Corrosion Monitoring of Non-Common Carrier

North Slope Pipelines

Technical Analysis

Of

BP Exploration (Alaska) Inc.

Commitment to Corrosion Monitoring Year 2004

Submitted by

COFFMAN ENGINEERS
800 F Street
Anchorage, Alaska 99501
907/276-6664
907/276-5042 Fax
www.coffman.com

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EXECUTIVE SUMMARY

Coffman Engineers, Inc. is responsible for the technical review of the 2004 corrosion program report submitted by BP Exploration (Alaska) Inc. (BPXA) to the Alaska Department of Environmental Conservation (ADEC). The report outlines the measures undertaken to mitigate corrosion of BPXA's non-common carrier North Slope pipelines. In addition, Coffman reviewed the presentation materials from the 2005 Meet & Confer sessions in Anchorage and Prudhoe Bay, Alaska.

The data provided by BPXA supports the conclusion that the corrosion management program is effective and exceeds common industry practice. Sufficient information has been presented to demonstrate that the corrosion control program meets the intent of the Charter Agreement.

It is notable that BPXA presented the 2004 monitoring and inspection program in a transparent way and answered all questions with candor. Information from written reports, presentations, and verbal questions are consistent. Additionally, the BPXA corrosion control staff is highly competent and an extensive QA/QC program is in place to monitor the performance of contractors.

Inspection activities in 2004 consisted of approximately 60,000 items (combined internal and external). The majority of the system had a corrosion rate of less than 2 mils/year. Monitoring, mitigation, and inspection data support the conclusion that the GPB assets are being preserved, but isolated locations of accelerated corrosion exist and have been found by inspections. In response to the isolated locations of accelerated corrosion, BPXA has implemented aggressive and thorough risk based monitoring and mitigation programs.

The GPB multiphase produced oil system is highly corrosive, if untreated. Corrosion in the majority of the pipeline system has been reduced to a negligible level as a result of the implementation and continuation of an aggressive corrosion inhibition program. Anomalies in the system are inspected, mitigated and monitored.

A significant injection water internal corrosion mechanism that BPXA is aggressively responding to is under-deposit corrosion. Inhibition levels were increased, cleaning pigs and a surfactant (SBG) were used to remove deposits and line velocities are being evaluated. The surfactant chemically removes deposits, particularly in locations where cleaning pigs cannot be run. These actions are consistent with good corrosion control practices.

External corrosion of above-ground piping is largely confined to weld packs, and BPXA has made a commendable commitment to removing this threat through inspection and repair (where necessary).

External corrosion at cased crossings represents a corrosion threat over which BPXA has a difficult challenge. This is because of the difficulty with accessing the pipe surface. In response to this challenge, BPXA is using visual, direct, smart pig and guided-wave assessments as part of their comprehensive inspection program. BPXA has proactively implemented guided-wave technology, recognizes the current technical limitations of this technology and is working to further enhance it.

CORROSION PROGRAM STATUS – GREATER PRUDHOE BAY

The data provided by BPXA supports the conclusion that the corrosion management program is effective and exceeds common industry practice. BPXA presented the 2004 monitoring and inspection program in a transparent way and answered all questions with candor. Information from written reports, presentations, and verbal questions are consistent.

BPXA utilizes a risk based corrosion management program. The program relies on an "as low as reasonably practical" strategy. In this approach there is no "acceptable" risk. High risk items get more attention and low risk items get less attention. For the most part, consequence of failure appears to be considered similarly high for the majority of the facility. Emphasis is therefore placed on reducing the likelihood of failure. Locations with highest likelihood of failure receive the greatest attention, and other locations are reduced as low as reasonably practical.

It should be noted that the planned field life has recently been significantly extended, and future production (especially natural gas) relies on maintaining the existing infrastructure. Maintenance and repair decisions are therefore justified on the basis of facility requirements for future production in addition to safety and environmental reasons.

Internal Corrosion Management

Production System (Well Lines and Flow Lines)

The data provided by BPXA supports the conclusion that the internal corrosion control/inspection program is effectively managed. The produced oil system at GPB is both extensive in size and highly corrosive, if untreated. Without mitigation, the natural corrosion rate would likely result in pipeline failure in less than a year because corrosion rates would likely range from 100 to 300 mpy. The corrosion mitigation program has reduced this corrosion rate to a negligible level for the majority of the pipeline internal surface, and efforts to further optimize the program are based on identifying, mitigating, and repairing locations of isolated high corrosion rate and/or damage.

The dominant corrosion mechanism (CO_2) has been reduced to a negligible level for the majority of the pipeline system. The average corrosion rate of coupons and probes are as low as can be practically achieved (i.e., <1 mpy), and inspection data supports the conclusion that most of the GPB asset has adequate corrosion control.

Data illustrating the distribution of internal corrosion rates as measured by monitoring and inspection was shared during meet and confer sessions. This data represents isolated locations of increased corrosion rates and reflects awareness by BPXA of the importance for considering extreme value corrosion rates rather than simple averages that may mask their existence.

The monitoring program identifies significant changes in corrosion mitigation effectiveness, and inspection verifies the effectives of the mitigation program. In addition, inspection 1) identifies locations where corrosion rates along a pipeline segment may exceed what is measured by coupons, and 2) is used to characterize previous corrosion damage (i.e., through remaining strength calculations).

Two unforeseen events occurred in the 3-phase corrosion inhibition program which resulted in higher than normal corrosion rates. Both were related to the chemical inhibitors (incumbent and test) that were being used and tested. These events were: 1) corrosion inhibitor instability at winter temperatures which resulted in the blockage of some of the chemical delivery systems, and 2) material incompatibility with a test inhibitor and the delivery system tubing. The problems were identified, analyzed and mitigated.

Seawater and Produced Water Injection

The seawater and produced water systems have relatively low corrosion rates and appear to be well managed.

The primary corrosion mechanisms in the seawater injection systems are dissolved oxygen (DO) and microbiological induced corrosion (MIC). Corrosion of the seawater system is mitigated by removing oxygen, injecting biocides, and cleaning the system of deposits.

The 100% seawater water injection systems have low corrosion rates and the overall program performance has been consistently improving since 2002. The "majority" seawater injection systems have experienced a decline in performance in 2004, after an increase in performance from 2002 to 2003. BPXA has initiated a thorough analysis to better understand the difference in performance and should be better able to address this matter in 2005.

There are a number of corrosion mechanisms of concern in the produced water injection system. Corrosion is mitigated by oxygen removal, injecting biocides, cleaning, and by carryover inhibition from the production system.

The majority of the produced water injection system had low corrosion rates. Information shared during meet and confer sessions illustrated that BPXA recognized that the corrosion rates in the product flow (coupon) may not always be representative of the corrosion rate at the pipe wall. Various corrosion mechanisms (i.e., under-deposit corrosion) may be attributed to these variances. BPXA has enhanced its cleaning program by increasing the frequency of maintenance pigging and by use of surfactants to dislodge deposits. Inspections and aggressive cleaning programs have minimized the number and potential threat of these variances.

External Corrosion Management

Above Grade Piping

Corrosion under insulation (CUI) is primarily associated with water ingress into the pipeline thermal insulation, in particular, at the field joints (weld packs). Water becomes trapped in the insulation and corrodes the uncoated pipe underneath. CUI is problematic throughout industry and is typically managed by inspection and monitoring programs.

There are approximately 300,000 weld packs at GPB and approximately 35,000 are inspected annually for wet insulation and the presence of corrosion product buildup. Roughly half have been found to contain water, and roughly 3% of those have corrosion damage (down from a high of 17% in 1995). There were two leaks due to external corrosion.

BPXA has implemented aggressive risk based monitoring and inspection programs to minimize the consequences of CUI. The priority for inspection is based on a number of variables, one of which is the consequence of failure (e.g., weld packs over tundra are higher priority than over the pad), ensuring that the highest consequence locations are repaired first. BPXA has implemented and is evaluating a new weld pack design that is intended to prevent future water ingress and corrosion at these weld pack locations.

Below Grade Piping

External corrosion at cased crossings represents a corrosion threat over which BPXA has a difficult challenge. This is because 1) the pipe cannot be directly accessed without excavation and removal of the casing and pipeline insulation (i.e., to identify damage), and 2) mitigation of active external corrosion is not easily achieved. This issue is an industry-wide problem and BPXA is actively addressing this treat with an aggressive and continually developing inspection program.

BPXA is using visual, direct, smart pig and guided-wave assessments as part of their inspection program. While each element is an important factor in the overall inspection program, it should be noted that all inspection techniques have limitations and each element should be applied where it delivers the most value.

There are approximately 1,500 cased pipe segments (approximately 28 miles) in the BPXA system. There have been two loss of containment incidents, 9 segment replacements and 6 sleeve repairs.

Baseline visual assessments have been performed on all cased crossings. The baseline inspections primarily involved looking for submerged segments and debris that could enter the annular space and support corrosion. Direct assessments (excavations or partial excavations) have been performed on 50 crossings (19 in 2004). In-line inspection tools (ILI or smart pigs) are used at GPB where pigging facilities and the process environment allow. ILI was performed on 4 lines in 2004. Advanced long-range inspection tools (guided-wave) are an important and developing part of the cased crossing inspection program and are being used within their technological limitations. Over 100 cased pipe segments were inspected using the guided-wave technology.

SATELLITE FIELDS

Endicott

The majority of the Endicott production system piping is constructed of Duplex Stainless Steel (DSS) that is intended to be corrosion resistant in the produced fluid environment. Minor components within the facility (i.e., C-spools) are carbon steel with corrosion managed by monitoring, inspection and repair/replacement (when necessary).

The primary corrosion concerns are in the water injection system, mainly the Inter-Island Water line (IIWL). Historically, corrosion control of the water injection system relied on corrosion inhibition of the injection water, supplemented by a biocide and maintenance pigging program. Improvements were made to the mitigation program in 2004. Corrosion inhibitor concentrations

were increased from 20 to 30 ppm and the biocide treatment was eliminated. The program changes appear to have reversed the increase in corrosion activity that the system was experiencing. The primary monitoring method for determining the effectiveness of this program consists of ultrasonic inspection of 25 locations. There were also 719 external corrosion inspections and slight corrosion damage was found at three locations, with no repairs required.

In the production system, the primary damage mechanism was erosion. The erosion rates are monitored through inspection and mitigated through velocity management (i.e., keeping flow rates below a threshold).

In 2004, there were four repair activities and no corrosion related spills. Three repairs were due to erosion and one was the result of external mechanical damage.

Milne Point

The primary corrosion concerns are in the water injection system and corrosion of the buried piping. BPXA has improved the internal corrosion management of Milne Point production and produced water systems. These improvements include increases in corrosion inhibition, maintenance pigging, and inspection. Monitoring data shows reduction of average corrosion rates to insignificant levels (i.e., <2 mpy).

Inspections have indicated the presence of under-deposit corrosion at Milne Point. Inhibition levels were increased, cleaning pigs were used to remove deposits and line velocities are being evaluated. These actions are consistent with good corrosion control practices.

Milne Point has buried pipe containing produced fluids that necessitate excavation for external inspection. In 2004, BPXA conducted 623 inspections in 45 excavation sites.

In 2004, there were 13 repair activities and no corrosion related spills. Seven repairs were the result of internal corrosion, five were the result of external corrosion and one was the result of a freeze burst (structural related).

Northstar

The threat of corrosion at Northstar is considered low, but may increase over time. Production began in late 2001 and fluids have low corrosivity. The production lines are inhibited and corrosion coupons indicate adequate effectiveness (i.e., <2 mpy).

Since the facility is less than 4-years old, an external inspection program has not been established. A program is scheduled to be implemented in 2006.

Badami

Badami is shut-in, so the safety and environmental risk from corrosion is negligible (i.e., there is no safety or environmental consequence). From an asset preservation standpoint, external corrosion can occur on buried and/or insulated piping (none has been documented), and internal corrosion could occur if lines were insufficiently dried or treated (e.g., for bacteria).

RECOMMENDATIONS

Recommendations for areas that warrant further review or information that should be included in future reports are as follows:

1. Provide additional discussions regarding the anticipated field life and the necessary changes to the corrosion monitoring and inspection program to ensure the integrity of the assets throughout the extended life of the field.
2. Provide additional discussions regarding the difference in performance between the 100% seawater and the "majority" seawater injection systems.
3. Continue the commitment to external corrosion inspection and mitigation on the weld packs. Identify the number of weld packs remaining to be inspected and the forecasted completion date.
4. Provide additional information regarding the mechanism of under-deposit corrosion and the effectiveness of the programs to control it.
5. Continue the commitment to develop and enhance long range inspection techniques used at cased crossings. Supplement this commitment with direct assessments and/or inline inspections (where possible).

CONCLUSIONS

The data provided by BPXA supports the conclusion that the corrosion management program is effective and exceeds common industry practice. Sufficient information has been presented to demonstrate that the corrosion control program meets the intent of the Charter Agreement.

It is notable that BPXA presented the 2004 monitoring and inspection program in a transparent way and answered all questions with candor. Information from written reports, presentations, and verbal questions are consistent. Additionally, the BPXA corrosion control staff is highly competent and an extensive QA/QC program is in place to monitor the performance of contractors.

BPXA utilizes a risk based corrosion management program. The program relies on an "as low as reasonably practical" strategy. In this approach there is no "acceptable" risk. High risk items gets more attention and low risk items get less attention.

The majority of the system had a corrosion rate of less than 2 mils/year. Monitoring, mitigation, and inspection data support the conclusion that the GPB assets are being preserved, but isolated locations of accelerated corrosion exists and have been found by inspections. Data shared during meet and confer sessions illustrated that BPXA recognized the existence of these extreme values and is addressing their identification, repair, and mitigation as part of its integrity management program.

The inherent integrity risk from internal corrosion in the multiphase production system is high. Corrosion in the majority of the pipeline system has been reduced to a negligible level as a result of the implementation and continuation of an aggressive corrosion inhibition program. Anomalies in the system are inspected, mitigated and monitored.

A significant injection water internal corrosion mechanism that BPXA is aggressively responding to is under-deposit corrosion. Inhibition levels were increased, cleaning pigs and a surfactant (SBG) were used to remove deposits and line velocities are being evaluated. These actions are consistent with good corrosion control practices.

Two significant external corrosion threats are below-ground cased crossings and weld packs on above-ground pipe. BPXA has made a notable commitment to inspect and repair (when necessary) weld-packs. BPXA is aggressively addressing cased crossings by using visual, direct, smart pig and guided-wave assessments as part of their comprehensive inspection program.

~End of Report~