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

April 7, 2008

Commitment to Corrosion Monitoring

8th Annual Report to the Alaska Department of Environmental Conservation

Prepared by

ConocoPhillips Corrosion Team

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1.0 OVERVIEW

The purpose of this 8th Annual Report is to communicate the details of the individual programs that implement the ConocoPhillips Alaska (CPAI) 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.

There are over $3 Billion in capital assets in the Greater Kuparuk Area (GKA). The GKA produces approximately 160,000 BOPD. The internal corrosion potential in Kuparuk lines continues to rise as water production and H_2S levels increase. Additionally, an external corrosion potential exists where moisture penetrates into breaches in the insulation jacketing and is trapped in the 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 15 years. Western North Slope (WNS) consists primarily of Alpine field. There are roughly $1.5 Billion in capital assets at Alpine. Alpine produces approximately 130,000 BOPD. The Alpine development produces from four Drill Sites. The corrosion management system used at Kuparuk is being applied to the Alpine field.

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

2.0 SIGNIFICANT ENHANCEMENTS TO CORROSION PROGRAMS

Exploring more technologically advanced maintenance pigging hardware to improve pigging efficiency.

Improved line decommissioning and reporting procedures.

Mini excavators are now being used to reduce hand shoveling and improve efficiencies on below-grade pipeline digs.

The corrosion team has been strengthened by addition of resources, e.g., inspection crews, chemical technicians, and system analysts.

Expanded the corrosion under insulation inspection program:

- Expanded number of locations considered susceptible to external corrosion to include all saddle areas irrespective of weld packs and increased the number of corrosion under insulation inspection areas (CUI IA's) by 75% to approximately 175,000 locations
- Established new TRT protocols to inspect additional areas threatened by external corrosion.
- Implemented the use of new C-arms with better imaging capability and a more-ergonomic design.

Added new corrosion inhibitor injection and storage facilities in the WNS and the GKA.

Improved communications with Operations via weekly meetings to discuss status of on-going programs and initiatives.

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3.0 SUMMARY OF CPAI PROGRAMS

CPAI had several significant accomplishments in 2007 including the following:

- Tested three new corrosion inhibitor formulations, placed one new inhibitor in a larger scale test at GKA, and changed to a better-performing corrosion inhibitor at WNS.
- Successfully executed our routine inspection programs in both GKA and WNS.
  - Completed internal corrosion inspection interval surveys on all 164 well lines scheduled for 2007.
  - Completed internal corrosion inspection interval surveys on all 27 flow lines scheduled for 2007.
  - Visually inspected and cleaned debris from all priority 1, 2 and 3 cased below-grade pipe circuits.
  - Completed our specialty inspection (Long Range UT) scope of work on 127 below grade circuits.
  - Excavated, inspected, refurbished and / or repaired (as required) 30 cased below-grade pipe circuits.
  - Completed verification inspection of Tarn-style weld packs (118 inspected) and Denso-tape refurbishments (420 inspected) ensuring these perform as intended.
- Completed 21,798 TRT surveys of flow line and well line CUI IA's due for re-inspection. This represents a tripling of the effort from 2006. The overall goal for 2007 was 23,030 locations. Approximately 1,200 on pad Cross Country flow line locations and three well lines were deferred until 2008 because of resource prioritization.
- Successfully executed a maintenance and smart pigging program of the 2P produced crude flow line. Smart pigged two other flow lines (16-inch Wet Oil line and 24-inch sea water line from the CW Skid to CPF2).

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4.0 GKA PROGRAM STATUS SUMMARY

A. Monitoring & Mitigation

In 2007 we had several significant accomplishments:

- Tested two new corrosion inhibitor formulations and placed one new inhibitor in a larger scale test.
- Continued enhancement of the maintenance pigging program including a pigging program for the 2P produced crude flow line.

Average general and pitting coupon corrosion rate data for Year 2007 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	Lines with Conformant General Corrosion Rates
Three-phase Production Flow Lines	55	0.02	55	100%
Seawater Transfer Flow Lines	2	3.43	1	50%
Water Injection Flow Lines	32	0.19	32	100%
Production Well Lines	519	0.19	514	99%
Water Injection Well Lines	412	0.23	405	98%

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	Lines with Conformant Pitting Corrosion Rates
Three-phase Production Flow Lines	55	2.58	51	93%
Seawater Transfer Flow Lines	2	2.33	2	100%
Water Injection Flow Lines	32	2.9	29	91%
Production Well Lines	519	1.75	509	98%
Water Injection Well Lines	412	5.63	347	84%

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

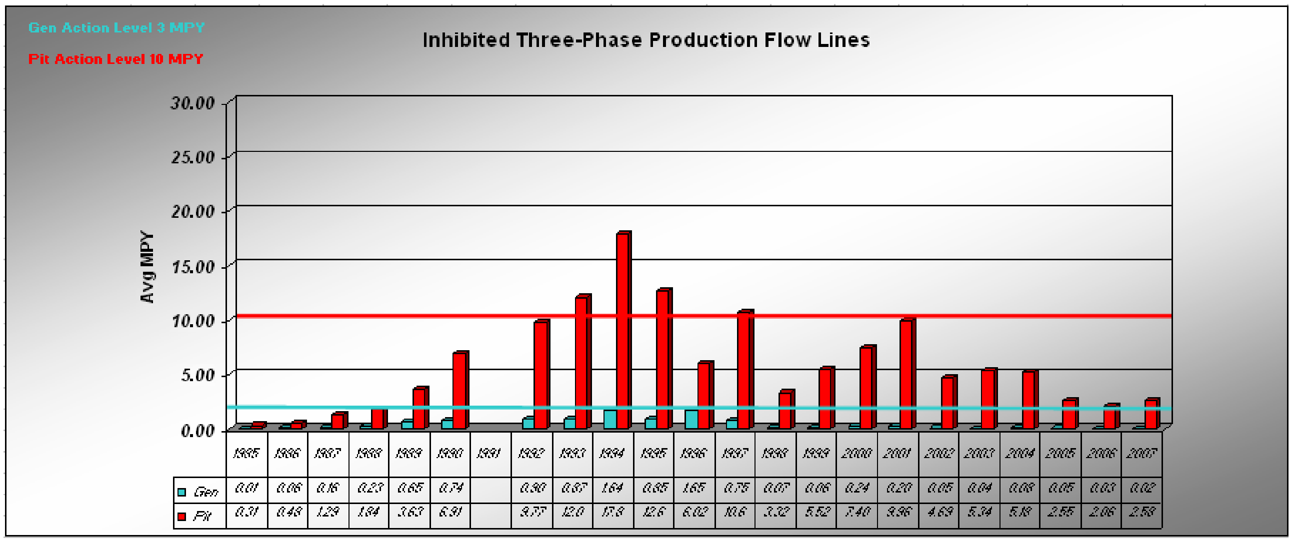

Figure 1. Inhibited Three-Phase Production Flow Line Coupons – general and pitting corrosion rates by year.

Three-phase Production Flow 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 corrosion-rate monitoring (CRM) inspections also support the conclusion that corrosion is under control in the three-phase production flow lines. In 2007, 861 CRM inspections were conducted, with 30 increases found. Other internal inspection data supporting the CRM data are discussed in section B.1.b, below.

Where corrosion rates exceeded targets, corrosion inhibitor concentrations were increased and the amount of inspection was increased. In 2007, coupon, probe or inspection-based corrosion rates exceeded targets or revealed increased damage on 21 lines. In 2007, inspection results indicated minor corrosion had occurred in 13 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.

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

Common Line	Probes	Coupons	Inspection	Action Taken
1APO			x	Increase Target PPM
1BPO		x		Increase Target PPM
1FPO		x	x	Increase Target PPM
1GPO			x	Increase Target PPM
1LPO			x	Increase Target PPM
1RPO	x	x	x	Increase Target PPM
2APO			x	Increase Target PPM
2EPO			x	Increase Target PPM
2FPO			x	Increase Target PPM
2GPO	x		x	Increase Target PPM
2HPO			x	Increase Target PPM
2KPO		x		Increase Target PPM
2MPO	x	x		Increase Target PPM
2PPO	x			Increase Target PPM
2VPO			x	Increase Target PPM
2ZPO			x	Increase Target PPM
3HPO	x		x	Increase Target PPM
3IPO	x	x		Increase Target PPM
3KPO	x	x		Increase Target PPM
3MPO	x			Increase Target PPM
3NPO		x		Increase Target PPM
21	**8**	**8**	**13**	

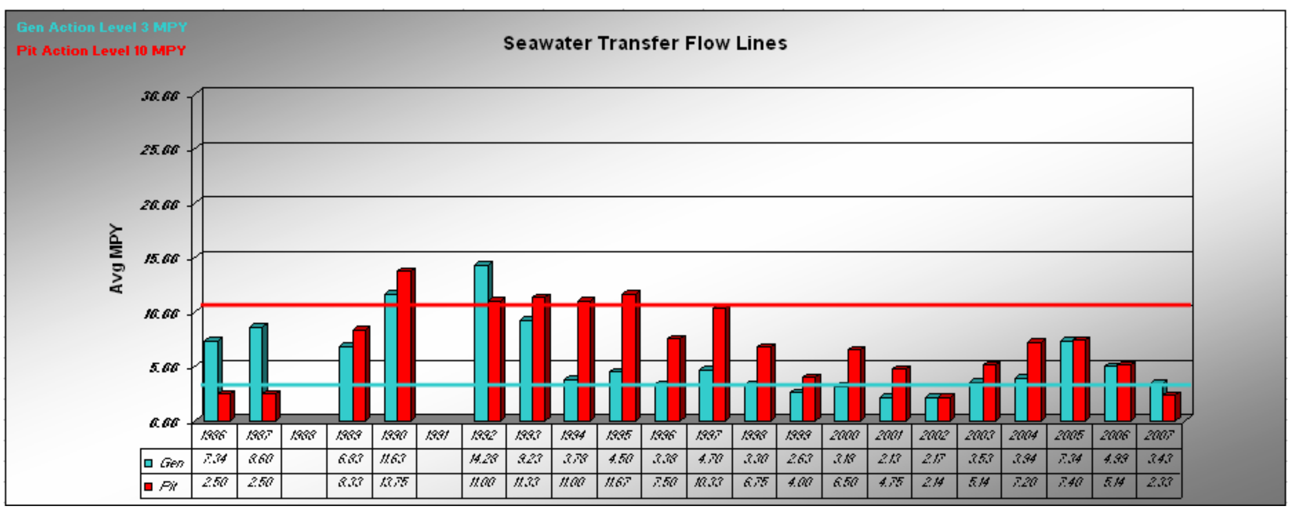

Figure 2. Seawater Transfer Flow Line Coupons – general and pitting corrosion rates by year.

Seawater Transfer Flow Lines: The monitoring data summarized in Tables 1 and 2 and presented in Figure 2 above, show the average corrosion rates for the sea water flow line coupons. Average general corrosion rates are above the threshold and pitting rates for the field are below the threshold. Biocide concentration is currently at 1000 ppm with weekly maintenance pigging.

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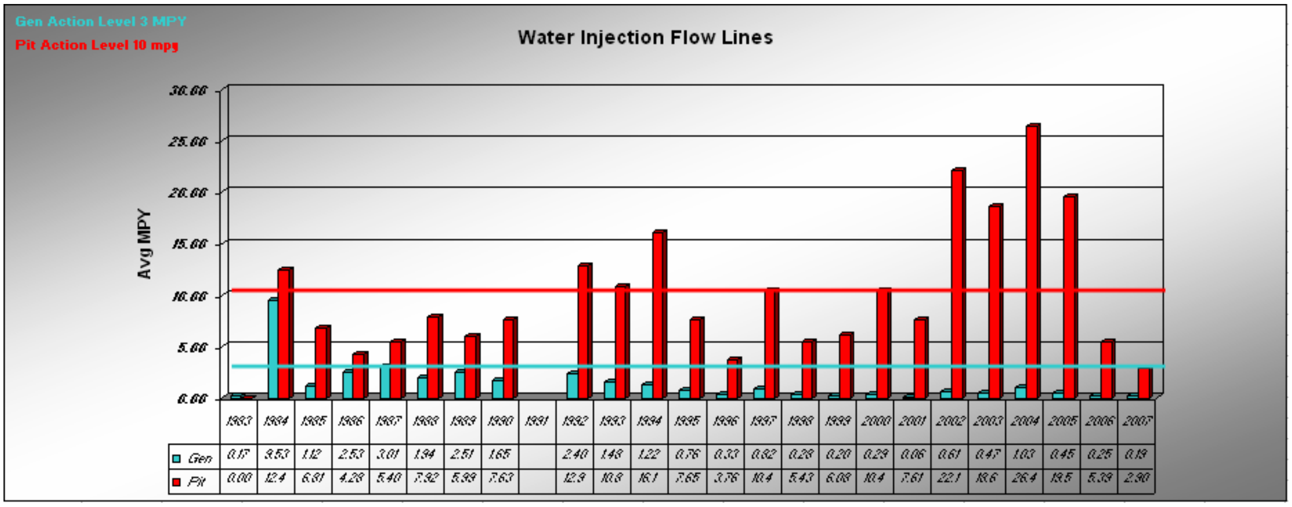

Figure 3. Water Injection Flow Line Coupons – general and pitting corrosion rates by year.

Water Injection Flow lines: The monitoring data summarized in Tables 1 and 2 are presented in Figure 3. Increased pigging and biocide have brought the WI flow lines coupon pitting rates under control. Since seawater and produced water commingling were suspended at CPF2 in 2005, pitting rates have been reduced markedly. Coupon results are used to prioritize inspection efforts. Additional chemical injection systems are being installed at all three CPF's to allow for chemical treatment of individual lines. Cleaning pig technology is continually being tested. New cleaning pig styles have been field proven and another pigging technology is under evaluation with promising results.

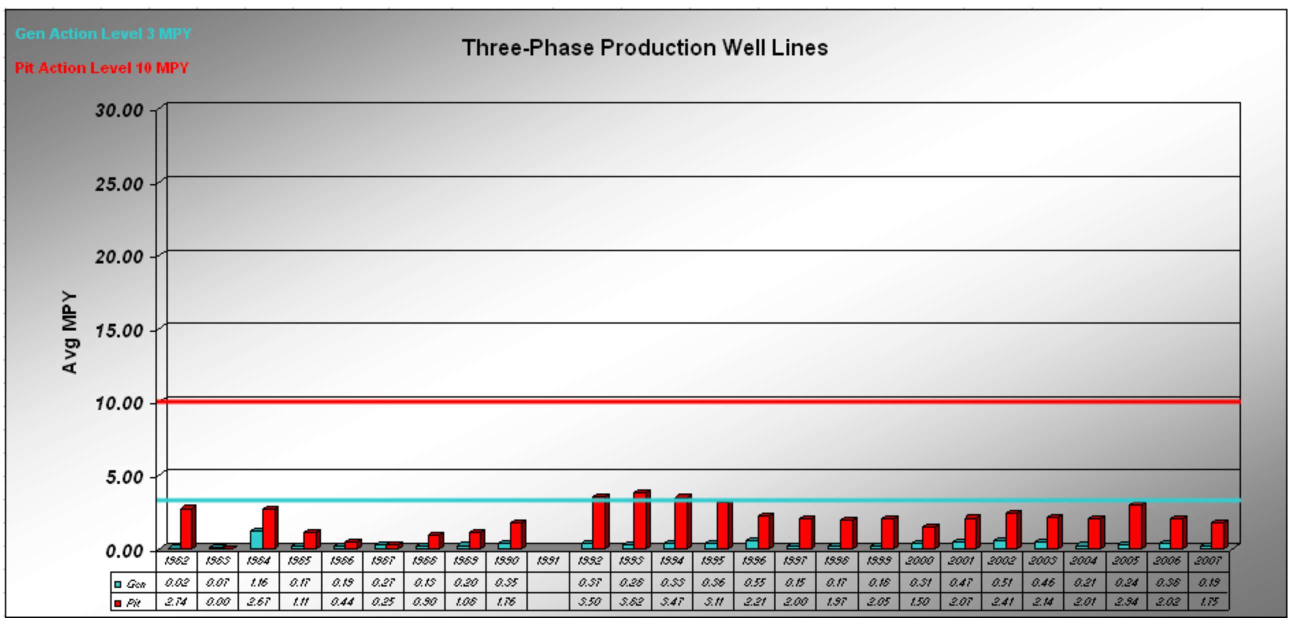

Figure 4. Three-Phase Production Well Line Coupons – general and pitting corrosion rates by year.

Three-phase Production Well Lines: While the monitoring data summarized in 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 B.1.a, 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.

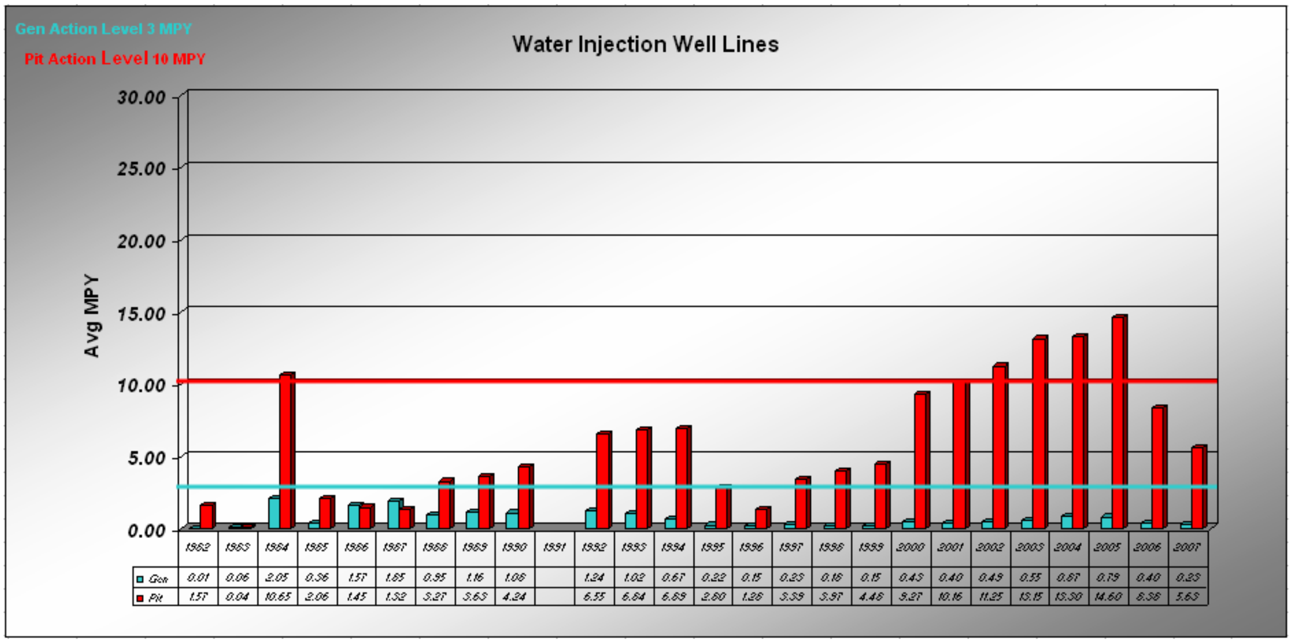

Figure 5. Water Injection Well Line Coupons – general and pitting corrosion rates by year.

Water Injection Well Lines: As discussed in section B.1.a, 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 Flow Line Coupons. We believe that corrosion in the water injection well lines is exacerbated by additional solids accumulating in the well lines because of low flow rates and improved pigging upstream of the well lines.

Mitigation:

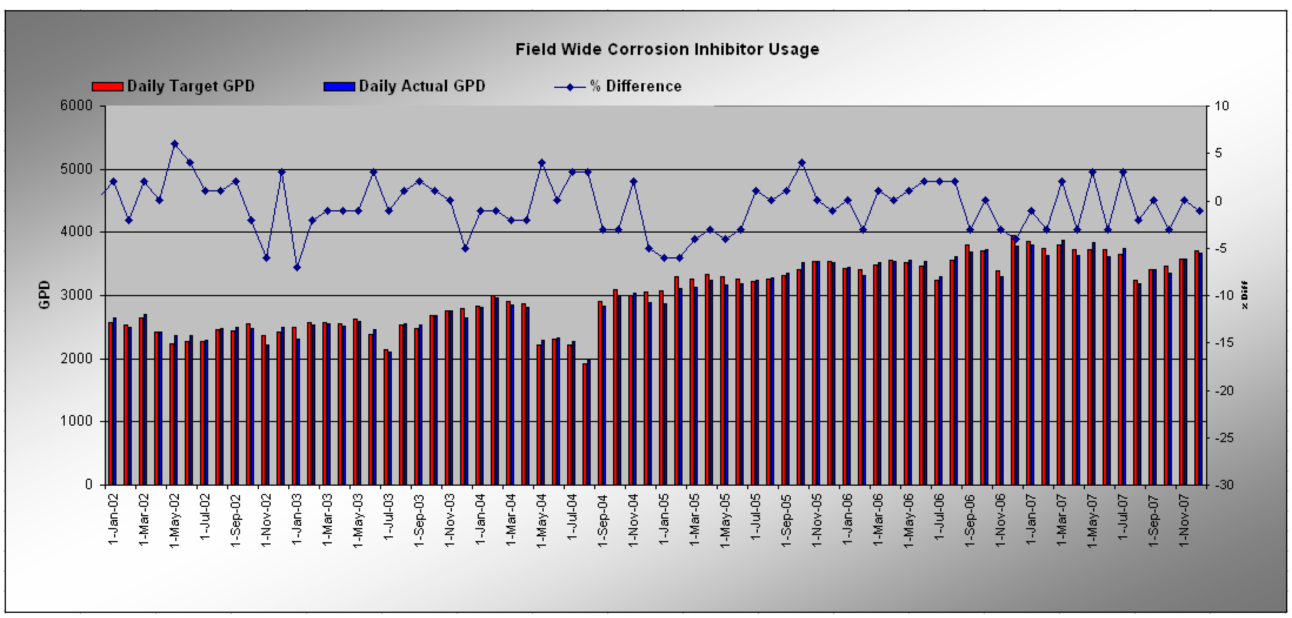

Figure 6. Field-wide Corrosion Inhibitor Use.

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 -0.67%. Corrosion inhibitor use has increased since 2003 mainly because of field-wide water rate increases and increased corrosion rates caused by water and solids handling.

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, above.

In addition to chemical mitigation, the use of four-inch diameter well lines has been shown to reduce the corrosion rates in both three-phase production and WI services. The GKA continues to use four-inch pipe for new and replacement well lines.

Maintenance Pigging:

Table 4. Field-wide Maintenance Pigging by Service.

Service	2006 Number Recommended	2006 Number Completed	2006 Percent Completed	2007 Number Recommended	2007 Number Completed	2007 Percent Completed
SW	420	291	69%	463	339	73%
PW	682	622	91%	923	889	96%
Oil	21	20	95%	28	54	193%*

*Note: Includes the maintenance pigging runs associated with smart pigging the 2PPO line.

For the Kuparuk field, Table 4 shows the actual number and the recommended number of maintenance pig runs conducted by service category. Services tracked are Sea Water (SW), Produced Water (PW) and Oil (including three-phase production and wet oil). The recommended maintenance pigging frequencies are as follows:

- Weekly for the 30" Sea Water supply line from STP to CW skid
- Monthly for CPF PW and SW Flow lines
- Monthly for the Wet Oil lines from CPF3 to CPF1 and CPF2, this service is tracked as Oil
- Quarterly for piggable Three-Phase Produced Crude Flow lines, this service is tracked as Oil

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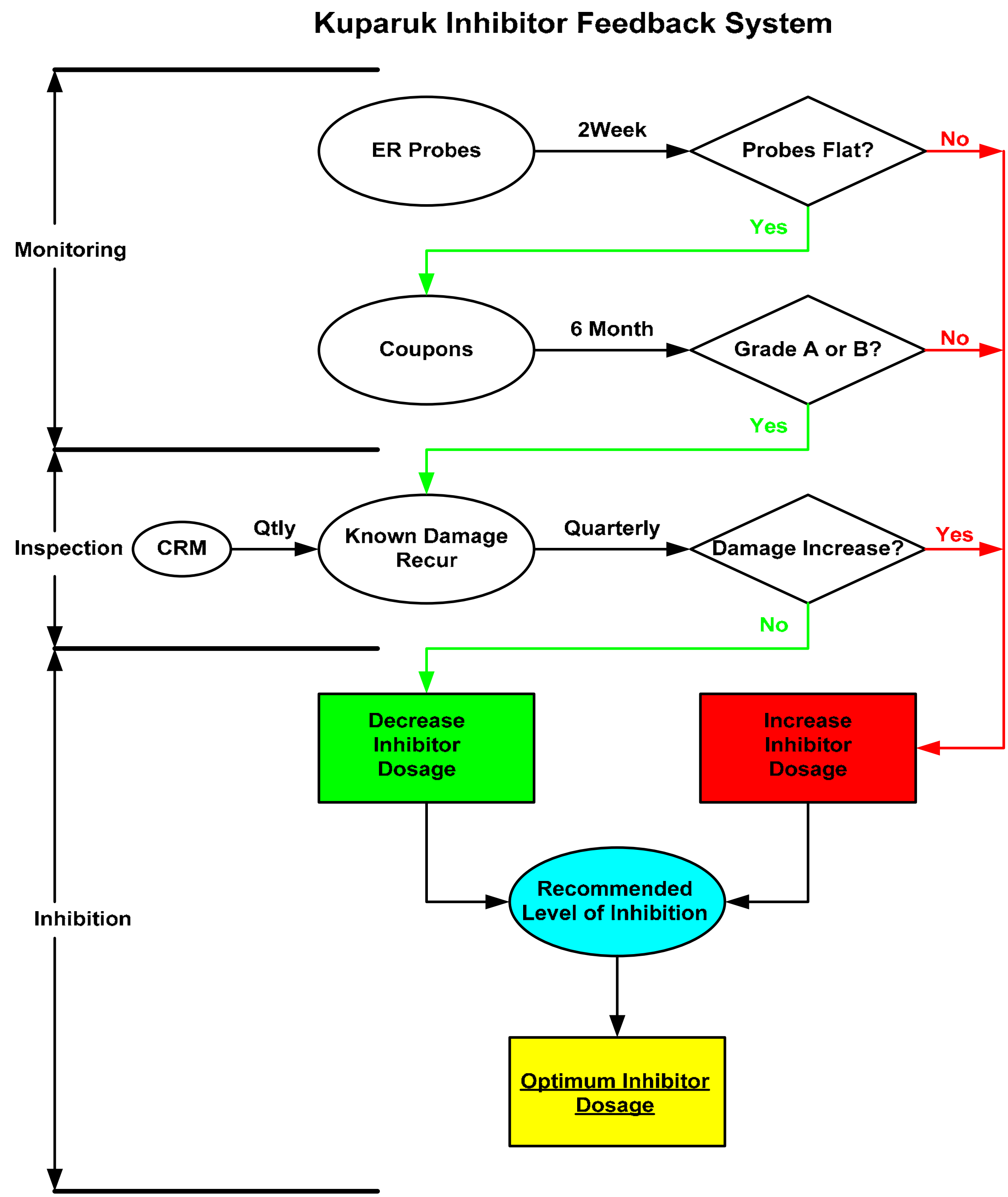

Figure 7. Corrosion Inhibitor Feedback System.

B. Inspection

B.1 Internal Corrosion Inspections

B. 1.a Well Lines Inspections for Internal Corrosion

We met our 2007 goal by completing interval surveys on all 164 well lines scheduled for inspection in 2007. In addition, we conducted a recur inspection of two four-inch well lines to validate the six-inch to four-inch well line replacement strategy; the strategy was validated when no damage was reported.

As indicated in Figure 8, below, repair recommendations were initiated on 55 well lines (41 water injection and 14 production) in 2007 because of internal corrosion or a combination of internal and external corrosion damage. The predominant corrosion mechanism was associated with solids (under-deposit corrosion or erosion). More information on the two leaks can be found in section C.

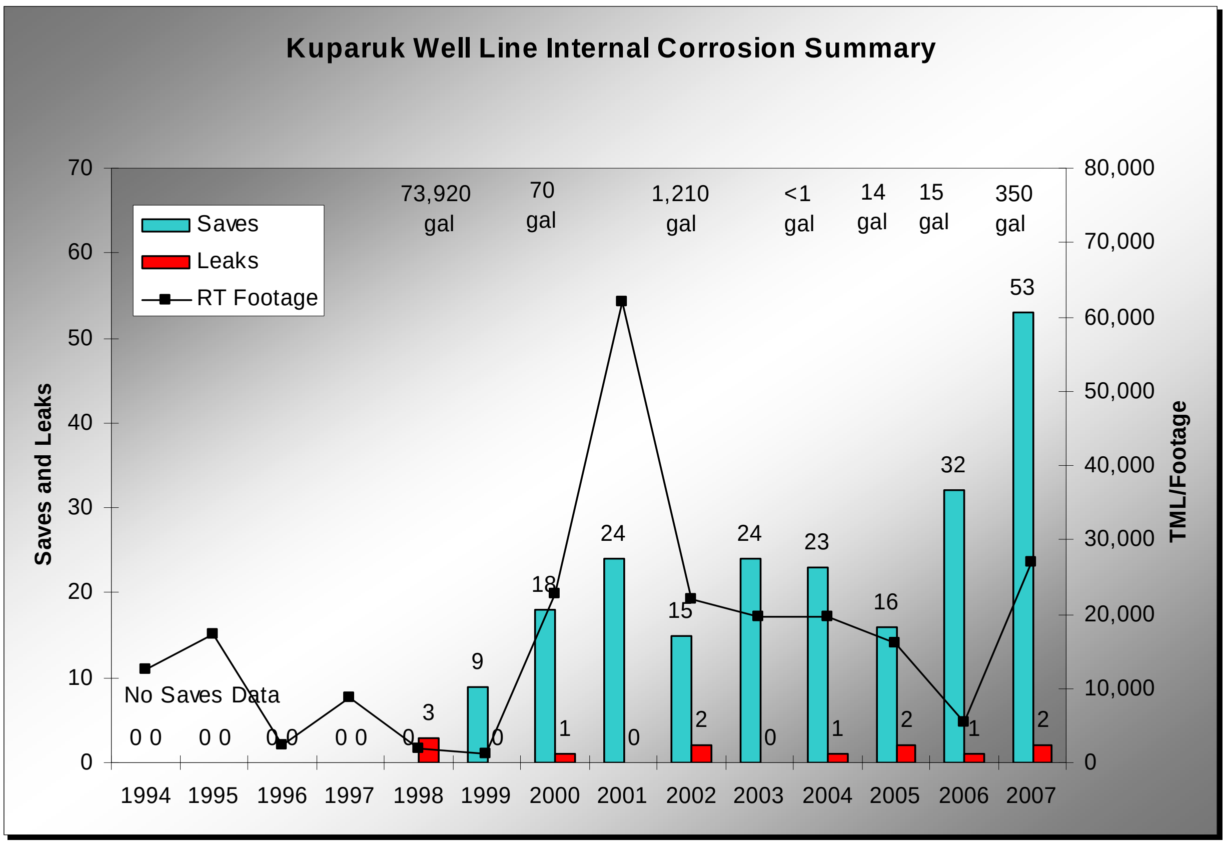

Figure 8. Summary of WI and Three-Phase Production Well Line Internal Corrosion Inspections – RT footage, leaks, and saves by year.

The 2007 results from the RTR / linear array surveys, manual RT, and manual UT are summarized in the following three tables.

- **RTR / Linear Array of Well Lines:**

Service	Feet Inspected	Number of Lines Inspected
Three-phase Production	10,293	100
Water Injection	12,923	64
Total	23,216	164

The 2007 RTR / Linear Array 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	Repeat Radiographs with Increases
Three-phase Production	214	1,827	425	19	4 %
Water Injection	128	1,835	289	51	18 %
Total	432	3,662	746	70	9 %

The 2007 manual RT well line data indicate a significant decreasing damage trend in both the three-phase and water injection well lines. The percentage of radiographs showing increased damage in three-phase well lines decreased from 10% in 2006 to 4% in 2007. The percentage of radiographs showing increased damage in the water injection system decreased from 28% in 2006 to 18% in 2007. This is the first decrease in the water injection well lines we have seen since 2004.

- **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	Repeat UT Inspections with Increases
Three-phase Production	189	1,248	921	68	7 %
Water Injection	96	370	210	43	20%
Total	285	1,618	1,131	111	10%

The 2007 manual UT well line data indicate a small increasing damage trend in both three-phase and water injection well lines.

B.1.b Flow Line Inspections for Internal Corrosion

We met our 2007 goal by completing interval surveys on all 27 lines scheduled for inspection in 2007. We also smart pigged three additional lines (the 16-inch Wet Oil line, the 24-inch sea water line from the CW Skid to CPF2, and the 24-inch 2PPO line).

As indicated in Figure 9 below, 12 repair recommendations were initiated on flow lines (5 water injection and 7 production) in 2007 because of internal corrosion damage. The corrosion mechanism for all repair recommendations was deadleg or solids-related corrosion. There were no leaks in flow lines caused by internal corrosion in 2007.

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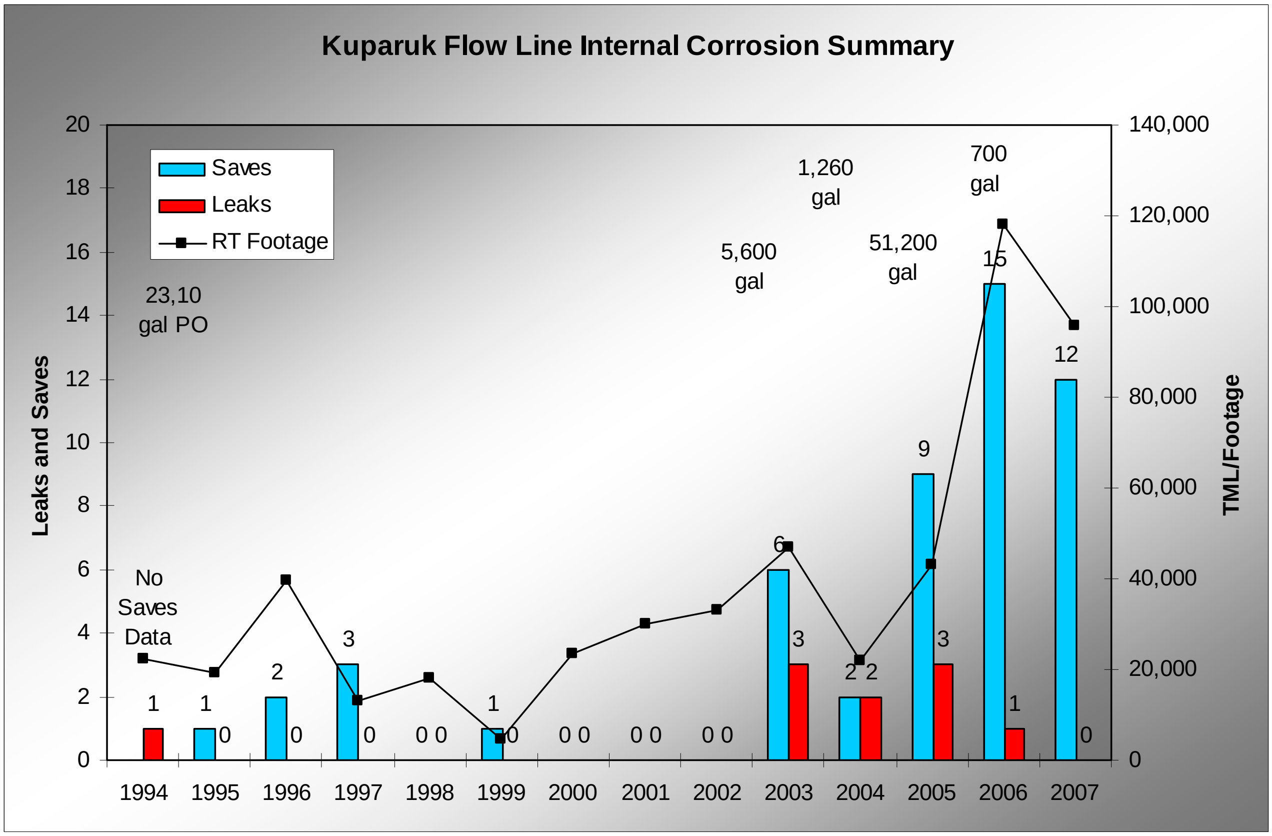

Figure 9. Summary of WI and Three-Phase Production Flow Line Internal Corrosion Inspections – RT footage, leaks, and saves by year.

The 2007 results from the RTR / linear array surveys, manual RT, and manual UT are summarized in the following three tables:

- **RTR / Linear Array of Flow line:**

Service	Feet Inspected	Number of Lines Inspected
Three-phase Production	40,712	13
Water Injection	43,948	14
Total	84,660	27

The 2007 RTR / linear array inspection results indicated no new damage trends.

- **Manual RT of Flow Lines:**

Service	Number of Lines Inspected	Number of Radiographs	Number of Repeat Radiographs	Number of Repeat Radiographs with Increases	Repeat Radiographs with Increases
Three-phase Production	96	6,367	1,189	36	3 %
Water Injection	45	4,553	196	2	1%
Total	141	10,920	1,385	38	3 %

The 2007 results from manual RT of flow lines indicated no new significant damage trends.

- **Manual UT of Flow Lines:**

Service	Number of Lines Inspected	Number of UT Inspections	Number of Repeat UT Inspections	Number of Repeat UT Inspections with Increases	Repeat UT Inspections with Increases
Three-phase Production	71	1,314	591	37	6 %
Water Injection	36	627	322	20	6 %
Total	107	1,941	913	57	6 %

The 2007 manual UT flow line data indicated no new damage trends.

- **Smart Pigging of Flow Lines:**

The 12-inch and 16-inch wet oil lines were smart pigged in 2006; because of sensor problems, the 16-inch wet oil line was smart pigged again in early-2007. Other than previously-known locations, no anomalies were found that indicated possible de-rating damage.

The 24-inch production flow line from DS2P to CPF2 was smart pigged in 2007. No anomalies were found that indicated possible de-rating damage.

The 24-inch sea water line from the CW Skid to CPF2 was smart pigged in 2007. No anomalies were found that indicated possible de-rating damage.

B.2 External Corrosion Inspections

In 2007 we had several significant accomplishments:

- Completed 21,798 TRT surveys of flow line and well line CUI IA's due for re-inspection. This represents a tripling of the effort from 2006. The overall goal for 2007 was 23,030 locations. Approximately 1,200 on pad Cross Country flow line locations and three well lines were deferred until 2008 because of resource constraints.
- Completed our goal of inspecting 100 Tarn-style weld packs (118 inspected) to ensure this new design continues to work properly. No corrosion has been detected on the piping within the weld pack areas.
- Completed our goal of inspecting 100 refurbished weld packs (420 inspected) to verify the soundness of the Denso tape refurbishments. The refurbishment technique appears to be performing well.
- Smart pigged the 24-inch sea water line from the CW Skid to CPF2.
- Smart pigged the 16-inch wet oil line from CPF3 to CPF1.
- Smart pigged the 24-inch 2P PO line.

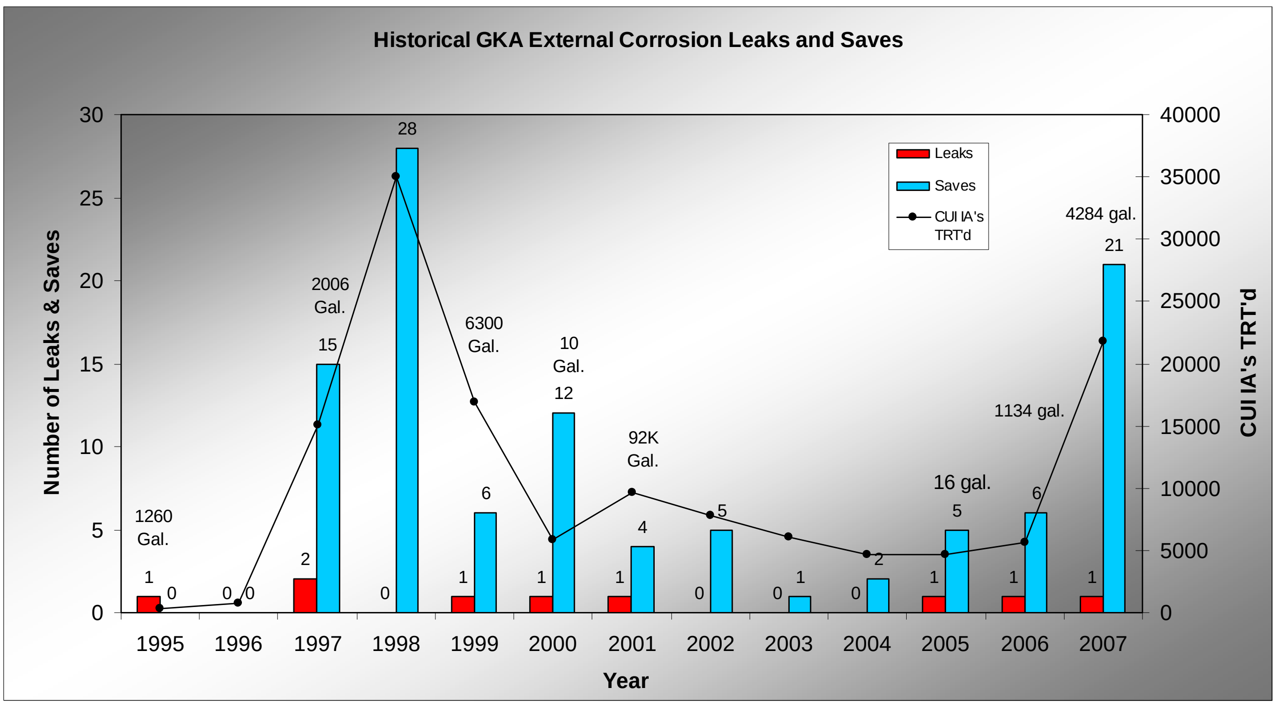

Figure 10. Leaks, saves, number of CUI IA's inspected with TRT, and volumes of leaks by year.

B.2.a Flow Line (On-Pad and Off-Pad) Inspections for External Corrosion

The baseline inspection effort for all flow lines was completed in 2004. The focus in 2007 was to begin the field-wide recur of all CUI IA's on cross country flow lines. The current inspection plan will re-evaluate the condition of each location on a five-year recur interval.

In 2007, 17,950 of the 19,150 scheduled CUI locations were inspected with TRT. The on-pad sections at three of the ten scheduled drill sites (~1,200 locations) were deferred until 2008. External corrosion was identified at 275 locations (244 of the 275 were located over tundra). The corroded locations were added to the refurbishment list for follow-up visual inspection (VT).

One flow line leak was caused by external corrosion in 2007. The leak was located on the 2WUPO at VSM 157 and resulted in a 4,284 gallon (102 barrel) spill. The damaged area was repaired with a welded pressure containing sleeve.

Field-wide, an additional 19 sleeve repair recommendations (saves) were issued as a result of external corrosion damage. These proactive recommendations included nine different flow lines [1WTEOR, 2EDPO, 2FPO, 2WUVGI (two sleeves), 2TWI, 3NTGL, 3RQONKCPO, CPF-3 Wet Oil (eleven sleeves)].

Inspection crews continue to perform TRT inspection at 12 o'clock (top-of-pipe) as well as 6 o'clock on CUI locations where needed. This technique is expected to reduce the likelihood of missing corrosion that might have formed higher up on the pipe when there is little to no indication of corrosion at 6 o'clock.

The 17,950 CUI inspections noted above included a sampling of the newer Tarn-style weld packs (118 locations) to evaluate how the design is continuing to perform. The results showed water inside the clamshell insulation (no water was found in the factory applied insulation) at 19 of 118 weld packs which were inspected. No corrosion under insulation (CUI) was found in any of the areas inspected.

Denso tape continues to be the material of choice to refurbish flow lines and well lines with external corrosion. The 2007 CUI inspection included a sampling of previously-refurbished weld packs (420 locations). The results showed no evidence of additional corrosion at the area wrapped with tape. This sampling technique will be used to continue monitoring the effectiveness of this material.

The 24-inch sea water line from the CW Skid to CPF-2 was smart pigged in 2007. No de-rating external corrosion was reported.

The 24-inch 2P PO line was smart pigged in 2007. No external corrosion was reported.

The 16-inch CPF-3 wet oil line was smart pigged in 2007. Other than previously-known locations, no anomalies were found that indicated possible de-rating damage.

B.2.b Well Line Inspections for External Corrosion

In 2007, 3,848 of the 3,878 scheduled CUI locations were inspected with TRT. This inspection consisted of 226 of the 229 scheduled well lines, all of the 22 scheduled header lines, and all of the scheduled sections of manifold piping outside the modules at nine of the 47 drillsites. The inspection of three well lines was deferred until 2008 because of access limitations. External corrosion was identified at 127 locations (38 of the 127 locations were over tundra). The corroded locations were added to the refurbishment list for follow-up VT.

Repair recommendations (saves) were issued as a result of external corrosion damage to two well lines [1Y-06GL and 2V-06]. There were no leaks caused by external corrosion on well lines in 2007.

Table 5: External CUI Inspection Summary for 2007.

Type of Equipment	2007 Goal	Number of Locations Inspected	Number of Corroded Locations	Percentage of Locations Corroded	Number of Locations Refurbished
Flow lines Over Tundra or On-Pad	19,150	17,950	275	1.5%	1434
Well Lines	3,880	3,848	127	3.3%	447
Total	**23,030**	**21,798**	**402**	**1.8%**	**1,881**

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

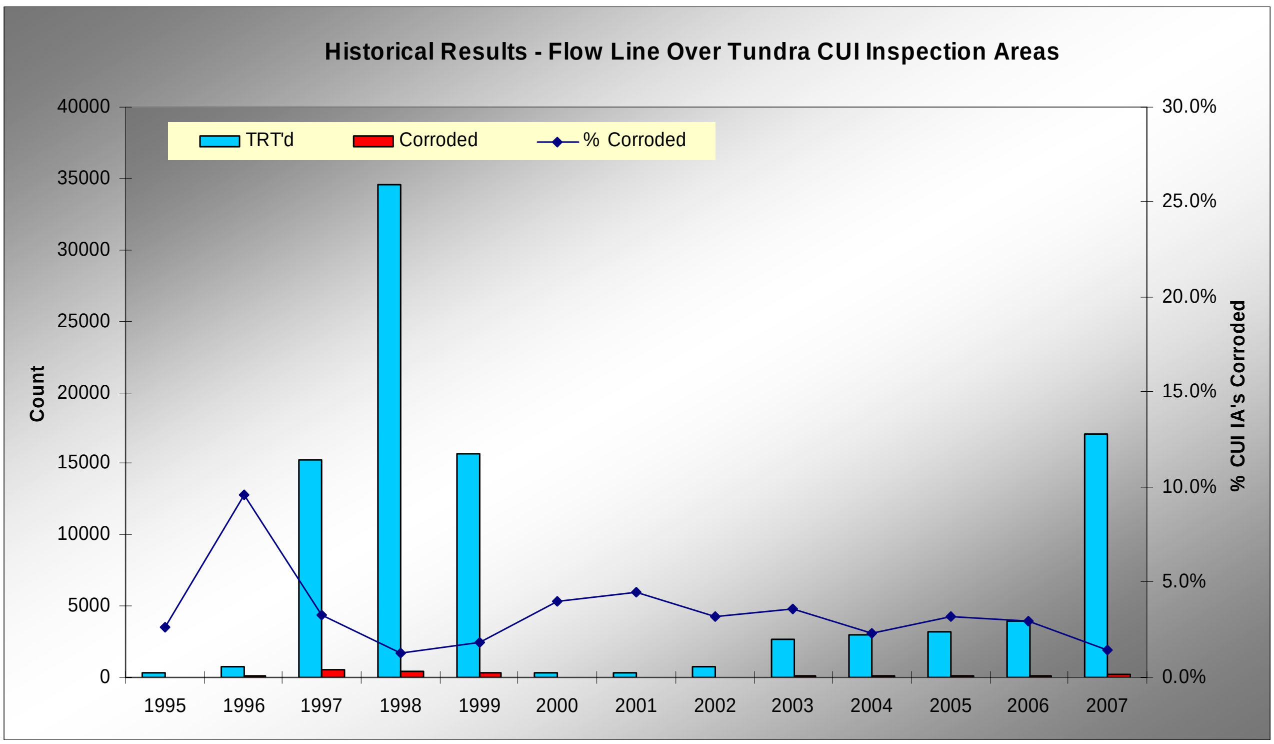

Figure 11. Summary of Flow Line Over-Tundra (off-pad) CUI Inspection Areas.

Figure 11 illustrates the latest results from the external corrosion inspection program. 2002 through 2006 values include recur follow-up inspections and clean-up of locations missed or not properly documented during the original base line effort. The increased inspection effort in 2007 is representative of our field-wide recur inspection to re-evaluate all locations on a 5 year inspection interval.

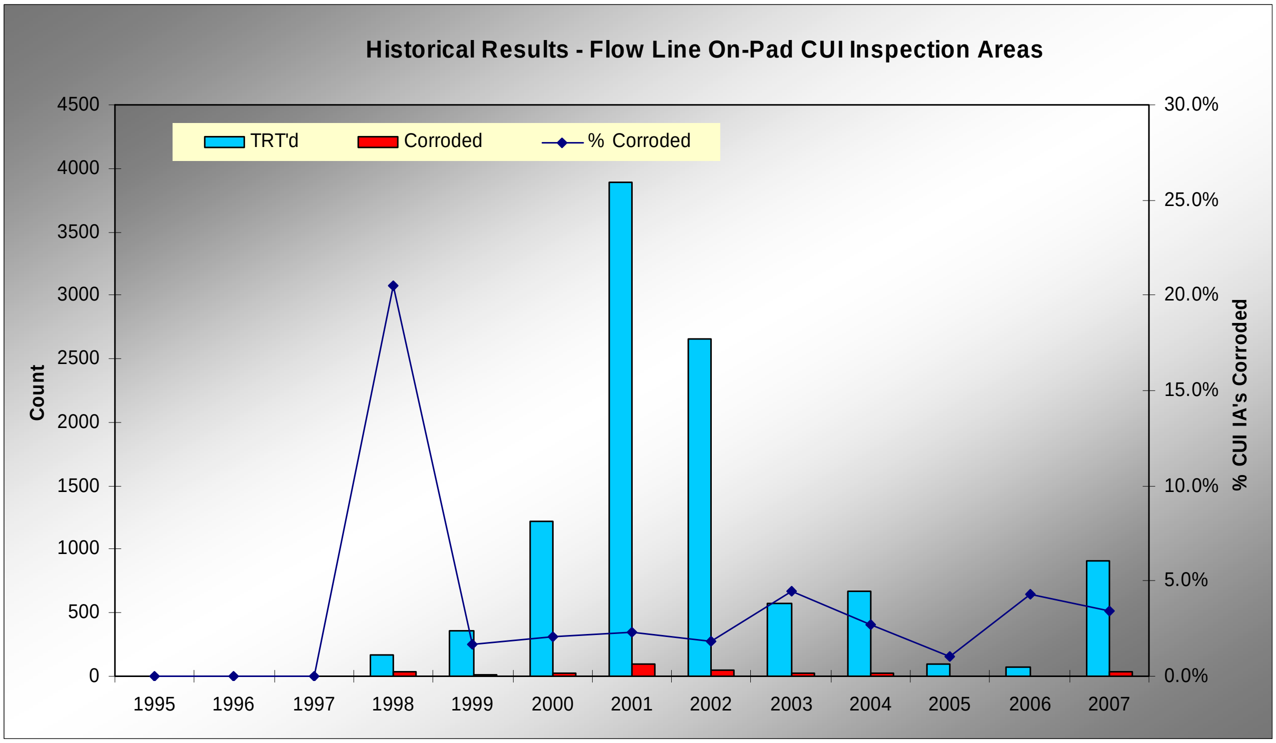

Figure 12. Summary of Flow Line On-Pad CUI Inspection Areas.

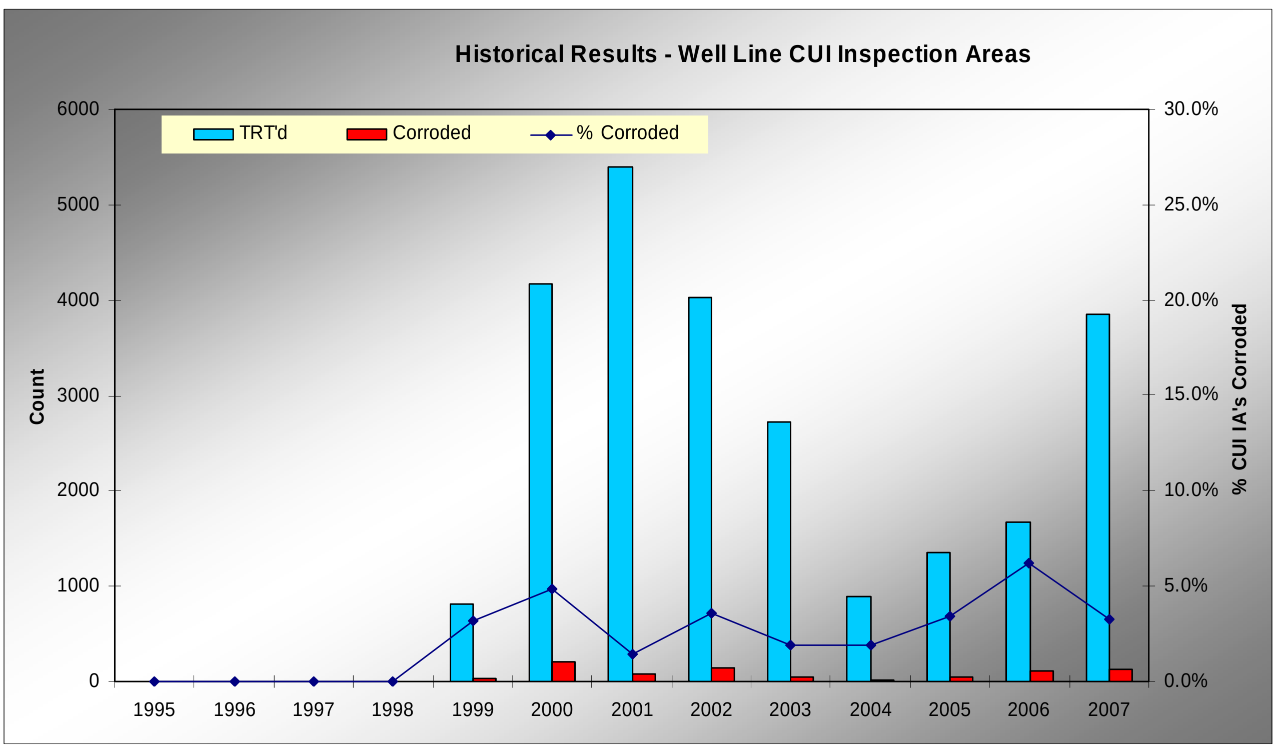

Figure 13. Summary of Well Line CUI Inspection Areas.

B.3 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 D.

In 2007 we had several significant accomplishments:

- Visually inspected and cleaned debris from all priority 1, 2 and 3 cased below grade pipe circuits.
- Completed our specialty inspection (Long Range UT (LRUT)) scope of work on 127 below grade circuits.
- Excavated, inspected, refurbished and / or repaired (as required) 30 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.

B.3.a Inventory and Survey of Below Grade Locations

GKA has 788 below grade circuits on flow lines. This includes priority 1, 2 and 3 circuits in the GKA (not including WNS circuits on the GKA side of the field). Of these locations, three are contained in utilidors. The remaining circuits are cased lines, the majority of which are either road, gravel pad or caribou crossings.

Utilidor Lines

Recent ADEC regulation changes include the addition of facility piping associated with oil storage tanks. This increased the number of pipelines in utilidors from one to three.

1. The original line is the Oily Waste Injection Line, (BG ID #286). This line was taken out of service in 2004 because it was no longer needed for operations. It had been on a two year inspection cycle and was last inspected in 2002. Because it has been taken out of service, it was not inspected in either 2004 or 2006.
2. One of the new lines is the pipeline that transports diesel from the bulk storage tank, on CPF1 pad, to the fueling pump on CPF1 pad. This line is scheduled for inspection during the summer of 2008.
3. The other new line is the sister line to #2 above. It provides fuel to an adjacent pump. This line is also scheduled for inspection during the summer of 2008.

Cased Lines

<u>Inspection Status:</u>
The annual visual survey of all the cased lines was conducted in 2007. 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.

<u>Results and Remedial Action:</u>
Of all GKA below-grade circuits, 215 were found to have pipe in direct contact with gravel/soil or debris in the casing. All locations were remediated in 2007.

B.3.b Results of Specialty Testing

<u>Inspection Status:</u>
In 2007, we completed LRUT inspections on 127 GKA priority one circuits. This was the fifth year of our recurring inspection program. Each priority one circuit is on a 5 year (maximum) re-inspection interval.

In 2007 only the LRUT 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 LRUT 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	74	0	52	18	4	0
Other	53	4	29	15	5	0
Total	127	4	81	33	9	0

The 2007 TWI data again showed a drop in "Incomplete / Inconclusive" results from 26 in 2005 to 12 in 2006 to only 4 in 2007.

B.3.c Results of Crossing Refurbishments

Thirty below grade circuits were refurbished in 2007. Twenty-five circuits were excavated and five were replaced without excavation (cut and pulled through casing). The five replacements (two on flow line 2XWI, two on flow line 2WWI and one on 1EWI well line) were the only "repairs" in 2007.

For all 30 below grade circuits excavated or replaced-without-excavation in 2007, the insulation was refurbished and the pipe wrapped with Denso tape to prevent further corrosion.

C. Repairs, Structural Concerns, and Spills/Incidents

Subsidence:

Existing Well Upgrade Program

- In 2007, no conductor-mounted floor kits were installed in existing well houses at Kuparuk. A total of 27 fiberglass floor kits were installed in well houses at Drill Sites 1A, 1B, 1C, 1E, 1F, 1G, 1L, 1Q, 1R, and 1Y.
- In 2007, 19 heat tubes were installed at Drill Sites 2K, 3F, 3I, and 3K. 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 2007, seven newly drilled wells at Kuparuk were installed with insulated conductors.
- In 2007, 35 newly drilled wells had heat tubes installed. Of these 35 newly-drilled wells, 17 had floors with permanent pipe supports.

Wind-Induced Vibration:

As a result of the 3AIM 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.

Because of the failure of the DS2F 8" WI line in 2006 and the DS2X 8" MI line in 2002, the wind fan was expanded five degrees in both directions to include all pipeline segments with azimuths oriented from

N50° W to N35° E (original wind fan N45° W to N30° E). All TVA's needed to address the expanded wind fan have been installed.

Corrosion and Structural-Related Spills/Incidents:

- The 3B-12 water injection well line leaked in June of 2007 because of internal deadleg corrosion. The spill volume was determined to be less than one gallon of produced water and was confined to the gravel pad. No fluids contacted the tundra. As such, it was determined to not be an ADEC reportable spill.

- The 3C-02 water injection well line leaked in April of 2007 because of internal under-deposit corrosion. The spill volume was determined to be 350 gallons of diesel used for freeze protection. The line leaked after it had been blocked in and freeze protected. This spill was reported to ADEC.

- The 2WUPO produced crude flow line leaked in December of 2007 because of external corrosion under insulation. The spill volume was determined to be 4,284 gallons of produced crude. Fluids contacted the snow covered tundra. This spill was reported to ADEC. Follow-up inspections on the entire 2WUVPO piping system are on-going and regular progress reports are being supplied to ADEC. A Physical Cause Analysis is underway.

- No flow lines leaks were caused by internal corrosion in 2007.
- No leaks were caused by subsidence or other structural reasons in 2007.

Figures 8, 9, and 10 above 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 flow lines. Figure 10 shows the leaks caused by external corrosion for flow lines, well lines, and below-grade piping locations.

D. Year 2008 Forecast

D.1 Monitoring & Mitigation

- Test additional inhibitor formulations.
- Install additional inhibitor storage capacity at several Drill Sites.
- Continue to evaluate maintenance pigging enhancements to the water injections systems.
- Plan installation of inhibitor/biocide injection capacity for the water injection system.
- Continue to evaluate biocide and maintenance pigging in the seawater system.
- Install new monitoring locations on water injection lines.

D.2 Inspection

D.2.a Internal Corrosion Inspections

D.2.a.i) Well Line Inspections for Internal Corrosion

Our recurring inspection program will continue in 2008. No in-service line will go longer than 10 years without some type of inspection.

D.2.a.ii) Flow Line Inspections for Internal Corrosion

Our recurring inspection program will continue in 2008. No in-service line will go longer than 5 years without some type of inspection.

Smart pigging is planned for several water injection flow lines.

D.2.b External Program

Flow lines over tundra:

- Inspect approximately 20% of the flow lines for CUI as part of our five-year-interval recurring inspection program. This includes CUI IA 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.
- Include all pipe support saddles as CUI IA's and inspect with TRT during flow line recur inspections.
- Increase inspection area from +/- one foot at each CUI IA to +/- four feet at each CUI IA.

Well lines:

- Inspect approximately 20% of the well lines for CUI as part of our recurring inspection program.
- Include all pipe support saddles as CUI IA's and inspect with TRT during flow line recurs.
- Increase inspection area from +/- one foot at each CUI IA to +/- four feet at each CUI IA.

D.2.c 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. Starting in 2007, the inspection interval was changed from 10 years to 5 years. By inspecting 20% of the 620 priority 1 cased below grade piping circuits each year all circuits will meet this criterion by the end of the 2008 inspection year.

- 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.

D.2.d Other

- Continue enhancements to the Kuparuk Corrosion Database.

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

- Update the Corrosion Strategy Manual.

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5.0 WNS PROGRAM STATUS SUMMARY

A. WNS Monitoring & Mitigation

In 2007 a new corrosion inhibitor formulation was selected for the treatment of three-phase production flow lines based on a successful test in 2006. In addition, another inhibitor formulation was tested.

Corrosion inhibitor injection facilities were added and enhanced, and inhibitor storage capacity was increased.

Average general and pitting coupon corrosion rate data for Year 2007 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	Lines with Conformant General Corrosion Rates
Three-phase Production Flow Lines	3	1.4	3	100%
Seawater Flow Line from KRU	1	0.1	1	100%
Infield Sea Water Injection Flow Lines	2	0.3	2	100%
Production Well Lines	53	1.0	49	92%*
Water Injection Well Lines	26	0.6	26	100%

** Of the four lines with greater than 3 mpy CR, one was 3.4 mpy and the other three were 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	Lines with Conformant Pitting Corrosion Rates
Three-phase Production Flow Lines	3	13.6	1	33%
Seawater Flow Line from KRU	1	0	1	100%
Infield Sea Water Injection Flow Lines	2	1.0	2	100%
Production Well Lines	53	0.7	53	100%
Water Injection Well Lines	26	12.6	16	62%

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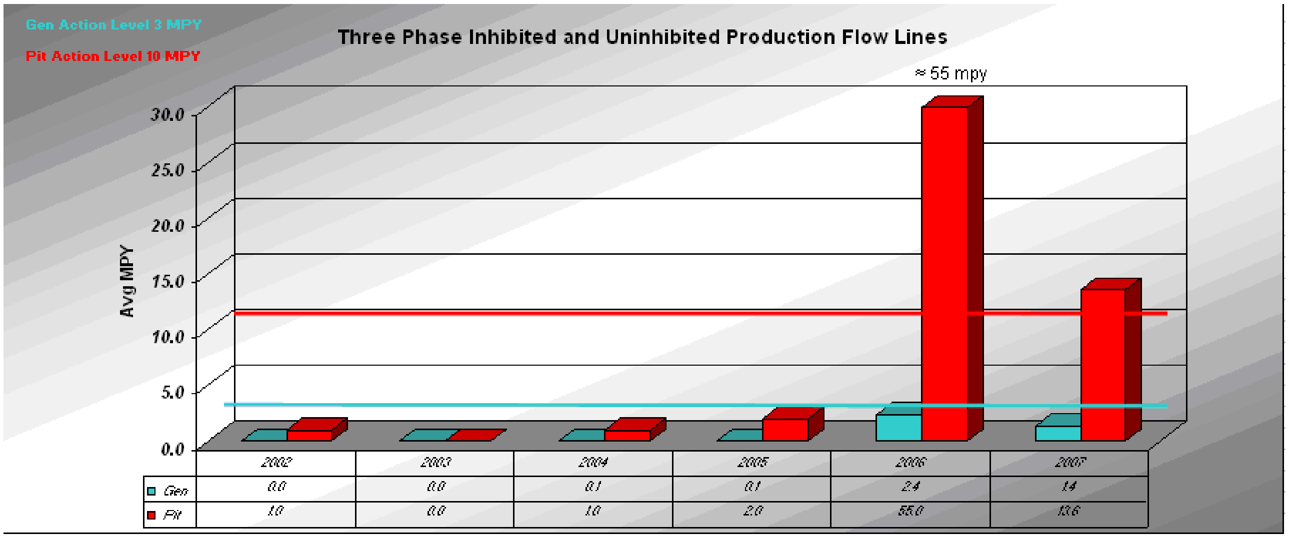

Figure 14. WNS Three-phase Production Flow Line Coupons – general and pitting corrosion rates by year.

Three-phase Production Flow Lines: The monitoring data summarized in Tables 7 and 8 and presented in Figures 14 show that pitting corrosion rates in 2007 exceeded the action level. In response to the coupon and probe corrosion rates, a new corrosion inhibitor formulation was selected for use at Alpine in the first quarter of 2007. In addition, a new corrosion inhibition formulation was tested in 2007. Inspection data, discussed in section B.1.b, indicate that significant corrosion damage has not taken place in these lines.

Corrosion inhibitor injection facilities were upgraded at CD1 to handle rising water production. At CD2, the installation of corrosion inhibitor injection facilities was accelerated because water production significantly outpaced the forecasted water rate. The subsequent coupon pull showed improvement.

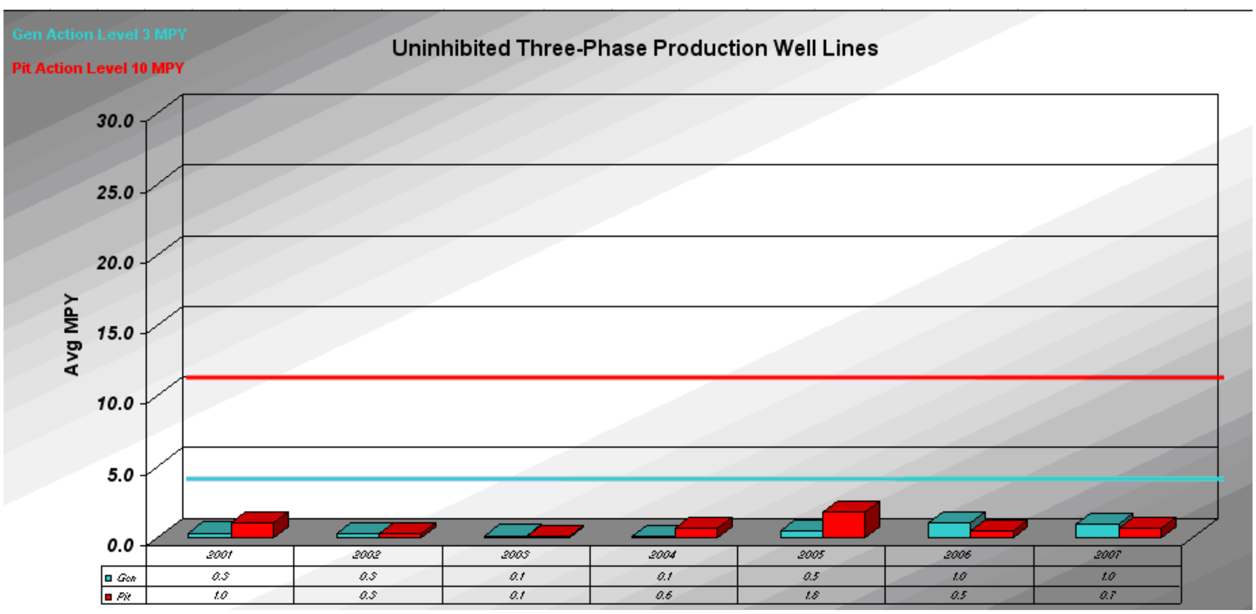

Figure 15. WNS Three-phase Production Well Line Coupons – general and pitting corrosion rates by year.

Three-phase Production Well Lines: The monitoring data summarized in Tables 7 and 8 and presented in Figures 15 show that corrosion rates have not approached action levels in the well lines. Inspection data, discussed in section B.1.a, indicate that significant corrosion damage has not taken place in these lines.

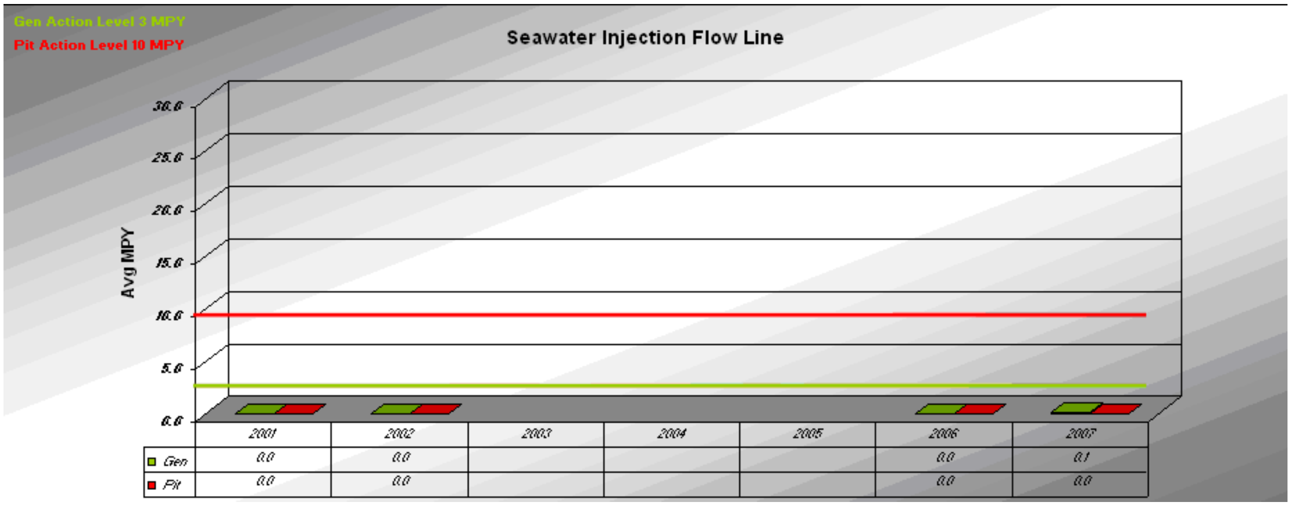

Figure 16. WNS Sea Water Flow Line Coupons – general and pitting corrosion rates by year.

Sea Water Flow Line from Kuparuk to Alpine: The monitoring data summarized in Tables 7 and 8, and presented in Figure 16 above, show the average corrosion rates for the sea water flow line coupons. Data collection resumed in 2006 when a coupon fitting was installed to replace the previous location which was obstructed by piping reconfiguration. Average general and pitting corrosion rates for this line are minimal. The biocide treatment at STP is currently at 1000 ppm with weekly maintenance pigging.

Infield Sea Water Injection Flow lines: The monitoring data summarized in Tables 7 and 8 show the average corrosion rates for the infield water injection flow line coupons. In 2007, coupons were installed in water injection flow lines as an enhancement to the monitoring program. In previous years, corrosion probes at the outlet of the central facility were used to monitor sea water injection corrosion rates. Average coupon and probe general and pitting corrosion rates for these lines are minimal. Inspection data, discussed in section B.1.b, indicate that significant corrosion damage has not taken place in these lines.

The infield sea water lines are treated with a weekly biocide treatment and quarterly maintenance pigging. New cleaning pig styles are being tested.

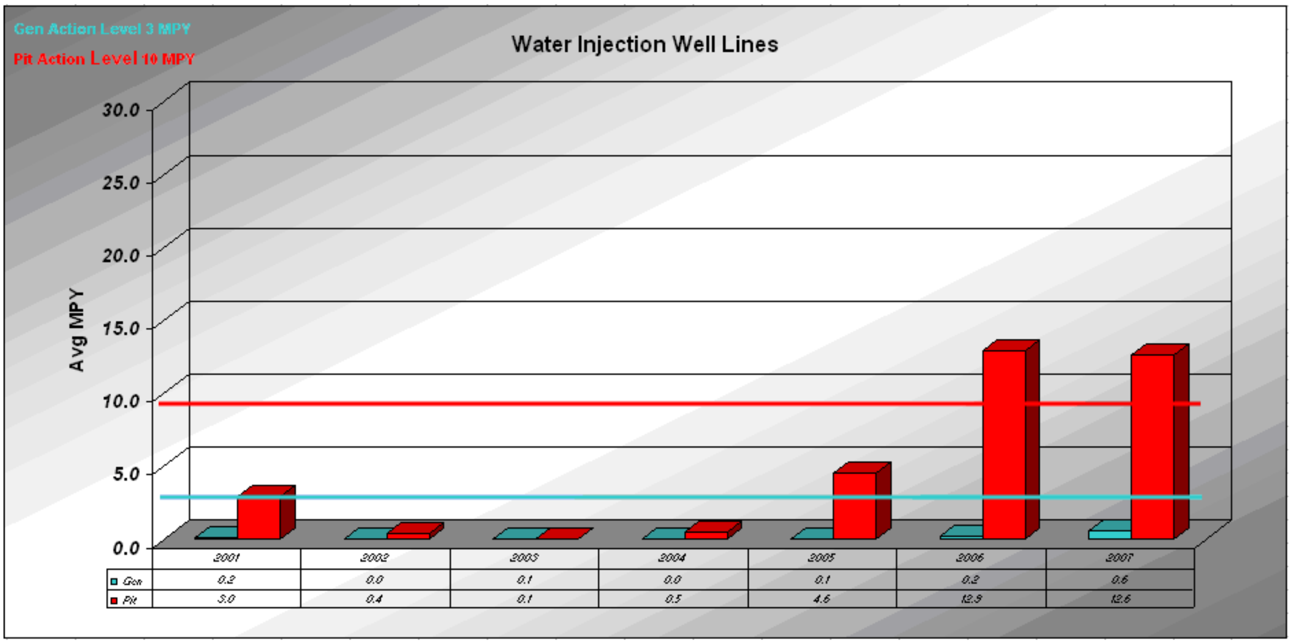

Figure 17. WNS Water Injection Well Line Coupons – general and pitting corrosion rates by year.

Water Injection Well Lines: The monitoring data summarized in Tables 7 and 8 and presented in Figure 17 show that pitting corrosion rates exceed the action level. Inspection data presented in section B.1.a do not indicate damage in these lines, but given Kuparuk's experience with corrosion-related repairs, WNS inspection programs will continue to look for damage in the injectors.

The seawater used for injection is filtered, deaerated, and biocided at the STP in Kuparuk before being shipped to the WNS. The produced water is biocided in the facility.

Maintenance Pigging:

Table 9. Field-wide Maintenance Pigging by Service.

Service	2006 Number Recommended	2006 Number Completed	2006 Percent Completed	2007 Number Recommended	2007 Number Completed	2007 Percent Completed
SW	6	6	100%	12	15	125%
PW	0	0	n/a	0	0	n/a
Oil	1	1	100%	1	1	100%

For the Alpine field, Table 9 shows the actual number and the recommended number of maintenance pig runs conducted by service category. Services tracked are Sea Water (SW), Produced Water (PW) and Oil (three-phase production). As of December 2007, the recommended maintenance pigging frequencies were as follows:

- Quarterly for the SW Injection Flow Lines to the Drill Sites
- Annually for Three-Phase Produced Crude Flow lines

B Inspection

B.1 Internal Inspections

B.1.a Well Line Inspections for Internal Corrosion

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.
In 2006, 19 well lines were inspected. One production line had 26% wall loss, 5 lines had very slight damage, and no damage was found on the remaining 13 lines.
In 2007, 35 well lines were inspected. Only three lines had slight damage, the worst being 10%.

B.1.b Flow Line Inspections for Internal Corrosion

Manual RT of 76 TML's on the CD1 three-phase production line was completed. Damage up to 18% wall loss was found on this line.

Manual RT of 108 TML's on the CD2 three-phase production line was completed. Damage up to 14% wall loss was found on this line.

In addition, 3000' of the CD2 water injection line was inspected by Linear Array. No damage was found.

B.2 External Inspections

In 2007 inspections were completed on 211 of the Tarn-style weld packs on four flow lines to ensure the design is working properly. The weld pack design appears to be performing well. Forty well lines were inspected for CUI and no significant concerns were identified.

B.3 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 D.2.c.

B.3.a Inventory and Survey of Below Grade Locations

CPAI has 21 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 2007. 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:
During the 2007 visual survey, no gravel, soil or debris was found in the casings. The casing boots on a stainless steel below grade line were found to have weathering cracks and are scheduled for repair.

Of all the below-grade lines, two lines have pipe in direct contact with soil. These two lines are considered to be "direct buried". These locations were excavated and evaluated in 2005. ADEC granted a waiver on these two lines, contingent on a stringent inspection program. The next inspection of the buried portions will be in 2009.

B.3.b Results of Specialty Testing

No specialty testing was performed in the WNS in 2007. Of the 51 WNS below grade circuits, 12 were smart pigged with the remainder of the line.

B.3.c Results of Crossing Digs

No excavations were done in 2007.

C. Repairs, Structural Concerns, and Spills/Incidents

C.1 Subsidence:

No subsidence piping concerns have been identified. Of the 141 wells, 138 have both insulated conductors and thermal siphons (heat tube). One well is without both an insulated conductor and a thermal siphon. One of the original exploration wells still in operation has a thermal siphon and lacks an insulated conductor. The third well is scheduled for thermal siphon installation within the year. The first piping support for well piping is located twenty-two feet from the well, providing an opportunity to identify subsidence events prior to potentially impacting piping integrity.

C.2 Wind-Induced Vibration:

No problems identified in 2007.

C.3 Corrosion and Structural-Related Spills/Incidents:

- No leaks were caused by external corrosion in 2007.
- No leaks were caused by wind-induced vibration in 2007.
- No leaks were caused by internal corrosion in 2007.
- No structural or subsidence concerns were identified in 2007.

D. Year 2008 WNS Forecast

D.1 Monitoring & Mitigation

- Pull coupons as scheduled
- Install corrosion inhibitor injection system for mixed water injection service
- Test inhibitor formulations for production and injection services
- Install additional production corrosion inhibitor storage capacity

D.2 Inspection

D.2.a Internal Corrosion Inspections

D.2.a.i) Well Line Inspections for Internal Corrosion

Inspect 30 lines (25% of existing total) for internal corrosion.

D.2.b.ii) Flow line Inspections for Internal Corrosion

Interval surveys are planned for the CD1 and CD2 production and water injection flow lines, as well as the CD3 water injection line.

D.2.b.iii) External Corrosion Inspections

Flow lines over tundra:
Inspections of 200 Tarn-style weld packs are planned.

Flow lines on pad:
No inspections on pad are planned, as the priority is weld packs over tundra.

Well lines:
TRT inspections are planned on 40 lines, with an emphasis on locations prone to CUI such as insulation jacketing damage or transitions from vertical to horizontal.

D.2.c Below Grade Piping Program

Visual inspection of all priority 1 and 2 cased lines is performed annually. The appropriate CPAI field department will be notified of any corrective actions early enough to complete clean out and re-inspection during the summer.

After the first ten years of service and every five years thereafter, the priority 1 and 2 cased lines will be evaluated using NDE. Each below grade section of these lines is externally coated, delaying the onset of external corrosion and allowing more time before the initial inspection.

D.2.d Other

Continue Alpine piping layout and piping information database development.

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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.
- **Flow 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 is 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 (PO)** – 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
- **VT** – Visual inspection
- **TWI –** The Welding Institute (Long range UT)\
- **KDR –** Known damage recur inspection
- **CUI** – Corrosion under insulation
- **CUI IA** – Corrosion under insulation inspection area
- **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.