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Corrosion Management For Aging Pipelines—Experience From the Forties Field

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Abstract

In 2003, Apache became the operator of the Forties Field. The field has now been in operation for 33 years and much of the infield pipeline system has exceeded its original design life of 20-25 years. Apache intend to continue production in the Forties Field for, potentially, in excess of a further 20 years. As such, they have identified numerous issues with respect to corrosion management of the infield pipeline system. Since late 2006, the Forties Field infield pipeline corrosion and integrity management has been carried out by IONIK Consulting/JP Kenny Caledonia ltd. Working closely with Apache, the infield pipeline system has been reviewed, a number of issues have been assessed and quantified and practices with respect to corrosion management, corrosion monitoring and inspection have been implemented. This document examines the issues identified, the corrosion management strategy put in place, and the inspection actions undertaken. Examples of issues identified with respect to corrosion management systems include a requirement for a dedicated pipeline corrosion management strategy, pipeline corrosion modelling, a corrosion risk assessment of the pipeline system, a review of corrosion inhibition and pigging, and a review of key performance indicators with emphasis on pipeline management. Specific corrosion issues identified include anode depletion, preferential weld corrosion, localised corrosion and 6 o'clock corrosion. Examples of other factors identified have been potential risks from microbial and under deposit corrosion due to low flow rates. This publication provides an overview of these issues and the implementation of solutions, alongside changes to items such as documentation and modification of existing procedures, risk assessment, corrosion management, and the implementation of an intelligent pigging program.

Introduction

The Forties Field began producing in 1975. Production from the field peaked in 1978 at 520,000 barrels per day. Acquired by Apache in 2003, the field still ranks in the top five North Sea fields in production and reserves after having produced approximately 2.6 billion barrels to date. Apache raised production from 42,000 barrels per day to a peak of 81,000 barrels per day. In 2006, daily production exceeded 58,000 barrels per day[1]. The Forties Field consists of five platforms, Forties Alpha, Bravo, Charlie, Delta and Echo. A schematic of the Forties Field is presented in Figure 1. Forties Charlie acts as the central hub for all Forties production as well as for a number of other UK sector North Sea fields, and exports the output via the 36" BP FPS export line to Cruden Bay via Forties Unity. Forties Unity remains under BP ownership. Forties Alpha, Forties Charlie and Forties Delta platforms have separation and processing facilities. The Forties Bravo platform has recently been converted from oil to direct export (transport of non-stabilised multiphase produced fluids), and separation and processing facilities have been removed. The Forties Echo platform does not possess separation facilities. The non-stabilised multiphase oil/gas/produced water is flowed onto Forties Alpha for subsequent separation train processing. The facilities are connected by a number of infield pipelines with various functions and transported fluids. These are described in Table 1.

Due to low oil prices, the 1990s were a time of cut backs and cost savings in the oil industry. Throughout the UK sector of the North Sea, the consequence of this was felt in many areas such as chemical injection, chemical analysis, corrosion monitoring and fabric maintenance spending. Given that such actions often lead to observable corrosion consequences perhaps five to ten years later, it is only recently that the corrosion consequences of many of the operational deficiencies of the 1990s have become apparent. With oil prices high and maintenance of ageing pipelines a priority, there is now a requirement for stabilization of the present situation and, where required, remedial action. Apache found on taking ownership of the Forties Field in 2003 that there were a number of issues with respect to the pipeline system that required examination.

Other issues have been identified since that point in time. A number of these issues are listed below. It is emphasized that these comments apply exclusively to the pipeline system and not the topsides or facilities.

Issues

Risk Assessment

No corrosion risk assessment was available for the infield pipelines.

Corrosion Management and Key Performance Indicators (KPIs)

Although a facilities corrosion management strategy was in place, this was oriented towards platforms and topsides. There was inadequate examination of the infield pipelines corrosion management requirements. This was reflected in the facilities KPIs, which were also not oriented towards infield pipeline requirements.

Corrosion Monitoring

All corrosion monitoring activities appeared to have ceased in 1996.

Chemical Analysis

With respect to the in field pipeline system, chemical analysis of fluids for items such as water chemistry, iron counts or corrosion inhibitor residuals was apparently not carried out on a regular basis or historical records were poor.

Intelligent Pig Surveys (In Line Inspection)

Two of the five in field pipelines had been intelligently pigged in 2001 and 2002. However, one line had not been intelligently pigged since the early 1990s, and two lines had not been intelligently pigged at all, even though one line was a replacement for a previously failed line. From the two lines that had been recently pigged, a number of corrosion issues had arisen, but had not been addressed under previous ownership.

Anode Depletion

Cathodic protection (CP) surveys and remote operated vehicle (ROV) visual inspection found that substantial anode depletion had occurred on the older pipelines. Given that the older sections of the pipeline system were beyond the original design life of 20-25 years, this is not unexpected.

Corrosion Inhibition

Due to the historical lack of corrosion monitoring activities, pipeline changes from oil transport to multiphase transport and as a result of the risk assessment, it was felt that a review of corrosion inhibition performance was also required.

Discussion

Pipeline Corrosion Risk Assessment

Upon taking responsibility for the infield pipeline system corrosion and integrity management, the first step for IONIK Consulting/J P Kenny Caledonia Ltd was to review the available information transferred across from the previous contract holder. One factor that quickly arose from this review was the need for an internal corrosion risk assessment for the pipeline system to establish or verify the pipeline corrosion mechanisms and mitigation requirements. This was carried out as a high level mechanistic internal corrosion risk assessment for the pipeline system. An in house methodology was used, examining the risks from various relevant internal corrosion mechanisms. In this case this included an assessment of the probability, consequence and risk associated with CO_2 corrosion (including preferential weld corrosion), H_2S corrosion, sour cracking, oxygen corrosion, under scale pitting, under deposit corrosion, microbial influenced corrosion (MIC), internal crevice corrosion/galvanic corrosion, top of the line corrosion, dew point corrosion and erosion/corrosion. The probability was defined as low, moderate or high. Mitigation reduces the probability rating, as long as the effectiveness of the mitigation can be verified. This was then cross indexed with hazard and operational consequences (also defined as low, moderate or high) to generate a risk category from 1-5, with category 1 best regarded as high risk, category 3 regarded as moderate risk and category 5 regarded as low risk. In a recent pipeline assessment project for an international oil major, for a development offshore Angola, the results of this methodology were found to be consistent with those obtained from that company's in house methodology, while also highlighting additional corrosion risk mechanisms.

It is not the purpose of this publication to describe the risk assessment methodology and output in detail. The general results of the corrosion risk assessment, based on the worst case corrosion mechanisms for each pipeline, are presented in Table 2.

The pipelines of most concern were the multiphase production pipelines and the infield oil transport pipelines as these are rigid carbon steel. The fuel gas and produced water re-injection (PWRI) lines are internally polymer lined flexibles and internal corrosion mechanisms were assessed as risk categories 3-5. For example, for the fuel gas lines the corrosion probability from the internal corrosion mechanisms examined was regarded as low. However, the consequences of a failure were assessed as high, especially for the risers and riser topsides, as the fuel gas lines contain high pressure gas. A high consequence combined with a low corrosion probability leads to a risk category of 3 under the risk assessment methodology used. For the multiphase pipelines the highest risks (category 1) were associated with CO_2 corrosion and under scale pitting due to a tendency for barium sulphate formation from the barium rich formation water and sulphate from the sea water flood. Although these lines are treated with corrosion inhibitor they were rated as risk category 1 due to the absence of corrosion monitoring and the lack of performance verification of the corrosion inhibitor against under scale pitting corrosion.

For the oil transport lines the probability of CO_2 corrosion in the presence of corrosion inhibitor was assessed as low. This is due to low separator pressures and the fact that these pipelines receive very high levels of corrosion inhibition. The high levels of corrosion inhibition are due to these pipelines acting as the corrosion inhibitor feed source for the BP Forties pipeline system. However, these 20" OD lines now transport less than 15% of their original design capacity and flow rates are very low (<0.3m/s). The arrival temperatures at the Forties Charlie facilities are 20-25^{o}C. The risk associated with under deposit corrosion was assessed as category 3, and the risk associated with unmitigated microbial corrosion was assessed as category 2.

The primary threat to the multiphase lines was thus evaluated as CO_2 corrosion and under scale pitting combined with a lack of corrosion monitoring, with the primary threat to the oil lines being under deposit/microbial corrosion.

Corrosion Inhibition

Due in part to the historical lack of corrosion monitoring activities and as a result of the risk assessment, it was felt that a review of corrosion inhibition performance was also required.

In the Forties Field, the in field oil transport pipelines from Forties Alpha and Forties Delta to Forties Charlie receive very high levels of corrosion inhibition as they act as the inhibitor source for the FPS main oil export line to Cruden Bay. Corrosion inhibitor requirements would nominally be 10-20ppm. However, up to 150ppm is routinely injected.

However, the multiphase lines from Forties Echo to Forties Alpha and Forties Bravo to Forties Charlie receive 30ppm-40ppm of corrosion inhibitor. This inhibitor is different to that used for the oil lines and has been selected due to the requirements for separation (to minimize oil in water) as well as corrosion inhibition. Given that the risk assessment had indicated under scale pitting as a possible corrosion mechanism for the multiphase lines, it was deemed important to examine whether the inhibitor was capable of preventing under scale pitting as well as general corrosion.

As such, working with the chemicals supplier, testing was performed for both general corrosion (repeating the tests performed during the original selection exercise) and corrosion under barium sulphate scale/deposits. General corrosion testing confirmed that the inhibitor used could reduce general corrosion rates to less than 0.1mm/yr. However, the test performed to examine corrosion under barium sulphate scale/deposits indicated that the inhibitor would not be predicted to reduce the under scale pitting corrosion rate to <0.3mm/yr. This appeared to be confirmed by re-examination of the 2002 intelligent pig data for the Forties Echo to Forties Alpha pipeline. For the sea line, the general corrosion rate was found to be very low (<<0.1mm/yr). However, isolated localized defects were found, with no particular circumferential orientation, with corrosion rates up to 0.3mm/yr. Because of the lack of any long axial component, analysis using DNV RP-F101 confirmed that these defects were not an integrity threat, but the results did support those from laboratory testing. Apache are now working with the chemicals supplier to obtain a corrosion inhibitor that is capable of inhibiting both the general corrosion rate and the under scale pitting, while retaining the required separation properties. In the interim, the recommended dosage of the incumbent corrosion inhibitor has been raised by an additional 10ppm.

Microbial Analyses and H_2S Monitoring

For the oil transport lines microbial influenced corrosion was the highest risk corrosion mechanism established by the internal corrosion risk assessment. As a result of this assessment a scheme of sampling for microbial analysis and H_2S monitoring has been initiated. The results of microbial sampling are still pending. However, H_2S monitoring has shown that, while H_2S levels are relatively low, an increase in H_2S levels (as established by bomb sampling followed by gas phase H_2S analysis offshore) has been identified as the produced fluids from some streams pass from the wellheads and through one of the multiphase pipelines. This is a strong indicator of sulphate reducing bacterial (SRB) activity. Given that microbial activity has been indicated in one of the multiphase pipelines it is possible that SRB activity may have initiated in some of the infield oil transport pipelines. Recent intelligent pigging has also indicated corrosion damage to present or former oil transport pipelines, where the rates of corrosion at the worst case defects, at the 6 o'clock position of the pipelines, are difficult to explain in terms of CO_2 corrosion alone. Operational pigging is already regarded as being at an acceptable level, with all in field lines being pigged on a schedule of either one or two times per month. This has led to the consideration of a biocide treatment program for pipelines identified as suffering from this corrosion mechanism, or deemed to be susceptible.

Corrosion Management Strategy and Key Performance Indicators (KPIs)

Although a facilities corrosion management strategy was in place, this was oriented towards platforms and topsides. There was inadequate examination of the in field pipelines corrosion management requirements. Also, the roles and responsibilities of personnel differ between the facilities and the in-field pipeline system. For example, different engineers have corrosion engineering responsibility for the facilities and pipelines. Also, the technical authorities differ, with facilities under the remit of the integrity manager and the pipelines under the remit of the subsea manager. As such, a specific pipeline corrosion management strategy document was prepared, to determine roles and responsibilities, interfaces with the facilities engineers and managers, and to ensure effective corrosion management of the pipeline system.

Key Performance Indicators

This lack of orientation towards the pipelines was reflected in the chemical treatment KPIs, which were again oriented towards topsides operations. In terms of pipeline corrosion and integrity management, it was felt that these required some revision. The revised pipeline KPIs are presented in Table 3.

Corrosion Inhibitor Injection

With respect to pipeline corrosion inhibition, it was felt that a move to an availability based concept[2-4] was required. In place of the penalty based corrosion inhibitor KPI that was previously in place, which indicated performance trends but did not give a clear indication of actual corrosion inhibitor activity, the corrosion inhibitor KPI for the pipelines is now based on two factors directly tied to corrosion inhibitor availability. These are volume of chemicals used against target volume, and injection pump availability. These criteria provide a better definition, in corrosion terms, of the actual corrosion inhibitor injection system performance.

Water Content

A second change was to the KPI for water content in the processed crude oil. For oil transport and export lines, the oil industry generally believes that if water content can be maintained below 1-2% then issues with water drop and associated microbial and corrosion issues can be mitigated. This is an erroneous belief to some extent. As described in work by Nešić[5] 1-2% water can be successfully entrained, even in light crudes. However, the flow rate of the crude oil stream has to be maintained at a velocity greater than 1m/s. As the oil flow rate drops below 1m/s there is a rapid drop in the water entrainment capability of the crude oil, and for light crudes flowing at very low velocities (<0.2m/s) even 0.2% water entrainment may be difficult. In many of the pipelines associated with facilities in the North Sea, the oil pipelines were originally designed for much higher peak oil flows, and present oil flow rates are well below 1m/s. Assuming that a 1-2% water cut is acceptable as an integrity criterion is not possible under these circumstances.

In the Forties Field, under Apache ownership water cuts in the processed oil have been low by industry standards and are typically less that 0.5%. This was regarded as entirely satisfactory under the previous KPIs. However, flow rates in the infield oil transport lines are lower than 1m/s and the actual water entrainment capability of the relatively light Forties Field crude oil output will be lower than the original KPI value. The new KPI reflects this situation and provides a stepped water content target based on pipeline flow velocity.

Corrosion Monitoring and Chemical Analysis

As described previously, all corrosion monitoring in the Forties Field appeared to have ceased in 1996. Building on an earlier report, a corrosion monitoring strategy document has been prepared. Offshore inspection of facilities has been undertaken to assess the condition of the available corrosion monitoring points, and these are being replaced where required. Corrosion monitoring requirements have been assessed, and corrosion monitoring is now being rolled out across the field facilities. This has started with Forties Bravo, where corrosion monitoring is now in place, and will progress through Forties Charlie and the other facilities during 2008.

With respect to the infield pipeline system, corrosion monitoring requirements are different when considering the multiphase lines and the oil transport lines.

Multiphase Pipelines

The primary threat to the multiphase pipelines has been identified as CO_2 corrosion and under scale pitting. The multiphase lines are dosed with relatively low doses of corrosion inhibitor, and have a tendency to barium sulphate scale formation and under scale pitting. The flow rates are relatively high, with water cuts of 65-85%, and bottom of the line deposits are not expected. This is supported by the operational pigging results, where no evidence of significant solids is found on pigging these lines.

Corrosion monitoring will consist of sand erosion probes, corrosion coupons and electrical resistance probes on the riser topsides at both the entry and exit points of the pipelines. These do not have to be mounted at the 6 o'clock position and can be intrusive. However, as there is a tendency to scale formation, the corrosion morphology is expected to consist of low general corrosion rates accompanied by pitting corrosion, unless sand erosion can occur. Sand erosion is however not expected as flow rates are less than 4m/s. Given that scaling may lead to erroneous corrosion rate measurements on the electrical resistance probes, these will be swapped out for pitting probes (specialized electrical resistance type probes capable of providing an indication of localized corrosion rates in addition to general corrosion rates) once they become commercially available. From discussion with various corrosion monitoring equipment companies, probes of this type are presently in the development stage at Cormon, but are for the time being only available as in house tools.

Oil Transport Pipelines

The primary threat to the oil pipelines has been identified as under deposit and microbial corrosion. The lines are dosed with very high levels of corrosion inhibitor as they act as the feed source for the corrosion inhibitor treatment for the BP FPS pipeline system. Flow rates are low and water drop and bottom of the line deposits are expected. Significant solids and wax deposits are routinely removed during operational pigging and water slugs have been identified in front of the pig as pigging takes place.

Corrosion monitoring will consist of coupons and electrical resistance probes on the riser topsides at both the entry and exit points of the pipelines. However, these will be mounted at the 6 o'clock position and will be flush mounted. Any attempt to monitor corrosion, given the tendency to water drop or bottom of the line deposits, requires that the coupons and probes see the water phase and the deposits. Intrusive probes even at six o'clock, will protrude through any water and deposits. Only the bottom portion of the coupon or probe will be water wetted, with the rest of the surface area being oil wetted. This will lead to erroneously low corrosion rate results. Coupons not mounted at the 6 o'clock position would be entirely oil wetted and would be expected to produce no meaningful data.

The requirement for chemical analysis for corrosion inhibitor residuals and iron counts for the pipeline system has been recognized as a result of the risk assessment performed. This has been incorporated into the pipeline corrosion management strategy, and is also to be rolled out throughout the Forties Field during 2008.

Intelligent Pigging (In Line Inspection)

Intelligent pigging has proved to be a vital tool in establishing the condition of the Forties Field in field pipelines, and establishing a basis for future life prediction. A summary of the findings from the in line inspection results for each pipeline examined is provided below:

PL54 Forties Alpha to Forties Charlie (Disused Oil Transport Pipeline)

This is the original line installed in 1975. This pipeline was examined by intelligent pigging in the early 1990s. This identified severe 6 o'clock grooving and pitting corrosion. The line was replaced in 1995 by PL54A, after 20 years in service. Damage was exclusively to the sea line, and the risers were in relatively good condition.

PL54A Forties Alpha to Forties Charlie (Oil Transport Pipeline)

The line was the replacement for PL54, and was installed in 1995. This pipeline has not been intelligently pigged to date, and is scheduled to be intelligently pigged in 2008.

PL55 Forties Bravo to Forties Charlie (Oil Transport Pipeline Converted to Multiphase)

This is the original line installed in 1975. This pipeline was intelligently pigged in 2007, post to conversion from an oil transport line to a multiphase line. In part, this conversion was due to the fact that flow rates in this line were so low that running an intelligent pig had been deemed impracticable. Although topsides inspection had not indicated any significant corrosion problems and the line was still rated to its design maximum allowed working pressure (MAWP), risk assessment, corrosion modelling and comparison with other similar lines in the field led to the belief that the sea line would have significant levels of 6 o'clock corrosion damage due to its history as an oil line. The pipeline MAWP was downgraded substantially, to the minimum value practicable with its use as a multiphase line. Upon running the intelligent pig, the sea line was found to be damaged in line with predictions, although the risers were in relatively good condition. Although not an immediate threat to integrity, the remaining life of the sea line under multiphase service was predicted to be relatively short and a repair or replacement program was required. However, even with multiple repairs, the line was not predicted to function until the end of field life. Taking the longer view, Apache decided on a replacement option. The replacement sealine was laid in a record 95 days from receipt of first notification from the intelligent pigging company and will be tied in during April 2008 under an already planned production shutdown[6].

PL56 Forties Delta to Forties Charlie (Oil Transport Pipeline)

This is the original line installed in 1975. The pipeline was first pigged in 1998. As with other oil transport pipelines, the risers were in relatively good condition. However, significant pitting and axial grooving damage was noted at the 6 o'clock position of the sealine. In this case pipeline wall penetration and defect growth rates were such that the pipeline MAWP could be de-rated and pipeline use could be continued. The pipeline was re-pigged in 2001, when it was shown that there was no significant defect growth rate. This allowed the line to continue functioning at its reduced MAWP. This line was re-examined by intelligent pigging in 2007. From the worst case defects found in 2001, no defect growth was observed. However, completely new defects were found, and some smaller defects were showing accelerated growth. The rate of growth was faster than could be accounted for by CO_2 corrosion. Given the evidence of SRB activity that has been found from H_2S formation in other pipelines and the topsides facilities, this has been attributed to microbial influenced corrosion (MIC). Microbial studies are under way. Given that the pigging regime of two operational pig runs per month is already considered to be reasonable, and the line already has low water cuts and high dosage corrosion inhibition, the use of a biocide treatment program for this pipeline is under review.

PL365 Forties Echo to Forties Alpha (Multiphase Pipeline)

This pipeline was installed in 1986. It was intelligently pigged in 2002 after 16 years in service. Two forms of corrosion were indentified. There was little evidence of general corrosion in the pipeline. However, throughout the sealine and risers, discrete areas of localized corrosion were identified. These defects had no specific circumferential orientation. Although the worst case growth rate was 0.3mm/yr, these were short axial defects and analysis with DNV RP-F101[7] indicates that they will not threaten the pipeline integrity until 85% of wall thickness penetration occurs. As such these defects can penetrate well beyond the original corrosion allowance without causing an integrity issue.

Of far more concern was evidence of preferential weld corrosion in the risers. This led to a de-rating of the pipeline MAWP, and the risers and where required the riser topsides were replaced in 2004. With the new risers in place and the sea line showing only localized corrosion, at the reduced MAWP this pipeline was attributed a remaining life in excess of 15 years given the potential growth rates in the sealine and the potential for a recurrence of preferential weld corrosion. The present Apache policy with damaged lines is to re-inspect the line based upon a half remaining life concept, and this line will be intelligently pigged in 2010.

Topsides Versus Subsea Inspection

One additional note of interest is a comparison of riser topsides inspection with the intelligent pig runs for the given lines. For the PL365 multiphase line there was some correlation between topsides damage and the condition and corrosion mechanisms in the sea line and risers. For the oil transport pipelines, the correlation was less evident and in one case riser topsides inspection completely failed to predict the sealine damage. For a slow flow oil transport or export pipeline you cannot assume that because topsides inspection indicates no problems, there are no problems occurring down inside the sealine.

Anode Depletion

In order to assess the current cathodic protection status of the Forties Field, previous jackets, pipelines and risers inspection records pertaining to cathodic protection systems was reviewed, summarised and compared with the results of the 2006 inspection campaign. Although measured cathodic protection levels continued to be adequate, the condition of the sacrificial anode systems gave concern with respect to their capacity to continue to provide cathodic protection for the remainder of the 15 to 20 year extended life.

Anode wastage on the jackets was not homogeneous. Jacket anodes were widely more than 75% depleted towards the bases and in the central areas, whilst top area anodes were only 25 to 50% depleted. Most of the riser and spoolpiece anodes were in excess of 75% depleted. Pipeline anodes also presented a high degree of wastage, especially near the pipeline ends. Due to the significant anode depletion it was concluded that the current anode materials were inadequate to protect the facilities for the predicted remaining life of 15-20 years. As such:

- An anode retrofit program has been completed on PL 54A, PL 55, PL 56 & PL 365.
- A jacket CP survey has also been completed and the results have been used as input to a jacket CP reinstatement program to be performed during 2008.

Anode retrofit has been via both anode sleds and anode pods. Examples are shown in Figure 2.

Conclusions and Lessons Learned

1. The importance of a corrosion risk assessment is emphasized. In this case the identification of unmitigated microbial corrosion rather than mitigated or even unmitigated CO_2 corrosion as the highest risk to infield oil transport pipeline integrity has led to a change of emphasis in corrosion control. Although yet to be verified by bacterial monitoring, gas analysis and intelligent pigging has indicated H_2S generation and microbial corrosion in some of the in field pipelines. This has led to the examination of a long term pipeline biocide treatment program as a supplement to the operational pigging program.
2. A corrosion management strategy had been put in place for the Forties Field by Apache and its contractors. However, this was oriented towards topsides and structures, with very little orientation towards the infield pipeline system. This was also reflected in the corrosion and chemical KPIs. A specific pipeline corrosion management strategy document was prepared, to determine roles and responsibilities, interfaces with the facilities engineers and managers, and to ensure effective corrosion management of the infield pipeline system. KPIs have also been modified to meet the needs of the pipeline system, with the emphasis on corrosion inhibitor injection and water content.
3. The identification of a risk from pitting under barium sulphate scale has shown the need for testing to ensure the corrosion inhibitor used can counter this mechanism.
4. For the pipeline with a multiphase history, damage occurred in the risers and riser topsides due to preferential weld corrosion, but was less extensive in the sea line where isolated localized defects with lower corrosion rates and no strong preference of circumferential orientation were identified.
5. For the pipelines with a history of oil transport, damage occurred predominantly in the horizontal sea lines with 6 o’clock grooving and/or pitting corrosion where water drop and deposits could occur. Damage to the risers was far less significant.

6. In the case of the Forties Field, topsides inspection has provided some indication of the sub sea pipeline performance for multiphase pipelines. However, topsides inspection has badly underestimated the corrosion damage identified in a number of the subsea oil transport lines.
7. Intelligent pigging has proved to be a vital tool in correctly assessing the pipeline condition for both multiphase and oil transport pipelines. It also allows the clock to be reset, giving a new baseline on which corrosion modelling or growth extrapolation can be used for future life prediction.
8. Corrosion defects exceeding the original design corrosion allowance are not the end of the world. In many cases the MAWP can be reduced in line with reduced wellhead pressures for multiphase lines or reduced pump pressure requirements for oil transport lines. This can win back substantial pipeline wall thickness for use as additional "corrosion allowance" for future life prediction.
9. Also, if defects are deep and with a relatively short axial component, analysis with recommended pipeline assessment practices such as DNV RP-F101 indicates that the defects can substantially exceed the corrosion allowance and may penetrate as deep as 85% of wall thickness before threatening the integrity of the pipeline.
10. For oil transport and export lines, the oil industry generally believes that if water cuts can be maintained below 1-2% then issues with water drop and associated microbial and other corrosion issues can be mitigated. This is an erroneous belief. 1-2% Water can be successfully entrained, even in light crudes. However, the flow rate of the crude oil stream has to be maintained at a velocity greater than 1m/s. As the oil flow rate drops below 1m/s there is a rapid drop in the water entrainment capability of the crude oil, and for light crudes flowing at very low velocities even 0.2% water entrainment may be difficult. In many of the pipelines associated with facilities in the North Sea, the oil pipelines were originally designed for much higher peak oil flows, and present oil flow rates are well below 1m/s. For example, in the Forties Field, the original infield lines were designed for peak flows of up to 10 times the present oil flow rates. As such, assuming that a 1-2% water cut is acceptable as an integrity criterion is not possible
11. Corrosion monitoring and chemical analyses for items such as iron counts and corrosion inhibitor residuals appears to have ceased, or had been poorly documented, since 1996. Corrosion monitoring requirements have been assessed, monitoring points have been identified and replaced where required, and corrosion monitoring is now being rolled out across the field facilities. This has started with Forties Bravo, where corrosion monitoring is now in place, and will progress through Forties Charlie and the other facilities during 2008. The requirement for chemical analysis for corrosion inhibitor residuals and iron counts has been recognized from the risk assessment, and is also to be rolled out throughout the Forties Field during 2008.

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Figures and Tables

TABLE 1

FORTIES INFIELD PIPELINES

Pipeline Reference	Description	Transported Fluids
PL 54	Forties Alpha to Forties Charlie disused 20” rigid oil pipeline	Redundant
PL 54A	Forties Alpha to Forties Charlie 20” rigid oil pipeline	Crude oil
PL 55	Forties Bravo to Forties Charlie 20” rigid production pipeline	Multiphase-oil/water fluids and gas
PL 56	Forties Delta to Forties Charlie 20” rigid oil pipeline	Crude oil
PL 365	Forties Echo to Forties Alpha 12” rigid production pipeline	Multiphase-oil/water fluids and gas
PL 380	Forties Echo to Forties Alpha disused 6” rigid test pipeline	Redundant
PL 2039	Forties Charlie to Forties Delta 4.5” flexible fuel gas pipeline	Fuel gas
PL 2040	Forties Alpha to Forties Delta 4.5” flexible fuel gas pipeline	Fuel gas
PL 2140	Forties Charlie to Forties Bravo 8” flexible produced water re-injection pipeline	Produced water

FIGURE 1

FORTIES FIELD SCHEMATIC

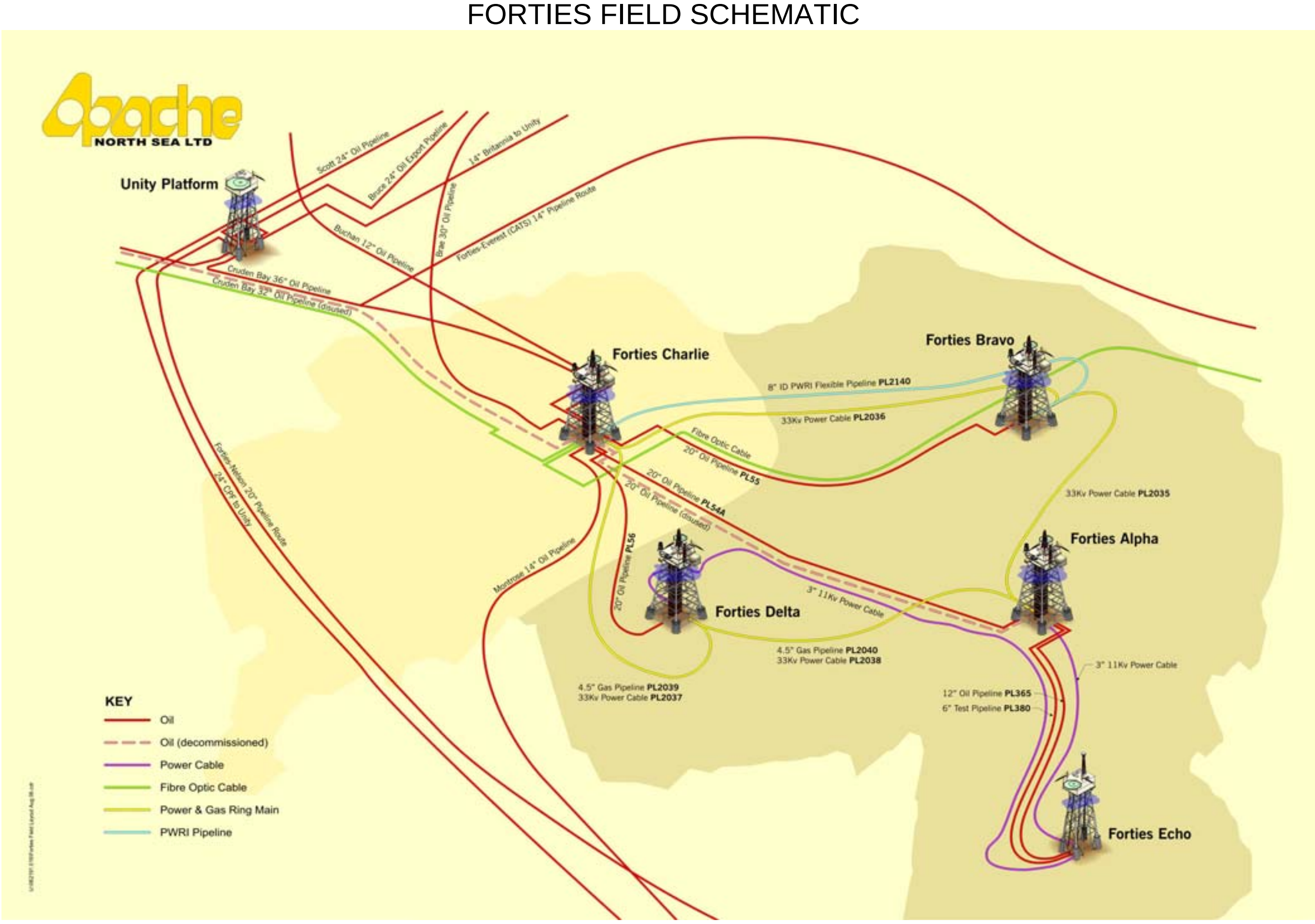

TABLE 2

INTERNAL CORROSION RISK ASSESSMENT FOR THE FORTIES INFIELD PIPELINES

Pipeline	Description	Hazard Consequence	Operational Consequence	Worst Case Corrosion Mechanism Probability	Risk Category
PL 54	Forties Alpha to Forties Charlie disused 20” rigid submarine pipeline	Low	Low	Moderate	5
PL 54A	Forties Alpha to Forties Charlie 20” rigid oil pipeline	Moderate	Moderate	High	2
PL 55	Forties Bravo to Forties Charlie 20” rigid oil pipeline	High	High	High	1
PL 56	Forties Delta to Forties Charlie 20” rigid oil pipeline	Moderate	Moderate	High	2
PL 365	Forties Echo to Forties Alpha 12” rigid oil pipeline	High	High	High	1
PL 380	Forties Echo to Forties Alpha disused 6” rigid oil pipeline	Low	Low	Moderate	5
PL 2039	Forties Charlie to Forties Delta 4.5” flexible fuel gas pipeline	High	High	Low	3
PL 2040	Forties Alpha to Forties Delta 4.5” flexible fuel gas pipeline	High	High	Low	3
PL 2140	Forties Charlie to Forties Bravo 8” flexible produced water re-injection pipeline	Moderate	Low	Low	5

TABLE 3

PIPELINE INTERNAL INTEGRITY KEY PERFORMANCE INDICATORS

PIPELINE TYPE and KPI	REQUIREMENTS
Oil Transport/Production Pipelines	
Corrosion inhibitor – Two criteria now recommended	1) Percentage of target volume achieved. Average of daily scores. 2) Percentage of pump injection time achieved over 1 month.
Water cuts – Oil export lines only (FA-FC, FD-FC)	10% off for every 0.2% above 2% at an average flow rate > 1m/s, for every 0.1% above 0.5% at an average flow rate > 0.7m/s, and <1m/s. and every 0.1% above 0.2% at an average flow rate <0.7m/s.
Pigging operations	4% off for every day over 37 days (14 days for FD-FC) and 33% off for every ‘pig report’ not completed and forwarded to the pipeline competent person
Biocide dosing	Under review
Fuel Gas Pipelines	
Dew point monitoring	10% off for every 1 C above -18C each day (-12 C on Alpha and Charlie). Average of daily score. The TEG is to reduce water content in the gas to 2lb/MMscf
Water Injection Pipelines	
Produced water re-injection (PWRI) Biocide dosing (not yet in operation)	Under review

FIGURE 2

EXAMPLES OF ANODE RETROFIT SLEDS AND PODS USED IN THE FORTIES INFIELD PIPELINES ANODE RETROFIT PROGRAM