Msc Thesis

Offshore and Dredging engineering

Investigating the Feasibility of Reusing Pipelines from Decommissioned Gas Fields for Carbon Capture and Storage (CCS)

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Abstract

The transition to a low-carbon economy necessitates innovative solutions to reduce greenhouse gas emissions, with Carbon Capture and Storage (CCS) emerging as a viable strategy. This thesis explores the reuse of existing offshore gas pipelines for CO2 transport within CCS projects, focusing on the technical feasibility while taking potential economical and permit related risks in consideration as well. The research leads to a tool that can be used to evaluate the technical feasibility of pipeline which is tested in a case study of the L11B pipeline, a decommissioned offshore gas infrastructure, to evaluate its suitability for repurposing. This tool can serve as a starting point to help make complex and capital intensive investment decisions.

A comprehensive framework was developed to assess pipeline reuse, integrating industry standards, relevant literature and degradation mechanisms. Material integrity assessments were conducted, including evaluations of historical operating conditions, pressure ratings, and corrosion allowances. Additionally, computational models were developed to simulate CO2 transport scenarios and predict long-term degradation behavior.

The findings highlight key challenges and opportunities associated with pipeline reuse. While the structural integrity of the L11B pipeline appears within acceptable limits for CO2 transport, the modifications to ensure system compatibility with CO2 transport, such as changes to the structural components are also taken into consideration.

This thesis contributes to the body of knowledge on CCS infrastructure by presenting a systematic approach to evaluating pipeline reuse. The proposed methodology can guide the process of repurposing pipelines into a more time efficient manner by providing the handles needed to evaluate large numbers of pipelines, giving a quick and thorough evaluation of which pipelines may be feasible for reuse and which are not.

Contents

1
Introduction

The increasing global concern over climate change and the need to reduce emissions urges the need for innovative solutions in, for example, CO_2 management. One of those promising opportunities is the repurposing of existing gas infrastructure for carbon capture and storage (CCS). This approach uses the extensive network of pipelines and facilities originally designed for natural gas transport and storage and re-purposes it to store carbon dioxide in the now empty offshore gas reservoirs.
The primary focus of this research is to explore the feasibility of reusing offshore gas infrastructure, specifically pipelines, for CO_2 transport. This study will examine mainly technical but also economical and permit-related factors, providing a thorough assessment of the opportunities and limitations involved in adapting these existing systems for CCS purposes. Building on previous research and current regulatory standards in the form of a literature study, this research aims to answer the question: *What is the feasibility of reusing existing gas pipelines for the transport of CO2 to depleted gas fields?*.

1.1. Background

The offshore gas industry has developed a vast network of infrastructure over the past several decades, including pipelines, platforms, and associated systems designed to facilitate the extraction and transportation of natural gas from offshore fields to onshore processing plants. As many offshore gas fields have reached or are nearing the end of their productive life cycles, the infrastructure initially built for gas extraction is becoming obsolete. This creates an opportunity to repurpose the infrastructure for alternative uses, such as CCS.
CCS involves capturing CO_2 emissions from industrial processes, compressing the gas for transport, and injecting it into depleted gas fields or other geological formations for long-term storage. Repurposing offshore gas infrastructure for this purpose could have significant benefits. Firstly, it reduces the need for new pipeline construction, which would lower both costs and environmental impacts. Secondly, it utilizes existing assets, making the transition to a low-carbon economy more efficient. However, technical and regulatory challenges remain, including ensuring the structural integrity of pipelines and compliance with the safety and environmental standards for CO_2 transport.

1.2. Problem Description

The European Union (EU) has come to an agreement in the Paris climate convention that includes regulations aimed at reducing CO_2 emissions by 55% by 2030 compared to baseline levels of 1990. This ambitious goal is part of a broader strategy which aims for the EU to become the first climate-neutral continent by 2050. Achieving this target requires significant reductions in greenhouse gas emissions across all sectors of industry and energy. However, as of today, many industries are struggling to meet these targets at the required pace.
The current approach to CO_2 reduction relies heavily on two main strategies:

1. **Reduction of CO2 production:** This involves the adoption of cleaner, more sustainable production methods that inherently generate less CO_2. Technologies such as electrification, renewable energy integration, and resource efficiency improvements fall into this category. While these

methods promise long-term benefits, they also come with substantial economic and time-related challenges. The development, design, and construction of entirely new production processes is an expensive and time-consuming task. The infrastructure required for these innovations takes years, if not decades, to implement. Therefore, while CO2 production reduction is crucial for long-term sustainability, it is unlikely to yield the necessary reductions by 2030.

2. **Reduction of CO2 emission:** The second, more short-term solution, is the reduction of CO2 emissions through Carbon Capture and Storage (CCS). CCS technology involves capturing CO2 produced from industrial processes of any kind and storing it in a storage facility such as underground in geological formations. This method has several advantages: it does not require significant changes to the existing production processes, making it easier to implement without causing large-scale disruptions to current operations. Additionally, it requires fewer short-term capital investments in comparison to developing new technologies for CO2 production reduction.

Despite these promising aspects, the deployment of CCS at the scale required to meet the 2030 targets has been slower than anticipated. Studies have shown that it takes anywhere from 6 to 8 years to develop a fully operational CCS plant, from the initial planning stages to commissioning. This timeline makes it unlikely that newly built CCS plants alone will significantly contribute to the 2030 emission reduction goals. To overcome this challenge, alternative solutions are necessary to accelerate CCS capacity deployment.
One such solution is the reuse of existing offshore gas infrastructure, which were originally built for natural gas transport but could potentially be repurposed for CO2 transport to the depleted gas reservoirs. The reuse of offshore infrastructure offers a significant advantage, as it can reduce the time and cost associated with building new pipelines. However, the suitability of these pipelines for CO2 transport is not guaranteed, as they were not initially designed with this purpose in mind. Therefore, a comprehensive feasibility assessment is necessary to determine whether existing pipelines can safely and efficiently be reused for CCS applications.

1.3. Objectives

The main objective of this thesis is to evaluate the feasibility of reusing offshore gas pipelines for the transport of CO2 to depleted offshore gas fields. This will be accomplished through the following specific objectives:

- **Assess the technical challenges associated with CO2 transport in existing infrastructure:** This includes evaluating the material integrity, corrosion resistance, and operational capacities of offshore gas pipelines when exposed to CO2 and its impurities, such as sulfur and nitrogen compounds. A detailed examination of how CO2 behaves differently from natural gas, particularly under the pressure and temperature conditions in offshore environments, will be conducted.
- **Investigate regulatory frameworks and identify necessary adaptations for CO2 transport:** The regulations used for offshore gas pipelines are designed around natural gas transport. This objective will explore whether these regulations are sufficient for CO2 transport, or if modifications are necessary to regulatory approval.
- **Evaluate environmental and safety concerns related to infrastructure reuse:** Reusing gas infrastructure for CO2 transport presents environmental and safety challenges, including the risk of pipeline leakage and the long-term storage of CO2 in depleted reservoirs. This objective aims to assess these risks and identify mitigation strategies, ensuring that the reuse of offshore infrastructure aligns with environmental protection goals.
- **Identify risks related to the reuse of offshore gas infrastructure:** By identifying the risks on the technical, economical and permit aspects of offshore infrastructure reuse, the measures and mitigation strategies can be set up. More importantly, the influences that a measure out of one of the categories has on a certain other category can be shown, for example a economical risk requires technical measures to ensure the mitigation that risk.

1.4. Research Question

The central research question guiding this thesis is:
What is the feasibility of reusing existing gas pipelines for CO2 transport to depleted gas fields?

To fully explore this question, several sub-questions will be addressed throughout the research:

1. **What are the technical differences between natural gas and CO2 transport that impact the reuse of existing gas pipelines?** This question will investigate the specific design and operational challenges posed by transporting CO2, especially considering the difference in medium and potential for causing corrosion. This also leads to a number of sub-questions:
   - How does exposure to CO2 and its impurities affect the structural integrity of gas pipelines?
   - What are the critical loadings and loading combinations when considering the feasibility of repurposing pipelines for CO2 transport?
2. **What regulatory adaptations are required for the safe and compliant reuse of offshore gas pipelines for CCS?** This sub-question will examine current pipeline regulations and codes, determining whether they are adequate for CO2 transport and what changes may be necessary to ensure compliance with safety and environmental standards.
3. **What are the risks associated with the reuse of gas infrastructure for CO2 transport, and how can they be mitigated?** This will explore potential risks such as pipeline leakage, CO2 containment, and the environmental impact of infrastructure reuse, offering strategies to minimize these risks.
4. **How can them term feasibility be defined?** This question will set a definition on what exactly is feasibility in the context of this research. By doing so, the areas relevant to this research can be found resulting in a structured approach to determine the feasibility.

These sub-questions will guide the analysis and discussion in the following chapters, ensuring that each aspect of the research question is thoroughly explored.

1.5. Structure of the Thesis

This thesis is structured as follows:

- **Chapter 2: Literature Review** This chapter provides an in-depth overview of the existing research on offshore gas infrastructure, CCS technology, and the regulatory frameworks governing CO2 transport. The chapter highlights the current understanding of the technical, regulatory, and environmental challenges related to the reuse of gas pipelines for CCS. In this chapter, a desicion will be made on which pipeline types there are and which pipeline type should be investigated.
- **Chapter 3 & 4: Feasibility Analysis Framework and Risk Analysis** Chapter 3 describes the decisions made to structurally assess the overall feasibility by setting three different areas of feasibility. These are the technical feasibility, economical feasibility and the permit feasibility. This research will be mainly focusing on the technical feasibility while still taking critical aspects of the economical en permit feasibility into account. The technical feasibility will be investigated by developing a approach for feasibility assessment in chapter 5 while in chapter 4 a risk analysis will be provided for the technical, economical and Feasibility. By doing so, the study will remain focused on the technical aspects while still identifying potential area's where a technical measures to a technical risk may have impact on the economical or permit feasibility, necessitating a reevaluation of for example the business case. This economical re-evaluation is outside of the scope of this research.
- **Chapter 5: Approach for Feasibility Assessment** This chapter will describe the feasibility assessment approach that has been developed in this thesis to investigate the technical feasibility of reusing an offshore gas platform pipeline for CO2 transport. This is done by taking the findings on the relevant loadings out of chapter 2 and using those findings to set a series of steps that have to be taken in order to assess the pipeline for reuse. In these steps, the risks out of the risk analysis matrix and their measures are incorporated in a series of checks that have to be carried out. In these checks, the presence of potential economical influence is highlighted.
- **Chapter 6: Case Study** Chapter 6 focuses on a specific offshore pipeline, applying the assessment approach set up in chapter 5 to assess its suitability for CO2 transport. This case study serves as a practical example to illustrate the challenges and opportunities identified in the research.

- **Chapter 7: Conclusion and recommendation** This chapter summarizes the key findings of the research, providing conclusions on the feasibility of repurposing gas pipelines for CO2 transport. It also offers recommendations for future research, industry practices, and policy development to support the wider adoption of CCS technologies.

2 Literature Review

A review of the existing literature reveals a growing amount of research exploring the potential of repurposing offshore gas infrastructure for CCS applications. Studies have investigated various aspects of this concept, including the technical feasibility of reusing pipelines and platforms for CO2 transport and storage and the regulatory frameworks governing CCS deployment in offshore environments. Recent developments in CCS technology, including advancements in CO2 capture and storage techniques, as well as innovations in offshore engineering and infrastructure design, have further peaked interest in repurposing offshore gas infrastructure for CCS.
In the context of the development of a tool that could assess a pipelines feasibility, the existing research should be investigated thoroughly and schematically in order to get a full understanding what the relevant aspects of offshore gas infrastructure are in relation to CCS and reuse. This chapter will dive into the existing research and give an overview of the different types of offshore gas infrastructure, loadings and regulations.

2.1. Offshore Gas Infrastructure

Before exploring the feasibility of reusing offshore infrastructure, it is necessary to gain a full understanding of the existing gas-related infrastructure at sea. A simplified example of such a system can be seen in figure 2.1. This section serves as overview, providing a schematic overview of offshore infrastructure related to the offshore gas industry.

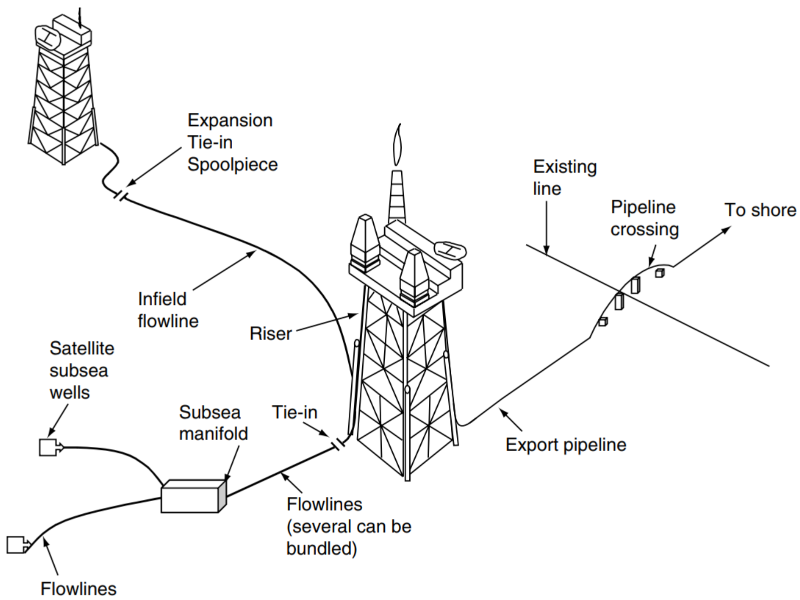

Figure 2.1: A basic overview of a pipeline system [1]

In the offshore environment there is a need for a diverse range of infrastructure, from production platforms and pipelines to storage facilities and support structures. Each component plays a role in facilitating the extraction and transportation of natural gas from offshore reservoir to onshore destinations and processing facilities. Understanding the importance of each of these systems is essential for assessing their potential for reuse. In order to understand these systems effectively, they can be broadly divided into two main parts: gas extraction systems and gas transport systems. This division helps in the understanding of the operations and maintenance of the entire offshore gas production process. The system is then further divided into different sections as can be seen in figure 2.2 This chapter will discuss each of these systems and their respective components.
This overview will serve as a reference point for further research, leading to the selection of specific components for further investigation. By narrowing this overview down into a subset aligned with the objectives of this study, the aim is to identify the components relevant to the reuse of pipeline infrastructure for CCS.

2.1.1. Gas Extraction Systems

The gas extraction systems are responsible for bringing natural gas from beneath the seabed to the wellhead. This includes various components and equipment used to manage and optimize gas extraction before it enters the in-field lines. The primary components involved in gas extraction systems are:

- **Subsea Trees:** Installed on wellheads to control the flow of gas. These trees are equipped with valves and chokes to manage the pressure and flow of the extracted gas. They play a critical role in ensuring safe and controlled extraction operations [2]. The subsea trees are designed to withstand the harsh underwater environment. Installed on these trees are automatic or remote-controlled valves to shut off flow in case of emergencies. They are crucial for preventing blowouts and ensuring the safety of the extraction process [3]. Safety valves are strategically placed to provide rapid response in the event of unexpected pressure changes, protecting both the infrastructure and the environment.
  Operating Pressure: The pressure at the wellhead typically ranges from 7 MPa to 70 MPa [4].
  Operating Temperature: The temperature at the wellhead can range from 277 K to 423 K [5].
- **Downhole Equipment:** Tools and equipment used within the wellbore to manage gas extraction, including packers, tubing, and safety valves. These components are essential for maintaining well integrity and optimizing production rates [3]. Downhole equipment ensures that the extraction process is efficient and that the well can be safely controlled under various conditions.

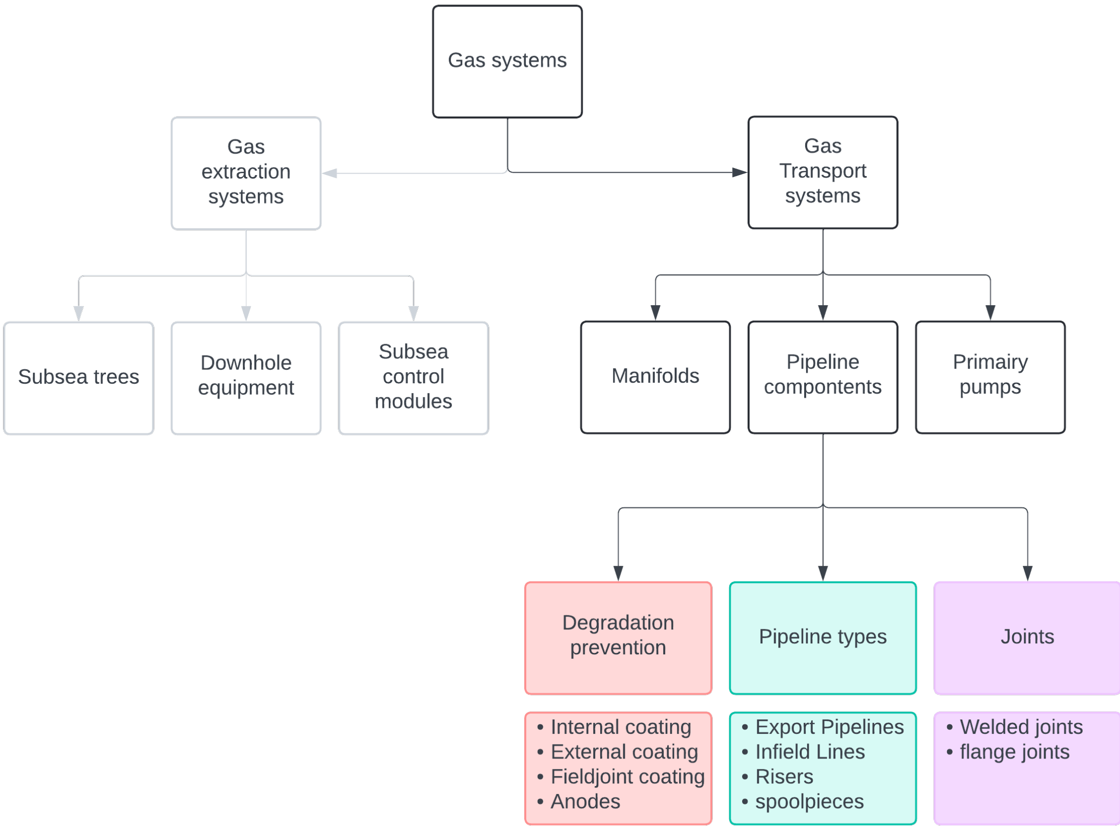

Figure 2.2: A schematic overview of the division between the different components

Operating Pressure: downhole pressures can range from approximately 20 MPa to over 100 MPa (200 to 1,000 bar) [6].
Operating Temperature: The temperature generally ranges from 363 K to 450 K [6].

- **Subsea Control Modules:** Next to the subsea trees the equipment for controlling subsea valves and monitoring well conditions is placed. These modules provide real-time data and control capabilities, enhancing the efficiency and safety of extraction operations [3]. The ability to remotely monitor and control the extraction process allows operators to quickly address any issues that arise, minimizing downtime and potential hazards.
  Operating Pressure: The pressure at the wellhead typically ranges from 7 MPa to 70 MPa [4].
  Operating Temperature: The temperature at the wellhead can range from 277 K to 423 K [5].

The goal of this study is to provide a foundation on which the feasibility research of reusing pipelines can be based. The components related to gas extraction systems are not within the scope of the research.

2.1.2. Gas Transport Systems

Gas transport systems are responsible for moving the extracted gas from the wellhead to processing facilities, either offshore or onshore. This section is further divided into three main categories: manifolds, pipeline components, and primary pumps. The division is based on the functional roles each component plays in ensuring the safe and efficient transport of natural gas.

Manifolds

Manifolds are crucial components in the gas transport systems, acting as junctions where multiple pipelines connect. They help in managing the flow of gas from various sources and direct it towards the main transport lines. Manifolds ensure efficient distribution and control of gas flow within the transport network. According to the Handbook for offshore engineering[7], manifolds are designed to handle high pressures and are equipped with various valves and control systems to manage the flow from different wellheads. This division helps in centralizing the control and distribution of gas, making the system more manageable and reducing the risk of leaks or failures.

Pipeline Components

Pipeline components are essential for the safe and efficient transportation of gas. These components include various types of pipelines, coatings, and joints. Dividing the pipeline components into specific types helps in addressing the unique challenges associated with different parts of the transport system.

Pipeline Types

Different types of pipelines are used in gas transport systems, each serving a specific purpose. The main pipeline types are:

- **Export Pipelines:** Pipelines transporting gas from offshore facilities to onshore facilities. These pipelines are typically long-distance and designed to handle high pressures and large volumes of gas [2]. Export pipelines are a critical link in the gas supply chain, ensuring that the extracted gas reaches processing and distribution centers efficiently.
  Operating Pressure: The pressure in the pipeline typically ranges from 7 MPa to 21 MPa [8].
  Operating Temperature: The temperature in the pipeline typically ranges from 277 K to 320 K [8].
- **In-Field Lines:** Pipelines connecting various offshore installations within a field. They facilitate the transfer of gas between different production and processing units [2]. In-field lines are essential for integrating the different components of an offshore field, allowing for flexible and efficient operations.
  Operating Pressure: In-field line pressures typically range from 5 MPa to 25 MPa (50 to 250 bar), though pressures can be higher in deepwater fields or in high-pressure reservoirs [5].
  Operating Temperature :The temperature in in-field lines typically ranges from 278 K to 338 K depending on the fluid composition and the thermal environment of the subsea floor [5]. .
- **Risers:** Vertical pipes that connect the subsea pipelines to surface facilities like platforms. Risers are designed to accommodate the dynamic movements of the sea and provide a flexible connection between subsea pipelines and surface facilities [7]. They are critical for ensuring the integrity of the pipeline system under varying environmental conditions.

Operating Pressure: Similar to the subsea pipeline, the pressure usually ranges from 7 MPa to 35 MPa [8].
Operating Temperature: The temperature in the riser typically ranges from 277 K to 338 K [5].

- **Spoolpieces:** Short pipeline segments that connect various subsea components. Spoolpieces provide flexibility in the layout and installation of subsea pipelines, allowing for connections between different sections of the pipeline network [3]. They are used to accommodate changes in direction and elevation.
  Operating Pressure: The pressure in spool pieces is generally similar to that in in-field lines, typically ranging from 5 MPa to 25 MPa (50 to 250 bar) [5]
  Operating Temperature: Spool pieces experience temperatures in the range of 278 K to 338 K [5].

Joints
Joints are used to connect different sections of pipelines. There are two main types of joints used in gas transport systems:

- **Welded Joints:** Permanent connections made by welding the pipeline sections together. Welded joints provide strong and leak-proof connections, essential for high-pressure gas transport [1]. These joints are critical for maintaining the structural integrity and safety of the pipeline under high pressure.
- **Flange Joints:** Connections made using flanges, which allow for easy disassembly and reassembly. Flange joints are used where pipelines need to be regularly inspected or maintained [1]. They provide flexibility in the pipeline system, allowing for easy access for maintenance and repairs.

Degradation Prevention components
Coatings are applied to pipelines to protect them from corrosion and other environmental factors. There are different types of coatings used in gas transport systems:

- **Internal Coating:** Applied to the inside of the pipeline to reduce friction and prevent corrosion. Internal coatings improve the flow efficiency and extend the lifespan of the pipelines [9]. They help in maintaining the integrity of the pipeline by preventing internal corrosion caused by the transported gas.
- **External Coating:** Applied to the outside of the pipeline to protect it from external corrosive environments, such as seawater and soil. External coatings are crucial for preventing corrosion and mechanical damage to the pipelines [7]. These coatings are essential for the long-term durability of pipelines exposed to harsh environmental conditions.
- **Fieldjoint Coating:** Applied to the joints of pipelines to ensure continuous protection at the connection points. Fieldjoint coatings are essential for maintaining the integrity of the entire pipeline system, especially at the welded or flanged joints [10]. Ensuring proper coating at joints is critical for preventing localized corrosion and potential leaks. This is considered a separate type of coating due to the fact that fieldjoints need to be coated in the field, making them significantly different from the internal and external coatings which are applied on the surface.
- **Anodes:**The primary function of anodes is to act as a sacrificial material that corrodes in place of the steel pipeline. In the cathodic protection system, the anodes are electrically connected to the pipeline, creating a galvanic cell. The anodes, being more reactive (having a more negative electrochemical potential) than the steel pipeline, corrode preferentially when exposed to seawater. This electrochemical reaction protects the pipeline by shifting the corrosion potential of the steel to a more negative value, effectively making it the cathode in the electrochemical cell, and thus preventing it from corroding.

Primary Pumps
Primary pumps play a vital role in gas transport systems by providing the necessary pressure to move the gas through the pipelines. These pumps ensure that the gas reaches its destination efficiently and safely, overcoming the resistance and distance involved in offshore transport. Primary pumps are designed to handle the high pressures and large volumes characteristic of offshore gas transport operations [7]. They are crucial for maintaining the flow of gas through the pipeline, especially over long distances and varying terrains.

2.1.3. Other components

Additional to the extraction and transportation related components, there also are some additional components such as production facilities, storage facilities and components that facilitate both some of the components mentioned in figure 2.2 and processing/storage facilities.

1. **Offshore Platforms:** These are the different types of platforms used for offshore gas exploration.
    - Fixed Platforms
    - Floating Platforms
    - Compliant Towers
    - Semi-Submersible Platforms
    - Tension Leg Platforms (TLPs)
    - Spar Platforms
2. **Storage Facilities:** Some offshore gas fields are connected to a storage facility before the gas is transported to the onshore facilites. Bellow are the components used for such an operation.
    - Floating Storage and Regasification Units (FSRUs)
    - Floating Storage Units (FSUs)
    - Offshore Storage Tanks
    - Subsea Storage Tanks
3. **Processing Facilities:** These are typical components used to process the raw gas and prepare it for transport.
    - Gas Processing Plants
    - Gas-to-Liquid (GTL) Plants

These components are not of importance for this study since almost all the components listed above are specialised for offshore gas operations. Only the Offshore platforms will be touched on briefly.

2.1.4. Infrastructure within the scope of this research

This research focuses on the gas transportation systems, more specifically on the pipeline components. Therefore the scope of this research is narrowed down and the list shown above will be shorted down. Additionally, the relevance and role of the jacket foundations in relation to the riser systems will also be looked at briefly due to the physical connection between a Riser and a jacket foundation. In the next chapter, the final selection of pipeline types within the scope of this research will be determined based on the loading types and most vulnerable components.

Pipelines

The most significant components for this research are the pipeline components themselves. This section contains a list of all the different types of pipelines considered.

- **Export Pipelines**
  Export pipelines form the bulk transportation part of offshore gas transportation, conveying raw or processed gas from offshore production platforms to onshore facilities or interconnecting pipelines. These pipelines are typically designed to withstand high pressures and varying seabed conditions. They may span vast distances, traversing diverse terrain, including deep water regions, subsea canyons, and shallow coastal waters. The engineering and construction of export pipelines involve meticulous planning, detailed route surveys, and adherence to stringent safety and environmental regulations. It is important to realise that export pipeline dimensions are determined by the installation loading instead of the much smaller operational loading[7].
- **Risers**
  Risers serve as vital connections between offshore structures and the seafloor. These vertical pipeline systems enable the transportation of fluids or gases. Risers in offshore oil and gas production, for instance, are crucial for conveying fluids or gasses from subsea wells to surface facilities. They can be rigid or flexible, depending on project requirements and environmental factors

- **Infield lines**
  infield lines connect individual wells or pipelines to production platforms or gathering hubs. These pipelines, for example, carry untreated gasses or fluids from the wellhead to processing facilities for initial treatment and separation. infield lines are characterized by relatively smaller diameters compared to export pipelines and are typically installed using flexible or rigid pipes, depending on water depth and seabed conditions. Subsea tie-ins and pigging facilities are often incorporated along the length of infield lines to facilitate maintenance and operational flexibility [1].
- **Spoolpieces**
  Spoolpieces are short sections of pipeline used to connect adjacent pipeline segments or facilitate changes in direction or elevation. These prefabricated components are crucial for maintaining pipeline integrity and facilitating efficient construction and installation operations. Spoolpieces are manufactured to precise specifications, ensuring a tight fit with existing pipeline infrastructure. They are commonly installed using specialized welding techniques or mechanical connections such as bolts, minimizing disruption to ongoing operations[1].

Offshore platform foundations
Offshore foundations, such as jacket structures and floating platforms, have a significant influence on the design, installation, and performance of risers in offshore oil and gas production systems and should therefore be taken into account for this research. The type of offshore foundation used can impact riser design considerations, operational safety, and environmental factors. Additionally, the connecting components between the riser and the platform have been looked at in order to potentially identify a critical point in the riser design which should be taken into account. NEN3656 states that the steel grade requirements for the bolts connecting the clamps to the platform have a stricter limit, ensuring that the connecting components will not form a critical point in the pipeline design[11]

- **Jacket Structures:**
  Support Structure Interaction: Jacket structures provide stable support for offshore platforms and serve as the primary interface between the seabed and topside facilities. The configuration and layout of jacket legs can affect the routing and installation of risers, influencing factors such as clearance, spacing, and bending radius. Dynamic Response: Jacket platforms are subjected to environmental loads, including wave, current, and wind forces, which can induce dynamic motions and vibrations. These dynamic responses can affect riser integrity and fatigue life, necessitating careful analysis and design considerations to mitigate potential risks. For the purpose of pipeline calculations, the displacements of the foundations should be known for the effect on the pipeline deformation.
- **Foundation Stability:**
  The stability and integrity of jacket foundations are critical for maintaining riser support and alignment, particularly in deepwater environments with challenging seabed conditions. Factors such as soil properties, foundation design, and installation techniques can impact the foundation's ability to resist lateral and vertical loads, affecting riser performance and reliability. For the sake of this research, the foundation stability is not within the scope. The foundation can be assumed stable for the remainder of it's lifetime.

2.2. Technical Requirements

This section examines the various types of loads affecting offshore pipelines, crucial for their design, maintenance, and operational strategies. It covers hydrostatic, thermal, operational, environmental, and hydrodynamic loads. These are all the relevant loads the system endures during operation and the leading parameters for determining the requirements for the pipelines. As can be seen, there is a connection between the environmental and operation loads applied in the area of temperature and pressure. This is a result of the fact that the loadings occur under a temperature gradient between the external and internal part of the pipeline. The relevant pressure for this type of loading is a combination between the hydrostatic pressure and the internal pressure.

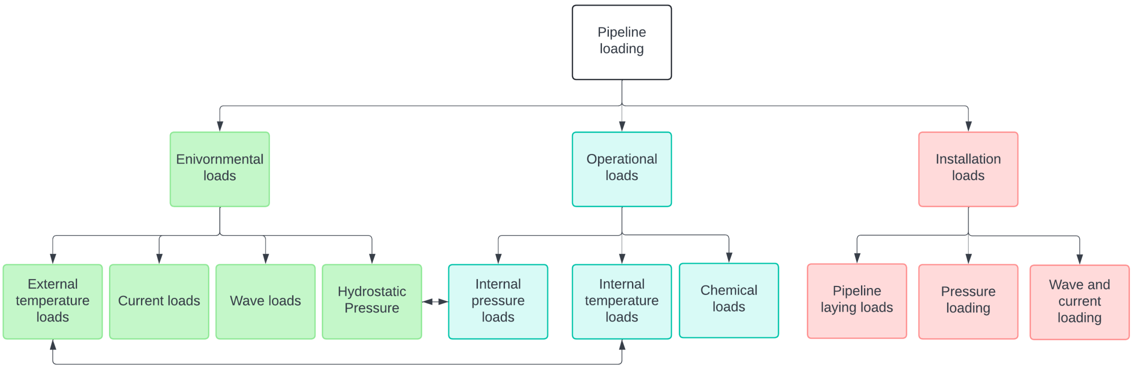

Figure 2.3: A schematic overview of the different types of loads, structured per type of load

2.3. Types of Loads

In order to better understand the different loads and where they act on, the loads are divided into several categories. These categories are shown in figure 2.3 and further explained in this chapter. The main division is made between environmental loads, operational loads and installation loads where some parts of the environmental and operational loads are connected. These connected loads are the temperature related loads and the pressure related loads which will be described as seperate sections.

2.4. Environmental loads

Environmental loads include all the loads that the sea, the wind or other nature related forces exert on the pipeline system. The four significant loading types are the current, wave, external pressure and external temperature loads. Both the external pressure and external temperature are tightly intertwined with the internal pressure and temperature, which will be further discussed in the coming sections.

2.4.1. Current loading

All seas have a current induced by wave motions [13]. Offshore structures are submitted to a loading of this current. The current profile follows a parabolic shape, being the lowest at the sea bottom due to bottom friction [14]. In figure 2.4, this current profile has been depicted.
The pipelines within the scope of this research are reused pipelines, therefore marine growth is a significant factor which should be included in the pipeline calculations. Current loading is calculated using the drag formula:

$$F_{current} = \frac{1}{2}\rho C_d D_{equivalent} U^2 \tag{2.1}$$

where:
C_d = The drag coefficient
$D_{equivalent}$ = The equivalent diameter of the pipeline
U = The velocity of the current

In this formula, the marine growth is accounted for in both the Drag coefficient C_D by adjusting the roughness of the pipe and by the increase of the equivalent diameter $D_{equivalent}$ [15].

2.4.2. Wave loading

With wave loading, the force that a wave exerts on a structure is meant. According to Gerwick et al.[3] the effects of wave action disappears at 3-4 meters in water depth, making wave loading only relevant for near waterline structures.
Since waves occur in all heights and lengths, it is important to determine which wave characteristics to use for Pipeline design. This section gives the wave heights and return periods as stated by the NEN, where for the stress analysis of a Riser is done by using the maximum wave height and period in an

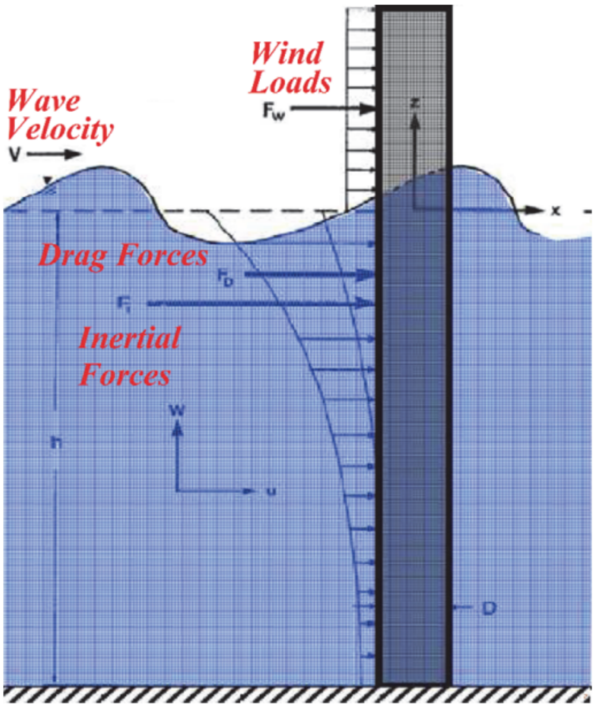

Figure 2.4: The different kinds of loadings an offshore structure can be submitted to[12]. Wind loads are not included in the loads since wind has no significant influence on subsea pipelines. Wind has influence on the platforms but this will be accounted for in a displacement of the pipeline.

interval of 100 years. However, Watters et al. [16] states that if the total load is a combination of the current and wave loading, a 50 year return period is more than enough due to the extreme remoteness of this combination happening. It can be concluded that the normative guidelines for Pipeline design regarding wave and current loading is stricter than necessary in certain combinations.
The wave characteristics have been determined at the beginning of each project. However, Aarnes et al. found out that the wave characteristics over time are changing [17]. Compared to the older historical data, many of the wave heights have increased over time, making it necessary to update the wave and current characteristics when assessing the pipeline for reuse.

2.5. Temperature Loading

Temperature loading on offshore gas pipelines is a significant factor that influences the structural integrity, operational performance, and safety of the pipeline system. This temperature loading arises from both external environmental conditions, such as seawater temperature, and internal factors, such as the temperature of the transported gas.

2.5.1. External Temperature Loading

External temperature loading refers to the thermal effects on the pipeline due to the surrounding seawater. Offshore pipelines are typically exposed to varying water temperatures, which can change significantly with water depth and geographic location. In deeper waters, the temperature is generally lower, which can induce contraction in the pipeline material, in shallower, warmer waters, the pipeline may expand [18]. The extent of this expansion or contraction depends on the thermal coefficient of expansion of the pipeline material and the temperature difference encountered along the pipeline's route.
These temperature-induced expansions and contractions generate axial and hoop stresses within the pipeline. If these stresses exceed the material's yield strength, they can lead to structural failures such as buckling or fracture. Moreover, thermal gradients, particularly those resulting from abrupt changes in water depth, can create zones of stress concentration[19]. These areas are prone to fatigue and may develop cracks over time. The design of offshore gas pipelines must account for these temperature variations to ensure their long-term reliability.

2.5.2. Internal Temperature Loading

Internal temperature loading arises from the temperature of the gas being transported through the pipeline. The temperature of the gas can vary significantly, especially when it enters the pipeline from different sources, such as wellheads, processing facilities, or other pipelines. The internal temperature can also change as the gas travels along the pipeline due to heat transfer with the surrounding environment.

High internal temperatures can cause the pipeline material to expand, which, when combined with external environmental conditions, may exacerbate the stresses experienced by the pipeline. On the other hand, low internal temperatures, particularly in deepwater environments, can lead to cooling of the pipeline material and contraction, which can result in excessive stress and potential failure. Additionally, temperature differences between the gas and the surrounding seawater can cause significant thermal gradients across the pipeline wall, leading to thermal stresses that can weaken the pipeline over time. In the case of offshore gas pipelines, maintaining a stable internal temperature is crucial to preventing the formation of hydrates and waxes, which can obstruct gas flow[20]. Insulation and heating systems are often employed to manage the internal temperature of the gas and prevent such issues [1].

2.5.3. Effect on fatigue lifetime

The some of the loadings presented in the previous section have cyclic behaviour. This cyclic behaviour can cause fatigue in the pipeline. Therefore the cyclic loading should be taken into account by performing a fatigue lifetime assessment.

2.6. Pressure Loading

Pressure loading is another significant factor in pipeline loading. This pressure loading arises from both internal sources, such as the pressure of the transported gas, and external sources, such as hydrostatic pressure from the surrounding seawater. For gas extraction, the pressure inside the reservoir will reduce over time since the reservoir is getting more and more empty. However, in the case of CO2 injection, the required pressure for injection will increase over time since the reservoir is getting fuller. This has to be taken into account to ensure safe operation.

2.6.1. Internal Pressure Loading

Internal pressure loading is generated by the gas being transported through the pipeline. The pressure within the pipeline is typically high to ensure the efficient transport of gas over long distances and to overcome frictional losses. The internal pressure exerts a circumferential (hoop) stress on the pipeline wall, which is a primary consideration in the design and operation of the pipeline.

The hoop stress is calculated using the formula[1]:

$$\sigma_h = \frac{p_i \cdot D}{2t} \tag{2.2}$$

where σ_h is the hoop stress, p_i is the internal pressure, D is the pipeline's internal diameter, and t is the wall thickness. This stress acts circumferential around the pipeline, tending to expand the pipeline's diameter.

If the internal pressure exceeds the material's yield strength, it can lead to plastic deformation or even rupture. Therefore, offshore gas pipelines are designed with safety factors to withstand maximum expected pressures.

2.6.2. External (Hydrostatic) Pressure

Hydrostatic pressure is the pressure exerted by the seawater surrounding the pipeline. This pressure increases with water depth and acts uniformly on the external surface of the pipeline. The hydrostatic pressure is given by:

$$p_h = \rho \cdot g \cdot h \tag{2.3}$$

where p_h is the hydrostatic pressure, ρ is the density of seawater, g is the acceleration due to gravity, and h is the depth of the water.

2.6.3. Combined Pressure Loading

The combination of internal and external pressures results in a net pressure loading that the pipeline must withstand. The net radial pressure on the pipeline wall is the difference between the internal and external pressures:

$$p_{net} = p_i - p_h \tag{2.4}$$

where:
p_{net} = The net radial pressure.
p_i = The external pressure.
p_e = The internal pressure.

This combined pressure loading creates a state of stress within the pipeline wall that includes both hoop stress from internal pressure and compressive stress from external hydrostatic pressure. The pipeline must be designed to handle these combined stresses without yielding or buckling.
In order to combine the internal pressure with the external pressure, the following formula is used[21]:

$$\sigma_\theta = \frac{(p_{net})\,R}{t} \tag{2.5}$$

where:
σ_θ = The hoop stress in the Pipeline
p_{net} = The net radial pressure.
R = The radius of the pipeline
t = The thickness of the pipeline

This formula gives a relation between the absolute pressure working on the pipeline, the geometric parameters of the pipeline and results in the maximum hoop stress on the pipeline, which can cause pipeline failure.

2.7. Operational Loads

The Operational loads of an offshore pipeline can be seen as all the loads a pipeline experiences when it is being used for its primary purpose; the transportation of a substance. For this research, the loads are divided into three different types of loading:

1. Internal Pressure loads
2. Internal temperature loads
3. Chemical loads

The first 2 loading types have already been discussed in the previous section due to their tight connection with both the environmental temperature and hydrostatic pressure. But in order to make the operational loads complete, the chemical loading of a pipeline should be considered as well.

2.7.1. Chemical Loads on Pipelines

Chemical loads refer to the stresses and potential damage exerted on pipeline materials due to chemical interactions, which can occur both internally, from the transported materials, and externally, from the environment surrounding the pipeline. The primary consequence of these interactions is corrosion, leading to material degradation, loss of mechanical integrity, and eventual failure of the pipeline infrastructure [22].

Internal Corrosion:
Internal corrosion occurs when the pipeline transports corrosive materials, such as water with high chloride content or hydrocarbons containing CO2 and H2S. Factors like temperature, pressure, and flow velocity can accelerate the corrosion processes [22]. Gas pipelines have such impurities according to the findings of Ammar Ali Abd et al. [23]. The typical compositions of substances found in a natural gas pipeline are listed in table 2.1. Internal corrosion is usually prevented by using certain materials for the pipeline itself, injecting corrosion preventing chemicals, putting a liner within the pipeline or using cathodic protection. These methods are further described in section 2.8.

Natural Gas Components (mol%)	Non-Hydrocarbons Components (mol%)
Methane 96	Argon ≤ 0.05
Ethane 2	Nitrogen ≤ 10
Propane 0.6	Hydrogen sulfide ≤ 5
Isobutane 0.18	Helium $\leq 0.5\%$
n-butane 0.12	Carbon dioxide ≤ 5
Isopentane 0.14	Oxygen ≤ 0.01
n-Pentane 0.06	Water ≤ 147 ppm
Hexanes 0.1	Hydrogen ≤ 0.02
Heptanes 0.8	

Table 2.1: Typical compositions of natural gas in-pipeline components

Interviews with experts from the industry resulted in the notion that all kinds of corrosion residue on the inside of the pipeline needs to be removed before CO2 can be transported through the pipeline due to the high solubility of CO2 which can cause additional corrosion [9]. Also the CO2 needs to be absolutely dry before transportation to prevent internal degradation by corrosion which can get as high as 20mm/year. This has proven to be a realistic and achievable requirement.
In order to calculate the internal corrosion rate, the corrosion mechanism must be found. In the handbook of pipeline engineering [7], the most damaging corrosion mechanism for gas pipelines is stated to be the sweet corrosion caused by the presence of CO2 in the pipeline stream. This corrosion rate can be calculated using the NORSOK M506 method [24]. This method uses the partial pressure of the CO2 present in the pipeline together with empirical determined constants to come to the following formula:

$$CR = A \times (P_{\text{CO2}})^B \times e^{C \times T}$$

Where:

- $A = 0.03$ (empirical constant)
- $B = 0.7$ (exponent for the relationship between CO2 partial pressure and corrosion)
- $C = 0.02$ (temperature effect constant)
- P_{CO2} is the partial pressure of CO2
- T is the temperature

This equation can calculate the corrosion rate per year.

External Corrosion:
External corrosion is influenced by environmental factors such as soil chemistry, moisture content, and for marine pipelines, the corrosive nature of saltwater [22]. External corrosion is usually prevented by coatings and cathodic protection. These methods are further described in section 2.8.

2.7.2. Stress Corrosion Cracking (SCC) in Offshore Gas Pipelines

SCC is a type of corrosion that occurs due to the combination of a tensile stress and a corrosive environment [25]. This can lead to sudden and unexpected failures in pipeline steels, especially under conditions where both mechanical stress and corrosive loadings are present, such as offshore environments. The combination of tensile stress and a corrosive environments in and on a material such as steel leads to localized anodic and cathodic reactions on the material's surface or at microstructural defects. Areas under tensile stress become anodic, where the metal starts to dissolve, while less stressed areas act as cathodes. This difference in electrochemical potential leads to the initiation of microscopic cracks, leading to critical failure of the pipeline.
Offshore pipelines are particularly vulnerable to SCC because they operate in harsh environmental conditions where they are exposed to high chloride marine atmospheres, varying pressures, and temperatures [25]. The presence of these factors, combined with the high mechanical stresses from ocean currents and installation processes, creates an ideal scenario for SCC.

The primary danger of SCC is its ability to lead to catastrophic failure with little to no prior deformation or visible damage, making it difficult to detect and predict without regular monitoring [25]. Cracks initiated by SCC grow rapidly and can compromise the structural integrity of the pipeline. section 2.8 dives deeper into SCC and it's mitigation strategies.

2.8. Degradation of steel pipelines

Steel pipelines are often used for transport in harsh offshore environments. These pipelines are exposed to various ways of degradation, primarily corrosion. This section provides a comprehensive review of the mechanisms, factors, and mitigation strategies associated with the degradation of offshore steel pipelines.

2.8.1. Mechanisms of Degradation

The degradation of offshore steel pipelines occurs through various mechanisms, with corrosion being the most prominent. Corrosion can be categorized into external and internal types, each influenced by different factors and environmental conditions [1].

External Corrosion

External corrosion occurs on the outer surface of pipelines, primarily due to interactions with the marine environment. Factors such as seawater salinity, temperature, dissolved oxygen content, and the presence of biofouling organisms significantly affect the rate of external corrosion. According to Farh et al. [26], the aggressive nature of seawater and the presence of microorganisms contribute significantly to the external corrosion of offshore pipelines.
External corrosion in offshore environments is exacerbated by various marine conditions. High salinity and dissolved oxygen levels accelerate the corrosion process. Additionally, marine growth and biofouling can create differential aeration cells that further increase corrosion rates [27]. According to Singh [28], about 70% of offshore pipeline failures are due to external corrosion.

Internal Corrosion

Internal corrosion occurs within the pipeline and is influenced by the transported fluids. Key factors include the presence of corrosive gases (e.g., CO2, H_2S), water content, flow velocity, temperature, and pH levels. As highlighted by Cabrini et al. [29], CO2 corrosion is a significant issue in oil and gas pipelines, often resulting in localized attacks and severe pitting.
Internal corrosion can degrade the pipeline's integrity, impacting flow efficiency and leading to potential leaks. The presence of impurities such as sulfur oxides (SOx) and nitrogen oxides (NOx) in CO2 streams can further exacerbate internal corrosion, especially under supercritical CO2 conditions [30].

2.8.2. Mitigation Strategies

Effective corrosion protection strategies are essential for extending the lifespan of offshore steel pipelines. These strategies can be broadly classified into passive, active, and hybrid methods.

Passive Protection Techniques

Passive protection involves isolating the pipeline material from the corrosive environment. Common techniques include coatings, linings, and the use of corrosion-resistant materials. Coatings, such as fusion-bonded epoxy and polyethylene, provide a physical barrier against corrosive agents [26]. Other coatings like bitumen, polyethylene encasements, and metallic coatings such as zinc can also be effective [27].
According to the comprehensive review by Hussein et al. [27], coatings can significantly reduce the corrosion rate. For instance, anti-fouling coatings are critical in offshore environments to prevent biofouling and subsequent corrosion [28].

Active Protection Techniques

Active protection methods involve the application of electrical currents to prevent corrosion. Cathodic protection, using either sacrificial anodes (galvanic protection) or impressed current systems, is widely used to protect pipelines from external corrosion [26]. These systems are effective in controlling corrosion by providing a continuous electrical current that counteracts the natural corrosion process [27].

Farh et al. [26] detailed that cathodic protection is especially beneficial for offshore pipelines exposed to highly corrosive seawater. Impressed current cathodic protection (ICCP) systems, although more complex and expensive, offer robust protection for long offshore pipelines by maintaining a constant protective current [28].

Hybrid Protection Techniques

Hybrid techniques combine passive and active methods to enhance corrosion protection. For instance, the use of coatings in conjunction with cathodic protection systems provides a comprehensive defense against both external and internal corrosion [26]. These methods ensure that even if the coating is damaged, the cathodic protection system can prevent corrosion at the exposed areas [27].
Hybrid protection techniques, as noted by Farh et al. [26], leverage the strengths of both approaches to offer a synergistic effect. For example, a combination of anti-fouling coatings and sacrificial anodes can provide excellent protection in the marine environment while reducing the overall maintenance requirements [28].

2.9. Installation Loads on Offshore Pipelines

Installation loads are all the loads associated with the installation phase of a pipeline. These loads occur during the handling, lowering, and positioning of the pipeline on the seabed or at the jacket structure. There are several loads associated with the installation of a pipeline, the following list gives the most significant loads.

- **Pipe laying loads**: As the pipeline is lowered down from the lay vessel and descends to the seabed, it passes through a series of bending moments due to the curvature it needs to make. This can induce significant stress in the pipeline material [31].
- **External Pressure and Collapse**: During the installation, parts of the pipeline might experience different external pressures, especially in deep waters, leading to potential collapse if not properly managed. This is particularly critical during the initial submersion and final placement [32] but it can be prevented by flooding or pressurising the pipeline to ensure the difference between the external and internal pressure it not going over the limit.
- **Wave and Current Interactions**: Particularly relevant for risers, wave and current interactions play a significant role during installation. Waves and currents can induce dynamic stresses on the riser, influencing its installation trajectory and tension requirements. These interactions must be modeled to optimize installation procedures and ensure the structural integrity of the riser as it is guided to its final position [33].

2.9.1. Installation loads in relation to research

While the installation loads must be considered for a proper pipeline design, these loads are not of importance in a situation where the aim is to reuse a pipeline. Therefore the installation loads are not within the scope of this research and will not be included in any further sections.

2.10. Other phenomena to take into account

Besides the physical en chemical loading of a pipeline, there also are other phenomena to take into consideration when looking at the feasibility of reusing pipelines. One of these most important phenomena is running ductile fractures.

2.10.1. Running Ductile Fracture

Running ductile fracture is a critical failure mode in pipelines, particularly in high-pressure systems such as those used for the transportation of carbon dioxide in Carbon Capture and Storage (CCS) projects. This phenomenon involves the rapid propagation of a crack along the length of a pipeline, driven by the internal pressure of the transported fluid. Understanding and mitigating running ductile fractures is essential for ensuring the safety and integrity of pipeline systems.

Mechanism of Running Ductile Fracture

Running ductile fractures occur in materials that experience significant plastic deformation before fracturing. The fracture typically initiates at a defect or stress concentration point within the pipeline, such

as a weld flaw, corrosion pit, or mechanical damage. Once initiated, the fracture propagates rapidly, with the pipeline material deforming plastically ahead of the crack tip [34].
The propagation of the fracture is sustained by the high internal pressure of the transported fluid, which continues to drive the crack forward. The rate of crack propagation can approach the speed of sound in the material, leading to a potentially catastrophic release of the pipeline's contents [35].

Factors Influencing Running Ductile Fracture
Several factors influence the initiation and propagation of running ductile fractures in pipelines:

- **Material Toughness:** The toughness of the pipeline material is a critical factor in determining its resistance to fracture. Higher toughness materials can absorb more energy before failing, reducing the likelihood of a running fracture [36].
- **Internal Pressure:** Higher internal pressures increase the driving force for crack propagation, making it more challenging to arrest a running fracture once it has initiated [35].
- **Temperature:** The temperature of the pipeline material can influence its ductility and toughness. Lower temperatures may reduce ductility, increasing the risk of brittle fracture, whereas higher temperatures generally enhance ductility [37].
- **Impurities and Gas Composition:** The presence of impurities or other gases mixed with CO2 can affect the fracture toughness of the pipeline material. Impurities may lead to localized corrosion, creating initiation points for fractures [5].

2.11. Scope of this research

Now that there a list of components and a list of loads has been established, a scope of this research can be determined. Out of the listed pipeline types, the joints, primairy pumps and manifolds are not within the scope of this research. These components typically have non metallic components which will react with CO2[38] and have to be replaced, looking at reuse for these types of components is of no use. The main goal is to find out if it is feasible to reusing offshore gas pipelines for carbon capture and storage purposes in expired gas reservoirs. This means that, in order to find the most probable failure point, the weakest part of the pipeline has to be investigated.
To do so, the different components and the different loadings have been put together in the table bellow, if the loading is relevant to the component mentioned, there's an x, if not, the cell is empty.

Pipeline types	**External temperature**	**current**	**Waves**	**Hydrostatic Pressure**	**Interal pressure**	**Internal Temperature**	**Chemical loads**	**Total:**
Export Pipelines	x			x	x	x	x	5
Infield Lines	x			x	x	x	x	5
Risers	x	x	x	x	x	x	x	**7**
Spool piece	x			x	x	x	x	5

Table 2.2: The pipeline types combined with which loadings apply to the different types.

As can be seen in table 2.2, the Riser has the largest range of loading conditions working on it. Export lines, infield lines and spool pieces do not experience critical loading from current and waves since they are located under or on the seafloor, where waves have no influence and current is at a minimum. The Riser experiences all the loading types and can be seen as the most vulnerable pipeline type. The main focus of the feasibility study will therefore be the Riser. The corrosion and degradation prevention components will be included in the research due to their role in ensuring the safety of the pipeline.

2.12. Natural gas and CO2 properties

The difference in properties during transport between natural gas and CO2 is one of the key elements when determining whether or not reusing pipeline components is feasible. Table 2.3 shows the difference in characteristics of natural gas and CO2. Although the pressure and temperature characteristics of CO2 and natural gas are of the same magnitude, CO2 is often transported in a super critical phase in order to maximize efficiency. This is dependend on the operating temperature and pressure of the pipeline itself. In most cases, the pressure and temperature of CO2 operations will be similar to the pressure and temperature of the gas pipeline due to the required pressure of the reservoir for injection and the outside temperature.

Characteristic	**Natural Gas**	**CO_2 (for CCS transport)**
Typical Pressure (Offshore Pipeline)	100-150 bar	100-150 bar (can go higher for dense-phase transport)
Typical Temperature (Pipeline)	5°C to 60°C	-10°C to 40°C (dependent on phase)
Phase (Pipeline Conditions)	Gaseous	Can be in gaseous, liquid or critical phase
Critical Pressure	$\sim$46 bar	$\sim$74 bar
Critical Temperature	-82.6°C	31.1°C
Density	0.8-0.9 kg/m^3 (gas at pipeline conditions)	400-1100 kg/m^3 (depending on phase and pressure)
Viscosity	0.01-0.02 cP	0.05-0.1 cP (dependent on phase)
Compressibility Factor (Z)	Typically around 0.85-0.95 for gas phase	0.2-1.0 (varies significantly with phase and pressure)
Corrosiveness	Low, but increases with impurities like CO_2	High, especially in presence of water (forms carbonic acid)
Hydrate Formation Conditions	Below $\sim$25°C and $\sim$50 bar (with water)	Forms hydrates below $\sim$10°C, high pressures, water
Main Phase in Reservoir	Gas	Supercritical or dense phase (in CCS applications)
Thermal Conductivity	$\sim$0.03 W/m·K (for gas phase)	$\sim$0.1-0.2 W/m·K (varies with phase and pressure)
Transport Phase Considerations	Always gaseous in pipelines	Typically transported in supercritical/dense phase for efficiency

Table 2.3: Comparison of Natural Gas and CO_2 Characteristics for Offshore Transport [39][40]

2.12.1. CO2 phase during transport

CO2 preferably is transported in a dense liquid or supercritical phase due to the added efficiency of such a phase. In the case of reuse, a certain amount of pressure is needed to inject the CO2 in the reservoir. Therefore, similar conditions between natural gas operations and CO2 operations are most likely and can be assumed. According to 2.5, this means that the CO2 will be transported in a liquid dense or supercritical phase.

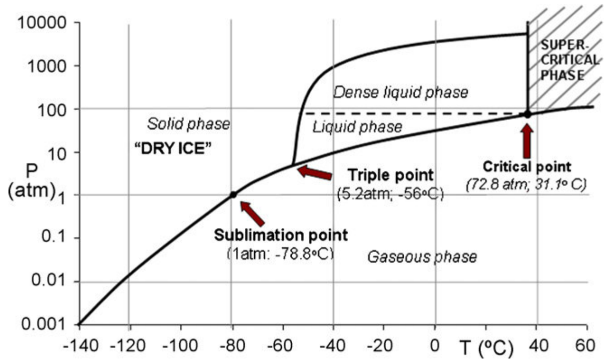

Figure 2.5: The phase diagram of CO2 [41]

2.13. Regulatory requirements for CO2 Pipelines

This section provides a detailed methodology for calculating the structural integrity of a pipeline system in accordance with NEN and DNV codes. The scope of this research is limited by these two types due to the NEN being based on the ISO codes where the NEN codes are often stricter and more conservative than the ISO codes. Secondly, the NEN codes often refer to the DNV codes for calculation methodes. This section includes relevant sections and equations of the NEN standards and DNV codes, ensuring adherence to the latest standards in pipeline engineering.

2.13.1. NEN Standards and DNV Codes Overview

The design and analysis of pipeline systems are governed by various standards and codes to ensure safety and reliability. The relevant standards and codes are:

1. **NEN-EN 13480 series:** Metallic industrial piping [42].
2. **NEN-EN-ISO 3183:** Steel pipelines for gas and oil transmission [43].
3. **NEN-EN 10208-2:** Steel pipes for pipelines used in the transport of combustible fluids [44].
4. **NEN 3650-1:** Determination of the resistance to internal pressure - Part 1: General principles [45].
5. **NEN 3650-2:** Determination of the resistance to internal pressure - Part 2: Unbonded flexible pipe [46].
6. **NEN 3650-3:** Determination of the resistance to internal pressure - Part 3: Reinforced thermoplastic pipe [47].
7. **NEN 3650-4:** Determination of the resistance to internal pressure - Part 4: Bonded flexible pipe [48].
8. **NEN 3656:** Requirements for steel offshore pipelines [11].
9. **NEN-EN-ISO 15589-2:** Cathodic protection of pipeline transportation systems - Part 2: Offshore [49].
10. **DNVGL-RP-D101** - Structural Analysis of Piping Systems [50]
11. **DNV-OS-F101** - Submarine Pipeline Systems [51]
12. **DNV-RP-E305** - On-Bottom Stability Design of Submarine Pipelines [52]
13. **DNV-RP-F116** - Integrity Management of Submarine Pipeline Systems [53]

The connection between the codes can be seen in figure 2.6. The NEN-codes NEN3656 and NEN3650-1 up to 4, are all part of the NEN3650 series where NEN3656 is specified into offshore pipelines. In figure 2.6 the specific input from the DNV codes are also shown since the NEN3650 series uses input and calculation methods from these DNV codes.

2.13.2. Design Data and Input Parameters

The initial step involves gathering all necessary design data, including environmental conditions, material properties, and pipeline specifications. This data is crucial for accurately modeling the pipeline

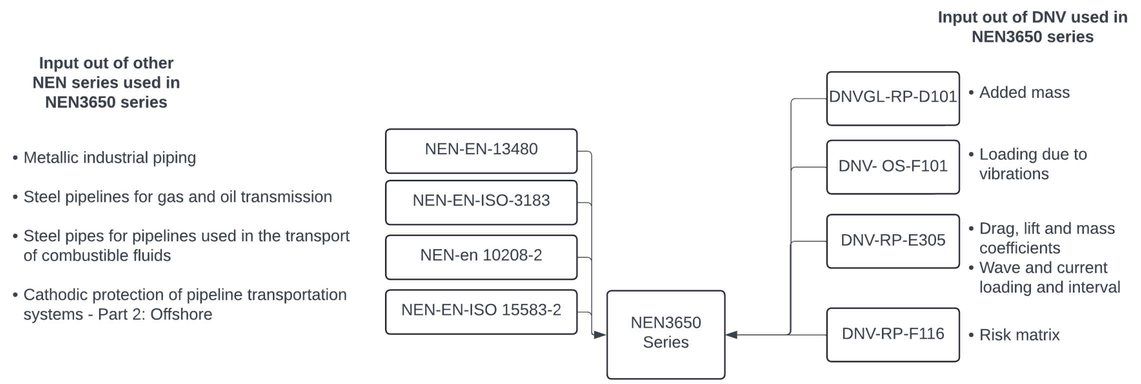

Figure 2.6: A diagram showing the connection between the different codes.

system and performing subsequent calculations. The main parameters are similar for most standards and include:

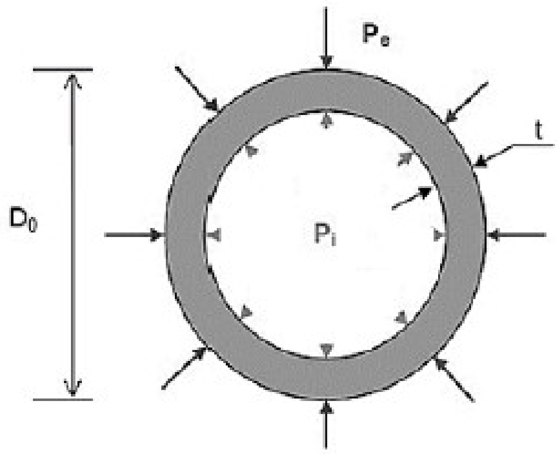

Figure 2.7: The main pipeline dimensions [54]

- **Pipeline Geometry**: Outer diameter (D_0), wall thickness (t), and length as can be seen in figure 2.7 [11] [55].
- **Material Properties**: Yield strength (σ_y), tensile strength, modulus of elasticity (E), Poisson's ratio (ν) [11][43][44][55]..
- **Environmental Conditions**: Soil properties, internal and external pressures (P_i),(P_e)[55].[56].
- **Operating Conditions**: Type of gas being transported, its density, and flow rate.
- **Material Selection**: Guidelines for selecting appropriate materials based on the operating environment and fluid properties [42][55]..
- **Inspection and Testing**: Non-destructive testing methods and inspection requirements to ensure pipeline integrity [42][44][55]..
- **Welding and Fabrication**: Standards for welding procedures, qualifications, and fabrication processes [42][11][55]..
- **Design Pressure**: Criteria for determining the design pressure based on operating conditions [43][55]..
- **Manufacturing Processes**: Standards for the manufacturing and testing of steel pipes [43][55]..
- **Quality Control**: Procedures for ensuring the quality and reliability of the pipelines [43][55]..
- **Corrosion Protection**: Coating systems and cathodic protection measures [44][49][57].

- **Pressure Ratings**: Guidelines for determining the pressure ratings of the pipes [44][55]..
- **Calculation Values for Loads and Material Properties**: Derivation of calculation values from representative loads and material properties [11][55]..
- **Geotechnical Parameters**: Soil-pipeline interaction parameters such as vertical and horizontal soil loads, soil stiffness values, and friction between pipeline and soil [11] [56].
- **Load Factors and Combinations**: Size and nature of load factors and combinations based on the pipeline's position and area class [11][55]..
- **Design of Cathodic Protection Systems**: Criteria for designing cathodic protection systems for offshore pipelines [49][57].
- **Materials and Installation for Cathodic Protection**: Requirements for materials and installation procedures for cathodic protection systems [49][57].
- **Monitoring and Maintenance of Cathodic Protection**: Guidelines for monitoring and maintaining cathodic protection systems to ensure long-term effectiveness [49][57].

The design data should also include details about the pipeline's operating conditions, such as the type of gas being transported, its density, and flow rate. This information is necessary for calculating the internal pressures and forces acting on the pipeline.

Design Loads
Design loads are the forces and pressures that the pipeline must withstand during its lifecycle. These include:

- **Environmental Loads**: Environmental loads include wave and current forces, as well as seabed interactions. These can be obtained through site-specific surveys and oceanographic data analysis [56].
- **Operational Loads**: These are the internal pressures due to the transported fluid. They are calculated based on the maximum operating pressure (MOP) and transient pressure surges [11][55].
- **Construction Loads**: These are loads applied during the installation of the pipeline, such as tension from pipelay operations. Construction load effects are typically evaluated using finite element analysis (FEA) [55]. This research focusses on the reuse of existing pipelines, therefore the construction loads are not within the scope of this research.

2.13.3. Environmental Loads

Wave and Current Loading
NEN3656 states that the wave and current loading for strength analysis shall be based on maximum and significant wave height. Table 2.4 shows, in the first row, the load cases combined with the relevant interval over which the wave height/period may occur. The second row shows the combinations of load cases and intervals for the determination of the pipeline stability [11].

Design aspect	**Section**	**Load case**	**Wave height** m	**Wave period** s	**Repeat interval** ***years***
Stress analysis	Pipeline	Buried within a year after installation	Maximum	Maximum	1
		Self-burying after *N* years	Maximum	Maximum	3*N*
		Not buried	Maximum	Maximum	100
	Riser	Attached to platform	Maximum	Maximum	100
Pipeline stability	Pipeline	Buried within a year after installation	Significant	Significant	1
		Self-burying after *N* years	Significant	Significant	3*N*
		Not buried	Significant	Significant	100
	Riser	Attached to platform	Maximum	Maximum	100

Table 2.4: Assumptions for hydrodynamic loads in the design [11]

NEN3656 states that ”Wind, wave and current loads based on known data as well as relevant hydrodynamic coefficients may be determined in accordance with generally accepted requirements, publications and/or model tests” [11]. Additional calculations should be done to further determine the loads on the pipeline by waves and currents. These methodologies and equations are described in the following sections and in combination with the additional calculations based on publications and model tests should ensure that submarine pipelines designed and assessed according to NEN standards and DNV codes are robust, reliable, and capable of withstanding the complex environmental and operational loads they encounter.

Wind Loads
Wind loads are calculated based on the wind speed at a reference height and the shape of the pipeline and its support structures. The wind speed is often derived from meteorological data, with design wind speeds typically selected for specific return periods as described in the previous section [56].
The wind force F_w acting on the pipeline can be estimated using:

$$F_w = \frac{1}{2}\rho_w C_d A v_w^2 \tag{2.6}$$

where:

- ρ_w is the air density,
- C_d is the drag coefficient,
- A is the projected area of the pipeline perpendicular to the wind direction,
- v_w is the relevant wind speed [56].

Wave Loads
Wave loads are calculated using the Morison equation, which takes into account both inertia and drag forces. The significant wave height (H_s) and wave period (T_s) are used to determine the wave-induced forces [56].
The total wave force F_w on a segment of the pipeline can be calculated as:

$$F_w = F_{inertia} + F_{drag} \tag{2.7}$$

where:

- $F_{inertia} = \rho_w \pi \frac{D^2}{4} a_m$,
- $F_{drag} = \frac{1}{2}\rho_w C_d D u_m |u_m|$

Here:

- ρ_w is the water density,
- a_m is the water particle acceleration,
- u_m is the water particle velocity,
- C_d is the drag coefficient,
- D is the diameter of the pipeline.

Current Loads

Current loads are similar to wave loads and are calculated based on the steady current velocity (v_c). The force F_c due to the current is given by:

$$F_c = \frac{1}{2}\rho_w C_d D L v_c^2 \tag{2.8}$$

where L is the length of the pipeline segment considered.

These calculations are based input parameters with a certain interval, for example the significant wave height in a 10 year period. By taking the right interval for the right parameter, the loads on the offshore structure can be determined without using an advanced FEM model [56].

2.13.4. Stress and Strain Analysis

NEN3656 determines the maximum hoop stress in relation to the yield strength. The geometrical parameters and loading of the pipe must be chosen in such a way that the hoop stress is smaller or equal to the yield strength of the material as can be seen in the formula stated below:

The critical circumferential stress (hoop stress) is determined by Formula (I.1):

$$\sigma_p = \frac{\gamma_s \times p_d \times D_g}{2 \times d} \leq R_e \tag{I.1}$$

where

- σ_p is the circumferential strain (hoop stress) from internal pressure, in N/mm^2;
- p_d is the design pressure, in MPa;
- D_g is the average diameter, in mm;
- d is the minimum wall thickness, in mm;
- R_e is the yield strength, in N/mm^2;
- γ_s is the critical load factor, this is equal to (γ_m) in the entire calculation model (see Table K.2).

Figure 2.8: NEN3656, ANNEX I

Given that the yield strength, the diameter, the wall thickness and the load factor are known, this formula gives the maximum design pressure the system can handle.

In order to adhere to NEN3656, a set of different load cases should be looked at. This variation of load cases can be seen in figure 2.9.

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Table 3 — Load combinations and load factors for ultimate limit states

Loads	Construction phase	**Load factors (γ_S) for load combinations (LC)** [a]							
		Operational phase							
		Internal pressure only operating pressure, incidental pressure [b]	External load with zero internal pressure	External load with internal pressure and temperature difference	Alternating loads (mainly statically loaded, e.g. temperature variations and pressure variations)	External pressure, external load and internal pressure zero	Incidental load (other than internal pressure)	Incidental loads (meteorological)	Alternating loads (dynamically loaded)
Load combinations	LC 1	LC 2	LC 3	LC 4	LC 5	LC 6	LC 7a	LC 7b	LC 8
Internal pressure (design pressure) [b]		1,25	–		–		1,00		1,00
Internal pressure (in combination with other loads)		–	–	1,15	1,15			1,00	1,15
Internal pressure (max. incidental pressure) [b]		1,10	–	–	–				1,10
Temperature differences [c, g]	1,00		–	1,10	1,10		1,00	1,00	
Geotechnical variables [d]			d	d	d			low	
Forced deformation [e]			1,10	1,10	1,10	1,10			
Dead weight	1,10		1,10	1,10	1,10	1,10	1,00		1,00
Any coating [h]	1,20		1,20	1,20	1,20	1,20	1,00	1,20	1,00
Weight of fluid [h]	1,10		1,10	1,10	1,10	1,10	1,00	1,10	1,00
Construction loads [f]	1,10		1,10			1,10			
External water pressure	1,10		1,10	1,10	1,10	1,10	1,00	1,10	
Marine growth (submarine pipeline) [h]			1,20	1,20	1,10		1,00	1,00	1,00
Current loads (submarine pipeline)	1,10		1,20	1,20	1,10	1,10	1,00	1,20	1,00

[a] If the load has a favorable influence on the limit state in question, it is not used in the calculation if it relates to a variable load, and when it is a permanent load, it is used in the calculation with a load factor of 0,9.

[b] The maximum incidental pressure does not have to be assessed separately, but shall be guaranteed by the pressure control system.

[c] When calculating stress ranges as a result of temperature variations the difference between the highest and lowest operating temperature occurring shall be used as temperature range in the calculation. In determining the displacement and forces and moments on connected equipment and/or structures, the design temperature range may be based on the difference between the construction temperature and the critical operating temperature.

[d] For factors for spatial variation of soil properties and model factors to take into account when calculating geotechnical parameters, see K.4.

[e] Imposed deformation may be: settlement differences, uneven trench bottom, subsidence differences following construction, deformation caused by impeded thermal expansion, deformation during horizontal directional drilling (HDD) and with trenching.

[f] Examples of construction loads are: loads resulting from tensile forces on trenching, loads during horizontal directional drilling, pressure forces from pipe thrust jacking and lifting forces from side booms, draglines and floating cranes.

[g] In combination with measurements.

[h] In the stability check (LC 7b), select the most unfavorable combination. If necessary, divide by the relevant factor.

Figure 2.9: All the load combinations stated by NEN3656[11]

Since this research aims to lay the first step towards the reuse of an existing pipeline, Load combination 1 is irrelevant due to the fact that this load combination specifically describes the construction phase whereas reused pipelines have already been installed.

In order to be suitable for reuse, the pipeline should be able to withstand all the load cases mentioned in figure 2.9 for the new operating conditions and in an corroded state. This results in new calculations where a lower wall thickness of the pipe is used, a larger outer diameter due to marine growth, lower steel quality due to the age of the pipeline and different operational conditions due to the new medium in the pipeline.

2.13.5. Conclusions

This review of the NEN standards and DNV codes reveals several critical aspects exist to the design and analysis of pipeline systems for CCS. While these standards aim provide frameworks for ensuring the structural integrity and safety of pipelines, there are some gaps and considerations specific to CCS that need attention.

Strengths of the Standards

- **Coverage of Material Properties and Design Loads**: Both NEN and DNV standards offer extensive guidelines on material properties, design loads, and load combinations. These guidelines ensure that pipelines are designed to withstand various operational and environmental conditions [11][55].
- **Detailed Stress Analysis Methods**: The standards provide comprehensive methodologies for stress analysis, including axial, bending, and hoop stresses. This ensures that pipelines can be accurately assessed for their structural integrity [11][55].
- **Emphasis on Corrosion Protection**: Both sets of standards emphasize the importance of corrosion protection, including external coatings and cathodic protection systems. This is crucial for the long-term durability of pipelines, especially in harsh offshore environments [11, 49, 57].

Areas for Improvement

- **Specific Guidelines for CCS and CO2 Transport**: While the standards cover general pipeline design and maintenance, specific guidelines for CCS and CO2 transport are limited. CCS involves unique challenges such as CO2 phase changes, potential impurities, and the corrosive nature of CO2. Future revisions of these standards should include detailed guidelines addressing these challenges [11][55].
- **Advanced Material Degradation Models**: The standards could benefit from incorporating advanced degradation models that account for long-term exposure to CO2 and its impurities. This would enhance the predictive maintenance and reliability of pipelines used in CCS applications.
- **Innovative Inspection Technologies**: Emerging technologies such as advanced robotics for pipeline inspection, machine learning for anomaly detection, and real-time monitoring systems are not discussed. Integrating these technologies into the standards could improve the detection and prevention of potential failures .
- **Dynamic Operational Conditions**: The standards focus more on static and known dynamic conditions. Including guidelines for such events could enhance the robustness of pipeline designs as well as making sure pipelines are not overengineerd which could drive up both cost and emissions. The guidelines now only have a recommendation that revers to other dynamic calculations, however there is not one approach that is accepted.

Conclusion

By following the steps outlined in the NEN standards and DNV codes, it is possible to calculate the desired loads and stresses on a pipeline for a given lifetime. However, there are many areas of improvement: calculations could be more precise, pipelines could have a more normalised way of calculating and additions to make the standards more up to date could be made. Also, the design lifetime is not included in the determining of significant loads and their relevant interval. The standards are assuming a set interval for a particular event to happen. This interval is not related to the lifetime of the pipeline, which could result in parameters being estimated or calculated to high. This is the main area of improvement and should be investigated further.

2.14. Challenges in Reusing Existing Infrastructure for CCS

In order to know which aspects of the pipeline should be looked at in the case of a reused pipe for CCS, it's important to know what the main challenges are considering CCS with a reused pipeline. These challenges must be addressed to ensure safe and effective CO2 transport and storage. This section highlights the primary challenges associated with adapting these infrastructures for CCS applications, building on findings from current research and guidelines.

2.14.1. Technical Challenges

The technical challenges associated with reusing pipeline components lie prominently in the difference in the transported medium and it's operating conditions. Table 2.3 shows the differences between natural gas and CO2. One of the main conclusions that can be drawn from this table is that CO2 can be transported in a similar pressure and temperature magnitude as natural gas. However, the CO2 will most likely be in a supercritical state, depending on the pressure in the reservoir.
The technical challenges associated with the transport of CO2 include the danger of corrosion due to impurities in CO2. These impurities, such as sulfur and nitrogen compounds, can enhance corrosion, especially in carbon steel pipelines that were not initially designed to withstand these aggressive conditions. The effects are enhanced due to the critical phase of the CO2. However, independent on the phase of the CO2, the effects of impurities must be mitigated [58].

2.14.2. Regulatory and Compliance Challenges

Adapting offshore infrastructure for CCS also brings regulatory challenges, as existing standards for gas pipelines do not fully encompass the requirements for CO2 transport. CO2 pipelines will be designed according to the NEN standards. However, these standards are set up for mostly oil gas and water pipeline design, whereas CO2 pipelines have their own challenges such as supercritical transport and extreme corrosion. There only is a small mentioning of CO2 pipelines in the NEN3656 which does not entail detailed design considerations. The regulatory standards should be extended towards the CO2 area in order to ensure safe CO2 transport operations.

2.14.3. Economic and Operational Risks

Economic viability is an important factor in the decision to repurpose gas pipelines for CO2 transport. The costs associated with retrofitting pipelines to handle CO2-specific risks, such as corrosion-resistant materials or enhanced monitoring systems, can be substantial [59]. Additionally, operational risks such as pressure fluctuations, which can induce stress on the pipeline materials, must be accounted for to prevent failures [60]. These factors affect not only the immediate costs but also the long-term financial sustainability of CCS projects utilizing repurposed pipelines.
The need for continuous monitoring and maintenance is another significant challenge, as CO2 transport conditions in an repurposed pipeline demand more frequent inspections and integrity checks compared to natural gas pipelines [61]. Operational costs can therefor increase, impacting the overall feasibility and competitiveness of reusing infrastructure versus constructing new, purpose-built CO2 transport systems.

2.14.4. Conclusion

Reusing offshore gas infrastructure for CCS offers a promising pathway for reducing emissions. However, it requires careful consideration of technical, regulatory, and economic challenges. Addressing these challenges through rigorous feasibility studies and tailored regulatory frameworks will be critical in enabling a safe and cost-effective transition to low-carbon infrastructure.

3 Feasibility Analysis Framework

The reuse of offshore pipelines for Carbon Capture and Storage (CCS) presents a significant opportunity to reduce the carbon footprint by leveraging existing infrastructure, thereby minimizing the need for new developments and associated environmental impacts. However, determining the feasibility of repurposing these pipelines is not a straightforward process. It requires a multi-faceted analysis that spans the technical, economic, and regulatory domains. This chapter provides a structured and comprehensive framework designed to guide the assessment process. The primary goal is to determine whether an offshore pipeline, originally designed for gas transportation, can be successfully repurposed for CO2 transportation within a CCS project.

Given the complexity of such an undertaking, the feasibility analysis is divided into three fundamental components: technical feasibility, economic feasibility, and permit feasibility. Each of these domains plays a critical role in the overall decision-making process, as they assess the project from different but equally important perspectives.

- **Technical feasibility** examines whether the pipeline's existing infrastructure is suitable for handling CO2 transport, particularly focusing on material integrity, pressure capacity, and corrosion resistance.
- **Economic feasibility** involves a evaluation of the project's financial viability, from retrofitting costs to long-term operational savings and revenue potential.
- **Permit feasibility** ensures that the project complies with local, national, and international legal and regulatory frameworks, as well as environmental and safety standards.

By addressing these three aspects, the framework deliverers a complete and extensive feasibility assessment. The main focus of this research will be on the technical aspects. However, many of the technical measures to mitigate certain risks have impact on the economical en permit related aspects of the feasibility. Therefore the economic feasibility and permit feasibility will be touched upon by conducting a risk analysis. This analysis will ensure the relevant economical and permit related risks are identified and proper measures can be taken to prevent these risks from happening.

3.1. Overview of Feasibility Study

The overarching objective of the feasibility study is to answer the central question:

"What is the feasibility of reusing existing gas pipelines for CO2 transport and storage in depleted gas fields?"

To address this question, the feasibility study is structured around the three core components mentioned above: technical, economic, and permit feasibility. These elements address all the essential considerations required to evaluate whether an existing pipeline can be repurposed for CCS.

Each component of the feasibility study presents its own set of challenges. Therefore, a systematic approach is essential for identifying and addressing potential risks. The following sections provide a detailed breakdown of each aspect, ensuring that all relevant factors are considered and that informed decisions can be made regarding the pipeline's reuse.

As said in the previous chapter, the feasibility of reusing a pipeline is best assessed if a riser is considered. This way, the most broadly loaded pipeline section is assessed and therefor the assessment is the most complete.

3.1.1. Technical Feasibility

The technical feasibility analysis focuses on the physical and operational characteristics of the pipeline. It aims to determine whether the pipeline, originally designed for gas transportation, can safely and effectively accommodate the unique requirements of CO2 transport in a CCS project. Key factors include:

- **Material Compatibility:** This involves assessing whether the pipeline materials, including steel composition and coatings, can withstand the corrosive nature of CO2, particularly in the presence of impurities such as nitrogen and sulfur compounds. Over time, exposure to CO2 may cause degradation, which could compromise the pipeline's integrity.
- **Pressure Containment and Structural Integrity:** The pipeline's ability to handle the high pressures required for transporting CO2 in a dense or supercritical state is critical. This includes conducting fatigue and stress analysis and evaluating the overall condition of the pipeline, particularly in relation to age and wear. Measures may be necessary to address weak points.
- **Corrosion Resistance and Protection Systems:** Given the potential for CO2 to accelerate corrosion, especially when impurities are present, evaluating the current state of protective coatings and considering additional corrosion mitigation techniques, such as cathodic protection, is essential.

This section ensures that the technical aspects of repurposing the pipeline are rigorously examined, with a particular focus on safety, reliability, and long-term operational performance.

3.1.2. Economic Feasibility

Economic feasibility centers on evaluating the financial aspects of repurposing the pipeline for CCS. The goal is to assess whether the project is economically viable, not just in terms of initial capital outlay but also in terms of long-term operational costs and potential revenues. Key considerations include:

- **Capital Expenditure (CapEx):** Estimating the costs associated with retrofitting the pipeline for CO2 transport, including repairs, upgrades, and the installation of necessary monitoring and safety systems.
- **Operational Expenditure (OpEx):** Identifying ongoing operational costs, such as pipeline maintenance, inspection, and integrity management, as well as monitoring CO2 injection and storage activities. These costs must be weighed against the savings from reusing existing infrastructure instead of constructing a new pipeline.
- **Potential Cost Savings:** Reusing an existing pipeline offers significant cost savings compared to building new infrastructure. These savings include reduced material and construction costs, a shorter project timeline, and fewer environmental impacts associated with new builds.
- **Revenue Streams and Incentives:** Potential revenue sources, such as carbon credits, government subsidies, and partnerships with industries involved in CO2 reduction, must be identified. Additionally, an analysis of market demand for CCS services and future growth projections can provide insight into the long-term economic viability of the project.

This economic analysis is vital for determining whether the project can deliver a satisfactory return on investment while aligning with broader market and policy goals related to carbon reduction. For this research, the scope will remain limited to the economical risks related to the reuse of gas pipelines.

3.1.3. Permit Feasibility

Permit feasibility involves evaluating the legal and regulatory challenges associated with repurposing offshore pipelines for CCS. This includes ensuring compliance with environmental, safety, and maritime regulations, as well as obtaining the necessary permits for CO2 injection and storage. Key components include:

- **Regulatory Compliance:** An in-depth review of national and international regulations governing offshore pipeline operations, CO2 transportation, and environmental protections must be conducted. This ensures that the project aligns with applicable laws and standards, reducing the risk of legal hurdles down the line.
- **Environmental Impact Assessment (EIA):** Conducting a thorough EIA is a critical step in identifying and mitigating potential environmental risks, such as CO2 leakage or disturbance to marine ecosystems. The assessment must also ensure that the project complies with stringent environmental regulations.
- **Stakeholder Engagement:** Securing approvals from regulatory bodies, local governments, environmental agencies, and other stakeholders is crucial. This process involves demonstrating that the project meets safety and environmental standards while minimizing any adverse impacts on local communities and ecosystems.

This legal and regulatory analysis ensures that the project can navigate complex permitting processes, reducing the risk of delays or compliance issues that could jeopardize its success. For this research, the risks connected to the permit feasibility will be analysed. Additionally the process of re-certification will be taken into the step by step assessment guide.

3.2. Methodology for Assessing Technical, Economic, and Permit Feasibility

In order to systematically assess the feasibility of reusing offshore pipelines for CCS, a structured methodology is required. This methodology includes:

- **Risk Analysis:** Utilizing a risk matrix (explained in Chapter 4), potential risks related to technical, economic, and permit feasibility will be identified. For each risk, potential causes will be outlined, along with corresponding mitigation strategies. This approach helps in understanding the probability and impact of risks and ensures that appropriate actions are taken to mitigate them.
- **Technical Assessment Tools:** A step-by-step assessment guide will be used to assess the technical feasibility of the pipeline. This will involve a series of calculations and models to determine the pipeline's current geometric parameters and conduct a stress-strain analysis, ensuring that it meets the operational demands of CO2 transport. These tools are further explained in Chapter 5.

By following this methodology, the feasibility study will provide a comprehensive evaluation of the pipeline's potential for reuse in CCS projects, offering clear guidance on the necessary steps to ensure technical, economic, and regulatory success.

4 Risk Analysis

In order to properly assess the feasibility of reusing offshore pipelines for CCS, it is essential to consider the risks associated with the three aspects discussed in the previous chapter: technical feasibility, economic feasibility, and permit feasibility. Risk analysis plays a vital role in identifying, quantifying, and mitigating these risks to ensure that the project remains viable. This chapter presents a risk analysis framework, leading to the development of a risk analysis matrix that categorizes relevant risks, their causes, and potential mitigation measures. The matrix assigns scores to risks based on their severity and likelihood, providing a structured approach to assessing and managing these risks. This chapter will describe the process of risk identification, explain the methodology used to create the matrix, and present the risk analysis matrix itself.

4.1. Risk Identification: Technical, Economic, and Permit-related Risks

The risk identification process is a critical first step in the development of the risk analysis matrix. It involves systematically identifying the potential risks in each of the three key areas: technical, economic, and permit feasibility. This process begins with defining a clear framework that can both capture the relevant risks and evaluate their severity and likelihood.

For technical feasibility, risks are typically associated with the pipeline's material integrity, corrosion resistance, and its ability to withstand high-pressure CO2 transport. These risks include material degradation due to CO2 impurities, structural failure, and the need for extensive replacement parts. The identification of these risks requires an understanding of the pipeline's current condition, the demands of CCS operations, and the potential impact of long-term CO2 exposure.

Economic feasibility-related risks focus on the financial aspects of the project. This includes the cost of replacement parts, the long-term operational expenses, and potential market fluctuations. Risks such as escalating replacement parting costs, unforeseen maintenance expenses, and insufficient revenue generation must be identified early in the process to evaluate their impact on the project's financial viability.

Permit feasibility risks involve compliance with regulatory frameworks and the ability to secure the necessary permits. These risks may include regulatory delays, failure to meet environmental protection standards, and public opposition to the project. Identifying these risks is crucial for ensuring the project adheres to national and international regulations and does not face legal roadblocks.

Once these risks are identified, each risk is assigned a score for both severity and likelihood, with each score ranging from 1 to 5, where 5 represents the highest level of risk. The severity score reflects the potential impact of the risk if it occurs, while the likelihood score reflects the probability of the risk occurring.

Score	Description	Explanation
1	*Insignificant*	Minimal impact on the project. No significant safety or operational concerns. Limited financial loss.
2	*Minor*	Low impact, minor operational disruptions, no significant safety issues. Manageable financial impact.
3	*Moderate*	Moderate impact on operations and safety. Significant financial costs, but the project can still proceed.
4	*Major*	Severe impact with serious operational disruption and safety concerns. High financial losses.
5	*Catastrophic*	Critical failure leading to project termination, environmental disaster, or significant safety risks. Extremely high financial losses.

Table 4.1: The risk related severity scores

4.2. Methodology for Risk Analysis Matrix

The risk analysis matrix is constructed based on the severity and likelihood scores assigned to each identified risk. By assigning scores from 1 to 5 for both severity and likelihood, the matrix provides a numerical representation of the risks associated with the project. The methodology used to create this matrix involves several steps: defining severity and likelihood, assessing the impact of each risk, and applying mitigation strategies to reduce these risks.

4.2.1. Severity

The severity score measures the impact that a particular risk will have on the project if it occurs. It is scored on a scale from 1 to 5, where 1 represents a minimal impact, and 5 represents a severe impact. Table 4.1 shows the scores and their descriptions. When assessing severity, several factors are considered:

- **Technical Severity:** A high-severity score in technical feasibility may indicate that the pipeline cannot be safely or efficiently repurposed for CCS, potentially leading to system failure or the need for large replacement parts. A risk with a severity score of 5 might suggest that the pipeline would require complete replacement or that the material degradation poses a threat to the overall integrity of the pipeline.
- **Economic Severity:** High severity in economic feasibility may suggest that the project is at high risk to not be financially viable. For example, if replacement part costs are higher than anticipated or operational expenses exceed projected revenues, the project could become economically unfeasible. A score of 5 might indicate that the costs involved would render the project unsustainable.
- **Permit Severity:** In the permit feasibility category, a high severity score indicates that non-compliance with legal and regulatory requirements could halt the project entirely. For instance, failure to meet environmental standards or secure necessary permits could result in significant delays, financial penalties, or the termination of the project.

4.2.2. Likelihood

The likelihood score measures the probability of a risk occurring and is also scored on a scale from 1 to 5, where 1 represents a very low likelihood and 5 represents a very high likelihood. Table 4.2 shows the scores and their descriptions. Several factors influence the likelihood score, including:

- **Technical Likelihood:** In terms of technical feasibility, the likelihood score may depend on factors such as the current condition of the pipeline, the level of degradation observed, and the materials used in construction. For example, pipelines made from materials that are highly susceptible to CO2-induced corrosion might have a likelihood score of 5 on the risk of CO2 induced corrosion, indicating a high probability of failure.
- **Economic Likelihood:** The likelihood of economic risks might depend on market conditions, cost estimates, and financial projections. A high score indicate sthat unforeseen economic challenges, such as fluctuating material costs or changes in market demand for CCS, are highly probable.
- **Permit Likelihood:** The likelihood of permit-related risks is influenced by regulatory environments, stakeholder engagement, and the complexity of the permitting process. A high likelihood score suggests significant challenges in obtaining the necessary approvals due to strict regulatory standards or opposition from environmental groups.

Score	Description	Explanation
1	Rare	The event may happen only in exceptional circumstances. Probability of occurrence is very low.
2	Unlikely	The event is not expected but could occur occasionally. Probability is low.
3	Possible	The event might occur at some point in the future. There's a moderate probability.
4	Likely	The event is expected to occur in the majority of cases. High probability.
5	Almost Certain	The event is very likely to occur and may happen regularly. Very high probability.

Table 4.2: The risk related likelihood scores

The severity and likelihood will be combined later on in an overview which indicated the problems from least to most critical. This way, the risks that will most likely not form a problem can be filtered out and the risks that definitely should be mitigated are shown as well.

4.3. Technical Risks

The following risks all apply to the technical feasibility of reusing an offshore gas pipeline for CO2 transport. Most of the risks shown have multiple causes. In order to keep the risks analysis orderly and comprehensible, the different causes are all put together under a single score for severity and likelihood. The scores for severity and likelihood are shown in the headings for the relevant risk

4.3.1. Water In Pipeline

If water enters into the pipeline, the CO2 and its impurities will react with the water, forming a highly corrosive substance capable of corroding the pipeline walls at rates exceeding 10 mm per year. Such corrosion would lead to catastrophic consequences for CCS operations, potentially resulting in the failure of the entire pipeline infrastructure.[62]

Causes

- Incomplete dehydration at the source
- CO2 reaching its dew point temperature during compression
- Improper sealing at valves, flanges, or connection points
- External water entering due to pipeline wall rupture as a result of corrosion
- Water produced by chemical reactions involving impurities in CO2
- CO2 and water combining under certain temperature/pressure conditions
- Water entering during pipeline maintenance or flooding

Severity [5]

This risk scored a 5 on the severity scale. The consequences of this risk include critical failure of the pipeline, potentially leading to its collapse, CO2 leakage, and significant environmental damage. The resulting loss of containment could halt CCS operations entirely and pose significant financial and environmental costs.

Likelihood [1]

The likelihood of water ingress is moderate due to several contributing factors, particularly incomplete dehydration processes, fluctuating temperatures and pressures, and the possibility of coating imperfections, leading to leaking or improper sealing.

Mitigation and Measures

To address the risk of water ingress and subsequent corrosion, several mitigation strategies and measures must be implemented:

- **Enhanced Dehydration Process:** Ensuring that CO2 is thoroughly dehydrated before being introduced into the pipeline. Regular monitoring of water content and dehydration systems at the source will reduce the chances of water entering the pipeline.
- **Continuous Monitoring:** Installing sensors to monitor for signs of water ingress, pressure fluctuations, or temperature changes in the pipeline that may lead to CO2 reaching its dew point. Real-time data analytics can help detect early warning signs and prevent severe corrosion.

- **Improved Sealing and Maintenance:** Regular inspection and maintenance of6+5 valves, flanges, and connection points, which are common entry points for external water.
- **Corrosion-Resistant Materials:** Utilizing pipeline materials with enhanced resistance to corrosion, such as corrosion-resistant alloys or internal coatings, can help mitigate the effects of CO2 and water interaction if ingress does occur, mitigating the damage caused by water in the pipeline.
- **Preventative Maintenance During Pipeline Downtime:** Taking special precautions during pipeline maintenance or in the event of flooding to prevent water from entering the pipeline. This includes ensuring proper drainage systems are in place and using nitrogen or other non-corrosive gases to flush the pipeline before resuming operations.

By applying these mitigation measures, the risk of water ingress can be significantly reduced, helping to prevent the formation of corrosive substances and ensuring the long-term integrity of the pipeline for CCS operations.

4.3.2. Carbon Steel Embrittlement

When exposed to high-pressure CO2, some materials, especially older carbon steels, can experience embrittlement. This makes the pipeline more prone to cracking and mechanical failure, especially in dynamic offshore environments.[63]

Causes

- Exposure to high-pressure CO2, especially in older carbon steel pipelines

Severity [4]

This risk scored a 4 on the severity scale. Embrittlement could lead to cracking and mechanical failure, particularly in older carbon steel pipelines, posing serious operational risks.

Likelihood [2]

The likelihood of this risk is moderate due to the material characteristics of older carbon steels under high-pressure CO2 conditions, especially in dynamic offshore environments. This is taken into acount in chapter 5 in the fatigue lifetime assessment.

Mitigation and Measures

- **Material Assessment:** Perform a material assessment to ensure that pipeline materials are suitable for CO2 transport.
- **Non-Destructive Testing:** Regular non-destructive testing should be conducted to detect early signs of embrittlement and cracking.
- **Consider Retrofitting:** If the materials are not suitable, consider retrofitting with CO2-resistant liners, although this may introduce additional economical risks.

4.3.3. Pressure Fluctuations

Injection and extraction of CO2 into depleted gas fields involve frequent pressure fluctuations. These pressure cycles can cause mechanical fatigue in the pipeline, especially at welds and joints, where stress concentration is higher. [64]

Causes

- Partial blockages or restrictions in the pipeline, such as scale, or hydrate formation, can cause localized pressure build-up, leading to fluctuations.
- The compressors used for injecting CO2 into the pipeline can introduce pulsations, leading to pressure variations within the pipeline.
- Temperature variations in the pipeline or reservoir can cause thermal expansion and contraction of CO2, which can lead to changes in pressure.

Severity [4]

This risk scored a 3 on the severity scale. Mechanical fatigue and pressure fluctuations can weaken pipeline welds and joints, requiring repairs and increasing maintenance costs.

Likelihood [2]
The likelihood of pressure fluctuations is low to moderate due to the steady stream of CO2. The absence of water will mitigate the potential for blockages or hydrate formation in the pipeline.

Mitigation and Measures
- **Install Pressure Control Systems:** Install pressure control systems to reduce pressure surges and ensure gradual pressure changes during injection and extraction phases. The pipeline design should take excessive pressure surges into account. If weak spots are identified, this may impact economic feasibility due to the cost of repairs or replacements.
- **Inject Hydrate Inhibitors:** Injecting hydrate inhibitors, such as methanol or glycols, can prevent hydrate formation, especially in cold or high-pressure conditions where hydrates are more likely to form.
- **Flow Monitoring and Sensors:** Use flow monitoring and pressure sensors along the pipeline to detect early signs of blockages or pressure build-up, allowing for timely intervention before significant fluctuations occur.
- **Temperature Variations in Design:** Account for temperature variations in the pipeline and the pressure changes they cause in pipeline design calculations.

4.3.4. Hydrate Formation
In the presence of free water, CO2 can form hydrates under certain temperature and pressure conditions, which can cause blockages within the pipeline. These blockages can restrict flow and create pressure build-up, potentially leading to pipeline rupture.

Causes
- Free water in the pipeline.

Severity [3]
This risk scored a 3 on the severity scale. Hydrate formation can cause blockages and lead to increased pressure, which may result in pipeline rupture if not properly addressed.

Likelihood [2]
The likelihood is low due to the absence of free water, taking away the potential for hydrate formation.

Mitigation and Measures
- **Dehydration Units:** Implement dehydration units to remove water from the CO2 stream before it enters the pipeline.
- **Temperature Control Systems:** Use temperature control systems to maintain conditions that prevent hydrate formation.
- **In-line Pigging Tools:** Utilize in-line pigging tools to keep the pipeline clean and free of hydrate build-up.

4.3.5. Stress Corrosion Cracking (SCC) due to Sour CO2 (H2S Contamination)
The presence of hydrogen sulfide (H2S) in the CO2 stream, even in small amounts, can lead to stress corrosion cracking (SCC) in carbon steel pipelines. SCC is a form of localized corrosion that occurs when tensile stress and a corrosive environment coincide. SCC can cause rapid failure of the pipeline, particularly in areas of high tensile stress, such as welds and bends, leading to CO2 leakage.

Causes
- Presence of H2S in the CO2 stream.
- High tensile stress in the pipeline, particularly in welds and bends.

Severity [4]
This risk scored a 4 on the severity scale. SCC can lead to rapid failure of the pipeline, especially in areas of high stress concentration, resulting in CO2 leakage and potential environmental hazards.

Likelihood [1]
The likelihood of this risk is low, but if H2S contamination occurs, the potential for SCC increases significantly. However, the absence of water is again a critical factor that reduces the likelihood for this risk

Mitigation and Measures
- **Dehydration Units:** Implement dehydration units to remove water from the CO2 stream before it enters the pipeline.
- **Temperature Control Systems:** Utilize temperature control systems to maintain conditions that prevent SCC by controlling the environment inside the pipeline.
- **Pipeline Cleaning Tools:** Use in-line pigging tools to keep the pipeline clean and free of contaminants, preventing conditions that could lead to SCC.

4.3.6. CO2 Penetration
CO2, particularly in its supercritical state, can permeate through certain pipeline materials over time, causing a gradual loss of containment. This is particularly a concern in non-metallic materials used as liners or seals.

Causes
- Non-metallic liners or seals.
- Prolonged exposure to CO2 accelerates the diffusion process.
- Even small defects in the liners or seals can result in leakage over time.

Severity [3]
This risk scored a 3 on the severity scale. CO2 penetration through non-metallic materials can lead to gradual containment loss, causing potential leakage over time.

Likelihood [2]
The likelihood of this risk is moderate, particularly due to the prolonged exposure of non-metallic liners or seals to supercritical CO2.

Mitigation and Measures
- **Replace Non-metallic Components:** Before operation, non-metallic components of the pipeline should be removed and replaced with metallic parts to ensure proper CO2 containment.
- **Quality Standards for Liners and Seals:** Ensure that high-quality standards are applied in the production of liners and seals to prevent leakage over time.

4.3.7. Wax or scale build-up
Wax or scale deposition, particularly in pipelines that have transported hydrocarbons previously, can obstruct CO2 flow and reduce pipeline efficiency. While CO2 alone doesn't form wax, remnants of hydrocarbons may lead to deposits under certain conditions.

Causes
- Residue from previous operations left due to improper cleaning.

Severity [2]
This risk scored a 2 on the severity scale. Even when there is still wax or scale build up in the pipeline, the pipeline is tested by a significantly higher test pressure, therefor pressure build up due to wax or scales is not likely to become a critical failure cause.

Likelihood [4]
The likelihood of this risk is moderate to high as it is difficult to guarantee the pipeline is completely clean before use due to the fact that visual inspections are difficult. Therefore a higher likelihood is considered to be the most save assumption.

Mitigation and Measures
Use pipeline cleaning (pigging) techniques to remove residual hydrocarbons and deposits. Regular maintenance and monitoring of internal pipeline conditions will help prevent build-up.

4.3.8. Pipeline Buckling Due to External Pressure

Subsea pipelines and risers are subject to external hydrostatic pressure from the ocean. If the internal CO2 pressure drops too low (during shutdowns or depressurization), the difference between the external and internal pressures could lead to pipeline buckling. The external water pressure remains while the internal pressure will reduce from 175 bar to 1 bar.

Causes
- During shutdowns, maintenance, or depressurization events, the internal pressure in the pipeline may drop significantly, leading to a significant absolute pressure difference.

Severity [4]
This risk scored a 4 on the severity scale. If the internal pressure drops too low, external hydrostatic pressure can cause pipeline buckling, leading to structural failure.

Likelihood [5]
The likelihood of this risk is high since shutdowns or maintenance will inevitably occur.

Mitigation and Measures
- **Design for External Pressure:** Design the risers to withstand external pressures, even during periods of low internal pressure. Installing internal pressure support systems or maintaining minimum operating pressures can mitigate this risk.
- **Buffer System:** Install a buffer system to ensure CO2 pressure and prevent complete depressurization.
- **Install Shutoff Valves:** Install shutoff valves to maintain pressure in critical sections of the pipeline.

4.4. Economical Risks

4.4.1. Price of CO2

The financial viability of CCS projects often depends on favorable carbon pricing or government incentives. If these incentives decrease or disappear, it could undermine the economic rationale for the project.

Causes
- Changes or removal of subsidies and tax credits.
- High initial costs make ROI challenging without support.
- Policy shifts can reduce support for CCS projects.
- Competes with cheaper or better-supported alternatives.
- Negative perception may limit investment opportunities.
- Fragmented markets reduce opportunities for consistent returns.

Severity [4]
This risk scored a 4 on the severity scale. The lack of favorable carbon pricing or government support can significantly affect the economic rationale of CCS projects.

Likelihood [3]
The likelihood is moderate, as CCS projects are heavily dependent on government incentives, subsidies, and consistent carbon pricing to remain financially viable. However, governments and global initatives are highly motivated to ensure the CO2 targets for 2030 and 2050 are met, therefore the likelihood of this risk is moderate to low.

Mitigation and Measures

- **Secure Long-term Contracts:** Secure long-term government support and contracts to stabilize financial returns.
- **Lower Costs:** Focus on lowering costs through technological advancements and improved efficiency.
- **Advocate for Supportive Policies:** Actively engage with policymakers to advocate for stable, supportive carbon pricing and incentives that encourage investment in CCS projects.
- **Explore Revenue Streams:** Explore diverse revenue streams, such as CO2 utilization, to reduce reliance on fluctuating carbon prices.
- **Educate Investors:** Educate investors on the long-term potential and benefits of CCS to secure funding.
- **Global Carbon Market:** Support the development of a global carbon market to stabilize carbon prices and increase investment opportunities.

4.4.2. Supply Shortage

The business cases for today's CCS projects are based on the known amount of CO2 emissions. However, as companies strive to become more environmentally friendly, the amount of CO2 emissions could drop significantly over the course of a number of years. As the supply of CO2 decreases, the demand for CCS decreases, and the business case might fail.

Causes

- Greener technologies reduce CO2 emissions, leading to reduced demand for CCS.
- Too much CCS infrastructure relative to CO2 supply.

Severity [4]

This risk scored a 4 on the severity scale. A reduction in CO2 supply can lead to an underutilization of CCS infrastructure, affecting the economic viability of CCS projects.

Likelihood [1]

The likelihood of this risk is low in the near term, but as greener technologies evolve, the demand for CCS could decline over time due to unforeseen emission saving technology breakthroughs.

Mitigation and Measures

- **Partnerships for Long-term Carbon Management:** Establish partnerships with companies and governments committed to long-term carbon management and sustainability goals. Align with sectors or regions with ongoing commitments to CCS, even in a low-emission future, to reduce the risk of business failure.
- **Flexible Infrastructure:** Develop flexible infrastructure that can accommodate CO2 from diverse sources to maintain a stable supply.
- **Long-term Contracts:** Secure long-term contracts with CO2 emitters to ensure a consistent supply of CO2 for CCS operations.

4.4.3. Monitoring Costs

The transition to CO2 transport requires more frequent monitoring and maintenance compared to natural gas transport. Specialized equipment and expertise are needed to ensure that the pipeline remains safe and operational. These additional monitoring and inspections could make the reuse of a pipeline more expensive than constructing a new pipeline.

Causes

- More frequent inspections needed for CO2 compared to natural gas.
- Specialized tools and sensors increase capital costs.
- Higher labor costs due to specialized skills required.
- More frequent integrity checks needed due to CO2's corrosive nature.

Severity [3]
This risk scored a 3 on the severity scale. The need for specialized monitoring can significantly increase costs and affect the financial viability of reusing pipelines for CO2 transport.

Likelihood [5]
The likelihood of this risk is high, as monitoring and maintenance requirements for CO2 transport are typically more frequent and involve more complex equipment than natural gas pipelines.

Mitigation and Measures
- **Include Costs in Business Case:** Implement these inspection, maintenance, and monitoring costs in the business case and compare them to constructing a new pipeline. This way, the cost difference becomes clear.
- **Remote Monitoring Systems:** Implement remote monitoring systems to reduce labor costs.
- **Predictive Maintenance:** Use predictive maintenance to anticipate and prevent repairs.
- **Retrofit with Corrosion-resistant Materials:** Retrofit pipelines with corrosion-resistant materials and sensors to minimize future costs.
- **Risk-based Inspection Programs:** Adopt risk-based inspection programs to optimize the frequency of inspections.

4.4.4. Degradation Costs
Technical challenges during the conversion of gas risers for CO2 transport, such as unexpected material degradation or failure of retrofitting measures, may cause project delays and drive up costs.

Causes
- Materials degrade faster due to exposure to CO2.
- Retrofitting components fail due to incompatibility with CO2.
- CO2 combined with water accelerates corrosion.

Severity [4]
This risk scored a 4 on the severity scale. Material degradation can significantly delay projects and lead to high costs due to retrofitting failures and repairs.

Likelihood [4]
The likelihood of this risk is moderate to high, as degradation risks are a known challenge in CO2 transport systems and monitoring systems are needed in most of the times to ensure save pipeline operations.

Mitigation and Measures
- **Engage Experienced Contractors:** Engage contractors with specialized knowledge of CO2 transport systems early in the project to avoid technical missteps.
- **Contingency Funds:** Allocate contingency funds to address unforeseen technical challenges and delays.
- **Material Testing:** Conduct material testing under CO2 conditions to ensure compatibility.
- **Engineering Assessments:** Perform detailed engineering assessments to identify potential weaknesses in materials or design.
- **Pipeline Inspections:** Perform inspections of the pipeline to ensure dry operations and mitigate corrosion risks.

4.5. Permit Risks
4.5.1. Regulation Changes
Existing regulations do not clearly address the reuse of gas pipelines for CO2 transport, which could lead to delays in obtaining permits and approvals. The regulatory landscape for CCS is evolving, and inconsistencies in how authorities handle CO2 transport can complicate project planning.[65]

Causes
- Lack of clear regulations slows down the permitting process.
- New policies complicate approval processes.
- More stakeholders result in longer timelines for permits.

Severity [3]
This risk scored a 3 on the severity scale. Delays in the permitting process can slow down project timelines, causing scheduling disruptions and potential financial impacts.

Likelihood [3]
The likelihood of this risk is moderate due to the evolving regulatory landscape and the involvement of multiple stakeholders in the approval process.

Mitigation and Measures
- **Early Engagement:** Engage early with regulatory bodies to clarify requirements for reusing pipelines for CCS.
- **Legal Expertise:** Work with legal experts for navigating evolving regulations and ensuring compliance.
- **Monitor Regulatory Changes:** Monitor global and local regulatory changes to stay informed and adjust project plans accordingly.

4.5.2. Environmental Impact
Environmental agencies may have concerns about the long-term risks of CO2 storage, particularly in offshore environments. These concerns can lead to stricter environmental impact assessments and harder approval processes.

Causes
- Concerns about long-term risks like leakage or contamination.
- Sensitive ecosystems can drive more stringent assessments.
- Public concerns can influence more cautious approaches and sudden regulatory changes.

Severity [4]
This risk scored a 4 on the severity scale. Stricter environmental regulations and impact assessments can delay project approvals and lead to additional costs for compliance.

Likelihood [4]
The likelihood of this risk is moderate to high, as environmental concerns, particularly in sensitive offshore ecosystems, are a major focus of regulatory scrutiny.

Mitigation and Measures
- **Environmental Impact Assessments:** Develop comprehensive environmental impact assessments before the project starts, addressing all potential risks.
- **Proactive Engagement:** Engage with environmental agencies proactively to ensure transparency and address concerns early in the project.
- **Use Environmental Experts:** Use environmental experts to navigate complex regulations and engage with relevant stakeholders.

4.5.3. HSE Regulation Changes
Offshore CCS operations are subject to stringent HSE (Health, Safety, and Environmental) regulations, particularly regarding the safety of personnel and the protection of the marine environment. Any changes in regulations or unforeseen HSE risks could require additional investments in safety systems or operational changes.

Causes
- New or updated future regulations may require additional safety investments.

Severity [4]
This risk scored a 4 on the severity scale. Changes in HSE regulations can require significant investments in new safety measures or equipment, increasing operational costs.

Likelihood [4]
The likelihood of this risk is high due to the dynamic nature of HSE regulations, especially in offshore environments where safety and environmental risks are critical.

Mitigation and Measures

- **Comprehensive HSE Management System:** Develop a comprehensive HSE management system that includes robust safety protocols, environmental monitoring, and emergency response plans.
- **Stay Updated on Regulations:** Stay up-to-date on evolving HSE regulations and make proactive adjustments to ensure full compliance.
- **Invest in Safety Systems:** Invest in advanced safety and monitoring systems to ensure compliance with current and future regulations.

4.5.4. Public Concerns Leading to Political Interference

Public concerns over CO2 storage, especially in sensitive offshore areas, could lead to political pressure and opposition from local communities or environmental groups. This could complicate the regulatory process and result in delayed or denied permits.

Causes

- Local communities and groups may raise concerns over potential risks.
- Politicians may face pressure from constituents or advocacy groups.
- Environmental groups may oppose projects in sensitive offshore areas.
- Negative media can amplify concerns and opposition.

Severity [3]
This risk scored a 3 on the severity scale. Public opposition and political interference can significantly delay or even halt the permitting process, especially in environmentally sensitive areas.

Likelihood [4]
The likelihood of this risk is high, as public and political concerns often influence the regulatory process, particularly for projects with potential environmental impacts.

Mitigation and Measures

- **Proactive Public Engagement:** Develop proactive public engagement strategies to address concerns early in the process.
- **Educational Campaigns:** Conduct educational campaigns to inform the public about the environmental benefits of CCS and the safety measures in place to mitigate risks.
- **Collaboration with Environmental Groups:** Collaborate with environmental groups to develop shared solutions and foster support for the project.
- **Transparency in Impact Assessments:** Ensure transparency in environmental impact assessments to build public trust and reduce opposition.

4.5.5. Risk analysis overview

Now that all the risks have been investigated, the risks are gathered in a matrix that shows the most and least critical risks. This matrix can be seen in figure 4.1. In this matrix all the risks out of this section are gathered and put it together in a single risk analysis matrix. The matrix shows which the most critical risks are, and which risks are of a lower priority. The most critical risks, shown in orange and red must be taken into account.

As can be seen, the most critical risk is risk T8, which will be investigated using the approach for feasibility assessment in chapter 5. Most economic risks and especially risk E4 and E3 are taken into account in the coming section. Risks P3 and P4 are risks related to health safety and environmental changes in regulations and public concerns. The mitigation strategies for these risks must be adopted when a repurposing project is realized by engaging with the public stakeholders and making sure the operations are in accordance with the HSE regulations that apply on the location of the project. Both of these mitigation strategies are not related to the assessment tool and do not affect the design of the pipeline. Therefor these strategies do not have to be taken into account for the approach for feasibility assessment.

		(LIKELIHOOD)				
		Occurs in almost no projects	Occurs in some projects	Occurs in projects	Occurs in most projects	Expected to occur in every project
		Extremely unlikely / virtually impossible	Low but not impossible	Fairly likely to occur	More likely to occur than not	Almost certainly will occur
		0-5%	5-20%	20-50%	50-80%	80-100%
		1 (VL)	2 (L)	3 (M)	4 (H)	5 (VH)
Severity	5 (VH)	T1				
	4 (H)	T5, E2	T2, T3	E1	E4, P3	T8
	3 (M)		T4, T6,	P1	P4	E3
	2 (L)				T7	
	1 (VL)					

Figure 4.1: The combined risk analysis matrix, T stands for the technical risks, E for the economical risks and P for the permit risks

4.6. Measures for risk mitigation

The risks and measures out of the risk analysis matrix that could affect the feasibility of the pipeline reuse process. These measures are depicted in Figure 4.2, which presents a flowchart illustrating the various aspects of the pipeline assessment and the steps where critical decisions are made.

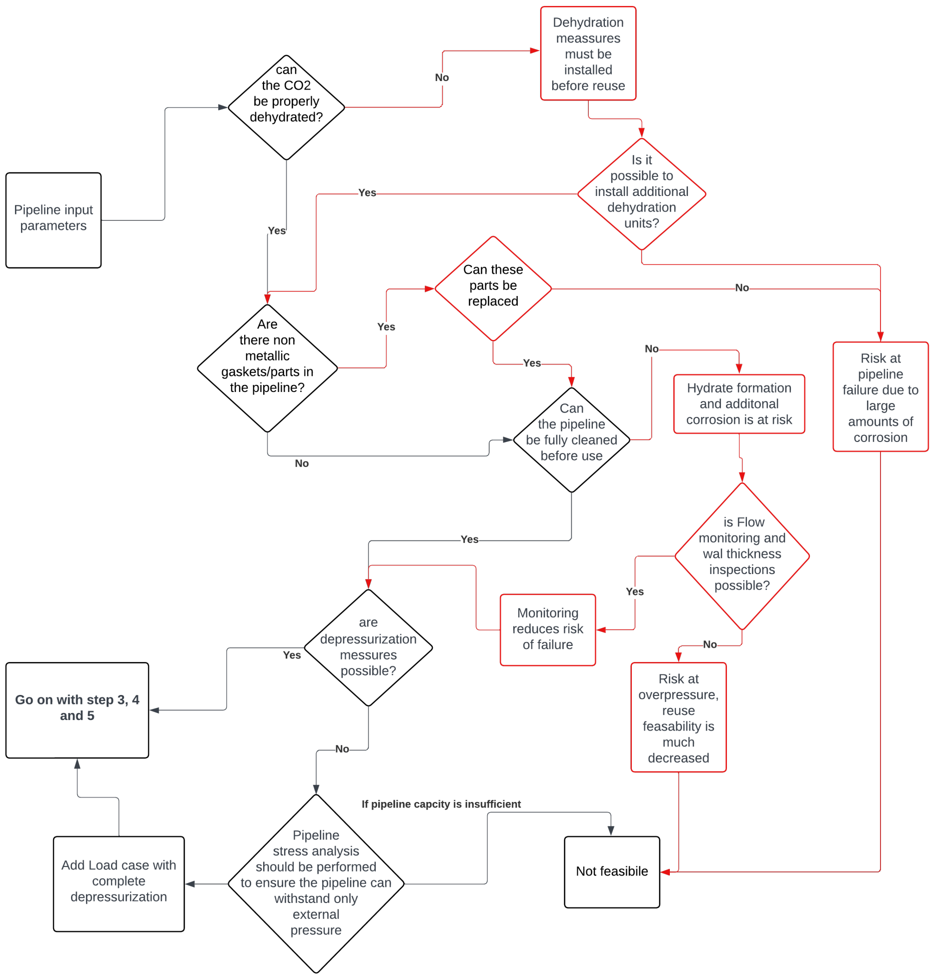


Figure 4.2: a schematic overview of the measures that can be taken in case of a certain risk.

In the flowchart shown in figure 4.2, specific measures are shown that can be taken if certain pipeline conditions are unfavorable. The red lines in the flowchart highlight pathways where a negative decision can significantly impact the business case for reuse. These points require a re-evaluation of the project due to increased risks, and these risks must be considered in the broader economic feasibility study, which is beyond the scope of this technical analysis. Below is a detailed explanation of the different measures shown in the figure:

- **Dehydration of CO2**: The first critical decision involves whether the CO2 can be properly dehydrated before entering the pipeline. If dehydration is inadequate, there is a significant risk of internal corrosion, especially when impurities are present. The inadequate dehydration of the CO2 or the presence of water in the pipeline is a showstopper for the complete repurposing project as corrosion rates can get as high as 20 mm/year. If the CO2 is not dehydrated enough, additional dehydration systems must be installed to ensure safe operation. This influences the financial aspect of the feasibility assessment, necessitating a re-evaluation of the business case for the project.

- **Non-metallic parts in the pipeline**: Another decision point concerns the presence of non-metallic gaskets or parts, which are vulnerable to degradation when exposed to CO2. If these non-metallic components are found, they must be replaced with CO2-resistant alternatives before reuse.
- **Pipeline cleaning**: The pipeline must also be thoroughly cleaned before reuse. If complete cleaning is not possible, the risk of hydrate formation and additional internal corrosion increases. Hydrates can cause blockages and operational hazards, while corrosion compromises structural integrity. In such cases, monitoring and mitigation measures must be implemented.
- **Flow monitoring and wall thickness inspections**: If continuous flow monitoring and wall thickness inspections are not feasible, the pipeline becomes more susceptible to undetected corrosion and overpressure failures. At this stage, implementing advanced monitoring systems or upgrading inspection technologies is critical to ensuring long-term pipeline safety.
- **Depressurization measures**: Another key measure involves evaluating the possibility of depressurizing the pipeline. If depressurization is feasible, it can help to mitigate the risk of failure by reducing the internal pressure during periods of inactivity. In contrast, if depressurization is not an option, stress analysis must be performed to verify whether the pipeline can withstand external pressure alone.
- **Re-evaluation of the project**: If any of these measures are not feasible, the risk to the pipeline's integrity increases significantly. In these cases, the business case for reuse may be adversely affected, and a re-evaluation of the project is necessary. The potential costs associated with mitigation measures, such as installing new equipment or conducting repairs, should be included in an economic feasibility study.

Figure 5.4 highlights the critical decision points during the pipeline assessment process and the corresponding measures that can be taken to address risks. Any negative decision indicated by red lines has the potential to influence the technical feasibility of the pipeline and must be carefully considered in the economic analysis to ensure a viable reuse strategy.

5

Approach for feasibility assessment

This chapter describes the approach for feasibility assessment. In the first sections, the steps described in this assessment are focused on the technical feasibility assessment parallel to this assessment a risk analysis matrix will be added. Together the approach for feasibility assessment and the risk analysis matrix from the previous chapter will be combined in a tool that focuses on the technical feasibility of repurposing offshore gas risers.
The approach described in this chapter will be used in the next chapter where, in the form of a case study, an offshore riser assessment will determine the feasibility for reuse. Each section consists out of the foundation for each step followed by the actual step itself.

5.1. Scope of assessment

The aim of this assessment tool, is to assess all pipelines and determine which pipelines can be reused in CO2 transport for CCS applications. However, due to the broadness of types of pipelines (export lines, in field lines, risers etc.) the assessment guide needs to be specified by a single pipeline type in order for it to contain the critical loading types. For example, waves have a significant influence on risers but not on export lines, whereas upheaval buckling is a concern for export lines but not for risers. Therefore, in this research the assessment guide is focused only on the riser. After the case study, the results of the assessment of a riser will be looked at in a broader perspective in order to conclude if the tool is also suitable for other pipeline types besides risers.

5.2. Methodology for assessment

The assessment guides follows a number of steps that ultimately leads to the final conclusion on whether or not the riser will be suitable for reuse for CO2 purposes. These steps are set up as a result of the findings in chapter 2: Literature review. These steps are based on the most significant factor, which will be discussed in this section.

5.3. Data gathering: step 1 and 2

The first two steps consist out of the gathering of all relevant data. This includes all relevant original riser design parameters such as the original wall thickness, the original riser diameter, the clamp placement and so on. This forms the starting point from which the riser can be updated to its current parameters. These current parameters are different because over time the wall thickness decreases due to corrosion and the outside diameter increases due to marine growth which all influence the loading capacity of the riser itself.
The second step gathers all relevant environmental data of the riser. In chapter 2 it is concluded that the wave and current characteristics have changed over time for some locations. Therefore, an update on the magnitude of these loadings should be conducted in order to meet the requirements for recertification.

5.3.1. Step 1: Collect Data on the riser

Design Specifications
The first step is to gather all available design data related to the riser, including:

- Outer Diameter (D) and Wall Thickness (t)
- Material Properties (yield strength and tensile strength)
- Coating Details (internal and external)
- Installation Date and expected lifespan
- Check for any non-metal parts, as these could dissolve due to CO2 exposure

5.3.2. Step 2: Review Environmental Loadings

Environmental Data
Gather historical records of wave heights, wave periods, and current patterns. Also, consider temperature variations in the water column, as risers are subjected to thermal stresses due to surrounding water. Saltwater exposure, marine growth, and corrosion from the marine environment must be accounted for.

Operational Data
Examine operational data such as:

- Internal pressure fluctuations (maximum and minimum operating pressure)
- Temperature variations from gas flow
- Chemical composition of the transported gas, especially CO2 and other corrosive agents

5.4. Parameter update: step 3

In chapter 2 it is shown that the riser wall thickness is of significance to the loading capacity of the riser. This means that this is one of the most important aspects of the riser and should be updated conservatively to ensure the results of the assessment are safe to use.
Besides the wall thickness, both the riser diameter, drag coefficient and interia coefficient are updated according to NEN3656 to what these parameters should be after a number of years in service. The update is necessary due to marine growth which not only increases the surface roughness and therefore the drag coefficient, but also the overall diameter and weight of the riser. Part of the wave force is due to the higher water velocity in the wave. This leads to a higher impact on the riser itself since the area of impact increases due to a higher diameter.

5.4.1. Step 3: Parameter Update After Corrosion and Marine Growth

For external influences, assessing the remaining lifespan of cathodic protection (CP) or coatings. Additionally, an update of the drag coefficient, interia coefficient and riser diameter due to marine growth must be done. Usually this is done using the data of an inspection. When data is unavailable, assumptions from NEN3656 can be used. Both the maximum value for C_d and C_m are set at 2.0 as a save assumption for the drag and interia coefficients.

Internal Corrosion
Use the NORSOK M-506 formula to calculate the internal corrosion rate caused by CO2:

$$CR = A \times (P_{\text{CO2}})^B \times e^{C \times T} \tag{5.1}$$

Where:

- $A = 0.03$ (empirical constant)
- $B = 0.7$ (exponent for the relationship between CO2 partial pressure and corrosion)
- $C = 0.02$ (temperature effect constant)
- P_{CO2} is the partial pressure of CO2
- T is the temperature

Partial pressure of CO2 is calculated as:

$$P_{\text{component}} = \frac{\text{Mole Fraction of Component}}{100} \times P_{\text{total}} \tag{5.2}$$

Finally, account for the effectiveness of internal coatings, which can reduce the corrosion rate by 70-90% (DNV-RP-F101).

5.5. Stress analysis: Step 4

The stress analysis is done by performing a finite element simulation using PLE4WIN. In this program, the updated riser parameters, the updated environmental data and the new medium are put together in a model which calculates all the stresses in the riser.

PLE4Win

PLE4Win is a finite element analysis (FEA) program designed specifically for the analysis of offshore risers and risers. PLE4Win includes features that account for the loading conditions experienced by offshore infrastructure. These include wave and current forces, seabed interactions, internal and external pressure effects, and thermal gradients.

5.5.1. Step 4: Evaluate the Structural Integrity

Stress and Strain Analysis

Perform a finite element analysis or use empirical formulas to evaluate the risers stress-bearing capacity. Use PLE4Win in combination with the wave and current characteristics defined by NEN3656. Parameters from Step 3, such as reduced wall thickness, updated diameter, and adjusted drag and interia coefficients, should be used.

Input Parameters for Stress Analysis

In the stress analysis, several key inputs are required to ensure that the simulation accurately reflects the real-world conditions the riser will experience during CO2 transport. These include:

- **riser geometry and material properties**: Updated values for wall thickness, outer diameter, and material strength are input based on the findings from the corrosion and material degradation assessment.
- **Environmental data**: Historical data on wave heights, periods, and currents are integrated into the model. These environmental factors significantly affect the external loading on the riser and must be accurately represented by the most recent data to ensure that the stress analysis reflects the true forces acting on the riser.
- **Internal pressure and temperature**: The properties of the transported medium are key inputs for the simulation. The internal pressure and temperature of the riser can induce thermal stresses and interact with the external forces from waves and currents.

Types of Stress Evaluated

The stress analysis in PLE4Win includes several types of stresses that are calculated for the offshore riser. However, the main criteria for NEN certification is the Von Mises stress. This stress is modeled in the most critical load combination; load combination 1. The upper limit for this stress is:

$$\sigma_v \leq 0.85 \frac{Re + Re(\theta)}{\gamma_m} \tag{5.3}$$

Where:

- σ_v: Von Mises equivalent stress (N/mm^2)
- Re: Yield strength at 20 degrees Celcius (N/mm^2)
- $Re(\theta)$: Yield strength at elevated temperature θ (N/mm^2)
- γ_m: Material safety factor, accounting for uncertainties in material properties

This equation gives the relation between the calculated stresses and the material properties to evaluate if the stresses that the riser is subjected to do exceed the risers capacity. As can be seen, the upper stress limit can be higher than the yield strength of the material. This is allowed by the so called plastic elastic design philosophy used in NEN3656. The plastic elastic design philosophy allows the stresses to be higher than the elastic limit of the material if the load combination is a critical load combination with the most critical loadings combined. The material will deform plastically in such a situation. However the deformation will stay within reasonable limits proven by lab testing [66], to ensure sufficient stress capacity of the riser.

Load combination 2 is created to simulate the situation where the internal pressure drops suddenly as a result of a shutdown. This load

Stress Results and Safety Margins
The results of the stress analysis in PLE4Win provide detailed information on the stress distribution throughout the riser. These results are used to identify areas of high stress concentration, such as connection points between the riser and the platform or seabed. Based on the stress results, engineers can evaluate the safety margins for the riser under various loading conditions.
The calculated stresses are compared against the material's yield strength and ultimate tensile strength to ensure that the riser operates within safe limits. Safety factors are applied to account for uncertainties in the input data and to provide a margin of safety against unexpected loading conditions as described in NEN3656. For this approach, this means that the most critical load combination from NEN3656 will be used to assess the capacity of the riser, where all input parameters have a safety margin of 20 percent.

5.6. Fatigue Lifetime Assessment: Step 5

The fatigue lifetime assessment of the riser structure under cyclic wave loading involves determining the stress range and subsequently calculating the number of allowable cycles to failure using an S-N curve approach. This assessment process is critical in estimating the remaining lifespan of the riser, considering the cumulative effect of cyclic bending stresses induced by wave forces. The methodology follows several key steps, which are detailed below. This section shows the theory and steps that should be followed to calculate the stresses and moments. However, PLE4Win also calculates these stresses and moments, and does so more accurately due to the incorporation of more factors, such as the corrosion tolerance, the supports leading to a more accurate span length and the addition of the weight of the medium in the riser. The calculation steps shown in this section are used to identify which parameters are significant and where alterations can be made in order to extend the lifetime of the pipe in case of a insufficient lifetime.

Estimation of the Critical Bending Moment
To begin the assessment, it is essential to identify the most critical bending moment, M, that occurs due to wave-induced forces acting on the riser. This critical bending moment is derived from the maximum hydrodynamic force, which is a combination of drag and inertia forces exerted on the riser by wave motion. These forces are calculated based on Airy wave theory, which provides the maximum water particle velocity $v_{\text{max},ij}$ as a function of wave height, wave period, and water depth.
The following parameters are used in the hydrodynamic force calculation:

- H_i: Wave height
- T_j: Wave period
- d: Water depth
- D_{riser}: Diameter of the riser
- ρ_{water}: Density of seawater
- C_D: Drag coefficient
- C_M: Inertia coefficient
- ω_J: Angular frequency $= \frac{2\pi}{T_J}$

Using statistical theory, the wave length L is determined iteratively by solving the dispersion relation:

$$L = \frac{g \cdot T_j^2}{2\pi \tanh\left(\frac{2\pi d}{L}\right)} \tag{5.4}$$

Once L is obtained, the maximum water particle velocity $v_{\text{max},ij}$ is calculated as:

$$v_{\text{max},ij} = \frac{H_i \cdot g \cdot T_j \cdot \cosh\left(\frac{2\pi(z+d)}{L}\right)}{2 \cdot L \cdot \cosh\left(\frac{2\pi d}{L}\right)} \tag{5.5}$$

where z is the depth of the element below the sea surface.
With $v_{\text{max},ij}$ known, the drag force F_{drag} and inertia force F_{inertia} are calculated as follows:

$$F_{\text{drag}} = \frac{1}{2}\rho_{\text{water}} C_D D_{\text{riser}} v_{\text{max},ij} \tag{5.6}$$

$$F_{\text{inertia}} = \frac{1}{4}\pi \rho_{\text{water}} C_M D_{\text{riser}}^2 v_{\text{max},ij} \omega_j \tag{5.7}$$

The maximum hydrodynamic force F_{hydro} acting on the riser is the sum of these forces:

$$F_{\text{hydro}} = F_{\text{drag}} + F_{\text{inertia}} \tag{5.8}$$

The resulting bending moment M is then given by:

$$M = a \cdot F_{\text{hydro}} \cdot L_{\text{span}} \tag{5.9}$$

where $a = \frac{1}{8}$ (constant DNV RP-C203[67]) and L_{span} is the span length.

Calculation of Bending Stress
Once the bending moment M is known, the bending stress σ_{bending} induced by the cyclic wave loading can be calculated. The bending stress is computed using the area moment of inertia I of the pipe, which accounts for the geometric properties of the riser:

$$\sigma_{\text{bending}} = \frac{M \cdot D_{riser}}{2I} \tag{5.10}$$

The moment of interia I for a hollow cylinder is given by:

$$I = \frac{\pi(D_{\text{riser}}^4 - D_{\text{inner}}^4)}{64} \tag{5.11}$$

Load combination 3
For the fatigue lifetime assessment, load combination 3 is used. This load combination models the situation described in this section. PLE4Win calculates both the bending moment and the bending stress. The calculation steps shown in this section show the way the bending moment and stress can be calculated by hand. This can be used to validate the outcome of the modeled load combination in order to prevent a miscalculation in the lifetime estimation, which could have catastrophic consequences.
As can be seen in the calculation steps, there are several factors that can be adjusted in order to alter the stresses and moments. For example, an additional clamp can be placed in order to lower the span length, which gives a lower bending moment. Also the drag coefficient can be adjusted by cleaning the marine growth of the riser, resulting in lower hydrodynamic forces.

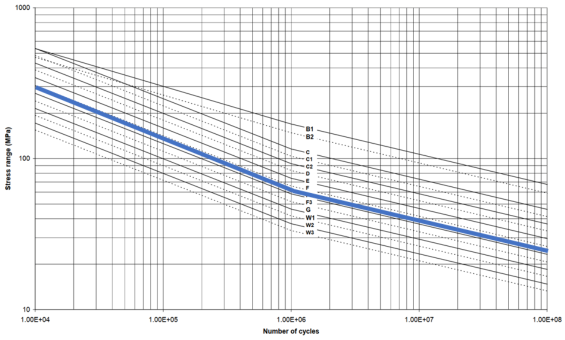


Figure 2-8
S-N curves in seawater with cathodic protection

Figure 5.1: The S-N curve for a pipeline in seawater[67]. The correct curve has been highlighted in blue.

Fatigue Lifetime Estimation Using S-N Curves
For the lifetime fatigue estimation, the standard DNV-RP-C203 method is used. This method relates a number of cycles a riser can handle before it fails to the stress that that cycle causes. This way, a number of cycles can be converted to the riser lifetime. The number of cycles is shown in figure 5.1. This figure shows a number of graphs, all representing the relation of a number of cycles until failure for a certain stress, where the graphs all have a different kind of way connecting two riser sections. Furthermore the number of allowable cycles till failure, N_p, is determined by the stress calculation from PLE4Win in step 4. The S-N curves, provided by DNV-RP-C203 standards, relate the stress range $\Delta\sigma$ to the fatigue life in terms of cycles to failure. Depending on the magnitude of $\Delta\sigma$, either the high-cycle or low-cycle S-N curve is applied.
The allowable cycles to failure are calculated using the formula:

$$\log N_p = \log(a_n) - m_n \cdot \log\left(\Delta\sigma \cdot \left(\frac{t}{t_{\text{ref}}}\right)^k\right) \tag{5.12}$$

Where:

- N_p is the predicted number of cycles to failure for stress range $\Delta\sigma$,
- a_n and m_n are material constants from the $S - N$ curve,
- $\Delta\sigma$ is the stress range for the wave,
- t is the wall thickness,
- t_{ref} is the reference wall thickness (typically 32 mm for risers),
- k is the thickness exponent.

Depending on the calculated stress range $\Delta\sigma$, the following cases apply:

- If $\Delta\sigma > 36.84$ MPa, the S-N curve for $N \leq 10^6$ cycles is used, with parameters $\log(a_1)$ and m_1.
- If $\Delta\sigma \leq 36.84$ MPa, the S-N curve for $N > 10^6$ cycles is used, with parameters $\log(a_2)$ and m_2.

This approach allows for a precise estimation of the fatigue lifetime of the riser based on cyclic loading conditions. By calculating the critical bending moment, associated bending stress, and applying the appropriate S-N curve parameters, the fatigue assessment provides insights into the structural integrity and remaining lifespan of the riser under wave-induced cyclic loading. In figure 5.1, the different S-N curves are given for different types of connections where each curve gives the correlation between the related connection and it's number of cycles to failure. Figure 5.2 shows what type of connection is related to which curve. Most risers have welded connections, which means that according to DNV-RP-C203 [67] and figure 5.2 Curve F3 should be considered.

Critical Loading and Stress Calculation
The critical loading for fatigue is primarily due to wave forces causing bending moments on the riser. The bending stress caused by this moment is calculated using standard beam theory:
For the riser, the appropriate S-N curve is curve F1 from DNV-RP-C203, as it accounts for bolted riser sections. The constants for the F1 curve can be found in table 5.1

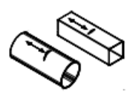
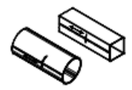
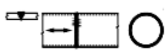
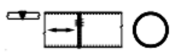
Table A-9 Hollow sections			
Detail category	*Constructional details*	*Description*	*Requirement*
B1	1. 	1. Non-welded sections	1. — Sharp edges and surface flaws to be improved by grinding
B2	2. 	2. Automatic longitudinal seam welds (for all other cases, see Table A-3)	2. — No stop /start positions, and free from defects outside the tolerances of OS-C401 Fabrication and Testing of Offshore Structures.
C1		3. Circumferential butt weld made from both sides dressed flush.	3., 4., 5. and 6. — The applied stress must include the stress concentration factor to allow for any thickness change and for fabrication tolerances, ref. section 3.3.7. — The requirements to the corresponding detail category in Table A-5 apply.
D		4. Circumferential butt weld made from both sides.	
E		5. Circumferential butt weld made from both sides made at site.	
F		6. Circumferential butt weld made from one side on a backing bar.	
F3	7. 	7. Circumferential butt weld made from one side without a backing bar.	7. — The applied stress should include the stress concentration factor to allow for any thickness change and for fabrication tolerances, ref. section 3.3.7. — The weld root proved free from defects larger than 1-2 mm.
C1		8. Circumferential butt welds made from one side that are machined flush to remove defects and weld overfill.	8. A machining of the surfaces will reduce the thickness. Specially on the root side material will have to be removed. A reduced thickness should be used for calculation of stress. The weld should be proved free from defects by non-destructive examination (It is assumed that this is fulfilled by Inspection category I). Category C may be achieved; ref. Table A-5.

Figure 5.2: Table A-9 from the DNV code [67] showing which curve should be used for which type of connection.

S-N Curve Designation	m_1	Log(a_1)	m_2	Log(a_2)	Fatigue limit at 10^7 cycles	Thickness component (k)
F_1	3.0	11.299	5.0	14.832	36.84	0.25

Table 5.1: Fatigue Curve Parameters

Number of Cycles to Failure
The number of cycles to failure for a given stress range $\Delta\sigma$ can be calculated using the equation:

$$N_p = 10^{\left(\log a_n - m_n \cdot \log\left(\Delta\sigma \cdot \left(\frac{t}{t_{\text{ref}}}\right)^k\right)\right)} \tag{5.13}$$

Remaining Fatigue Life
Once the number of cycles to failure (N_p) has been determined, the remaining lifetime of the riser can be estimated using the average wave period. The wave period represents the time between successive wave crests, which directly affects the frequency of cyclic loading on the riser. By multiplying the total number of cycles to failure (N_p) by the duration of the wave period, the overall lifespan of the riser due to fatigue from wave-induced forces can be calculated.
The total life expectancy (T_{total}) of the riser is given by:

$$T_{\text{total}} = N_p \times T_{\text{wave}} \tag{5.14}$$

Where:

- T_{total} is the total fatigue-based life expectancy of the riser,
- N_p is the number of cycles to failure,
- T_{wave} is the average wave period (in seconds).

After determining the total life expectancy of the riser, the next step is to account for the time the riser has already been in service. The risers remaining lifetime ($T_{\text{remaining}}$) is calculated by subtracting the time already spent in operation (T_{service}) from the total life expectancy:

$$T_{\text{remaining}} = T_{\text{total}} - T_{\text{service}} \tag{5.15}$$

Where:

- $T_{\text{remaining}}$ is the remaining operational life of the riser (in years),
- T_{service} is the cumulative time the riser has been in service (in years).

This final step provides a clear estimation of how much longer the riser can safely remain in operation before fatigue failure is expected. It also offers valuable insights for any additional measures that can be taken in order to extend the lifetime of the riser.

5.7. Document Findings and Recommendations: Step 6

After completing the analysis, document the results, including:

- Remaining lifetime of the riser riser based on fatigue and wave loading cycles
- Structural integrity of the riser, confirming its ability to withstand wave, current, and pressure loading
- Recommendations for repair or further monitoring if necessary

By following these steps, you can accurately assess the degradation and remaining lifespan of a riser riser in a CO2 transport system.

5.8. Feasibility assessment Riser

The steps described in the previous section form the complete methodology for the technical feasibility assessment tool. This assessment includes factors such as environmental loadings, material degradation, stress analysis, and fatigue life, to ensure that the riser remains structurally sound for future use.
Next to these calculation related steps, the results from the risk analysis matrix should also be included in the assessment. The following section will describe how these risks factor in at the feasibility assessment tool.

5.8.1. Overview of Assessment process

The assessment process consists of six key steps, each addressing technical aspects necessary for evaluating the feasibility of reusing a riser. These steps form a framework, guiding the assessment from initial data collection through to the final decision on the risers suitability for reuse. Figure 5.3 provides a schematic overview of the assessment workflow, illustrating how each step flows from the initial input data to the final output.
The workflow is designed to systematically progress from gathering essential information to analyzing and evaluating the riser's condition under operational circumstances. Each step is needed in the overall evaluation to ensuring that all relevant aspects, such as material degradation, environmental loadings, and stress analyses, are accounted for.
In the following subsections, each of these steps will be explained in detail. This breakdown will provide a clear understanding of how the input data is processed and transformed into actionable insights that contribute to the final assessment of the riser's feasibility for reuse in carbon capture and storage (CCS) or other applications.

5.9. Measures for risk mitigation

In Chapter 4, a risk analysis has been conducted, identifying several risks and associated mitigation measures that could affect the feasibility of the pipeline reuse process. These measures are depicted in Figure 5.4, which presents a complete flowchart illustrating the various aspects of the pipeline assessment and the steps where critical decisions are made.

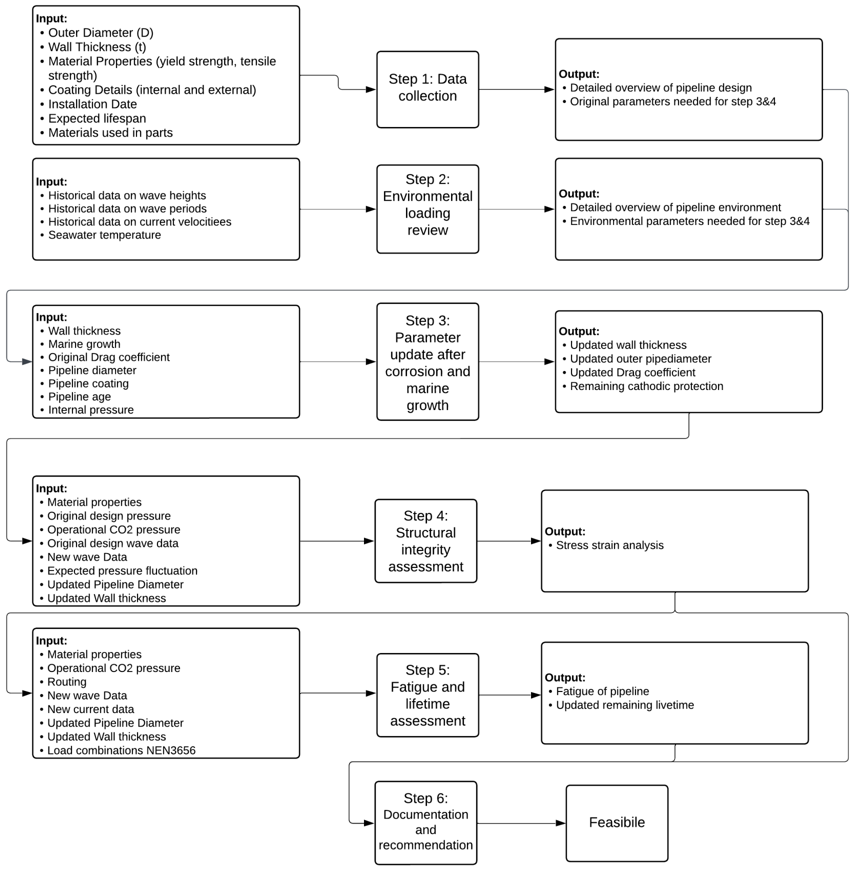


Figure 5.3: A schematic overview of the different steps taken in the process of assessing the riser for reuse.

The flowchart follows a step-by-step approach combining the steps in this chapter with the risks out of chapter 4, starting from data collection and proceeding through environmental loading review, parameter updates, structural integrity assessments, fatigue analysis, and documentation of recommendations.

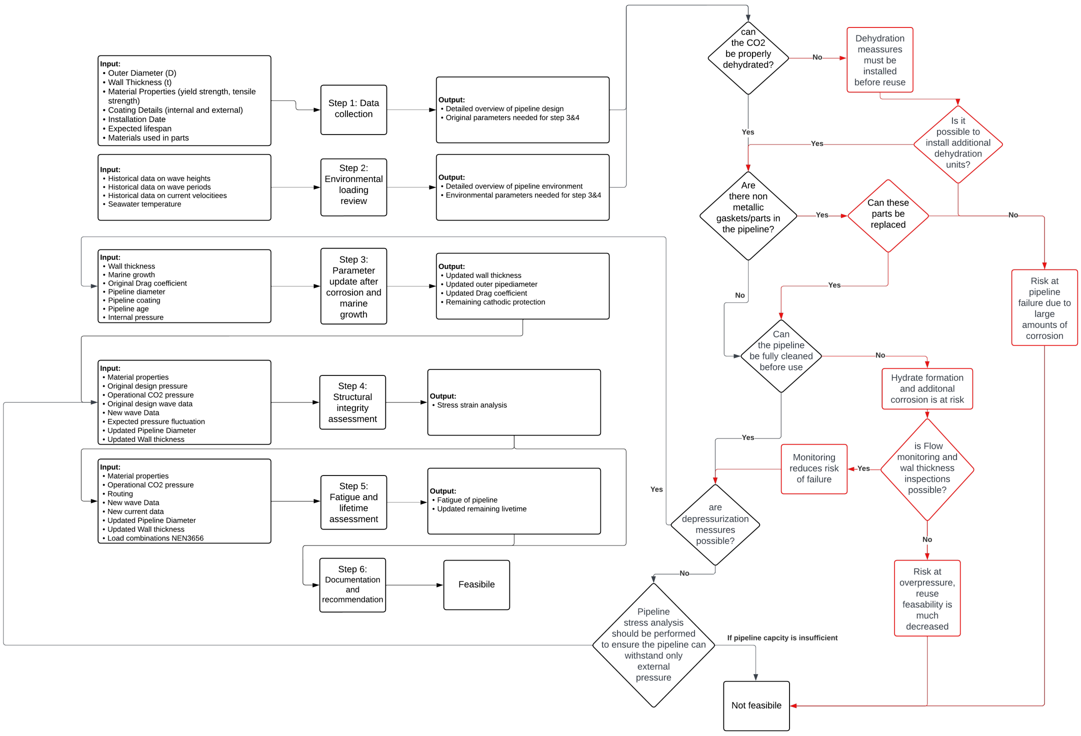


Figure 5.4: a schematic overview of the measures that can be taken in case of a certain risk.

This complete flowchart illustrates the complete approach for feasibility assessment tool.

6

Case Study

This chapter will describe a case study on the L11B riser from which data has been provided by ONE-Dyas.

6.1. Introduction to the Selected Case Study

Figure 6.1: The L11B platform [68]

The L11B platform is part of a larger offshore gas production system located in the North Sea, off the coast of the Netherlands. It was originally designed for the extraction and transport of natural gas, making it a key component of the Dutch offshore energy infrastructure. The platform is situated in the L11 block of the Dutch continental shelf, a region known for its significant natural gas reserves.

The L11B platform was constructed during the 1980s as part of the broader development of the North Sea's extensive gas fields and has started production in 1986. The riser in this casestudy has been active since 2015 when the old riser was replaced. The platform is located in the southern sector of the North Sea, approximately 100 kilometers off the Dutch coast. It forms part of the broader L11 gas field, which has been developed to exploit the gas reserves beneath the seabed. The location of this platform can be seen in figure 6.2.
The platform was originally designed to facilitate the extraction and transportation of natural gas. The infrastructure on the platform includes facilities for gas processing, compression, and export through subsea pipelines to onshore facilities.

Many offshore platforms in the North Sea, including the L11B platform, are approaching the end of their natural gas production life cycle. As gas reserves become depleted, these platforms are increasingly being considered for decommissioning or repurposing. One of the potential repurposing options for

Figure 6.2: Location of the L11B Platform relative to the Netherlands

platforms like L11B is their reuse in Carbon Capture and Storage (CCS) projects. In such cases, the existing infrastructure, including the riser system, could be repurposed for transporting captured CO2 to depleted gas reservoirs for long-term storage. The L11B platform presents a strong candidate for reuse in future CCS projects, particularly as the North Sea is being recognized as a key region for large-scale carbon storage initiatives.

6.2. Technical Assessment of the Offshore Riser for CCS. Step 1

The technical assessment of the riser connected to the L11B platform begins by step 1: gathering of all the relevant data of the original design. In this case study, this data has been supplied by Onedyas. All the relevant data out of the design reports can be found in the tables bellow. The tables include all information that is of relevance to the case study.

Parameter	Value
Product Transported	Natural Gas
Design Life	25 years
Steel Material Grade	L360 Full Body Normalized
Manufacturing Process	HFIW Carbon Steel
Pipe Outside Diameter	219.1 mm (8” NB)
Wall Thickness	12.7 mm
Wall Thickness Tolerances	-0.7 mm
Internal Corrosion Allowance	3.0 mm
Anti-corrosion Coating	Polypropylene
Anti-corrosion Coating Thickness	2.8 mm
Gas Export Pressure	90 bar
Design Pressure	125 bar
Hydrotest Pressure	185 bar
Maximum Operating Temperature	25 °C
Minimum Operating Temperature	10 °C
Maximum Design Temperature	+95 °C
Minimum Design Temperature	-20 °C

Table 6.1: Riser Design Parameters for L11B Platform

Property	Value
Density	7850 kg/m3
Specified Minimum Yield Strength at 20°C	360 MPa
Specified Minimum Yield Strength at 150°C	284 MPa
Specified Minimum Yield Strength at 95°C	316 MPa
Specified Minimum Tensile Strength	460 MPa
Young’s Modulus	2.07×10^{11} Pa
Poisson’s Ratio	0.3
Coefficient of Thermal Expansion	1.17 x 10□□ m/m°C

Table 6.2: Steel Material Properties for L11B Riser

Property	Value
Mass Flow Rate	39529 (kg/h)
Condensate to Gas Ratio (CGR)	0.8 m3/d at 500,000 Nm3/d gas production
Gas Export Pressure	90 bar
Design Pressure	125 bar
Hydrotest Pressure	185 bar
Maximum Operating Temperature	25°C
Minimum Operating Temperature	10°C
Maximum Design Temperature	+95°C
Minimum Design Temperature	-20°C

Table 6.3: Operational Data

Table 6.4: Product Weight and Densities

Description	Value
Molecular Weight	17.72 (g/mol)
Product Density	88.03 (kg/m^3)

Environmental Loading Data, Step 2

The following tables contain all data regarding the environmental loading including the significant wave height, the maximum wave height, the wave periods related to these wave heights and the maximum current velocity. The data in these tables has been checked with the most recent Royal dutch meteorological institute [69] meta-ocean database and is for this location still accurate. Therefore, the wave and current data provided by Onedyas will be used in this case study

Table 6.5: Significant Wave Height Data

Return Period (Years)	Wave Height (m)								
	N	NE	E	SE	S	SW	W	NW	ALL
All Year:									
1	5.2	3.5	2.8	2.4	2.7	4.4	5.5	6.1	6.1
10	6.5	4.3	3.4	2.9	3.3	5.4	6.8	7.6	7.6
50	7.3	4.8	3.9	3.3	3.8	6.1	7.6	8.6	8.6
100	7.6	5.1	4.1	3.5	3.9	6.4	8.0	9.0	9.0
April to September:									
1	3.6	2.2	2.5	2.1	2.3	3.0	3.6	4.4	4.4
10	4.4	2.8	3.1	2.6	2.9	3.7	4.4	5.4	5.4
50	5.0	3.1	3.5	3.0	3.2	4.2	5.0	6.1	6.1
100	5.2	3.3	3.7	3.1	3.4	4.4	5.2	6.4	6.4

Table 6.6: Significant Wave Height Associated Period Data

Return Period (Years)	Wave Period (s)								
	N	NE	E	SE	S	SW	W	NW	ALL
All Year:									
1	8.4	6.8	6.1	5.6	6.0	7.7	8.6	9.1	9.1
10	9.3	7.6	6.8	6.3	6.7	8.6	9.6	10.1	10.1
50	9.9	8.1	7.2	6.7	7.1	9.1	10.2	10.8	10.8
100	10.2	8.3	7.4	6.8	7.3	9.3	10.4	11.0	11.0
April to September:									
1	6.9	5.5	5.8	5.4	5.6	6.4	6.9	7.7	7.7
10	7.7	6.1	6.5	6.0	6.2	7.1	7.7	8.5	8.5
50	8.2	6.5	6.9	6.4	6.6	7.6	8.2	9.1	9.1
100	8.4	6.6	7.0	6.5	6.8	7.7	8.4	9.3	9.3

Table 6.7: Maximum Wave Height Data

Return Period (Years)	Wave Height (m)								
	N	NE	E	SE	S	SW	W	NW	ALL
All Year:									
1	9.0	6.3	5.1	4.4	5.0	7.7	9.4	10.4	10.4
10	10.8	7.6	6.2	5.4	6.1	9.3	11.2	12.4	12.4
50	12.0	8.4	6.9	6.0	6.8	10.3	12.4	13.6	13.6
100	12.4	8.8	7.3	6.3	7.1	10.8	12.9	14.2	14.2
April to September:									
1	6.4	4.2	4.7	4.0	4.4	5.6	6.4	7.7	7.7
10	7.8	5.1	5.7	4.9	5.3	6.7	7.8	9.3	9.3
50	8.7	5.7	6.3	5.5	5.9	7.5	8.7	10.4	10.4
100	9.0	6.0	6.6	5.7	6.2	7.8	9.0	10.7	10.7

Table 6.8: Maximum Wave Height Associated Peak Period Data

Return Period (Years)	Wave Period (s)								
	N	**NE**	**E**	**SE**	**S**	**SW**	**W**	**NW**	**ALL**
All Year:									
1	9.0	7.3	6.6	6.1	6.5	8.3	9.2	9.8	9.8
10	10.0	8.2	7.3	6.7	7.2	9.2	10.3	10.9	10.9
50	10.7	8.7	7.8	7.2	7.7	9.8	10.9	11.6	11.6
100	10.9	8.9	8.0	7.3	7.8	10.0	11.2	11.9	11.9
April to September:									
1	7.5	5.9	6.2	5.8	6.0	6.9	7.5	8.3	8.3
10	8.3	6.6	6.9	6.4	6.7	7.6	8.3	9.2	9.2
50	8.8	7.0	7.4	6.8	7.1	8.1	8.8	9.9	9.9
100	9.0	7.1	7.6	7.0	7.3	8.3	9.0	10.0	10.0

Table 6.9: Current Data

Return Period (Years)	Maximum Current Speed (m/s)								
	N	**NE**	**E**	**SE**	**S**	**SW**	**W**	**NW**	**ALL**
All Year:									
1	0.25	0.59	0.59	0.35	0.32	0.75	0.81	0.28	0.81
10	0.30	0.70	0.70	0.42	0.38	0.89	0.96	0.33	0.96
50	0.32	0.76	0.76	0.46	0.42	0.97	1.05	0.36	1.05
100	0.34	0.79	0.79	0.48	0.44	1.01	1.09	0.38	1.09
April to September:									
1	0.20	0.48	0.48	0.29	0.26	0.61	0.66	0.23	0.66
10	0.24	0.57	0.57	0.34	0.31	0.72	0.78	0.27	0.78
50	0.26	0.62	0.62	0.37	0.34	0.79	0.85	0.29	0.85
100	0.27	0.65	0.65	0.39	0.36	0.82	0.89	0.31	0.89

6.2.1. Step 3: Parameter Update After Corrosion and Marine Growth

Step 3 is the parameter update after the pipeline has been subjected to corrosion for it's years in operation as a Gas riser. To calculate the new wall thickness, the Norsok M-506 method is used to calculate the internal corrosion. The external corrosion can be neglected due to the fact that the pipeline has a coating that prevents the outside of the pipeline from corroding. Both the maximum value for C_d and C_m are set at 2.0 as a save assumption for the drag and interia coefficients [11].

Internal Corrosion

Use the NORSOK M-506 formula to calculate the internal corrosion rate caused by CO2:

$$CR = A \times (P_{\text{CO2}})^B \times e^{C \times T} \tag{6.1}$$

Where:

- $A = 0.03$ (empirical constant)
- $B = 0.7$ (exponent for the relationship between CO2 partial pressure and corrosion)
- $C = 0.02$ (temperature effect constant)
- P_{CO2} is the partial pressure of CO2
- T is the temperature

Partial pressure of CO2 is calculated as:

$$P_{\text{component}} = \frac{\text{Mole Fraction of Component}}{100} \times P_{\text{total}} \tag{6.2}$$

Component	Mole (%)
Methane	0.907
Ethane	4.01E-02
Propane	5.96E-03
i-Butane	7.37E-04
n-Butane	1.11E-03
22-Mpropane	4.15E-05
i-Pentane	2.52E-04
n-Pentane	2.97E-04
Cyclopentane	7.29E-06
2-Mpentane	1.61E-04
n-Hexane	1.32E-04
Mcyclopentan	1.49E-05
Benzene	8.39E-04
Cyclohexane	1.11E-04
2-Mhexane	1.03E-04
n-Heptane	7.65E-05
Mcyclohexane	1.04E-04
Toluene	6.73E-05
224-Mpentane	8.44E-05
n-Octane	5.38E-05
E-Benzene	2.29E-06
m-Xylene	1.81E-05
n-Nonane	1.48E-04
n-Decane	4.49E-04
Helium	5.23E-04
H2O	6.83E-19
Nitrogen	2.17E-02
CO2	2.02E-02
Methanol	0.00
Hydrogen Sulfide	0.00
TEGlycol	9.21E-08

Table 6.10: Gas Product Composition, this table shows all the components present in the natural gas that has originally been transported through the pipeline. This data will be used for the corrosion update

Table 6.10 shows the components of the natural gas the pipeline originally transported. If this data is combined with the operating pressure of the riser under natural gas transport circumstances (125 Bar), the new wall thickness is found to be 11.8 mm (account for the effectiveness of internal coatings, which can reduce the corrosion rate by 70-90% [70]) opposed to the original wall thickness of 12.7 mm.

6.3. Stress strain analysis Using PLE4Win, Step 4

This section describes step 4, the stress-strain analysis using PLE4Win. The input parameters for this analysis include the main geometric parameters, such as the updated wall thickness and the updated riser diameter. The riser will be assessed in the three load combinations given in chapter 5, LC1, which is the most critical load combination that assesses the maximum stresses occurring in the riser when it's operating as a CO2 transport riser, LC2 which tests the ability of the riser to withstand the event of a decrease in internal pressure, and LC3 which will be used for the fatigue lifetime assessment. In the following sections, the main input used for the stress-strain assessment in PLE4Win is given and explained.

6.3.1. Loads and limits of case study

In order to achieve a realistic stress strain analysis, the pressure and temperature should be put into the analysis. However, these input values depend on numerous cases including the reservoir pressure, the export riser pressure and the state of the transported CO2. Since this case study is based on a decommissioned gas riser, these values should all be assumed based on findings in literature. The reservoir pressure is estimated at 125 Bar since the riser has a design pressure of 125 Bar. Additionally, an average of 50 bar is needed on top of the resevoir pressure for injection. This means that the required pressure capacity of the riser to inject the CO2 into the field has to be approximately 175 Bar.

For stress calculations in load combination 1, the following equation must hold according to NEN3656[11]:

$$\sigma_v \leq 0.85\frac{Re + Re(\theta)}{\gamma_m} \tag{6.3}$$

Where:

- σ_v: Von Mises equivalent stress (N/mm^2)
- Re: Yield strength at room temperature (N/mm^2)
- $Re(\theta)$: Yield strength at elevated temperature θ (N/mm^2)
- γ_m: Material safety factor, accounting for uncertainties in material properties

For load combination 2, the following equation must hold:

$$\sigma_v \leq 1.1\frac{Re}{\gamma_m} \tag{6.4}$$

In this case study this results in the following stress limits for LC1 and LC2 respectively:

$$\sigma_{v,LC1} \leq 0.85\frac{Re + Re(\theta)}{\gamma_m} \tag{6.5}$$

$$\sigma_{v,LC2} \leq 1.1\frac{R_e}{\gamma_m} \tag{6.6}$$

$$R_e(\theta) = \frac{R_e(720-\theta)}{1400} \tag{6.7}$$

$$R_e(\theta) = \frac{420(720-32)}{1400} = 206.4MPa \tag{6.8}$$

$$\sigma_{v,LC1} \leq 0.85\frac{360 + 206.4}{1.1} \leq 437.67MPa \tag{6.9}$$

$$\sigma_{v,LC1} \leq 437.67MPa \tag{6.10}$$

$$\sigma_{v,LC2} \leq 1.1\frac{360}{1.1} \tag{6.11}$$

$$\sigma_{v,LC2} \leq 360MPa \tag{6.12}$$

- $R_m = 460$MPa (tensile strength of the material)
- $\theta = 32$ degrees Celsius(Temperature of the medium)
- $\gamma_m = 1.1$ (material safety factor)

6.3.2. Platform deflection

The riser is also submitted to the deflection of the platform since the two are attached to each other. This will result in additional stresses on the riser and will be taken into account in the stress analysis. The platform deflections are listed in table 6.11.

Description	Elevation wrt LAT (m)	Deflection X (mm)	Deflection Y (mm)	Deflection Z (mm)
Topside Elevation	27.31	Max: 80.1	Max: 38.8	Max: 1.0
		Min: -42.2	Min: -103.3	Min: -27.7
Mudline Elevation	-26.00	Max: 21.2	Max: 13.5	Max: 0.9
		Min: -15.8	Min: -30.7	Min: -18.5

Table 6.11: L11B Platform Deflections out of the design report. This data is used to model the forced riser displacement due to platform deflections

6.3.3. Physical riser model

The riser model in PLE4Win has been constructed using the provided routing data, ensuring that the model accurately represents the actual riser configuration. This routing data is based on drawings developed during the design phase of the riser, which includes key structural details. The data provided consists of a 3D overview of the entire platform (Figure 6.3), a side view of the platform's substructure, which highlights the positioning of the clamps (Figure 6.4), and a schematic routing of the riser, which shows the path from the seafloor up to the platform (Figure 6.5).

These drawings and routing data ensure that the physical model in PLE4Win is representative of the real-world setup, allowing for more accurate analysis of the structural behavior of the riser under various loading conditions.

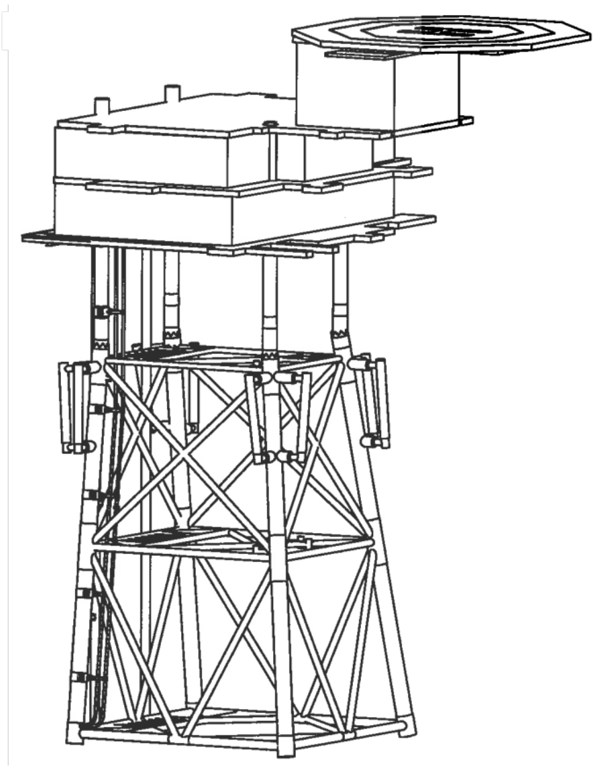


Figure 6.3: An orthographic projection of the whole platform

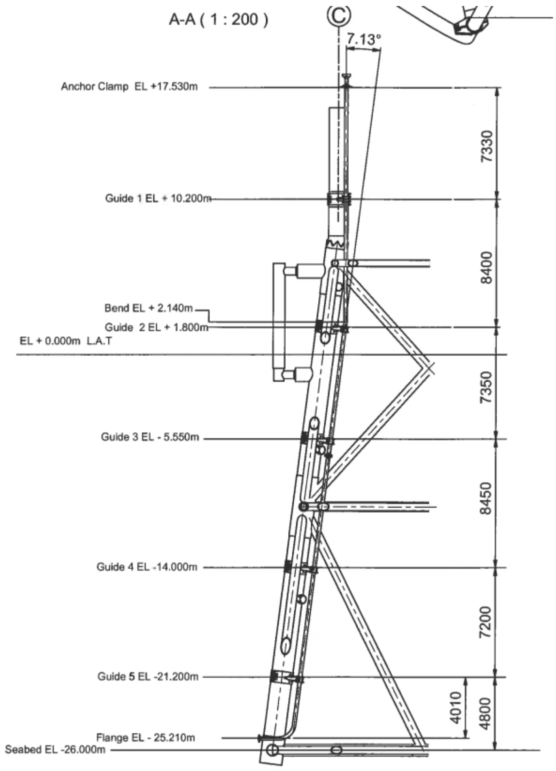


Figure 6.4: The side view of the platform's substructure showing the distances between the clamps

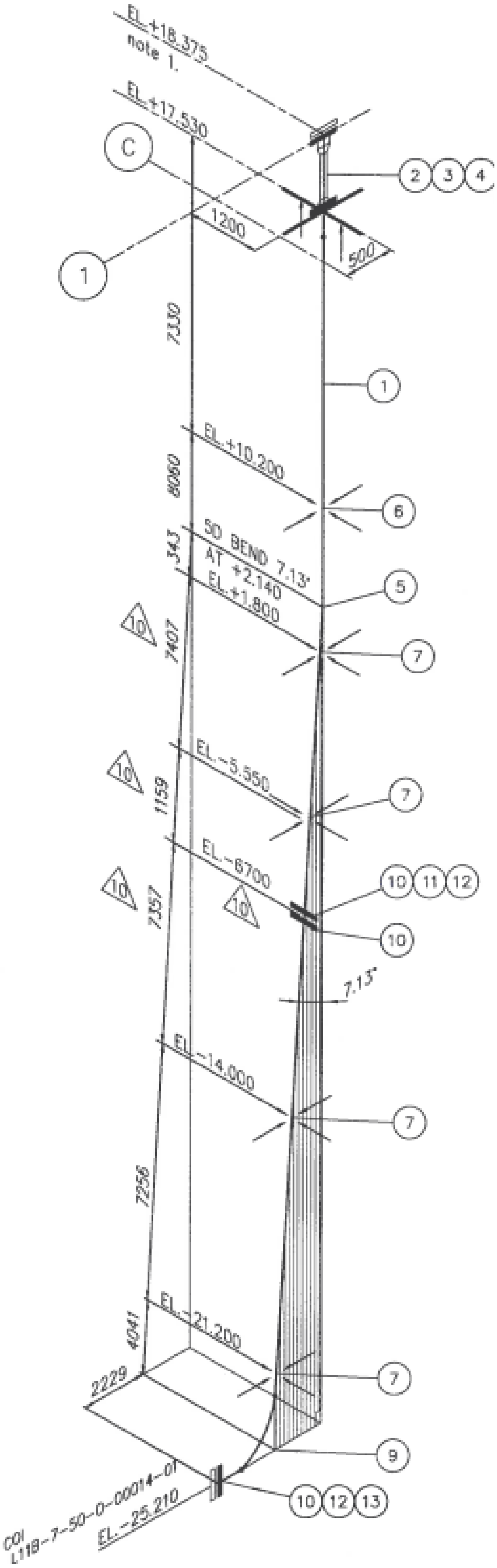


Figure 6.5: The routing of the riser from the seafloor to the platform

Clamp supports
The riser has been modeled from the flange located at the seafloor up to the final clamp that secures the riser to the topside of the platform. Along this route, the riser is fastened to the platform using riser clamps. These clamps are crucial structural components, an example of how one of the clamps looks is shown in Figure 6.6.

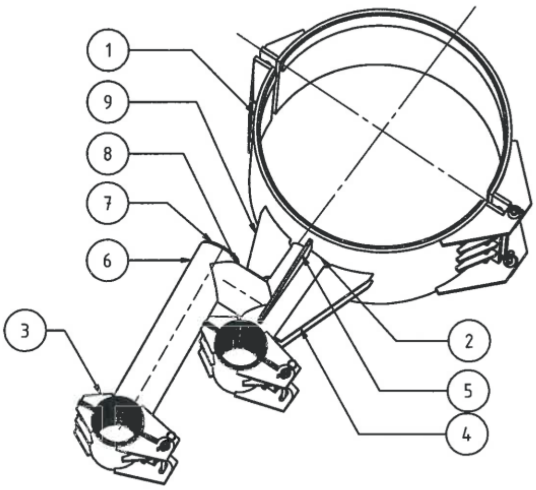


Figure 6.6: The shop drawing of the clamps securing the riser to the platform

In the PLE4Win model, these clamps are represented as external supports. These supports are modeled as point supports, meaning the physical length of the clamp is not taken into account. Instead of distributing the load over the actual length of the clamp, the model applies the support condition at a single point, which may result in higher stress concentrations at the clamp locations.

This modeling approach is considered conservative because it tends to overestimate the stress and deflection at the clamp locations, leading to a more cautious evaluation of the riser's structural integrity. While this might result in slightly higher perceived risks of failure or more stringent design requirements, it provides a safer assessment framework by addressing potential worst-case scenarios. This conservative approach is especially suitable for reuse assessments, where the actual riser can differ from the calculations for example due to unforeseen damages to the riser.

6.3.4. Pipline input data
PLE4Win requires a set of input parameters for the riser specifications. The parameter listed bellow are all the input parameters used in the model. These values are based on the data shown in the tables in section 6.2. It can be seen in the coating thickness of coating 2 that the marine growth has been increased to 50mm. The corrosion allowance remains at 3 mm since this is the minimum used in any pipeline project.

riser Material Properties
- **Material Type**: Steel
- **Young's Modulus** : 207,000 N/mm2
- **Poisson's Ratio**: 0.3
- **Thermal Expansion Coefficient** : 0.000012 1/C
- **Yield Strength**: 448 N/mm2
- **Material Density**: 0.000078 N/mm3

riser Dimensions
- **Outer Diameter**: 219 mm

- **Nominal Wall Thickness**: 11.8 mm
- **Corrosion Allowance**: 3 mm
- **Minimum Wall Thickness**: 8.8 mm
- **Dead Weight**: 0.572619 N/mm
- **Medium in riser**: CO2
- **Weight Medium**: 0.000009 N/mm3
- **Coating Thickness 1**: 2.8 mm (External Coating)
- **Coating Thickness 2**:50 mm (Marine Growth)
- **Coating Weight 1**: 0.000009 N/mm3 (External Coating)
- **Coating Weight 2**: 0.000013 N/mm3 (Marine Growth)

6.3.5. Soil Data

The next input required by PLE4Win is the soil data. For buried risers, PLE4Win offers a soil wizard that can automatically calculate all relevant pipe-soil interaction parameters based on the soil profiles through which the riser passes. However, in this case study, this feature is not needed since the bottom flange of the riser rests on the seafloor rather than being buried, running through a number of soil profiles. As a result, the only soil data input required is the type of ground material. For this assessment, the ground material is dense sand.

6.3.6. Model boundary

PLE4Win offers several options for defining the model boundaries, specifically at the start and end points of the riser. The available boundary conditions are *fixed*, *free*, and *infinite*. A fixed boundary condition in PLE4Win means that the point is completely restrained, with infinite spring stiffness in all directions. A free boundary condition, on the other hand, implies zero spring stiffness, allowing the point to move freely in all directions. The infinite boundary condition simulates a riser that behaves as though it extends infinitely in length.

For the start of the riser, a fixed boundary condition has been selected, as the riser is firmly attached to the foundation of the platform at the start of the riser section. At the end of the riser, a free boundary condition has been chosen, but with an additional guide of a known stiffness applied to this point. This approach was taken because PLE4Win does not allow for specifying a displacement at a fixed boundary. By defining the boundary as free with a known stiffness at the support, a force can be applied at this location, resulting in the desired deflection, which corresponds to the platform deflection experienced by the riser.

6.3.7. Wave and current loading

In PLE4Win, wave and current data can be used for simulating the hydrodynamic forces acting on the riser. The wave and current data input must be detailed enough to capture the relevant environmental conditions to which the riser is exposed, this involves choosing the right wave characteristics for the right loading cases. In this case study, 3 loading combinations will be used; LC1, LC2 and LC3. One for step 4 of the approach for feasibility assessment (LC1) and two for step 5 (LC2 and LC3).
The wave characteristics uses in LC1 and LC2 must model the most critical situation. According to NEN3656, the maximum wave height, period and maximum current with a 100 year interval must be used. This results in the wave and current input as shown bellow:

- **Wave Height**: 14,200 mm (14.2 meters)
- **Wave Period**: 11.9 seconds
- **Wave Direction**: 315 degrees (NW)
- **Current Direction**: 315 degrees (aligned with the wave direction)
- **Velocity Profile**: Parabola profile (second order)
- **Surface Velocity**: 380 mm/s
- **Drag coefficient**: 2.0

For LC1 in the approach for feasibility assessment, the goal is to find a loading combination representative of the average wave induced forces and stresses. In order to get the most average situation representable for a long period of wave impacts, the root mean square wave height and average period has been selected for this load combination with an interval of 50 years in accordance with the findings by Watters et al. [16]. Since the current will increase the wave velocity and with that it's impact on the riser, the current will be modeled in the same direction as the wave. This leads to the following wave and current input:

- **Wave Height**: 6330 mm (6.3 meters)
- **Wave Period**: 9.9 seconds
- **Wave Direction**: 315 degrees (NW)
- **Current Direction**: 315 degrees (aligned with the wave direction)
- **Velocity Profile**: Parabola profile (second order)
- **Surface Velocity**: 250 mm/s
- **Drag coefficient**: 2.0

The current velocity profile was modeled using a parabola shape, which reflects the typical velocity distribution in offshore currents. The surface velocity of 380 mm/s or 250 mm/s for step 4 and step 5 respectively is relatively low compared to the data provided in the riser design. However the overall forces and stresses on the riser are highest in the situation where the wind and wave direction align. Additionally, the wave loading leads significantly higher stresses than the current loading, making the wave loading the most critical components of the loading combination[71]. Therefore the surface velocity has been chosen as the highest value in the same direction as the highest wave direction.
In all the load combinations, the drag coefficient and the inertia coefficient has been set to 2.0, which is the prescribed maximum value for a riser with marine growth by NEN3656 [11].

6.3.8. riser Loading

In PLE4Win, riser loading data is used for assessing the structural behavior of the riser under operational conditions. The loading parameters include internal pressure, temperature differences, point forces and settlement values. In this case study the settlement values play no role since they are focused on the riser soil interaction

- **Internal Pressure**: The internal pressure of the medium flowing through the riser directly influences the hoop stress and overall load on the riser walls.
- **Temperature Difference**: Temperature variations cause thermal expansion or contraction in the riser material, inducing additional stresses.
- **Point forces**: The point forces, nodal forces called in PLE4Win, are used to apply a given force on the riser on specific points. In this case study this is used to apply forces on the clamps in order to simulate the displacement of the platform. These forces are applied solely on the supports and not on the riser itself, preventing ovalisation from happening due to these forces.
- **Settlements**: Settlements (vertical, lateral, and longitudinal) are displacements of the riser due to soil conditions, affecting the overall riser alignment. Not of importance to this case study due to the lack of pipe-soil interactions.

For the case study, the following riser loading data has been input into the PLE4Win model for load combinations LC1 and LC2:

- **Internal Pressure**: 17.5 N/mm^2
- **Absolute Temperature**: 32 C (The highest value for CO_2 transport)
- **Relative Temperature**: 5 C (This temperature is used to calulate the loading due to temperature differences. 5 degrees Celsius is the lowest seawater temperature at -25m waterdepth. This is the relevant temperature since this is the temperature of the riser if the transport comes to a hold.

The aim of LC3 is to calculate if the riser has enough structural integrity left to endure the outside pressure without any internal pressure. This is a scenario that could happen in case of a sudden production stop and no measures to mitigate this presure loss could be taken. The input paramters for LC3 are:

- **Internal Pressure**: 0 N/mm²
- **Absolute Temperature**: 32 C (The highest value for CO2 transport)
- **Relative Temperature**: 5 C

6.3.9. Summary of Loading Combinations

The loading combinations used in the PLE4Win model are designed to represent different environmental and operational conditions that the riser might encounter. The table below summarizes the key parameters for each loading combination.

- **LC1**: This loading combination considers the maximum wave and current conditions with a 100-year interval as per NEN3656, providing insight into the riser's behavior under extreme conditions.
- **LC2**: This combination evaluates the riser's ability to withstand external pressure without internal pressure, simulating a production stop scenario.
- **LC3**: This loading combination represents average wave-induced forces and stresses, which are used for the fatigue lifetime assessment in step 5.

Parameter	**LC1**	**LC2**	**LC3**
Wave Height (mm)	Maximum 100 year	Maximum 100 year	Root mean square 100 year
Wave Period (s)	Maximum 100 year	Maximum 100 year	Mean 100 year
Wave Direction	NW	NW	-
Current Direction	NW	NW	-
Velocity Profile	Parabola (2nd order)	Parabola (2nd order)	-
Surface Velocity (mm/s)	Maximum 100 year	Maximum 100 year	None
Internal Pressure (N/mm^2)	17.5	0	0

Table 6.12: Summary of Loading Combinations LC1, LC2, and LC3

6.4. Results stress strain analysis

This section presents the results of the stress-strain analysis performed on the riser model. The analysis evaluates the structural response of the riser to various loading conditions. By examining the results of the modeled load combinations, conclusions on the structural integrity of the riser can be made.

6.4.1. Load combination 1 original situation

In order to properly compare and validate the riser stresses, the original situation is also modeled in the original situation when the riser still served as a transport line for natural gas. This model is made for load combination 1, with the original wall thickness, original design temperature and original design pressure. These input parameters are shown in table 6.13. The maximum found Von Mises stress in this load combination is: $346.36Mpa$, which is well within the limits. The total von mises stress over the whole length of the riser can be found in figure 6.7.

Paramter	**value**
Wall thickness	12.9 mm
Marine growth Thickness	20 mm
Design temperature	25 C
Design pressure	125 Bar
Wave height	100 year maximum
Wave period	100 year maximum
Current velocity	100 year maximum

Table 6.13: The original riser paramters and loadings used to model the original situation in LC1

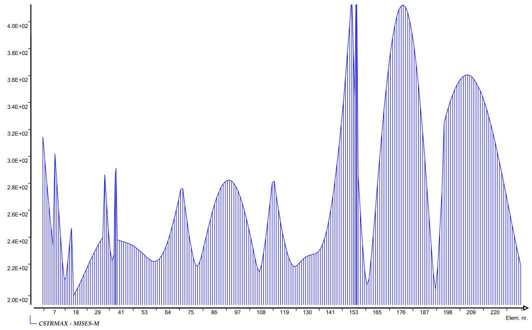


Figure 6.8: The Von Mises stress plotted against the length of the pipe for LC1, the dotted line represents the upper limit for LC1

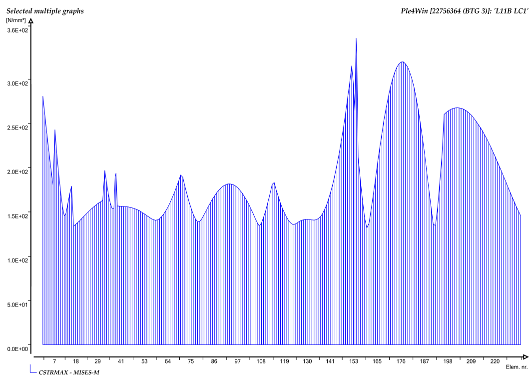


Figure 6.7: The Von Mises stress over the riser in the original situation for Natural gas.

6.4.2. Load combination 1

The purpose of Load combination 1 is to determine the most critical loading scenario for the riser, ensuring that it remains within the allowable stress limits defined in chapter 5:

$$\sigma_v \leq 0.85\frac{Re + Re(\theta)}{\gamma_m} \tag{6.13}$$

$$\sigma_{v,max} = 437.67MPa \tag{6.14}$$

This specific combination involves a series of environmental and operational loads that the riser will most likely experience as a maximum during its lifetime.

The results of this load combination are depicted in figure 6.8, which shows the distribution of the Von Mises stress along the length of the riser on the horizontal axis. The Von Mises criterium is employed here as it provides a conservative measure of the equivalent stress in complex loading conditions, combining the stresses of all three principal directions into a single value. This allows for an effective evaluation of whether the riser will exceed the material limitations under combined loading conditions.

In this load combination, the analysis revealed that the maximum Von Mises stress reached $432.9,$ MPa. This value is within the allowable limit of $437.67,$ MPa, demonstrating that the riser is capable of handling this most critical loading scenario without exceeding its the maximum Von Mises stress. The proximity of the maximum stress to the limit, however, indicates that the riser is operating near its maximum design capacity.
Load combination 1 demonstrates that, while the riser is in a high load scenario, it can operate within the prescribed limits set by the NEN3656 standard.

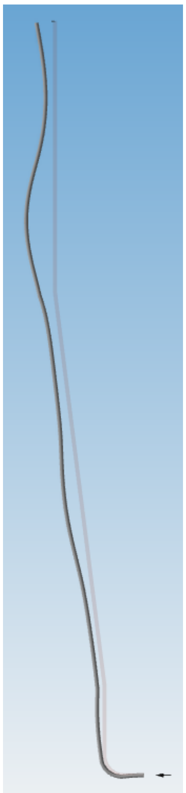


Figure 6.9: This figure shows the displaced riser as a result of loading combination 1. In order to emphasize the most displaced locations, the displacement has been magnified by a factor 10.

6.4.3. Load combination 2

Load combination 2 is designed to assess whether the riser would collapse under external pressure in the event of a total system depressurizing, without any mitigating measures in place to prevent the riser from losing pressure. This scenario assumes the complete removal of internal pressure. The objective is to verify if the Von Mises stress remains below the allowable limit set by NEN3656 for a situation with no internal pressure:

$$\sigma_v \leq 1.1\frac{Re}{\gamma_m} = 360\,\text{MPa} \tag{6.15}$$

The resulting Von Mises stress from this load combination is depicted in Figure 6.10.

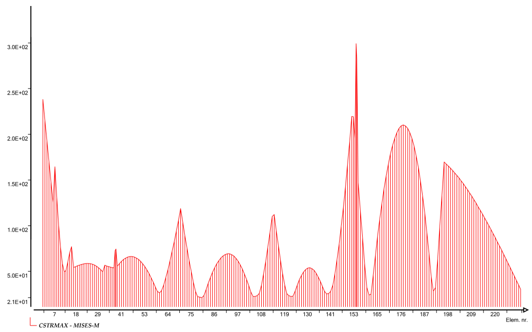


Figure 6.10: The Von Mises stress plotted against the length of the pipe for LC2, the dotted line represents the upper limit for LC2

In this case, the maximum Von Mises stress is found to be 346.01 MPa, which is within the limit found in equation 6.15. It can be concluded that the riser is able to withstand solely outside pressure in case of a shutdown. Additionally mitigation measures are not needed, which has a positive inlfuence on the ecnomic feasibility as can be seen in the flowchart in figure 5.4.

6.4.4. Load combination 3

The last load combination is used to calculate the fatigue lifetime of the riser. In order to calculate the fatigue lifetime, the bending moment must be retrieved from the model. In figure 6.9 the displaced riser due to wave loading can be seen. In figure 6.11 A), the bending moment as a result of the load combination in scenario one is shown. as can be seen, the bending moments differs over the length of the riser.

For this analysis, then bending moment and stress must be highest around the water level. This is expected due to the fact that the cyclic wave loading is investigated. This type of loading is expected to result in stresses around the water level. In figure 6.11 the bending moment and bending stresses are shown. It can be seen that the concentrations for both the bending moment and the bending stress are located above and bellow the waterline. This is to be expected for wave loading. The resulting bending moment is found to be: $1.838 * 10^7 Nmm$.

Furthermore the bending stress can also be found in the model. This is the value that wil l be used for the lifetime fatigue assessment. However, the steps will be validated in this section by performing a hand calculation. Load combination gives a bending stress of: $32.18MPa$

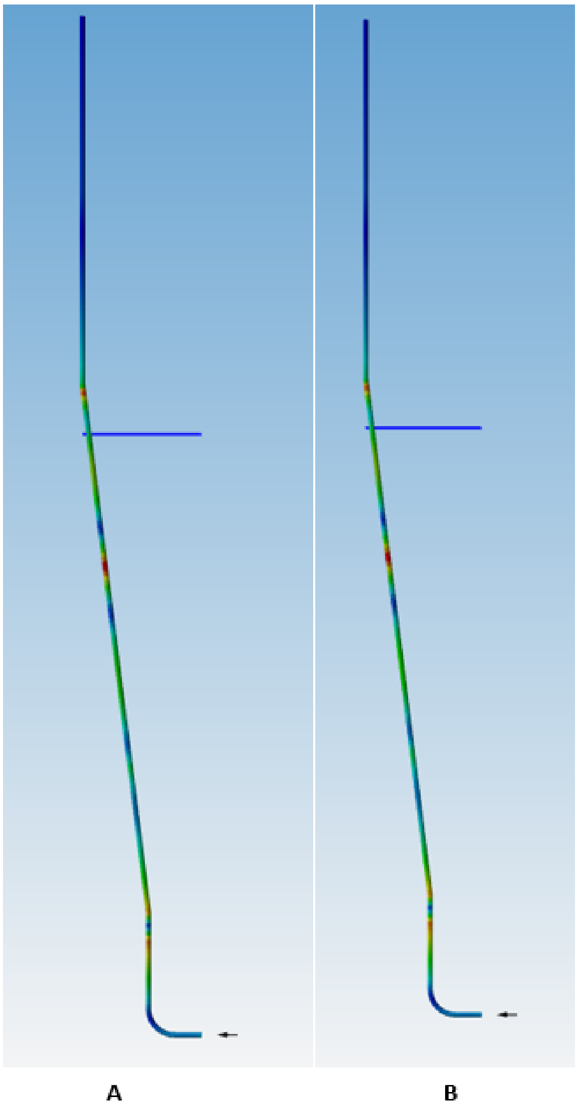


Figure 6.11: A) is the bending stress in the riser, B) is the bending moment in the riser. The colors indicate the hight of the moment and stresses relative to the rest of the riser with red being the highest amount of stress. The blue line represents the average water line.

Fatigue lifetime assessment, Step 5

The value found as the true maximum bending stress can be validated by doing a hand calculation. This is done by using step 5 out of chapter 5.

To start, the wave length must be determined. This is done by solving the dispersion relation:

$$L = \frac{g \cdot T_j^2}{2\pi \tanh\left(\frac{2\pi d}{L}\right)} \tag{6.16}$$

$$L = 128.56m \tag{6.17}$$

Once L is obtained, the maximum water particle velocity $v_{\text{max},ij}$ is calculated as:

$$v_{\text{max},ij} = \frac{H_i \cdot g \cdot T_j \cdot \cosh\left(\frac{2\pi(z+d)}{L}\right)}{2 \cdot L \cdot \cosh\left(\frac{2\pi d}{L}\right)} = 0.85\frac{m}{s} \tag{6.18}$$

The drag force F_{drag} and inertia force F_{inertia} are calculated as follows:

$$F_{\text{drag}} = \frac{1}{2}\rho_{\text{water}} C_D D_{\text{riser}} v_{\text{max},ij} \quad (6.19)$$

$$F_{\text{inertia}} = \frac{1}{4}\pi\rho_{\text{water}} C_M D^2_{\text{riser}} v_{\text{max},ij}\omega_j \quad (6.20)$$

$$F_{hydro} = F_{\text{drag}} + F_{\text{inertia}} \quad (6.21)$$

The resulting bending moment M is then given by:

$$M = a \cdot F_{\text{hydro}} \cdot L_{\text{span}} \quad (6.22)$$

$$\sigma_{\text{bending}} = \frac{M_{ij} D_{\text{riser}}}{2I} \quad (6.23)$$

This leads to the following set of equations:

$$\sigma_{\text{bending}} = \frac{M_{ij} D_{\text{riser}}}{2I} \quad (6.24)$$

$$\sigma_{\text{bending}} = \frac{a \cdot F_{\text{hydro}} \cdot L_{\text{span}} D_{\text{riser}}}{2I} \quad (6.25)$$

$$\sigma_{\text{bending}} = 30.14MPa \quad (6.26)$$

As can be seen, the value out of the model and the value out of the hand calculation are of the same magnitude. The difference of 2 MPa can be explained by the fact that the model has a more detailed calculation since the routing of the riser, the clamp stiffness and the corrosion tolerances are taken into account. However, both calculations have an outcome of similar magnitude which validates the outcomes. For the actual lifetime calculation, the highest bending stress variation will be used: $32.18MPa$ This value can than be inserted in the formula to find the value for N:

$$\log N_p = \log a_2 - m_2 \cdot \log\left(\Delta\sigma_{ij} \cdot \left(\frac{t}{t_{\text{ref}}}\right)^k\right) \quad (6.27)$$

$$\log N_p = 14.832 - 5.0 \cdot \log\left(32.18MPa \cdot \left(\frac{11.8mm}{32mm}\right)^{0.25}\right) \quad (6.28)$$

$$\log N_p = 7.87 \quad (6.29)$$

$$N_p \approx 10^{7.87} \quad (6.30)$$

This outcome can also be retrieved from the SN curve shown in figure 6.12.
Given that a cycle lasts 9.9 seconds, this gives the riser a total lifetime of:

$$10^7.87 * 9.9s = 23.47years \quad (6.31)$$

This means that the riser still has about 14.5 years of lifetime left.

6.5. Risk Analysis

As outlined in Chapter 5, the risk analysis is conducted in parallel with the technical steps in the assessment tool's flowchart. This section applies the risk analysis framework to the case study.

Dehydration of CO2

The initial step involves verifying that the CO2 is adequately dehydrated prior to transport. In the context of this case study, specific data regarding the dehydration status of CO2 is unavailable. As a result, it is assumed that the CO2 is fully dehydrated before entering the riser, ensuring minimal risk of corrosion formation during operations.

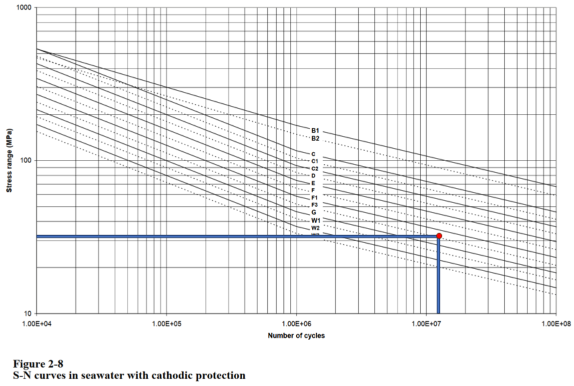


Figure 6.12: The S-N curve [56], the highlighted point is the combination between the stress variation and the number of cycles till failure.

Presence of Non-Metallic Materials in the riser

The second step is to identify any non-metallic materials within the riser system. For this case study, the riser has a welded design, eliminating the need for flanges and, therefore, gaskets. As a result, there are no non-metallic components within the riser, mitigating potential incompatibility risks associated with CO2 exposure.

riser Cleaning Feasibility

The third step assesses the feasibility of thoroughly cleaning the riser before it is repurposed for CO2 transport. Given that this riser was originally used for gas transport, where hydrate formation posed a significant challenge, it is equipped with a pigging system. This feature enables complete cleaning and inspection of the riser, ensuring that any potential residues or contaminants are removed before the CO2 transport operations.

Depressurization Measures

To ensure operational safety, the fourth step examines the feasibility and necessity of implementing depressurization measures. A dedicated load combination analysis was conducted in step 4 to evaluate the riser's response to potential rapid pressure drops. The results indicated that, even in the absence of specific depressurization measures, the riser possesses sufficient structural integrity to withstand the stress impacts associated with significant internal pressure reduction. This assessment confirms the riser's resilience under varying pressure conditions, reinforcing its suitability for reuse.

6.6. Conclusion and Discussion of Results

This case study focused on assessing the structural integrity of the L11B riser for potential reuse in CO2 transport. Through the application of PLE4Win software, three different load combinations were analyzed to simulate various operational and environmental conditions. Each load combination provided valuable insights into the riser's performance under different stress scenarios, and the results were compared against the NEN3656 standard to determine whether the riser remained within allowable limits.

6.6.1. Load combination 1: Maximum Operational and Environmental Loads

In Load combination 1, the riser was assessed under its most critical operational and environmental loading conditions, including internal pressure, external pressure, and thermal effects. The analysis showed that the maximum Von Mises stress reached 432.9 MPa, which is within the allowable limit of 437.67 MPa set by NEN3656. This result indicates that the riser is capable of handling extreme conditions without exceeding the material's strength. However, it is important to note that the riser is operating close to its design capacity. As a result, any additional stressors, such as unexpected temperature fluctuations, pressure surges, or material degradation, could push the riser beyond its safe operating limits. For future reuse in CCS projects, this factor must be considered, and mitigation strategies, such as regular inspections and load management, should be implemented.

Furthermore it can be seen that the transport of CO2 puts more stress on the riser than in the original situation. This is a result of several factors:

- The wall thickness has been reduced.
- The Marine growth thickness has increased.
- Both the drag and interia coefficients have increased.
- The pressure for CO2 is significantly higher than for Natural gas (175 Bar against 125 Bar).

The increase from 346.36 MPa to 432.9 MPa is therefore to be expected and reasonable for a degraded riser.

6.6.2. Load combination 2: Total Depressurization Scenario

Load combination 2 simulated a worst-case scenario where the riser is completely depressurized and subjected to external pressure alone. The analysis revealed that the maximum Von Mises stress in this scenario was 346.01 MPa, which is bellow the found limit of 360 MPa. This means that the riser itself is able to withstand the scenario in which the riser suddenly depressurizes. As outlined in the assessment flowchart (Figure 5.4), mitigation measures such as shut-off valves and buffer systems can be implemented to prevent total depressurization, however in this scenario these prevention systems are not required to prevent structural failure.

6.6.3. Load Combination 3: Fatigue Lifetime Assessment

The results of Load Combination 3 focused on the fatigue life of the riser, considering wave-induced forces and operational conditions whit a root mean square wave height and a 50 year interval. The bending moment calculated in this scenario was critical in determining the remaining fatigue life of the riser. Based on the analysis, the riser still has approximately 19 years of operational life remaining under normal operating conditions. This result is encouraging for the potential reuse of the riser, as it demonstrates that the riser can continue to operate without significant risk of fatigue failure in the near future. However, ongoing monitoring and maintenance will be essential to ensure that the riser remains in good condition throughout its extended life cycle.

6.6.4. Case Study Conclusion and Discussion

The results of this case study highlight the importance of a thorough technical assessment when considering the reuse of existing infrastructure for new applications, such as CCS. The L11B riser shows promising potential for reuse, in all the load combinations the riser demonstrated adequate strength and fatigue life under both average and extreme conditions.

From a broader perspective, the reuse of the L11B riser for CCS presents a sustainable alternative to building new infrastructure. Furthermore, the results of this case study show that the approach for feasibility assessment works for risers. If the case study is put in a broader perspective, there are several areas of improvement of the riser design that may extend it's lifetime or capacity.

One of these areas is the placement of additional clamps. The riser is clamped in several places in order to attach it to the platform, if the lifetime needs to be extended, an additional clamp can be placed in order to reduce the span length, which reduces the bending stresses and gives the riser a longer lifetime.

Another area of improvement for the riser design could be to clean them outside of the riser and therefore reduce the marine growth and the drag coefficient. This will reduce the wave and current loading. Therefore a riser that exceeds the stress limits in LC1 and LC2 can be approved. Additionally, depending on the size of the reservoir, the riser will only be needed for a limited amount of time. If the period the riser is needed is shorter than the period it takes for the marine growth to reach a critical level, this could give the possibility to reduce the drag coefficient and the weight of the riser for a certain period, which might be long enough for the reservoir to fill.

The case study mainly indicated that the tool to assess pipelines for their feasibility for repurposing works for risers. But other conclusions can be drawn as well. To start with, other pipeline types can also be repurposed. As the riser is one of the most critical parts in a pipeline system due to its properties and loading, other pipeline types should also be suitable for repurposing. For example, export lines often have a thicker wall thickness due to higher laying stresses, lower forces acting on them due to their location far away from the waterline, and better protection from corrosion as they are welded, coated and checked before they are lowered on the seafloor where they do not have any cyclic impact that could damage the protection layers. Therefore, it can be said that if the riser is suitable for repurposing, so will the other pipeline types listed in chapter 2.

7 Conclusion

This research has explored the feasibility of repurposing offshore gas risers for the transport of CO2 in Carbon Capture and Storage applications. The research was framed around three aspects: technical, economic, and regulatory considerations from which the technical feasibility iss the core aspect. Through detailed technical analysis and an overall risk analysis, the study aims to provide insights into whether existing gas infrastructure could be repurposed to meet the requirements of CO2 transport, and whether this approach offers a viable and sustainable solution for future CCS deployment.

7.1. Approach for feasibility assessment

In this research, the decision has been made to focus on the riser due to the broadest variety of loading types the riser has to endure. The idea behind this decision is that, if the assessment tool is suitable and effective for the most broadly loaded pipeline type, it will work for other pipeline types as well. It can be concluded that by addressing the loadings put on the riser, such as its exposure to both environmental loads (wave and current forces) and operational stresses (pressure variations and temperature gradients) the tool demonstrates that all the loadings are included.

This adaptability implies that, with minimal adjustments, the tool will be effective for pipelines subjected to fewer or less complex load conditions, such as infield lines or export pipelines. Consequently, the assessment tool developed in this thesis holds potential as a framework applicable across various pipeline types, providing a solution for evaluating infrastructure reuse applications. Further testing on different pipeline configurations would validate its general applicability and ensure reliability.

7.1.1. Other pipeline types

As stated in the literature research, the other types of pipelines consist of export lines, in-field lines and spool pieces. Of these categories, the majority of the pipelines are export lines. However, due to the fact that risers have the greatest variety of loads acting on them, the decision has been made to tailor the tool described in this research especially for the risers. This has led to the tool being applicable on all the different pipeline types because the other types of pipelines have similar degredation mechanisms and similar load combinations, only with fewer loads.

On these other types of pipelines, there are some phenomena and situations that can occur. For example free spans or upheaval buckling. But since the CO2 in the state described in chapter 5 has similar weight, temperature and pressure conditions, there is little difference between the original situation where the pipelines were transporting natural gas and the new situation where the pipelines are transporting CO2. Therefore these phenomena and situations are not expected to influence the feasibility of repurposing pipelines for CO2 transport.

7.2. Technical challanges

One of the main challenges identified is the significant difference in the physical and chemical properties of CO2 compared to natural gas, which necessitates a reevaluation of the materials used and structural integrity of existing gas risers. The research highlighted several critical technical conclusions. This section will explain those conclusions.

7.2.1. Material Integrity and Corrosion Risk

CO2 is known to be significantly more corrosive than natural gas, particularly when impurities such as sulfur and nitrogen compounds are present. These impurities can increase the corrosive effects, leading to accelerated degradation of pipeline materials. The study concluded that while most existing risers are not inherently designed to withstand such aggressive corrosion, the dehydration of the to be transported CO2 mitigates this risk fully. This is One of the critical technical findings; The necessity to transport CO2 in an absolutely dry state to prevent internal corrosion. The presence of even small amounts of water in the CO2 stream could lead to the formation of carbonic acid, further accelerating corrosion rates. The study underlined the importance of achieving and maintaining CO2 purity standards, which are realistic given current technological capabilities, but require stringent monitoring and control measures.

7.2.2. Pressure and Temperature Management

CO2 transport demands higher pressures compared to natural gas. The research concluded that the existing gas riser in the case study are capable of handling these increased pressures. However, it was found to be necessary to implement measures to prevent a full depressurisation from happening since this will cause the pipeline to exceed it's limits.

7.2.3. Environmental Loading and Marine Conditions

The impact of external environmental conditions, such as wave action, current loads, and marine growth, was also assessed. The study found that marine growth and other environmental factors do not pose significant additional risks to the risers in terms of structural integrity, provided that regular inspections and maintenance are carried out. However, the accumulation of marine organisms can increase hydrodynamic drag, which must be factored into ongoing maintenance schedules.
In conclusion, the technical feasibility of reusing offshore gas risers for CO2 transport was found to be viable, though contingent upon targeted material upgrades, regular monitoring, and strict adherence to operational protocols. These measures are essential to ensure the long-term sustainability of the infrastructure under new operating conditions.

7.3. Economic and Permit Aspects

Although a full economic analysis or regulatory assessment is beyond the scope of this thesis, several economic and permit-related conclusions can be drawn based on the risks identified in this study.

7.3.1. Economic Considerations

Repurposing existing offshore infrastructure for CO2 transport provides a potentially cost and time effective solution, offering significant savings over new pipeline construction. By reusing existing pipelines, costs associated with material, installation, and environmental impact can be significantly affected. However, economic feasibility remains risk-full upon several factors:

- **Carbon Pricing and Government Incentives**: The financial viability of CCS projects is highly sensitive to carbon pricing policies and government incentives, such as subsidies and tax credits. Without favorable policies, the project's business case may be instable. Stable and supportive policies are essential to maintaining the economic appeal of CCS infrastructure reuse.
- **Monitoring and Maintenance Costs**: As repurposed pipelines were originally designed for different operational conditions, they may require enhanced monitoring systems to detect corrosion, CO2 leakage, or material degradation. These ongoing operational costs may be higher than for pipelines designed specifically for CO2 transport, impacting long-term economic sustainability.
- **CO2 Supply Stability**: A steady supply of CO2 is crucial for sustaining the business model of CCS projects. If emission reductions through greener technologies lead to a reduced CO2 supply,

there may be a shortage demand for CCS infrastructure, potentially affecting its economic viability. Strategic partnerships and diversified CO2 sources may mitigate this risk.

7.3.2. Permitting Considerations

The regulatory landscape for CO2 transport in repurposed pipelines is evolving, introducing several potential challenges for securing permits:

- **Regulatory Compliance**: Adapting offshore pipelines for CO2 transport involves navigating complex regulations that may not fully account for CO2 transport requirements. Ensuring compliance with national and international standards remains crucial to avoid potential legal hurdles that could delay the project. Proactive engagement with regulatory bodies can clarify requirements and mitigate unforeseen regulatory obstacles.
- **Environmental Impact Assessments**: CO2 transport projects, particularly in sensitive offshore areas, are subject to stringent environmental scrutiny. Thorough addressing potential risks, such as CO2 leakage or disturbance to marine ecosystems, are essential for obtaining permits. Comprehensive impact assessments can help mitigate potential delays by addressing regulatory and environmental concerns early in the project lifecycle.
- **Health, Safety, and Environmental (HSE) Regulations**: Offshore CCS operations are subject to strict HSE standards, which may require additional safety investments if new HSE regulations emerge. Continuous monitoring and adaptation to these evolving standards are critical for regulatory compliance and ensuring safe operations.
- **Public and Political Considerations**: Public concerns and political pressures can affect regulatory decisions, especially in environmentally sensitive regions. Transparent public engagement and educational outreach are key to addressing potential opposition and securing community support. Engaging environmental groups and stakeholders early can foster collaboration and reduce resistance to the project.

while reusing offshore pipelines for CO2 transport offers economic advantages, it also introduces economic and regulatory risks that must be managed carefully. A thorough understanding of economic drivers, combined with proactive regulatory engagement, is essential to mitigate risks and promote the viability of CCS infrastructure repurposing.

7.4. Overall Conclusion

This thesis has systematically assessed the feasibility of repurposing the L11B offshore gas riser for CO2 transport, providing insights into the technical, economic, and regulatory challenges involved in adapting existing gas infrastructure for Carbon Capture and Storage applications. Through detailed analysis and risk assessment, this study has demonstrated the viability of the pipeline under various load conditions, while highlighting critical considerations that must be addressed to ensure safe and effective operation.

The technical assessment in the case study showed that the pipeline is structurally capable of withstanding CO2 transport stresses, although operating close to its design limits. The findings indicate that the pipeline can endure maximum operational and environmental loads, total depressurization scenarios, and fatigue from cyclic wave forces, confirming its suitability for reuse.

The regulatory standards commonly applied to pipeline design are often incomplete in their coverage of CO2 transport requirements, leaving gaps in guidance specific to CO2 pipelines. Additionally, the NEN3656 standard relies heavily on other standards such as those from DNV and ISO to calculate various pipeline parameters. This reliance on multiple overlapping standards introduces a confusing and sometimes chaotic workflow, which is problematic given the urgency of achieving CO2 emission targets set in the Paris agreement.

As a solution to these regulatory complexities, the tool presented in this thesis provides a structured risk analysis with a systematic approach to feasibility assessment, resulting in a guide through the diverse standards and calculation methods involved in pipeline calculation. The tool offers a number of steps that assists in determining whether a pipeline can be safely and effectively repurposed for CO2 transport. The risk analysis component enables the identification of potential technical, economic, and permit-related risks, while the feasibility assessment approach applies these insights to evaluate the pipeline's suitability for reuse. Together, these components offer a practical solution to navigating regulatory requirements.

7.5. Recommendations for Future Research

This thesis has established a foundation for evaluating the feasibility of reusing offshore gas infrastructure for CO2 transport. While comprehensive, several areas warrant further investigation to optimize repurposing projects in Carbon Capture and Storage applications. The following recommendations outline potential directions for future research:

7.5.1. Case Studies on Different Pipeline Configurations

While this thesis focused on a specific riser case study, additional research involving various pipeline configurations and environmental settings would broaden the applicability of the assessment tool. Analyzing diverse configurations would provide insights into the adaptability of the tool, helping validate its use across different types of offshore infrastructure and offering practical recommendations for diverse CCS scenarios.

Additionally, specific phenomena should be further investigated and potentially integrated into the feasibility assessment tool. For example, challenges specific to export lines, such as free spans, upheaval buckling, and other structural considerations, need particular attention. Although these pipelines have been previously evaluated and deemed capable of withstanding such stresses, it would enhance the tool if these aspects could be quickly reassessed for the new medium within the pipeline. This quick re-evaluation would confirm structural integrity under CO2 transport conditions, ensuring continued reliability and safety.

7.5.2. Advanced Material Degradation Models for CO2 Exposure

Future studies should develop and apply advanced material degradation models that specifically address the long-term effects of CO2 and its impurities on pipeline materials. Given the properties of CO2 compared to natural gas, particularly regarding its corrosive nature, further research is needed to find acuate degradation rates and predict the lifespan of repurposed pipelines. CCS projects often only need a certain amount of years until the reservoir is filled. By having a more accurate corrosion rate, the lifespan until the wall thickness becomes critical can be better assessed resulting in potentially more pipelines suitable for reuse.

7.5.3. Refinement of Regulatory Standards for CO2 Pipelines

The current regulatory framework is limited in it guidelines for CO2 transport. Future research should focus on developing specific regulatory guidelines that focus on CO2 transport requirements, including updated safety and environmental protocols. This would reduce reliance on multiple standards and create a streamlined regulatory process, supporting faster implementation of CCS projects.

7.5.4. Public Perception and Policy Development

Public acceptance is a significant factor in the feasibility of CCS projects. Further research should examine strategies to enhance public understanding and support for CO2 infrastructure reuse, exploring how transparent communication and stakeholder engagement can address environmental and safety concerns. Additionally, investigating policy frameworks that encourage CCS adoption through incentives and streamlined permitting processes would support broader implementation.

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