Annual Report to Alaska Department of Environmental Conservation

Commitment to Corrosion Monitoring Year 2004

Prepared by

Corrosion, Inspection and Chemicals (CIC) Group
BP Exploration (Alaska), Inc.

March 2005

Commitment to Corrosion Monitoring

Year 2004

Foreword

This is the fifth annual report that meets the commitment made by BPXA to the State of Alaska to provide a regular review of BPXA's corrosion monitoring and management practices for non-common carrier pipelines on the North Slope. The contents of this report reflect the Work Plan[1] agreed jointly between BPXA, Phillips and ADEC, the Guide for Performance Metric Reporting[2], and feedback from previous ADEC reports. The report is divided into 2 main parts.

> **Part 1** contains information regarding the BPXA operated fields within the Greater Prudhoe Bay (GPB) Performance Unit. This consists principally of fluids produced from Prudhoe Bay, Lisburne, Point McIntyre and Niakuk field areas but also includes smaller volumes of fluids from satellite accumulations.
>
> **Part 2** contains information regarding the BPXA operated fields within the Alaska Consolidated Team (ACT) Performance Unit. This consists principally of fluids from Endicott, Badami, Milne Point and Northstar field areas. As with GPB, several smaller satellite accumulations are also produced through ACT facilities.

The report provides an overview of the corrosion management process, and provides data and discussion of the corrosion control, monitoring, inspection and fitness-for-service programs. These individual programs, in concert, form the core of the integrity/corrosion management system designed to deliver our corporate goal of no accidents, no harm to people and no damage to the environment[3]. The program also reflects the core values of BP: innovation, performance driven, environmental leadership and progressive.

Innovation is evident in several areas, from the development of more effective corrosion inhibitors and corrosion inhibition programs, to the application of new inspection technologies. These innovations are only made possible by working closely with partners, major suppliers and the regulatory community, to bring the best available technology to Alaskan oilfields.

Performance management and the drive for improved performance are central to all aspects of the corrosion management program. This report demonstrates an on-going effort to improve corrosion management. Since 1992, corrosion rates have been reduced by almost a factor of 10 in the cross-country pipelines that transport a mixture of oil, water and gas (3-phase). Consistent with the pledge to report openly both good and bad performance, the report highlights areas for improvement and the plans in-place to deliver performance improvement.

Environmental protection and corrosion management are closely linked. The improvements in corrosion management have resulted in lower corrosion rates and a lower risk of loss of containment. Opportunities to improve environmental performance still exist and the investment in continuous corrosion inhibitor injection at Drill Site 5 and 7 as well as the continued effort on our external corrosion inspection program is evidence of this on-going commitment.

---

1 Appendix 2 (a) 2000 Work Plan
2 Appendix 2 (b) Guide for Performance Metric Reporting
3 BP HSE Policy Statement, EJP Browne, Group CEO, January, 1999, http://www.bp.com/

Progressive evolution of the corrosion management programs is an on-going activity driven by changing field conditions and the desire to improve performance. Progress involves the continued refinement of the existing programs, but also, the development and implementation of new programs and corrosion management technologies.

The current corrosion management process has delivered a significantly improved level of corrosion control. Notwithstanding the successes, the corrosion management program must remain focused on the future in order to maintain the current level of control and, where necessary, implement the actions necessary to improve performance.

The continuous improvement of the corrosion management programs has enabled BPXA to deliver the programs strategic objectives of:

- Minimizing the health, safety and environmental impacts of loss of containment due to corrosion
- Providing a fit-for-service infrastructure for the remainder of field life
- Producing satellite accumulations through existing equipment and pipe-work
- Providing an infrastructure capable of supporting gas sales in the future

In addition, with the information in this report, BPXA intends to build a healthy relationship with the North Slope stakeholders through consultation, open reporting and striving to raise the standards of the industry.

BP Exploration (Alaska) Inc.
March 2005

Table of Contents

Table of GPB Figures

Table of ACT Figures

Table of Appendix Figures

Table of GPB Tables

Table of ACT Tables

Table of Appendix Tables

Section A

Charter Agreement – Corrosion Related Commitments

Section A Charter Agreement – Corrosion Related Commitments

The BPXA contact for all corrosion matters relating to the Charter Agreement is,

Brett W. Leach, Integrity & Assurance Manager

E-mail: brett.leach@bp.com

Phone: (907) 564-4437

Section A.1 Project Achievements

Oct-Nov 2000	Work Plan agreed between BPXA/PAI and ADEC (Appendix 2a)
March 2001	1st Annual Report submitted to ADEC
April 2001	1st 2001 Meet and Confer session held
Oct-Dec 2001	Consultations with ADEC and ADEC's consultant
November 2001	2nd 2001 Meet and Confer session held
Dec 01-Jan 02	Developed and agreed corrosion management metrics
February 2002	BPXA/PAI and ADEC agreed on performance metrics (Appendix 2b)
March 2002	2nd Annual Report submitted to ADEC
April 2002	1st 2002 Meet and Confer session held
November 2002	2nd 2002 Meet and Confer session held
March 2003	3rd Annual Report submitted to ADEC
May 2003	1st 2003 Meet and Confer session held
October 2003	2nd 2003 Meet and Confer session held
March 2004	4th Annual Report submitted to ADEC
April 2004	1st 2004 Meet and Confer session held
August 2004	North Slope Field Trip
March 2005	5th Annual Report submitted to ADEC

Section A.2 Annual Charter Timetable

March 31st	Annual Report submitted
April 30th	1st Semi-Annual Review/Meet and Confer
October 31st	2nd Semi-Annual Review/Meet and Confer

Part 1 – Greater Prudhoe Bay Performance Unit

Section B

2004 Corrosion Program Summary

Section B 2004 Corrosion Program Summary

Section B.1 Introduction

This section provides a summary of key performance indicators (KPI) for 2004. Additional information regarding the Corrosion Management System and historical program data and development are shown in subsequent sections of the report.

Section B.2 Corrosion Monitoring

The plan and objective for corrosion monitoring is to measure the effectiveness of the mitigation programs. The primary monitoring techniques are intrusive weight loss coupons (WLC) and Electrical Resistance Probes (ER Probe) which provide the feedback for corrective action when control targets are exceeded.

Program:	Weight Loss Coupon
Target:	<2 mills per year (mpy)
KPI:	% Conformance WLC <2 mpy
Section Reference:	Section C Weight Loss Coupons and ER Probes

1. 7,185 coupons were analyzed to monitor the effectiveness of the mitigation programs.
2. 3-phase flow line WLC data showed 98% were <2 mpy with an average corrosion rate of 0.4 mpy.
3. 3-phase well line WLC data showed 94% were <2 mpy with an average corrosion rate of 0.6 mpy.
4. Water injection flow line (produced and seawater) WLC were 86% <2 mpy with an average corrosion rate of 1.0 mpy.
5. 100% produced water service well line WLC showed 99% less than 2 mpy and average corrosion rate of 0.1 mpy.
6. 100% seawater service well line WLC showed 100% less than 2 mpy and average corrosion rate of 0.3 mpy.
7. Majority service produced water well line WLC showed 98% less than 2 mpy and average corrosion rate of 0.2 mpy.
8. Majority service seawater well line WLC showed 85% less than 2 mpy and average corrosion rate of 1.4 mpy.

Program:	Electrical Resistance Probe
Target:	<2 mills per year (mpy)
KPI:	Conformance <2 mpy
Section Reference:	Section C.3 Electrical Resistance Probes

9. 3-phase flow line ER Probes showed 92% of the data was <2 mpy.

The monitoring data for the majority of the 3-phase production system demonstrate an effective level of corrosion control as direct result of the mitigation programs. However, there were two unforeseen events that originated in the 4th Quarter, which resulted in several 3-phase WLC exceeding the 2 mpy target. These events were: 1) corrosion inhibitor instability at winter temperature which caused blockage of some chemical inhibition delivery systems, and 2) material incompatibility with a test corrosion inhibitor degrading the delivery system tubing.

The monitoring data for the water injection system also demonstrate an effective level of corrosion control although the data show a slight reduction in corrosion control in majority service seawater well lines where service changes between produced water and seawater occur.

Section B.3 Corrosion Mitigation/Corrosion Inhibition

The plan and objective for corrosion mitigation is to control corrosion rates to acceptable levels. For internal corrosion control the principal means of mitigation is through the application of corrosion inhibitors.

Program:	Corrosion Mitigation – Corrosion Inhibitor (CI)
Target:	Control corrosion to acceptable levels
KPI:	Monitoring <2 mpy and inspection percent of increases, Target versus actual CI usage, injection volumes (ppm)
Section Reference:	Section D Chemical Optimization Activities

1. The field wide average inhibitor concentration increased from 147 to 151 ppm.
2. The corrosion inhibitor usage was 2.71 million gallons which was delivered at 99% of target.

The effectiveness of corrosion mitigation as a result of the application of corrosion inhibition is determined from corrosion monitoring and inspection programs. Corrosion monitoring data are a leading indicator and inspection data are a lagging indicator of corrosion mitigation efforts. There is a strong correlation between monitoring and inspection data, which gives confidence mitigation with corrosion inhibition can be managed in a timely manner using monitoring data.

Section B.4 External Inspection Program

The plan and objectives for the External Corrosion Program are comprehensive inspection coverage of equipment susceptible to Corrosion Under Insulation (CUI), minimize loss as a result of external corrosion failures and assure the equipment is fit-for-service (FFS) and safe to operate.

Program:	Corrosion Under Insulation
Target:	35,000 inspections/year
KPI:	% of locations inspected with external corrosion, Leak/Save ratio
Section Reference:	Section E.1 External Inspection

1. There were 35,384 external corrosion inspections completed, 3% were found with corrosion degradation.
2. There were 85 mechanical repairs identified as a result of external corrosion.
3. There were two leaks due to external corrosion, 1 on a 3-phase well line, 1 on a 3-phase flow line.
4. The Leak/Save ratio for the External Corrosion (CUI) Program was 98%.

Unlike internal corrosion, where mitigation can be managed through chemical inhibition, mechanical cleaning and/or operational controls, CUI is managed through detection and repair. Once CUI has been found through inspection activities, locations are scheduled for insulation and by-product removal, fit-for-service assessment, mechanical repair if needed and rehabilitation of the insulation system. The 2004 External Program met the program target completing over 35,000 inspections with a find rate of 3% consistent with recent history. The 85 mechanical repairs is similar the level of repair activity seen in 2003.

Section B.5 Cased Pipe Program

The plan and objective for the Cased Pipe Program is comprehensive inspection coverage of cased pipe segments at road and/or animal crossings. The excavation of crossings, as required, is performed to mitigate active corrosion and assure the equipment is fit-for-service and safe to operate.

Program:	Cased Pipe Inspection
Target:	100 inspection/yr
KPI:	Increases or active corrosion determined from repeat examinations.
Section Reference:	Section E.1.2 Cased Piping Survey Results

1. 108 cased piping segments were re-inspected using ILI or guided-wave inspection techniques.
2. 9 of the inspections showed potential active corrosion sites.
3. 21 cased pipe crossings were either fully or partially excavated and inspected.
4. Minor to moderate corrosion damage was found at 19 locations, no mechanical repairs were required and the damaged areas were rehabilitated.

After completing a baseline survey of all cased pipe segments, a long-term cased piping management strategy was implemented, consisting of repeat inspection and excavations. The long-term cased piping strategy will continue to evolve as the program is refined and more information is available.

Section B.6 Internal Inspection Program

The plan and objective for the Internal Program is comprehensive inspection coverage of equipment susceptible to internal degradation, the assessment of mechanisms and rate of wastage, minimize loss as a result of failures and assure the equipment is fit-for-service and safe to operate.

Program:	Internal Inspection Program
Target:	60,000 inspections/yr split between Field (~25,000) and Facility (~35,000) equipment
KPI:	% of locations inspected with increased metal loss, Leak/Save ratio
Section Reference:	Section E.2 Internal Inspection Program Results

1. There were 11,327 inspections on 3-phase flow lines, with 1% showing an increase.

2. There were 9,724 inspections on 3-phase well lines, with 4% showing an increase.
3. There were 1,897 inspections on water injection flow lines, with 6% showing an increase.
4. There were 2,759 inspections on water injection well lines, with 7% showing an increase.
5. There were 46 mechanical repairs identified as a result of internal corrosion.
6. There was one leak due to internal corrosion on a water injection pigging return well line.
7. The Leak/Save ratio for the Internal Inspection Program was 98%.

For 3-phase production and water injection systems, the inspection program shows a reduction in corrosion activity over the prior year based upon a decline in the percentage of inspection increases.

The number of internal corrosion repairs is higher than recent history. This is the result of two distinct activities: 1) pressure up-rating specific equipment to handle increased seawater capacity, 2) a thorough review of historical data and application of a more conservative fit-for-service criterion.

Section C

Weight Loss Coupons and Probes

Section C Weight Loss Coupons and ER Probes

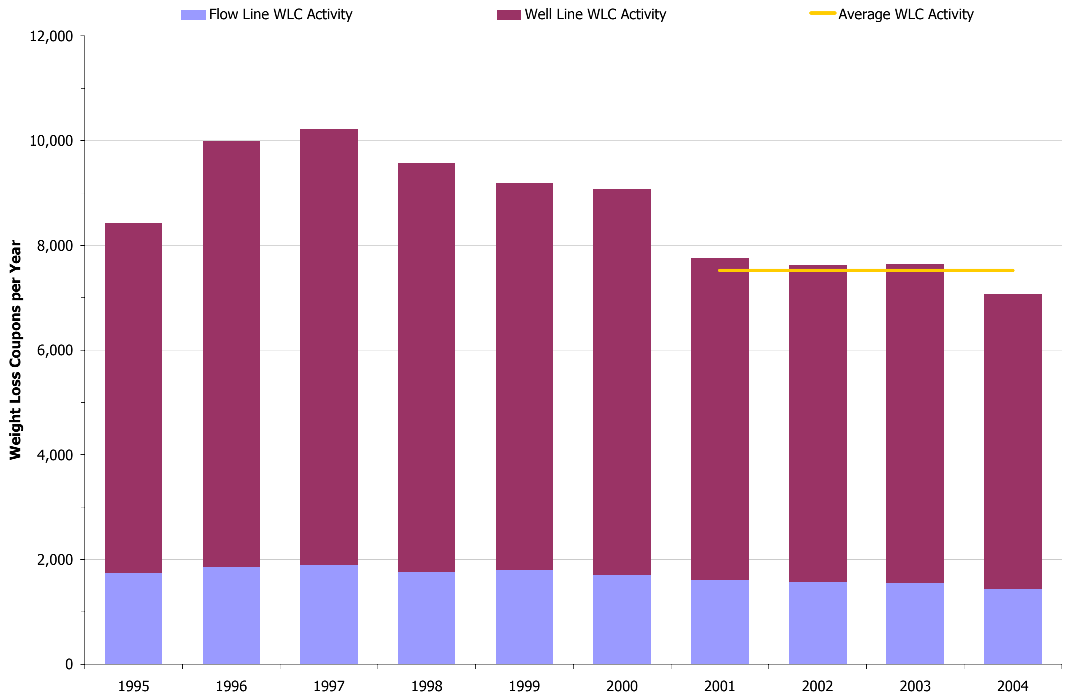
This section summarizes the results of the weight loss coupon corrosion monitoring and ER probe programs. Each of the major service categories are reviewed in turn with the results of the program discussed along with major conclusions and significant recommendations.

The number of weight loss coupon (WLC) monitoring locations by equipment type and service, is summarized in GPB Table C.1. The number of WLC processed over time is presented in GPB Figure C.1.

Detailed data tables for each configuration of equipment type, flow line and well line, and each service category, 3-phase, produced water and seawater, are provided in GPB Table C.6 and **GPB Table C.7**.

Service	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**
Flow Line										
3 Phase	219	315	268	272	266	254	256	257	255	242
Export/PO	3	7	7	5	5	6	4	6	5	5
Gas	3	3	1	1	1	0	0	0	1	0
Other	5	6	5	7	6	5	6	6	3	5
Water	36	37	45	43	46	45	44	44	48	38
Total	266	368	326	328	324	310	310	313	312	290
Well Line										
3 Phase	1,047	1,168	1,216	1,202	1,166	1,162	1,081	1,096	1,105	1,062
Export/PO	0	3	3	3	3	3	3	0	2	0
Gas	6	7	7	7	6	6	7	6	5	4
Other	8	9	9	7	8	8	6	8	8	6
Water	199	210	211	205	193	186	186	191	173	151
Total	1,260	1,397	1,446	1,424	1,376	1,365	1,283	1,301	1,293	1,223
Grand Total	1,526	1,765	1,772	1,752	1,700	1,675	1,593	1,614	1,605	1,513

GPB Table C.1 Corrosion Monitoring Locations by Equipment and Service



GPB Figure C.1 Corrosion Monitoring Activity Statistics by Equipment

Two corrosion coupons are typically recovered for each WLC pull with the exception of those lines that are regularly maintenance pigged where single flush mounted coupons are installed. The number of coupons, coupons per pull, and pull frequency has been optimized through time to gain greater value from the data obtained by the program.

As discussed in prior reports, there has been a gradual reduction in the number of weight loss coupons being evaluated, which reflects the on-going effort to optimize the program. Following the rationalization in 2000/01, the level of WLC activity has stabilized at ~7,500 coupons per year. The number of weight loss coupons reported for 2004 does not reflect the inventory of coupons that are installed in the system at year-end and still to be 'processed.' The reduction in 2004 coupon numbers therefore represents a timing effect and not a reduction in the program scope or activity level.

Section C.1 Three Phase Production Systems

Section C.1.1 Introduction

The corrosion mechanism of concern in the 3-phase production system is CO_2 corrosion, in which CO_2 from the produced fluids dissolves and dissociates in the produced water to form an acidic environment that is, if untreated, corrosive to carbon steel[4,5]. The primary corrosion control method is the continuous addition of corrosion inhibitor in the flow lines and a mix of continuous and batch inhibitor additions in the well lines. For the 3-

4 Corrosion Control in Petroleum Production, Harry G Byers, NACE, 1999
5 Corrosion Control in Oil and Gas Production, Treseder and Tuttle, NACE, 1998

phase production system the target corrosion rate from weight loss coupons is a general corrosion rate of 2 mpy or less (WLC ≤2 mpy).

The 3-phase production system has seen a consistently strong improvement in corrosion control since the early 1990's with a near order of magnitude reduction in the cross-country flow line corrosion rates. A similar trend is also seen in the inspection history discussed later in Section E. The decrease in corrosion rates in the 3-phase systems is attributable to the implementation and continuation of the aggressive corrosion inhibition program. The correlation between corrosion inhibitor concentration and corrosion rates in 3-phase flow lines is discussed in detail in Section D.

Section C.1.2 Cross Country Flow Line Coupons

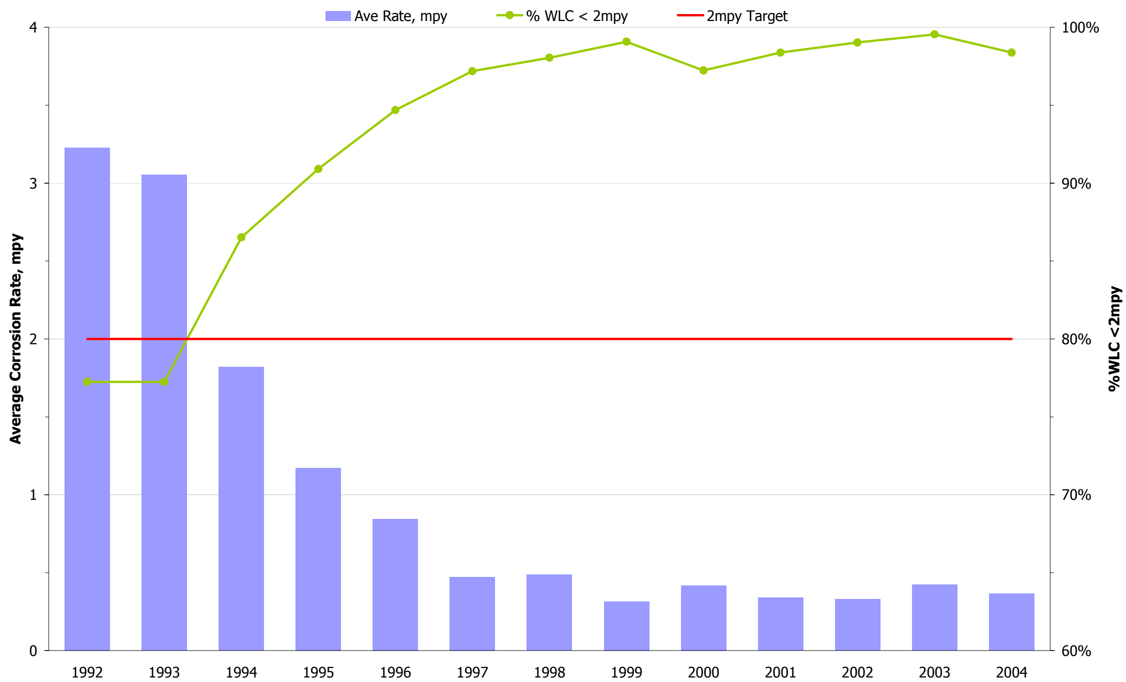
GPB Figure C.2 shows the average corrosion rate and percentage of coupons meeting the performance standard target since 1992. The results show the percentage of conformant flow lines has improved consistently over the last decade. The average corrosion rate for 2004 across GPB is approximately a factor of 10 lower than the corrosion rates from the early 1990's.

The slight decrease in the percentage of WLC <2 mpy can be attributed to three main causes. First, there were two flow lines that had an increase in fluid corrosivity. Second, there were precipitation problems with the winter corrosion inhibitor that lead to plugging of several continuous injection systems. Lastly, there was an incompatible test corrosion inhibitor which required the shutdown of the injection system in early 2005. Although the system shutdown occurred in 2005, the coupon reporting metrics (i.e. exposure mid-date) was in 2004. Refer to Section H.1.5 for details and corrective actions.

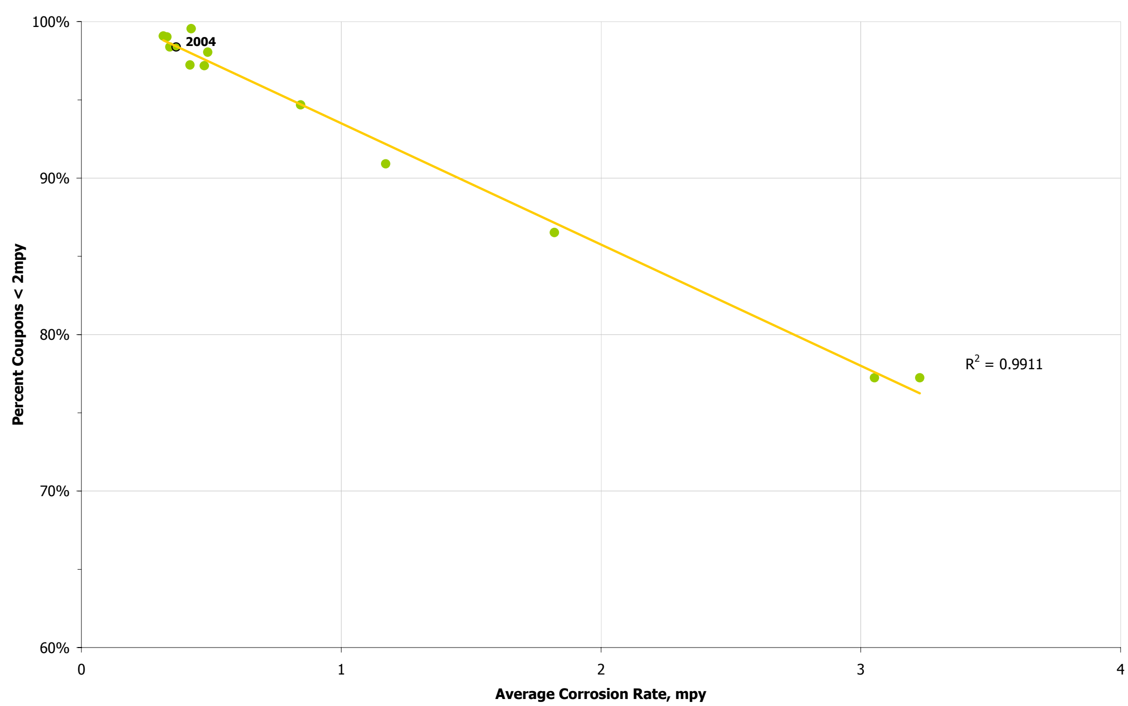
The overall reduction in corrosion rate is a direct result of the implementation of an aggressive corrosion mitigation program consisting primarily of continuous addition of corrosion inhibitor into the production fluids. This mitigation program has been implemented at considerable capital and operating expense but has resulted in flow lines which are now expected to be fit-for-service (FFS) for approximately 10 times as long as that expected in the early 1990's due to the reduction in corrosion rate.

GPB Figure C.3 shows the correlation between average corrosion rate and the percentage of weight loss coupons meeting the 2 mpy target. As might be expected, there is a very strong correlation between these two metrics. However, they should be viewed as being complementary. The percentage less than 2 mpy target has the advantage of highlighting non-conformances that would otherwise be lost in the calculation of the average.

Conversely, the average corrosion rate has the advantage of showing the overall performance trend that would otherwise be lost when only looking at the exceptions >2 mpy. Hence, it is necessary to review both metrics in order to gain an overall understanding of the performance of the program.



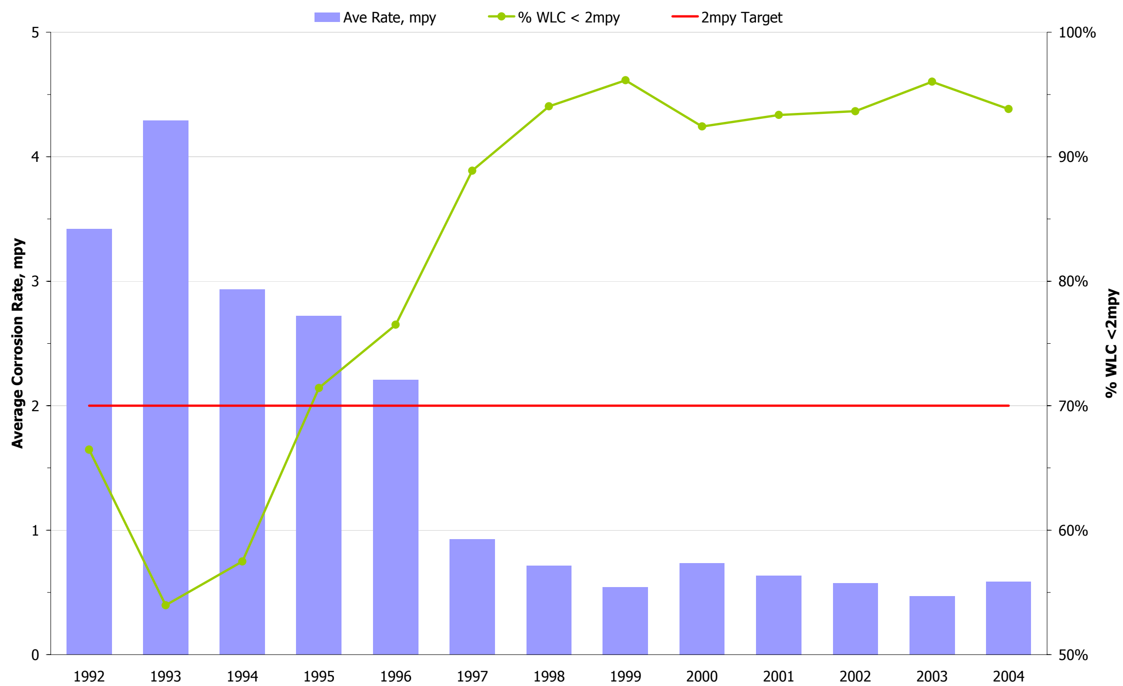
GPB Figure C.2 Flow Line Oil Service Corrosion Rate Trend



GPB Figure C.3 Correlation Between Flow Line Corrosion Rate and Percentage Conformance

Section C.1.3 Well Line Coupons

GPB Figure C.4 shows the average corrosion rate and percentage of WLC ≤2 mpy since 1992. The trends are very similar to those seen in the cross-country oil flow lines, showing a long-term improvement in the level of control from early 1990's to the present day with a slight decrease in performance from 2003 to 2004. This decrease in performance is largely due to the plugging event, previously discussed. Corrective actions are identified in Section H.1.5.



GPB Figure C.4 Well Line Oil Service Corrosion Rate Trend

The long term corrosion control improvement in the well lines is of the same magnitude as that seen in the flow lines with corrosion rates being reduced from an average >4 mpy in 1993 down to an average of 0.5 to 0.6 mpy over the past three years.

Section C.2 Water Injection Systems

The Water Injection System at GPB is comprised of produced water from the primary processing/separation facilities and seawater extracted from the Beaufort Sea and processed through the Seawater Treatment Plant (STP). During 2004, the seawater injection volumes increased from ~650 Mbpd to just over 1,000 Mbpd

As noted in the 2002 Report, the production database has now been linked to the corrosion and inspection database. This dynamic link provides a much more detailed view of service history/changes for the well line equipment, enabling an improved level of data analysis and quality.

The reporting format, which augments the performance metrics and was agreed with ADEC, can be summarized as follows:

Report Date Mid point of the WLC's exposure period,

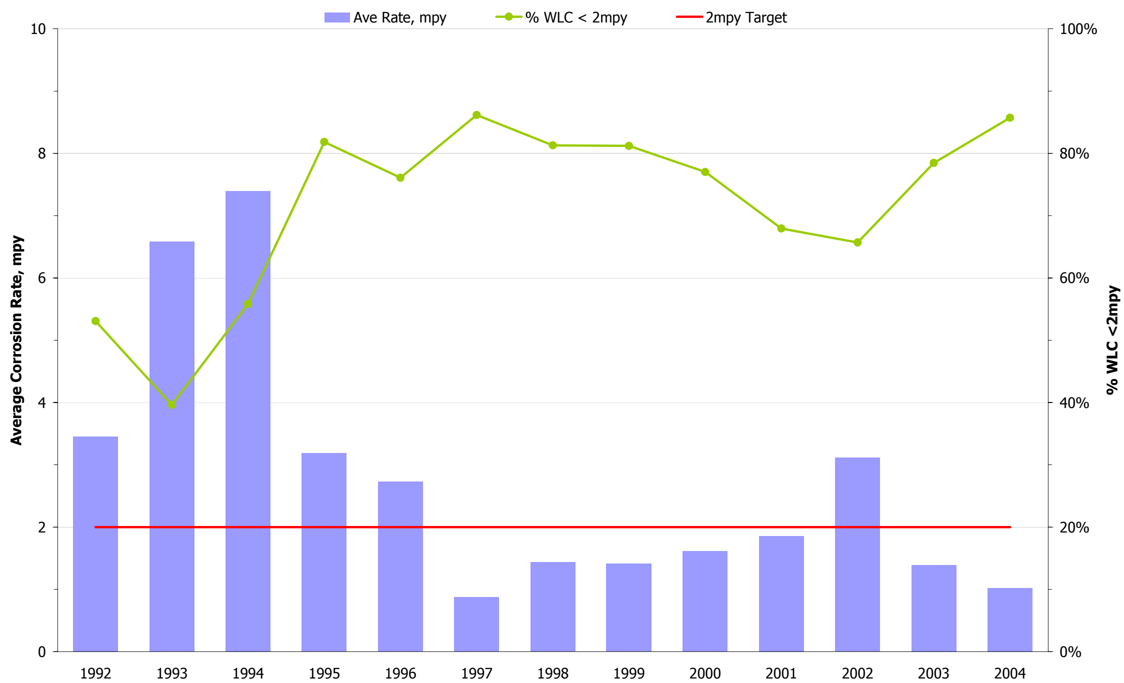
$$\text{Mid Date} = \text{Date In} + \frac{(\text{Date Out} - \text{Date In})}{2}$$

Service Type (a) Average corrosion rate with 100% exposure to service

(b) Average corrosion rate with simple service majority

Section C.2.1 Water Injection System Flow Lines

GPB Figure C.5 is a summary of aggregate data for produced water and seawater flow lines. The data show the 2003 and 2004 WLC corrosion rates have decreased below the 2 mpy target demonstrating improved corrosion control over the past two years.



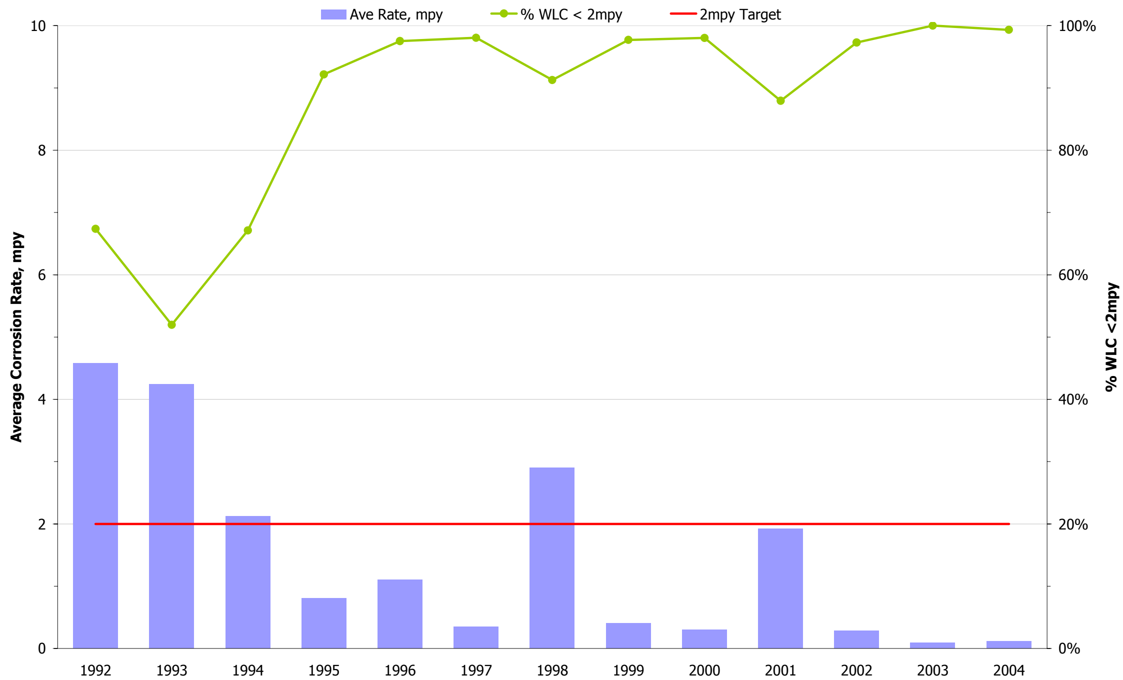
GPB Figure C.5 Flow Line PW/SW Service Corrosion Rate Trend

In summary, the average WLC corrosion rates for the aggregate water injection service continued to improve in 2004. This improvement is attributable to several different activities outlined in Section C.2.2 and Section C.2.3.

Section C.2.2 Produced Water Injection Well Lines

There are a number of corrosion mechanisms of concern in the produced water (PW) injection system. These mechanisms include CO_2 corrosion and differential concentration effects due to the high particulate content of the system. The particulates consist primarily of residual hydrocarbon remaining after the separation process, entrained production chemicals, and iron sulfides.

GPB Figure C.6 through GPB Figure C.8 summarize the historical corrosion rate data for produced water well lines. The data show the general corrosion rates in the produced water system have fallen as the level of inhibition in the 3-phase system was increased and supplemental produced water corrosion inhibitor injection was initiated.



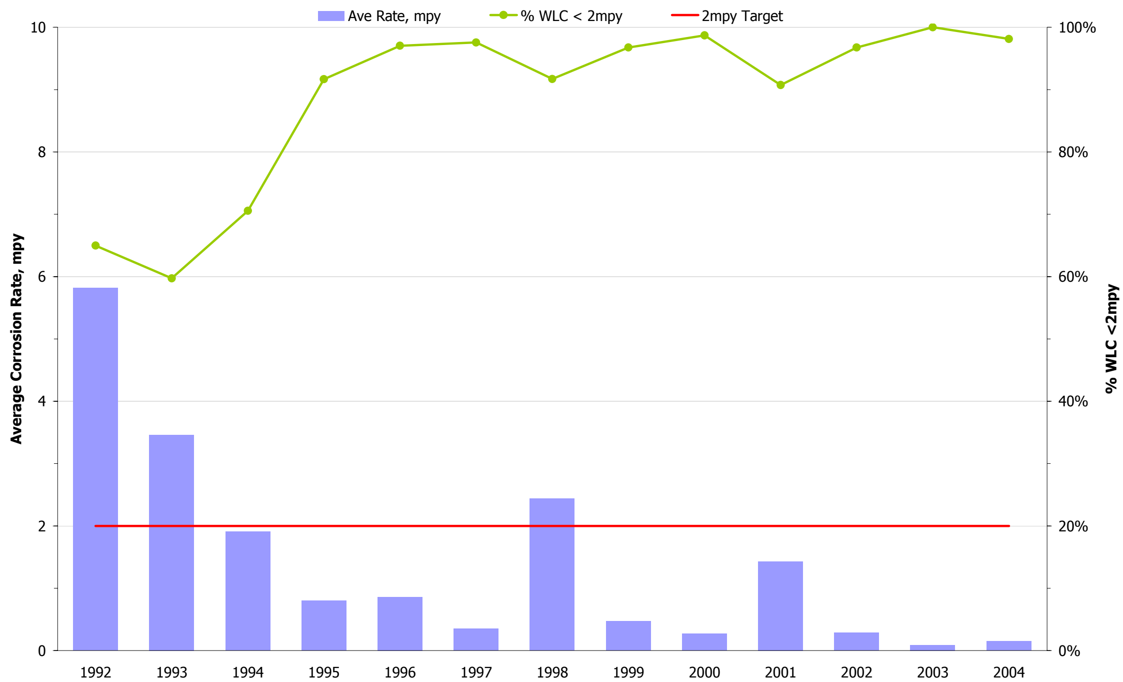
GPB Figure C.6 Corrosion Rates for 100% PW System

GPB Figure C.6 shows the performance for 100% produced water service. The 2004 levels maintained average corrosion rates at ~0.1 mpy and ~100% WLC ≤2 mpy.

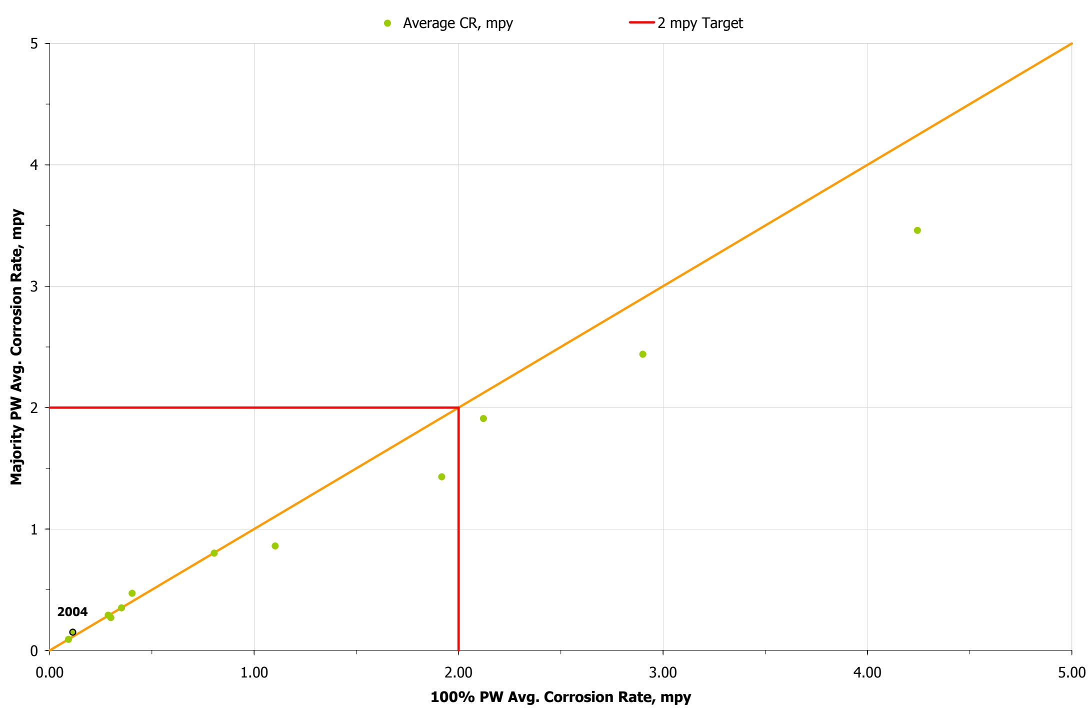
For those coupons where produced water was the majority service, GPB Figure C.7 shows the corrosion rate trends were very similar to those seen for 100% produced water service. The results for 2004 are encouraging in 100% and majority service, but caution is warranted as the data set is limited, and a long-term trend has not been established.

A comparison of the average corrosion rate for produced water between the 100% service and majority service is provided in GPB Figure C.8. The figure shows little difference between the data.

The overall improvement in the performance of the PW system from 2001 to date can be attributed primarily to three factors. First, there was a change in the upstream 3-phase continuous corrosion inhibitor in 2002 that gave more favorable partitioning characteristics to the water phase than the prior product. This had the effect of increasing the levels of corrosion inhibitor carried from the upstream system into the produced water distribution network. The second contributor was the expansion of corrosion mitigation programs specific to the PW system started in 2002. The program now includes limited inhibitor injection in the PW system at FS-1, FS-3, GC-1, GC-2 and GC-3. The third contribution is the increase in field-wide average concentration of 3-phase corrosion inhibitor over time.



GPB Figure C.7 Corrosion Rates for Majority PW System



GPB Figure C.8 Comparison of Corrosion Rates for 100% and Majority PW

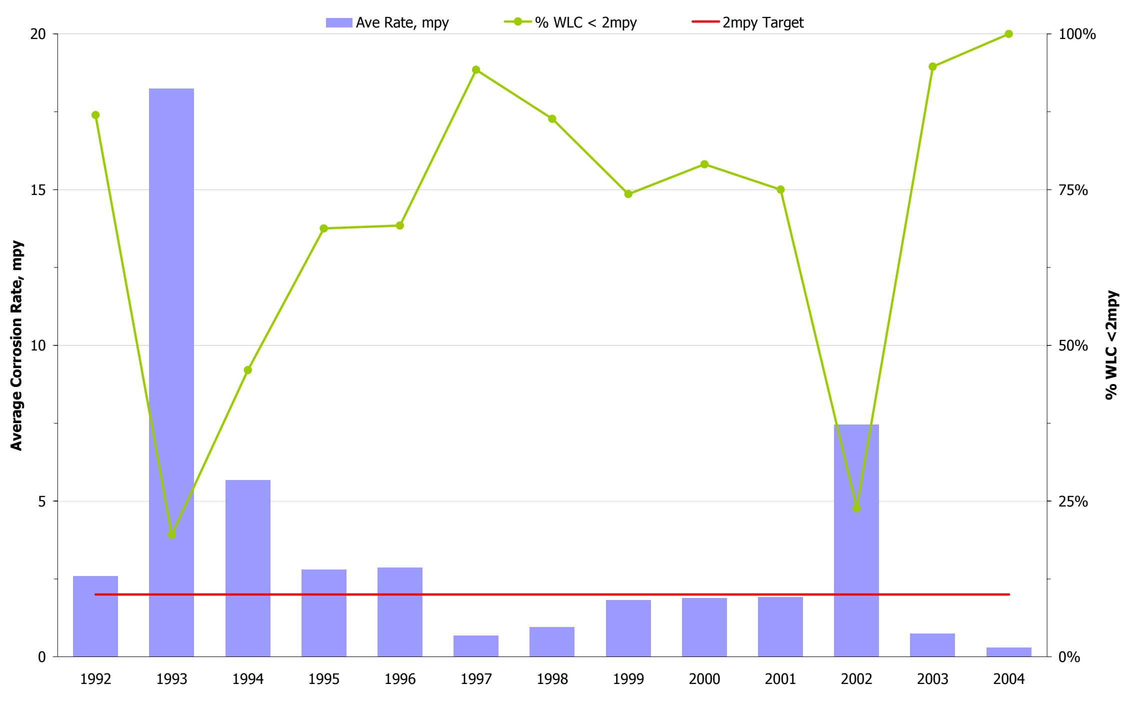
Section C.2.3 Seawater Injection Well Lines

The main corrosion mechanisms in the seawater (SW) injection systems are,

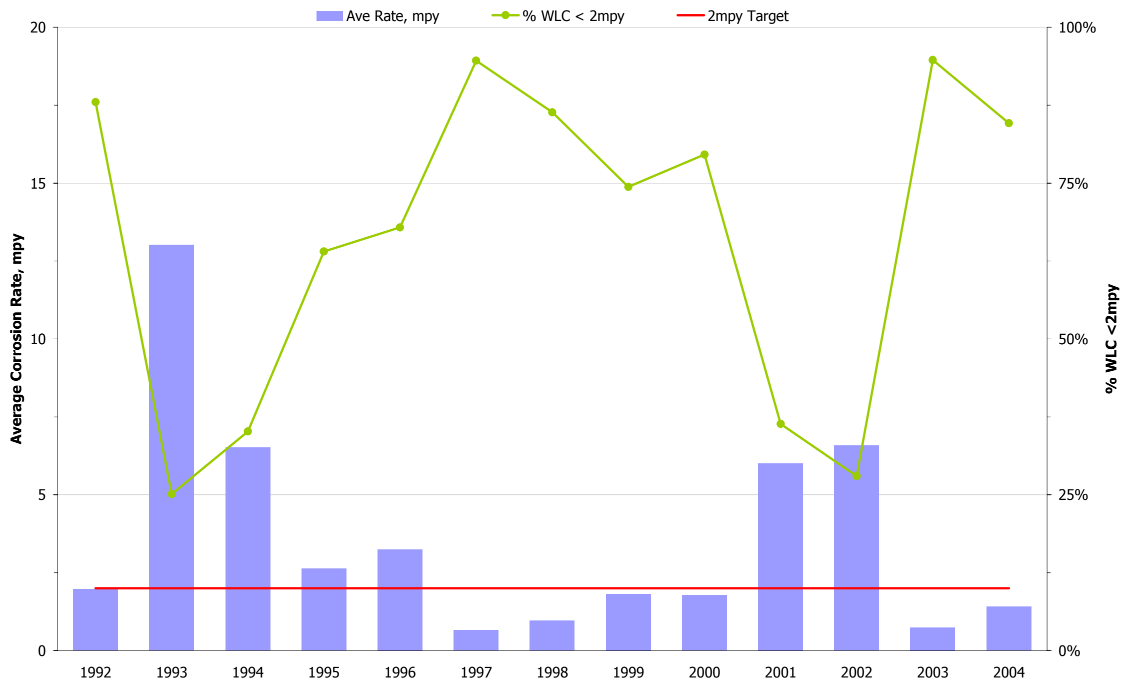
- Dissolved oxygen (DO) corrosion – This mechanism is mitigated by processing the seawater to remove the oxygen. Initial DO removal is achieved mechanically by vacuum stripping, which is then followed by chemical oxygen scavenging.
- Microbiological corrosion (MIC) – MIC is due to the action of anaerobic bacteria, and is mitigated by batch treatment with biocide, after processing to remove DO and prior to seawater transfer to the main cross country flow lines.

As with the PW system, the SW system data are presented as both 100% and majority service for the well line data, along with a comparison of general corrosion rates and pitting corrosion rates.

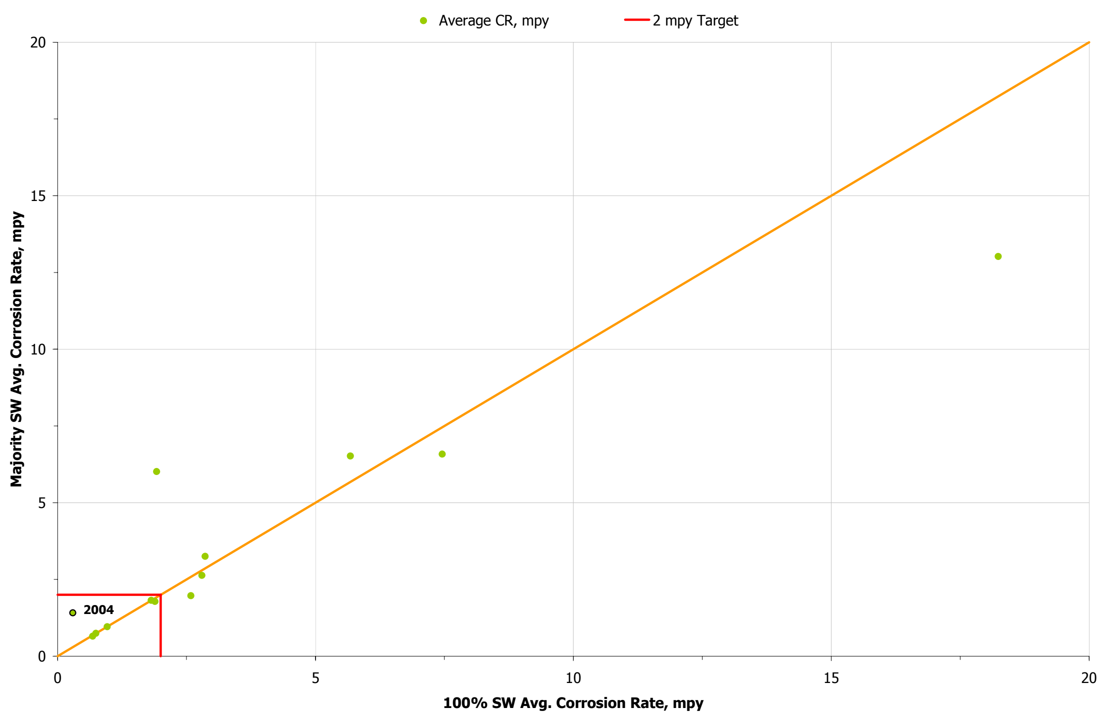
GPB Figure C.9 through GPB Figure C.11 show the corrosion rate trends in the SW system for both 100% SW service and majority SW service. For the 100% SW service, the improvement since 2002 is a result of implementation of the corrective actions outlined in previous reports. For the majority SW service, the decline in performance is believed to be due to a service change between PW and SW. Additional analysis will be performed during 2005 to better understand the difference between 100% and majority service.



GPB Figure C.9 Corrosion Rate for 100% Seawater System

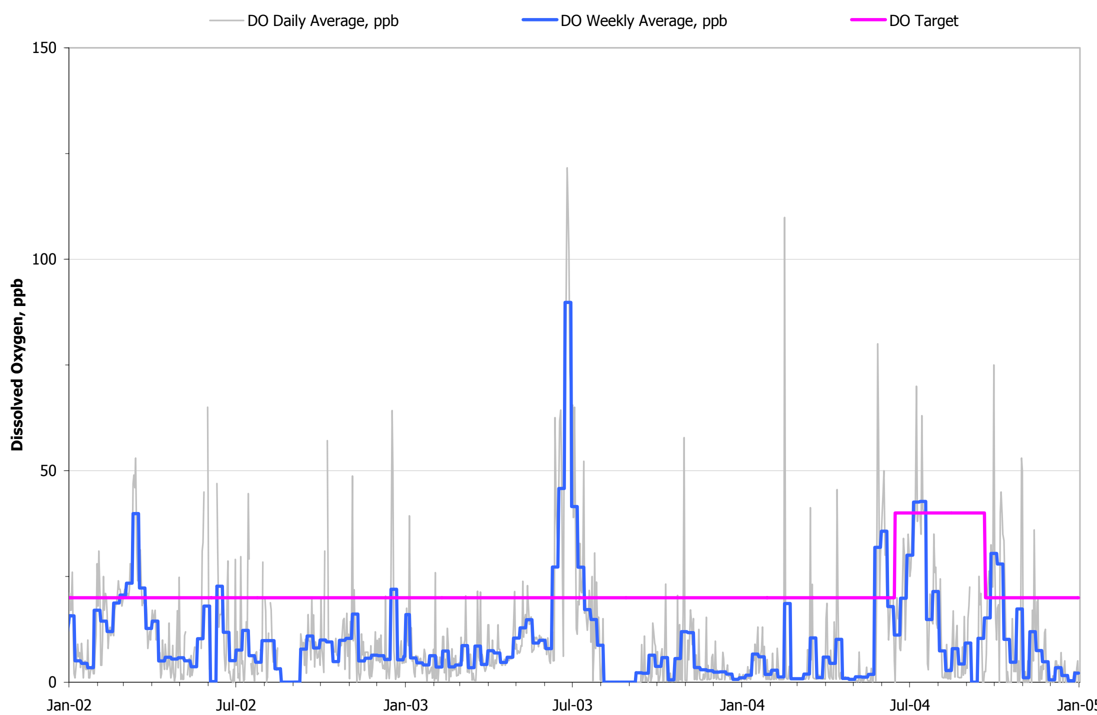


GPB Figure C.10 Corrosion Rates for Majority SW System



GPB Figure C.11 Comparison of Corrosion Rates for 100% and Majority SW System

GPB Figure C.12 shows the daily and weekly average level of dissolved oxygen control in the seawater system from 2002 through 2004. The DO excursion during the summers is due to seasonal decreases in rates of the chemical oxygen scavenging reactions during periods of spring runoff and seawater turbidity. DO control has improved markedly since the second half of 2003, and diligent plant operation continues to deliver good DO control.



GPB Figure C.12 Dissolved Oxygen Control Performance for the Seawater System

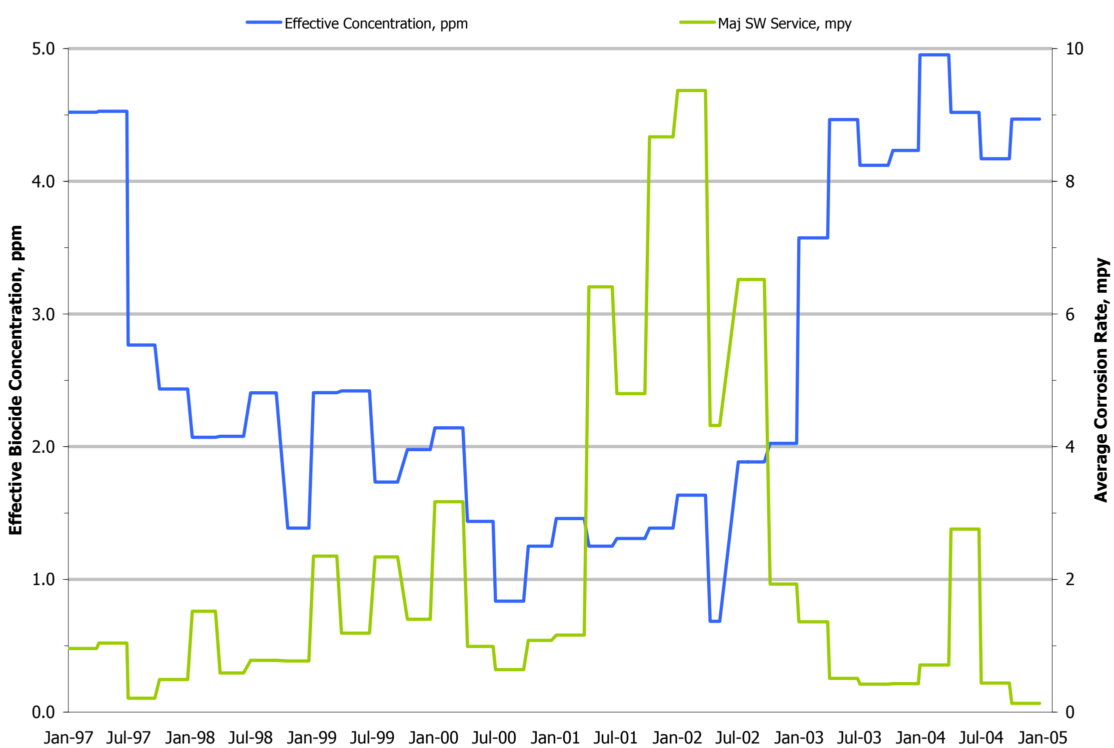
GPB Table C.2 summarizes the changes in the biocide treatment program for the SW system. Biocide dosage was increased in Mar-03 by 50% at STP to increase the effectiveness in downstream parts of the seawater system. This action decreased the downstream coupon corrosion rates faster than expected. In Dec-03, the glutaraldehyde/quaternary amine biocide was replaced temporarily with glutaraldehyde. In Oct-04, the biocide was switched back to glutaraldehyde/quaternary amine.

GPB Figure C.13 shows the corresponding effective concentration of biocide and the average corrosion rate for well line coupons in majority SW service. The beneficial effect of increasing the biocide injection concentration at STP is clearly depicted and helped to reduce seawater system corrosion rates below the 2 mpy target.

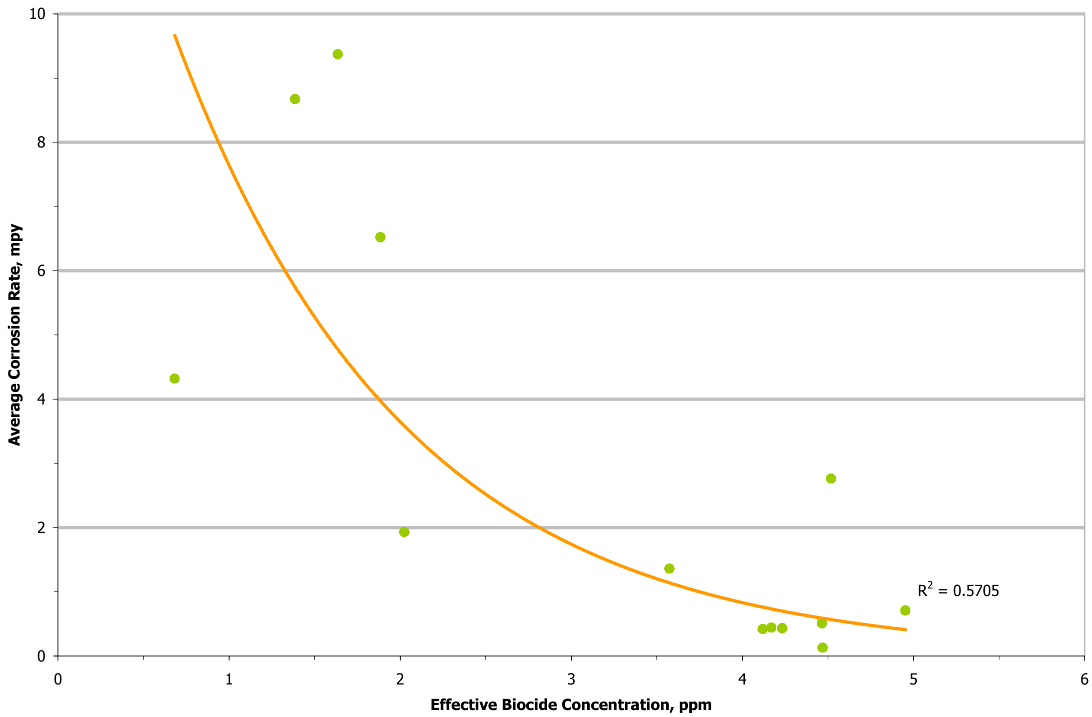
From	To	ppm	Interval days	Product
Jan-97	Jul-97	750	7	Glutaraldehyde
Jul-97	Feb-00	750	14	Glutaraldehyde
Feb-00	Aug-01	450	14	Glutaraldehyde/quaternary amine blend
Aug-01	Jul-02	500	14	Glutaraldehyde/quaternary amine blend
Jul-02	Dec-02	500	7	Glutaraldehyde/quaternary amine blend
Dec-02	Mar-03	500	7	Glutaraldehyde/quaternary amine blend
Mar-03	Dec-03	750	7	Glutaraldehyde/quaternary amine blend
Dec-03	Oct-04	750	7	Glutaraldehyde
Oct-04	Present	750	7	Glutaraldehyde/quaternary amine blend

GPB Table C.2 Biocide Treatment Concentration and Interval

The effect of increasing biocide on the corrosion rates in the SW system are more clearly shown in GPB Figure C.14, which shows the correlation between the average corrosion rate and effective biocide concentration for 2001 through 2004.



GPB Figure C.13 Biocide Treatment Concentration and Corrosion Rate



GPB Figure C.14 Average Corrosion Rate vs. Effective Concentration, 2001 - 2004

In summary, improvements made in DO control and increased biocide injection rate have reduced corrosion rates in the seawater system. The data suggest progress has been made in returning the seawater system to control; however as with the produced water system, caution is warranted. Therefore, there will be an on-going effort in 2005 to assure that this trend is confirmed and continued. Should a long-term trend of reduced corrosion rates not be established, then further corrective actions will be implemented.

Section C.3 Electrical Resistance Probes

ER probes are installed in various locations to monitor corrosion rates in flow lines throughout GPB. ER probes measure a change in resistance due to material loss from corrosion and the measurements are converted to provide corrosion rates in mils per year. ER probes are equipped with remote data collectors (RDC), which measure and record the metal loss data every 4 hours. This provides an adequate number of data points to assess corrosion rates while maximizing battery life in the units.

The type of ER probe used is a T-10 that has 5 mils (0.005") of usable metal thickness. All flow line ER probes are replaced based on a 1-year service life, or when one half the usable metal thickness has been consumed. This reduces false negative and false positive readings as a result of damaged or unresponsive probes.

ER probes are located on both the upstream (well pad) end and downstream (gathering center) end of flow lines located on the west side of GPB. On the east side, probes are only located on the downstream (flow station) end of flow lines.

For the electrical resistance (ER) probes, the number of active locations in the flow lines is given in GPB Table C.3. 2004 had the greatest number of ER probes in service which reflects an ongoing effort to utilize ER probe monitoring equipment on all large diameter oil service flow lines.

Year	Total Probe Locations
2001	83
2002	82
2003	85
2004	87

GPB Table C.3 Active ER Probe Locations

ER probe data are collected in the field and uploaded to the corrosion and inspection database once per week. The target for ER probe corrosion rate is ≤2 mpy. Each ER probe with a corrosion rate greater than 2 mpy is evaluated to determine data validity. After verifying an increase in corrosion rates based on the probe data and other supporting data, an action is determined. The action is typically a corrosion inhibitor increase, but other sorts of mitigation may be recommended.

GPB Table C.4 shows the number of probes with corrosion rates greater than target as compared to the number actioned dating back to 2001.

Year	% <2 mpy	No. ER Probe > 2	No. ER Probes Actioned
2001	97%	193	6
2002	97%	137	6
2003	96%[6]	138	21
2004	92%	316	59

GPB Table C.4 Number of ER Probes >2 mpy and Actioned

The 59 occurrences greater than 2 mpy in 2004 were mitigated with corrosion inhibitor rate increases. The percentage of ER probes actioned has increased from 2% in 2001 to 19% in 2004. This increase is the result of emphasis on ER probe reliability and a more conservative approach responding to monitoring data.

Section H.1.5 shows the corrective mitigation actions taken as a result of ER probe readings exceeding target and Appendix 3.3.1 describes by example, the methodology

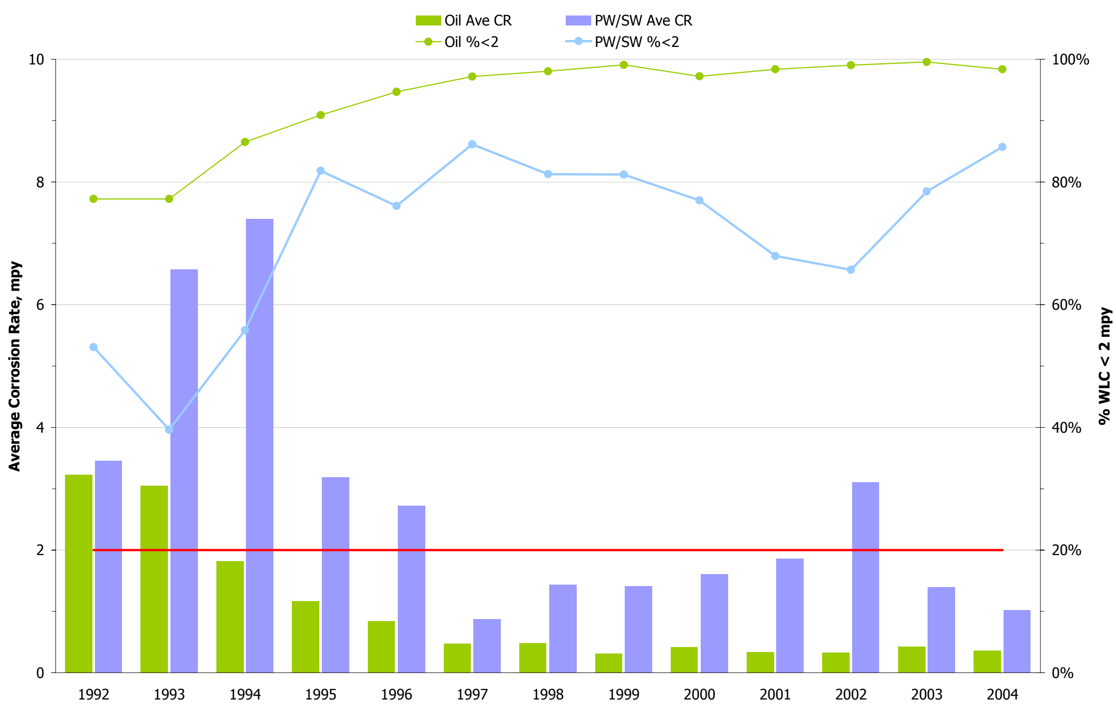
[6] Incorrectly reported as 93% in 2003 Report

by which corrosion inhibitor concentration is increased as a result of ER probes monitoring.

Section C.4 1992 to Date Summary

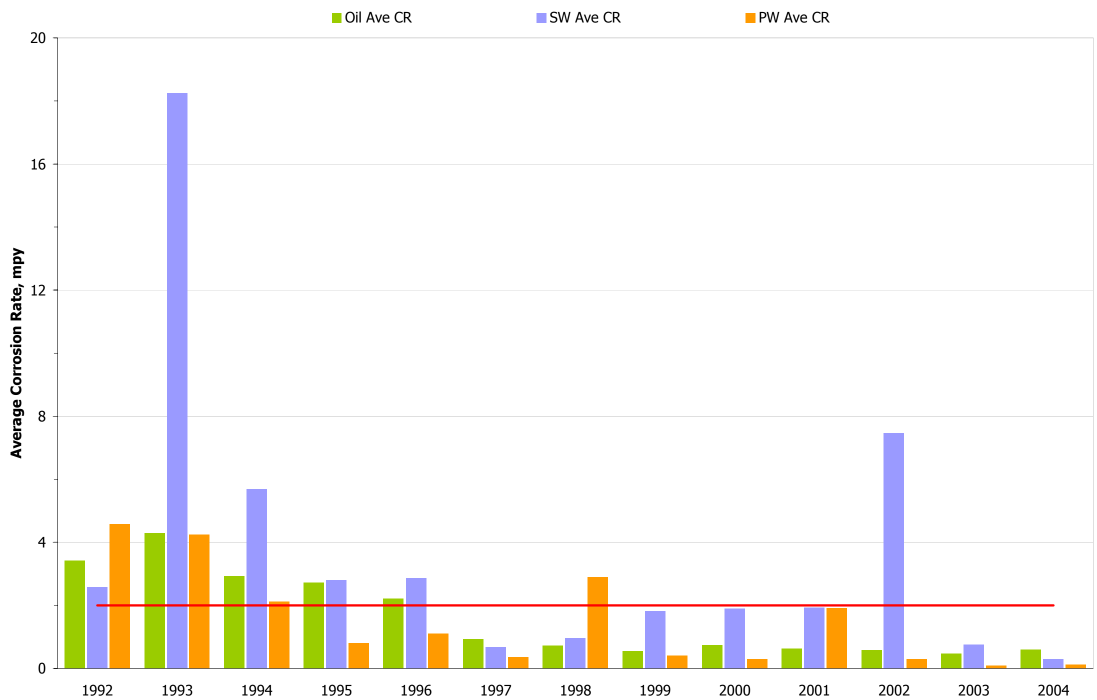
Section C.4.1 System by System Summary

This section provides system-by-system summary since 1992 for the major systems at GPB. GPB Figure C.15 shows the corrosion rate and corrosion target conformance since 1992. The high performance in the 3-phase production system has remained essentially unchanged since 2000. The reasons for improvement in the water injection system performance were provided in Section C.2.

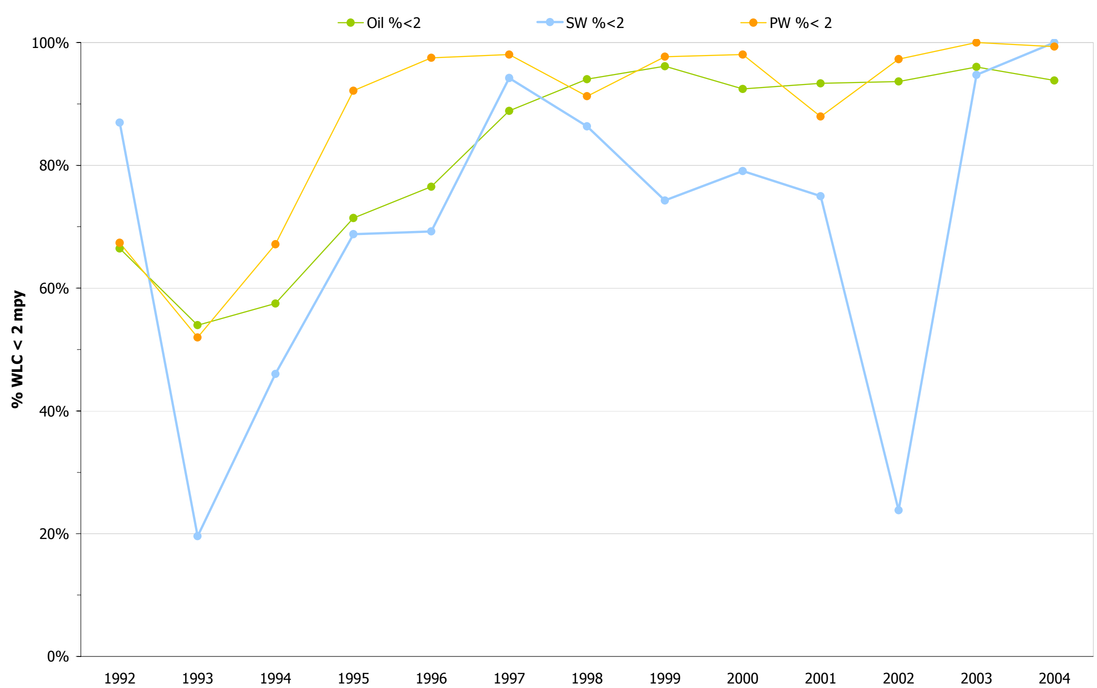


GPB Figure C.15 Flow Line Corrosion Coupon Summary by Equipment and Service

GPB Figure C.16 shows the corrosion rate and GPB Figure C.17 shows corrosion conformance for well lines. The well line 3-phase system performance has remained essentially unchanged since 2000. The produced water well lines corrosion performance has remained essentially consistent since 2002. The well lines in seawater service show additional improvement in performance.

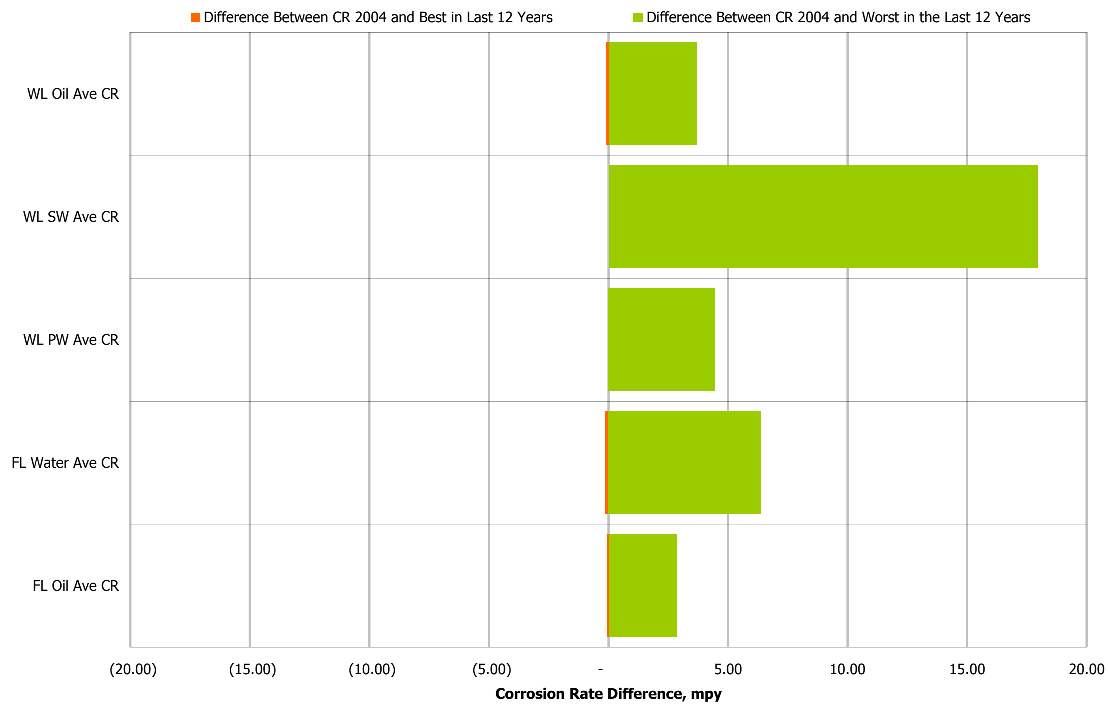


GPB Figure C.16 Well Line Average Corrosion Rate Summary by Equipment and Service



GPB Figure C.17 Well line %<2 mpy Summary by Equipment and Service

In order to assess the relative performance of the corrosion management program today versus that of the last 12 years, GPB Table C.5 and GPB Figure C.18 were generated as a summary. The data show the difference between the 2004 WLC corrosion rate for each of the systems and the best, or lowest, WLC corrosion rate and the worst, or highest, WLC corrosion rate observed since 1992. This is an approximate measure of the successes and/or shortcomings of the program today versus the ~12-year history and highlights areas for attention. The results indicate the current level of corrosion control, as determined by weight loss coupons, is at or near the best levels of control in the last 12 years for each system.



GPB Figure C.18 WLC Corrosion Rate Difference by Service and Type

System	2004 CR mpy	Best mpy	(Best – 2004) mpy	Worst mpy	(Worst – 2004) Mpy
FL Oil Ave CR	0.37	0.32	-0.05	3.2	2.86
FL Water Ave CR	1.02	0.87	-0.15	7.4	6.37
WL PW Ave CR	0.11	0.09	-0.02	4.6	4.47
WL SW Ave CR	0.30	0.30	0.00	18.2	17.94
WL Oil Ave CR	0.59	0.47	-0.12	4.3	3.70

GPB Table C.5 WLC Corrosion Rate Difference by Service and Type

In summary,

Well Line Oil Service – Significant improvements in performance occurred from 1992 to 1997 when the average corrosion rate (CR) was reduced from 3.6 to 1.0 mpy (~70%

improvement) and conformance to the 2 mpy target was increased from 64% to 88% (~40% improvement). Since then, average CR has been <1 mpy, and target conformance performance has been >90%. In 2004, values were 0.6 mpy and 94% respectively.

Flow Line Oil Service - Significant improvements in performance occurred from 1992 to 1997 when the average CR was reduced from 3.3 to 0.5 mpy (~85% improvement) and conformance to the 2 mpy target was increased from 77 to 97% (~25% improvement). Since then, CR and target conformance performance has improved. The 2004 CR and target conformance performance were 0.4 mpy and 98%, respectively.

Flow Line Processed Oil – These are the flow lines supplying processed hydrocarbon to Pump Station 1 and as might be expected for a very low water cut production stream, the corrosion rates are consistently very low with 100% of the coupons being reported as less than 2 mpy from 1995 to 2004.

Well Line PW Service – Average CR and percent conformance with the 2 mpy target was just under the historical best performance, with 0.1 mpy and 99%. The two excursions, 1998 and 2001, were likely the result of reduced system velocities and oil system corrosion inhibitor changes. Work continues in the evaluation of new corrosion control techniques designed specifically for the PW system.

Well Line SW Service – Performance deteriorated from 1997 through 2002 with the average CR increased from 0.7 to 7.5 mpy. Average CR and percent conformance with the 2 mpy target rebounded in 2003 to 0.7 mpy and 95% respectively. For the 100% SW service, this trend continued in 2004, with an average CR of 0.3 mpy and percent conformance of 100% <2 mpy. For the Majority SW service, there was a decline in 2004 with 1.4 mpy and 85% <2 mpy. This decline is believed to be due to the service change between SW and PW.

Flow Line PW/SW Service – Performance deteriorated from 1992 to 1994 when average CR increased from 3.5 to 7.4 mpy. However, significant improvements occurred from 1994 to 1997 when the average CR was reduced to 0.8 mpy. Since then, CR and target conformance degraded until 2003 when performance improved to 1.4 mpy and 78% respectively. The improved performance continued in 2004 with the CR and target conformance performance at 1.0 mpy and 86%, respectively..

BU	Equip	Service	Metric	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
GPB	FL	OIL	WLC	782	949	972	1,397	1,542	1,597	1,487	1,513	1,443	1,294	1,338	1,321	1,236
GPB	FL	OIL	Ave CR	3.23	3.05	1.82	1.17	0.84	0.47	0.49	0.32	0.42	0.34	0.33	0.42	0.37
GPB	FL	OIL	SD CR	8.64	10.41	5.13	5.37	3.95	1.82	3.77	0.57	0.84	0.90	0.67	2.39	0.99
GPB	FL	OIL	WLC < 2	604	733	841	1,270	1,460	1,552	1,458	1,499	1,403	1,273	1,325	1,315	1216
GPB	FL	OIL	% WLC < 2mpy	77%	77%	87%	91%	95%	97%	98%	99%	97%	98%	99%	100%	98%
GPB	FL	PW/SW	WLC	81	106	154	198	184	195	171	181	161	131	137	144	112
GPB	FL	PW/SW	Ave CR	3.45	6.58	7.40	3.18	2.73	0.87	1.44	1.41	1.61	1.86	3.11	1.39	1.02
GPB	FL	PW/SW	SD CR	4.43	9.13	15.37	9.52	6.15	1.77	3.72	2.42	2.77	2.54	5.39	2.52	1.46
GPB	FL	PW/SW	WLC < 2	43	42	86	162	140	168	139	147	124	89	90	113	96
GPB	FL	PW/SW	%<2mpy	53%	40%	56%	82%	76%	86%	81%	81%	77%	68%	66%	78%	86%
GPB	FL	PO	WLC		16	23	24	34	44	32	34	36	22	28	44	36
GPB	FL	PO	Ave CR		0.43	0.56	0.13	0.23	0.13	0.16	0.14	0.17	0.08	0.09	0.11	0.10
GPB	FL	PO	SD CR		0.41	0.39	0.17	0.29	0.19	0.11	0.05	0.07	0.06	0.03	0.04	0.05
GPB	FL	PO	WLC < 2		16	23	24	34	44	32	34	36	22	28	44	36
GPB	FL	PO	%< 2 mpy		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
GPB	WL	OIL	WLC	6,826	5,660	4,997	5,277	6,607	6,821	6,449	6,219	6,265	4,889	5,327	5,568	5,087
GPB	WL	OIL	Ave CR	3.42	4.29	2.93	2.72	2.21	0.92	0.72	0.54	0.74	0.64	0.58	0.47	0.59
GPB	WL	OIL	SD CR	7.81	8.05	4.51	6.96	6.18	2.33	3.69	1.20	1.49	1.60	1.12	1.15	1.43
GPB	WL	OIL	WLC < 2	4,537	3,055	2,873	3,769	5,055	6,062	6,065	5,979	5,791	4,564	4,989	5,347	4773
GPB	WL	OIL	%< 2 mpy	66%	54%	57%	71%	77%	89%	94%	96%	92%	93%	94%	96%	94%
GPB	WL	Majority PW	WLC	531	514	662	829	976	1,073	966	740	699	659	464	430	374
GPB	WL	Majority PW	Ave CR	5.82	3.46	1.91	0.80	0.86	0.35	2.44	0.47	0.27	1.43	0.29	0.09	0.15
GPB	WL	Majority PW	SD CR	12.84	4.81	1.92	1.19	8.68	2.26	12.05	1.64	0.43	8.55	0.88	0.13	0.41
GPB	WL	Majority PW	WLC < 2	345	307	467	760	947	1,047	886	716	690	598	449	430	367
GPB	WL	Majority PW	% WLC <2 mpy	65%	60%	71%	92%	97%	98%	92%	97%	99%	91%	97%	100%	98%
GPB	WL	100% PW	WLC	282	304	286	485	604	717	721	524	459	473	332	358	302
GPB	WL	100% PW	Ave CR	4.58	4.24	2.12	0.81	1.10	0.35	2.90	0.40	0.30	1.92	0.29	0.09	0.11
GPB	WL	100% PW	SD CR	9.25	5.34	2.05	1.19	10.98	2.62	13.64	1.50	0.51	10.05	0.97	0.13	0.28
GPB	WL	100% PW	WLC < 2	190	158	192	447	589	703	658	512	450	416	323	358	300
GPB	WL	100% PW	% WLC < 2mpy	67%	52%	67%	92%	98%	98%	91%	98%	98%	88%	97%	100%	99%
GPB	WL	Majority SW	WLC	434	410	384	317	162	56	44	82	98	44	25	19	26
GPB	WL	Majority SW	Ave CR	1.97	13.02	6.52	2.63	3.25	0.65	0.96	1.82	1.78	6.01	6.58	0.74	1.41
GPB	WL	Majority SW	SD CR	5.48	16.14	7.55	3.86	5.26	1.20	1.14	2.36	2.77	6.88	5.27	0.68	2.87
GPB	WL	Majority SW	WLC < 2	382	103	135	203	110	53	38	61	78	16	7	18	22
GPB	WL	Majority SW	% WLC < 2mpy	88%	25%	35%	64%	68%	95%	86%	74%	80%	36%	28%	95%	85%
GPB	WL	100% SW	WLC	184	194	176	189	78	52	44	70	86	16	21	19	12
GPB	WL	100% SW	Ave CR	2.59	18.24	5.68	2.80	2.86	0.68	0.96	1.82	1.89	1.92	7.46	0.74	0.30
GPB	WL	100% SW	SD CR	7.13	19.04	8.04	4.43	5.39	1.24	1.14	2.50	2.93	1.07	5.28	0.68	0.27
GPB	WL	100% SW	WLC < 2	160	38	81	130	54	49	38	52	68	12	5	18	12
GPB	WL	100% SW	% WLC < 2mpy	87%	20%	46%	69%	69%	94%	86%	74%	79%	75%	24%	95%	100%

GPB Table C.6 Flow and Well Line General Corrosion Rate Data Summary

This page is intentionally blank

BU	Equip	Service	Metric	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
GPB	FL	OIL	WLC	782	949	972	1,397	1,542	1,597	1,487	1,513	1,443	1,294	1,338	1,321	1,236
GPB	FL	OIL	Ave P CR	7.0	5.5	4.1	8.81	7.71	6.74	2.93	1.65	1.93	1.28	0.74	0.65	1.2
GPB	FL	OIL	SD P CR	21.9	14.8	13.2	21.95	14.92	13.88	6.67	6.17	7.73	10.59	3.93	8.32	5.9
GPB	FL	OIL	P WLC < 20	688	869	923	1,280	1,448	1,542	1,461	1,490	1,410	1,279	1,317	1,319	1,221
GPB	FL	OIL	% P WLC <20mpy	88%	92%	95%	92%	94%	97%	98%	98%	98%	99%	98%	100%	99%
GPB	FL	PW/SW	WLC	81	106	154	198	184	195	171	181	161	131	137	144	112
GPB	FL	PW/SW	Ave P CR	8.5	15.8	17.3	17.03	14.40	15.26	11.36	5.31	6.47	9.37	13.12	7.07	3.7
GPB	FL	PW/SW	SD P CR	8.5	5.4	8.6	6.60	5.40	4.10	3.01	2.53	2.32	0.91	0.01	0.01	0.0
GPB	FL	PW/SW	P WLC < 20	80	97	140	190	178	195	170	181	161	131	134	144	112
GPB	FL	PW/SW	% P WLC <20mpy	99%	92%	91%	96%	97%	100%	99%	100%	100%	100%	98%	100%	100%
GPB	FL	PO	WLC		16	23	24	34	44	32	34	36	22	28	44	36
GPB	FL	PO	Ave P CR		0.5	0.7	1.88	2.56	3.73	2.19	1.26	1.44	1.05	0.77	0.32	0.7
GPB	FL	PO	SD P CR		1.2	2.5	3.42	4.64	4.31	5.65	2.43	3.49	3.47	3.92	2.11	2.9
GPB	FL	PO	P WLC < 20		16	23	24	34	44	31	34	36	22	26	44	36
GPB	FL	PO	% P WLC <20mpy		100%	100%	100%	100%	100%	97%	100%	100%	100%	93%	100%	100%
GPB	WL	OIL	WLC	6,826	5,660	4,997	5,277	6,607	6,821	6,449	6,219	6,265	4,889	5,327	5,568	5,087
GPB	WL	OIL	Ave P CR	7.3	9.4	5.2	11.37	11.71	5.24	3.24	2.76	3.28	1.97	1.71	1.66	2.0
GPB	WL	OIL	SD P CR	22.4	24.7	14.3	31.31	28.93	14.67	10.08	7.80	10.16	6.43	5.61	5.33	5.9
GPB	WL	OIL	P WLC < 20	5,897	4,998	4,660	4,619	5,739	6,540	6,285	6,094	6,078	4,784	5,251	5,518	4,991
GPB	WL	OIL	% P WLC <20mpy	86%	88%	93%	88%	87%	96%	97%	98%	97%	98%	99%	99%	98%
GPB	WL	Majority PW	WLC	531	514	662	829	976	1073	966	740	699	659	464	430	374
GPB	WL	Majority PW	Ave P CR	34.1	24.7	15.8	20.18	15.02	9.65	20.65	8.87	4.65	6.69	2.95	1.08	2.3
GPB	WL	Majority PW	SD P CR	41.1	31.9	27.1	29.05	29.64	28.96	58.54	26.07	9.75	17.52	8.97	3.01	9.4
GPB	WL	Majority PW	P WLC < 20	258	294	499	574	802	968	807	674	670	579	452	429	369
GPB	WL	Majority PW	% P WLC < 20mpy	49%	57%	75%	69%	82%	90%	84%	91%	96%	88%	97%	100%	99%
GPB	WL	100% PW	WLC	282	304	286	485	604	717	721	524	459	473	332	358	302
GPB	WL	100% PW	Ave P CR	4.6	4.2	2.1	0.81	1.10	0.35	2.90	0.40	0.30	1.92	0.29	0.09	0.1
GPB	WL	100% PW	SD P CR	9.3	5.3	2.0	1.19	10.98	2.62	13.64	1.50	0.51	10.05	0.97	0.13	0.3
GPB	WL	100% PW	WLC < 20	190	158	192	447	589	703	658	512	450	416	323	358	300
GPB	WL	100% PW	% P WLC <20mpy	67%	52%	67%	92%	98%	98%	91%	98%	98%	88%	97%	100%	99%
GPB	WL	Majority SW	WLC	434	410	384	317	162	56	44	82	98	44	25	19	26
GPB	WL	Majority SW	Ave P CR	4.7	17.3	9.5	11.36	16.88	1.50	1.55	5.62	6.61	18.80	29.33	9.11	9.1
GPB	WL	Majority SW	SD P CR	15.6	44.3	14.2	15.43	23.11	4.52	2.31	8.16	10.40	18.59	27.35	20.21	16.0
GPB	WL	Majority SW	P WLC < 20	404	320	331	263	115	55	44	80	92	24	15	16	23
GPB	WL	Majority SW	% P WLC < 20mpy	93%	78%	86%	83%	71%	98%	100%	98%	94%	55%	60%	84%	88%
GPB	WL	100% SW	WLC	184	194	176	189	78	52	44	70	86	16	21	19	12
GPB	WL	100% SW	Ave P CR	5.2	13.3	7.8	9.09	10.10	0.54	1.55	5.24	5.57	9.13	31.62	9.11	9.2
GPB	WL	100% SW	SD P CR	18.9	18.8	12.1	13.41	19.87	2.18	2.31	8.49	6.38	7.30	29.49	20.21	21.4
GPB	WL	100% SW	P WLC < 20	172	157	156	162	62	52	44	68	82	14	12	16	10
GPB	WL	100% SW	% P WLC <20mpy	93%	81%	89%	86%	79%	100%	100%	97%	95%	88%	57%	84%	83%

GPB Table C.7 Flow and Well Line Pitting Rate Data Summary

Section D

Chemical Optimization Activities

Section D Chemical Optimization Activities

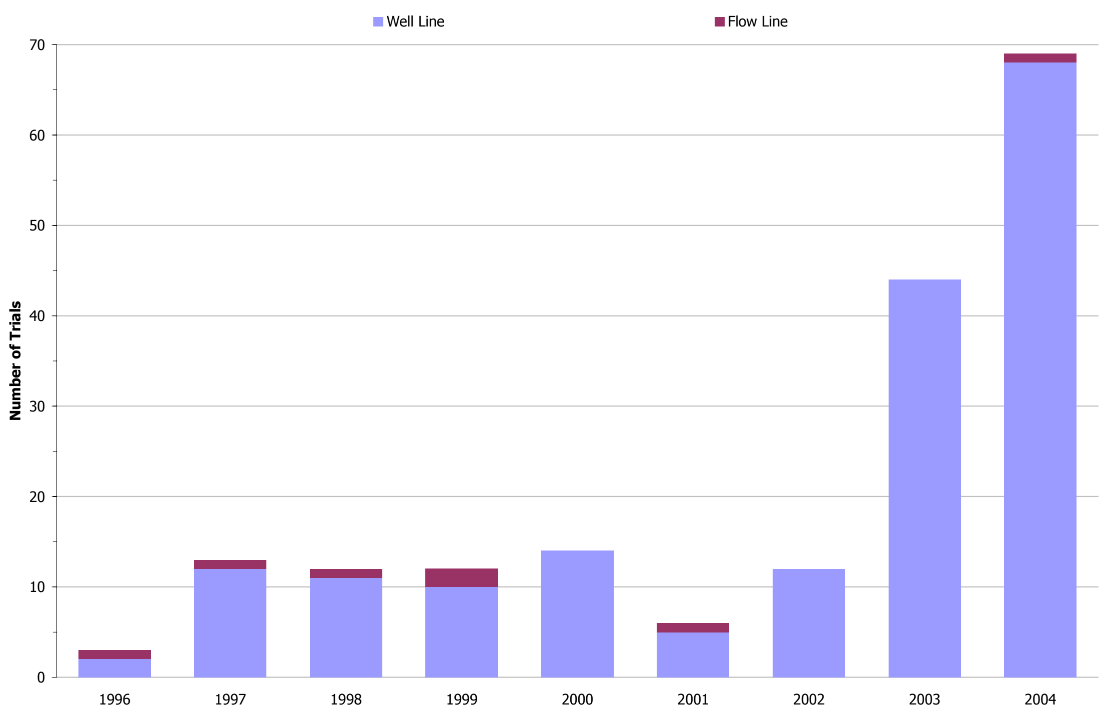
Section D.1 Chemical Optimization

Chemical optimization is an on-going process that encompasses a broad range of activities, from developing new corrosion inhibitors for improved performance, to the allocation of extra chemical for additional corrosion control. The following sections provide an update on chemical development, field wide chemical deployment, chemical usage and finally corrosion control.

Section D.2 Corrosion Inhibitor Testing

GPB Figure D.1 summarizes the number of well line and flow line tests which have been completed since 1996. The level of well line test activity increased during 2003 and 2004 due to a change in the screening protocol, which reduced the time required per test. The combined number of well line and flow line tests has increased from ~10-14 per year to more than 65 during 2004.

The data prior to 2000 are incomplete and represents the test work completed on the heritage WOA only. This level of activity represents a substantial investment of resources towards the development of new and more effective corrosion inhibitors.



GPB Figure D.1 Number of Well Line and Flow line Tests

One test chemical was advanced from the well line test program to large scale flow line testing. While this test chemical was an effective corrosion inhibitor, it was not compatible with the stainless steel delivery system. The test was concluded after ~120 days with no plans to pursue that particular chemistry.

Section D.3 Field Wide Corrosion Inhibitor Deployment

The chemical development and testing program has been highly successful in recent years, with 18 new products being developed for use in the continuous wellhead inhibition program since 1995. All these changes over the last 9 years represent a significant improvement in overall corrosion control performance.

GPB Table D.1 summarizes the changes in corrosion inhibitor products since 1995. The table does not include test products which did not make it to field wide usage. In addition, the summary table does not include summer versions of products that differ only in pour point from the winter version shown in the table.

Supplier	Chemical	95	96	97	98	99	00	01	02	03	04
Nalco Exxon	EC1110A	■	■								
Nalco Exxon	EC1259			■	■						
Nalco Exxon	97VD129				■	■	■				
Nalco Exxon	98VD118				■	■	■	■			
ONDEO Nalco	99VD049					■	■	■			
ONDEO Nalco	01VD017							■			
ONDEO Nalco	01VD121							■	■	■	■
Nalco	DVE4D002										■
Champion	RU205	■									
Champion	RU210	■	■	■							
Champion	RU223	■	■	■	■						
Champion	RU258			■							
Champion	RU271				■	■	■				
Champion	RU126A						■				
Champion	RU256[1]			■	■	■	■	■	■	■	■
Champion	2004-15[1]										■

[1]Used for the batch treatment of well lines while the remaining chemicals are all used for continuous application

GPB Table D.1 Summary of the Chemical Deployment History

Section D.4 Corrosion Inhibitor Usage and Concentration

Another measure of chemical optimization is the amount of corrosion inhibitor used relative to the volume of water produced from the reservoir. GPB Table D.2 summarizes the annual water production, corrosion inhibitor volumes, and concentrations since 1995. The inhibitor volumes are expressed as a 'winter product equivalent', i.e. the lower volumes of highly concentrated chemical used during the summer have been normalized to the winter equivalent.

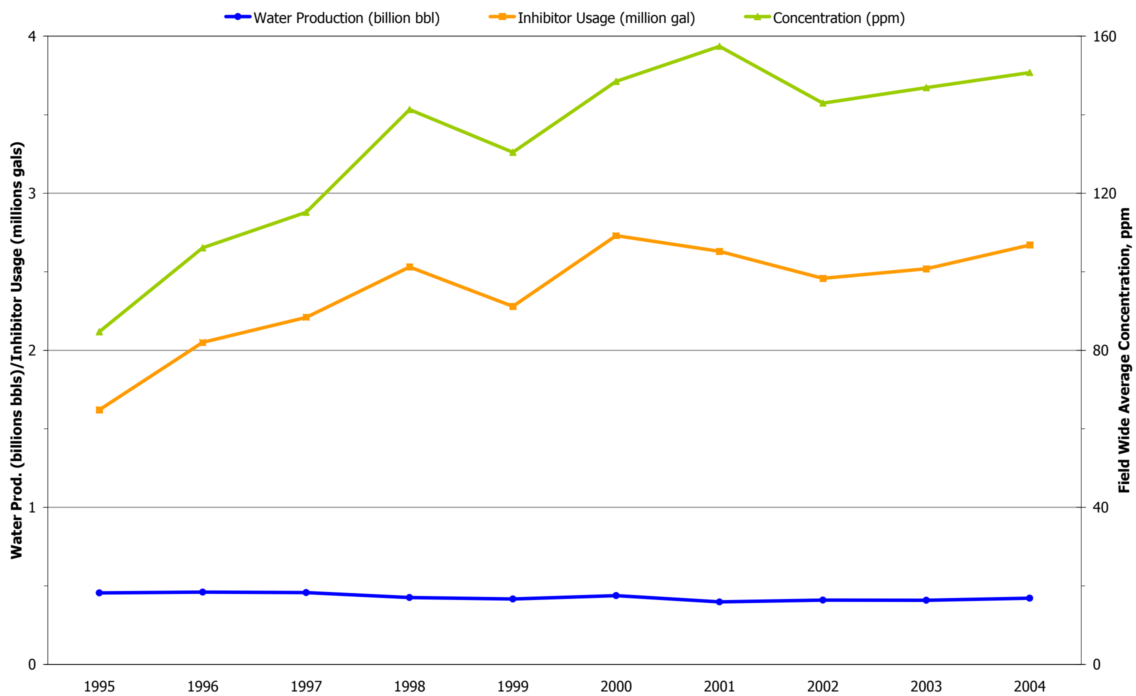
The concentration of inhibitor in the water phase provides a relative measure of the effectiveness of the chemical used to control corrosion. However, such data can be misleading as the types of corrosion inhibitors used can vary from year to year (GPB Table D.1). As more effective chemicals are developed, 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. 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.

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
2003	408	72	2.52	147
2004	422	74	2.67	151

GPB Table D.2 Summary of the Chemical Usage History

The advances in the development of more effective corrosion inhibitors is counteracted by the increasing water cuts associated with an aging oil field and increased flow velocities due to increased gas rates. These changes generally increase the amount of chemical required to control corrosion. As GPB Figure D.2 shows, the volume of corrosion inhibitor has increased since 1995 while the water volumes have remained relatively constant.

The metrics in GPB Figure D.2 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. For 2004 the target chemical usage was 2.71 million gallons as compared to actual usage of 2.67 million gallons; or 98.5% of the target volume.



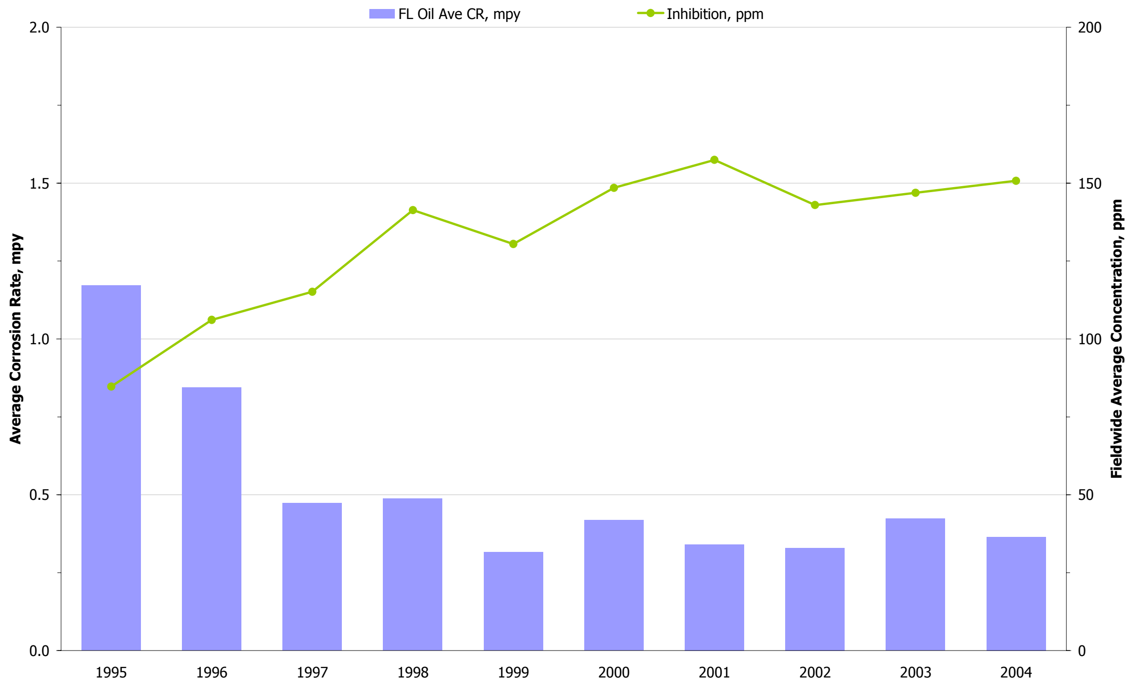
GPB Figure D.2 Field Wide Chemical Usage

Section D.5 Corrosion Inhibition and Corrosion Rate Correlation

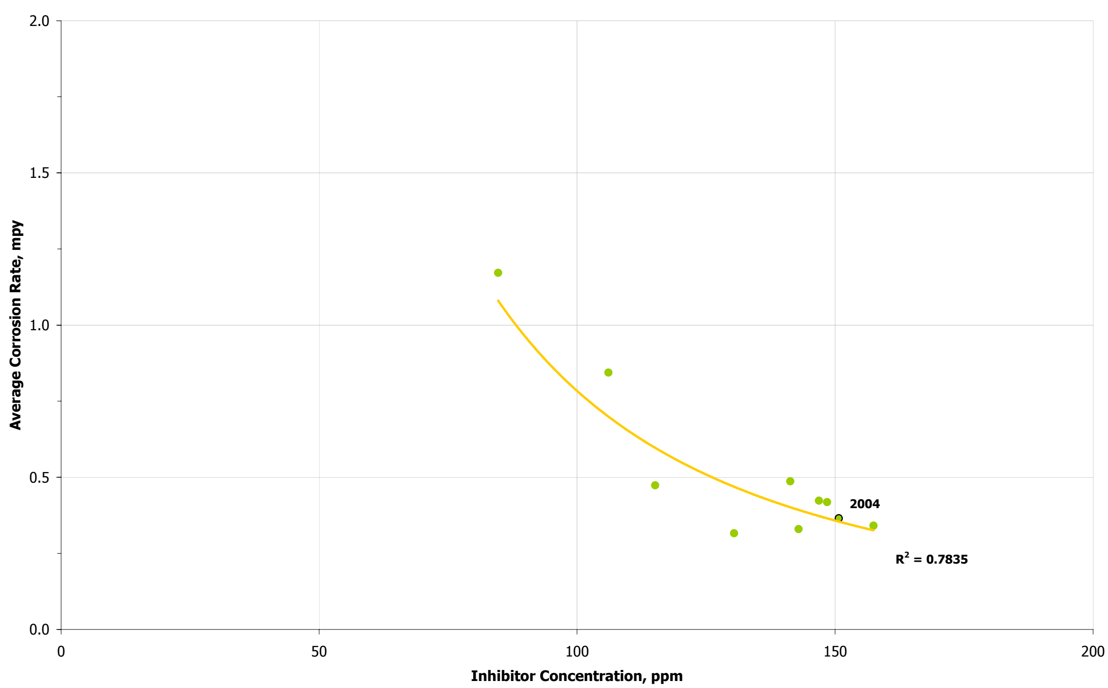
As discussed in Section C.1, the reduction in corrosion rates in the 3-phase production system flow lines and well lines are largely attributable to the implementation of an aggressive corrosion inhibition program across GPB.

GPB Figure D.3 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 ~80% from 1995 to 2004, with a field-wide average concentration of 85 ppm to 151 ppm. As a result the corrosion rates have fallen from 1.4 mpy in 1995 to ~0.4 mpy in 2004.

GPB Figure D.4 shows the annual field-wide average corrosion inhibitor concentrations versus annual average corrosion rates for 3-phase production flow lines. The figure shows how additional corrosion inhibitor has reduced the average 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.



GPB Figure D.3 Average Corrosion Rate Versus Inhibitor Concentration



GPB Figure D.4 Corrosion Inhibitor Concentration vs. Average Corrosion Rate

Section D.6 Chemical Optimization Summary

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

Section E

External/Internal Inspection

Section E External/Internal Inspection

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

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

Section E.1 External Inspection

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

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

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

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

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

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

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

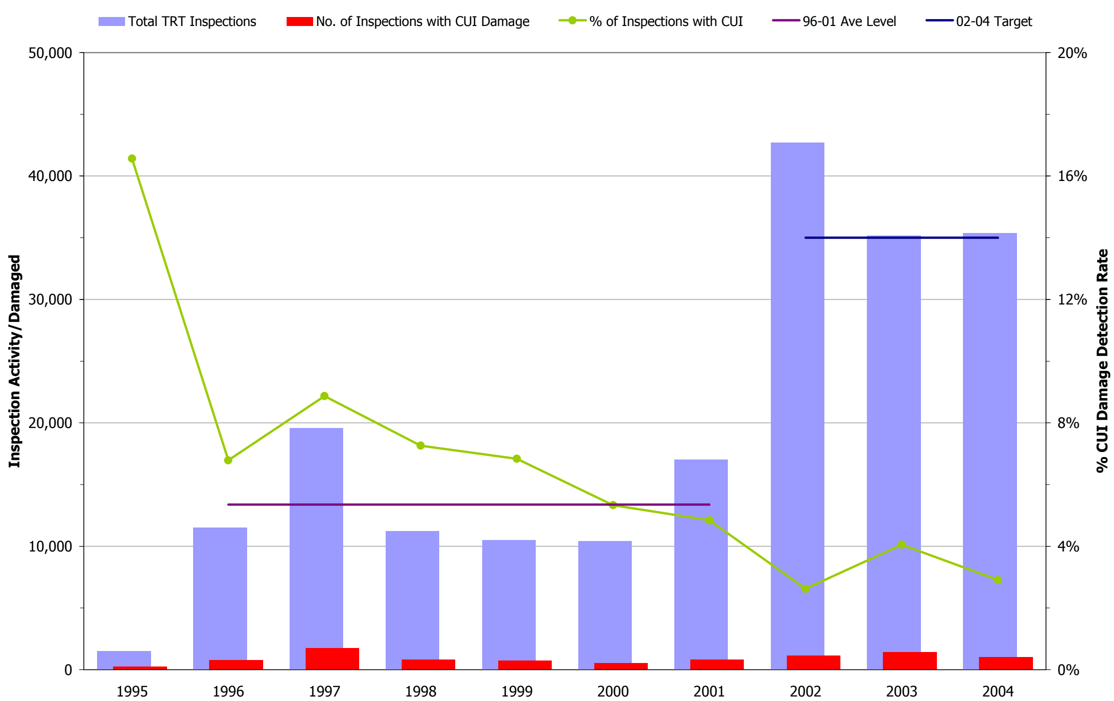
Section E.1.1 External Inspection Program Results

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

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

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

GPB Table E.2 External Corrosion Activity and Detection Summary



GPB Figure E.1 External Corrosion Activity and Detection Summary

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

Section E.1.2 Cased Piping Survey Results

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

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

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

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

GPB Table E.3 Cased Pipe Survey Results

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

Section E.1.3 Excavation History

In 2004, nineteen crossings were partially excavated at the casing end as a continuation of the lessons learned from the Y-36[7] incident. Two additional crossings were completely excavated. The excavation and subsequent inspection at all 21 locations were used to verify monitoring results. Although external corrosion was found and mitigated, there were no mechanical repairs required.

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

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

Section E.2 Internal Inspection Program Results

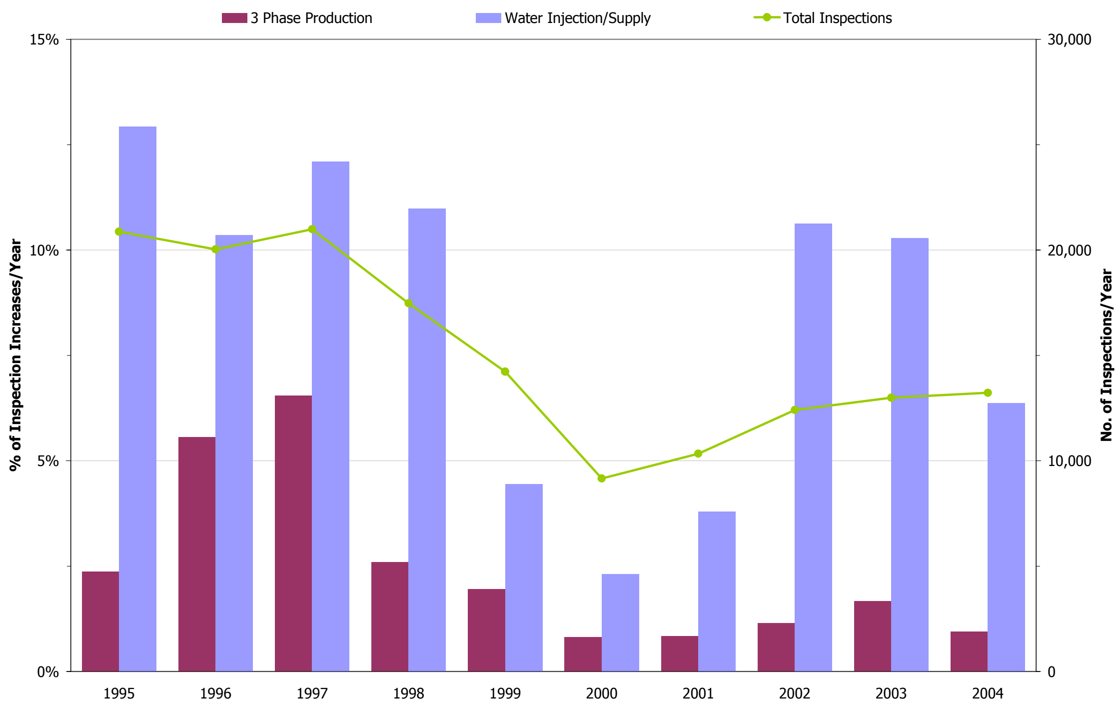
The results presented in this section are aggregate data obtained from flow line and well line inspections. The program results are presented in terms of the number of locations that show an increase in corrosion damage since the last inspection as a percentage of the total number of repeat inspections,

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

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

[7] Previously discussed in the 2003 Annual Report

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



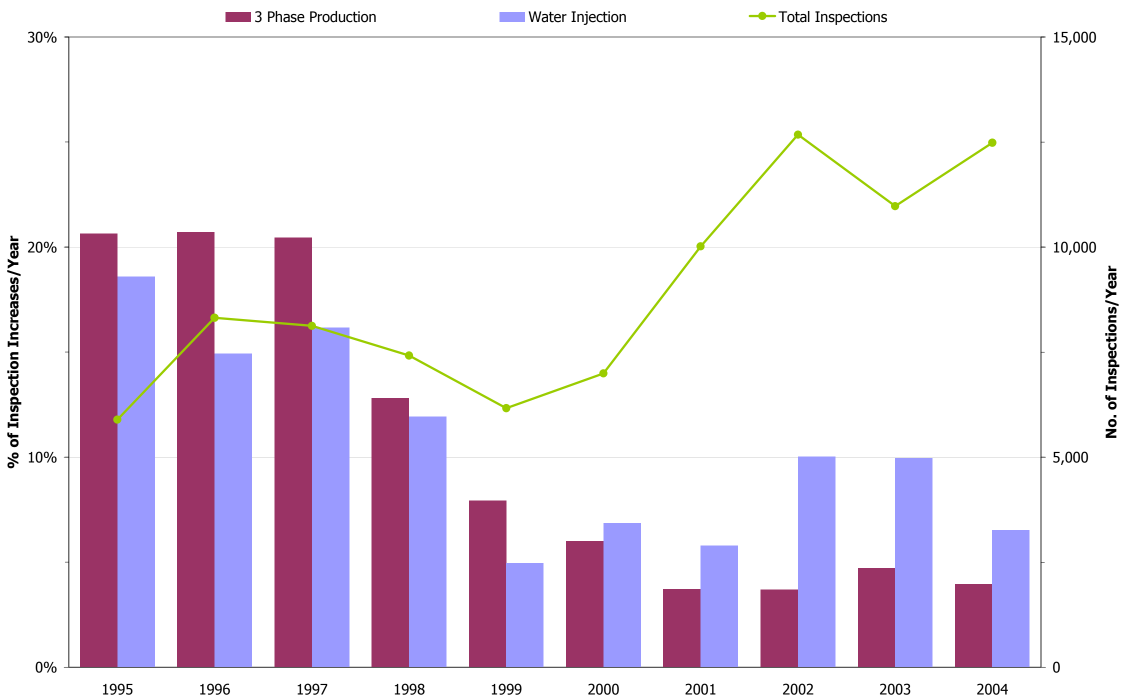
GPB Figure E.2 Flow Line Internal Inspection Increase by Service

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

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

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

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



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

Section E.3 Correlation Between Inspection and Corrosion Monitoring[8]

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

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

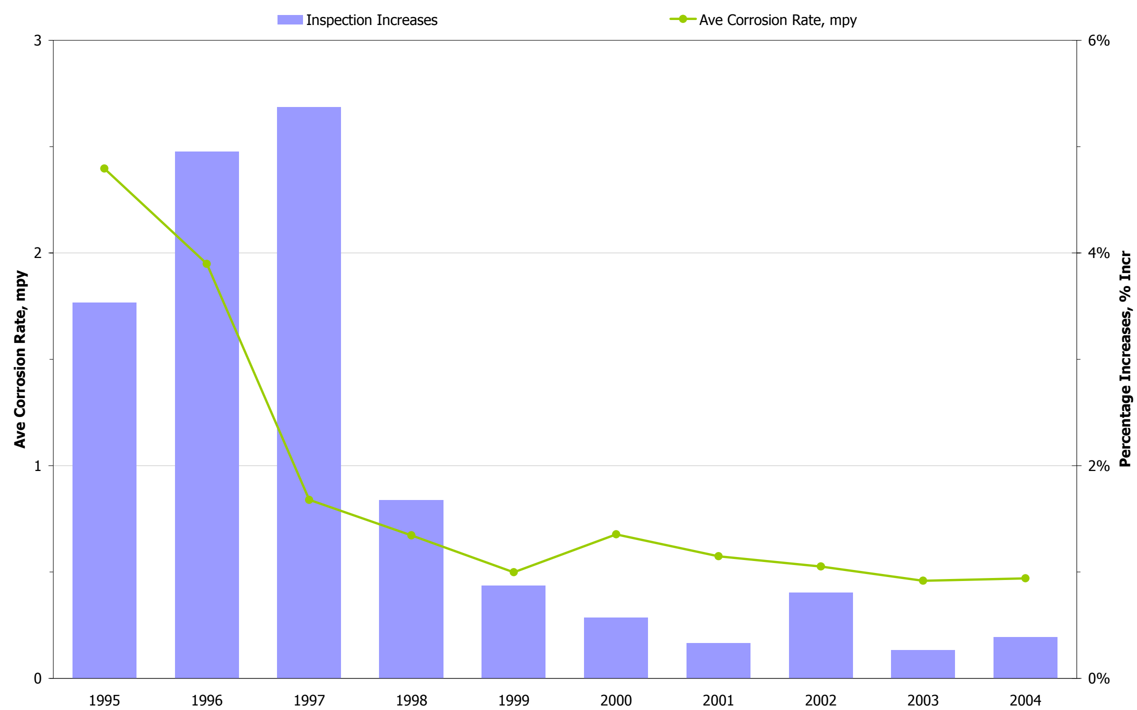
GPB Figure E.4 shows a similar decreasing trend in average corrosion rate from WLC and the percentage of increases found in the inspection program for the 3-phase well line and flow line. It should be noted that the inspection results included in the analysis are not the full data set but has been refined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

---

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

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

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



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

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

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

Section E.4 In-line Inspection

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

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

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

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

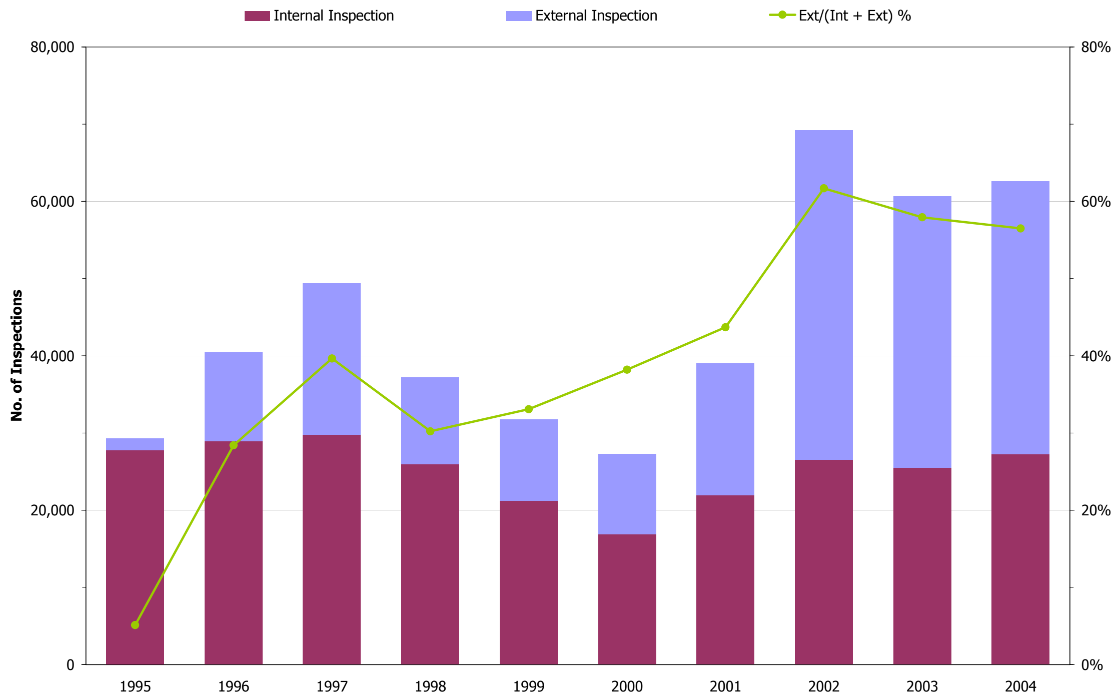
GPB Table E.4 Completed Smart Pig Assessments

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

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

Section E.5 Internal/External Inspection Comparison

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



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

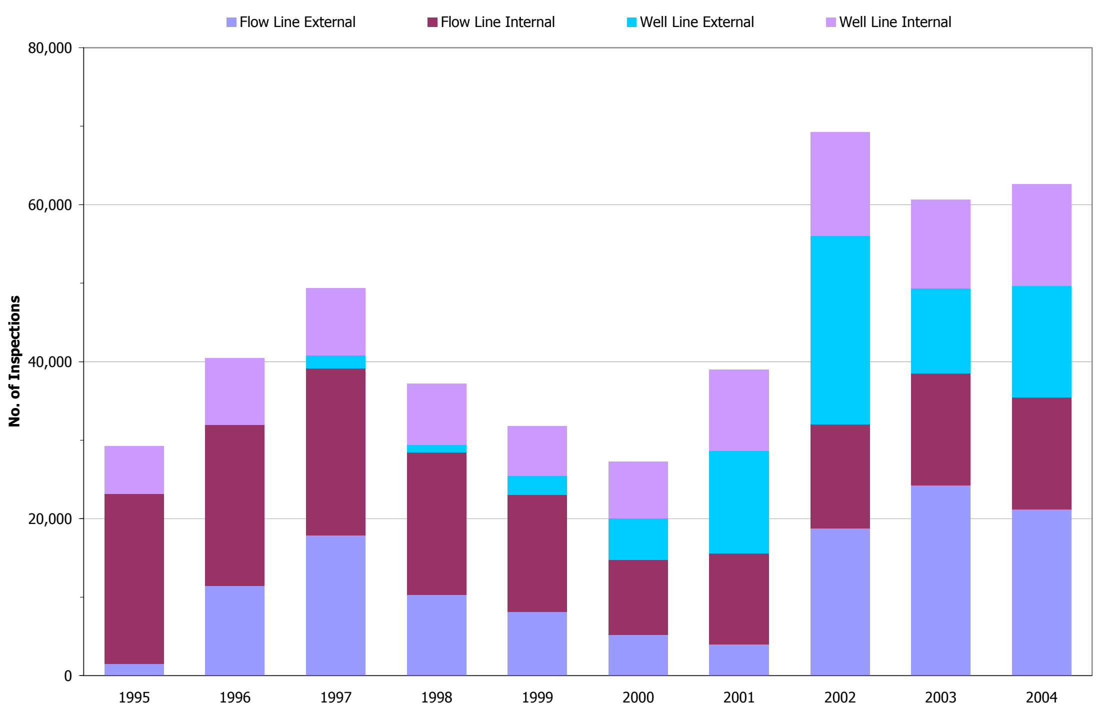
Year	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
External	1,497	11,492	19,573	11,235	10,515	10,424	17,038	42,696	35,148	35,384
Internal	27,749	28,969	29,796	25,945	21,271	16,861	21,963	26,512	25,518	27,253
Total	29,246	40,461	49,369	37,180	31,786	27,285	39,001	69,208	60,666	62,637
$\frac{\text{Ext}}{(\text{Ext}+\text{Int})}\%$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

GPB Table E.5 Internal and External Inspection Activity Breakdown

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

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

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



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

Section E.6 Inspection Summary

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

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

BU	Type	Service	Result	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
GPB	FL	OIL	I	368	924	1,153	394	238	67	60	102	152	100
GPB	FL	OIL	NC	15,143	15,695	16,461	14,802	11,935	8,150	7,080	8,743	8,959	10,422
GPB	FL	OIL	NL	3,616	2,100	1,969	441	359	146	1,715	1,875	1,951	805
GPB	**FL**	**OIL**	**Total**	**19,127**	**18,719**	**19,583**	**15,637**	**12,532**	**8,363**	**8,855**	**10,720**	**11,062**	**11,327**
GPB	FL	WTR	I	171	124	154	192	72	17	43	139	176	107
GPB	FL	WTR	NC	1,152	1,073	1,119	1,557	1,551	720	1,091	1,170	1,537	1,574
GPB	FL	WTR	NL	422	116	135	88	75	61	351	384	217	216
GPB	**FL**	**WTR**	**Total**	**1,745**	**1,313**	**1,408**	**1,837**	**1,698**	**798**	**1,485**	**1,693**	**1,930**	**1,897**
GPB	**FL**	**Total**	**Total**	**20,872**	**20,032**	**20,991**	**17,474**	**14,230**	**9,161**	**10,340**	**12,413**	**12,992**	**13,224**
GPB	WL	OIL	I	641	918	874	600	311	264	213	274	323	290
GPB	WL	OIL	NC	2,462	3,512	3,398	4,077	3,613	4,121	5,498	7,119	6,519	7,040
GPB	WL	OIL	NL	965	1,777	1,979	710	577	514	2,467	3,502	2,273	2,394
GPB	**WL**	**OIL**	**Total**	**4,068**	**6,207**	**6,251**	**5,387**	**4,501**	**4,899**	**8,178**	**10,895**	**9,115**	**9,724**
GPB	WL	WTR	I	225	262	201	216	74	126	78	125	148	146
GPB	WL	WTR	NC	985	1,493	1,042	1,594	1,417	1,712	1,267	1,122	1,336	2,085
GPB	WL	WTR	NL	617	358	634	221	176	258	495	535	374	528
GPB	**WL**	**WTR**	**Total**	**1,827**	**2,113**	**1,877**	**2,031**	**1,667**	**2,096**	**1,840**	**1,782**	**1,858**	**2,759**
GPB	**WL**	**Total**	**Total**	**5,895**	**8,320**	**8,128**	**7,418**	**6,168**	**6,995**	**10,018**	**12,677**	**10,973**	**12,483**
GPB	**Total**	**Total**	**Total**	**26,767**	**28,352**	**29,119**	**24,892**	**20,398**	**16,156**	**20,358**	**25,090**	**23,965**	**25,707**

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

GPB Table E.7 Flow and Well Line Inspection Data

This page is intentionally blank

Year	Cased Pipe Location	Equipment Excavated	Observation	Corrective Action
1992	COTU Access Road	FS1 to FS2 12" MI Distribution	10% external wall loss	Insulation/coating/tape repair
1995	S Pad West Entrance Crossing	S Pad 24" 3 Phase Production	61% external wall loss	Sleeve/insulation/coat repair
		S Pad 14" Produced Water	36% int/ext wall loss	Sleeve/insulation/coat repair
		S Pad 10" Gas Lift	34% external Wall Loss	Insulation/coating repair
		S Pad 8" Miscible Injection	41% external wall loss	Replaced segment/FBE
	GC1 Main Entrance	Distribution 24" Gas Lift	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
1998	S Pad East Entrance Crossing	S Pad 10" Gas Lift	~80% wall loss - ext rupture	Replaced segment
	GC2 to GC1 Caribou Crossing	Distribution 24" Gas Lift	9% external wall loss	Insulation/coating repair
	GC2 to GC1 Q Pad Rd Crossing	Distribution 34" Natural Gas	No corrosion damage	Insulation/FBE coated

GPB Table E.8 Cased Piping Excavation History

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

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

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

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

This page is intentionally blank

Section F

Repair Activities

Section F Repair Activities

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

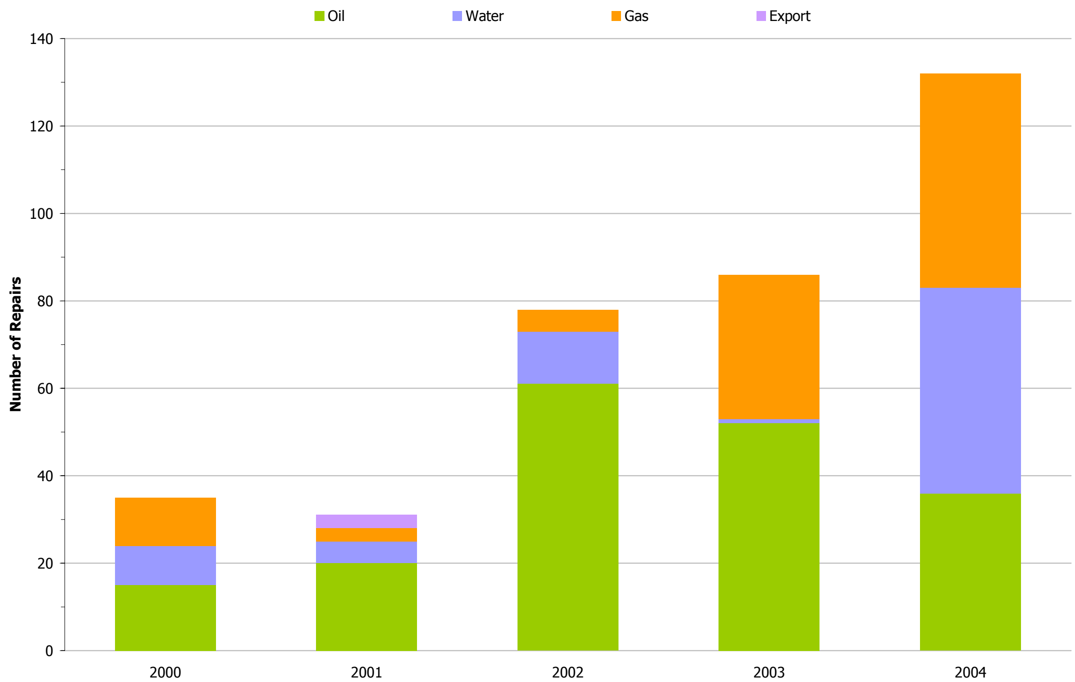
Service	Type	Internal	External	Mechanical	Total
Oil	FL	5	13	-	18
	WL	5	13	-	18
Water	FL	23	9	1	33
	WL	13	1	-	14
Gas	FL	-	12	-	12
	WL	-	37	-	37
Total		**46**	**85**	**1**	**132**

GPB Table F.1 Repair Activity

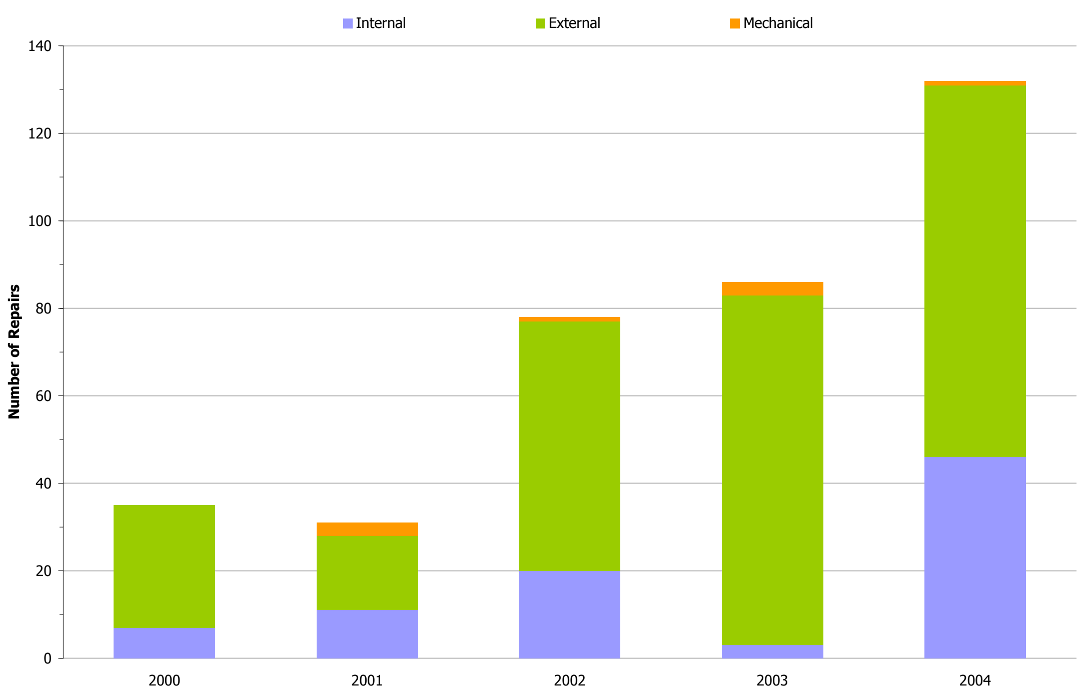
There were 85 repairs associated with external corrosion which is similar to the number of repairs in 2003.

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

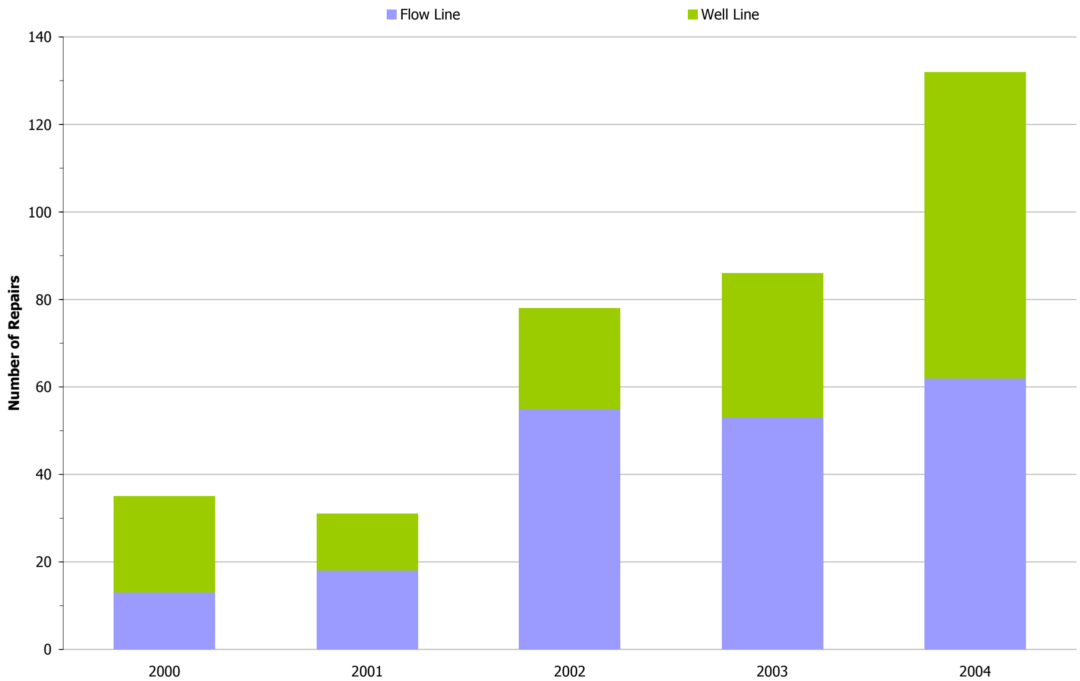
The 46 repairs due to internal corrosion can be attributed to two major areas of focus. First, there was a need to increase system pressure capacity in order to deliver the increased volumes of high-pressure seawater. Second, prior to single-operatorship, there were two FFS criteria (GPB East and GPB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



GPB Figure F.1 Repairs by Service



GPB Figure F.2 Repairs by Damage Mechanism



GPB Figure F.3 Repairs by Equipment

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

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

GPB Table F.2 Historical Repairs by Service

This page is intentionally blank

Section G

Corrosion and Structural Related Spills and Incidents

Section G Corrosion and Structural Related Spills and Incidents

Section G.1 Corrosion Related Leaks

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

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

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

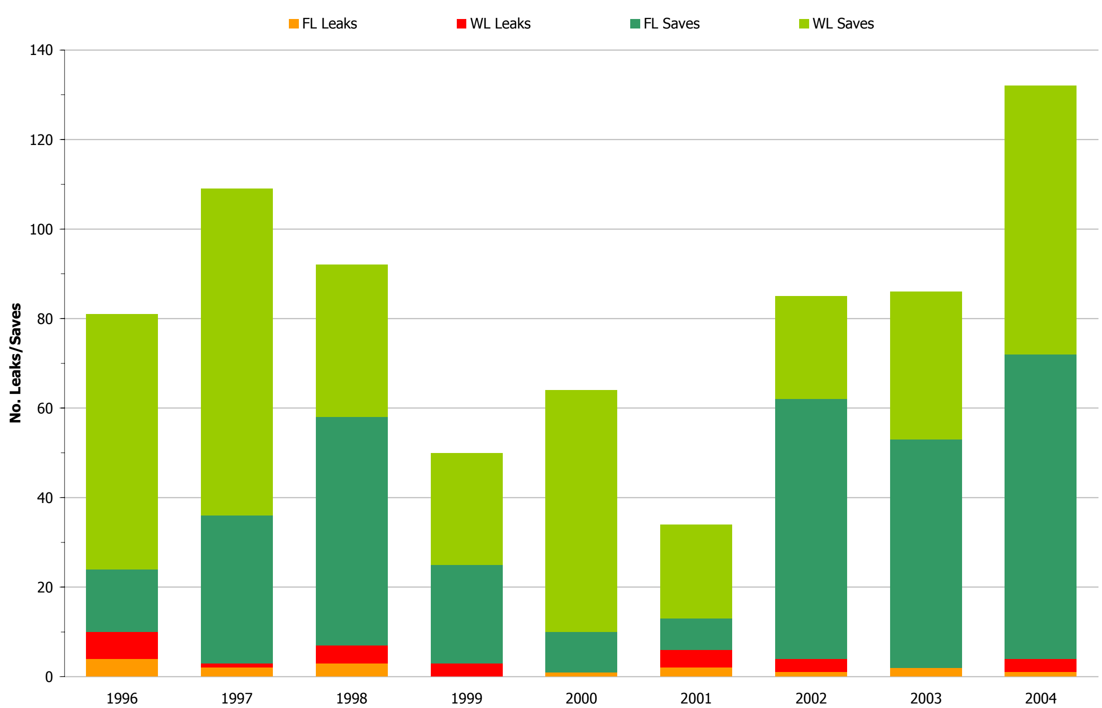
	Surface		Service				Mechanism			
	Int	Ext	OIL	SW	PW	Gas	CO_2	Int	CUI	Mech
WL	2	1	1		2			1	1	1
FL		1	1						1	

GPB Table G.1 Leaks Due to Corrosion/Mechanical

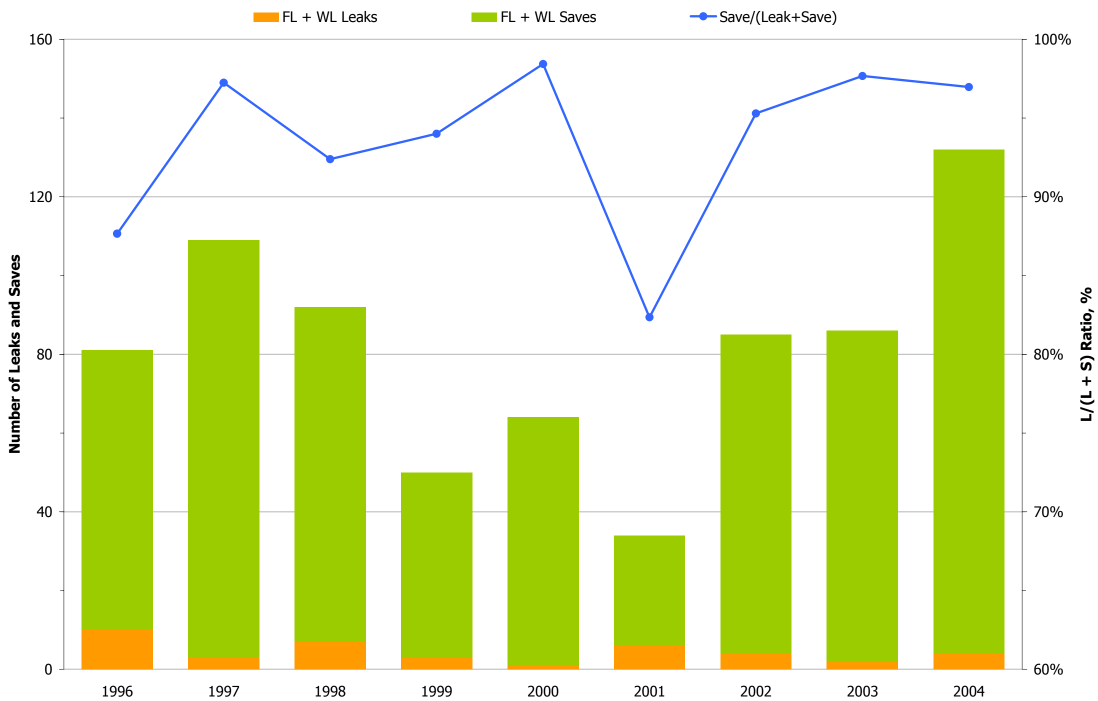
GPB Table G.2, GPB Figure G.1 and GPB Figure G.2 show the number of corrosion related leaks and saves since 1996. The ratio of leaks to saves provides a high level measure of the performance of the inspection program at detecting severe damage before it results in a failure. A 'save' is defined as a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

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

GPB Table G.2 Historical Corrosion Leaks and Saves



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



GPB Figure G.2 Historical Corrosion Leaks and Saves

Section G.2 Structural Integrity Issues

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

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

Section G.2.1 Walking Speed Survey

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

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

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

- Pipe line road and animal crossings

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

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

GPB Table G.3 Structural/Walking Speed Survey Schedule

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

Section G.2.2 Routine Surveillance

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

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

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

Section H

2004 Corrosion Monitoring and Inspection Goals

Section H Corrosion Monitoring and Inspection Goals

Section H.1 2004 Corrosion and Inspection Goals Reviewed

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

Section H.1.1 Corrosion Monitoring

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

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

GPB Table H.1 Coupon Pull Frequency

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

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

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

Section H.1.2 Inspection Programs

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

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

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

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

Section H.1.3 Chemical Optimization

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

Section H.1.4 Program Reviews

A number of reviews were conducted during 2004, including:

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

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

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

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

Section H.1.5 2004 Corrective Actions

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

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

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

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

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

Equipment ID	No. of Action	Cause	Action
PTMCLS01/02	1	Increased Corrosivity	Increased CI by 20%

GPB Table H.3 Corrective Mitigation Actions from Inspection Data

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

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

GPB Table H.4 Corrective Mitigation Actions from Coupon Data

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

Section H.2 2005 Corrosion Management Goals

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

Section H.2.1 Corrosion Monitoring

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

Section H.2.2 Inspection Programs

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

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

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

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

Section H.2.3 Chemical Optimization

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

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

Part 2 – Alaska Consolidated Team Performance Unit

Section B-H

Section B Corrosion Monitoring Activities

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

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

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

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

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

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

ACT Table B.1 illustrates, on a relative basis, the unique corrosivity of each producing field within ACT along with the materials of construction and corrosion mitigation. GPB is included in the table for comparative purposes. Listed in the table are, for each field, the typical water cut in percent, average wellhead temperature, and the percent CO_2 in the produced gas.

	Prod Fluid Characteristics				Material of Construction (a)			
					Production		Injection	
Field	H_2O (%)	T (°F)	P_{CO_2}(%)	CR (b)	WL	FL	WL	FL
GPB	74	150	12	H	CS+CI	CS+CI (c)	CS+CI	CS+CI
END	89	150	18	H	DSS	DSS	CS+CI	CS+CI
MPU	49	125	1.5	L/M	CS	CS (d)	CS+CI	CS+CI
Northstar	4	160	5	M	CS+CI	N/A	N/A	N/A
Badami	~0	65	~0	L	CS	N/A	N/A	N/A

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

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

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

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

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

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

Section B.1 Endicott

Endicott is a mature waterflood field. The fluid properties (high water cut, high temperatures, high CO_2 content) indicate the corrosivity of the produced fluids to be high. Due to this anticipated high corrosivity, the majority of the oil production system was fabricated from duplex stainless steel, a corrosion resistant alloy and therefore, corrosion risk is low for this system. In the oil production system, the only carbon steel is the C-Spool, connecting the wellhead to the duplex stainless steel well line. These C-

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

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

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

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

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

Section B.2 Milne Point

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

Although the low temperatures and low CO_2 content of the production fluids result in lower corrosivity for MPU, solids contribute to the corrosion mechanism of the production system. Corrosion inhibition of the K-pad production flow line was initiated in 2001 and the F-L-C Pads flow line in 2003. Additionally, corrosion inhibition of the newly developed S-Pad began late 2002.

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

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

[1] Totals not available
[2] The external corrosion program concentrated significantly on the Oil Sales line and outside facility piping in 2002.
[3] Included with internal numbers as part of the excavations.

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

Section B.3 Northstar

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

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

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

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

Section B.4 Badami

Low productivity necessitated the shut-in of the Badami Field in the third quarter of 2003 and throughout all of 2004. Shut-in consisted of de-inventory and warm storage of major equipment. Prior to shut-in, Badami's production fluids were considered a low risk from a corrosivity standpoint, as there is little water production and low CO_2 content. ACT Table B.6 summarizes the inspection program for Badami throughout the shut-in period in 2004.

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

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

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

Section B.5 Overall Inspection Activity Level

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

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

ACT Table B.7 Overall Inspection Activity Summary

Section C Weight Loss Coupons

Section C.1 Endicott

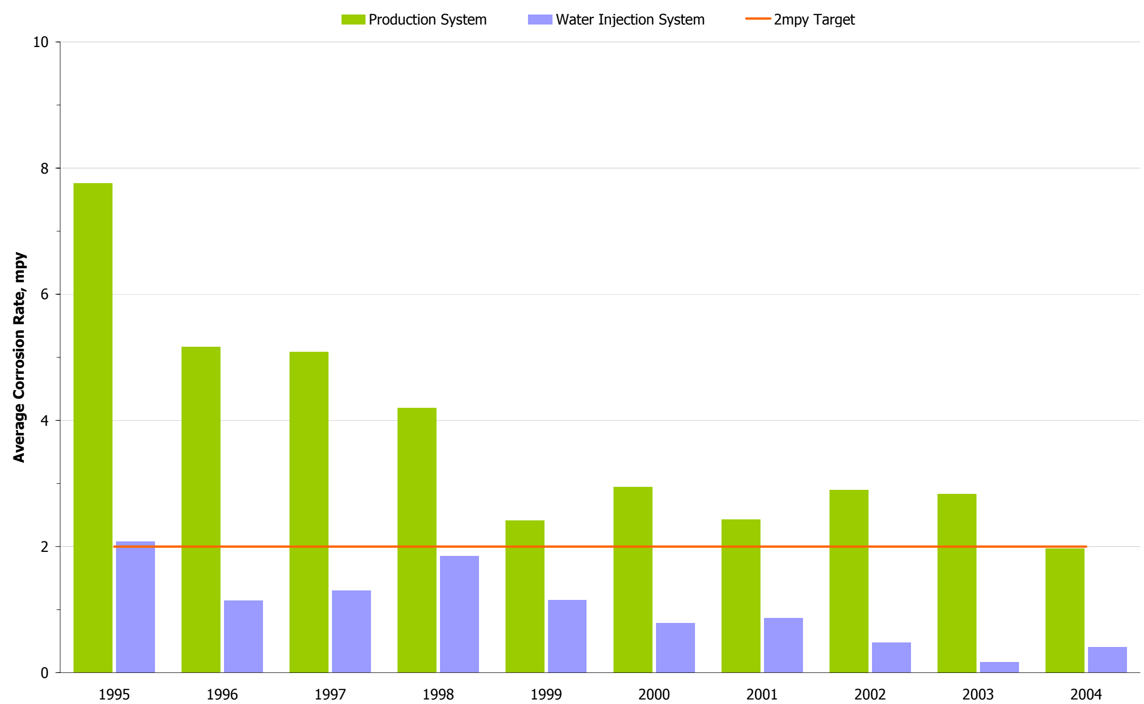
ACT Table C.1 summarizes the corrosion monitoring performance for 2004 and historical data are shown in ACT Figure C.1.

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

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

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

ACT Table C.1 Endicott Corrosion Coupon Monitoring



ACT Figure C.1 Endicott Corrosion Coupon Summary

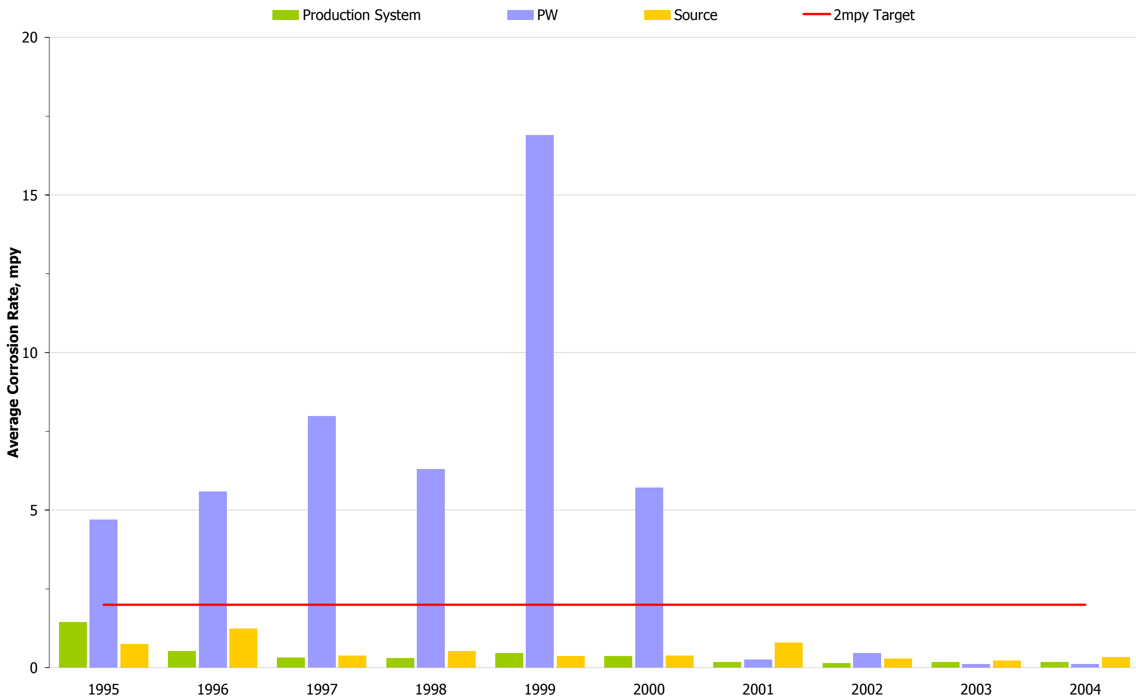
Section C.2 Milne Point

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

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

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

ACT Table C.2 MPU Corrosion Coupon Monitoring



ACT Figure C.2 MPU Corrosion Coupon Summary

Section C.3 Northstar

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

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

ACT Table C.3 Northstar Corrosion Coupon Monitoring

The 3-phase production is currently inhibited; however monitoring data continues to indicate the corrosion rates are above the 2 mpy target. This is due to the corrosion monitoring locations being located upstream of the corrosion inhibitor injection location. Monitoring data collected from downstream locations show the inhibition program is effective in reducing corrosion rates to acceptable levels. The coupons from the upstream locations indicate the need for inhibition of the upstream section. Operations is proceeding with the recommendation to move the corrosion inhibitor injection point further upstream, to the wellhead for the producing wells. Additionally, all new wells will be equipped to inject corrosion inhibitor at the well head.

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

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

Section C.4 Badami

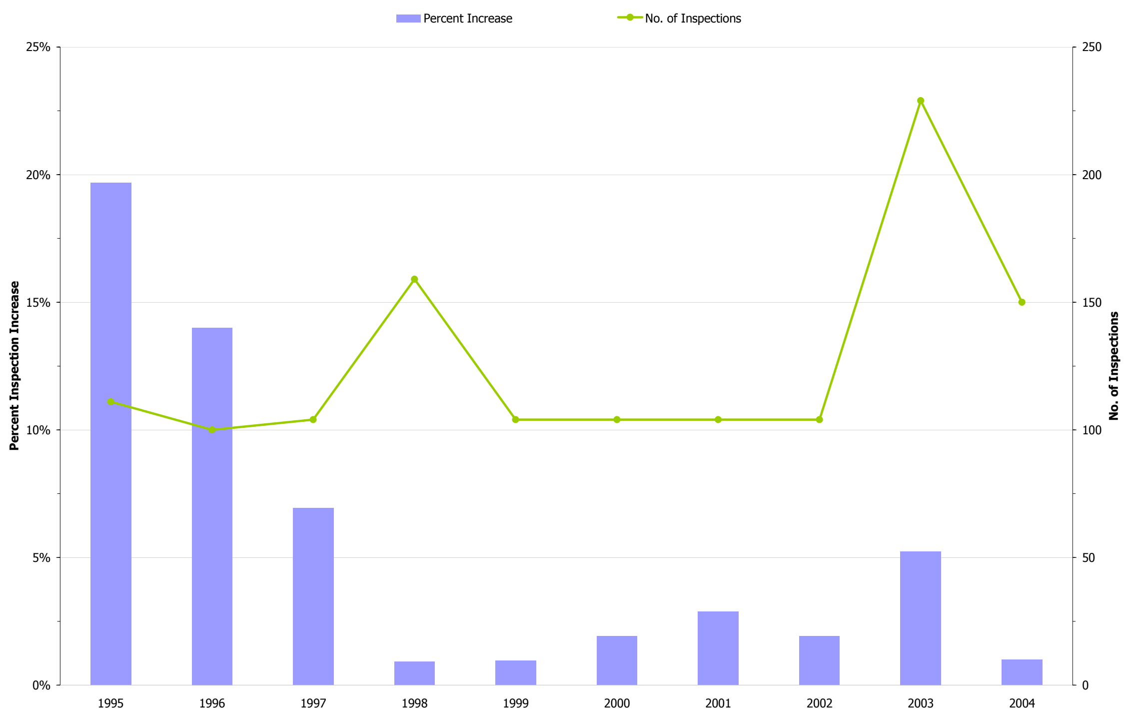
Badami currently has no WLC-monitoring program, but relies on an inspection program presented in Section E.

Section D Corrosion Mitigation Activities

Section D.1 Endicott

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

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



ACT Figure D.1 Endicott IIWL UT Readings

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

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

In the production system, the primary damage mechanism is erosion. The erosion rate is monitored through inspection and mitigated through velocity management. Wells are risk ranked by mixture velocity once per month and the information is used to adjust the inspection frequency and fluid velocity. ACT Table D.1 is an overview of the velocity data for 2001 to 2004. Shown are the number of wells within L/R ratio ranges, where L is the actual mixture velocity and R is the allowable erosion velocity as defined by API-RP-14E[9].

L/R Range	2001 No. Wells	2001 Percent	2002 No. Wells	2002 Percent	2003 No. Wells	2003 Percent	2004 No. Wells	2004 Percent
L/R<1	23	38%	12	21%	19	31%	25	38%
1<L/R<2	25	42%	31	54%	29	47%	27	41%
2<L/R<3	11	18%	12	21%	13	21%	13	20%
L/R>3	1	2%	2	4%	1	2%	1	2%
Total	**60**	**100%**	**57**	**100%**	**62**	**100%**	**66**	**100%**

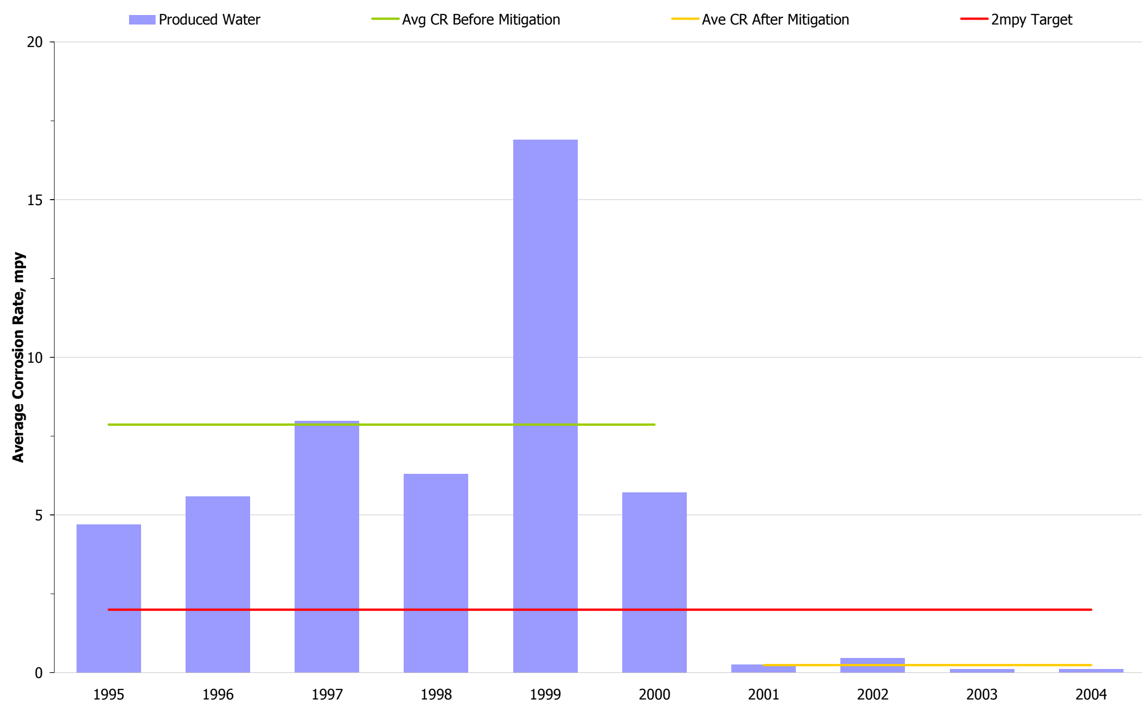
ACT Table D.1 Endicott Velocity Monitoring

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. The aim is to limit actual velocities to less than 3 times the allowable velocity (L/R<3). This factor of 3 reflects BPXA's experience with production fluids that contain minimal amounts of entrained solids flowing through stainless steel pipelines. 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 well showing an L/R>3 has been increased to monthly, and there were no inspection increase in 2004.

Section D.2 Milne Point

Corrosion inhibition of the water injection system began in mid-2000, in addition to a more frequent maintenance pigging program. Corrosion inhibitor concentration is at 40 ppm. Weight loss coupon data indicate the system is under control as the WLC corrosion rates have averaged <2 mpy since mid-2000. This represents a significant reduction from previous years as can be seen in ACT Figure D.2. For the period 1996-2000, the average corrosion rate was ~7 mpy. Since the enhancement of the corrosion management program in 2000, the average WLC corrosion rate for the PW system has been reduced to <1 mpy.

[9] API-RP-14E - Recommended Practice for Design and Installation of Offshore Production Platform Piping System 5th Edition.



ACT Figure D.2 Milne Point Produced Water Corrosion Rate Trend

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 low fluid velocities, allowing solids to accumulate in the line. In conjunction with the inhibition program, the K-Pad flow line is cleaned with a maintenance pig on routine schedule. Inhibition levels were increased in October 2003 to 56 ppm and again in April 2004 to 100 ppm as a result of active corrosion detected through routine inspection monitoring.

The development at S-Pad was designed for continuous inhibition injection into the power fluid supply for the downhole hydraulic pumps. Since this water is separated and re-circulated as power fluid at the pad, only ~10% of the produced water is sent through the 3-phase flow line to the main 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 continuous inhibition of the production flow line carrying production from F, L, and C Pads remains unchanged at 56 ppm.

The remaining uninhibited production flow lines are under review for corrosion inhibition. Inspection results from these production well lines indicate there is slight corrosion activity occurring over the long term. An analysis of these data was started in 2004 and recommendations will be made in 2005.

As production rates are typically low for the pipeline capacity, the fluid velocities are low and erosion is not a significant concern, therefore there is 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 rates, with a minimum of 2 gallons/day regardless of the production characteristics.

As noted in Section C.3, work began in 2004 to relocate the chemical injection upstream to the wellhead.

Section D.4 Badami

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

If the Badami Field is brought back on-line, BPXA will reinstitute the integrity monitoring plan beyond what has been done for the shutdown inspections.

Section E External/Internal Inspection

Section E.1 External Inspection

Section E.1.1 Endicott

Cased flow lines at Endicott were last inspected by electromagnetic pulse test (EMT) and no significant anomalies were noted.

Line	Crossings	Year Surveyed	Method	Max Inspection Interval
Water - Inter-Island	1	2001	EMT	10 Years
Gas Lift - Inter-Island	1	2001	EMT	10 Years
Oil	1	N/A		N/A Duplex Stainless Steel
MI Line	1[1]	N/A		
Water – WL	2	1 line in 2000	EMT	10 Years for Carbon Steel Other line is Duplex Stainless Steel
Gas - WL	1	2000	EMT	10 Years

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

ACT Table E.1 Cased Piping Inspections

In addition, the vaults where the production, IIWL, and gas-lift pipelines pass are visually inspected annually. Minor external corrosion exists, but it has not increased.

In 2004, IIWL was inspected for external corrosion with ATRT at 719 locations and slight corrosion damage was found at 3 locations, with none requiring repair.

Section E.1.2 Milne Point

ACT Table E.2 summarizes above-ground the external inspection program at MPU since 1997. No increase in corrosion was noted in any of the re-inspected locations. Four new locations were identified as requiring repairs.

Year	Total Insp	Repeat Insp	Increases	% I's
1997	26	0	0	n/a
1998	441	10	0	0
1999	101	65	0	0
2000	205	104	28	27
2001	179	20	5	25
2002	70	5	1	20
2003	1,583	55	1	2
2004	1,738	251	0	0

ACT Table E.2 MPU External Inspection Summary for Above-Ground Piping

With regard to buried piping, 623 inspections were conducted in forty-five excavation sites throughout the MPU field in 2004. The excavations were primarily centered on Tract 14 piping on the well pads. Piping examined included well lines and headers and was focused on soil to air interface areas and deeper. These interfaces are located behind the well houses and at pigging facilities, test separators, isolation valves, and pad piping extension areas. Excavations were also done on Tract 14 well pad header to main flow line tie-in points. B Pad, C Pad, D Pad and CFP Pad also had excavations done on various lines at air to soil interfaces.

Of the 623 inspections:

- 227 inspections were repeat locations, of which 30 locations (13%) had slight increases in internal damage.
- 301 locations were baseline inspections
- 95 locations were visual inspections of piping at well pad extensions that were being demolished or isolated from service at H Pad, I Pad and L Pad.

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.1.4 Northstar

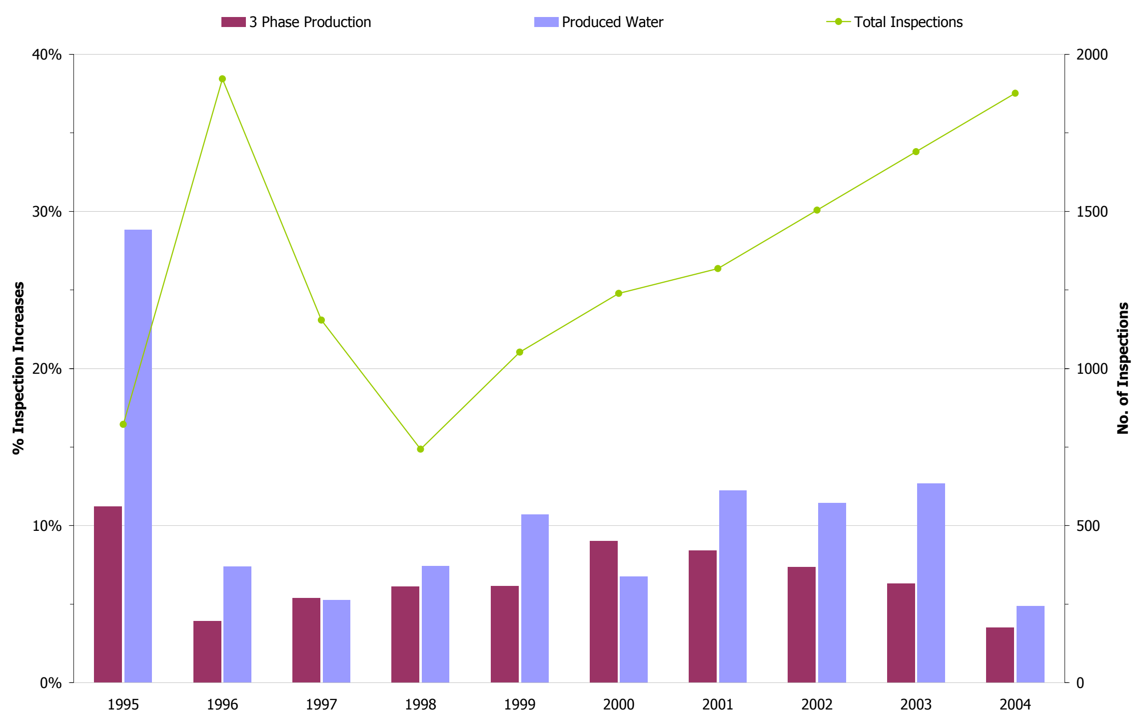
Since the facility is less than 4-years old, an external inspection program has not yet been established. Based on GPB experience, CUI typically takes several years to initiate. A program will be implemented within 5-years from startup (2006).

Section E.2 Internal Corrosion Inspection

Section E.2.1 Endicott

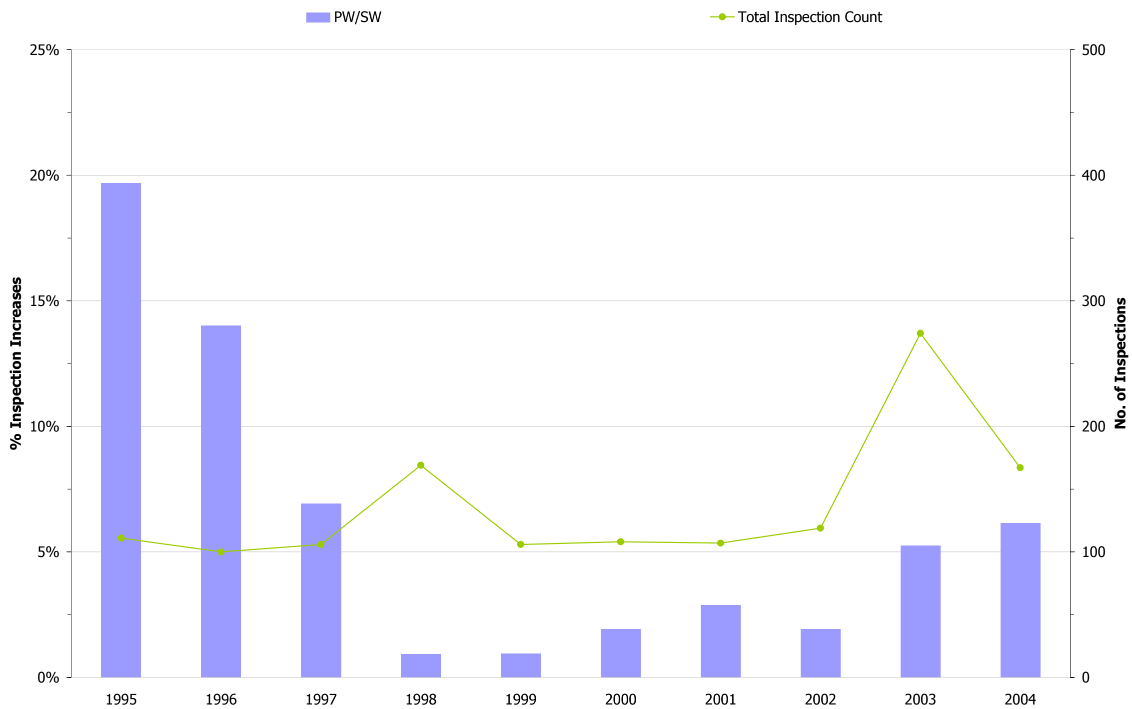
ACT Figure E.1 and ACT Figure E.2 indicate the percentage of inspection increases since 1995 for the well lines and flow lines at Endicott. There were no increases in the 3-phase, DSS production cross-country line. The inspection data for the 3-phase production system are used to alert Operations of potential replacements of the carbon steel C-Spools at the wellheads. The corrosion increases in carbon steel C-Spools are managed through planned replacement using the FFS criteria discussed in Appendix 3.3.5 .

Corrosion activity in the water injection well lines had been increasing since 2000 and was addressed by increasing the corrosion inhibitor concentration by ~18% in 2003 and then by another 50% in late 2004 to 30 ppm. The additional corrosion inhibitor has reversed the increasing trend.



ACT Figure E.1 Endicott Well Line Internal Inspection Increases

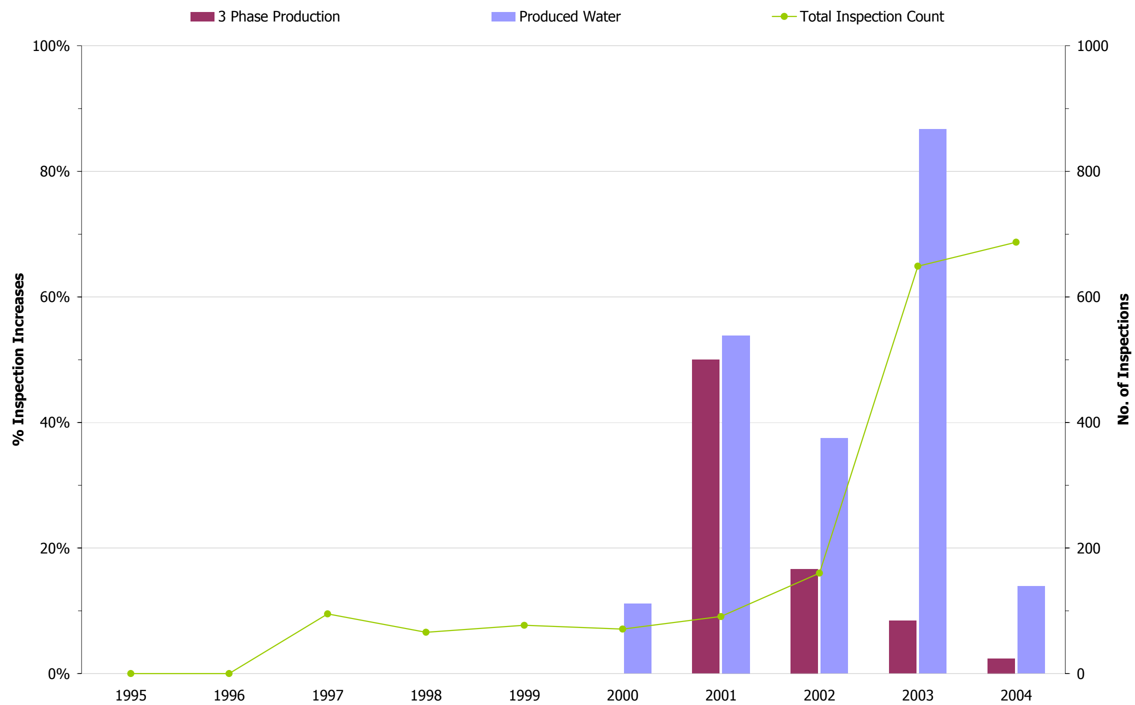
ACT Figure E.2 shows a significant decline of inspection increases from 1995 through 1998 for the IIWL at Endicott. There has been a increasing trend in %I's from 1998 through 2004, however these data include the addition of inspection locations that have not been inspected in several years. These additional locations confirm that corrosion was occurring in the line; however the time period between inspections makes it difficult to determine when the corrosion actually occurred. A more accurate representation of corrosion activity through time was shown previously in ACT Figure D.1 which includes only data from inspections performed on a frequent basis. The frequently monitored locations show a decrease in corrosion activity during 2004.



ACT Figure E.2 Endicott Flow Line Internal Inspection Increases

Section E.2.2 Milne Point

BPXA became operator at Milne Point in 1994, and from this date to 2000 the inspection program was 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. The results of this comparative data can be seen in ACT Figure E.3. The figure shows the total number of inspection items has consistently increased since 1998.

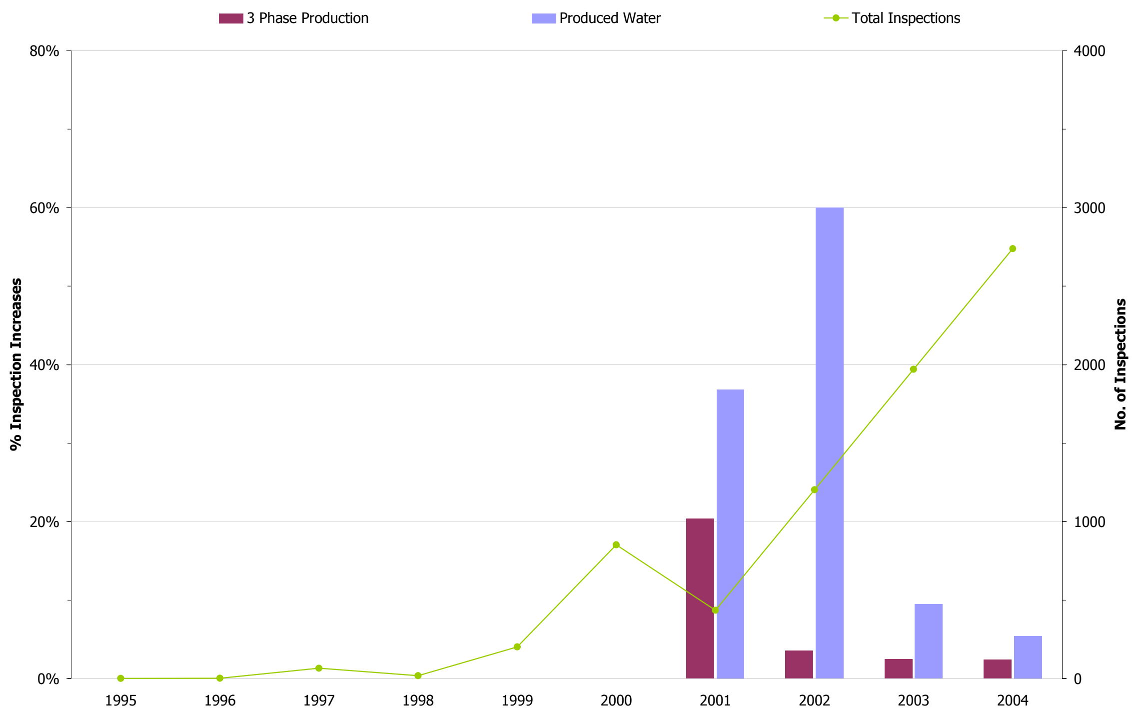


ACT Figure E.3 MPU Flow Line Internal Inspection Increases

Overall the 3-phase flow lines continue to show a decreasing trend of locations with corrosion activity. This is a direct result of increased inhibition of several of the 3-phase flow lines at MPU.

Inspection increases in the produced water dropped significantly in 2004 as compared the prior year. As reported in the 2003 report, the percentage of repeat locations in produced water flow lines had shown a significant increase in 2003, up to 87% from 29% in 2002. The level of the increases were the result of inspections which covered periods both before and after the establishment of corrosion inhibition (late-2000). The average time between inspections was ~4-5 years, indicating much of the corrosion activity reported may have occurred prior to the establishment of inhibition. Repeat inspections performed during 2004 with shorter intervals verify the improvement in corrosion control. These inspection data correlate with the WLC monitoring data in Section C.2.

ACT Figure E.4 shows the %I's and number of inspections on well lines. There has been a significant decrease in the number of repeat locations showing active corrosion since 2002. As noted in the discussion above, this represents a more consistent repeat inspection basis from prior years, as the majority of repeat locations were ~1-year apart, whereas in previous years the time difference between repeat inspections was several years.



ACT Figure E.4 MPU Well Line Internal Inspection Increases

Section E.2.3 Badami

The Badami Field was shut in August of 2003 due to declining productivity. A post shutdown inspection was performed to serve as a baseline for a follow-up inspection in the third quarter of 2004 as a check to assure equipment was properly laid up in 2003. A follow up inspection performed in 2004 indicates no increase in corrosion activity from the2003 baseline survey.

Although the data set is limited, inspections support the overall assertion that Badami fluids have low corrosivity. ACT Table E.3 is a summary of well line inspections for Badami.

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

Note: Increasing damage location associated with shutdown operation

ACT Table E.3 Inspection Summary of Badami Well Lines

Section E.2.4 Northstar

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

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

ACT Table E.4 Inspection Summary of Northstar

Section F Repair Activities

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

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

ACT Table F.1 ACT Repair Activity

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

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

Section G Corrosion and Structural Related Spills and Incidents

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

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

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

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

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

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

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

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

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

Section H 2005 Corrosion Monitoring and Inspection Goals

Section H.1 Endicott

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

The well line erosion rate monitoring program will continue.

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

Section H.2 Milne Point

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

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

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

Section H.3 Northstar

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

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

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

Section H.4 Badami

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

Appendix 1

Glossary of Terms

Glossary of Terms

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

Glossary of Terms

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

Appendix 2

Work Plan
Guide for Performance Metric Reporting

2000 Work Plan

Commitment to Corrosion Monitoring

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

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

Work Plan Purpose:

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

Corrosion Monitoring Performance Management Program

Purpose: To provide for 'the regular review of BP and PAI's corrosion monitoring and related practices for non-common carrier North Slope pipelines' operated by BP or PAI.
'Corrosion Monitoring' specifically refers to the activity of monitoring pipeline corrosion rates via corrosion probes, corrosion coupons, internal pipeline inspections, and external pipeline inspections.
'Related practices' refers to the assessment of corrosion monitoring data and the associated response to the assessment, specifically chemicals, inspection, and repairs.

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

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

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

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

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

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

2. BP and PAI will submit annual reports to ADEC, which will provide the status of current and projected monitoring activities. These reports will be issued on or before March 31st of each year, and reflect the prior calendar year. The following information will be provided:

   A. Annual bullet item reporting the progress of the Charter Agreement corrosion related commitment.

   B. A general overview of the previous year's monitoring activities.

   C. Metrics that depict coupon and probe corrosion rates.

   D. Metrics that characterize chemical optimization activities.

   E. Metrics that depict the number and type of internal/external inspections done, and, as applicable, the corrosion increases/rates and corresponding inspection intervals.

   F. Metrics that characterize the quantity and type of repairs made in response to the internal/external inspections done per the above paragraph.

   G. Metrics that depict the numbers and types of corrosion and structural related spills and incidents.

   H. A forecast of the next year's monitoring activities in terms of focus areas and inspection goals. These forecasts cannot be viewed as binding, as corrosion strategies are dynamic and priorities will change over the course of the year. However, changes in focus will be communicated to ADEC during the semi-annual meetings described above.

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

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

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

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

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

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

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

Annual Timetable

March 31st Annual Report

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

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

Guide for Performance Metric Reporting

General

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

Timescale

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

Equipment Classification

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

Service Definitions

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

Basic Summary Statistics

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

Weight Loss Coupon Data

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

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

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

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

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

Internal Inspection Data

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

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

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

The data sets to be provided for internal inspection are,

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

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

Corrosion Inhibition

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

External Corrosion Inspection

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

The data sets to be provided for external inspection are,

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

Repair and Leak Statistics

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

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

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

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

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

Below Grade Piping

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

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

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

Other Programs

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

Appendix 3

Corrosion Management System

Appendix 3 Corrosion Management System

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

Appendix 3.1 Corrosion Management System

Appendix 3.1.1 Description

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

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

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

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

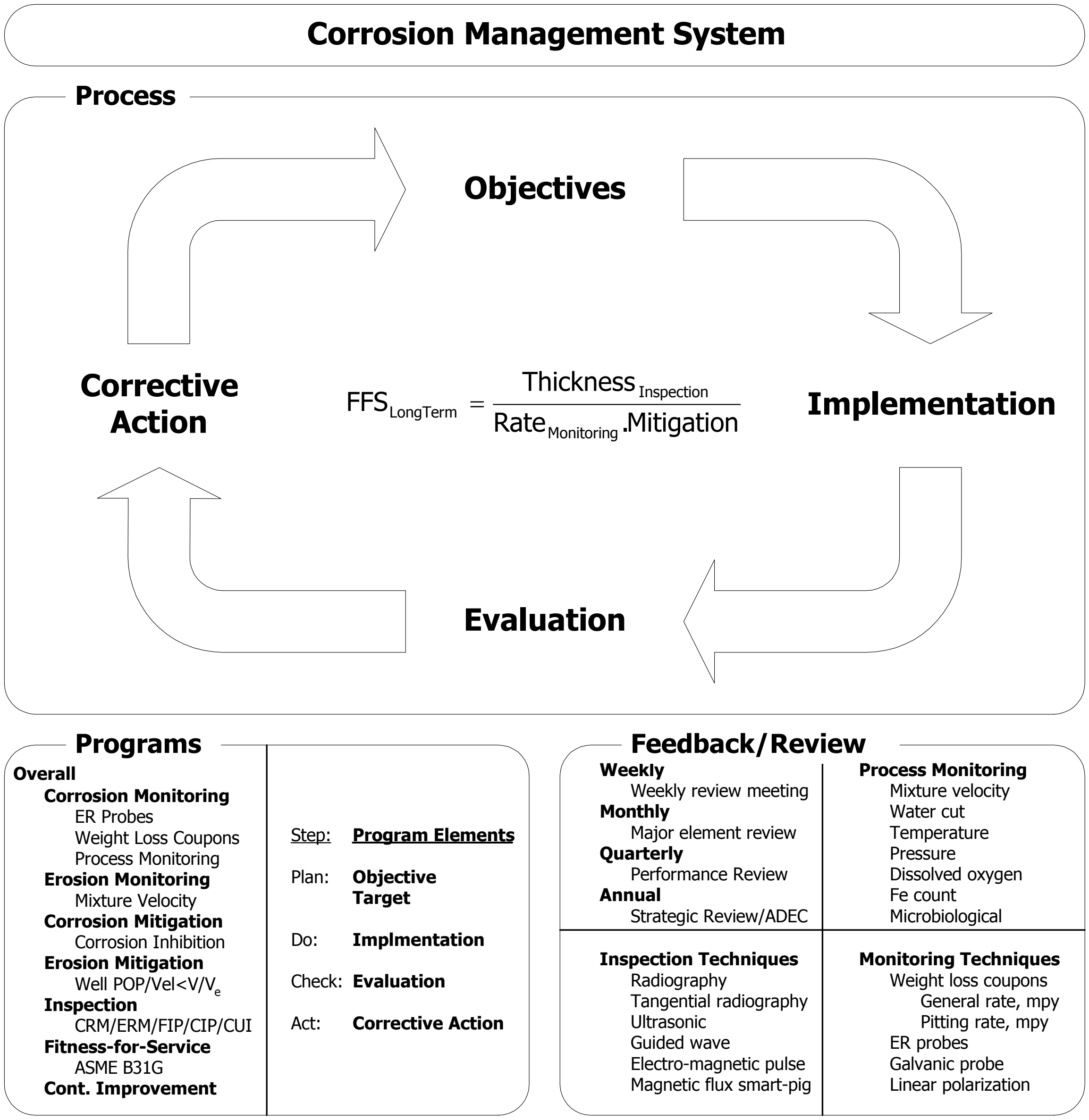


Figure 1 Overview of the Corrosion Management Process

Appendix 3.1.2 Process

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

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

Table 1 Corrosion Management Process

Appendix 3.1.3 Objectives and Targets

The objectives[10] for the CMS are set in order to support the delivery of the corporate objective and BPXA objectives described in the Foreword. For the purposes of the CMS these can be translated into the corrosion management objectives of;

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

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

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

Appendix 3.1.4 Implementation

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

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

Appendix 3.1.5 Evaluation

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

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

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

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

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

Table 2 Corrosion Management Feedback Cycles

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

Appendix 3.1.6 Corrective Action

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

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

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

Appendix 3.2 Corrosion and Inspection Data Management

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

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

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

Appendix 3.2.1 MIMIR Database

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

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

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

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

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

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

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

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

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

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

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

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

Table 3 Database Record Accumulation Rate

Appendix 3.2.2 Historical Data

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

Appendix 3.3 Corrosion Management Context

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

Appendix 3.3.1 ER Probe and Corrosion Inhibitor Response

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

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

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

Table 4 Corrosion Inhibitor Concentration vs. Corrosion Rate

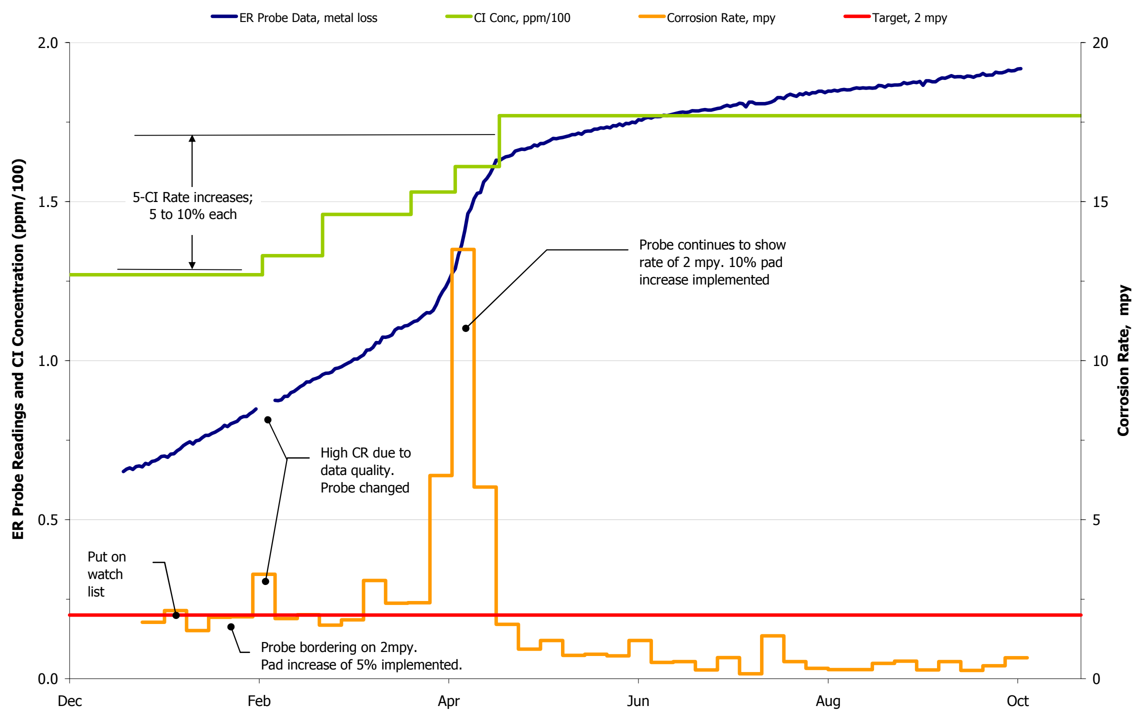


Figure 2 Corrosion Inhibitor Concentration vs. Corrosion Rate

Appendix 3.3.2 Corrosion Inhibitor Development

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

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

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

Location	Test	Description

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

Table 5 Summary Description of the Typical Test Program Components

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

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

Table 6 Flow line Test Program Result Summary

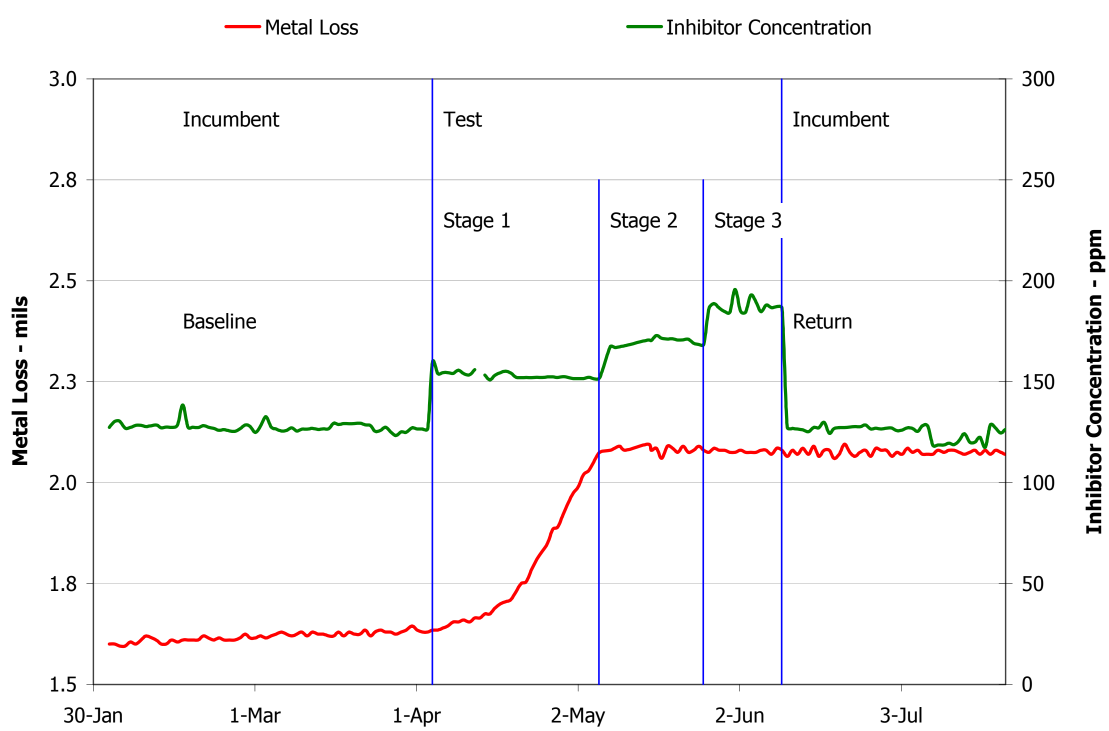


Figure 3 ER Probe Chemical Optimization Test

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

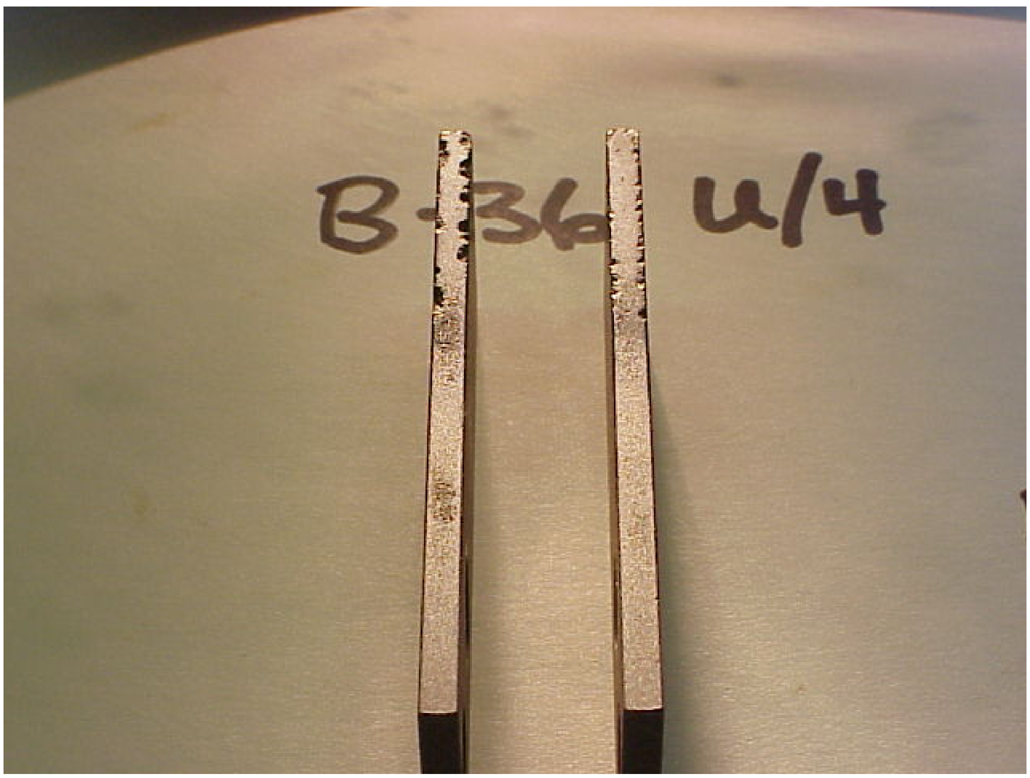


Figure 4 Corrosion coupons pulled after an 'unsuccessful' chemical trial

Appendix 3.3.3 Internal Inspection Program – Scope

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

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

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

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

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

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

Appendix 3.3.4 Corrosion Under Insulation

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

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

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

GPB Joint Design	Joint Type Freq	CUI Incident Rate
Anchor Joint	4.4%	2.8%
Damaged Insul	8.4%	2.0%
Damaged Weld Pack Insul	0.1%	2.4%
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 7 CUI Incident Rate by Joint Type

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

Appendix 3.3.5 Fitness for Service Assessment

The basic fitness-for-service criterion used by BPXA is ANSI/ASME B31G. The base document is the modified B31G, PRC 3-805, which is augmented with additional requirements defined in BP specification SPC-PP-00090, "Evaluation and Repair of Corroded Piping Systems".

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

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

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

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

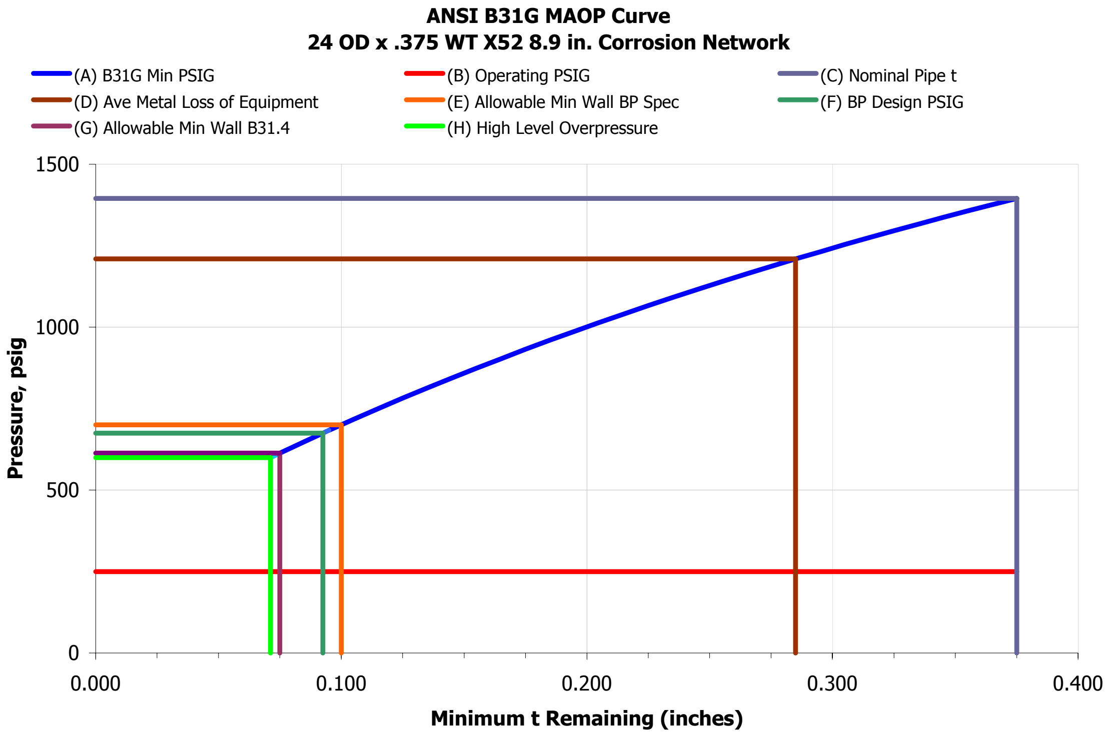
Localized/Pitting Corrosion Localized/pitting corrosion consisting of clearly defined relatively isolated regions of metal loss. The axial and circumferential extent of such regions needs to be determined and any potential areas of interaction where there is axial overlap between pitting regions.

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

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

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

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



	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 flow line (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 pipe-work. Any location at or below this level is actioned regardless of the calculated MAOP
(F)	BPXA 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/slug-catcher

Figure 5 MAOP versus Remaining Wall Thickness

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 8 Thickness, MAOP Correlation

Figure 6 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.

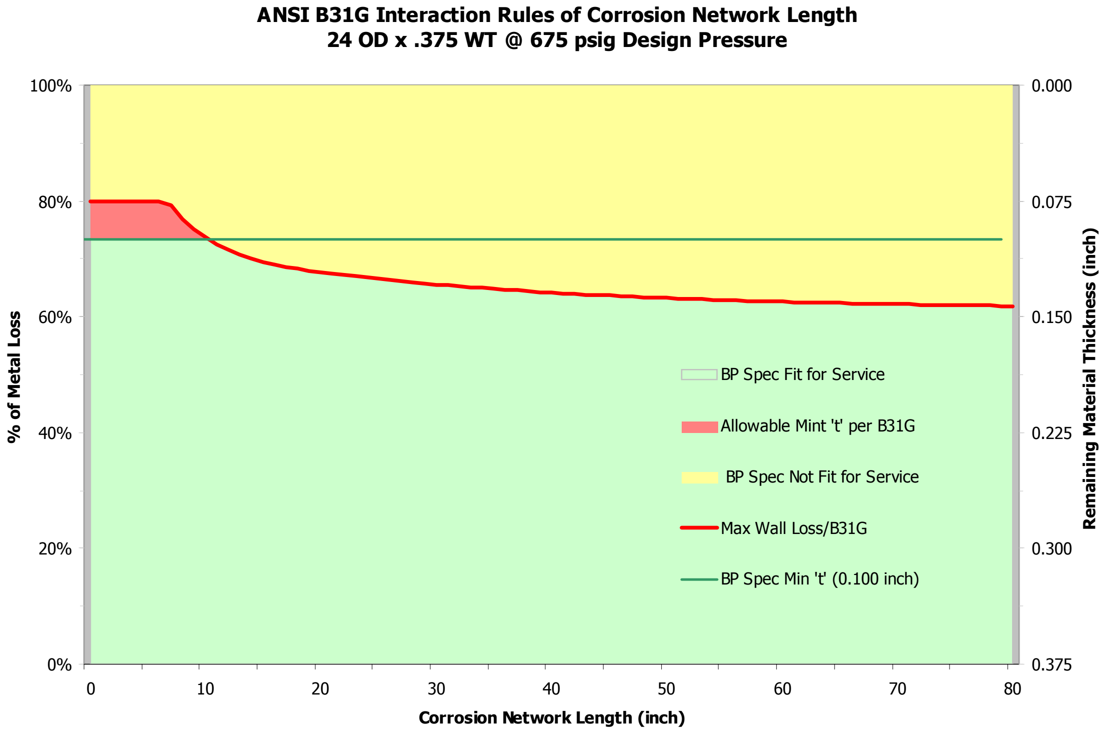


Figure 6 Fitness-for-Service Envelope Based on BP SPC-PP-00090

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,

- Remaining strength of material is sufficient to contain internal pressure as calculated by ANSI/ASME B31G/modified B31G methodology,
- Minimum thickness, regardless of pressure retaining calculation, is equal to the greater of 0.100 inch or 20% remaining wall thickness.

whichever is the greater remaining wall thickness of the assessment criteria. These same criteria are applied to remaining flow and well lines with the appropriate characteristics and parameters.

Appendix 3.3.6 In-line Inspection

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

It is important to note that because the vast majority of the cross-country flow lines are above ground, the value of ILI data are 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 flow line can be more effectively managed through the use of targeted manual NDE techniques.

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 fitness-for-service is determined and where the on-going corrosion rate and level of corrosion mitigation can be monitored.

There are limitations with the ILI technology currently used at GPB. A typical high resolution[11] MFL smart pig gives wall thickness measurements that are ±10% of the nominal 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/65-71°C.

While the ILI 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 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 overall NDE summary.

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

[11] MFL manufacturer technical data sheet

Program	Plan/Objectives	Target	Implementation	Evaluation	Corrective Action
1.0 Overall program goals	Eliminate corrosion/erosion related failures	No harm to people No accidents No damage to environment Regulatory compliance Compliance with industry standards	Integrated program with monitoring, inspection, operational controls, and corrosion inhibitor	Key performance indicators Leading and lagging indicators	Adjust mitigation, monitoring, and operational targets to meet objective Defect elimination - repair/replace/abandon
	Provide equipment availability to end of Field life	2050	Integrated Program with Monitoring, Inspection, Operational Controls, and Corrosion Inhibition	Key Performance Indicators Leading and Lagging Indicators	Adjust Mitigation, Monitoring, and Operational Targets to Meet Objective
	Cost effective Corrosion Management	Budget	Alliance Partnerships Technical Incentive Contracts Continuous Improvement	Key Performance Indicators Leading and Lagging Indicators	Develop more Cost Effective Methods For Delivering the Program Best in Class Technology Investment for the Future

Table 9 Corrosion Management System

Program	Plan/Objectives	Target	Implementation	Evaluation	Corrective Action
1.1 Corrosion Monitoring	Monitor for changes in corrosion rates	System dependant targets Corrosion rate to meet overall objectives Regulatory compliance Compliance with industry standards	Short term corrosion rate determination Medium term corrosion rate determination	ER probes Weight loss coupon rate Pitting Rates	Adjust Mitigating action to achieve corrosion rate target
	Monitor effectiveness of the chemical mitigation programs	Optimize Corrosion Inhibitor Rates and Distribution Optimize chemical mitigation programs e.g. Oxygen scavenger Biocide Drag reducing agent Scale	See above	See above	Provide feedback to Chemical treatment Operations Inspection activities Adjust Mitigation Effort Production Chemistry
	Monitor changes in the process conditions	Field-wide Velocity Management targets	Weekly Review of Operational Controls by CIC Group Operations review of fluid velocities Velocity alarms in Distributive Control System (DCS)	Mixture Velocities, Water Cuts, and Water Rates	Adjust production rates to meet velocity management targets
	Corrosion mechanism changes with time	Mitigation action in place prior to threat to mechanical integrity	Data availability and access Ease of 'data mining' and evaluation Single data storage Comprehensive data management and reporting process	Long-Term Process Change	Develop mitigation program Mechanism management as part of routine business
1.2 Erosion Monitoring	Monitor the effectiveness of the erosion mitigation programs	V/Ve <2.5 Max mixture Velocity and water cut matrix Well Put-On-Production (POP) process Regulatory compliance Compliance with industry standards	Unified velocity management standard across the North Slope Monthly compilation Of High Risk Wells Inspection of High Risk Wells Mixture velocity calculation in DCS	Mixture Velocities Inspection results	Additional inspection and monitoring at high risk sites Adjust Process Conditions Well shut-in Production reduction Design/debottleneck facilities

Table 10 Corrosion Management System Element – Monitoring

Program	Plan/Objectives	Target	Implementation	Evaluation	Corrective Action
1.3 Corrosion Mitigation	Mitigate Corrosion Through Application of Corrosion Inhibitors	Control Corrosion Rates to Acceptable Levels (See Overall Program Goals) Regulatory compliance Compliance with industry standards	Continuous Injection into individual wells as far upstream as possible - currently at Wellhead Protect all equipment between injection point and separation plant	ER Probes WLC's Inspection	Corrosion Inhibitor Development Adjust Mitigation Effort
		Control Corrosion Rates to Acceptable Levels (See Overall Program Goals)	Batch Treatments on a routine schedule with injection at the Wellhead	WLC's Inspection	Corrosion Inhibitor Development Adjust Mitigation Effort Through Reviews
	Mitigate Corrosion through Operational Controls	Operational Guidelines	Weekly Reviews by CIC Group	Mixture Velocities	Adjust Process Conditions
	Mitigate Corrosion through Maintenance Pigging	Achieve Scheduled Frequency	Maintenance Pigging	Inspection Pigging Returns	Adjust Maintenance Pigging Schedule
1.4 Erosion Mitigation	Mitigate Erosion Through Operational Controls and Design	Control Erosion Rates to Acceptable Levels (See Overall Program Goals) V/Ve < 2.5 Regulatory compliance Compliance with industry standards	Well POP process V/Ve Guidelines	V/Ve Inspection (ERM)	Adjust Process Conditions

Table 10 (continued) Corrosion Management System Element – Mitigation

Program	Plan/Objectives	Target	Implementation	Evaluation	Corrective Action
1.5 Inspection	Integrated inspection program to provide a overall assessment of plant condition and corrosion rates	Inspection activity level Leak/save target Inspection increases Plant condition Regulatory compliance	Corrosion rate monitoring program (CRM) Erosion rate monitoring program (ERM) Comprehensive inspection program (CIP) Frequent inspection program (FIP) Corrosion under insulation program (CUI)	NDE technique sheets and procedures Standardized assessment of piping condition, degradation rate and mechanism	Provide feedback to chemical mitigation program Erosion management program Fitness for service assessment Equipment life assessment Proactive repair scheduling
	Assessment of Current Damage Mechanisms	Zero Increases	Internal and external programs	See above	Repair/replace/monitor
	Search for New Damage Mechanisms	Mitigation action in place prior to threat to FFS	Baseline new equipment Apply lessons learnt from industry practice else where in the world Apply lessons learned for other BP operations Apply learnings across the field for similar equipment/process conditions Communications with Operations and Reservoir Engineers	See above	Develop mitigation program Mechanism management as part of routine business
1.6 Fitness for Service	Fitness for service assurance	Regulatory compliance Compliance with industry standard	See above inspection programs	Battelle Modified B31G fitness-for-service criteria (note piping only) BP internal specification for the assessment of damaged pipe	Repair equipment Replace equipment Derate equipment Abandon equipment
	Structural integrity	Regulatory compliance Compliance with industry standard	Walking speed survey every 5 years	Piping design code BP Spec, B31.4 and B31.8 Piping stress analysis Nondestructive testing as required	Repair/replace Correct support defect Monitor for further degradation

Table 10 (continued) Corrosion Management System Element – Inspection

Program	Plan/Objectives	Target	Implementation	Evaluation	Corrective Action
1.7 Continuous Improvement	Provide Feedback to Monitoring, Mitigation, and Inspection Programs	Continuous Improvement	Integrated Program with Monitoring, Inspection, Operational Controls, and Corrosion Inhibitor Provides Feedback Control Loop for Program Improvements Consolidated data store, MIMIR	Weekly program review Quarterly program review Annual program reviews and strategy assessment Annual equipment life/availability review Key Performance Indicators	Strategic adjustment Budget/funding level changes Mitigation process change and review Technical/R&D requirements and programs

Table 10 (continued) Corrosion Management System Element – Inspection

Program	Plan/Objectives	Target	Implementation	Evaluation	Corrective Action
1.1.1 Monitoring – Electrical Resistance Probes (ER)	Monitor the Effectiveness of the Mitigation Programs	< 2mpy Regulatory compliance Compliance with industry standard	ER Probes - Upstream and/or Downstream Ends of Flow lines	Investigate Cause for Corrosion Rate Increase	Mitigation Adjustments ER Probe Maintenance
1.1.2 Monitoring – Weight Loss Coupons (WLC)	Monitor the Effectiveness of the Mitigation Programs	Gen CR: < 2mpy Pit CR: < 20mpy Regulatory compliance Compliance with industry standard	WLC – Installed Flow lines, Well lines, Headers, and Piping	Investigate Cause for Corrosion Rate Increase	Mitigation Adjustments Inspection Program Adjustments
1.1.3 Monitoring – Process Conditions	Monitor changes in the Process Conditions	(See Mixture Velocity and Erosion Sections Below) Regulatory compliance Compliance with industry standard		Investigate Cause for Process Upset Long-Term Process Change Monitor Impact	Mitigation Adjustments
1.1.4 Monitoring – Mixture Velocity Management Program	Monitor the Effectiveness of the Mitigation Programs	Operational Guidelines Mix Vel Limits Regulatory compliance Compliance with industry standard	Operations Acceptance of Mixture Velocity Guidelines SETCIM	Review Alarm List to Determine True Offenders	Adjust Process Conditions
1.1.5 Monitoring – Erosion Management Program	Monitor the Effectiveness of the Erosion Mitigation Programs	Operational Guidelines Well Put on Production (POP) $V/V_e < 2.5$ Regulatory compliance Compliance with industry standard	Operations Acceptance of Erosion Guidelines High Risk Well Inspection Program (ERM)	Monthly Reviews to Determine High Risk Equipment and Repeat Offenders	Adjust Process Conditions

Table 11 Monitoring Program Techniques

Program	Plan/Objectives	Target	Implementation	Evaluation	Corrective Action
1.2.1 Mitigation – Corrosion Inhibitor	Mitigate Corrosion Through Application of Corrosion Inhibitors	Control Corrosion Rates to Acceptable Levels (See Overall Program Goals) Regulatory compliance Compliance with industry standard	Continuous Injection Into Individual Wells as Far Upstream As Possible – Currently at Wellhead Protect All Equipment Between Injection Point and Separation Plant	ER Probes WLC's Inspection	Corrosion Inhibitor Development Adjust Mitigation Effort
		Control Corrosion Rates to Acceptable Levels (See Overall Program Goals)	Batch Treatments on a Routine Schedule with Injection at the Wellhead	WLC's Inspection	Corrosion Inhibitor Development Adjust Mitigation Effort through Reviews
1.2.2 Mitigation – Operational Control, Maintenance, and Material Selection	Mitigate Corrosion Through Operational Controls	Operational Guidelines Mixture Velocity Limits Regulatory compliance Compliance with industry standard	Operations Acceptance of Mixture Velocity Guidelines	Mixture Velocities Review Alarm List to determine true offenders	Adjust Process Conditions
	Mitigate Erosion through Operational Controls	Operational Guidelines Well POP V/Ve < 2.5	Operations Acceptance of Erosion Guidelines High Risk Well Inspection Program (ERM)	Monthly Reviews to Determine High Risk Equipment and Repeat Offenders	Adjust Process Conditions
	Mitigate Corrosion through Maintenance Pigging	Achieve Scheduled Frequency	Maintenance Pigging	Inspection Pigging Returns	Adjust Maintenance Pigging Schedule
	Corrosion Resistant Alloys	Zero Increases (I's)	Selected Facilities & Equipment	Inspection Applicability For Service Requirements	Replace as Necessary
1.2.3 Mitigation – Structural Integrity	Mitigate structural damage caused by subsidence, jacking, vibration, impact, snow loading, etc. through inspections	No failures due to structural damage Regulatory compliance Compliance with industry standard	Operational procedures for visual surveillance of pipelines Piping stress analysis as required NDE inspections as required	Review Pipeline Design Code/BP Specification	Repair, replace and correct deficiencies as required Add Pipeline Vibration Dampeners (PVDs) as required

Table 11 (continued) Mitigation Program Techniques

Program	Plan/Objectives	Target	Implementation	Evaluation	Corrective Action
1.3.1 Corrosion Rate Monitoring (CRM)	Assessment of current corrosion mechanisms Monitor for new corrosion mechanisms	No measurable active corrosion -Zero increases (I's) Regulatory compliance Compliance with industry standard	CRM Program – Fixed locations on approximately bi-annual frequency	Inspections Condition of Equipment Rate of degradation	Mitigation Adjustments Repair/Replace Preventative Maintenance
1.3.2 Erosion Rate Monitoring (ERM)	Monitor high risk wells Assessment of current erosion locations	Manageable rate of degradation Regulatory compliance Compliance with industry standard	ERM Program – monthly to quarterly	Inspections Condition of Equipment Rate of degradation	Mitigation Adjustments Repair/Replace Preventative Maintenance
1.3.3 Frequent Inspection Program (FIP)	Assessment of High Corrosion Rates Monitor locations near repair	Fitness-for-Service Regulatory compliance Compliance with industry standard	FIP Program – monthly to bi-annual	Inspections Condition of Equipment Rate of degradation	Mitigation Adjustments Repair/Replace Preventative Maintenance
1.3.4 Comprehensive Integrity Program (CIP)	Comprehensive Coverage of equipment Fitness-for-Service review	Fitness-for-Service Regulatory compliance Compliance with industry standard	CIP – Condition and rate based half-life recurring frequency Extend coverage through new locations	Inspections Condition of Equipment Rate of degradation	Mitigation Adjustments Repair/Replace Preventative Maintenance
1.3.5 Corrosion Under Insulation (CUI)	Comprehensive Coverage of equipment	Inspection of Locations susceptible to CUI Fitness For Service Regulatory compliance Compliance with industry standard	CUI – Risk based annual program Management of location inventory through recurring examinations	Detect Damage Areas Analysis of occurrence	Repair/Replace Preventative Maintenance

Table 11 (continued) Mitigation Program Techniques

Method	Technique	Description	Sensitivity	Accuracy	Freq	Notes/Comments
Corrosion Monitoring	Electrical Resistance (ER) Probes	Measurement of corrosion rate by monitoring changes in electrical resistance of a metal probe due to volume loss	High	Low	H/D	Correlate poorly to actual pipewall corrosion rates
	Weight Loss Coupons Corrosion Rate	Exposure of metal samples to corrosive fluid and calculation of volume loss rates based on weight	Medium	Medium	M	Limited benefit in determining short-term effects, such as flow regime changes on corrosion rates
	Weight Loss Coupons Pitting Rate	Exposure of metal samples and assessment of pitting rate via measurement of pit depths	Medium	Medium	M	Not a very sensitive measure for GPB 3phase but more effective in the PW system
	Galvanic Probe	Detects changes in corrosivity as a function of current flow between two dissimilar metals.	High	Low	C	Not a reliable measurement of mild steel corrosion rate. Very suitable to monitor oxygen and chlorine changes in seawater
	Linear Polarization Resistance (LPR)	Electrochemical technique for assessing corrosion rate by application of controlled voltage and measuring current response	High	Low	H/D	Not used at GPB due to the interference of hydrocarbon films on measurement

Table 12 Corrosion Monitoring Techniques – Benefits and Limitations

Method	Technique	Description	Sensitivity	Accuracy	Freq	Notes/Comments
Process Monitoring	Mixture velocity	Mixture velocity of fluids in pipe-work	Medium	Medium	D	Accuracy dependent upon production information (T, P, Oil, Water, Gas)
	Water cut	Percent water in liquid fluids	Medium	Medium	D	Accuracy dependent upon production information (Oil, Water)
	Temperature and pressure	Measured temperature and pressure in process equipment	Medium	Medium	D	
	Dissolved Oxygen	Amount of oxygen dissolved in Sea Water	High	Medium	D	In-line accuracy problematic. Chemet method more accurate
	Iron (Fe) counts	Amount of Iron (Fe) dissolved in process water	High	Low	M	
	Microbiological activity	Amount of microbiological life forms in process fluids	Medium	Low	M	

Table 13 Process Monitoring techniques – Benefits and Limitations

Method	Technique	Description	Sensitivity	Accuracy	Freq	Notes/Comments
Inspection/NDE	Radiographic Testing (RT)	Assessment of pipe wall degradation by passing gamma or x-ray radiation through a specimen and projecting an image on conventional lead screen/film. Irregular density variations of the image can indicate metal loss.	Medium	Medium	M/Q/H/Y	Utilized for detection, monitoring, and fit for service assessment of pipe metal loss in the form of mechanical, corrosion, and erosion degradation. Currently being phased out in lieu of 'greener' process of DRT – see below
	Digital Radiographic Testing (DRT)	Assessment of pipe wall degradation by passing gamma or x-ray radiation through a specimen and projecting an image on phosphor screen/imaging plate. Irregular density variations of the image can indicate metal loss.	Medium	Medium	M/Q/H/Y	Utilized for detection, monitoring, and fit for service assessment of pipe metal loss in the form of mechanical, corrosion, and erosion degradation. DRT provides additional benefits in waste reduction associated with conventional film and processing chemicals
	Tangential Radiography Testing (TRT)	Assessment of pipe wall degradation by passing gamma or x-ray radiation through insulation at the tangent of the specimen and projecting an image on screen/film, phosphor screen/imaging plate, or detector array.	High	Low	Y	Utilized for detection of corrosion under insulation (CUI). Deployed where potential moisture ingress is suspected on thermally insulated piping
	Ultrasonic Testing (UT)	Assessment of pipe wall thickness by sending/receiving ultrasound through a specimen. Echoes returning indicate remaining thickness of the specimen.	Medium	High	M/Q/H/Y	Utilized for detection, monitoring, and fit for service assessment of pipe metal loss in the form of mechanical, corrosion, and erosion degradation
	Guided Wave Ultrasonic Testing (GUT)	Volumetric assessment of pipe wall by sending/receiving ultrasound through a specimen in the form of cylinder Lamb Waves. Monitoring changes in these waves indicate potential changes in pipe thickness. Alternatively, echoes returning to the source transducer may also indicate interruptions or pitting in the pipe segment.	Low	Low	Y	Utilized for cased piping assessment where access does not support use of traditional inspection methods. The method is capable of semi-quantifying metal loss but cannot discriminate between internal and external corrosion
	Electromagnetic Pulse Testing (EMT)	Assessment of pipe wall by propagating broadband electromagnetic waves on the exterior surface of the specimen. When waves traveling down steel pipe encounter corrosion on the pipe surface, the waves are distorted. Distortions in waveform may indicate rust by-product on the surface of the steel and subsequent metal loss.	High	Low	Y	Utilized for cased piping assessment where access does not support use of traditional inspection methods. The method cannot quantify metal loss and has a tendency to report false positive results but seldom overlooks surface atmospheric corrosion

Table 14 Inspection/Non-Destructive Examination Techniques – Benefits and Limitations

Method	Technique	Description	Sensitivity	Accuracy	Freq	Notes/Comments
Inspection/NDE (Cont)	In-line Inspection – Smart Pig Magnetic Flux (MFL) Technique	Assessment of pipelines for the detection and measurement of metal loss. These pigs carry high strength magnets, which apply a strong magnetic field into the pipe wall. The magnetic field saturates the pipe steel with magnetic flux. As a result, areas of metal loss cause the flux to leak out of the pipe wall. The flux leakage data are recorded and used to infer the size and depth of any metal loss defects in the pipe.	High	Medium	N/A	Utilized where design and process operation permit in-line pigging. Metal loss MFL In-line Inspection provides complete evaluation of pipeline integrity within the limitations of the MFL technique.

Table 14 (continued) Inspection/Non-Destructive Examination Techniques – Benefits and Limitations

Service	Equipment Type	Monitoring Technique	Inspection Program	Mitigation Program*
Oil	Flow line	ER Probes WLC Process Monitoring	CRM FIP CIP CUI	CI Injection Mixture Velocities Periodic Maintenance Pigging Operational Controls
	Well line	WLC Process Monitoring	CRM ERM FIP CIP CUI	CI Injection Mixture Velocities Mixture Velocities Operational Controls
Produced Water	Flow line	WLC	CRM FIP CIP CUI	CI Injection** CI Carry Over Periodic Maintenance Pigging Mixture Velocities Operational Controls
	Well line	WLC	CRM FIP CIP CUI	CI Injection** CI Carry Over Mixture Velocities Operational Controls
Seawater	Flow line	WLC Galvanic Probes Dissolved 0_2 Microbiological Activity	CRM FIP CIP CUI	Biocide Treatment 0_2 Scavenger Periodic Maintenance Pigging Operational Controls
	Well line	WLC Microbiological Activity	CRM FIP CIP CUI	Biocide Treatment Periodic Maintenance Pigging Operational Controls
Export oil	Flow line	WLC ER Probes	CRM FIP CIP CUI	CI Carry Over Mixture Velocities Operational Controls Periodic Maintenance Pigging

*Applicable to all inspection programs noted
**No CI injection for FS-2 PW

Table 15 Corrosion Management System Implementation by Equip Type and Service

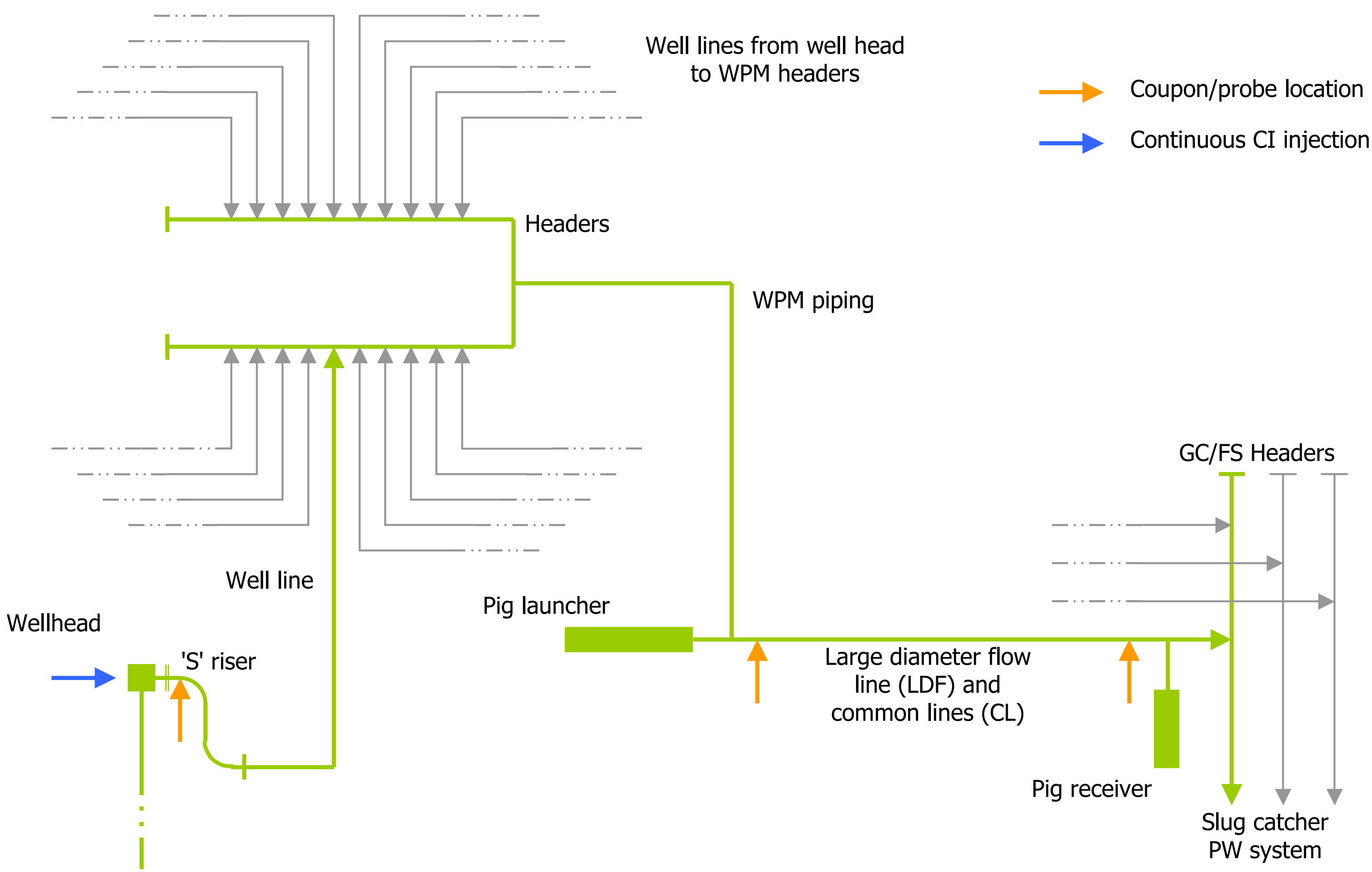


Figure 7 Facility Schematic

This page is intentionally blank

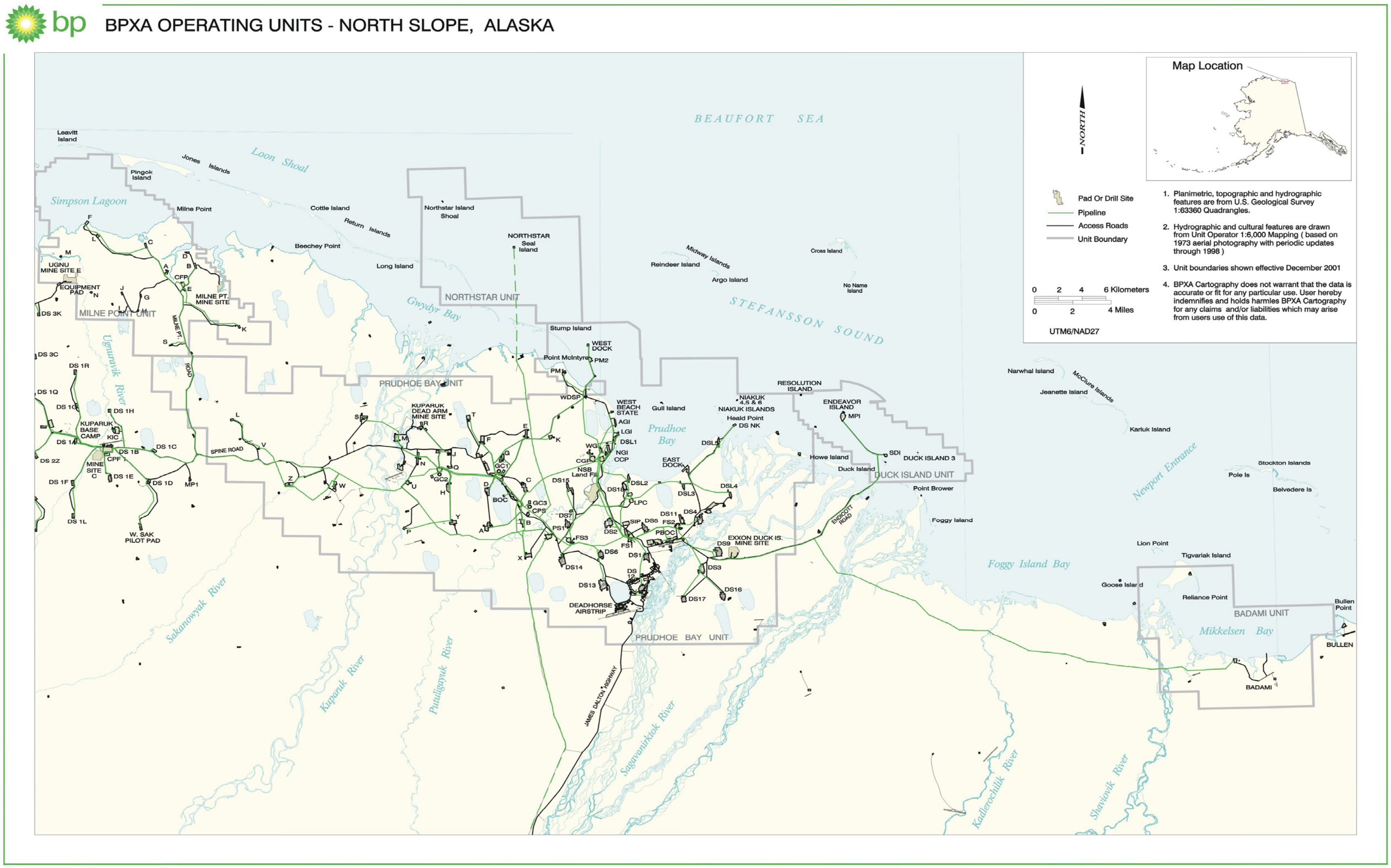


Figure 8- Map of North Slope

This page is intentionally blank

BP North Slope Operations	**Field Data (current 1/01)**	
Greater Prudhoe Bay	Field Area	150,000 acres
	Original Oil in Place (Gross)	25 billion barrels
	Original Gas in Place (Gross)	47 trillion Std. Cu Ft
	Oil Production Wells	1,080
	Gas Injection Wells	36
	Water Injection Wells	174
	Major Separation Plants	6
	Major Gas Handling Plants	2
	Major Water Handling Plants	3
	Miles of Pipelines (approximate)	1,300
Midnight Sun	Field Area	3,000 acres
	Original Oil in Place (Gross)	0.06 billion barrels
	Original Gas in Place (Gross)	trillion Std Cu Ft
	Oil Production Wells	2
	Water Injection Wells	1
	Miles of Pipelines (approximate)	4
Aurora	Field Area	10,000 acres
	Original Oil in Place (Gross)	billion barrels
	Original Gas in Place (Gross)	trillion Std Cu Ft
	Oil Production Wells	5
	Miles of Pipelines (approximate)	1
Pt. McIntyre	Field Area	8,000 acres
	Original Oil in Place (Gross)	0.8 billion barrels
	Original Gas in Place (Gross)	0.9 trillion Std Cu Ft
	Oil Production Wells	59
	Gas Injection Wells	1
	Water Injection Wells	15
	Miles of Pipelines (approximate)	6
Lisburne	Field Area	30,000 acres
	Original Oil in Place (Gross)	1.8 billion barrels
	Original Gas in Place (Gross)	trillion Std Cu ft
	Oil Production Wells	74
	Gas Injection Wells	4
	Major Separation Plants	1
	Miles of Pipelines (approximate)	27
Niakuk & Western Niakuk	Field Area	1,900 acres
	Original Oil in Place (Gross)	billion barrels
	Original Gas in Place (Gross)	trillion Std Cu Ft
	Oil Production Wells	18
	Water Injection Wells	7
	Miles of Pipelines (approximate)	6

BP North Slope Operations	**Field Data (current 1/01)**	
Milne Point	Field Area	36,454 acres
	Original Oil in Place (Gross)	0.92 billion barrels
	Oil Production Wells	107
	Gas/Water Injection Wells	59
	Source Water Wells	8
	Major Separation Plants	1
	Miles of Pipelines (approximate)	55
Schrader Bluff	Field Area	28,000 acres
	Original Oil in Place (Gross)	1.97 billion barrels
	Oil Production Wells	49
	Gas\Water Injection Wells	14
	Source Water Wells	3
	Miles of Pipelines (approximate)	15
Eider	Field Area	300 acres
	Original Oil in Place (Gross)	0.013 billion barrels
	Original Gas in Place (Gross)	0.052 trillion Std Cu Ft
	Oil Production Wells	1
	Gas Injection Wells	1
	Miles of Pipelines (approximate)	.5
Endicott	Field Area	8,800 acres
	Original Oil in Place (Gross)	billion barrels
	Original Gas in Place (Gross)	1.4 trillion Std Cu Ft
	Oil Production Wells	47
	Gas Injection Wells	5
	Water Injection Wells	21
	Major Separation Plants	1
	Miles of Pipelines (approximate)	52
Sag Delta North	Field Area	380 acres
	Original Oil in Place (Gross)	0.014 billion barrels
	Oil Production Wells	2
	Gas Injection Wells	2
	Miles of Pipelines (approximate)	.5
Badami	Original Oil in Place (Gross)	0.160 billion barrels
	Oil Production Wells	6
	Gas Injection Wells	2
	Major Separation Plants	1
	Miles of Pipelines (approximate)	50
Northstar (current 3/02)	Field Area	38,000 acres
	Original Oil in Place (Gross)	.176 billion barrels
	Oil Production Wells	4
	Disposal Injection Wells	1
	Gas Injection Wells	2
	Major Separation Plants	1
	Miles of Pipelines (approximate)	30

GPB Table 3.1 - BPXA North Slope Operations

Corrosion, Inspection and Chemical (CIC) Group
BP Exploration (Alaska) Inc.
900 E Benson Boulevard
Anchorage
Alaska