

FLORIDA GOVERNMENT FILES, 2000-2009

11963 SENATE RESOURCES

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

Table D.2 Flowline Test Program Result Summary

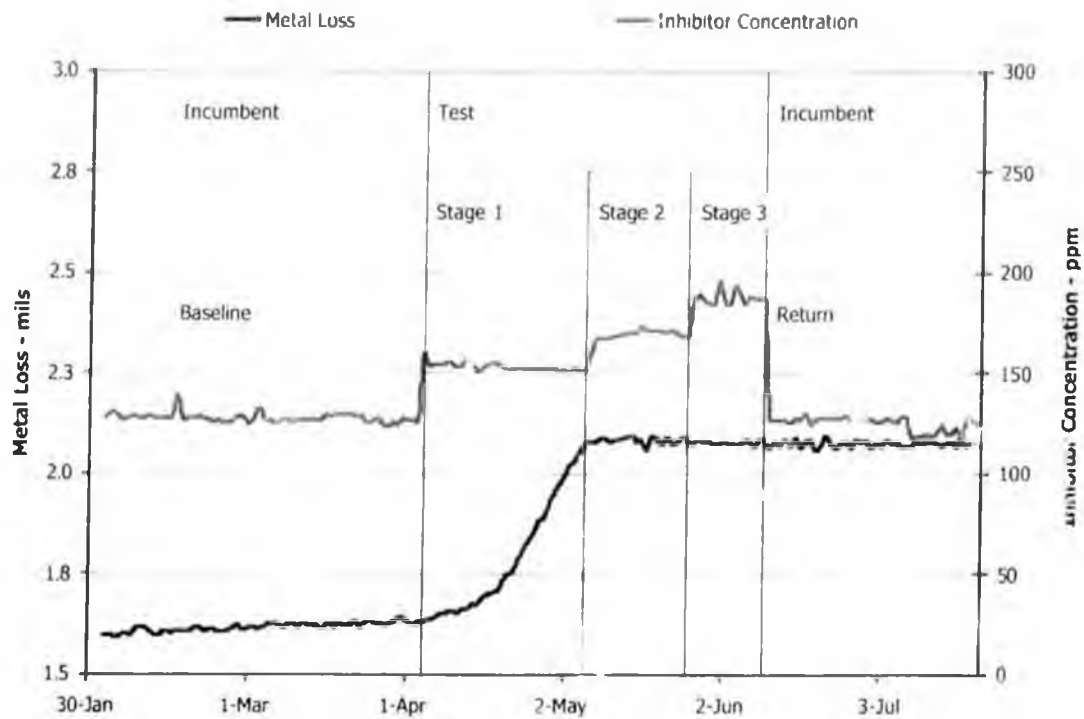


Figure D.3 ER Probe Chemical Optimization Test



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

### Section D.3 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 7 years represent a significant improvement in cost effectiveness and corrosion control performance.

Table D.5 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
Nalco Exxon	EC1110A							
Nalco Exxon	EC1259							
Nalco Exxon	97VD129							
Nalco Exxon	98VD118							
ONDEO Nalco	99VD049							
ONDEO Nalco	01VD017							
ONDEO Nalco	01VD121							
Champion	RU205							
Champion	RU210							
Champion	RU223							
Champion	RU258							
Champion	RU271							
Champion	RU126A							
Champion	RU256 <sup>1</sup>							

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

**Table D.5** Summary of the Chemical Deployment History at GPB

#### Section D.4 Corrosion Inhibitor Usage and Concentration

Another measure of chemical optimization is the amount of corrosion inhibitor used relative to the volume of water produced from the reservoir. Table D.6 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 vary from year to year, as shown in Table D.5. As more cost 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.

These effects are counteracted by the increasing water cuts associated with an ageing oil field and increased flow velocities due to increased gas handling capacity. These changes generally increase the amount of chemical required to control corrosion. As Figure D.7 shows, the volume of corrosion inhibitor has increased since 1995 while the water volumes have remained relatively constant.

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 <sub>2</sub> O Prodn. 10 <sup>6</sup> bbl/yr	Water Cut %	CI Usage 10 <sup>6</sup> gal/yr	CI Conc. (ppm)
1995	455.3	59.2%	1.62	85
1996	460.0	62.0%	2.05	106
1997	457.0	62.4%	2.21	115
1998	426.2	65.8%	2.53	141
1999	416.2	68.0%	2.28	130
2000	437.8	69.9%	2.73	148
2001	397.7	69.9%	2.63	157

Table D.6 Summary of the Chemical Usage History at GPB

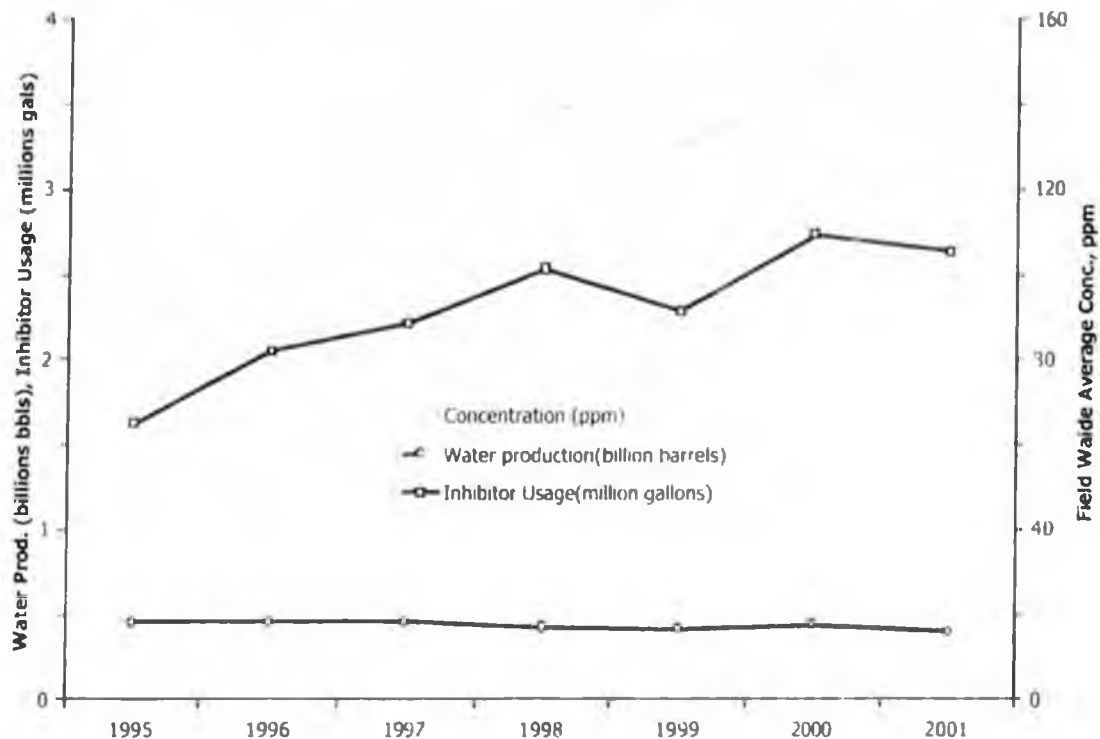


Figure D.7 Field Wide Chemical Usage

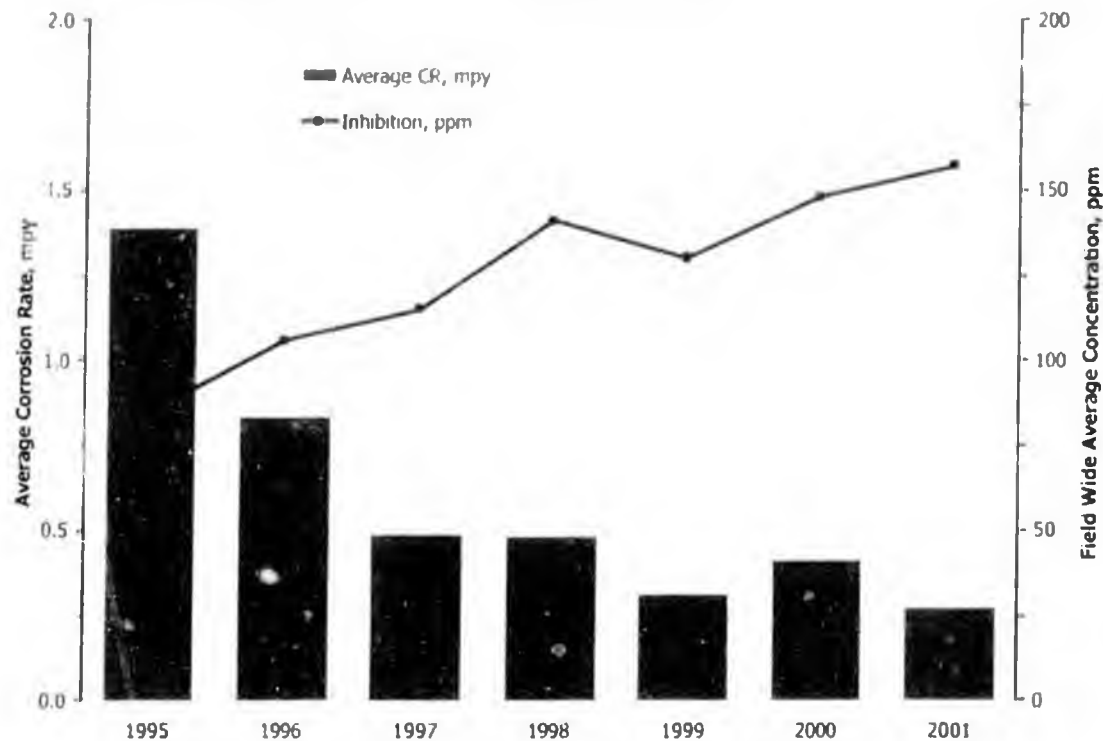
The metrics in Figure D.7 deal with chemical usage at the field level but much of the chemical optimization activity concentrates on injecting the correct amount of corrosion inhibitor to each piece of equipment. The inhibitor requirement is driven by factors such as water cut, water volume, flow regime, and condition of the equipment and varies over a wide range, from a few parts per million (ppm) to several hundred ppm.

For 2001 the target chemical usage was 2.59 million gallons as compared to actual usage of 2.63 million gallons; this represents an over injection of 1.6% for the year.

### Section D.5 Corrosion Inhibition and Corrosion Rate Correlation

As discussed in the section on corrosion monitoring, the reduction in corrosion rates in the 3-phase production system flow lines and well lines is largely attributable to the implementation of an aggressive corrosion inhibition program across Greater Prudhoe Bay.

Figure D.8 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 80% from 1995 to 2001, with a field-wide average concentration of 85 ppm to 157 ppm, respectively. As a result the corrosion rates have fallen by ~80% from 1.4 mpy in 1995 to 0.3 mpy in 2001.



Description	1995	1996	1997	1998	1999	2000	2001
FL OIL Ave CR, mpy	1.4	0.8	0.5	0.5	0.3	0.4	0.3
Inhibitor Conc., ppm	85	106	115	141	130	148	157

Figure D.8 Average Concentration versus Corrosion Rate

Figure D.9 shows the annual field-wide average corrosion inhibitor concentrations and annual average corrosion rates for 3-phase production flow lines plotted against each other. The figure shows how the additional corrosion inhibitor has reduced the corrosion rate through time, but it also shows an inherent limitation of corrosion inhibition as the minimum corrosion rate (or maximum corrosion inhibitor efficiency) is approaching an asymptote of  $\sim 0.25$  mpy.

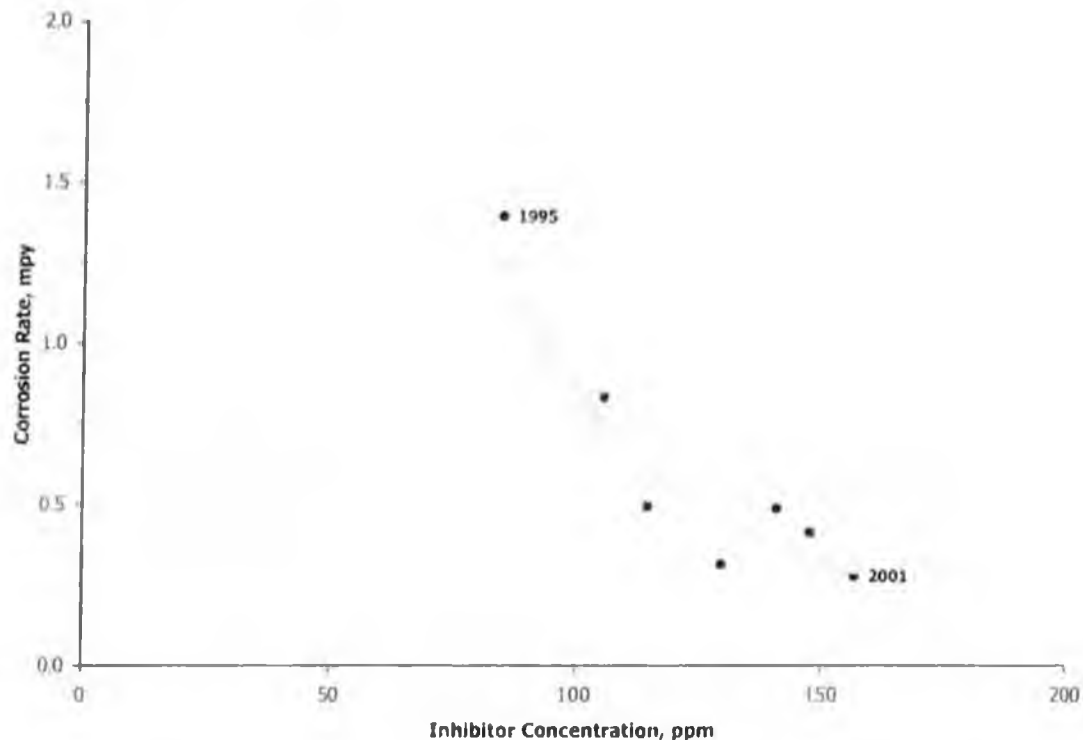


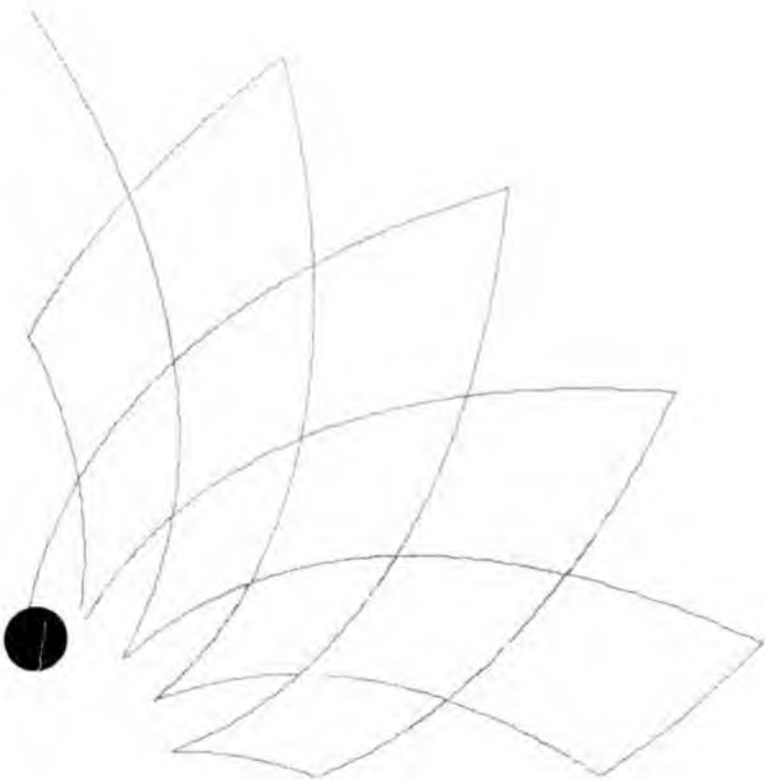
Figure D.9 Corrosion Inhibitor Concentration vs. Corrosion Rate

### Section D.6 Chemical Optimization Summary

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

**Section E**

**External/Internal Inspection**



## **Section E External/Internal Inspection**

### **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 thermal insulation of pipelines at Greater Prudhoe Bay, in particular, at the field applied insulation joints.

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

The main challenge in managing Corrosion Under Insulation (CUI) is the detection of the external corrosion damage. Water ingress into the weld packs is random and therefore it is difficult to apply rules to target the inspection program.

In order to detect CUI, a recurring screening program has been implemented as the best method to identify equipment at risk. Prioritization of inspection surveys is determined by configuration, average temperature of the equipment, age of equipment, and/or the last time a complete screening process was completed. If screening has been completed, sites are revisited at prescribed intervals. As a result of findings from the screening process, the extent of additional examination 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**

Table E.1 and Figure E.2 show the number and results of the external corrosion inspections performed between 1995 and 2001. The data includes all the Tangential Radiographic (TRT) techniques applied to external corrosion, including Automated-TRT (ATRT), and C-Arm Fluoroscopy (CTRTR).

	1995	1996	1997	1998	1999	2000	2001	2002
<b>Well Line</b>								
Activity level	-	36	1682	946	2114	5283	12730	
Corrosion detected	-	6	237	66	72	243	711	
% corroded		17%	14%	7%	3%	5%	6%	
<b>Flow Line</b>								
Activity level	1508	11474	18009	10316	8139	5184	2675	
Corrosion detected	245	763	1498	765	566	258	96	
% corroded	16%	7%	8%	7%	7%	5%	4%	
<b>GPB Overall</b>								
Activity level	1508	11510	19691	11262	10253	10464	15405	35000
Corrosion detected	245	769	1735	831	638	501	807	
% corroded	16%	7%	9%	7%	6%	5%	5%	

Table E.1 External Corrosion Activity and Detection Summary

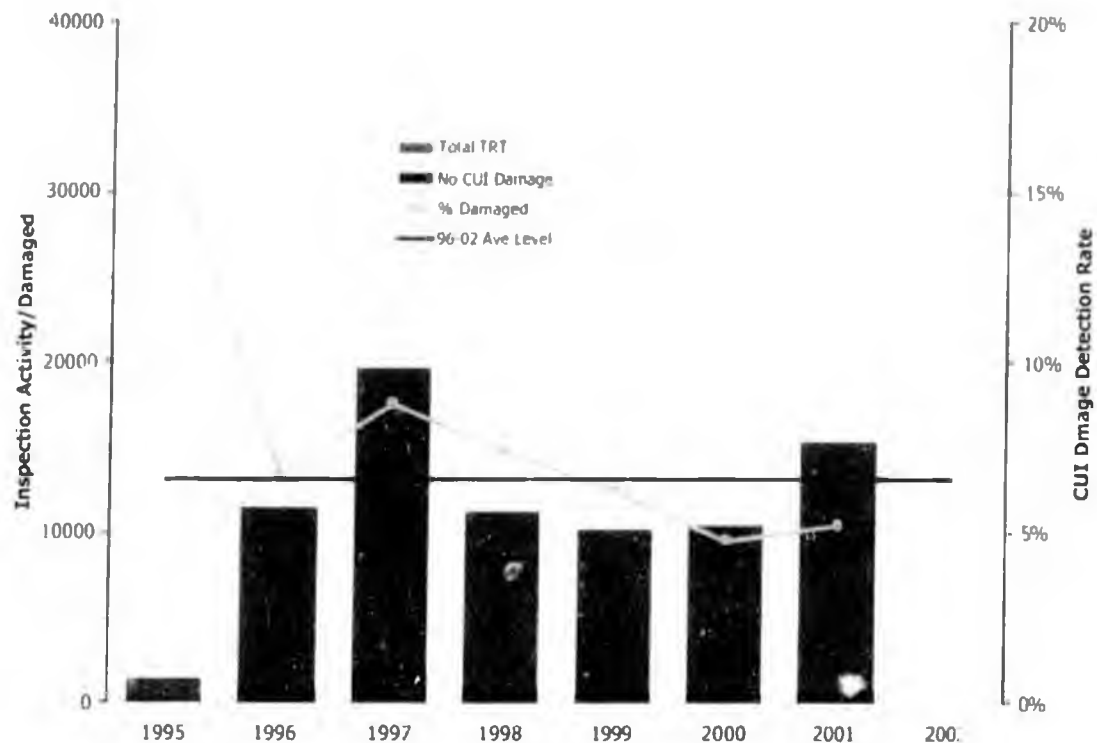


Figure E.2 External Corrosion Activity and Detection Summary

Table E.1 and Figure E.2 summarize the annual level of CUI inspection activity, the number of damaged locations found through the inspection program, and the percentage of inspected locations that exhibited damage. In general, the inspection levels over the period 1996 to 2001 have remained relatively constant at an average of ~13,000 per year. In contrast, the percentage of locations found with damage has fallen from an initial high of >15% to a field-wide average of ~5%.

Table E.3 summarizes the CUI inspection program for the period 1995 to 2001 broken out by service and equipment type, well line and flow line, and the aggregate of both data sets.

Service	Flow Line			Well Line		
	# Insp.	# Corr	% Corr	# Insp.	# Corr	% Corr
GAS	20114	1231	6%	3871	139	4%
OIL	29059	1922	7%	15632	982	6%
PO	277	7	3%	-	-	-
WTR	7813	1030	13%	3185	194	6%
<b>Total</b>	<b>57263</b>	<b>4190</b>	<b>7%</b>	<b>22688</b>	<b>1315</b>	<b>6%</b>

Service	Aggregate Flow/Well Line		
	# Insp.	# Corr	% Corr
GAS	23985	1370	6%
OIL	44691	2904	6%
PO	277	7	3%
WTR	10998	1224	11%
<b>Total</b>	<b>79951</b>	<b>5505</b>	<b>7%</b>

Table E.3 CUI Inspections by Service Type

The data suggests that there is some dependence of external corrosion occurrence based on service type with the Processed Oil (PO) showing a lower rate of occurrence of 3% compared to water injection service (WTR) with an occurrence rate of 13%. This difference is driven in part by the difference in temperature between these services. However, much greater variability in damage occurrence is found based on the location and orientation of the weld-pack location.

Table E.4 shows the distribution of insulation joint types based on a sample of approximately 12,000 locations. For each of the specified joint types, there is associated CUI incident rate. The overall average CUI incident rate for the sample was 6% that corresponds closely with average find rate of 7% for the full data set shown in Table E.3.

From the Tables E.3 and E.4 it can be seen that there is a much larger variability in the CUI incident rate between the insulation joint configurations than there is associated with the service type. For example, insulation joints in the mid-span, by far the most common joint type, have a CUI incident rate of just 3%. In comparison, insulation joints at elevation changes constitute less 0.5% of the total joint population yet have an incident frequency of 50%.

GPB Joint Design	Joint Type Freq	CUI Incident Rate
Anchor Joint	4%	8%
Damaged Insul. @ Saddle	1%	8%
Damaged Insulation Mid-span	11%	1%
Elbow Joint in Saddle	1%	22%
Elbow Joint	7%	10%
Ell Joint @ Elev in Saddle	<0.5%	28%
Ell Joint @ Elevation Change	18%	8%
Insulation Joint @ Elev Change	<0.5%	50%
Insulation Joint @ Saddle	15%	9%
Mid-span Insul Joint	44%	3%
Tee Insulation Joint	0%	17%
<b>Average CUI Incident Rate</b>		<b>6%</b>

Table E.4 CUI Incident Rate by Joint Type

This suggests that the joint configuration and insulation joint location have as much, if not greater, influence on the occurrence of external corrosion at weld-packs compared to the service type and hence temperature. This probably reflects the relatively narrow range of operating temperature differences between services.

### Section E.1.2 Cased Piping Survey Results

Table E.5 shows cased pipe segments inspected in 2001. Potential metal loss areas are reported as anomalies and severity of loss is semi-quantified as minor, moderate, or significant.

Service	Technique	Segment	Minor	Moderate	Significant	Anomaly Action
3 Phase	Electrical Pulse	93	10	-	-	Proof/Monitor Guided Wave
	Guided Wave	20	2	-	-	Monitor Guided Wave
PW/SW	Electrical Pulse	15	4	-	-	Proof/Monitor Guided Wave
	Guided Wave	15	2	1	-	Monitor Guided Wave
WAG	Electrical Pulse	6	-	-	-	
Gas	Electrical Pulse	105	13	1	-	Proof/Monitor Guided Wave
	Guided Wave	14	2	-	-	Monitor Guided Wave
PO	Electrical Pulse	7	1	-	-	Proof/Monitor Guided Wave
<b>Total</b>		<b>275</b>	<b>34</b>	<b>2</b>	<b>-</b>	

Table E.5 2001 Cased Pipe Survey Results

The 2001 scope included examination of segments that had not previously been inspected as well as the on going monitoring of reported anomalies from prior

years' testing. The near-term strategy for management of cased pipe segments is to complete an initial inspection baseline of all GPB cased piping by year-end 2003. In accordance with the agreement with ADEC, 2001 is year 3 of a 5-year program to complete a baseline inspection on all cased piping segments. To date, baseline inspections have been completed on approximately 60% of the segments, which is on track to complete the program by year-end 2003.

Additionally, all cased piping road crossings are visually inspected annually during the summer months. Mitigation includes removal of any material, i.e. debris, gravel, dirt, from the casing ends.

### Section E.1.3 External Program Summary

In summary, the level of activity directed at external corrosion has been relatively constant over the last 5 years at approximately 13,000 locations per year. However, through the review process it was recognized that there was a potential that the level of risk of failure could increase as the field ages and therefore the GPB partners have decided to fund an additional level of inspection for 2002. The activity level for 2002 is anticipated to be considerably greater than prior years at approximately 35,000 inspection locations

## Section E.2 Internal inspection

### Section E.2.1 Internal Inspection Program – Scope and Results

This section summarizes the scope and results of the internal corrosion inspection program. The detailed objectives for the inspection program are given in Table B.8 and are summarized in Table E.6.

<b>CRM</b>	<b>Corrosion Rate Monitoring</b> Detection of active corrosion in the production system in support of the corrosion mitigation and management programs
<b>ERM</b>	<b>Erosion Rate Monitoring</b> Similar to the CRM program but in support of the erosion management and velocity management programs
<b>FIP</b>	<b>Frequent Inspection Program</b> The aim of this program is to manage the mechanical integrity of locations which have significant damage based on proximity to repair criteria and/or unusually high corrosion rate
<b>CIP</b>	<b>Comprehensive Inspection Program</b> An annual program aimed at detecting new corrosion mechanisms by examining new locations, searching for damaged locations under known mechanisms and the monitoring of known damaged locations

Table E.6 Internal Inspection Programs

The results presented are the aggregate of the data obtained for all of these programs for flow lines and well lines. The results of the inspection program 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.

Figure E.7 shows the percentage of inspection increases (%I's) for the flow lines broken out by 3-phase production (OIL) and water injection (seawater and produced water) service. The percentage of inspection increases in the 3-phase system has declined considerably from 1997 to 2001. There was a slight increase in the %I's in 2001 compared to 2000 which probably reflects the increase in corrosion rates detected in the coupon monitoring program. Given the decline in average corrosion rates in 2001, it is expected that the percentage of inspection increases will decrease in 2002. The long term 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, there is a strong corrective action plan in place to address the corrosion in the water injection system and it is expected that the increase in corrosion activity shown in the 2001 inspection data will be reduced in 2002.

Figure E.7 also shows the total inspection activity for flow lines. As discussed in Section B, there is a shift in emphasis from the flow lines, to the well lines, to the facilities and not a reduction in the overall inspection activity level.

Figure E.8 shows the inspection increases trend for the well lines.

For the 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, however, the increase in corrosion activity seen in the flow lines is not reflected in the well line data.

For the water system, corrosion activity is seen to be declining over the last 5 years; however, the increase in activity seen in the flow lines has not yet translated to activity in the well line data.

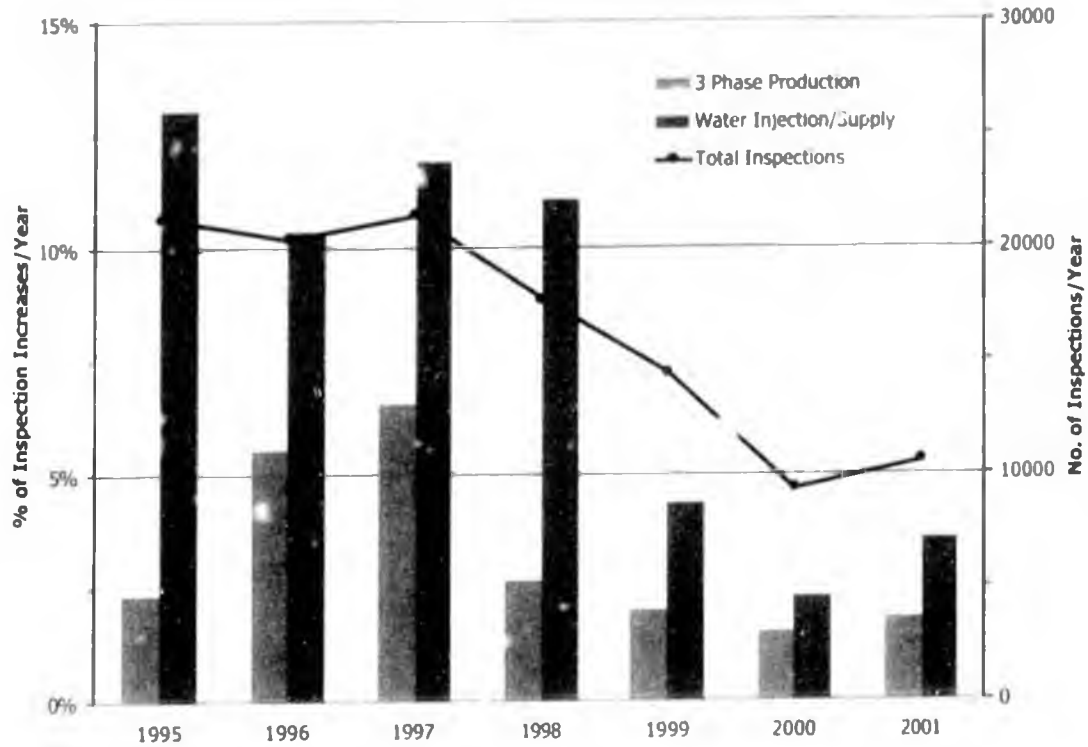


Figure E.7 Flow Line Internal Inspection Increase by Service

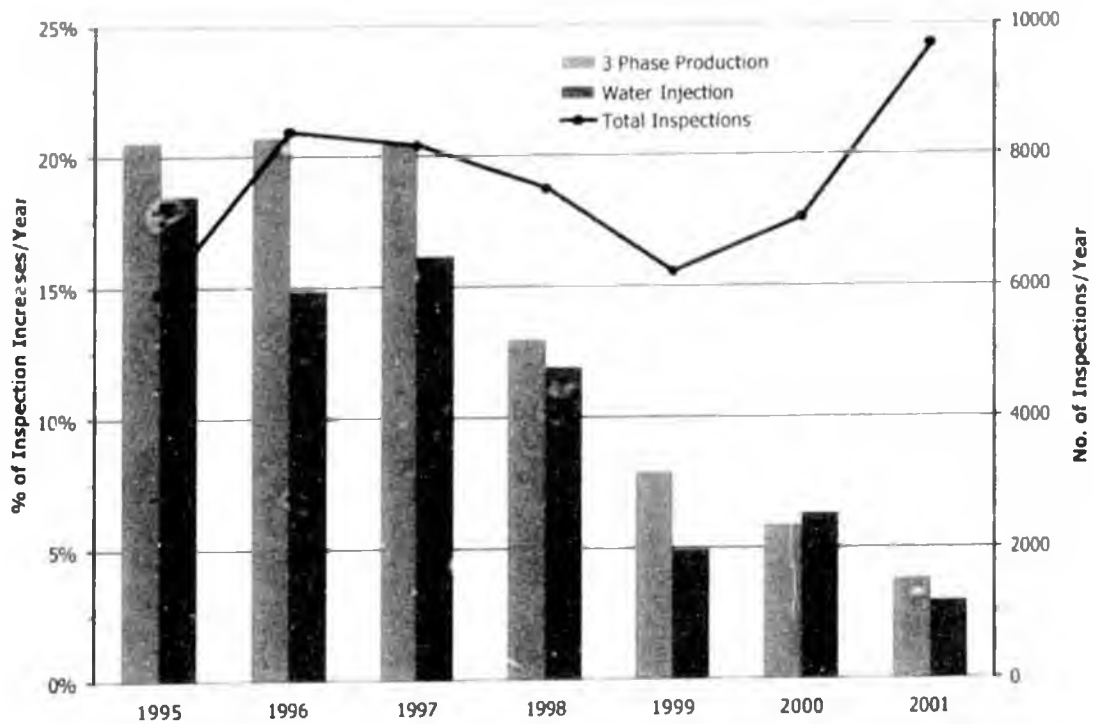


Figure E.8 Well Line Internal Inspection Increase by Service

The discrepancies in the short-term trends between the data for flow lines and well lines for both oil and water services are probably attributable to the variability in the data associated with the number of pieces of equipment, the inspection frequency and the inspection interval. The long-term trends however are consistent showing a reduction in the corrosion activity level over the last 5 years.

### **Section E.2.2 Internal Inspection Intervals**

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

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

**FIP – Frequent Inspection Program:** The aim of this program is to manage mechanical integrity at locations where significant corrosion damage is detected. Locations are added to the FIP if they are approaching repair or derate criteria or if unusually high corrosion or erosion rates are detected. As the name implies, inspections are performed frequently until the item is repaired, replaced,

derated, taken out of service, or corrosion/erosion rates reduced. The inspection interval varies, depending on how close the location is to repair/derate and the rate of corrosion but does not exceed 1 year. All equipment is covered by the FIP.

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

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

### **Section E.3 Correlation Between Inspection and Corrosion Monitoring<sup>9</sup>**

As noted in Table B.9, inspection and corrosion monitoring have different characteristics; in particular, inspection techniques are relatively insensitive but are the most accurate as they measure actual wall loss. In comparison, 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 pipeline wall.

Therefore, in order to have good confidence in the results from the corrosion monitoring program, it 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 program and monitoring program for the 3-phase production system.

Figure E.9 shows the trend in average corrosion rate from weight loss coupons and the percentage of increases found in the inspection program. It should be noted that the inspection results included in the analysis is 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 in Figure E.9 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 coupon corrosion rates are reported as the mid-point of the exposure cycle rather than the removal date.

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<sup>9</sup> In addition to Charter Work Plan, this information supplied to provide additional context and help in understanding BP corrosion management activities

Figure E.9 also shows that the same trend of reducing corrosion activity is seen in both the inspection results and corrosion monitoring data.

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

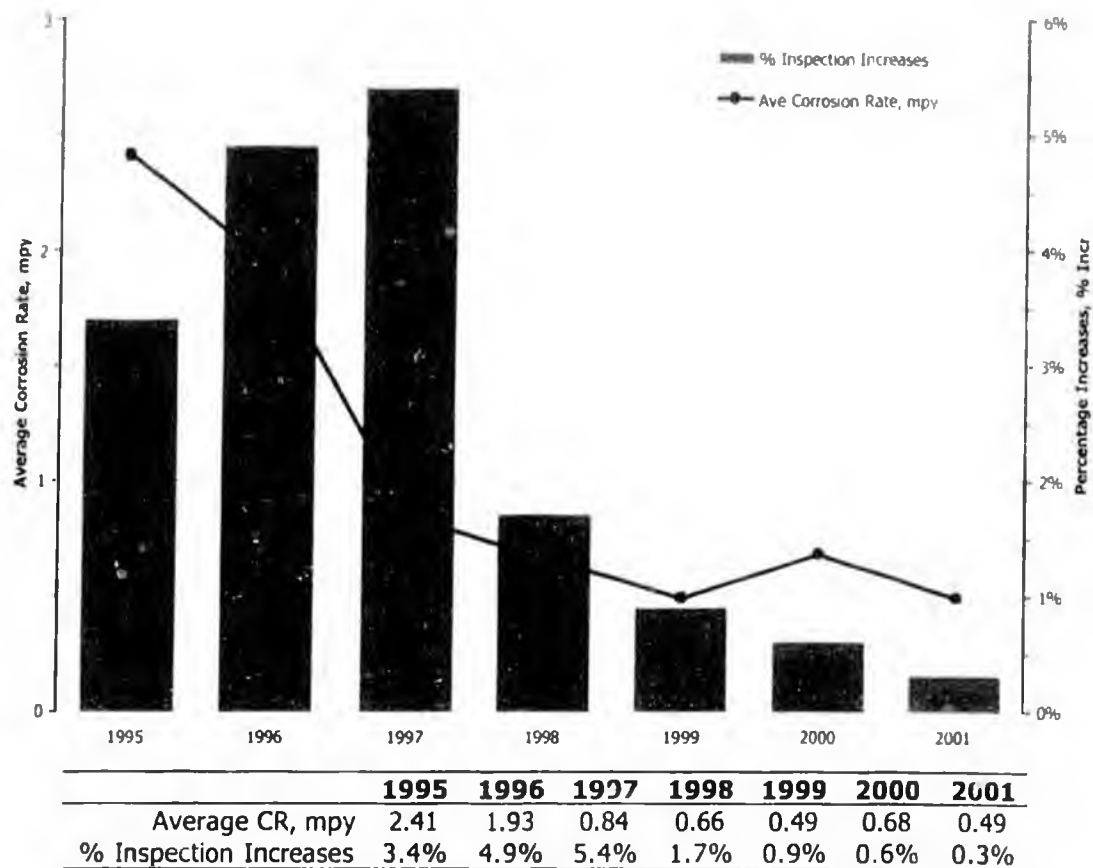


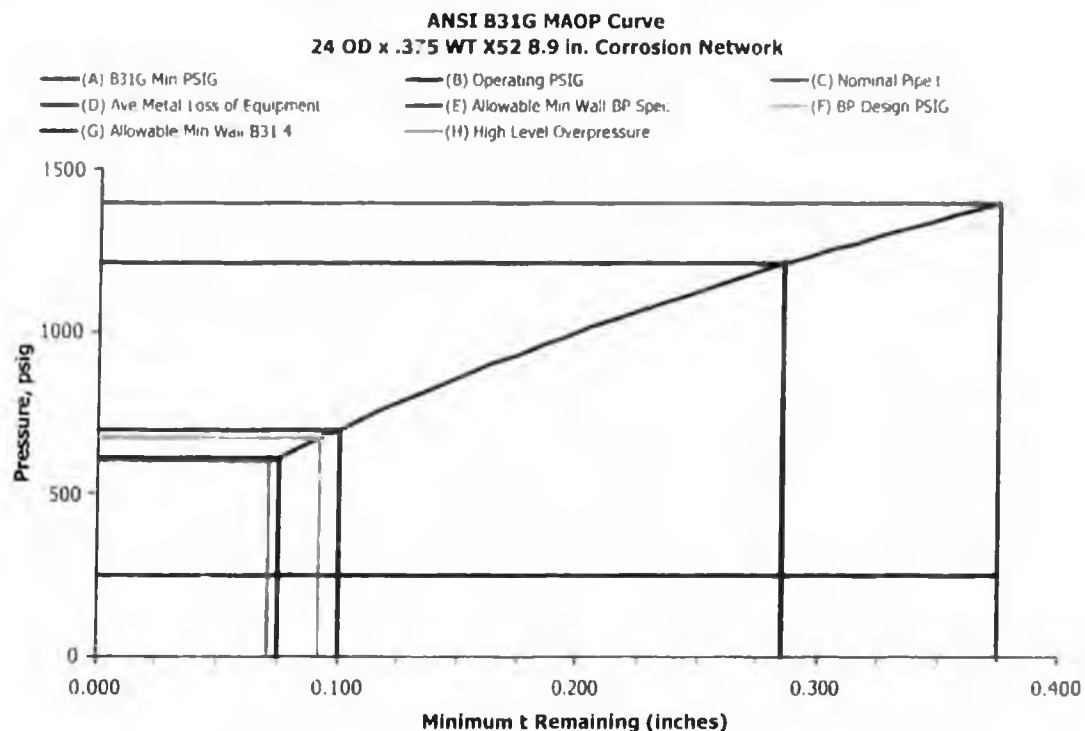
Figure E.9 Correlation of Corrosion Rate and %Increases

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.4 Fitness for Service Assessment

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

Figure E.10 summarizes the dependence of Maximum Allowable Operating Pressure (MAOP) with the remaining wall thickness of a section of flowline based on ANSI/ASME B. 1G. The example and discussion below is for a typical cross-country 24" diameter low-pressure (LP) flowline. The same ANSI/ASME B31G criteria are applied to remaining flow and well lines with the appropriate characteristics and parameters substituted from the example below.



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 flowline (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 pipework. Any location at or below this level is actioned regardless of the calculated MAOP
(F) BP 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/slugcatcher

**Figure E.10 (cont.)** Detailed Legend Explanation

Figure E.10 and the subsequent explanation are 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, a typical flow line has a B31G calculated MAOP of ~1400 psi. As the wall thickness is reduced by corrosion, this pressure containment capacity is reduced.

Table E.11 shows the MAOP for various wall thicknesses starting from the original installed wall thickness of 375 mils. From Figure E.10 and Table E.11, 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.

#### **Section E.4.1 Fitness for Service Assessment for Oil Flow Lines**

The fitness-for-service example illustrated above is for a 24" diameter low-pressure flow line. For this system the average depth of damage for cross-country oil line 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 had happened since the beginning of field life in 1977. Figure E.12 shows the actual damage profile as determined from inspection data for all the flow lines in oil service regardless of diameter.

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

Table E.11 Thickness, MAOP Correlation

The chart shows that as of 2001, the average flow line condition shows a depth of damage of approximately 10% wall loss which is considerably less than the average damage seen in the larger diameter, 24", low-pressure lines discussed above with an average wall loss of 24%.

In addition, Figure E.12 shows that the majority of the damage occurred in the period 1990-1995 as the continuous inhibition program was being implemented, and that since the implementation of the inhibition program, little increase in corrosion damage has occurred.

Figure E.13 shows the piping condition history against time for the well lines. As with the 3-phase production flow lines, the corrosion damage occurred in the

early part of the 1990's and has been considerably reduced since the introduction of an aggressive corrosion inhibition program.

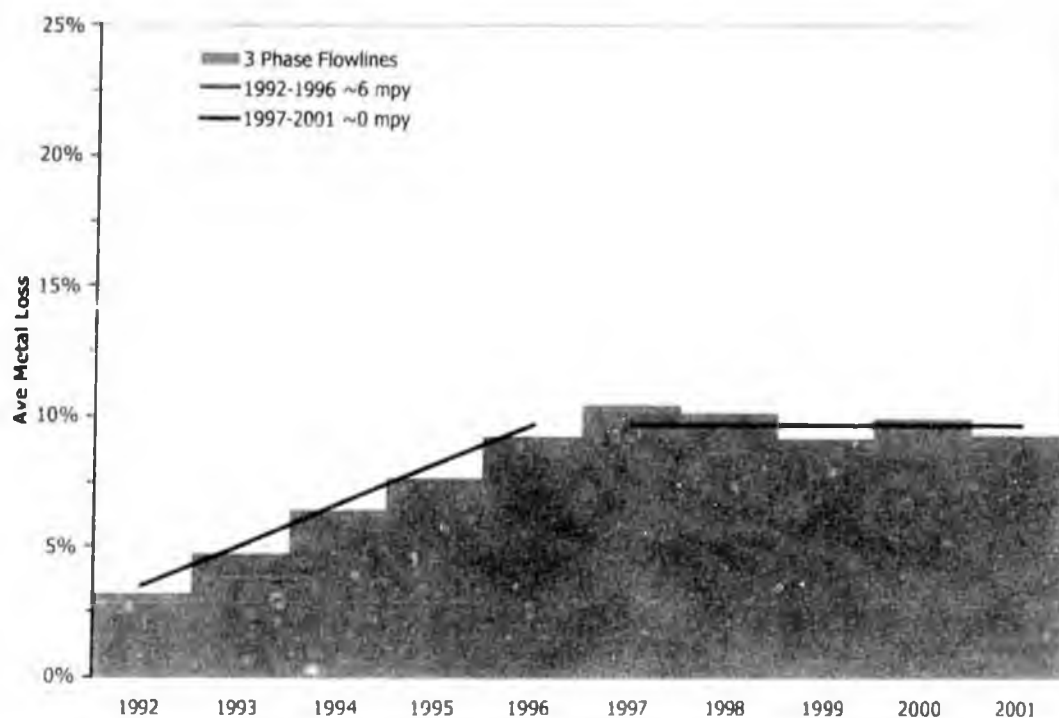


Figure E.12 GPB Average Flow Line Condition Since 1992

## Section E.5 Inspection Increases and Condition

### Section E.5.1 Inspection Increases and Condition

Figure E.14 shows the relationship between the percentage inspection increases and the average flow/well line damage for the 3-phase production systems. This pulls together the data from Section E.3 and Section E.5 to show, as would be expected, that as the corrosion rates have decreased, the plant condition has stabilized and the rate of degradation has been reduced.

The effective corrosion rate between 1992 and 1997 was about 6 mpy assuming 375 mil wall pipe. A consequence of an aggressive inhibition program is the decrease of corrosion rates in the system, as represented by the percentage of inspection increases. With this reduction in corrosion rate, the amount of wall loss has essentially stabilized at the 1996/7 levels, with little further loss of material in the last 5 years.

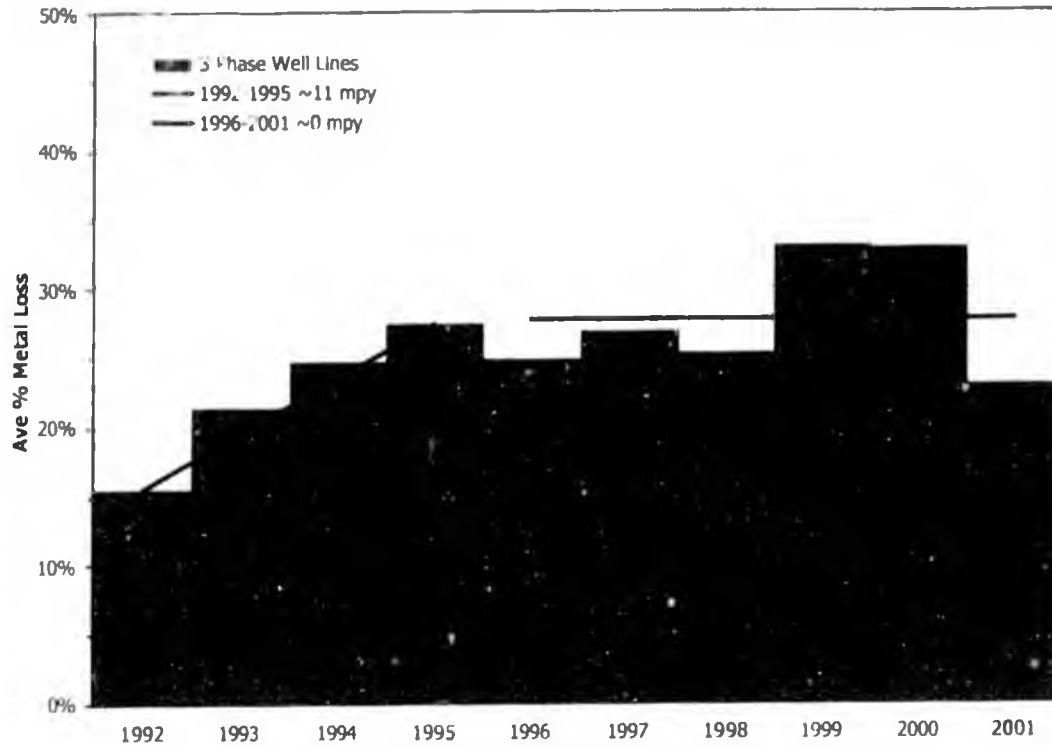


Figure E.13 Pipin Condition History

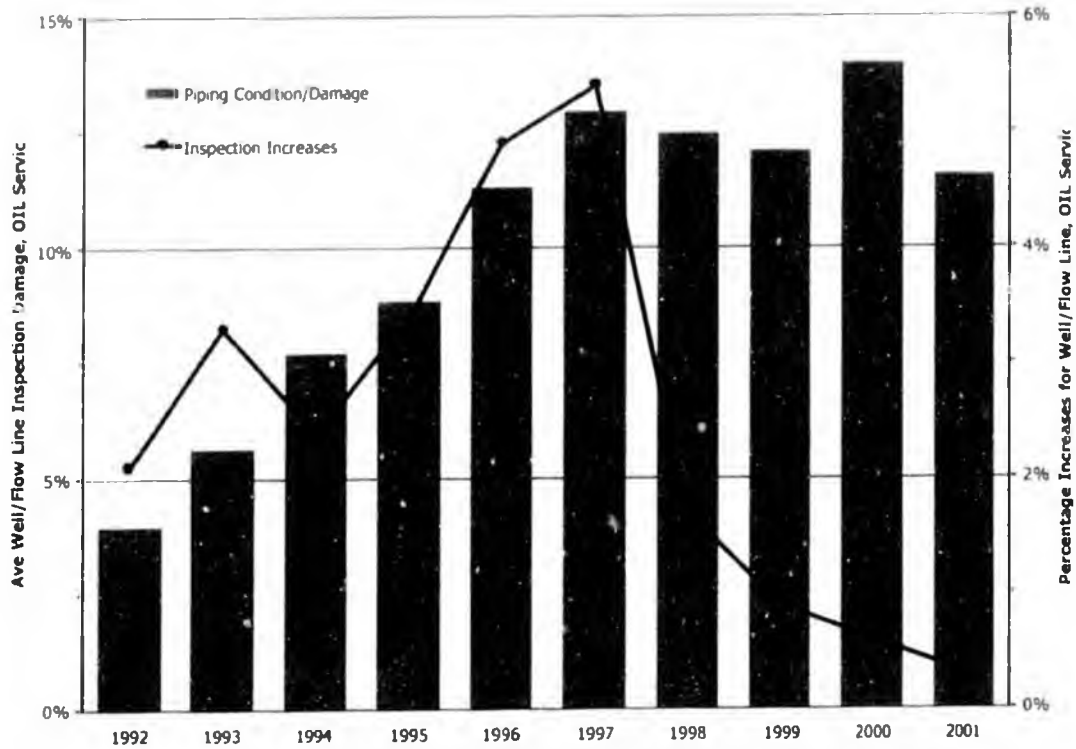


Figure E.14 Inspection Damage versus Percentage Increases

The combination of both condition and corrosion rate provide a tool for assessing the remaining useful life of the equipment before the repair criteria described in Section E.4 are reached.

### **Section E.6 Inspection Summary**

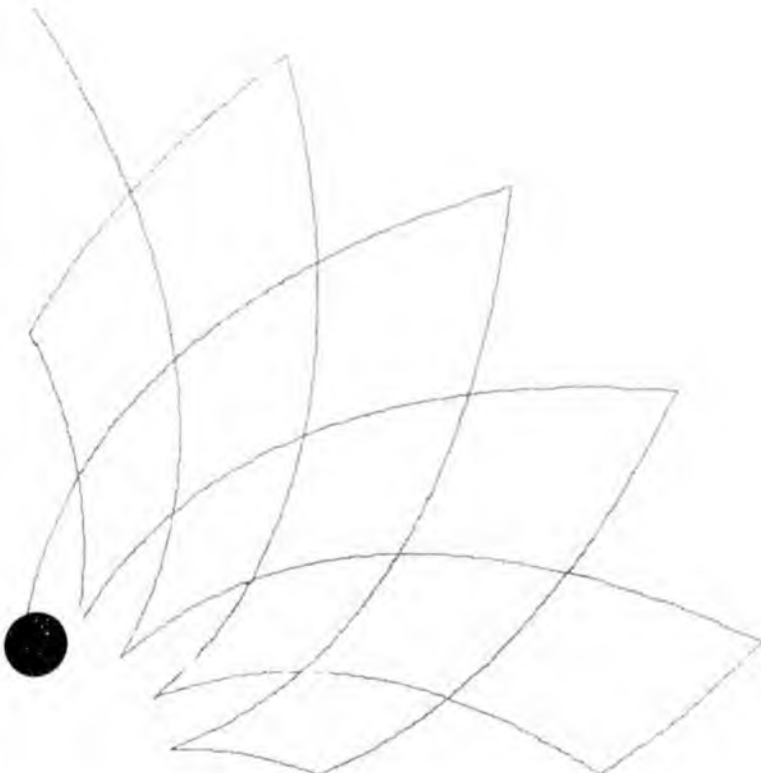
In summary, the main conclusions from the inspection section are,

- The external corrosion inspection program at 15,000 items for 2001 was slightly above the historical average. Of the 15,000 items, approximately 5% showed damage, which is consistent with the prior 5 years.
- The 2002 external corrosion program is planned to be about 35,000 items, which is substantially higher than the 5-year average activity level of 13,000 items.
- The cased piping survey is on-track to complete the initial baseline survey by year-end 2003 as agreed with ADEC.
- A unified internal inspection philosophy and program structure has been implemented across Greater Prudhoe Bay with a total program size of approximately 60,000 items.
- There has been a shift in the inspection program focus from the flow/well lines to the facilities. This is as a result of the improved levels of corrosion control in the field systems.
- Within the field inspection program, there has also been a shift in focus from the cross-country flow lines to the well lines. Again, this is as a result of the much-improved levels of corrosion control in the 3-phase production flow lines allowing this change in emphasis.
- The inspection results for both the flowline 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 on the flow lines. This is expected to be reversed following the trend 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, corrective actions have been put in place in the sea water system and additional inhibition has been added to the 2002 produced water program.

- The inspection interval and fitness-for-service criteria, as defined by B31G, was 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.

**Section F**

**Repair Activities**



## Section F Repair Activities

Table F.1 summarizes the repair activity for the flow line and well lines for 2001.

<b>GPB 2001 Mechanical Repairs</b>				
<b>Service</b>	<b>Type</b>	<b>Int</b>	<b>Ext</b>	<b>Mechanical</b>
Oil	FL	2	7	-
	WL	4	5	2
Water	FL	1	3	-
	WL	1	-	-
Gas	FL	-	2	-
	WL	-	-	1
Processed Oil	FL	3	-	-
<b>Total</b>		<b>11</b>	<b>17</b>	<b>3</b>

**Table F.1** Repair Activity

As can be seen from Table F.1, the majority of the repairs have been for external corrosion damage on all services. The repair data reported above and the inspection data together contributed to the decision to increase the level of external corrosion inspection in 2002.

The three repairs reported for the processed oil flow-line were associated with a dead-leg/stagnant flow segment of piping on a pig receiver by-pass. There are plans to remove this dead-leg section in 2002.

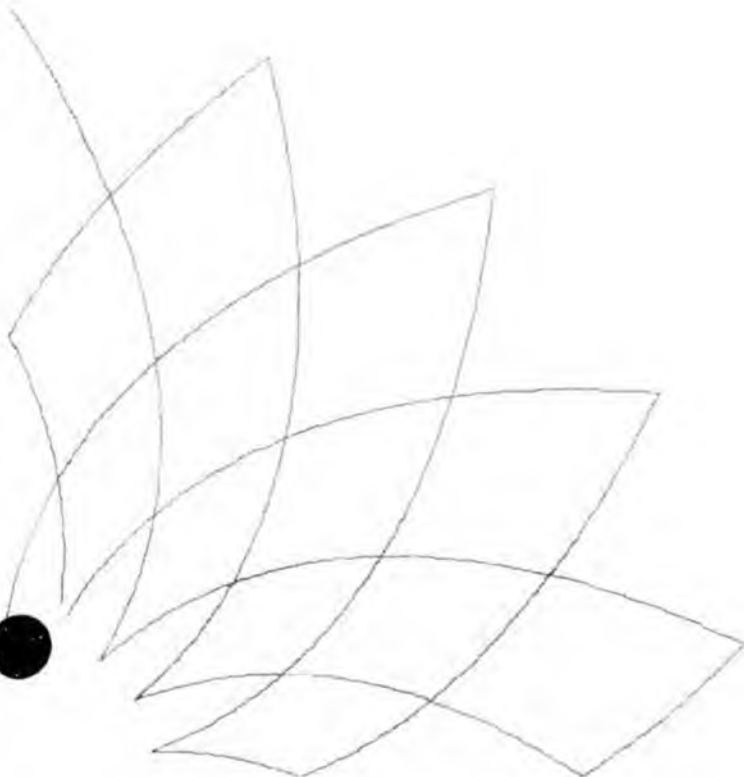
There were no structural related repairs in 2001. The repair activities in 2001 include a total of 31 mechanical repairs as compared to 35 in year 2000. Repair categories include,

- Internal – Erosion and/or corrosion metal loss
- External – External corrosion metal loss (CUI)
- Mechanical – Third party damage, fabrication defect, etc.

The level of repair activity in 2001 is consistent with that seen in 2000.

**Section G**

**Corrosion and Structural Related Spills and Incidents**



## Section G Corrosion and Structural Related Spills and Incidents

### Section G.1 Corrosion Leaks

Table G.1 summarizes the leaks due to corrosion in 2001.

Service	Location	Type	Date	Mechanism	Volume
3 phase production	DS-01	WL	14-Jul-2001	Ext	200 gal
3 phase production	Pt Mac CL	FL	21-Jul-2001	Ext	420 gal
Produced Water	DS-14	WL	16-Aug-2001	Int	5 gal
3 phase production	DS-15	WL	23-Dec-2001	Int	5 gal
3 phase production	DS-07	WL	19-Feb-2001	Erosion	280 barrels
G&I Slurry	G&I	FL	6-Mar-2001	Erosion	400 barrels

	Surface		Service			Mechanism		
	Int	Ext	OIL	SW	PW	CO <sub>2</sub>	Erosion	CUI
WL	3	1	3		1	2	1	1
FL	1	1	1	1			1	1

Table G.1 2001 Leaks Due to Corrosion/Erosion

Table G.2 shows the number of corrosion related leaks and saves from 1996 through 2001. 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. This data is also displayed in Figure G.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.

	Flow Line			Well Line			Total
	Saves <sup>1</sup>	Leaks	L/(L+S)%	Saves <sup>1</sup>	Leaks	L/(L+S)%	L/(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%	97%
1999	22	0	100%	25	3	89%	94%
2000	9	1	90%	54	0	98%	97%
2001	7	2	78%	21	4	84%	82%

<sup>1</sup> Save can be attributed to a derate which does not appear in the repair statistics

Table G.2 Historical Corrosion Leaks and Saves

Table G.2 and Figure G.3 show the number of leaks and the number of saves, plus the ratio of leak to saves. The trend in the total number of saves, locations that have reached FFS criteria, plus the number of leaks, is an approximate measure of the overall performance of the corrosion management program. As can be seen from Figure G.3, the total number of leaks plus saves is declining.

This suggests that overall the corrosion management program is delivering an improved level of corrosion control.

However, in absolute terms the number of leaks increased in 2001 versus 2000. Of the 6 leaks that occurred in 2001, 2 were associated with erosion, 2 with external corrosion and 2 internal corrosion – see Table G.1.

As a result of these leaks a number of corrective actions have been put in-place,

**Erosion** A unified fluid velocity management and mitigation program was agreed with operations and implemented across Greater Prudhoe Bay at the beginning of 2002. The results of this program will be reported in the next annual report, however, the basic criteria are summarized in Table B.8 (c) 1.1.4 and 1.1.5.

**External Corrosion** The external corrosion inspection program for 2002 is planned to be substantially increased, see Section E.1, addressing the external corrosion leaks seen in 2001.

**Internal Corrosion** Excursion from the prescribed level of corrosion control is typically addressed through the introduction of additional corrosion inhibitor. The corrective actions taken to address corrosion control anomalies are summarized in Tables H.2, H.3 and H.4.

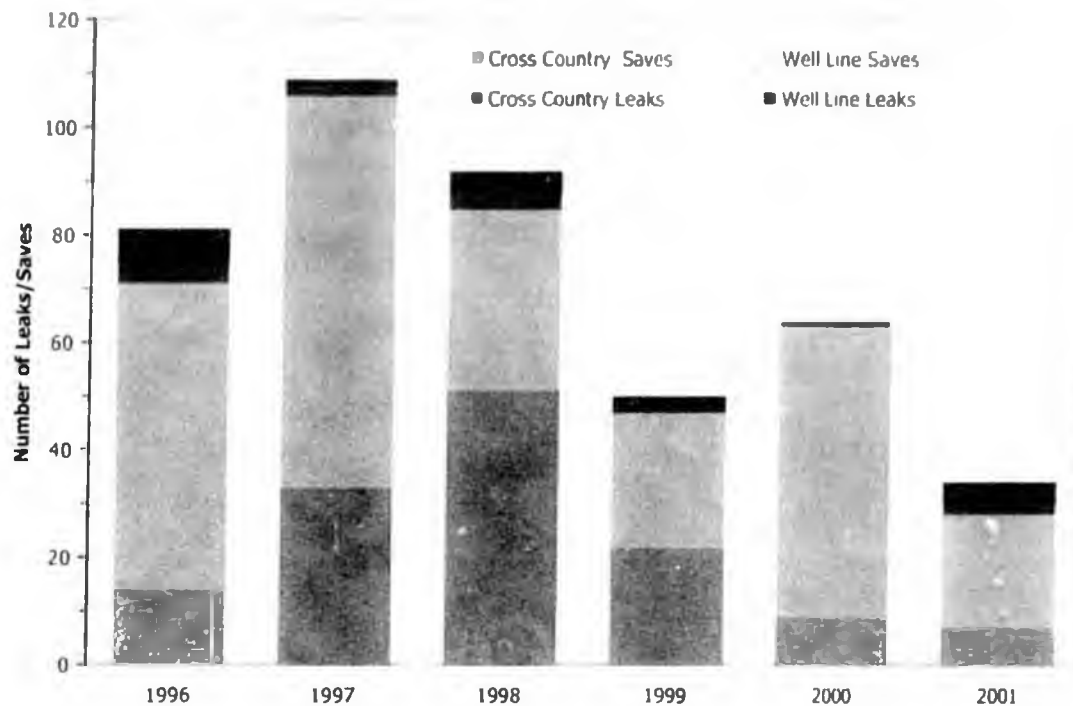


Figure G.3 Historical Corrosion Leaks

## Section G.2 Structural Issues

There were no structural related pipeline failures in 2001.

A letter dated January 15, 2002, was sent to ADEC regarding spot checks of piping, pipe supports, tank truck loading areas, and well houses performed by ADEC personnel in July, 2001. In the response BP committed to completing necessary repairs in 2002.

Field Operations and Security personnel are tasked as the primary identifiers of flow lines and well lines with potential structural integrity problems. Observations of wind-induced vibration, excessive pipe movement, out-of-place pipe guides, bent piping, etc. are reported. A visual inspection by a competent engineer is first completed to determine any required action.

The engineer may request assistance from the Field Mechanical Piping Engineer to perform a more detailed piping stress analysis. CIC may be requested to perform NDE inspections to assist in determining the required repair action.

When evaluating possible damage caused by structural movement, i.e. subsidence, jacking, vibration, impact, slugging, snow loading, etc., the following items are considered:

- Insulation damage
- Piping damage
- Bent piping
- Piping saddles at adjacent pipe supports
- Locations of line anchors
- Road crossings
- Expansion loops
- Branch connections

A piping stress analysis is completed as deemed necessary by the Field Mechanical Piping Engineer. Third-party piping stress analysis engineering experts may be involved as determined by the Field Mechanical Piping Engineer.

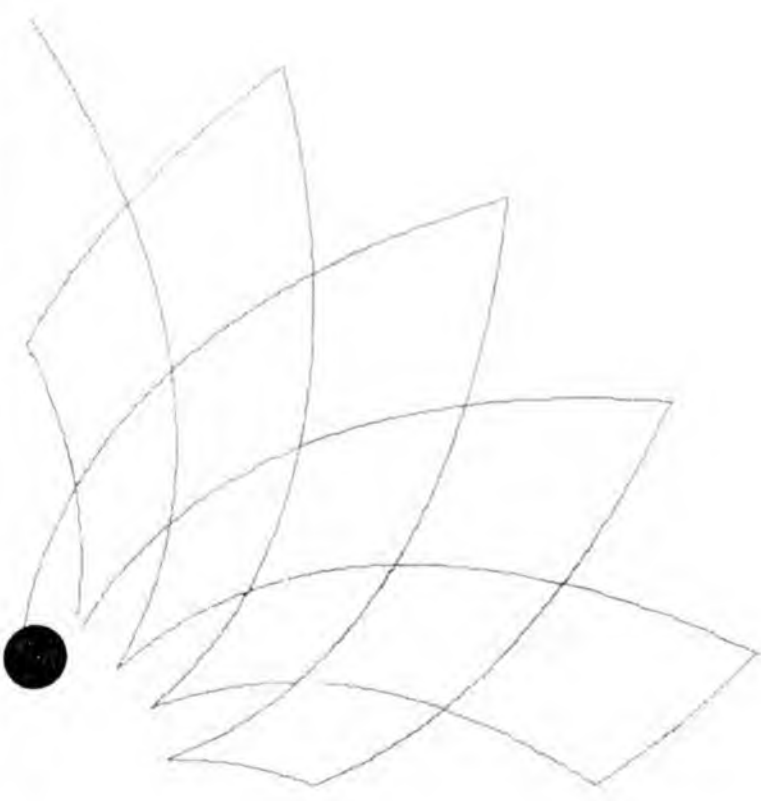
If significantly bent piping is observed, NDE inspection of the areas in question is performed. To accomplish the inspection the insulation is removed. The purpose of the inspection is to determine if any detrimental damage (i.e. wall thinning, cracks, ovality, buckling) exists. The NDE methods typically used include visual, ultrasonic, magnetic particle, radiography, and dye penetrant as appropriate. The applicable ANSI/ASME B31 piping Code acceptance limits are used to determine acceptability. BP has found by experience that the aesthetic appearance of pipes

is not a conclusive sign that the pipes lack structural integrity or are not fit-for service.

When the inspections and analysis warrant action, a recommendation is provided to Operations for creation of a work order to address the location in question. An engineering design package is prepared to complete and document the work action. Management of Change and other procedures are applied as required.

## Section H

### 2002 Corrosion Monitoring and Inspection Goals



## Section H 2002 Corrosion Monitoring and Inspection Goals

### Section H.1 2001 Corrosion and Inspection Goals Reviewed

The introduction of single operatorship at Greater Prudhoe Bay was a significant event in 2000. Although much of the integration of the corrosion management programs was completed in 2000, a significant focus for 2001 was the completion of this activity for all aspects of the corrosion management system.

#### Section H.1.1 Corrosion Monitoring

The consolidated weight loss coupon program was implemented as discussed in the 2001 report. Table H.1 summarizes the coupon pull frequency by service and equipment type.

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

Table H.1 Coupon Pull Frequency

#### Section H.1.2 Inspection Programs

The elements of the inspection program, CRM, ERM, FIP, CIP and CUI discussed in detail earlier in this report, were implemented across Greater Prudhoe Bay as planned in the 2000 report. These programs now form the framework for the on-going inspection programs at GPB.

A significant piece of activity for 2001 was associated with the integration of two heritage database and data sets. This has occupied a significant amount of time and resources over the last 12 months. The corrosion coupon and inspection portion of the new unified database, MIMIR (**M**echanical **I**ntegrity **M**anagement **I**nformation **R**epository), was implemented in 4<sup>th</sup> Quarter of 2001. The new database has significantly improved the ability to retrieve and analyze inspection and corrosion monitoring records.

Digital radiography was implemented throughout 2001 and is now a standard inspection tool at GPB. The benefits associated with the technique include improved productivity, elimination of waste associated with traditional film development, digital image storage, and data analysis.

As noted previously, only two of the three planned smart pig runs were completed due to scheduling/operational conflicts with the smart pig contractor. The problems were associated with the availability of the correct smart pig tool size required for the pipeline planned.

Corrosion under insulation inspections were at or slightly above the level originally planned for 2001 with approximately 15,000 locations completed over the course of the year. The frequency of damaged location was consistent with that seen in prior years at about 5%.

The below grade cased piping inspection program for 2001 was planned to be approximately 200 locations. At the close of 2001, 275 have been completed which was slightly over the planned number. The program is therefore on track to complete the 5-year initial baseline as previously agreed with ADEC.

### **Section H.1.3 Chemical Optimization**

The rationalization and optimization of the surface inhibition program at Greater Prudhoe Bay continued throughout 2001. The number of bulk chemicals was significantly reduced with the majority of facilities being protected with 99VD049 or the related product 01VD117, which are similar to 049 but without the emulsion breaker. Throughout the course of the year both summer and winter versions of these products were deployed. The only difference being the summer version has less solvent and therefore a higher pour point resulting in savings on transportation and handling costs.

As noted in the 2000 Report, proper distribution of the corrosion inhibitor to each of the wellhead locations had been problematic. Greater attention to injection rates and manufacturing process change has helped significantly to better distribute the corrosion inhibitor. Evidence of the impact of these changes is illustrated in the well-line coupon data with the average corrosion rate dropping to 0.6 mpy, reversing the trend seen in 2000.

### **Section H.1.4 Program Reviews**

A number of reviews were conducted throughout the year on specific elements of the corrosion and inspection programs. Specific reviews conducted were,

- **Wet Gas System** - A review of the wet gas inhibition system inside the separation facilities was conducted with both company and chemical supplier experts.

- **Produced Water System** - The corrosion inhibition of the produced water system was reviewed internally and with the GPB partners. This resulted in additional funding for 2002 to expand the program scope.
- **External Corrosion** - A review of the GPB external corrosion control program was conducted with company, partners', and third-party experts from around the world. The review resulted in additional funding for 2002 for an expanded external corrosion inspection and mitigation program.
- **ADEC Review** - ADEC and third party consultant review and comments on the BP 2000 Corrosion Monitoring Charter Report

The mixture of topics and number of reviews differs slightly from that originally planned in 2001 and reflects the change in emphasis throughout the year and the impact of external factors.

### Section H.1.5 2001 Corrective Actions

Table H.2 notes the corrective mitigation actions taken as a result of ER probe information.

Equipment ID	Cause	Action
N-74	Increased Corrosivity	See Table H.4
09A	Increased Corrosivity	See Table H.4
12C	Increased Corrosivity	Increased CI by 10%
04B	Increased Corrosivity	Increased CI by 5%
03D	Increased Corrosivity	Increased CI by 10%
14D	Increased Corrosivity	See Table H.3

**Table H.2** Correction Mitigation Actions from ER Probe Data

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

Equipment ID	Cause	Action
U-384	Poor water production values	Implemented new procedure for CI distribution
Y-74	Poor water production values	Implemented new procedure for CI distribution
Q Pad	Increased Corrosivity	Increased CI by 20%
14D	Increased Corrosivity	Increased CI by 10%
07C/15C	Possible under injection	Now checking rates
N-74	Increased Corrosivity	See Table H.4
07D (Pit Rate)	Possible under injection	Under investigation

**Table H.3** Correction Mitigation Actions from Coupon Data

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

Equipment ID	Cause	Action
09E	Increased Corrosivity	Increased CI by 10%
04C	Increased Corrosivity	Increased CI by 10%
E-46 (K Pad)	Increased Corrosivity	Increased CI by 75%
S-36	Increased Corrosivity	Increased CI by 10%
Z-74	Increased Corrosivity	Increased CI by 20%
N-74	Increased Corrosivity	Increased CI by 25%
09A	Increased Corrosivity	Increased CI by 10%
G-42	Increased Corrosivity	Increased CI by 150%
H-36	Increased Corrosivity	Increased CI by 10%
PW System	Change In Upstream CI	Changed Upstream CI 1Q02
SW System	Increased O <sub>2</sub> Content	Increased O <sub>2</sub> Control

**Table H.4** Correction Mitigation Actions from Inspection Data

## Section H.2 2002 Corrosion and Inspection Goals

Now that single-operatorship issues regarding corrosion are largely complete, the focus for 2002 will be on optimization and continuous improvement of the newly implemented programs.

### Section H.2.1 Corrosion Monitoring

There are no significant plans to change the corrosion weight loss coupon-monitoring program at this time. The new pull frequency was implemented in 2001, so the focus for 2002 will be to review the data generated and ensure that the benefits from the changes implemented in 2001 are realized.

### Section H.2.2 Inspection Programs

The internal inspection program is planned to be largely unchanged in 2002 from 2001. The expected activity level again will be about 60,000 in total for GPB spread between both the field and facilities.

The major change in the inspection program for 2002 will be the implementation of a much larger external corrosion inspection program. At present the current activity level is planned to be about 35,000 items compared with the historical norm of 13,000.

2002 will be year 4 of a 5-year program to conduct a baseline inspection on all the cased piping segments. As with prior years, the program is expected to be

on-track for completion within the 5-year timeframe. Therefore, 2002 scope will be typical of prior years at 200-300 segments.

### **Section H.2.3 Chemical Optimization**

Chemical optimization will continue in 2002 with the next generation of corrosion inhibitor that was introduced into the field in January 2002. The main focus for 2002 will therefore be two-fold, first, to gain assurance that the new product is functioning as effectively as the prior product, and secondly, to optimize the product to deliver the improvement in performance anticipated.

### **Section H.2.4 Program Improvement**

As discussed in the report, there are two main areas of focus for improvement and both of these are in the injection systems - seawater and produced water system.

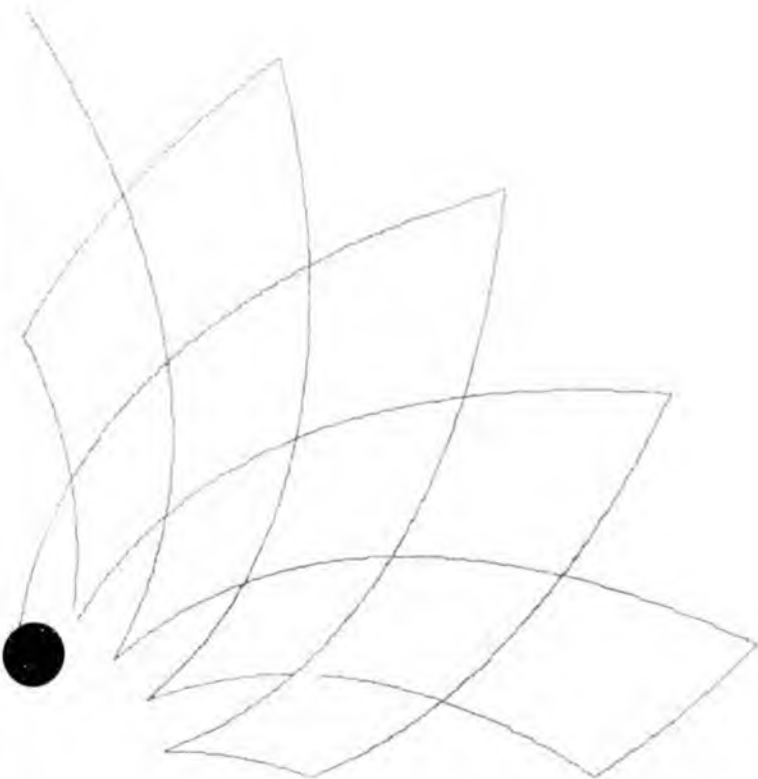
For the seawater system, a number of corrective actions were instigated in the latter half of 2001. The focus will be to ensure that these corrective actions deliver the performance improvement anticipated. Clearly, if there is no improvement in performance, additional corrective actions will be required.

For the produced water system, additional corrosion inhibition is being implemented in 2002, which is expected to reduce the corrosion rates in the system. The focus for 2002 will be to monitor the performance of the new inhibition program and optimize as appropriate.

**Part 2**

**Alaska Consolidated Team Business Unit**

**Section B-H**



## Section B ACT – Corrosion Monitoring Activities

ACT presently consists of four producing areas: Endicott, Milne Point Unit (MPU), North Star and Bad mi. Northstar was added as it came on production in the second half of 2001. The following briefly summarizes the corrosive nature of each producing field.

### Section B.1 Endicott

The Endicott Field is a mature waterflood field. The fluid properties (high temperatures, high CO<sub>2</sub> content) indicate the corrosivity of the produced water to be high. Due to this high corrosivity, much of the field production system was fabricated from duplex stainless steel, a corrosion resistant alloy and therefore, corrosion is not a significant concern for much of the production system. In the Endicott production system, the only carbon steel is the "C Spool", connecting the wellhead to the duplex stainless steel well line. These C-Spools are inspected regularly for replacement as damage dictates.

The primary corrosion concerns are in the water injection system, mainly the Inter-Island Water Line (IIWL) carrying injection water to the satellite production island (SDI) from the main production island (MPI). Corrosion control of the water injection system relies on corrosion inhibition of the injection water, supplemented by a biocide and maintenance pigging program. The primary monitoring method for the IIWL is ultrasonic inspection of 25 locations along the IIWL. Table B.1 summarizes the inspection program for Endicott for 2001.

Service	Miles	Int. Insp.	Ext. Insp.
Oil x-country lines	3.5	4 (in vault)	4 (in vault)
Oil - Well Pads	2.5	1134	0
Water x-country lines	3.5	104	4 (in vault)
Water - Well Pads	1.7	194	2 (in vault)
Gas x-country (GLT/MI)	7	4 (in vault)	4 (in vault)
Gas - Well Pads	1.2	40	2 (in vault)

Table B.1 Endicott Summary of Lines and NDE Inspections

### Section B.2 Milne Point

Fluid properties (low temperatures, low CO<sub>2</sub> content) indicate the corrosivity of the production fluids at MPU to be low. The primary corrosion concerns are in the water injection system and external corrosion of buried piping. Solids play a role in the corrosion of the production system as evidenced by under-deposit corrosion found in the one production flow line in 2001. Corrosion inhibition, supplemented by a biocide and maintenance pigging program began in mid-2000

in the water injection system. As a result, the overall effectiveness of the inhibition is not known due to the limited history. However the initial monitoring results are very encouraging. Corrosion inhibition of one production flow line (K-Pad) was initiated in 2001. Table B.2 summarizes the inspection program for Milne Point for 2001.

Service	Miles	Int. Insp.	Ext. Insp. <sup>2</sup>
Oil x-country lines	24	73	225
Oil – Well Pads	N/A <sup>1</sup>	363	265
Water x-country	15	29	138
Water – Well Pads	N/A <sup>1</sup>	90	142
Gas x-country	14	31	715
Gas – Well Pads	N/A <sup>1</sup>	43	92

<sup>1</sup> Data not immediately available

<sup>2</sup> The external numbers include TRT work performed in 2001.

**Table B.2** Milne Point Unit Summary of Lines and NDE Inspections

### Section B.3 Northstar

The Northstar Field began producing in November 2001. Corrosivity is expected to be moderate initially, but will tend to increase with the injection of Prudhoe Bay Unit gas into the reservoir over time. Table B.3 summarizes the inspection program for Northstar. Data is limited as the production facility is relatively new. Note that the line lengths for Northstar are in feet as the production facility is contained in a small footprint.

Service	Feet	Int. Insp.	Ext. Insp.
Oil Pipe rack	1200	0	0
Oil – Well Pad	280	12	0
Water Pipe rack <sup>1</sup>	2400	0	0
Water – Well Pad <sup>1</sup>	70	0	0
Gas Pipe rack	600	0	0
Gas – Well Pad	140	4	0

<sup>1</sup> Numbers reflect initial baseline inspections. Northstar does not have an active water injection system.

**Table B.3** Northstar Summary of Lines and NDE Inspections

### Section B.4 Badami

The Badami field is currently considered a low risk from a corrosivity standpoint, as there is little water production and low CO<sub>2</sub> content. Table B.4 summarizes the inspection program for Badami.

<b>Service</b>	<b>Feet</b>	<b>Int. Insp.</b>	<b>Ext. Insp.</b>
Oil -Well Pad	840'WL , 320' HDR	7	0
Gas	240'WL, 320'HDR	2	0
Disposal Well	400'	0	0

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

**Table B.4** Badami Summary of Lines and NDE Inspections

## Section C ACT - Coupon and Probe Corrosion Rates

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

### Section C.1 Endicott

Table C.1 depicts the metrics for corrosion monitoring at Endicott for 2001. Historical data are shown in Figure C.2.

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

System	Access Fittings	% WLC < 2 mpy
Water Injection - Pads	18	100%
Water Injection - x-country	1	100%
Oil Production - Pads	77	75%

Table C.1 Endicott Corrosion Coupon Monitoring 2001

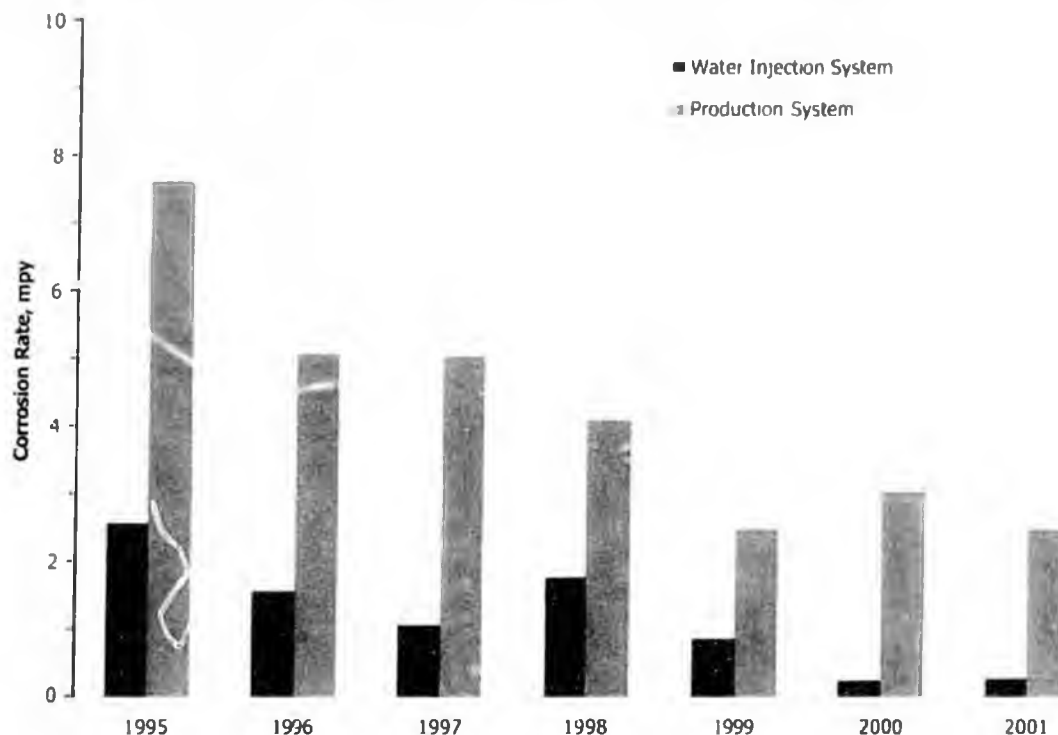


Figure C.2 Corrosion coupon data from Endicott 1995-2001

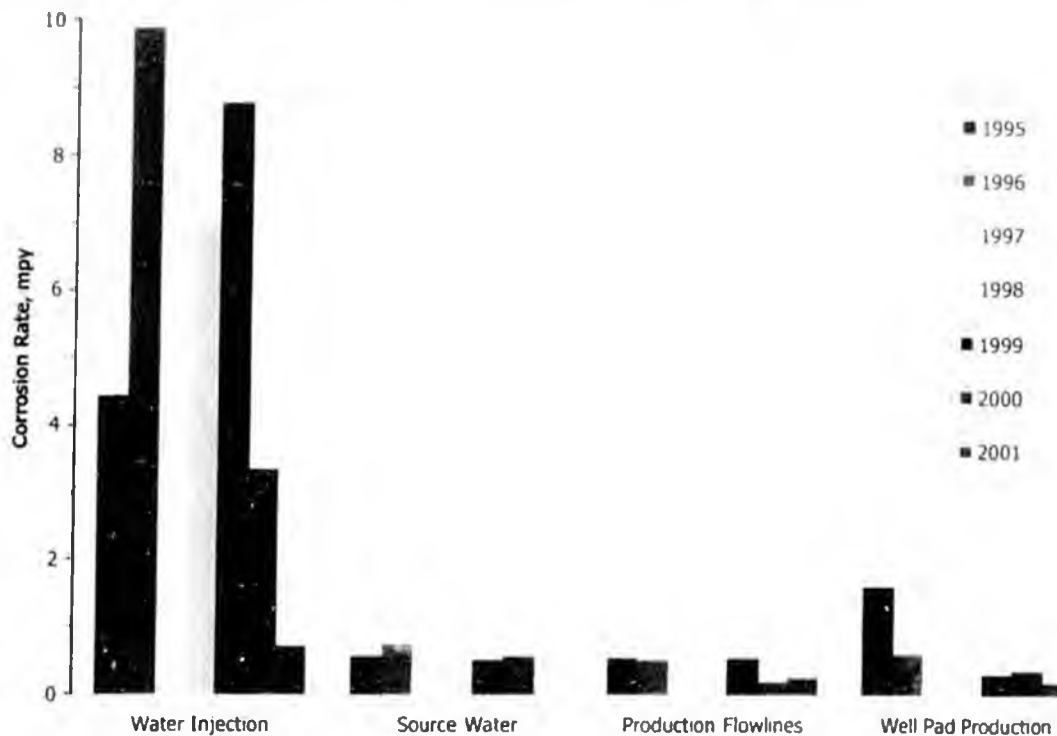
**Section C.2 Milne Point**

Table C.3 depicts the metrics for corrosion monitoring at Milne Point for 2001. Historical data are shown in Figure C.4.

Figure C.4 indicates the low corrosion rates for the MPU production and source water systems. Of concern previously were the relatively higher 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 initial indications are that the inhibition is having a positive effect on the corrosion as the weight loss rates have averaged less than 2 mpy for the first time.

System	Access Fittings	% WLC < 2 mpy
Production System Pads	23	100%
Production System x-country	16	100%
Water Injection System	7	100%
Source Water Coupons	3	100%

**Table C.3** MPU Corrosion Coupon Monitoring 2001



**Figure C.4** Corrosion coupon data from MPU 1995-2001

**Section C.3 Northstar**

The Northstar facility is equipped with corrosion monitoring locations. However, no data is currently available, as no coupons have been pulled and analyzed yet. This data will be reported in the future as it becomes available.

**Section C.4 Badami**

Badami currently has no corrosion-monitoring program.

## Section D ACT - Corrosion Monitoring Activities

### Section D.1 Endicott

Chemical optimization at Endicott has concentrated on a three-pronged approach of maintenance pigging for line cleanliness, biociding to control bacterial activity and continuous injection of a corrosion inhibitor for corrosion control. As noted earlier, the primary monitoring tool for effectiveness is the quarterly UT inspection of 25 locations along the IIWL. These inspections indicate there is very little corrosion activity in the IIWL. Figure D.1 shows a historical perspective of the IIWL inspection activity. Corrosion activity has been minimal since the three-pronged approach was implemented in 1998. The slight increase in 2001 over 2000 is under review.

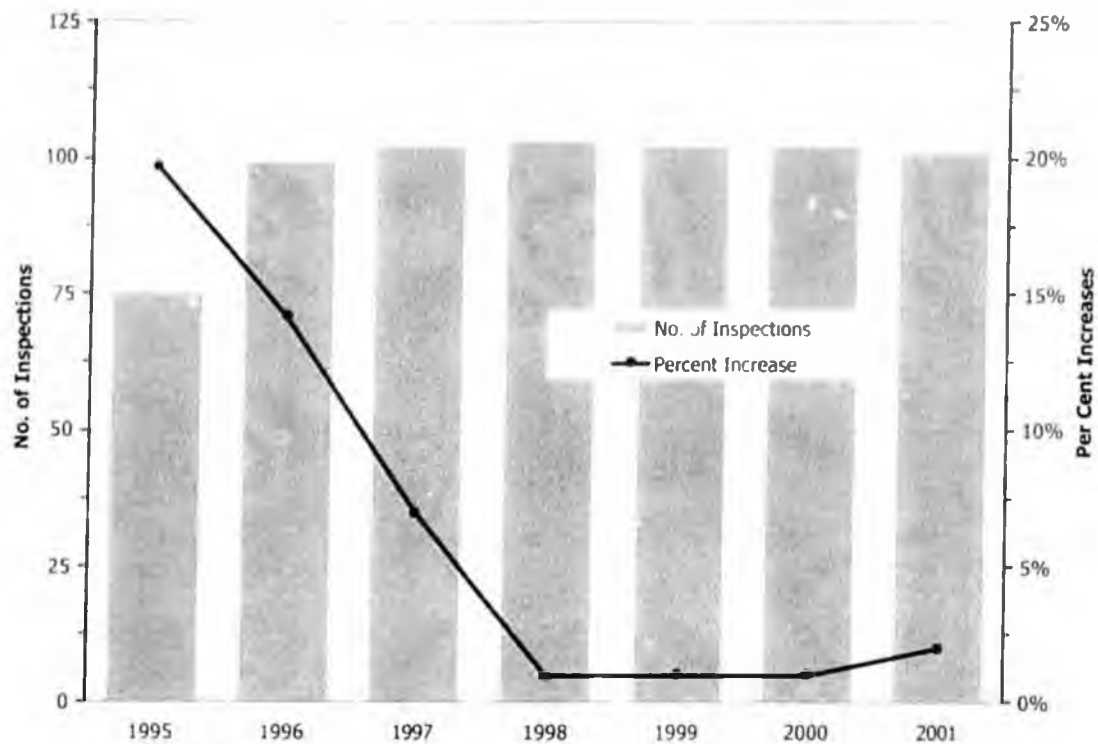


Figure D.1 Endicott IIWL Quarterly UT Readings

Inspection in the production system is primarily geared towards detecting erosion damage. Although not strictly a corrosion mechanism, it is included here for information. Approximately monthly, a risk ranking is performed to determine which wells are producing at high mixture velocities. This information is used by the CIC group to determine inspection frequency levels, and is also used by the operating personnel to determine if wells require choking back. Figure D.2 is an overview of the velocity data for Endicott for 2001. Shown are the numbers of

wells within L/R ratio ranges, where L is the mixture velocity and R is the allowable erosional velocity as defined by API RP 14E.

API RP 14E defines an allowable velocity for the avoidance of erosion, based on the fluid properties (namely density) and material of construction. API RP 14E 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 BP's North Slope experience that production fluids with minimal amounts of entrained solids may exceed the API RP 14E erosional velocity through stainless steel pipelines by this amount with minimal risk of erosion. The single well showing an L/R Ratio greater than 3 had averaged 3.03 for the year. This ratio has since dropped back under 3.0.

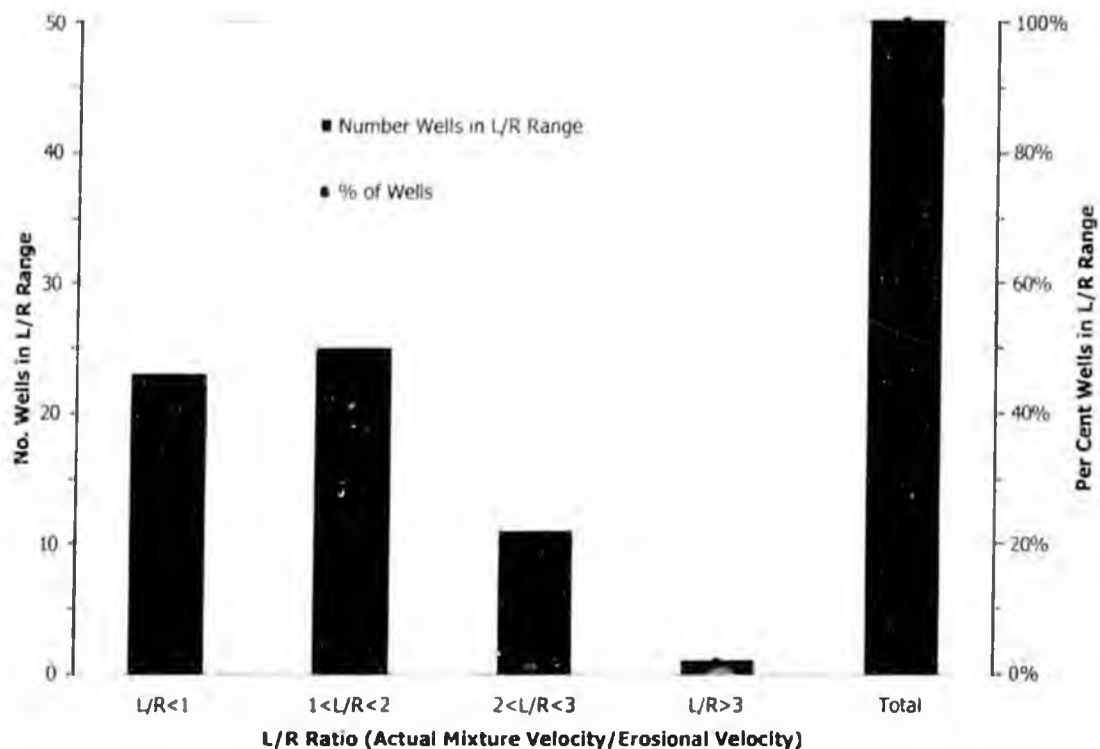


Figure D.2 Endicott Velocity Monitoring 2001

### Section D.2 Milne Point

As indicated earlier, corrosior. inhibition of the water injection system began in mid 2000. It is therefore too early to determine if this program is optimized, however, weight loss coupon data does indicate the system is coming under

control. As production rates are typically lower than Endicott, the velocities are consequently also lower and erosion is not a significant concern. There is therefore no formal velocity management program.

Corrosion inhibition on K-Pad flow line was initiated in 2001 after inspections indicated under-deposit corrosion damage. This is the first production line at Milne Point to be inhibited. The remaining lines are under review for potential corrosion inhibition. Prioritization will be based on flow characteristics and inspection data.

### **Section D.3 Northstar**

Northstar is inhibited with continuous injection of corrosion inhibitor into the well production lines. Injection rates are currently low, as the production contains virtually no water at this time.

### **Section D.4 Badami**

Corrosion inhibition is currently not required at the Badami field based on the results of the inspection program.

## Section E ACT - Inspection and Corrosion Increases/Rates

### Section E.1 External Inspection

#### Section E.1.1 Endicott

Underground/cased lines at Endicott are inspected per the frequency listed in Table E.1. Of the lines inspected in 2001, no significant corrosion was noted.

Line	Crossings	Year Surveyed	Method	Max Inspection Interval
WTR - Inter-Island	1	2001	EMI	10 Years
GAS - Inter-Island	1	2001	EMI	10 Years
OIL	1	N/A		N/A Duplex Stainless Steel
MI Line	1 <sup>1</sup>	N/A		
WTR - WL	2	1 line in 2000	EMI	10 Years for Carbon Steel Other line is Duplex Stainless Steel
GAS - WL	1	2000	EMI	10 Years

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

Table E.1 Cased Piping Inspections

In addition, the vaults where the Inter-Island Water and Gas Lines pass are visually inspected annually. Minor external corrosion has been found, but it has not increased. The above-ground MI line and Gas Line are to be inspected with TRT in 2002.

#### Section E.1.2 Milne Point

Table E.2 summarizes the external inspection program at MPU since 1997. In addition, 30 digs were performed on buried cross-country lines and headers for external corrosion inspection and analysis in 2001. Of these 30 inspections, 19 were new locations; eight showed no change and three showed slight increases in corrosion. The corroded areas were repaired.

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

Table E.2 MPU Inspection Summary- External

The above table does not reflect the total number of TRT inspections performed in 2001. These figures are reported in Table E.2.

Electromagnetic inspections were performed at road crossings in 1998 and 2000. No electromagnetic anomalies were recorded that were significant enough to warrant excavation.

In 2001 guided wave inspection was performed on six lines. The results were inconclusive, however, on three of these lines. There were no significant anomalies on the remaining three lines.

### **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.2 Internal Inspection**

### **Section E.2.1 Endicott**

Figures E.1 and 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 three-phase production cross-country line as it is manufactured from corrosion resistant alloy. Minor activity has been noted in the water injection system.

Figure E.1 shows corrosion activity in the well lines by inspection for both the production and water injection systems at Endicott. These trends have remained relatively constant since 1996. The production system inspection data is used to alert Operations of potential replacements of the carbon steel "C spools" at the wellheads. The inspection increases in the water injection system well lines have been relatively low since 1996 reflecting the improvements in the chemical mitigation program undertaken at Endicott. The slight increase in the PW/SW well lines in 2001 is under review.

Figure E.2 shows a trend of declining inspection increases since 1995 for the Inter-Island Water Line at Endicott. This trend is indicative of the improvements made to the water injection mitigation program. There has been, however a slight increase in activity in the inter-island water line over the past two years. This is currently under review.

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.

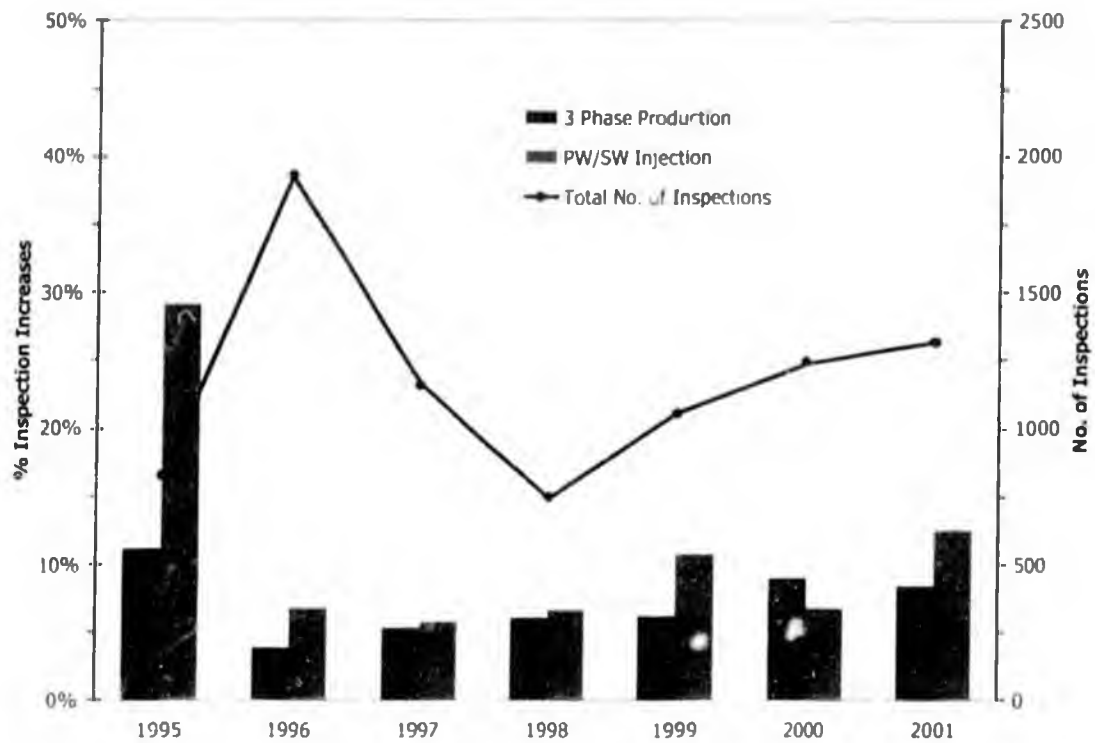
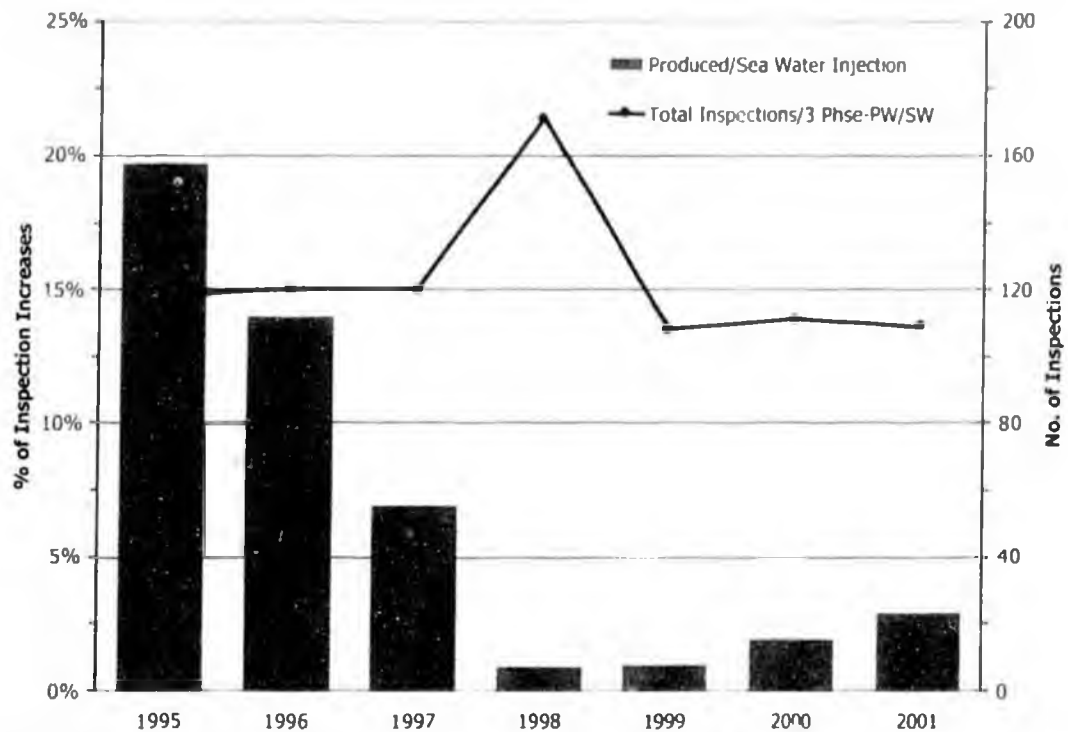


Figure E.1 Detection of internal corrosion of well lines by inspection at Endicott



Note: There were no inspection increases in the production line as it is comprised of duplex stainless steel

Figure E.2 Detection of internal corrosion of flow lines by inspection at Endicott

### Section E.2.2 Milne Point

Prior to 2000, the inspection history at MPU has been somewhat variable. As such, it is difficult to obtain a true trend of corrosion rates via the inspection program due to the limited data set. In 1998, a concerted effort was made towards obtaining a more consistent inspection survey. This will allow a detailed trending history, year-on-year as this data is developed. Table E.3 includes the number of internal inspections since 1994.

Year	Inspection	Repeat Insp.	Increases	I's
1994	332	0	0	N/A
1995	6	0	0	N/A
1996	13	0	0	N/A
1997	632	72	20	28%
1998	994	276	33	12%
1999	931	72	5	7%
2000	1469	280	27	10%
2001	733	262	62	24%

**Table E.3** MPU Inspection summary - Internal

The F-Pad production flowline was smart pigged in 2001. A detailed follow-up will be completed in 2002.

### Section E.2.3 Badami

As Badami only came on stream in 1998, there is little historical data for this field. A 2001 follow-up to the baseline survey performed in 2000 indicates no damage. Inspection locations included the oil production well lines and header, and the gas injection well lines and header.

**Section F Act – Repair Activities**

There were no repairs made to pipelines at Milne Point, Badami, or Northstar in 2001.

At Endicott three S-risers were replaced in 2001. Two were in oil service and one in PW/SW service.

One well line in oil service experienced a fatigue crack on a threaded connection sampling point fitting. As a result, similarly configured fittings have been removed from most well lines. This work is on-going.

Several blind flanges and drains on PW/SW headers were also replaced. Options are being reviewed to allow flushing of the deadleg areas.

## Section G ACT - Corrosion and Structural Related Spills and Incidents

Tables G.1, G.2 and G.3 summarize leak/save and mechanical repair data for Endicott, MPU and Badami, respectively. A table will be added for Northstar in future reporting.

Service	Leaks	Saves	Sleeves	Comments
Oil x-country lines	0	0	0	
Oil Well Pads	1	2	0	3-31; 4-06 S-Risers replaced 1-01 Sample point threaded joint cracked (leak)
Water x-country lines	1	0	0	SDI Water header blind flange replaced
Water Well Pads	0	1	0	1-69 S-Riser replaced
Gas x-country GLT/MI	0	0	0	
Gas Well Pads	0	0	0	

**Note:** Leak / Save and mechanical repair data is for year 2001 only.

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

Service	Leaks	Saves	Sleeves	Comments
Oil x-country	0	1	0	C-Pad pig launcher bypass
Oil Well Pads	0	0	0	
Water x-country	0	0	0	
Water Well Pads	0	0	0	
Gas x-country	0	0	0	
Gas Well Pads	0	0	0	

**Note:** Leak / Save and mechanical repair data is for year 2001 only.

**Table G.2** Milne Point Leak/Save & 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	

**Note:** Leak / Save and mechanical repair data is for year 2001 only.

**Table G.3** Badami Leak/Save and Mechanical Repair Data

## **Section H 2002 Corrosion Monitoring and Inspection Goals**

### **Section H.1 Endicott**

The plan is to investigate the causes for the increases noted in the Inter-Island Water Line (IIWL) and well line inspection data for PW/SW service.

No significant changes to the corrosion monitoring plan are anticipated.

### **Section H.2 Milne Point**

The plan will continue to focus on the gains made in the past, in particular, continuing to build a more comprehensive inspection base for MPU. Given the corrosion damage found in the K-Pad production flow line, the inspection efforts will be increased.

Additional candidates for smart pigging are being considered for 2002.

Analysis of additional production flow lines requiring corrosion inhibition is underway. It is anticipated that the S-Pad flow line (currently under construction) will be treated continuously with inhibitor when it is commissioned.

The three lines with inconclusive external inspection data will be re-inspected in 2002.

### **Section H.3 Badami**

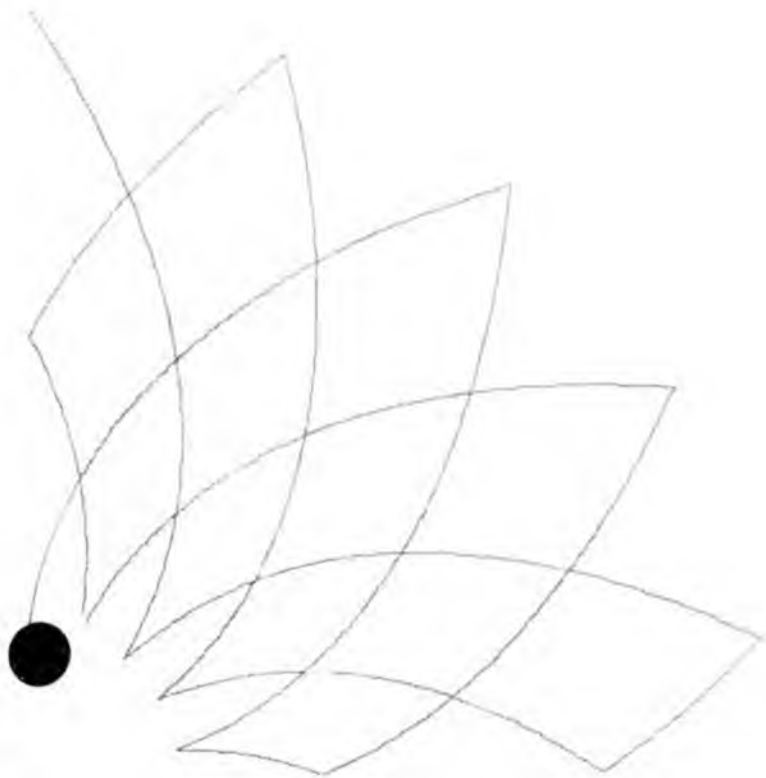
As the Badami fluids are showing to be of relatively low corrosivity, no major changes are anticipated. The plan is to monitor corrosion activity with the annual integrity surveys as has been done in the past.

### **Section H.4 Northstar**

Corrosion monitoring and inspection data will be reviewed as it becomes available. Changes to the inspection and mitigation activity will be dictated by this data in conjunction with process data.

# Appendix 1

## Glossary of Terms



### Glossary of Terms

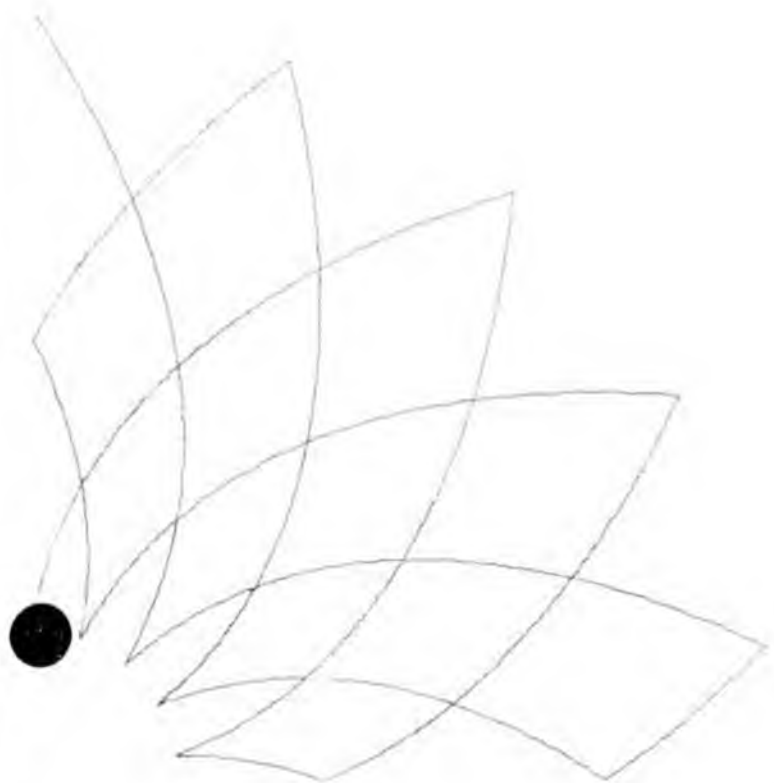
Term	Definition/Explanation
3 phase production	Unprocessed well head fluids, oil, water, gas – same as OIL
ACT	Alaska Consolidated Team
ATRT	Automated tangential radiographic testing
BAD	Badami
BP/BPX(A)	BP Exploration (Alaska) Inc.
CCL	Cross country line
CI	Corrosion inhibitor
CIC	Corrosion, Inspection and Chemicals
CIP	Comprehensive Inspection Program
CL	Common line – same as LDF
CMS	Corrosion Management System
CPF	Central processing facility
CR	Corrosion rate, mpy
CRA	Corrosion resistant alloy
CRM	Corrosion rate monitoring inspection program
Cross Country lines	Pipelines from the manifold building to major facility
CUI	Corrosion under insulation
CW	Commingled Water
DRT	Digital radiography
END	Endicott
ER	Electrical resistance probe – see corrosion monitoring
ERM	Erosion rate monitoring inspection program
FL	Flow line – same as cross-country
FIP	Frequent inspection program
Frequency C	Continuous
Frequency D	Daily
Frequency H	Hourly
Frequency M	Month
Frequency Q	Quarterly
Frequency Y	Yearly/annual
FS	Flow station
G	Gas
GC	Gathering center
GLT	Gas lift transit
GPB	Greater Prudhoe Bay
IIWL	Inter Island Water Line - Endicott
LDF	Large diameter flowline – same as CL
LIS	Lisburne
MFL	Magnetic flux leakage
MI	Miscible injectant
mil	$\frac{1}{1000}$ th of an inch
MIMIR	<b>Mechanical Integrity Management Information Repository</b> BPX(A) corrosion and inspection database
MPI	Main Production Island - Endicott
mpy	Corrosion rate/degradation rate – mils per year
MPU	Milne Point Unit
MW	Mixed water
NDE/NDT	Non-destructive examination/testing
NIA	Niakuk

### Glossary of Terms

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

**Appendix 2**

- (a) **Work Plan**
- (b) **Guide for Performance Metric Reporting**



## Work Plan

### Commitment to Corrosion Monitoring

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

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

#### **Work Plan Purpose:**

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

#### **Corrosion Monitoring Performance Management Program**

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

4. During the semi-annual 'Meet and Confer' working meetings with BP and/or PAI, ADEC may use the services of a corrosion expert(s) (contracted from funds under Charter Commitment paragraph II.A.7) to assist in the review of performance trends and corrosion program features.
  
5. BP has assigned CIC Manager, R. Woollam/564-4437, and Phillips has assigned Kugaruk Engineering and Corrosion Supervisor M. Cherry and J. Huber/659-7384, to be the contacts responsible for ensuring these commitments are met, including ADEC notification of scheduled times for the semiannual presentations. The ADEC contact for this effort is (Pipeline Integrity Section Manager/S. Colberg/269-3078) who will notify interested personnel of the presentation times, maintain the reports for distribution to the public when requested and coordinate other issues relating to this commitment.

#### **Annual Timetable**

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

## Guide for Performance Metric Reporting

### General

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

### Timescale

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

### Equipment Classification

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

### Service Definitions

- **Three Phase Production(3ø or OWG)** Basic reservoir fluids (O/W/G – oil, water and gas) produced from down hole through to the main separation plants that typically see only see changes in temperature and pressure from reservoir conditions and are therefore essentially un-separated

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

**Basic Summary Statistics**

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

**Weight Loss Coupon Data**

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

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

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

- Count of coupons
- Average corrosion rate
- Number non-conformant

- % Conformant i.e. 1 minus the % non-conformant

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

### Internal Inspection Data

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

	Well Lines	CCL/ FL
<b>3 0 Production</b>	All	All
<b>Commingled Water</b>	All	All

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

The data sets to be provided for internal inspection are,

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

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

### Corrosion Inhibition

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

### External Corrosion Inspection

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

The data sets to be provided for external inspection are,

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

### Repair and Leak Statistics

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

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

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

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

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

#### **Below Grade Piping**

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

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

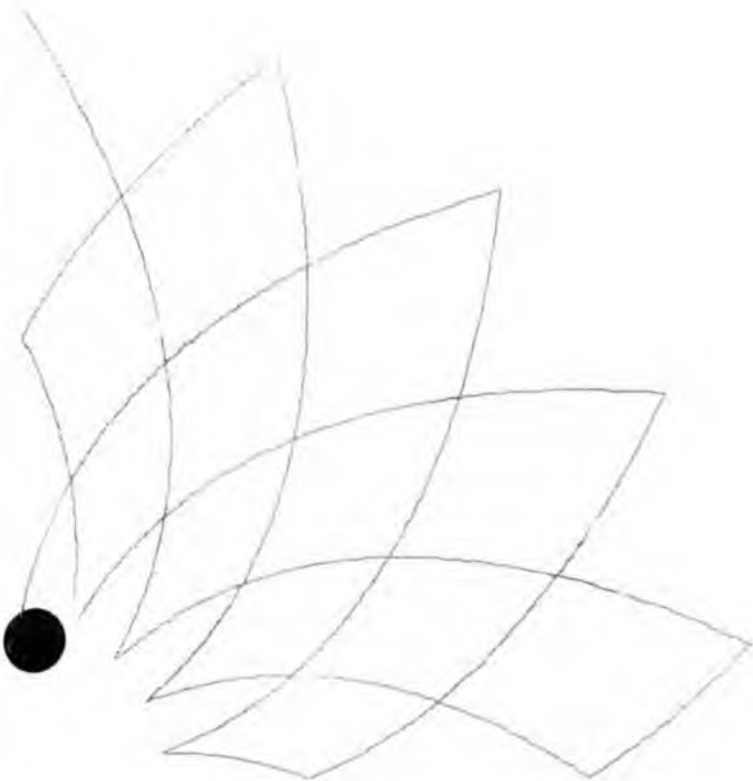
Results of casing digs, visual casing inspections and casing clean-out to be reported as appropriate.

#### **Other Programs**

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

## Appendix 3

- (a) Map of the North Slope
- (b) North Slope Oil Field Facility and Piping Summary



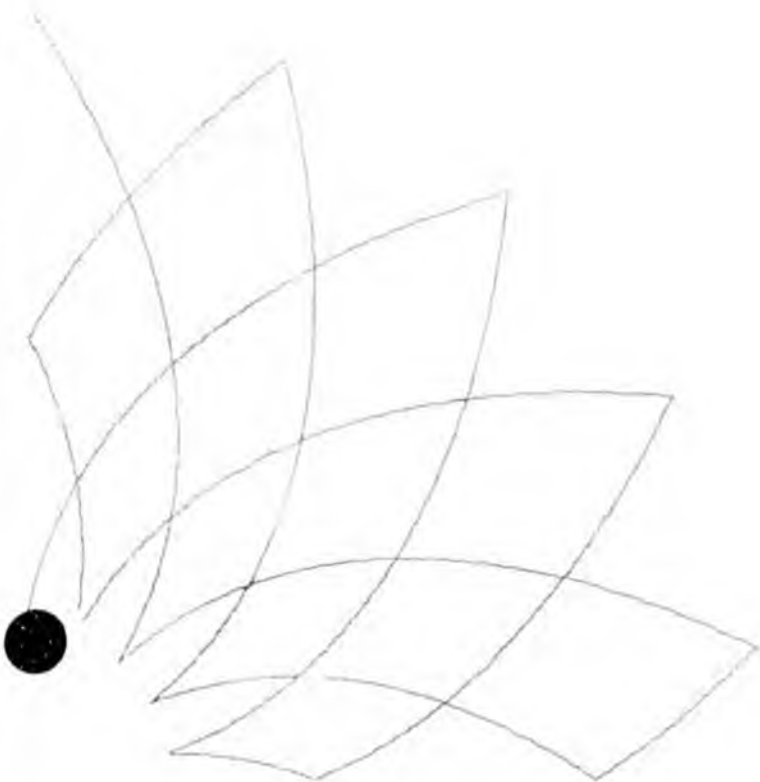


<b>BP North Slope Operations</b>	<b>Field Data (current 1/01)</b>	
Greater Prudhoe Bay	Field Area	150,000 acres
	Original Oil in Place (Gross)	25 billion barrels
	Original Gas in Place (Gross)	47 trillion Std. Cu Ft
	Oil Production Wells	1,080
	Gas Injection Wells	36
	Water Injection Wells	174
	Major Separation Plants	6
	Major Gas Handling Plants	2
	Major Water Handling Plants	3
Miles of Pipelines (approximate)	1,300	
Midnight Sun	Field Area	3,000 acres
	Original Oil in Place (Gross)	0.06 billion barrels
	Original Gas in Place (Gross)	0.1 trillion Std Cu Ft
	Oil Production Wells	2
	Water Injection Wells	1
	Miles of Pipelines (approximate)	4
Aurora	Field Area	10,000 acres
	Original Oil in Place (Gross)	0.1 billion barrels
	Original Gas in Place (Gross)	0.1 trillion Std Cu Ft
	Oil Production Wells	5
	Miles of Pipelines (approximate)	1
Pt. McIntyre	Field Area	8,000 acres
	Original Oil in Place (Gross)	0.8 billion barrels
	Original Gas in Place (Gross)	0.9 trillion Std Cu Ft
	Oil Production Wells	59
	Gas Injection Wells	1
	Water Injection Wells	15
	Miles of Pipelines (approximate)	6
Lisburne	Field Area	30,000 acres
	Original Oil in Place (Gross)	1.8 billion barrels
	Original Gas in Place (Gross)	0.3 trillion Std Cu Ft
	Oil Production Wells	74
	Gas Injection Wells	4
	Major Separation Plants	1
	Miles of Pipelines (approximate)	27
Niakuk & Western Niakuk	Field Area	1,900 acres
	Original Oil in Place (Gross)	0.2 billion barrels
	Original Gas in Place (Gross)	0.1 trillion Std Cu Ft
	Oil Production Wells	18
	Water Injection Wells	7
Miles of Pipelines (approximate)	6	

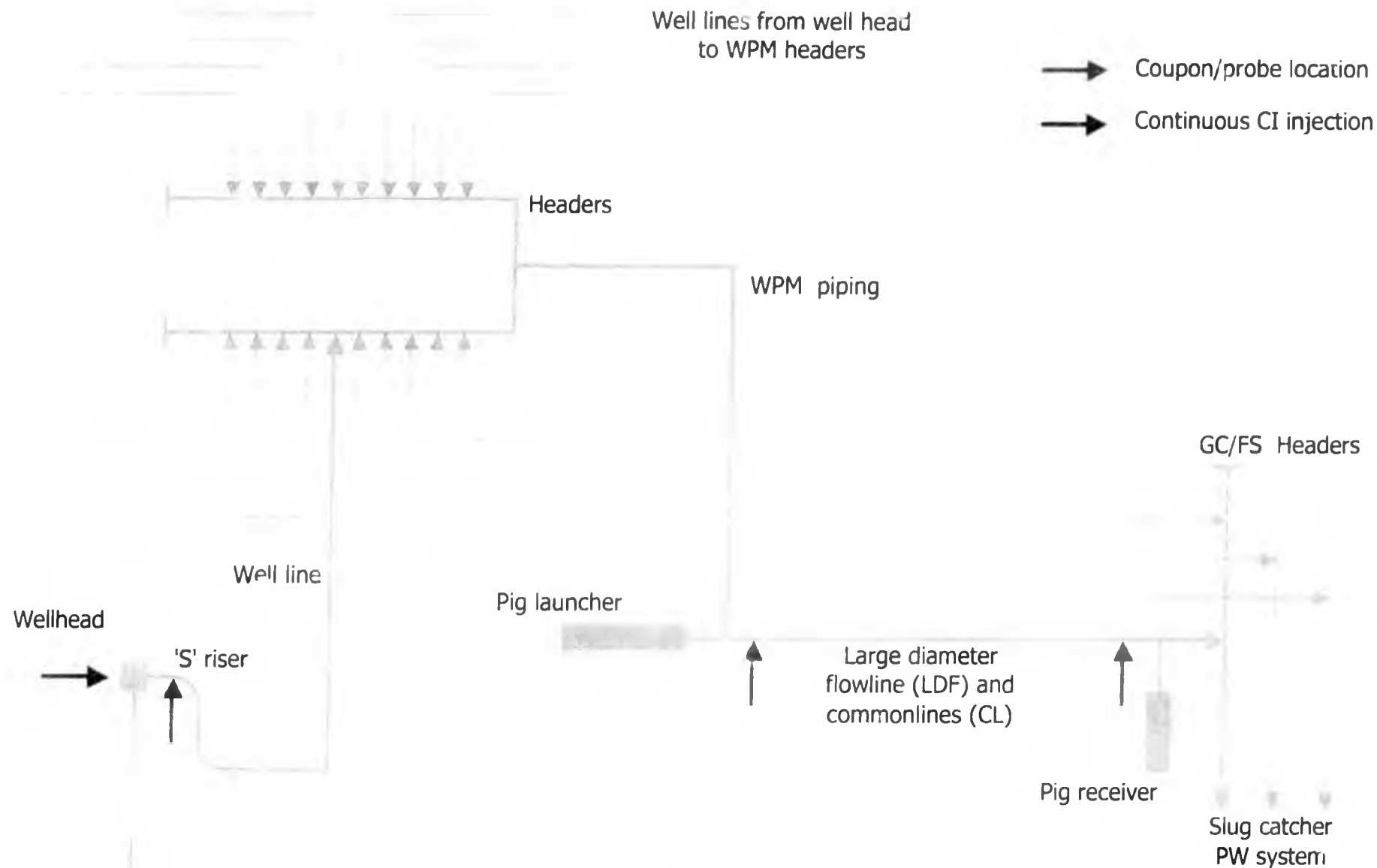
<b>BP North Slope Operations</b>	<b>Field Data (current 1/01)</b>	
Milne Point	Field Area	36,454 acres
	Original Oil in Place (Gross)	0.92 billion barrels
	Oil Production Wells	107
	Gas/Water Injection Wells	59
	Source Water Wells	8
	Major Separation Plants	1
	Miles of Pipelines (approximate)	55
Schrader Bluff	Field Area	28,000 acres
	Original Oil in Place (Gross)	1.97 billion barrels
	Oil Production Wells	49
	Gas\Water Injection Wells	14
	Source Water Wells	3
	Miles of Pipelines (approximate)	15
	Eider	Field Area
Original Oil in Place (Gross)		0.013 billion barrels
Original Gas in Place (Gross)		0.052 trillion Std Cu Ft
Oil Production Wells		1
Gas Injection Wells		1
Miles of Pipelines (approximate)		.5
Endicott	Field Area	8,800 acres
	Original Oil in Place (Gross)	1.1 billion barrels
	Original Gas in Place (Gross)	1.4 trillion Std Cu Ft
	Oil Production Wells	47
	Gas Injection Wells	5
	Water Injection Wells	21
	Major Separation Plants	1
	Miles of Pipelines (approximate)	52
Sag Delta North	Field Area	380 acres
	Original Oil in Place (Gross)	0.014 billion barrels
	Oil Production Wells	2
	Gas Injection Wells	2
	Miles of Pipelines (approximate)	.5
Badami	Original Oil in Place (Gross)	0.160 billion barrels
	Oil Production Wells	6
	Gas Injection Wells	2
	Major Separation Plants	1
	Miles of Pipelines (approximate)	50
Northstar (current 3/02)	Field Area	38,000 acres
	Original Oil in Place (Gross)	.176 billion barrels
	Oil Production Wells	4
	Disposal Injection Wells	1
	Gas Injection Wells	2
	Major Separation Plants	1
	Miles of Pipelines (approximate)	30

## Appendix 4

### Facilities Schematic

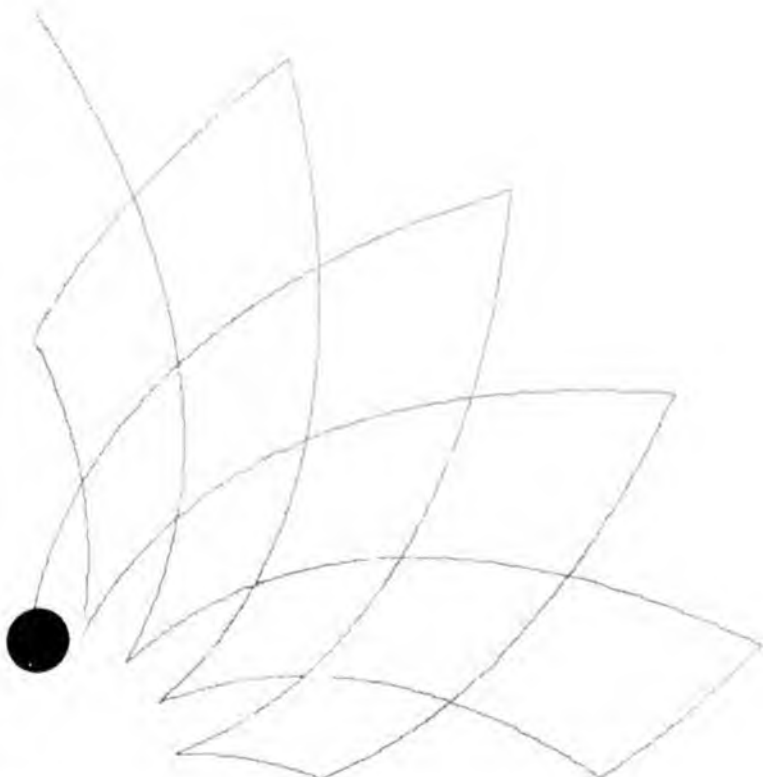


# Facility Schematic



## Appendix 5

### Data Tables



## Appendix 5 – Data Tables

### Introduction

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

Over 2001 there has been a significant investment in resources in order to bring together these two different histories from incompatible databases based on early 1990's technology.

As of the end of 2001, the inspection program and corrosion-monitoring program have largely been integrated into a single database on an Oracle platform with a user interface in VisualBasic.

The database development effort has involved a dedicated team of software developers and database administration but also significant resources from within the CIC Group. The program is currently incomplete and in 2002 BP/CIC will be working on the development of chemical management, electronic data recording, tank and vessel, and standard reporting modules.

It should be noted that this is a 'live' database and therefore as the system changes then the records returned will change. The following are some of reasons why returned values change through time,

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

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

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

audit tools are applied to the translated data, error and mistranslations are removed.

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

BU	Type	Service	Statistic	1995	1996	1997	1998	1999	2000	2001
GPB	FL	OIL	WLC	1441	1573	1612	1506	1541	1460	1190
GPB	FL	OIL	Ave Rate	1.39	0.83	0.49	0.48	0.31	0.41	0.32
GPB	FL	OIL	SD Rate	6.93	3.92	2.06	3.74	0.57	0.83	0.86
GPB	FL	OIL	WLC <2mpy	1,306	1,489	1,568	1,476	1,527	1,420	1,176
GPB	FL	OIL	PC WLC<2mpy	90.6%	94.7%	97.3%	98.0%	99.1%	97.3%	98.8%
GPB	FL	PW	WLC	120	108	115	93	101	80	59
GPB	FL	PW	Ave Rate	4.92	3.40	1.41	1.17	1.13	0.36	0.53
GPB	FL	PW	SD Rate	11.95	7.76	5.46	4.03	5.50	0.59	1.53
GPB	FL	PW	WLC <2mpy	90	86	105	84	92	75	55
GPB	FL	PW	PC WLC<2mpy	75.0%	79.6%	91.3%	90.3%	91.1%	93.8%	93.2%
GPB	FL	SW	WLC	8	4	2	2	2	2	
GPB	FL	SW	Ave Rate	1.53	0.19	2.65	0.00	9.45	7.80	
GPB	FL	SW	SD Rate	1.49	0.37	0.00	0.00	0.54	0.07	
GPB	FL	SW	WLC <2mpy	6	4	0	2	0	0	
GPB	FL	SW	PC WLC<2mpy	75.0%	100.0%	0.0%	100.0%	0.0%	0.0%	
GPB	WL	OIL	WLC	5506	6862	7064	6659	6372	6407	3994
GPB	WL	OIL	Ave Rate	2.68	2.19	0.92	0.70	0.54	0.74	0.66
GPB	WL	OIL	SD Rate	6.85	6.09	2.30	3.63	1.19	1.49	1.72
GPB	WL	OIL	WLC <2mpy	3,938	5,245	6,273	6,274	6,126	5,916	3,713
GPB	WL	OIL	PC WLC<2mpy	71.5%	76.4%	88.8%	94.2%	96.1%	92.3%	93.0%
GPB	WL	PW	WLC	595	626	596	536	374	329	229
GPB	WL	PW	Ave Rate	1.69	0.98	0.33	0.89	0.98	0.61	1.34
GPB	WL	PW	SD Rate	2.84	2.86	1.43	5.54	2.99	1.74	3.90
GPB	WL	PW	WLC <2mpy	466	584	589	512	337	311	197
GPB	WL	PW	PC WLC<2mpy	78.3%	93.3%	98.8%	95.5%	90.1%	94.5%	86.0%
GPB	WL	SW	WLC	64	76	78	78	74	74	50
GPB	WL	SW	Ave Rate	0.91	1.05	0.15	0.41	0.59	1.07	2.65
GPB	WL	SW	SD Rate	1.82	2.94	0.50	0.87	0.80	2.23	3.36
GPB	WL	SW	WLC <2mpy	60	68	77	74	72	66	28
GPB	WL	SW	PC WLC<2mpy	93.8%	89.5%	98.7%	94.9%	97.3%	89.2%	56.0%

Table 5.1 GPB Flow and Well Line General Corrosion Rate Data Summary

BU	Type	Service	Statistic	1995	1996	1997	1998	1999	2000	2001
GPB	FL	OIL	P WLC	1441	1573	1612	1506	1541	1460	1190
GPB	FL	OIL	Ave P Rate	9.41	7.64	6.79	2.94	1.61	1.92	1.10
GPB	FL	OIL	SD P Rate	24.27	14.93	14.00	6.65	6.11	7.73	10.46
GPB	FL	OIL	P WLC <20mpy	"1,313"	"1,480"	"1,555"	"1,480"	"1,518"	"1,426"	"1,183"
GPB	FL	OIL	PC WLC<20mpy	91.1%	94.1%	96.5%	98.3%	98.5%	97.7%	99.4%
GPB	FL	PW	P WLC	120	108	115	93	101	80	59
GPB	FL	PW	Ave P Rate	23.34	18.21	15.34	11.74	8.07	7.16	8.80
GPB	FL	PW	SD P Rate	31.28	28.44	33.86	37.04	28.09	20.61	33.41
GPB	FL	PW	P WLC <20mpy	80	84	102	85	91	72	54
GPB	FL	PW	PC WLC<20mpy	66.7%	77.8%	88.7%	91.4%	90.1%	90.0%	91.5%
GPB	FL	SW	P WLC	8	4	2	2	2	2	
GPB	FL	SW	Ave P Rate	9.63	13.25	2.00	0.00	12.50	15.50	
GPB	FL	SW	SD P Rate	19.36	10.78	0.00	0.00	0.71	3.54	
GPB	FL	SW	P WLC <20mpy	7	2	2	2	2	2	
GPB	FL	SW	PC WLC<20mpy	87.5%	50.0%	100.0%	100.0%	100.0%	100.0%	
GPB	WL	OIL	P WLC	5506	6862	7064	6659	6372	6407	3994
GPB	WL	OIL	Ave P Rate	11.30	11.71	5.18	3.18	2.77	3.28	1.96
GPB	WL	OIL	SD P Rate	31.81	28.88	14.48	9.86	7.76	10.07	7.12
GPB	WL	OIL	P WLC <20mpy	4,825	5,952	6,780	6,493	6,245	6,221	3,897
GPB	WL	OIL	PC WLC<20mpy	87.6%	86.7%	96.0%	97.5%	98.0%	97.1%	97.6%
GPB	WL	PW	P WLC	595	626	596	536	374	329	229
GPB	WL	PW	Ave P Rate	16.38	12.83	7.80	11.41	10.35	6.50	9.20
GPB	WL	PW	SD P Rate	18.65	16.26	18.08	34.56	36.37	14.73	21.15
GPB	WL	PW	P WLC <20mpy	436	521	565	478	340	304	185
GPB	WL	PW	PC WLC<20mpy	73.3%	83.2%	94.8%	89.2%	90.9%	92.4%	80.8%
GPB	WL	SW	P WLC	64	76	78	78	74	74	50
GPB	WL	SW	Ave P Rate	2.11	9.25	5.04	10.23	7.26	3.84	14.70
GPB	WL	SW	SD P Rate	4.61	30.85	18.22	42.28	18.50	6.53	19.57
GPB	WL	SW	P WLC <20mpy	63	69	71	74	69	72	33
GPB	WL	SW	PC WLC<20mpy	98.4%	90.8%	91.0%	94.9%	93.2%	97.3%	66.0%

Table 5.2 GPB Flow and Well Line Pitting Rate Data Summary