6/7/07 TAPS TARRIFF PROCEED-INGS, & OIL PIPELINE INTEGRITY & CORROSION (FILE 2)

bp

BP Alaska update to the House Resources Committee

June 7 2007

Agenda

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August 2006 Business Resumption

- Cleanup and recovery
- Bypass construction
- Listening and learning

Operations Integrity Assurance

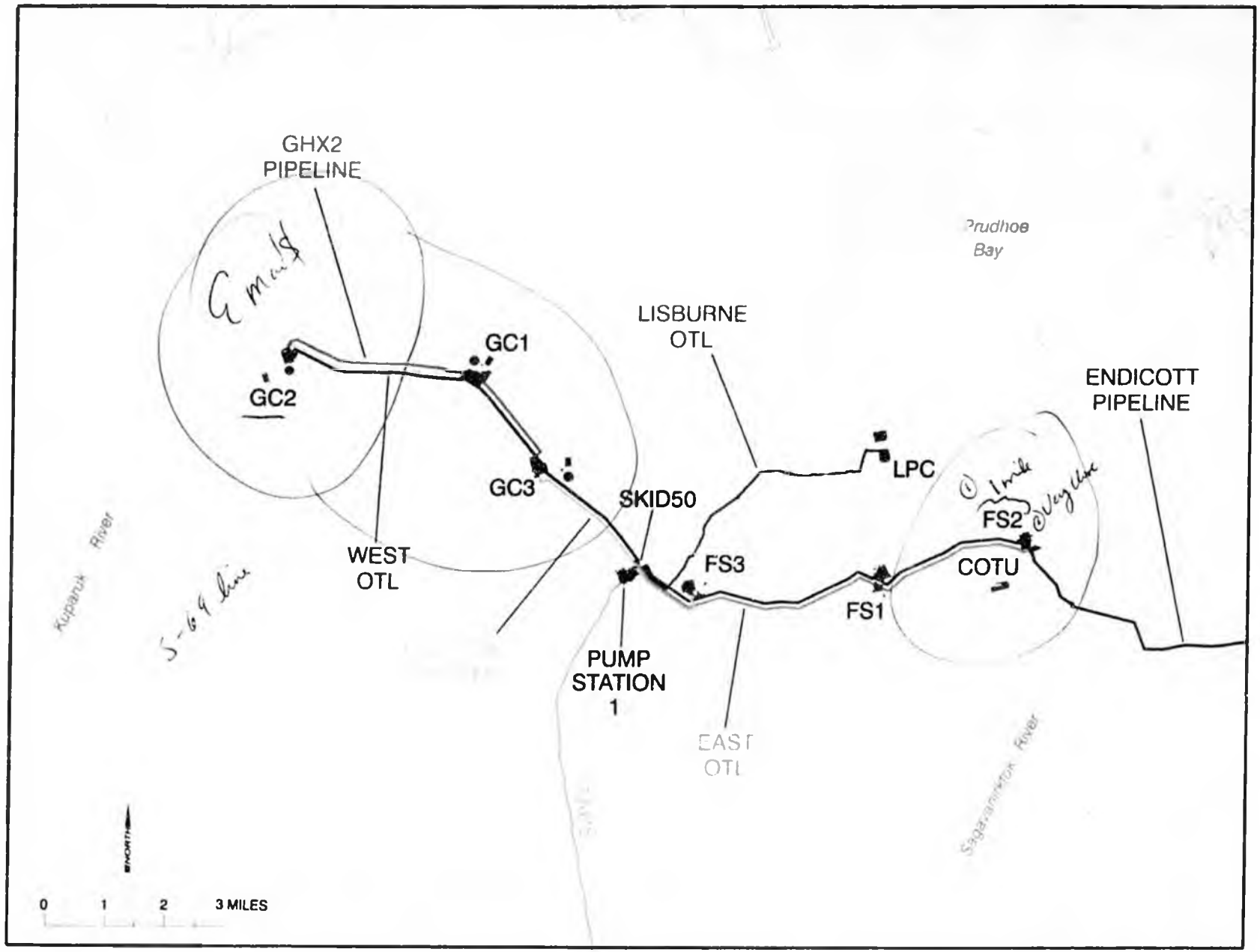
- Corrosion management
- Ongoing inspection and surveillance

Pipeline Renewal

- OTL system project
- Leak detection

BPX Alaska Forward Plan

Prudhoe Bay Orientation



BPXA Cartography/10.18.06/pe15382.dgn

Business Resumption Program

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In 100 days:

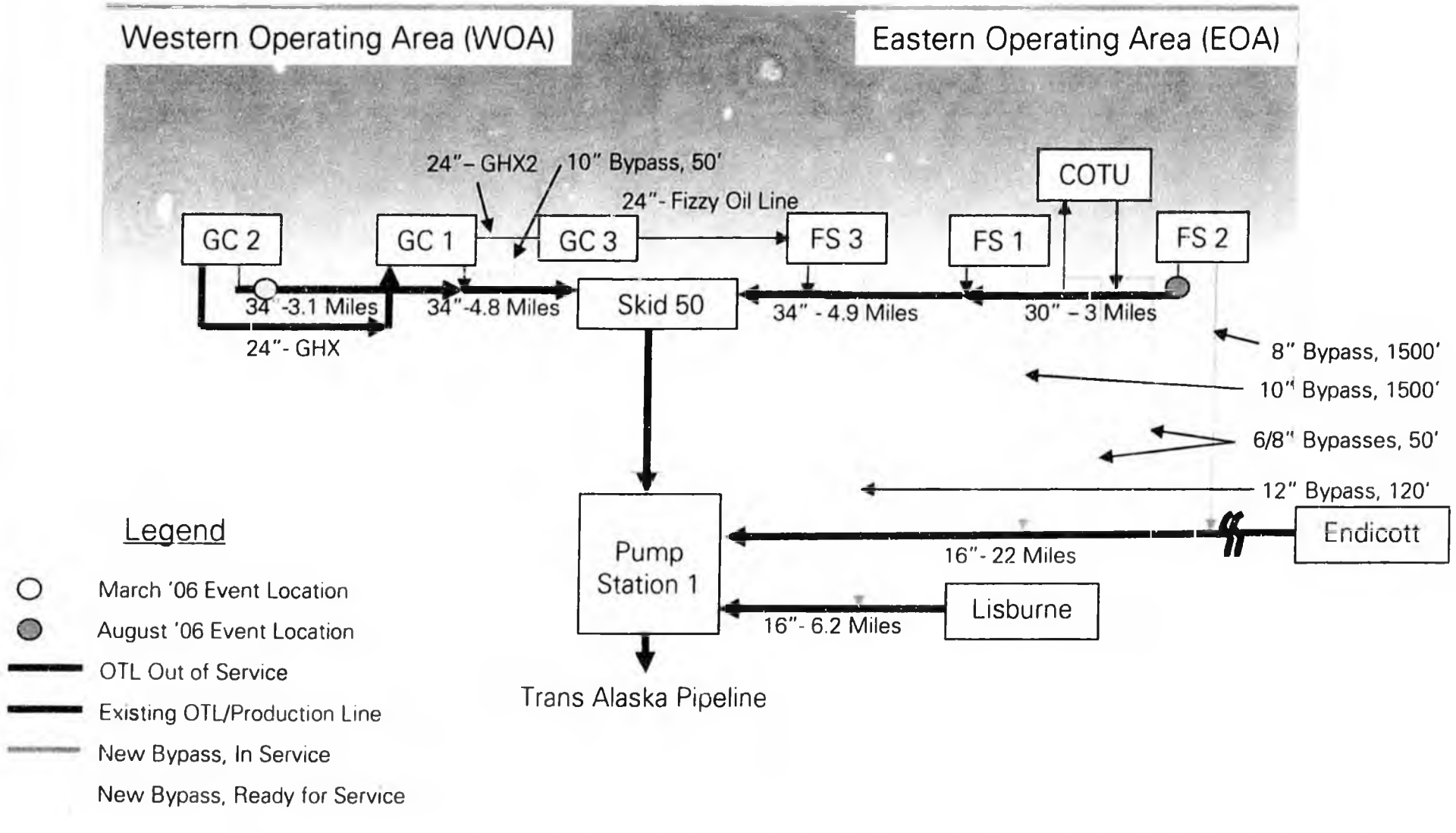
- Removed insulation, inspected and re-insulated over **43,000 ft (8 miles)** of oil transit lines (inc. 4 caribou and 2 road crossings)
- Installed **5 new pipeline bypass** projects
- Completed **34 hot taps**
- De-oiled and fully isolated GC2 to GC1 and FS2 to FS1 OTLs in preparation for abandonment
- Built and installed a new temporary 34 "pig launcher at GC1 and solids bypass facilities at skid 50 to enable WOA and EOA OTL pigging
- **Ran 6 cleaning, 1 gauge and 2 smart pigs** through the FS1 to skid 50 EOA OTL to determine suitability to remain in service until the lines can be replaced. Began weekly maintenance pigging
- **Ran 6 cleaning, 1 gauge and 2 smart pigs** through the GC1 to skid 50 WOA OTL to determine suitability to remain in service until the lines can be replaced. Began weekly maintenance pigging
- Restarted FS2 and COTU through the Endicott pipeline
- Provided contingency routing for oil export to PS1 from 4 other facilities

Business Resumption Program (continued)

In 100 days:

- Received all necessary regulatory permits and commercial agreements without any impact to schedule
- Removed 40 ft section of GC2 to GC1 OTL and shipped to L48 for further sectioning and analysis by DOJ
- Increased North Slope camp population supporting GPB by **700 (44%)**
- Shutdown and restarted **7 major production facilities** (some twice). Partially shutdown and restarted the gas plants
- January 2007 production >430mbd

North Slope Oil Transit Lines - Bypasses



East/West Operating Area Bypass Status

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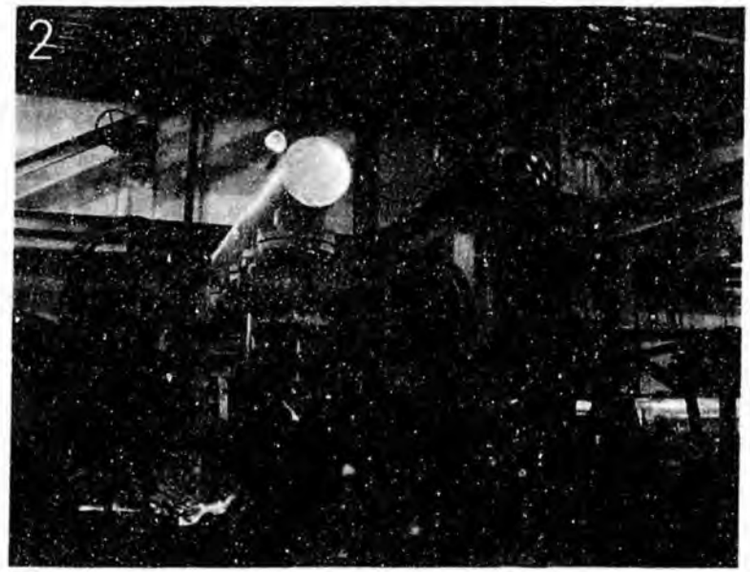
Production Facility	Bypass Status	Comments
EOA Flow Station 2 (FS2)	Fully Operational. In Service to Endicott.	
EOA Crude Oil Topping Unit (COTU)	Fully Operational. In Service to Endicott.	
EOA Flow Station 1 (FS1)	Ready to Be Placed Into Service to Endicott. Requires Valve Installation & Final Tie-in for Use.	2 day Shutdown Required. Estimated Duration to Commission – 5 days.
EOA Flow Station 3 (FS3)	Ready to Be Placed Into Service to Lisburne. Requires Spool & Final Tie-in for Use.	Estimated Shutdown & Commissioning Duration – 7 days.
WOA Gathering Center 2 (GC2)	Fully Operational. In Service through GHX to GC1.	Installed Following the March OT21 Event
WOA Gathering Center 1 (GC1)	Ready to Be Placed Into Service to GHX2. Requires Spool & Final Tie-in for Use.	Estimated Shutdown & Commissioning Duration – 5 days.
WOA Gathering Center 3 (GC3)	Slug Catcher Bypass Ready to be Placed Into Service. Requires Spool Final Tie-in for Use.	

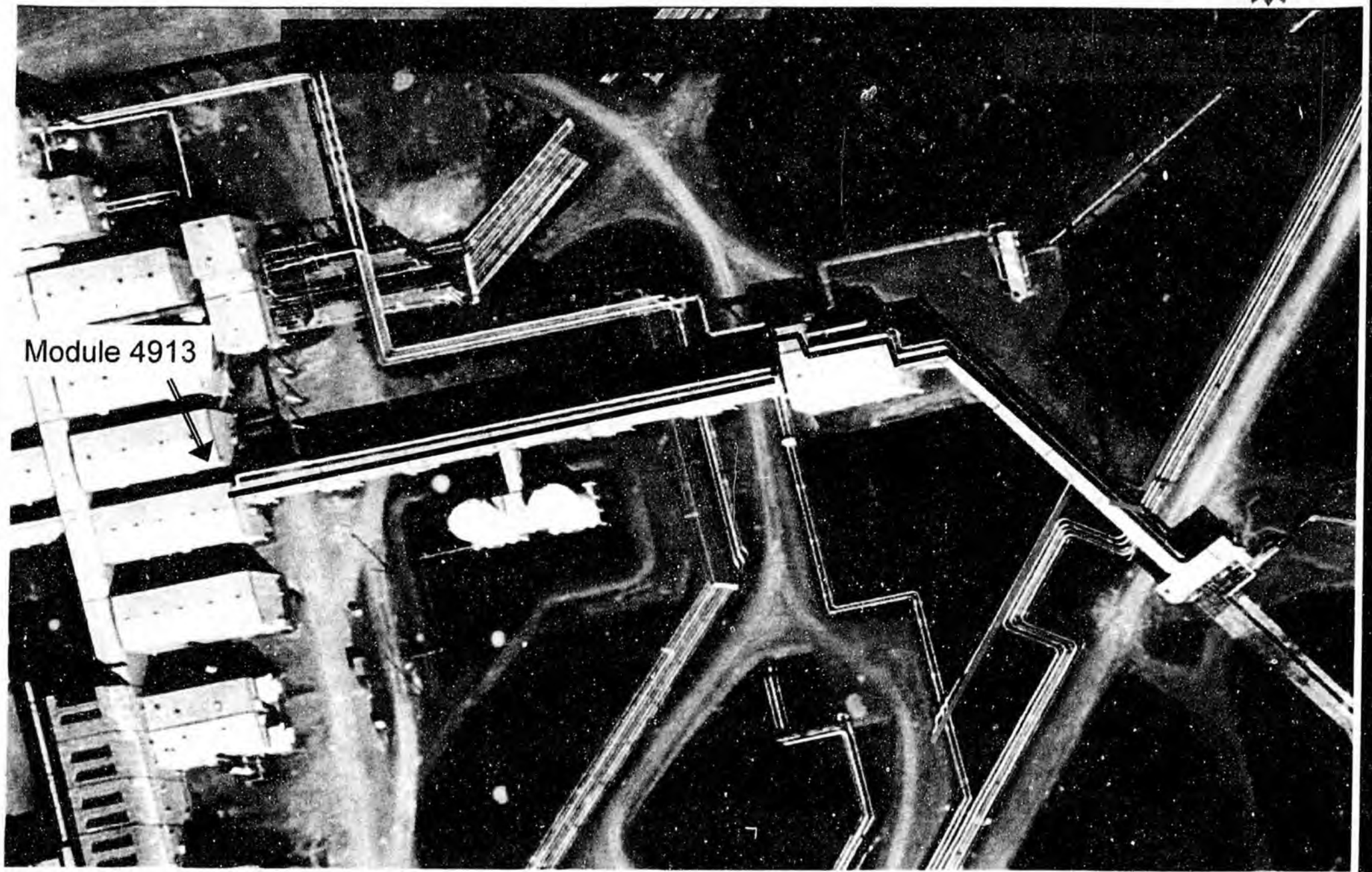
GPB Bypass Photographs



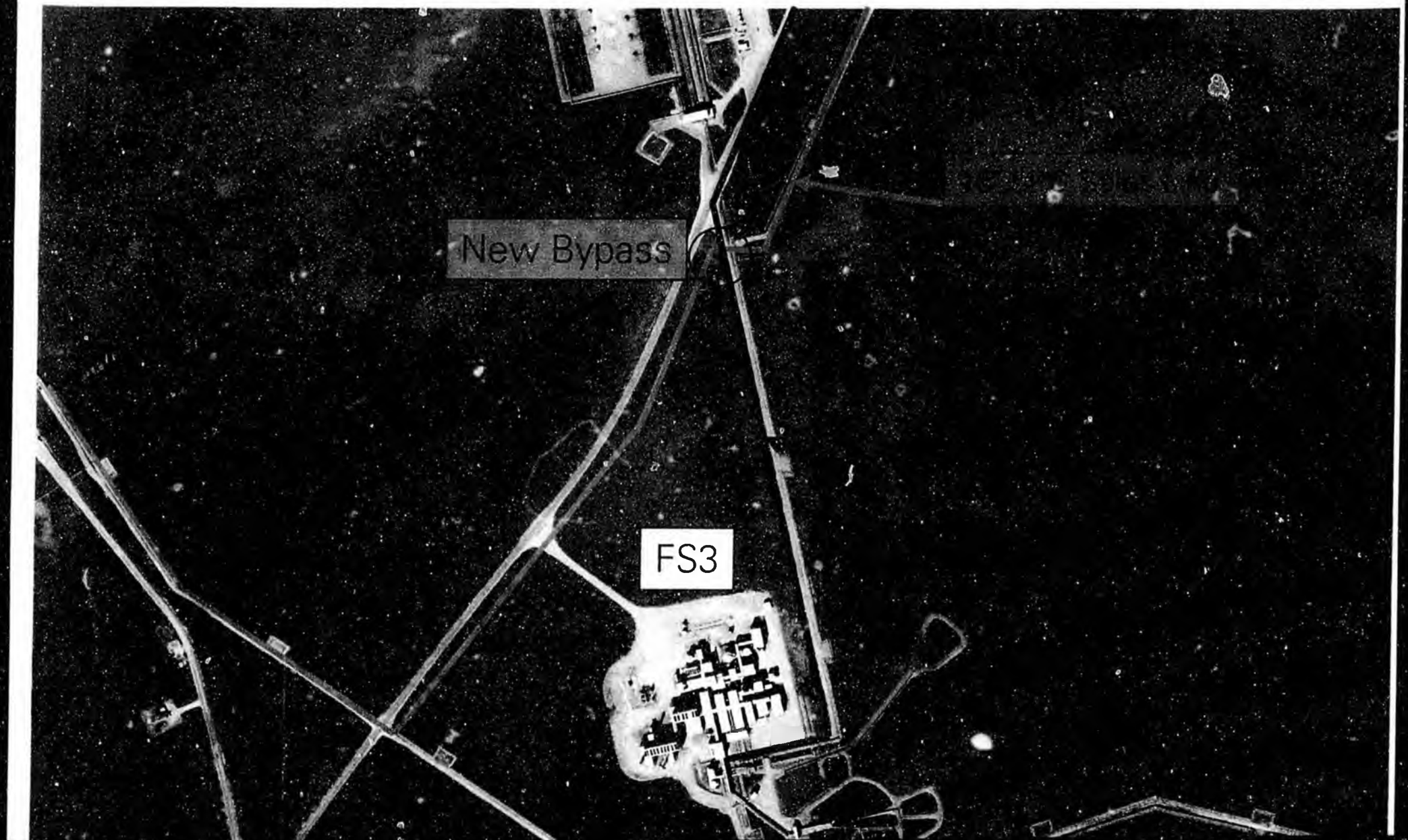
Legend

- 1 – Hot Tap to Endicott for FS2 Bypass
- 2 - FS1 Bypass Piping in the Module
- 3 – FS1 Bypass Piping Installation Outside FS1

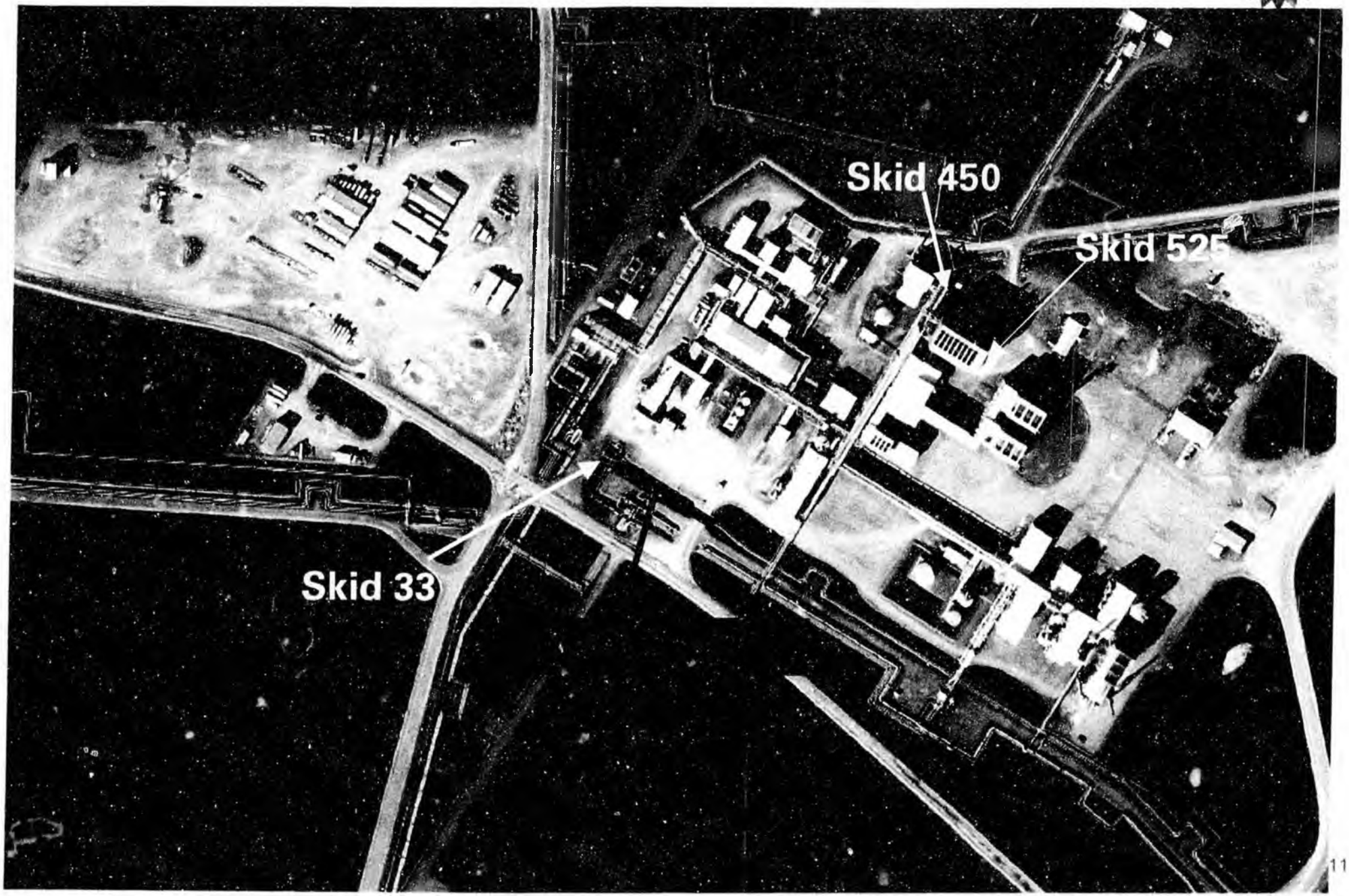
FS1 Bypass Option



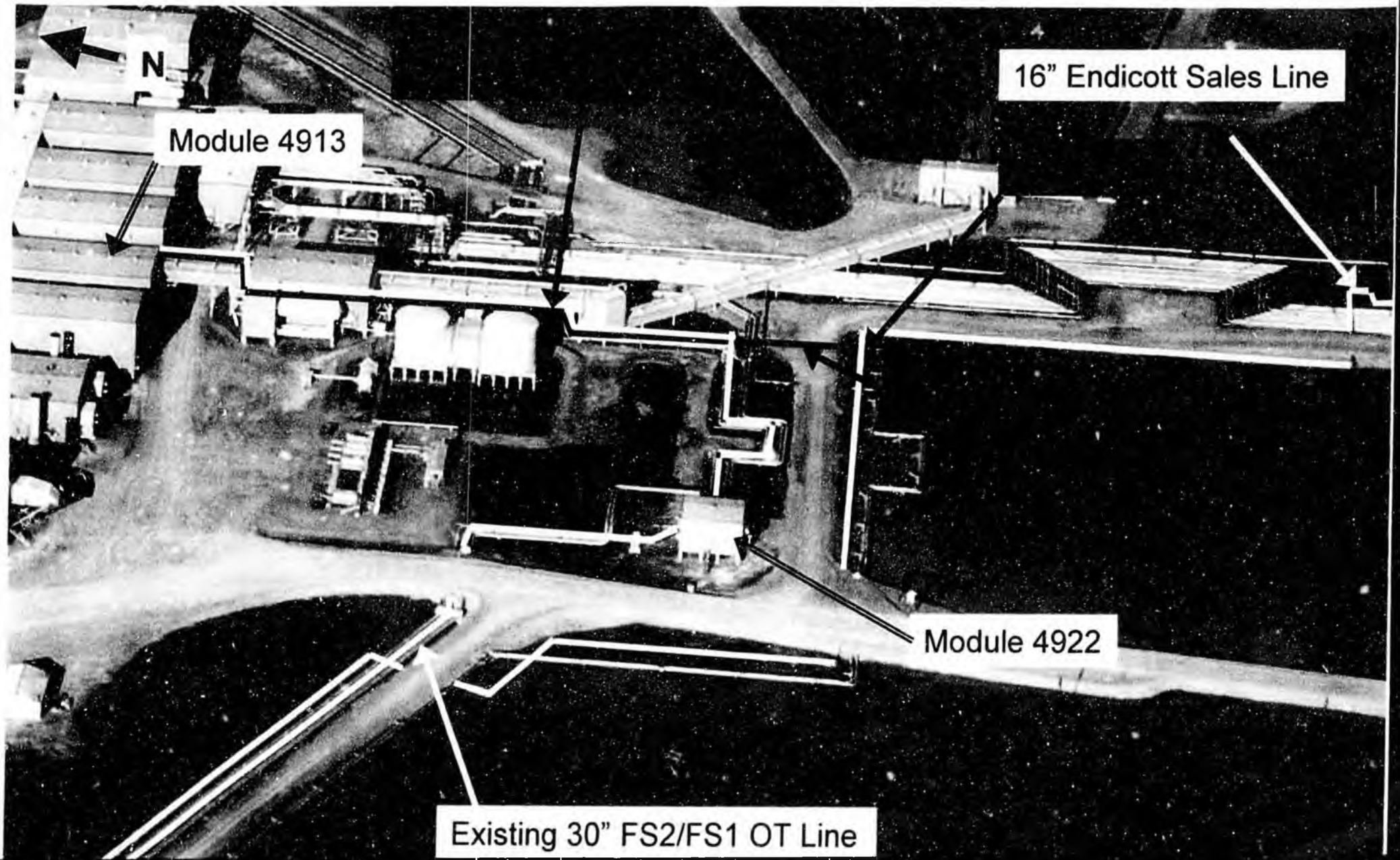
FS3 Bypass to Lisburne Pipeline



GC-1 Bypass Overview



FS2 Bypass to Endicott Pipeline



Listening and Learning

• Restore GPB production safely but swiftly	• Restored production in 44 days and production now at pre-August Shutdown rates of > 440MBOED
• Seek to understand why this system failed (Corrosion mechanism)	• Extensive technical evaluations undertaken to determine failure mechanisms but 3 clear causal factors now understood, sediments, water and flow velocities .These factors allowed microbial inducted corrosion (MIC) to occur, we will continue further studies to define the identification of the specific types of bacteria
• Begin immediate maintenance pigging and "Intelligent" pigging of Transit lines	• Mechanical pigging weekly now and all OTL lines intelligent pigged twice
• Include all Oil transit Lines in DOT's Pipeline Integrity Management Program	• Working with DOT, phase 1 transition of all lines (except 1 NGL line by 03/08) have been incorporated into the DOT Pipeline Integrity Management Program
• Change BP's Alaska organization to create an independent Technical Directorate	• Technical Directorate formed in Aug, 2006 with more than 150 technical staff working outside of the line organization to provide independent integrity assurance.
• Identify and accelerate maintenance spending across operations	• Maintenance spending has been increased 4 fold since 2004 to c.a. $195mm in 2007
• Work openly with Federal, State and Industry to identify learning's and best practices	• Tremendous efforts, recognized by many of the agencies and industry to openly share and incorporate ideas, processes and learning's to mitigate future risks

Operations Integrity Assurance

Inspection and Surveillance

Corrosion Mitigation Program Status

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Mechanisms

- External investigation identified Microbiological Influenced Corrosion (MIC) as primary cause
- 3 causal factors are water, sediment and bacteria.
  - These factors are now mitigated and we are confident in the ongoing integrity of these lines

Corrosion Mitigation Strategy

- Carbon Dioxide: Continuous corrosion inhibitor
- Stagnant water &/or sediments: Remove using maintenance pigs
- Bacteria: Scraping pipe walls (pigs) & using biocide
  - Cl is also a biocide

Status

- Pipelines were cleaned prior to ILI
- Weekly & monthly cleaning pigs
- Supplemental corrosion inhibitor injection directly into OTLs
- Analysis of pigging returns - virtually no deposits recovered since cleaning

Inspections

- 23,804 Inspections now completed since August 6
- Repeat Ultrasonic inspections over areas of known corrosion
- Repeat smart pig runs scheduled for summer 2007 for EOA/WOA pipelines (XF21 completed 6/5)

Inspection Accelerated Integrity Assurance

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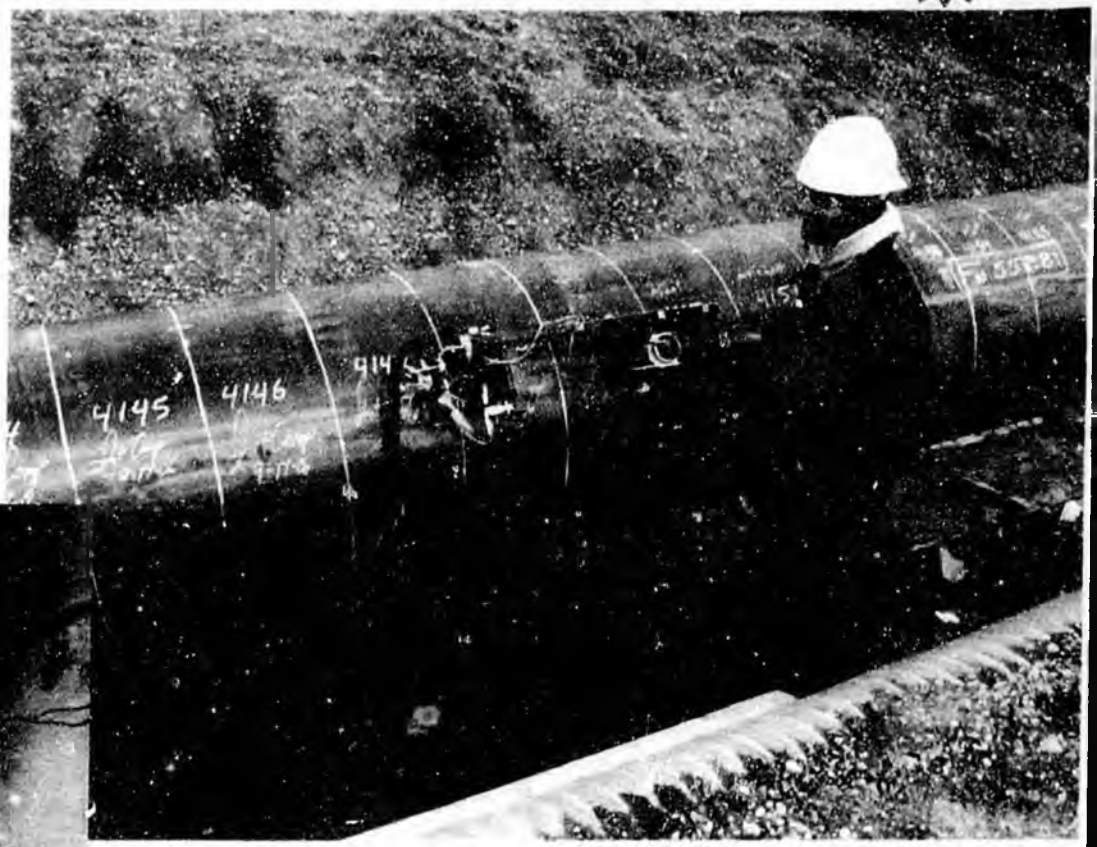
Ultrasonic testing of 34" transit line between FS1 and skid 50



Automatic ultrasonic testing of 34" transit line between GC1 and skid 50

Inline Inspection Tool ("smart pig")

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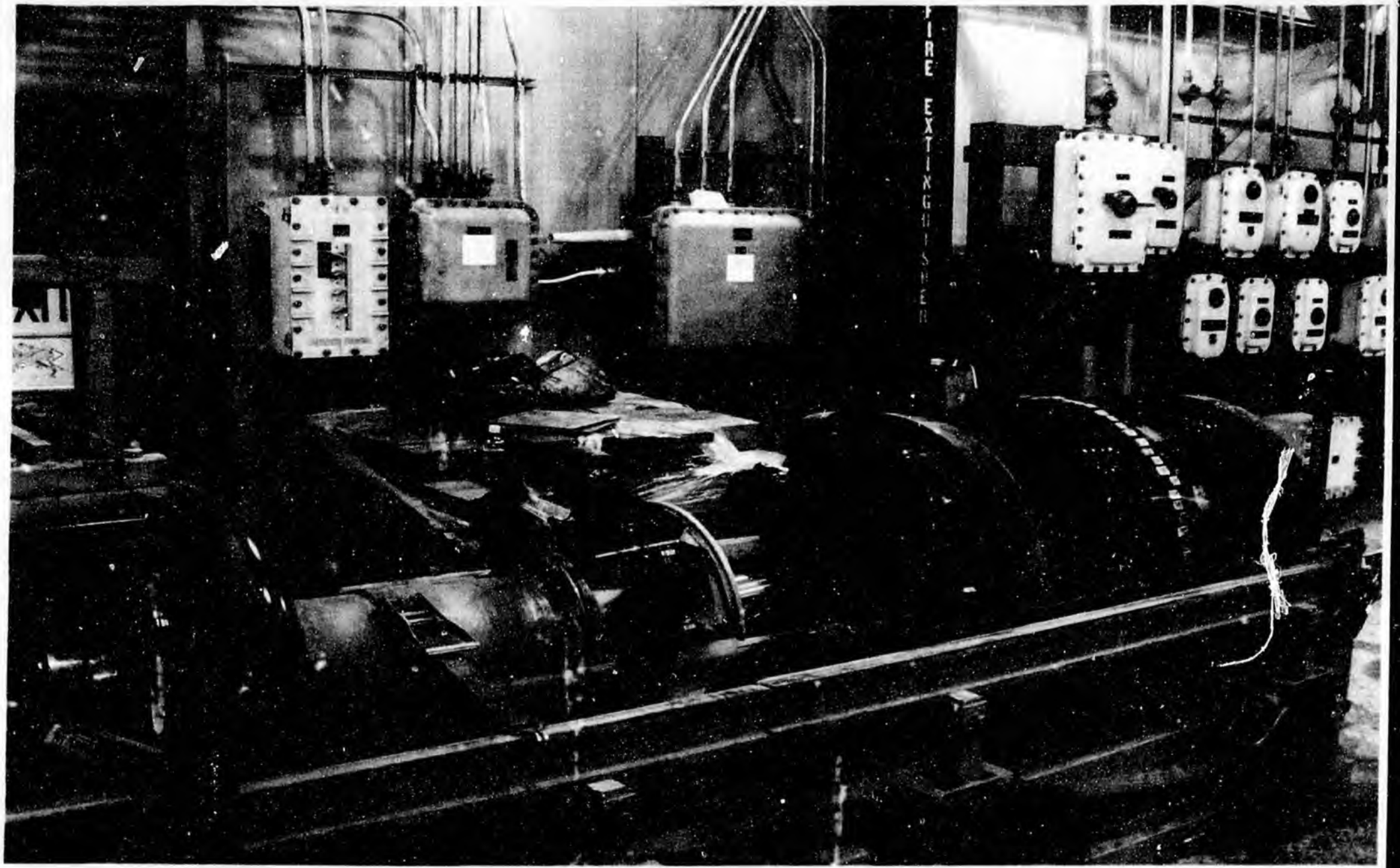
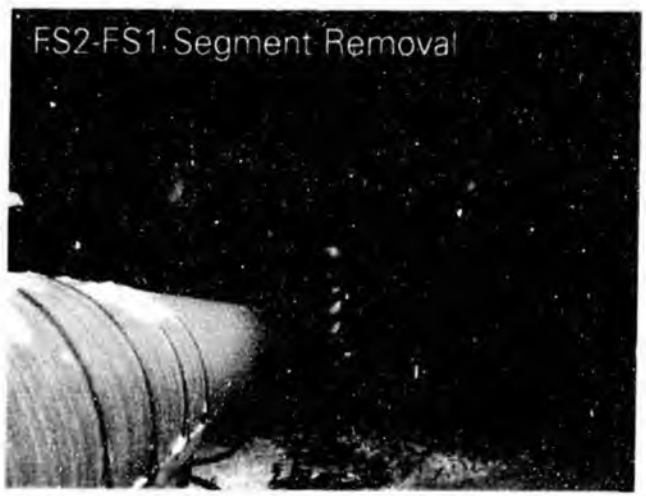
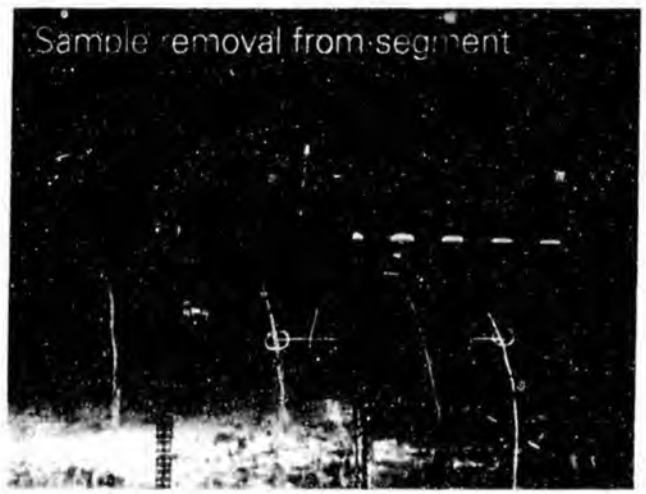
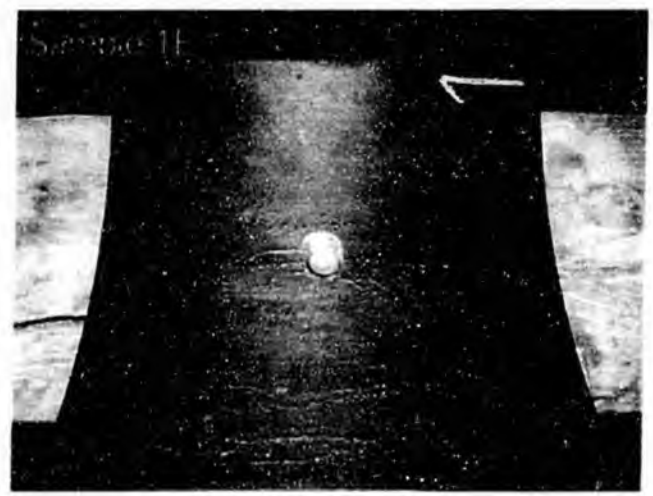


Oil Transit Lines Corrosion Management

- Corrosion Mechanism
  - WOA – OT21
    - Dr. David Duquette investigation completed 1Q07
    - Primary cause was Microbiological Influenced Corrosion (MIC)
  - EOA – FS2-FS1
    - ~40ft section removed Feb 3rd
    - Samples were cut out and shipped to labs for analysis
    - Tentative report delivery 2Q07







Continuous Improvement

- Support of 2 Alaska Pigging Conferences in 4Q06
- New Corrosion Control Strategy Developed 1Q07
  - BP, CPAI, XOM, Consultants
  - Implementation in progress
- 60% increase in CIC Team Staffing
  - Moving to 100%
- Commitment to recruit a CIC Lead in every N.Slope Area in 2007
- 5 year smart pig plan developed
  - 18 smart pigs in 2007 (historical average 2-3/year)
- NACE "Advanced Corrosion" Cc irse development
  - 100% BP Funding

Ongoing Pipeline Surveillance

- 4x daily handheld FLIR on all OTL lines and bypasses – total 80 miles per day covered
- Use of 2 snow-CAT machines to access pipelines during heavy snow
- Daily overhead FLIR flights
- Added 2 x 25 man shifts added since August
- New operating procedures for (FLIR) surveillance includes equipment, training and reporting

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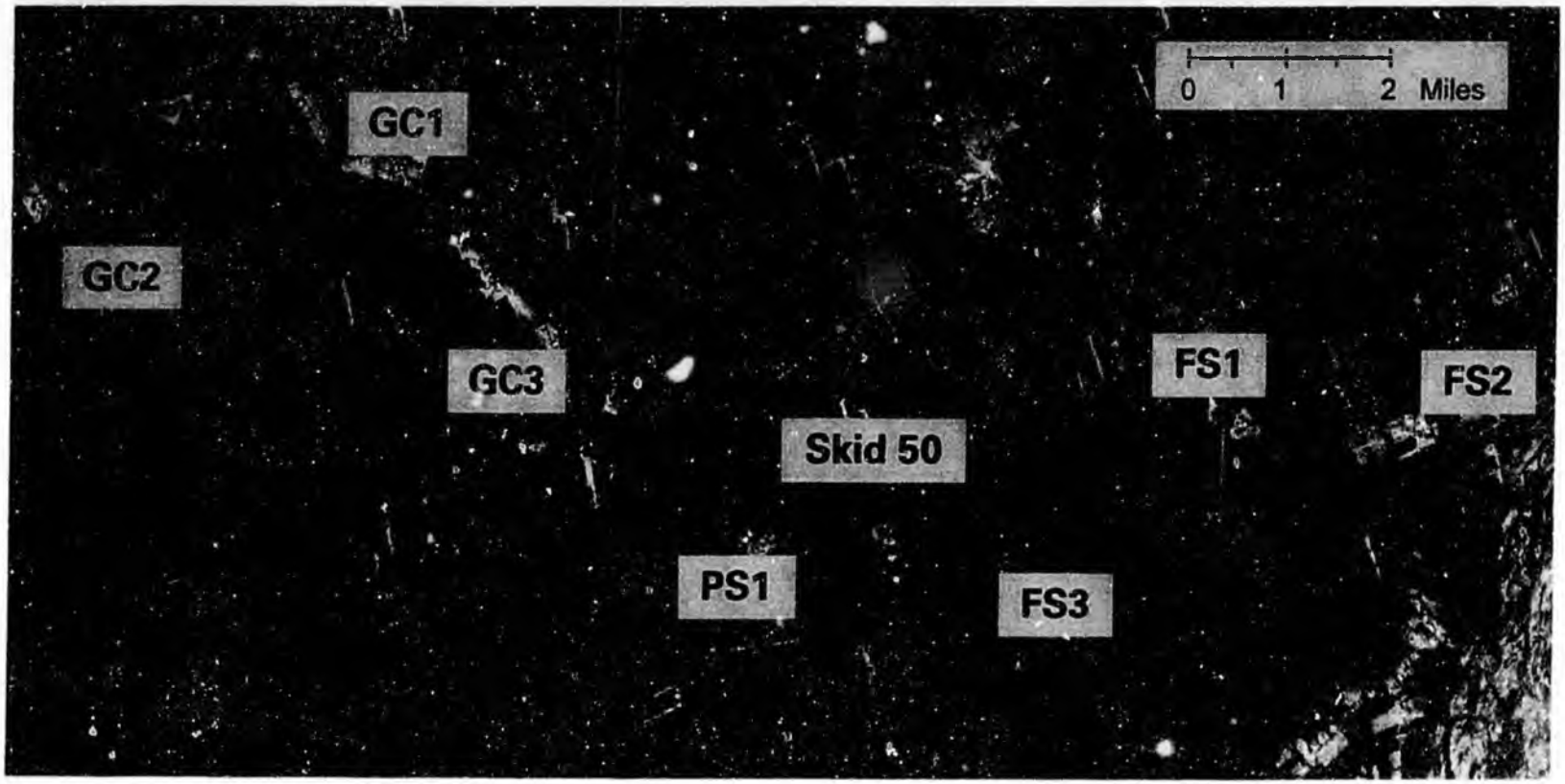
Oil Transit Line System Replacement

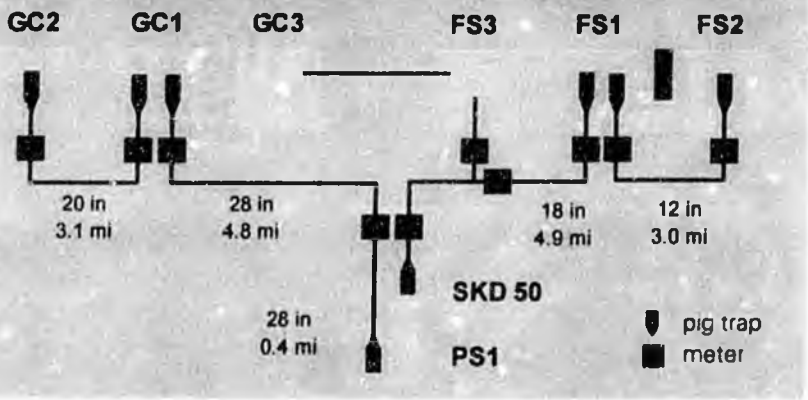
Status as of May 07

Route and Scope



- Five segment manifold
- Eight new launcher/receivers
- Ten new leak detection meters
- Twenty new modules/skids

Process Schematic



System Upgrades

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	Improvements
Pig Launcher/Receivers	all segrnents smart/maintenance pigable
Dedicated Chemical Injection	all segments continuous injection automated controls
Leak Detection System	more sensitive and repeatable new turbine flow meters new ATMOS software package LEOS pilot
Pipelines	DOT 49 CFR part 195 design Fusion Bond Epoxy external coating 30 yr life accommodating viscous dev smaller diameters to increase velocity new VSM's at 7ft for visibility and caribou more access platforms for inspection additional corrosion coupons concrete anchor replacement double block isolation all segments

Typical Pig Launcher Module

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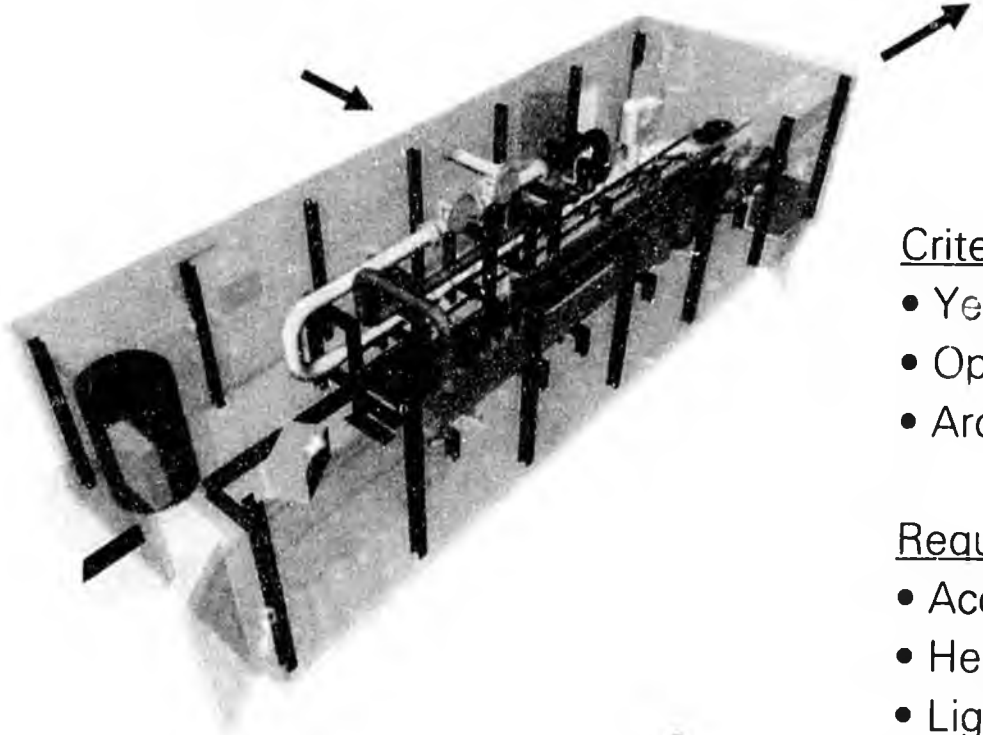
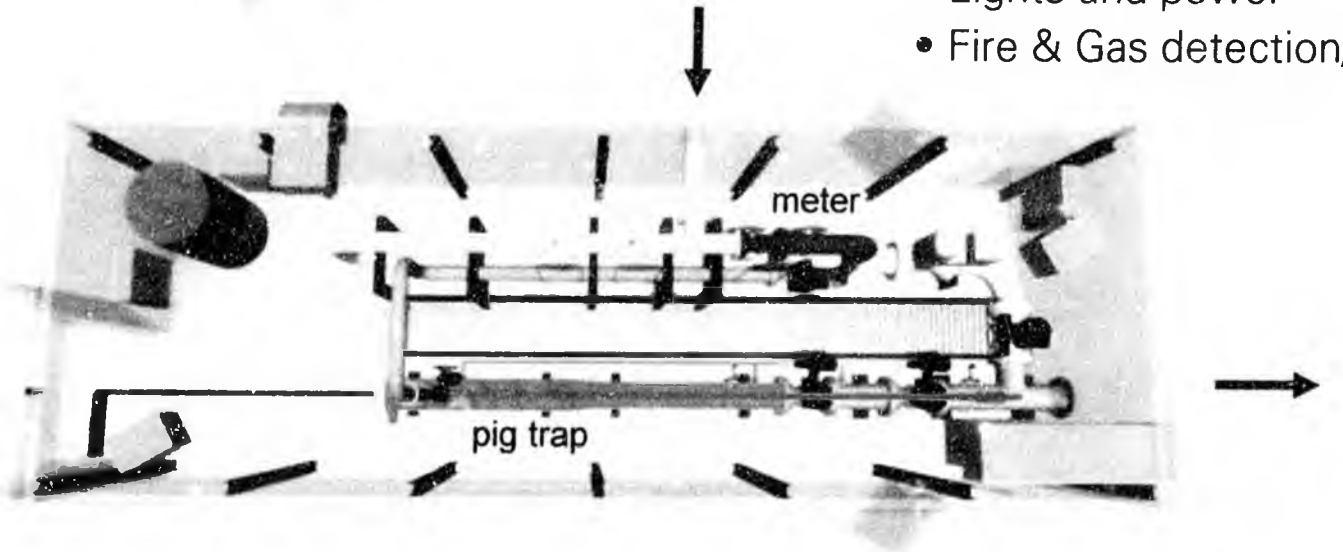


Criteria

- Year round access
- Operations and maintenance
- Arctic environment

Requirements

- Access and clearance
- Heat and ventilation
- Lights and power
- Fire & Gas detection/suppression



Permitting

	OTL-WOA	OTL-EOA
Approved	11	11
Pending	1	2

- Full Cooperation of all Local, State and Federal Agencies
- Timely approval of Permits

Upgraded Leak Detection System

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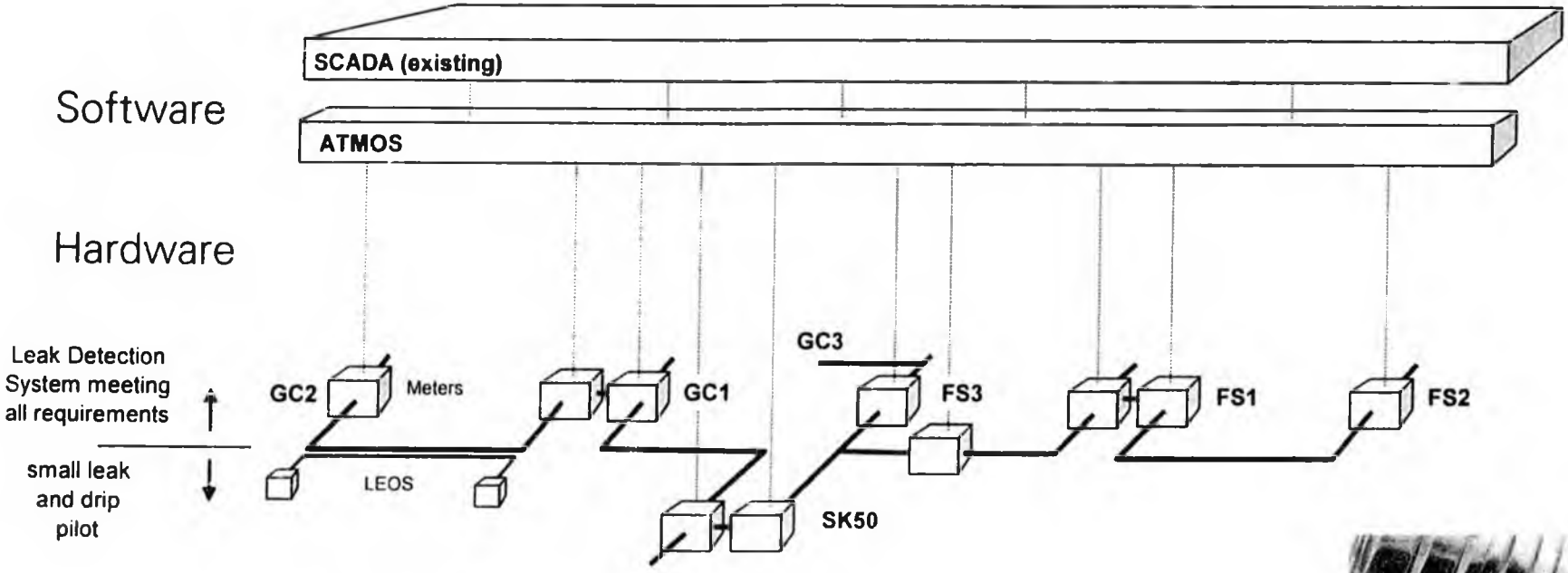
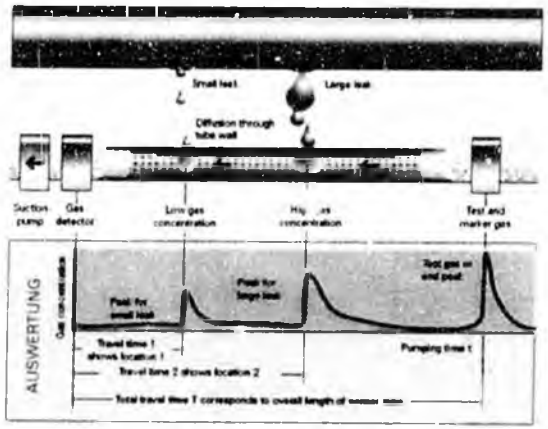
Software

Hardware



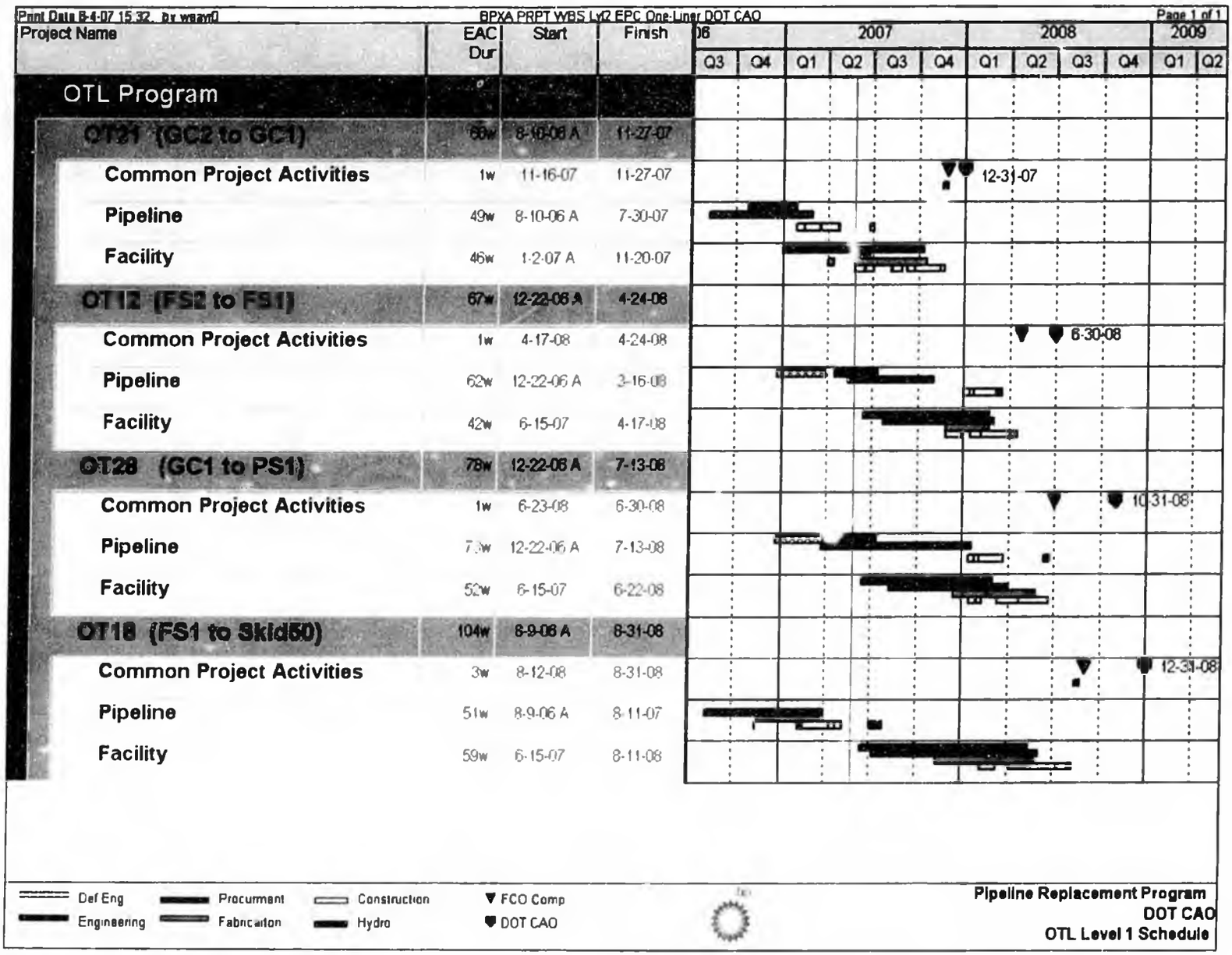


LEOS small leak detection system

LEOS tubing under OT21 line

Current Execution Schedule

OTL Level 1 Schedule



Project Accomplishments

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Engineering and Design:

- WOA P/L segments 95% complete
- EOA P/L segments 95% complete
- Facilities 40% complete

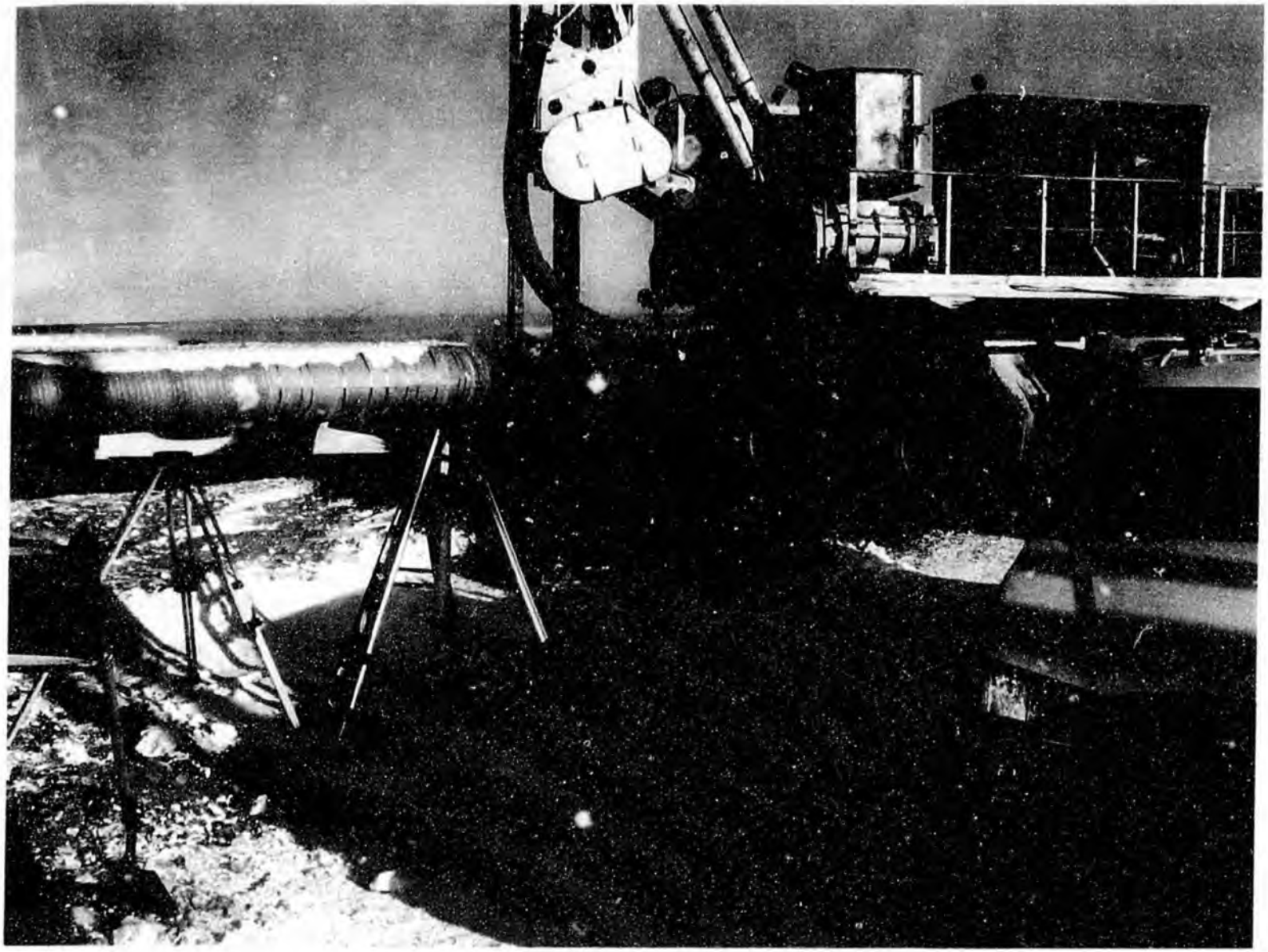
Materials and Fabrication:

- All Pipe Ordered
- Pipe coating, insulation and delivery in progress
- Early module fabrication in progress
- 80% of long lead items ordered

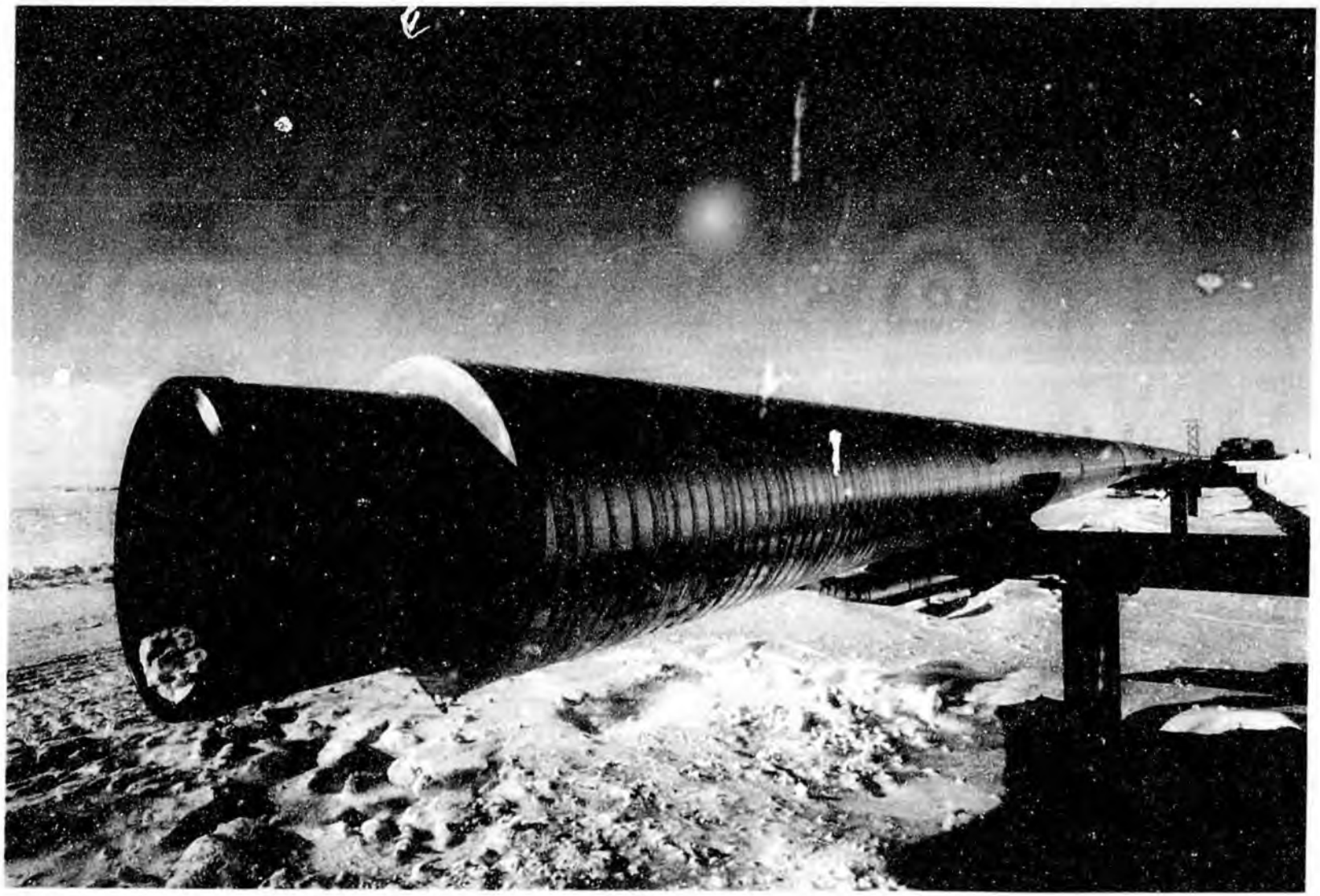
Construction:

- 20" and 18" segments installed
- Leos system installed

Drilling permafrost / Pipeline VSM installation



End of coated, insulated pipe spool



VSM - Vertical Support Members

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OTL welding

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Sand blasting pi

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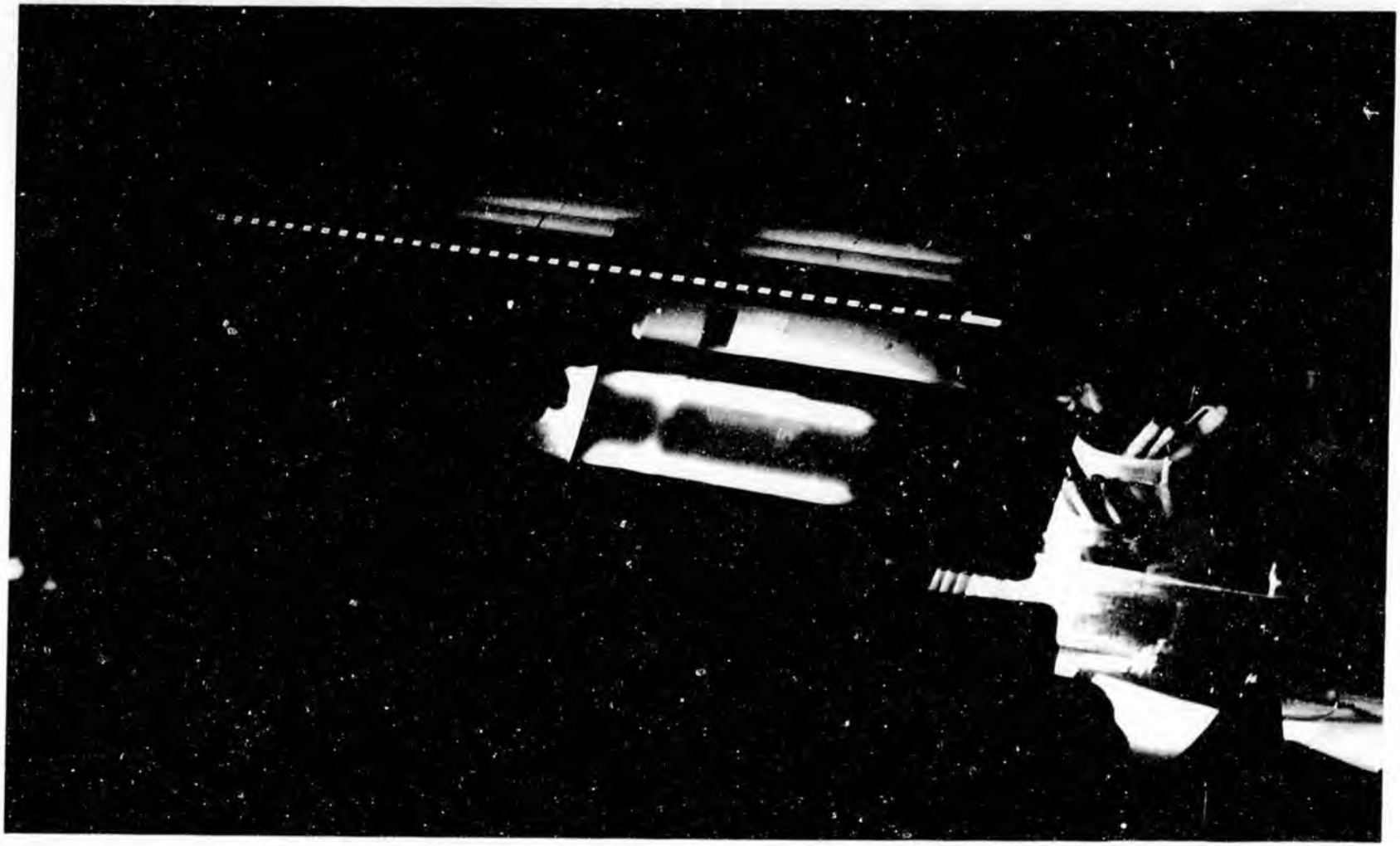
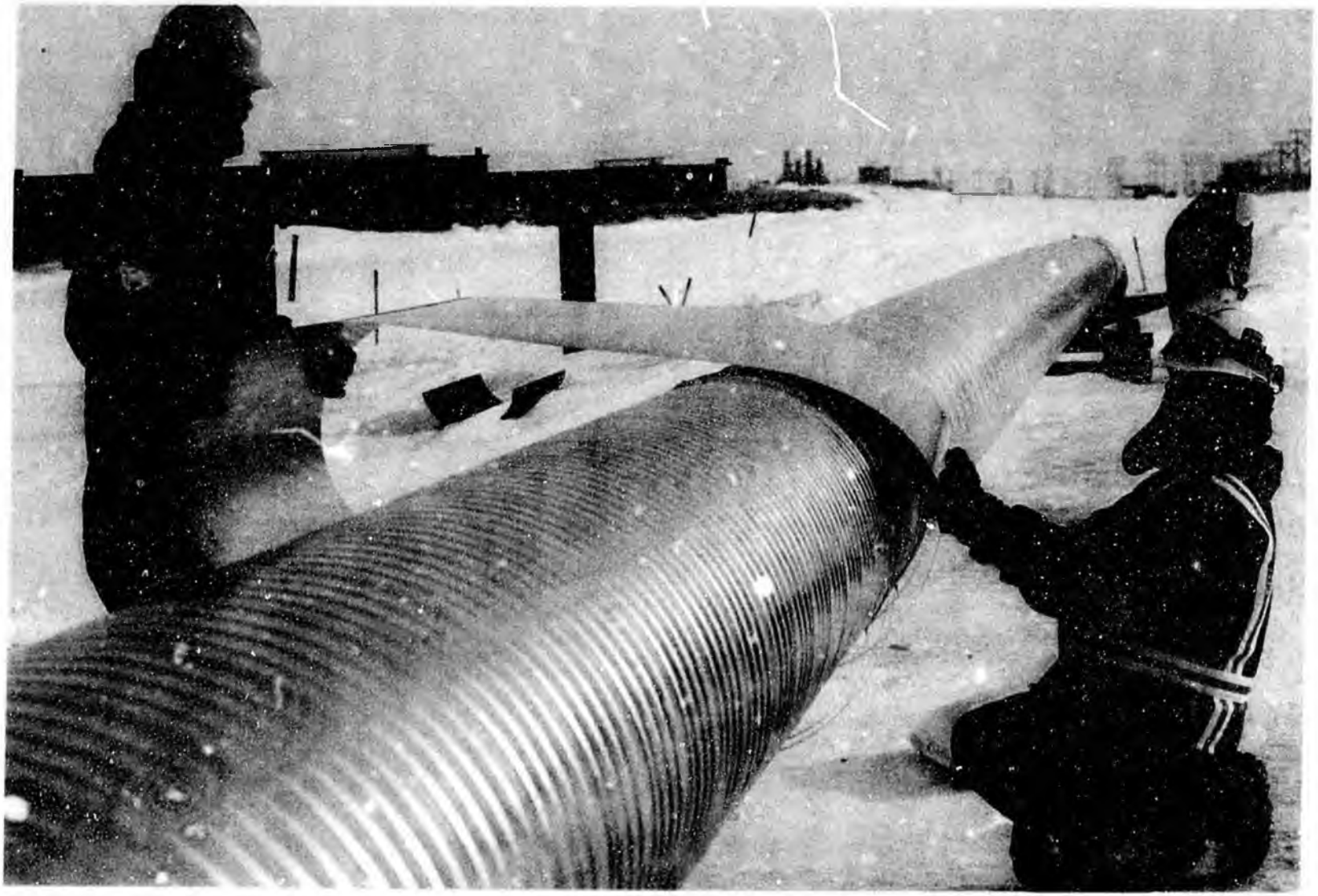
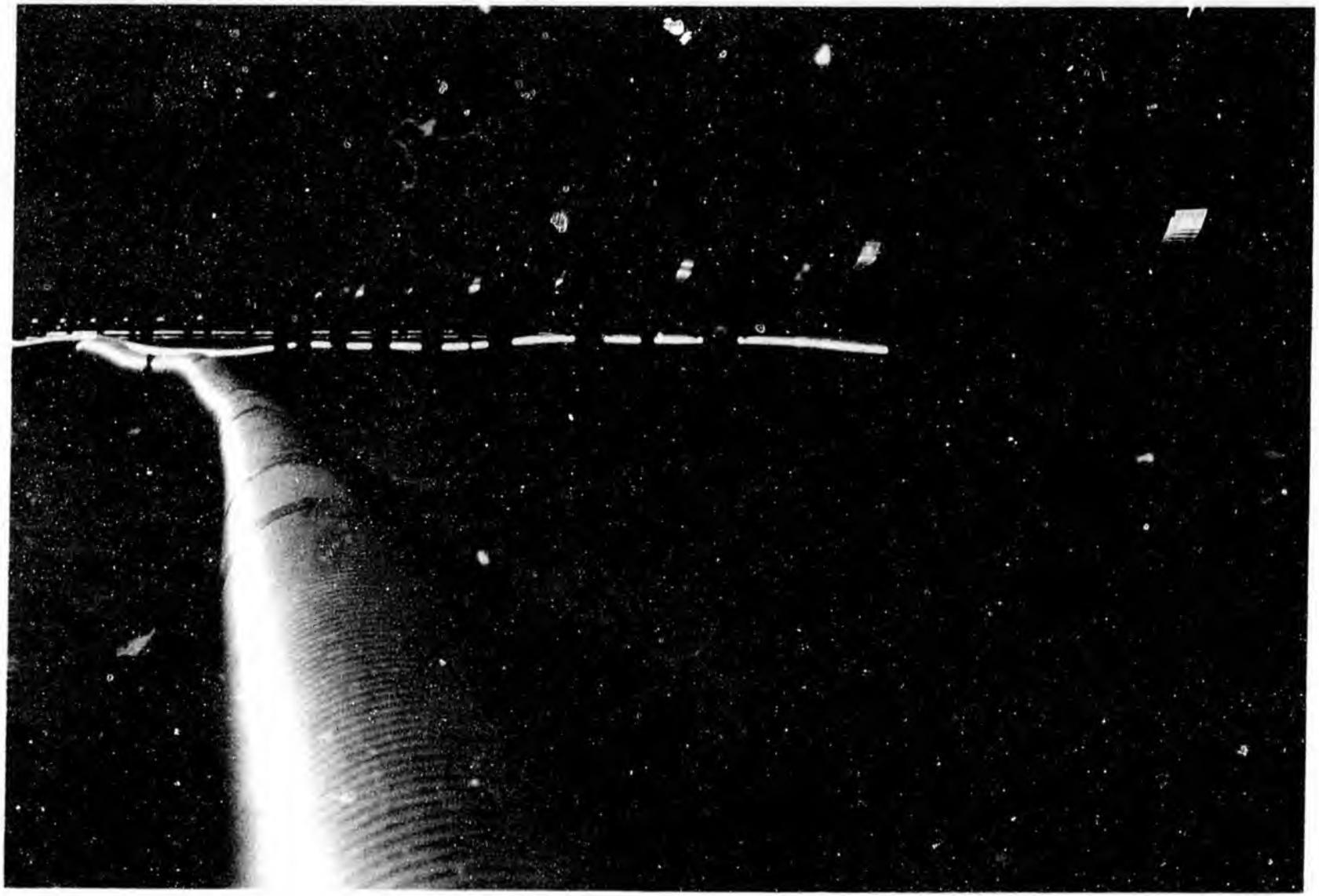
Field X-Ray inspection of pipe welds



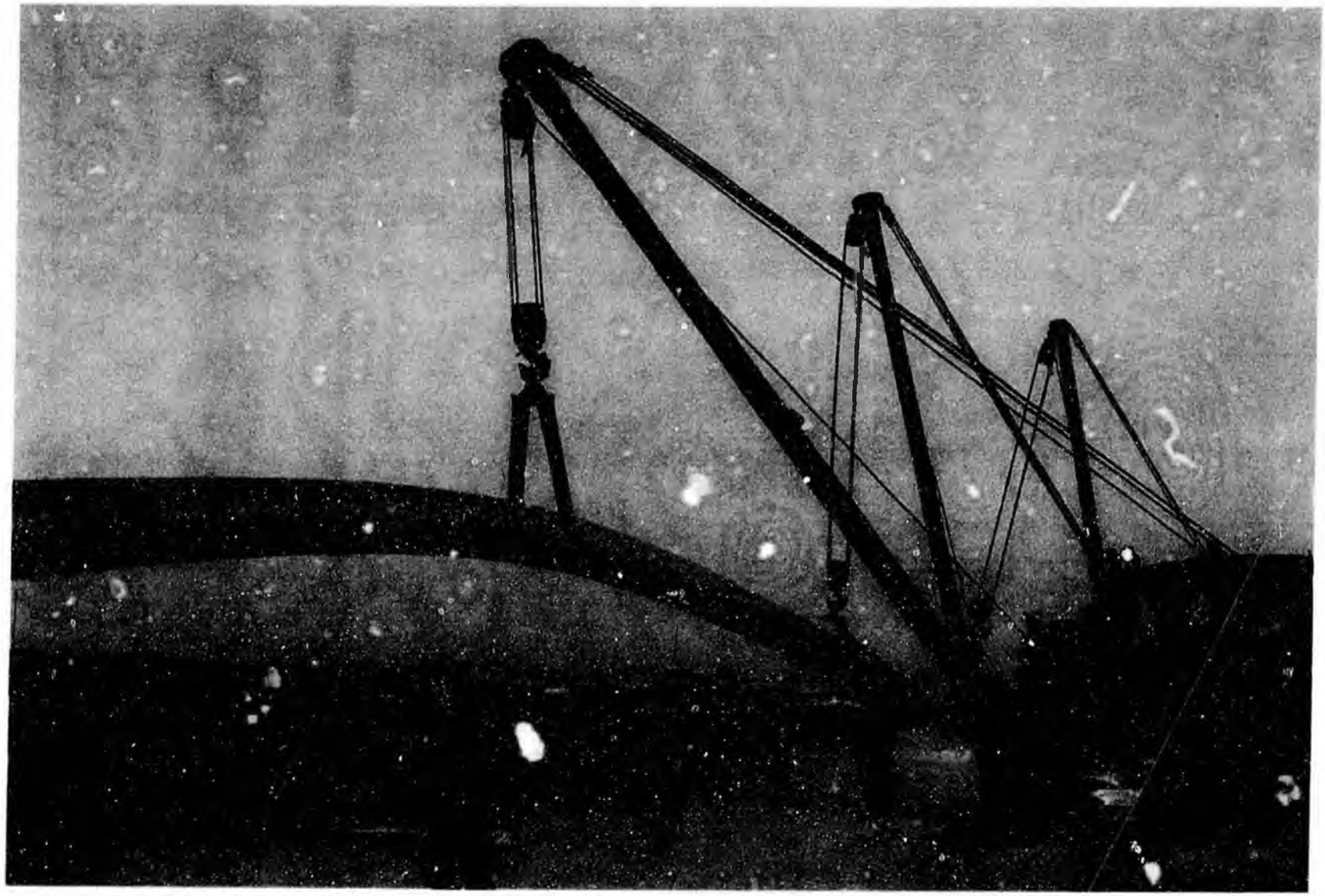
Installing insulation, sheathing over welds



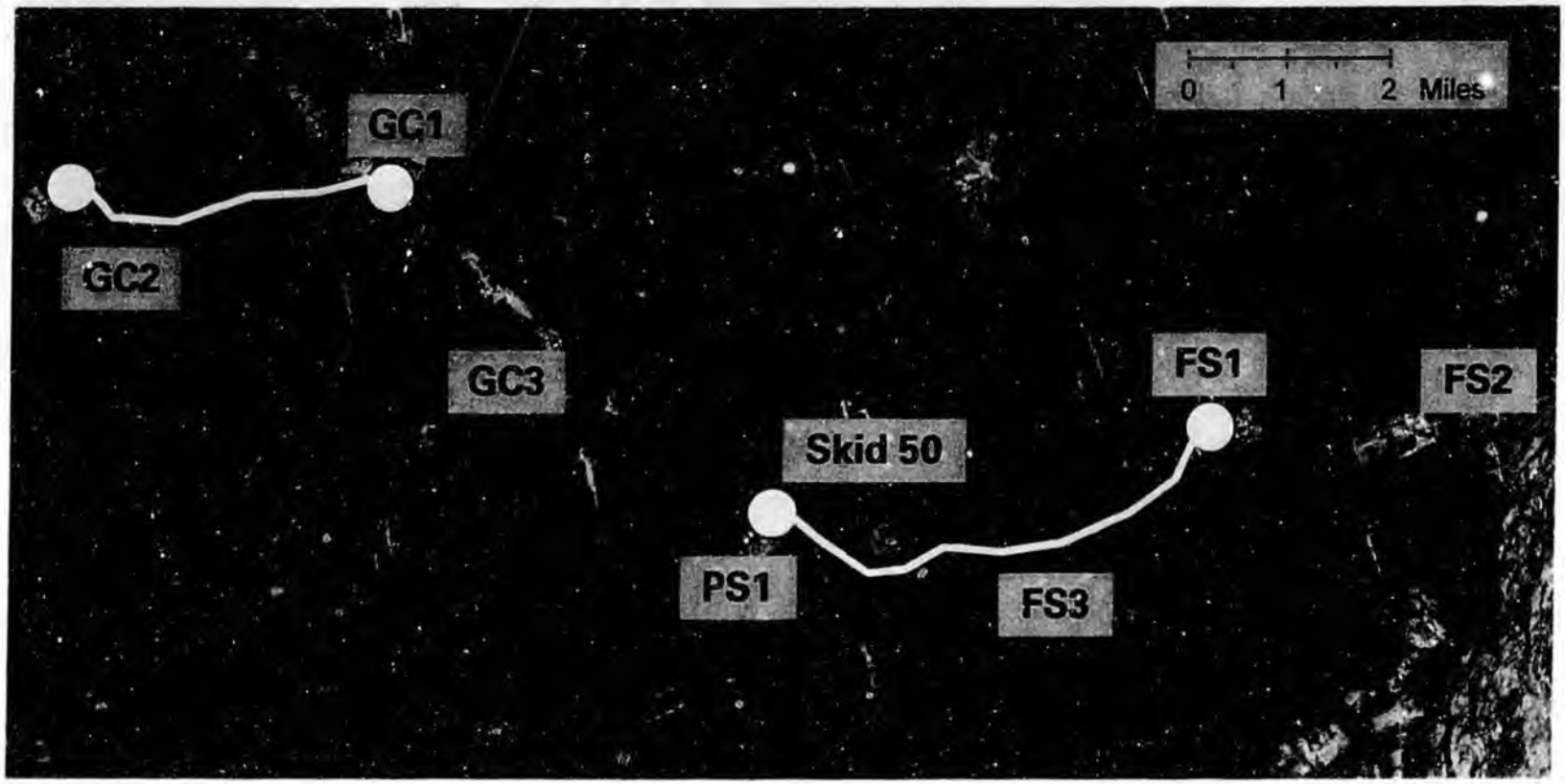
Welded line ready to lift into place



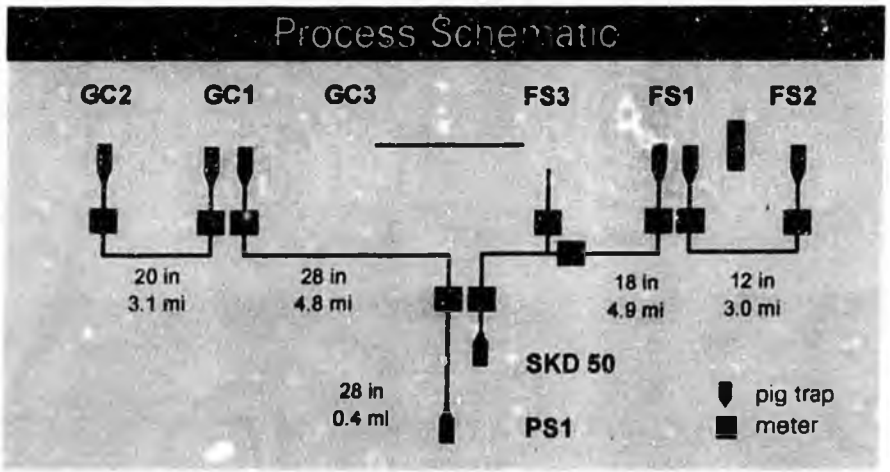
New OTL lifted onto VSM



Route and Scope



- Five segment manifold
- Eight new launcher/receivers
- Ten new leak detection meters
- Twenty new modules/skids
- Yellow overlay shows progress of line replacement



Foundation for the Future
BP Alaska Renewal Plan

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Listening and Learning

- Close Corrosion Management Gaps
- Improve Risk Management
- Renew the Infrastructure
- Show Visible Leadership
- Get the balance right on Cost Management
- Get the Organization Right
- Pay Attention to Communication and Culture

People
- Organizational Changes
- Accountability Clarifications
- Workforce Renewal
- Expanded Communications
- Culture Improvements

Plant
- Immediate OTL Mitigations
- Comprehensive Inspections
- OTL Replacement
- Renewal of Additional Infrastructure
- Standard Technical Practices

Process
- Compliance to New Regulation/CA
- Improved Risk Management
- Comprehensive Corrosion Strategy
- Improved Inspection
- Conformance to BP Standards

Performance
- Clear Leading and Lagging Metrics
- Accountable Technical Authorities
- Transparent Reporting

Plan

- Growth and renewal
- High integrity, purpose-built infrastructure
- Enhanced risk management approaches
- Leading corrosion management systems and processes
- Accountable and capable organization
- Improved communication
- Transparent and cooperative regulatory relationships
- Restored reputation
- Reliable production

Objectives

Public Trust

An Industry Leader

Transformed Culture

Sustainable Performance Through a System of Systems (OMS)

Goals

Brena, Bell & Clarkson, P.C.

Presentation
to
House Resources Committee

Overview of TAPS Rate Litigation and FERC Judge Cintron's May 17, 2007, Initial Decision

June 7, 2007

Overview

- **Alaska's Oil and Gas Resources are Transported Through Pipelines with No Competition.**

- **Economic Regulation of These Noncompetitive Pipelines Must Meet Two Basic Goals:**
  - **(1) Fair access, and**
  - **(2) Just and reasonable rates.**

- **Meeting These Goals will Optimize:**
  - **(1) The development of our oil and gas resources,**
  - **(2) Royalty and severance taxes, and**
  - **(3) Value-added manufacturing and jobs in Alaska.**

The TAPS Settlement

- **TAPS Settlement:** In 1985, the TAPS Carriers and the State of Alaska settled prior rate issues and agreed that the State would not protest future rates as unjust and unreasonable so long as those rate filings were at or below the ceiling rates established under the TAPS Settlement Method ("TSM").

- **Request to Review TAPS Settlement Under "Public Interest" Standard:** The TAPS Carriers and the State asked the FERC and the RCA to review the TAPS Settlement under the "public interest" standard and not to review it under the "just and reasonable" rate standard.

- **Representation that Shippers Could Protest Future TSM Rates:** The TAPS Carriers and the State represented to the FERC and the RCA that if their TAPS Settlement was approved, any third-party shipper could protest future TSM ceiling rates as unjust and unreasonable and have the FERC or the RCA set just and reasonable rates.

- **Establishing Just and Reasonable Rates Does Not Violate the TAPS Settlement:** No party has requested the premature termination of the TAPS Settlement. The rate litigation before the FERC and the RCA is consistent with, and does not contradict, any term of the TAPS Settlement. The TAPS Carriers and the State continue to receive every benefit under the TAPS Settlement. The State still enjoys rates at or less than the TSM ceiling rates. The TAPS Carriers still enjoy the resolution of all prior rate issues and not having the State protest their TSM rates as unjust and unreasonable.

Rate Methods for TAPS

- **TAPS Settlement Method ("TSM")**
  - Settlement method for ceiling rates only.
  - Rejected by the RCA, the Superior Court of Alaska, and Judge Cintron for establishing just and reasonable rates.

- **Stand Alone Cost ("SAC") Method**
  - Based on hypothetical costs of new pipeline.
  - Rejected by Judge Cintron for establishing just and reasonable rates.

- **Original Cost Rate Methods**
  - Depreciated Original Cost ("DOC") Method. RCA applied to TAPS for establishing just and reasonable rates in RCA Order P-97-4(151).
  - Trended Original Cost ("TOC") Method. FERC adopted for all oil pipelines, with some modification, through FERC Opinion 154-B. Judge Cintron applied to TAPS in Initial Decision.

RCA Rate Proceedings

- **Major Claims:**
  - In 1997, Tesoro claimed the state rates were unjust and unreasonable and asked the RCA to establish rates based on the DOC method.
  - The TAPS Carriers and the State of Alaska defended the state rates and asked the RCA to continue to charge TSM rates.

- **RCA Decision:**
  - In Order P-97-4(151), the RCA rejected the use of the TSM and established rates based on the DOC method. The state rate today is $1.96 for all carriers.

- **Procedural Status of RCA Decision:**
  - In January 2006, Superior Court Judge Suddock "affirmed the decision of the RCA in all respects."
  - The TAPS Carriers appealed to the Supreme Court of Alaska. The case has been argued before the Supreme Court and is awaiting decision.

FERC Rate Proceedings

- **Major Claims:**
  - In 2005, Anadarko/Tesoro claimed the federal rates ranging from $3.78 to $4.41 (2006) were unjust and unreasonable and asked the FERC to establish a $2.04 (2006) federal rate based on Opinion 154-B.
  - The State of Alaska claimed the federal rates were discriminatory because they were higher than the state rate and asked the FERC to lower the federal rates.
  - The TAPS Carriers claimed the state rate was noncompensatory and a burden on interstate commerce and asked the FERC to raise the state rate.

- **Judge Cintron's initial Decision:**
  - Established a $2.04 (2006) federal rate based on Opinion 154-B.
  - Dismissed the State of Alaska's claims as moot.
  - Dismissed the TAPS Carriers' claims as moot.

- **Procedural Status of Initial Decision:**
  - Appeal to FERC
  - Appeal to the D.C. Circuit

Summary of Initial Decision

- **TSM:**
  - The TAPS Carriers failed to provide cost support for the TSM rate elements, so the TSM rates could not be found to be just and reasonable.

- **Opinion 154-B:**
  - Opinion 154-B must be used to establish just and reasonable rates;
  - Opinion 154-B does not permit the Carriers to double recover their investment, deferred earnings, AFUDC, or ADIT;
  - The Carriers are not entitled to a starting rate base write up;
  - Return must be based on a representative proxy group without a risk premium; and
  - Anadarko/Tesoro's Opinion 154-B calculation was adopted.

- **DR&R:**
  - Collections and earnings must be accounted for; and
  - Overcollections may be refunded.

- **Uniform Rate**

- **State of Alaska's Discrimination Claims:**
  - Dismissed as moot

- **TAPS Carriers' Section 13(4) Claims:**
  - Dismissed as moot.

- **Remedies:**
  - Refunds of rate increases for 2005 and 2006.
  - Cost-based Opinion 154-B rates going forward.

Just and Reasonable Rates

- Just and reasonable rates are generally rates based upon the costs of providing service.

- Just and reasonable rates permit the Carrier an opportunity to recover:
  - (1) Operating costs,
  - (2) Investment, and
  - (3) A reasonable return on remaining unrecovered investment.

TSM Rates Are Not Just and Reasonable

- **EXCESSIVE COLLECTIONS:** From 1977 through 2004 the TSM has resulted in $18 billion in overcollections under the DOC method. During this period, the TAPS Carriers have invested $10 billion in capital to build TAPS and $15 billion to operate TAPS, but have collected $60 billion in rates.

- **THE TSM IS FATALLY FLAWED:**
  - Allowance Per Barrel
  - Rates Are Based on Subjective Projections
  - Depreciation Based on the Wrong Economic Life
  - True-up of Total Revenue
  - Faulty Jurisdictional Separations

- **IMPACT TO STATE:** The TSM has cost the State of Alaska $4.5 billion in royalty and severance taxes ($18 billion * 25 percent) plus earnings.

TSM Rates Filed by TAPS Carriers

Carrier	Rates			
	2004	2005	2006	2007
BP Pipelines (Alaska) Inc.	$3.01	$3.86	$4.08	$5.10
ConocoPhillips Transportation Alaska, Inc.	$3.09	$3.52	$3.78	$5.29
ExxonMobil Pipeline Company	$3.07	$3.60	$3.93	$4.95
Koch Alaska Pipeline Company, LLC	N/A	$3.97	$4.41	$4.75
Unocal Pipeline Company	$3.00	$3.59	$3.92	$4.63

Comparison of
Anadarko/Tesoro's 154-B and TAPS Carriers' 154-B
Total 2006 Revenue Requirements and Rates
($Millions)

Line No.	Description	A/T 154-B	TAPS Carriers' 154-B
1	Operating Expenses	$559.65	[illegible]
2	Depreciation Expense	$13.48	[illegible]
3	Amortization of Deferred Earnings	$7.13	[illegible]
4	Amortization of AFUDC	$0.86	[illegible]
5	DR&R Allowance	$0.00	[illegible]
6	Return Allowance		
7	Return on Equity	$30.58	[illegible]
8	Interest	$13.77	[illegible]
9	Total Return Allowance	$44.34	[illegible]
10	Income Tax Allowance	$22.13	[illegible]
11	Non-Transportation Revenues	($0.27)	[illegible]
12	Total Revenue Requirement	$647.32	[illegible]
13	Composite System Barrels (Millions)	326.795	[illegible]
14	Composite Rate ($/Bbl)	$1.98	[illegible]
15	Valdez Interstate Rate ($/Bbl)	$2.04	[illegible]

Differences Between
TAPS Carriers' 2006 154-B Proxy Revenue Requirement and Rate and Anadarko/Tesoro's 154-B Revenue Requirement and Rate
($Millions)

	Revised Revenues	Revised Rate
TAPS Carriers' 154-B	$1,751.18	[illegible]
Less Revenue from Deferred Earnings	($580.60)	[illegible]
Less Revenue from Starting Rate Base	($95.02)	($0.29)
Less Revenue from Accelerated Portion of Depreciation and Other	($428.23)	($1.31)
Anadarko/Tesoro's 154-B	$647.32	$1.98

2.04 volumes

Dismantlement, Removal & Restoration ("DR&R")

- DR&R is the cost of taking a pipeline out of service at the end of its economic life.

- A pipeline carrier is entitled to collect DR&R from its shippers. DR&R should be a zero-sum game for the carrier.

- The TAPS Carriers have collected $1.5 billion for DR&R from 1977 to date. They have had the unrestricted use of these shipper funds for decades and have actually earned approximately $15.7 billion on those funds through 2005. The TAPS Carriers have said they only need $2.6 billion (2005) for DR&R.

Judge Disagreed w/

(2.9 Billion)

History of the State of Alaska's Pipeline Positions

- **Out Resourced**
  - Out litigated
  - Out negotiated
  - Out staffed
- **Limited Successes**
  - Never established a just and reasonable rate
- **Bad Settlements**
  - Negotiating away the basic right to ensure the settlement remains fair
  - TAPS Settlement
  - Feeder lines to TAPS (Depreciation/DR&R)
  - Murkowski Gas Line Agreement
  - CIPL
- **Restrictive Interpretation of Duty to Defend in the TAPS Settlement**
  - Forecloses the State from protesting TSM ceiling rates as unjust and unreasonable
  - Does not foreclose the State from clarifying that shippers have the right to request just and reasonable rates (TAPS Carriers' misrepresentations concerning the TAPS Settlement)
  - Does not foreclose the State from litigating issues not settled in the TAPS Settlement (DR&R)
  - Does not require the State to continue to litigate against shippers trying to get just and reasonable state rates (P-97-4, P-86-2)
- **No Clear and Consistent Policy or Client**
  - No clear policy concerning access
  - No clear policy concerning just and reasonable rates
  - No clear client. AS 42.06.140(a)(10) Attorney General—Attorney and Client

State of Alaska's Financial Stake

- 25 Percent of Refunds and Interest for 2005 and 2006.
- 25 Percent of Lower Refunds and/or Interest for 2007 Forward.
  - DOR Understates Benefit to State by Assuming Benefit Ends in 2008.
  - Example: $211.7 Million for 2007
    [($4.94 - $2.04) * 800,000 BPD] * 365 * 25%
- 25 Percent of DR&R Refunds

Lessons for the Gas Line

- Don't Leave Anything to the FERC
- Resource the Effort
- Get Gas for Alaskans
- Get Access Right
- Get Rates Right
- Have a Very Good Reason If You Decide to Give Control of the Line to a Few Major Producers (Alignment)
  - Impact on Access
  - Impact on Rates
  - Impact on State of Alaska's Power to Manage and Tax its Own Resources

Additional Materials

- **RCA's Order 151:**
  Order Rejecting 1997,1998,1999 and 2000 Filed TAPS Rates; Setting Just and Reasonable Rates; Requiring Refunds and Filings; and Outlining Phase II Issues (11/27/02)
  http://www.state.ak.us/rca/orders/pipeline/1997/p97004_151.pdf

- **Judge Suddock's Decision Affirming Order 151:**
  Decision and Order (01/19/06)
  http://rca.alaska.gov/data/docketDetail.html?docket=P-97-004A(1) at 012020060858327

- **Judge Cintron's Decision:**
  Initial Decision (05/17/07)
  http://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20070522-0215

  Errata to Judge Cintron's Decision:
  Errata to Initial Decision (05/31/07)
  http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20070531-3066

DUTY TO DEFEND

The State is party to a Settlement Agreement with the TAPS Carriers that was executed by the parties and approved by the FERC in 1985. I'll refer to that settlement as the TSA. T' TSA is a legally binding contract between its parties, and its term runs through at least the end of 2008.

The TSA provides a formula and criteria under which the Carriers annually calculate and file new TAPS rates.

The TSA expressly requires the parties to defend against any litigation that affects the validity and enforceability of the Agreement, or any provision thereof. [Section I-3]

This duty to defend is a contractual duty, and in essence it requires the State to support and defend TAPS rates filed in conformance with the TSA.

If the State were to protest TSA--conforming TAPS rates at the FERC, the TAPS Carriers would surely petition the FERC to dismiss the State Protest (as they have repeatedly done in the current FERC litigation), and in our judgment, the FERC would dismiss the State to keep it from breaching its FERC-approved contract.

STATE'S DISCRIMINATION PROTEST

In December 2004, the TAPS Carriers filed 2005 interstate rates for TAPS shipments from PS-1 to Valdez that averaged $3.71 / bl.

The RCA-regulated intrastate rates for shipments from PS-1 to Valdez have remained at $1.96 / bl since the RCA's decisions on Tesoro's protests in dockets P-97-4 and P-03-4.

Thus, the 2005 TAPS rates for identical shipping services varied by $1.75 / bl depending on whether the shipments were in interstate or intrastate commerce.

The final paragraph of the TSA rate methodology [II-11(e)] provides that 'notwithstanding any other provision of the TSA, rates charged for TAPS services are subject to legal prohibitions on unjust discrimination and undue preference.' [paraphrased]

In other words, rates that are unjustly discriminatory or unduly preferential are not TSA conforming rates.

The TSA duty to defend applies only to TSA conforming rates, and thus does not apply to unjustly discriminatory rates. The State therefore protested the TAPS 2005 interstate rates on the grounds of unjust discrimination and undue preference.

The legal prohibitions on unjust discrimination and undue preference are set out in sections 2 and 3 of the Interstate Commerce Act. The ICA was enacted in 1885, and there is a long history of rate discrimination caselaw to rely on in applying its terms.

The basic premise of the ICA discrimination caselaw is that rates charged for substantially identical services must be substantially identical. Thus the State's protest cites to the nearly double rates charged for interstate vs intrastate services on TAPS as proof of unjust discrimination.

The remedy for unjust discrimination under ICA section 2, is to reduce the higher rate to a level comparable to the lower rate. The State is therefore seeking to have the interstate TAPS rate reduced to approximately the level of the $1.96 intrastate rate.

PROCESS THROUGH HEARING

The State initiated the current litigation by filing its discrimination protest of the 2005 TAPS rates. A day after the State filed its protest, Anadarko and Tesoro jointly filed a protest of the 2005 TAPS rate on separate grounds. The FERC consolidated the protests for hearing. The parties have since continued their protests on the TAPS 2006 and 2007 rates, on the same grounds

Anadarko / Tesoro are not parties to the TSA. They are not subject to the duty to defend and have taken no position in this litigation on whether the 2005, 2006 and 2007 TAPS rates are calculated and filed in conformance with the TSA.

A/T instead challenges the rates as not in conformance with the FERC **non**-settlement rate methodology -- the "Opinion 154-B" methodology.

In response to the A/T evidence regarding its TAPS 154-B calculation, the TAPS Carriers filed their own (much higher) 154-B calculation.

In response to the State's discrimination protest, the Carriers claimed that their 154-B calculation showed that the intrastate rate was too low, and that any discrimination should be alleviated by increasing the intrastate rate.

The State therefore responded by presenting its own 154-B reference rate calculation, and thereby established that the $1.96 intrastate rate did indeed cover its fair share of the costs of TAPS operations. The State's 154-B

evidence presents rates and rate components very close to those presented by A/T.

The focus of the litigation thus became an argument over the proper calculation of non-settlement 154-B rates for TAPS.

JUDGE CINTRON'S DECISION

Following a lengthy review of the filed testimony and arguments from all of the parties regarding the appropriate calculation of TAPS rates under the 154-B methodology, Judge Cintron ruled in favor of A/T's protest and found that the Carriers should be required to file new rates going forward (after 2006) at approximately $2 / bl.

She then moves on to address the State's discrimination claim, and in paragraph 263, at pages 112-113 she rules:

> "this decision contemplates new rate filings that will be substantially less than the Carriers 2005 and 2006 original filings . . . A/T's Opinion 154-B interstate rate calculation . . . is $2.04 for 2005 and $1.83 for 2006. The State's Opinion 154-B reference rate . . . for interstate rates . . . is $1.96 and $2.05 for 2005 and 2006, respectively. The intrastate rate set by the RCA is $1.96 . . . THE DIFFERENCE BETWEEN THESE RATES AND THE RCA ESTABLISHED RATE ARE MINIMAL. ACCORDINGLY, THE DISCRIMINATION HAS BEEN ALLEVIATED AND THE STATE'S DISCRIMINATION CLAIMS ARE RENDERED MOOT.

In summary, Judge Cintron found that by equalizing the TAPS interstate and intrastate rates going forward, her ruling for Anadarko/Tesoro alleviated the discrimination.

Now that sounds reasonable, as far as it goes, HOWEVER

the State's discrimination protest does not seek relief only from discrimination in rates charged after 2006, we also seek to cure the discrimination in rates already charged in 2005 and 2006.

And in ordering refunds for 2005 and 2006, Judge Cintron ignores our discrimination protest (which she found to be moot) and relies on a legal precedent that has applied only in a select few J&R -- that is, non-discrimination -- rate cases.

The precedent she relies on limits refunds to the difference between the rates actually charged and the last permanent (unprotested) rate that was in effect prior to the filing of the current protested rate. In this case she ruled that the 2004 TAPS rate was the "last legal rate" for calculation of refunds.

So, based on that narrow precedent, Judge Cintron has limited the refunds for 2005 and 2006 to the difference between the TAPS rates charged and the 2004 TAPS rate -- which averaged about $3.05 / bl.

Her decision to limit the refunds is subject to legal challenge even when applied in the context of a J&R rate protest, and the FERC staff has well presented that legal challenge in their Reply Brief.

The State has an alternative, perhaps stronger, argument to raise against the refund limitation ruling through its discrimination protest.

That's because, under ICA Sections 2 and 3, rates that are unjustly discriminatory and/or unduly prejudicial are illegal, and the remedy for such illegal rates is to remove all of the discrimination by resetting the interstate rates at a level comparable to the lower intrastate rate charged for comparable services.

Judge Cintron acknowledged this requirement for equivalence in the interstate and intrastate rates when she determined (as I quoted earlier)

that by setting interstate rates that are "minimally" different from the intrastate rates, she had "alleviated" the rate discrimination protested by the State.

However, the effect of her proposed refund decision is to allow the Carriers to retain tariff payments at a $3.05 / bl rate for 2005 and 2006.

This is still $1 more than the $1.96 intrastate rate or than the rate that she established as J&R for 2005 forward.

Her refund decision thus does not create the "minimal" difference between interstate and intrastate rates that she relied upon to support her finding that the State's discrimination claim is moot.

STATE'S RESPONSE

So, where do we go from here?

The State is considering possibly filing exceptions to Judge Cintron's decision along the following lines:

First that the State's discrimination claim is not moot since, as the judge's refund decision shows, different rules apply to the calculation of refunds in in J&R rate litigation, as opposed to in discrimination litigation, and

Second, that allowing the Carriers to retain a $3.05 / bl rate in calculation of the refunds for 2005 and 2006, does not appropriately remedy the discrimination in rates for those years. In accordance with her ruling on the discrimination claim, the refunds must result in no more than minimal differences between the TAPS interstate and intrastate rates for 2005 and 2006, as well as going forward.

ARCO Alaska Inc. Internal Correspondence

Date: June 5, 1990 File Code: Corrosion File

Subject: Inspection of Oil Sales Lines

From: M. A. Morris/G. D. Herring PRB Box 5

To: S. J. Massey/J. D. Ottoson PRB Box 20

As previously discussed, the Corrosion Group recommends smart pig inspections of the oil sales lines from Flow Station 2 to Flow Station 1 and from Flow Station 1 to Skid 50. A discussion of this recommendation, an alternative and the advantages and disadvantages of each follows.

Background

Sales oil flows from FS 2 through a 30" pipeline (15,794' long) to Module 4922 at FS 1, where it is commingled with oil from FS 1. The combined stream is transported through a 34" line (25,996' long) to Skid 50 and then to Pump Station 1. Production from FS 3 goes through a 30" line which tees into the 34" line near FS 3. The normal operating temperature of the lines is about 115 degrees F., although they have been operated in the 140 degree range in the past.

To date, only minimal monitoring and inspection data has been gathered on the lines. A coupon location has been added to the FS 2 line at FS 1's Module 4922. This location has been pulled only two times. The first pull, from the fourth quarter of 1989, was graded "D" due to a single pit in one of the coupons which may have been mechanical in origin. The coupons from the first quarter of 1990 were graded "A". No organic deposits, such as paraffin, were on the coupons. Coupon locations will be added to the FS 1 and FS 3 lines and the main line outside of Skid 50 as soon as operationally feasible. Only about 115 square feet of piping at the 4922 modules and Skid 50 has been inspected with automated UT (C-scan); no corrosion indications were identified. The lines are insulated with GE insulation, which is scheduled to be replaced this year due to external corrosion concerns.

Because of the low water content of the crude in the sales lines (the spec is 0.35%), significant internal corrosion is not expected. To our knowledge, none has been detected by the smart pig inspections performed to date in the TAPS line. On the other hand, severe corrosion has been experienced in the uninhibited flowlines and tubing strings of wells making only trace amounts of water early in the life of the field. If the water in the sales line segregates and flows along the bottom of the line, there is the potential for bacterial or underdeposit corrosion, which could result in scattered pitting, or carbonic acid attack, which could lead to a more continuous channelling type of damage. In either case, the most severe damage would be expected at bottom dead center of the lines.

There are two proven inspection methods which could be used on the sales lines: smart pigging and C-scan. The other option, of course, is to do no inspection. The Corrosion Group believes that the "do nothing" option is not prudent. The inspection options are discussed below.

Smart Pigging - (Recommended)

Smart pigging would involve running a series of cleaning pigs and the inspection pigs through the lines from FS 2 to FS 1 and from FS 1 to Skid 50. As far as we know, the lines have not been pigged since field start-up. Tentative plans have been made to run the Pipetronix smart pig in October, 1990. Preliminary cleaning and gauge pigs could be run as soon as operationally feasible.

Advantages

- Comprehensive inspection: The smart pig inspection would yield information about the entire circumference of the line, from the launcher to the receiver. It would locate external as well as internal corrosion. However, because the insulation on the sales lines is to be reconditioned this year, external corrosion should not be an issue. In addition, future repeat inspections would be relatively simple to perform.

- Production impact: Since the entire operation can be done on line, no reduction in production rates is necessary.

- Cost: The estimated cost of the entire smart pigging operation for both lines, including support labor and cleaning runs, is about $150,000.

Disadvantages

- Risk of sticking: Although the risk of sticking either a cleaning pig or an inspection pig is very low, we acknowledge that the cost of such a mishap would be quite high. The chance of an incident can be minimized by planning thoroughly and following a carefully developed procedure. The Corrosion Group is developing a detailed procedure for preparing the lines and running the smart pigs. In addition, a contingency plan will be developed to minimize the down time in the event that a pig does get stuck.

Automated UT - (Second choice)

If the C-scan UT method of inspection were to be employed on the sales lines, the scanning would probably be limited to the bottom 6" or 12" of the line. We would recommend scanning all accessible areas of the lines. As discussed above, if there is significant internal corrosion in the lines, it is most likely to occur at bottom dead center. The lines will be stripped of insulation later in the summer; this provides an opportunity to perform a C-scan inspection without the incremental cost of insulation removal.

Advantages

- No production impact or risk of sticking: C-scan can be performed on the lines while in service. Of course, there is no risk of getting anything stuck or lost in the line when using an external NDT device.

Disadvantages

- More expensive: If a one foot wide strip of pipe is C-scanned, the cost of inspection would probably be about $30 per linear foot. Scanning all accessible areas of the lines would cost about $1,065,000.

- Less comprehensive: The proposed C-scan inspection would yield no information concerning the existence of corrosion or defects anywhere away from the bottom of the

lines. A 12-inch wide scan would give us 11% radial coverage on the 34-inch line and 13% on the 30-inch line. Saddle areas, anchor blocks and eleven road and caribou crossings would not be inspected, further reducing our confidence in finding corrosion. The road and caribou crossings are of particular concern, as there are currently no plans to replace the GE insulation in these areas.

- Recurring inspections more difficult: After the insulation is reconditioned, any external NDT method becomes much more difficult. Any repeat scans would involve stripping the new insulation, coating and tape wrap, which would be considerably more expensive.

Summary

The Corrosion Group recommends smart pigging the sales lines because it is a reliable, comprehensive inspection method. We believe the risk of encountering significant operational difficulties is small. The alternative, C-scanning the bottom of the accessible areas of the lines, is a viable alternative. However, it is considerably more expensive than smart pigging. The proposed C-scan inspection would give us a lower confidence in finding corrosion or defects because we would not be inspecting the road crossings, anchor blocks and saddle areas and because radial coverage is limited. Since very little monitoring or inspection has been done on these lines in the past, we strongly recommend against doing no inspection

Marshall C. Mains

Corrosion Control Supervisor

cc:	D. F. Scheve	ATO 1576
	E. W. Skaalure	ATO 1526
	W. W. Patterson	ATO 1796
	D. E. Powell	ATO 1788
	J. M. McCarthy/J. S. Dayton	PRB Box 10
	R. Farque/D. Siekkinen	PRB Box 15
	D. Cavin/D. Beaudry	PRB Box 14
	H. Hong/	PRB Box 13
	N. J. Mabile/M. R. Engblom	PRB Box 5
	B. A. Servin/A. L. Dahlquist	PRB Box 5

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Sprague, Kip P

From: PBU, CIC Flow Lines
Sent: Thursday, July 17, 1997 5:44 PM
To: PBU, CIC Supt
Cc: PBU, CIC Fld TL Felix/Woollam
Subject: RE: Oil Transit Pigging

Greg,

We have been UT monitoring the oil transit line since 1988. Excluding the by-pass at Skid 50, CIC has identified ~70 locations with internal corrosion between GC2 and Sk 50. The by-pass (320' ft) @ Sk 50 is corroded almost the entire length and three sleeve repairs were made in 1991. Today we have three locations at the by-pass with an MAOP below design. Joel/Chuck have these listed on the PMP tracker for action, (MOC to derate the line).

In 1995 a substantial increase of internal corrosion was observed. During the 1996 survey, a baseline Automated UT program (CRM) was established to determine internal corrosion rates. We hope this years CRM program will provide current internal corrosion activity/rates.

Of equal or more concern is external damage on the line. The oil transit was last smart pigged in 1990 at which time there were a few locations of CUI detected, worst case near 50% wall loss. Unfortunately because of the type of insulation and diameter of the line, reliance on spot TRT examination for integrity assurance will not eliminate a whole lot of risk. We had initially planned to smart pig examine the oil transit this year but, the launcher and trap will no longer accommodate the new high resolution smart pig vehicles without modification. As it stands, plans are to modify launcher and trap and smart pig in '98. Depending on completion of some of the other projects there is still some consideration to perform limited spot TRT inspections this year.

Kind of a brief summary but if you want more detail let me know. .... Kip

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From: PBU, CIC Fld TL Felix/Woollam
Sent: Thursday, July 17, 1997 3:40 PM
To: PBU, CIC Flow Lines
Subject: FW: Oil Transit Pigging

Kip - response pls.

Thx, Rick

From: PBU, CIC Supt
Sent: Wednesday, July 16, 1997 12:08 PM
To: PBU, CIC Fld TL Felix/Woollam
Subject: FW: Oil Transit Pigging

Rick;

Do we already have UT or TRT info on this transit line? Could let me know how much we already may know.

Greg

From: PBU, Pigging Operators
Sent: Saturday, July 12, 1997 6:15 PM
To: PBU, CIC Fld TL Felix/Woollam; PBU, CIC Fac TL Phillips/Merrett; PBU, Prod Ctl & Optimization
Cc: PBU, CIC Corrosion Engr; PBU, CIC Flow Lines; PBU, CIC Prod Chem Todd/Wasem; PBU, CIC QA/Vessel; PBU, CIC Supt; PBU, Chemical Foreman
Subject: Oil Transit Pigging

Rick,

I talked to Tom Carnahan (Pump Station #1 Planner) and he only recalls one problem when Arco pigged their transit line and that was plugging the strainers.

I contacted Kevin Mahoney (Pigging Tech that performed that job). He informed me that they had two people at the strainers to change them as they plugged off. It takes about 1.5 hours to pull a strainer. He also stated by blocking in a strainer for about 10 seconds after it plugged, the heavy solids would fall to the bottom and then they could reopen the strainer and get approximately 80% flow. The metering had to be bypassed also to prevent damage to meters. The finer solids that passed through the strainers collected in the Pump Station tanks.

Based on the current daily average production the run would take approximately 6.5 hours actual run time.

GC-2 to GC-1 102 MBPD 1.1 fps 255 minutes
GC-1 to GC-3 176 + 102 = 278 MBPD 3.0 fps 68 minutes
GC-3 to Sk-50 73 + 278 = 351 MBPD 3.8 fps 56 minutes

379 minutes (6.5 Hours) actual run. + set up and returns cleaning etc....

Still need to get approval from Alyeska.

Hope this helps. A lot of people are out of the office at Arco. 4&3 schedule which limited my information gathering. Please respond if you need more info.

Doug

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Sprague, Kip P

From: PBU, CIC Fld TL Felix/Woollam
Sent: Sunday, July 27, 1997 2:15 PM
To: PBU, Field Ops Mgr
Cc: PBU, CIC Flow Lines; PBU, CIC Supt; GPB, Prod Opt TL; PBU, CIC Fac TL Phillips/Merrett; PBU, CIC Fld TL Felix/Woollam; GPB, Pigging Operators
Subject: RE: Smart Pigging of oil transit line

John,

Thanks for the support on this issue.

This line has been both maintenance pigged and smart pigged in the past, so we do have some history on this line. The main concern is the fact that velocities in this line have been significantly reduced over the last few years and the quantity of solids which are laying in the bottom is entirely unknown.

Should these solids be significant, then we will have a problem at Pump 1 with the meter sleves blocking off. The conern therefore has to be to have sufficient contingency plans in place to allow us to pig and capture the solids without knocking Pump 1 over.

We are currently working through Bill and Garry with Pump 1 to get a consensus with Alyeska as to the contingencies which we need to have in place, and plan to maintenance pig the line a couple of months prior to to the smart pig run in 1998.

We are at present working with British Gas to come up with a long term smart pigging contract which will secure a price b eak on BGs services in exchange for minimum/maximum number of lines to be pigged in any given year. Our approach, is likely to consist of a rolling 5-10 year program which Inspect ALL the major WOA flow lines, gas/oil/water, over the life of the contract. This will require putting together an suitable long term AFE.

As plans progress I'll keep you informed, however, if you have any comments or questions please let me know.

Thanks.

Richard.

From: PBU, Field Ops Mgr
Sent: Sunday, July 27, 1997 1:59 PM
To: PBU, Field Maint Ctlr; PBU, CIC Fld TL Felix/Woollam
Cc: PBU, Facility Ops Mgr; PBU, Prod Controllers
Subject: Smart Pigging of oil transit line

Richard,

I understand Smart pigging of the Oil Transit line was considered this year, but decided against given the short preparation time. Can you please work towards making a recommendation on Smart pigging of this line for 98 and work the schedule and any budget issues with Bill/Garry and Dan/Dennis. We'll also need to address the operational issues/risks of which I believe you are aware and I would appreciate your assessment of them.

Thx,

John

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rcw_home
From: Woollam, Richard C
rcw_home Thursday, June 03, 1999 4:31 PM
To: Felix, Rick D; PBU, CIC NS TL Felix/Phillips
Subject: RE: Draft - Budget Review 1 Pager

Rick/John,

Sounds like a plan, 9:00 am ASCG Monday morning - 7th June, OK?

Richard.

From: PBU, CIC NS TL Felix/Phillips
Sent: Thursday, June 03, 1999 11:40 AM
To: Felix, Rick D
Cc: Woollam, Richard C.
Subject: RE: Draft - Budget Review 1 Pager

RDF/RCW,
I'll plan to be in Sunday night, back to Fairbanks Monday PM.
JP

From: Felix, Rick D
Sent: Thursday, June 03, 1999 7:56 AM
To: PBU, CIC NS TL Felix/Phillips; Woollam, Richard C.
Subject: RE: Draft - Budget Review 1 Pager
Importance: High

Let's do it on 6/7 - better to get this phase of work off of our plate. I'm assuming that FMT & Dave are "comfortable" with the associated risks.

John - can you make it in Sun. night?
Thx,
Rick

From: Woollam, Richard C.
Sent: Wednesday, June 02, 1999 8:05 PM
To: PBU, CIC NS TL Felix/Phillips; Felix, Rick D
Subject: RE: Draft - Budget Review 1 Pager

John/Rick,

My impression from the FMT meeting is that we will not be getting any relief on the budget. They all think that PW inhibition is the right thing to do, but, no one is prepared to let loose the purse strings. However, I think we might be able to make a better case in 2000, if we go into the budget process with PW as additional line item.

So we would move forward assuming this to be the case and plan on taking out the PW and x% on the Corrosion Inhibition and y% on the inspection program - ugly I'm afraid.

When would be a good opportunity in the near future to get together and plan the way-forward? Monday 7th or the 14th June?

rcw_home
From: Woollam, Richard C
Sent: Friday, June 04, 1999 6:09 PM
To: PBU, CIC NS TL Felix/Phillips
Subject: RE: PW Inhibitor at GC2 and GC3

John,

Excellent! Good note - when we've decided what we wish to trim from the budget on Monday, we should write something similar to Dave Calvin et al, explaining and making sure that they do realise what they are asking us to do.

Richard.

From: PBU, CIC NS TL Felix/Phillips
Sent: Friday, June 04, 1999 2:53 PM
To: PBU, Operations Manager
Cc: Woollam, Richard C.; PBU, Field OTL; PBU, GC1 OpsTmLdr; PBU, GC2 OpsTmLdr; PBU, GC3 OpsTmLdr
Subject: FW: PW Inhibitor at GC2 and GC3

Frank,

FYI - We have conducted the field "trial" of the PW inhibition chemical and found it to be very successful at cleaning up the PW system and arresting corrosion activity. Unfortunately, we did not budget for a full year's chemical expense as the program was highly experimental at the time of the budget planning process. We are now at a point where the original monies for this program are used up, so we will be shutting it down till year's end, with the intent of raising it as a line item for next year's budget.

In the meantime, the PW system may be subject to increased corrosion activity and fouling. This may have some impact on corrosion repair activity and also possibly BS&W quality during pigging operations. We will be putting the remainder of our EC1081A inventory into the S pad PW line for the rest of the year, as this is our highest risk cross country PW line at this time.

I presume you may be getting some feedback on this so wanted to assure you're informed (You may have been at the session with Richard Woollam the other day where this was discussed).

Regards,
John

From: PBU, CIC Prod Chem Todd/Spano
Sent: Friday, June 04, 1999 11:42 AM
To: PBU, GC2 OpsTmLdr; PBU, GC2 Lead Techs; PBU, GC3 OpsTmLdr; PBU, GC3 Lead Techs
Cc: PBU, Mail Coord - FOC; PBU, CIC NS TL Felix/Phillips; Crawford, Gary R; Paisley, Dominic M.; Woollam, Richard C.; 'RA Brown'; Sprague, Kip P
Subject: PW Inhibitor at GC2 and GC3

All,

Due to budgetary constraints, the decision has been made to discontinue the PW inhibitor (EC1081A) currently being injected at GC2 and GC3. The GC2 bulk tank should run out within the next two days and it will not be refilled. Please shut the pump down and flush the equipment with water once the tank is empty. The GC3 tank was recently filled and is

estimated to last about 13 more days (around June 17th). Again, when the tank is empty, please shut the pump down and flush the equipment with water.
The current plan is to inject the remaining inventory of EC1081A into the high risk S-69 line that runs from M to S pads. At a 40 ppm rate, we will have enough product to treat this 40,000 BWD for about 250 days.

Best Regards,

John Todd

rcw_home

From: Paisley, Dominic M
Sent: Tuesday, June 08, 1999 4:06 PM
To: PBU, CIC Prod Chem Todd/Spano
Cc: Woollam, Richard C.
Subject: RE: MOC for Discontinuation of EC1081A

Andy,

Here are a couple of paragraghs to summarise the technical aspects of shutting off the PW treatment.

The corrosion mechanism in the PW system is microbially induced corrosion. Bacteria thrive in dirty systems and treatment requires injection of a chemical with strong surfactant and biocidal properties to clean the lines and reduce bactena numbers. Various chemicals have been tried at GC-2 over the past year with the aim of finding a suitable, low cost chemical. The program has been successful and the data shows that the PW systems at GC-2 and GC-3 have been cleaned and bacterial numbers have been reduced. The corrosion monitoring and inspection data have also improved significantly.

The net effect of these improvements is to significantly increase the projected life of the PW system. Much of the system is in poor condition and, without injection of supplemental chemical, well line replacements are predicted from 2001 onwards, with flow lines from 2003 onwards. Supplemental injection is estimated to delay these near-term line replacements by approximately 7 years and many of the replacements would be delayed indefinitely. For example, the retirement of S-69 is predicted to be delayed from 2003 to 2016.

Suspending the supplemental injection in to the PW system is therefore unlikely to cause loss of containment or equipment retiral in the short term (1 to 2 years). However, it will shorten the life of the system, resulting in either abandonment or expensive repair/replacement in the medium to long term (3 years+). The longer the corrosion continues at the uncontrolled rate, the harder it will be to arrest it and achieve satisfactory life of the equipment.

Feel free to cut and paste so it fits in with the rest of the MoC document and the data from the QPR that Richard sent.

Dominic

From: Woollam, Richard C.
Sent: Saturday, June 05, 1999 10:43 AM
To: PBU, CIC Prod Chem Todd/Spano
Cc: Crawford, Gary R; PBU, CIC NS TL Felix/Phillips; Paisley, Dominic M.; Felix, Rick D
Subject: RE: MOC for Discontinuation of EC1081A

John/Andy,

I would suggest that you use as the basis of the risk assessment, not only technical but financial, the following material which we was lifted staright out of the QPR.

<<File: PW CI Injection FMT II.ppt>>

As far as the requirement to complete the MOC is concerned, surely any action which increases the risk of significant HSE/financial impact to the business or the environment should be thoroughly reviewed and documented by senior management prior to implementation. This is the point, isn't it, of the MOC process to ensure that any

process/system changes should be thoroughly reviewed and documented in order to indentify risks associated with that actions - exactly what is happening here!

In the mean time, please move ahead with the stopping the program and implementing the S pad injection as quick as possible as noted in your E-mail yesterday.

Thanks.

Richard.

From: PBU, CIC Prod Chem Todd/Spano
Sent: Saturday, June 05, 1999 10:58 AM
To: Paisley, Dominic M.
Cc: Crawford, Gary R; PBU, CIC NS TL Felix/Phillips; Woollam, Richard C
Subject: MOC for Discontinuation of EC1081A

<<File: CIHAZA~1.DOC>>

Dominic,

I have been asked by Richard and John P. to initiate an MOC to document the discontinuation of the EC1081A Cl injection at GC2 and GC3. This is a somewhat unique MOC, as far as I am concerned, and it is probably not legally required. However, the idea is to make management formally sign off on the change and to briefly outline the risks. I will discuss the process impacts (BS&W and possibly water quality), but I need you (or Gary) to outline the corrosion risks to the PW system. It doesn't need to be terribly detailed or something that takes a lot of your time. Andy and I use the enclosed Hazard Review document most of the time for chemical changes, and it is nothing more than a one or two paragraph statement. However, you may have other documentation that you want to add. Your input will constitute part of the Technical Review (Stage 3 of the MOC) and I will then present all the data to Operations for signatures at Stage 4 and 5. Thanks for your help.

Best Regards,

John T.

rcw_home

From: PBU, Operations Manager
Sent: Wednesday, June 09, 1999 2:08 AM
To: PBU, CIC NS TL Felix/Phillips
Cc: Woollam, Richard C.; PBU, Field OTL
Subject: RE: PW Inhibitor at GC2 and GC3

John/Rick,

Thanks for the warning. Is this the right thing to do?

-does this place the line integrity in jeopardy in the short term and give us a risk of a spill near term? I assume not or you wouldn't be recommending this?
-does this jeopardise or significantly shorten the life of these lines? If so does the discounted cost of accelerated repair exceed the cost of the inhibitor for this year?
-are we putting our expenditure on chemicals in the critical areas? I thought that the PW lines were the ones least in control and therefore the ones we are most worried about Could we discontinue chemical injection on some other lower risk systems to provide the financial space to continue this treatment?

How much money are we talking about if we continue the chemical injection at the optimal rate?

Frank

From: PBU, CIC NS TL Felix/Phillips
Sent: Friday, June 04, 1999 2:53 PM
To: PBU, Operations Manager
Cc: Woollam, Richard C.; PBU, Field OTL; PBU, GC1 OpsTmLdr; PBU, GC2 OpsTmLdr; PBU, GC3 OpsTmLdr
Subject: FW: PW Inhibitor at GC2 and GC3

Frank,

FYI - We have conducted the field "trial" of the PW inhibition chemical and found it to be very successful at cleaning up the PW system and arresting corrosion activity. Unfortunately, we did not budget for a full year's chemical expense as the program was highly experimental at the time of the budget planning process. We are now at a point where the original monies for this program are used up, so we will be shutting it down till year's end, with the intent of raising it as a line item for next year's budget.

In the meantime, the PW system may be subject to increased corrosion activity and fouling. This may have some impact on corrosion repair activity ar also possibly BS&W quality during pigging operations. We will be putting the remainder of our EC1081A inventory into the S pad PW line for the rest of the year, as this is our highest risk cross country PW line at this time.

I presume you may be getting some feedback on this so wanted to assure you're informed. (You may have been at the session with Richard Woollam the other day where this was discussed).

Regards,
John

[redacted]

From: [redacted]
Sent: Friday, June 04, 1999 8:48 PM
To: [redacted]
Subject: FW: PW Inhibitor at GC2 and GC3

Here's one for our HSE files. We'll see if this is a "safe" way to do business
[redacted]

From: PBU, CIC Prod Chem Todd/Spano
Sent: Friday, June 04, 1999 11:42 AM
To: PBU, GC2 OpsTmLdr; PBU, GC2 Lead Techs; PBU, GC3 OpsTmLdr; PBU, GC3 Lead Techs
Cc: PBU, Mail Coord - FOC; PBU, CIC NS TL Fells/Phillips; Crawford, Gary R; Paisley, Danielle M.; Woolam, Richard C.; 'RA Brasfi'; Sprague, Kip P
Subject: PW Inhibitor at GC2 and GC3

All,

Due to budgetary constraints, the decision has been made to discontinue the PW inhibitor (EC1051A) currently being injected at GC2 and GC3. The GC2 bulk tank should run out within the next two days and it will not be refilled. Please shut the pump down and flush the equipment with water once the tank is empty. The GC3 tank was recently filled and is estimated to last about 13 more days (around June 17th). Again, when the tank is empty, please shut the pump down an flush the equipment with water.
The current plan is to inject the remaining inventory of EC1051A into the high risk S-69 line that runs from M to S pads. At a 40 ppm rate, we will have enough product to treat this 40,000 BWD for about 250 days.

Best Regards,

John Todd

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5

From: Daniel_G_Rey@nalcoexxon.com
Sent: Wednesday, June 09, 1999 6:53 AM
To: "David Horsup at SUG_HUB.CCNEEC"@nalcoexxon.com; "Daniel G Rey at SUG_HUB.CCNEEC"@nalcoexxon.com; Crawford, Gary R
Cc: PBU, CIC Prod Chem Todd/Spano; Brown, Richard A (NEEC)
Subject: Re[2]: Urgent - Please Review and Comment

Additional Header Information:
Received: from amgw3.bp.com ([208.221.178.129]) by mail.nalcoexxon.com (Lotus SMTP MTA v4.6.1 (569.2 2-6-1998)) with SMTP id 86256789.007B350E; Mon, 7 Jun 1999 17:25:45 -0500
Received: by amgw3.bp.com; id SAA19350; Mon, 7 Jun 1999 18:22:21 -0400

Received: from amclvx8.clv.am.bp.com(161.99.146.100) by amgw3 via smap (V2.1)
id xma019311; Mon, 7 Jun 99 18:21:55 -0400
Received: by AMCLVX8 with Internet Mail Service (5.5.2232.9)
id <M36MQY5G>; Mon, 7 Jun 1999 18:21:55 -0400
Message-ID: <05481C2F274CD011882A0000F8024BCD02E70A91@AMANCX2>
From: "Crawford, Gary R" <CrawfoGR@BP.com>
To: "'David_Horsup@nalcoexxon.com'" <David_Horsup@nalcoexxon.com>,
"'D. Rey'" <Daniel_G_Rey@nalcoexxon.com>
Cc: "PBU, CIC Prod Chem Todd/Spano" <PBUCICProdChem@BP.com>,
"Brown, Richard A (NEEC)" <BrownR1@BP.com>
Subject: RE: Urgent - Please Review and Comment
Date: Mon, 7 Jun 1999 18:20:41 -0400
MIME-Version: 1.0
X-Mailer: Internet Mail Service (5.5.2232.9)
Content-Type: multipart/mixed;
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David and Danny,

We will be pursuing field conversion of 99VD049 on an accelerated schedule to help meet the budget pressure for this year (Discontinuing EC1081A is the other key part to meeting the budget). We feel that this is less risky than an across-the-board cut of 10% which we are most confident would allow significant measurable c rosion damage to occur. The good news is that we have enough 98VD019 and 99VD054 in Alaska or on its way, that conversion cannot logistically happen before September 1 which is just in time to meet the budget! Also, very importantly, this gives us time to gather more B, X, and R LDF data as well as complete the well line test at A-13.

Attached, are some slides summarizing our intentions at this time.
The
timeline is critical and we have been instructed to work back from September
1 to nail down the dates for ordering and shipping 99VD049. Please review these slides and provide input regarding the drop-dead order and ship dates.
We will not be ordering any more 98VD019 or 99VD054 unless something goes wrong with the 99VD049.

Preliminary ER probe data from X pad indicates no change in performance.
However, R pad data may show a shift toward slightly higher corrosivity (2.8 to 4.3 mpy) but we feel it is still too early to judge that small of change.

Also, significant production changes from R pad have been occurring, creating more complexity. The EOA still has no corrosion data from their well line test sites.

Are there any other concerns that need to be addressed before we finalize the plan for Richard?

John/Andy - I assume we still have EB at the WPM's and GC's to inject if OIW/BS&W become a problem?

Thanks,

Gary

<<99VD049ExpPlan.ppt>>

> ----------
> From:
> David_Horsup@nalcoexxon.com[SMTP:David_Horsup@nalcoexxon.com]
> Sent: Monday, June 07, 1999 9:48 AM
> To: Paisley, Dominic M.; Crawford, Gary R; Woollam, Richard C.
> Cc: "Richard A Brown at SUG_HUB.CCNEEC"@nalcoexxon.com; PBU, CIC NS TL
> Felix/Phillips; Felix, Rick D; PBU, CIC Prod Chem Todd/Spano; "Daniel G
> Rey at SUG_HUB.CCNEEC"@nalcoexxon.com
> Subject: Re: Urgent - Please Review and Comment
>
>
>
> Richard,
>
> The team discussed this, this morning and the general consensus was
> that migration over to the 049 chemistry would offer the minimum risk
> scenario. Obviously there are risks associated with it but these
> would be less than a total field-wide reduction in dosage of 10%.
> Since this product contains a new demulsifier at a lower dosage, it
> might be wise to have some of this on hand in case of an upset at the
> Gathering Centres. In terms of logistics I do not foresee any
> problems at this end. Danny will be able to give you a clearer
> indication of timings for subsequent rail car quantities. How soon
> would you look to implement this?
>
> Best wishes,
> David
>
>
> _____ Reply Separator
> _____
> Subject: Urgent - Please Review and Comment
> Author: "Woollam, Richard C." <WoollaRC@BP.com> at NEEC
> Date: 06/06/99 21:29
>
>
> Additional Header Information:
> Received: from amgw3.bp.com ([208.221.178.129]) by mail.nalcoexxon.com
> (Lotus SMTP MTA v4.6.1 (569.2 2-6-1998)) with SMTP id
> 86256788.00766E10; Sun, 6 Jun 1999 16:33:34 -0500

> Received: by amgw3.bp.com; id RAA08296; Sun, 6 Jun 1999 17:30:15
-0400
>
> Received: from amclvx8.clv.am.bp.com(161.93.146.100) by amgw3 via
smap
> (V2.1)
>   id xma008266; Sun, 6 Jun 99 17:30:10 -0400
> Received: by AMCLVX8 with Internet Mail Service (5.5.2232.9)
>   id <LX5S10HJ>; Sun, 6 Jun 1999 17:30:11 -0400
> Message-ID: <05481C2F274CD011882A0000F8024BCD02E6A68D@AMANCX2>
> From: "Woollam, Richard C." <WoollaRC@BP.com>
> To: "Paisley, Dominic M." <PaisleDM@BP.com>,
>   "Crawford, Gary R"
>   <CrawfoGR@BP.com>
> Cc: "'Brown, Richard A (NEEC - Anchorage)'"
>   <Richard_A_Brown@nalcoexxon.com>,
>   "PBU, CIC NS TL Felix/Phillips"
>   <PBUCICNSTL@BP.com>,
>   "Felix, Rick D" <FelixRD@BP.com>,
>   "PBU, CIC Prod Chem Todd/Spano" <PBUCICProdChem@BP.com>,
"'Rey,
>   Danny (NEEC - Sugarland)'"
> <Daniel_G_Rey@nalcoexxon.com>,
>   "'Horsup, David (NEEC - Sugarland)'"
> <David_Horsup@nalcoexxon.com>
> Subject: Urgent - Please Review and Comment
> Date: Sun, 6 Jun 1999 17:29:05 -0400
> Importance: high
> X-Priority: 1
> Return-Receipt-To: "Woollam, Richard C." <WoollaRC@BP.com>
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>
> ----------
>
>
>
>
>
>
> Gary/Dominic,
>
> As we discussed we are under significant pressure to reduce the budget.
>
> One of the options that was discussed was to reduce chemical
injection
> rates
> by approximately 10% through the remainder of the year. As
alternative
> I
> would like to also consider expanding the 049 to the pads shown in
the
> attached, effective immediately.
>
> If we were to pursue the 049 expansion, I think we would get almost
as
> much
> cost reduction as we would be cutting 10% on injection rates, can
you
> please
> confirm this is the case including the timing and logistics. Can we
> target an August 1st start date?

>
> From a risk perspective, if we need to reduce cost by 10% then with
> the current corrosion inhibitor technology we would simply be taking
> 10% out of the system with the resultant increase in corrosion rate.
> If we move to 049, we will get the 10% reduction in corrosion
> inhibitor costs and we
may
> not
> get the increase in corrosion rate.
>
> I fully accept that this is a risky call and we will have to review
> the risks associated with it.
>
> In order to maximize the benefit from such a move we will have to
make
> some
> decisions very quickly. John, Rick and I are meeting Monday to
discuss
> this
> and a number of other budget options. Could you please have your
> thoughts together, cost implications, timing, logistics etc., by noon
> Monday, June 7th, so we can make a decision in the afternoon.
>
> The above, and the cessation of the PW injection (with the exception
> of S
> pad) should put us on track for the budget through the remainder of
> the year.
>
> If you have any questions, concerns then please let me know (break
> into the TL's meeting as required).
>
> Thanks and sorry for the short notice - it only occurred to me
> yesterday that this was an option!
>
> Richard.
>
> <<Chemical Budget Buster.xls>>
>
> PS Danny/David - Can you please start working some of the issues
first
> thing
> in Houston - the logistics are going to be a big part of this one! I
> would also like some thoughts from Sugarland on the potential risks -
likely
> performance of 049 in essence!
>
>

Gary:

Thanks for the heads up. You indicate in the PPT slides that you will order RC quantities of 99VD049 on July 7 for a July 15 ship date. What is the anticipated quantity? Are staggered ship dates ok?

We need to make sure we're ready on this end with production scheduling, raw materials, etc.

Thanks, Danny

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From: Woollam, Richard C.
Sent: Wednesday, March 08 2000 10:57 AM
To: PBU, APC Manager
Cc: Martin, Michelle O; 'Gabrielson, Lee'; 'Burrows, Don'; Laasch, Jack (APCI); PBU, Chemical Foreman; PBU, CIC NS TL Felix/Phillips
Subject: RE: APC Budget

Bob,

Thanks for the note.

Unfortunately, the oil business is essentially assessed on lifting cost not on the oil price, therefore, as the production level at PBU continues on its relentless decline so must our costs follow. The general decline rate over the last few years has been between 12 and 15% and while the forecast is for this to reduce it still represents a reduction of some 10% per annum. Just to emphasise the point, the amount of money/budget is almost completely independent of the oil price.

As a consequence, the overall PBU budget is declining and the CIC Group, as part of that overall, is also declining. The type of performance we are asking of you is not different to that which we expect of anybody in the organization.

The idea behind a managed service is that you, as the expert, are best able to reduce cost and increase efficiency, if this is something that you do not wish to do then please let me know and I'll do it. However, clearly, if I manage the program rather than yourselves then we need to look at the contract structure in detail.

We have a meeting scheduled for next week - I will be available between now and then if to discuss the way-forward.

Thanks.

Richard.

From: PBU, APC Manager
Sent: Tuesday, March 07, 2000 7:16 PM
To: Woollam, Richard C.
Cc: Martin, Michelle O; 'Gabrielson, Lee'; 'Burrows, Don'; Laasch, Jack (APCI); PBU, Chemical Foreman; PBU, CIC NS TL Felix/Phillips
Subject: APC Budget

Richard,

Thank you for your response to our proposal to reduce the APC budget by 8% for the year 2000. I am disappointed in your answer.

Over the last several years, the management and employees of APC have worked tirelessly to meet BP expectations for service quality and cost. 1999 was our most challenging year yet. Our crews worked hard and made many personal sacrifices to try to meet your goals. Now, they're tired. They haven't had raises in years. There aren't enough people to do the demanded work load. They are frustrated because they can't get everything done; frustrated because they can't meet their own expectations for a high quality of thorough work; and frustrated because your employees are quick to make negative comments about APC as an employer.

When oil prices were below $10.00 per barrel, we were all willing to pitch in and help reduce costs. We did as much work as before (or as close as we could get) with reduced resources. Now, with oil at over $30.00 per barrel, you are asking us to cut another approximately $300,000.00.

We can't cut people (we don't have enough to do the work now!), we can't cut wages (we'll lose the excellent people we have worked so hard to keep!), and about $55,000 of the cuts is from money paid to vendors (VECO, PEAK, ARCO, etc.) over which we have little hope of control.

So, what you are asking us to do is to give up almost $300,000.00 in corporate profits. Profits that have already

been cut from what was available in previous years. Profits that go to Alaska Natives - not a nameless corporation but real people who depend on this money for their existence, for basic human services, and to develop a future for their children.

You have demanded that I take $300 000.00 away from our shareholders, and then continue to find some way to make our employees continue to work beyond their capacity, deny them any additional help (or finance help by taking even more money from the shareholders), and then expect the employees to keep their high standards of service quality, safety and environmental stuardship.

I can not, in any manner of good faith, make such a suggestion to my employer, my employees, or even to BP. I will be meeting with Lee tomorrow (March 8) here in Deadhorse and will discuss my concerns with him. I urge you to reconsider your demands. In my opinion, they are not in the best interests of your company.

Bob Carmichael

7

Preliminary 2001 Budget

All $ in $000's	2000			2001	
	EOA	WOA	00 Total	-10%	01 Total
CIC Manager/Staff	$ 1,420	$ 1,300	$ 2,720	$ (272)	$ 2,448
Process	$ -	$ 710	$ 710	$ (71)	$ 639
Corrosion Inhibition	$ 14,627	$ 8,761	$ 23,388	$ (2,339)	$ 21,049
Monitoring	$ 1,052	$ 450	$ 1,502	$ (150)	$ 1,352
Pigging	$ -	$ 400	$ 400	$ (40)	$ 360
Inspection	$ 7,852	$ 3,050	$ 10,902	$ (1,090)	$ 9,812
Total $	**$24,952**	**$14,671**	**$39,623**	**$(3,962)**	**$35,661**
PW Inhibition					$ 1,000
Wet gas inhib					$ 500
Total $					**$37,161**

8

From: Woollam, Richard C
Sent: Sunday, January 07, 2001 5:38 PM
To: Sprague, Kip P (ASCG)
Cc: Matthews, Lonnie T; PBU, CIC NS TL Felix/Phillips
Subject: Smart Pigging the Oil Sales Lines

Kip,

Can we smart pig both the EOA and the WOA oil sales line? If there are issues what are they?

Also, what sort of inspection data and damage, if any, are we seeing in the oil sales lines?

The reason is, as part of the 1% leak detection for ADEC rather than install $ 20 million of metering one option would be to smart pig every 3 years instead, at approx $50,000 x 2, every third year is considerably cheaper than $ 20 million!!!

Thanks.

Richard.

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From: Woollam, Richard C
Sent: Monday, January 08, 2001 12:10 PM
To: Anderson, Doug M (ASCG)
Cc: Sprague, Kip P (ASCG)
Subject: FW: Smart Pigging the Oil Sales Lines

Attachments: OT Metal Loss.ppt

Doug,

Could you please pull the inspection data for the EOA and WOA oil sales lines and review.

Thanks.

RIchard.

-----Original Message-----
From: Sprague, Kip P (ASCG)
Sent: Monday, January 08, 2001 10:43 AM
To: Woollam, Richard C
Subject: RE: Smart Pigging the Oil Sales Lines

Richard,

We could likely Smart Pig each of these lines but not without considerable amount of work. A few issues are:

- Difficult launch do to short traps and long pigs. (managed in '98 but had to modify the nose cone of the pig to squeeze it in the trap)
- Flow rates are below smart pig recommended specifications. Successful in the '98 and data was pretty good but, PII cannot guarantee quality/sizing.
- Current configuration of EOA piping at SK-50 (18" jumper to WOA 34"). Piping would have to be reconfigured and I believe the PS1 metering has been removed. Would likely have to speak with shared service to find out hat would be required or what options exist. Also, I am not familiar with physical access to the launch trap but, assume we can load the pig.

WOA has seen quite a bit of internal and a fair amount of external damage. Internal is small pit networks @ 6:00 azimuth. I don't have access to CATS right now but my thoughts are that the oils sales line has continued to degrade very slowly. I am fairly sure we did very little of the planned flowline program in 1999 and 2000 so, not sure there is much recent inspection to analyze.

EOA has done little or nothing for inspection of the sales line. Nothing to offer there.

Enclosed plot of '98 S_Pig Reported Metal Loss -

Let me know if you want to proceed with the smart pig option, when you have to have all the answers, and I will do some investigation.

Kip

10

From: Foust, Nancy C
Sent: Monday, May 14, 2001 7:47 PM
To: Woollam, Richard C
Subject: RE: CIC Group Team Leader Meeting - 21st May

Richard --

I had not heard this. I will be attending the FMT meeting tomorrow and will attempt to ascertain the status of these programs in regards to the MR budget.

-----Original Message-----
From: Woollam, Richard C
Sent: Monday, May 14, 2001 7:24 PM
To: Foust, Nancy C
Subject: FW: CIC Group Team Leader Meeting - 21st May

Nancy,

Please see below, obviously these are difficult times for the GPB budget and, unfortunately, I shall not be at the FMT meeting tomorrow, however given all the press coverage recently around integrity I would like to understand the thinking behind the decision John/Rick are indicating has been taken for the CUI (corrosion under insulation) and below-grade road crossings (smart pigging). Could youn please help me understand the context/forward plan

Thanks.

Richard.

-----Original Message-----
From: PBU, CIC NS TL Felix/Phillips
Sent: Monday, May 14, 2001 6:36 PM
To: Woollam, Richard C
Cc: Felix, Rick D
Subject: RE: CIC Group Team Leader Meeting - 21st May

Based on what RDF just showed me at handover, CUI Mitigation, CUI Detection, and Smart Pigging are all on "hold" and are below the line. I believe he just found this from Jack out prior to handover, so hadn't had time to relay it yet. It does look quite bad thus far. Rick can provide better context than I can on the discussions held over the past few days.
John

-----Original Message-----
From: Woollam, Richard C
Sent: Monday, May 14, 2001 6:30 PM
To: PBU, CIC NS TL Felix/Phillips
Subject: RE: CIC Group Team Leader Meeting - 21st May

John,

What is the latest on the MR? Did s-pigging/CUI fall off the list?

Richard.

-----Original Message-----
From: PBU, CIC NS TL Felix/Phillips
Sent: Monday, May 14, 2001 6:28 PM
To: Woollam, Richard C

Subject: RE: CIC Group Team Leader Meeting - 21st May

I take it the current ASCG issues will be covered under Inspection Program delivery? Also, we need to be ready to commit to what we're really going to do (or not do) this year based on the new bloodbath numbers. i.e. drop s-pigging, scale back CUI, drop crews/activity, whatever.
John

-----Original Message-----
From: Woollam, Richard C
Sent: Monday, May 14, 2001 5:50 PM
To: PBU, CIC NS TL Felix/Phillips; Paisley, Dominic M; Felix, Rick D
Cc: Foust, Nancy C
Subject: CIC Group Team Leader Meeting - 21st May

All,

Please plan on a CIC Group Team Leader meeting for the 21st May, 10:00 am start.

The main agenda topics,

- YTD HSE Review
- YTD Technical Review
- YTD Financial Review
- New people issues
- Inspection program delivery
- GPB budget pressure and options

Are there any other topics? Please be prepared to talk about our options around the GPB budget, in particular, can we see any cross-department opportunities?

Richard.

From: Woollam, Richard C
Sent: Monday, May 14, 2001 7:57 PM
To: Foust, Nancy C
Subject: RE: CIC Group Team Leader Meeting - 21st May

Nancy,

Thanks, I know there are some tough decisions to be made, but, on the face of it this seems like a poor choice, however, there maybe some other grand plan which I am simply not aware of or some other circumstances/background - I'd really just like to understand the context.

If, at the end of the day, the FMT has decided that the this is the most appropriate action and the FMT is prepared to deal with the regulatory/reputational fallout then we, the CIC Group, will defer the external program and stand-down our current contract manpower.

Did you get copied on the FMT agenda?

Thanks.

Richard.

-----Original Message-----
From: Foust, Nancy C
Sent: Monday, May 14, 2001 7:47 PM
To: Woollam, Richard C
Subject: RE: CIC Group Team Leader Meeting - 21st May

Richard --

I had not heard this. I will be attending the FMT meeting tomorrow and will attempt to ascertain the status of these programs in regards to the MR budget.

-----Original Message-----
From: Woollam, Richard C
Sent: Monday, May 14, 2001 7:24 PM
To: Foust, Nancy C
Subject: FW: CIC Group Team Leader Meeting - 21st May

Nancy,

Please see below, obviously these are difficult times for the GPB budget and, unfortunately, I shall not be at the FMT meeting tomorrow, however given all the press coverage recently around integrity I would like to understand the thinking behind the decision John/Rick are indicating has been taken for the CUI (corrosion under insulation) and below-grade road crossings (smart pigging). Could youn please help me understand the context/forward plan

Thanks.

Richard.

-----Original Message-----
From: PBU, CIC NS TL Felix/Phillips
Sent: Monday, May 14, 2001 6:36 PM
To: Woollam, Richard C
Cc: Felix, Rick D

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From: PBU, CIC NS TL Felix/Phillips. Sent: 5/16/2001 12:14 PM.

To: Felix, Rick D; Woollam, Richard C; Paisley, Dominic M.

Cc:

Bcc:

Subject: RE: CIC Group Team Leader Meeting - 21st May

Gents,

Discussed all this with Ruth yesterday. She indicated that $2MM will be earmarked from contingency to do CUI work; we're already working on a program redesign based on that assumption. Several of us will be having a telecon meeting this morning at 10:00 to discuss further. I assume we will focus on detection and let repairs get covered outside the CIC AFE's.

I also have a meeting with Ruth and George Blankenship tomorrow to plead our case for smart pigging. Dominic/Kip are working up some backup material to support that discussion, i.e. ADEC commitments and pipeline integrity management philosophy.

I am also intending to tell ASCG Site Supervisor to freeze hiring till they hear from us next week after our related discussions are held. There was a package rolled out at the morning Ops meeting today which attempts to explain why we're taking the budget measures that are happening, will roll that out to core staff today. Other groups are in the process of scaling back work, so the work environment here at GPB is not going to be too good the next few weeks.

Regards,
John

-----Original Message-----
From: Felix, Rick D
Sent: Wednesday, May 16, 2001 1:07 AM
To: Woollam, Richard C
Cc: PBU, CIC NS TL Felix/Phillips
Subject: RE: CIC Group Team Leader Meeting - 21st May

Richard,

Those projects are indeed below the line. Discussions at Sundays Ops meeting definitely recognized (by Jack and several of other OTLs) that at least "some" of the CUI work had to get done this year. However, no one volunteered to drop any of the items above the line to make room. My understanding is that Jack/Ruth or ?? will be taking the latest iteration of the MR Budget back to the Owners to show/tell them what we've decided (or not) to do. My guess, and I think Jack's, is that they will also see that not doing CUI will put us at odds with the regulators, resulting in them authorizing more funds or will expect BP to identify which items above the line will fall off to make room.

John - can you talk with Ruth if she's up this week to see what spin she has. Any repsonse from Jack on the smart pigging?

Rick
CIC NS Team Leader
x5050, bpr 2267

-----Original Message-----
From: Woollam, Richard C
Sent: Monday, May 14, 2001 6:40 PM
To: Felix, Rick D
Cc: PBU, CIC NS TL Felix/Phillips
Subject: RE: CIC Group Team Leader Meeting - 21st May

Rick,

What's the story here? How did it all change or was there no rationale?

Richard.

-----Original Message-----
From: PBU, CIC NS TL Felix/Phillips
Sent: Monday, May 14, 2001 6:36 PM
To: Woollam, Richard C
Cc: Felix, Rick D
Subject: RE: CIC Group Team Leader Meeting - 21st May

Based on what RDF just showed me at handover, CUI Mitigation, CUI Detection, and Smart Pigging are all on "hold" and are below the line. I believe he just found this from Jack out prior to handover, so hadn't had time to relay it yet. It does look quite bad thus far. Rick can provide better context than I can on the discussions held over the past few days.
John

-----Original Message-----
From: Woollam, Richard C
Sent: Monday, May 14, 2001 6:30 PM
To: PBU, CIC NS TL Felix/Phillips
Subject: RE: CIC Group Team Leader Meeting - 21st May

John,

What is the latest on the MR? Did s-pigging/CUI fall off the list?

Richard.

-----Original Message-----
From: PBU, CIC NS TL Felix/Phillips
Sent: Monday, May 14, 2001 6:28 PM
To: Woollam, Richard C

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From: Foust, Nancy C
Sent: Monday, October 15, 2001 10:34 AM
To: Woollam, Richard C
Subject: RE: ACTION: 2001 Year End Forecast

Thanks, Richard. If the things you're working come to fruition, along with the increases, you should end up $2.0m over instead of the current $3.0m. Hopefully additional insights will come up that will help to reduce the negative variance even more.

Nancy

-----Original Message-----
From: Woollam, Richard C
Sent: Monday, October 15, 2001 8:52 AM
To: Foust, Nancy C
Cc: NSU, CIC TL; Felix, Rick D (Anchorage)
Subject: RE: ACTION: 2001 Year End Forecast

Nancy,

The following budget adjustments are known to date,

- ~$ 750,000 moving as much O&M money to CUI AFEs as appropriate
- ~$ 300,000 of MeOH which should have been charged to the field
- ~$ 100,000 in stores issues which can be charged to ASCG Insp Inc. under the contract
- ~$ 50,000 in overhaul crew costs/manhours which should have been charged to Operations Support

Being worked,

- ~$ 150,000 in scaffolding costs which should be charged to Operations Support as this was a temporary installation rather than permanent
- ~$ 100,000 in AII overhead costs and manpower if negotiations are succesful

Upward pressure/declined options,

- ~$ 200,000/month in PW/CI costs which can not be saved as indicated by George
- ~$ 200,000/month in AII manpower coists which can not be saved, again as directed by George, however, I have not told AII as I'm still trying to get an overhead reduction and this is all part of the pressure
- ~$ 200,000/month in increased CI costs when B Train and Big AL come back on line

If there are anyt questions please let me know.

Thanks.

Richard.

-----Original Message-----
From: Foust, Nancy C
Sent: Monday, October 15, 2001 8:12 AM

To: Woollam, Richard C
Subject: RE: ACTION: 2001 Year End Forecast

Richard --

What is the impact of this for you?

Nancy

-----Original Message-----
From: Blankenship, George R
Sent: Friday, October 12, 2001 11:01 AM
To: Foust, Nancy C
Cc: Woollam, Richard C
Subject: RE: ACTION: 2001 Year End Forecast

Two issues. 1) stopping the planned CUI program at the end of the program. I think we are clear, we will stop.
2) where the money gets charged. I do not have an opinion on that, it all comes out of the opex budget and it does not change how much is available to spend.

George

-----Original Message-----
From: Foust, Nancy C
Sent: Friday, October 12, 2001 10:47 AM
To: Blankenship, George R; Woollam, Richard C
Subject: RE: ACTION: 2001 Year End Forecast

Yes, it makes sense. To make sure we're all clear, you want Richard to move the $800k from O&M to the $2.0m AFE?

-----Original Message-----
From: Blankenship, George R
Sent: Friday, October 12, 2001 10:38 AM
To: Foust, Nancy C; Woollam, Richard C
Subject: RE: ACTION: 2001 Year End Forecast

The planned program for the CUI inspection has been completed therefore the program is over for 2001. We will have a stepped up program for 2002. The sound bite is that this is NOT a reduction, but a completion of the planned program.

Does that make sense?

George

-----Original Message-----
From: Foust, Nancy C
Sent: Friday, October 12, 2001 10:16 AM
To: Woollam, Richard C; Blankenship, George R
Subject: RE: ACTION: 2001 Year End Forecast

George --

Refresh my memory -- did you decide to leave the $800k CUI O&M where it is (i.e. not move it to the $2m CUI AFE which would effectively shut down the program for the rest of the year)? I don't recall a decision but you did ask about the possible explanatory "sound bite."

Nancy

-----Original Message-----
From: Woollam, Richard C
Sent: Thursday, October 11, 2001 4:59 PM
To: Blankenship, George R
Cc: GPB, Ops Mgr; Foust, Nancy C; NSU, CIC TL; Felix, Rick D (Anchorage)

Subject: RE: ACTION: 2001 Year End Forecast

George,

Just to confirm our conversation,

- CIC Group will look for all and every opportunity to close the budget gap and save funds through the remainder of this year, including, eliminating overtime, giving folk the opportunity to go on vacation, reducing stores/warehouse issues etc., etc...

However, the following options are not, at this time, viewed as viable,

- PW corrosion inhibition - reinstate this program which was terminated yesterday
- Production adding corrosion inhibtion - make sure that the added production is cost effective, highly likely, otherwise continue
- Seek opportunities to reduce NDE manpower costs, as discussed above, but do not implement a 1/3 reduction in workforce
- Move the $ 800,000 O&M money to the AFE therefore completing the 2001 program of $ 2 million
- It is recognized that there will be an up-tick in corrosion inhibition costs with the start-up of B-Train at FS-2 and with Big Al

To be implemented,

- Back-out corrosion inhibition changes due to ER probes - do this quietly

Hopefully, this summarizes the discussion, if I made any errors, please let me know.

Thanks.

Richard.

-----Original Message-----
From: Woollam, Richard C
Sent: Thursday, October 11, 2001 2:25 PM
To: Blankenship, George R
Cc: GPB, Ops Mgr; Foust, Nancy C
Subject: RE: ACTION: 2001 Year End Forecast

George,

Certainly, 4:00 pm it is. In summary, here are the imediate actions I'm proposing to take to reduce the CIC Group costs/over-run,

- Shut-off the PW corrosion inhibitor on the WOA
- Remove the corrosion inhibitor added for velocity control/management and lower the velocity limit to the new operating procedure
- Back-out some chemical changes which were implemented based on ER probes, these are pretty conservative changes so not a huge risk
- Reduce the O&M NDE/inspection crews by approx. 1/3 for remainder of the

year, this is approximately 30 people. The concern is that they are members of PACE/OCAW and how this would be interpreted in view of the integrity issues raised by ORT

- Move O&M costs which have been spent on external corrosion to the external corrosion AFE. In a sense this will reduce expenditure on external corrosion since we would have effectively spent an additional ~$1 milion had we not been forced to move this money to the AFE

There is a major up-tick coming in CIC costs with the re-start of FS-2 B Train/Big AL and the large water volumes associated with this production.

Hope this helps.

Richard.

-----Original Message-----
From: Blankenship, George R
Sent: Thursday, October 11, 2001 2:12 PM
To: Woollam, Richard C
Cc: GPB, Ops Mgr; Foust, Nancy C
Subject: RE: ACTION: 2001 Year End Forecast

Richard, apparently me and several other folks are confused. I have a meeting in Jack Fritts' office at the BOC with Nancy at 4pm. Can you call in there and we can talk about this.

Thanks,

George

-----Original Message-----
From: Woollam, Richard C
Sent: Thursday, October 11, 2001 2:01 PM
To: Blankenship, George R
Subject: RE: ACTION: 2001 Year End Forecast

... I'm confused because I haven't suggested at anytime reducing our external corrosion program, the NDE crew reductions are for the general/internal inspection program.

The only impact for external is that we are going to move some costs which are currently carrying under the O&M budget, which we accumulated in the first half of the year awaiting various decisions, into the correct AFE.

Richard.

-----Original Message-----
From: Blankenship, George R
Sent: Thursday, October 11, 2001 1:58 PM
To: Woollam, Richard C
Subject: RE: ACTION: 2001 Year End Forecast

Specifically "corrosion under insulation" inspection, I thought the second sentence said that. Sorry if I confused you.

George

-----Original Message-----
From: Woollam, Richard C
Sent: Thursday, October 11, 2001 1:48 PM

To: Blankenship, George R
Subject: RE: ACTION: 2001 Year End Forecast

George,

Sorry, I'm confused, does this refer to the external inspection program? Internal inspection program? PW inhibition? Can I give you a call somewhere to clarify?

Thanks.

Richard.

----Original Message----
From: Blankenship, George R
Sent: Thursday, October 11, 2001 1:26 PM
To: Woollam, Richard C; Foust, Nancy C; GPB, Ops Mgr; GPB, Ops Support Mgr
Cc: Farnham, C Drais
Subject: RE: ACTION: 2001 Year End Forecast

We have actually had quite a bit of discussion on this subject with Neil McCleary and Steve Marshall up here on the slope the last couple of days. It is a consensus that reducing corrosion under insulation for the last couple months of this year is not a good business decision, given all the factors involved. While I appreciate and applaud the effort to identify opportunities for savings, we need to keep looking. This one will not pass the test.

Thanks,

George

-----Original Message-----
From: Woollam, Richard C
Sent: Wednesday, October 10, 2001 12:00 PM
To: Foust, Nancy C; Blankenship, George R; GPB, Ops Mgr
Subject: RE: ACTION: 2001 Year End Forecast

All,

I agree, we need to understand the variances, however, I needed to take some immediate action in order to get after reducing costs. Given the timing before year-end which didn't allow time to analyse and then react.

If I need to reverse the PW because of employee/integrity concerns then please let me know, the others, I think are good solid optimization opportunities.

Richard.

-----Original Message-----
From: Foust, Nancy C
Sent: Tuesday, October 09, 2001 8:44 PM
To: Woollam, Richard C; Blankenship, George R; GPB, Ops Mgr
Subject: RE: ACTION: 2001 Year End Forecast

Richard --

Although, I believe this particular proposed cost-cutting measure is a George/Ruth/Jack call, I am concerned about making decisions of this sort when we don't know what really is driving our negative variances. It may be that we find it necessary to jerk around because it's imperative we meet the budget and we have a very short time to make up the variance. It does really highlight, however, the need for us to stay on top of our costs and understand what is driving them so that we can respond early and in a controlled, thoughtful manner. Been a great (although not fun!) learning experience for me.

I encourage you and your team leaders to continue digging to determine what it is that is driving the costs and what may be differing in our operations from the 2001 plan.

Let me know if there is anything at all I can do to help.

Nancy

-----Original Message-----
From: Woollam, Richard C
Sent: Tuesday, October 09, 2001 6:51 PM
To: Foust, Nancy C; Blankenship, George R; GPB, Ops Mgr
Cc: NSU, CIC TL; Felix, Rick D (Anchorage)
Subject: FW: ACTION: 2001 Year End Forecast

Nancy/George/Ruth/Jack,

Please see below, we are taking some very specific short term actions to reduce the spend rate within the CIC Group. Note that some of this action is to reduce and/or eliminate chemical injection in the last three months of this year, these are the lower risk options available to us, but, you should be aware that there may be some concerns raised within the workforce.

If there are any questions, please let me know.

Thanks.

Richard

-----Original Message-----
From: Woollam, Richard C
Sent: Tuesday, October 09, 2001 6:44 PM
To: Morales, Noah L (NEEC); Crawford, Gary R; NSU, CIC TL
Cc: Felix, Rick D (Anchorage); Foust, Nancy C
Subject: FW: ACTION: 2001 Year End Forecast

Gary/Dominic/Noah,

As you may know we under a huge budget pressure for the last quarter of the year and therefore we have to take some rather disagreeable meaures. Can you please implement the following changes/reviews,

- Shut down the PW inhibition systems for remainder of the year
- Dis-continue the addition of corrosion inhibition for velocity control
- Reverse all chemical changes made since 1/1/01 which were based on purely ER probe changes and which did not involve either WLC > 2 or alpha > 0
- Wet gas inhibition to continue - the consequences are too high here
- Review all the CL/LDF data for potential reductions beyond the reversals identified above

These need to happen as soon as possible.

Thanks.

Richard.

-----Original Message-----

From: NSU, CIC TL
Sent: Tuesday, October 09, 2001 8:51 AM
To: Woollam, Richard C
Cc: Felix, Rick D (Anchorage)
Subject: RE: ACTION: 2001 Year End Forecast

Richard,

Based on your other note, it appears that Ops Corrosion and Inspection are the 2 areas that are over spent based on 3 quarters of the year.

The **Ops Corrosion** is not too surprising as 1Q and some of 2Q were expensive, with 129/118 on the East and Summer version not in the system. The comparison I did with Andy's numbers indicated we are broadly in line to meet the (non linear) projections for chemical & transportation costs, with costs currently running under projections by $0.25 million. The detail showed costs to be down by $1 million at FS-2 due to B-train etc but up elsewhere, most nobably GC-2. There is a potential over-spend of ~ $0.5 million if B-train, Big AL and 16/17C come on mid-October, which seems a worst case estimate.

Of course, this doesn't compare the current status with the budget but it does indicate that chemical

and transportation costs are largely where we predicted them to be, with the exception of GC-2. As we predicted a spend of ~ $3.5 million less than we started the year, it looks like we are still going to deliver the $3 million we set out to, even if B-train comes back up.

Re: **Inspection**, do these costs include the external inspection that we have not transferred to an AFE ? If that is backed out, where do we stand ? Can we work up some simple inspection costs from the ground up in a similar manner, to give an indication if the costs are reasonable i.e. X,000 items at Y items/manhour and Z $/hour. It may give us something to focus us.

Ideas for saving money, in no particular order:

- Turn off PW chemical and hope the BCQ inhibitor will help out here.
- Turn off the wet gas inhibitor on the West (not a wise choice but could be defended as a short term measure ?).
- Stop the velocity additional chemical. This is proposed in the revised velocity g'lines but not enacted until the new g'lines are formally adopted by Ops. ~ $125,000/qtr. Easy win.
- Re: backing out CI increases. There are a couple of options:
    - We recently decided to limit CI increases based on ER probe data to +5% due to data quality/reliability. We could apply this retroactively to the start of the year. This would have the advantage of not breakng any of our protocols - just back dating a recent revision.
    - Remove all ER-probe based changes since 1/1/01, as proposed.

I can carry on digging in to cost codes but it would be great to get some professional help. Who can help us one on this ?

Cheers,

Dominic

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- Satellite production and E/F pad impacts $ 0.750 million

Total **$ 1.155 million**

Details below,

RE: F and E PAD
Production Imp...

The intent, as discussed in the e-mail above is to meet both these challenges within the original $44.5 million budget for 2002 through judicious program management and optimization As a conseqeunce of these pressures there is little room for further program 'optimization' however, with careful management of OT and strict closure of programs at completion of work scope it is probable that a revised LE for 2002 of $44 million is a challenging but achievable target for 2002.

Note, the proposed target of $44 million is approximately $0.5 million below the last LE submitted at the beginning to Steve St J and John B., please see below.

RE: GPB Budget LE
Update

Further reductions beyond the proposed LE of $ 44 million will require significant changes to the program scope above and beyond the optimization opportunities which will allow us to deliver the $44 million discussed above.

In order to deliver substantial costs in the second half of 2001 then major changes to the major elements of the CIC's programs would be required. The major drivers for the program are,

Amount of in-service equipment	Drives inspection activitiy Drives monitoring activity
Fluid composition and rates	Drives chemical activity

Below are a list of options from within the CIC budget, each of which will deliver approximately $1 million if implemented in the seocnd half of the year. In summary,

- **Inhibition Program Reduction 8%** Reducing second half inhibition rates by approximately 8%, while it is difficult to estimate this associated corrosion rates, based on past years for a 10% change in inhibition rate there would be an approximately 30% increase in corrosion rates in flow lines and well lines

- **Internal Inspection Program Reduction 30%** Reducing the inspection program in the second half of the year by 30%, moving from approximately 9 to 6 crews, would reduce the 2H inspection scope by about 10,000 items. The obvious concern here is with impacts/perceptions of ORT and possibly PACE.

- **External Corrosion Inspection Reduction 40%** Reducing the external inspection program by 40% yield a new 2H scope of 10,000 versus the plannned 17,500 for a total of 28,000 items as opposed to the 35,000 commitment to both partners and ADEC. In addition to the ORT perception impacts and ADEC, there is also the issue of partner perception since partners were concerned that money for external corrosion would be diverted once agreed.

Detailed calculations for the above options are contained in the attached spreadsheet. It should be noted that some gross assumptions about average unti costs have been made in order to arrive at the above estimates.

2002 Budget
Opbons.xls (51 KB...

The above options reflect action being taken within the CIC Group. There are an option which could be taken by

Operations/Production which would impact our budget directly, in summary,

- **Reduce Water Rates** Shutting-in the 30 most expensive wells across the field would reduce 2H 02 expenses by approximately $3 million in corrosion inhibition costs - see e-mail exchange below. This data is a little out of date, but, it is save to assert that a $1-2 million could be removed with the shut-in of the appropriate suit of wells **provided** that this production was not repalced elsewhere in the field.

RE: Vol vs exp

If you need any additional information on the items discussed above please let me Iknow.

Thanks.

Richard.

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From: GPB, GC1/GC2/Fld Proc Engr
Sent: Tuesday, October 16, 2001 05:45 AM
To: GPB, Fld AMC
Subject: FW: MOC Velocity change & Removal of additional corrosion inhibitor

Attachments: FW: Operational Limits for Management of Erosion and Corrosion

Jerry
here is the gist of it.
Richard

-----Original Message-----
From: GPB, Ops Mgr
Sent: Saturday, October 13, 2001 10:59 PM
To: Demby, Richard A; Powell, Jim E
Cc: GPB, Fld TL; GPB, FS1 TL; GPB, FS2 TL; GPB, FS3/GC3 TL; NSU, CIC TL; GPB, Prod Opt TL
Subject: MOC Velocity change & Removal of additional corrosion inhibitor

Richard and Jim,
I was wondering if you guys would take the lead on putting together the MOC raising the allowable erosional flow velocity for the WOA to match that used on the EOA. Attached is the recommendation sent to Ruth and I in August by the CIC Group. If you need additional information or insight from me, let me know. If you have any other questions, please give Dominic or John a call.

Thanks in advance for your assistance,
Jack

-----Original Message-----
From: NSU, CIC TL
Sent: Thursday, October 11, 2001 1:58 PM
To: GPB, Ops Mgr; GPB, Prod Opt TL; GPB, Gas Lift Engr
Cc: Woollam, Richard C; G SST Corr Engrs
Subject: Removal of additional corrosion inhibitor

Jack, Hal & Russ,

We have made the decision to stop the practice of adding extra corrosion inhibitor to mitigate corrosion at elevated flow velocities, in order to meet our 2001 budget.

The practice of adding extra chemical was introduced last year and enabled CIC and Operations to raise the allowable flow velocities by 25 ft/sec and therefore increase production. In the new unified velocity guidelines we proposed dropping this program as it is inefficient, both in terms of chemical management and time. Our proposed guidelines allow for elevated flow velocities typically 10 to 15 ft/sec higher than the old guidelines without the requirement for additional chemical to be added proactively; rather we will add extra corrosion inhibitor in response to observed corrosion through our monitoring programs, as we have always done. The new guidelines also recommend raising the allowable erosional flow velocity (V/Ve) from 2.0 to 2.5, thereby increasing production. I believe therefore that implementation of the new guidelines should be broadly production neutral, relative to the curret status although Russ will know much better.

As the proposed guidelines have not been formally adopted, the removal of the extra chemical program will return us to the previous default velocity limits. There will clearly be a production impact associated with this and therefore we should re-visit the recommendations to see if and when we can implement them. To quote from the recommendations:

"It should be recognized that these are only recommendations; unlike other operational parameters such as temperature

and pressure, there are no codified limits for flow velocity and therefore you may accept or reject these recommendations. These recommendations are presented as appropriate technical limits that aim to maintain the integrity of equipment whilst enabling high production rates and minimizing operational costs such as chemical consumption and equipment repair or replacement."

What this means in practice is that CIC and Operations can work together to implement a program quickly that meets the main requirements of the guidelines while maintaining production and this should probably be done via an MoC. Let me know how you want to proceed,

FW: Operational Limits for Man...

Cheers,

Dominic
Dominic Paisley
North Slope Team Leader
Corrosion, Inspection & Chemicals Team
BPX Alaska
E-mail: nsucictl@bp.com
Phone: +1 (907) 659 5050
Fax: +1 (907) 659 5152
Pager: +1 (907) 659 5100, pager 2267

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CIC Group 2002 Budget Challenge - $ 1 Million Opportunities

	Budget Area	Full Year 2002 Bud.	Half Year 2002 Bud.	Scope	Unit	Rate		$ 1,000 New Scope	% Reduction	Half Year New 02 2H
4DF	CIC Supervisor	$ 1,948	$ 974							$ 974
4DG	Chemical Ops - Process	$ 2,591	$ 1,296							$ 1,296
4DH	Chemical Ops - Corrosion	$ 25,392	$ 12,696	1.5	MM Gals	8.46	$/gal	1.38	7.9%	$ 11,696
4DI	Field Pigging Operations	$ 1,259	$ 630							$ 630
4DJ	Inspection	$ 7,285	$ 3,643	35000	Items	104	$/Item	25,391	27%	$ 2,643
4DK	External Corrosion	$ 5,000	$ 2,500	17500	Items	143	$/item	10,500	40%	$ 1,500
4DY	N/S Svcs - Anc Tech Labor	$ 1,078	$ 539							$ 539
	Subtotal CIC Group	**$ 44,553**	**$ 22,277**							**$ 19,277**

Notes

4DF Largely BP labour and therefore difficult to impact in the short term

4DG Process chemicals such as EB which is impoacting to production if altered

4DI Major BP labour component

4DI Smart pigging program for which work is complete or commitments made to service supplier

4DY Largely BP labour and therefore difficult to impact in the short term

4DH Difficult to assess but based on history a 10% reduction in inhibition levels would result in a 30% increase in corrosion rate

4DJ Obvious impacts wrt ORT and PACE

4DK Partner perception since this is the very issue they were concerned about

Note: The commitments made in the 2001 Corrosion Report to ADEC for 2002 were based on the $44.5 million budget clearly this would be a concern to the agency if the program was substantially lower than forecast.

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was needed on the WOA. However, there has not been any communication with partners since that time that I am aware of.

Rick

Corrosion, Inspection, Chemicals
Anchorage, AK
(907)564-4466
(907)748-3961 (cell)

-----Original Message-----
From: NSU, CIC TL
Sent: Wednesday, February 05, 2003 12:53 PM
To: Felix, Rick D (Anchorage)
Subject: FW: Master ID 2996 GPB Pig Launcher and Receiver Prelim Engineering

Rick,

Any input?

Thx,
John

-----Original Message-----
From: Farnham, C Drais
Sent: Wednesday, February 05, 2003 11:59 AM
To: GPB, Ops Support Mgr; GPB, Ops Mgr; Woollam, Richard C; NSU, CIC TL
Cc: GPB, Business Lead; Northcott, John (Accenture)
Subject: Re: Master ID 2996 GPB Pig Launcher and Receiver Prelim Engineering

Folks, can anyone tell me if we have Partner "buy-in" on the above subject project anymore than we did on AFE 4N0492 which they rejected and requested withdrawn.

While I was of the understanding that the above subject AFE was related to preliminary engineering related to temporary / portable pigging facilities I would still have to ask if this is a way forward conversation which has been had with our Partners. While I am sure it is not our intention, approving the subject AFE within existing operator authority (WEOA) and communicating to our Partners as an fyi, could be misconstrued as circumventing the approval process and subject BP to future audit claims, given their position on 4N0492. We very much want to have them in agreement on this AFE, regardless of WEOA.

Also of concern is the description / justification ..... should this proceed as an AFE I would have expected it to be significantly different than the earlier AFE rejected / with drawn.

Master ID 2996 ..... to be approved WEOA $1.0M:
Develop scope and perform preliminary engineering for temporary or portable pig launching and receiving facilities on selected lines across GPB. Installations are required to support maintenance pigging activities to reduce corrosion rates on GPB cross-country lines. Facilities will also provide availability to intelligent pig GPB cross-country lines for the detection of both internal and external corrosion. New installations will be concentrated on historic EOA production common lines, and transit sales lines. These pigging facility installations will be for FS1, FS2, and, FS3, and associated drill sites to support integrity operations at these operating areas. See attachment " Pigging Facility Priority Listing" for an itemized listing of exact pipeline locations and relative priority. The purchase of some long lead materials will also be covered under this AFE.

Maintenance pigging is required to optimize existing corrosion control programs. Maintenance pigging will also eliminate flow restrictions present from sediment and fouling within the pipelines. Intelligent pigging is required to provide a full evaluation of current pipeline condition to ensure pipeline integrity and meet regulatory requirements. Intelligent pigging will provide an economic inspection opportunity for both internal and external corrosion monitoring. Intelligent pigging provides a comprehensive survey of the pipeline profile, which then allows other inspection resources to be more effectively utilized in verification of damage networks, which have already been discovered.

AFE 4N0492 ..... rejected by Partners for approval $2.5M:
Install permanent pig launching and receiving facilities on selected lines across GPB. Installations are required to support maintenance pigging activities to reduce corrosion rates on GPB cross-country lines. Facilities will also provide availability to intelligent pig GPB cross-country lines for the detection of both internal and external corrosion. New installations will be concentrated on historic EOA production common lines, and transit sales lines. These pigging facility installations will be for FS1, FS2, and, FS3, and associated drill sites to support integrity operations at these operating areas. See attachment " Pigging Facility Priority Listing" for an itemized listing of exact pipeline locations and relative priority.

Maintenance pigging is required to optimize existing corrosion control programs. Maintenance pigging will also eliminate flow restrictions present from sediment and fouling within the pipelines. Intelligent pigging is required to provide a full evaluation of current pipeline condition to ensure pipeline integrity and meet regulatory requirements. Intelligent pigging will provide an economic inspection opportunity for both internal and external corrosion monitoring. Intelligent pigging provides a comprehensive survey of the pipeline profile which then allows other inspection resources to be more effectively utilized in verification of damage networks which have already been discovered.

My "two cents" ..... please let me know as to George / Partner "buy-in". As I noted below I am genuinely interested in not putting George between a "rock and hard spot", and not degrading the Partner relationships we have "grown" over the last couple years, and want to make sure we have appropriately communicated.

Thanks, Drais

-----Original Message-----
From: GPB, Business Lead
Sent: Wednesday, January 29, 2003 4:13 PM
To: Farnham, C Drais
Cc: Northcott, John (Accenture); GPB, Ops Support Mgr; Woollam, Richard C; NSU, CIC TL; GPB, Ops Mgr
Subject: RE: AFE 4N0492 Install Pig Launchers/Receivers in Flowlines

Drais,
Just finished the MR/Capex meeting and the subject line item was discussed. The subject AFE is being dropped and replace by different scope. Nancy agreed to follow-up with the WIO's request for 'full scope' with regard to what are the total plans for GPB and pig launchers/receivers. My understanding is the original AFE was for permanent pig launchers / receivers the new approach calls for portable launchers / receivers.
Certainly agree that we do not want to put George in a difficult situation with the WIO's as you have outlined below.
Thanks,
Steven E. St. John
GPB, Business Lead
Phone (907) 659-8054
GPBBusinessLead@bp.com

-----Original Message-----
From: Farnham, C Drais
Sent: Wednesday, January 29, 2003 3:54 PM
To: GPB, Business Lead
Cc: Northcott, John (Accenture)
Subject: RE: AFE 4N0492 Install Pig Launchers/Receivers in Flowlines

Steve, getting further into my e-mail ..... I do not think this is a good idea; not sure who's idea it is. At the last Ops Forum, both ConocoPhillips and ExxonMobil requested that this AFE also be removed from the list ..... except their reasons were quite different.

CPAI indicated that they had rejected this AFE and therefore saw no reason for it to be on the list, while ExxonMobil asked for it to be removed as they were also not likely to approve until further discussion and understanding of the Pig Launcher / Receiver strategy had been held and agreed to. They see this as the "tip of the iceberg" relative to projects of this sort and want to understand how they fit within the greater corrosion mitigation / management program.

I absolutely do not think dropping this below the threshold is the right thing to do ..... and before we put George between a "rock and hard spot", maybe discuss this with him. I know he does not like the Partners "directing" our work efforts, but I know he also doesn't want to have to explain this after the fact either.

Thanks, Drais

-----Original Message-----
From: GPB, Business Lead
Sent: Monday, January 27, 2003 1:53 PM

To: Farnham, C Drais
Subject: AFE 4N0492 Install Pig Launchers/R ceivers in Flowlines

Drais,
The subject AFE is listed on the Ops Forurn, you can pull it off (it's for $2.5M & was submitted June-03). Speaking with Rick Felix today they are going to revise it & change the scope which will bring it below the $1m threshold. The rev. will be for front end loading and engineering only.
Thanks,

Steven E. St. John
GPB, Business Lead
Phone (907) 659-8054
GPBBusinessLead@bp.com

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From: NSU, CIC TL
Sent: Sunday, December 07, 2003 5:39 PM
To: Woollam, Richard C
Subject: FW: ACTION: 2003 August LE's and Field OVERVIEW

Importance: High

FYI...

-----Original Message-----
From: NSU, CIC TL
Sent: Wednesday, September 10, 2003 2:43 PM
To: Woollam, Richard C
Cc: Felix, Rick D (Anchorage)
Subject: RE: ACTION: 2003 August LE's and Field OVERVIEW
Importance: High

Richard,

Steve generated a report for Roger and Jack showing CIC Actuals vs. Budget through August. His primary focus was on salaries which were apparently over estimated due to an error in a spreadsheet calculation when the 2003 budgets were created. The same error was propagated through all budgets and has been adjusted out of other LE's so significant pressure was placed on CIC to do the same. Steve calculated that CIC's salary budget had been over estimated by $1MM so we were expected by the Ops and Ops Support Managers to adjust our LE.

I met with Roger and Nancy both this morning for a few hours (at separate times - they changed out)

Roger was very clear that we needed to adjust the budget and that he was mainly concerned about the overall Ops Support budget and individual groups would be viewed based upon that success (most other groups have increased 2003 budgets over 2002 while ours was significantly less carrying much of the organization) . He wanted us to generate a challenging LE (25% probability of success), acknowledged that we have invoicing (outstanding $2.3MM from August) and extra pressure issues (Y-36). His belief was that due to phasing in December and the salary error we could handle the budget reduction and still have a chance to meet the target.

Nancy was not in favor of the cut but felt we had to do it based upon pressure and Steve's comments. She was clear that she would not allow program cuts without being directed by George to do so and is sensitive to news of this cut getting out to the workforce which would undoubtedly cause HSE concerns regardless of impact on performance. Based upon burn rate through August and outstanding invoices of $2.3MM for August (BJ for $350k, BE/PTI for $700k, Canspec for $800k, U2 for $400k) we calculated the LE to be $40MM but obviously did not know how the entire budget had been planned so realized this simple exercise was not without risk. If we get into a position where the budget will be exceeded, she wants us to get with her to develop a plan as soon as possible.

Steve adjusted our LE by taking the $1MM from the salary budgets

Thanks,

Gary

-----Original Message-----
From: Woollam, Richard C
Sent: Tuesday, September 09, 2003 7:11 PM
To: NSU, CIC TL
Cc: Felix, Rick D (Anchorage)
Subject: RE: ACTION: 2003 August LE's and Field OVERVIEW

Gary,

An interesting list, please note I do not want to roll-over on any of this stuff so don't use the term minimal risk. We

are being asked to cut our budget because others were not responsible budget owners at the beginning of the year - hence there is an overview while we cut our budget 5%.

There needs to be greater emphasis on regulatory impacts, relationship with ADEC, workforce perception, as well as the increased corrosion risks.

I have added a couple of comments, please amend the risks as per my comments. Once again, I don't want to give Roger et al any easy decisions as this whole process is bullshit - we should not have to compensate for other incompetence. Therefore, the bulk of the decisions the FMT should be forced to make should be difficult.

Richard.

<< File: Budget Challenge III.xls (Compressed) >>

-----Original Message-----
From: NSU, CIC TL
Sent: Tuesday, September 09, 2003 4:46 PM
To: Woollam, Richard C
Cc: Felix, Rick D (Anchorage)
Subject: RE: ACTION: 2003 August LE's and Field OVERVIEW

Richard,

Please see the attached draft of options within CIC control. Also, we feel the high cost well lists could be useful for Operations to help reduce our costs.

Please let me know your comments. I will forward to Roger tomorrow when necessary with a note that you have not reviewed this if I do not hear back from you due to travel.

Thanks,

Gary

<< File: Budget Challenge II.xls (Compressed) >>

-----Original Message-----
From: Woollam, Richard C
Sent: Monday, September 08, 2003 5:11 PM
To: NSU, CIC TL; Felix, Rick D (Anchorage)
Cc: GPB, Ops Support Mgr; Foust, Nancy C
Subject: RE: ACTION: 2003 August LE's and Field OVERVIEW

John/Rick,

Please see below a request from Roger.

As with previous years, our variable costs are in basically in two areas,

- Inspection scope - reduce scope and increase risks
- Inhibition levels - reduce inhibition levels and increase risks

When outlining the risks, it will be important to make sure that we note the all the potential risks not just the increased corrosion and leak risks, including,

- Commitments to ADEC
- Reputational issues
- Workforce perception if reducing inspection/inhibition levels

- Regulatory requirements - any risks here

Need to also identify any added workscope issues we face including Y-36 and whether to not these will be impacted.

I'll try and check my e-mail tomorrow morning your time, if the phone connections from Siberia permit, if you have any additional comments or questions.

Thanks.

Richard.

-----Original Message-----
From: GPB, Ops Support Mgr
Sent: Monday, September 08, 2003 7:01 AM
To: Woollam, Richard C; GPB, Business Lead
Cc: NSU, CIC TL
Subject: RE: ACTION: 2003 August LE's and Field OVERVIEW

Richard, you and your team need to work up a plan to safely reduce your spend. All teams are being asked to participate in this effort, including CIC. I want to see what it will take in terms of actions and risks and mitigations to those risks to reduce your LE by 1 million bucks by Wednesday morning. Then we will decide if the LE remains unchanged.

John, I know Richard wont see this note till tonite due to his trip, so you need to take the lead to make this happen.

Thanks,
Roger

-----Original Message-----
From: Woollam, Richard C
Sent: Monday, September 08, 2003 1:59 AM
To: GPB, Business Lead
Cc: GPB, Ops Support Mgr; NSU, CIC TL
Subject: RE: ACTION: 2003 August LE's and Field OVERVIEW

Steve,

The LE remained and remains unchanged, as we agreed earlier - Nancy/Steve and I, due to the fact we have a significant outstanding invoices and the NDE costs associated with the Y-36 spill.

Richard.

-----Original Message-----
From: GPB, Business Lead
Sent: Sunday, September 07, 2003 6:13 PM
To: NSU, CIC TL
Cc: Woollam, Richard C; GPB, Ops Support Mgr
Subject: RE: ACTION: 2003 August LE's and Field OVERVIEW

Richard/John,
I agree with what is stated. However it doesn't change the fact that we have an $11M overview that has to be addressed or we will bust the budget and risk eating the over run 100% BP dollars. We are in the process of shutting down major repair work to contribute some $2m to $4m.

Steven E. St. John
GPB, Business Lead
Phone (907) 659-8054
GPBBusinessLead@bp.com

-----Original Message-----
From: NSU, CIC TL
Sent: Sunday, September 07, 2003 6:05 PM
To: GPB, Business Lead
Cc: Woollam, Richard C
Subject: RE: ACTION: 2003 August LE's and Field OVERVIEW

Steve,

At last month's LE review, Richard was hesitant to change our LE because of the following:

- In inspection, Canspec invoices have been lagging on submittal
- In pigging, the smart pigging vendor has yet to be paid for work just completed in August. This will drive the burn rate up near normal in this area

I have copied this memo to Richard directly so he can further comment. I would be hesitant to change our LE significantly until we understand what the costs of the above are going to be.

Thanks,
John

-----Original Message-----
From: GPB, Business Lead
Sent: Sunday, September 07, 2003 5:31 PM
To: G GPB Operations OTLs
Subject: FW: ACTION: 2003 August LE's and Field OVERVIEW
Importance: High

All,
This is the note I spoke to in the Ops / Ops Support TL meeting and that Ruth asked me to forward to you (Gary H. this doesn't reflect the additional $200k from GC-1 O&M).
Thanks,
Steven E. St. John
GPB, Business Lead
Phone (907) 659-8054
GPBBusinessLead@bp.com

-----Original Message-----
From: GPB, Business Lead
Sent: Saturday, September 06, 2003 8:06 PM
To: GPB, Ops Mgr; GPB, Ops Support Mgr; GPB, Field Services TL; Hawley, Robert S; Higgs, Joseph A; Seccombe, Jim C; Merrill, Mark J; Gunkel, Fritz; Stanley, Mark J (ANC); Wiggs, Craig L; GPB, Safety TL; Seymour, Len I
Cc: Farnham, C Drais; Boland, Dan (Accenture)
Subject: ACTION: 2003 August LE's and Field OVERVIEW
Importance: High

All,
Enclosed is the roll up of the August 2003 Field LE's as submitted.
<< File: 2003 Monthly LE INPUTS.xls (Compressed) >>
If I publish as is we will be flagging an $8.7M overview to upper management and the WIO's. I do not believe the remaining overview is that large and would propose the enclosed additional LE adjustments (see tab # 1). Tab # 2 shows the Aug YTD Actuals vs submitted LE's.
<< File: Aug_2003 LE's.xls >>
We Need to land this early this week or we will delay the publishing of the WIO / Management reporting.

If You have any questions please give me a call.

Thanks,
Steven E. St. John
GPB, Business Lead

Phone (907) 659-8054
GPBBusinessLead@bp.com

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Opportunity to Make Stretch Budget

- *Reduce WOA Weight Loss Coupon Program*
  - Reduce WOA weight loss coupon program by 25%
  - Relax the WOA weight loss coupon pull frequency from every three months to every four months
  - Estimated cost saving: 1.1 man yr ($250,000)

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Grater Prudhoe Bay / 2004 Field Lifting Cost Challenge (LCC) Maintenance and Reliabili

Opportunity	Sustaining (Yes / No)	2004 Savings / Efficiencies / Deferrals $M	Future Annual Savings / Efficiencies / Deferrals $M
CIC: Cancel 2004 Smart Pigging Program	No	$250	$0
CIC: Cancel partial PW inhibition at GC's	No	$670	$0
CIC: 25% Reduction in AES Chemical Operators	YES	$150	$200
CIC: 17% Inhibition Program Reduction"	No	$1,560	$0
CIC: 17% Inspection Program Reduction"	No	$1,370	$0
Managed Service: VECO Reduce ESI program by 50%. Eliminate UOSS inspectors and replace with VECO Inspector/repair. Make easy repairs part of inspection eliminating steps. Same folks that do inspection do repairs.	YES	$150	$300
Managed Services: VECO Project Manager budget reduced 10%	YES	$300	$400
Managed Services: ASCI Reduce ASCI by 10%	No	$300	$0
Managed Service: Utilities Reduce contract services.	No	$100	$0
Managed Service: Utilities Revisit charging lighting upgrade to a capital AFE. Lighting upgrade eliminated the need for scaffold or the construction of platforms.	No	$70	$0
Managed Service: Utilities Eliminate contract vacation relief position.	No	$50	$0
CPS: Defer all CPS turbine field device PM's to be performed only when unit comes down for HGP or Full Major Overhaul.	YES	$28	$28
CPS: Cut one permanent BP position.	No	$200	$0
CPS: Cut all Sunday BBQ's, CPS Fun Run and CPS Safety Fair booth for Safety Fairs	YES	$25	$25
CPS: Cut all discretionary spend on materials that are absolutely not required to produce electricity or maintain Safety, SCADA, COE and equipment for power production.	YES	$20	$20
CPS: Cut 10% Veco/AIM contract services to CPS	No	$80	$0
F&G: Discontinue Sunday Team Meetings	No	$100	$50
F&G: Vendor Technical Training	No	$25	$0
F&G: Transfer as built responsibility for project closeouts to document control	Yes	$50	$100
F&G: Transfer WOA/EOA Halon Shop refurbishment expenses to AFE 4N0705	No	$100	$0
AE&I: Eliminate Flow Measurements Contractor	No	$75	$0
AE&I: Reduce 619 Misc Personnel Expense	No	$30	$0
AE&I: Reduce 133 Parts and Materials	NO	$20	$0

TEMP00067590.0001

ty

First Pass RBG

Opportunity Implications (LTO, HSE, Production, People, Deferral, Can Do)
* LTO/HSE Defer smart pig on three 24" lines on the WOA. * Reputation
* LTO/HSE Will cause rate of pipe wall loss to increase. * Reputation
* Inefficient use of corrosion inhibitor. Eliminates one position but can be managed. * Reputation and workforce concerns
* LTO/HSE Maybe able to attain part of savings without significant risk. Requires detailed review. * Reputation
* LTO/HSE Maybe able to attain part of savings without significant risk. Requires detailed review. * Reputation
Still demonstrates a presence but time doubled to complete project. Will generate employee concerns. Performing risk assessment prior to implementation may reduce employee concerns. EA may offset some issues. Major Repair.
Since Project Manager Budget is tied to head count VECO would have to do an additional 10% lay off for a total of 20%. HSE Production LTO
Any reductions in ASCI will directly impact service and would most likely increase costs in other areas. Would negatively impact resolution of Exxon audit findings. Production and People.
Will cause work to be deferred into 2005.
Work is complete. Only involves transferring charges. Originally intended for capital AFE but ended up below the line.
LTO and People. Eliminates our ability to develop renewal (Certifications) and runs a high risk of being out of compliance. Reduction of BP personnel either cause immediate compliance issue or only displace folks to other jobs with no cost savings. Reducing contractors is the only alternative.
WE have a full real time SCADA system that tells us with alarms if we have a problem with our turbines/generators. This is definitely a 'CAN DO". BP policy change required.
Safety, Production, People and power reliability. CPS is already minimally staffed for all the duties it performs. Also CPS is at a time when we should be putting on a couple of trainee positions in both Operators and T&D ranks. CPS already has approximately one third of its total staffing getting three vacations a year.
People, Safety, Morale, will be viewed as take aways and could effect morale and productivity. BBQ's are used as a means of enhancing working relationships betweem non-bargaining, bargaining and contract employees. The CPS fun run and Safety Fair booth are Health, Safety and morale builders for CPS/T&D personnal. These would be viewed very negatively as take aways.
Can do, may not be as convenient or exactly what employees want, but is a can do,
Production, Safety and People Impacts, not sustainable for safety of all production facilities or power reliability.
Long-term impact on HSE performance and PM Effectiveness (e.g. knowledge sharing and skills improvement). Reduction maybe possible as a result of increased efficiency. *Do not recommend as a sustained opportunity, as impacts have proven to eventually out way savings.*
Long-term impact toward maintaining F&G Engineer and Technician skills and knowledge base. *Do not recommend as sustained opportunity.*
Eliminate 1/2 position by finishing shop drawing updates. Work will be complete on 6/1/04.
Ops CAPEX budget impact of $100k, in progress, AFE already approved.
LTO - Possibility exists that environmental or custody meter proving could backlog could force a non-compliance situation.
Deferral - This bucket carries software license renewals, test equipment replace and upgrades. Risk is that maintenance and support for some test equipment may not be available.
Deferral - This bucket carries parts and materials and operations costs primarily for generator set maintenance and testing for fixed generator sets. This defers some discretionary costs for non-generator items

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From: Woollam, Richard C
Sent: Friday, April 16, 2004 8:27 AM
To: NSU, CIC TL
Subject: RE: Cost Challenge feedback

John,

If, by the end of your shift, you could take a look at North Slope activities and identify any opportunities for cost reduction in 2004 that would be helpful.

Thanks.

Richard.

-----Original Message-----
From: NSU, CIC TL
Sent: Friday, April 16, 2004 6:00 AM
To: Woollam, Richard C
Subject: RE: Cost Challenge feedback

OK, the feedback was requested by Nancy at her last Monday's meeting, Gary had passed on the info at handover.

-----Original Message-----
From: Woollam, Richard C
Sent: Thursday, April 15, 2004 6:18 PM
To: NSU, CIC TL; Sprague, Kip P; Felix, Rick D (Anchorage)
Subject: RE: Cost Challenge feedback

All,

We need to coordinate our response back to Nancy thru me. Our budget position is not as it appears in the Field Cost Management (FCM) reports due to some issues with accruals - for example we will have a reversal of nearly $1 million from correcting AES accurals alone!

Therefore, what we really need to look for is some options for removing costs from 2004 which have little or no material impact on the 2004 program - items 1 and 2 below are material in my opinion - so what activities do we not need to do in 2004!?!

Thanks.

Richard.

-----Original Message-----
From: NSU, CIC TL
Sent: Thursday, April 15, 2004 5:59 PM
To: Sprague, Kip P
Cc: Woollam, Richard C
Subject: Cost Challenge feedback

Confidential

Kip,

Gary was at a budget session the other day, and we require some feedback on consequences of a couple of options for Nancy by Monday. (Richard may have already briefed you).

- One option is to cancel the 2004 smart pigging program - what are the consequences of not doing it this year (the 3 LDF's)?
- Another option is to cancel partial PW inhibition at GC's - any opinions?
- There are also some reductions of inhibition and inspection programs proposed, although RCW doubts those will be necessary.

Thanks,
John

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Jeanne Pascal, Esq.
Northwest District Debarment Counsel
U.S. Environmental Protection Agency
Seattle, Washington

May 8, 2004

Re: Conversation with Joel Degner, Wasilla, Alaska

Dear Ms. Pascal,

This letter is being sent at your request relating to my telephone conversation with Joel Degner in April, 2004.

As you are aware, Mr. Degner was previously employed by British Petroleum as a corrosion control supervisor for their production operations on the North Slope of Alaska. He has also had considerable additional experience and credentials as a corrosion control expert. I am somewhat familiar with the Prudhoe Bay operations from my previous experience in Alaska, both in the oil industry and in government. Therefore, I felt I was in a position to understand the concerns expressed by Mr. Degner

First, Mr. Degner impressed me with the scope of his knowledge as it relates to the corrosion control applications necessary for the production operations at Prudhoe Bay and to what was actually being implemented (or neglected) by the local management of British Petroleum. During our hour and a half conversation, I found him to be sincere and very concerned for the welfare of the workers at Prudhoe Bay as well as for the negative effect any major incident would have on the future of the ANWR development. In over fifty years of experience in the oil industry, I found him to be one of the most knowledgeable corrosion experts to whom I have talked. He definitely is not someone with an "ax to grind" In fact, he made it very clear, he is currently very successful with his corrosion control business and has no further interest in working for B.P.

Mr. Degner advised me that proper corrosion control, detection, monitoring, and repair procedures were often being ignored in favor of "cost saving". He also said necessary (in his opinion) repairs were being delayed beyond the projected critical time for piping and associated equipment to the extent it has now become a hazard to the safety of workers and that procedures were being used to hide these problems from higher management. I am sure you are aware that corrosion detection and control is one of the major problems facing all oil and gas production operations. Pitting of the flow lines and associated piping causes thinning of the walls reducing the allowable internal operating pressure, otherwise the resulting burst pipe and sudden release of hydrocarbons to the surrounding atmosphere, indoor or outdoor, can cause serious harm to personnel and the environment. This can range from a minor oil spill problem in low-pressure "stripper" wells, to a very serious problem at Prudhoe Bay where much higher pressures exist.

It is Mr. Degner's opinion, and I concur, the upper management of British Petroleum consists of men and women of integrity who would never deliberately endanger employees to enhance the "bottom line". This type of unconscionable managerial behavior would never be sanctioned by the upper management in London. Therefore, it must be assumed they are unaware of the problems being created resulting from the decisions being made by some lower-level managers in Alaska.

I hope this serves to clarify, at least in part, the issue of B.P. corrosion control on the North Slope of Alaska.

Yours Truly,

Charles A. Champion
Registered Petroleum Engineer
State of Alaska 1738EP
State of California P1098

TOWER PETROLEUM CORPORATION

10101 Slater Avenue, Suite 120
Fountain valley, CA 92708
Phone (714) 593-8723 • Fax (714) 593-8724

Jeanne Pascal, Esq.
Northwest District Deterrent Counsel
U.S. Environmental Protection Agency
Seattle, Washington

May 8, 2004

Re: Conversation with [redacted], Alaska

Dear Ms. Pascal,

This letter is being sent at your request relating to my telephone conversation with [redacted] in April, 2004.

As you are aware, Mr. [redacted] was previously employed by British Petroleum as a corrosion control supervisor for their production operations on the North Slope of Alaska. He has also had considerable additional experience and credentials as a corrosion control expert. I am somewhat familiar with the Prudhoe Bay operations from my previous experience in Alaska, both in the oil industry and in government. Therefore, I felt I was in a position to understand the concerns expressed by Mr. [redacted].

First, Mr. [redacted] impressed me with the scope of his knowledge as it relates to the corrosion control applications necessary for the production operations at Prudhoe Bay and to what was actually being implemented (or neglected) by the local management of British Petroleum. During our hour and a half conversation, I found him to be sincere and very concerned for the welfare of the workers at Prudhoe Bay as well as for the negative effect any major incident would have on the future of the ANWR development. In over fifty years of experience in the oil industry, I found him to be one of the most knowledgeable corrosion experts to whom I have talked. He definitely is not someone with an "ax to grind" In fact, he made it very clear, he is currently very successful with his corrosion control business and has no further interest in working for B.P.

Mr. [redacted] advised me that proper corrosion control, detection, monitoring, and repair procedures were often being ignored in favor of "cost saving". He also said necessary (in his opinion) repairs were being delayed beyond the projected critical time for piping and associated equipment to the extent it has now become a hazard to the safety of workers and that procedures were being used to hide these problems from higher management. I am sure you are aware that corrosion detection and control is one of the major problems facing all oil and gas production operations. Piping of the flow lines and associated piping causes thinning of the walls reducing the allowable internal operating pressure, otherwise the resulting burst pipe and sudden release of hydrocarbons to the surrounding atmosphere, indoor or outdoor, can cause serious harm to personnel and the environment. This can range from a minor oil spill problem in low-pressure "stripper" wells, to a very serious problem at Prudhoe Bay where much higher pressures exist.

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It is Mr. [redacted] opinion, and I concur, the upper management of British Petroleum consists of men and women of integrity who would never deliberately endanger employees to enhance the "bottom line". This type of unconscionable managerial behavior would never be sanctioned by the upper management in London. Therefore, it must be assumed they are unaware of the problems being created resulting from the decisions being made by some lower-level managers in Alaska.

I hope this serves to clarify, at least in part, the issue of B.P. corrosion control on the North Slope of Alaska.

Yours Truly,

Charles A. Champion
Registered Petroleum Engineer
State of Alaska 17358EP
State of California P1098

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To: Sprague, Kip P
Subject: RE: Emailing: CIC MR-Capex AFE Tracker 2006 .xls

Kip,

What I would like to get out from under is relying on the Detection Coordinator to determine what work gets done and when to call it complete - too many times burned by them not being organized enough to accomplish this.

From: Sprague, Kip P
Sent: Sunday, April 10, 2005 5:03 PM
To: NSU, CIC TL
Subject: RE: Emailing: CIC MR-Capex AFE Tracker 2006 .xls

Gary,

What I think, wouldn't actually be helpful and what is being asked isn't practical.

Reliable funding and resources is a yo-yo, accurate scheduling activities is a joke and predicting line lifts or impacts is even further out of the real of reality. We are sitting on a backlog of over 1000 locations with CUI and there are a dozen road crossings that need to be dug up and we have a huge infrastructure that is hanging-on with no margin for error. Without margin, we are not in a position for long-term detail planning, it is difficult enough just reacting to keep product inside the pipe. What we have is a log-term strategic plan and that should not be confused with a detailed execution plan.

Analogy: Plan-do-check act: You been asked to provide the 'plan' (which is fine, but that is short-term not long-term). You have also been asked to provide the 'act' before we have done, 'do - check', which of course determine that 'act' and as a result changes the 'plan'. Ridiculous to think we can predict all this (that is the fallacy).

Same story, can't do effective planning overnight after 20 years of minimalist resources and maintenance (which doesn't seem to be keeping pace with the curr lofty ideas).

Bitch, bitch, bitch... I will try to wrestle down some middle ground between the reality of the situation and some feel good placeholders just to get people off your back. However, I will not run/sacrifice an inspection strategy and program with limited resources based on the conveyance of maintenance and/or operation impact. That, in my opinion, is negligent.

Wednesday, is the goal. Thanks for the reminder.

Kip

-----Original Message-----
From: NSU, CIC TL
Sent: Sunday, April 10, 2005 3:29 PM
To: Sprague, Kip P
Cc: Keck, Danny L; GPB, Planner 6 East
Subject: FW: Emailing: CIC MR-Capex AFE Tracker 2006 .xls

Kip,

A few items for discussion/comments.

CUI Detection Schedule

From a field execution perspective I believe we need to establish an external corrosion inspection schedule - something to show what category of equipment will be looked at when. My initial thought is the CUI detection work should be treated like the CIP's for the purpose of execution in the field (take a logical block of work, based upon system risk and geography which is similar to current methodology, but complete it as close to 100% as possible within access constraints then move to the next block). The blocks of work should be chosen by taking saddle lifts and repairs into consideration along with execution efficiency (currently, we can lift water injection and production lines on stream while gas/MI lines need to be depressured)

Line lifts

In addition to generating a 2006 line lift list based upon what we know now, we should probably ensure a list is complete for lift work this year - I have not seen anything like this yet.

Cased piping

In addition to getting the cased piping scope together for 2006 (at least what we suspect), we need to get the 2005 scope nailed down so we can begin the planning process.

I believe if we head toward the direction of having as much of our work scope as possible defined for 2006 soon (drop dead is around June 1st to match budget cycle goal), we can at least get the place holders in the planning and maintenance systems to ensure folks do not feel like we are 'surprising' them.

Please let me know what you think.

Thanks,

Gary

Danny - how is the list coming along?

-----Original Message-----
From: NSU, CIC TL
Sent: Sunday, April 03, 2005 1:17 PM
To: Keck, Danny L
Cc: Sprague, Kip P; GPB, Planner 6 East; Kuzma, John H; ACT, CIC Ops Integrity Support Specialist; NSU, CIC Fld Integ Ops; NSU, CIC Mech Integrity Insp; NSU, CIC OU Insp
Subject: Emailing: CIC MR-Capex AFE Tracker 2006 .xls

Danny,

I would like to get an initial draft list for our potential 2006 MR and Capex projects put together by mid week (Wednesday). I sent a note out several weeks ago to folks to solicit ideas and have received some feedback which is captured in the spreadsheet.

In addition to typical MR and Capex project work, we need to capture any O&M work that could impact operations next year (potential for production impacts) It appears that all known vessel/tank/PMP work scope has already been captured and relayed to Operations and the TAR TL.

Some potential areas for projects...

1) Cased piping digs
2) Any external corrosion special projects (lifts that could impact production or require special attention such as DOT regulated piping)
3) Smart pigging

John/Ray/Lumber - I would like to start adding ACT projects to the list also, please forward any potential projects you would like considered next year (EB tank at MPU, etc.)

Thanks,

Gary

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From: NSU, CIC TL
Sent: Saturday, October 22, 2005 6:43 AM
To: Leach, Brett W
Cc: Sprague, Kip P; Hedges, Bill
Subject: Emailing: Control Options 10 22 05.xls

Attachments: Control Options 10 22 05.ZIP

Control Options 10 22 05.ZIP (...

rett,

Attached, please find a list of potential budget control options - broken out by chemicals and manpower. If you are interested in exploring more detail about any of the options please let me know.

Bill/Kip - if you have any edits or additions, lets discuss so I can update the list...

Thanks,

Gary

Option	Rank	Category	Monthly Savings	2 Month Savings
3 Phase CI: Eliminate Xylene		Chemical	$ 75,000	$ 150,000
3 Phase CI: Shut in top 5 CI users		Chemical	$ 75,000	$ 150,000
3 Phase CI: Potential Optimization (5%)		Chemical	$ 40,500	$ 81,000
PW CI: Slow deployment/reduce injection rates		Chemical	$ 400,000	$ 800,000
STP: Reduce Biocide frequency to every two weeks		Chemical	$ 36,000	$ 72,000
Production Chemicals		Chemical	$ -	$ -
Corrosion Monitoring		Manpower	$ -	$ -
Chemical Deployment (C Pad and Chem. Ops.)		Manpower	$ -	$ -
Pigging: Contract support crew		Manpower	$ 16,700	$ 33,400
Pump Crew: Eliminate TD jobs		Manpower	$ -	$ -
Inspection: Comprehensive Inspection Program		Manpower	$ 66,667	$ 133,333
Inspection: Corrosion Rate Monitoring		Manpower	$ 66,667	$ 133,333
Inspection: Erosion Rate Monitoring		Manpower	$ 16,667	$ 33,333
Inspection: Corrosion Under Insulation Detection		Manpower	$ 66,667	$ 133,333
Inspection: Frequent Inspections		Manpower	$ 16,667	$ 33,333
Inspection: Special Request/ADHOC		Manpower	$ 16,667	$ 33,333
Rope Access Technology		Manpower	$ 16,667	$ 33,333
Veco		Manpower/Materials	$ 195,000	$ 390,000

Purpose	Risk
Potential for plugging continuous injection system	High
Production exceeds cost by >10x	Low
Plan not fully developed and locations not identified, 2-4 weeks to implement	Low
Lot of effort spent on getting the system up and running this year based on owner approvals. Technically, probably the least short-term risk of the options presented	Medium
MIC locations established resulting in long term effects	High
Without these chemicals, facilites would shutdown.	High
Regulatory commitments and significant attention over the last few years. There was an effort to unify the coupon schedule, but that is on hold.	High
Reduction in chemical volumes in 1 and 2 contain a labor component	High
Eliminate support crew - 2 personnel. Program has only been meeting ~75% of target YTD.	Medium
Program has been focused on freeze protects, with only 5 TDs performed in the past 3 months.	Low
Eliminate program to YE - 4 positions. 9750 items	Medium/High
Eliminate program to YE - 4 positions. 1840 items	Low
Eliminate program to YE - 1 positon. 768 items	High
Eliminate program to YE - 4 positions. 6000 items	High
Eliminate program to YE - 1 positon. 384 items	High
Eliminate program to YE - 1 position. 536 items	Medium
Eliminate RAT to YE - 1 position	Medium
Eliminate CUI Mitigation program to YE - 9 positions	Medium

Risk Mitigation	Reputation/Perception Risks
Batch treatment program	ADEC/Workforce - only if problem occurs
None	Governor/ADEC/Partners/Workforce
Follow technical review protocol. Increase rates if data suggests necessary.	Workforce
Increase rates January 1 2006. Corrosion mechanism is relatively slow. Initial cleaning to remove deposits may reduce corrosion rates substantially.	ADEC/Partners/Workforce
Increase rates January 1, 2006.	ADEC/Partners/Workforce
Shutdown facilities	Governor/ADEC/Partners/Workforce
Inspection	ADEC/Workforce
Third pary contractors	ADEC/Partners/Workforce
BP Operators still pig with help of BP Ops and ad-hoc contractor help	Workforce
Restart program January 1, 2006	Workforce
Reschedule FS1, LPC, STP, SIP and remaining FL/WL programs	ADEC/Workforce
Rely on monitoring only	ADEC
Reduce maximum allowable mixture velocities/ Minimize or cancel well-work and well strat-ups)	Workforce
Shut-in Y LDF	ADEC
Repair or shut-in equipment (PMP - High wastage areas i.e. G&I)	ADEC/Workforce
No response or action as a result of observations/discoveries	Workforce
Built scaffold for percieved or at risk locations	Workforce
No response or action as a result of observations/discoveries	ADEC/Partners/Workforce

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From: Dengler, John M
Sent: Thursday, March 09, 2006 4:45 AM
To: Neill, David H (Baku)
Subject: RE: GC-2 Oil Transit Line Spill

Attachments: image001.jpg

image001.jpg (2 KB)

The Daily News - now there is a source to believe.
It isn't pretty,
Refresh my memory - wasn't the line from FS 2 to FS 1 so packed with solids just downstream of Module 4922 that an ultrasonic meter wouldn't work? Think there is any corrosion in that section of line?
John

From: Neill, David H (Baku)
Sent: Wednesday, March 08, 2006 8:04 PM
To: Dengler, John M
Subject: RE: GC-2 Oil Transit Line Spill

John,

Thanks for the update. I have been following the Daily News stories also. Too bad about the leak detection system not picking this up. I'm sure there will be renewed pressure from DEC regarding leak detection. FYI. I am installing the EFA leak detection system on our Western Route pipeline to the Black Sea. Stay Warm!

Dave

From: Dengler, John M
Sent: Wednesday, March 08, 2006 1:39 AM
To: terrymorgan_wyo@yahoo.com; James Ferguson; James. steward (James.steward@nana-colt.com); Schwab, Lorinda A; Connick, Eugene (Baku); Neill, David H (Baku); Athans, Murray P; Huff, Richard E.; Collins, Matt G (ConocoPhillips)
Subject: FYI: GC-2 Oil Transit Line Spill

I'm headed to the slope tomorrow to get more involved. I don't like the second sentence of the first bullet. I REALLY don't like the second sentence of the fifth bullet.

John

From: Johnson, Maureen L
Sent: Tuesday, March 07, 2006 12:21 PM
To: G AK All Users; G ANC ALT; G ANC Extended Leadership Team; G ANC External AFFRS Group; Pillari, Ross J;

Taggart, Sally B; Chappell, Ronnie W; Markin, Thomas A; Miller, Brian W; Hudson, Peggy R; Caballero, Jaime E.; Chapman, Nell A; Depland, Hugh; Tiernan, Elizabeth P; Foust, Nancy C; Nicolson, Don; Brock, Tony; 'sonny.rix@exxonmobil.com'; Hanus, Michael (Exxon); Jones, Darren C. (ConocoPhillips); Kruse, Dan P. (ConocoPhillips); Stramp, Ryan L (ConocoPhillips); Richard J. Owen; Tison, Joel K
Subject: Update #8: GC-2 Oil Transit Line Spill

BPXA GC-2 Oil Transit Line Spill

[redacted]

03/07/06 1100

Spill Response

- Leak was discovered 16'8" from east culvert. Visual indications are that the leak was caused by internal corrosion.
- Preparation is underway for line lift procedure. In addition to removing all non-essential personnel, job review meeting will be held to insure this procedure is safely performed. Additional safety personnel are being sent to the North Slope to augment the current coverage.
- As of 0630, 3/7/06, 1335 bbls. of liquids have been recovered; recovery efforts have been temporally shut-down due to line lift.
- Volume estimation survey will continue during daytime.
- Temperature is -20 Fahrenheit and getting colder. Thursday's weather prediction is -35.
- Contingency plan for blowing snow conditions is under development and snow fence is under construction

Business Resumption

- **Pipeline Integrity**: UT inspection around leak site is planned for today.
- **Repair options**: sleeving plans at the known areas of integrity concern are being developed and material ordered. A temporary repair is currently in place for source control at the leak site.
- **Return to service**: options to return GC2 to service are being studied. Engineering, Operations, and CIC will be reviewing details for the selected option.
- **Priorities**: Unchanged - Focus is on pipeline integrity assessment, repair execution, jumper options, GC-2 start-up and return to normal operation.
- **Source control**: source control achieved this morning by technical staff on team.

Incident Investigation

- The investigation team is up and running. The team consists of the lead, Bryant Chapman - Performance Unit Leader, Operations Excellence of Houston, John Alkire - EPTG Corrosion Expert, BJ Harris - Safety Engineer, Barry Vest – GC2 Operator and union rep, Gary Evans – DEC, Shelia Barnes – Administrative Assistant.

Please Note

- The Joint Information Center (JIC) continues to provide ongoing communication materials to the ADEC website: http://www.dec.state.ak.us/spar//gc2 and continues to provide requested information to various organizations/agencies.
- Next update tentatively planed to be provided at 11:00 a.m. AST on Wednesday, March 8, 2006. Now that temporary source control has been achieved, we expect to reduce the frequency of the updates in the near future. Your feedback is welcome in determining update frequency.

Maureen Johnson
Performance Unit Leader, GPB
(907) 564-5671
johnsml@bp.com

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From: GPB, FS2/COTU Area Mgr
Sent: Thursday, March 23, 2006 2:24 PM
To: Leach, Brett W
Subject: FW: Pigging Facility Walk Down - Need your input on Pigging Concerns

Brett,
I know this is a little later than you requested but here's our input.....yes we can do it but it will require some effort.

In my opinion this is extreme overkill. Pigging is probably not a bad idea but the frequency should be more along the lines of twice a year or once a quarter.....not weekly.

Chris Rhoads
alt: Bob Walker
FS-2/COTU Area Manager
office: (907) 659-5492
pager: (907) 659-5100 #1115
fax: (907) 659-8405
e-mail: rhoadsca@bp.com

From: GPB, FS2 Ops Lead
Sent: Thursday, March 23, 2006 2:09 PM
To: GPB, FS2/COTU Area Mgr
Subject: RE: Pigging Facility Walk Down - Need your input on Pigging Concerns

Chris,
I have a couple concerns; the biggest being that we haven't pigged our sales transit line in over 15 years and I really don't know what to expect... Also, the condition of the launcher, i.e. the launcher door seal o-ring, the sump, sump pump and all of the associated piping are unknown. We can functionally check the drain sump system, but it would probably be prudent to have all of the associated lines inspected prior to returning this system to service as they are at a low point and have been stagnant for years. We need to spec out and order some replacement o-rings for the launcher doors - they haven't been opened for fifteen years. And operating procedures will need to be developed to include FS1 for their part in receiving the pig.

Otherwise, yeah - we can do it...

From: GPB, FS2/COTU Area Mgr
Sent: Thursday, March 23, 2006 12:39 PM
To: GPB, FS2 Ops Lead
Subject: FW: Pigging Facility Walk Down - Need your input on Pigging Concerns

Brad,
Will you take a look at this and give me your ideas/opinions?
Thanks,

Chris Rhoads
alt: Bob Walker
FS-2/COTU Area Manager
office: (907) 659-5492
pager: (907) 659-5100 #1115
fax: (907) 659-8405
e-mail: rhoadsca@bp.com

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(907) 670-3331
alternate: George Ahumada

From: NSU, CIC Prod Chem (Nalco)
Sent: Sunday, June 04, 2006 3:10 PM
To: Pogue, Cleve C; Todd, John B (Nalco); Spano, A J
Cc: Ahumada, George R; Kuzma, John H
Subject: RE: Sales Oil Pipeline Protection

Cleve,

Certainly there has been a lot of discussion lately about what to do with the oil transit lines. I think that virtually everyone agrees that the most important piece of preventive maintenance that can be done is to keep the line clean by pigging it on a regular basis. That will cure almost all your "ills". Currently, GC2 is the only one that is adding a supplemental corrosion inhibitor directly into their transit line for reasons that are probably obvious. We need to get John Kuzma involved in the discussion as I can't answer your question directly. Whether or not to treat the systems will certainly be an issue that will require further discussion, likely at a high level. My personal belief is that pigging is by far the most important single thing that you can do to prevent problems.

Best Regards,

John T.

From: Pogue, Cleve C
Sent: Sunday, June 04, 2006 11:12 AM
To: Todd, John B (Nalco); Spano, A J
Cc: Ahumada, George R; Pogue, Cleve C
Subject: Sales Oil Pipeline Protection

John and Andy,
Dale and myself had a discussion about corrosion concerns in the MPU Sales Oil Pipeline. What has been the common practice across the slope on Sales Oil Lines. I know you guys are reviewing a lot of the current practices. Should we or do we plan to do anything along the lines of chemical injection.

Cleve Pogue
Milne Point Facilities Supervisor
(907) 670-3331
alternate: George Ahumada

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ONE HUNDRED TENTH CONGRESS

U.S. House of Representatives
Committee on Energy and Commerce
Washington, DC 20515–6115

JOHN D. DINGELL, MICHIGAN
CHAIRMAN

May 2, 2007

Mr. Robert A. Malone
Chairman and President
BP America, Inc.
200 Westlake Park Blvd.
Houston, TX 77079

Dear Mr. Malone:

We are in receipt of your April 30 letter (attached) requesting a postponement of the hearing scheduled for May 3, 2007, before the Subcommittee on Oversight and Investigations of the Committee on Energy and Commerce entitled "2006 Prudhoe Bay Shutdown: Will Recent Regulatory Changes and BP Management Reforms Prevent Future Failures?" This hearing had been planned for some time as a follow up to our September 7, 2006, hearing. It was intended to assess the adequacy of efforts BP and various regulators have taken to address the organizational and mechanical failures leading to the March 2, 2006, leak in the "Western Operating Area" transit line and the subsequent discovery of severe corrosion and leaking in the "Eastern Operating Area" transit line.

Your request for a postponement of the hearing is based upon your recent discovery that "information relevant to the September, 2006 hearing was not provided to the Subcommittee." In addition, this information was apparently neither disclosed to you nor Steve Marshall, the former President of BP Alaska, before your testimony at our September hearings. The discovery of this material has clearly raised questions about the adequacy of your response to the Committee, as well as previous spending decisions made by your company—concerns that you clearly acknowledge in your April 30 letter and that form the basis for your request for additional time to investigate both issues in more detail.

Despite numerous requests for such material, going back nearly a year, it was only on April 17, 2007, that BP provided the Committee with a number of BP documents which reveal important internal discussions suggesting a severe cost-cutting atmosphere existed in your crude oil production operations at Prudhoe Bay. On their face, this new material raises concerns that shortsighted cost-cutting may have led to the spills and corrosion problems in Alaska. Some of

the documents discuss stopping the injection of corrosion inhibitor to meet budget targets. Others suggest that other activities related to corrosion mitigation had to be reduced or put on hold due to budget constraints.

Equally troubling, these documents raise questions about the accuracy of Mr. Marshall's testimony when he suggested that "cost is not a consideration" as it relates to issues of both safety and integrity in Prudhoe Bay operations.

It is our understanding that significant redesign and rebuilding has already occurred on some of the key transit lines that failed last year. It is also our understanding that BP has made a number of management and personnel changes in Alaska, and that these efforts appear to be taking the company in a positive direction. We applaud your company for those undertakings. Nevertheless, to assess whether BP's new path forward will be successful, the Committee needs to explore whether the climate of top down cost-cutting affected the health, safety, or the environment of the Prudhoe Bay field and its workers. In order to make such a determination, we need you to respond to the questions raised by the newly discovered documents, as well as all previous requests for information made by this Committee.

As you know, in response to our receipt of the newly discovered documents, we forwarded to you another document request on April 30, 2007, which included: (1) documents that discuss whether BP managers ordered that corrosion inhibitor be turned off due to budgetary constraints; (2) answers to the question of if, when, and where corrosion inhibitor may have been turned off, and what consequences this may have had on program integrity; (3) records related to requests for smart pigging and maintenance pigging from officials in the Prudhoe Bay's Corrosion, Inspection, and Chemicals (CIC) Group from 2000-2005; and (4) e-mails sent or received by the CIC group related to reducing, suspending, or cutting back on corrosion inhibitor.

We are pleased that BP has promised to respond quickly to this request and accept BP's explanation that it needs "additional time to complete investigations and document searches, and to ensure the Subcommittee has all of the information it needs to complete its work."

Based upon your assurances that you need additional time to comply with our document requests and to be prepared to respond to the issues raised by the newly discovered internal BP documents, we have acquiesced to your request for a continuance and have rescheduled the hearing for 9:30 a.m. on Wednesday, May 16, 2007. At that hearing, we expect you and other BP officials to be prepared to address the following issues:

- BP's plan to rebuild and sustain the integrity of the oil pipeline system, including the Eastern Operating Area and Western Operating Area transit lines that failed and caused last year's shutdown. How is this effort progressing and what are the expected milestones for completion?

- Whether BP believes the environment of cost-cutting as apparently reflected in some of these documents affected the ability of workers to safely operate the Prudhoe Bay field and, in particular, ensure adequate corrosion control. To the extent BP believes these documents do suggest a climate where workers had to make difficult decisions between budget savings and program integrity, what steps does the company intend to take to prevent the reoccurrence of such an atmosphere?

- What role did top down cost-cutting play in both Texas City and Alaska? What changes is BP institutionalizing that would reflect the lessons learned from both Texas City and Alaska, as identified in the Baker Panel report, the Booz Allen Hamilton report, and the Chemical Safety Board Investigation report?

- How will BP ensure that there is no tolerance for retaliation against workers who may attempt to raise safety and health concerns? In addition, as new concerns arise, how will BP put in place a transparent mechanism to ensure they are resolved in a timely manner?

If you have any questions regarding this matter, please contact us or have your staff contact Christopher Knauer or Richard Miller with the Committee staff at (202) 226-2424.

Sincerely,

John D. Dingell
Chairman

Bart Stupak
Chairman
Subcommittee on Oversight and Investigations

Attachment

cc: The Honorable Joe Barton, Ranking Member
Committee on Energy and Commerce

The Honorable Ed Whitfield, Ranking Member
Subcommittee on Oversight and Investigations
Committee on Energy and Commerce

bp

Robert A. Malone
Chairman & President

BP America Inc.
4101 Winfield Road
314 O
Warrenville, IL 60555
USA

April 30, 2007

The Honorable Bart Stupak
Chairman
Oversight and Investigations
Committee on Energy and Commerce
2352 Rayburn House Office Building
Washington, DC 20515

The Honorable Ed Whitfield
U.S. House of Representatives
2411 Rayburn House Office Building
Washington, DC 20515

Direct 630 821 2588
Fax 630 821 2590
Mobile 325 226 4111
MaloneRA@bp.com

Dear Chairman Stupak and Representative Whitfield:

A hearing currently is scheduled before the Subcommittee on May 3, 2007, as a follow on to the September 7, 2006 hearing regarding the Prudhoe Bay issues resulting from the two Oil Transit Lines (OTLs) on the North Slope of Alaska. For the reasons explained below, BP respectfully requests that the hearing be rescheduled.

First, it has recently come to my attention that information relevant to the September, 2006 hearing was not provided to the Subcommittee – or to the President of BP Alaska or me. By way of background, as you know, I commissioned an investigation into the reasons that the OTL leak detection Compliance Order by Consent (COBC) was not disclosed to the Subcommittee prior to the first hearing. While that investigation is not yet complete, I have received, reviewed and provided to the Subcommittee staff the Interim COBC Report.[1] The Interim COBC Report identified a breakdown in our response and preparation process that resulted in relevant documents not being provided. Some of these documents are the same documents that the Subcommittee staff has identified as raising questions on the impact of the budget process on operational decision-making during 2000 - 2005.

Second, some of the documents recently produced to the Subcommittee staff raise concerns about previous spending decisions that cause me concern. We need time to determine how the concerns and frustrations expressed by workers were ultimately resolved. For example, as set out in some of the documents, it appears that there were serious discussions about discontinuing injection of corrosion inhibitor into some of the Produced Water lines in 2001- 2004. I do not know whether this happened at all; or, if it did, for how long, or what was the impact on the lines. I want to have, and I want the Subcommittee to have, a complete understanding of what happened in this case and why.

[1] I am advised that the final investigation cannot be completed until all the relevant documents are reviewed and any necessary follow up interviews are completed.

Additionally, I was troubled to see in some of the documents the extent of the frustration being expressed by the workforce throughout the 2000-2005 time frames. I want to eliminate the frustration voiced in many of the documents by creating a culture in which workers are confident their concerns will be heard and addressed before they would ever reach the level of frustration expressed in these historical documents. This process takes time, but I believe that we are making changes in the way we manage our business, and in building a positive safety culture.

I recognize that the Subcommittee wants to ensure that BP fully understands what led to the situation in Alaska and that it incorporates the lessons learned into its processes going forward. I want to do that as well. In order to do that, I would request additional time to complete investigations and document searches, and to ensure that the Subcommittee staff has all of the information it needs to complete its work.

Finally, as we have explained to the Subcommittee staff on a number of occasions, BP is involved in a substantial document production process in cooperation with various governmental investigations of the Prudhoe Bay spills of 2006.[2] Despite enormous effort the database is not yet complete. In some cases, the searches may have to be refined. As a result some of our responses on specific issues are not yet complete, while certain questions may require additional information, research and investigation. This will also apply to responding to the document request that we understand the Subcommittee is submitting to us today.

It has always been my intention to be fully responsive to the Committee, and I apologize for the breakdown in our process that has occurred. For these reasons, I respectfully request that the May 3 hearing be rescheduled so that we are able to more fully develop the record prior to the hearing.

Regards,

Robert A. Malone

[2] As we said in our transmittal letter of April 17, 2007, we have created a searchable database of over 20 million documents, which we winnowed down in the interest of providing the subset of documents that appeared most relevant to the Subcommittee's interests. Our letter noted that we anticipated and welcomed additional questions. Following our further discussions with Subcommittee staff, we are searching for additional responsive documents and will invest the time and resources needed to provide them.

bp

PRIVILEGED AND CONFIDENTIAL
ATTORNEY WORK PRODUCT

Doug Suttles
President

BP Exploration (Alaska) Inc.
P.O. Box 196612
900 E. Benson Boulevard
Anchorage, Alaska 99519-6612

April 30, 2007

BY HAND DELIVERY

The Honorable John D. Dingell
Chairman, House Energy and Commerce Committee
U.S. House of Representatives
2328 Rayburn House Office Building
Washington, D.C. 20515-2215

Direct 907 564 5422
Main 907 561 5111
Fax 907 564 5900
doug suttles@bp.com

Dear Chairman Dingell:

We have received a copy of a March 17, 2007 communication to you that raised two issues regarding our operations in Alaska. We address each issue below.

Prudhoe Bay Gathering Center #2 Fire Suppression System

The letter first alleges risks in connection with the deactivation of the fire suppression system at our Gathering Center #2 (GC-2) facility during radiographic testing associated with corrosion monitoring activities.

I will address the specific allegations of the letter below, but I want to be clear at the outset that BP Exploration Alaska ("BPXA") is committed to safety. To that end, BPXA has acted to ensure all appropriate measures are taken in response to concerns such as those raised in the March 17 letter. BPXA assembled an internal team with appropriate experience and expertise to conduct a Process Hazard Analysis (PHA) to review whether the existing compensatory measures taken when the UV fire detection system is deactivated are sufficient and whether additional safety measures might be appropriate. This process addresses the review requested by the Office of the Ombudsman in response to a similar concern raised earlier by a worker.

The PHA team concluded that our practice of temporary disabling of the UV detectors is appropriate and necessary and identified additional safety measures that we are implementing. For example, we require an hourly patrol of the area with disabled UV detectors by an operator and we are managing the radiographic testing more actively to minimize the time the UV detectors are disabled.

Below, I have provided additional context about the UV detector deactivation issue to ensure that the March 17 letter does not leave any misimpressions.

First, the letter suggests that the entire fire suppression system at GC-2 is turned off during "x-ray corrosion monitoring." That is not the case. The GC-2 fire and gas detection and fire suppression system consists of multiple elements, including ultraviolet (UV) detectors, combination ultraviolet and infrared (UVIR) detectors, flammable gas

detectors, smoke detectors, flicker detectors, fusible links in a water deluge system, and halon fire suppression. During radiographic (x-ray) activity in or near the facility, *only* the UV detectors are deactivated; all other detection and suppression systems remain activated and fully functional. The purpose of this temporary deactivation is to prevent the radiography from creating a false UV detection and triggering the fire suppression system.

Second, the letter does not identify the safety measures used when the UV detection system is disabled during radiographic testing. All other fire and gas detection and fire suppression systems remain activated and fully functional during the radiographic activity. Areas of the facility which have UV detectors also have gas detectors which are not deactivated during radiography. A minimum of five (5) operators must be present at the GC-2 facility for radiographic testing to take place to allow appropriate patrolling.

Additionally, the State of Alaska Department of Natural Resources, Oil & Gas Division investigated these same allegations. The Agency did not take exception with the practices and procedures that are used when the UV detection system is disabled during radiographic testing. The Agency's investigation recognized our thorough examination of the impact of disabling the UV detectors, the continued activation of other detection and suppression systems, and the additional safety measures recommended by the PHA team. Finally, the Agency concluded that the existing procedures to mitigate disabling the UV detectors are adequate.

Third, the letter describes the GC-2 fire suppression system as "defective." The fact is, the fire and gas detection and fire suppression system at GC-2, when implemented as designed, is adequate and, although it is somewhat cumbersome and not the system that BPXA would install today, it is fully functional. We continue to maintain these systems, and they provide the necessary protection for personnel and facilities. Indeed, at this point, a plan is under development for upgrading the fire and gas systems as part of our wider renewal efforts. This plan will be implemented in phases over the next several years. The company is committed to ensuring that fire and gas issues are addressed and to committed to providing the resources necessary to do so.

In addition, the Ombudsman's Office has been reviewing BPXA's fire and gas systems as part of the review of legacy employee concerns. The Ombudsman has engaged an independent engineering firm to evaluate the fire and gas system legacy concerns raised by BPXA employees and, in particular, to assess any need for near-term corrective action. The firm's initial examination of the system is ongoing, and a report is in development as part of the review of legacy employee concerns.

Operations Review Team

The March 17 letter also suggests that the Operations Review Team (ORT) Report completed in October 2001 -- a copy of which was provided to the Committee at that time, and which we are providing again with this letter -- omitted certain employee interview excerpts. In fact, as you know, no interview excerpts were selectively omitted because the ORT Report did not contain *any* interview excerpts in an effort to protect the confidentiality of the cooperating employees.

The ORT team was formed at the request of [Robert Malone, who was then BP's Regional President Western United States] to examine employee concerns about North Slope operating conditions. The review team examined employee and contractor operational integrity concerns, interviewed approximately 300 employees and contractors, and gathered more than 700 employee and contractor concerns. These employee concerns were analyzed and grouped into categories of related findings for further action by the review team.

In developing its recommendations for dealing with the issues raised by the workforce, the review team took into account suggestions made by the workforce for resolution of those concerns. A relatively small number of concerns (in comparison to other concerns) were expressed regarding corrosion management issues. Those concerns did result in findings and recommendations that we accepted and implemented.

If you would like any further information on either of these topics, please let us know. We would be happy to address any questions or concerns that you may have.

Sincerely,

Doug Suttles

cc: The Honorable Sarah Palin, Governor, Alaska *via hand delivery*

ONE HUNDRED TENTH CONGRESS

U.S. House of Representatives
Committee on Energy and Commerce
Washington, DC 20515–6115

JOHN D. DINGELL, MICHIGAN
CHAIRMAN

April 30, 2007

Mr. Robert A. Malone
Chairman and President
BP America, Inc.
200 Westlake Park Boulevard
Houston, TX 77079

Dear Mr. Malone:

BP recently provided documents to the Subcommittee on Oversight and Investigations of the Committee on Energy and Commerce that suggest a severe cost-cutting atmosphere existed between 2000 and 2005 in crude oil production operations at Prudhoe Bay. Last week, BP representatives met with Committee staff to discuss these documents and explain what impact budget cuts may have had on Prudhoe Bay's Corrosion, Inspection, and Chemicals Group (CIC), which was responsible for corrosion mitigation at BP Exploration (Alaska) Inc. BP's representatives also commented on whether these budget cuts were in any way associated with the recent failures that led to last year's shutdown of the Prudhoe Bay field.

The documents suggest that budget pressures were severe enough that some BP field managers were considering measures as draconian as reducing corrosion inhibitor to save money. BP provided e-mails that detail proposals to cut funding for corrosion inhibitor during at least two different years and in two different locations. These locations included the "produced water" lines that are highly susceptible to corrosion. If senior BP managers were willing to consider turning off inhibitor at these locations, it suggests a budgetary environment in which other corrosion management activities may have been eliminated or reduced to a degree that may have directly affected corrosion of the portions of the oil transit lines (OTL) that experienced leaks last year.

Similarly, the documents suggest that corrosion-monitoring efforts such as smart pigging, coupon pulling, and digging up road crossings for visual inspection, were either reduced, put on hold, or "squeezed" in some cases due to budget constraints. In other words, important action items related to health, safety, and the environment, were being delayed, or cut altogether, and

that this was related to tight budgets possibly in an effort to maintain "flat lifting costs."

The documents provided to the Subcommittee confirm that people on the front lines of corrosion management believed that they were under extreme pressure, and they were attempting to do their best with what they had. As you prepare your testimony for the Subcommittee's hearing regarding operations at Prudhoe Bay, we ask that you be prepared to discuss your understanding of the impact that budget had on the CIC Group and how this may have affected both employee morale and the integrity of the corrosion monitoring program, including the willingness to raise concerns regarding imprudent decisions. As long as BP lacks an understanding of the environment in which these individuals were working, we remain skeptical that effective policies can be implemented to prevent recurrences of these kinds of incidents.

In light of this recent information, we ask that you include in your written testimony responses to the following questions regarding the CIC group's corrosion mitigation efforts:

1. At any time from 2000 to 2005, did BP managers order corrosion inhibitor injection to be turned off, specifically to save money or stay within budget constraints? If so, where in the system did this occur, during which dates, and what potential impact did such actions have on the lines or systems when it was halted?

2. On April 15, 2004, an e-mail was sent to Messrs. Kip Sprague and Richard Woollam in the CIC Group (Bates number 7159) referring to a proposal to cancel corrosion inhibitor at "GC's." Assuming that this abbreviation refers to the Gathering Centers, where within the Gathering Centers was the halting of inhibitor being proposed (regardless of whether such action was ever taken)? In view of the changing composition of crude oil being produced at Prudhoe Bay, would reducing corrosion inhibitor at the Gathering Centers have any impact on "carry over" to the OTLs that leaked?

3. Provide all records related to any requests for smart pigging and maintenance pigging from any officials in the CIC Group for the years 2000 through 2005.

4. Provide all e-mails sent and received by the CIC Group involving reducing, suspending, or cutting back on corrosion inhibitor, or any general concerns regarding corrosion in the OTLs.

If you have any questions on this matter, please contact us or have your staff contact Christopher Knauer or Richard Miller with the Majority Committee staff at (202) 226-2424, or Dwight Cates with the Minority Committee staff at (202) 225-3641.

Sincerely,

John D. Dingell
Chairman

Bart Stupak
Chairman
Subcommittee on Oversight and Investigations

cc: The Honorable Joe Barton, Ranking Member
Committee on Energy and Commerce

The Honorable Ed Whitfield, Ranking Member
Subcommittee on Oversight and Investigations

ONE HUNDRED NINTH CONGRESS

U.S. House of Representatives
Committee on Energy and Commerce
Washington, DC 20515–6115

JOE BARTON, TEXAS
CHAIRMAN

October 6, 2006

Mr. Kurt Fredriksson
Commissioner
Alaska Department of Environmental Conservation
410 Willoughby Ave., Suite 303
P.O. Box 111800
Juneau, AK 99811-1800

Mr. Robert A. Malone
Chairman and President
BP America, Inc.
501 Westlake Park Boulevard
Houston, TX 77079

Dear Commissioner Fredriksson and Mr. Malone:

Attached please find a copy of Compliance Order by Consent No. 02-138-10 between the State of Alaska and BP Exploration (Alaska) Inc. (BPXA). Several of the issues contained in this Order appear directly related to the spills on the Prudhoe Bay Western Operating Line (WOL) and the Prudhoe Bay Eastern Operating Line (EOL) that were the subject of a hearing by this Committee on September 7, 2006.

As you are aware, on March 15, 2006, the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) issued a Corrective Action Order (CAO) in response to the WOL failure. The CAO delineated specific requirements that BPXA needed to undertake to bring both its Eastern and Western lines into compliance.

Among the several items in the CAO was a requirement that BPXA "pig" several pipelines including the EOL and WOL. Subsequent to the issuance of the CAO, it was revealed that large sections of both the WOL and the EOL contained potentially significant amounts of scale, sludge, and/or other solids. For several months, following the issuance of the March CAO, BPXA attempted to develop solutions to (a) determine the amount of solids in each line, and (b) determine if and how it could pig these lines as required by the CAO. In early August of this year, BPXA discovered, after pigging part

of the EOL, that numerous instances of corrosion existed. Upon learning of this corrosion, BPXA subsequently ordered the shutdown of the Prudhoe Bay field.

In our September 7, 2006, hearing, BPXA acknowledged that it should have pigged both the WOL and EOL more frequently and that it had been caught off guard by the amounts of solids that were presently in these lines, particularly the EOL. However, this Compliance Order shows that BPXA was aware in at least 2001 that these lines possibly contained unacceptable amounts of solids and that the lines should be pigged. On page 5 of the Order are the following requirements:

- Determine sediment levels in EOL and WOL pipelines at Skid 50. [by 3/31/02]
- Modify EOL pig receiver at Skid 50. [by 3/31/02]
- Pig EOA pipeline from PS - 1 launcher to Skid 50. [by 6/30/02]
- Pig WOL pipeline segments if necessary. [by 9/30/02]
- Test and select flow meters at EOL pipelines, Skid 50 if necessary. [by 9/30/02]
- Complete WOL crude oil flow smoothing modifications. [by 12/31/02]
- Install and test meters on all pipelines. [by 12/31/02]
- Evaluate and establish leak detection systems' compliance. [by 12/31/02]

Had these actions been taken, BPXA would likely have been in a better position to understand the conditions that were forming in both the WOL and EOL -- conditions that ultimately resulted in the failures of these lines. However, it is unclear which, if any, of these actions occurred. Given the potential seriousness of this Order, and the direct relevance to the matters that occurred on both the Western and Eastern lines, we ask that you respond to the following questions by no later than Friday, October 20, 2006:

1. Was this Order received by BPXA? If so, by whom, and what actions were taken? If certain of these actions were not taken, explain why not.

2. The order is signed by a BPXA employee named Mr. Jack M. Fritts who is identified as the Greater Prudhoe Bay Unit Operations Manager. Does Mr. Jack M. Fritts still hold this position with the company? If not, is Mr. Fritts still employed by BPXA? If not, explain why not and provide the Committee with any documents surrounding his departure. Who did Mr. Fritts report to when this Order was signed, and is that person still employed by BPXA?

3. Why was this Order not provided to the Committee by BPXA pursuant to the Committee's document request letter dated August 31, 2006?

4. Prior to their sworn testimony before the Committee on September 7, 2006, was either Mr. Robert A. Malone or Mr. Steve Marshall briefed on or otherwise made aware of the existence of this Compliance Order? If not, why not? If so, why didn't either of them discuss the Order in their

written testimony, oral testimony, or in response to questions posed by members of the Committee?

Sincerely,

Joe Barton
Chairman
Committee on Energy
and Commerce

John D. Dingell
Ranking Member
Committee on Energy
and Commerce

Ed Whitfield
Chairman
Subcommittee on Oversight
and Investigations

Bart Stupak
Ranking Member
Subcommittee on Oversight
and Investigations

cc: The Honorable Frank Murkowski, Governor
State of Alaska

The Honorable Ted Stevens, Senator
U.S. Senate

The Honorable Lisa Murkowski, Senator
U.S. Senate

The Honorable Don Young, Member
U.S. House of Representatives

The Honorable Alberto R. Gonzales, Attorney General
Department of Justice

Vice Admiral Thomas J. Barrett, USCG (Ret.), Administrator
Pipeline and Hazardous Materials Safety Administration

Attachment

N. McCleary
G. Blankenship
J. Fritz / R Germany
G. Campbell
R. Jacobsen
C. Phillips
R. Klies
M. Merrill
N. Glover

BEFORE THE STATE OF ALASKA
DEPARTMENT OF ENVIRONMENTAL CONSERVATION

In the Matter of:
STATE OF ALASKA, DEPARTMENT OF ENVIRONMENTAL CONSERVATION

Complainant,

vs.

BP Exploration (Alaska) Inc.

Respondent.

BPXA LAW DEPT
WHO JCC RMJ JKD SJS KJW
JUN 3 2002
Fully executed
COM

Consent Order No. 02-138-10

COMPLIANCE ORDER BY CONSENT

Whereas the Complainant, the State of Alaska, Department of Environmental Conservation ("ADEC"), and the Respondent, BP Exploration (Alaska) Inc. ("BPXA" or "Respondent"), desire to resolve and settle a disputed matter and to avoid the uncertainty and expense of formal enforcement proceedings, it is hereby agreed as follows:

I. JURISDICTION

1. This Compliance Order by Consent (hereinafter Order) is entered into under the authority of ADEC under AS 44.46.020, AS 46.03.020, AS 46.03.760(e), AS 46.03.765, AS 46.03.850, and 18 AAC 95.160, and the settlement authority of the Attorney General under AS 44.23.020.

II. BACKGROUND

2. BPXA is an owner and the operator of the Greater Prudhoe Bay Unit crude oil transmission pipeline system (hereinafter "FACILITY"). BPXA operates the FACILITY on the North Slope of Alaska, and receives mail at: P.O. Box 196612, Anchorage, Alaska 99519-6612. The FACILITY is a system of "pipelines" as that term is defined in AS 46.04.900(18).

3. In January 1999, ADEC approved and issued to ARCO Alaska Inc.

("AAI") a renewal of oil discharge prevention and contingency plan number 984-CP-4138 for the Prudhoe Bay eastern operating area ("EOA") crude oil transmission pipeline system ("EOA Plan"). Condition of approval number 8 of the EOA Plan required AAI to submit to ADEC a proposed leak detection system for the EOA crude oil transmission pipeline system that met the 1 percent daily throughput standard in 18 AAC 75.055(a) ("1% Standard") and a best available technology ("BAT") analysis for the leak detection system that met the BAT requirement in 18 AAC 75.425(e)(4)(A)(iv) ("BAT Requirement") by the end of August 1999.

4. In January 1999, ADEC approved and issued to BPXA a renewal of oil discharge prevention and contingency plan number 984-CP-4129 for the Prudhoe Bay western operating area ("WOA") crude oil transmission pipeline system ("WOA Plan"). Condition of approval number 8 of the WOA Plan required BPXA to submit to ADEC a proposed leak detection system for the WOA crude oil transmission pipeline system that met the 1% Standard and a BAT analysis for the leak detection system that met the BAT Requirement by the end of August 1999.

5. In August 1999, AAI submitted a proposed leak detection system for the EOA crude oil transmission pipeline system to ADEC. ADEC determined that the proposal was too general, did not include a BAT analysis and, accordingly, was insufficient for review. AAI requested an extension to submit a revised proposed leak detection system and the BAT analysis. ADEC granted an extension to October 15, 1999.

6. In August 1999, BPXA submitted a proposed leak detection system for the WOA crude oil transmission pipeline system to ADEC. ADEC determined that the proposal was too general, did not include a BAT analysis and, accordingly, was insufficient for review. BPXA requested an extension to submit a revised proposed leak detection system and the BAT analysis. ADEC granted the extension to mid October 1999.

7. In October 1999, AAI resubmitted a proposed leak detection system for the EOA crude oil transmission pipeline system and a BAT analysis. ADEC determined these submissions satisfied the EOA Plan condition of approval number 8 requirement and initiated review of both documents under 18 AAC 75.455.

8. In mid-October 1999, BPXA resubmitted a proposed leak detection for the WOA crude oil transmission pipeline system and a BAT analysis. ADEC determined these submissions satisfied the WOA Plan condition of approval number 8 requirement and initiated

review of both documents under 18 AAC 75.455.

9. In June 2000 operational control of the EOA crude oil transmission pipeline system changed from AAI to Phillips Alaska, Inc.

10. On July 1, 2000, BPXA assumed the sole operator role for the EOA and WOA crude oil transmission pipeline systems (the FACILITY).

11. In August 2000, ADEC requested BPXA to submit an engineering package to verify that the proposed leak detection system for the EOA and WOA crude oil transmission pipeline systems would meet the 1% Standard for the FACILITY.

12. In October 2000, BPXA submitted the requested engineering package to ADEC.

13. In December 2000, ADEC determined that the proposed leak detection system for the FACILITY did not meet the 1% Standard and that the BAT analysis did not meet the BAT Requirement. ADEC interpreted the 1% standard as applying to each pipeline segment in the pipeline system, while BPXA's analysis used the combined flow into pump station 1 against which to measure the 1% detection accuracy. ADEC required BPXA to submit a revised leak detection system proposal for the FACILITY that met the 1% Standard and a BAT analysis that met the BAT Requirement by January 31, 2001.

14. In January 2001, BPXA submitted to ADEC a revised leak detection system proposal for the FACILITY that it maintains will meet the 1% Standard.

15. On March 1, 2001, BPXA submitted a BAT analysis to ADEC for the FACILITY leak detection system that it maintains will meet the BAT Requirement.

16. On April 30, 2001 BPXA met with ADEC to discuss BPXA's revised leak detection system proposal for the FACILITY. BPXA agreed to verify that the proposed leak detection system meets the 1% Standard for each pipeline segment by completing 12 action items within specified timelines in 2001. However, PBXA discovered settled solids in some pipeline segments that interfered with the proper functioning and operability of the meters. Those pipeline segments containing solids will need to be cleaned out, which will require the installation of pipeline pigging facilities prior to functional testing of the meters and leak detection system. Due to the unexpected discovery of these solids, BPXA completed only 5 of the action items within the agreed timelines. BPXA expects to complete the remaining action items on or before December 1, 2002.

III. ADEC ALLEGATIONS

COUNT I

17. Since at least December 7, 2000 BPXA has failed to comply with EOA Plan condition of approval number 8 and WOA Plan condition of approval number 8 which require BPXA to submit a leak detection system for the FACILITY that meets the requirements of 18 AAC 75.055(a) and 18 AAC 75.425(e)(4)(A)(iv).

18. Based on the facts set out in paragraphs 2-16 above, since at least December 7, 2000 BPXA has operated the FACILITY in violation of AS 46.04.030(b) which requires operation of a pipeline in compliance with an oil discharge prevention and contingency plan.

COUNT II

19. Under this Order, BPXA will not comply with EOA Plan condition of approval number 8 and WOA Plan condition of approval number 8 and, accordingly, will continue to violate AS 46.04.030(b) until BPXA verifies that the proposed leak detection system for the FACILITY meets the requirements in 18 AAC 75.055(a) and 18 AAC 75.425(e)(4)(A)(iv).

COUNT III

20. Since at least December 7, 2000, BPXA has not equipped the FACILITY with the enhanced leak detection system to satisfy the requirement in 18 AAC 75.055(a) consistent with 18 AAC 75.425(e)(4)(A)(iv).

21. Based on the facts set out in paragraphs 2-16 above, since at least December 7, 2000, BPXA has been operating the FACILITY in violation of 18 AAC 75.055(a).

COUNT IV

22. Under this Order, BPXA will continue to operate the FACILITY in violation of 18 AAC 75.055(a) until BPXA verifies that the proposed leak detection system for the FACILITY satisfies the requirement in 18 AAC 75.055(a) consistent with 18 AAC 75.425(e)(4)(A)(iv).

IV. REMEDIAL MEASURES

23. In order to address the violations outlined in Counts I-IV of Section III of the Order, the Respondent agrees to complete all outstanding action items to verify that the leak detection system for the FACILITY satisfies both the 1% leak detection requirement in 18 AAC 75.055(a), as applied to each pipeline segment, and the BAT requirement of 18 AAC 75.425(e)(4)(A)(iv). Specifically, BPXA agrees to perform the following tasks by the dates indicated herein:

- Determine sediment levels in EOA and WOA pipelines at Skid 50. [by 3/31/02]
- Modify EOA pig receiver at Skid 50. [by 3/31/02]
- Pig EOA pipeline from FS-1 launcher to Skid 50. [by 6/30/02]
- Pig WOA pipeline segments if necessary. [by 9/30/02]
- Test and select flow meters at EOA pipeline, Skid 50 if necessary. [by 9/30/02]
- Complete WOA crude oil flow smoothing modifications. [by 12/31/02]
- Install and test meters on all pipelines. [by 12/31/02]
- Evaluate and establish leak detection systems' compliance. [by 12/31/02]

24. BPXA and ADEC agree to meet and/or confer as necessary to reach a common understanding of the meaning and interpretation of 18 AAC 75.055(a) and 18 AAC 75.425(e)(4)(A)(iv), and to evaluate the Facility's compliance with those regulations.

V. TIME FOR COMPLIANCE

25. Time is of the essence in the Order. Failure to submit any document or make any payment by the deadlines set forth in this Order is a violation of the Order triggering any suspended damages and penalties unless a written extension of time is obtained from ADEC pursuant to paragraph 27.

26. Failure to submit any document or make any payment by the deadlines set forth in the Order, unless a written extension of time is obtained from ADEC pursuant to paragraph 27, may also terminate or serve as the basis for termination of the Order.

27. ADEC, in its discretion, may grant a written extension of time if the Respondent requests the extension prior to the deadline, and proves to the satisfaction of ADEC that any delay is beyond the control of the Respondent due to unforeseen circumstances such as adverse weather or natural disaster. Increases in costs incurred by the Respondent shall not be a basis for any extension of time. Any request for an extension of time must be provided in writing. A request for an extension of time does not toll any deadlines unless ADEC provides a written extension.

28. Unless otherwise specified, all references to days in this Order are to calendar days; however, if a deadline occurs on a weekend or legal holiday the deadline is extended to the next working day.

VI. ADMINISTRATION FEES

29. The Respondent agrees to reimburse ADEC for ADEC and Department of Law staff time spent developing and implementing this Order.

VII. OTHER PAYMENTS

30. Damages and Penalties. The Respondent agrees to pay damages and penalties pursuant to AS 46.03.760(e) as follows:

a. the Respondent agrees to pay the State of Alaska the sum of $300,000 in damages and penalties, with $150,000 suspended on the condition that the Respondent complies with all terms and conditions of the Order to the reasonable satisfaction of ADEC. For purposes of this Order, $121,000 represents economic savings realized by the Respondent in not complying with the requirements for which the violations were alleged; and $29,000 represents the "gravity component" designed to deter future noncompliance;

b. the Respondent agrees to pay the State of Alaska the unsuspended portion of the damages and penalties, $150,000, within thirty days of the effective date of the Order;

c. the Respondent agrees to pay the State of Alaska the suspended portion of the damages and penalties within seven calendar days after failing to submit any document or make any payment by the deadlines set forth in the Order, or after receiving notice of termination if the Order is

terminated pursuant to the provisions of paragraph 43(a) or 43(b) of this Order;

d. all payments under this section shall be made payable to the State of Alaska, Department of Environmental Conservation, shall include the number of the Order, and shall be directed to the Attention of: Cost Recovery Unit, SPAR Director's Office, Alaska Department of Environmental Conservation, 410 Willoughby Ave., Suite 105, Juneau, Alaska 99801-1795.

31. If any payment required by paragraph 30 of the Order is not made, or if any negotiable instrument presented as payment is not honored, ADEC may file a civil action to collect the amount due under the Order, plus interest, attorney's fees, and costs. In any collection action, the validity, amount, and appropriateness of damages and penalties is not subject to review.

VIII. RESERVATION OF RIGHTS

32. The requirements, duties, and obligations set forth in the Order are in addition to any requirements, duties, or obligations contained in any permit or plan approval which ADEC has issued or may issue to the Respondent and are in addition to any requirements, duties, or obligations imposed by State, local, or federal law. Other than as expressly provided herein, the Order does not relieve the Respondent from the duty to comply with requirements contained in any such permit or plan approval or with any State, local, or federal law.

33. ADEC expressly reserves the right to initiate administrative or legal proceedings relating to any violation not expressly described in Counts I-IV of Section III of the Order. In addition, ADEC expressly reserves the right to initiate administrative or legal proceedings and to seek additional civil assessments or seek injunctive relief for violations described in the Order if the Respondent does not comply with the provisions set forth herein to the reasonable satisfaction of ADEC or if, in ADEC's reasonable opinion, subsequently discovered events or conditions constitute an immediate threat to public health, public safety, or the environment, regardless of whether ADEC may have been able to discover the event or condition prior to entering into the Order. In the event that ADEC seeks civil assessments for violations described in the Order, amounts required to be paid under paragraph 30 of the Order may offset any subsequent assessments for those violations, but in no event shall a refund of any

portion of the penalties and damages assessed in this Order be required.

34. In signing the Order, the Respondent and ADEC do not admit, and reserve the right to controvert in any subsequent proceedings, other than for enforcement of the Order, the validity of, or responsibility for, any of the factual or legal determinations made herein.

IX. COVENANT NOT TO SUE

35. Subject to the provisions of Section VIII (Reservation of Rights), and provided the Respondent complies with the terms of the Order to the reasonable satisfaction of ADEC, ADEC shall not institute any further action against the Respondent for the violations alleged in Counts I-IV of Section III of the Order. However, nothing herein shall be construed as limiting ADEC's right to seek damages, penalties, and fines for violation of the terms and conditions of the Order.

36. The Respondent acknowledges and agrees that the Order constitutes a lawful order of ADEC for the purposes of AS 46.03.760, AS 46.03.765, AS 46.03.790, AS 46.03.850, 18 AAC 95.160 and for all other purposes. The Respondent shall not institute any action challenging the validity of the Order or the authority of ADEC to enforce the Order. The Respondent shall not controvert or challenge, in any subsequent proceedings initiated by the State of Alaska, the validity of the Order or the authority of ADEC to issue and enforce the Order.

37. The Respondent acknowledges that, by executing the Order, with regard to violations alleged in Counts I-IV of Section III of the Order, it is waiving the rights and procedures that would otherwise protect it in any formal administrative adjudicatory proceeding or any civil action in a court of law including the right to the filing of a notice of intent, to present evidence and witnesses on its behalf, to cross-examine ADEC's witnesses, to a jury trial, and to administrative and judicial review. The Respondent acknowledges that it is knowingly and voluntarily waiving these rights.

X. DISPUTE RESOLUTION

38. The parties agree to make reasonable efforts to informally resolve at the staff level all disputes that may arise in connection with this Order. If any dispute is still unable to be resolved, the Respondent may make a written request for the ADEC Commissioner or the Commissioner's delegate to resolve the dispute. The pendency of any dispute pursuant to this

paragraph shall not affect Respondent's responsibility for timely performance of the requirements of the Order. The Commissioner or the Commissioner's delegate will issue a final determination in writing. The written decision will be final for purposes of judicial review pursuant to Alaska Rule of Appellate Procedure 602(a)(2). The determination of the Commissioner or the Commissioner's delegate will remain in effect pending resolution of any judicial appeal unless a stay is sought and granted by the court on appeal.

XI. REPORTING

39. BPXA will submit monthly reports to ADEC that summarize activites undertaken under this Order. Either BPXA or ADEC may request a meeting at any time to discuss issues associated with this Order, and the party receiving such a request shall make itself available as promptly as practicable.

XII. JURISDICTION AND VENUE

40. Any judicial action brought by either party to enforce or adjudicate any provision of the Order shall be brought in the Superior Court for the State of Alaska, Third Judicial District at Anchorage.

XIII. EFFECTIVE DATE

41. The effective date of the Order shall be the date of the last signature when the Order is signed by authorized representatives of the BPXA, ADEC and the Alaska Attorney General's Office.

XIV. SUCCESSORS

42. The Order shall be binding upon the Respondent, its agents, successors, and assigns (including any lessee or grantee of the FACILITY), and upon all persons contractors and consultants acting on behalf of the Respondent. The Respondent shall incorporate a copy of the Order into any conveyance of its interest in the FACILITY and into any lease or management agreement, and shall require in any conveyance that the grantee or lessee shall comply with all of the requirements of the Order.

XV. TERMINATION

43. The Order shall terminate on the first to occur of the following:

a. the day after the Respondent misses a deadline imposed under paragraph 23, unless the delay is excused pursuant to paragraph 27;

b. the day after ADEC notifies the Respondent that ADEC is terminating the Order due to the Respondent's failure to comply with any of the provisions set forth herein to the reasonable satisfaction of ADEC;

c. the day after ADEC issues a voluntary written termination of the Order; ADEC will terminate the Order upon request if Respondent establishes to ADEC's satisfaction that it has established compliance for all of the issues outlined in Counts I-IV of Section III of the Order and has complied with the provisions of this Order.

DATED: 5/29/02

DEPARTMENT OF ENVIRONMENTAL CONSERVATION

By: _____

Jeff Mach
Oil and Gas Coordinator

DATED: 30 May 2002

BRUCE M. BOTELHO
ATTORNEY GENERAL

By: _____

Cameron Leonard
Assistant Attorney General

DATED: 05-14-02

BP EXPLORATION (ALASKA) INC.

By: _____

Jack M. Fritts
Greater Prudhoe Bay Unit ~~Field~~ Operations Manager

I, JACK M. FRITTS, hereby certify that I hold the position of Greater Prudhoe Bay Operations Manager and that I am a responsible official for the Respondent's FACILITY and that I have the authority to enter into agreements on behalf of the Respondent and the FACILITY and to otherwise legally bind the Respondent and the FACILITY. I hereby acknowledge that I have freely and voluntarily entered into this agreement with the State of Alaska on behalf of the Respondent.

SUBSCRIBED AND SWORN to before me this 14th day of May, 2002.

MONICA P. BREWSTER NOTARY PUBLIC STATE OF ALASKA

Monica P. Brewster
Notary Public, State of Alaska
My commission expires: _____

My Commission Expires
November 9, 2004

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		REPORT				
		Baker Panel	CSB	Mogford	Booz Allen Hamilton	MAP
THEMES	**PEOPLE**					
	Trusting & Open Communications	X	X	X	X	X
	Importance of Leadership	X	X	X	X	X
	Management's Technical Knowledge	X	X	X		X
	Accountability and Clarity of Expectations	X		X	X	X
	Worker Fatigue and Excessive Overtime	X	X	X		X
	Knowledge, Expertise, and Training	X	X	X		X
	PLANT					
	Risk Identification and Assessment	X	X	X	X	X
	PROCESSES					
	Effective Process Safety/Integrity Management System	X	X	X	X	X
	Adherence to Formal Processes	X	X	X	X	X
	Incident Investigations and Reporting	X	X	X	X	X
	Sufficiency of Resources	X	X	X	X	X
	PERFORMANCE					
	Audit, Compliance, and Monitoring	X	X	X	X	X
	Process Safety as a Core Value	X	X	X	X	X

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MSNBC.com

BP admits knowing of corrosion problems

Workers had predicted 'major catastrophic event' because of cost-cutting

By Lisa Myers
Senior investigative correspondent
Updated: 7:35 p.m. ET Aug 9, 2006

WASHINGTON - BP now admits that senior company officials were warned three years ago about serious corrosion problems in the pipeline being shut down this week.

The warnings were laid out in correspondence obtained by NBC News, between Chuck Hamel, an advocate for oil workers, and senior BP officials.

Hamel writes that BP workers had come to him predicting a "major catastrophic event" and warning that "cost cutting" had caused "serious corrosion damage to flow lines and systems."

"They were cheating in what's required of them in normal business practice in an oil field to save money, to cut corners," Hamel says.

BP officials responded at the time, but said: "We cannot investigate or act without specific information."

In the last few months, a number of BP workers have told the FBI that beginning in 1999, supervisors ordered them to cut back on a key chemical — known as corrosion inhibitor — put into the system to protect pipes. After a major spill last March, BP told federal regulators there was "a reduced level of corrosion inhibitor" in the system that failed. Federal officials ordered BP to inject more chemicals into the pipeline.

On Wednesday, BP America's CEO defended the company's anti-corrosion program.

"We're learning," says Ross Pillari. "We recognize that we thought we had a program that was sufficient, that we need to do more."

A learning process likely to soon cost consumers at the pump.

URL: http://www.msnbc.msn.com/id/14273574/

31

Interview Name:	Bill Hedges	Date:	12/14/2006
Interview Title:	CIC Strategy & Planning	Location:	Anchorage
Interviewer:	Tom Williams		
Notes:			

Prior to the arrival of Tony Brock and the creation of the Technical Directorate, there was no formal process for assessing risk.
There were many informal processes, run by individuals.
They had no process for trying to quantify risk.

Kip Sprague, almost single-handedly tried to develop and keep up a kind of risk register as he built the annual facility reviews. This was mostly in his spare time, outside of his normal job.

In the past, they sat down with senior leadership as part of the QPR. They identified some major risk areas they were concerned with, but one-off

- Production water system
- Seawater system
- CUI

CIC was resourced to be a reactive team. Did not have the resources to be truly forward looking.

After the first leak, management started to seek out CIC, which was in another building until recently. Bernard Looney (ACT) came by to ask what risks he might be facing.

The major vehicle for communicating to senior management was the QPR and the annual review.
CIC had very limited time (20-30 minutes) as part of the broader M&R presentation (usually around 2 hours). Usually talked about what was going on, what CIC was doing, no time for a discussion around risk assessment.

There has been a big change since the leak. Lots more management attention and inquiry about risk issues.

The PAIT (Pipeline Assessment and Intervention Team) look at all the equipment was the major CIC input into the Risk Register
Risk Register is developed under Technical Director (Tony Brock). Cory Herod manages its development.

For example, CUI has always been a big issue.
Use radiographic inspection of low points on pipeline. Plan was to cut backlog of known corrosion issues in half.
At the end of 2005, this follow up list was about 2,000 items (inspection revealed corrosion issues)
Rather than reduce the backlog, the list has grown to 3,000 items that require visual inspection and follow-up.

For the first time, they have actually taken some lines out of service (e.g., Point McIntyre)

PAIT was an effort following the first leak to get at the state of the infrastructure. Assess each piece of kit with a view to:

- Shut in now
- Replace now
- Replace in 3 years

For risk assessment, PAIT is all about probability, since severity of any leak is high (zero tolerance).

Soon after he arrived here from Trinidad in July 2005, he asked for 3 more people in CIC town, and was turned down.
He now has 19 open slots in CIC town, and another 14 in Field.

He gave me a demonstration of the query capabilities of MIMIR, producing a list of all level "F" inspections in 2005. It took about 1 minute.

Exhibit 32

PBU - Management of Change

Work Order #	29314644
Action Tracking #	
Reference #	

STAGE 1 - INITIATION

Initiated by: John Todd/ Andy Spano Phone: 4578

Title: NS Prod Chem Date: 6/5/99

Department/Facility: CIC

Work Location: WOA GC2 and GC3

X Permanent Change

Emergency Change

Temporary Change

Duration End Date

Description of Change:

This MOC evaluates the elimination of the EC1081A corrosion inhibitor injection into the produced water at GC2 and GC3.

Reason for Change: [X] See Attachment

The purpose of this MOC is to document the discontinuation of the produced water corrosion inhibitor and to examine the potential risks to the surface equipment as well as to the oil and water treating process. Funding for the continuation of this chemical program is not available, therefore it is being discontinued. The remaining inventory of the EC1081A will be utilized in the high risk S-69 produced water line until the stock is depleted.

Yes	No	MoC CHECKLIST ("YES" for any of these items indicates the need for an MoC)
	X	Does this change require documentation revisions?
X		Does this change use equipment or parts that are not replacement-in-kind?
	X	Does this change add new or delete existing equipment?
	X	Does this change require modifications to operating limits, parameters, or logic?
	X	Does this change require revisions to existing BP or Contractor procedures?

STAGE 2 - DEVELOPMENT AUTHORIZATION

Yes	No	Responsibility	Activity
X		End User Department	Development authorized?
	NA	End User Department	If change has a precedent, complete Precedent Form and go to Stage 4.
X		End User Department	Hazard Analysis method determined?
	X	End User Department	Process Hazards Analysis (PHA) required?
X		End User Department	Documentation Checklist initiated?
	X	End User Department	Detailed work package required?

J.R. Gillespie R.W. Todd — CIC Team Leader — 6-5-99 Date — x4776 Phone

STAGE 3 - TECHNICAL AND HSE REVIEW

Yes	No	Responsibility	Activity
	X	Review Department	Review Team Lead assigned (if required).
X		Review Department	Technical Review Checklist completed.
X		Review Department	HSE Review Checklist completed.

Technical Reviewer [signature] HSE Reviewer Dominic Paisley (Risk Analysis)

Date 6/8/99 Phone 659-4578 Date 6/8/99 Phone 564-4466

PBU - Management of Change

Work Order #	29314644
Action Tracking #	
Reference #	

STAGE 4 - AUTHORIZATION FOR CHANGE

Yes	No	Responsibility	Activity
X		End User Department	Change is authorized.
	X	End User Department	Does this change affect other Assets, create an HSE precedent or have external implications?

Change authorization is NOT approval for startup

First Line Supervisor — Date: 6/10/99 — Phone: x4905

STAGE 5 - END USER ACCEPTANCE

Yes	No	N/A	Responsibility	Activity
X		N/A	End User Department	Duration of temporary change and tracking system established.
		X	End User Department	Pre-Startup Safety Review completed (Ref: DOP #P-6-PM).
X			End User Department	Documentation Checklist reviewed and all applicable documentation complete. **Attach Checklist to MOC.**
		X	End User Department	Outstanding punchlist items assigned and scheduled.
X			End User Department	Forward documentation to Design/Drafting Supervisor.

Stage 5 must be approved before the change can be activated or put in service

Endorse this as a temporary change on the understanding that injection will recommence at the start of [illegible] 2000

End User Department Superintendent — Date: 6/12/99 — Phone: x4574

STAGE 6 - RECORDS

Yes	No	Responsibility	Activity
		Design/Drafting Supv.	Punchlist completion schedule received.
		Design/Drafting Supv.	All documentation complete.
		Design/Drafting Supv.	End User Department Superintendent advised on status of change.

Design/Drafting Supervisor — Date — Phone

COMMENTS (add attachments as required and note)

This is a unique chemical change MOC in that we are discussing the removal of a product and not the addition of one. In this case there are some risks to the equipment and the process associated with the discontinuation of this chemical program. While this change is defined as "permanent", the CIC Dept. will attempt to reinstate the program in the year 2000, if the budget is approved.

MoC DOCUMENT CHECKLIST

Work Order #	29314644
Action Tracking #	
Reference #	

ITEMS BELOW THAT ARE REQUIREMENTS OF THIS MOC NEED TO ACCOMPANY THE ORIGINAL MOC WHEN FORWARDING TO DESIGN DRAFTING FOR CLOSE OUT

DOCUMENTATION	REQUIRED		COMPLETED		ENCLOSED		COMMENTS
	Yes	No	Yes	No	Yes	No	
Design/Process Parameters		x					
Pre-startup Safety Review		x					not applicable in this case
Hazard Review	x		x		x		
Technical Review Checklist		x					no new chemicals are being introduced, one is being removed
HSE Review Checklist	x		x		x		
PROCEDURES							
- ESD Procedure		x					
- Inspection Procedure		x					
- Maintenance Procedure		x					
- Operating Procedure		x					
- PM Procedure		x					
- Testing Procedure		x					
- Other (note in Comments)							
TRAINING							
- E-Book Update		x					
- Informal (Toolbox, etc.)		x					not applicable in this case
- N/S Training Department		x					
Emergency Response Plans		x					
MSDS	x		x		x		included only to identify the product being discontinued
Computer System Updates (PLC, SCADA, etc.)		x					
FCO Documents		x					
Data Sheets / Process Safety Info		x					
Redlined Drawings		x					
MEL Information		x					
Other (note in Comments)		x					

Comments:
The applicable GC's and the field OTL's have been notified of the discontinuation of the EC1001A at the GC's.

Completed By — Date: 6/6/07

End User Acceptance — Date

TIMM100 WORK TASK OUTLINE 06/05/99 07:43

W/O : 29314644 W/O Type = NR Status = PLAN 06/05/99
Title : MOC FOR DISCONTINUING INJECTION OF THE PW CORROSION INHIB.
Facility= WOA Work Status= OPEN Ref ID =
Priority= R W/O Group =
WO Due = 06/30/99 W/O Planner= TODDJB Outage =
In Srvce: PM Early : Proj = Prop:
PCTR = Model W/O : PM Late: Attr:
Orig W/O: Mod W/O Rev: Capital: N Sched: Est :
Xref W/O: Reimbrs: N Cmplt: A/T :

•	TN	SN	Status	Pri	Pro	Ins	Rsc	Mtl	Doc	Req	Tls	Ots	Qc	Com	Eql	Description
[ ]	01	01	PLAN	R												MOC FOR DISCONT

More:

Select to step thru task planning. Execute to create new task.

TIMM102 TASK INSTRUCTIONS 06/05/99 07:39

W/O Task: 29314644 01 Status: PLAN 06/05/99
Desc : MOC FOR DISCONTINUING INJECTION OF THE PW CORROSION INHIB.

* Description

The purpose of this MOC is to document the discontinuation of the
produced water corrosion inhibitor at GC2 and GC2. There are some
risks and potential process problems assocated with this change. The
program is being discontinued due to budgetary constraints,even
though it has proven to be a very cost effective program.

More:

*	Fac	Work Std	Description	OLE	Prt

More:

Enter task instructions. Use More Detail to step through task planning.

Hazards Review Statement

To Be Completed by a Designated Authority and Attached to MOC

MOC Number: 29314644

MOC Description: Stop EC1081A PW Cl Injection at GC-2 and GC-3

MOC Originator: John Todd/ Andy Spano

This Chemical Change does pose HSE / Financial risks.. The following is a brief description of the technical Review:

The corrosion mechanism in the PW system is microbially induced corrosion. Bacteria thrive in dirty systems and treatment requires injection of a chemical with strong surfactant and biocidal properties to clean the lines and reduce bacteria numbers. Various chemicals have been tried at GC-2 over the past year with the aim of finding a suitable, low cost chemical. The program has been successful and the data shows that the PW systems at GC-2 and GC-3 have been cleaned and bacterial numbers have been reduced. The corrosion monitoring and inspection data have also improved significantly.

The net effect of these improvements is to significantly increase the projected life of the PW system. Much of the system is in poor condition and, without injection of supplemental chemical, well line replacements are predicted from 2001 onwards, with flow lines from 2003 onwards. Supplemental injection is estimated to delay these near-term line replacements by approximately 7 years and many of the replacements would be delayed indefinitely. For example, the retirement of S-69 is predicted to be delayed from 2003 to 2016.

Suspending the supplemental injection in to the PW system is therefore unlikely to cause loss of containment or equipment retiral in the short term (1 to 2 years). However, it will shorten the life of the system, resulting in eitner abandonment or expensive repair/replacement in the medium to long term (3 years+). The longer the corrosion continues at the uncontrolled rate, the harder it will be to arrest it and achieve satisfactory life of the equipment.

Dominic Paisley	dlf for Dominic Paisley
Printed Name	Signature
Corrosion Engineer	6/9/99
Area of Authority	Date

Note: A Plant Change which is not a Replacement-In-Kind may require a Plant Change Request (PCR) to comply with OSHA regulations. See PCR Procedure if it is uncertain that this form is applicable.

Hazards Review Statement (Part I)

To Be Completed by a Designated Authority and Attached to MOC

MOC Number: 29314644

MOC Description: PW Corrosion Inhibitor Discontinuation

MOC Originator: John Todd/ Andy Spano

This Chemical Change does pose some HSE/ Financial risks. The following is a brief description of the risks to the Oil/ Water treatment process only:

In recent years, by far the largest negative impact to the oil and water quality at GC2 has been as a result of our produced water line pigging program, where the debris swept out of the line by the pig is returned via the LDF's to GC2. With the introduction in mid 1998 of a highly surface active water soluble corrosion inhibitor (EC1081A) injected directly into the produced water stream, we were able to substantially clean-up the surface water injection lines to the point where pigging returns at GC2 caused minimal disruption to the process. Water quality improved, which meant that less suspended solids went into the injection system, and the monthly BS&W averages declined to levels not seen for many years. In addition, the WOA induced upsets at Pump Station #1 declined dramatically.

The discontinuation of the EC1081A type chemistry into the produced water system represents a step backwards in our pursuit of producing oil and water that is consistently within the BPX guidelines. The end result of the program elimination is quite predictable - the quality of the oil and water produced by the WOA will decline, process upsets will be more frequent and much more severe, and stress on the mechanical equipment and infrastructure will increase.

JOHN B. TODD — Printed Name

Signature

Production Chemistry — Area of Authority

6/6/99 — Date

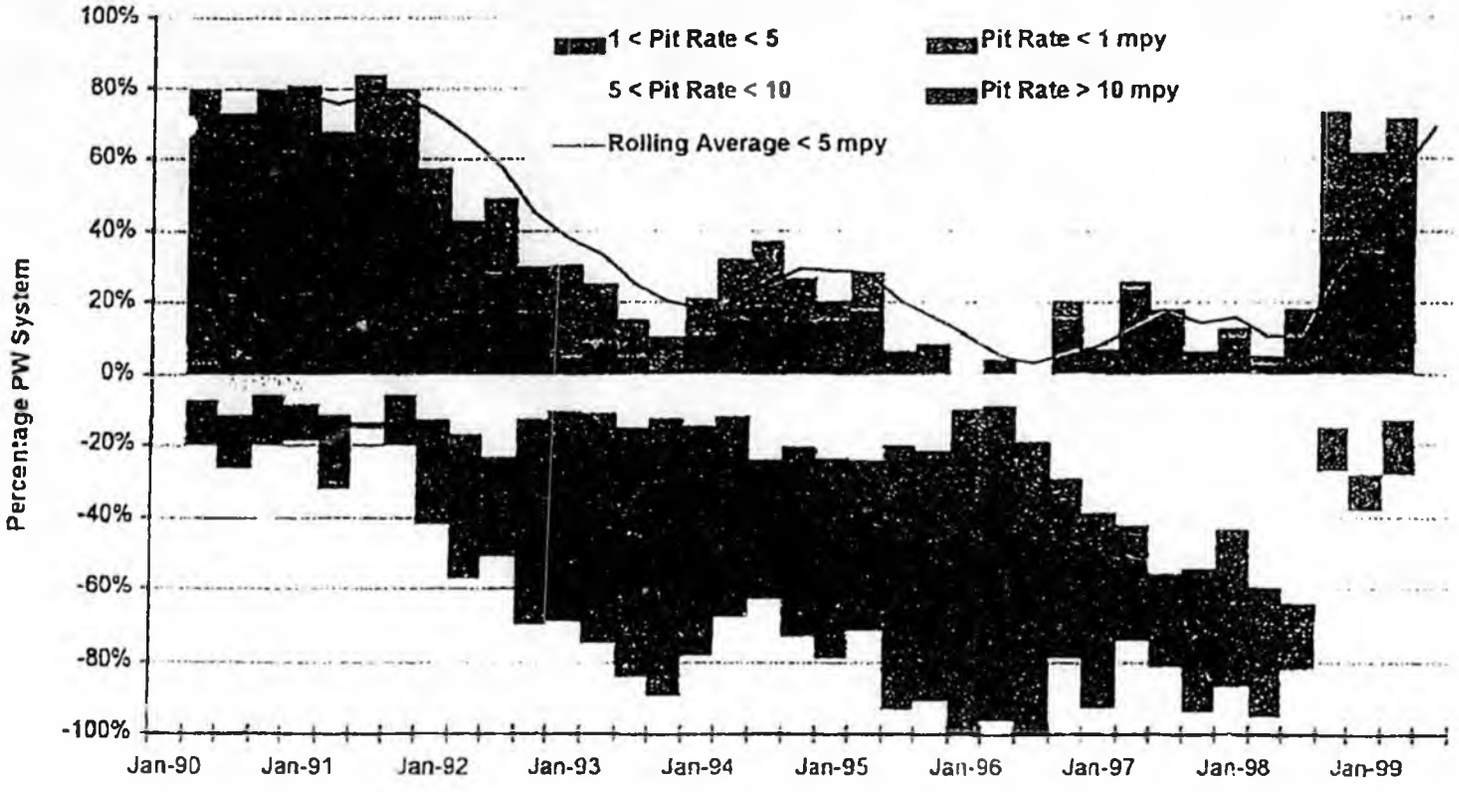
Note: A Plant Change which is not a Replacement-in-Kind may require a Plant Change Request (PCR) to comply with OSHA regulations. See PCR Procedure if it is uncertain that this form is applicable.

Produced Water - Corrosion Control

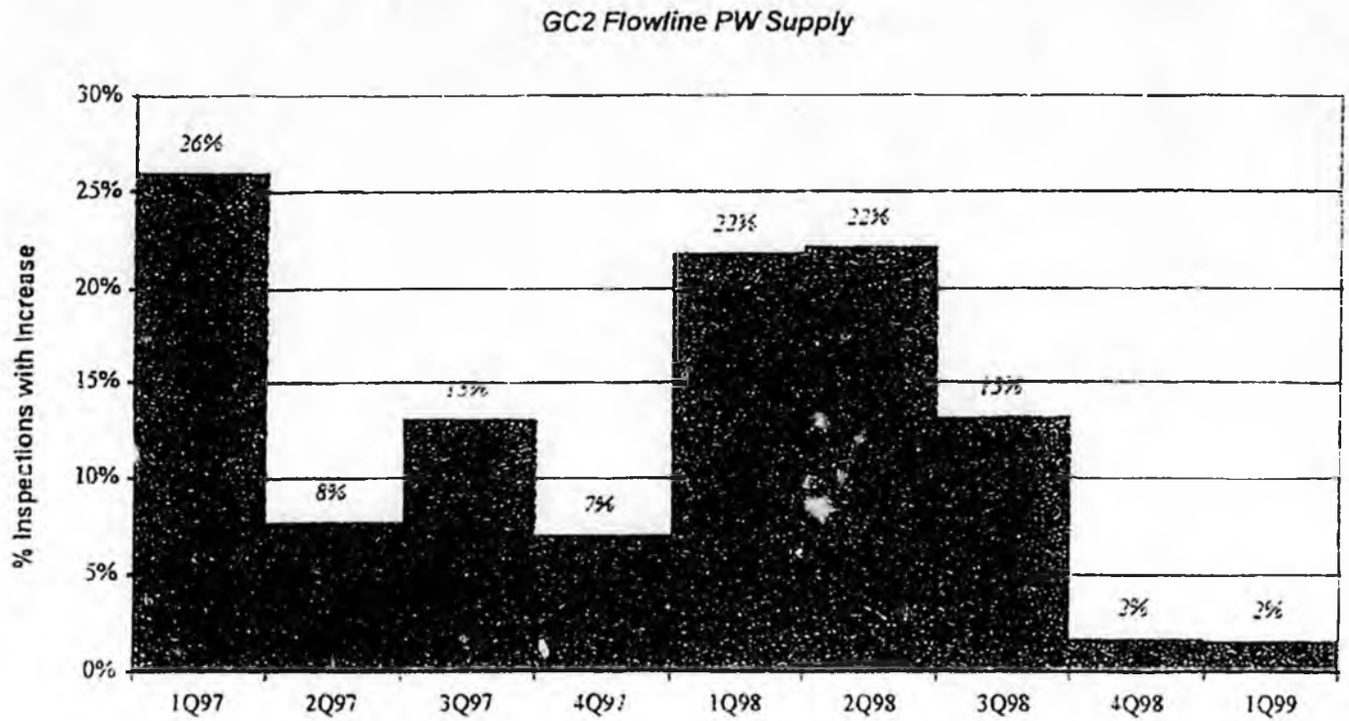
- ***Status of Supplemental Injection***
  - GC-2: started July '98
  - GC-3: started Feb '99
  - Total cost $1.5 M per annum($1.25 M in '99)
- ***System Simplification***
  - T-pad well lines and F-T flowline to be abandoned in June
    - F-pad under consideration by reservoir team - decision by end 3Q
  - WSW 2 line to be mothballed in July
  - Benefits
    - Improves mechanical integrity through elimination
    - Stops corrosion & preserves infrastructure
    - Reduces costs associated with pigging & inspection

Produced Water - Corrosion Control

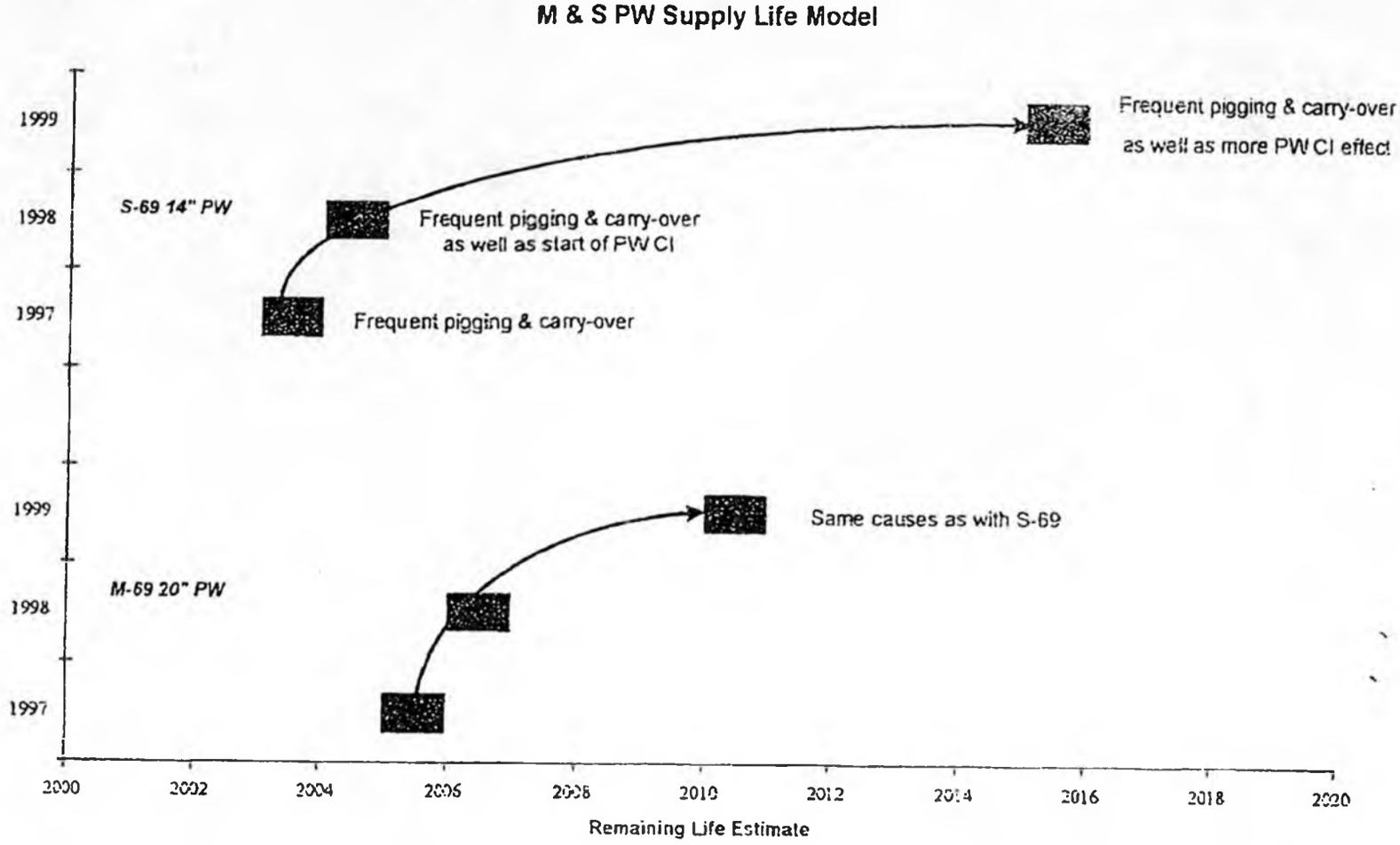
Percentage of Produced Water System with Corrosion Under Control



Produced Water - Corrosion Control



Value Of Supplemental PW Injection - M&S FL's



Produced Water - Corrosion Control

- ***Value of Supplemental Injection over 20 years***
  - Option 1 - no injection
    - Cost of replacements: NPV $ 36 million
  - Option 2 - supplemental injection
    - Cost of replacements: NPV $ 17.5 million
    - Δ over Option 1 NPV $ 18.5 million
    - Cost of injection: NPV $ 11 million
    - Cost benefit: NPV $ 7.5 million
  - Approach does not consider
    - Environmental cost due to leaks
    - Value of deferred oil due to PW system failures
  - Conservative analysis
    - Cost reduction through optimisation of chemical
    - Minimum costs assumed for replacements
    - Life extended by 7 years
  - Additional benefits due to reductions in BS&W and plant upsets

Produced Water - Corrosion Control

- ***Near Term Actions***
  - Implement injection at GC-1
  - Mothball / abandon T-pad & WSW
  - Achieve 100% compliance with Performance Measure
  - Optimise chemical treatment for mechanical / reservoir life
  - Re-visit options for not treating Cretaceous Injection water
    - Potential saving of $250 K on annual basis

Exhibit 33

N. McCleary
G. Blankenship
J. Fritz / R Germeny
G. Campbell
R. Jacobsen
C. Pilcher
R. Klie
M. Merrill
N. Glover

BEFORE THE STATE OF ALASKA
DEPARTMENT OF ENVIRONMENTAL CONSERVATION

In the Matter of:
STATE OF ALASKA, DEPARTMENT OF ENVIRONMENTAL CONSERVATION

Complainant,

vs.

BP Exploration (Alaska) Inc.

Respondent.

Consent Order No. 02-138-10

COMPLIANCE ORDER BY CONSENT

Whereas the Complainant, the State of Alaska, Department of Environmental Conservation ("ADEC"), and the Respondent, BP Exploration (Alaska) Inc. ("BPXA" or "Respondent"), desire to resolve and settle a disputed matter and to avoid the uncertainty and expense of formal enforcement proceedings, it is hereby agreed as follows:

I. JURISDICTION

1. This Compliance Order by Consent (hereinafter Order) is entered into under the authority of ADEC under AS 44.46.020, AS 46.03.020, AS 46.03.760(e), AS 46.03.765, AS 46.03.850, and 18 AAC 95.160, and the settlement authority of the Attorney General under AS 44.23.020.

II. BACKGROUND

2. BPXA is an owner and the operator of the Greater Prudhoe Bay Unit crude oil transmission pipeline system (hereinafter "FACILITY"). BPXA operates the FACILITY on the North Slope of Alaska, and receives mail at: P.O. Box 196612, Anchorage, Alaska 99519-6612. The FACILITY is a system of "pipelines" as that term is defined in AS 46.04.900(18).

3. In January 1999, ADEC approved and issued to ARCO Alaska Inc.

("AAI") a renewal of oil discharge prevention and contingency plan number 984-CP-4138 for the Prudhoe Bay eastern operating area ("EOA") crude oil transmission pipeline system ("EOA Plan"). Condition of approval number 8 of the EOA Plan required AAI to submit to ADEC a proposed leak detection system for the EOA crude oil transmission pipeline system that met the 1 percent daily throughput standard in 18 AAC 75.055(a) ("1% Standard") and a best available technology ("BAT") analysis for the leak detection system that met the BAT requirement in 18 AAC 75.425(e)(4)(A)(iv) ("BAT Requirement") by the end of August 1999.

4. In January 1999, ADEC approved and issued to BPXA a renewal of oil discharge prevention and contingency plan number 984-CP-4129 for the Prudhoe Bay western operating area ("WOA") crude oil transmission pipeline system ("WOA Plan"). Condition of approval number 8 of the WOA Plan required BPXA to submit to ADEC a proposed leak detection system for the WOA crude oil transmission pipeline system that met the 1% Standard and a BAT analysis for the leak detection system that met the BAT Requirement by the end of August 1999.

5. In August 1999, AAI submitted a proposed leak detection system for the EOA crude oil transmission pipeline system to ADEC. ADEC determined that the proposal was too general, did not include a BAT analysis and, accordingly, was insufficient for review. AAI requested an extension to submit a revised proposed leak detection system and the BAT analysis. ADEC granted an extension to October 15, 1999.

6. In August 1999, BPXA submitted a proposed leak detection system for the WOA crude oil transmission pipeline system to ADEC. ADEC determined that the proposal was too general, did not include a BAT analysis and, accordingly, was insufficient for review. BPXA requested an extension to submit a revised proposed leak detection system and the BAT analysis. ADEC granted the extension to mid October 1999.

7. In October 1999, AAI resubmitted a proposed leak detection system for the EOA crude oil transmission pipeline system and a BAT analysis. ADEC determined these submissions satisfied the EOA Plan condition of approval number 8 requirement and initiated review of both documents under 18 AAC 75.455.

8. In mid-October 1999, BPXA resubmitted a proposed leak detection for the WOA crude oil transmission pipeline system and a BAT analysis. ADEC determined these submissions satisfied the WOA Plan condition of approval number 8 requirement and initiated

review of both documents under 18 AAC 75.455.

9. In June 2000 operational control of the EOA crude oil transmission pipeline system changed from AAI to Phillips Alaska, Inc.

10. On July 1, 2000, BPXA assumed the sole operator role for the EOA and WOA crude oil transmission pipeline systems (the FACILITY).

11. In August 2000, ADEC requested BPXA to submit an engineering package to verify that the proposed leak detection system for the EOA and WOA crude oil transmission pipeline systems would meet the 1% Standard for the FACILITY.

12. In October 2000, BPXA submitted the requested engineering package to ADEC.

13. In December 2000, ADEC determined that the proposed leak detection system for the FACILITY did not meet the 1% Standard and that the BAT analysis did not meet the BAT Requirement. ADEC interpreted the 1% standard as applying to each pipeline segment in the pipeline system, while BPXA's analysis used the combined flow into pump station 1 against which to measure the 1% detection accuracy. ADEC required BPXA to submit a revised leak detection system proposal for the FACILITY that met the 1% Standard and a BAT analysis that met the BAT Requirement by January 31, 2001.

14. In January 2001, BPXA submitted to ADEC a revised leak detection system proposal for the FACILITY that it maintains will meet the 1% Standard.

15. On March 1, 2001, BPXA submitted a BAT analysis to ADEC for the FACILITY leak detection system that it maintains will meet the BAT Requirement.

16. On April 30, 2001 BPXA met with ADEC to discuss BPXA's revised leak detection system proposal for the FACILITY. BPXA agreed to verify that the proposed leak detection system meets the 1% Standard for each pipeline segment by completing 12 action items within specified timelines in 2001. However, PBXA discovered settled solids in some pipeline segments that interfered with the proper functioning and operability of the meters. Those pipeline segments containing solids will need to be cleaned out, which will require the installation of pipeline pigging facilities prior to functional testing of the meters and leak detection system. Due to the unexpected discovery of these solids, BPXA completed only 5 of the action items within the agreed timelines. BPXA expects to complete the remaining action items on or before December 1, 2002.

III. ADEC ALLEGATIONS

COUNT I

17. Since at least December 7, 2000 BPXA has failed to comply with EOA Plan condition of approval number 8 and WOA Plan condition of approval number 8 which require BPXA to submit a leak detection system for the FACILITY that meets the requirements of 18 AAC 75.055(a) and 18 AAC 75.425(e)(4)(A)(iv).

18. Based on the facts set out in paragraphs 2-16 above, since at least December 7, 2000 BPXA has operated the FACILITY in violation of AS 46.04.030(b) which requires operation of a pipeline in compliance with an oil discharge prevention and contingency plan.

COUNT II

19. Under this Order, BPXA will not comply with EOA Plan condition of approval number 8 and WOA Plan condition of approval number 8 and, accordingly, will continue to violate AS 46.04.030(b) until BPXA verifies that the proposed leak detection system for the FACILITY meets the requirements in 18 AAC 75.055(a) and 18 AAC 75.425(e)(4)(A)(iv).

COUNT III

20. Since at least December 7, 2000, BPXA has not equipped the FACILITY with the enhanced leak detection system to satisfy the requirement in 18 AAC 75.055(a) consistent with 18 AAC 75.425(e)(4)(A)(iv).

21. Based on the facts set out in paragraphs 2-16 above, since at least December 7, 2000, BPXA has been operating the FACILITY in violation of 18 AAC 75.055(a).

COUNT IV

22. Under this Order, BPXA will continue to operate the FACILITY in violation of 18 AAC 75.055(a) until BPXA verifies that the proposed leak detection system for the FACILITY satisfies the requirement in 18 AAC 75.055(a) consistent with 18 AAC 75.425(e)(4)(A)(iv).

IV. REMEDIAL MEASURES

23. In order to address the violations outlined in Counts I-IV of Section III of the Order, the Respondent agrees to complete all outstanding action items to verify that the leak detection system for the FACILITY satisfies both the 1% leak detection requirement in 18 AAC 75.055(a) as applied to each pipeline segment, and the BAT requirement of 18 AAC 75.425(e)(4)(A)(iv). Specifically, BPXA agrees to perform the following tasks by the dates indicated herein:

- Determine sediment levels in EOA and WOA pipelines at Skid 50. [by 3/31/02]
- Modify EOA pig receiver at Skid 50. [by 3/31/02]
- Pig EOA pipeline from FS-1 launcher to Skid 50. [by 6/30/02]
- Pig WOA pipeline segments if necessary. [by 9/30/02]
- Test and select flow meters at EOA pipeline, Skid 50 if necessary. [by 9/30/02]
- Complete WOA crude oil flow smoothing modifications. [by 12/31/02]
- Install and test meters on all pipelines. [by 12/31/02]
- Evaluate and establish leak detection systems' compliance. [by 12/31/02]

24. BPXA and ADEC agree to meet and/or confer as necessary to reach a common understanding of the meaning and interpretation of 18 AAC 75.055(a) and 18 AAC 75.425(e)(4)(A)(iv), and to evaluate the Facility's compliance with those regulations.

V. TIME FOR COMPLIANCE

25. Time is of the essence in the Order. Failure to submit any document or make any payment by the deadlines set forth in this Order is a violation of the Order triggering any suspended damages and penalties unless a written extension of time is obtained from ADEC pursuant to paragraph 27.

26. Failure to submit any document or make any payment by the deadlines set forth in the Order, unless a written extension of time is obtained from ADEC pursuant to paragraph 27, may also terminate or serve as the basis for termination of the Order.

27. ADEC, in its discretion, may grant a written extension of time if the Respondent requests the extension prior to the deadline, and proves to the satisfaction of ADEC that any delay is beyond the control of the Respondent due to unforeseen circumstances such as adverse weather or natural disaster. Increases in costs incurred by the Respondent shall not be a basis for any extension of time. Any request for an extension of time must be provided in writing. A request for an extension of time does not toll any deadlines unless ADEC provides a written extension.

28. Unless otherwise specified, all references to days in this Order are to calendar days; however, if a deadline occurs on a weekend or legal holiday the deadline is extended to the next working day.

VI. ADMINISTRATION FEES

29. The Respondent agrees to reimburse ADEC for ADEC and Department of Law staff time spent developing and implementing this Order.

VII. OTHER PAYMENTS

30. Damages and Penalties. The Respondent agrees to pay damages and penalties pursuant to AS 46.03.760(e) as follows:

a. the Respondent agrees to pay the State of Alaska the sum of $300,000 in damages and penalties, with $150,000 suspended on the condition that the Respondent complies with all terms and conditions of the Order to the reasonable satisfaction of ADEC. For purposes of this Order, $121,000 represents economic savings realized by the Respondent in not complying with the requirements for which the violations were alleged; and $29,000 represents the "gravity component" designed to deter future noncompliance;

b. the Respondent agrees to pay the State of Alaska the unsuspended portion of the damages and penalties, $150,000, within thirty days of the effective date of the Order;

c. the Respondent agrees to pay the State of Alaska the suspended portion of the damages and penalties within seven calendar days after failing to submit any document or make any payment by the deadlines set forth in the Order, or after receiving notice of termination if the Order is

terminated pursuant to the provisions of paragraph 43(a) or 43(b) of this Order;

d. all payments under this section shall be made payable to the State of Alaska, Department of Environmental Conservation, shall include the number of the Order, and shall be directed to the Attention of: Cost Recovery Unit, SPAR Director's Office, Alaska Department of Environmental Conservation, 410 Willoughby Ave., Suite 105, Juneau, Alaska 99801-1795.

31. If any payment required by paragraph 30 of the Order is not made, or if any negotiable instrument presented as payment is not honored, ADEC may file a civil action to collect the amount due under the Order, plus interest, attorney's fees, and costs. In any collection action, the validity, amount, and appropriateness of damages and penalties is not subject to review.

VIII. RESERVATION OF RIGHTS

32 The requirements, duties, and obligations set forth in the Order are in addition to any requirements, duties, or obligations contained in any permit or plan approval which ADEC has issued or may issue to the Respondent and are in addition to any requirements, duties, or obligations imposed by State, local, or federal law. Other than as expressly provided herein, the Order does not relieve the Respondent from the duty to comply with requirements contained in any such permit or plan approval or with any State, local, or federal law.

33. ADEC expressly reserves the right to initiate administrative or legal proceedings relating to any violation not expressly described in Counts I-IV of Section III of the Order. In addition, ADEC expressly reserves the right to initiate administrative or legal proceedings and to seek additional civil assessments or seek injunctive relief for violations described in the Order if the Respondent does not comply with the provisions set forth herein to the reasonable satisfaction of ADEC or if, in ADEC's reasonable opinion, subsequently discovered events or conditions constitute an immediate threat to public health, public safety, or the environment, regardless of whether ADEC may have been able to discover the event or condition prior to entering into the Order. In the event that ADEC seeks civil assessments for violations described in the Order, amounts required to be paid under paragraph 30 of the Order may offset any subsequent assessments for those violations, but in no event shall a refund of any

portion of the penalties and damages assessed in this Order be required.

34. In signing the Order, the Respondent and ADEC do not admit, and reserve the right to controvert in any subsequent proceedings, other than for enforcement of the Order, the validity of, or responsibility for, any of the factual or legal determinations made herein.

IX. COVENANT NOT TO SUE

35. Subject to the provisions of Section VIII (Reservation of Rights), and provided the Respondent complies with the terms of the Order to the reasonable satisfaction of ADEC, ADEC shall not institute any further action against the Respondent for the violations alleged in Counts I-IV of Section III of the Order. However, nothing herein shall be construed as limiting ADEC's right to seek damages, penalties, and fines for violation of the terms and conditions of the Order.

36. The Respondent acknowledges and agrees that the Order constitutes a lawful order of ADEC for the purposes of AS 46.03.760, AS 46.03.765, AS 46.03.790, AS 46.03.850, 18 AAC 95.160 and for all other purposes. The Respondent shall not institute any action challenging the validity of the Order or the authority of ADEC to enforce the Order. The Respondent shall not controvert or challenge, in any subsequent proceedings initiated by the State of Alaska, the validity of the Order or the authority of ADEC to issue and enforce the Order.

37. The Respondent acknowledges that, by executing the Order, with regard to violations alleged in Counts I-IV of Section III of the Order, it is waiving the rights and procedures that would otherwise protect it in any formal administrative adjudicatory proceeding or any civil action in a court of law including the right to the filing of a notice of intent, to present evidence and witnesses on its behalf, to cross-examine ADEC's witnesses, to a jury trial, and to administrative and judicial review. The Respondent acknowledges that it is knowingly and voluntarily waiving these rights.

X. DISPUTE RESOLUTION

38. The parties agree to make reasonable efforts to informally resolve at the staff level all disputes that may arise in connection with this Order. If any dispute is still unable to be resolved, the Respondent may make a written request for the ADEC Commissioner or the Commissioner's delegate to resolve the dispute. The pendency of any dispute pursuant to this

paragraph shall not affect Respondent's responsibility for timely performance of the requirements of the Order. The Commissioner or the Commissioner's delegate will issue a final determination in writing. The written decision will be final for purposes of judicial review pursuant to Alaska Rule of Appellate Procedure 602(a)(2). The determination of the Commissioner or the Commissioner's delegate will remain in effect pending resolution of any judicial appeal unless a stay is sought and granted by the court on appeal.

XI. REPORTING

39. BPXA will submit monthly reports to ADEC that summarize activites undertaken under this Order. Either BPXA or ADEC may request a meeting at any time to discuss issues associated with this Order, and the party receiving such a request shall make itself available as promptly as practicable.

XII. JURISDICTION AND VENUE

40. Any judicial action brought by either party to enforce or adjudicate any provision of the Order shall be brought in the Superior Court for the State of Alaska, Third Judicial District at Anchorage.

XIII. EFFECTIVE DATE

41. The effective date of the Order shall be the date of the last signature when the Order is signed by authorized representatives of the BPXA, ADEC and the Alaska Attorney General's Office.

XIV. SUCCESSORS

42. The Order shall be binding upon the Respondent, its agents, successors, and assigns (including any lessee or grantee of the FACILITY), and upon all persons, contractors and consultants acting on behalf of the Respondent. The Respondent shall incorporate a copy of the Order into any conveyance of its interest in the FACILITY and into any lease or management agreement, and shall require in any conveyance that the grantee or lessee shall comply with all of the requirements of the Order.

XV. TERMINATION

43. The Order shall terminate on the first to occur of the following:

a. the day after the Respondent misses a deadline imposed under paragraph 23, unless the delay is excused pursuant to paragraph 27;

b. the day after ADEC notifies the Respondent that ADEC is terminating the Order due to the Respondent's failure to comply with any of the provisions set forth herein to the reasonable satisfaction of ADEC;

c. the day after ADEC issues a voluntary written termination of the Order; ADEC will terminate the Order upon request if Respondent establishes to ADEC's satisfaction that it has established compliance for all of the issues outlined in Counts I-IV of Section III of the Order and has complied with the provisions of this Order.

DATED: 5/29/02

DEPARTMENT OF ENVIRONMENTAL CONSERVATION

By: _____

Jeff Mach
Oil and Gas Coordinator

DATED: 30 May 2002

BRUCE M. BOTELHO
ATTORNEY GENERAL

By: _____

Cameron Leonard
Assistant Attorney General

DATED: 05-14-02

BP EXPLORATION (ALASKA) INC.

By: _____

Jack M. Fritts
Greater Prudhoe Bay Unit ~~Field~~ Operations Manager

I, JACK M. FRITTS, hereby certify that I hold the position of Greater Prudhoe Bay Operations Manager and that I am a responsible official for the Respondent's FACILITY and that I have the authority to enter into agreements on behalf of the Respondent and the FACILITY and to otherwise legally bind the Respondent and the FACILITY. I hereby acknowledge that I have freely and voluntarily entered into this agreement with the State of Alaska on behalf of the Respondent.

SUBSCRIBED AND SWORN to before me this 14th day of May, 2002.

MONICA P. BREWSTER NOTARY PUBLIC STATE OF ALASKA

Monica P. Brewster
Notary Public, State of Alaska
My commission expires: _____

My Commission Expires
November 9, 2004

ALASKA STATE HOUSE OF REPRESENTATIVES

Interim Address:
345 W. Sterling Hwy
Suite 102B
Homer AK 99603
(907)-235-2921
Fax# (907)-235-4008

Session:
(907)-465-2689
FAX# (907) 465-3472
State Capital
Room 102

REPRESENTATIVE PAUL SEATON
DISTRICT 35

Memorandum

From: Rep. Paul Seaton
To: House Resources Co-Chair Rep. Ralph Samuels
House Resources Co-Chair Rep. Jay Ramras
Senate Resources Chair Sen. Tom Wagoner
Date: September 14, 2006
Re: BP Transit lines pigging information request

Please submit the following requests for information to BP for so we can have a discussion of the matter at the next Resources meeting:

1. We would like to see a copy and analysis of the pressure log data for the pigging operations on BP transit lines in 1992 again in 2006. We would like to determine if any increased pressure needed to move a pig down a line with a lot of contamination built up could have caused or played a role in the subsequent pipeline leaks.

2. Please provide the committee with a two-year summary of the pigging done on transit pipelines in fields that BP operates worldwide. Please specify which examples of the pigging frequency in other BP operated fields are similar to the Prudhoe Bay NS transit lines.

We have been provided information that standard industry practice is to pig often to prevent problems. We have been informed that each field has different oil and gas characteristics that require different procedures but nowhere to our understanding is regular pigging not done. If you have examples of such, please specify and provide details of the reasons for such a low maintenance determination.

3. Was the fact that the Prudhoe Bay transit lines were carrying much less than design volume combined with the idea that the pipeline diameter could be reduced by sludge accumulation without increasing pump pressure or otherwise impacting the operational efficiency of the line a consideration in the determination not to clean or maintenance pig the transit lines?

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REPRESENTATIVE PAUL SEATON
DISTRICT 35

Memorandum

From: Rep. Paul Seaton
To: House Resources Co-Chair Rep. Ralph Samuels
House Resources Co-Chair Rep. Jay Ramras
Senate Resources Chair Sen. Tom Wagoner
Date: September 7, 2006
Re: Transit Lines and TAPS Pigging Schedules

BP testified to the Joint House and Senate Resources Committee meeting on August 18th that they did not think they needed to pig clean and smart pig the transit lines because they were handling market ready oil - that is oil with the majority of the water and contaminants removed. However, other information has circulated that the clean pigging was not done previously because TAPS Pump Station #1 could not handle the built-up volume of sludge with its filtration system and other arrangements were not made to alternatively handle that volume of sludge. I requested from BP verification of that information and any BP correspondence with TAPS on the issue at the last meeting and am awaiting a response.

Additional information available from Alyeska Stakeholders Information Office published August 2006 entitled "Pigging the Trans Alaska Pipeline System" says that "cleaning pigs run weekly or every other week, smart pigs are scheduled every three years...." and "...in 29 years of operation, 60 smart pigs have been run to inspect the pipeline."

Please submit the following question for an answer at the next Resources meeting: since BP is an owner of Alyeska, how can it justify not pigging the transit lines it operates in the Prudhoe Bay unit handling market oil while the same market oil in TAPS requires a substantial expenditure and aggressive cleaning pig and smart pigging schedule as outlined above?

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL & GAS

SARAH PALIN, GOVERNOR

550 WEST 7TH AVENUE, SUITE 800
ANCHORAGE, ALASKA 99501-3560
PHONE: (907) 269-8800
FAX: (907) 269-8938

June 5, 2007

The Honorable Bart Stupak, Chairman
Subcommittee on Oversight and Investigations
Committee on Energy and Commerce
U.S. House of Representatives
2125 Rayburn House Office Building
Washington, D.C. 20515

Dear Chairman Stupak:

On May 16, 2007 I testified on behalf of the State of Alaska at the hearing entitled "2006 Prudhoe Bay Shutdown: Will Recent Regulatory Changes and BP Management Reforms Prevent Future Failures?" This letter responds to the following questions asked by yourself and by Rep. Inslee:

1. What did BP tell the Alaska Department of Environmental Conservation (ADEC) in order to justify its request that ADEC waive the pigging requirement in the May 29, 2002 Compliance Order By Consent (COBC)?

2. Why did ADEC agree to waive the pigging requirement?

In support of my responses, several relevant documents are provided for your reference. Some of these documents have only recently been received by the State of Alaska, and help significantly to clarify the events in question. With the exception of the documents identified with the prefix "BPXA-ADEC" and the excerpts from the "Commitment to Corrosion Monitoring Reports," it is my understanding that all of the attached documents have previously been received by the Subcommittee.

In response to the first question, the short answer is that BP told ADEC that testing indicated its original report regarding solids in the oil transit lines (OTLs) was incorrect, and that only minimal sediment existed. BP then told ADEC that it had made facility modifications which would allow it to pig the OTLs at any time in the future.

The state's previous response on this issue is captured in the October 16, 2006 letter from ADEC Commissioner Kurt Fredriksson to Chairman Barton providing information on the COBC. The requirement that BP pig the pipeline segments was included in the COBC as a result of BP's earlier report that solids had been discovered in the OTLs that could interfere with tests of the leak detection system. However, in August 2002, after the COBC was entered into, BP notified ADEC that flow meter testing indicated that in fact only minimal sediment existed. This information sets forth BP's position that its earlier sediment estimates had been incorrect such that pigging the OTLs as a prerequisite to testing the leak detection system was no longer necessary. The attached August 9, 2002 letter from Gary Campbell to Lydia Miner, and Ms. Miner's August 14, 2002 response further support this conclusion. The October 13, 2002 letter from Kevin Gaynor on this issue includes as attachments additional internal BP

documents attempting to reconcile BP's original representations to ADEC and BP's subsequent retraction of its statements regarding sediment levels following additional ultrasonic testing. Last, BP's October 2002 internal timeline summarizes events relating to the leak detection requirements, and draws from internal BP e-mail discussing this issue.

The "Billie Garde Report," in particular pages 16-22, sheds additional light on BP's inconclusive determination regarding whether sediment existed in the OTLs. Importantly, none of the correspondence or data underlying the debate was shared with ADEC or any other Alaska agency until recently. The Garde Report also does not address the fact that ADEC was ultimately told that only minimal sediment existed in the OTLs.

Finally, I draw your attention to key statements in several of the "Commitment to Corrosion Monitoring" reports submitted by BP each year pursuant to the Charter Agreement. (The full reports are available at the following website: http://www.dec.state.ak.us/spar/ipp/nscharter.htm .) These reports focused on well lines and flow lines, only reporting on the OTLs by exception, and then only briefly. However, the reports for 2002, 2003, and 2004 did specifically address the issue of pigging the OTLs. In those reports, BP informed the state that "periodic maintenance pigging" was part of its corrosion mitigation plan for "export oil" lines, i.e., the OTLs. We now know that no maintenance pigging had been done on the Western Operating Area OTLs since 1998, and on the Eastern Operating Area OTLs since 1990. However, since BP informed ADEC in Mr. Campbell's August 9, 2002 letter that it had made modifications which would allow it to pig the OTLs at any time in the future without further facility modifications, and subsequently stated that periodic maintenance pigging was in fact being performed on the OTLs, ADEC had no reason to believe that sediment build-up was an ongoing problem on those lines. This answers your second question.

Thank you for the opportunity to provide additional information in response to your questions, and for the opportunity to appear before the Subcommittee.

Sincerely,

Jonne Slemons
Petroleum Systems Integrity Office Coordinator

Enclosures:

Compliance Order By Consent, Consent Order No. 02-138-10
October 16, 2006 Fredriksson/ADEC Letter to Hon. Joe Barton
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August 14, 2002 Miner/ADEC Letter to G. Campbell
November 26, 2002 Conrad letter to C. Leonard/ADEC
March 25, 2003 Bronson Letter to J. Mach/ADEC
April 3, 2003 Hutmacher/ADEC Letter to J. Fritts
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February 13, 2002 Phillips Letter to M. Barnes
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October 19, 2002 Campbell E-mail to Phillips, Blankenship, Conrad
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cc (w/enclosures):
The Honorable Sarah Palin, Governor, State of Alaska
The Honorable Ted Stevens, Senator, U.S. Senate
The Honorable Lisa Murkowski, Senator, U.S. Senate
The Honorable Don Young, Representative, U.S. House of Representatives
Vice Admiral Thomas J. Barrett, USCG (Ret.), Deputy Secretary, U.S. Department of Transportation
Stacey Gerard, Chief of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation
Commissioner Thomas Irwin, Alaska Department of Natural Resources
John Katz, Director, Alaska Governor's Office, Washington, D.C.

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL & GAS

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June 5, 2007

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Subcommittee on Oversight and Investigations
Committee on Energy and Commerce
U.S. House of Representatives
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Washington, D.C. 20515

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Petroleum Systems Integrity Office Coordinator

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Vice Admiral Thomas J. Barrett, USCG (Ret.), Deputy Secretary, U.S. Department of Transportation
Stacey Gerard, Chief of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation
Commissioner Thomas Irwin, Alaska Department of Natural Resources
John Katz, Director, Alaska Governor's Office, Washington, D.C.