ALASKA LEGISLATURE COMMITTEE FILES, 2005-2006 8672
11961 SENATE RESOURCES

ADEC Corrosion Charter
Meet & Confer - Field Visit 2005
September 27 – 29, 2004

Overall Meeting Objectives

- Present an overview of the corrosion program to enhance understanding on the part of ADEC/Coffman regarding strategy, guidelines, risk-based approach.
- Understand the rationale behind coupon location selection & monitoring of accelerated corrosion rate coupons.
- Visit selected 2004/2005 leak sites and locations where CPA is likely experiencing greater than average corrosion rates to understand location-specific parameters and prevention/mitigation measures.
- Review of below grade inspection program and how the long-range inspection technologies correlate with excavations or direct assessment results.
- Discuss the maintenance pigging program status

ADEC & Coffman Team Members

- Dianne Munson — North Slope Charter Agreement Manager, ADEC
- Sam Saengsudham — Section Manager, Pipeline and Tank Integrity, ADEC
- Gary Evans — EPR C-plan Reviewer, ADEC
- Wade Gilpin — EPR C-plan Reviewer, ADEC
- Kirsten Ballard — Environmental Specialist, ADEC
- Laurie Silfven — Environmental Specialist, ADEC
- Dan Stears — Manager, Coffman Engineering
- Rodney Evans — Corrosion Engr., Coffman Engineering
- Oliver Moghissi — Consultant, CC Technologies

SPRING 2006

Charter II.A.6
Meet & Confer Calendar, agenda
May 3, 2006

BP / CPAI - ADEC Meeting

Location: CPAI Conference Room ANO-259

Date: 3 May 2006

Time: 8:30 am - 4:45 pm

Session I – 2005 Report Meet & Confer

8:30 - 8:45am	Opening remarks • ADEC • BP • ConocoPhillips
8:45 - 10:15 am	BP Annual Report presentation
10:15 - 10:45 am	Break
10:45 am - 12:15 pm	ConocoPhillips Annual Report presentation
12:15 - 1:15 pm	Lunch

Session II – Extraordinary Events Discussion

1:15 - 1:30 pm	Opening Remarks
1:30 - 2:45 pm	BP Incidents
2:45 - 4:00 pm	ConocoPhillips Incidents
4:00 - 4:45 pm	Q&A, Comments, Adjournment

Meeting Attendees

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Meeting Attendees (contd.)

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BP

Commitment to Corrosion Monitoring Year 2005

Meet and Confer XI
May 03, 2006

Outline

- Corrosion Management Program Overview
- GPB
  - Overall Activity
  - Corrosion Monitoring
  - Internal Inspection
  - External Corrosion
  - Cased Piping Inspection
  - [illegible] line Inspection
  - Corrective Actions
  - 2005 Leaks & Repairs
  - Summary & Look Forward
- ACT
  - ACT Description
  - ACT Overall Activity
  - Endicott
  - Milne Point
  - Northstar
  - Badami
  - 2005 Leaks & Repairs
  - Summary and Look Forward

BPXA Operated Facilities and Equipment

- Facilities
- Pipeline Network
- Vessels
- Tanks
- Production

GPB/ACT Comparisons

Metric	ACT	GPB	% ACT GPB
Production [illegible]	4	[illegible]	[illegible]
Prod/Inject Wells	[illegible]	1,650	[illegible]
Regulated Tanks	[illegible]	[illegible]	[illegible]
Non Regulated Tanks	[illegible]	[illegible]	[illegible]
Active vessels	[illegible]	[illegible]	[illegible]
DOT Pipelines	[illegible]	[illegible]	[illegible]
Non-regulated [illegible]	100 miles	[illegible] miles	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	100	[illegible]	[illegible]
Total Acreage	[illegible]	[illegible]	[illegible]

Corrosion Management Program

- Strategic Objectives
  1. Minimize HSE Impacts
     - Eliminate corrosion and erosion failures
  2. Fit-for-service Infrastructure
     - Remaining field life
  3. Future Major Gas Development
     - Utilize existing facilities
     - Gas sales demands longevity (50+ years)

Step	Program Elements
[illegible]	Objective
	[illegible]
	Target
	[illegible]
Do	Implementation
	[illegible]
[illegible]	Evaluation
	[illegible]
[illegible]	Corrective Action
	[illegible]

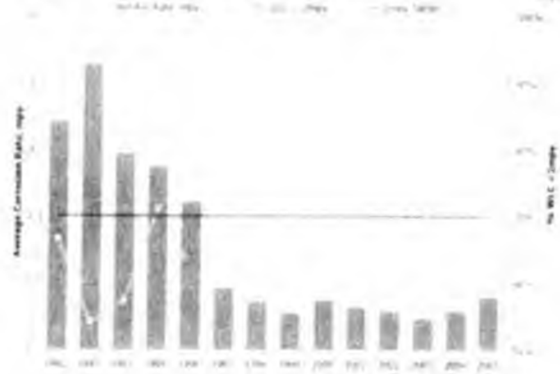
GPB Corrosion Mitigation Activity

	2001	2002	2003	2004	2005
Internal Inspections					
Well lines	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Flow lines	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
External Inspections					
Well lines	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Flow lines	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	38,966	69,086	60,461	62,637	59,043
Coupon Activity, pulls	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
ER Probe Activity, sites	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
3-Phase Chemical					
Volume, gal	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Concentration, ppm	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Water Cut, %	[illegible]	71	72	[illegible]	76

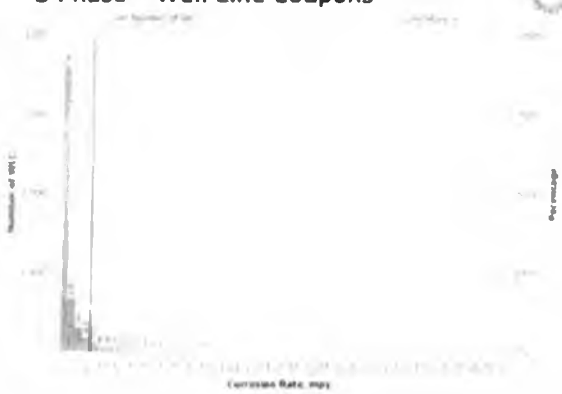
3-Phase Monitoring and Mitigation

- **Weight Loss Coupons**
  - Well lines
  - Flow lines
- **Corrosion Inhibitor Injection**
  - Concentration
  - Unplanned Events

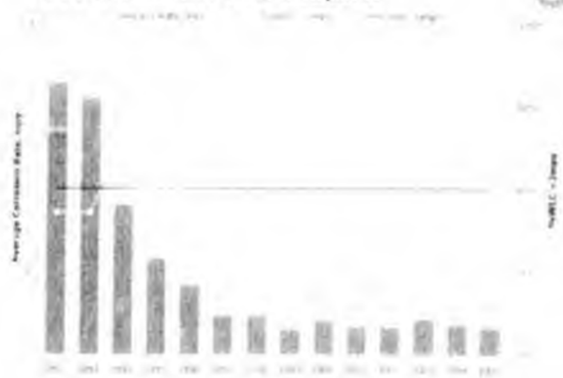
3 Phase – Well Line Coupons



3 Phase – Well Line Coupons

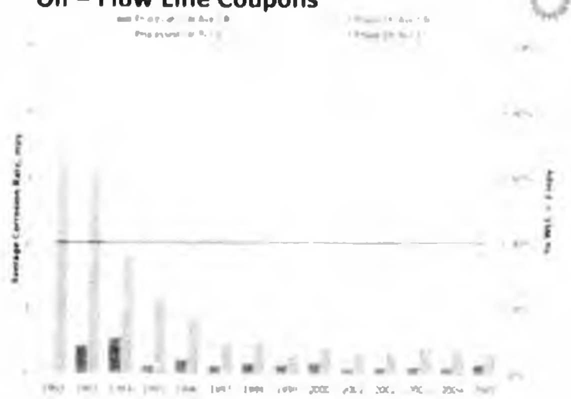


3 Phase – Flow Line Coupons

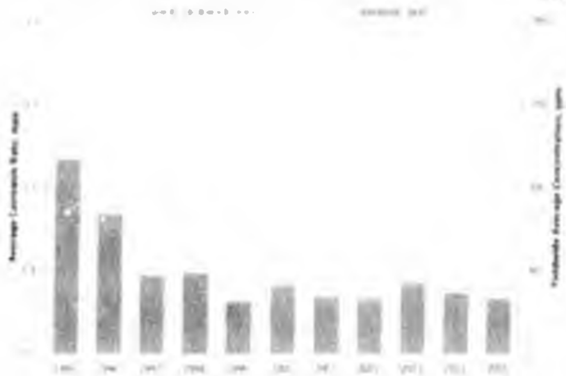


3 Phase – Flow Line Coupons

Oil – Flow Line Coupons



Corrosion Inhibitor Concentration



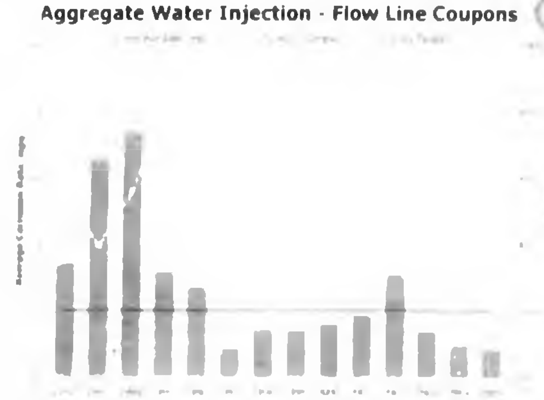
2 Unplanned Chemical Events

- 1. Chemical instability at winter temperatures
- 2. Trial chemical material incompatibility

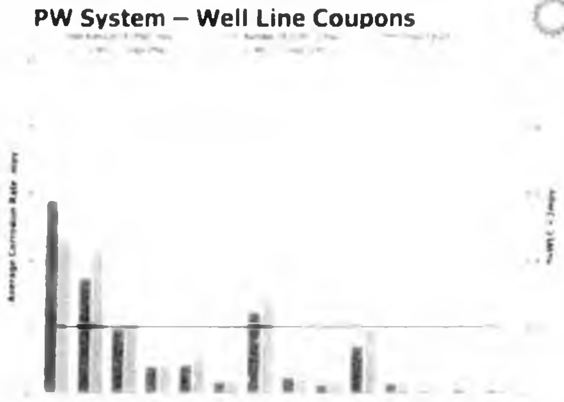
Water Injection Systems

- **Aggregate flow lines**
  - Weight Loss Coupons
- **Produced Water well lines**
  - Weight Loss Coupons
  - Strategy Update
- **Seawater well lines**
  - Weight Loss Coupons
  - Strategy Update

Aggregate Water Injection - Flow Line Coupons



PW System – Well Line Coupons



Reality is not so good....

Injection System Integrity 4Q'04

- Coupons give false sense of security
  - Compare Inspection data
- Bulk Fluid has low corrosivity
- Pipe wall mechanism is different
  - Under depo
  - Bacteria (MIC)
- Historically Managed by de-Rating:
  - Design 3,600 psig
  - Typical now 2,500 psig

Recent History

- 4Q 2004 — Water Infrastructure Study
- 1Q 2005 — Multi Disciplinary Team Formed
  - Engineering, Reservoir, CIC, Projects, WIO OF
- 1Q 2005 — Strategy Developed
  - Inhibition (3-phase carry over & direct)
  - Clean Pipelines
    - Chemical
    - Pigging
- 2Q 2005 — Partner Endorsement
  - $2.9 MM in 2005
- 3Q 2005 — Implementation

Inhibition Increase Work completed

- All sites now converted to EC1081A (proven)
  - EC9041A (incumbent) has been depleted
- Most sites now at target 60ppm
  - Down from initial 80ppm
  - FS2: Target 2Q 06 (Large water producer)
- Significant Logistic Work Completed
  - 90 day supply of EC1081A on hand
  - 15 new railcars

Produced Water Summary

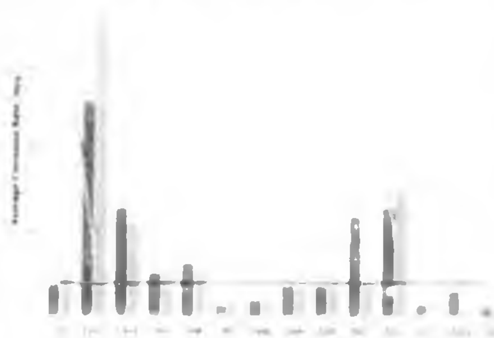
2005.......

- Strategy Developed
- Partner approval
- Implementation
  - EC1081A increased to 80 [illegible]
  - Improved pigging performance

2006.....

- Gaps identified:
  - Monitoring
  - 3 Phase carry over
  - Feed system upgrades
  - Pigging performance
  - Strategy completion

SW System – Well Line Coupons



2005 Review
8 Opportunities: Reverse "Creeping Changes"

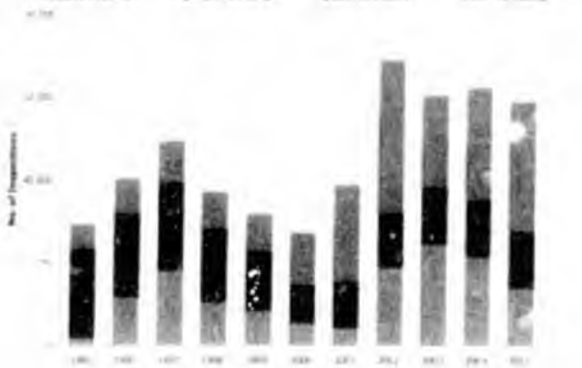
1. Investigate different water intake (cleaner)
2. Re-instate filters
3. Resume biociding of STP
   - Plant modification options already scoped
4. Better DO control (especially summer)
5. Orbisphere – restore confidence in data
6. Pigging (weekly, 6 weeks, quarterly?)
7. Supplemental biocide at IMF2
   - Trial – for low-velocity, "special problem" circuit
8. PW/SW swaps – line cleaning
   - "schmoo be gone," hot diesel, etc

- Implement 2006

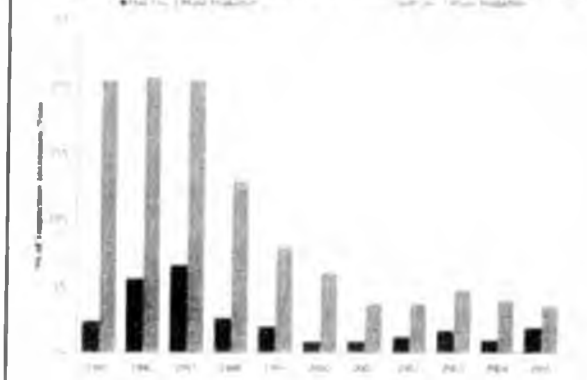
Inspection Program

- Internal Inspection
  - 3 phase – flow and well line
  - Water injection – flow and well line
- External Inspection
- Cased Piping Inspection
- In-line Inspection

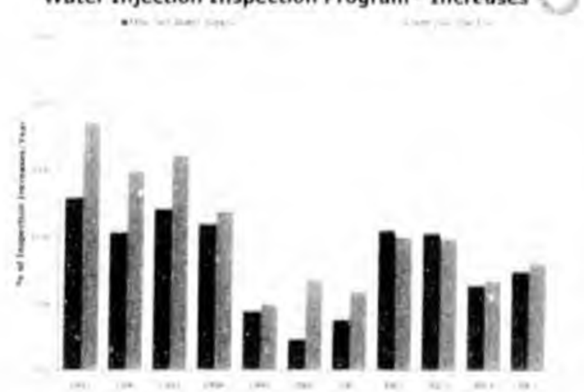
Flow/Well Line Inspection Activity



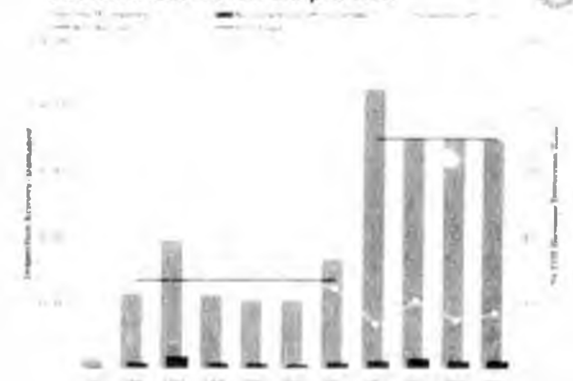
3-Phase Inspection Program - Increases



Water Injection Inspection Program - Increases



External Corrosion Inspection



2005 External Corrosion Pyramid

Cased Pipe Management Program

- **Use guided-wave/ILI/visual inspection**
  - Baseline inspections completed in 2003
  - GUT resource brought "in-house"
  - Used to identify and prioritize excavations
- **79/100 segments were re-inspected**
  - 5 with ILI
  - 74 with GUT permanently installed
    - Cobalt probe shortage
- **6 segments were excavated**
  - 4 – no corrosion damage
  - 1 – external corrosion
  - 1 – mechanical repair

In-line Inspection

- 3 pipelines inspected with ILI
- Follow-up work still in progress
  - No repairs identified to date

Equipment	Service	Diameter	Previous ILI	From	To	Length (miles)
E 36	3 Phase	24	1995	E Pad	GC1	7.9
W 24	3 Phase	24	1997	W Pad	EWE Junction	0.8
Z 16	3 Phase	24	1997	Z Pad	EWE Junction	[illegible]

2005 Leaks and Repairs

- Corrective Actions
- 2005 Leak Details
- 2005 Repairs

Flow Line Corrective Actions

- ER Probe
  - 241 - 2mpy
  - 11 Chemical Increase
- Weight Loss Coupons
  - 19 FL - 2mpy
  - 6 Chemical Increase
- Inspection Program
  - 1 Chemical increase & Operational change

2005 Leaks

- Leak Summary
  - Total of 6 Leaks

Service	Location	Type	Date	Mechanism	Volume
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Surface		Service					Mechanism		
Int	Ext	Oil	SW	PW	Gas	CO	Int	CUI	Mech
[illegible]									

2005 Leak/Spill Detail

- DS11-08 8" SW Injector
  - Leak detected - Feb
  - SW Injector
  - Internal corrosion
  - 270 gallon spill
  - Section replacement
    - 40 ft new pipe

- DS06 3/4" nipple GLT
  - Leak detected - March
  - Mechanical - Heavy equipment incidental
  - Low point drain
  - 400,000 scf of gas
  - Shut-in and replace

2005 Leak/Spill Detail

- M-74 24" LDF
  - Leak detected - April
  - 3 phase production
  - Mechanical
  - 4 gallon spill
  - Section replacement
    - ~50 ft new pipe

- DS14 – 6" Warm-up gas
  - Leak detected - April
  - Warm up gas line to LDF
  - Low cycle fatigue @ weld
    - 3rd Party Evaluation
  - ~ 1,260 gallon spill
  - Segment isolated
    - Cut out and blinded

2005 Leak/Spill Detail

- **DS16 – 3" 16/17AL**
  - Leak detected – July
  - Gas lift
  - External corrosion @ weld pack
  - Small gas release
    - Shut in – awaiting repair

- **DS11-02**
  - Leak detected – October
  - Seawater
  - Internal corrosion
  - ~10 gallon spill
    - [illegible]

2005 Repairs

- **Repair Summary**

Service	Type	Internal	External	Mechanical	Total
[illegible]	[illegible]	[illegible]	[illegible]	1	[illegible]
	[illegible]	[illegible]	[illegible]		[illegible]
Water	[illegible]	[illegible]		[illegible]	[illegible]
	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Gas	[illegible]		[illegible]	[illegible]	[illegible]
	[illegible]		[illegible]	1	[illegible]
[illegible]					0
Total		12	49	10	71

GPB Summary

- **Internal Corrosion**
  - 3 Phase Systems
    - Lines showing sustained performance
      - Chemical events
      - Proactive process of corrective action
  - Water Injection Systems
    - Produced water Strategy Implementation
    - Sea Water Plan Developed
- **External Corrosion**
  - >35,000 locations as planned
- **Cased Pipe**
  - Executing long term management strategy
- **6 Leaks**

GPB 2006 Goals and Objectives

	2005 Actual	2006 Plan
Review ALL Strategies		
Corrosion Monitoring		
Coupons – no significant changes	–	No change
ER probes – no significant changes	–	No change
Internal Inspection Program		No change
External Inspection Program		
Weld pack inspections – 35,000		40,000
Cased Piping Inspection		
Long term management	[illegible]	125
Chemical Mitigation		
Rapid Screen testing	[illegible]	No Change
Large scale facility trial	[illegible]	No Change
PW Mitigation at facilities		Plan
SW Implement Actions		Plan
Technology		
ER probe remote monitoring [illegible]	[illegible]	Continue
Remote tank strap reading [illegible]	[illegible]	Continue
Fixed monitoring for cased piping	[illegible]	Continue
[illegible] monitoring of CI [illegible]		Plan
[illegible] array real time [illegible]		Plan

Outline

- **ACT**
  - ACT Description
  - ACT Overall Activity
  - Endicott
  - Milne Point
  - Northstar
  - Badami
  - 2005 Leaks & Repairs
  - Summary and Look Forward

Alaska Consolidated Team (ACT)

- **Producing Fields**
  - Endicott
  - Milne Point
  - Badami
  - Northstar
- **Relative Comparison**
  - ACT smaller than GPB
  - Differences in age
  - Non common carrier FL
    - None at Northstar
    - None at Badami
  - Materials of construction

Metric	ACT	GPB	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]

Relative Corrosivity of BP North Slope Fields

Field	Prod Fluid Characteristics: H_2O (%)	T (°F)	P_{CO_2} (%)	CR[b]	Material of Construction[a]: Production WL	Production FL	Injection WL	Injection FL
GPB	75	150	12	H	CS+CI	CS+CI	CS+CI	CS+CI
END	92	155	18	H	DSS	DSS	CS+CI	CS+CI
MPU	52	125	1.5	L/M	CS	CS	CS+CI	CS+CI
Northstar	16	160	8	H	CS+CI	N/A	N/A	N/A
Badami	<8	85	~0	L	CS	N/A	N/A	N/A

Notes:

ACT Corrosion Mitigation Activity

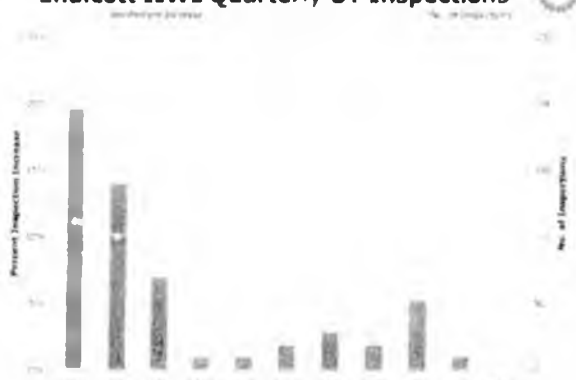
	2001	2002	2003	2004	2005
Internal Inspections					
Endicott	1,486	1,604	2,072	2,716	1,152
Milne Point	679	1,601	4,388	4,040	1,467
Northstar	16	144	204	127	105
Badami		5	24	26	40
External Inspections					
Endicott	11	40	656	711	104
Milne Point	1,570	70	1,563	1,738	177
Total	**3,718**	**3,551**	**9,132**	**9,086**	**7,355**
Coupon Activity	130	148	511	664	545
Chemical Volume					
Produced Water, gal	NA	NA	101,835	86,951	117,244
Three Phase, gal	NA	NA	17,595	31,239	53,300
Total			139,430	118,190	170,544

Endicott Overview

- **Production System**
  - Primarily Duplex Stainless Steel
  - Exception are the carbon steel C spools
    - velocity monitoring
    - Inspection program
    - Manage to repair/replace
- **PW/SW Injection System**
  - Inter-Island Water Line (IIWL) main concern
    - Control by
      - Maintenance pigging
      - Inhibitor
      - Biocide [illegible]
- **External Corrosion**
  - 104 Inspections
    - 1 Sleeve repair (IIWL)
    - 1 identified replacement in 2006 [illegible]

Endicott Corrosion Monitoring

Endicott IIWL Quarterly UT Inspections



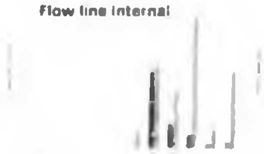
Milne Point Unit Overview

- **Production System**
  - Progressing inhibition program
    - K-Pad flow line initiated in 2001
    - S Pad inhibited in power fluid in 2002
    - F, L, C production flow line inhibition initiated in 2003
    - B pad flow line inhibition recommended (started 2Q06)
    - Tract 14 inhibition recommended
- **Water Injection system improvements**
  - Inhibition initiated & increased maintenance pigging program in 2000
  - Significant decrease in corrosion activity

MPU - Inspection Summary

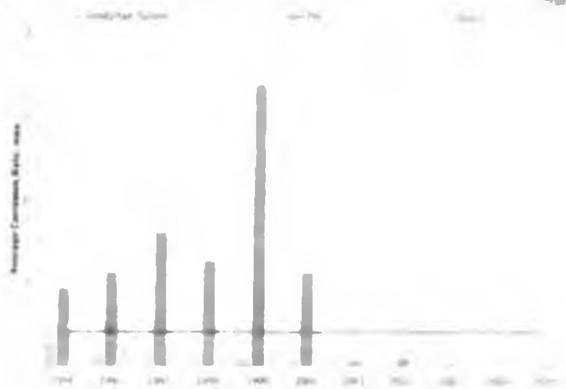
- **External Corrosion**
  - 177 inspections
    - 131 at above grade locations
    - 46 in 9 below grade excavations
- **Internal Corrosion**
  - 3,487 inspections
    - ~100 in 9 below grade excavations
- **No repairs identified**

Flow line internal



Well line internal

MPU Corrosion Monitoring



Badami and Northstar Overview

- **Badami**
  - Began production in 1998
    - Production below expectations
    - No water injection system
      - [illegible]
    - No significant corrosion experienced
  - Warm shut in in Aug 2001
    - [illegible] formed baseline and follow up inspections of equipment [illegible]
  - Restart in Oct 2005
- **Northstar**
  - Began production in late 2001
  - Continuous inhibition into well production lines
    - Relocating CI injection further upstream in progress
  - No water injection system
  - Corrosion monitoring program – WLC and ER probe
  - Inspection baseline and historical record establishment ongoing

ACT – Leaks and Repairs

- **10 - Repairs/replacement activity**
  - 8 – Saves
  - 2 – Corrosion related leaks
    - 1 erosion on S spool at Endicott during well POP
      - Minimal volume crude well house
    - 1 corrosion on C spool at Endicott (HAZ)
      - Small gas release, no liquid

		Badami		Endicott		Milne Point		Northstar	
Equipment Type	Service	Int	Ext	Int	Ext	Int	Ext	Int	Ext
Well lines	3 Phase	1		6					
	Gas				1				
Flowline	Produced Water				1		1		

ACT 2006 Goals and Objectives

- **Review ALL Strategies**
- **Dedicated ACT Integrity Team**
- **Endicott** — 05 Act — 06 Plan
  - [illegible]
- **Northstar**
  - [illegible]
- **Badami**
  - [illegible]
- **Milne Point Unit**
  - [illegible]

Overall Summary

- **Delivery of Objectives**
  - Long term Fitness-for-Service
- **Corrosion Management System**
  - Integration of key elements
    - Remaining wall – Inspection program
    - Rate – Corrosion monitoring
    - Mitigation – Corrosion inhibitor
- **2006**
  - Review ALL strategies
  - Increase Staff
  - Dedicated ACT Team

BP Leaks 2006

ADEC Meet & Confer XI
3rd May 2006

2006 Leak/Spill Detail

- **11-10**
  - Leak detected – January
  - Seawater
  - Internal corrosion
  - No Volume Estimate
    - Shut in – No repair to date
- **OT21**
  - Leak detected – March
  - Processed Oil
  - Internal corrosion
  - ~5,000 bbls
    - Shut in

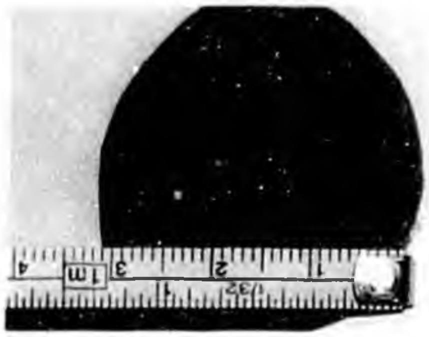
2006 Leak/Spill Detail

- **04-13**
  - Leak detected – April
  - Produced water line
  - Under Investigation
- **R-Pad – 3" R-19 GLT**
  - Leak detected – April
  - Gas lift
  - External corrosion
  - Small gas release
    - Shut in – No repair to date

GC21 – Oil Transit Line Leak

GC2 to GC1 pipeline spill site

Impression of hole, circa 0.25"x 0.5"



GPB Oil Transit Lines

- **Large diameter transmission lines**
  - 4 pipelines
  - 22 miles total length
  - Diameters
    - 1-16", 1-30", 2-34"
- **Transport processed crude oil**
  - From separation facility to Pump Station 1
  - 0.35% BS&W
- **Operating pressure is < 20% SMYS**

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	MAOP	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
WOA OTL	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
		Total	22	Miles		

Oil Transit Lines – Corrosion Management

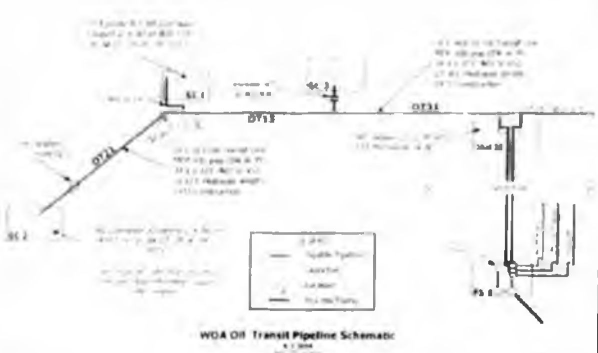
- **Internal**
  - Mitigation
    - CI injected at Wellhead, carryover into flow & OT
    - Final stage separation 15psig (removes CO_2), 0.35% BS&W
  - Corrosion Monitoring
    - Weight loss coupons and ER probes
    - Spot UT/RT and ILI
- **External**
  - Mitigation
    - Replace pipe insulation at corroded locations
  - Corrosion Monitoring
    - ILI, tangential RT, GUT (cased pipe)

WOA Oil Transit Line Design & Operations Data

- **Four segments**
  - GC2 to GC1 – OT21
  - GC1 to GC3 – OT13
  - GC3 to Skid50 – OT31
  - Skid50 to PS1 – OT501

Outside Diameter (OD - inches)	34"
Nominal Wall Thickness (inches)	0.375" - 12% Tolerance
Material Specification	API 5L X52 (standard material)
Design Code	ASME B31.4
Year of Commission	1977
Design Pressure	720 psig
Current MOP	500 psig (de-rated in 1999)
Typical Operating Pressure	70-100 psig
Normal Operating Pressure % SMYS	8.72%
Fluids	Sales Specification Crude Oil -BS&W 0.35%

WOA Oil Transit Line – Schematic



WOA OTL, 5 Year Inspection History

- **January, 2001 to December, 2005**
- **OTL was monitored annually and appeared to be manageable**
- **"Bypass" was removed when monitoring data showed "end of life"**
  - The same practice would apply to any other pipeline system

	OT 21	OT 13	OT 31	OT 31 Bypass	OT 501
Total No. of Inspections (Radiographs & Ultrasonic)	124	96	172	130	57
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
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[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]			[illegible]	[illegible]	[illegible]
[illegible]					
[illegible]			[illegible]		[illegible]
[illegible]			[illegible]		[illegible]
[illegible]			[illegible]		[illegible]
[illegible]			[illegible]	[illegible]	[illegible]
[illegible]					

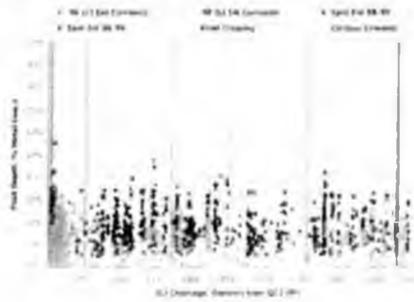
NOTE: OT 31 Bypass was [illegible]

WOA OTL Internal Inspection History

- **Pipeline actively inspected throughout service life**
  - 1988 identified 1st internal corrosion
  - 1990 In-Line Inspection
    - 20-30% internal corrosion
  - 1991-1998 continued annual monitoring
  - 1998 2nd In-Line Inspection
    - Corrosion moderate – CI program in place ~1995
    - External (CUI) more of a concern than internal
  - 1999-2004 continued annual monitoring
    - No significant increases
  - 2004 detected increased corrosion activity in GC2 PO Plant Piping
  - 2005 added scope & frequency to Inspection
    - 37 to 108 inspections
    - Included bi-annual inspection monitoring
    - Planned in-line inspection for 2006 based on 2005 UT inspections
  - 2006 Pipeline Leaked

OT-21, 1998 ILI & Verification

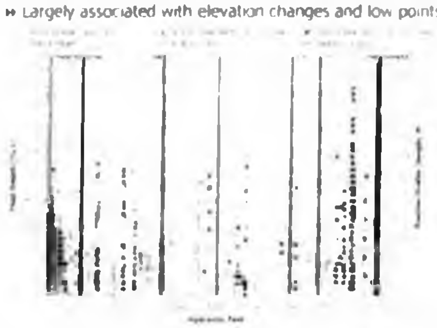
- **Corrosion degradation after ~21 years**
  - Moderate internal and external corrosion damage, Pipe FFS



1,016 Ultrasonic and Radiographic Inspections
March 3rd to April 1st 2006

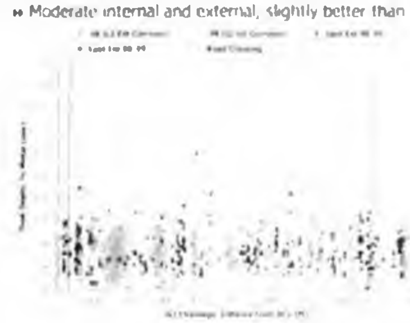
OT-21, 1998 ILI & Post Leak Data

- **Significant internal corrosion increases**
  - Largely associated with elevation changes and low points



OT-13, 1998 ILI & Verification

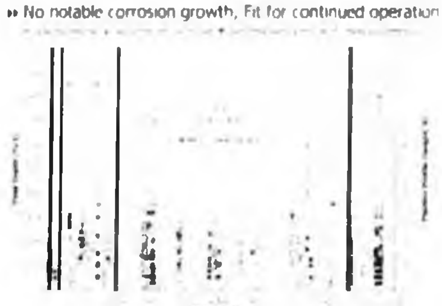
- **Corrosion degradation after ~21 years**
  - Moderate internal and external, slightly better than 21 segment



273 Ultrasonic and Radiographic Inspections
March 4th to March 23rd 2006

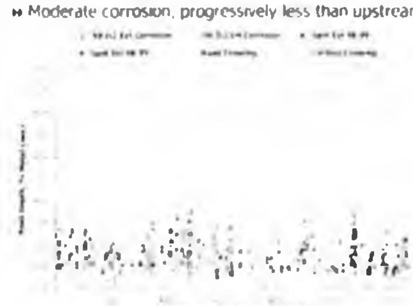
OT-13, 1998 ILI & Post Leak Dat

- **No appreciable increases to existing damage**
  - No notable corrosion growth, Fit for continued operation



OT-31, 1998 ILI & Verification

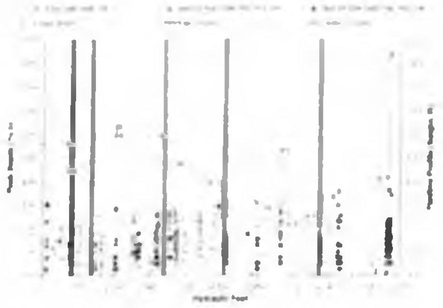
- **Corrosion degradation after ~21 years**
  - Moderate corrosion, progressively less than upstream



421 Ultrasonic and Radiographic Inspections
March 4th to March 23rd 2006

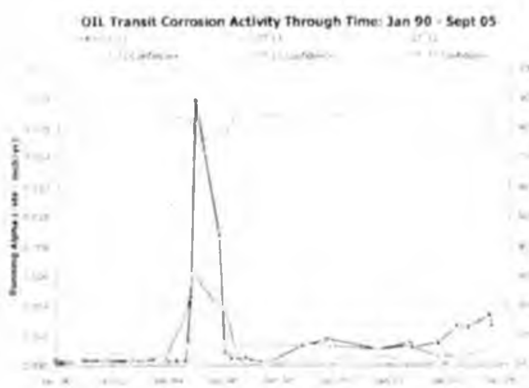
OT-31, 1998 ILI & Post Leak Data

- **No appreciable increases to existing damage**
  - No notable corrosion growth, Fit for continued operation



Rapid increase in Corrosion Rate in WOA OT21 Section after 3Q 2005

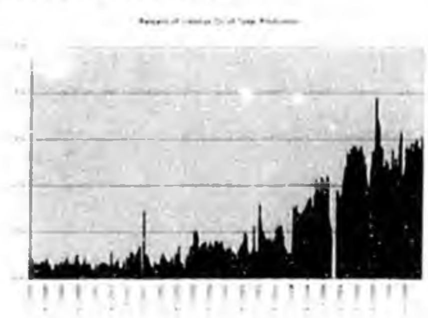
-not seen in other WOA OT sections or pipelines



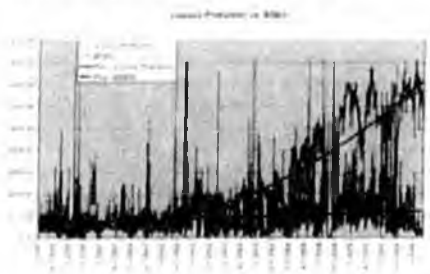
Investigation

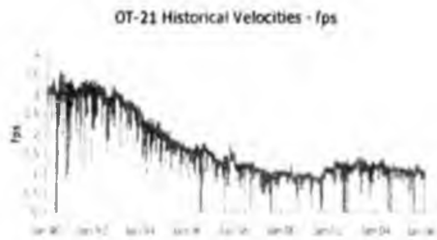
Preliminary Findings

Viscous oil production

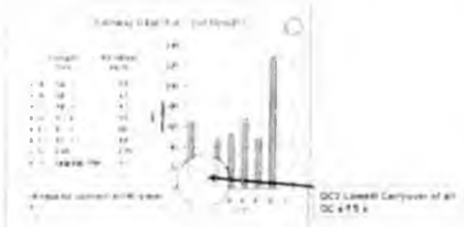


Viscous oil production & BS&W

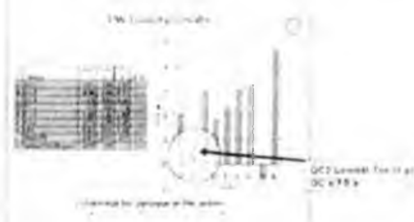




Inhibitor carry over test Feb 2005



Produced water toxicity to bacteria



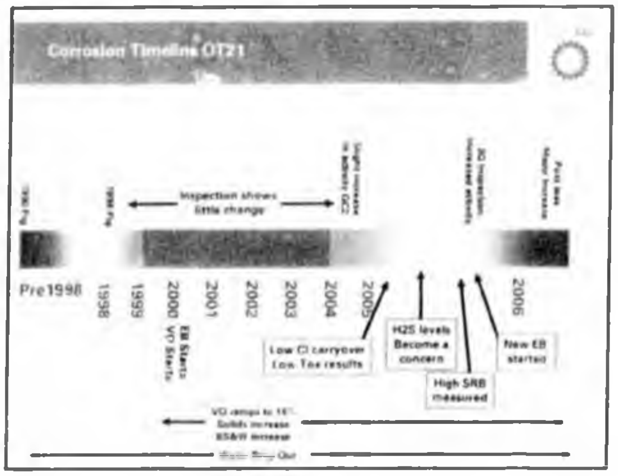
Increased presence of H2S, July 2005

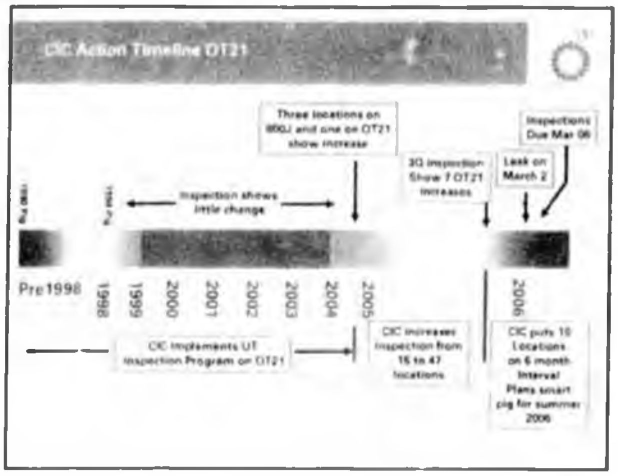
GC H2S Sample Log Sheet

Location	[illegible]	[illegible]	[illegible]	Date	Sample Method
Gas Off B Slug Catcher	30	30	30	7.1.05	direct gas
Gas Off C Slug Catcher	20	[illegible]	20	7.1.05	direct gas
Water Off C Slug Catcher	140	140	[illegible]	7.1.05	gas off the water [illegible]
Water Out of A Dehy	180	150	[illegible]	7.1.05	gas off the water [illegible]
Water Out of B Dehy	50	30	30	7.1.05	gas off the water [illegible]
Water Out of C Dehy	25	30	30	7.1.05	gas off the water [illegible]
Water Out of D Dehy	275	350	325	7.1.05	gas off the water [illegible]
Water Out of T-6512	500	400	400	7.1.05	gas off the water [illegible]
Water Out of T-7700	600	625	600	7.1.05	gas off the water [illegible]
Vent Gas Common gas	175	200	200	7.1.05	direct gas
Discharge of Booster Pump #401	400	500	600	7.1.05	gas off the water [illegible]
Discharge of Booster Pump #402	275	350	300	7.1.05	gas off the water [illegible]
Dirty Water Tank Gas Phase	175	225	200	7.1.05	direct gas

Possible Factors

- Low Velocity
- BS&W Excursions
- Reduced Corrosion Inhibitor
- Reduced Water Toxicity
- Increased Viscous Oil (~15%) at GC2
  - Fine Sand
- Increased H2S in GC2 Vessels





Summary – Oil Transit Lines

- **Corrosion inspection programs are in place**
  - Above ground pipelines
  - Inspection incorporates frequent Spot UT/RT (RBI)
  - Complimented with ILI
- **OT21 Failure**
  - Rapid mechanism
    - Corrosion management programs detected and responded to change in OT21 activity
    - Pipeline leaked before the significance of the corrosion activity was fully understood
    - Mechanism still under investigation
- **Remainder of Oil Transit pipelines are Fit-for-service**
  - Demonstrated by RBI pre/post leak inspections
- **Going forward**
  - Implement Maintenance/cleaning pigging
  - Regularly scheduled In line inspection (5 yr Max)
  - Review ALL strategies

Acronyms

CPA

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Commitment To Corrosion Monitoring Overview

presented to the

Alaska Department of Environmental Conservation

9th Meet & Confer

May 3, 2006

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Program Enhancements

- Linear array very valuable for evaluation of 12-16" diameter water-packed Cross Country (CC) lines.
- Pigging program for CC WI lines standardized with disk/brush/disk pigs & monitoring of pigging returns.
- Monitoring of biocide application with residual measurements initiated.
- The number of below-grade piping circuits excavated tripled from 2004 to 2005.
- Rope Access Technology (RAT) added to inspection capabilities.
- The extent of tangential radiographic (TRT) inspection expanded to include 12 O'clock position; a 360-degree inspection is performed where possible.

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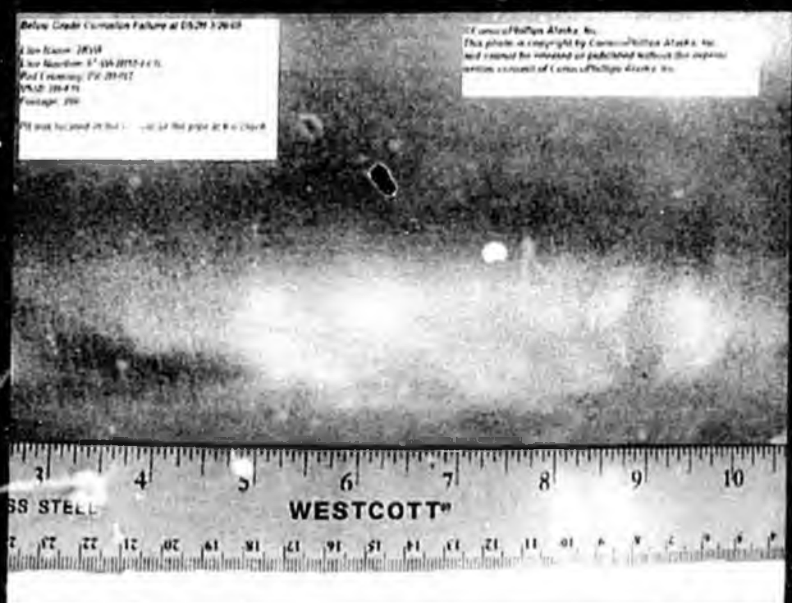
Spills/Incidents

- On 3/26/05 At ~10:45 AM, a leak from a ¼ inch X ¼ hole was discovered on the below-grade section of a 6" CC WI line at DS2H pad.
- The leak was discovered during a routine corrosion survey.
- Original estimate of **113,000 gallons**, eventually revised to 51,198 gallons. The approx. 2-acre spill was a mixture of PW and SW.



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Spills/Incidents

- Line put in WI service in 1989
- Initial inspection in 2001 w/ 5% RTR (463') showed 9 of 12 segments had no damage. Scattered internal pitting in 3 segments - 17% wall loss max.
- Below grade long range inspection for external corrosion on this line by Profile Technology Inc. (PTI) in July of 2001; no indications.
- Between 2001 and the time of the leak, 7 recurs by manual inspections at 3 locations showed minor increases and 35% max. wall loss by RT.
- In 2005, another 5% RTR inspection (614') showed widely scattered internal pitting in all 16 segments inspected with 29% max. wall loss.

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Spills/Incidents

- Commingling of PW & SW caused additional solids deposition and rendered corrosion inhibition less effective
- Coupon mpy rates increased post 2000 due to the above
- Under-deposit/MIC corrosion accelerated due to nutrients from SW/PW
- Maintenance pigging ineffective in removing solids
- The line was subject to low flow velocities

ADEC & BP were represented in the Physical Cause Analysis Team

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Lessons Learned & Path Forward

- Fourteen Near, Medium and Long-term recommendations from Physical Cause Analysis under various stages of implementation
- Commingling of PW & SW at CPF2 is suspended; plans to commingle at CPF3 is now on HOLD
- More aggressive maintenance pigging with disk-brush-disk combo in operation; pigging returns (TSS) monitored
- Risk-based inspection protocols further strengthened with more frequent interval inspections
- TWI technique for internal & external long range inspection prioritized field-wide
- Recent data indicate lines are 'cleaning up' and corrosion rates have receded

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Other Spills/Leak

- 3JPO 12" CC line leaked on 10/26/2005 at saddle weld-pack - external corrosion
- Leaks at 10 O'clock position on line – corrosion was 360 degrees around
- Weld-pack previously inspected 12/2001 - no corrosion or water detected
- This weld-pack was not scheduled for re-inspection under the existing CC line interval inspection program.
- TRT Program Guidelines changed – Require Top and Bottom inspection over entire CUI length when medium wet or damaged insulation – An increased CUI inspection frequency has been proposed

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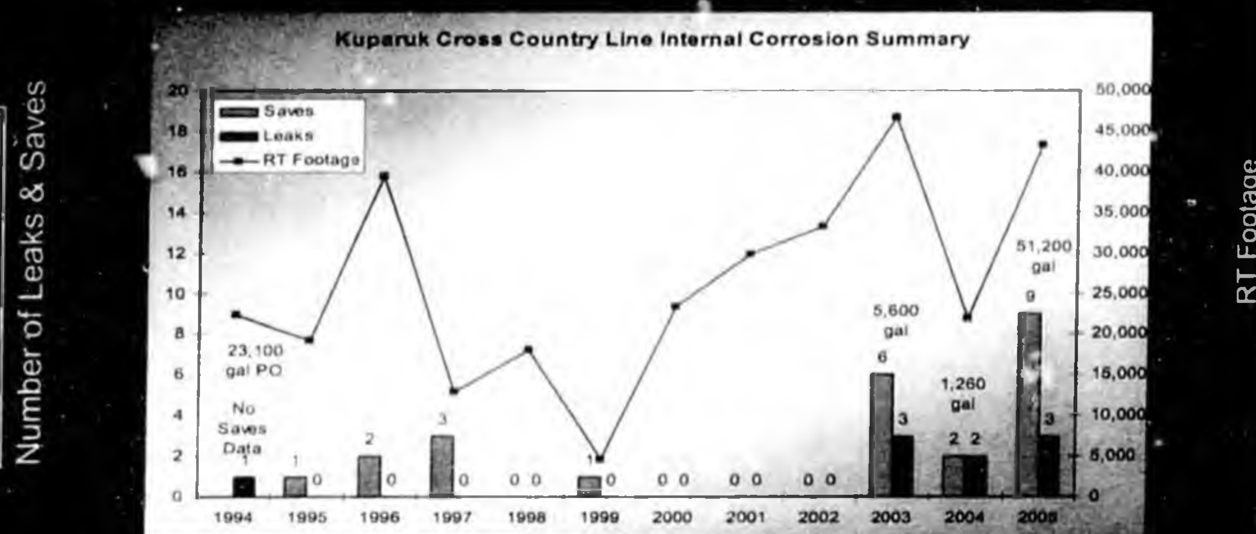
Internal Inspection

2005

- ✓ Completed all 2005 goals except for 30" SWI Line Smart Pig.
- ✓ Over 43,000 ft over 160 lines inspected (RTR and RT)
- ✓ Completed baseline survey of on-pad deadlegs.
- ✓ 3 Leaks (1 water injection, 2 production), 9 Saves (5 WI, 4 PO). WI leak caused by MIC.

Internal Corrosion Spills - Cross Country Lines

1994 Spill	24" 1Y	Crude Oil
2003 Spill	6" 3R	Sea Water
2004 Leak	6" 3R	Sea Water
2005 Spill	6" 2K	Mixed Water



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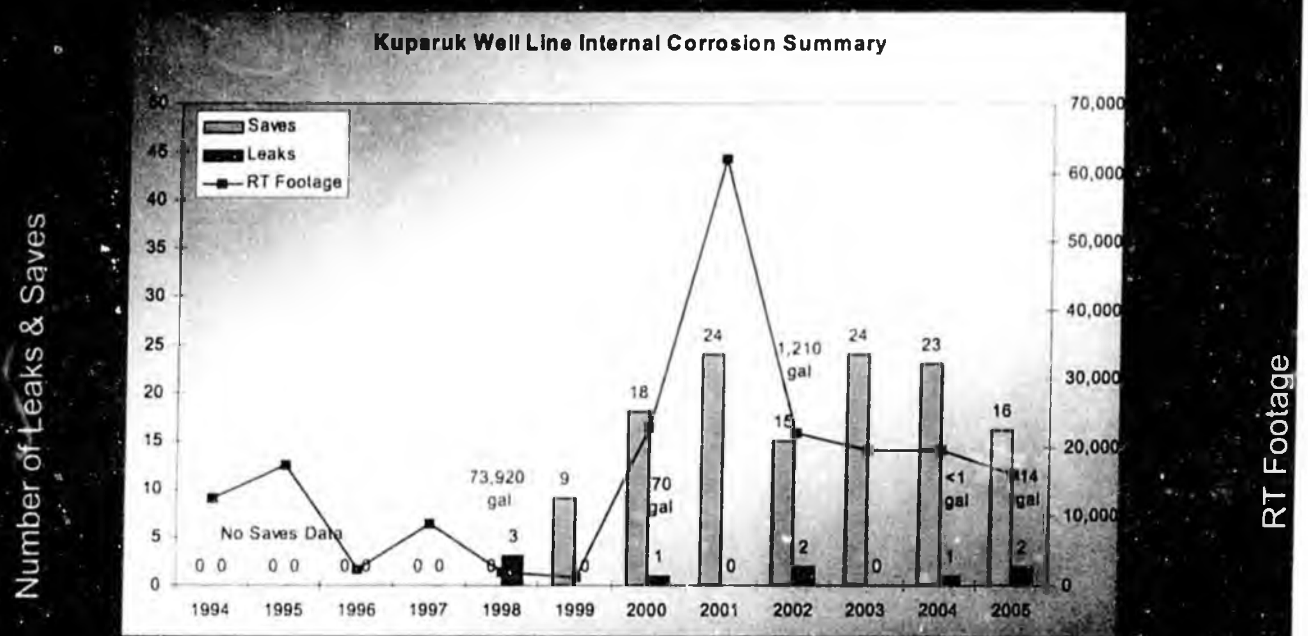
Internal Inspection

- ✓ Completed all 2005 goals.
- ✓ Roughly 16,000 ft of over 300 lines inspected (RTR and RT).
- ✓ 18 lines required repair (11 injection, 7 production).
- ✓ 2 Leak, 16 Saves. Leaks due to under-deposit corrosion and erosion.

2005

Internal Corrosion Spills – Well Lines

[illegible] Spills	1L-[illegible] 6" WI
	1L-3 6" WI
	1A-9 6" WI
200[illegible] Spill	1G-8 6" PC
2002 Spills	2A-1[illegible] 6" PC
	2T-13 6" PC
2004 Spill	1Y-02 3" WI
2005 Spill	1G-09 6" WI



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Internal Inspection

Cross-Country Lines	
Goal	***Status***
Continue Recurring Interval Inspection Program, KDR Program and TFS Program	On Schedule
Smart pig 30" SWI line in '06.	Deferred from 2005. Evaluating feasibility of smart pigging 12-inch WI lines.
Well Lines	
Continue Recurring Interval Inspection Program, KDR Program and Erosion Program	On Schedule

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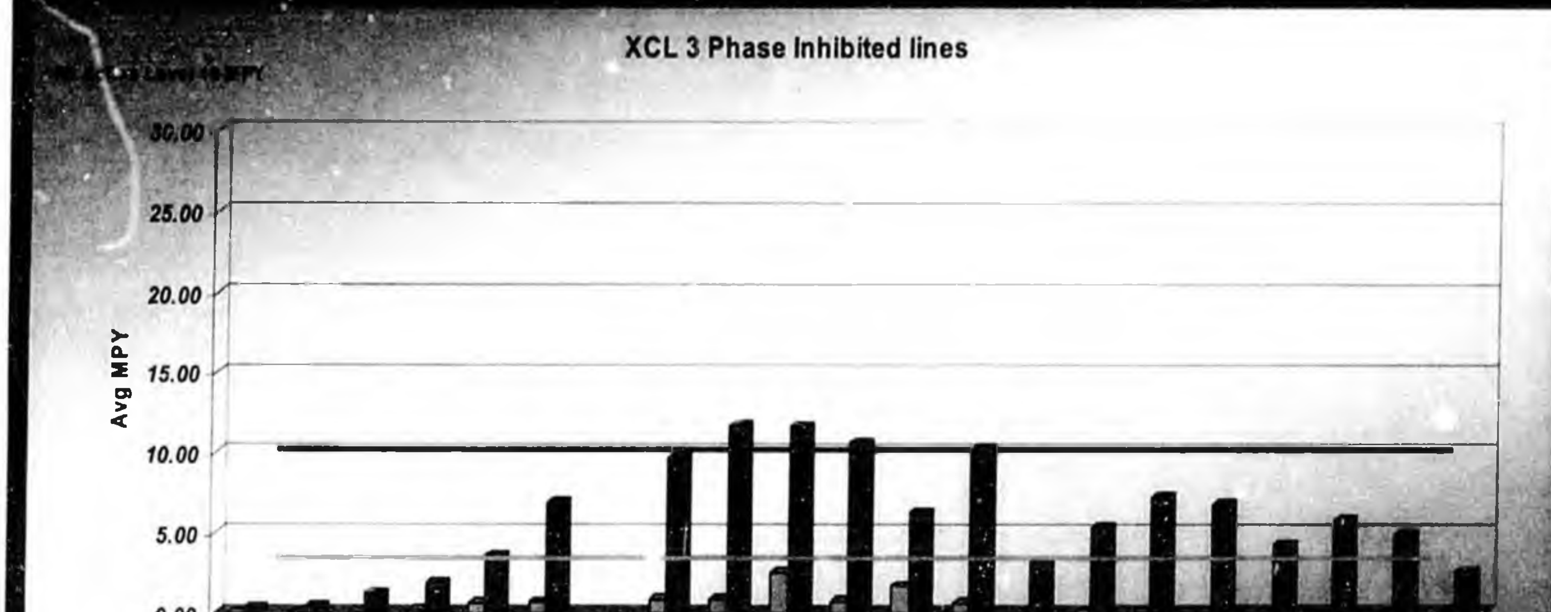
Monitoring/Mitigation

Corrosion Inhibition is Effective

2005



	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Gen	0.01	0.06	0.16	0.23	0.65	0.74		0.90	0.89	2.59	0.76	1.76	0.71	0.07	0.05	0.12	[illegible]	0.05	0.07	[illegible]	[illegible]
Pit	0.31	0.48	1.29	1.89	3.63	6.91		9.68	11.70	11.67	10.67	6.30	10.23	3.20	5.34	7.23	6.82	4.31	5.77	[illegible]	[illegible]

- ✓ Coupon average rates remain below thresholds.
- ✓ 96% of 3-Phase Production CC lines have ER probe rates < 2 mpy.
- ✓ Inspection continues to support monitoring with 419 corrosion-rate monitoring (CRM) inspections conducted, with one minor increase found
- ✓ All 3-Phase Production CC lines with probe, coupon, or inspection corrosion rates above thresholds had corrective action taken.

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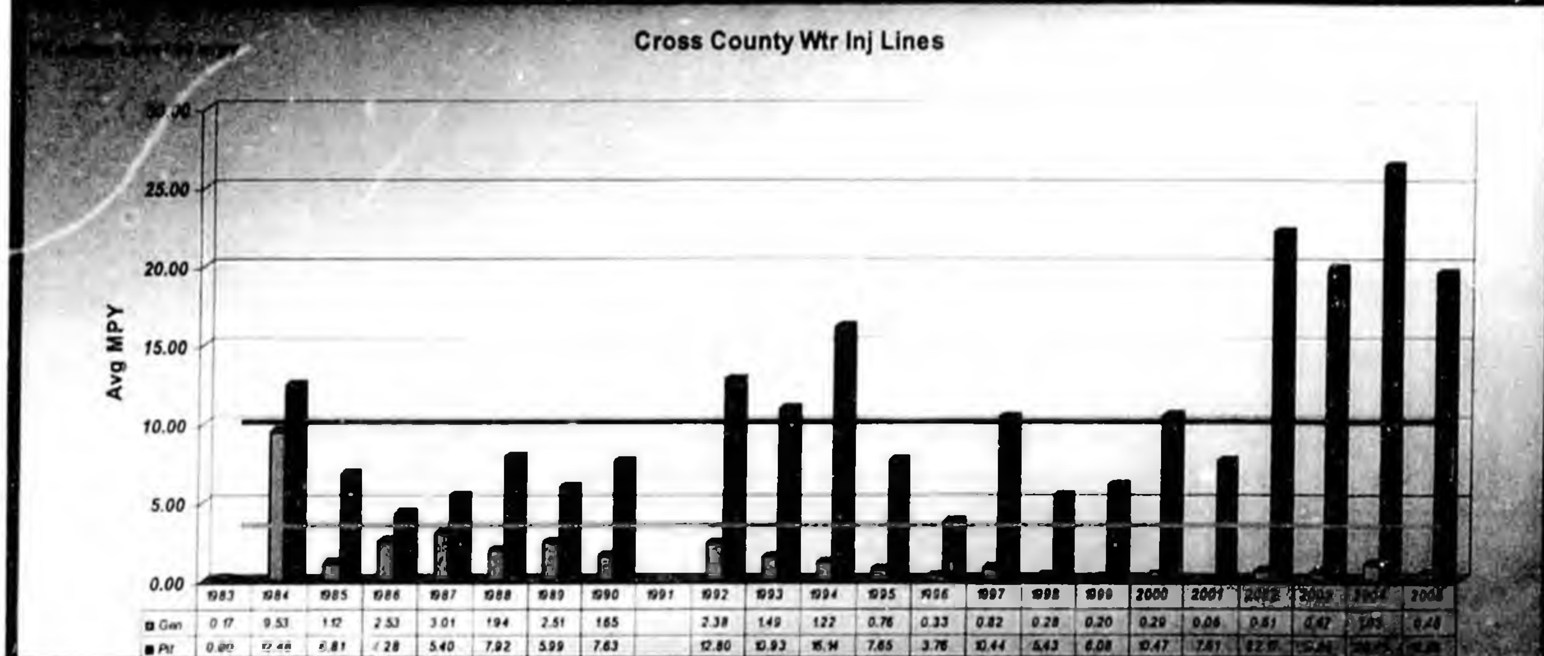
Monitoring/Mitigation



2005

- ✓ Coupons changed after CPF2 split the SW & PW, were pulled 3 months later with pitting rates dropping on all header coupon locations from a high of 185 mpy to a high of 18 mpy.
- ✓ Inspection continues to corroborate monitoring data
- ✓ Continuing to adjust and analyze mitigation program with adjustments to pigging at all facilities and additional adjustment to STP biocide treatment.

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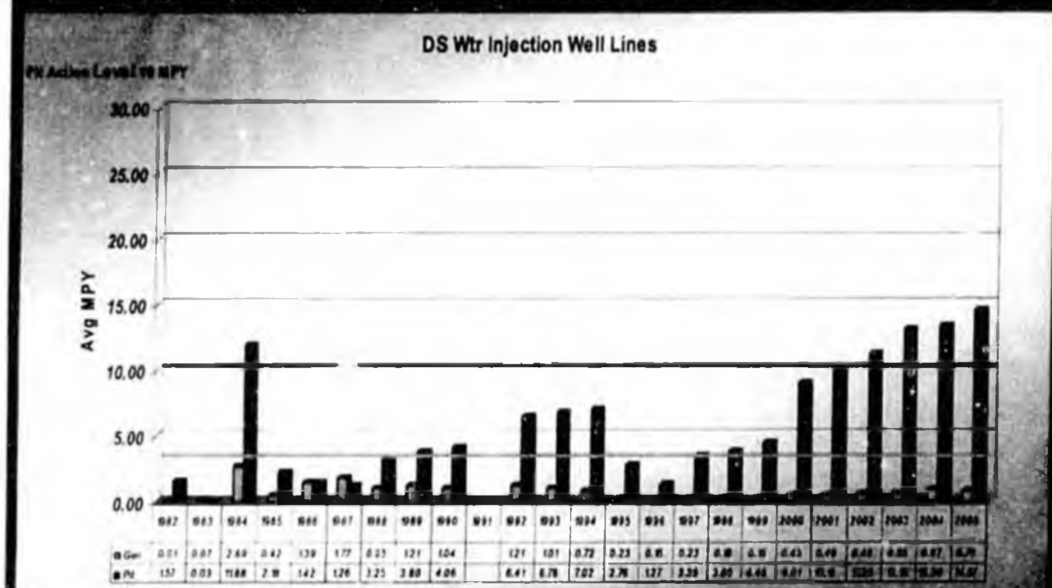
Monitoring/Mitigation

2005



- ✓ Coupon average corrosion rates remain below threshold levels
- ✓ Inspection supports lower 3 phase system corrosion rate with lower number of repairs identified in this system
- ✓ Inspection continues to identify lines requiring repair / replacement.

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Monitoring & Mitigation

Monitoring & Mitigation	
Goal	***Status***
Continue testing for more effective corrosion inhibitors	• Field test of Baker RE5273 started moved from DS1R to next phase large scale testing at CPF2 Drillsites 2U, V and W • Next test at DS1R should begin mid summer
Continue improvements to all three CPF Water injection System treatment programs	•Biocide injection residuals along with Total Suspended Solids and serial dilution are being monitored to verify mitigation system performance •New pig sampling position created
Improve Field wide Maintenance Pigging Program	•New field wide maintenance pigging recommendation issued and currently being implemented
Install additional monitoring locations in water injection system.	•Both additional coupon locations and inspection corrosion rate monitoring (CRM) locations are being established and installed.

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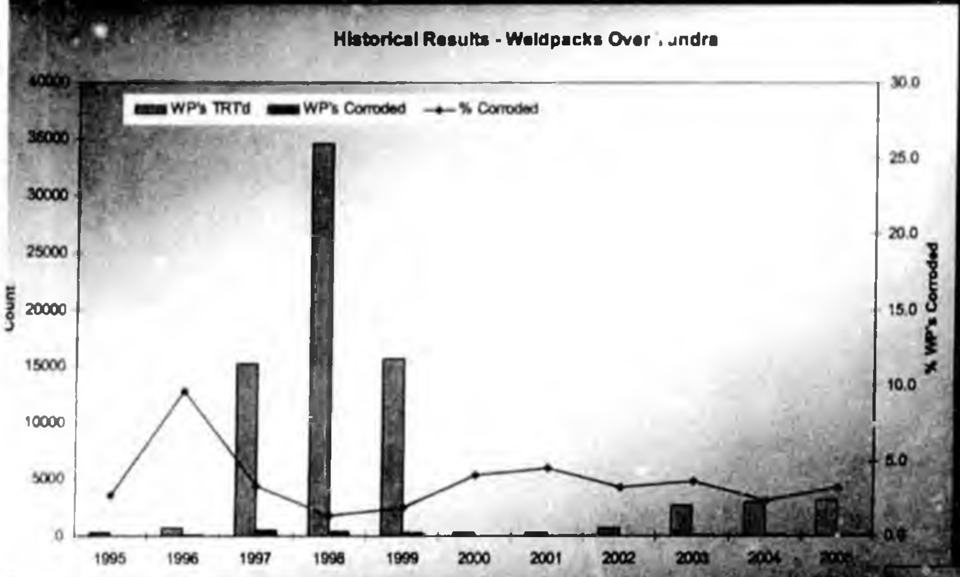
External Inspection

2005

Mature Ongoing Program

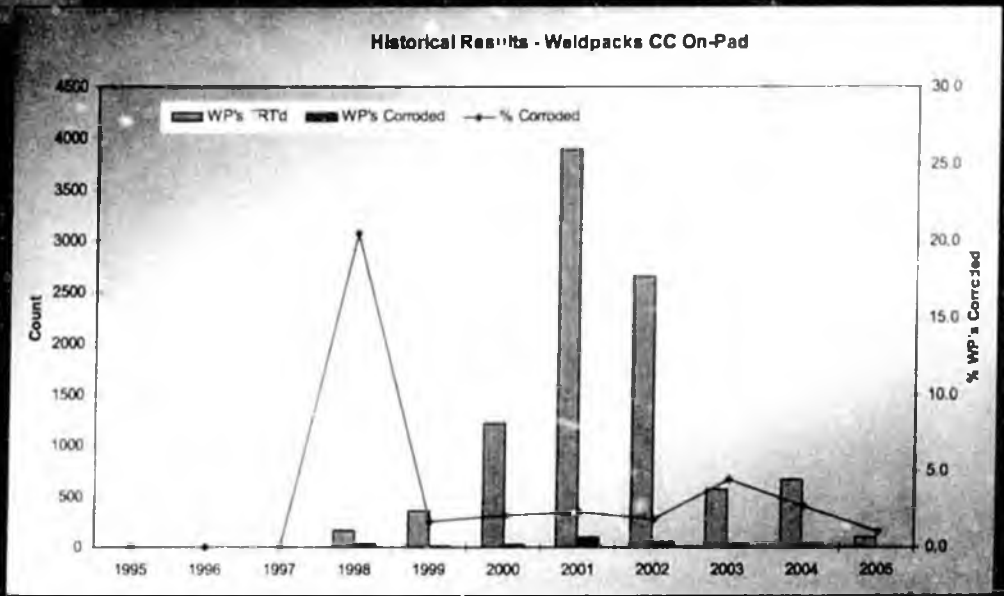


⇐⇐

- ✓ 3205 weld packs TRT inspected.
- ✓ 102 (~3.2%) had corrosion. One location required a temporary sleeve (DS3K-PO).

CC Lines On Pad ⇒⇒

- ✓ 94 weld packs TRT inspected.
- ✓ Only one location was found to have corrosion (~1.%). No repairs required.



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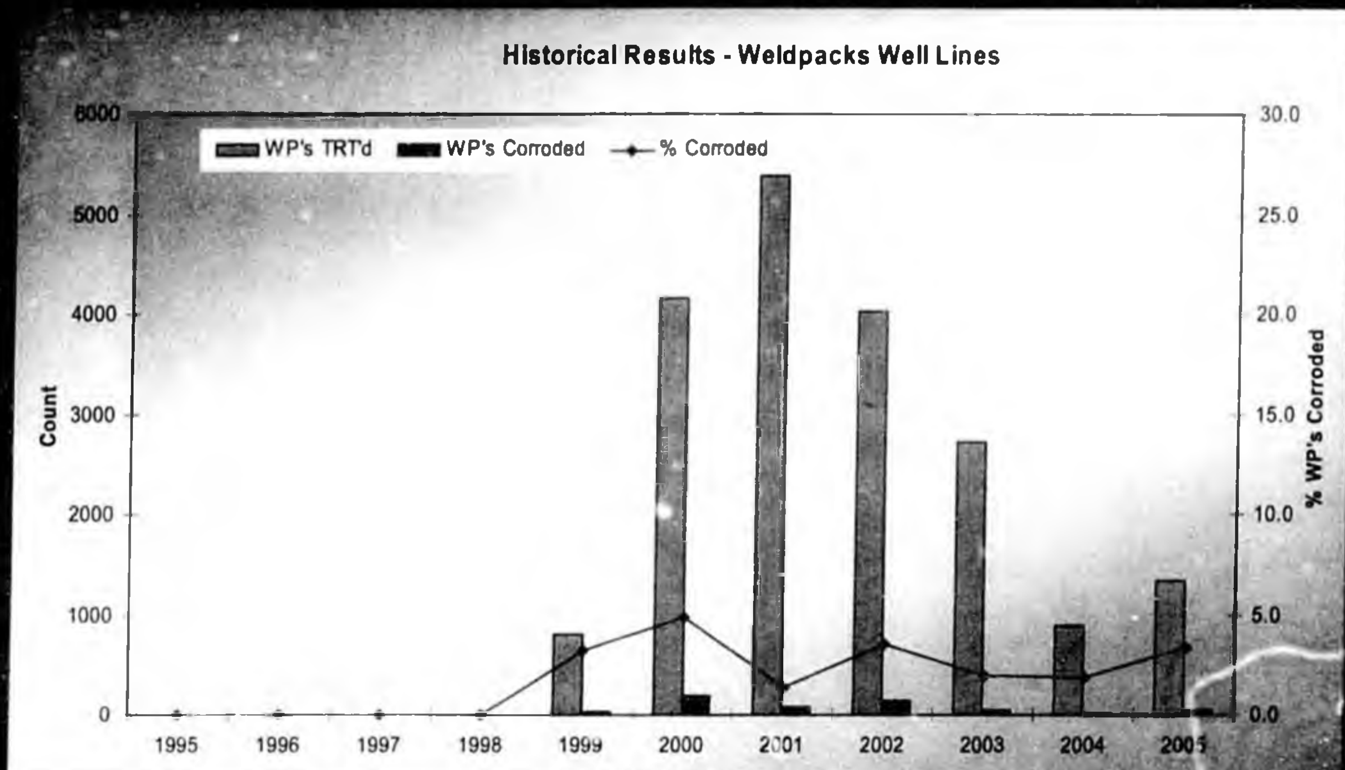
External Inspection

2005

- 1347 weld packs T.RT'd. Baseline inspections were completed in 2004. 2005 was the first year of our recur inspection program.
- 46 (~3.4%) were corroded. No repairs were required. The corroded weld packs were refurbished.



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External Inspection

Cross-Country Line Corrosion Under Insulation Inspections	
Goal	***Status***
Cross-Country On/Off - Pad	
TRT 100 Weld Packs to Evaluate the Tarn WP Design	On Schedule
TRT 100 Weld Packs refurbished with Denso Tape to monitor performance	On Schedule
TRT approximately 3950 Weld Packs (based on seven lines)	On Schedule
Well Line Weld Packs	
TRT approximately 1500 Weld Packs (based on 130 lines)	On Schedule
Misc.	
Complete Buffer Spike Report and Issue Recommendations.	On Schedule

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Inspection Results

2005

- ✓ Completed all 2005 goals.
- ✓ Inspected 127 priority 1 locations with TWI (double that of 2004).
- ✓ Inspected all priority 2 locations.
- ✓ 24 cased pipes excavated (goal was 5 to 9)
  - Four repairs, 2 replacements (1 CUI, 1 int), 2 sleeves (1 CUI, 1 combo).
  - Twenty had only minor or no corrosion.
  - Final Tally: 24 Refurbishments, 3 Saves, 1 Leak
- ✓ Completed Annual Visual Casing Inspection - cleared all obstructions.

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Inspection Results

Note: The only uninspected priority 1 lines are those that are newer than 10 years old

All Lines in GKA Inventory	Inspected Through 2005	Un-inspected Lines	Total	Previously Uninspected Lines Inspected in 2005
Priority 1	529	58	587	2
Priority 2	118	0	118	0
Priority 3	67	0	67	0
2005 Total Inventory	714	58	772	0

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Inspection Results

Goal	Status
Inspect ~ 130 priority 1 pipes using TWI.	On Schedule
Inspect all priority 2 circuits (visual & gas sniff)	On Schedule
Prioritize and excavate ~24 circuits	On Schedule
Continue cooperative effort with equipment vendors, COP R&D and BP to improve current technology and explore new technologies.	On Schedule

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Spills/Incidents

2005

External Corrosion

- ✓ 3JPO

Internal Corrosion

- ✓ 2KWI CC line spill
- ✓ 1G-09 WI well line spill due to under-deposit corrosion

Other Structural Concerns

- ✓ 3I GL Wind Induced Vibration

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Alpine Overview

2005

Alpine: 1st production in November of 2000

Two Drill sites on production

Internal Corrosion

- ✓ Production lines: Coupon rates all less than 2 mpy
- ✓ 2600 ft of a X-C production line inspected – no damage.
- ✓ Water Injection lines: 18 mpy pitting on a single coupon, remainder: < 10mpy threshold. All general corrosion rates below 1 mpy
- ✓ 32 Well lines inspected: no damage
- ✓ 330 ft of the CD2 WI line inspected, but resolution was poor

2005

External Corrosion

- ✓ Improved design standards incorporated into 'new construction'.
- ✓ Two direct buried lines identified; no CP or external coating. Excavations and inspections were performed to assess the integrity of the lines and placed on a very conservative inspection schedule.
- ✓ Spot TRT on 10 well lines. No damage.

No corrosion related leaks since start-up.

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Inspection - WNS

2006 Goals

Goal	*Status*
Inspect 20 lines for CUI	None yet – pending the end of the winter construction
Perform interval inspection on 20 well lines	None yet – pending the end of the winter construction season
Layout and API-570 visual for lines 5 yrs old	On schedule

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THE END

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Glossary of Terms

Equipment Classification:

Well Line – Pipe from the wellhead to the Drill Site manifold. For production wells, a well line handles the flow from a single well prior to commingling with fluids from other wells and transportation to the Central Processing Facility. For water injection wells, a well line handles the water flow going from a common manifold to a single wellhead.

Cross-Country Line – Pipe from the Drill Site manifold to the Central Processing Facility (CPF).

Below-Grade Location – That portion of a single pipeline, which crosses underneath a road or other earthen feature at a single location. The linear extent of the location consists of the length of pipeline between casing ends.

Service Definitions:

Three-phase Production – Basic reservoir fluids (oil, water, and gas) produced from down hole through to the CPF. Typically sees changes in temperature and pressure only from reservoir changes and are essentially un-separated.

Seawater (SW) – Water from the Beaufort Sea that has been treated at the Seawater Treatment Plant (STP). Note that seawater treatment at the Kuparuk STP consists of filtration; oxygen stripping using produced gas, and biociding.

Produced Water (PW) – The water separated at the CPF from three-phase production.

Mixed Water (MW) – Produced water and seawater that have been commingled.

Gas – Generic term for the different gas systems that transport dry (no liquids) gas between facilities. Includes fuel gas, artificial lift gas, and miscible Injectant.

Produced Oil – The liquid hydrocarbon separated at the CPF from three-phase production.

Inspection Terminology:

CRM – Corrosion rate monitoring.
UT- Ultrasonic testing
RT – Radiographic testing
RTR – Real time radiographic testing
TRT – Tangential radiographic testing
PTI – Profile Technologies Inc. (Electro magnetic inspection)
TWI – The Welding Institute (Long range UT)
KDR – Known damage recur inspection
TFS – Turbulent Flow Survey
WOL – Weld-O-Let

PRUDHOE BAY CORROSION CRISIS, 8/18/06 (FILE 6)

BP Exploration Alaska
Commitment to Corrosion Monitoring
Annual Reports 2000 – 2005

Charter for Development of the Alaskan North Slope
Section II.A.6

Volume 1 of 2

2000

Annual Report to Alaska Department of Environmental Conservation

Commitment to Corrosion Monitoring

Year 2000

BP Exploration (Alaska) Inc.

Prepared by

Corrosion, Inspection & Chemicals Team, BPX(A)

March 2001

Executive Summary

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

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

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

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

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

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

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

FOREWORD

This report is divided into 2 main parts.

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

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

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

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

Contents

Section A: Charter Agreement Corrosion Related Commitments

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

Milestones/Timing

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

Item Complete.

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

Item Complete.

11/15/00 - Final endorsement of Work Plan

Item Complete.

3/31/01 - 1st Annual report due

Item Complete.

4/30/01 - 1st Meet and Confer

10/31/01 - 2nd Meet and Confer

Annual Timetable

March 31st Annual Report

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

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

PART 1

Greater Prudhoe Bay

Business Unit

Section B - GPB
Corrosion Monitoring Activities

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

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

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

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

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

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

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

Table 1: Summary of Well Pad / Drill Site Pipelines

Service	No. of Lines	Miles of Piping	No. of Internal Inspections	No. of External Inspections
Gas Injection	35	3	0	72
Miscible Injection	107	1[illegible]	12	389
3 Phase Production	1088	266	6956	3192
Gas Lift	675	160	15	2537
PW/SW/WAG Inj	180	42	2988	1442

Table 2: Summary of Cross Country Pipelines

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

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

Table 3: Smart pig inspections

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

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

Table 4: Number of Corrosion Monitoring Coupons

Year	Cross country	Well Lines	PW	SW	GL & Inj	Total
1995	1,324	6,195	1,125	750	4	9,536
1996	1,489	7,676	1,140	744	10	11,193
1997	1,467	7,784	1,207	968	10	11,574
1998	1,490	7,582	1,138	732	10	11,09[illegible]
1999	1,425	6,875	1,010	782	10	10,238
2000	1,371	5,855	816	782	10	8,970

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

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

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

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

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

Table 5: Corrosion Monitoring Probes

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

Section C - GPB
Coupon and Probe Corrosion Rates

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

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

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

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

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

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

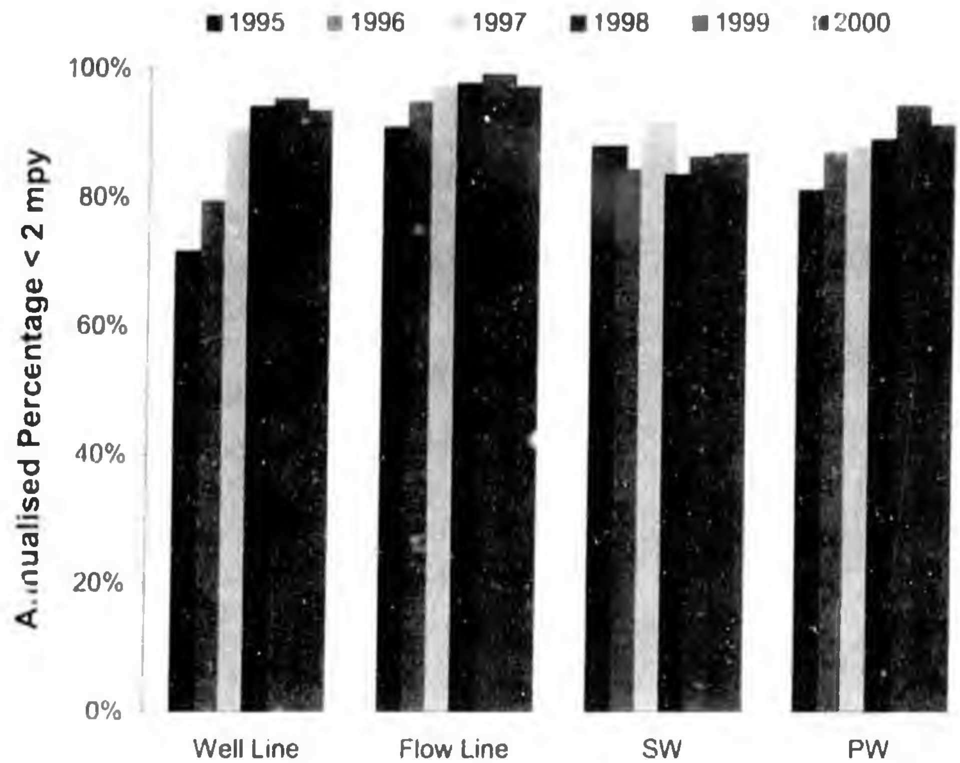

Figure 1: Summary of corrosion coupon data 1995 to 2000

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

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

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

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

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

Section D – GPB
Chemical Optimization Activities

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

The development of new corrosion inhibitors starts in the R&D laboratories of the chemical suppliers, with promising products being tested under field conditions using dedicated test facilities at GPB. Typically one or two new products are tested each month on a small scale test, using an individual well line with each test lasting 10 days and using approximately 100 gallons of test chemical. If this is successful, the product is considered for a large scale test, which involves converting between 1 and 3 well pads to the test product for 90 days and using 20 to 40,000 gallons of test chemical. This enables corrosion probe, coupon, and inspection data to be generated to verify the test product's effectiveness as a corrosion inhibitor. It also enables the effect of the product on the oil separation and stabilization process to be tested.

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

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

Table 6: Corrosion inhibitors used across Greater Prudhoe Bay

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

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

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

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

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

Table 7: Water production, corrosion inhibitor usage and concentration

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

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

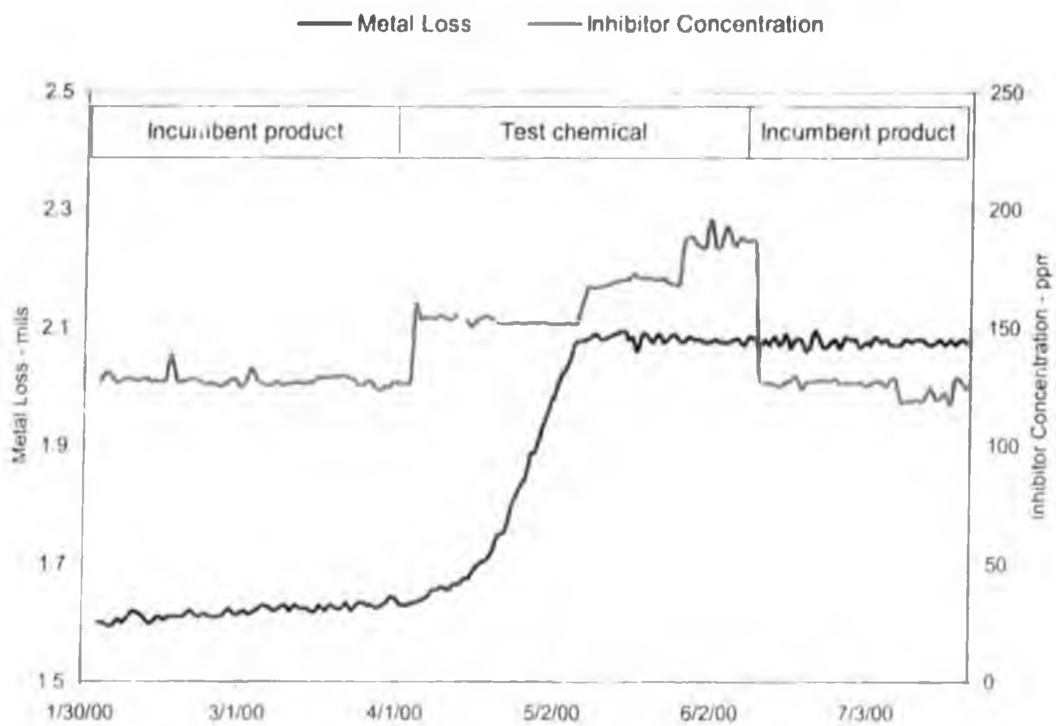

Figure 2: Chemical optimization in response to corrosion probe data

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

Section E.1 External Inspections

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

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

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

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

Section E.1.1 Detection Methods

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

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

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

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

MFL Smart Pig Inspection

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

Eddy Current

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

Methods of CUI detection applicable to cased piping

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

Electromagnetic Inspection

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

Guided Wave

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

Section E.1.2 Program Results

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

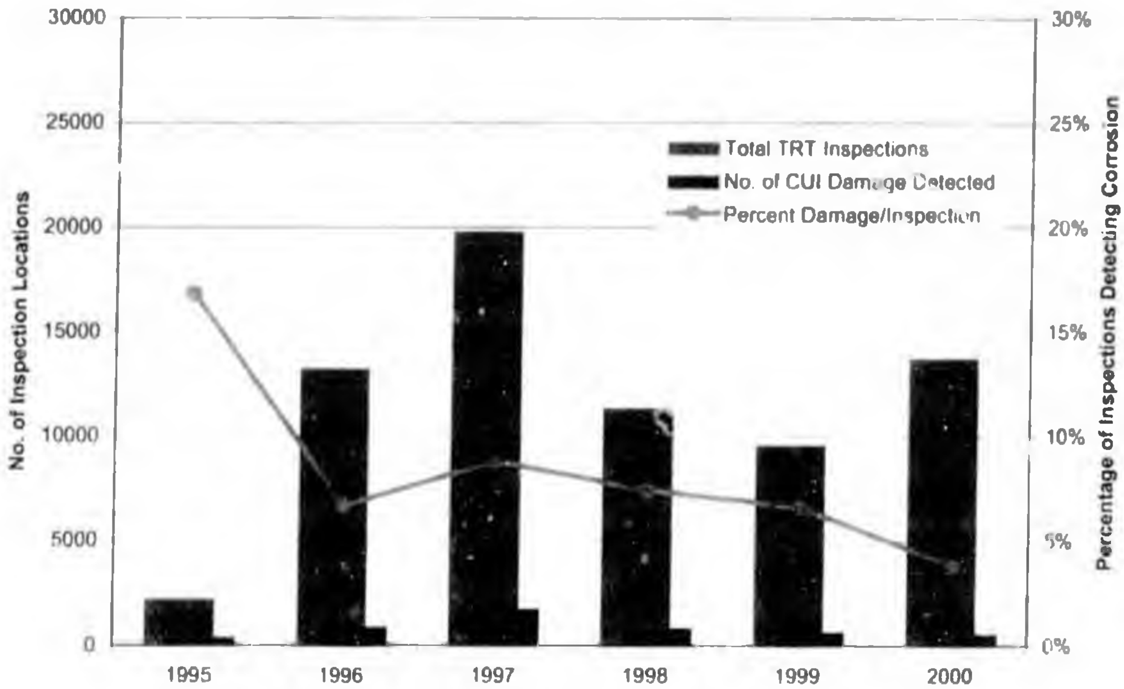

Figure 3: External inspection using Tangential Radiographic Testing

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

Tabie 9: Electromagnetic Inspections

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

Table 10: Guided Wave Inspections

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

Section E.2 Internal Inspections

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

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

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

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