

ALABAMA LEGISLATURE COMPLETION FILES, 2003-2008 86/2

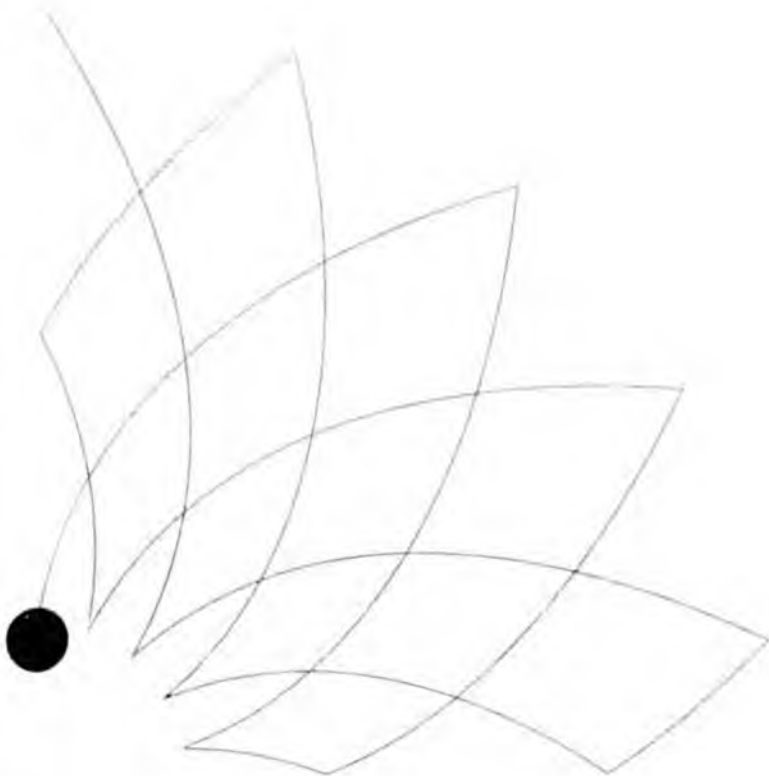
11969 SENATE RESOURCES

Section D.6 Chemical Optimization Summary

In summary, chemical optimization covers a number of different areas from chemical testing and development to field-wide deployment of new products delivering improved levels of corrosion control more cost effectively. However, all this activity is ultimately directed toward one end — the reduction in corrosion rate. The effectiveness of the chemical optimization program in delivering improved corrosion rates is clearly demonstrated.

Section E

External/Internal Inspection



Section E External/Internal Inspection

The inspection program covers the piping, piping components, pressure vessels and tanks across GPB. Radiographic imaging or ultrasonic flaw evaluation makes up the majority of inspection techniques. However, there are some specialized techniques in use for specific applications. The details for these techniques are shown in Appendix 3, Table 11.

A number of factors contribute to the selection and allocation of inspection resources including, but not limited to, current equipment condition, current known rate (from inspection or corrosion monitoring) of wastage, operational risks associated with the fluids being transported, active or passive corrosion mitigation, and design and age of the equipment.

Section E.1 External Inspection

This section summarizes the inspections performed to detect external corrosion and the results of those inspections. GPB Table E.1 summarizes the CUI inspection program for the period 1995 to 2004 broken out by service and equipment type, well line and flow line, and the aggregate of both data sets.

These data suggest there is some dependence of external corrosion occurrence based on service type. This dependence is driven in part by the difference in operating temperature between these services. However, there is as much variability in damage occurrence is found based on the location and orientation of the weld-pack location. For additional information about CUI, refer to Appendix 3.3.4.

The CUI program covers all cross-country flow lines and well lines. There are approximately 300,000 weld packs at GPB, of which approximately 200,000 are off-pad and 100,000 are on-pad.

In order to manage CUI, a recurring inspection program has been implemented as the best method to identify equipment and locations susceptible to CUI. Prioritization of inspection surveys is determined by configuration, average temperature of the equipment, age of equipment, health, safety, environment (HSE), and/or the last time a complete inspection was completed. As a result of findings from inspections, the extent or recurring frequency of any additional examinations is determined.

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Service	Flow Line			Well Line		
	# Insp.	# Corr	% Corr	# Insp.	# Corr	% Corr
3 Phase	44,193	2,790	6%	42,978	1,652	4%
Export	5,481	244	4%	-	-	-
Gas	50,432	2,213	4%	20,982	241	1%
Other	61	3	5%	567	28	5%
Water	22,434	1,806	8%	7,884	275	3%
Total	122,601	7,056	6%	72,411	2,196	3%

Service	Aggregate		
	# Insp.	# Corr	% Corr
3 Phase	87,171	4,442	5%
Export	5,481	244	4%
Gas	71,414	2,454	3%
Other	628	31	5%
Water	30,318	2,081	7%
Total	195,012	9,252	5%

GPB Table E.1 CUI Inspections by Service Type, 1995-2004

Section E.1.1 External Inspection Program Results

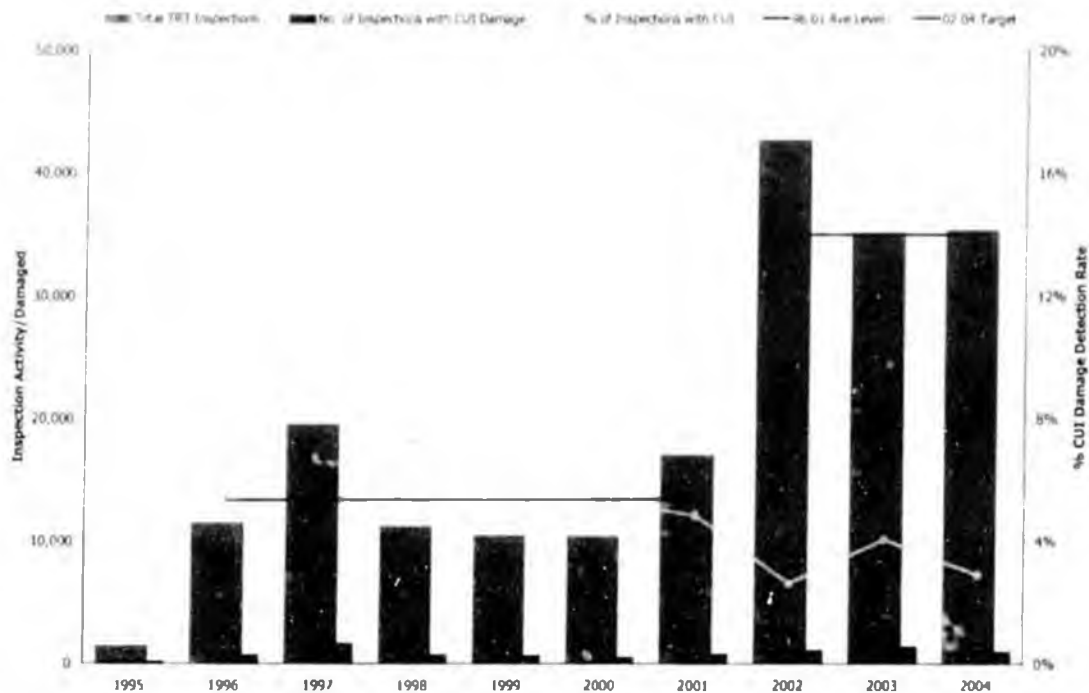
GPB Table E.2 and GPB Figure E.1 show the number and results of the external corrosion inspections performed from 1995 through 2004. The data includes all the Tangential Radiographic (TRT) techniques applied to detect external corrosion, including Automated-TRT (ATRT), and C-Arm Fluoroscopy (CTRT).

In general, the inspection levels over the period 1996 to 2001 remained relatively constant at an average of ~13,000 per year. In 2002 the activity level was increased substantially, targeting 35,000 inspections per year. In 2004 the activity level was slightly over the target of 35,000 inspections.

Section E External/Internal Inspection

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Well Line										
Activity Level	-	36	1,680	941	2,376	5,251	13,072	23,969	10,855	14,231
Corrosion Detected	-	6	235	65	79	243	715	351	140	362
%Corroded	-	17%	14%	7%	3%	5%	5%	1%	1%	3%
Flow Line										
Activity Level	1,497	11,459	17,893	10,294	8,139	5,180	3,966	18,727	24,293	21,153
Corrosion Detected	248	774	1,501	751	640	313	110	769	1,284	666
%Corroded	17%	7%	8%	7%	8%	6%	3%	4%	5%	3%
GPB Overall										
Activity Level	1,497	11,495	19,573	11,235	10,515	10,431	17,038	42,696	35,148	35,384
Corrosion Detected	248	780	1,736	816	719	556	825	1,120	1,424	1,028
%Corroded	17%	7%	9%	7%	7%	5%	5%	3%	4%	3%

GPB Table E.2 External Corrosion Activity and Detection Summary



GPB Figure E.1 External Corrosion Activity and Detection Summary

There was a slight decrease in CUI damage detected in 2004 as compared to 2003. Overall, the percentage of locations found with damage has fallen from an initial high of >15% to a field-wide average of 3 to 4% in recent years.

Section E.1.2 Cased Piping Survey Results

In accordance with the agreement with ADEC, 2003 was the final year of a 5-year program to complete a baseline inspection on all cased piping segments. Having completed the initial baseline inspections, a thorough review of cased pipe inspection activity and results has been performed. Each of the anomalies identified through the baseline inspection survey from 1997 to 2003 have been prioritized for re-inspection as part of the long-term management of cased pipe segments. Currently the preferred test methodologies will be either guided wave and/or in-line inspection (ILI) in order to determine the presence of an active corrosion mechanism. The program in 2004 consisted of repeat examinations/monitoring and excavation.

GPB Table E.3 shows the 2004 inspection results for cased pipe segments. Potential metal loss areas are reported and severity is semi-quantified as non-relevant (i.e. no metal loss), minor, moderate, or significant. Distinction from previous examinations is reported as no change (NC) or an increase (I). An increase may be associated with active corrosion therefore additional verification would be required to determine the appropriate response.

Service	Inspection Method	NC or I	Non Relv	Anomaly Type			Anomaly Action
				Minor	Mod	Sig	
Gas	G-Wave	NC			1		Full Excavation '04
	G-Wave	NC		3	5	4	G-Wave Monitor
	G-Wave	NC				3	Partial Excavation '04
	G-Wave	NC		1			Partial Excavation '04
	G-Wave	NC	12				
Oil	G-Wave	I				1	Full Excavation '04
	G-Wave	I			1		G-Wave Monitor
	G-Wave	I				2	Partial '04 - Eval. for Full Excav.
	G-Wave	NC		2	20	8	G-Wave Monitor
	G-Wave	NC		1	1	1	Partial Excavation '04
	G-Wave	NC	8				
	ILI	I			1		Evaluation for Full Excavation
	ILI	NC		2	1		G-Wave Monitor
	ILI	NC	8				
	ILI/G-Wave	I			1		Evaluation for Full Excavation
	ILI/G-Wave	I		2			G-Wave Monitor
	ILI/G-Wave	I			1		Partial '04 - Eval. for Full Excav.
	ILI/G-Wave	NC		1			G-Wave Monitor
	ILI/G-Wave	NC		3			Partial Excavation '04
	ILI/G-Wave	NC			1		Partial Excavation '04
ILI/G-Wave	NC	1					

Service	Inspection Method	NC or I	Non Relv	Anomaly Type			Anomaly Action
				Minor	Mod	Sig	
PO	G-Wave	NC		2	1	1	G-Wave Monitor
	G-Wave	NC	1				
PW/SW	G-Wave	NC			3	3	G-Wave Monitor
	G-Wave	NC			1		Partial Excavation '04
Cased Pipe Inspection Total			30	17	38	23	

GPB Table E.3 Cased Pipe Survey Results

In summary, a long-term management strategy, consisting of repeat examinations, analysis of results and corrective action as warranted has been implemented for cased piping segments. The strategy and execution will continue to develop as the program is refined and more information and/or experience with emerging long-range inspection technologies are gained.

Section E.1.3 Excavation History

In 2004, nineteen crossings were partially excavated at the casing end as a continuation of the lessons learned from the Y-36⁷ incident. Two additional crossings were completely excavated. The excavation and subsequent inspection at all 21 locations were used to verify monitoring results. Although external corrosion was found and mitigated, there were no mechanical repairs required.

Since 1992, there have been 50 cased pipeline segments at road and/or animal crossings excavated in GPB. Two of these excavations were as a result of loss of pressure containment, the remaining 48 excavations were verification of inspection results. GPB Table E.8, at the end of this section, shows 44 were found with external corrosion damage and 6 were found with no external corrosion damage.

The identification of potential damage areas through the inspection program and subsequent actions of monitoring and/or excavation, gives confidence that inaccessible pipe segments can be effectively managed to minimize loss as a result corrosion degradation.

Section E.2 Internal Inspection Program Results

The results presented in this section are aggregate data obtained from flow line and well line inspections. The program results are presented in terms of the number of locations that show an increase in corrosion damage since the last inspection as a percentage of the total number of repeat inspections,

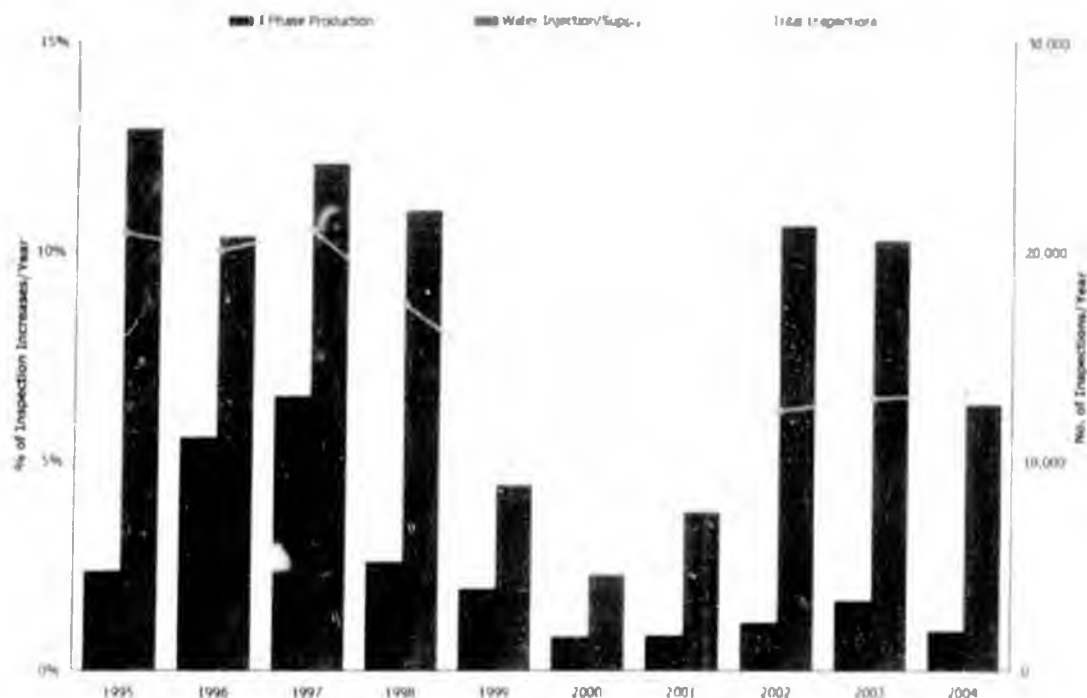
$$\% \text{ Increases} = \frac{\text{Locations with active corrosion}}{\text{Total \# of reinspected locations}} \times 100$$

The percentage increases is therefore a high level measure of the amount of active corrosion in any given system.

⁷ Previously discussed in the 2003 Annual Report

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GPB Figure E.2 shows the percentage of inspection increases (%I's) and the number of inspections per year for the flow lines broken out by 3-phase production and water injection (seawater and produced water) service.



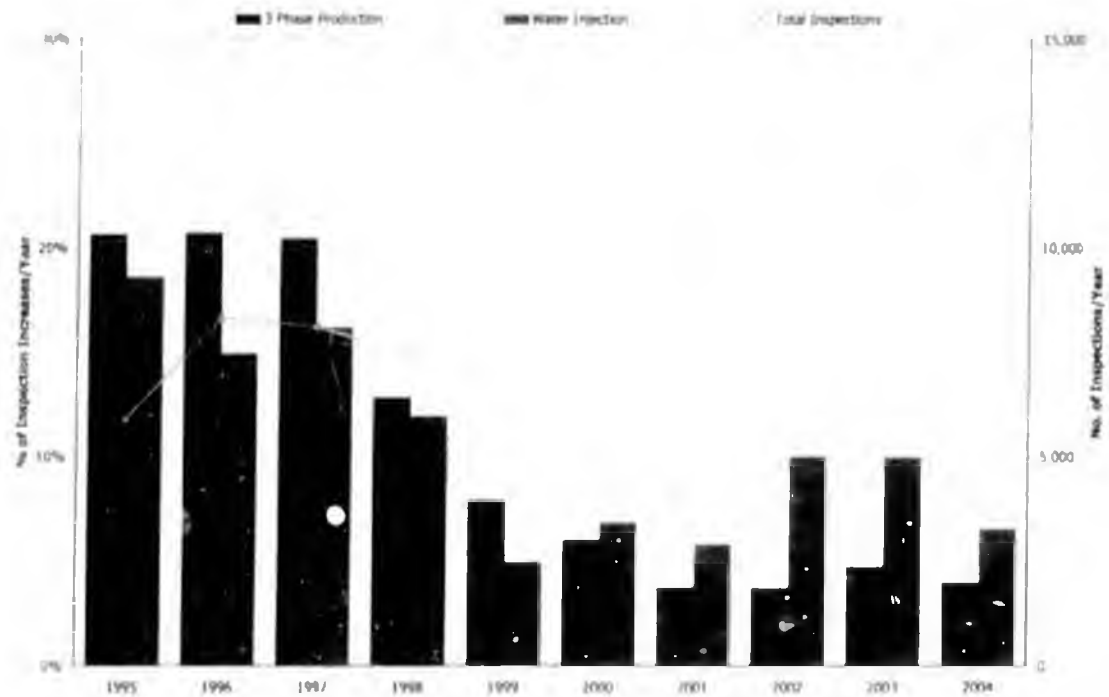
GPB Figure E.2 Flow Line Internal Inspection Increase by Service

The percentage of inspection increases in the 3-phase system has declined considerably since 1997. However, there was a slight increase in the %I's from 2000 through 2003, which likely reflects the increase in corrosion rates detected in the coupon monitoring program during 2000. As predicted in the 2003 report, there was an improvement in the %I's during 2004. The delayed response of the inspection program compared with the monitoring program is a result of the longer time base on which this program is typically completed.

Inspection data for 2004 show improvement in reversing the rising trend of %I's. As noted in Section C.2, several factors have influenced the improved corrosion control of the water injection system.

GPB Figure E.3 shows the %I's trend and the number of inspections per year for the well lines. For 3-phase well lines, over the long term, there is a decrease in corrosion activity as measured by %I's. In the short term, the rise in corrosion activity seen in 2003 and decline in corrosion activity in 2004 is also reflected in the flow line data.

For the water system, corrosion activity is seen to be declining from 1995 through 2001. As with the flow line injection service, there was an marked increase in corrosion activity in 2002 and a decrease in activity 2004.



GPB Figure E.3 Well Line Internal Inspection Increase by Service

Section E.3 Correlation Between Inspection and Corrosion Monitoring⁸

Inspection and corrosion monitoring have different characteristics; in particular, inspection techniques are comparatively insensitive but are the most accurate as they measure actual wall loss. In contrast, corrosion monitoring is more sensitive but less accurate as a measure of corrosion rate as the weight loss coupon is not an integral part of the pipe wall. Refer to Table 12 for additional information regarding these techniques.

Therefore, in order to have good confidence in the results from the corrosion-monitoring program, it is necessary to show a correlation between the monitoring program and the results of the inspection program. The following section describes the correlation between inspection and monitoring programs for the 3-phase production system.

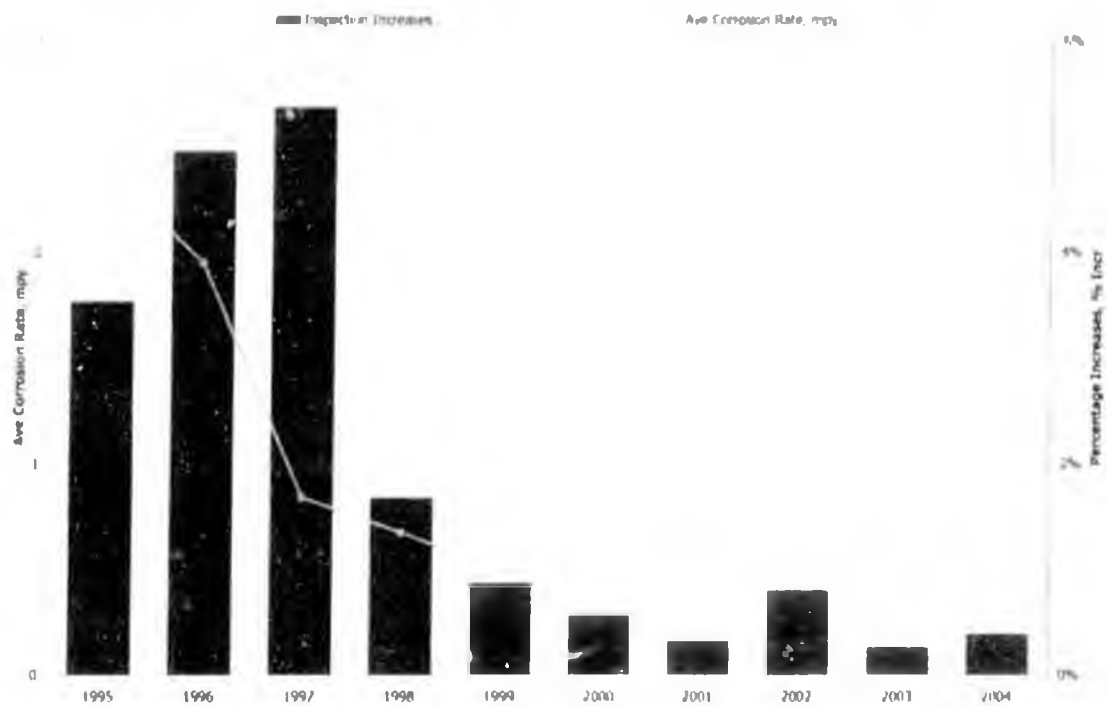
GPB Figure E.4 shows a similar decreasing trend in average corrosion rate from WLC and the percentage of increases found in the inspection program for the 3-phase well line and flow line. It should be noted that the inspection results included in the analysis are not the full data set but has been refined to include only that data which has an inspection interval (time since last inspection) of less than 730 days (two years). Also, the indicated reporting year has been changed to reflect the mid-point of the inspection interval rather than the time of inspection as in the other figures in this report. This change in the reporting time compensates for the fact that corrosion is occurring over the entire time interval between inspections. Similarly, the weight loss coupon corrosion rates are reported as the mid-point of the exposure period not the removal date.

⁸ In addition to Charter Work Plan, this information supplied to provide additional context and help in understanding BPXA's corrosion management activities

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From the correlation between inspection and corrosion monitoring, a number of important conclusions can be drawn,

- As the corrosion rates decrease due to the effectiveness of the inhibition program, then further program optimization will be driven by the information gained from the corrosion monitoring program rather than the inspection program
- Timely optimization of the chemical program can not be reliant on feedback from the inspection data but must be managed through the corrosion monitoring program
- Because of the lower sensitivity of the techniques used in the inspection program, the corrosion rates in the 3-phase flow lines are below the detection limits for inspection; therefore corrosion rate monitoring becomes a function of the coupon program leaving inspection as a confirmation and integrity assessment tool



GPB Figure E.4 Correlation of Corrosion Rate and %Increases, 3-phase Production

A similar degree of correlation exists between the corrosion monitoring and the inspection data for the water injection systems. GPB Figure E.2 and GPB Figure E.3 show similar trends in both the flow lines and well lines which is also reflected in the corrosion monitoring data depicted in GPB Figure C.15 and GPB Figure C.16.

In summary, the data in this section shows the correlation between the inspection data and the corrosion monitoring data. This in turn, allows the corrosion monitoring data to be used with confidence to manage the chemical treatment program in a timelier manner.

Section E.4 In-line Inspection

In-line inspection (ILI) tools, or smart pigs, are used at GPB where pigging facilities and process environment allow for technical and cost effective performance within the capabilities of the instruments. Magnetic flux leakage (MFL) type tools are the most commonly used by BPXA.

ILI was performed on four 3-phase production flow lines. GPB Table E.4 summarizes equipment service, diameter, and length.

Equipment	Service	Diameter	Previous ILI	From	To	Length (miles)
D-36	3 Phase	24	2001	D-Pad	GC-1	1.5
F-74	3 Phase	24	1999	F-Pad	GC-1	2.5
STP-36	3 Phase	36	1990 ¹	PM-02	GC-1	9.7
X-74	3 Phase	24	1997	X-Pad	GC-3	5.5

¹ Pipeline was idle with nitrogen gas from 1996 to 2004. It was re-commissioned for 3-phase production in 2004.

GPB Table E.4 Completed Smart Pig Assessments

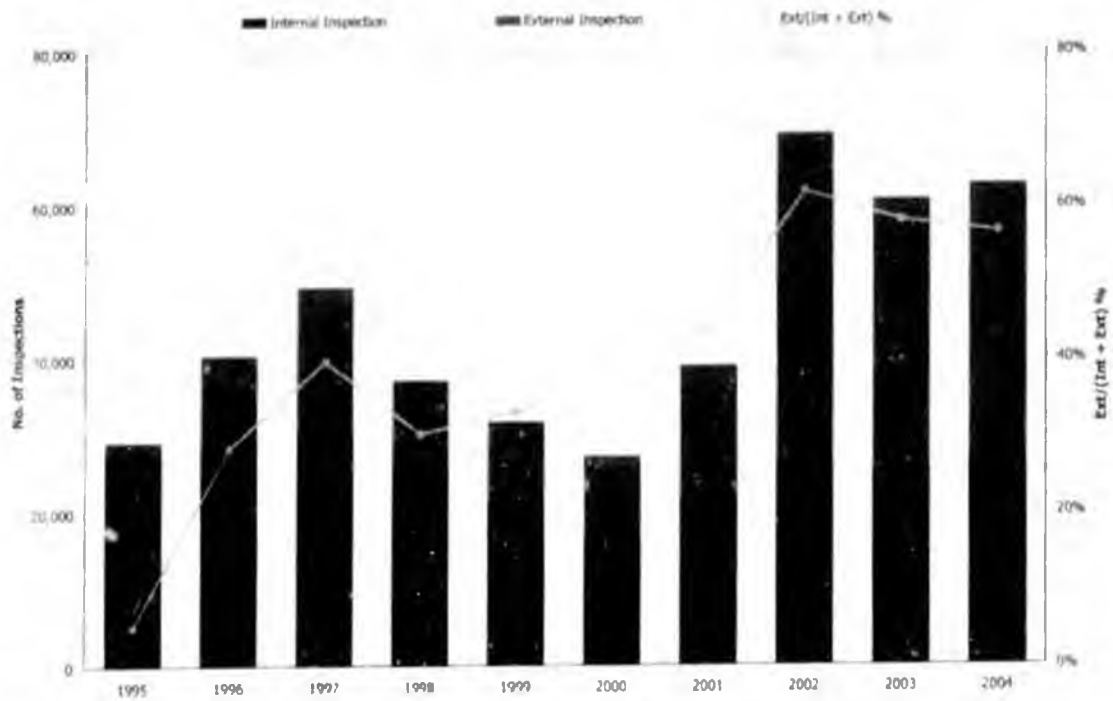
The reported metal loss features reported have been prioritized for verification by radiographic and/or ultrasonic inspection. The verification results through 2004 are included in the aggregate inspection data. Additional follow-up of the reported features is an ongoing part of the normal radiographic and ultrasonic NDE activity at GPB.

In summary, ILI is an important tool to have available for the management of the long-term integrity of the flow lines. Conversely, ILI is not always the most appropriate or applicable for GPB because of the operating conditions, design and accessibility of the pipelines to manual methods of NDE. However, ILI will continue to be used to assist and complement the overall program.

Section E.5 Internal/External Inspection Comparison

GPB Figure E.5 and GPB Table E.5 summarizes the level of internal and external inspection activity across GPB since 1995 for both cross-country flow lines and well lines. The inspection activity for both the internal and external programs has been consistent over the past three years.

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GPB Figure E.5 Internal and External Inspection Activity for Flow and Well Lines

Year	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
External	1,497	11,492	19,573	11,235	10,515	10,424	17,038	42,696	35,148	35,384
Internal	27,749	28,969	29,796	25,945	21,271	16,861	21,963	26,512	25,518	27,253
Total	29,246	40,461	49,369	37,180	31,786	27,285	39,001	69,208	60,666	62,637
Ext (Ext + Int) %	5%	28%	40%	30%	33%	38%	44%	62%	58%	56%

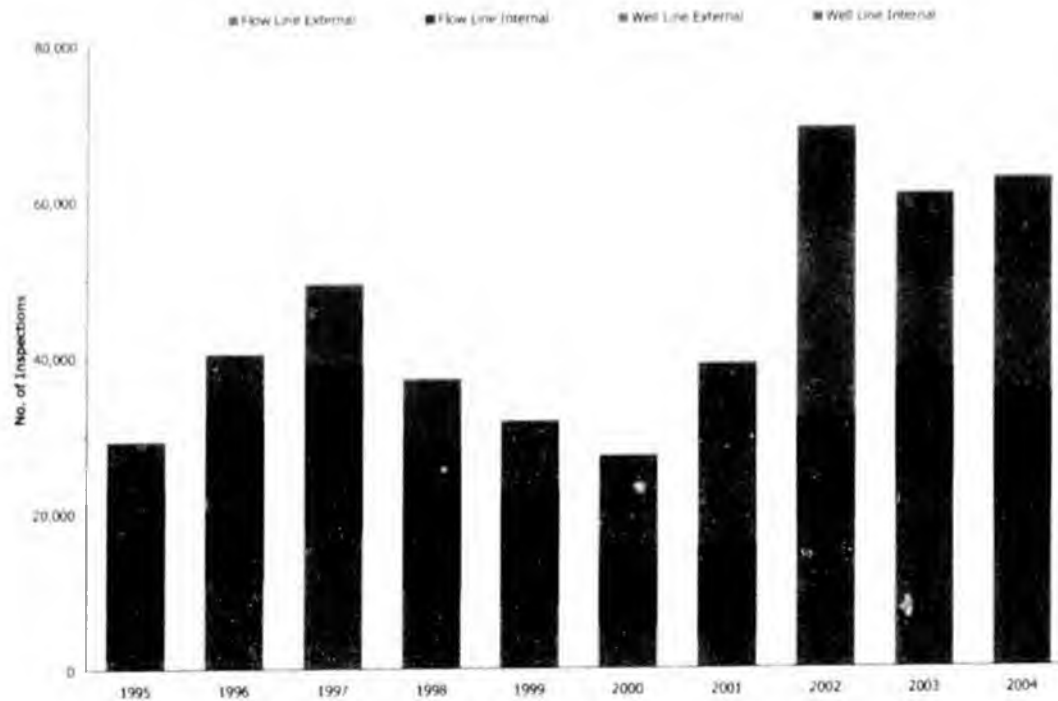
GPB Table E.5 Internal and External Inspection Activity Breakdown

GPB Table E.6 and GPB Figure E.6 show the split between flow line and well line inspections for both the internal and external programs. The overall inspection activity is running at or above 60,000 inspections per year, in line with the 2002 increased emphasis on external corrosion detection.

Section E External/Internal Inspection

Year		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Flow Line	External	1,497	11,456	17,893	10,294	8,139	5,173	3,966	18,727	24,293	21,153
	Internal	21,669	20,478	21,263	18,183	14,913	9,607	11,639	13,305	14,213	14,284
	Total	23,166	31,934	39,156	28,477	23,052	14,780	15,605	32,032	38,506	35,437
$\frac{\text{Ext}}{\text{(Ext + Int)}}\%$		6%	36%	46%	36%	35%	35%	25%	58%	63%	60%
Well Line	External		36	1,680	941	2,376	5,251	13,072	23,969	10,855	14,231
	Internal	6,080	8,491	8,533	7,762	6,358	7,254	10,324	13,207	11,305	12,969
	Total	6,080	8,527	10,213	8,703	8,734	12,505	23,396	37,176	22,160	27,200
$\frac{\text{Ext}}{\text{(Ext + Int)}}\%$		0%	0%	16%	11%	27%	42%	56%	64%	49%	52%
Grand Total		29,246	40,461	49,369	37,180	31,786	27,285	39,001	69,208	60,666	62,637
$\frac{\text{FL}}{\text{(FL + WL)}}\%$		79%	79%	79%	77%	73%	54%	40%	46%	63%	57%

GPB Table E.6 Internal and External Inspection Activity Summary by Flow/Well Line



GPB Figure E.6 Internal and External Inspection Activity Summary by Flow/Well Line

Section E.6 Inspection Summary

In summary, the main conclusions from the inspection section are,

- The external corrosion inspection program, at >35,000 items, for 2004 was above the target. Approximately 3% of these inspections showed damage, which is consistent with the overall average in recent years.
- The cased piping survey completed a base line inspection on all pipeline segments as agreed with ADEC and the program is continuing to evolve into a process of monitoring and corrective action.
- A unified internal inspection philosophy and program structure has been implemented across GPB with a total program size of approximately 60,000 items, split between field and facility piping.
- The inspection results for both the flow line and well line 3-phase systems show improved performance in the long term. There was a slight increase in the corrosion activity in 2003. This, as expected, reversed in 2004 following the trend seen in the corrosion coupon program as a result of the better performance of the corrosion inhibitor.
- The water injection systems show a long term improving trend from 1995 through 2001. There was an increase in the corrosion activity during 2002 and 2003. In 2004, the trend was reversed, showing improvement, likely as a result of corrective actions were put in place for both the produced water and seawater systems.
- The results of the inspection program and the weight loss coupon program from the 3-phase oil service were shown to be strongly correlated. The reduction in corrosion activity from both measures being attributable to the implementation of an aggressive and increasing corrosion inhibition program in the 3-phase service since 1995.
- A similar level of correlation was seen in the water injection system information for both inspection and corrosion monitoring.

BU	Type	Service	Result	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
GPB	FL	OIL	I	368	924	1,153	394	238	67	60	12	152	100
GPB	FL	OIL	NC	15,143	15,695	16,461	14,802	11,935	8,150	7,080	8,743	8,959	10,422
GPB	FL	OIL	NL	3,616	2,100	1,969	441	359	146	1,715	1,875	1,951	805
GPB	FL	OIL	Total	19,127	18,719	19,583	15,637	12,532	8,363	8,855	10,720	11,062	11,327
GPB	FL	WTR	I	171	124	154	192	72	17	43	139	176	107
GPB	FL	WTR	NC	1,152	1,073	1,119	1,557	1,551	720	1,091	1,170	1,537	1,574
GPB	FL	WTR	NL	422	116	135	88	75	61	351	384	217	216
GPB	FL	WTR	Total	1,745	1,313	1,408	1,837	1,698	798	1,485	1,693	1,930	1,897
GPB	FL	Total	Total	20,872	20,032	20,991	17,474	14,230	9,161	10,340	12,413	12,992	13,224
GPB	WL	OIL	I	641	918	874	600	311	264	213	274	323	290
GPB	WL	OIL	NC	2,462	3,512	3,398	4,077	3,613	4,121	5,498	7,119	6,519	7,040
GPB	WL	OIL	NL	965	1,777	1,979	710	577	514	2,467	3,502	2,273	2,394
GPB	WL	OIL	Total	4,068	6,207	6,251	5,387	4,501	4,899	8,178	10,895	9,115	9,724
GPB	WL	WTR	I	225	262	201	216	74	126	78	125	148	146
GPB	WL	WTR	NC	985	1,493	1,042	1,594	1,417	1,712	1,267	1,122	1,336	2,085
GPB	WL	WTR	NL	617	358	634	221	176	258	495	535	374	528
GPB	WL	WTR	Total	1,827	2,113	1,877	2,031	1,667	2,096	1,840	1,782	1,858	2,759
GPB	WL	Total	Total	5,895	8,320	8,128	7,418	6,168	6,995	10,018	12,677	10,973	12,483
GPB	Total	Total	Total	26,767	28,352	29,119	24,892	20,398	16,156	20,358	25,090	23,965	25,707

Note: I = Inspection Increase
 NC = No Change
 NL = New Inspection Location

GPB Table E.7 Flow and Well Line Inspection Data

Year	Cased Pipe Location	Equipment Excavated	Observation	Corrective Action
1992	COTU Access Road	FS1 to FS2 12" MI Distribution	10% external wall loss	Insulation/coating/tape repair
1995	S Pad West Entrance Crossing	S Pad 24" 3 Phase Production	61% external wall loss	Sleeve/insulation/coat repair
		S Pad 14" Produced Water	36% int/ext wall loss	Sleeve/insulation/coat repair
		S Pad 10" Gas Lift	34% external Wall Loss	Insulation/coating repair
		S Pad 8" Miscible Injection	41% external wall loss	Replaced segment/FBE
GC1 Main Entrance	Distribution 24" Gas Lift Y Pad 24" 3 Phase Production	29% external wall loss	Insulation/coating repair	
		24% external wall loss	Insulation/coating repair	
GC2 to GC1 Caribou Crossing	Distribution 24" Gas Lift Y Pad 24" 3 Phase Production	42% external wall loss	Sleeve/insulation/coat repair	
		26% external wall loss	Insulation/coating repair	
1996	GC-1 Spine Road	Distribution 24" Gas Lift	53% external wall loss	Sleeve/insulation/coat repair
		D Pad 24" 3 Phase Production	33% external wall loss	Insulation/coating repair
		Y Pad 24" 3 Phase Production	16% external wall loss	Insulation/coating repair
		Distribution 20" Produced Water	8% external wall loss	Insulation/coating repair
		E Pad Entrance	E Pad 24" 3 Phase Production	21% external wall loss
GC3 to FS3 Caribou Crossing	Distribution 24" Gas Lift	No corrosion damage	None	
FS1 to FS2 Caribou Crossing	Distribution Natural Gas 30" Sales Oil 30" Distribution 24" Gas Lift Distribution 32" Sea Water	11% external wall loss	Insulation/coating/tape repair	
		14% external wall loss	Insulation/coating/tape repair	
		No corrosion damage	None	
		No corrosion damage	None	
1998	S Pad East Entrance Crossing	S Pad 10" Gas Lift	~80% wall loss - ext rupture	Replaced segment
	GC2 to GC1 Caribou Crossing	Distribution 24" Gas Lift	9% external wall loss	Insulation/coating repair
	GC2 to GC1 Q Pad Rd Crossing	Distribution 34" Natural Gas	No corrosion damage	Insulation/FBE coated

GPB Table E.8 Cased Piping Excavation History

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Year	Cased Pipe Location	Equipment Excavated	Observation	Corrective Action
2000	S Pad East Entrance Crossing	S Pad 24" 3 Phase Production S Pad 14" Produced Water S Pad 8" Miscible Injection	~60% external wall loss ~50% external wall loss 25% external wall loss	Replaced segment/coat repair Replaced segment/coat repair Sleeve/insulation/coat repair
2003	GC2 to GC1 Caribou Crossing	Y Pad 24" 3 Phase Production	Leak -external corrosion	Partial excavation/sleeve repair
	X Pad Pipeline Access Rd Crossing	X Pad 24" 3 Phase Production	~75% external wall loss	Partial excavation/sleeve repair
	F Pad Pipeline Access Rd Crossing	F Pad 24" 3 Phase Production	24% external wall loss	Partial excavation/none
	NGI Pad Road Crossing	NGI Pad 14" Gas Cap Injection	58% external wall loss	Replaced segment
2004	WGI to West Dock Road Crossing	AGI Pad 16" Gas Cap Injection	no corrosion damage	none
	CCP Pad Road Crossing	CCP/NGI-NGL 4" NGL	10% external wall loss	partial excavation/insulation tape repair
	GC1 Entrance Road Crossing	D Pad 24" 3 Phase Production	16% external wall loss	partial excavation/insulation tape repair
	GC1 to F Pad Caribou Crossing	F Pad 24" 3 Phase Production	21% external wall loss	partial excavation/insulation tape repair
	GC1 to GC2 Road Crossing	U Pad 6" Gas Lift Supply	5% external wall loss	partial excavation/insulation tape repair
	F Pad/Frontier Camp Rd Crossing	F Pad 24" 3 Phase Production	16% external wall loss	partial excavation/insulation tape repair
	F Pad Pipeline Access Rd Crossing	F Pad 24" 3 Phase Production	18% external wall loss	partial excavation/insulation tape repair
	GC1 to G Pad Caribou Crossing	G Pad 6" 3 Phase Production	no corrosion damage	none

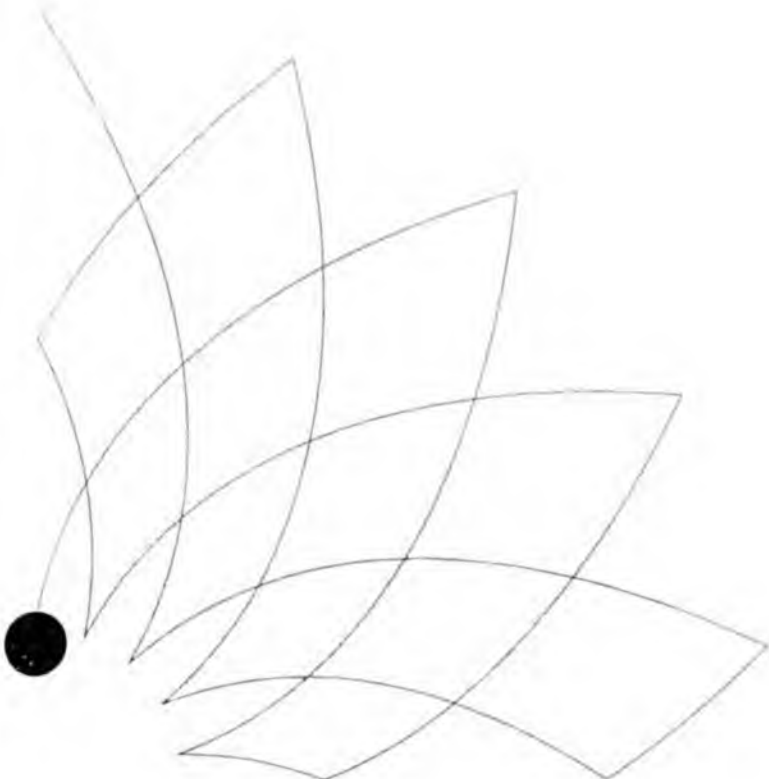
GPB Table E.8 (Continued) Cased Piping Excavation History

Year	Cased Pipe Location	Equipment Excavated	Observation	Corrective Action
2004	Q Pad Access Road Crossing	GC3/GC2 12" MI Supply	9% external wall loss	partial excavation/insulation tape repair
		H Pad 24" 3 Phase Production	24% external wall loss	partial excavation/insulation tape repair
		Y Pad 12" PW Supply	39% external wall loss	partial excavation/insulation tape repair
	Q Pad Spur Road Crossing	Y Pad 12" PW Supply	12% external wall loss	partial excavation/insulation tape repair
	West Dock to GC1 Road Crossing	K Pad 24" 3 Phase Production	8% external wall loss	partial excavation/insulation tape repair
	GC2 to N Pad Caribou Crossing	N Pad 24" 3 Phase Production	37% external wall loss	partial excavation/insulation tape repair
	CCP Pad Road Crossing	NGI Pad 14" Gas Cap Injection	14% external wall loss	partial excavation/insulation tape repair
	S Pad Entrance Road Crossing	S Pad 24" 3 Phase Production	10% external wall loss	partial excavation/insulation tape repair
		S Pad 14" Produced Water	11% external wall loss	partial excavation/insulation tape repair
	U Pad Road Crossing	U Pad 6" Production Well Line	18% external wall loss	partial excavation/insulation tape repair
U Pad 3" Gas Lift Well Line		16% external wall loss	partial excavation/insulation tape repair	
X Pad to B Pad Caribou Crossing	X Pad 24" 3 Phase Production	5% external wall loss	partial excavation/insulation tape repair	
	X Pad 8" MI Supply	17% external wall loss	partial excavation/insulation tape repair	

GPB Table E.8 (Continued) Cased Piping Excavation History

Section F

Repair Activities



Section F Repair Activities

The repair activities shown in GPB Table F.1 include a total of 132 repairs as compared to 86 in year 2003. GPB Figure F.1, GPB Figure F.2, GPB Figure F.3, and GPB Table F.2, show the 5-year trend in repairs grouped by service, damage mechanism, and equipment, respectively.

Service	Type	Internal	External	Mechanical	Total
Oil	FL	5	13	-	18
	WL	5	13	-	18
Water	FL	23	9	1	33
	WL	13	1	-	14
Gas	FL	-	12	-	12
	WL	-	37	-	37
Total		46	85	1	132

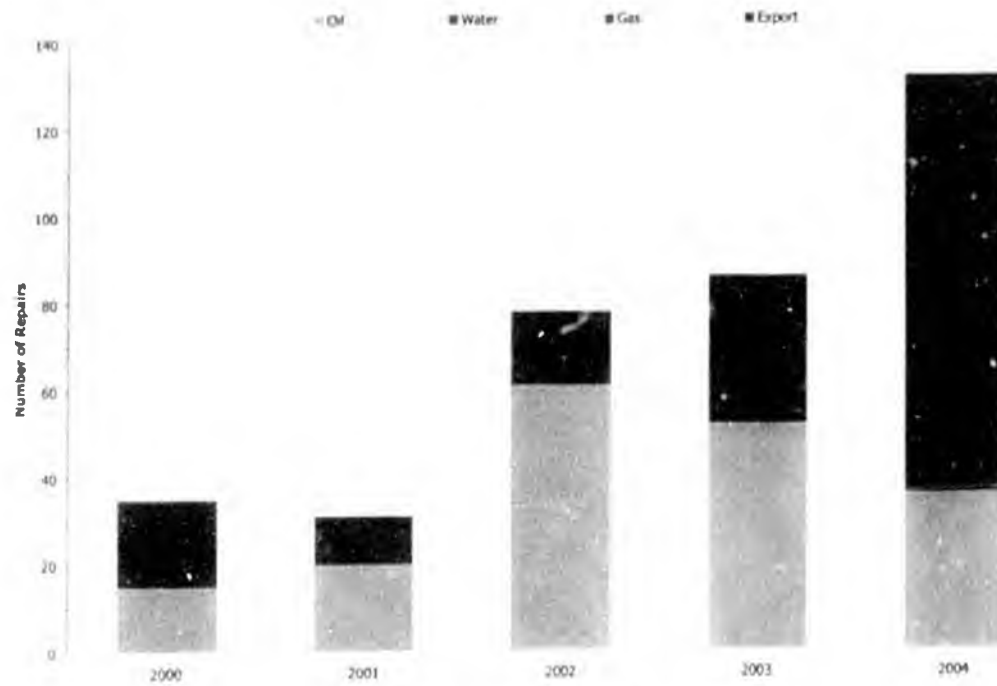
GPB Table F.1 Repair Activity

There were 85 repairs associated with external corrosion which is similar to the number of repairs in 2003.

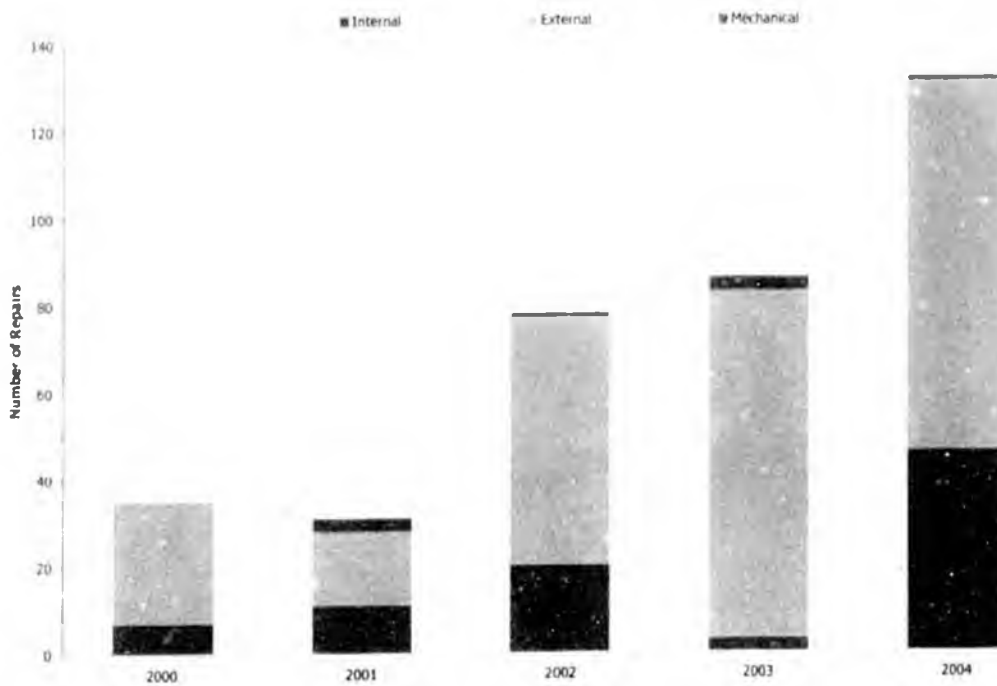
The only mechanical repair was required as a result of a freeze burst of a well line. This line was not in service at the time of the failure.

The 46 repairs due to internal corrosion can be attributed to two major areas of focus. First, there was a need to increase system pressure capacity in order to deliver the increased volumes of high-pressure seawater. Second, prior to single-operatorship, there were two FFS criteria (GPB East and GPB West). While there were similarities between the two criterion, the current unified criterion is more conservative with respect to the minimum required thickness (0.100" or thickness required for 105% MAOP, see Appendix 3.3.5) and the allowable extent of circumferential corrosion. During 2004 a thorough review of the historical data was performed to ensure the current criterion is uniformly applied across GPB.

Part 1 – Greater Prudhoe Bay Performance Unit

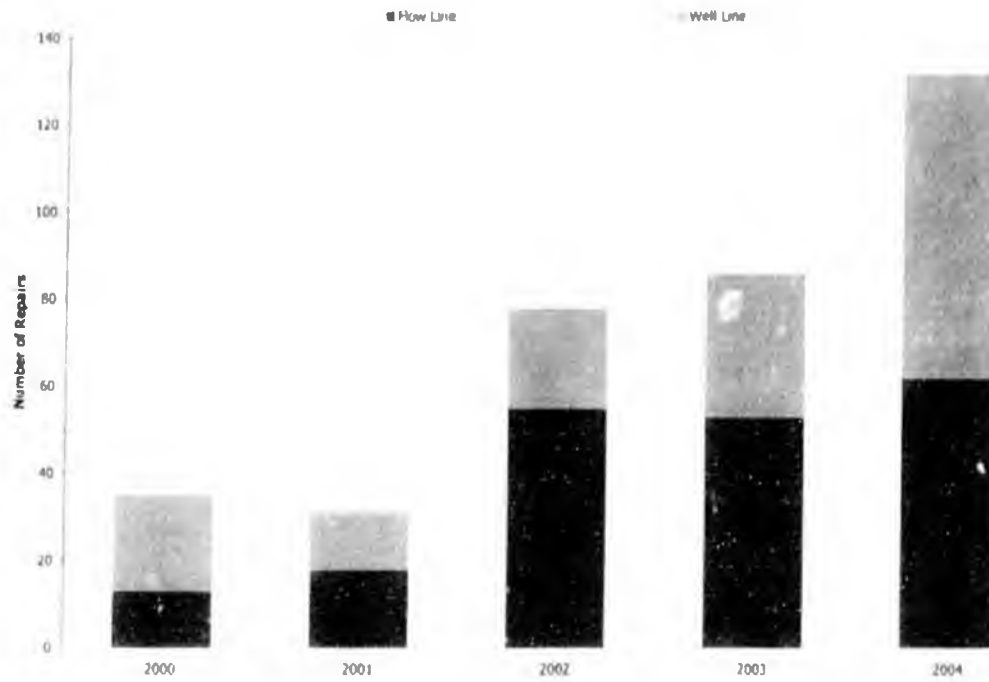


GPB Figure F.1 Repairs by Service



GPB Figure F.2 Repairs by Damage Mechanism

Section F Repair Activities



GPB Figure F.3 Repairs by Equipment

In summary, the number of repairs due to mechanical and external corrosion is consistent with 2003. The marked increase in the number of repairs due to internal corrosion can be attributed to the two major areas of focus during 2004.

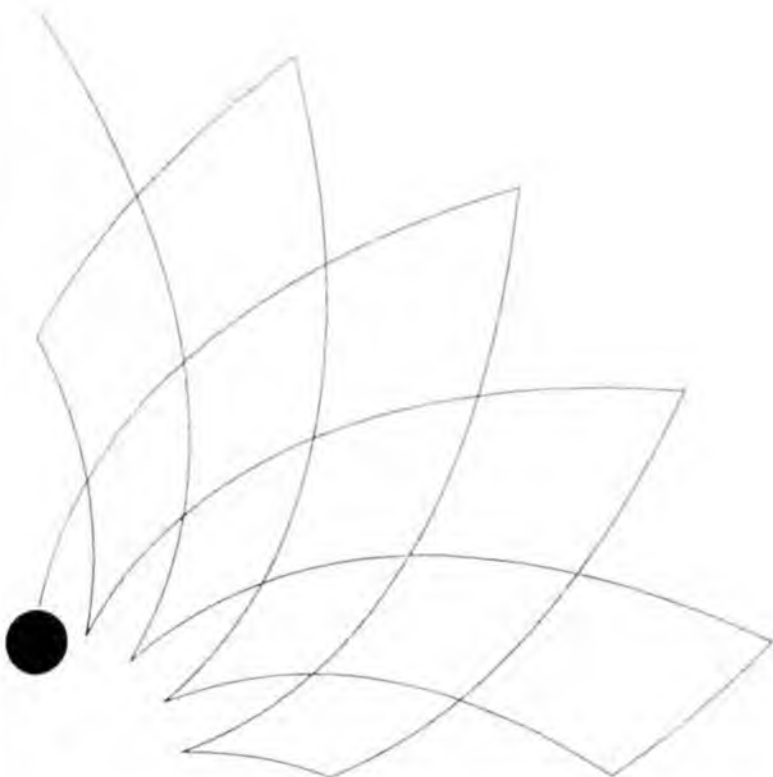
Section F Repair Activities

	Oil		Water		Gas		PO	Total
	Flow Line	Well Line	Flow Line	Well Line	Flow Line	Well Line	Flow Line	
2000								
Internal	2	5	-	-	-	-	-	7
External	1	7	2	7	8	3	-	28
Mechanical	-	-	-	-	-	-	-	0
Total	3	12	2	7	8	3	0	35
2001								
Internal	2	4	1	1	-	-	3	11
External	7	5	3	-	2	-	-	17
Mechanical	-	2	-	-	-	1	-	3
Total	9	11	4	1	2	1	3	31
2002								
Internal	8	7	1	4	-	-	-	20
External	35	11	6	1	4	-	-	57
Mechanical	-	-	-	-	1	-	-	1
Total	43	18	7	5	5	0	0	78
2003								
Internal	-	3	-	-	-	-	-	3
External	28	20	-	1	23	8	-	80
Mechanical	1	-	-	-	1	1	-	3
Total	29	23	0	1	24	9	0	86
2004								
Internal	5	5	23	13	-	-	-	46
External	13	13	9	1	12	37	-	85
Mechanical	-	-	1	-	-	-	-	1
Total	18	18	33	14	12	37	0	132
Grand Total	102	82	46	28	51	50	3	362

GPB Table F.2 Historical Repairs by Service

Section G

Corrosion and Structural Related Spills and Incidents



Section G Corrosion and Structural Related Spills and Incidents

Section G.1 Corrosion Related Leaks

This section summarizes the corrosion and structural related incidents that occurred in 2004 and provides a historical perspective on the leaks (loss of containment) and saves (repairs before leak of non-FFS equipment).

GPB Table G.1 summarizes the equipment, failure mechanism and volume of leaks that occurred in 2004. Of the 4 leaks that occurred in 2004, 2 were associated with external corrosion, 1 with internal corrosion, and 1 with freeze burst.

Service	Location	Type	Date	Mechanism	Volume
3-phase production	17-14	WL	28-Apr-04	CUI	5 gal
Produced water	M-13	WL	24-May-04	Mech/Freeze	20 gal
PW pig return line	DS-04	WL	25-Jun-04	Int	30 gal
3-phase production	06C/13B	FL	01-Sep-04	CUI	153 gal

	Surface		Service				Mechanism			
	Int	Ext	OIL	SW	PW	Gas	CO ₂	Int	CUI	Mech
WL	2	1	1		2			1	1	1
FL		1	1						1	

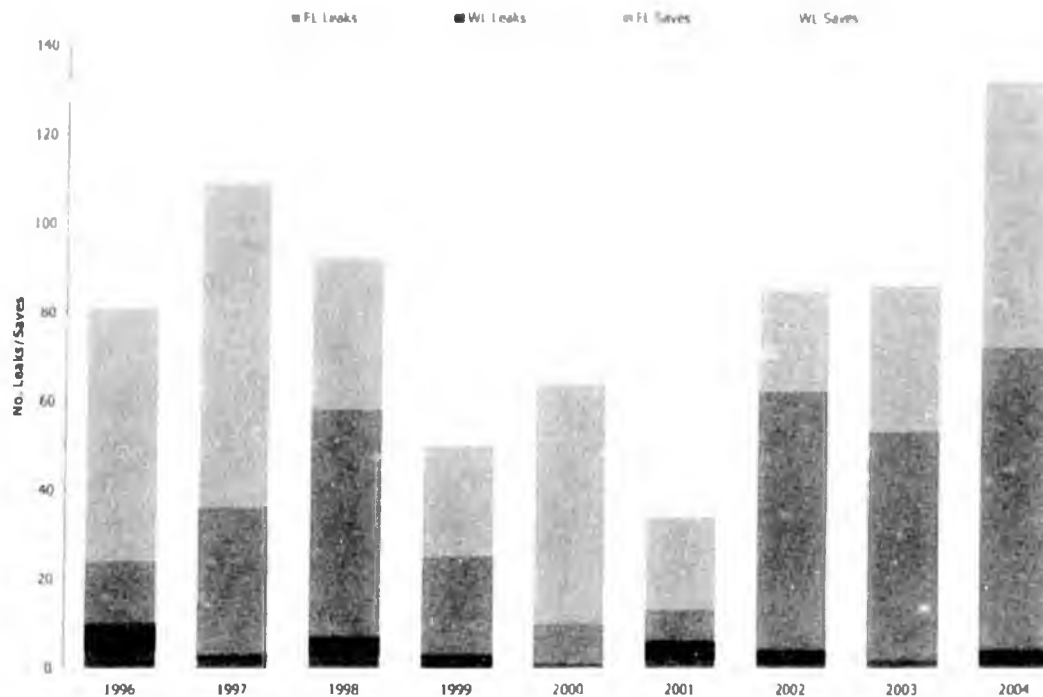
GPB Table G.1 Leaks Due to Corrosion/Mechanical

GPB Table G.2, GPB Figure G.1 and GPB Figure G.2 show the number of corrosion related leaks and saves since 1996. The ratio of leaks to saves provides a high level measure of the performance of the inspection program at detecting severe damage before it results in a failure. A 'save' is defined as a location found via the inspection program that warrants a repair, system de-rate, replacement or removal from service as the equipment no longer meets the FFS criteria defined in Appendix 3.3.5. It should be noted that items are typically scheduled for repair at 105% of MAOP, to allow time to schedule and complete the repair before the item requires removal from service.

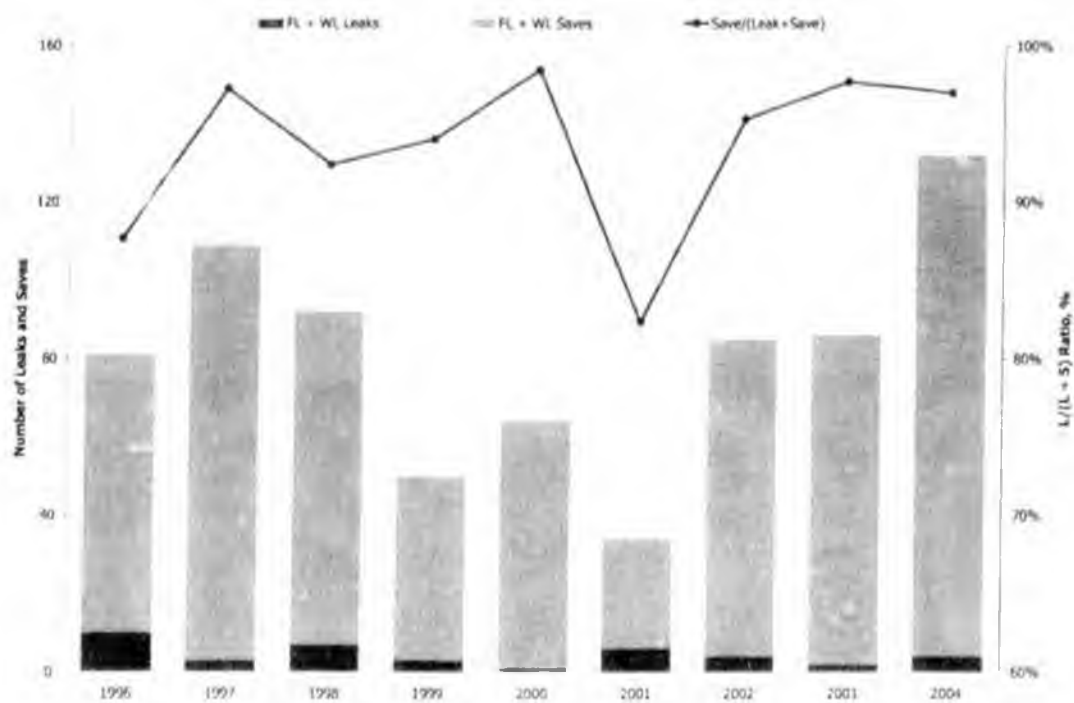
Part 1 – Greater Prudhoe Bay Performance Unit

	Flow Lines			Well Lines			Total
	Saves	Leaks	$\frac{S}{(L + S)}\%$	Saves	Leaks	$\frac{S}{(L + S)}\%$	$\frac{S}{(L + S)}\%$
1996	14	4	78%	57	6	90%	88%
1997	33	2	94%	73	1	99%	97%
1998	51	3	94%	34	4	89%	92%
1999	22	0	100%	25	3	89%	94%
2000	9	1	90%	54	0	98%	97%
2001	7	2	78%	21	4	84%	82%
2002	58	1	98%	23	3	89%	95%
2003	53	2	96%	33	0	100%	98%
2004	68	1	99%	60	3	95%	97%

GPB Table G.2 Historical Corrosion Leaks and Saves



GPB Figure G.1 Historical Corrosion Leaks and Saves by Line Type



GPB Figure G.2 Historical Corrosion Leaks and Saves

Section G.2 Structural Integrity Issues

Structural integrity issues are related to damage caused by structural movement: subsidence, jacking, cyclic fatigue, impact, slugging, snow loading, etc. There are several activities designed to observe and report these structural issues.

There were numerous structural repairs to pipeline support members during 2004. These repairs were essentially pipeline re-leveling due to support member subsidence.

Section G.2.1 Walking Speed Survey

Where there is perambulatory access, a Walking Speed Survey (WSS) is performed. The WSS consists of a visual examination of process equipment and system components to identify mechanical integrity deficiencies. Anomalies are noted and evaluated by the Field Mechanical Piping Engineer for action as appropriate.

As the name implies the observations are made at 'walking speed' and are focused on, but not limited to,

- Piping and insulation
- Structural components
- Electrical equipment
- Instrumentation equipment
- Communication equipment
- Chemical injection tubing

- Pipe line road and animal crossings

WSS is a 5-year recurring program with the following schedule,

Year	Scheduled	Completed	Equipment Description
1	2002	✓	GPB East Cross Country Pipelines
2	2003	✓	GPB West Cross Country Pipelines
3	2004	✓	GPB East Well Pads
4	2005		GPB West Well Pads
5	2006		Lisburne Cross Country Pipelines/Drill Sites

GPB Table G.3 Structural/Walking Speed Survey Schedule

A WSS of the GPB east well pads was completed in 2004.

Section G.2.2 Routine Surveillance

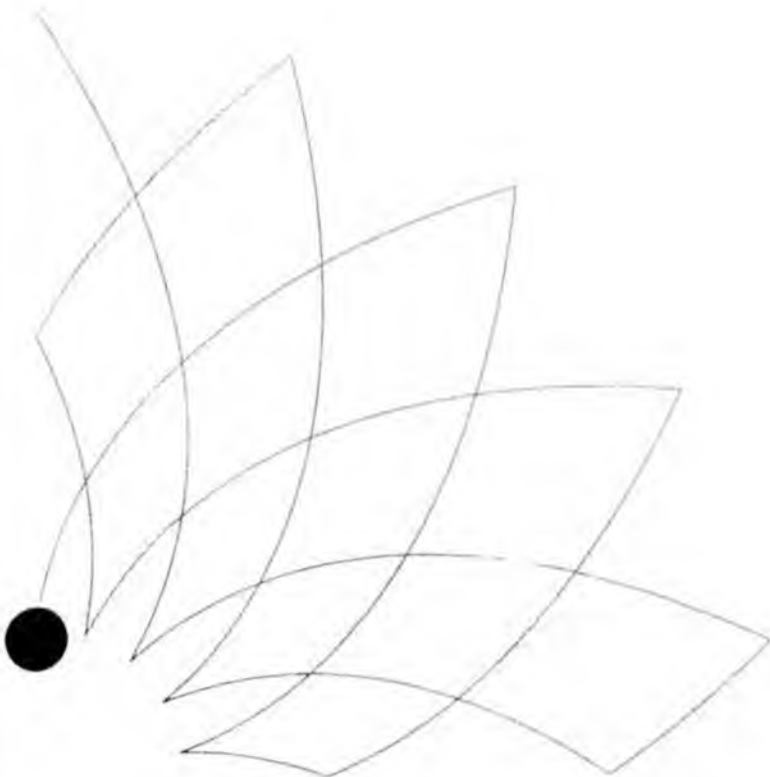
Field Operations and Security personnel are tasked as the primary identifiers of flow lines and well lines with potential structural integrity anomalies. Observations of wind-induced vibration, excessive pipe movement, out-of-place pipe guides, bent piping, etc. are reported.

An analysis of potential integrity anomaly is completed by a competent engineer to determine any required action. Additional analysis may be required by the Field Mechanical Piping Engineer or third party engineering experts.

For example, if excessive sagging between pipeline supports is observed, the engineer requests an NDE inspection of the affected area. The purpose of the NDE inspection is to determine if any detrimental damage (i.e. wall thinning, cracks, ovality, buckling) exists. The NDE methods typically used include visual, caliper, ultrasonic, magnetic particle, radiography, and dye penetrant as appropriate. The data are analyzed to assure the pipeline is structurally sound and fit-for-service. If the pipeline is not structurally sound, an engineering design package is prepared to initiate, complete and document the work action. Management of Change and other procedures are applied as required.

Section H

2004 Corrosion Monitoring and Inspection Goals



Section H Corrosion Monitoring and Inspection Goals

Section H.1 2004 Corrosion and Inspection Goals Reviewed

Overall, the corrosion inspection, monitoring and mitigation programs were expected to be substantially unchanged from 2003. In particular, the corrosion control target of less than 2 mpy remained in place with the inspection and monitoring activity levels to again be substantially as 2003.

Section H.1.1 Corrosion Monitoring

The weight loss coupon program frequency was expected to remain unchanged in 2004 compared to recent years and is summarized in GPB Table H.1.

Service	Flow Lines (months)	Well Lines (months)
3-phase production	3	4
Produced water	6	8
Seawater	3	3
Processed Oil	3	N/A

GPB Table H.1 Coupon Pull Frequency

As a consequence, the activity level from the weight loss coupon program was anticipated to be similar in 2004 to that seen in 2003 and indeed this was the case. There were some changes in the number of coupons reported compared to prior years. This is as a result of the following factors:

- Continued efforts to clean historical data records.
- The removal and addition of equipment associated with abandonment and installation of satellite production equipment.
- The historical data was updated to reflect the current equipment inventory.

The ER probe program was planned to be substantially the same as 2003 with probes being located on the 3-phase production lines. The 2004 result was largely as anticipated with the exception that the level of reliability of the ER probes systems was improved to more consistently deliver data throughout the year.

Section H.1.2 Inspection Programs

The fundamental elements of the Inspection Programs outlined in Appendix 3.3.3 (CRM, ERM, FIP, CIP and CUI) form the foundation for the inspection program. There were no major changes for this program anticipated in 2004 with an overall combined internal and external activity level of 60,000 items.

There were 3 smart pig runs forecast and 4 were completed.

Corrosion under insulation or external corrosion inspection activity was substantially increased in 2002. This similar level of activity was scheduled in 2004 with approximately 35,000 planned items completed as expected.

2003 represented the conclusion of a 5-year program of work to baseline all the single-line cased piping segments across GPB. In 2004, a long-term management strategy was implemented for cased piping segments consisting of repeat inspections and excavation.

Section H.1.3 Chemical Optimization

There were forecast to be no large-scale changes in the corrosion mitigation program and this proved to be the case. However, developments in the small scale testing of corrosion inhibitors continued throughout the year resulting in a substantial increase in well line test results compared to prior years.

Section H.1.4 Program Reviews

A number of reviews were conducted during 2004, including:

GPB Partner Reviews – Regular reviews of the corrosion management program at GPB were conducted with the major GPB partners.

BP Internal Integrity Management Review – A BP internal review team from United Kingdom conducted an Integrity Management Audit which included a review of the corrosion and inspection program covered under the Charter Agreement.

ADEC Review – ADEC and their third party consultant reviewed and commented on the BPXA Corrosion Monitoring Charter Agreement report and Meet and Confer sessions. In addition a field trip to GPB was organized to review the major elements of the Corrosion Management Program.

FFS Criterion Review – A third party engineering consultant was contracted to review BPXA's piping fitness criterion relative to industry practice. The criterion was determined to be consistent with current industry standards, and no changes were recommended.

Section H.1.5 2004 Corrective Actions

This section summarizes the corrective actions taken on cross-country flow lines as a result of corrosion monitoring and inspection results exceeding the specified targets. These targets are detailed in Appendix 3.1.3.

GPB Table H.2 notes the corrective mitigation actions taken as a result of ER probe readings exceeding target.

Section H Corrosion Monitoring and Inspection Goals

Equipment ID	No. of Action	Cause	Action
01D	11	Increased Corrosivity	Increased CI by 50%
03D	3	Increased Corrosivity	Increased CI by 15%
04B	6	Increased Corrosivity	Increased CI by 30%
05B	2	Increased Corrosivity	Increased CI by 5%
05D	1	Increased Corrosivity	Increased CI by 1 gpd
05E	1	Increased Corrosivity	Increased CI by 1 gpd
06D	1	Increased Corrosivity	Increased CI by 5%
12B	2	Increased Corrosivity	Increased CI by 10%
14D	5	Increased Corrosivity	Increased CI by 25%
B-36	1	Increased Corrosivity	Increased CI by 5%
Q-01	1	Increased Corrosivity	Increased CI by 20%
R-36	4	Increased Corrosivity	Increased CI by 20%
W-74	1	Increased Corrosivity	Increased CI by 5%
WZ-LDF	6	Increased Corrosivity	Increased CI by 35%
X-74	9	Increased Corrosivity	Increased CI by 50%
Y-36	4	Increased Corrosivity	Increased CI by 35%

GPB Table H.2 Corrective Mitigation Actions from ER Probe Data

GPB Table H.3 notes the corrective mitigation actions taken as a result of inspection information.

Equipment ID	No. of Action	Cause	Action
WZ-CLS01/02	1	Increased Corrosivity	Increased CI by 20%

GPB Table H.3 Corrective Mitigation Actions from Inspection Data

GPB Table H.4 notes the corrective mitigation actions taken as a result of weight loss coupons exceeding target.

Equipment ID	WLC CR, mpy	Cause	Action
01D	3.77	CI Incompatibility	Re-established inhibition with common line pump.
04B	2.41	Increased Corrosivity	CI increased due to ER Probes
14D	4.33	CI Plugging	Batch treat, re-establish continuous injection
A-49	6.47	Increased Corrosivity	Increased CI by 20%
A-49	7.78		
G-46	24.22	Long term Shut-In	Monitor with Inspection
J-45	2.79	CI Plugging	Batch treat, re-establish continuous injection
J-41	2.38	CI Plugging	Batch treat, re-establish continuous injection

GPB Table H.4 Corrective Mitigation Actions from Coupon Data

Two major setbacks occurred in 2004 related to the 3-phase corrosion inhibition program. First, there were several manufacturing changes to the incumbent corrosion inhibitor that ultimately resulted in poor stability and precipitation at winter temperatures. The precipitation in turn plugged injection tubing at multiple drill/well pads. A program was put in place to batch treat, unplug/replace the affected tubing and prevent additional precipitation. Second, a test chemical that was advanced to flow line testing was found to be incompatible with the 316L stainless steel CI delivery system. This incompatibility resulted in pitting failure of the tubing, and a complete shutdown of the CI delivery system at the two drill sites in early 2005. The affected drill sites were also put on batch treatment while the delivery system integrity is being evaluated and restored.

Section H.2 2005 Corrosion Management Goals

The 2005 corrosion and inspection goals will be focused on the continued delivery and optimization of the current programs. In general, there are not expected to be any substantial changes in the overall scope and scale of the 2005 effort in comparison to 2004.

Section H.2.1 Corrosion Monitoring

There are no plans to significantly change the corrosion weight loss coupon-monitoring program in 2005. The emphasis in the produced water and 3-phase production systems will be on sustaining the current level of performance, and in the seawater system maintaining the progress made in 2004. However, based on the two setbacks previously described, it is fully expected the 2005 WLC data will be adversely impacted.

Section H.2.2 Inspection Programs

The overall internal inspection program is planned to be substantially unchanged in 2005 from that implemented in 2004. The expected activity level will again be approximately 60,000 inspection items in total distributed between the field and facilities. Of the overall 60,000 inspection items approximately 45% will be associated with cross country flow line and well lines and hence be reported under the Charter Agreement Work Plan.

The external program increased substantially in 2002 with this program increase continuing into 2004 at approximately 35,000 items per year. The current schedule for 2005 is 35,000 inspection items for the full year.

2005 will see a continuation of the long-term management strategy for cased piping segments; consisting of repeat examinations and excavations as warranted. The 2005 work scope for cased piping is scheduled to be approximately 100 inspections.

The ILI program is planned to be of a similar scale to 2004 dependant upon tool and pipeline availability.

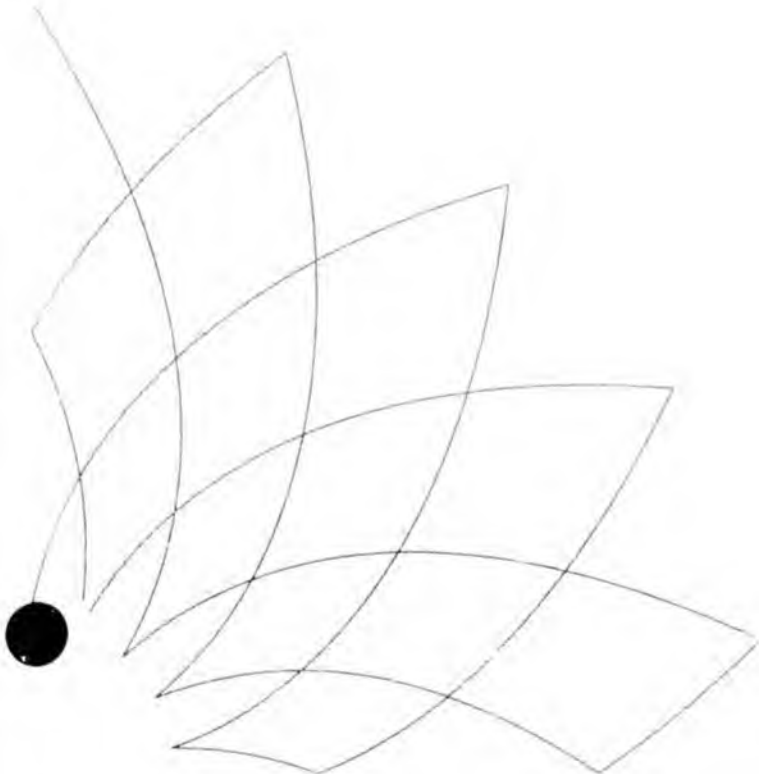
Section H.2.3 Chemical Optimization

Corrosion Inhibition will continue to be the primary means of internal corrosion control at GPB. The emphasis for 2005 will be on the optimization of treatments to provide a deliberate improvement of corrosion control.

A Management of Change process is being developed in conjunction with the current chemical supplier to ensure any future changes to the incumbent chemistry are thoroughly evaluated and approved prior to implementation. In addition, any proposed test inhibitors will have to pass well defined and rigorous materials compatibility testing. Once this process is established, flow line testing can be resumed if there is a suitable candidate. The 2005 well line test program will continue and should have a similar number of test products evaluated as in 2004.

Part 2 – Alaska Consolidated Team Performance Unit

Section B-H



Section B Corrosion Monitoring Activities

Alaska Consolidated Team (ACT) Performance Unit presently consists of four producing areas: Endicott, Milne Point Unit (MPU), Northstar and Badami. Northstar was added to ACT as it came on production in the second half of 2001. Production from Badami was shut in and the facility was put in warm storage during 2003.

Each of the producing fields within ACT has its own unique set of circumstances and challenges.

Milne Point - Located approximately 25 miles west of Prudhoe Bay, the field began production in 1985. On January 1st, 1994, BPXA acquired a majority working interest and assumed operatorship. Since 1994 production and proven reserves have been increased and Milne Point production now averages approximately 50,000 bpd.

Endicott - Located north of Prudhoe Bay, Endicott consists of two islands, the main Production Island (MPI), and the satellite-drilling island (SDI) at the end of a causeway. Endicott 3-phase production piping is made largely of duplex stainless steel, which significantly reduces the environmental risks. Endicott production averages approximately 20,000 bpd.

Badami - Remotely located east of Prudhoe Bay, Badami had a relatively low production volume due to challenging reservoir conditions. The Badami production facilities, like other recent developments on the North Slope, are constructed using a much smaller surface footprint than GPB and do not have permanent road access, therefore having a much reduced impact on the environment. Production from Badami was shut in during the third quarter of 2003.

Northstar - Located offshore, Northstar is the first offshore oil field in the Beaufort Sea not connected to land by a causeway. As with Badami and other recent developments, Northstar drilling and production operations are built on a smaller footprint than the original North Slope facilities. Northstar produces a light, 42 degrees API gravity, high quality sweet crude, that is transported to shore through a pipeline with a wall thickness that is three times that required for pressure containment. Northstar production currently averages approximately 70,000 bpd.

ACT Table B.1 illustrates, on a relative basis, the unique corrosivity of each producing field within ACT along with the materials of construction and corrosion mitigation. GPB is included in the table for comparative purposes. Listed in the table are, for each field, the typical water cut in percent, average wellhead temperature, and the percent CO₂ in the produced gas.

Field	Prod Fluid Characteristics				Material of Construction ^(a)			
	H ₂ O (%)	T (°F)	P _{CO₂} (%)	CR ^(b)	Production		Injection	
					WL	FL	WL	FL
GPB	74	150	12	H	CS+CI	CS+CI ^(c)	CS+CI	CS+CI
END	89	150	18	H	DSS	DSS	CS+CI	CS+CI
MPU	49	125	1.5	L/M	CS	CS ^(d)	CS+CI	CS+CI
Northstar	4	160	5	M	CS+CI	N/A	N/A	N/A
Badami	~0	65	~0	L	CS	N/A	N/A	N/A

Notes

- (a) CS is carbon steel, CI is corrosion inhibitor, DSS is duplex stainless steel
- (b) Unmitigated relative corrosion rate, H – high, M – medium, and L – low
- (c) There are a limited number of Duplex Stainless Steel flow lines in GPB
- (d) Two production flow lines are inhibited at MPU

ACT Table B.1 Relative Corrosivity of BPXA North Slope Production

Badami, MPU, and Northstar production fluids have a lower corrosivity compared to GPB. Endicott's production fluid characteristics are more corrosive than GPB and this corrosion risk is mitigated largely through the use of duplex stainless steel (DSS).

ACT Table B.2 shows the ACT fields combined are of a much smaller scale than GPB. For example, neither Northstar nor Badami have any significant non-common carrier cross-country flow lines. Also, it should be noted, that when comparing GPB and ACT facilities, these facilities vary in age from over 27 years for GPB to ~3 years for Northstar.

Metric	ACT	GPB	ACT (ACT + GPB) %
Number of Production Trains	4	21	16%
Number of Prod and Inj Wells	230	1,475	13%
Non-common carrier FL miles	105	1,350	7%
Total Acreage	75,000	203,000	27%

ACT Table B.2 Illustrative Comparison of Scale Between ACT and GPB

Section B.1 Endicott

Endicott is a mature waterflood field. The fluid properties (high water cut, high temperatures, high CO₂ content) indicate the corrosivity of the produced fluids to be high. Due to this anticipated high corrosivity, the majority of the oil production system was fabricated from duplex stainless steel, a corrosion resistant alloy and therefore, corrosion risk is low for this system. In the oil production system, the only carbon steel is the C-Spool, connecting the wellhead to the duplex stainless steel well line. These C-

Spools are inspected regularly and replaced when no longer fit-for-service as per the criteria discussed in Appendix 3.3.5. ACT Table B.3 reflects the historical inspection activity level for Endicott.

Service	Length (Miles)	Int. Insp.			Ext. Insp. ¹		
		2002	2003	2004	2002	2003	2004
Oil x-country lines	3.5	4 (in vault)	14 (4 in vault)	4 (in vault)	4 (in vault)	4 (in vault)	4 (in vault)
Oil - Well Pads	2.5	1,327	1,531	1900	-	-	-
Water x-country lines	3.5	104	229	163	4 (in vault)	4 (in vault)	723
Water - Well Pads	1.7	200	224	135	9 (in vault)	5	-
Gas x-country (GLT/MI)	7	15	45	4 (in vault)	4 (in vault)	774	4 (in vault)
Gas - Well Pads	1.2	26	29	10	9 (in Vault)	69	-
Fuel Line - Gasoline	N/A	5 foot excavation	-	-	5 foot excavation	-	-
Fuel line - diesel	N/A	5 foot excavation	-	-	5 foot excavation	-	-
Totals		1,686	2,072	2,216	40	856	731

¹ The external corrosion program concentrated significantly on the Oil Sales line in 2002

ACT Table B.3 Endicott Summary of Lines and NDE Inspections

The primary corrosion concerns are in the water injection system, mainly the Inter-Island Water Line (IIWL) carrying injection water to SDI from the MPI. Corrosion control of the water injection system relies on corrosion inhibition of the injection water, supplemented by a biocide and maintenance pigging program. Originally, this line primarily carried seawater. In the early 1990's, in an effort to increase waterflood efficiency, the line was converted to commingled PW+SW service. As produced water volumes have risen, the percentage of SW mixed in the line has dropped significantly, remaining under ten percent since 2002. As a result, some significant changes have been made to the mitigation program for the IIWL in 2004. These changes include increasing the corrosion inhibitor concentration by 50% (from 20 to 30 ppm) and eliminating the biocide treatment. The effectiveness of corrosion control on the IIWL is monitored by ultrasonic inspection at 25 locations.

Section B.2 Milne Point

The primary corrosion concerns are in the water injection system and corrosion of buried piping. Corrosion inhibition, supplemented by a biocide and maintenance pigging program began in mid-2000 in the water injection system. As a result, corrosion rates, as exhibited by weight loss coupons, have dropped significantly over the past four years.

Although the low temperatures and low CO₂ content of the production fluids result in lower corrosivity for MPU, solids contribute to the corrosion mechanism of the production system. Corrosion inhibition of the K-pad production flow line was initiated in 2001 and the F-L-C Pads flow line in 2003. Additionally, corrosion inhibition of the newly developed S-Pad began late 2002.

ACT Table B.4 reflects the historical inspection activity for MPU from 2002 - 2004.

Service	Length (Miles)	Int. Insp.			Ext. Insp. ²		
		2002	2003	2004	2002	2003	2004
Oil x-country lines	24	80	465	480	-	964	70
Oil – Well Pads	N/A ¹	754	2,754	2,049	47	N/A ³	
Water x-country	15	35	185	249	-	97	1,065
Water – Well Pads	N/A ¹	449	635	863	23	N/A ³	
Gas x-country	14	-	20	26	-	522	603
Gas – Well Pads	N/A ¹	283	99	83	-	N/A ³	
Water/Alternating Gas Well Pads	N/A ¹	-	230	298	-	-	-
Totals		1,601	4,388	4,048	70	1,583	1,738

¹ Totals not available

² The external corrosion program concentrated significantly on the Oil Sales line and outside facility piping in 2002

³ Included with internal numbers as part of the excavations.

ACT Table B.4 MPU Summary of Lines and NDE Inspections

Section B.3 Northstar

Northstar began production in November 2001. Production fluid corrosivity is moderate, but will tend to increase over time with the injection of GPB gas into the reservoir. ACT Table B.5 summarizes the inspection program for Northstar from 2002 through 2004 and shows an increase of inspection activity through time.

Service	Length (feet)	Int. Insp.			Ext. Insp.		
		2002	2003	2004	2002	2003	2004
Oil Pipe rack	1,200	-	-	-	-	-	-
Oil - Well Pad	280	106	114	204	-	-	-
Water Pipe rack ¹	2,400	-	-	-	-	-	-
Water - Well Pad ¹	70	17	25	46	-	-	-
Gas Pipe rack	600	-	-	-	-	-	-
Gas - Well Pad	140	26	65	77	-	-	-
Totals		149	204	327	-	-	-

¹ Disposal system; Northstar does not have an active water injection system.

ACT Table B.5 Northstar Summary of Lines and NDE Inspections

Section B.4 Badami

Low productivity necessitated the shut-in of the Badami Field in the third quarter of 2003 and throughout all of 2004. Shut-in consisted of de-inventory and warm storage of major equipment. Prior to shut-in, Badami's production fluids were considered a low risk from a corrosivity standpoint, as there is little water production and low CO₂ content. ACT Table B.6 summarizes the inspection program for Badami throughout the shut-in period in 2004.

Service	Length (Feet)	Int. Insp.	Ext. Insp.
Oil -Well Pad	840 WL, 320 HDR	18	-
Gas	240 WL, 320 HDR	5	-
Disposal Well	400	3	-

Note: Badami does not have an active water injection system.

ACT Table B.6 Badami Summary of Lines and NDE Inspections

Section B.5 Overall Inspection Activity Level

ACT Table B.7 summarizes the overall inspection activity since 2000. As can be seen, the overall activity level has remained approximately constant at ~3,400 items per year through 2002. However, a significant increase in inspections occurred in 2003. This is the result of additional inspections performed at Endicott and MPU, both internal and external.

Part 2 – Alaska Consolidated Team Performance Unit

	Surface	2000	2001	2002	2003	2004
Endicott	Int	1,346	1,480	1,686	2,072	2216
	Ext	16	16	40	856	731
	Total	1,362	1,496	1,726	2,928	2,947
Milne Point	Int	1,419	629	1,601	4,388	4048
	Ext	378	1,577	70	1,583	1738
	Total	1,797	2,206	1,671	5,971	5,786
Northstar	Int	-	16	143	204	327
	Ext	-	-	-	-	-
	Total	-	16	149	204	327
Badami	Int	27	-	5	29	26
	Ext	-	-	-	-	-
	Total	27	-	5	29	26
Grand Total		3,186	3,718	3,551	9,132	9,086

ACT Table B.7 Overall Inspection Activity Summary

Section C Weight Loss Coupons

Section C.1 Endicott

ACT Table C.1 summarizes the corrosion monitoring performance for 2004 and historical data are shown in ACT Figure C.1.

The average WLC corrosion rate for the production system has remained above 2 mpy; however as noted previously, the major portion of the system is fabricated from duplex stainless steel and these data are used primarily for monitoring produced fluid corrosivity and erosion tendency.

The lower, relatively constant corrosion rates in the water injection system reflect the effectiveness of the corrosion mitigation program. Three WLC locations were above the 2 mpy target for 2004. All three of these locations experienced corrosion rates above 2 mpy in the early part of the year and the corrosion is consistent with the increased corrosion activity from the year earlier. On average, the corrosion rate remained below the 2 mpy target for the year.

System	Access Fittings	%WLC <2 mpy
Water Injection - Pads	16	81%
Water Injection - x-country	1	100%
Oil Production - Pads	75	64%

ACT Table C.1 Endicott Corrosion Coupon Monitoring

Year	Oil	Gas	Disposal	Total	Repeat Insp	Locations with Increasing Damage
1998	28	3	-	31	0	-
1999	-	-	-	-	-	-
2000	15	6	6	27	18	-
2001	-	-	-	-	-	-
2002	5	-	-	5	4	-
2003	21	5	3	29	19	1
2004	18	5	3	26	26	-

Note: Increasing damage location associated with shutdown operation

ACT Table E.3 Inspection Summary of Badami Well Lines

Section E.2.4 Northstar

During 2004, a total of 327 well line inspections were completed, up from 204 the previous year. Twenty five locations in the 3-phase system, four locations in the disposal system, and three locations in the gas system had inspection increases. The 25 3-phase locations and the three gas system locations showing increasing corrosion are all in heavy wall target tees and elbows. This heavy wall piping presents a significant challenge to determining if the wall loss is due to corrosion or to the rough geometry effects of the thick walled sections. The rough geometry can skew readings by 2-3 percent or ~50 mils in a piece 1-1/2 inches thick. For this reason, these locations are monitored on a quarterly basis. The disposal well problems are believed to be associated with the mud plant operation prior to having been shut down. These data are summarized in ACT Table E.4.

	3-Phase	Disposal	Gas	Total
Number of Inspections	204	46	77	327
Number of Repeat Inspections	184	40	77	301
Locations with Increasing Damage	25	4	3	32
% Inspection Increase	14%	10%	4%	11%

ACT Table E.4 Inspection Summary of Northstar

Section F Repair Activities

ACT Table F.1 summarizes the repair activity for ACT. There were 17 repairs identified for ACT. Four repairs were at Endicott and 13 repairs were at Milne Point.

Service	Type	Internal	External	Mechanical
Oil	FL	6	1	-
	WL	3	-	1
Gas	FL	-	-	-
	WL	-	-	-
PW	FL	-	4	-
	WL	1	-	1
Total		10	5	2

ACT Table F.1 ACT Repair Activity

The four repairs at Endicott consisted of three replacements in the DSS system due to erosion and one as a result of external mechanical damage on a oil well line.

At Milne Point, seven repairs were a result of internal corrosion, five repairs as a result of external corrosion and one as a result of a freeze burst. In addition to the corrosion related repair activity, buried header expansions on two pads were removed and replaced with above grade piping.

Section G Corrosion and Structural Related Spills and Incidents

There was one structural related leak and no corrosion related spills in ACT in 2004. ACT Table G.1, ACT Table G.2, ACT Table G.3, and ACT Table G.4 summarize leak/save and mechanical repair data for Endicott, MPU, Northstar and Badami, respectively.

Service	Leaks	Saves
Oil x-country lines	-	-
Oil Well Pads	-	4
Water x-country lines	-	-
Water Well Pads	-	-
Gas x-country GLT/MI	-	-
Gas Well Pads	-	-

ACT Table G.1 Endicott Leak/Save and Mechanical Repair Data

Service	Leaks	Saves
Oil x-country	-	7
Oil Well Pads	-	-
Water x-country	-	4
Water Well Pads	1	1
Gas x-country	-	-
Gas Well Pads	-	-

ACT Table G.2 Milne Point Leak/Save & Mechanical Repair Data

Service	Leaks	Saves
Oil – Well Pad	-	-
Gas – Well Pad	-	-
Disposal Well	-	-

ACT Table G.3 Northstar Leak/Save and Mechanical Repair Data

Part 2 – Alaska Consolidated Team Performance Unit

Service	Leaks	Saves
Oil – Well Pad	-	-
Gas – Well Pad	-	-
Disposal Well	-	-

ACT Table G.4 Badami Leak/Save and Mechanical Repair Data

Section H 2005 Corrosion Monitoring and Inspection Goals

Section H.1 Endicott

The IIWL will continue to be evaluated to determine if the current decreasing trends in corrosion activity are sustainable.

The well line erosion rate monitoring program will continue.

No significant changes to the corrosion-monitoring program are anticipated.

Section H.2 Milne Point

The 2005 plan will continue the inspection program to provide feedback for corrosion control and mechanical integrity.

A comprehensive review of all Milne Point corrosion monitoring locations was to be undertaken in 2004 to determine the need for additional monitoring points. This review has been moved to 2005.

A study was made in 2004 to determine the best way forward for corrosion mitigation of remaining uninhibited areas of the field. These options will be progressed in 2005/2006.

Section H.3 Northstar

Corrosion monitoring and inspection data will continue to be reviewed as the information becomes available. Changes to the inspection and mitigation activity will be dictated by these data in conjunction with process data. This is an ongoing activity that will continue for a number of years as the corrosion management programs are established at the relatively new production facility.

The recommendation to relocate the chemical injection points to the wellhead was provided, and Operations is proceeding with these modifications as materials become available. Additionally, all new wells will be equipped with capability to inject corrosion inhibitor at the wellhead.

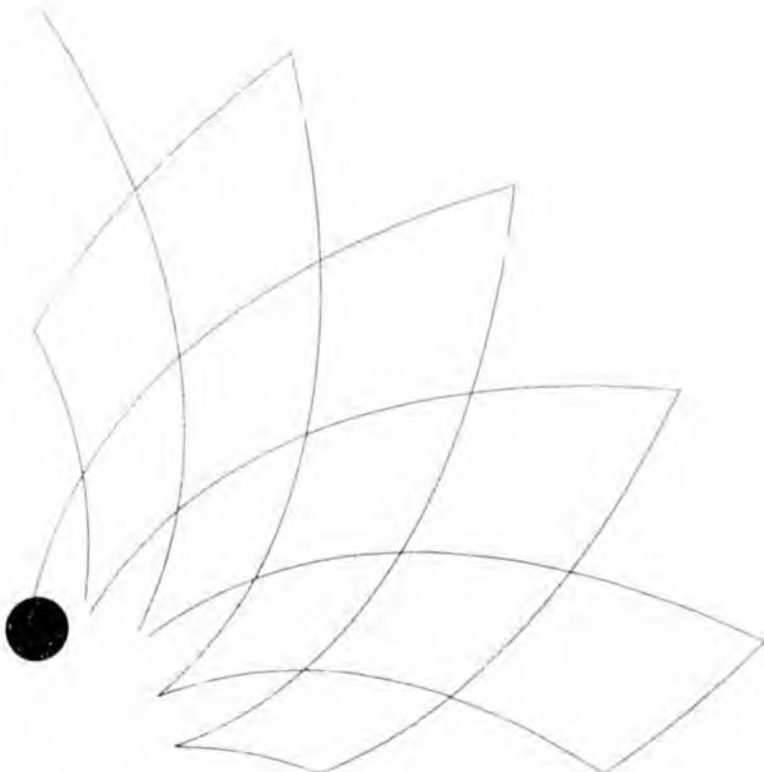
The water disposal system was to be evaluated after the mud plant shut down occurred to determine if the corrosion activity had subsided. With additional rig work to be done, the mud plant has been re-commissioned and further corrosion associated with dissolved oxygen is anticipated. Further analysis will be performed to determine the level of corrosion activity and recommendations will be based on that evaluation.

Section H.4 Badami

Follow up inspections were performed on shut in equipment as previously noted, with no corrosion activity seen. Should Badami re-start, the integrity plan will be re-initiated.

Appendix 1

Glossary of Terms



Glossary of Terms

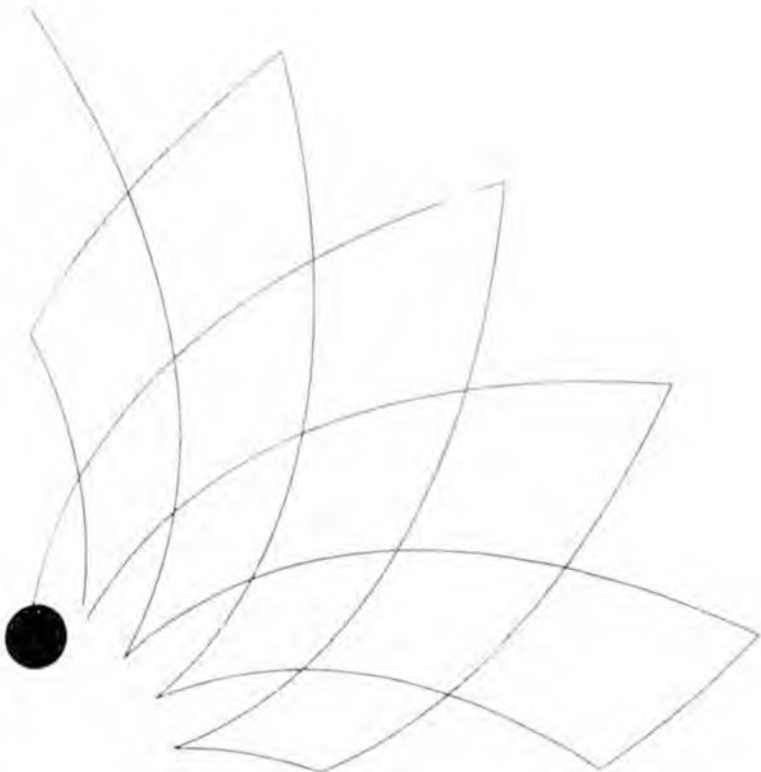
Term	Definition/Explanation
3 phase production	Unprocessed well head fluids, oil, water, gas – same as OIL
ACT	Alaska Consolidated Team
ATRT	Automated tangential radiographic testing
BAD	Badami
BPXA	BP Exploration (Alaska) Inc.
CCL	Cross country line
CI	Corrosion inhibitor
CIC	Corrosion, Inspection and Chemicals
CIP	Comprehensive Inspection Program
CL	Common line – same as LDF
CMS	Corrosion management system
CPF	Central processing facility
CR	Corrosion rate, mpy
CRA	Corrosion resistant alloy
CRM	Corrosion rate monitoring inspection program
Cross Country lines	Pipelines from the manifold building to major facility
CUI	Corrosion under insulation
CW	Commingled Water
DRT	Digital radiography
END	Endicott
ER	Electrical resistance probe – see corrosion monitoring
ERM	Erosion rate monitoring inspection program
FL	Flow line – same as cross-country
FIP	Frequent inspection program
Frequency C	Continuous
Frequency D	Daily
Frequency H	Hourly
Frequency M	Monthly
Frequency Q	Quarterly
Frequency Y	Yearly/annual
FS	Flow station
G	Gas
GC	Gathering center
GLT	Gas lift transit
GPB	Greater Prudhoe Bay
IIWL	Inter Island Water Line - Endicott
ILI	In-line Inspection or Smart Pig
LDF	Large diameter flow line – same as CL
LIS	Lisburne
MAOP	Maximum Allowable Operating Pressure
MFL	Magnetic flux leakage
MI	Miscible injectant
mil	0.001 in.
MIMIR	M echanical I ntegrity M anagement I nformation R epository BPXA corrosion and inspection database
MPI	Main Production Island - Endicott
mpy	Corrosion rate/degradation rate – mils per year
MPU	Milne Point Unit
MW	Mixed water

Glossary of Terms

Term	Definition/Explanation
NDE/NDT	Non-destructive examination/testing
NIA	Niakuk
NGL	Natural gas liquids
NST	Northstar
OIL	OIL service is 3-phase production service
OWG	Oil, water and gas – 3-phase production
PBU	Prudhoe Bay Unit
PO	Processed oil
ppb	Parts per billion
ppm	Parts per million
PR	Pitting rate, mpy
PTMAC	Point McIntyre
PW	Produced water
RT	Radiographic testing
SDI	Satellite drilling island
Sleeve	Mechanical repair
Slug catcher	First stage pressure vessel of OWG separation facility
STP	Seawater Treatment Plant
SW	Seawater
TRT	Tangential radiographic testing
UT	Ultrasonic testing
VSM	Vertical support member
WAG	Water alternating gas
WL/Well lines	Pipelines from the well head to manifold building
WLC	Weight loss coupon
WPM	Well pad manifold building
WSS	Walking speed survey
WTR	Combined seawater and produced water injection
X-country	Cross country

Appendix 2

Work Plan
Guide for Performance Metric Reporting



2000 Work Plan

Commitment to Corrosion Monitoring

Phillips Alaska, Inc.
BP Exploration (Alaska) Inc.

"BP and Phillips will, in consultation with ADEC, develop a performance management program for the regular review of BP's and Phillips' corrosion monitoring and related practices for non-common carrier North Slope pipelines operated by BP or Phillips. This program will include meet and confer working sessions between BP, Phillips and ADEC, scheduled on average twice per year, reports by BP and Phillips of their current and projected monitoring, maintenance and inspection practices to assess and to remedy potential or actual corrosion and other structural concerns related to these lines, and ongoing consultation with ADEC regarding environmental control technologies and management practices."

Work Plan Purpose:

The purpose of this work plan is to clearly define the purpose, scope, content, reporting requirements, roles and responsibilities, and milestones/timing for the development and implementation of the Corrosion Monitoring Performance Management Program required by Paragraph II.A.6 of the North Slope Charter Agreement.

Corrosion Monitoring Performance Management Program

Purpose: To provide for 'the regular review of BP and PAI's corrosion monitoring and related practices for non-common carrier North Slope pipelines' operated by BP or PAI.

'Corrosion Monitoring' specifically refers to the activity of monitoring pipeline corrosion rates via corrosion probes, corrosion coupons, internal pipeline inspections, and external pipeline inspections.

'Related practices' refers to the assessment of corrosion monitoring data and the associated response to the assessment, specifically chemicals, inspection, and repairs.

Scope: Non-common carrier North Slope pipelines operated by BP or Phillips Alaska, Inc.

"Non-common carrier pipelines" refer to Non-DOT-regulated pipelines. Included in this designation are cross-country and on-pad pipelines in crude, gas, and other hydrocarbon services, as well as, produced water and seawater service pipelines. In module and inter-module on pad piping are not considered part of the scope of this review program.

Content: This Corrosion Monitoring Performance Management Program consists of the following:

1. BP and PAI will "meet and confer" with ADEC twice per year, on average. These sessions will be "working sessions" where BP and PAI will inform ADEC of the following:
 - A. Summary description of the inspection and maintenance practices used to assess and to remedy potential or actual corrosion, or other significant structural concerns relating to these lines, which have arisen from actual operating experience. This description will address overall areas of focus, the rationale for this focus, and the nature of monitoring and related practices used during the time since the last meeting. This description may be brief if strategies/focus areas have not changed since the last meeting.
 - B. Summary overview of ongoing coupon and probe monitoring results.
 - C. Summary overview of chemical optimization activities.
 - D. Summary overview of ongoing internal inspection activities.
 - E. Summary overview of ongoing external inspection activities.
 - F. Summary overview of ongoing structural concerns.
 - G. Summary of conclusions drawn and responses taken to remedy potential or actual corrosion concerns relating to these lines.
 - H. Review/discussion of corrosion or structural related spills and incidents
 - I. Review the actions developed by the operator to address any corrosion performance trends that significantly exceed expected parameters.
 - J. Summary of program improvements and enhancements, if applicable.
 - K. Review of annual monitoring report (see below) at the next scheduled semi-annual meeting.

The agenda for these meetings will also include an opportunity for open discussion and an opportunity for ADEC to ask questions, provide feedback, etc.

These meetings will be targeted for April and October of each year, although this timing can be adjusted upon the mutual agreement of BP, PAI, and ADEC. The location of the meetings will alternate between the parties.

2. BP and PAI will submit annual reports to ADEC, which will provide the status of current and projected monitoring activities. These reports will be issued on or before March 31st of each year, and reflect the prior calendar year. The following information will be provided:
 - A. Annual bullet item reporting the progress of the Charter Agreement corrosion related commitment
 - B. A general overview of the previous year's monitoring activities.
 - C. Metrics that depict coupon and probe corrosion rates.
 - D. Metrics that characterize chemical optimization activities.
 - E. Metrics that depict the number and type of internal/external inspections done, and, as applicable, the corrosion increases/rates and corresponding inspection intervals.
 - F. Metrics that characterize the quantity and type of repairs made in response to the internal/external inspections done per the above paragraph.
 - G. Metrics that depict the numbers and types of corrosion and structural related spills and incidents.
 - H. A forecast of the next year's monitoring activities in terms of focus areas and inspection goals. These forecasts cannot be viewed as binding, as corrosion strategies are dynamic and priorities will change over the course of the year. However, changes in focus will be communicated to ADEC during the semi-annual meetings described above.

Note: These reports will be presented in, and be part of, a comprehensive North Slope Charter Agreement status report.

3. In addition to the semi-annual "meet and confer" working sessions referenced above, BP and PAI will remain accessible to provide "ongoing consultation" to ADEC regarding environmental control technologies and management practices.

'Environmental Control Technologies' refer to those technologies specifically related to corrosion monitoring and mitigation of the subject pipelines.

'Management practices' refer to corrosion monitoring and related practices as defined above.

4. During the semi-annual 'Meet and Confer' working meetings with BP and/or PAI, ADEC may use the services of a corrosion expert(s) (contracted from

funds under Charter Commitment paragraph II.A.7) to assist in the review of performance trends and corrosion program features.

5. BP has assigned CIC Manager, R. Woollam/564-4437, and Phillips has assigned Kugaruk Engineering and Corrosion Supervisor M. Cherry and J. Huber/659-7384, to be the contacts responsible for ensuring these commitments are met, including ADEC notification of scheduled times for the semiannual presentations. The ADEC contact for this effort is (Pipeline Integrity Section Manager/S. Colberg/269-3078) who will notify interested personnel of the presentation times, maintain the reports for distribution to the public when requested and coordinate other issues relating to this commitment.

Annual Timetable

March 31st Annual Report

April 30th 1H Semi-Annual Review (Meet and Confer)

October 31st 2H Semi-Annual Review (Meet and Confer)

Guide for Performance Metric Reporting

General

- Different metrics show and reveal different aspects of the business and as a consequence there are rarely any 'right' or 'wrong' measures only 'right' or 'wrong' application and usage.
- Summary statistics described below may be provided as a data appendix to the annual reports with the more pertinent tables and graphics being contained in the text as appropriate. The intent is not to clutter and interrupt the flow of the text with extraneous data.
- Format of data, the order in which it is presented, etc. of each company's annual report may differ from the order presented below, depending on key messages and data context. For example, one company may choose to imbed Leak/Save data into an inspection graph as opposed to presenting the Leak/Save data in standalone tabular format.
- This is an initial document for implementation in the 2001 annual report to ADEC, it should be noted, that the guidelines provided below can and will be adjusted to improve the efficacy of the annual report and reporting mechanism.

Timescale

- Data to be presented on an aggregate annualized basis.
- Base year 1995 providing 5 year history before the start of the Charter Agreement and each year's annual report will add to time series starting in 1995.

Equipment Classification

- **Well Line** Pipe work from the well head to the Well Pad Manifold Building, generally, the flow from a single well prior to commingling before transportation to the separation plant.
- **Flow Line** Pipe work from the Well Pad Manifold Building to the Separation plant, generally, cross country and off pad pipe work which carries commingled flow to/from a well pad. Also, straight run flow from the wellhead to separation plant, without commingling, is classified at Flow Line pipe work.
- **Exceptions** Pipe work not conforming to these basic definitions will be reported by exception.

Service Definitions

- **Three Phase Production (3ø or OWG)** Basic reservoir fluids (O/W/G – oil, water and gas) produced from down hole through to the main separation plants that typically see only see changes in temperature and pressure from reservoir conditions and are therefore essentially un-separated.
- **Seawater (SW)** Water sourced typically from the Beaufort Sea that has undergone primary treatment at the Seawater Treatment Plant. Note, that the seawater treatment plants differ across the slope in the primary treatment methods, most importantly oxygen removal, with both production gas and vacuum stripping being employed.
- **Produced Water (PW)** The water produced with the primary reservoir 3 phase production after passing through the separation and treatment
- **Commingled Water (CW)** or Mixed Water (MW) Water which has been commingled and is therefore multi-sourced, this is typically a mix of SW and PW although other combinations exist in the operations on the North Slope.
- **Gas (G)** Generic term for a number of different gas systems which transport essentially dry gas between facilities including fuel gas, lift gas and miscible injectant.
- **Processed Oil (PO)** The oil/hydrocarbon produced with the primary reservoir 3 phase production after separation and treatment, this is primarily black oil but could include black oil plus NGL's.

Basic Summary Statistics

- **Distribution** The data is fundamentally of log-normal distribution, with a lower limit of zero or no-change and potentially unlimited upper extent.
- **Count** A count of the number of activities completed i.e. coupons pulled in a given year.
- **Average** The average or mean for the criteria being summarized i.e. average corrosion rate.
- **Target Value** The target value against which non-conformance, see below, is reported.
- **Number Non-conformant** The number of items not conforming to the control criteria i.e. the number of coupons exceeding the control value.
- **Percentage Non-conformance** The percentage not conforming to the control value as a percentage of the total.

Weight Loss Coupon Data

Table below summarizes the reporting of weight loss coupon data for the major fields on the North Slope

	Well Lines	CCL/FL
3 ø Production	All	All
Seawater	GPB	All
Prod. Water	GPB	GPB
Commingled Water	All	All

The data sets to be provided for both general corrosion rates and pitting rates are,

- Count of coupons,
- Average corrosion rate,
- Number non-conformant,
- % Conformant i.e. 1 minus the % non-conformant.

A corrective action list for non-conformant flow lines (FL/LDF/CCL/CLs) will also be provided.

Internal Inspection Data

Table below summarizes the reporting of internal corrosion inspection data for the major fields on the North Slope:

	Well Lines	CCL/FL
3 ø Production	All	All
Commingled Water	All	All

Note that no distinction will be made between water services across the North Slope since in many cases the service is variable making meaningful analysis and aggregation difficult.

The data sets to be provided for internal inspection are,

- Count of inspections,
- Number of increases on repeat inspection locations,
- Percentage of increases on repeat inspections.

A corrective action list for flow lines (FL/LDF/CCL/CLs) with inspection increases will also be provided.

Corrosion Inhibition

The corrosion inhibition program is to be reported as the target and actual total annual gallons and gallons per day, and as concentration, ppm, based on a field wide average.

External Corrosion Inspection

External corrosion inspection program is to be reported as an aggregate of all piping systems without distinction or differentiation of service and equipment type with a summary of the overall program status.

The data sets to be provided for external inspection are,

- Count of inspected location,
- Number of corroded locations,
- Percentage of inspection locations corroded.

Repair and Leak Statistics

The repair and leak/spill statistics to be reported for each year plus the historical trend back to 1995 consistent with other performance metrics. The basic definitions,

Leak/Spill An agency reportable leak/spill for the pipelines covered under the Charter Agreement which was caused by corrosion and/or erosion

Save A location which required repair action as a result of corrosion and/or erosion damage but which was found through inspection prior to causing a leak/spill

The data sets to be provided for Repair/Leak statistics,

- Count of Leaks/Saves by flow line and well lines,
- Summary of leak/spill causes.

Below Grade Piping

The data sets to be provided for Below Grade Piping (BGP) program,

- Number of segments/crossings inspected broken out by inspection method,
- Number with anomalies and severity of anomaly.

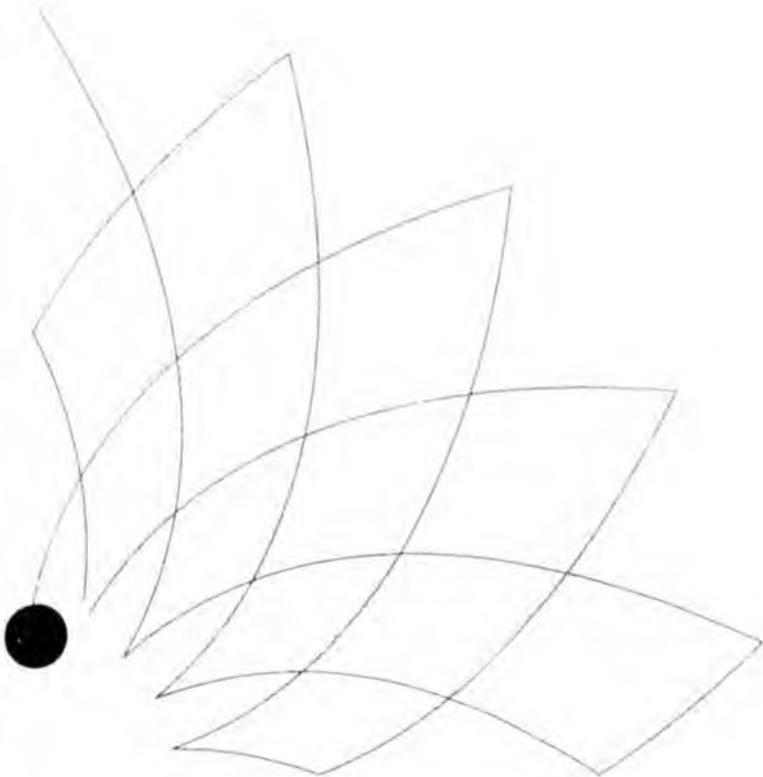
Results of casing digs, visual casing inspections and casing clean-out to be reported as appropriate.

Other Programs

Reporting of ER probe, smart pigging, maintenance pigging, structural issues, and details of individual spill incidents to be reported as dictated by the current year's program activity.

Appendix 3

Corrosion Management System



Appendix 3 Corrosion Management System

This section summarizes the Corrosion Management System (CMS) in use at Greater Prudhoe Bay (GPB) Performance Unit. Figure 7 contains a schematic of a typical production facility configuration. A map and brief description of each field and the associated production facilities can be found in Figure 8 and GPB Table 3.1.

Appendix 3.1 Corrosion Management System

Appendix 3.1.1 Description

The Corrosion Management System consists of a number of major program elements: Corrosion Monitoring, Erosion Monitoring, Corrosion Mitigation, Inspection and Fitness-For-Service assessment, which follow a simple management process, represented in Figure 1. The CMS elements are summarized in Table 9, Table 10 and Table 11, at the end of this section. The Corrosion, Inspection and Chemical (CIC) Group utilizes data presented in this report as part of the overall Corrosion Management System.

The overall objective of the CMS is to meet the corporate objectives of 'no accidents, no harm to people and no damage to the environment' which translates for corrosion management within BPXA to delivering a mechanical integrity program which:

- Minimizes health, safety, and environmental impacts of corrosion resulting from a loss of containment.
- Provides an infrastructure fit-for-service for the remainder of the life of the oilfield.
- Provides infrastructure of sufficient mechanical integrity capable of producing satellite fields/accumulations through existing main production facilities and infrastructure.
- Provides an infrastructure to support future major gas production and sales through current North Slope facilities.

These overall goals and objectives are achieved through a comprehensive Corrosion Management System that consists of an integrated system of strategy, processes and programs.

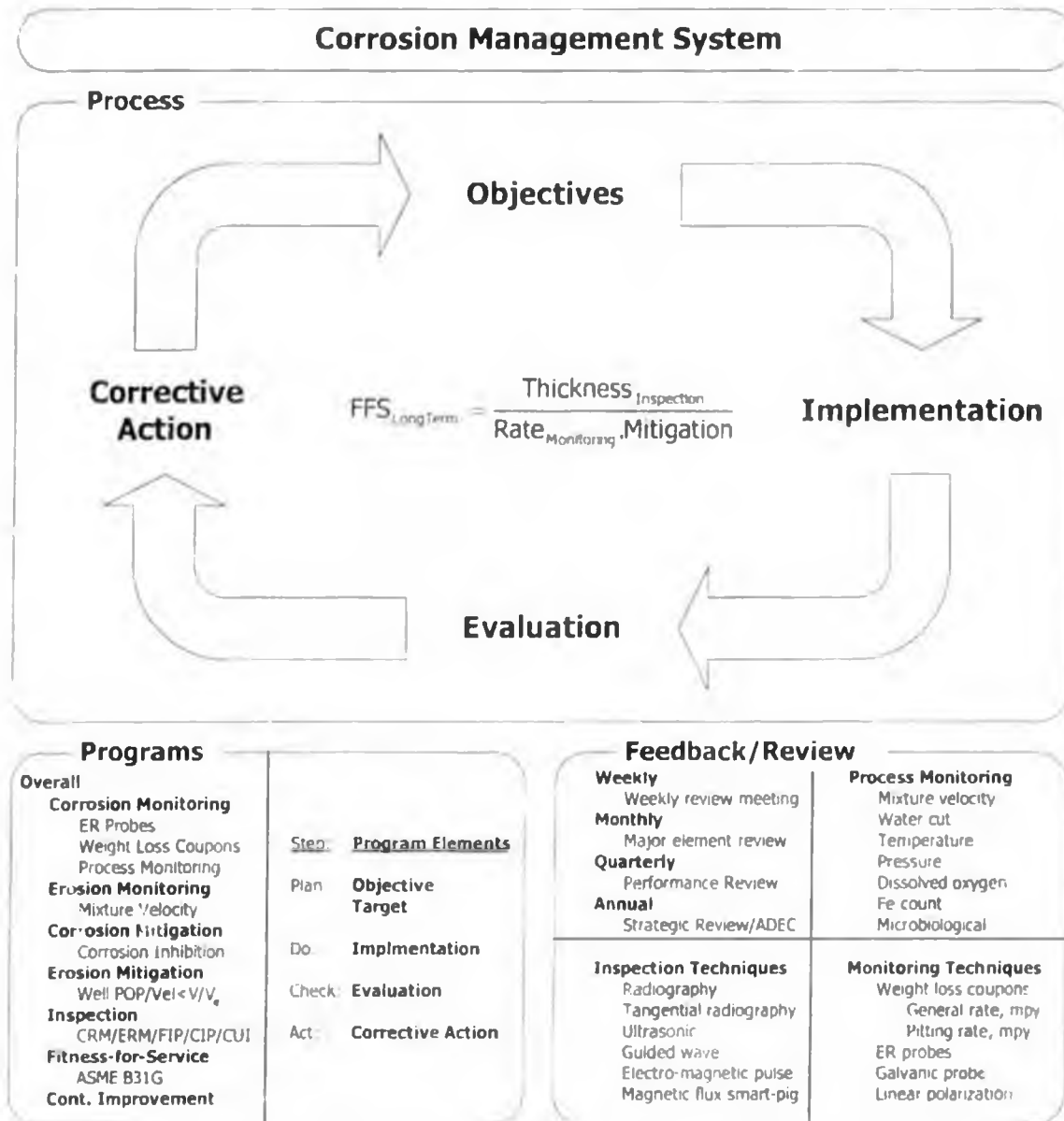


Figure 1 Overview of the Corrosion Management Process

Appendix 3.1.2 Process

Within the overall Corrosion Management System, each specific program element, i.e. Corrosion Monitoring, Mitigation, Inspection and Fitness-For-Service, follows the classic TQM (Total Quality Management) process of 'plan-do-check-act' and consists of,

Step	Activity	Description
Plan	Objective	The program objective and purpose
	Target	The metric against which performance is assessed
Do	Implementation	Implementation plan to achieve objective
Check	Evaluation	Method to evaluate performance of plan against target
Act	Corrective Action	The action required to correct deviation from target

Table 1 Corrosion Management Process

Appendix 3.1.3 Objectives and Targets

The objectives¹⁰ for the CMS are set in order to support the delivery of the corporate objective and BPXA objectives described in the Foreword. For the purposes of the CMS these can be translated into the corrosion management objectives of:

- Eliminate corrosion and erosion related failures,
- Provide Fit-For-Service infrastructure to the end of field life.

Based on these objectives, individual targets are set for the corrosion, erosion, mitigation and inspection programs, which in combination are designed to deliver the objectives. The overall business objectives and individual program objectives and targets are described in detail in Table 9, Table 10 and Table 11.

For example, the weight loss coupons (WLC) in the 3-phase production system have a corrosion rate target of 2 mils per year (mpy). The monitoring program objective is to meet or beat this target, which means an actual WLC corrosion rate of 2 mpy or less (WLC \leq 2 mpy).

Appendix 3.1.4 Implementation

There are a number of different corrosion monitoring and inspection techniques, each of which has both advantages and disadvantages. The advantages and disadvantages, or strengths and weaknesses, make the results from an individual technique more or less applicable depending on the application circumstances.

Table 12, Table 13, and Table 14 summarize the main categories of corrosion monitoring, process monitoring, inspection techniques and briefly summarize relative strengths and weaknesses for different applications.

Appendix 3.1.5 Evaluation

The elements of the CMS have to be applied to each system at GPB to reflect their applicability and efficacy. The corrosion and erosion monitoring, inspection and

¹⁰ In addition to Charter Work Plan, some information is supplied to provide additional context and help in understanding BPXA corrosion management activities

mitigation practices for the major services and equipment type are summarized in Table 15.

The results from each of the corrosion management programs are reviewed on a regular basis to provide feedback and to take any necessary corrective action based on deviation from target performance. In general, the major review cycles within the CMS are presented in Table 2.

Review	Description
Weekly	A weekly internal review meeting at which the latest corrosion monitoring, mitigation, inspection and process data are analyzed and reviewed, and any tactical changes implemented
Monthly	Monthly summary of the major elements of the program are reviewed for the need for longer term corrective action
Quarterly	Quarterly strategic performance review held in order to ensure that the implementation plan is delivering the strategic objectives
Annual	Annual program and strategy review designed to review the strategic direction of the program and review effectiveness of the current programs in delivering the strategic direction, e.g. Annual Report to ADEC

Table 2 Corrosion Management Feedback Cycles

Based on the results of the evaluation process, corrective action plans are developed and the overall management program and strategic direction are reviewed.

Appendix 3.1.6 Corrective Action

Corrective actions provide feedback to the adjustment and setting of Objectives and Targets. Corrective actions can be broken down into five basic categories;

- Chemical Mitigation,
- Operational Intervention,
- Reduce Maximum Operating Pressure (Derate),
- Repair/Replacement,
- Abandon or Remove from Service.

Chemical mitigation is discussed in detail in Section D. Operational intervention centers on the GPB Velocity Management Program that is designed to control internal mixture velocity below target values dependent on equipment type, water cut and line size. Repair/replacement programs are driven by the inspection findings and include mechanical sleeves, pipe work refurbishment, and pipeline replacement.

Appendix 3.2 Corrosion and Inspection Data Management

In order to deliver a comprehensive corrosion management program and manage the extensive corrosion monitoring and inspection activity, it is necessary to have an active and structured electronic database.

With the introduction of single-operatorship at Greater Prudhoe Bay one of the major problems faced by the CIC Group was the integration of two historical data sets for inspection, corrosion monitoring and corrosion mitigation information.

There has been a significant investment in resources in order to bring together these two different histories from incompatible databases based on early 1990's technology.

Appendix 3.2.1 MIMIR Database

The database development effort has involved a dedicated team of software developers and also significant resources from within the CIC Group. The program is currently a "work in progress" and in 2005 BP/CIC will continue work on the development of chemical management, electronic data recording, tank and vessel, and standard reporting modules.

Users of the system are provided two primary methods for accessing data stored in the database. The first is a custom user interface written in Microsoft Visual Basic[®], and the second is through ad-hoc data query tools such as BrioQuery[®] and BusinessObjects[®] which allow free-form SQL[®] access to the data.

Checks for data integrity are provided at a number of different levels including error checking at the point of data capture and data entry, regular reviews of data quality, and data entry rules within the database.

The data is continuously monitored for integrity, quality and consistency; as a consequence any errors detected are corrected as they are found. In addition, as better analysis tools become available through further integration then records are amended to reflect the improved level of analysis.

As a result of the ongoing quality effort and the tracking of production/service changes, this is a 'live' database and therefore as the system changes then the records returned will change. The following are some of reasons why returned values change through time,

Quality Control and Audit A fundamental design philosophy for the database was that errors should be corrected through time as they are discovered. Therefore as the database is used and the quality control rules and procedures applied, data-entry, translation and record-keeping errors are eliminated.

Equipment Service Changes The database tracks active, in or out-of-use equipment, and equipment service changes. As a piece of equipment moves through different services and different status, then the data in the database tracks the equipment status.

Transition Issues As noted above, the two historical databases, heritage East and heritage West, were incompatible with very different structures and data fields. Therefore these have had to be translated to the new system. As the quality control and audit tools are applied to the translated data, error and mistranslations are removed.

Time The database is in active use with data being added everyday, given that there is sometimes a time delay between the reporting date and entry date then the data totals can and do change.

Table 3 gives an illustration of the number of records and the rate at which those records are accumulated on an annual basis in the database. The table clearly shows the level of complexity and volume of data involved in managing the corrosion programs at GPB.

In addition, the table also shows that the range and types of information being gathered is being improved through time to enable better overall corrosion management at the GPB. The most notable examples of this increasing range of coverage of the corrosion and inspection database is the inclusion of the production and injection data, the introduction of chemical usage data and the long term storage of ER probe data.

Data Record	Unit	Records	#/year	History
Weight loss coupons	10 ⁶	0.2	0.01	20+ years
ER probes readings	10 ⁶	1.7	0.4	2½ years
Equipment	10 ³	28	-	-
Inspection locations	10 ⁶	0.6	.07	-
Inspection records	10 ⁶	1.2	0.1	~13 years
Chemical injection	10 ³	52	22	2½ years
Production rates	10 ⁶	8.3	0.5	~15 years
Injection rates	10 ⁶	2.0	0.2	~12 years

Table 3 Database Record Accumulation Rate

Appendix 3.2.2 Historical Data

The small differences in data between Annual Reports reflect the movement of lines into and out of service, the addition or abandonment of equipment, and the addition or removal of corrosion access fittings to the program. The historical data for prior years has been updated to reflect the current equipment inventory.

Appendix 3.3 Corrosion Management Context

The following sections are provided to lend context to the current year results.

Appendix 3.3.1 ER Probe and Corrosion Inhibitor Response

This section describes, by example, the methodology by which corrosion inhibitor concentration is increased as a result of corrosion monitoring through the use of ER probes. ER probes are in use across GPB on the large diameter 3-phase production flow lines.

Figure 2 and Table 4 illustrate the use of ER probes in managing changing corrosion conditions in a large diameter flow lines. Figure 2 shows the ER probe readings and derived corrosion rates, over a period of approximately 10 months in 2003. For the first 10 weeks the measured corrosion rate is bordering on 2 mpy and a 5% increase in CI is implemented. In early February the existing ER probe was replaced due to data quality issues. In mid March another increase of CI was implemented based on ER probe corrosion rate. During April and part of May, the CR still exceeded the target and two additional CI increases were implemented. Finally in mid-May, the CR falls below the 2 mpy target and the CI remains at the increased concentration.

Time Period	Comments
14-Jan	Probe placed on watch list
14-Jan to Feb 11	Probe at or near 2 mpy, 5% increase in pad CI target
14-Feb	Poor data quality, ER probe replaced.
18-Feb to 21-Mar	Probe continues to show rate >2mpy, 10% increase in pad CI target
21-Mar to 30 Apr	Probe continues to show rate >2mpy, 10% increase in pad CI target
01-May to 01-Oct	Probe shows rate <2mpy, No adjustments to CI target

Table 4 Corrosion Inhibitor Concentration vs. Corrosion Rate

Appendix 3 – Corrosion Management System

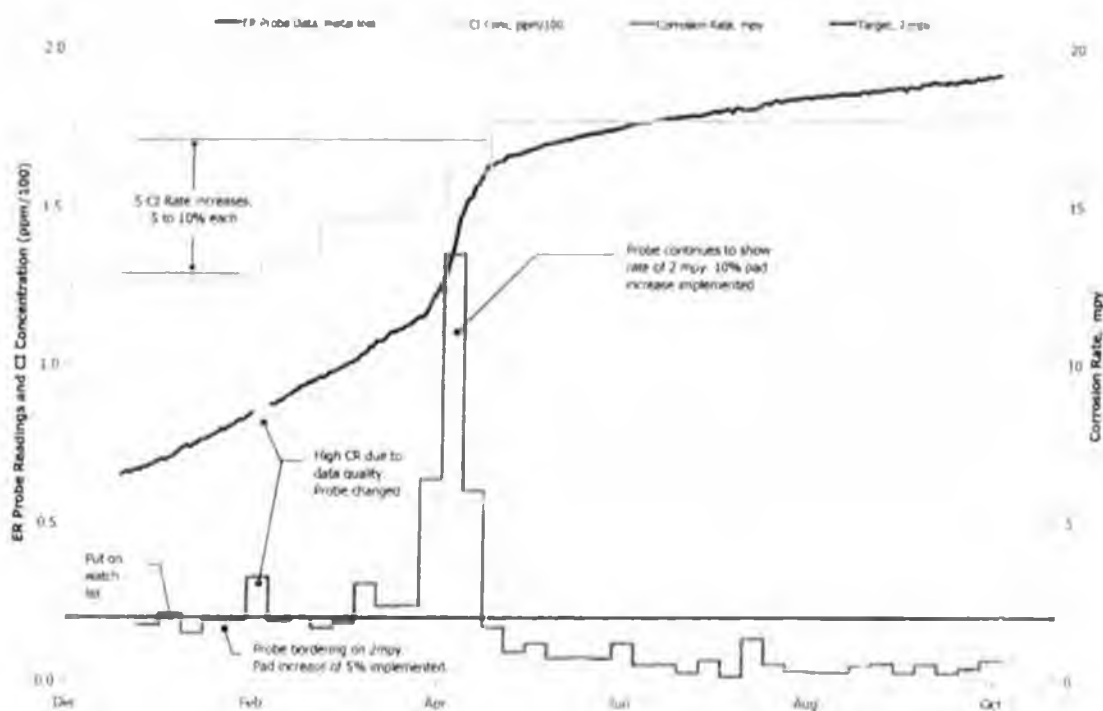


Figure 2 Corrosion Inhibitor Concentration vs. Corrosion Rate

Appendix 3.3.2 Corrosion Inhibitor Development

The development of new corrosion inhibitors starts in the research and development laboratories of the chemical suppliers where potential products are tested for effectiveness under a range of conditions designed to simulate production fluids. Once these preliminary test chemistries have passed the laboratory screening process, the promising products are tested under field conditions using dedicated test facilities at GPB. The test process is summarized in Table 5.

In 2003, a new standardized protocol for well line testing was developed. Approximately ten new products are tested each quarter on a small scale test using an individual well line with each test lasting ~2 days and using approximately 5 gallons of the corrosion inhibitor under evaluation. Products that successfully pass the well line test program are then considered for a large-scale field trial.

The large-scale field trial involves converting between one and three well pads to the test product for 90 days and using 20-40,000 gallons of test chemical. This enables corrosion probe, coupon, and inspection data to be generated to verify the test product's effectiveness as a corrosion inhibitor. The large-scale field trial also allows assessment of the impact of the product on oil separation and stabilization process. Progress is being made in developing a new, standardized protocol for more rapid verification of a product's effectiveness as a corrosion inhibitor.

Location	Test	Description
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Location	Test	Description
Laboratory	Wheel-box Test	Performance of new potential corrosion inhibitor actives is compared to high performing actives. The test conditions simulate GPB and the test is run for 24 hours. Performance is determined by coupon weight loss.
	Kettle Test	This investigates the ability of an inhibitor formulation to partition from an oil phase into a brine phase under stagnant conditions. Test duration is 16 hours and corrosion rate is determined by linear polarization resistance (LPR) probes.
	HP Autoclave	This method determines the performance of inhibitors under high pressure and high temperature conditions. Monitoring method is by either coupon weight loss measurements or LPR. Test duration varies from 1 to 7 days.
	Jet Impingement	A once-through jet impingement configuration evaluates the performance of an inhibitor formulation under extremely high shear conditions. The persistency of the inhibitor film can also be determined. Test duration is one hour and corrosion rate is determined by LPR measurements.
	Flow Loop Test	The ultimate laboratory scale test that simulates temperature, pressure and flow conditions including velocity and water cut. Typical test duration is 24 hours and corrosion rate is determined by LPR measurements.
Field	Well Line Test	Dedicated test well lines are used at GPB as the first step in the field-testing process. Typically 5 gals of chemical used with a test duration of 2 days.
	Large Scale Test	1 to 3 well pads using 20-40,000 gallons of corrosion inhibitor with a test duration of 90+ days. Allows the evaluation of corrosion Inhibitor performance by ER, WLC, and inspection, as well as impact of product on separation plant performance.
	Evaluation	Products are evaluated against both technical performance and cost effectiveness criteria in order to assess if there is an overall improvement in performance.
GPB	Implementation	Once a decision has been made to convert the field to a new product, additional precautions are taken with additional corrosion monitoring and plant performance evaluations in order to assure product efficacy.

Table 5 Summary Description of the Typical Test Program Components

Appendix 3 – Corrosion Management System

As an example, the ER probe results from a typical cross-country flow line test are shown in Table 6 and are summarized in Figure 3. Based on these data, the test chemical in this example was not cost effective and therefore was not utilized across the field.

Status	Chemical	Conc. ppm	CR, mpy	Notes/Comments
Baseline	Incumbent	130	0.2	
Stage 1	Test	150	8.1	Even at a higher dose rate the test chemical was unable to inhibit corrosion to the same level as the incumbent.
Stage 2	Test	170	2.0	Reduces corrosion rate.
Stage 3	Test	190	0.8	Dose rate was increased in order to achieve the same level of corrosion control as the incumbent. At this increased level of corrosion inhibition the test product was uneconomic and the test was terminated.
Return	Incumbent	130	0.1	Re-inject the incumbent product and corrosion rates return to the same level as those prior to the test.

Table 6 Flow line Test Program Result Summary

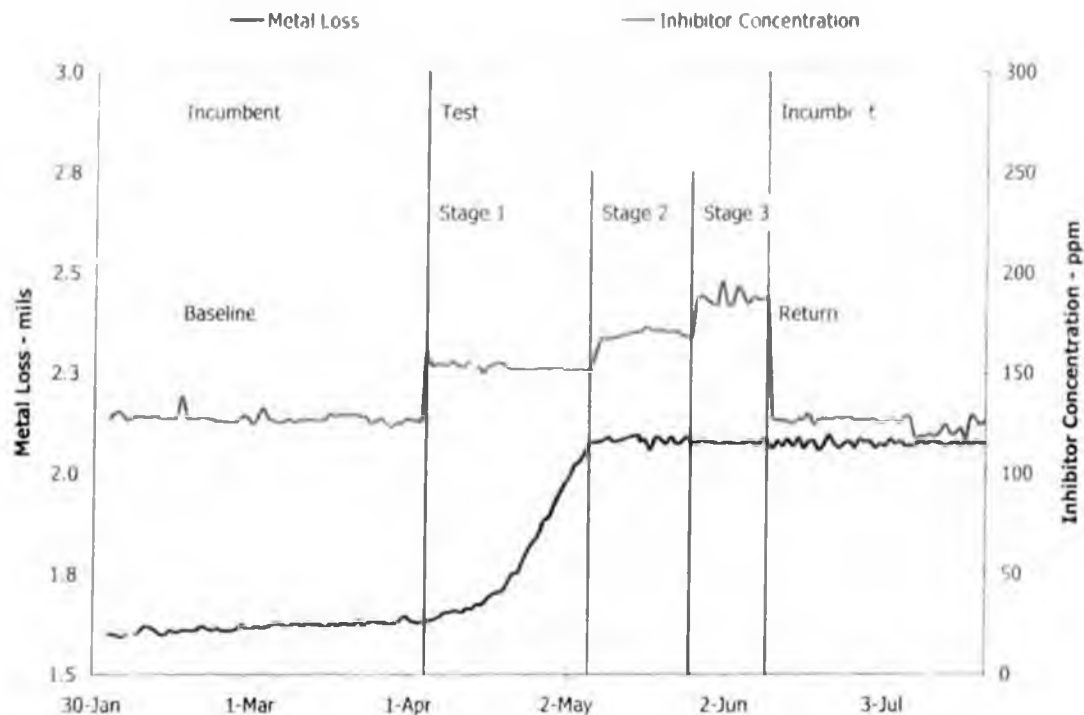


Figure 3 ER Probe Chemical Optimization Test

A second example, utilizes the output from the weight loss coupon program. This example from a test performed in 2001, demonstrates the need/value of multiple monitoring techniques when evaluating corrosion inhibitor performance. The trial product was tested for a 90-day period with no negative response observed by the ER probes. However, after the 90-day test period the corrosion coupons were pulled and showed relatively high general corrosion and pitting rates - see Figure 4. The product evaluated was a failure and the incumbent product was re-instated based on the coupon results. Corrosion inhibitor tests use all the monitoring tools available such as corrosion probes, coupons, and inspection data to determine corrosion control performance. In addition, the corrosion inhibitor is evaluated for plant production performance to show compatibility with the separation process.

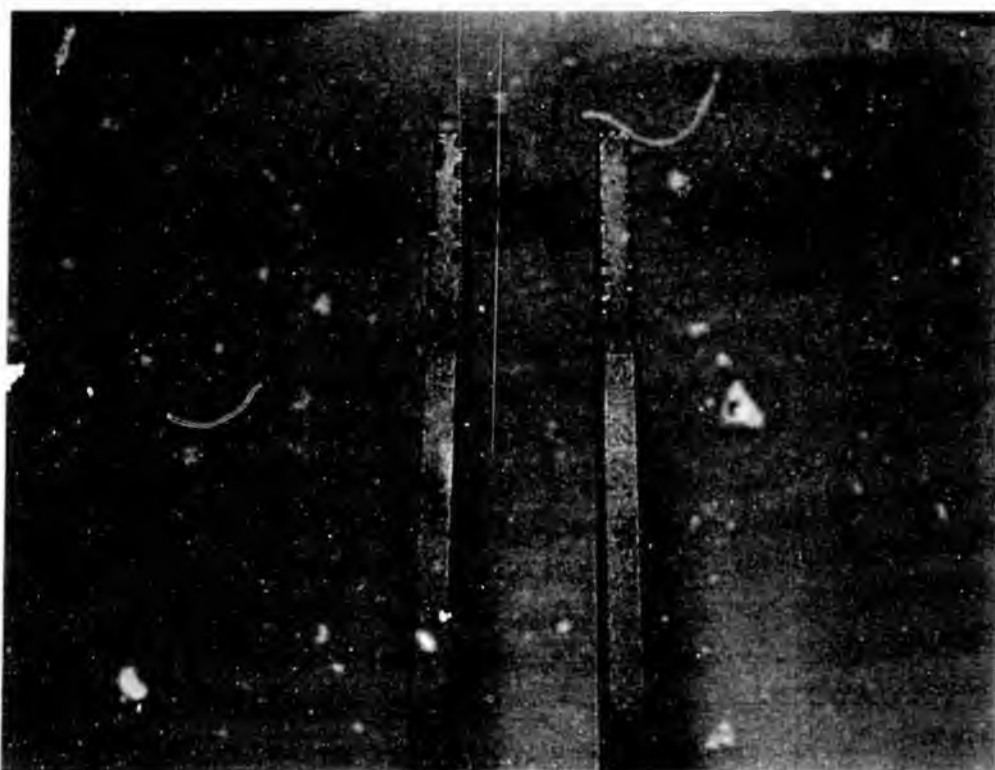


Figure 4 Corrosion coupons pulled after an 'unsuccessful' chemical trial

Appendix 3.3.3 Internal Inspection Program – Scope

This section summarizes the scope and criteria used to determine the frequency of inspection for the internal corrosion inspection program. The over-riding factor in determining inspection intervals is the purpose of inspection based on a combination of equipment condition, corrosion rate, and operating environment. The internal inspection program is sub-divided into four elements, each with a separate purpose and therefore frequency of inspection:

CRM – Corrosion Rate Monitoring: The goal of this program is to detect active corrosion in support of corrosion control activities, primarily the chemical inhibition program. The data are complimentary to other monitoring data, such as corrosion probes and corrosion coupons. As the primary aim is to determine when corrosion occurs, this program is of fixed scope at fixed inspection intervals. For a typical cross-country pipeline, the CRM program includes up to 40 inspection locations which include examples of all locations susceptible to corrosion, such as elbows, girth welds, long seam welds, bottom of lines sections, etc. These locations are each inspected twice per year. The inspections are staggered, with half the set being completed in the 1st calendar quarter and half in the 2nd. These are repeated in the 3rd and 4th quarters, respectively. Therefore, information regarding the level of active corrosion (or lack of) in a pipeline is generated every 3 months. The CRM program covers all cross-country pipelines in corrosive service.

ERM – Erosion Rate Monitoring: The purpose of this program is similar to the CRM but is aimed at monitoring erosion activity. As this damage mechanism is driven by production variables, i.e. production rates and solids loading, it is driven by 'triggers', such as velocity limits, well work, etc. If such triggers are exceeded, inspections are performed on a monthly to quarterly basis until confidence is gained that erosion is not occurring.

FIP – Frequent Inspection Program: The aim of this program is to manage mechanical integrity at locations where significant corrosion damage is detected. Locations are added to the FIP if they are approaching repair or derate criteria or if unusually high corrosion or erosion rates are detected. As the name implies, inspections are performed frequently until the item is repaired, replaced, derated, taken out of service, or corrosion/erosion rates reduced. The inspection interval varies, depending on how close the location is to repair/derate and the rate of corrosion but does not exceed 1 year. All equipment is covered by the FIP.

CIP – Comprehensive Integrity Program: This is an annual program and is aimed at detecting new corrosion mechanisms and new locations of corrosion as well as monitoring damage at known locations. The CIP therefore provides an assessment of the extent of degradation and the fitness-for-service. All equipment is covered by the CIP, although not all equipment is inspected annually.

The scope of the internal inspection program is relatively constant at approximately 60,000 inspection items per year. This includes both field and facility inspections.

Appendix 3.3.4 Corrosion Under Insulation

Corrosion under insulation is primarily associated with water ingress into the pipeline thermal insulation, in particular, at the field-applied insulation joints (weld packs).

The pipelines are generally uncoated carbon steel and are therefore vulnerable to external corrosion under the insulation (CUI) if water comes into contact with the pipe surface. The pipelines are constructed from either single or double joints (40 - 80 ft. long) with a shop-applied polyurethane insulation protected with a galvanized wrapping. The area around the girth welds are insulated with 'weld packs.' The detailed design of weld packs varies but all are prone to water ingress.

Table 7 shows the distribution of insulation joint types based on a sample of ~50,000 locations. For each specified joint type, there is an associated CUI incident rate. These data show there is as much variability in the CUI incident rate between the insulation joint configurations as there is associated with the service type. This suggests that the joint configuration and insulation joint location, along with age, have as much influence on the occurrence of external corrosion at weld-packs compared to the service type and operating temperature.

GPB Joint Design	Joint Type Freq	CUI Incident Rate
Anchor Joint	4.4%	2.8%
Damaged Insul	8.4%	2.0%
Damaged Weld Pack Insul	0.1%	2.4%
EII Anchor Joint	0.1%	6.8%
EII Bottom Elev	3.6%	6.3%
EII Bottom Elev Saddle	0.5%	9.9%
EII Horiz Saddle	1.0%	8.4%
EII Horizontal	10.1%	3.8%
EII Top Elev	2.6%	1.3%
EII Top Elev Saddle	0.3%	4.5%
Mid-Span Weld Pack	56.4%	1.8%
Saddle Joint	11.1%	3.6%
Vertical Joint	0.1%	5.3%
Wall Penetration	1.2%	1.4%
Average CUI Incident Rate		2.5%

Table 7 CUI Incident Rate by Joint Type

The main challenge in managing CUI is the detection of the external corrosion damage. Water ingress into the weld packs is a random process and therefore it is difficult to apply highly specific rules to target the inspection program.

Appendix 3.3.5 Fitness for Service Assessment

The basic fitness-for-service criterion used by BPXA is ANSI/ASME B31G. The base document is the modified B31G, PRC 3-805, which is augmented with additional

requirements defined in BP specification SPC-PP-00090, "Evaluation and Repair of Corroded Piping Systems".

Application of fitness-for-service is best illustrated by the following example and discussion using a typical 24" diameter, 375-mil wall thickness cross-country low-pressure (LP) flow line. The average depth of damage for this example is approximately 24% or 90 mils and average corrosion network length of 8.9". In calculating the corrosion rate to achieve this depth of damage, it was assumed that the corrosion rate is linear since the beginning of field life in 1977.

Figure 5 summarizes the dependence of Maximum Allowable Operating Pressure (MAOP) with the remaining wall thickness of a section of flow line based on ANSI/ASME B31G and is intended to show the multiple-layers of protection to the environment provided by the current fitness-for-service criteria. At the original wall thickness of 375 mils, the example flow line has a B31G calculated MAOP of ~1400 psi. As the wall thickness is reduced by corrosion, this pressure containment capacity is also reduced.

Table 8 shows the MAOP for various wall thicknesses starting from the original wall thickness of 375 mils. It can be seen that the repair criterion used provide a significant level of conservatism over the minimum wall thickness required to retain the maximum operating pressure. In addition, high-level over-pressure protection provides additional protection over the normal operating pressure.

In addition to the depth of damage discussed, there are a number of other considerations that have to be accounted for when assessing fitness-for-service. Some of the concerns are,

Localized/Pitting Corrosion Localized/pitting corrosion consisting of clearly defined relatively isolated regions of metal loss. The axial and circumferential extent of such regions needs to be determined and any potential areas of interaction where there is axial overlap between pitting regions.

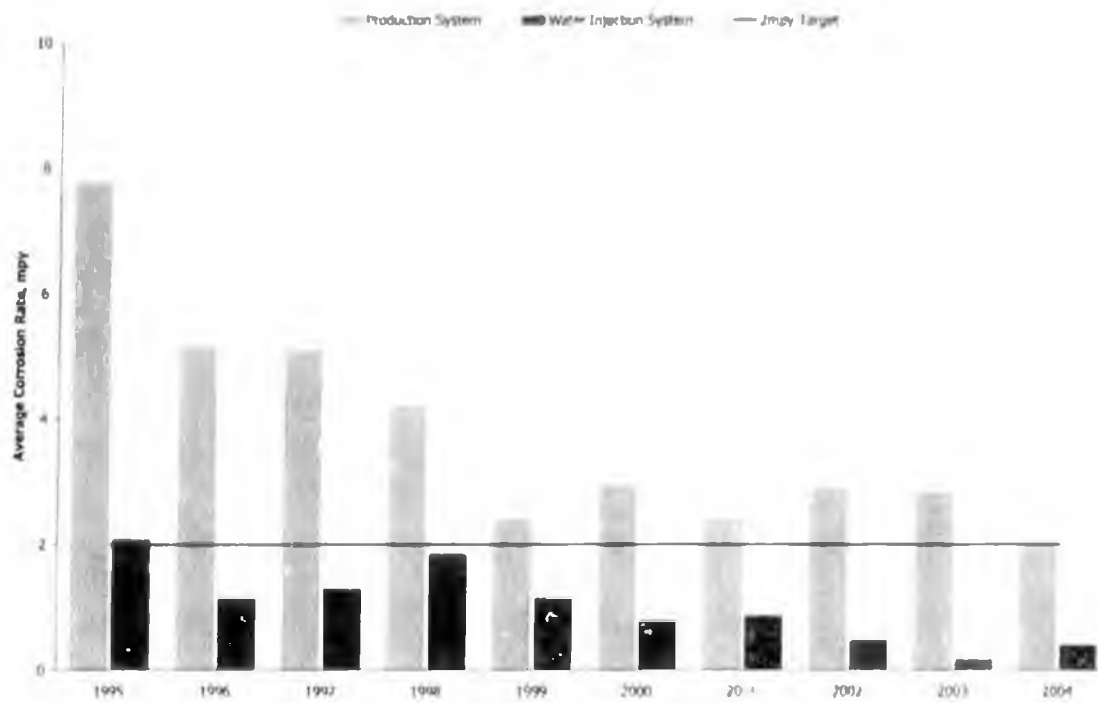
General/Uniform Corrosion General corrosion consisting of widespread corrosion between islands of original material, again, as with pitting corrosion, the axial and circumferential extent of such regions need to be determined. The extent of damage is determined by the boundaries of good or non-corroded material surrounding the damaged area.

Interaction If more than one areas of metal loss exist in close proximity, the possible interaction between these corroded areas needs to be considered. The worst case for interaction of several corroded areas is that a composite of all the profiles within a given metal-loss area needs to be considered.

Critical Dimensions The critical dimensions of metal loss, whether internal or external corrosion damage, need to be determined depending on the corrosion damage morphology described above. The most important dimensions being, the axial or longitudinal length, and the maximum depth of damage.

Evaluation of Corroded Pipe The evaluation of corroded pipe involves determining the remaining strength and safe operating pressure on the basis of the overall axial length, circumferential extent, and maximum depth of the corroded area.

Part 2 – Alaska Consolidated Team Performance Unit



ACT Figure C.1 Endicott Corrosion Coupon Summary

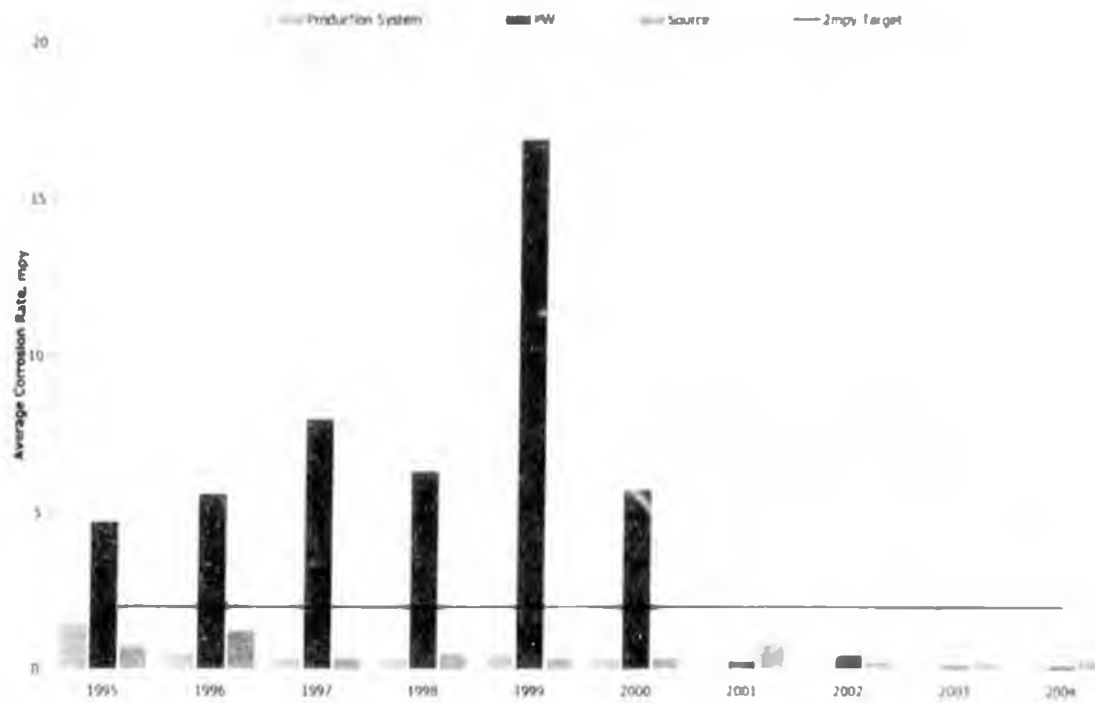
Section C.2 Milne Point

ACT Table C.2 summarizes the corrosion monitoring performance for 2004 and historical data are shown in ACT Figure C.2.

ACT Figure C.2 illustrates the low corrosion rates for the MPU production and water systems. Of concern historically were the relatively higher corrosion rates in the water injection system. These higher corrosion rates led to the initiation of corrosion inhibition in the water injection system in mid-2000. The monitoring results indicate the inhibition is having a positive effect, reducing corrosion rate as the WLC corrosion rates have consistently averaged less than 2 mpy.

System	Access Fittings	%WLC <2 mpy
Production System	26	100%
Water Injection System	6	100%
Source Water Coupons	6	100%

ACT Table C.2 MPU Corrosion Coupon Monitoring



ACT Figure C.2 MPU Corrosion Coupon Summary

Section C.3 Northstar

ACT Table C.3 shows the results of the corrosion monitoring program at Northstar for 2004. There are no historical data prior to 2003.

System	Location	Access Fittings	%WLC <2 mpy
Oil Production			
	Upstream of CI Injection	13	23%
	Downstream of CI Injection	3	100%
Water Disposal			
	Upstream of Mud Addition	9	100%
	Downstream of Mud Addition	2	50%

ACT Table C.3 Northstar Corrosion Coupon Monitoring

The 3-phase production is currently inhibited; however monitoring data continues to indicate the corrosion rates are above the 2 mpy target. This is due to the corrosion monitoring locations being located upstream of the corrosion inhibitor injection location. Monitoring data collected from downstream locations show the inhibition program is

effective in reducing corrosion rates to acceptable levels. The coupons from the upstream locations indicate the need for inhibition of the upstream section. Operations is proceeding with the recommendation to move the corrosion inhibitor injection point further upstream, to the wellhead for the producing wells. Additionally, all new wells will be equipped to inject corrosion inhibitor at the well head.

High corrosion rates in one of the water disposal wells is attributed to oxygenated mud from the grind-and-inject plant. Although an oxygen scavenger has been tested in the grind-and-inject fluids, it was ineffective due to the low fluid temperatures. This system is inspected on a quarterly basis to monitor for active corrosion metal loss.

A second disposal well was added to Northstar in 2004 and the monitoring data indicate the corrosion rate to be <2 mpy, similar to the inhibited portion of the produced water piping. Operationally, this new disposal well has not seen any of the oxygenated fluids.

Section C.4 Badami

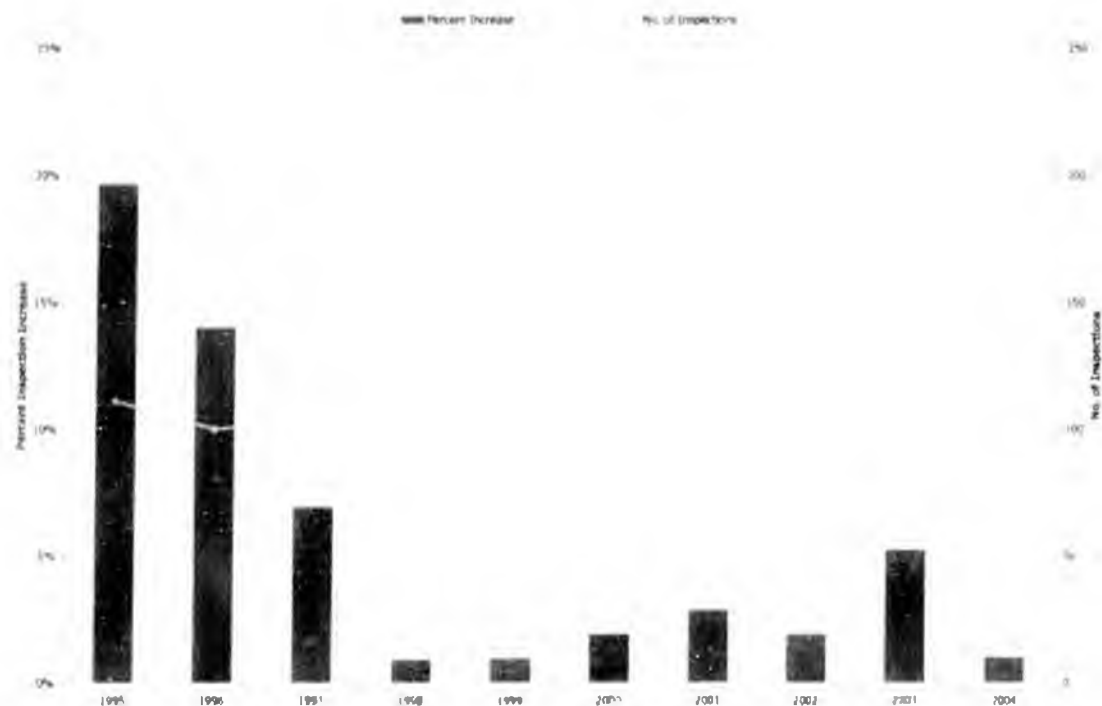
Badami currently has no WLC-monitoring program, but relies on an inspection program presented in Section E.

Section D Corrosion Mitigation Activities

Section D.1 Endicott

Corrosion mitigation for the IIWL had historically relied on maintenance pigging for line cleanliness, biocide treatments to control bacterial activity and continuous injection of a corrosion inhibitor for corrosion control. The primary monitoring tool for effectiveness of these programs is the frequent UT inspection of 25 locations along the pipeline. These UT inspections are repeated quarterly.

ACT Figure D.1 shows the %I's and the number of inspections from 1998 through 2004 for the IIWL. A significant decrease in corrosion activity is shown in 2004 as compared to the previous year. This is attributed to the remedial actions discussed in the 2003 report; which included re-establishing maintenance pigging schedule and increasing the corrosion inhibitor in the system by ~18%.



ACT Figure D.1 Endicott IIWL UT Readings

In late 2004, an additional change was made to the corrosion mitigation efforts to the IIWL. A review of the PW and SW volumes through the pipeline showed the amount of SW for the past few years has been consistently under 10%. Based on this review, the biocide was eliminated and the corrosion inhibitor increased from 20 ppm to 30 ppm (50%).

Maintenance pigging targets were met 100% of the time during 2004.

In the production system, the primary damage mechanism is erosion. The erosion rate is monitored through inspection and mitigated through velocity management. Wells are