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

March 31, 2009

Commitment to Corrosion Monitoring

9th 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 9th 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.

The Greater Kuparuk Area (GKA) produces approximately 150,000 BOPD from 47 drill sites into three processing facilities. Effective management of corrosion at GKA is critical to maintain environmental and facility integrity, to reduce field operating costs, and to extend infrastructure life to maximize oil recovery.

The Western North Slope (WNS) consists primarily of the Alpine field and produces approximately 115,000 BOPD from four drill sites into one processing facility. The corrosion management system used at GKA has been adapted to WNS.

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

2.0 SIGNIFICANT ENHANCEMENTS TO CORROSION PROGRAMS

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

Added new corrosion inhibitor (CI) injection and storage facilities to GKA and WNS.

Expanded use of infrared thermography (IR) to detect wet insulation on well lines with up to three inches of insulation.

Smart pigged (in-line inspected) 22 water injection (WI) flow lines for the first time.

Inspected the below-grade fuel gas supply line to the Kuparuk Seawater Treatment Plant (STP) using a tethered smart pig. This is the first known tethered pig application on the North Slope.

Developed a prototype smart (wireless) pipeline crawler to improve safety and increase inspection productivity.

Implemented advanced imagers in hand-held C-arm tangential radiography devices.

Sponsored or attended knowledge sharing fora on corrosion under insulation (CUI), maintenance pigging, and insulation stripping.

Commissioned biocide facility to treat individual WI lines at CPF1, progressing at other two CPFs.

Proactively removed from service flow lines 1-2ZPO and 1L10PO to reduce risk profile.

Increased resources, especially in layout and API 570 inspection.

Formalized API 570 inspection protocols and corrective action notification workflow processes.

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3.0 SUMMARY OF CPAI PROGRAMS

CPAI had several significant accomplishments in 2008 including the following:

- Re-established a small scale test location for new CI evaluation at GKA.
- Changed to a better-performing CI at WNS.
- Successfully executed our routine inspection programs in both GKA and WNS.
  - Completed internal interval surveys on 192 well lines scheduled for inspection in 2008, four short of our goal. Completed our external interval inspection program on 161 well lines, 16 short of our goal. The lines not completed in 2008 are prioritized for completion in early 2009.
  - Completed internal corrosion inspection interval surveys on all flow lines scheduled for 2008.
  - Using conventional inspection techniques and in-line inspection (ILI), completed approximately 33% of the flow line CUI IA's at GKA.
  - 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 all below grade circuits scheduled for 2008.
  - Excavated, inspected, refurbished and / or repaired all targeted cased below-grade pipe circuits.
  - Found no failures of Tarn-style weld packs or Denso-tape refurbishments.
- Successfully ran ILI in 23 flow lines that had never been smart pigged before, 22 of them WI (21 at GKA, one WNS), and one PO line at WNS.

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4.0 GKA PROGRAM STATUS SUMMARY

A. Monitoring & Mitigation

In 2008 we had several significant accomplishments:

- Re-established a small scale test location for new corrosion inhibitor evaluation in the GKA.
- Implemented use of more aggressive maintenance pigs.
- Commissioned the CPF1 supplemental biocide batch injection system.

Average general and pitting coupon corrosion rate data for Year 2008 are presented in Tables 1 and 2.

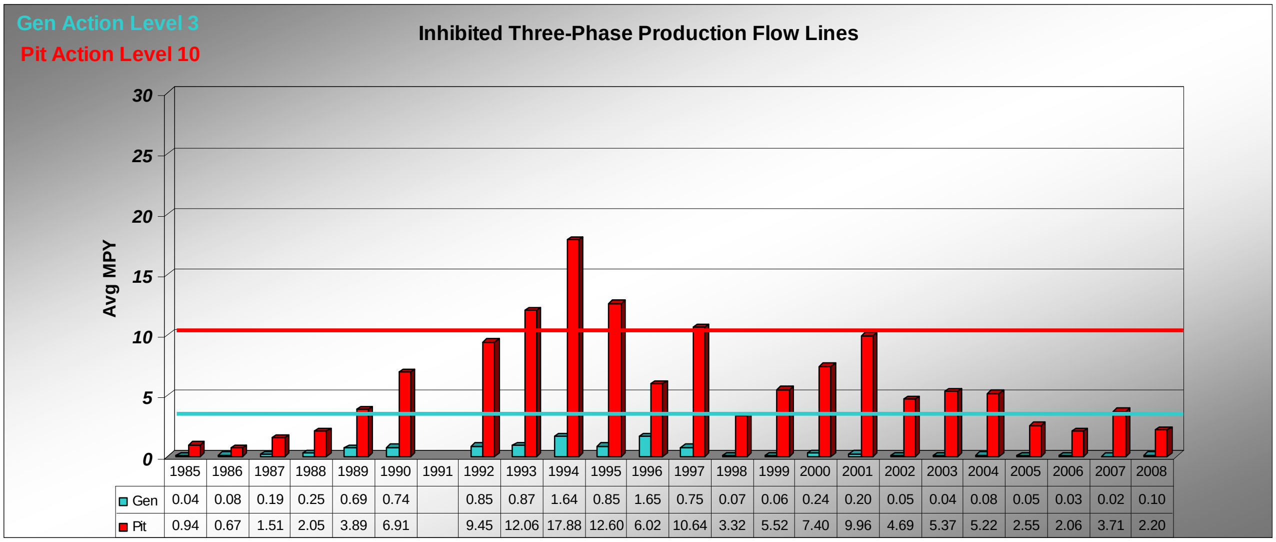
Table 1. Average general corrosion rates for corrosion coupons by service category.

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	56	0.10	55	98%
Seawater Transfer Flow Lines	2	1.15	2	100%
Water Injection Flow Lines	48	0.41	47	98%
Production Well Lines	570	0.15	562	99%
Water Injection Well Lines	408	0.22	398	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	56	2.21	52	93%
Seawater Transfer Flow Lines	2	7.83	1	50%
Water Injection Flow Lines	48	7.23	32	67%
Production Well Lines	570	2.68	545	96%
Water Injection Well Lines	408	4.90	353	87%

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



	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Gen	0.04	0.08	0.19	0.25	0.69	0.74		0.85	0.87	1.64	0.85	1.65	0.75	0.07	0.06	0.24	0.20	0.05	0.04	0.08	0.05	0.03	0.02	0.10
Pit	0.94	0.67	1.51	2.05	3.89	6.91		9.45	12.06	17.88	12.60	6.02	10.64	3.32	5.52	7.40	9.96	4.69	5.37	5.22	2.55	2.06	3.71	2.20

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 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 line system from CPF3 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 2008, 1059 CRM inspections were conducted, with 26 increases found. Other internal inspection data supporting the CRM data are discussed in Section B.1.b, below.

Where corrosion rates exceeded targets, CI concentrations were increased and the amount of inspection was increased. In 2008, coupon, probe or inspection-based corrosion rates exceeded targets or revealed increased damage on 22 lines. In 2008, inspection results indicated minor corrosion had occurred in 15 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	Increased Target PPM
1BPO	x			Increased Target PPM
1CPO	x			Increased Target PPM
1DPO			x	Increased Target PPM
1EPO	x		x	Increased Target PPM
1GPO			x	Increased Target PPM
1HPO	x	x		Increased Target PPM
1L10PO			x	Increased Target PPM and later took out of service
1L12PO	x			Increased Target PPM
1QGPO			x	Increased Target PPM
1RPO	x			Increased Target PPM
1YRPO			x	Increased Target PPM
2APO			x	Increased Target PPM
2DPO			x	Increased Target PPM
2UPO			x	Increased Target PPM
2WUVPO			x	Increased Target PPM
2VPO			x	Increased Target PPM
2ZPO			x	Increased Target PPM
3APO		x		Increased Target PPM
3HPO			x	Increased Target PPM
3MIPO		x		Increased Target PPM
3WO			x	Increased Target PPM
22	**6**	**3**	**15**	

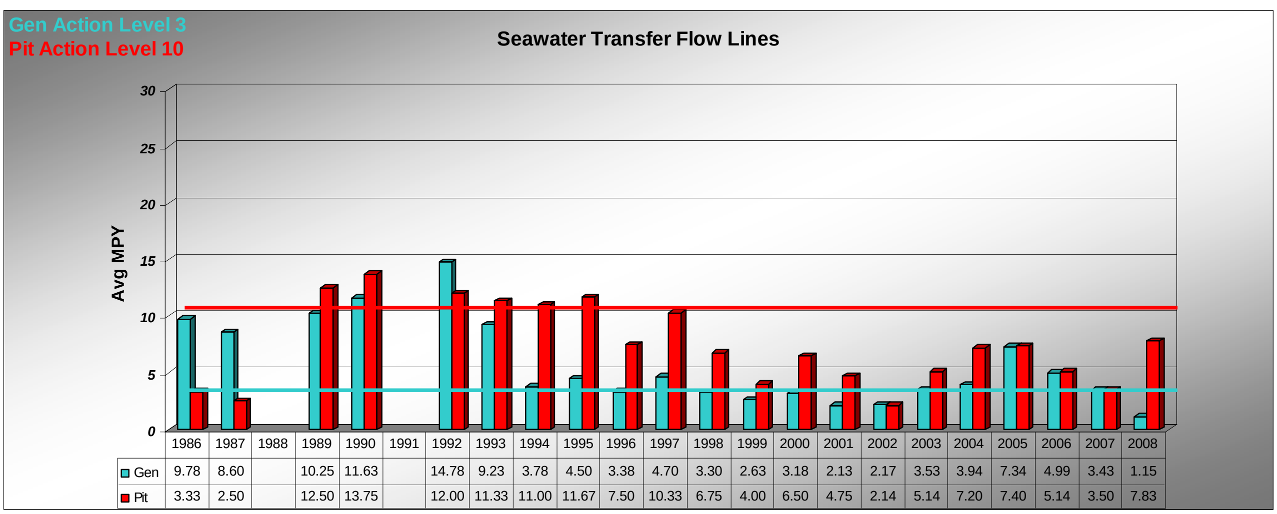

Figure 2. Seawater Transfer Flow Line Coupons – general and pitting corrosion rates by year.

Seawater Transfer Flow Lines: The monitoring data summarized in Tables 1 and 2 and presented in Figure 2, show the average corrosion rates for the SW flow line coupons. Average general corrosion rates have dropped below threshold with inclusion of oxygen scavenger full time at STP and pitting rates for the field are below the threshold. Biocide concentration is currently at 1000 ppm with weekly maintenance pigging. There are two coupon locations on the SW system, one at the STP and one on the SW line that supplies Alpine. The STP coupon on the SW discharge had an average pitting corrosion rate of 11 mpy from oxygen excursions. The Alpine line coupon had an average pitting corrosion rate of one mpy.

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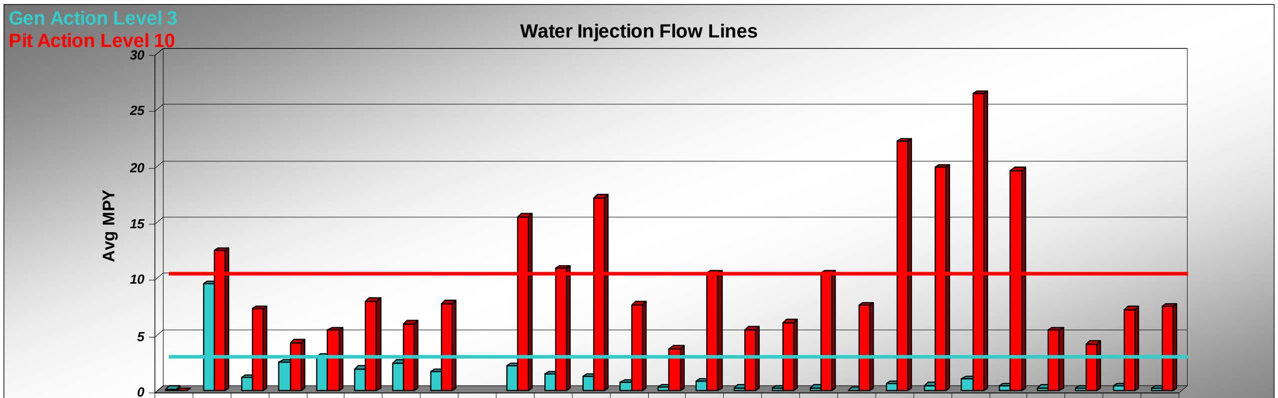
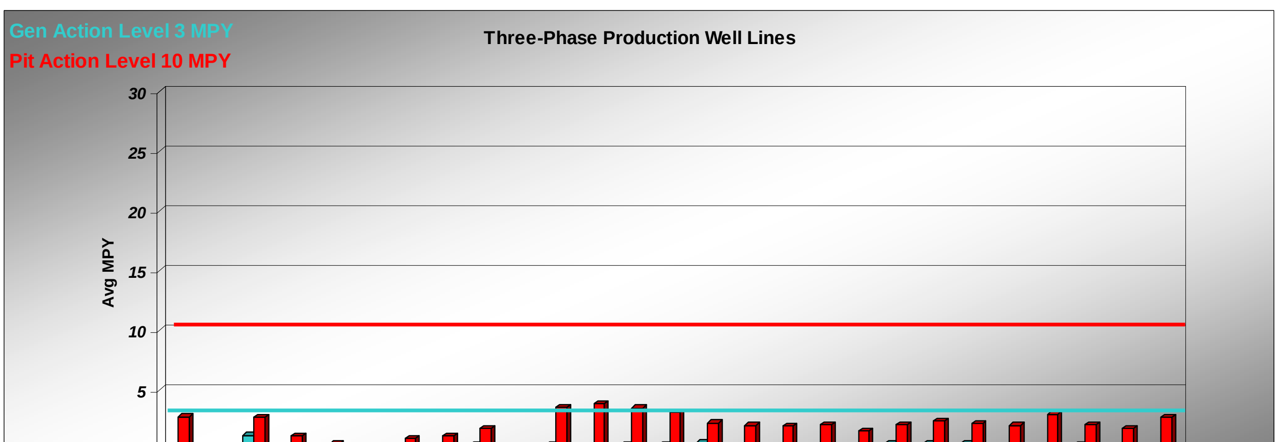


	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Gen	0.17	9.53	1.19	2.53	3.01	1.95	2.51	1.68		2.25	1.48	1.29	0.76	0.33	0.82	0.28	0.20	0.29	0.06	0.61	0.47	1.03	0.45	0.25	0.19	0.41	0.19
Pit	0.00	12.46	7.27	4.28	5.40	7.97	5.99	7.75		15.47	10.86	17.16	7.65	3.76	10.44	5.43	6.08	10.47	7.61	22.17	19.85	26.41	19.58	5.39	4.17	7.23	7.48

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

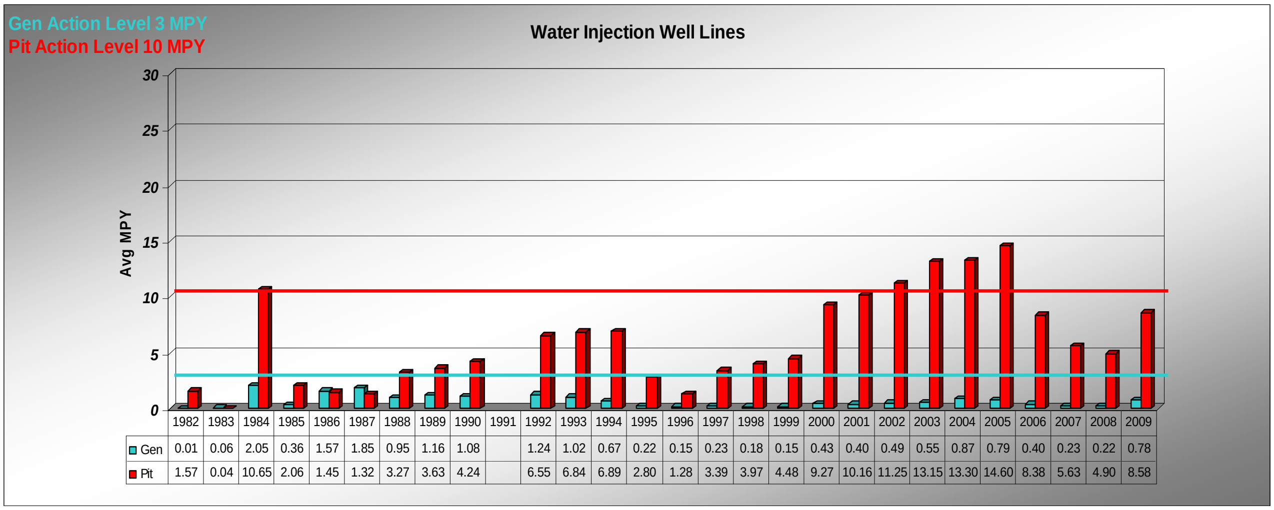
Water Injection Flow lines: The monitoring data summarized in Tables 1 and 2 are presented in Figure 3. Increased pigging and biocide have brought the WI flow lines coupon pitting rates under control. Since SW and PW commingling were suspended at CPF2 in 2005, pitting rates have been reduced markedly. Coupon results are used to prioritize inspection efforts. Additional chemical injection systems have been installed on individual lines at CPF1 and are being installed at the other two CPF's. New cleaning pig styles have been field-tested and additional pigging technology is under evaluation. These lines also benefit from the weekly biocide treatment of the sand jet systems. Data from new coupon locations installed in water injection flow lines during 2007 were available for the first time in 2008. Many of these new coupon locations were at the drill site end of flow lines. Exposed to pigging effluent, the pitting corrosion rates of the new coupons were greater than ten mpy. CPF1 water injection flow lines treated with biocide after pigging for half the year had an average corrosion pitting rate of three mpy.



	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Gen	0.02	0.07	1.16	0.17	0.19	0.27	0.13	0.20	0.35		0.37	0.28	0.33	0.36	0.55	0.15	0.17	0.18	0.31	0.47	0.51	0.46	0.21	0.24	0.38	0.25	0.15
Pit	2.74	0.00	2.67	1.11	0.44	0.25	0.90	1.08	1.76		3.50	3.82	3.47	3.11	2.21	2.00	1.97	2.05	1.50	2.07	2.41	2.14	2.01	2.94	2.02	1.75	2.68

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.



	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Gen	0.01	0.06	2.05	0.36	1.57	1.85	0.95	1.16	1.08		1.24	1.02	0.67	0.22	0.15	0.23	0.18	0.15	0.43	0.40	0.49	0.55	0.87	0.79	0.40	0.23	0.22	0.78
Pit	1.57	0.04	10.65	2.06	1.45	1.32	3.27	3.63	4.24		6.55	6.84	6.89	2.80	1.28	3.39	3.97	4.48	9.27	10.16	11.25	13.15	13.30	14.60	8.38	5.63	4.90	8.58

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 increased velocities from decreasing the riser and well line diameters are contributing to the decrease in coupon corrosion rates.

<u>Mitigation:</u>

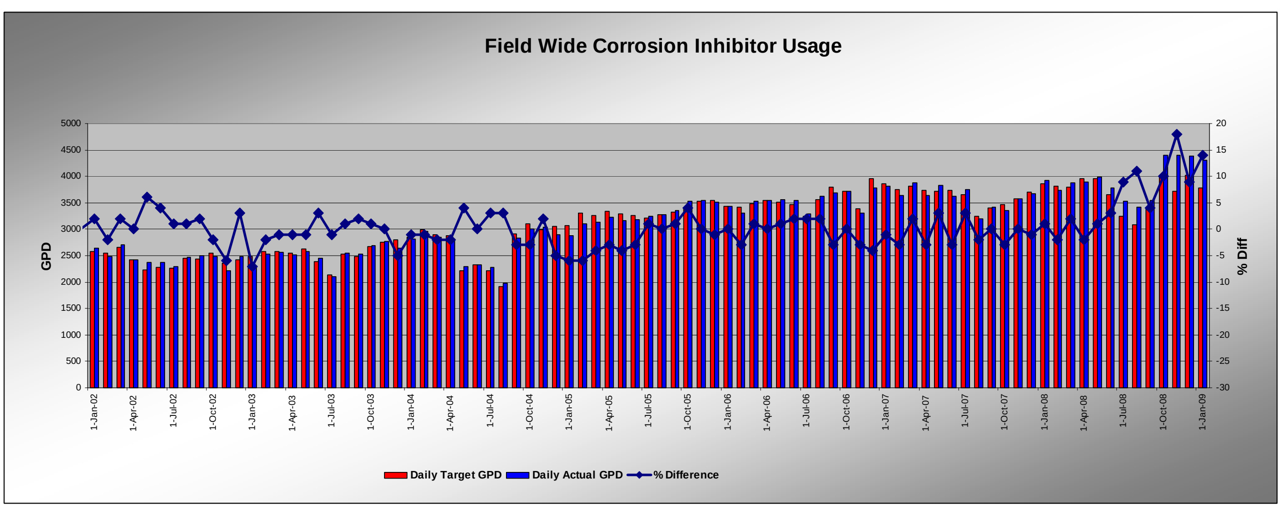


Figure 6. Field-wide Corrosion Inhibitor Use.

Figure 6 shows the actual number of gallons of CI pumped per day, the recommended (target) number of gallons per day and the percent difference between the two. The average deviation for the year was +5%, which is a result of maintaining rates at normal winter volumes during the summer maintenance activities.

Coupon corrosion rate results have reflected maintaining these volumes during these activities. CI use has increased since 2003 because of higher water cuts and solids.

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

Maintenance Pigging:

Service	2006 Number Recom.	2006 Number Comp.	2006 Percent Comp.	2007 Number Recom.	2007 Number Comp.	2007 Percent Comp.	2008 Number Recom.	2008 Number Comp.	2008 Percent Comp.
SW	420	280	67	463	339	73	325	315	97
PW	682	615	90	923	883	96	818	721	88
Oil	20	21	105	25	49*	196	20	28	140

Table 4. Field-wide Maintenance Pigging by Service.
*Note: 2007 data include the maintenance pig cleaning runs associated with 2PPO ILI.

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 maintenance pigging frequencies are as follows:

- Weekly for the 30” SW 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 (except for 2PPO that is pigged every six months)

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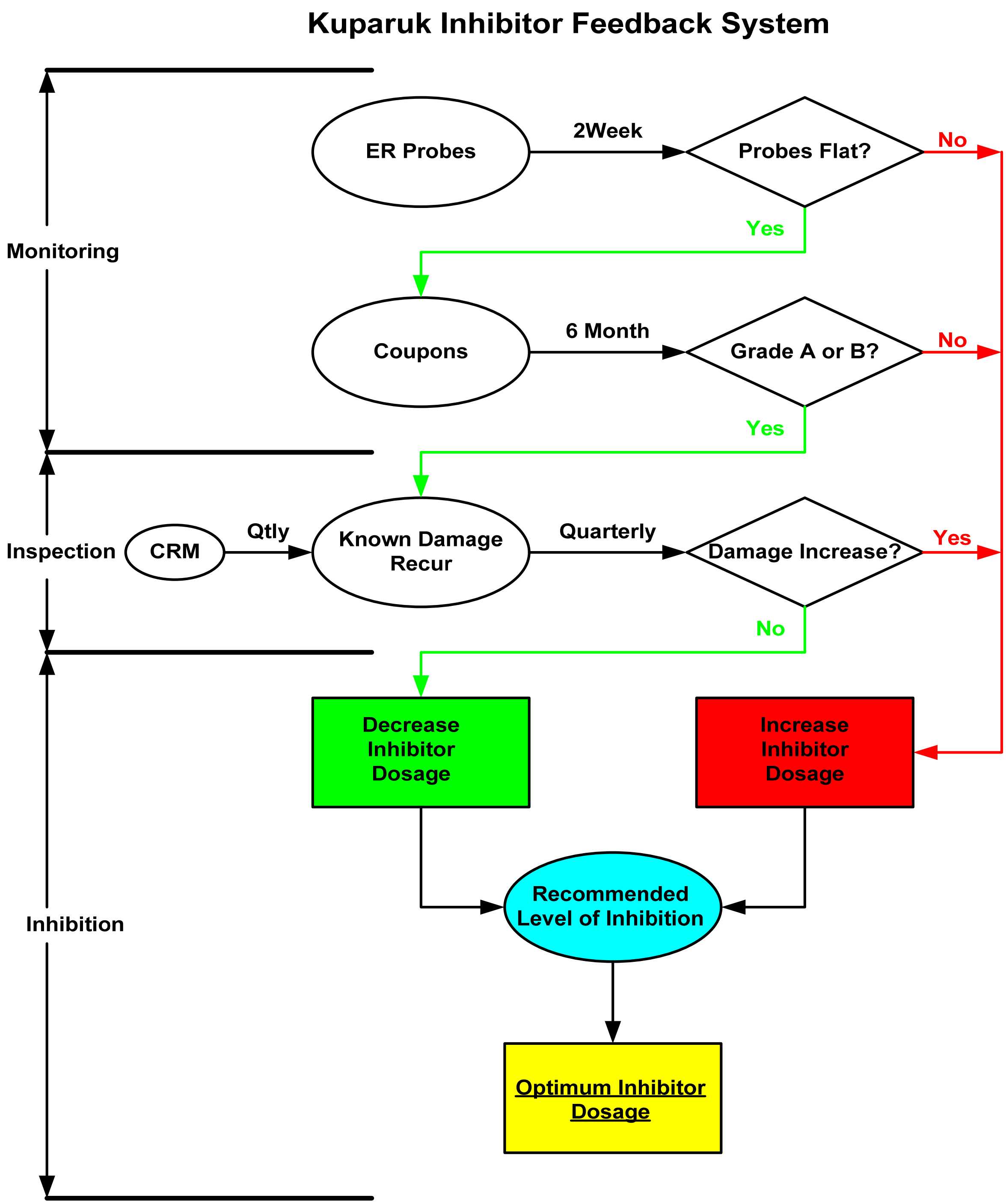

Figure 7. Corrosion Inhibitor Feedback System.

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B. Inspection

B.1 Internal Corrosion Inspections

There were no leaks caused by internal corrosion on flow lines in 2008.

B. 1.a Well Lines Inspections for Internal Corrosion

Because of drill site access restrictions, we did not complete our planned 2008 conventional well line internal inspection program. We completed interval surveys on 162 of the 166 well lines scheduled for inspection in 2008. The remaining four well lines are scheduled to be inspected in early 2009. 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; no damage was reported.

As indicated in Figure 8, below, repair recommendations were initiated on 37 well lines (19 WI and 18 PO) in 2008 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 shown in Figure 8 can be found in Section C.

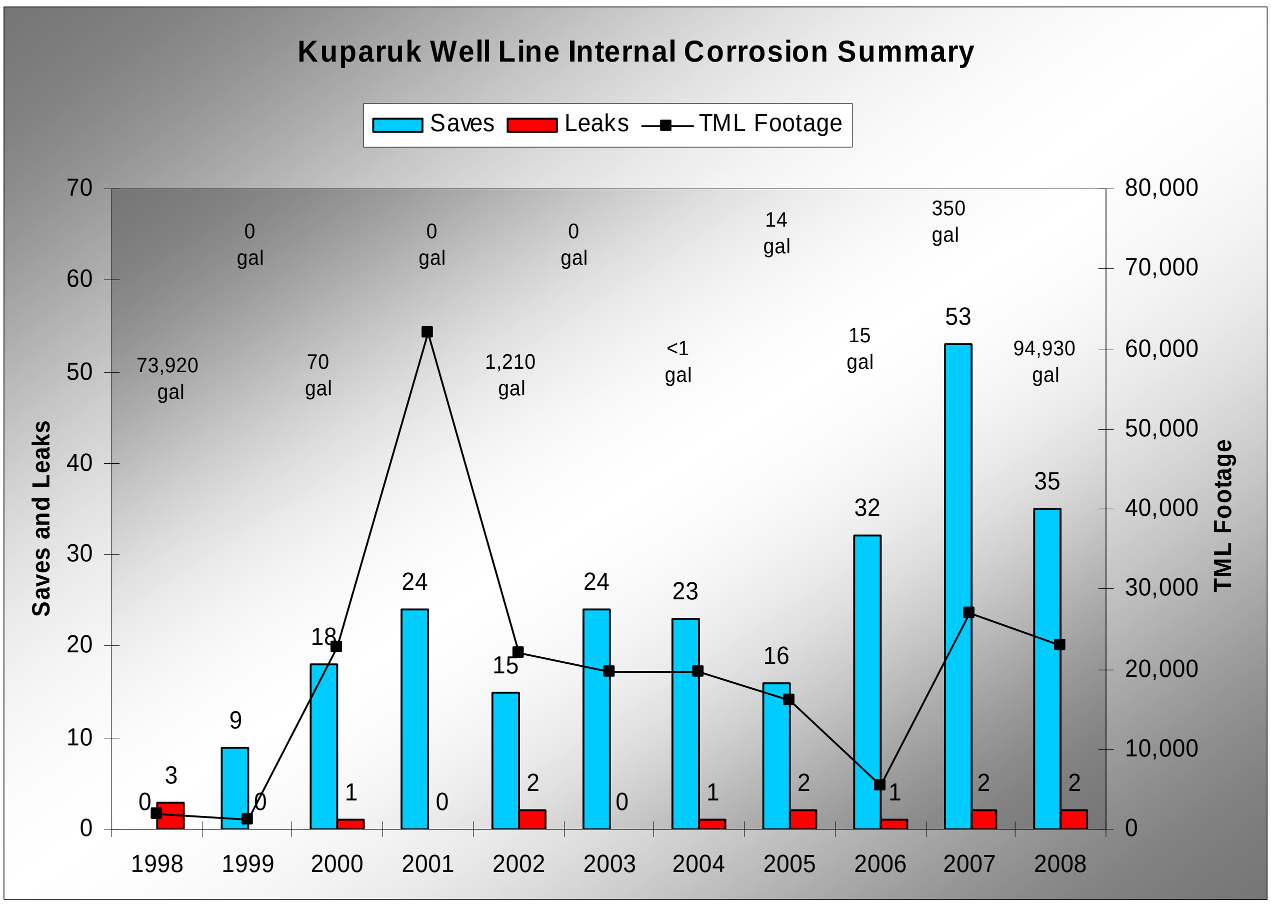


Figure 8. Summary of WI and Three-Phase Production Well Line Internal Corrosion Inspections – RT footage, leaks, and saves by year.

The 2008 results from the RTR / linear array surveys, manual RT, and manual UT are summarized in the following three tables.

- **Interval Surveys of Well Lines:**

Service	Feet Inspected	Number of Lines Inspected
Three-phase Production	13,022	109
Water Injection	6,727	53
Total	19,749	162

The 2008 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	195	1,945	493	33	7 %
Water Injection	112	1,190	227	31	14 %
Total	307	3,135	720	64	9 %

The 2008 manual RT well line data indicated no significant damage trend changes in either the three-phase or the WI well lines.

- **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	151	858	619	36	6 %
Water Injection	74	196	161	16	10%
Total	225	1,054	780	52	7%

The 2008 manual UT well line data indicate a small decreasing damage trend in the WI well lines. The percentage of recurring UT increases dropped from 20% in 2007 to 10% in 2008.

B.1.b Flow Line Inspections for Internal Corrosion

We exceeded our 2008 goal by completing interval surveys on 45 lines in 2008. Our original goal was 35 lines. We were only able to do this by dramatically increasing our 2008 ILI program. This is also the reason for the large increase in footage inspected in 2008.

As indicated in Figure 9 below, ten repair recommendations were initiated on flow lines (two WI and eight PO) in 2008 because of internal corrosion damage. The corrosion mechanism for all repair recommendations was either deadleg or solids-related. There were no leaks in flow lines caused by internal corrosion in 2008.

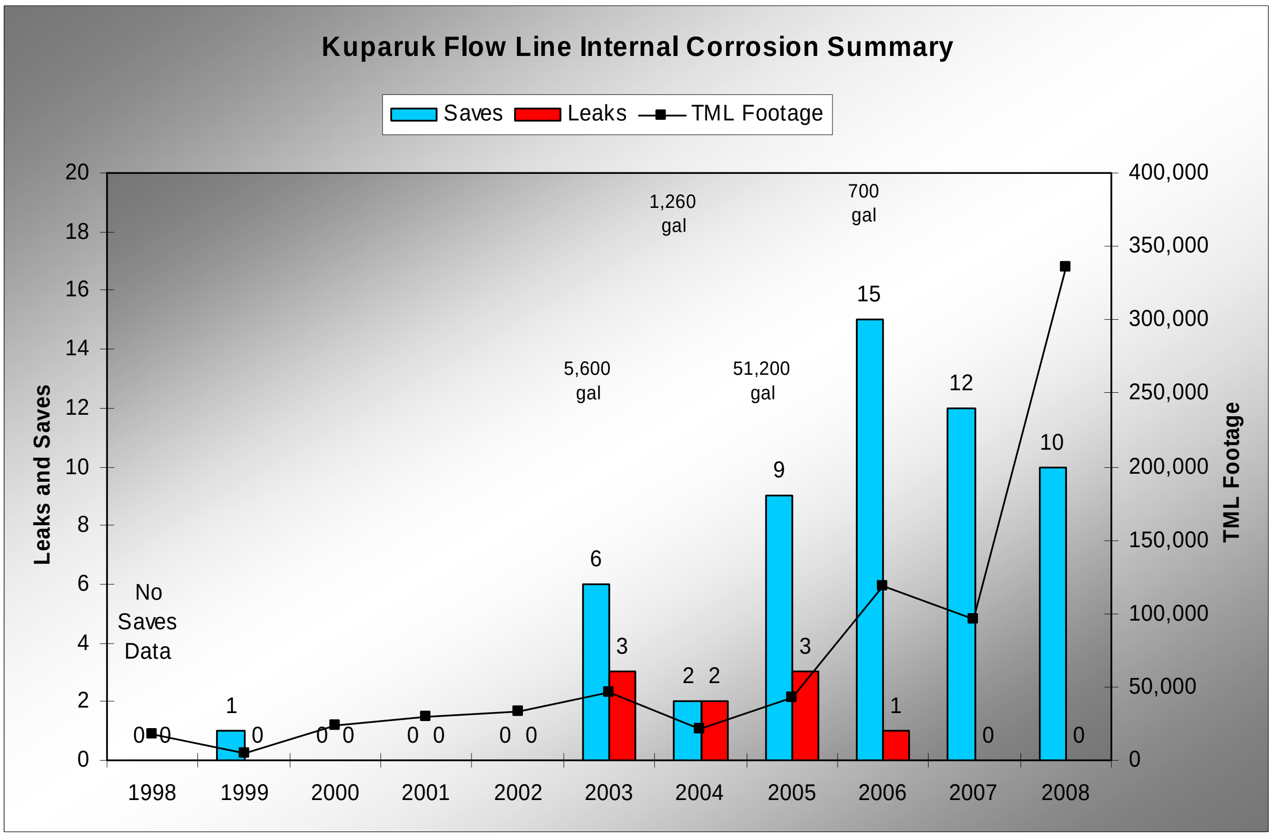


Figure 9. Summary of WI and Three-Phase Production Flow Line Internal Corrosion Inspections – Footage (RT and ILI), leaks, and saves by year.

The 2008 results from the RTR / linear array surveys, ILI, manual RT, and manual UT are summarized in the following three tables:

- **Interval Surveys of Flow Lines:**

Service	Feet Inspected	Number of Lines Inspected
Three-phase Production	32,570	17
Water Injection	296,161	28
Total	328,731	45

The 2008 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	90	4,023	719	18	3 %
Water Injection	41	3,234	156	3	2%
Total	131	7,257	875	21	2 %

The 2008 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	84	2,066	634	39	6 %
Water Injection	32	575	372	30	8 %
Total	116	2,641	1,006	69	7 %

The 2008 manual UT flow line data indicated no new damage trends.

- **ILI of Flow Lines:**

In 2008, 22 WI flow lines were evaluated with ILI at Kuparuk for the first time. This is the highest number of ILI by CPAI to date and illustrates the commitment to continuous improvement of the inspection program.

Table 5 summarizes equipment service, diameter, and length of lines that were evaluated with ILI in 2008.

Table 5. ILI runs in 2008.

Line Name	Service	Diameter (inches)	Line Start	Line End	Length (miles)
1RGWI	Water Injection	NPS12	CPF1	DS1G	4.2
1QYWI	Water Injection	NPS12	DS1A	DS1Y	3.4
1QYA16WI	Water Injection	16	CPF1	DS1A	2.2
2EDCWI	Water Injection	NPS10	CPF2	DS2C	1.3
2EDWI	Water Injection	NPS8	DS2C	DS2D	2.6
2KWI	Water Injection	NPS6	DS2H	DS2K	2.5
2MAWI/2MWI	Water Injection	NPS8	DS2A	DS2M	4.4
2TAWI	Water Injection	NPS10	CPF2	DS2T	6.2
2WUVWI/2WUWI	Water Injection	NPS12	CPF2	DS2U	5.7
2WWI	Water Injection	NPS10	DS2U	DS2W	2.1
2XWI	Water Injection	NPS10	CPF2	DS2X	3.9
3CWI	Water Injection	NPS8	CPF3	DS3C	2.2
3HWI	Water Injection	NPS6	DS3A	DS3H	2.1
3HAMIWI	Water Injection	NSP10	CPF3	DS3A	3.3
3JWI	Water Injection	NPS8	CPF3	DS3J	1.5
3RQOWI/3RQWI	Water Injection	NPS10	CPF3	DS3Q	7.2
3SGFWI	Water Injection	NPS10	DS3B	DS3F	2.5
3SGFBWI	Water Injection	NPS12	CPF3	DS3B	1.8

The metal loss features reported by ILI have been prioritized for verification by radiographic and/or ultrasonic inspection. The verification results through 2008 are included in the aggregate inspection data.

Additional follow-up of the reported features is an ongoing part of the normal radiographic and ultrasonic inspection program.

In summary, ILI has become an integral part of the overall inspection program.

B.2 External Corrosion Inspections

In 2008 we had several significant accomplishments:

- We exceeded our 2008 goal of 44,511 CUI surveys and completed inspection of 61,392 (42,218 by TRT and 19,174 by ILI) flow line and well line CUI IA's. This represents a tripling of the effort from 2007.
- Exceeded our goal of inspecting 100 Tarn-style weld packs (605 inspected) to ensure this design continues to work as intended. No corrosion has been detected on the piping within the weld pack areas.
- Exceeded our goal of inspecting 100 refurbished CUI IA's (1,622 inspected) to verify the soundness of the Denso tape refurbishments. The refurbishment technique appears to be performing well.
- Inspection procedures were revised to include all saddle locations (regardless of insulation type) during future TRT surveys, all previously-refurbished areas to check insulation interfaces, and an additional four feet of insulation upstream and downstream at each CUI IA. These changes resulted in an increase that roughly doubled the overall number of CUI IA's.

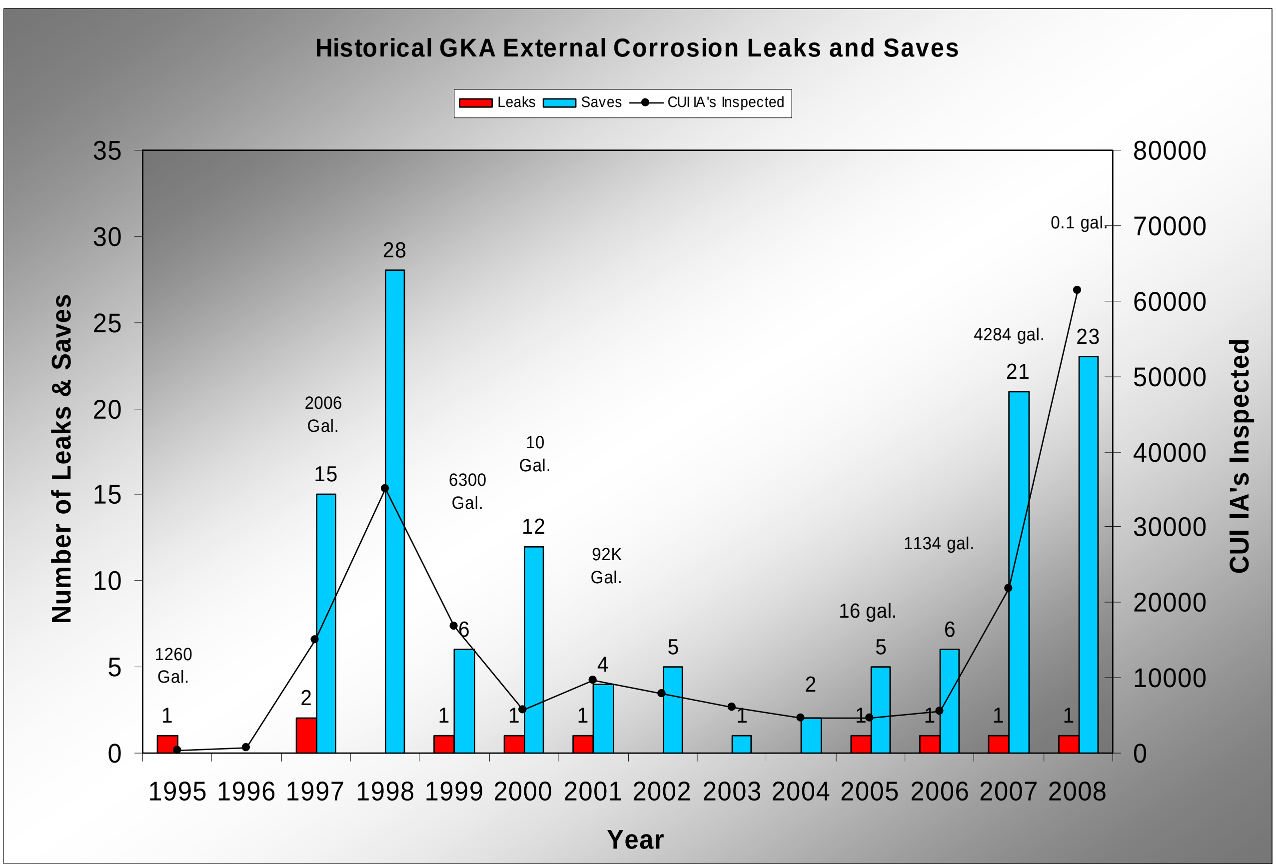


Figure 10. Leaks, saves, number of CUI IA's inspected with TRT, and volumes of leaks by year.

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 2008 was to continue the field-wide recur of all CUI IA's on cross country flow lines. Each location is currently on a five-year recur interval.

In 2008, 58,003 of the 58,217 scheduled CUI IA's were inspected using a combination of ILI and TRT. Only a small portion of the scheduled piping was deferred until 2009 because of access restrictions (~214 on-pad CUI IA's). External corrosion was identified at 397 locations (326 of the 397 were located over tundra). The corroded locations were added to the list for follow-up visual inspection (VT) and refurbishment.

One flow line leak was caused by external corrosion in 2008. The leak occurred on 1YRPO at VSM 675/673 and resulted in a 0.1 gallon spill. The damaged area was identified during the insulation refurbishment process and the location was repaired with a welded pressure-containing sleeve.

Field-wide, 19 sleeve repair recommendations (saves) were issued as a result of external corrosion damage on flow lines. These recommendations included 16 flow lines [1QGL, 1RGI, 1RWI, 1YEOR, 1YRPO (two sleeves – one leak/one save), 2ETEOR, 2FTEST, 2VGI (two sleeves), 2WTGL, 2WUGI, 2WUVPO, 3HAPO, 3HPO (two sleeves), 3RQOPO, 3RQPO, 3WTGL].

The 2008 CUI inspections noted above included a sampling of the newer Tarn-style weld packs (605 locations) to evaluate how the design is continuing to perform. No water or 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 2008 surveys included previously-refurbished weld packs (1,622 locations) to monitor the performance of the Denso product and to check the piping at the insulation interfaces for possible damage. The results showed no evidence of additional corrosion at the area wrapped with tape.

B.2.b Well Line Inspections for External Corrosion

Because of higher priority work on the flow lines, we did not complete our planned 2008 conventional well line CUI program. The remaining well lines were deferred until 2009 to support increased TRT inspection efforts on the 2008 flow line inspection program.

In 2008, 228 well lines (5,468 CUI IA's) were scheduled for conventional TRT inspection. Of these, 121 lines (3,389 CUI IA's) were inspected with conventional TRT. Of the 107 remaining lines, 44 were scheduled (but were not due) for inspection in 2008 and were deferred. Of the 63 remaining lines, 47 had a valid infrared thermography (IR) inspection within the past three years. The remaining 16 are scheduled to be inspected in early 2009. External corrosion was identified at 212 locations (32 of the 212 locations were over tundra). The corroded locations were added to the list for follow-up VT and refurbishment.

We began evaluating IR in 2006 to identify wet insulation and have determined that IR provides a fast and accurate means of screening large sections of pipe for wet insulation. During the development phase, parameters were established that determine the limits of the tool, such as, weather conditions, piping temperature, and insulation thickness. Based upon the positive test results, well line CUI inspection will be conducted using IR screening in place of TRT screening on applicable lines starting in 2009.

Repair recommendations (saves) were issued as a result of external corrosion damage on two well lines (1L-06 and 2D-01). There were no leaks caused by external corrosion on well lines in 2008.

Table 6: External CUI Inspection Summary for 2008.

Type of Equipment	2008 Goal	Number of Locations Inspected	Number of Corroded Locations	Percentage of Locations Corroded	Number of Locations Refurbished
Flow lines Over Tundra or On-Pad	58,217	58,003	397	0.7%	1413
Well Lines	5,468	3,389	212	6.3%	333
Total	**63,685**	**61,392**	**609**	**1.4%**	**1,746**

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

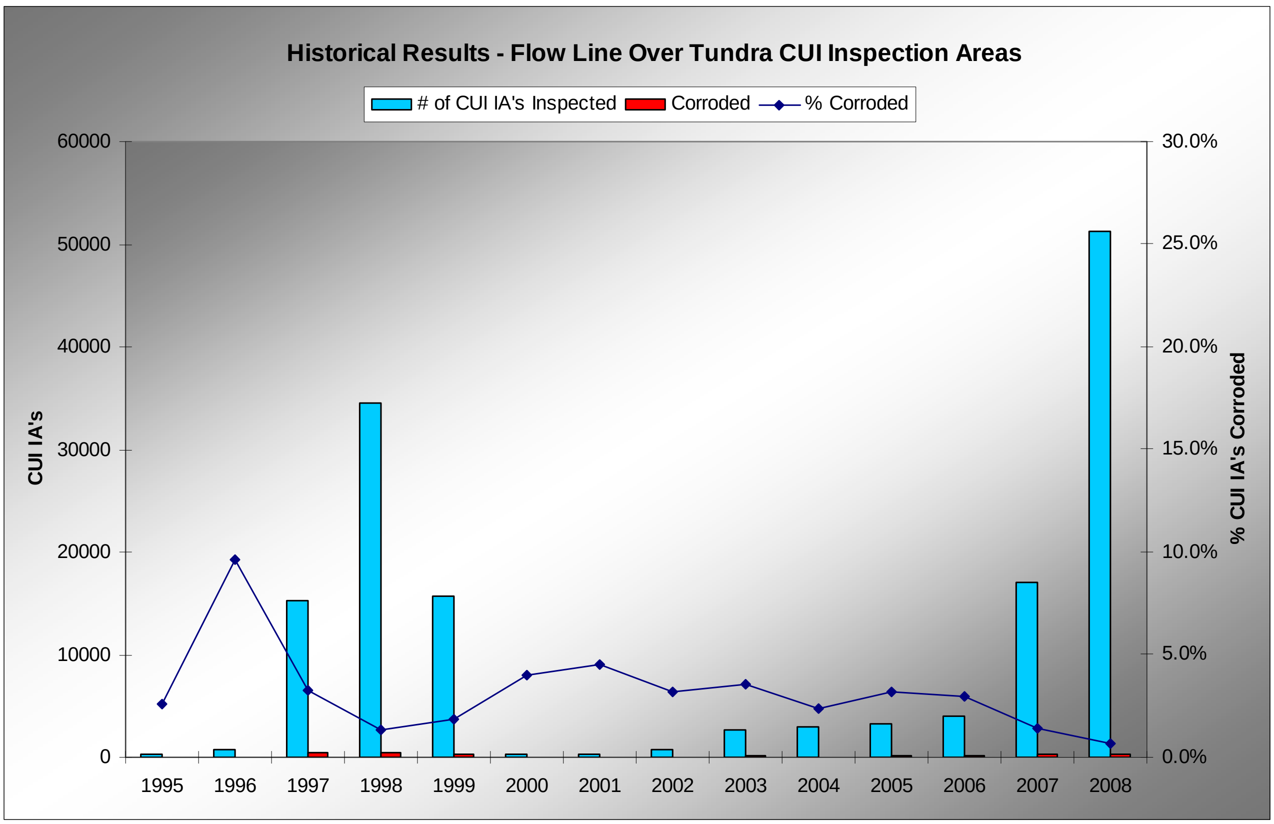


Figure 11. Summary of Flow Line Over-Tundra (off-pad) CUI IA's

Figure 11 illustrates the latest results from the external corrosion inspection program. The 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 and 2008 is representative of our field-wide recur inspection to re-evaluate all locations on a five-year inspection interval. The 2008 data include ILI results on flow lines.

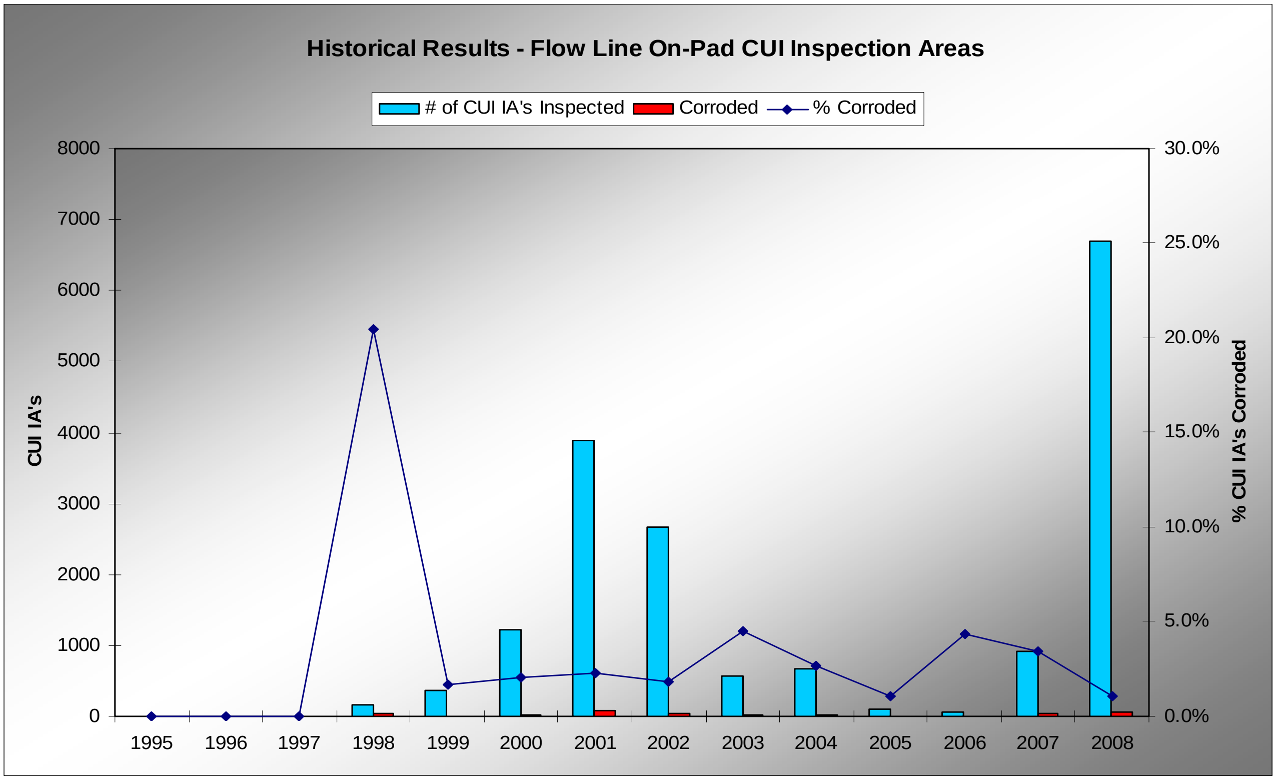


Figure 12. Summary of Flow Line On-Pad CUI IA's

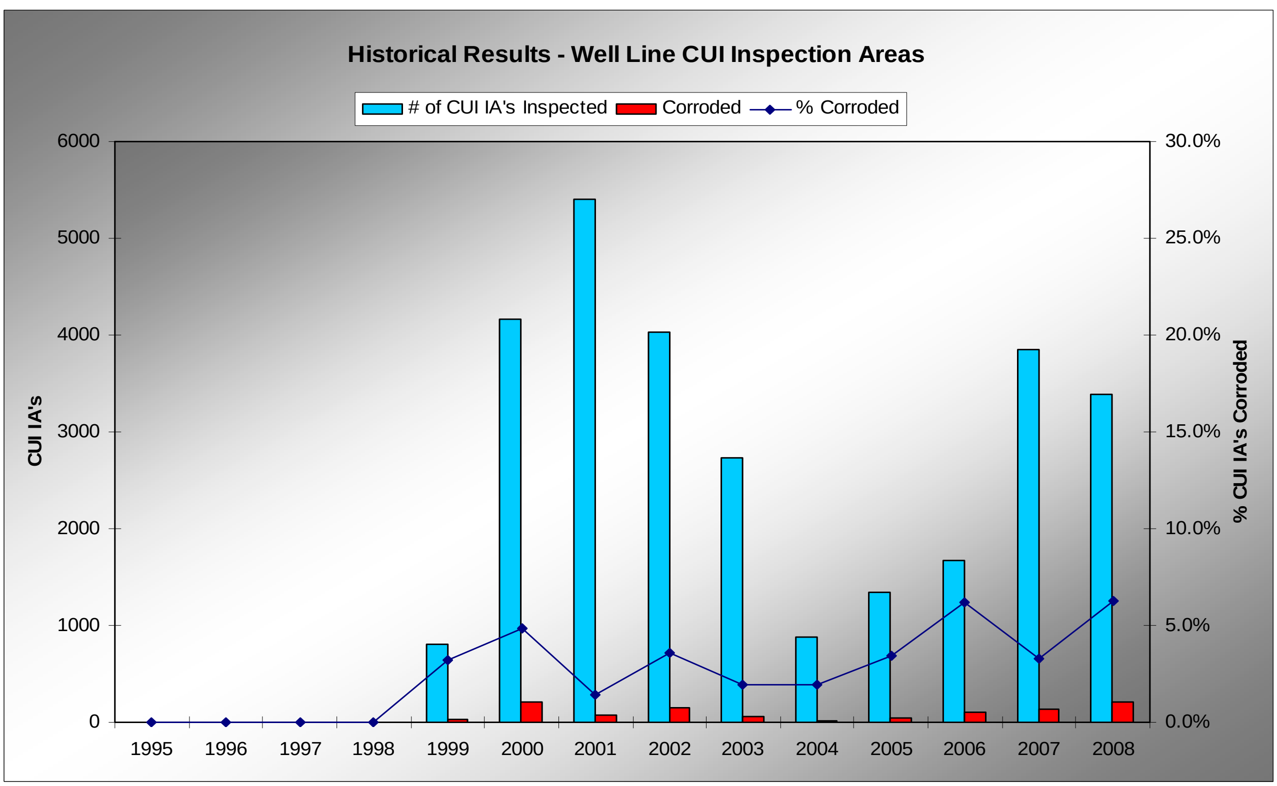


Figure 13. Summary of Well Line CUI IA's

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 2008 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)] on 62 circuits.
- Completed ILI on 71 circuits.
- Excavated, inspected, refurbished and / or repaired (as required) 43 cased circuits.

The Alaska Department of Environmental Conservation (ADEC) regulations under 18 AAC 75.080 apply 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 790 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 has not been inspected since 2002.
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 was inspected in 2008.
3. The other new line is the sister line to #2 above. It provides fuel to an adjacent pump. This was also inspected in 2008.

Cased Lines

<u>Inspection Status:</u>
The annual visual survey of all the cased lines was conducted in 2008. 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, 238 were found to have pipe in direct contact with gravel/soil or debris in the casing. All locations were remediated in 2008.

B.3.b Results of Specialty Testing

<u>Inspection Status:</u>
In 2008, we completed either LRUT or ILI on 133 GKA priority one circuits. This was the sixth year of our recurring inspection program. Each priority one circuit is on a five-year (maximum) re-inspection interval.

In 2008 The Welding Institute (TWI) was the only LRUT inspection system used. TWI technology is capable of finding evidence of both internal and external corrosion damage.

Results and Remedial Action:

Table 7 shows the results of the LRUT specialty testing performed by TWI.

Table 7. 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	53	1	29	22	1	0
Other	9	1	6	2	0	0
Total	62	2	35	24	1	0

The 2008 TWI data again showed a drop in "Incomplete / Inconclusive" results from 26 in 2005 to 12 in 2006 to 4 in 2007 to only 2 in 2008. This trend is a result of on-going data analysis and close communication with the LRUT vendor.

B.3.c Results of Crossing Refurbishments

Forty-three below grade circuits were refurbished in 2008. Thirty-eight circuits were excavated and five were replaced without excavation (cut and pulled through casing). Ten below grade circuits were repaired in 2008:

- Five total replacements (two on 1RPO and three on 2EDWI)
- One partial replacement (CPF1 diesel loading dock line)
- One replaced o-let on a fire water line. The o-let was cracked.
- Three sleeved (1RWI, two on 2ETEOR, and STPtoCW)

All below grade circuits which were excavated for inspection in 2008 were refurbished and the pipe wrapped with denso tape to prevent future corrosion.

All below grade circuits replaced-without-excavation in 2008 were externally coated with fusion bonded epoxy to prevent corrosion.

C. Repairs, Structural Concerns, and Spills/Incidents

Subsidence:

Existing Well Upgrade Program

- In 2008, no conductor-mounted floor kits were installed in existing well houses at Kuparuk. A total of 31 fiberglass floor kits were installed in well houses distributed between CPF1, CPF2, and CPF3 area Drill Sites.

- In 2008, 28 heat tubes were installed at Drill Sites 1D, 2T, and 3A. These heat tubes are used to keep the ground frozen or to re-freeze the ground where it has been thawed.

- In 2008, 22 combination heat tube / pipe vertical support member (VSM) were installed at Drill Sites 1E, 1F, 1G, 1R, 1Y, 2A, 2B, 2E, 2F, 2G, 2M, 2W, 2X, 2Z and 3B as part of well line upgrade projects. These combination heat tube / pipe VSM's provide the benefits or a standalone heat tube while providing additional pipe support for the well lines.

New Wells & Producer to Water Injection Well Conversions

- In 2008, four newly drilled wells at Kuparuk were installed with insulated conductors.
- In 2008, all four newly drilled wells had heat tubes installed. Of these wells, one had a conductor-mounted floor kit that also provided permanent pipe support and three had fiberglass floor kits with independent permanent pipe supports.

Wind-Induced Vibration:

As a result of the 3IM eight-inch miscible injectant 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 dampeners.

As a result 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).

Corrosion and Structural-Related Spills/Incidents:

- The 1L-22 WI well line leaked in December of 2008 because of internal corrosion. The spill volume was determined to be 94,920 gallons of produced water and, except for a light misting, all liquids were confined to the gravel pad. The spill was reported to ADEC and the investigation into the cause of the leak is complete and follow-up actions are ongoing.
- The 1YRPO leaked in September of 2008 because of external corrosion under insulation. The spill volume was determined to be 0.1 gallons of produced crude, some of which contacted the tundra. This spill was reported to ADEC.
- The Drill Site 3A crossover line between a production line and a seawater line leaked in May of 2008 because of internal under-deposit corrosion. The spill volume was determined to be 10 gallons of crude oil and produced water. This spill was reported to ADEC.
- No flow line leaks were caused by internal corrosion in 2008.
- No leaks were caused by subsidence or other structural reasons in 2008.

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 2009 Forecast

D.1 Monitoring & Mitigation

- Test additional CI formulations.
- Install additional CI storage capacity at several drill sites.
- Continue to evaluate maintenance pigging enhancements to the WI systems.
- Plan installation of inhibitor/biocide injection capacity for the WI systems.
- Continue to evaluate biocide and maintenance pigging in the SW system.
- Install new monitoring locations on WI flow lines.

ConocoPhillips

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 2009. Our goal is that no in-service line will go longer than ten years without some type of inspection.

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

Our recurring inspection program will continue in 2009. Our goal is that no in-service line will go longer than five years without some type of inspection.

ILI is planned for several WI 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's 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 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 well lines that fall within the model with IR at one-third of all drill sites (~16 of 47 per year) as part of our recurring CUI inspection program. Those well lines that fall outside the model will be inspected with conventional TRT on the same interval as internal corrosion inspections.
- Include all pipe support saddles as CUI IA's and inspect during well line recur inspections.
- Increase inspection area from +/- one foot at each CUI IA to +/- four feet at each CUI IA.

D.2.c Below Grade Piping Program

- Evaluate the criteria for inspection interval based on service, internal and external corrosion likelihood, etc. as noted in API 570.
- 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.
- Excavate, inspect, refurbish, and repair (as necessary) approximately 20 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 Corrosion Database (CDB).
- Continue to evaluate, and prioritize subsidence and WIV mitigation efforts.

5.0 WNS PROGRAM STATUS SUMMARY

A. WNS Monitoring & Mitigation

In 2008, CI storage capacity was increased. A new CI formulation was field-tested.

Average general and pitting coupon corrosion rate data for Year 2008 are presented in Tables 8 and 9.

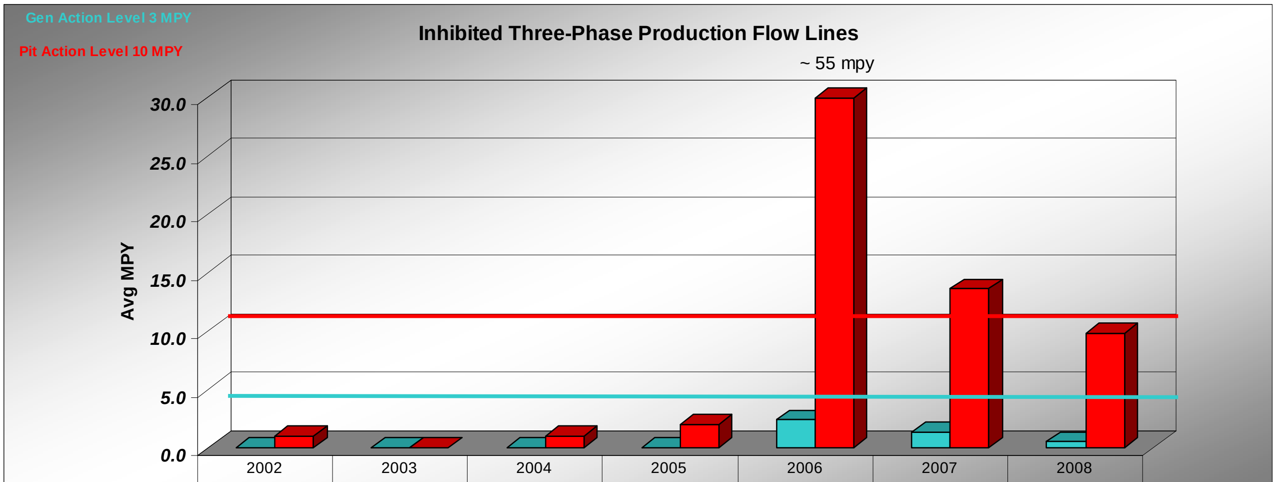
Table 8. Average general corrosion rates for corrosion coupons by service category.

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	4	0.5	4	100%
Seawater Flow Line from KRU	1	0	1	100%
Infield Sea Water Injection Flow Lines	3	0.2	3	100%
Production Well Lines	53	2.1	44	83%*
Water Injection Well Lines	16	0.1	16	100%

** Results greater than three mpy CR (nine lines) were caused by erosion associated with our frac program.*

Table 9. Average pitting corrosion rates for corrosion coupons by service category.

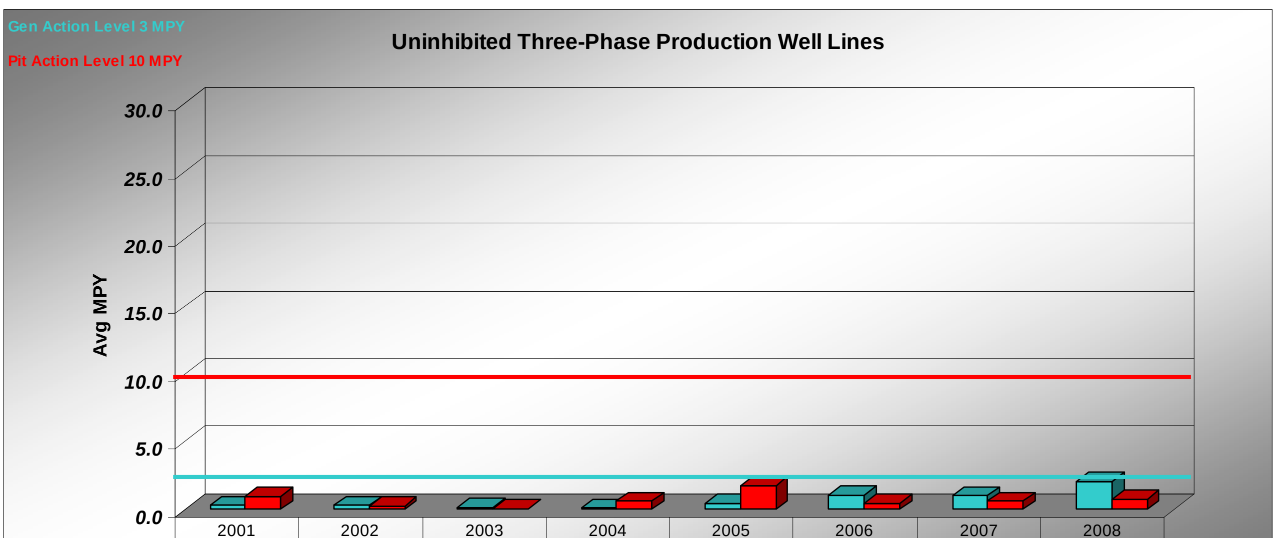
Asset Group	Number of Lines with Coupons Analyzed	Coupon Average Pitting Corrosion Rate, mpy (target=<10)	Number of Lines with Conformant Pitting Corrosion Rates	Lines with Conformant Pitting Corrosion Rates
Three-phase Production Flow Lines	4	9.8	3	75%
Seawater Flow Line from KRU	1	0	1	100%
Infield Sea Water Injection Flow Lines	3	5	2	67%
Production Well Lines	53	0.8	53	100%
Water Injection Well Lines	16	3.2	14	88%



	2002	2003	2004	2005	2006	2007	2008
Gen	0.0	0.0	0.1	0.1	2.4	1.4	0.5
Pit	1.0	0.0	1.0	2.0	55.0	13.6	9.8

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 8 and 9 and presented in Figure 14 show that pitting corrosion rates in 2008 are barely below the action level. In response to the coupon and probe corrosion rates, adjustments were made to the CI dosage on the CD2 production line. In addition, a new CI formulation was tested in 2008. Inspection data, discussed in section B.1.b, indicate that significant corrosion damage has not taken place in these lines.



	2001	2002	2003	2004	2005	2006	2007	2008
Gen	0.3	0.3	0.1	0.1	0.5	1.0	1.0	2.1
Pit	1.0	0.3	0.1	0.6	1.8	0.5	0.6	0.8

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 8 and 9 and presented in Figure 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.

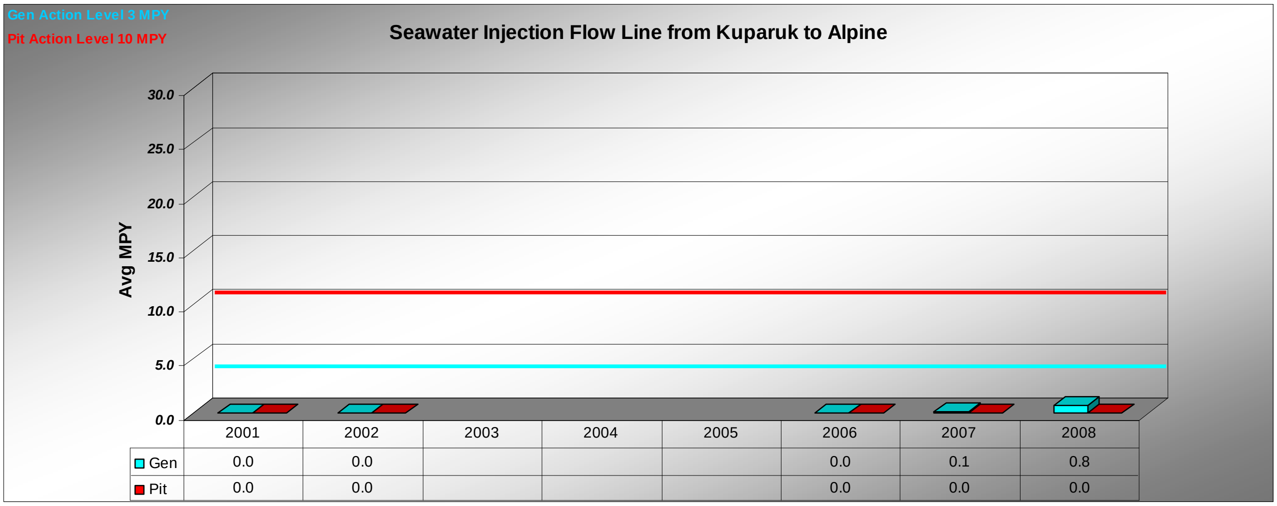


Figure 16. WNS Sea Water Flow Line Coupons – general and pitting corrosion rates by year.

Sea Water Flow Line from Kuparuk to Alpine: The monitoring data summarized in Tables 8 and 9, and presented in Figure 16 above, show the average corrosion rates for the SW 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 three hours at 1000 ppm with weekly maintenance pigging.

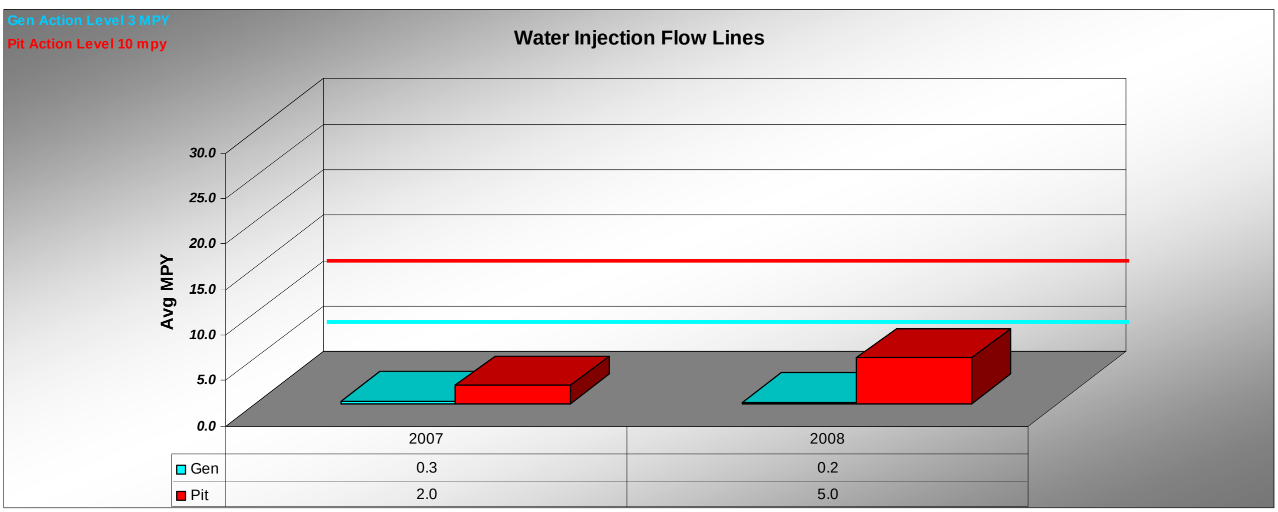


Figure 17. WNS Water Injection Flow Line Coupons – general and pitting corrosion rates by year.

Infield Sea Water Injection Flow lines: The monitoring data summarized in Tables 8 and 9 show the average corrosion rates for the infield WI flow line coupons. In 2007, coupons were installed in WI 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 SW injection system 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 SW lines are treated with a weekly biocide treatment and monthly maintenance pigging. New cleaning pig styles are being tested.

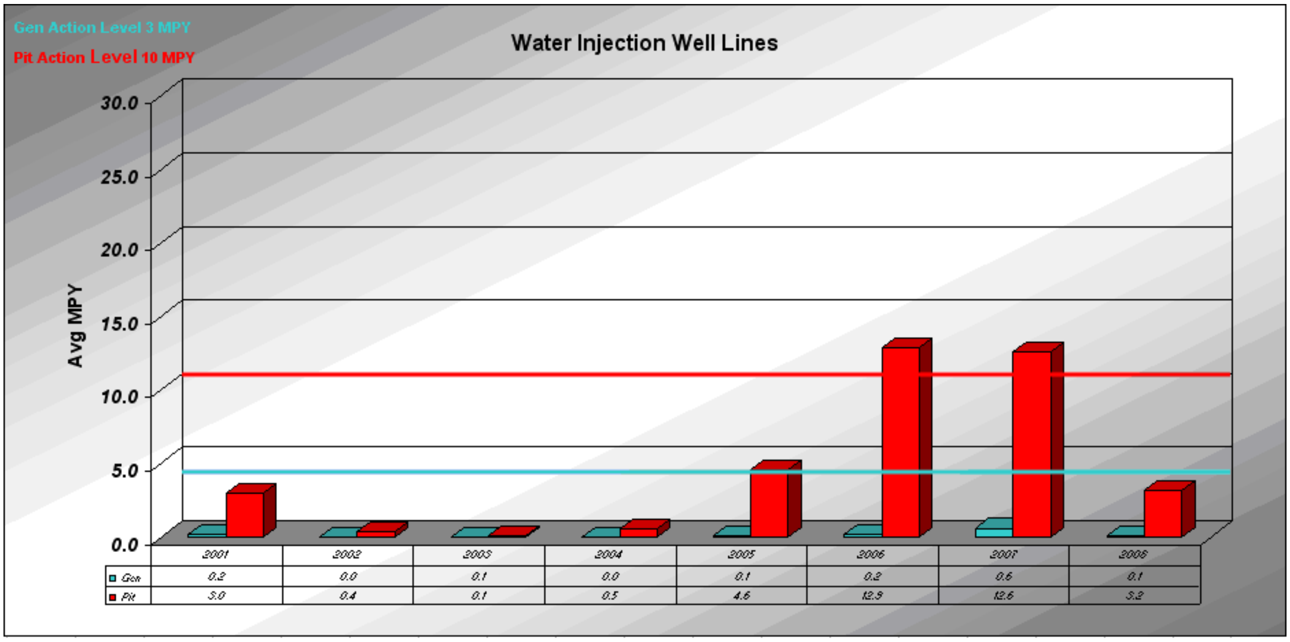


Figure 18. WNS Water Injection Well Line Coupons – general and pitting corrosion rates by year.

Water Injection Well Lines: The monitoring data summarized in Tables 8 and 9 and presented in Figure 18 show that pitting corrosion rates no longer exceed the action level. Inspection data presented in Section B.1.a do not indicate damage in these lines.

The SW used for injection is filtered, deaerated, and biocided at the Kuparuk STP before being shipped to the WNS. The PW is treated with biocide in the facility.

Maintenance Pigging:

Table 10. Field-wide Maintenance Pigging by Service.

Service	2007 Number Recommended	2007 Number Completed	2007 Percent Completed	2008 Number Recommended	2008 Number Completed	2008 Percent Completed
SW	12	15	125%	24	31	129%
PW	0	0	n/a	12	38	316%
Oil	1	1	100%	1	5	500%

For the Alpine field, Table 10 shows the actual number and the recommended number of maintenance pig runs conducted by service category. Services tracked are SW, PW and Oil (three-phase production). As of December 2008, the recommended maintenance pigging frequencies were as follows:

- Monthly for the WI 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, five 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%.
In 2008, 30 well lines were inspected. The worst damage was less than 10% wall loss.

B.1.b Flow Line Inspections for Internal Corrosion

Manual RT of 81 TML's on the CD1 three-phase production line were completed. Damage up to 18% wall loss was found on this line.

The CD2 three-phase production line was evaluated with ILI in 2008. No indications needing immediate attention were identified. Verification inspections are planned for 2009.

The CD2 WI line was evaluated with ILI in 2008. No indications needing immediate attention were identified. Verification inspections are planned for 2009.

B.2 External Inspections

In 2008, 168 Tarn-style weld packs on four flow lines were inspected to ensure the design is working properly. The weld pack design appears to be performing well. Five hundred forty-five CUI inspections were performed on well lines and no significant concerns were identified. The CD2 three phase production line and the CD2 WI line were inspected for CUI using ILI. No significant damage was identified; verification inspections are pending.

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. The below grade portions of the CD2 three phase production and the CD2 WI line were evaluated with ILI.

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

<u>Inspection Status:</u>
The annual visual survey of all the cased lines was conducted in 2008. The purpose of the survey was to identify, rectify, and report local conditions (e.g., debris found in casings and culverts, pipe insulation jacket in contact with soil) that require remedial action.

<u>Results and Remedial Action:</u>
During the 2008 visual survey, no gravel, soil or debris was found in the casings. The casing boots on a stainless steel below grade line were confirmed to be repaired subsequent to the 2007 findings.

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. These lines have since been replaced with above ground piping and were de-inventoried. These will be officially removed from service early in 2009.

B.3.b Results of Specialty Testing

No specialty testing was performed in the WNS in 2008. Of the 51 WNS below grade circuits, two were evaluated with ILI with the remainder of the line. These are the CD2 lines mentioned above.

B.3.c Results of Crossing Digs

No excavations were done in 2008.

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 heat tubes. One well is without either an insulated conductor or a heat tube. One of the original exploration wells still in operation has a heat tube and lacks an insulated conductor. The third well is scheduled for heat tube 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 2008.

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

- No leaks were caused by external corrosion in 2008.
- No leaks were caused by wind-induced vibration in 2008.
- No leaks were caused by internal corrosion in 2008.
- No structural or subsidence concerns were identified in 2008.

D. Year 2009 WNS Forecast

D.1 Monitoring & Mitigation

- Pull coupons as scheduled
- Test CI formulations for production and injection services
- Install additional CI 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

Conduct interval surveys on 15 well lines.

D.2.b.iii) External Corrosion Inspections

Flow lines:
Perform CUI inspections to ensure that lines do not exceed a five-year inspection interval.

Well lines:
TRT inspections are planned on 15 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.

Evaluate the CD3 water injection flow line with ILI. This line includes one below grade segment.

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 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 that 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 bicoiding.
- **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
- **ILI** – In-line inspection (smart pigging)
- **TWI –** The Welding Institute (Long range UT)
- **KDR –** Known damage recur inspection
- **CUI** – Corrosion under insulation
- **CUI IA** – Corrosion under insulation inspection area (Note: this is not necessarily identical to a weld pack)
- **IR**- Infra-red thermography
- **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 than priority 1 lines. 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 if the pipe leaked.