Annual Report to Alaska Department of Environmental Conservation

Commitment to Corrosion Monitoring

Year 2000

BP Exploration (Alaska) Inc.

Prepared by

Corrosion, Inspection & Chemicals Team, BPX(A)

March 2001

Executive Summary

The attached report meets the commitment made by BP Amoco to the State of Alaska, to provide the Alaska Department of Environmental Conservation with an annual report on its corrosion monitoring programs. The contents of this report reflect the Work Plan agreed jointly between BPX(A), Phillips and ADEC. As such, it summarizes the year 2000 corrosion management programs for cross country, non-common carrier pipelines operated by BPX(A). Background information is provided for previous years to enable the 2000 results to be viewed in context.

The report provides data and discussion relating to the corrosion control, monitoring and inspection programs that together form the core of the integrity management system. Our corporate goals are no accidents, no harm to people and no damage to the environment. We believe that the programs reflect the core values of BP: innovative, performance driven, environmental leadership and progressive.

Innovation is evident in several areas, from the development of more effective corrosion inhibitors to new inspection techniques for buried pipelines. These innovations are only made possible by working closely with our partners, major suppliers, competitors and regulators.

Performance management and the drive for improved performance are key to all aspects of the corrosion management programs. The report demonstrates a trend of continual improvement in integrity management over the past six years. It is out intent to report openly, good or bad and the report also highlights areas for improvement, along with our plans to address these areas.

Corrosion management and environmental protection are closely related and the progress made in corrosion management has resulted in lower corrosion rates and consequently lower risks associated with loss of containment of pipelines. A new inspection technique, digital radiography, has also been implemented, resulting in a reduction in the volumes of hazardous waste generated while improving productivity.

The corrosion management programs are also progressive, constantly evolving both to changing field conditions and in pursuit of continuous improvement. The programs are the result of many years of development and are seen as “Best Available Technology” within BP. BPX(A) is committed to continuing this improvement. To this end, the level of company staff in the Corrosion, Inspection and Chemical department has recently increased and is now greater than the combined totals of the relevant BPX(A) and ARCO teams prior to single operatorship of Prudhoe Bay.

In summary, we believe that the corrosion management programs are set to deliver long term integrity of the existing infrastructure on the North Slope, enabling BPX(A) to achieve its goals of expanding satellite production and the bridge to gas sales. We look forward to a healthy relationship with our stakeholders by consultation, open reporting and striving to raise the standards of our industry.

FOREWORD

This report is divided into 2 main parts.

Part 1 contains information with regard to the BP fields within the Greater Prudhoe Bay Business Unit.

Part 2 contains information with regard to the BP fields within the Alaska Consolidated Team Business Unit.

Both parts follow a similar format but the sections relating to Greater Prudhoe Bay have more in the way of discussion. This discussion is also generally applicable to the Alaska Consolidated Team section but is not repeated.

There are also 4 appendices that apply to both parts of the main report.

Contents

Section A: Charter Agreement Corrosion Related Commitments

The BP contact for all corrosion matters relating to the Charter Agreement is Richard Woollam, Manager CIC Department.

Milestones/Timing

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

Item Complete.

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

Item Complete.

11/15/00 - Final endorsement of Work Plan

Item Complete.

3/31/01 - 1st Annual report due

Item Complete.

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)

PART 1

Greater Prudhoe Bay

Business Unit

Section B - GPB
Corrosion Monitoring Activities

This Section summarizes the corrosion monitoring activities at Greater Prudhoe Bay. It incorporates Prudhoe Bay, Pt McIntyre, Lisburne & Niakuk. 'Corrosion Monitoring' is taken to mean any activities that monitor corrosion and therefore inspection data are also included. The corrosion monitoring data are used by the CIC department to manage the corrosion control programs.

Each type of data has its benefits and limitations and the data from corrosion probes, coupons and inspection are therefore complimentary and cannot be viewed in isolation. For example, corrosion probe data is the most sensitive to changes in the corrosivity of fluids but the corrosion rates measured correlate poorly to actual pipewall corrosion rates. Corrosion probes are also prone to generating false data if the probe element is damaged.

Corrosion coupons provide more reliable data that correlates better with pipewall corrosion rates but the relatively long exposure periods (typically 3 to 4 months) mean that the coupons provide limited benefit in determining short term effects, such as flow regime changes on corrosion rates. Inspection data is the most accurate in that it is a direct measure of pipewall corrosion but, like coupon data it is only generated every few months.

Inspection techniques (primarily UT & RT) are relatively insensitive and pipewall thickness changes of less than 10 mils are hard to detect reliably.

The corrosion monitoring program therefore generates data from corrosion probes, coupons and inspection and the relative strengths and weaknesses of these monitoring techniques together with process data allow a clear picture to be formed of corrosion activity in the equipment.

The data summarized in this Report is generated throughout the year and new data is reviewed weekly. Each type of data has a corresponding target limit, typically 2 mpy for corrosion coupons, zero detectable corrosion via inspection and between 0.5 and 10 mpy for corrosion probes. The latter is based on historical norms for each location and the wide range of target values reflects the poor correlation of corrosion probes to pipewall corrosion rates. If one or more of these target values is exceeded, the cause is investigated and, if appropriate, mitigating action is taken. In addition to the weekly reviews of current data, more in depth reviews are made at the end of each calendar quarter, looking for broader changes or trends.

Tables 1 and 2 summarize the inspection program for well lines and cross country pipelines in 2000. The data relating to miles of piping are approximate, based on typical lengths and are provided as background information. The terms 'internal' and 'external' inspections are used to describe the purpose of the inspection, i.e. looking for internal or external corrosion, not the inspection method. With the exception of smart pigging, all of these inspections were performed external to the pipelines. These definitions are consistent throughout this Report.

Table 1: Summary of Well Pad / Drill Site Pipelines

Service	No. of Lines	Miles of Piping	No. of Internal Inspections	No. of External Inspections
Gas Injection	35	3	0	72
Miscible Injection	107	18	12	389
3 Phase Production	1088	266	6956	3192
Gas Lift	675	160	15	2537
PW/SW/WAG Inj	180	42	2988	1442

Table 2: Summary of Cross Country Pipelines

Service	No. of Lines	Miles of Piping	No. of Internal Inspections	No. of External Inspections
Fuel Gas	7	22	0	0
Gas Transport	12	38	3	0
Gas Injection	7	10	0	35
Gas Lift Supply	40	121	7	101
Miscible Injection	27	61	23	1,177
NGL	4	11	0	0
Nitrogen Storage	1	12	0	0
3 Phase Production	153	333	9,361	3,759
Export Oil	2	13	239	17
PW/SW	33	103	816	553

Table 3 summarizes the smart (intelligent) pig inspections performed since 1995. The equipment is all heritage BP operated and the reason for this is covered in Section E.3.

Table 3: Smart pig inspections

	Tool diameter(s)	No. of Lines	Lines Inspected
1995	14", 16", 20", 24"	14	A-74, D-36, E-36, F-74, H-36, J-74, K-74, M-69, M-74, N-74, S-69, U-384, X-74, XF-21
1996	24"	1	GLT-24
1997	24"	6	B-36, S-36, W-74, X-74, Y-36/74, Z-74
1998	12", 34"	3	OT, U-69, Y-69
1999	24"	6	A-74, E-36, F-74, J-74, M-74, N-74
2000	16", 24"	5	D-36, H-74, K-74, U-384, XF-21

Table 4 contains the numbers of corrosion coupons used, divided by service. The 3 phase production system is sub-divided in to cross country pipelines and well lines. For the other services, the total includes both cross country and well lines. Data for 1995 to 1999 is provided as background information.

Table 4: Number of Corrosion Monitoring Coupons

Year	Cross country	Well Lines	PW	SW	GL & Inj	Total
1995	1,324	6,195	1,125	750	4	9,536
1996	1,489	7,676	1,140	744	10	11,193
1997	1,467	7,784	1,207	968	10	11,574
1998	1,490	7,582	1,138	732	10	11,094
1999	1,425	6,875	1,010	782	10	10,238
2000	1,371	5,855	816	782	10	8,970

The great majority of coupons are installed as pairs, therefore the number of pulls (the action of removing coupons from a live system) is approximately half the numbers shown in Table 4. Note: some systems, such as cross country PW lines, use disc coupons and these are installed singly. Pull frequency is typically 3 months (cross country production lines) to 4 months (production wellheads).

The reduction in the number of produced water coupons in 2000 is a reflection of their relatively low accuracy in that system when installed for short periods. To improve the value of coupons in the PW system, their installation period was doubled in 2000 to better simulate pipewall conditions e.g. from 3 months to 6 months for cross country lines. The number of locations where coupons are installed in the PW system has not been reduced.

The reduction in the number of coupons in production well lines in 2000 is a result of a review of the coupon program. The data from these coupons are used to optimize the chemical program but a number of coupons are installed upstream of the chemical injection location and therefore provided no meaningful data. These locations have been removed from the coupon pull schedule. Likewise, some wells are on long term shut in and these have also been removed from the pull schedule.

The small number of gas lift and gas injection coupons reflects the non-corrosive nature of the fluids. This is dry gas and it is planned to remove these from this coupon program in 2001.

Table 5 summarizes the number of corrosion monitoring probe locations. Unlike corrosion coupons, which are replaced at a fixed frequency, probes are replaced as required to maintain data quality. Although data are not presented for earlier years, the number of probe locations has been relatively constant since 1995.

Table 5: Corrosion Monitoring Probes

Location	No. of Probes
Well lines	78
Cross Country pipelines	84

Section C - GPB
Coupon and Probe Corrosion Rates

This Section includes metrics which depict corrosion rates from coupons. As mentioned in Section B, corrosion coupons generally provide reliable data that correlates well with pipewall corrosion rates. Coupons therefore form a key part of the corrosion management programs. For coupon data to be meaningful, the local environment around the coupon must approximate that at the pipewall. In the production system this is achieved by using 2 strip coupons per location, which intrude in to the flow stream at the bottom of the pipeline, to ensure they contact the water phase. Analysis of coupon and inspection data over many years has shown that such coupons provide a good measure of corrosion activity of the pipelines in the production system.

Corrosion coupons are not as a good a measure of pipewall corrosion in the produced water system as they are in the production system. This is believed to be due to the nature of the corrosion, which in the PW system is related to the presence of solids at the pipewall. Coupons that are installed for relatively short time periods do not build up the same layer of solids and therefore do not experience the same type of corrosion as the nearby pipewall. In an effort to overcome this, the exposure period of coupons in the PW system was doubled in 2000 to allow time for the layer of solids to become established, although it is too early to tell if this has improved the data quality.

Corrosion coupons have a target rate of 2 mpy and this has been shown to correlate to very low pipewall corrosion rates. If a coupon exceeds 2 mpy, the possible causes are investigated and, if appropriate, mitigating action is taken. This may mean a change in production rates or an increase in corrosion inhibitor dose rates.

Figure 1 summarizes the corrosion coupon data for the corrosive services, 3 phase production, seawater and produced water. The data are expressed as a percentage less than 2 mpy general corrosion rate. Data from 1995-1999 are provided as background information, together with 2000. The 3 phase production system is sub-divided in to well lines and cross country pipelines. The dramatic improvement in 1995-7 for the well lines reflects the installation of wellhead continuous corrosion inhibitor injection.

For the three data sets relating to produced fluids (well lines, cross country pipelines, and produced water) 2000 showed the first reversal in a trend of continuous improvement in corrosion control since 1995. This trend of continuous improvement with a reversal in 2000 is also seen in Figures 4 and 6. It is believed that there are separate reasons for the reduced corrosion control in the 3 classes of equipment (well lines, cross country pipelines, and produced water).

For well lines it is believed that a lessening in the ability to achieve target corrosion inhibitor injection rates at the well head is the cause. This is covered in more detail in Section E.2 but has resulted in a wide ranging but moderate increase in corrosion rates of well lines. This is not assumed to be the case for the cross country pipelines as they receive the flow from numerous wells and therefore variations in chemical allocations to individual wells are smoothed out.

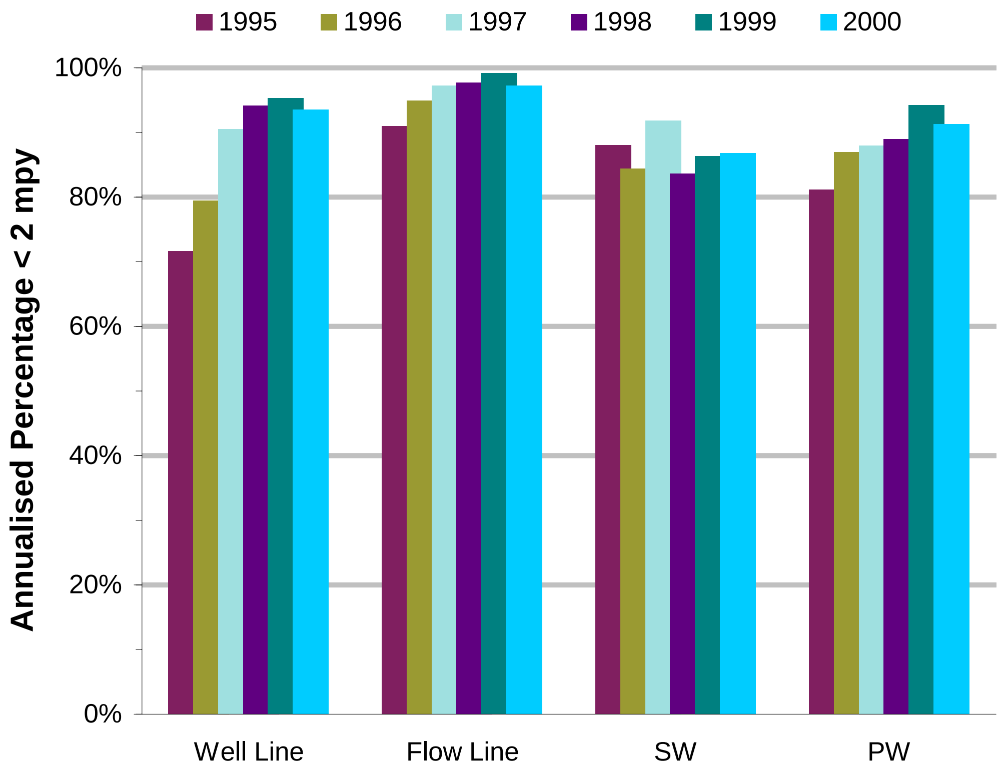


Figure 1: Summary of corrosion coupon data 1995 to 2000

Unlike well lines, the reduction in corrosion control of cross country pipelines is not wide ranging and Figures 5 and 6 demonstrate that overall, the trend of continuous improvement in corrosion control was maintained. The reduction in corrosion control for this equipment was highly specific, in particular the corrosion rate in N-74 (24" pipeline from N-pad to GC-2) increased markedly during 2000. In response, the target concentration of corrosion inhibitor was increased in several steps from 100 ppm to 300 ppm. Also, an unsuccessful chemical trial at drill site 14 resulted in elevated corrosion rates.

The reasons for the reduction in corrosion of the produced water system are somewhat different again. As mentioned earlier, the correlation between data from corrosion coupons and pipewall corrosion in the PW system is not as strong as it is in the production system. In an attempt to improve this correlation, the exposure period of coupons in the PW system was doubled in 2000, to better simulate the under-deposit corrosion conditions present on the pipewall. It may be that this change has resulted in an overall increase in the corrosion rate experienced by the corrosion coupons, although it is too early to state definitively.

There has also been an on-going study to identify a cost effective method of corrosion control in the PW system, with a range of chemicals being field tested at GC-2 and GC-3 since 1998. One chemical that was tested at GC-2 and GC-3 in 1999 was successful and it has since remained in use at GC-2. However, a subsequent test chemical used at GC-3 since 1Q 2000 appears to be less successful and may have contributed to the observed decrease in corrosion control, although the trial will not be completed until April 2001.

The seawater system differs from the PW and produced crude systems in the sense that no inhibitors are used to control corrosion. The very low CO_2 and H_2S levels in seawater together with a neutral pH and low water temperatures enable operation without chemical inhibition. Corrosion control in the SW system is mainly achieved through dissolved oxygen control, regular biocide treatments and maintenance pigging. Coupon corrosion rates have varied somewhat over the years due to varying levels of success in biofouling and dissolved oxygen control. Biocide treatments have been improved in recent years by moving biocide injection further upstream and further by the conversion to a more effective biocide product. The current focus is on improving dissolved oxygen control with the help of new dissolved oxygen monitoring system, which will be installed this spring.

Metrics relating to corrosion probes are hard to define. As corrosion probes are interrogated semi-continuously, they may have several different corrosion rates in a given day and therefore summarizing the range of corrosion rates over a year is meaningless. Instead, an example of how corrosion probe data are used is shown in Section D – Chemical Optimization Activities. Generally, corrosion probes have target corrosion rates based on historical norms for that location, such as 0.5, 2, or 10 mpy. Probes exceeding these limits are triggers for further investigation. However, relative changes in corrosion rates from probes are more important than absolute rates and therefore, probe data are analyzed for trends as well as absolute rate.

Section D – GPB
Chemical Optimization Activities

Chemical optimization is an on-going task and encompasses a broad range of activities, from allocating extra chemical to a particular well for corrosion control, to developing new corrosion inhibitors for improved cost performance. The following are some examples of how chemical usage is optimized.

The development of new corrosion inhibitors starts in the R&D laboratories of the chemical suppliers, with promising products being tested under field conditions using dedicated test facilities at GPB. Typically 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. If this is successful, the product is considered for a large scale test, which involves converting between 1 and 3 well pads to the test product for 90 days and using 20 to 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. It also enables the effect of the product on the oil separation and stabilization process to be tested.

The chemical development work has been highly successful, with ten new products being developed for use in the continuous wellhead inhibition program since 1996 with significant improvements in cost performance over that time frame.

Table 6 summarizes the changes in corrosion inhibitor products since 1996. The table does not include test products. It also does not include summer versions, which are simply more concentrated versions of the products listed.

Table 6: Corrosion inhibitors used across Greater Prudhoe Bay

Supplier	Chemical	1996	1997	1998	1999	2000
Nalco Exxon	EC1110A					
Nalco Exxon	EC1259					
Nalco Exxon	97VD129					
Nalco Exxon	98VD118					
Nalco Exxon	99VD049					
Champion	RU223					
Champion	RU210					
Champion	RU258					
Champion	RU-271					
Champion	126A					
Champion	RU256 *					

Note: RU256 is used for batch treatment of pipelines, whereas the other chemicals are used for continuous application.

Another measure of chemical optimization is the amount of corrosion inhibitor used, relative to the volume of water produced from the reservoir. Table 7 summarizes the annual water production, corrosion inhibitor volumes, and concentrations from 1996 to 2000. The inhibitor volumes are expressed as a ‘winter product equivalent’, i.e. the lower volumes of highly concentrated chemical used during the summer are not reflected in these data.

The concentration of inhibitor in the water phase therefore provides a relative measure of the volume of chemical used to control corrosion. However, such data can be misleading as the types of corrosion inhibitors used vary from year to year, as shown in Table 6. As more effective chemicals are developed, lower volumes and concentrations should be required. There has also been a shift from batch treatments to continuous injection of chemical at the well head. The latter is more efficient in terms of protection achieved per gallon of chemical and therefore lower chemical usage would be expected

These effects are counteracted by the increasing water cuts associated with an ageing oil field and increased flow velocities, due to increased gas handling capacity. These changes increase the amount of chemical required to control corrosion. As Table 7 shows, the water volumes produced and the volume of corrosion inhibitors used has varied slightly over the last 5 years. The ultimate measure of whether enough corrosion inhibitor is used can only be determined by consideration of other factors such as corrosion monitoring data and/or the amount of active corrosion detected by the inspection program.

Table 7: Water production, corrosion inhibitor usage and concentration

Year	Water production (million barrels)	Inhibitor Usage (million gallons)	Concentration (ppm)
1996	458.4	2.05	106
1997	456.3	2.21	115
1998	426.0	2.53	141
1999	415.7	2.28	130
2000	436.3	2.73	149

The metrics above deal with chemical usage at the field level but a lot of the chemical optimization activity concentrates on getting the correct amount of corrosion inhibitor to each piece of equipment. The inhibitor requirement is driven by factors such as water cut, water volume, flow regime, and condition of the equipment and varies over a wide range, from a few parts per million (ppm) to several hundred ppm. By way of example, Figure 2 shows corrosion probe data for a cross country pipeline during a chemical test. Soon after the test started, the corrosion rate increased and the concentration of inhibitor was increased to reduce the corrosion rate – see highlighted area. The required increase in dose rate made the test chemical uneconomic and therefore the test was halted and the incumbent chemical was re-used at the original target dose rate. This type of optimization is done in response to probe, coupon, and inspection data, while testing new chemicals, as well as during normal operations as the amount of corrosion inhibitor required changes due to production variables such as water cut, water volume, or flow rates.

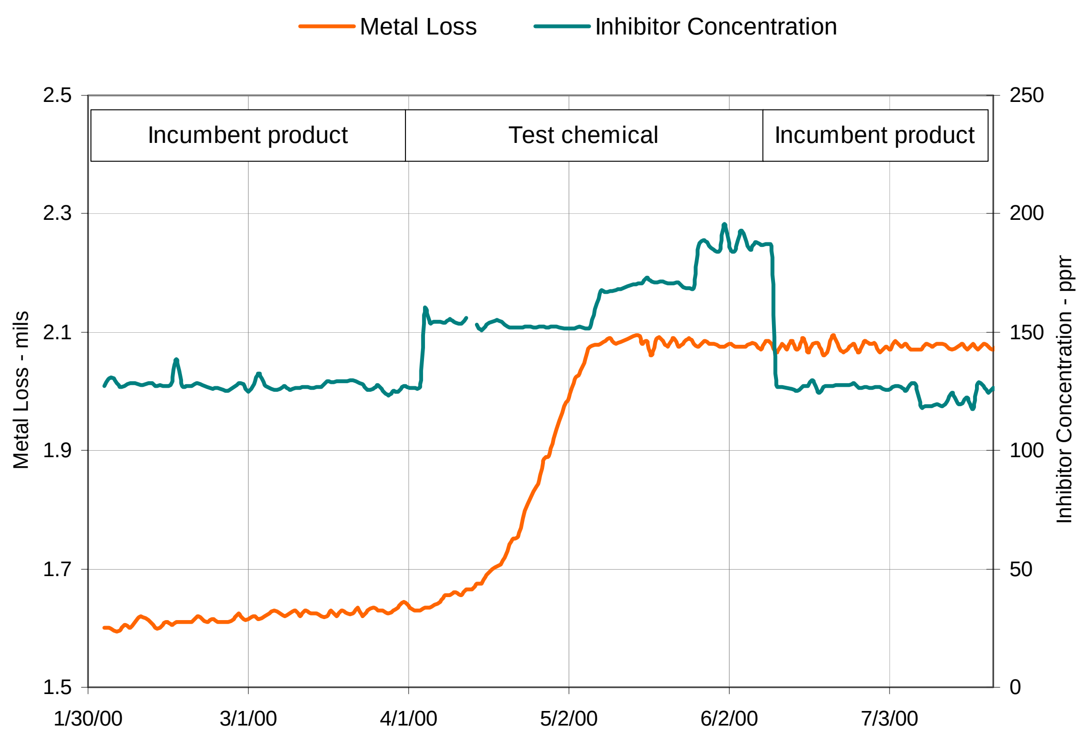


Figure 2: Chemical optimization in response to corrosion probe data

Section E - GPB
Internal/External Inspections & Corrosion Rate Increases/Rates

Section E.1 External Inspections

This Section summarizes the inspections performed to detect external corrosion and the results of those inspections. External corrosion is primarily associated with wet insulation of pipelines, as atmospheric corrosion of uninsulated equipment is a slow process in the arctic.

The pipelines are generally uncoated carbon steel and are therefore prone to external corrosion if water comes into contact with the outer pipe surface. The pipelines are constructed from single or double joints with shop applied polyurethane insulation protected with galvanized wrapping. The area around the girth welds are insulated with ‘weld packs’. The detailed design of weld packs varies but they are all prone to water ingress to a greater or lesser extent.

CUI is therefore a significant issue at weld packs but can also arise along the pipe joints, away from girth welds. The main challenge in managing CUI is in detecting the corrosion. Water ingress in to weld packs is essentially a random process and therefore it is difficult to apply rules to target the inspection program. There are approximately 185,000 weld packs at GPB.

Since CUI mitigation is linked to detection, the main focus of the CUI program over the years has been on developing better techniques to detect the corrosion.

Section E.1.1 Detection Methods

<u>Methods of CUI detection applicable to above ground pipelines</u>

Tangential Radiography (TRT)
- Non-intrusive spot radiographic technique that images the exterior tangent (profile) of the component. Irregular surface contour indicates potential corrosion by-product and subsequent wall loss.

Automated Tangential Radiography (ATRT)
- Non-Intrusive automated motorized vehicle able to perform real-time radiographic imaging of the exterior tangent (profile) of the component. Irregular surface contour indicates potential corrosion by-product and subsequent wall loss.

C-arm Fluoroscopic X-ray
- Hand held fluoroscopic imaging system for real-time examination of the exterior tangent (profile) of the component. Irregular surface contour indicates potential corrosion by-product and subsequent wall loss.

MFL Smart Pig Inspection

- Intrusive, indirect measuring technique that carries high strength magnets that apply a strong magnetic field into the pipe wall. As a result, area's of metal loss causes the flux to leak from the pipe wall. On board forward magnetic sensors measure the strength of the leakage to determine size and depth of metal loss features in the pipe. In addition to the first or forward magnetic sensors, a second ring of sensors located at the back is used to determine whether the feature is internal or external.

Eddy Current

- Non-intrusive technique that uses an electromagnetic method of pulsed eddy current. A transmitter coil is used to establish a magnetic field in the pipe wall. The current is switched off and the magnetic field vanishes. As a result, eddy currents are induced in the OD pipe wall. These eddy currents diffuse into depth and decay with a certain rate. The time of arrival at the back wall is sensed with a receiver coil. Where there is metal loss the arrival time will be earlier than at places with no wall loss. This time of arrival is used to calculate average wall thickness and interpreted as volume loss and encompasses both internal and external degradation.

<u>Methods of CUI detection applicable to cased piping</u>

With the exception of smart pigging, none of the inspection methods above are applicable to cased piping. Due to the relatively new technologies utilized for long range testing of cased pipe segments, the current strategy includes two primary non-intrusive methods of examination, Electromagnetic and Guided Wave Inspection. The use of each technique in unison supports confidence in findings and assists the mitigation prioritization.

Electromagnetic Inspection

- Non-intrusive technique utilized to screen pipework for possible external corrosion. When a broad-band electromagnetic pulse propagates along a pipe, there is a complex propagation constant for each frequency component of the wave spectrum. These propagation constants are a function of the electromagnetic properties of the material through which the waves travel. When waves traveling down the steel pipe encounter corrosion on the pipe surface, the waves are distorted. This phenomena forms the basis of electromagnetic inspection technology. Pipe segments are categorized in four rankings of No Electromagnetic Anomalies, Electromagnetic Anomalies, Significant Electromagnetic Anomalies, and Inconclusive. GPB experience has revealed the technique has a high percentage of false positive claims (indicating metal loss where none exists) but does not appear to generate false negative claims. For this reason the technique is applied as a screening tool to identify potential external corrosion sites for further investigation.

Guided Wave

- Non-intrusive technique that uses guided ultrasonic waves propagated along the pipe from a single point. Stress waves travel along the pipe in the form of cylinder Lamb waves. 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. In either case, the presence of possible defects is determined in a response signal indicating an impedance change within the pipe. The response signal is interpreted as volume loss and encompasses both internal and external degradation. Pipe segments are categorized in rankings of No Significant Indications, Significant Indications, and Inconclusive Test. The Significant Indications are further described as Minor Anomalies, Moderate Anomalies, and Severe Anomalies. The guided wave is employed to evaluate claims from electromagnetic inspection and/or utilized when there is a threat from internal corrosion damage.

Section E.1.2 Program Results

Figure 3 shows the number of TRT inspections performed to detect external corrosion, 1995 to 2000. It includes all tangential radiographic methods (TRT, ATRT, C-arm X-ray). It also shows the number of locations where corrosion is detected as a total and as a percentage of the number of inspections. The Figure shows that the total number of inspections per year has been fairly constant since 1996 but the number of new locations where corrosion is detected has been reducing. This reflects the random nature of CUI as once damage is located and mitigated, the probability of finding active CUI decreases.

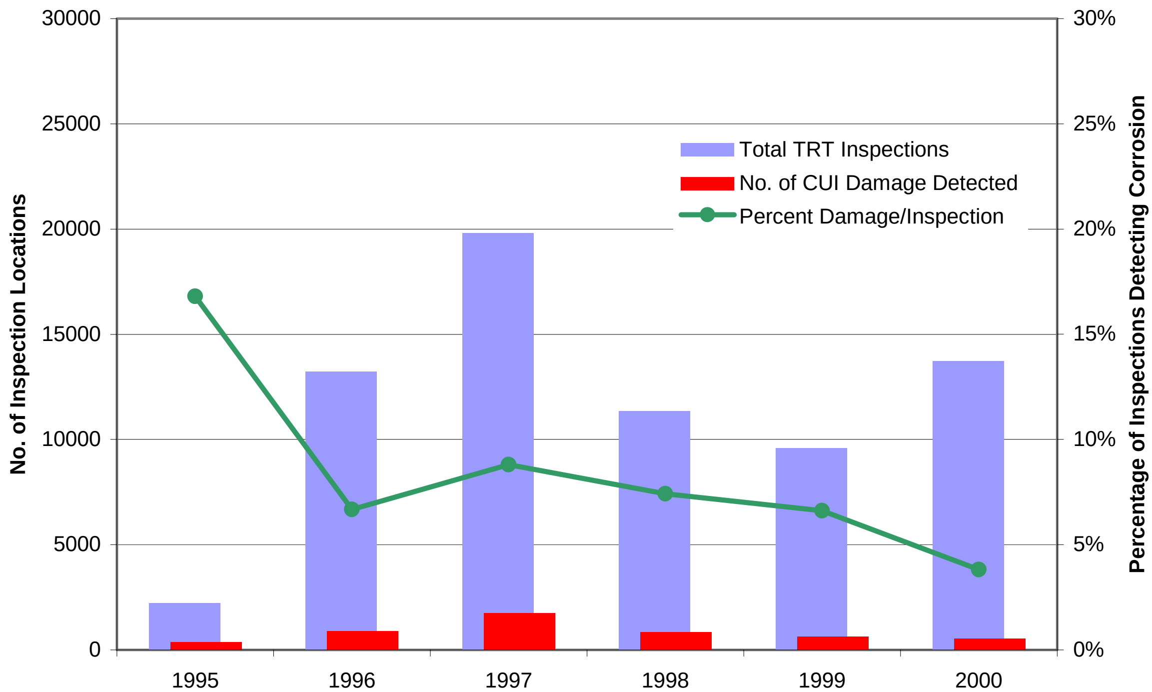


Figure 3: External inspection using Tangential Radiographic Testing

Table 9 summarizes the EM inspections performed in 2000 and Table 10 provides similar data for guided wave inspections. As a result of earlier inspections, one excavation was completed in 2000, on S-36 production, S-69 produced water, and S-804 miscible injection cross country pipelines. S-36 and S-69 cased pipe segments were replaced and S-804 was locally repaired as a result of findings.

Table 9: Electromagnetic Inspections

	No. of Cased Pipe Segments	Footage Tested	No EM Anomalies	EM Anomalies	Significant EM Anomalies
Gas/Gas Lift	88	7,249	75	13	0
Miscible Injection	31	2,196	28	3	0
NGL	2	255	1	1	0
3 Phase Production	82	6,655	67	13	2
Oil Export	1	75	1	0	0
PW/SW/WAG	32	2,771	25	7	0

Table 10: Guided Wave Inspections

	No. of Cased Pipe Segments	Footage Tested	No Significant Indications	Minor Anomalies	Moderate Anomalies	Severe Anomalies
Gas/Gas Lift	26	2,643	24	2	0	0
Miscible Injection	1	42	1	0	0	0
NGL	5	728	4	1	0	0
3 Phase Production	16	1,342	13	3	0	0
PW/SW	27	2,604	22	3	2	0

Section E.2 Internal Inspections

This Section summarizes the results of inspections performed to detect internal corrosion. The number of inspections performed is detailed in Section B – Corrosion Monitoring Activities.

Figure 4 shows the percentage of inspections that detect active corrosion in well lines. That is, if the extent of corrosion found by inspection is greater than the extent when that location was last inspected, it is classified as an increase in damage. The percentage of inspections detecting increased damage is therefore a high level measure of the amount of active corrosion in a system

$$\text{Percent of inspection increases} = \frac{\text{Number of inspections detecting active corrosion}}{\text{Total number of inspections}}$$

Figure 4 shows that there has been a year on year reduction in the level of active corrosion detected in the 3 phase production system and generally reducing levels in the other services, with a slight reversal of this trend in 2000.

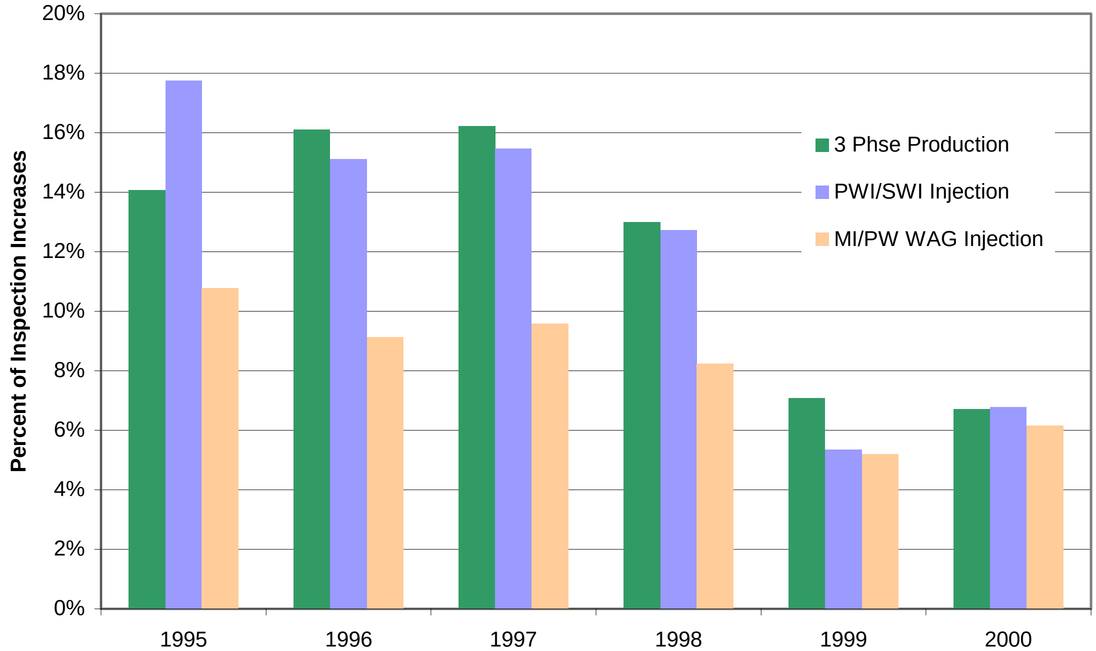


Figure 4: Detection of internal corrosion of well lines by inspection

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.

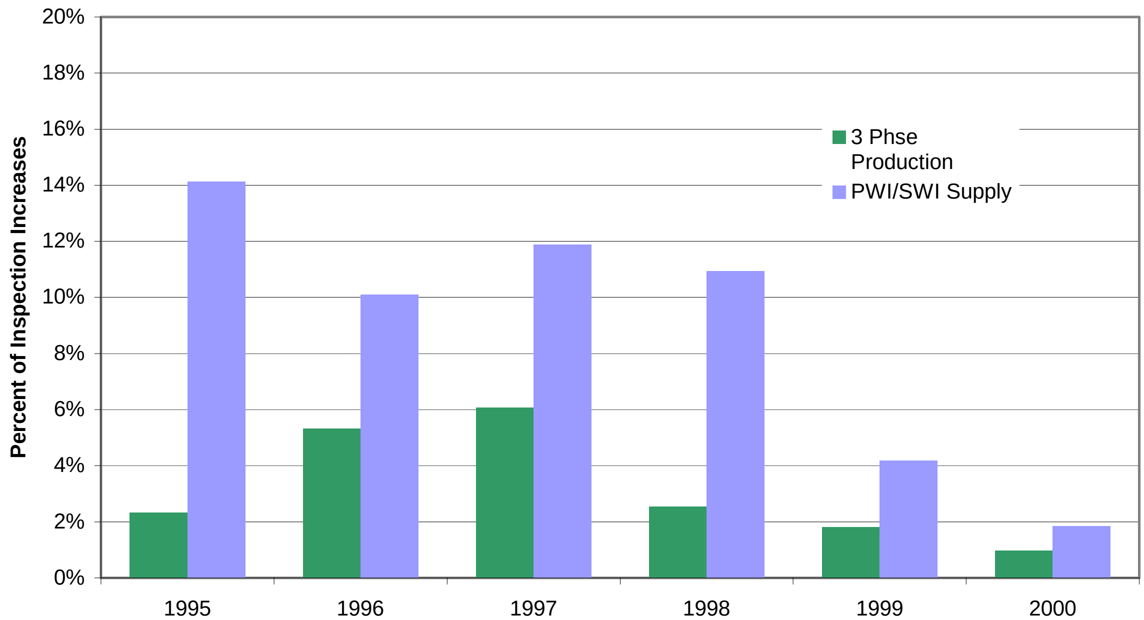


Figure 5: Detection of internal corrosion of cross country pipelines by inspection

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.

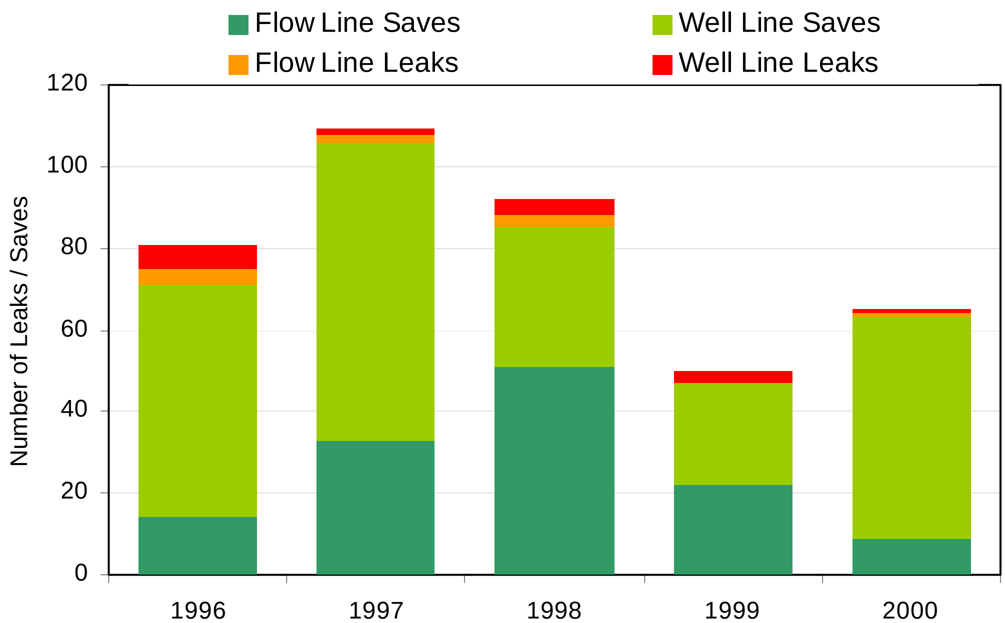


Figure 6: Leaks and Saves of well lines and cross country lines

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 at 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 remained above 2 mpy; however as noted previously, the major portion of the system is fabricated from duplex stainless steel and the data are used primarily for monitoring produced fluid corrosivity and erosion tendency. The lower, relatively constant corrosion rates in the water system reflect the effectiveness of the corrosion mitigation program.

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%

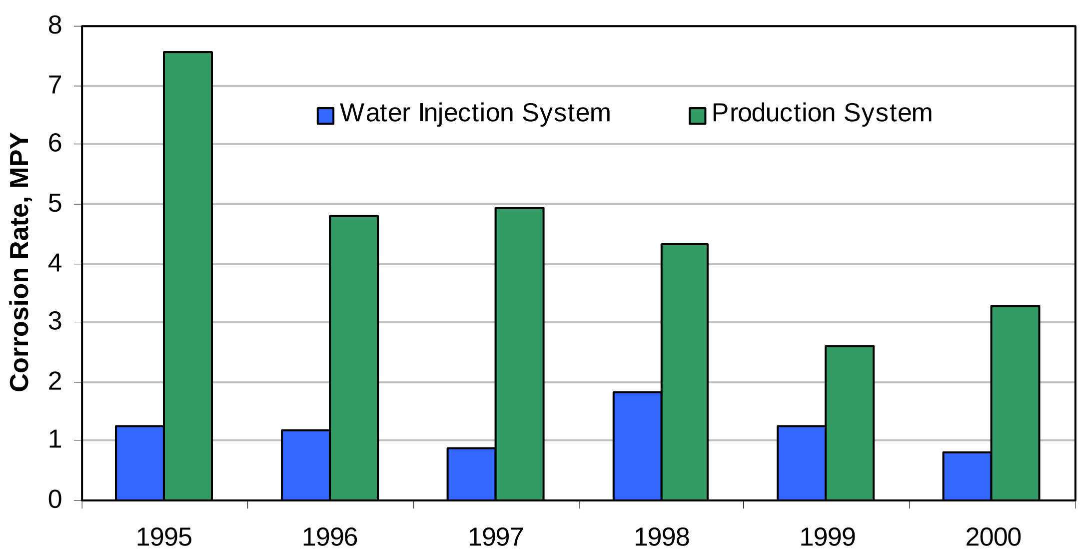


Figure A1: Corrosion coupon data from Endicott 1995-2000

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%

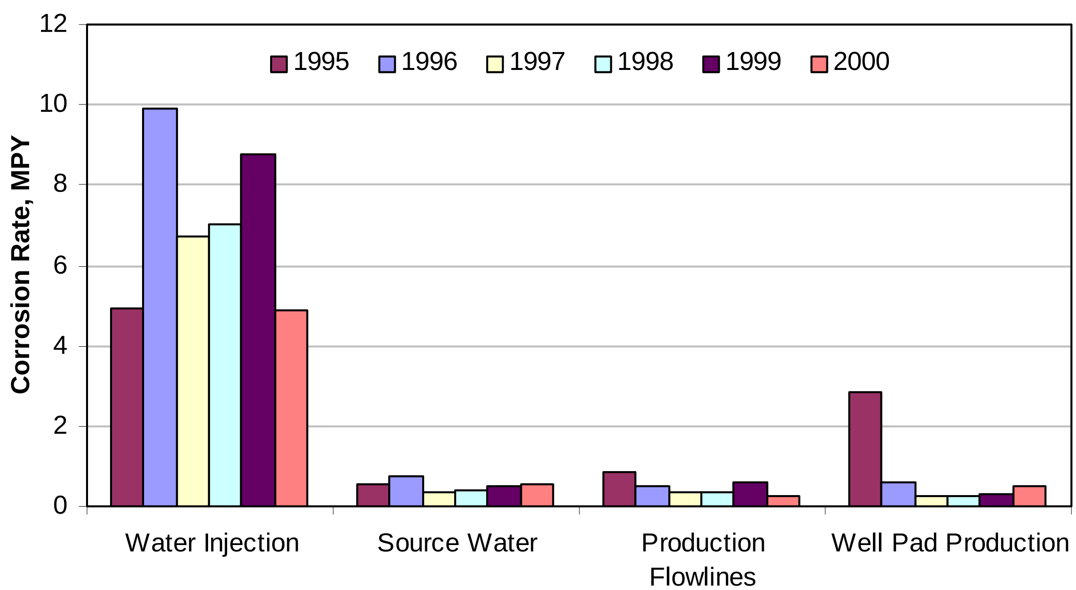


Figure A2: Corrosion coupon data from MPU 1995-2000

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 indicate 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.

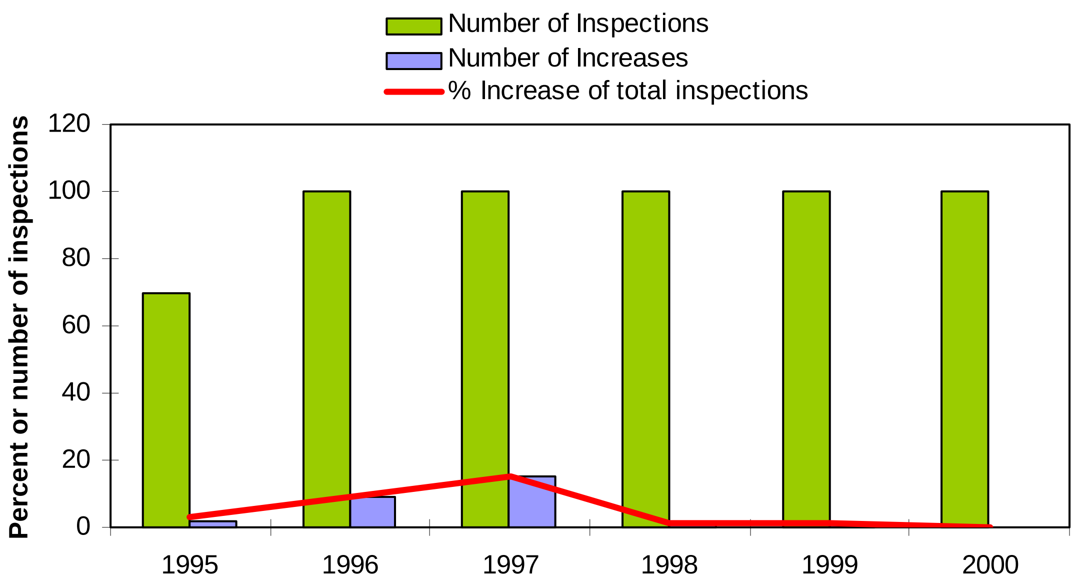


Figure A3: Endicott IIWL Quarterly UT Readings

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.

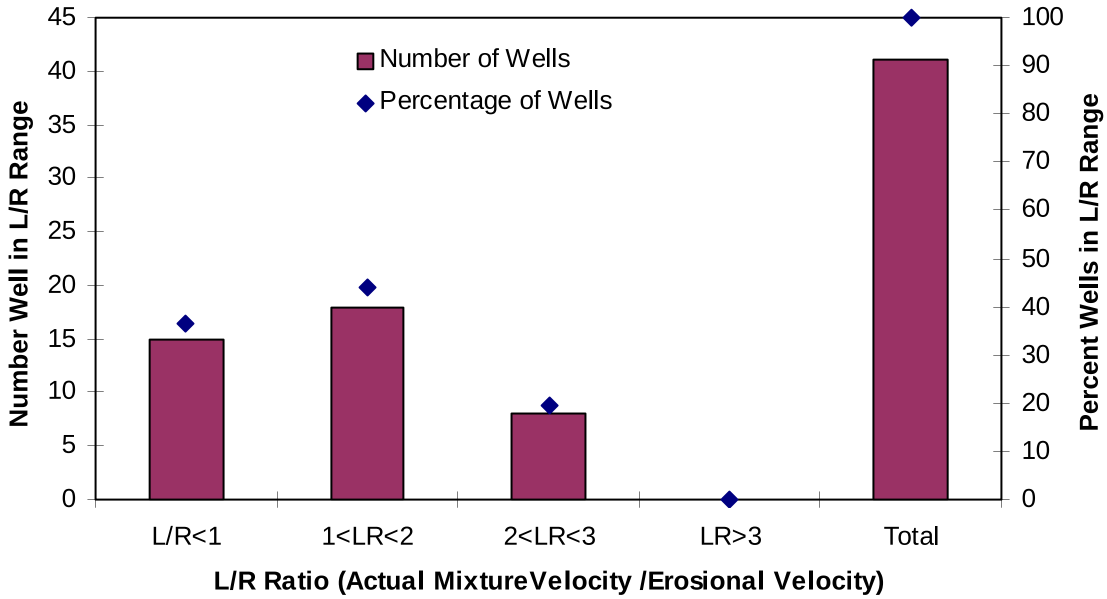


Figure A4: Endicott Velocity Monitoring

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.

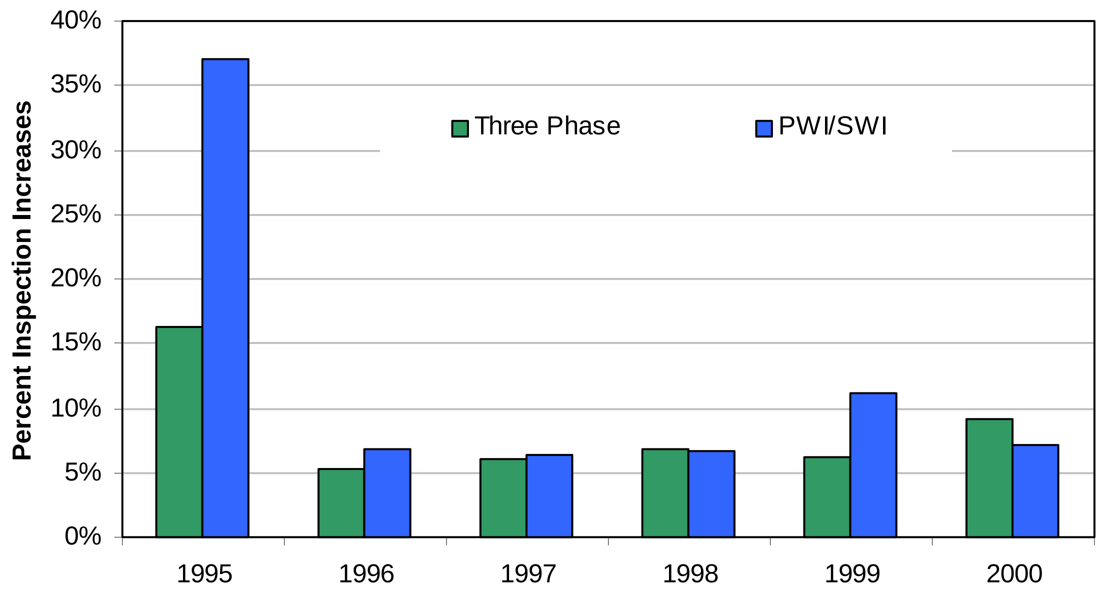


Figure A5: Detection of internal corrosion of well lines by inspection at Endicott

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.

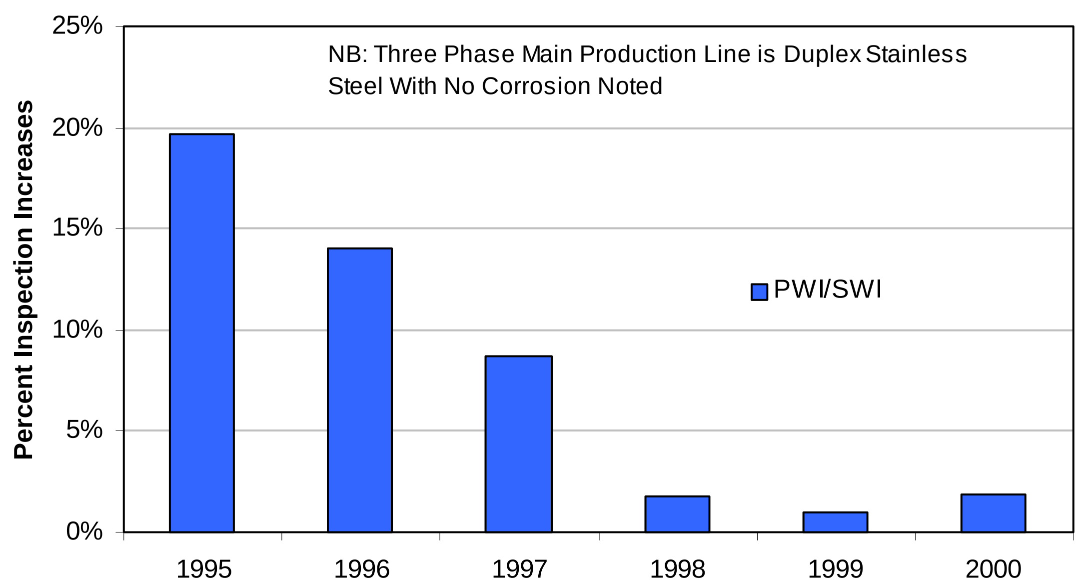


Figure A6: Detection of internal corrosion of cross country pipelines by inspection at Endicott

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

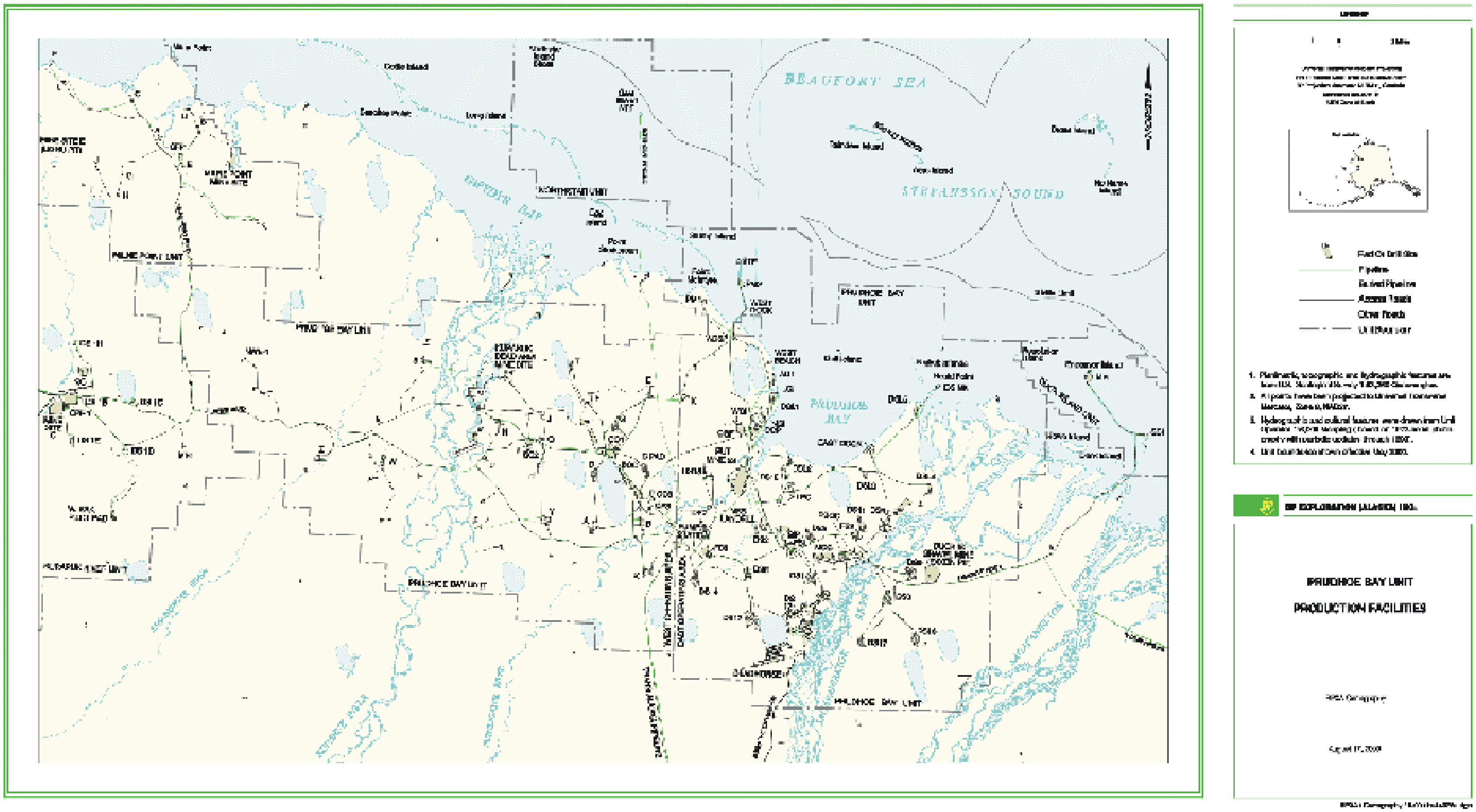
10/31/01 - 2nd Meet and Confer

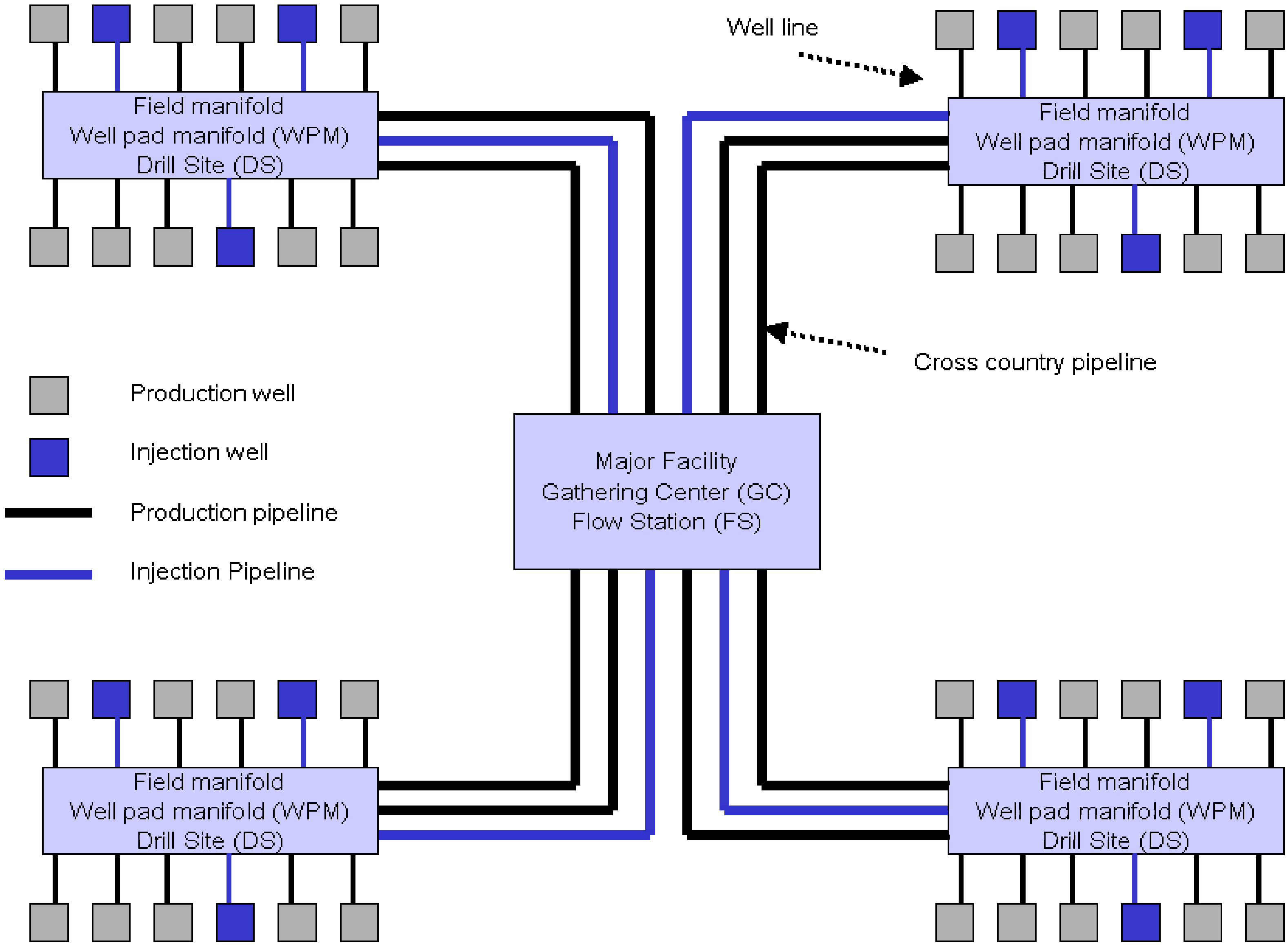
<u>Annual Timetable</u>

<u>March 31st Annual Report</u>

<u>April 30th 1H Semi-Annual Review (Meet and Confer)</u>

<u>October 31st 2H Semi-Annual Review (Meet and Confer)</u>


BEAUFORT SEA
PRUDHOE BAY UNIT
PRODUCTION FACILITIES


Well line
Field manifold
Well pad manifold (WPM)
Drill Site (DS)
Field manifold
Well pad manifold (WPM)
Drill Site (DS)
Cross country pipeline
Production well
Injection well
Production pipeline
Injection Pipeline
Major Facility
Gathering Center (GC)
Flow Station (FS)
Field manifold
Well pad manifold (WPM)
Drill Site (DS)
Field manifold
Well pad manifold (WPM)
Drill Site (DS)