ALASKA LEGISLATURE COMMITTEE FILES, 2005-2006 8672

11965 SENATE RESOURCES

year, as shown in Table D.7. As more cost effective chemicals are developed, volumes and concentrations will change depending on the individual product's performance characteristics. There has also been a shift from batch treatments to continuous injection of chemical at the wellhead. The latter is more efficient in terms of protection achieved per gallon of chemical and therefore lower chemical usage would be expected.

The changes directed at developing more cost effective corrosion inhibitors are counteracted by the increasing water cuts associated with an ageing oil field and increased flow velocities due to increased gas handling capacity. These changes generally increase the amount of chemical required to control corrosion. As Figure D.9 shows, the volume of corrosion inhibitor has increased since 1995 while the water volumes have remained relatively constant.

Year	**H_2O Production** 10^6 bbl/yr	**Water Cut**	**CI Usage** 10^6 gal/yr	**CI Concentration** ppm
1995	455	59 %	1.62	85
1996	460	62 %	2.05	106
1997	457	62 %	2.21	115
1998	426	66 %	2.53	141
1999	416	68 %	2.28	130
2000	438	70 %	2.73	148
2001	398	70 %	2.63	157
2002	407	71 %	2.45	143

Table D.8 Summary of the Chemical Usage History at GPB

However, the ultimate measure of whether or not enough corrosion inhibitor is used can only be determined by consideration of other factors such as corrosion monitoring data and/or the amount of active corrosion detected by the inspection program.

The metrics in Figure D.9 deal with chemical usage at the field level but much of the chemical optimization activity focuses on injecting the correct amount of corrosion inhibitor to each piece of equipment. The inhibitor requirement is driven by factors such as water cut, water volume, flow regime, and condition of the equipment and varies over a wide range, from a few parts per million (ppm) to several hundred ppm.

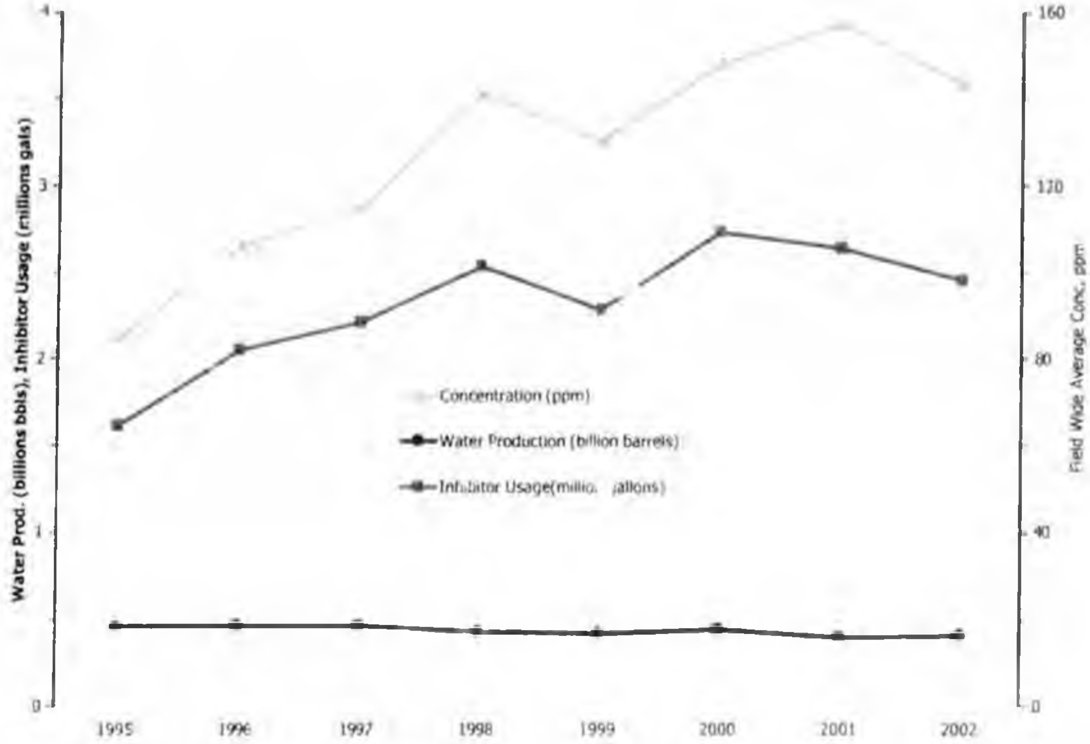


Figure D.9 Field Wide Chemical Usage

For 2002 the target chemical usage was 2.46 million gallons as compared to actual usage of 2.45 million gallons; this represents near perfect performance by the chemical crews for corrosion inhibitor injection in 2002.

Section D.6 Corrosion Inhibition and Corrosion Rate Correlation

As discussed in the section on corrosion monitoring, the reduction in corrosion rates in the 3-phase production system flow lines and well lines is largely attributable to the implementation of an aggressive corrosion inhibition program across GPB.

Figure D.10 shows the correlation between the increased level of corrosion inhibitor and the reduction in average corrosion rate from 1995. As might be expected, the decline in average corrosion rate correlates with the increase in corrosion inhibition levels over time. The inhibition levels have increased approximately 70% from 1995 to 2002, with a field-wide average concentration of 85 ppm to 143 ppm. As a result the corrosion rates have fallen from 1.4 mpy in 1995 to 0.3 mpy in 2002.

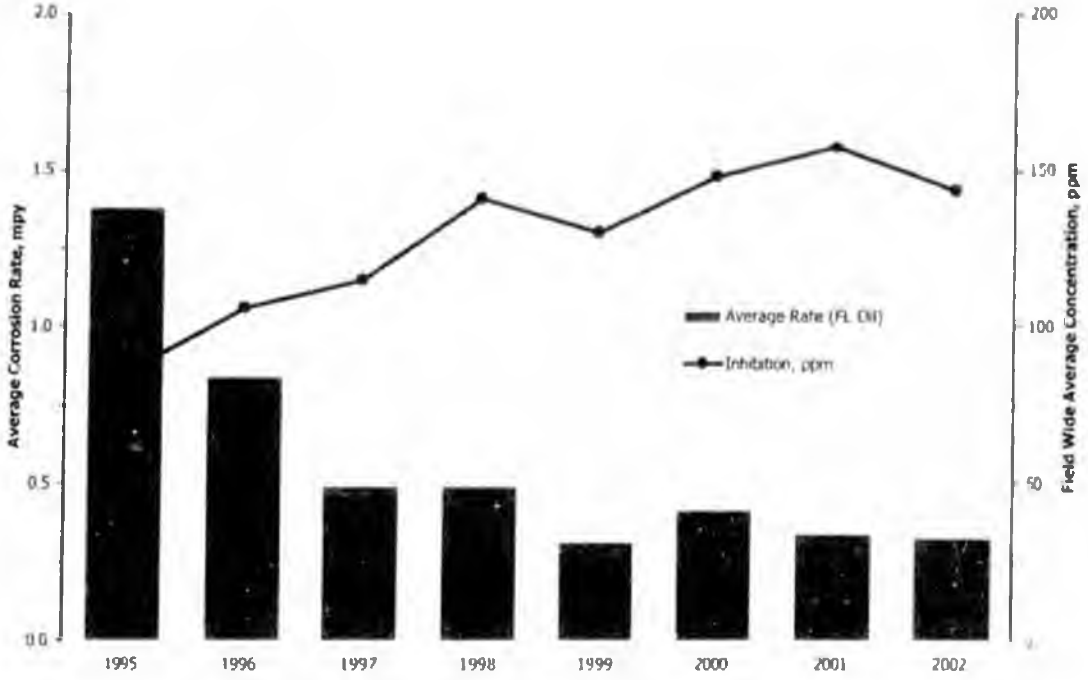


Figure D.10 Average Corrosion Rate Versus Inhibitor Concentration

Figure D.11 shows the annual field-wide average corrosion inhibitor concentrations and annual average corrosion rates for 3-phase production flow lines plotted against each other. The figure shows how the additional corrosion inhibitor has reduced the corrosion rate through time, but also shows an inherent limitation of corrosion inhibition as the minimum corrosion rate (or maximum corrosion inhibitor efficiency) is approaching an asymptote of ~0.25 mpy.

Section D.7 ER Probe and Corrosion Inhibitor Response

This section of the report 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 major 3 phase production flow lines.

ER probe data is automatically stored 8 times per day (or every 3 hours) using battery powered data loggers. The data is downloaded weekly and then transferred to the corrosion and inspection database once per week for analysis.

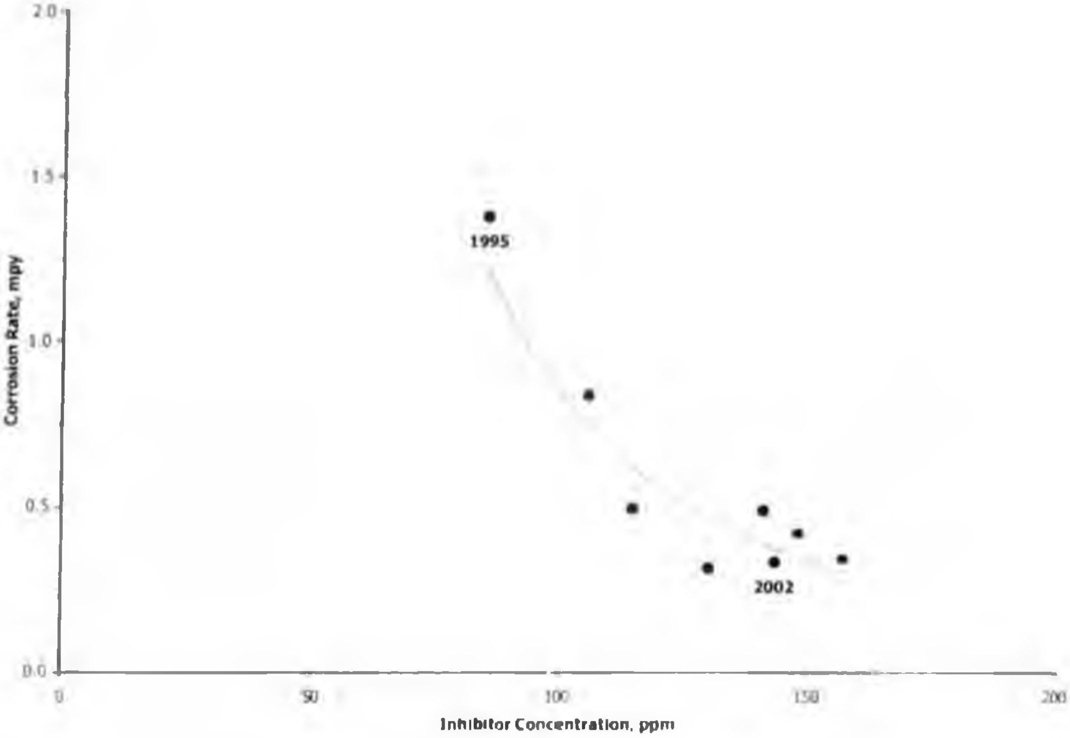


Figure D.11 Corrosion Inhibitor Concentration vs. Corrosion Rate

Figure D.12 (a) and (b) gives an example of the use of ER probes in managing changing corrosion conditions in A-74, one of the large diameter flow lines at GPB. Figure D.12 (a) shows the ER probe readings and derived corrosion rates, over a period of approximately 6 months. For the first 2 months the measured corrosion rate is less than 2 mpy However, in mid-July there is a significant increase in corrosion rate that triggers action. Initially, the response is to conduct a detailed review of the critical operational parameters such as the corrosion inhibitor injection rates, production history, fluid velocity, inspection results and other monitoring information.

Following the initial data review, further ER probe data shows that the increasing corrosion trend is continuing and as a consequence the corrosion inhibitor concentration is increased 10% from 128 ppm to 141 ppm.

With the increase in corrosion inhibitor concentration, the corrosion rate is significantly reduced. This corrosion rate reduction is clearly demonstrated by the long-term corrosion rates derived over several months of ER probes data. This long-term data is shown in Figure D.12 (b) and summarized in Table D.13.

The data in Table D.13 clearly shows the long-term effectiveness of the corrosion inhibitor increase with the corrosion rate in the flow line remaining below 1 mpy for the 4-month period following the 10% inhibitor concentration increase.

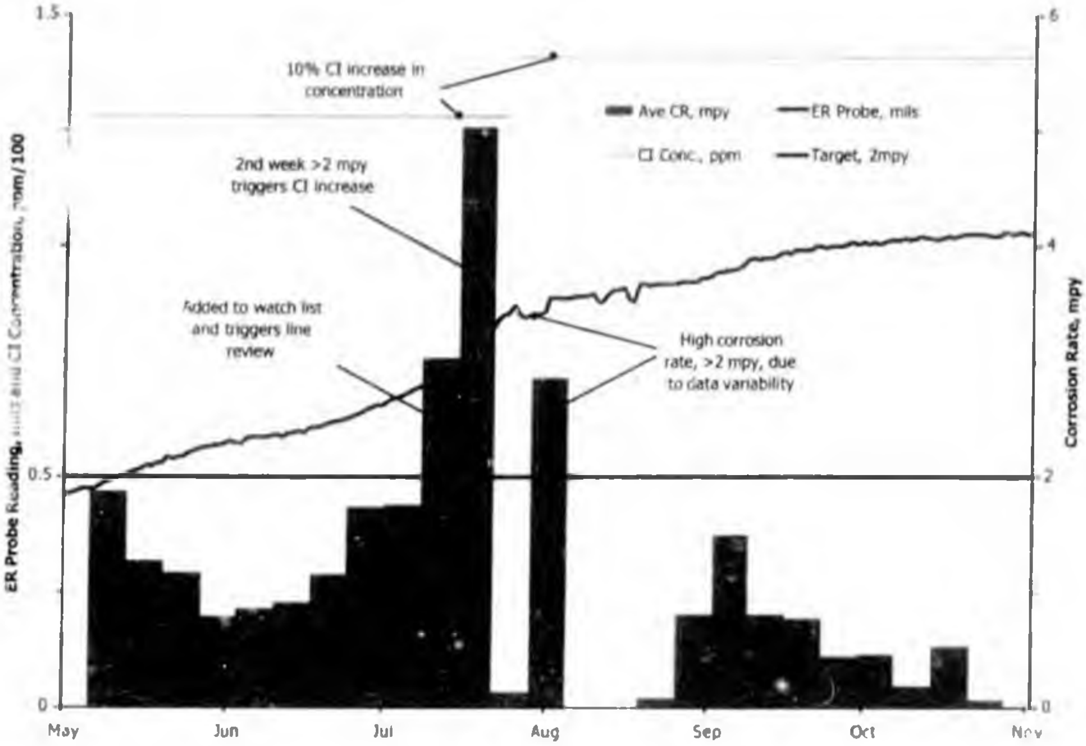


Figure D.12 (a) Corrosion Inhibitor Concentration vs. Corrosion Rate

Time Period	CR, mpy	Comments
6-May to 7-July	1.1	Corrosion rates consistently below target rate of 2 mpy
8-July to 28-July	3.3	Corrosivity of the flow line increasing over successive weeks. Corrosion inhibitor concentration increased 10%.
29-July to 22-Sept	0.9	Corrosion rates fall below target level following increase in corrosion inhibitor concentration.
22-Sept to 27-Sept	0.3	Continued corrosion control below target corrosion control level of 2 mpy

Table D.13 Corrosion Inhibitor Concentration vs. Corrosion Rate

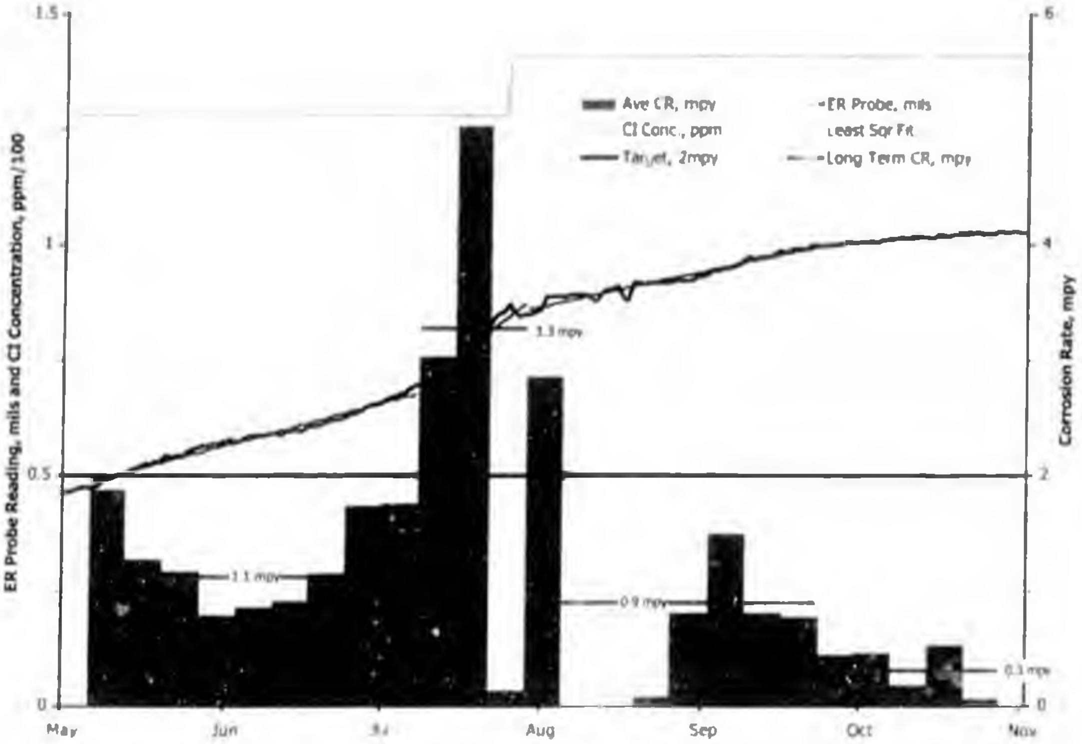


Figure D.12 (b) Corrosion Inhibitor Concentration vs. Corrosion Rate

Section D.8 Chemical Optimization Developments

Historically tank levels or tank strapping has been recorded manually in the Chemical Operators' logbooks. This manual process has made access to chemical usage data for individual lines difficult. With the advent of handheld data recorders and bar-code readers, the corrosion inhibitor management program at GPB is moving toward an electronic system for managing chemical usage and tank strap reading data.

Starting 2Q 2002, the major corrosion inhibitor tanks have been individually identified and bar-coded and the Chemical Operators assigned handheld data recorders with a built-in barcode reader. This enables the operators to uniquely identify tanks and enter the tank strap reading directly into the handheld device and hence download into the database without the need to transcribe the information.

The automated uploading of chemical usage information into the database eliminates a number of manual steps during which the data was consolidated and transcribed resulting in numerous transcription errors. The improved quality and quantity of data will allow for more efficient and effective corrosion inhibitor usage and management in the future.

In particular, pad level injection rates should more closely match the targeted value providing better corrosion management. Also with better visibility into the tank level data, there will be a more capable inventory management providing for just-in-time delivery to individual tanks, reducing the number of deliveries, and hence the numbers of fluid transfer operations. The reduced number of fluid transfer operations reduces the potential for spills and leaks associated with tank filling operations.

An example of the data that is now available is given in Figure D.14. The figure shows the tank strap reading history for C-Pad fluids that flow into GC-3 via a 24" diameter flow line. This and similar data sets will allow for much improved and consistent levels of corrosion inhibitor injection for the future.

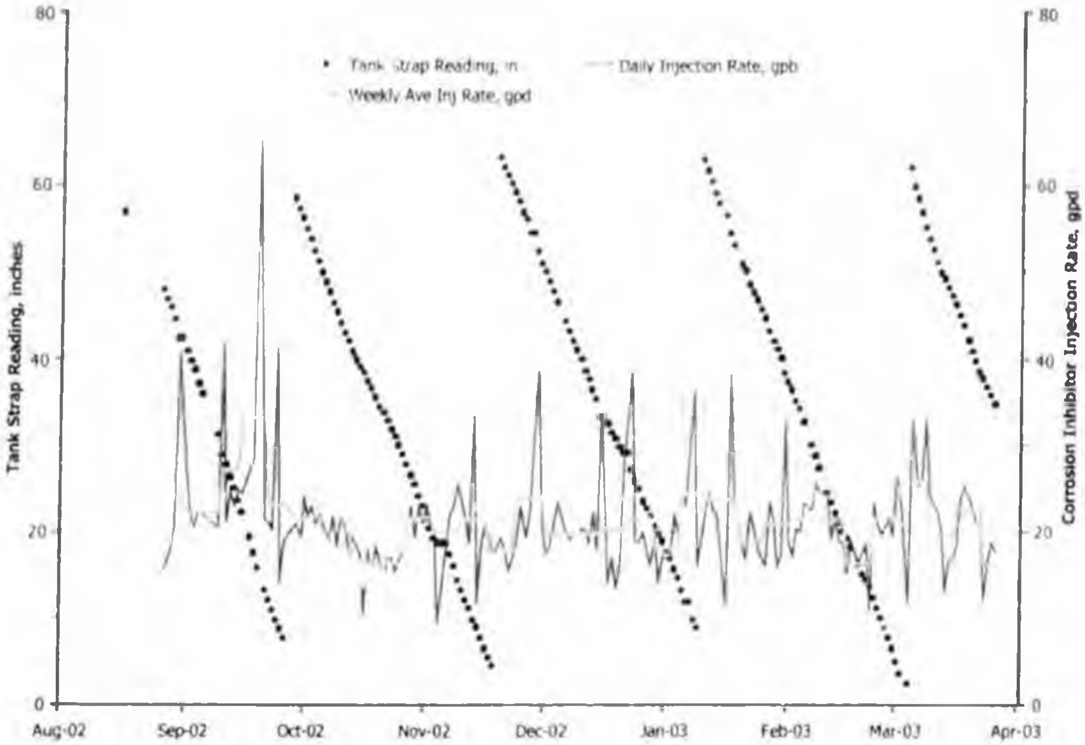


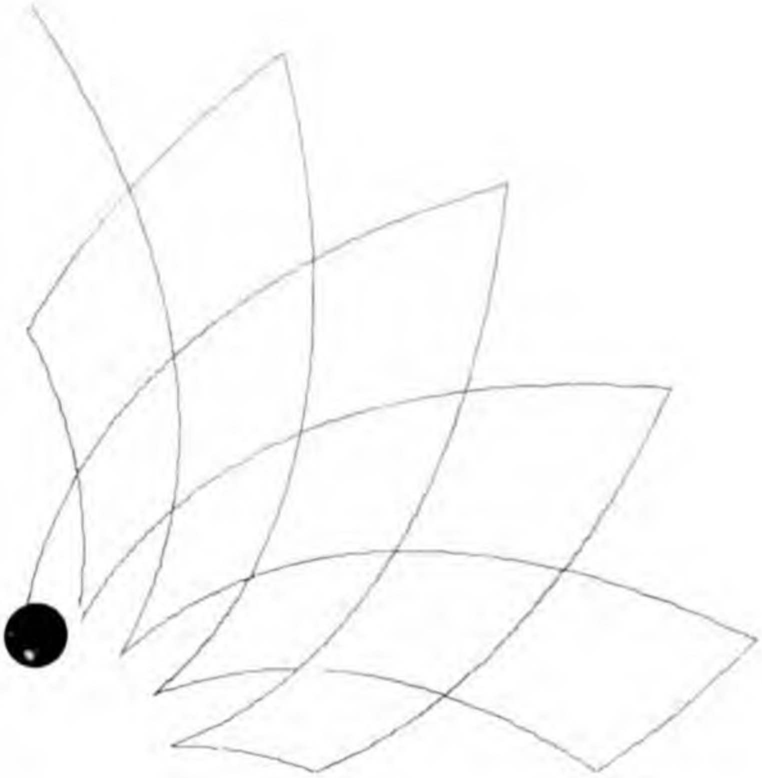
Figure D.14 Tank Strap Reading and Inhibitor Usage

Section D.9 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 particular applications. The details for these techniques are shown in Table B.12 (c).

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. Details of the individual inspection programs are provided in Table B.11 (c). The inspection program is one element in the overall integrity management of equipment in GPB.

Section E.1 External Inspection

This section summarizes the inspections performed to detect external corrosion and the results of those inspections. External corrosion is primarily associated with water ingress into the thermal insulation of pipelines at GPB, in particular, at the field-applied insulation joints.

The pipelines are generally uncoated carbon steel and are therefore vulnerable to external corrosion if water comes into contact with the outer surface of the pipe. 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 to a greater or lesser extent.

The main challenge in managing Corrosion Under Insulation (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.

In order to detect CUI, a recurring screening program has been implemented as the best method to identify equipment and locations at risk. Prioritization of inspection surveys is determined by configuration, average temperature of the equipment, age of equipment, and/or the last time a complete screening process was completed. If screening has been completed, sites are revisited at prescribed intervals. As a result of findings from the screening process, the extent or recurring frequency of any additional examinations is determined.

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.

Section E.1.1 External Inspection Program Results

Table E.1 and Figure E.2 show the number and results of the external corrosion inspections performed between 1995 and 2002. The data includes all the Tangential Radiographic (TRT) techniques applied to external corrosion, including Automated-TRT (ATRT), and C-Arm Fluoroscopy (CTRT).

	1995	1996	1997	1998	1999	2000	2001	2002
Well Line								
Activity Level	-	36	1680	946	2376	5233	13122	23797
Corrosion Detected	-	6	234	66	72	242	711	345
%Corroded	-	17%	14%	7%	3%	5%	5%	1%
Flow Line								
Activity Level	1508	11472	17934	10315	8119	5179	3963	18931
Corrosion Detected	245	763	1491	763	546	253	103	692
%Corroded	16%	7%	8%	7%	7%	5%	3%	4%
GPB Overall								
Activity Level	1508	11508	19614	11261	10495	10412	17085	42728
Corrosion Detected	245	769	1725	829	618	495	814	1037
%Corroded	16%	7%	9%	7%	6%	5%	5%	2%

Table E.1 External Corrosion Activity and Detection Summary

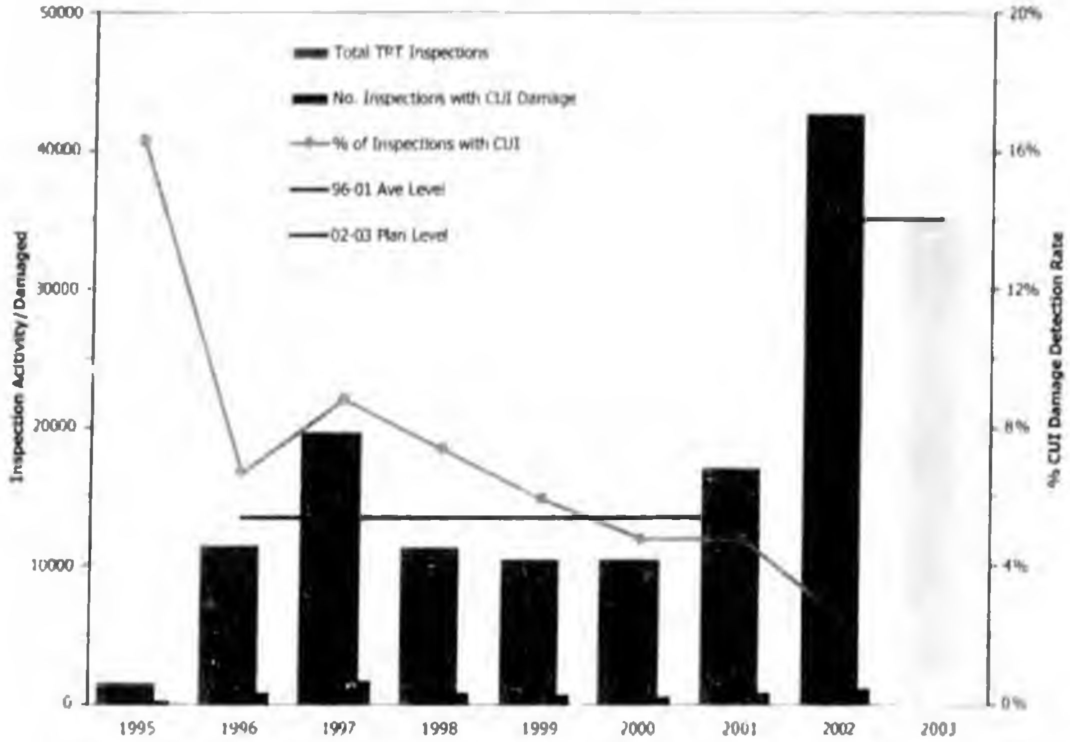


Figure E.2 External Corrosion Activity and Detection Summary

Table E.1 and Figure E.2 summarize the annual level of CUI inspection activity, the number of damaged locations found through the inspection program, and the percentage of inspected locations that exhibited damage. In general, the inspection levels over the period 1996 to 2001 remained relatively constant at an average of ~13,000 per year. The inspection level in 2002 was greater than three times the historical average and ~43,000 inspections were completed. In contrast, the percentage of locations found with damage has fallen from an initial high of >15% to a field-wide average of ~2%.

Table E.3 summarizes the CUI inspection program for the period 1995 to 2002 broken out by service and equipment type, well line and flow line, and the aggregate of both data sets.

The data suggests that there is some dependence of external corrosion occurrence based on service type with the Processed Oil (Export) showing a lower rate of occurrence of 3% compared to water injection service (Water) with an occurrence rate of 9%. This difference is driven in part by the difference in temperature between these services. However, as much variability in damage occurrence is found based on the location and orientation of the weld-pack location.

	Flow Line			Well Line		
Service	**# Insp.**	**# Corr**	**% Corr**	**# Insp.**	**# Corr**	**% Corr**
3 Phase	24350	1728	7%	30964	1266	4%
Export	312	10	3%	-	-	-
Gas	40335	1743	-	11007	177	0%
Other	41	2	5%	187	22	0%
Water	12383	1373	11%	5032	211	4%
Total	77421	4856	6%	47190	1676	4%

	Aggregate		
Service	**# Insp.**	**# Corr**	**% Corr**
3 Phase	55314	2994	5%
Export	312	10	3%
Gas	51342	1920	0%
Other	228	24	11%
Water	17415	1584	9%
Total	**124611**	**6532**	**5%**

Table E.3 CUI Inspections by Service Type

Table E.4 shows the distribution of insulation joint types based on a sample of approximately ~50,000 locations. For each of the specified joint types, there is an associated CUI incident rate. The overall average CUI incident rate for the sample was 2½% that is consistent with average find rate for the 2002 data set shown in Table E.1.

From Tables E.3 and E.4 it can be seen that 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 hence 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%
Ell Anchor Joint	0.1%	6.8%
Ell Bottom Elev	3.6%	6.3%
Ell Bottom Elev Saddle	0.5%	9.9%
Ell Horiz Saddle	1.0%	8.4%
Ell Horizontal	10.1%	3.8%
Ell Top Elev	2.6%	1.3%
Ell 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 E.4 CUI Incident Rate by Joint Type

Section E.1.2 Cased Piping Survey Results

Table E.5 shows cased pipe segments inspected in 2002. Potential metal loss areas are reported as anomalies and severity is semi-quantified as minor, moderate, or significant.

The 2002 scope included examination of segments that had not previously been inspected as well as the on going monitoring of reported anomalies from prior years' testing. The near-term strategy for management of cased pipe segments is to complete an initial inspection baseline of all GPB cased piping by year-end 2003. In accordance with the agreement with ADEC, 2002 was year 4 of a 5-year program to complete a baseline inspection on all cased piping segments. To date, baseline inspections have been completed on approximately 80% of the piping segments, which is on track to complete the program by year-end 2003.

Additionally, all cased piping road crossings are visually inspected annually during the summer months. Mitigation includes removal of any material, i.e. debris, gravel, dirt, from the casing ends.

Service	Technique	Segment	Minor	Moderate	Significant	Anomaly Action
3 Phase	E-Pulse	90	27	-	6	Proof/Monitor G-Wave
	G-Wave	27	13	7	-	Monitor Guided Wave
PW/SW	E-Pulse	20	1	-	1	Proof/Monitor G-Wave
	G-Wave	11	-	9	-	Monitor G-Wave
Gas	E-Pulse	95	15	-	22	Proof/Monitor G-Wave
	G-Wave	19	11	5	-	Monitor Guided Wave
PO	E-Pulse	6	2	-	1	Proof/Monitor G-Wave
	G-Wave	1	1	-	-	Monitor G-Wave
Total		**269**	**60**	**21**	**30**	

Table E.5 2002 Cased Pipe Survey Results

Figures E.6, E.7 and Table E.8 show the cased piping inspection activity level over the last 6 years. As can been seen in the graphic, the activity level has been fairly consistent since 1999, delivering approximately 280 cased pipe inspections per year.

The total inventory of ~1400 pipe segments consists of cased road and animal crossings for well and flow lines which are in active service, it does not include abandoned or out of service pipe segments. It is anticipated by year-end 2003 all in-service cased piping segments will have been examined. However, some level of activity, to include monitoring or repeat examinations and possibly excavation, will continue into future years.

Electrical Pulse inspection technique had an increase in the number of significant anomalies reported in 2002 against the historical average. These anomalies are thought to be a result of the service provider making changes to the procedures and analysis methods employed in 2002. The provider of the Electrical Pulse technology has acknowledged the potential increase in false-positive indications reported in 2002 and is working to improve the analysis and identification of electromagnetic anomalies that are associated with corrosion. Each of these anomalies will be re-examined using guided wave and/or re-employment of electrical pulse inspection in order to verify the presence or otherwise pipe wall loss of an active corrosion mechanism.

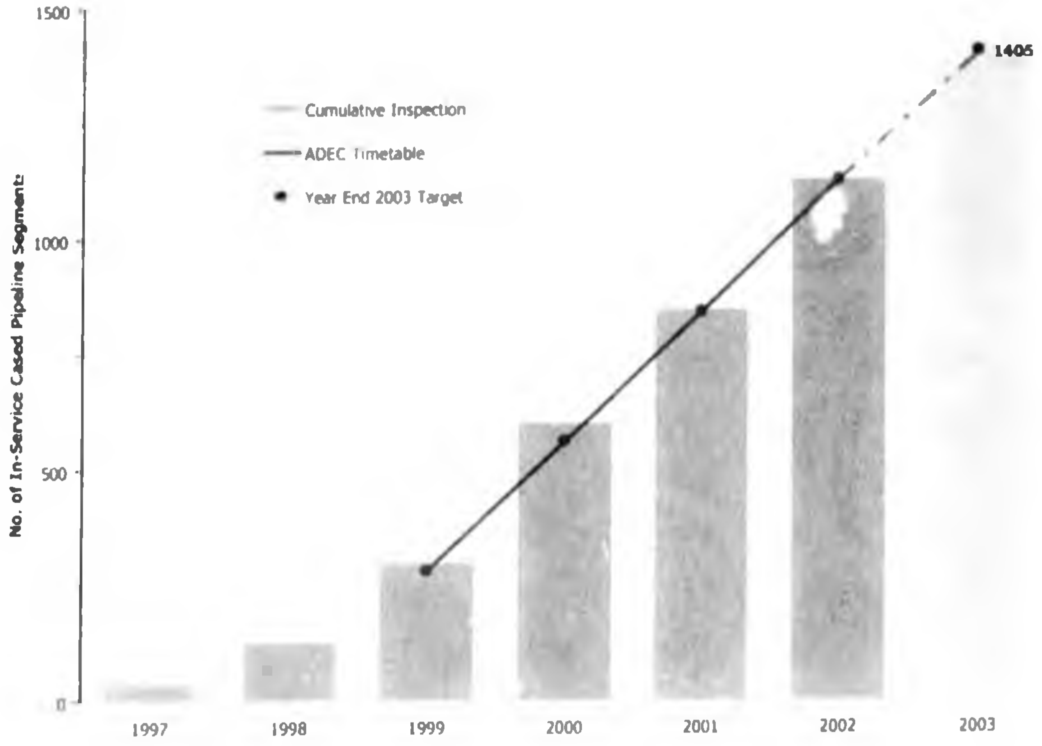


Figure E.6 Cumulative Cased Pipe Inspection Activity from 1997 to 2002

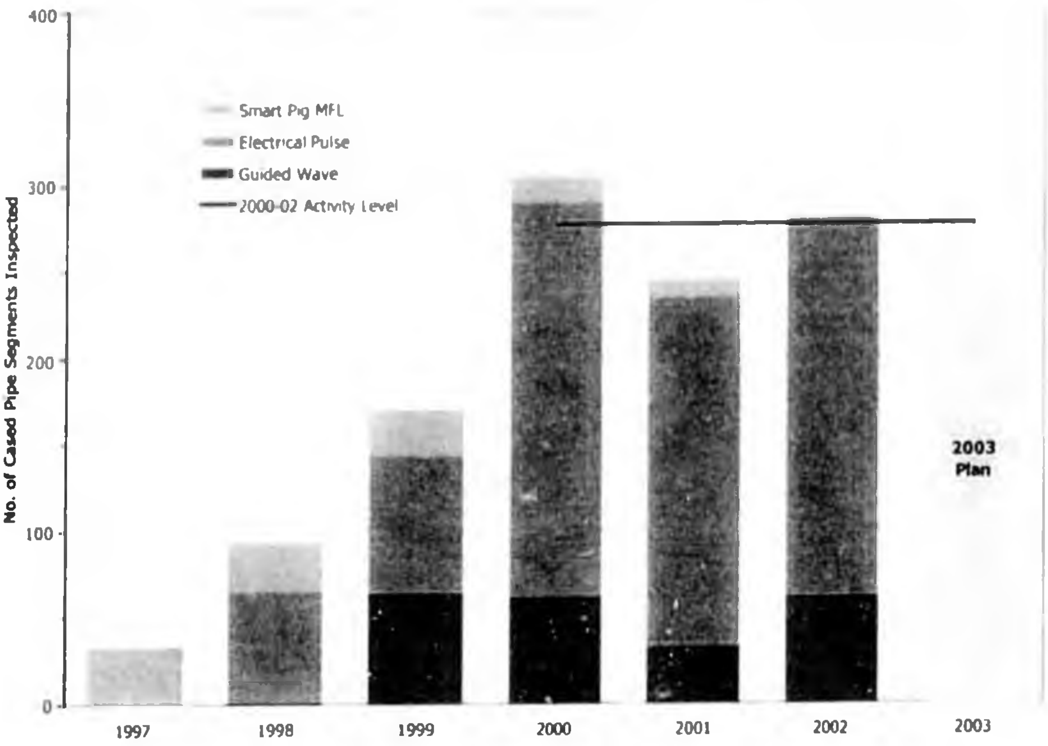


Figure E.7 Cased Piping Inspection History by Detection Method

Method	1997	1998	1999	2000	2001	2002
Guided Wave	-	1	64	62	33	62
Electrical Pulse	-	64	80	228	202	218
Smart Pig (MFL)	33	28	26	15	10	-
Total	**33**	**93**	**170**	**305**	**245**	**280**

Table E.8 Cumulative Cased Pipe Inspection Activity from 1997 to 2002

In summary, the cased piping survey activity level has been consistent over the last 5 years with the commitment to deliver a base line survey by year-end 2003. The cased piping inventory has been inspected using a number of different techniques including guided wave, electrical pulse, and MFL smart pigging. The 2003 program is expected to be at the same level as 2002 at approximately 280 cased pipe segments for the year. It should be noted that having completed the base line survey the intent for future years, 2004 and beyond, is to move the program to the next phase consisting of repeat examinations and monitoring.

Section E.1.3 Excavation History

There have been 25 cased pipeline segments at road and/or animal crossings excavated over the last 10 years at GPB. Of the 25 excavations, 1 was as a result of loss of pressure containment, the remaining 24 excavations resulted from inspection observations.

Table E.19, at the end of Section E, shows that 20 of the segments excavated were found with corrosion damage and 4 were found with no corrosion damage. The identification of potential damage areas through the inspection program and subsequent actions of monitoring and/or excavation, gives confidence that even pipe segments that our for the most part inaccessible, can be effectively managed to minimize loss as a result corrosion degradation.

Section E.1.4 External Program Summary

In summary, the level of activity directed at external corrosion has been relatively constant between 1996 and 2001 at approximately 13,000 locations per year. However, through the review process it was recognized that there was a potential that the level of risk of failure could increase as the field ages and therefore the GPB partners have decided to fund an additional level of inspection for 2002 and 2003. The activity level for 2002 was considerably greater than prior years at approximately 43,000 inspection locations. The activity level for 2003 is expected to be 35,000 inspections.

The cased piping program is on-track to complete the initial base line survey by year-end 2003. At this time the program will move into a new phase of monitoring, corrective action and repair.

Section E.2 Internal inspection

Section E.2.1 Internal Inspection Program – Scope and Results

This section summarizes the scope and results of the internal corrosion inspection program. The detailed objectives for the inspection program are given in Table B.11 and are summarized in Table E.9.

CRM	**Corrosion Rate Monitoring** Detection of active corrosion in the production and injection system in support of the corrosion mitigation and management programs
ERM	**Erosion Rate Monitoring** Similar to the CRM program but in support of the erosion management and velocity management programs
FIP	**Frequent Inspection Program** The aim of this program is to manage the mechanical integrity of locations which have significant damage based on proximity to repair criteria and/or unusually high corrosion rate
CIP	**Comprehensive Inspection Program** An annual program aimed at detecting new corrosion mechanisms by examining new locations, searching for damaged locations under known mechanisms and the monitoring of known damaged locations

Table E.9 Internal Inspection Programs

The results presented are the aggregate of the data obtained for all of these programs for flow lines and well lines. The results of the inspection program are presented in terms of the number of locations that showed 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.

Figure E.10 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 (OIL) and water injection (seawater and produced water) service.

UT is considered the most appropriate for wall thickness determination for the large diameter water pipe work. Because of internal fluid density the sensitivity of RT is too low to accurately access corrosion increases. The damage is detectable by RT, but because of the relatively short inspection interval the change in wall thickness or corrosion rate is difficult to access. UT provides the sensitivity for a shorter inspection interval than does RT.

The percentage of inspection increases in the 3-phase system has declined considerably from 1997 to 2002. There was a slight increase in the %I's in 2001 and 2002 on flow lines compared to 2000, which reflects the increase in corrosion rates detected in the coupon monitoring program during 2000. But, because the inspection program is a lagging indicator of corrosion control, given the decline in average corrosion rates in 2001 and 2002 realized through the monitoring data, it is expected that the percentage of inspection increases will decrease in 2003. The long-term 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.

The increased corrosion activity in the water injection system reflects the increasing corrosion trends already discussed in the corrosion monitoring section. As noted, there is a strong corrective action plan in place to address the corrosion in the water injection system and it is expected that the increase in corrosion activity shown in the 2001 and 2002 inspection data will be reduced in 2003.

Figure E.11 shows the inspection increases trend and the number of inspections per year for the well lines.

For the 3 phase well lines in the long term, there is a decrease in corrosion activity as measured by the percentage of inspection increases. This is the same trend as seen in the flow lines. In the short term, however, the slight increase in corrosion activity seen in the flow lines is not reflected in the well line data although this minor discrepancy is not considered significant.

For the water system, corrosion activity is seen to be declining from 1995 through 2000. However, as with the flow lines, there has been an increase in activity in the well line data.

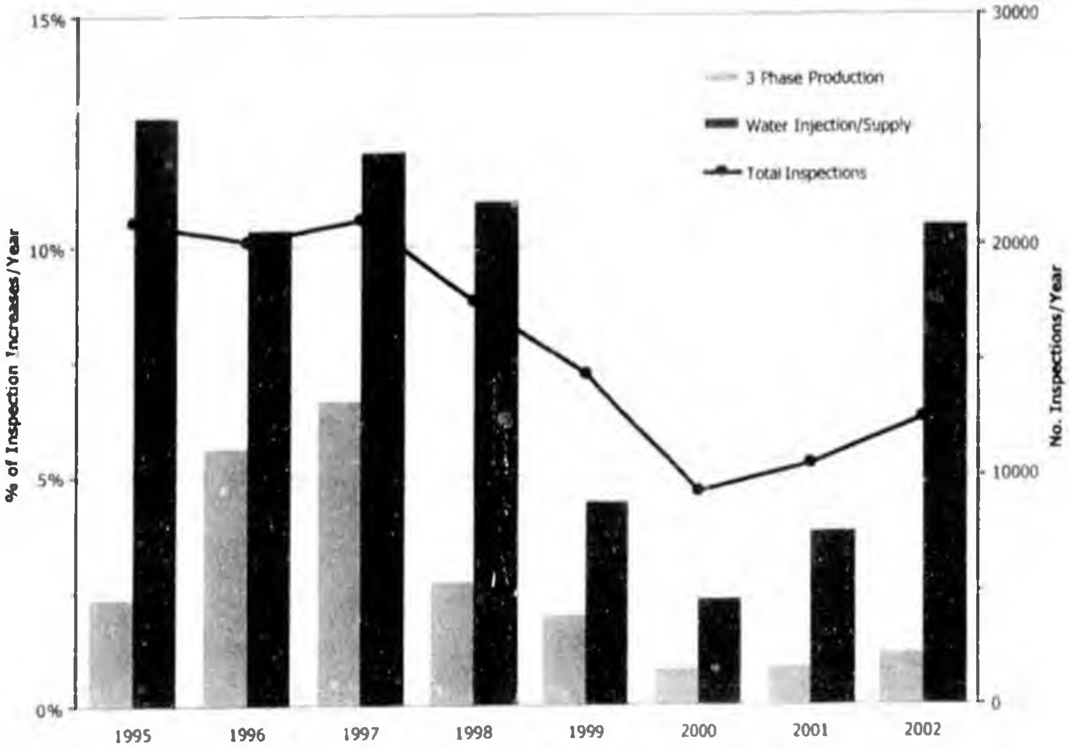


Figure E.10 Flow Line Internal Inspection Increase by Service

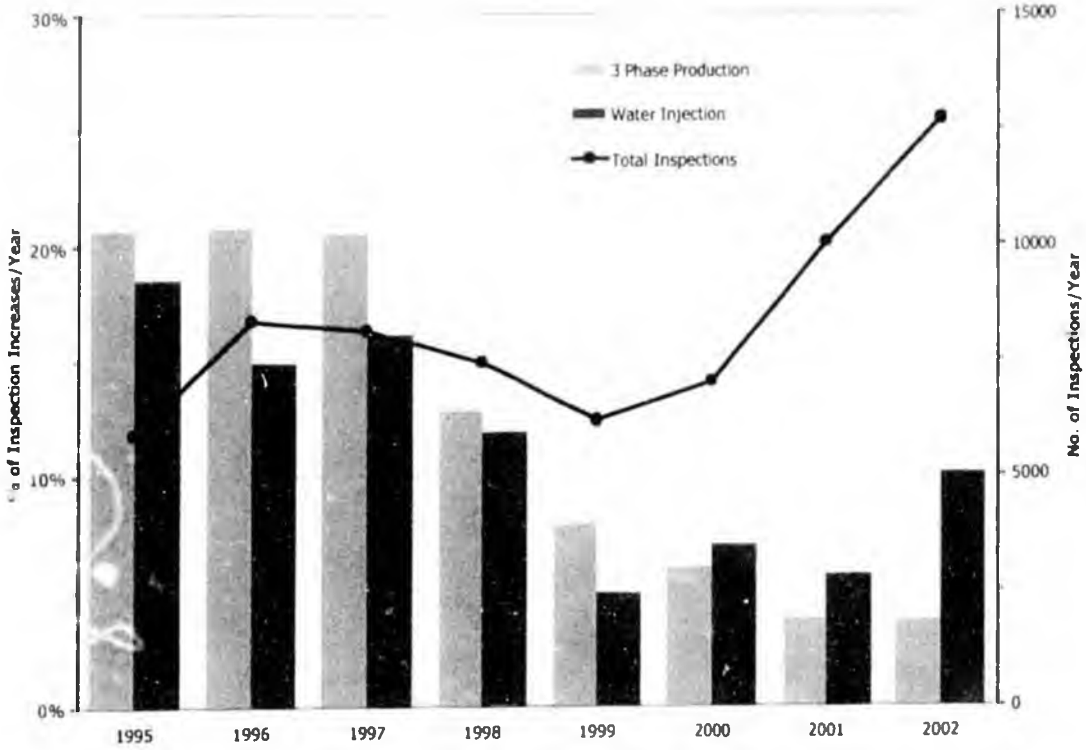


Figure E.11 Well Line Internal Inspection Increase by Service

In summary, the long term trends in the for the 3-phase production system are very similar for both the flow lines and the well lines. In each case the level of corrosion activity has dropped dramatically from the mid-1990's to the levels which have been seen over the last two years. In the water systems, again, there is significant correlation between the trends in the flow lines and those in the well lines. In each case, the level of corrosion activity has fallen from the mid-1990's through 2000/2001. However, since 2001 there has been an increase in the level of corrosion activity in the seawater system as discussed in detail in Section C Corrosion Monitoring.

Section E.2.2 Internal Inspection Intervals

This Section describes the criteria used to determine the frequency of inspection. Many factors determine the interval between successive inspections. The overriding 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 is 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.

Section E.3 Fitness for Service Assessment

The basic fitness-for-service criterion used by BP is ANSI/ASME B31G. The bas 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".

Figure E.12 (a) and E.12 (b) summarizes the dependence of Maximum Allowable Operating Pressure (MAOP) with the remaining wall thickness of a section of flowline based on ANSI/ASME B31G. The example and discussion below is for a typical cross-country 24" diameter low-pressure (LP) flowline. The same ANSI/ASME B31G criteria are applied to remaining flow and well lines with the appropriate characteristics and parameters substituted from the example below.

Figure E.12 and the subsequent explanation are 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, a typical flow line has a B31G calculated MAOP of ~1400 psi. As the wall thickness is reduced by corrosion, this pressure containment capacity is reduced.

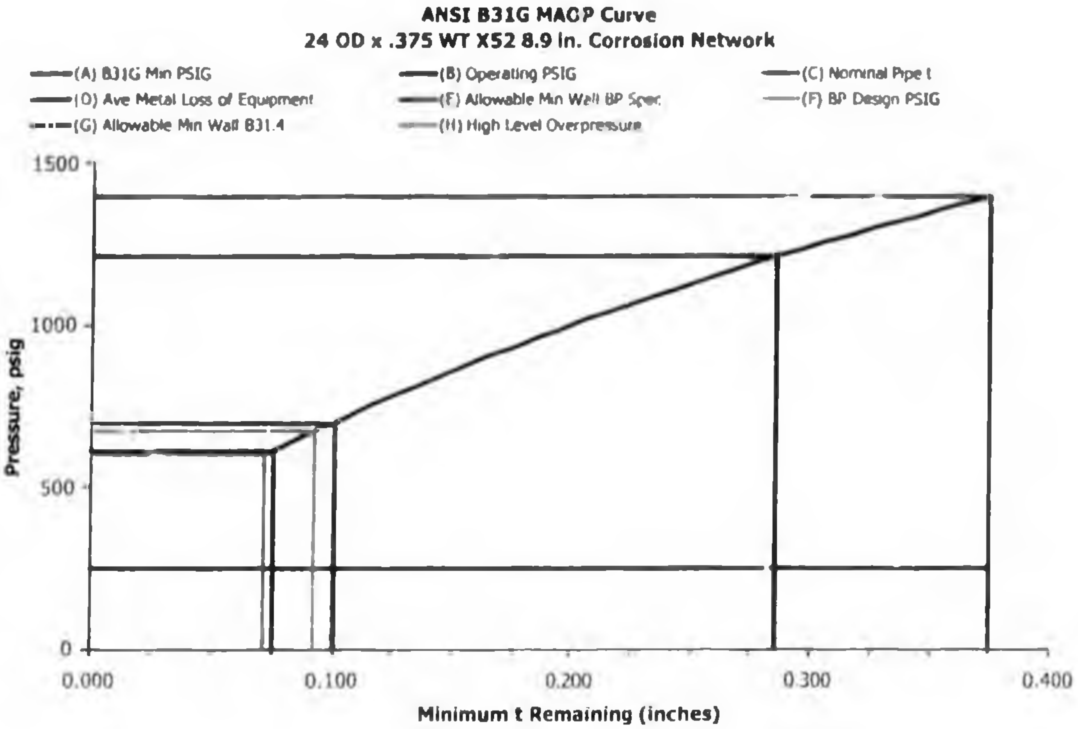


Figure E.12 (a) MAOP versus Remaining Wall Thickness

	Legend	Description/Comments
(A)	B31G Min PSIG	The relationship between maximum allowable operating pressure, MAOP, as given by B31G and the remaining wall thickness
(B)	Operating PSIG	The normal operating pressure for a typical low pressure common line or flowline (CL/LDF)
(C)	Nominal Pipe t	The original nominal pipe wall thickness which for this example is 0.375" (375 mils) as is the case for many of the flow lines at GPB
(D)	Ave metal loss	From the inspection data an average pit depth or depth of damage across the field for the 24" LP OIL flow lines
(E)	Min Wall BP Spec	The minimum wall thickness, 0.100", which is permitted under BP specification SPC-PP-00090 for the management of corroded pipework. Any location at or below this level is actioned regardless of the calculated MAOP
(F)	BP Design PSIG	The original design pressure that the pipe wall thickness was designed to retain
(G)	Allowable Min Wall	Allowable minimum wall thickness under B31 below which a repair is mandated by code
(H)	High level P protection	High level over-pressure protection for the LP systems as either a pressure switch or the PSV's on the separator/slugcatcher

Figure E.12 (b) MAOP versus Remaining Wall Thickness – Legend

Table E.13 shows the MAOP for various wall thicknesses starting from the original installed wall thickness of 375 mils. From Figure E.12 and Table E.13, 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.

Step	t, mils	MAOP	Curve	Description
1	375	1395	(C)	As constructed pipe condition with no corrosion or degradation of wall thickness
2	285	1209	(D)	After 25+ years of service the average wall loss for the flow line system is 24% or 90 mils and has a MAOP of 1209 psi. This is an equivalent corrosion rate of ~4 mpy. At the average corrosion rate seen to date, in approximately 50 years the wall loss will be such that it reaches the repair criteria in Step 3. Note that the target corrosion rate is 2 mpy to provide additional protection and scope for extended field life.
3	100	700	(E)	The BP repair criterion from BP Specification SPC-PP-00090 is 100 mils with an MAOP of 700 psi. This repair criterion is 25 psi above the design pressure and 25 mils or 33% above minimum wall thickness defined by code B31G giving significant level of additional protection
4	95	675	(F)	The original system design pressure
5	75	614	(G)	The minimum wall thickness allowed under B31G for this application which is 80% wall loss regardless of pressure
6	71	600	(H)	High level over-pressure protection for the low pressure production system at Greater Prudhoe Bay
7		250	(B)	The normal operating pressure for the system

Table E.13 Thickness, MAOP Correlation

The fitness-for-service example illustrated above is for a 24" diameter low-pressure flow line. For this system the average depth of damage for cross-country oil line 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 had happened since the beginning of field life in 1977.

Section E.3.1 FFS Interaction Between Length and Depth

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 in the extent of corrosion damage needs to be determined.

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 limits of the extent of damage being 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.

Figure E.14 illustrates the FFS envelop for a combination of depth and length of defect as defined in BP Specification SPC-PP-00090. As can be seen from the curve, the criteria for allowable operating service condition is more conservative than the industry standard at the low end of the remaining wall thickness. This conservatism reflects two issues, (a) the need to provide a margin for error in the determination of wall thickness and corrosion rate, and hence remaining life, and (b) the decreased accuracy of the NDE techniques in use at a wall thickness of less 100 mils.

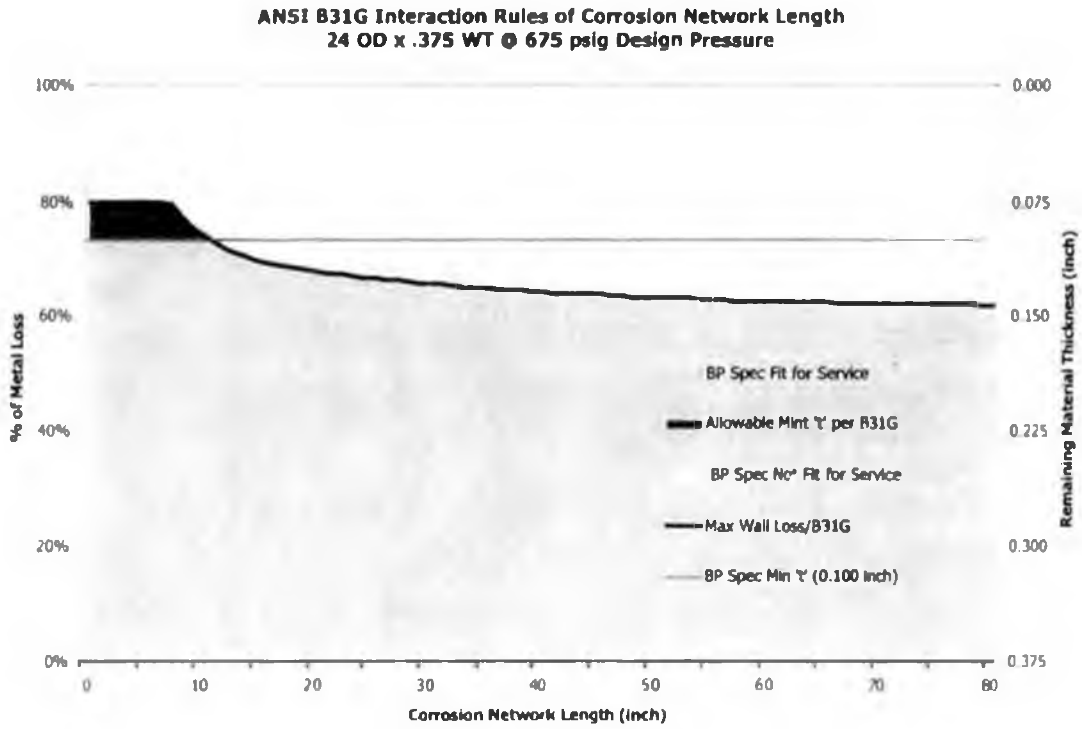


Figure E.14 Fitness-for-Service Envelope Based on BP SPC-PP-00090

In addition, repairs are typically scheduled when the corrosion damage has reached 105% of the repair criteria. This additional conservatism is in order to allow repairs to be planned rather than requiring an immediate plant shutdown.

In summary, the current equipment FFS assessment for piping accounts for two major elements,

(1) Remaining strength of material is sufficient to contain internal pressure as calculated by ANSI/ASME B31G/modified B31G methodology,

and

(2) Minimum thickness, regardless of pressure retaining calculation, equal to or greater than 0.100 inch,

whichever is the greater remaining wall thickness of the two assessment criteria.

Section E.4 Correlation Between Inspection and Corrosion Monitoring[7]

As noted in Table B.12, 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.

Therefore, in order to have good confidence in the results from the corrosion-monitoring program, it is necessary to show a correlation between the chosen 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.

Figure E.15 shows the trend in average corrosion rate from weight loss coupons and the percentage of increases found in the inspection program. 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 in Figure E.15 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.

Figure E.15 also shows that the same trend of reducing corrosion activity is seen in both the inspection results and corrosion monitoring data.

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

- As the corrosion rates decrease as a result of 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

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[7] In addition to Charter Work Plan, this information supplied to provide additional context and help in understanding BP corrosion management activities

- 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

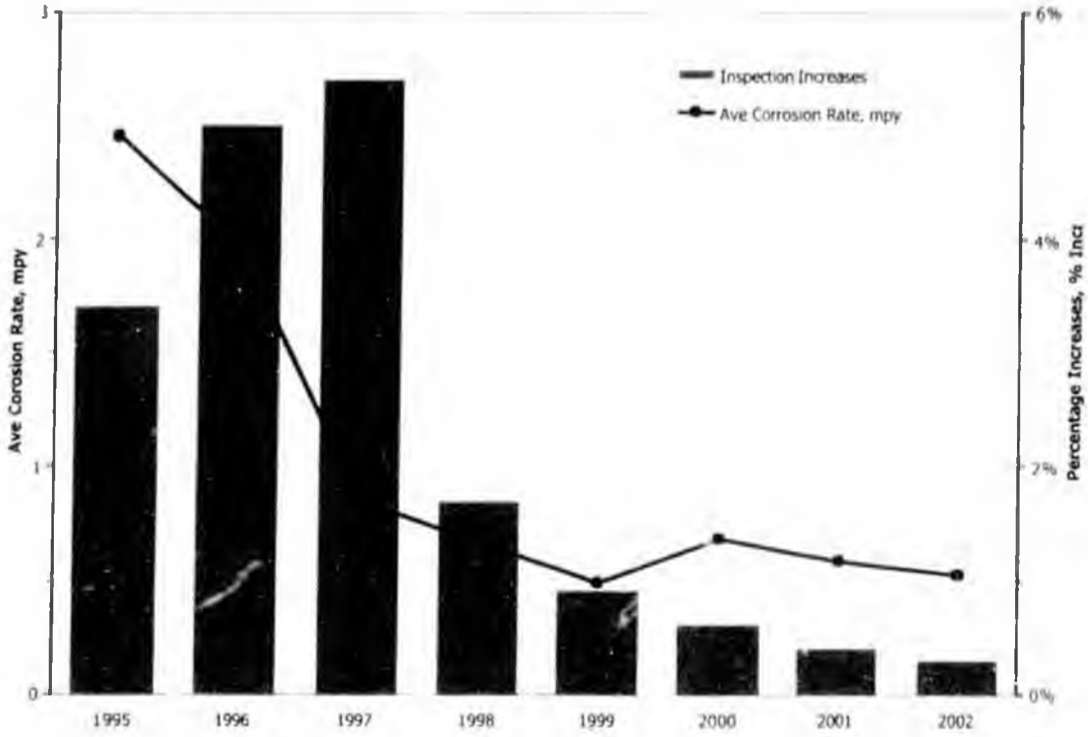

Figure E.15 Correlation of Corrosion Rate and %Increases

The data in Figure E.15 demonstrates the correlation between the corrosion monitoring and the inspection data for the 3-phase production system. A similar degree of correlation exists between the corrosion monitoring and the inspection data for the water injection systems. Figures E.10 and E.11 show increasing corrosion activity in both the flow lines and well lines for the water system which is also reflected in the corrosion monitoring data depicted in Figures C.12 and C.13.

In summary, the data in this section clearly shows that corrosion rates as determined by both inspection and corrosion-monitoring techniques are falling and that the corrosion management plan for internal corrosion in 3-phase production service is effective. Furthermore, the correlation between the inspection data and the corrosion monitoring data allows the corrosion monitoring data to be used with confidence to manage the chemical treatment program in a timelier manner.

Section E.5 Smart Pigging

Smart pigs or instrumented in-line inspection tools are used by exception 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 BP on the North Slope.

It is important to note that because the vast majority of the cross-country flow lines are above ground, the value of smart pigging is considerably lessened compared to buried or underground systems. The primary value for GPB is in the initial identification and location of damaged locations within a pipeline system. Having initially identified the location of damaged areas, the long-term integrity, pipeline condition and current corrosion rate, of the flowline can be much more effectively managed through the use of targeted manual NDE techniques.

As a consequence, smart pigging is used at GPB to initially establish the condition and location of corrosion damage in lines at risk. Having established the condition and location of damaged sections of line the locations are then added to the routine NDE program where the condition and hence immediate fitness for service is determined and where the on-going corrosion rate and level of corrosion mitigation can be monitored.

It should also be noted that there are some limitations with the capabilities of the smart pig technology currently available. A typical high resolution[8] MFL smart pig gives wall thickness measurements that are ±10% of the wall thickness and sizing resolution of 3 times wall thickness for length and width assessment. In addition, there are temperature and pressure limitations that prevent or make difficult the use of MFL tools in many lines at GPB. The typical upper operating temperature for the MFL tools is 122°F/50°C compared with a typical separator fluids temperature of 150-160°F.

While the smart pig program is an important element in the overall corrosion and integrity management program, it should be considered like any other inspection or monitoring technique as simply another tool to be applied where it delivers the most value.

When used, smart pig inspections are performed to gain a relative understanding of pipeline condition and rate of deterioration and/or to provide confidence that

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[8] MFL manufacturer technical data sheet

the internal and external conventional inspection programs have identified locations where mechanical integrity is at risk. Because MFL tools do not directly measure pipeline condition, results from in-line inspections are not reported in as received from the smart pig service company but are reported as part of the NDE summary in Section E.

Areas identified by smart pigging and interpreted as being a risk to future operation of equipment, are proofed through visual, radiographic and/or ultrasonic inspection techniques and the results of the verifications are reported through routine inspection programs.

In 2002 three produced water flow lines were examined by smart pig (MFL) inspection. These lines have not previously been subject to smart pig examination, summarized in Table E.16.

Equipment	Service	Diameter	From	To	Length (ft)
03-PWI	PW	12"	FS-2	DS-03	15521'
04-PWI	PW	12"	FS-2	DS-03	7077'
09-SWI	PW	12"	FS-2	DS-09	16882'

Table E.16 2002 Completed Smart Pig Assessments

The majority of the metal loss features reported in each of the lines smart pigged in 2002 were external corrosion locations. There were no areas reported where the pipeline did not meet the fit-for-service criteria for the equipment. Proofing examinations by ultrasonic inspection has been completed on the severest reported anomalies and the results are included in the aggregate data from 2002. Additional follow-up of the reported features is an ongoing part of the normal radiographic and ultrasonic NDE activity at GPB.

Table E.17 below shows the historical level of smart pigging activity at GPB

Type	92	93	94	95	96	97	98	99	00	01	02
MFL	11	-	6	14	1	6	3	6	5	3	3
UT	12	9	-	-	-	-	-	-	-	-	-
Total	23	9	6	14	1	6	3	6	5	3	3

Table E.17 Smart Pig Activity 1992 to 2002

Figure E.18 shows the smart pig activity level from 1992 through 2002. As can be seen from the chart, the level of activity has fallen from a high of 25 runs per year in 1992 to the 3 runs completed in 2002. In addition to the smart pigging activity level, the chart also shows the average corrosion rate for the oil service flows lines. The reduction in smart pigging activity level coincides with the decline in corrosion rate and reflects the change in emphasis of the program. As the corrosion rates have fallen, then the immediate concern of the program has shifted from the short-term integrity of the flowline, which is focused on condition, to the long-term integrity of the flow line, which has a dual focus of condition and corrosion rate. This long-term integrity is better managed through higher resolution methods such as corrosion monitoring and manual radiographic and ultrasonic NDE.

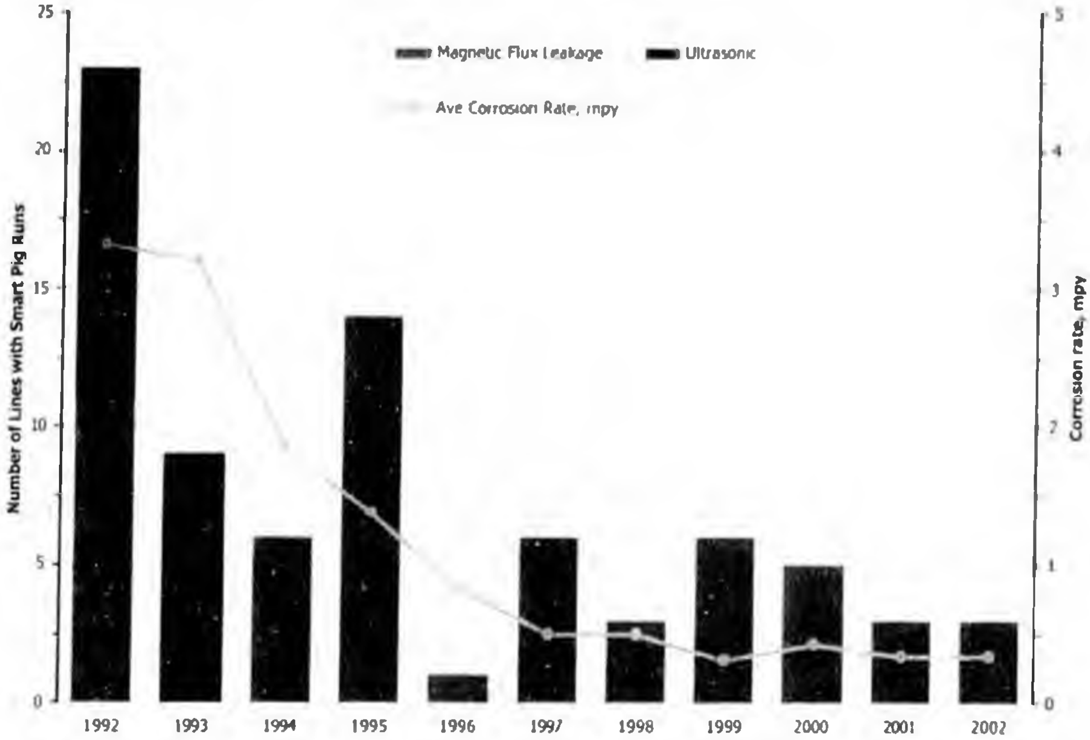


Figure E.18 Smart Pig Activity and Corrosion Rate 1992 to 2002

In summary, while smart pigging is an important tool to have available in the management of the long term integrity of the flow lines, it is not always the most appropriate or applicable for GPB because of the operating conditions, design and accessibility of the pipelines to precision manual methods of NDE.

Section E.6 Inspection Summary

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

- The external corrosion inspection program, at ~43,000 items, for 2002 was significantly above the historical average. Of the 43,000 items, approximately 2½% showed damage, which is less than prior years.

- The 2003 external corrosion program is planned to be about 35,000 items, which is again is substantially higher than the average activity level from 1995 through 2001.
- The cased piping survey is on-track to complete the initial baseline survey by year-end 2003 as agreed with ADEC.
- A unified internal inspection philosophy and program structure has been implemented across GPB with a total program size of approximately 60,000 items.
- The inspection results for both the flow line and well line 3-phase systems show improved performance in the long term. In the short term there is a slight increase in the corrosion activity on the flow lines. This is expected to be reversed following the trend 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. However, there is an increase in the corrosion activity in the short term and, as discussed in Section C, corrective actions have been put in place in the sea water system and additional inhibition has been added in 2002 to the produced water system.
- The inspection interval and fitness-for-service criteria, as defined by B31G, was discussed in the context of the current piping corrosion rate and piping condition.
- 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 flow lines since 1995.
- A similar level of correlation was seen in the water injection system information for both inspection and corrosion monitoring.

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
1995	GC1 Main Entrance	Distribution 24" Gas Lift	29% external wall loss	Insulation/coating repair
		Y Pad 24" 3 Phase Production	24% external wall loss	Insulation/coating repair
	GC2 to GC1 Caribou Crossing	Distribution 24" Gas Lift	42% external wall loss	Sleeve/insulation/coat repair
		Y Pad 24" 3 Phase Production	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	18% 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	Insulation/coating repair
	GC3 to FS3 Caribou Crossing	Distribution 24" Gas Lift	No corrosion damage	None
	FS1 to FS2 Caribou Crossing	Distribution Natural Gas 30"	11% external wall loss	Insulation/coating/tape repair
		Sales Oil 30"	14% external wall loss	Insulation/coating/tape repair
		Distribution 24" Gas Lift	No corrosion damage	None
		Distribution 32" Sea Water	No corrosion damage	None

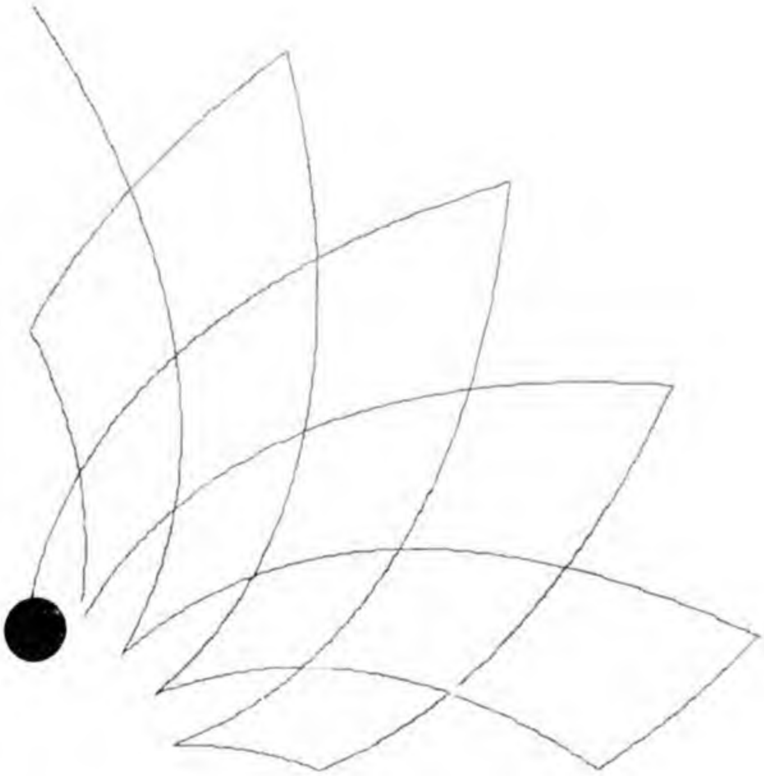
Table E.19 Cased Piping Excavation History

Year	Cased Pipe Location	Equipment Excavated	Observation	Corrective Action
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
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

Table E.19 (Cont.) Cased Piping Excavation History

Section F

Repair Activities



Section F Repair Activities

The repair activities in 2002 include a total of 78 repairs as compared to 31 in year 2001. This 2½ fold increase in corrosion related repairs does not represent a large scale increase in corrosion activity across GPB, but, instead, represents some very specific actions taken to address specific concerns within the field.

Table F.1 summarizes the repair activity for the flow line and well lines for 2002.

Service	Type	Internal	External	Mechanical	Total
Oil	FL	8	35	-	43
	WL	7	11	-	18
PW	FL	1	6	-	7
	WL	1	1	-	2
SW	FL	-	-	-	-
	WL	3	-	-	3
Gas	FL	-	4	1	5
	WL	-	-	-	-
Total		20	57	1	78

Table F.1 2002 Repair Activity

Of the 78 repairs, 57 were associate with external corrosion and therefore reflect the large scale ramp-up in external corrosion inspection activity in 2002. The 2001 external inspection program of ~15,000 items resulted in 17 repairs, this compares with the 2002 inspection program of ~43,000 items which resulted in 57 repairs. The repair ratio for the 2 years is approximately the same at about 1 repair every 1000 items inspected.

The increase in internal corrosion related repairs is dominated by the increase in flow line internal corrosion repair activity. Of the 8 internal corrosion related repairs, 7 were associated with the 24" flow lines from Point McIntyre. In addition to the 7 internal repairs, an additional 25 repairs on this line were associated with external corrosion. The majority of the damage found on these flow lines did not exceed the fitness-for-service criteria defined in Section E. However, the corroded areas were repaired preemptively in order to avoid unnecessary environmental risks associated with ongoing operations due to lack of road access. As an example, 12 sleeve repairs were installed on the section of the 24" Point McIntyre flowline that crosses over the Putuligayuk River.

The three well line repairs noted for SW were in the Grind and Inject system. The Grind and Inject plant takes waste material and processes it through a ball mill prior to permitted disposal down hole. Therefore, the fluids down stream of the Grind and Inject plant are an oxygenated-slurry and the repairs on this system are unrelated to the problems being encountered else where in the seawater system.

The 78 repairs were broken down into three categories for further analysis,

- Internal – Erosion and/or corrosion metal loss
- External – External corrosion metal loss (CUI)
- Mechanical – Third party damage, fabrication defect

Figures F.2, F.3, and F.4, and Table F.5, show the 3-year trend in repairs grouped by service, damage mechanism, and equipment, respectively. The increase in repairs noted for 2002 was a result of the increased scope of the External Inspection program.

It should be noted that this summary does not include structural related remedial work that is addressed in detail in Section G.

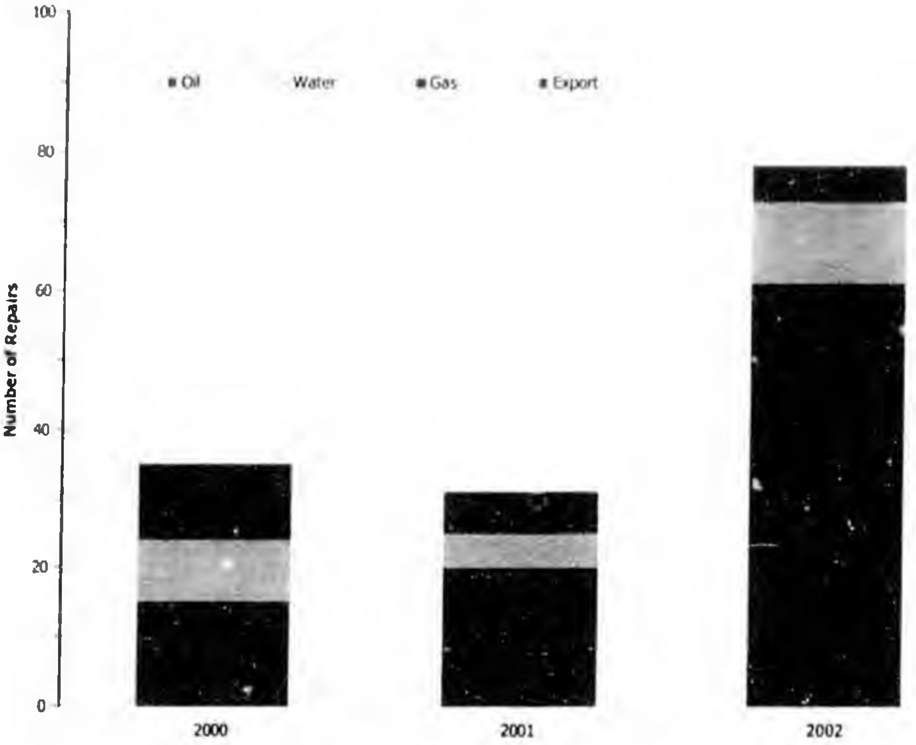


Figure F.2 Repairs by Service

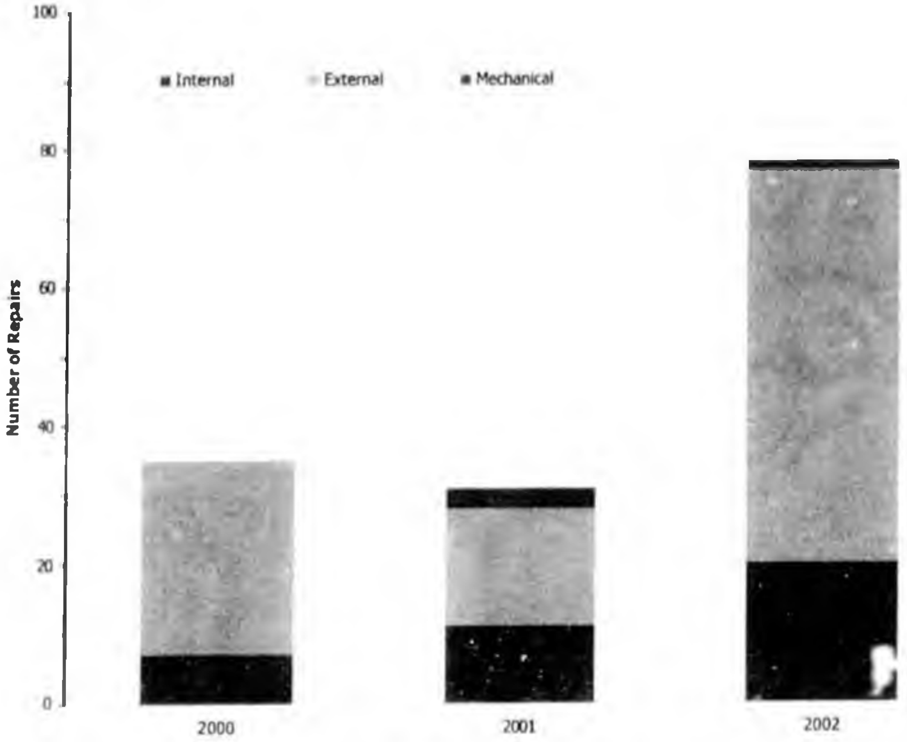


Figure F.3 Repairs by Damage Mechanism

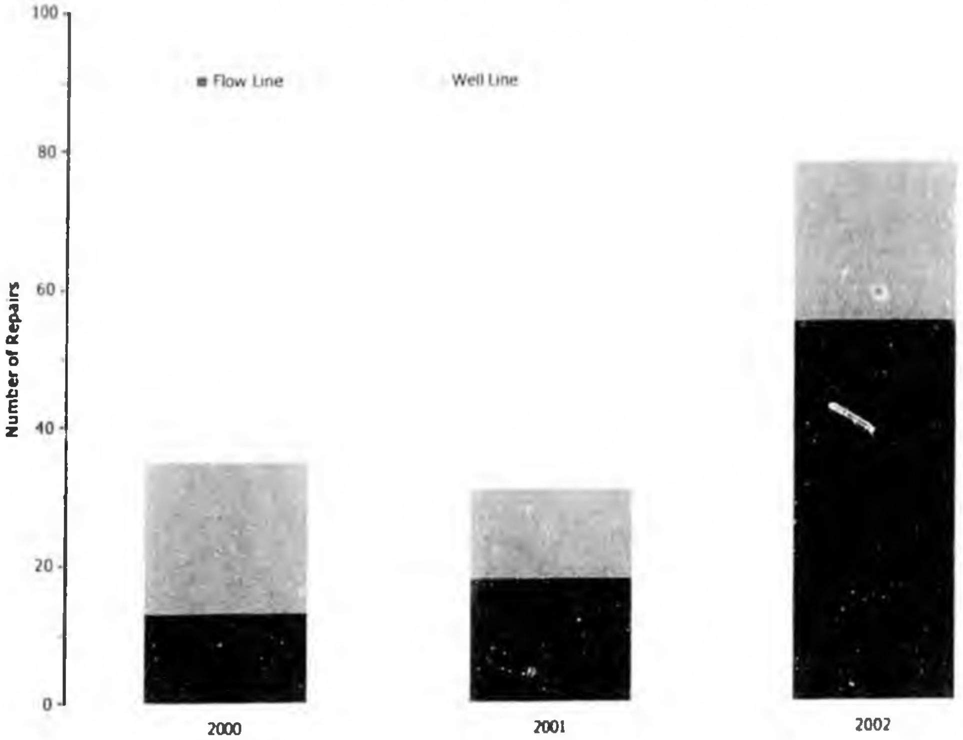


Figure F.4 Repairs by Equipment

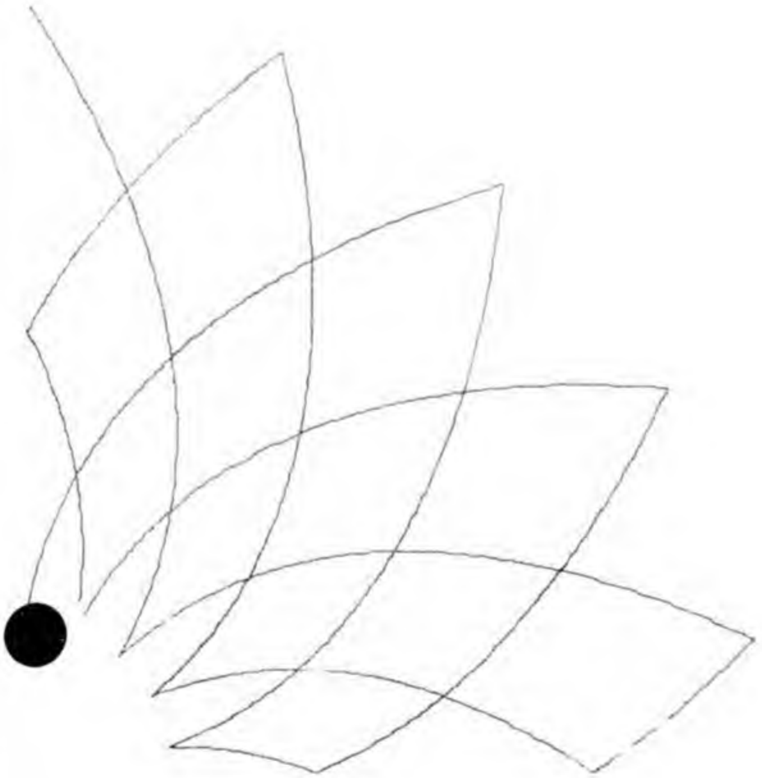
In summary, there was a significant increase in the number of repairs in 2002 compared to 2001, 31 and 78 respectively. There were 2 main causes of this increased activity, first, the increased level of external corrosion inspection. Second, preemptive repairs on the Point McIntyre 24" flow line as a consequence of the follow-up inspection after the July 2001 leak on this system.

		2000			2001			2002						
Service	**Type**	**Int**	**Ext**	**Mech**	**Int**	**Ext**	**Mech**	**Int**	**Ext**	**Mech**	**Total**	**Int**	**Ext**	**Mech**
Oil	FL	2	1		2	7	-	8	35	-	55	12	43	-
	WL	5	7		4	5	2	7	11	-	41	16	23	2
Water	FL	-	2		1	3	-	1	6	-	13	2	11	-
	WL	-	7		1	-	-	4	1	-	13	5	8	-
Gas	FL	-	8		-	2	-	-	4	1	15	-	14	1
	WL	-	3		-	-	1	-	-	-	4	-	3	1
PO	FL	-	-		3	-	-	-	-	-	3	3	-	0
Total		**7**	**28**		**11**	**17**	**3**	**20**	**57**	**1**	**144**	**38**	**102**	**4**
Grand Total				**35**			**31**			**78**				**144**

Table F.5 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 2002 and provides a historical perspective on the leaks (loss of containment) and saves (repairs before leak of non-FFS equipment).

Table G.1 summarizes the equipment, failure mechanism and volume of leaks due to corrosion that occurred in 2002. There were no structural related leaks in 2002.

Service	Location	Type	Date	Mechanism	Volume
3 phase production	F-48	S-riser	14-Jan-02	Erosion	115 gal
3 phase production	H-21	S-riser	18-April-02	Int	84 gal
3 phase production	13-12	WL	14-June-02	Ext	1 qrt
3 phase production	Z-LDF	FL	4-Oct-02	Ext	4 gal

	Surface		Service			Mechanism		
	Int	Ext	OIL	SW	PW	CO_2	Erosion	CUI
WL	2	1	3			1	1	1
FL		1	1					1

Table G.1 2001 Leaks Due to Corrosion/Erosion

Table G.2 shows the number of corrosion related leaks and saves from 1996 through 2002. 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 derate, replacement or removal from service as the equipment no longer meets the FFS criteria defined in Section E. This data is also shown in Figure G.4.

It should be noted that items are typically scheduled for repair at 105% of design pressure, to allow time to schedule and complete the repair before the item requires removal from service.

Table G.2 and Figure G.4 (a) and (b) show the number of leaks and the number of saves, plus the ratio of leak to saves. The trend in the total number of saves, locations that have reached FFS criteria, plus the number of leaks, is an approximate measure of the overall performance of the corrosion management program. The significant increase in number of saves is a direct result of the ramp-up of the External Inspection program.

Of the 4 leaks that occurred in 2002, 1 was associated with erosion, 2 with external corrosion and 1 with internal corrosion – see Table G.1.

	Flow Lines			Well Lines			Total
	Saves[1]	Leaks	$\frac{S}{(L+S)}\%$	Saves[1]	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%

Table G.2 Historical Corrosion Leaks and Saves

Section G.2 Structural Issues

There were no structural related pipeline failures in 2002.

A Walking Speed Survey (WSS) of the GPB east flow lines was completed in 2002. As part of the WSS, anomalies are noted and then reviewed and evaluated by the Field Mechanical Piping Engineer for action as appropriate. The Walking Speed Survey is a 5-year recurring program with the following schedule,

Year	Scheduled	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

Table G.3 Structural/Walking Speed Survey Schedule

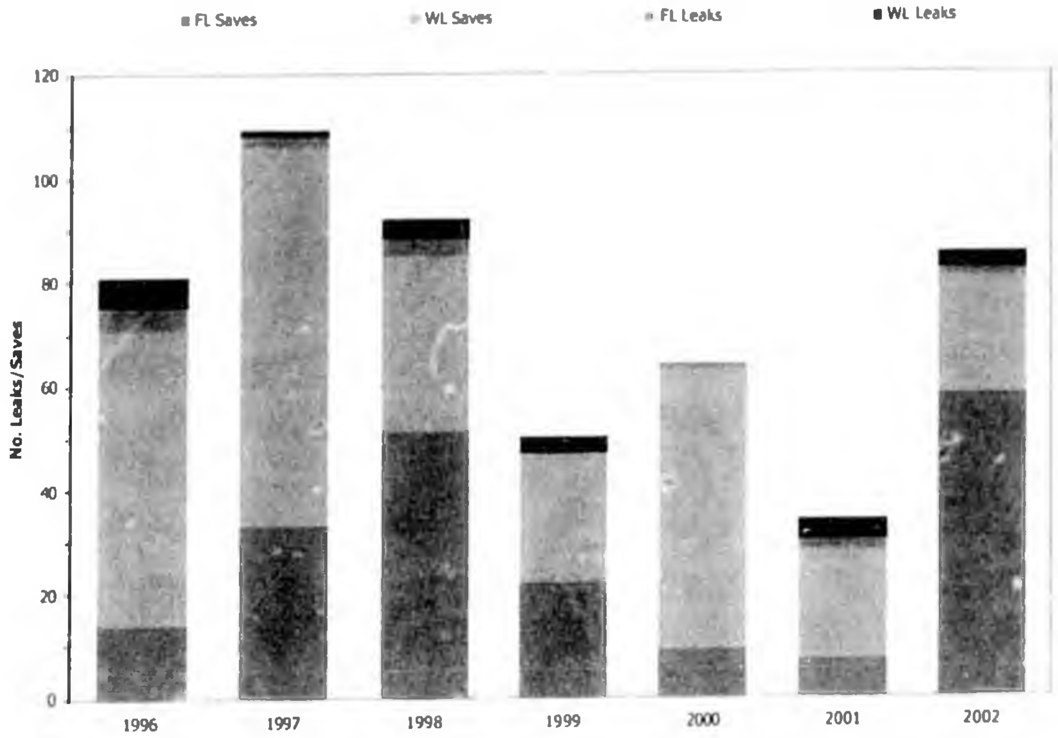


Figure G.4 (a) Historical Corrosion Leaks

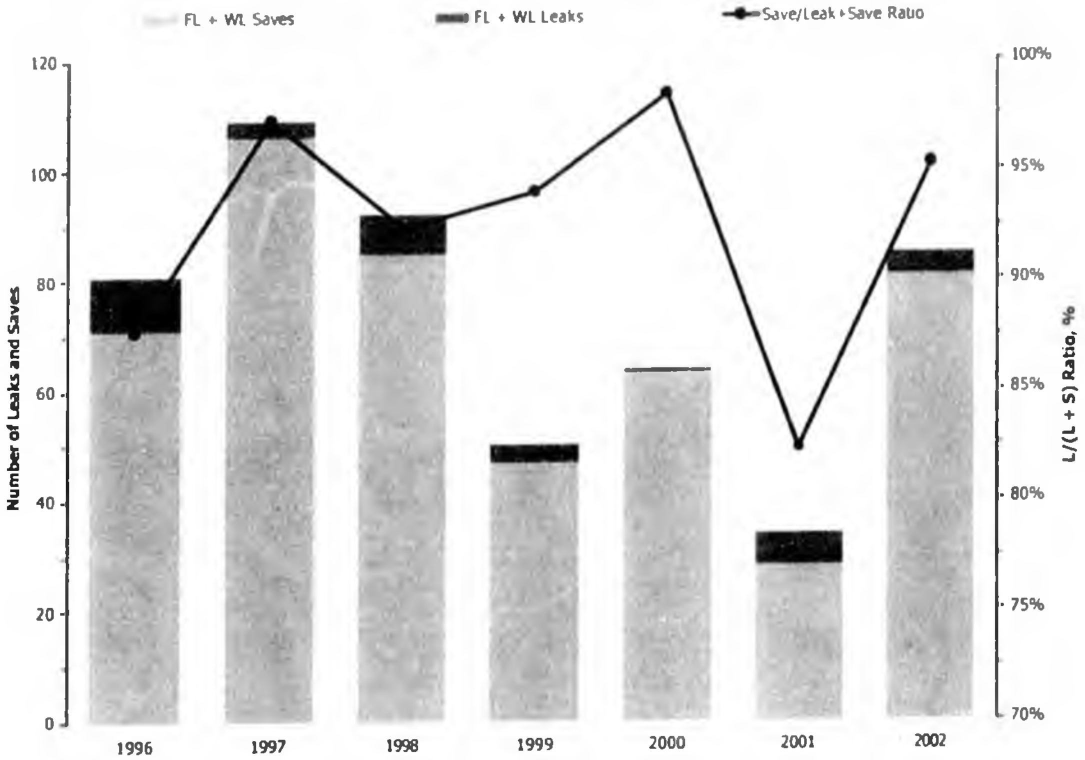


Figure G.4 (b) Historical Corrosion Leaks

Where there is perambulatory access, the Walking Speed Survey consists of a visual examination of process equipment and system components to identify mechanical integrity deficiencies. 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

Anomalies are recorded in a field report against each of these categories according to specific guidelines. The 2002 Walking Speed Survey of the east side cross-country flow lines was completed as per the schedule shown in Table G.4.

In addition to the Walking Speed Survey, there was significant work completed in 2002 to address known structural concerns,

GPB West

- Modified existing vertical support members (VSM) or installed new VSMs to correct sagging lines, repositioned saddles at A, B, D, F, H, J, N, S, Y pads
- Remediation of the M pad pipe line supports and anchors following the flooding of the Kuparuk river during break-up in 2002

GPB East

- DS-01 saddles - lines lifted to reposition in saddles and the saddles replaced onto VSMs
- DS-06 - installed new VSM
- DS14 – installed new VSMs and lines repositioned

Inspection and repairs due to structural anomalies is an ongoing program. As items are identified, each is evaluated and appropriate corrective action is initiated.

Beside the Walking Speed Survey, year round, Field Operations and Security personnel are tasked as the primary identifiers of flow lines and well lines with potential structural integrity problems. Observations of wind-induced vibration, excessive pipe movement, out-of-place pipe guides, bent piping, etc. are reported. A visual inspection by a competent engineer is first completed to determine any required action.

When evaluating possible damage caused by structural movement, i.e. subsidence, jacking, vibration, impact, slugging, snow loading, etc., the following items are considered:

- Insulation damage
- Piping damage
- Bent piping
- Piping saddles at adjacent pipe supports
- Unsupported spans
- Locations of line anchors
- Road crossings
- Expansion loops
- Branch connections

A piping stress analysis is completed as deemed necessary by the Field Mechanical Piping Engineer. Third-party piping stress analysis engineering experts may be involved as determined by the Field Mechanical Piping Engineer.

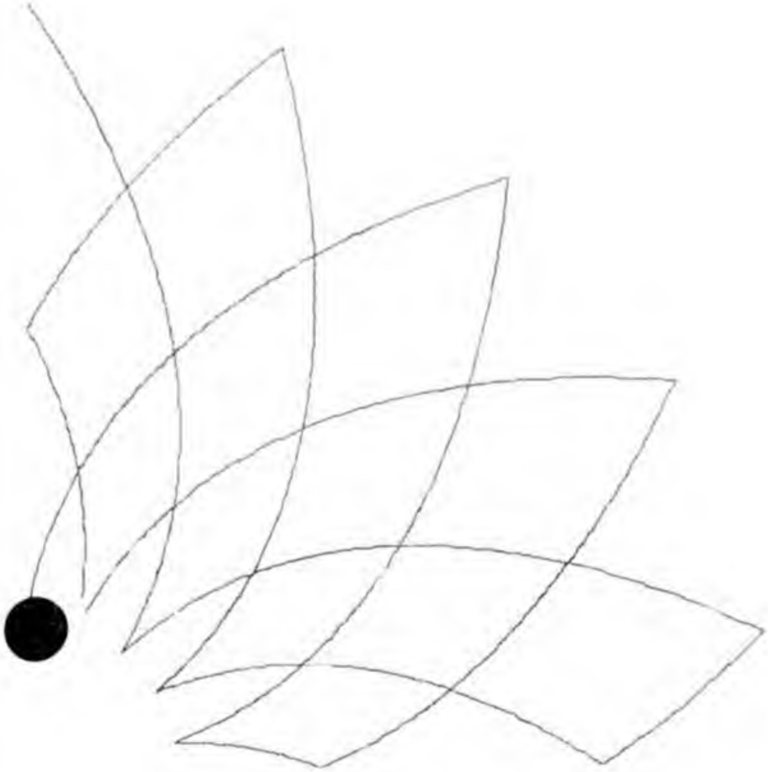
If significantly bent piping is observed, NDE inspection of the areas in question is performed. To accomplish the inspection the insulation is removed. The purpose of the inspection is to determine if any detrimental damage (i.e. wall thinning, cracks, ovality, buckling) exists. The NDE methods typically used include visual, ultrasonic, magnetic particle, radiography, and dye penetrant as appropriate. The applicable ANSI/ASME B31 piping Code acceptance limits are used to determine acceptability. BP has found by experience that the aesthetic appearance of pipes is not a conclusive sign that the pipes lack structural integrity or are not fit-for service.

When the inspections and analysis warrant action, a recommendation is provided to Operations for creation of a work order to address the location in question. An engineering design package is prepared to complete and document the work action. Management of Change and other procedures are applied as required.

In summary, structural related problems are addressed through two processes, first, is a Walking Speed Survey, which inspects piping on a 5-year cycle. Second, are the reported observations of Field and Security personnel of structural anomalies.

Section H

2003 Corrosion Monitoring and Inspection Goals



Section H 2003 Corrosion Monitoring and Inspection Goals

Section H.1 2002 Corrosion and Inspection Goals Reviewed

The introduction of single operatorship at Greater Prudhoe Bay was a significant event in 2000. Although much of the integration of the corrosion management programs was completed in 2000, a significant focus for 2002 was the completion of this activity for all aspects of the corrosion management system.

Section H.1.1 Corrosion Monitoring

The weight loss coupon program frequency remains unchanged from 2001 and is summarized in 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

Table H.1 Coupon Pull Frequency

ER probes are currently located, where possible, on the major cross-country oil service flow lines at either the upstream or down steam end of the pipeline. These probes are replaced when they have reached half of the useful probe life or every year, which ever is least.

Section H.1.2 Inspection Programs

The elements of the inspection program, CRM, ERM, FIP, CIP and CUI were discussed in detail earlier in report. These programs form the foundation for the on-going inspection programs at GPB. There are no major changes to this program anticipated in 2003.

There were three smart pig runs completed in 2002. The 2003 plan is for three 24" 3-phase oil production flow lines to be smart pigged subject to the availability of the smart pig tool of the correct size and capability required for the planned pipelines.

Corrosion under insulation inspections in 2002 were significantly above the level seen in the previous 5 years and above the planned level of 35,000. The 2003 program will be of a similar size to that planned for 2002 at approximately 35,000 items. Included in this scope will be locations that have historically been difficult to access due to the lack of roads along the pipelines. These pipeline segments will be accessed via a tracked vehicle under a tundra permit and include the P-pad to Y-pad pipelines that cross the tundra and the S-pad to M-pad pipelines that cross the Kuparuk river flood plain.

The below grade cased piping inspection program for 2002 was completed with approximately 280 location inspected. The program for 2003 is of a similar size and will complete the initial 5-year inspection of all active case pipe segments at road and animal crossings.

Section H.1.3 Chemical Optimization

The rationalization and optimization of the surface inhibition program at Greater Prudhoe Bay was completed in 2001. In 2002 the primary 3-phase corrosion inhibitor was replaced in 1Q 2002 with the intent of improving the level of corrosion control in low-velocity portions of the upstream system and the in the produced water distribution network.

In 2003 there are unlikely to be any similar large-scale changes to the inhibition program. However, 2003 is expected to have a significant number of well line tests and 1 or 2 full-scale flow lines trials in preparation for an expected 3-phase corrosion inhibitor change in 2004 to a more cost effective product.

Section H.1.4 Program Reviews

A number of reviews were conducted throughout the year on specific elements of the corrosion and inspection programs. Specific reviews conducted were,

- **GPB Partner Reviews** – Regular reviews of the corrosion management program at GPB were conducted with corrosion and integrity experts for the major GPB partners.
- **DOT Presentation** – Presented the GPB corrosion management programs described in the 2001 charter report to the Western Regional Chief of the DOT and a number of his staff.
- **ADEC Review** – ADEC and third party consultant review and comments on the BP Corrosion Monitoring Charter Agreement Reports.

The mixture of topics and the number of reviews in 2003 will differ from those completed in 2002 and reflects the change in emphasis in the program through time and the impact of other external factors.

Section H.1.5 2002 Corrective Actions

This section summarizes the corrective actions taken as a result of corrosion monitoring and inspection results exceeding the specified targets. These targets are detailed in Section B Table B.11.

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

Equipment ID	Cause	Action
A Pad	Increased Corrosivity	Increased CI by 5%
A Pad	Increased Corrosivity	Increased CI by 5%
DS04	Increased Corrosivity	Increased CI by 5%
GHX-E	Increased Corrosivity	See Table H.4
A Pad	Increased Corrosivity	Increased CI by 5%
CL05B	Increased Corrosivity	Increased from 3 to 4 gpd.

Table H.2 Correction Mitigation Actions from ER Probe Data

Table H.3 notes the corrective mitigation actions taken as a result of weight loss coupons exceeding target.

Equipment ID	Cause	Action
DS14	Increased Corrosivity	Increaded CI by 10%
CL14D	Increased Corrosivity	Increased CI by 10%
CL05D	Increased Corrosivity	Increased CI by 20%
F Pad	Increased Corrosivity	See Table H.4
Seawater	O_2/Microbiological	Multiple

Table H.3 Correction Mitigation Actions from Coupon Data

Table H.4 notes the corrective mitigation actions taken as a result of inspection information.

Equipment ID	Cause	Action
DS09	Increased Corrosivity	Increaded CI by 10%
H Pad	Increased Corrosivity	Increased CI by 10%
F Pad	Increased Corrosivity	Increased CI by 10%
GHX-E	Increased Corrosivity	Increased CI by 25%
PW system	Increased Corrosivity	Multiple
SW system	O_2/Microbiological	Multiple

Table H.4 Correction Mitigation Actions from Inspection Data

Section H.2 2003 Corrosion and Inspection Goals

The 2003 corrosion and inspection goals will be focused on optimization and continuous improvement of the programs. In general, there are not expected to be any significant changes from the overall scope and scale of the 2002 effort.

Section H.2.1 Corrosion Monitoring

There are no plans to significantly change the corrosion weight loss coupon-monitoring program in 2003. The emphasis in the produced water and 3-phase production system will be on maintaining the current level of performance, and in the seawater system reversing the negative trends seen in the last 24 months.

Section H.2.2 Inspection Programs

The internal inspection program is planned to be largely unchanged in 2003 from 2002. The expected activity level again will be about 60,000 in total for GPB spread between both the field and facilities.

The major change in the inspection program for 2002 was the implementation of a much larger external corrosion inspection program. The current planned activity level for 2003 is similar to that for 2002 at about 35,000.

2003 will see the completion of the 5-year program to conduct a baseline inspection on all the cased piping segments. As with prior years, the program is expected to be on-track for completion with a scope typical of prior years at ~280 segments.

Section H.2.3 Chemical Optimization

Chemical dosage optimization will continue in 2003 with a particular focus on optimization of rates by minimizing the variability in the dosage rates. This will primarily be achieved through the improved level of access to the corrosion inhibitor injection rate data provided by the fully electronic recording system implemented in late 2002.

There are currently no plans to replace the current 3-phase continuous corrosion innibitor at GPB in 2003. The next generation of corrosion inhibitor is expected to be introduced to the field in 2004. Therefore the main focus for 2003 will be the testing and verification, via well line and flow line trials, of the candidate replacement products.

For the seawater system, there will be a continued focus on the chemical mitigation programs, oxygen scavenger injection and biocide treatments, which were augmented in 2002 and are intended to reverse the negative corrosion rate trends in the last 2 years.

Section H.2.4 Program Improvements

As discussed in the report, the main focus for improvement is the seawater injection system. Although a number of improvements were made throughout 2002, the operational upsets at the plant have made it difficult to assess the impact of these improvements.

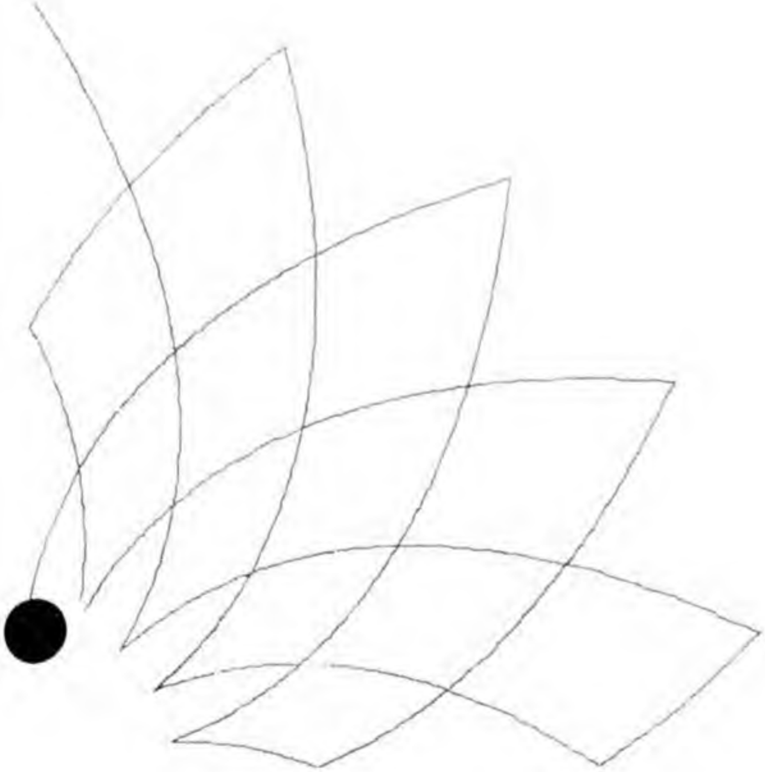
For the seawater system, a number of corrective actions were instigated in the latter half of 2001 and 2002. The focus for 2003 will be to ensure that these corrective actions deliver the performance improvement anticipated. Clearly, if there is no improvement in performance, additional corrective actions will be required.

In addition to the obvious area of improvement in the seawater system, the intention is to be able to retain and continue the current levels of control in the other major systems such as 3-phase and produced water injection. Since the performance of these systems is often closely and subtly linked, 'maintenance' of corrosion control continues to represent a highly complex and resource intensive activity

Part 2

Alaska Consolidated Team Business Unit

Section B-H



Section B ACT – Corrosion Monitoring Activities

ACT 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.

Each of the producing field 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, BP acquired a majority working interest from the prior owners, and assumed operatorship. Since 1994 production and proven reserves have been increased and Milne Point production now averages approximately 45,000 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.

Badami Remotely located east of Prudhoe Bay, Badami has 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.

Northstar Located offshore, 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 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 in a pipeline that is three times thicker than required for pressure containment.

In addition to the unique challenges associated with location and history, each of the ACT producing field has its own unique corrosion environment. Table B.1 illustrates, on a relative basis, the 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 CO_2 in the produced gas. Also listed, for each field are the generally used materials of construction for both the production system and the water injection system.

					Material of Construction[a]			
	Prod Fluid Characteristics				Production		Injection	
Field	**H_2O, %**	**T °F**	**P_{CO_2} %**	**CR[b]**	**WL**	**FL**	**WL**	**FL**
GPB	70	150	12	H	CS+CI	CS+CI[c]	CS+CI	CS+CI
END	90	150	18	H	DSS	DSS	CS+CI	CS+CI
MPU	47	125	1.5	L/M	CS	CS[d]	CS+CI	CS+CI
Northstar	0.8	160	5	M	CS+CI	N/A	N/A	N/A
Badami	0.3	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

Table B.1 Relative Corrosivity of BP North Slope Production

The table shows that in general the production fluid characteristics for the ACT producing field are general less susceptible to corrosion compared with those at GPB with the exception of Endicott. However, for Endicott, this corrosion risk is mitigated in the production system through the use of duplex stainless steel as the material of construction for the production flow lines.

In addition, with the exception of Endicott, to the generally lower risk of corrosion, the ACT fields are of a smaller scale when compared to GPB. For example, as can be seen in Table B.1, neither Northstar nor Badami have any significant non-common carrier cross-country flow lines. An illustrative assessment of the relative size of the ACT producing field and GPB is provided in Table B.2.

In general, Table B.2 shows that the ACT fields combined are of a much smaller scale than GPB. Also, it should be noted, that when comparing GPB and ACT facilities that these facilities differ enormously in age from over 25 years since first oil for GPB to ~12 months for Northstar.

Metric	ACT	GPB	$\frac{ACT}{(ACT + GPB)}\%$
Production Trains	4	21	16%
Prod and Inj Wells	230	1475	13%
Non-common carrier FL	105	1350	7%
Acreage	75000	203000	27%

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 temperatures, high CO_2 content) indicate the corrosivity of the produced water to be high. Due to this high corrosivity, much of the field production system was fabricated from duplex stainless steel, a corrosion resistant alloy and therefore, corrosion is not a significant concern for much of the production system. In the Endicott 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 GPB Section E.

Service	Miles	Int. Insp.	Ext. Insp.[1]
Oil x-country lines	3.5	4 (in vault)	4 (in vault)
Oil - Well Pads	2.5	1327	0
Water x-country lines	3.5	104	4 (in vault)
Water - Well Pads	1.7	200	9 (in vault)
Gas x-country (GLT/MI)	7	15	4 (in vault)
Gas - Well Pads	1.2	26	9 (in Vault
Fuel Line - Gasoline	N/A	5 foot excavation	5 foot excavation
Fuel line - diesel	N/A	5 foot excavation	5 foot excavation

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

Table B.3 Endicott Summary of Lines and NDE Inspections 2002

The primary corrosion concerns are in the water injection system, mainly the Inter-Island Water Line (IIWL) carrying injection water to the satellite production

CORRECTION

THE FOLLOWING DOCUMENT(S)
HAVE BEEN REFILMED TO
ASSURE LEGIBILITY OR PAGINATION

Central Microfilm Services
Departement of Education & Early Development
State of Alaska

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Water - Well Pads	1.7	200	9 (in vault)
Gas x-country (GLT/MI)	7	15	4 (in vault)
Gas - Well Pads	1.2	26	9 (in Vault
Fuel Line - Gasoline	N/A	5 foot excavation	5 foot excavation
Fuel line - diesel	N/A	5 foot excavation	5 foot excavation

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

Table B.3 Endicott Summary of Lines and NDE Inspections 2002

The primary corrosion concerns are in the water injection system, mainly the Inter-Island Water Line (IIWL) carrying injection water to the satellite production island (SDI) from the main production island (MPI). Corrosion control of the water injection system relies on corrosion inhibition of the injection water, supplemented by a biocide and maintenance pigging program. The primary monitoring method for the IIWL is ultrasonic inspection of 25 locations. Table B.3 summarizes the inspection program for Endicott for 2002.

Section B.2 Milne Point

Fluid properties (low temperatures, low CO_2 content) indicate the corrosivity of the production fluids at MPU to be low. The primary corrosion concerns are in the water injection system and external corrosion of buried piping. Solids contribute to the corrosion mechanism of the production system as evidenced by under-deposit corrosion found in the production system in 2001. 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 two years. Corrosion inhibition of the K-pad production flow line was initiated in 2001. Additionally, corrosion inhibition of the newly developed S-Pad began late 2002. Table B.4 summarizes the inspection program for Milne Point for 2002.

Service	Miles	Int. Insp.	Ext. Insp.[2]
Oil x-country lines	24	80	0
Oil – Well Pads	N/A[1]	754	47
Water x-country	15	35	0
Water – Well Pads	N/A[1]	449	23
Gas x-country	14	0	0
Gas – Well Pads	N/A[1]	283	0

[1] Totals not available
[2] The external corrosion program concentrated significantly on the Oil Sales line, and outside facility piping in 2002.

Table B.4 Milne Point Unit Summary of Lines and NDE Inspections 2002

Section B.3 Northstar

Northstar began production in November 2001. Corrosivity is expected to be low to moderate initially, but will tend to increase over time with the injection of Prudhoe Bay Unit gas into the reservoir, which has a higher CO_2 content than the natural Northstar reservoir. Table B.5 summarizes the inspection program for

Northstar in 2002. Data is limited as the production facility is relatively new. Note that the line lengths for Northstar are in feet as the production facility is contained in a comparatively small footprint.

Service	Feet	Int. Insp.	Ext. Insp.
Oil Pipe rack	1200	0	0
Oil – Well Pad	280	106	0
Water Pipe rack[1]	2400	0	0
Water – Well Pad[1]	70	17	0
Gas Pipe rack	600	0	0
Gas – Well Pad	140	26	0

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

Table B.5 Northstar Summary of Lines and NDE Inspections 2002

Section B.4 Badami

Badami is currently considered a low risk from a corrosivity standpoint, as there is little water production and low CO_2 content. Table B.6 summarizes the inspection program for Badami.

Service	Feet	Int. Insp.	Ext. Insp.
Oil –Well Pad	840'WL , 320' HDR	9	0
Gas	240'WL, 320'HDR	0	0
Disposal Well	400'	0	0

Note Badami does not have an active water injection system.

Table B.6 Badami Summary of Lines and NDE Inspections 2002

Section B.5 Overall Inspection Activity Level

Table B.7 summarizes the overall inspection activity since 2000, as can be seen from the table the overall activity level has remained approximately constant at between ~3400 items per year.

	Surface	**2000**	**2001**	**2002**
Endicott	Int	1346	1480	1676
	Ext	16	16	30
	Total	**1362**	**1496**	**1706**
Milne Point	Int	1419	629	1601
	Ext	378	1577	70
	Total	**1797**	**2206**	**1671**
Northstar	Int	-	16	149
	Ext	-	0	0
	Total	**-**	**16**	**149**
Badami	Int	0	9	9
	Ext	0	0	0
	Total	**0**	**9**	**9**
Grand	**Total**	**3159**	**3727**	**3526**

Table B.7 Overall Inspection Activity Summary 2000 - 2002

Section C ACT - Coupon Corrosion Rates

Corrosion probes are not extensively used in ACT fields. The following data therefore relate to corrosion coupons only.

Section C.1 Endicott

Table C.1 depicts the metrics for corrosion monitoring at Endicott for 2002. Historical data are shown in Figure C.2.

As shown in Figure C.2, the corrosion trend 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 the data are used primarily for monitoring produced fluid corrosivity and erosion tendency. The lower, relatively constant corrosion rates in the water system reflect the effectiveness of the corrosion mitigation program.

System	Access Fittings	% WLC < 2 mpy
Water Injection - Pads	15	100%
Water Injection – x-country	1	100%
Oil Production – Pads	72	58%

Table C.1 Endicott Corrosion Coupon Monitoring 2002

Section C.2 Milne Point

Table C.3 depicts the metrics for corrosion monitoring at Milne Point for 2002. Historical data are shown in Figure C.4.

Figure C.4 illustrates the low corrosion rates for the MPU production and source 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 initial indications are that the inhibition is having a positive effect on the corrosion rate as the weight loss coupon corrosion rates have consistently averaged less than 2 mpy since the inhibition program was implemented.

System	Access Fittings	% WLC < 2 mpy
Production System	27	100%
Water Injection System	7	95%
Source Water Coupons	5	100%

Table C.3 MPU Corrosion Coupon Monitoring 2002

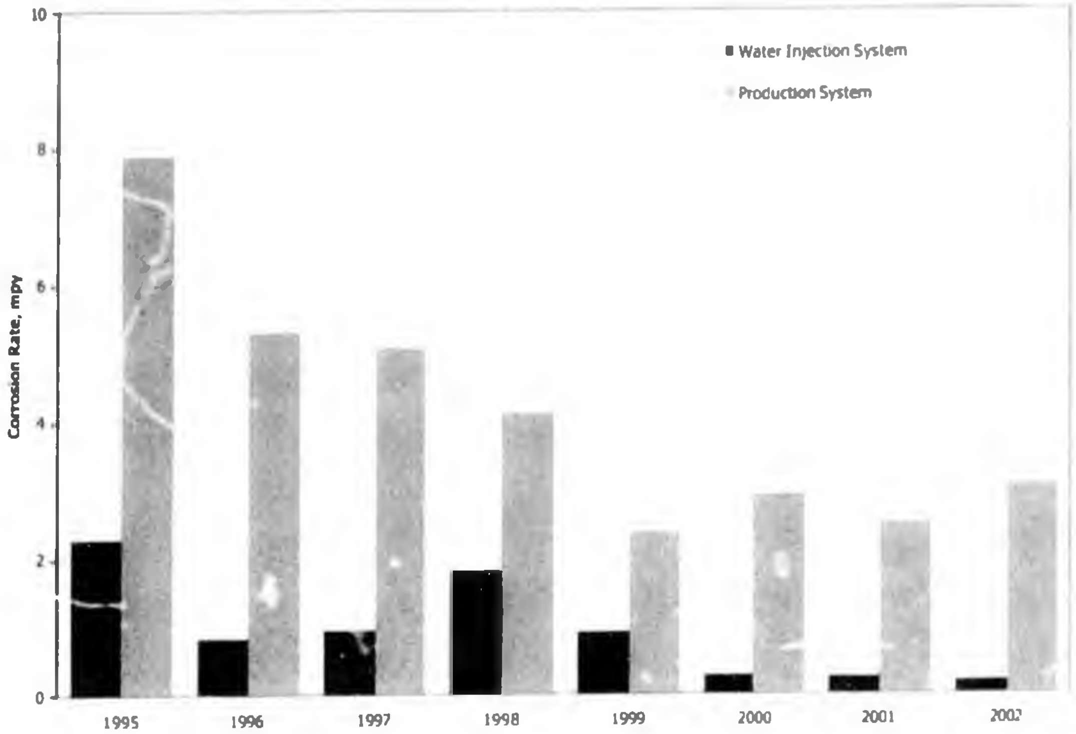


Figure C.2 Corrosion coupon data from Endicott 1995-2002

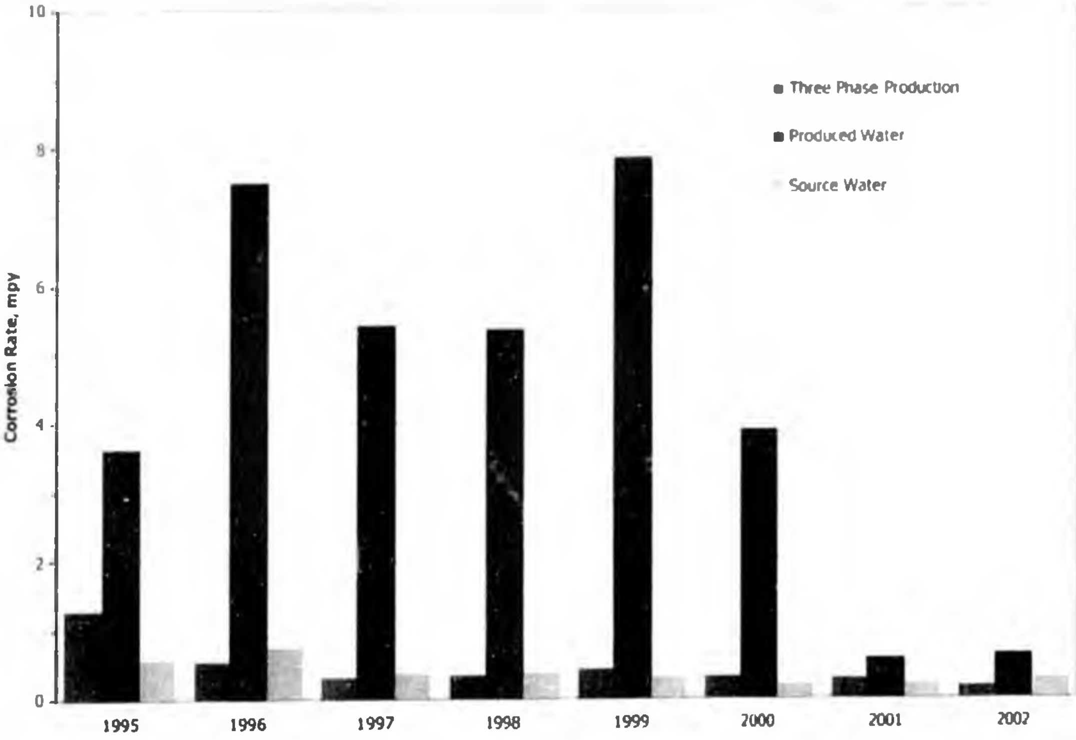


Figure C.4 Corrosion coupon data from MPU 1995-2002

Section C.3 Northstar

The Northstar facility is equipped with corrosion monitoring locations. However, no data is currently available, as coupons have been pulled but not analyzed yet. This data will be reported in the future as it becomes available.

Section C.4 Badami

Badami currently has no corrosion-monitoring program.

Section D ACT - Corrosion Mitigation Activities

Section D.1 Endicott

Corrosion mitigation at Endicott has concentrated on a three-pronged approach of maintenance pigging for line cleanliness, biociding to control bacterial activity and continuous injection of a corrosion inhibitor for corrosion control. As noted earlier, the primary monitoring tool for effectiveness is the quarterly UT inspection of 25 locations along the IIWL. These inspections indicate there is currently slight corrosion activity in the IIWL, but down significantly from the 1995-1997 timeframe. A historical perspective of the reduction in corrosion activity since this three-pronged approach was implemented is shown in Figure D.1. The number of locations showing corrosion increases has been fairly constant over the past three years, indicating slight corrosion activity. The maintenance pigging program was suspended for approximately two months in 2002 for repairs to the launcher. Also, a slight inhibitor modification was made in 2002, however the inhibitor formulation is virtually unchanged from the previous version. Treatment volumes vary dependant upon operational swings in injection rates and reservoir optimization efforts. The current treatment concentration is 17 ppm. Optimization efforts prior to 2003 had concentrated on the biocide program. The line is currently under review to modify the corrosion inhibitor treatment type and/or rate.

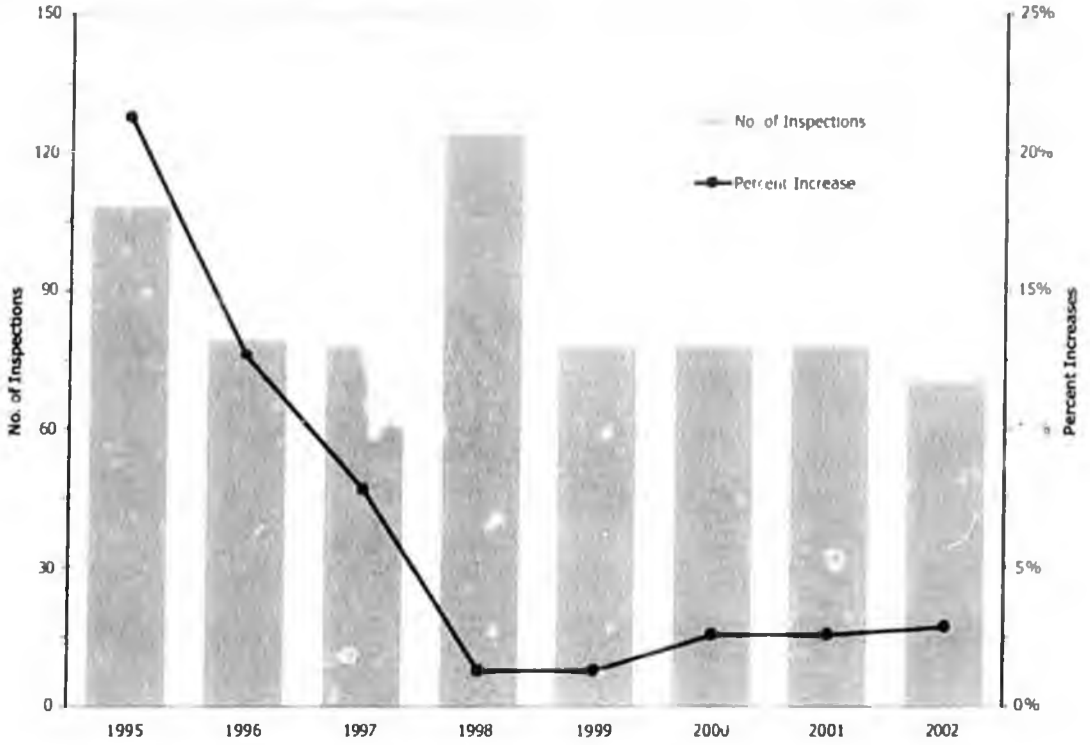


Figure D.1 Endicott IIWL Quarterly UT Readings Through 2002

In the production system, the primary damage mechanism is erosion. The erosion rate, in this mainly duplex stainless steel system, is mitigated through inspection and velocity management. Wells are risk ranked by mixture velocity approximately once per month. This information is used to determine inspection frequency, and is also used by the operating personnel to determine if production rate, and hence fluid velocity, for the well should be reduced. Figure D.2 is an overview of the velocity data for Endicott for 2001 and 2002. Shown are the numbers of wells within L/R ratio ranges, where L is the mixture velocity and R is the allowable erosion velocity as defined by API RP 14E.

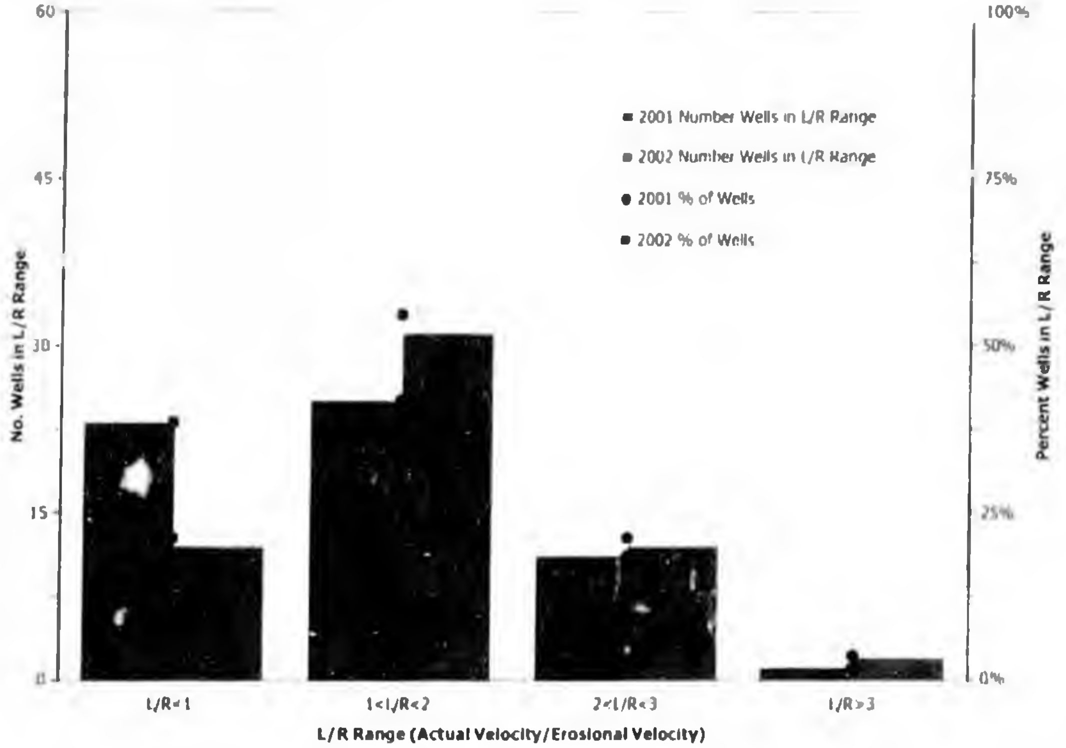


Figure D.2 Endicott Velocity Monitoring 2001-2002

API RP 14E defines an allowable velocity for the avoidance of erosion, based on the fluid properties (namely density) and material of construction. API RP 14E is based on experience with steam service and is known to be conservative when applied to oil production systems, particularly where corrosion and erosion resistant materials are used. Actual velocities are expressed as a ratio of the allowable velocity as defined by API RP 14E, with the aim being to limit velocities to less than 3 times the allowable velocity. This factor of 3 reflects BP's North Slope experience that production fluids with minimal amounts of entrained solids may exceed the API RP 14E erosion velocity through stainless steel pipelines by this amount with minimal risk of erosion. Equipment exhibiting high velocities is inspected at intervals ranging from weekly to bi-annually dependant upon the L/R Ratio, input from Well Operations, and inspection results. The inspection frequency for the two wells showing an L/R Ratio greater than 3 has been increased from quarterly to monthly.

Section D.2 Milne Point

Corrosion inhibition of the water injection system began in mid-2000, along with a more frequent maintenance pigging program. Weight loss coupon data indicates the system is coming under control as the corrosion rates have averaged less than 2 mpy since mid-2000. This represents a significant reduction from previous years and can be seen in Figure D.3.

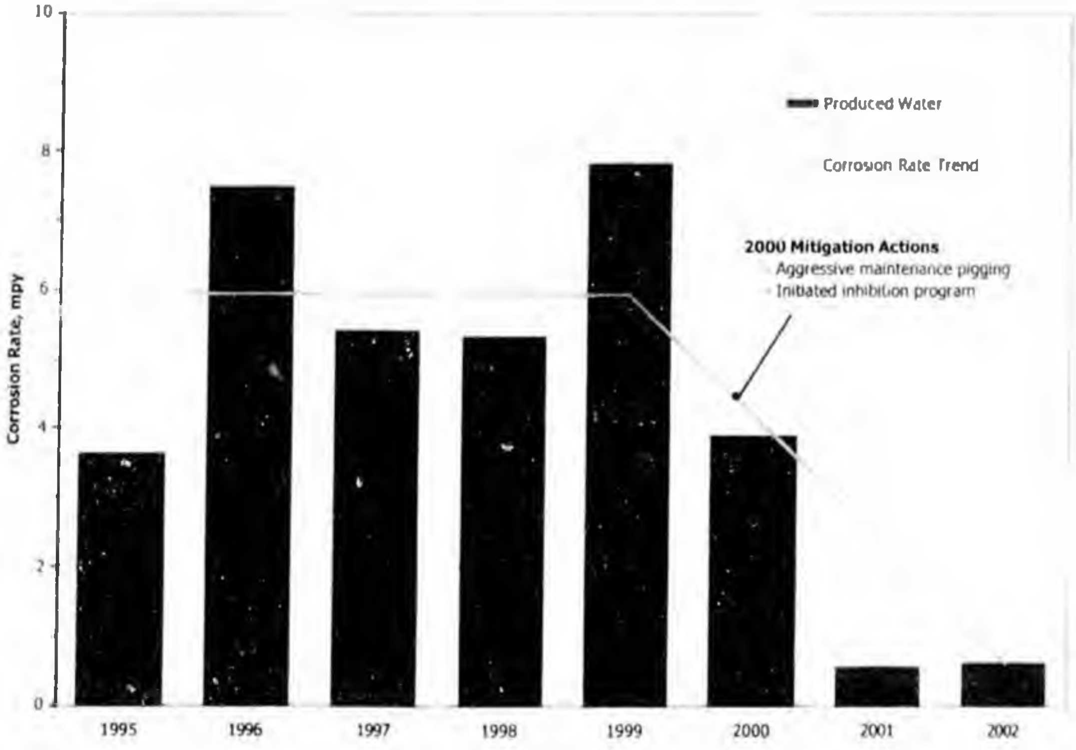


Figure D.3 Milne Point Produced Water Corrosion Rate Trend

The majority of the production lines are not currently inhibited, although the long-term goal is to continuously inject corrosion inhibitor into the three-phase system. Corrosion inhibition on the K-Pad 3-phase production flow line was initiated in 2001 after inspections indicated significant under-deposit corrosion damage. The damage was associated with extremely low flow conditions, allowing solids to accumulate in the line.

Treatment concentration is 100 ppm based on water production. In conjunction with the initiation of inhibitor injection, the K-Pad production line is pigged approximately monthly.

In addition, as a result of finding the corrosion damage in the K-pad line, the line was smart pigged in June 2002 and the results from the smart pig run were added to the routine inspection program.

The newly developed S-Pad was designed for continuous inhibition. Corrosion inhibitor is continuously injected into the power fluid supply for the down hole hydraulic pumps. Since this water is separated and re-circulated as power fluid at the pad, only minor amounts of water are sent through the cross-country flow line to the separation facility. Additional makeup water for use in the power fluid system is treated at a rate of 20 ppm corrosion inhibitor. This program will be optimized based on the results from the inspection and corrosion monitoring programs.

The remaining flow lines are under review for potential corrosion inhibition. Prioritization will be based on flow characteristics and inspection trends.

Inspection increases in the well pad production lines indicates there is slight corrosion activity occurring over the long term. As a result, it is anticipated that the MPU production system will eventually be on continuous corrosion inhibition. This evaluation is ongoing.

As production rates are typically low, the velocities are consequently also lower and erosion is not a significant concern. There is therefore no formal velocity management program.

Section D.3 Northstar

Northstar is inhibited with continuous injection of corrosion inhibitor into the well production lines. Inhibitor concentration is set at 100 ppm based on water, but a minimum amount of 2 gallons/day is injected regardless as the production contains very little water at this time (one percent or less water cut).

Section D.4 Badami

Corrosion inhibition is currently not required at the Badami field based on modeling of the corrosivity of the fluids, the low water-cut, results from the facility and pipeline inspection program.

Section E ACT - Inspection and Corrosion Increases/Rates

Section E.1 External Inspection

Section E.1.1 Endicott

Underground/cased lines at Endicott are inspected per the frequency listed in Table E.1. Of the lines inspected in 2001, no significant corrosion was noted.

Line	Crossings	Year Surveyed	Method	Max Inspection Interval
WTR - Inter-Island	1	2001	EMI	10 Years
GAS - Inter-Island	1	2001	EMI	10 Years
OIL	1	N/A		N/A Duplex Stainless Steel
MI Line	1[1]	N/A		
WTR – WL	2	1 line in 2000	EMI	10 Years for Carbon Steel Other line is Duplex Stainless Steel
GAS - WL	1	2000	EMI	10 Years

[1] New in 1998, inspection ports for sniffing, permanently sealed, can be inspected by excavation only

Table E.1 Cased Piping Inspections

In addition, the vaults where the Inter-Island Water and Gas Lines pass are visually inspected annually. Minor external corrosion has been found, but it has not increased. The aboveground MI line and Gas Line are to be inspected with TRT in 2003.

Section E.1.2 Milne Point

Table E.2 summarizes the external inspection program at MPU since 1997. In 2002, five excavations were performed on buried lines at I-Pad for external corrosion inspection. This is the 70 items accounted for in Table E.2 for 2002. Five locations were repeat locations with one of these repeat locations showing a slight increase in corrosion. An additional seven locations showed minor external corrosion, less than 20% wall loss. The corroded areas were mitigated.

Year	Total Insp	Repeat Insp	Increases	% I's
1997	26	0	0	n/a
1998	441	10	0	0.0
1999	101	65	0	0.0
2000	205	104	28	26.9
2001	179	20	5	25
2002	70	5	1	20

Table E.2 MPU Inspection Summary- External

Table E.2 does not reflect the total number of TRT inspections performed in 2001. A total 2100 items were inspected with TRT in 2001, however the majority of these were associated with outdoor facility piping.

Section E.1.3 Badami

External inspections that have been done to date at Badami are associated with the internal inspection program where insulation was removed for ultrasonic inspection of well line elbows. No evidence of corrosion was noted.

Section E.2 Internal Corrosion Inspection

Section E.2.1 Endicott

Figures E.3 and E.4 indicate the percentage of inspection increases since 1995 for the well lines and flow lines at Endicott. There were no increases in the 3-phase production cross-country line as it is manufactured from duplex stainless steel, a corrosion resistant alloy. Minor activity has been noted in the water injection system flow line, the Inter-Island Water Line (IIWL).

Figure E.3 shows corrosion activity in the well lines by inspection for both the production and water injection systems at Endicott. These trends have remained relatively constant since 1998. The production system inspection data is used to alert Operations of potential replacements of the carbon steel C-Spools at the wellheads. The inspection increases in the water injection system well lines have been relatively constant since 1996 reflecting the improvements in the chemical mitigation program undertaken at Endicott. The increases in the PW/SW well lines in 2002 are under review as noted in ACT Section B, for potential inhibitor change and/or concentration increase.

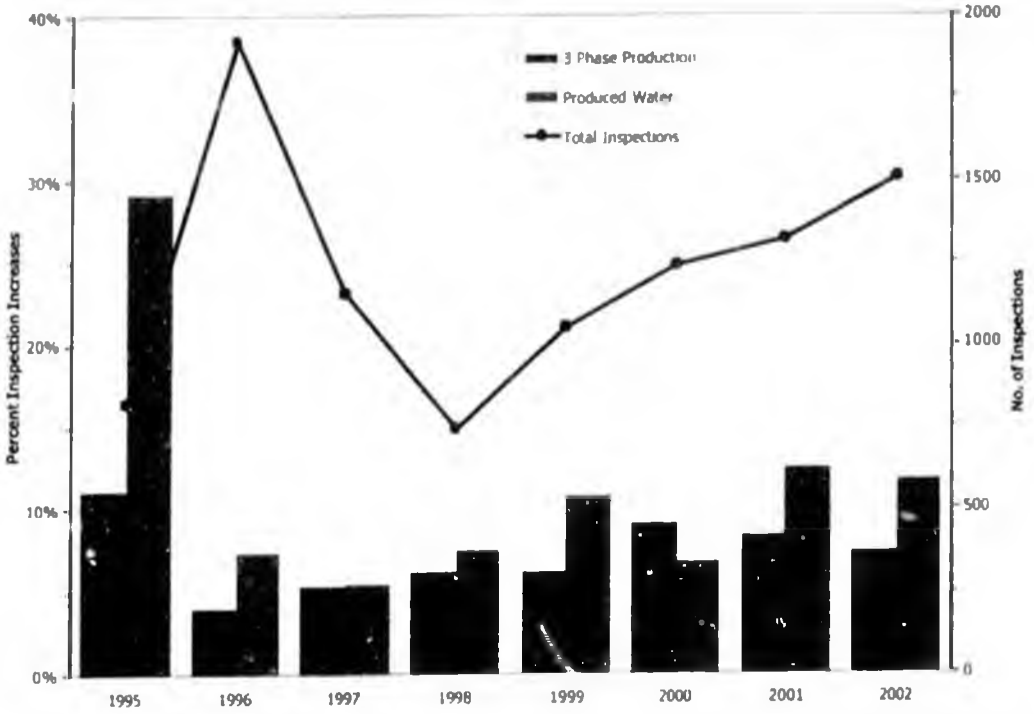
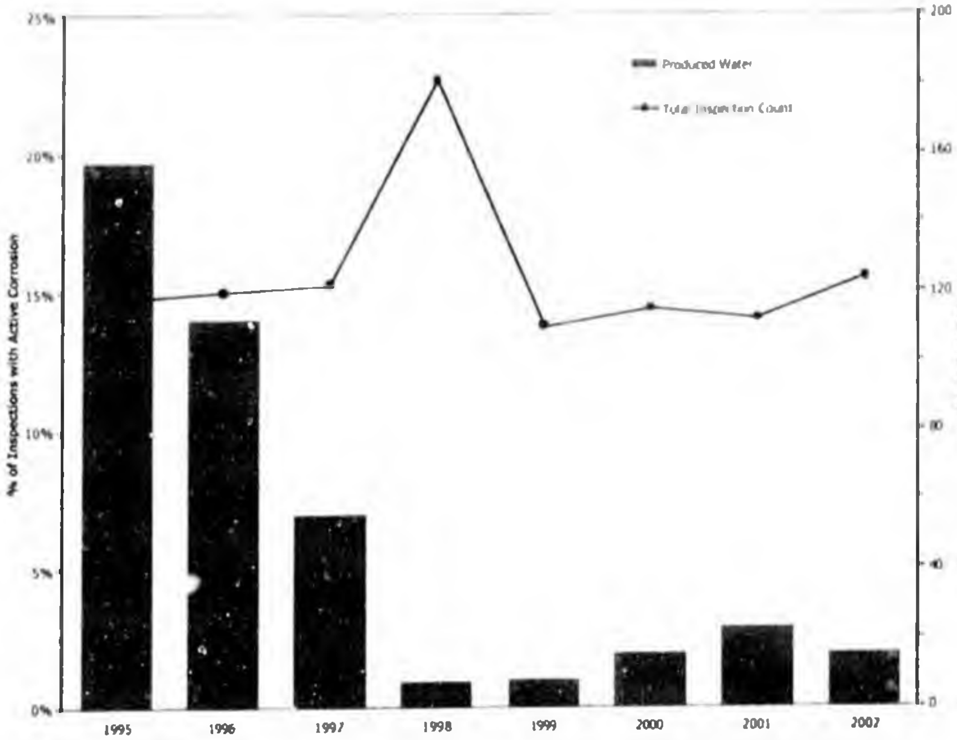


Figure E.3 Detection of internal corrosion of well lines by inspection at Endicott 2002



Note: Historically, there are no inspection increases in the production line or the gas line since 1995

Figure E.4 Detection of internal corrosion of flow line by inspection at Endicott 2002

Figure E.4 shows a trend of declining inspection increases since 1995 for the IIWL at Endicott. This trend is indicative of the improvements made to the water injection mitigation program. There has been, however a slight increase in activity in the inter-island water line over the past two years. As discussed above, the treatment regime for the PW/SW system is under review for potential inhibitor changes. In addition, the pigging program was suspended for approximately two months in 2002 while awaiting repairs to the pig launcher.

It should be noted that the corrosion increases in the three-phase production are in carbon steel C-Spools that are managed through planned replacement at the FFS criteria discussed in GPB Section E.

Section E.2.2 Milne Point

BP became operator at Milne Point in 1994, and from this date to 2000 the inspection program has been aimed at establishing the baseline condition in the MPU systems. It is only with the 2000 data and beyond that trending of inspection increases has been possible with inspection locations being repeated. The results of this comparative data can be seen in Figure E.5. The figure shows that the total number of inspection items has consistently increased since 1998. Locations showing increased corrosion activity has reduced for both the 3-phase production and the produced water lines from 2001 to 2002. All increases in the production flow lines are attributable to the corrosion in the K-pad flow line as discussed previously.

With the corrosion identified in the K-pad line, additional inspections using real time radiography were performed on several other lines. These inspections included 1400 feet (approximately 15%) of the next lowest velocity line in the field, B-pad production line, with no additional corrosion noted, and 400 feet (approximately 18%) of the E-pad production line, also with no additional corrosion noted. The E-pad line takes production from the K-pad line.

Approximately 400 feet of real time radiography was also performed on the F-pad 3-phase production flow line, as a follow-up verification to the smart pig run in 2001. The smart pig reported significant damage along the first 1000 feet of line length. Upon verification, only one minor internal pit was detected, indicating the smart pig erroneously over-estimated the depth and extent of corrosion damage.

The locations showing increased corrosion activity in the produced water flow lines are over an extended timeframe that included the period of corrosion activity prior to the establishment of the corrosion inhibition and maintenance pigging programs begun in 2000.

Figure E.6 shows the historical detection of internal corrosion of well lines by inspection at MPU through 2002. This again shows the progress made in obtaining increasing total and repeatable inspection data. In the Produced Water data, numerous repeat inspections were done from the period of 2000 or earlier, indicating that corrosion inhibition had not been fully established as it only began in 2000. For example, of the increases shown for the Produced Water System in 2002 in Figure E.6, fully 64% of these increases were from a period of the previous inspection being in 1999 or earlier.

Section E.2.3 Badami

As Badami only came on stream in 1998, there is little historical data for this field. A 2002 follow-up to the baseline survey performed in 2000 indicates no corrosion, erosion or mechanical damage on the oil production well lines.

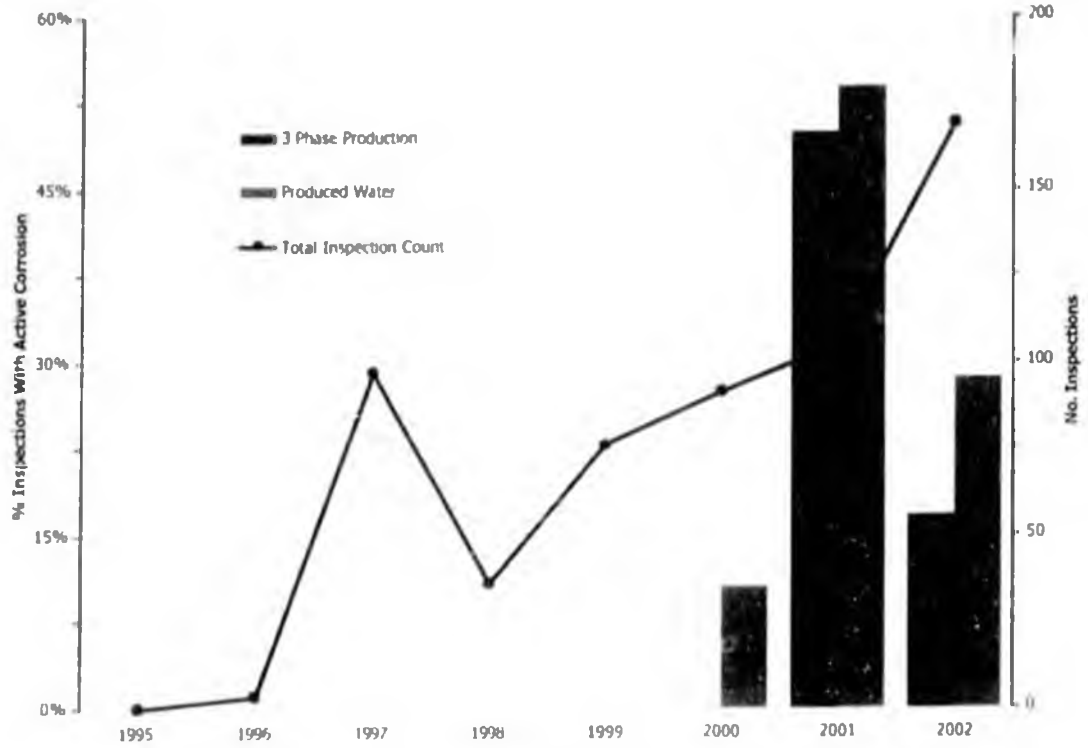


Figure E.5 Detection of internal corrosion of flow lines by inspection at MPU 2002

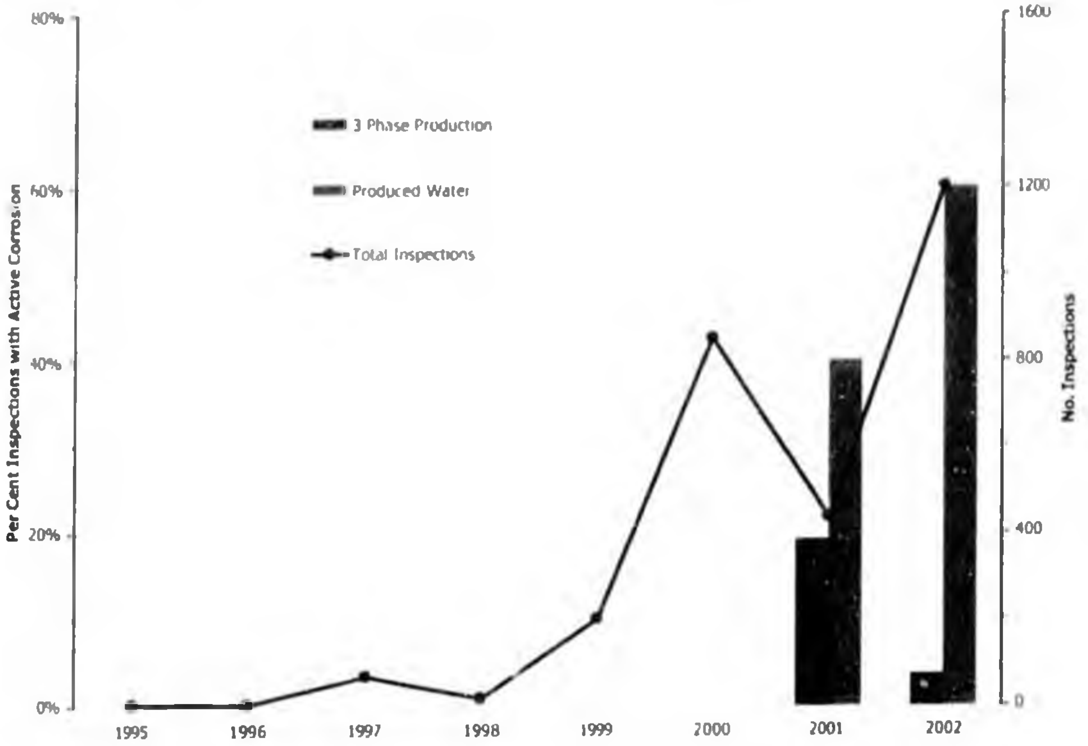


Figure E.6 Detection of internal corrosion of well lines by inspection at MPU 2002

Section F Act – Repair Activities

Table F.1 summarizes the repair activity for ACT. There were 13 repairs identified for ACT of which 8 were at Endicott and 5 at Milne Point.

Service	Type	Int	Ext	Mechanical
Oil	FL	4	1	-
	WL	6	-	1
PW	FL	-	-	-
	WL	1	-	-
	Total	**11**	**1**	**1**

Table F.1 ACT Repair Activity

Four of the Endicott repairs were to well line C-spool sections due to corrosion of the weld heat-affected zone (HAZ). Two well line production risers were replaced due to internal corrosion of which one was as a result of a pinhole leak. One duplex pipe spool was replaced due to erosion damage. The one produced water pipe spool was identified for replacement after corrosion damage to two elbows was found.

The five Milne Point repairs were all on the K-pad production flow line of which one was due to external corrosion.

Section G ACT - Corrosion and Structural Related Spills and Incidents

As noted in the previous section, there was only one pin hole leak in 2002 due to corrosion. There were no leaks attributable to structural deficiencies.

Tables G.1, G.2, G.3 and G.4 summarize leak/save and mechanical repair data for Endicott, MPU, Northstar and Badami, respectively.

Service	Leaks	Saves	Sleeves	Comments
Oil x-country lines	0	0	0	
Oil Well Pads	0	6	0	Well 2-30 erosion
Water x-country lines	0	1	0	
Water Well Pads	1	0	0	Well 1-31 pin hole
Gas x-country GLT/MI	0	0	0	
Gas Well Pads	0	0	0	

Note: Leak / Save and mechanical repair data is for year 2002 only.

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

Service	Leaks	Saves	Sleeves	Comments
Oil x-country	0	5	5	K-pad flow line
Oil Well Pads	0	0	0	
Water x-country	0	0	0	
Water Well Pads	0	0	0	
Gas x-country	0	0	0	
Gas Well Pads	0	0	0	

Note: Leak / Save and mechanical repair data is for year 2001 only.

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

Service	Leaks	Saves	Sleeves	Comments
Oil – Well Pad	0	0	0	
Gas – Well Pad	0	0	0	
Disposal Well	0	0	0	

Note: Leak / Save and mechanical repair data is for year 2001 only.

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

Service	Leaks	Saves	Sleeves	Comments
Oil – Well Pad	0	0	0	
Gas – Well Pad	0	0	0	
Disposal Well	0	0	0	

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

The repair table shows that, to date, the relatively low corrosivity assessment from the beginning of the section is reflected in the level of repair activity.

Section H 2003 Corrosion Monitoring and Inspection Goals

Section H.1 Endicott

The increases in the Inter-Island Water Line (IIWL) and well line inspection data for PW/SW service are the result of minor corrosion activity in a line with extensive pre-existing corrosion. An inhibitor increase is in progress, the effectiveness of which will be monitored through 2003.

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

Section H.2 Milne Point

The 2003 plan will continue to focus on the gains made in the past, in particular, continuing to build a more comprehensive baseline inspection for MPU and build the repeat inspection location to establish corrosion inhibition and chemical treatment performance trends.

Analysis of additional production flow lines requiring corrosion inhibition was initiated in 2002 along with the inhibition of the newly commissioned S-Pad flow line. A major goal for 2003 will be demonstrating the efficacy and optimizing these treatment levels.

The Milne Point corrosion evaluation of buried pipe will trial an alternative detection technology that includes fixed monitoring locations of the buried pipe segments. One of the goals for 2003 will be to install these permanent monitoring locations and gain a baseline data set.

Section H.3 Northstar

Corrosion monitoring and inspection data will be reviewed as it becomes available. Changes to the inspection and mitigation activity will be dictated by this 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 new production facility.

Section H.4 Badami

As the Badami fluids are shown to be of relatively low corrosivity, no major changes are anticipated. The plan is to monitor corrosion activity with the annual integrity surveys as has been done in the past.

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.