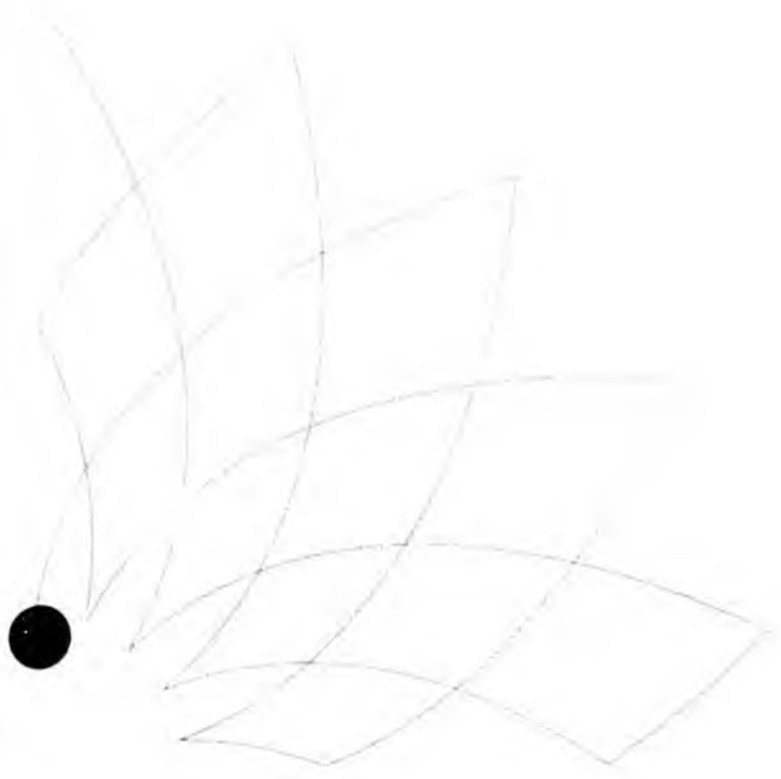


ALASKA LEGISLATURE COMMITTEES, 2000-2001

11967 SENATE RESOURCES

Section D

Chemical Optimization Activities



Section D Chemical Optimization Activities

Section D.1 Chemical Optimization

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

Section D.2 Corrosion Inhibitor Development

The development of new corrosion inhibitors starts in the research and development laboratories of the chemical suppliers where potential products are tested for effectiveness under a range of conditions designed to simulate production fluids. Once these preliminary test chemistries have passed the laboratory screening process, the promising products are tested under field conditions using dedicated test facilities at GPB. The test process is summarized in GPB Table D.1.

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

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

Part 1 - Greater Prudhoe Bay Performance Unit

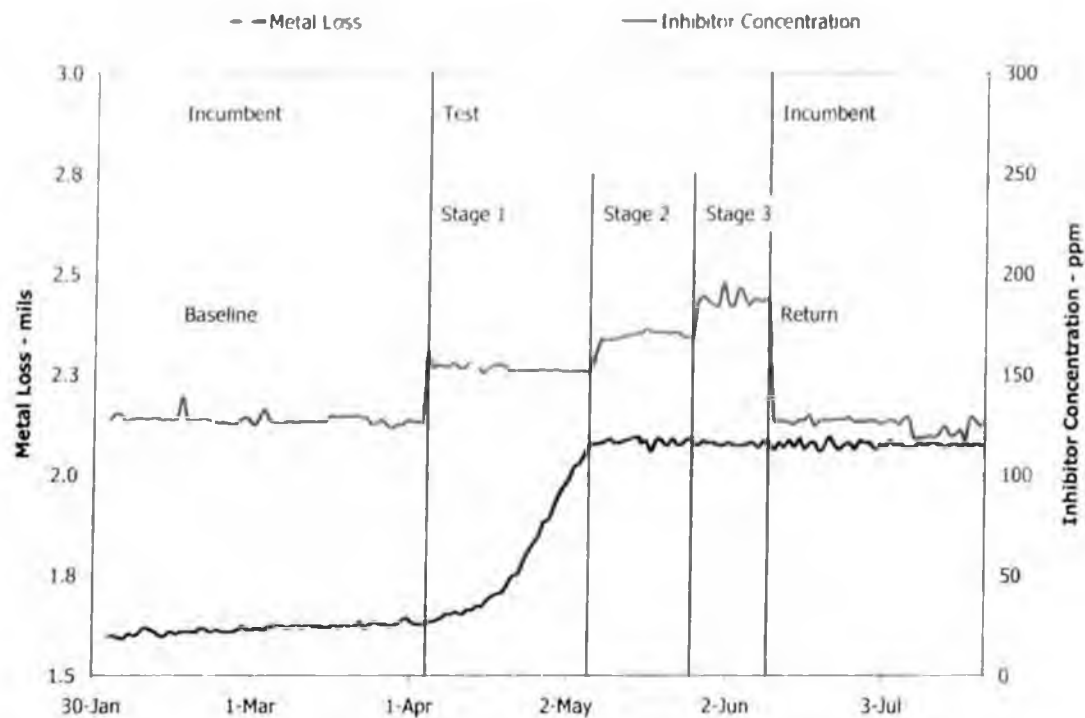
Location	Test	Description
Laboratory	Wheel-box Test	Performance of new potential corrosion inhibitor actives is compared to high performing actives. The test conditions simulate GPB and the test is run for 24 hours. Performance is determined by coupon weight loss.
	Kettle Test	This investigates the ability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

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

As an example, the ER probe results from a typical cross-country flow line test are shown in GPB Table D.2 and are summarized in GPB Figure D.1. Based on these data, the test chemical in this example was not cost effective and therefore was not utilized across the field.

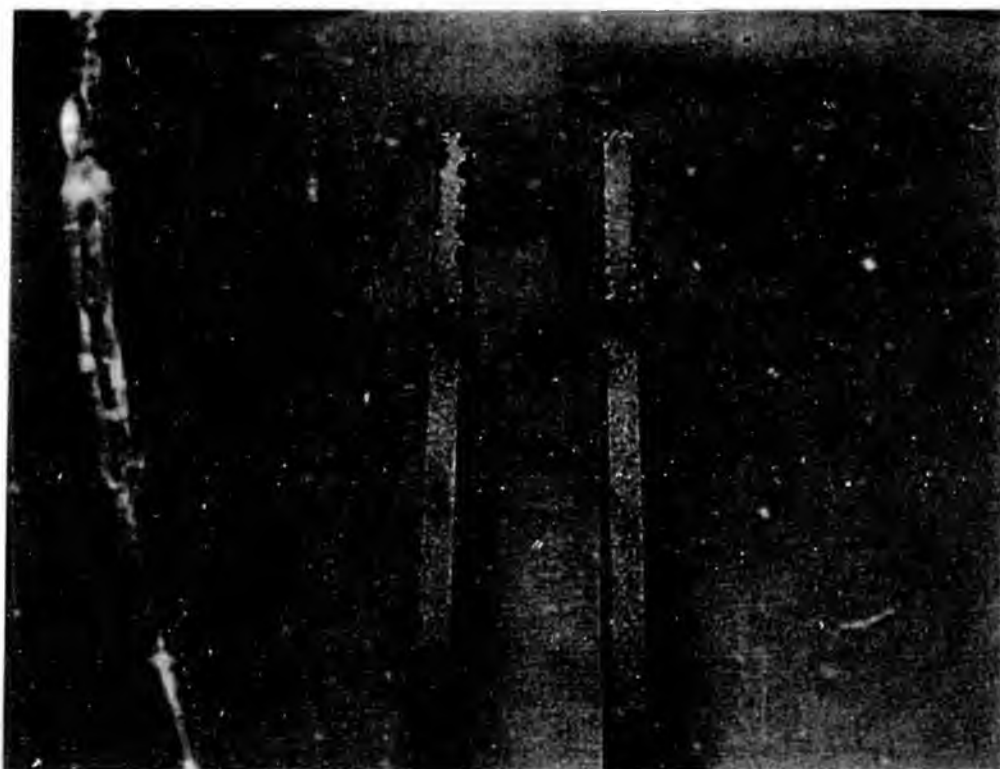
Status	Chemical	Conc. ppm	CR, mpy	Notes/Comments
Baseline	Incumbent	130	0.2	
Stage 1	Test	150	8.1	Even at a higher dose rate the test chemical was unable to inhibit corrosion to the same level as the incumbent.
Stage 2	Test	170	2.0	Reduces corrosion rate.
Stage 3	Test	190	0.8	Dose rate was increased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

GPB Table D.2 Flow line Test Program Result Summary



GPB Figure D.1 ER Probe Chemical Optimization Test

A second example, utilizes the output from the weight loss coupon program. This example from a test performed in 2001, demonstrates the need/value of multiple monitoring techniques when evaluating corrosion inhibitor performance. The trial product was tested for a 90-day period with no negative response observed by the ER probes. However, after the 90-day test period the corrosion coupons were pulled and showed relatively high general corrosion and pitting rates - see GPB Figure D.2. The product evaluated was a failure and the incumbent product was re-instated based on the coupon results. Corrosion inhibitor tests use all the monitoring tools available such as corrosion probes, coupons, and inspection data to determine corrosion control performance. In addition, the corrosion inhibitor is evaluated for plant production performance to show compatibility with the separation process.

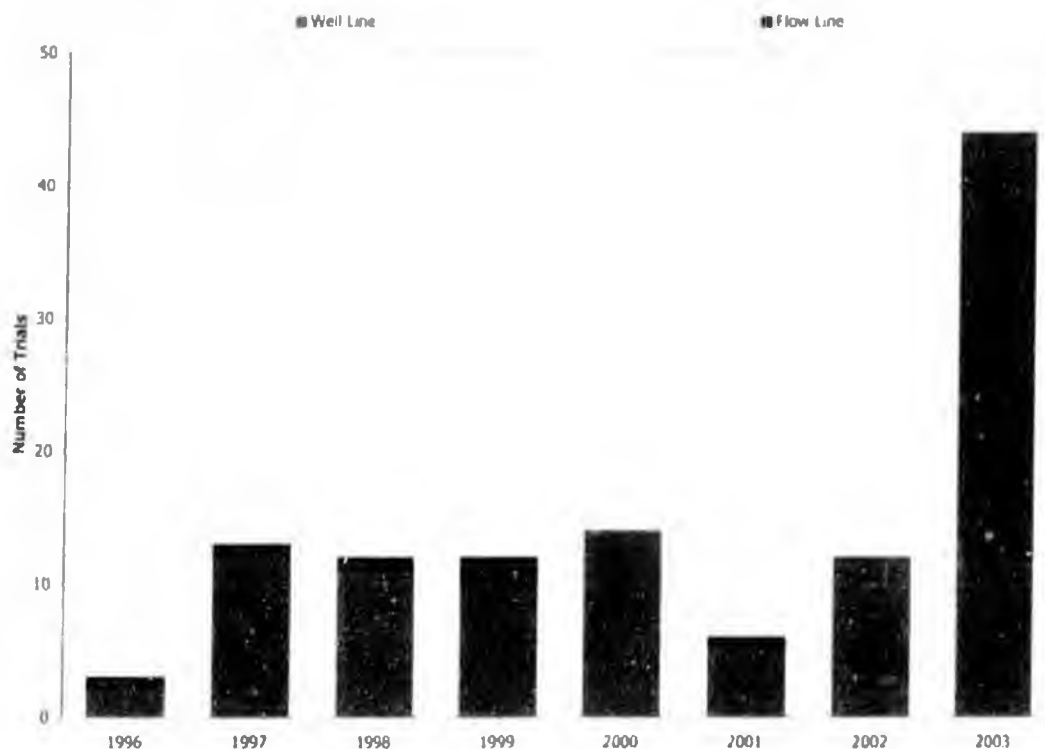


GPB Figure D.2 Corrosion coupons pulled after an 'unsuccessful' chemical trial

Section D.3 Corrosion Inhibitor Testing

GPB Figure D.3 summarizes the number of well line and flow line tests which have been completed since 1996. The level of well line test activity has increased during 2003 due to a change in the screening protocol, which reduced the time required per test. The combined number of well line and flow line tests has increased from ~10-14 per year to more than 40 during 2003.

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



GPB Figure D.3 Number of Well Line and Flow line Tests

The criteria to move from a well line test to flow line testing are rigorous and no candidates from 2002 or 2003 progressed to a large scale flow line test.

Section D.4 Field Wide Corrosion Inhibitor Deployment

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

GPB Table D.3 summarizes the changes in corrosion inhibitor products since 1995. The table does not include test products which did not make it to field wide usage. In addition, the summary table does not include summer versions of products that differ only in pour point from the winter version shown in the table.

Supplier	Chemical	1995	1996	1997	1998	1999	2000	2001	2002	2003
Nalco Exxon	EC1110A	█	█							
Nalco Exxon	EC1259			█	█	█	█	█		
Nalco Exxon	97VD129				█	█	█	█	█	
Nalco Exxon	98VD118					█	█	█	█	
ONDEO Nalco	99VD049						█	█	█	█
ONDEO Nalco	01VD017							█	█	█
ONDEO Nalco	01VD121							█	█	█
Champion	RU205	█	█	█	█	█	█	█	█	█
Champion	RU210	█	█	█	█	█	█	█	█	█
Champion	RU223	█	█	█	█	█	█	█	█	█
Champion	RU258			█	█	█	█	█	█	█
Champion	RU271				█	█	█	█	█	█
Champion	RU126A						█	█	█	█
Champion	RU256 ¹			█	█	█	█	█	█	█

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

GPB Table D.3 Summary of the Chemical Deployment History

Section D.5 Corrosion Inhibitor Usage and Concentration

Another measure of chemical optimization is the amount of corrosion inhibitor used relative to the volume of water produced from the reservoir. GPB Table D.4 summarizes the annual water production, corrosion inhibitor volumes, and concentrations since 1995. The inhibitor volumes are expressed as a 'winter product equivalent', i.e. the lower volumes of highly concentrated chemical used during the summer have been normalized to the winter equivalent.

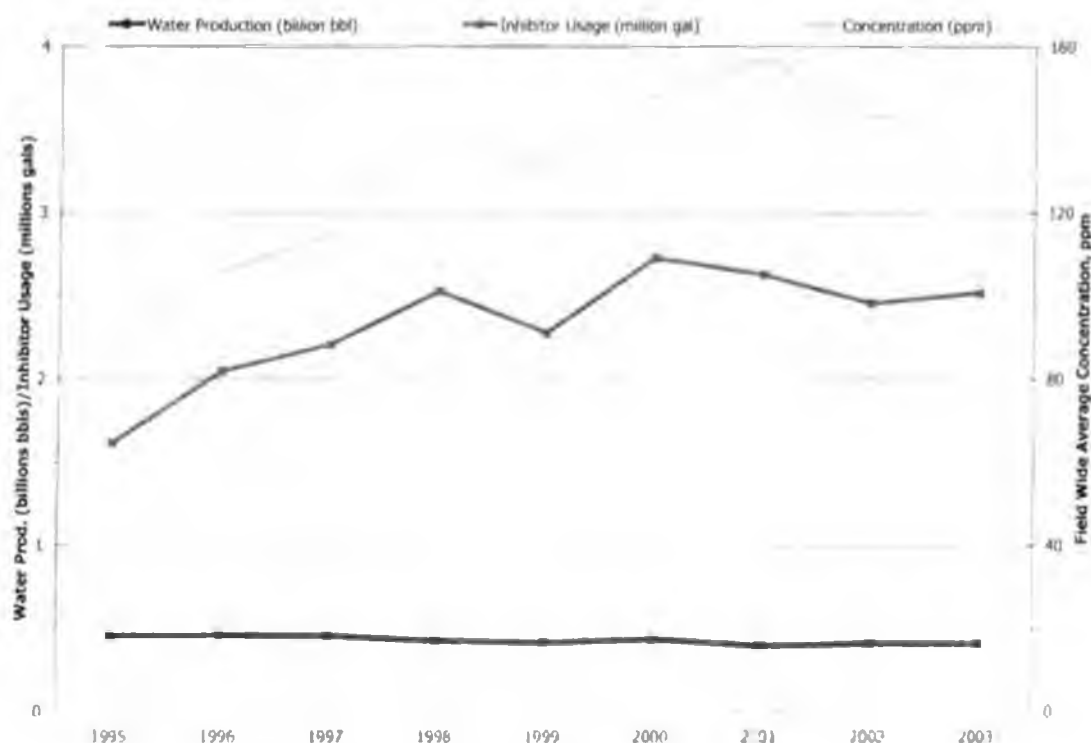
The concentration of inhibitor in the water phase provides a relative measure of the effectiveness of the chemical used to control corrosion. However, such data can be misleading as the types of corrosion inhibitors used can vary from year to year (GPB Table D.3). As more effective chemicals are developed, volumes and concentrations will change depending on the individual product's performance characteristics. There has also been a shift from batch treatments to continuous injection of chemical at the wellhead. The latter is more efficient in terms of protection achieved per gallon of chemical and therefore lower chemical usage would be expected. However, the ultimate measure of whether or not enough corrosion inhibitor is used can only be determined by consideration of other factors such as corrosion monitoring data and/or the amount of active corrosion detected by the inspection program.

Year	H ₂ O Production 10 ⁶ bbl/yr	Water Cut %	CI Usage 10 ⁶ gal/yr	CI Concentration ppm
1995	455	59	1.62	85
1996	460	62	2.05	106
1997	457	62	2.21	115
1998	426	66	2.53	141
1999	416	68	2.28	130
2000	438	70	2.73	148
2001	398	70	2.63	157
2002	407	71	2.45	143
2003	408	72	2.52	147

GPB Table D.4 Summary of the Chemical Usage History

The advances in the development of more effective corrosion inhibitors is counteracted by the increasing water cuts associated with an ageing oil field and increased flow velocities due to increased gas rates. These changes generally increase the amount of chemical required to control corrosion. As GPB Figure D.4 shows, the volume of corrosion inhibitor has increased since 1995 while the water volumes have remained relatively constant.

The metrics in GPB Figure D.4 deal with chemical usage at the field level but much of the chemical optimization activity focuses on injecting the correct amount of corrosion inhibitor to each piece of equipment. The inhibitor requirement is driven by factors such as water cut, water volume, flow regime, and condition of the equipment and varies over a wide range, from a few parts per million (ppm) to several hundred ppm. For 2003 the target chemical usage was 2.53 million gallons as compared to actual usage of 2.52 million gallons; or 99.6% of the target volume.



GPB Figure D.4 Field Wide Chemical Usage

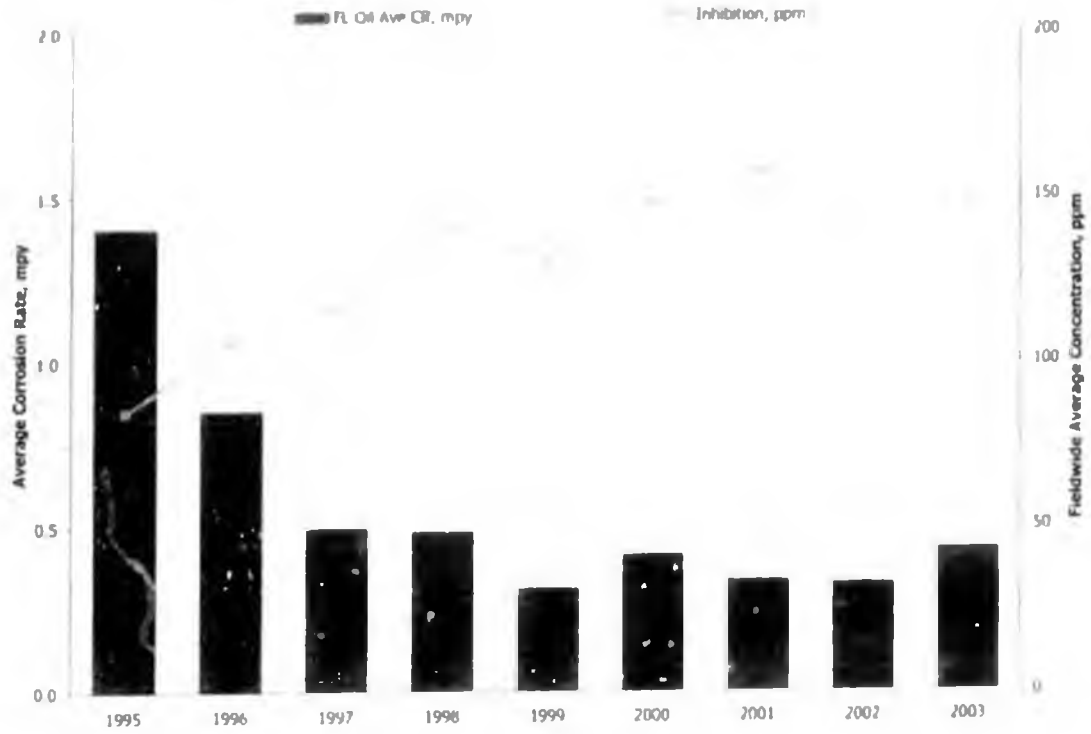
Section D.6 Corrosion Inhibition and Corrosion Rate Correlation

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

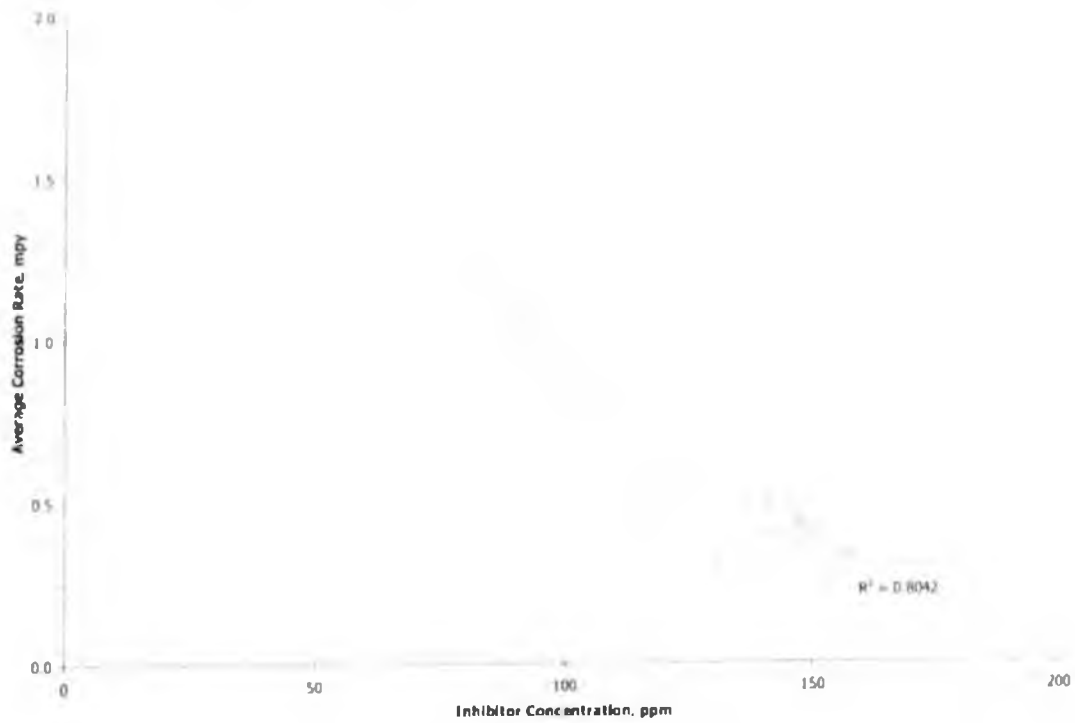
GPB Figure D.5 shows the correlation between the increased level of corrosion inhibitor and the reduction in average corrosion rate from 1995. As might be expected, the decline in average corrosion rate correlates with the increase in corrosion inhibition levels over time. The inhibition levels have increased approximately 70% from 1995 to 2003, with a field-wide average concentration of 85 ppm to 147 ppm. As a result the corrosion rates have fallen from 1.4 mpy in 1995 to 0.4 mpy in 2003.

GPB Figure D.6 shows the annual field-wide average corrosion inhibitor concentrations versus annual average corrosion rates for 3-phase production flow lines. The figure shows how additional corrosion inhibitor has reduced the average corrosion rate through time, but also shows an inherent limitation of corrosion inhibition as the minimum corrosion rate (or maximum corrosion inhibitor efficiency) is approaching an asymptote of ~0.25 mpy.

Section D Chemical Optimization Activities



GPB Figure D.5 Average Corrosion Rate Versus Inhibitor Concentration

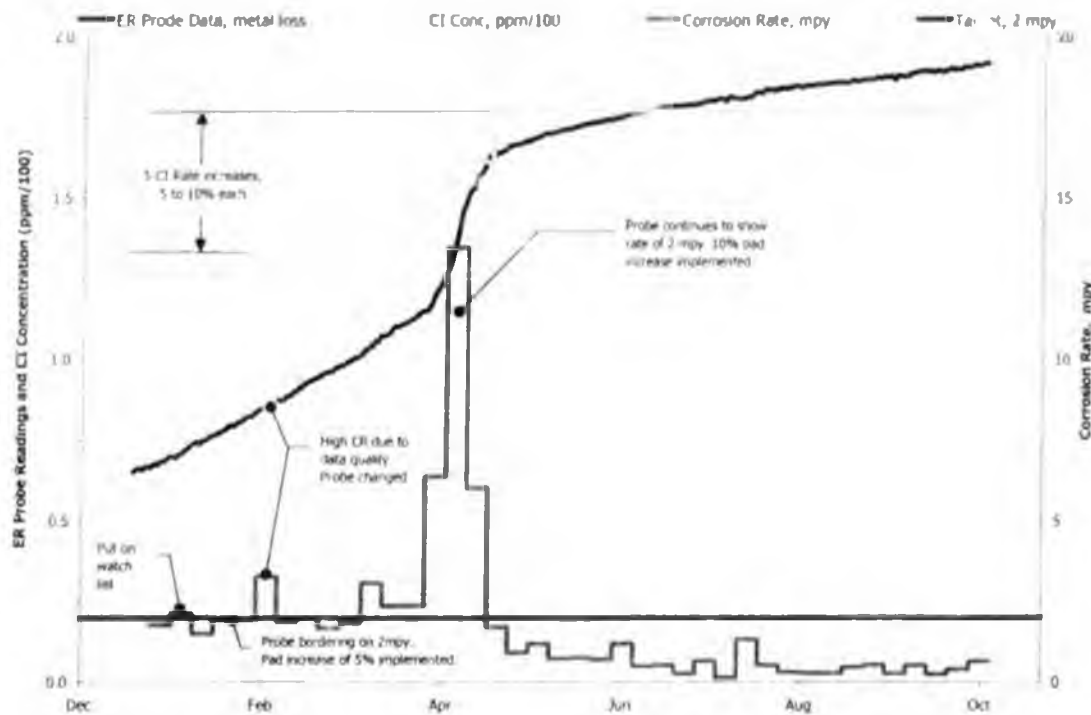


GPB Figure D.6 Corrosion Inhibitor Concentration vs. Average Corrosion Rate

Section D.7 ER Probe and Corrosion Inhibitor Response

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

GPB Figure D.7 and GPB Table D.5 illustrate the use of ER probes in managing changing corrosion conditions in a large diameter flow lines. GPB Figure D.7 shows the ER probe readings and derived corrosion rates, over a period of approximately 10 months in 2003. For the first 10 weeks the measured corrosion rate is bordering on 2 mpy and a 5% increase in CI is implemented. In early February the existing ER probe was replaced due to data quality issues. In mid-March another increase of CI was implemented based on ER probe corrosion rate. During April and part of May, the CR still exceeded the target and two additional CI increases were implemented. Finally in mid-May, the CR falls below the 2 mpy target and the CI remains at the increased concentration.



GPB Figure D.7 Corrosion Inhibitor Concentration vs. Corrosion Rate

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

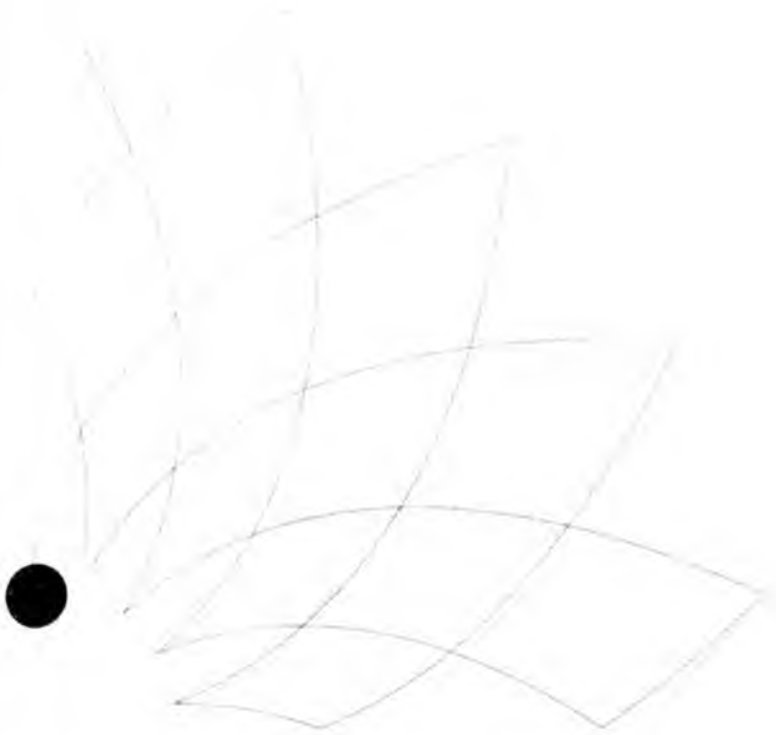
GPB Table D.5 Corrosion Inhibitor Concentration vs. Corrosion Rate

Section D.8 Chemical Optimization Summary

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

Section E

External/Internal Inspection



Section E External/Internal Inspection

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

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

Section E.1 External Inspection

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

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

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

GPB Table E.1 summarizes the CUI inspection program for the period 1995 to 2003 broken out by service and equipment type, well line and flow line, and the aggregate of both data sets.

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

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Service	Flow Line			Well Line		
	# Insp.	# Corr	% Corr	# Insp.	# Corr	% Corr
3 Phase	34,437	2,391	7%	37,208	1,375	4%
Export	2,615	130	5%	-	-	-
Gas	45,083	1,921	4%	14,660	192	1%
Other	61	3	5%	275	24	9%
Water	19,196	1,655	9%	5,993	223	4%
Total	101,392	6,100	6%	58,136	1,814	3%

Service	Aggregate		
	# Insp.	# Corr	% Corr
3 Phase	71,645	3,766	5%
Export	2,615	130	5%
Gas	59,743	2,113	4%
Other	336	27	8%
Water	25,189	1,878	7%
Total	159,528	7,914	5%

GPB Table E.1 CUI Inspections by Service Type, 1995-2003

GPB Table E.2 shows the distribution of insulation joint types based on a sample of ~50,000 locations. For each specified joint type, there is an associated CUI incident rate. These data show there is as much variability in the CUI incident rate between the insulation joint configurations as there is associated with the service type. This suggests that the joint configuration and insulation joint location, along with age, have as much influence on the occurrence of external corrosion at weld-packs compared to the service type and operating temperature.

GPB Joint Design	Joint Type Freq	CUI Incident Rate
Anchor Joint	4.4%	2.8%
Damaged Insul	8.4%	2.0%
Damaged Weld Pack Insul	0.1%	2.4%
EII Anchor Joint	0.1%	6.8%
EII Bottom Elev	3.6%	6.3%
EII Bottom Elev Saddle	0.5%	9.9%
EII Horiz Saddle	1.0%	8.4%
EII Horizontal	10.1%	3.8%
EII Top Elev	2.6%	1.3%
EII Top Elev Saddle	0.3%	4.5%
Mid-Span Weld Pack	56.4%	1.8%
Saddle Joint	11.1%	3.6%
Vertical Joint	0.1%	5.3%
Wall Penetration	1.2%	1.4%
Average CUI Incident Rate		2.5%

GPB Table E.2 CUI Incident Rate by Joint Type

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

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

Section E.1.1 External Inspection Program Results

GPB Table E.3 and GPB Figure E.1 show the number and results of the external corrosion inspections performed from 1995 through 2003. The data includes all

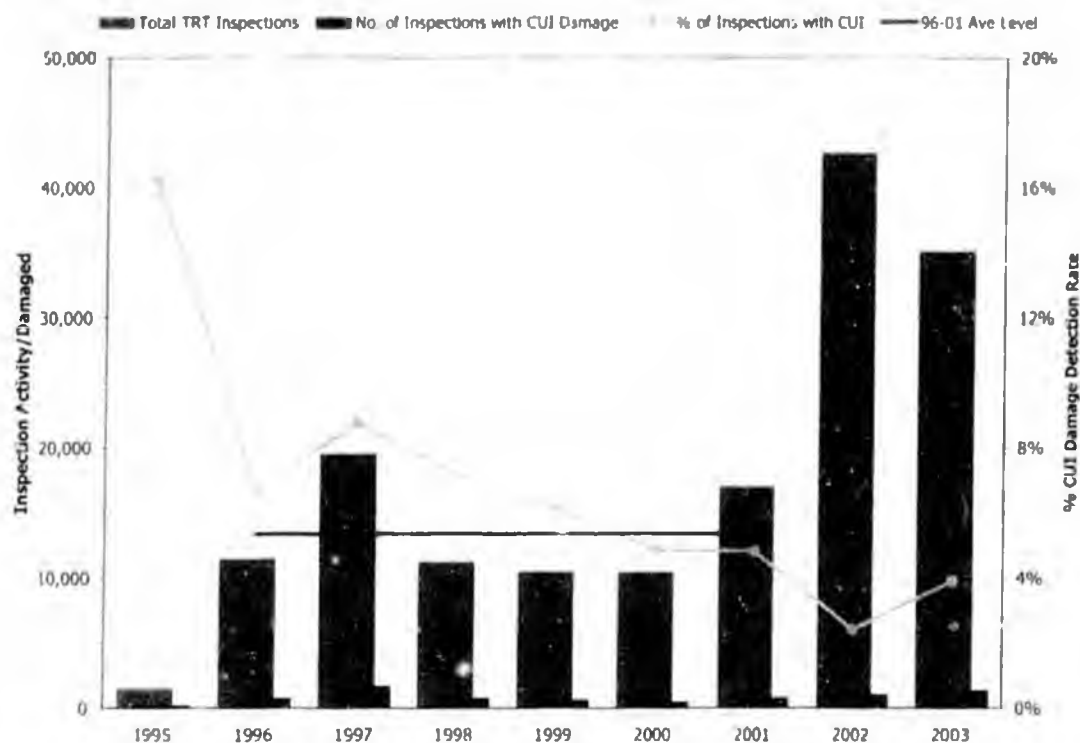
Part 1 – Greater Prudhoe Bay Performance Unit

the Tangential Radiographic (TRT) techniques applied to detect external corrosion, including Automated-TRT (ATRT), and C-Arm Fluoroscopy (CTRT).

	1995	1996	1997	1998	1999	2000	2001	2002	2003
Well Line									
Activity Level	-	36	1,680	946	2,376	5,257	13,071	23,949	10,821
Corrosion Detected	-	6	234	66	75	241	711	342	139
%Corroded	-	17%	14%	7%	3%	5%	5%	1%	1%
Flow Line									
Activity Level	1,508	11,461	17,866	10,289	8,136	5,180	3,966	18,727	24,258
Corrosion Detected	245	765	1,477	743	573	266	110	690	1,231
%Corroded	16%	7%	8%	7%	7%	5%	3%	4%	5%
GPB Overall									
Activity Level	1,508	11,497	19,546	11,235	10,512	10,437	17,037	42,676	35,079
Corrosion Detected	245	771	1,711	809	648	507	821	1,032	1,370
%Corroded	16%	7%	9%	7%	6%	5%	5%	2%	4%

GPB Table E.3 External Corrosion Activity and Detection Summary

In general, the inspection levels over the period 1996 to 2001 remained relatively constant at an average of ~13,000 per year. In 2002 the activity level was increased substantially, targeting 35,000 inspections per year. In 2003 the activity level was slightly over the target of 35,000 inspections. The difference between 2002 and 2003 is the result of ease of access for performing external corrosion inspections. A significant amount of time was spent in the 1Q03 performing off-road inspections, specifically the pipelines over the Kuparuk River and pipelines over tundra without road access from Y Well Pad to P Well Pad. Additionally, activities following the May Y-36 spill and lessons learned directed activities across GPB on equipment with similar configurations as the Y-36 caribou crossing.



GPB Figure E.1 External Corrosion Activity and Detection Summary

There was a slight increase in CUI damage detected in 2003 as compared to 2002. Overall, the percentage of locations found with damage has fallen from an initial high of >15% to a field-wide average of 4% in 2003.

Section E.1.2 Cased Piping Survey Results

In accordance with the agreement with ADEC, 2003 was the final year of a 5-year program to complete a baseline inspection on all cased piping segments. There were approximately 280 segments remaining to complete the 5-year commitment. However, based on the recommendations of the Y-36 Incident Investigation Team, a visual inspection of all cased crossings was completed to identify potential deficiencies similar to Y-36 that may reduce pipeline integrity. As a result of the visual inspections, additional scope was added to the 2003 cased pipe inspection plan to include a total of 492 cased pipe inspections comprising of both baseline and repeat examinations.

GPB Table E.4 shows the 2003 inspection results for cased pipe segments. Potential metal loss areas are reported as anomalies and severity is semi-quantified as non-relevant (i.e. no metal loss), minor, moderate, or significant.

Part 1 – Greater Prudhoe Bay Performance Unit

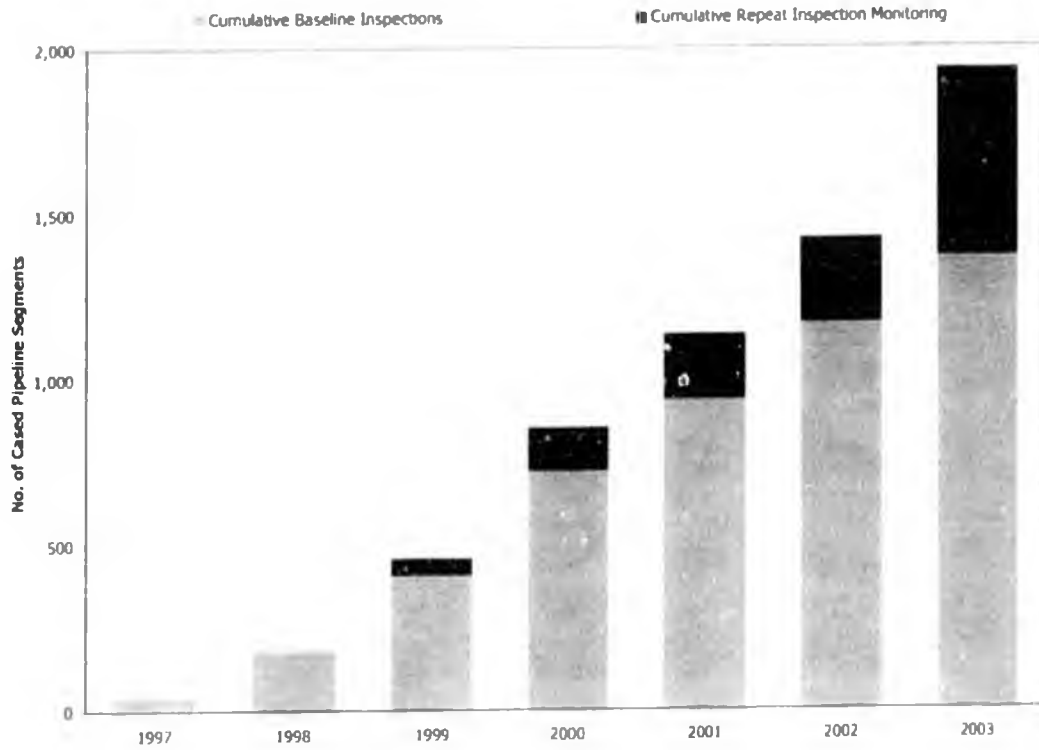
Service	Technique	Segment	Non-Relevant	Minor	Moderate	Significant	Anomaly Action
3 Phase	E-Pulse	89	63	26	-	-	Proof/Monitor G-Wave
	G-Wave	96	38	20	31	7	Monitor Guided Wave
PW/SW	E-Pulse	21	13	8	-	-	Proof/Monitor G-Wave
	G-Wave	53	23	12	14	4	Monitor Guided Wave
Gas	E-Pulse	86	56	27	1	-	Proof/Monitor G-Wave
	G-Wave	112	55	19	31	7	Monitor Guided Wave
Other	E-Pulse	6	4	2	-	-	Proof/Monitor G-Wave
	G-Wave	2	2	-	-	-	Monitor Guided Wave
PO	E-Pulse	2	1	1	-	-	Proof/Monitor G-Wave
	G-Wave	25	15	6	4	-	Monitor Guided Wave
Total		492	272	121	81	18	

GPB Table E.4 Cased Pipe Survey Results

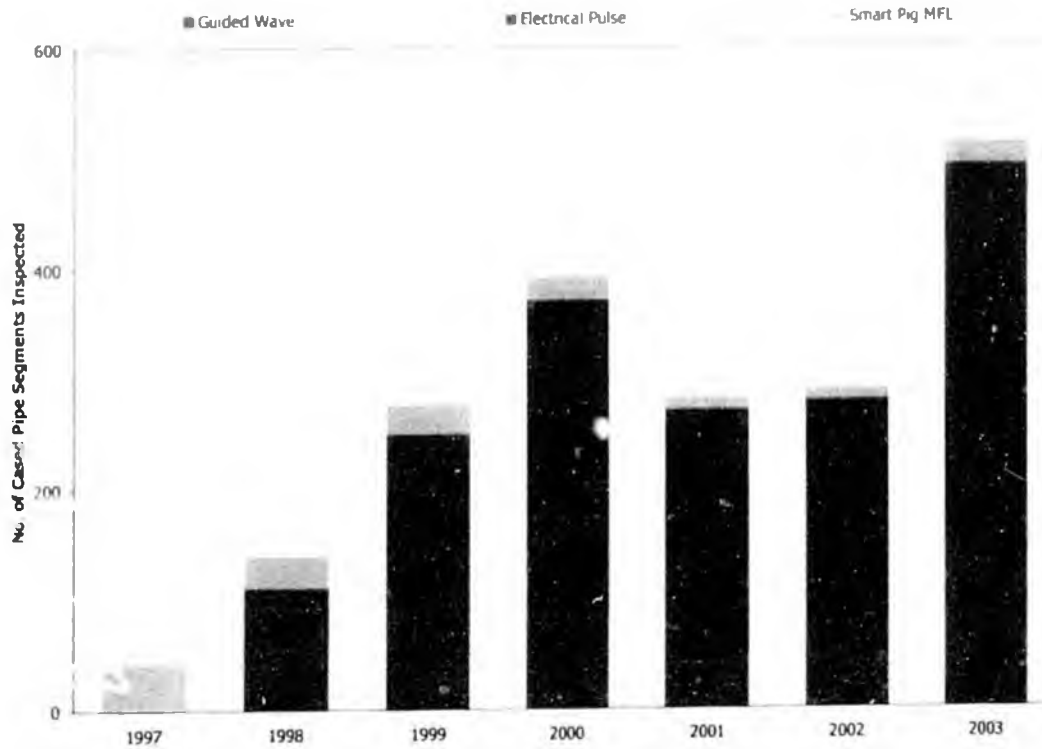
All the potential metal loss anomalies have been prioritized and scheduled for re-inspection based on the reported severity.

GPB Figure E.2, GPB Figure E.3, and GPB Table E.5 show the cased piping inspection activity level over the last 7 years. The activity level has been fairly consistent and includes baseline and monitoring or repeat examinations.

Section E External/Internal Inspection



GPB Figure E.2 Cumulative Cased Pipe Inspection Activity



GPB Figure E.3 Cased Piping Inspection History by Detection Method

Method	1997	1998	1999	2000	2001	2002	2003
Guided Wave	-	4	90	81	44	62	288
Electrical Pulse	-	107	160	290	227	217	204
Smart Pig (MFL)	43	29	27	21	10	10	19
Total	43	140	277	392	281	289	511

GPB Table E.5 Cumulative Cased Pipe Inspection Activity

Having completed the initial baseline inspections, a thorough review of cased pipe inspection activity and results has been performed. The intent now is to move the program to the next phase consisting of repeat examinations and monitoring and possibly excavation.

Each of the anomalies identified through the baseline inspection survey from 1997 to 2003 will be prioritized for re-inspection as part of the long-term management of cased pipe segments. Currently the preferred test methodologies will be either guided wave and/or I.I in order to determine the presence of an active corrosion mechanism.

In summary, the cased piping survey activity level has been consistent meeting the commitment to deliver a baseline survey by year-end 2003. The cased piping inventory has been inspected using a number of different techniques including guided wave, electrical pulse, and MFL in-line inspection. The intent now is to move the program to the next phase consisting of repeat examinations and monitoring.

Section E.1.3 Excavation History

There have been 28 cased pipeline segments at road and/or animal crossings excavated over the last 11 years at GPB. Of the 28 excavations, 2 were as a result of loss of pressure containment, the remaining 26 excavations resulted from inspection observations.

In 2003, three crossings (Y-36, X-74, F-74) were partially excavated at the casing end. Three sleeve repairs were installed as a result of external corrosion damage. In addition, a complete cased pipe segment (NGI-14) was replaced by cutting and removing the segment from the casing and installing a new pipe segment.

GPB Table E.8, at the end of this section, shows that of the total 28 segments excavated, 24 were found with external corrosion damage and 4 were found with no external corrosion damage. The identification of potential damage areas through the inspection program and subsequent actions of monitoring and/or excavation, gives confidence that inaccessible pipe segments can be effectively managed to minimize loss as a result corrosion degradation.

Section E.1.4 External Program Summary

In summary, the level of activity dedicated to external corrosion detection has been relatively constant between 1996 and 2001 at approximately 13,000 locations per year. However, in 2001 it was recognized there was a failure risk that would increase as the field ages. Therefore, the GPB partners agreed to fund an increased level of inspection activity. The activity level for 2003 was considerably greater than historical average at approximately 35,000 inspection locations.

The cased piping program completed the initial base line survey as well as additional inspections resulting from the Y-36 investigation. The program will move into a new phase of repeat inspections, monitoring, and corrective action and repair as warranted.

Section E.2 Internal inspection

Section E.2.1 Internal Inspection Program – Scope

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

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

ERM – Erosion Rate Monitoring: The purpose of this program is similar to the CRM but is aimed at monitoring erosion activity. As this damage mechanism is driven by production variables, i.e. production rates and solids loading, it is driven by 'triggers', such as velocity limits, well work, etc. If such triggers are exceeded, inspections are performed on a

monthly to quarterly basis until confidence is gained that erosion is not occurring.

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

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

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

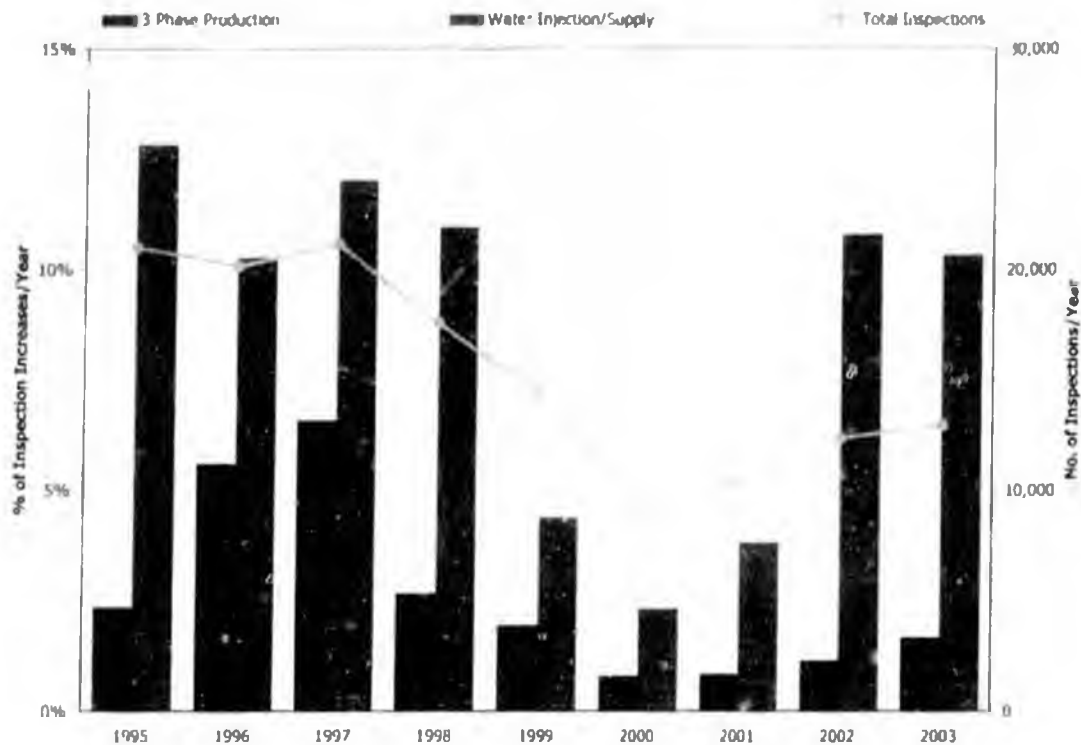
Section E.2.2 Internal Inspection Program Results

The results presented are aggregate data obtained for all of the above programs for flow lines and well lines. The inspection program results are presented in terms of the number of locations that showed an increase in corrosion damage since the last inspection as a percentage of the total number of repeat inspections,

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

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

GPB Figure E.4 shows the percentage of inspection increases (%I's) and the number of inspections per year for the flow lines broken out by 3-phase production and water injection (seawater and produced water) service.

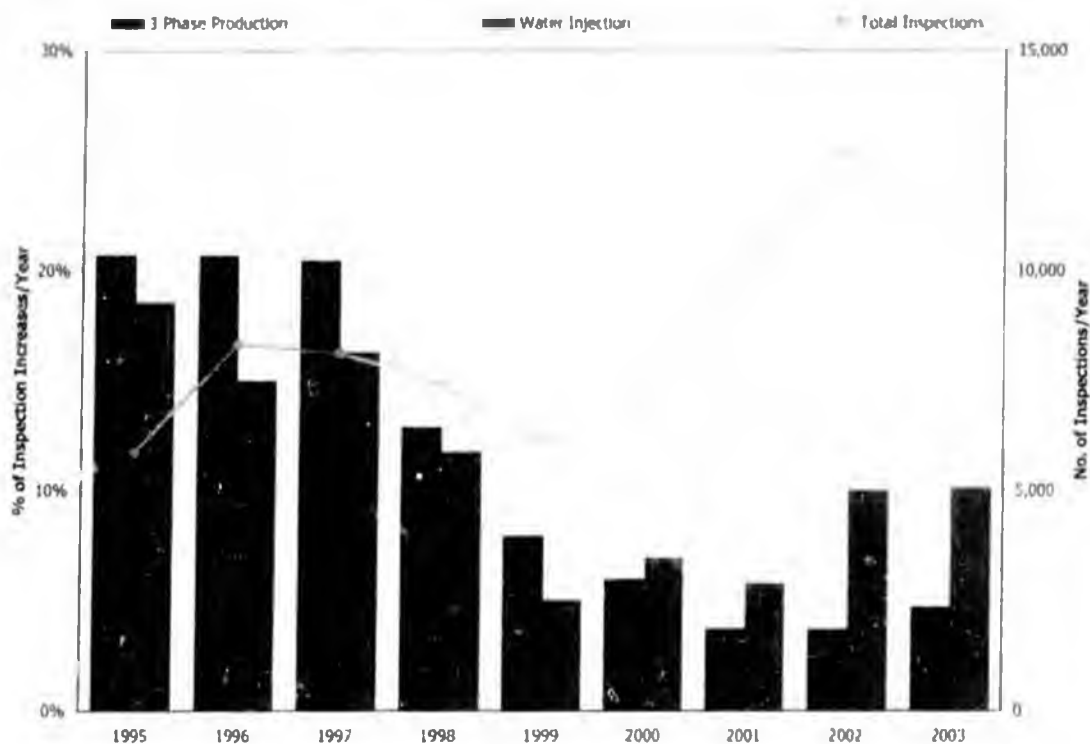


GPB Figure E.4 Flow Line Internal Inspection Increase by Service

The percentage of inspection increases in the 3-phase system has declined considerably from 1997 to 2003. However, there was a slight increase in the %I's in 2002 and 2003 on flow lines compared to 2000, which likely reflects the increase in corrosion rates detected in the coupon monitoring program during 2000. Since the inspection program is a lagging indicator of corrosion control, and there is a decline in average WLC corrosion rates realized through the monitoring data, it is expected that the percentage of inspection increases will decrease in the coming year. The delayed response of the inspection program compared with the monitoring program is a result of the longer time base on which this program is typically completed.

The increased corrosion activity in the water injection system reflects the increasing corrosion trends already discussed in the corrosion monitoring section. As noted in Section C.2, there is a strong corrective action plan in place to address the corrosion in the water injection system and the 2003 inspection data suggests some improvement in reversing the negative trend.

GPB Figure E.5 shows the inspection increases trend and the number of inspections per year for the well lines.



GPB Figure E.5 Well Line Internal Inspection Increase by Service

For the 3-phase well lines in the long term, there is a decrease in corrosion activity as measured by the percentage of inspection increases. This is the same trend as seen in the flow lines. In the short term, the slight increase in corrosion activity seen in the flow lines is similarly reflected in the well line data.

For the water system, corrosion activity is seen to be declining from 1995 through 2001. However, as with the flow lines, there has been a recent increase in activity in the well line data.

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

Section E.3 Fitness for Service Assessment

The basic fitness-for-service criterion used by BPXA is ANSI/ASME B31G. The base document is the modified B31G, PRC 3-805, which is augmented with

additional requirements defined in BP specification SPC-PP-00090, "Evaluation and Repair of Corroded Piping Systems".

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

GPB Figure E.6 summarizes the dependence of Maximum Allowable Operating Pressure (MAOP) with the remaining wall thickness of a section of flow line based on ANSI/ASME B31G and is intended to show the multiple-layers of protection to the environment provided by the current fitness-for-service criteria. At the original wall thickness of 375 mils, the example flow line has a B31G calculated MAOP of ~1400 psi. As the wall thickness is reduced by corrosion, this pressure containment capacity is also reduced.

GPB Table E.6 shows the MAOP for various wall thicknesses starting from the original wall thickness of 375 mils. It can be seen that the repair criterion used provide a significant level of conservatism over the minimum wall thickness required to retain the maximum operating pressure. In addition, high-level over-pressure protection provides additional protection over the normal operating pressure.

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

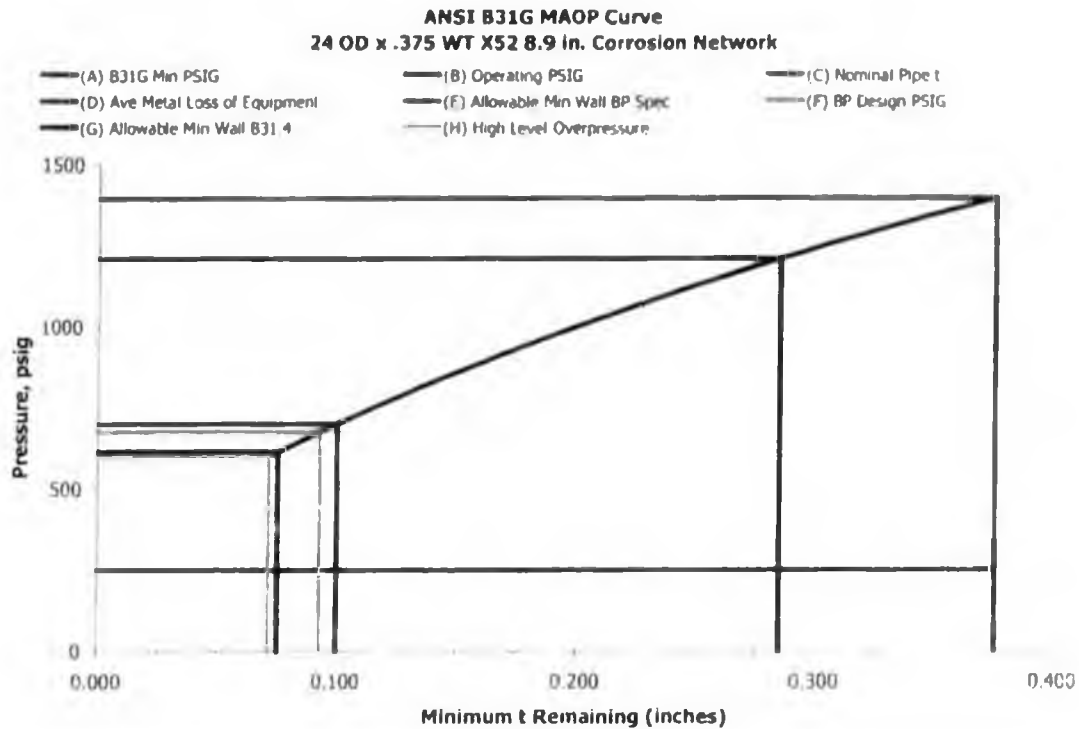
Localized/Pitting Corrosion Localized/pitting corrosion consisting of clearly defined relatively isolated regions of metal loss. The axial and circumferential extent of such regions needs to be determined and any potential areas of interaction where there is axial overlap between pitting regions.

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

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

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

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



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

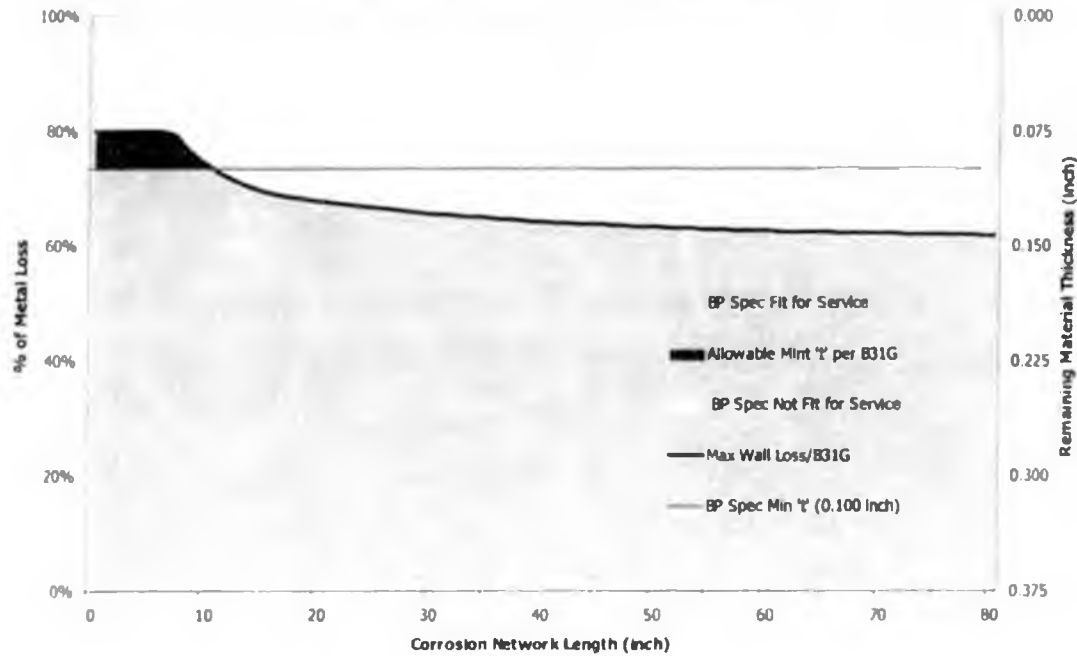
GPB Figure E.6 MAOP versus Remaining Wall Thickness

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

GPB Table E.6 Thickness, MAOP Correlation

GPB Figure E.7 illustrates the FFS envelop for a combination of depth and length of defect as defined in BP Specification SPC-PP-00090. As can be seen from the curve, the criteria for allowable operating service condition is more conservative than the industry standard at the low end of the remaining wall thickness. This conservatism reflects two issues, (a) the need to provide a margin for error in the determination of wall thickness and corrosion rate, and hence remaining life, and (b) the decreased accuracy of the NDE techniques in use at a wall thickness of less 100 mils.

**ANSI B31G Interaction Rules of Corrosion Network Length
24 OD x .375 WT @ 675 psig Design Pressure**



GPB Figure E.7 Fitness-for-Service Envelope Based on BP SPC-PP-00090

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

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

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

and

- Minimum thickness, regardless of pressure retaining calculation, is equal to the greater of 0.100 inch or 20% remaining wall thickness

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

Section E.4 Correlation Between Inspection and Corrosion Monitoring⁷

As noted in GPB Table B.12, inspection and corrosion monitoring have different characteristics; in particular, inspection techniques are comparatively insensitive but are the most accurate as they measure actual wall loss. In contrast, corrosion monitoring is more sensitive but less accurate as a measure of corrosion rate as the weight loss coupon is not an integral part of the pipe wall.

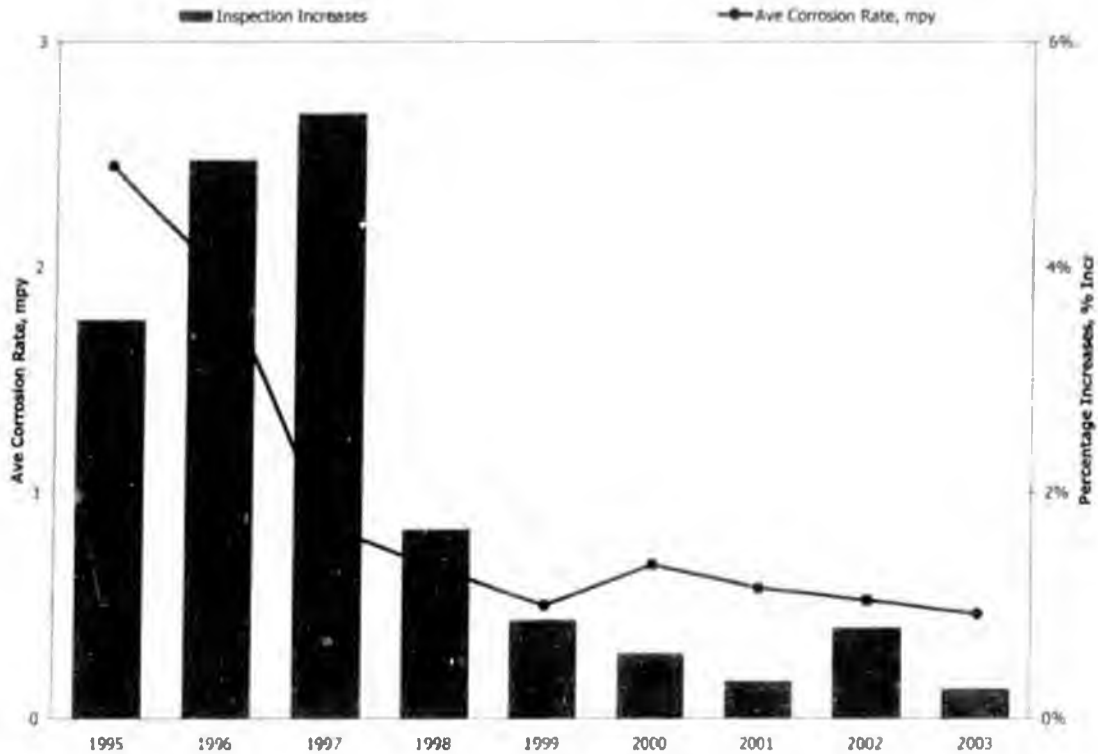
Therefore, in order to have good confidence in the results from the corrosion-monitoring program, it is necessary to show a correlation between the chosen monitoring program and the results of the inspection program. The following section describes the correlation between inspection and monitoring programs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

GPB Figure E.8 shows a similar decreasing trend in average corrosion rate from WLC and the percentage of increases found in the inspection program for the 3-phase well line and flow line. It should be noted that the inspection results included in the analysis are not the full data set but has been refined to include only that data which has an inspection interval (time since last inspection) of less than 730 days (two years). Also, the indicated reporting year has been changed to reflect the mid-point of the inspection interval rather than the time of inspection as in the other figures in this report. This change in the reporting time compensates for the fact that corrosion is occurring over the entire time interval between inspections. Similarly, the weight loss coupon corrosion rates are reported as the mid-point of the exposure period not the removal date.

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

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

⁷ In addition to Charter Work Plan, this information supplied to provide additional context and help in understanding BPXA's corrosion management activities



GPB Figure E.8 Correlation of Corrosion Rate and %Increases, 3-phase Production

A similar degree of correlation exists between the corrosion monitoring and the inspection data for the water injection systems. GPB Figure E.4 and GPB Figure E.5 show increasing corrosion activity in both the flow lines and well lines for the water system, which is also reflected in the corrosion monitoring data depicted in GPB Figure C.15 and GPB Figure C.16.

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

Section E.5 In-line Inspection

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

It is important to note that because the vast majority of the cross-country flow lines are above ground, the value of ILI data are considerably lessened

compared to buried or underground systems. The primary value for GPB is in the initial identification and location of damaged locations within a pipeline system. Having initially identified the location of damaged areas, the long-term integrity, pipeline condition and current corrosion rate, of the flow line can be more effectively managed through the use of targeted manual NDE techniques.

Having established the condition and location of damaged sections of line the locations are then added to the routine NDE program where the condition and fitness-for-service is determined and where the on-going corrosion rate and level of corrosion mitigation can be monitored.

There are limitations with the ILI technology currently used at GPB. A typical high resolution⁸ MFL smart pig gives wall thickness measurements that are $\pm 10\%$ of the nominal wall thickness and sizing resolution of 3 times wall thickness for length and width assessment. In addition, there are temperature and pressure limitations that prevent or make difficult the use of MFL tools in many lines at GPB. The typical upper operating temperature for the MFL tools is 122°F/50°C compared with a typical separator fluids temperature of 150-160°F/65-71°C.

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

When used, smart pig inspections are performed to gain a relative understanding of pipeline condition and rate of deterioration and/or to provide confidence that the internal and external conventional inspection programs have identified locations where mechanical integrity is at risk. Because MFL tools do not directly measure pipeline condition, results from in-line inspections are not reported in as received from the smart pig service company but are reported as part of the overall NDE summary.

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

In 2003, three 3-phase production flow lines were examined by smart pig (MFL) inspection. One of these lines, PTMCLS01/02, had not previously been subject to ILI, the other two, S-36 and Y-36, were last smart pigged in 1997. GPB Table E.7 summarizes equipment service, diameter, and length.

⁸ MFL manufacturer technical data sheet

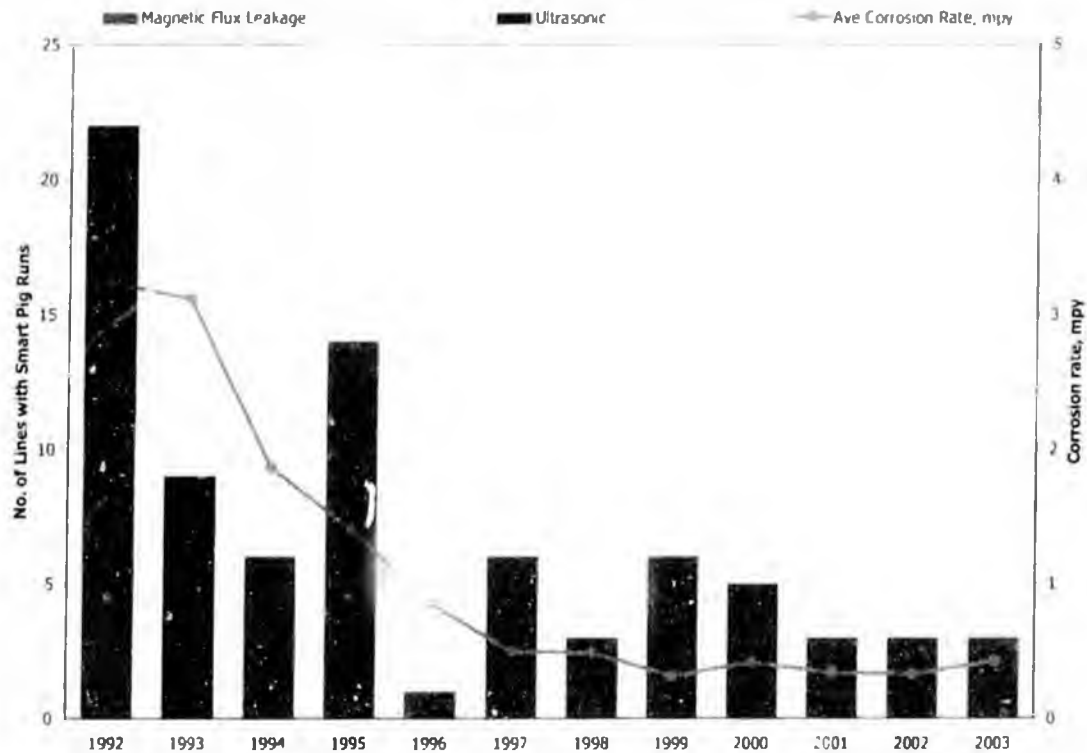
Part 1 – Greater Prudhoe Bay Performance Unit

Equipment	Service	Diameter	From	To	Length (ft)
PTMCLS01/02	3 Phase	24"	Drill Site LS01	LPC	25,725
S-36	3 Phase	24"	S Pad	GC2	32,444
Y-36	3 Phase	24"	Y Pad	GC1	33,478

GPB Table E.7 Completed Smart Pig Assessments

Metal loss features reported in each of the lines smart pigged have been prioritized for verification by radiographic and/or ultrasonic inspection. The verification results through 2003 are included in the aggregate inspection data. As a result of the verification process in 2003, two (2) repairs were identified resulting from external corrosion degradation. Additional follow-up of the reported features is an ongoing part of the normal radiographic and ultrasonic NDE activity at GPB.

GPB Figure E.9 shows the ILI activity level from 1992 through 2003. The level of activity has fallen from a high of 25 in-line inspections per year in 1992 to 3 inspections completed in 2003. In addition to the ILI activity level, the chart also shows the average corrosion rate for the oil service flow lines.



GPB Figure E.9 Historical Smart Pig Activity and Corrosion Rate

The reduction in ILI activity level coincides with the decline in corrosion rate and reflects the change in emphasis of the program. As the corrosion rates have fallen, the immediate concern of the program has shifted from the short-term integrity of the flow line, which is focused on condition, to the long-term integrity of the flow line, which has a dual focus of remaining wall thickness and corrosion rate. This long-term integrity is better managed through higher resolution methods such as corrosion monitoring and manual radiographic and ultrasonic NDE.

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

Section E.6 Inspection Summary

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

- The external corrosion inspection program, at >35,000 items, for 2003 was above the target. Approximately 4% of these inspections showed damage, which is consistent with the overall average in recent years.
- The cased piping survey completed a base line inspection on all pipeline segments as agreed with ADEC and the program is continuing to evolve into a process of monitoring and corrective action.
- A unified internal inspection philosophy and program structure has been implemented across GPB with a total program size of approximately 60,000 items.
- The inspection results for both the flow line and well line 3-phase systems show improved performance in the long term. In the short term there is a slight increase in the corrosion activity. This is expected to be reversed following the trend seen in the corrosion coupon program as a result of the better performance of the corrosion inhibitor.
- The water injection systems show a long term improving trend. However, there is an increase in the corrosion activity in the short term and, as discussed in Section C.2, corrective actions have been put in place in the sea water system and additional inhibition has been added in 2002 to the produced water system.
- The inspection interval and fitness-for-service criteria, as defined by B31G, were discussed in the context of the current piping corrosion rate and piping condition.
- The results of the inspection program and the weight loss coupon program from the 3-phase oil service were shown to be strongly correlated. The reduction in corrosion activity from both measures being

attributable to the implementation of an aggressive and increasing corrosion inhibition program in the 3-phase flow lines since 1995.

- A similar level of correlation was seen in the water injection system information for both inspection and corrosion monitoring.

Year	Cased Pipe Location	Equipment Excavated	Observation	Corrective Action
1992	COTU Access Road	FS1 to FS2 12" MI Distribution	10% external wall loss	Insulation/coating/tape repair
1995	S Pad West Entrance Crossing	S Pad 24" 3 Phase Production	61% external wall loss	Sleeve/insulation/coat repair
		S Pad 14" Produced Water	36% int/ext wall loss	Sleeve/insulation/coat repair
		S Pad 10" Gas Lift	34% external Wall Loss	Insulation/coating repair
		S Pad 8" Miscible Injection	41% external wall loss	Replaced segment/FBE
GC1 Main Entrance	GC1 Main Entrance	Distribution 24" Gas Lift	29% external wall loss	Insulation/coating repair
		Y Pad 24" 3 Phase Production	24% external wall loss	Insulation/coating repair
GC2 to GC1 Caribou Crossing	GC2 to GC1 Caribou Crossing	Distribution 24" Gas Lift	42% external wall loss	Sleeve/insulation/coat repair
		Y Pad 24" 3 Phase Production	26% external wall loss	Insulation/coating repair
1996	GC-1 Spine Road	Distribution 24" Gas Lift	53% external wall loss	Sleeve/insulation/coat repair
		D Pad 24" 3 Phase Production	33% external wall loss	Insulation/coating repair
		Y Pad 24" 3 Phase Production	18% external wall loss	Insulation/coating repair
		Distribution 20" Produced Water	8% external wall loss	Insulation/coating repair
E Pad Entrance	E Pad Entrance	E Pad 24" 3 Phase Production	21% external wall loss	Insulation/coating repair
GC3 to FS3 Caribou Crossing	GC3 to FS3 Caribou Crossing	Distribution 24" Gas Lift	No corrosion damage	None
FS1 to FS2 Caribou Crossing	FS1 to FS2 Caribou Crossing	Distribution Natural Gas 30"	11% external wall loss	Insulation/coating/tape repair
		Sales Oil 30"	14% external wall loss	Insulation/coating/tape repair
		Distribution 24" Gas Lift	No corrosion damage	None
		Distribution 32" Sea Water	No corrosion damage	None

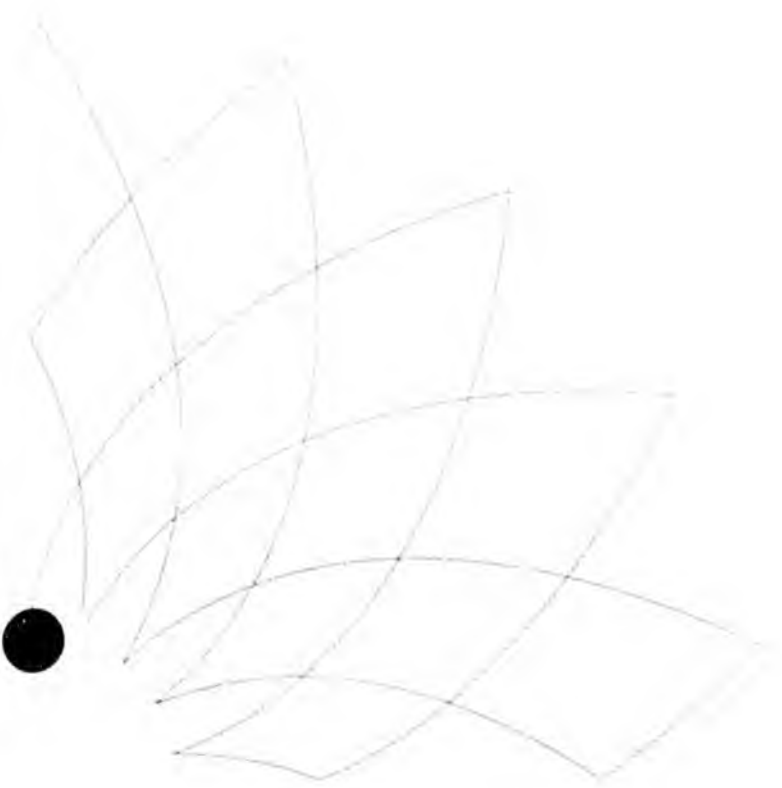
GPB Table E.8 Cased Piping Excavation History

Year	Cased Pipe Location	Equipment Excavated	Observation	Corrective Action
1998	S Pad East Entrance Crossing	S Pad 10" Gas Lift	~80% wall loss - ext rupture	Replaced segment
	GC2 to GC1 Caribou Crossing	Distribution 24" Gas Lift	9% external wall loss	Insulation/coating repair
	GC2 to GC1 Q Pad Rd Crossing	Distribution 34" Natural Gas	No corrosion damage	Insulation/FBE coated
2000	S Pad East Entrance Crossing	S Pad 24" 3 Phase Production	~60% external wall loss	Replaced segment/coat repair
		S Pad 14" Produced Water	~50% external wall loss	Replaced segment/coat repair
		S Pad 8" Miscible Injection	25% external wall loss	Sleeve/insulation/coat repair
2003	GC2 to GC1 Caribou Crossing	Y Pad 24" 3 Phase Production	Leak -external corrosion	Partial excavation/sleeve repair
	X Pad Pipeline Access Rd Crossing	X Pad 24" 3 Phase Production	~75% external wall loss	Partial excavation/sleeve repair
	F Pad Pipeline Access Rd Crossing	F Pad 24" 3 Phase Production	24% external wall loss	Partial excavation/none
	NGI Pad Road Crossing	NGI Pad 14" Gas Cap Injection	58% external wall loss	Replaced segment

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

Section F

Repair Activities



Section F Repair Activities

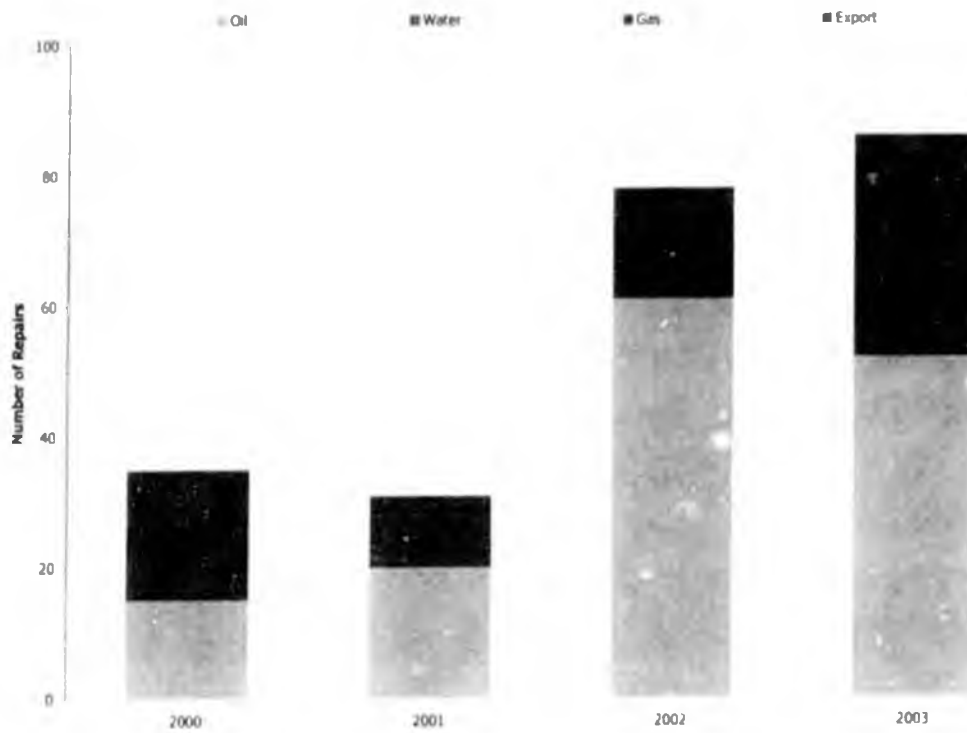
The repair activities shown in GPB Table F.1 include a total of 86 repairs as compared to 78 in year 2002. GPB Figure F.1, GPB Figure F.2, GPB Figure F.3, and GPB Table F.2, show the 4-year trend in repairs grouped by service, damage mechanism, and equipment, respectively.

Service	Type	Internal	External	Mechanical	Total
Oil	FL	-	28	1	29
	WL	3	20	-	23
PW	FL	-	-	-	-
	WL	-	1	-	1
SW	FL	-	-	-	-
	WL	-	-	-	-
Gas	FL	-	23	1	24
	WL	-	8	1	9
Total		3	80	3	86

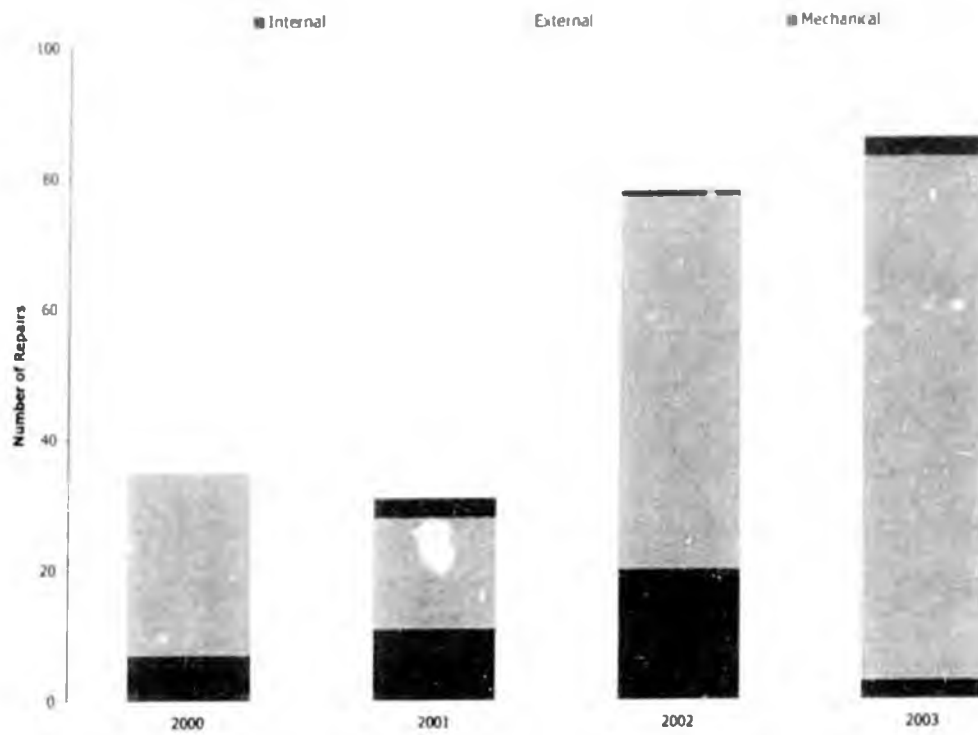
GPB Table F.1 2003 Repair Activity

Of the 86 repairs, 80 were associated with external corrosion and reflect the continued emphasis on external corrosion inspection. All three (3) internal corrosion related repairs were on well lines.

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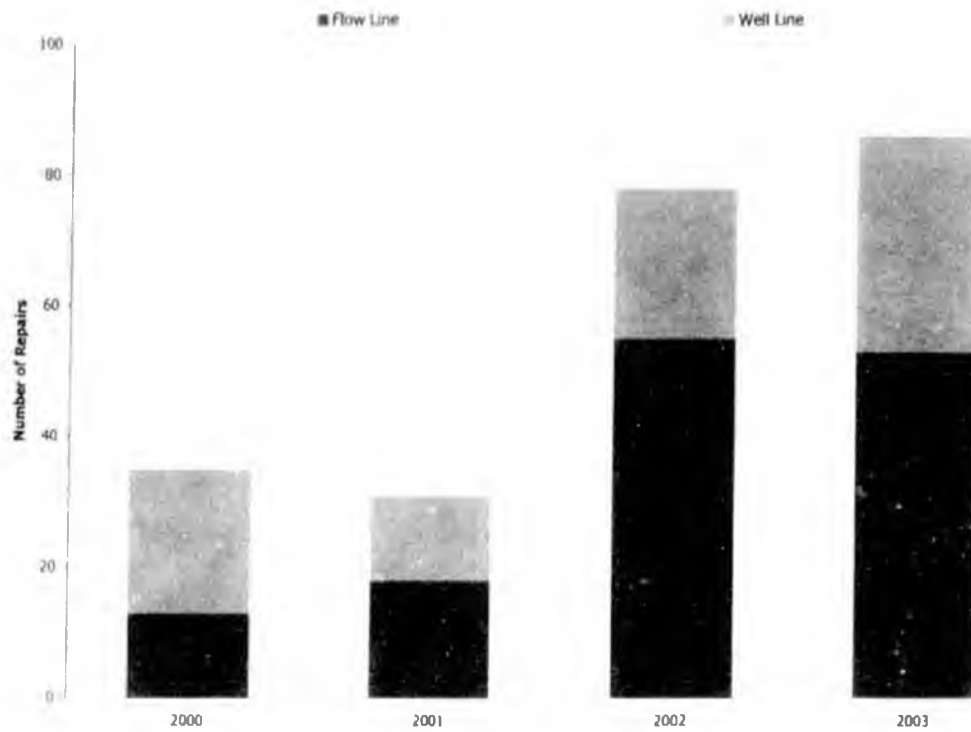


GPB Figure F.1 Repairs by Service



GPB Figure F.2 Repairs by Damage Mechanism

Section F Repair Activities



GPB Figure F.3 Repairs by Equipment

In summary, there was a small increase in the number of repairs in 2003 compared to 2002, 78 and 88 respectively. External repairs dominate the level of repair activity, which reflects the continued emphasis on the external corrosion program.

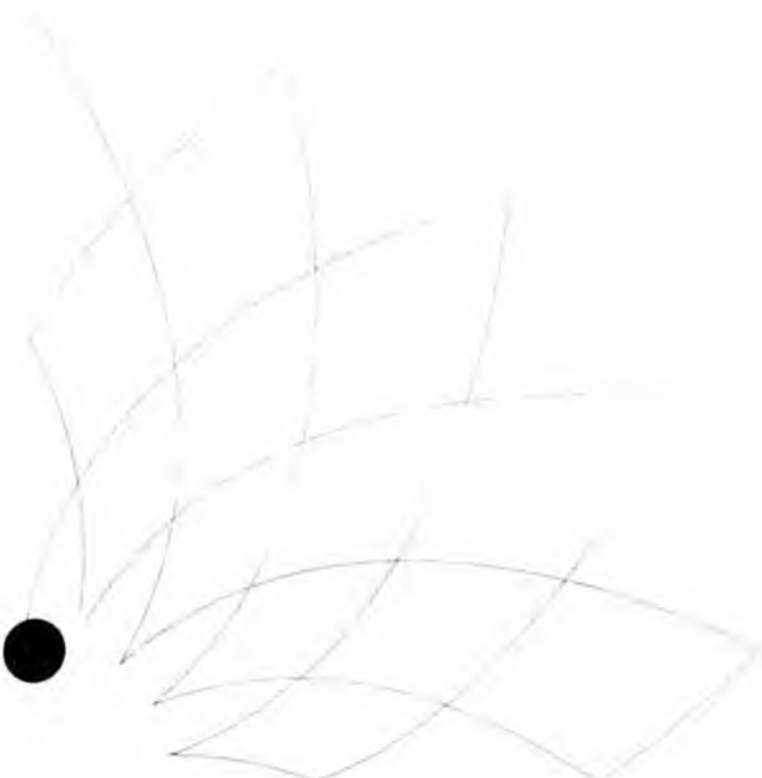
Section F Repair Activities

	Oil		Water		Gas		PO	Total
	Flow Line	Well Line	Flow Line	Well Line	Flow Line	Well Line	Flow Line	
2000								
Internal	2	5	-	-	-	-	-	7
External	1	7	2	7	8	3	-	28
Mechanical	-	-	-	-	-	-	-	0
Total	3	12	2	7	8	3	0	35
2001								
Internal	2	4	1	1	-	-	3	11
External	7	5	3	-	2	-	-	17
Mechanical	-	2	-	-	-	1	-	3
Total	9	11	4	1	2	1	3	31
2002								
Internal	8	7	1	4	-	-	-	20
External	35	11	6	1	4	-	-	57
Mechanical	-	-	-	-	1	-	-	1
Total	43	18	7	5	5	0	0	78
2003								
Internal	-	3	-	-	-	-	-	3
External	28	20	-	1	23	8	-	80
Mechanical	1	-	-	-	1	1	-	3
Total	29	23	0	1	24	9	0	86
Grand Total	84	64	13	14	39	13	3	230

GPB Table F.2 Historical Repairs by Service

Section G

Corrosion and Structural Related Spills and Incidents



Section G Corrosion and Structural Related Spills and Incidents

Section G.1 Corrosion Related Leaks

This section summarizes the corrosion and structural related incidents that occurred in 2003 and provides a historical perspective on the leaks (loss of containment) and saves (repairs before leak of non-FFS equipment).

GPB Table G.1 summarizes the equipment, failure mechanism and volume of leaks due to corrosion that occurred in 2003. Of the 2 leaks that occurred in 2003, 1 was associated with external corrosion and 1 with cyclic fatigue cracking.

Service	Location	Type	Date	Mechanism	Volume
3-phase production	Y-36	FL Caribou X-ing	26-May-03	CUI	Oil - 1,325 gal. PW - 4,986 gal
Gas	W/Z-804	FL	08-Dec-03	Mech	NGL - 0.5 gal

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

GPB Table G.1 2003 Leaks Due to Corrosion/Erosion

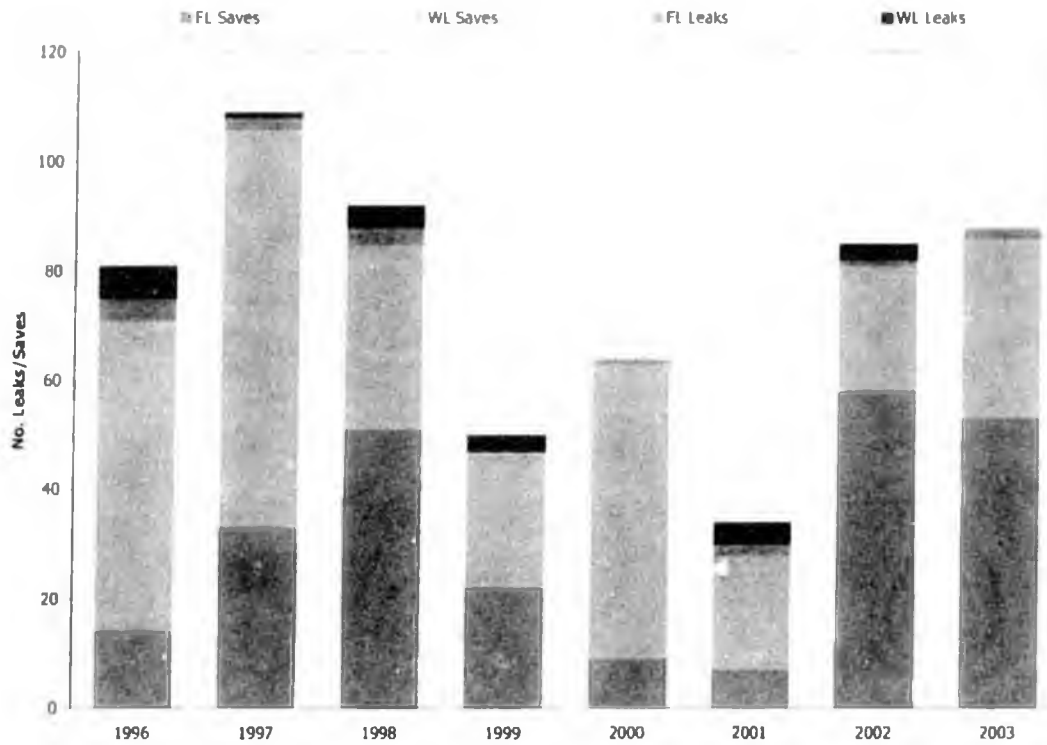
GPB Table G.2, GPB Figure G.1 and GPB Figure G.2 show the number of corrosion related leaks and saves from 1996 through 2003. The ratio of leaks to saves provides a high level measure of the performance of the inspection program at detecting severe damage before it results in a failure. A 'save' is defined as a location found via the inspection program that warrants a repair, system derate, replacement or removal from service as the equipment no longer meets the FFS criteria defined in Section E.3. It should be noted that items are typically scheduled for repair at 105% of design pressure, to allow time to schedule and complete the repair before the item requires removal from service.

The significant increase in number of saves is a direct result of the ramp-up of the external inspection program.

Part 1 – Greater Prudhoe Bay Performance Unit

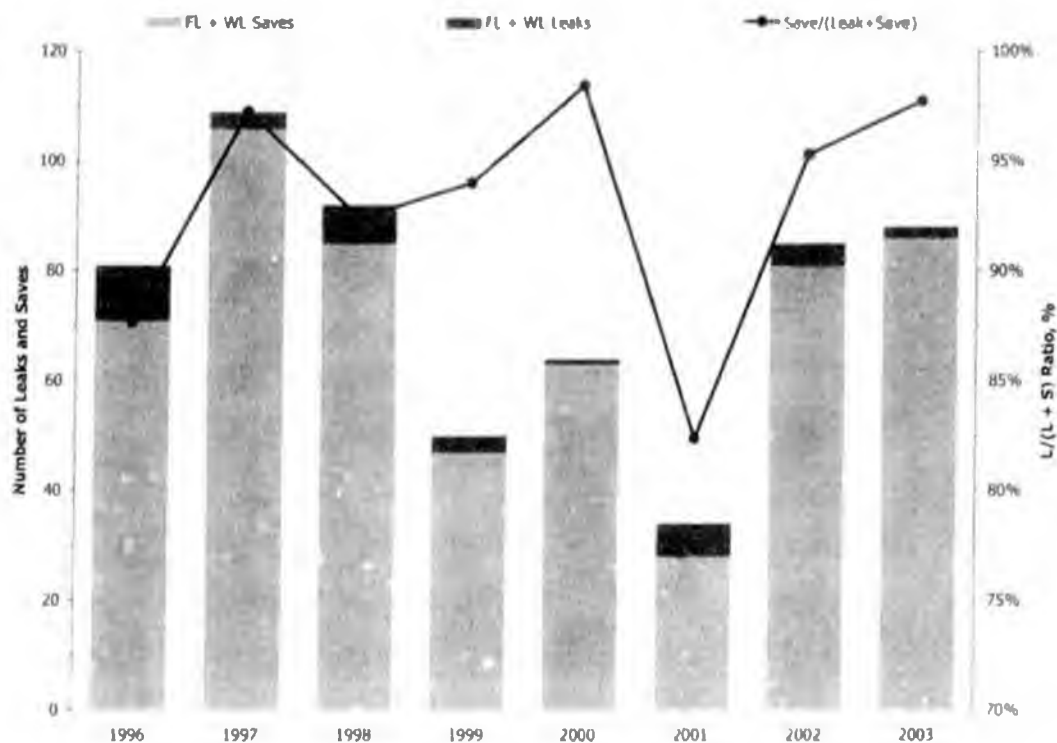
	Flow Lines			Well Lines			Tota:
	Saves	Leaks	$\frac{S}{(L + S)}\%$	Saves	Leaks	$\frac{S}{(L + S)}\%$	$\frac{S}{(L + S)}\%$
1996	14	4	78%	57	6	90%	88%
1997	33	2	94%	73	1	99%	97%
1998	51	3	94%	34	4	89%	92%
1999	22	0	100%	25	3	89%	94%
2000	9	1	90%	54	0	98%	97%
2001	7	2	78%	21	4	84%	82%
2002	58	1	98%	23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

GPB Table G.2 Historical Corrosion Leaks and Saves



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

Section G Corrosion and Structural Related Spills and Incidents



GPB Figure G.2 Historical Corrosion Leaks and Saves

Section G.2 Structural Integrity Issues

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

Section G.2.1 Walking Speed Survey

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

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

- Piping and insulation
- Structural components
- Electrical equipment
- Instrumentation equipment
- Communication equipment

- Chemical injection tubing
- Pipe line road and animal crossings

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

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

GPB Table G.3 Structural/Walking Speed Survey Schedule

A WSS of the GPB west flow lines was completed in 2003.

Section G.2.2 Routine Surveillance

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

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

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

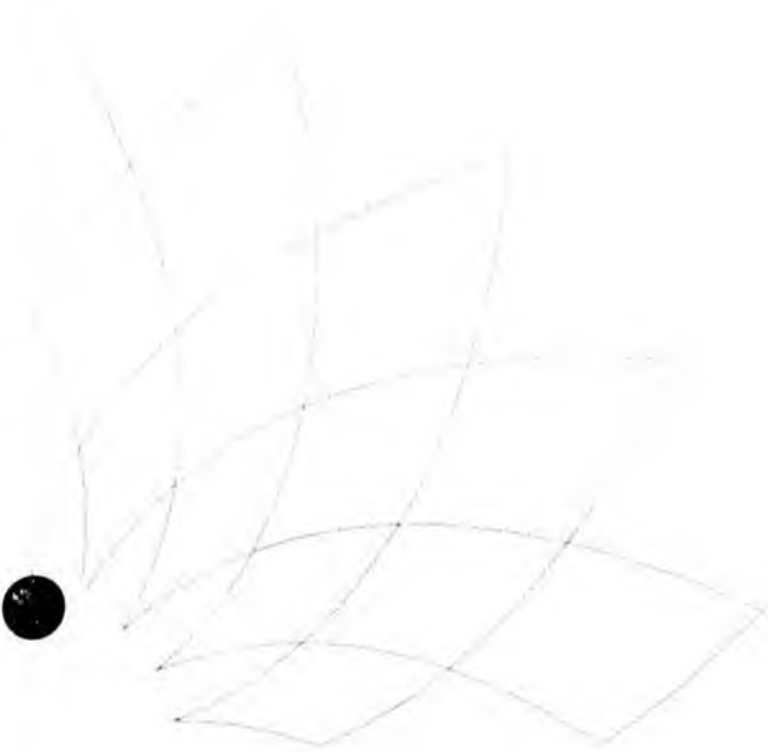
Section G.2.3 2003 Summary

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

In December 2003 there was one structural related pipeline failure (10" W/Z 804) as a result wind induced vibration, or cyclic fatigue. The failure occurred at a mid-span girth weld and the pipeline was shut-in for the remainder of 2003.

Section H

2003 Corrosion Monitoring and Inspection Goals



Section H Corrosion Monitoring and Inspection Goals

Section H.1 2003 Corrosion and Inspection Goals Reviewed

Overall, through 2003, the corrosion inspection, monitoring and mitigation programs were expected to be substantially unchanged from 2002. In particular, the corrosion control target of less than 2 mpy remained in place with the inspection and monitoring activity levels to again be substantially as 2002.

Section H.1.1 Corrosion Monitoring

The weight loss coupon program frequency was expected to remain unchanged in 2003 compared to the prior year 2002 and is summarized in GPB Table H.1.

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

GPB Table H.1 Coupon Pull Frequency

As a consequence, the activity level from the weight loss coupon program was anticipated to be similar in 2003 to that seen in 2002 and indeed this was the case. There were some changes in 2003 in the number of coupons reported compared to prior years. This is as a result of the following factors:

- Continued efforts to clean historical data records
- Addition of water injection coupons from the facilities to the reported data set
- The removal and addition of equipment associated with abandonment and installation of satellite production equipment.
- The historical data was update to reflect the current equipment inventory

The ER probe program for 2003 was planned to be substantially the same as 2002 with probes being located on the 3-phase production lines. The 2003 result was largely as anticipated with the exception that the level of reliability of the ER probes systems was improved to more consistently deliver data throughout the year.

Section H.1.2 Inspection Programs

The fundamental elements (CRM, ERM, FIP, CIP and CUI) form the foundation for the inspection program. There were no major changes for this program anticipated in 2003 with an overall combined internal and external activity level of 60,000 items.

There were 3 smart pig runs forecast for 2003 and these were completed as planned.

Corrosion under insulation or external corrosion inspection activity was substantially increased in 2002. This increased level of activity was expected again in 2003 with the approximately 35,000 planned items completed as expected.

2003 also represented the conclusion of a 5-year program of work to baseline all the single-line cased piping segments across GPB. At the start of 2003 this was forecast to be approximately 280 cased piping locations. However, as a result of the Y-36 incident, this program ultimately ended-up being substantially greater than this forecast value. All cased piping segments were visually inspected and more than 450 locations were inspected with 'long-range' inspection.

Section H.1.3 Chemical Optimization

For 2003 there were forecast to be no large-scale changes in the corrosion mitigation program and this proved to be the case. However, developments in the small scale testing of corrosion inhibitors continued throughout the year resulting in a substantial increase in well line test results in 2003 compared to prior years.

Section H.1.4 Program Reviews

A number of reviews were conducted during 2003, including:

- **GPB Partner Reviews** – Regular reviews of the corrosion management program at GPB were conducted with the corrosion and integrity experts from the major GPB partners.
- **DOT IMP Audit** – The procedures for analyzing and assessing ILI data and for assessing fitness-for-service for DOT regulated pipelines were presented to the DOT IMP Audit Team. It should be noted that these procedures are substantially the same as those used for non-common carrier pipelines described in this report.
- **BP Internal Integrity Management Review** – A BPXA internal review team conducted an Integrity Management Audit which included a review of the corrosion and inspection program covered under the Charter Agreement

- **ADEC Review** – ADEC and their third party consultant reviewed and commented on the BPXA Corrosion Monitoring Charter Agreement report and Meet and Confer sessions.

Section H.1.5 2003 Corrective Actions

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

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

Equipment ID	No. of Action	Cause	Action
01D	5	Increased Corrosivity	Increased CI by 30%
01D & 01C	1	Increased Corrosivity	Increased CI by 5%
03D	3	Increased Corrosivity	Increased CI by 25%
05D	1	Increased Corrosivity	Batch Pad. Increased CI 25 gpt
16D	2	Increased Corrosivity	Increased CI by 10%
17D	1	Increased Corrosivity	Increased CI by 5%
F-49	1	Increased Corrosivity	Increased CI by 5%
U-384	1	Increased Corrosivity	Increased CI by 5%
Y-36	6	Increased Corrosivity	Increased CI by 57%

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

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

Equipment ID	No. of Action	Cause	Action
14D	1	Increased Corrosivity	Increased CI by 10%
Q-01	1	Increased Corrosivity	Increased CI, Dilute Pad
Q-01	1	Line Shut-In	No Action
Q-06	1	Line Shut-In	No Action
13B	1	Increased Corrosivity	10% Pad increase

GPB Table H.3 Corrective Mitigation Actions from Coupon Data

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

Equipment ID	No. of Action	Cause	Action
Y-36	2	Increased Corrosivity	Increased CI by 20%
W-74	1	Increased Corrosivity	Increased CI by 10%
PMTCL	1	Increased Corrosivity	Increased CI by 20%
CL16C/17C	1	Increased Corrosivity	Increased CI by 5%

GPB Table H.4 Corrective Mitigation Actions from Inspection Data

Section H.2 2004 Corrosion Management Goals

The 2004 corrosion and inspection goals will be focused on the continued delivery and optimization of the current programs. In general, there are not expected to be any substantial changes in the overall scope and scale of the 2004 effort in comparison to 2003.

Section H.2.1 Corrosion Monitoring

There are no plans to significantly change the corrosion weight loss coupon-monitoring program in 2004. The emphasis in the produced water and 3-phase production system will be on sustaining the current level of performance, and in the seawater system maintaining the progress made in 2003.

Section H.2.2 Inspection Programs

The overall 2004 internal inspection program is planned to be substantially unchanged in 2004 from that implemented in 2003. The expected activity level will again be approximately 60,000 inspection items in total distributed between the field and facilities. Of the overall 60,000 inspection items approximately 45% will be associated with cross country flow line and well lines and hence be reported under the Charter Agreement Work Plan.

The external program increased substantially in 2002 with this program increase continuing into 2003 at approximately 35,000 items per year. The current schedule for 2004 is for this level of external corrosion activity to continue at the 2003 pace at 35,000 inspection items for the full year.

2003 saw the completion of the 5-year base-line inspection on all the cased piping segments. As a result of completing the base-line survey the character of the cased piping inspection work will change in 2004 as the program moves into a phase of monitoring and planned mitigation based on the results of the base-line survey work. The 2004 work scope for cased piping is scheduled to be approximately 100 inspections.

The ILI program is planned to be of a similar scale to 2003 dependant upon tool availability and capability.

Section H.2.3 Chemical Optimization

Corrosion inhibition will continue to be the primary means of internal corrosion control at GPB. The emphasis for 2004, as with 2003, will be on the optimization of treatments to minimize the variability in injection rates between planned and actual dosage.

For 2003 the main corrosion inhibitor in use across GPB was unchanged and the program focused on improving the field-testing protocol and analysis techniques. With the introduction of the improved test procedure it is expected that a number of large-scale field trials will take place in 2004 based on the results of the well line test program. While the outcome of these large scale trials can not be predicted, it is anticipated that as a result of the large scale test work, a more effective corrosion inhibitor could be introduced into the field either late 2004 or early 2005.

The changes in the chemical programs in the SW system have reduced corrosion rates, however, the data set available to date is limited and no long-term trends have been established. It is therefore anticipated that there will still be considerable focus on seawater system corrosion rates for 2004.

Section H.2.4 Program Improvements and Modification

3 Phase Production System - The 3-phase flow line production system corrosion control is currently operating at approximately 99% conformant with the corrosion rate target of 2 mpy or less. The goal for 2004 will be to move the current level of corrosion control in the well lines toward these higher levels of performance compared with the current level of 95% less than or equal to the 2 mpy target.

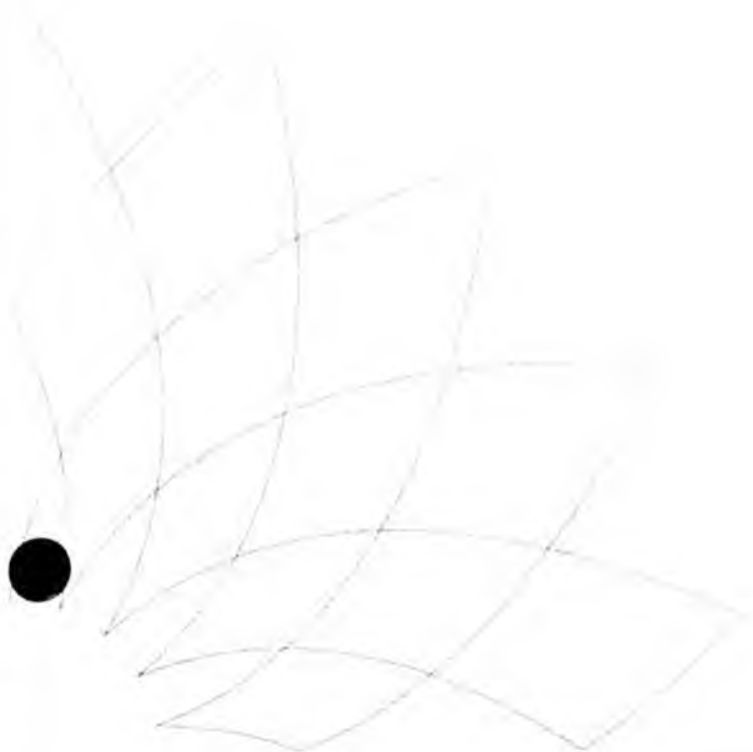
Produced Water System - The produced water system shows improved levels of corrosion control and therefore the goal for 2004 will be to maintain this level of control as water rates continue to rise across the field.

Seawater System - This system has been the focus of significant effort in recent years due to unacceptably high corrosion rates. A number of significant actions have been taken to address dissolved oxygen levels and microbiological corrosion control. These efforts have resulted in data for 2003 showing a significant improvement in corrosion control performance. As noted, this data are preliminary and limited, and therefore the seawater system will continue to be an area of focus and attention through 2004.

Cased Piping Inspection - The cased piping inspection completed the 5-year baseline survey in 2003. The program will therefore be evolving in 2004 from this initial assessment activity into a period of monitoring and planned mitigation.

Part 2 – Alaska Consolidated Team Performance Unit

Section B-H



Section B Corrosion Monitoring Activities

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

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

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

Endicott - Located north of Prudhoe Bay, Endicott consists of two islands, the main Production Island (MPI), and the satellite-drilling island (SDI) at the end of a causeway. Endicott 3-phase production piping is made largely of duplex stainless steel, which significantly reduces the environmental risks. Endicott production averages approximately 27,000 bpd.

Badami - Remotely located east of Prudhoe Bay, Badami had a relatively low production volume due to challenging reservoir conditions. The Badami production facilities, like other recent developments on the North Slope, are constructed using a much smaller surface footprint than GPB and do not have permanent road access, therefore having a much reduced impact on the environment. Production from Badami was shut in during the third quarter of 2003. There are currently no plans to bring Badami production back online in the foreseeable future.

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

ACT Table B.1 illustrates, on a relative basis, the unique corrosivity of each producing field within ACT along with the materials of construction and corrosion mitigation. GPB is included in the table for comparative purposes. Listed in the table are, for each field, the typical water cut in percent, average wellhead temperature, and the percent CO₂ in the produced gas.

Field	Prod Fluid Characteristics				Material of Construction ^(a)			
	H ₂ O (%)	T (°F)	P _{CO₂} (%)	CR ^(b)	Production		Injection	
					WL	FL	WL	FL
GPB	72	150	12	H	CS+CI	CS+CI ^(c)	CS+CI	CS+CI
END	89	150	18	H	DSS	DSS	CS+CI	CS+CI
MPLI	49	125	1.5	L/M	CS	CS ^(d)	CS+CI	CS+CI
Northstar	4	160	5	M	CS+CI	N/A	N/A	N/A
Badami	~0	65	~0	L	CS	N/A	N/A	N/A

Notes

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

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

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

ACT Table B.2 shows the ACT fields combined are of a much smaller scale than GPB. For example, neither Northstar nor Badami have any significant non-common carrier cross-country flow lines. Also, it should be noted, that when comparing GPB and ACT facilities, these facilities vary in age from over 26 years for GPB to ~24 months for Northstar.

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

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

Section B.1. Endicott

Endicott is a mature waterflood field. The fluid properties (high temperatures, high CO₂ content) indicate the corrosivity of the produced fluids to be high. Due to this high corrosivity, the majority of the oil production system was fabricated from duplex stainless steel, a corrosion resistant alloy and therefore, corrosion is

not a significant concern for this system. In the oil production system, the only carbon steel is the C-Spool, connecting the wellhead to the duplex stainless steel well line. These C-Spools are inspected regularly and replaced when no longer fit-for-service as per the criteria discussed in Section E.3. ACT Table B.3 reflects the historical inspection activity level for Endicott.

Service	Length (Miles)	Int. Insp.			Ext. Insp. ¹		
		2001	2002	2003	2001	2002	2003
Oil x-country lines	3.5	4 (in vault)	4 (in vault)	14 (4 in vault)	4 (in vault)	4 (in vault)	4 (in vault)
Oil - Well Pads	2.5	1,134	1,327	1,531	-	-	-
Water x-country lines	3.5	104	104	229	4 (in vault)	4 (in vault)	4 (in vault)
Water - Well Pads	1.7	194	200	224	2 (in vault)	9 (in vault)	5
Gas x-country (GLT/MI)	7	4 (in vault)	15	45	4 (in vault)	4 (in vault)	774
Gas - Well Pads	1.2	40	26	29	2 (in vault)	9 (in Vault)	69
Fuel Line - Gasoline	N/A	-	5 foot excavation	-	-	5 foot excavation	-
Fuel line - diesel	N/A	-	5 foot excavation	-	-	5 foot excavation	-
Totals		1,480	1,686	2,072	16	40	856

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

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

The primary corrosion concerns are in the water injection system, mainly the Inter-Island Water Line (IIWL) carrying injection water to the satellite drilling 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 effectiveness of corrosion control on the IIWL is monitored by ultrasonic inspection at 25 locations.

Section B.2 Milne Point

The primary corrosion concerns are in the water injection system and 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, corrosion rates, as exhibited by weight loss coupons, have dropped significantly over the past three years.

Although the low temperatures and low CO₂ content of the production fluids result in lower corrosivity for MPU, solids contribute to the corrosion mechanism of the production system. Corrosion inhibition of the K-pad production flow line was initiated in 2001 and the F-L-C Pads flow line in 2003. Additionally, corrosion inhibition of the newly developed S-Pad began late 2002.

ACT Table B.4 reflects the historical inspection activity for MPU from 2001-2003.

Service	Length (Miles)	Int. Insp.			Ext. Insp.		
		2001	2002	2003	2001	2002 ²	2003
Oil x-country lines	24	73	80	465	225	-	964
Oil – Well Pads	N/A ¹	363	754	2,754	265	47	N/A ³
Water x-country	15	29	35	185	138	-	97
Water – Well Pads	N/A ¹	90	449	635	142	23	N/A ³
Gas x-country	14	31	-	20	715	-	522
Gas – Well Pads	N/A ¹	43	283	99	92	-	N/A ³
Water/Alternating Gas Well Pads	N/A ¹	-	-	230	-	-	-
Totals		629	1,601	4,388	1,577	70	1,583

¹ Totals not available

² The external corrosion program concentrated significantly on the Oil Sales line and outside facility piping in 2002.

³ Included with internal numbers as part of the excavations.

ACT Table B.4 MPU Summary of Lines and NDE Inspections 2003

Section B.3 Northstar

Northstar began production in November 2001. Production fluid corrosivity is low to moderate, but will tend to increase over time with the injection of GPB gas into the reservoir. ACT Table B.5 summarizes the inspection program for Northstar from 2001- 2003. Data are limited as the production facility is relatively new.

Service	Length (feet)	Int. Insp.			Ext. Insp.		
		2001	2002	2003	2001	2002	2003
Oil Pipe rack	1,200	-	-	-	-	-	-
Oil - Well Pad	280	12	106	114	-	-	-
Water Pipe rack ¹	2,400	-	-	-	-	-	-
Water - Well Pad ¹	70	-	17	25	-	-	-
Gas Pipe rack	600	-	-	-	-	-	-
Gas - Well Pad	140	4	26	65	-	-	-
Totals		16	149	204	-	-	-

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

ACT Table B.5 Northstar Summary of Lines and NDE Inspections 2003

Section B.4 Badami

Low productivity necessitated the shut-in of the Badami Field in the third quarter of 2003. Shut-in consisted of de-inventory and mothball of major equipment. Prior to shut-in, Badami's production fluids were considered a low risk from a corrosivity standpoint, as there is little water production and low CO₂ content. ACT Table B.6 summarizes the inspection program for Badami.

Service	Length (Feet)	Int. Insp.	Ext. Insp.
Oil - Well Pad	840 WL, 320 HDR	21	-
Gas	240 WL, 320 HDR	5	-
Disposal Well	400	3	-

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

ACT Table B.6 Badami Summary of Lines and NDE Inspections 2003

Section B.5 Overall Inspection Activity Level

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

Part 2 – Alaska Consolidated Team Performance Unit

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

ACT Table B.7 Overall Inspection Activity Summary 2000 – 2003

Section C Weight Loss Coupons

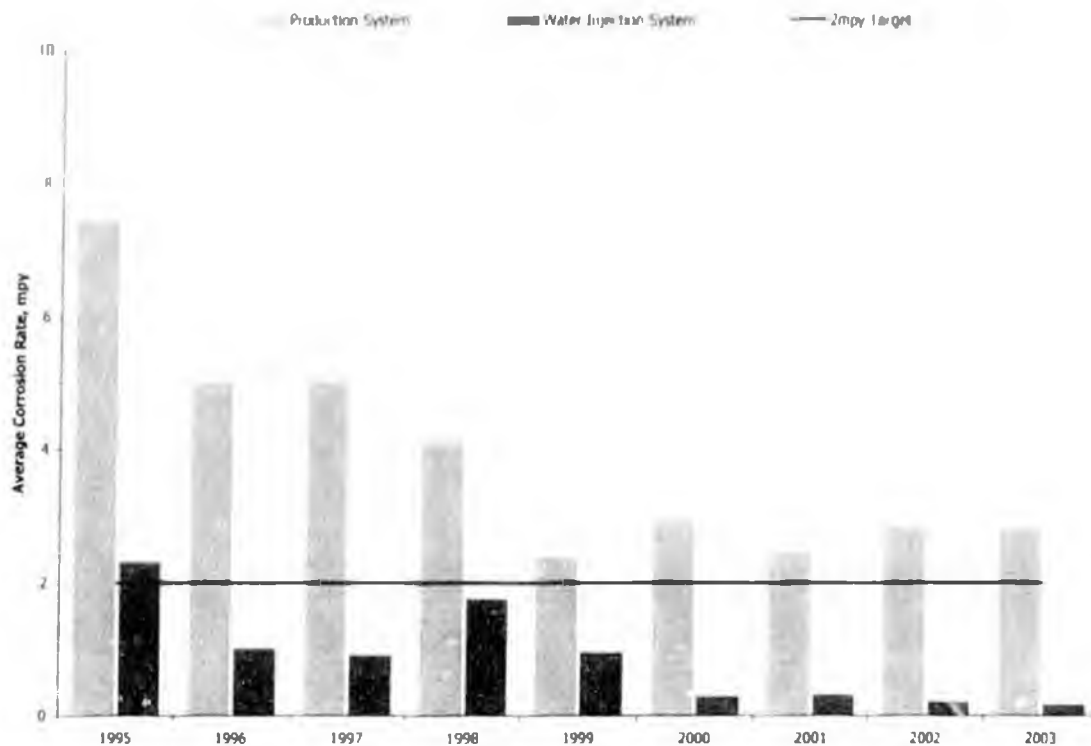
Section C.1 Endicott

ACT Table C.1 summarizes the corrosion monitoring performance for 2003 and historical data are shown in ACT Figure C.1.

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 DSS and the data are used primarily for monitoring produced fluid corrosivity and erosion tendency. The lower, relatively constant corrosion rates in the water injection system reflect the effectiveness of the corrosion mitigation program. No WLC corrosion rates above 2 mpy were experienced at Endicott in the water injection lines in 2003.

System	Access Fittings	WLC <2 mpy
Water Injection - Pads	15	100%
Water Injection - x-country	1	100%
Oil Production - Pads	76	70%

ACT Table C.1 Endicott Corrosion Coupon Monitoring 2003



ACT Figure C.1 Corrosion coupon data from Endicott 1995-2003

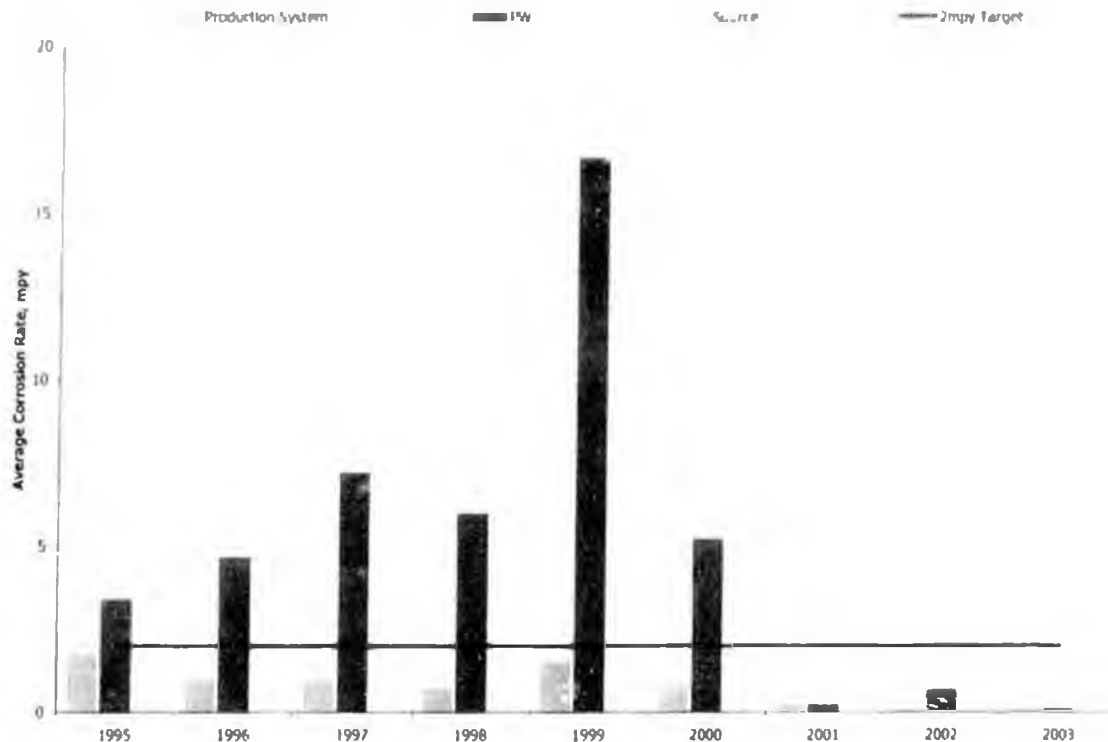
Section C.2 Milne Point

ACT Table C.2 summarizes the corrosion monitoring performance for 2003 and historical data are shown in ACT Figure C.2.

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

System	Access Fittings	WLC <2 mpy
Production System	27	100%
Water Injection System	8	100%
Source Water Coupons	6	100%

ACT Table C.2 MPU Corrosion Coupon Monitoring 2003



ACT Figure C.2 Corrosion coupon data from MPU 1995-2003

The historical WLC corrosion rate for the produced water system is greater than shown in previous reports. This is due to a reclassification of service correcting several coupons previously identified as being in produced water service to source water service.

Section C.3 Northstar

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

System	Location	Access Fittings (Pad)	No. WLC >2 mpy	% WLC <2 mpy
Oil Production				
	Upstream of CI Injection	8	7	13%
	Downstream of CI Injection	4	-	100%
Water Disposal				
	Upstream of Mud Addition	6	-	100%
	Downstream of Mud Addition	1	1	0%

ACT Table C.3 Northstar Corrosion Coupon Monitoring 2003

The 3-phase production is currently inhibited; however monitoring data indicate the corrosion rates are above the 2 mpy target. The reason is the corrosion monitoring locations are upstream of the corrosion inhibitor injection location. The table shows the inhibition program is effective in reducing corrosion rates to acceptable levels, as indicated by the monitoring locations downstream of the injection point in the facility. The coupons from the upstream location indicate the need for inhibition of the upstream section. Recommendations have been made to move the corrosion inhibitor injection further upstream to the wellhead.

The high corrosion rates in the water disposal well have been caused by highly oxygenated mud from the drilling project grind-and-inject plant. Although an oxygen scavenger has been tested in the grind-and-inject fluids, it has shown to be ineffective due to the low fluid temperatures. The drilling rig and the grind-and-inject plant are scheduled to shut down in the first quarter of 2004 and it is anticipated the corrosion rate will be reduced to the acceptable levels as seen in upstream portions of the water disposal system.

Section C.4 Badami

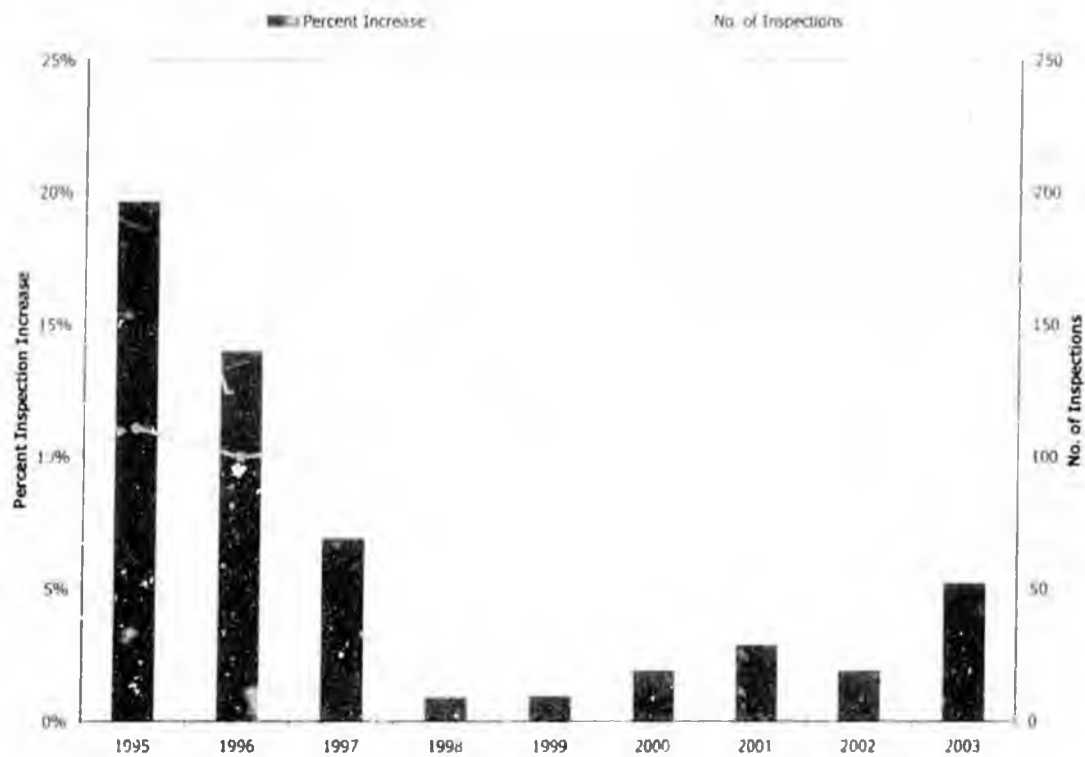
Badami currently has no WLC-monitoring program, but relies on an inspection program presented in Section E.

Section D Corrosion Mitigation Activities

Section D.1 Endicott

Corrosion mitigation for the IIWL relies on maintenance pigging for line cleanliness, biociding to control bacterial activity and continuous injection of a corrosion inhibitor for corrosion control. The primary monitoring tool for effectiveness of these programs is UT inspection.

ACT Figure D.1 shows there is an increase in corrosion activity in the IIWL in 2003 compared with 1998 to 2002. While the 2003 results are cause for concern, the results are still below the levels seen prior to 1997. The number of locations showing corrosion increases has been fairly constant over the previous three years, indicating slight corrosion activity. Unfortunately the maintenance pigging program was suspended for approximately 12 weeks in 2003 for repairs to the launcher. As a result of the pigging suspension, the IIWL experienced an increase in corrosion activity. To monitor the corrosion activity, the inspection frequency was changed from quarterly to monthly until control is once again assured. Pigging was resumed in late 2003 and current inspection data indicate corrosion is under control.



ACT Figure D.1 Endicott IIWL UT Readings Through 2003

As well as maintenance pigging, corrosion control of the IIWL relies on corrosion inhibition and biocide. Treatment volumes vary dependant upon operational

swings in injection rates and reservoir optimization efforts. However, as an additional preventative measure the continuous corrosion inhibitor concentration was increased by 17½% to 20 ppm.

In the production system, the primary damage mechanism is erosion. The erosion rate is monitored through inspection and mitigated through velocity management. Wells are risk ranked by mixture velocity once per month and the information is used to adjust the inspection frequency and fluid velocity. ACT Table D.1 is an overview of the velocity data for 2001 to 2003. Shown are the number of wells within L/R ratio ranges, where L is the mixture velocity and R is the allowable erosion velocity as defined by API RP 14E⁹.

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

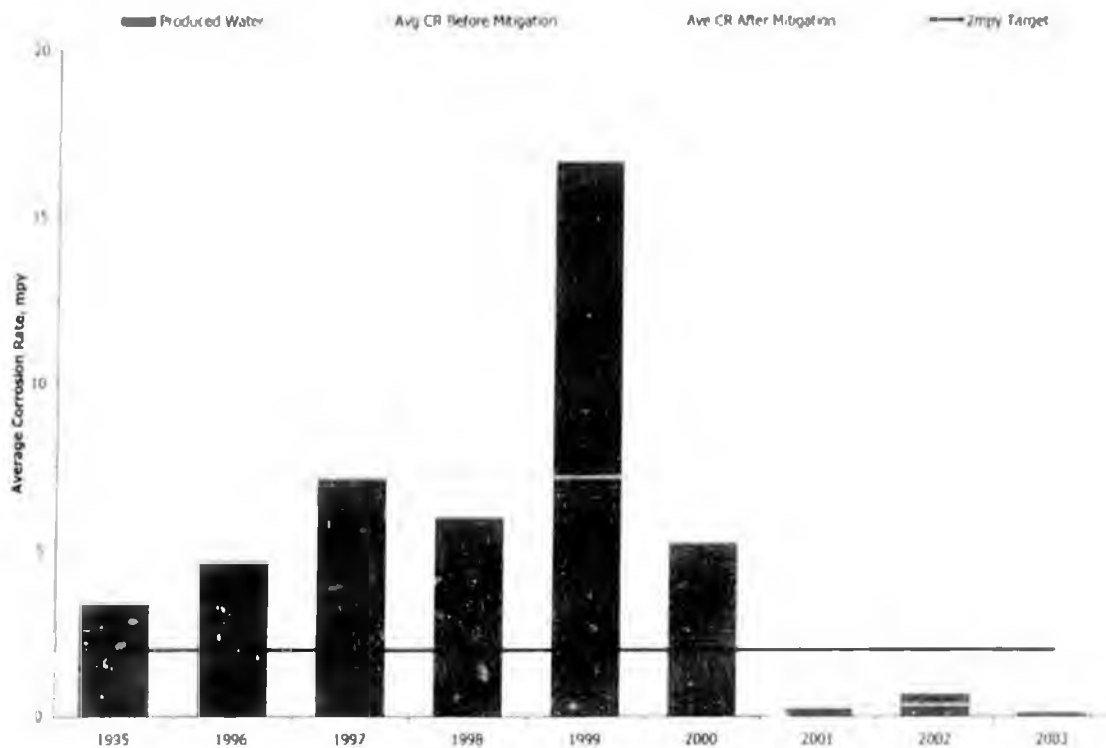
ACT Table D.1 Endicott Velocity Monitoring 2001-2003

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

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

Section D.2 Milne Point

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



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

Corrosion inhibition on the K-Pad 3-phase production flow line was initiated in 2001 after inspections indicated significant under-deposit corrosion damage. The damage was associated with low fluid velocities, allowing solids to accumulate in the line. In conjunction with the inhibition program, the K-Pad flow line is cleaned with a maintenance pig on approximately a monthly basis. Inhibition levels were increased in October 2003 when additional increasing damage was

noted in the line. The current inhibition level based on water production is 80 ppm versus 56¹⁰ ppm, originally.

The K-pad 3-phase flow line will be a focus of activity during 2004 to assure the corrective action identified above result in a decrease in the corrosion activity.

The development at S-Pad was designed for continuous inhibition injection into the power fluid supply for the downhole hydraulic pumps. Since this water is separated and re-circulated as power fluid at the pad, approximately ten percent of the produced water is sent through the cross-country flow line to the separation facility. Additional makeup water for use in the power fluid system is treated at a rate of 20-ppm corrosion inhibitor. This program will be optimized based on the results from the inspection and corrosion monitoring programs.

Continuous inhibition was initiated in flow line carrying production from F, L, and C Pads in 2003 due to corrosion damage detected with the 2002 ILI. The initial injection rate was set at 56 ppm. Adjustments to the corrosion inhibitor concentration will be dependent on results of corrosion monitoring program.

The remaining uninhibited production flow lines are under review for corrosion inhibition. Inspection increases in these production well lines indicates there is slight corrosion activity occurring over the long term. This evaluation is expected to be completed and recommendations made in 2004.

As production rates are typically low for the pipeline capacity, the fluid velocities are low and erosion is not a significant concern, therefore there is no formal velocity management program.

Section D.3 Northstar

Northstar is inhibited with continuous injection of corrosion inhibitor into the well production lines. Inhibitor concentration is set at 100 ppm based on water rates, with a minimum of 2 gallons/day regardless of the production characteristics.

As noted in Section C.3, a recommendation has been made to relocate the chemical injection upstream to the wellhead.

Section D.4 Badami

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

¹⁰The treatment rate reported in the 2002 Annual Report was incorrectly stated at 100 ppm.

Section E External/Internal Inspection

Section E.1 External Inspection

Section E.1.1 Endicott

Cased flow lines at Endicott are inspected by electromagnetic pulse test (E-Pulse) per the frequency listed in ACT Table E.1. During the most recent inspection, no significant anomalies were noted.

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

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

ACT Table E.1 Cased Piping Inspections

In addition, the vaults where the production, IIWL, and gas-lift pipelines pass are visually inspected annually. Minor external corrosion has occurred, but no increased activity was observed in 2003.

In 2003, the MI and gas-lift pipeline were inspected with tangential radiography and no increase in corrosion damage was found. Producing well 5-01 was inspected and found to have external corrosion; the damaged section was replaced.

Section E.1.2 Milne Point

ACT Table E.2 summarizes the external inspection program at MPU since 1997. Sixty-six (66) small-scale excavations were completed throughout the MPU field in 2003. The locations were focused on piping along the roadways for Tract 14 and L-Pad.

Year	Total Insp	Repeat Insp	Increases	% I's
1997	26	0	0	n/a
1998	441	10	0	0.0
1999	101	65	0	0.0
2000	205	104	28	26.9
2001	179	20	5	25
2002	70	5	1	20
2003	1583	55	1	1.8

ACT Table E.2 MPU Inspection Summary - External

Tract 14 excavations included the production header; test header and water injection header weld packs. Of the locations selected, 36 were previously un-inspected and 13 were repeat locations. All three headers were found to be free of external corrosion.

The L-Pad roadway piping inspection included 12 weld packs along the previously abandoned oil piping and in-service water injection piping. No external corrosion was noted for either pipeline. The water injector was found to have internal corrosion at all locations, however no repairs were required.

L-Pad headers were excavated at five locations and found to have external corrosion on both the production and test headers, which required one well line repair. As a result, an above ground header has replaced the buried production header. The buried header has been drained of fluids, blinded and inerted with nitrogen.

Section E.1.3 Badami

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

Section E.1.4 Northstar

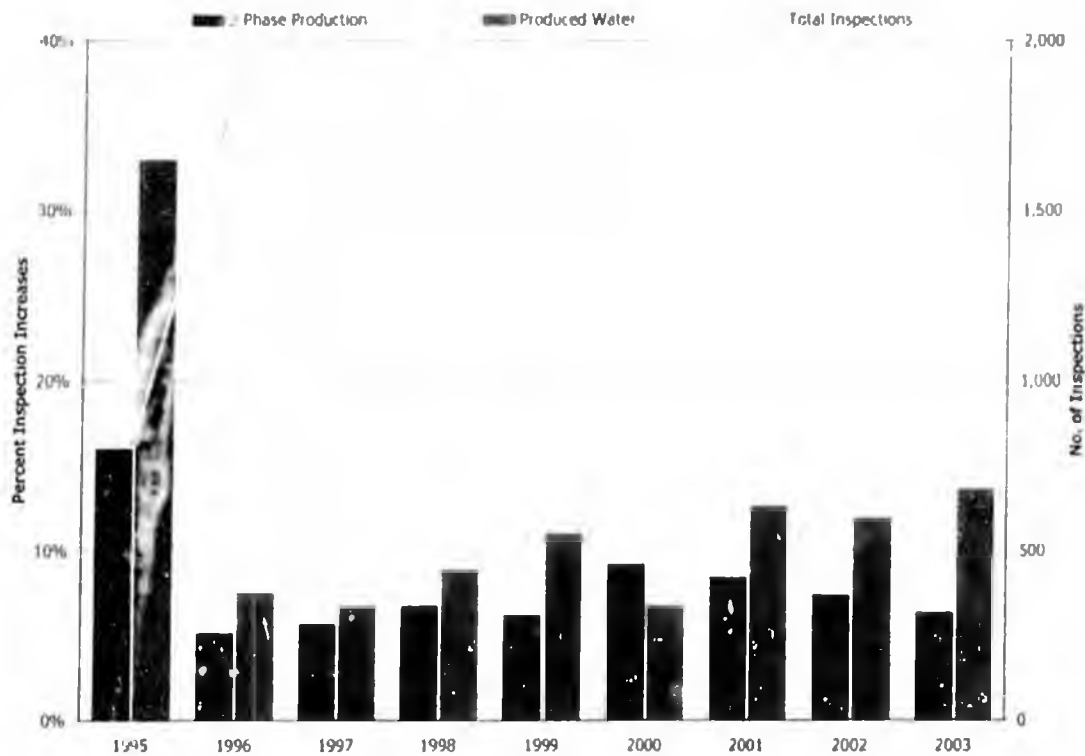
Since the facility is less than 3-years old, an external inspection program has not yet been established. Based on GPB experience, CUI typically takes several years to initiate. A program will be implemented within 5-years from startup (2006).

Section E.2 Internal Corrosion Inspection

Section E.2.1 Endicott

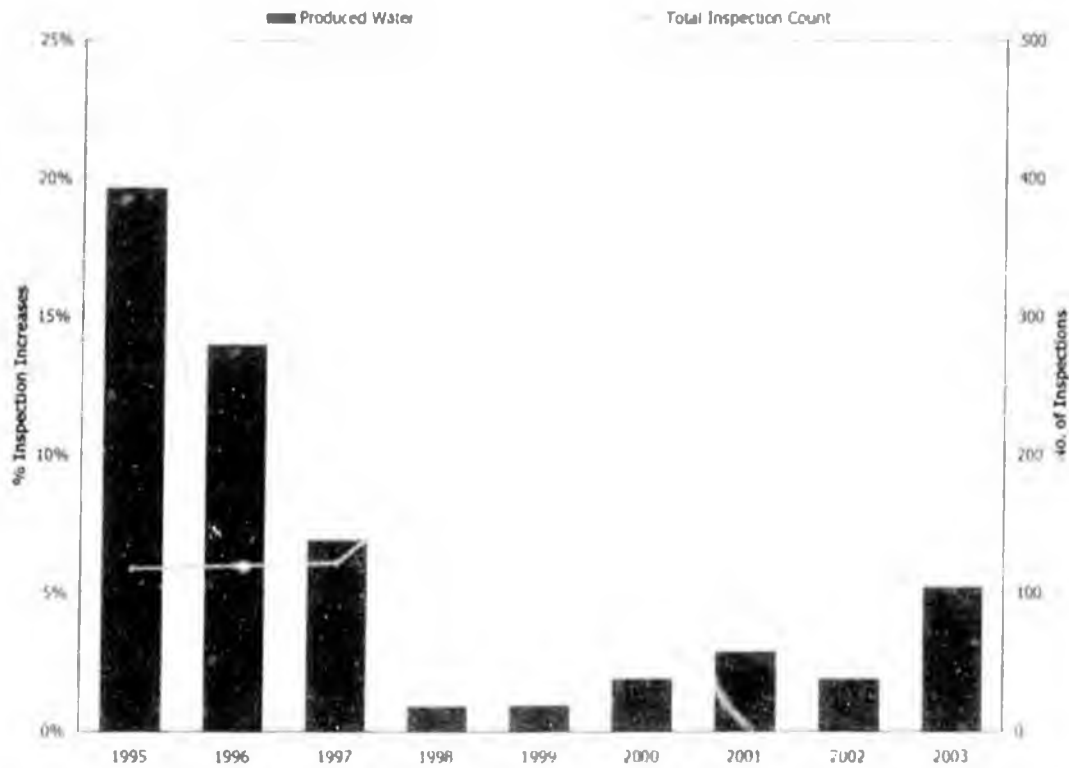
ACT Figure E.1 and ACT Figure E.2 indicate the percentage of inspection increases since 1995 for the well lines and flow lines at Endicott. There were no increases in the 3-phase, DSS production cross-country line. The production system inspection data are used to alert Operations of potential replacements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

Corrosion activity in the water injection well lines has risen since 1998 and has been addressed by increasing the corrosion inhibition concentration by 17½% as previously noted.



ACT Figure E.1 Detection of internal corrosion of well lines by inspection at Endicott - J03

ACT Figure E.2 shows a significant decline of inspection increases from 1995 through 1998 for the IIWL at Endicott. There has been a gradual increase in inspection increases since 1998. As discussed in Section D.1, the increase in corrosion activity in the IIWL was exacerbated by the temporary suspension in the pigging program and addressed by an increase in corrosion inhibition in 2003.



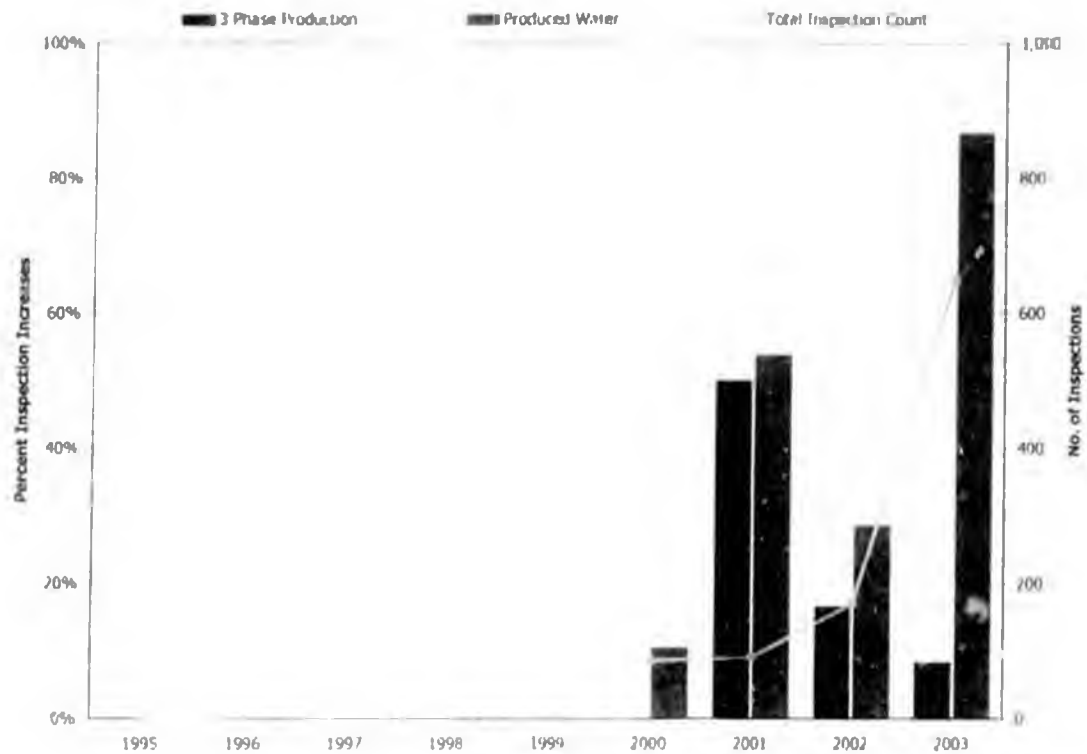
ACT Figure E.2 Detection of internal corrosion of flow line by inspection at Endicott 2003

It should be noted that the corrosion increases in the 3-phase production are in carbon steel C-Spools that are managed through planned replacement at the FFS criteria discussed in Section E.3.

Section E.2.2 Milne Point

During the period of 1994-2000, the inspection program established a baseline condition of the production facilities and pipelines. Since 2000, trending of inspection increases has been made possible with repeat inspections. The results of this comparative data can be seen in ACT Figure E.3. The figure shows that the total number of inspection items has consistently increased since 1998.

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ACT Figure E.3 Detection of internal corrosion of flow lines by inspection at MPU 2003

The percentage of repeat locations in produced water flow lines shows a significant increase in 2003, up to 87% from 29% in 2002. The increases are believed to be the result of inspections which cover the period before and after the establishment of corrosion control as shown in ACT Figure D.2. These lines were put on corrosion inhibition in the latter half of 2000. The average time between inspections is on the order of 4-5 years, indicating much of the corrosion noted may have occurred prior to the establishment of corrosion inhibition.

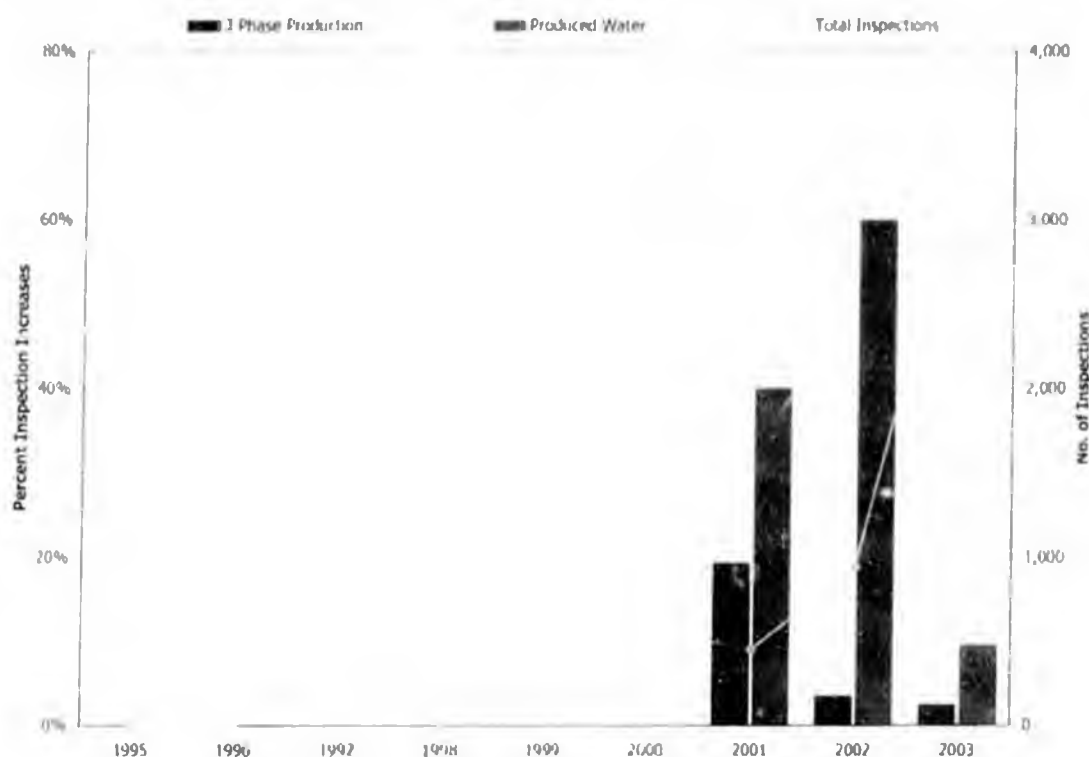
The effectiveness of the corrective actions is demonstrated by low WLC corrosion rates since corrosion inhibition was established. The well line repeat inspections are much closer to a year apart on average for 2003 as compared to 2002. As a result, the well line repeat inspections showing active corrosion have dropped significantly.

The produced water system will be monitored carefully to assure that the above analysis is correct and that corrosion control has been established.

Overall the 3-phase flow lines continue to show a decreasing trend of locations with corrosion activity. This is a direct result of increased inhibition of 3-phase flow lines at MPU. However, an expanded inspection program on the K-Pad flow line has identified six locations requiring sleeve repair in 2003. Inhibition levels were increased in the third quarter of 2003 as a result of this additional damage.

Further verification of 2001 ILI data has confirmed the upstream section of the F-Pad flow line has internal corrosion damage. As a result, corrosion inhibition program was established in 2003, subsequent inspection of these areas in late 2003 reveals no increased corrosion damage.

ACT Figure E.4 shows the historical detection of internal corrosion of well lines by inspection and the progress made in expanding the inspection program. There has been a significant decrease in the number of repeat locations showing active corrosion from 2002 to 2003. As noted in the discussion above, this represents a more consistent repeat inspection basis from prior years, as the majority of repeat locations were at approximately a year apart, whereas in previous years the time difference between repeat inspections was several years.



ACT Figure E.4 Detection of internal corrosion of well lines by inspection

ACT Table E.3 shows the results from the inspection program for the recent S-Pad development. A total of 1,500 3-phase and 179 produced water locations were inspected in 2003 on 34 wells. Of the 1,679 total inspections performed, 1,477 were repeat locations. The inspection results indicate corrosion activity is relatively minor with only 16 locations showing an increase. All locations showing corrosion activity are re-inspected on a monthly basis.

	3-Phase	PW	Total
Number of Inspections	1,500	179	1,679
Number of Repeat Insp	1,305	172	1,477
Number of Insp with Damage	16	0	16

Notes: Data represents inspections from 34 wells
All damage locations being evaluated on a monthly basis

ACT Table E.3 Inspection Summary of MPU S-Pad

Section E.2.3 Badami

The Badami Field was shut in August of 2003 due to declining productivity. There are currently no plans to produce the field. A post shutdown inspection was performed to serve as a baseline for a follow-up inspection in the third quarter of 2004 as a check to assure equipment was properly laid up.

Although the data set is limited, inspections support the overall assertion that Badami fluids have low corrosivity. ACT Table E.4 is a summary of well line inspections for Badami. Only one location has shown an increase in inspection damage. The interval between inspections suggests the increased damage was associated during shutdown work.

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

Note: Increasing damage location associated with shutdown operation

ACT Table E.4 Inspection Summary of Badami well Lines

Section E.2.4 Northstar

During 2003, a total of 204 well line inspections were completed, up from 146 the previous year. Four locations in the 3-phase system and two locations in the water disposal system had an inspection increase. No increases were experienced in the gas system. The four 3-phase locations showing corrosion are all in heavy wall target tees and are currently monitored on a quarterly basis.

The water disposal well problems are associated with the mud plant operation have been discussed previously. It is anticipated that when the mud plant shuts down operation, the corrosion rates will be lower as seen in locations further upstream of the system. This data are summarized in ACT Table E.5.

	3-Phase	Disposal	Gas	Total
Number of. Inspections	114	25	65	204
Number of Repeat Inspections	94	25	60	179
Locations with Increasing Damage	4	2	0	6

ACT Table E.5 Inspection Summary of Northstar

Section F Repair Activities

ACT Table F.1 summarizes the repair activity for ACT. There were 14 repairs identified for ACT of which 7 were at Endicott and 7 at Milne Point.

Service	Type	Int	Ext	Mechanical
Oil	FL	5	1	0
	WL	6	0	0
Gas	FL	0	0	0
	WL	0	1	0
PW	FL	0	0	0
	WL	1	0	0
Total		12	2	0

ACT Table F.1 ACT Repair Activity

Four of the Endicott repairs were production well lines; three C-spool replacements due to internal corrosion and one pipe spool replacement due to erosion. One spool replacement was in a water injection well line due to internal corrosion. One spool replacement was in gas injection well line due to external corrosion. One sleeve was installed on a duplex stainless steel well line due to erosion.

Six of the Milne Point repairs were all on the K-pad production flow line of which one was due to external corrosion. Additional areas have been identified for sleeve repair.

The Milne Point L-Pad well line and production headers were found to have external corrosion upon excavation. The entire header was redirected above ground and the existing header was drained and abandoned in place.

Section G Corrosion and Structural Related Spills and Incidents

There was no corrosion or structural related spills in ACT in 2003. ACT Table G.1, ACT Table G.2, ACT Table G.3, and ACT Table G.4 summarize leak/save and mechanical repair data for Endicott, MPU, Northstar and Badami, respectively.

Service	Leaks	Saves	Sleeves	Comments
Oil x-country lines	0	0	0	
Oil Well Pads	0	5	1	Well 1-57 sleeved. 1-49, 2-28, 2-36, 3-25 C-Spools replaced
Water x-country lines	0	0	0	
Water Well Pads	0	1	0	2-34 C-Spool replaced
Gas x-country GLT/MI	0	0	0	
Gas Well Pads	0	1	0	Spool replaced (Well 5-01)

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

Service	Leaks	Saves	Sleeves	Comments
Oil x-country	0	6	6	K-pad flow line
Oil Well Pads	0	1	1	L-3 Mechanical sleeve. Header abandoned in place
Water x-country	0	0	0	
Water Well Pads	0	0	0	
Gas x-country	0	0	0	
Gas Well Pads	0	0	0	

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

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

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

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

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

Section H 2004 Corrosion Monitoring and Inspection Goals

Section H.1 Endicott

The increases in the Inter-Island Water Line (IIWL) and well line inspection data for PW/SW service are the result of corrosion activity in a line with extensive pre-existing corrosion. The repairs made to the pigging facilities and resumption of maintenance pigging is expected to minimize further corrosion in the line. This line will continue to be inspected to determine the effectiveness of the corrosion inhibition changes and determine if damage is continuing. Additionally, further changes will be made to the corrosion inhibition and/or biociding programs will be made if the line continues to show degradation.

The well line erosion rate monitoring program will continue.

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

Section H.2 Milne Point

The 2004 plan will continue to expand the inspection program to provide timely feedback for corrosion control and mechanical integrity.

Analysis of additional production flow lines requiring corrosion inhibition was initiated in 2002. Treatment recommendations will be made in 2004. A major goal for 2004 will be demonstrating the efficacy and optimizing these treatment levels.

A goal in 2003 stated that the Milne Point corrosion evaluation of buried pipe will trial an alternative detection technology that includes fixed monitoring locations of the buried pipe segments. This opportunity did not present itself in 2003, but will remain a goal in 2004 to install these permanent monitoring locations and gain a baseline data set should the opportunity arise. Until such technology proves to be effective, it is planned to carry on with the buried piping excavation program.

A comprehensive review of all Milne Point corrosion monitoring locations will be undertaken in 2004 to determine the need for additional monitoring points.

A study will be made in 2004 to determine the best way forward for corrosion mitigation of remaining uninhibited areas of the field.

Section H.3 Northstar

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