

## **EXTENDING THE LIFE OF AN AGEING 42 YEAR OLD OFFSHORE WET CRUDE OIL PIPELINE**

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### **ABSTRACT**

This paper presents the approach used for performing life extension of an aging forty two years offshore pipeline thereby providing necessary assurance for safe and continued operation. Offshore pipeline systems are susceptible to a number of damage mechanisms including but not limited to internal corrosion, external corrosion, concrete weight coat damage, excessive free spans, loss of supports and structural (third party) damage. The life extension approach identified the relevant damage mechanisms, internal corrosion modeling and evaluated the current integrity status of the offshore pipeline. This involved reviewing the available pipeline data including inspection & monitoring records, history of leaks & repairs as well as previous engineering assessments. The key findings from the integrity assessment included discrepancies in wall thickness depth measurement between the ILI results and the actual field measurements, presence of large number of external corrosion anomalies and low internal corrosion rate & flow velocity. It was recommended to utilize an advanced ILI technology capable of detecting and sizing small anomalies to overcome the limitations with currently utilized ILI technique. The external corrosion activities were attributed to ineffective cathodic protection due to shielding by disbonded coating. Furthermore, pipeline repair readiness plan was recommended to be in place considering the criticality of the pipeline. Based on the integrity assessment, determining the current condition of the offshore pipeline, it was concluded that the pipeline is currently fit for service and can continue to operate provided that the recommendations are implemented.

**Key words:** Subsea, offshore pipeline, Trunkline, Internal Corrosion, Coating Disbondment, Inline Inspection (ILI).

## INTRODUCTION

The hydrocarbon exploration in the ocean and deep sea was started as early as early as the 1850s, when the first drilling was carried out in California, USA. Other early oil explorations activities were later recorded in Pakistan (1886), Peru (1869), India (1890) and Dutch East Indies (1893).<sup>1</sup> In 1930s, the development of the Gulf of Mexico as an offshore area started with oil first being produced in 1938.<sup>1</sup> The production from the North Sea brought more technical challenges to the offshore industry. The North Sea was first explored as a potential production area in the early 1960s.<sup>1</sup> Since then the pace of oil exploration and production in shallow water has gradually increased to deep water with the exploration phase started in 1975 while production began twenty years later.<sup>1</sup>

The development of an offshore industry is directly related to the development of subsea pipelines as well. As the industry expands towards deeper waters, the pipelines are required to have better materials, designs, operation practices and maintenance strategies to withstand the challenging environments. These pipelines are exposed to elevated temperatures, high pressures, and corrosive fluids. Subsea pipelines Operators find it difficult to regularly check pipelines of significant length and with pipes of large diameter, which are frequently laid in inaccessible places. Besides corrosion, the pipelines are also exposed to hazards such as extreme weather conditions, collision with vessels, trawl impact and pipeline spans, as presented in Figure 1.<sup>1</sup>

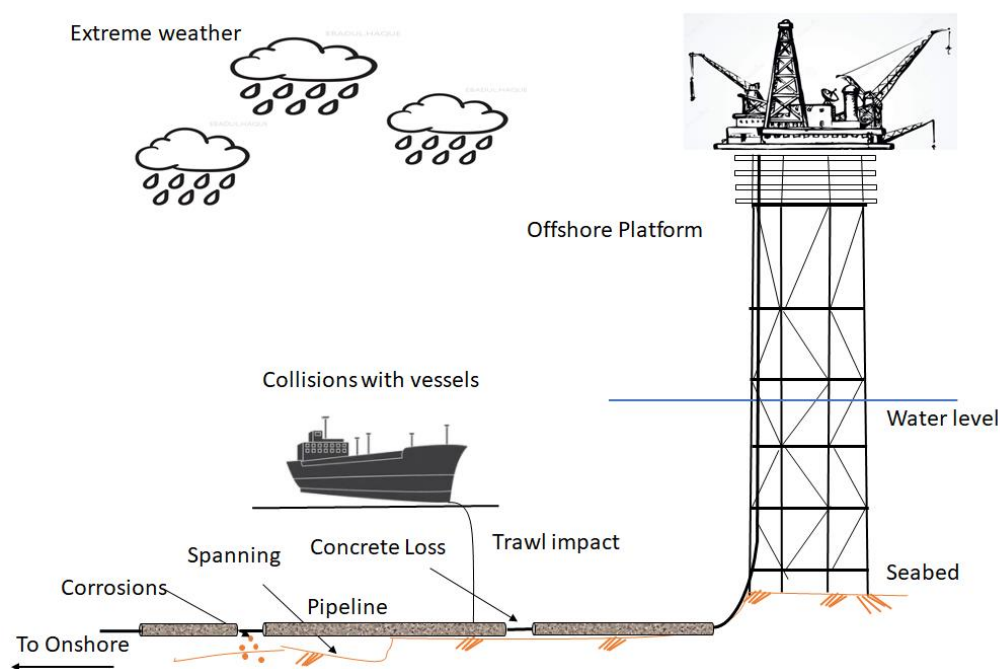


**Figure 1: Different types of threats to Subsea pipelines**

Internal and external corrosion are together one of the major causes of pipeline failures. The Committee on the Safety of Marine Pipelines reported the major causes of subsea pipeline failures in the USA, Figure 2. As shown in Figure 2, corrosion is the highest threat (48%), followed by other hazards (26%), maritime activities (14%) and natural forces (12%).<sup>2</sup>

In most cases, the accessibility and inspection activities of the subsea pipelines are expensive. Costs for maintaining corrosion represent a significant portion of operating expenses in the offshore industry, especially for aged pipelines. Different risk approaches might be designed and used to minimize these costs and to direct the efforts to improve reliability and availability of the structure.<sup>1-2</sup>

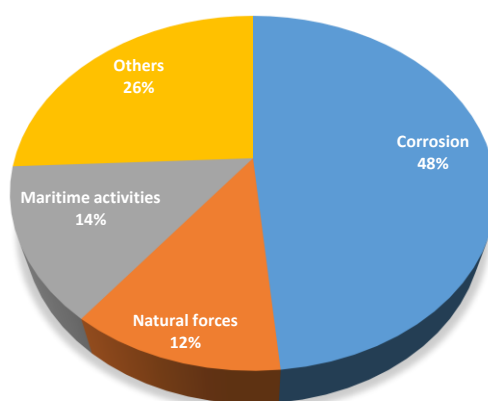


**Figure 2: Causes of Subsea pipelines Failures as reported by the Committee on the Safety of Marine Pipelines (1994)<sup>2</sup>**

Transport subsea pipelines are designed to withstand all the loads during their entire lifetime (normally 20-30 years). Most of the structural threats are identified and taken care of during the design phase. However, operational experience has demonstrated that safeguarding the structural integrity of subsea pipelines throughout their entire lifetime is not always easy. This can be even more challenging when the lifetime is extended beyond the original design lifetime. This paper presents the results of comprehensive integrity study performed for life extension of an aging forty two years old critical offshore trunkline thereby providing necessary assurance for safe continued operation. This pipeline is 48 inch processed, degassed crude oil. The operation data is shown in Table 1.

**Table 1: Trunkline Design and Operation Data**

| Parameter                                   | Value                                                            |
|---------------------------------------------|------------------------------------------------------------------|
| Outside Diameter (OD)                       | 48"                                                              |
| Wall Thickness                              | 0.75" (0-23.1Km)<br>0.688" (23.1-47.9Km)<br>0.625" (47.9-63.8Km) |
| Age                                         | 42 years                                                         |
| Material Grade                              | API 5L X60                                                       |
| Maximum Allowable Operating Pressure (MAOP) | 1125 psi                                                         |
| Operating Pressure                          | 600 psi                                                          |
| Design Temperature                          | 150 degree F                                                     |
| Scrapable                                   | Yes                                                              |
| Water cut                                   | 8%                                                               |
| CO <sub>2</sub> Pressure                    | 0.42 psi                                                         |

### **LIFE EXTENSION STUDY APPROACH**

The life extension study approach included consideration of the following:

- Mechanical structural Integrity
- Internal Corrosion
- External Corrosion

#### ***Mechanical Integrity***

Mechanical integrity assessment includes evaluation of pipeline metal loss resulting from either internal or external corrosion through fitness for service (FFS) analysis. The suitability of the pipeline to withstand the maximum allowable operating pressure (MAOP) is evaluated, the MAOP may have to be reduced to avoid a leak or risk of rupture. The following sections present the mechanical integrity assessment method used for this study.

### ***Fitness for service (FFS)***

The fitness for service assessment was performed considering the maximum metal loss and Estimate Repair Factor (ERF) value. The pipelines condition data were generated using in-line inspection (ILI) that employed the Magnetic Flux Leakage (MFL) technique to detect corrosion and structural anomalies. The data collected by the tool was analyzed per the industry accepted methods using ASME<sup>†</sup> B31G “Manual for Determining the Remaining Strength of Corroded Pipelines”. The methods used in this manual provide conservative techniques to assess the suitability of a corroded pipeline to withstand the MAOP of the system for safe operation.<sup>3</sup>

ASME B31G provides evaluation methods for assessing the remaining strength of a corroded pipeline designed in accordance with ASME B31.4 and ASME B31.8 for liquid and gas pipelines. The user can select from four (04) evaluation methods with Analysis Level 1 being the most conservative and Level 4 being the least conservative, requiring complex and data-intensive calculations.<sup>3-5</sup> The evaluations rely on the original pipeline properties (specified minimum yield strength, tensile strength, wall thickness, MAOP, etc.), the existing condition (measured wall thickness loss, length/width of the anomaly, and distance between anomalies) and finally the operating pressure of the pipeline.

It should be noted that the evaluation is a function of all these parameters, which can result in small size (length/width) pits with high metal loss passing the assessment whereas large size anomalies (such as general corrosion) with low metal loss requiring repair. Finally, in order to prescribe the safe MAOP of the subject pipeline under evaluation, the guideline uses the Estimated Repair Factor (ERF) which is the ratio of the pipeline MAOP to the Predicted Failure Pressure.  $ERF \geq 1$  shall be repaired immediately in order to maintain the existing pipeline MAOP. Careful monitoring shall also be applied to areas with  $ERF \geq 0.95$  if the corrosion activity is not completely arrested.<sup>3</sup>

Furthermore, the impact of the following external threats or damages to subsea pipelines were addressed:

- Concrete coating damage
- Free spans exceeding allowable length
- External damage e.g. dents, cracks, gouges, bending etc.
- Crossings status

### ***Internal Corrosion***

The internal corrosion assessment included the following reviews:

- *Corrosion Severity Predictions*: The corrosion severity of a system depends on fluid compositions, presence of corrosion species (i.e. water, gases, organic acids, solids, and microorganism) and velocity. These elements determine the type of damage

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<sup>†</sup> ASME International, Two Park Avenue, New York, NY 10016-5990.

mechanisms and corrosion rate of the system. For this case, the corrosion rates were determined by using predictive software such as Multicorp<sup>‡</sup> and CORLIS<sup>§</sup> as well as available in-line inspection (ILI) data.

- *Existing Corrosion Control Review:* Assess the application and effectiveness of existing corrosion control practices that include; corrosion inhibitors and scraping.

### **External Corrosion**

The external corrosion assessment included the following reviews:

- *Cathodic Protection (CP):* Cathodic Protection involves galvanic anode protection installed along the pipeline length at frequent intervals to protect against external corrosion. CP is considered complementary corrosion protection measure to the external coating. The external CP condition was assessed based on data provided by the ROV/diver surveys and subsea inspection reports.
- *Coating:* The external coating condition was assessed based on data provided by the ROV/diver surveys, subsea inspection reports, leak, repairs history and ILI reports. External coating is considered primary corrosion protection measure, whereas CP is considered complementary corrosion protection measure to the external coating.

## **RESULTS AND ANALYSIS**

### **Mechanical Structural Integrity**

The FFS repair curve generated from the FFS assessment of the 48" trunkline based on a MAOP of 1,125 psig is shown in Figure 3. Generally, anomalies with ERF less than 1 do not require repair at the MAOP. However, considering the criticality of this pipeline, offshore sleeves have been installed where wall thickness metal loss exceeded 50%.

Based on the ILI results, the distribution of external and internal corrosion anomalies along the pipeline length are presented in Figure 4a and b, respectively. It can be seen from the figures that external corrosion anomalies are concentrated along the pipeline segments between KP 18-28 and KP 60-64. On the other hand, Figure 4b shows that the majority of internal corrosion anomalies are in the first ~35 KM section, which is considered the low elevation section of the system. The proximity of external corrosion features to girth weld is shown in Figure 5 below which shows that the majority of external corrosion anomalies are in the vicinity of the girth welds.

Furthermore, the external subsea inspection report shows a number of locations with concrete weight coat damage/loss. However, the evaluation revealed that damage or loss of

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<sup>‡</sup> Trade Name

<sup>§</sup> Trade Name