

11964 SENATE RESOURCES

BU	Type	Service	Statistic	1995	1996	1997	1998	1999	2000	2001
GPB	FL	OIL	WLC	1441	1573	1612	1506	1541	1460	1190
GPB	FL	OIL	Ave Rate	1.39	0.83	0.49	0.48	0.31	0.41	0.32
GPB	FL	OIL	SD Rate	6.93	3.92	2.06	3.74	0.57	0.83	0.86
GPB	FL	OIL	WLC <2mpy	1,306	1,489	1,568	1,476	1,527	1,420	1,176
GPB	FL	OIL	PC WLC<2mpy	90.6%	94.7%	97.3%	98.0%	99.1%	97.3%	98.8%
GPB	WL	OIL	WLC	5506	6862	7064	6659	6372	6407	3994
GPB	WL	OIL	Ave Rate	2	2.19	0.92	0.70	0.54	0.74	0.66
GPB	WL	OIL	SD Rate	6.85	6.09	2.30	3.63	1.19	1.49	1.72
GPB	WL	OIL	WLC <2mpy	"3,938"	"5,245"	"6,273"	"6,274"	"6,126"	"5,916"	"3,713"
GPB	WL	OIL	PC WLC<2mpy	71.5%	76.4%	88.8%	94.2%	96.1%	92.3%	93.0%
GPB	FL	PO	WLC	28	42	50	38	40	42	24
GPB	FL	PO	Ave Rate	0.11	0.18	0.11	0.14	0.12	0.16	0.07
GPB	FL	PO	SD Rate	0.17	0.28	0.18	0.12	0.06	0.07	0.06
GPB	FL	PO	WLC <2mpy	28	42	50	38	40	42	24
GPB	FL	PO	PC WLC<2mpy	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
GPB	WL + FL	PW	WLC	715	734	711	629	475	409	288
GPB	WL + FL	PW	Ave Rate	2.23	1.34	0.51	0.93	1.01	0.56	1.17
GPB	WL + FL	PW	SD Rate	5.65	4.06	2.58	5.34	3.66	1.58	3.56
GPB	WL + FL	PW	WLC <2mpy	556	670	694	596	429	386	252
GPB	WL + FL	PW	PC WLC<2mpy	77.8%	91.3%	97.6%	94.8%	90.3%	94.4%	87.5%
GPB	WL + FL	SW	WLC	72	80	80	80	76	76	50
GPB	WL + FL	SW	Ave Rate	0.98	1.00	0.21	0.40	0.83	1.24	2.65
GPB	WL + FL	SW	SD Rate	1.73	2.87	0.63	0.86	1.63	2.45	3.36
GPB	WL + FL	SW	WLC <2mpy	66	72	77	76	72	66	28
GPB	WL + FL	SW	PC WLC<2mpy	91.7%	90.0%	96.3%	95.0%	94.7%	86.8%	56.0%

Table 5.3 Aggregate GPB Flow and Well Line General Rate Data Summary

BU	Type	Service	Result	1995	1996	1997	1998	1999	2000	2001
GPB	FL	OIL	I	373	939	1181	411	247	126	134
GPB	FL	OIL	NC	15493	16013	16807	15017	12141	8294	7183
GPB	FL	OIL	NL	3699	2132	2030	444	376	151	1788
<b>GPB</b>	<b>FL</b>	<b>OIL</b>	<b>Total</b>	<b>19565</b>	<b>19084</b>	<b>20018</b>	<b>15872</b>	<b>12764</b>	<b>8571</b>	<b>9105</b>
GPB	FL	WTR	I	175	126	156	194	71	17	40
GPB	FL	WTR	NC	1167	1090	1157	1562	1565	725	1097
GPB	FL	WTR	NL	422	116	141	87	77	61	345
<b>GPB</b>	<b>FL</b>	<b>WTR</b>	<b>Total</b>	<b>1764</b>	<b>1332</b>	<b>1454</b>	<b>1843</b>	<b>1713</b>	<b>803</b>	<b>1482</b>
<b>GPB</b>	<b>FL</b>	<b>Total</b>	<b>Total</b>	<b>21329</b>	<b>20416</b>	<b>21472</b>	<b>17715</b>	<b>14477</b>	<b>9374</b>	<b>10587</b>
GPB	WL	OIL	I	640	920	877	612	311	263	214
GPB	WL	OIL	NC	2468	3519	3409	4103	3619	4155	5429
GPB	WL	OIL	NL	976	1801	1989	726	601	542	2442
<b>GPB</b>	<b>WL</b>	<b>OIL</b>	<b>Total</b>	<b>4084</b>	<b>6240</b>	<b>6275</b>	<b>5441</b>	<b>4531</b>	<b>4960</b>	<b>8085</b>
GPB	WL	WTR	I	183	184	142	129	35	52	25
GPB	WL	WTR	NC	620	853	621	855	603	726	665
GPB	WL	WTR	NL	231	227	127	120	94	77	344
<b>GPB</b>	<b>WL</b>	<b>WTR</b>	<b>Total</b>	<b>1034</b>	<b>1264</b>	<b>890</b>	<b>1104</b>	<b>732</b>	<b>855</b>	<b>1034</b>
<b>GPB</b>	<b>WL</b>	<b>Total</b>	<b>Total</b>	<b>5118</b>	<b>7504</b>	<b>7165</b>	<b>6545</b>	<b>5263</b>	<b>5815</b>	<b>9119</b>
<b>GPB</b>	<b>Total</b>	<b>Total</b>	<b>Total</b>	<b>26447</b>	<b>27920</b>	<b>28637</b>	<b>24260</b>	<b>19740</b>	<b>15189</b>	<b>19706</b>

Table 5.4 GPB Flow and Well Line Inspection Data



bp



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BP Exploration (Alaska) Inc.  
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Anchorage  
Alaska

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**PRUDHOE  
BAY  
CORROSION  
CRISIS,  
8/18/06  
(FILE 7)**

2002



Annual Report to Alaska Department of Environmental Conservation

# **Commitment to Corrosion Monitoring**

## **Year 2002**

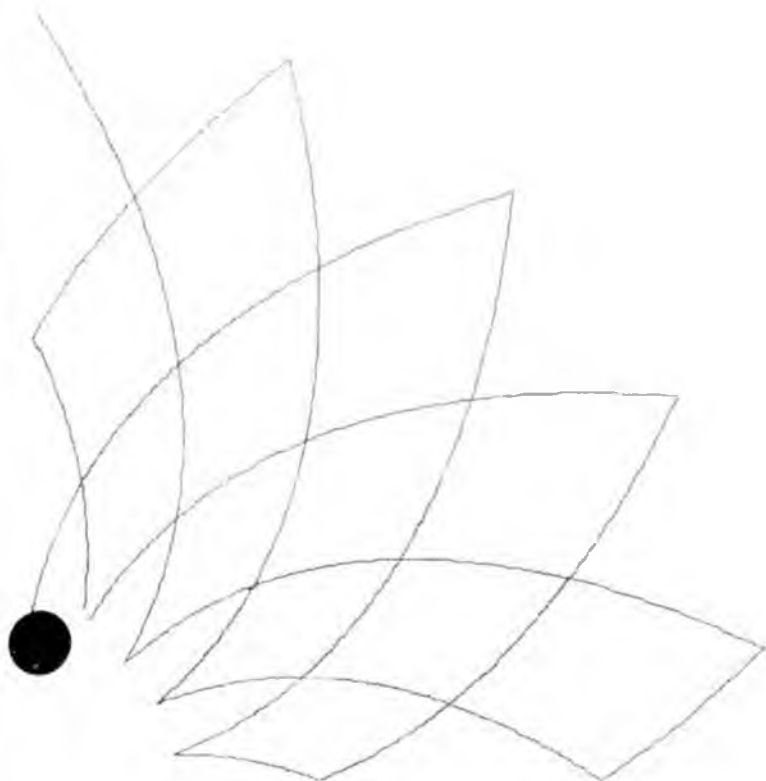
Prepared by

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

March 2003

# **Commitment to Corrosion Monitoring**

**Year 2002**



## Executive Summary

This is the third annual report that meets the commitment made by BP to the State of Alaska to provide a regular review of BP's corrosion monitoring and management practices for non-common carrier pipelines on the North Slope. The contents of this report reflect the Work Plan<sup>1</sup> agreed jointly between BP, Phillips and ADEC, the Guide for Performance Metric Reporting<sup>2</sup>, and feedback from ADEC on the 2000 and 2001 reports.

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. 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. Over the last decade 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. 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 expansion of the external corrosion inspection program in 2002 is evidence of this on-going commitment.

**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

---

<sup>1</sup> Appendix 2 (a) 2000 Work Plan

<sup>2</sup> Appendix 2 (b) Guide for Performance Metric Reporting

programs, but also, the development and implementation of new programs and corrosion management technologies.

In summary, the current corrosion management process has delivered a significantly improved level of corrosion control that has reduced corrosion rates in the cross-country flow lines by a factor of 10 in the last 10 years. Notwithstanding the successes of the last 10 years 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 delivered over the last 10 years has enabled BP 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
- ▶ Ability to produce satellite accumulations through existing equipment and pipe-work
- ▶ Provide an infrastructure capable of supporting gas sales in the future

In addition, with the information in this report, BP 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 2003

## Foreword

This is the third annual report that meets the commitments made by BP in the Charter Agreement for Development of the Alaskan North Slope. The structure of the report is similar to that of prior years.

In addition to the requirements set out in the Work Plan and the Guide to Performance Metric Reporting, BP has provided additional material that is intended to provide additional context and background to aid in understanding the corrosion management program and the corrosion problems encountered in the flow lines on the North Slope.

The report is divided into 2 main sections.

**Part 1** contains information regarding the BP operated fields within the Greater Prudhoe Bay (GPB) Business 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 BP operated fields within the Alaska Consolidated Team (ACT) Business 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.

There are 5 appendices. Appendices 1-4 apply to both parts of the main report, and Appendix 5 contains the detailed data tables for GPB and ACT.

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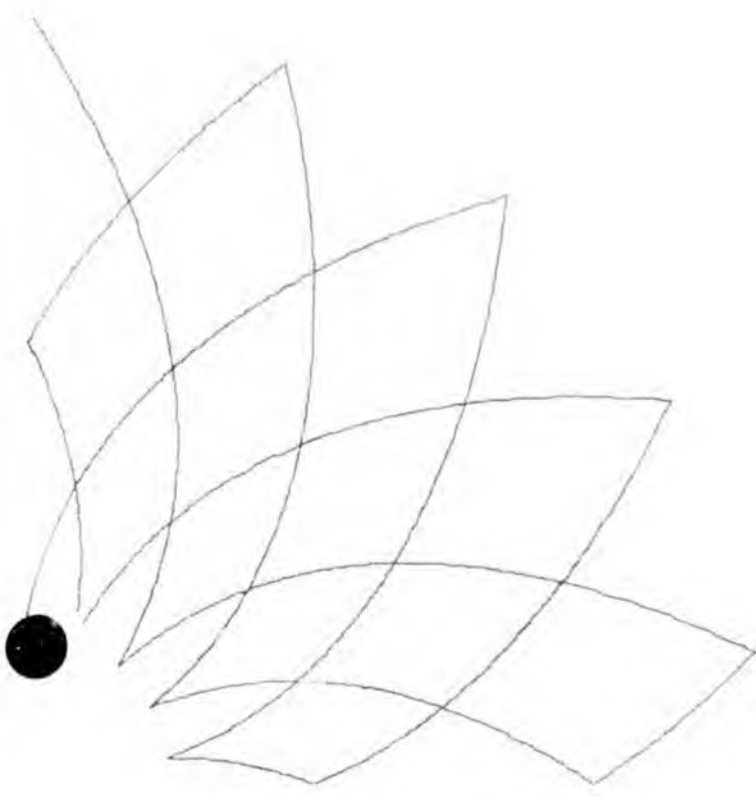
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**Section A**

**Charter Agreement – Corrosion Related Commitments**



## Section A Charter Agreement – Corrosion Related Commitments

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

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### Section A.1 Project Achievements

Oct-Nov 2000	Work Plan agreed between BP/PAI and ADEC Details of the Work Plan in Appendix 1
March 2001	1 <sup>st</sup> Annual Report submitted to ADEC
April 2001	1 <sup>st</sup> 2001 Meet and Confer session held
Oct-Dec 2001	Consultations with ADEC and ADEC's consultant
November 2001	2 <sup>nd</sup> 2001 Meet and Confer session held
Dec 01-Jan 02	Developed and agreed corrosion management metrics
February 2002	BP/PAI and ADEC agreed performance metrics Details of the Performance Metrics in Appendix 2
March 2002	2 <sup>nd</sup> Annual Report submitted to ADEC
April 2002	1 <sup>st</sup> 2002 Meet and Confer session held
November 2002	2 <sup>nd</sup> 2002 Meet and Confer session held

### Section A.2 Annual Charter Timetable

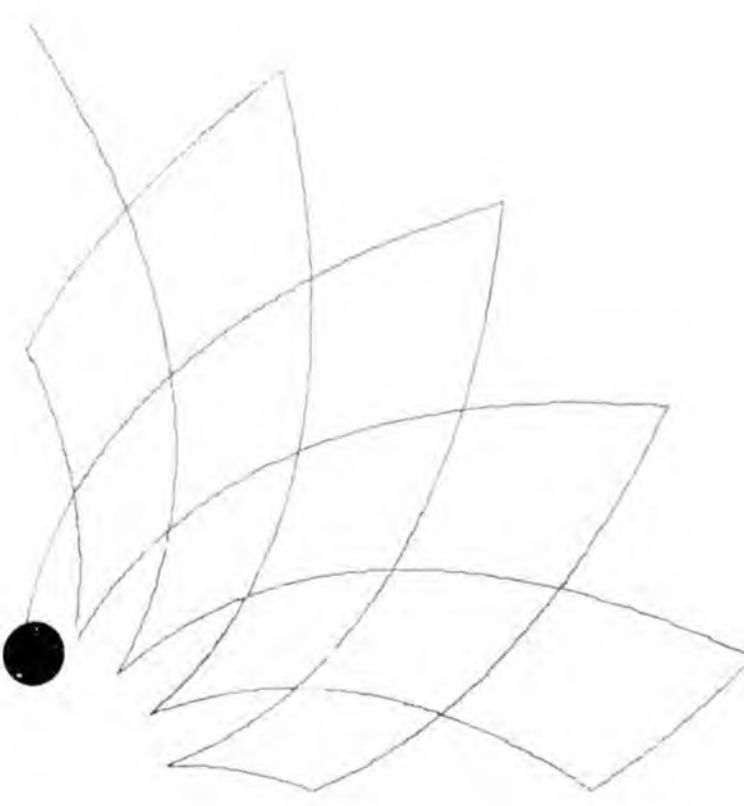
March 31 <sup>st</sup>	Annual Report submitted
April 30 <sup>th</sup>	1 <sup>st</sup> Semi-Annual Review/Meet and Confer
October 31 <sup>st</sup>	2 <sup>nd</sup> Semi-Annual Review/Meet and Confer

**Part 1**

**Greater Prudhoe Bay Business Unit**

**Section B**

**Corrosion Monitoring Activities**



## **Section B Corrosion Monitoring Activities**

This section summarizes the Corrosion Management System (CMS) in use at Greater Prudhoe Bay (GPB) Business Unit. The GPB Business Unit incorporates Prudhoe Bay, Point McIntyre, Lisburne and Niakuk oilfields plus a number of smaller satellite accumulations all of which are produced through the main separation facilities.

A map and brief description of each field and the associated production facilities can be found in Appendices 3 (a) and 3 (b). Appendix 4 contains a schematic of a typical production facility configuration.

### **Section B.1 Corrosion Management System Strategic Objectives<sup>3</sup>**

The following section provides an overview of the corrosion management process used within BP. The overall objective of the program is to meet the corporate objectives of 'no accidents, no harm to people and no damage to the environment'<sup>4</sup> which translates for corrosion management within BP 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. The main elements of the Corrosion Management System are Corrosion Monitoring, Corrosion Mitigation, Inspection and Fitness-For-Service assessment. The elements of the CMS are summarized in Table B.11 (a), (b) and (c) at the end of Section B.

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<sup>3</sup> In addition to Charter Work Plan, this information supplied to provide additional context and help in understanding BP corrosion management activities

<sup>4</sup> BP HSE Policy Statement, EJP Browne, Group CEO, January, 1999, <http://www.bp.com/>

### Section B.1.1 Corrosion Management System

The Corrosion Management System consists of a number of major program elements, which follow a simple management process. The overall system is shown in Figure B.1.

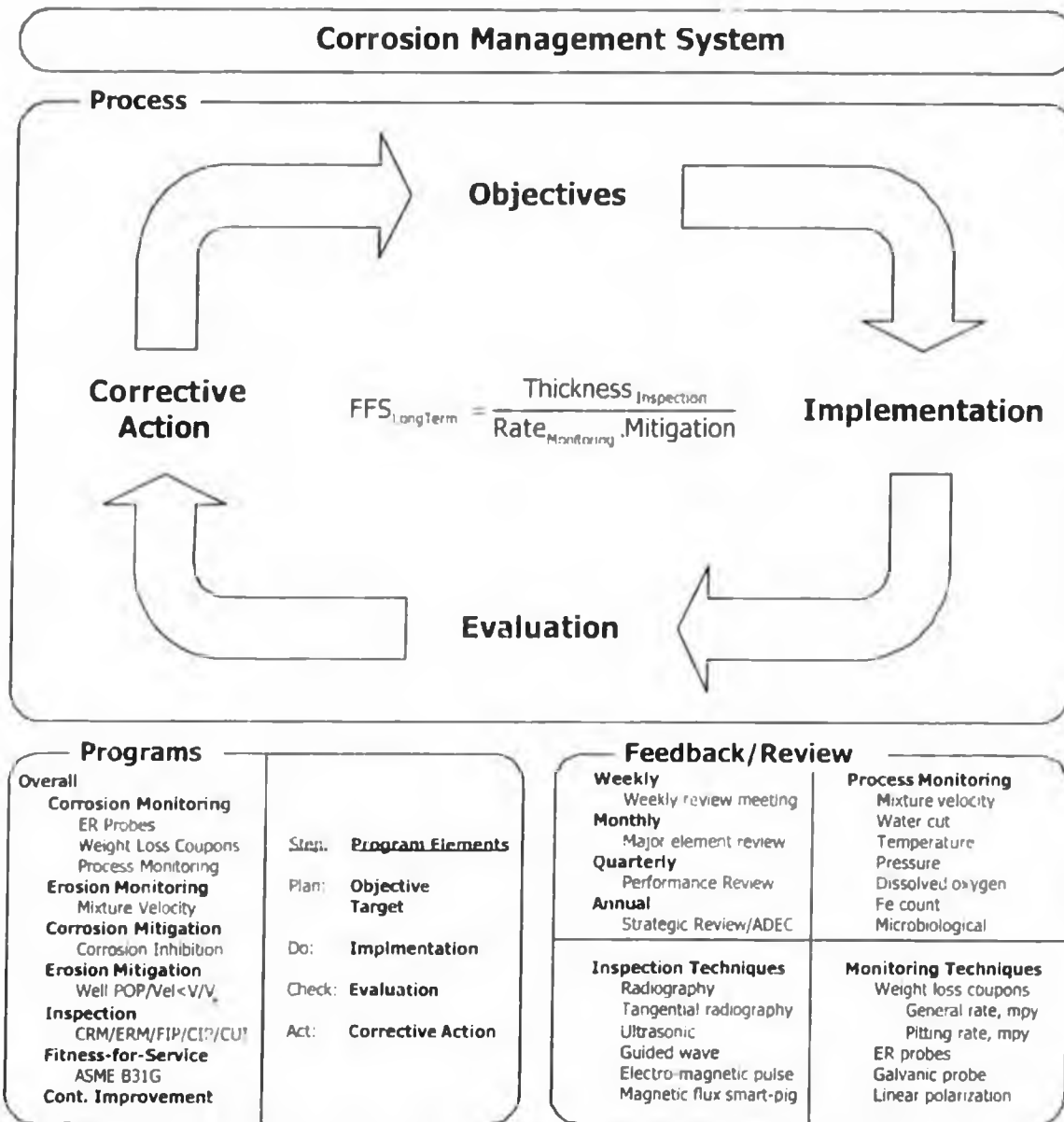


Figure B.1 Overview of the Corrosion Management Process

### Section B.1.2 Corrosion Management Process

Within the overall Corrosion Management System each of the specific program elements, i.e. Corrosion Monitoring, Mitigation, Inspection and Fitness-For-

Service, follows a simple process. The management process can be described in terms of the classic TQM (Total Quality Management) process of 'plan-do-check-act' and consists of,

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

**Table B.2** Corrosion Management Process

The elements of the CMS program and process are also detailed in Table B.11 (a), (b), and (c).

### Section B.1.3 Corrosion Management Process - Evaluation

Within the Corrosion Management Process (CMP) 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 CMP are,

Review	Description
Weekly	A weekly internal review meeting at which the latest corrosion monitoring, mitigation, inspection and process data is 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 B.3** Summarizing Corrosion Management Feedback Cycle

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

#### **Section B.1.4 Corrosion Measurement Techniques**

The data summarized in the remainder of this report is used by the Corrosion, Inspection and Chemical (CIC) Group as part of the overall Corrosion Management System. 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 the individual techniques more or less applicable depending on the application circumstances.

Table B.12 (a), (b) and (c) summarize the main categories of corrosion and process monitoring, inspection techniques and briefly summarizes relative strengths and weaknesses for different applications.

#### **Section B.1.5 Integration of Monitoring, Inspection and Mitigation**

The elements of the corrosion management program have to be applied to each of the systems on the North Slope to reflect their applicability and efficacy. The corrosion and erosion monitoring, inspection and mitigation practices for the major services and equipment type are summarized in Table B.13.

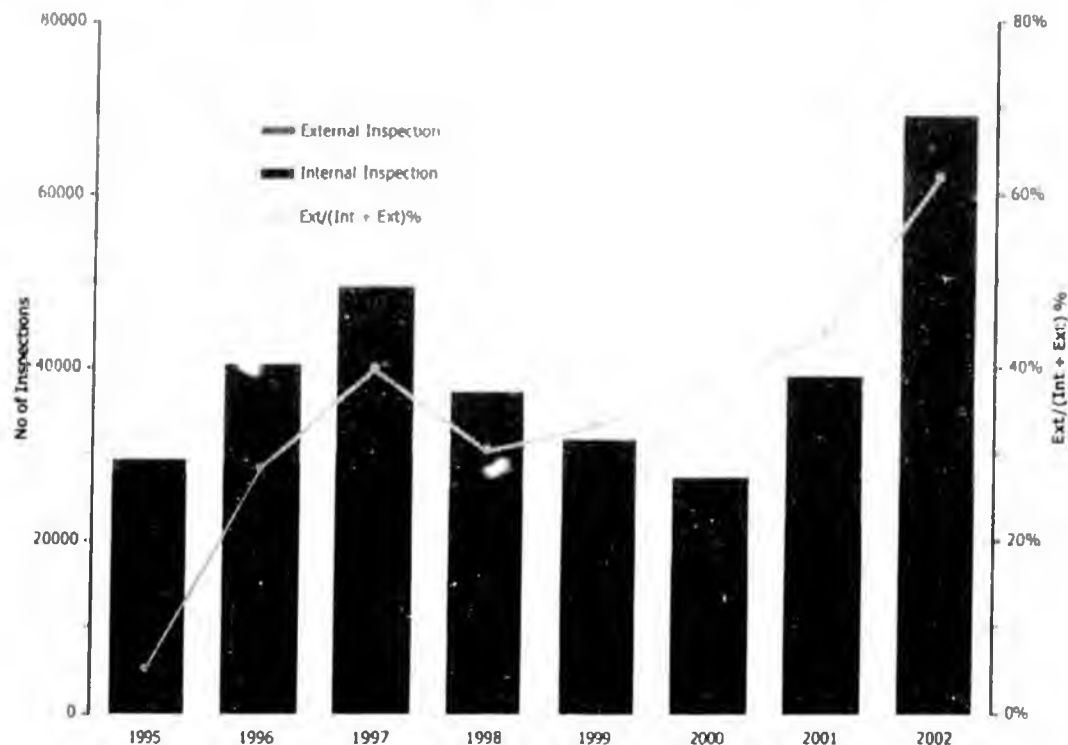
#### **Section B.2 Inspection and Corrosion Monitoring Activity Level**

Figure B.4 summarizes the level of internal and external inspection activity across GPB since 1995 for both cross-country flow lines and well lines. The 2002 internal inspection activity of ~26,000 was only slightly above the 1995-2001 average of 24,500 and therefore consistent with historical levels of activity. As can be seen from Table B.6, the level of external corrosion inspection activity has been increased significantly in 2002 from the 5-year average of ~13,000 to ~43,000 locations.

The 2002 external corrosion inspection activity was significantly above the 35,000 locations forecast in the 2001 report. This was primarily due to the accessibility of the locations in the 2002 survey. The ease of accessibility in 2002 is not expected to be repeated in 2003 and therefore the 2003 forecast activity level for external corrosion inspection is 35,000 consistent with the original 2002 forecast.

Figure B.4 also shows the breakdown of the inspection program between internal and external inspection. From the figure it can be seen that the percentage,  $\frac{\text{Ext}}{(\text{Ext} + \text{Int})} \%$ , of the overall inspection effort consumed by the external corrosion inspection effort has increased significantly with the increased effort in 2002. As noted above, it is anticipated that for 2003 the percentage will be lower at approximately 55% compared to the 65% for 2002.

Table B.5 provides the details of inspection activity for the internal and external programs. The level of external corrosion inspection activity has been ramped-up from a broadly flat level of 10-15,000 in 1995 to over 43,000 external inspection items in 2002. Based on the results of the data generated in the 1996-2001 external corrosion inspection surveys, the 2002 program was expanded to reduce the risk of a leak because of the external corrosion. This is discussed in detail in Section E. The average activity level for the program from 1996-2001 was ~13,000 items per year, in comparison the 2002 program achieved ~43,000 items which is over 3 times the average for the prior five years.



**Figure B.4** Breakdown of Inspection Activity Between Internal and External for Field Piping

Year	1995	1996	1997	1998	1999	2000	2001	2002
External	1508	11509	19616	11262	10515	10441	17090	42728
Internal	27802	28998	29796	25858	21187	16836	21894	26382
<b>Total</b>	29310	40507	49412	37120	31702	27277	38984	69110
$\frac{\text{Ext}}{\text{Ext} + \text{Int}}\%$	5%	28%	40%	30%	33%	38%	44%	62%

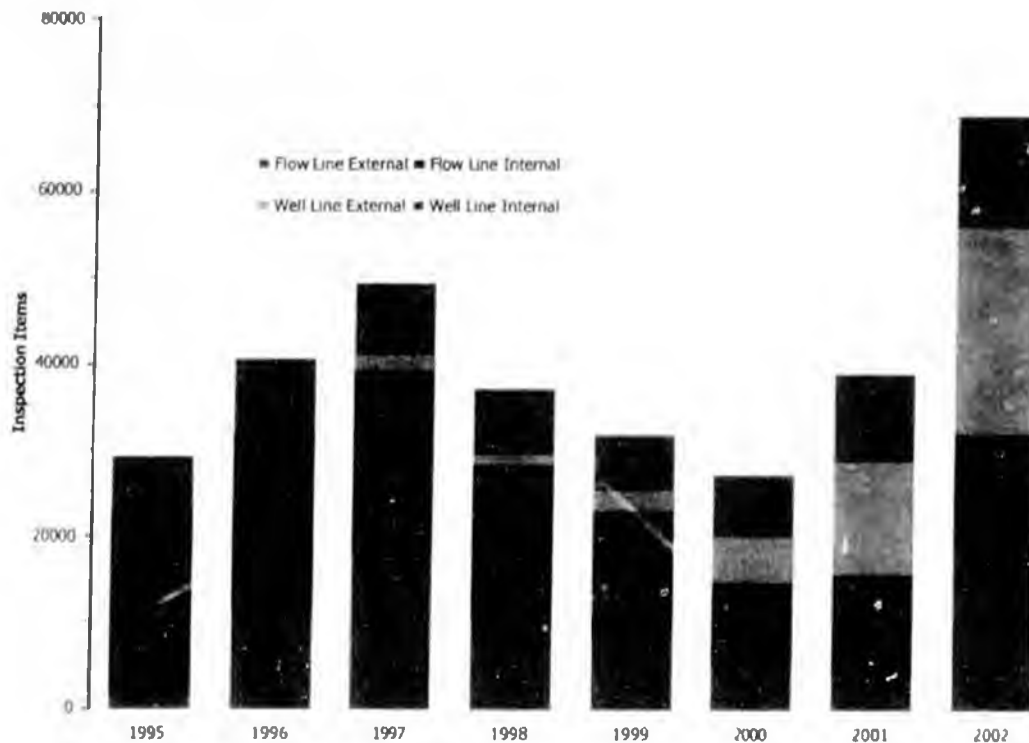
**Table B.5** Internal and External Inspection Activity Breakdown

Year	1995	1996	1997	1998	1999	2000	2001	2002	
Flow Line	External	1508	11473	17935	10316	8139	5184	3966	18931
	Internal	21769	20544	21317	18115	14870	9625	11576	13206
<b>Total</b>	23277	32017	39252	28431	23009	14809	15542	32137	
$\frac{\text{Ext}}{\text{Ext} + \text{Int}}\%$	6%	36%	46%	36%	35%	35%	26%	59%	
Well Line	External		36	1681	946	2376	5257	13124	23797
	Internal	6033	8454	8479	7743	6317	7211	10318	13176
<b>Total</b>	6033	8490	10160	8689	8693	12468	23442	36973	
$\frac{\text{Ext}}{\text{Ext} + \text{Int}}\%$	0%	0%	17%	11%	27%	42%	56%	64%	
<b>Grand Total</b>	29310	40507	49412	37120	31702	27277	38984	69110	
$\frac{\text{FL}}{\text{FL} + \text{WL}}\%$	79%	79%	79%	77%	73%	54%	40%	47%	

**Table B.6** Internal and External Inspection Activity Summary by Flow/Well Line

Tables B.6 Shows the split between flow line and well line inspections for both the internal and external programs. The data shows that there has been a shift in the inspection program from the flow lines to the well lines. This reflects the higher degree of corrosion control in the flow lines compared to the well lines.

For the year 2002, the level of internal inspection activity for the well lines and the flow lines was approximately equal at ~13,200 items. Similarly, the external corrosion inspection program activity was approximately equally distributed between the well line and flow lines at ~20,000 items for each. The split between internal and external inspection for the flow lines and well lines is summarized in Figure B.7



**Figure B.7** Internal and External Inspection Activity Summary by Flow/Well Line

The 2002 smart pig program consisted of the examination of 3 produced water lines located on the east side of GPB. Due to the limitations of the magnetic flux leakage (MFL) technique, see Table B.12 (c), the output of the analysis of the pig run is used as a guide to the depth and location of damage in the pipeline inspected. This relative assessment of pipeline condition from the smart pig program is then incorporated into the ultrasonic and radiographic detailed inspection described above. The routine inspection program then verifies the depth of damage and the location is then scheduled for repair and/or re-inspection as necessary.

The number of monitoring locations in any given year, by equipment type and service, is summarized in Table B.8 (a). As can be seen, the table shows that the number of active locations has been approximately constant since 1995. The relatively small number of differences between years reflects 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.

Equipment	Service	1995	1996	1997	1998	1999	2000	2001	2002
Flow Line	3 Phase	178	181	177	178	175	173	175	177
	Export/PO	3	6	6	5	5	5	4	6
	Gas	3	3	1	1	1	1	1	1
	Other	2	2	1	1	1			
	Water	18	18	18	18	20	19	19	22
	<b>Total</b>	204	210	203	203	202	198	199	206
Well Line	3 Phase	1057	1172	1226	1208	1173	1169	1073	1076
	Export/PO		3	3	3	3	3	3	
	Gas	7	9	7	7	7	7	7	8
	Water	182	187	191	188	181	175	172	180
		<b>Total</b>	1246	1371	1427	1406	1364	1354	1255
<b>Grand</b>	<b>Total</b>	1450	1581	1630	1609	1566	1552	1454	1470

Table B.8 (a) Corrosion Monitoring Locations by Equipment and Service

The corrosion-monitoring program is further detailed in Table B.8 (b). The table shows for the active corrosion monitoring locations in Table B.8 (a), the number of coupon pulls and the number of coupons retrieved on average for each active location. It should be noted that for a typical corrosion access fitting at GPB, two corrosion coupons are recovered for each corrosion pull with the exception of those lines which are regularly pigged where single flush mounted coupons are installed.

Table B.8 (b) also shows that the weight loss coupon activity level from 1995 to year-end 2002. As discussed in prior reports, there has been a gradual reduction in the number of weight loss coupons being evaluated, which reflects the ongoing effort to optimize the program to deliver maximum corrosion management information. The reducing trend in the number of corrosion weight loss coupons is also shown in Figure B.9.

The pull frequency and number of coupons per pull is summarized in Table B.8 (b). The number of coupons, the number of coupons per pull, and the pull

frequency has been optimized through time to gain greater value from the data obtained from the program.

The two most significant changes are, first, the PW system pull cycle has been extended from 3 months to 6 months in order to improve the quality of the damage rate information.

Equipment	Statistic	1995	1996	1997	1998	1999	2000	2001	2002
Flow Line	Locations	204	210	203	203	202	198	199	206
	Pulls	872	880	924	850	855	820	729	776
	WLC	1610	1729	1770	1627	1674	1574	1433	1473
	WLC/Pull	1.85	1.96	1.92	1.91	1.96	1.92	1.97	1.90
	Pull/Year	4.3	4.2	4.6	4.2	4.2	4.1	3.7	3.8
Well Line	Locations	1246	1371	1427	1406	1364	1354	1255	1264
	Pulls	3361	4057	4147	3900	3685	3677	2987	2926
	WLC	6690	8130	8314	7797	7385	7364	5944	5837
	WLC/Pull	1.99	2.00	2.00	2.00	2.00	2.00	1.99	1.99
	Pull/Year	2.7	3.0	2.9	2.8	2.7	2.7	2.4	2.3

**Table B.8 (b)** Corrosion Monitoring Activity Statistics by Equipment Type

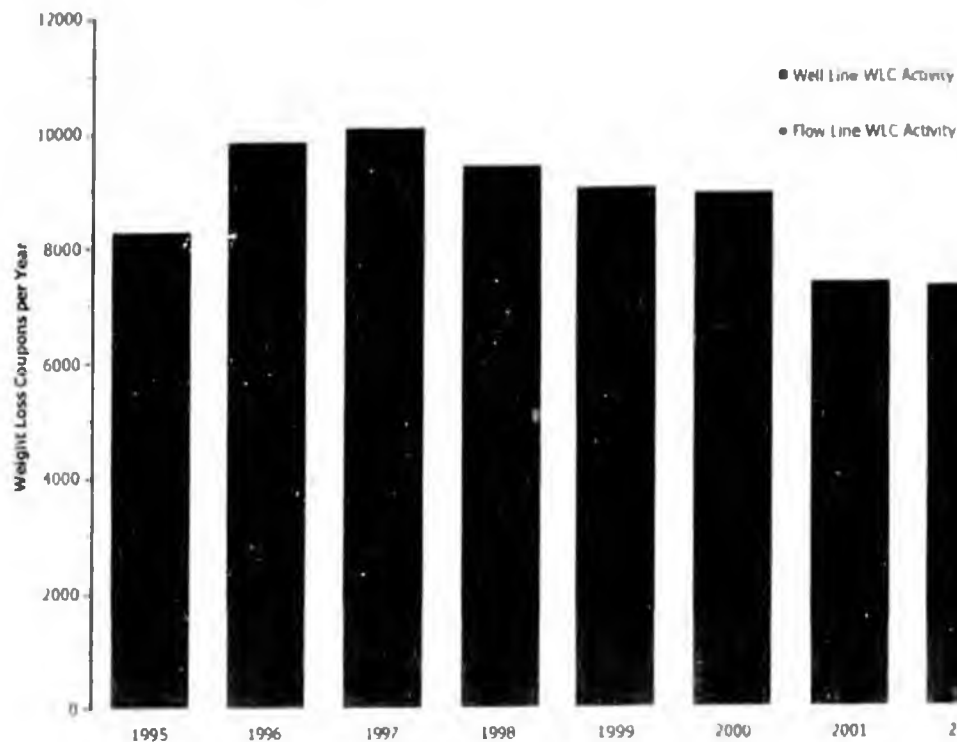
The second significant change was the standardization at single-operatorship of wellhead 3-phase production program to a 4-month pull cycle from a mix of 3 and 4 months as was the case previously. Both of these changes were covered in detail in prior year's reports. However, it should be noted that the effect of these extended exposure periods is a reduction in the number of coupons reported in future years.

It should be noted that the drop in the number of weight loss coupons reported for 2002 reflects the inventory of coupons that are installed in the system at year-end and are still to be 'processed.' The drop in 2002 coupon numbers therefore represents a timing effect and not a reduction in the program scope or activity level.

For the ER probes, the number of active ER probe locations in the flow lines in 2002 was 87 compared to 83 in 2001. The addition of 4 represents the addition of three new probes on the Oil system and one trial probe in the SW system.

Similar data for years prior to 2000 was not tracked and is therefore not available.

The well line ER probe-monitoring program reported in 2000 was historically used for the assessment of corrosion inhibitor performance. With the advent of single-operatorship and the revised corrosion inhibitor evaluation process, see Section D, these probes are no longer required and have been removed.



**Figure B.9** Corrosion Monitoring Activity Statistics by Equipment

There is an on-going effort to optimize the corrosion-monitoring program and any future changes in pull frequency will be reported as part of the annual Charter Agreement Report.

### **Section B.3 Corrosion and Inspection Data Management**

In order to deliver the comprehensive corrosion management program described in Section B.1, and manage the extensive corrosion monitoring and inspection activity described in Section B.2, it is necessary to have an active and structured electronic database.

Single-operatorship at Greater Prudhoe Bay (GPB) necessitated the integration of the two archaic data systems into a single unified program. This process has been an on-going effort for the last two years. Today, the weight loss coupon, inspection, electrical resistance (ER) probe and production data is held and accessed through a single database supported by Oracle<sup>®</sup> technology.

Users of the system are provided two primary methods of access to the underlying data stored in the database. The first is a custom user interface written in Microsoft Visual Basic<sup>®</sup>, and the second is through ad-hoc data query tools such as BrioQuery<sup>®</sup> and BusinessObjects<sup>®</sup> which allow free-form SQL<sup>®</sup> 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 the data quality, and data rules within the database.

The data is continuously monitored for integrity and quality, and any errors 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.

Data Record	Unit	Records	#/year	History
Weight loss coupons	10 <sup>6</sup>	0.2	0.01	~20 years
ER probes readings	10 <sup>6</sup>	0.8	0.5	~1½ years
Equipment	10 <sup>3</sup>	28	-	-
Inspection locations	10 <sup>6</sup>	0.4	.07	-
Inspection records	10 <sup>6</sup>	1.1	0.1	~10 years
Chemical injection	10 <sup>3</sup>	5	22	3 months
Production rates	10 <sup>6</sup>	7.3	0.5	~14 years
Injection rates	10 <sup>6</sup>	1.8	0.2	~11 years

**Table B.10** Database Record Accumulation Rate

Table B.10 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 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.

<b>Program</b>	<b>Plan/Objectives</b>	<b>Target</b>	<b>Implementation</b>	<b>Evaluation</b>	<b>Corrective Action</b>
1.0 Overall program goals	<ul style="list-style-type: none"> <li>Eliminate corrosion/erosion related failures</li> </ul>	<ul style="list-style-type: none"> <li>No harm to people</li> <li>No accidents</li> <li>No damage to environment</li> </ul>	<ul style="list-style-type: none"> <li>Integrated program with monitoring, inspection, operational controls, and corrosion inhibitor</li> </ul>	<ul style="list-style-type: none"> <li>Key performance indicators</li> <li>Leading and lagging indicators</li> </ul>	<ul style="list-style-type: none"> <li>Adjust mitigation, monitoring, and operational targets to meet objective</li> <li>Defect elimination - repair/replace/abandon</li> </ul>
	<ul style="list-style-type: none"> <li>Provide equipment availability to end of Field life</li> </ul>	<ul style="list-style-type: none"> <li>2050</li> </ul>	<ul style="list-style-type: none"> <li>Integrated Program with Monitoring, Inspection, Operational Controls, and Corrosion Inhibition</li> </ul>	<ul style="list-style-type: none"> <li>Key Performance Indicators</li> <li>Leading and Lagging Indicators</li> </ul>	<ul style="list-style-type: none"> <li>Adjust Mitigation, Monitoring, and Operational Targets to Meet Objective</li> </ul>
	<ul style="list-style-type: none"> <li>Cost effective Corrosion Management</li> </ul>	<ul style="list-style-type: none"> <li>Budget</li> </ul>	<ul style="list-style-type: none"> <li>Alliance Partnerships</li> <li>Incentive Contracts</li> <li>Continuous Improvement</li> </ul>	<ul style="list-style-type: none"> <li>Key Performance Indicators</li> <li>Leading and Lagging Indicators</li> </ul>	<ul style="list-style-type: none"> <li>Develop more Cost Effective Methods For Delivering the Program</li> <li>Best in Class Technology</li> <li>Investment for the Future</li> </ul>

<b>Table B.11 (b) Corrosion Management System Element – Monitoring</b>					
<b>Program</b>	<b>Plan/Objectives</b>	<b>Target</b>	<b>Implementation</b>	<b>Evaluation</b>	<b>Corrective Action</b>
1.1 Corrosion Monitoring	<ul style="list-style-type: none"> <li>Monitor for changes in corrosion rates</li> </ul>	<ul style="list-style-type: none"> <li>System dependant targets</li> <li>Corrosion rate to meet overall objectives</li> </ul>	<ul style="list-style-type: none"> <li>Short term corrosion rate determination</li> <li>Medium term corrosion rate determination</li> </ul>	<ul style="list-style-type: none"> <li>ER probes</li> <li>Weight loss coupon rate</li> <li>Pitting Rates</li> </ul>	<ul style="list-style-type: none"> <li>Adjust Mitigating action to achieve corrosion rate target</li> </ul>
	<ul style="list-style-type: none"> <li>Monitor effectiveness of the Chemical Mitigation Programs</li> </ul>	<ul style="list-style-type: none"> <li>Optimize Corrosion Inhibitor Rates and Distribution</li> <li>Optimize chemical mitigation programs e.g.               <ul style="list-style-type: none"> <li>oxygen scavenger</li> <li>biocide</li> <li>DRA</li> <li>scale</li> </ul> </li> </ul>	<ul style="list-style-type: none"> <li>See above</li> </ul>	<ul style="list-style-type: none"> <li>See above</li> </ul>	<ul style="list-style-type: none"> <li>Provide feedback to               <ul style="list-style-type: none"> <li>o Chemical treatment</li> <li>o Operations</li> <li>o Inspection activities</li> </ul> </li> <li>Adjust Mitigation Effort</li> <li>Production Chemistry</li> </ul>
	<ul style="list-style-type: none"> <li>Monitor Changes in the Process Conditions</li> </ul>	<ul style="list-style-type: none"> <li>Field-wide Velocity Management targets</li> </ul>	<ul style="list-style-type: none"> <li>Weekly Review of Operational Controls by CIC Group</li> <li>Operations review of fluid velocities</li> <li>Velocity alarms in DCS</li> </ul>	<ul style="list-style-type: none"> <li>Mixture Velocities, Water Cuts, and Water Rates</li> </ul>	<ul style="list-style-type: none"> <li>Adjust production rates to meet velocity management targets</li> </ul>
	<ul style="list-style-type: none"> <li>Corrosion mechanism changes with time</li> </ul>	<ul style="list-style-type: none"> <li>Mitigation action in place prior to threat to mechanical integrity</li> </ul>	<ul style="list-style-type: none"> <li>Data availability and access</li> <li>Ease of 'data mining' and evaluation</li> <li>Single data storage</li> <li>Comprehensive data management and reporting process</li> </ul>	<ul style="list-style-type: none"> <li>Long-Term Process Change</li> </ul>	<ul style="list-style-type: none"> <li>Develop mitigation program</li> <li>Mechanism management as part of routine business</li> </ul>
1.2 Erosion Monitoring	<ul style="list-style-type: none"> <li>Monitor the Effectiveness of the Erosion Mitigation Programs</li> </ul>	<ul style="list-style-type: none"> <li><math>V/V_c &lt; 2.5</math></li> <li>Max mixture Velocity and water cut matrix</li> <li>Well Put-On-Production (POP) process</li> </ul>	<ul style="list-style-type: none"> <li>Unified velocity management standard across the North Slope</li> <li>Monthly compilation Of High Risk Wells</li> <li>Inspection of High Risk Wells</li> <li>Mixture velocity calculation in DCS</li> </ul>	<ul style="list-style-type: none"> <li>Mixture Velocities</li> <li>Inspection results</li> </ul>	<ul style="list-style-type: none"> <li>Additional inspection and monitoring at high risk sites</li> <li>Adjust Process Conditions               <ul style="list-style-type: none"> <li>o Well shut-in</li> <li>o Production reduction</li> <li>o Design/debottleneck facilities</li> </ul> </li> </ul>

<b>Table B.11 (b) (continued) Corrosion Management System Element – Mitigation</b>					
<b>Program</b>	<b>Plan/Objectives</b>	<b>Target</b>	<b>Implementation</b>	<b>Evaluation</b>	<b>Corrective Action</b>
1.3 Corrosion Mitigation	<ul style="list-style-type: none"> <li>Mitigate Corrosion Through Application of Corrosion Inhibitors</li> </ul>	<ul style="list-style-type: none"> <li>Control Corrosion Rates to Acceptable Levels (See Overall Program Goals)</li> </ul>	<ul style="list-style-type: none"> <li>Continuous injection into individual wells as far upstream as possible - currently at Wellhead</li> <li>Protect all equipment between injection point and separation plant</li> </ul>	<ul style="list-style-type: none"> <li>ER Probes</li> <li>WLC's</li> <li>Inspection</li> </ul>	<ul style="list-style-type: none"> <li>Corrosion Inhibitor Development</li> <li>Adjust Mitigation Effort</li> </ul>
		<ul style="list-style-type: none"> <li>Control Corrosion Rates to Acceptable Levels (See Overall Program Goals)</li> </ul>	<ul style="list-style-type: none"> <li>Batch Treatments on a routine schedule with injection at the Wellhead</li> </ul>	<ul style="list-style-type: none"> <li>WLC's</li> <li>Inspection</li> </ul>	<ul style="list-style-type: none"> <li>Corrosion Inhibitor Development</li> <li>Adjust Mitigation Effort Through Reviews</li> </ul>
	<ul style="list-style-type: none"> <li>Mitigate Corrosion through Operational Controls</li> </ul>	<ul style="list-style-type: none"> <li>Operational Guidelines</li> </ul>	<ul style="list-style-type: none"> <li>Weekly Reviews by CIC Group</li> </ul>	<ul style="list-style-type: none"> <li>Mixture Velocities</li> </ul>	<ul style="list-style-type: none"> <li>Adjust Process Conditions</li> </ul>
	<ul style="list-style-type: none"> <li>Mitigate Corrosion through Maintenance Pigging</li> </ul>	<ul style="list-style-type: none"> <li>Achieve Scheduled Frequency</li> </ul>	<ul style="list-style-type: none"> <li>Maintenance Pigging</li> </ul>	<ul style="list-style-type: none"> <li>Inspection</li> <li>Pigging Returns</li> </ul>	<ul style="list-style-type: none"> <li>Adjust Maintenance Pigging Schedule</li> </ul>
1.4 Erosion Mitigation	<ul style="list-style-type: none"> <li>Mitigate Erosion Through Operational Controls and Design</li> </ul>	<ul style="list-style-type: none"> <li>Control Erosion Rates to Acceptable Levels (See Overall Program Goals)</li> <li><math>V/V_e &lt; 2.5</math></li> </ul>	<ul style="list-style-type: none"> <li>Well POP process</li> <li><math>v/V_c</math> Guidelines</li> </ul>	<ul style="list-style-type: none"> <li><math>V/V_e</math></li> <li>Inspection (ERM)</li> </ul>	<ul style="list-style-type: none"> <li>Adjust Process Conditions</li> </ul>

<b>Table B.11 (b) (continued) Corrosion Management System Element – Inspection</b>					
<b>Program</b>	<b>Plan/Objectives</b>	<b>Target</b>	<b>Implementation</b>	<b>Evaluation</b>	<b>Corrective Action</b>
1.5 Inspection	<ul style="list-style-type: none"> <li>Integrated inspection program to provide a overall assessment of plant condition and corrosion rates</li> </ul>	<ul style="list-style-type: none"> <li>Inspection activity level</li> <li>Leak/save target</li> <li>Inspection increases</li> <li>Plant condition</li> <li>Regulatory compliance</li> </ul>	<ul style="list-style-type: none"> <li>Corrosion rate monitoring program (CRM)</li> <li>Erosion rate monitoring program (ERM)</li> <li>Comprehensive inspection program (CIP)</li> <li>Frequent inspection program (FIP)</li> <li>Corrosion under insulation program (CUI)</li> </ul>	<ul style="list-style-type: none"> <li>NDE technique sheets and procedures</li> <li>Standardized assessment of piping condition, degradation rate and mechanism</li> </ul>	<ul style="list-style-type: none"> <li>Provide feedback to chemical mitigation program</li> <li>Erosion management program</li> <li>Fitness for service assessment</li> <li>Equipment life assessment</li> <li>Proactive repair scheduling</li> </ul>
	<ul style="list-style-type: none"> <li>Assessment of Current Damage Mechanisms</li> </ul>	<ul style="list-style-type: none"> <li>Zero Increases</li> </ul>	<ul style="list-style-type: none"> <li>Internal and external programs</li> </ul>	<ul style="list-style-type: none"> <li>See above</li> </ul>	<ul style="list-style-type: none"> <li>Repair/replace/monitor</li> </ul>
	<ul style="list-style-type: none"> <li>Search for New Damage Mechanisms</li> </ul>	<ul style="list-style-type: none"> <li>Mitigation action in place prior to threat to FFS</li> </ul>	<ul style="list-style-type: none"> <li>Baseline new equipment</li> <li>Apply lessons learnt from industry practice else where in the world</li> <li>Apply lessons learnt for other BP operations</li> <li>Apply learnings across the field for similar equipment/process conditions</li> <li>Communications with Operations and Reservoir Engineers</li> </ul>	<ul style="list-style-type: none"> <li>See above</li> </ul>	<ul style="list-style-type: none"> <li>Develop mitigation program</li> <li>Mechanism management as part of routine business</li> </ul>
1.6 Fitness for Service	<ul style="list-style-type: none"> <li>Fitness for service assurance</li> </ul>	<ul style="list-style-type: none"> <li>Compliance with industry standard</li> </ul>	<ul style="list-style-type: none"> <li>See above inspection programs</li> </ul>	<ul style="list-style-type: none"> <li>Battelle Modified B31G fitness-for-service criteria (note piping only)</li> <li>BP internal specification for the assessment of damaged pipe</li> </ul>	<ul style="list-style-type: none"> <li>Repair equipment</li> <li>Replace equipment</li> <li>Derate equipment</li> <li>Abandon equipment</li> </ul>
	<ul style="list-style-type: none"> <li>Structural integrity</li> </ul>	<ul style="list-style-type: none"> <li>Compliance with industry standard</li> </ul>	<ul style="list-style-type: none"> <li>Walking speed survey every 5 years</li> </ul>	<ul style="list-style-type: none"> <li>Piping design code BP Spec, B31.4 and B31.8</li> <li>Piping stress analysis</li> <li>Nondestructive testing as required</li> </ul>	<ul style="list-style-type: none"> <li>Repair/replace</li> <li>Correct support defect</li> <li>Monitor for further degradation</li> </ul>

<b>Table B.11 (b) (continued) Corrosion Management System Element – Inspection</b>					
<b>Program</b>	<b>Plan/Objectives</b>	<b>Target</b>	<b>Implementation</b>	<b>Evaluation</b>	<b>Corrective Action</b>
1.7 Continuous Improvement	<ul style="list-style-type: none"> <li>• Provide Feedback to Monitoring, Mitigation, and Inspection Programs</li> </ul>	<ul style="list-style-type: none"> <li>• Continuous Improvement</li> </ul>	<ul style="list-style-type: none"> <li>• Integrated Program with Monitoring, Inspection, Operational Controls, and Corrosion Inhibitor</li> <li>• Provides Feedback Control Loop for Program Improvements</li> <li>• Consolidated data store, MIMIR</li> </ul>	<ul style="list-style-type: none"> <li>• Weekly program review</li> <li>• Quarterly program review</li> <li>• Annual program reviews and strategy assessment</li> <li>• Key Performance Indicators</li> </ul>	<ul style="list-style-type: none"> <li>• Strategic adjustment</li> <li>• Budget/funding level changes</li> <li>• Annual equipment life/availability review</li> <li>• Mitigation process change and review</li> <li>• Technical/R&amp;D requirements and programs</li> </ul>

<b>Program</b>	<b>Plan/Objectives</b>	<b>Target</b>	<b>Implementation</b>	<b>Evaluation</b>	<b>Corrective Action</b>
1.1.1 Monitoring – Electrical Resistance Probes (ER)	<ul style="list-style-type: none"> <li>• Monitor the Effectiveness of the Mitigation Programs</li> </ul>	<ul style="list-style-type: none"> <li>• &lt; 2mpy</li> </ul>	<ul style="list-style-type: none"> <li>• ER Probes - Upstream and/or Downstream Ends of Flowlines</li> </ul>	<ul style="list-style-type: none"> <li>• Investigate Cause for Corrosion Rate Increase</li> </ul>	<ul style="list-style-type: none"> <li>• Mitigation Adjustments</li> <li>• ER Probe Maintenance</li> </ul>
1.1.2 Monitoring – Weight Loss Coupons (WLC)	<ul style="list-style-type: none"> <li>• Monitor the Effectiveness of the Mitigation Programs</li> </ul>	<ul style="list-style-type: none"> <li>• Gen CR: &lt; 2mpy</li> <li>• Pit CR: &lt; 20mpy</li> </ul>	<ul style="list-style-type: none"> <li>• WLC – Installed Flowlines, Well lines, Headers, and Piping</li> </ul>	<ul style="list-style-type: none"> <li>• Investigate Cause for Corrosion Rate Increase</li> </ul>	<ul style="list-style-type: none"> <li>• Mitigation Adjustments</li> <li>• Inspection Program Adjustments</li> </ul>
1.1.3 Monitoring – Process Conditions	<ul style="list-style-type: none"> <li>• Monitor changes in the Process Conditions</li> </ul>	<ul style="list-style-type: none"> <li>• (See Mixture Velocity and Erosion Sections Below)</li> </ul>		<ul style="list-style-type: none"> <li>• Process Upset</li> <li>• Long-Term Process Change</li> </ul>	<ul style="list-style-type: none"> <li>• Monitor impact</li> <li>• Mitigation Adjustments</li> </ul>
1.1.4 Monitoring – Mixture Velocity Management Program	<ul style="list-style-type: none"> <li>• Monitor the Effectiveness of the Mitigation Programs</li> </ul>	<ul style="list-style-type: none"> <li>• Operational Guidelines</li> <li>• Mix Vel Limits</li> </ul>	<ul style="list-style-type: none"> <li>• Operations Acceptance of Mixture Velocity Guidelines</li> <li>• SETCIM</li> </ul>	<ul style="list-style-type: none"> <li>• Mixture Velocities</li> <li>• Review Alarm List to Determine True Offenders</li> </ul>	<ul style="list-style-type: none"> <li>• Adjust Process Conditions</li> </ul>
1.1.5 Monitoring – Erosion Management Program	<ul style="list-style-type: none"> <li>• Monitor the Effectiveness of the Erosion Mitigation Programs</li> </ul>	<ul style="list-style-type: none"> <li>• Operational Guidelines</li> <li>• Well POP</li> <li>• <math>V/V_c &lt; 2.5</math></li> </ul>	<ul style="list-style-type: none"> <li>• Operations Acceptance of Erosion Guidelines</li> <li>• High Risk Well Inspection Program (ERM)</li> </ul>	<ul style="list-style-type: none"> <li>• Monthly Reviews to Determine High Risk Equipment and Repeat Offenders</li> </ul>	<ul style="list-style-type: none"> <li>• Adjust Process Conditions</li> </ul>

**Table B.11 (c) (continued) Mitigation Program Techniques**

<b>Program</b>	<b>Plan/Objectives</b>	<b>Target</b>	<b>Implementation</b>	<b>Evaluation</b>	<b>Corrective Action</b>
1.2.1 Mitigation – Corrosion Inhibitor	<ul style="list-style-type: none"> <li>Mitigate Corrosion Through Application of Corrosion Inhibitors</li> </ul>	<ul style="list-style-type: none"> <li>Control Corrosion Rates to Acceptable Levels (See Overall Program Goals)</li> <li>Control Corrosion Rates to Acceptable Levels (See Overall Program Goals)</li> </ul>	<ul style="list-style-type: none"> <li>Continuous Injection Into Individual Wells as Far Upstream As Possible – Currently at Wellhead</li> <li>Protect All Equipment Between Injection Point and Separation Plant</li> <li>Batch Treatments on a Routine Schedule with Injection at the Wellhead</li> </ul>	<ul style="list-style-type: none"> <li>ER Probes</li> <li>WLC's</li> <li>Inspection</li> <li>WLC's</li> <li>Inspection</li> </ul>	<ul style="list-style-type: none"> <li>Corrosion Inhibitor Development</li> <li>Adjust Mitigation Effort</li> <li>Corrosion Inhibitor Development</li> <li>Adjust Mitigation Effort through Reviews</li> </ul>
1.2.2 Mitigation – Operational Control, Maintenance, and Material Selection	<ul style="list-style-type: none"> <li>Mitigate Corrosion Through Operational Controls</li> <li>Mitigate Erosion through Operational Controls</li> <li>Mitigate Corrosion through Maintenance Pigging</li> <li>Corrosion Resistant Alloys</li> </ul>	<ul style="list-style-type: none"> <li>Operational Guidelines</li> <li>Mixture Velocity Limits</li> <li>Operational Guidelines</li> <li>Well POP</li> <li><math>V/V_e &lt; 2.5</math></li> <li>Achieve Scheduled Frequency</li> <li>Zero Increases (I's)</li> </ul>	<ul style="list-style-type: none"> <li>Operations Acceptance of Mixture Velocity Guidelines</li> <li>SETCIM</li> <li>Operations Acceptance of Erosion Guidelines</li> <li>High Risk Well Inspection Program (ERM)</li> <li>Maintenance Pigging</li> <li>Selected Facilities &amp; Equipment</li> </ul>	<ul style="list-style-type: none"> <li>Mixture Velocities</li> <li>Review Alarm List to determine true offenders</li> <li>Monthly Reviews to Determine High Risk Equipment and Repeat Offenders</li> <li>Inspection</li> <li>Pigging Returns</li> <li>Inspection</li> <li>Applicability For Service Requirements</li> </ul>	<ul style="list-style-type: none"> <li>Adjust Process Conditions</li> <li>Adjust Process Conditions</li> <li>Adjust Maintenance Pigging Schedule</li> <li>Replace as Necessary</li> </ul>
1.2.3 Mitigation – Structural Integrity	<ul style="list-style-type: none"> <li>Mitigate structural damage caused by subsidence, jacking, vibration, impact, snow loading, etc. through inspections</li> </ul>	<ul style="list-style-type: none"> <li>No failures due to structural damage</li> </ul>	<ul style="list-style-type: none"> <li>Operational procedures for visual surveillance of pipelines</li> <li>Piping stress analysis as required</li> <li>NDE inspections as required</li> </ul>	<ul style="list-style-type: none"> <li>Pipeline Design Code/BP Specification</li> </ul>	<ul style="list-style-type: none"> <li>Repair, replace and correct deficiencies as required</li> <li>Add Pipeline Vibration Dampeners (PVDs) as required</li> </ul>

<b>Program</b>	<b>Plan/Objectives</b>	<b>Target</b>	<b>Implementation</b>	<b>Evaluation</b>	<b>Corrective Action</b>
1.3.1 Corrosion Rate Monitoring (CRM)	<ul style="list-style-type: none"> <li>Assessment of current corrosion mechanisms</li> <li>Monitor for new corrosion mechanisms</li> </ul>	<ul style="list-style-type: none"> <li>No measurable active corrosion - Zero increases (I's)</li> </ul>	<ul style="list-style-type: none"> <li>CRM Program – Fixed locations on approximately bi-annual frequency</li> </ul>	<ul style="list-style-type: none"> <li>Number of inspection increases</li> </ul>	<ul style="list-style-type: none"> <li>Mitigation Adjustments</li> <li>Repair/Replace Preventative Maintenance</li> </ul>
1.3.2 Erosion Rate Monitoring (ERM)	<ul style="list-style-type: none"> <li>Monitor high risk wells</li> <li>Assessment of current erosion locations</li> </ul>	<ul style="list-style-type: none"> <li>Manageable rate of degradation</li> </ul>	<ul style="list-style-type: none"> <li>ERM Program – monthly to quarterly</li> </ul>	<ul style="list-style-type: none"> <li>Condition of Equipment</li> <li>Rate of degradation</li> </ul>	<ul style="list-style-type: none"> <li>Mitigation Adjustments</li> <li>Repair/Replace Preventative Maintenance</li> </ul>
1.3.3 Frequent Inspection Program (FIP)	<ul style="list-style-type: none"> <li>Assessment of High Corrosion Rates</li> <li>Monitor locations near repair</li> </ul>	<ul style="list-style-type: none"> <li>Fitness-for-Service</li> </ul>	<ul style="list-style-type: none"> <li>FIP Program – monthly to bi-annual</li> </ul>	<ul style="list-style-type: none"> <li>Condition of Equipment</li> <li>Rate of degradation</li> </ul>	<ul style="list-style-type: none"> <li>Mitigation Adjustments</li> <li>Repair/Replace Preventative Maintenance</li> </ul>
1.3.4 Comprehensive Integrity Program (CIP)	<ul style="list-style-type: none"> <li>Comprehensive Coverage of equipment</li> <li>Fitness-for-Service review</li> </ul>	<ul style="list-style-type: none"> <li>Fitness-for-Service</li> </ul>	<ul style="list-style-type: none"> <li>CIP – Condition and rate based half-life recurring frequency</li> <li>Extend coverage through new locations</li> </ul>	<ul style="list-style-type: none"> <li>Condition of Equipment</li> <li>Rate of degradation</li> </ul>	<ul style="list-style-type: none"> <li>Mitigation Adjustments</li> <li>Repair/Replace Preventative Maintenance</li> </ul>
1.3.5 Corrosion Under Insulation (CUI)	<ul style="list-style-type: none"> <li>Comprehensive Coverage of equipment</li> </ul>	<ul style="list-style-type: none"> <li>Inspection of Locations susceptible to CUI</li> <li>Fitness For Service</li> </ul>	<ul style="list-style-type: none"> <li>CUI – Risk based annual program</li> <li>Management of location inventory through recurring examinations</li> </ul>	<ul style="list-style-type: none"> <li>Damage Areas Detected</li> <li>Analysis of occurrence</li> </ul>	<ul style="list-style-type: none"> <li>Repair/Replace Preventative Maintenance</li> </ul>

**Table B.12 (a) Corrosion Monitoring Techniques – Benefits and Limitations**

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 B.12 (b) Process 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	

<b>Method</b>	<b>Technique</b>	<b>Description</b>	<b>Sensitivity</b>	<b>Accuracy</b>	<b>Freq</b>	<b>Notes/Comments</b>
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 positives results but seldom overlooks surface atmospheric corrosion

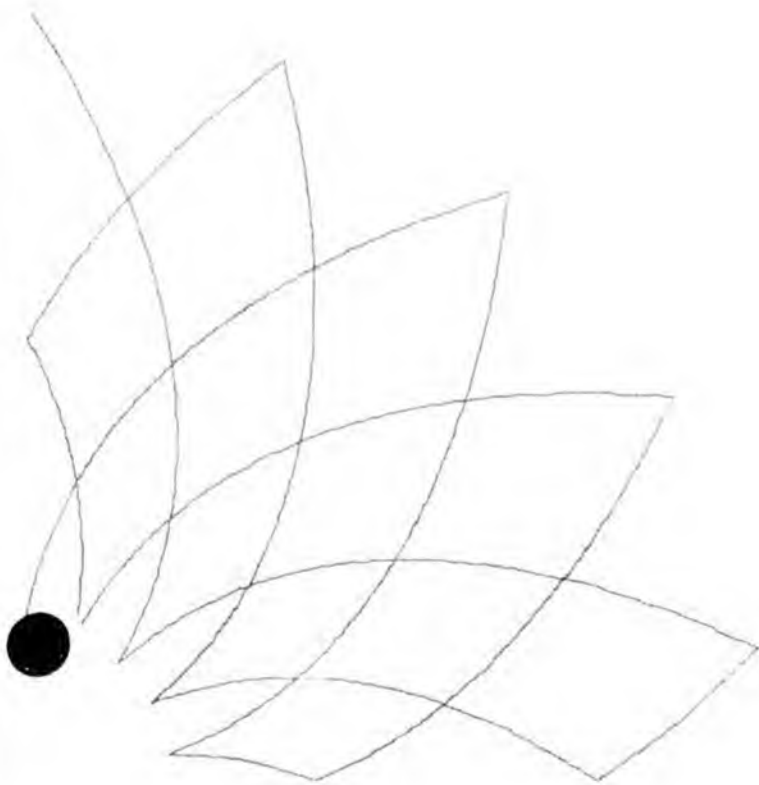
<b>Table B.12 (c) Inspection/Non-Destructive Examination (NDE) Techniques – Benefits and Limitations</b>						
<b>Method</b>	<b>Technique</b>	<b>Description</b>	<b>Sensitivity</b>	<b>Accuracy</b>	<b>Freq</b>	<b>Notes/Comments</b>
Inspection/NDE (Cont)	In-line Inspection – Smart Pig Magnetic Flux (MFL) 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 is 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.

<b>Service</b>	<b>Equipment Type</b>	<b>Monitoring Technique</b>	<b>Inspection Program</b>	<b>Mitigation Program</b>
Oil	Flow line	<ul style="list-style-type: none"> <li>• ER Probes</li> <li>• WLC</li> <li>• Process Monitoring</li> </ul>	<ul style="list-style-type: none"> <li>• CRM</li> <li>• FIP</li> <li>• CIP</li> <li>• CUI</li> </ul>	<ul style="list-style-type: none"> <li>• CI Injection</li> <li>• Mixture Velocities</li> <li>• Periodic Maintenance Pigging</li> <li>• Operational Controls</li> </ul>
	Well line	<ul style="list-style-type: none"> <li>• WLC</li> <li>• Process Monitoring</li> </ul>	<ul style="list-style-type: none"> <li>• CRM</li> <li>• ERM</li> <li>• FIP</li> <li>• CIP</li> <li>• CUI</li> </ul>	<ul style="list-style-type: none"> <li>• CI Injection</li> <li>• Mixture Velocities</li> <li>• Mixture Velocities</li> <li>• Operational Controls</li> </ul>
Produced Water	Flow line	<ul style="list-style-type: none"> <li>• WLC</li> </ul>	<ul style="list-style-type: none"> <li>• CRM</li> <li>• FIP</li> <li>• CIP</li> <li>• CUI</li> </ul>	<ul style="list-style-type: none"> <li>• CI Injection*</li> <li>• CI Carry Over</li> <li>• Periodic Maintenance Pigging</li> <li>• Mixture Velocities</li> <li>• Operational Controls</li> </ul>
	Well line	<ul style="list-style-type: none"> <li>• WLC</li> </ul>	<ul style="list-style-type: none"> <li>• CRM</li> <li>• FIP</li> <li>• CIP</li> <li>• CUI</li> </ul>	<ul style="list-style-type: none"> <li>• CI Injection*</li> <li>• CI Carry Over</li> <li>• Mixture Velocities</li> <li>• Operational Controls</li> </ul>
Seawater	Flow line	<ul style="list-style-type: none"> <li>• WLC</li> <li>• Galvanic Probes</li> <li>• Dissolved O<sub>2</sub></li> <li>• Microbiological Activity</li> </ul>	<ul style="list-style-type: none"> <li>• CRM</li> <li>• FIP</li> <li>• CIP</li> <li>• CUI</li> </ul>	<ul style="list-style-type: none"> <li>• Biocide Treatment</li> <li>• O<sub>2</sub> Scavenger</li> <li>• Periodic Maintenance Pigging</li> <li>• Operational Controls</li> </ul>
	Well line	<ul style="list-style-type: none"> <li>• WLC</li> <li>• Microbiological Activity</li> </ul>	<ul style="list-style-type: none"> <li>• CRM</li> <li>• FIP</li> <li>• CIP</li> <li>• CUI</li> </ul>	<ul style="list-style-type: none"> <li>• Biocide Treatment</li> <li>• Periodic Maintenance Pigging</li> <li>• Operational Controls</li> </ul>
Export oil	Flow line	<ul style="list-style-type: none"> <li>• WLC</li> <li>• ER Probes</li> </ul>	<ul style="list-style-type: none"> <li>• CRM</li> <li>• FIP</li> <li>• CIP</li> <li>• CUI</li> </ul>	<ul style="list-style-type: none"> <li>• CI Carry Over</li> <li>• Mixture Velocities</li> <li>• Operational Controls</li> <li>• Periodic Maintenance Pigging</li> </ul>

\* No CI injection for FS-2 PW

**Section C**

**Weight Loss Coupons and Probes**



## Section C Weight Loss Coupons and Probes

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

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 the Appendix 5 - Data Tables.

### Section C.1 Three Phase (OWG) Production Systems

The corrosion mechanism of concern in the 3-phase production system is CO<sub>2</sub> corrosion, in which CO<sub>2</sub> from the produced fluids dissolves and dissociates in the produced water to form an acidic environment that is, if untreated, corrosive to carbon steel<sup>5,6</sup>. 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-phase production system the target corrosion rate from weight loss coupons is 2 mpy or less for general corrosion rate and 20 mpy for the pitting rate.

Figure C.1 shows the average corrosion rate and percentage of coupons meeting the performance standard of  $\leq 2$  mpy over the last 10 years for the cross-country flow lines. The results show that the corrosion rate and percentage of conformant flow lines has improved consistently over the last decade such that now the average corrosion rate across GPB is approximately a factor of 10 lower than the corrosion rates from the early 1990's.

The reduction in corrosion rate by a factor of 10 over the last decade 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 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.

Figure C.2 shows the correlation between average corrosion rate, mpy, and the percentage of weight loss coupons meeting the 2 mpy target. As might be

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<sup>5</sup> Corrosion Control in Petroleum Production, Harry G Byers, NACE, 1999

<sup>6</sup> Corrosion Control in Oil and Gas Production, Treseder and Tuttle, NACE, 1998

expected, there is a very strong correlation between these two metrics. However these two metrics 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.

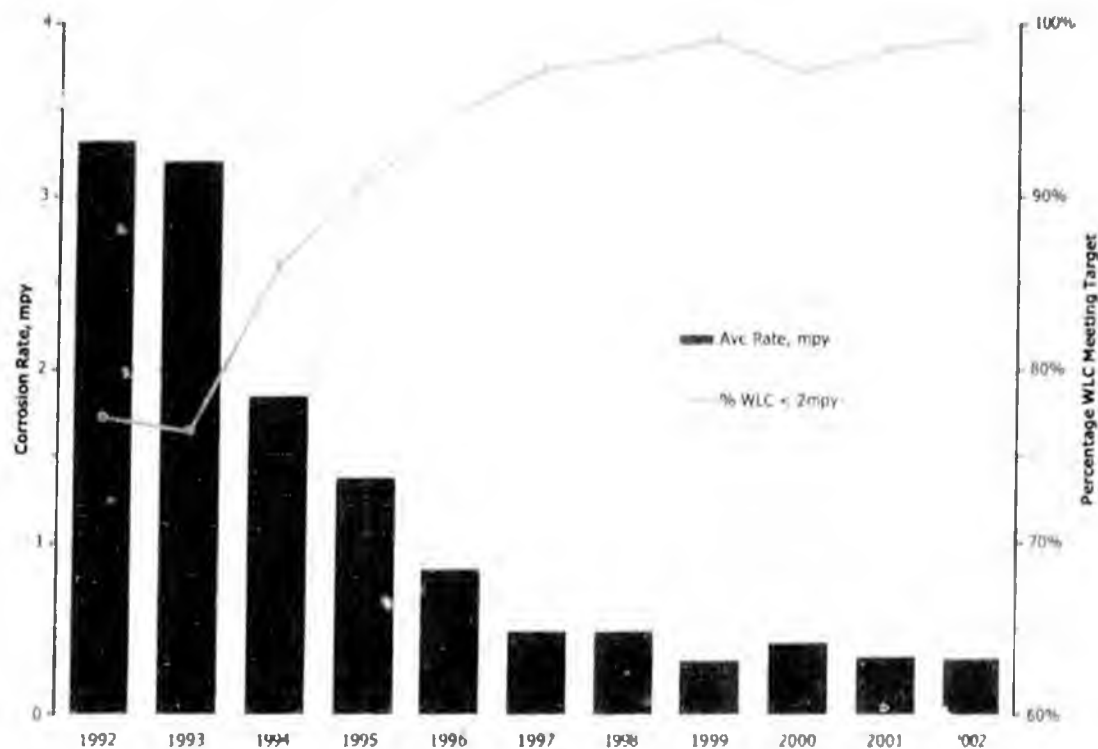


Figure C.1 Flow Line Corrosion Rate Trend 1992 to 2002

Conversely, the average has the advantage of showing the overall performance trend that might 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.

Figure C.3 shows the same data set for the well lines in oil service. The trends are very similar to those seen in the cross-country flow lines. The well lines show a long-term improvement in the level of control from early 1990's to the present day. In the short term there has been a reversal in the trend of increased corrosion rates seen between 1999 and 2000 with the corrosion rates falling in both 2001 and again in 2002.

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 of 3-4 mpy in 1992/3 down to an average of ~0.6 mpy for 2002.

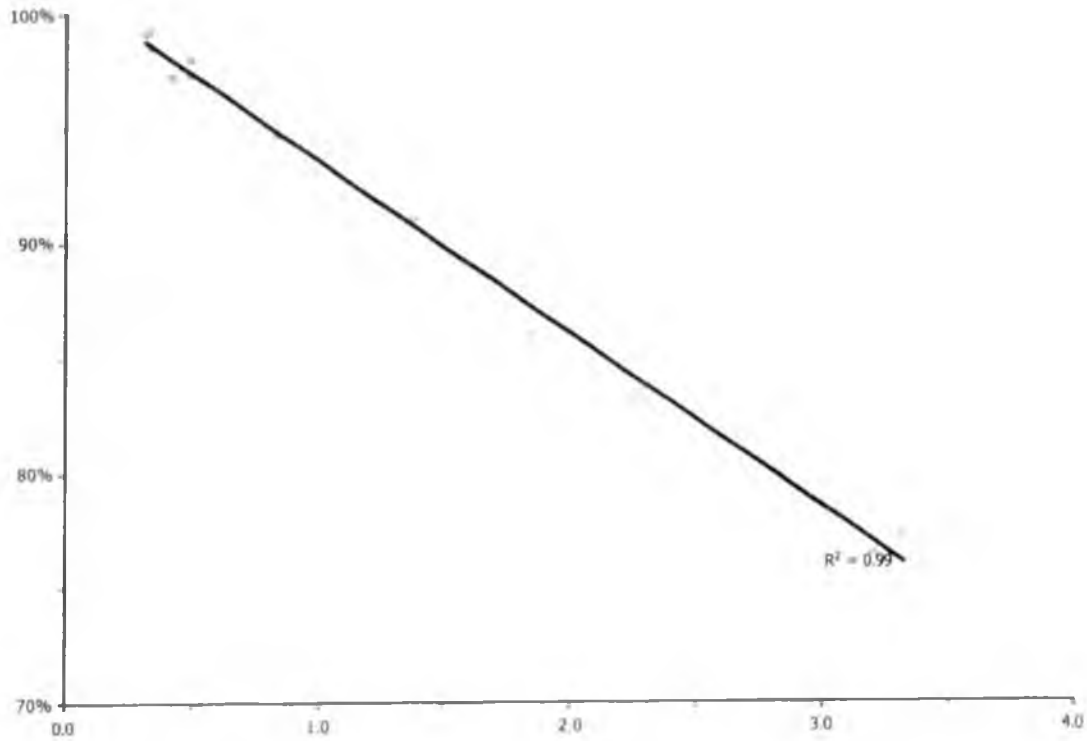


Figure C.2 Correlation Between Flow Line Corrosion Rate and Percentage Conformance

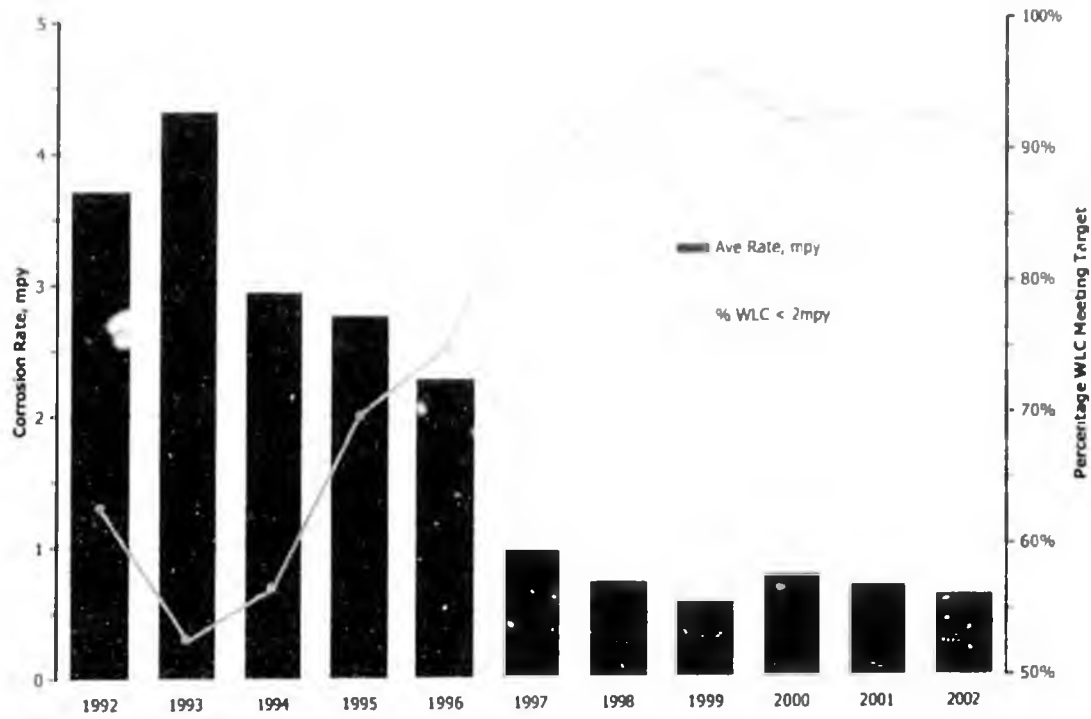


Figure C.3 Well Line Oil Service Corrosion Rate Trend 1992 to 2002

In summary, the 3-phase production system has seen a 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. This same trend is also seen in the inspection history as discussed in a Section E. The decrease in corrosion rate in the 3-phase systems is attributable to the implementation of an aggressive corrosion inhibition program. A similar trend in performance improvement is seen in the well lines. However, the ultimate performance is not as good as the flow lines but still considerably below the 2 mpy target rate.

The correlation between corrosion inhibitor injection rates and concentration, and the corrosion rates in the flow lines is discussed in detail in Section D.

### **Section C.2 Water Injection Systems**

The Water Injection System at GPB is comprised of produce water from the primary processing/separation facilities and seawater extracted from the Beaufort Sea through the Seawater Treatment Plant (STP).

In 2002 the production database was 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. As a result of this enhanced ability to analyze the wellhead coupon and injection information, the data-reporting format in the 2002 report has changed from that given in prior years.

For operational reasons such as reservoir injection conformance management, operational availability of water and miscible injectant, and the water-alternating-gas (WAG) schedule for secondary recovery, the fluids being injected at a given wellhead change frequently. As a consequence when reporting the fluid which any given weight loss coupon is exposed to is not always as simple as reporting the injection service at coupon installation or removal. Historically, the service code reported has been a single value, however, with the dynamic linking of the weight loss coupon data and the actual injection history it is possible to report composite services for a coupon exposure period.

Table C.4 summarizes the number of coupons in the injection system over the last 5 years, 1998-2002, and shows how a significant portion of those coupons were exposed to multiple changes in injection service during the exposure period.

From the table it can be seen that ~60% of the injection service weight loss coupons have seen single service during the exposure period and ~40% have seen multiple services. The principle injection fluids are seawater (SW), produced

water (PW), and miscible injectant (MI). If the analysis is expanded from 100% single service to a simple majority description then the amount of data included in the analysis increases. However, it should be noted that even as a simple plurality, only ~85% of the injection service weight loss coupons are included in the analysis of water injection system corrosion rates.

As a consequence of the dynamic linking of the weight loss coupon history to the injection and production data, the totals in Section C will not match the activity totals in Section B which are reported independent of the injection or production service.

Statistic	WLC	%	Statistic	WLC	%
100% SW service	237	5%	Majority SW service	293	7%
100% PW service	2458	56%	Majority PW service	3443	79%
100% MI service	183	4%	Majority MI service	575	13%
Other	1491	38%	Other	58	1%
<b>Total</b>	<b>4369</b>	<b>100%</b>	<b>Total</b>	<b>4369</b>	<b>100%</b>

**Table C.4** Summary of Coupons in Injection Service

In summary, the new reporting format that augments the performance metrics and was agreed with ADEC can be summarized as follows,

<b>Report Date</b>	Mid point of the WLC's exposure period, $\text{MidDate} = \text{Date In} + \frac{(\text{Date Out} - \text{Date In})}{2}$
<b>Service Type</b>	(a) Ave corrosion Rate with 100% exposure to service (b) Ave Corrosion Rate with simple service majority

Full data sets are included in the data tables in Appendix 5.

### Section C.3 Water Injection System Main Distribution Lines

Figure C.5 is a summary of flowline data for produced water and seawater reported in aggregate. The data shows that the 2002 corrosion rates in the flow lines have increased but are in general still below the 2 mpy criteria, ~90% less than 2 mpy. The increase in rate is largely due to activity in the seawater system discussed in Section C.5.

The period, 1993-1996, of increased in corrosion rate is the last time there were significant issues within the SW system. Although there are on-going issues in the SW system, see Section C.5, SW service flow lines now constitute a lower percentage of the overall injection service system and therefore have a less significant impact on the aggregate flow line statistics presented in this report.

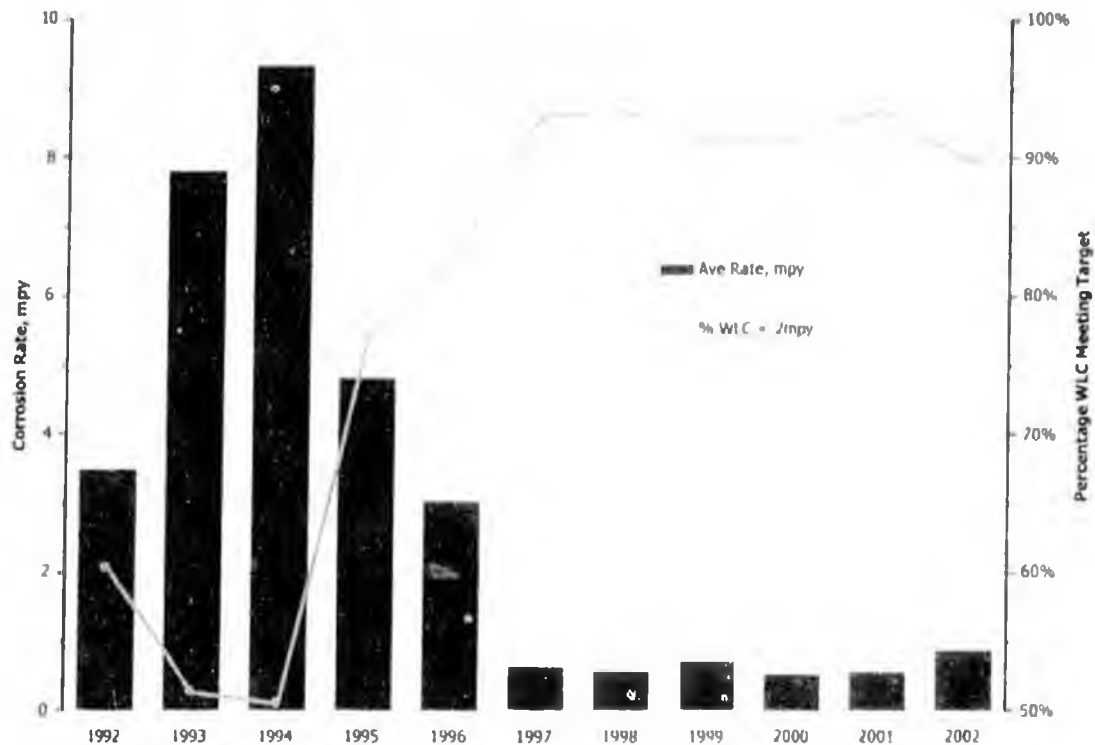


Figure C.5 Flow Line PW/SW Service Corrosion Rate Trend 1992 to 2002

In summary, the average internal corrosion rates for the aggregate water injection service have risen slightly in 2002 when compared with the average for the prior 5 years. As the average corrosion rate has risen so the number meeting the corrosion rate target of 2 mpy has fallen from 93% in 2001 to 90% in 2002. The primary cause of this deterioration in corrosion control is attributed to the problems encountered in the seawater system that is discussed in detail later in Section C.5.

#### Section C.4 Produced Water Injection Systems

There are a number of corrosion mechanisms of concern in the produced water section of the injection system. These mechanisms include  $\text{CO}_2$  corrosion and differential concentration effects due to the high particulate content of the

system. The particulates consist primarily of residual hydrocarbon remaining after oil, water, gas separation, production chemicals, and iron sulfide.

Figure C.6 (a)-(e) summarize the historical corrosion rate data for produced water well lines through year-end 2002. The data shows that the general corrosion rates in the produced water system have fallen as the level of inhibition in the 3-phase system has increased and supplemental produced water injection systems have been initiated.

The trend for 100% produced water service is summarized in Figure C.6 (a). For 2002 the average corrosion rate in the well lines in produced water service was 0.3 mpy with 97% of the well lines falling below the target corrosion rate of 2 mpy.

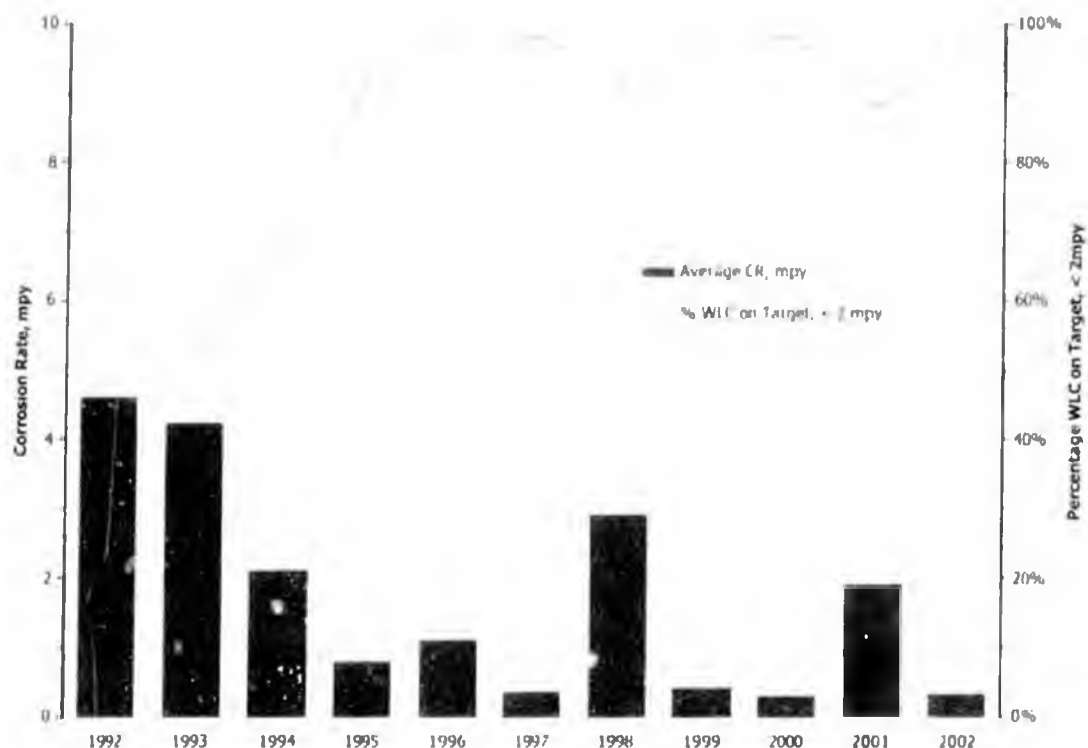


Figure C.6 (a) Corrosion Rates for 100% PW System 1995 to 2002

For those coupons where the produced water was the majority service, Figure C.6 (b) shows that the corrosion rate trends were very similar to that seen for 100% produced water service. The average corrosion rate for 2002 was 0.3 mpy and approximately 96% of the coupons met the corrosion control target of 2 mpy.

A comparison of the corrosion rate trends for produced water between the 100% service and majority service is provided in Figure C.6 (c). The figure shows there is little or no difference between the two trends.

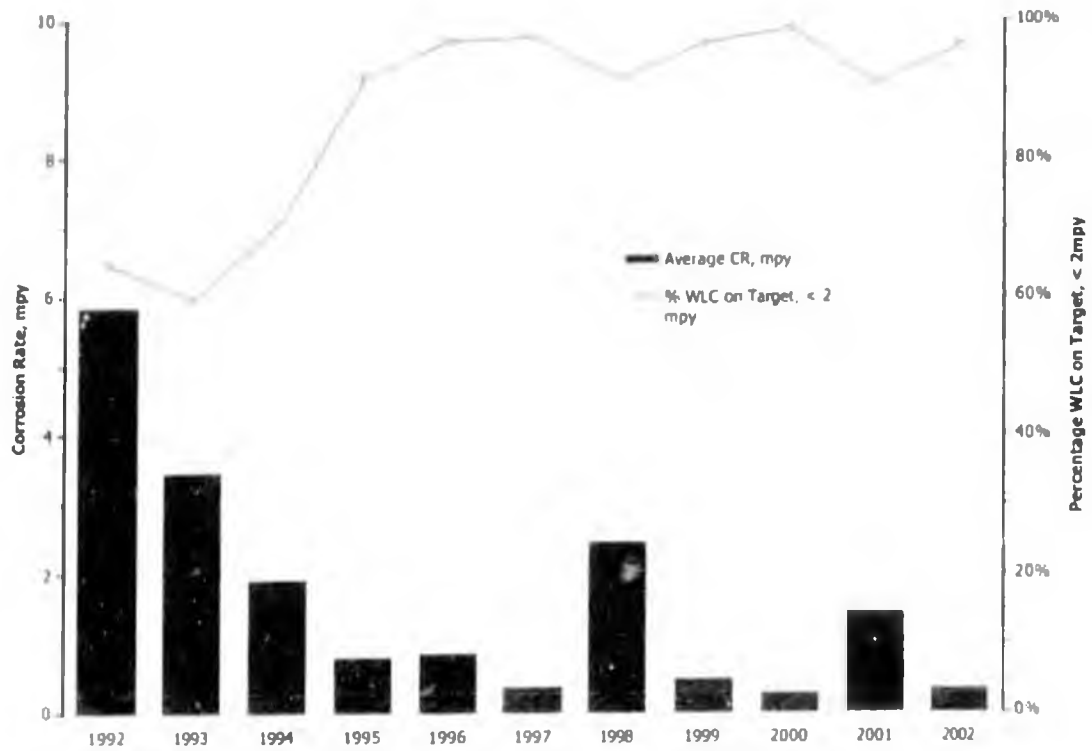


Figure C.6 (b) Corrosion Rates for Majority PW System 1992 to 2002

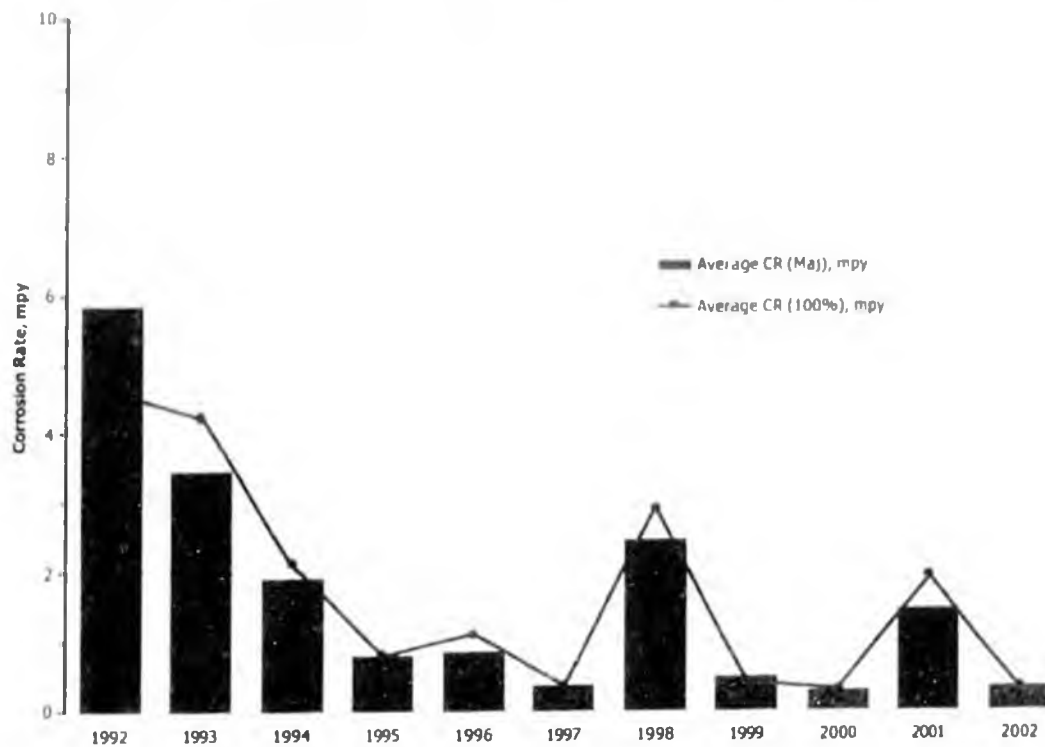


Figure C.6 (c) Comparison of Corrosion Rates for 100% and Majority PW System 1992 to 2002

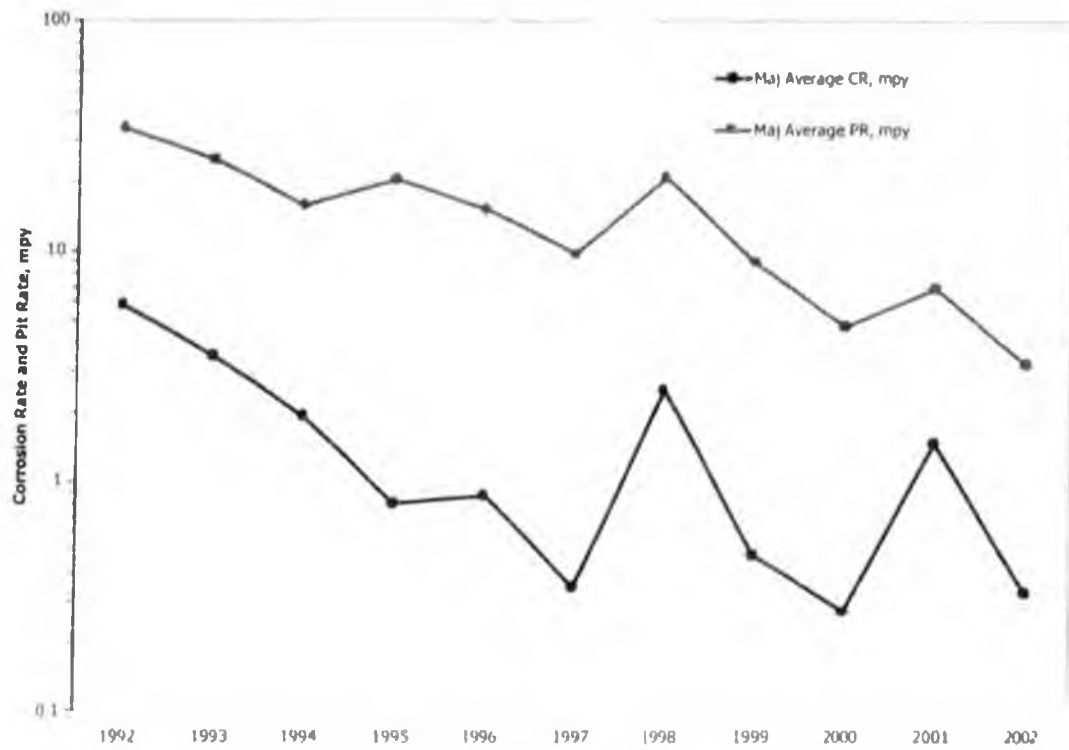


Figure C.6 (d) Corrosion Rates and Pitting Rates for Majority PW System 1992 to 2002

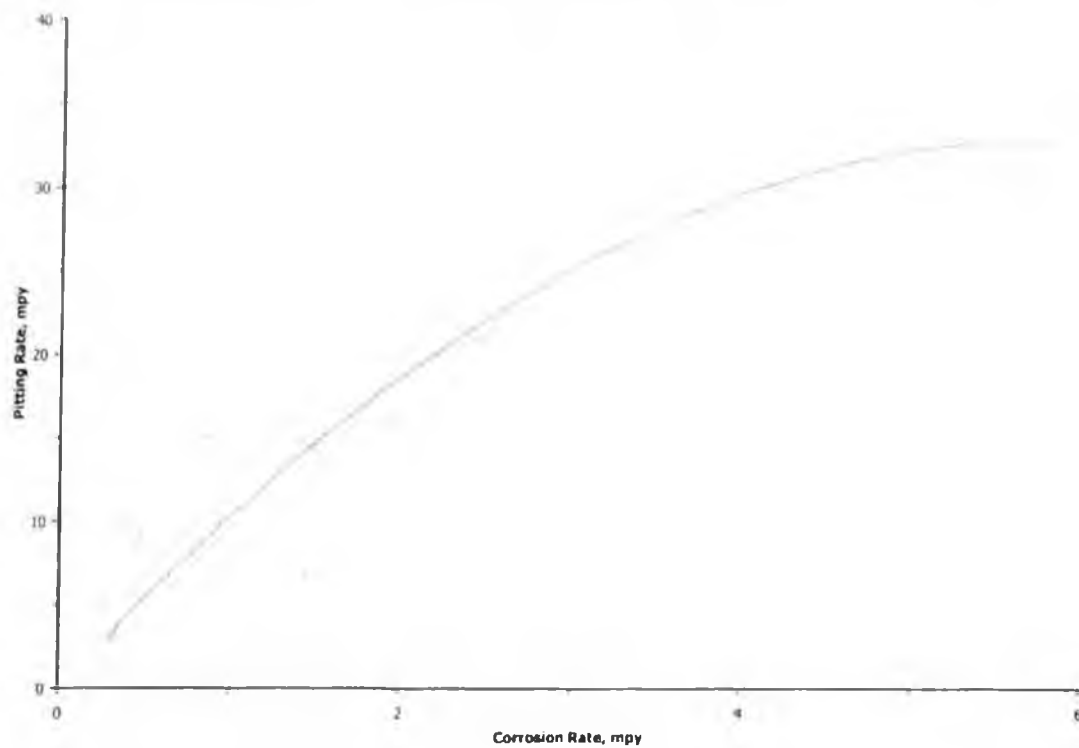


Figure C.6 (e) Correlation Between Corrosion Rates and Pitting Rates for Majority PW System

Figure C.6 (d) and (e) are a comparison between the general corrosion rate and the pitting rates for the produced water system. From both figures it is clear that there is a correlation between the two trends with the pitting rate being approximately 10-fold higher than the general corrosion rate.

The overall improvement in the performance of the PW system can be attributed primarily to two factors. First, there was a change in the upstream 3-phase production 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 implementation of corrosion mitigation programs specific to the PW system through 2002 with the program being expanded to include PW systems at FS-1 and FS-3 in addition to the existing program at GC-1, GC-2 and GC-3.

### **Section C.5 Seawater Injection System**

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

- Dissolved oxygen (DO) corrosion is mitigated by processing the seawater to remove oxygen. Initial DO removal is achieved mechanically by vacuum stripping which is then followed by chemical oxygen scavenging
- Microbiological corrosion, due to the action of anaerobic bacteria, is mitigated by batch treatment with biocide, after processing to remove O<sub>2</sub>, and prior to 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.

Figures C.7 (a)-(e) shows the corrosion rate trends in the SW system. In all cases, 100% SW service, majority SW service, and both pitting and general corrosion rates, the corrosion rates are seen to be increasing from 2000 through 2002.

As a consequence of the increasing corrosion rate trends in the seawater system, and as discussed in the 2001, and again at the 2<sup>nd</sup> 2002 Meet and Confer session with ADEC, a number of corrective actions have been taken to reverse this trend.

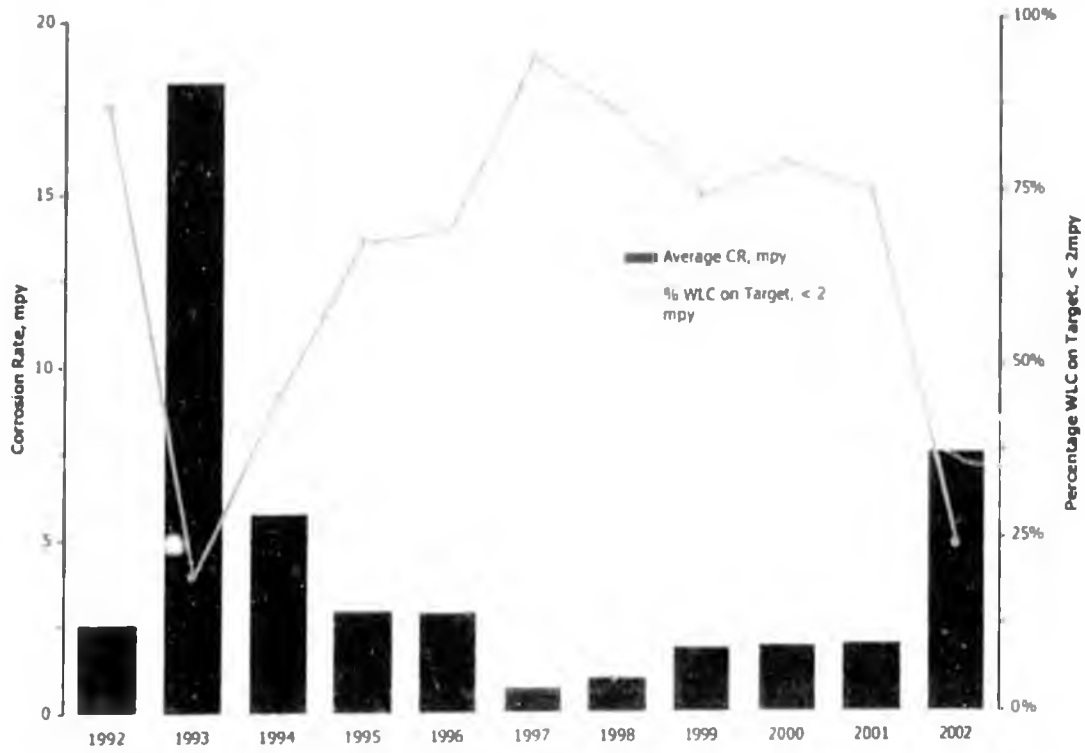


Figure C.7 (a) Corrosion Rate for 100% Seawater System 1992 to 2002

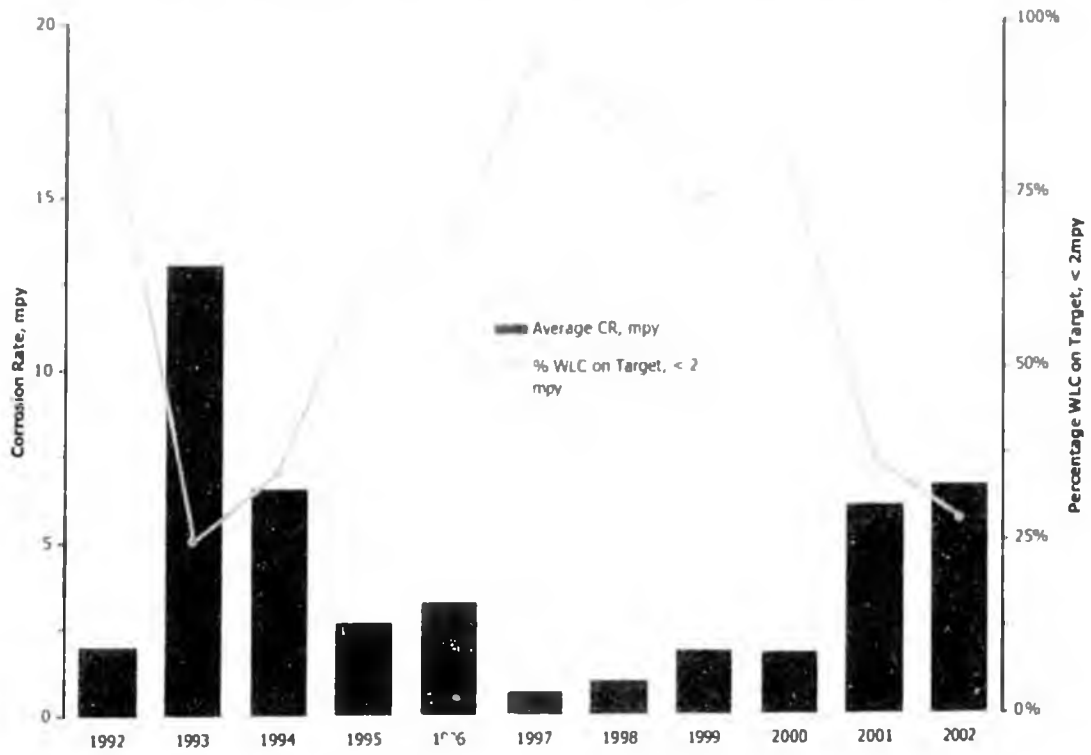


Figure 7.6 (b) Corrosion Rates for Majority SW System 1992 to 2002

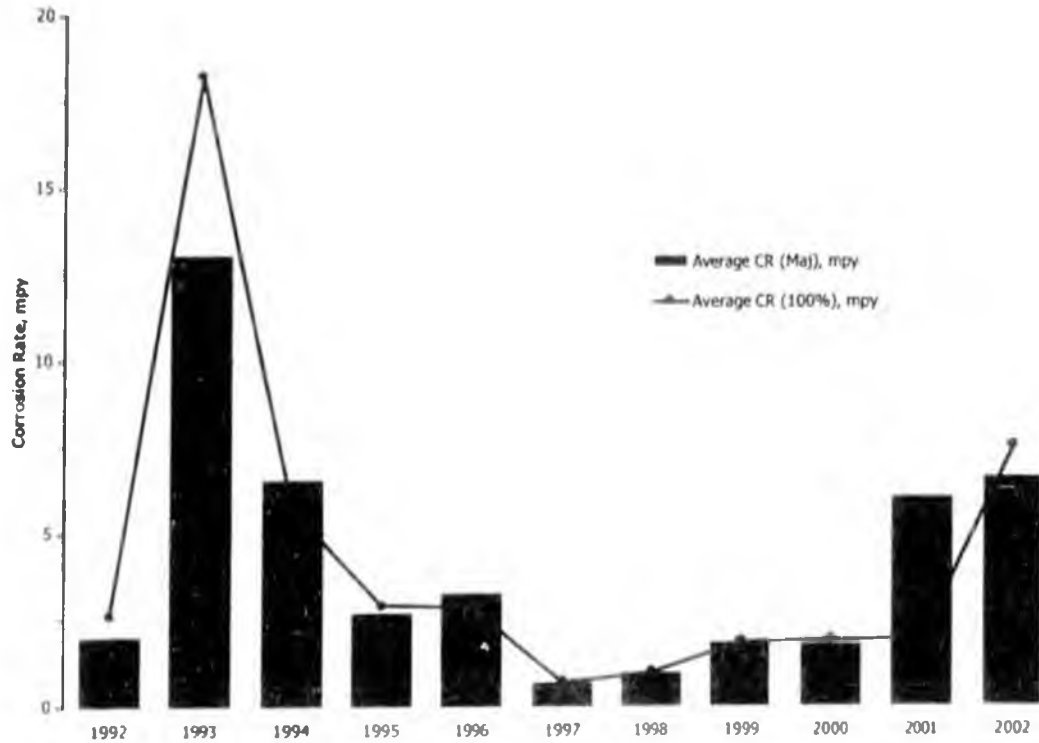


Figure C.7 (c) Comparison of Corrosion Rates for 100% and Majority SW System 1992 to 2002

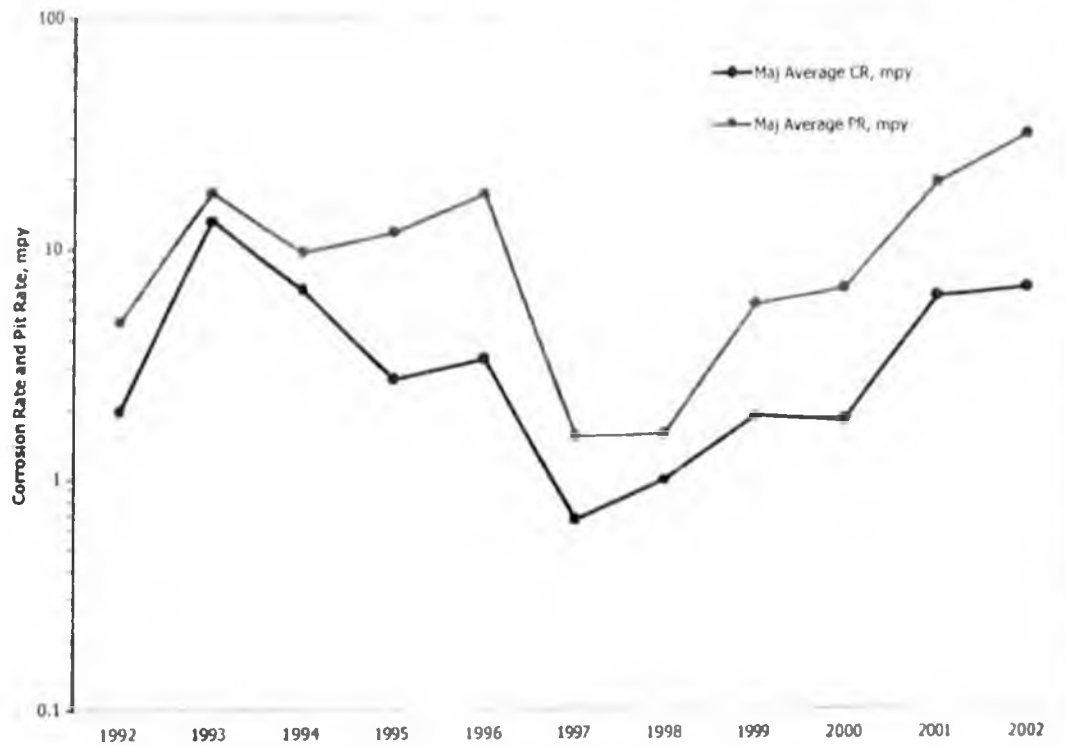
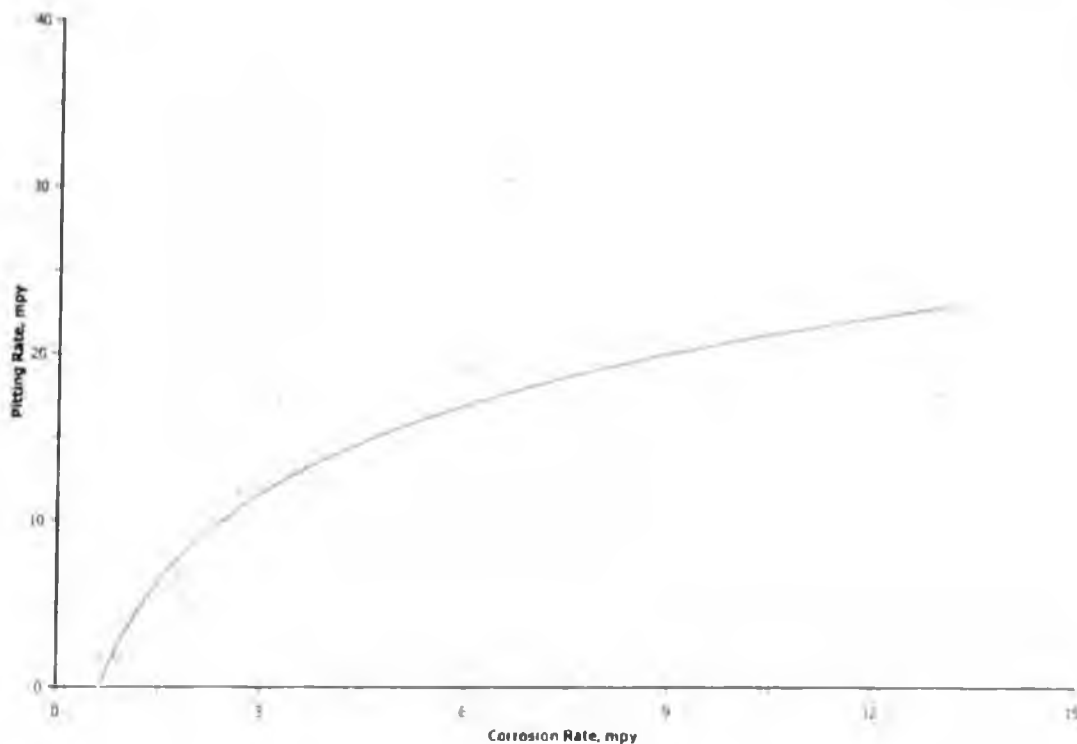


Figure C.7 (d) Correlation Between Corrosion Rates and Pitting Rates for Majority SW System



**Figure C.7 (e)** Correlation Between Corrosion Rates and Pitting Rates for Majority SW System

Unfortunately, while the corrosion mitigation improvements have been put in-place in 2002, the Seawater Treatment Plant (STP) and the downstream distribution system were shut-in for a substantial portion of the year. The seawater system is being rehabilitated and upgraded to provide additional water injection capacity for the future. The lack of steady state conditions through the year has complicated the evaluation of the corrective actions established in 2002 and it is at this time unclear whether or not these actions have been successful.

The determination of the effectiveness of the mitigation changes in 2002 and whether or not additional corrective action is required will continue to be a major focus for 2003 as a sustained and long term supply of seawater is required for optimal water flood/oil recovery and reservoir pressure support.

The most significant of the corrective actions are summarized below. To achieve corrosion control in the SW system, a combination of microbiological and oxygen control is required. Problems with oxygen control in the system were addressed in 2001 and 2002. The following targets, controls and corrective actions reduced oxygen in the seawater,

- Residual dissolved oxygen (DO) target was set to < 20 ppb (parts per billion) after vacuum deaeration and chemical oxygen scavenging

- The DO meter was upgraded and meter maintenance and calibration frequency were increased
- Antifoam was added to the vacuum towers to improve the performance and hence reduce DO levels leaving the tower
- Extensive plant repair and maintenance in preparation for SW volume ramp-up

Despite the non-steady state operation of STP throughout 2002, it is believed that the improved oxygen control has decreased corrosion in the upstream portion of the SW system, but corrosion continued to increase in the downstream parts of the system. The preliminary data suggests that there is an improved level of corrosion control in the upstream portion of the system as shown in Table C.8, which shows the percentage of inspection results that are showing increases. The inspection data for 2000, 2001, and 2002 has been divided into 2 groups, upstream which is that portion of the SW injection system immediately downstream of STP, and the downstream which is main in-field distribution lines.

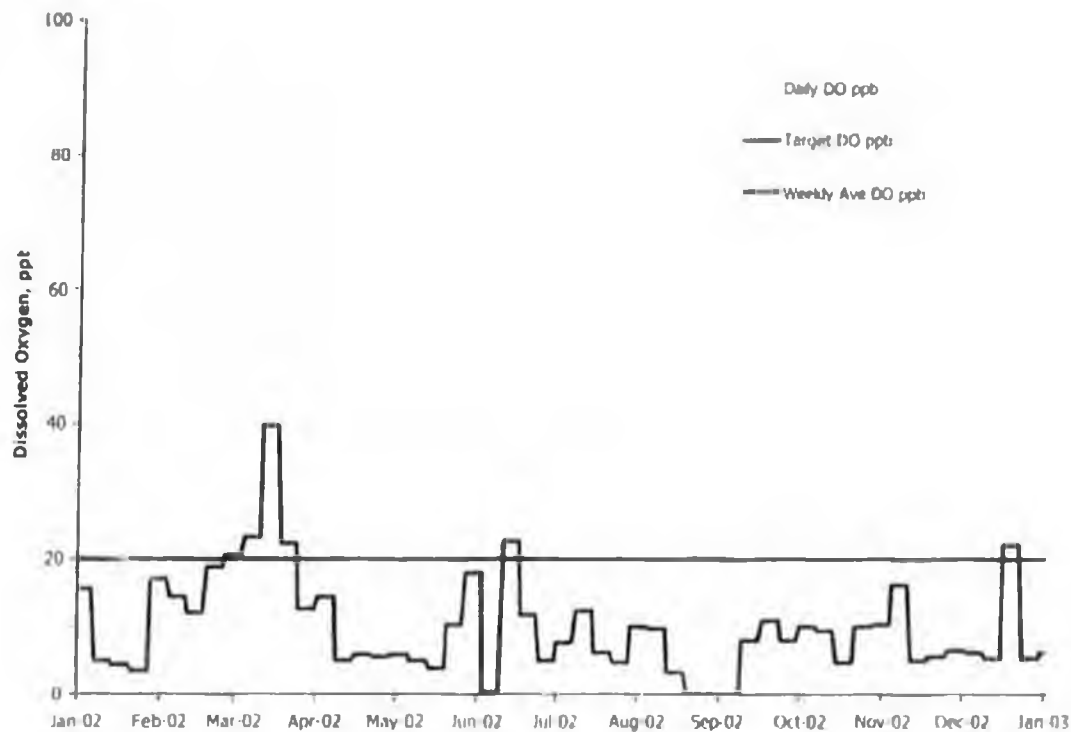
	2000	2001	2002
<b>Upstream Flow Lines</b>	8%	0%	1%
<b>Downstream Flow Lines</b>	26%	8%	22%

**Table C.8** Inspection Increases for the SW System

Figure C.9 shows the daily and weekly average level of dissolved oxygen control in the seawater system through 2002. The figure shows that there were 6 occasions when the weekly average DO level exceeded the 20 ppb billion target. Of these six occurrences, 4 occurred in 1Q 2002 with just a single incident in 2Q, none in 3Q, and 1 in 4Q. Clearly the actions taken to address the performance of the dissolved oxygen content of the processed seawater leaving STP have resulted in a significant level of conformance to target in 2002.

High corrosion rates were expected in 2002 due to long periods of shut-in while the system was upgraded to achieve higher seawater rates. However, the seawater system has been, and continues to be, a main focus of concern. The following actions were taken to improve microbiological control of the seawater system despite the complications associated with the periods of shut-in due to the system upgrade,

- Maintenance pigging frequency has been doubled along with an improved disc/brush pig design
- Biocide treatment frequency was doubled, from once every 2 weeks to once a week



**Figure C.9** Dissolved Oxygen Control Performance for the Seawater System 2002

- The microbial monitoring program was reconsidered and improved. Microbial monitoring is done monthly
- A biocide soak of the entire system was done at high biocide concentration during system shut-in
- Measurement of biocide residuals was implemented and used to track biocide concentrations through the system
- Biocide treatment regimes were modeled, and various treatments are being tested for efficacy in delivering biocide at effective concentrations to the downstream parts of the system
- Technical support was solicited and received from biocide supplier in guiding reconsideration of the biocide treatment program
- The corrosion-monitoring program in the main seawater supply line was changed to increase the pull frequency of weight loss coupons from annual to quarterly, effective at the end of 2001

Table C.10 summarizes the changes in the biocide treatment regime for the SW system and Figure C.11 shows the corresponding effective weekly concentration of biocide as ppm against the quarterly average corrosion rate for the well head coupons with a majority service of SW.

From	To	ppm	Interval	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	Present	750	7	Glutaraldehyde/quaternary amine blend

Table C.10 Biocide Treatment Concentration and Interval

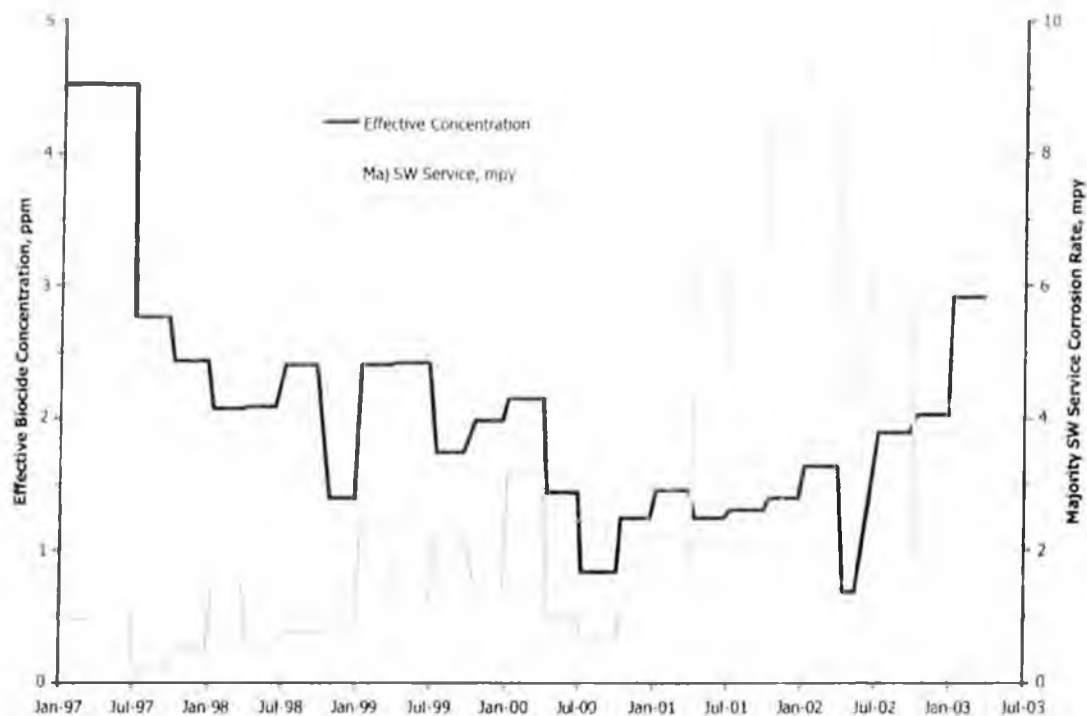


Figure C.11 Biocide Treatment Concentration and Corrosion Rate

While Figure C.11 contains only preliminary information, and no long-term trend has been established, the data does suggest that the increase in biocide

additions and the changes in the biocide treatment regime are beginning to have an impact. The data for the second half of 2002 at least shows that the problem is getting no worse and potentially indicates that corrosion rates are declining if not yet at or below target rate. Clearly this data is still preliminary and continued effort will be required in 2003 to assure that full control of the seawater system has been established and implementation of the long-term treatment regime.

In summary, a number of changes have been made in 2002 to the treatment rates and targets within the seawater injection system to rectify problems that were identified in prior years. The preliminary data suggest that these changes have been effective with the inspection program showing a reduction in corrosion activity level in the upstream pipe work and the weight loss coupon program suggesting progress in reversing the corrosion trends at the extremities of the seawater distribution system. Although the initial data suggests that progress has been made in returning the seawater system to control, there will be an on-going effort in 2003 to assure that this trend is confirmed and continued. Should the reduction in corrosion rates not be established then further corrective action will be required.

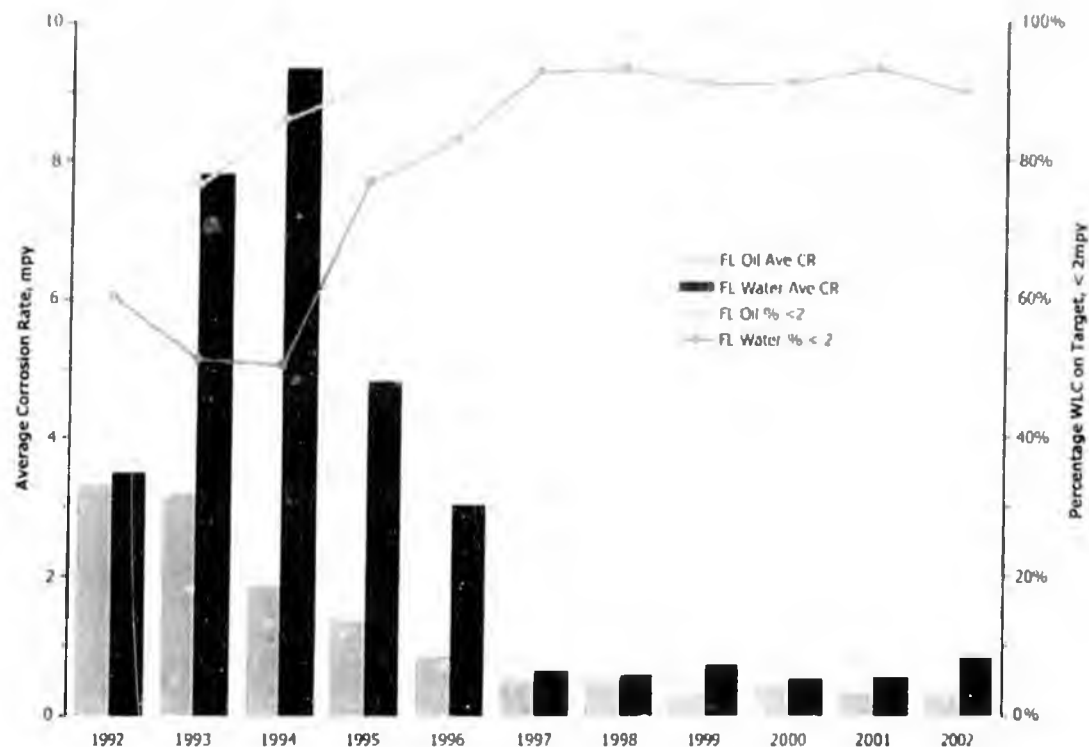
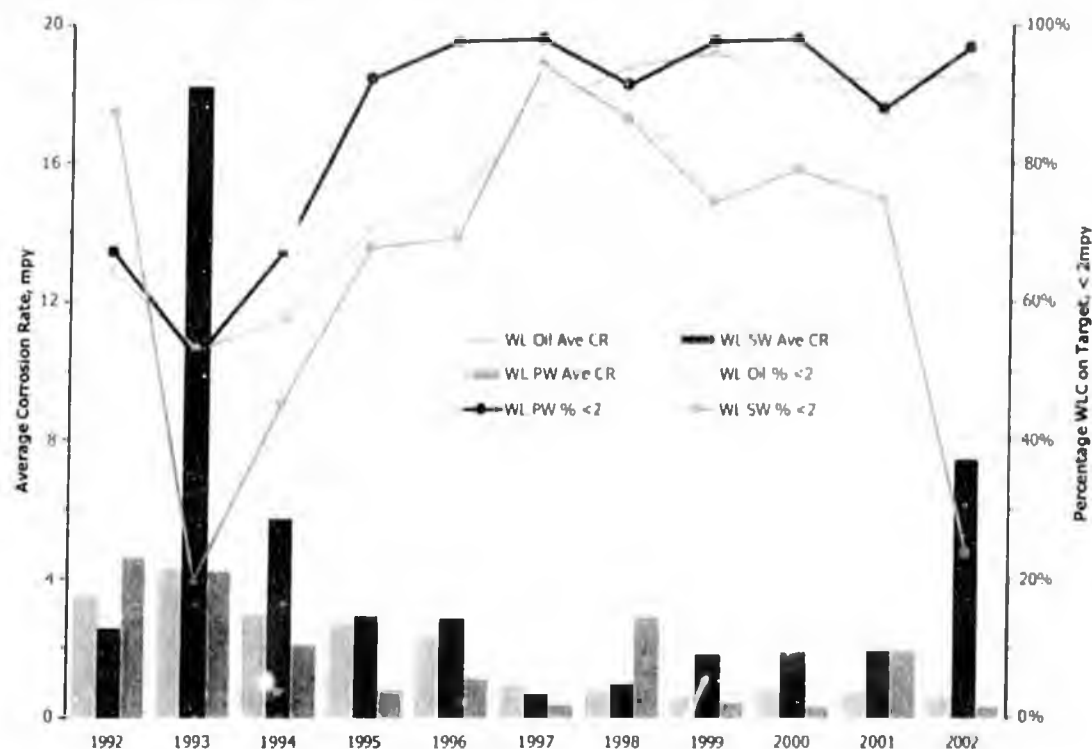


Figure C.12 Flow Line Summary by Equipment and Service for Corrosion Coupon Data

## Section C.6 1992 to Date System Summary

The figures in Section C.6 provide a system-by-system summary since 1992 for the major corrosive process streams at GPB. Figure C.12 shows the corrosion rate and corrosion conformance performance since 1992. The figure shows that the performance in the 3-phase production system has been maintained or slightly improved from 2001. The performance of the water injection flow lines has deteriorated from 2001 to 2002. This deterioration is as a result of the on-going problems in the SW injection system.

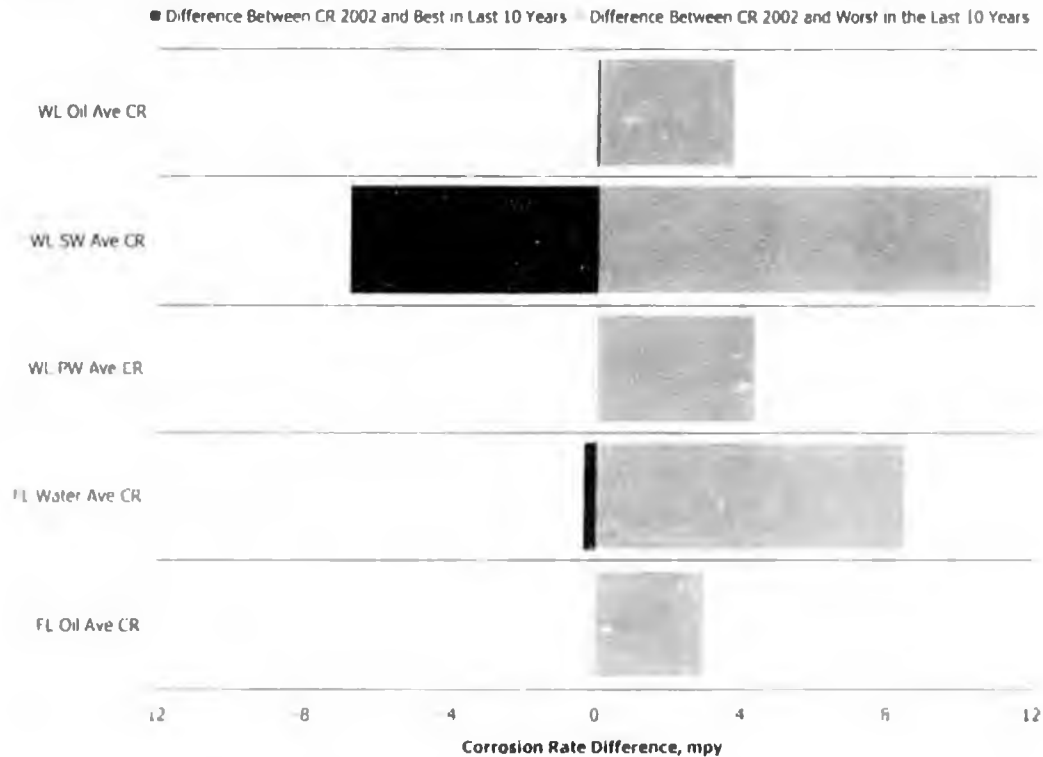
Figure C.13 shows the corrosion rate and corrosion conformance for the well lines. The well line 3-phase system has remained essentially constant between 2001 and 2002. For the produced water well lines there has been a significant improvement between 2001 and 2002, however, this improvement has only returned the system to the levels seen in 1999 and 2001.



**Figure C.13** Well Line Summary by Equipment and Service for Corrosion Coupon Data

As might be expected, the well lines in seawater service show a marked reduction in performance, both in terms of deterioration in the corrosion rate and in the level of conformance to the 2 mpy target. As is discussed elsewhere there have been a number of changes made to the mitigation programs in the SW system with the intention of addressing this deterioration in performance in 2003.

In order to assess the relative performance of the corrosion management program today versus that of the last 10 years, Figure C.14 was generated as a summary. The data shows the difference between the 2002 corrosion rate for each of the systems and the best, or lowest, corrosion rate seen in the prior 10 years and the worst, or highest, corrosion rate seen in the prior 10 years. This is an approximate measure of the successes and/or shortcomings of the program today versus the 10-year history and highlights areas for attention.



**Figure C.14** Corrosion Rate Difference by Service and Type

Figure C.14 shows that the current level of corrosion control as assessed by the difference in average corrosion rate for the system is at or near the best levels of control that have been seen in the last 10 years with the exception of the seawater system. The data given in Figure C.14 is also summarized in the Table C.15.

In summary,

**Flow Line Oil Service** - Consistent with historical best performance, 99% of coupons pulled in 2002 met or beat the corrosion control target of 2 mpy. 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 increased subtly to the 2002 values of 0.3 mpy and 99%, respectively.

**Well Line Oil Service** - Slightly under historical best performance, 93% of coupons pulled in 2002 achieved the corrosion control target of 2 mpy or less. Significant improvements in performance occurred from 1992 to 1997 when the average 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, CR and target conformance performance has increased to the 2002 values of 0.6 mpy and 93% respectively. Continued improvements are expected due to corrosion inhibitor distribution optimization (individual target rates and expansion of continuous injection systems).

System	2002 CR mpy	Best mpy	(2002 - Best) mpy	Worst mpy	(2002 - Worst) mpy
FL Oil Ave CR	0.33	0.31	-0.02	3.32	2.99
FL Water Ave CR	0.86	0.54	-0.32	9.34	8.48
WL PW Ave CR	0.32	0.30	-0.02	4.61	4.3
WL SW Ave CR	7.46	0.68	-6.8	18.0	10.7
WL Oil Ave CR	0.63	0.57	-0.06	4.3	3.7

Table C.15 Corrosion Rate Difference by Service and Type

**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 2002.

**Flow Line PW/SW Service** - Less than historical best performance, 90% of coupons pulled in 2002 achieved the corrosion control target of 2 mpy or less. Performance deteriorated from 1992 to 1994 when average CR increased from 3.5 to 9.3 mpy and conformance to the 2 mpy target reduced from 60 to 51%. However, significant improvements occurred from 1994 to 1997 when the average CR was reduced to 0.7 mpy (~90% improvement) and conformance to the 2 mpy target was increased

to 93% (~80% improvement). Since then, CR and target conformance remained relatively constant until 2002 when performance dropped subtly to 0.9 mpy and 90% respectively.

**Well Line PW Service** – Average CR and percent conformance with the 2 mpy target were consistent with historical best performance at 0.3 mpy and 97%. Two excursions occurred in 1998 and 2001, these most likely resulted from reduced system velocities (countered by implementing PW corrosion inhibitor evaluations) and oil system corrosion inhibitor chemistry changes (countered by modifying chemistry) respectively. Continued increase in performance is expected due to expansion of a corrosion inhibitor program designed specifically for the PW system.

**Well Line SW Service** - Average CR and % conformance with the 2 mpy target declined substantially in 2002. Only 25% of coupons pulled in 2002 achieved the corrosion control target of 2 mpy or less with an average CR of 7.5 mpy. As a result, a set of specific corrective actions have been implemented in 2001 and 2002, which are expected to reduce the corrosion rates and return the system to corrosion rates that meet target.

As an overall representation of the progress of improving corrosion control at GPB, Figure C.16 shows the aggregate performance for all equipment and all services discussed in this report. The figure shows that average corrosion rates have fallen by 80% from 2.3 mpy in 1995 to 0.5 mpy in 2002 and that the number of coupons meeting or beating the 2 mpy target has increased from 76% in 1995 to 95% in 2002.

It should be noted that the majority of the pipelines are in 3-phase (OIL) service and hence the majority of the corrosion monitoring is also in 3-phase service. As a consequence, the aggregate data shown above is dominated by the performance of the 3-phase system.

### **Section C.7 Electrical Resistance Probes**

Electrical Resistance (ER) probes are installed in various locations to monitor corrosion rates in flow lines throughout the GPB field piping systems. ER probes show increases due to material loss from corrosion and the measurements are converted to provide corrosion rates in mils per year (mpy). Field ER probes are equipped with remote data collectors (RDC), which measure and record the metal loss data at specified time intervals. The RDC units throughout GPB are set

to record metal loss data every 3 hours. This provides an adequate number of data points to assess corrosion rates while maximizing battery life in the units.

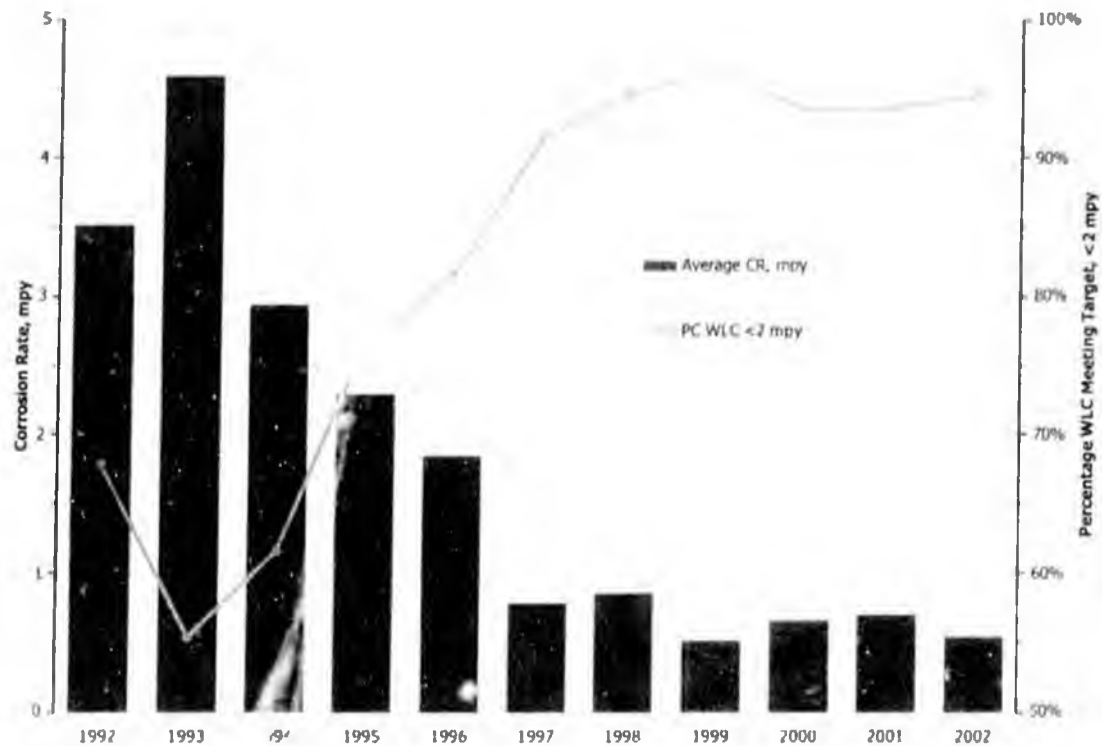


Figure C.16 GPB Aggregate Performance

The type of ER probe used is a T-10 that has 5 mils of metal thickness available for use. All flow line probes are replaced based on 1-year service, or when one half the usable metal thickness has been used. This reduces false negative and false positive readings as a result of a bad, used up, or unresponsive probe.

ER probes are located on both the upstream (well pad) end and downstream (gathering center) end of all flow lines located on the West side of GPB. On the East, probes are located on the downstream (flow station) end of the flow lines only. Expansion to include the upstream location of the flow lines for the East is under review.

ER probe data is collected in the field and uploaded to the corrosion and inspection database once per week. More frequent readings can be made to closely monitor suspect locations/readings. The data is then reviewed and analyzed to identify any negative trends that need to be addressed. After verifying an increase in corrosion rates based on the probe data, a corrosion inhibitor increase may be recommended, as discussed in Section D and shown in the example given in Figure C.17.

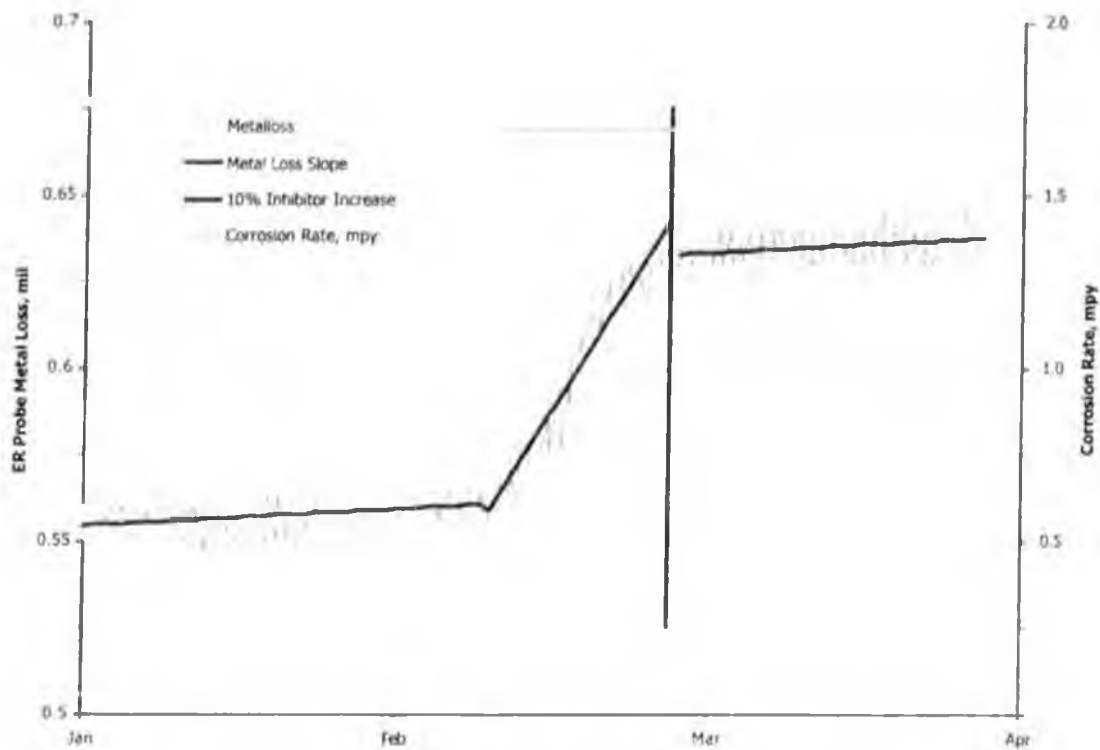


Figure C.17 ER Probe Inhibitor Change Example

The ER probe rate target is less than 2 mpy. In 2002 there were 137 occurrences when the ER probes exceeded 2 mpy as compared to 193 occurrences in 2001. Only 6 occurrences of the 137 were attributable to increases in corrosion rate. The corrosion inhibitor rate was increased for each of the 6 occurrences – see Section H.

The remaining 131 were as a result of,

- Probe element failure
  - Mechanical damage
- Thermal swings as a result of operational fluid rate changes
- Exceeded probe life, 12 months or 50% of active element
- Loss of electrical power/batteries

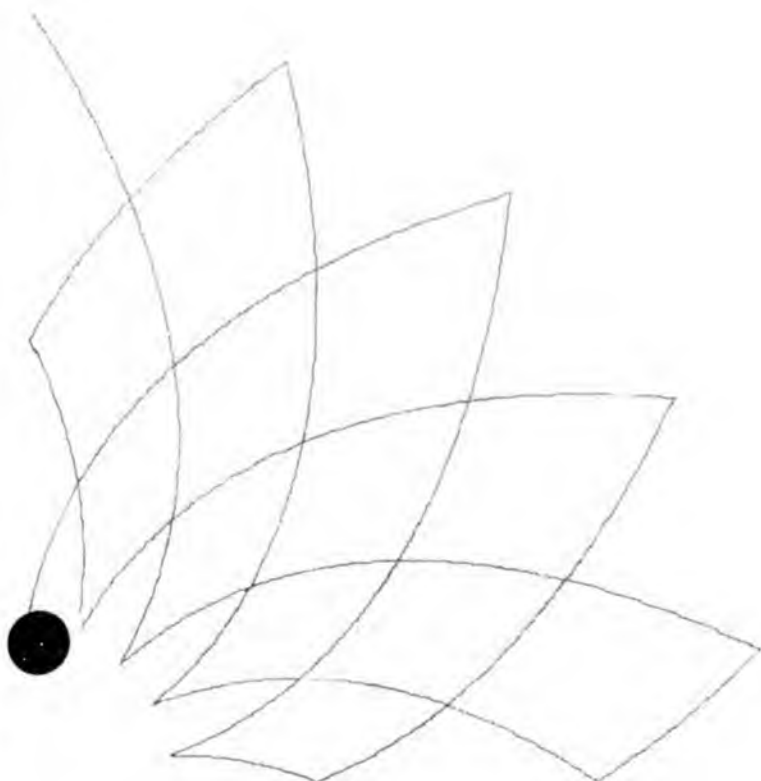
Additional information on the use of ER probes in the corrosion management process is provided in Section D – Chemical Optimization Activities.

**Section C.8 Coupon Processing Recommended Practice.**

Coupons are processed and analyzed consistent with NACE recommended practice NACE RP0775-99.

## 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 describe the main areas in this range including chemical development, field wide chemical deployment, chemical usage and finally corrosion control.

### **Section D.2 Corrosion Inhibitor Development**

The development of new corrosion inhibitors starts in the R&D laboratories of the chemical suppliers with potential chemistries being tested for effectiveness under a range of conditions to simulate GPB 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.

Typically, using a standardized protocol, one or two new products are tested each month on a small scale test using an individual well line with each test lasting ~10 days and using approximately 100 gallons of the corrosion inhibitor being evaluated. 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.

This test process is summarized in Table D.1

As an example, the ER probe results from a typical cross-country flow line test are shown in Table D.2 and are summarized in Figure D.3. As can be seen from the figure and the details in the table, the test chemical in this example was not cost effective and therefore was not utilized across the field.

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 D.4. The product was evaluated as a failure and the incumbent product was re-instated based on the coupon results. Corrosion inhibitor tests use all monitoring tools such as corrosion probes, coupons, and inspection data to determine corrosion control performance.

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.

**Table D.1** Summary Description of the Typical Test Program Components

Location	Test	Description
Field	Well Line Test	Dedicated test lines are used at GPB as the first step in the field-testing process. Typically 100 gals of chemical used with a test duration of 10 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 criterion in order to assess if there is an overall improvement in cost effectiveness.
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 D.1 (Cont.)** Summary Description of the Typical Test Program Components

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 D.2** Flowline Test Program Result Summary

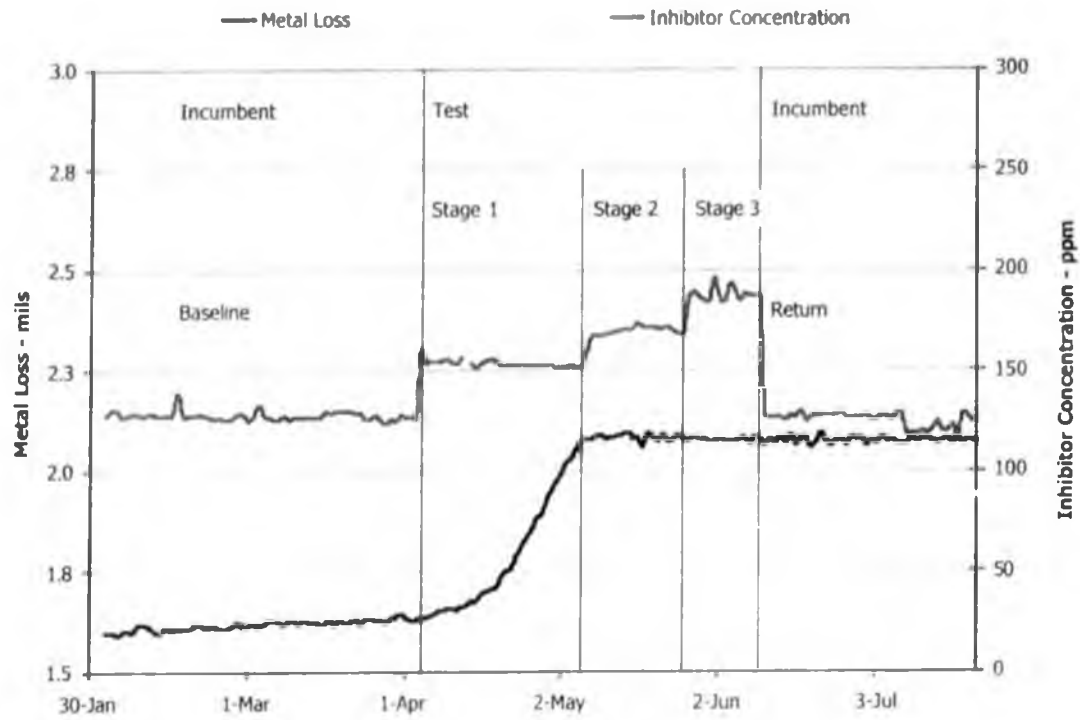


Figure D.3 ER Probe Chemical Optimization Test

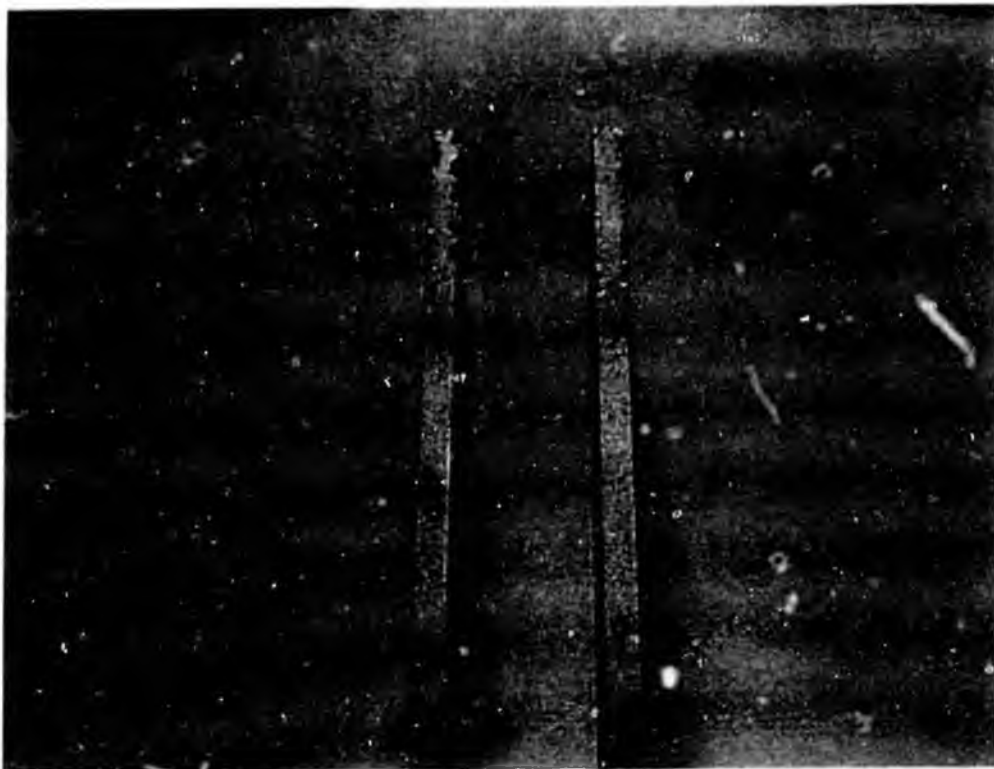


Figure D.4 Corrosion coupons pulled after an 'unsuccessful' chemical trial

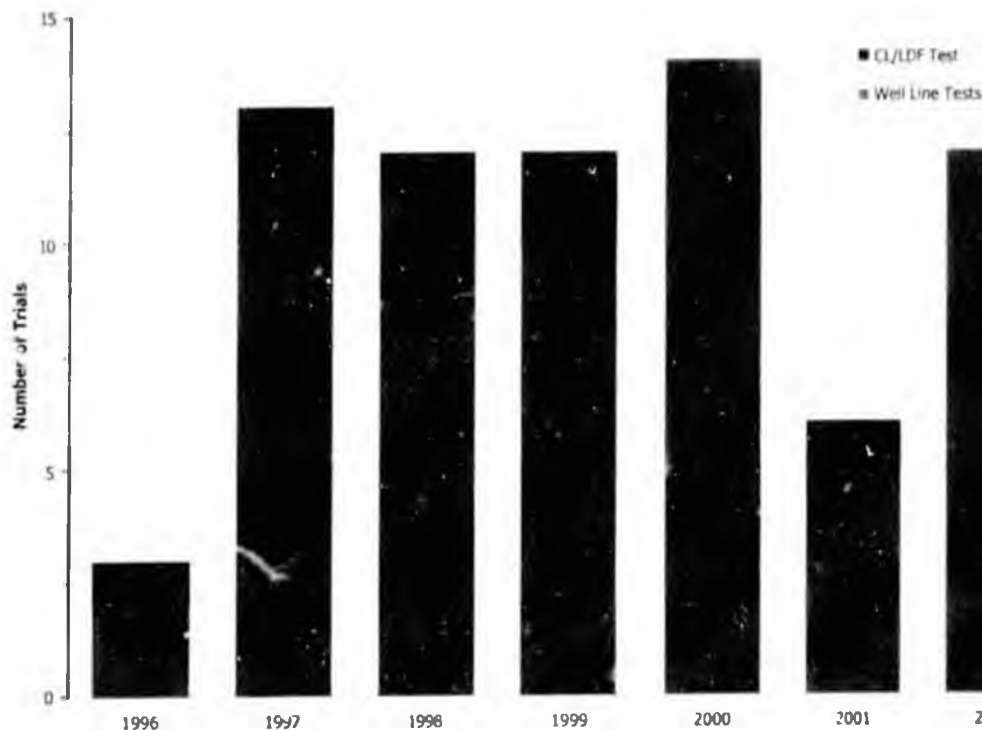
### Section D.3 Corrosion Inhibitor Testing

Table D.5 below summarizes the number of well line and full-scale flowline tests which have been completed since 1996. As can be seen from Table D.5 and the accompanying chart, Figure D.6, the level of activity has remained relatively constant since 1997 at between 10-14 well line and full-scale flow line trials per year.

	1996	1997	1998	1999	2000	2001	2002
Well line test	2	12	11	10	14	5	12
Flow line test	1	1	1	2	0	1	0
<b>Total</b>	<b>3</b>	<b>13</b>	<b>12</b>	<b>12</b>	<b>14</b>	<b>6</b>	<b>12</b>

**Table D.5** Number of Well Line and Flowline Trials

The data prior to 2000 is 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 more effective corrosion inhibitors.



**Figure D.6** Number of Well Line and Flowline Trials

### Section D.4 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 8 years represent a significant improvement in cost effectiveness and corrosion control performance.

Table D.7 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.

### Section D.5 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. Table D.8 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.

Supplier	Chemical	1995	1996	1997	1998	1999	2000	2001	2002
Nalco Exxon	EC1110A								
Nalco Exxon	EC1259								
Nalco Exxon	97VD129								
Nalco Exxon	98VD118								
ONDEO Nalco	99VD049								
ONDEO Nalco	01VD017								
ONDEO Nalco	01VD121								
Champion	RU205								
Champion	RU210								
Champion	RU223								
Champion	RU258								
Champion	RU271								
Champion	RU126A								
Champion	RU256 <sup>1</sup>								

<sup>1</sup> Used for the batch treatment of well lines while the remaining chemicals are all used for continuous application

**Table D.7** Summary of the Chemical Deployment History at GPB

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 vary from year to