# PRUDHOE BAY CORROSION CRISIS, 8/18/06 (FILE 10)

# Technical Analysis of
# BP and ConocoPhillips Annual Corrosion Reports
# by Coffman Engineers for ADEC
# 2000 - 2004

## Charter for Development of the Alaskan North Slope
## Commitment to Corrosion Monitoring
## Section II.A.6

2000-BP

309.3.503

# 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

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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 throughou e 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.

2000-CPA

303.30.50.3

# Corrosion Monitoring of Non-Common Carrier North Slope Pipelines

## Technical Analysis

## Of

## Phillips Alaska Inc. – 2000 Commitment to Corrosion Monitoring for Greater Kuparuk Area & Alpine

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## EXECUTIVE SUMMARY

Coffman Engineers, Inc. has been charged with reviewing the corrosion program report submitted by Phillips Alaska Incorporated (PAI) to the Alaska Department of Environmental Conservation (ADEC). The report outlines the measures undertaken to mitigate corrosion in PAI's non-common carrier North Slope pipelines. In addition, Coffman reviewed the presentation materials from the April 2000 Meet & Confer session. The goal of this review is to examine the corrosion program report, gain a qualitative understanding of PAI's corrosion control program, and identify initial recommendations for improvement to the content and extent of topics covered.

PAI has demonstrated a clear commitment to corrosion control, and has developed a robust monitoring and inspection capability. Internal corrosion in cross-country lines indicates a clear degree of corrosion inhibition: no leaks and only one save in the last three years were reported. Chemical inhibition has reduced the leak/save frequency; corrosion damage increases have been almost eliminated in the cross-country gathering lines through corrosion inhibitor injection.

While results are currently good, PAI will have to remain vigilant, as coupon pitting corrosion rates in the three-phase cross-country gathering lines and produced water injection lines have recently increased. Increased coupon pitting rates may be signaling potential risks to the future pipeline integrity.

External corrosion at weld-packs (above and below grade) also poses an integrity risk. There has been an average of one leak per year over the past four years (1997-2000) and at least one leak this year due to external corrosion mechanisms. The level of risk requires a consistent inspection effort, and while PAI has maintained this effort, the efficiency (number of weld-packs inspected) has decreased due to piping configuration for on-pad piping. The level of inspection resources for external corrosion of on-pad piping should be re-evaluated to ensure it is commensurate with the corrosion risk.

There was one failure in 2000 attributed to well subsidence, which currently is the only other structural concern for PAI. A mitigation plan has been developed and is being implemented to control further subsidence. The corrosion group will need to continue its close coordination with those tasked with maintaining pipeline structural integrity in order to address the confluence of corrosion and structural concerns.

The PAI report and presentation materials were an initial step towards meeting the expectations outlined in the Commitment to Corrosion Monitoring plan. PAI 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 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 any specific corrosion or pipeline structural issues warranting 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 STRATEGIES

This section outlines the strategy presented in the report and presentation. It is divided into Internal and External corrosion sections. Each section is further divided into monitoring, inspection and mitigation components. The current program status is presented in a subsequent section.

### Internal Corrosion Strategy

The Produced fluid gathering lines have been seeing increased corrosivity over the past several years due to increasing water production, reservoir souring (Hydrogen Sulfide ($H_2S$)), and solids deposition (pgs. 4,5). Most of the field piping follows a trunk-and-lateral design that increases in nominal diameter as it approaches the production facility. Drill site production joins a trunk line through smaller diameter lateral pipelines; therefore several drill-sites contribute to the corrosion environment in downstream piping. Corrosion inhibitor injection is the primary mitigation method employed in the GKU. Maintenance pigging for the removal of solids is not available in the majority of the production gathering system. A telescoping trunk-and-lateral piping design further complicates efforts to retrofit pigging equipment.

*Monitoring*

Corrosion Coupons and Probes are the primary means of monitoring the corrosivity of the environment inside the pipeline. Slides 8 and 9 reports more than 1,100 physical locations are monitored. Coupon and probe data are used to optimize inhibition concentration and to set inspection intervals.

*Inspection*

Radiographic and ultrasonic methods are the primary Non-Destructive Testing (NDT) techniques used to locate corrosion damage and track changes over time (pg. 14). Smart pigging, or inline inspection, as a means of corrosion inspection is not available for three phase production-gathering lines, and it is unclear if it is available for the produced water and seawater cross-country pipelines.

*Mitigation*

Chemical inhibition is PAI's primary means of corrosion mitigation in the production gathering system (slide 6, pg. 16). Since corrosion mitigation through chemical inhibitor injection is the primary corrosion mitigation tool, it is crucial that PAI have the most efficient chemistry available. PAI does not protect on-pad well lines with inhibitor. The stated strategy is to "... conduct surveillance with appropriate NDT..." This strategy is changing or undergoing a trial variation as plans for installing wellhead inhibitor injection on three drill-sites are proceeding forward at this time. The project plan calls for installation of wellhead inhibition on 3-5 drill-sites per year "...until the appropriate level of drill site inhibition has been provided for the drill-sites." PAI's inability to pig solids from the production gathering system places a strong reliance on chemical inhibition and proactive inspection.

## 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 penetrate 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, oxygen corrosion cells can form. Corrosion under insulation is likely to require an ongoing commitment throughout the life of the field.

*Monitoring*

Presently, there are no monitoring techniques used for this corrosion mechanism. This places greater emphasis on the inspection program.

*Inspection*

Inspection methods for corrosion under insulation are radiographic and visual. Tangential radiography (TRT), C-arm fluoroscopy 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 easily ascertained. Beginning in 2003, PAI will begin a program to re-inspect weld-packs that have not been previously refurbished, which is a significant commitment to future inspection levels. In addition, weld-packs that have been refurbished need to be sampled to verify the method is an adequate long-term solution. The weld-pack refurbishment was not characterized as a cure for corrosion-under-insulation, and this mechanism can be expected to be active throughout the rest of the field life.

*Mitigation*

Refurbishment requires the exclusion of oxygen saturated water from contact with the external pipe wall. Draining the weld-pack, refurbishing the seals to eliminate water ingress, coating the pipe, and replacing the saturated insulation is the primary refurbishment method. A more in-depth review of the measures taken in the past by PAI would be necessary before any sort of recommendation could be formulated.

## CORROSION PROGRAM STATUS

### Risk

The Kuparuk Corrosion Strategy (pg. 5) reports one of the specific program strategies is to "Develop specific risk based corrosion mitigation, monitoring, and inspection programs based upon the corrosion mechanism for a given system." The report further states "The risk assessment methodology used to develop the Strategy was based upon a subjective assessment of the consequence of a single failure of the particular type asset," and the last paragraph on page 5 states "The risk assessment conducted did not include consideration of the frequency of the risk occurring. However the likelihood of a failure was taken into account..." This calls into question the way in which the consequences of corrosion are weighed. For example, higher than normal system corrosivity in the injection well lines places more than a single flow-line at risk: the probable consequence of higher than normal pitting rates throughout a produced water injection system is multiple injection flow-line failures. PAI has identified the corrosion mechanism but it is not clear how the risk assessment methodology accounts for the probability (or frequency) of an occurrence. The risk-based methodology outlined would benefit by quantifying the frequency of a potential corrosion event. Using the consequence of a single flow-line failure to allocate assets in a situation where multiple failures are likely, underestimates the potential consequences of a given corrosion control strategy.

### Internal Corrosion Management

Once a corrosion mechanism is postulated and identified, the overall corrosion picture can be analyzed with the goal of predicting where corrosion might occur, i.e. solids deposits drop to the bottom of the pipe in slow moving liquid streams, creating under-deposit corrosion cells that impede or block the corrosion mitigating effects of inhibitor injection. Mitigating the effect of the identified corrosion mechanism becomes more difficult because solids cannot be removed from the production gathering lines. Only produced water injection distribution lines, sea-water injection distribution lines, and the wet-oil lines from CPF-3 to CPF-1/2 are piggable in the KRU. The three-phase production gathering system is not equipped with pigging facilities. PAI does not discuss how solids deposition and flow stagnation are dealt with in three-phase production lines. Reference is made to the fact that new installations in satellite fields have pigging capability in their three-phase production gathering lines. The trunk-and-lateral piping design will allow solids generated by pigging of newer satellite production lines into older gathering systems which are not piggable unless appropriate design controls are employed.

*Monitoring*

Slide 13 shows the results of production well flowline monitoring using coupons. The average corrosion rates are less than one mil per year (mpy or 0.001 in/yr) general corrosion and less than four mpy pitting corrosion. Slide 13 also shows an action level at 3 mpy general corrosion and 10 mpy pitting and the statement on the slide cautions that inspection shows that actual pipe wall losses are higher. Slides 17 and 18 discuss inspection results for well flowlines. Slide 18 summarizes the inspection efforts for all well lines for the past seven years but does not differentiate between injector and producer wells. Slide 17 does state that 8 injectors and 10 producers required repair in 2000. It would be helpful to be able to link the monitoring results for a particular service category (i.e. production well flowlines) to the inspection results for that particular category.

Coupon pitting rates are higher, down stream in the gathering lines, than upstream in the well flowlines. One possible explanation for this result is the coupon locations at the well head and the cross-country lines are not exposed to a similar environment. The well head coupons are located generally in small diameter, vertical riser pipe while the larger diameter cross-country lines have coupon locations at the six o'clock position in horizontal pipe runs.

A coupon in a vertical position on a relatively small diameter line sees a much different pipeline environment even though it is exposed to the same fluids as solids have no place to accumulate and liquid/gas velocities can be much higher. In horizontal six o'clock positions, the coupon access fitting length can be adjusted and when it is sufficiently short the lower end of the coupon is recessed into the access fitting. This type of coupon/access fitting set-up creates a small stagnant environment at the base of the coupon where solids and microbes have the opportunity to work on the coupon. Accurate evaluation of coupon results requires understanding the coupon location and the internal hydraulic environment surrounding the coupon in question. It is not clear how PAI values these results and what steps are necessary to mitigate the increased coupon pitting rates. .

*Inspection*

Successful corrosion control for the cross-country injection pipelines is credited to mechanical pigging efforts and corrosion inhibitor carry-over in these pipelines. While inhibitor carryover can be a benefit, it is hard to quantify. Residual concentration levels are difficult to monitor and therefore, not reported. Inspection results for this service category cannot be related to the monitoring results because slide 12 and slide 20 use different service category definitions.

Slide 20 (Inspection: internal corrosion in cross-country lines) indicates a clear degree of corrosion inhibition: no leaks and only one save in the last three years reported. Chemical inhibition has reduced the leak/save frequency; corrosion damage increases have been almost eliminated in the cross-country gathering lines through corrosion inhibitor injection. The concern in these systems is the increase in pitting corrosion noted by coupons for the last three years. No explanation of the increase in pitting seen on slide 10 is reported. In addition, the cross-country injection piping average coupon rates have exceeded the 10 mpy pitting rate action level in 12 of the last 16 years (slide 12). The inspection strategy has, appropriately, driven increases in the number of inspections as the risk of a corrosion event increased. Slide 20 clearly shows the inhibition strategy can be an effective corrosion mitigation tool. An average bulk fluid inhibitor concentration of 100 ppm (pg. 16) is reported.

Slide 18 (Inspection: internal well line) shows an increase in the number of "saves" occurring in well line piping as well as a steady increase in RT footage inspected. Eight injectors and ten producers required repair in 2000. The corrosion mechanisms vary from producer to injector and many of the well lines see service as producers or injectors. No chemical inhibition occurs at this stage in the gathering system. Any decrease in the leak frequency is due to inspection efforts catching a defect before it de-rates the line pressure or causes a leak. PAI is managing corrosion damage in this untreated piping through inspection. Previously, only minor efforts were being made to inhibit well lines, but this is changing; well-head injection is being evaluated. The inspection program seems to have reacted to early input (monitoring and inspection data) and increased the number of inspections on this category of asset.

An additional concern is the difficulty of inspecting produced water injection piping with diameters larger than ten inches. Larger diameter (>10"), water packed piping is radio-opaque and makes it impossible to pick out defects on the pipe wall. An explanation of the ability to detect defects in larger diameter, water packed pipelines should be provided.

*Mitigation*

As stated earlier, chemical inhibition is the primary means of fighting corrosion in their cross-country gathering lines. However, there are other service categories that do not appear to be protected by chemical inhibition (i.e. well flow lines). PAI operates a vigorous program of inhibitor development (slide 15), which has significant vendor; academic, and corporate research components. A testing protocol is employed and the results are statistically validated. A corrosion inhibitor feedback system is used to determine when, where, and how much corrosion inhibitor is used (see slide 9). An average bulk fluid inhibitor concentration of 100 ppm (pg. 16) is reported.

Inhibitor injection concentration compliance may be an issue. While the target inhibitor concentration ranges within 90-105% range of the recommended concentration, the report does not state the degree of compliance actually attained. The pitting rate in slide 10 depicts an increasing coupon pitting rate that could be signaling the onset of increased pipe wall damage.

Residual inhibitor carry-over is credited with some level of mitigation in the PW injection system. Obtaining residual inhibitor concentration in the produced water system is a difficult task; however there may be other methods available such as a correlation between upstream concentration and downstream coupon corrosion rates. Slide 12 and 14 show that the PW injection distribution system coupon corrosion rates do not demonstrate the same level of corrosion control as the three-phase gathering lines upstream of the CPF (see slide 10).

Wellhead chemical inhibitor injection should lower the leak/save numbers as is seen in the treated cross-country gathering line rates on slide 20. Going to wellhead injection will increase the number of injection locations and allow for a degree of redundancy that PAI does not currently benefit from.

Internal coupon pitting corrosion rates in the three-phase cross-country gathering lines and produced water injection lines have increased. Increased coupon pitting rates may be signaling an increasing risk to the future pipeline integrity; however current inspection data shows no problems. Coupon monitoring for three-phase common lines and produced water injection flowlines is showing an increasing corrosivity trend for the last three years (slides 10 and 14). The coupon pitting rates in the injection flowlines are at their highest level for the period beginning in 1985.

Slide 12 reports the monitoring results for the produced water cross-country distribution lines; current corrosion levels are in excess of both historic minimums and overall average. Slide 12 shows pitting rates varying from less than 5 mpy to approximately 35 mpy in an apparently random fashion. The corrosivity is not under the same degree of control as that seen in lines that are directly treated with corrosion inhibitor (slide 10 for example). In addition, the slide states the corrosion activity is localized in stagnant, un-piggable section. Coupon corrosion rates in the cross-country common lines have responded favorably in the past to changes in corrosion inhibitor chemistry and concentration. Direct injection of corrosion inhibitor into the produced water injection system may be necessary to gain the same degree of control as that seen in the cross-country gathering system pipelines.

## External Corrosion Management

There are more than 101,000 weld-pack locations; ~67,000 on off-pad, cross-country pipelines and ~34,000 on on-pad pipelines. Since these pipelines are not smart-piggable, all of these locations must be manually examined with visual and radiographic techniques. PAI began the examination of all off-pad weld-packs in 1997-98, and reports being "99+ % complete" (pg. 24). To date, 75% of all the weld-packs have been inspected and 3,963 (~6%) weld-packs have required refurbishment.

Damaged weld-packs are refurbished, but the report does not detail how effective the method is against the recurrence of corrosion under insulation. Beginning in 2003, PAI will begin a program to re-inspect weld-packs that have not been previously refurbished (five years after the initial inspection). This activity will likely remain necessary through the end-of-field life.

During 1997-1999, roughly 70,000 weld-packs were TRT'd, while the plan for 2001 called for inspection of roughly 6,000 weld-packs, which represent ~25% of the remaining weld-packs. While there appears to be a reduction in this inspection program for 2000 and 2001, the level of effort remains fairly constant. The reduction in number of inspected weld-packs can be attributed to lower efficiencies for on-pad piping versus off-pad piping. This is due to the relatively complex piping configurations for on-pad piping compared to the long, straight runs of piping off-pad. Inspection of the remaining 34,400 weld-packs is proceeding on a risk-ranked basis and scheduled to be completed by YE2005.

Using the information provided, 1.9% (~1,280) had corrosion damage and 0.06% (43) weld-packs required sleeves. Applying these same percentages to the remaining population of 34,400 yields a possible 650 additional weld-packs with damage and a possible 20 weld-packs requiring sleeves.

A time-release inhibitor spike is also being tested but there are no results reported for this technique yet.

*Below Grade Piping*

The inspection of 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 is the only certain method 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. PAI plans to inspect 100 locations using these techniques in 2001 in an effort to refine them. The report stated that the results of the below-grade-piping program were reported in an earlier communication, which was not evaluated by Coffman. In the future, the results of the BGPP will be combined with the annual reports.

## Structural Concerns

Subsidence - Subsidence is the only other structural concern for PAI, and one failure was reported in 2000 (2M-01) due to this concern. Piping support subsidence places additional strain on piping (which may already be weakened through corrosion). As a well is used, hot fluids and gases are circulated in and out of the ground, a thaw bulb grows around the well, the piping supports resting on or buried in the soil begin to sink into the wet ground, giving rise to what is seen in slide 30. Pipe in this condition will have higher stresses than originally planned for in the design. Incidental loads on the piping due to snow cover will also increase the stress in these areas. Placing thermal siphons behind each wellhead is an attempt to keep the permafrost intact and eliminate the subsidence of pipe supports. No results for this subsidence mitigation strategy were reported.

# RECOMMENDATIONS

Recommendations for future reports are as follows:

1. In the future it would be helpful if results reported by PAI to ADEC were presented in a format using metrics which 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 injection wells are reported in slide 14 (injection well coupon monitoring) it would be nice to see a summary of inspection results for the same service category (i.e. injection wells). While PAI reports inspection results for well lines, both injectors and producers are lumped together, making any comparison of monitoring to inspection results problematic.
3. Provide details describing the resolution of inspection methods used to report internal corrosion in water-packed pipelines (especially in diameters in excess of 10").

4. A summary of actual corrosion inhibitor injection concentration over time would be helpful. A highlight of any lines which are exceptions would be beneficial (i.e., is there a line which requires significantly more or less inhibitor than the others, and why?).
5. A summary quantifying the degree of inhibitor injection compliance over time would be useful.
6. 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).
7. A discussion of details pertaining to how coupons are analyzed and ranked would be beneficial.
8. A discussion of the basis for the coupon action levels (3 mpy weight loss and 10 mpy pitting) would be beneficial.
9. A summary in the next report, identifying any significant structural concerns impacting non-common-carrier pipelines would be beneficial. If a historical look at leaks/repairs due to structural reasons were available it would place PAI's current efforts into a useful context.

## CONCLUSIONS

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

Produced fluid corrosivity is increasing and the average corrosion inhibition concentration is 100 ppm. Corrosion inhibitor injection has been proven effective so far in the three-phase gathering system and may remain effective until water-cut or pipeline hydraulic factors change. Solid sedimentation and transport coupled with microbial induced corrosion under deposits may become an issue in the three-phase gathering system, as this system is currently un-piggable. While results are currently good, PAI will have to remain vigilant, as coupon pitting corrosion rates in the three-phase cross-country gathering lines and produced water injection lines have been on the increase. Increased coupon pitting rates may be signaling potential risks to the future pipeline integrity.

The inhibitor program is mitigating corrosion damage and where damage is ongoing, inspection is used to manage the defect until it requires repair. PAI may be over-reliant on the inspection component of its mitigation strategy to prevent leaks. The inspection component has significantly increased the footage examined by radiographic methods compared previous years; this is a significant commitment in resources. The lack of pigging facilities in KRU's older, three-phase production systems is a big driver for this man-power requirement. A line that is piggable could use smart-pigs to evaluate 100% of the internal and external pipeline. PAI is installing pigging facilities in newer satellite developments.

One leak due to internal corrosion in a producing well line (1G-08) was reported for 2000. Of the approximately 6,800 RT and UT inspections for internal corrosion on well lines, 115 increases and 18 repairs were noted. This is significantly more than the inspection results for cross country piping which had ~2,000 inspections with only 13 increases and no repairs. PAI has recently undertaken steps to provide corrosion inhibitor injection on selected wellhead locations.

External corrosion under insulation will remain a risk factor in the future. The effectiveness of the weld-pack refurbishment is unknown and the re-inspection of a sample of refurbished weld-packs will allow PAI to adjust its inspection interval. As stated in the report, on-pad piping has not received the same attention as off-pad piping (the consequence of an off-pad failure was deemed greater than an on-pad failure). PAI should consider additional resources aimed at finishing the initial inspection of the weld-packs ahead of the 2005 schedule.

Below grade piping poses a leak risk. No reliable means of assessing defects in below grade pipeline segments has been validated as yet, but efforts are moving forward.

PAI reportedly has no structural issues beyond well piping support subsidence. A mitigation plan has been developed and is being implemented to control further subsidence. Pipeline sagging due to support member frost-jacking, subsidence, and snow loading of pipelines already at risk due to pipe-wall thinning are concerns that would benefit from discussion in future reports.

2001-BP

# Corrosion Monitoring of Non-Common Carrier North Slope Pipelines

## Technical Analysis

## Of

## BP Exploration (Alaska) Inc. – Commitment to Corrosion Monitoring Year 2001 for Greater Prudhoe Bay, Endicott, Badami and Milne Point

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# EXECUTIVE SUMMARY

Coffman Engineers, Inc. has been charged with reviewing the 2001 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 October 2001 and April 2002 Meet & Confer sessions. BPXA and ADEC mutually agreed to a performance metric guide prior to drafting the 2001 report. The results are a much improved report that better defines the service categories and basic summary statistics.

The 2001 report contain more detail and is wider in scope than the 2000 Report and covers corrosion management strategy and objectives. BPXA has done a good job in further clarifying how it uses raw corrosion data to focus its inspection and inhibition programs. However, in some cases, the facility piping population was included with the non-common carrier piping population. While the facility piping information is useful, it makes an analysis of the non-common carrier piping difficult to perform.

Internal corrosion control in oil flow lines is clearly indicated by coupons and inspections, with average corrosion rates approaching the historical minimum. Produced water flow lines had a slight increase in the corrosion rates compared to 2000. A specific corrosion inhibitor test program was implemented for the produced water system and will continue in 2002. There were two flow lines inspected using an inline inspection tool. There were 11,369 inspections, six saves and one leak for flow lines during 2001.

Internal corrosion control in oil well lines is clearly indicated by coupons and inspections, with average corrosion rates approaching the historic minimum. Coupons for produced water well lines indicate an increase in corrosion rates, but a corrosion inhibitor program specifically aimed at the produced water system is under development. Coupons for the seawater injection well lines indicate an increase in corrosion rates, almost doubling since 1999. The cause has been identified and remedial actions were taken in 2001, results will be available during 2002. There were 9,780 inspections in 2001, substantially more than previous years. There were five saves and one leak for well lines in 2001.

Presently, external corrosion is a significant risk for pipeline repairs and/or leaks for BPXA. External corrosion under insulation was reported as the cause for 28 repairs and two leaks in 2000 and 17 repairs and two leaks in 2001. The percent corroded remained consistent with the past 3-year average (~5%). Overall, the weld-pack inspection program is ~40% complete, with ~120,000 weld-packs remaining. Plans are to more than double the number of weld-pack inspections for 2002. Below grade piping baseline program is on schedule for completion in 2003 with roughly 60% completed through 2001. There were no excavations in 2001.

The ACT corrosion programs continue to evolve in 2001. Endicott is unique given the use of duplex stainless steels in the production system. The main concern here is the inter-island water pipeline (IIWL). Corrosion control for the IIWL uses a combination of maintenance pigging, biociding, and inhibition. Inspection of the IIWL indicates little corrosion activity. Milne Point is unique given the amount of buried piping associated with this field. There have been 60 excavations of buried piping over the past two years with some locations showing corrosion.

The water injection system coupons have exceeded the 2 mpy corrosion rate until 2001. This is a result of a specific inhibition program started in 2000. Northstar and Badami are relatively new fields and have limited data, which shows no corrosion.

# CORROSION PROGRAM STATUS – GREATER PRUDHOE BAY

## Internal Corrosion Management

### *Monitoring & Inspection – General*

Coupon monitoring activity levels have remained relatively flat from 1995 to the present. BPXA continuously updates its program in an ongoing effort to optimize the coupon program to deliver "maximum corrosion management information". Overall, the coupon results for the current reporting period are very encouraging. BPXA states that the "The reduction by a factor of 10 (of coupon corrosion rates) over the last 10 years is a direct result of an aggressive corrosion mitigation program…" Clearly the inhibition program is making advances in corrosion mitigation.

BPXA presents the total number of inspections for GPB as ~60,000 per year since 1995. The total number of inspections actually increased in 2001 to ~61,000, reversing a 3-year trend of lower inspection numbers (Figure B.4). The 2001 total includes ~40,000 inspections which are performed on the facilities (not non-common carrier piping) and considered outside the scope of the Charter. This information is useful as it lends context to the inspection program, but one must be careful when trying to analyze the aggregate information. It is interesting to note the shift from a 50/50 split to a 66/33 split between facilities and field piping in the past two years. This change in emphasis is due to BPXA asserting corrosion control on field piping is adequately addressed. Lastly, within the field piping category the ratio of flow line (cross-country) inspections to well-line inspections has changed from a 70/30 to 55/45.

Percent inspection increases is a useful metric for quantifying the gross effort expended, but it is function of the number of re-inspected locations. According to Table B.8(c), the target is zero increases. It is not clear if the number of re-inspected locations is a statistical sample of known damaged locations, a fixed number of locations, or based on some other criteria.

Several graphs were included to demonstrate the effectiveness over time of the inhibition program using inspection increases and pipe condition for three phase oil lines (flow and well). The major effort is now on fine tuning the system to maintain or increase the current level of corrosion control for the piping.

### *Monitoring & Inspection – Cross Country (Flow) Pipelines*

Coupon monitoring for "oil" system indicates the average corrosion rate in cross-country flowlines is at or near its historical minimum. The number of coupons at or below the 2 mpy threshold set by BPX for conformance is approaching the 100% mark.

Coupon monitoring in produced water system shows a slight increase in corrosion rate as well as pitting rate when compared to 2000, however both levels are below their respective targets.. In general, an increase in corrosion inhibitor in the 3-phase system shows some carryover benefit to the produced water system. BPXA has been testing corrosion inhibitors for this system, and two successful candidates were identified in 2001 and the program will continue in 2002.

Coupon monitoring for the seawater injection system shows no data for 2001 (Table 5.1 and 5.2). It should be noted there were only two coupons in 2000, so the lack of data is not a significant issue.

There were 11,369 inspections of flow lines during 2001, >9,000 for oil and >1,400 for water. The percent inspection increases for re-inspected water and oil flow lines increased slightly from 2000, but compared to the overall average they are lower. There were six saves (two oil, one water, three processed oil) and one leak in 2001. The three repairs for processed oil occurred are associated with a dead-leg which is scheduled to be removed in 2002.

Two produced water lines (M-69 and S-69) were inspected with an inline inspection tool (smart pig). With the exception of stating follow-up manual inspections to "proof" the tool were performed, no results are discussed.

### *Monitoring & Inspection – Well Lines*

Coupons monitoring corrosion in oil production service show a significant reduction in corrosion rates with a step reduction in the average corrosion rate in 1997 (figure C.3). In 2001 93% of all coupons in this service category were below the 2 mpy conformance threshold. This is also a slight improvement over 2000 results. Conformance levels in the 99% range should be possible given the corrosion mitigation performance in cross-country lines.

Coupon monitoring in produced water system show a 6-year high in corrosion rate as well as an increase in pitting rate from 2000. The previously described inhibitor testing program will hopefully have a beneficial effect for this service.

Coupon monitoring in seawater injection system stands out in this report because of the increasing corrosion rate trend illustrated by Figure C.5. Pitting and weight loss rates in this service category have almost doubled since 1999. The primary factors responsible for this increase are cited as dissolved oxygen levels and microbial corrosion. BPXA is vigorously moving ahead with a program to reverse this corrosion trend in. Dissolved oxygen targets have been set to "<20 ppb", dissolved oxygen metering is being improved, vacuum tower performance is being upgraded through the use of an anti-foaming compound, a new oxygen scavenger catalyst is being tested and plant repair and maintenance schedules are being evaluated. Coupon pull frequencies have been shortened in this service category to allow for more frequent monitoring.

There were 9,780 inspections of well lines during 2001, >8,000 for oil and >1,000 for water service categories. This represents the largest number of inspections on well lines for the reported period. Given the number of leaks and number of saves for well lines is greater than that of the flow lines, the balance in emphasis appears to be a positive move. The percent inspection increases for re-inspected well lines decreased slightly, continuing the 4-year downward trend. There were five saves (4 oil and 1 water) and three leaks in 2001 attributed to internal corrosion.

### *Internal Corrosion Mitigation*

BPXA expends considerable effort to develop and test new corrosion inhibitors. A rigorous testing procedure is outlined in the report showing, illustrating how inhibitors transition from the laboratory to field testing. Figure D.4 clearly shows pitting on coupons exposed to production in an unsuccessful corrosion inhibitor trial. Eighteen new products have been developed for use in the continuous well-head injection program since 1995. BPXA is carefully working to consolidate the number of products used field-wide.

$CO_2$ and solids deposition (both mechanisms can produce deep pitting) are cited as the main challenges in produced water systems where most coupon pitting is found. BPXA is moving forward in developing a corrosion mitigation plan specific to produced water, with corrosion inhibitors were tested in 1999 and 2000. Two successful candidates were identified in 2001 and BPXA states that funds were budgeted in 2002 for inhibitor injection.

Optimizing the injected volumes is critical to the economic application of inhibitor chemistry. Table D.6 and D.7 show how the average inhibitor concentration has varied over time. Inhibitor average concentration has risen from 85 ppm in 1995 to 157 ppm in 2001. BPXA is injecting nearly twice the volume it was using only 6 years ago. This increase is delivering measurable results in the systems in which it is being injected; cross-country production piping is nearing 100% corrosion rate conformance. The actual volume of chemical usage was 2.63 million gallons, which is 1.6% over the target amount of 2.59 million gallons. Based on monitoring and inspection data, corrosion inhibitor concentrations were increased (10-20% typical) in 14 pipelines.

## External Corrosion Management

### *Above Grade Piping*

BPXA exceeded their stated external inspection goals in 2001. There were twelve repairs and one leak on off-pad piping; five repairs and one leak on on-pad piping; and presumably more than 800 weld-packs refurbished at locations were corrosion was detected. The percent corroded and percent repaired results in 2001 are consistent with the 1999-2000 average percentages, and likely means there are 100+ repairs to be made on the remaining weld-packs. There were 17 repairs (12 flow lines and 5 well lines) and two leaks (1 flow line and 1 well line) in 2001. Table 1 summarizes the overall weld-pack inspection program status based on information presented for 2001.

**Table 1 – GPB Above grade, non common carrier pipeline weld-pack inspection status**

| Service | Total Number (approx.) | Number Inspected During 2001 | Number Inspected thru YE2001 | % Inspected thru YE2001 | Number Remaining (approx.) | 2002 Forecast |
|---|---|---|---|---|---|---|
| X-Country/Flow Line – Off-pad | | 2,675 | 57,263 | | | |
| Well Lines – On-pad | | 12,730 | 22,688 | | | |
| **Totals** | **200,000** | **15,405** | **79,951** | **40%** | **120,049** | **35,000** |

The 2000 Report states there are ~185,000 weld-packs while the 2001 Report states there are ~300,000 weld-packs. The increase can be attributed to combination of weld-packs on non-common carrier piping and facility piping. The status of piping associated with facilities is a bonus, but beyond the scope of the Charter. Furthermore, reporting only the combined population makes an assessment of non-common carrier pipeline status difficult.

BPXA has committed to accelerating its weld-pack inspection program through the addition of more resources, more than doubling the number of weld-packs (35,000 versus 13,000 avg.) to be inspected in 2002. It is unclear what percentage of the inspections is planned for non-common carrier pipelines versus facility piping.

### *Below Grade Piping*

BPXA exceeded their stated below grade inspection goals in 2001, inspecting ~280 locations using a combination of electromagnetic pulse and guided wave technologies. BPXA is 60% complete with the inspection of a combined total of 460 cased crossings by YE2001. They are on track to complete the remainder by YE2003. Additionally all cased crossings are visually inspected to ensure they are clear of debris and if found, they are cleaned out.

There were two "moderate" and zero "severe" anomalies and no excavations performed during 2001.

## Structural Concerns

There were no leaks due to structural issues in 2001. The process for identifying and repairing other structural issues was presented in the report.

# CORROSION PROGRAM STATUS – ALASKA CONSOLIDATED TEAM

## General

The ACT corrosion programs status continues to evolve in 2001. The level of effort applied to the satellite field corrosion programs varies between them. New piping and facilities are expected not to need as much attention as decades old, fully mature, fields, consequently BPXA has not taken its fully mature GPB corrosion program and duplicated it in these smaller fields.

Monitoring and inspection should be conducted in a proactive manner that will discover new and different corrosion mechanisms before they become a serious problem.

## Endicott

Endicott "is a mature waterflood field," and the production fluid is characterized as "high temperature and high $CO_2$." The production system was constructed mostly of Duplex Stainless Steel (DSS), which is a corrosion resistant alloy that combines good weldability, strength, and toughness. It is highly resistant to $CO_2$ corrosion. Problems can occur in Duplex installations when chlorides are present or when microbial induced corrosion (MIC) takes hold. Solids deposition in stagnant internal areas and contact with stagnating brines can induce isolated pitting corrosion in this alloy. The presence of solids and microbes in the injection water may point to future challenges for the DSS piping

Coupon data indicates the production system corrosion rate remains above the 2 mpy threshold however BPXA states this is not a concern for the piping since it is fabricated mostly from DSS. Since the piping is corrosion resistant Endicott could benefit from a corrosion program targeted at solids removal and microbial control. Coupon data also indicates the water system corrosion control program is effective.

The primary corrosion concern at Endicott is the inter-island-water-line (IIWL). It is assumed that the IIWL line is carbon steel because BPXA is pigging, biociding, and inhibiting the water in the IIWL. UT Inspection results (fig. D.1) for the IIWL are good. While the number of inspection increases in the IIWL is down overall since 1998; there was a slight increase in 2001. The IIWL line was inspected using and inline inspection tool in 1995, there was no discussion of results or if another inline inspection is planned.

Table E.1 lists the cased piping external inspections performed at Endicott. Some external corrosion has been detected. The oil line inspection interval is characterized as "N/A Duplex Stainless Steel". Depending on the chloride concentrations in the ground water and ingress through weld-packs, a full baseline inspection should be made and a reasonable re-inspection interval set.

DSS is not corrosion proof, just corrosion resistant. BPX may need to reassess its surveillance philosophy in systems fabricated from DSS. BPX does not mention which DSS alloy is used in Endicott's construction. BPX provided a table (table B.1. pg 99) which lists line lengths and the number of internal and external inspections. Pitting and microbial corrosion are threats to the DSS system, some discussion of how these mechanisms progress in DSS installations and how they are controlled (pigging/biociding/solids mitigation) would be useful in the next reporting cycle.

## Milne Point

Milne Point fluids are characterized by low $CO_2$, low operating temperature and low velocities. Corrosion under insulation and internal under-deposit corrosion mechanisms are mentioned and are consistent with the stated operating conditions. There were no leaks or repairs during 2001. Coupon data indicate very good mitigation with the single exception of the water injection system. Coupon rates in the water injection system exceeded the 2 mpy threshold until 2001. In mid-2000 corrosion inhibitor injection was begun in the water injection system and the initial results appear to be encouraging.

It is stated that Milne Point internal inspection history has been "variable" and that in 1998 a policy change was made to rectify this situation stating "a concerted effort was made towards obtaining a more consistent inspection survey". Internal under-deposit corrosion was found in the K-pad line and an inhibitor injection was begun. It is too early to determine the inhibitor effectiveness at this time. F-pad production flow line was inspected using an inline inspection tool, with the follow-up to occur in 2002.

Table E.2 shows the number of external inspections decreased from a high of 205 in 2000 to 179 in 2001. The percent inspection increases for re-inspected locations is 27% avg. for the last two years, which is well in excess of the GPB field average. Buried pipe is also an issue in the MPU since many of the gathering lines and product distribution lines are buried along the roadway. Excavations were made at 30 locations in 2001 looking for external corrosion; nineteen were new locations, eight were recurring inspections with no increases and three locations showed "slight increases". Excavations were also made at 30 locations in 2000 but results were not discussed.

### Northstar

Northstar began production in late 2001 and consequently has very limited data. Fluid corrosivity is expected to moderate initially but will increase with the injection of Prudhoe Bay Gas. There are corrosion monitoring locations installed and data will be reported in the future. Presently, well production lines are treated with low concentrations of continuously injected corrosion inhibitor. No Internal and external inspection data were presented, presumably data were not collected.

### Badami

Badami started in 1998 and fluid corrosivity is considered low due to the small volumes of water and low $CO_2$ content. There is no corrosion inhibition or corrosion monitoring (coupon) program in place. Corrosion control is monitored through the use of a small inspection program. While no external weld-packs have been inspected to date, the pipe condition is observed in conjunction with internal inspections. Internal inspections have shown no corrosion.

## RECOMMENDATIONS

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

1. Total number/population of well lines, cross country lines, weld packs, below grade pipe segments would be beneficial. In addition, the number of baseline inspections and related percentages for the weld-pack and below grade piping programs would be beneficial to track overall progress during the multi-year effort. These data could be presented as a cumulative graph or in a tabular format.

2. If facility piping is to be included in future reports, an individual breakdown and presentation of the facility piping and non-common carrier piping data sets will aid future analysis of items related to the Charter.
3. In order to gain a better understanding of the operating conditions for the various pipelines, a histogram depicting the number of pipelines in each service within different %SMYS categories would be beneficial. Suggested %SMYS categories are: <10%, 10-20%, 20-30%, and >30%.
4. Provide an explanation/procedure used for selecting location for re-inspection as well as how the results are used.
5. Provide more details on the inspection techniques for large diameter (>8") cross-country water injection piping.
6. When smart pig runs were made on non-common carrier pipelines, inclusion of the results would be useful. The report indicates smart pigs were run on non-common carrier pipelines in the GPB and ACT but no results were presented. Include discussion regarding inspection intervals.
7. Pitting and microbial corrosion can be threats to the DSS system, some discussion of how these mechanisms progress in DSS installations and how they are controlled (pigging or biociding?) at Endicott would be beneficial.
8. Milne Point information regarding the results of the ongoing excavation program such as how locations are picked, leak/save data, results from previous excavations.

## CONCLUSIONS

BPXA continues its thorough and aggressive corrosion control program. The 2001 Report contains more detail and is wider in scope than the 2000 Report. BPXA has consolidated/integrated the corrosion programs for GPB and will focus on optimization and continuous improvement of the program in 2002. Integration of "heritage" databases into on database (MIMIR) continues and will improve the ability to obtain and analyze data in a timely fashion.

Internal corrosion in cross-country gathering lines and oil well lines is clearly being controlled. The coupon monitoring in the seawater injection system stands out in the report because of the increasing corrosion rate trend. BPXAs planned steps to improve operations in the seawater treatment plant should reverse this negative trend for 2002. An inhibitor project aimed specifically at produced water system will continue development in 2002.

Presently, external corrosion remains a significant risk for pipeline repairs and/or leaks for BPXA. The weld-pack baseline inspection program is ~40% complete and the goal for 2002 is ~35,000 weld-pack inspection, more than double previous years effort. The below grade piping inspection program is 60% complete and on track for completion in 2003.

The corrosion programs for the ACT fields (Endicott, MPU, Badami, and Northstar) would benefit from a more consistent application of the programs developed in the GPB. Inspection and monitoring in the ACT need to be conducted in a consistent manner that will discover new and different corrosion mechanisms before they become a serious problem.

BPXA is making continual improvements to it many corrosion mitigation operations and if implemented for 2002 the next report should show reverses in the few negative corrosion trends.

2001-CPA

# Corrosion Monitoring of Non-Common Carrier North Slope Pipelines

## Technical Analysis

## Of

## Phillips Alaska Inc. – 2001 Commitment to Corrosion Monitoring for Greater Kuparuk Area & Alpine


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# EXECUTIVE SUMMARY

Coffman Engineers, Inc. has been charged with reviewing the 2001 corrosion program report submitted by Phillips Alaska Incorporated (PAI) to the Alaska Department of Environmental Conservation (ADEC). The report outlines the measures undertaken to mitigate corrosion in PAI's non-common carrier North Slope pipelines. In addition, Coffman reviewed the presentation materials from the October 2001 and April 2002 Meet & Confer sessions. PAI and ADEC mutually agreed to a performance metric guide prior to drafting the 2001 report. The results are a much improved report that better defines the service categories and basic summary statistics.

Internal corrosion in cross-country lines indicates a clear degree of corrosion inhibition: no leaks and no saves were reported in 2001. Corrosion control, primarily inhibitor injection, has maintained the low leak/save frequency; corrosion damage increases have been almost eliminated in the cross-country gathering lines through corrosion control. However, coupon pitting rates for three phase and water injection pipelines have seen relatively steady increases since 1998. While the rates are still below the target limits, PAI changed inhibitors late in 2001 in an effort to reverse this trend. In addition, the number of locations with corrosion damage increases (UT and RT) has increased compared to 2000, 35 versus 13.

Internal corrosion in well lines is an area that requires PAI's continued focus, no leaks and 24 saves (repairs) were reported in 2001. The number of saves has increased over the past three years, albeit at slower rate than the amount of pipe inspected. This suggests PAI could be approaching the "top of the curve" for internal well line corrosion control. The number of locations with corrosion damage increases (UT and RT) has also increased compared to 2000, 163 versus 115.

External corrosion at weld-packs (above and below grade) continues to pose an integrity risk. There has been an average of one leak per year over the past five years (1997-2001) due to external corrosion mechanisms. A baseline inspection of all weld-packs on off-pad, cross country pipelines was completed in 2001. Baseline inspection of on-pad weld-packs (well and cross country lines) is progressing ahead of schedule and average percent of corroded weld-packs has dropped slightly to ~2%. There were four repairs and 800+ weld-packs refurbished on above grade piping. One leak in 2001 (1HBWI) occurred on below grade piping at a weld-pack. PAI has responded by accelerating the screening inspections for below grade piping during 2001 and plans to continue at an accelerated rate in 2002. Nine below grade locations were excavated and two locations required repair; one location was sleeved and the other location was on piping that was, and has remained, out of service.

There was one failure in 2001 attributed to wind induced vibration (WIV) coupled with a potential weld anomaly. An evaluation of the design envelope is underway to ensure it is still valid. Another structural concern is well subsidence. The well subsidence mitigation plan was being implemented to control further subsidence. The corrosion group will need to continue its close coordination with those tasked with maintaining pipeline structural integrity in order to address the confluence of corrosion and structural concerns.

# CORROSION PROGRAM STATUS

## Internal Corrosion Management

### *Cross Country Pipelines – Monitoring & Inspection*

Internal corrosion in cross-country lines indicates a clear degree of corrosion inhibition: no leaks and no saves were reported in 2001. Corrosion control, primarily inhibitor injection, has maintained the low leak/save frequency; corrosion damage increases have been nearly eliminated in the cross-country gathering lines through corrosion control. However, coupon pitting rates for three phase and water injection pipelines have seen relatively steady increases since 1998. While the rates are still below the target limits, if the trend continues unabated, the average pitting rate will exceed the nominal threshold of 10 mpy. In addition, the total number of locations with corrosion damage increases (UT and RT) has increased compared to 2000, 35 versus 13. PAI responded by changing inhibitors late in 2001 in an effort to reverse this trend.

PAI reports that coupon or probe corrosion rates exceeded threshold targets in 19 lines and they responded by increasing the corrosion inhibitor concentrations for all 19 lines. In addition, inspection showed nine lines with "minor" corrosion where the coupons did not exceed the target corrosion rate. The corrosion inhibitor concentrations for all nine of these lines were also increased. This helps to illustrate and reinforce the importance of both programs.

An ongoing item of concern is the difficulty of inspecting produced water injection piping with diameters larger than eight to ten inches, which is considered radio-opaque and limits the use of radiographic techniques. PAI states they are going to "evaluate the possibility of smart pigging cross-country water injection lines larger than 8" O.D." during 2002. However the report states the corrosion tends to manifest in the un-piggable, stagnant portions of the systems. It is not clear if there are segments that met both criteria (>8" and stagnant flow) and how they will be inspected.

### *Well Lines - Monitoring & Inspection*

Internal corrosion in well lines is an area that requires PAI's continued focus; no leaks and 24 saves (17 injection and 7 production) were reported in 2001. The number of saves has increased over the past three years, albeit at slower rate than the amount of pipe inspected. This suggests PAI could be approaching the "top of the curve" for internal well line corrosion control. PAI will need to reassess its corrosion management situation when new production horizons are brought on line and fed into the existing production gathering system. Corrosion control may be lost due to the addition of new production.

Production well line coupon data indicate very low general and pitting corrosion rates. Injection well line coupon data indicates very low general corrosion rates. Pitting rates for this service are below the action limit; however they are above the historic average and have an increasing trend over the past 5 years.

The number of locations with corrosion damage increases (UT and RT) has also increased compared to 2000, 163 versus 115. 124 increases were in production service and 39 increases were in the injection service. The 2000 data is presented as an aggregate so comparisons between service types are not possible. It is unclear if there are specific targets for repeat inspections using manual RT and UT techniques but the percent repeated for each inspection type and service type vary widely. It is also unclear if there is a target or action limit for the percent increase value.

### *Internal Corrosion Mitigation*

PAI switched to a different corrosion inhibitor (Cortron 2000-25) during 2001, but has plans to return to the previous incumbent (Cortron RU-276) in 2002. Figure 6 depicts the field wide corrosion inhibitor usage, recommended volume, and the % difference between the recommended volume and the actual volume. PAI's compliance with its own corrosion inhibition targets has improved over time; reporting an average deviation of +0.7% for 2001, a slight over-treatment, showing an excellent level of control. Figure 6 also shows a step-like increase in inhibitor volume occurring in the third quarter of 2001.

PAI is continuing to move forward with the wellhead inhibitor injection program, but the program appears to be slipping in schedule. The 2000 Report and April 2001 slides indicated 3-5 drill sites were scheduled for startup in 2001. The November 2001 slides indicated one drill site (1G) would be constructed late 2001 to early 2002. April 2002 slides indicate construction is still planned for 1G and other sites are funded and in the design/procurement stages. As discussed previously, the well lines should benefit greatly from this program.

## External Corrosion Management

### *Above Grade Piping*

PAI exceeded their stated external inspection goals in 2001. During 2001, the baseline inspection for all off-pad weld-packs was completed and all weld-packs found with corrosion have been refurbished. Also during 2001, the baseline inspection for on-pad weld-packs was 48% complete overall and is progressing ahead of PAI's stated 2005 completion schedule.

There were three repairs on off-pad piping, two repairs on on-pad piping and more than 800 weld-packs refurbished. The percent corroded and percent repaired results for 2001 are consistent with the overall average percentages, and likely means there are 5-10 repairs to be made on the remaining ~18,000 weld-packs. Refer to Table 1 for the overall weld-pack program status of the PAI weld-pack inspection program.

In April 2001, PAI stated they were going to test "inhibitor spikes" on 25-50 weld-packs, however little information was provided as to the status of this test program.

In 2003, PAI will begin a prioritized program to re-inspect weld-packs that have not been previously refurbished (five years after the baseline inspection). This activity will likely remain necessary through the end-of-field life.

**Table 1 - Above grade weld-pack inspection status**

| Service | Total Number (approx.) | Number Inspected During 2001 | Number Inspected thru YE2001 | % Inspected thru YE2001 | Number Remaining | 2002 Forecast |
|---|---|---|---|---|---|---|
| X-Country-Off-pad | 67,291 | 292 | 67,291 | 100% | 0 | 0 |
| X-Country-On-pad | 10,400 | 3,919 | 6,344 | 61% | 4,056 | 1,780 |
| Well LinesOn-pad | 24,000 | 5,489 | 10,320 | 43% | 13,680 | 4,000 |
| **Totals** | **101,691** | **9,700** | **83,955** | **83%** | **17,736** | **5,780** |

Note: This table represents an effort to reconcile numbers presented in the 2000 and 2001 PAI reports. There is the possibility for minor discrepancies.

### *Below Grade Piping*

PAI exceeded their stated below grade inspection goals in 2001, inspecting 228 new locations using a combination of electromagnetic pulse and guided wave technologies. One additional screening technology, guided-ultrasonic, was evaluated and deemed "not superior" to the incumbent and will not be used at this time. Additionally all cased crossings are visually inspected to ensure they are clear of debris and if found, they are cleaned out.

One leak in 2001 (1HBWI) occurred on below grade piping at a weld-pack. PAI has responded by accelerating the screening inspections for below grade piping during 2001 and plans to continue at an accelerated rate in 2002. Nine below grade locations were excavated and two locations required repair; one location was sleeved and the other location is on piping that was, and has remained, out of service.

A proper accounting of the total population of below grade piping would lend context to the status of this program. Based on information presented in the 2000 and 2001 reports there appears to be a total population of ~740 below grade locations. Refer to Table 2 for an initial attempt to summarize the status of this program.

**Table 2 - Below Grade Piping Baseline Inspection Status**

| | Total Number (approx.) | Number Inspected During 2001 | Number Inspected thru YE2001 | Number Remaining |
|---|---|---|---|---|
| Oil - Significant | 385 | | | |
| Non Oil - Significant | 210 | | | |
| Oil - Low Risk | 46 | | | |
| Non Oil – Low Risk | 95 | | | |
| **Totals** | **739** | **228** | **438** | **301** |

Note: This table represents an effort to reconcile numbers presented in the 2000 and 2001 PAI reports. There is the possibility for minor discrepancies.

## Structural Concerns

### *Subsidence*

There were no leaks attributed to subsidence in 2001. PAI continues to prioritize and upgrade existing wellhead riser supports and flooring susceptible to subsidence. Thermal siphons are also being installed in near well-bore location to promote re-freezing and stabilization of the soil. PAI has updated its new well construction and water injection conversion requirements to include thermal siphons and riser supports on the well installations.

### *Wind Induced Vibration*

Vibration dampeners are installed on all lines lying within a range of degrees perpendicular to the prevailing wind direction. One failure (DS2X) occurred at a weld on a pipeline orientated 1° outside of the range. Metallurgical analysis is being performed to rule out a weld defect. In response PAI is re-evaluating the design criteria to ensure the envelope is still large enough. Perhaps of greater concern is the identification of one "area" that is within the existing envelope but did not have dampeners installed. While dampeners are planned for installation during 2002, the integrity of pipelines in this "area" should be verified. Information such as age of lines/length of exposure, corrosion history, etc. could be used in a qualitative assessment to ensure there are no anomalies in the susceptible areas of the pipelines.

## RECOMMENDATIONS

Recommendations for future reports are as follows:

1. Total number/population of well lines, cross country lines, weld packs, below grade pipe segments would be beneficial. In addition, the number of baseline inspections and related percentages for the weld-pack and below grade piping programs would be beneficial to track overall progress during the multi-year effort. These data could be presented as a cumulative graph or in a tabular format.
2. A histogram depicting the number of pipelines in each service within different %SMYS categories would be beneficial. Suggested %SMYS categories are: <10%, 10-20%, 20-30%, and >30%.
3. Provide an explanation/procedure used for selecting location for re-inspection as well as how the results are used.
4. Provide more details on the inspection of large diameter (>8") cross-country water injection piping and the results of the proposed smart-pigging evaluation.
5. In addition to the existing data presentation, consider combining the leaks and saves from the BGPP with the External Leaks and Saves data. Presently it appears the 2001 leak is included but the two repairs (saves) are not.
6. Additional information on the number and integrity of lines identified in the WIV envelope without dampeners.

# CONCLUSIONS

PAI continues their vigorous corrosion control program and has met or exceeded all of the stated inspection goals during 2001. The new report format is much improved and easier to comprehend.

Cross-country pipelines inspection data indicates a clear degree of internal corrosion control however the coupon pitting rates have been increasing in recent years and the number of corrosion damage increases also increased over last year. PAI has responded by returning to a previous inhibitor formulation as well as increasing the overall inhibitor concentrations. Lastly, smart-pigging is being investigated for inspection of large diameter Mixed Water cross-country piping.

Well line internal corrosion control appears to be approaching the "top of the curve," but still requires significant effort. The number of corrosion increases and number of saves were greater than the previous year. The schedule for testing wellhead inhibitor injection has slipped; but there should be preliminary results during 2002.

External corrosion control is progressing and all of the off-pad piping baseline inspections are completed. There are still more than 17,000 on-pad weld-packs remaining, and extrapolating the results to date, means there are several areas that will require repair. After the failure (1HBWI), the below grade screening program was accelerated during 2001 and two additional repairs were required.

Improvements were made to the well construction specifications to include floors with permanent pipe supports and thermo-siphons on new wells and retrofits to existing structures. Wind-Induced-Vibration specifications are being evaluated to determine whether or not a change needs to be made in light of the failure (DS2X) in 2001.

Beyond the Mitigation, Monitoring and Inspection goals outlined for 2002, PAI will be performing testing and/or improvements in the following areas:

- Engineered surfactant treatment aimed at removing solids in hard to treat water injection distribution lines.
- Corrosion Inhibitor development/testing
- Kuparuk corrosion database improvements
- Alpine database development
- WIV and well subsidence prioritization/evaluation.

2002-BP

# Corrosion Monitoring of Non-Common Carrier North Slope Pipelines

## Technical Analysis

## Of

## BP Exploration (Alaska) Inc. – Commitment to Corrosion Monitoring Year 2002 for Greater Prudhoe Bay, Endicott, Badami and Milne Point

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# EXECUTIVE SUMMARY

Coffman Engineers, Inc. has been charged with reviewing the 2002 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 October 2002 and April 2003 Meet & Confer sessions. The 2002 report contains similar detail and scope as the 2001 Report and repeats the corrosion management strategy and objectives.

BPXA made a significant improvement to their database related to multiple injection services. This change provides the ability to track well service changes, which is turn provides the ability to determine that impact on the coupon corrosion rates.

Internal corrosion control in oil flow lines is indicated by coupons and inspections, with average corrosion rates approaching the historical minimum. Produced water flow lines had a slight increase in the corrosion rates compared to 2000. There were three produced water flow lines inspected using an inline inspection tool. There were ~12,500 inspections, nine saves and no leaks in flow lines attributed to internal corrosion

Internal corrosion control in oil well lines is clearly indicated by coupons and inspections, with average corrosion rates approaching the historic minimum. Coupons, for produced water well lines, show a decrease in corrosion rates from 2001 due to increased inhibitor carryover from the oil system and supplemental inhibitor specific to this system. Coupons for the seawater injection well lines indicate an increase in corrosion rates. The cause has been identified and remedial actions were taken in 2001, but the effects of these actions have not been fully realized due to operational issues. There were ~12,700 inspections in 2002, substantially more than previous years. In 2002, there were eleven saves and two well line leaks attributed to internal corrosion.

External corrosion continues to be a significant risk for pipeline repairs and/or leaks for BPXA, and they nearly tripled the number of weld-packs inspected to ~43,000 in 2002. External corrosion under insulation was reported as the cause for 57 repairs and two leaks in 2002. Overall, the weld-pack inspection program is ~40% complete, with ~175,000 weld-packs remaining to be inspected. The below grade piping baseline program is on schedule for completion in 2003 with roughly 80% completed through 2002. There were no below grade piping excavations in 2002.

The Alaska Consolidated Team (ACT) corrosion programs continued to evolve in 2002. Endicott is unique given the use of duplex stainless steel in the production system. The primary concern is in the inter-island water pipeline (IIWL) and carbon steel C-spools. Corrosion control for the IIWL uses a combination of maintenance pigging, biocides, and inhibition. Inspection of the IIWL indicates low levels of corrosion activity. Milne Point is unique given the amount of buried piping associated with this field. There have been multiple inspections of buried piping over the past three years with 24% (average) of the locations showing increases in corrosion in addition to new areas with corrosion. The produced water system inspection data also indicates additional work is required to bring corrosion under control. Northstar and Badami are relatively new fields and have limited data, which currently shows no corrosion.

# CORROSION PROGRAM STATUS – GREATER PRUDHOE BAY

## Internal Corrosion Management

### *Monitoring & Inspection – General*

Coupon monitoring activity levels have remained relatively constant from 1995 to the present. BPXA continuously updates its program in an ongoing effort to optimize the coupon program to deliver "maximum corrosion management information". Overall, the coupon results for the current reporting period are very encouraging.

BPXA presents the average number of inspections for GPB as ~24,500 per year since 1995. The total number of inspections in 2002 was ~26,000. This level of inspection is consistent with 1998 levels and completes the reversal of a multi-year trend of lower inspection numbers (Figure B.4). The ratio of flow line (cross-country) inspections to well-line inspections was 46/54.

Percent inspection increases is a useful metric for quantifying the gross effort expended, but it is a function of the number of re-inspected locations. According to Table B.11(c), the target is zero increases. It is still not clear if the number of re-inspected locations is a statistical sample of known damaged locations, a fixed number of locations, or based on some other criteria.

BPXA made a significant improvement to their database related to multiple injection services. This change provides the ability to track well service changes, which in turn provides the ability to determine that impact on the coupon corrosion rates. Sixty percent of the injection service coupons have seen a single service during their exposure period. The remaining 40% were exposed to multiple services and BPXA reports the simple majority service category for these coupons.

Several graphs were included to demonstrate the effectiveness over time of the inhibition program using inspection increases and pipe condition for three phase oil lines (flow and well). The major effort is now on fine tuning the system to maintain or increase the current level of corrosion control for the piping.

BPXA has performed analyses showing the strong correlation between monitoring and inspection, which helps to validate that the monitoring locations are located where corrosion is expected to occur.

### *Monitoring & Inspection – Cross Country (Flow) Pipelines*

Coupon monitoring for the "oil" system indicates the average corrosion rate in cross-country flow lines is at or near its historical minimum. The number of coupons at or below the 2 mpy threshold set by BPXA for conformance is approaching the 100% mark.

Coupon monitoring in the produced water system shows an improvement in corrosion control for this system, as compared to 2001, and is on par with historical averages. The comparison between coupons with 100% exposure and simple majority exposure to produced water show nearly identical trends, which suggests that produced water is the controlling factor for the majority exposure corrosion rates. The expansion of a produced water inhibitor program will help to maintain or increase corrosion control for this system.

Coupon monitoring for the seawater injection system shows increasing corrosion rates since 1997, with the most significant increases occurring since 2000. BPXA has acknowledged this trend multiple times and has implemented several "corrective actions" at the Seawater Treatment Plant (STP). While several mitigation measures have been implemented, BPXA is yet to see any significant benefit or reduction in corrosion rates for this system. BPXA will be focusing on this area in 2003.

There were ~12,500 inspections of flow lines during 2002, ~10,800 for oil and ~1,700 for water. The percent inspection increases for re-inspected oil flow lines increased slightly for the second year, but are still lower than the overall average. The percent inspection increases for re-inspected water flow lines more than doubled that in 2001 and is now over 10%. This increase is attributed to the increasing corrosivity in the seawater injection, which in turn was due to problems at the STP. There were nine saves (eight oil and one water) and no leaks attributed to internal corrosion in 2002.

Three produced water lines were inspected with an inline inspection (ILI) tool based on magnetic flux leakage (MFL) technology. There is a limited discussion of the results, essentially stating there were no areas that did not meet fit-for-service criteria. Also presented is the historical ILI frequency, showing a high of 25 inspections in 1992 and decreasing to 3-6 inspections since 1997. Even though ILI provides data for essentially the entire length of the pipeline, BPXA states it is "not always the most appropriate or applicable..." based on a variety of reasons.

### *Monitoring & Inspection – Well Lines*

In 2002, 92% of all coupons in this service category were below the 2 mpy conformance threshold, which is a slight decrease from 2001 results. While coupons in oil production service show a significant reduction in corrosion rates since 1992, conformance levels in the 95-99% range should be possible given the corrosion mitigation performance in cross-country lines.

Coupon monitoring in the produced water system returned to their recent levels. These levels are expected to be maintained or improved due to the addition of an inhibitor designed for this system.

Coupon monitoring in the seawater injection system stands out for the second year because of the increasing corrosion rate trend. Weight loss rates in this service category have nearly tripled the 2001 results. These results are again attributed to problems at the STP previously discussed. The seawater injection system results will be of particular interest in 2003.

There were ~12,700 inspections of well lines during 2002, ~10,900 for oil and ~1,800 for water. This represents the largest number of inspections on well lines for the reported period. Given the number of leaks and number of saves for well lines is greater than that of the flow lines, the balance in emphasis appears to be a positive move. The percent inspection increases for re-inspected oil well lines continued a four-year downward trend. The percent inspection increases for re-inspected water well lines nearly doubled that in 2001 and is now over 10%. This increase is attributed to increasing corrosivity in the Seawater injection system, which in turn was due to problems at the STP. There were eleven saves (7 oil and 4 water) and two leaks in 2002 attributed to internal corrosion/erosion.

### *Internal Corrosion Mitigation*

$CO_2$ and solids deposition (both mechanisms can produce deep pitting) are cited as the main challenges in produced water systems where most coupon pitting is found. BPXA is expanding the corrosion inhibitor program specific to produced water.

BPXA expends considerable effort to develop and test new corrosion inhibitors. A rigorous testing procedure is outlined in the report which illustrates how inhibitors transition from the laboratory to field testing. There were 12 full-scale inhibitor trials in 2002.

Optimizing the injected volumes is critical to the economic application of inhibitor chemistry. BPXA is injecting nearly twice the volume it was using only 6 years ago. This increase is delivering measurable results in the systems in which it is being injected; cross-country production piping is nearing 100% corrosion rate conformance. The actual volume of chemical usage was 2.46 million gallons, which is slightly over the target amount of 2.45 million gallons. Based on monitoring and inspection data, corrosion inhibitor concentrations were increased (5-20% typical) in 14 pipelines.

## External Corrosion Management

### *Above Grade Piping*

BPXA exceeded their stated external inspection goals in 2002 and reached a new high of ~43,000 external inspections. There were 45 repairs and one leak on flow lines; twelve repairs and one leak on well lines; and more than 800 weld-packs refurbished at locations where corrosion was detected. The percent corroded and percent repaired results in 2002 are consistent with the 1999-2001 average percentages, and likely means there are 100+ repairs to be made on the remaining weld-packs. Table 1 summarizes the overall weld-pack inspection program status based on information presented for 2002. It is still unclear if the total population presented in the report consists of only non-common carrier pipe, or if there is a mix of facility piping included[1].

**Table 1 – GPB Above grade, non common carrier pipeline weld-pack inspection status**

| Service | Total Number (approx.) | Numb Inspected During 2002 | Number' Inspected thru YE2002 | Inspected thru YE2002 | mber Remaining (approx.) | 2003 Forecast |
|---|---|---|---|---|---|---|
| X-Country/Flow Line – Off-pad | 200,000 | 18,931 | 77,421 | **39%** | 122,579 | |
| Well Lines – On-pad | 100,000 | 23,797 | 47,190 | **47%** | 52,810 | |
| **Totals** | **300,000** | **42,728** | **124,611** | **42%** | **175,389** | 35,000 |

[1] This is based on conflicting information presented in earlier reports, and is addressed in our 2001 Report Recommendations.

BPXA has accelerated the weld-pack inspection program through the addition of more resources, more than tripling the number of weld-packs (~43,000 versus 13,000 avg.) inspected in 2002. The emphasis appears to be on Well lines, while the higher risk appears to be Flow lines. Flow lines have higher % Corroded, higher % Repair, and would have higher repair and cleanup costs.

*Below Grade Piping*

BPXA exceeded their stated below grade inspection goals in 2002, inspecting 269 locations using a combination of electromagnetic pulse and guided wave technologies. BPXA is 80% complete with the inspection of all ~1,400 cased crossings and on track to complete the remainder by YE2003. Additionally all cased crossings are visually inspected to ensure they are clear of debris and if found, they are cleaned out.

There were 21 "moderate" and 30 "significant" anomalies and no excavations performed during 2002. This represents a significant increase in anomalies, but they are believed to be "false-positives" due to data analysis methods. BPXA has committed to re-examine each of the "significant" anomalies in 2003. There have been no excavations on cased crossings since 2000.

### Structural Concerns

There were no leaks due to structural issues in 2002. The process for identifying and repairing other structural issues was presented in the report.

## CORROSION PROGRAM STATUS – ALASKA CONSOLIDATED TEAM

### General

The ACT corrosion programs status continued to evolve in 2002. The level of effort applied to the satellite field corrosion programs varied between them. Monitoring and inspection should be conducted in a proactive manner that will discover new and different corrosion mechanisms before they become a serious problem.

### Endicott

Coupon data indicates that the production system corrosion rate remains above the 2 mpy threshold; however BPXA states this is not a concern for the piping since it is fabricated mostly from Duplex Stainless Steel (DSS). Coupon data also indicates the water system corrosion control program is effective.

The primary corrosion concern at Endicott is the inter-island-water-line (IIWL). The percent inspection increases for flow and well lines are within historical norms; however the produced water well lines percent inspection increases have been above 10% in three of the last four years

There were no below-grade/cased piping inspections in 2002. The oil line inspection interval is characterized as "N/A Duplex Stainless Steel". Depending on the chloride concentrations in the ground water and ingress through weld-packs, a full baseline inspection should be made and a reasonable re-inspection interval set.

There were eight repairs (6 oil and 2 water) and one leak in 2002 reported for Endicott.

## Milne Point

Milne Point fluids are characterized by low $CO_2$, low operating temperature and low velocities. Corrosion under insulation and internal under-deposit corrosion mechanisms are mentioned and are consistent with the stated operating conditions. There were five repairs (oil lines), five sleeves (oil lines) and no leaks during 2002. Coupon data indicates good corrosion mitigation across all three systems.

Table E.2 shows the number of external inspections decreased from a high of 205 in 2000 to 70 in 2002. The percent inspection increases for external corrosion averaged 24% for the last three years, which is well in excess of the GPB field average. Buried pipe is a corrosion concern at MPU since many of the gathering lines and product distribution lines are buried along the roadway. There were 70 inspections and five excavations made in 2002. One of the five (20%) re-inspected locations showed an increase in corrosion. An additional seven inspection locations showed "minor" (<20% wall loss) external corrosion.

The number of internal inspections for flow lines has more than tripled the 1998 numbers. With the exception of the 1997 high point, the number of inspections has grown almost exponentially since 1995. The inspection trend is similar for the well lines. The produced water percent increases for internal corrosion is well above GPB levels, even allowing for when the inhibitor program was established.

## Northstar

Northstar began production in late 2001 and consequently has limited data. Fluid corrosivity is expected to be initially moderate, but will likely increase with the injection of Prudhoe Bay Gas. There are corrosion monitoring locations installed and data will be reported in the future. Presently, well production lines are treated with low concentrations of continuously injected corrosion inhibitor. No internal or external inspection data was presented, presumably data was not collected.

## Badami

Badami started in 1998 and the fluid corrosivity is considered low due to the small volumes of water and low $CO_2$ content. There is no corrosion inhibition or corrosion monitoring (coupon) program in place. Corrosion control is monitored through the use of a small inspection program. While no external weld-packs have been inspected to date, the pipe condition is observed in conjunction with internal inspections. Internal inspections have shown no corrosion.

## RECOMMENDATIONS

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

1. Total number/population of well lines, cross country lines, weld packs, below grade pipe segments would be beneficial. In addition, the number of baseline inspections and related percentages for the weld-pack and below grade piping programs would be beneficial to track overall progress during the multi-year effort. This data could be presented as a cumulative graph or in a tabular format.
2. We recognize the desire to publish complete reports that combine the background information along with the current period results. However, it would be easier to write and review the reports if the background information and current results are presented in distinct or separate sections (background and historical information can be placed in appendices).
3. It appears the external inspection program has more emphasis on Well lines, while Flow lines appear to have higher risk. Provide information related to mitigating the highest risk pipelines for the remaining inspections.
4. Provide an explanation/procedure used for selecting locations for re-inspection as well as how the results are used.
5. Provide more details on the inspection techniques for large diameter (>8") cross-country water injection piping.
6. Additional information regarding the inline inspection (ILI) program would be of value. It is interesting that in MPU the ILI data was significantly inaccurate; 1,000 feet with significant damage versus one minor pit.

## CONCLUSIONS

BPXA continues its thorough and aggressive corrosion control program. BPXA has consolidated/integrated the corrosion programs for GPB and continues to focus on optimization and continuous improvement of the program. Improvements to the database (MIMIR) continues and will improve the ability to obtain and analyze data in a timely fashion.

Internal corrosion in cross-country gathering lines and oil well lines is being controlled. The coupon monitoring in the seawater injection system stands out in the report because of the increasing corrosion rate trend. BPXA has implemented measures to improve operations in the seawater treatment plant, but operational issues have prevented the benefits from being realized. The produced water system has benefited from the inhibitor program targeted specifically at this system. Additional improvements in this program are planned in 2003.

External corrosion remains a significant risk for pipeline repairs and/or leaks for BPXA. The weld-pack baseline inspection program is ~40% complete and the goal for 2003 is ~35,000 weld-pack inspections. The below grade piping inspection program is 80% complete and on track for completion in 2003.

The corrosion programs for the ACT fields (Endicott, MPU, Badami, and Northstar) would benefit from a more consistent application of the programs developed in the GPB. MPU needs additional attention to their program. Inspection and monitoring in the new ACT fields need to be conducted in a consistent manner that will discover corrosion mechanisms before they become a serious problem.

BPXA is making continual improvements to its many corrosion mitigation operations and if implemented for 2003, the next report should show reversals in the few negative corrosion trends.

2002-CPA

# Corrosion Monitoring of Non-Common Carrier North Slope Pipelines

## Technical Analysis

## Of

## ConocoPhillips Alaska Inc. – 2002 Commitment to Corrosion Monitoring for Greater Kuparuk Area & Alpine

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# EXECUTIVE SUMMARY

Coffman Engineers, Inc. has been charged with reviewing the 2002 corrosion program report submitted by ConocoPhillips Alaska Incorporated (CPAI) to the Alaska Department of Environmental Conservation (ADEC). The report outlines the measures undertaken to mitigate corrosion in CPAI's non-common carrier North Slope pipelines. In addition, Coffman reviewed the presentation materials from the October 2002 and April 2003 Meet & Confer sessions.

Internal corrosion in cross-country lines indicates a clear degree of corrosion inhibition; no leaks and no saves were reported in 2002. Corrosion control, primarily inhibitor injection, has maintained the low leak/save frequency. Corrosion damage increases have been almost eliminated in the cross-country production gathering lines. Coupon pitting rates for three phase pipelines reversed the increasing trend seen during the past 5 years, due primarily to a change in inhibitors late in 2001. The mixed water injection average coupon pitting rates are above the target levels and is mostly attributed to piping at CPF2 locations. The percentage of locations with corrosion damage increases (UT and RT) has increased significantly for water injection service compared to 2001, 22%[1] vs. 0%.

Internal corrosion in well lines is an area that requires CPAI's continued focus; 2 leaks and 17 saves (repairs) were reported in 2002. The number of saves is roughly the same as in 2000, as is the footage of inspected pipe. The percentage of locations with corrosion damage increases (UT and RT) decreased slightly compared to 2001.

A baseline inspection of all weld-packs on cross country off-pad pipelines was completed in 2001. Baseline inspection of on-pad weld-packs (well and cross country lines) is progressing ahead of schedule and average percent of corroded weld-packs is around 3%. There were six repairs (~3% of corroded weld-packs) and more than 800 weld-packs refurbished on above grade piping.

CPAI completed the screening inspections for all Priority 1, below grade piping locations during 2002. Eight below grade locations were excavated and two locations required repair; one location was sleeved and the other location was replaced/upgraded.

There were no failures in 2002 due to structural related issues. An evaluation of the wind induced vibration (WIV) design envelope was completed in 2002 and recommendations implemented. The well subsidence mitigation program continued during 2002.

[1] Manual RT – 4 increases/14 repeats; Manual UT – 1 increases/9 repeats; Total – 5 increases/23 repeats = 22%

# CORROSION PROGRAM STATUS

## Internal Corrosion Management

### *Cross Country Pipelines – Monitoring & Inspection*

Internal corrosion in cross-country lines indicates a clear degree of corrosion inhibition; no leaks and no saves were reported in 2002. Corrosion control, primarily inhibitor injection, has maintained the low leak/save frequency. Corrosion damage increases have been nearly eliminated in the cross-country production gathering lines. Coupon pitting rates for the three phase and water injection pipelines reversed the increasing trend seen during the past 5 years, due primarily to a change in inhibitors late in 2001

Monitoring data for cross country water injection pipelines shows the average pitting rate exceeds the target. These data are largely dominated by results from CPF2 and work is ongoing in 2003 to determine the cause. The percentage of locations with corrosion damage increases (UT and RT) has increased significantly for water injection service compared to 2001, 22% vs 0%. The increases are primarily confined to one pipeline, 2EDCWI, and are the first increases identified to date on the water injection system.

CPAI reports that coupon or probe corrosion rates exceeded threshold targets in 20 pipelines and they responded by increasing the corrosion inhibitor concentrations target for all 20 pipelines. Eleven of these pipelines were also reported in 2001 as having exceeded corrosion rate targets and the response was increasing the corrosion inhibitor concentration target. Most of these eleven pipelines show little improvement and in some cases had worse results. Refer to Table 1 for a comparison of these eleven pipelines.

**Table 1 - 2000 and 2001 Three-phase CC Production pipelines with corrosion rates exceeding targets**

| Common Line | 2001 | | | 2002 | | |
|---|---|---|---|---|---|---|
| | Coupon Grade | Probe Rate | Inspection Increase | Coupon Grade | Probe Rate | Inspection Increase |
| 1-2Z1QGPO | A | <.5 | Yes | A | <.5 | Yes |
| 1RPO | F,D | >.5 | Yes | C | <.5 | |
| 2KPO | D | <.5 | | C | <.5 | |
| 2TAMKHPO | A | <.5 | Yes | A | >.5 | Yes |
| 2TPO | D | >.5 | | D | <.5 | |
| 2UPO | A | <.5 | Yes | A | <.5 | Yes |
| 3CPO | D | <.5 | | D | <.5 | |
| 3MIPO | C | <.5 | | D | <.5 | |
| 3RQOPO | D | >.5 | | C | <.5 | |

| Common Line | 2001 | | | 2002 | | |
|---|---|---|---|---|---|---|
| | Coupon Grade | Probe Rate | Inspection Increase | Coupon Grade | Probe Rate | Inspection Increase |
| XCL/WO at CPF2 | F,C | <.5 | | C | <.5 | |
| XCL/WO at CPF1 | D | <.5 | | B | N/A | Yes |

Note: Shaded cells indicate either no change or condition is worse than 2001 result

In addition, inspection showed five lines with inspection increases where the coupons did not exceed the target corrosion rate. The corrosion inhibitor concentrations for all five of these lines were also increased. This helps to illustrate and reinforce the importance of both programs.

An ongoing item of concern is the difficulty of inspecting produced water injection piping with diameters larger than eight inches, which is considered radio-opaque and limits the use of radiographic techniques. CPAI evaluated the feasibility of using inline inspection for these pipelines during 2002, and concluded that while technically feasible it is cost prohibitive. CPAI will continue to rely on "spot UT" measurements for these pipelines.

### *Well Lines - Monitoring & Inspection*

Internal corrosion in well lines is an area that requires CPAI's continued focus; two leaks and 17 saves (8 injection and 9 production) were reported in 2002. The number of saves is roughly the same as in 2000, as is the footage of inspected pipe.

Production well line coupon data indicate very low general and pitting corrosion rates, however CPAI notes that the inspection data indicates higher rates are being experienced. Injection well line coupon data indicates very low general corrosion rates. Pitting rates for this service are below the action limit, however they are 2-3 times above the historic minimums and have been so for the past three years.

The percentage of locations with corrosion damage increases (UT and RT) decreased slightly compared to 2001. It is unclear if there are specific targets for repeat inspections using manual RT and UT techniques, but the percent repeated for each inspection type and service type vary widely. It is also unclear if there is a target or action limit for the percent increase value.

### *Internal Corrosion Mitigation*

CPAI's compliance with its own corrosion inhibition targets has improved over time; reporting an average deviation of +0.9% for 2002; a slight over-treatment. CPAI is continuing to move forward with the wellhead inhibitor injection program; with four additional drill sites to be added during 2003. The well lines should benefit greatly from this program. CPAI continues to develop and test new inhibitor formulations with lab and field trials continuing through 2003.

Under deposit corrosion has been identified as a key corrosion mechanism and a test using a chemical surfactant product to promote wetting of oil fouled solids is being put in place at DS1E.

## External Corrosion Management

### *Above Grade Piping*

CPAI exceeded their stated external inspection goals in 2002. The baseline inspection for all off-pad weld-packs was completed in 2001 and a program for recurring inspections targeted at "medium wet" weld-packs was begun in 2002. The baseline inspection for on-pad weld-packs was 70% complete overall and is progressing in accordance with CPAI's stated 2005 completion schedule. The forecasted number of weld-pack inspections for 2003 is roughly 1/3 of 2002 and 2001 inspection levels. It is not clear if this represents a reduction in effort, an increase in physical complexity of the piping system, or a combination of both.

There were zero repairs on off-pad piping, six repairs of piping on-pad and more than 800 weld-packs refurbished. The percent corroded and percent repaired results for 2002 are consistent with the overall average percentages, and likely means there are still ~10 repairs to be made on the remaining ~10,000 weld-packs. Refer to Table 2 for the overall weld-pack baseline inspection status.

**Table 2 - Above grade weld-pack baseline inspection status**

| Service | Total Number (approx.) | Number Inspected During 2002 | Number Inspected thru YE2002 | % Inspected thru YE2002 | Number Remaining | 2002 Forecast |
|---|---|---|---|---|---|---|
| X-Country-Off-pad | 67,291 | 0 | 67,291 | 100% | 0 | 0 |
| X-Country-On-pad | 10,400 | 2,658 | 9,568 | 92% | 832 | 416 |
| Well Lines On-pad | 24,000 | 4,116 | 14,400 | 60% | 9,600 | 1,632 |
| **Totals** | **101,691** | **6,774** | **91,259** | **90%** | **10,432** | **2,048** |

Note: This table represents an effort to reconcile numbers presented in previous CPAI reports. There is the possibility for minor discrepancies.

The number of saves is roughly the same as in 2000, as is the footage of inspected pipe (RTR). The percentage of locations with corrosion damage increases (UT and RT) decreased slightly compared to 2001.

Buffer spikes were installed at 76 weld-packs locations as part of a test. The concept is a time-release sodium phosphate salt that serves to increase the pH of the electrolyte in contact with the steel surface, helping to create a passive layer on the steel surface. Little additional information was provided as to the status of this test program.

### *Below Grade Piping*

CPAI exceeded their stated below grade inspection goals in 2002, inspecting 130 previously un-inspected Priority 1 locations using a combination of electromagnetic pulse and guided wave technologies. One additional screening technology, torsional wave, was evaluated and deemed "not superior" to the incumbent and will not be used at this time. Additionally all cased crossings are visually inspected to ensure they are clear of debris and if found, they are cleaned out.

Eight below grade locations were excavated and two locations required repair; one location was sleeved and the other location was replaced. The remaining six locations were refurbished to prevent further corrosion. Refer to Table 3 for a summary status of this program. The only Priority 1 locations left to inspect are on piping that is less than 10 years old. While age is an important factor, it is unlikely to be the controlling factor for corrosion of the below grade piping. Additional significant factors include: pipeline wall thickness, pipeline operating temperature, location of crossing in relation to drainage, fluid velocities, and fluid corrosivity. It is unclear if these other factors have been considered for the remaining Priority 1 locations.

**Table 3 - Below Grade Piping Baseline Inspection Status**

| Description | Total Number (approx.) | Number Inspected During 2002 | Number Inspected thru YE2002 | Number Remaining |
|---|---|---|---|---|
| Priority 1 Oil | 375 | 38 | 331 | 44[2] |
| Priority 1 Non-Oil | 243 | 92 | 226 | 17 |
| Priority 2 Oil | 19 | 0 | 1 | 18 |
| Priority 2 Non-Oil | 98 | 0 | 0 | 98 |
| Priority 3 Oil | 22 | 0 | 1 | 21 |
| Priority 3 Non-Oil | 15 | 0 | 2 | 13 |
| **Totals** | **772** | **130** | **561** | **211** |

Notes:
1) This table represents an effort to reconcile numbers presented in previous CPAI reports. There is the possibility for minor discrepancies.
2) The only un-inspected Priority 1 pipelines are less than 10 years old

## Structural Concerns

### *Subsidence*

There were no leaks attributed to subsidence in 2002. CPAI continues to prioritize and upgrade existing wellhead riser supports and flooring susceptible to subsidence. Thermal siphons are also being installed in near well-bore location to promote re-freezing and stabilization of the soil.

### *Wind Induced Vibration*

There were no leaks attributed to WIV in 2002. An evaluation of the WIV design envelope was completed in 2002 and recommendations implemented.

## RECOMMENDATIONS

Recommendations for future reports are as follows.

1. In addition to the existing data presentation, consider combining the leaks and saves from the BGPP with the External Leaks and Saves data. Presently it appears the 2001 leak is included, but the two repairs (saves) are not. Refer to CPAI Figure A1.
2. Coupon corrosion rate data is the only specific data presented for Alpine. It is not clear if inspection and mitigation information is commingled or excludes Alpine. Clarification of the treatment of Alpine data in future reports would be beneficial.

## CONCLUSIONS

CPAI continues their vigorous corrosion control program and has met or exceeded all of the stated inspection goals during 2002.

Cross-country pipelines inspection data indicates a clear degree of internal corrosion control and the increasing coupon corrosion trend was reversed in 2002. Corrosion control, primarily inhibitor injection, has maintained the low leak/save frequency. Corrosion damage increases have been almost eliminated in the cross-country production gathering lines. The mixed water injection average coupon pitting rates are above the target levels and is mostly attributed to piping at CPF2 locations.

Inline inspection was evaluated for large diameter mixed water cross-country piping and deemed too costly to pursue as a primary inspection method. CPAI proposes to use spot UT measurements for these pipelines; however it is unclear if this will yield an adequate degree of confidence as to the condition of these pipelines. The percentage of locations with corrosion damage increases (UT and RT) has increased significantly for water injection service compared to 2001, 22% vs. 0%.

Well line internal corrosion control appears to be approaching the "top of the curve," but still requires significant focus. There were 2 failures and 17 repairs on well lines during 2002. The percentage of corrosion increases, level of inspections and number of saves were equivalent to 2000 results. The testing of wellhead inhibitor injection began in 2002 and plans are to add four additional well sites during 2003.

The external corrosion control program is progressing and the off-pad piping recur inspection program will begin in earnest during 2003. There are still more than 10,000 on-pad weld-packs requiring baseline inspections and extrapolating the results to date, there are several areas that will require repair. All of the Priority 1 below grade piping, older than 10 years, has had a baseline inspection.

There were no failures in 2002 due to structural related issues. An evaluation of the WIV design envelope was completed in 2002 and recommendations implemented. The well subsidence mitigation program continued during 2002.

2003-BP

# Corrosion Monitoring of Non-Common Carrier North Slope Pipelines

# Technical Analysis

# Of

# BP Exploration (Alaska) Inc. – Commitment to Corrosion Monitoring Year 2003 for Greater Prudhoe Bay, Endicott, Northstar and Milne Point


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# EXECUTIVE SUMMARY

Coffman Engineers, Inc. is responsible for the technical review of the 2003 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 April and August 2004 Meet & Confer sessions.

From a global perspective of oil and gas production, Greater Prudhoe Bay (GPB) and related facilities have an aggressively managed corrosion control program. This suggests an adequate long-term commitment to preserving facilities for future production and sensitivity to environmental consequences.

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. The isolated locations of corrosion are where leaks may occur (including Endicott's duplex stainless steel system). BPX has responded to this threat by implementing aggressive and thorough monitoring and mitigation programs; however, it does not appear to be presently possible to predict the onset of all new locations of accelerated corrosion.

Monitoring data, presented by BPX, is in conformance to metrics agreed to by ADEC. However, the significance of isolated areas of aggressive internal corrosion is not intuitively reflected by monitoring data because 1) extreme values cannot be readily determined, and 2) monitoring tools are generally not located where the isolated corrosion occurs. In the future, it would be beneficial for the distribution of coupon corrosion rate data be preserved for an improved representation of the extreme corrosion rates.

Inspection data supports the conclusion that the seawater and produced water systems are being adequately managed for internal corrosion and program improvements are continuously being made.

External corrosion of above-ground piping is largely confined to weld packs and BPX has made a notable commitment to removing this threat through inspection and repair (where necessary) of all weld pack locations.

Long range inspection tools are used to detect external corrosion of cased pipe and buried pipe. Although this is a proactive risk based approach, it should be recognized that industry experience with these inspection methods are mixed and there may be technical issues to be resolved as is the case with many state-of-the-art technologies. It is recommended that BPX provide a comparison of inspection results versus direct examination so that the accuracy and reliability of this inspection method can be evaluated by ADEC.

# CORROSION PROGRAM STATUS – GREATER PRUDHOE BAY

## Internal Corrosion Management

### *Production System (Well Lines and Flow Lines)*

The data provided by BPX supports the conclusion that the internal corrosion control/inspection program is well managed and effectively preserving the facilities for the future. However, the existence of isolated locations of accelerated corrosion could potentially result in leaks. Although isolated locations of corrosion are repairable, they could have an environmental consequence if not detected. BPX has responded to this threat by implementing aggressive and thorough monitoring, inspection and mitigation programs.

From a global perspective of oil and gas production, GPB has one of the most aggressively managed internal corrosion control programs. The level of inspection and corrosion mitigation resources directed by BPX corrosion experts is commendable. This suggests a long-term commitment to preserving facilities for future production and sensitivity to environmental consequences.

Inspection, monitoring, and mitigation data support the conclusion that the GPB assets are being adequately maintained and preserved. Corrosion control efforts exceed standard oilfield industry practice. The average corrosion rates of coupons and probes are as low as can be practically achieved (i.e., <1 mpy). A 1 mpy corrosion rate is put into context by considering that a 0.375 inch wall thickness pipe would have 80% of its wall thickness after 75 years. Inspection data supports the conclusion that most of the asset has insignificant corrosion. However, isolated locations with high corrosion rates remain. It would be beneficial to identify in future reports (in one location, if possible) what fraction of the piping experiences accelerated corrosion rates, what the pipeline services are, what the accelerated corrosion rates are (i.e., >10 mpy) and the remedial action that was taken to reduce the corrosion rates (Note: This information is currently not required by the reporting metrics agreed to by ADEC and some of the information is currently identified in various sections of the report).

The significance of isolated areas of accelerated corrosion within GPB is not intuitively reflected in the monitoring data presented by BPX because many of the coupons and probes are not located where accelerated corrosion occurs. Rather, they are installed at locations that are convenient for installation and retrieval (as is common practice in the industry). Future coupons should be placed at locations that represent the highest susceptibility to corrosion.

The impracticality of prioritizing susceptibility to isolated aggressive corrosion is compensated by an aggressive field-wide inspection program. The effectiveness of this program is demonstrated by the high ratio of 'saves' to leaks (with 'saves' defined by detecting damage requiring repair or pressure reduction).

### *Seawater and Produced Water Injection*

The seawater and produced water systems have relatively low corrosion rates and appear to be well managed. The presence of only one phase (i.e., water) makes corrosion management less complicated than the multiphase production system. Corrosion of the seawater system is mitigated by removing oxygen and injecting biocides. Corrosion of the produced water injection system is mitigated by oxygen removal, injecting biocides and by carryover inhibition from the production system.

Corrosion rates in the seawater systems decreased in 2003, reversing a 5-year trend. A number of actions were taken to address dissolved oxygen levels and microbiological corrosion control. Corrosion rates in the produced water systems also decreased in 2003. The upstream 3-phase corrosion inhibitor was changed and the corrosion mitigation programs were expanded specifically to address the produced water system in 2002.

## External Corrosion Management

### *Above Grade Piping*

BPXA plans to inspect and repair (as necessary) approximately 35,000 weld packs per year. This is a commendable commitment to address and remove the pipeline integrity problems associated with corrosion under insulation. Additionally, the priority for inspection is based on 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. A new weld pack design is in use and is intended to prevent future water ingress and corrosion at these field-applied insulation locations.

### *Below Grade Piping*

BPX plans to inspect cased crossings using long range inspection methods (i.e., electromagnetic pulse and guided wave technologies). Although this is a proactive risk based approach, there may be issues to be resolved with these technologies, as is the case with many state-of-the art technologies. BPX should provide data that quantifies the ability of long range inspection to detect defects that could lead to failure (i.e., compare inspection results with subsequent direct examination of the cased pipe). Where it is not practical to perform a direct exam, determining the ability to characterize defects on a pipe where a defect has been detected by long range inspection would provide added confidence to the method.

# 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). Carbon steel coupons are used to monitor corrosivity, and their average rate in 2002-2003 was approximately 3 mpy. It should be noted that the coupons are not expected to reflect the rate that would be seen on the DSS (if it were to corrode) because its mechanism and rate of corrosion differs. That is, a breakdown in DSS passivity would result in localized corrosion (i.e., pitting) with a corrosion rate much higher than the rate observed by the carbon steel coupons.

The stated BPX primary corrosion concern at Endicott is the inter-island-water-line (IIWL). However, its corrosion management is similar to the produced water injection system at Prudhoe Bay and the monitoring data shows average corrosion rates near zero.

There were seven repair activities at Endicott. Five C-spools were replaced due to corrosion, one C-spool was replaced due to erosion and one stainless steel well line was sleeved due to erosion.

## Milne Point

BPX has significantly 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., <1 mpy).

Milne Point has buried pipe containing produced fluids that require excavation for external inspection. Because of this, BPX is considering the use of long range inspection methods (i.e., guided wave ultrasonics). As previously stated, there may be issues to be resolved regarding these technologies.

There were 7 repair activities at Milne Point. Six of the repairs were on the K-pad production flow line. Additional areas have been identified for sleeve repair.

## Northstar

The threat of corrosion at Northstar is considered low. Production began in late 2001 and fluids have low corrosivity. The production lines are inhibited and corrosion coupons indicate adequate effectiveness. Inspection activities have also increased.

## Badami

Badami is shut-in, so damage as a result of corrosion should not result in leaks (i.e., there is no environmental consequence). From an asset preservation standpoint, external corrosion can occur on buried and/or insulated piping, and internal corrosion can occur where lines have been 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. 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.
2. Future coupons should be placed at locations that represent the highest susceptibility to corrosion.
3. Identify criteria to be used for locating future coupons.
4. Based on the inspection methodology and guidelines in the GPB corrosion inspection program, define matrix or priority indices used for selecting inspection locations that may be prone to accelerated corrosion.
5. Provide data that quantifies the ability of long range inspection to detect defects that could lead to failure (i.e., compare inspection results with subsequent direct examination of the cased pipe).

## CONCLUSIONS

BPXA has presented sufficient information to demonstrate that its corrosion control program meets the spirit of the Charter Agreement. This suggests a proactive long-term commitment to preserving facilities for future production and sensitivity to environmental consequences. Recommendations and observations contained in this document should be viewed as opportunities for incremental improvement.

Although the vast majority of internal pipeline corrosion is being mitigated, isolated areas of accelerated corrosion have been detected through comprehensive inspections and by way of leaks that have occurred on isolated occasions. Priority should be given to those locations that represent the highest susceptibility to corrosion for future inspections.

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 also intends to inspect cased crossings with long-range inspection tools; however, it should be recognized that long-range inspection tools may have technical issues that need to be resolved.

2003-CPA

# Corrosion Monitoring of Non-Common Carrier North Slope Pipelines

## Technical Analysis

## Of

## ConocoPhillips Alaska Inc. – Commitment to Corrosion Monitoring Year 2003 for Greater Kuparuk Area & Alpine

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# EXECUTIVE SUMMARY

Coffman Engineers, Inc. is responsible for the technical review of the 2003 corrosion program report submitted by ConocoPhillips to the Alaska Department of Environmental Conservation (ADEC). The report outlines the measures undertaken to mitigate corrosion of ConocoPhillips non-common carrier North Slope pipelines. In addition, Coffman reviewed the presentation materials from the April and August 2004 Meet & Confer sessions.

From a global perspective of oil and gas production, Greater Kuparuk Area (GKA) has a conservatively managed corrosion control program. This suggests a long-term commitment to preserving facilities for future production and sensitivity to environmental consequences.

Monitoring, mitigation, and inspection data support the conclusion that the GKA assets are being preserved, but isolated locations of accelerated internal corrosion exist and have been found by inspections. The isolated locations of corrosion are where leaks may occur. ConocoPhillips appears to have responded to this threat by conducting wide-ranging inspections. Additional inspections are focused on known damage locations, but it does not appear presently possible to predict the onset of all new locations of accelerated corrosion.

Monitoring data, presented by ConocoPhillips, is in conformance to metrics agreed to by ADEC. However, the significance of isolated areas of aggressive internal corrosion is not intuitively reflected by monitoring data because 1) extreme values cannot be readily determined, and 2) monitoring tools are generally not located where the isolated corrosion occurs. In the future, it would be beneficial for the distribution of coupon corrosion rate data be presented for an improved representation of the extreme corrosion rates. Presentation of in-line inspection data would also be useful.

Inspection data supports the conclusion that seawater and mixed water systems are being adequately managed for internal corrosion and program improvements are continuously being made. A problem in the Central Processing Facility #2 (CPF2), resulting in corrosion in the mixed water system, was identified and addressed.

External corrosion of above-ground piping is largely confined to weld packs and ConocoPhillips has made a notable commitment to removing this threat through inspection and repair (where necessary) of all weld pack locations.

Long range inspection tools are used to detect external corrosion of cased and buried pipe. Although this is a proactive risk based approach, it should be recognized that industry experience with these inspection methods are mixed and there may be technical issues to be resolved as is the case with many state-of-the-art technologies. It is recommended that ConocoPhillips provide a comparison of inspection results versus direct examination so that the accuracy and reliability of this inspection method can be evaluated by ADEC.

# CORROSION PROGRAM STATUS – GREATER KUPARUK AREA

## Internal Corrosion Management

### *Production System (Well Lines and Flow Lines)*

The data provided by ConocoPhillips supports the conclusion that the internal corrosion control/inspection program is well managed and effectively preserving the facilities for the future. It is notable that ConocoPhillips presents data in a transparent way and answers questions with candor. However, the data presented does not fully reflect the existence of isolated locations of accelerated corrosion that could potentially result in leaks. Although isolated locations of corrosion are repairable, they could have an environmental consequence if not detected. The ConocoPhillips approach to controlling these leaks appear to consist of a wide-sweeping and aggressive inspection program.

From a global perspective of oil and gas production, GKA has one of the most conservatively managed internal corrosion control programs. Corrosion inhibition appears to be controlling general corrosion and isolated locations of accelerated corrosion are identified by an expansive inspection program. This suggests a long-term commitment to preserving facilities for future production and sensitivity to environmental consequences.

Monitoring, mitigation, and inspection data support the conclusion that the GKA assets are being adequately maintained and preserved. Corrosion control efforts meet or exceed standard oilfield industry practice. The average corrosion rates of coupons and probes are near zero and the average pitting rate is <5 mpy. A 5 mpy corrosion rate is put into context by considering that a 0.375-inch wall thickness pipe would have over 70% of its wall thickness after 20 years. Inspection data supports the conclusion that most of the asset has low corrosion rates, but isolated locations of accelerated corrosion rates do exist. It would be beneficial to identify in future reports (in one location, if possible) what fraction of the piping experiences accelerated corrosion rates, what the pipeline services are, what the accelerated corrosion rates are (i.e., >10 mpy) and the remedial action that was taken to reduce the corrosion rates (Note: This information is currently not required by the reporting metrics agreed to by ADEC and some of the information is currently identified in various sections of the report).

The inspection intervals and methods at GKA are set by a risk based program approach, identified in the 2000 report, for all pipelines. The program methodology is based on the consequence and likelihood of corrosion related failures. Isolated locations of accelerated corrosion exist and have been found by inspections. The significance of isolated areas of accelerated corrosion within GKA is not intuitively reflected in the monitoring data presented by ConocoPhillips because many of the coupons and probes are not located where accelerated corrosion occurs (an effort has been made since 1997 to improve this). Rather, they are installed at locations that are convenient for installation and retrieval (as is common practice in the industry). Future coupons should be placed at locations that represent the highest susceptibility to corrosion. Additionally, presenting in-line inspection data would aid in understanding the distribution of accelerated corrosion within a pipeline system.

### *Seawater and Mixed Water Injection*

The seawater and produced water systems have relatively low corrosion rates and appear to be well managed. The presence of only one phase (i.e., water) makes corrosion management less complicated than the multiphase production system. Corrosion of the seawater system is mitigated by removing oxygen and injecting biocides. Corrosion of the mixed produced/seawater injection system is mitigated by carryover inhibition from the production system and the upstream treatment of the seawater.

Significant corrosion caused by the mixed water from CPF2 was identified by inspections and by monitoring results that indicated high coupon corrosion rates. Since the outcome of a CPF2 biocide program review was to revise the treatment procedures, it is assumed that the root cause of corrosion was determined to be bacteria. It is not clear if the bacteria originated from the seawater system (which should have already been treated with biocide) or from the commingled produced water. Biocide treatments are generally most effective when applied furthest upstream.

## External Corrosion Management

### *Above Grade Piping*

ConocoPhillips plans to complete inspection and repair (as necessary) of all weld packs in 2004. This is a commendable commitment to address and remove the pipeline integrity problems associated with corrosion under insulation. Additionally, the priority for inspection is based on the consequence of failure (e.g., weld packs over tundra are a higher priority than over the pad), ensuring that the highest consequence locations are repaired first. A new weld pack design is in use and is intended to prevent future water ingress and corrosion at these field-applied insulation locations.

### *Below Grade Piping*

In 2003 ConocoPhillips inspected 82 cased crossings (chosen by risk prioritization) using long range inspection methods (i.e., electromagnetic pulse and guided wave technologies). Although this is a proactive risk based approach, there may be issues to be resolved with these technologies, as is the case with many state-of-the art technologies. ConocoPhillips should provide data that quantifies the ability of long range inspection to detect defects that could lead to failure (i.e., compare inspection results with subsequent direct examination of the cased pipe). Where it is not practical to perform a direct exam, determining the ability to characterize defects on a pipe where a defect has been detected by long range inspection would provide added confidence to the method.

## RECOMMENDATIONS

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

1. Future coupons should be placed at locations that represent the highest susceptibility to corrosion.
2. Identify criteria to be used for locating future coupons.
3. Based on the inspection methodology and guidelines in the GKA corrosion inspection program, define matrix or priority indices used for selecting inspection locations that may be prone to accelerated corrosion.
4. Provide data that quantifies the ability of long range inspection to detect defects that could lead to failure (i.e., compare inspection results with subsequent direct examination of the cased pipe).
5. Continue the commitment to external corrosion inspection and mitigation of the weld packs.

## CONCLUSIONS

ConocoPhillips has presented sufficient information to demonstrate that its corrosion control program meets the spirit of the Charter Agreement. This suggests a long-term commitment to preserving facilities for future production and sensitivity to environmental consequences. Recommendations and observations contained in this document should be viewed as opportunities for incremental improvement.

Although the vast majority of internal pipeline corrosion is being mitigated, isolated areas of accelerated corrosion have been detected through comprehensive inspections and by way of leaks that have occurred on isolated occasions. Priority should be given to those locations that represent the highest susceptibility to corrosion for future inspections.

Two significant external corrosion threats are below-ground cased crossings and weld-packs on above-ground pipe. ConocoPhillips has made a notable commitment to inspect and repair (when necessary) all of the weld-packs. ConocoPhillips inspects cased crossings by using visual inspections and state-of-the-art long-range inspection tools; however, it should be recognized that long-range inspection tools may have technical issues that need to be resolved.

2004-BP

# Corrosion Monitoring of Non-Common Carrier

# North Slope Pipelines

## Technical Analysis

## Of

## BP Exploration (Alaska) Inc.

## Commitment to Corrosion Monitoring Year 2004

Submitted by


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ADEC Contract Number 18-6000-02

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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). 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~

# 2004-CPA

# Corrosion Monitoring of Non-Common Carrier North Slope Pipelines

## Technical Analysis

## Of

## ConocoPhillips Alaska Inc. – Commitment to Corrosion Monitoring Year 2004 for Greater Kuparuk Area & Western North Slope

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# EXECUTIVE SUMMARY

Coffman Engineers, Inc. has been charged with reviewing the 2004 corrosion program report submitted by ConocoPhillips Alaska, Inc. (CPAI) to the Alaska Department of Environmental Conservation (ADEC). The report outlines the measures undertaken to manage corrosion in CPAI non-common carrier North Slope pipelines. In addition, Coffman reviewed the presentation materials from the 2005 Meet & Confer sessions.

The data provided by CPAI 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.

The CPAI corrosion program emphasizes the identification of locations where 1) the likelihood of previous damage is greatest, and 2) corrosion rates are likely to be highest. Highest priority is placed on locations where the likelihood of damage and high corrosion rates coincide.

The overall corrosivity of the three phase production system is relatively low, but isolated locations of accelerated corrosion are known to exist. These locations are identified primarily through an extensive inspection program and controlled by chemical corrosion inhibitors.

Although seawater and produced water injection systems are normally considered to have lower susceptibility to corrosion compared to three phase production systems, a leak occurred in 2005. Although information existed on increasing corrosion rates, the lack of previous corrosion in this system did not prompt a major increase in its risk priority. Because of the leak, the injection system priority was elevated and increased mitigation and inspection actions are being taken.

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

External corrosion at cased crossings represents a corrosion threat over which CPAI has a difficult challenge. This is because of the difficulty with accessing the pipe surface. In response to this challenge, CPAI has proactively implemented state-of-the-art technologies in further development of long range inspection techniques. CPAI recognizes the current technical limitations of these tools and is working with a vendor to further enhance them.

# CORROSION PROGRAM STATUS – GREATER KUPARUK AREA (GKA) & WESTERN NORTH SLOPE (WNS)

The data provided by CPAI supports the conclusion that the corrosion management program is effective and exceeds ommon industry practice.

The CPAI corrosion program emphasizes the identification of locations where time to failure is shortest. That is, the program seeks to find locations where 1) the likelihood of previous damage is greatest, and 2) corrosion rates are like to be highest. Highest priority is placed on locations where the likelihood of damage and high corrosion rates coincide. The consequence of a leak in any part of its system is considered to have similar safety or environmental consequences. Risk is therefore controlled by reducing the likelihood of failure.

It is notable that CPAI continues to present data in a transparent way and answers all questions with candor. Information from written reports, presentations, and verbal questions consistent. In addition, the CPAI corrosion control staff is highly competent and an e. .nsive QA/QC program is in place to monitor the performance of contractors.

## Internal Corrosion Management

### *Three Phase Production System (Well Lines and Flow Lines)*

The overall corrosivity of the GKA system is relatively low, but isolated locations of accelerated corrosion are known to exist. Corrosion inhibition appears to be making general corrosion unlikely and appears to be minimizing localized corrosion. Localized corrosion, not mitigated by inhibition, is primarily identified by an expansive inspection program.

Localized corrosion appears to be associated with the presence of solids and/or deposits that create crevices under which corrosion is accelerated and/or delivery of chemical treatment is restricted. The effect of solids on corrosion is reduced by chemical action (i.e., surfactants) that is aided by production velocities sufficient to keep solids mobilized.

All inspection, monitoring, mitigation, and inspection data support the conclusion that the GKA assets are being adequately preserved. Corrosion control efforts exceed standard oilfield industry practice. The average corrosion rates of coupons and probes are near zero and the average pitting rate is low.

The corrosion inspection and monitoring program has several components:

- Real-time radiography (RTR) is performed system-wide at approximately 5-year intervals. This inspection covers long continuous lengths of pipe selected to serve at least two purposes. The first is that defects that could result in leaks are identified and repaired. The second is that locations of corrosion damage that are not near-term integrity threats are identified as known-damage-recurs (KDR's) so that a growth rate can be determined. KDR's are scheduled for ultrasonic inspection at a time sooner than the next RTR survey. KDR's are also identified by conventional factors to prioritize susceptibility to corrosion (e.g., dead-legs, high velocity flow).

- KDR's are measured ultrasonically at less than 3-year intervals (2 month minimum), and the results are used for 1) determining if the location becomes an integrity threat in need of repair, and 2) determining corrosion growth rate for feedback to mitigation. The rate of KDR inspections is approximately 5% of the system every 5 years. All lines with internal corrosion damage are monitored by KDR inspections. The number of KDR locations on each line is determined by the severity and amount of damage. Guidelines specify there should be three to ten KDR locations per damaged line unless there is a good reason for fewer or more locations.
- Corrosion monitoring consists of corrosion coupons and probes. Their purpose is primarily to identify changes in corrosivity over time. It is recognized that coupons are not typically placed in the most susceptible location and that the rates do not necessary represent what is occurring on the pipe wall. This limitation in the coupon program is compensated by the KDR program. An increase in coupon corrosion rate therefore serves as an indication of a possible problem triggering further action. It is recognized that a coupon without corrosion does not necessarily indicate the lack of corrosion in a line.

In the 2003 report, a concern was raised that data reported by CPAI did not reflect the significance of isolated corrosion. This was because 1) corrosion coupons and probes are not typically located where the corrosion is considered most likely, and 2) presenting coupon data in an averaged form does not reflect the isolated high corrosion rate coupons. This issue was resolved by further communication from CPAI regarding the use of KDR's at locations considered most susceptible to corrosion. Since CPAI does not rely on coupons to identify locations most susceptible to corrosion, the importance of the coupon corrosion rates and their distribution of corrosion rates are of lesser importance than what is found by inspections.

***Seawater and Mixed Water Injection***

In general, seawater and produced water injection systems have lower susceptibility to corrosion compared to three phase production systems. The gas phase containing $CO_2$ and $H_2S$ has been removed, and the presence of only one phase (i.e., water) simplifies delivery of chemical treatment. Corrosion caused by bacteria or oxygen are the most likely corrosion mechanisms. Corrosion of the CPAI seawater system is mitigated by removing oxygen and injecting biocides. Corrosion of the mixed produced/sea-water injection system is mitigated by carryover inhibition from the production system (and the upstream treatment of seawater) and increased line velocities to help reduce under-deposit corrosion. Additionally, cleaning pigs and a biocide are being used to remove deposits and kill bacteria. These actions are consistent with good corrosion control practices.

In 2005, a leak occurred in the water injection system at 2H pad, which was attributed to microbiologically induced corrosion (MIC). It is noteworthy that coupon corrosion rates have been high since 2002, and pitting rates exceeded 25 mpy in 2004. In hindsight, the high coupon rates are consistent with the leak, but it should be recognized that corrosion management programs (including that of CPAI) typically prioritize locations where likelihood of previous damage and high existing corrosion rates coincide. In this case, information existed that corrosion rates had increased, but the likelihood of previous corrosion damage was considered low. On that basis, other locations within the system were given higher priority. Because of the leak, the future risk priority of the water injection system has been raised and additional mitigation, monitoring, and inspection has been implemented.

## External Corrosion Management

### *Above Grade Piping*

CPAI is committed to removing corrosion under weld-pack insulation as an integrity threat. No leaks were caused by external corrosion in 2004. CPAI completed tangential radiography testing (TRT) on all cross country lines and well lines. Two locations of severe damage were identified and repaired. A new weld pack design is intended to prevent future water ingress and corrosion at these field-applied insulation locations. To check the performance of the new design, at least 100 of the refurbished weld packs were inspected for water ingress. No corrosion under insulation was found in any of the areas inspected.

### *Below Grade Piping*

External corrosion at cased crossings represents a corrosion threat over which CPAI has a difficult challenge. This is because of the difficulty with accessing the pipe surface. In response to this challenge, CPAI has proactively implemented state-of-the-art technologies in further development of long range inspection techniques. CPAI recognizes the current technical limitations of these tools and is working with a vendor to further enhance them.

In 2004, all casings were visually inspected (i.e., at the ends), and identified problems were remediated (e.g., pipe insulation in contact with casing, debris). Nine casing locations were excavated, inspected refurbished and repaired (as required). Additionally, 63 cased crossings were assessed using long-range ultrasonic inspection.

CPAI reports that 764 cased crossings are located in GKA. Because the pipe cannot be accessed without excavation and removal of the casing and insulation, inspection from outside of the pipe is not considered practical. The inspection program at GKA is heavily based on radiography of above ground insulated pipe, resulting in limited capability for inline inspection. The remaining alternative is long-range ultrasonic inspection, but the resolution of this method is less than other inspection methods used at GKA.

The primary reason for inspecting casings is for external pipeline corrosion because water and debris may enter the annular space and support corrosion. Although some differences in internal corrosion susceptibility might exist at the crossings because of elevation changes, the pipe upstream and downstream of the casing is considered representative. On that basis, it is reasonable to conclude that the absence of internal corrosion surrounding the crossing indicates low likelihood of internal corrosion within the crossing.

## RECOMMENDATIONS

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

1. Further clarification regarding the mechanism of under-deposit corrosion in the three-phase oil production system.
2. Continue improvements to the mixed water injection systems until corrosion rates are below established threshold limits.
3. 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).
4. Continue commitment to aggressively address corrosion under insulation at weld pack areas.
5. Provide additional information confirming that WNS corrosion management has equal or equivalent rigor to GKA programs.

## CONCLUSIONS

The data provided by CPAI 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 CPAI continues to present data in a transparent way and answers all questions with candor. Information from written reports, presentations, and verbal questions are consistent. In addition, the CPAI corrosion control staff is very competent and an extensive QA/QC program is in place to monitor the performance of contractors.

The CPAI corrosion program emphasizes the identification of locations where 1) the likelihood of previous damage is greatest, and 2) corrosion rates are likely to be highest. Highest priority is placed on locations where the likelihood of damage and high corrosion rates coincide.

Internal corrosion of the three phase production and water injection systems are effectively managed, but a leak occurred in a water injection system considered to have low susceptibility to corrosion. CPAI has increased the risk priority of this system and has increased mitigation and inspection activity.

External corrosion of above-ground piping is largely confined to weld packs, and CPAI continues to make notable progress on removing this threat through inspection and repair (where necessary) of all locations.

External corrosion at cased crossings represents a corrosion threat over which CPAI has a difficult challenge. This is because of the difficulty with accessing the pipe surface. In response to this challenge, CPAI has proactively implemented state-of-the-art technologies in further development of long range inspection techniques. CPAI recognizes the current technical limitations of these tools and is working with a vendor to further enhance them.