Entergy	CONDITION REPORT	CR-IP2-2009-00666

Originator: Rohla III,Otto R
Originator Group: Operations Watch Staff IP2
Supervisor Name: Gates,Clifton
Discovered Date: 02/15/2009 15:29

Originator Phone: 5295
Operability Required: Y
Reportability Required: N
Initiated Date: 02/15/2009 15:35

Condition Description:
Water filling floor guard collar on CST return line and spilling onto floor on 18' AFB. Chemist has been contacted for sampling.
Chemist reports 54ppB of Hydrazine in water.

Immediate Action Description:
Secured recirculation of CST-Hotwell. Chemist dispatched for sampling

Suggested Action Description:
Determine source of leakage

EQUIPMENT:

Tag Name	Tag Suffix Name	Component Code	Process System Code
CST	HCLM/SR/MR	ACCUMU	AFW

REFERENCE ITEMS:

Type Code	Description
CR	IP2-2009-02874
CR	IP3-2009-00556
CR	IP3-2009-02788
CR	IP3-2009-02150
LOCR	LO-IP3LO-2009-00118 (Effectiveness Review)
LTCR	Approved by CARB on 5/14/09 w-Eng Director Present
TEAM 2C	
WON	00183296
WRN	00171129
WRN	00171130
WRN	00171137
WRN	WR#00156027
WRN	00171140
WRN	00171141
WRN	00171143

TRENDING (For Reference Purposes Only):

Trend Type	Trend Code
REPORT WEIGHT	1
HEP FACTOR	E
INPO BINNING	ER3
EL	ESPC
KEYWORDS	KW-LEAKS-WATER
KEYWORDS	KW-CONDENSATE STORAGE TANK
KEYWORDS	KW-PIPE BREAK
KEYWORDS	KW-ENVIRONMENTAL DISCHARGE

IPEC00202297

~~**TRENDING (For Reference Purposes Only):**~~

Trend Type	Trend Code
UPGRADED CR CATEGORY	CAT B to CAT A
GRADE RCA	20.4
CAUSAL FACTOR	OP4A
CAUSAL FACTOR	OP2J
CAUSAL FACTOR	OP5E
LT-MOD/DESIGN	CA#14 Per NSA Director CARB chairperson
# PERIODIC REVIEW - INITIAL	

IPEC00202298

Initiated Date: 2/15/2009 15:35 **Owner Group :** P&C Eng Codes Mgmt IP2

Current Contact:

Current Significance: A

Closed by:

Summary Description:

Water filling floor guard collar on CST return line and spilling onto floor on 18' AFB. Chemist has been contacted for sampling.
Chemist reports 54ppB of Hydrazine in water.

Remarks Description:

CR #4 to perform a Root Cause evaluation was initially performed by the owner department on 3/19/09 (<30 days). The Site VP has requested the RCA be extended until failure analysis and evaluation of the failed section of pipe is complete. CA re-opened to owner department to extend. MLT 3/20/09.

Closure Description:

IPEC00202299

Entergy	OPERABILITY	CR-IP2-2009-00666

OperabilityVersion: 1

Operability Code: EQUIPMENT INOPERABLE

Immediate Report Code: NOT REPORTABLE

Performed By: Spagnuolo,Frank M 02/16/2009 01:05

Approved By: Dewey Jr,Donald J 02/16/2009 01:34

Operability Description:

CST is inoperable due to external pipe leakage and the potential of draining the CST upon a pipe break.

Approval Comments:

Agree and Approve

IPEC00202300

IPEC00202300

OperabilityVersion: 2

Operability Code: EQUIPMENT INOPERABLE

Immediate Report Code: NOT REPORTABLE

Performed By: Huron,Robert W 02/20/2009 17:34

Approved By: Baker,John R 02/20/2009 18:05

Operability Description:

CST was declared inoperable on Monday, Feb 16, 2009

Approval Comments:

Approved

IPEC00202301

Entergy	**OPERABILITY**	**CR-IP2-2009-00666**

OperabilityVersion: 3

Operability Code: EQUIPMENT OPERABLE

Immediate Report Code: NOT REPORTABLE

Performed By: Spagnuolo,Frank M 02/24/2009 20:12

Approved By: Dewey Jr,Donald J 02/24/2009 20:42

Operability Description:

The CST was returned to OPERABLE on 2/21/09 at 0656 after replacement of the defective length of pipe. All Post Work testing has been completed satisfactorily.

Approval Comments:

Agree and Approve.

IPEC00202302

Version: 2

Significance Code: A

Classification Code: RCA

Owner Group: P&C Eng Codes Mgmt IP2

Performed By: Harrison,Christine B 02/20/2009 12:11

Assignment Description:

2/20/09: At the direction of senior management, Category of this CR upgraded from a "B" to an "A". CA-00002 has been closed to new CA-00004 which reflects this new assignment. CARB Review CA has been edited to reflect this new assignment.

IPEC00202303

Entergy	ASSIGNMENTS	CR-IP2-2009-00666

Version: 1

Significance Code: B

Classification Code: HT-ACE CARB

Owner Group: P&C Eng Codes Mgmt IP2

Performed By: Harrison,Christine B 02/19/2009 10:53

Assignment Description:

IPEC00202304

IPEC00202304

Entergy	**REPORTABILITY**	**CR-IP2-2009-00666**

Reportability Version: 2

Report Number:

Report Code: NOT REPORTABLE

Boilerplate Code:

Performed By : Rokes,Charles B 03/17/2009 11:28

Reportability Description:

The recorded condition does not meet reporting criteria of SMM-LI-108 based on engineering response to CA-8 concluding the as-found condition and past condition did not result in inoperability of the AFWS. The condition of the leak in the Condensate Return Line did not affect past operability of TS components, specifically the AFW System (TS 3.7.5) and the Condensate Storage Tank (TS 3.7.6) as demonstrated by the attached safety significance review. The AFW System was not affected as the Return Line was determined by calculation to remain operable. By conservative estimates the leak would have required an additional 21,600 gals above the 360,000 gal required for the 24hr decay heat removal of TS 3.7.6. This means that an additional 1.13 ft in CST level or a minimum of 17 ft indicated would have to be maintained to account for the additional loss from this past leakage. Except for outages, the plot of past CST level shows level was maintained far above that required by TS 3.7.6.

IPEC00202305

Entergy	REPORTABILITY	CR-IP2-2009-00666

Reportability Version: 1

Report Number:

Report Code: INDETERMINATE - EVAL

Boilerplate Code:

Performed By : Rokes,Charles B 03/03/2009 08:27

Reportability Description:

The impact of the condition on CST or AFW operability is not known therefore CA-8 was issued for SE to determine if the condition during past operation could have resulted in a TS violation or a safety system functional failure. A TS Prohibited condition would be a 60-day LER under 10CFR50.73(a)(2)(i)(B), and a SSFF would be a 60-day LER under 10CFR50.73(a)(2)(v).

IPEC00202306

Entergy	CORRECTIVE ACTION	CR-IP2-2009-00666

CA Number: 1

	Group	Name
Assigned By:	Operations Watch Staff IP2	Dewey Jr,Donald J
Assigned To:	Engineering Director IP2	Burroni,Richard J
Subassigned To :		

Originated By:	Dewey Jr,Donald J	2/16/2009 01:51:36
Performed By:	McCaffrey,Thomas S	2/20/2009 10:49:09
Subperformed By:		
Approved By:		
Closed By:	Baker,John R	2/20/2009 13:28:38

Current Due Date: 02/20/2009 **Initial Due Date:** 02/20/2009

CA Type: OPERABILITY INPUT

Plant Constraint: #NONE

CA Description:

Develop an operability evaluation for the operability of the CST supply to the AFW pumps and the CST return line because of the suspected leakage below ground from either of these lines.

Response:

Based on investigateion of the pipe crack, it was recommeneded that the line be repaired. Based on this repair, no operability evaluation has been performed for the as found condition.

Subresponse :

Closure Comments:

Response accepted. Return line repairs in progress.

IPEC00202307

IPEC00202307

Entergy	CORRECTIVE ACTION	CR-IP2-2009-00666

CA Number: 2

	Group	Name
Assigned By:	CRG-CARB-SARB IP2	Harrison,Christine B
Assigned To:	P&C Eng Codes Mgmt IP2	Azevedo,Nelson F
Subassigned To :		

Originated By:	Harrison,Christine B	2/19/2009 10:17:18
Performed By:		
Subperformed By:		
Approved By:		
Closed By:	Harrison,Christine B	2/20/2009 12:07:45

Current Due Date: 03/11/2009 **Initial Due Date:** 03/12/2009

CA Type: DISP - ACE/HT

Plant Constraint: #NONE

CA Description:

Please perform higher-tier apparent cause evaluation and assign further corrective actions as required. Note that your evaluation is to be presented to CARB and a corrective action is being assigned to CA&A to document this presentation.

Response:

Subresponse :

Closure Comments:

2/20/09: At the direction of senior management, Category of this CR upgraded from a "B" to an "A". This CA is being closed to new CA-00004 which reflects this new assignment.

IPEC00202308

IPEC00202308

Entergy	**CORRECTIVE ACTION**	**CR-IP2-2009-00666**

CA Number: 3

	Group	Name
Assigned By:	CAA Staff IP2	Harrison,Christine B
Assigned To:	CAA Staff IP2	Harrison,Christine B
Subassigned To :		

Originated By:	Harrison,Christine B	2/19/2009 10:18:06
Performed By:	Tumicki,Michael L	5/15/2009 11:51:27
Subperformed By:		
Approved By:		
Closed By:	Tumicki,Michael L	5/15/2009 11:51:27

Current Due Date: 05/29/2009 **Initial Due Date:** 05/29/2009

CA Type: CARB REVIEW

Plant Constraint: #NONE

CA Description:

Document the results of the root cause analysis presentation to CARB.

IPEC00202309

Response:

5/14/09: The Root Cause Analysis was presented to, and accepted with edit by, the CARB with the NSA Director serving as chairman. The report received an average grade of 20.4. The CARB provided the following insight to be included in the report:

P 9 - remove words about estimated 10-12 gpm leak
P 10 - remove section about DC-343
P 16 - remove last sentence referencing att 9.4
P 19 - Delete the first paragraph under the title "Conditions That Lead To The Corrision and Leak" and remove the section titles
P 20 - add words about failure analysis performed by vendor and remove the section titles
P 22 - add backfill spec # in root cause paragraph
P 23 - delete CC2
P 25 section D - clarify "resources" is referring to specification for backfill and add construction worker practices/supervisory oversight during original construction to discussion
P 26 - second paragraph delete word "preliminary"
□Delete last two sentences on page
P 27 - extent of cause- last sentence delete words "when developed"
P 31 - #2 - change words so it is clear that 650,000 gallons is the lowest CST can drain to
□#4 and delete reference to CST trends
□Add bullet # 7 that city water backup is available if CST is unavailable
P 34 - delete CC2, CC3 from first line of causes
□Delete everything from second line of causes except CC2
□CC 1 change words to "need/feasibility" and replace words "any or all" with "selected"
□Change CC3 to CC2 and delete words "and accessability"
□Change CC3 to CC2 and change due date from from 9/15 to 11/15
□EOC - change words "once add'l inspection and analysis complete, assign actions needed and present to CARB
□Other - change teak to tank
P 35 - change all CC3's to EOC
□Delete entire EOC corrective action line -second from bottom of page
P 36 - under CAPR's delete all # 2 CAPR's from page
P 39 - label all attachments
□Add #3 - vendor pipe failure analysis
P 40 why staircase - add another box between bottom two boxes to say - use of blast rock from unit 3 was allowed as backfill

3/20/09: Per special CARB meeting and based on request by Site Vice President, approval was given by CARB to extend the due date for the completion of this root cause analysis to May 21, 2009.

Subresponse :

Closure Comments:

IPEC00202310

Entergy	**CA DUE DATE EXTENSION**	**CR-IP2-2009-00666**

Corrective Action : CR-IP2-2009-00666 CA-00003

Version: 1 **Approved:** ✓

Requested Duedate: 05/29/2009 **Previous Duedate:** 03/21/2009

Requested By: Tumicki,Michael L 03/20/2009

Approved By: Tumicki,Michael L 03/20/2009

Request Description:

The due date to perform the RCA evaluation CA #4 has been extended to 5/21/2009 to complete, evaluation and incorporation of a failure analysis into the RCA report. The extension of CA #4 was approved by the Site VP, CARB and P&C Manager IAW EN-LI-102 to exceed the 30 day disposition requirement. This administrative CARB tracking CA has been extended to accommodate the new RCA evaluation due date. There is no impact to Nuclear, Radiological, Environmental or Personnel safety by extending this CA. The CA&A Manager concurs with this extension.

Approved Description:

Approved per above discussion.

IPEC00202311

Entergy	CORRECTIVE ACTION	CR-IP2-2009-00666

CA Number: 4

	Group	Name
Assigned By:	CRG-CARB-SARB IP2	Harrison,Christine B
Assigned To:	P&C Eng Codes Mgmt IP2	Azevedo,Nelson F
Subassigned To :	P&C Eng Component Mgmt IP2	Manzione,Stephen J

Originated By:	Harrison,Christine B	2/20/2009 12:05:50
Performed By:	Azevedo,Nelson F	5/15/2009 15:12:27
Subperformed By:	Azevedo,Nelson F	5/15/2009 15:12:01
Approved By:		
Closed By:	Tumicki,Michael L	5/15/2009 16:08:19

Current Due Date: 05/20/2009 **Initial Due Date:** 05/21/2009

CA Type: DISP - RCA

Plant Constraint: #NONE

CA Description:

Please perform root cause analysis and assign further corrective actions as required. Note that your evaluation is to be presented to CARB within 30 days and a corrective action is being assigned to CA&A to document this presentation.

CA REFERENCE ITEMS:

Type Code	Description
CARB-ACCEPT W-EDIT	Minor

Response:

See sub response below.

Subresponse :

See attachment files for RCA and other supporting documentation. All CARB comments have been incorporate and all CAs have been assigned. No additional actions required under this CA.

Closure Comments:

The RCA report was presented to and accepted with edit by the CARB on 5/14/09. CA 3 captures the CARB comments. The CARB comments have been satisfactorly incorporated into the report and the revised report is attached to this CAs sub-response. This CA therefore closed.

CA re-opened to responsible department to extend per VP request. MLT 3/20/09

The Root Cause Report contains the required sections and discussion popints and has been approved by an independant reviewer and the Responsible Manager as indicated on the cover sheet. It is noted the CAs in the report CA plan are not presently in PCRS and owner has elected to issue the CAs associated with the RCA after CARB review. RCA Report accepted pending CARB review and approval. MLT 3/19/09

Attachments:

Subresponse Description
Part 2 - SIA Failure Analysis Report

Subresponse Description
Part 1 - SIA Failure Analysis Report

Subresponse Description
Root Cause Analysis Report

Subresponse Description
Internal OE Review

Subresponse Description
External Operating Experience Review

IPEC00202312

Attachments:

Subresponse Description
Why Staircase Analysis

Subresponse Description
Equipment Failure Evaluation

Subresponse Description
K-T Analysis

IPEC00202313

Attachment Header

Document Name:

untitled

Document Location

Subresponse Description

Attach Title:

Part 2 - SIA Failure Analysis Report

IPEC00202314

Structural Integrity Associates, Inc.

16912 Gridley Place
Cerritos, CA 90703
Phone: 562-402-3076
Fax: 562-924-9281
www.structint.com
bamend@structint.com

May 15, 2009

Mr. Robert Altadonna
Indian Point Energy Center
295 Broadway
PO Box 308
Buchanan, NY 10511-0308

Project:. 0900235.00
Report: 0900235.402 R0

Subject: **Analysis of 8" Condensate Water Storage Tank Return Line CD-183**
Final report

Dear Robert:

The report of our failure analysis of the leaking condensate piping is attached for your review. This final version contains no changes to Draft B, (other than the date of distribution and an updated report number) which you have reviewed and approved. Please contact me if you have any technical questions about this report, or Ken Rach for questions regarding any administrative issues about this project.

Best Regards,

William E. Amend

Associate

IPEC00202315

Structural Integrity Associates, Inc.

16912 Gridley Place
Cerritos, CA 90703
Phone: 562-402-3076
Fax: 562-924-9281
www.structint.com

Project 0900235.00
Report No. 0900235.402
May 15, 2009

ANALYSIS OF 8" CONDENSATE RETURN LINE FAILURE

Prepared For:

Entergy, Indian Point Nuclear Station

Prepared By:

Structural Integrity Associates, Inc.
Cerritos, California

Prepared By: William E Amend Date: May 8, 2009
Bill Amend, P.E.
Associate

Reviewed By: : G J Licina Date: May 11, 2009
George Licina
Chief Materials Consultant

Approved By: Kenneth R Rach Date: May 15, 2009
Ken Rach
Associate

IPEC00202316

REVISION CONTROL SHEET

Document Number:	0900235.402
Title:	**Analysis Of 8"Condensate Return Line Failure**
Client:	Entergy– Indian Point Nuclear Station
SI Project Number:	0900235.00

Section	Pages	Revision	Date	Comments
All	All	Draft A	4/9/09	Initial Draft for Review
All	All	Draft B	5/8/09	Second draft for Review
All	All	Final	5/15/09	No changes to draft B

IPEC00202317

CONTENTS

FIGURES

IPEC00202318

<u>TABLES</u>

IPEC00202319

ANALYSIS OF 8" CONDENSATE RETURN LINE FAILURE

Executive Summary

The leak in the steel condensate piping was caused by external corrosion. Patterns of corrosion on the piping and observations of the backfill indicate that the corrosion on the pipe occurred at localized areas of coating damage that most likely occurred during installation of the pipe or during installation of the fill. The corrosion on the elbow is more widespread than on the straight section of pipe and is typical of corrosion related to difficulties in applying a good quality wrap coating on a more difficult or irregular shape. It is likely that similar corrosion exists on adjacent piping if exposed to comparable soil conditions. The piping was not cathodically protected.

Corrosion on the inside surfaces was superficial.

No evidence of cracking was observed.

The metallurgical characteristics of the pipe and elbow were normal and the workmanship of the girth weld was good. Where corrosion pitting was present on the weld, the weld metal appeared to be more resistant to corrosion than the adjacent heat affected zone or base metal.

The analysis results did not definitively determine the mechanism of the external corrosion. Features of the corrosion (morphology and corrosion products) support a determination that the corrosion is either the result of exposure to a specific range of ground water characteristics, and/or to microbiologically influenced corrosion (MIC). The corrosion was not consistent with the characteristics of stray current corrosion, even though stray current was previously identified on other buried pipe at the plant.

XRD (x-ray diffraction analysis) showed that the ID corrosion products were generally iron oxides and hydroxides. The OD corrosion product was primarily siderite, an iron carbonate. The difference in corrosion products on the ID and OD indicate that the corrosion on the two surfaces is unrelated.

Recommendations related to selection of locations for further inspection, corrosion monitoring, and soil sampling are included.

Introduction

Indian Point Generating Station Unit 2 (Indian Point) experienced a leak on 8 inch buried piping identified as Condensate Storage Tank Return Line CD-183. The circumstances regarding the discovery of the leak are described in the narrative by Engineering staff in Appendix A. SI performed a long range guided wave (G-Scan™) inspection on February 17th, 2009. to screen several pre-selected sections of pipe for wall loss[1]. The inspection was performed while the

[1] Bass, A., " G-Scan™ Assessment of 8" Condensate Water Storage Tank Return Line CD-183, Inspection Date: February 17th, 2009",SI report no. 0900235.401.R0, March 13, 2009.

IPEC00202320

plant was in operation and water was flowing through the pipes. After identifying the leak location and adjacent areas of significant wall loss, Indian Point excavated the area and in accordance with their Technical Specifications replaced the leaking section of the piping..

As described in SI proposal 0900308.00 Rev. 1 of March 20, 2009, the objective of this analysis was to determine the probable failure mechanism and describe the overall condition of the pipe sample. Background information pertaining to the condensate piping is described in the next section. The piping sample was received by SI on March 23, 2009 after removal of the potentially hazardous external coating and related decontamination by Entergy.

Background Information

The following information was provided to SI by the staff of Entergy in response to our request for pertinent background information.

Table 1 –Background Information

Item	Inquiry	Response
1	Applicable design standard(s) for this piping (list applicable industry standard and company standards, particularly if company standards impose additional restrictions related to materials, construction, testing, or inspection) Copies of company or A-E specs	Construction code is B31.1 1955. Design piping specification- 9321-01-248-18 Class C-1. Lacquer coating by spool fabricator (dwg 17D523) All underground piping to be field coated and wrapped in accordance with AWWA spec C-203. Specification imposes no additional restrictions.
2	Installation year	Piping installed in late 1960's
3	Expected life or design life of this piping	Design life of pipe is not specified or known. Design life of plant is 40 years.
4	Expected life limited by what? (external corrosion following coating degradation, internal corrosion, fatigue, no longer needed, etc.)	Pipe life limitation appears to be based upon life of external coating. Based upon visual results, Entergy staff noted that the areas of pipe where coating was intact appears like new and has no external corrosion. Internal corrosion appears minor.
5	Specified wall thickness	Specified wall thickness- 0.322" (nominal wall thickness for 8"SCH40 pipe)
6	Minimum design thickness	Min design thickness- 0.064" per calculation IP-CALC-09-00035
7	Specified diameter	Pipe diameter-8"
8	Specified grade (pipe and elbow)	Pipe- A106 Gr B, Elbow- A234 WCB
9	Design pressure	665 PSIG
10	Normal operating pressure (including ranges)	Static head- approximately 45 PSIG at leak location

11	Original test pressure	Original test pressure unknown. Spool fabrication drawing does not specify a test pressure. After installation, one end is open to atmospheric tank. Not known if B31.1 hydrostatic test was performed.
12	Periodic test pressure (if any) and date of last test	Static head- Last test date unknown- Pressure drop test once every 3 years. Ref 2PT-3Y7
13	Description of the fluid on ID	Clean condensate
14	Operating temperature	90 to 115°F
15	Operating conditions consistent?	Continuous flow
16	Original construction inspection (radiography?, visual? UT?, other?)	Visual inspection of welds
17	Any other periodic inspection, monitoring, or testing	Pressure drop test once every 3 years. Ref 2PT-3Y7
18	Approximate depth of burial	Seven feet at leak location from top of building concrete floor slab
19	Specified backfill (description of what the pipe was supposed to be buried in)	Per specification 9321-01-8-4. This specification does not describe requirements for backfill materials below two feet below grade
20	Observed condition of backfill (as expected per item #19, wet, dry, contaminated by construction debris, rocky, gravelly, sandy, clay, other?)	See interview reports in Appendix A.
21	Measured soil resistivity	No soil resistivity measurements available for the location of the leak. Soil resistivity measurements for soil around this pipe approximately 100 feet and 200 feet from the leak location are described in Background Reference #7 and range from 8000 ohm-cm to 63,000 ohm-cm depending upon location and depth.
22	Any other soil analysis results available?	See 21 above and Background References #8 and #9.
23	Specified external coating (thickness, type, manufacturer, inspection or QA methods used during construction and installation) (refer also to item #1)	External coatings per specification AWWA C-203 "Coal-Tar Protective Coatings And Linings For Steel Water Pipelines - Enamel And Tape - Hot Applied"
24	Coating on welds same as coating on pipe?	The same coating was used on pipe and on welds.
25	Observed condition of coating upon excavation (mechanically damaged, disbonded, water under coating, obvious degradation, etc.)	See interview reports in Appendix A

IPEC00202322

26	Electrically continuous with different alloys? If so, what alloys and how far away.	No other buried alloys as part of this condensate piping. The copper grounding grid is believed to be electrically continuous with this piping
27	Cathodic protection installed? If so, describe system type (impressed current, galvanic) and history of potentials, CP maintenance, or operational history	No cathodic protection installed on this system. CP is installed on some other underground systems as described in Background Reference #7
30	Any potential source of electrical interference or history of lightning strikes or ground faults or source of electrical current pick-up and discharge from this pipe?	No known electrical interference, lightening strikes, etc. on this piping. Background Reference #7 does describe interference on another piping system related to a crossing foreign line that is cathodically protected
29	Free corrosion potential (potential of unprotected steel in the same backfill vs. Cu-CuSO4 reference electrode)	Potential measurements are listed in Background reference #7. The measurements range from -248 mV to -328 mV (some possible minor effects of active CP elsewhere in the plant, although this pipe was not cathodically protected)
31	History of significant external corrosion on adjacent piping, if so, describe pipe, service conditions, and approx. date of discovery	No corrosion history on adjacent 12" pipe (same fluid & design). The adjacent 12" line is coated the same as the failed pipe and carrying the same fluid. A 10" CMP drain line is approximately 12 feet from the failed piping at the leak location. The drain line is coated with the same coating as the failed pipe.
32	Any new pipe installations in this line or near by	No new pipe installations
33	Any photographic information from the leak location.	See Figures 1-3 of this report

IPEC00202323

Table 2 - Other Background Reference Materials Provided by Entergy Staff for Review

1	UT survey results for the 8" CST pipe, "UT Erosion/Corrosion Examination" report IP2-UT-09-010
2	Relicensing Ground Water Samples. Xls
3	Relicensing Sample Locations.doc (Monitoring Well locations)
4	Attachment 1 IP2 FSAR CP Discussion: This documents the original plant design information concerning underground piping, cathodic protection and soil resistivity.
5	Attachment 2 CST Lines.pdf: This shows the locations of the excavations performed on this line in 2008. This is an elevation view. The leak was at the very bottom left and the 1st excavation is off the page at the top right.
6	Attachment 3 Condition Report : This is a report on the condition of the coating and pipe in the first excavation.
7	Attachment 4 "Corrosion/Cathodic Protection Field Survey and Assessment of Underground Structures at Indian Point Energy Center Unit Nos. 2 and 3 during October 2008" prepared by PCA Engineering, revised December 2 2008?.
8	Attachment 5 GEL Labs 11-07-08 Soil Sample Package for Engineerng.pdf: This is the report of the soil evaluation performed for the two 2008 excavations. They are labeled U2-CST-1 through 4.
9	Attachment 6 02-20-09 Soil Sample Results Package.pdf(2) : This is the soil analysis from the leak location taken 2-20-2009.
10	"Specification for Placing & Compaction of Backfill", Spec. No. 9321-01-8-4, April 10, 1967, by United Engineers & Constructors, Inc. for Westinghouse Electric Corporation for Indian Point Generating Station – Unit No. 2
11	Page 14 of specification for piping materials, Specification No. 9321-01-248-18 Part A, July 29, 1966, Revision 6A, September 1, 1990.

IPEC00202324

Figure 1- View of pipe coating as observed in the excavation by Entergy Staff
This photograph was provided to SI by Entergy staff. It was taken before the pipe sample was removed. Note wrinkling of the coating typical of soil stress. (Soil stress refers to distortion of external pipe coatings of this type. The distortion is typically caused by relative movement of the pipe and soil resulting from pipe expansion and contraction, soil settlement, or other events.) Arrows point to examples of angular rocks in the backfill.

IPEC00202325

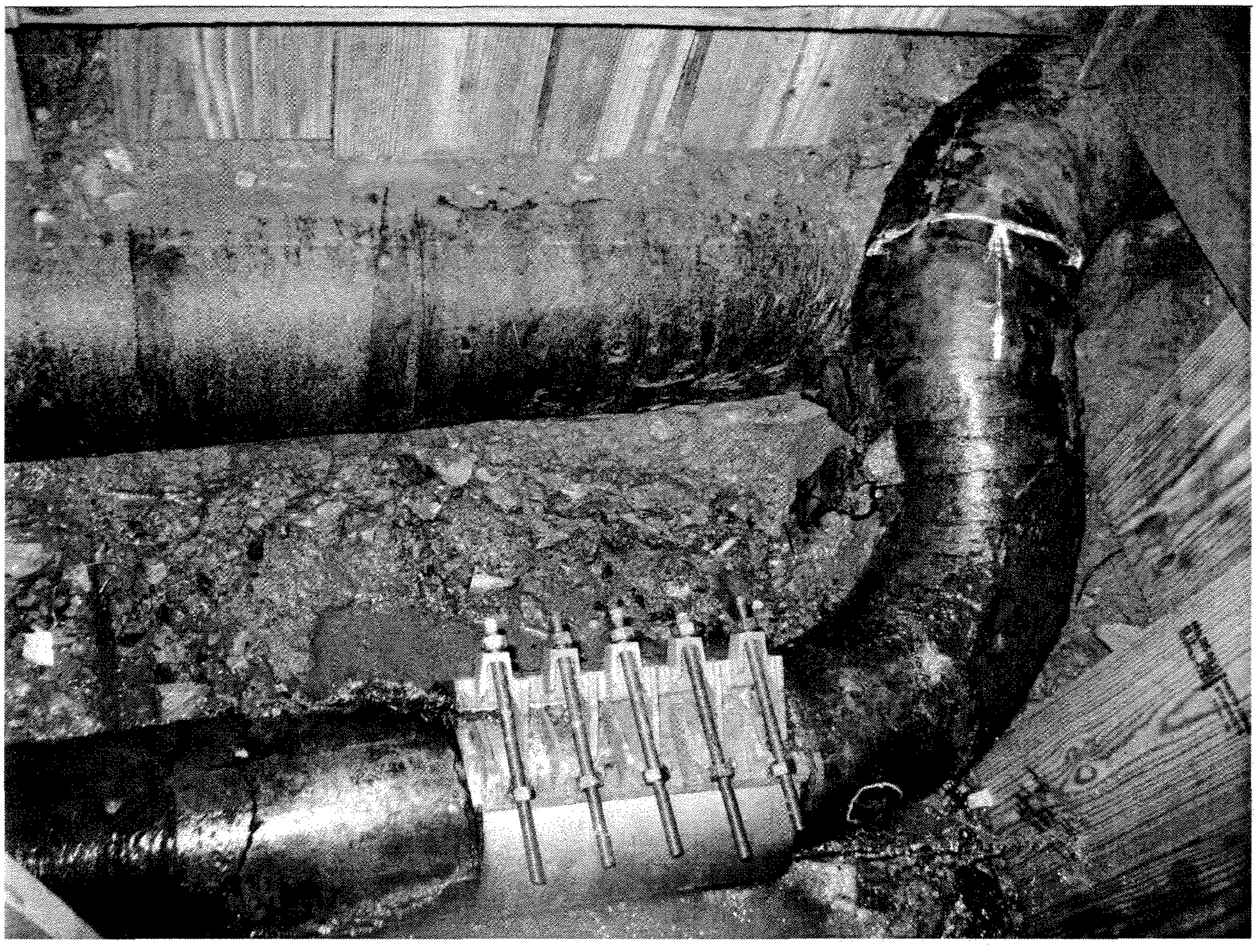

Figure 2 - Photograph of pipe in the excavation before removal of the pipe sample. This photograph was provided to SI by Entergy staff. A leak clamp has been applied to the area of the leak. The white arrow and lines at upper right indicate the limits of coating that was to be removed during the process of replacing the segment of leaking pipe. See next figure for detail of rocks in the backfill to the upper left of the clamp.

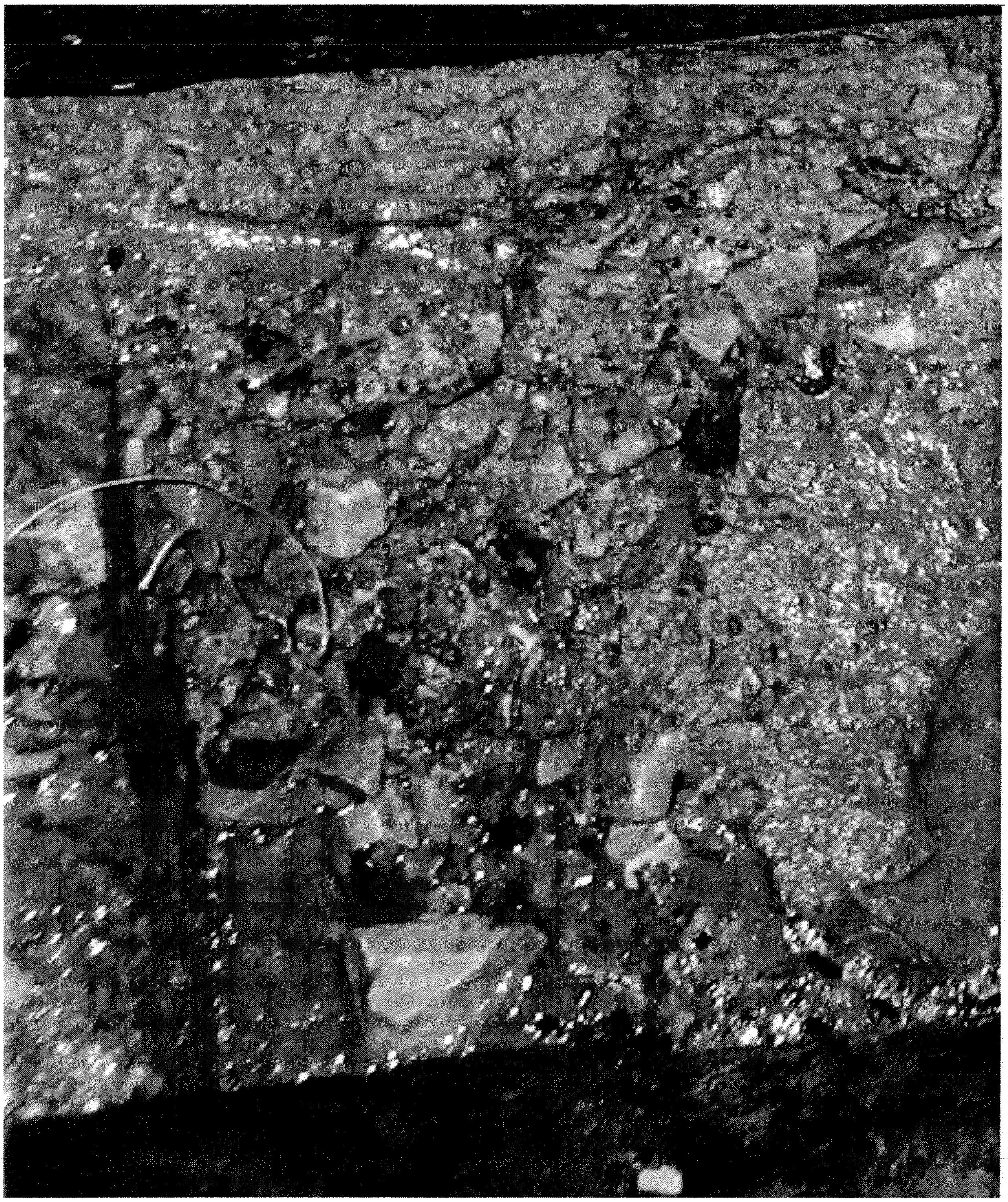

Figure 3 - Detail of previous figure showing angular rocks in the backfill.

IPEC00202327

Analysis and Results

The analysis tasks included the following:

- Detailed receipt inspection of the sample
- Detailed visual inspection of the outside diameter (OD) of the pipe for cracks, mechanical damage, thinning, corrosion product, etc.
- Visual examination of the inside surface of the pipe for evidence of features that might have influenced the failure
- Dimensional characterization from the OD
- Detailed corrosion mapping
- Metallography to determine the general microstructure and correlation between failure location and microstructure, proper microstructure, any anomalies
- EDS (energy dispersive spectroscopy) and XRD (x-ray diffraction) of corrosion products
- Bulk steel composition
- Tensile Properties of pipe and elbow

The significant findings are summarized below. Details of the results and relevant comments are included in the figures and tables that follow.

Visual Examination: The external coating had been removed and the external surfaces wire brushed and washed by site personnel prior to shipping. As a result, no soil or external coating was present when we received the sample. Some external corrosion product may have been removed by the washing process. The as-received condition of the pipe is illustrated in Figures 4 through 9. Segments removed for further analysis are illustrated in Figure 10. Photographs of manufacturer's markings are illustrated in Figures 11 through 14.

External corrosion on the straight pipe generally consisted of deep isolated pits surrounded by surfaces that were completely uncorroded. The pattern of corrosion was consistent with isolated breaks in the coating. The observed corrosion is mapped in Figure 15. Photographs illustrating representative areas of the corrosion are included in Figures 16 though 32.

The external corrosion on the elbow was more widespread and included relatively large areas of more generalized corrosion. This corrosion pattern was more characteristic of less effective performance of the external coating, perhaps as a result of the difficulty in producing a good wrap pattern when coating irregular shapes such as elbows and other fittings.

In both the elbow and the pipe the morphology of the metal loss included features often associated with MIC including tunneling, striations, overlapping cup-shaped pits, and steep sided pits that sometimes had metal loss that undercut the surface of the pipe. However, similar corrosion patterns can also be produced by abiotic corrosion mechanisms.

The internal corrosion consisted of very shallow scattered pits in the elbow and more widespread, generalized corrosion in the pipe. The appearance of the corrosion is illustrated in Figures 33 through 37. Nothing observed on the inside surface of the pipe would have contributed to this leak.

The girth weld appeared to be of good workmanship with no significant visible flaws from anything other than corrosion.

Ultrasonic Thickness Surveys and Corrosion Mapping: Ultrasonic thickness data provided by Entergy were spot checked and then supplemented with additional measurements. The supplemental measurements were located around the circumference of the sample at four locations, including near the end of the pipe, the end of the elbow, and on each side of the girth weld. No unexpected results were obtained and the SI data were similar to measurements made by Entergy staff at the corresponding locations.

Visible areas of external corrosion were measured to record the maximum axial length and circumferential width and maximum depth of each area. On the straight pipe, the measurements were made using a digital pit depth gage with a resolution of 0.0005 inches. On the elbow where the pit depth gage and bridging bar could not be used, the pit profile was replicated using a contour gage and the contour was traced. The depth of the pit as indicated by the trace was measured using a magnifying glass and a machinist's scale with a resolution of 0.01 inches. Prior comparisons of this method with a conventional pit depth gage show that the contour gage measurements are typically accurate to about 0.010 inches.

Corrosion Product Analysis: The corrosion product on the external surface was relatively soft and friable and was generally nonmagnetic or very weakly ferromagnetic. The corrosion products did not extend above the surface of the pipe, but pits were either completely or partially filled with corrosion product in most cases. Analysis by XRD showed that the external corrosion products consisted primarily of iron carbonate (siderite). EDS showed the presence of very little chloride and only small amounts of sulfur.

The corrosion product on the inside was very hard, tightly adherent, and strongly attracted to a magnet. The corrosion products resulted in distinct raised bumps above each small pit. Analysis by XRD showed that the corrosion product was composed of various iron oxides, including about 70% magnetite, which was likely responsible for the hard, adherent, ferromagnetic properties. Only small amounts of chlorine and sulfur were present.

Analysis of the Steel: The tensile properties of the pipe and elbow were normal. The chemical composition of the elbow met the specification. The chemical composition of the pipe deviated from the ASTM A106 requirement that the steel contain at least 0.1% silicon. Two samples of the steel pipe both were found to contain 0.02% silicon, which meets the requirements of both API 5L grade B pipe and ASTM A53 grade B seamless pipe. It is unlikely that the deviation influenced the external corrosion. However, we have seen other cases in which the silicon killed steels appeared to be slightly more resistant to some forms of internal corrosion. The small difference in composition may explain the differences in the patterns of internal corrosion observed between the elbow and the pipe (i.e., general corrosion vs. pitting).

Microstructural Analysis: The metallographic cross sections of the pipe, elbow, and girth weld showed no metallurgical anomalies. All microstructures were as expected. The pipe and the elbow both consisted of fine pearlite and proeutectoid ferrite phases, as is typical for hot worked

mild steel. The cross sections showed that the mill scale (magnetite) on the outside surface of the pipe was intact except in areas of corrosion pits, indicating that the surface was not prepared by abrasive blasting prior to coating. The microstructures are illustrated in Figures 40-48. See the figures for explanation of the illustrated features.

Determination of Corrosion Mechanism: The determination of the likely mechanism for the external corrosion was based mainly upon the characteristics of the corrosion product and the morphology of the corrosion. As noted above, the external corrosion product is virtually all iron carbonate. Iron carbonate is most commonly associated with corrosion resulting from exposure of steel to wet CO_2 . However, several sources discuss the formation of iron carbonate in fresh and salt waters where CO_2 corrosion is unlikely[2 3 4 5]. The references cite the finding of siderite among fresh water and salt water corrosion products but do not describe the morphology of the metal loss associated with the siderite or the corrosion rates related to its formation. Reference 2 relates the formation of siderite to near neutral pH conditions (i.e., about pH 7.2 to 9.4) in which some alkalinity is present, and oxygen is either absent or in which the oxidation of ferrous iron Fe(II) to Fe(III) is kinetically inhibited. Examples of oxidation inhibitors that would favor the formation of siderite include natural organic matter and calcium. The same reference, though, describes siderite as a relatively protective corrosion product, relative to the protectiveness of other corrosion products.

Siderite has also been shown to be related to microbiological processes[6 7 8], although it is less commonly cited than some other corrosion products as a MIC-related corrosion product in the corrosion literature.

[2] Wilson, B.M., Johnson, D.L., et.al., "Corrosion Studies on the USS Arizona with Application to a Japanese Midget Submarine" TMS website at http://www.tms.org/pubs/journals/jom/0710/wilson-0710.html
[3] AWWA Research Foundation "Internal Corrosion of Water Distribution Systems", ISBN 0898677599, published by American Water Works Association, 1996
[4] McNeill, L.S., Edwards, M. "Review of Iron Pipe Corrosion in Drinking Water Distribution Systems"
[5] Cook, D.C., Peterson, C. E., "Corrosion of Submerged Artifacts and the Conservation of the USS Monitor", AIP Conference Proceedings, Journal Vol 765, Issue 1,International Symposium on the Industrial Applications of the Mossbauer Effect, Madrid, Spain, May 2006
[6] Zhang, C.L., Horita, J, et. al., "Temperature-Dependant Oxygen and Carbon Isotope Fractionations of Biogenic Siderite" downloaded from http://www.sciencedirect.com
[7] Weber, K. A., Picardal, F.W., Roden, E.E. "Microbially Catalyzed Nitrate Dependant Oxidation of Biogenic Solid-Phase Fe(II) Compounds" *Environmental Science & Technology*, 2001, vol. 35,No. 8, pp 1644-1650.
[8] Mattiesen, H., Hilbert, L.R., Gregory, D.J., "Siderite as a Corrosion Porduct on Archaeological Iron From a Waterlogged Environment" *Studies in Conservation,* vol 48., 2003, pp 183-194

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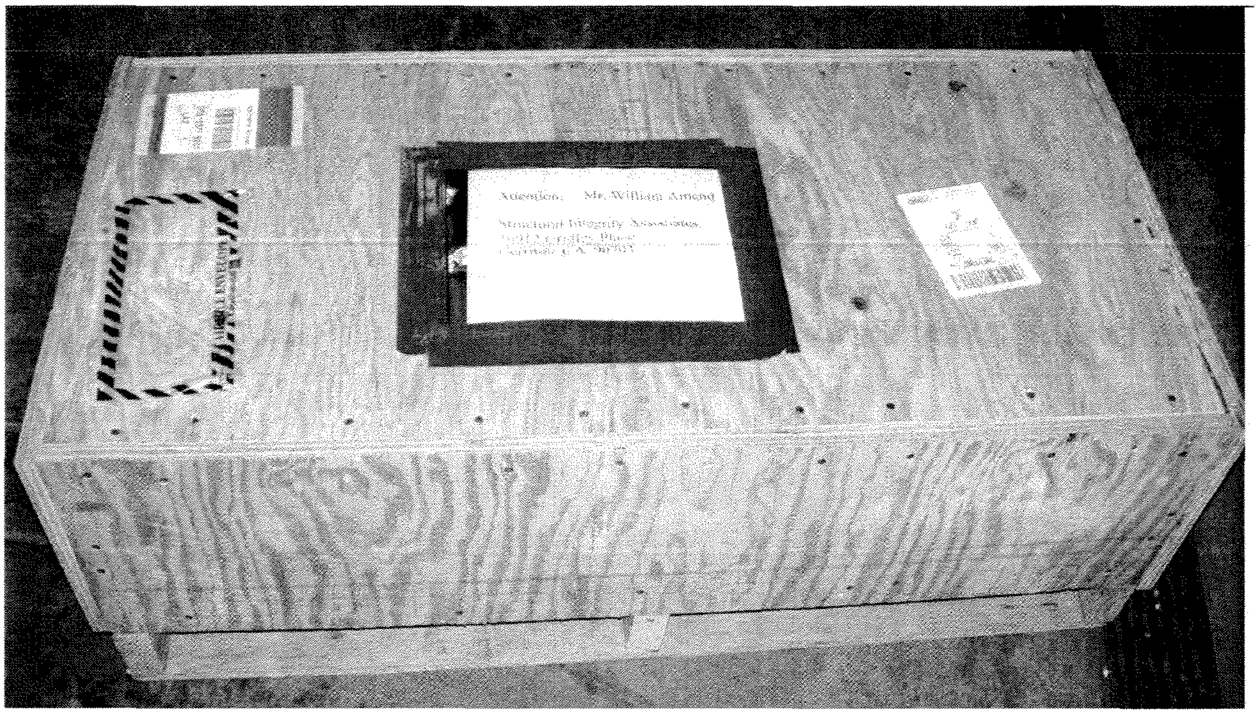

Figure 4 - Shipping container for pipe sample, as-received on March 23, 2009

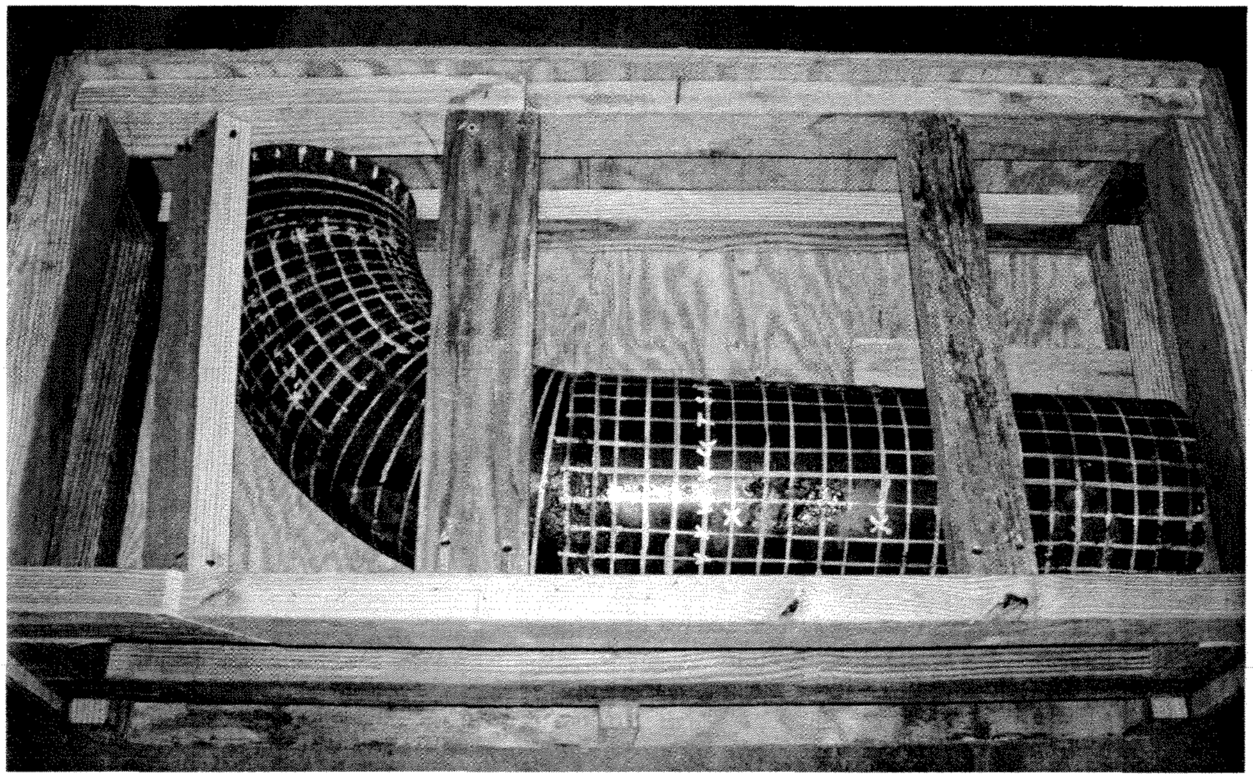

Figure 5 – Pipe sample as-received in the shipping container.

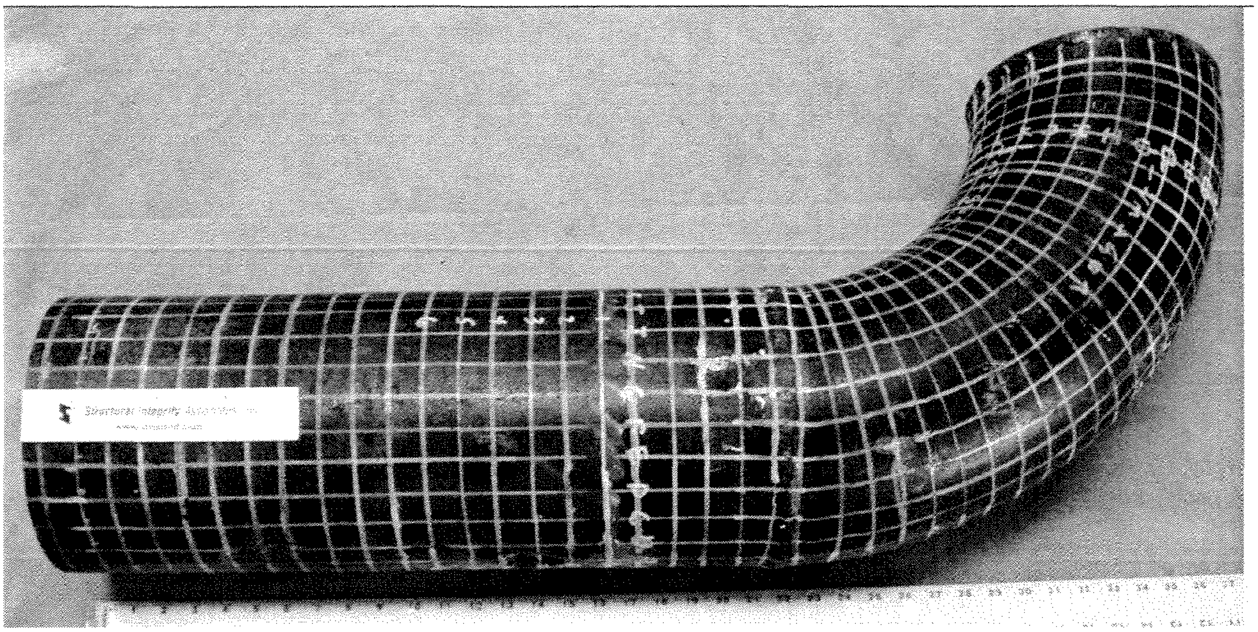

Figure 6 - Pipe sample as received, view 1

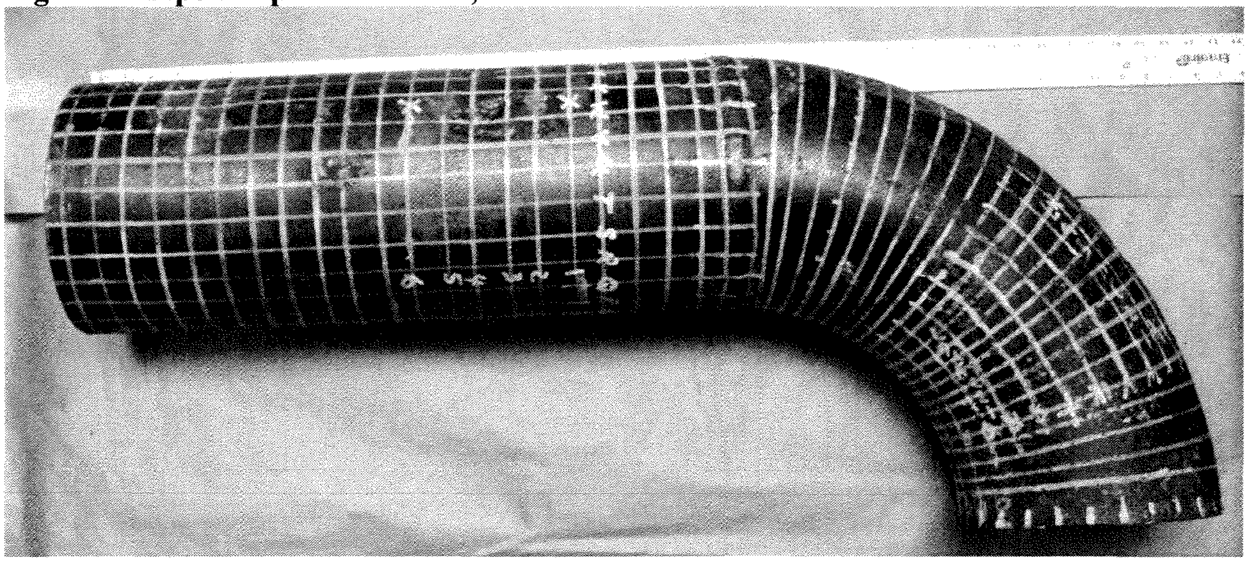

Figure 7 - Pipe sample, as-received view 2

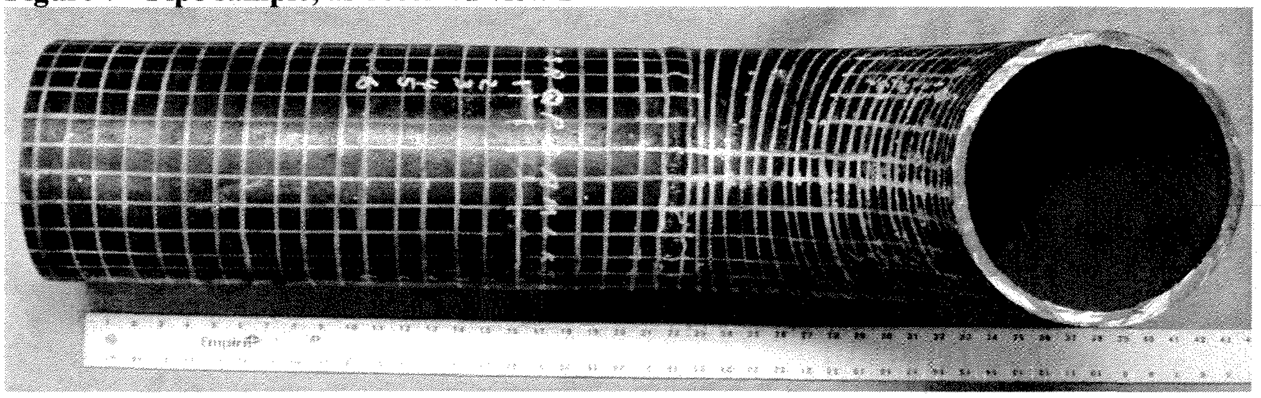

Figure 8 - Pipe sample, as-received, view 3

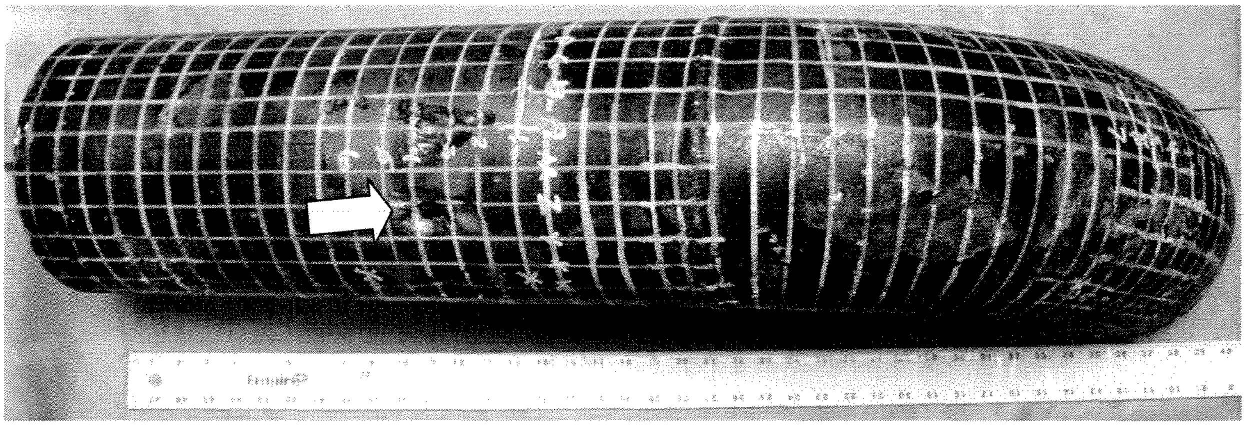

Figure 9 - Pipe sample, as-received , view 4. Arrow points to location of leak

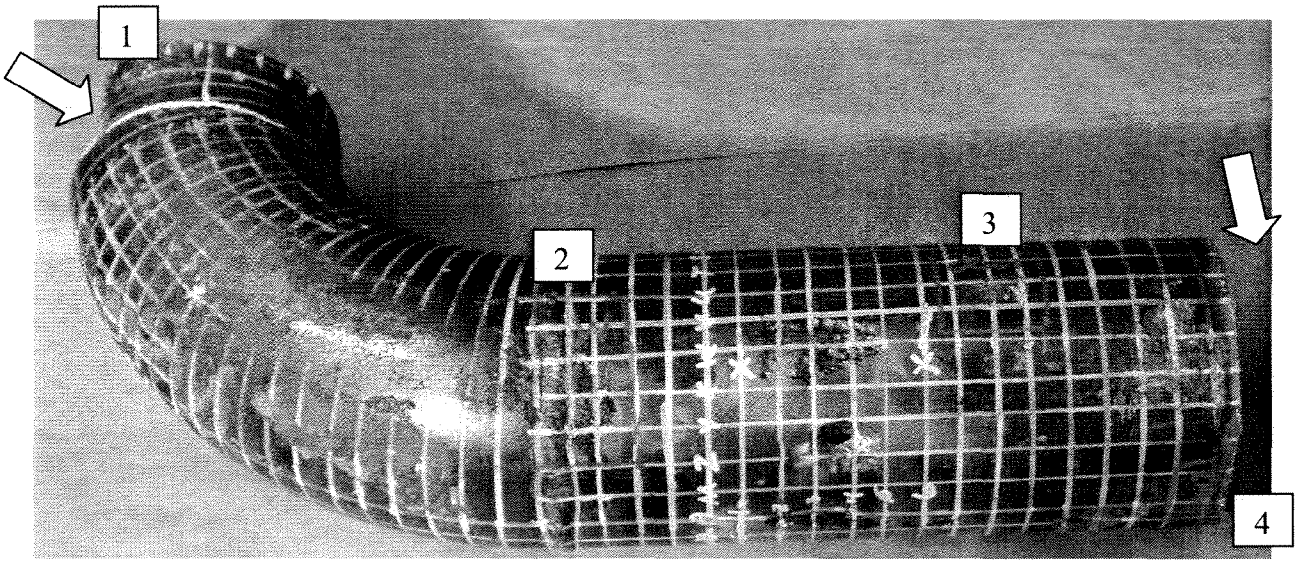

Figure 10 - Pipe sample marked with red boxes to show locations of samples removed for further analysis

1. Elbow sample with ID corrosion for metallographic examination,
2. Girth weld sample for metallographic examination,
3. External corrosion pit with internal corrosion on pipe for metallographic examination and EDS analysis of the corrosion product
4. Second sample of pipe for metallographic examination (investigation of possible ERW seam).

Segments at arrows at ends of the sample were previously removed for tensile testing and analysis of steel composition.

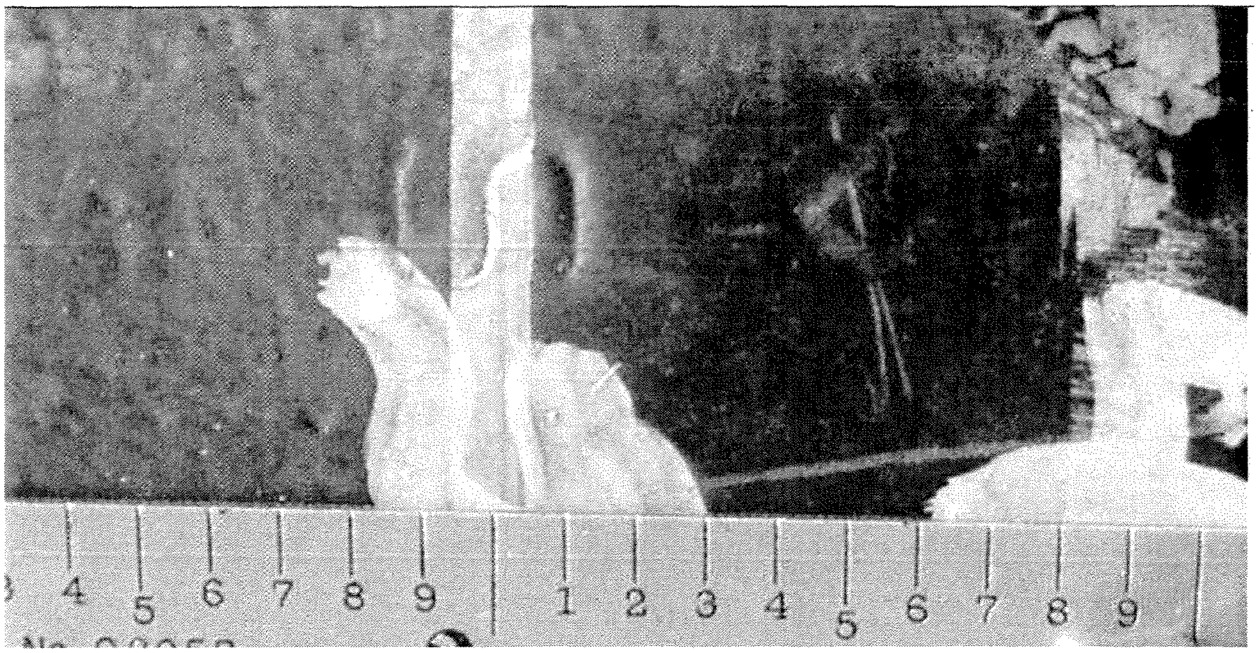

Figure 11 - "YS" stamp mark on pipe.
The stamp marks indicate that this pipe is pipe manufactured by Youngstown Steel. At this location the stamps have been partially polished away by erosion from the nearby leak (in this pipe).

Figure 12 - API monogram stamp mark on pipe.
Monogram indicates that pipe met requirements of API specification 5L. It may have also been manufactured to meet ASTM specifications. Grids outlined by white lines are approximately 1" x 1".

Figure 13 - Manufacturer's stamp marks on the neutral axis of the elbow.
See next figure for detail of the stamp mark after cleaning.

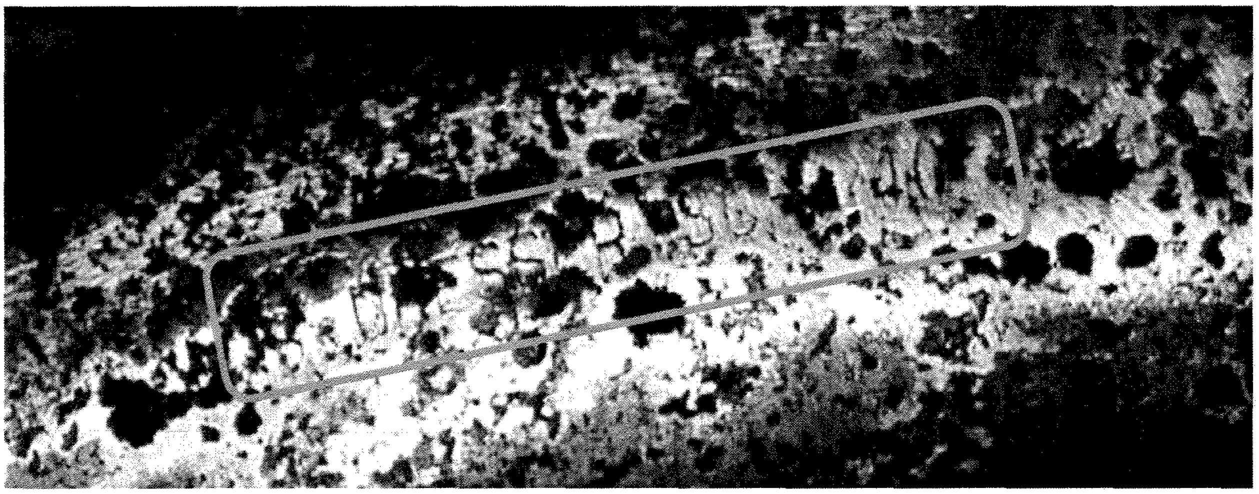

Figure 14 - Manufacturer's stamp mark after light abrasion with sandpaper.
The stamp marks on the neutral axis of the elbow identify it as an 8" schedule 40 fitting manufactured by Dresser. The grade of the fitting is obscured by corrosion.

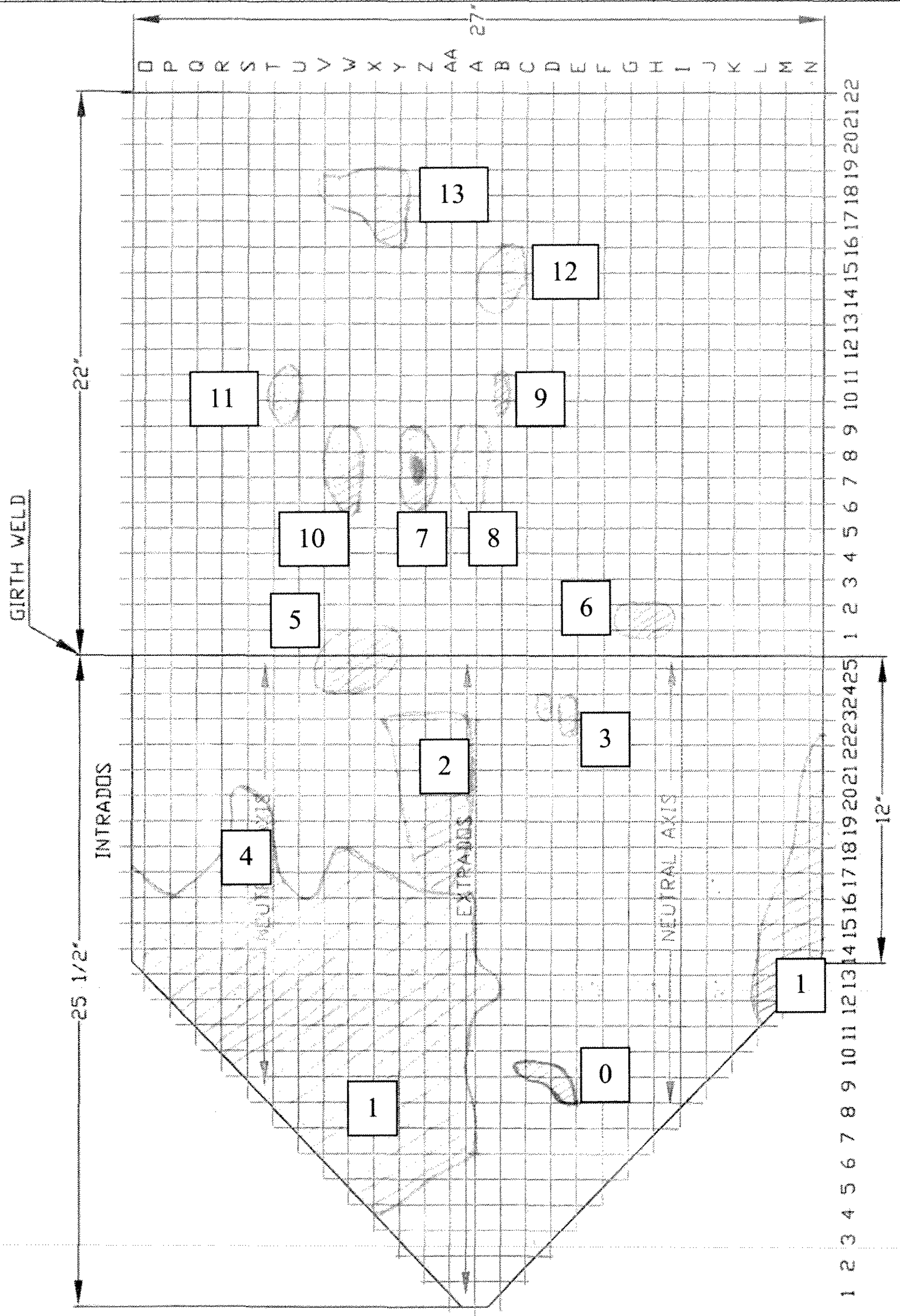

Figure 15 – Map of external corrosion
Major areas of corrosion are sketched and numbered. The axial grid lines (marked A, B, C, etc.) are as marked by Entergy. The leak is at location #7. See Table 3 for additional details

Table 3 – Dimensions of Major Areas of Corrosion

Area (see Fig. 15)	Maximum length (inch)	Maximum depth (inch)	Maximum width (inch)	CSA (%) (Note 1)	Related Figures
0	1.7	0.11	2.6	2.3	16
1	9.7	0.20	19	30.2 (note 2)	17, 18
2	7	0.17	3.5	4.7	-
3	1.2	0.09	0.75	0.5	-
4	See Area 1data, see note 3				19, 20
5	2.8	0.09	3.2	2.3	21, 22, 38-41
6	1.8	0.276	2	4.4	23
7	2.9	Hole (leak)	1.5	3.8	24,26
8	3.6	0.247	1.4	2.7	24
9	1.8	0.103	0.5	0.4	24, 25
10	3.4	0.184	1.8	2.6	26
11	2.3	See note 4	1.3	NA	27, 28
12	2.4	0.251	2	4.0	-
13	3.2	0.171	3	4.1	29-32

Notes:

1) The %CSA represents the portion of the pipe wall area (as measured in a circumferential cross section through the pipe) that is affected by the metal loss. It relates to the detectability of the corrosion using guided wave UT inspection methods. Larger %CSA values typically represent flaws that are more easily detectable. The %CSA (cross sectional area) of each significant flaw is approximated by the following equation:
% CSA =100 x (2/3 x flaw depth x flaw width)/(pi x outside radius^2 – pi x inside radius^2)
For the purpose of detectablility by use of guided wave UT inspection ,the %CSA separate flaw areas located in the same circumferential plane may be combined to estimate the total %CSA, as shown below:

Flaw Areas in a shared circumferential plane	Total % CSA
0, 1	32.5
2, 4	34.9
2, 3	5.2
5, 6	6.7
7, 8, 10	9.1
9, 11	>0.4 (see note 4)

2) The majority of the corrosion was shallow, therefore the equation used to estimate %CSA is overestimating the area of metal loss
3) This area is continuous with Area 1
4) This pit was metallographically cross sectioned with corrosion product intact. Pit depth could not be measured and cross section may not have revealed deepest point

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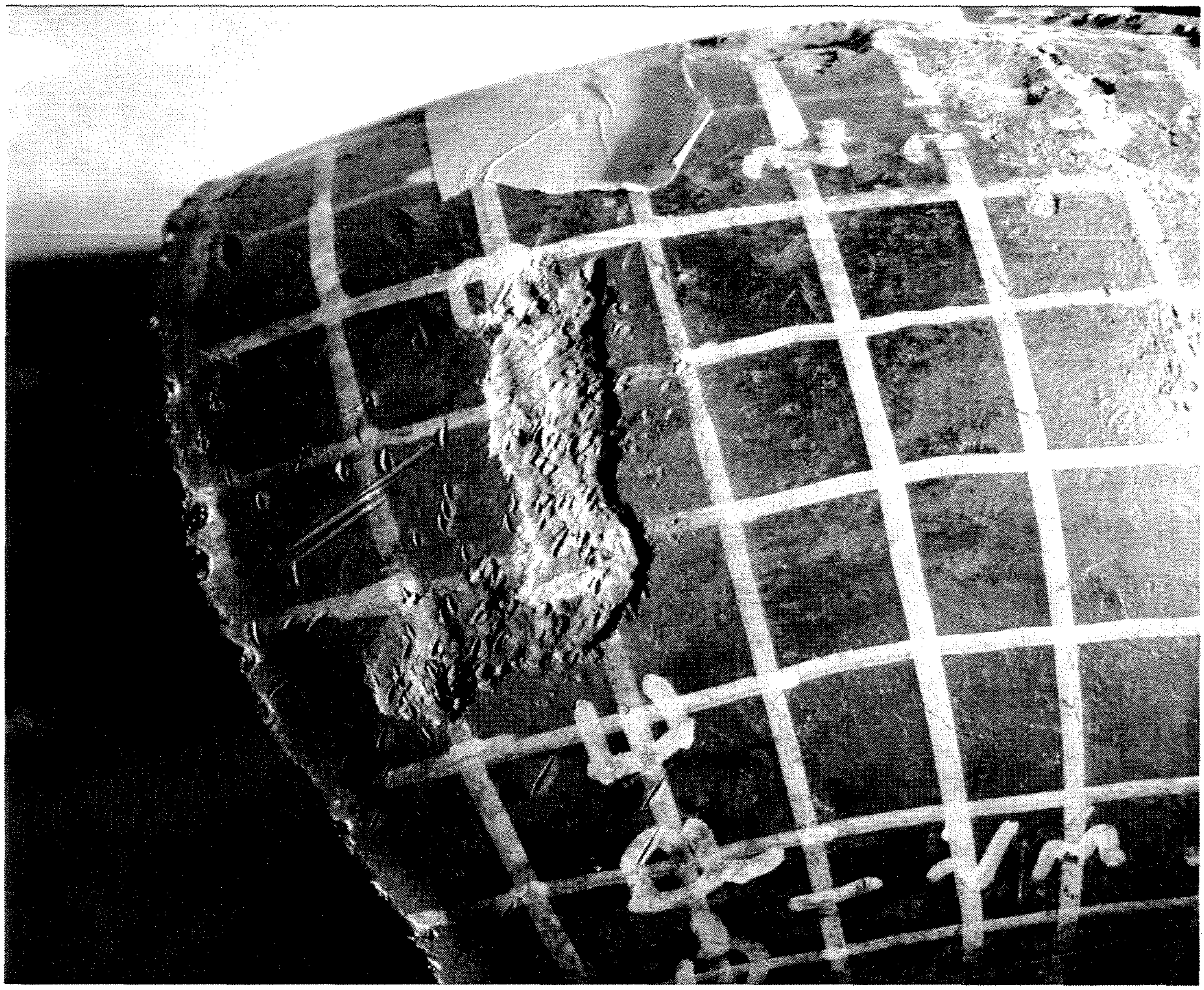

Figure 16 - External corrosion on elbow (as-received condition) designated Area 0
Note the absence of any corrosion surrounding the "L" shaped pit.

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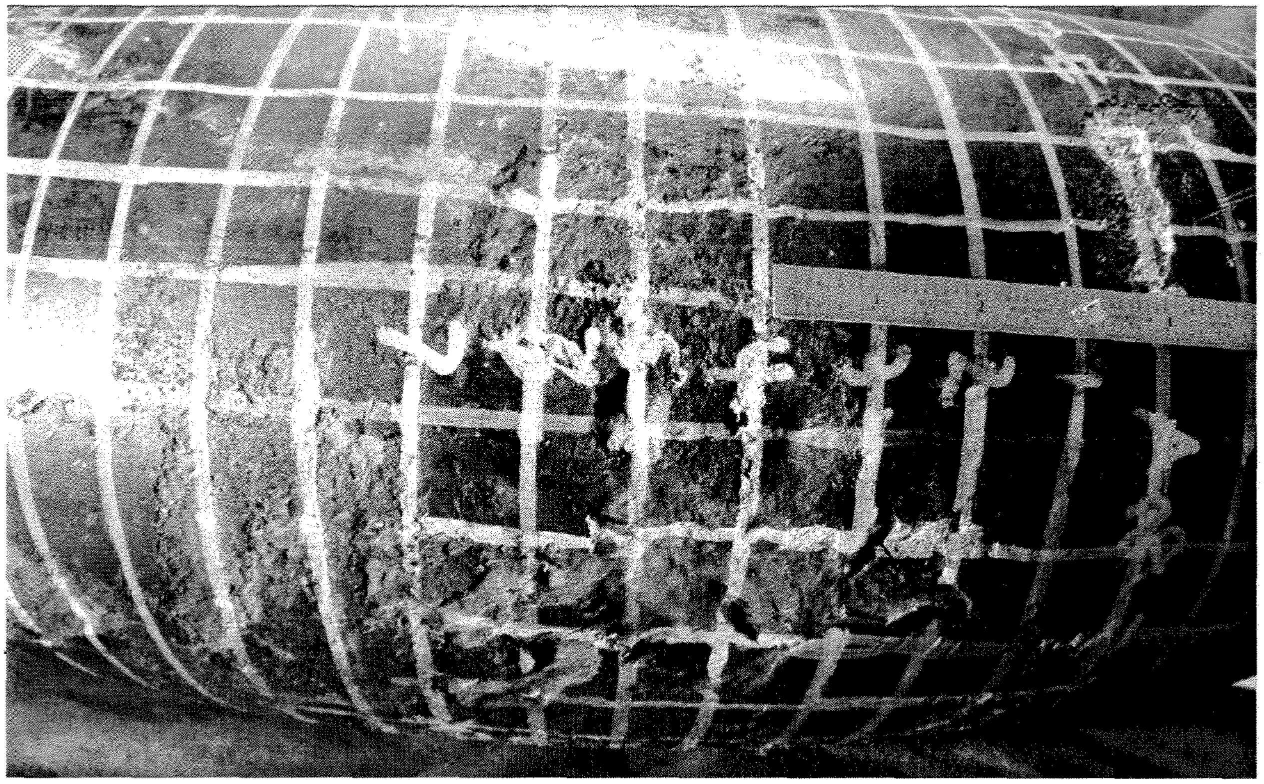

Figure 17 – External corrosion on the extrados of the elbow, as-received; designated Area 1

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Figure 18-- Extrados of ell after cleaning, Area 1.
Note extensive general corrosion compared to the straight pipe. A circumferential band was masked off to prevent loss of the grid line identifications

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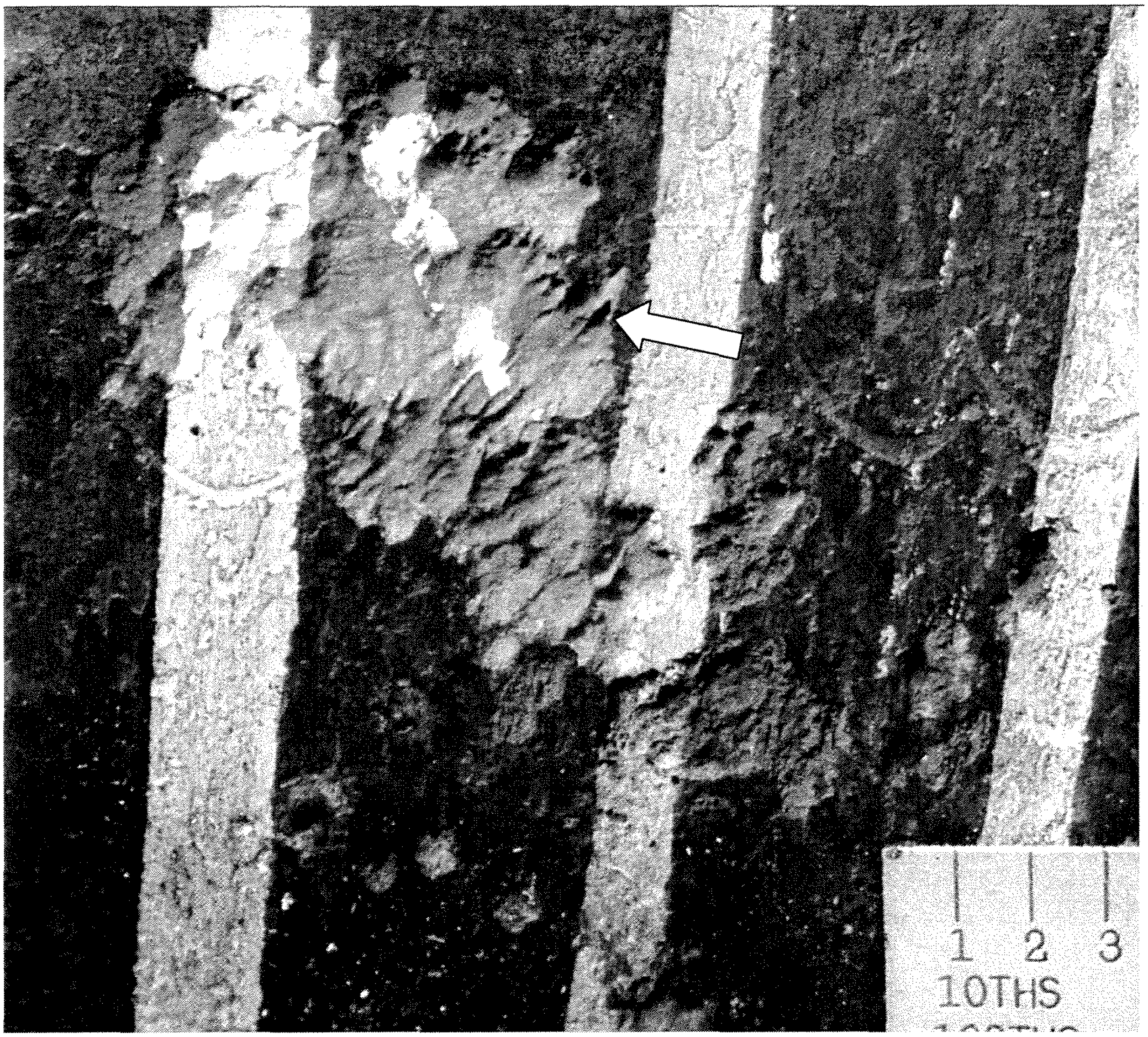

Figure 19 – Detail of corrosion in Area 4, Location 1
Note sharp edges of pits and tunnel like features (arrow points to one example of tunneling).

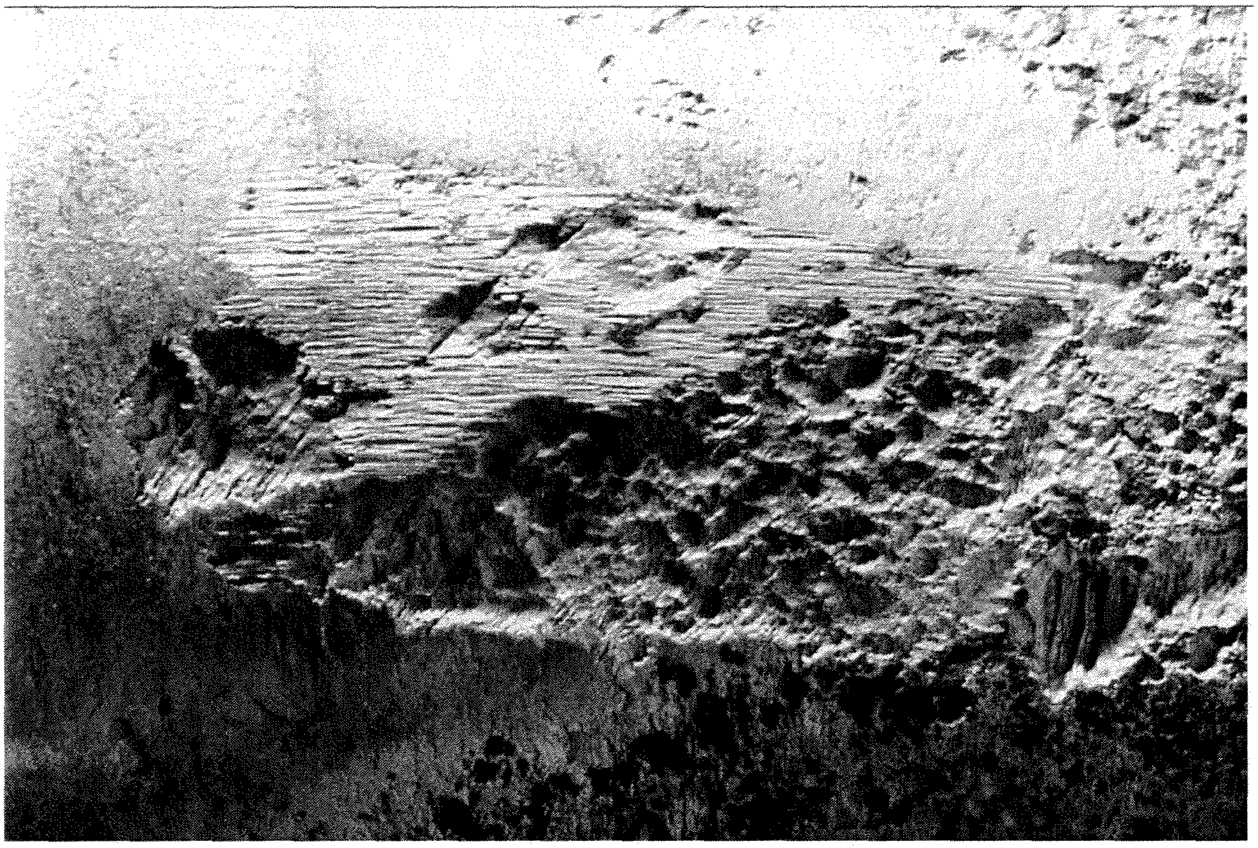

Figure 20 - Area of Area 4, Location 2 after cleaning by glass bead blasting
Note scrape marks. These scrape marks appeared to have discoloration and oxidation comparable to the surrounding uncorroded pipe surface suggesting they may have been formed either during the installation process, or prior to the pipe coating process. If they were formed after coating, the coating would have been damaged and exposed the scraped area to the soil. As a result, the scrape would have been eliminated by subsequent corrosion. The striations are elongated features oriented from lower left to upper right in the round pit at upper left.

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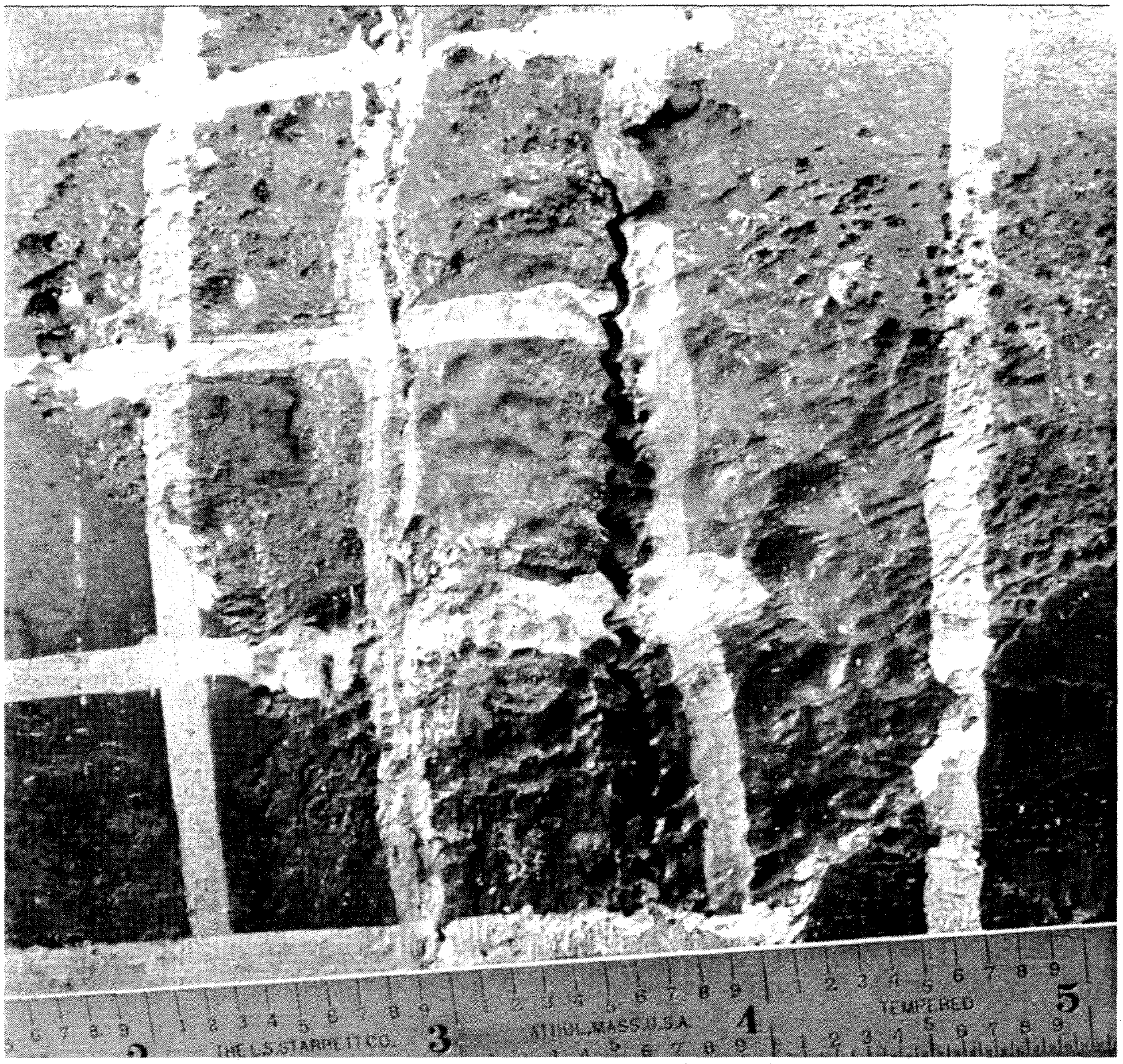

Figure 21 – Detail of corrosion on girth weld in the location designated Area 5.
Note corrosion undercutting the toe of the weld and striations in adjacent corrosion on the elbow. The striations are short linear features oriented about 25 degrees off the longitudinal axis of the pipe and are most visible to the right of the weld

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Figure 22 – Second view showing detail of the corrosion undercutting the toe of the weld

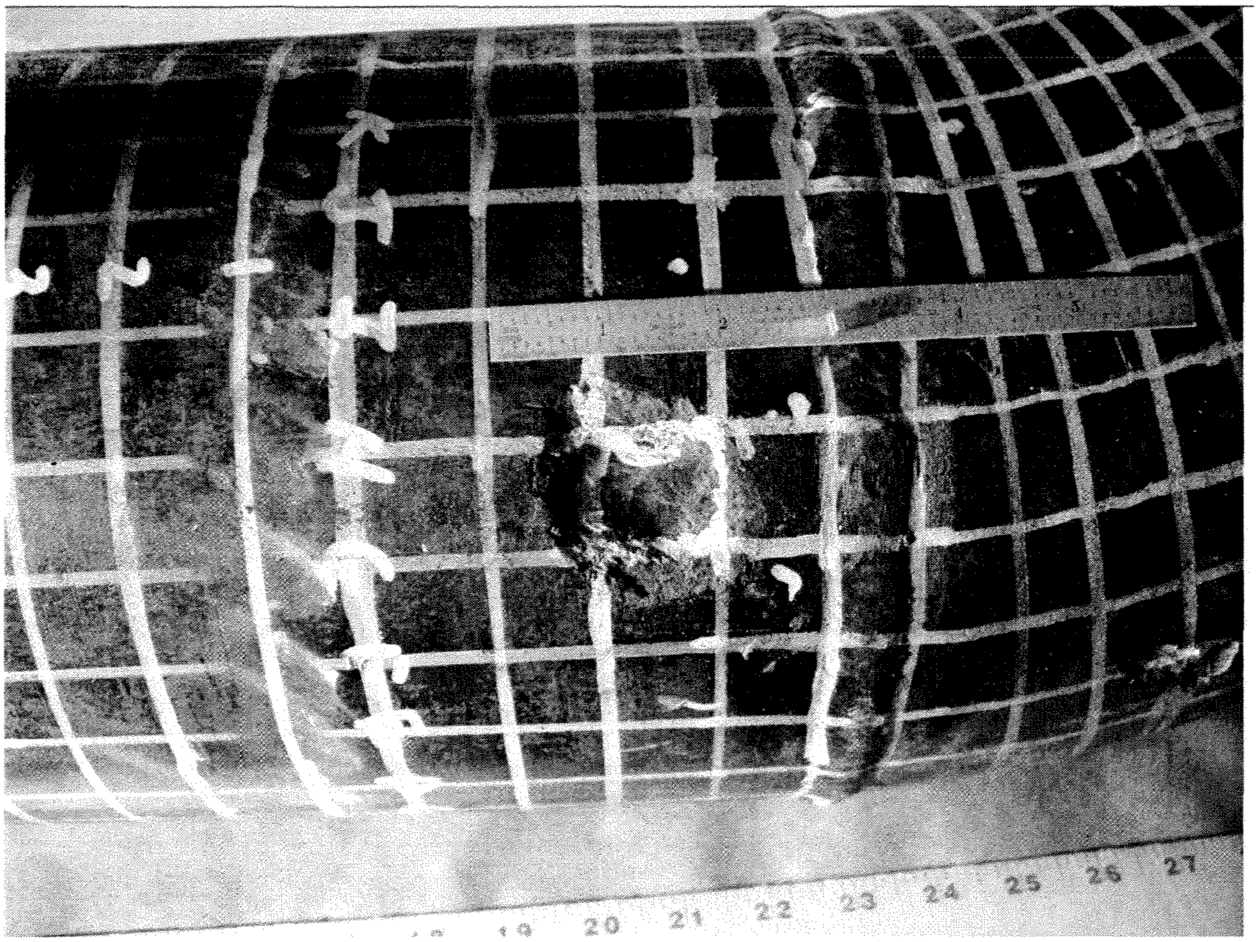

Figure 23 – External corrosion on the pipe (as-received condition), designated Area 6. Note absence of corrosion around this pit.

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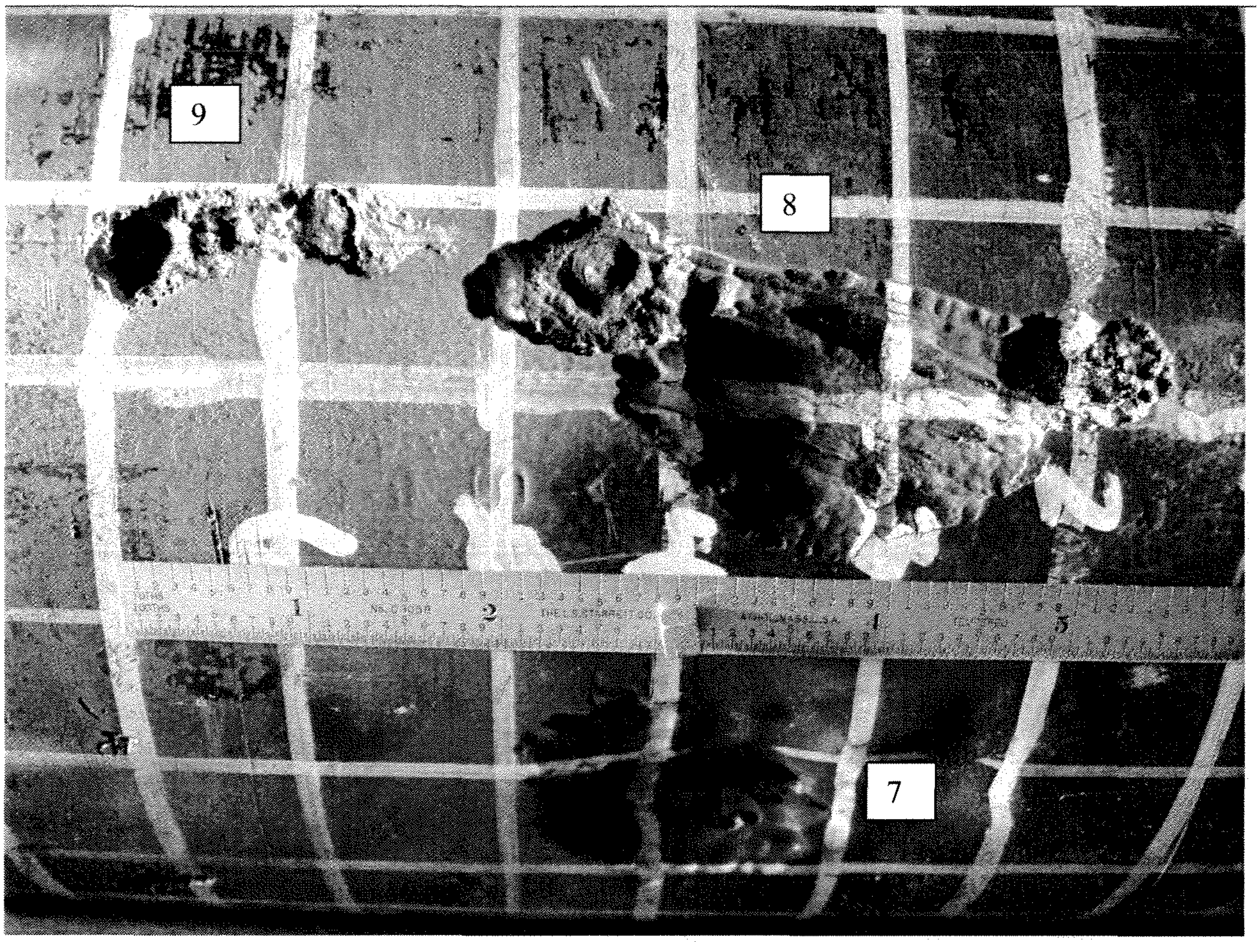

Figure 24 – Outside surface of pipe (as received) showing leak and two other areas of corrosion in addition to identifying "YS" and "API" stamp marks. Areas designated 7, 8, and 9

A very subtle feature that appeared to be an ERW seam runs horizontally through the "YS" stamp mark. Youngstown Steel manufactured both seamless pipe and ERW pipe in this size range. Only the seamless pipe could have met the requirements of ASTM A106. Subsequent metallographic examination of the location showed no microstructural evidence of a seam and the seam-like feature may be the remnants of the embossing wheel that produced the "YS" stamp during the manufacturing process of seamless pipe. The area surrounding the leak (Area 7) was eroded and polished as a result of turbulent water in the area of the leak. In comparison, areas of metal loss a few inches or more from the leak (i.e., see areas 8 and 9) have irregular topographies typical of corrosion that has not been modified by erosion.

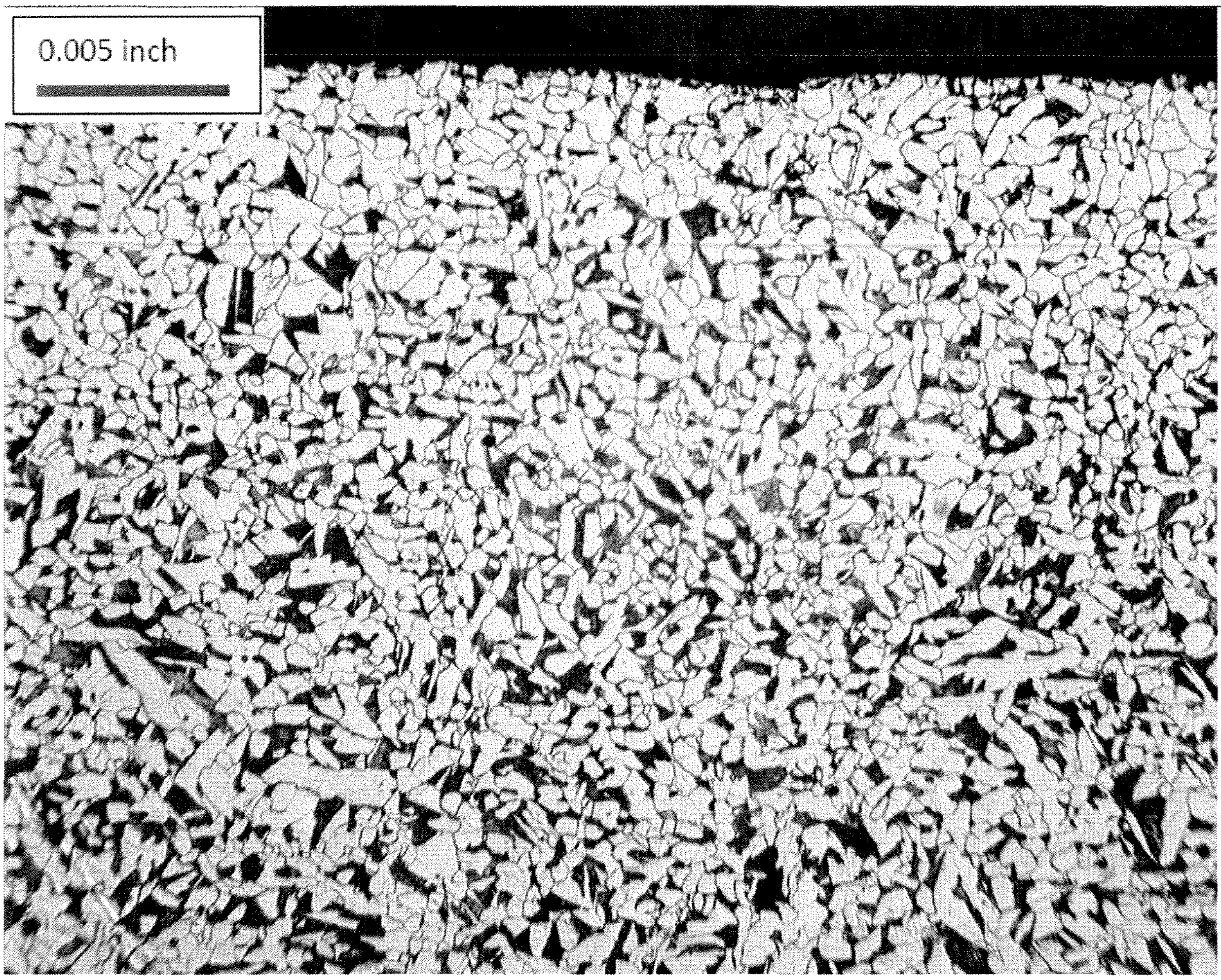

Figure 46 - Microstructure of pipe at outside surface.
There is no external corrosion at this location. The outside surface is at the top of the figure.

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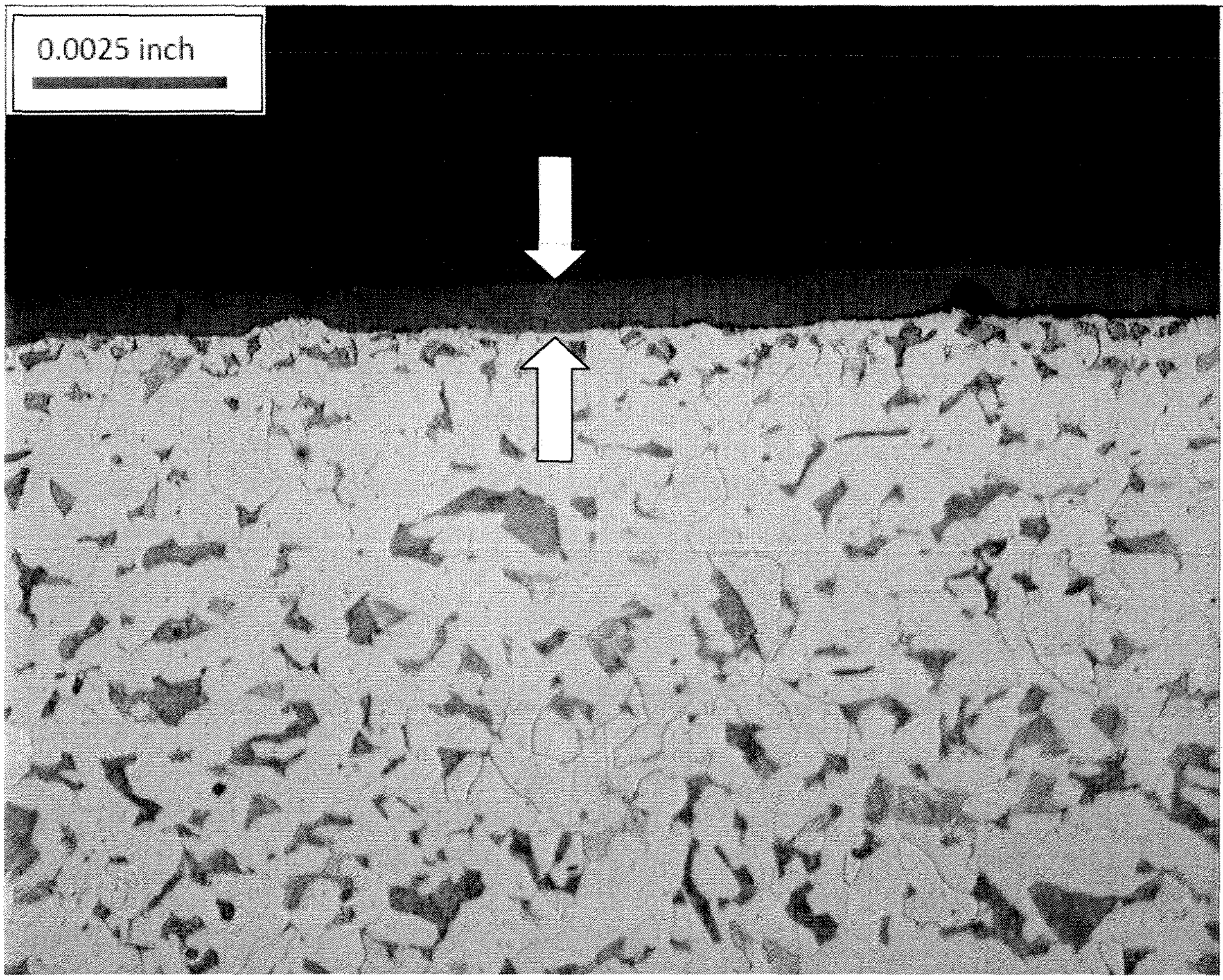

Figure 47 - Cross section through the pipe immediately adjacent to an external corrosion pit showing intact mill scale (between arrows)

The presence of intact mill scale indicates that there was no corrosion on this surface and that there was no surface preparation prior to external coating. A small amount of decarburization of the surface is present, as expected for this type of steel product.

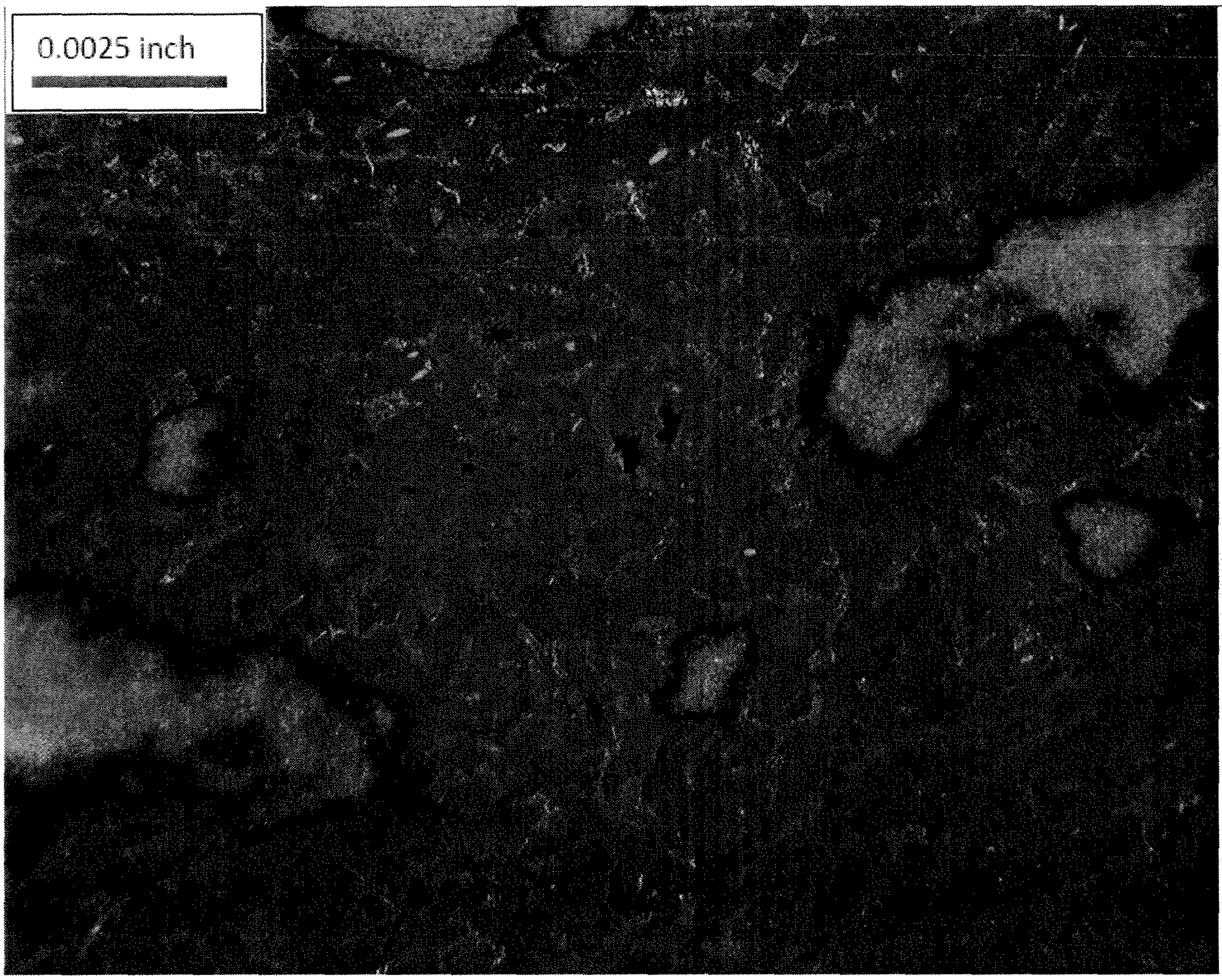

Figure 48- Detail of corrosion product in a pit on the outside of the pipe
The corrosion has preferentially corroded the proeutectoid ferrite and the ferrite lamellae of the pearlite leaving the iron carbide constituent of the pearlite grains uncorroded. The resulting shiny irregular globular-shaped areas replicate in the corrosion product the size and shape of the original pearlite grains. This appearance is typical of iron carbonate corrosion products.

IPEC00202239

Table 4 – Ultrasonic Thickness Measurements (inches)

Specified nominal wall thickness = 0.322 inch

Location Per Entergy Grid (note 1)			SI Data	Corresponding Entergy Data
Row	Row	Column		
Pipe	A	1	0.296	0.298
Pipe	D	3	0.300	0.303
Pipe	G	5	0.310	0.304
Pipe	M	6	0.319	0.321
Pipe	S	2	0.317	0.317
Pipe	V	4	0.322	0.322
Pipe	Z	1	0.290	0.278
Pipe	AA	6	0.311	0.312
Elbow	AA	1	0.363	0.368
Elbow	C	7	0.358	0.353
Elbow	F	4	0.339	0.330
Elbow	J	2	0.324	0.321
Elbow	O	6	0.334	0.333
Elbow	S	3	0.351	0.350
Elbow	W	5	0.388	0.384
Elbow	Z	3	0.350	0.354

Location (2-inch Circumferential Increments)	~1 inch From End of Pipe	~1 inch From Girth Weld, on Pipe Side	~1 inch From Girth Weld, on Elbow Side,	~1 inch From End of Elbow
1	0.301	0.290	0.359	0.385
2	0.328	0.290	0.353	0.340
3	0.327	0.311	0.341	0.346
4	0.330	0.316	0.328	0.335
5	0.337	0.324	0.331	
6	0.315	0.334	0.320	0.314
7	0.308	0.345	0.322	0.323
8	0.311	0.343	0.327	0.329
9	0.294	0.326	0.335	
10	0.290	0.327	0.330	
11		0.319	0.341	
12		0.304	0.357	

Note 1: Measurements by SI at grid locations were made approximately at the intersection of the grid lines. Small differences in measurements between SI and Entergy data may reflect small variations in the location of the transducers during measurements.

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Table 5 - Chemical Composition of Pipe and Elbow

Element	Pipe, location 1 (%)	Pipe, location 2 (%)	Spec. ASTM A106 Gr. B (%)	Elbow (%)	Spec. ASTM A234 WPB (%)
Carbon	0.20	0.23	0.30 max	0.18	0.30 max
Manganese	0.67	0.69	0.29-1.06	0.62	0.29-1.06
Phosphorous	0.008	0.008	0.025 max	0.007	0.050 max
Sulfur	0.016	0.020	0.025 max	0.12	0.058 max
Silicon	0.02	0.02	0.10 min	0.18	0.10 min
Nickel	0.01	0.01	0.40 max	0.01	NA
Chromium	0.06	0.06	0.40 max	0.01	NA
Molybdenum	0.01	0.02	0.15 max	0.02	NA
Copper	0.02	0.02	0.4 max	0.01	NA
Aluminum	<0.01	<0.01	NA	<0.01	NA

Note: Specifications limits are per ASTM Volume 01.01, 1991 and may not be the same as the requirements that were in effect at the time of construction.

Table 6 - Mechanical Properties of Pipe and Elbow

Property	Pipe, location 1	Pipe location 2	ASTM A106 Gr. B	Elbow	ASTM A234 WPB
0.2% offset Yield Strength (ksi)	43.5	42.3	35.0 min.	39.5	35.0 min
Ultimate Tensile Strength (ksi)	65.8	66.9	60.0 min	62.1	60.0-85.0
% Elongation	31.2	35.8	26.5 min	35.1	20 min
% Reduction of Area	52.6	54.7	NA	54.6	NA

IPEC00202241

Table 7 - Results of XRD Analysis of Corrosion Products

Sample	Fe_3O_4 Magnetite*	α-Fe_2O_3 hematite	α-FeOOH goethite	γ-FeOOH lepidocrocite	$FeCO_3$ siderite	$Fe_2(OH)_2CO_3$
Inside corrosion	~70 wt%	~5 wt%	~15 wt%	~5 wt%	~5 wt%	~5 wt%
Outside corrosion					Major	Minor

*most likely combined with maghemite γ-Fe_2O_3 (=decomposed magnetite)

Table 8 - Results of EDS Analysis of Outside Surface Corrosion Products

Element	Concentration in Bulk Deposit	Concentration at Interface with Steel	Units
O	32.2	30.2	wt.%
Si	1.2	0.2	wt.%
S	0.6	0.4	wt.%
Cl	0.1	ND	wt.%
Cr	0.2	0.1	wt.%
Mn	0.3	0.5	wt.%
Fe	60.7	64.4	wt.%

Table 9 – Typical Results of EDS Analysis of Inside Surface Corrosion

Element	Bulk Deposit Location 1	Bulk Deposit Location 2	Steel Interface Location 1	Steel Interface Location 2	Units
O	30	26.1	24.7	31.3	wt.%
Al	0.1	0.2			wt.%
Si	0.7	1.2	0.6	0.8	wt.%
P	0.2	0.12			wt.%
S	0.1	0.2	0.3	0.6	wt.%
Cl	0.1			0.7	wt.%
Cr	0.5	0.2		0.2	wt.%
Mn	0.2	0.3	0.3	0.2	wt.%
Fe	58.4	66.5	68.0	60.1	wt.%
Ni	0.2				wt.%
Cu	0.4	0.3			wt.%

IPEC00202242

Summary

The leak in the 8" steel condensate piping was caused by external corrosion. Corrosion on the exterior of the pipe consisted of a large number of localized pits, rather than of widespread general corrosion. The surfaces around the pits on the straight pipe had no evidence at all of corrosion and the original mill scale (high temperature iron oxide) was intact, indicating that where the coating remains intact the pipe surfaces are adequately protected against corrosion. The external surfaces of the elbow had more widespread corrosion, although a few portions (less than half of the surface) still showed no evidence of external corrosion. The patterns of corrosion on the pipe are consistent with localized mechanical damage to the coating. The corrosion on the elbow was consistent with an imperfect coating resulting from the difficulties inherent in coating an irregular surface such as the elbow.

During and after the excavation process, Entergy staff observed that the backfill in the area of the pipe included debris and angular rocks. Those materials could have damaged the coating in multiple locations during the pipe installation or backfilling process, resulting in vulnerability of the small areas of exposed steel to corrosion. Since a relatively large surface area of the sample has no evidence of corrosion, exposure to leaking water or to water-saturated soil apparently did not have a significant effect on the protectiveness of the coating on the pipe. Rather, the large number of observed pits is more likely related to the occurrence of coating damage that occurred during installation; not to gradual or long term coating degradation that could potentially as a result of exposure to leaking water or water-saturated soil.

While the morphology of the external pitting included features that are typical of corrosion associated with MIC, the features are not unique to MIC. Likewise, the corrosion products in the external corrosion pits consisted primarily of siderite (iron carbonate), which can result from either MIC or from corrosion unrelated to microbiological activity (i.e., from abiotic corrosion). The siderite corrosion product can be formed either by MIC, or can be generated as a result of electrochemical corrosion of steel exposed to well buffered water containing little or no oxygen, a neutral to moderately high pH, and low calcium. The reported pH of the ground water matches this requirement. The available water analysis and soil analysis does not contain the information required to determine if the other attributes are within the range for siderite to be formed abiotically.

We determined that the corrosion rate responsible for causing the leak must have been at least 8 mpy (0.008 inches per year or 8 mils per year) to cause penetration of the pipe wall in about 40 years. Many soils could cause a long term corrosion rate of about 8 mpy or higher in the absence of MIC, so the high corrosion rates often associated with MIC are not necessary to cause the leakage. It is likely that the corrosion progressed discontinuously as water table levels rose and fell, or as the soil environment underwent other seasonal or temporary changes. As a result, the peak corrosion rate could have been significantly higher than 8 mpy and within the range associated with MIC. However, it is apparent that if MIC did contribute to the metal loss, it was not active the entire time the pipe was in service because the leak would have occurred much sooner.

Determining the probable rate of future metal loss at other locations of coating damage on this piping would require either directly measuring the rate with corrosion probes or buried coupons, or modeling the likely abiotic corrosion rates using soil analysis data. Insufficient soil data

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currently exists to estimate the corrosion rate that could be caused by the backfill in the absence of MIC.

Some preferential corrosion of the girth weld heat affected zone was apparent on both the ID and OD of the pipe, but the maximum depth of metal loss in the HAZ was no greater than the maximum depth of metal loss remote from the weld.

Corrosion on the inside surface of the sample was superficial and does not represent a significant threat to the integrity of the pipe. ID corrosion on the straight pipe was more widespread than in the elbow, resulting in an appearance more typical of general corrosion, rather than of pitting. ID pitting on the elbow consisted of individual small pits. The composition of the corrosion products from the inside of the sample was characteristic of corrosion by low oxygen content water and was significantly different from corrosion products on the OD of the pipe.

The metallurgical characteristics of the pipe, elbow, and girth welds were normal. The workmanship of the weld was good. No abnormalities in the steel or weld were present that could have contributed significantly to the corrosion, although the pipe composition deviated from the ASTM A106 specification with regard to silicon content. The composition did meet the requirements for comparable seamless pipe specifications.

Conclusions

1. Internal corrosion is present, but it is superficial and does not represent a threat to the operation of the piping. Minor differences in the extent of corrosion observed on the pipe and on the elbow are attributed to minor differences in the steel composition. The weld HAZ of the elbow appeared be to somewhat less resistant to corrosion than the areas of ethe elbow away from the weld, but no less resistant than the pipe.
2. We found no evidence of abnormalities in the metallurgical characteristics of the pipe, elbow, or the girth weld that would have contributed to the observed corrosion. The workmanship of the girth weld was very good. A minor variance in the chemical composition of the pipe from the applicable specification is inconsequential to its performance.
3. The coating quality could not be determined directly from the pipe samples submitted for analysis since the coating had been previously removed during the pipe repair process. However, the observed patterns of corrosion indicate that the coating continues to be protective where it is intact, but the existing coating quality may be somewhat lower on surfaces that are more difficult to wrap, such as fittings, as evidenced by larger areas of general corrosion on the surface of the elbow. The primary cause of localized pitting corrosion in areas surrounded by coating that appears to be generally intact is probably localized mechanical damage to the coating. The mechanical damage causes localized penetrations of the coating resulting in exposure of small areas of the steel surface to the soil environment. The coating damage most likely occurred during installation as a result of using backfill that contained angular rocks and debris. The calculated minimum average long term corrosion rate (about 8 mpy) that would have produced the recent leak is within the range of corrosion rates observed for pipe that is not cathodically protected when exposed to some soils, but lower than expected for MIC if the MIC mechanism was continuously active. Some soil analysis data was provided to SI, but not all of the

attributes required for input into our SoilPro model were included in the available data. As a result, we are unable to determine if the soil characteristics at this leak site would be expected to cause an 8 mpy corrosion rate in the absence of MIC. The potential influence of MIC should not be disregarded since both the morphology of the metal loss and the type of external corrosion product present can be related to MIC, (although neither one is a definitive indicator of MIC). Two scenarios could describe the cause of the relatively low average corrosion rate in the presence of a MIC mechanism. First, it is possible that corrosion rates fluctuated during the time of service as water table depths rose and fell, resulting in periodic variations in soil properties. Those variations in soil properties could alternatively support or fail to support a MIC mechanism. In a second scenario, the initial corrosion rate could have been low and unrelated to MIC. After some time in service some environmental change occurred, such as a long term change in the water table, or a leak in adjacent piping. That transition could have triggered the onset of long term MIC (or of higher abiotic corrosion rates). Either case describes how the significantly higher corrosion rates often associated with MIC could have occurred only during a portion of the total service time.

Recommendations

1. Generalizations regarding what constitutes "corrosive soil" can be misleading, particularly when based on assessment of one or only a few soil parameters. Consider installing corrosion probes or corrosion coupons in the backfill with the means to monitor or retrieve the assemblies. Coupons or probes can help quantify corrosion rates, detect transients in corrosion rates, and assist in the determination of the mechanism of corrosion. Alternatively, if available, an additional soil sample could be analyzed to determine the attributes needed to run the SI SoilPro program and estimate the likely pitting rate that would be expected at the location of the sample. However, the SoilPro data will represent the snapshot in time at which the sample was obtained and will not address seasonal changes or transient conditions in the environment unless additional samples are taken at a later time

2. Consider focusing any future piping inspection on areas containing:
    a. Elbows and other harder to wrap fittings since those are preferential locations for coating anomalies.
    b. Backfill suspected of having the same characteristics at those observed at this leak since angular rocks may have caused coating damage at which corrosion can occur
    c. Areas where results of soil analyses indicate that corrosion rates may be the highest. In the absence of data that is sufficient to run the SI SoilPro corrosion rate model , select areas of lowest elevation and low resistivity since low resistivity is often associated with more corrosive soil. Note however that high resistivity soil may still be corrosive.

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d.

Appendix A – Observations by Entergy Engineering Staff Regarding the Excavation Conditions

Observation 1

- The initiating event was a report by Operations that the water level was rising in the sleeve of the 8" Condensate Return line in the Aux Feed Pump Room where the pipe goes into the floor
- On his own initiative, an Operator looked in the manhole just outside the Aux Feed Pump Room in the Main Feed Reg Valve Room and noticed water flowing in the manhole.
- The Condensate Storage Tank was declared inoperable
- Once the core boring was complete there appeared to be undermining of the area under the concrete slab.
- A lot of water was still coming into the hole during excavation
- During excavation and shoring, there were a lot of large rocks, cans, and other garbage in the fill that was used. The rocks were large enough to get stuck in the hose that was sucking out the mud from the hole
- Upon inspection of the pipe (the pipe was still leaking) there appeared to be a hole at the 7:00 position approximately 22" from the elbow weld joint.
- The coating was not present in the areas of the hole and/or indications. It appears to have been blown away over time. This could have been caused by initial damage to the coating during the backfill
- The area of the holes/indications probably saw constant groundwater and could have caused the erosion in the areas of the damaged coating. Note that the inside of the pipe was in pristine condition; no internal corrosion noted.

Observation 2

- Observed the area being excavated with sump pump installed, but no shoring yet. The hole was still ~ ½ full of water.
- Inspected pipe after clamp was installed. No areas coating had been stripped for UTs yet however, the coating appeared to be in bad shape and chewed up. Not sure if this was a result of the excavation, from original construction, or degradation over time.
- Additional observations of the coating indicated that it was not in uniform contact with the pipe and not tightly adhered to. Some scaling had occurred at some point as well.
- Did not witness the excavation activities however, did notice a lot of debris, especially stones in the area under the pipe. These were fist size or greater and seemed to be crushed rock not normally seen in areas of backfill.
- An indication was noted to have the appearance of a rock (or other object) that had been forced into the pipe and caused damage to the coating.
- Some of the pitting was very shiny which is unusual. It also appeared to be uniform in depth.

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Observation 3

- Did not observe excavation efforts, but did see ~ 6" – 7" in the area around the pipe once it was exposed.
- The coating was already stripped and prepped for UTs.
- Based on a review of the photos it appears that the coating may not have been applied consistently during original construction. The workmanship was not up to current standards. The coating has a "rippled" look to it.
- Pipe thickness looked good

Observation 4

- Once the core boring was complete, observed a lot of debris in the hole during excavation.
- Items included large rocks, metal pieces, and Styrofoam packaging material.
- The rocks were large enough to clog the hose that was used to suck out the mud during excavation
- The hose was getting clogged frequently due to the large rocks and debris to the point where the hose needed to be disconnected at the truck end in order to clear it out.
- The sump pumps also appeared to be clogging frequently.
- The pressure from the rocks could have been enough to damage the coating and the surface of the pipe.

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Attachment Header

Document Name:

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Document Location

Subresponse Description

Attach Title:

Part 1 - SIA Failure Analysis Report

IPEC00202248

Attachment Header

Document Name:

untitled

Document Location

Subresponse Description

Attach Title:

Root Cause Analysis Report

IPEC00202249

IPEC00202249

Root Cause Analysis Report

CST Underground Recirc Line Leak

CR-IP2-2009-00666

REPORT DATE: 05-14-2009, Rev. 0

Root Cause Evaluator:	**Anthony DeDonato**	**5/14/09**
Team Leader (optional)	**Steve Manzione**	**5/14/09**
Reviewer:	**Bob Sergi**	**5/14/09**
Responsible Manager:	**Mike Tesoriero**	**5/14/09**
(APPROVALS ABOVE REQUIRED BEFORE CARB REVIEW)		
CARB Chairman:	**Pat Conroy**	**5/14/09**

Authenticated by Electronic Signatures in PCRS (LI-118, [3.0](8) b.3)

IPEC00202250

Problem Statement

"On February 16, 2009, Unit 2 entered a 7 day shutdown AOT due to an underground leak in the condensate storage tank return line."

Team Members

Team Lead	Steve Manzione
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IPEC00202251

Event Narrative

On February 15, 2009, a CR was entered at 1629 EST. An Operator observed water filling the floor guard collar on the CST return line and spilling onto the floor on the 18' AFB pump area. Operations secured recirculation of CST-Hotwell. The Chemistry Department was contacted for sampling the spilling fluid. The Chemist reported 54ppb of Hydrazine in the water, which identified the water as condensate. CST was declared inoperable on Monday, February 16, 2009 at 0205 EST. Unit 2 was operating at 100% Rx power throughout the event.

The source of the leak was determined to be just outside of the Auxiliary Feed Pump Room (AFPR) based on observations of the leakage at the pipe collar in the AFPR, the leakage observed from Manhole #5 just outside the AFPR door, and Engineering experience and judgment of the leak to be near a pipe bend. Work forces were mobilized and boring through the concrete slab and excavation of the pipes was commenced. The area was full of water, just below the concrete slab. A vacuum truck was used to remove the water and fine debris from the area. Larger objects were removed by hand.

Workers reported the material was mostly clay under the floor. There was no evidence of any sand around the pipes. Some construction debris was also unearthed. Based on the condition of portions of the coating, the through wall leak and other defects on the pipe, a decision was made to replace the section of the pipe.

<u>Timeline of Major Events</u>

Sunday, 2/15/09 @ approximately 1500	Water was identified leaking into the IP2 Auxiliary Feedwater Pump Building through a vertical pipe sleeve for the 8 CST return line.
Sunday, 2/15/09 @ approximately 1600	Chemistry results show 54ppb Hydrazine, which indicates it is condensate. The FSS contacts the Engineering Duty Manager (EDM). A conference call is held between Engineering management and supervisors.
Sunday, 2/15/09 @ approximately 1900	The EDM arrives on site, inspects the pipe sleeve, confirms water is rising up and requests another chemistry sample for confirmation of condensate.
Sunday, 2/15/09 @ approximately 2100	Further Engineering inspection reveals water is leaking into Manhole #5 at two locations through the masonry joints. (Manhole #5 is located in the FRV Room approximately 5' west of the underground location of the 8" line.) The Watch Chemist is instructed to take samples of incoming flows into Manhole #5.

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Timeline of Major Events (continued)

Monday, 2/16/09 @ approximately 0205	The CST was declared inoperable and entered the 7-day AOT. Chemistry samples confirm the water is condensate in both the pipe sleeve and the effluents entering Manhole #5. The group decided to meet at 10:00 AM the following morning.
Monday, 2/16/09 @ approximately 1200	Civil Engineering maps out the line location underground and determines the area to be excavated based on the configuration of the pipe. Construction is mobilized.
Monday, 2/16/09 @ approximately 1900	Core drilling operations commenced in preparation of slab removal for excavation of the area. First indications that water saturation is present under the slab. Demolition by jackhammer is not allowed due to possible undermining.
Monday, 2/17/09 @ approximately 0500	Core drilling operations in progress; the first 2' x 2' section of the slab is removed. Standing water is present under the slab. Three small sump pumps are needed to keep up with the water.
Monday, 2/17/09 @ approximately 1700	Removal of the concrete slab was completed.
Tuesday, 2/17/09 @ approximately 2200	Shoring is installed in the excavation; a containment area for removed soil is set up.
Tuesday, 2/17/09 @ approximately 2400	The vacuum truck arrives on site.
Wednesday, 2/18/09 @ approximately 0230	Excavation of the site begins.
Wednesday, 2/18/09 @ approximately 1800	Chemistry increases the amount of Hydrazine in the Condensate System and monitors the level of Hydrazine in the area.
Wednesday, 2/18/09 @ approximately 2100	Operations calculates the make up to the CST is approximately 17gpm. Chemistry confirms the leak in the 8" line to the CST based on rising Hydrazine levels in Manhole #5.

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Event Narrative

Timeline of Major Events (continued)

Thursday, 2/19/09 @ approximately 0100	12" pipe is exposed and no leakage is seen.
Thursday, 2/19/09 @ approximately 0330	8" pipe is exposed and the leak is seen at the horizontal section of the pipe.
Thursday, 2/19/09 @ approximately 0400	Engineering assesses the leak is located at the 5:00 position of the pipe and determines the pipe is structurally sound to accept a housekeeping patch.
Thursday, 2/19/09 @ approximately 0600	A full circle clamp with longer bolts is installed over the leak; it slows it down enough for the sump pumps to keep up with dewatering, allowing further inspections.
Thursday, 2/19/09 @ approximately 1200	Abatement of the coal-tar coating begins.
Thursday, 2/19/09 @ approximately 2100	Abatement is completed; visual inspection and UT of the line is started.
Thursday, 2/19/09 @ approximately 2230	Visual inspection and UT of the line is completed. Several areas of minor degradation were found on the lower elbow and horizontal section of the pipe. A decision was made to replace the elbow and damaged section of the pipe.
Friday, 2/20 @ approximately 0100	Shop work on the replacement pipe is started.
Friday, 2/20 @ approximately 0500	Shop weld is completed. NDE was performed on the weld, MT SAT.
Friday, 2/20 @ approximately 0500	Entered a 72-hour AOT for 22ABFP in order to accommodate the pipe and elbow replacement and isolated line #1509.

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Timeline of Major Events (continued)

Friday 2/20/09 @ approximately 1200	Pipe and elbow section removed.
Friday 2/20/09 @ approximately 1700	Pipe fitted into place. Weld out of two field welds begins.
Saturday 2/21/09 @ approximately 0400	Work completed, NDE performed, MT reading SAT, Operations commence clearance of PTO and filling line.
Saturday 2/21/09 @ approximately 0530	Line verified fill, in service VT-1 leak inspection performed by Operations; no leaks observed.
Saturday 2/21/09 @ approximately 0600	ABFP 22 declared operable, exited the 72-hour AOT.
Saturday 2/21/09 @ approximately 0630	CST Line declared operable, exited the 7-day AOT. All work secured.

IPEC00202255

Event Narrative

Background Information

- Lines 1505 and 1509 are carbon steel, schedule 40. Line 1505 is the 12" supply from the CST to the AFPs. Line 1509 is the 8" CST return line. These lines were deemed not to require cathodic protection during original plant design due to favorable soil resistivity and drainage characteristics. As a defense against localized corrosion attack, however, lines 1505 and 1509 were externally coated with coal tar enamel and have a coal tar enamel saturated felt overwrap. These pipes are sloped from the CST elevation to the AFPB, and are each approximately 320-330 feet in length.

- Several months prior, a similar event occurred when water was observed at the same pipe sleeve. Excavation of the CST lines at 2 locations was in-progress at this time of inspection. The leak was attributed to groundwater due to the open excavations. No hydrazine was detected. This was based on Chemistry testing for activity, pH and hydrazine.

- The backfill that was used in this area during original installation contained various size rocks and other foreign material such as cans and wire. The backfill used was for a light load area.

- Groundwater is suspected to also infiltrate the area.

- Line 1509 does not experience "movement". The buried pipe is installed below the freeze line. Other than seismic activity, there is no ground movement accounted for in the design nor anticipated to occur. Thermal expansion is very small due to the small delta T that may be experienced if the water from the CST was at its high temperature of approximately 100 degrees °F. However, thermal growth would not cause pipe movement since the pipe is restrained by the ground in the vertical rise at both ends.

- The area is used as a walkway. If there is significant heavy load on top of the slab and the fill has 3" to 8" large rocks (confirmed by observers), the heavy load can force the pipe to deflect downward and pinch on the rock, causing damage to the coating.

- Underneath the 6'x 6' cut hole on the floor slab, the fill was washed out locally.

- AFW building is supported by the foundation and containment building wall. The foundation is into the bedrock and loss of fill will not affect the load transfer capability from the slab, to the wall, to the foundation and onto the bedrock. The containment mat foundation is into the bedrock and will not be affected by the leak.

IPEC00202256

Background Information (continued)

- Sections of the bituminous type wrap were discovered damaged some voids around the area of the leak and 90° elbows.

- The specific 1989 ASME Code requirement to be met for the buried pipe #1509 is IWA-5244(c) which requires verification of non-impairment of flow in the non-isolated and non-redundant line to the heat sink. This specific requirement is met by performance of a pump test which verifies the ability to obtain and control recirculation flow. This inspection is required to be performed three times within the 10 year interval. Successful performance of PT-Q34 in conjunction with the PI-3Y4A Inservice Inspection services as verification of non-impairment of flow.

- Seismic concerns: based on outside study, historical seismic activities around IPEC from 1974 until 2007 fell into a range of modified Mercalli scale of 2.4 to 3.0. The range of seismic activity at the plant is less than 3.0 (0.007g) and IPEC is designed to M = 6.5, well below the plant's design ground response spectrum. The leak location has exterior surface/coating damages that appeared to be caused by impact from large, angular external object. It is highly unlikely that uniform seismic ground movement with a buried pipe could cause such a surface impact.

- An Entergy Engineering Fleet Call was conducted on March 4, 2009, which discussed the failure of the CST return line #1509.

CST Operation and Secondary leak detection

The condensate Storage Tank (CST) supplies makeup water to the Condensate System and to the Auxiliary Feed Water Pumps (AFP) during hot shutdown decay removal via a common 12" underground pipe. The CST is sized to supply a minimum inventory of 360,000 gals for 24 hrs of decay removal in hot standby following a plant trip as well as additional inventory for Condensate operation. This 12" supply line first feeds an 8" common AFW supply header in the ABFP, and then is routed to the Turbine Bldg via LCV-1158 which will automatically isolate make up to the Condensate System to protect this minimum inventory for AFW in this 600,000 gal design capacity tank. An 8" return header off condensate pump discharge is routed underground back to the CST for inventory control. AFPs recirc back to the CST via individual 3" lines that tap into this 8" Condensate Return header to maintain minimum design pump flow whenever running AFPs are not feeding Steam Generators.

Normal operational lineup in the Turbine building is as follows, the CST supply valves (LCV-1127 & 1128A) to the condenser hotwells are throttled open in manual control. Condensate System return is controlled in manual via LCV-1129 which is normally kept shut in warm weather. In the winter, LCV-1129 is throttled open to maintain CST temperature between 50 and 65°F. Summer CST temperatures can range in the 80's.

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CST Operation and Secondary Leak Detection (continued)

A mobile unit supplies primary water to U2 via portable demineralizers to the three U1 Condensate Storage Tanks. From here, water factory Deaerator Booster Pumps supplyU2 condensate makeup to the Drains Collecting Tank (normal path) or to the U2 CST. Flow to the Drains Collecting Tank (DCT) is adjusted using Booster Pump (BP) flow (FI-531) or Primary Water Flow to the DCT (FIT-10001) meters for rough monitoring of manual changes.

Operators control secondary makeup by monitoring average Hotwell level in the Control Room. They attempt to match BP flow to the DCT with condensate losses. These losses include 100 gpm S/G Blowdown (or 70 gpm cold), 20 gpm Aux Steam heating (winter), 10-20 gpm condensate leakage and steam loss. Other than S/G blowdown there are no meters to track process losses. Operators allow CST level to track down slowly to makeup for the difference between DCT supply and secondary losses

Operations initially estimated the return line loss at 17gpm by shutting LCV-1158 and 1129 and subtracting the difference in CST rates of level change. This assumes no leak by LCV-1158 and no siphon break in the Return line.

A 10 gpm loss equals 14, 000 gallons a day. This equates to a CST level loss of 9 in/day or 3/8 in/hr. This would be hard to detect by monitoring CST level changes because the indicator in the CCR has intervals of feet, and such small changes cannot be visibly seen unless tracked over a few days. Since the CST is not the primary means of making up secondary losses, a 10 gpm leak would go unnoticed by watching CST levels. Hotwell level is maintained at about 4' or 76,000 gals. At 19,000gal/ft., a 10 gpm loss equates to about 3/8 in/hr change in hotwell level. Since operators maintain hotwell level within a close band, leak rate changes can't be detected by hotwell level.

IPEC00202258

Event Narrative

IPEC Buried Piping and Tank Inspection and Monitoring Program

The IPEC Buried Piping and Tank Inspection and Monitoring Program, hereafter simply referred to as BPT Program, is under development. The foundational elements of the program have been completed per scheduled milestones identified in Entergy fleet procedure EN-DC-343, which went into effect on Nov. 19, 2007. The fleet procedure required that all systems having buried portions of piping be included in the program, including but not limited to those systems that were identified in the IPEC License Renewal Application (LRA).

Once all buried piping systems were identified, the piping was assessed as having High, Medium or Low Impact, based on the consequences of a failure of the piping in the following areas:

- Safety (High = Nuclear Safety Related; Medium = Augmented Quality/Category M; Low = non-safety related)
- Public risk (High = potential radiological consequence; Medium = environment discharge or hazardous fluid; Low = non-contaminated, non-hazardous fluids)
- Economic impact of equipment failure on plant operation (High = >$1M; Medium = $100K - $1M; Low = <$100K.)

Table 1 presents the details for performing the impact assessment.

Using the impact assessment results, the High Impact systems are Corrosion Risk assessed with consideration of the following four (4) factors:

1. Soil resistivity
2. drainage
3. material
4. coatings/cathodic protection.

Tables 2 and 3 present the details for performing the corrosion risk assessments. Corrosion risk assessments were performed sequentially for the High, Medium and Low Impact system.

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IPEC Buried Piping and Tank Inspection and Monitoring Program (continued)

In conjunction with the corrosion risk assessments, the inspection priorities for performing the initial inspections and subsequent inspection intervals were determined for each buried piping system based on the results of the Impact and Corrosion Risk assessments. Table 4 provides the guidance for scheduling these inspections.

Buried pipe inspection parameters will include:

- External pipe coating and wrap condition
- Pipe wall thickness
- Cathodic Protection effectiveness (if applicable)

Current plans are for a Central Engineering Programs document for buried pipe and tanks be developed (target issue by end of 2009), and for each site to manage its buried pipe activities (surveys, excavations, inspections, etc.) using IDDEAL Scheduleworks, or similar software.

IPEC License Renewal Application (LRA) commitments for Buried Piping and Tanks Program:

IP2	Commitment NL-07-039	Sept. 28, 2013
IP3	Commitment NL-07-153	Dec. 12, 2015

The excavations and inspections of the IP2 AFW lines to the CST were performed in response to the ISE Panel recommendation to complete same by the end of 2008.

IPEC00202260

Event Narrative

Utility Experience

Most utilities are in the process of early Buried Piping and Tank Program development. Some (as IPEC, in 2005) have received INPO AFI's for non-functioning Cathodic Protection systems for their buried piping. At IPEC, however, Cathodic Protection systems are generally not provided for buried piping systems (exceptions being the sewage treatment pipeline, and underground diesel fuel oil lines). Resolution of the IPEC AFI is focused on correcting deficiencies in the installed cathodic protection system.

According to the Unit 2 and Unit 3 USFARs, the basis for not providing cathodic protection systems for buried piping was an engineering study performed during original licensing of the plants. Determinations of the soil resistivities at locations away from the river were concluded to be sufficiently high to preclude the need for cathodic protection for buried piping. The study recommended the application of protective coating to prevent local corrosion attack. Based on recent resistivity testing, the original resistivity determinations remain consistent.

An EPRI guidelines document (1016456) for an effective buried pipe program was issued in Dec. 2008. Future revision to the document is planned and will include:

- Buried tanks
- Non-metallic pipe

Industry initiatives are being taken to identify underground piping assessment technologies to perform assessments of coating integrity/condition, to identify degraded pipe locations and to quantify associated wall loss.

The EPRI buried piping guidance document has identified several methods that are used in the gas and oil pipe lines industries, but has not endorsed them.

IPEC00202261

Table 1 – Impact Assessment

	High	Medium	Low
Safety (Class per EN-DC-167)	Safety-related	Augmented QP and Fire Protection	Non-Safety related
Public Risk	Radioactive Contamination e.g. Tritium	Chemical/Oil-Treated System Gases	Untreated Water, SW, Demineralized Water
Economics (Cost of buried equipment failure to the plant)	> $1M or potential shutdown	$100K - $1M	< $100K
Notes: 1.	Any buried section with at least one High Impact gets an overall High Impact rating.		
2.	Any buried section with no High Impact rating but at least one Medium Impact rating gets an overall rating of Medium Impact.		
3.	Any buried section with all Low Impact ratings is to be rated as Low Impact.		

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Table 2 – Corrosion Risk Assessment

Soil Resistivity Ω-cm (Note 1)	Corrosivity Rating	Soil Resistivity Risk Weight
> 20,000	Essential Non-Corrosive	1
10,001 – 20,000	Mildly Corrosive	2
5,001 – 10,000	Moderately Corrosive	4
3,001 – 5,000	Corrosive	5
1,000 – 3,000	Highly Corrosive	8
< 1,000	Extremely Corrosive	10
Drainage		Drainage Risk Weight
Poor	Continually Wet	4.0
Fair	Generally Moist	2.0
Good	Generally Dry	1.0
Material		Material Risk Weight
Carbon and Low Alloy Steel		2.0
Cast and Ductile Iron		1.5
Stainless Steel		1.5
Copper Alloys		1.0
Concrete		0.5
Cathodic Protection	Coating	CP/Coating Risk Weight
No CP	Degraded Coating	2.0
No CP	Sound Coating	2.0
No CP	No Coating	1.0
Degraded CP	Degraded Coating	1.0
Degraded CP	Sound Coating	1.0
Degraded CP	No Coating	0.5
Sound CP	Degraded Coating	0.5
Sound CP	Sound Coating	0.5
Sound CP	No Coating	0.5

Note: Soil resistivity measurements must be taken at least once per 10 years unless areas are excavated and backfilled or if soil conditions are known to have changed for any reason.

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Table 3 – Corrosion Risk Tabulation

Corrosion Condition	Risk Weight Points
Soil Conditions Resistivity Drainage	 1 – 10 1 – 4
Materials Material	 0.5 – 2
Component Protection Cathodic Protection / Coating	 0.5 – 2
Final Corrosion Risk Tabulation Multiply all weights together in Steps 5.5 [2] (a) thru (d)	 0.25 – 160

Corrosion Risk:	High	61 – 160 points
	Medium	30 – 60 points
	Low	0 – 29 points

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Table 4 – Inspection Intervals vs Inspection Priority

Impact – Corrosion Risk	Inspection Priority	Initial Inspection (Years)	Inspection Interval (Years)
High-High	High	5	8
High-Medium	High	5	8
Medium-High	High	5	8
High-Low	Medium	8	10
Medium-Medium	Medium	8	10
Low-High	Medium	8	10
Medium-Low	Low	10	15
Low-Medium	Low	10	15
Low-Low	Low	10	15

Notes:

1. High priority initial inspections shall be scheduled within 5 years. Subsequent high priority inspections shall be scheduled within 8 years thereafter.
2. Medium priority initial inspections shall be scheduled within 8 years. Subsequent medium priority inspections shall be scheduled within 10 years thereafter.
3. Low priority initial inspections shall be scheduled within 10 years. Subsequent low priority inspections shall be scheduled within 15 years thereafter.
4. Regardless of the above inspection schedule (reference EN-DC-343), compliance with IPEC LRA commitments prevail.
5. Once initial inspections are performed and conditions before known, a re-prioritization may maintain, decrease or increase a component future inspection priority.

The CST line (#1509) was assessed per EN-DC-343 to be a "High" inspection priority.

IPEC00202265

Event Narrative

Previous Inspections of CST 8" Line

As a result of the Indian Point Independent Safety Evaluation (ISE) Report dated July 31, 2008, the following recommendation (R-7) was issued via LOCR IP3LO-2008-00151, CA-19: "to explore options for reducing the vulnerability of buried piping to the occurrence of any future unanticipated leak. Such options include excavating a few selected locations to confirm the presence of protective coating on the piping, as well as to measure and confirm the existence of sufficient wall thickness of the thus exposed piping using existing inspection techniques." Two areas of the Unit 2 CST lines were selected for inspection. The following information was retrieved from CR IP2-2008-04754.

The three CST pipes (Aux Feed Pump supply, CST return and CST overflow) were exposed at two locations for approximately 10' piping runs each.

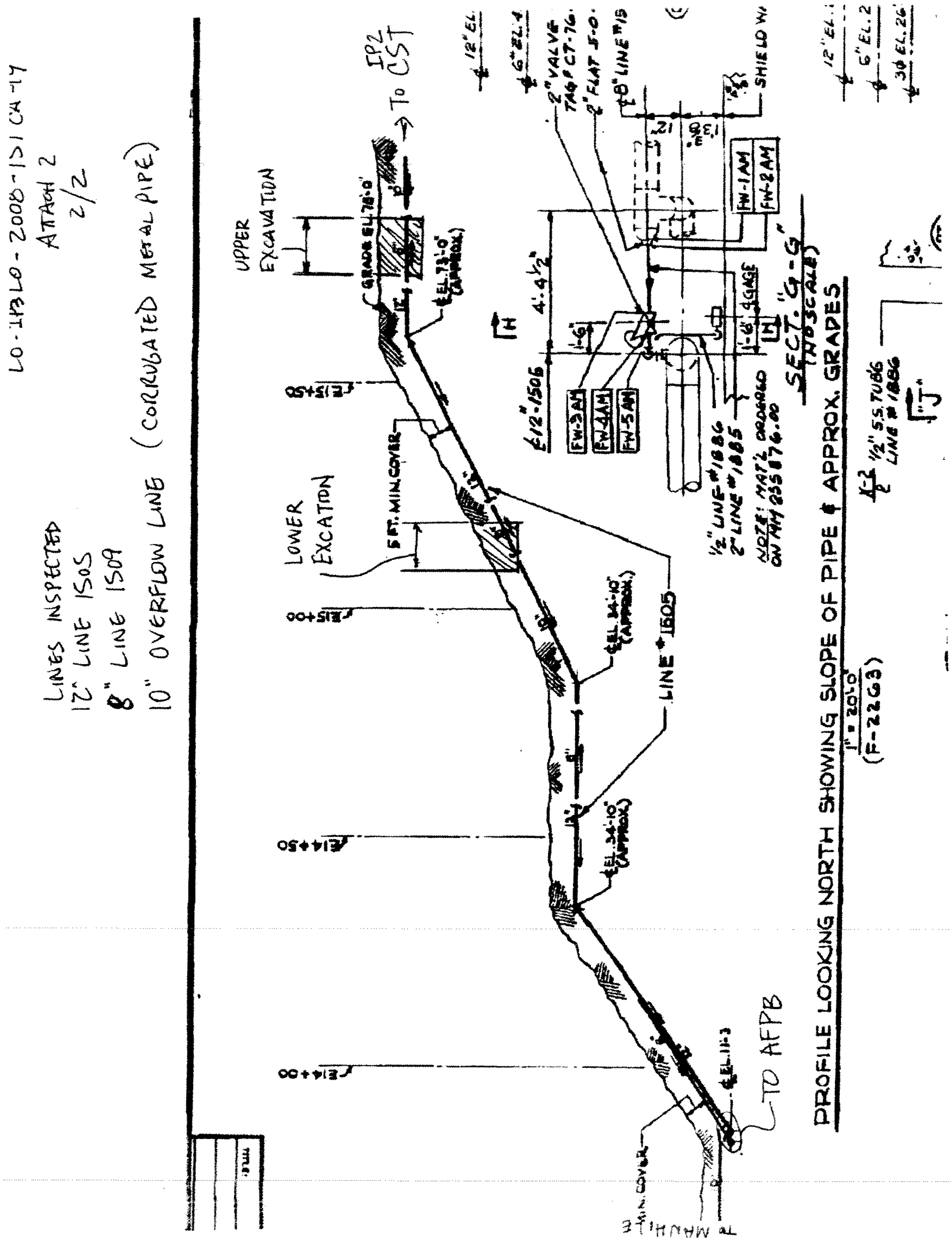
The three inspected lines were: 12" Line 1505, AFP Suction line,
8" Line 1509, Condensate supply to the CST
10" Overflow Line (no line number assigned, corrugated metal pipe to Manhole #5

Upper and lower holes were excavated. An inspection in the upper hole identified five areas which required coating repair. UT thickness measurements were also performed on those areas where the base metal was exposed and these inspections confirmed that the pipe thickness remains at nominal thickness (i.e. within the manufacturer's tolerance). All of these activities were performed under WO 164495.

The visual inspection of these pipes at the lower excavation revealed that they were in generally good condition, with the coating intact and in acceptable condition. A minor coating repair was required at one location on 8" Line 1509 and the 10" overflow line required repair at the top portion of the pipe at the crests of the corrugations, possibly indicative of coating damage during the digging. Based on the results of these pipe visual inspections (at the upper and lower holes), and the coating repairs performed, there was no evidence of any significant pipe degradation that would warrant the re-inspection of these pipes at the same locations. Future inspection of these lines will be performed at different location(s) along their length. The scheduling of the future inspections will be controlled under the IPEC Buried Pipe Program. Specifically for the CST lines, CA-5 of CR IP2-2008-04754 reads, "Given the results of the leak in the AFP Building, determine if the scope and/or frequency of future buried condensate lines should be modified. This should cover both IP2 and IP3." See elevation drawing on the next page.

Completed assessments of these lines determined these lines to be of HIGH impact (two lines are safety related), MEDIUM corrosion risk and HIGH inspection priority. The HIGH inspection priority results from the safety function performed by Lines 1505 and 1509. The pipe material, soil resistivity and site condition factors result in these lines being of medium corrosion risk. Accordingly, with the initial inspection of these lines performed in October/November 2008, re-inspection of these lines is required within eight years, or by September 2016.

IPEC00202266



LINES INSPECTED
12" LINE 1505
8" LINE 1509
10" OVERFLOW LINE (CORRUGATED METAL PIPE)
UPPER EXCAVATION
LOWER EXCATION
IP2 TO CST
TO AFPB
LINE # 1505
PROFILE LOOKING NORTH SHOWING SLOPE OF PIPE ℄ APPROX. GRADES
SECT. "G-G" (NO SCALE)

The configuration of the underground structures in the area is laid out as follows:

The ABFP Building column wall #22 is a solid concrete wall anchored directly to the bedrock that spans from the east wall to the west wall. The ABFP Building wall begins at approximately the 12' elevation (6' below grade) and is connected to the containment shield wall on the east end and the ABFP shield wall on the west end. The column wall #21 is a solid wall anchored directly to the bedrock. The east wall running north to south does not penetrate below grade. The west wall running north to south does not penetrate below grade but the structure for Manhole #5 is located in this area. There are two concrete slabs under the pipes in this area. One is the pad for the stairs and the other is believed to be related to Manhole #5. They are between 4-8" below the pipe. Based on this, the area can be described as being similar to a "bath tub" that drains slowly.

The slab construction in this area is approximately 6-8" thick and was poured as a monolithic slab on grade with sporadic reinforcement installed. There was one area that had what appeared to be 6 x 6 welded wire mesh. But it was not consistent throughout the slab and was not heavily supported when the slab was originally poured. This arrangement would not be unusual for a walkway design.

Once excavation began, it was apparent that there was significant amount of standing water beneath the slab and the backfill was saturated. The backfill also had significantly reduced in volume and was not supporting the slab in this area. The gap between the slab and top of the backfill was approximately 6" to 10", covering an area approximately 8' x 8'. There also was an area that appeared to be washed out measuring 2' x 2' and greater than 6' deep.

The backfill in the area contained rocks measuring up to 8" and other debris such as several aluminum cans and other debris. The large rocks were found throughout the excavation area and a concentration was found closer to the pipe, especially in the area of the 2' x 2' sinkhole. The debris and rocks would hamper the achievement of proper compaction of the area due to the creation of voids and an increase in the amount of un-compactable material.

The configuration of the underground structures that encompass the area allows some ground water to collect due to run off from the north hill and surrounding area. The elevation of the 8" pipe is estimated to be at or just above the groundwater table area; this is based on the surveys of the installed test wells in the area. Some groundwater infiltration has been seen leaching into the bottom of the excavation site, creating a wet environment around these lines.

The 12" line (#1505) and the 8" line (#1509) are carbon steel, schedule 40. These lines were deemed not to require cathodic protection during original plant design due to favorable soil resistivity and drainage characteristics. As a defense against localized corrosion attack, however, lines 1505 and 1509 are externally coated with coal tar enamel and utilize a coal tar enamel saturated felt overwrap for further protection of the coating.

It is a general coating practice to pull a glass matt into the hot enamel as reinforcement, and the outer side of the coating is saturated asbestos felt. The same corresponding lines at Unit 3 are above ground, insulated and heat traced, except outside the ABFB as described on page 35.

The bituminous coatings, as a class, are the most widely used protective media. These classes include asphalt enamels, the greases or waxes, and other mastics which consist of an asphalt or coal-tar base plus an inert binder. Of the large group of coatings tested under the joint effort of the National Bureau of Standards and the American Petroleum Institute, concluded that asphalts and coal-tar enamels were the best.

IPEC00202268

Event Narrative

Coal-tar coatings have been used for over 100 years to protect ferrous metals against underground corrosion. In 1913, an early form of coal-tar enamel was used in protecting gates, locks and penstocks of the Panama Canal. Examination after 35 years of service showed them to be in perfect condition. Coal-tar pitch is almost completely inert to moisture and soil chemicals. Coal-tar coatings and coal-tar pitch used as pipe coatings and for waterproofing have been dug up after 20 to 50 years of service underground. Coal-tar pitch does not absorb any appreciable water and is not affected to any appreciable extent by soil bacteria. These properties make it eminently more suitable for waterproofing and coating of buried steel pipe lines to protect them from the corrosion action of wet soil. If properly applied, the coating should be able to protect the lines in there currently installed environment and is within the life span of the protective coating.

Flow accelerated corrosion (FAC) was not part of the failure mechanism as described below.

Flow accelerated corrosion of carbon steel in water occurs due to the dissolution of the normally protective magnetic film that forms on the surface. (Mechanical removal, i.e. cavitation-erosion, does not normally occur under FAC conditions.) This corrosion was outside to inside on the pipe, and temperature attributes for FAC are generally between 212 °F and 572 °F.

The leak in the condensate piping was caused by external corrosion. Patterns of corrosion on the piping and observations of the backfill indicate that the corrosion on the pipe likely occurred at localized areas of coating damage that occurred during installation of the pipe. In comparison, other corrosion found on the removed elbow which affected a larger area but it was not as deep is more typical of corrosion related to difficulties in applying a good quality coating on more complex surfaces such as elbows and other fittings. For additional details on the failure analysis, see Structural Integrity Associates (SIA) Report No. 0900235.402.

IPEC00202269

Event Narrative

Conclusions

From the information gathered, the event was caused by the failure of the protective coal-tar epoxy coating that was applied at the time of original construction. Based on historical date, the coating, if properly applied, remains undamaged is sufficient to provide corrosion protection of the pipe. This is based on outside studies and the results of the previous inspection and analysis performed in 2008.

The coating failure was a direct result from the installation and type of backfill.

The eventual location of the "through wall leak" on the straight horizontal pipe at this location was due to a localized coating failure in this area that made it the most susceptible area to degrade once the mechanism for corrosion started. There were other localized areas on the straight pipe section and 90° elbow that were in a very advanced state of corrosion, also would have, given more time, would have eventually produced additional leak locations.

The ground water infiltration, soil composition, and the location of the leak at the lowest point of the system were all contributing factors to the leak developing in this area.

IPEC00202270

Root Cause Evaluation

The **Direct Cause (DC)** was a through-wall defect in the CST return line located below grade in the ABF Building. There is evidence that the pipe coating had degraded allowing corrosion to eventually penetrate its way through the pipe wall.

A. Root Cause(s)

1. **RC_1 -** The Root Cause (RC-1) is the installation specification 9321-01-8-4 in effect at the time of plant construction. There is evidence that sections of the pipe coating were damaged by rocks that were present in the backfill for the CST lines. The pipe coating material is fiber-based saturated with coal-tar. The material is then applied to the pipe. Since it is a fiber, the coating is susceptible to damage from the various size rocks found in close proximity to and in some cases, up against the pipes themselves.

   The rocks present in the backfill caused coating degradation in some areas of the pipes, making the pipes susceptible to external corrosion. It is evident that soil conditions influence the corrosion rate on those sections of pipe where there is coating degradation. For example, in the sample inspection holes, some coating degradation was found accompanied by minor surface rust. Ultrasonic Testing (UTs) of these areas found virtually no pipe wall loss. The soil conditions in the sample inspection holes were mostly dry, with minimal ground water present. By contrast, the soil in the failure location was found to be moist, which is consistent with the water table in the area estimated to be at the eight to ten foot elevation. The absence of gravel and sand surrounding the pipe promotes wicking of the ground water through the soil which also contributes to the moist conditions in the area. Therefore, the combination of degraded pipe coating and high water table served to accelerate corrosion of the failed pipe.

IPEC00202271

B. CONTRIBUTING CAUSE(S)

CC_1 – The water table in the area of the leak is between eight to ten feet with the pipe elevation at approximately ten feet. The backfill specification did not specify the use of clean sand and gravel under the pipe that would have limited the wicking of the ground water to the soil surrounding the pipes. This kept the soil in the area moist, and at times wet. These soil conditions would find its way into defects in the coating causing corrosion external to the pipe.

CC_2 – The inspection techniques used to preemptively detect underground pipe through wall leaks was ineffective. Buried Piping and Tank Inspection and Monitoring Program does not identify the low point of a pipe line as a suggested sample test point. The procedure inspection locations are based on risk and impact assessments, ease of access, limitations of inspections and ability to isolate lines.

IPEC00202272

C. ORGANIZATIONAL AND PROGRAMMATIC WEAKNESS EVALUATION:

The team performed an Organization and Programmatic Issues Review in accordance with Attachment 9.5 of EN-LI-118.

1. Organization and Programmatic Issues for Installation Concerns

   OP2J – Is there evidence that personnel exhibited insufficient awareness if the impact of actions on safety and reliability?

   Yes. The drawings and specifications allowed the use of material (already available on site) from blasted areas as fill for this buried pipe.

   OP4A – Is there evidence that there are insufficient details in a procedure to perform the task?

   Yes, at the time of installation, UE&C Specification No. 9321-01-8-4, Placing and Compaction of Backfill, was used as backfill guidance. This spec only stated the following, "Place fill in 12" layers and compact with tamper in small areas or by dozer or trucks in open areas. Top 12" shall be clean and compacted as noted on drawings." Drawing 9321-F-1002 states to "top off with gravel." Drawing 9321-F-1024, Containment Building Backfilling and Grading North and East Side, has a note which reads, "Surface of fill to be random size blasted rock from Unit 3 excavation."

   Presently for Unit 2, Con Edison Specification 02200 governs excavation and backfilling. For Unit 3, today's specification is UE&C Specification 9321-05-8-4, Placing and Compaction of Backfill, which is very similar to the original Unit 2 specification.

   OP5E – Is there evidence of inadequate job skills, work practices or decision making?

   Yes, there could have been the potential for poor job skills and work practices when applying the pipe coating, because the fill used was a contributor to the coating damage that was observed.

   All of the above identified issues occurred over 30 years ago, and there are corrective actions to address them. Present equipment and construction specifications and quality control/assurance review, the Engineering modification process would minimize these occurrences from repeating themselves. Interim corrective actions will be issued with this report to address these concerns.

2. Organization and Programmatic Issues for an Inadequate Buried Pipe Program (EN-DC-343)

   OP4A – Is there evidence that there are insufficient details in a procedure to perform the task?

   Yes, EN-DC-343, Buried Piping and Tank Inspection and Monitoring Program does not identify the low point of a pipe line as a suggested sample test point. The procedure inspection locations are based on risk and impact assessments, ease of access, limitations of inspections and ability to isolate lines.

   A corrective action to address this issue would be for the Entergy Fleet team to assess the addition of this point in the procedure, EN-DC-343.

IPEC00202273

D. Safety Culture Evaluation

The root cause and contributing causes were reviewed against EN-LI-118, Attachment 9.6, Safety Culture Evaluation. It was determined that 12 of the 13 impact areas were not applicable to the causes identified within this root cause analysis. However the Human Performance portion of the Safety Culture was impacted because complete, accurate and up-to-date Design Specifications were not in place during original backfill and supervisory and management oversight of work activities and contractors were not effectively implemented to prevent inappropriate backfill practices.

E. Equipment Failure Evaluation – see Attachment.

IPEC00202274

Generic Implications

Extent of Condition Review

As previously stated in this evaluation, the condition of the CST return line through-wall degradation and eventual leakage, was corrosion of the carbon steel piping material caused by coating imperfections and soil/ground water conditions.

Based on the cause of the corrosion and a review of the IPEC Buried Piping Program, it has been determined that all buried coated carbon steel piping could be susceptible to the same corrosion mechanism since the same materials and construction practices used to install the CST return pipe could have been used in other systems. Although all buried piping could be susceptible to external corrosion, recent inspections and operating experience indicate that piping buried at the lower site elevations could have a higher susceptibility because of the closer proximity to the ground water. This was confirmed by the Fall of 2008 excavations which indicated that piping with areas of degraded coating experienced essentially no degradation other than minor surface corrosion. On the other hand, the auxiliary steam pipe between IP1 and IP3, and the IP2 condensate return lines, experienced significant degradation in areas where the protective coating or insulation was either missing or degraded. In the case of the auxiliary steam piping, the incorrect type of insulation was installed (water retentive vs. water shedding). Both the IP2 CST return line and the auxiliary steam piping were buried under the 15' ground level while the two excavated locations were at the 60'+ elevation.

Unlike IP2, the piping at IP3 from the CST down to the transformer yard is supported above grade, heat traced and insulated.

The impact and risk assessments performed for the Buried Piping Program identified the following systems having buried piping that are deemed high priority for inspection:

IP2	IP3
City Water	City Water
EDG Fuel Oil	EDG Fuel Oil
Service Water	Service Water
CST Piping	CST Piping
	Aux Steam
	Steam Generator Blowdown

IPEC00202275