

ALASKA LEGISLATURE COMMITTEES, 2003-2007

11957 SENATE RESOURCES



# Inspection Results

Below Grade Piping



## Doubled Program Work Scope

# 2001

- ✓ **Inspected 228 previously un-inspected locations with PTI/TWI**
  - represents roughly 40% of the population to be inspected
  - approx. half of these locations are regulated “oil” piping
- ✓ **9 cased pipes were excavated (vs. base plan of 4)**
  - 2 had moderate external damage, one was sleeved, one is out-of-service
  - 7 were inspected, with no significant corrosion, and refurbished
- ✓ **10 Refurbishments, 3 Saves, 1 Leak**
- ✓ **Completed Annual visual inspection**
- ✓ **Completed field test of new technology – GUL (Wavemaker)**
  - Evaluation complete, technology not to be adopted



# Inspection Results

Below Grade Pipelining



**2002 Goals**

- ✓ **Complete initial inspection of all significant lines ~ 150 lines**
  - Inspect using PTI and/or TWI technologies
- ✓ **Prioritize and excavate lines as appropriate ~ 5-9 lines**
- ✓ **Work with equipment vendors, Phillips R&D, and BP to improve technology, and explore new technologies**
- ✓ **Test Southwest Research Magneto Strictive System**



# Structural Concerns



## Subsidence Mitigation at the Drill Sites

### **Existing Well Upgrade Program:**

- ✓ **16 floors with riser piping supports were installed in well houses at Drill Site 2M.**
  - Well house floors are supported by the well conductor and provide table riser piping supports.
- ✓ **More than thirty heat tubes were installed at 1A, 1C, 2A, 2K, 2N, 3G.**
  - Heat tubes are used to keep the ground frozen or to re-freeze the ground where it has been thawed.

### **New Wells & Producer to Water Injection Well Conversions:**

- ✓ **New wells had heat tubes, and floors with permanent pipe supports**
- ✓ **Producers converted to water injection wells, and EOR conversions were also upgraded with heat tubes and floors with permanent pipe support**

## Wind Induced Vibration

- ✓ **Identified 4 line segments within design envelope needing dampers – design/procurement in progress**
- ✓ **Engineering is re-evaluating design envelope to ensure validity**
- ✓ **An annual PM is conducted by Engineering and Operations to review all existing PVD installations, and to repair/replace any deficient devices**



# Spills/Incidents



2001

## External Corrosion

- 1HB' VI Water Injection Line Leak, 4/15/01 (Below Grade); previously reported

## Internal Corrosion

- No Leaks in 2001

## Other Structural

- DS 2X Miscible Injectant Line Incident, 12/31/01
  - Through-wall crack, No spill
  - Original weld defect (LF), coupled with WIV was cause
  - Oriented 1 degree outside of PVD Design Envelope

# Spills/Incidents

6" 2A-18 PO Well Line Leak 4/7/02

## Scenario:

- Drill Site Operator discovered oil leaking from the flowline of Well 2A-18, which was immediately shut in
  - The spill occurred sometime between 0430 and 1030 hrs (last walkdown of area done by night operator @ 0430 hrs)
  - Due to the size of the hole, the pressure drop in the line was not enough to alarm or shut in the well
  - Leak area was a pinhole located just above the weld, where a thread-o-let used for Cosasco fitting access was located in a 90° elbow
  - The spill was estimated to be 1200 gallons of product (8% oil and 92% produced water) and covered approximately 1700 ft<sup>2</sup> of the pad
  - The spill was contained on the pad
  - With the C-sands perforations in 1999 the fluid rate in the well increased to 7000 bpd and continue to average 4000 to 6000 bpd.
- ⇒ Cause appears to be flow-assisted corrosion in flow disturbance area





# Spills/Incidents



6" 2A-18 PO Well Line Leak 4/7/02

---

## Background/Inspection History

- Erosion prone areas of this flowline ('S' riser and areas downstream of the choke) have been inspected seven times since 9/20/00. These inspections showed minor damage, but well within acceptable limits
- The last inspection downstream of the choke was done on 3/16/02 and showed minor damage, but was within acceptable limits
- This section of the flow line was thicker walled, 0.863", larger diameter and not where we have historically found erosion/corrosion concerns

## Post-Spill Inspections

- 23% wall loss by UT in the wellhead riser,
- 30% wall loss by RT due to erosion in the 4"x 6" reducer,
- Scattered corrosion pitting in the range of 8% to 15% wall loss throughout the majority of the 6" section of the flowline.
- The manifold piping exhibited erosion to the impingement areas in the range of 4% to 34% wall loss by RT & UT
- A total of 61 locations were inspected by (RT) Radiography and 11 locations by (UT) Ultrasonics.
- No locations on the well line needed to be repaired, other than leak area



# Spills/Incidents

6" 2A-18 PO Well Line Leak 4/7/02



## Incident Investigation Action Items

- Inspect the rest of the 2A-18 flow line prior to putting it back into service  
- **Complete**
- Determine where other similar locations exist at Kuparuk on drill sites  
i.e. thread-o-lets with Cosasco fittings on well lines on the outside  
radius of 90° elbows – **Complete** (Approx. 220 locations)
- Inspect all the locations identified above using radiography to  
determine if there is a pattern of corrosion in these locations.
- Based on the inspection results, develop and implement a long-term  
inspection and repair plan for the identified problem areas.
- All Items to be completed by YE 2002

FALL 2002

MEET &amp; C FOR VII

NOVEMBER 9, 2002

NAME	COMPANY	EMAIL
TIM BIERI	COFFMAN ENGINEERS,	bieri@alaska.coffman.c
RICK FELIX	BP	felix rd @ bp.com
Amanda Leffel	ADEC	amanda_Leffel@envirocon.state.ak.us
KIP SPRAGUE	BP	spragukpc@bp.com
Kirsten Ballard	ADEC	kirsten_ballard@envirocon.state.ak.us
CHRIS DASH	CPAI	LCDASHE@ppco.com
STEVE GEDDES	CPA	SGEDDES@ppco.com
Jeanie Yarnell	CPA	jmyarne@ppco.com
Todd Christensen	CPA	tchrist2@ppco.com
Mike Morris	CPA	mmorris3@ppco.com
Jeff Huber	CPA	n1085@ppco.com
Maria Cherry	CPA	n1085@ppco.com
SAM SAENGSUDHAM	ADEC	SAM_SAENGSUDHAM@envirocon.state.ak.us
- Lydia Minor	ADEC	lydia_minor@envirocon.state.ak.us
BOB BRAY	CPA	rdbray@ppco.com
Braed Frates	CPAI	n1462@ppco.com
Randy Brunes	CPAI	N1297@ppco.com
Mike Gahr	CPAI	N1297@ppco.com
Al Dahlquist	CPAI	N1195@ppco.com
MATT COLLINS	CPAI	n1412@ppco.com
MIKE WATTS	COFFMAN	mikebike1@att.net
RICHARD WOOLAM	BP	woolarc@bp.com

BP



*Richard Wallen*

# BP and State of Alaska Charter Agreement

## Corrosion - 2002 Meet and Confer IV

November 4<sup>th</sup> 2002



*GPB*

*Handwritten notes this year to date*

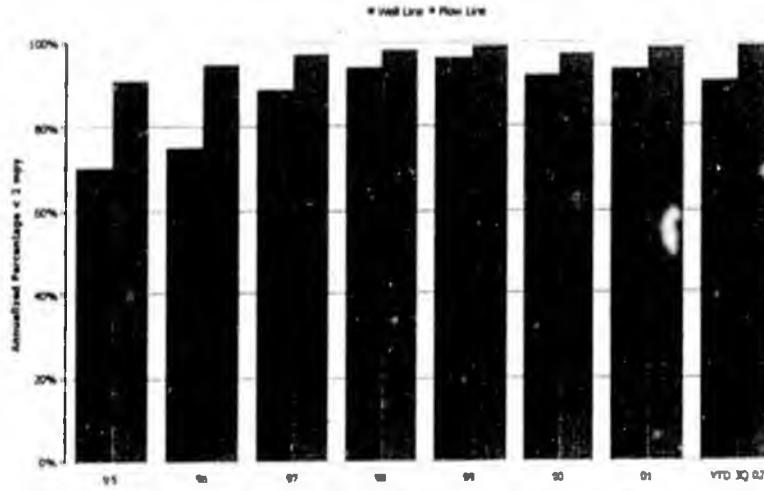


### Outline

- ▶ **Corrosion Monitoring**
  - ▶ 3 Phase production
    - Inhibition
  - ▶ Produced water injection system
  - ▶ Seawater injection system
- ▶ **Inspection Program**
  - ▶ Internal
  - ▶ External
- ▶ **Cased Piping Inspection**
- ▶ **GPB Structural Survey**
- ▶ **Incident Summaries**
- ▶ **Technology**
- ▶ **Summary**

### 3 Phase Corrosion Monitoring

3 Phase Production WLC Corrosion Rates



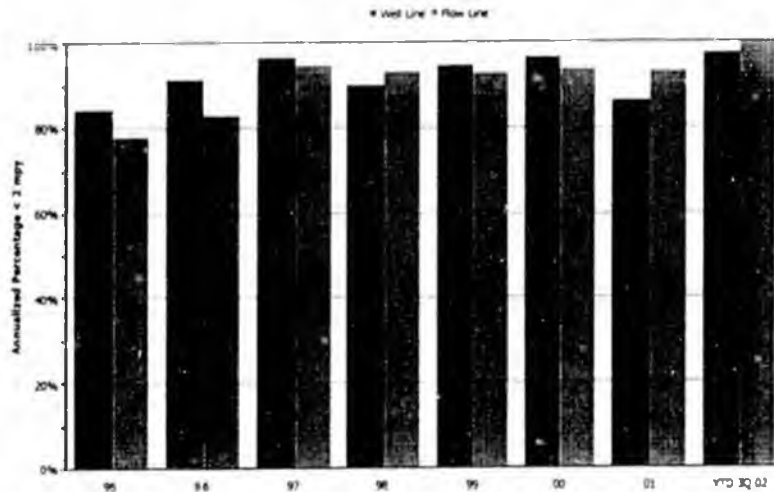
Nov 02

BP/ADEC Meet and Confer IV

3

### PW System Corrosion Monitoring

PW System WLC Corrosion Rates



Nov 02

BP/ADEC Meet and Confer IV

4

reflects in Cor Inhib.  
better water sol characteristics



## Corrosion Inhibition

### ► GPB Chemical Changes

- January 2001 :
  - Multiple chemistry across slope
- May 2001
  - Implementation Summer/Winter cross GPB
- October 2001
  - Implemented blending from concentrate
- November 2001
  - Single chemistry - winter version
- January 2002
  - Moved to new chemistry - Partitioning characteristics
    - Improve protection in W system and dead legs/drains
- May 2002
  - Summer version, Q1VD120
    - Pour point 0°F
- November 2002
  - Winter version, Q1VD121
    - Pour point -40°F

*Handwritten notes:*

-40°F pour pt

0°F pour pt - 100% methanol

intensity of acid and acid

10% ...

blend 10/50/50

methanol

is needed for concentration

Nov 02

BP/ADEC Meet and Confer IV

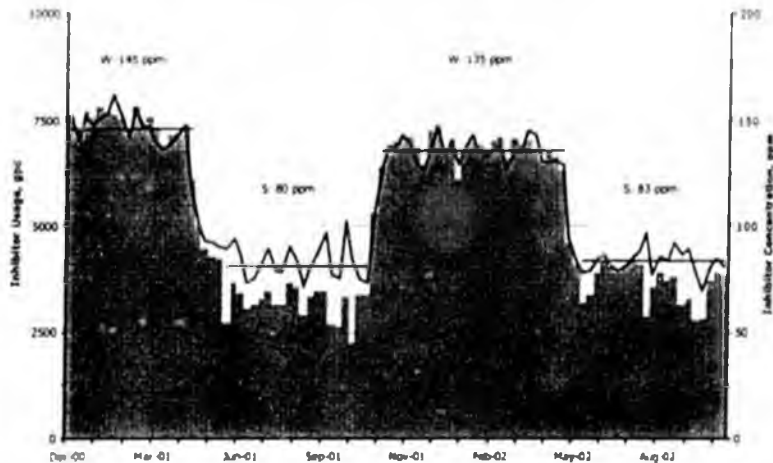
5



## Corrosion Inhibition Trends

Corrosion Inhibitor Usage and Concentration

Weekly Ave (gpd) Average ppm GPB Water ppm



Nov 02

BP/ADEC Meet and Confer IV

6

*Handwritten notes:*

reduction in water rates in summer

Spd & more than ppm



# 2002 Flow Line Action Log I

## ER Probe Corrective Actions

Equipment ID	Cause	Action
A-74	Calculation adjustment	Added 9 gpd
A-74	Increased Corrosivity	Increase Cl by 5%
A-74	Test well under injection	Increase Cl by 5%
04B	Increased Corrosivity	Increase Cl by 5%
GHX-E	Increased Corrosivity	See Inspection Log
A-74	Increased Corrosivity	Increase Cl by 5%

*Empty*  
*to appropriate water to make when to program*

## Coupon Corrective Actions

Equipment ID	Cause	Action
140	Increased Corrosivity	Increase Cl by 10%
05D	Inconsistent Batch Treatment	Rescheduled Batch Program
140	Increased Corrosivity	Increase Cl by 10%
F44	Increased Corrosivity	Increase Cl by 10%
05D	Increased Corrosivity	Increase Cl by 20%

*on last year's log + more*

Nov 02

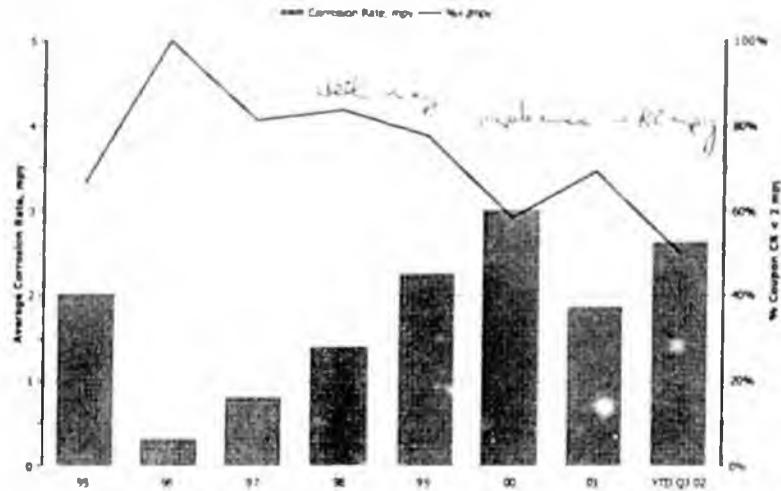
BP/ADEC Meet and Confer IV

7



# SW System Corrosion Monitoring

SW System WLC Corrosion Rates



*with a log*  
*impurities - 80 mpy*

Nov 02

BP/ADEC Meet and Confer IV

8

*increase in activity*

## SW System Detailed Analysis



### Corrosion Mechanisms

→ Oxygen corrosion

→ Microbiological

### Oxygen

→ Drives corrosion in upstream

### Microbiological

→ Drives corrosion in downstream

### Oxygen Control Actions

→ Set O<sub>2</sub> control < 20 ppb

→ Mechanical fixes to tower

- Vacuum pump replace/rebuild

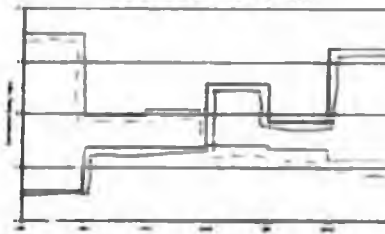
→ O<sub>2</sub> scavenger

- Continuous addition

### Next Steps

→ Microbiological control

	FL	WL	All
1999	9.5	1.4	2.3
2000	7.8	2.6	3.0
2001	1.8	1.9	1.9
2002	0.7	3.3	2.6



Nov 02

BP/ADEC Meet and Confer IV

9

## SW System - Microbiological Corrective Action



### Upstream

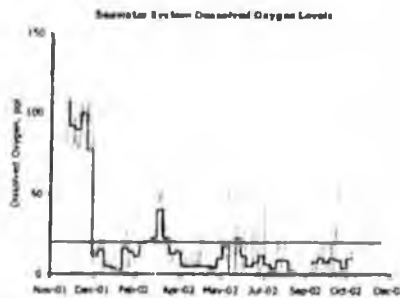
- Improved Corrosion Control
- Improvement dissolved oxygen control

### Downstream

- Increasing Corrosion
- Attributed to microbiological activity

### Microbiological - Corrective Action

- Doubled biocide frequency at mid-year
  - 500 ppm once per week
- Supplemental biocide treatments
  - SIP to DS04
    - slug with 500 ppm biocide
  - Entire SW System
    - 4 day soak with 500 ppm biocide
- Pigging increased
  - Entire system pigged 3Q 02 - wash brush pipe - maint.



Nov 02

BP/ADEC Meet and Confer IV

10

Some parts can be smart pigged

XC lines just inactive to see degradation

many lines switch over to local to diet cause of drug

one more shut down

1 Q 03 - hope to reach '96 levels

when plant up to speed

hope to see by mid next yr - will make DS

bp  
 1999  
 2000  
 2001  
 2002  
 improvement O<sub>2</sub> removal  
 due to A/C

now doubled and  
 prev  
 250 ppm  
 every 2 hrs  
 has been done every 2 hrs

procedure Superior Initiative  
 the thump x 3  
 while system down - untreated

5

## Corrosion Monitoring Summary



			1999	2000	2001	2002
OIL	FL	Ave CR, mpy	0.3	0.4	0.3	0.4
		% < 2 mpy	99%	97%	98%	99%
OIL	WL	Ave CR, mpy	0.5	0.7	0.6	0.7
		% < 2 mpy	96%	92%	93%	91%
PW	FL	Ave CR, mpy	0.5	0.4	0.5	0.2
		% < 2 mpy	93%	94%	93%	100%
PW	WL	Ave CR, mpy	0.6	0.5	2.1	0.3
		% < 2 mpy	95%	97%	86%	97%
SW	FL	Ave CR, mpy	9.4	7.8	1.8	0.7
		% < 2 mpy	0%	0%	100%	100%
SW	WL	Ave CR, mpy	1.4	2.6	1.9	3.3
		% < 2 mpy	88%	64%	67%	33%

### 2001 to 2002 Summary

- ▶▶ 3 Phase (OWG) – Largely unchanged
- ▶▶ Produced water – Performance improved
- ▶▶ SW Systems – Needs improvement

NOV 02

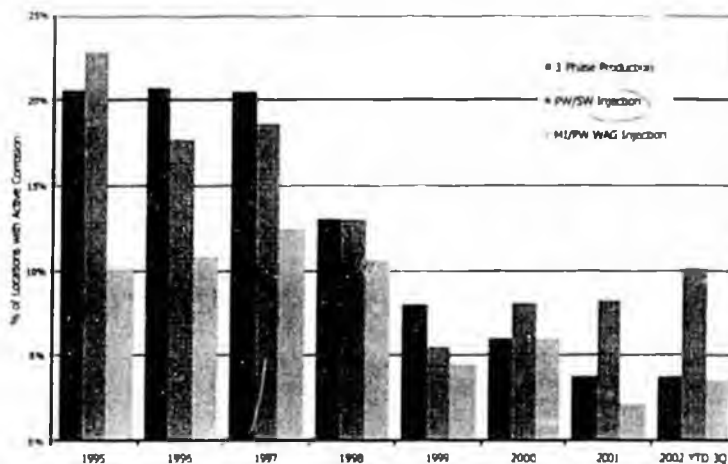
BP/ADEC Meet and Confer IV

11

## Inspection Program – Well Lines



GPB Well Pad/Drill Site Pipelines  
Inspection Measure - Internal Corrosion



NOV 02

BP/ADEC Meet and Confer IV

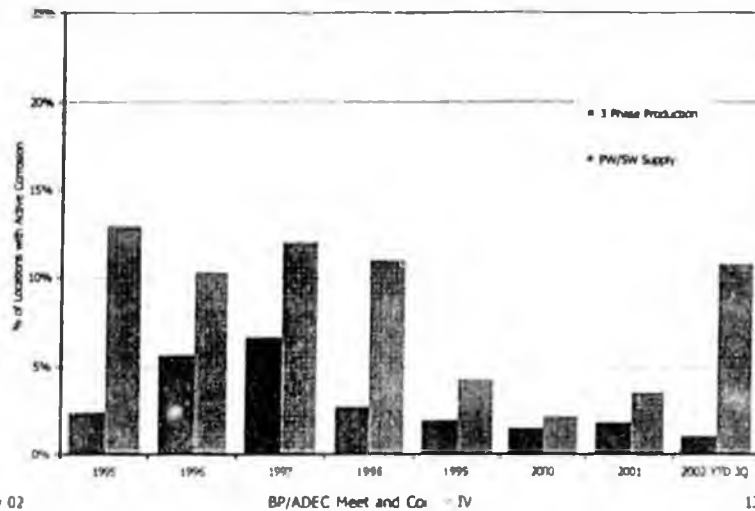
12

sub set of no inspected locations



## Inspection Program – Flow Lines

GPB Cross Country Pipelines  
Inspection Measure - Internal Corrosion



Nov 02

BP/ADEC Meet and Confer IV

13



## 2002 Flow Line Action Log II

### ► Inspection

Equipment ID	Cause	Action
098	Increased Corrosivity	Increase CI by 10%
H-36	Increased Corrosivity	Increase CI by 10%
GHX-E	Increased Corrosivity	Increase CI by 10%
PW System	Changed Upst team CI	Changed Upstream CI 1Q02
SW System	Biocide rate low	Increased Biocide

Nov 02

BP/ADEC Meet and Confer IV

14

## Smart Pigging Program



### GPB Scope 2002

#### 16" Produced Water Supply

- Flow Station 2 to Drill Site 3  
- Length - 2.9 miles (15,521 ft)
- Flow Station 2 to Drill Site 4  
- Length - 1.3 miles (7,077 ft)
- Flow Station 2 to Drill Site 9  
- Length - 3.2 miles (16,882 ft)

#### Report Status

- Minimal internal corrosion/moderate external corrosion
- Proofing/validation of anomalies scheduled in 2002-03

### ACT Scope 2002

#### 14" Three Phase Production

- K Pad to CFP  
- Length - 4.8 miles (25,175 ft)

#### Report Status

- Minimal external corrosion/Extensive internal corrosion
- Proofing/validation of anomalies in progress

### FFS - Anomalies added to NDE program



Inertial Pipeline Mapping



Triaxial Feature Analysis

Nov 02

BP/ADEC Meet and Confer IV

15

Internal corrosion  
fixed everything  
not in for control  
etc

using gloves

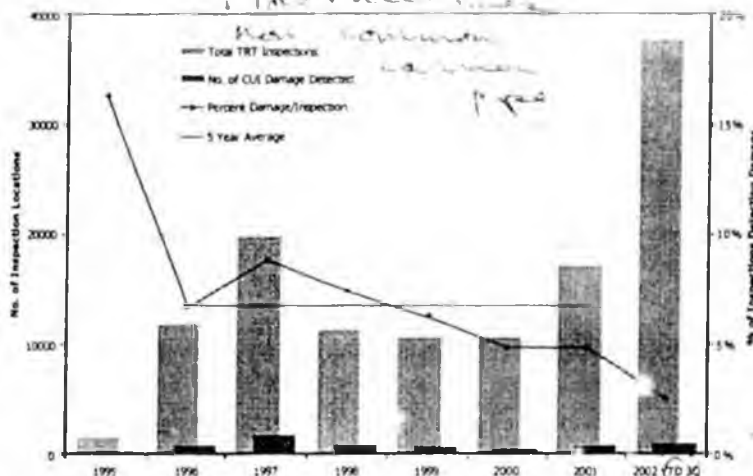
repair everyone  
they help

but P,  $\Delta$  from 196 to 1997 by the pipe  
color red multiple clean runs by

## External Inspection Activity



GPB Pipeline TRT Inspection Summary



Nov 02

BP/ADEC Meet and Confer IV

16

~25 repairs (guess)

remediated more than  
they repaired - weld/pack  
repairs

3x larger program 4  
yr

does not meet for 8  
100%

fitting for  
suc called  
24,000,000

they could  
run pig  
before pig  
temporal need  
water to cool  
them  
general problem  
thinks elbows  
was water pig

~2.5% damage rate  
index for this season

## GPB Cased Piping



### Inventory

- ▶ Completed field-wide review
- ▶ Established casing index/register

### Location Identification

- ▶ Crossing identified on aerial

### Applicable Technologies

- ▶ Guided wave
  - Switched to magnetostrictive
  - Established permanent monitoring
    - At detected anomalies
- ▶ Electromagnetic wave
  - Ongoing test/evaluation program



### Status

- ▶ 90+% complete with 1 year remaining on 5 year program - all casing crossings

Nov 02

BP/ADEC Meet and Confer IV

17

to a D  
 next  
 given false  
 pos  
 EM, guided wave  
 then guided wave  
 suspected  
 wet locations  
 put in monitoring -  
 metal loss  
 → concern  
 no core analysis  
 on incul that  
 might be wet

Summer hire project to keep wells out of casing  
 EM, guided wave - Transient Rad. maybe no  
 longer used

## Cased Piping – Long Range Inspection



### Guided Wave Technology

- ▶ Two concepts for excitation and reception of guided waves
  - Origins differ but concepts are applicable for long range inspection
    - Electromagnetic coupling (e.g. magnetostrictive, EMAT)
    - Piezo-electric coupling (e.g. strain gauge, comb)
- ▶ Comparison of Techniques
  - No significant difference observed between the 2 concepts with respect to false calls and probability of detection
    - GPB Trial November 1993
    - RTD for PRC/AGA August 1999
- ▶ Strategy Shift
  - Permanent/fixing monitoring of magnetostrictive sensors
    - Increase confidence in repeatability tests, reduce false positive
    - Monitor change/growth -vs- isolated evaluation
    - Cost control; single installation, unnecessary excavation

follow up  
 w/krp if  
 more GS

Nov 02

BP/ADEC Meet and Confer IV

18



## GPB Structural Survey

### ▶ Field Observation

- ▶▶ Recurring program
- ▶▶ Opportunity program

### ▶ Recurring - Walking Speed Survey

- ▶▶ Five year recurring program
  - 2002 - GPB East Cross Country Pipelines Complete
  - 2003 - GPB West Cross Country Pipelines
  - 2004 - GPB East Well Pads
  - 2005 - GPB West Well Pads
  - 2006 - Lisburne Cross Country Pipelines/Drill Sites
  - Repeat Cycle

### ▶ Opportunity Program

- ▶▶ Security
- ▶▶ Operators

### ▶ FFS

- ▶▶ Anomalies added to ongoing FFS program

Nov 02

BP/ADEC Meet and Confer IV

19



## Kuparuk Flooding

### ▶ Food water behind East channel bridge of Spine Road

- ▶▶ Historically not flooded to the same extent
- ▶▶ Water levels high enough to submerge flow lines between M-pad and GC-2

### ▶ Two 3-bundle lines were the only equipment with observed damage

- ▶▶ Flooding caused the bundles to shift
- ▶▶ Misc. insulation damage/wetting
- ▶▶ One anchor location where each of the bundle lines failed to re-seat properly

### ▶ Actions

- ▶▶ Engineer review
- ▶▶ Insulation & Anchor repair
- ▶▶ CUI inspection scheduled 2003



Anchors not seated



Insulation damage

Nov 02

BP/ADEC Meet and Confer IV

20

600 300 yr flood

## 2002 Leak/Spill Summary



### Leak/Spill Location Summary

	Affected Surface	
	Internal	External
Well Line	2	1
Flow Line	-	1

### Leak/Spill Mechanism Summary

	Mechanism		
	CO <sub>2</sub>	Erosion	CUI
Well Line	1	1	1
Flow Line	-	-	1

### Leak/Spill Fluid Summary

	Service			
	Prod	SW	PW	CUI
Well Line	2	-	-	1
Flow Line	-	-	-	1

Nov 02

BP/ADEC Meet and Confer IV

21

## H-21 S-Riser

### Inspection

- » Prior Inspections
  - 6 locations by Radiography
  - No damage greater than 20%

### Well Head Corrosion Inhibition

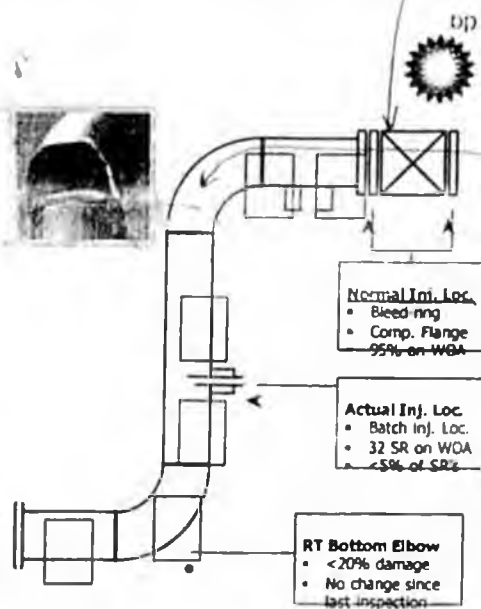
- » Normal location + 95% WOA
  - Bleed ring
  - Companion flange
- » 32 exceptions < 5%
  - Continuous CI on S-riser

### System Breakdown

- » Upper elbow risk not recognized
  - Inspection/mitigation program
  - Not synchronized
- » Inhibitor Injection Point not moved

### Corrective Action

- » Short term - complete
  - Inspected 347 GPB s-risers
  - 2 repairs identified
- » Long term - ongoing
  - Move corrosion inhibitor injection locations



Nov 02

BP/ADEC Meet and Confer IV

22

## 13-12 Well Line



### ▶ Incident Summary

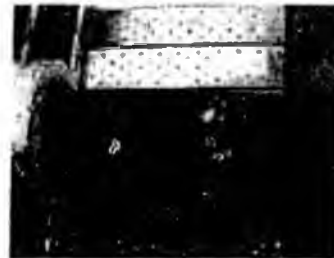
- ▶ May 31st small leak detected
- ▶ Line shut-in and insulation removed

### ▶ Inspection

- ▶ Failure caused by external corrosion
  - Weld pack in saddle
  - 7:00 to 10:00 clock position
  - 8" x 10" network with pinhole leak

### ▶ Corrective Action Plan

- ▶ Complete line review performed
  - All insulation joints
- ▶ Sleeve repair leak location
  - No additional sleeves required



*external*

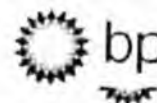
Nov 02

BP/ADEC Meet and Confer IV

23

## F-48 S-Riser

*300000  
1/2 hrs  
occurs in 10 min*

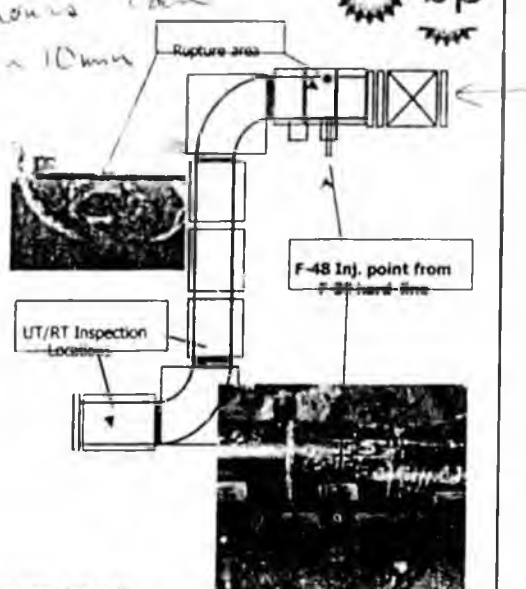


### ▶ Incident Summary

- ▶ Erosion by produced solids
  - Hard-line from F-39 to F-48

### ▶ Corrective Action Plan

- ▶ Inspection of adjacent piping
- ▶ Long term
  - Identify similar locations
  - Integrate into O&M program
- ▶ Interface with Operations



Nov 02

BP/ADEC Meet and Confer IV

24

## Z Pad Large Diameter Flowline



### Incident Summary

- » October 4th a small leak detected
- » Line shut-in and insulation removed

### Inspection

- » A breach found in insulation at low point drain
- » Failure caused by external corrosion
- » Corrosion network present 360°
  - Leak at 12:00 o'clock position

### Corrective Action Plan

- » Inspect adjacent piping
- » Sleeve repair leak location



Rupture area before insulation removal



Rupture area

*leak was not properly sealed.*

*pinhole leak*

Nov 02

BP/ADEC Meet and Confer IV

25

## Technologies for Corrosion and Integrity Management



### PDT/MIMIR

- Paperless environment
- Improved access to data
  - Electronic versus paper copy



### Remote Access Technology (RAT)

- Alternative to access via scaffolding
- Use of ropes to access equipment and piping

### Remote Operated Vehicle (ROV)

- Inspection of firewater and raw/potable water tanks
- Used for sediment removal
- Capable of performing visual and UT inspections



### Digital Radiography (DRT)

- 100% use of technology by CIC across BPX assets
- Reduced HSE risks
  - chemicals, radiation exposure
- Multi-location access to images



*helped of data tank + cap data*

*personal data to minimize*

*using ropes to access*

Nov 02

BP/ADEC Meet and Confer IV

26



## Summary

- ▶ **Internal Corrosion**
  - ▶▶ 3 Phase production – largely unchanged
  - ▶▶ Produced water - improving
  - ▶▶ Seawater
    - Oxygen control - dramatically improved
    - Microbiological control – biocide dosage increased
- ▶ **External Corrosion** *inspection*
  - ▶▶ YTD approximately 3 times historical average
- ▶ **Incident Summary**
  - ▶▶ YTD 50% internal/50% external *1/4 d 4 (4-6 last yr)*
- ▶ **Cased Piping**
  - ▶▶ In year 4 90+% complete of 5 year program
- ▶ **Technology** *improvements - trying new*

CPA

309, 30, 50 B



# Greater Kuparuk Area

## Commitment To Corrosion Monitoring Overview

presented to the

Alaska Department of Environmental Conservation

*4<sup>th</sup> Meet & Confer*

November 4, 2002



# Inspection Results

Internal Corrosion



## Cross Country Lines

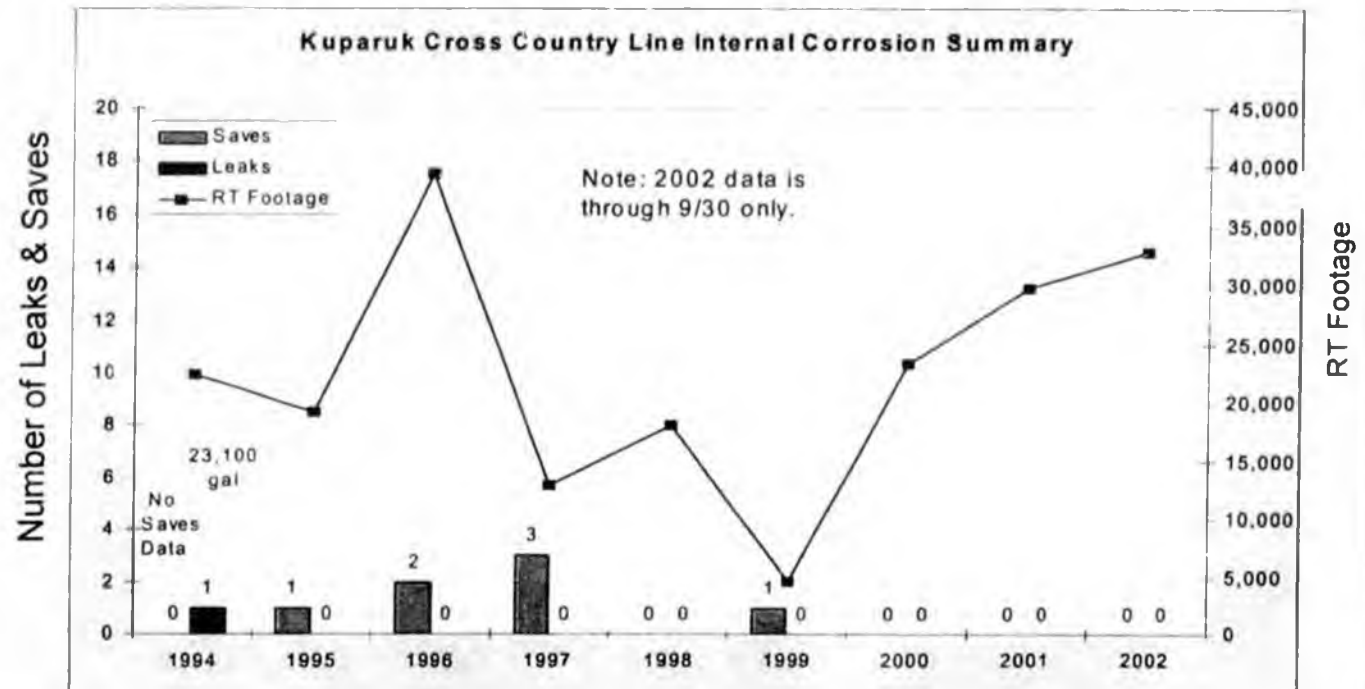
Corrosion Is Under Control

- ✓ Exceeded RTR goal of matching 2001 footage
- ✓ Over 30,000 ft of over 233 lines inspected (RTR and RT) through 9/30
- ✓ Integrated Turbulent Area Inspection Program
- ✓ 0 Leaks, 0 Saves through 9/30
- ✓ Smart pig of water lines >10" appears feasible – evaluation ongoing

2002 YTD

### Internal Corrosion Spills - Cross Country Lines

1994 Spill 24" 1Y/R Crude CC Line



### Well Lines

#### Internal Inspection Focus Area

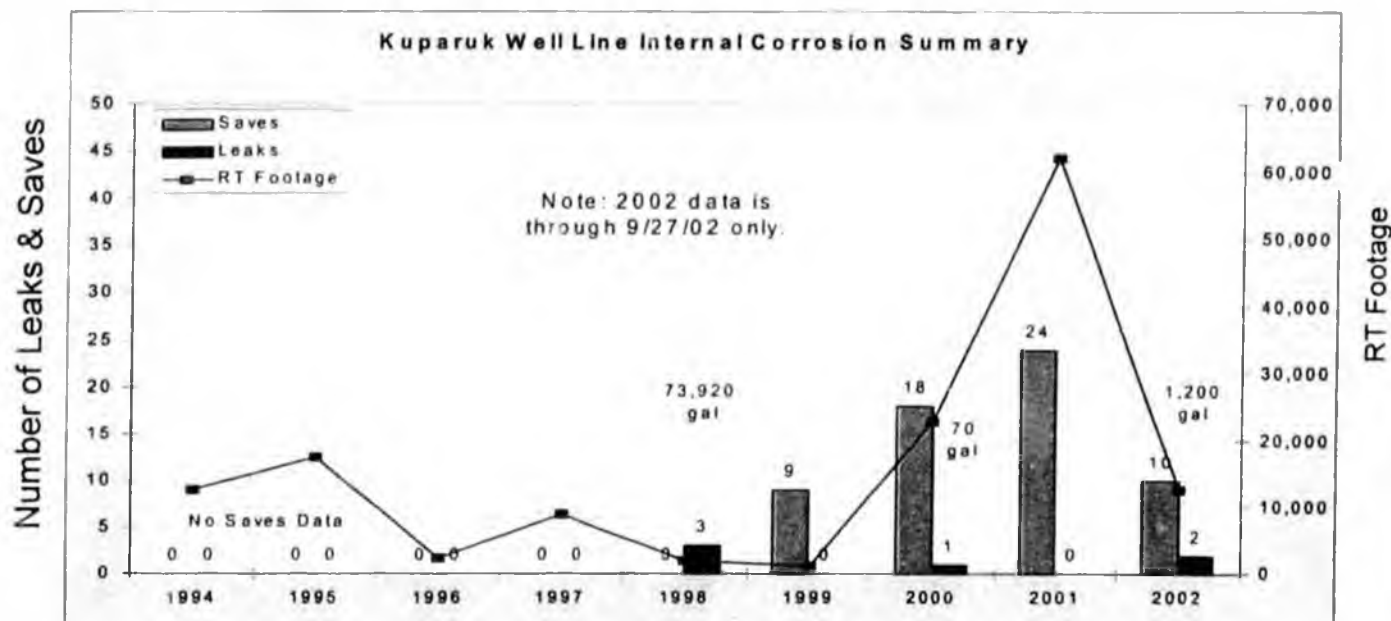
2002 YTD

On schedule with 2002 goal to complete all .312" lines.

- ✓ Over 12,000 ft of over 448 lines inspected (RTR and RT) through 9/30
- ✓ 12 lines required repair through 9/30 (4 injectors, 8 producers)
- ✓ 2 Leaks, 10 Saves through 9/30
- ✓ Pursuing expanded inspection scope @ DS 2T

#### Internal Corrosion Spills – Well Lines

38 Spills	1L-1 6" WI
	1L-3 6" WI
	1A-9 6" WI
2000 Spill	1G-8 6" PC
2002 Spills	2A-18 6" PC
	2T-13 6" PC





# Inspection Results

Internal Corrosion



2A-18 anomalies -  
2T-13 This is wall pitting thickness

- ✓ **Continue to Focus on and Inspect Well Lines**
  - Inspect next 100 highest priority well lines.
  - Priority based on wall thickness, age of line, and time since previous inspection
  
- ✓ **Maintain Inspection of Cross Country Lines**
  - Inspect roughly 15,000 feet by RTR *1/2 mil - much - 1 mil 1/2"*
  - Complete backlog of "Turbulent Area Program" inspections (formerly called "Elbow Inspection Program")



# Monitoring/Mitigation

ConocoPhillips

## Results & Accomplishments

YTD 2002

### Monitoring:

- ✓ In the 3-phase production system, coupon general and pitting rate averages remain under threshold limits and are trending down
- ✓ Over 90% of 3-Phase Production CC lines with ER probe rates < 2 mpy
- ✓ Corrosion rates on the water injection well line coupons have decreased
- ✓ Corrosion rates on the wet oil cross country line coupons have decreased markedly

### Mitigation:

- ✓ Inspection data shows corrosion is under control in the cross country lines
- ✓ All inhibited 3-Phase Production CC lines with probe, coupon, or inspection rates above thresholds had corrective action taken (inhibitor rates were increased during 1<sup>st</sup> half 2002 opt cycle) \* excluding test DS1R, which was pulled after opt cycle and was 'A' grade  
*optimization cycle*
- ✓ Continuous wellhead injection system installed and operating at DS1G
  - Additional Drill Sites installations funded; construction to start this winter

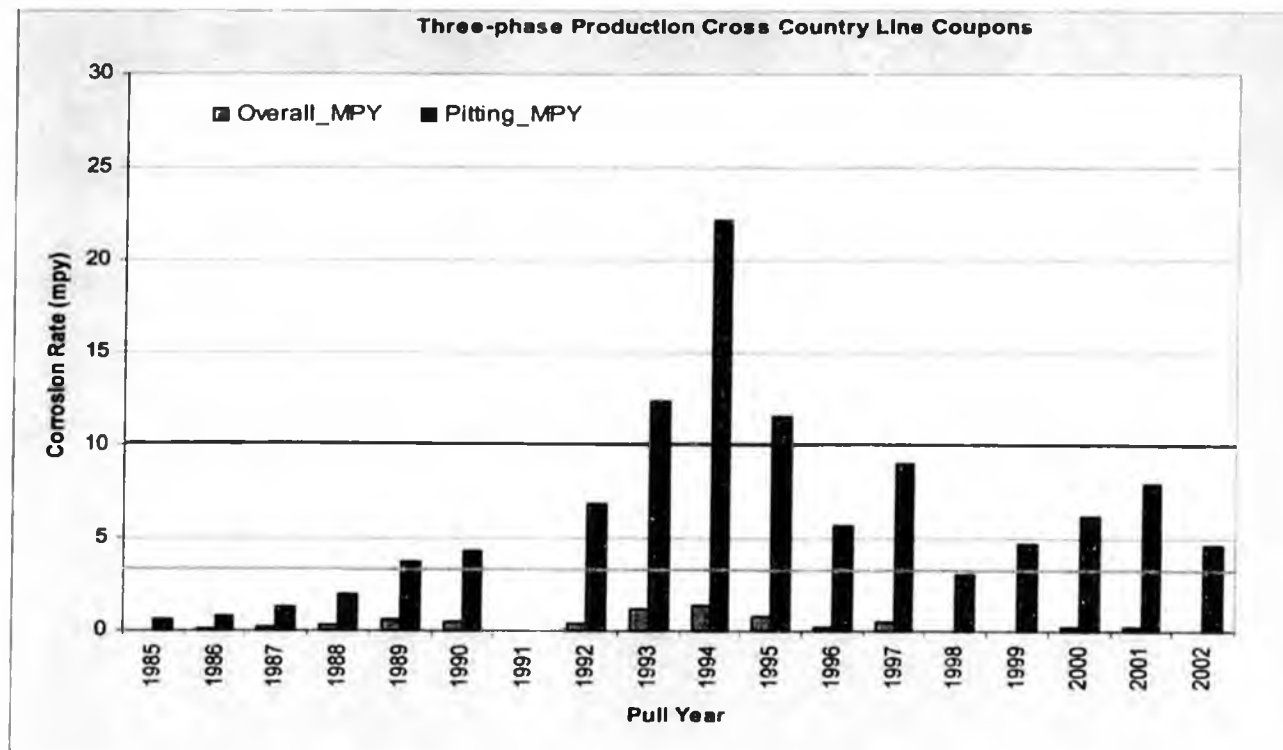


# Monitoring/Mitigation Three-Phase Cross Country Lines



## Summary YTD 2002

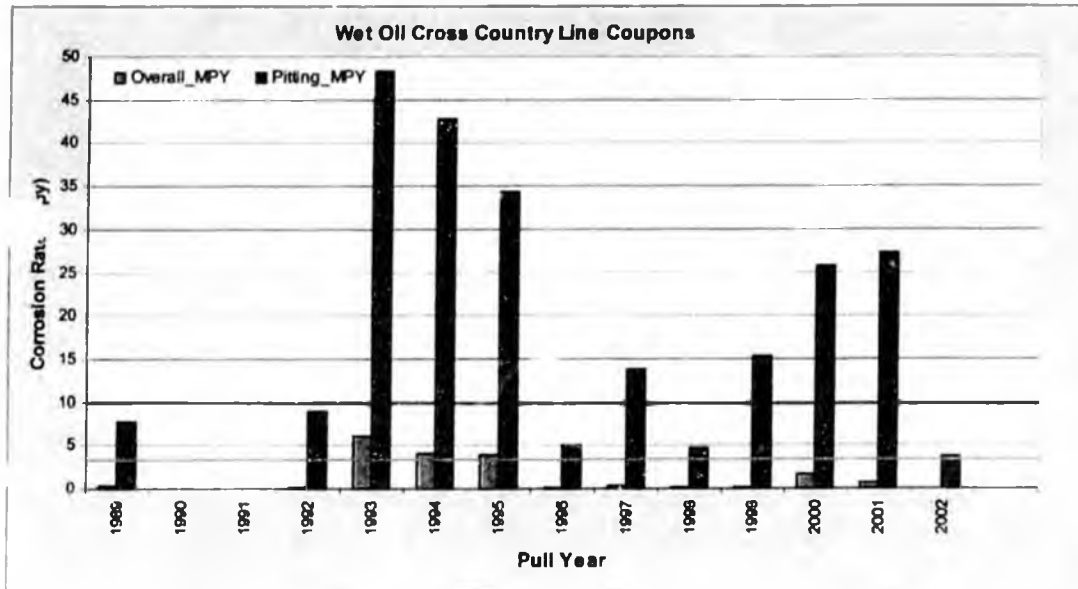
*Bill calls them  
flow lines*



- ✓ Coupon average corrosion rates in the 3-phase production lines have improved due to optimization cycles and perhaps change to RU276
- ✓ Coupon corrosion rates are a conservative measure, and are an advance indicator
- ✓ Inspection data shows corrosion is under control in the 3-phase CC lines
  - Less than 5% of repeat inspection locations showed increases

*See record to news 1  
w/ M. 2/1/02*

*< .5 mil pt no show on 117*

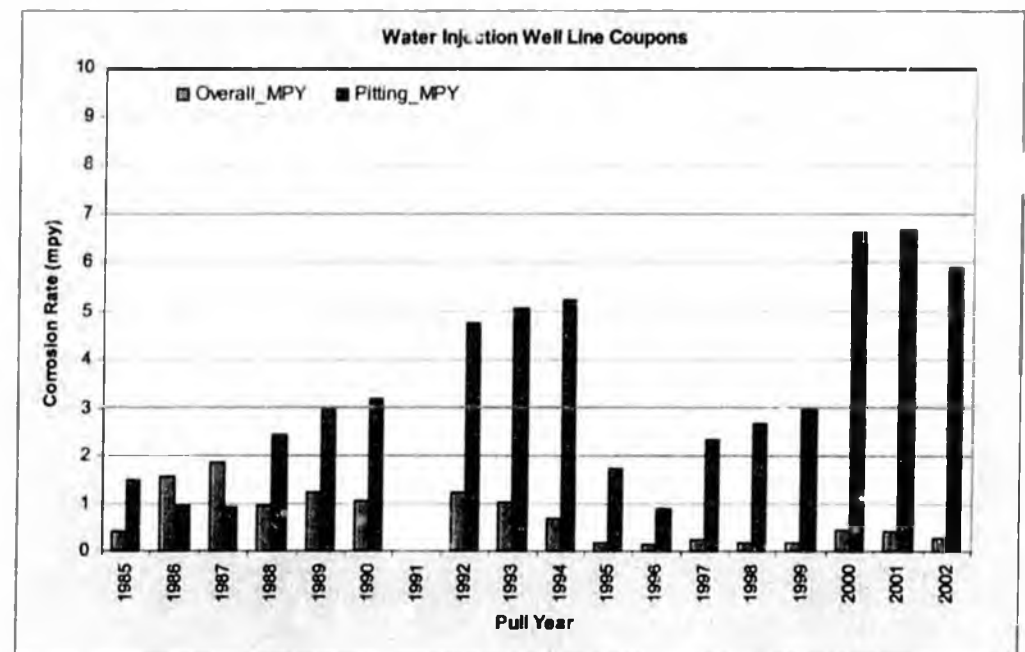


⇐⇐ Wet Oil CC Lines:

- ✓ Wet oil lines coupon corrosion rates have decreased markedly
- ✓ 24" wet oil line removed from service in 2001 *low velocity*
- ✓ 16" and 12" wet oil lines coupon corrosion rates are lower – more effective inhibition

Water Injection Well Lines: ⇒⇒

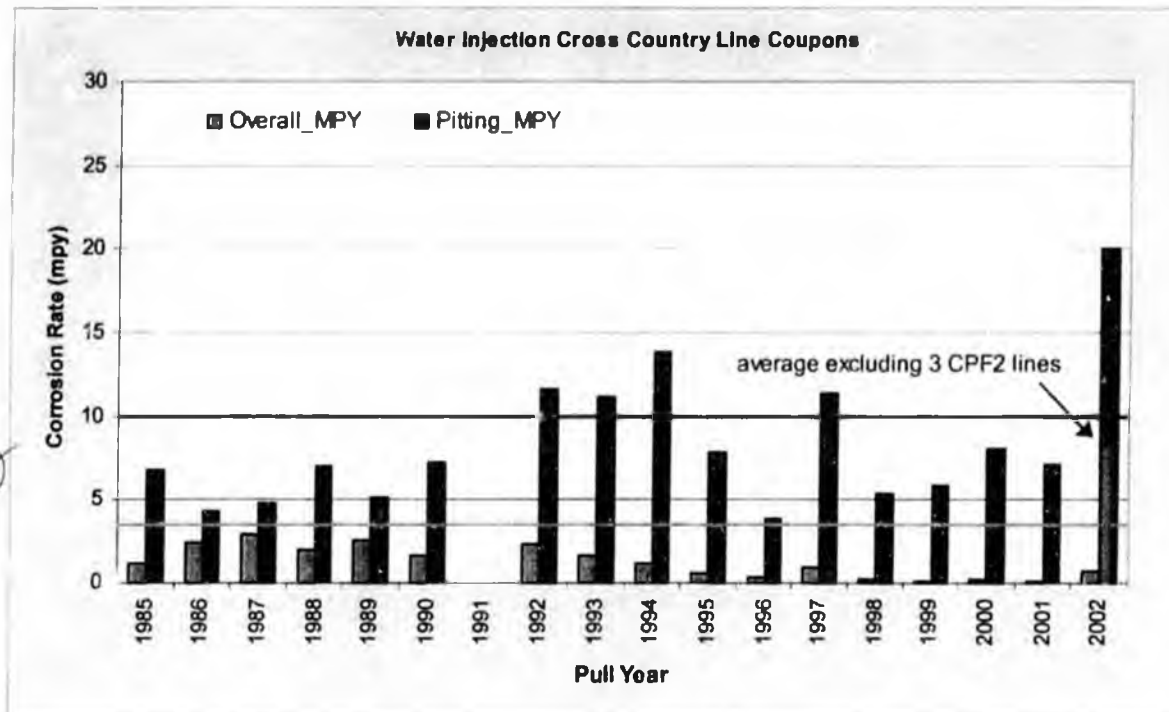
- ✓ Coupon corrosion rates have decreased slightly YTD
- ✓ Past upward trend is currently reversing



# Summary

## YTD 2002

*in survey avg*



*CPF2 lines  
all @  
facility  
unpassable  
6-10-02  
100-100  
-103*

### Area of Concern

- ✓ Coupon average corrosion rates in the water injection cc lines have increased
- ✓ Average affected mainly by a 3 lines at CPF2. Field average pitting rate excluding "bad actors" falls below threshold.
- ✓ Recent inspection data from the 3 CPF2 lines shows only minor damage (worst case B grade)
- ✓ Nevertheless, work is underway to find the cause

*Ru270 used in 1999  
in lower concentrations*

*TRCO → PA1 is - manufactured  
API 570 regime, nearby*



✓ **Find more effective corrosion inhibitors**

- Implemented RU-276 field-wide in first quarter of 2002
- Previous upward trend in coupon rates appears to have turned
- Field test completed at DS1R yielded good quality data
- New lab screening process implemented with good results

✓ **Implement wellhead continuous injection**

- New system is pumping corrosion inhibitor at DS1G well head locations.
- Technology evaluation in progress (automated system)
- Starting construction this winter at additional drill sites.

✓ **Schmoo B Gone Test Update**

- Capital project funded and in design stage.

*- poss. mit. injection  
for low-flow areas to keep  
solids from building*



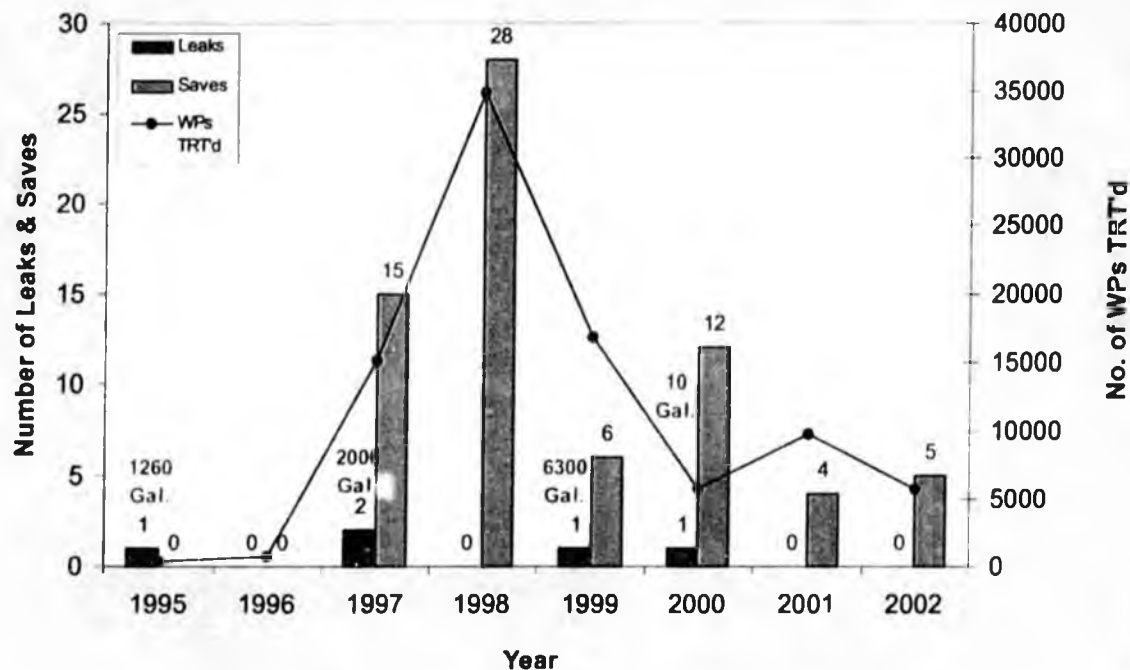
# Inspection Results

External Corrosion

ConocoPhillips

## 2002 YTD Summary

Historical GKA External Leaks and Saves



ABU GRADE

### External Corrosion Line Failure History

- 1995 2C-04 Well Line
- 1997 2 ea. 24" Crude CC Lines (Weld Pack @ Saddle)
- 1999 1A-15 Well Line (Weld Pack @Saddle)
- 2000 2X-16 Well Line

# Inspection Results

CC Lines External Corrosion

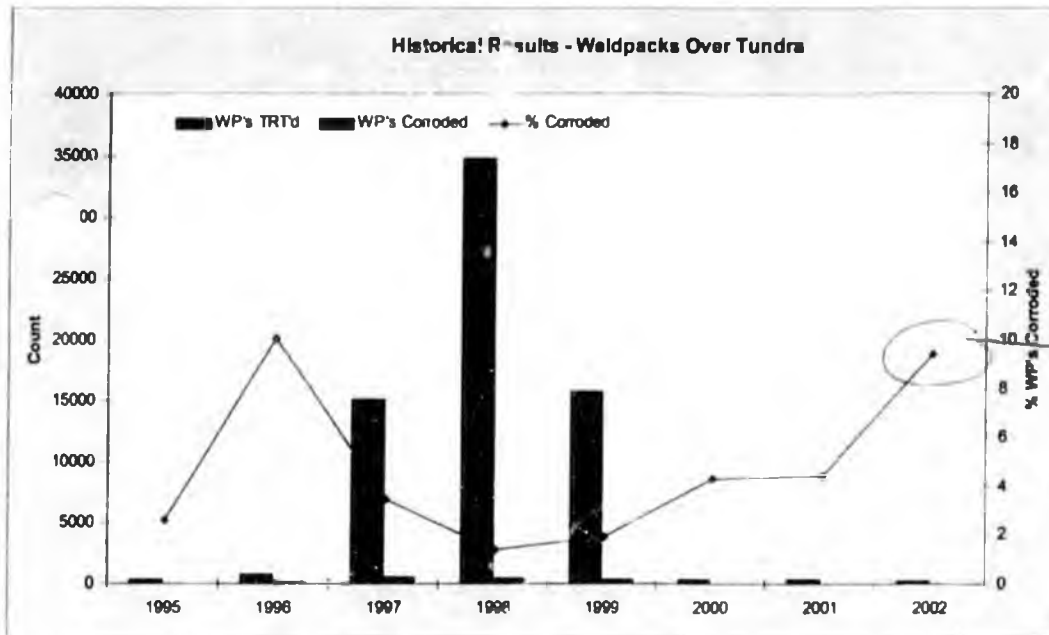
ConocoPhillips

## CC Lines Over Tundra:

- ✓ Initial TRT inspection of over-tundra CC weld packs and refurbishment of heavy wet and corroded weld packs was completed by YE 2001. Final walk down verifications are underway.

Began initial recur effort in 2002, targeted medium-wet weld packs in saddles from initial survey

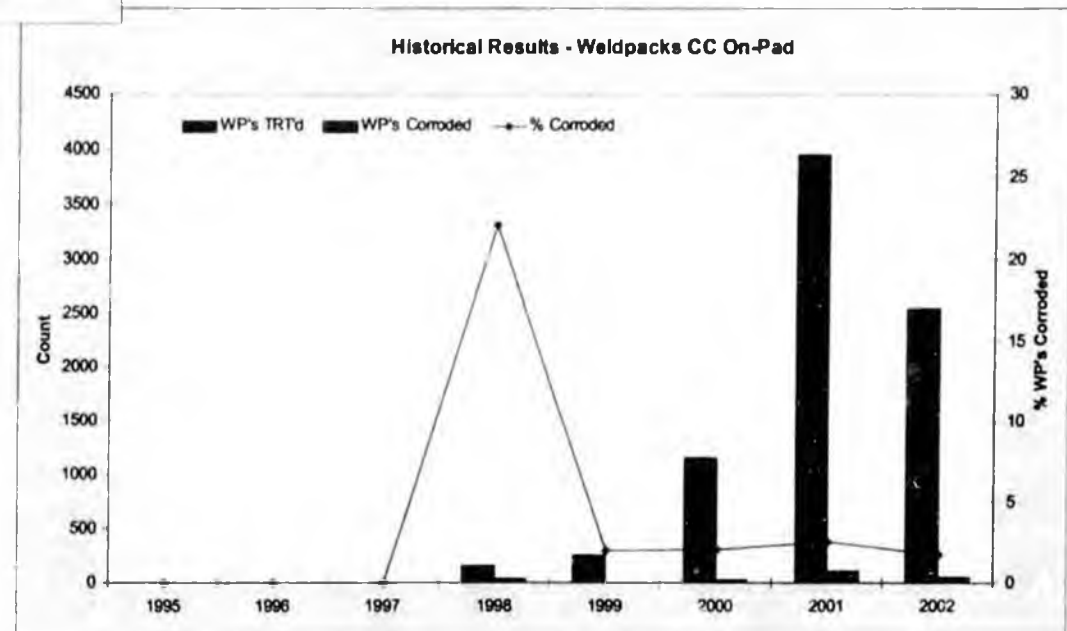
- ✓ Increase in %-Corroded was expected due to target population



*near cycle 2003 - should move to a more even cycle ~ 5000/yr*

## CC Lines On Pad: ⇒⇒

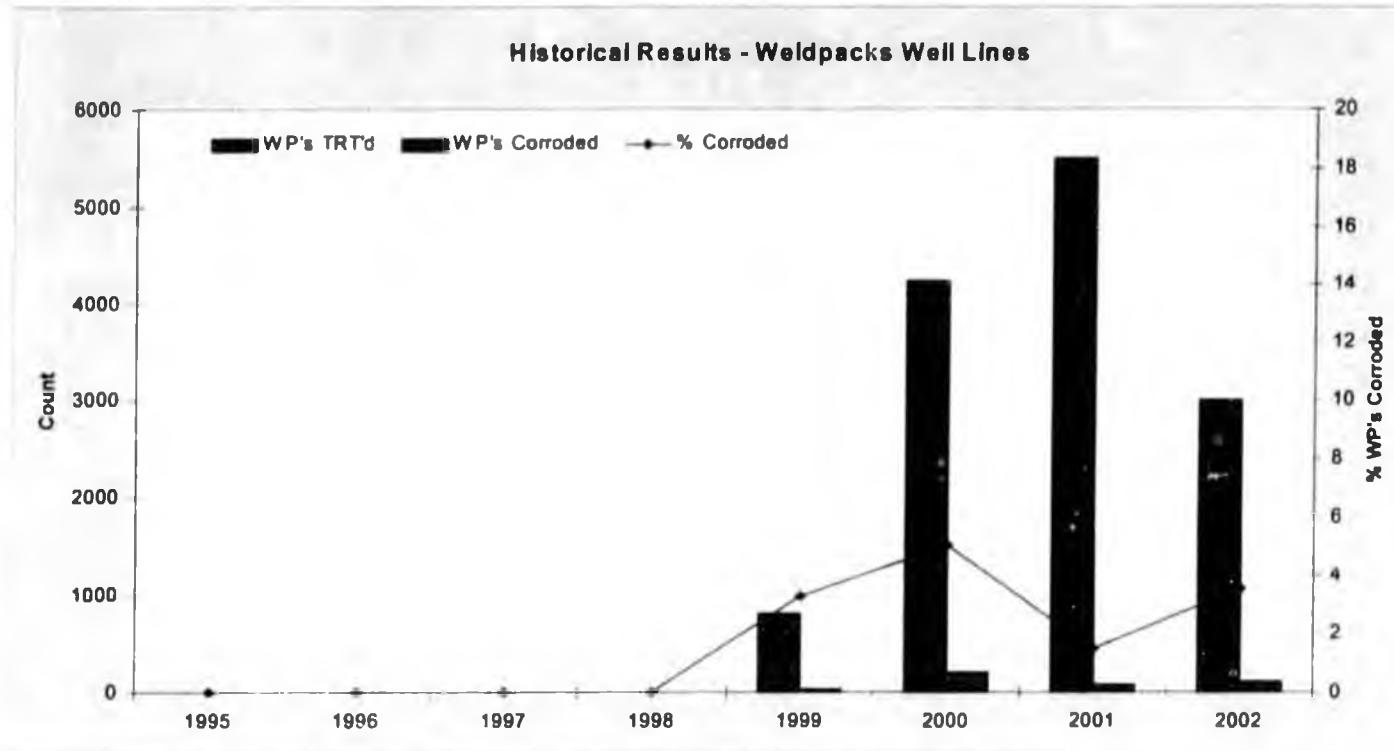
- ✓ TRT'd 2542 on-pad cross country weld packs YTD, exceeding 2002 FY goal of 1780
- ✓ 91% of on pad cross-country line weld packs have been TRT'd to-date
- ✓ The % corroded weld packs found has dropped slightly, ~ 1.8%





# Inspection Results

## Well Lines External Corrosion



### Well Lines :

- ✓ TRT'd 3007 well line weld packs YTD
- ✓ On-track to reach 2002 goal of 4000 weld packs TRT'd *now met*
- ✓ 55% of the well line weld packs have been TRT'd YTD
- ✓ Goal is to complete well line weld pack TRT baseline inspections by YE 2005
- ✓ Continue to monitor %-corroded and respond to trends

2002



# Inspection Results

Below Grade Piping



*Cased Pipe*

2002 YTD

## Met Goal of Inspecting All Priority 1 Pipes

*would be category 1-2-3*

- ✓ Inspected all 130 previously un-inspected priority 1 locations with PTI/TWI
- ✓ 8 cased pipes were excavated (goal was 5 to 9)
  - 2 had severe to moderate damage (1 internal, 1 external).
  - The external damage was sleeved, the internal damage was replaced/upgraded
  - 6 had minor or no significant corrosion
- ✓ 8 Refurbishments, 2 Saves, No Leaks
- ✓ Completed Annual Visual Casing Inspection; cleared all obstructions
- ✓ Will share BP's evaluation of Magneto Strictive technology from B&E

*EM general issues  
(conductance issues)*

*inconclusive / incomplete results → patch or replacement*

# Inspection Results

Below Grade Piping



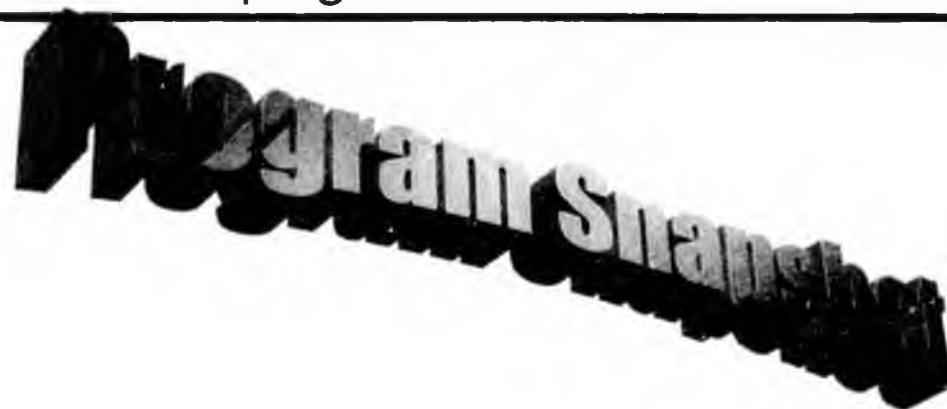
2003 Goals

- ✓ **Re-inspect roughly 60 priority 1 pipes**
  - Inspect using PTI and/or TWI technologies
- ✓ **Complete initial inspection of all priority 2 lines ~ 115 lines**
  - Mostly atmospheric/low pressure flare/gas lines - Inspect by visual inspection and “sniff” for gas
  - Selectively use PTI and/or TWI technologies where warranted
- ✓ **Prioritize and excavate lines as appropriate ~ 5-9 lines**
- ✓ **Work with equipment vendors, Phillips R&D, and BP to improve technology, and explore new technologies**



# Inspection Results

## Below Grade Piping



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

All Lines in GKA/AOA Inventory	Inspected Thru 10/31/02	Un-inspected Lines	Total	Previously Uninspected Lines Inspected in 2002
Priority 1 Oil	331	44	375	38
Priority 1 Non-Oil	225	17	243	92
Priority 2 Oil	1	18	19	0
Priority 2 Non-Oil	0	98	98	0
Priority 3 Oil	1	21	22	0
Priority 3 lines Non-Oil	2	13	15	0
<b>2002 Total Inventory</b>	<b>561</b>	<b>211</b>	<b>772</b>	<b>130</b>

## Subsidence Mitigation at the Drill Sites

### Existing Well Upgrade Program - 2002:

- ✓ Installed approximately 53 floors with pipe supports
  - Drill Sites 1A, 1D, 2T, 3F, 3O, and 3Q
- ✓ Installation of approximately 23 heat tubes in progress at Drill Sites 1D & 1R
  - Heat tubes are used to keep the ground frozen or to re-freeze the ground where it has been thawed
- ✓ Installation of permanent fixed pipe supports in progress at Drill Sites 2K & 2M

*well head shelter floor  
safe working platform for operations*

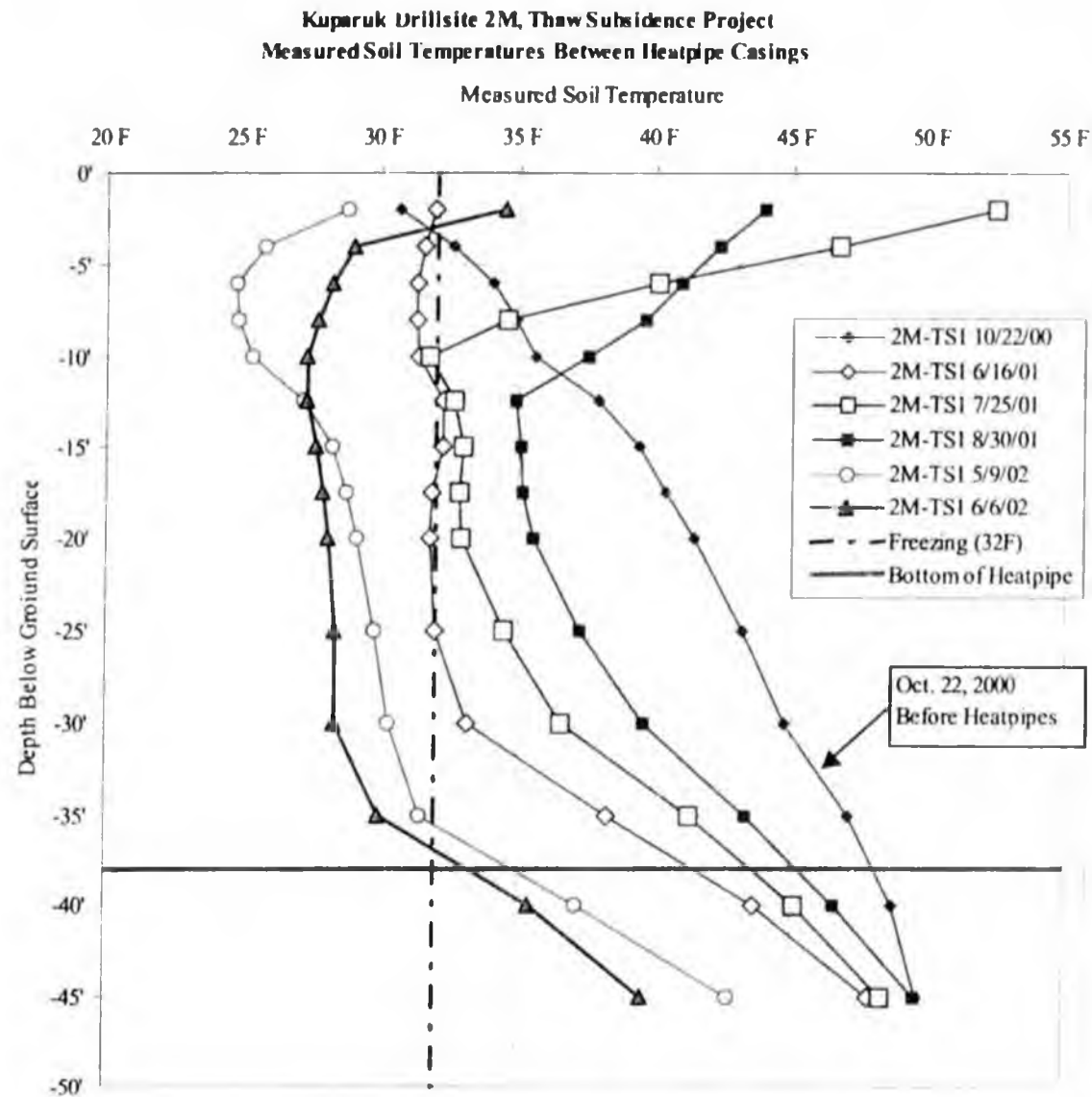
### New Wells & Producer to Water Injection Well Conversions:

- ✓ New wells had heat tubes, and floors with permanent pipe supports
- ✓ Producers converted to water injection wells, and EOR conversions were also upgraded with heat tubes and floors with permanent pipe support (approximately 15 heat tubes)

### Effectiveness/Monitoring

- ✓ Periodic subsurface thermistor monitoring indicates the heat tubes are achieving the desired results, showing the expected thaw bulb contraction

## Subsidence Mitigation at Drill Site 2M



## Wind Induced Vibration

- ✓ Progressive improvement since program inception - 1991
  - PVD elastomer improvements (Generation I, II, III & IV elastomers) - *several no degradation*
  - TVA development *active v. vibration dampener*
    - Eliminates elastomer problems - *shielded from elements*
    - Decreases maintenance
    - Decreases device failure frequency
    - Increases system performance
- ✓ Annual PM conducted by Engineering & Operations to review all existing PVD/TVA installations and to repair/replace any deficient devices
- ✓ WIV study on 12" and 14" Alpine Pipelines (November 2000 – November 2001)
  - Existing WIV Mitigation Program performs as designed
  - Design wind fan criteria valid (N45°W-N30°E) *paper & field wedge use TVA/PVDs*
- ✓ NO failures attributed to pipelines employing PVD/TVA devices since program inception *place*
  - 2X failure in January, 2002 (small LOF in weld root) *Small low displacement passing by what was*
    - 1° outside wind fan design criteria *(= 10% of design)*
    - No PVD/TVA devices installed prior to failure

## Wind Induced Vibration

- ✓ Identified 6 cross-country pipeline routes within design envelope requiring PVD/TVA devices
  - Design/installation in progress
  - DS3N to be monitored – falls directly on N45°W periphery of design envelope
- ✓ PVD/TVA installation effectively remediates initiation and/or propagation of any indications or defects
  - Vibration P-P amplitude limited
  - Stress range limited
- ✓ Quantitative & Qualitative Assessment
  - TRT, VT – (435 weld pack locations – 70 locations w/ C-rank & D-rank damage)
  - UT – (22 locations – 1 locations w/ C-rank damage)
  - RTR – (Aggregate total of 10,892 ft – 11% worst-case wall loss)
  - Exhaustive NDE techniques during construction
  - Tough, ductile materials (Specifications, CVN, CTOD, hardness, etc.) *Co. Specs for -50° requirements - goes beyond wall*
  - Continuous improvement of PVD/TVA system performance
  - Regardless of pipe wall damage mechanism, no failures have occurred since program inception validating the remediation effectiveness of PVD/TVA installations

2002

## External Corrosion

- No incidents to report

## Internal Corrosion

- 2A-18 Well Line Leak at Cosasco Fitting/Elbow (4/7/02); previously reported
- 2T-13 Well Line Leak (7/25/02)

## Other Structural

- No incidents to report

# Spills/Incidents

6" 2A-18 PO Well Line Leak

4/7/02

ConocoPhillips

## Scenario:

- Leak area was a pinhole located just above the weld, where a thread-o-let used for Cosasco fitting access was located in a 90° elbow
- 1200 gallons of product (8% oil and 92% produced water) on-pad
- ⇒ Cause appeared to be flow-assisted corrosion in flow disturbance area



## All Action Items Complete:

- ✓ Inspected remainder of 2A-18 well line prior to returning to service
  - Post-spill inspection of well line showed no areas required repair, other than leak location
- ✓ Completed survey for similar locations at all Drill Sites (283 locations)
- ✓ Completed RT inspections on all 283 similar locations on 6/22/02
  - No repairs required due to this corrosion mechanism
  - Two repairs due to other causes (questionable original weld, deteriorated threads)
- ⇒ Inspections confirm theory of isolated mechanism
- ✓ Added these locations to recurring interval survey for each well line

*2000 ft of pipe had been in numerous service types - do not think there is benefit in making surveys for rep interval determinations*

# Spills/Incidents

6" 2T-13 PO Well Line Leak

7/25/02

ConocoPhillips

## Scenario:

- Leak occurred shortly after shutting-in well at manifold building
- Leak was isolated within 5 minutes by closing wing valve at wellhead
- 10 gallons of product (41% oil and 59% produced water) spilled, contained on-pad
- Leak occurred in 0.375" wall thickness section of line at a weld pack
- Completion of investigation delayed due to lack of access

*determined 2 weeks ago*

## Background/Inspection History:

- Pre-spill inspections on this line consisted of:
  - weld-packs
  - branch connections (part of 2A-18 follow-up inspections)
- Piping was originally installed at DS 3R, then reclaimed for use at 2T-13 in 1996
  - Pipe was new when installed and abandoned at DS 3.
  - Condition of pipe when installed at 2T-13 in 1996 is unknown
- Based on age (6 years) and wall thickness of 0.375", this section was not scheduled for initial internal inspection until 2004.

*don't know if hydrotested  
@ 3R was Hydrotested  
@ 2T ←*



# Spills/Incidents

6" 2T-13 PO Well Line Leak

7/25/02 ConocoPhillips

## Post-Spill Inspections:

- Post-spill inspections initially limited to accessible areas:
  - Showed substantial, but non-derating damage on 0.312" wt section
  - Showed only minor (<20%) damage in accessible 0.375" wt section
- Access finally allows completion of inspections (October 2002):
  - Showed cause to be severe internal under-deposit corrosion, evident throughout the 0.375" wt section
  - Low fluid velocity is causal factor (???)

*diff Reservoir*

## Action Plan:

- Evaluate replacement line size for well 2T-13 to minimize under deposit corrosion when well is placed back into service - **Complete** (4" piping will be used)
- Inspect all well lines at DS 2T for internal corrosion, to determine if similar conditions exist
- Based on inspection results, determine if inspection criteria across field should be modified
- Target completion March 2003

*not just 0.312"*

*rechemical or other 3R lines  
re configuration pipe - also need @ 2T  
must det FFS in place -  
11/4/02 when*

- **CUI Buffer Spikes installed at 76 test locations in fall 2002**
- **Initial pH readings found at 6 to 7 pH** *- Baseline*
- **Follow-up pH testing and evaluation scheduled for summer 2003**

*Test for diffusion*

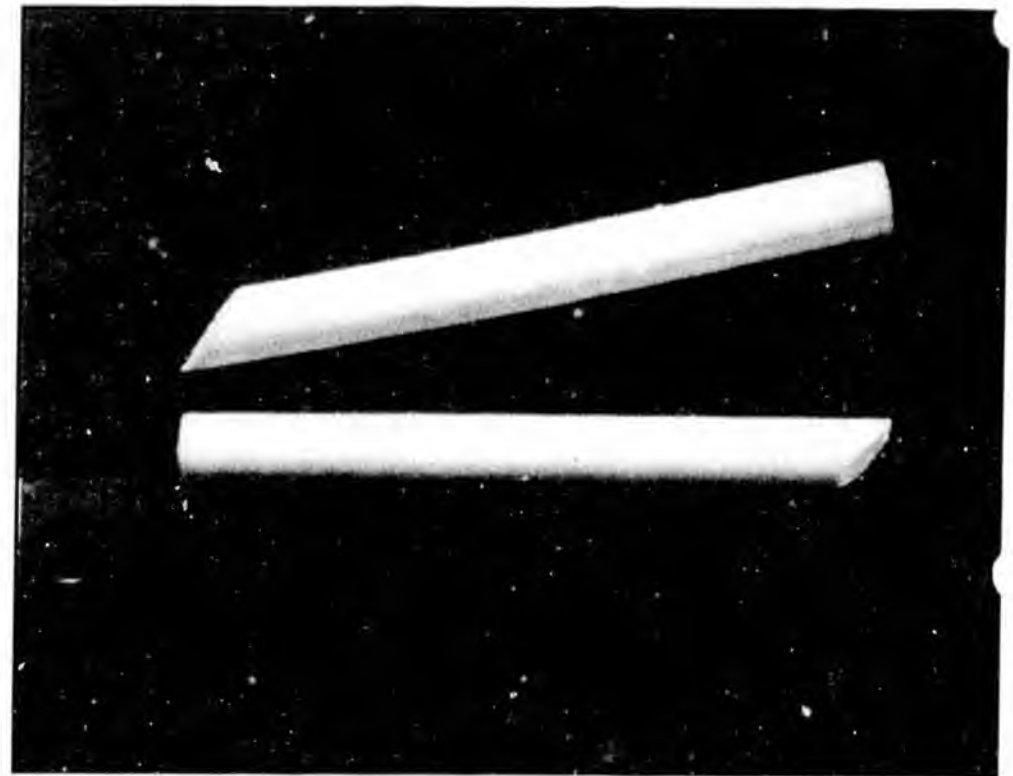
## Buffer spike:

stick of sodium phosphate (a buffer salt)

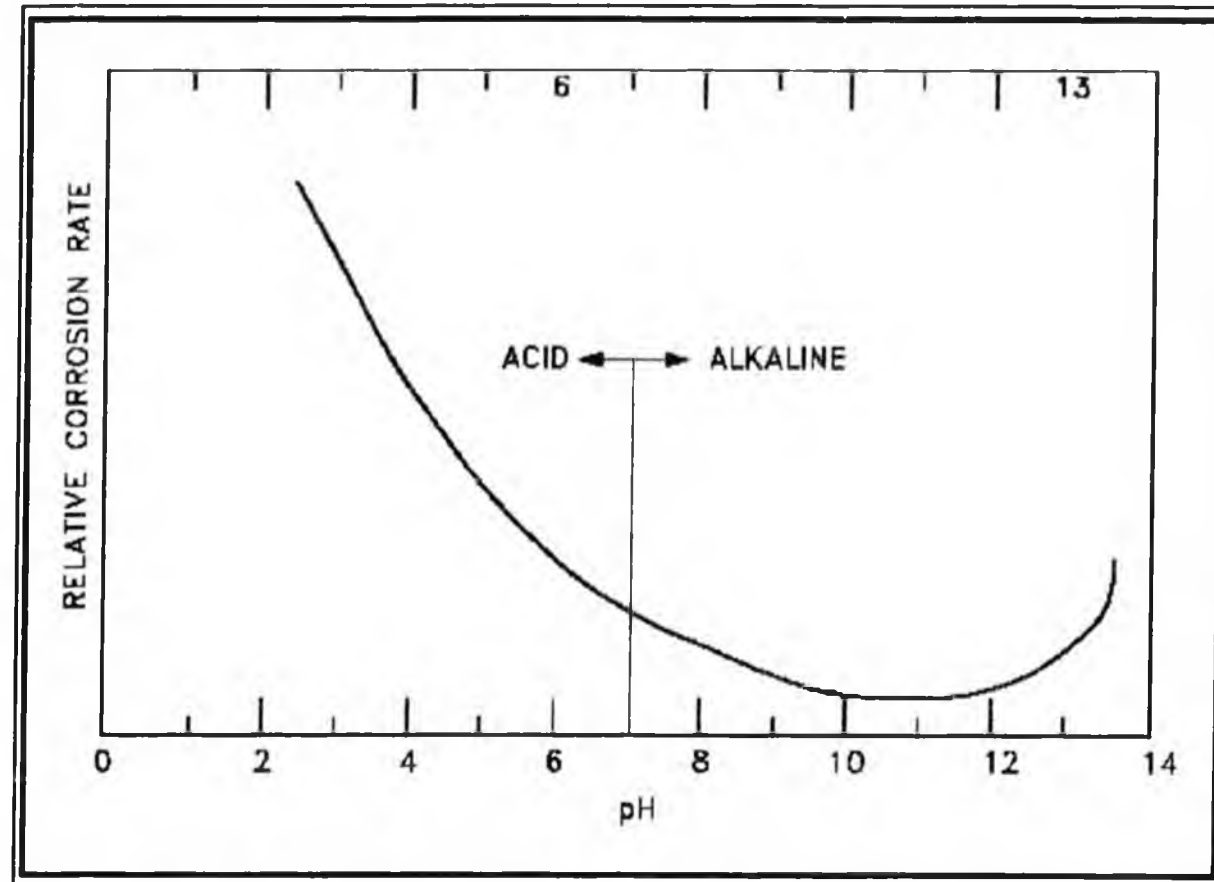
Dissolve into weld pack moisture

Create an environment with a stable pH of about 10 (basic):

*capillary action*



Steel corrosion rates decrease as pH increases  
(Alkaline solutions slow corrosion)



SPRING 2003

4/28/03

# ADEC MEET & CONFER V

<u>NAME/TITLE</u>	<u>COMPANY</u>	<u>PHONE/EMAIL</u>
FELIX / CORR. ENGR	BP	564-4466 / felixrd@bp.com
KIP SPRAGUE / INT. ANALYST	BP	564-4462 / spragukp@bp.com
RICHARD C WOOLAM / CIC Manager	BP	564-4437 / woollarc@bp.com
Mike Scribner / Prod Assurance	COP	918 661-0400 / mikescribner@conocophillips.com
David Blument / Prod Assurance	COP	918-661-5414 / david.blument@conocophillips.com
Jeff Huber / CPF3 Prod. Sup	CPAI	659-7682 / j1175@conocophillips.com
Bob Bray / O&A OPERATIONS SUPPORT MGR	CPAI	659-7284 / rdbray@pcc.com
CHRIS DASH / CORROSION ENGINEER	CPAI	263-4870 / Chris.Dash@conocophillips.com
Red Faires / Corr. Engr.	CPAI	659-7149 / n1462@conocophillips.com
Phil Goldman / Corr Engr	CPAI	659-7149 / n1462@conocophillips.com
Ken Kuzma / Corr. Engr.	BP&A	564-4439 / kuzmak@bp.com
Randy Heald / Director of Process Analysis	ConocoPhillips	918 661-3156 / randy.l.heald@conocophillips.com
Mike Gahr / Corr Engr.	CPAI	907-659-7869 n1297@conoco
Tom DeRuyter / Environmental Specialist	ADEC	451-2145 Tom.DeRuyter@dec.state.ak.us
MICHAEL WATTS / CORROSION ENG	1 <sup>ST</sup> PRIN	310-367-8632 / MIKEBIKE1@aol.com
Al Dahlquist / CPA corrosion Eng (Insp)	CPAI	651-7773 / n1115@conocophillips.com
Tim BIERI / COFFMAN ENGINEERS		276 6664 / bieri@alaska.coffman.com
Lydia Miner / EPR Section Manager	ADEC	269-7640 / lydia-miner@dec.state.ak.us
SAM SAENGSUDHAM / <del>PTI</del> SECTION MANAGER	ADEC/SPAC	269-3075 / SAM_SAENGSUDHAM@DEC.STATE.AK.US
TED MOORE / EST III	ADEC/SPAC/IPF	267-2567 / TED.MOORE@DEC.STATE.AK.
ARIA CHERRY / Eng & Corr Supv		

BP

# CORRECTION

THE FOLLOWING DOCUMENT(S)  
HAVE BEEN REFILMED TO  
ASSURE LEGIBILITY OR PAGINATION



Central Microfilm Services  
Department of Education & Early Development  
State of Alaska

4/28/03

# ADEC MEET & CONFER V

<u>NAME/TITLE</u>	<u>COMPANY</u>	<u>PHONE/EMAIL</u>
FELIX / CORR ENGR	BP	564-4466 / felixrd@bp.com
KIP SPRAGUE / INT. ANALYST	BP	564-4462 / spraguokp@bp.com
RICHARD C WOOLAM / CIC MANAGER	BP	564-4437 / woollarc@bp.com
Mike Scribner / Prod Assurance	COP	918 661-0400 / mikes.scribner@conocophillips.com
David Blunier / Prod Assurance	COP	918-661-5414 / david.blunier@conocophillips.com
Jeff Huber / CPF3 Prod. Sup	CPAI	659-7682 / jh1175@conocophillips.com
BOB BRAY / O&A OPERATIONS SUPPORT MGR	CPAI	659-7289 / rdbray@poco.com
CHRIS DASH / CORROSION ENGINEER	CPAI	263-4878 / Chris.Dash@conocophillips.com
KEVIN FRANKS / CORR ENGR	CPAI	550-... / n1462@conocophillips.com
EL GOLDMANN / CORR ENGR	CPAI	659-7149 / n1462@conocophillips.com
KU ZMAJKA - CORR. ENGR.	BP&A	564-4449 / kuzmajka@bp.com
Randy Heald / Director of Process Analysis	ConocoPhillips	918 661-3156 / Randy.L.Heald@conocophillips.com
MIKE GAHR / CORR ENGR.	CPAI	907-659-7869 n1297@conoco
Tom DeRuyter / Environmental Specialist	ADEC	451-2145 Tom.DeRuyter@DEC.state.ak.us
MICHAEL WATTS / CORROSION ENG	1ST PRIN	310-367-8632 / MIKEBIKE1@att.net
Al Danquist / CPA corrosion Eng (Insp)	CPAI	657-7773 / n1115@conocophillips.com
TIM BIERI / COFFMAN ENGINEERS		276 6664 / bieri@alaska.coffman.com
Lydia Miner / EPR Section Manager	ADEC	264-7480 / lydia-miner@dec.state.ak.us
SAM SAENGSUDHAM / <del>PTI</del> SECTION MANAGER	ADEC/SPAR	269-3078 / SAM_SAENGSUDHAM@DEC.STATE.AK.US
TED MOORE / EST III	ADEC/SPAR/IPF	267-2567 / TED_MOORE@DEC.STATE.AK.
MARIA CHERRY / Eng & Corr Supv		

<u>NAME/TITLE</u>	<u>COMPANY</u>	<u>PHONE/EMAIL</u>
Gary R Crawford <sup>aka North Slope</sup> TL	BP	659-5050 <a href="mailto:gcrawford@bp.com">gcrawford@bp.com</a>
George Blankenship / BP CPO Ad Mgr	BP	509-5111 <a href="mailto:george.blankenship@bp.com">george.blankenship@bp.com</a>
John Phillips	BP	857-5000 / <a href="mailto:jphillips@nsluic.tl.ep.gov">jphillips@nsluic.tl.ep.gov</a>
Bill Hutmacher	ADEC	269-3054 / <a href="mailto:bill-hutmacher@dec.state.ak.us">bill-hutmacher@dec.state.ak.us</a>

BP

28 April 2003



**BP and State of Alaska Charter Agreement**  
**Corrosion Monitoring Review 2002**  
**Meet and Confer V**

**April 28<sup>th</sup>, 2003**



**Outline**

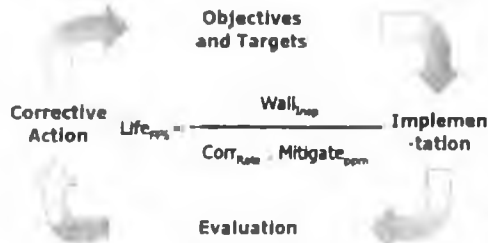
- ▶ **Corrosion Management Program/Objectives**
- ▶ **GPB**
  - » **3 Phase Production**
    - Weight loss coupons
    - ER probe
    - Corrective actions
  - » **Water Injection Systems**
    - Weight loss coupons
    - Corrective actions
  - » **External Corrosion**
    - Inspection
    - Cased Piping Segments
- ▶ **ACT**
  - » **GPB and ACT Comparison**
    - Size and corrosivity
  - » **ACT Highlights**
    - Selected corrosion management examples
- ▶ **Summary**

## Corrosion Management Program



### ▶ Strategic Objectives

- ▶ Minimize HSE Impacts
  - Corrosion loss of containment
- ▶ Fit-for-service Infrastructure
  - Remaining field life
  - With gas sales 50+ years
- ▶ Infrastructure Integrity
  - Satellite fields
  - Use of existing infrastructure
- ▶ Future Major Gas Development
  - Utilize existing facilities
  - Gas sales demands longevity



Step	Program Elements
Plan	<b>Objective</b> Program objective and purpose
Do	<b>Target</b> Performance metric
Check	<b>Implementation</b> Plan to achieve objective
Act	<b>Evaluation</b> Method to evaluate performance
	<b>Corrective Action</b> Correct deviation from target

April 2003

BP/ADEC Meet and Confer V

3

## System-by-System Review



### ▶ Elements of Long Term Fitness For Service

- ▶ Corrosion monitoring
- ▶ Inspection
  - Condition
  - Increases
- ▶ Mitigation/corrosion control
- ▶ **Weight Loss Coupons**
  - ▶ Flow Line
  - ▶ Well Line
- ▶ **Inspection Increases**
  - ▶ Correlation between inspection increases and WLC
- ▶ **Equipment Condition**
  - ▶ Increases and condition correlation
- ▶ **Mitigation**
  - ▶ Correlation between corrosion rate and CI concentration

April 2003

BP/ADEC Meet and Confer V

4



### 3 Phase Production

- ▶ **Weight Loss Coupons**
  - ▶▶ Flow lines
  - ▶▶ Well lines
- ▶ **ER Probe Example**
- ▶ **Corrosion Inhibitor Injection**
  - ▶▶ Concentration
  - ▶▶ Water rates
- ▶ **Monitoring Corrective Actions**
  - ▶▶ ER probes and coupons
- ▶ **Inspection**
  - ▶▶ Flow and well line summaries
- ▶ **Inspection Corrective Actions**
- ▶ **3 Phase Inhibition Summary**

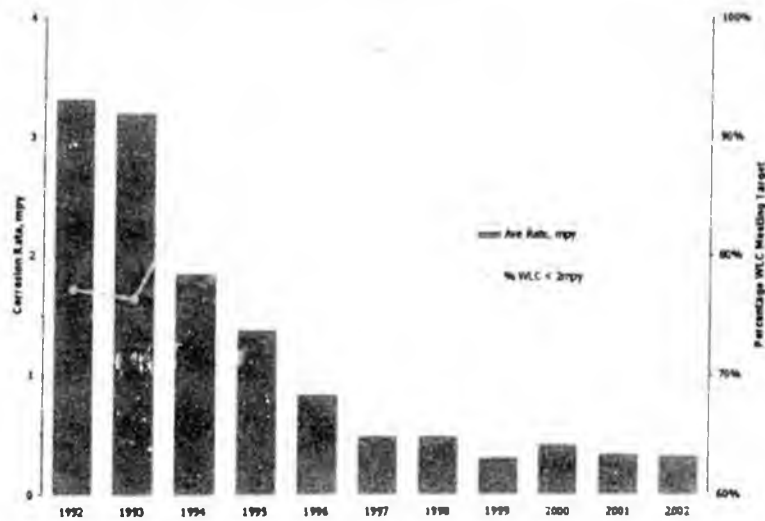
April 2003

BP/ADEC Meet and Confer V

5



### 3 Phase – Flow Line Coupons

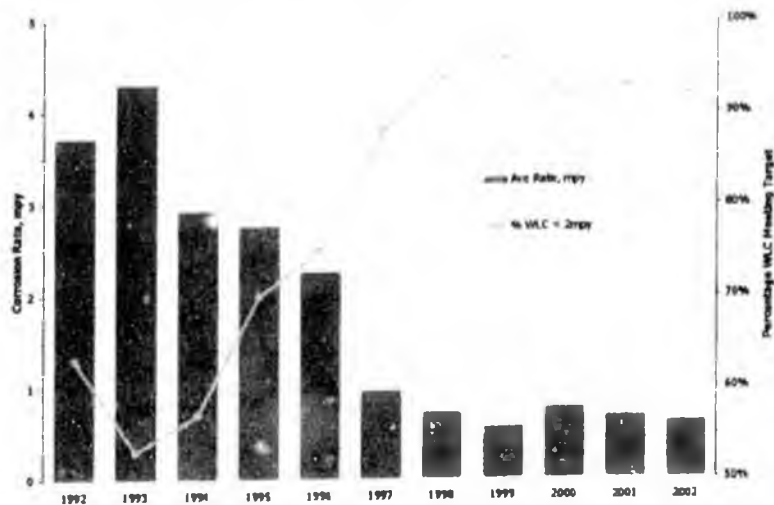


April 2003

BP/ADEC Meet and Confer V

6

### 3 Phase – Well Line Coupons



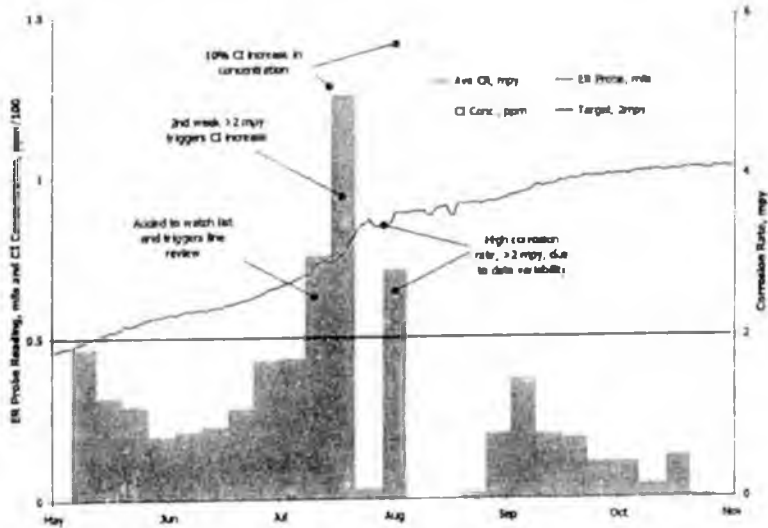
April 2003

BP/ADEC Meet and Confer V

7

*7/3 wells are in continuous well head injection*

### ER Probe Example I

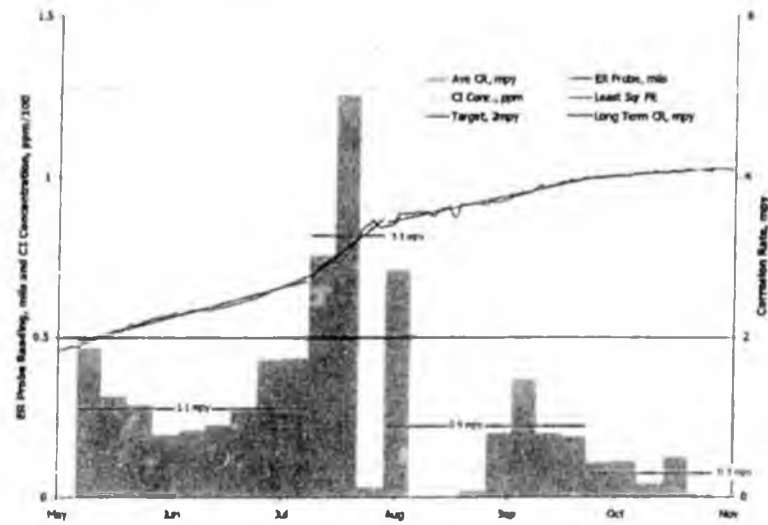


April 2003

BP/ADEC Meet and Confer V

8

## ER Probe Example II



April 2003

BP/ADEC Meet and Confer V

9

## Monitoring Corrective Actions

### ▶ ER Probe Corrective Actions

Equipment ID	Cause	Action
A Pad	Increased Corrosivity	Increased CI by 5%
A Pad	increased Corrosivity	increased CI by 5%
D504	increased Corrosivity	increased CI by 5%
GRX-E	increased Corrosivity	See Table H 4
A Pad	increased Corrosivity	increased CI by 5%
C105B	increased Corrosivity	increased from 3 to 4 gpd

### ▶ Coupon Corrective Actions

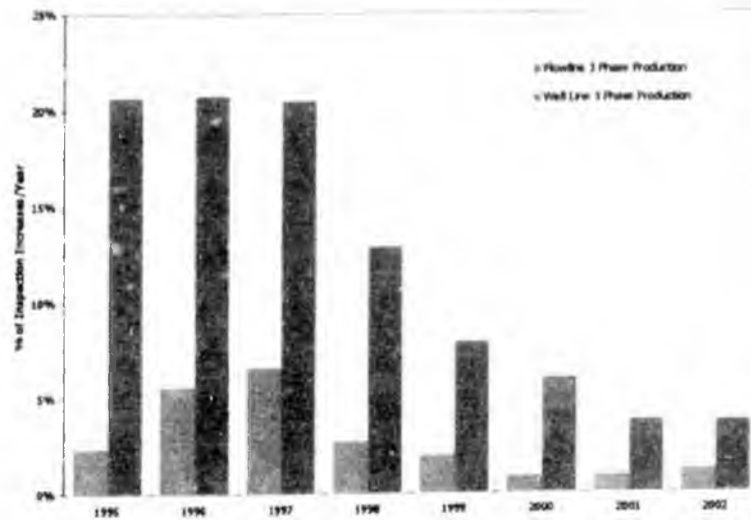
Equipment ID	Cause	Action
D514	increased Corrosivity	increased CI by 10%
C14D	increased Corrosivity	increased CI by 10%
C105D	increased Corrosivity	increased CI by 20%
F Pad	increased Corrosivity	See Table H 4
Seawater	O <sub>2</sub> Microbiological	Multiple

April 2003

BP/ADEC Meet and Confer V

10

## Inspection Program



April 2003

BP/ADEC Meet and Confer V

11

## Inspection Corrective Actions



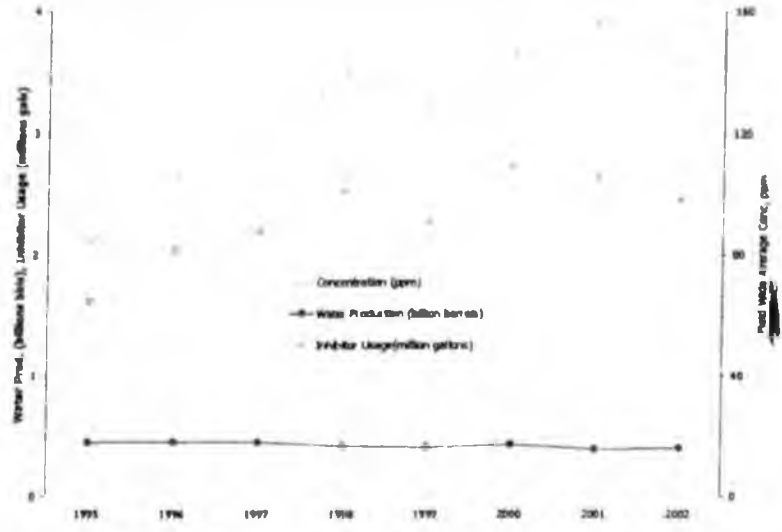
Equipment ID	Cause	Action
D509	Increased Corrosivity	Increased $\square$ by 10%
H Pad	Increased Corrosivity	Increased $\square$ by 10%
F Pad	Increased Corrosivity	Increased $\square$ by 10%
GH-E	Increased Corrosivity	Increased $\square$ by 25%
PW system	Increased Corrosivity	Multiple
SW system	O <sub>2</sub> /Microbiological	Multiple

April 2003

BP/ADEC Meet and Confer V

12

## Corrosion Inhibition Summary I



April 2003

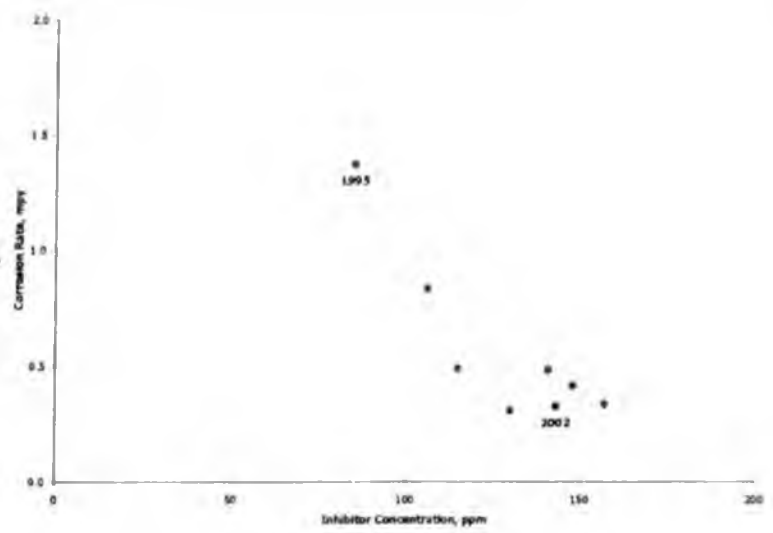
BP/ADEC Meet and Confer V

13

## Corrosion Inhibition Summary II



*3 phase Flow Line Coupons*



April 2003

BP/ADEC Meet and Confer V

14

## Water Injection Systems



- ▶ **Flow Line Water Injection**
  - ▶ Mixed service
- ▶ **Reporting Format**
  - ▶ Single service
  - ▶ Service plurality
- ▶ **Weight Loss Coupons**
  - ▶ Produced Water system
  - ▶ Seawater system
- ▶ **SW Mitigation**
  - ▶ Oxygen control
  - ▶ Biocide and corrosion rate
- ▶ **Inspection**
  - ▶ Flow and well line

April 2003

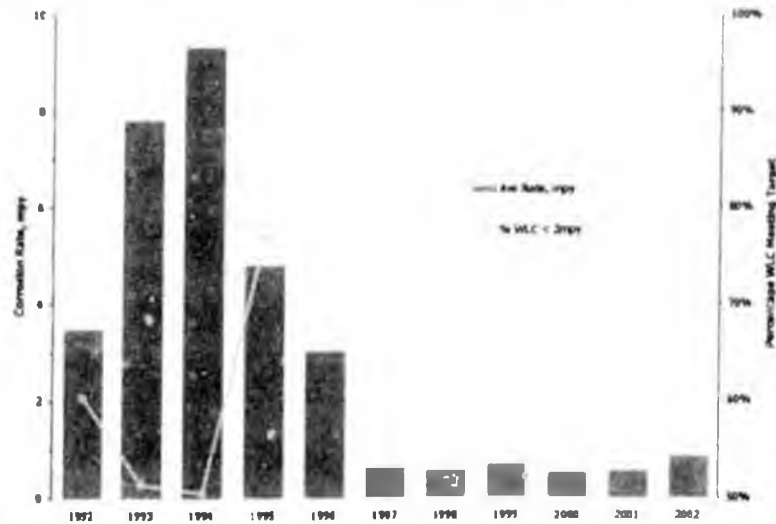
BP/ADEC Meet and Confer V

15

*Upstream CI helps*

## Water Injection Flow Line

*dominant*  
*produced water and seawater*



April 2003

BP/ADEC Meet and Confer V

16

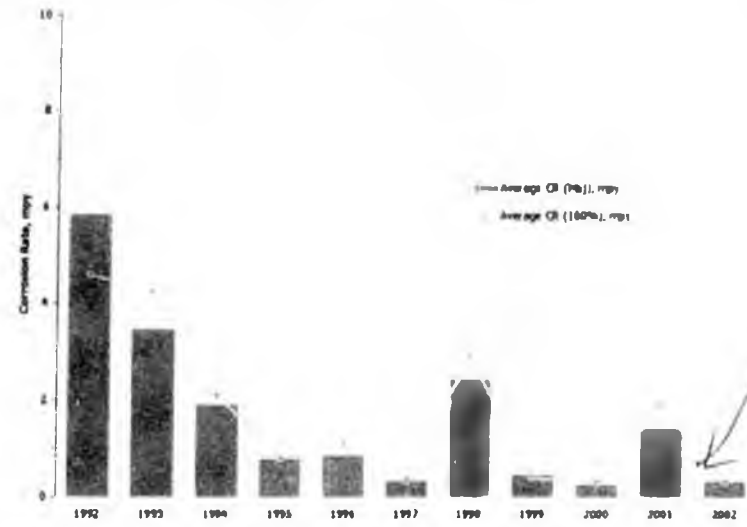


## Well Line Reporting Format Change

- ▶ Follow-up to 4Q 2002 Meet and Confer Session
- ▶ Subsequent BP Activities to Address ADEC Concerns
  - ▶ Investment in IT technology
  - ▶ Dynamic link production database with corrosion and inspection database
  - ▶ Positive
    - Can now report detailed service changes
    - Improved data quality and tracking
  - ▶ Negative
    - Change in reported results format
- ▶ Proposed Change to Reporting Format
  - ▶ By Report Date      Mid point of the exposure period  
Date In + (Date Out - Date In)/2
  - ▶ By Service Type      (a) Ave corrosion rate with 100% exposure to service  
                                  (b) Ave corrosion rate with simple service plurality

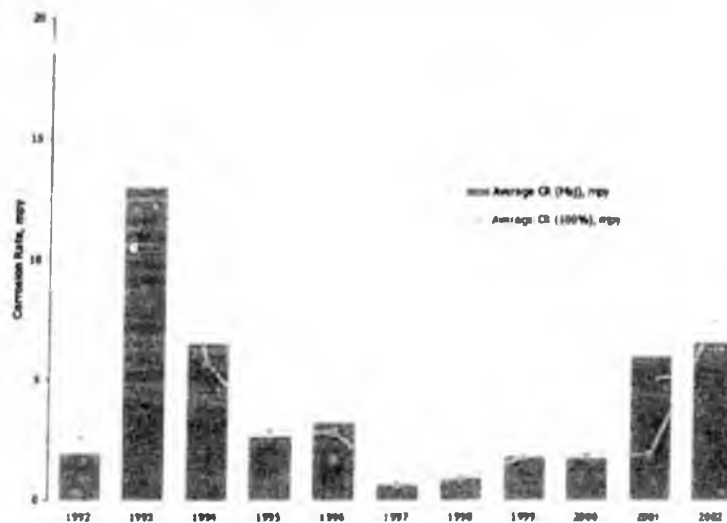


## PW System - Well Line



Changed chemical to potentially go to water system.  
Added CI at Island ES3

### SW System – Well Line – Corrosion Rate



April 2003

BP/ADEC Meet and Confer V

19

*100% SW since is a very small data set (about 5 coupons)*

### SW System – Well Line – Pitting Rate

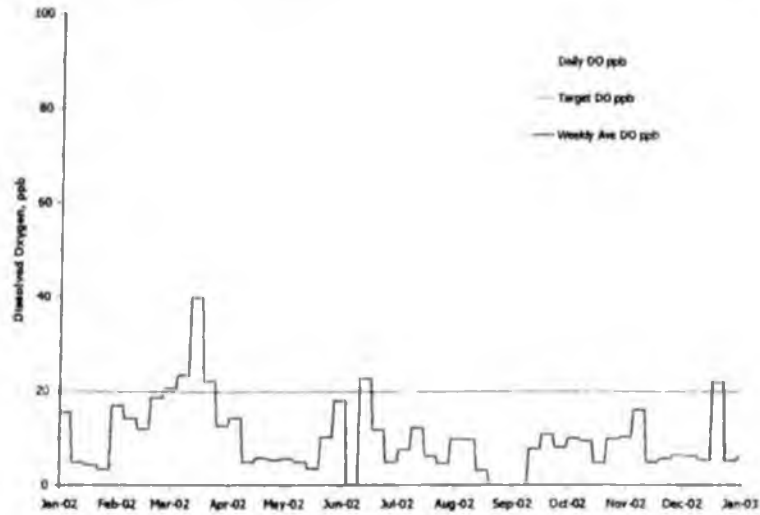


April 2003

BP/ADEC Meet and Confer V

20

## 2002 Oxygen Control

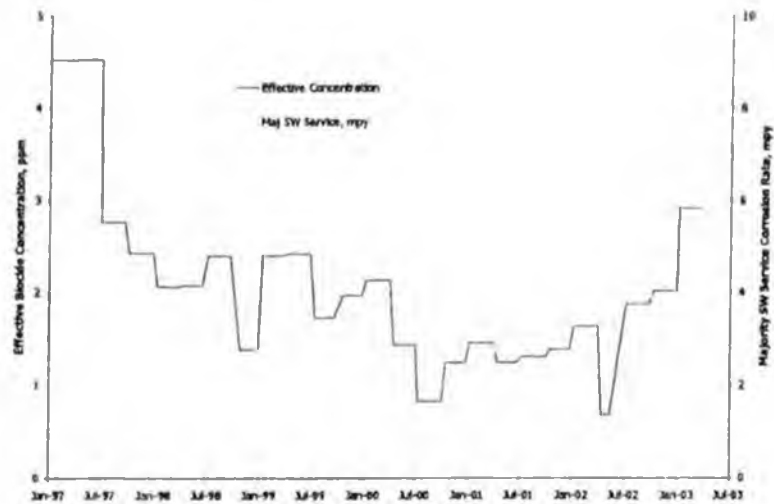


April 2003

BP/ADEC Meet and Confer V

21

## Biocide and Corrosion Rate

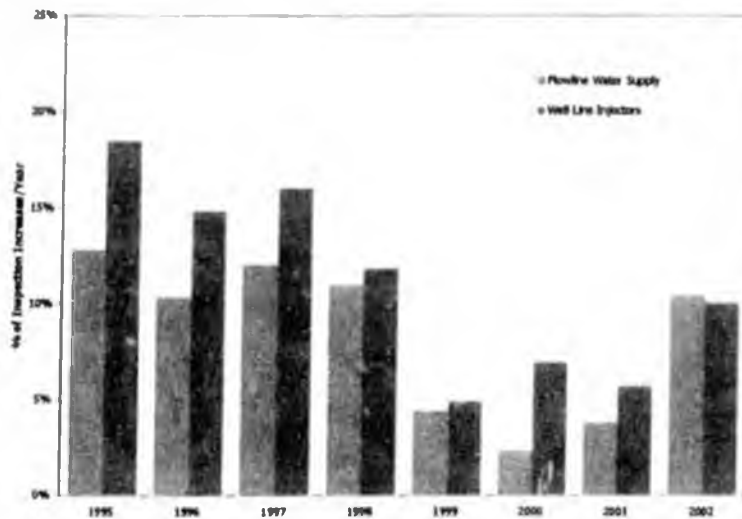


April 2003

BP/ADEC Meet and Confer V

22

## Flow and Well Line Inspection

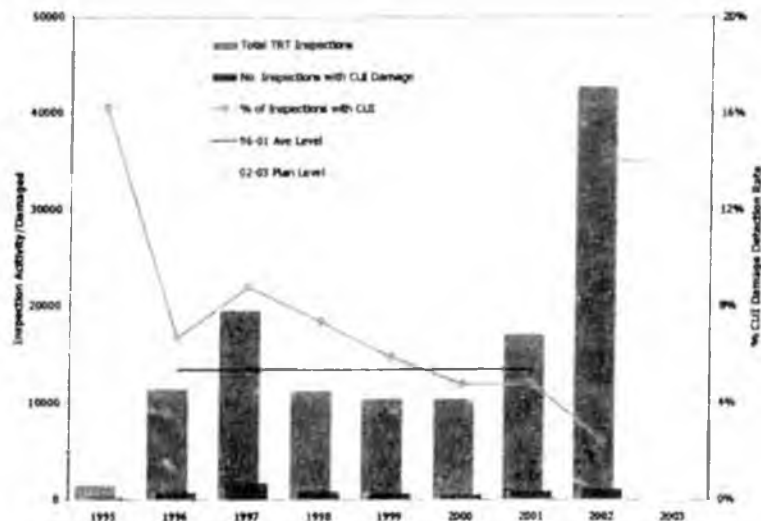


April 2003

BP/ADEC Meet and Confer V

23

## External Corrosion Inspection

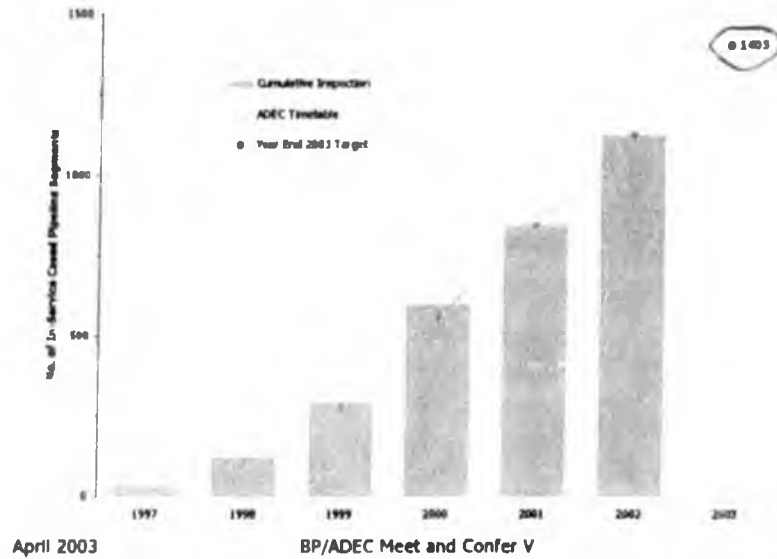


April 2003

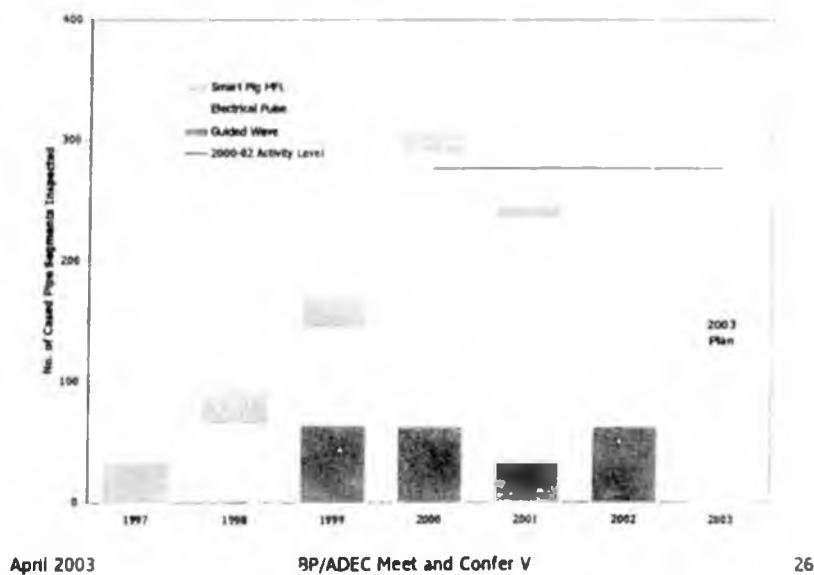
BP/ADEC Meet and Confer V

24

## Cased Piping Inspection I



## Cased Piping Inspection II





## 2002 Program Performance I

### ▶ 4 Corrosion Related Leaks in 2002

Service	Location	Type	Date	Mechanism	Volume
3 phase production	F-48	S-riser	14-Jan-02	Erosion	115 gal
	H-21	S-riser	18-Apr-02	Int	84 gal
	13-12	WL	14-Jun-02	Ext	1 qt
	Z-LDF	FL	4-Oct-02	Ext	4 gal

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

### ▶ Repairs

- ▶▶ 78 repairs
  - 57 - external corrosion
  - 20 - internal/erosion
  - 1 - mechanical damage

April 2003

BP/ADEC Meet and Confer V

27



## 2002 Overview

### ▶ Maintained Three-Phase System

- ▶▶ No impact as a result of chemical change

### ▶ SW/PW Program Improvement

- ▶▶ Seawater
  - Performance improvement from implemented corrective actions
  - Additional actions as required in 2003
- ▶▶ Produced water
  - Supplemental corrosion inhibitor
  - Improved compatibility of upstream inhibition

### ▶ Inspection Program

- ▶▶ Implementation of expanded External Corrosion Program
  - ~43,000 items versus historical ~13,000
- ▶▶ Baseline Inspection of cased piping segments
  - ~269 segments to be inspected in 2002
  - On target to complete baseline in 2003

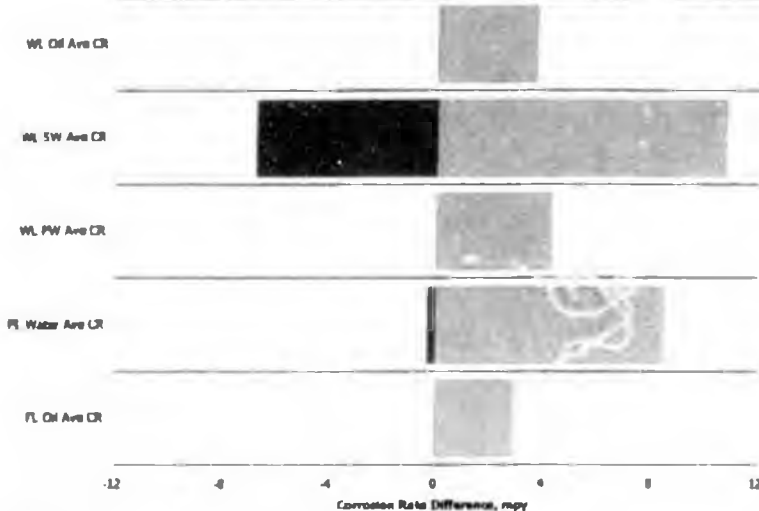
April 2003

BP/ADEC Meet and Confer V

28

## 2002 Corrosion Rate Status Against History

\* Difference Between CR 2002 and Best in Last 10 Years / Difference Between CR 2002 and Worst in the Last 10 Years



April 2003

BP/ADEC Meet and Confer V

29

## GPB 2003 Goals and Objectives

- ▶ **Corrosion Monitoring**
  - ▶ Coupon – no significant changes
  - ▶ ER probes – no significant changes
- ▶ **Inspection Program**
  - ▶ No significant changes planned for 2003
- ▶ **External Corrosion Inspection**
  - ▶ Weld pack inspections ~35,000
- ▶ **Cased Piping Inspection**
  - ▶ Complete baseline assessments
- ▶ **Chemical Mitigation**
  - ▶ Large scale changes – none planned
  - ▶ Testing/field trials – significant activity planned
- ▶ **Technology**
  - ▶ High speed/sensitivity ER probes
  - ▶ Remote tank strap reading – CI trucks

April 2003

to monitor injection rate  
BP/ADEC Meet and Confer V

30