

ALASKA LEGISLATURE COMMITTEES, 2002-2003

11974 SENATE RESOURCES

## 3.1.c Cross-Country Line Inspection

In 2004 we had several significant accomplishments:

- Completed the inspection survey of all over tundra dead-legs and weld-o-lets on cross country pipelines.
- Met our primary 2004 goal by completing interval surveys on 32 cross country lines.

As indicated in Figure 9, four repair recommendations were initiated on cross-country lines (1 seawater injection, 3 production) because of internal corrosion damage in 2004. The corrosion mechanism for the three production lines was deadleg corrosion. The corrosion mechanism for the seawater injection line leak, determined not to be an ADEC-reportable spill, was microbiologically induced corrosion. More information on the leak can be found in section 3.1.g.

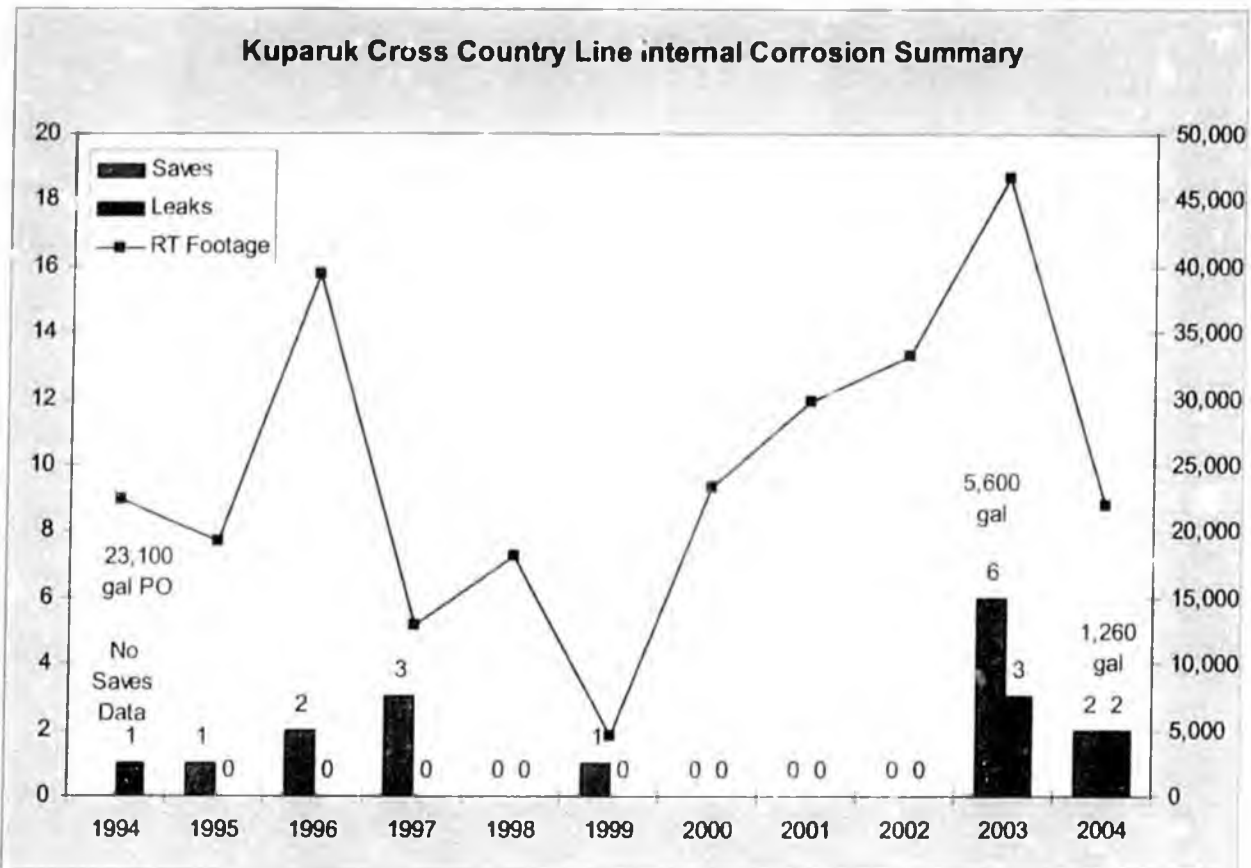


Figure 9. Summary of Cross-Country Line Internal Corrosion Inspections – RT footage, leaks, and saves as a function of time.

# ConocoPhillips

The 2004 results from the RTR surveys, manual RT, and manual UT are summarized in the following three tables:

- **RTR of Cross Country (CC) Lines:**

Service	Feet Inspected	Number of Lines Inspected
Three-phase Production	13,020	21
Water Injection	6,099	10
Total	19,119	31

The 2004 RTR CC line data indicated no new damage trends. The number of lines inspected by RTR decreased from previous years because we completed our initial baseline inspection in 2003 and started our mature recurring program in 2004.

- **Manual RT of CC Lines:**

Service	Number of Lines Inspected	Number of Radiographs	Number of Repeat Radiographs	Number of Repeat Radiographs with Increases	% of Repeat Radiographs with Increases
Three-phase Production	254	2,410	413	10	2
Water Injection	75	387	11	3	27
Total	329	2,797	424	13	3

The 2004 RT CC line data inspection results corroborated the increases seen by monitoring

- **Manual UT of CC lines:**

Service	Number of Lines Inspected	Number of UT Inspections	Number of Repeat UT Inspections	Number of Repeat UT Inspections with Increases	% Of Repeat UT Inspections with Increases
Three-phase Production	103	1,050	678	19	3
Water Injection	36	256	39	2	5
Total	139	1,306	717	21	3

The 2004 UT CC line data indicated no new damage trends

## 3.1.d External (Weld-Pack) Program

In 2004 we had several significant accomplishments:

- Completed baseline tangential radiography testing (TRT) survey of all well line weld packs due for inspection, ahead of our scheduled 2005 planned completion date.
- Completed baseline TRT survey of all cross country line weld packs due for inspection.
- Completed our goal of inspecting at least 100 Tam-style weld packs to ensure this new design is working properly.
- Completed our visual inspection and refurbishment of ten 30" sea water pipeline weld packs.

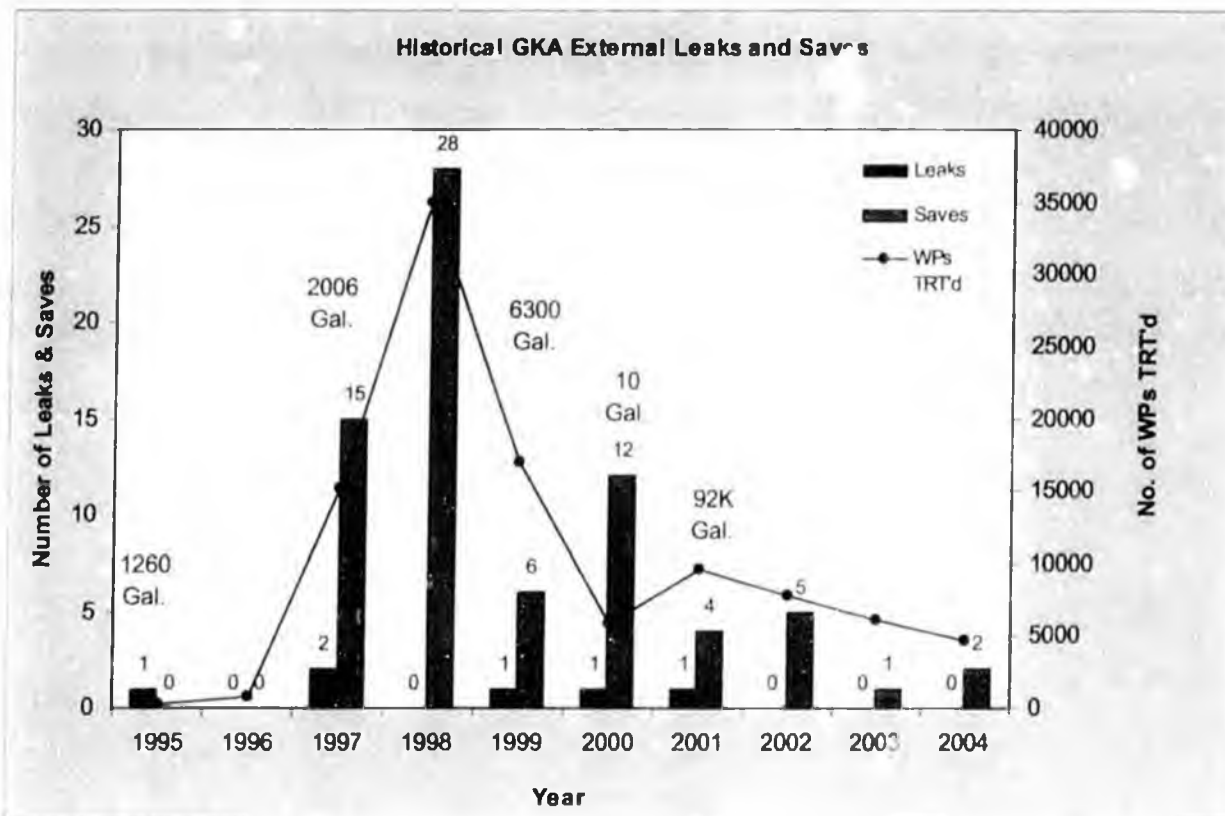


Figure 10. Leaks, saves, number of weld packs inspected with TRT, and volumes of leaks as a function of time.

### Cross-Country Lines (On-Pad)

A total of 672 locations were inspected using tangential radiography (TRT), significantly exceeding the goal of 406 for 2004. Of the 672 locations, none needed repair while 96 locations were refurbished. The baseline inspections on all weld packs due for inspection is now considered complete.

## Cross-Country Lines Over Tundra (Off-Pad)

The baseline inspection of these weld-packs was believed complete by year-end 2001. However, in 2003 a walk-down verification survey revealed that several weld pack locations had been missed during the initial layout. In 2004, 3094 CUI locations were inspected, surpassing our goal of inspecting 3020 locations. These numbers include inspections of weld packs that had been inspected previously (recurs), as well as weld packs where documentation of a previous inspection could not be verified. Two piping repairs were required as a result of this on-going effort and 354 locations were refurbished. The baseline inspections on all weld packs due for inspection is now considered complete.

Additionally, 111 of the new, Tarn-style weld packs were inspected with TRT to see how they are holding up. All 111 locations had no previous inspection history. A total of six weld packs were found with light wet insulation. The rest were found to be completely dry. No corrosion under insulation (CUI) was found in any of the areas inspected. This is the first year that we have discovered any water in this style of weld pack; the insulation does not contact the pipe so even though the insulation is wet, it should not cause CUI.

## Well Lines

In 2004, 885 well line weld packs were inspected. With this effort, the baseline inspection and documentation of all well line weld packs due for inspection was considered complete. Our stated goal was 1700 weld packs; the reason for the overestimate of the number of weld packs is the uncertainty in the total count of the well line weld packs before inspections commenced. Corrosion was found at 17 (or 1.9%) of the 885 locations. Also during 2004, 38 well line weld pack locations were refurbished.

Table 5: External Weld Pack Inspection Summary for 2004.

Type of Equipment	2004 Goal	Number of Locations Inspected	Number of Corroded Locations	Percentage of Locations Corroded	Number of Locations Refurbished
Cross-Country Lines (On Pad)	406	672	13	2.7	96
Cross-Country Lines Over Tundra (Off-Pad)	3020	3094	71	2.3	354
Well Lines	1700	885	17	1.9	38
<b>Total</b>	<b>5126</b>	<b>4651</b>	<b>106</b>	<b>2.3 (avg.)</b>	<b>488</b>

The number of weld packs TRT'd, number of weld packs corroded, and the percentage of weld packs corroded for the cross-country lines over tundra, cross-country lines on-pad, and well lines are given in Figures 11, 12, and 13.

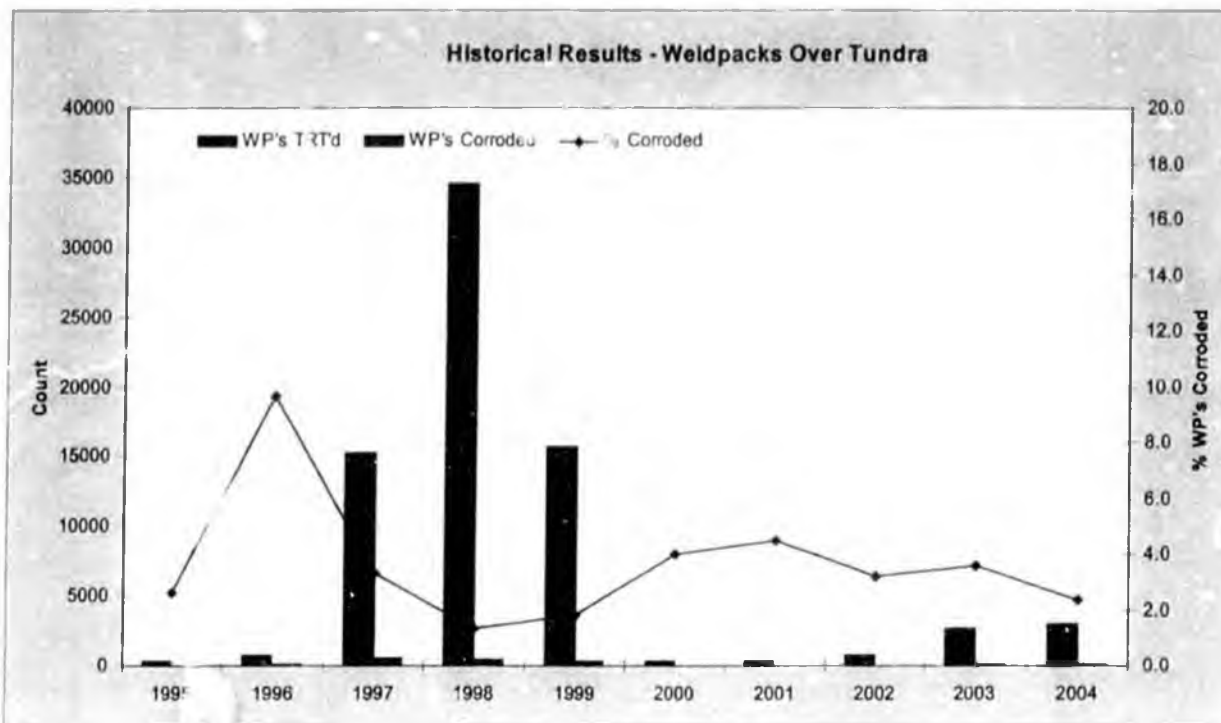


Figure 11. Summary of Weld Packs on Cross-Country Lines over Tundra (off-pad).

Figure 11 illustrates the most-complete external corrosion inspection program of the three external corrosion programs. 2002, 2003, and 2004 values include re-inspections and clean-up of locations missed or not properly documented during the original base line effort.

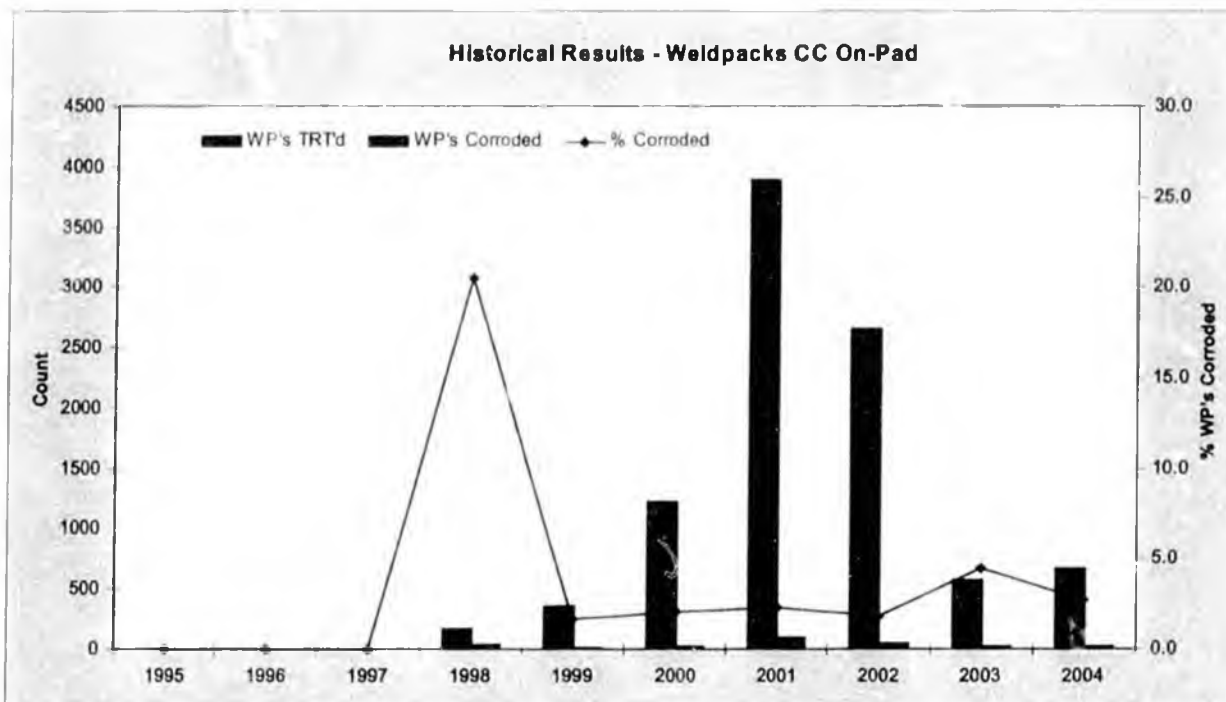


Figure 12. Summary of Weld Packs on Cross-Country Lines on Pads.

Figures 12 and 13 depict the results of the major focus of the external weld pack inspection program in 2004. The cross-country program and the well line weld pack program met milestones in 2004 by completing all of the baseline TRT inspections of all weld packs in their respective areas.

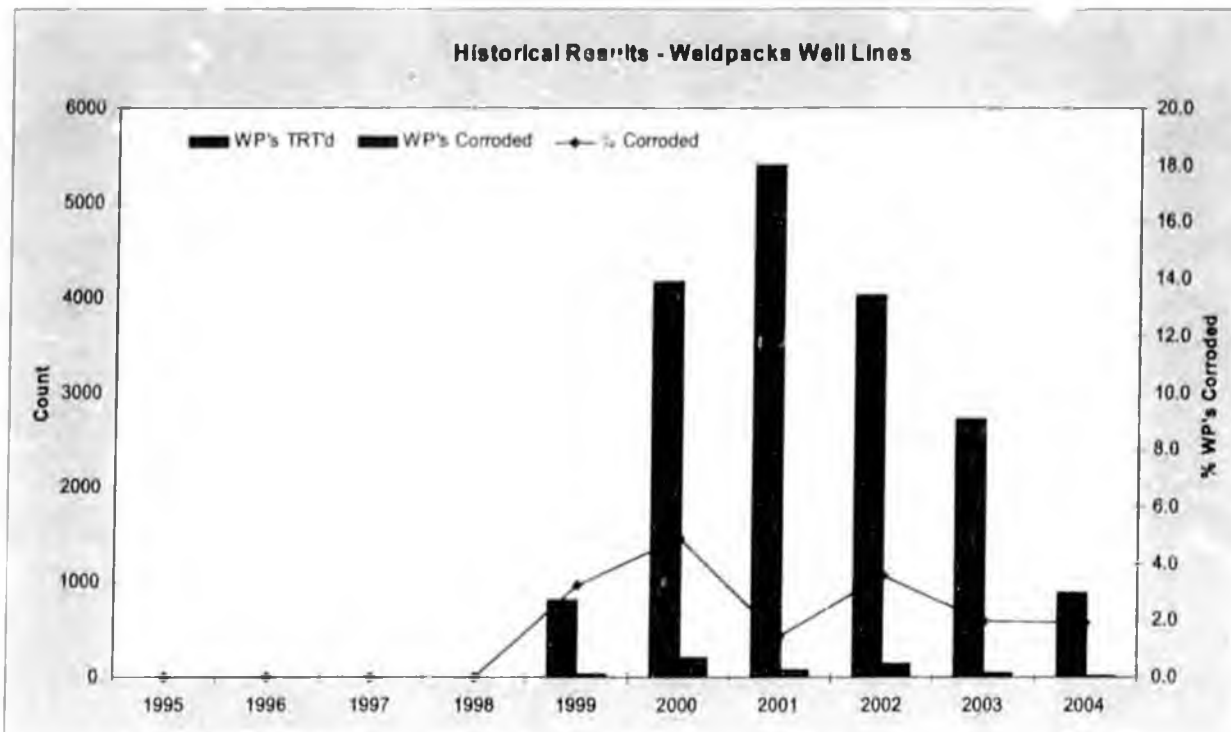


Figure 13. Summary of Weld Packs on Well Lines.

#### Corrosion Under Insulation Buffer Spike Program

In 2002, a test of "CUI Buffer Spikes" was initiated on 50 over-tundra cross-country weld pack locations. The program was expanded later in 2002 to include weld packs on drillsite well and facility piping. In addition, two electric resistance probes were installed in two heavy water weld packs at DS1E to monitor potential corrosion activity. The sodium phosphate salt contained in these spikes dissolves in wet insulation and raises the pH to 10. Prior to installation of these spikes, wet insulation measurements fell within a consistent 6 to 7 pH range. Corrosion of carbon steel is minimized in alkaline conditions. During 2003, each of these locations was monitored for pH. The 2003 follow-up inspections showed that the pH did rise in the wet areas of the weld packs. Three locations were also stripped and verified with an indicator dye the pH probe results.

TRT inspections were proposed for all buffer spike locations in 2004. These follow-up inspections were not conducted due to priorities elsewhere in the field to complete the baseline weld pack inspection before year-end. The TRT survey has been scheduled for 2005.

Monitoring of the ER probes at DS 1E indicated low, but not zero, corrosion rates.

### 3.1.e Below Grade Piping Program

This section details the inventory and survey of below grade locations and the results of Specialty Testing. The plans for future inspections are given in section 3.2 e.

In 2004 we had several significant accomplishments:

- Visually inspected and cleaned all debris from all cased below grade pipe locations.
- Completed our specialty inspection (TWI) scope of work.
- Excavated, inspected, refurbished and repaired (as required) nine cased below grade pipe locations.
- Continued to work with TWI by testing a focused ultrasonic inspection method.

The Alaska Department of Environmental Conservation (ADEC) regulations under 18 AAC 75.080 applies to the Kuparuk oilfield facilities operated by ConocoPhillips Alaska, Inc. (CPAI). To meet the requirements of 18 AAC 75.080, CPAI submitted their corrosion control program for below-grade piping in early 1998. The program also included a field-wide inventory of all below-grade piping in the Kuparuk field. ADEC approved the program in written correspondence dated October 26, 1998.

#### 3.1.e (1) Inventory and Survey of Below Grade Locations

CPAI has 764 locations (includes priority 1, priority 2, priority 3, and Alpine lines) of below grade piping located in the GKA. Of these locations, one is contained in an utilidor. The remaining locations are cased lines, the majority of which are either road, gravel pad or caribou crossings.

##### Utilidor Line

The line in the utilidor (Oily Waste Injection Line, BG ID #286) was taken out of service in 2004. It had been on a two year inspection cycle and was last inspected in 2002. Because it has been taken out of service the 2004 inspection was deferred.

##### Cased Lines

###### Inspection Status:

The annual visual survey of all the cased lines was conducted in 2004. The purpose of the survey was to identify, rectify, and report local conditions (e.g., debris found in casings and culverts, pipe insulation in contact with soil) that require remedial action.

###### Results and Remedial Action:

Of all the below-grade lines, 123 locations were found to have pipe in direct contact with soil and/or gravel/soil or debris in the casing. All 123 locations were remediated in 2004.

#### 3.1.e (2) Results of Specialty Testing

###### Inspection Status:

In 2004, we completed TWI inspections on 63 priority one locations. This was the second year of our recurring inspection program where each priority one pipe will be inspected at a maximum ten-year interval.

In 2004 only the long-range ultrasonic system technology from The Welding Institute (TWI) was used. TWI technology is capable of finding evidence of both internal and external corrosion damage.

Results and Remedial Action:

Tables 6 and show the results of the specialty testing performed by TWI.

**Table 6. Results from the TWI inspections by service.**

Service	Number of Cased Pipes Inspected	Incomplete or Inconclusive Results (I)	Number without any Significant Indications (N)	Number of Minor (Low) Anomalies (L)	Number of Minor to Moderate and Moderate Anomalies (M)	Number of Moderate to Severe and Severe Anomalies (S)
Oil	23	1	16	5	1	0
Other	40	12	11	15	2	0
Total	63	13	27	20	3	0

The 2004 TWI data indicated no new damage trends.

**3.1.e (3) Results of Crossing Digs**

Nine cased pipes were excavated in 2004:

- One of the nine pipes had a repair recommendation issued because it was found to be derated because of CUI damage. The location was repaired with a pressure containing sleeve
- Eight of the nine pipes excavated and inspected did not require de-rating, repair, or replacement because only minor or no corrosion damage was found.

For all nine cased pipes that were excavated in 2004, the insulation was refurbished and the pipe wrapped with Densyl tape to prevent further corrosion.

**3.1.f Other Structural Concerns**

**Subsidence:**

**Existing Well Upgrade Program**

- In 2004, 12 floors with riser piping supports were installed in well houses at Drill Sites 1L, 2C, 2F, 2T, 2V, and 2W. Well house floors are supported by the well conductor and provide table riser piping supports.
- In 2004, 24 heat tubes were planned to be installed at Drill Sites 1C, 1E, 1L, 2L, 2N, 2W, 3A, 3F, 3N, and 3R. However, the heat tubes were delayed in manufacturing by the vendor and were installed in March 2005. Heat tubes are used to keep the ground frozen or to re-freeze the ground where it has been thawed.

**New Wells & Producer to Water Injection Well Conversions**

- In 2004, 16 newly drilled wells at Kuparuk were installed with insulated conductors; of these, 15 had heat tubes installed and one new well was not hooked up.
- In 2004, three newly drilled wells had heat tubes and conductor-mounted steel well house floors installed.
- In 2004, two existing producers converted to water injection wells were upgraded to include heat tubes and steel conductor-supported well house floors.

## Wind-Induced Vibration:

As a result of the 3A-I-M eight-inch gas lift line failure that occurred in December 2004 (described in section 3.1.g), Kuparuk is reviewing existing pipelines to evaluate the need for secondary mode vibration dampers. We are also revising the CPAI criteria and specifications to ensure that both primary and secondary mode WIV are considered.

### 3.1.g Corrosion and Structural-Related Spills/Incidents:

- Well 1Y-02 water injection well line leaked in July because of erosion. The erosion was caused by an obstructed straightening vane which forced produced water to flow around the vane pack rather than through it as designed. The subsequent flow impingement on the pipe wall eventually caused a pinhole leak. The spill volume was less than one gallon which was contained by the well house floor and, as such, it was determined not to be an ADEC reportable spill. No fluids contacted the tundra or the gravel pad. As a result of this leak the vane pack areas on all other high velocity water lines in the GKA were inspected. One other damaged location was found and remediated. In addition, this area will be inspected on all future well line interval inspection surveys.
- Drillsite 3R test separator bypass line leaked in October because of internal deadleg corrosion. The spill volume was less than one gallon which was contained on the gravel pad and, as such, it was determined not to be an ADEC reportable spill. As a result of this leak all similar deadlegs on all other drillsites were inspected. No damage requiring a repair recommendation was found. As a result of our 2003 inspection year, deadlegs on cross country lines were made a high inspection priority. Over-tundra deadlegs were our highest priority due to the environmental risk. The inspection of all over-tundra deadlegs was completed in 2004. On-pad deadlegs are scheduled for inspection in 2005.
- Drillsite 3R water injection line leaked in a non-piggable section of the line between the pig receiver and the well injection header. The leak occurred in January and was caused by microbiologically induced corrosion (MIC). The line had seen both produced water injection and sea water injection; however it was on sea water injection at the time of the leak. The released volume was estimated to be 1,260 gallons, but because the material was sea water released to a sea water environment it was not an ADEC reportable spill. As a result of this leak the WI supply line to 3R (piggable), the rest of the non-piggable line and all similar lines at all other drillsites were inspected. No repairs and very little damage were found during these inspections.
- No leaks were caused by external corrosion in 2004.
- The eight-inch diameter gas lift pipeline running between CPF3 and DS3I experienced a failure at a pipeline girth weld at  $\frac{1}{4}$  span location (one-quarter of the distance from one support to another support) in December. Aside from insulation and jacketing debris, the area was clean with no liquid spill to the tundra. Subsequent field investigation of this pipeline revealed a second girth weld failure. The failure has been attributed to secondary mode wind-induced vibration (WIV).

Of the 163 welds inspected with phased array UT, only one other crack was found – also on the 8" line at a  $\frac{1}{4}$  span location. No internal or external corrosion was found on the lines during these or previous inspections. Repairs were completed in late January 2005, and the lines were returned to service on 2/3/05.

The failed pipe section and the other cracked location were sent to the ConocoPhillips Failure Analysis Lab in Bartlesville for evaluation. The evaluation determined that the crack was caused by high-cycle fatigue. No signs of brittle fracture, over-pressure, or impact were present. The welds were of high quality and exhibited excellent toughness.

The tuned vibration absorbers on the DS-3I/3M gas lift line were installed in March, 2005.

Currently, work is underway to expand the WIV model to better understand when and how secondary modes of WIV can occur, and to develop more robust predictive tools so that potential recurrence of such a failure can be prevented. Once these tools are in place, other pipeline segments will be evaluated for susceptibility to similar WIV fatigue failure and mitigating actions taken as appropriate.

- No leaks were caused by subsidence in 2004.

Figures 8, 9, and 10 show the number of leaks and the volumes of leaks as a function of time. Figure 8 depicts the leaks caused by internal corrosion for the well lines. Figure 9 depicts the leaks caused by internal corrosion for the cross-country lines. Figure 10 shows the leaks caused by external corrosion for cross-country lines, well lines, and below-grade piping locations.

## 3.2 Year 2005 Forecast

### 3.2.a Monitoring & Mitigation

- Test four additional inhibitor formulations.
- Evaluate the biocide program changes to the mixed water systems because of the monitoring and inspection data trends.
- Consider internal corrosion inhibition for the mixed water systems.

### 3.2.b Well Line Inspection

Our recurring inspection program will continue in 2005. No in-service line will go longer than 10 years without an inspection.

### 3.2.c Cross-Country Line Inspection

Our recurring inspection program will continue in 2005. No in-service line will go longer than 10 years without an inspection.

### 3.2.d External (Weld-Pack) Program

Inspect all 86 buffer spike locations installed in 2002. Inspect for corrosion using TRT at 3, 6, and 9 o'clock positions. Measure the pH in the buffered weld packs and install ER probes in non-buffered weld packs.

Cross-country lines over tundra:

- Inspect approximately 4200 cross-country line weld packs over tundra as part of our recurring inspection program.
- Inspect a minimum of 100 Tarn-style weld packs (insulation not touching the pipe) with TRT to continue to evaluate the efficacy of the design.
- Inspect a minimum of 100 refurbished weld packs to continue to evaluate the performance of the Densotape system.

Cross-country lines on-pad:

Inspect approximately 50 cross-country line weld packs on-pad as part of our recurring inspection program.

Well lines:

Inspect approximately 1500 well line weld packs as part of our recurring inspection program.

## 3.2.e Below Grade Piping Program

- Continue our annual visual inspection of all priority one and two cased lines. The appropriate CPAI field department will be notified of any corrective actions early enough to complete clean out and re-inspection during the summer.
- Continue our recurring TWI inspection program of priority one cased lines.
- Excavate, inspect, refurbish, and repair (as necessary) five-to-nine lines in cased crossings.
- Continue to work with TWI and ConocoPhillips R&D to refine inspection data reduction and interpretation.

## 3.2.f Other

- Continue enhancements to the Kuparuk Corrosion Database.
- Continue to evaluate, and prioritize subsidence mitigation efforts at the existing drill sites.

## 4.0 Program Status Summary - WNS

### 4.1 Year 2004 Overview

#### 4.1.a WNS Monitoring & Mitigation

Average general and pitting coupon corrosion rate data for Year 2004 are presented in Tables 4.1 and 4.2.

**Table 4.1. Average general corrosion rates for corrosion coupons by service category.**

Asset Group	Number of Lines with Coupons Analyzed	Coupon Average General Corrosion Rate, mpy (target=<3)	Number of Lines with Conformant General Corrosion Rates	Percent of Lines with Conformant General Corrosion Rates
Three-phase Production Cross-Country Lines	1	0.5	1	100
Seawater Cross-Country Lines	1	0.4	1	100
Seawater Injection Cross-Country Lines	0*			
Production Well Flow Lines	31	0.1	31	100
Seawater Injection Well Flow Lines	13	0.1	13	100

**Table 4.2. Average pitting corrosion rates for corrosion coupons by service category.**

Asset Group	Number of Lines with Coupons Analyzed	Coupon Average Pitting Corrosion Rate, mpy (target=<10)	Number of Lines with Conformant Pitting Corrosion Rates	Percent of Lines with Conformant Pitting Corrosion Rates
Three-phase Production Cross-Country Lines	1	1	1	100
Seawater Cross-Country Lines	1		1	100
Seawater Injection Cross-Country Lines	0*			
Production Well Flow Lines	31	0.6	31	100
Seawater Injection Well Flow Lines	13	0.6	13	100

\* NOTE: This coupon location is currently not accessible because of a new piping obstruction.

#### 4.1.b Well Line Inspection

In 2003, 33 three-phase production lines and 22 water injection lines were inspected; no damage was found. In 2004, 18 three-phase production lines were inspected at direction changes; no damage was found.

#### 4.1.b Cross-Country Line Inspection

None performed.

#### 4.1.d External (Weld-Pack) Program

None performed.

#### 4.1.e Below Grade Piping Program

This section details the inventory and survey of below grade locations and the results of Specialty Testing. The plans for future inspections are given in section 4.2.e.

##### 4.1.e (1) Inventory and Survey of Below Grade Locations

CPAI has 15 locations of below grade piping in the WNS. These locations are cased lines at road or pad crossings. There are an additional 15 crossings, located at CPF2 that are associated with the WNS, but included in the GKA section of this report.

##### Cased Lines

##### Inspection Status:

The annual visual survey of all the cased lines was conducted in 2004. The purpose of the survey was to identify, rectify, and report local conditions (e.g., debris found in casings and culverts, pipe insulation in contact with soil) that require remedial action.

##### Results and Remedial Action:

Of all the below-grade lines, zero locations were found to have pipe in direct contact with soil and/or gravel/soil or debris in the casing.

##### 4.1.e (2) Results of Specialty Testing

No specialty testing was performed in the WNS in 2004.

##### 4.1.e (3) Results of Crossing Digs

None occurred.

#### 4.1.f Other Structural Concerns

##### **Subsidence:**

- No concerns identified.
- In 2004, 15 newly drilled wells at Alpine were installed with insulated conductors; of these, 15 had heat tubes installed.

##### **Wind-Induced Vibration:**

No problems identified in 2004.

#### 4.1.g Corrosion and Structural-Related Spills/Incidents:

- No leaks were caused by external corrosion in 2004.
- No leaks were caused by wind-induced vibration in 2004.
- No leaks were caused by internal corrosion in 2004.
- No structural or subsidence concerns were identified in 2004.

## 4.2 Year 2005 WNS Forecast

### 4.2.a Monitoring & Mitigation

- Pull coupons as scheduled
- Ensure new drill site development provides for adequate monitoring

### 4.2.b Well Line Inspection

Inspect 15 lines, 15% of existing total for internal corrosion.

### 4.2.c Cross-Country Line Inspection

Inspect over 2000 ft of three-phase production lines.

### 4.2.d External (Weld-Pack) Program

Cross-country lines over tundra:

Complete baseline TRT inspections on the remaining 200 possible CUI locations to verify the new weld pack design is working as anticipated.

Cross-country lines on pad:

Complete baseline TRT inspections on the remaining 200 possible CUI locations to verify the new weld pack design is working as anticipated.

Well lines:

TRT most likely locations for CUI on ten lines.

### 4.2.e Below Grade Piping Program

Continue the annual visual inspection of all priority one and two cased lines. The appropriate CPAI field department will be notified of any corrective actions early enough to complete clean out and re-inspection during the summer.

### 4.2.f Other

Continue Alpine piping layout and piping information database development.

## APPENDIX A Glossary

### Equipment Classification:

- **Well Line** – Pipe from the wellhead to the Drill Site manifold. For production wells, a well line handles the flow from a single well prior to commingling with fluids from other wells and transportation to the Central Processing Facility. For water injection wells, a well line handles the water flow going from a common manifold to a single wellhead.
- **Cross-Country Line** – Pipe from the Drill Site manifold to the Central Processing Facility (CPF).
- **Below-Grade Location** – That portion of a single pipeline, which crosses underneath a road or other earthen feature at a single location. The linear extent of the location consists of the length of pipeline between casing ends.

### Service Definitions:

- **Three-phase Production** – Basic reservoir fluids (oil, water, and gas) produced from down hole through to the CPF. Typically sees changes in temperature and pressure only from reservoir changes and are essentially un-separated.
- **Seawater (SW)** – Water from the Beaufort Sea that has been treated at the Seawater Treatment Plant (STP). Note that seawater treatment at the Kuparuk STP consists of filtration, oxygen stripping using produced gas, and biociding.
- **Produced Water (PW)** – The water separated at the CPF from three-phase production.
- **Mixed Water (MW)** – Produced water and seawater that have been commingled.
- **Gas** – Generic term for the different gas systems that transport dry (no liquids) gas between facilities. Includes fuel gas, artificial lift gas, and miscible Injectant.
- **Produced Oil** – The liquid hydrocarbon separated at the CPF from three-phase production.

### Inspection Terminology:

- **CRM** – Corrosion rate monitoring.
- **UT** – Ultrasonic testing
- **RT** – Radiographic testing
- **RTR** – Real time radiographic testing
- **TRT** – Tangential radiographic testing
- **PTI** – Profile Technologies Inc. (Electro magnetic inspection)
- **TWI** – The Welding Institute (Long range UT)
- **KDR** – Known damage recur inspection
- **Leak** – Through-wall pipe damage that causes loss of product. Product volume may not be sufficient to be classified as a "spill".
- **Save** – When the Corrosion Group recommends a repair before a leak occurs.
- **Below Grade (priority 1)** – These are pipes with a higher probability and consequence of failure. In general they have larger diameters and higher pressures and would probably cause damage to the environment or cause safety concerns if they leaked.
- **Below Grade (priority 2)** – These are pipes with a lower probability or consequence of failure. In general, these have smaller diameters and lower pressures and would probably cause little, if any, environmental damage or safety concern if they leaked. Examples include un-insulated dry gas lines and flare lines.
- **Below Grade (priority 3)** – These are pipes with a low probability and consequence of failure. Examples include decommissioned pipes, pipes in fresh or fire water service and pipes constructed of corrosion resistant materials. In addition, they contain product that would cause little, if any, environmental damage or safety concern the pipe leaked.

2005



**Greater Kuparuk Area (GKA)  
Western North Slope (WNS)  
Corrosion Programs Overview**

March 31, 2006

*Commitment to Corrosion Monitoring  
6<sup>th</sup> Annual Report to the Alaska Department of Environmental Conservation*

Prepared by  
**ConocoPhillips Corrosion Team**

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### 4.0 Western North Slope (WNS) Program Status Summary

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### Appendix A Glossary of Terms used in this Report

## 1.0 OVERVIEW

There are over \$4 Billion in capital assets in the Greater Kuparuk Area (GKA). The internal corrosion potential in Kuparuk lines continues to rise as water production and H<sub>2</sub>S levels increase. Additionally, an external corrosion potential exists where moisture penetrates and is trapped in insulation. Effective management of corrosion at Kuparuk is critical to maintain environmental and facility integrity, to reduce field operating costs, and to extend the life of the field infrastructure to meet future needs.

Alpine is ConocoPhillips Alaska's newest development and the largest onshore oil field discovered in North America in the past decade. Alpine has a nominal processing capacity of 125,000 BOPD. The Alpine development produces from a pad area of 97 acres, and has two Drill Sites; two additional satellite drill sites are being built. The corrosion management system used at Kuparuk is being applied to the Alpine field.

The purpose of this 6<sup>th</sup> Annual Report is to communicate the details of the individual programs that implement the ConocoPhillips Alaska Corrosion Strategy. In addition to the requirements of the North Slope Charter Agreement between ConocoPhillips Alaska, Inc., BP Exploration (Alaska), and the Alaska Department of Environmental Conservation, previous reporting requirements pertaining to the Below Grade Piping Program will be incorporated into this and future North Slope Charter Corrosion Reports.

A glossary of terms used in this report is included as Appendix A.

## 2.0 SIGNIFICANT ENHANCEMENT TO CORROSION PROGRAMS

Linear array continues to be a valuable tool for evaluation of corrosion damage in large diameter cross-country water injection lines.

The field-wide pigging program was enhanced by standardizing on the use of brush/disk pigs, monitoring of total suspended solids, and monitoring of biocide application with residual measurements.

The number of below-grade piping circuits excavated was roughly tripled from 2004 to 2005 because of a revised risk assessment of the below-grade piping circuits.

Rope Access Technology (RAT) was added to the Corrosion inspection capabilities to allow the examination of difficult-to-reach areas in piping that would otherwise require extensive scaffolding.

The amount of tangential radiographic (TRT) inspection coverage was increased at weld packs where "medium" water is found at the 6 o'clock (bottom-of-pipe) position to include a minimum of an additional 12 o'clock inspection; a 360-degree inspection is performed where possible.

### 3.0 Program Status Summary - Kuparuk

#### 3.1 Year 2005 Overview

##### 3.1.a Kuparuk Monitoring & Mitigation

In 2005 we had several significant accomplishments:

- Tested two new corrosion inhibitor formulations and placed one new corrosion inhibitor in a larger scale test.
- Enhanced the maintenance pigging program for the water injection system at CPF-2 using multiple pig runs, improved biocide treatments, and total suspended solids monitoring.
- Deferred commingling of waters at CPF3 based on lessons learned from the 2K WI spill.
- Moved data reporting for the coupon monitoring system from an MS Access based reporting system to an Oracle based reporting and tracking system for ease in future analysis.
- Enhanced the pump performance at selected drill sites to increase consistency of chemical inhibition.

Average general and pitting coupon corrosion rate data for Year 2005 are presented in Tables 1 and 2.

**Table 1. Average general corrosion rates for corrosion coupons by service category.**

Asset Group	Number of Lines with Coupons Analyzed	Coupon Average General Corrosion Rate, mpy (target=<3)	Number of Lines with Conformant General Corrosion Rates	Percent of Lines with Conformant General Corrosion Rates
Three-phase Production Cross-Country Lines	55	0.05	55	100
Seawater Cross-Country Lines	2	7.3	1	50
Mixed Water Injection Cross-Country Lines	24	0.5	24	100
Production Well Flow Lines	501	0.2	495	99
Water Injection Well Flow Lines	388	0.8	358	92

**Table 2. Average pitting corrosion rates for corrosion coupons by service category.**

Asset Group	Number of Lines with Coupons Analyzed	Coupon Average Pitting Corrosion Rate, mpy (target=<10)	Number of Lines with Conformant Pitting Corrosion Rates	Percent of Lines with Conformant Pitting Corrosion Rates
Three-phase Production Cross-Country Lines	55	2.6	52	95
Seawater Cross-Country Lines	2	7.4	2	100
Mixed Water Injection Cross-Country Lines	24	19.5	15	63
Production Well Flow Lines	501	2.9	478	95
Water Injection Well Flow Lines	388	14.6	243	63

Note: See graph and associated discussion on Figures 1 through 5 of this report.

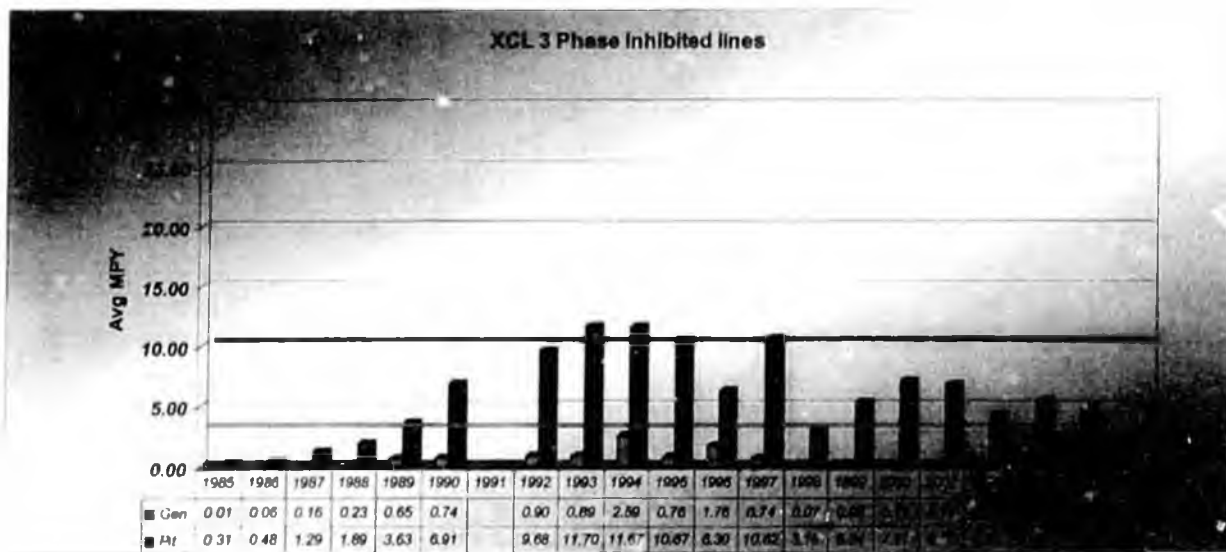
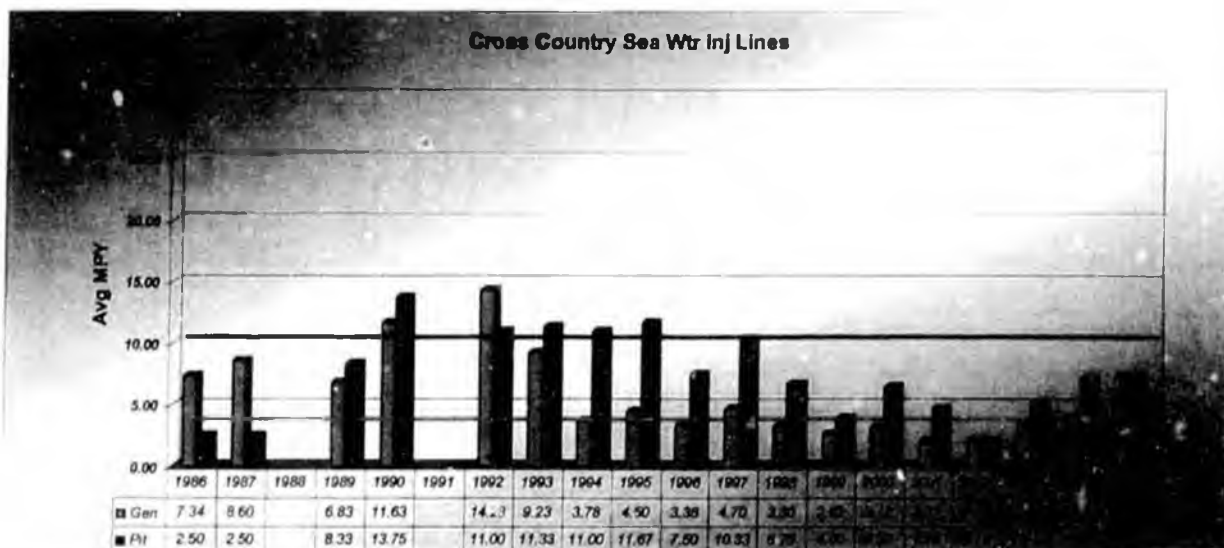


Figure 1. Three-phase Production Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.

*Three-phase Production Cross-Country Lines:* The monitoring data summarized in Kuparuk Tables 1 and 2 and presented in Figure 1 suggest that general corrosion is under control. The data presented in Tables 1 and 2 and in Figure 1 include corrosion coupon data from the wet oil lines starting at CPF3 and going to CPF1 and CPF2.

Recurring CRM inspections also support the conclusion that corrosion is under control in the three-phase production cross-country lines. In 2005, 419 corrosion-rate monitoring (CRM) inspections were conducted, with one minor increase found. Other internal inspection data supporting the CRM data are discussed in section 3.1.c, below.

Where corrosion rates exceeded targets, corrosion inhibitor concentrations were increased and/or the amount of inspection was increased. In 2005, coupon, probe or inspection-based corrosion rates exceeded targets or revealed increased damage on eight lines. In 2005, inspection results indicated minor corrosion had occurred in four of these eight lines. A complete listing of the lines with coupon/probe corrosion rates that exceeded targets and/or where inspection indicated increased damage is given in Table 3.



**Figure 2. Seawater Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.**

*Sea Water Cross-Country Lines:* The monitoring data summarized in Kuparuk Tables 1 and 2 and presented in Figure 2 above, show the average corrosion rates for the sea water cross-country line coupons. Higher coupon corrosion rates were caused by higher dissolved oxygen concentrations seen during 2005 break-up and oxygen scavenger was added to decrease the dissolved oxygen concentration; these coupons are located near the exit of the sea water treatment plant (STP) and are not believed to be indicative of corrosion in the sea water injection system. Increased coupon corrosion rates detected are currently under review, with biocide concentration and pigging frequency increased in early 2006. Smart pigging of the 30-inch sea water line from the STP to the CW Skid is planned for 2006.

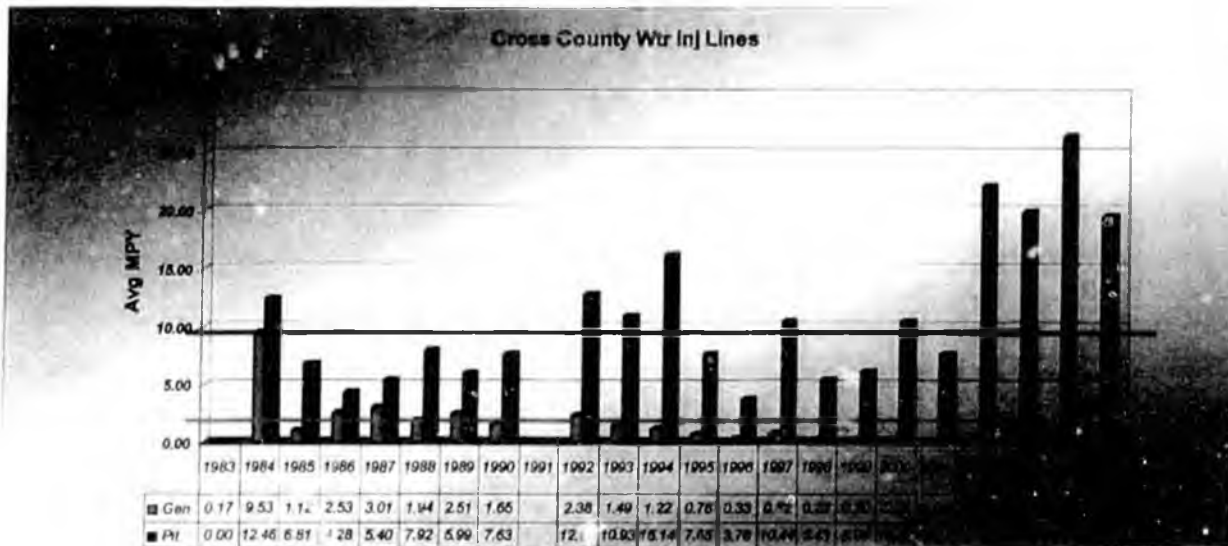
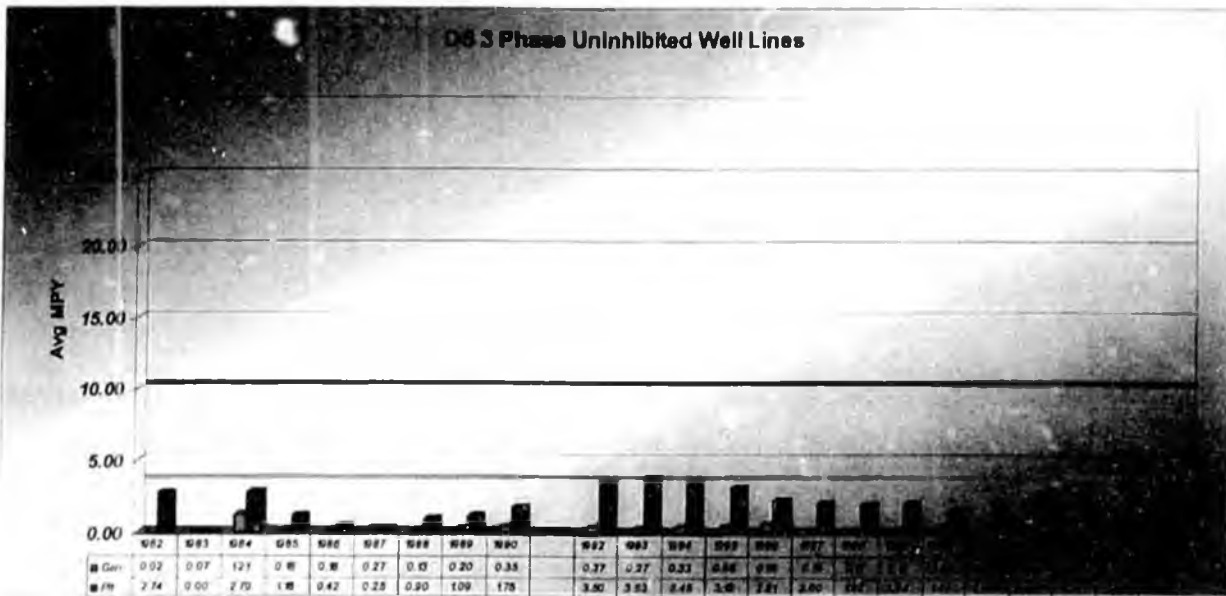


Figure 3. Water Injection Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.

*Water Injection Cross-Country Lines:* The monitoring data summarized in Kuparuk Tables 1 and 2 and presented in Figure 3 show that average general corrosion rates are below the threshold, but that pitting rates for the field are above the threshold. Seawater and produced water commingling was suspended at CPF2 in August 2005 and coupons replaced then; coupons were retrieved from CPF2 in late November with pitting rates reduced markedly from previous pulls. Coupon results are used to prioritize inspection efforts. During 2005 additional equipment was installed and procedures were implemented to provide enhanced biocide treatments at CPF2. Cleaning pigs were upgraded to include brushes in addition to the disks and the pigging procedures changed to include multiple (three) pig runs per monthly cleaning cycle.



**Figure 4. Three-phase Production Well Line Coupons – general and pitting corrosion rates as a function of time.**

*Three-phase Production Well Flow Lines:* While the monitoring data summarized in Kuparuk Tables 1 and 2 and presented in Figures 4 and 5 suggest that corrosion rates are below targets, inspection data indicate that higher corrosion rates have been experienced historically. The well line inspection data are discussed in section 3.1.b below, and are a good example of why monitoring data alone cannot be relied upon to characterize corrosion in a given system. For three-phase production, coupons monitor free flowing fluid and have not shown the predominant, under-deposit corrosion mechanism.

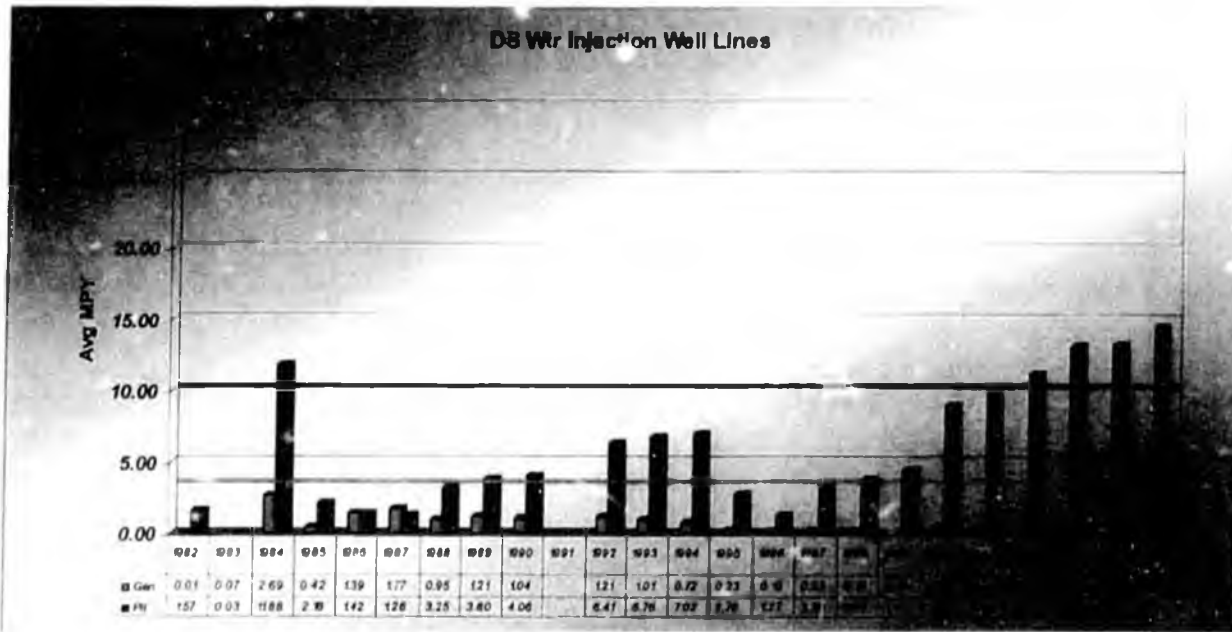


Figure 5. Water Injection Well Line Coupons – general and pitting corrosion rates as a function of time.

*Water Injection Well Flow Lines:* As discussed in section 3.1 b below, the well line inspection data on water injectors show that there are a significant number of corrosion related repairs. The water feeding this system is treated at the facilities with biocide and is discussed under Figure 3 - Water Injection Cross-Country Line Coupons. We believe that the increasing trend of coupon corrosion rates in the water injection well lines is caused by additional solids accumulating in the well lines because of low flow rates and improved pigging upstream of the well lines.

## Mitigation:

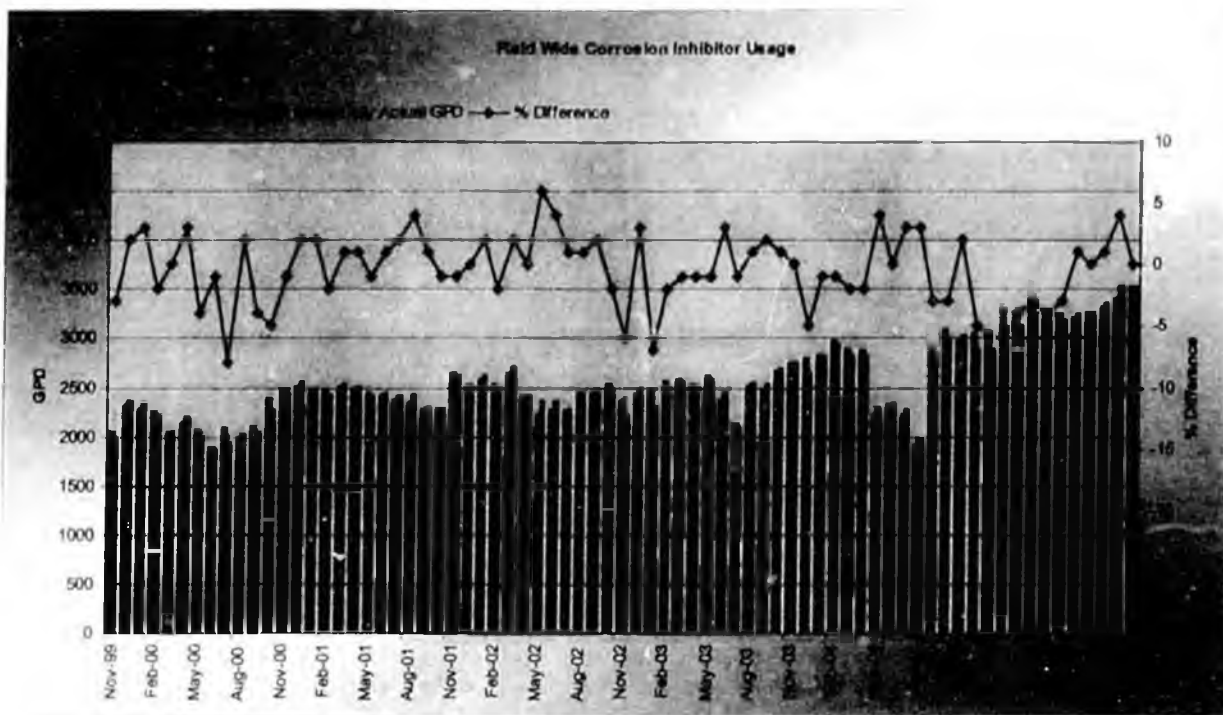


Figure 6. Field-wide Corrosion Inhibitor Use.

For the Kuparuk field, Figure 6 shows the actual number of gallons of corrosion inhibitor pumped per day, the recommended (target) number of gallons of corrosion inhibitor per day, and the percent difference between the two. The average deviation for the year was -1.85%. The large variation seen in the early parts of the year are usually caused by the extreme weather. Several pump upgrades were accomplished in 2005 to accommodate increased volumes.

The mitigation program is described in the inhibitor feedback flow chart, Figure 7 below. Reasons for changes to target inhibitor concentrations are given in Table 3 below.

Table 3 Three-phase Production Cross-Country lines with corrosion rates that exceeded targets and the action that was taken.

<u>Common</u> <u>Line</u>	<u>Probes</u>	<u>Coupon</u> <u>s</u>	<u>Inspectio</u> <u>n</u>	<u>Action Taken</u>
1DPO		x		Increased Target PPM
1EPO			x	Increased Target PPM
1LPO			x	Increased Target PPM
2APO			x	Increased Target PPM
2UPO				Reduced for Baker RE-5273 Test
2VPO				Reduced for Baker RE-5273 Test
2WPO				Reduced for Baker RE-5273 Test
2ZPO			x	Increased Target PPM
3NPO		x		Increased Target PPM
3OPO		x		Increased Target PPM
3QPO		x		Increased Target PPM

Kuparuk Inhibitor Feedback System

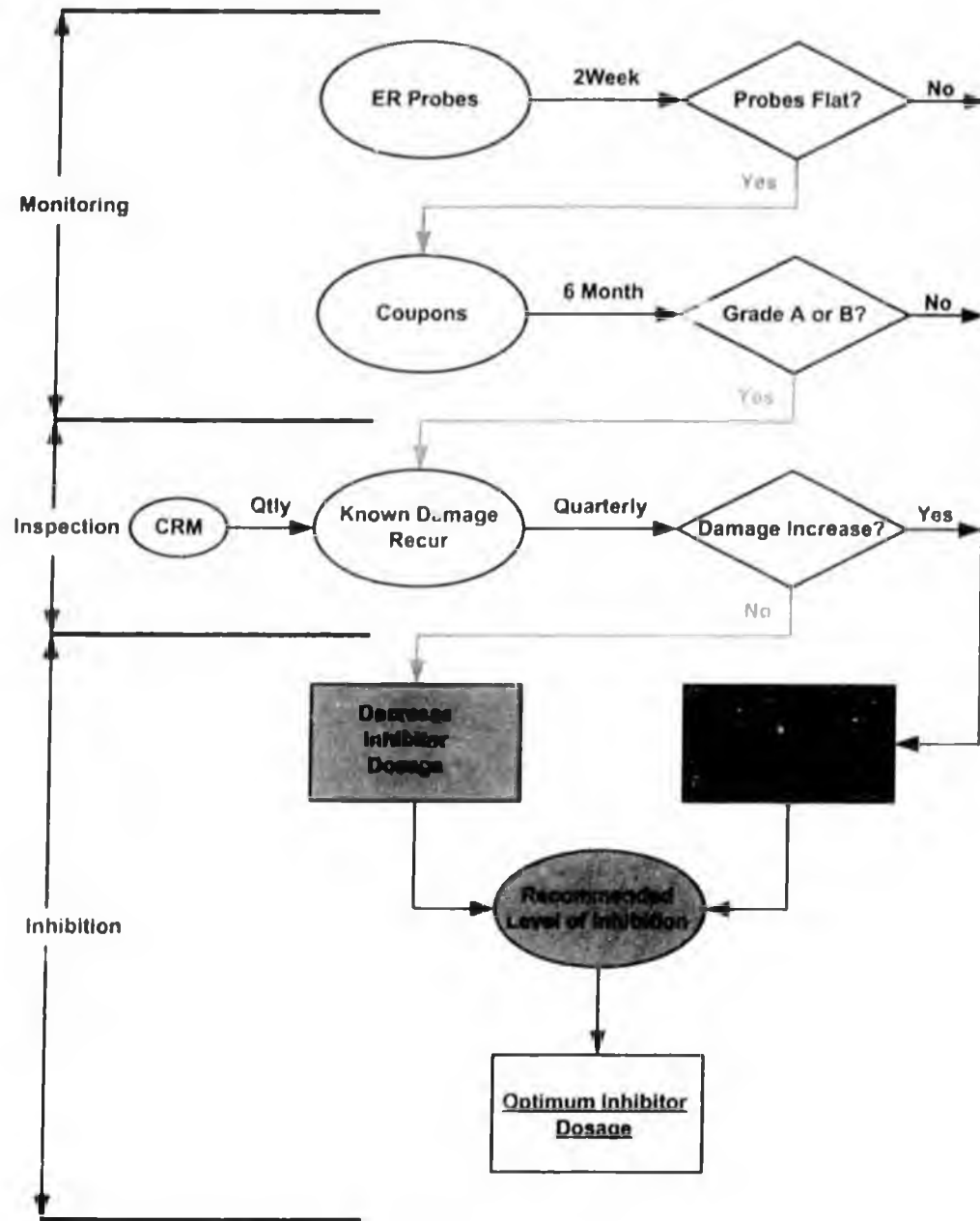


Figure 7. Corrosion Inhibitor Feedback System.

## 3.1.b Well Line Inspection

We met our primary 2005 goal by completing interval surveys on 133 well lines.

As indicated in Figure 8 below, repair recommendations were initiated on 18 well lines in 2005 because of internal corrosion or erosion damage (11 corroded water injection lines, 6 corroded production lines and 1 eroded production line). Except for the leak that was caused by erosion, the corrosion mechanisms were all underdeposit corrosion. More information on the leaks can be found in section 3.1.g.

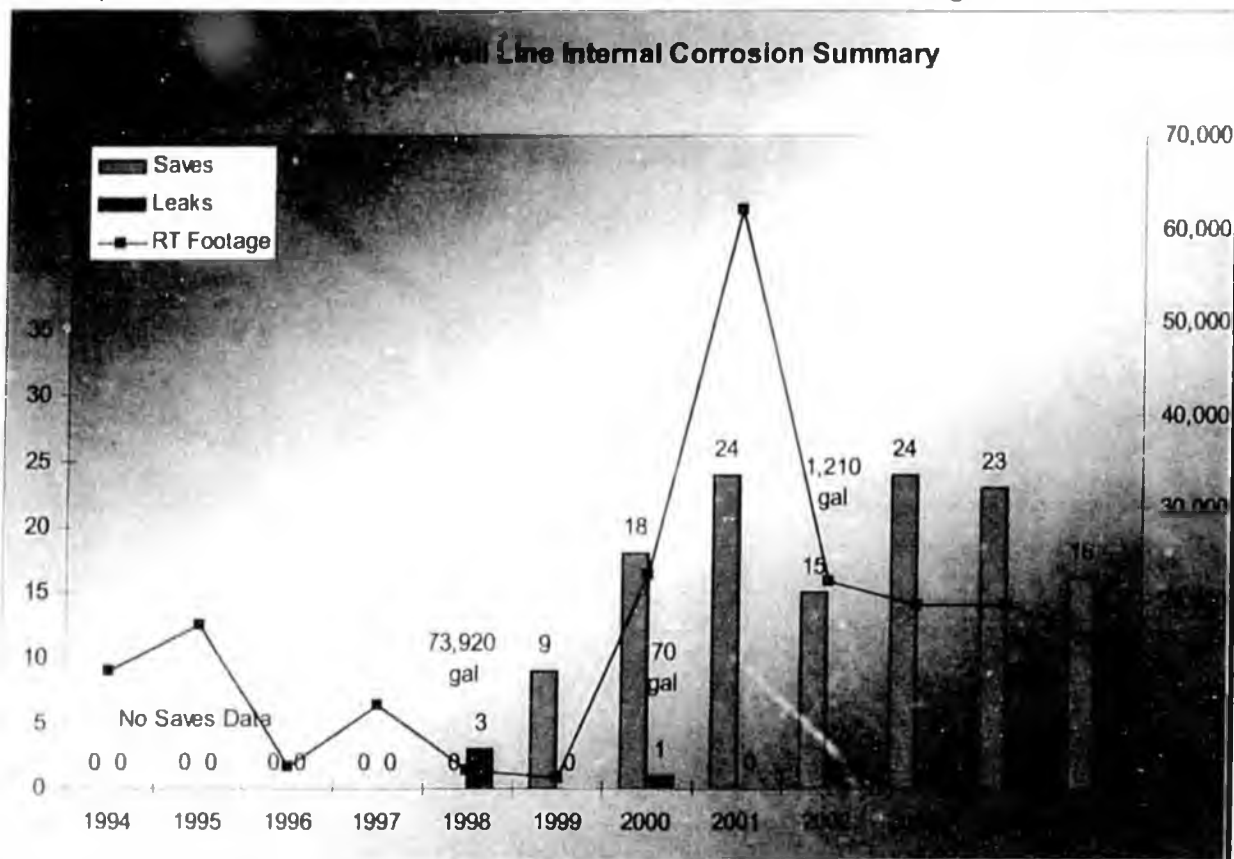


Figure 8. Summary of Well Line Internal Corrosion Inspections – RT footage, leaks, and saves as a function of time.

The 2005 results from the RTR surveys, manual RT, and manual UT are summarized in the following three tables.

- RTR of Well Lines:

Service	Feet Inspected	Number of Lines Inspected
Three-phase Production	8,980	77
Water Injection	5,379	56
Total	14,359	133

The 2005 RTR well line data indicated no new damage trends.

• Manual RT of Well Lines:

Service	Number of Lines Inspected	Number of Radiographs	Number of Repeat Radiographs	Number of Repeat Radiographs with Increases	% Of Repeat Radiographs with Increases
Three-phase Production	199	942	311	20	6
Water Injection	120	798	180	35	19
Total	319	1,740	491	55	11

The 2005 manual RT well line data indicate a possible increasing damage trend in the water injection well lines. The percentage of radiographs showing increased damage increased from 9% to 19% from 2004 to 2005.

• Manual UT of Well Lines:

Service	Number of Lines Inspected	Number of UT Inspections	Number of Repeat UT Inspections	Number of Repeat UT Inspections with Increases	% Of Repeat UT Inspections with Increases
Three-phase Production	167	894	769	53	7
Water Injection	65	296	253	31	12
Total	232	1,190	1,022	84	8

The 2005 manual UT well line data indicate a possible increasing damage trend in the water injection well lines. The percentage of radiographs showing increased damage increased from 8% to 12% from 2004 to 2005.

## 3.1.c Cross-Country Line Inspection

In 2005 we met our primary cross-country line goals by completing:

- Interval surveys on 33 cross country lines and
- An "On-pad Deadleg Inspection Survey" at all drill sites.

As indicated in Figure 9, 12 repair recommendations were initiated on cross-country lines (8 water injection, 4 production) because of internal corrosion damage in 2005. The corrosion mechanism for all repair recommendations was deadleg/underdeposit corrosion. All three leaks were in the water injection system. More information on the leaks can be found in section 3.1.g.

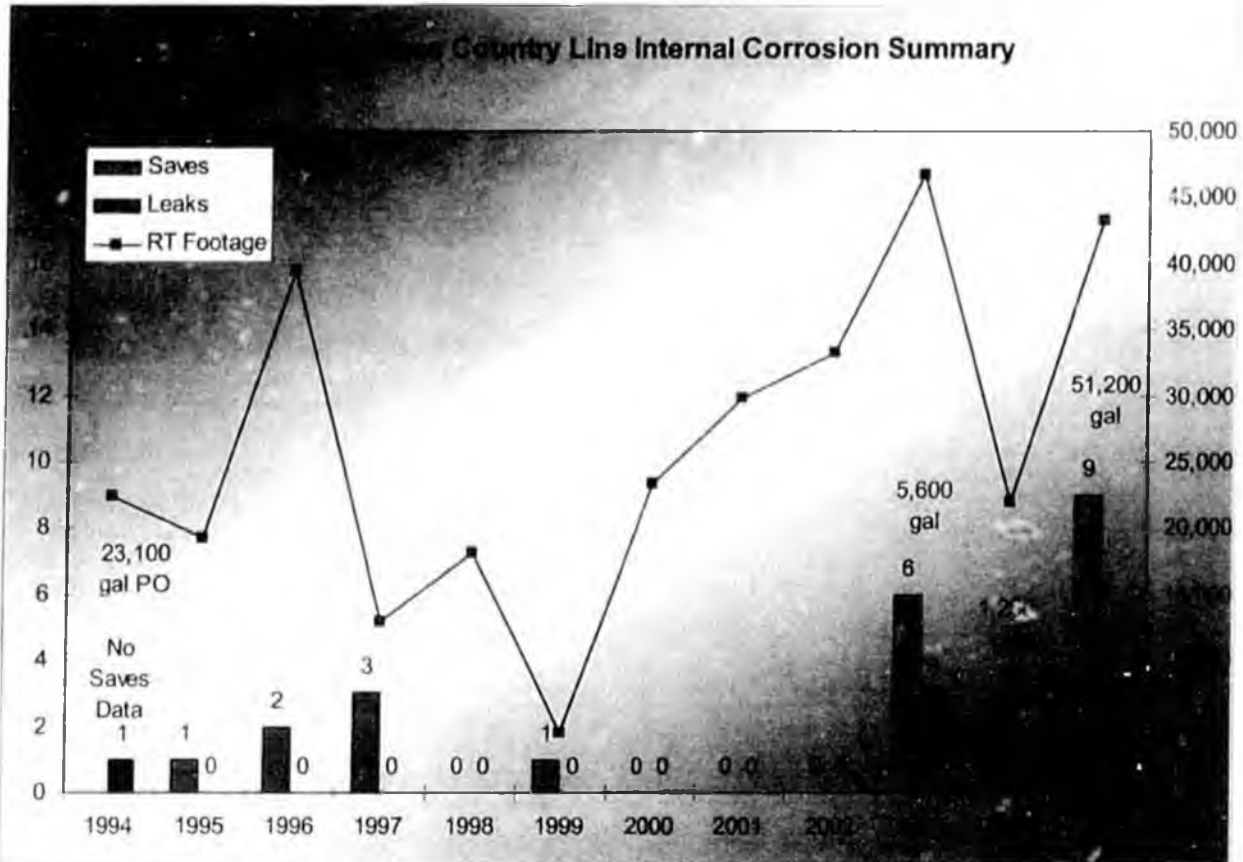


Figure 9. Summary of Cross-Country Line Internal Corrosion Inspections – RT footage, leaks, and saves as a function of time.

The 2005 results from the RTR surveys, manual RT, and manual UT are summarized in the following three tables:

### • RTR of Cross Country (CC) Lines:

Service	Feet Inspected	Number of Lines Inspected
Three-phase Production	6,067	8
Water Injection	28,267	25
Total	34,334	33

The 2005 RTR CC line data show an increase in the footage and number of lines inspected. This is a result of the failure analysis of the DS2K water injection line leak in 2005.

• Manual RT of CC Lines:

Service	Number of Lines Inspected	Number of Radiographs	Number of Repeat Radiographs	Number of Repeat Radiographs with Increases	% of Repeat Radiographs with Increases
Three-phase Production	115	3,274	533	21	4
Water Injection	52	5,633	70	8	11
Total	167	8,907	603	29	5

The only significant change in these data from 2004 to 2005 was that the 2005 RT CC water injection line data inspection results decreased in the percentage of radiographs indicating increased damage from 27% in 2004 to 11% in 2005; however, the 2004 RT inspection data had a small sample size and we believe that the larger 2005 sample size is more indicative of what is happening in the CC water injection system. In addition, the number of radiographs on water injection system increased and the number of repeat inspections increased due to the DS2K WI line failure analysis.

• Manual UT of CC lines:

Service	Number of Lines Inspected	Number of UT Inspections	Number of Repeat UT Inspections	Number of Repeat UT Inspections with Increases	% Of Repeat UT Inspections with Increases
Three-phase Production	64	950	378	20	5
Water Injection	39	414	101	21	21
Total	103	1,364	479	41	9

The only significant change in these data from 2004 to 2005 was that the 2005 UT CC water injection line data indicate an increasing damage trend. The percentage of repeat inspections indicating increased damage jumped to 21% in 2005 from 5% in 2004. In addition, the number of inspections on the water injection system increased and the number of repeat inspections increased due to the DS2K WI line failure analysis.

## 3.1.d External (Weld-Pack) Program

In 2005 we had several significant accomplishments:

- Completed 4,646 TRT surveys of cross country line and well line weld packs due for recur inspection.
- Completed our goal of inspecting 100 additional Tarn-style weld packs (~257 to date) to ensure this new design is working properly. The weld pack design appears to be performing as planned. No corrosion has been detected.
- Inspection of 100 refurbished weld packs to verify the soundness of the Denso Tape refurbishments. The refurbishment technique appears to be performing as planned.

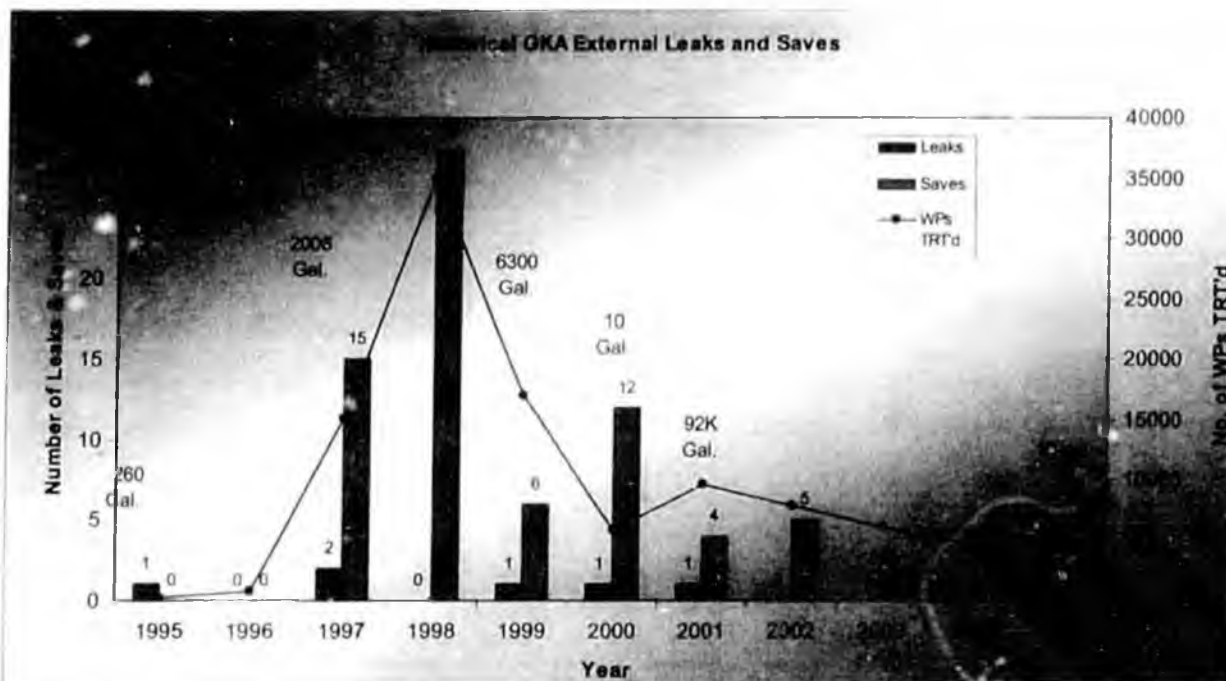


Figure 10. Leaks, saves, number of weld packs inspected with TRT, and volumes of leaks as a function of time.

### Cross-Country Lines (On-Pad and Off-Pad)

The baseline inspection effort for all cross-country lines was completed in 2004. Starting in 2005, the focus changed from making sure that all CUI locations were inspected and included in our inspection program to one of recur inspections priority-based on corrosion risk. A goal of 4,250 CUI locations on cross-country lines over tundra (off-pad) and on-pad was set. A total of 3,299 CUI locations were inspected. The goal was missed mainly because of lost TRT crew time spent on special projects such as follow-up work related to the DS2K WI and DS3J PO leaks. An estimate of the number of CUI locations was generated at the beginning of the year. The actual number of CUI locations turned out to be less than the estimate. Lastly, fewer weld packs were inspected late in the year after the TRT inspection guideline was modified as a result of the enhanced inspections related to the findings from the DS3J PO leak. The new guideline involves inspection at the pipe 6 o'clock position as before, and has been expanded to include a minimum of an inspection at 12 o'clock (the top of the pipe) if medium or heavy water is detected at 6 o'clock position.

A total of 103 locations on the over-tundra lines were found with corrosion. One location required installation of a temporary sleeve (DS3K PO). A total of 94 cross-country on-pad locations were recur inspected in 2005 using TRT. Only one location (DS3J PO near leak) was found to have corrosion; it was placed on the refurbishment list.

Included in the 3,299 TRT inspections noted above, 157 of the new Tarn-style weld packs were inspected with TRT to gauge how they are holding up in service. A total of six weld packs were found with light-wet insulation. The rest were found to be completely dry. No corrosion under insulation (CUI) was found in any of the areas inspected.

External corrosion at on-pad CUI locations was also found while doing other inspection or maintenance work. This effort resulted in two sleeve repairs (CPF1 MI, 2KHWI @ DS2B).

A change in the way external corrosion locations will be reported was started in 2005. In the past, CUI locations in support saddles over a VSM were counted as one location. This report, and all future reports, break each support saddle location into two distinct pieces with the VSM centerline as the dividing point. The motivation behind this change was to aid in the layout and recur inspections at these locations. This will affect the total reported number of CUI locations by essentially doubling the number of CUI locations associated with saddles.

### Well Lines

In 2005, 1,347 well line CUI locations were examined. Our stated goal was 1,500 weld packs (based on inspection of seven lines); the reason for the underestimate in the number of weld packs is the uncertainty in the total count of the well line CUI locations before inspections commenced. The number of CUI locations is estimated based on the length of a typical section of pipe. Corrosion was found at 46 of the 1,347 locations. No piping repairs were required. The corroded weld packs were refurbished.

**Table 5: External CUI Inspection Summary for 2005.**

Type of Equipment	2005 Goal	Number of Locations Inspected	Number of Corroded Locations	Percentage of Locations Corroded	Number of Locations Refurbished
Cross-Country Lines Over Tundra or On-Pad	4,250	3,299	103	3.1	953
Well Lines	1,500	1,347	46	3.4	58
<b>Total</b>	<b>5,750</b>	<b>4,646</b>	<b>149</b>	<b>3.2</b>	<b>1,011</b>

The number of CUI locations inspected with TRT, the number of CUI locations found corroded, and the percentage of CUI locations corroded for the cross-country lines over tundra, cross-country lines on-pad, and well lines are given in Figures 11, 12, and 13 beginning on the next page.

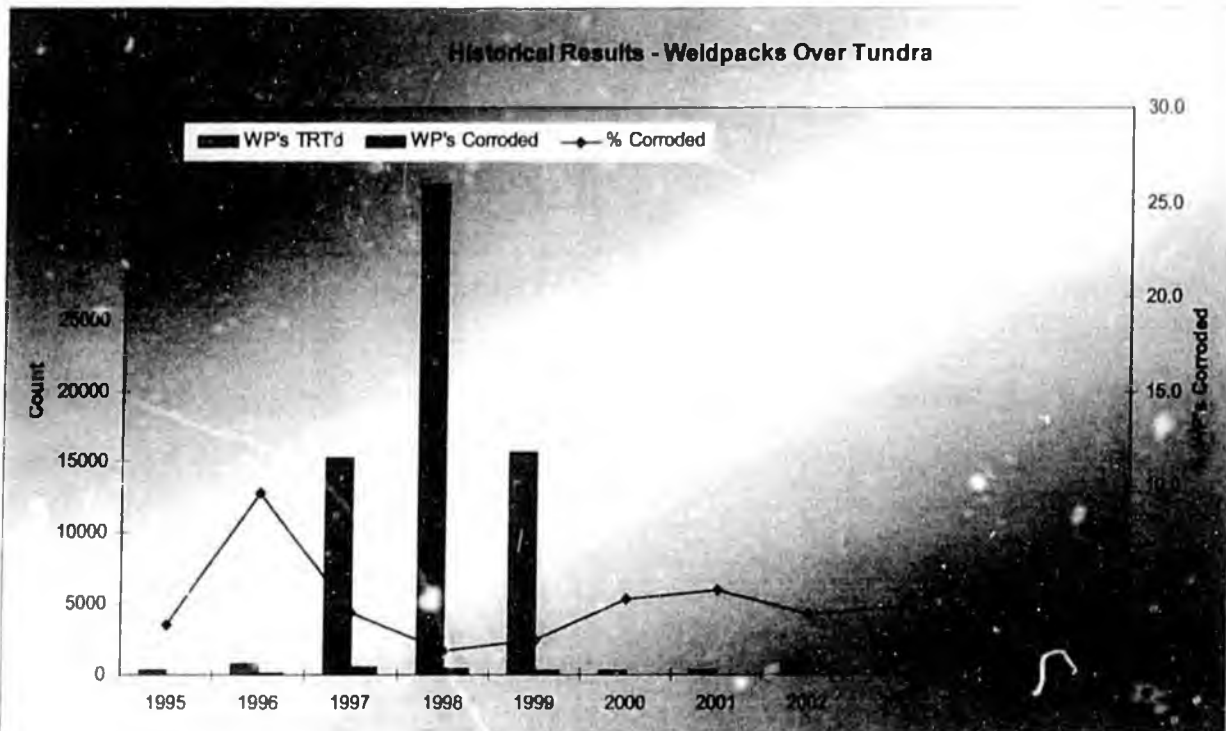


Figure 11. Summary of Weld Packs on Cross-Country Lines over Tundra (off-pad).

Figure 11 illustrates the most-complete external corrosion inspection program of the three external corrosion programs. 2002 through 2005 values include re-inspections and clean-up of locations missed or not properly documented during the original base line effort.

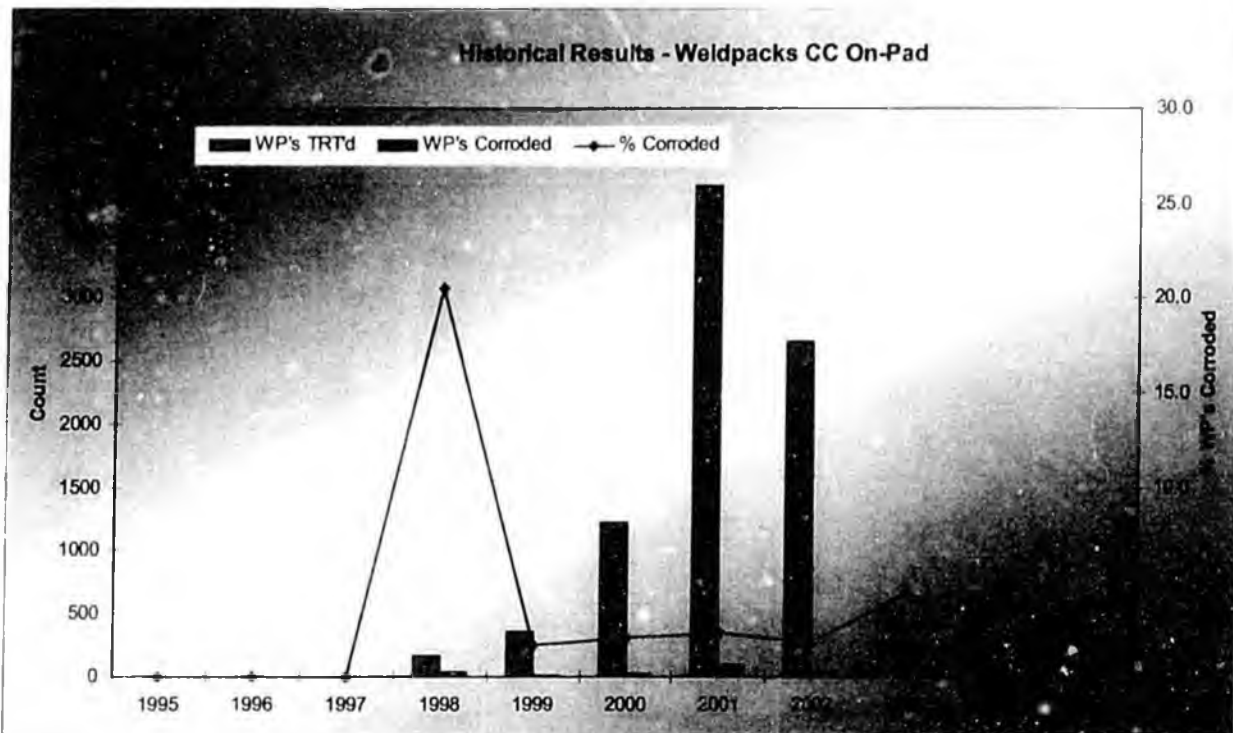


Figure 12. Summary of Weld Packs on Cross-Country Lines on Pads.

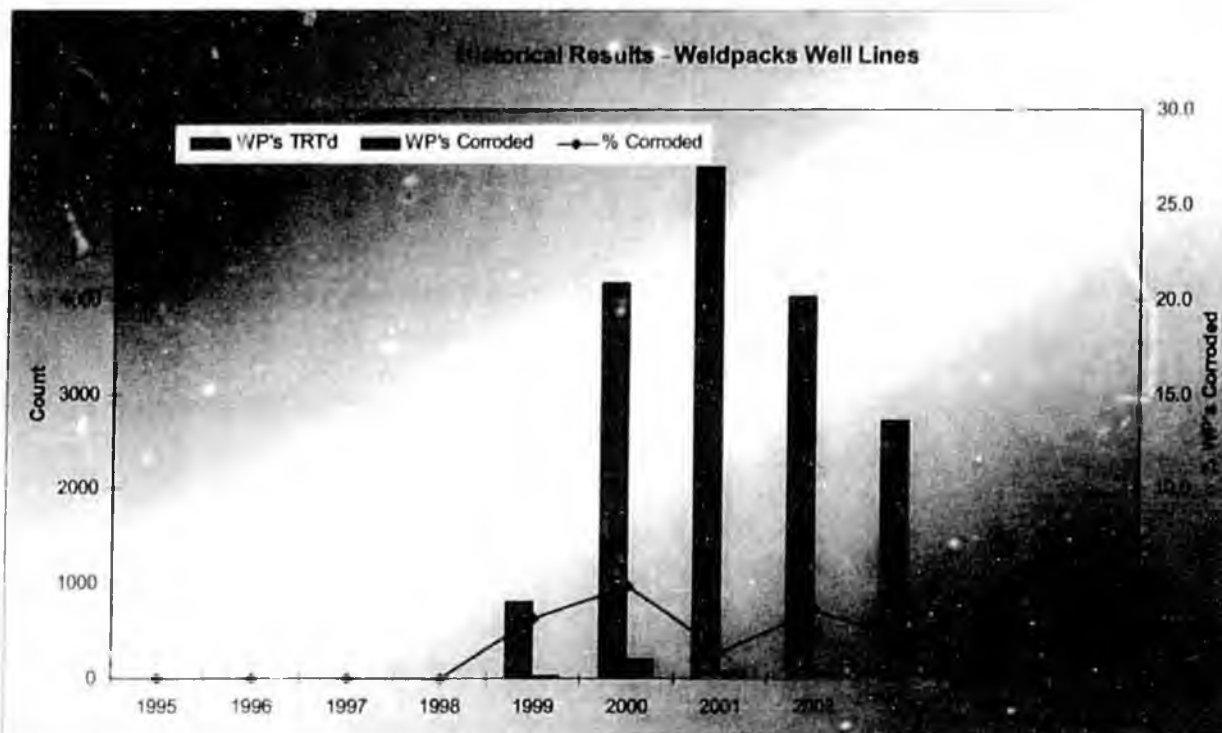


Figure 13. Summary of Weld Packs on Well Lines.

## Corrosion Under Insulation Buffer Spike Program

In 2002, a test of "CUI Buffer Spikes" was initiated on 50 over-tundra cross-country weld pack locations. The concept is that by establishing an alkaline environment within the weld pack the corrosion rate can be reduced to an acceptable level at a lower cost than stripping and refurbishing the wet insulation.

The program was expanded later in 2002 by an additional 39 locations to include weld packs on drill site well and facility piping. In addition, two electric resistance probes were installed in two heavy water weld packs at DS1E to monitor potential corrosion activity. The sodium phosphate salt contained in these spikes dissolves in wet insulation and raises the pH to 10. Prior to installation of these spikes, wet insulation measurements fell within a consistent 6 to 7 pH range. During 2003, each of these locations was monitored for pH. The 2003 follow-up inspections showed that the pH did rise in the wet areas of the weld packs. Three locations were also stripped and tested with an indicator dye to verify the pH probe results.

TRT inspections of the buffer spike locations were performed during 2005 and early in 2006. All locations were re-inspected. Seven weld packs indicated an increase in the water content. None of the inspections reported any new corrosion. The survey revealed that 19 of the locations had been inadvertently refurbished. Visual inspection of the exposed pipe in these locations discovered very slight external corrosion (three-to-four percent wall loss) at three of these locations. It is likely that this minor corrosion was present before the buffer spikes were introduced. Corrosion damage that slight would have been difficult to detect using C-Arm (CART), especially with water in the insulation.

A pH survey was conducted during the summer of 2005 to test approximately 60 locations. Testing indicated that the spikes were maintaining an alkaline environment inside of the weld packs. An indicator dye check was conducted on two of the weld packs to verify that the pH profile across the insulation thickness was showing a high alkaline environment at the pipe wall. These tests showed that the buffer spikes were maintaining a high pH close to the pipe.

Monitoring of the ER probes at DS 1E indicated low, but not zero, corrosion rates. These probes collect a reading every six hours and the data are downloaded every two weeks.

The buffer spike concept has been tested over a sufficient timeframe to collect meaningful results. A final report on the project is forthcoming from our Bartlesville research center. Review and discussion of the results shall be conducted and a plan determined in 2006.

### 3.1.e Below Grade Piping Program

This section details the inventory and survey of below grade piping circuits and the results of Specialty Testing. The plans for future inspections are given in section 3.2.e.

In 2005 we had several significant accomplishments:

- Visually inspected and cleaned all debris from all cased below grade pipe circuits.
- Completed our specialty inspection (TWI) scope of work.
- Excavated, inspected, refurbished and repaired (as required) 24 cased below-grade pipe circuits.

The Alaska Department of Environmental Conservation (ADEC) regulations under 18 AAC 75.080 applies to the Kuparuk oilfield facilities operated by ConocoPhillips Alaska, Inc. (CPAI). To meet the requirements of 18 AAC 75.080, CPAI submitted their corrosion control program for below-grade piping in early 1998. The program also included a field-wide inventory of all below-grade piping in the Kuparuk field. ADEC approved the program in written correspondence dated October 26, 1998.

#### 3.1.e (1) Inventory and Survey of Below Grade Locations

GKA has 772 circuits (includes priority 1, priority 2 and priority 3 lines) of below grade piping. Of these locations, one is contained in an utilidor. The remaining circuits are cased lines, the majority of which are either road, gravel pad or caribou crossings.

##### Utilidor Line

The line in the utilidor (Oily Waste Injection Line, BG ID #286) was taken out of service in 2004. It had been on a two year inspection cycle and was last inspected in 2002. Because it has been taken out of service the 2004 inspection was deferred and no 2005 inspection was done.

##### Cased Lines

###### Inspection Status:

The annual visual survey of all the cased lines was conducted in 2005. The purpose of the survey was to identify, rectify, and report local conditions (e.g., debris found in casings and culverts, pipe insulation in contact with soil) that require remedial action.

###### Results and Remedial Action:

Of all GKA below-grade circuits, 107 were found to have pipe in direct contact with gravel/soil or debris in the casing. All locations were remediated in 2005.

#### 3.1.e (2) Results of Specialty Testing

###### Inspection Status:

In 2005, we completed TWI inspections on 127 GKA priority one circuits. This was the third year of our recurring inspection program where each priority one circuit will be inspected at a maximum ten-year interval.

In 2005 only the long-range ultrasonic system technology from The Welding Institute (TWI) was used. TWI technology is capable of finding evidence of both internal and external corrosion damage.

## Results and Remedial Action:

Table 6 shows the results of the specialty testing performed by TWI.

**Table 6. Results from the TWI inspections by service.**

Service	Number of Cased Circuits Inspected	Incomplete or Inconclusive Results (I)	Number without any Significant Indications (N)	Number of Minor (Low) Anomalies (L)	Number of Minor to Moderate and Moderate Anomalies (M)	Number of Moderate to Severe and Severe Anomalies (S)
Oil	13	0	8	3	2	0
Other	114	26	47	34	7	0
Total	127	26	55	37	9	0

The 2005 TWI data indicated no new damage trends.

### 3.1.e (3) Results of Crossing Digs

After a revised risk assessment of the below-grade piping circuits that included water accumulation points, the number of below-grade piping circuits excavated was increased from eight in 2005 to 24 in 2006.

There were 24 below-grade circuits refurbished in 2005. Twenty-three circuits were excavated and one was replaced without excavation (cut and pulled through casing). Four of these circuits were considered repairs:

- Two repairs were made because of CUI damage only (West Trunk EOR at CPF1 and HPO at DS 1H pad). The EOR circuit was replaced and the HPO circuit was repaired with a pressure containing sleeve.
- One repair was made because of internal damage only (2KWI at 2H pad). This piping circuit was replaced by cutting and pulling the old pipe from the casing and pulling the new pipe into the casing.
- One repair was made because of a combination of CUI and internal corrosion damage (2KHBWI at the 2B pad crossing). This circuit was repaired with a pressure containing sleeve.
- Twenty of the excavated circuits inspected did not require de-rating, repair, or replacement because only minor or no corrosion damage was found.

For all twenty-four below grade circuits excavated in 2005, the insulation was refurbished and the pipe wrapped with Densyl tape to prevent further corrosion.

### 3.1.f Other Structural Concerns

#### Subsidence:

#### Existing Well Upgrade Program

- In 2005, four steel, conductor-mounted floor kits were installed in well houses at Drill Sites 1E, 2A, and 2Z. Well house floors are supported by the well conductor and provide table riser piping supports.
- In 2005, 17 heat tubes were installed at Drill Sites 1E, 2A, 2C, 2H and 3N. Heat tubes are used to keep the ground frozen or to re-freeze the ground where it has been thawed.

## New Wells & Producer to Water Injection Well Conversions

- In 2005, 10 newly drilled wells at Kuparuk were installed with insulated conductors.
- In 2005, ten newly drilled wells had heat tubes installed. Of these 10 newly-drilled wells, two had floors with permanent pipe supports.
- In 2005, four existing producers converted to water injection wells or converted to jet pump lift already had insulated conductors and heat tubes and did not require a floor kit.

## Wind-Induced Vibration:

As a result of the 3A-I-M eight-inch gas lift line failure that occurred in December 2004 (described in section 3.1.g of the 2004 report), Kuparuk continues to review existing pipelines to evaluate the need for secondary mode vibration dampers.

During original development of the North Slope WIV program, secondary mode WIV failures were deemed highly unlikely and therefore mitigating measures for such events were not established. However, based on the unforeseen December 2004 secondary mode WIV failure on the DS3I 8" GL line, an effort to determine if secondary mode WIV is expected to be a fatigue threat to all the pipelines within the Kuparuk Wind Fan was sanctioned.

Through a comprehensive field-wide inventory of all the pipelines within the current Kuparuk Wind Fan and a more-detailed WIV analysis than had been possible previously, a critical Reynolds Number ( $R_c$ ) corresponding to the "random shedding" threshold has been established. Vibration modes established below this "random shedding" threshold are referred to as "sub-critical" modes and pipelines subject to these conditions are most susceptible to both primary and secondary mode WIV responses.

As a result of these analyses, up to 440 pipe spans will receive secondary mode WIV protection in 2006. More detailed evaluations will be completed once enhancements are completed to the WIV evaluation model to take into account broad-banded WIV events more typical of higher wind velocities.

## 3.1.g Corrosion and Structural-Related Spills/Incidents:

- Well 2A-17 production well line leaked in March 2005 because of erosion in a two inch branch line off of the main six inch line at the 2<sup>nd</sup> elbow (lower) from the well head. The spill volume was less than one gallon of produced fluids and was confined to the well-house floor. No fluids contacted the tundra or the gravel pad. As such, it was determined to not be an ADEC reportable spill. This location is inspected on a regular basis during our well line interval survey. As a result of this leak all other erosion susceptible areas on this line were inspected and no additional erosion was found.
- Well 1G-09 water injection well line leaked in July 2005 because of a combination of internal under-deposit corrosion and CUI damage at a weld pack located in a saddle. The spill volume was determined to be 13 gallons. The spill was reported to ADEC. As a result of this leak the previous internal and external corrosion inspection records were reviewed. The review indicated that this line and the location of the leak had received regularly scheduled inspections within a time frame which should have detected the damage before the leak. As a result of this finding inspection records for several other lines and locations were reviewed under the inspection contractor's QA/QC program. This review resulted in tighter controls regarding RTR inspections of lines with high solid build-up and more coverage of CUI areas when found to be "Medium Wet."
- Drill site 2K water injection line leaked in March 2005 in the below-grade circuit at DS 2H pad because of internal corrosion damage. The spill volume was determined to be 51,198 gallons. The spill was reported to ADEC. As a result of the leak, a formal Failure Analysis that included ADEC and BP representatives was completed on this incident. Several enhancements to our monitoring, inhibition and inspection programs have been initiated based on this report.

- Drill site 2H warm-up line leaked in April 2005 under the 2H manifold building because of internal under-deposit corrosion in a dead-leg. The spill volume was less than one gallon of produced water confined to the pipe surface and the snow on top of the gravel pad. As such, it was determined not to be reportable to ADEC. This location was scheduled to be inspected under our "On-pad Deadleg Inspection Survey" in 2005. Unfortunately the leak occurred before our crews inspected it. We are confident that the damage would have been detected, and the location repaired before the leak, under our current inspection methods and procedures if the location had been scheduled earlier in the year. It should be noted that inspection of all piping similar to this at all drill sites was completed in 2005.
- Drill site 2U warm-up line leaked in December 2005 under the 2U manifold building. The same comments as noted in 2H (directly above) apply to this leak.
- The DS3J produced oil line leaked in October 2005 because of external corrosion at a weld pack located partially in a saddle. The spill of 16 gallons of produced fluids was reported to ADEC. There were three perforations in the weld pack area, with the heaviest corrosion located near the top of the pipe. Corrosion was noted around the entire circumference over two feet of the five-foot corrosion network. The 6 o'clock position of this particular location had been scanned with C-arm TRT (CART) in 2001 and determined to have no corrosion. CART is not strong enough to inspect the pipe through the saddle so the location would have been scanned right up to the saddle and then picked up again on the other side. The weld pack had been labeled as having CART inspection only. This failure has led the Corrosion Department to re-evaluate several aspects of its external corrosion program. Specifically, the layout and labeling guidelines have been reviewed and updated to assure that a CUI location will not be missed. Additionally, the weld pack inspection guidelines have been updated to include inspection of the upper portion of the pipe when medium or heavy wet insulation is detected at the six o'clock position or when a penetration exists in the outer jacket up high on the pipe (e.g., a branch connection, tear, etc.).
- No leaks were caused by subsidence in 2005.

Figures 8, 9, and 10 show the number of leaks and the volumes of leaks as a function of time. Figure 8 depicts the leaks caused by internal corrosion for the well lines. Figure 9 depicts the leaks caused by internal corrosion for the cross-country lines. Figure 10 shows the leaks caused by external corrosion for cross-country lines, well lines, and below-grade piping locations.

### 3.2 Year 2006 Forecast

#### 3.2.a Monitoring & Mitigation

- Test additional inhibitor formulations.
- Continue to evaluate the biocide program and the maintenance pigging enhancements to the water injections systems.
- Increase biocide and maintenance pigging in the seawater system.
- Expand guideline for use of brush / disk combo cleaning pigs to CPF1 and CPF3.

#### 3.2.b Well Line Inspection

Our recurring inspection program will continue in 2006. No in-service line will go longer than 10 years without some type of inspection.

### 3.2.c Cross-Country Line Inspection

Our recurring inspection program will continue in 2006. No in-service line will go longer than 5 years without some type of inspection.

Smart pigging is planned for the 30-inch sea water line from the STP to the CW skid.

### 3.2.d External (Weld-Pack) Program

Cross-country lines over tundra:

- Inspect approximately 3,950 cross-country line weld packs (based on seven lines) as part of our recurring inspection program. This includes CUI locations over tundra as well as on-pad.
- Inspect a minimum of 100 Tarn-style weld packs (insulation not touching the pipe) with TRT to continue to evaluate the efficacy of the design.
- Inspect a minimum of 100 refurbished weld packs to continue to evaluate the performance of the Denso tape system.

Well lines:

Inspect approximately 1,500 well line corrosion-under-insulation locations (based on 130 lines) as part of our recurring inspection program.

### 3.2.e Below Grade Piping Program

- Continue our annual visual inspection of all (Priority 1, 2, and 3) cased lines. The appropriate GKA field department will be notified of any corrective actions early enough to complete clean out and re-inspection during the summer.
- Continue our recurring TWI inspection program of priority one cased lines.
- Excavate, inspect, refurbish, and repair (as necessary) fifteen to twenty-seven lines in cased crossings.
- Continue to work with TWI and ConocoPhillips R&D to refine inspection data reduction and interpretation.

### 3.2.f Other

- Continue enhancements to the Kuparuk Corrosion Database.
- Continue to evaluate, and prioritize subsidence mitigation efforts at the existing drill sites.

## 4.0 Program Status Summary - WNS

### 4.1 Year 2005 Overview

#### 4.1.a WNS Monitoring & Mitigation

Average general and pitting coupon corrosion rate data for Year 2005 are presented in Tables 7 and 8.

**Table 7. Average general corrosion rates for corrosion coupons by service category.**

Asset Group	Number of Lines with Coupons Analyzed	Coupon Average General Corrosion Rate, mpy (target=<3)	Number of Lines with Conformant General Corrosion Rates	Percent of Lines with Conformant General Corrosion Rates
Three-phase Production Cross-Country Lines	1	0.1	1	100
Seawater Cross-Country Lines	1	2.4	1	100
Seawater Injection Cross-Country Lines	0			
Production Well Flow Lines	29	0.5	28	96*
Seawater Injection Well Flow Lines	9	0.1	9	100

\* The one line with greater than 3 mpy CR was due to erosion

**Table 8. Average pitting corrosion rates for corrosion coupons by service category.**

Asset Group	Number of Lines with Coupons Analyzed	Coupon Average Pitting Corrosion Rate, mpy (target=<10)	Number of Lines with Conformant Pitting Corrosion Rates	Percent of Lines with Conformant Pitting Corrosion Rates
Three-phase Production Cross-Country Lines	1	2	1	100
Seawater Cross-Country Lines	1	1	1	100
Seawater Injection Cross-Country Lines	0*			
Production Well Flow Lines	29	1.8	28	96
Seawater Injection Well Flow Lines	9	4.7	9	100

\* NOTE: This coupon location is currently not accessible because of a new piping obstruction.

#### 4.1.b Well Line Inspection

In 2003, 33 three-phase production lines and 22 water injection lines were inspected; no damage was found. In 2004, 18 three-phase production lines were inspected at direction changes; no damage was found. In 2005, 32 well lines were inspected, no damage found.

#### 4.1.b Cross-Country (CC) Line Inspection

2,900 ft of the CD2 produced crude CC line was inspected with R.R. No damage was identified.

#### 4.1.d External (Weld-Pack) Program

No inspections for external corrosion were performed.

#### 4.1.e Below Grade Piping Program

This section details the inventory and survey of below grade locations and the results of Specialty Testing. The plans for future inspections are given in section 4.2.e.

##### 4.1.e (1) Inventory and Survey of Below Grade Locations

CPAI has 15 locations of below grade piping in the WNS, and 30 associated with WNS at GKA. These locations are cased lines at road or pad crossings.

##### Cased Lines

##### Inspection Status:

The annual visual survey of all the cased lines was conducted in 2005. The purpose of the survey was to identify, rectify, and report local conditions (e.g., debris found in casings and culverts, pipe insulation in contact with soil) that require remedial action.

##### Results and Remedial Action:

Of all the below-grade lines, two lines were found to have pipe in direct contact with soil and/or gravel/soil or debris in the casing. These two lines are considered to be "direct buried". Locations were excavated, evaluated and a request for waiver, contingent on a stringent inspection program, has been submitted to ADEC. The next inspection of the buried portions will be in 2009.

##### 4.1.e (2) Results of Specialty Testing

No specialty testing was performed in the WNS in 2005. Of the 45 WNS below grade circuits, 10 are smart pigged with the remainder of the line. The remaining circuits will be inspected with TWI at their 10 year (max) interval even though they are externally coated.

##### 4.1.e (3) Results of Crossing Digs

Two lines were excavated and are referenced in Results and Remedial Action above.

#### 4.1.f Other Structural Concerns

##### **Subsidence:**

- No concerns identified.

##### **Wind-Induced Vibration:**

No problems identified in 2005.

## 4.1.g Corrosion and Structural-Related Spills/Incidents:

- No leaks were caused by external corrosion in 2005.
- No leaks were caused by wind-induced vibration in 2005.
- No leaks were caused by internal corrosion in 2005.
- No structural or subsidence concerns were identified in 2005.

## 4.2 Year 2006 WNS Forecast

### 4.2.a Monitoring & Mitigation

- Pull coupons as scheduled
- Ensure new drill site development provides for adequate monitoring.

### 4.2.b Well Line Inspection

Inspect 15 lines, 15% of existing total for internal corrosion.

### 4.2.c Cross-Country Line Inspection

Obtain spot RT of CD1 PC line (on pad).

### 4.2.d External (Weld-Pack) Program

Cross-country lines over tundra:  
No inspections planned.

Cross-country lines on pad:  
No inspections planned.

Well lines:  
TRT most likely locations for CUI on 20 lines.

### 4.2.e Below Grade Piping Program

Continue the annual visual inspection of all priority one and two cased lines. The appropriate CPAI field department will be notified of any corrective actions early enough to complete clean out and re-inspection during the summer.

### 4.2.f Other

Continue Alpine piping layout and piping information database development.

## APPENDIX A Glossary

### Equipment Classification:

- **Well Line** – Pipe from the wellhead to the Drill Site manifold. For production wells, a well line handles the flow from a single well prior to commingling with fluids from other wells and transportation to the Central Processing Facility. For water injection wells, a well line handles the water flow going from a common manifold to a single wellhead.
- **Cross-Country Line** – Pipe from the Drill Site manifold to the Central Processing Facility (CPF).
- **Below-Grade Location** – That portion of a single pipeline, which crosses underneath a road or other earthen feature at a single location. The linear extent of the location consists of the length of pipeline between casing ends.

### Service Definitions:

- **Three-phase Production** – Basic reservoir fluids (oil, water, and gas) produced from down hole through to the CPF. Typically sees changes in temperature and pressure only from reservoir changes and are essentially un-separated.
- **Seawater (SW)** – Water from the Beaufort Sea that has been treated at the Seawater Treatment Plant (STP). Note that seawater treatment at the Kuparuk STP consists of filtration, oxygen stripping using produced gas, and biociding.
- **Produced Water (PW)** – The water separated at the CPF from three-phase production.
- **Mixed Water (MW)** – Produced water and seawater that have been commingled.
- **Gas** – Generic term for the different gas systems that transport dry (no liquids) gas between facilities. Includes fuel gas, artificial lift gas, and miscible injectant.
- **Produced Oil** – The liquid hydrocarbon separated at the CPF from three-phase production.

### Inspection Terminology:

- **CRM** – Corrosion rate monitoring.
- **UT** – Ultrasonic testing
- **RT** – Radiographic testing
- **RTR** – Real time radiographic testing
- **TRT** – Tangential radiographic testing
- **PTI** – Profile Technologies Inc. (Electro magnetic inspection)
- **TWI** – The Welding Institute (Long range UT)
- **KDR** – Known damage recur inspection
- **Leak** – Through-wall pipe damage that causes loss of product. Product volume may not be sufficient to be classified as a "spill".
- **Save** – When the Corrosion Group recommends a repair before a leak occurs.
- **Below Grade (priority 1)** – These are pipes with a higher probability and consequence of failure. In general they have larger diameters and higher pressures and would probably cause damage to the environment or cause safety concerns if they leaked.
- **Below Grade (priority 2)** – These are pipes with a lower probability or consequence of failure. In general, these have smaller diameters and lower pressures and would probably cause little, if any, environmental damage or safety concern if they leaked. Examples include un-insulated dry gas lines and flare lines.
- **Below Grade (priority 3)** – These are pipes with a low probability and consequence of failure. Examples include decommissioned pipes, pipes in fresh or fire water service and pipes constructed of corrosion resistant materials. In addition, they contain product that would cause little, if any, environmental damage or safety concern the pipe leaked.

**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

# 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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January 2002

ADEC Contract Number – 18-6000-02

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## EXECUTIVE SUMMARY

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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 material from the April 2001 Meet & Confer session. The goal of this review is to examine the corrosion program report, gain a qualitative understanding of BPXA's corrosion control program and identify recommendations for improvement to the content and extent of topics covered.

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

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

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

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

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

## COMMITMENT TO CORROSION MONITORING

---

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

- A. Annual bullet item reporting the progress of the Charter Agreement corrosion related commitment.
- B. A general overview of the previous year's monitoring program.
- C. Metrics which depict coupon and probe corrosion rates.
- D. Metrics which characterize chemical optimization activities.
- E. Metrics which depict the number and type of internal/external inspection done and, as applicable, the corrosion increases/rates and corresponding inspection intervals.
- F. Metrics which characterize the quantity and type of repairs made in response to the internal/external inspections done per the above paragraph.
- G. Metrics which depict the numbers and types of corrosion and structural related spills and incidents.
- H. A forecast of the next year's monitoring activities in terms of focus areas and inspection goals. These forecasts cannot be viewed as binding, as corrosion strategies are dynamic and priorities will change over the course of the year. However, changes in focus will be communicated to ADEC during the semi-annual meeting described above.

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

## **CORROSION CONTROL STRATEGY**

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

### **Internal Corrosion Strategy**

#### *Monitoring & Inspection*

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

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

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

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

### *Mitigation*

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

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

### **External Corrosion Strategy**

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

### *Monitoring & Inspection*

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

### *Mitigation*

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

## **CORROSION PROGRAM STATUS**

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### **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 be 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, 290 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 form 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 be 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

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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

# 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

Submitted by



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## EXECUTIVE SUMMARY

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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

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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<sub>2</sub>S)), 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**

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### **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

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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

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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 contains 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**

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### **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.

Coupons 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<sub>2</sub> 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 where 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			
<b>Totals</b>	<b>200,000</b>	<b>15,405</b>	<b>79,951</b>	<b>40%</b>	<b>120,049</b>	<b>35,000</b>

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<sub>2</sub>." 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<sub>2</sub> 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 an 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<sub>2</sub>, 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<sub>2</sub> 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**

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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.