

Commitment to Corrosion Monitoring



- **External corrosion**
 - Significant exposure to leaks and reputation
 - Both of GPB's corrosion related pipeline leaks in 2000
 - Highly localized damage, random process
 - Leads to localized repairs, not pipeline replacement
 - Managing 1/3 million weld packs, not 2,400 pieces of equipment
 - ▫ Cased road crossings difficult to inspect & repair

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Commitment to Corrosion Monitoring



- **External corrosion control**
 - Removal or repair of insulation
 - Localized coating
 - Cathodic protection in cased crossings
 - 'Inhibitor spikes' being developed
- **Typical target values**
 - Remove or repair insulation before pipeline requires a mechanical repair
 - External corrosion control is currently reactive
 - Aim to move to proactive control with inhibitor spikes

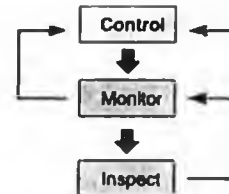


Table 11: Mechanical Repairs Installed

Service	Internal	External
Cross country	1	1
Production well line	6	13
Lift Gas	0	3
PWI	0	6

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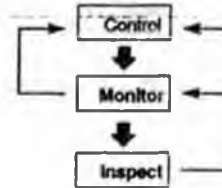
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Commitment to Corrosion Monitoring



External monitoring & inspection

- Tangential radiographic testing - TRT
- Automated TRT
- C-scan
- Eddy current
- Smart pig
- Electromagnetic wave
- Guided wave



Typical target values

- Control
 - Irregular surface contour - T_{max}
 - 'Significant' or 'severe' anomalies
- Mechanical Integrity
 - Modified B31.G
 - 0.105" minimum wall thickness
 - 105% MAOP

Table 8: Recurring Frequency of CUI Inspection Surveys

Equipment Temperature	Interval Between Examinations (Years)
≤80° F	10
>80 - 120° F	8
>120 - 150° F	6
>150° F	4

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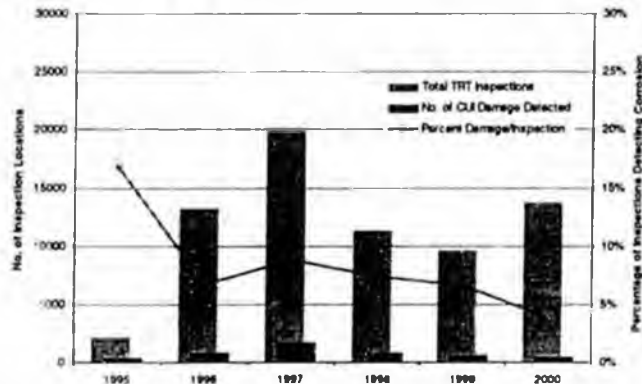
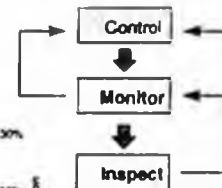
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GPB external corrosion control

- Driven by inspection program
- Detection & repair rates falling
- Indicates program is successful at reducing risk



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Commitment to Corrosion Monitoring



• Summary

- Internal corrosion
 - Control method is understood and manageable
 - Current rates of corrosion are the lowest for 12 years
 - Remaining pipeline life is being managed via reduction in corrosion rates
 - Strategies for field life and corrosion management are in alignment
- External corrosion
 - Limited options for control and monitoring
 - Current program is reducing risk by eliminating corroded areas
 - New control and inspection technology will play key role in the future
- Overall
 - Corrosion rates are lower than for many years
 - Risk of loss of containment is lower than for many years

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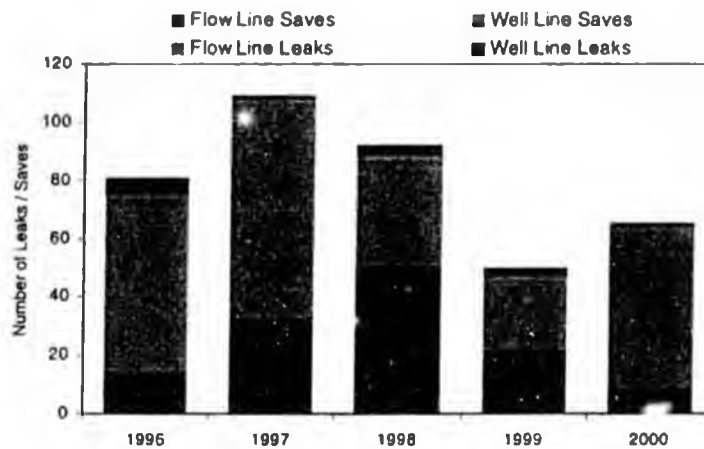
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Summary of recent leak & save data



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Commitment to Corrosion Monitoring



Areas of Focus for 2001

- Program Integration
 - Significant progress made in 2000
 - Substantial work remains to be done
- Control
 - Maintain or improve corrosion control of cross country pipelines
 - Rationalize number of corrosion inhibitors
 - Automated chemical tracking system
 - Improve chemical wellhead distribution
- Monitor
 - Development of enhanced erosion monitoring program
 - Unification of weight loss coupon program
- Inspect
 - Common database
 - Digital radiography
 - Smart pig 3 pipelines
 - 200 cased pipe segments using electromagnetic & guided wave

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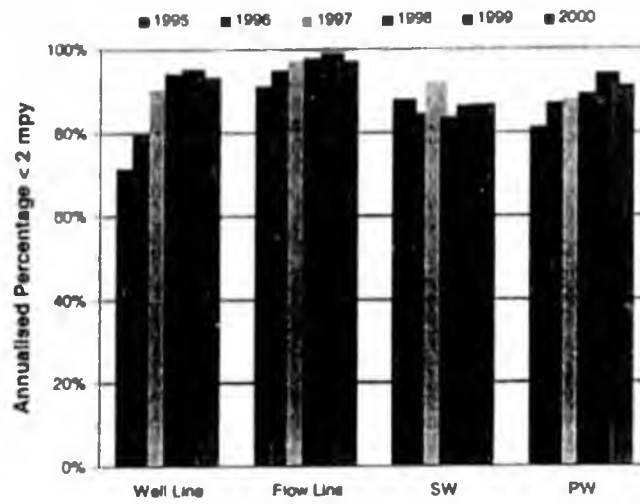


Back Up Slides

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Greater Prudhoe Bay Figure 1
Summary of Corrosion Coupon data 1995 - 2000



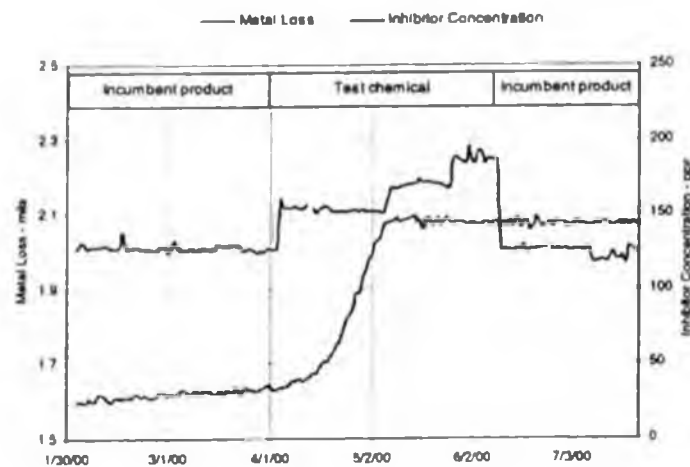
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Greater Prudhoe Bay Figure 2
Chemical optimization in response to corrosion probe data



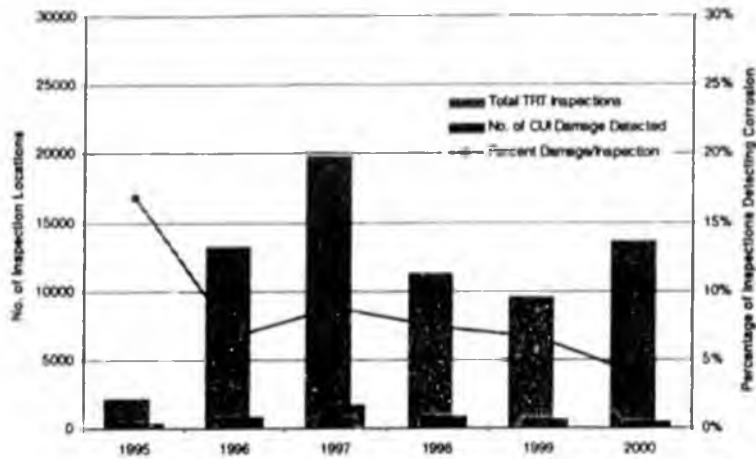
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Greater Prudhoe Bay Figure 3
External Inspection using tangential radiographic testing



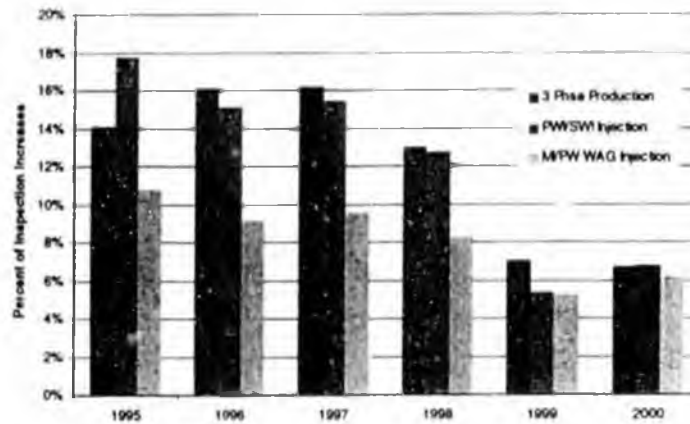
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Greater Prudhoe Bay Figure 4
Detection of internal corrosion of well lines by inspection



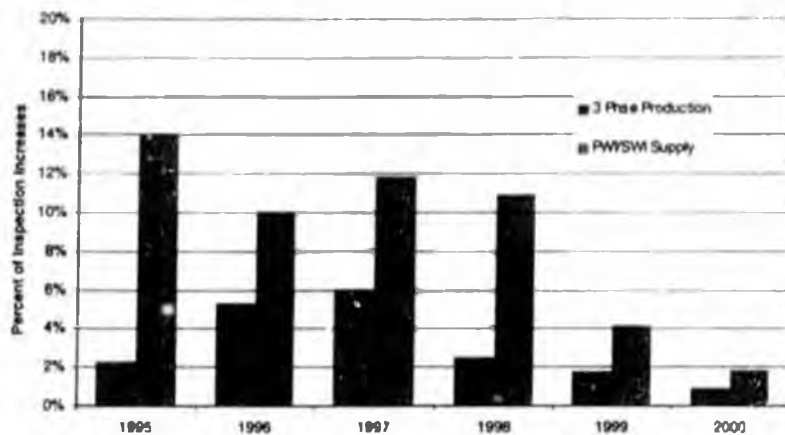
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Greater Prudhoe Bay Figure 5
Detection of internal corrosion of cross country pipelines



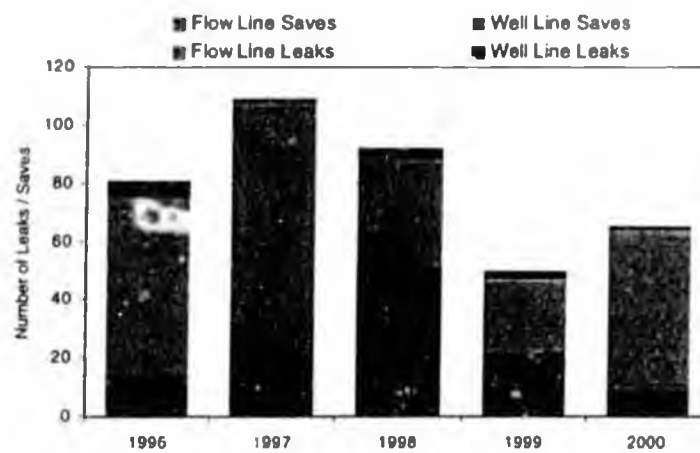
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Greater Prudhoe Bay Figure 6
Leaks and saves of well lines and cross country lines



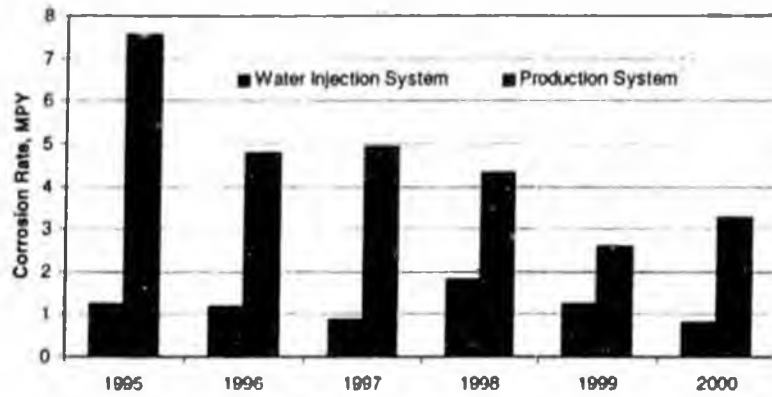
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Alaska Consolidated Team Figure A1
Corrosion coupon data from Endicott 1995-2000



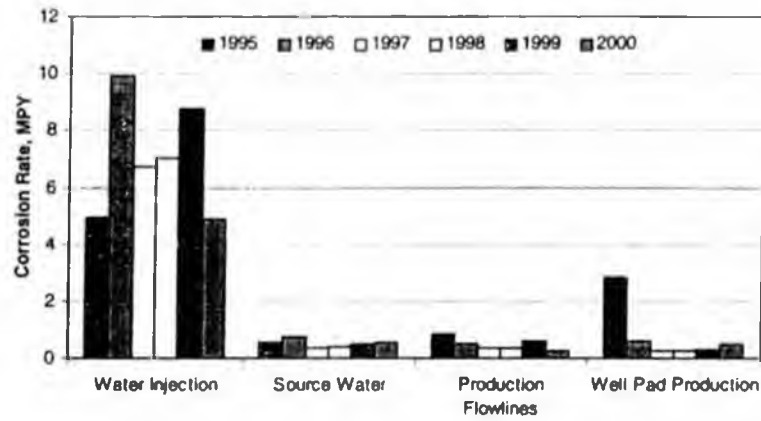
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Alaska Consolidated Team Figure A2
Corrosion coupon data from Milne Point 1995-2000



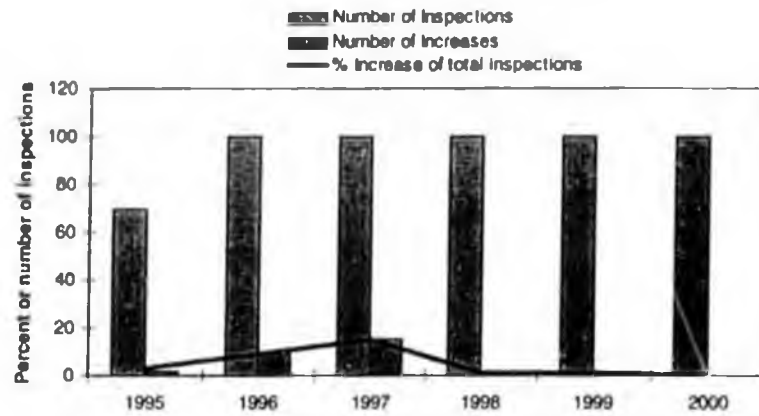
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Alaska Consolidated Team Figure A3
Endicott IIWL quarterly UT readings



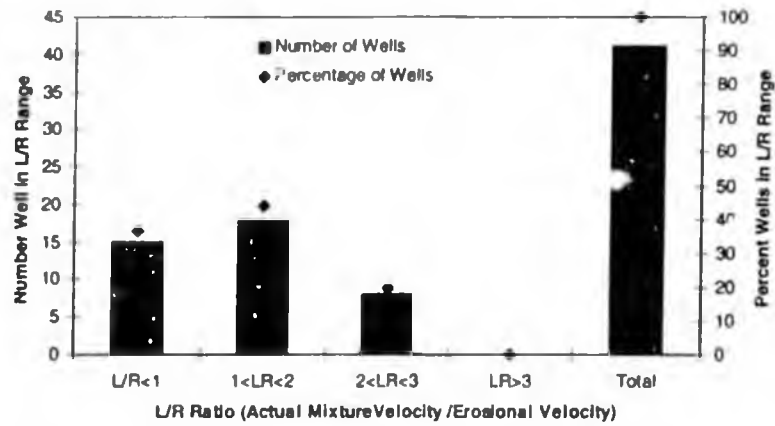
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Alaska Consolidated Team Figure A4
Endicott Velocity Monitoring



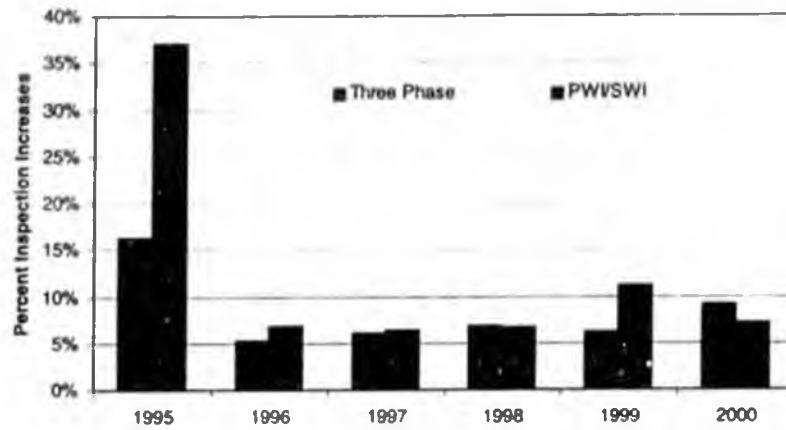
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Alaska Consolidated Team Figure A5
Detection of internal corrosion of well lines at Endicott



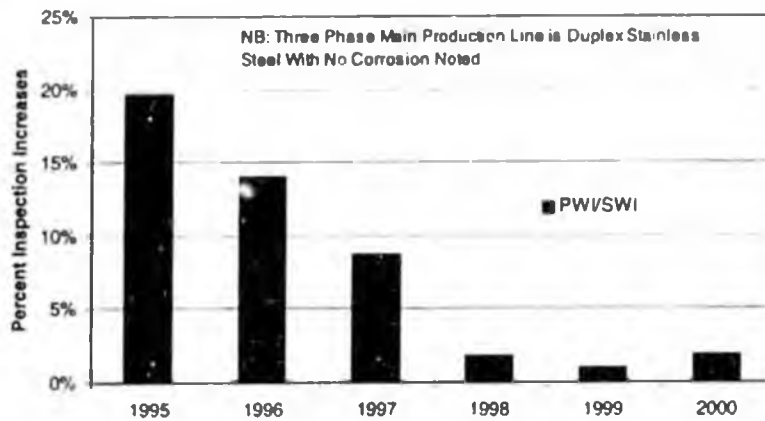
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Alaska Consolidated Team Figure A6
Detection of internal corrosion of cross country pipelines at Endicott



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Greater Prudhoe Bay Tables 1 to 2

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	18	12	389
3 Phase Production	1088	268	6956	3192
Gas Lift	675	160	15	2537
PW/SWAG Inj	180	42	2998	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	117
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

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Greater Prudhoe Bay Tables 3 to 4

Table 3: Smart pig Inspections

Year	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: 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	11,094
1999	1,425	6,875	1,010	782	10	10,238
2000	1,371	5,855	816	782	10	8,970

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Greater Prudhoe Bay Tables 5 to 6

Table 5: Corrosion Monitoring Probes

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

Table 6: Corrosion Inhibitors used across Greater Prudhoe Bay

Supplier	Chemical	1996	1997	1998	1999	2000
Nalco Exxon	EC1110A					
Nalco Exxon	EC1259					
Nalco Exxon	87VD129					
Nalco Exxon	86VD118					
Nalco Exxon	90VD048					
Champion	RU223					
Champion	RU210					
Champion	RU256					
Champion	RU-271					
Champion	125A					
Champion	RU256*					

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Greater Prudhoe Bay Tables 7 to 8

Table 7: Water production, corrosion inhibitor usage and concentration

Year	Water production (million barrels)	Inhibitor Usage (million gallons)	Concentration (ppm)
1996	456.4	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

Table 8: Recurring Frequency of CUI Inspection Surveys

Equipment Temperature	Interval Between Examinations (Years)
≤80° F	10
>80 - 120° F	8
>120 - 150° F	6
>150° F	4

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Greater Prudhoe Bay Tables 9 to 10



Table 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 Injector	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

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Greater Prudhoe Bay Table 11 to 12



Table 11: Mechanical Repairs Installed

Service	Internal	External
Cross country	1	1
Production well line	6	18
Lift Gas	0	3
PWI	0	6

Table 12: Leaks due to corrosion

Service	Location	Date	Internal/External	Volume
3 phase production	S pad	6/18/00	External	50 gals
Gas lift	DS 09	9/2/00	External	0

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Greater Prudhoe Bay Tables 13 to 14



Table 13: Leaks and Saves

Year	Cross Country Saves	Well Line Saves	Cross Country Leaks	Well Line Leaks	Cross Country Leak save	Well line leak save	Overall leak save
1996	14	57	4	8	78%	90%	88%
1997	33	73	2	1	94%	99%	97%
1998	51	34	3	4	94%	89%	92%
1999	22	25	0	3	100%	80%	94%
2000	9	54	1	1	90%	98%	97%

Table 14: Planned Coupon | Schedule for Greater Prudhoe Bay

Service	Cross Country (months)	Well line (months)
3 phase production	3	4
Produced water	6	8
Sea water	3	4
NGL	3	N/A
Sales Oil	3	N/A

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Alaska Consolidated Team Tables A1 to A2



Table A1: Endicott Summary of Lines and NDT Inspections

Service	Miles of Piping	No. Internal Inspections	No. External Inspections
Oil x-country lines	3.5	4 (in vault)	4 (in vault)
Oil - Well Pads	2.5	1112	0
Water x-country lines	3.5	104	4 (in vault)
Water - Well Pads	1.7	101	2 (in vault)
Gas x-country (GLT/M)	7	4 (in vault)	4 (in vault)
Gas - Well Pads	1.2	21	2 (in vault)

Table A2: Milne Point Unit Summary of Lines and NDT Inspections

Service	Miles of Piping	No. Internal Inspections	No. External Inspections
Oil x-country lines	24	15	41
Oil - Well Pads	Note	497	138
Water x-country	15	95	51
Water - Well Pads	Note	812	150
Gas x-country	14	0	0
Gas - Well Pads	Note	0	0

Note: Data not immediately available

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Alaska Consolidated Team Tables A3 to A4



Table A3: Badami Summary of Lines and NDI Inspections

Service	Feet of Piping	No. Internal Inspections	No. External Inspections
Oil - Well Pad	840'WL, 320' HDR	21 well line, 4 Header	0
Gas	240'WL, 320' HDR	8 well line, 4 Header	0
Disposal Well	400'	6 well line	0

Note: Badami does not have an active water injection system

Table A4: Endicott Corrosion Coupon Monitoring 2000

System	Number of Locations with Access Fittings	% Coupons < 2MPY Corrosion Rate
Water Injection - Pads	15	100%
Water Injection - s-country	1	100%
Oil Production - Pads	81	64%

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Alaska Consolidated Team Tables A5 to A8



Table A5: MPU Corrosion Coupon Monitoring 2000

System	Number of Locations with Access Fittings	% Coupons < 2MPY Corrosion Rate
Production System Pads	11	91%
Production System s-country	19	100%
Water Injection System	6	33%
Source Water Coupons	3	100%

Table A8: MPU Inspection Summary- External

Inspection Year	Total Inspections - External	Total Repeat Inspections	Total Increases	Percent Increase
1997	26	0	0	n/a
1998	441	10	0	0.0
1999	101	65	0	0.0
2000	205	104	28	26.9

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Alaska Consolidated Team Tables A9 to A10



Table A9: MPU Inspection Summary- Electromagnetic External Inspections

	No. of Cased Pipe Segments	Footage Tested	No EM Anomalies	EM Anomalies	Significant EM Anomalies
Gas/Gas Lift	3	256	2	1	0
Production	3	253	1	2	0
PW/SW/WAG	3	222	1	2	0
Source Water	1	82	0	1	0

Table A10: MPU Inspection Summary - Internal

Inspection Year	Total Inspections - Internal	Total Repeat Inspections	Total Increases	Percent Increase
1994	332	0	0	n/a
1995	6	0		n/a
1996	13	0		n/a
1997	632	72	20	27.8
1998	994	276	33	12.0
1999	931	72	5	6.9

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Alaska Consolidated Team Tables A11 to A12



Table A11: Endicott Leak / Save and Mechanical Repair Data

Service	# of Leaks	# of Saves	# of Sleeves	Comments
Oil x-country lines	0	0	0	
Oil Well Pads	1	2	0	1-45 S-rear Save, 1-63 S-spool Save, 2-04 S-spool leak.
Water x-country lines	0	1	0	MPI PW Header Blind flange and valve replaced.
Water Well Pads	0	0	0	
Gas x-country GLT/M	0	0	0	
Gas Well Pads	0	0	0	

Note: Leak / Save and mechanical repair data is for year 2000 only

Table A12: Milne Point Leak / Save & Mechanical Repair data

Service	# of Leaks	# of Saves	# of Sleeves	Comments
Oil x-country	1	3	0	In plant ORT piping only
Oil Well Pads	0	0	0	
Water x-country	0	0	0	
Water Well Pads	0	0	0	
Gas x-country	0	0	0	
Gas Well Pads	0	0	0	

Note: Leak / Save and mechanical repair data is for year 2000 only

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Alaska Consolidated Team Table A13



Table A13: Badami Leak / Seve and Mechanical Repair Data

Service	# of Leaks	# of Seves	# of Sleeves	Comments
Oil - Well Pad	0	0	0	
Gas - Well Pad	0	0	0	
Disposal Well	0	0	0	

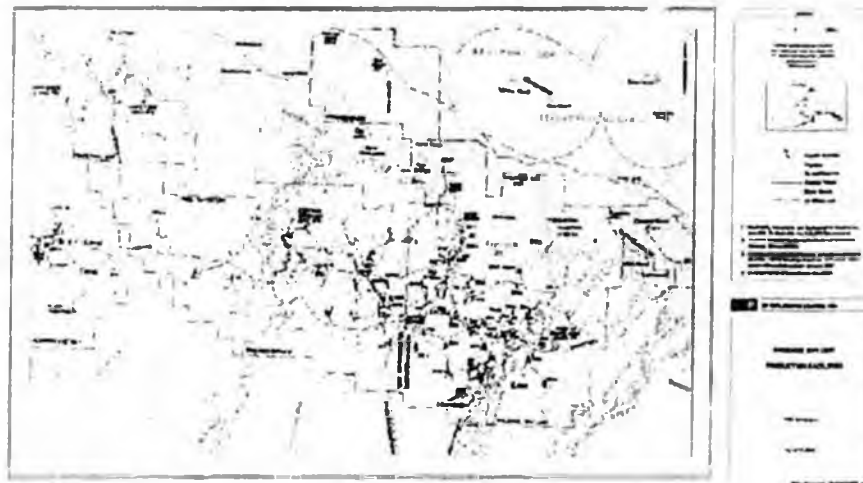
Note: Leak / Seve and mechanical repair data is for year 2000 only

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North Slope Map



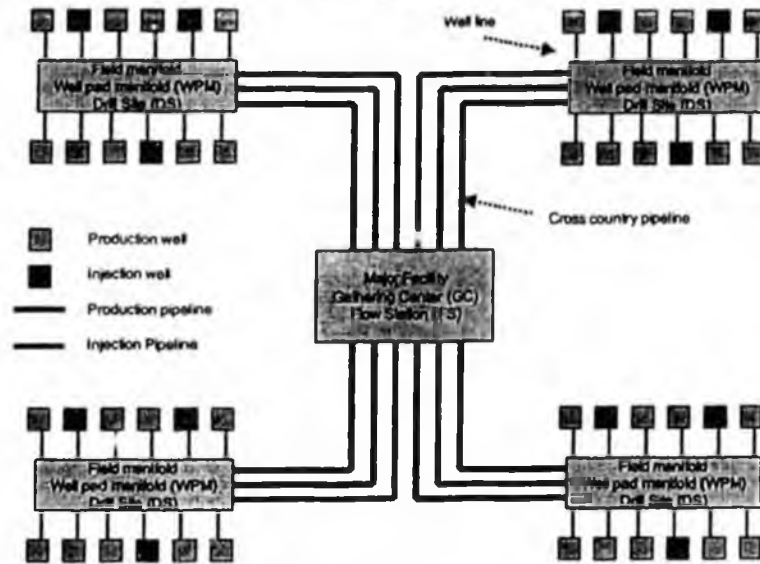
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Facilities Schematic



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CPA



Greater Kuparuk Area

Corrosion Programs

Overview

presented to the

Alaska Department of Environmental Conservation

April 30, 2001



Overview

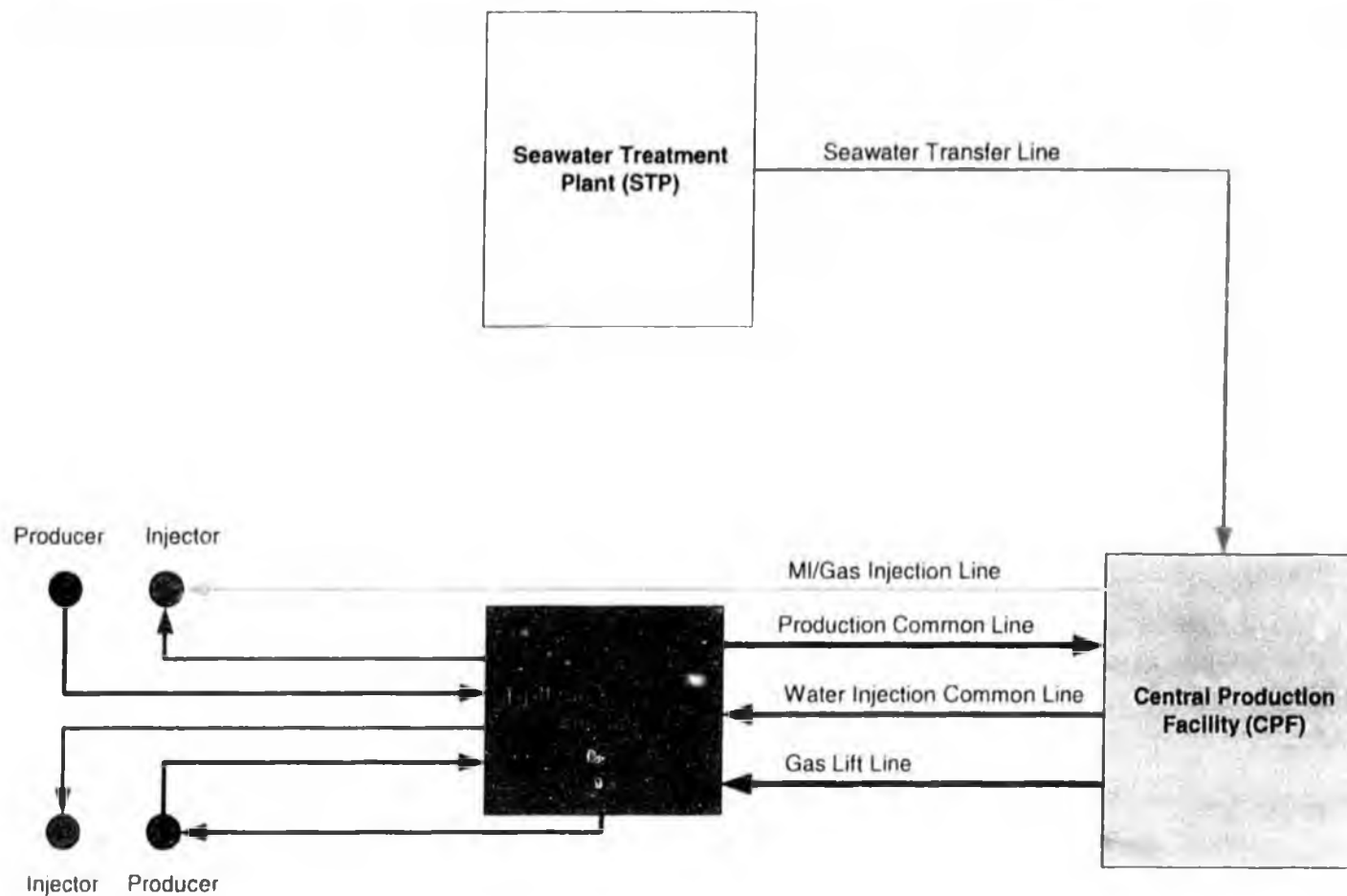


- **Effective corrosion management is critical:**
 - ≈ Safety & Environmental exposure
 - ≈ Asset preservation (\$)
 - ≈ Minimize downtime/lost production

- **Corrosion Factors**
 - ≈ Aging of field infrastructure
 - ≈ Corrosivity of produced fluids increasing (due to CO₂ production) (due to CO₂ production)
 - water production
 - H₂S

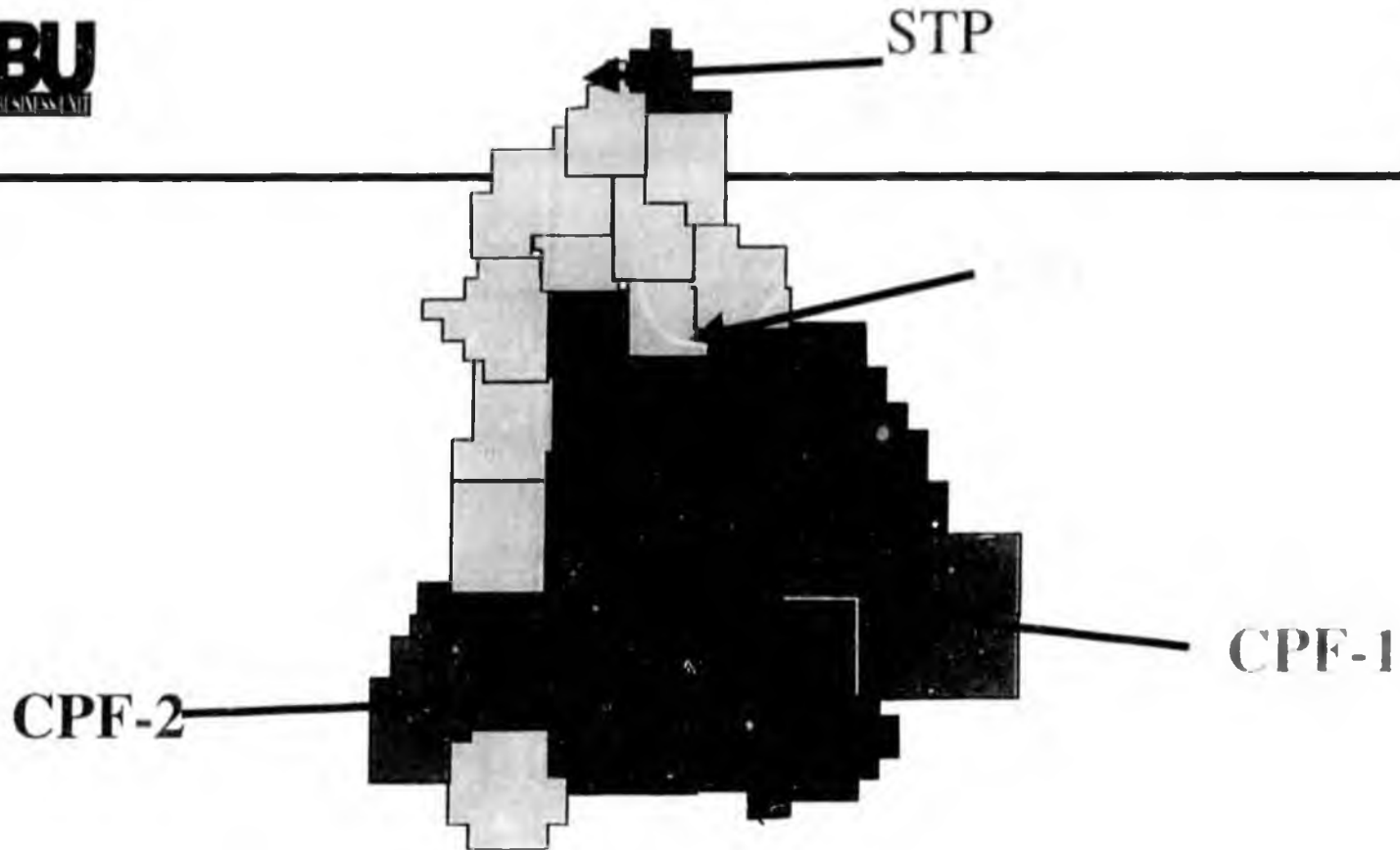
- **Over \$4 Billion in assets**
 - ≈ 530 miles of insulated pipelines
 - 60 miles well lines (900+ wells)
 - ≈ 237 cross country lines
 - ≈ 750 road crossings
 - ≈ 100,000+ weld-packs

Overview



“Well Lines”

“Cross Country Lines”



Start up Timing

- 1981
- 1982-1985
- 1986-1990
- 1991-1995



TALW

Historical Overview

Mechanisms

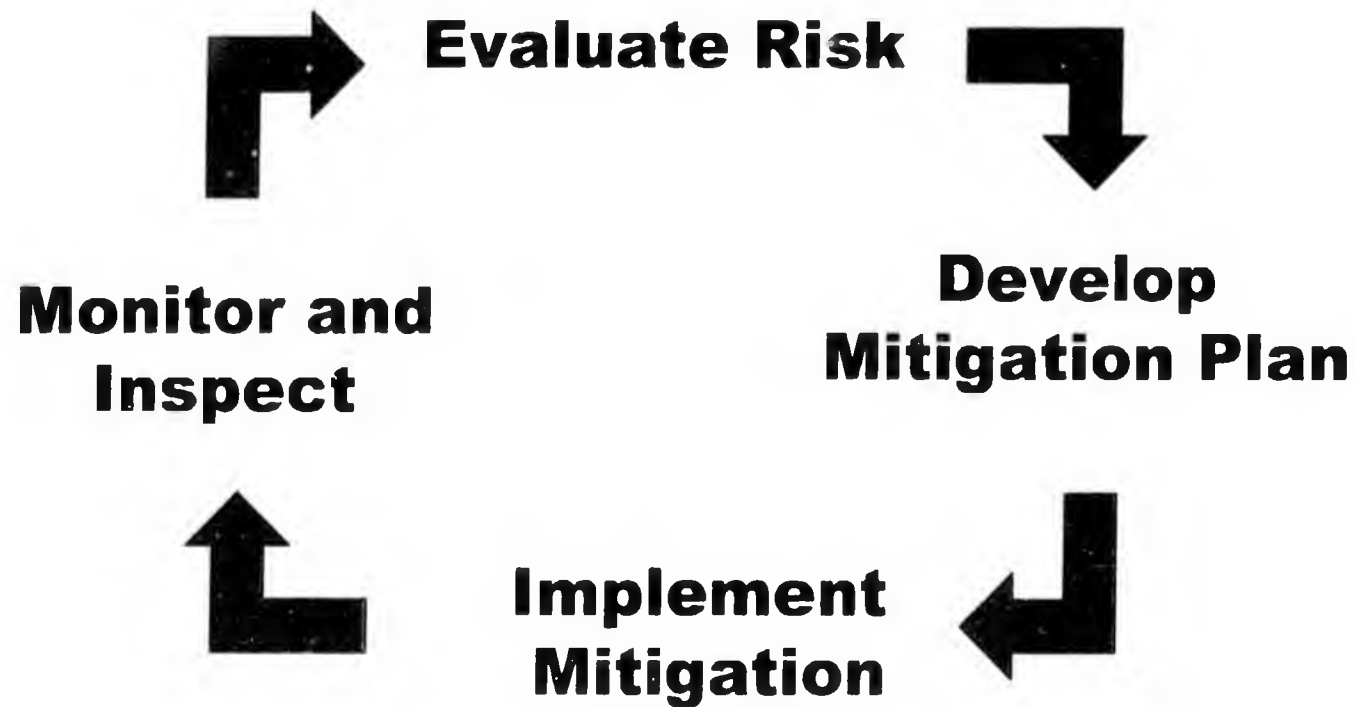
- Internal Corrosion
 - ≈ Erosion Corrosion
 - ≈ Under Deposit Corrosion
 - ≈ Microbially Induced Corrosion (MIC)
- External Corrosion
 - ≈ Corrosion Under Insulation (CUI)

Methods

- Monitoring
 - ≈ Coupons
 - ≈ Probes
- Mitigation
 - ≈ Chemical Inhibition
 - ≈ Mechanical Pigging
- Inspection
 - ≈ Radiography
 - ≈ Ultrasonics
 - ≈ Corrosion Rate Monitoring (CRM)

- ELECTROCHEMICAL / INSTRUMENTAL
- Smart pigging - 1 hr on line
1 hr on line

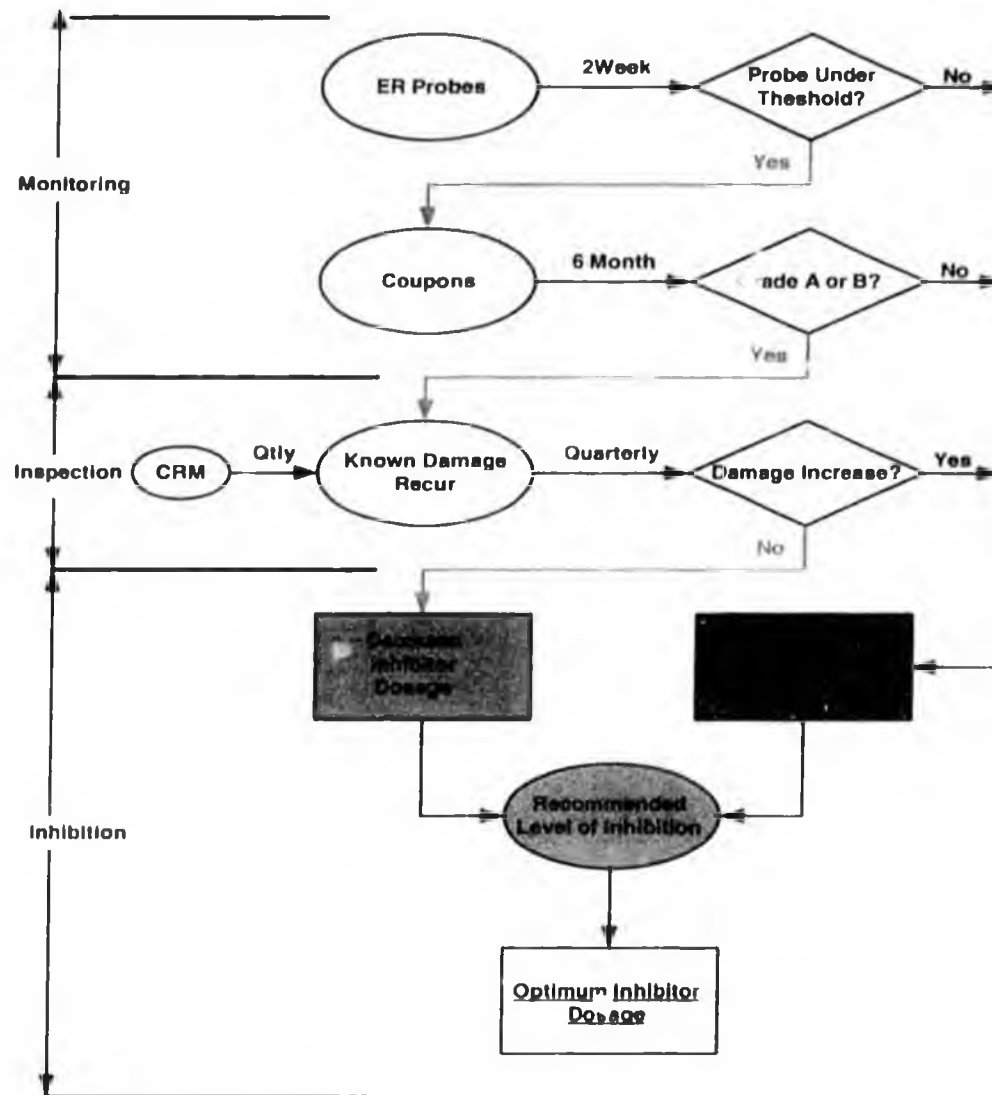
- ① Use **chemical inhibitors** as primary means of control
- ② Monitor **corrosivity** of system to provide feedback and allow effective resource management
- ③ Implement **risk-based inspection** to provide feedback and prevent leaks *priority inspection*
- ④ Increase understanding of Corrosion Mechanisms through **data analysis**
- ⑤ Pursue **technology improvements** in chemicals and inspection to increase efficiencies

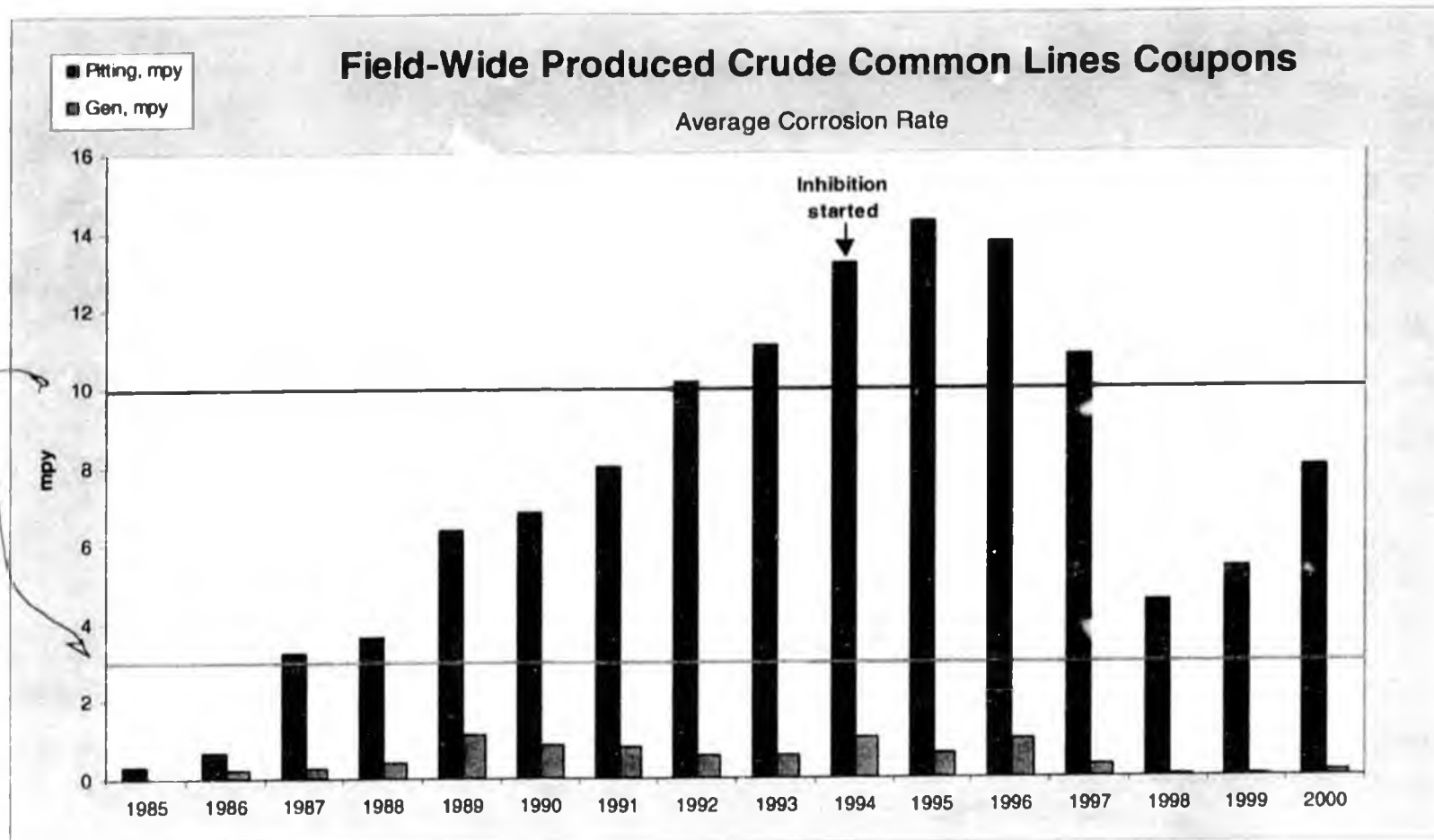


- ✓ Identifies changes/trends in corrosivity of system
- ✓ Optimization tool for chemical inhibition and inspection programs
- **Electrical-Resistance Probes**
 - ⇒ Short-term Feedback; can identify transient corrosion events
 - ⇒ May not accurately reflect general pipewall corrosion rates
- **Coupons** >1100 locations
 - ⇒ Longer-Term Feedback; average corrosivity over time period
 - ⇒ Better correlation with general pipewall corrosion rates
- **Inspection Data**
 - ⇒ Identify and track actual corrosion damage
 - ⇒ Measures actual pipewall corrosion rates, but after damage is done

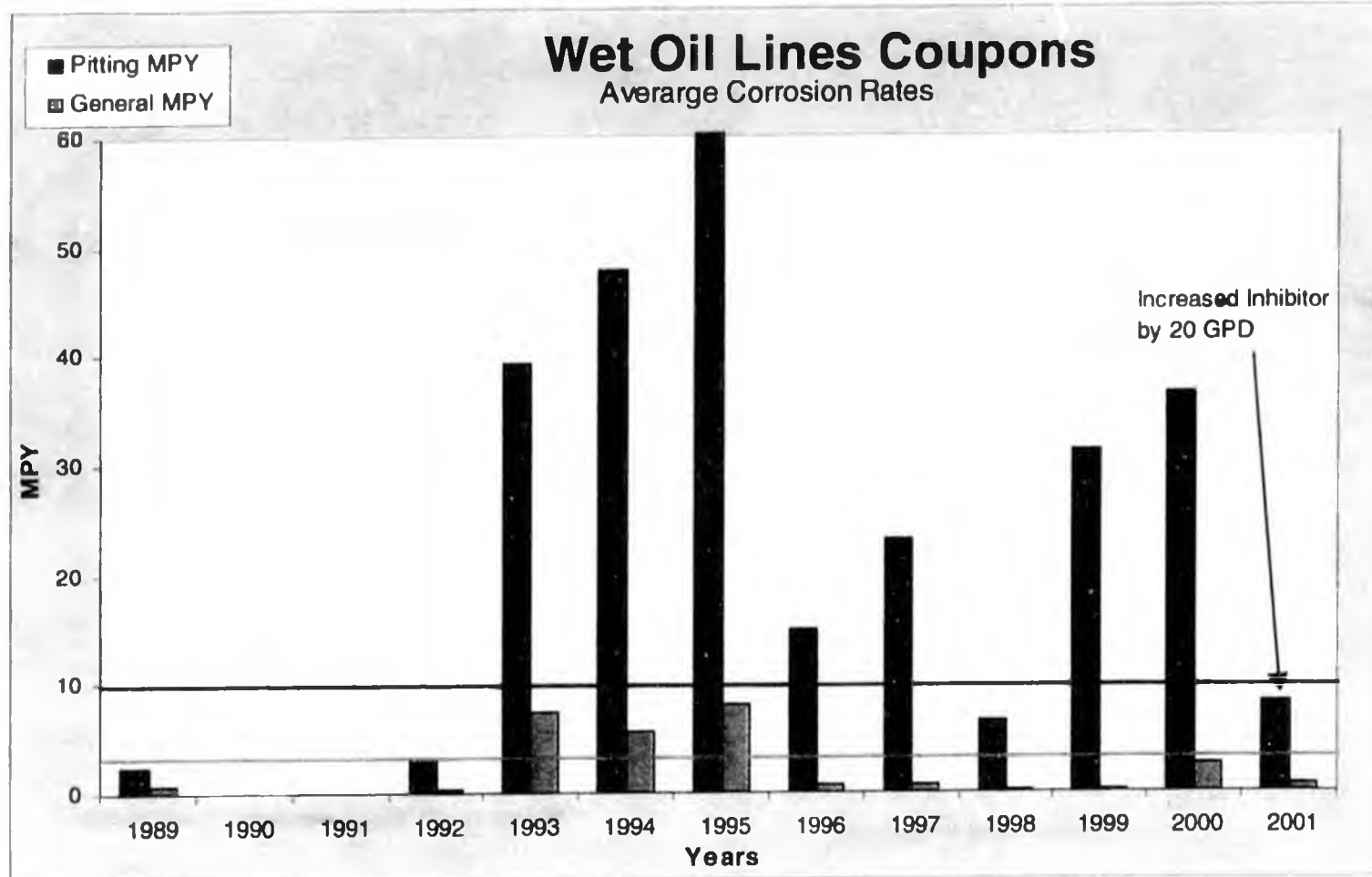
Monitoring

Kuparuk Inhibitor Feedback System

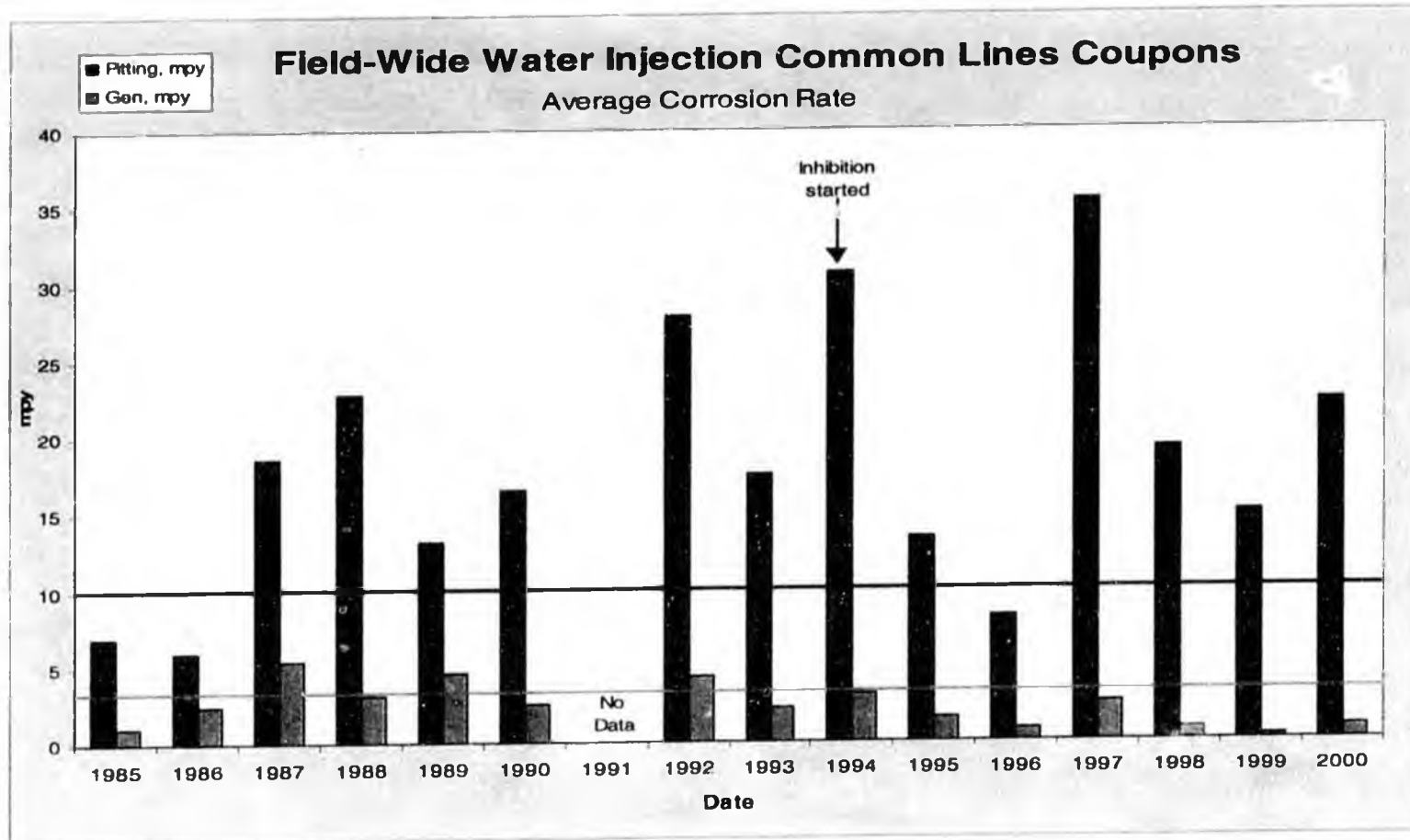




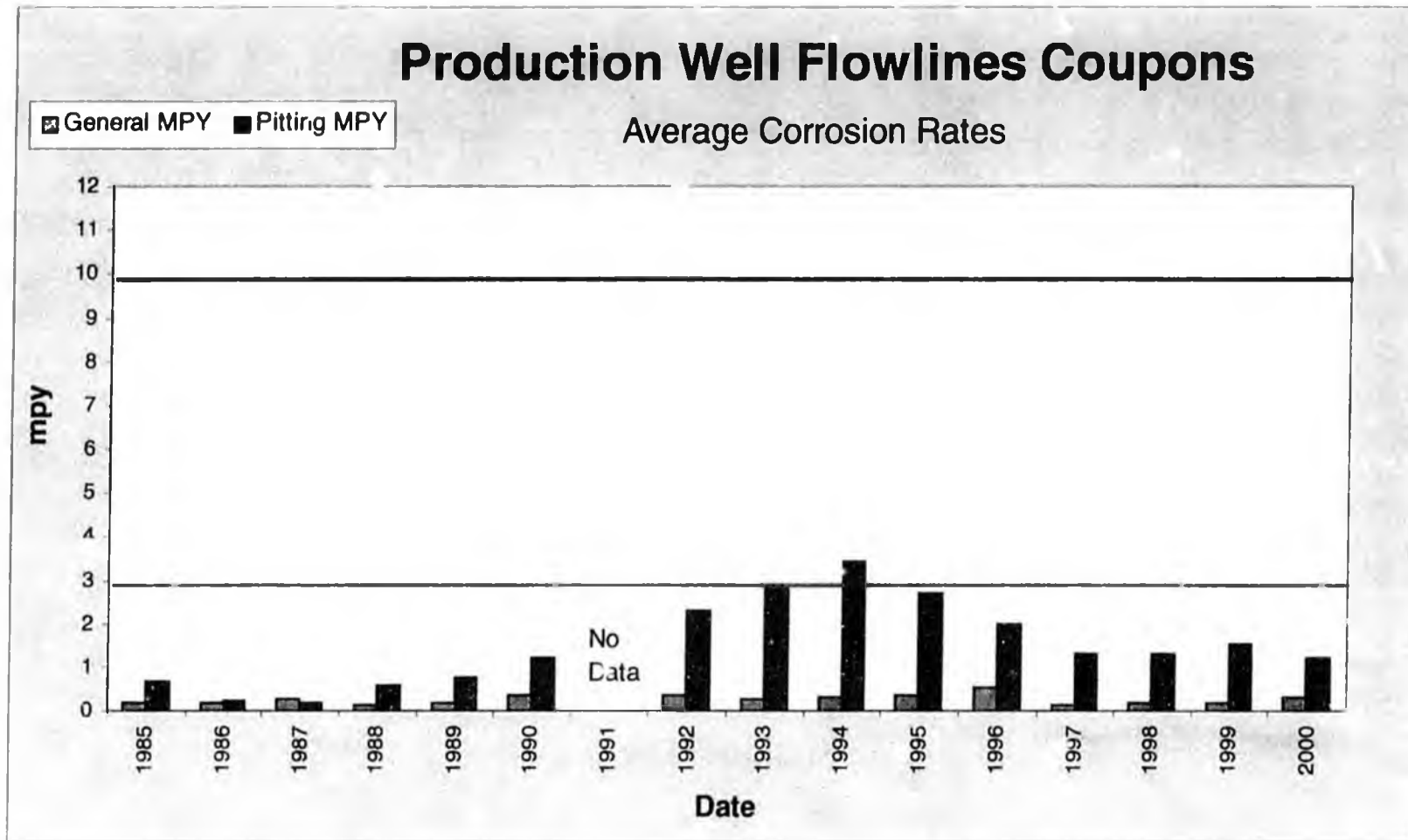
- Probes, Year 2000: Average Rate <1 mpy
- Inspection data indicates corrosion is under control



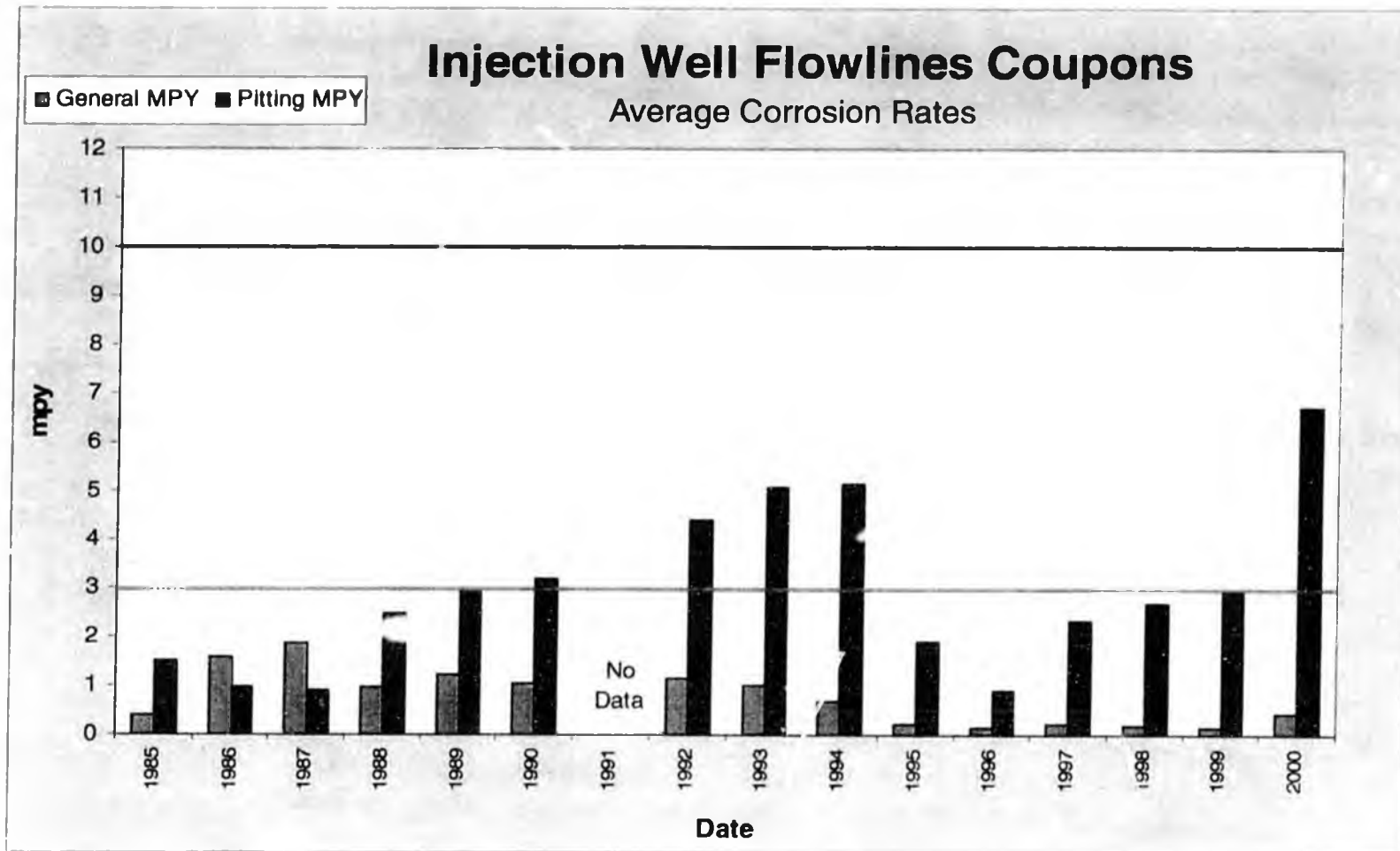
- > Year 2000 average pitting rate of 36 mpy including 24" line
- > Year 2000 average pitting rate of 11 mpy for 16" line & 12" line
- > 24" WO Line scheduled for decommissioning in June 2001



- Inspection data indicates that corrosion activity localized in stagnant, un-piggable sections of line
- Corrosion rate increasing as injection source water is mixed



➤ Inspection data suggests that actual pipewall corrosion rates are higher



➤ Inspection data suggests that actual pipewall corrosion rates are higher



Mitigation



- Over \$8MM/year spent on corrosion chemicals
- Continuously search for better chemistry
 - ≈ Vendor Proposals
 - ≈ Laboratory Testing
 - ≈ Field Testing
 - ≈ Full-field Implementation
- ✓ New inhibitor, Cortron 2000-25, scheduled for full-field implementation in 1st half 2001
- ✓ First stage (3-5 Drill Sites) of wellhead chemical inhibition facilities scheduled for start-up in 2001
- ✓ 24" Wet Oil Line decommissioning in 2001



Inspection



➤ Internal Corrosion Surveillance

- ≈ Real-Time Radiography (RTR)
- ≈ Manual Radiography (RT)
- ≈ Ultrasonics (UT)
- ≈ Corrosion Rate Monitoring (CRM) - Uses UT at discrete locations to provide feedback for Inhibitor Optimization System

➤ External Corrosion Surveillance

- ≈ Tangential Radiography (TRT)
- ≈ Automated Tangential Radiography (ATRTR)

➤ Below-Grade Piping Program

- ≈ PTI - Electromagnetic wave pulse system
- ≈ TWI - Guided ultrasonic wave system



Inspection - Internal Corrosion



Year 2000

➤ Well Lines

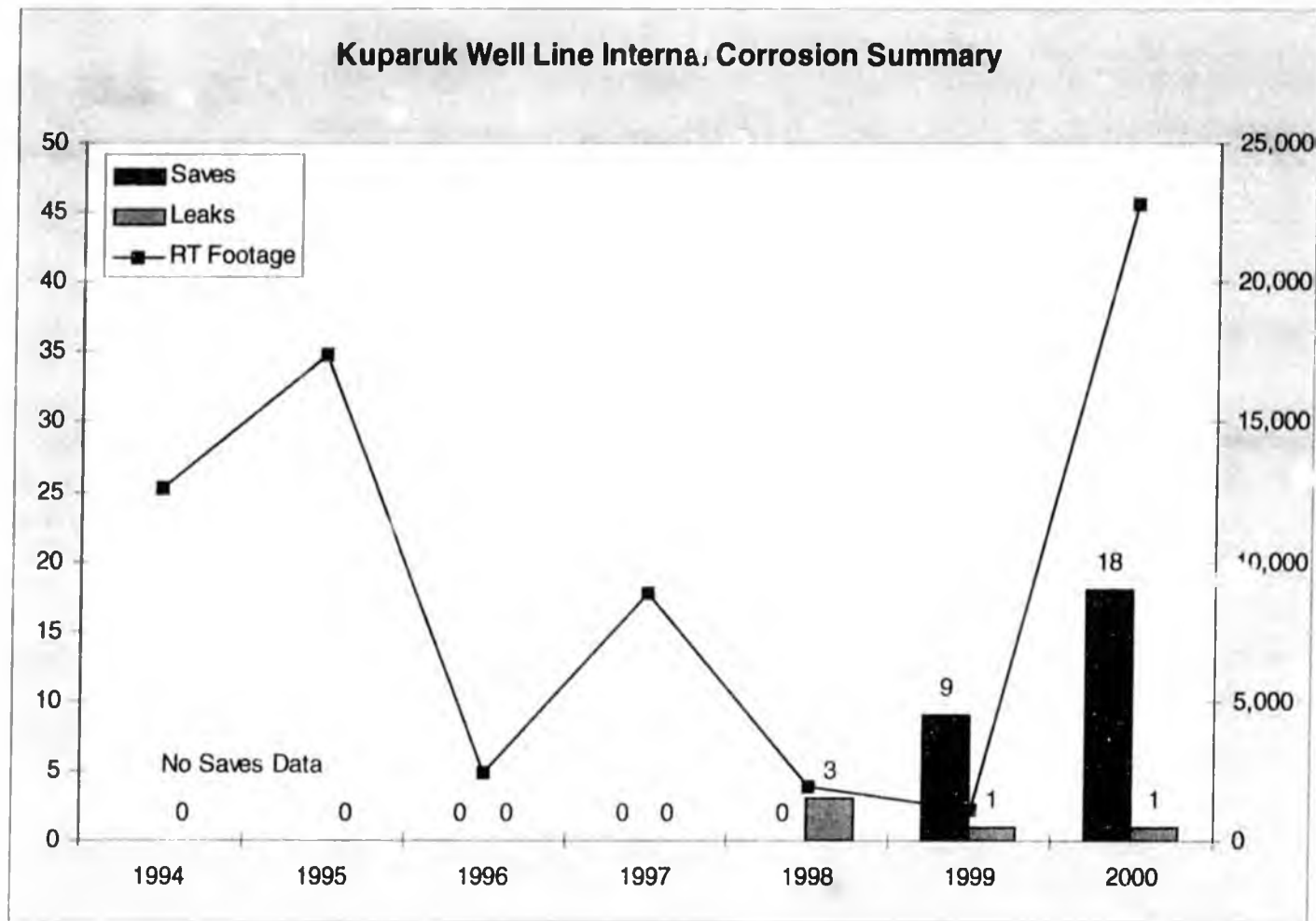
- ✓ Approximately 1000 well lines at Kuparuk
- ✓ inspected 21,000 feet on 70 well lines using RTR
- ✓ 2,650 RT inspections on 297 well lines; 20 increases
- ✓ 4,137 UT inspections on 277 well lines; 95 increases
- ✓ 358 baseline UT inspections on 156 well lines, done in conjunction with External (CUI) program
- ✓ 18 well lines required repair (8 injectors, 10 producers)



Inspection - Internal Corrosion



Well Lines





Inspection - Internal Corrosion



Year 2000

➤ **Cross Country Lines**

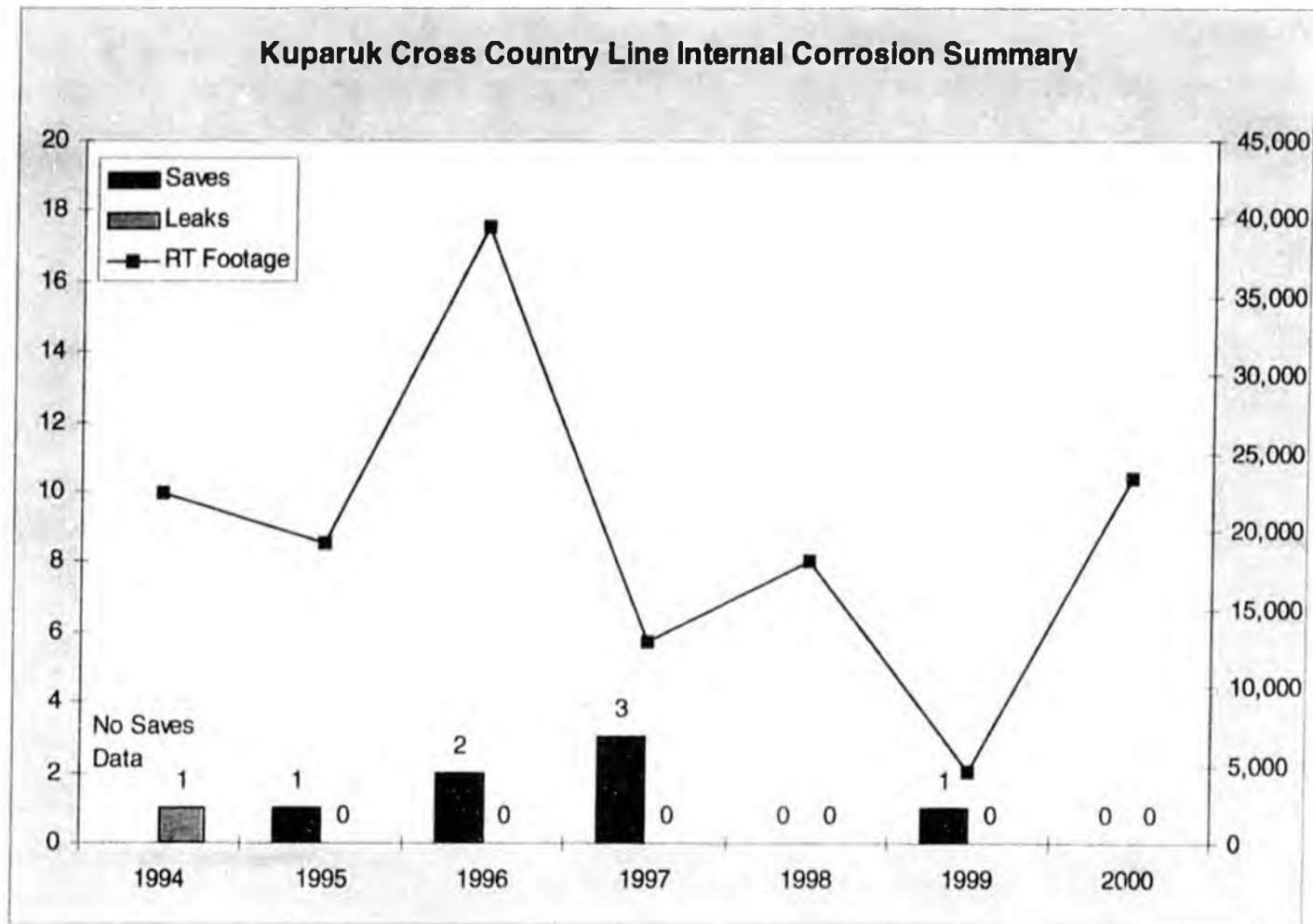
- ✓ 237 cross-country lines at Kuparuk
- ✓ Inspected 21,200 feet on 16 CC lines using RTR
- ✓ 1,530 RT inspections on 101 CC lines; 1 increase
- ✓ 497 UT inspections on 43 CC lines; 12 increases
- ✓ 366 baseline UT inspections on 88 CC lines, done in conjunction with External (CUI) program
- ✓ 0 CC lines required repair



Inspection - Internal Corrosion



Cross Country Lines





Inspection - Internal Corrosion



Year 2001 Forecast

- ⇒ Increase RTR on well lines, decrease RTR on Cross Country lines
- ⇒ Prioritization of RTR has been adjusted to focus more on thin-walled, older lines, with less emphasis on service
- ⇒ Decrease “screening” RTR footage from 30% of total length to 20-25%; will increase number of lines inspected
- ⇒ Initiate “wandering can” inspection to confirm prioritization and look for anomalies
- ⇒ Implement a risk-ranked Elbow Program to increase effectiveness of Cross Country line inspections



Inspection - External Corrosion



Year 2000

➤ **Cross Country Lines, Off-Pad**

- ✓ Off-pad weld pack inspection 99.9% complete (50 left out of ~67,000 total)
- ✓ 5 repair locations in 2000
- ✓ Complete inspection of off-pad weld packs by end of 2001

➤ **Cross Country Lines, On-Pad**

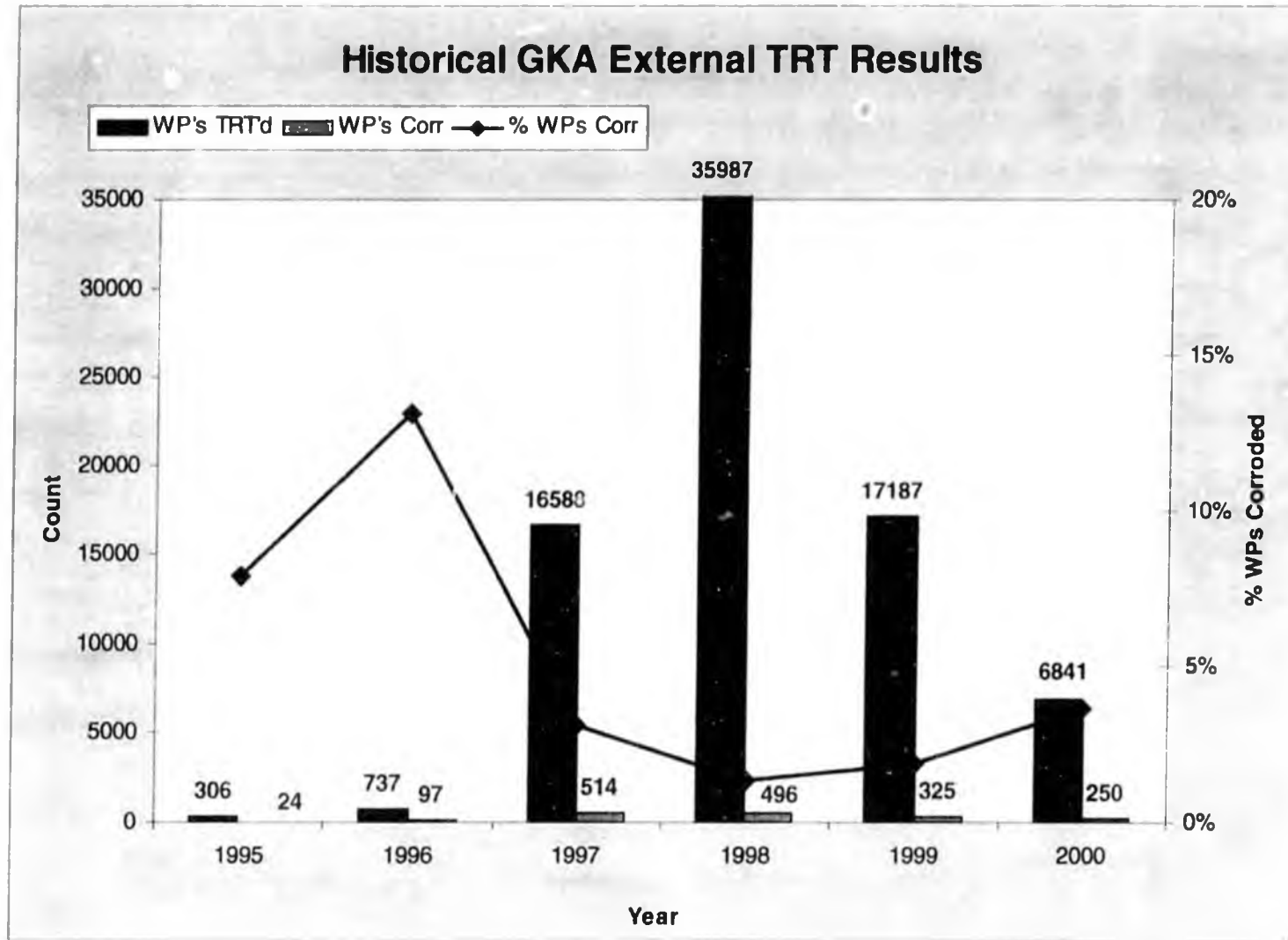
- ✓ On-pad weld pack inspection 30% complete (out of ~10,500 total)
- ✓ Complete inspection of on-pad weld packs by end of 2004

➤ **Well Lines**

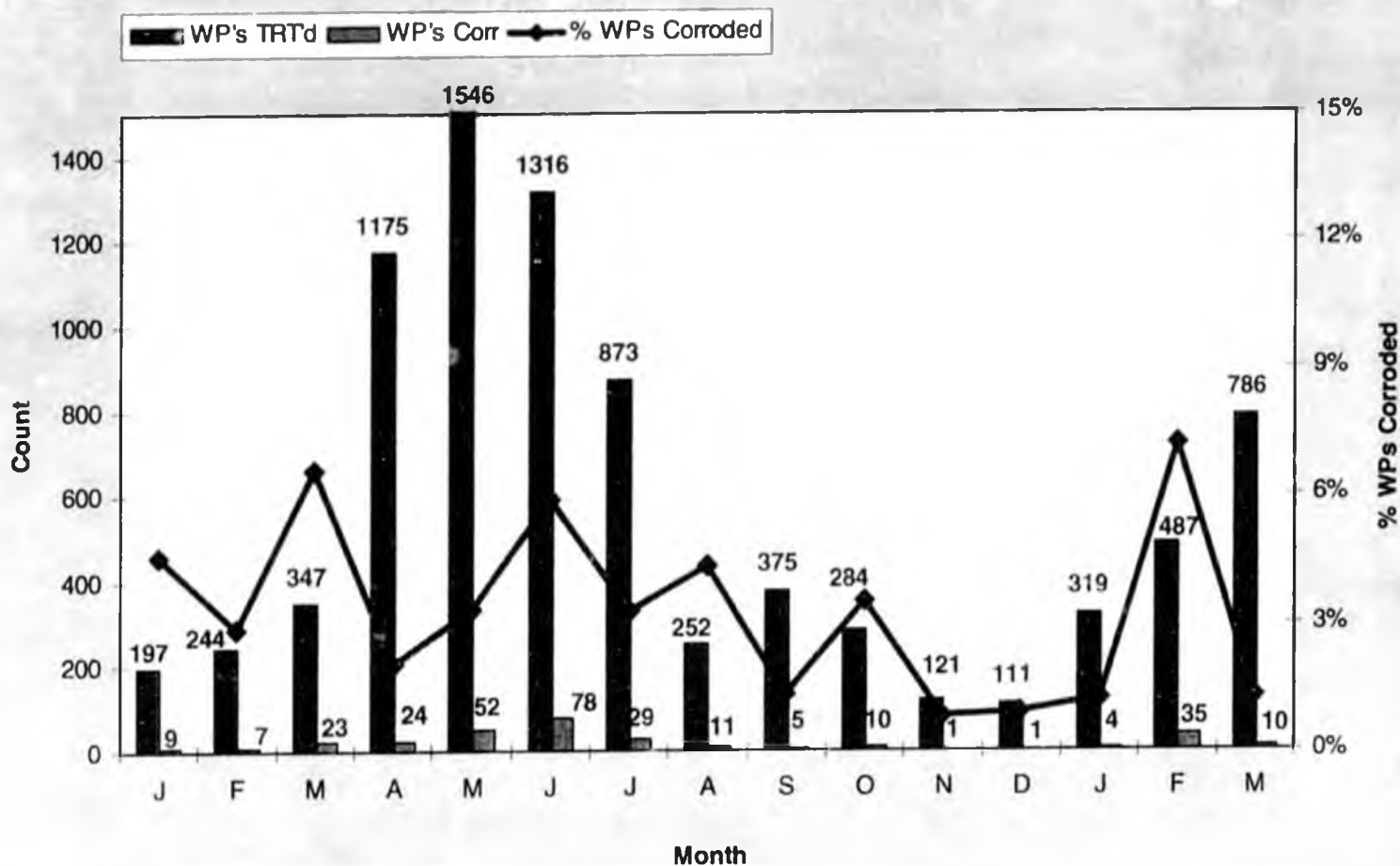
- ✓ Weld pack inspection ~25% complete (out of ~24,000 total)
- ✓ 3 repair locations in 2000
- ✓ Complete inspection of well line weld packs by end of 2005



Inspection - External Corrosion



External Inspections - Last 15 Months (On Pad Piping)

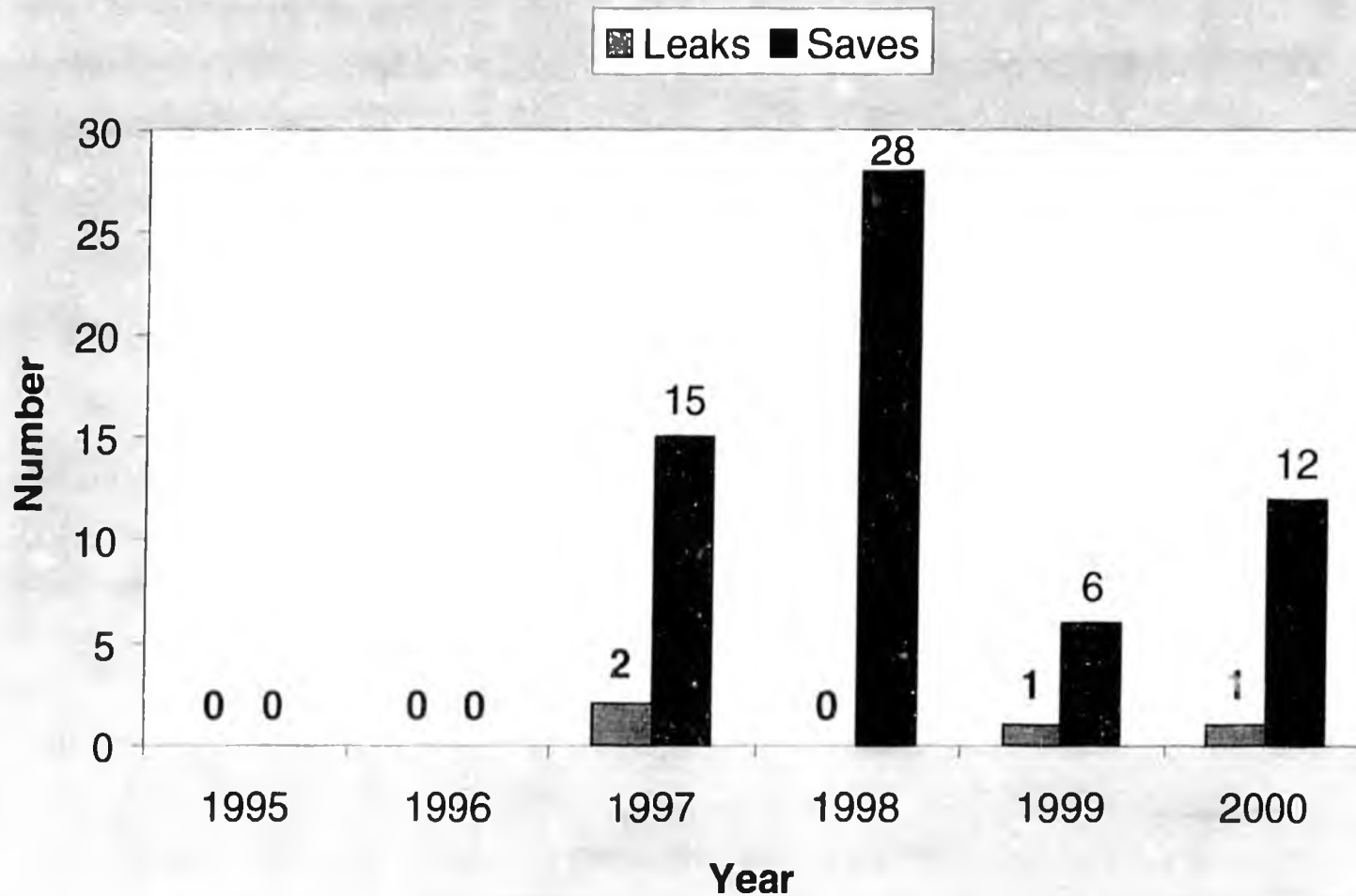




Inspection - External Corrosion



Historical GKA External Leaks and Saves





Inspection - External Corrosion



WELL-2001 FORWELL

➤ **External (Weld-Pack) Program**

- ⇒ Complete inspection of remaining CC Off-Pad weld packs
- ⇒ Inspect 20% of CC On-Pad and well line weld packs.

➤ **Inhibitor Spikes For Weld Packs Pilot Program**

- ⇒ Test Inhibitor Spikes on 25 - 50 weld pack locations



Inspection - Below-Grade Piping



4R 2000

ETIOWIN only

Electromagnetic Inspection (PTI)				
Service	No. of Cased Pipe Segments	No EM (N)	EM (E)	Significant EM (S)
Gas (lift, Injection, Fuel)	6	5	1	0
Miscible Injection (MI)	3	3	0	0
Nat Gas Liquids (NGL)	0	0	0	0
Oil Sales (OS)	5	4	0	1
3 Phase Production (PC, PO)	12	10	2	0
2 Phase Oil & Water (WO)	0	0	0	0
Water Injection (PW, SW, Mixed)	31	26	5	0
Totals	57	48	8	1

*1598
2/13/00*

Guided Wave Inspections (TWI)						
Service	No. of Cased Pipe Segments	Inconclusive Anomalies (I)	No Significant Indication (N)	Minor (Low) Anomalies (L)	Moderate Anomalies (M)	Severe Anomalies (S)
Gas (lift, Injection, fuel)	7	1	5	1	0	0
Miscible Injection (MI)	0	0	0	0	0	0
Nat Gas Liquids (NGL)	1	0	0	1	0	0
Oil Sales (OS)	1	0	1	0	0	0
3 Phase Production (PC, PO)	26	2	19	4	1	0
2 Phase Oil & Water (WO)	10	1	9	0	0	0
Water Injection (PW, SW, Mixed)	10	0	6	1	3	0
Totals	55	4	40	7	4	0



Inspection - Below-Grade Piping



➤ 739 BGP Locations in Field

- ✓ 210 locations inspected using PTI/TWI

- ✓ 7 locations excavated - '98, '99, '01

 - ⇒ 1 location required repair

 - ⇒ All locations refurbished

- ✓ Based on TRT inspections at casing ends... '98, '99, '00

 - ⇒ 3 locations replaced without excavation

 - ⇒ 1 location refurbished

➤ 388 significant locations remain for inspection

 - ✂ 54 lines - plastic, new, replace

 - ✂ 87 lines - flare pit gas & drain lines ≤ 2 " diameter



Inspection - Below-Grade Piping

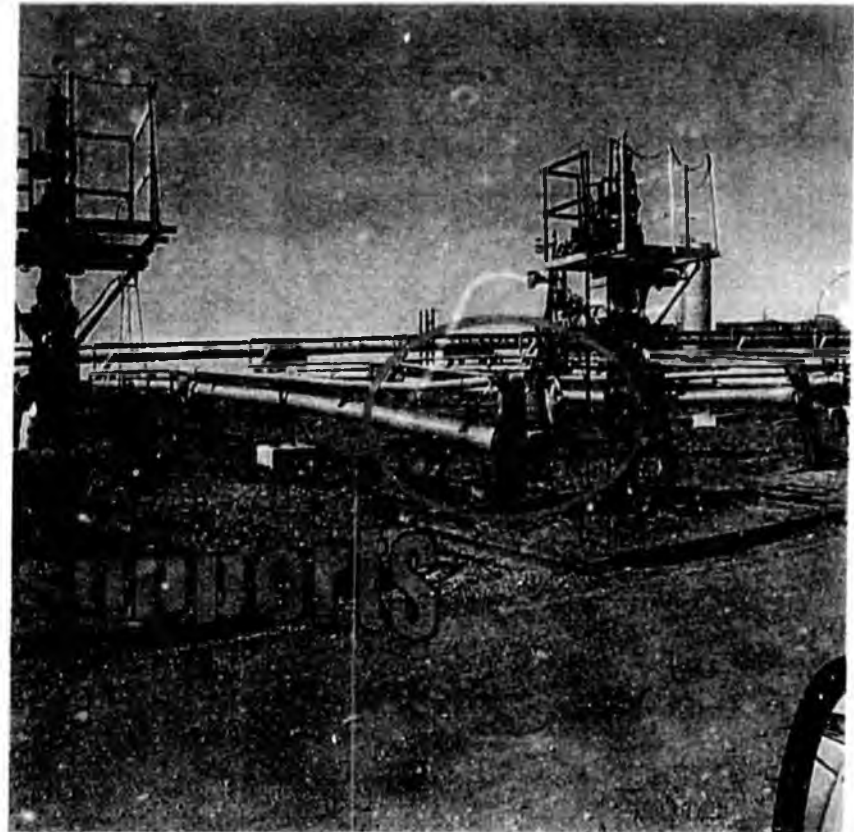
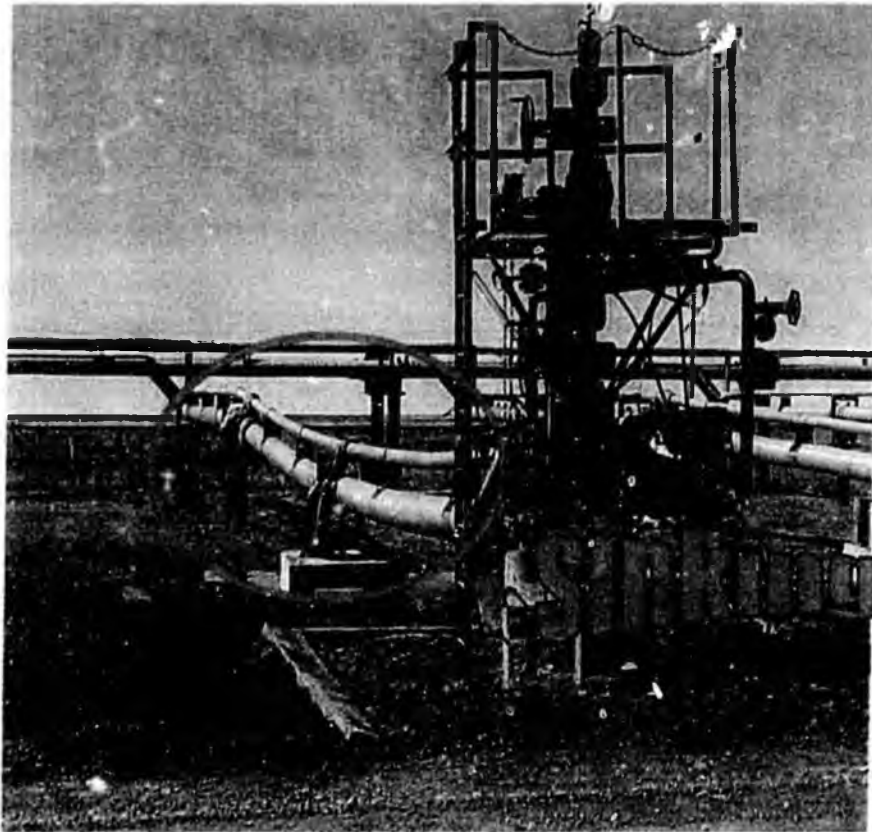


ALASKA 2001 FUNDING

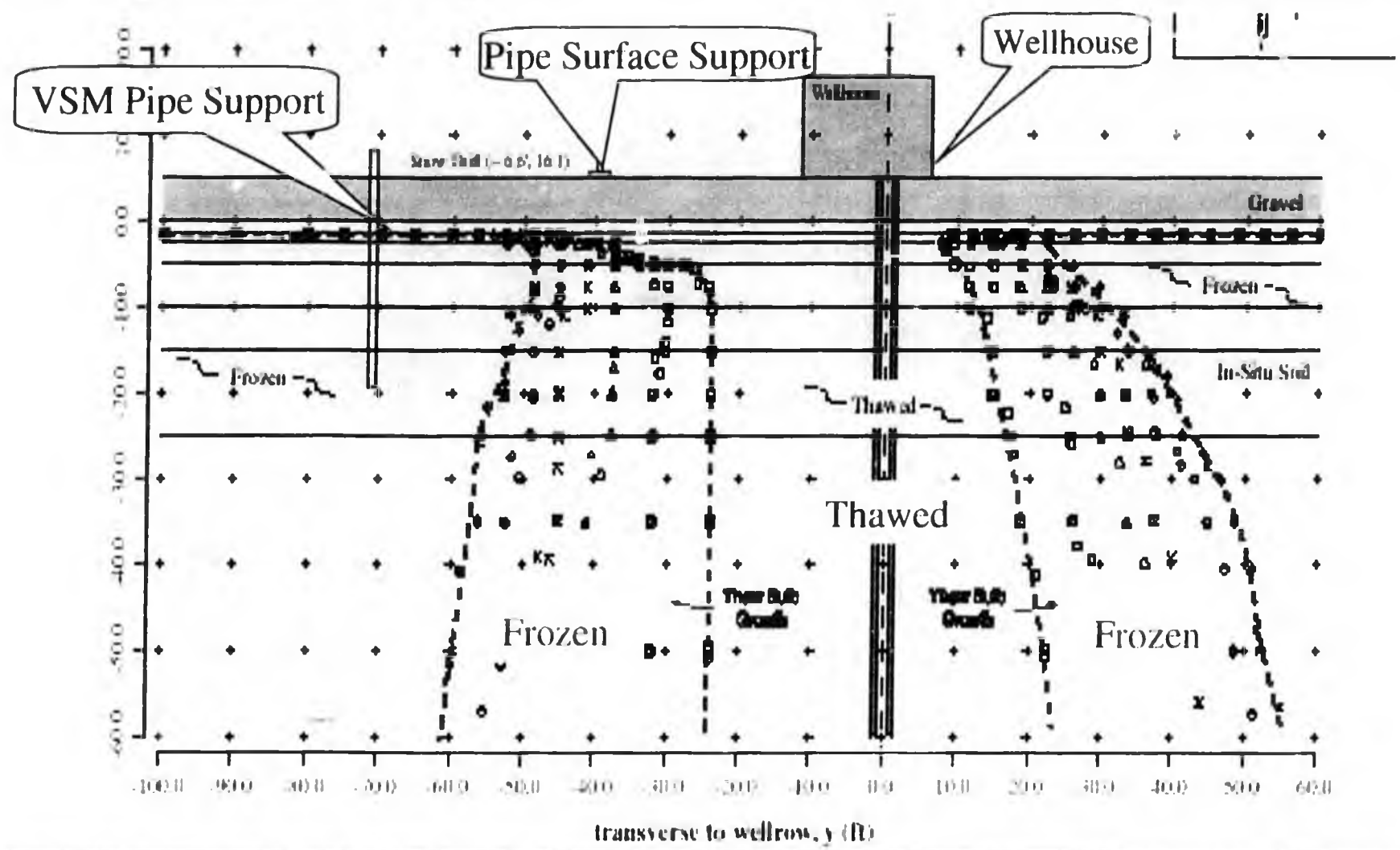
➤ Below Grade Piping Program

- ⇒ Inspect 100 road crossings using PTI/TWI (base plan)
- ⇒ Pursue significant acceleration of PTI/TWI inspection program
- ⇒ Excavate 4 road crossings (base plan)
 - Refine PTI/TWI data reduction and interpretation using visual inspections
- ⇒ Planning additional excavations to improve alignment of PTI/TWI results and with other risk factors
- ⇒ Reprioritization of BGPP based on data from expanded work scope described above.

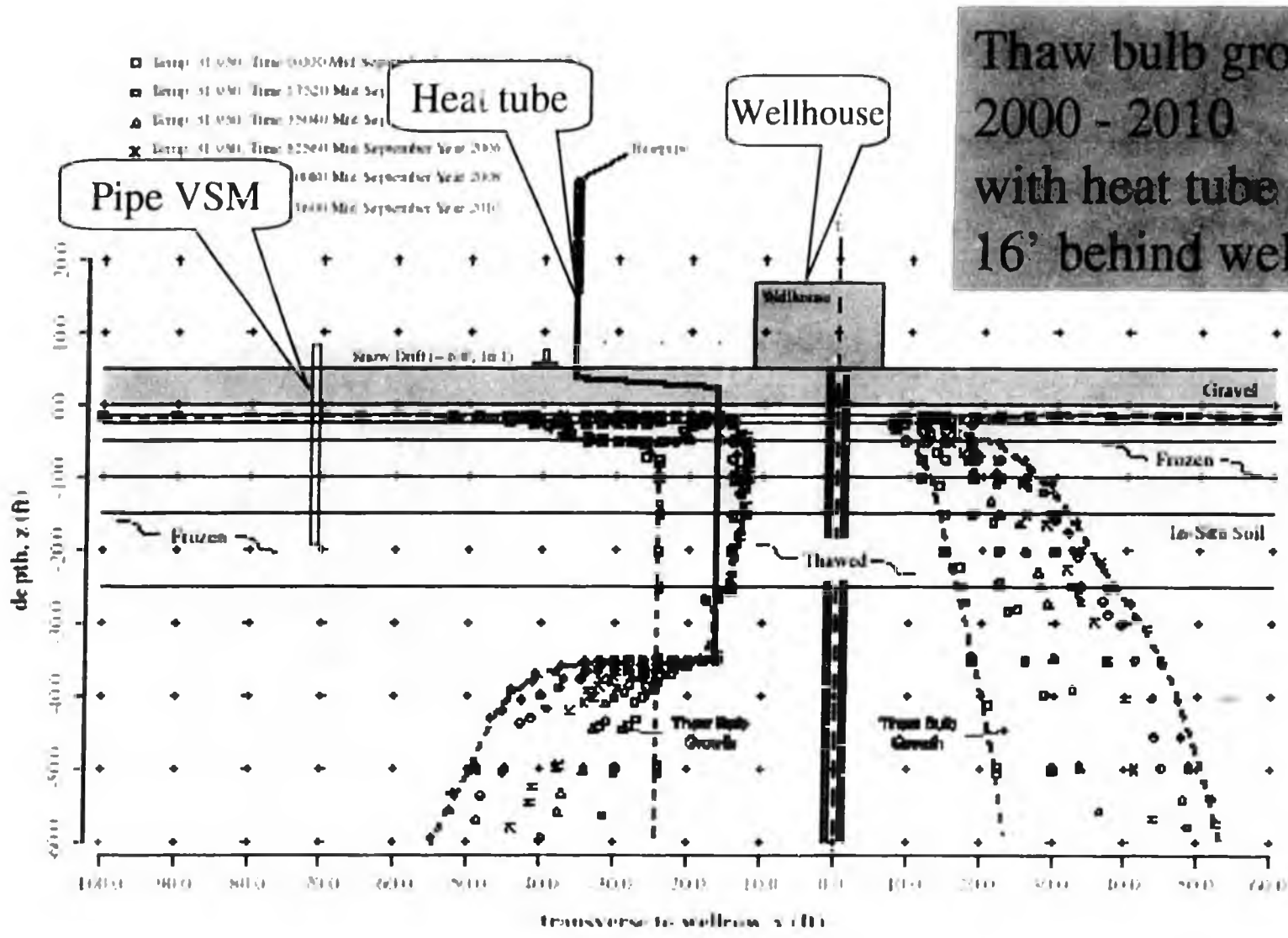
Structural Concerns



Real issue is **sinking supports** combined with snowloading.
(Lines will bend until support is met.)



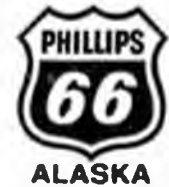
Predicted thaw bulb growth (worst case) over next 10 yrs.



Thaw bulb growth
2000 - 2010
with heat tube located
16' behind well



Structural Concerns



- Subsidence Mitigation at the Drill Sites
 - ⇒ Heat tubes being installed behind well houses
 - ⇒ Freeze back & pipe support
 - ⇒ Floors/Riser piping supports off of conductors
 - ⇒ All new wells and conversions to water injection
 - ⇒ Existing wells prioritize based on history
 - ⇒ \$1MM + spent on summer gravel work in 2000
 - ⇒ \$4MM total spent on mitigation 2000 - 2001

Well Line Piping - Sagging Pipe

- ⇒ Preliminary studies suggest no immediate loss of strength
- ⇒ Ductility/strain hardening over time is primary concern (i.e. cracking)
- ⇒ Deformed lines are evaluated and corrective action applied on a case-by-case basis

YEAR 2001 FORWARD

Decision and execute enhancements to the Kuparuk Corrosion Database.

Continue to evaluate, prioritize, and implement subsidence mitigation efforts at the drill sites.

Evaluate suitability of snow fences to minimize snow accumulation on well lines.

Continue with heightened level of snowload monitoring and snow removal.



Spills/Incidents



- 2M-01 Well Line Riser Leak 5/6/00 200 gallons
 - ⇒ Fatigue-type failure @ wellhead riser
 - ⇒ caused by slugging, coupled with pipe support subsidence and snow loading
- 2X-16 Well Line Leak 7/3/00 10 gallons
 - ⇒ External corrosion damage was identified prior to leak - well was shut-in and displaced with diesel
 - ⇒ Began leaking after it was shut-in; leak found while additional inspection was being done
 - ⇒ Thermal expansion of the trapped diesel was the cause
- 1G-08 Well Line Leak 12/27/00 70 gallons
 - ⇒ Caused by internal corrosion
 - ⇒ Thin-walled (0.280") piping, producing well
 - ⇒ Was lower-tier priority on our inspection list



Spills/Incidents



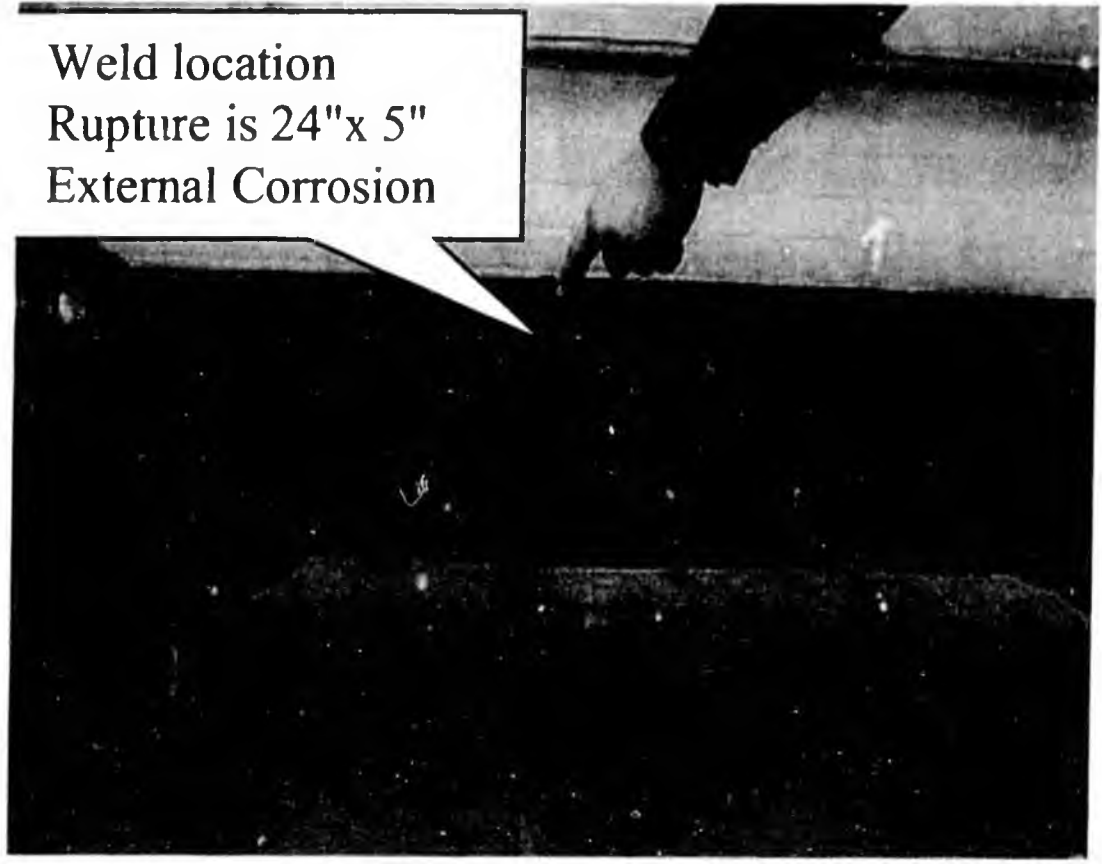
- **1B Injection Line Rupture 4/15/01 92M gallons**
 - ⇒ **Line ruptured, and low pressure alarm was received**
 - ⇒ **Leak detected and isolated within 12 minutes**
 - ⇒ **Rupture located in road crossing behind CFF1**
 - ⇒ **External corrosion @ weld pack in road crossing was cause**
 - ⇒ **Spill area on tundra, just less than 1 acre**
 - ⇒ **All accessible weld packs inspected**
 - ⇒ **2nd 1B-WI culvert location being excavated & inspected**



Spills/Incidents



➤ 1B Injection Line Rupture 4/15/01 92M gallons



Weld location
Rupture is 24"x 5"
External Corrosion



Spills/Incidents



➤ **1B Injection Line Rupture** **4/15/01** **92M gallons**

⇒ Reviewed Monitoring & Inspection History.....

- ✓ TRT'd in 1998 & 2000, 149 weld packs out of 157 total
 - All over-tundra and on-pad @ Drillsite weld packs TRT'd
 - No derating corrosion found
- ✓ Coupon data since 1982 indicated low internal corrosion risk
- ✓ Maintenance Pigging schedule on-target
- ✓ RTR'd in 1993 & 1997, 3000' total - no internal corrosion noted
- ✓ RTR 'd additional 243' on 4/23/01 - no internal corrosion noted
- ✓ Road crossing was scheduled for inspection late 2001



Closing



Topics for discussion

- * Data reporting - What is meaningful to ADEC? What is not?
- * BGP - Incorporate annual reporting into this NS Charter Agreement Report?
- * BGP - Include all BGP inspection data, not just “oil” lines?

FALL 2001

BP

CPA



Greater Kuparuk Area

Corrosion Programs

Overview

presented to the

Alaska Department of Environmental Conservation

2nd Meet & Confer

November 5, 2001

Drivers

- > Internal Corrosion
 - ≈ Well Line Inspections
 - ≈ 1G-08 Production Well Line Spill
 - ≈ 24" Wet Oil Line Coupons
 - ≈ Corrosion Inhibitor Testing
- > External Corrosion
 - ≈ 10" 1HBWI Water Injection Common Line Spill

Strategic Shifts

- > Inspection
 - ≈ Doubled Well Line Internal Inspection RTR Program Funding
 - ≈ Revised Internal Inspection Prioritization Scheme
 - ≈ Increased Well Line Inspection Efficiency
 - ≈ Tripled Below Grade Piping Program Funding
- > Monitoring/Mitigation
 - ≈ Decommissioned 24" Wet Oil Line
 - ≈ Fieldwide Deployment of New Corrosion Inhibitor (2000-25)
 - ≈ Implementing Wellhead Inhibition



Internal Corrosion Monitoring Methods

Electrical Resistance Probes

- target values < 1 mpy (mills per year)

Coupons

Two types of evaluation used for coupons:

overall weight loss ≈ indication of fluid corrosivity

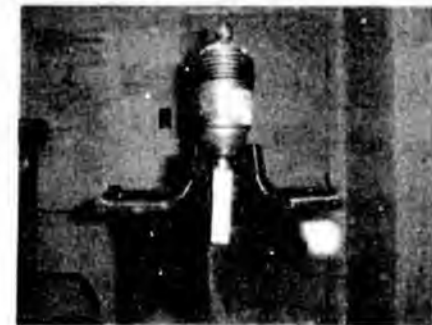
- target values < 3 mpy based on weight loss analysis

pitting depth ≈ indication of pitting corrosion, primary corrosion mechanism at Kuparuk

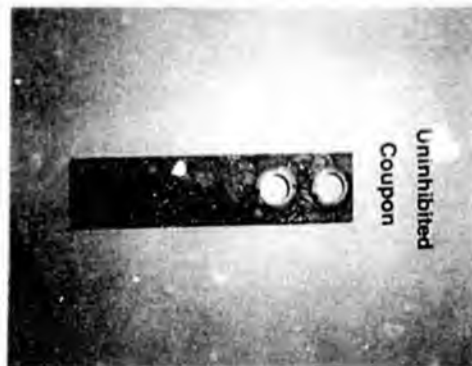
- target values < 10 mpy based on pit depth analysis



Cutaway of ER Probe



Cutaway of coupon in line

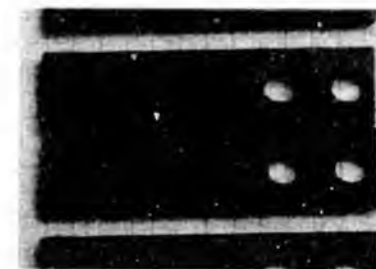


Weight Loss Analysis:

$$MPY = \frac{\text{Initial Weight} - \text{Final Weight}}{\text{Coupon Density} \times \text{Surface Area} \times \text{time exposed}}$$

Pit Depth Analysis:

$$MPY = \frac{\text{Pit Depth}}{\text{time exposed}}$$



coupons

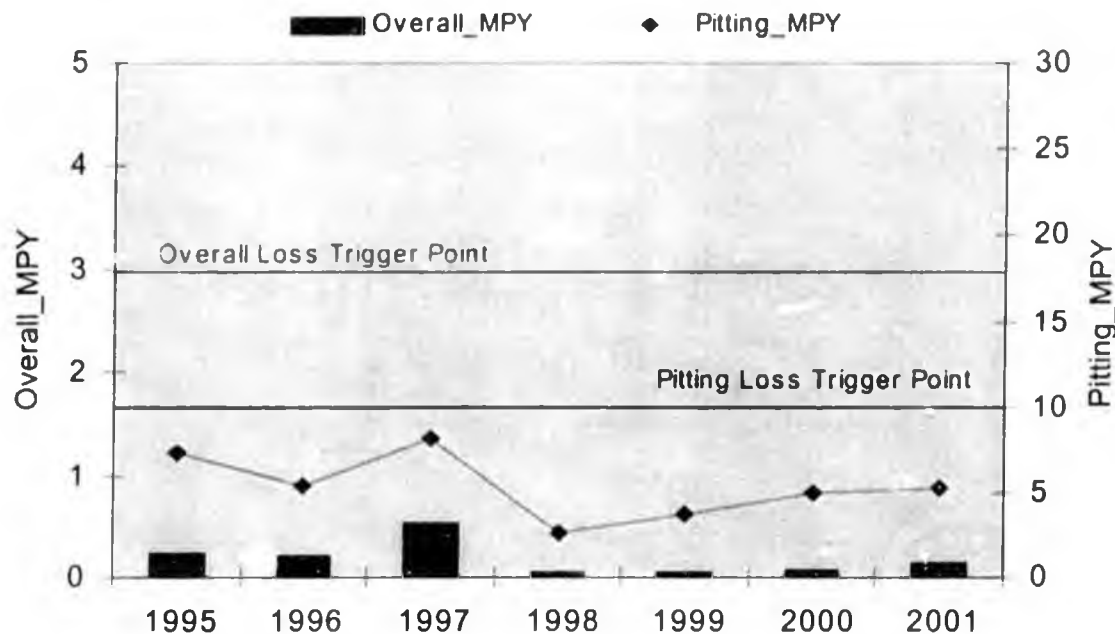
Monitoring Results

Crude Cross Country Lines

- Corrosion in Crude CC Lines is under control
- Average coupon and probe corrosion rates remain well under triggers
- Inspection data confirms corrosion is in check
- Probes - 95% of Line probes had corrosion rate <1.0 mpy
- Coupons - 6 Lines had corrosion rates exceeding trigger level
 - ✓ Inspected 4 of 6, three had at least 1 confirming increase location
 - ✓ Increased Corrosion Inhibitor rates on all 6 lines
 - ✓ Remaining 2 lines scheduled for inspection in 2002

"feel pretty good"

50-60 lines total produced crude since 11 lines have 10-106 coupon locations



Shows the manifold injector @ compressor is correct position

Handwritten notes on the left margin, partially illegible.



Monitoring Results

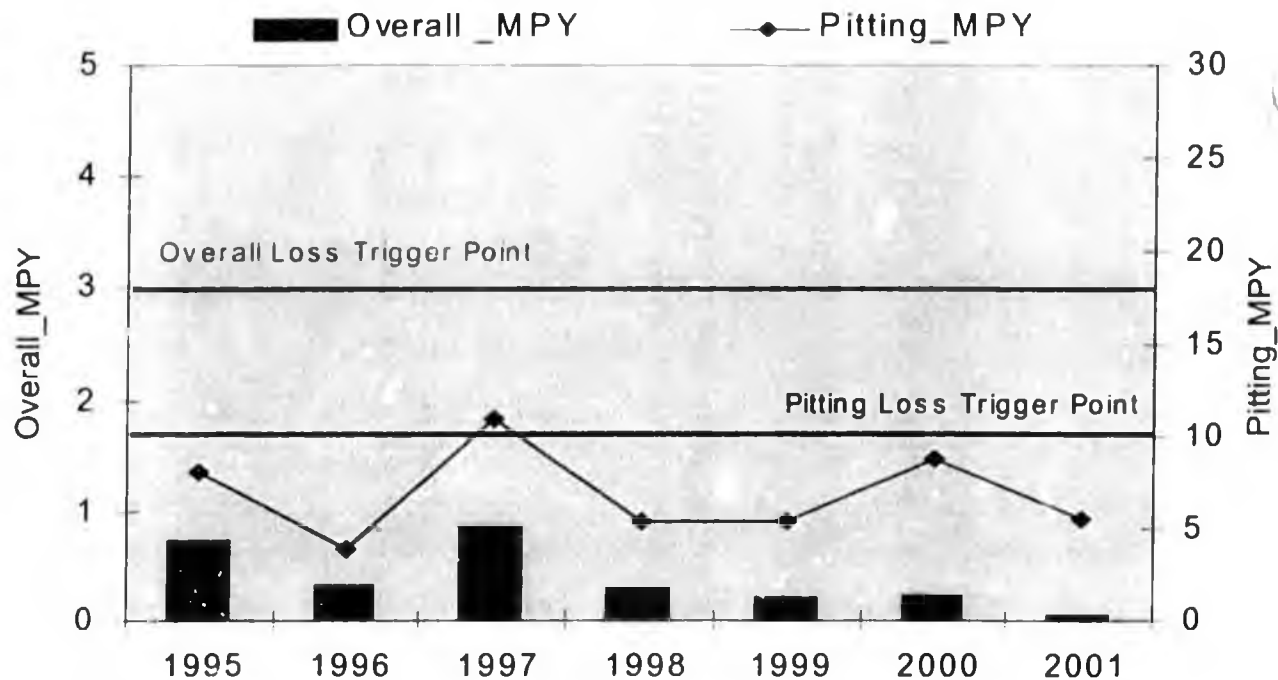
Water Injection Cross Country Lines



- > Corrosion is under control in Water Injection CC Lines
- > Average coupon data has remained below triggers since 1998
- > Inspection data confirms that corrosion is in check
- > Coupons - 8 Lines had corrosion rates exceeding trigger level
 - ✓ Inspected 6 of 8; 5 were baseline and 1 recur with no increase
 - ✓ 4 of inspected lines showed less than 5% wall loss
 - ✓ 2 of inspected lines showed ~30% wall loss (worst case)
 - ✓ 5 of 8 lines had subsequent coupons below trigger level

*Water Chemistry
1/12/01*

operation of pipeline lines?
CPE is still in coupon on corrosion (How many lines?)
inspector from 2-2001

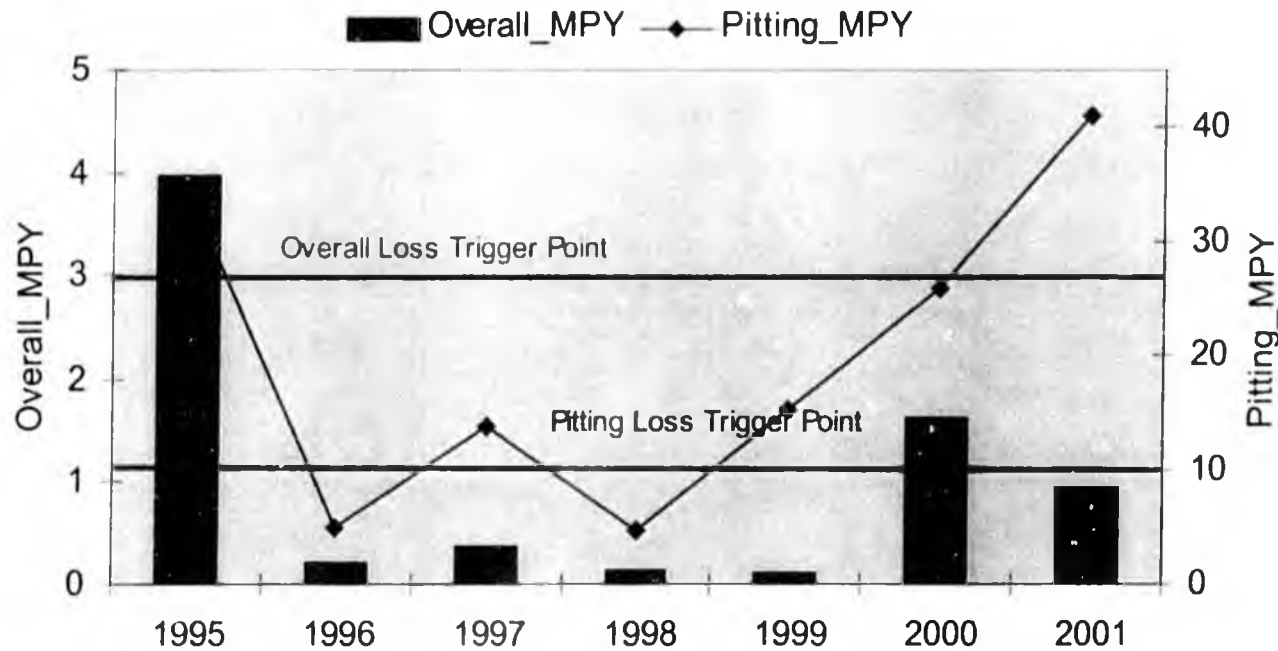


Monitoring Results

Wet Oil Cross Country Lines

- Corrosivity in wet oil lines a result of high water cut
- 24" Wet Oil Line was decommissioned in June 2001
- Coupons - 2 Lines had corrosion rates exceeding trigger level (includes abandoned 24")
 - ✓ Inspection on 12 " Line indicated no damage
 - ✓ Corrosion Inhibitor rates were increased and remain at high levels
 - ✓ Pigging frequency increased from 3 months to 2 months

Handwritten note:
24" Wet Oil Line
decommissioned
June 2001
off





Monitoring Results

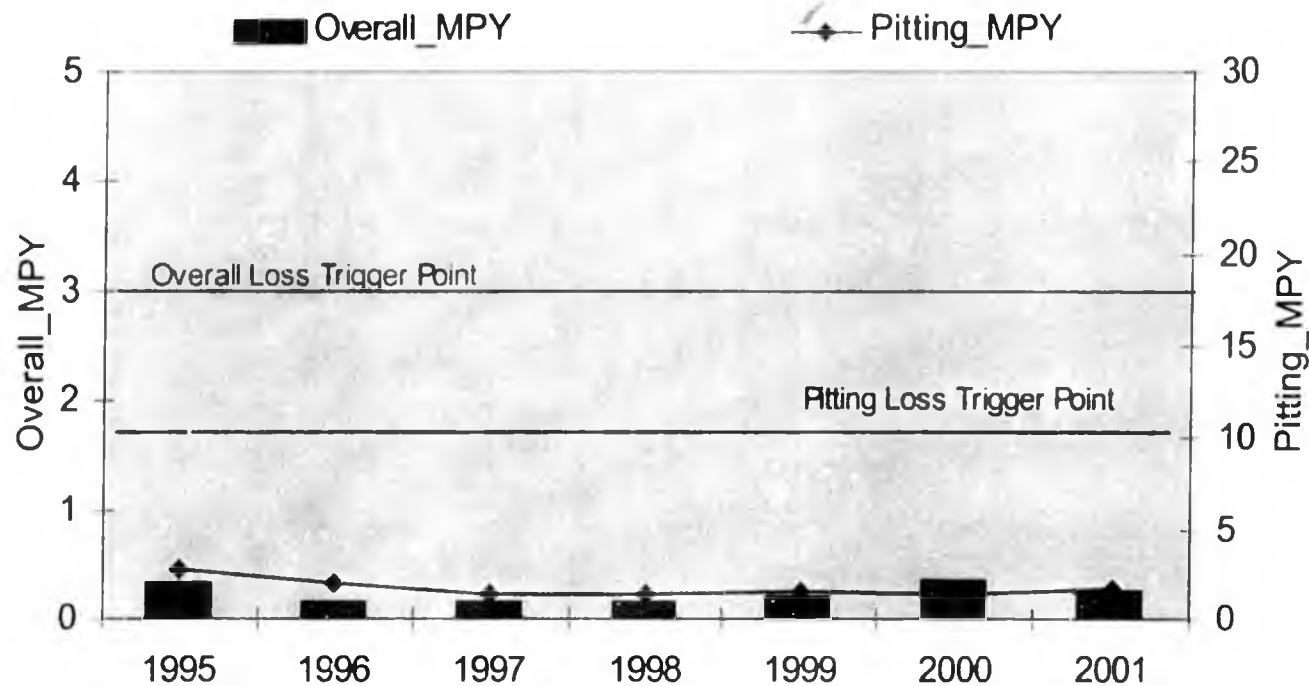


Production Well Lines

- Coupon Trends indicate corrosivity not increasing, but don't indicate full story
- Inspection data on older/thinner lines indicates significant corrosion damage
- Doubled inspection effort on well lines in 2001
- Coupons - 2% or 13 Lines had corrosion rates above trigger level
- All lines inspected in 2001
 - ✓ Maximum wall loss 25% for 1 line
 - ✓ 8 Lines showed less than 20% wall loss
 - ✓ 4 Lines showed no damage

*one monitor
to monitor - needs*

*1/2 in. water,
2000 ft,
100 ft
produced
water*



Monitoring Results

Water Injection Well Lines

- > Trends indicate corrosivity on the rise
- > Inspection data on older/thinner lines indicates significant corrosion damage
- > Coupons - 20% or 72 Lines had corrosion rates above trigger level
 - ✓ Coupon results factored into well line inspection prioritization
 - ✓ Doubled inspection effort on well lines in 2001

