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# Risk Based Internal Corrosion Assessment of Pipe in Pipe Flowline

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## Abstract

Safety and protection of the environment are paramount to successful, effective operations. A prominent challenge in the offshore oil and gas industry is striking a balance between maximizing production from a field and managing risks to meet or exceed regulatory compliance and safety goals. Noble Energy currently manages integrity of its Gulf of Mexico deepwater assets through implementation of a risk-based integrity management (IM) program. The objective of this paper is to demonstrate the value of a risk-based assessment process to mitigate internal corrosion of a pipe-in-pipe (PIP) flowline by progressively advancing detailed engineering assessments from routine monitoring activities. The results improved understanding of internal corrosion degradation mechanism and allowed for an update to the IM plan for remaining service life.

As part of Noble Energy's subsea IM program, annual asset risk assessments are conducted to identify, assess and control operational risks. Key performance indicators (KPIs) have been implemented to manage degradation mechanisms during design review and flag potentially unfavorable operational conditions. The exceedance of a KPI limit and the reliability of monitoring data directly affect the predictability of the associated degradation mechanisms. Elevated corrosion rates from a conservative corrosion model, combined with discrepancies in topsides corrosion coupon sampling, resulted in lower confidence for threat predictability. This prompted a more detailed assessment to confirm integrity of the flowline. The assessment included a review of design and historical monitoring data. A complete produced water analysis was executed to update the corrosion model. A flow regime analysis was conducted to assess the pipeline water-wet condition and water hold-up potential for current operational conditions.

This paper presents challenges and assumptions in identifying representative load cases from a 10-year operational history. The result of the assessment was the identification of areas along the flowline with medium to high water-wetting probability, and understanding of the hazards associated with internal corrosion at the identified locations. This study provided significant improvement in visibility of the internal corrosion degradation mechanism of the flowline and develop continued risk management strategy.

This paper presents a holistic approach to managing internal corrosion threats for subsea flowlines. It demonstrates the value of linking data to degradation mechanisms to improve understanding of risks on

the assets, and the value of a structured program to ensure informed and confident decisions can be made by an operator.

## Introduction

Noble Energy implemented a risk-based Integrity Management (IM) program in 2011 to manage the integrity of their producing assets in the Gulf of Mexico (GoM). The objective of the IM program is to ensure continued fitness for service of the equipment and manage risks to meet or exceed regulatory compliance and safety goals while maximizing production uptime. The initial stage of the IM program included a technical review of available design documentation and operational records. Subsequently, a baseline risk assessment of all the components within the program scope was conducted to identify credible degradation mechanisms and to document applicable mitigation, monitoring, and inspection activities for risk management. The second stage of the IM program focused on execution of the recommended IM activities and the continuous improvement of the IM program based on operational IM feedback.

The Swordfish field located in Viosca Knoll block is majority-owned and operated by Noble Energy and consists of two oil-producing wells that tie back to a floating production unit in the Gulf of Mexico. The tieback also featured a gas-producing well that has been plugged and abandoned (P&A) in 2013. The production flowloop consists of two flowlines; one oil pipe-in-pipe (PIP) flowline and one single pipe gas flowline. The gas flowline is no longer used for production. The two oil-producing wells (Well A and B) are produced commingled through the oil PIP flowline as shown in Figure 1. Well B has been producing since 2005. Well A started producing in 2010.

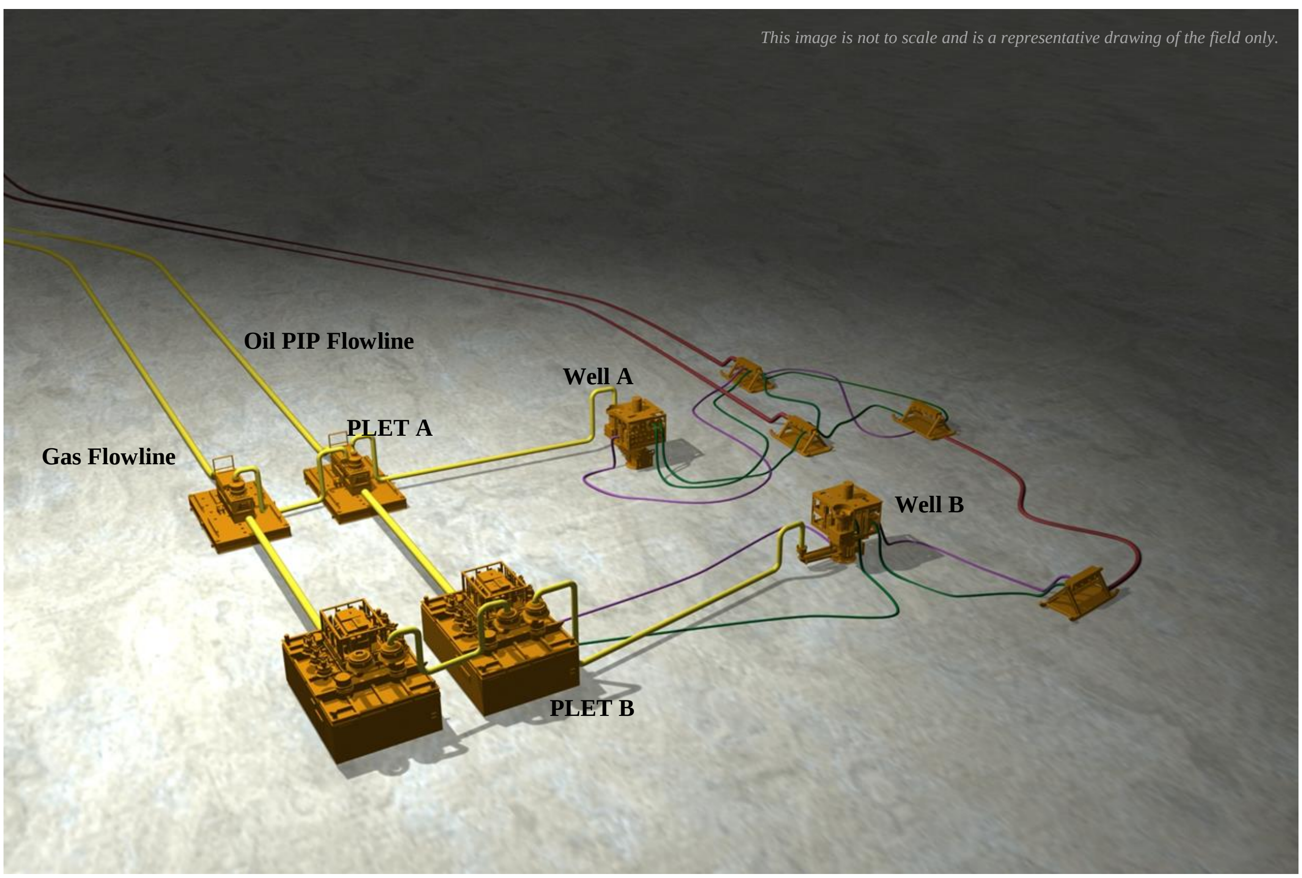



**Figure 1–Swordfish Field layout**

The baseline risk assessment highlighted the need to improve understanding of the internal corrosion degradation mechanism for the Swordfish 6in x 10in oil PIP flowline. A few key inputs into the baseline risk assessment included:

- The internal corrosion allowance of the inner pipe was identified as a gap in the design documentation.
- Internal corrosion mitigation in the form of corrosion inhibitor (CI) was planned for the service life of field. However, CI injection has not been conducted subsea since 2007 due to chemical injection tubing blockages.
- The field started to produce water in 2010 and experienced a continual increase in water production reaching 26% commingled water cut by 2012.

The IM activities recommended for management of the oil PIP flowline internal corrosion degradation mechanism included a corrosion model, periodic produced fluid analysis and monthly corrosion rate monitoring via topsides corrosion coupons. Corrosion rate monitoring was identified as the KPI for internal corrosion because it provides a lagging indication of the health of the subsea flow path.

As part of the Noble subsea IM program, annual asset health reviews are conducted to review results from assessment of the monitoring and inspection activities and to update the risk assessments and associated recommendations for the IM plan. Through the annual asset health review, inadequacies with the corrosion rate KPI monitoring were identified. This resulted in a decreased level of confidence for threat predictability and prompted a review of all operational monitoring data and a detailed engineering assessment to improve understanding of the internal corrosion degradation mechanism during the three years of remaining service life of the field starting from 2016.

## Risk Based IM Program

The IM program was developed building upon Clarus's experience implementing IM processes for other operators, including the riser IM program for BP GoM (Cook et al. 2006). At the heart of the IM program is the risk assessment, which takes into consideration the asset design and installation information, asset operational performance, operational procedures, as well as company learnings, industry knowledge, historical information, and associated anomalies from the field to determine the integrity risk of the components. There is a strong effort to record all details and assumptions used in the assessment to provide a cohesive history and to assist in future revisions of the assessments. The recommended IM activities are broadly divided into mitigation, monitoring, and inspection categories and formally documented in the asset-specific IM plan to be executed over an annual basis to manage the overall integrity of the equipment.

Noble Energy's GoM subsea IM program is continuously improving because of the understanding that integrity risks change with time. The changes to risk level and resulting IM recommendations take place either because of physical changes in equipment condition or because new information becomes available (Patil et al. 2016). For this reason, annual asset health reviews are conducted to feed back the results of the monitoring and inspection activities into the IM plan. Thus, the adequacy of the inspection and monitoring data gathered, the consistency of operational records, and the reliability of data retrieval methods directly impact the integrity recommendations.

An overview of the risk assessment process is shown in Figure 2.

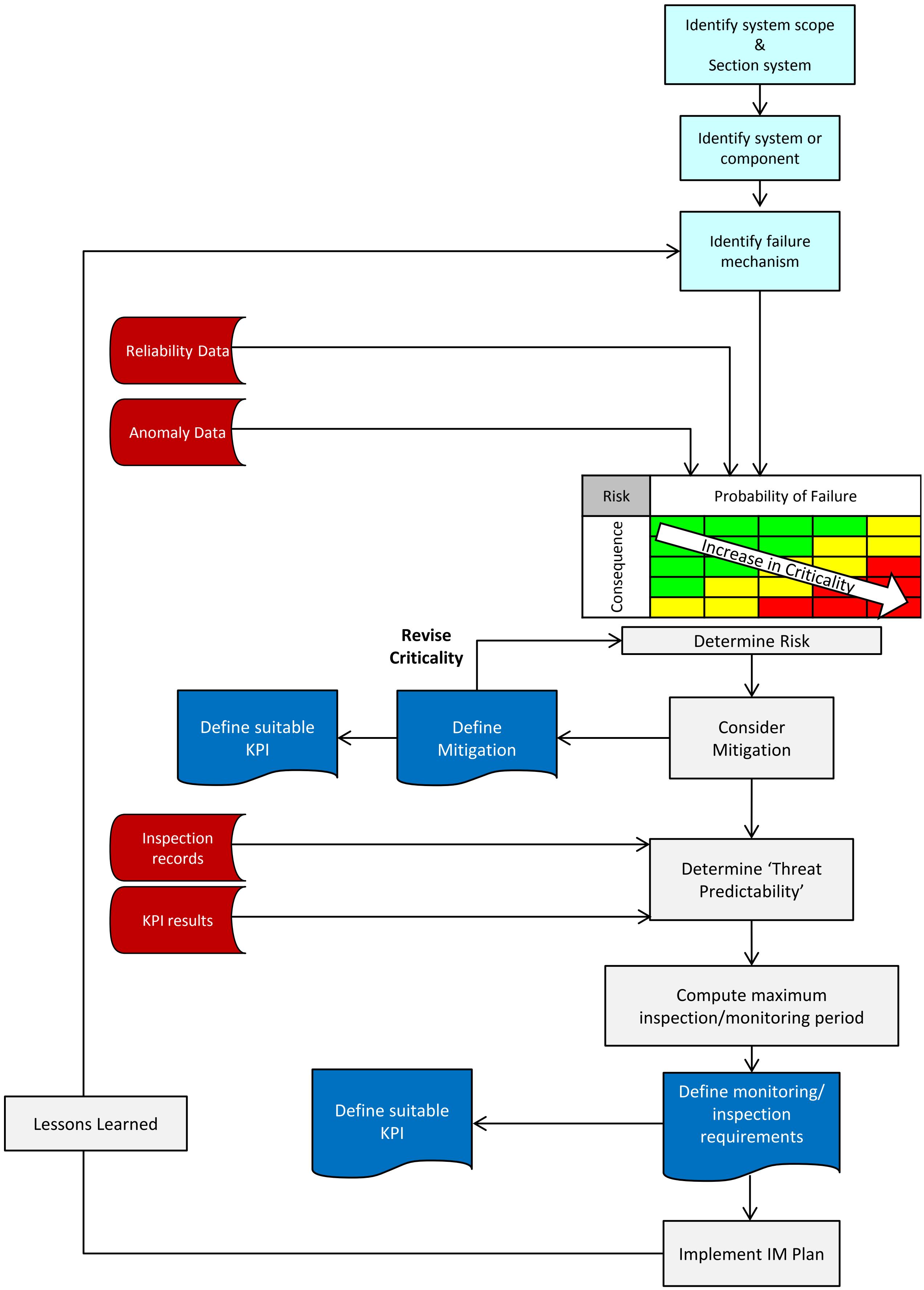



**Figure 2–Risk Assessment Process Flowchart**

# Basis for the Detailed Engineering Assessment (2005-2015)

## System Description

The Swordfish field consists of two oil-producing wells which tie back to a floating production unit in the GoM. The tieback also featured a gas producing well that has been P&A. The production flowloop consists of two flowlines, one 6in x 10in pipe-in-pipe (PIP) oil flowline and one 6in single pipe gas flowline. The gas flowline is no longer used for production and is filled with dry gas. The oil PIP flowline and gas flowline are connected via flowline jumpers at Well A and Well B locations, respectively. The flowlines are separated by cross-over valves allowing for independent production in the two flowlines and preventing commingling of fluids subsea. The oil PIP flowline system consists of a 6in inner pipe that conveys the produced oil from the two oil-producing wells to the facility and a 10in outer casing pipe with polyurethane foam in the annulus. The cross section of the PIP flowline is shown in Figure 3.

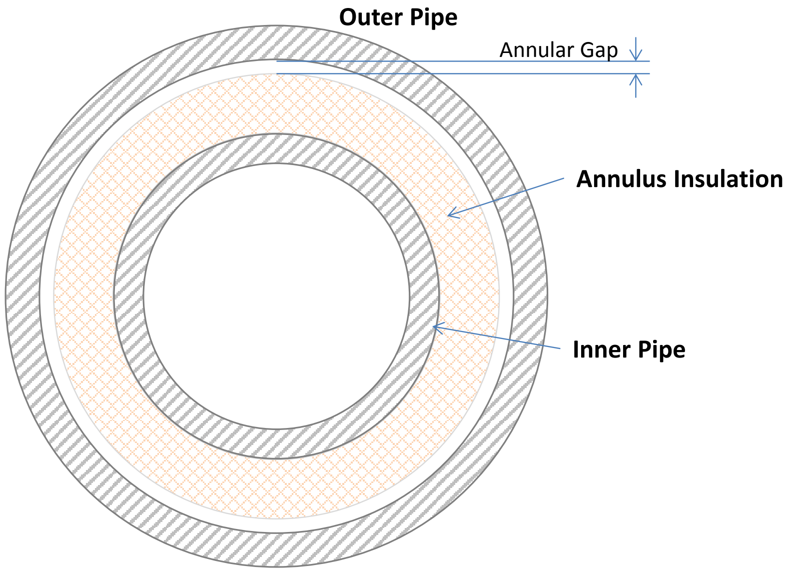



**Figure 3–6in x 10in PIP Flowline Cross Section**

Well B has been producing since 2005. Well A started producing in 2010. The oil PIP flowline section between the Well B and Well A has only been exposed to production fluids from Well B during its service life, while the section of the oil PIP flowline downstream of Well A up to the facility has been exposed to commingled produced fluids since 2010.

## Production Design Data

The Swordfish tieback was designed for sweet service with a 20-year design life. Internal corrosion allowance of the inner pipe was identified as a gap during the review of the design documentation. From the reservoir conditions measured during drilling, the presence of carbon dioxide ($CO_2$) was of most concern when considering possible corrosion mechanisms. $CO_2$ forms a weak acid when dissolved in water, which then results in corrosion of carbon steel. The reservoir analysis confirmed hydrogen sulfide ($H_2S$) corrosion was not a concern. Additional to $CO_2$ corrosion, the formation water composition indicated a likely potential for calcium carbonate scaling deposition. The design production data is given Table 1.

**Table 1-Design Production Data**

| Parameter | Value | |
|---|---|---|
| Well | Well A | Well B |
| Fluid Type | Oil and Gas | Oil and Gas |
| $CO_2$ Content (mol%) | 0.22 | 0.15 |
| $H_2S$ Content (mol%) | 0 | 0 |
| Formation Water pH | 7.5 | 6.6 |
| Reservoir Temperature (°F) | 184 | 182 |
| Reservoir Pressure (psi) | 6300 | 6337 |

A chemical injection plan was set up after initial production operations to mitigate the internal corrosion and flow assurance risks along the production flow path. However, a series of chemical injection tubing blockages identified between 2007 and 2010, including blockages of the CI and scale inhibitor umbilical lines, have prevented subsea chemical injection from being performed.

## Risk Assessment and Integrity Management Plan

The risk assessment process used for Noble Energy's GoM subsea assets considers various integrity threats that may potentially lead to different risk scenarios. Internal corrosion is one of the threats assessed for the PIP flowlines. Specifically, $CO_2$ corrosion is the degradation mechanism applicable. The potential risk event assumed for the oil PIP flowline during the baseline risk assessment conducted in 2012 was through wall localized corrosion of the PIP inner pipe, subsequent flooding of the annulus and rupture of the PIP outer pipe when exposed to operating pressures. The consequences of such a potential risk event are high, and based on industry experience, the probability of this risk event for a PIP flowline system with active risk management in the GoM is low. However, the lack of corrosion mitigation measures (i.e. loss of CI injection) resulted in an increase in the probability to a medium grading. The high consequence combined with a medium probability highlighted the need to improve understanding of the internal corrosion for the Swordfish oil PIP flowline.

Consideration was given to specifying mitigation, monitoring and inspection activities to gather the data needed to understand the integrity of the asset prior to any defect developing into a catastrophic failure. The activities recommended to manage the internal corrosion of flowlines in the IM plan included:

- Corrosion rate monitoring via topsides corrosion coupons. Corrosion rate monitoring was identified as the KPI for internal corrosion because it provides a lagging indication of the health of the subsea flow path.
- Production fluid (oil, water and gas) analysis to identify changes in fluid composition that may affect the potential for internal corrosion.
- A one-time corrosion model to allow understanding of the corrosion rate with respect to field conditions and provide a baseline for future assessments. .

Periodic inspection activities were not included within the IM plan, rather considered to be evaluated on an as needed basis.

## Corrosion Model

A corrosion model using Electronic Corrosion Engineer (ECE) software was conducted in 2012 to evaluate the internal corrosion of the oil PIP flowline based on up-to-date operating conditions and produced fluid monitoring results. At that moment in the service life of the tieback, the water cut for Well B had increased to 37% and the water cut for Well A had increased to 10%. As initially assessed in the design phase, $CO_2$ was determined to be the dominant corrosion mechanism. However, assessment of the produced water composition showed the presence of acetic acid as given in Table 2. Acetic acid increases the corrosion rate by dissolving the protective iron carbonate film that forms as a result of $CO_2$ corrosion.

**Table 2-2012 Corrosion Model Data**

| Parameter | Value |
|---|---|
| Well | Combined Well A/B Production |
| Fluid Type | Oil and Gas |
| $CO_2$ Content (mol%) | 0.18 |
| $H_2S$ Content (mol%) | 0 |
| Produced Water pH | 5.78 |
| Acetic Acid (mg/L) | 755 |
| Wellhead Temperature (°F) | 160 |
| Wellhead Pressure (psi) | 2060 |

The corrosion model results show an uninhibited corrosion rate of 4.16mm/year or 164 mils per year (mpy). The corrosion model results generally show a potential for $CO_2$ corrosion along the flowline water-wet areas.

The ECE corrosion model has inherent conservatism and analytical limitations that are taken into account when interpreting these results. Some notable conservatisms are as follows:

- The model assumes 100% water-wet flow conditions in the pipeline ignoring the oil-wetting benefits in multi-phase flow.
- Scale deposits can act as natural corrosion inhibitors and form semi-protective layers along the flowline reducing the corrosion rate. The model does not consider the water scale potential and its effect in the corrosion rates.

In addition, the maximum corrosion rate is expected to occur at the flowline locations closest to the subsea wellheads driven by the higher operating pressure and temperature. The corrosion rates are expected to decrease along the length of the flowline.

## Monitoring Activities and KPI Results

As part of the asset IM plan, a production fluid analysis was conducted to gather data relevant to the internal corrosion degradation mechanism. Corrosion rate KPI monitoring via topsides corrosion coupons was conducted as an indicator of the structural integrity of the subsea flowline system. The corrosion rate KPI limits represent a level for each parameter at which, in combination with other conditions, degradation mechanisms may accelerate. As part of the IM program, when a KPI limit is exceeded, the measured data is examined in more detail to confirm whether the response is acceptable and if additional assessments are necessary to improve understanding of the degradation mechanism and confirm integrity.

Corrosion rate KPI monitoring for the Swordfish field has historically been conducted through the monthly retrieval of coupons located topsides at the flowline arrival location upstream of the first phase separator system, as shown in Figure 4. During the annual update to the risk assessment, it was identified that the location of the corrosion coupons had been moved to a location downstream of the topsides CI injection point, which did not provide a representative corrosion rate trend for the subsea flow path. The combination of a period of non-representative coupon data and historical exceedance of the elevated KPI limits resulted in the requirement for an additional assessment(s) to accurately determine the corrosion rate of the flowline.

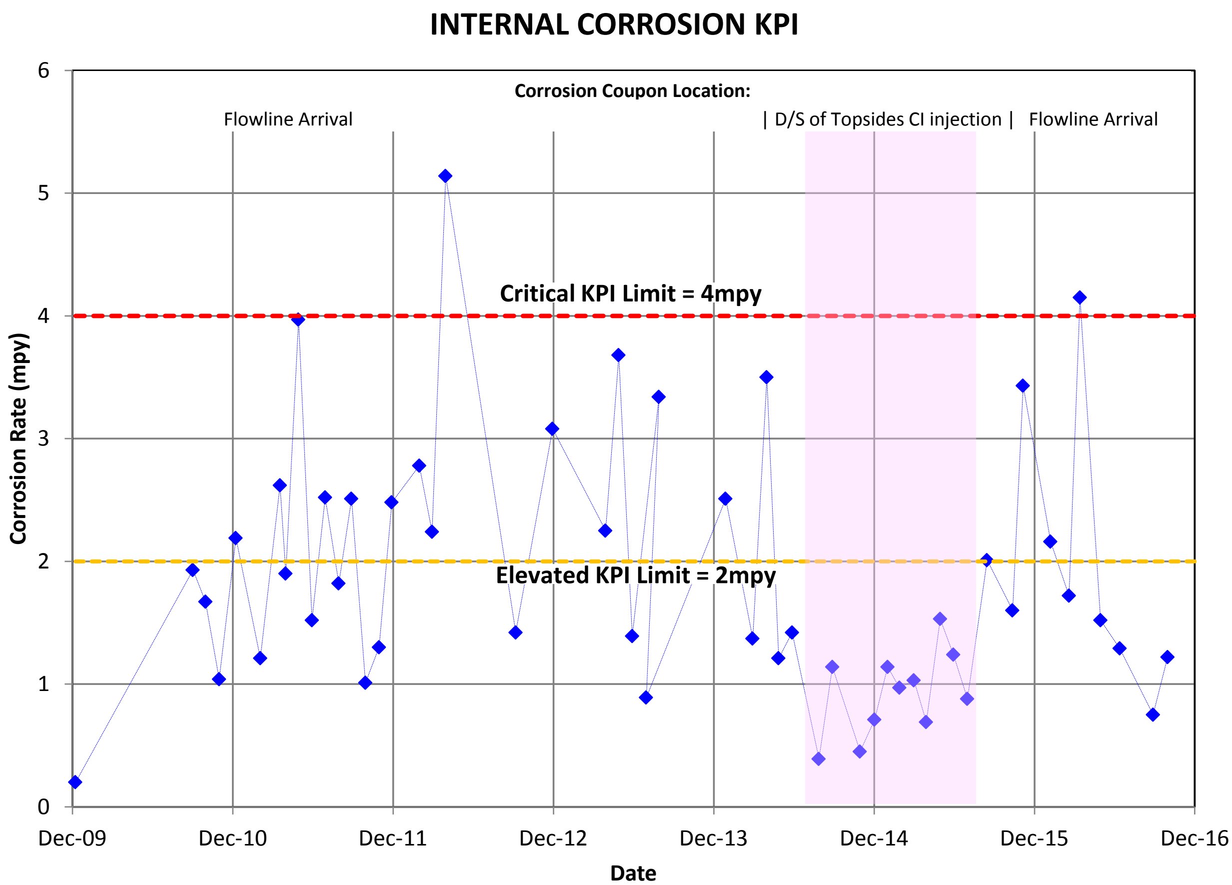



**Figure 4–History of KPI Monitoring, Corrosion Rate in Mils per Year (MPY)**

## Recommendations for Detailed Assessment

Considering results of the integrity evaluation within the risk-based IM program and the goal to ensure fitness for service of the equipment, a detailed assessment was required to improve the understanding of the internal corrosion of the PIP flowline and to allow for the prioritization and optimization of IM activities to adequately manage internal corrosion of the flowline for the remaining service life.

The following recommendations have been made:

1. Conduct a complete water analysis to establish current water chemistry.
2. Update the corrosion model with current water chemistry data.
3. Conduct a flow regime analysis to assess the pipeline water-wet condition and water hold-up potential for current operational conditions.

## Internal Corrosion Assessment (2016)

Once the requirement for a detailed assessment is established, the risk-based IM program allows for prioritization of the recommended IM activities and progressively advancing the different analysis. The approach used for evaluating the internal corrosion of the oil PIP flowline is shown in Figure 5. It included a review of historical monitoring and operational data to select load cases for assessment, an update to the corrosion model, a flow regime analysis to assess the pipeline water-wet conditions, and a review of the risk assessment based on all the data gathered and IM activities for the remainder of the field service life.

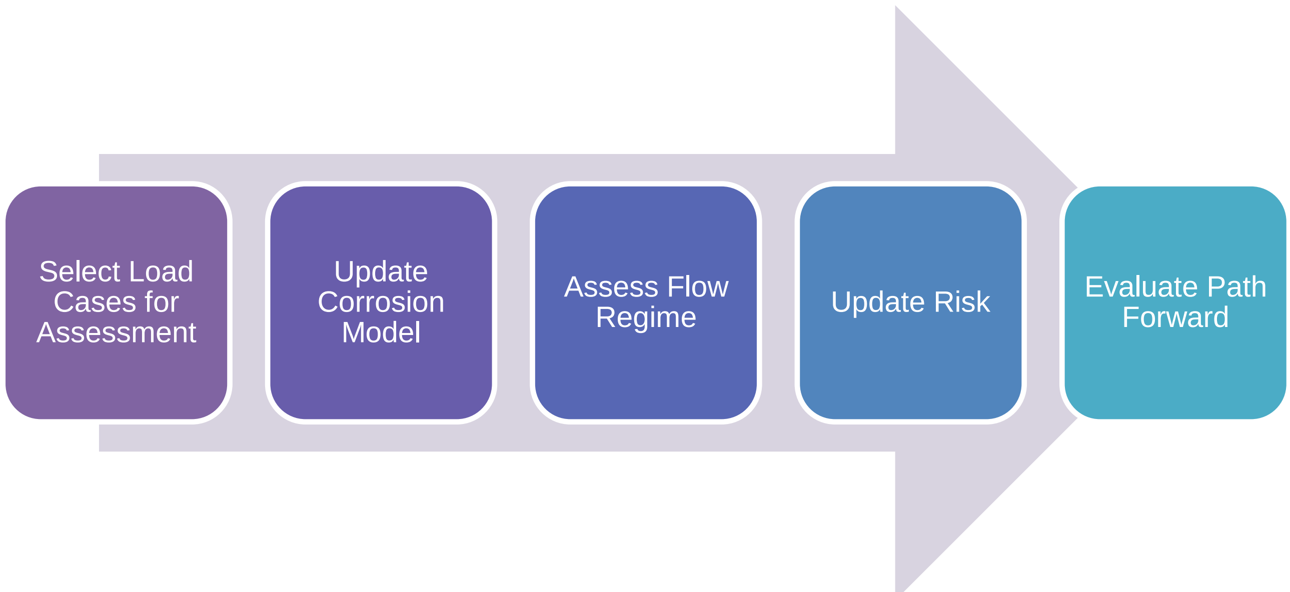



**Figure 5–Risk Based Internal Corrosion Detailed Assessment Process**

### Representative Load Cases

A comprehensive review of the operational parameters relevant to the internal corrosion (pressure, temperature, oil/water/gas flow rates, and well tests) gathered during a 10-year operational history was conducted to select load cases for the corrosion model update and the flow regime analysis.

Selecting representative load cases presented challenges for the execution of the assessment. Primarily, it was essential to select cases for which available data could be linked to analysis results. Although historical production data was available for the entire service life of the field, key monitoring and analytical results, such as corrosion model and water chemistry, required to link data gathered through IM activities to the degradation mechanism were only available for selected cases. The second challenge required striking a balance between assessing an optimum number of load cases and gaining adequate knowledge of the internal corrosion risk throughout the history of the asset to efficiently assess the threat for the remainder of the field life. Therefore, three representative load cases were selected:

- Early life: this case occurs at the beginning of water production and is used to benchmark flow conditions.
- Mid life: this case occurs at low water cut levels and is used to link to the available corrosion model data.
- Late life: this case occurs at the high water cut levels and is used to evaluate the flow regime and update the corrosion model.

The representative load cases selected are summarized in Table 3.

**Table 3-Detailed Assessment Load Cases**

| Cases | Water Cut | Available Data | Gaps and Assumptions |
|---|---|---|---|
| Early Life – Water Onset (2009) | Well A: No production<br>Well B: 0.4% | Operating conditions<br>Corrosion rate KPI results | Water chemistry and $CO_2$ content are assumed to be as per design conditions with no presence of acetic acid.<br>Corrosion rate is negligible because water cut is very low.<br>Flow regime analysis is conducted for benchmarking purposes. |
| Mid Life – Low Water Cut (2012) | Well A: 10%<br>Well B: 37%<br>Combined (D/S of Well A): 26% | Corrosion model<br>Water chemistry results<br>Operating conditions<br>Corrosion rate KPI results | Corrosion model represents potential for $CO_2$ corrosion in water-wet areas.<br>Flow regime analysis is conducted to assess water-wet areas. |
| Late Life – High Water Cut (2016) | Well A: 39%<br>Well B: 65%<br>Combined (D/S of Well A): 50% | Operating conditions<br>Corrosion rate KPI results | Water chemistry and $CO_2$ content are required to update corrosion model.<br>Corrosion model update is conducted to assess potential for $CO_2$ corrosion in water-wet areas.<br>Flow regime analysis is conducted to assess water-wet areas. |

The water cut for the wells and the representative load cases are shown in Figure 6.

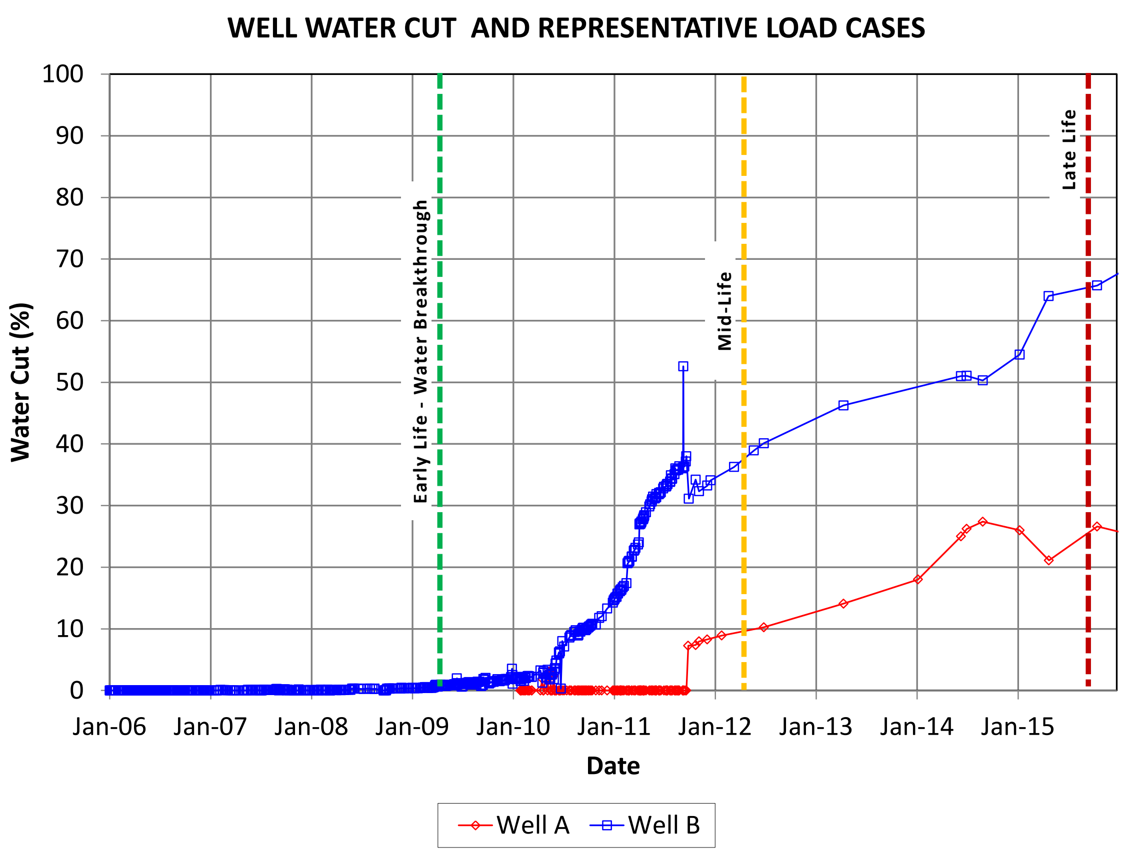



**Figure 6–Historical Water Cut Monitoring**

## Corrosion Model Update

A complete water analysis was conducted to establish water composition data to be used for the corrosion model. The ECE corrosion model was updated with the results of the produced fluid analysis and operating conditions for the late life case. At the time in the service life of the tieback, the water cut for Well B had increased to 65% and the water cut for Well A had increased to 39%. The input parameters used for the corrosion model update are given in Table 4.

**Table 4-2016 Corrosion Model Data**

| Parameter | Value |
|---|---|
| Well | Combined Well A/B Production |
| Fluid Type | Oil and Gas |
| $CO_2$ Content (mol%) | 0.258 |
| $H_2S$ Content (mol%) | 0 |
| Produced Water pH | 6.0 |
| Acetic Acid (mg/L) | 700 |
| Wellhead Temperature (°F) | 168 |
| Wellhead Pressure (psi) | 1890 |

The corrosion model update resulted in an uninhibited corrosion rate of 5.21mm/year or 205mpy indicating the observed changes in produced fluid chemistry increase the risk of internal corrosion. These changes, including increase of $CO_2$ content and acetic acid concentration, result in a higher potential for $CO_2$ corrosion along the flowline's water-wet areas.

## Flow Regime Assessment

A thermal-hydraulic flow regime assessment was conducted to assess the liquid hold-up areas along the flowline and to confirm the water-wetting assumption of the corrosion model. The flow regime assessment considered the operating pressure, temperature profiles, fluid composition, production rates, component geometry and seabed bathymetry.

The gas-liquid and water-oil flow patterns along the flowline are compared to each other to assess for the potential water-wetting conditions. Based on the flow conditions, the following three risk zones are considered:

- High water-wetting probability: takes place when stratified gas-liquid flow, which consists of the gas layer flowing through the top of the pipe with the liquid layer flowing below, is predicted in areas of stratified water-oil flow, which consist of water and oil flowing continuously in separate layers with the water layer wetting the bottom of the flowline.
- Moderate water-wetting probability: takes place when slug gas-liquid flow, which consists of gas pockets flowing inside the liquid production mix, is predicted in areas of stratified water-oil flow. Gas slugs are predicted to disrupt the stratified oil-water flow potentially leaving an oil film and reducing water-wet conditions and resulting in a medium water-wetting condition in these areas.
- Low water-wetting probability: takes place when dispersed oil-water flow, which consists of water droplets suspended in the liquid flow, is predicted resulting in a low water-wetting condition risk in this region.

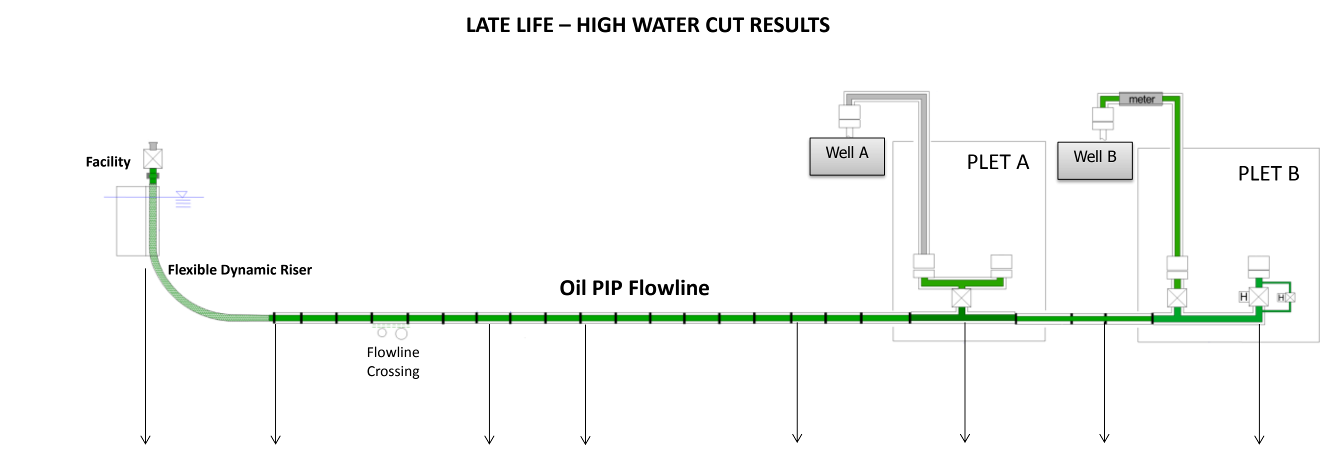
The matrix used to assess water-wetting likelihood along the PIP flowline is shown in Figure 7.

| Relative Water-Wetting Probability | | Oil-Liquid Flow Pattern | |
|---|---|---|---|
| | | Stratified | Dispersed |
| Gas-Liquid Flow Pattern | Stratified | High | Low |
| | Slug | Moderate | Low |

**Figure 7–Water-Wetting Condition Evaluation**

In multi-phase flow regimes like the Swordfish oil PIP flowline, the gas and liquid streams flow at different velocities. The liquid hold-up assessment consists of determining the percentage of cross-sectional area of the pipe occupied by liquid as well as the percentage of water hold-up in the liquid phase. The liquid hold-up results, in conjunction with the flow patterns, is used to determine the overall water-wetting probability along the flowline.

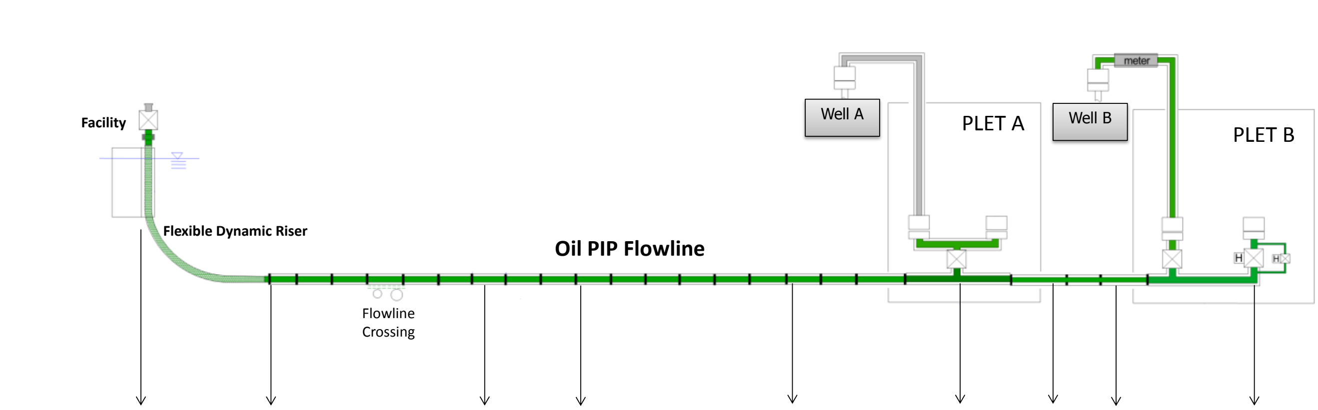
The results for the late life, mid life and early life cases are shown in Figure 8 through Figure 10. The results indicate that the section of PIP flowline with the greater likelihood of water-wet conditions is the section between Well B and Well A for mid life and late life conditions. For the late life case, this flowline section exhibits areas of stratified oil-water flow concurrently with areas of stratified gas-liquid flow and an average static liquid hold-up of 13%, indicating a high potential for water-wet conditions. For all the cases evaluated, the flowline section downstream of Well A up to the facility exhibits a combination of stratified and dispersed oil-water flow with slug gas-flow and average liquid hold-up lesser than the upstream flowline section. This indicates a moderate potential for a water-wet condition.




| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Flow Pattern Gas – Liquid** | Bubble | Slug | Stratified | Slug | Slug | Stratified | Slug |
| **Flow Pattern Oil – Water** | Dispersed | Stratified | Dispersed | Stratified | Dispersed | Stratified | Stratified |
| **Water-Wetting Probability** | Low | Moderate | Low | Moderate | Low | High | Moderate |
| **Static Liquid Hold-up (%)** | 2% | 7% | | 5% | | 13% | |
| **Water Hold-up in Liquid (%)** | 40% | 41% | | 39% | | 42% | |

**Figure 8– Flow Regime Results – Late Life/High Water Cut Case**

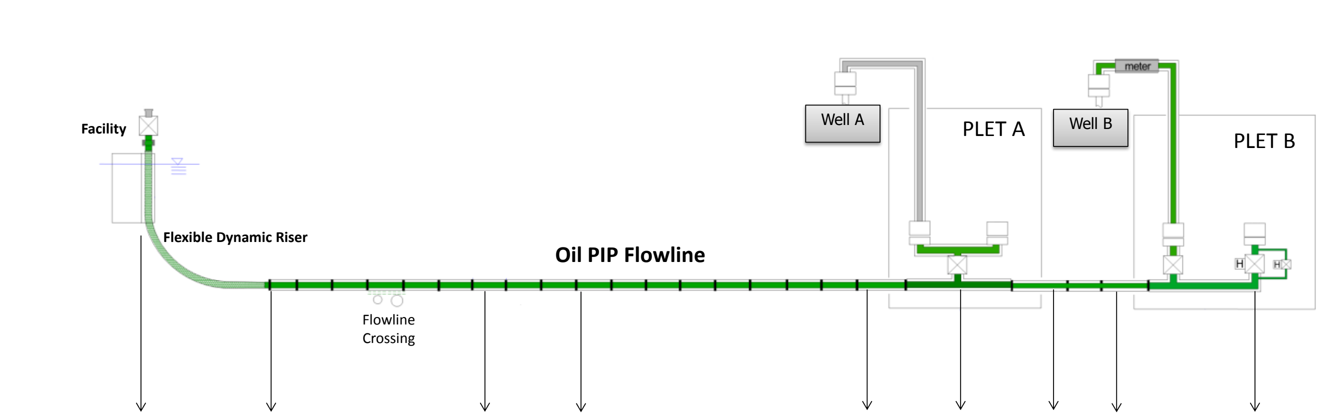
MID LIFE – LOW WATER CUT RESULTS




| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Flow Pattern Gas – Liquid | Bubble | Slug | Stratified | Slug | Slug | Stratified | Strat. | Slug |
| Flow Pattern Oil – Water | Dispersed | Stratified | Dispersed | Stratified | Dispersed | Stratified | Disp. | Stratified |
| Water-Wetting Probability | Low | Moderate | Low | Moderate | Low | High | Low | Moderate |
| Static Liquid Hold-up (%) | 1% | 6% | | 4% | | 10% | | |
| Water Hold-up in Liquid (%) | 19% | 23% | | 21% | | 26% | | |

**Figure 9– Flow Regime Results – Mid Life/Low Water Cut Case**

EARLY LIFE – WATER ONSET RESULTS




| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Flow Pattern Gas – Liquid | Bubble | Slug/Bubble | Stratified | Slug | Slug | Slug | Bubble | Slug |
| Flow Pattern Oil – Water | Dispersed | Stratified | Dispersed | Stratified | Dispersed | Stratified | Disp. | Stratified |
| Water-Wetting Probability | Low | Moderate | Low | Moderate | Low | Moderate | Low | Moderate |
| Static Liquid Hold-up (%) | 0% | 5% | 3% | | | 6% | | |
| Water Hold-up in Liquid (%) | 0.25% | 0.6% | 0.5% | | | 0.8% | | |

**Figure 10– Flow Regime Results – Early Life/Water Onset Case**

## Risk Assessment Update

Based on the results of the liquid/water hold-up, flow regime, and corrosion rate assessments, the probability of through-wall corrosion of the oil PIP flowline inner pipe was increased from medium to high for the section of flowline between Well A and Well B. The high probability combined with the high consequence of the potential risk event prompted a reassessment of failure barrier mechanisms.

Based on the up-to-date operating conditions in the potential event of localized through wall corrosion of the inner pipe, the oil PIP flowline annular gap would flood with production fluid up to the water stops on either side of the breach. The water stops are seal tight and are not expected to slide within the annulus. The burst capacity of the outer pipe was checked against API-RP-1111 (2009) and although the outer pipe was not originally designed to withstand production pressures, the outer pipe is not expected to burst based on the well shut-in tubing pressure and normal operating pressures. The update to the internal corrosion potential risk event hence results in a low consequence assessment.

## Conclusions

In this case study, a risk-based approach was used to evaluate the internal corrosion of an oil PIP flowline. The risk assessment process highlighted internal corrosion as a key degradation mechanism requiring further assessment due to non-representative KPI monitoring and limited data. This involved a detailed engineering assessment to improve understanding of the risk and prioritize remediation and mitigation activities.

Annual asset health reviews highlighted that the increasing produced water, changes to water chemistry, and gaps in corrosion rate KPI monitoring led to reduced confidence in internal corrosion threat predictability for the oil PIP flowline. The recommendations for risk management take into consideration the objective of continued service of the field beyond its design life. The analytical assessments improved our visibility into areas of interest associated with internal corrosion along the PIP flowline which is critical information for considerations of direct measurements with non-destructive examination techniques.

Due to the nature of the internal corrosion degradation mechanism and the analytical limitations of the corrosion model used, additional IM activities have been evaluated by Noble to support the ongoing risk management strategy for the PIP flowline.

In summary, this case study demonstrates a strong example of robust IM program implementation that helped Noble identify and prioritize review and assessment of the internal corrosion of the flowline followed by a progressively detailed risk management plan.

## Lessons Learned

In order to improve the implementation of IM programs and risk management, the following lessons should be considered:

- Risk assessment is an educational tool that helps understand the link between integrity data and degradation mechanism including impact of data gaps in the interpretation and engineering assessments.
- Start IM implementation early in the project phase to allow for integrity experience feedback to improve design, establish monitoring requirements, identify accurate KPIs, and to minimize data gaps at handover from projects to operations.
- Early implementation helps gather relevant integrity data from established KPIs from the start of operations. This data plays vital role in life of field IM and offers significant benefits in life extension considerations.
- Early implementation of the IM program helps flag redundancies in monitoring or lack thereof for critical KPIs, as well as helps identify alternatives to monitoring including applicable inspection techniques.

## Acknowledgements

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## Nomenclature

| | |
|---|---|
| CI | Corrosion Inhibitor |
| ECE | Electronic Corrosion Engineer |
| GoM | Gulf of Mexico |
| IM | Integrity Management |
| KPI | Key Performance Indicator |
| MPY | Mils Per Year |
| NDE | Non-Destructive Examination |
| PIP | Pipe-in-Pipe |
| P&A | Plug and Abandonment |

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