Corrosion Monitoring of Non-Common Carrier North Slope Pipelines

Technical Analysis

Of

BP Exploration (Alaska) Inc. – Commitment to Corrosion Monitoring Year 2000 for Greater Prudhoe Bay, Endicott, Badami and Milne Point

Submitted by

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ADEC Contract Number – 18-6000-02

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EXECUTIVE SUMMARY

Coffman Engineers, Inc. has been charged with reviewing the 2000 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 in BPXA's non-common carrier North Slope pipelines. In addition, Coffman reviewed the presentation materials from the April 2001 Meet & Confer session. The goal of this review is to examine the corrosion program report, gain a qualitative understanding of BPXA's corrosion control program and identify recommendations for improvement to the content and extent of topics covered.

BPXA has demonstrated a clear commitment to corrosion control. BPXA has developed a comprehensive program of monitoring and inspection. Reported results indicate internal pipeline corrosion trends for GPB West have been steadily improving since 1993 and are currently at their lowest levels in 12 years. BPXA has made a significant commitment to corrosion inhibitor testing and development, as well as reducing the number of products to a more manageable selection.

BPXA reports coupon corrosion rates as "Annualized Percentage < 2 mpy." These coupon corrosion rates increased slightly in 2000 for well flow lines, drill site gathering lines, and produced water injection lines; while they decreased slightly in the seawater injection lines. The average magnitude of the coupon corrosion rate change is not presented, however the majority, 85+%, has rates below the 2mpy threshold. BPXA has analyzed the causes relating to the coupon corrosion rate increases and has taken steps to reverse the trends.

Compared to 1999, inspection results for well lines show increases in the number of locations reporting damage to the pipe wall in all injection (PW/SW/MI) service categories; conversely three-phase production well lines are relatively flat and are at their lowest levels in the period reported (1995-2000).

Presently, external corrosion is a significant risk to pipeline integrity for BPXA. External corrosion under insulation was reported as the cause for both leaks in 2000 and two additional leaks in 2001. The need for additional resources for external corrosion management should be re-examined.

The BPXA report and presentation materials were a positive step towards meeting the expectations outlined in the Commitment to Corrosion Monitoring plan. BPXA and ADEC have committed to better define reporting metrics and definitions for future reports.

COMMITMENT TO CORROSION MONITORING

The Charter agreement between the State of Alaska, BPXA and PAI required the development of a "performance management program for the regular review" of the corrosion monitoring and related practices for the non-common carrier North Slope pipelines. As a result of the subsequent meetings, the annual reporting requirements were defined as follows:

A. Annual bullet item reporting the progress of the Charter Agreement corrosion related commitment.

B. A general overview of the previous year's monitoring program.

C. Metrics which depict coupon and probe corrosion rates.

D. Metrics which characterize chemical optimization activities.

E. Metrics which depict the number and type of internal/external inspection done and, as applicable, the corrosion increases/rates and corresponding inspection intervals.

F. Metrics which characterize the quantity and type of repairs made in response to the internal/external inspections done per the above paragraph.

G. Metrics which depict the numbers and types of corrosion and structural related spills and incidents

H. A forecast of the next year's monitoring activities in terms of focus areas and inspection goals. These forecasts cannot be viewed as binding, as corrosion strategies are dynamic and priorities will change over the course of the year. However, changes in focus will be communicated to ADEC during the semi-annual meeting described above.

ADEC contracted with Coffman Engineers, Inc to provide a technical analysis of the information presented in the annual report and determine if there are any specific corrosion or pipeline structural issues which warrant further review or corrective action. In addition to the annual report, Coffman reviewed the presentation materials from the April 2001 Meet and Confer Session.

CORROSION CONTROL STRATEGY

This section outlines the strategy presented in the report and presentation. It is divided into internal and external corrosion strategies and describes the monitoring, inspection and mitigation components. The current program status is presented in a subsequent section.

Internal Corrosion Strategy

Monitoring & Inspection

BPXA uses probes, coupons and numerous inspection methods to monitor internal corrosion throughout the field. It is unclear how the coupons are analyzed and how the data are weighted. The target, or action, limit for coupons is 2 mils per year (mpy). The target, or action, limit for probes is based on location and is between 0.5 mpy and 10 mils per year.

BPXA employs manual and automated RT and UT inspection techniques. The report discusses the limitations of the various inspection methods and BPXA has a clear understanding of their strengths and weaknesses. Wall losses less than 10 mils (0.010") are difficult to detect reliably using RT. The target, or action, limit for inspection is "zero detectable corrosion."

The data generated from the monitoring and inspection programs are reviewed weekly and in-depth reviews are made at the end of each quarter. If target values are exceeded, there is an investigation and possible repair/replacement/mitigation.

Lastly, BPXA discusses the use of Magnetic Flux Leakage (MFL) pigging technology. MFL pigging allows an operator to inspect the entire length of pipe for both internal and external corrosion indications and can be a significant tool for determining the actual fitness for purpose of a pipeline. In future reports, a more in-depth discussion about the MFL pigging strategy (location, frequency, results, etc.) would be helpful.

Mitigation

Internal corrosion at BPXA is controlled primarily by corrosion inhibitor application and secondarily by erosional velocity controls and well start-up procedures (slide 6). Other engineering tools, such as design, material selection, coating selection, etc., are also used by BPXA to control corrosion.

Chemical optimization is an on-going task for BPXA. As promising new inhibitors are developed they are tested on a small scale initially, followed by a larger scale test, and if successful, used within the facilities. Several products have been developed in the past years. BPXA's strategy is to inject inhibitor volumes until coupon corrosion rates of less than 2 mpy are achieved.

External Corrosion Strategy

External corrosion under wet insulation is a concern for all North Slope producers. The vast majority of pipelines is above ground and thermally insulated. Snow and water can be forced under the insulation where pipe segments are joined and field applied insulation was installed. These areas are known as weld-packs. When the line is warm and the water trapped under the insulation is above freezing, corrosion cells can form. Corrosion under insulation is likely to require an ongoing commitment of resources throughout the life of the field.

Monitoring & Inspection

BPXA is currently managing 1/3 of a million weld-packs (slide 15) between GPB and ACT. Presently, there are no monitoring techniques used for this corrosion mechanism. This places greater emphasis on the inspection program. Inspection methods for corrosion under insulation are radiographic and visual. TRT (tangential radiography), C-arm fluoroscopy and MFL smart pigging, eddy current, and digital radiography are used in conjunction with visual inspection to detect corrosion under insulation. The weld-pack locations are externally identifiable, so the precise location of possible corrosion cells is known in advance. This mechanism can be expected to be active throughout the rest of the field life. In addition, BPXA is also using two new technologies for inspecting the below grade, cased pipeline crossings; electromagnetic and guided wave inspection.

Mitigation

Refurbishment of the weld-pack requires the exclusion of oxygen saturated water from contact with the external pipe wall. The primary refurbishment method is to drain the weld-pack, refurbish the seals to eliminate water ingress, coat the pipe, and replace the saturated insulation. A more in-depth review, of past BPXA measures taken, would be necessary before recommendations could be formulated.

CORROSION PROGRAM STATUS

Risk

While not required by the Charter agreement, risk (risk assessment, risk based inspection, etc.) is an important tool used in corrosion control. It would beneficial if BPXA would further elaborate on how risk is utilized in future reports. For example, how BPXA evaluates the probability of a failure due to a specific corrosion mechanism and then how the consequences of the potential failure were evaluated to formulate a mitigation plan. It is clear that a form of risk based resource allocation is used by BPXA; the corrosion team has identified and responded to corrosion events and developed continuous improvements to its corrosion program when changes were deemed necessary (pg 12 and 13).

Internal Corrosion Management

Internal coupon corrosion rates at GPB have increased slightly in every service category except seawater in 2000 (Fig 1). It was reported that seven repairs and 63 saves were recorded due to internal corrosion in 2000 (Table 11 and 12). Results reported for the year 2000 show increases in the number of locations reporting ongoing pipe wall damage in all of the injection service categories (PW/SW/MI). Conversely, three-phase production well lines are relatively flat for the last two years and are at their lowest levels in the reported period (1995-2000).

BPXA reports a loss of corrosion control due to under-treatment with corrosion inhibitor in 2000 (pg 23). The loss of control is attributed to damaged corrosion inhibitor chemical (the active ingredients precipitated out of solution and plugged the injection tubing) and to manpower reductions incurred during the reorganization. These events lead to a period of corrosion inhibitor under-treatment and a subsequent increase in corrosivity. The problem was identified and these issues have been addressed, and they expect to be back on-track in 2001. BPXA believes damage due to these corrosion rate increases were probably limited to on-pad piping because off-pad piping is protected by the redundancy inherent in the wellhead corrosion inhibitor injection program. It would be beneficial to understand how the coupon and probe rates varied during this episode and whether or not inspection results saw correlative increases in pipe wall damage to the on-pad piping.

Monitoring & Inspection

BPXA used 8,970 coupons in 2000, down from 11,574 in 1997. The reduction is explained by the following:

- changes in pull frequencies in the produced water system not a reduction in locations,
- reduction in the number of coupons in the production well lines, primarily upstream of chemical injection, and
- wells that are in long term shut-in.

The number of coupon locations per service category (PW/SW/3-phase, etc.) would be beneficial for clarifying performance of the coupon monitoring program. Coupon grading usually contains a judgment-based analysis of the coupon surface condition as well as objective pit depth and weight loss measurements. A discussion detailing how coupons are evaluated by BPXA would be beneficial, as it is apparent that there are differences in the way various operators perform this function.

Table 13 reports "Leaks and Saves" by year. Saves outnumber leaks by approximately 10:1 with overall leak/save ratios running from a low of 88% to a high of 97% achieved in 2000. The change is due to inspection, BPXA found defects before they became leaks. It would be helpful, in future reports, to know the cause of the leak (internal vs. external, isolated pit or network). Some discussion of how the defect was dealt with would also be beneficial; for instance was the defect sleeved or was the pipe segment replaced.

Mitigation

BPXA runs an extensive and proactive corrosion inhibitor development program. Table 6 shows the progression of corrosion inhibitor products over time. Six inhibitor formulations were used across the GPB in 2000. Table 7 shows the produced water volume treated and the inhibitor concentration per year. The field-wide average inhibitor concentration required for mitigation (coupon corrosion rates < 2mpy) has risen from a low of 106 ppm in 1996 to a high of 149 ppm in 2000. BPXA reports that even though water volumes remain relatively flat, water-cuts have increased along with flow velocities (increased gas handling is cited) requiring an increase in inhibitor concentration over time. Continuous trials are run seeking to improve inhibitor performance and cost effectiveness.

External Corrosion Management

There are approximately 185,000 weld-packs in the GPB. Slide 4 states the two corrosion related pipeline leaks it experienced in 2000 were due to external corrosion under insulation. Inspections in the year 2000 identified approximately 500 locations (out of 13,274 inspected) where damage increased due to external corrosion under insulation. Figure 3 shows that for the last four years between 4% and 8% of all the locations inspected with TRT yielded external corrosion damage. Table 8 displays the recur frequency for external corrosion under insulation inspections, recur inspection frequencies are assigned by pipeline operating temperature. Pipeline age and wall thickness are also factors that may need to be evaluated in this context.

During 2000, BPXA repaired 28 locations due to external corrosion and only 7 locations due to internal corrosion. External corrosion will require an ongoing commitment of resources by BPXA for the life of the field. The inspection effort appears to be changing the focus from, off-pad cross-country lines to the on-pad weld packs. In 2000, BPXA inspected 7,632 on-pad weld-packs and 5,642 off-pad weld-packs for external corrosion. However, there were 20,420 (~50%

more) inspections for internal corrosion. External corrosion inspection levels do not seem to be consistent with the current relative risk of an internal vs. external corrosion event. The need for additional resources for external corrosion management should be re-examined.

While it is difficult to be exact, it appears there have been inspections on ~70,000 weld-packs, or 38% of the total (185,000) and ~5% show external pipe wall damage detected. Of the 500 locations found in 2000, there were 28 repairs, or ~5% of damaged locations. If the same percentages are applied to the remaining population there are approximately 5,700 weld–packs with potential pipe wall damage and almost 300 potential repairs to be made.

There are 1,800 below grade, cased piping segments in 350 crossings. Below grade piping is affected by both of the internal and external corrosion mechanisms reported above. Since the below grade locations are cased and buried, excavation of the location or inline inspection (not available on every pipeline) are the only certain methods of defect assessment at this time. Currently, two techniques (electromagnetic pulse and guided wave) are being investigated that allow a degree of defect detection without requiring excavation. During 2000, 200 to 300 below-grade segments were inspected and there were 3 segments either replaced or repaired. The overall total number of inspected segments to date was not reported. Extrapolating the 2000 results to the entire population, there may be several areas that could require repair.

RECOMMENDATIONS:

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

1. It would be beneficial if results reported by BPXA to ADEC were presented in a format using metrics that are mutually agreed upon by PAI, BPXA and ADEC.
2. Inspection and monitoring data quality would benefit from being reported using a consistent definition of each service category. For example, when coupon monitoring results for produced water injection wells are reported, it would be useful to see a summary of inspection results for the same service category (i.e. produced water injection wells). BPXA did report inspection results for well lines by service category, but it is not always apparent that the service category definition used for monitoring results is the same as that used for inspection.
3. If smart pig runs were made on non-common carrier pipelines, inclusion of the results would be useful. Table 3 indicates smart pigs were run on non-common carrier pipelines in the GPB but no results were presented.
4. A discussion of details pertaining to how coupons are analyzed and ranked would be beneficial.
5. A summary leak/repair history for a five year period would be useful. Include service category, internal/external corrosion, and physical pipe information (diameter, wall thickness, and years in service).
6. In addition to the field-wide average inhibitor concentration discussions, provide some case specific examples. For instance, if BPXA has an individual line or

gathering system that requires significantly more (or less) inhibitor than the field wide average, it would beneficial to report these exceptions.

7. If maintenance pigging is a part of the corrosion mitigation effort, then discussing the pigging intervals and program details for various service categories would be useful.
8. BPXA reports no current structural issues or concerns in the 2000 report. Other operators on the North Slope report subsidence and jacking issues in areas affected by permafrost thawing around well bores. BPXA's experience in this regard would be beneficial.

CONCLUSIONS

The BPXA report and presentation demonstrates a proactive commitment to mitigate corrosion of non-common carrier pipelines, and were a positive step towards meeting the expectations outlined in the Commitment to Corrosion Monitoring plan. BPXA and ADEC have committed to better define reporting metrics and definitions for future reports.

Results show that overall pipeline internal corrosion trends have been steadily improving since 1993 and are currently reported to be at the lowest levels in 12 years. However, internal corrosion rates increased slightly in 2000 in some production gathering systems and produced water injection systems. BPXA has taken corrective steps for those systems and hopes to measure improvements in the coming year.

External corrosion is a significant risk to BPXA pipeline integrity. Both leaks reported for 2000 and 2001 were due to external corrosion. Additional resources may be required to achieve the same level of corrosion control as demonstrated for internal corrosion.