ALASKA LEGISLATURE COMMITTEE FILES, 2005-2006 8672

11962 SENATE RESOURCES

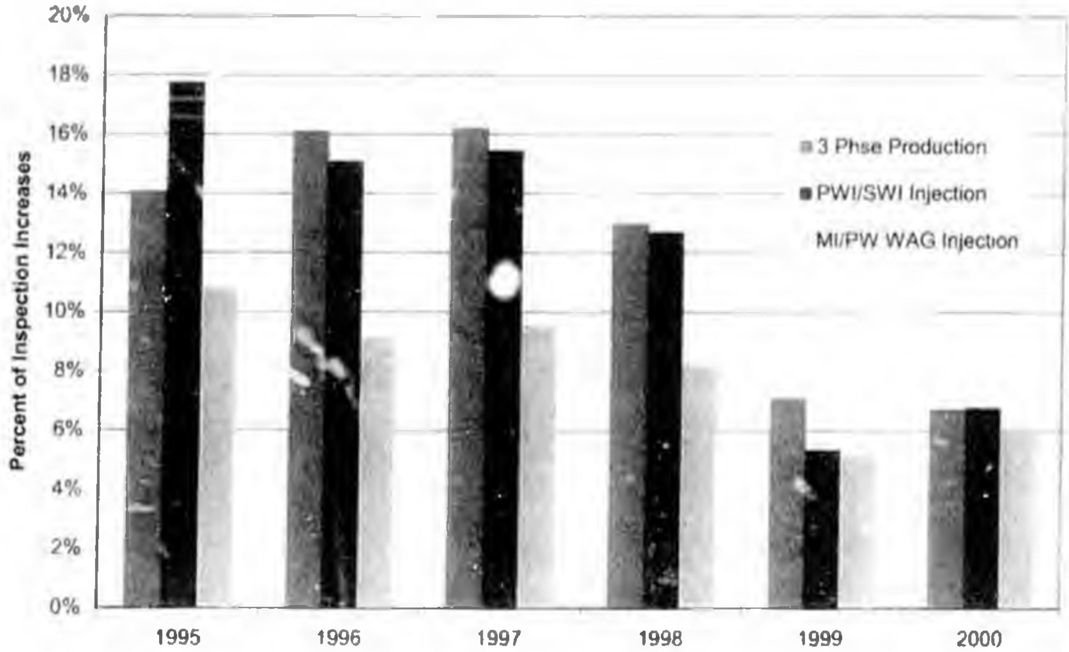


Figure 4: Detection of internal corrosion of well lines by inspection

Figure 5 shows similar data to Figure 4, but for cross country pipelines. Similar trends can be observed to those seen for well lines but with the improving trend continuing through 2000.

The reduction in corrosion control of the well lines in 2000, shown in Figure 4, relative to previous years contrast strongly with the continuing improving trend in cross country pipelines shown in Figure 5. It is believed that the main cause for this is poor distribution of corrosion inhibitor at the well head. Specifically, the amount of chemical injected at each well head has varied from the target value by a greater degree than achieved in previous years, with the result that corrosion rates have been higher. This has not had a significant impact on the cross country pipelines as they are fed by a number of wells, such that the variation in corrosion inhibitor volumes is smoothed out. There are a number of reasons why distribution of chemical at the wellhead was less efficient in 2000, including precipitation problems with the corrosion inhibitor during the winter of 1999/2000 that lead to some chemical tubing being blocked. This problem was solved by diluting the chemical, however the increased volumes of product that were used placed a greater work load on the chemical operators and, in hindsight, it appears that this had a negative impact on their ability to achieve target chemical injection rates. Crew sizes were also reduced in mid-2000, which also impacted the ability to achieve target chemical injection rates at the well level. This reduction has now been reversed and chemical operator crew size is the same as it was in 1999. Re-establishing satisfactory distribution of corrosion inhibitor is an important activity for the CIC group in 2001.

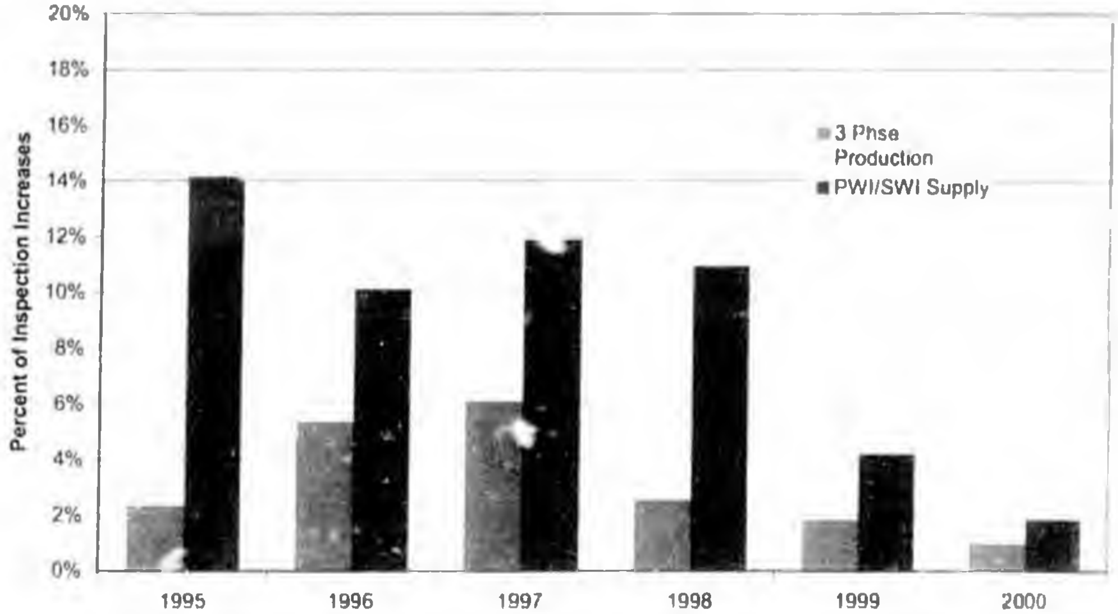


Figure 5: Detection of internal corrosion of cross country pipelines by inspection

These high level measures show general trends across the field. These high level measures are useful and demonstrate the continuous improvement in corrosion management. However, the integrity management programs are structured to work at the level of individual equipment and, where necessary, at individual location level. Section E3 describes the inspection programs that generate these data.

Section E.3 Inspection Intervals

This Section describes the criteria used to determine the frequency of inspection. Many factors determine the interval between successive inspections. The over-riding factor in determining inspection intervals is the purpose of inspection. The internal inspection program is sub-divided in to four elements, each with a separate purpose and therefore frequency of inspection. The external inspection program has one element. Smart pigging is used to support both the internal and external inspection programs.

The scope of the inspection program is relatively constant at approximately 60,000 inspection items per year. This includes plant inspections.

CRM – Corrosion Rate Monitoring: The goal of this program is to detect active corrosion in support of corrosion control activities, primarily the chemical inhibition program. The data is complimentary to other monitoring data, such as corrosion probes and corrosion coupons. As the primary aim is to determine when corrosion occurs, this program is of fixed scope at fixed inspection intervals. For a typical cross country pipeline, the CRM includes up to 40 inspection locations which include examples of all locations susceptible to corrosion, such as elbows, girth welds, long seam welds, bottom of lines sections etc. These locations are each inspected twice per year. The inspections are staggered, with half the set being completed in the 1st calendar quarter and half in the 2nd. These are repeated in the 3rd and 4th quarters respectively, therefore information regarding the level of active corrosion (or lack of) in a pipeline is generated every 3 months. All cross country pipelines in corrosive service will be covered by the CRM by the end of 2001.

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

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

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

In-line Inspection - smart (intelligent) pigging: Smart pigs are used to inspect for internal and external corrosion of cross country pipelines. The extent of their use has differed between the heritage BP and ARCo facilities, with the former WOA performing a number of smart pig runs each year, whereas the former EOA rarely used smart pigs. The main reason for this difference is the provision of permanent pig launchers and receivers on the WOA, which greatly facilitate the use of smart pigs. The interval between smart pig runs is typically 5 years.

CUI – Corrosion Under Insulation: A recurring screening program has been determined to be the best measure to identify equipment at risk. Prioritization of inspection surveys is determined by average temperature of the equipment, age of equipment and/or the last time a complete screening process was completed. If screening has been completed or once screening is completed, sites are revisited at intervals described in Table 8. As a result of findings from the screening process the extent of additional examination is determined. All cross country and well lines are covered by the CUI program.

Table 8: Recurring Frequency of CUI Inspection Surveys

Equipment Temperature	Interval Between Examinations (Years)
≤80° F	10
>80 -120° F	8
>120 - 150° F	6
>150° F	4

Section F - GPB
Repair Activities

Table 11 shows the number of mechanical repairs performed during 2000 and the cause (internal or external corrosion).

Table 11: Mechanical Repairs installed

Service	Internal	External
Cross country	1	1
Production well line	6	18
Lift Gas	0	3
PWI	0	6

Section G - GPB
Corrosion and Structural Related Spills and Incidents

Table 12 summarizes the leaks due to corrosion in 2000.

Table 12: Leaks due to corrosion

Service	Location	Date	Internal/External	Volume
3 phase production	S-pad	6/18/00	External	50 gals
Gas lift	DS 09	9/2/00	External	0

Table 13 shows the number of corrosion related leaks and saves from 1996 through 2000. The ratio of leaks to saves provides a high level measure of the performance of the inspection program at detecting severe damage before it results in a failure. A "save" is defined as a location found via the inspection program that warrants a repair, system derate, replacement or removal from service. These data are also displayed in Figure 6.

Note: Items are typically scheduled for repair at 105% of design or derate pressure, to allow time to complete the repair before the item requires removal from service.

Table 13: Leaks and Saves

Year	Cross Country Saves	Well Line Saves	Cross Country Leaks	Well Line Leaks	Cross Country leak save	Well line leak save	Overall leak save
1996	14	57	4	6	78%	90%	88%
1997	33	73	2	1	94%	99%	97%
1998	51	34	3	4	94%	89%	92%
1999	22	25	0	3	100%	89%	94%
2000	9	54	1	1	90%	98%	97%

Table 13 and Figure 6 show reducing numbers of saves for cross country pipelines for 1998-2000 while the number of leaks has remained similar, in the narrow range of 0 to 3/year. This indicates that there is less active corrosion in the cross country pipelines than there was in 1998 and supports the same trend shown in Figure 5.

However, there were significantly more saves for well lines in 2000 than in the 2 previous years and this indicates more active corrosion in the well lines. Again, this supports the trends shown in Figures 1 and 4. The reduction in the number of leaks despite the increase in the number of saves is due to the success of the inspection program at locating severe corrosion damage. The reasons for the increase in corrosion rate are discussed in Section E.2.

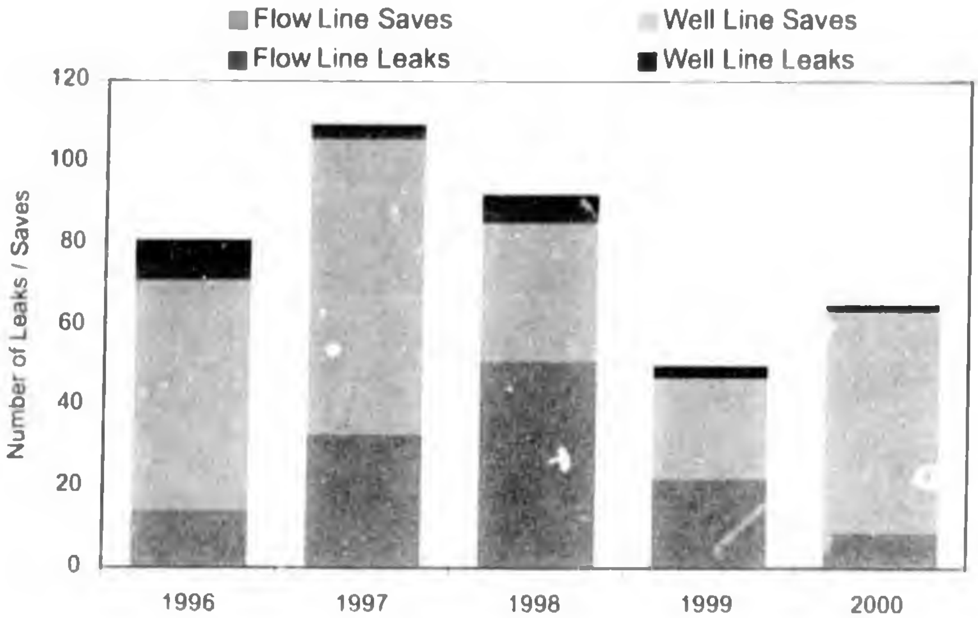


Figure 6: Leaks and Saves of well lines and cross country lines

Section H - GPB
2001 Corrosion Monitoring and Inspection Goals

Single operatorship of Greater Prudhoe Bay meant that 2000 was a year of significant change for BPX(A). Although a lot of the integration of the corrosion management programs was completed during 2000, significant work remains to be done and completing this integration will be a major focus in 2001 for all parts of the program.

Corrosion Monitoring

Heritage BP and heritage ARCo facilities used slightly different coupon pull schedules. It is planned to unify these in 2001, as shown in Table 14. Some corrosion coupons are currently installed in non-corrosive service, such as gas lift and gas injection service. These coupons provide no useful data and it is planned to remove these services from the coupon program in 2001. The specifications for corrosion coupons and their analysis also differed between the heritage organizations and will be consolidated in 2001.

Table 14: Planned Coupon Pull Schedule for Greater Prudhoe Bay

Service	Cross Country (months)	Well lines (months)
3 phase production	3	4
Produced water	6	8
Sea water	3	4
NGL	3	N/A
Sales Oil	3	N/A

Inspection Programs

The primary focus for 2001 will be to implement common inspection programs across the business unit, based on the elements described earlier (CRM, ERM, FIP, CIP, CUI and smart pigging). A common database is being constructed to support this effort and it is planned to be completed in 4Q 2001 and it will include historical data from both heritage organizations.

Digital radiography was introduced during 1Q 2001 and it is planned to expand its use. The benefits are improved productivity, elimination of waste associated with traditional film developing, digital storage and data analysis.

Smart pig inspections are planned for 3 lines during the summer, WZ-LDF 30", M-69 20", S-69 14".

CUI detection in 2001 will continue at a similar level as past years. Due to the unpredictable nature of the damage mechanism, a trial screening program will be implemented to assist prioritization of comprehensive equipment inspection.

Equipment will be examined as outlined in the following:

- 100% of insulation joints at lower bends on vertical elevation risers
- 100% of insulation joints on off takes and branch connections
- 100% of insulation joints in saddle supports
- 10% examination of horizontal straight run and bend insulation joints on each piping circuit.

Concurrent with the screening process and as a result of initial findings, cause for additional examination will be determined. CUI damage found as a result of 10% sampling will bring about additional examinations of insulation joints and damaged insulation for the individual piping circuit in which degradation was observed. Once examinations are completed, equipment will fall back into the cycle of screening described above in Section E.3, Table 8.

Cased piping examination will continue in 2001 utilizing electromagnetic and guided wave inspection techniques. Greater than 200 cased pipe segment inspections are planned for 2001.

Chemical Optimization

At the start of 2001, there were five corrosion inhibitors in use across GPB. The focus for 2001 will be to rationalize these to one incumbent product, with one large scale test product. This rationalization is planned to be complete during 2Q 2001. A summer version will be used across GPB for the first time from May through October. Chemical development will focus on the use of highly concentrated versions of the current corrosion inhibitors, with the aim of reducing freight costs. This will require local blending with locally sourced solvents.

Establishing satisfactory distribution of the corrosion inhibitor at the well head will be a prime focus to re-establish the continuous improvement in corrosion control seen up to 2000. The entire process, from the methods used for allocating chemical to tracking target -v- actual rates is being reviewed and it is planned to implement process tracking equipment, known as PRIDE to enable individual well chemical usage to be tracked.

In order to support the aspiration of continuous improvement in all aspects of integrity management, the CIC department is planning four Peer Reviews during 2001. A Peer Review is a BP process that involves a small group of specialists critically reviewing a program and making suggestions or recommendations for improvement. Such reviews typically take 3 to 5 days and involve 2 to 5 specialists, drawn from the BP Group or its suppliers. One Peer Review on the wet gas inhibition program was completed in 1Q 2001 and 3 more are planned on the tank program (2Q), produced water corrosion control program (3Q) and an overall review of the entire integrity management program (4Q).

PART 2

Alaska Consolidated Team

Business Unit

Section B - ACT
Corrosion Monitoring Activities

ACT presently consists of three producing areas; Endicott, Milne Point Unit (MPU), and Badami. Northstar will be added once it comes on production. The following briefly summarizes the corrosive nature of each producing field.

Endicott

The Endicott Field is a mature waterflood field. The fluid properties (high temperatures, high CO_2 content) indicate the corrosivity of the produced water to be high. Due to this high corrosivity, much of the field production system was fabricated from duplex stainless steel, a corrosion resistant alloy and therefore, corrosion is not a significant concern for much of the production system. In the Endicott production system, the only carbon steel is the "C Spool", connecting the wellhead to the duplex stainless steel well line. These C-Spools are inspected regularly for replacement as damage dictates.

The primary corrosion concerns are in the water injection system, mainly the Inter-Island Water Line (IIWL) which carries injection water to the satellite production island (SDI) from the main production island (MPI). Corrosion control of the water injection system relies on corrosion inhibition of the injection water, supplemented by a biocide and maintenance pigging program. The primary monitoring method for the IIWL is ultrasonic inspection of 25 locations along the IIWL. Table A1 summarizes the inspection program for Endicott for 2000.

Table A1: Endicott Summary of Lines and NDT Inspections

Service	Miles of Piping	No. Internal Inspections	No. External Inspections
Oil x-country lines	3.5	4 (in vault)	4 (in vault)
Oil - Well Pads	2.5	1112	0
Water x-country lines	3.5	104	4 (in vault)
Water - Well Pads	1.7	101	2 (in vault)
Gas x-country (GLT/MI)	7	4 (in vault)	4 (in vault)
Gas - Well Pads	1.2	21	2 (in vault)

Milne Point

Fluid properties (low temperatures, low CO_2 content) indicate the corrosivity of the produced water at MPU to be low. The primary corrosion concerns are in the water injection system and external corrosion of buried piping. Corrosion inhibition, supplemented by a biocide and maintenance pigging program began in mid-2000 in the water injection system. As a result, the overall effectiveness of the inhibition is not known due to the limited history. Table A2 summarizes the inspection program for Milne Point for 2000.

Table A2: Milne Point Unit Summary of Lines and NDT Inspections

Service	Miles of Piping	No. Internal Inspections	No. External Inspections
Oil x-country lines	24	15	41
Oil – Well Pads	Note	497	136
Water x-country	15	95	51
Water – Well Pads	Note	812	150
Gas x-country	14	0	0
Gas – Well Pads	Note	0	0

Note: Data not immediately available

Badami

The Badami field is currently considered a low risk from a corrosivity standpoint as there is little water production and low CO_2 content. Table A3 summarizes the inspection program for Badami.

Table A3: Badami Summary of Lines and NDT Inspections

Service	Feet of Piping	No. Internal Inspections	No. External Inspections
Oil –Well Pad	840'WL , 320' HDR	21 well line, 4 Header	0
Gas	240'WL, 320'HDR	6 well line , 4 header	0
Disposal Well	400'	6 well line	0

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

Section C - ACT
Coupon and Probe Corrosion Rates

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

Endicott
Table A4 depicts the metrics for corrosion monitoring at Endicott for 2000. Historical data are shown in Figure A1.

As shown in Figure A1, the corrosion trend for the production system has rem. ined above 2 mpy; however as noted , .eviously, the major portion of the system is fabricated from duplex stainless steel and the data are used primarily for monitori.ıg produced fluid corrosivity and erosion tendency. The lower, relatively constant corrosion rates in the water system reflect the effectiveness of the corrosion mitigation program.

Table A4: Endicott Corrosion Coupon Monitoring 2000

System	Number of Locations with Access Fittings	% Coupons < 2MPY Corrosion Rate
Water Injection - Pads	15	100%
Water Injection – x-country	1	100%
Oil Production – Pads	81	64%

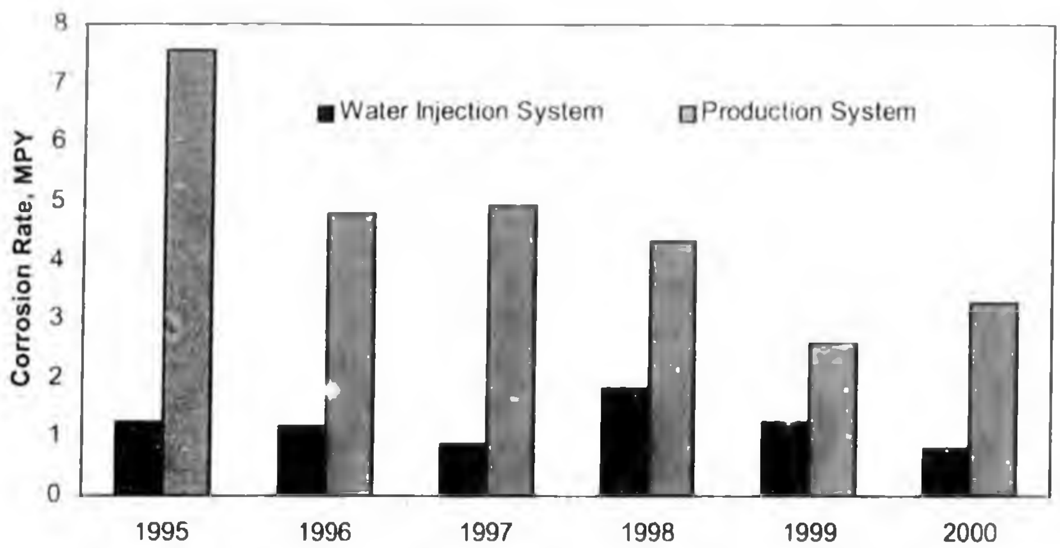


Figure A1: Corrosion coupon data from Endicott 1995-2000

Milne Point

Table A5 depicts the metrics for corrosion monitoring at Milne Point for 2000. Historical data are shown in Figure A2.

Figure A2 indicates the low corrosion rates for the MPU production and source water systems. Of concern are the relatively higher rates in the water injection system. These higher corrosion rates led to the initiation of corrosion inhibition in water injection system in mid-2000.

Table A5: MPU Corrosion Coupon Monitoring 2000

System	Number of Locations with Access Fittings	% Coupons < 2MPY Corrosion Rate
Production System Pads	11	91%
Production System x-country	19	100%
Water Injection System	6	33%
Source Water Coupons	3	100%

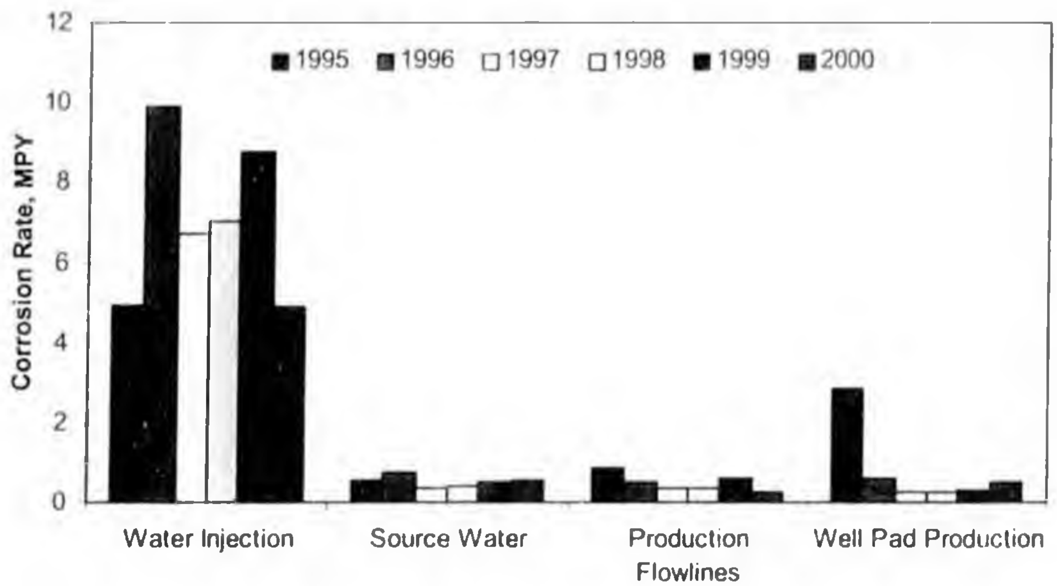


Figure A2: Corrosion coupon data from MPU 1995-2000

Badami

Badami currently has no corrosion monitoring program.

Section D - ACT
Chemical Optimization Activities

Endicott
Chemical optimization at Endicott has concentrated on a three-pronged approach of maintenance pigging for line cleanliness, biociding to control bacterial activity and continuous injection of a corrosion inhibitor for corrosion control. As noted earlier, the primary monitoring tool for effectiveness is the UT inspection of 25 locations along the IIWL. These inspections indicat there is very little corrosion activity in the IIWL. Figure A3 shows an historical perspective of the IIWL inspection activity. The last corrosion activity was noted to be in July 1999.

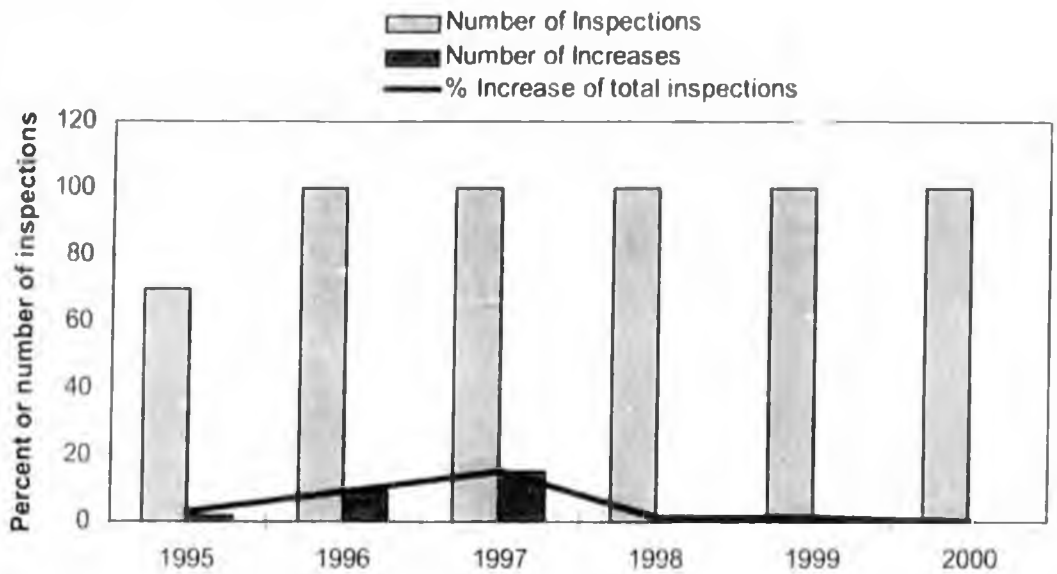


Figure A3: Endicott IIWL Quarterly UT Readings

Inspection in the production system is primarily geared towards detecting erosion damage. Although not strictly a corrosion mechanism, it is included here for information. Approximately monthly, a risk ranking is performed to determine which wells are producing at high velocities. This information is used by the inspection group to determine inspection frequency levels, and is also used by the operating personnel to determine if wells require choking back. Figure A4 is an overview of the velocity data for Endicott for 2000. Shown are the numbers of wells within L/R ratio ranges, where L is the mixture velocity and R is the allowable erosional velocity as defined by API RP 14E.

API RP 14E defines an allowable velocity for the avoidance of erosion, based on the fluid properties (namely density) and material of construction. API RP 14E was written many years ago and is based on experience with steam service and is known to be conservative when applied to oil production systems, particularly where corrosion and erosion resistant materials are used. Actual velocities are expressed as a ratio of the allowable velocity as defined by API RP 14E, with the aim being to limit velocities to less than 3 times the allowable velocity. This factor of 3 reflects BPX(A)'s experience that production fluids with minimal amounts of entrained solids may exceed the API RP 14E erosional velocity through stainless steel pipelines by this amount with minimal risk of erosion.

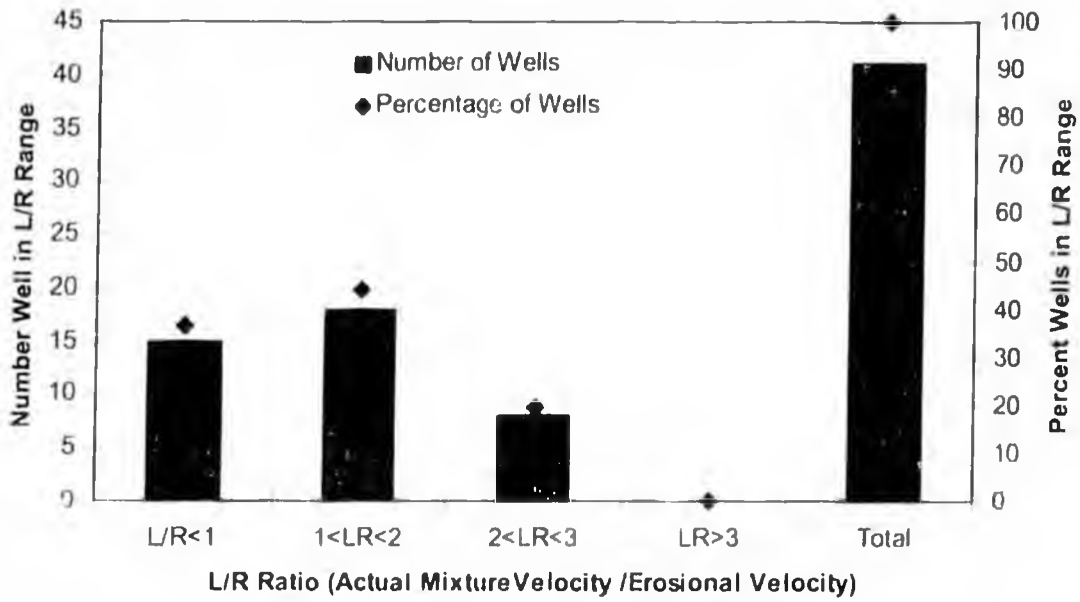


Figure A4: Endicott Velocity Monitoring

Milne Point

As indicated earlier, corrosion inhibition of the water injection system began in mid 2000. It is therefore too early to determine if this program is optimized. This will be an ongoing activity, as more data is obtained. As production rates are typically lower than Endicott, the velocities are consequently also lower and erosion is not a significant concern. There is therefore no formal velocity management program.

Badami

There is currently no corrosion inhibition at the Badami field.

Section E - ACT
Internal/External Inspections & Corrosion Increases/Rates

Section E.1 External Inspections

Endicott

Electromagnetic inspections were performed on cased piping for Well 5-01 and 5-02 (167 feet each) in 2000. Electromagnetic anomalies were detected in both, but none were significant enough to warrant excavation.

Other external surveys at Endicott have been conducted previous to 2000:

1) The GLT line was inspected with ATRT and C-ARM in 1997 (at weld packs). Four locations were identified as having external corrosion. Byproduct was removed, corrosion mitigated and the locations reinsulated.

2) The gas header in both 241 and 245 pipe racks were inspected with C-ARM in 1997. One location was identified as having external corrosion. Byproduct was removed, corrosion mitigated and location reinsulated.

3) The IIWL was inspected using an MFL smart pig by British Gas on June 24th 1995.

Milne Point

Table A8 summarizes the external inspection program at MPU since 1997. In addition, 30 digs were performed on buried cross country lines and headers for external corrosion inspection and analysis. Corroded areas were repaired.

Table A8: MPU Inspection Summary- External

Inspection Year	Total Inspections – External	Total Repeat Inspections	Total Increases	Percent Increase
1997	26	0	0	n/a
1998	441	10	0	0.0
1999	101	65	0	0.0
2000	205	104	28	26.9

Electromagnetic inspections were performed at road crossings in 1998 and 2000. The 2000 summary is listed below in Table A9. No electromagnetic anomalies were recorded that were significant enough to warrant excavation.

Table A9: MPU Inspection Summary- Electromagnetic External Inspections

	No. of Cased Pipe Segments	Footage Tested	No EM Anomalies	EM Anomalies	Significant EM Anomalies
Gas/Gas Lift	3	256	2	1	0
3 Phase Production	3	253	1	2	0
PW/SW/WAG	3	222	1	2	0
Source Water	1	82	0	1	0

Badami

As a result of a wind induced vibration crack on the six-inch cross country gas utility line from Endicott to Badami, a detailed inspection of critical welds will be conducted in the near future.

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

Section E.2 Internal Inspections

Endicott

Figures A5 and A6 indicate the percentage of inspection increases since 1995 for the well lines and cross country lines at Endicott. There were no increases in the three-phase production cross country line as it is corrosion resistant alloy. Minor activity has been noted in the water injection system.

Figure A5 shows corrosion activity in the well lines by inspection for both the production and water injection systems at Endicott. These trends have remained relatively constant since 1996. The production system inspection data is used to alert operations of potential replacements of the carbon steel "C spools" at the wellheads. The inspection increases in the water injection system well lines have been consistently low since 1996 and reflects the improvements to the chemical mitigation program undertaken at Endicott.

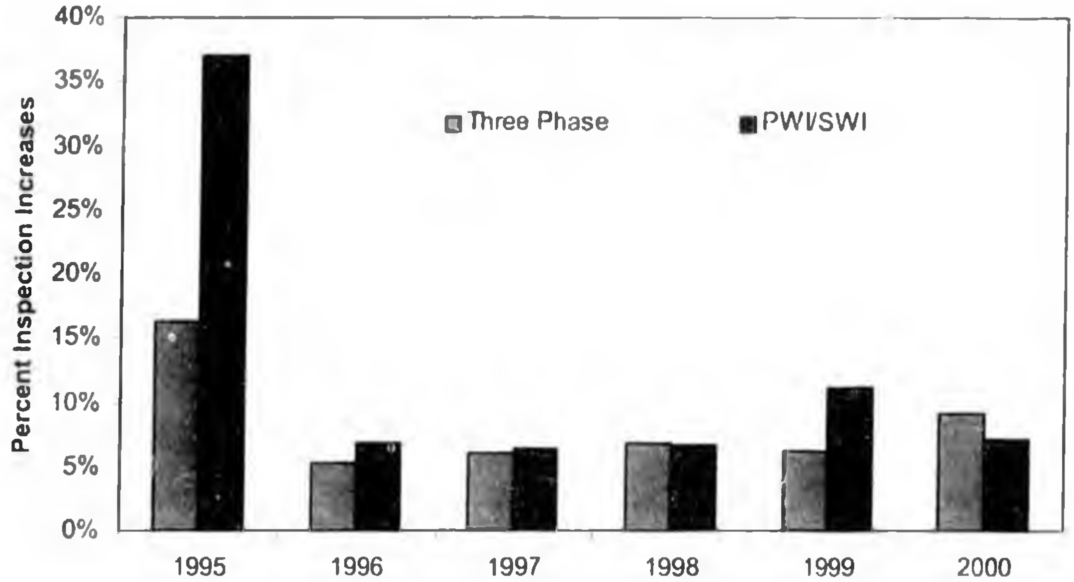


Figure A5: Detection of internal corrosion of well lines by inspection at Endicott

Figure A6 shows a trend of declining inspection increases since 1995 for the Inter-Island Water line at Endicott. This trend is indicative of the improvements made to the water injection mitigation program.

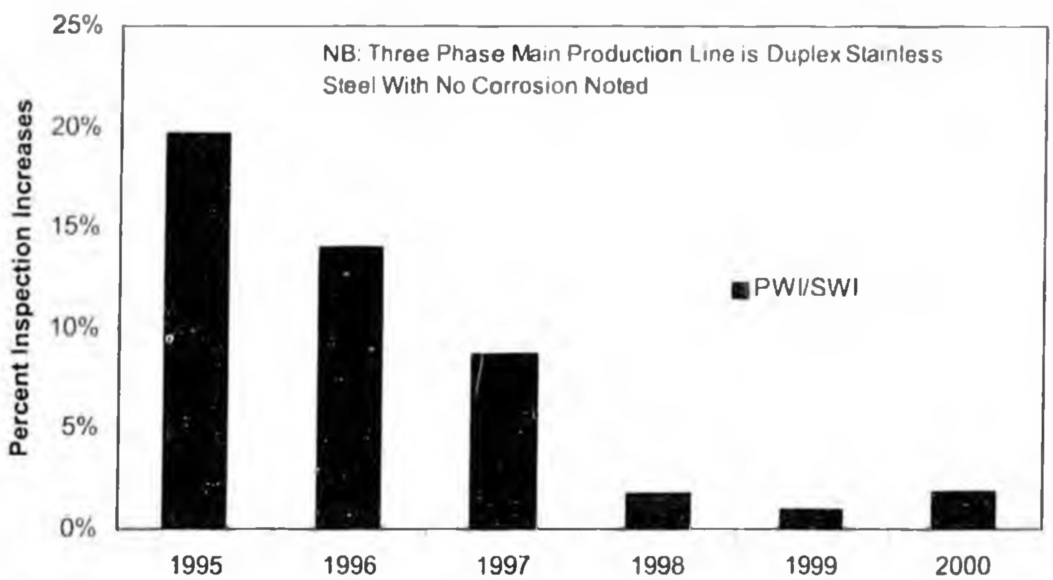


Figure A6: Detection of internal corrosion of cross country pipelines by inspection at Endicott

Milne Point

Previous to 2000, the inspection history at MPU has been somewhat variable. As such, it is difficult to obtain a true trend of corrosion rates via the inspection program due to the limited data set. In 1999 and 2000, a concerted effort was made towards obtaining a more consistent inspection survey. This will allow a detailed trending history, year-on-year as this data is developed. Table A10 includes the number of internal inspections from 1994.

Table A10: MPU Inspection Summary - Internal

Inspection Year	Total Inspections – Internal	Total Repeat Inspections	Total Increases	Percent Increase
1994	332	0	0	n/a
1995	6	0	0	n/a
1996	13	0	0	n/a
1997	632	72	20	27.8
1998	994	276	33	12.0
1999	931	72	5	6.9
2000	1469	280	27	9.6

Badami

As Badami only came on stream in 1998, there is no historical data for this field. A baseline survey performed in 2000 indicates no damage. Inspection locations included the oil production well lines and header, the gas injection well lines and header, and the disposal well line (refer to Table A3).

Section F - ACT
Repair Activities

There were no repairs made during 2000 to pipelines in the ACT business unit. The recent history pipeline repairs is included below.

Endicott
There are no mechanical repairs on pipelines at Endicott.

Milne Point
The B-pad cross country line currently has 2 mechanical repairs (sleeves) applied because of external corrosion in 1998. One sleeve is on the pad and the other is midway between B-Pad and CFP. The C-Pad cross country line currently has 2 sleeves applied because of external corrosion in 1998. One sleeve is on the pad and the other is midway between C-Pad and CFP.

Badami
There are no mechanical repairs on pipelines at Badami.

Section G – ACT
Corrosion and structural related spills and incidents

Tables A11, A12 and A13 summarize leak/save and mechanical repair data for Endicott, MPU and Badami, respectively.

Table A11: Endicott Leak / Save and Mechanical Repair Data

Service	# of Leaks	# of Saves	# of Sleeves	Comments
Oil x-country lines	0	0	0	
Oil Well Pads	1	2	0	1-45 S-riser Save, 1-63 S-spool Save, 2-04 S-spool leak.
Water x-country lines	0	1	0	MPI PW Header Blind flange and valve replaced.
Water Well Pads	0	0	0	
Gas x-country GLT/MI	0	0	0	
Gas Well Pads	0	0	0	

Note: Leak / Save and mechanical repair data is for year 2000 only.

Table A12: Milne Point Leak / Save & Mechanical Repair data

Service	# of Leaks	# of Saves	# of Sleeves	Comments
Oil x-country	1	3	0	In plant ORT piping only
Oil Well Pads	0	0	0	
Water x-country	0	0	0	
Water Well Pads	0	0	0	
Gas x-country	0	0	0	
Gas Well Pads	0	0	0	

Note: Leak / Save and mechanical repair data is for year 2000 only.

Table A13: Badami Leak / Save and Mechanical Repair Data

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

Note: Leak / Save and mechanical repair data is for year 2000 only.

Section H - ACT
2001 Corrosion Monitoring and Inspection Goals

The plan for 2001 for ACT fields will continue to focus on the gains made in the past, in particular, in building a more comprehensive inspection base for MPU. No significant changes to the scope of inspection or corrosion monitoring are foreseen with the following two exceptions.

1) At MPU, an effort is being made to smart pig several water injection and oil production lines. The total number has not been finalized, but will be reported at a future date. This will be the first attempt to perform smart pigging at MPU.
2) The North Star Field will become a part of ACT When the field is brought on line. At that time, reporting of corrosion and inspection activities will become part of this portion of the corrosion/inspection review.

Glossary of Terms

ATRT	Automated tangential radiographic testing
3 phase production	Unprocessed well head fluids, oil, water, gas
ACT	Alaska Consolidated Team business unit
CIC	Corrosion, Inspection and Chemicals
CIP	Comprehensive integrity program
CPF	Central processing facility
CRA	Corrosion resistant alloy
CRM	Corrosion rate monitoring inspection program
Cross Country lines	Pipelines from the manifold building to major facility
CUI	Corrosion under insulation
ERM	Erosion rate monitoring inspection program
FIP	Frequent inspection program
GLT	Gas lift transit
GPB	Greater Prudhoe Bay business unit
IIWL	Inter Island Water Line - Endicott
MFL	Magnetic flux leakage
MI	Miscible injectant
MPI	Main production island - Endicott
MPU	Milne Point Unit
NGL	Natural gas liquids
PW	Produced water
RT	Radiographic Testing
SDI	Satellite production island
Sleeve	Mechanical repair
SW	Sea water
TRT	Tangential radiographic testing
UT	Ultrasonic Testing
WAG	Water alternating gas
Well lines	Pipelines from the well head to manifold building
X-country	Cross country

WORK PLAN

Commitment to Corrosion Monitoring

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

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

Work Plan Purpose:

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

Corrosion Monitoring Performance Management Program

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

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

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

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

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

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

1. BP and PAI will "meet and confer" with ADEC twice per year, on average. These sessions will be "working sessions" where BP and PAI will inform ADEC of the following:

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

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

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

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

   A. Annual bullet item reporting the progress of the Charter Agreement corrosion related commitment.
   B. A general overview of the previous year's monitoring activities.
   C. Metrics which depict coupon and probe corrosion rates.
   D. Metrics which characterize chemical optimization activities.
   E. Metrics which depict the number and type of internal/external inspections done, and, as applicable, the corrosion increases/rates and corresponding inspection intervals.
   F. Metrics which characterize the quantity and type of repairs made in response to the internal/external inspections done per the above paragraph.
   G. Metrics which depict the numbers and types of corrosion and structural related spills and incidents.
   H. A forecast of the next year's monitoring activities in terms of focus areas and inspection goals. These forecasts cannot be viewed as binding, as corrosion strategies are dynamic and priorities will change over the course of the year. However, changes in focus will be communicated to ADEC during the semi-annual meetings described above.

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

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

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

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

4. During the semi-annual 'Meet and Confer' working meetings with BP and/or PAI, ADEC may use the services of a corrosion expert(s) (contracted from funds under Charter Commitment paragraph II.A.7) to assist in the review of performance trends and corrosion program features.

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

Milestones/Timing:

10/25/00 - BP and PAI to meet with ADEC to review and comment on this Work Plan.

11/1/00 - Draft of Work Plan due to ADEC/BP/PAI Managers.

11/15/00 - Final endorsement of Work Plan.

3/31/01 - 1st Annual report due

4/30/01 - 1st Meet and Confer

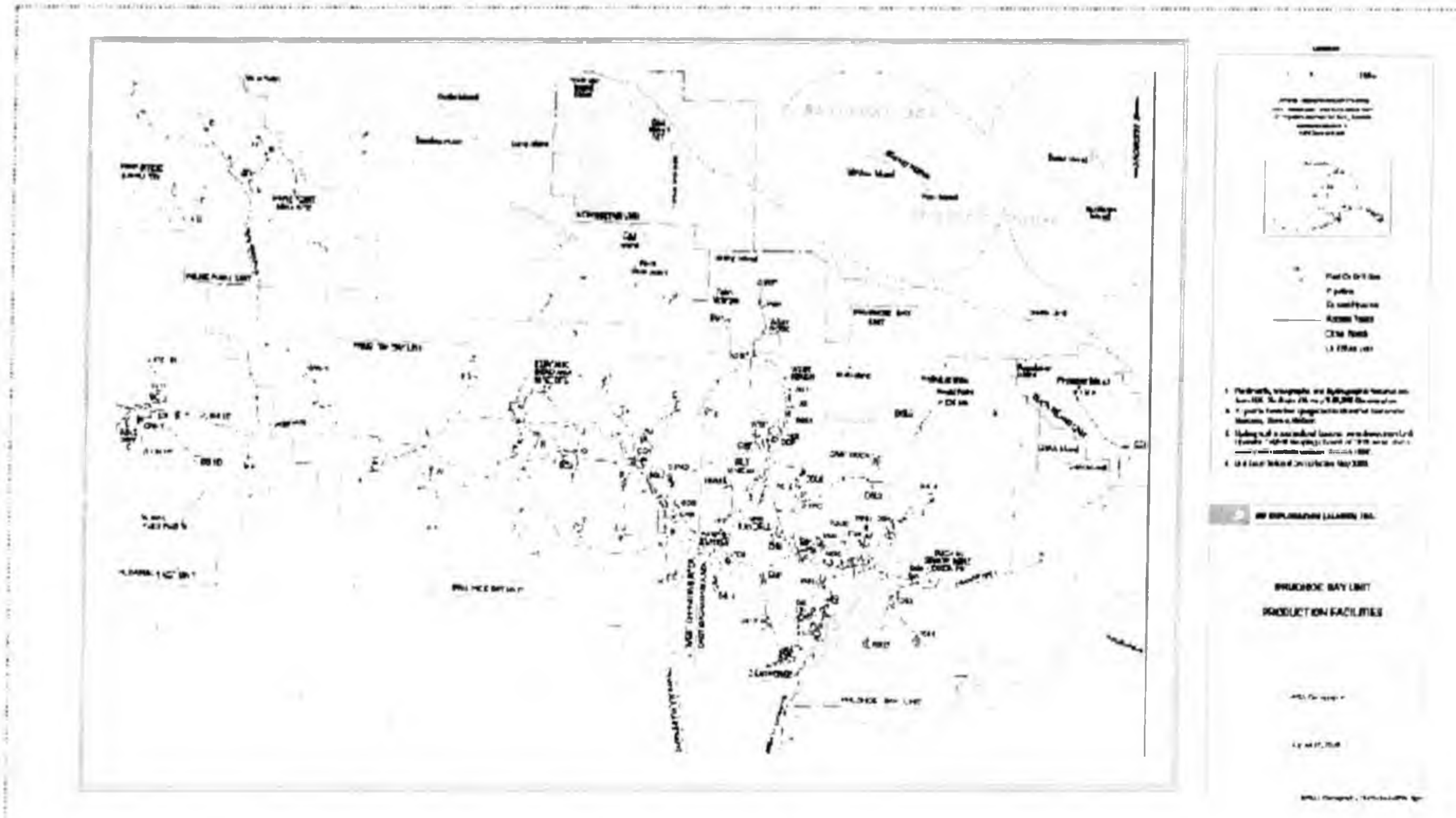
10/31/01 - 2nd Meet and Confer

Annual Timetable

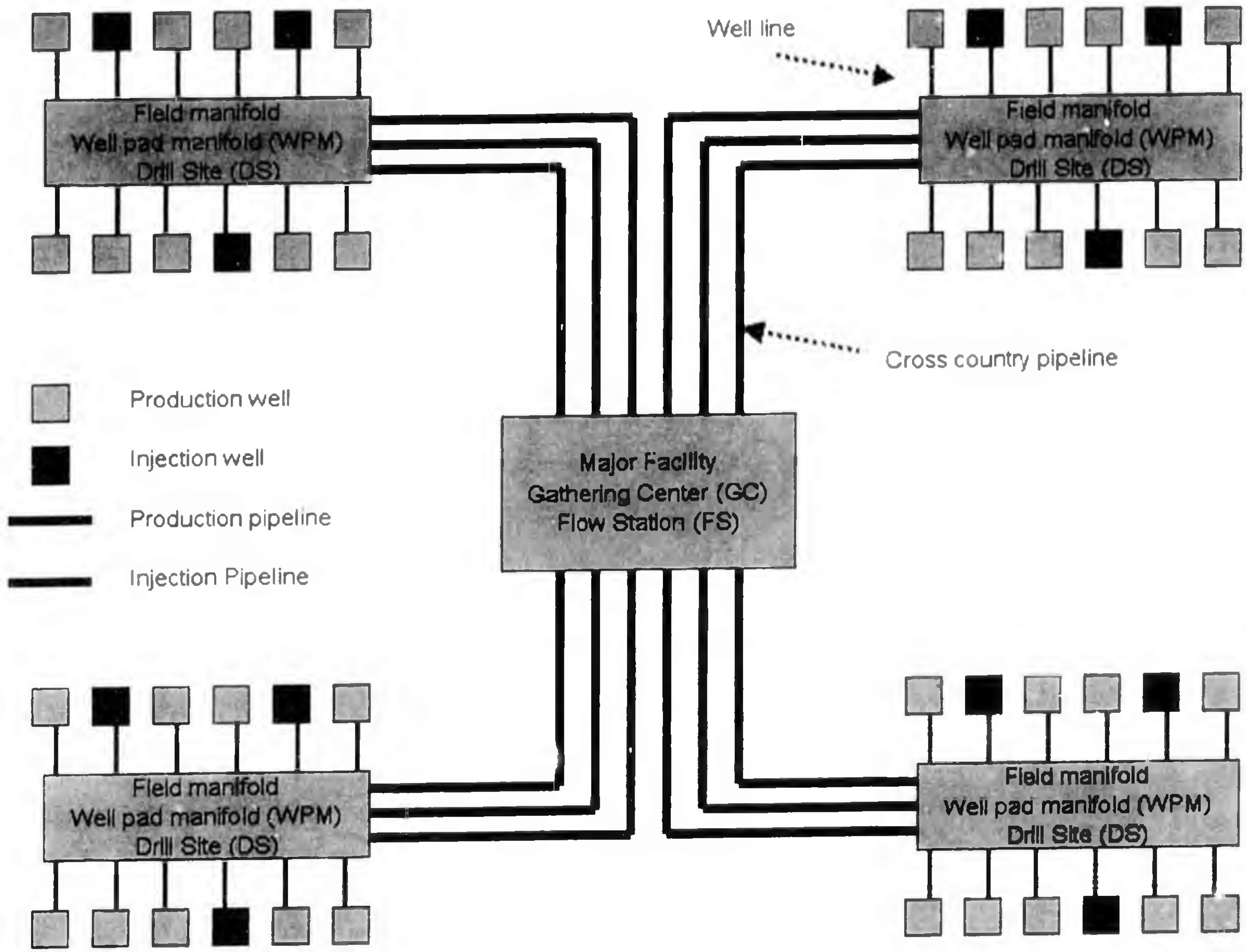
March 31st Annual Report

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

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


PRUDHOE BAY UNIT
PRODUCTION FACILITIES

Facilities Schematic



2001

bp

Annual Report to Alaska Department of Environmental Conservation

Commitment to Corrosion Monitoring

Year 2001

Prepared by

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

March 2002

Commitment to Corrosion Monitoring

Year 2001

Executive Summary

Presented herein is the second annual report that meets the commitments made by BP to the State of Alaska to provide a regular review of BP's corrosion management practices for non-common carrier pipelines on the North Slope. The contents of this report reflect the 2000 Work Plan[1] agreed jointly between BP, Phillips and ADEC, the Guide for Performance Metric Reporting[2], and the feedback from ADEC on the BP Year 2000 Commitment to Corrosion Monitoring Report[3].

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 programs, in concert, form the core of the integrity/corrosion management system 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 new inspection techniques. These innovations are only made possible by working closely with partners, major suppliers and the regulators, to bring 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 quest for improved corrosion management. Over the last decade corrosion rates have dropped 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 the good and the bad, the report highlights areas for improvement and the plans in-place to deliver this performance improvement.

Environmental protection and corrosion management are closely linked. The improvements in corrosion management have resulted in lower corrosion rates and lower risks associated with loss of containment. Opportunities to improve environmental performance exist and the expanded external corrosion inspection program for 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

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1 Appendix 2 (a) 2000 Work Plan

2 Appendix 2 (b) Guide for Performance Metric Reporting

3 http://www.bp.com/alaska

performance. Progress involves the continued refinement of the existing programs, but also, the development and implementation of new programs. The new corrosion management programs on the North Slope have resulted in a corrosion management budget increase of 20% for 2002.

In summary, the corrosion management programs have delivered a significantly improved level of corrosion management as exemplified by the factor of 10 reduction in corrosion rate in the cross-country flow lines. However, there is always room for further progress and development, as demonstrated by a 20% increase in corrosion management budget to expand/implement three new/expanded corrosion management programs on the North Slope. This process of continuous improvement will enable BP to deliver the objectives of,

- Minimizing the health, safety and environmental impacts of corrosion
- Fit-for-service infrastructure for the remainder of field life
- Ability to produce satellite accumulations and gas for sale through existing equipment and pipe-work

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 2002

Foreword

Presented herein is the second 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 the 2000 report but reflects additions resulting from the development of ɪe Guide for Performance Metric Reporting and feedback from ADEC.

In addition to the requirements setout in the Work Plan and the newly developed Guide to Performance Metric Reporting, BP has provided additional material that is intended to provide further context and help in understanding the corrosion management system.

The report is divided into 2 main parts.

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 .:cilities.

Both parts follow a similar format but the sections relating to Greater Prudhoe Bay have more detailed discussion. The bulk of the discussion is also generally applicable to the Alaska Consolidated Tear but is not repeated.

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.

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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,

Richard C Woollam
Manager CIC Group

E-mail: woollarc@bp.com
Phone: (907) 564-4437

Section A.1 2001/2002 Achievements

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

Section A.2 Annual Timetable

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

Part 1

Greater Prudhoe Bay 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 facility can be found in Appendices 3 (a) and 3 (b). Appendix 4 contains a schematic of the production facility configuration.

Section B.1 Corrosion Management System Strategic Objectives[4]

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'[5] 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.8 (a), (b) and (c) at the end of this section.

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

[5] 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.

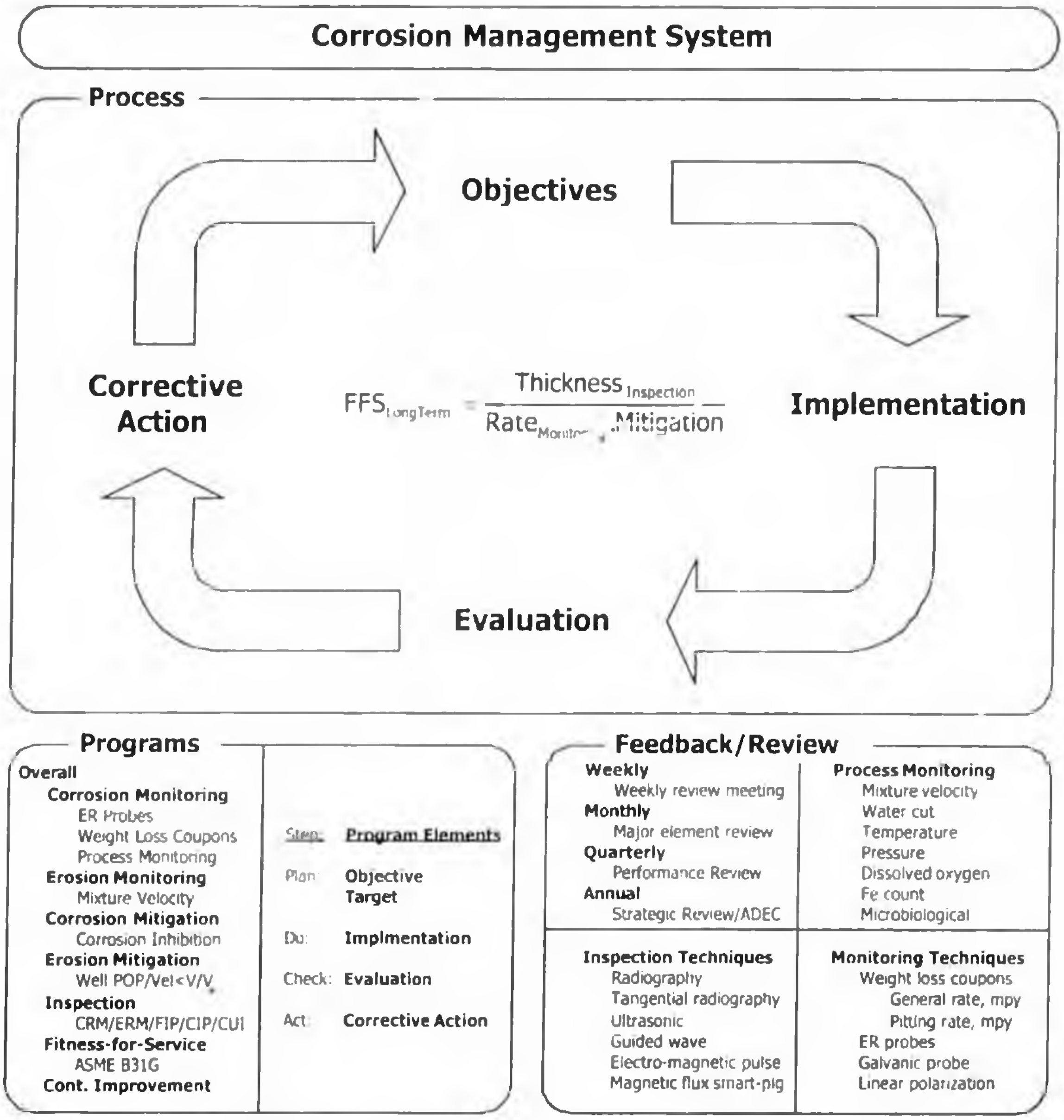

Figure B.1 Overview of the Corrosion Management Process

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 simply described in terms of the classic quality process of 'plan-do-check-act' and consists of,

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

Table B.2 Corrosion Management Process

The elements of the CMS program and process are also detailed in Table B.8 at the end of Section B.

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 particular circumstances.

Table B.9 summarizes the main categories of corrosion and process monitoring, inspection techniques and briefly summarizes relative strengths and weaknesses for different applications.

Section B.2 Corrosion Monitoring and Inspection Activity Level

Figure B.4 summarizes the level of internal inspection activity across GPB including facilities[6], and field inspections that include both cross-country flow lines and well lines. As can be seen from the table, the level of inspection activity has been consistent since 1995 at ~60,000 inspection items for the internal inspection program.

The relative effort of the program has changed over this timeframe from approximately 50/50 distribution between the facilities and the field, to the distribution seen today of approximately $^{1}/_{3}{}^{rd}$ field and $^{2}/_{3}{}^{rd}$ facilities – see Figure B.4. This represents a change in emphasis of the inspection toward the facilities program as the majority of the field corrosion control issues have been or are being addressed and are managed through the corrosion monitoring program which provides more timely feedback on the performance of the corrosion mitigation effort than is possible with inspection.

Within the field piping inspection program, the inspection activity is distributed between the well lines and the cross-country flow lines. The inspection activity for each is noted in Table B.5.

Table B.6 summarizes the level of external corrosion inspection activity for the same timeframe as the internal program. The table shows that from a level of 1500 items in 1995, the program has been ramped-up to a broadly flat level of 10-15,000 external inspection items per year from 1996 to 2001. Based on the results of the data generated in the 1996-2001 external corrosion inspection surveys, the 2002 program is expected to show a significant increase – this is discussed in greater detail in Section H. The average activity level for the program from 1996-2001 was ~13,000 items per year, the 2002 program is anticipated to be ~35,000 items or 2½ times the average for the prior five years.

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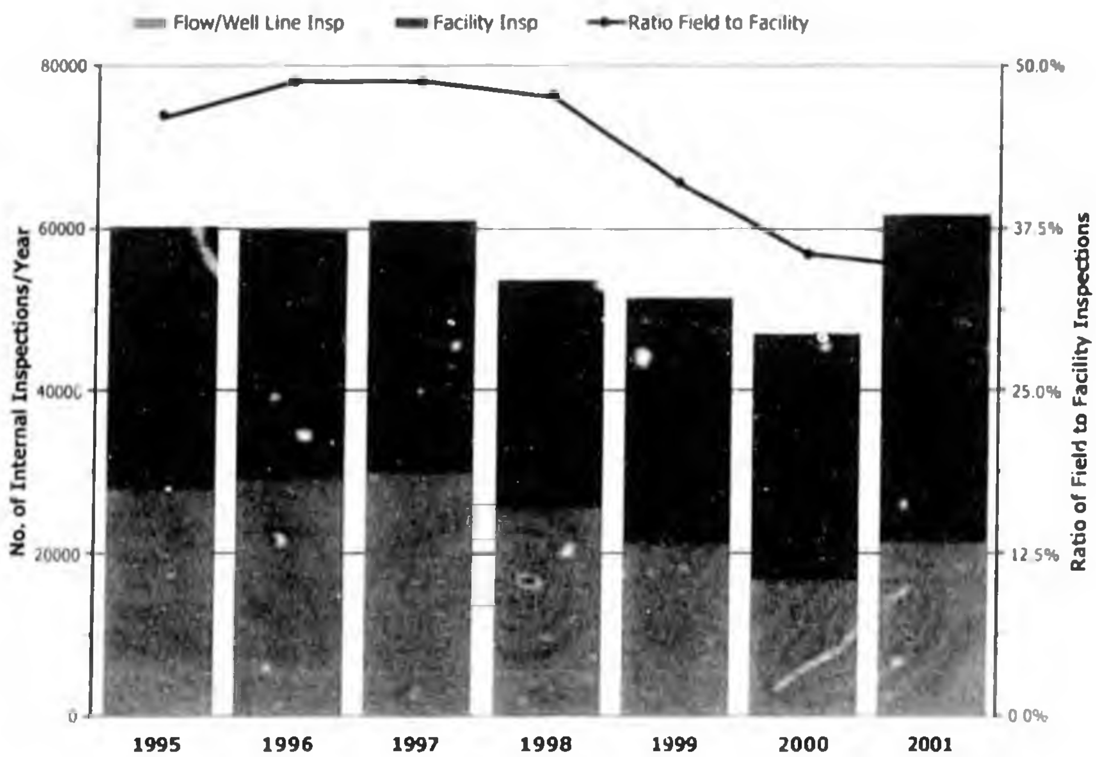
[6] In addition to Charter Work Plan, this information is supplied to provide additional context and help in understanding BP corrosion management activities



Year	1995	1996	1997	1998	1999	2000	2001
Field Piping	27715	29059	29696	25503	21033	16627	21149
Facility Piping	32451	30619	31278	28050	30417	30308	40400
Ratio Field to Facility	46%	49%	49%	48%	41%	35%	34%

Figure B.4 Breakdown of Inspection Activity Between Field and Facility Piping

Year	1995	1996	1997	1998	1999	2000	2001
Flow Line Piping	21796	20680	21522	17995	14809	9602	11369
Well Line Piping	5919	8379	8174	7508	6224	7025	9780
Ratio Flow Line to Field	79%	71%	72%	71%	70%	58%	54%

Table B.5 Internal Inspection Activity Summary

Year	1995	1996	1997	1998	1999	2000	2001	2002
WL Activity level	-	36	1682	946	2114	5283	12730	
FL Activity level	1508	11474	18009	10316	8139	5184	2675	
Overall Activity level	1508	11510	19691	11262	10253	10[illegible]64	15405	35000[1]

[1] Program scope planned for 2002

Table B.6 External Inspection Activity Summary

The plan for 2001 was to smart pig WZ-LDF, M-69, and S-69. Due to operational/scheduling difficulties with the smart pig contractor, only M-69 and S-69 produced water lines were completed. Follow-up manual inspections were conducted on numerous locations to proof the feature sizing reported by the smart pig. Additional manual follow-up inspections, which were not already part of the routine inspection program, will be included in the 2002 survey.

The weight loss coupon activity level is summarized in the Table B.7. The table shows that weight loss coupon activity level from 1995 to year-end 2001. As discussed in the 2000 report, there is a gradual reduction in the number of weight loss coupons being evaluated, which reflects the on-going effort to optimize the program to deliver maximum corrosion management information.

Table B.7 shows that the number of active locations is approximately constant. However, the pull frequency and number of coupons per pull is being optimized to gain greater value from the data obtained. In particular, 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, which was discussed in detail in the 2000 Report. The effect of this extended exposure period will be 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 2001 reflects the inventory of coupons that are installed in the system at year-end and are still to be 'processed.' The drop in 2001 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 2001 was 83 compared to 84 in 2000. The reduction of 1 represents the elimination of a duplicate on a flow line that was no longer necessary; otherwise, the program is consistent between 2000 and 2001. 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.

	Detail	1995	1996	1997	1998	1999	2000	2001
Flow Line	Locations	179	181	178	178	177	174	173
	Pulls	847	858	900	836	830	798	712
	# WLC	1569	1685	1729	1601	1650	1542	1426
	WLC/Pull	1.85	1.96	1.92	1.92	1.99	1.93	2.00
	Freq	4.73	4.74	5.06	4.70	4.69	4.59	4.12
Well Lines	Locations	1122	1248	1290	1300	1247	1236	1104
	Pulls	3389	4065	4137	3894	3650	3635	2827
	# WLC	6779	8183	8326	7837	7361	7322	5674
	WLC/Pull	2.00	2.01	2.01	2.01	2.02	2.01	2.01
	Freq	3.02	3.26	3.21	3.00	2.93	2.94	2.56
Overall	Locations	1301	1429	1468	1478	1424	1410	1277
	Pulls	4236	4923	5037	4730	4480	4433	3539
	# WLC	8348	9868	10055	9438	9011	8864	7100
	WLC/Pull	1.97	2.00	2.00	2.00	2.01	2.00	2.01
	Freq	3.26	3.45	3.43	3.20	3.15	3.14	2.77

Table B.7 Overall Weight Loss Coupon Activity Summary

Table B.8 (a) Corrosion Management System

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

Table B.8 (b) Corrosion Management System Element – Monitoring					
Program	**Plan/Objectives**	**Target**	**Implementation**	**Evaluation**	**Corrective Action**
1.1 Corrosion Monitoring	• Monitor for changes in corrosion rates	• System dependant targets • Corrosion rate to meet overall objectives	• Short term corrosion rate determination • Medium term corrosion rate determination	• ER probes • Weight loss coupon rate • Pitting Rates	• Adjust Mitigating action to achieve corrosion rate target
	• Monitor effectiveness of the Chemical Mitigation Programs	• Optimize Corrosion Inhibitor Rates and Distribution • Optimize chemical mitigation programs e.g. o oxygen scavenger o biocide o DRA o scale	• See above	• See above	• Provide feedback to o Chemical treatment o Operations o Inspection activities • Adjust Mitigation Effort • Production Chemistry
	• Monitor Changes in the Process Conditions	• Field-wide Velocity Management targets	• Weekly Review of Operational Controls by CIC Group • Operations review of fluid velocities • Velocity alarms in DCS	• Mixture Velocities, Water Cuts, and Water Rates	• Adjust production rates to meet velocity management targets
	• Corrosion mechanism changes with time	• Mitigation action in place prior to threat to mechanical integrity	• Data availability and access • Ease of 'data mining' and evaluation • Single data storage • Comprehensive data management and reporting process	• Long-Term Process Change	• Develop mitigation program • Mechanism management as part of routine business
1.2 Erosion Monitoring	• Monitor the Effectiveness of the Erosion Mitigation Programs	• V/V_e <2.5 • Max mixture Velocity and water cut matrix • Well Put-On-Production (POP) process	• Unified velocity management standard across the North Slope • Monthly compilation Of High Risk Wells • Inspection of High Risk Wells • Mixture velocity calculation in DCS	• Mixture Velocities • Inspection results	• Additional inspection and monitoring at high risk sites • Adjust Process Conditions o Well shut-in o Production reduction o Design/debottleneck facilities

Table B.8 (b) (continued) Corrosion Management System Element – Mitigation					
Program	**Plan/Objectives**	**Target**	**Implementation**	**Evaluation**	**Corrective Action**
1.3 Corrosion Mitigation	• Mitigate Corrosion Through Application of Corrosion Inhibitors	• Control Corrosion Rates to Acceptable Levels (See Overall Program Goals)	• Continuous Injection into individual wells as far upstream as possible - currently at Wellhead • Protect all equipment between injection point and separation plant	• ER Probes • WLC's • Inspection	• Corrosion Inhibitor Development • Adjust Mitigation Effort
		• Control Corrosion Rates to Acceptable Levels (See Overall Program Goals)	• Batch Treatments on a routine schedule with injection at the Wellhead	• WLC's • Inspection	• Corrosion Inhibitor Development • Adjust Mitigation Effort Through Reviews
	• Mitigate Corrosion through Operational Controls	• Operational Guidelines	• Weekly Reviews by CIC Group	• Mixture Velocities	• Adjust Process Conditions
	• Mitigate Corrosion through Maintenance Pigging	• Achieve Scheduled Frequency	• Maintenance Pigging	• Inspection • Pigging Returns	• Adjust Maintenance Pigging Schedule
1.4 Erosion Mitigation	• Mitigate Erosion Through Operational Controls and Design	• Control Erosion Rates to Acceptable Levels (See Overall Program Goals) • V/Ve < 2.5	• Well POP process • V/Ve Guidelines	• V/Ve • Inspection (ERM)	• Adjust Process Conditions

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

Table B.8 (b) (continued) Corrosion Management System Element – Inspection

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

Table B.8 (c) Monitoring Program Techniques

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

Table B.8 (c) (continued) Mitigation Program Techniques

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

Table B.8 (c) (continued) Inspection Program Techniques					
Program	**Plan/Objectives**	**Target**	**Implementation**	**Evaluation**	**Corrective Action**
1.3.1 Corrosion Rate Monitoring (CRM)	• Assessment of current corrosion mechanisms • Monitor for new corrosion mechanisms	• No measurable active corrosion - Zero increases (I's)	• CRM Program – Fixed locations on approximately bi-annual frequency	• Number of inspection increases	• Mitigation Adjustments • Repair/Replace Preventative Maintenance
1.3.2 Erosion Rate Monitoring (ERM)	• Monitor high risk wells • Assessment of current erosion locations	• Manageable rate of degradation	• ERM Program – monthly to quarterly	• Condition of Equipment • Rate of degradation	• Mitigation Adjustments • Repair/Replace Preventative Maintenance
1.3.3 Frequent Inspection Program (FIP)	• Assessment of High Corrosion Rates • Monitor locations near repair	• Fitness-for-Service	• FIP Program – monthly to bi-annual	• Condition of Equipment • Rate of degradation	• Mitigation Adjustments • Repair/Replace Preventative Maintenance
1.3.4 Comprehensive Integrity Program (CIP)	• Comprehensive Coverage of equipment • Fitness-for-Service review	• Fitness-for-Service	• CIP – Condition and rate based half-life recurring frequency • Extend coverage through new locations	• Condition of Equipment • Rate of degradation	• Mitigation Adjustments • Repair/Replace Preventative Maintenance
1.3.5 Corrosion Under Insulation (CUI)	• Comprehensive Coverage of equipment	• Inspection of Locations susceptible to CUI • Fitness For Service	• CUI – Risk based annual program • Management of location inventory through recurring examinations	• Damage Areas Detected • Analysis of occurrence	• Repair/Replace Preventative Maintenance

Table B.9 (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.9 (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	

Table B.9 (c) Inspection/Non-Destructive Examination (NDE) Techniques – Benefits and Limitations						
Method	**Technique**	**Description**	**Sensitivity**	**Accuracy**	**Freq**	**Notes/Comments**
Inspection/NDE	Radiographic Testing (RT)	Assessment of pipe wall degradation by passing gamma or x-ray radiation through a specimen and projecting an image on conventional lead screen/film. Irregular density variations of the image can indicate metal loss.	Medium	Medium	M/Q/H/Y	Utilized for detection, monitoring, and fit for service assessment of pipe metal loss in the form of mechanical, corrosion, and erosion degradation. Currently being phased out in lieu of 'greener' process of DRT – see below
	Digital Radiographic Testing (DRT)	Assessment of pipe wall degradation by passing gamma or x-ray radiation through a specimen and projecting an image on phosphor screen/imaging plate. Irregular density variations of the image can indicate metal loss.	Medium	Medium	M/Q/H/Y	Utilized for detection, monitoring, and fit for service assessment of pipe metal loss in the form of mechanical, corrosion, and erosion degradation. DRT provides additional benefits in waste reduction associated with conventional film and processing chemicals
	Tangential Radiography Testing (TRT)	Assessment of pipe wall degradation by passing gamma or x-ray radiation through insulation at the tangent of the specimen and projecting an image on screen/film, phosphor screen/imaging plate, or detector array.	High	Low	Y	Utilized for detection of corrosion under insulation (CUI). Deployed where potential moisture ingress is suspected on thermally insulated piping
	Ultrasonic Testing (UT)	Assessment of pipe wall thickness by sending/receiving ultrasound through a specimen. Echoes returning indicate remaining thickness of the specimen.	Medium	High	M/Q/H/Y	Utilized for detection, monitoring, and fit for service assessment of pipe metal loss in the form of mechanical, corrosion, and erosion degradation
	Guided Wave Ultrasonic Testing (GUT)	Volumetric assessment of pipe wall by sending/receiving ultrasound through a specimen in the form of cylinder Lamb Waves. Monitoring changes in these waves indicate potential changes in pipe thickness. Alternatively, echoes returning to the source transducer may also indicate interruptions or pitting in the pipe segment.	Low	Low	Y	Utilized for cased piping assessment where access does not support use of traditional inspection methods. The method is capable of semi-quantifying metal loss but cannot discriminate between internal and external corrosion
	Electromagnetic Pulse Testing (EMT)	Assessment of pipe wall by propagating broadband electromagnetic waves on the exterior surface of the specimen. When waves traveling down steel pipe encounter corrosion on the pipe surface, the waves are distorted. Distortions in waveform may indicate rust by-product on the surface of the steel and subsequent metal loss.	High	Low	Y	Utilized for cased piping assessment where access does not support use of traditional inspection methods. The method cannot quantify metal loss and has a tendency to report false positives results but seldom overlooks surface atmospheric corrosion

Table B.9 (c) Inspection/Non-Destructive Examination (NDE) Techniques – Benefits and Limitations						
Method	**Technique**	**Description**	**Sensitivity**	**Accuracy**	**Freq**	**Notes/Comments**
Inspection/NDE (Cont)	In-line Inspection – Smart Pig Magnetic Flux Technique (ILI)	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 comprehensive evaluation of pipeline integrity

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 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_2 corrosion, in which CO_2 from the produced fluids dissolves and dissociates in the produced water to form an acidic environment that is corrosive to carbon steel[7,8]. 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 rates 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 ≤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 Greater Prudhoe Bay is approximately a factor of 10 lower than that seen in the early 1990's. Also, the slight increase in corrosion rate reported in 2000 has been reversed and the average corrosion rate is now at or below the previous best observed in 1999.

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

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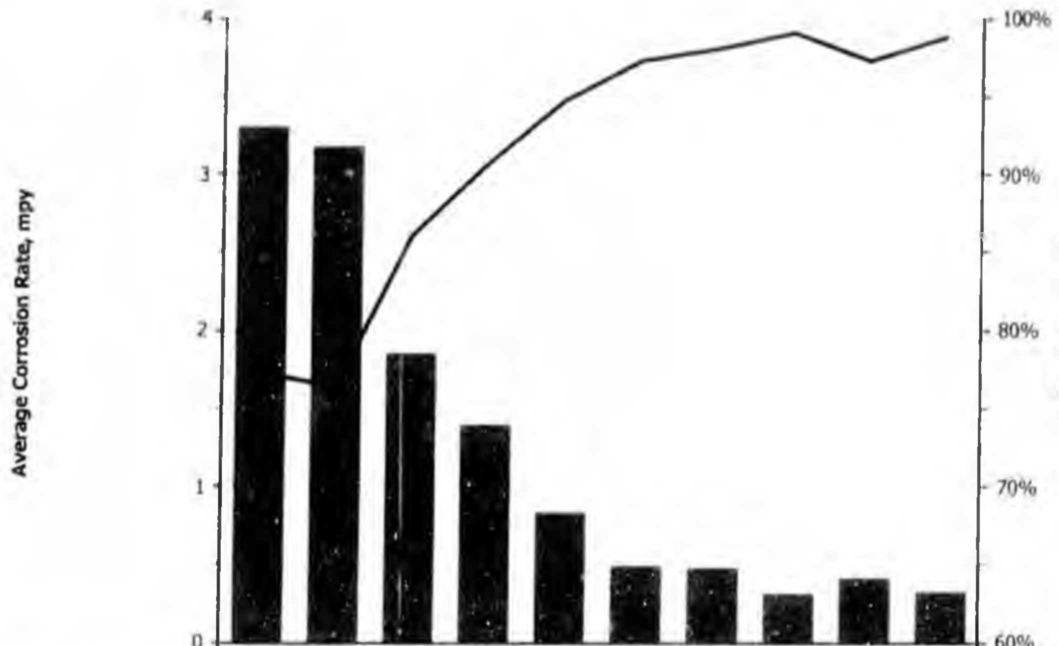
7 Corrosion Control in Petroleum Production, Harry G Byers, NACE, 1999
8 Corrosion Control in Oil and Gas Production, Treseder and Tuttle, NACE, 1998



	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Ave Rate	3.3	3.2	1.9	1.4	0.8	0.5	0.5	0.3	0.4	0.3
PC WLC<2mpy	77.3%	76.4%	86.0%	90.6%	94.7%	97.3%	98.0%	99.1%	97.3%	98.8%

Figure C.1 Flow Line Corrosion Rate Trend 1992 to 2001

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 expected, there is a very strong correlation between these two metrics. The percentage less than 2 mpy target has the advantage of highlighting non-conformances that might otherwise be lost in the calculation of the average. Equally, 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.

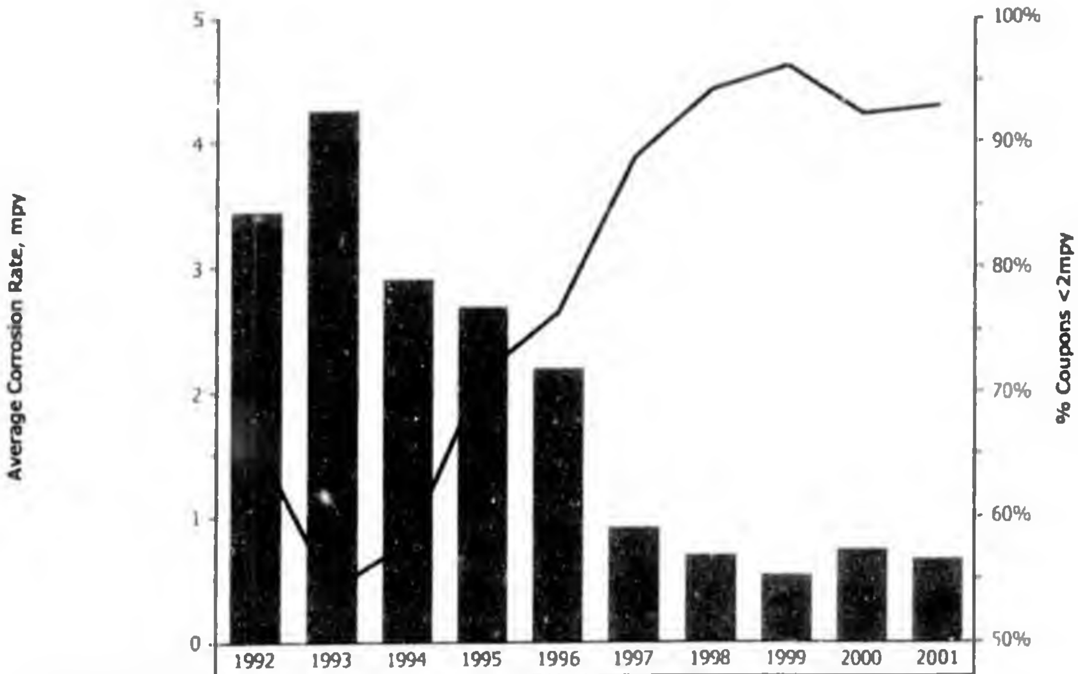
Figure C.3 shows the same data set for the well lines in oil service. The trends are very similar to those seen in the cross-country flow lines. The well lines show a long-term improvement in the level of control from early 1990's to present day. In the short term there is a reversal in the trend of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

The long term corrosion control improvement in the well lines is of the same order 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 2001.

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

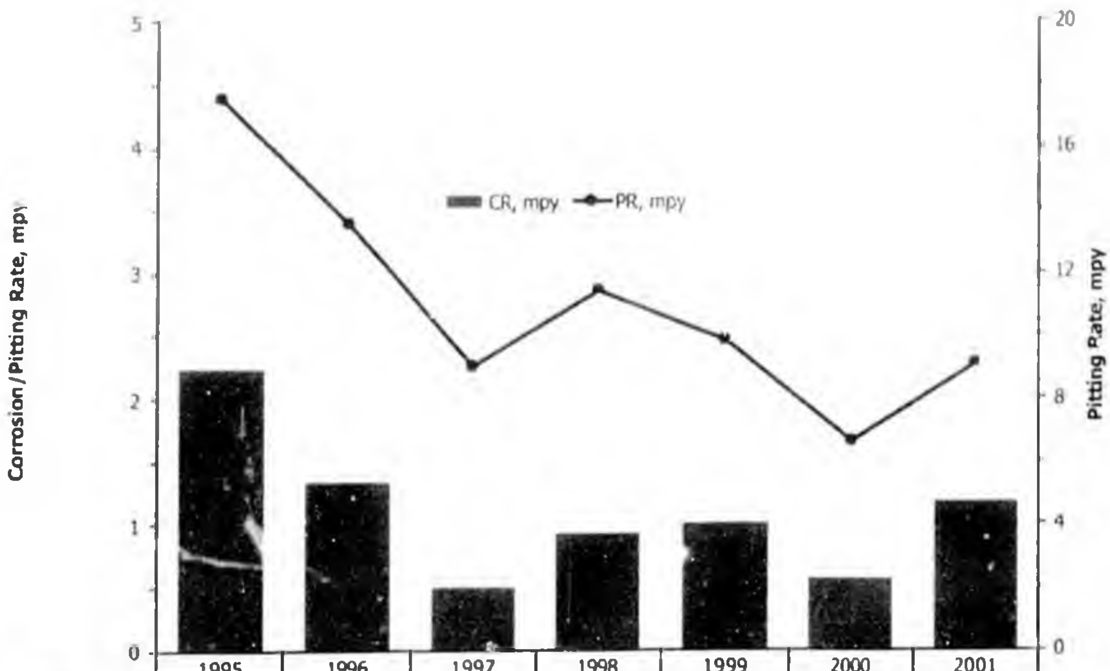
Table B.8 (c) Monitoring Program Techniques

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



	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Ave Rate	3.5	4.3	2.9	2.7	2.2	0.9	0.7	0.5	0.7	0.7
PC WLC<2mpy	66.0%	54.3%	57.9%	71.5%	76.4%	88.8%	94.2%	96.1%	92.3%	93.0%

Figure C.3 Well Line OIL Service Corrosion Rate Trend 1992 to 2001



	1995	1996	1997	1998	1999	2000	2001
CR, mpy	2.2	1.3	0.5	0.9	1.0	0.6	1.2
PR, mpy	17.6	13.6	9.0	11.5	9.9	6.6	9.1

Figure C.4 Pitting Rate and Corrosion Rates for the PW System

As a result of this increase, a corrosion mitigation program specific to the PW system is in the process of being implemented. PW corrosion inhibitor(s) were tested on the west side of Greater Prudhoe Bay in 1999 and again in 2000, with the trial continuing into 2001 with two successful candidates identified. Based on this initial PW inhibitor test work from GC's 1, 2 and 3, additional budget funding has been secured from the GPB partners and the program is being expanded in 2002.

Section C.3 Seawater Injection System

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

- Dissolved oxygen (DO) corrosion which is mitigated through processing the seawater to remove oxygen, initially mechanically by vacuum stripping and then chemically with an oxygen scavenger
- Microbiological corrosion, due to the action of sulphate reducing bacteria, which is mitigated with a batch treatment of biocide after processing to remove O_2 and prior to transfer to the main cross country flow lines

As with the PW system, the SW system data is presented as an aggregate of both the well and flow line data. This is because the system is a single source that is treated uniformly.

Figure C.5 shows the corrosion rates and pitting rates in the SW system which both show a rising trend. As a consequence and as discussed at the 2nd 2001 Meet and Confer session with ADEC, a series of corrective actions have been put in-place in 2001. The corrective actions are designed to reverse the trend and bring the corrosion rates down to less than or equal to the target of 2 mpy.

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. The current problems in the seawater system have been linked primarily to the level of oxygen control. The following targets, controls and corrective actions have been taken to reduce the residual oxygen in the seawater,

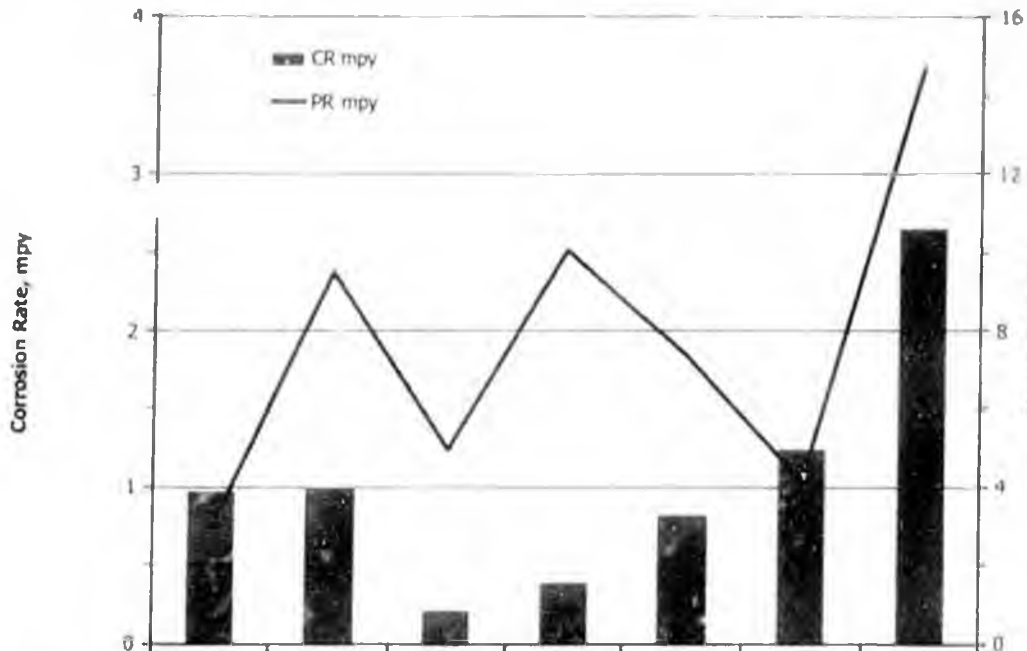
- Residual dissolved oxygen (DO) target set to < 20 ppb (parts per billion) after vacuum deaeration and chemical oxygen scavenging
- Upgrade dissolved oxygen meter and increase preventative maintenance frequency
- Antifoam added to the vacuum tower to improve performance

- Catalyzed oxygen scavenger to improve performance at low O_2 concentrations and lower temperatures
- Plant repair and maintenance in preparation for SW volume ramp-up planned for 2002

Although microbiological corrosion is not believed to be a significant contributor to the current corrosion problems found in the SW system, the following actions have been taken to improve the microbiological control of the seawater system,

- Maintenance pigging frequency has been doubled along with an improved disc/brush pig design
- Biocide program has been improved utilizing a more effective glutaraldehyde/quaternary amine blend of biocide

In addition, the corrosion-monitoring program in the main seawater supply line has been changed to increase the pull frequency of the weight loss coupons from annual to quarterly effective end 2001.



	1995	1996	1997	1998	1999	2000	2001
CR mpy	1.0	1.0	0.2	0.4	0.8	1.2	2.7
PR mpy	2.9	9.5	5.0	10.0	7.4	4.1	14.7

Figure C.5 Pitting Rate and Corrosion Rates for the SW System

Section C.4 1995 to Date Summary

The 2001 and 6-year history for corrosion control performance in the major systems at GPB is summarized in the following tables and figures. Table C.6

summarizes the definitions for equipment types and services categories in the remainder of this section.

	Service Description
OIL	Three phase production – oil, water and gas
PO	Processed oil – separated crude/hydrocarbon for export to PS-1
SW	Seawater service
PW	Produced water service
WTR	Combined PW and SW data – primarily for inspection
	Equipment Description
FL	Cross country flow lines between well pad and separation plant
WL	Well lines between well head and well pad manifold building
FL+WL	Aggregate data for both WL and FL equipment types

Table C.6 Summary definition for Equipment and Service

Table C.7 and Figure C.8 show the percentage of weight loss coupons that meet or exceed the corrosion rate target of 2 mpy for the corrosion management program.

Equip	Service	Metric	1995	1996	1997	1998	1999	2000	2001
FL	OIL	WLC	1441	1573	1612	1506	1541	1460	1190
FL	OIL	Ave Rate	1.4	0.8	0.5	0.5	0.3	0.4	0.3
FL	OIL	%<2mpy	91%	95%	97%	98%	99%	97%	99%
WL	OIL	WLC	5506	6862	7064	6659	6372	6407	3994
WL	OIL	Ave Rate	2.7	2.2	0.9	0.7	0.5	0.7	0.7
WL	OIL	%<2mpy	71.50%	76.40%	88.80%	94.20%	96.10%	92.30%	93.00%
FL	PO	WLC	28	42	50	38	40	42	24
FL	PO	Ave Rate	0.11	0.18	0.11	0.14	0.12	0.16	0.07
FL	PO	%<2mpy	100%	100%	100%	100%	100%	100%	100%
WL + FL	PW	WLC	715	734	711	629	475	409	288
WL + FL	PW	Ave Rate	2.23	1.34	0.51	0.93	1.01	0.56	1.17
WL + FL	PW	%<2mpy	78%	91%	98%	95%	90%	94%	88%
WL + FL	SW	WLC	72	80	80	80	76	76	50
WL + FL	SW	Ave Rate	0.98	1	0.21	0.4	0.83	1.24	2.65
WL + FL	SW	%<2mpy	92%	90%	96%	95%	95%	87%	56%

Table C.7 Summary by Equipment and Service for Corrosion Coupon Data

In summary,

Flow Line Oil Service - For the cross-country flow lines in 3-phase production service, 99% of these lines met or beat the corrosion control target of 2 mpy in 2001. This continues a trend from 1995 of improving corrosion control in this system with the average corrosion rate falling from 1.4 mpy in 1995 to 0.3 mpy in 2001.

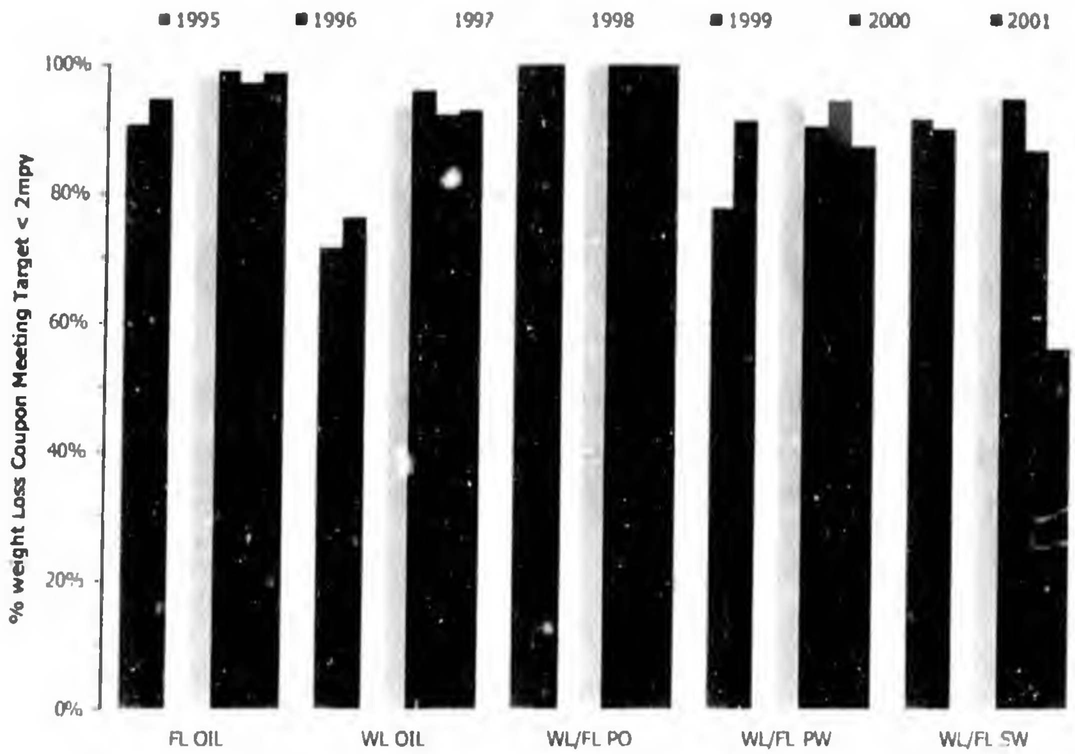


Figure C.8 Summary Equipment and Service Corrosion Coupons Meeting Target

Well Line Oil Service - As with the flow lines in oil service, corrosion control has improved significantly since 1995 with >94% of the well lines meeting or beating the corrosion control target. The average corrosion rate has been markedly reduced from 2.7 mpy in 1995 to 0.6 mpy in 2001.

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 2001. However, as reported in Section F, there has been a number of repairs associated with deadlegs on this system.

All Lines Produced Water Service - The general corrosion rates in the Produced Water system have improved since 1995 with 90% of the these lines showing corrosion rates of less than 2 mpy. However, corrosion and pitting rates are increasing. As a consequence a corrosion inhibition program specifically designed to address the PW system corrosion is under development.

All Lines Seawater Service - All the lines in seawater service have seen a reduction in the level of corrosion control with only 56% of the lines meeting or beating the corrosion rate target of 2 mpy. The average corrosion rate for this system has been increasing. As a result a set of specific corrective actions has been implemented in 2001, 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 Greater Prudhoe Bay, Figure C.9 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 2001 and that the number of coupons meeting or beating the 2 mpy target has increased from 76% in 1995 to 95% in 2001.

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.

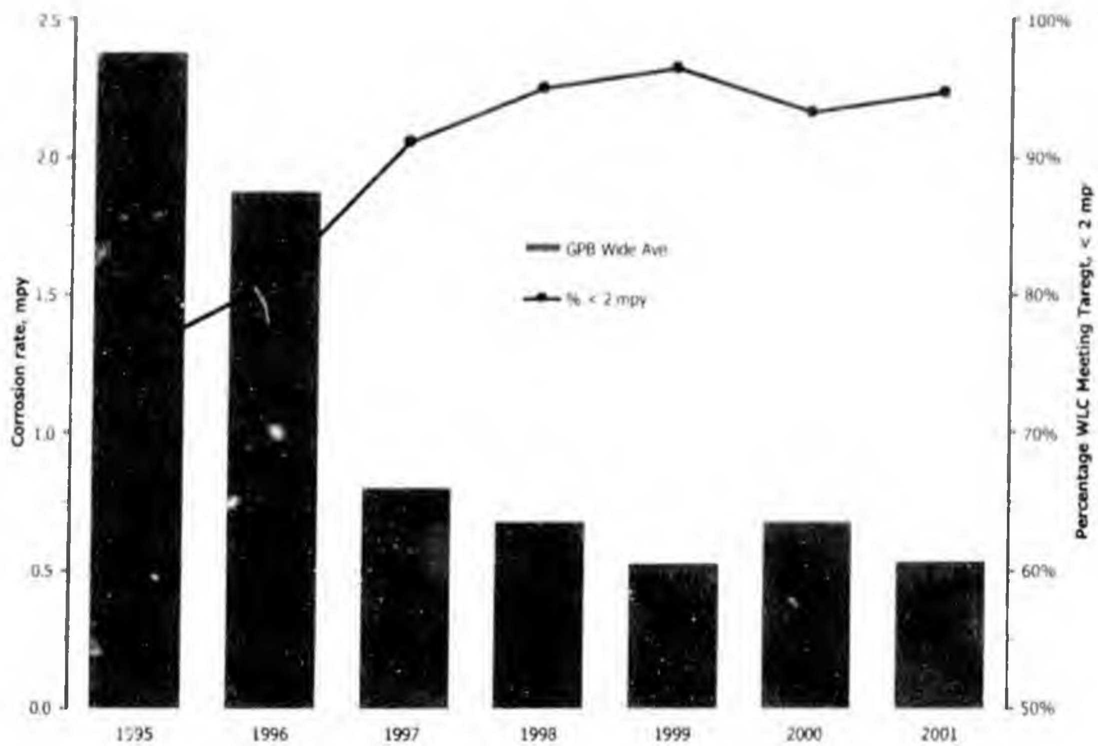


Figure C.9 GPB Aggregate Performance

Section C.5 Electrical Resistance Probes

Electrical resistance probes are extremely sensitive to process changes, which makes them highly susceptible to reading erroneously high corrosion rates, which are not a result of changes in the system corrosion rate or changes in the corrosivity of system fluids.

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

The remaining 187 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

Section C.6 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 task 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 simulated GPB conditions. 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 test chemical. 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.

The test process is summarized in Table D.1

As an example, the ER probe results from a typical cross-country flowline test are shown in Figure D.3 and are summarized in Table D.2. 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 test 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 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.
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 Summary Description of the Typical Test Program Components