

ALABAMA LEGISLATION COMMITTEES, 2003 2000 00/2

11970 SENATE RESOURCES

risk ranked by mixture velocity once per month and the information is used to adjust the inspection frequency and fluid velocity. ACT Table D.1 is an overview of the velocity data for 2001 to 2004. Shown are the number of wells within L/R ratio ranges, where L is the actual mixture velocity and R is the allowable erosion velocity as defined by API-RP-14E⁹.

L/R Range	2001		2002		2003		2004	
	No. Wells	Percent	No. Wells	Percent	No. Wells	Percent	No. Wells	Percent
L/R<1	23	38%	12	21%	19	31%	25	38%
1<L/R<2	25	42%	31	54%	29	47%	27	41%
2<L/R<3	11	18%	12	21%	7	21%	13	20%
L/R>3	1	2%	2	4%	1	2%	1	2%
Total	60	100%	57	100%	62	100%	66	100%

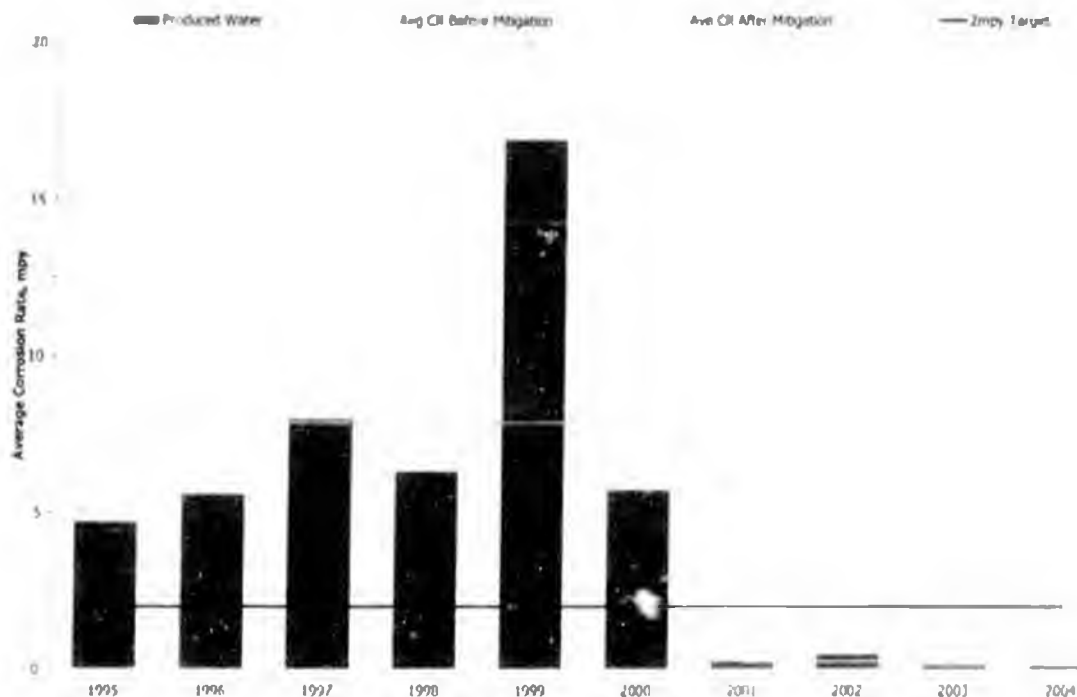
ACT Table D.1 Endicott Velocity Monitoring

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. The aim is to limit actual velocities to less than 3 times the allowable velocity (L/R<3). This factor of 3 reflects BPXA's experience with production fluids that contain minimal amounts of entrained solids flowing through stainless steel pipelines. Equipment exhibiting high velocities is inspected at intervals ranging from weekly to bi-annually dependant upon the L/R Ratio, input from Well Operations, and inspection results. The inspection frequency for the well showing an L/R>3 has been increased to monthly, and there were no inspection increase in 2004.

Section D.2 Milne Point

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

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



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

Corrosion inhibition on the K-Pad 3-phase production flow line was initiated in 2001 after inspections indicated significant under-deposit corrosion damage. The damage was associated with low fluid velocities, allowing solids to accumulate in the line. In conjunction with the inhibition program, the K-Pad flow line is cleaned with a maintenance pig on routine schedule. Inhibition levels were increased in October 2003 to 56 ppm and again in April 2004 to 100 ppm as a result of active corrosion detected through routine inspection monitoring.

The development at S-Pad was designed for continuous inhibition injection into the power fluid supply for the downhole hydraulic pumps. Since this water is separated and re-circulated as power fluid at the pad, only ~10% of the produced water is sent through the 3-phase flow line to the main separation facility. Additional makeup water for use in the power fluid system is treated at a rate of 20-ppm corrosion inhibitor. This program will be optimized based on the results from the inspection and corrosion monitoring programs.

The continuous inhibition of the production flow line carrying production from F, L, and C Pads remains unchanged at 56 ppm.

The remaining uninhibited production flow lines are under review for corrosion inhibition. Inspection results from these production well lines indicate there is slight corrosion activity occurring over the long term. An analysis of these data was started in 2004 and recommendations will be made in 2005.

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

Section D.3 Northstar

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

As noted in Section C.3, work began in 2004 to relocate the chemical injection upstream to the wellhead.

Section D.4 Badami

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

If the Badami Field is brought back on-line, BPXA will reinstitute the integrity monitoring plan beyond what has been done for the shutdown inspections.

Section E External/Internal Inspection

Section E.1 External Inspection

Section E.1.1 Endicott

Cased flow lines at Endicott were last inspected by electromagnetic pulse test (EMT) and no significant anomalies were noted.

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

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

ACT Table E.1 Cased Piping Inspections

In addition, the vaults where the production, IIWL, and gas-lift pipelines pass are visually inspected annually. Minor external corrosion exists, but it has not increased.

In 2004, IIWL was inspected for external corrosion with ATRT at 719 locations and slight corrosion damage was found at 3 locations, with none requiring repair.

Section E.1.2 Milne Point

ACT Table E.2 summarizes above-ground the external inspection program at MPU since 1997. No increase in corrosion was noted in any of the re-inspected locations. Four new locations were identified as requiring repairs.

Year	Total Insp	Repeat Insp	Increases	% I's
1997	26	0	0	n/a
1998	441	10	0	0
1999	101	65	0	0
2000	205	104	28	27
2001	179	20	5	25
2002	70	5	1	20
2003	1,583	55	1	2
2004	1,738	251	0	0

ACT Table E.2 MPU External Inspection Summary for Above-Ground Piping

With regard to buried piping, 623 inspections were conducted in forty-five excavation sites throughout the MPU field in 2004. The excavations were primarily centered on Tract 14 piping on the well pads. Piping examined included well lines and headers and was focused on soil to air interface areas and deeper. These interfaces are located behind the well houses and at pigging facilities, test separators, isolation valves, and pad piping extension areas. Excavations were also done on Tract 14 well pad header to main flow line tie-in points. B Pad, C Pad, D Pad and CFP Pad also had excavations done on various lines at air to soil interfaces.

Of the 623 inspections:

- 227 inspections were repeat locations, of which 30 locations (13%) had slight increases in internal damage.
- 301 locations were baseline inspections
- 95 locations were visual inspections of piping at well pad extensions that were being demolished or isolated from service at H Pad, I Pad and L Pad.

Section E.1.3 Badami

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

Section E.1.4 Northstar

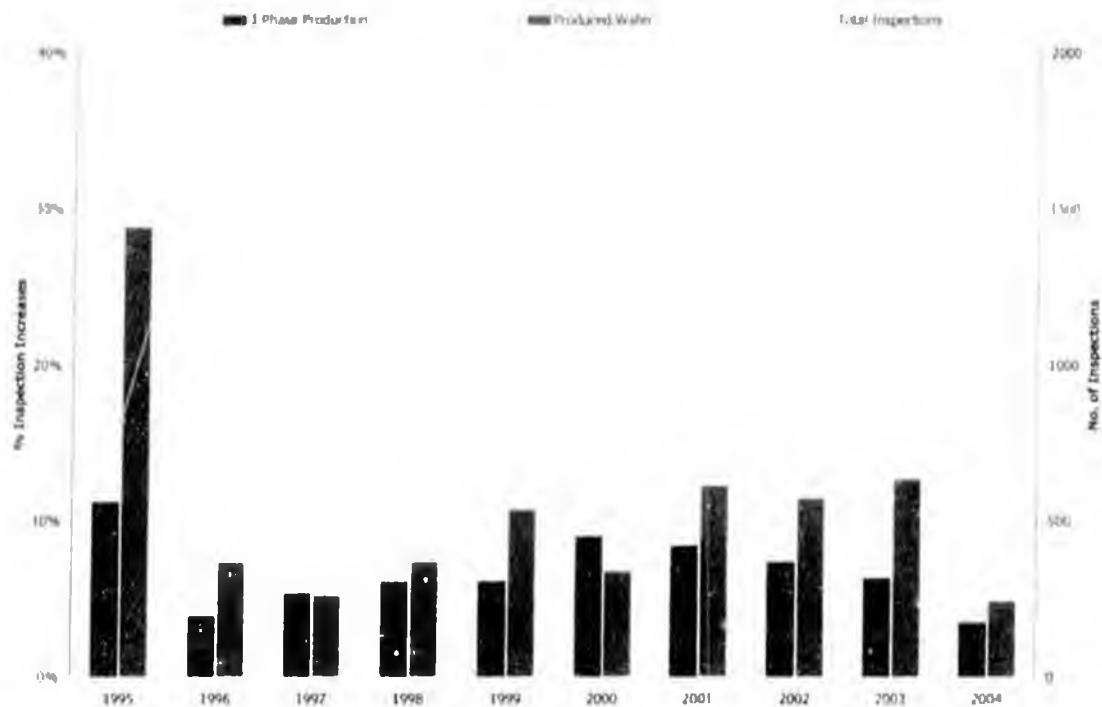
Since the facility is less than 4-years old, an external inspection program has not yet been established. Based on GPB experience, CUI typically takes several years to initiate. A program will be implemented within 5-years from startup (2006).

Section E.2 Internal Corrosion Inspection

Section E.2.1 Endicott

ACT Figure E.1 and ACT Figure E.2 indicate the percentage of inspection increases since 1995 for the well lines and flow lines at Endicott. There were no increases in the 3-phase, DSS production cross-country line. The inspection data for the 3-phase production system are used to alert Operations of potential replacements of the carbon steel C-Spools at the wellheads. The corrosion increases in carbon steel C-Spools are managed through planned replacement using the FFS criteria discussed in Appendix 3.3.5.

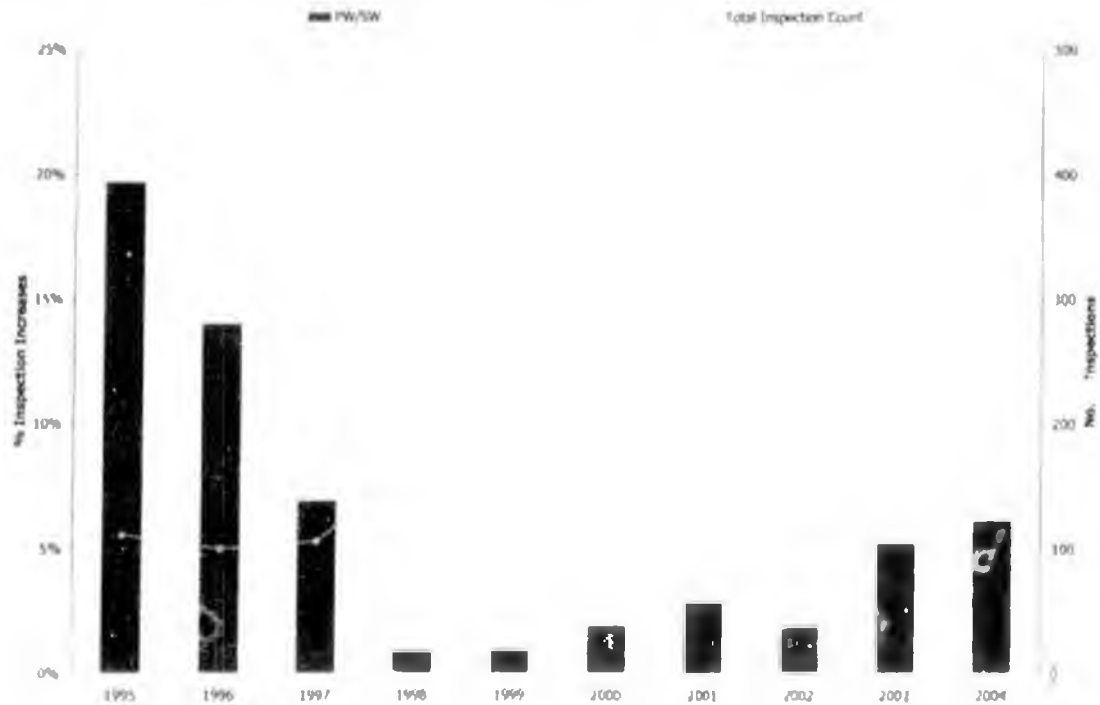
Corrosion activity in the water injection well lines had been increasing since 2000 and was addressed by increasing the corrosion inhibitor concentration by ~18% in 2003 and then by another 50% in late 2004 to 30 ppm. The additional corrosion inhibitor has reversed the increasing trend.



ACT Figure E.1 Endicott Well Line Internal Inspection Increases

ACT Figure E.2 shows a significant decline of inspection increases from 1995 through 1998 for the IIWL at Endicott. There has been an increasing trend in %I's from 1998 through 2004, however these data include the addition of inspection locations that have not been inspected in several years. These additional locations confirm that corrosion was occurring in the line; however the time period between inspections makes it difficult to determine when the corrosion actually occurred. A more accurate representation of corrosion activity through time was shown previously in ACT Figure D.1 which includes

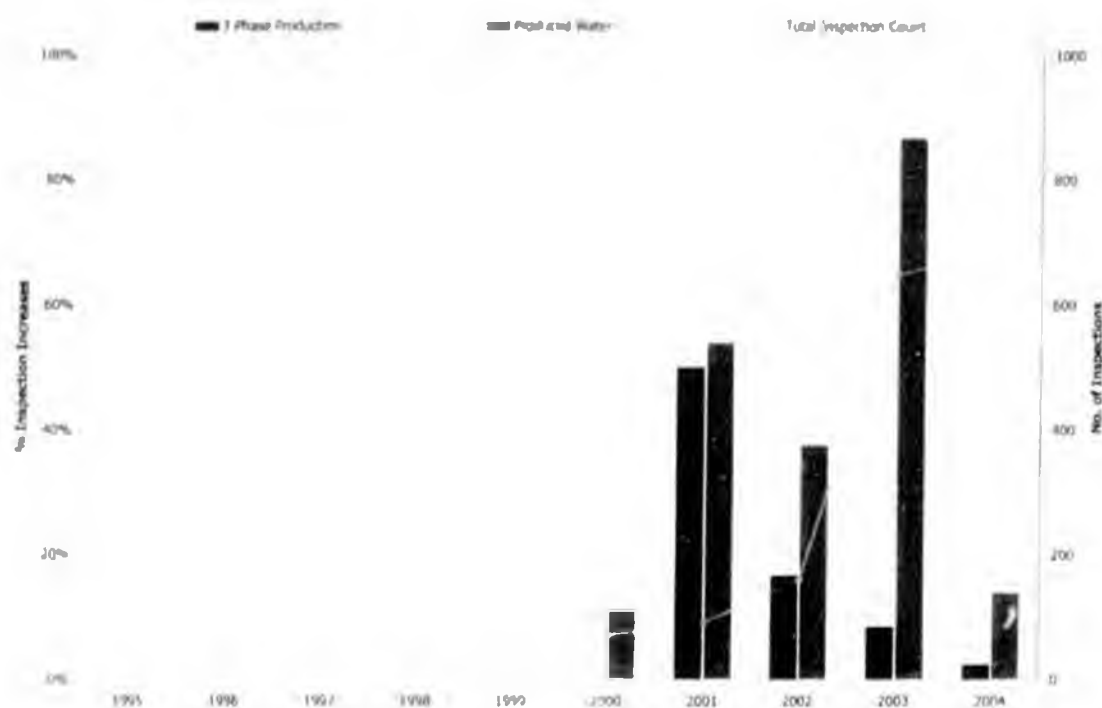
only data from inspections performed on a frequent basis. The frequently monitored locations show a decrease in corrosion activity during 2004.



ACT Figure E.2 Endicott Flow Line Internal Inspection Increases

Section E.2.2 Milne Point

BPXA became operator at Milne Point in 1994, and from this date to 2000 the inspection program was aimed at establishing the baseline condition in the MPU systems. It is only with the 2000 data and beyond that trending of inspection increases has been possible. The results of this comparative data can be seen in ACT Figure E.3. The figure shows the total number of inspection items has consistently increased since 1998.



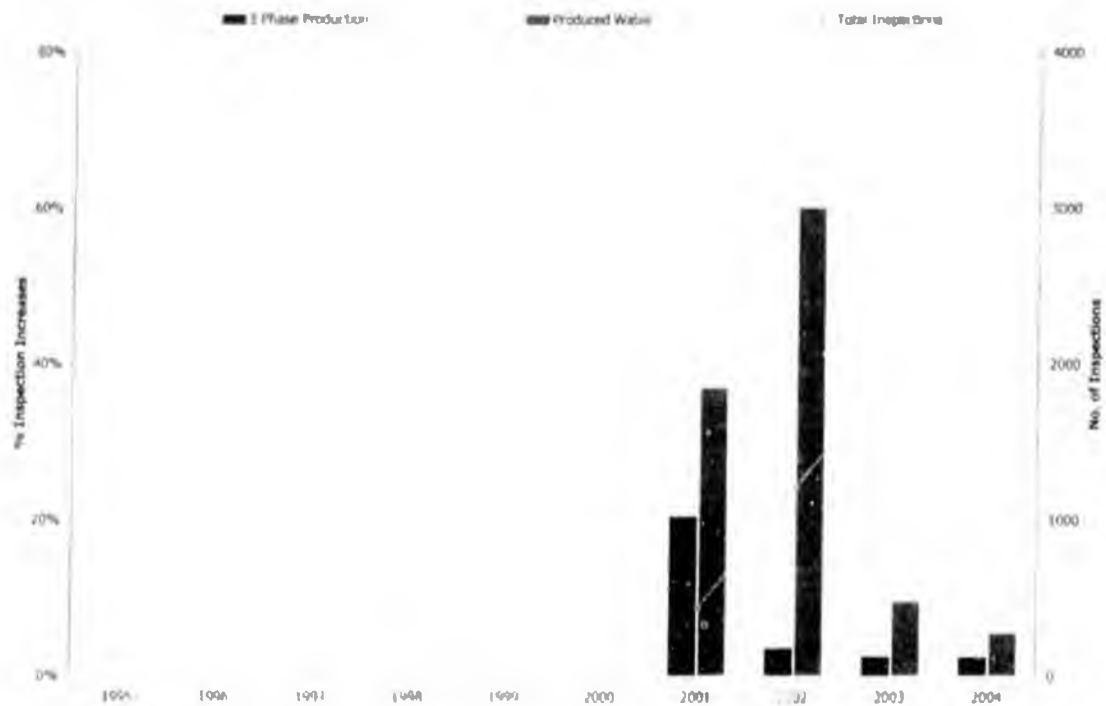
ACT Figure E.3 MPU Flow Line Internal Inspection Increases

Overall the 3-phase flow lines continue to show a decreasing trend of locations with corrosion activity. This is a direct result of increased inhibition of several of the 3-phase flow lines at MPU.

Inspection increases in the produced water dropped significantly in 2004 as compared the prior year. As reported in the 2003 report, the percentage of repeat locations in produced water flow lines had shown a significant increase in 2003, up to 87% from 29% in 2002. The level of the increases were the result of inspections which covered periods both before and after the establishment of corrosion inhibition (late-2000). The average time between inspections was ~4-5 years, indicating much of the corrosion activity reported may have occurred prior to the establishment of inhibition. Repeat inspections performed during 2004 with shorter intervals verify the improvement in corrosion control. These inspection data correlate with the WLC monitoring data in Section C.2.

ACT Figure E.4 shows the %I's and number of inspections on well lines. There has been a significant decrease in the number of repeat locations showing active corrosion since 2002. As noted in the discussion above, this represents a more consistent repeat inspection basis from prior years, as the majority of repeat locations were ~1-year apart, whereas in previous years the time difference between repeat inspections was several years.

Part 2 – Alaska Consolidated Team Performance Unit

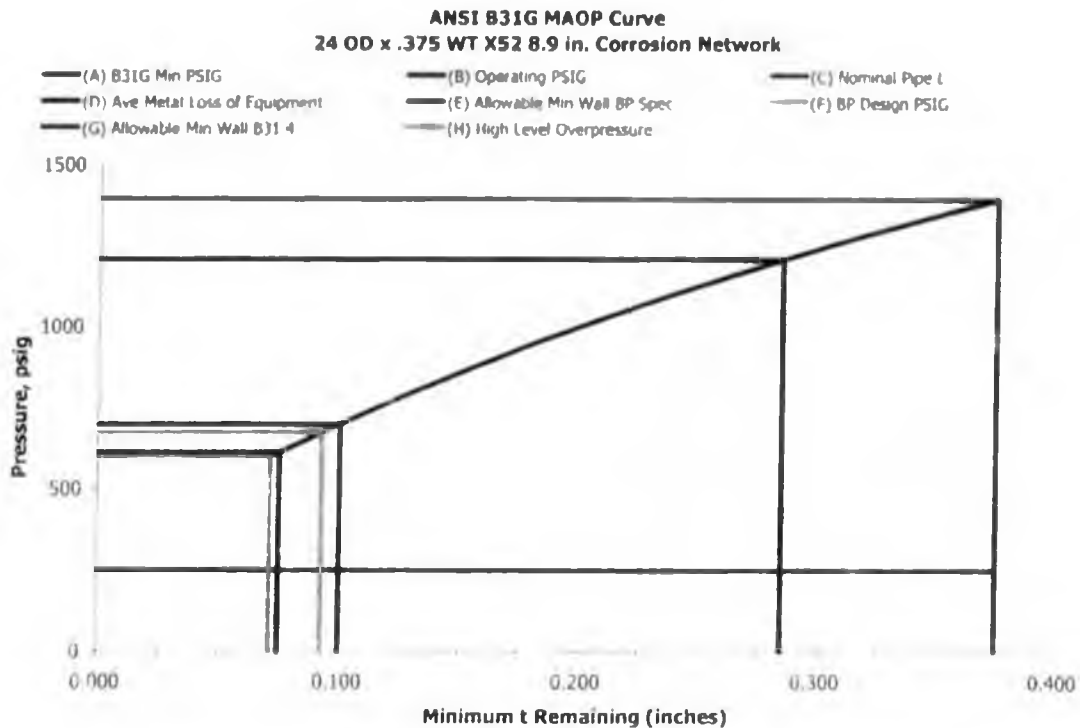


ACT Figure E.4 MPU Well Line Internal Inspection Increases

Section E.2.3 Badami

The Badami Field was shut in August of 2003 due to declining productivity. A post shutdown inspection was performed to serve as a baseline for a follow-up inspection in the third quarter of 2004 as a check to assure equipment was properly laid up in 2003. A follow up inspection performed in 2004 indicates no increase in corrosion activity from the 2003 baseline survey.

Although the data set is limited, inspections support the overall assertion that Badami fluids have low corrosivity. ACT Table E.3 is a summary of well line inspections for Badami.



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

Figure 5 MAOP versus Remaining Wall Thickness

Appendix 3 – Corrosion Management System

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	35	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	21	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 8 Thickness, MAOP Correlation

Figure 6 illustrates the FFS envelop for a combination of depth and length of defect as defined in BP Specification SPC-PP-00090. As can be seen from the curve, the criteria for allowable operating service condition is more conservative than the industry standard at the low end of the remaining wall thickness. This conservatism reflects two issues, (a) the need to provide a margin for error in the determination of wall thickness and corrosion rate, and hence remaining life, and (b) the decreased accuracy of the NDE techniques in use at a wall thickness of less 100 mils.

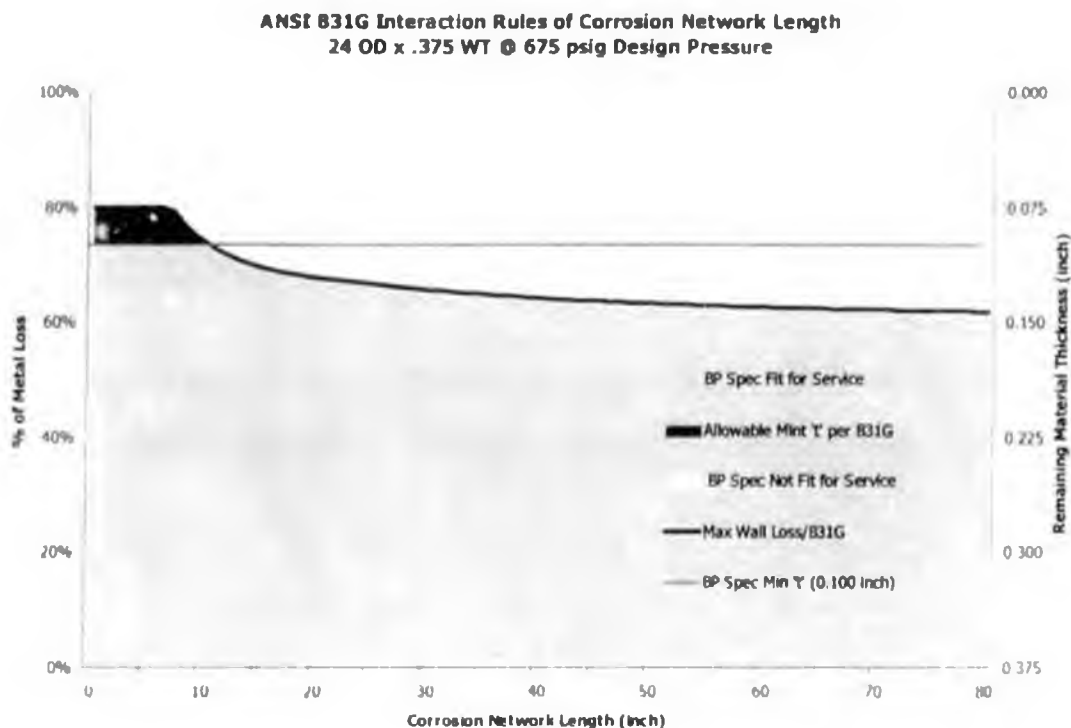


Figure 6 Fitness-for-Service Envelope Based on BP SPC-PP-00090

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

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

- Remaining strength of material is sufficient to contain internal pressure as calculated by ANSI/ASME B31G/modified B31G methodology,
- Minimum thickness, regardless of pressure retaining calculation, is equal to the greater of 0.100 inch or 20% remaining wall thickness.

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

Appendix 3.3.6 In-line Inspection

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

It is important to note that because the vast majority of the cross-country flow lines are above ground, the value of ILI data are considerably lessened compared to buried or underground systems. The primary value for GPB is in the initial identification and

location of damaged locations within a pipeline system. Having initially identified the location of damaged areas, the long-term integrity, pipeline condition and current corrosion rate, of the flow line can be more effectively managed through the use of targeted manual NDE techniques.

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

There are limitations with the ILI technology currently used at GPB. A typical high resolution¹¹ MFL smart pig gives wall thickness measurements that are $\pm 10\%$ of the nominal wall thickness and sizing resolution of 3 times wall thickness for length and width assessment. In addition, there are temperature and pressure limitations that prevent or make difficult the use of MFL tools in many lines at GPB. The typical upper operating temperature for the MFL tools is 122°F/50°C compared with a typical separator fluids temperature of 150-160°F/65-71°C.

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

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

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

¹¹ MFL manufacturer technical data sheet

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

Table 9 Corrosion Management System

Appendix 3 – Corrosion Management System

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

Table 10 Corrosion Management System Element – Monitoring

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

Table 10 (continued) Corrosion Management System Element – Mitigation

Appendix 3 – Corrosion Management System

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

Table 10 (continued) Corrosion Management System Element – Inspection

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

Table 10 (continued) Corrosion Management System Element – Inspection

Appendix 3 – Corrosion Management System

Program	Plan/Objectives	Target	Implementation	Evaluation	Corrective Action
1.1.1 Monitoring – Electrical Resistance Probes (ER)	Monitor the Effectiveness of the Mitigation Programs	< 2mpy Regulatory compliance Compliance with industry standard	ER Probes - Upstream and/or Downstream Ends of Flow lines	Investigate Cause for Corrosion Rate Increase	Mitigation Adjustments ER Probe Maintenance
1.1.2 Monitoring – Weight Loss Coupons (WLC)	Monitor the Effectiveness of the Mitigation Programs	Gen CR: < 2mpy Pit CR: < 20mpy Regulatory compliance Compliance with industry standard	WLC - Installed Flow lines, Well lines, Headers, and Piping	Investigate Cause for Corrosion Rate Increase	Mitigation Adjustments Inspection Program Adjustments
1.1.3 Monitoring – Process Conditions	Monitor changes in the Process Conditions	(See Mixture Velocity and Erosion Sections Below) Regulatory compliance Compliance with industry standard		Investigate Cause for Process Upset Long-Term Process Change Monitor Impact	Mitigation Adjustments
1.1.4 Monitoring – Mixture Velocity Management Program	Monitor the Effectiveness of the Mitigation Programs	Operational Guidelines Mix Vel Limits Regulatory compliance Compliance with industry standard	Operations Acceptance of Mixture Velocity Guidelines SETCIM	Review Alarm List to Determine True Offenders	Adjust Process Conditions
1.1.5 Monitoring – Erosion Management Program	Monitor the Effectiveness of the Erosion Mitigation Programs	Operational Guidelines Well Put on Production (POP) V/V ₀ < 2.5 Regulatory compliance Compliance with industry standard	Operations Acceptance of Erosion Guidelines High Risk Well Inspection Program (ERM)	Monthly Reviews to Determine High Risk Equipment and Repeat Offenders	Adjust Process Conditions

Table 11 Monitoring Program Techniques

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

Table 11 (continued) Mitigation Program Techniques

Appendix 3 – Corrosion Management System

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

Table 11 (continued) Mitigation Program Techniques

Method	Technique	Description	Sensitivity	Accuracy	Freq	Notes/Comments
Corrosion Monitoring	Electrical Resistance (ER) Probes	Measurement of corrosion rate by monitoring changes in electrical resistance of a metal probe due to volume loss	High	Low	H/D	Correlate poorly to actual pipewall corrosion rates
	Weight Loss Coupons Corrosion Rate	Exposure of metal samples to corrosive fluid and calculation of volume loss rates based on weight	Medium	Medium	M	Limited benefit in determining short-term effects, such as flow regime changes on corrosion rates
	Weight Loss Coupons Pitting Rate	Exposure of metal samples and assessment of pitting rate via measurement of pit depths	Medium	Medium	M	Not a very sensitive measure for GPB 3phase but more effective in the PW system
	Galvanic Probe	Detects changes in corrosivity as a function of current flow between two dissimilar metals.	High	Low	C	Not a reliable measurement of mild steel corrosion rate. Very suitable to monitor oxygen and chlorine changes in seawater
	Linear Polarization Resistance (LPR)	Electrochemical technique for assessing corrosion rate by application of controlled voltage and measuring current response	High	Low	H/D	Not used at GPB due to the interference of hydrocarbon films on measurement

Table 12 Corrosion Monitoring Techniques – Benefits and Limitations

Method	Technique	Description	Sensitivity	Accuracy	Freq	Notes/Comments
Process Monitoring	Mixture velocity	Mixture velocity of fluids in pipe-work	Medium	Medium	D	Accuracy dependent upon production information (T, P, Oil, Water, Gas)
	Water cut	Percent water in liquid fluids	Medium	Medium	D	Accuracy dependent upon production information (Oil, Water)
	Temperature and pressure	Measured temperature and pressure in process equipment	Medium	Medium	D	
	Dissolved Oxygen	Amount of oxygen dissolved in Sea Water	High	Medium	D	In-line accuracy problematic. Chemet method more accurate
	Iron (Fe) counts	Amount of Iron (Fe) dissolved in process water	High	Low	M	
	Microbiological activity	Amount of microbiological life forms in process fluids	Medium	Low	M	

Table 13 Process Monitoring techniques – Benefits and Limitations

Appendix 3 – Corrosion Management System

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

Table 14 Inspection/Non-Destructive Examination Techniques – Benefits and Limitations

Method	Technique	Description	Sensitivity	Accuracy	Freq	Notes/Comments
Inspection/NDE (Cont)	In-line Inspection – Smart Pig Magnetic Flux (MFL) Technique	Assessment of pipelines for the detection and measurement of metal loss. These pigs carry high strength magnets, which apply a strong magnetic field into the pipe wall. The magnetic field saturates the pipe steel with magnetic flux. As a result, areas of metal loss cause the flux to leak out of the pipe wall. The flux leakage data are recorded and used to infer the size and depth of any metal loss defects in the pipe.	High	Medium	N/A	Utilized where design and process operation permit in-line pigging. Metal loss MFL In-line Inspection provides complete evaluation of pipeline integrity within the limitations of the MFL technique.

Table 14 (continued) Inspection/Non-Destructive Examination Techniques – Benefits and Limitations

Appendix 3 – Corrosion Management System

Service	Equipment Type	Monitoring Technique	Inspection Program	Mitigation Program*
Oil	Flow line	ER Probes WLC Process Monitoring	CRM FIP CIP CUI	CI Injection Mixture Velocities Periodic Maintenance Pigging Operational Controls
	Well line	WLC Process Monitoring	CRM ERM FIP CIP CUI	CI Injection Mixture Velocities Mixture Velocities Operational Controls
Produced Water	Flow line	WLC	CRM FIP CIP CUI	CI Injection** CI Carry Over Periodic Maintenance Pigging Mixture Velocities Operational Controls
	Well line	WLC	CRM FIP CIP CUI	CI Injection** CI Carry Over Mixture Velocities Operational Controls
Seawater	Flow line	WLC Galvanic Probes Dissolved O ₂ Microbiological Activity	CRM FIP CIP CUI	Biocide Treatment O ₂ Scavenger Periodic Maintenance Pigging Operational Controls
	Well line	WLC Microbiological Activity	CRM FIP CIP CUI	Biocide Treatment Periodic Maintenance Pigging Operational Controls
Export oil	Flow line	WLC ER Probes	CRM FIP CIP CUI	CI Carry Over Mixture Velocities Operational Controls Periodic Maintenance Pigging

*Applicable to all inspection programs noted

**No CI Injection for FS-2 PW

Table 15 Corrosion Management System Implementation by Equip Type and Service

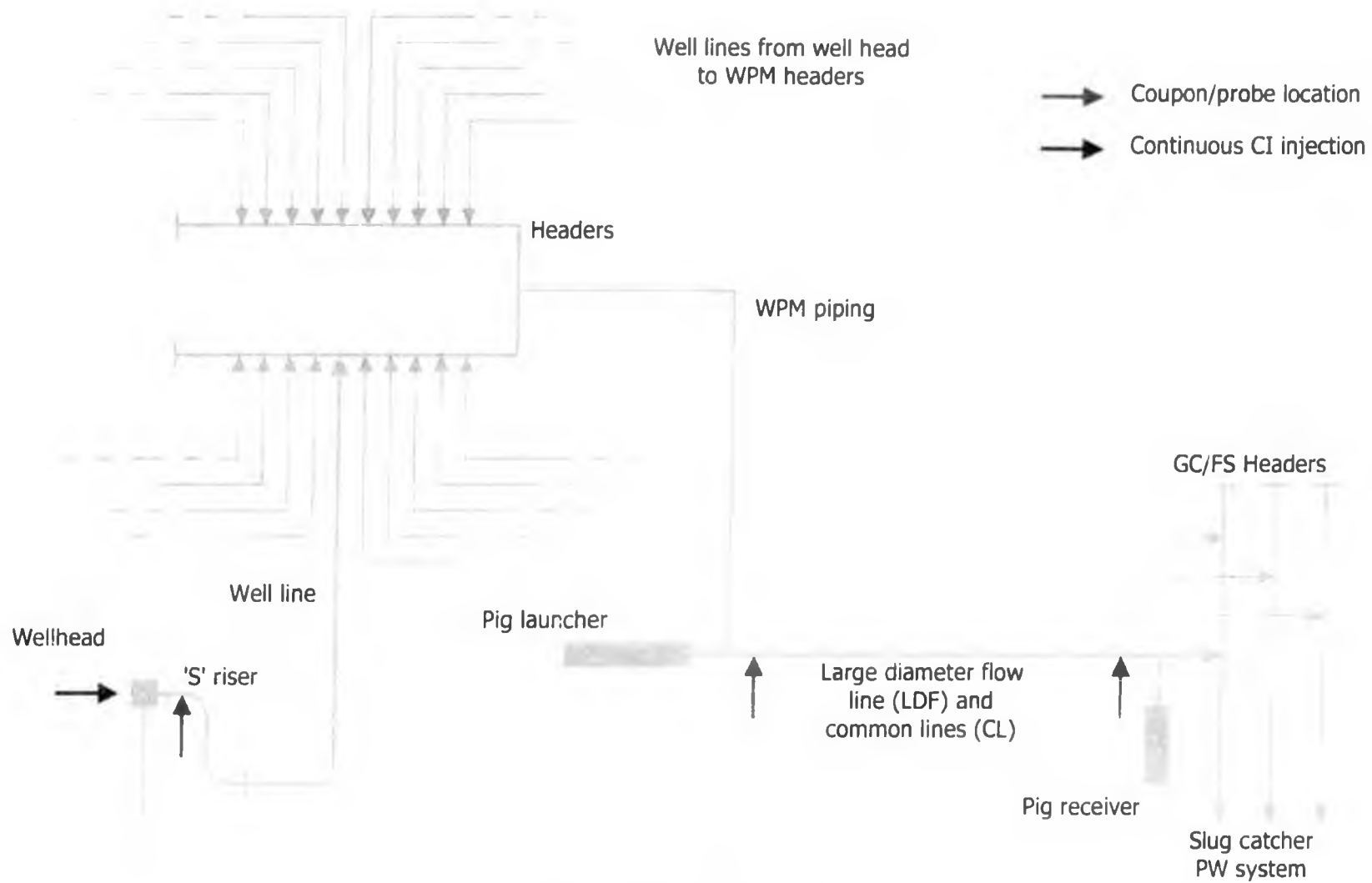


Figure 7 Facility Schematic

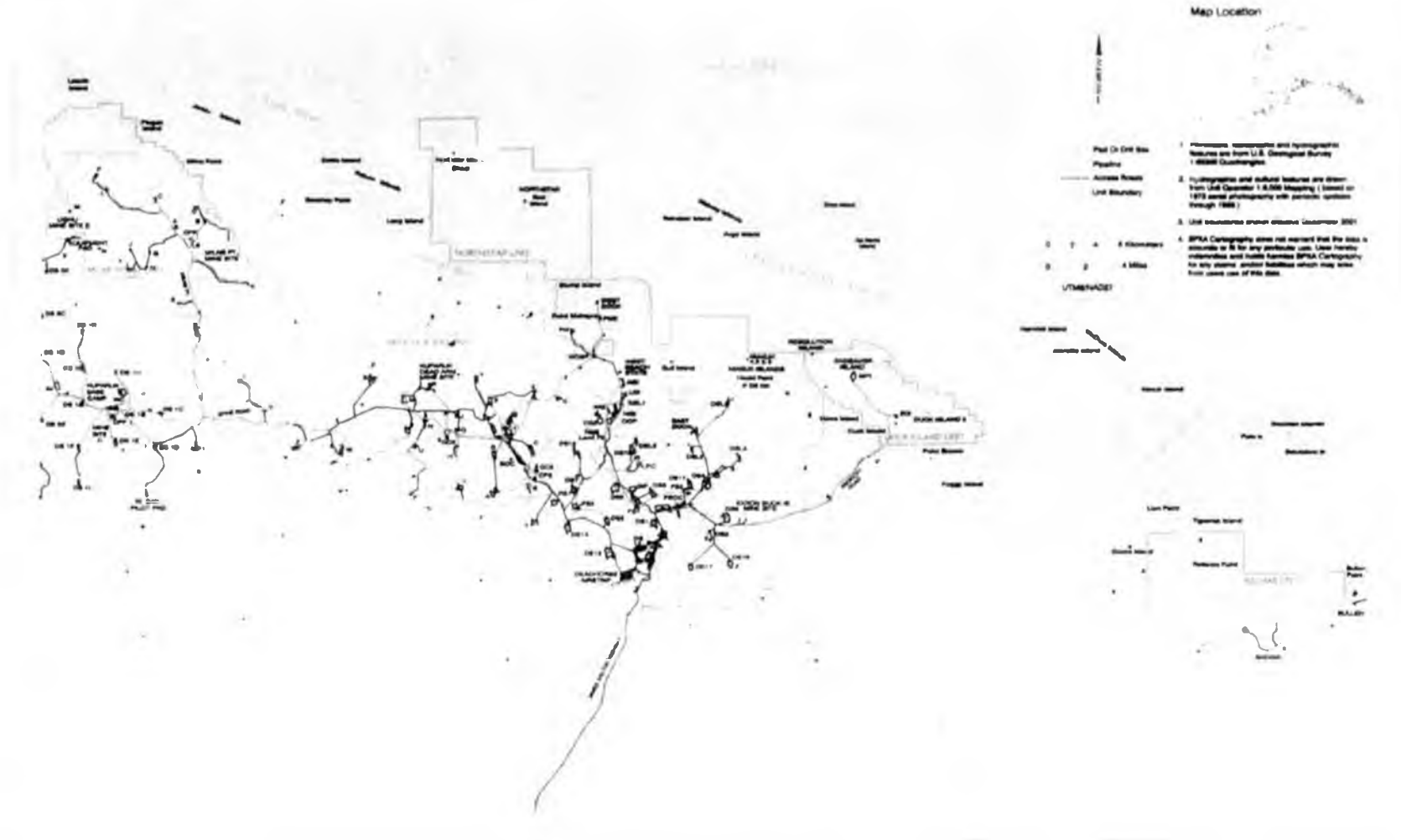


Figure 8- Map of North Slope

BP North Slope Operations	Field Data (current 1/01)	
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)	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)	billion barrels
	Original Gas in Place (Gross)	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)	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)	billion barrels
	Original Gas in Place (Gross)	trillion Std Cu Ft
	Oil Production Wells	18
	Water Injection Wells	7
	Miles of Pipelines (approximate)	5

Appendix 3 – Corrosion Management System

BP North Slope Operations	Field Data (current 1/01)	
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	300 acres
	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)	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
	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

GPB Table 3.1 - BPXA North Slope Operations



Corrosion, Inspection and Chemical (CIC) Group
BP Exploration (Alaska) Inc.
900 E Benson Boulevard
Anchorage
Alaska

© 2005 BP Exploration (Alaska) Inc.

2005



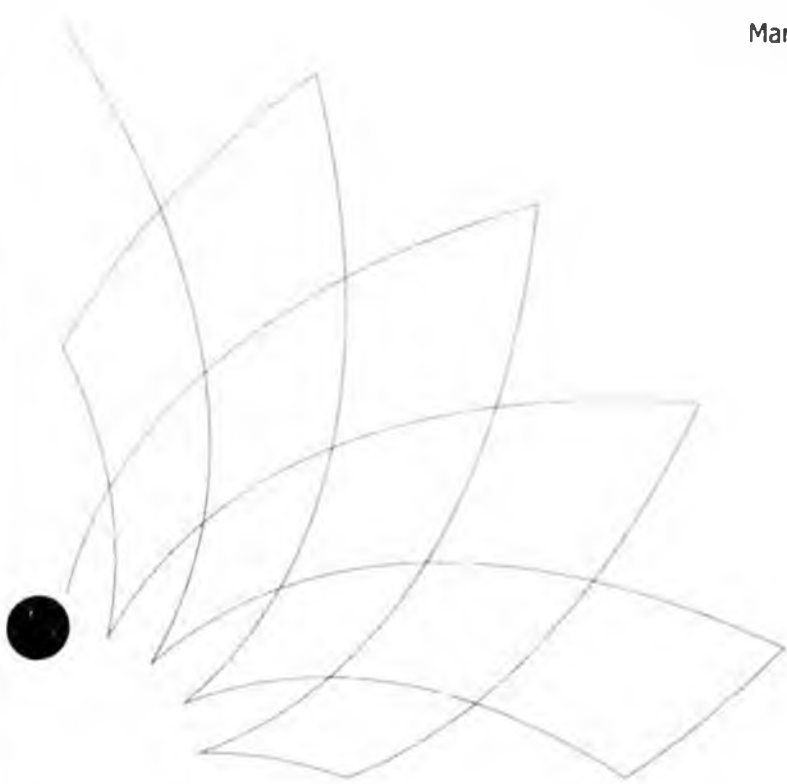
Annual Report to Alaska Department of Environmental Conservation

Commitment to Corrosion Monitoring Year 2005

Prepared by

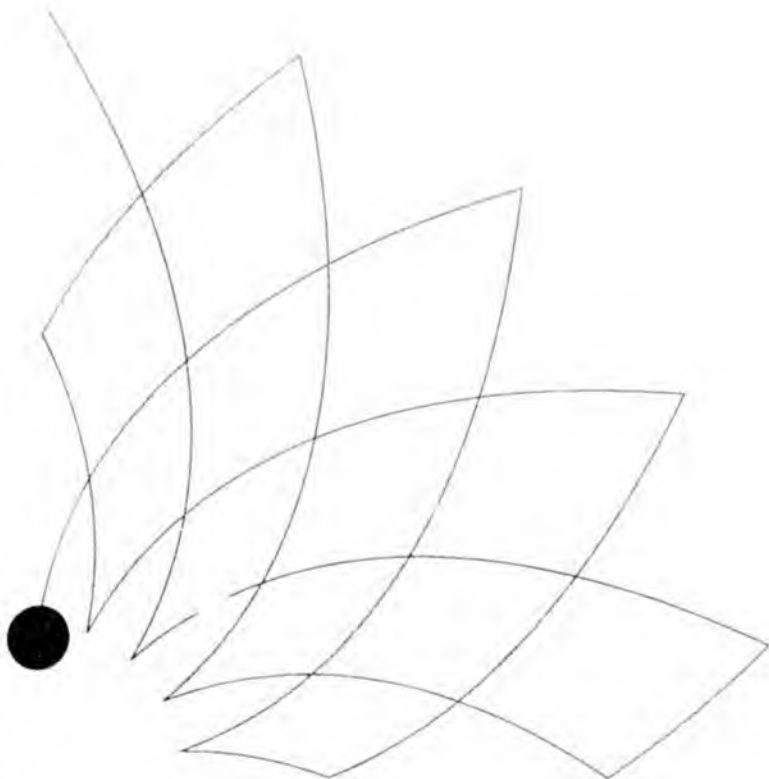
Corrosion, Inspection and Chemicals (CIC) Group
BP Exploration (Alaska), Inc.

March 2006



Commitment to Corrosion Monitoring

Year 2005



Foreword

This is the sixth annual report that meets the commitment made by BPXA to the State of Alaska to provide a regular review of BPXA's corrosion monitoring and management practices for non-common carrier pipelines on the North Slope. The contents of this report reflect the Work Plan¹ agreed jointly between BPXA, Phillips and ADEC, the Guide for Performance Metric Reporting², and feedback from previous ADEC reports. The report is divided into 2 main parts.

Part 1 contains information regarding the BPXA operated fields within the Greater Prudhoe Bay (GPB) Performance Unit. This consists principally of fluids produced from Prudhoe Bay, Lisburne, Point McIntyre and Niakuk field areas but also includes smaller volumes of fluids from satellite accumulations.

Part 2 contains information regarding the BPXA operated fields within the Alaska Consolidated Team (ACT) Performance Unit. This consists principally of fluids from Endicott, Badami, Milne Point and Northstar field areas. As with GPB, several smaller satellite accumulations are also produced through ACT facilities.

The report provides an overview of the corrosion management process, and provides data and discussion of the corrosion control, monitoring, inspection and fitness-for-service programs. These individual programs, in concert, form the core of the integrity/corrosion management system designed to deliver our corporate goal of no accidents, no harm to people and no damage to the environment³. The program also reflects the core values of BP: innovation, performance driven, environmental leadership and progressive.

Innovation is evident in several areas, from the development of more effective corrosion inhibitors and corrosion inhibition programs, to the application of new inspection technologies. These innovations are only made possible by working closely with partners, major suppliers and the regulatory community, to bring the best available technology to Alaskan oilfields.

Performance management and the drive for improved performance are central to all aspects of the corrosion management program. This report demonstrates an on-going effort to improve corrosion management. Since 1992, corrosion rates have been reduced by almost a factor of 10 in the cross-country pipelines that transport a mixture of oil, water and gas (3-phase). Consistent with the pledge to report openly both good and bad performance, the report highlights areas for improvement and the plans in-place to deliver performance improvement.

Environmental protection and corrosion management are closely linked. The improvements in corrosion management have resulted in lower corrosion rates and a lower risk of loss of containment. Opportunities to improve environmental performance still exist and the investment in continuous corrosion inhibitor injection at remaining batch pads well as the continued effort on our external corrosion inspection program is evidence of this on-going commitment.

¹ Appendix 2 (a) 2000 Work Plan

² Appendix 2 (b) Guide for Performance Metric Reporting

³ BP HSE Policy Statement, EJP Browne, Group CEO, January, 1999, <http://www.bp.com/>

Progressive evolution of the corrosion management programs is an on-going activity driven by changing field conditions and the desire to improve performance. Progress involves the continued refinement of the existing programs, but also, the development and implementation of new programs and corrosion management technologies.

The current corrosion management process has delivered a significantly improved level of corrosion control. Notwithstanding the successes, the corrosion management program must remain focused on the future in order to maintain the current level of control and, where necessary, implement the actions necessary to improve performance.

The continuous improvement of the corrosion management programs has enabled BPXA to deliver the programs strategic objectives of:

- Minimizing the health, safety and environmental impacts of loss of containment due to corrosion
- Providing a fit-for-service infrastructure for the remainder of field life
- Producing satellite accumulations through existing equipment and pipe-work
- Providing an infrastructure capable of supporting gas sales in the future

In addition, with the information in this report, BPXA intends to build a healthy relationship with the North Slope stakeholders through consultation, open reporting and striving to raise the standards of the industry.

BP Exploration (Alaska) Inc.
March 2006

Table of Contents

Foreword.....	i
Table of Contents.....	iii
Table of GPB Figures.....	vi
Table of ACT Figures.....	vii
Table of Appendix Figures.....	vii
Table of GPB Tables.....	viii
Table of ACT Tables.....	ix
Table of Appendix Tables.....	ix
Section A Charter Agreement – Corrosion Related Commitments..	3
Section A.1 Project Achievements.....	3
Section A.2 Annual Charter Timetable.....	4
Part 1 – Greater Prudhoe Bay Performance Unit.....	5
Section B 2005 Corrosion Program Summary.....	7
Section B.1 Introduction.....	7
Section B.2 Corrosion Monitoring.....	7
Section B.3 Corrosion Mitigation/Corrosion Inhibition.....	8
Section B.4 External Inspection Program.....	9
Section B.5 Cased Pipe Program.....	9
Section B.6 Internal Inspection Program.....	10
Section C Weight Loss Coupons and ER Probes.....	15
Section C.1 Three Phase Production Systems.....	16
Section C.1.1 Introduction.....	16
Section C.1.2 Cross Country Flow Line Coupons.....	17
Section C.1.3 Well Line Coupons.....	19
Section C.2 Water Injection Systems.....	19
Section C.2.1 Water Injection System Flow Lines.....	20
Section C.2.2 Produced Water Injection Well Lines.....	20
Section C.2.3 Seawater Injection Well Lines.....	23
Section C.3 Electrical Resistance Probes.....	28
Section C.4 1992 to Date Summary.....	29
Section C.4.1 System by System Summary.....	29
Section D Chemical Optimization Activities.....	41
Section D.1 Chemical Optimization.....	41
Section D.2 Corrosion Inhibitor Testing.....	41
Section D.3 Field Wide Corrosion Inhibitor Deployment.....	42
Section D.4 Corrosion Inhibitor Usage and Concentration.....	42
Section D.5 Corrosion Inhibition and Corrosion Rate Correlation.....	44
Section D.6 Chemical Optimization Summary.....	46
Section E External/Internal Inspection.....	49
Section E.1 External Inspection.....	49

Section E.1.1	External Inspection Program Results	50
Section E.1.2	Cased Piping Survey Results	51
Section E.1.3	Excavation History	52
Section E.2	Internal Inspection Program Results	52
Section E.3	Correlation between Inspection and Corrosion Monitoring	54
Section E.4	In-line Inspection	56
Section E.5	Internal/External Inspection Comparison	56
Section E.6	Inspection Summary	58
Section F	Repair Activities	69
Section G	Corrosion and Structural Related Spills and Incidents	77
Section G.1	Corrosion Related Leaks	77
Section G.2	Structural Integrity Issues	79
Section G.2.1	Walking Speed Survey	79
Section G.2.2	Routine Surveillance	80
Section H	Corrosion Monitoring and Inspection Goals	83
Section H.1	2005 Corrosion and Inspection Goals Reviewed	83
Section H.1.1	Corrosion Monitoring	83
Section H.1.2	Inspection Programs	83
Section H.1.3	Chemical Optimization	84
Section H.1.4	Program Reviews	84
Section H.1.5	2005 Corrective Actions	84
Section H.2	2006 Corrosion Management Goals	86
Section H.2.1	Corrosion Monitoring	86
Section H.2.2	Inspection Programs	86
Section H.2.3	Chemical Optimization	87
Part 2 – Alaska Consolidated Team Performance Unit.....		89
Section B	Corrosion Monitoring Activities	91
Section B.1	Endicott	92
Section B.2	Milne Point	93
Section B.3	Northstar	94
Section B.4	Badami	94
Section B.5	Overall Inspection Activity Level	95
Section C	Weight Loss Coupons	97
Section C.1	Endicott	97
Section C.2	Milne Point	98
Section C.3	Northstar	99
Section C.4	Badami	100
Section D	Corrosion Mitigation Activities	101
Section D.1	Endicott	101
Section D.2	Milne Point	102
Section D.3	Northstar	103
Section D.4	Badami	104
Section E	External/Internal Inspection	105
Section E.1	External Inspection	105
Section E.1.1	Endicott	105
Section E.1.2	Milne Point	105
Section E.1.3	Badami	106
Section E.1.4	Northstar	106

Section E.2	Internal Corrosion Inspection.....	107
Section E.2.1	Endicott.....	107
Section E.2.2	Milne Point.....	108
Section E.2.3	Badami.....	110
Section E.2.4	Northstar.....	111
Section F	Repair Activities.....	112
Section G	Corrosion and Structural Related Spills and Incidents.....	113
Section H	2006 Corrosion Monitoring and Inspection Goals.....	115
Section H.1	Endicott.....	115
Section H.2	Milne Point.....	115
Section H.3	Northstar.....	115
Section H.4	Badami.....	115
Appendix 1	117
Glossary of Terms	119
Appendix 2	121
2000 Work Plan	123
Guide for Performance Metric Reporting	127
Appendix 3	133
Appendix 3	Corrosion Management System.....	135
Appendix 3.1	Corrosion Management System.....	135
Appendix 3.1.1	Description.....	135
Appendix 3.1.2	Process.....	136
Appendix 3.1.3	Objectives and Targets.....	137
Appendix 3.1.4	Implementation.....	137
Appendix 3.1.5	Evaluation.....	137
Appendix 3.1.6	Corrective Action.....	138
Appendix 3.2	Corrosion and Inspection Data Management.....	139
Appendix 3.2.1	MIMIR Database.....	139
Appendix 3.2.2	Historical Data.....	140
Appendix 3.3	Corrosion Management Context.....	140
Appendix 3.3.1	ER Probe and Corrosion Inhibitor Response.....	140
Appendix 3.3.2	Corrosion Inhibitor Development.....	142
Appendix 3.3.3	Internal Inspection Program – Scope.....	145
Appendix 3.3.4	Corrosion Under Insulation.....	146
Appendix 3.3.5	Fitness for Service Assessment.....	147
Appendix 3.3.6	In-line Inspection.....	151

Table of GPB Figures

GPB FIGURE C.1 CORROSION MONITORING ACTIVITY STATISTICS BY EQUIPMENT.....	16
GPB FIGURE C.2 FLOW LINE OIL SERVICE CORROSION RATE TREND.....	17
GPB FIGURE C.3 CORRELATION BETWEEN FLOW LINE CORROSION RATE AND PERCENTAGE CONFORMANCE ...	18
GPB FIGURE C.4 FLOW LINE OIL SERVICE WLC HISTOGRAM	18
GPB FIGURE C.5 WELL LINE OIL SERVICE CORROSION RATE TREND.....	19
GPB FIGURE C.6 FLOW LINE PW/SW SERVICE CORROSION RATE TREND.....	20
GPB FIGURE C.7 CORROSION RATES FOR 100% PW SYSTEM.....	21
GPB FIGURE C.8 CORROSION RATES FOR MAJORITY PW SYSTEM.....	22
GPB FIGURE C.9 COMPARISON OF CORROSION RATES FOR 100% AND MAJORITY PW.....	23
GPB FIGURE C.10 CORROSION RATE FOR 100% SEAWATER SYSTEM.....	24
GPB FIGURE C.11 CORROSION RATES FOR MAJORITY SW SYSTEM.....	24
GPB FIGURE C.12 COMPARISON OF CORROSION RATES FOR 100% AND MAJORITY SW SYSTEM	25
GPB FIGURE C.13 DISSOLVED OXYGEN CONTROL PERFORMANCE FOR THE SEAWATER SYSTEM	25
GPB FIGURE C.14 BIOCIDES TREATMENT CONCENTRATION AND CORROSION RATE.....	27
GPB FIGURE C.15 AVERAGE CORROSION RATE VS. EFFECTIVE CONCENTRATION, 2001 - 2005.....	27
GPB FIGURE C.16 FLOW LINE CORROSION COUPON SUMMARY BY EQUIPMENT AND SERVICE	30
GPB FIGURE C.17 WELL LINE AVERAGE CORROSION RATE SUMMARY BY EQUIPMENT AND SERVICE	30
GPB FIGURE C.18 WELL LINE %<2 MPY SUMMARY BY EQUIPMENT AND SERVICE	31
GPB FIGURE C.19 WLC CORROSION RATE DIFFERENCE BY SERVICE AND TYPE	32
GPB FIGURE D.1 NUMBER OF WELL LINE AND FLOW LINE TESTS.....	41
GPB FIGURE D.2 FIELD WIDE CHEMICAL USAGE	44
GPB FIGURE D.3 AVERAGE CORROSION RATE VERSUS INHIBITOR CONCENTRATION	45
GPB FIGURE D.4 CORROSION INHIBITOR CONCENTRATION VS. AVERAGE CORROSION RATE	45
GPB FIGURE E.1 EXTERNAL CORROSION ACTIVITY AND DETECTION SUMMARY	50
GPB FIGURE E.2 FLOW LINE INTERNAL INSPECTION INCREASE BY SERVICE	53
GPB FIGURE E.3 WELL LINE INTERNAL INSPECTION INCREASE BY SERVICE	54
GPB FIGURE E.4 CORRELATION OF CORROSION RATE AND %INCREASES, 3-PHASE PRODUCTION	55
GPB FIGURE E.5 INTERNAL AND EXTERNAL INSPECTION ACTIVITY FOR FLOW AND WELL LINES.....	57
GPB FIGURE E.6 INTERNAL AND EXTERNAL INSPECTION ACTIVITY SUMMARY BY FLOW/WELL LINE	58
GPB FIGURE F.1 REPAIRS BY SERVICE	70
GPB FIGURE F.2 REPAIRS BY DAMAGE MECHANISM	70
GPB FIGURE F.3 REPAIRS BY EQUIPMENT	71
GPB FIGURE G.1 HISTORICAL CORROSION/MECHANICAL LEAKS AND SAVES BY LINE TYPE.....	78
GPB FIGURE G.2 HISTORICAL CORROSION/MECHANICAL LEAKS AND SAVES	79

Table of ACT Figures

ACT FIGURE C.1 ENDICOTT CORROSION COUPON SUMMARY 1995-2005.....	97
ACT FIGURE C.2 MPU CORROSION COUPON SUMMARY	98
ACT FIGURE D.1 ENDICOTT IIWL UT READINGS.....	101
ACT FIGURE D.2 MILNE POINT PRODUCED WATER CORROSION RATE TREND	103
ACT FIGURE E.1 ENDICOTT WELL LINE INTERNAL INSPECTION INCREASES.....	107
ACT FIGURE E.2 ENDICOTT FLOW LINE INTERNAL INSPECTION INCREASES	108
ACT FIGURE E.3 MPU FLOW LINE INTERNAL INSPECTION INCREASES.....	109
ACT FIGURE E.4 MPU WELL LINE INTERNAL INSPECTION INCREASES.....	110

Table of Appendix Figures

FIGURE 1 OVERVIEW OF THE CORROSION MANAGEMENT PROCESS.....	136
FIGURE 2 CORROSION INHIBITOR CONCENTRATION VS. CORROSION RATE.....	141
FIGURE 3 ER PROBE CHEMICAL OPTIMIZATION TEST.....	144
FIGURE 4 CORROSION COUPONS PULLED AFTER AN 'UNSUCCESSFUL' CHEMICAL TRIAL	145
FIGURE 5 MAOP VERSUS REMAINING WALL THICKNESS	149
FIGURE 6 FITNESS-FOR-SERVICE ENVELOPE BASED ON BP SPC-PP-00090.....	151
FIGURE 7 FACILITY SCHEMATIC	165
FIGURE 8 MAP OF NORTH SLOPE	167

Table of GPB Tables

GPB TABLE C.1 CORROSION MONITORING LOCATIONS BY EQUIPMENT AND SERVICE	15
GPB TABLE C.2 BIOCIDES TREATMENT CONCENTRATION AND INTERVAL	26
GPB TABLE C.3 ACTIVE ER PROBE LOCATIONS	28
GPB TABLE C.4 NUMBER OF ER PROBES >2 MPY AND ACTIONED	29
GPB TABLE C.5 WLC CORROSION RATE DIFFERENCE BY SERVICE AND TYPE	32
GPB TABLE C.6 FLOW AND WELL LINE GENERAL CORROSION RATE DATA SUMMARY.....	35
GPB TABLE C.7 FLOW AND WELL LINE PITTING RATE DATA SUMMARY	37
GPB TABLE D.1 SUMMARY OF THE CHEMICAL DEPLOYMENT HISTORY	42
GPB TABLE D.2 SUMMARY OF THE CHEMICAL USAGE HISTORY.....	43
GPB TABLE E.1 CUI INSPECTIONS BY SERVICE TYPE, 1995-2005	49
GPB TABLE E.2 EXTERNAL CORROSION ACTIVITY AND DETECTION SUMMARY	50
GPB TABLE E.3 CASED PIPE SURVEY RESULTS	51
GPB TABLE E.4 COMPLETED SMART PIG ASSESSMENTS.....	56
GPB TABLE E.5 INTERNAL AND EXTERNAL INSPECTION ACTIVITY BREAKDOWN	57
GPB TABLE E.6 INTERNAL AND EXTERNAL INSPECTION ACTIVITY SUMMARY BY FLOW/WELL LINE.....	58
GPB TABLE E.7 FLOW AND WELL LINE INSPECTION DATA	61
GPB TABLE E.8 CASED PIPING EXCAVATION HISTORY	63
GPB TABLE F.1 REPAIR ACTIVITY	69
GPB TABLE F.2 HISTORICAL REPAIRS BY SERVICE	73
GPB TABLE G.1 LEAKS DUE TO CORROSION/MECHANICAL.....	77
GPB TABLE G.2 HISTORICAL CORROSION/MECHANICAL LEAKS AND SAVES.....	78
GPB TABLE G.3 STRUCTURAL/WALKING SPEED SURVEY SCHEDULE	80
GPB TABLE H.1 COUPON PULL FREQUENCY	83
GPB TABLE H.2 CORRECTIVE MITIGATION ACTIONS FROM INSPECTION DATA	84
GPB TABLE H.3 CORRECTIVE MITIGATION ACTIONS FROM ER PROBE DATA	85
GPB TABLE H.4 CORRECTIVE MITIGATION ACTIONS FROM COUPON DATA	86

Table of ACT Tables

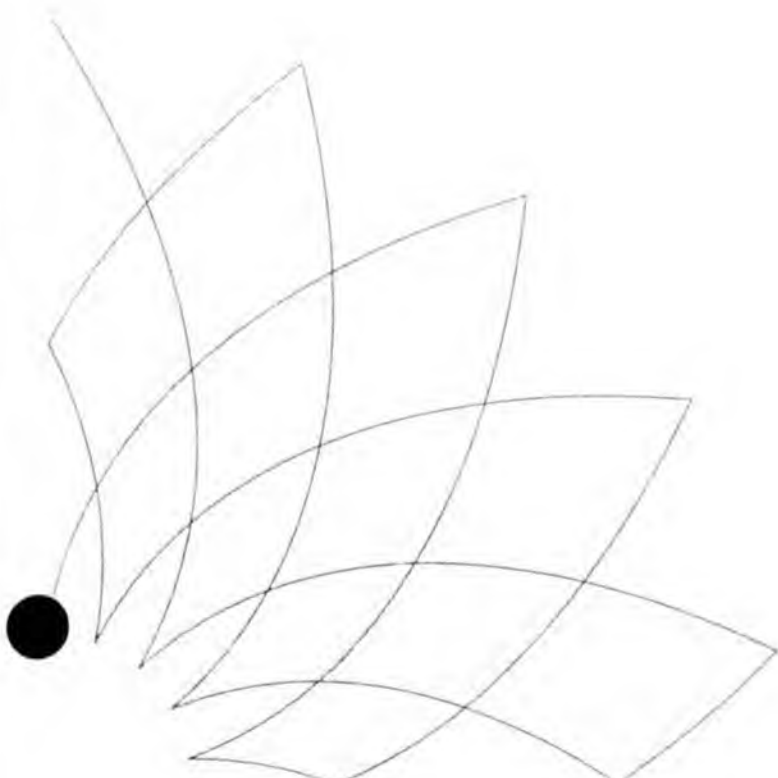
ACT TABLE B.1 RELATIVE CORROSIVITY OF BPXA NORTH SLOPE PRODUCTION.....	92
ACT TABLE B.2 ILLUSTRATIVE COMPARISON OF SCALE BETWEEN ACT AND GPB.....	92
ACT TABLE B.3 ENDICOTT SUMMARY OF LINES AND NDE INSPECTIONS	93
ACT TABLE B.4 MPU SUMMARY OF LINES AND NDE INSPECTIONS	94
ACT TABLE B.5 NORTHSTAR SUMMARY OF LINES AND NDE INSPECTIONS.....	94
ACT TABLE B.6 BADAMI SUMMARY OF LINES AND NDE INSPECTIONS	95
ACT TABLE B.7 OVERALL INSPECTION ACTIVITY SUMMARY	96
ACT TABLE C.1 ENDICOTT CORROSION COUPON MONITORING	97
ACT TABLE C.2 MPU CORROSION COUPON MONITORING	98
ACT TABLE C.3 NORTHSTAR CORROSION COUPON MONITORING.....	99
ACT TABLE D.1 ENDICOTT VELOCITY MONITORING.....	102
ACT TABLE E.1 CASED PIPING INSPECTIONS	105
ACT TABLE E.2 MPU EXTERNAL INSPECTION SUMMARY FOR ABOVE-GROUND PIPING	106
ACT TABLE E.3 INSPECTION SUMMARY OF BADAMI WELL LINES.....	111
ACT TABLE E.4 INSPECTION SUMMARY OF NORTHSTAR	111
ACT TABLE F.1 ACT REPAIR ACTIVITY	112
ACT TABLE G.1 ENDICOTT LEAK/SAVE AND MECHANICAL REPAIR DATA	113
ACT TABLE G.2 MILNE POINT LEAK/SAVE AND MECHANICAL REPAIR DATA	113
ACT TABLE G.3 NORTHSTAR LEAK/SAVE AND MECHANICAL REPAIR DATA.....	114
ACT TABLE G.4 BADAMI LEAK/SAVE AND MECHANICAL REPAIR DATA	114

Table of Appendix Tables

TABLE 1 CORROSION MANAGEMENT PROCESS.....	137
TABLE 2 CORROSION MANAGEMENT FEEDBACK CYCLES	138
TABLE 3 DATABASE RECORD ACCUMULATION RATE	140
TABLE 4 CORROSION INHIBITOR CONCENTRATION VS. CORROSION RATE	141
TABLE 5 SUMMARY DESCRIPTION OF THE TYPICAL TEST PROGRAM COMPONENTS	143
TABLE 6 FLOW LINE TEST PROGRAM RESULT SUMMARY	144
TABLE 7 CUI INCIDENT RATE BY JOINT TYPE	147
TABLE 8 THICKNESS, MAOP CORRELATION	150
TABLE 9 CORROSION MANAGEMENT SYSTEM	153
TABLE 10 CORROSION MANAGEMENT SYSTEM ELEMENT – MONITORING	154
TABLE 11 MONITORING PROGRAM TECHNIQUES.....	158
TABLE 12 CORROSION MONITORING TECHNIQUES – BENEFITS AND LIMITATIONS.....	161
TABLE 13 PROCESS MONITORING TECHNIQUES – BENEFITS AND LIMITATIONS.....	161
TABLE 14 INSPECTION/NON-DESTRUCTIVE EXAMINATION TECHNIQUES – BENEFITS AND LIMITATIONS.....	162
TABLE 15 CORROSION MANAGEMENT SYSTEM IMPLEMENTATION BY EQUIP TYPE AND SERVICE.....	164
TABLE 16 BPXA NORTH SLOPE OPERATIONS	170

Section A

Charter Agreement – Corrosion Related Commitments



Section A Charter Agreement – Corrosion Related Commitments

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

Brett W. Leach, Integrity & Assurance Manager

E-mail: brett.leach@bp.com

Phone: (907) 564-4437

Section A.1 Project Achievements

Oct-Nov 2000	Work Plan agreed between BPXA/PAI and ADEC (Appendix 2a)
March 2001	1 st Annual Report submitted to ADEC
April 2001	1 st 2001 Meet and Confer session held
Oct-Dec 2001	Consultations with ADEC and ADEC's consultant
November 2001	2 nd 2001 Meet and Confer session held
Dec 01-Jan 02	Developed and agreed corrosion management metrics
February 2002	BPXA/PAI and ADEC agreed on performance metrics (Appendix 2b)
March 2002	2 nd Annual Report submitted to ADEC
April 2002	1 st 2002 Meet and Confer session held
November 2002	2 nd 2002 Meet and Confer session held
March 2003	3 rd Annual Report submitted to ADEC
May 2003	1 st 2003 Meet and Confer session held
October 2003	2 nd 2003 Meet and Confer session held
March 2004	4 th Annual Report submitted to ADEC
April 2004	1 st 2004 Meet and Confer session held
August 2004	North Slope Field Trip
March 2005	5 th Annual Report submitted to ADEC
May 2005	1 st 2005 Meet and Confer session held
August 2005	North Slope Field Trip
March 2006	6 th Annual Report submitted to ADEC

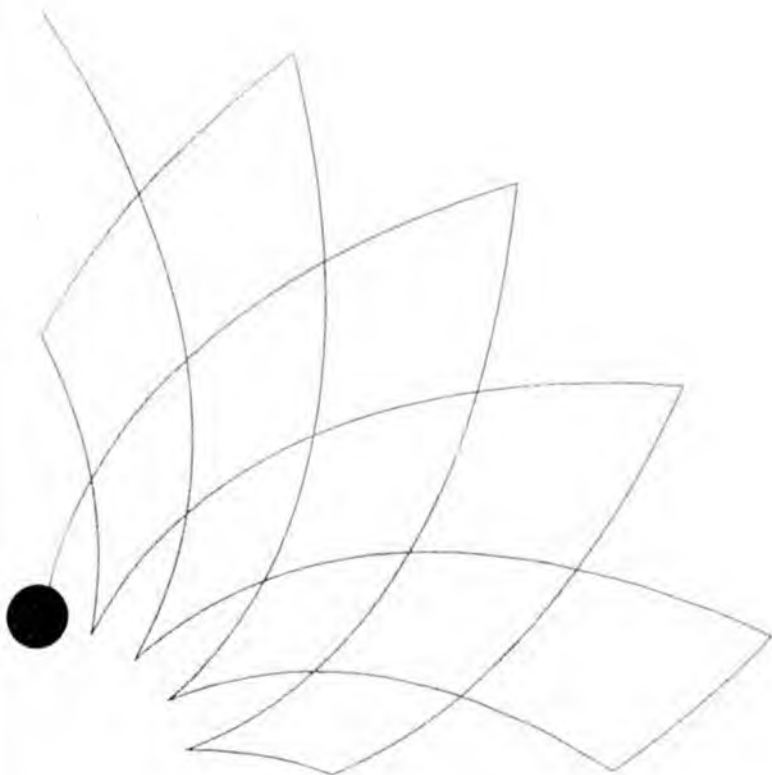
Section A.2 Annual Charter Timetable

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

Part 1 – Greater Prudhoe Bay Performance Unit

Section B

2005 Corrosion Program Summary



Section B 2005 Corrosion Program Summary

Section B.1 Introduction

This section provides a summary of key performance indicators (KPI) for 2005. Additional information regarding the Corrosion Management System and historical program data and development are shown in subsequent sections of the report.

Section B.2 Corrosion Monitoring

The plan and objective for corrosion monitoring is to measure the effectiveness of the mitigation programs. The primary monitoring techniques are intrusive weight loss coupons (WLC) and Electrical Resistance Probes (ER Probe) which provide the feedback for corrective action when control targets are exceeded.

Program:	Weight Loss Coupon
Target:	<2 mils per year (mpy)
KPI:	% Conformance WLC <2 mpy
Section Reference:	Section C Weight Loss Coupons and ER Probes

1. 7,491 coupons were utilized to monitor the effectiveness of the mitigation programs.
2. 3-phase flow line WLC data showed 98% were <2 mpy with an average corrosion rate of 0.3 mpy.
3. Water injection flow line (produced and seawater) WLC data showed 86% were <2 mpy with an average corrosion rate of 0.8 mpy.
4. Processed oil flow line WLC data showed 100% were <2 mpy with an average corrosion rate of 0.2 mpy.
5. 3-phase well line WLC data showed 92% were <2 mpy with an average corrosion rate of 0.8 mpy.
6. Majority service produced water well line WLC showed 100% less than 2 mpy and average corrosion rate of 0.1 mpy.
7. 100% produced water service well line WLC showed 100% less than 2 mpy and average corrosion rate of 0.1 mpy.
8. Majority service seawater well line WLC showed 95% less than 2 mpy and average corrosion rate of 0.6 mpy.
9. 100% seawater service well line WLC showed 94% less than 2 mpy and average corrosion rate of 0.6 mpy.

Program:	Electrical Resistance Probe
Target:	<2 mils per year (mpy)
KPI:	Conformance <2 mpy
Section Reference:	Section C.3 Electrical Resistance Probes

10. 3-phase flow line ER Probes showed 88% of the data was <2 mpy.

The monitoring data for the majority of the 3-phase production system demonstrate an effective level of corrosion control as direct result of the mitigation programs. However, there were two unforeseen events that originated in 4Q2004 and continued through 2Q2005, which resulted in several 3-phase WLC exceeding the 2 mpy target. These events were: 1) corrosion inhibitor instability at winter temperature which caused blockage of some chemical inhibition delivery systems, and 2) material incompatibility with a test corrosion inhibitor degrading the delivery system tubing.

The monitoring data for the water injection system suggests an effective level of corrosion control although a long-term trend in correlation with inspection data has not been established.

Section B.3 Corrosion Mitigation/Corrosion Inhibition

The plan and objective for corrosion mitigation is to control corrosion rates to acceptable levels. For internal corrosion control, the principal means of mitigation is through the application of corrosion inhibitors.

Program:	Corrosion Mitigation – Corrosion Inhibitor (CI)
Target:	Control corrosion to acceptable levels
KPI:	Monitoring <2 mpy and inspection percent of increases, Target versus actual CI usage, injection volumes (ppm)
Section Reference:	Section D Chemical Optimization Activities

1. The field wide average inhibitor concentration decreased from 151 to 147 ppm. This is due in large part to the chemical deployment events mentioned in Section B.2.
2. The corrosion inhibitor usage was 2.66 million gallons which was delivered at 98.1% of target.

The effectiveness of corrosion mitigation, as a result of the application of corrosion inhibition, is determined from corrosion monitoring and inspection programs. Corrosion monitoring data are a leading indicator and inspection data are a lagging indicator of corrosion mitigation efforts. There is a strong correlation between monitoring and inspection data, which gives confidence mitigation with corrosion inhibition can be managed in a timely manner using monitoring data.

Section B.4 External Inspection Program

The plan and objectives for the external corrosion program are comprehensive inspection coverage of equipment susceptible to corrosion under insulation (CUI), minimize loss as a result of external corrosion failures and assure the equipment is fit-for-service (FFS) and safe to operate.

Program:	Corrosion Under Insulation
Target:	35,000 inspections/year
KPI:	% of locations inspected with external corrosion, Leak/Save ratio
Section Reference:	Section E.1 External Inspection

1. There were 34,994 external corrosion inspections completed, 3% were found with corrosion degradation.
2. There were 49 mechanical repairs identified as a result of external corrosion.
3. There was 1 leak due to external corrosion on a gas well line
4. The Leak/Save ratio for the External Corrosion (CUI) Program was 98%.

Unlike internal corrosion, where mitigation can be managed through chemical inhibition, mechanical cleaning and/or operational controls, CUI is managed through detection and repair. Once CUI has been found through inspection activities, locations are scheduled for insulation and by-product removal, fit-for-service assessment, mechanical repair if needed and rehabilitation of the insulation system. The 2005 external program completed 34,994 inspections with a corrosion find rate of 3% consistent with recent history. The 49 mechanical repairs are lower than the previous two years.

Section B.5 Cased Pipe Program

The plan and objective for the cased pipe program is comprehensive inspection coverage of cased pipe segments at road and/or animal crossings where historically the prominent mechanism has been external corrosion. The excavation of crossings, as

required, is performed to mitigate active corrosion and assure the equipment is fit-for-service and safe to operate.

Program:	Cased Pipe Inspection
Target:	100 inspection/yr
KPI:	Increases or active corrosion determined from repeat examinations.
Section Reference:	Section E.1.2 Cased Piping Survey Results

1. 79 cased piping segments were re-inspected using ILI or guided-wave inspection techniques.
2. One of the inspections showed potential active corrosion.
3. Six cased pipe segments were either fully or partially excavated and inspected. Minor to moderate corrosion damage was found in two segments, with one mechanical repair and damaged areas were rehabilitated.

A long-term cased piping management strategy has been implemented, consisting of repeat inspection and excavations. The strategy will continue to evolve as the program is refined and more information is available. In 2005, the number of inspected piping segments did not meet target due to a shortage of specialized materials utilized with guided wave technique.

Section B.6 Internal Inspection Program

The plan and objective for the internal program is comprehensive inspection coverage of equipment susceptible to internal degradation including; the assessment of mechanisms and rate of wastage, minimize loss as a result of failures and assure the equipment is fit-for-service and safe to operate.

Program:	Internal Inspection Program
Target:	60,000 inspections/yr split between Field (~25,000) and Facility (~35,000) equipment
KPI:	% of locations inspected with increased metal loss, Leak/Save ratio
Section Reference:	Section E.2 Internal Inspection Program Results

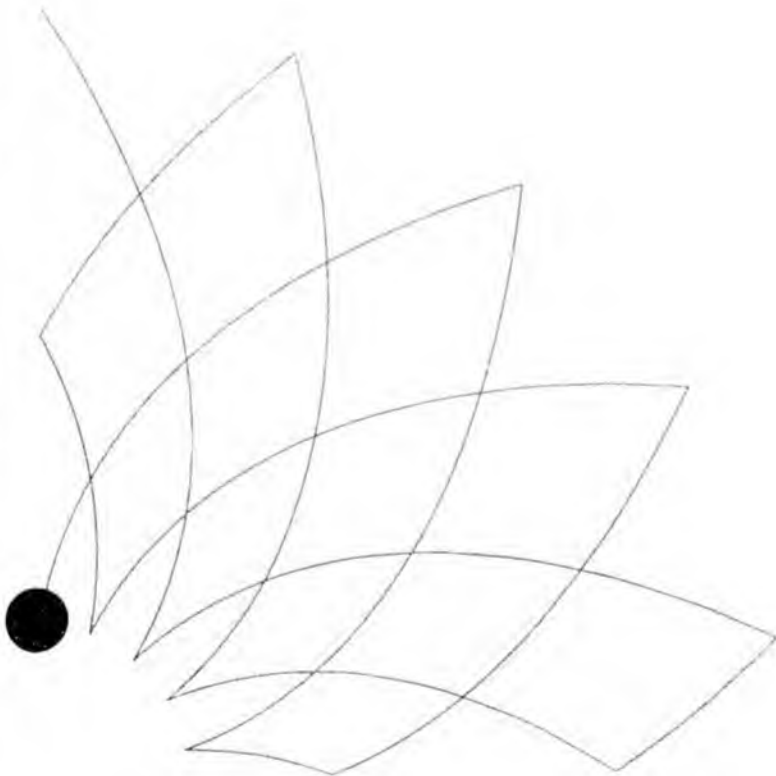
1. There were 10,894 inspections on 3-phase flow lines, with 2% showing an increase.
2. There were 7,776 inspections on 3-phase well lines, with 4% showing an increase.
3. There were 2,171 inspections on water injection flow lines, with 8% showing an increase.
4. There were 1,859 inspections on water injection well lines, with 9% showing an increase.
5. There were 12 mechanical repairs identified as a result of internal corrosion.
6. There were 2 leaks due to internal corrosion on the DS11 seawater injection system.
7. The Leak/Save ratio for the Internal Inspection Program was 83%.

For 3-phase production, flow line inspection increases data show a slight increasing trend in active corrosion, while the well line inspection increases are consistent at 4-5% for the past 5 years.

For the water injection systems, both flow and well lines show an increase in corrosion activity in 2005.

Section C

Weig Loss Coupons and Probes



Section C Weight Loss Coupons and ER Probes

This section summarizes the results of the weight loss coupon corrosion monitoring and ER probe programs. Each of the major service categories are reviewed in turn with the results of the program.

The number of weight loss coupon (WLC) monitoring locations by equipment type and service, is summarized in GPB Table C.1. The number of WLC processed over time is presented in GPB Figure C.1.

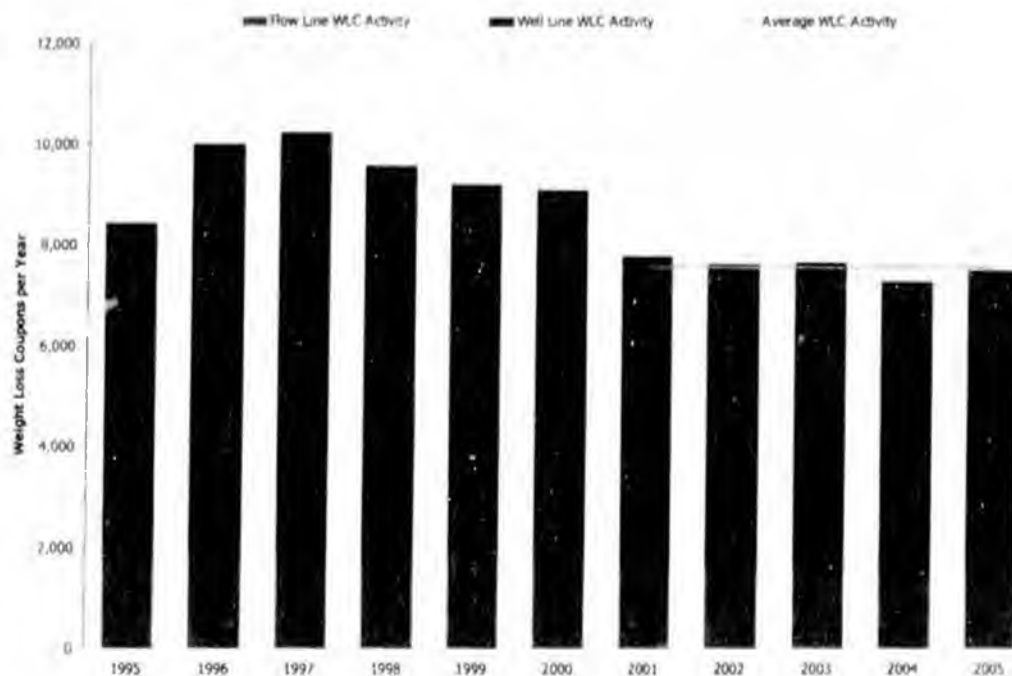
Detailed data tables for each configuration of equipment type are provided in GPB Table C.6 and GPB Table C.7.

Service	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Flow Line											
3 Phase Oil	219	315	268	272	266	254	256	257	255	242	235
Processed Oil	3	7	7	5	5	6	4	5	5	5	5
Gas	3	3	1	1	1	0	0	0	1	0	0
Other	5	6	5	7	6	5	6	6	3	5	4
Water	36	37	45	43	46	45	44	44	48	38	31
Total	266	368	326	328	324	310	310	313	312	290	275
Well Line											
3 Phase	1,047	1,168	1,216	1,202	1,166	1,162	1,081	1,096	1,105	1,062	1,048
Processed Oil	0	3	7	3	3	3	3	0	2	0	0
Gas	5	7	7	7	6	6	7	6	5	4	2
Other	8	9	9	7	8	8	6	8	8	6	4
Water	199	210	211	205	193	186	186	191	173	151	166
Total	1,260	1,397	1,446	1,424	1,376	1,365	1,283	1,301	1,293	1,223	1,220
Grand Total	1,526	1,765	1,772	1,752	1,700	1,675	1,593	1,614	1,605	1,513	1,495

GPB Table C.1 Corrosion Monitoring Locations by Equipment and Service

Two corrosion coupons are typically recovered for each WLC pull with the exception of those lines that are regularly maintenance pigged where single flush mounted coupons are installed. The number of coupons, coupons per pull, and pull frequency continue to be adjusted through time to gain greater value from the data obtained by the program.

As discussed in prior reports, there has been a gradual reduction in the number of weight loss coupons being evaluated, which reflects the on-going effort to optimize the program. Following the rationalization in 2000/01, the level of WLC activity has stabilized at ~7,500 coupons per year. The number of weight loss coupons reported for 2005 does not reflect the inventory of coupons that are installed in the system at year-end and still to be 'processed.' The reduction in 2005 coupon numbers therefore represents a timing effect and not a reduction in the program scope or activity level.



GPB Figure C.1 Corrosion Monitoring Activity Statistics by Equipment

Section C.1 Three Phase Production Systems

Section C.1.1 Introduction

The primary corrosion mechanism of concern in the 3-phase production system is CO₂ corrosion, in which CO₂ from the produced fluids dissolves and dissociates in the produced water to form an acidic environment that is, if untreated, corrosive to carbon steel^{4,5}. The primary corrosion control method is the continuous addition of corrosion inhibitor in the flow lines and a mix of continuous and batch inhibitor additions in the well lines. For the 3-phase production system the target corrosion rate from weight loss coupons is a general corrosion rate of 2 mpy or less (WLC ≤ 2 mpy).

The 3-phase production system has seen a consistently strong improvement in corrosion control since the early 1990's with a near order of magnitude reduction in the cross-country flow line corrosion rates. This reduction in corrosion rate is a direct result of the implementation of an aggressive corrosion mitigation program consisting primarily of continuous addition of corrosion inhibitor into the production fluids. This mitigation program has been implemented at considerable capital and operating expense but has resulted in flow lines which are now expected to be fit-for-service (FFS) for approximately 10 times as long as that expected in the early 1990's due to the reduction in corrosion rate. The correlation between corrosion inhibitor concentration and corrosion rates in 3-phase flow lines is discussed in detail in Section D. A similar reduction is also seen in the inspection history discussed later in Section E.

⁴ Corrosion Control in Petroleum Production, Harry G Byers, NACE, 1999

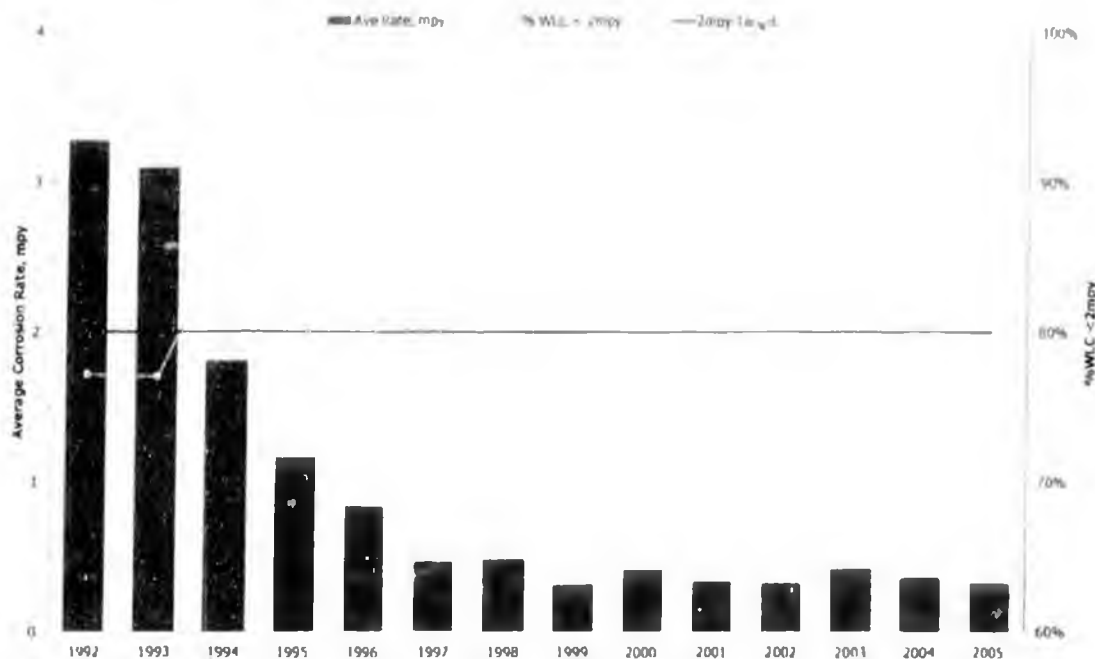
⁵ Corrosion Control in Oil and Gas Production, Treseder and Tuttle, NACE, 1998

Section C.1.2 Cross Country Flow Line Coupons

GPB Figure C.2 shows the average corrosion rate and percentage of coupons meeting the performance standard target since 1992. The results show the percentage of conformant flow lines has improved consistently over the last decade. The average corrosion rate for 2005 across GPB is approximately a factor of 10 lower than the corrosion rates from the early 1990's.

GPB Figure C.3 shows the correlation between average corrosion rate and the percentage of weight loss coupons meeting the 2 mpy target. As might be expected, there is a very strong correlation between these two metrics. However, they should be viewed as being complementary. The percentage less than 2 mpy target has the advantage of highlighting non-conformances that would otherwise be lost in the calculation of the average.

Conversely, the average corrosion rate has the advantage of showing the overall performance trend that would otherwise be lost when only looking at the exceptions >2 mpy. Hence, it is necessary to review both metrics in order to gain an overall understanding of the performance of the program.



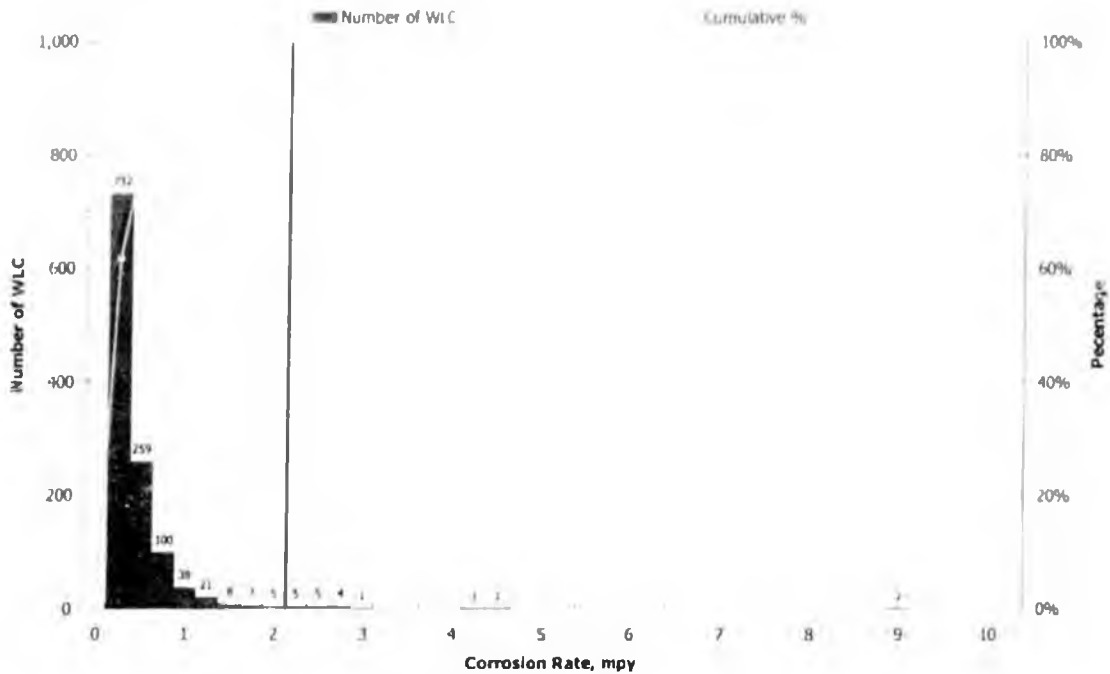
GPB Figure C.2 Flow Line Oil Service Corrosion Rate Trend

Part 1 - Greater Prudhoe Bay Performance Unit



GPB Figure C.3 Correlation Between Flow Line Corrosion Rate and Percentage Conformance

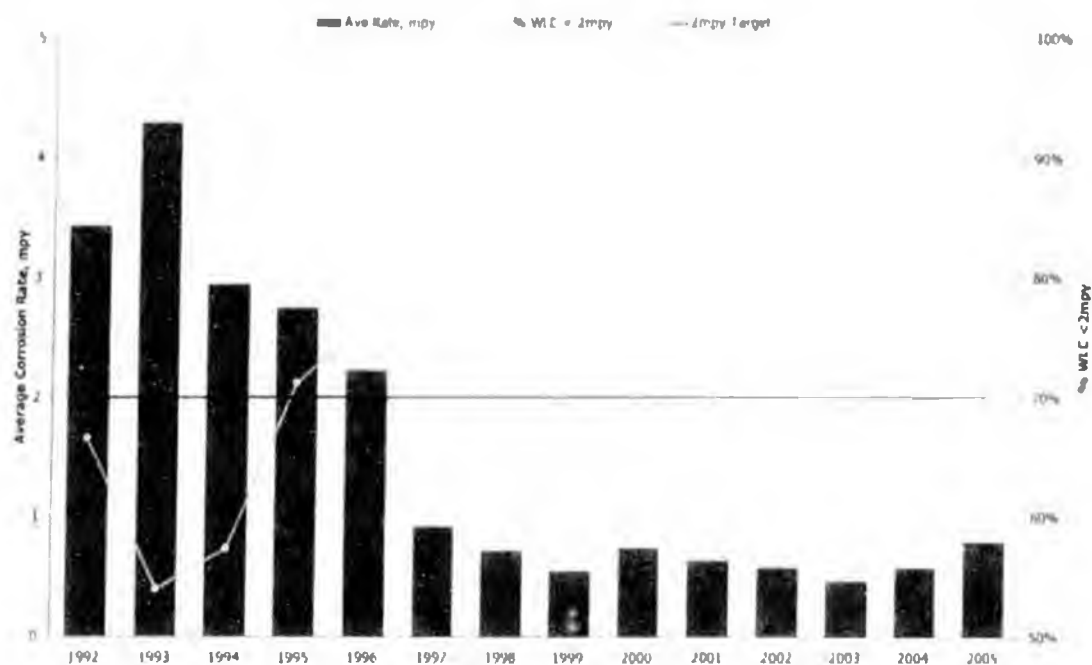
GPB Figure C.4 shows a distribution of corrosion rate for WLC in flow line oil service. There were 19 WLC greater than the 2 mpy target. Refer to Section H.1.5 for details and corrective actions.



GPB Figure C.4 Flow Line Oil Service WLC Histogram

Section C.1.3 Well Line Coupons

GPB Figure C.5 shows the average corrosion rate and percentage of WLC ≤ 2 mpy since 1992. The trends are very similar to those seen in the cross-country 3-phase oil flow lines, showing a long-term improvement in the level of control from early 1990's to the present day with a slight decrease in performance from 2003 to 2005. This decrease in performance is largely due to two reasons; first there were precipitation problems with the winter corrosion inhibitor that lead to plugging of several continuous injection systems, and second, there was an incompatible test corrosion inhibitor which required the shutdown of the injection system in early 2005.



GPB Figure C.5 Well Line Oil Service Corrosion Rate Trend

The long term corrosion control improvement in the well lines is of the same magnitude as that seen in the flow lines with corrosion rates being reduced from an average >4 mpy in 1993 down to an average of 0.5 to 0.8 mpy over the past six years.

Section C.2 Water Injection Systems

The Water Injection System at GPB is comprised of produced water from the primary processing/separation facilities and seawater extracted from the Beaufort Sea and processed through the Seawater Treatment Plant (STP). During 2005, the average seawater injection volumes was just over 831 Mbd

As noted in the 2002 Report, the production database has now been linked to the corrosion and inspection database. This dynamic link provides a much more detailed view of service history/changes for the well line equipment, enabling an improved level of data analysis and quality.

The reporting format, which augments the performance metrics and was agreed with ADEC, can be summarized as follows:

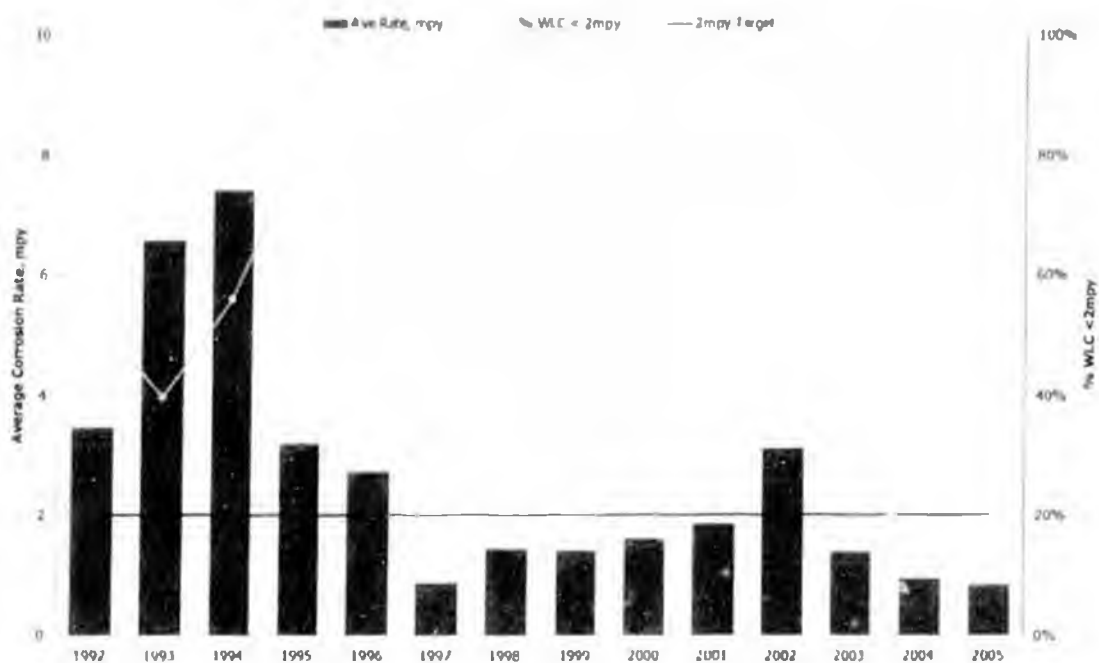
Report Date Mid point of the WLC's exposure period,

$$\text{MidDate} = \text{Date In} + \frac{(\text{Date Out} - \text{Date In})}{2}$$

Service Type (a) Average corrosion rate with 100% exposure to service
(b) Average corrosion rate with simple service majority

Section C.2.1 Water Injection System Flow Lines

GPB Figure C.6 is a summary of aggregate data for produced water and seawater flow lines. The data show the 2005 WLC corrosion rates at the lowest level since 1997 and demonstrate improved corrosion control over the past three years.



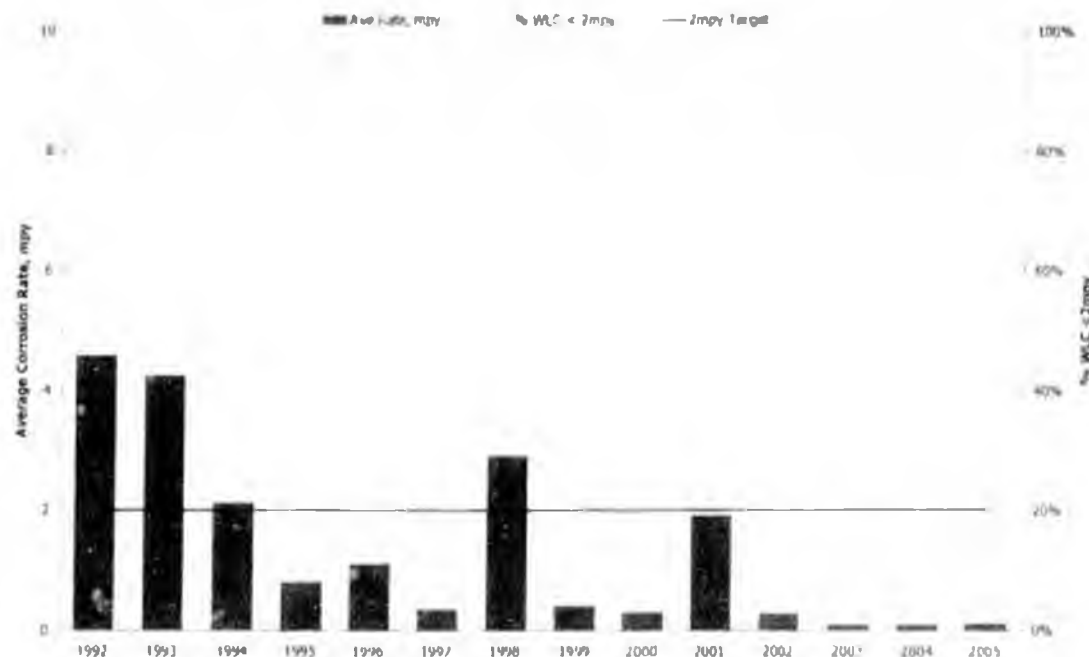
GPB Figure C.6 Flow Line PW/SW Service Corrosion Rate Trend

In summary, the average WLC corrosion rates for the aggregate water injection service continued to improve in 2005. This improvement is attributable to several different activities outlined in Section C.2.2 and Section C.2.3.

Section C.2.2 Produced Water Injection Well Lines

There are a number of corrosion mechanisms of concern in the produced water (PW) injection system. These mechanisms include CO₂ corrosion and differential concentration effects due to the high particulate content of the system. The particulates consist primarily of residual hydrocarbon remaining after the separation process, entrained production chemicals, and iron sulfides.

GPB Figure C.7 through GPB Figure C.9 summarizes the historical corrosion rate data for produced water well lines. The data show general corrosion rates in the produced water system have fallen as the level of inhibition in the 3-phase system was increased and supplemental produced water corrosion inhibitor injection was initiated.



GPB Figure C.7 Corrosion Rates for 100% PW System

GPB Figure C.7 shows the performance for 100% produced water service. The 2005 levels maintained average corrosion rates at ~ 0.1 mpy and $\sim 100\%$ WLC ≤ 2 mpy.

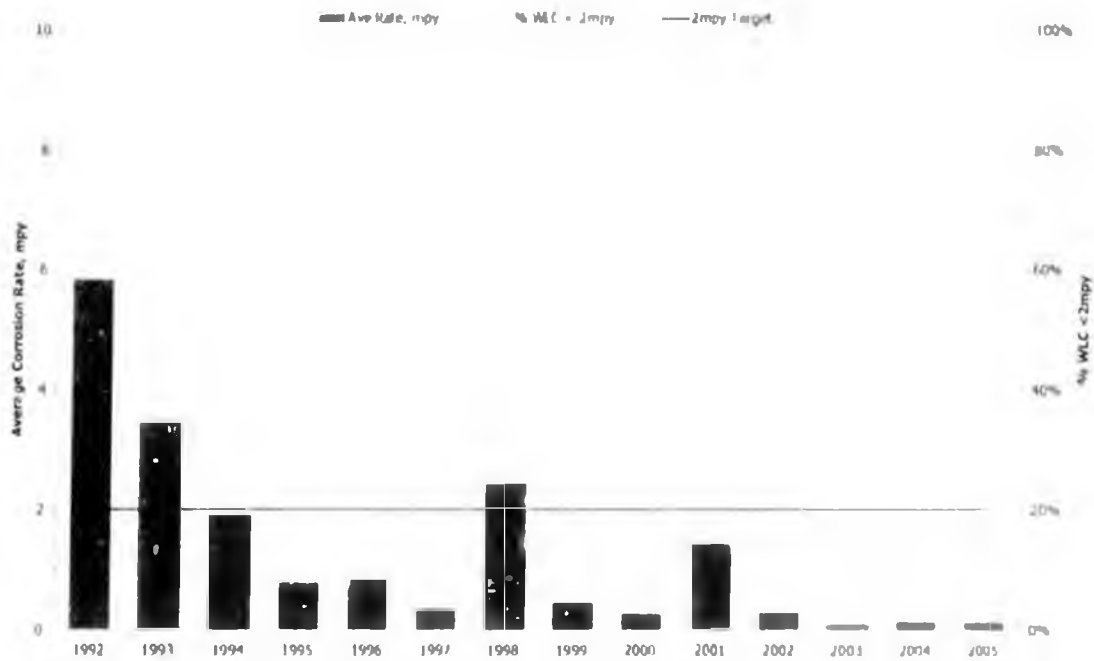
For those coupons where produced water was the majority service, GPB Figure C.8 shows the corrosion rate trends were very similar to those seen for 100% produced water service. The results for 2005 are encouraging in 100% and majority service, but caution is warranted as the data set is limited, and a long-term trend in correlation with inspection data has not been established.

A comparison of the average corrosion rate for produced water between the 100% service and majority service is provided in GPB Figure C.9. The figure shows good agreement between the data.

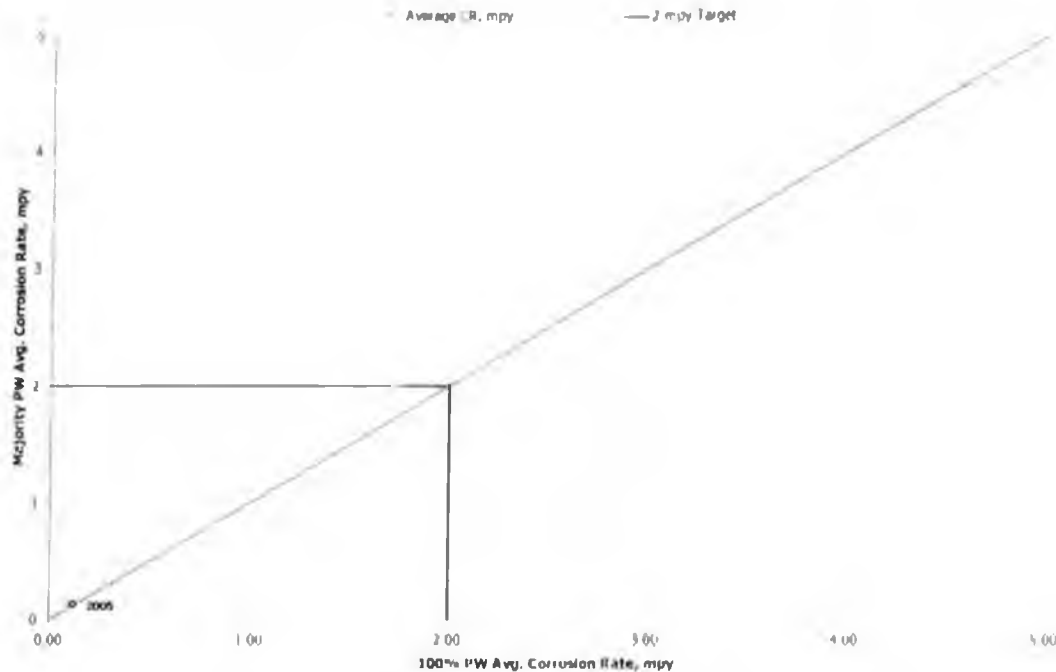
The overall improvement in the PW monitoring data from 2001 to date can be attributed primarily to three factors. First, there was a change in the upstream 3-phase continuous corrosion inhibitor in 2002 that gave more favorable partitioning characteristics to the water phase than the prior product. This had the effect of increasing the levels of corrosion inhibitor carried from the upstream system into the produced water distribution network. The second contributor is the increase in field-wide average concentration of 3-phase corrosion inhibitor over time. The third contribution is the expansion of corrosion mitigation programs specific to the PW system started in 2002. This program had significant expansion during the 2nd half of 2005 including:

Part 1 – Greater Prudhoe Bay Performance Unit

- Change from a surfactant based chemistry to a corrosion inhibitor based chemistry
- Chemical deployment infrastructure and supply chain upgrades to support higher concentrations
- An increase in chemical concentration from 20 ppm to a cleaning concentration of 80 ppm for ~90 days, followed by maintenance concentration of 60 ppm.
- The program includes continuous inhibitor injection in the PW system at FS-1, FS-3, GC-1, GC-2 and GC-3. FS-2 upgrades were started in 2005 and will be completed in 2006.



GPB Figure C.8 Corrosion Rates for Majority PW System



GPB Figure C.9 Comparison of Corrosion Rates for 100% and Majority PW

Section C.2.3 Seawater Injection Well Lines

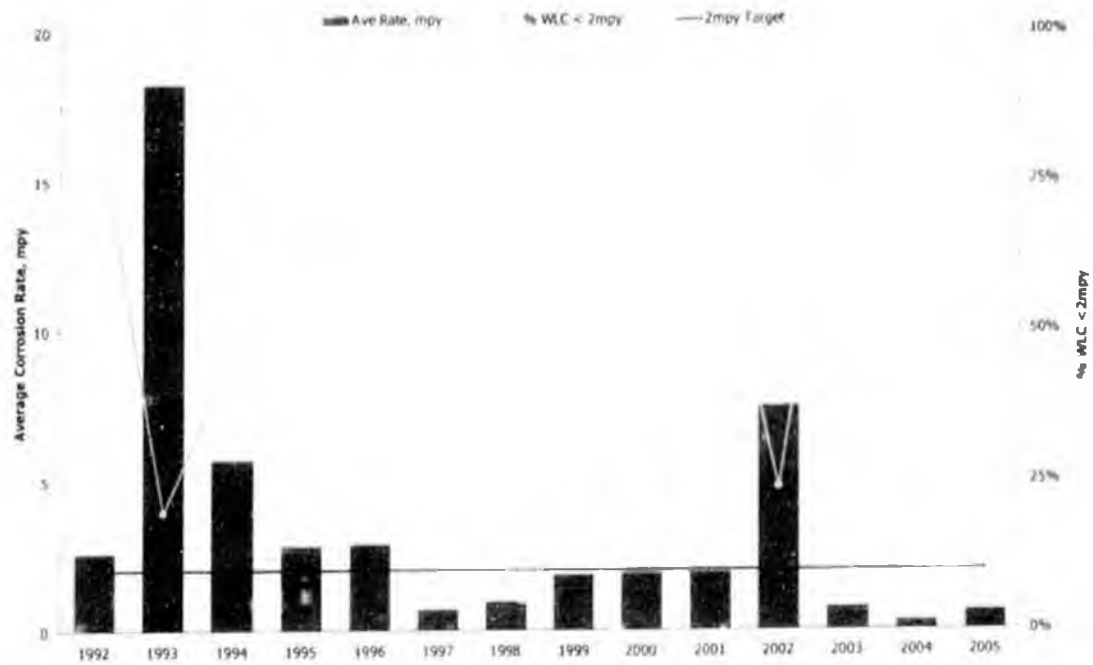
The main corrosion mechanisms in the seawater (SW) injection systems are,

- Dissolved oxygen (DO) corrosion – This mechanism is mitigated by processing the seawater to remove the oxygen. Initial DO removal is achieved mechanically by vacuum stripping, which is then followed by chemical oxygen scavenging.
- Microbiological corrosion (MIC) – MIC is due to the action of anaerobic bacteria, and is mitigated by batch treatment with biocide, after processing to remove DO and prior to seawater transfer to the main cross country flow lines.

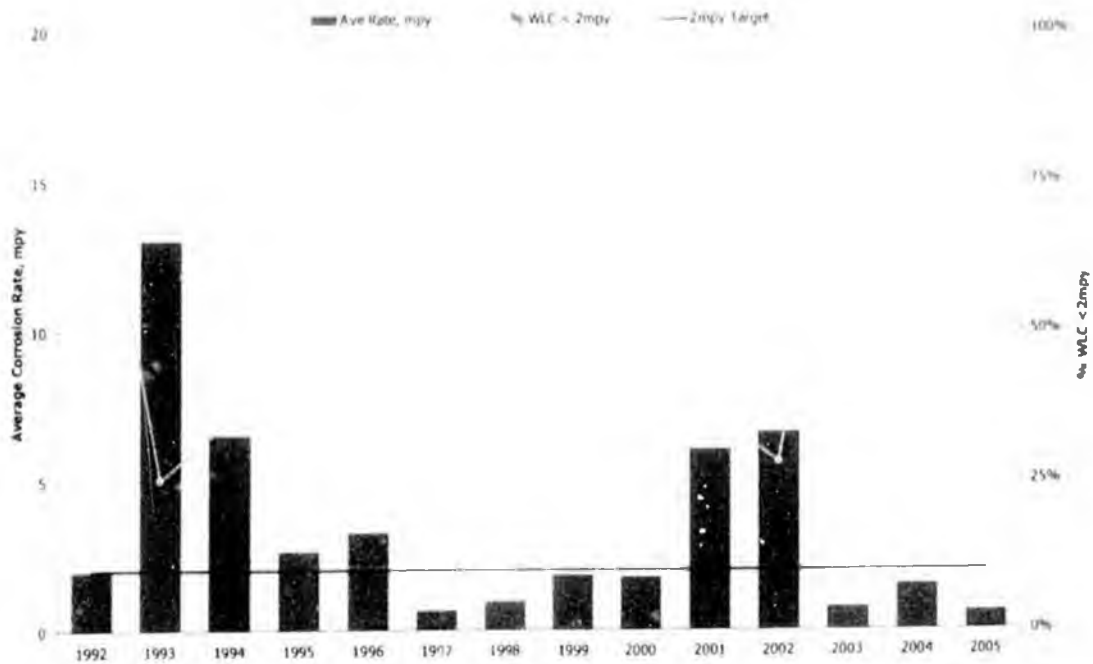
As with the PW system, the SW system data are presented as both 100% and majority service for the well line data, along with a comparison of general corrosion rates and pitting corrosion rates.

GPB Figure C.10 through GPB Figure C.12 show the corrosion rate trends in the SW system for both 100% SW service and majority SW service. For the 100% SW service, the improvement since 2002 is a result of implementation of the corrective actions outlined in previous reports. For the majority SW service, the decline in performance is believed to be due to a service change between PW and SW. This service change is due to the increased SW injection for enhanced oil recovery.

Part 1 – Greater Prudhoe Bay Performance Unit

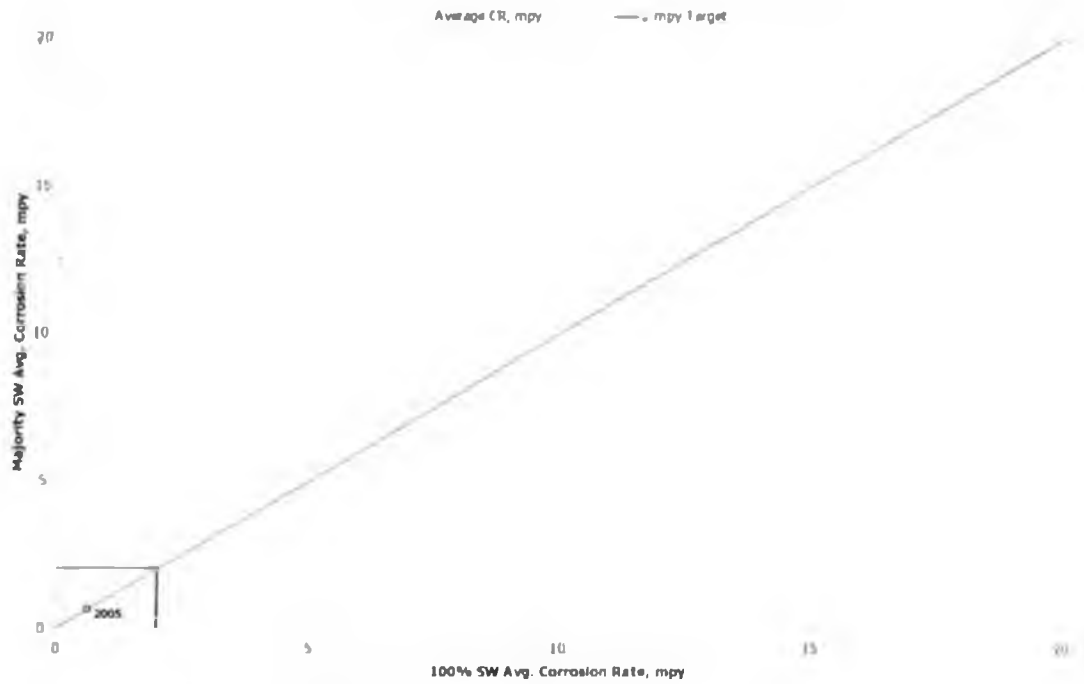


GPB Figure C.10 Corrosion Rate for 100% Seawater System

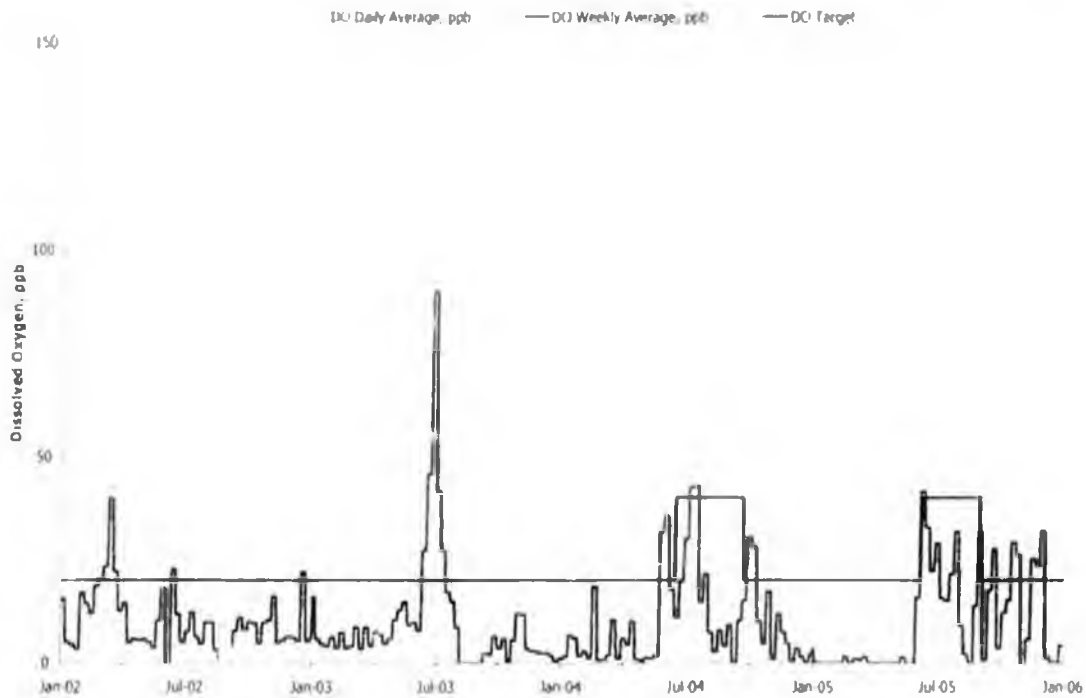


GPB Figure C.11 Corrosion Rates for Majority SW System

Section C Weight Loss Coupons and ER Probes



GPB Figure C.12 Comparison of Corrosion Rates for 100% and Majority SW System



GPB Figure C.13 Dissolved Oxygen Control Performance for the Seawater System

GPB Figure C.13 shows the daily and weekly average level of dissolved oxygen control in the seawater system from 2002 through 2005. The DO excursion during the summers is

Part 1 – Greater Prudhoe Bay Performance Unit

due to seasonal decreases in rates of the chemical oxygen scavenging reactions during periods of spring runoff and seawater turbidity. DO monitoring and control continues to be a challenge with the increased seawater volume.

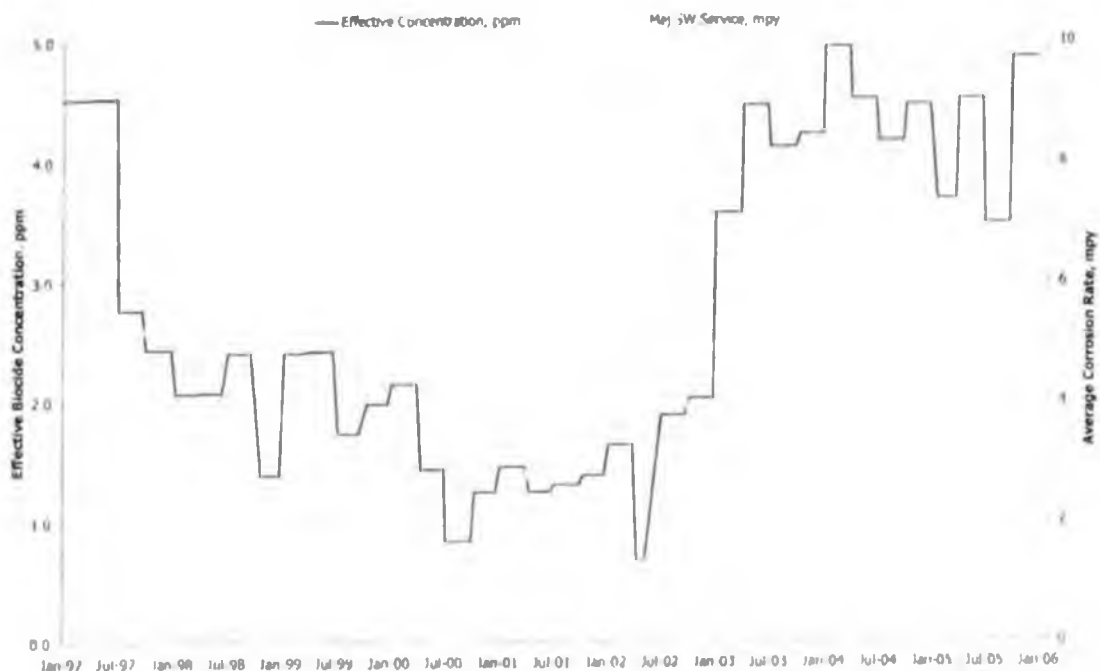
GPB Table C.2 summarizes the changes in the biocide treatment program for the SW system. Biocide dosage was increased in Mar-03 by 50% at STP to increase the effectiveness in downstream parts of the seawater system. This action decreased the downstream coupon corrosion rates faster than expected. In Dec-03, the glutaraldehyde/quaternary amine biocide was replaced temporarily with glutaraldehyde. In Oct-04, the biocide was switched back to glutaraldehyde/quaternary amine.

GPB Figure C.14 shows the corresponding effective concentration of biocide and the average corrosion rate for well line coupons in majority SW service. The beneficial effect of increasing the biocide injection concentration at STP is clearly depicted and helped to reduce seawater system corrosion rates below the 2 mpy target.

From	To	ppm	Interval days	Product
Jan-97	Jul-97	750	7	Glutaraldehyde
Jul-97	Feb-00	750	14	Glutaraldehyde
Feb-00	Aug-01	450	14	Glutaraldehyde/quaternary amine blend
Aug-01	Jul-02	500	14	Glutaraldehyde/quaternary amine blend
Jul-02	Dec-02	500	7	Glutaraldehyde/quaternary amine blend
Dec-02	Mar-03	500	7	Glutaraldehyde/quaternary amine blend
Mar-03	Dec-03	750	7	Glutaraldehyde/quaternary amine blend
Dec-03	Oct-04	750	7	Glutaraldehyde
Oct-04	Present	750	7	Glutaraldehyde/quaternary amine blend

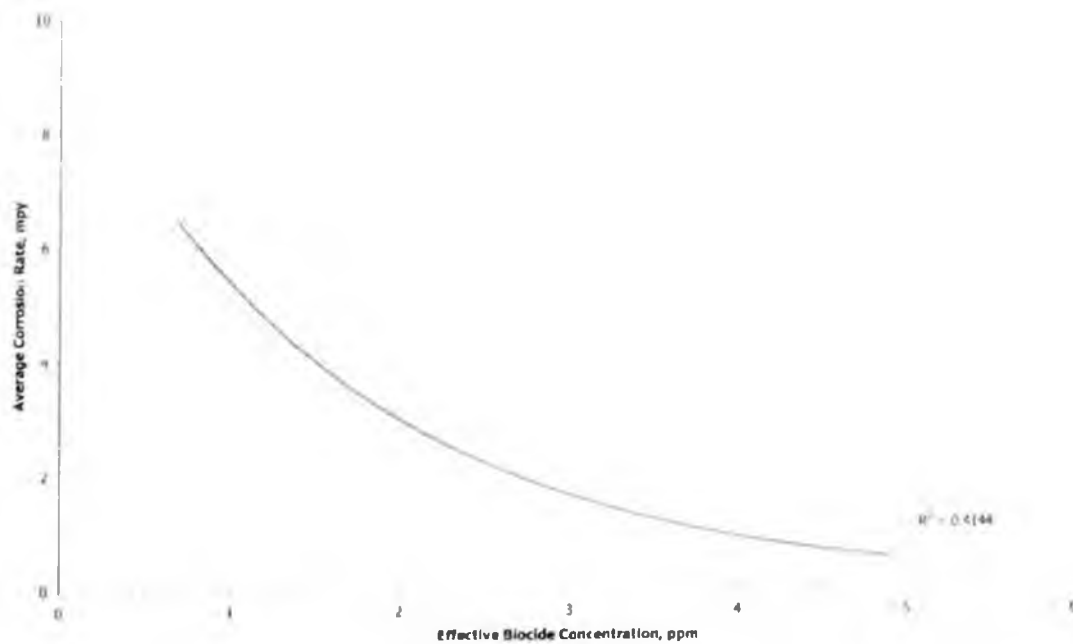
GPB Table C.2 Biocide Treatment Concentration and Interval

Section C Weight Loss Coupons and ER Probes



GPB Figure C.14 Biocide Treatment Concentration and Corrosion Rate

GPB Figure C.15 shows the correlation between the average corrosion rate and effective biocide concentration for 2001 through 2005.



GPB Figure C.15 Average Corrosion Rate vs. Effective Concentration, 2001 - 2005

In summary, the corrosion monitoring data suggest progress has been made in returning the seawater system to control. However as with the produced water system, the data are limited and caution is warranted. Therefore, there will be an on-going effort in 2006 to correlate the corrosion monitoring trend with inspection data and identify program improvements.

Section C.3 Electrical Resistance Probes

ER probes are installed in various locations to monitor corrosion rates in flow lines throughout GPB. ER probes measure a change in resistance due to material loss from corrosion and the measurements are converted to provide corrosion rates in mils per year. ER probes are equipped with remote data collectors (RDC), which measure and record the metal loss data every 4 hours. This provides an adequate number of data points to assess corrosion rates while maximizing battery life in the units.

The typical ER probe used is a T-10 that has 5 mils (0.005") of usable metal thickness. All flow line ER probes are replaced based on a 1-year service life, or when one half the usable metal thickness has been consumed. This reduces false negative and false positive readings as a result of damaged or unresponsive probes.

ER probes are located on both the upstream (well pad) end and downstream (gathering center) end of flow lines located on the west side of GPB. On the east side, probes are only located on the downstream (flow station) end of flow lines.

For the electrical resistance (ER) probes, the number of active locations in the flow lines is given in GPB Table C.3.

Year	Total Probe Locations
2001	83
2002	82
2003	85
2004	87
2005	87

GPB Table C.3 Active ER Probe Locations

ER probe data are collected in the field and uploaded to the corrosion and inspection database once per week. The target for ER probe corrosion rate is ≤ 2 mpy. Each ER probe with a corrosion rate greater than 2 mpy is evaluated to determine data validity. After verifying an increase in corrosion rates based on the probe data and other supporting data, an action is determined. The action is typically a corrosion inhibitor increase, but other sorts of mitigation may be recommended.

GPB Table C.4 shows the number of probes with corrosion rates greater than target as compared to the number actioned dating back to 2001.

Year	Average % <2 mpy	No. ER Probe > 2	No. ER Probes Actioned
2001	97%	193	6
2002	97%	137	6
2003	96% ⁶	138	21
2004	92%	316	59
2005	88%	241	11

GPB Table C.4 Number of ER Probes >2 mpy and Actioned

The 11 occurrences greater than 2 mpy in 2005 were mitigated with corrosion inhibitor rate increases. The percentage of ER probes actioned has decreased from 19% in 2004 to 5% in 2005. This decrease is the result of an aggressive approach in 2004 which was scaled back in 2005. There are a number of probes that have been identified as "chronic offenders", which is defined as probes with suspect metal loss data due to fluid flow and/or temperature fluctuations which cause the calculated corrosion rate for the ER probe to exceed the 2 mpy target. Chronic offenders are evaluated in the same manner as other ER probe data.

Section H.1.5 shows the corrective mitigation actions taken as a result of ER probe readings exceeding target and Appendix 3.3.1 describes by example, the methodology by which corrosion inhibitor concentration is increased as a result of ER probes monitoring.

Section C.4 1992 to Date Summary

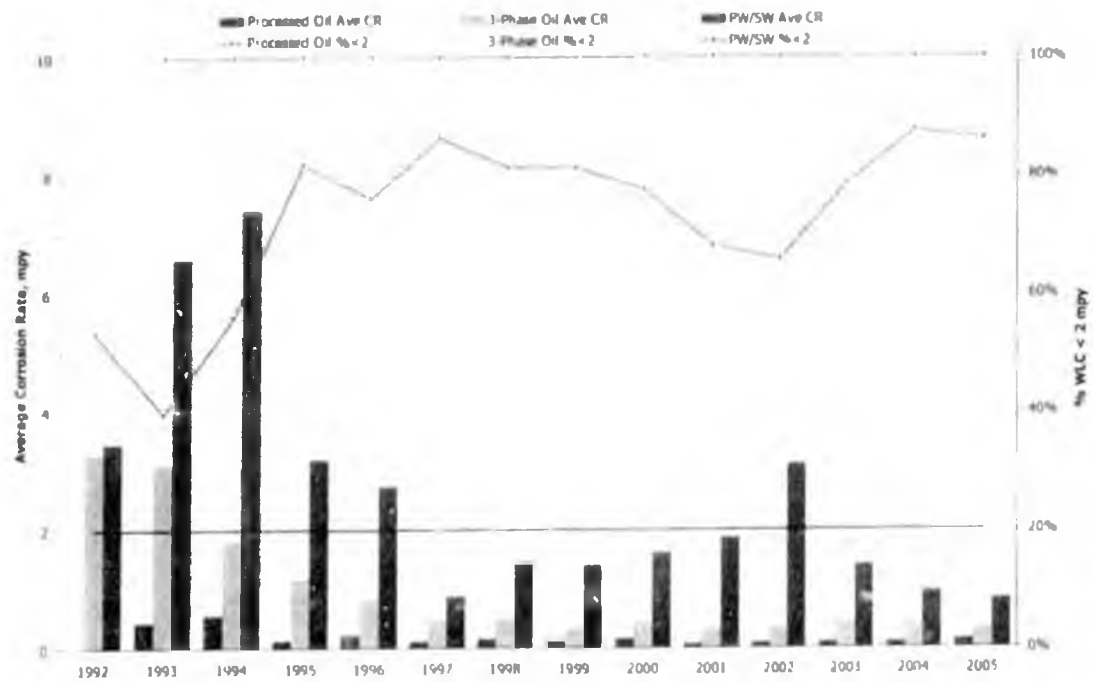
Section C.4.1 System by System Summary

This section provides system-by-system summary since 1992 for the major systems at GPB. GPB Figure C.16 shows the corrosion rate and corrosion target conformance since 1992. The high performance in the 3-phase production system has remained essentially unchanged since 2000. The reasons for improvement in the water injection system performance were provided in Section C.2.

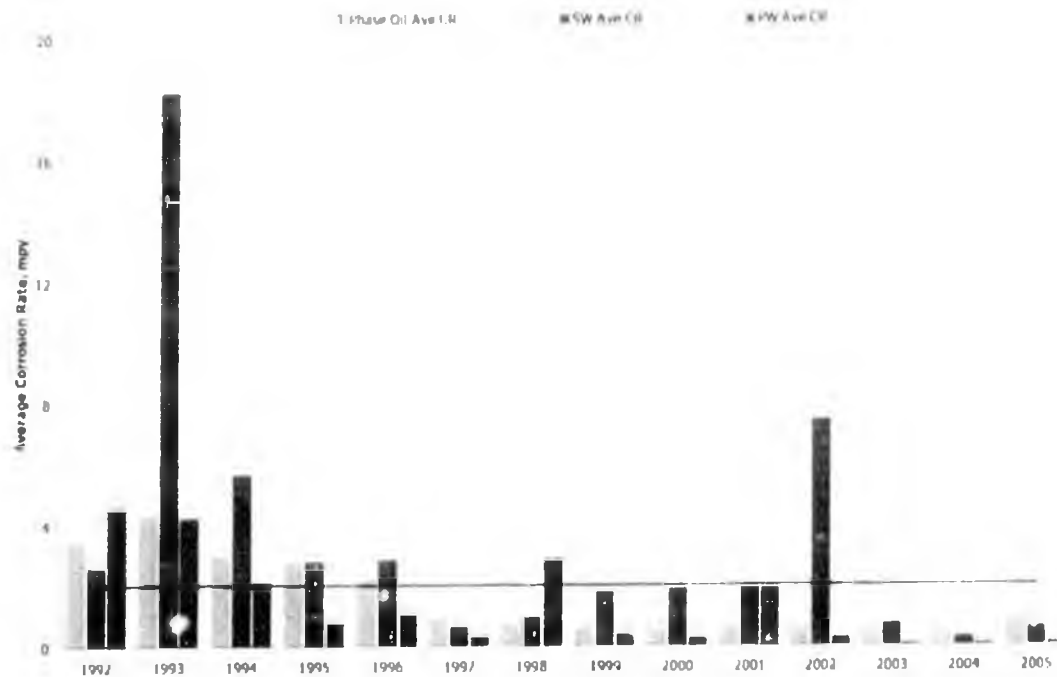
GPB Figure C.17 shows the corrosion rate and GPB Figure C.18 shows corrosion conformance for well lines. The well line 3-phase system performance has remained essentially unchanged since 2000. The produced water and seawater well lines corrosion performance has remained essentially consistent since 2002.

⁶ Incorrectly reported as 93% in 2003 Report

Part 1 - Greater Prudhoe Bay Performance Unit



GPB Figure C.16 Flow Line Corrosion Coupon Summary by Equipment and Service



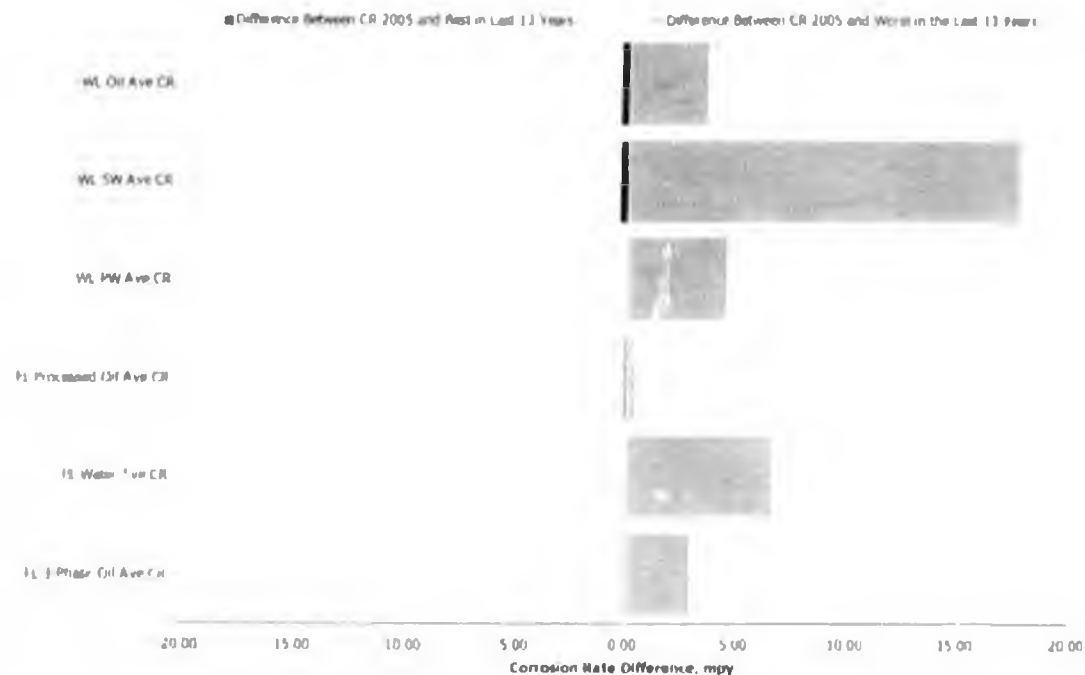
GPB Figure C.17 Well Line Average Corrosion Rate Summary by Equipment and Service



GPB Figure C.18 Well line %<2 mpy Summary by Equipment and Service

In order to assess the relative performance of the corrosion management program today versus that of the last 13 years, GPB Table C.5 and GPB Figure C 19 were generated as a summary. The data show the difference between the 2005 WLC corrosion rate for each of the systems and the best, or lowest, WLC corrosion rate and the worst, or highest, WLC corrosion rate observed since 1992. This is an approximate measure of the successes and/or shortcomings of the program today versus the ~13-year history and highlights areas for attention. The results indicate the current level of corrosion control, as determined by weight loss coupons, is at or near the best levels of control for each system.

Part 1 – Greater Prudhoe Bay Performance Unit



GPB Figure C.19 WLC Corrosion Rate Difference by Service and Type

System	2005 CR mpy	Best mpy	(Best – 2005) mpy	Worst mpy	(Worst – 2005) Mpy
WL Oil	0.79	0.46	-0.33	4.3	3.49
WL SW	0.63	0.30	-0.33	18.2	17.61
WL PW	0.12	0.09	-0.03	4.6	4.45
FL Processed Oil	0.15	0.08	-0.07	0.6	0.41
FL Water	0.84	0.84	0.00	7.4	6.56
FL 3-Phase Oil	0.33	0.31	-0.02	3.3	2.94

GPB Table C.5 WLC Corrosion Rate Difference by Service and Type

In summary,

Well Line 3-Phase Oil Service – Significant improvements in performance occurred from 1992 to 1997 when the average corrosion rate (CR) was reduced from 3.6 to 1.0 mpy (~70% improvement) and conformance to the 2 mpy target was increased from 64% to 88% (~40% improvement). Since then, average CR has been <1 mpy, and target conformance performance has been >90%. In 2005, values were 0.79 mpy and 92% respectively.

Well Line SW Service – Performance deteriorated from 1997 through 2002 with the average CR increased from 0.7 to 7.5 mpy. Average CR and percent conformance with the 2 mpy target rebounded in 2003 to 0.7 mpy and 95% respectively. For the 100% SW service, the average CR of 0.63 mpy and percent conformance of 94% <2 mpy. For the Majority SW service, there was an increase in 2005 with 0.60mpy and 95% <2 mpy.

Well Line PW Service – Average CR and percent conformance with the 2 mpy target was just under the historical best performance, with 0.12 mpy and 100%. The two excursions, 1998 and 2001, were likely the result of reduced system velocities and oil system corrosion inhibitor changes. Work continues in the evaluation of new corrosion control techniques designed specifically for the PW system.

Flow Line Processed Oil – These are the flow lines supplying processed hydrocarbon to Pump Station 1 and as might be expected for a very low water cut production stream, the corrosion rates are consistently very low with 100% of the coupons being reported as less than 2 mpy from 1993 to 2005.

Flow Line PW/SW Service – Performance deteriorated from 1992 to 1994 when average CR increased from 3.5 to 7.4 mpy. However, significant improvements occurred from 1994 to 1997 when the average CR was reduced to 0.8 mpy. Since then, CR and target conformance degraded until 2003 when performance improved to 1.4 mpy and 78% respectively. The improved performance continued in 2005 with the CR and target conformance performance at 0.84 mpy and 86%, respectively.

Flow Line 3-Phase Oil Service - Significant improvements in performance occurred from 1992 to 1997 when the average CR was reduced from 3.3 to 0.5 mpy (~85% improvement) and conformance to the 2 mpy target was increased from 77 to 97% (~25% improvement). Since then, CR and target conformance performance has improved. The 2005 CR and target conformance performance were 0.33 mpy and 98%, respectively.

Section C Weight Loss Coupons and ER Probes

BU	Equip	Service	Metric	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
GPB	FL	3-Phase Oil	WLC	787	958	998	1,435	1,562	1,507	1,495	1,521	1,451	1,296	1,338	1,321	1,242	1,133
GPB	FL	3-Phase Oil	Ave CR	3.28	3.10	1.81	1.17	0.84	0.47	0.48	0.31	0.42	0.34	0.33	0.42	0.36	0.33
GPB	FL	3-Phase Oil	SD CR	8.77	10.53	5.07	5.34	3.93	1.82	1.76	0.57	0.84	0.90	0.67	2.39	0.98	0.54
GPB	FL	3-Phase Oil	WLC < 2	607	738	864	1,306	1,478	1,567	1,466	1,507	1,411	1,275	1,325	1,315	1,222	1,114
GPB	FL	3-Phase Oil	% WLC < 2mpy	77%	77%	87%	91%	95%	97%	98%	99%	97%	98%	99%	100%	98%	98%
GPB	FL	PW/SW	WLC	81	106	154	198	184	195	171	181	160	131	137	144	119	107
GPB	FL	PW/SW	Ave CR	3.45	6.58	7.40	3.18	2.73	0.87	1.44	1.41	1.60	1.86	3.11	1.39	0.95	0.84
GPB	FL	PW/SW	SD CR	4.43	9.13	15.37	9.52	6.15	1.77	3.72	2.42	2.78	2.54	5.39	2.52	1.43	1.03
GPB	FL	PW/SW	WLC < 2	43	42	86	162	140	168	139	147	124	89	90	113	104	92
GPB	FL	PW/SW	% < 2mpy	53%	40%	56%	82%	76%	86%	81%	81%	78%	68%	66%	78%	87%	86%
GPB	FL	Processed Oil	WLC		16	23	24	34	44	32	34	36	22	28	44	36	40
GPB	FL	Processed Oil	Ave CR		0.43	0.56	0.13	0.23	0.13	0.16	0.14	0.17	0.08	0.09	0.11	0.10	0.15
GPB	FL	Processed Oil	SD CR		0.41	0.39	0.17	0.29	0.19	0.11	0.05	0.17	0.06	0.03	0.04	0.05	0.16
GPB	FL	Processed Oil			16	23	24	34	44	32	34	36	22	28	44	36	40
GPB	FL	Processed Oil	% < 2 mpy		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
GPB	WL	3-Phase Oil	WLC	6,764	5,622	4,979	5,245	6,571	6,787	6,403	6,193	6,243	4,858	5,298	5,564	5,215	4,907
GPB	WL	3-Phase Oil	Ave CR	3.43	4.29	2.94	2.75	2.22	0.92	0.72	0.55	0.74	0.64	0.58	0.46	0.58	0.79
GPB	WL	3-Phase Oil	SD CR	7.84	8.04	4.52	7.00	6.20	2.32	3.70	1.20	1.50	1.61	1.12	1.13	1.41	5.06
GPB	WL	3-Phase Oil	WLC < 2	4,503	3,036	2,853	3,733	5,018	6,032	6,020	5,950	5,757	4,533	4,960	5,347	4,902	4,531
GPB	WL	3-Phase Oil	% < 2 mpy	67%	54%	57%	71%	76%	89%	94%	96%	92%	93%	94%	96%	94%	92%
GPB	WL	Majority PW	WLC	531	514	662	829	976	1,073	964	740	699	659	464	426	452	327
GPB	WL	Majority PW	Ave CR	5.82	3.46	1.91	0.80	0.86	0.35	2.44	0.47	0.27	1.43	0.29	0.09	0.13	0.12
GPB	WL	Majority PW	SD CR	12.84	4.41	1.92	1.19	8.68	2.26	12.06	1.64	0.43	8.55	0.88	0.13	0.31	0.14
GPB	WL	Majority PW	WLC < 2	345	307	467	760	947	1,047	884	716	690	598	449	426	447	322
GPB	WL	Majority PW	% WLC < 2 mpy	65%	60%	71%	92%	97%	98%	92%	97%	99%	91%	97%	100%	99%	100%
GPB	WL	100% PW	WLC	282	304	286	485	604	717	719	524	459	473	332	354	368	286
GPB	WL	100% PW	Ave CR	4.58	4.24	2.12	0.81	1.10	0.35	2.91	0.40	0.30	1.92	0.29	0.09	0.09	0.12
GPB	WL	100% PW	SD CR	9.25	5.34	2.05	1.19	10.98	2.62	13.66	1.50	0.51	10.05	0.97	0.13	0.08	0.13
GPB	WL	100% PW	WLC < 2	190	158	192	447	571	703	656	512	450	416	323	354	368	286
GPB	WL	100% PW	% WLC < 2mpy	67%	52%	67%	92%	98%	98%	91%	98%	98%	88%	97%	100%	100%	100%
GPB	WL	Majority SW	WLC	434	410	384	317	162	56	44	82	98	44	25	19	34	78
GPB	WL	Majority SW	Ave CR	1.97	13.02	6.52	2.63	3.25	0.65	0.96	1.82	1.78	6.01	6.58	0.74	1.49	0.60
GPB	WL	Majority SW	SD CR	5.48	16.14	7.55	3.86	5.26	1.20	1.14	2.36	2.77	6.88	5.27	0.68	2.72	0.54
GPB	WL	Majority SW	WLC < 2	382	103	135	203	110	53	38	61	78	16	7	18	27	74
GPB	WL	Majority SW	% WLC < 2mpy	88%	25%	35%	64%	68%	95%	86%	74%	80%	30%	28%	95%	79%	95%
GPB	WL	100% SW	WLC	184	194	176	189	78	52	44	70	86	16	21	19	12	72
GPB	WL	100% SW	Ave CR	2.59	18.24	5.68	2.80	2.86	0.68	0.96	1.82	1.89	1.92	7.46	0.74	0.30	0.63
GPB	WL	100% SW	SD CR	7.13	19.04	8.04	4.43	5.39	1.24	1.14	2.50	2.93	1.07	5.28	0.68	0.27	0.55
GPB	WL	100% SW	WLC < 2	160	38	81	130	54	49	38	52	68	12	5	18	12	68
GPB	WL	100% SW	% WLC < 2mpy	87%	20%	46%	69%	69%	4%	86%	74%	79%	75%	24%	95%	100%	94%

Note: Majority Service data include 100% Service data

GPB Table C.6 Flow and Well Line General Corrosion Rate Data Summary

Section C Weight Loss Coupons and ER Probes

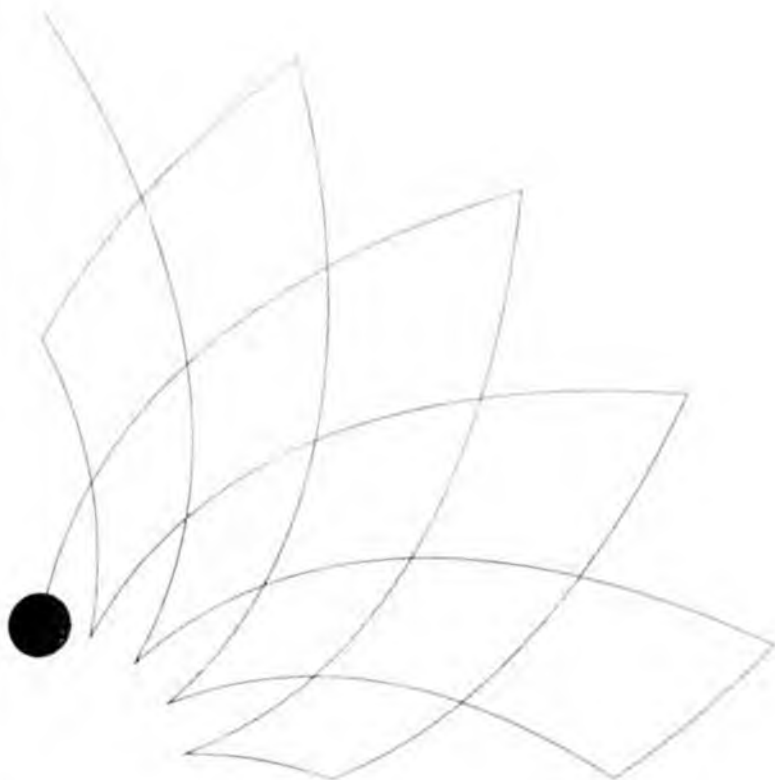
BU	Equip	Service	Metric	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
GPB	FL	3-Phase Oil	WLC	787	958	998	1,435	1,562	1,607	1,495	1,521	1,451	1,296	1,338	1,321	1,242	1,133
GPB	FL	3-Phase Oil	Ave P CR	7.29	5.60	4.10	8.90	7.67	6.72	2.91	1.65	1.92	1.28	0.74	0.65	1.24	0.42
GPB	FL	3-Phase Oil	SD P CR	22.83	15.42	13.30	22.74	14.85	13.85	6.66	6.16	7.71	10.58	3.93	8.32	5.90	2.62
GPB	FL	3-Phase Oil	P WLC < 20	691	876	946	1,315	1,467	1,552	1,469	1,498	1,418	1,281	1,317	1,319	1,227	1,130
GPB	FL	3-Phase Oil	% P WLC < 20mpy	87.8%	91.4%	94.8%	91.6%	93.9%	96.6%	98.3%	98.5%	97.7%	98.8%	98.4%	99.8%	98.8%	99.7%
GPB	FL	PW/SW	WLC	10	36	46	56	52	52	48	58	47	41	59	84	64	53
GPB	FL	PW/SW	Ave P CR	12.20	10.92	2.50	3.52	3.75	2.08	5.02	7.57	8.00	12.93	18.76	8.70	3.91	4.89
GPB	FL	PW/SW	SD P CR	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00
GPB	FL	PW/SW	P WLC < 20	8	32	45	54	50	51	47	53	46	31	35	70	64	50
GPB	FL	PW/SW	% P WLC < 20mpy	80.0%	89.0%	98.0%	96.0%	96.0%	98.0%	98.0%	91.0%	98.0%	76.0%	59.0%	83.0%	100.0%	94.0%
GPB	FL	Processed Oil	WLC		16	23	24	34	44	32	34	36	22	28	44	36	40
GPB	FL	Processed Oil	Ave P CR		0.50	0.70	1.88	2.56	3.73	2.19	1.26	1.44	1.05	0.77	0.32	0.69	0
GPB	FL	Processed Oil	SD P CR		1.15	2.48	3.42	4.64	4.31	5.65	2.43	3.49	3.47	3.92	2.11	2.91	0
GPB	FL	Processed Oil	P WLC < 20		16	23	24	34	44	31	34	36	22	26	44	36	40
GPB	FL	Processed Oil	% P WLC < 20mpy		100.0%	100.0%	100.0%	100.0%	100.0%	96.9%	100.0%	100.0%	100.0%	92.9%	100.0%	100.0%	100.0%
GPB	WL	3-Phase Oil	WLC	6,764	5,622	4,979	5,245	6,571	6,787	6,403	6,193	6,243	4,858	5,298	5,564	5,215	4,907
GPB	WL	3-Phase Oil	Ave P CR	7.33	9.41	5.21	11.58	11.85	5.24	3.23	2.78	3.31	1.95	1.71	1.66	1.95	1.69
GPB	WL	3-Phase Oil	SD P CR	22.54	24.36	14.30	32.41	29.31	14.69	10.08	7.82	10.18	6.42	5.62	5.33	5.78	5.81
GPB	WL	3-Phase Oil	P WLC < 20	5,837	4,961	4,641	4,586	5,694	6,508	6,243	6,069	6,054	4,755	5,223	5,514	5,120	4,819
GPB	WL	3-Phase Oil	% P WLC < 20mpy	86.3%	88.2%	93.2%	87.4%	86.7%	95.9%	97.5%	98.0%	97.0%	97.9%	99.1%	98.6%	99.2%	98.2%
GPB	WL	Majority PW	WLC	531	514	662	829	976	1,073	964	740	699	659	464	426	412	322
GPB	WL	Majority PW	Ave P CR	34.12	24.67	15.84	20.18	15.02	9.65	20.69	8.87	4.65	6.69	2.95	1.03	1.89	1.27
GPB	WL	Majority PW	SD P CR	41.07	31.95	27.13	29.05	28.64	28.96	58.60	26.07	9.75	17.52	8.97	2.93	7.75	4.22
GPB	WL	Majority PW	P WLC < 20	258	294	499	574	802	758	805	674	670	579	452	425	449	320
GPB	WL	Majority PW	% P WLC < 20mpy	48.6%	57.2%	75.4%	69.2%	82.2%	90.2%	83.5%	91.1%	95.9%	87.9%	97.4%	99.8%	91.3%	99.4%
GPB	WL	100% PW	WLC	282	304	286	485	604	717	719	524	459	473	332	354	368	286
GPB	WL	100% PW	Ave P CR	4.58	4.24	2.12	0.81	1.10	0.35	2.91	0.40	0.30	1.92	0.29	0.09	0.09	0.12
GPB	WL	100% PW	SD P CR	9.25	5.34	2.05	1.19	10.98	2.62	13.66	1.50	0.51	10.05	0.97	0.13	0.08	0.13
GPB	WL	100% PW	P WLC < 20	190	158	192	447	589	703	656	512	450	416	323	354	368	286
GPB	WL	100% PW	% P WLC < 20mpy	67.4%	52.0%	67.1%	92.2%	97.5%	91.7%	91.2%	97.7%	98.0%	87.9%	97.3%	100.0%	100.0%	100.0%
GPB	WL	Majority SW	WLC	434	410	384	317	162	56	44	82	98	44	25	19	34	78
GPB	WL	Majority SW	Ave P CR	4.74	17.32	9.45	11.36	16.88	1.50	1.55	5.62	6.61	18.80	29.1	9.11	13.32	2.42
GPB	WL	Majority SW	SD P CR	15.65	44.26	14.21	15.43	23.11	4.52	2.31	8.16	10.40	18.59	27.1	20.21	31.01	4.31
GPB	WL	Majority SW	P WLC < 20	404	320	331	263	115	55	44	80	92	24	15	16	30	78
GPB	WL	Majority SW	% P WLC < 20mpy	93.1%	78.0%	86.2%	83.0%	71.0%	98.2%	100.0%	97.6%	93.9%	54.5%	60.0%	84.2%	88.2%	100.0%
GPB	WL	100% SW	WLC	184	194	176	189	78	52	44	70	86	16	21	19	12	72
GPB	WL	100% SW	Ave P CR	5.19	13.31	7.79	9.09	10.10	0.54	1.55	5.24	5.57	7.13	31.62	9.11	9.17	2.33
GPB	WL	100% SW	SD P CR	18.94	18.79	12.14	13.41	19.87	2.18	2.31	8.49	6.38	7.30	29.49	20.21	21.36	4.33
GPB	WL	100% SW	P WLC < 20	172	157	156	162	62	52	44	68	82	14	12	16	10	72
GPB	WL	100% SW	% P WLC < 20mpy	93.5%	80.9%	88.6%	85.7%	79.5%	100.0%	100.0%	97.1%	95.3%	87.5%	57.1%	84.2%	83.3%	100.0%

Note: Majority Service data include 100% Service data

GPB Table C.7 Flow and Well Line Pitting Rate Data Summary

Section D

Chemical Optimization Activities



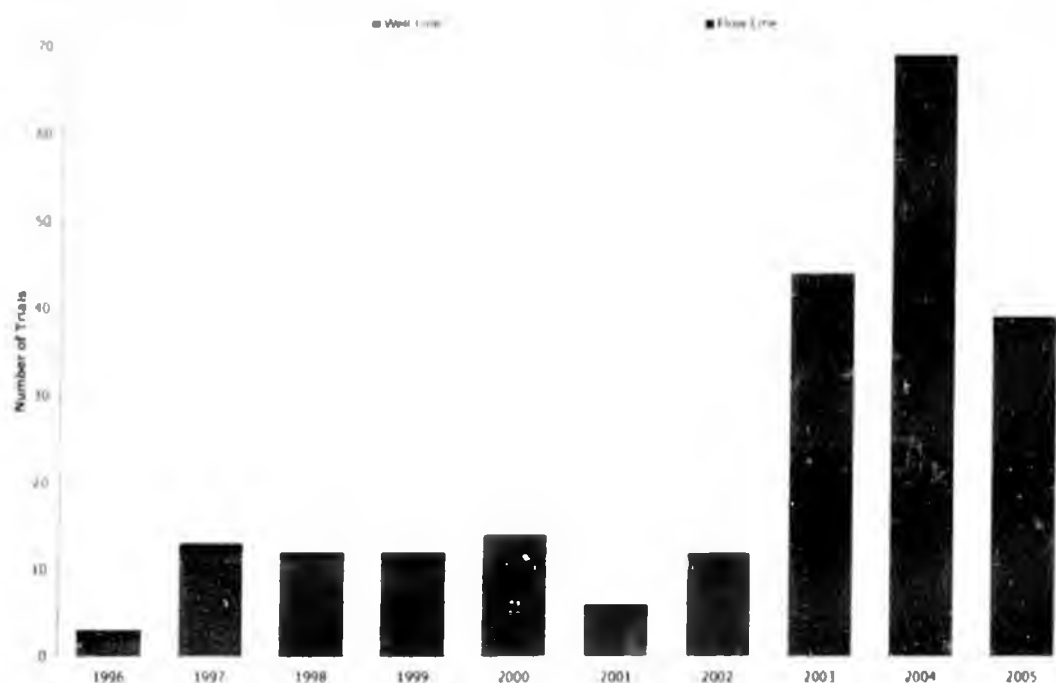
Section D Chemical Optimization Activities

Section D.1 Chemical Optimization

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

Section D.2 Corrosion Inhibitor Testing

GPB Figure D.1 summarizes the number of well line and flow line tests which have been completed since 1996. The level of well line test activity increased beginning in 2003 due to a change in the screening protocol, which reduced the time required per test. The combined number of well line and flow line tests has increased from ~10-14 per year⁷ to more than 35 during 2005. This level of activity represents a substantial investment of resources towards the development of new and more effective corrosion inhibitors.



GPB Figure D.1 Number of Well Line and Flow line Tests

Two test chemical were advanced from the well line test program to large scale flow line testing. However, neither chemical met the technical performance requirements to advance further.

⁷ The data prior to 2000 are incomplete and represents the test work completed on the heritage WOA only.

Section D.3 Field Wide Corrosion Inhibitor Deployment

The chemical development and testing program has been highly successful in recent years, with 16 new products being developed for use in the continuous wellhead inhibition program since 1995. All these changes represent a significant improvement in overall corrosion control performance.

GPB Table D.1 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	95	96	97	98	99	00	01	02	03	04	05
Nalco Exxon	EC1110A	█										
Nalco Exxon	EC1259		█									
Nalco Exxon	97VD129			█								
Nalco Exxon	98VD118				█							
ONDEO Nalco	99VD049					█						
ONDEO Nalco	01VD017						█					
ONDEO Nalco	01VD121							█				
Nalco	DVE4D002										█	
Champion	RU205	█										
Champion	RU210	█	█									
Champion	RU223	█	█	█								
Champion	RU258			█								
Champion	RU271				█							
Champion	RU126A						█					
Champion	RU256 ¹											█
Champion	2004-15 ¹											█

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

GPB Table D.1 Summary of the Chemical Deployment History

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. GPB Table D.2 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.