SIZE AREA

d_4 = 2 inch

= 0,0508 m

π = 3,14

$$A_n = \frac{3{,}14\ x 0{,}0508^2}{4}$$

= 2.025,80 m^2

STEP 3.3 For liquid release, for each release hole size, calculate the viscosity correction factor ($K_{v,n}$)

Viscosity Correction Factor ($K_{v,n}$) can be determined using both equation 4 of graph below, which have been printed from API Standard 520 Part 1. Another option, the conservative value of viscosity correction factor may be used the value of 1.0

$$K_{v,n} = \left(0{,}9935 + \frac{2{,}878}{Ren^{0,5}} + \frac{342{,}75}{Ren^{1,5}}\right)^{-1}$$

Because the store fluid phase determined in STEP 1.2 is gaseous or vapor phase, then, this step is no neeed to be considered.

STEP 3.4 For each hole size, calculate the release eate, W_n , for each release area A_n

$$W_n = \frac{C_d}{C_2}\ x\ A_n\ x\ P_s \sqrt{\left(\frac{k\ x\ MW\ x\ g_c}{R\ x\ T_s}\right)\left(\frac{2}{k+1}\right)^{\frac{k+1}{k-1}}}$$

Abbreviation list :

C_d	=	0,9	
A_{n1}	=	31,65	m^2
A_{n2}	=	-	m^2
A_{n3}	=	-	m^2
A_{n4}	=	2.025,80	m^2
P_s	=	4500	kPa
P_{atm}	=	101,3	kPa
k	=	1,22	
MW	=	23	(kg / kg - mol)
g_c	=	9,8	m/s^2
R	=	8,314	J/(kg-mol-K)
T_s	=	291,83	K
C_2	=	1	

1. **SMAL RELEASE HOLE SIZE AREA**

$$W_n = \frac{C_d}{C_2}\ x\ A_{n1}\ x\ P_s \sqrt{\left(\frac{k\ x\ MW\ x\ g_c}{R\ x\ T_s}\right)\left(\frac{2}{k+1}\right)^{\frac{k+1}{k-1}}}$$

$$W_n = \frac{0{,}9}{1} x\ (31{,}65)\ x4500 \sqrt{\left(\frac{1{,}22\ x\ 23\ x\ 9{,}8}{8{,}314\ x\ 291{,}83}\right)\left(\frac{2}{1{,}22+1}\right)^{\frac{1{,}22+1}{1{,}22-1}}}$$

= 8590,29125 kg/s

2. **MEDIUM RELEASE HOLE SIZE AREA**

$$W_n = \frac{C_d}{C_2}\ x\ A_{n2}\ x\ P_s \sqrt{\left(\frac{k\ x\ MW\ x\ g_c}{R\ x\ T_s}\right)\left(\frac{2}{k+1}\right)^{\frac{k+1}{k-1}}}$$

$$W_n = \frac{0{,}9}{1} x\ (0)\ x4500 \sqrt{\left(\frac{1{,}22\ x\ 23\ x\ 9{,}8}{8{,}314\ x\ 291{,}83}\right)\left(\frac{2}{1{,}22+1}\right)^{\frac{1{,}22+1}{1{,}22-1}}}$$

= 0 kg/s

3. **LARGE RELEASE HOLE SIZE AREA**

$$W_n = \frac{C_d}{C_2}\ x\ A_{n3}\ x\ P_s \sqrt{\left(\frac{k\ x\ MW\ x\ g_c}{R\ x\ T_s}\right)\left(\frac{2}{k+1}\right)^{\frac{k+1}{k-1}}}$$

$$W_n = \frac{0{,}9}{1} x\ (0)\ x4500 \sqrt{\left(\frac{1{,}22\ x\ 23\ x\ 9{,}8}{8{,}314\ x\ 291{,}83}\right)\left(\frac{2}{1{,}22+1}\right)^{\frac{1{,}22+1}{1{,}22-1}}}$$

= 0 kg/s

4. **RUPTURE RELEASE HOLE SIZE AREA**

$$W_n = \frac{C_d}{C_2}\ x\ A_{n4}\ x\ P_s \sqrt{\left(\frac{k\ x\ MW\ x\ g_c}{R\ x\ T_s}\right)\left(\frac{2}{k+1}\right)^{\frac{k+1}{k-1}}}$$

$$W_n = \frac{0{,}9}{1} x\ (2025{,}8\ )\ x4500 \sqrt{\left(\frac{1{,}22\ x\ 23\ x\ 9{,}8}{8{,}314\ x\ 291{,}83}\right)\left(\frac{2}{1{,}22+1}\right)^{\frac{1{,}22+1}{1{,}22-1}}}$$

= 549778,64 kg/s

SUMMARY of STEP 3 :

1 The chosen equation for determining the theoretical release rate (W_n) is using equation below because, the release fluid is modeled as gas-gas and the storage pressure is greater than the transition pressure.

$$W_n = \frac{C_d}{C_2} x\, A_n\, x\, P_s \sqrt{\left(\frac{k\, x\, MW\, x\, g_c}{R\, x\, T_s}\right)\left(\frac{2}{k+1}\right)^{\frac{k+1}{k-1}}}$$

2 For calculating the release hole size area (A_n), all of assumed size of release hole for piping must be considered to determine theoretical release rate.

3 It is no need to calculate the viscosity correction factor because the release fluid is modeled as gas-gas. The voscosity correction factor calculation is adjusted for only the liquid phase.

4 After determining each release hole size are from the small until the rupture, then, the theoretical release rate can be calculated.

W_{n1}	=	8590,2912	kg/s
W_{n2}	=	0	kg/s
W_{n3}	=	0,0	kg/s
W_{n4}	=	549778,64	kg/s

PART 4 : ESTIMATE THE TOTAL AMOUNT OF FLUID INVENTORY AVAILABLE FOR RELEASE

4.1 Release Rate

The leaking component's inventory is combined with inventory with the other attached components that can contribute fluid mass.

Table 3.A.3.2 -– Assumptions Used When Calculating Liquid Inventories Within Equipment

Equipment Description	Component Type	Examples	Default Liquid Volume Percent
Piping	PIPE-xx		100% full, calculated for Level 2 methodology

4.2 Maximum Mass Available for Release

The available mass for release is estimated for each release hole size as the lesser of two quantities:

Inventory Mass

The component being evaluated is part of a larger group of components that can be expected to provide fluid inventory to the release. The inventory calculation as presented here is used as an upper-limit and does not indicate that this amount of fluid would be released in all leak scenarios. The inventory group mass can be calculated using this below equation:

$$Mass_{inv} = \sum_{i=1}^{N} (Mass_{comp,i}) \quad \text{..} \quad \text{(Equation 7)}$$

Component Mass

It is assumed that for large leaks and above, operator intervention will occur within 3 minutes, thereby limiting the amount of release material. Therefore, the amount of available mass for the release is limmited to the mass of the component plus an additional mass, $mass_{add,n}$, that is calculated based on three minutes of leakage from the component's inventory group.

STEP 4.1 Group components and equipment items into inventory groups

This step of determining the group components and equipment items can be referred to API 581 Part 3 Annex 3.A.3.3 says that when a component or equipment type is evaluated, the inventory of the component is combined with inventory from associated equipment that can contribute fluid mass to the leaking components. Theoritically, the total amount of fluid that can be released is the amount that is held within pressure containing equiment between isolation valves that can be quickly closed.

STEP 4.2 Calculate the fluid masss, $mass_{comp}$, in the component being evaluated

$ID = 306{,}32$ mm

$V_{tot} = 117586{,}101$ m^3

$= 4152513{,}97$ ft^3

$\rho_{gas} = 0{,}668$ kg/m^3

$= 0{,}04170188$ lb/ft^3

$L = 6418$ mm

$Mass_{comp} = 78547{,}5155$ kg

STEP 4.3 Calculate the fluid masss in each of the other component that are included in the inventory group mass

Based on the design of the gas plant, there is no other component or equipment type that can be combined to contribute the fluid mass to the leaking components.

STEP 4.4 Calculate the fluid mass in the inventory group, $mass_{mv}$

$$Mass_{inv} = \sum_{i=1}^{N}\left(Mass_{comp,i}\right)$$

Abbreviation list :

$Mass_{comp}$ = is the inventory fluid mass for the component or piece of equipment being evaluated, kgs [lbs]

$Mass_{inv}$ = is the inventory group fluid mass, kgs [lbs]

= 78547,5155 kg

STEP 4.5 Calculate the flow rate from a 203 mm (8 inch) diameter hole, W_{max8}

Calculate the flow rate from a 203 mm (8 inch) diameter hole, Wmax8, using the equation 8 as applicable with $A_n = A_8 = 32.450$ mm^2 (50.3 $inch^2$). This is the maximum flow rate that can be added to the equipment fluid mass from the surrounding equipment in the inventory group.

$$W_{max8} = \frac{C_d}{C_2} \; x \; A_n \; x \; P_s \sqrt{\left(\frac{k \; x \; MW \; x \; g_c}{R \; x \; T_s}\right)\left(\frac{2}{k+1}\right)^{\frac{k+1}{k-1}}} \quad \text{.................. (Equation 8)}$$

Abbreviation list :

C_d = Discharge coefficient, for turbulent liquid flow from the sharp-edge orifices in the range of $0.85 \leq C_d \leq 1.00$

= 0,9

A_n = Release hole sized area = 50,3 $inch^2$

= 0,0324 m^2

P_s = Storage operating pressure = 676 psi

			=	4500	kPa
P_{atm}	=	Atmosphere pressure	=	15	psi
k	=	Ideal gas specific heat capacity ratio	=	1,22	
MW	=	Molecular weight	=	23	(kg / kg - mol)
g_c	=	Gravitational constant	=	9,8	m/s^2
R	=	Universal gas constant	=	8,314	J/(kg-mol-K)
T_s	=	Storage operating temperature	=	18,83	°C
			=	65,89	°F
			=	291,8	K
C_2	=	SI customary conversion factors	=	1	

So,

$$W_{max8} = \frac{C_d}{C_2}\ x\ A_n\ x\ P_s \sqrt{\left(\frac{k\ x\ MW\ x\ g_c}{R\ x\ T_s}\right)\left(\frac{2}{k+1}\right)^{\frac{k+1}{k-1}}}$$

$$W_{max8} = \frac{0,9}{1}\ x\ (0,0324)\ x 4500 \sqrt{\left(\frac{1,22\ x\ 23\ x\ 9,8}{8,314\ x\ 291,83}\right)\left(\frac{2}{1,22+1}\right)^{\frac{1,22+1}{1,22-1}}}$$

= 8,80477943 kg/s

STEP 4.6 Calculate the added fluid mass, $mass_{add,n}$ for each release hole size

Determining the additional fluid mass for each release hole size resulting from three minutes of flow from the inventory group using equation 9:

$$mass_{add,n} = 180.\min[W_n, W_{max8}]$$ .... (Equation 9)

1. **SMAL RELEASE HOLE SIZE AREA**

   $mass_{add,n} = 180.\min[W_n; W_{max8}]$

   = 1584,9 kgs

2. **MEDIUM RELEASE HOLE SIZE AREA**

   $mass_{add,n} = 180.\min[W_n; W_{max8}]$

   = 0 kgs

3. **LARGE RELEASE HOLE SIZE AREA**

   $mass_{add,n} = 180.\min[W_n; W_{max8}]$

   = 0 kgs

4. **RUPTURE RELEASE HOLE SIZE AREA**

$$mass_{add,n} = 180.\min[W_n; W_{max8}]$$

$$mass_{add,4} = 180.\min[19792031; 8{,}80477943]$$

$$= 1584{,}9 \text{ kgs}$$

STEP 4.7 Calculate the mass for release for each hole size

For each release hole size, calculate the available mass for release using equation

$Mass_{avail,n} = \min.\left[\{Mass_{comp} + Mass_{add,n}\}, Mass_{inv}\right]$........... (Equation 10)

1. **SMAL RELEASE HOLE SIZE AREA**

$$Mass_{avail,n} = \min.\left[\{Mass_{comp} + Mass_{add,1}\}, Mass_{inv}\right]$$
$$= 78547{,}52 \text{ kgs}$$

2. **MEDIUM RELEASE HOLE SIZE AREA**

$$Mass_{avail,n} = \min.\left[\{Mass_{comp} + Mass_{add,2}\}, Mass_{inv}\right]$$
$$= 78547{,}52 \text{ kgs}$$

3. **LARGE RELEASE HOLE SIZE AREA**

$$Mass_{avail,n} = \min.\left[\{Mass_{comp} + Mass_{add,3}\}, Mass_{inv}\right]$$

$$= 78547{,}52 \text{ kgs}$$

4. **RUPTURE RELEASE HOLE SIZE AREA**

$$Mass_{avail,n} = \min.\left[\{Mass_{comp} + Mass_{add,4}\}, Mass_{inv}\right]$$
$$= 78547{,}52 \text{ kgs}$$

SUMMARY of STEP 4 :

1 For group inventory, theoritically, the total amount of fluid that can be released is the amount that is held within pressure containing equiment between isolation valves that can be quickly closed.

2 Calculating the fluid mass and the mass of component to determine the mass inventory.

3 There is no other components contributing the mass of the equipment evaluated.

4 $Mass_{inv}$ = 78548 kg

5 Determining the maximum flow rate of a hole size within the diameter of 203 mm (8 inch) with the hole size area of 32.450 mm^2 (50.3 $inch^2$).

W_{max8} = 8,80477943 kg/s

6 Determining the additional fluid mass for release hole size starting for the small release hole size until the rupture release hole size.

$Mass_{add1}$ = 1584,86 kgs

$Mass_{add2}$ = 0,00 kgs

$Mass_{add3}$ = 0,00 kgs

$Mass_{add4}$ = 1584,86 kgs

7 Determining the available mass for each release hole size

$Mass_{avail1}$ = 78547,52 kgs

$Mass_{avail2}$ = 78547,52 kgs

$Mass_{avail3}$ = 78547,52 kgs

$Mass_{avail4}$ = 78547,52 kgs

PART 5 : DETERMINE THE RELEASE TYPE (CONTINOUS OR

5.1 Release Type

The release is modeled as one of these two followinng types:

A). Instantaneous Release

An instataneous or puff release is one that occurs so rapidly that the fluid disperses as a single large cloud or pool.

B). Continous Release

A continous or plume release is one that occurs over a longer period of time, allowing the fluid to dispers in the shape of elongated ellipse (dependening in the weather conditions).

The process for determining the appropriate type for release to model requires to determine the time required to release 4536 kgs (10000 lbs) of fluid, t_n, through each release hole size.

STEP 5.1 Calculate the time required to release 4536 kgs (10000 lbs) of fluid for each hole size.

To determine the time required to release 4536 kgs (10000 lbs) of fluid for each hole size can be adopted from the equation below:

$$t_n = \frac{C_3}{W_n} \quad \text{(Equation 11)}$$

Abbreviation list :

t_n = time required to release 4536 kgs (10000 lbs) of fluid

C_3 = SI and US customary conversion factors

= 4536 kgs

= 10000 lbs

W_n = Theoretical release rate associated with the n^{th} release hole size, kg/s

W_1 = 8590,29125 kg/s

W_2 = 0 kg/s

W_3 = 0 kg/s

W_4 = 549778,64 kg/s

1. **SMAL RELEASE HOLE SIZE AREA**

$$t_n = \frac{C_3}{W_n}$$

= 0,52803798 s

2. **MEDIUM RELEASE HOLE SIZE AREA**

$$t_n = \frac{C_3}{W_n}$$

$= \quad 0 \quad s$

3. **LARGE RELEASE HOLE SIZE AREA**

$$t_n = \frac{C_3}{W_n}$$

$= \quad 0 \quad s$

4. **RUPTURE RELEASE HOLE SIZE AREA**

$$t_n = \frac{C_3}{W_n}$$

$= \quad 0{,}00825059 \quad s$

STEP 5.2 Determine the release type for each release hole size.

For each release hole size, determine the release type either instataneous or continous using this following criteria:

a. If the release hole size is 6.35 mm(0.25 inch) or less, then the release type is continous

b. b. If t_n<180 sec and the releaase mass is gretaer than 4536 kgs (100000 lbs), then the release is instataneous: otherwise the release is continous

1. **SMAL RELEASE HOLE SIZE AREA**

d_1 = 0,25 inch

t_1 = 0,52803798 s (Instantaneous)

2. **MEDIUM RELEASE HOLE SIZE AREA**

d_2 = 0 inch

t_2 = 0 s (Continous)

3. **LARGE RELEASE HOLE SIZE AREA**

d_3 = 0 inch

t_3 = 0 s (Continous)

4. **RUPTURE RELEASE HOLE SIZE AREA**

d_4 = 2 inch

t_4 = 0,00825059 s (Instantaneous)

SUMMARY of STEP 5 :

1 Calculating the time required to release 4536 kgs (10000 lbs) of fluid for each hole size, starting for the small until the rupture release hole size.

t_1	=	0,52803798	s
t_2	=	0	s
t_3	=	0	s
t_4	=	0,00825059	s

2 Based on the characteristic that if the release hole size is 0.25 inch or less, then, automatically including into the continuous release type. And the other hand, if t_n<180 sec and the release mass is gretaer than 4356 kgs (10000 lbs), it is including into instantaneous release type.

PART 6 : ESTIMATE THE IMPACT OF DETECTION AND ISOLATION SYSTEMS ON RELEASE MAGNITUDE

STEP 6.1 Determine the detection and isolation systems present in the unit using Table 4.5 and 4.6 API 581 Part 3

Table 4.5- Detection and Isolation System Rating Guide

Type of Detection System	**Det. Classification**
Instrumentation designed specifically to detect material losses by changes in operating conditions (i.e. loss of pressure or flow) in the system	A
Suitably located detectors to determine when the material is present outside the pressure-containing envelope	B
Visual detection, cameras, or detectors with marginal	C
Type of Isolation System	**Iso. Classification**
Isolation or shutdown systems activated directly from process instrumentation or detectors, with no operator intervention	A
Isolation or shutdown systems activated by operators in the control room or other suitable location remote from the leak	B
Isolation dependent on manually operated valves	C

Table 4.6-Adjustment to Release Based on Detection and Isolation Systems

System Classification		Release Magnitude Adjustment	Reduction Factor, $fact_{di}$
Detection	Isolation		
A	A	Reduce release rate or mass by 25%	0,25
A	B	Reduce release rate or mass by 20%	0,20
A or B	C	Reduce release rate or mass by 10%	0,10
B	B	Reduce release rate or mass by 15%	0,15
C	C	No adjustment to release rate or mass	0,00

STEP 6.2 Type of detection system = Suitably located detectors to determine when the material is present outside the pressure-containing envelope *

Detection Classification = B

STEP 6.3 Type of isolation system = Isolation or shutdown systems activated by operators in the control room or other suitable location remote from the leak *

Isolation Classification = B

STEP 6.4 Determine the release reduction factor $fact_{di}$ using Table 4.6

Release Magnitude Adjustment	=	Reduce release rate or mass by 15%
Reduction Factor, $fact_{di}$	=	**0,15**

STEP 6.5 Determine the total leak durations for each release hole sizes using Table 4.7

Table 4.7 - Leak Durations Based on detection and Isolation Systems

Detection System Rating	Isolation System Rating	Maximum Leak Duration, ld_{max}
A	A	20 minutes for 1/4 inch leaks
		10 minutes for 1 inch leaks
		5 minutes for 4 inch leaks
A	B	30 minutes for 1/4 inch leaks
		20 minutes for 1 inch leaks
		10 minutes for 4 inch leaks
A	C	40 minutes for 1/4 inch leaks
		30 minutes for 1 inch leaks
		20 minutes for 4 inch leaks
B	A or B	40 minutes for 1/4 inch leaks
		30 minutes for 1 inch leaks
		20 minutes for 4 inch leaks
B	C	1 hour for 1/4 inch leaks
		30 minutes for 1 inch leaks
		20 minutes for 4 inch leaks
C	A, B, or C	1 hour for 1/4 inch leaks
		40 minutes for 1 inch leaks
		20 minutes for 4 inch leaks

1. **SMAL RELEASE HOLE SIZE AREA**

d_1 = 0,25 inch

t_1 = 0,528 s (Continous)

$ld_{max,1}$ = 40 minutes for 1/4 inch leaks

2. **MEDIUM RELEASE HOLE SIZE AREA**

d_2 = 0 inch

t_2 = 0 s (Continous)

$ld_{max,2}$ = 30 minutes for 1 inch leaks

3. **LARGE RELEASE HOLE SIZE AREA**

d_3 = 0 inch

t_3 = 0 s (Continous)

$ld_{max,3}$ = 20 minutes for 4 inch leaks

4. RUPTURE RELEASE HOLE SIZE AREA

d_4 = 2 inch

t_4 = 0,0083 s (Instantaneous)

$ld_{max,4}$ = 20 minutes for 4 inch leaks

SUMMARY of STEP 6 :

1 Detection and isolation system of process gas piping which ones of the following options provided by the API RP 581 suits them better.

2 Type detection system of process gas piping in Muara Karang Peaker classified as "B" detection, which mean : Suitably located detectors to determine when the material is present outside the pressure-containing envelope

3 Type isolation system of process gas piping in Muara Karang Peaker classified as "B" isolation, which mean : Isolation or shutdown systems activated by operators in the control room or other suitable location remote from the leak

4 Based on the category both of detection and isolation system, then we could determine the percentage of the release factor magnitude ($fact_{di}$) of the whole piping safety plan. From the result above, the release factor magnitude ($fact_{di}$) is 15% because of both detection and isolation system are including into Category B.

5 Based on the Category B of both detection and isolation systems, the maximum leaks duration can be known.

$Id_{max,1}$ = 40 minutes for 1/4 inch leaks

$Id_{max,2}$ = 30 minutes for 1 inch leaks

$Id_{max,3}$ = 20 minutes for 4 inch leaks

$Id_{max,4}$ = 20 minutes for 4 inch leaks

PART 7 : DETERMINE THE RELEASE RATE AND MASS FOR CONSEQUENCE OF FAILURE

7.1 Continous Release Rate

For continous releases, the release is modeled as a steady state plume: therefore, the release rate is used as an input to the consequence analysis. The release rate that is used in the analysis is the theoretical release adjusted for the presence of unit detection and isolations as formulated in the equation below:

$$Rate_n = \mathrm{W_n}\,(1 - fact_{di}) \quad \text{.. (Equation 12)}$$

7.2 Instaneous Release Rate

For transient instataneous puff releases, the release mass is required to perform the analysis. The available release mass for each hole size, $mass_{avail,n}$, is used ass an upper bound for the release mass, $mass_n$, as shown in the equation below:

$$\mathrm{Mass}_n = min\,.\,[\{\mathrm{Rate_n}\,.\,\mathrm{ld_n}\},\mathrm{Mass_{avail,n}}] \quad \text{..................................... (Equation 13)}$$

STEP 7.1 Calculate the adjusted release rate, $rate_n$ for each release hole size

For each release hole size, determine the adjusted release rate, $rate_n$, using equation 12 above where the theoreical release rate, W_n, and also note that the release reduction factor, $fact_{di}$, account for any detection and isolation systemss that are present.

Reduction Factor, $fact_{di}$ = 0,15

W_{n1} = 8590,29125 kg/s

W_{n2} = 0 kg/s

W_{n3} = 0 kg/s

W_{n4} = 549778,64 kg/s

1. **SMALL RELEASE HOLE SIZE AREA**

   $Rate_1 = \mathrm{W_n}\,(1 - fact_{di})$

   = 7301,75 kg/s

2. **MEDIUM RELEASE HOLE SIZE AREA**

   $Rate_2 = \mathrm{W_n}\,(1 - fact_{di})$

   = 0 kg/s

3. **LARGE RELEASE HOLE SIZE AREA**

   $Rate_3 = \mathrm{W_n}\,(1 - fact_{di})$

   = 0 kg/s

4. **RUPTURE RELEASE HOLE SIZE AREA**

   $Rate_4 = \mathrm{W_n}\,(1 - fact_{di})$

   = 467311,844 kg/s

STEP 7.2 Calculate the leak duration, ld_n, for each release hole size

For each release hole size, calculate the leak duration, ld_n, of the release using this equation below, ,. Note that the leak duration cannot exceed the maximum duration $ld_{max,n}$.

$$ld_n = min.[\{\frac{Mass_{avail,n}}{Rate_n}\},\{60 . ld_{max,n}]$$ .... (Equation 14)

$ld_{max,1}$	=	40 minutes for 1/4 inch leaks	40	$Mass_{avail,1}$	=	78547,52	kgs
$ld_{max,2}$	=	30 minutes for 1 inch leaks	30	$Mass_{avail,2}$	=	78547,52	kgs
$ld_{max,3}$	=	20 minutes for 4 inch leaks	20	$Mass_{avail,3}$	=	78547,52	kgs
$ld_{max,4}$	=	20 minutes for 4 inch leaks	20	$Mass_{avail,4}$	=	78547,52	kgs

1. **SMALL RELEASE HOLE SIZE AREA**

$$ld_1 = min.[\{\frac{Mass_{avail,n}}{Rate_1}\},\{60 . ld_{max,1}]$$

= 10,757 s

2. **MEDIUM RELEASE HOLE SIZE AREA**

$$ld_2 = min.[\{\frac{78547,52}{116,828}\},\{60 . ld_{max,2}\}]$$

= 0 s

3. **LARGE RELEASE HOLE SIZE AREA**

$$ld_3 = min.[\{\frac{Mass_{avail,n}}{Rate_3}\},\{60 . ld_{max,3}]$$

= 0 s

4. **RUPTURE RELEASE HOLE SIZE AREA**

$$ld_4 = min.[\{\frac{Mass_{avail,n}}{Rate_4}\},\{60 . ld_{max,4}]$$

= 0,1681 s

STEP 7.3 Calculate the release mass, $mass_n$, for each release hole size

For each release hole size, calculate the release mass, $mass_n$, using equation in section 7.2 above based on the release rate, $rate_n$, the leak duration, Id_n, and the available mass, $mass_{avail,n}$.

1. **SMALL RELEASE HOLE SIZE AREA**

$$Mass_1 = min.[\{Rate_1 . ld_1\},Mass_{avail,1}]$$

= 78547,5155 kgs

2. **MEDIUM RELEASE HOLE SIZE AREA**

$$Mass_2 = min.[\{Rate_2 . ld_2\},Mass_{avail,n}]$$

= 0 kgs

3. LARGE RELEASE HOLE SIZE AREA

$$Mass_3 = min . [\{Rate_3 . ld_3\}, Mass_{avail,n}]$$

= 0 kgs

4. RUPTURE RELEASE HOLE SIZE AREA

$$Mass_4 = min . [\{Rate_4 . ld_4\}, Mass_{avail,n}]$$

= 78547,5155 kgs

SUMMARY of STEP 7:

1 Determining the adjusted release rate, $rate_n$, for each release hole size. This adjusted release rate is quite different with the theoretical release rate, W_n because the adjusted release rate is based on the real condition with the theoretical release rate referrence. Otherwise, the theoretical release rate, $W_{n,}$ is purely based on the theory and approching equationg provided by API RP 581.

$Rate_1$	=	7301,74756	kg/s
$Rate_2$	=	0,000	kg/s
$Rate_3$	=	0,00	kg/s
$Rate_4$	=	467311,844	kg/s

2 Determining the leak duration, ld_n, for each release hole size.

ld_1	=	10,757	s
ld_2	=	0,000	s
ld_3	=	0,000	s
ld_4	=	0,1681	s

3 Determining the release mass for each release hole size based on the release rate, leak duration, and available mass for each release hole size.

$Mass_1$	=	78547,52	kgs
$Mass_2$	=	0,00	kgs
$Mass_3$	=	0,00	kgs
$Mass_4$	=	78547,52	kgs

PART 8 : DETERMINE FLAMMABLE AND EXPLOSIVE CONSEQUENCE

8.1 Consequence Area Equations

The following equations are used to determine the flammable consequence areas for comoponent damage and personnel injury. There are two kind of equantions explained based on its type of release, either continous release or instataneous release as mentioned below:

1. **Continous Release** $(CA_n^{CONT} = a(rate_n)^b)$ .... (Equation 15)
2. **Instataneous Release** $(CA_n^{INST} = a(mass_n)^b)$ .... (Equation 16)

The coefficients for those equations for component damage areas and personel injury are provided in Table 4.8 and 4.9 in API RP 581 Part 3 of COF.

STEP 8.1 Select the consequence area mitigation reduction factor, factmit, from Table 4.10

Table 4.10 - Adjustment to Flammable Consequence for Mitigation Systems

Mitigation System	Consequence Area Adjustment	Consequence Area Reduction Factor, $fact_{mit}$
Inventory blowdown, couple with isolation system classification B or higher	Reduce consequence area by 25 %	0,25
Fire water deluge system and monitors	Reduce consequence area by 20%	0,2
Fire water monitor only	Reduce consequence area by 5%	0,05
Foam spray system	Reduce consequence area by 15%	0,15

Mitigation Systen = Inventory blowdown, couple with isolation system classification B or higher

Consequence Area = Reduce consequence area by 15%

$fact_{mit}$ = 0,15

STEP 8.2 Calculate the energy efficiency, $eneff_n$, for each hole size using equation mentioned below.

$$eneff_n = 4 \, . \, log_{10} \, [C_{4A} \, . \, mass_n] \, - 15$$ .... (Equation 17)

This correction is made for instantaneous events exceeding a release mass of 4,536 kgs (10,000 lbs). Comparison of calculated consequence with those of actual historical releases indicates that there is need to correct large instantaneous releases for energy efficiency.

C_{4A} = 2205 1/kg

1. **SMALL RELEASE HOLE SIZE AREA**

$$eneff_1 = 4 \, . \, log_{10} \, [C_{4A} \, . \, mass_1] \, - 15$$
$$eneff_1 = 17{,}954164$$

2. **MEDIUM RELEASE HOLE SIZE AREA**

$$eneff_2 = 4 \, . \, log_{10} \, [C_{4A} \, . \, mass_2] \, - 15$$
$$eneff_2 = 0$$

3. **LARGE RELEASE HOLE SIZE AREA**

$$eneff_3 = 4 \, . \, log_{10} \, [C_{4A} \, . \, mass_3] \, - 15$$
$$eneff_3 = 0$$

4. **RUPTURE RELEASE HOLE SIZE AREA**

$$eneff_4 = 4 \, . \, log_{10} \, [C_{4A} \, . \, mass_4] \, - 15$$
$$eneff_4 = 17{,}95416$$

STEP 8.3 Determine the Fluid Type

Determine the fluid type, either TYPE 0 or TYPE 1 based on Table 4.1 of API RP 581 Part 3 of COF.

Table 4.1 – List of Representative Fluids Available for Level 1 Consequence Analysis

Representative Fluid	Fluid TYPE (see Section 4.1.5)	Examples of Applicable Materials
$C_1 - C_2$	TYPE 0	Methane, Ethane, Ethylene, LNG, Fuel Gas

LNG (Methane)	=	TYPE 0	T	=	18,83 °C
MW	=	23 (kg / kg - mol)	T	=	65,89 °F
AIT	=	557,8 °C	T	=	291,8 K
AIT	=	830,8 K			

STEP 8.4 **For each release hole size, calculate the component damage consequence areas for Auto-Ignition Not Likely, Continous Release (AINT-CONT), $CA^{AINL\text{-}CONT}$**

1. **Determine the appropriate constant a and b from the Table 4.8**

Table 4.8M - Component Damage Flammable Consequence Equation Constants

Fluid	Continuous Release Constant								Instantaneous Release Constan							
	Auto Ignition Not Likely (CAINL)				Auto Ignition Likely (CAIL)				Auto-Ignition Not Likely (IAINL)				Auto-Ignition Likely (IAIL)			
	Gas		Liquid		Gas		Liquid		Gas		Liquid		Gas		Liquid	
	α	b	α	b	α	b	α	b	α	b	α	b	α	b	α	b
Methane (LNG)	8,67	0,98			55,13	0,95			6,469	0,67			163,7	0,62		

α = $\alpha_{cmd,n}^{AINL-CONT}$ = 8,67 b = $b_{cmd,n}^{AINL-CONT}$ = 0,98

2. **Calculate the consequence of area using equation 18**

Rate1 = 7301,75 kg/s
Rate2 = 0,00 kg/s
Rate3 = 0,00 kg/s
Rate4 = 467311,84 kg/s

$$CA_{cmd,n}^{AINL-CONT} = \alpha\,(rate_n)^b.(1-fact_{mit}) \quad \text{......................} \quad (\text{Equation } 18)$$

A. SMALL RELEASE HOLE SIZE AREA

$$CA_{cmd,1}^{AINL-CONT} = \alpha\,(rate_1)^b.(1-fact_{mit})$$

$$CA_{cmd,1}^{AINL-CONT} = 45034{,}59 \text{ m}^2$$

B. MEDIUM RELEASE HOLE SIZE AREA

$$CA_{cmd,2}^{AINL-CONT} = \alpha\,(rate_2)^b.(1-fact_{mit})$$

$$CA_{cmd,2}^{AINL-CONT} = 0{,}0 \text{ m}^2$$

C. LARGE RELEASE HOLE SIZE AREA

$$CA_{cmd,3}^{AINL-CONT} = \alpha\,(rate_3)^b.(1-fact_{mit})$$

$CA_{cmd,3}^{AINL-CONT}$ = 0 m^2

D. RUPTURE RELEASE HOLE SIZE AREA

$$CA_{cmd,4}^{AINL-CONT} = \alpha\,(rate_4)^b.(1-fact_{mit})$$

$CA_{cmd,4}^{AINL-CONT}$ = 2652177,47 m^2

STEP 8.5 For each release hole size, calculate the component damage consequence areas for Auto-Ignition Likely, Continous Release (AIL-CONT), CA$^{AIL\text{-}CONT}$

1. Determine the appropriate constant a and b from the Table 4.8

α = $\alpha_{cmd,n}^{AIL-CONT}$ = 55,13 b = $b_{cmd,n}^{AIL-CONT}$ = 0,95

2. Calculate the consequence of area using equation 19

$$CA_{cmd,n}^{AIL-CONT} = \alpha\,(rate_n)^b.(1-fact_{mit})$$ .... (Equation 19)

A. SMALL RELEASE HOLE SIZE AREA

$$CA_{cmd,1}^{AIL-CONT} = \alpha\,(rate_1)^b.(1-fact_{mit})$$

$CA_{cmd,1}^{AIL-CONT}$ = 219312 m^2

B. MEDIUM RELEASE HOLE SIZE AREA

$$CA_{cmd,2}^{AIL-CONT} = \alpha\,(rate_2)^b.(1-fact_{mit})$$

$CA_{cmd,2}^{AIL-CONT}$ = 0 m^2

C. LARGE RELEASE HOLE SIZE AREA

$$CA_{cmd,3}^{AIL-CONT} = \alpha\,(rate_3)^b.(1-fact_{mit})$$

$CA_{cmd,3}^{AIL-CONT}$ = 0 m^2

D. RUPTURE RELEASE HOLE SIZE AREA

$$CA_{cmd,4}^{AIL-CONT} = \alpha\,(rate_4)^b.(1-fact_{mit})$$

$CA_{cmd,4}^{AIL-CONT}$ = 11400748,5 m^2

STEP 8.6 For each release hole size, calculate the component damage consequence areas for Auto-Ignition Not Likely, Instantaneous Release (AINL-CONT), CA$^{AINL\text{-}INST}$

1. **Determine the appropriate constant a and b from the Table 4.8**

α = $\alpha_{cmd,n}^{AINL-INST}$ = 6,469 b = $b_{cmd,n}^{AINL-INST}$ = 0,67

2. **Calculate the consequence of area using equation 20**

$$CA_{cmd,n}^{AINL-INST} = \alpha\,(mass_n)^b.\left(\frac{1-fact_{mit}}{eneff_n}\right)$$ .... (Equation 20)

From step 7, know that :

$Mass_1$	=	78547,51547	kgs
$Mass_2$	=	0	kgs
$Mass_3$	=	0	kgs
$Mass_4$	=	78547,51547	kgs

A. SMALL RELEASE HOLE SIZE AREA

$$CA_{cmd,1}^{AINL-INST} = \alpha\,(mass_1)^b.\left(\frac{1-fact_{mit}}{eneff_1}\right)$$

$CA_{cmd,1}^{AINL-INST}$ = 583,22 m^2

B. MEDIUM RELEASE HOLE SIZE AREA

$$CA_{cmd,2}^{AINL-INST} = \alpha\,(mass_2)^b.\left(\frac{1-fact_{mit}}{eneff_2}\right)$$

$CA_{cmd,2}^{AINL-INST}$ = 0 m^2

C. LARGE RELEASE HOLE SIZE AREA

$$CA_{cmd,3}^{AINL-INST} = \alpha\,(mass_3)^b.\left(\frac{1-fact_{mit}}{eneff_3}\right)$$

$CA_{cmd,3}^{AINL-INST}$ = 0 m^2

D. RUPTURE RELEASE HOLE SIZE AREA

$$CA_{cmd,3}^{AINL-INST} = \alpha\,(mass_4)^b.\left(\frac{1-fact_{mit}}{eneff_4}\right)$$

$CA_{cmd,4}^{AINL-INST}$ = 583,22 m^2

STEP 8.7 For each release hole size, calculate the component damage consequence areas for Auto-Ignition Likely, Instantaneous Release (AIL-CONT), CA^{AIL-}

INST

1. **Determine the appropriate constant a and b from the Table 4.8**

α = $\alpha_{cmd,n}^{AIL-INST}$ = 163,7   b = $b_{cmd,n}^{AIL-INST}$ = 0,62

2. **Calculate the consequence of area using equation 21**

$$CA_{cmd,n}^{AIL-INST} = \alpha\ (mass_n)^b . \left(\frac{1-fact_{mit}}{eneff_n}\right) \quad \text{.................. (Equation 21)}$$

From step 7, know that :

$Mass_1$	=	78547,51547	kgs
$Mass_2$	=	0	kgs
$Mass_3$	=	0	kgs
$Mass_4$	=	78547,51547	kgs

A. SMALL RELEASE HOLE SIZE AREA

$$CA_{cmd,1}^{AIL-INST} = \alpha\ (mass_1)^b . \left(\frac{1-fact_{mit}}{eneff_1}\right)$$

$$CA_{cmd,1}^{AIL-INST} = 8400,1\ m^2$$

B. MEDIUM RELEASE HOLE SIZE AREA

$$CA_{cmd,2}^{AIL-INST} = \alpha\ (mass_2)^b . \left(\frac{1-fact_{mit}}{eneff_2}\right)$$

$$CA_{cmd,2}^{AIL-INST} = 0\ m^2$$

C. LARGE RELEASE HOLE SIZE AREA

$$CA_{cmd,3}^{AIL-INST} = \alpha\ (mass_3)^b . \left(\frac{1-fact_{mit}}{eneff_3}\right)$$

$$CA_{cmd,3}^{AIL-INST} = 0\ m^2$$

D. RUPTURE RELEASE HOLE SIZE AREA

$$CA_{cmd,3}^{AIL-INST} = \alpha\ (mass_4)^b . \left(\frac{1-fact_{mit}}{eneff_4}\right)$$

$$CA_{cmd,4}^{AIL-INST} = 8400,1\ m^2$$

STEP 8.8 For each release hole size, calculate the personnel injury consequence areas for Auto-Ignition Not Likely, Continous Release (AINL-CONT), $CA^{AINL-CONT}$

1. **Determine the appropriate constant a and b from the Table 4.9**

Table 4.9 - Personnel Injury Flammable Consequence Equation Constant

Fluid	Continuous Release Constant								Instantaneous Release Constant							
	Auto Ignition Not Likely (CAINL)				Auto Ignition Likely (CAIL)				Auto-Ignition Not Likely (IAINL)				Auto-Ignition Likely (IAIL)			
	Gas		Liquid		Gas		Liquid		Gas		Liquid		Gas		Liquid	
	α	b	α	b	α	b	α	b	α	b	α	b	α	b	α	b
Methane (LNG)	21,83	0,96			143,2	0,92			12,46	0,67			473,9	0,63		

$\alpha = \alpha_{inj,n}^{AINL-CONT} = 21{,}83$ $\qquad b = b_{inj,n}^{AINL-CONT} = 0{,}96$

2. **Calculate the consequence of area using equation 22**

$$CA_{inj,n}^{AINL-CONT} = [a\,.(rate_n^{AINL-CONT})^b]\,.(1 - fact_{mit}) \quad \text{(Equation 22)}$$

A. SMALL RELEASE HOLE SIZE AREA

$$CA_{inj,1}^{AINL-CONT} = \left[a\,.\left(rate_1^{AINL-CONT}\right)^b\right].(1 - fact_{mit})$$

$$CA_{inj,1}^{AINL-CONT} = 94921{,}02 \ \text{m}^2$$

B. MEDIUM RELEASE HOLE SIZE AREA

$$CA_{inj,2}^{AINL-CONT} = \left[a\,.\left(rate_2^{AINL-CONT}\right)^b\right].(1 - fact_{mit})$$

$$CA_{inj,2}^{AINL-CONT} = 0 \ \text{m}^2$$

C. LARGE RELEASE HOLE SIZE AREA

$$CA_{inj,3}^{AINL-CONT} = \left[a\,.\left(rate_3^{AINL-CONT}\right)^b\right].(1 - fact_{mit})$$

$$CA_{inj,3}^{AINL-CONT} = 0 \ \text{m}^2$$

D. RUPTURE RELEASE HOLE SIZE AREA

$$CA_{inj,4}^{AINL-CONT} = \left[a\,.\left(rate_3^{AINL-CONT}\right)^b\right].(1 - fact_{mit})$$

$$CA_{inj,4}^{AINL-CONT} = 5143932 \ \text{m}^2$$

STEP 8.9 For each release hole size, calculate the personal injury consequence areas for Auto-Ignition Likely, Continous Release (AIL-CONT), $CA^{AIL\text{-}CONT}$

1. **Determine the appropriate constant a and b from the Table 4.9**

α = $\alpha_{inj,n}^{AIL-CONT}$ = 143,2 b = $b_{cinj,n}^{AIL-CONT}$ = 0,92

2. **Calculate the consequence of area using equation 23**

$$CA_{inj,n}^{AIL-CONT} = [a\,.(rate_n^{AIL-CONT})^b]\,.(1 - fact_{mit}) \ldots\ldots \quad \text{(Equation 23)}$$

A. SMALL RELEASE HOLE SIZE AREA

$$CA_{inj,1}^{AIL-CONT} = \left[a\,.\left(rate_1^{AIL-CONT}\right)^b\right].(1 - fact_{mit})$$

$$CA_{inj,1}^{AIL-CONT} = 436229{,}08 \ \text{m}^2$$

B. MEDIUM RELEASE HOLE SIZE AREA

$$CA_{inj,2}^{AIL-CONT} = \left[a\,.\left(rate_2^{AIL-CONT}\right)^b\right].(1 - fact_{mit})$$

$$CA_{inj,2}^{AIL-CONT} = 0 \ \text{m}^2$$

C. LARGE RELEASE HOLE SIZE AREA

$$CA_{inj,3}^{AIL-CONT} = \left[a\,.\left(rate_3^{AIL-CONT}\right)^b\right].(1 - fact_{mit})$$

$$CA_{inj,3}^{AIL-CONT} = 0 \ \text{m}^2$$

D. RUPTURE RELEASE HOLE SIZE AREA

$$CA_{inj,4}^{AIL-CONT} = \left[a\,.\left(rate_4^{AIL-CONT}\right)^b\right].(1 - fact_{mit})$$

$$CA_{inj,4}^{AIL-CONT} = 20017055{,}3 \ \text{m}^2$$

STEP 8.10 For each release hole size, calculate the component damage consequence areas for Auto-Ignition Not Likely, Instantaneous Release (AINL-INST), $CA^{AINL\text{-}INST}$

1. **Determine the appropriate constant a and b from the Table 4.9**

α = $\alpha_{inj,n}^{AINL-INST}$ = 12,46 b = $b_{inj,n}^{AINL-INST}$ = 0,67

2. **Calculate the consequence of area using equation 24**

$$CA_{inj,n}^{AINL-INST} = [a\,.(mass_n^{AINL-INST})^b].\left(\frac{1 - fact_{mit}}{eneff_n}\right) \quad \text{(Equation 24)}$$

A. SMALL RELEASE HOLE SIZE AREA

$$CA_{inj,1}^{AINL-INST} = \left[a\,.\left(mass_1^{AINL-INST}\right)^b\right].\left(\frac{1-fact_{mit}}{eneff_1}\right)$$

$$CA_{inj,1}^{AINL-INST} = 1123{,}34\ \text{m}^2$$

B. MEDIUM RELEASE HOLE SIZE AREA

$$CA_{inj,2}^{AINL-INST} = \left[a\,.\left(mass_2^{AINL-INST}\right)^b\right].\left(\frac{1-fact_{mit}}{eneff_2}\right)$$

$$CA_{inj,2}^{AINL-INST} = 0\ \text{m}^2$$

C. LARGE RELEASE HOLE SIZE AREA

$$CA_{inj,3}^{AINL-INST} = \left[a\,.\left(mass_3^{AINL-INST}\right)^b\right].\left(\frac{1-fact_{mit}}{eneff_3}\right)$$

$$CA_{inj,3}^{AINL-INST} = 0\ \text{m}^2$$

D. RUPTURE RELEASE HOLE SIZE AREA

$$CA_{inj,4}^{AINL-INST} = \left[a\,.\left(mass_4^{AINL-INST}\right)^b\right].\left(\frac{1-fact_{mit}}{eneff_4}\right)$$

$$CA_{inj,4}^{AINL-INST} = 1123{,}34\ \text{m}^2$$

STEP 8.11 **For each release hole size, calculate the component damage consequence areas for Auto-Ignition Likely, Instantaneous Release (AIL-INST), $CA^{AIL-INST}$**

1. Determine the appropriate constant a and b from the Table 4.9

α = $\alpha_{inj,n}^{AIL-INST}$ = 473,9 b = $b_{inj,n}^{AIL-INST}$ = 0,63

2. Calculate the consequence of area using equation 25

$$CA_{inj,n}^{AIL-INST} = [a\,.(mass_n^{AIL-INST})^b].\left(\frac{1-fact_{mit}}{eneff_n}\right) \quad \text{(Equation 25)}$$

A. SMALL RELEASE HOLE SIZE AREA

$$CA_{inj,1}^{AIL-INST} = \left[a\,.\left(mass_1^{AIL-INST}\right)^b\right].\left(\frac{1-fact_{mit}}{eneff_1}\right)$$

$$CA_{inj,1}^{AIL-INST} = 27219{,}11 \quad m^2$$

B. MEDIUM RELEASE HOLE SIZE AREA

$$CA_{inj,2}^{AIL-INST} = \left[a\,.\left(mass_2^{AIL-INST}\right)^b\right].\left(\frac{1-fact_{mit}}{eneff_2}\right)$$

$$CA_{inj,2}^{AIL-INST} = 0 \ m^2$$

C. LARGE RELEASE HOLE SIZE AREA

$$CA_{inj,3}^{AIL-INST} = \left[a\,.\left(mass_3^{AIL-INST}\right)^b\right].\left(\frac{1-fact_{mit}}{eneff_3}\right)$$

$$CA_{inj,3}^{AIL-INST} = 0 \ m^2$$

D. RUPTURE RELEASE HOLE SIZE AREA

$$CA_{inj,4}^{AIL-INST} = \left[a\,.\left(mass_4^{AIL-INST}\right)^b\right].\left(\frac{1-fact_{mit}}{eneff_4}\right)$$

$$CA_{inj,4}^{AIL-INST} = 27219{,}11 \quad m^2$$

STEP 8.12 **For each release hole size, calculate the instantaneous / continous blending factor, $fact_n^{ic}$**

1. FOR CONTINOUS RELEASE

$$fact_n^{IC} = \min\left[\left\{\frac{rate_n}{C_5}\right\}, 1.0\right]$$ .... (Equation 26)

C_5 = 25,2 kg/s

A. SMALL RELEASE HOLE SIZE AREA

$$fact_1^{IC} = \min\left[\left\{\frac{rate_1}{C_5}\right\}, 1.0\right]$$

$$fact_1^{IC} = 1$$

B. MEDIUM RELEASE HOLE SIZE AREA

$$fact_2^{IC} = \min\left[\left\{\frac{rate_2}{C_5}\right\}, 1.0\right]$$

$$fact_1^{IC} = 0$$

C. LARGE RELEASE HOLE SIZE AREA

$$fact_3^{IC} = \min\left[\left\{\frac{rate_3}{C_5}\right\}, 1.0\right]$$

$$fact_3^{IC} = 0$$

D. RUPTURE RELEASE HOLE SIZE AREA

$$fact_4^{IC} = \min\left[\left\{\frac{rate_4}{C_5}\right\}, 1.0\right]$$

$$fact_4^{IC} = 1$$

2. FOR INSTATANEOUS RELEASE

$$fact_n^{IC} = 1$$

STEP 8.13 **Calculate the AIT blending factor, $fact^{AIT}$, using the optional equation below**

$$fact^{AIT} = 0 \qquad \text{for,} \quad T_S + C_6 \leq AIT$$

$$fact^{AIT} = \frac{(T_S - AIT + C_6)}{2 \, . \, C_6} \qquad \text{for,} \quad T_S + C_6 > AIT > T_S - C_6$$

$$fact^{AIT} = 1 \qquad \text{for,} \quad T_S + C_6 \geq AIT$$

T_S	=	18,83	°C	AIT	=	558	°C
T_S	=	65,89	°F	AIT	=	831	K
T_S	=	291,83	K	C_6	=	55,6	K

$T_S + C_6$	=	347,43	K
$T_S - C_6$	=	236,23	K

So, $fact^{AIT} = 0$

STEP 8.14 **Calculate the continuous/instantaneous blended consequence area for the component using equation (3.53) through (3.56) based on the consequence areas calculated in previous steps**

$CA^{AIL}_{cmd,n} = CA^{AIL-INST}_{cmd,n} . fact^{IC}_{n} + CA^{AIL-CONT}_{cmd,n} . (1 - fact^{IC}_{n})$...... (Equation 27)

A. SMALL RELEASE HOLE SIZE AREA

$CA^{AIL-INST}_{cmd,1}$ = 8400,1015 m^2 $fact^{IC}_{1}$ = 1

$fact^{IC}_{1}$ = 1

$CA^{AIL-CONT}_{cmd,1}$ = 219312 m^2

$CA^{AIL}_{cmd,1}$ = 8400,1015 m^2

B. MEDIUM RELEASE HOLE SIZE AREA

$CA^{AIL-INST}_{cmd,2}$ = 0,0000 m^2 $fact^{IC}_{2}$ = 1

$fact^{IC}_{2}$ = 0

$CA^{AIL-CONT}_{cmd,2}$ = 0,0 m^2

$CA^{AIL}_{cmd,2}$ = 0 m^2

C. LARGE RELEASE HOLE SIZE AREA

$CA^{AIL-INST}_{cmd,3}$ = 0,0000 m^2 $fact^{IC}_{3}$ = 1

$fact^{IC}_{3}$ = 0

$CA^{AIL-CONT}_{cmd,3}$ = 0 m^2

$CA^{AIL}_{cmd,3}$ = 0 m^2

D. RUPTURE RELEASE HOLE SIZE AREA

$CA^{AIL-INST}_{cmd,4}$ = 8400,101 m^2 $fact^{IC}_{4}$ = 1

$fact^{IC}_{4}$ = 1

$CA^{AIL-CONT}_{cmd,4}$ = 11400748,5 m^2

$CA^{AIL}_{cmd,4}$ = 8400,1015 m^2

$CA_{inj,n}^{AIL} = CA_{inj,n}^{AIL-INST} . fact_n^{IC} + CA_{inj,n}^{AIL-CONT} . (1 - fact_n^{IC})$ ...... (Equation 28)

A. SMALL RELEASE HOLE SIZE AREA

$CA_{inj,1}^{AIL-INST}$ = 27219,11 m^2 $fact_1^{IC}$ = 1

$fact_1^{IC}$ = 1

$CA_{inj,1}^{AIL-CONT}$ = 436229,08 m^2

$CA_{inj,1}^{AIL}$ = 27219,108 m^2

B. MEDIUM RELEASE HOLE SIZE AREA

$CA_{inj,2}^{AIL-INST}$ = 0,00 m^2 $fact_2^{IC}$ = 1

$fact_2^{IC}$ = 0

$CA_{inj,2}^{AIL-CONT}$ = 0,0 m^2

$CA_{inj,2}^{AIL}$ = 0 m^2

C. LARGE RELEASE HOLE SIZE AREA

$CA_{inj,3}^{AIL-INST}$ = 0,000 m^2 $fact_3^{IC}$ = 1

$fact_3^{IC}$ = 0

$CA_{inj,3}^{AIL-CONT}$ = 0,0 m^2

$CA_{inj,3}^{AIL}$ = 0 m^2

D. RUPTURE RELEASE HOLE SIZE AREA

$CA_{inj,4}^{AIL-INST}$ = 27219,108 m^2 $fact_4^{IC}$ = 1

$fact_4^{IC}$ = 1

$CA_{inj,4}^{AIL-CONT}$ = 20017055,29 m^2

$CA_{inj,4}^{AIL}$ = 27219,108 m^2

$CA_{cmd,n}^{AINL} = CA_{cmd,n}^{AINL-INST} . fact_n^{IC} + CA_{cmd,n}^{AINL-CONT} . (1 - fact_n^{IC})$ ... (Equation 29)

A. SMALL RELEASE HOLE SIZE AREA

$CA_{cmd,1}^{AINL-INST}$ = 583,21627 m^2 $fact_1^{IC}$ = 1

$fact_1^{IC}$ = 1

$CA_{cmd,1}^{AINL-CONT}$ = 45034,59 m^2

$CA_{cmd,1}^{AINL}$ = 583,21627 m^2

B. MEDIUM RELEASE HOLE SIZE AREA

$CA_{cmd,2}^{AINL-INST}$ = 0,00000 m^2 $fact_2^{IC}$ = 1

$fact_2^{IC}$ = 0

$CA_{cmd,2}^{AINL-CONT}$ = 0,0 m^2

$CA_{cmd,2}^{AINL}$ = 0 m^2

C. LARGE RELEASE HOLE SIZE AREA

$CA_{cmd,3}^{AINL-INST}$ = 0,00000 m^2 $fact_3^{IC}$ = 1

$fact_3^{IC}$ = 0

$CA_{cmd,3}^{AINL-CONT}$ = 0 m^2

$CA_{cmd,3}^{AINL}$ = 0 m^2

D. RUPTURE RELEASE HOLE SIZE AREA

$CA_{cmd,4}^{AINL-INST}$ = 583,2163 m^2 $fact_4^{IC}$ = 1

$fact_4^{IC}$ = 1

$CA_{cmd,4}^{AINL-CONT}$ = 2652177,47 m^2

$CA_{cmd,4}^{AINL}$ = 583,21627 m^2

$$CA_{inj,n}^{AINL} = CA_{inj,n}^{AINL-INST} . fact_n^{IC} + CA_{inj,n}^{AINL-CONT} . (1 - fact_n^{IC}) \quad \text{(Equation 30)}$$

A. SMALL RELEASE HOLE SIZE AREA

$CA_{inj,1}^{AINL-INST}$ = 1123,338 m^2 $fact_1^{IC}$ = 1

$fact_1^{IC}$ = 1

$CA_{inj,1}^{AINL-CONT}$ = 94921,02 m^2

$CA_{inj,1}^{AINL}$ = 1123,3382 m^2

B. MEDIUM RELEASE HOLE SIZE AREA

$CA_{inj,2}^{AINL-INST}$ = 0,000 m² $fact_2^{IC}$ = 1

$fact_2^{IC}$ = 0

$CA_{inj,2}^{AINL-CONT}$ = 0,0 m²

$CA_{inj,2}^{AINL}$ = 0 m²

C. LARGE RELEASE HOLE SIZE AREA

$CA_{inj,3}^{AINL-INST}$ = 0,000 m² $fact_3^{IC}$ = 1

$fact_3^{IC}$ = 0

$CA_{inj,3}^{AINL-CONT}$ = 0,00 m²

$CA_{inj,3}^{AINL}$ = 0 m²

D. RUPTURE RELEASE HOLE SIZE AREA

$CA_{inj,4}^{AINL-INST}$ = 1123,3382 m² $fact_4^{IC}$ = 1

$fact_4^{IC}$ = 1

$CA_{inj,4}^{AINL-CONT}$ = 5143932 m²

$CA_{inj,4}^{AINL}$ = 1123,3382 m²

STEP 8.15 **Calculate the AIT blended consequence areas for the component using equations (31) and (32) based on the consequence areas determined in step 8.14 and the AIT blending factors, $fact^{AIT}$, calculate in step 8.13. the resulting consequence areas are the component damage and personnel injury flammable consequence areas, $CA^{flam}_{cmd,n}$ and $CA^{flam}_{inj,n}$ for each release hole size selected in step 2.2**

$$CA_{cmd,n}^{flam} = CA_{cmd,n}^{AIL} \cdot fact^{AIT} + CA_{cmd,n}^{AINL} \cdot (1 - fact^{AIT}) \quad \text{(Equation 31)}$$

A. SMALL RELEASE HOLE SIZE AREA

$CA_{cmd,1}^{AIL}$ = 8400,1 m²

$fact^{AIT}$ = 0

$CA_{cmd,1}^{AINL}$ = 583,2163 m²

$CA_{cmd,1}^{flam}$ = 583,21627 m^2

B. MEDIUM RELEASE HOLE SIZE AREA

$CA_{cmd,2}^{AIL}$ = 0,0 m^2

$fact^{AIT}$ = 0

$CA_{cmd,2}^{AINL}$ = 0,0000 m^2

$CA_{cmd,2}^{flam}$ = 0 m^2

C. LARGE RELEASE HOLE SIZE AREA

$CA_{cmd,3}^{AIL}$ = 0,0 m^2

$fact^{AIT}$ = 0

$CA_{cmd,3}^{AINL}$ = 0,0000 m^2

$CA_{cmd,3}^{flam}$ = 0 m^2

D. RUPTURE RELEASE HOLE SIZE AREA

$CA_{cmd,4}^{AIL}$ = 8400,1 m^2

$fact^{AIT}$ = 0

$CA_{cmd,4}^{AINL}$ = 583,2163 m^2

$CA_{cmd,4}^{flam}$ = 583,21627 m^2

$$CA_{inj,n}^{flam} = CA_{inj,n}^{flam-AIL} . fact^{AIT} + CA_{inj,n}^{AINL} . (1 - fact^{AIT})$$ (Equation 32)

A. SMALL RELEASE HOLE SIZE AREA

$CA_{inj,1}^{flam-AIL}$ = 27219,11 m^2

$fact^{AIT}$ = 0

$CA_{inj,1}^{AINL}$ = 1123,338 m^2

$CA_{inj,1}^{flam}$ = 1123,3382 m^2

B. MEDIUM RELEASE HOLE SIZE AREA

$CA_{inj,2}^{flam-AIL}$ = 0,00 m^2

$fact^{AIT}$ = 0

$CA_{inj,2}^{AINL}$ = 0,000 m^2

$CA_{inj,2}^{flam}$ = 0 m^2

C. LARGE RELEASE HOLE SIZE AREA

$CA_{inj,3}^{flam-AIL}$ = 0,00 m^2

$fact^{AIT}$ = 0

$CA_{inj,3}^{AINL}$ = 0,000 m^2

$CA_{inj,3}^{flam}$ = 0 m^2

D. RUPTURE RELEASE HOLE SIZE AREA

$CA_{inj,4}^{flam-AIL}$ = 27219,108 m^2

$fact^{AIT}$ = 0

$CA_{inj,4}^{AINL}$ = 1123,338 m^2

$CA_{inj,4}^{flam}$ = 1123,3382 m^2

STEP 8.16 **Determine the final consequence areas (probability weighted on release hole size) for component damage and personnel injury using Equations (33) and (34) based on the consequence areas from STEP 8.15.**

Equipment Type	Component Type	*gff* as a Functional of Hole Size				*gff* total (failure/yr
		Small	Medium	Large	Rupture	
Pipe	Pipe 8"	2,8E-05	0	0	2,6E-06	0,0000306
	Pipe10"					
	Pipe 12"					
	Pipe 16"					

CONSEQUENCE AREA FOR COMPONENT DAMAGE

$$CA_{cmd}^{flam} = \left(\frac{\sum gff_n \cdot CA_{cmd.n}^{flam}}{gff_{total}}\right)$$ .... (Equation 33)

$$CA_{cmd}^{flam} = \left(\frac{gff_1 . CA_{cmd,1}^{flam} + gff_2 \cdot CA_{cmd,2}^{flam} + gff_3 \cdot CA_{cmd,3}^{flam} + gff_4 \cdot CA_{cmd,}^{flam}}{gff_{total}}\right)$$

$$CA_{cmd}^{flam} = \left(\frac{8.10^{-6}.583{,}216 + 2.10^{-5}.0 + 2.10^{-6}.0 + 6.10^{-7}.583{,}216}{3{,}06.10^{-5}.}\right)$$

CA_{cmd}^{flam} = 583,216 m^2

CONSEQUENCE AREA FOR PERSONEL INJURY

$$CA_{inj}^{flam} = \left(\frac{\sum gff_n \, . CA_{cmd.n}^{flam}}{gff_{total}}\right)$$ .... (Equation 34)

$$CA_{inj}^{flam} = \left(\frac{gff_1 . CA_{inj,1}^{flam} + gff_2 \, . CA_{inj,2}^{flam} + gff_3 \, . CA_{inj,3}^{flam} + gff_4 \, . CA_{inj,4}^{flam}}{gff_{total}}\right)$$

$$CA_{inj}^{flam} = \left(\frac{2{,}8.10^{-5}.1123{,}34 + 0.0 + 0.0 + 2{,}6.10^{-6}.1123{,}34}{3{,}06.10^{-5}.}\right)$$

CA_{inj}^{flam} = 1123,34 m^2

PART 9: CALCULATE THE TOXIC CONSEQUENCE

STEP 9.1 For each release hole size selected in STEP 2.2, calculate the effective duration of the toxic release using equation 35.

Table 4.13 – Continuous Gas and Liquid Release Toxic Consequence Equation Constants for Miscellaneous Chemicals

Chemical	Release Duration (Minutes)	Gas Release Constants		Liquid Release Constants	
		e	f	e	f
Aluminum Chloride (AlCl3)	All	17.663	0.9411	N/A	N/A
Carbon Monoxide (CO)	3	41.412	1.15	N/A	N/A
	5	279.79	1.06	N/A	N/A
	10	834.48	1.13	N/A	N/A
	20	2,915.9	1.11	N/A	N/A
	40	5,346.8	1.17	N/A	N/A
	60	6,293.7	1.21	N/A	N/A
Hydrogen Chloride (HCL)	3	215.48	1.09	N/A	N/A
	5	536.28	1.15	N/A	N/A
	10	2,397.5	1.10	N/A	N/A
	20	4,027.0	1.18	N/A	N/A
	40	7,534.5	1.20	N/A	N/A
	60	8,625.1	1.23	N/A	N/A
Nitric Acid	3	53,013	1.25	5,110.0	1.08
	5	68,700	1.25	9,640.8	1.02
	10	96,325	1.24	12,453	1.06
	20	126,942	1.23	19,149	1.06
	40	146,941	1.22	31,145	1.06
	60	156,345	1.22	41,999	1.12
Nitrogen Dioxide (NO_2)	3	6,633.1	0.70	21,32.9	0.98
	5	9,221.4	0.68	2,887.0	1.04
	10	11,965	0.68	6,194.4	1.07
	20	14,248	0.72	13,843	1.08
	40	22,411	0.70	27,134	1.12
	60	24,994	0.71	41,657	1.13
Phosgene	3	12,902	1.20	3,414.8	1.06
	5	22,976	1.29	6,857.1	1.10
	10	48,985	1.24	21,215	1.12
	20	108,298	1.27	63,361	1.16
	40	244,670	1.30	178,841	1.20
	60	367,877	1.31	314,608	1.23
Toluene Diisocyanate (TDI)	3	N/A	N/A	3,692.5	1.06
	5	N/A	N/A	3,849.2	1.09
	10	N/A	N/A	4,564.9	1.10
	20	N/A	N/A	4,777.5	1.06
	40	N/A	N/A	4,953.2	1.06
	60	N/A	N/A	5,972.1	1.03
Ethylene Glycol Monoethyl Ether (EE)	1.5	3.819	1.171	N/A	N/A
	3	7.438	1.181	N/A	N/A
	5	17.735	1.122	N/A	N/A
	10	33.721	1.111	3.081	1.105
	20	122.68	0.971	16.877	1.065
	40	153.03	0.995	43.292	1.132
	60	315.57	0.899	105.74	1.104

Because of no chemical toxic in this equipment, so this step not calculate.

PART 10 :CALCULATE THE NON - FLAMMABLE, NON TOXIC CONSEQUENCE AREA

STEP 10.1 **For each release hole size,calculate the non - flammable, non - toxic consequence**

1) **FOR STEAM**

For Steam - Calculate $CA^{CONT}_{inj,n}$ using Equation (3.69) and $CA^{INST}_{inj,n}$ using Equation (3.70)

This piping process is not steam. So, thus value is 0

2) **FOR ACID OR CAUSTICS**

Calculate $CA^{CONT}_{inj,n}$ using Equation 36, 37. Note that data is not provided for an instantaneous release; therefore, $CA^{INST}_{inj,n}$ = 0

For caustics/acids that have splash type consequences. Acid or caustic leaks do not result in a component damage consequence. The consequence area was defined at the 180° semi-circular area covered by the liquid spray or rainout. Modeling was performed at three pressures; 103.4 kPa, 206.8 kPa, and 413.7 kPa (15 psig, 30 psig, and 60 psig) for four release hole sizes (see Table 4.4). The results were analyzed to obtain a correlation between release rate and consequence area, and were divided by 5 since it is believed that serious injuries to personnel are only likely to occur within about 20% of the total splash area as calculated by the above method

The resulting consequence area for non-flammable releases of acids and caustics is calculated using Equations (36) and (37)

$$CA^{CONT}_{inj,n} = 0.2 \cdot C_8 \cdot g(C_4 \cdot rate_n)^h \qquad \text{(Equation 36)}$$

$$CA^{INST}_{inj,n} = 0 \qquad \text{(Equation 37)}$$

The constants g and h shown in Equation (36),are functions of pressure and can be calculated using Equations (38) and (39), respectively.

$$g = 2696 - 21.9 \cdot C_{11}\,(P_S - P_{atm}) + 1.474\,[C_{11}(P_S - P_{atm})]^2 \qquad \text{(Equation 38)}$$

$$h = 0.31 - 0.00032\,[C_{11}(P_S - P_{atm}) - 40]^2 \qquad \text{(Equation 39)}$$

$Rate_1$	=	7301,747559 kg/s		C_8	=	0,0929	$m^2.s$
$Rate_2$	=	0,0000 kg/s		C_4	=	2,205	s/kg
$Rate_3$	=	0,000 kg/s		C_{11}	=	0,145	1/kPa
$Rate_4$	=	467311,8438 kg/s				0,00145	1/bar
				P_S	=	4500	kPa
						45	bar
				P_{atm}	=	101,33	kPa
						1,01	bar

$$g = 2696 - 21.9 \cdot C_{11}\,(P_S - P_{atm}) + 1.474\,[C_{11}(P_S - P_{atm})]^2$$
$$g = 2696 - 21.9 \cdot 0{,}145\,(45 - 101{,}33) + 1.474\,[0{,}00145(4500 - 1{,}01)]^2$$
$$g = 2694{,}609197$$

$$h = 0.31 - 0.00032\,[C_{11}(P_S - P_{atm}) - 40]^2$$
$$h = 0.31 - 0.00032\,[0{,}00145(45 - 1{,}01) - 40]^2$$
$$h = -0{,}2$$

A. SMALL RELEASE HOLE SIZE AREA

$$CA_{inj,1}^{CONT} = 0.2 \cdot C_8 \cdot g(C_4 \cdot rate_1)^h$$
$$CA_{inj,1}^{CONT} = 0.2 \cdot 0{,}0929 \cdot 2694{,}6092(2{,}205 \cdot 7301{,}75)^{-0{,}2}$$
$$CA_{inj,1}^{CONT} = 7{,}1883 \quad m^2$$

B. MEDIUM RELEASE HOLE SIZE AREA

$$CA_{inj,2}^{CONT} = 0.2 \cdot C_8 \cdot g(C_4 \cdot rate_2)^h$$
$$CA_{inj,2}^{CONT} = 0.2 \cdot 0{,}0929 \cdot 2694{,}6092(2{,}205 \cdot 116827{,}96)^{-0{,}2}$$
$$CA_{inj,2}^{CONT} = 0 \quad m^2$$

C. LARGE RELEASE HOLE SIZE AREA

$$CA_{inj,3}^{CONT} = 0.2 \cdot C_8 \cdot g(C_4 \cdot rate_3)^h$$
$$CA_{inj,3}^{CONT} = 0.2 \cdot 0{,}0929 \cdot 2694{,}6092(2{,}205 \cdot 1869247{,}38)^{-0{,}2}$$
$$CA_{inj,3}^{CONT} = 0 \quad m^2$$

D. RUPTURE RELEASE HOLE SIZE AREA

$$CA_{inj,3}^{CONT} = 0.2 \cdot C_8 \cdot g(C_4 \cdot rate_4)^h$$
$$CA_{inj,3}^{CONT} = 0.2 \cdot 0{,}0929 \cdot 2694{,}6092(2{,}205 \cdot 6823226{,}38)^{-0{,}2}$$
$$CA_{inj,3}^{CONT} = 3{,}1241 \quad m^2$$

STEP 10.2 **For each release hole size,calculate the instantaneous / continous blending factor $fact_n^{IC}$. For steam, use Equation (3.71). For Acids or Caustics, $fact_n^{IC}$ = 0**

Because its acid, so : $fact_n^{IC}$ = 0

STEP 10.3 **For each release hole size, calculate the blended non - flammable, non-toxic personal injury consequence area for steam or acid leaks, $CA_{inj,n}^{IC}$, using Equation 41 based on the consequencw areas from STEP 10.1 and the blending factor, $fact_n^{IC}$, From STEP 10.2. Note that there is no need to calculate area component damage area for the Level 1 non - flammable releases (steam or acid/ caustic):**

$$CA_{inj,n}^{IC} = 0 \text{ m}^2 \quad \text{...} \quad \text{(Equation 40)}$$

$$CA_{inj,n}^{leak} = CA_{inj,n}^{INST} \cdot fact_n^{IC} + CA_{inj,n}^{CONT} \cdot (1 - fact_n^{IC}) \quad \text{...........} \quad \text{(Equation 41)}$$

$fact_1^{IC}$ = 1
$fact_2^{IC}$ = 0
$fact_3^{IC}$ = 0
$fact_3^{IC}$ = 1

A. SMALL RELEASE HOLE SIZE AREA

$$CA_{inj,1}^{leak} = CA_{inj,1}^{INST} \cdot fact_1^{IC} + CA_{inj,1}^{CONT} \cdot \left(1 - fact_1^{IC}\right)$$

$$CA_{inj,1}^{leak} = 0 \cdot 1 + 7{,}1883 \cdot (1 - 1)$$

$$CA_{inj,1}^{leak} = 0 \quad \text{m}^2$$

B. MEDIUM RELEASE HOLE SIZE AREA

$$CA_{inj,2}^{leak} = CA_{inj,2}^{INST} \cdot fact_2^{IC} + CA_{inj,2}^{CONT} \cdot \left(1 - fact_2^{IC}\right)$$

$$CA_{inj,2}^{leak} = 0 \cdot 1 + 4{,}1244 \cdot (1 - 1)$$

$$CA_{inj,2}^{leak} = 0 \quad \text{m}^2$$

C. LARGE RELEASE HOLE SIZE AREA

$$CA_{inj,3}^{leak} = CA_{inj,3}^{INST} \cdot fact_1^{IC} + CA_{inj,3}^{CONT} \cdot \left(1 - fact_3^{IC}\right)$$

$$CA_{inj,3}^{leak} = 0 \cdot 1 + 2{,}3664 \cdot (1 - 1)$$

$$CA_{inj,3}^{leak} = 0 \quad \text{m}^2$$

D. RUPTURE RELEASE HOLE SIZE AREA

$$CA_{inj,3}^{leak} = CA_{inj,3}^{INST} \cdot fact_1^{IC} + CA_{inj,3}^{CONT} \cdot \left(1 - fact_3^{IC}\right)$$

$$CA_{inj,3}^{leak} = 0 \cdot 1 + 1{,}5237 \cdot (1 - 1)$$

$$CA_{inj,3}^{leak} = 0 \quad \text{m}^2$$

STEP 10.4 **Determine the final non-flammable, non toxic consequence areas for personnil injury, $CA_{inj,n}^{nfnt}$ using Equation 42 based on consequence area calculated for each release hole size in Step 10.3. Note that there is no need to calculate a final - flammable, non-toxic consequence area for component damage area for the Level 1 non-flammble relese (steam or acid/caustic) :**

$CA_{inj,n}^{infnt}$ = 0 m^2

$$CA_{inj}^{nfnt} = \left(\frac{\sum gff_n \cdot CA_{inj,n}^{leak}}{gff_{total}}\right) \quad \text{.. (Equation 42)}$$

Equipment Type	Component Type	*gff* as a Functional of Hole Size				*gff* total (failure/yr
		Small	Medium	Large	Rupture	
Pipe	Pipe 1"	2,8E-05	0	0	2,6E-06	0,0000306
	Pipe 2"					

$$CA_{inj}^{nfnt} = \left(\frac{\sum gff_n \cdot CA_{inj,n}^{leak}}{gff_{total}}\right)$$

$$CA_{inj}^{nfnt} = \left(\frac{\left(gff_1 \cdot CA_{inj,1}^{leak}\right)+\left(gff_2 \cdot CA_{inj,2}^{leak}\right)+\left(gff_3 \cdot CA_{inj,3}^{leak}\right)+\left(gff_4 \cdot CA_{inj,4}^{leak}\right)}{gff_{total}}\right)$$

$$CA_{inj}^{nfnt} = \left(\frac{(2{,}8 \cdot 10^{-5} \cdot 0)+(0 \cdot 0)+(0 \cdot 0)+(2{,}6 \cdot 10^{-7} \cdot 0)}{3{,}06 \cdot 10^{-5}}\right)$$

$$= 0 \quad m^2$$

PART 11 : CALCULATION OF FINAL CONSEQUENCE AREA

STEP 11.1 **Calculate the final component damage consequences area CA_{cmd}**

Note that since the component damage consequence areas for toxic releases, CA_{cmd}^{tox}, and non-flammable, non-toxic releases, CA_{cmd}^{nfnt}, are both equal to zero. Then, the final component damage consequence area is equal to the consequence area calculated for flammable releases, CA_{cmd}^{flam}.

$$CA_{cmd} = CA_{cmd}^{flam}$$
$$= 583,216 \ \text{m}^2$$

STEP 11.2 **Calculate the final personnel injury consequences area CA_{inj}**

$$CA_{inj} = max\left[CA_{inj}^{flam}, CA_{inj}^{tox}, CA_{inj}^{nfnt}\right] \quad \text{.................................... (Equation 43)}$$

$$CA_{inj}^{flam} = 1123,3382 \ \text{m}^2$$

$$CA_{inj}^{tox} = 0 \ \text{m}^2$$

$$CA_{inj}^{nfnt} = 0 \ \text{m}^2$$

$$CA_{inj} = max\left[CA_{inj}^{flam}, CA_{inj}^{tox}, CA_{inj}^{nfnt}\right]$$
$$CA_{inj} = max[1123,3382; 0; 0]$$
$$CA_{inj} = 1123,3382$$

STEP 11.3 **Calculate the final consequences area CA, using Equation 44**

$$CA = max\left[CA_{cmd}, CA_{inj}\right] \text{.. (Equation 44)}$$
$$CA = max[583,216; 1123,3382]$$
$$= 1123,338177 \ \text{m}^2$$

	INSPECTION PROGRAM PLANNING OF PROCESS GAS PIPING USING RISK BASED INSPECTION API 581 IN MUARA KARANG PEAKER GAS METER

ATTACHMENT 3D :

RISK CALCULATION

2" - PG - 06255 - C

Rev.	Tanggal	Keterangan	Disusun Oleh:		Disetujui Oleh:	
			Nama	Paraf	Pembimbing	Paraf
			Ade Ratih Anggraini		Ir. Dwi Priyanta, M.SE	
			No. Registration :		Nurhadi Siswantoro,ST.,MT.	
			04211641000008			

DETERMINE THE RISK

A. Last Inspection Date

Last known inspection date is November 15rd 2018

B. RBI Date

RBI date is the date when the Risk - Based Inspection is conducted. In this case, the RBI date is set on default date September 20th 2019.

$$R_{RBI} = POF_{RBI} \times COF_{RBI}$$

Where ;

POF_{RBI} = 3,408735E-05 (Based on RLA data)

= 3,408787E-05 (Based on the corrosion rate calculation)

COF_{RBI} = 1123,338177 m^2

So,

R_{RBI} = $POF_{RBI} \times COF_{RBI}$

= 0,0382916188 m^2/year (Based on RLA data)

= 0,0382922008 m^2/year (Based on the corrosion rate calculation)

= 0,4121734203 ft^2/year

C. Plan Date

The plan date is 3,23 years, starting from the installation date on a plant was on 15^{rth} November 2018, until the plan date 11st November 2022.

$$R_{PD} = POF_{PD} \times COF_{PD}$$

Where ;

POF_{PD} = 3,406940E-05 (Based on RLA data)

= 3,406902E-05 (Based on the corrosion rate calculation)

COF_{PD} = 1123,338177 m^2

So,

R_{PD} = $POF_{PD} \times COF_{PD}$

= 0,0382714612 m^2/year (Based on RLA data)

= 0,0382710260 m^2/year (Based on the corrosion rate calculation)

= 0,4119454963 ft^2/year

	INSPECTION PROGRAM PLANNING OF PROCESS GAS PIPING USING RISK BASED INSPECTION API 581 IN MUARA KARANG PEAKER GAS METER

ATTACHMENT 3E :

INSPECTION PLANNING

2" - PG - 06255 - C

Rev.	Tanggal	Keterangan	Disusun Oleh:		Disetujui Oleh:	
			Nama	Paraf	Pembimbing	Paraf
			Ade Ratih Anggraini		Ir. Dwi Priyanta, M.SE	
			No. Registration :		Nurhadi Siswantoro,ST.,MT.	
			04211641000008			

INSPECTION PLAN

A. PIPE SPECIFICATION

Tag Number	=	2"-PG-06255-C
Diameter (inch)	=	2
Material	=	A 106 GR, SMLS, SCH 80
Min. Wall Thickness Design (mm)	=	3,33
Fluid Handle	=	C1 - C2
Operating Pressure (barg)	=	46
Operating Temperature (^{O}C)	=	18,78
PID	=	MKP-05-EN-PR-PID-002

B. RBI SUMMARY

a. Probability Assessment

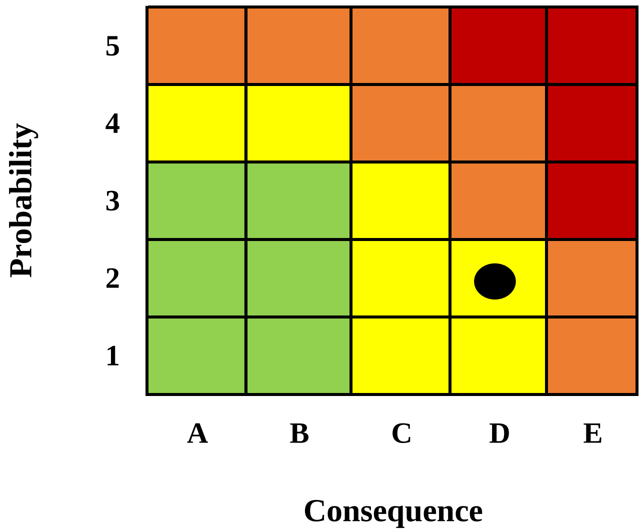
Total Damage Factor	=	1,113982536
Probability	=	3,40879E-05
Probability Category	=	2
Active Damage Mechanism	=	Thinning Damage Factor, Mechanical Fatigue Damage Factor, External Corrosion Damage Factor

b. Consequence Assessment

Fluid Representative	=	C1 - C2
Fluid Phase	=	Gas
Consequence Area (m^2)	=	1123,338177
Consequence Category	=	D

c. Risk Ranking

Probability Category	=	2
Consequence Category	=	D
Risk Ranking	=	Medium
Area Risk (m^2)	=	3,8292201E-02
Risk Category	=	Acceptable



d. Recommendation

	Thinning	Mechanical Fatigue	External Corrosion
Effectiveness	D	-	D
Due Date	26/09/2023	01/05/2026	06/09/2022
Description	For the total surface area;>20% ultrasonic scanning or profile radiography.	Visual examination	Visual inspection of >5% of the exposed surface area with follow up by Ultrasonic Test, Radiography Test or pit gauge as required

RISK PLOTTING

Corrosion Rate

	Time	Risk (ft^2/year)	Risk target (ft^2/year)
Last insp. date	15/11/2018	0	10
RBI date	20/08/2019	0,412173420	10
Plan date	11/11/2022	0,411945496	10

DF Target = (RBI Date) . (Time Plan Date - RBI Date) $^{n-1}$

10 = (0,412173420) . (3,23) $^{n-1}$

24,2616 = (3,23) $^{n-1}$

Interpolation

X_1	3	Y_1	10,42
X	x	Y	24,2616
X_2	4	Y_2	33,63

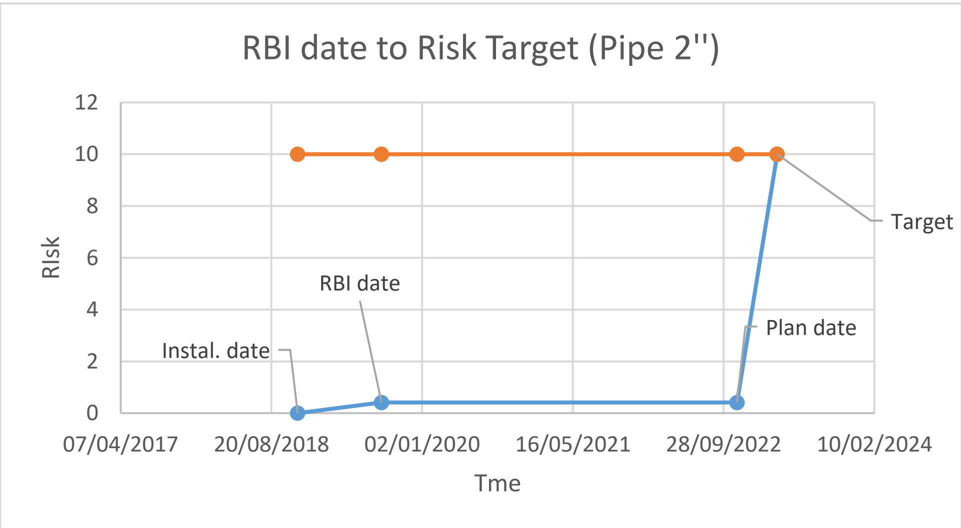
$$X = X_1 + \left(\frac{Y - Y_1}{Y_2 - Y_1}\right)(X_2 - X_1)$$

$$X = 3 + \left(\frac{24{,}2616 - 33{,}63}{108{,}57 - 33{,}63}\right)(3 - 2)$$

= 3,596286323 Year

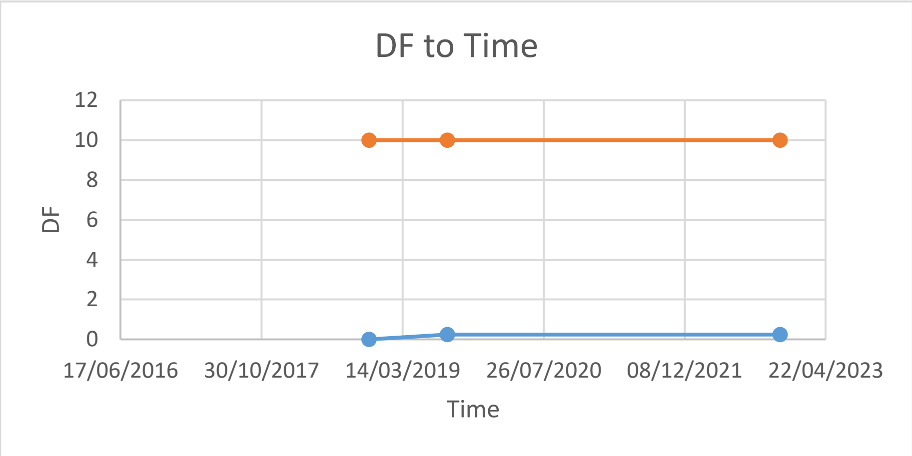
So, time to risk target is on 24/03/2023

	Time	Risk (ft^2/year)	Risk target (ft^2/year)
Last insp. date	15/11/2018	0	10
RBI date	20/08/2019	0,412173420	10
Plan date	11/11/2022	0,411945496	10
Target	24/03/2023	10	10



Thinning

	Time	DF	DF target
Last insp. date	15/11/2018	0	10
RBI date	20/08/2019	0,240940675	10
Plan date	11/11/2022	0,240937439	10



DF Target = (DF RBI Date) . (Time Plan Date - RBI Date) $^{n-1}$

10 = (0,240920909) . (3,23) $^{n-1}$

41,5040 = (3,23) $^{n-1}$

Interpolation

X_1	4	Y_1	33,63
X	x	Y	41,5040
X_2	5	Y_2	108,57

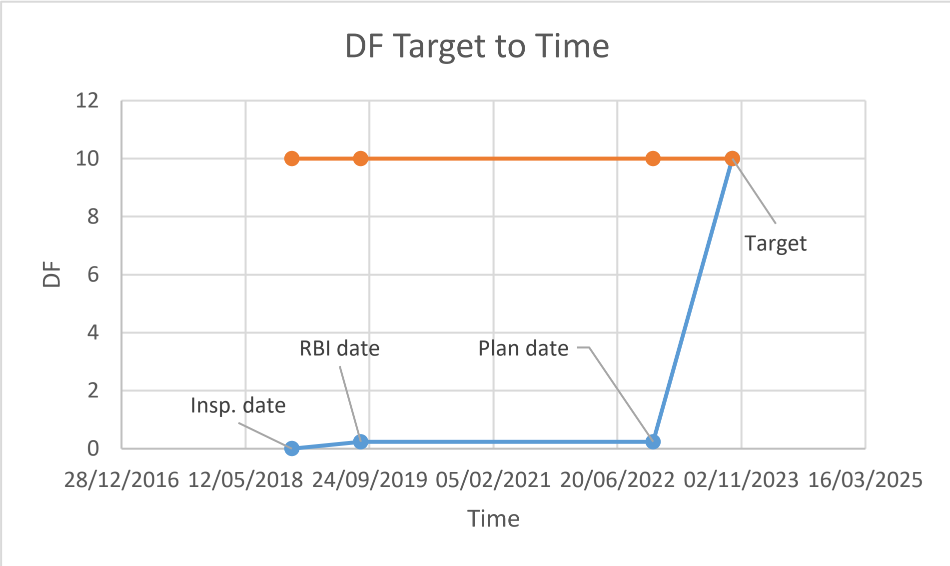
$$X = X_1 + \left(\frac{Y - Y_1}{Y_2 - Y_1}\right)(X_2 - X_1)$$

$$X = 4 + \left(\frac{41{,}5074 - 33{,}63}{108{,}57 - 33{,}63}\right)(4 - 3)$$

= 4,105035485 Year

So, time to risk target is on 26/09/2023

	Time	DF	DF target
Last insp. date	15/11/2018	0	10
RBI date	20/08/2019	0,240940675	10
Plan date	11/11/2022	0,240937439	10
Target	26/09/2023	10	10



Mechanical Fatigue

	Time	DF	DF target
Last insp. date	15/11/2018	0	10
RBI date	20/08/2019	0,011111111	10
Plan date	11/11/2022	0,011111111	10

DF Target = (DF RBI Date) . (Time Plan Date - RBI Date) $^{n-1}$

10 = (0,24087829) . (3,23) $^{n-1}$

900 = (3,23) $^{n-1}$

Interpolation

X_1	6	Y_1	350,44
X	x	Y	900
X_2	7	Y_2	1131,21

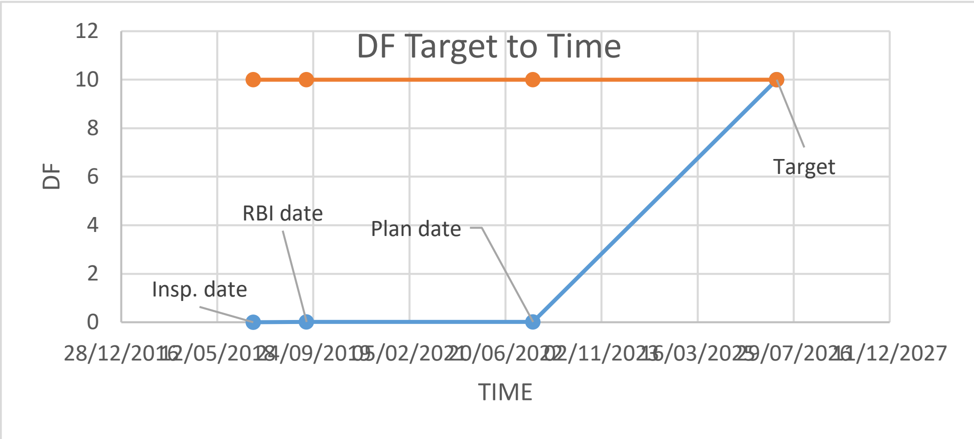
$$X = X_1 + \left(\frac{Y - Y_1}{Y_2 - Y_1}\right)(X_2 - X_1)$$

$$X = 6 + \left(\frac{900 - 350{,}44}{1131{,}21 - 350{,}44}\right)(5 - 4)$$

= 6,703872078 Year

So, time to risk target is on 01/05/2026

	Time	DF	DF target
Last insp. date	15/11/2018	0	10
RBI date	20/08/2019	0,011111111	10
Plan date	11/11/2022	0,011111111	10
Target	01/05/2026	10	10



External Corrosion

	Time	DF	DF target
Last insp. date	15/11/2018	0	10
RBI date	20/08/2019	0,861930750	10
Plan date	11/11/2022	0,861317975	10

DF Target = (DF RBI Date) . (Time Plan Date - RBI Date) $^{n-1}$

10 = (0,861920044) . (3,23) $^{n-1}$

11,60186 = (3,23) $^{n-1}$

Interpolation

X_1	3	Y_1	10,42
X	x	Y	11,60186
X_2	4	Y_2	33,63

$$X = X_1 + \left(\frac{Y - Y_1}{Y_2 - Y_1}\right)(X_2 - X_1)$$

$$X = 3 + \left(\frac{11{,}60186 - 10{,}42}{33{,}63 - 10{,}42}\right)(2 - 1)$$

= 3,050933011 Year

So, time to risk target is on 06/09/2022

	Time	DF	DF target
Last insp. date	15/11/2018	0	10
RBI date	20/08/2019	0,861930750	10
Plan date	11/11/2022	0,861317975	10
Target	06/09/2022	10	10