FINAL REPORT

GTI PROJECT NUMBER 20386

Demonstration of ECDA Applicability and Reliability for Demanding Situations

DOT Prj#195

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Executive Summary

On June 2, 2005, PHMSA issued the fifth Broad Agency Announcement, #DTPH56-05-BAA-0001, which included research to improve the understanding of Direct Assessment (DA) methods and practices in challenging situations.

This project received support from a group of over two dozen gas company participants, some of which contributed pipeline segments for assessment, pipe inspection resources, and excavation and examination costs to demonstrate the assessment technologies (i.e., case study segments/locations).

The objective of this project was to support the identification and demonstration of ECDA specific technologies for demanding pipeline situations (e.g., bare pipe, cased and non-cased crossings, and crowded right of ways such as city gate stations). Project emphasis was placed on the use of GWUT for these circumstances at the request of all the stakeholders involved in these efforts.

The *project stakeholder group* reviewed the External Corrosion Direct Assessment (ECDA) Demanding Situations from *2005 PHMSA R&D Forum* and Previous Research Activities. They agreed to and volunteered the following three high priority situations to focus on for potential case studies:

- *Multiple Pipes (Structures) in Congested Right of Way*: Interference issues with above ground inspections; Stray currents; Complex Meter & Station piping.
- *Bare Pipe Segments*
- *Cased Crossings* - Industry needs better differentiation between metal loss and casing/pipe contact points. Sizing of defects inside casings; Uncased crossing and deep crossing situations; Long crossings (e.g., us pitch-catch vs. pulse-echo GWUT)
- The following tools were used during the integrity assessments performed during this project: GWUT (GUL and Teletest): torsional and longitudinal signals, pitch-catch and pulse-echo, C-scan, and multiple frequency ranges; magnetic tomography inspection; visual inspection; manual and Porta-Scan UT; radiography (X-ray); Magnetic Particle Inspection (MPI); Close Interval Surveys (CIS); Direct Current Voltage Gradient (DCVG); Pipeline Current Mapper (PCM), native potential and side-drain surveys; soil resistivity.

These three situations resulted in 30 excavations for GWUT application and when combined with the in kind data, included a total of approximately 100 dig sites with fifty-five confirmed (a 100% validation) indications for analysis.

All validated data was collected, analyzed, and summarized in graphical form, which included: inspection ranges, confirmed defect sizes (depth, length, width, and volume) as well as probabilities of detection (both false/true positives and negatives). Some general lessons learned were:

For Multiple Pipes (structures) in Congested ROW Situations:

> ECDA standard tools worked well in open areas where interferences did not preclude the use of CIS, DCVG, and PCM as validated by 100% excavation with visual inspection & pit gauge and magnetic particle inspection.

> GWUT was very effective when standard DA tools could not be used. GWUT also identified the presence of sludge and deposits in pipe sections.

For the Bare Pipe Situations

> CIS coupled with Native Potential Surveys and Side-Drain Surveys (aka Hot Spot Surveys) worked well and predicted areas of potential past corrosion.

> GWUT had a relatively short range due to the very adherent and "plastic" clay soil.

> Magnetic Tomography did not correlate well (false positive indications) for corrosion but did locate a wrinkle bend type feature outside of the GWUT inspected section.

For Cased Pipe Situations

> GWUT correlated with the direct exam findings.

> For thick, pliable, well adhered asphalt coatings, the GWUT range was severely restricted.

> PCM inspections provided another means of determining short situations between carrier and casing pipes.

All these lessons learned and many more from this project were compiled and are presented as a, *"Guided Wave Ultrasonic Testing Background, Technical Explanation, and Field Implementation Protocol to Assist Operators"*.

The capability and reliability of GWUT technology for integrity assessment for the chosen challenging situations was demonstrated as part of the DA process when following the included protocol.

GWUT reliability from 55 indications at 18 case study sites resulted in no false negatives, 1 false positive, and a 98% chance of correct prediction as shown in Figure 1 below.

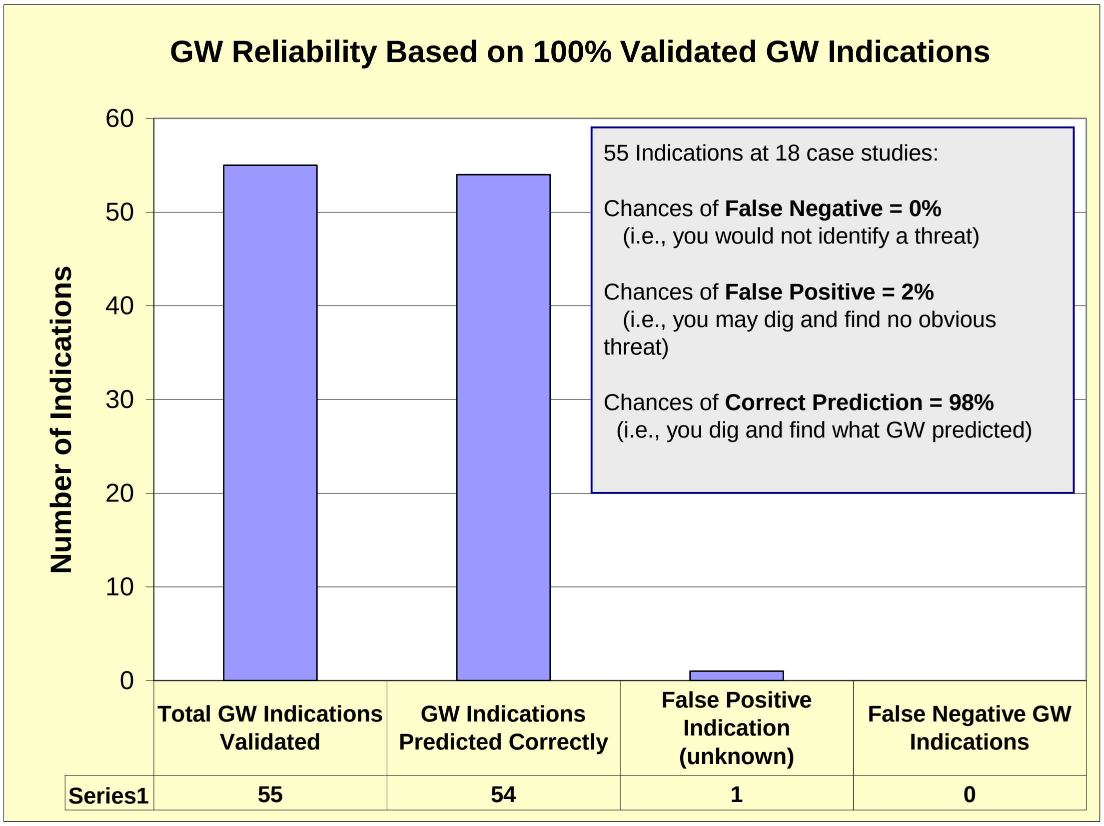


Figure 1. Guided Wave reliability based on 100% validated GW indications (18 case studies - 55 indications; all pipe was uncovered; coating was removed to get to bare metal; further inspection beyond visual was done as necessary, e.g. X-Ray, PortaScan UT, etc.). Note: the lack of any false negatives *includes* all the length of pipe inspected and is a very encouraging result in itself.

GWUT produced very good reliability numbers even though the cases all had very small corrosion damage or none at all. When the casing and coatings were removed, the GWUT operator successfully called all the predictions.

No corrosion was found that was not predicted, however one location had corrosion less severe than the prediction, confirming that the tool signals (when interpreted by the current service providers) are basically conservative.

A Summary of General Guided Wave Findings Included:

> Depending on coating type and soil conditions, the inspection range varied from 10ft on the low side to greater than 100ft on the high side (this is with a 5% CSA threshold).

> Torsional waves tended to provide a better resolution vs. longitudinal waves.

> Longitudinal waves tended to provide the longest range, although at a lower frequency and resolution.

> A multitude of frequencies was necessary to differentiate spacers from anomalies.

> C-Scan images were very helpful at determining the extent and radial distribution of anomalies.

> GWUT was efficient at finding asymmetric weld geometries (verified by X-ray inspection).

A Summary of ECDA Tool Performance for Challenging Situations - When the pipe was coated and not in a casing:

> DCVG had a finer location resolution than PCM, e.g. inches versus feet and located coating defects that were the size of a pinhole to 300 in^2 within 1-3 inches of their actual location.

> CIS located defects less precisely than DCVG, but correlated well with the excavated location; and correctly differentiated between locations with little or no cathodic protection and those that were well protected. CIS also greatly assisted in setting overall classifications and prioritizations.

> Cell-to-Cell and Side-Drain (hot spot surveys) appeared to correlate well with corrosion found on bare pipe

> PCM worked well in indicating general regions of coating defects or large holidays (4 in^2) on well coated pipe. If the pipe had large and long holidays along the bottom, PCM did not isolate the indication.

> PCM A-Frame worked well at locating isolated, small defects and found a defect under an asphalt driveway. Comparable to DCVG in ability to locate small coating holidays if one already knows their general location.

To help move these project results into general use, contact with the appropriate SDO committees (e.g., ASME and NACE) has been initiated. These results and recommendations will be presented to the applicable Standards Development Organizations (SDOs) to ensure timely implementation of research benefits -- improved safety, ability to assess pipeline segments that have no alternate method available (i.e., expand DA applicability), and increased knowledge of the DA method that incorporates GWUT.

GTI also conducted a feasibility analysis (at PHMSA's request) using a subset of the validated data. GWUT successfully called out defects that were ≤ 5% Cross Sectional Area (CSA) "criteria" curve. The anomalies that were ≥ 5% Cross Sectional Area (CSA) were dug up, had their coating removed, and the subsequent pits were physically measured (both length and depth with an engineering ruler and a pit gauge). The pit dimensions were input into ASME B31G criteria at the test pressure for the class location. All the pits passed this criteria for failure at the test pressure for their respective class location. Additionally (and more conservatively), all the defects *also* met the ASME B31G criteria for a pressure (greater than the pressure test pressure) that would have resulted in a hoop stress equal to 100% SMYS (P=2St/D), i.e. they met (passed) the standard ASME B31G criteria. This also follows from the fact that the Class 1, 2, 3, and 4 Test Pressures (used in this case) were all below the pressure required to achieve 100% SMYS pipe wall stress.

It was also clear from the feasibility analysis that (1) more field data with validation excavations and (2) possible analytical refinements are needed to link the %CSA cutoff criteria accurately to the defects that GWUT was successful at identifying.

As a *next step* (i.e., follow on research efforts to this project), one suggestion would be to analyze a larger data set of GWUT inspected/predicted indications with the associated direct examination measurements. If one could demonstrate that GWUT finds defects that would pass a pressure test (and therefore substantiating that GWUT will find all larger defects than these) it would facilitate the acceptance of GWUT as an acceptable *stand-alone* inspection technique. A final deliverable from such and effort could be the development a methodology to serve as the basis for a GWUT standard (from an SDO) and the validated supporting data.

Introduction

Basis/Need for Project Results

The United States of America is critically dependent on natural gas and petroleum liquids transported through pipelines. The infrastructure that currently transports these energy resources is aging, with a significant fraction being more than fifty years old. While new pipelines are being planned and constructed, pipeline operators typically plan on continued operation of the vast majority of existing pipeline mileage. Assuring the long-term integrity and security of these existing pipelines is essential.

Recognizing these facts, the U.S. Department of Transportation (DOT), Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS) designed a continuing process to emphasize the importance of continuing pipeline-related Research and Development (R&D). States, industry, and other Federal Agencies strongly support PHMSA's initiative.

PHMSA's pipeline safety R&D Blueprint planning process focuses on the following objectives:

- Facilitate better R&D planning by organizations that fund pipeline-related R&D;
- Increase the assurance that major industry, regulatory and public concerns are being addressed by ongoing or planned R&D;
- Assemble diverse stakeholder input on R&D needs and priorities;
- Assemble and communicate R&D plans among funding organizations; and
- Promote more effective technology transfer.

In March 2005, PHMSA conducted a government/Industry Pipeline R&D Forum in Houston, Texas. A large group of representatives from Government and industry organizations attended. The forum led to a common understanding of current research efforts, a listing of key challenges facing government and industry, and a compilation of potential research areas whose exploration can help meet these challenges and thus be considered in developing new R&D applications. PHMSA pipeline safety representatives determined that the following major research areas needed to be addressed: a) Damage Prevention; b) Mechanical Damage; c) Direct Assessment; d) Inspection; e) Leak Detection; f) Pipeline Design; and g) Other Safety Improvements (includes E-communications and Human Factors). On June 2, 2005, PHMSA issued the fifth Broad Agency Announcement, #DTPH56-05-BAA-0001, addressing each of these major areas.

This project addressed the Direct Assessment area with a special emphasis on the use of Guided Wave Ultrasonic Testing (GWUT) use as part of the assessment process for situations that are challenging to inspect.

Project Background

Pipeline integrity management mandates for natural gas transmission pipelines have been in place since December 17, 2002, when the President signed the Pipeline Safety Improvement Act of 2002. This Act required the Office of Pipeline Safety (OPS) to issue the Integrity Management Program (IMP) regulation, by December, 2003, that provided more specificity on what transmission lines are covered and the elements of an integrity management program. Both the Act and the regulation require the integrity of natural gas transmission pipelines in High Consequence Areas (HCA) to be assessed on a periodic seven year or less basis. For the majority of Local Distribution Companies (LDCs) with transmission lines, Direct Assessment has proven to be the primary method to evaluate these pipelines.

The Pipeline Safety Act and Integrity Management Regulations provided the impetus for the first three AGA/GTI research collaboration efforts on integrity management that began back in September of 2002. This prior work has already delivered protocols for the application of External Corrosion Direct Assessment (ECDA), Internal Corrosion Direct Assessment (ICDA), and for Guided Wave Ultrasonic Testing (GWUT) as well as detailed case studies for crossings, and casings. Both State and Federal Regulators have witnessed the application of these protocols which helps boost confidence in the overall Direct Assessment process itself.

However, there are still situations that need unique/generic protocols to assist pipeline operators in applying ECDA on challenging situations (i.e. bare pipe, congested meter stations, cased pipe sections, or similar circumstances).

Operators, regulators and other stakeholders must have confidence that these particular situations do have a proven solution for performing an integrity assessment. The industry must work with regulators in demonstrating that adequate procedures/protocols are in place to address these critical issues. Audits are already underway and these difficult situations need validated answers and protocols.

This project, "Demonstration of ECDA Applicability and Reliability for Demanding Situations", Pipeline and Hazardous Materials Safety Administration (PHMSA) Project

#195 had the main objective to support the identification and demonstration of ECDA specific technologies for demanding pipeline situations (e.g., bare pipe, cased and non-cased crossings, and crowded right of ways such as city gate stations). Project emphasis was placed on the use of GWUT for these circumstances at the request of all the stakeholders involved in these efforts.

Demonstration of the capability and reliability of GWUT technology for these specific situations resulted in a generic protocol/recommend practice and the associated validated data (from direct exams).

These results and recommendations have been presented to the applicable Standards Development Organizations (SDOs) to ensure timely implementation of research benefits -- improved safety, ability to assess pipeline segments that have no alternate method available (i.e., expand DA applicability), and increased knowledge of the DA method that incorporates GWUT. This project received support from a group of over two dozen gas company participants, some of which contributed pipeline segments for assessment, pipe inspection resources, and excavation and examination costs to demonstrate the assessment technologies (i.e., case study segments/locations).

Project Deliverables

- Provide a list of demanding situations (from gap analysis) that standard ECDA techniques will not adequately cover.
- Provide a list of complementary inspection tools (beyond standard ECDA tools) for testing and validation on pipeline segments that cannot be assessed with the standard spectrum of ECDA tools.
- Provide a set of assessment techniques for each of the case study demanding situations that include recommended new (alternate) assessment methodologies and the applicable existing/standard ECDA tools and techniques that may be used in conjunction with them. At stakeholder request, special project emphasis was placed on the development of the proper use of GWUT and its validation.
- Solicit, prioritize, and execute a set of field trials (i.e., case study sites) for the challenging situation direct assessment process.
- Collect, analyze, and present validation test results of the application of the recommended assessment techniques for the demanding situations.
- Provide GWUT reliability parameters (based on the project's validated assessments) for the challenging situations.
- Provide concise input to the appropriate SDO committees (e.g., ASME and NACE) to move the research results into general use.

Project Meeting with Industry (Operators) to Confirm Needs and Provide Focus

Kickoff Meeting with Industry Representatives and PHMSA

A Kickoff Meeting held June 20, 2006 with participation from Gas Technology Institute (Project Manager and Principal Investigators); 23 Natural Gas Pipeline Operators; American Gas Association; Guided Wave UT providers; & Northeast Gas Association.

The group reviewed the External Corrosion Direct Assessment (ECDA) Demanding Situations from *2005 PHMSA R&D Forum* and Previous Research Activities. They then suggested and discussed the following three high priority situations to focus on for potential case studies:

- *Multiple Pipes (Structures) in Congested Right of Way*: Interference issues with above ground inspections; Stray currents; Complex Meter & Station piping.
- *Bare Pipe Segments*
- *Cased Crossings* - Industry needs better differentiation between metal loss and casing/pipe contact points. Sizing of defects inside casings; Uncased crossing and deep crossing situations; Long crossings (e.g., us pitch-catch vs. pulse-echo GWUT)

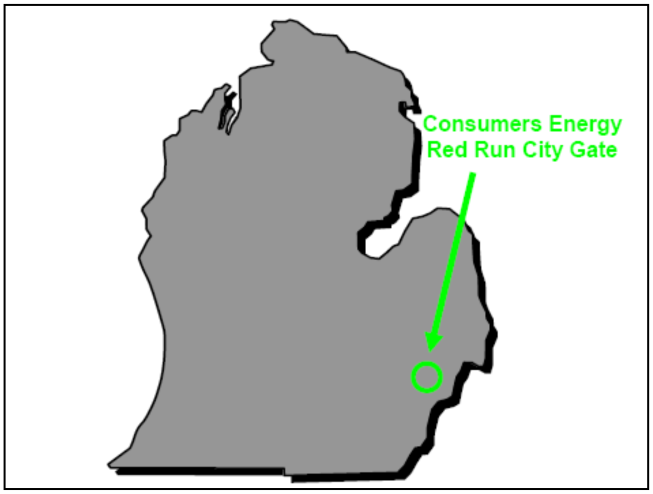
GTI then solicited volunteer operators and secured commitments for case study segments. Together, these covered the top three demanding situations that were suggested for further research activities.

The stakeholders involved with this project had only used two commercially available GWUT technologies either manufactured by Guided Ultrasonics and Teletest Companies. Therefore, other Guided Wave alternatives such as the Magnetostrictive sensor (MsS) technology were not available. This report therefore validates and describes the GUL and Teletest systems used.

Results and Discussion - Crowded City Gate Station

Red Run City Gate Background Information

- 26” diameter city gate station (~1966 rebuilt in 1980’s), Coal Tar coated.
- X-60 line at ~865 psig.
- Four drips to be removed (40’ drip on each side of two heaters)
- Internal corrosion failure in 1982 at heater bypass.
- Had synthetic natural gas with high CO & CO_2 in the past.
- Have had liquids in the line in the past.
- Pipe internally coated for flow control.
- System is electrically shorted into distribution system.
- Many parallel and ancillary lines make assessment difficult.
- Lines penetrate concrete walls difficult to assess.
- Conducted PCM/CIS/DCVG inspections.
- <u>Case Study Included:</u>
  - > Broke up the station into areas easy to assess and those difficult to assess.
  - > Developed procedure/process to assess the demanding situations, including:
    - Pitch-Catch Guided Wave for more complex station piping shapes.
    - Screen PCM/CIS/DCVG results and identify indications that should be further assessed with guide wave technology or other technology.
  - > Validated findings with direct examinations, UT, Porta-Scan UT, and Radiography.



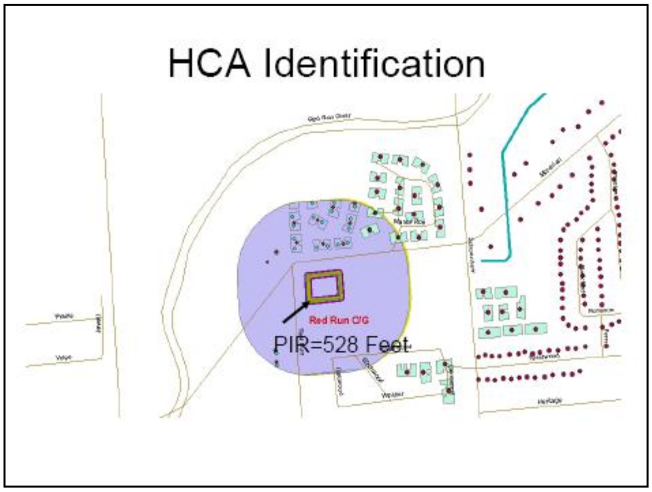


Figure 2. Location of Field Site.

General Description/Overview

- The facility is operated out of the Eastern Area and provides natural gas to a sizable distribution system servicing the northeast metropolitan Detroit area.
- The station has an Inlet MAOP of 865 psig and Outlet MAOP of 300 psig.
- The Station is typically shut in and placed in standby during summer operations. This presents a higher potential for internal corrosion.
- In 1982 the Station experienced an internal corrosion failure at the heater bypass area. High levels of CO and CO_2 were in the system for a period of time and contributed to the failure. These high levels are no longer present. Mainline and station piping was inspected and replaced as necessary.
- Station piping consists primarily of 1982 and 1966 - 26 inch and 12 inch piping.
- Site had a total of four drip logs. A leak within the last year resulted in evaluation of drip log design and capacity.
    - Drips installed upstream have reduced the volume of liquids seen at Red Run.
    - A redesign, going to two smaller drip logs is near completion.
    - Since the drips are to be replaced, inspection of the drip logs is no longer necessary for this assessment. This eliminated the need for installation of access flange, cleaning, and assessment of four original drip logs and resulted in lower assessment cost.

Figure 3. Site View.

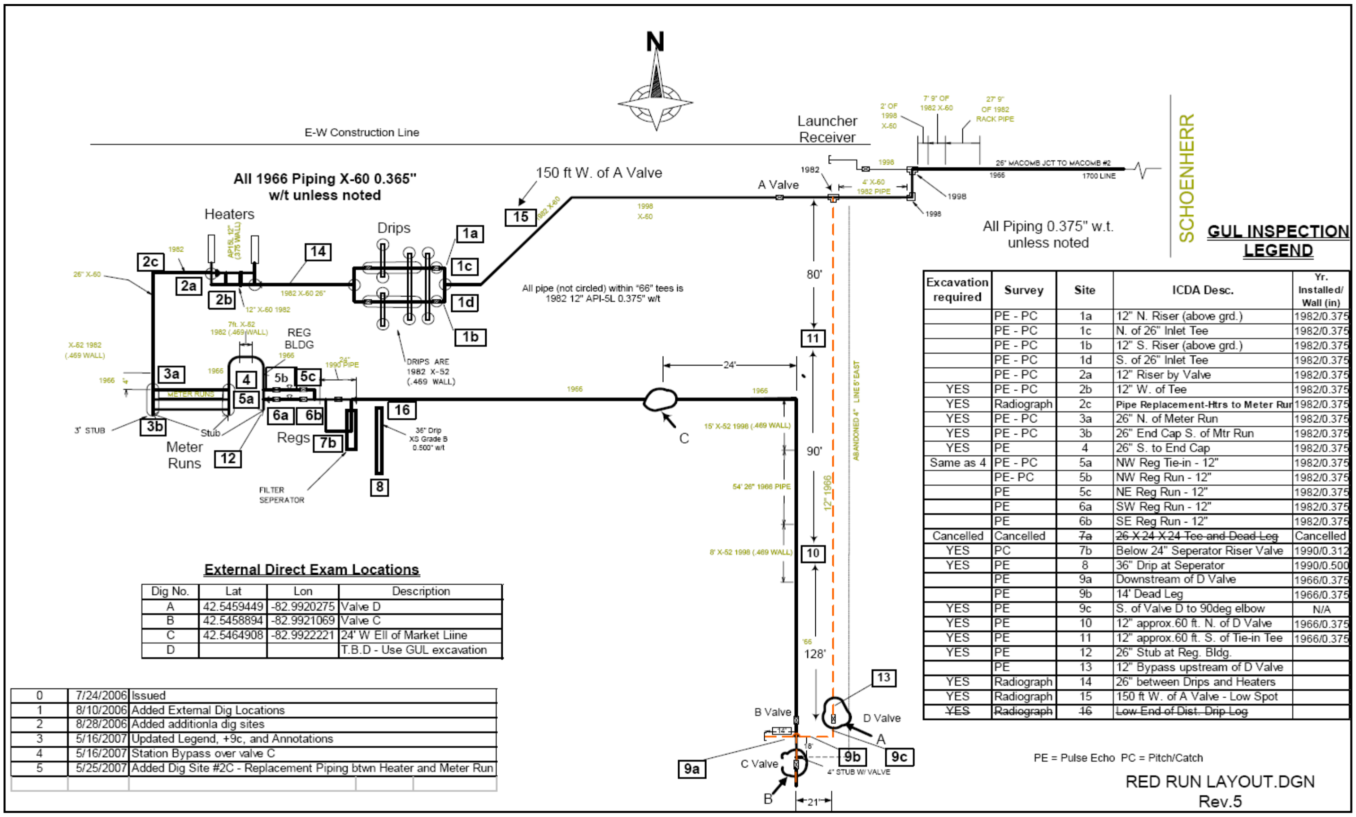


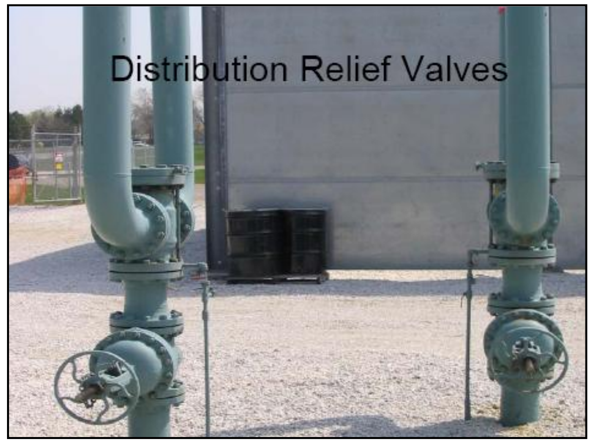
Figure 4. Schematic of City Gate Layout.

Gas Flow Through the City Gate Station

1. 26" transmission inlet line to station ends at Launcher/Receiver area.
2. Meter/Regulator Station begins at 26" Valve 'A'.
3. Gas flows from Valve 'A' to inlet of Drips via 26" Line, Radiography Only Dig Site #15 at low elevation point along this section.
4. This feeds into the drips at Dig Site #1 (a, b, c, & d). Drips are to trap condensed water.
5. From outlet of Drips, gas flows to inlet of Heaters via 26" section, Dig Site #14.
6. The gas then feeds into the Heaters at Dig Site #2 (a, b, and c). Heaters are to raise the gas temperature prior to pressure reduction (with Joule-Thompson cooling).
7. From the Heaters the gas flows to the Meter Run Header at Dig Site #3 (a&b).
8. The gas flows through the Meters into the Regulator Header at Dig Site #4 and #12.
9. From the Regulator Header the gas flows through both concrete wall (west and east sides of Regulator Building) either side of two Regulators at Dig Sites #5 (a, b, & c) and #6 (a & b) respectively.

10. The gas then flows through the Filer-Separator at Dig Site #7b.
11. Condensates separating out at the Filter-Separator drop out into the Slop Tank at Dig Site #8.
12. The gas continues out of the Filter-Separator in the 26" line and turns south to feed the network after Valve C.
13. FULL STATION BYPASS
    a. Begins upstream of Valve 'A' at a 26" to 12" Tee.
    b. This bypass heads south approximately 300' to 12" Valve 'D', this section includes Dig Sites #10, #11, & #13.
    c. After Valve 'D' the 12" bypass line flows into the 26" Main after passing through 12" Valve 'C', Dig Sites #9 (a, b, & c) are in this section.
14. DIRECT ASSESSMENT DIRECT EXAM SITES
    a. Site A around 12" Valve 'D'
    b. Site B around 12" Valve 'C'
    c. Site C validation site downstream of Filter Separator.

Figure 5. **Launcher, Drips, Heaters, and Meter Runs.**



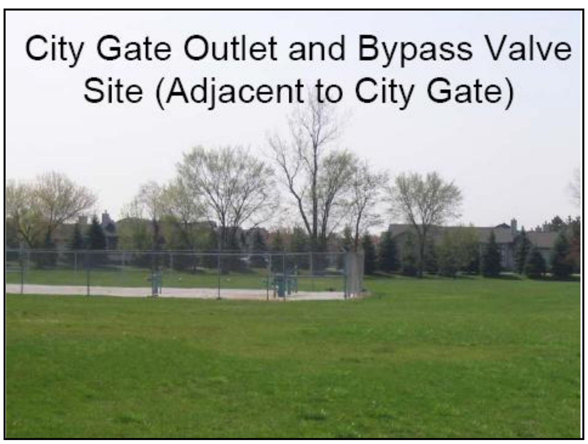


Figure 6. Regulators, Relief Valves, Filter Separator, Drip Log, and Outlet & Bypass Valves.

ECDA Pre-Assessment

- Drawings along with other records were assembled and reviewed for content and pertinence.
- During preliminary testing the station was discovered to be shorted to both electric neutral and gas distribution system.
- CP levels have been good since construction of station with only minor instances of below potential readings that were repaired promptly.
- Though congested, the site did not present any particular problems in respect to obtaining good Close Interval Survey (CIS)/Direct Current Voltage Gradient (DCVG) measurements.

ECDA Indirect Inspection

- Contractor performed an Indirect Inspection of the facility and collected data using the following test methods. In addition, Global Positioning System (GPS) data was collected at each test measurement location:
    - CIS
    - DCVG
    - Pipeline Current Mapper (PCM)
    - Soil Resistivity
    - Pipe elevation survey.

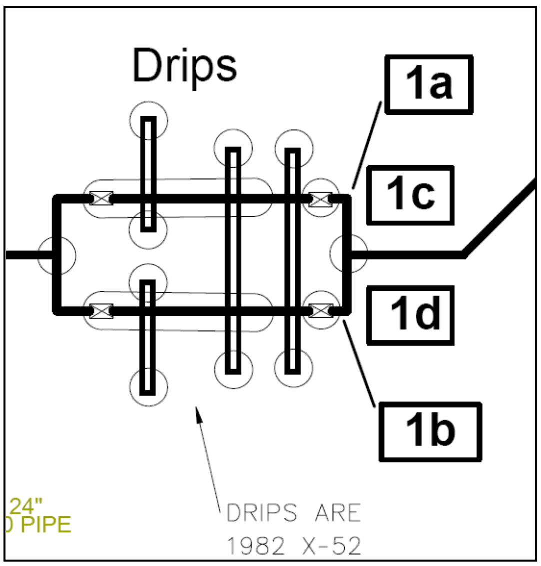
Results of Indirect Inspections

- A total of 23 DCVG indications were identified. Three were evaluated as Moderate. The remaining indications were identified as Minor. In all cases pipe-to-soil potentials were in the range of -1.000V Off.
- One area, adjacent to the outlet of the Regulator Building indicated localized low CIS potential readings without a DCVG indication.
    - Additional testing was performed and found that while low for a distance of 3 to 5 ft from the wall, actual potentials were better than indirect inspection data reported.
    - Further investigation led to the conclusion that potentials were affected by a bare steel sleeve used as a penetration thru the concrete wall.

Direct Exam Dig Schedule

- External Direct Examinations:
  - The review of the data indicted three scheduled action indications. All three of the indications were selected for direct exam.
  - An Internal corrosion site was used for external corrosion validation to complete requirements.
- Internal Direct Examinations:
  - Internal Corrosion Inspection sites were determined through analysis of operating modes looking for potential liquid hold up and dead leg areas.
  - It was decided that a total of 18 segments of piping be inspected with Guided Wave, Radiographic, and Ultrasonic testing.
  - A total of 14 areas were selected for potential liquid hold-up areas
  - Four additional segments at wall penetrations of the Regulator Bldg were to be inspected by Guided Wave.

Dig Site: **#1 a, b, c, and d - Header into Drip Run**



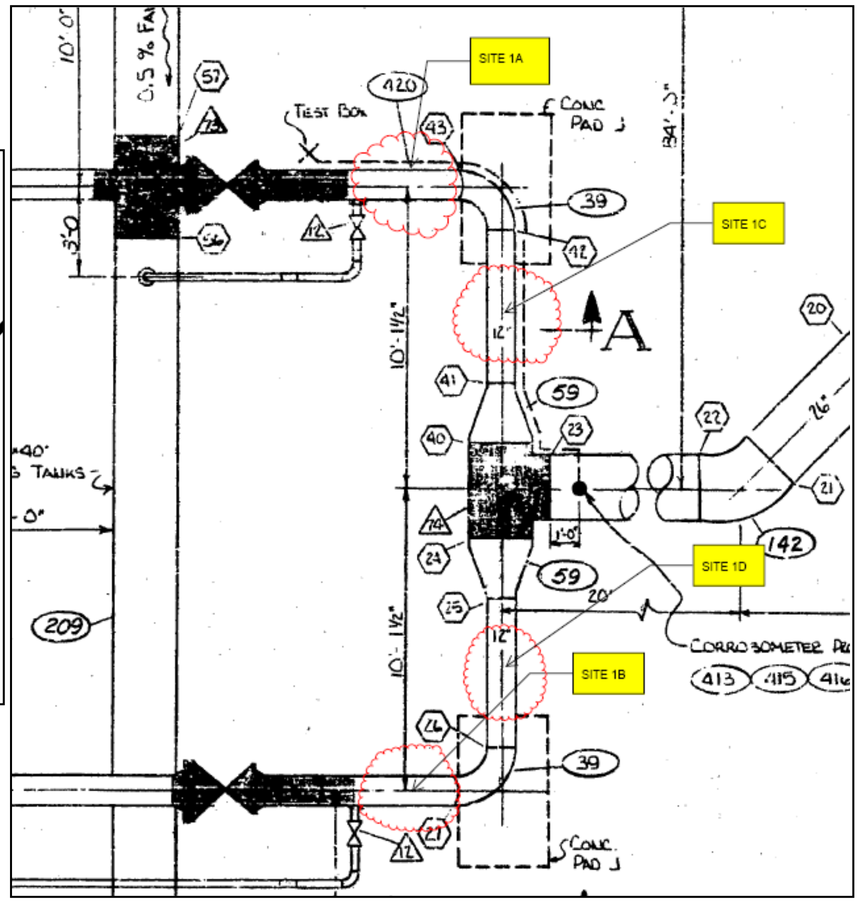


Figure 7. **Schematic of Header into Drip Run.**

(a) (b)

Figure 8. (a) 26" Inlet tee to drip run showing P-C GW inspection. (b) Risers a & b along drip runs.

Guided Wave Results

Dig Site 1A - PE

Pipe: 12" 1A Red Run St	Ring: R2B12(285)-Circum
Site: Consumers Energy	Config: 7.0FR, T(0,1)
Location: Riser pipe +4inch	Calibration: Automatic (505.187 mV)
Size: 12 inch (0.375 in)	Version: 3.92, Wavemaker G312
Tested: Aug 21 2006 14:00	Client: Consumers Energy
Tested by: David Alleyne[GUL]	Procedure: GU 1.1

General Notes: TP 10 test location 1A on the vertical section of the penetration into ground. No reflections have been interpreted to be from corrosion above the call level

Feature	Location	ECL	Length	Class	Notes
+F1	0'4"	-	0	Weld	Visible but in the transducer dead-zone
+F2	2'0"	-	0	45 deg Bend	
+F3	4'6"	-	0	Flange	
-F1	-1'7"	-	~	Bitumen	Some minor reflections from the entry area, contact and surface conditions.
-F2	-2'0"	-	~	Earth	
-F3	-5'8"	-	0	1D Bend	

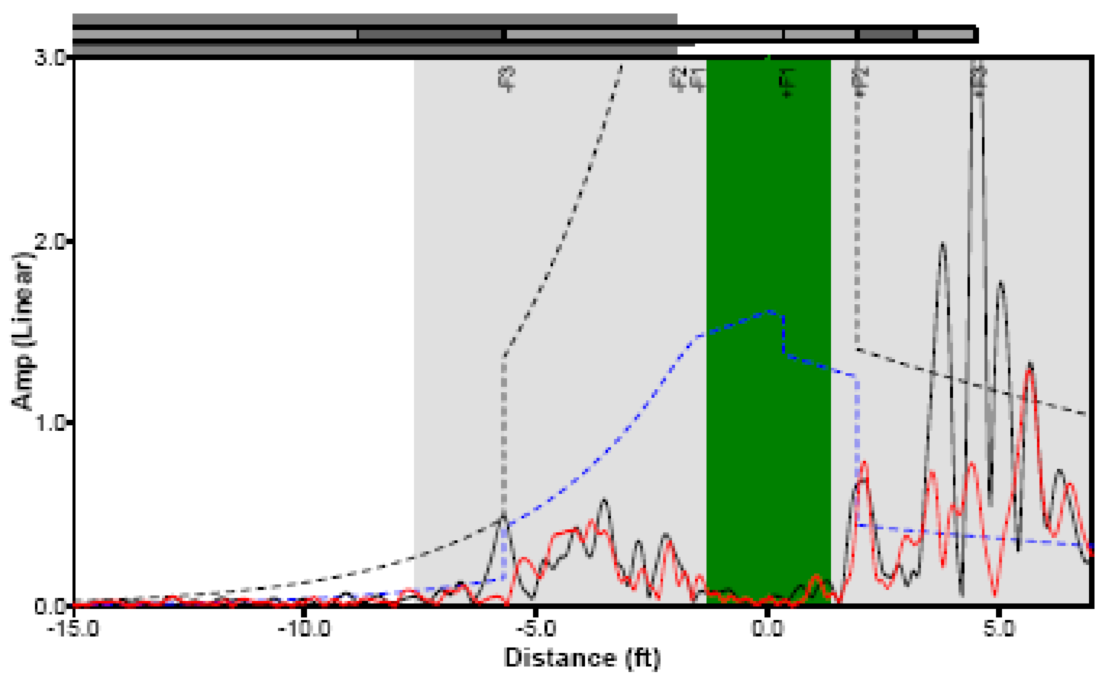


Figure 9**. Dig Site 1A - PE.**

Dig Site 1B - PE

Pipe: 12" 1B Red Run St
Site: Consumer Energy
Location: Riser pipe Sections +4inch
Size: 12 inch

Tested: 21 Aug 2006 15:08
Tested by: David Alleyne[GUL]

Ring: R2BCM(12424)-Circum-35mm
Config: 4.8FR, T(0,1)
Calibration: Automatic (1946.97 mV)
Version: 3.91, Wavemaker G312
GPS: 0°15.7786'W, 51°29.9452'N
Client: Consumer Energy
Procedure: GU 1.1

General Notes: TP 9 test location 1B

Feature	Location	ECL	Class	Notes
+F1	0'4"	-	Weld	
+F2	2'0"	-	45 deg Bend	
+F3	4'6"	-	Flange	
-F1	-2'1"	-	Bitumen	
-F2	-3'0"	-	Earth	
-F3	-5'8"	-	1D Bend	

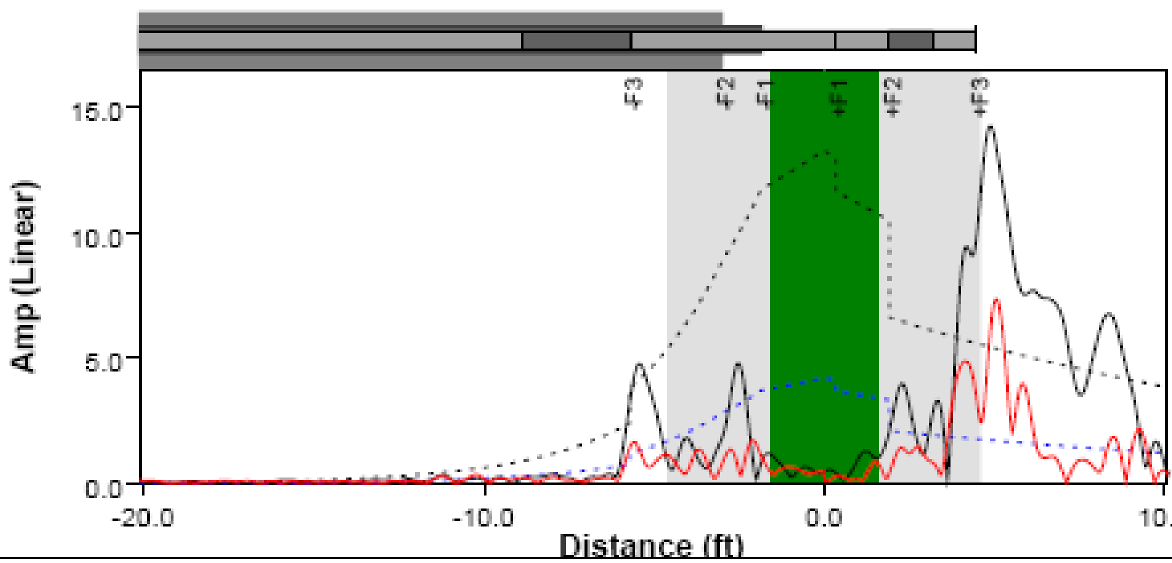


Figure 10. **Dig Site 1B - PE.**

Dig Site 1C - PE

Pipe:	12" 1D Red Run St	Ring:	R2B12PE(30)
Site:	Consumers Energy	Config:	5.4FR, T(0,1)
Location:	Branch T to 26inch -1ft	Calibration:	Automatic (0 mV)
Size:	1inch 12 inch	Version:	3.92, Wavemaker G312
Tested:	22 Aug 2006 10:28	Client:	Consumers Energy
Tested by:	David Alleyne[GUL]	Procedure:	GU 1.1

General Notes: TP 12 Pitch Catch data with two rings at test locations 1C and 1D. This is the Pulse-Echo result from location 1C. There are no reflections above the call level that have been interpreted to be from significant corrosion. The large reflections in the negative directions are echoes that have propagated within the reducer or that are reverberated between the reducer and the bend weld.

Feature	Location	ECL	Class	Notes
+F1	3'4"	-	Entrance	Start of buried section of pipe towards location 1A
+F2	4'1"	-	Bend	
-F1	-1'5"	-	T	
-F2	-3'3"	-	False Echo	Trailing echoes and reverberation reflections
-F3	-6'9"	-	False Echo	
-F4	-8'8"	-	False Echo	Possible path through the reducer feature

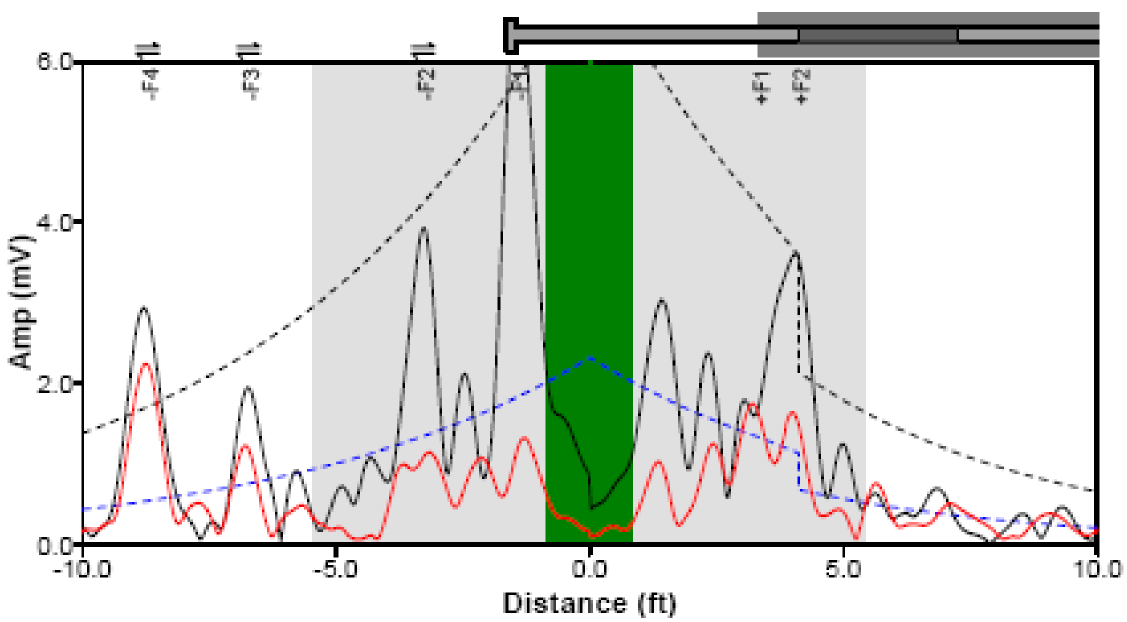


Figure 11. **Dig Site 1C - PE.**

Dig Site 1D - PE

Pipe: 12" 1D Red Run St
Site: Consumers Energy
Location: Branch T to 26inch -1ft
Size: 1inch
12 inch

Ring: R2B12PE(30)
Config: 5.4FR, T(0,1)
Calibration: Automatic (552.065 mV)
Version: 3.92, Wavemaker G312

Tested: 22 Aug 2006 10:28
Tested by: David Alleyne[GUL]

Client: Consumers Energy
Procedure: GU 1.1

General Notes: TP 11 Pitch Catch data with two rings at test locations 1C and 1D. This is the Pulse-Echo result from location 1D. There are no reflections above the call level that have been interpreted to be from significant corrosion. The large reflections in the negative directions are echoes that have propagated within the reducer or that are reverberated between the reducer and the bend weld.

Feature	Location	ECL	Class	Notes
+F1	3'4"	-	Entrance	Start of buried section of pipe towards location 1B
+F2	4'1"	-	Bend	
-F1	-1'5"	-	T	Reducer feature
-F2	-3'3"	-	False Echo	Trailing echoes and reverberation reflections
-F3	-6'9"	-	False Echo	
-F4	-8'8"	-	False Echo	Possible path through the reducer feature

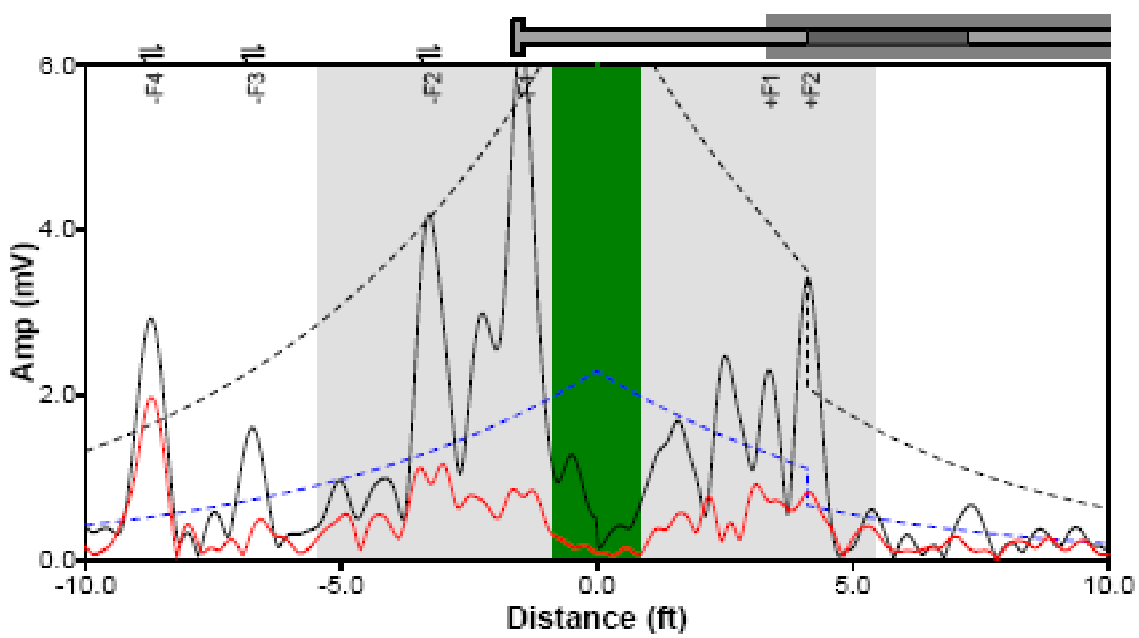


Figure 12**. Dig Site 1D - PE.**

Dig Site 1C - 1D - PC

Pipe:	12" 1D Red Run St	Ring:	R2B12PE(30)
Site:	Consumers Energy	Config:	7.3FR, T(0,1)
Location:	Branch T to 26inch -1ft	Calibration:	Automatic (552.065 mV)
Size:	1inch 12 inch	Version:	3.92, Wavemaker G312
Tested:	22 Aug 2006 10:28	Client:	Consumers Energy
Tested by:	David Alleyne[GUL]	Procedure:	GU 1.1

General Notes: TP 13 Pitch Catch test data with the two rings at test locations 1C and 1D. This is the pitch-catch result of propagating through the reducer feature. The large reflection at -5ft is the direct signal that traveled from location 1D to 1C. The measured attenuation rate is -1.6db/ft. The distance is calibrated for pitch-catch results.

Feature	Location	ECL	Class	Notes
-F1	-5'0"	-	Flange	Direct transmission between the rings. The non-symmetry (red) is caused by the reducer.

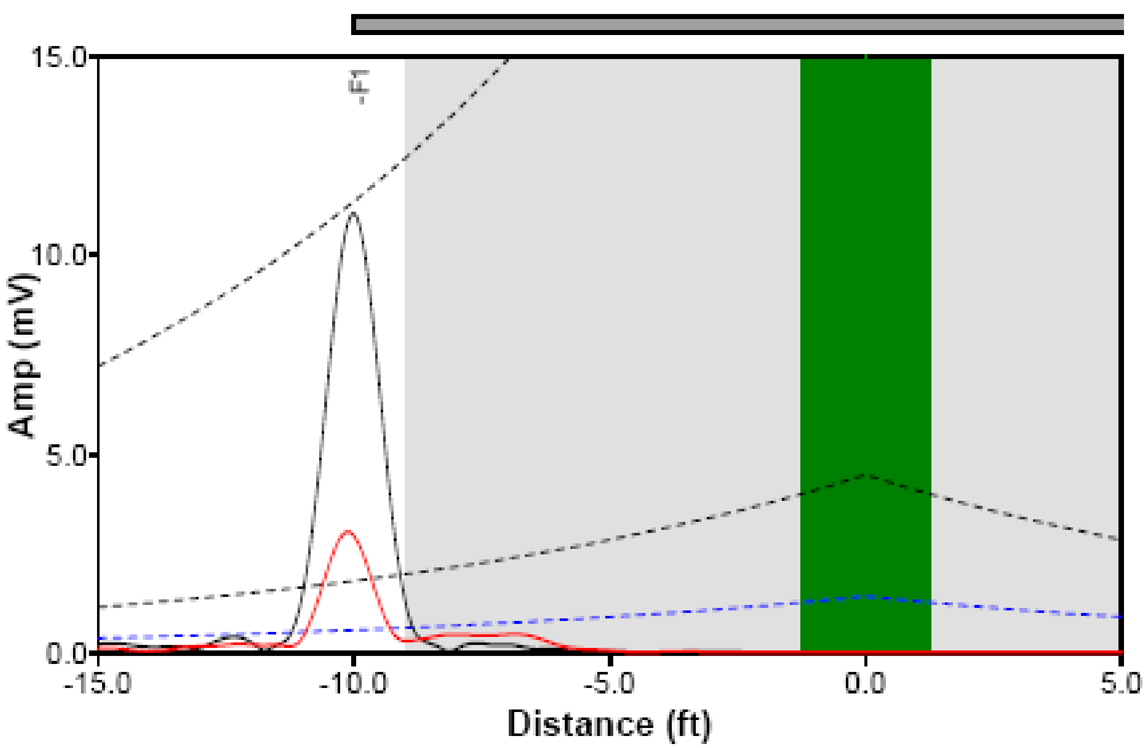


Figure 13**. Dig Site 1D - PC.**

Summary of GW

All GW scans/reflections suggest no significant corrosion or wall loss (medium confidence).

Radiography

Figure 14. **The 26" diameter tee and the 12" diameter south branch (Area 1D) were Radiographic Testing (RT) inspected at the pipe bottom (6 o'clock position) for internal corrosion. No density changes consistent with the presence of localized corrosion were visible.**

Direct Exam Visual Pipe and Coating Inspection

Coating: Good condition, hot applied tape and coal tar.

Pipe: 26" diameter pipe tee with 0.780" thick wall, reducer section 0.55" thick wall, 12" diameter pipe with 0.375" wall, all with no signs of external corrosion.

Dig Site: **#2 a, b, c - Heaters**

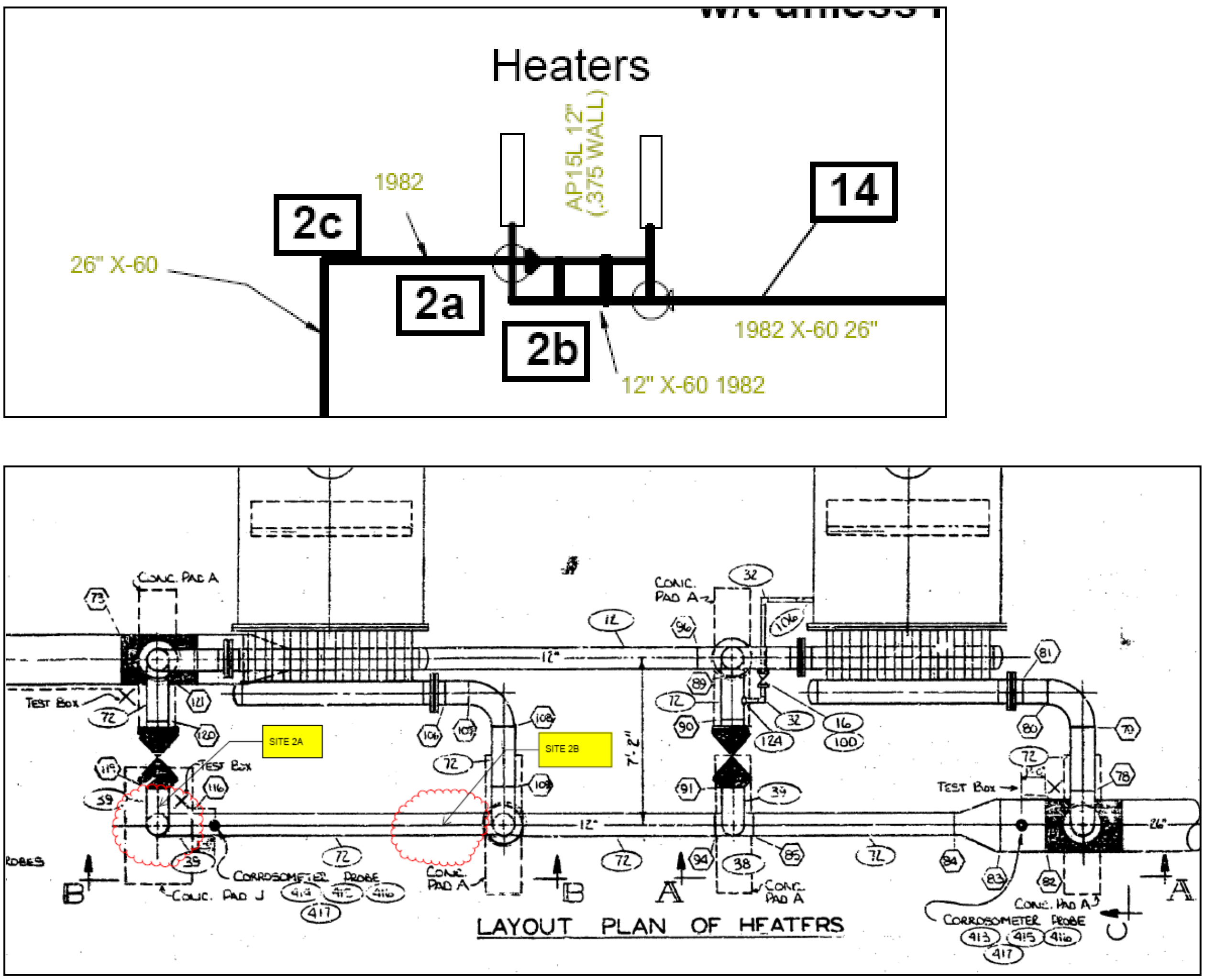


Figure 15**. Schematic of Heaters.**

Figure 16**. Dig Site #2.**

Guided Wave Results

Dig Site 2A - PE

Pipe:	12" 2A Red Run St	Ring:	R2B12(30)-Circum
Site:	Consumers Energy	Config:	3.4FR, T(0,1)
Location:	Riser pipe Elbow +4inch	Calibration:	Automatic (579.013 mV)
Size:	12 inch (0.375 in)	Version:	3.92, Wavemaker G312
Tested:	Aug 21 2006 09:53	Client:	Consumers Energy
Tested by:	David Alleyne[GUL]	Procedure:	GU 1.1

General Notes: TP 3 test location 2A on a vertical riser section of 12" piping at the Red Run Regulator Station in Warren. The pipe has a bitumen coating about 1/8" thick which is uneven over the extent of the pipe section that is buried. Reflections at the reportable level have been identified to be from coating changes, hard material well adhered to the pipe surface and contact support.

Feature	Location	ECL	Length	Class	Notes
+F1	0'4"	-	0	1D Bend	
+F2	6'4"	-	0	Flange	
-F1	-1'1"	-	0	Weld	Visible in the dead-zone
-F4	-2'1"	-	0	Bend	
-F2	-1'3"	-	~	Bitumen	
-F3	-1'5"	-	~	Earth	
-F5	-6'4"	-	0	Support	

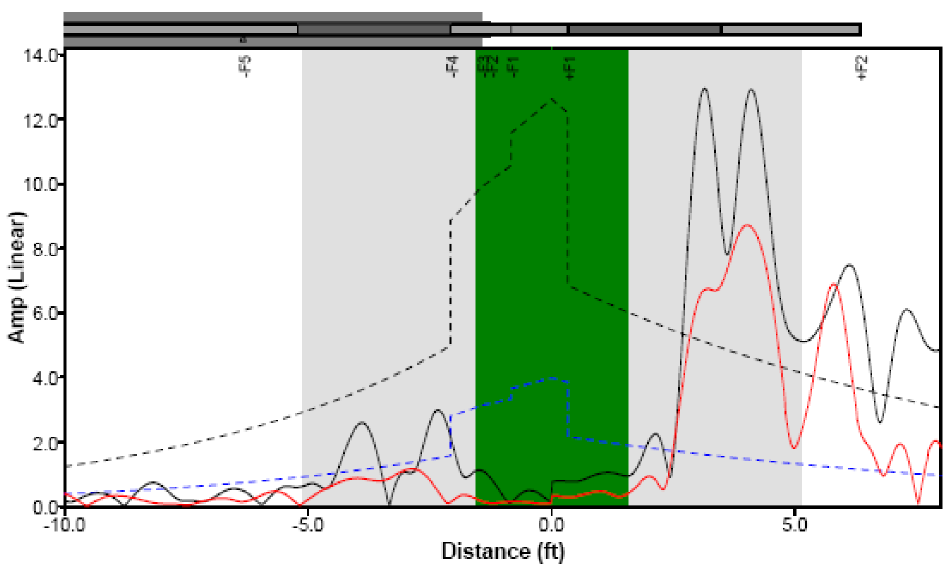


Figure 17. Dig Site 2A - PE.

Dig Site 2B - PE

Pipe:	12" 2B Red Run St	Ring:	R2B12(285)-Circum
Site:	Consumers Energy	Config:	6.2FR, T(0,1)
Location:	Riser pipe Tee -2ft 9inch	Calibration:	Automatic (837.774 mV)
Size:	12 inch (0.375 in)	Version:	3.92, Wavemaker G312
Tested:	Aug 21 2006 09:28	Client:	Consumers Energy
Tested by:	David Alleyne[GUL]	Procedure:	GU 1.1

General Notes: TP 2 test location 2B in a pit location at the Red Run Regulator Station in Warren. The pipe has a tape wrap bitumen coating about 1/8" thick which is uneven over the extent of the buried pipe section. Reflections at the reportable level have been identified to be from coating changes and hard material well adhered to the pipe surface. The reflection at +F3 is from a weld the non-symmetry is interpreted to be from slight mis-alignment.

Feature	Location	ECL	Length	Class	Notes
+F3	5'2"	20	0	Weld	Visually confirmed under coating
+F4	**5'4"**	**25**	**0**	**Minor**	**Localized feature (bottom of the pipe) in the weld area confirmed to be hard deposit well adhered to the pipe**
+F2	3'0"	-	~	Earth	
+F1	2'3"	-	~	Bitumen	
+F5	6'7"	-	0	Weld	Localized reflection from this area of the pipe where the coating is rough and uneven. Visually verified to be from a weld, level of non-symmetry due to slight mis-alignment
+F6	11'3"	-	0	Support	Concrete support
+F7	12'0"	-	0	1D Bend	
-F1	-2'9"	-	0	T	T into vertical running pipe

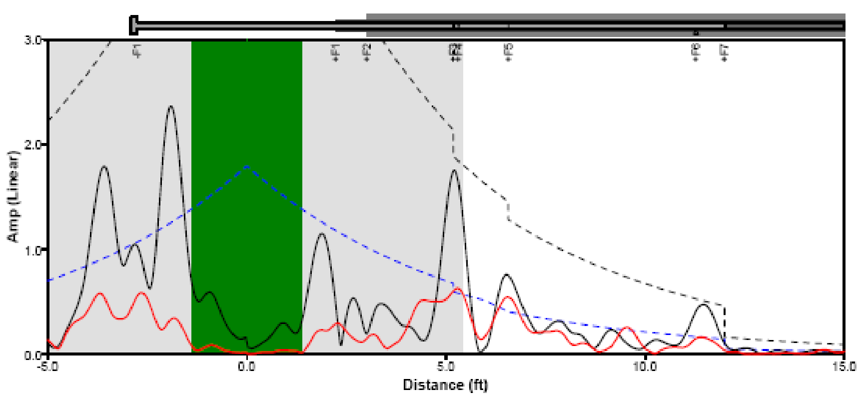


Figure 18**. Dig Site 2B - PE.**

Dig Site 2B - PE - C-Scan

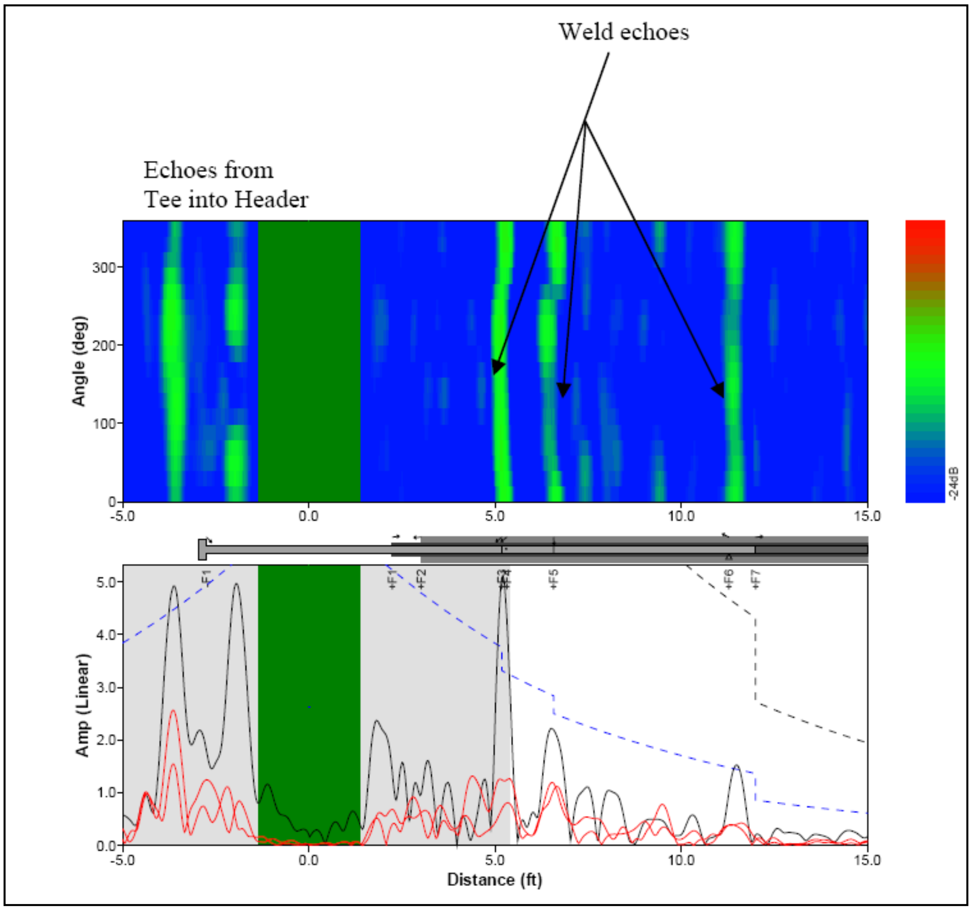


Figure 19**. Dig Site 2B - PE C-Scan.**

Dig Site 2A-2B - PC

Pipe: 12" 2 Red Run St
Site: Consumers Energy
Location: Test positions 2A & 2B
Size: 12 inch (0.0375 in)

Ring: R2B12PE(285)-Circum
Config: 5.4FR, T(0,1)
Calibration: Automatic (917.378 mV)
Version: 3.92, Wavemaker G312

Tested: Aug 21 2006 10:35
Tested by: David Alleyne[GUL]

Client: Consumers Energy
Procedure: GU 1.1

General Notes: TP 4 using the 2 rings in a pitch catch configuration. The rings are at test positions 2A and 2B on the 12" pipe in the Red Run Regulator Station at Warren. The reflection from the weld area has changed from the previous test because the hard deposit was removed near to the F1 weld and the coating was removed to expose the F2 weld before this data collection. No reflections were interpreted to be from corrosion above the call level.

Feature	Location	ECL	Length	Class	Notes
+F1	1'6"	-	~	Bitumen	
+F3	5'2"	-	0	Weld	Visually confirmed under coating
+F2	2'4"	-	~	Earth	
+F4	6'7"	-	0	Weld	Reduced non-symmetry (red curve amplitude) of the reflection from the weld after the removal of the non-uniform coating
+F5	12'0"	-	0	1D Bend	
-F1	-2'9"	-	0	T	

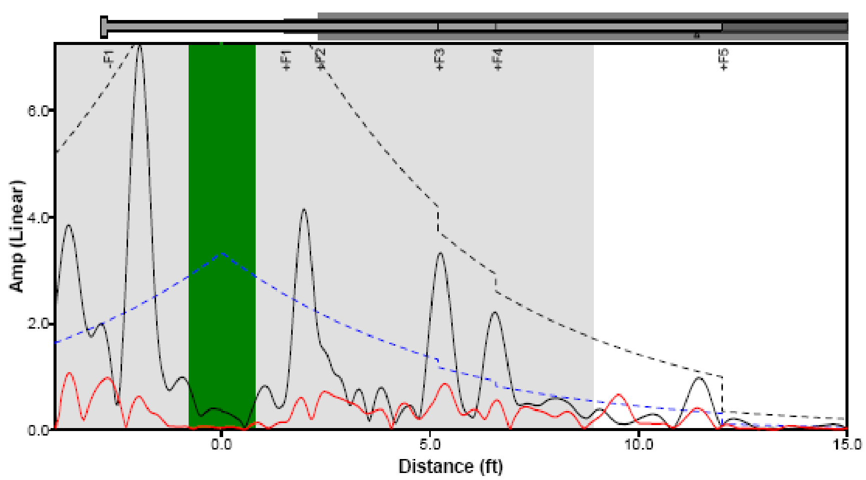


Figure 20**. Dig Site 2A-2B - PC.**

Summary of GW

Reflections between 2A and 2B were considered minor and were due to well adhered, hard deposits and coating.

Figure 21**. Length between 2A and 2B.**

Indications presented by the GWUT inspection are believed to have been caused by the presence of an unknown girthweld that was not visible due to OD pipe.

Radiography

Figure 22**. Scan 2 and Scan 1 locations.**

No density changes consistent with the presence of localized corrosion were visible. Light density of the film with minor changes was visible and is believed to have been caused by material buildup in the pipe.

Porta-Scan UT

Figure 23. Porta-Scan UT in operation.

Ultrasonic Inspection consisting of two scans were performed. Each scan measured 1 foot longitudinally at the 5:00 to 7:00 positions on the pipe. The green arrow shows the 12:00 Lo position on the pipe. Yellow arrows show the starting positions of Scans 1 and 2. Ultrasonic Inspection consisting of two scans were performed. Average wall readings for both scans measured 0.369" and the minimum reading for both scans measured 0.329" at Lo+12.5", 6:30 position.

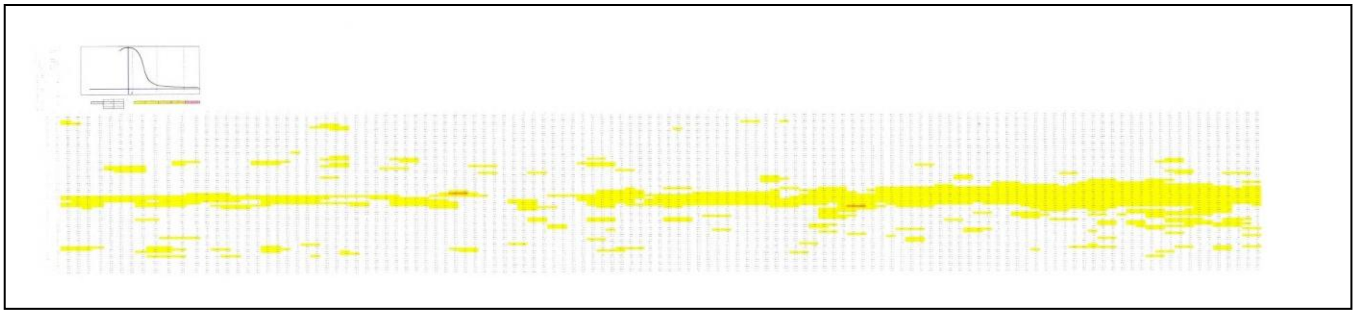


Figure 24**. Dig 2B, Scan 2: Lo+2.5".**

Figure 25**. Dig 2B, Scan 1: Lo-9.25".**

Magnetic Particle Inspection (MPI)

Figure 26**. Magnetic Particle Inspection found no cracks.**

Direct Exam Visual Pipe and Coating Inspection

Coating: Tapecoat and primed mastic repairs, good condition.

Pipe: 12" pipe is 0.375" wall, elbow is 0.420" wall. Backfill was sand. No external corrosion noted. Hard deposit noted near girth weld.

Figure 27**. Dig Site #2c (no guided wave performed here, only pipe/elbow cut out and replacement).**

Meter Run Piping Replacement Diagram.

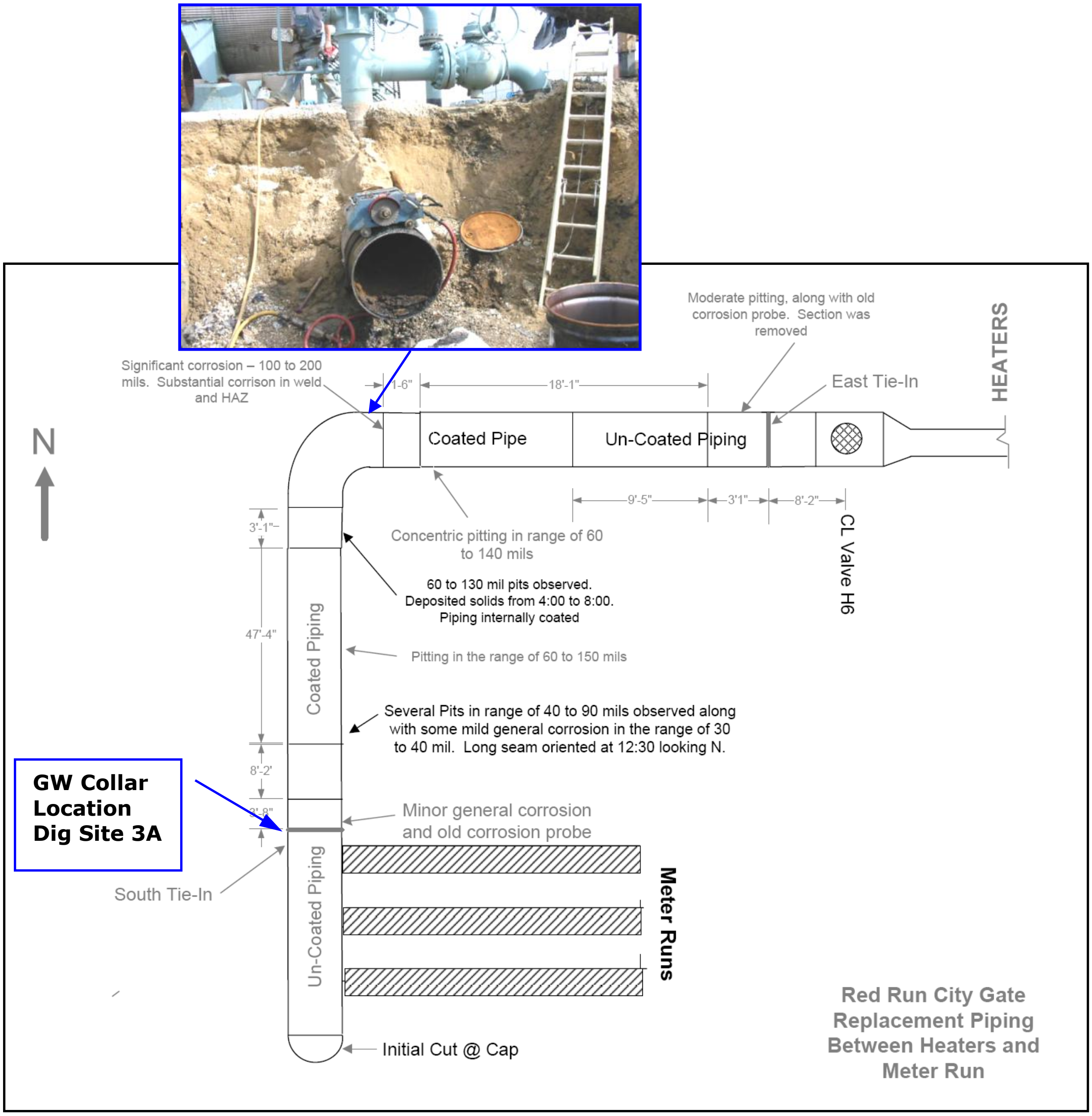
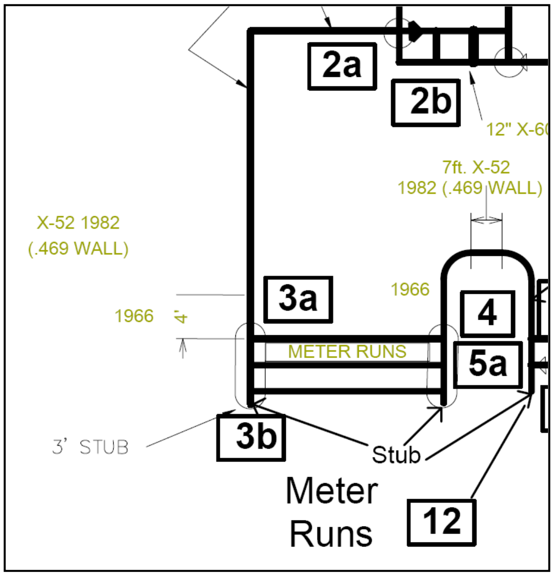


Figure 28. This inspection and replacement was done after all the guided wave was complete. All the areas that contained corrosion were not assessed by GW (i.e., beyond detection range). The inspection at Dig Site #3A first located the presence of deposits leading to this major excavation and replacement.

Dig Site: #3 a, b - Meter Run Header



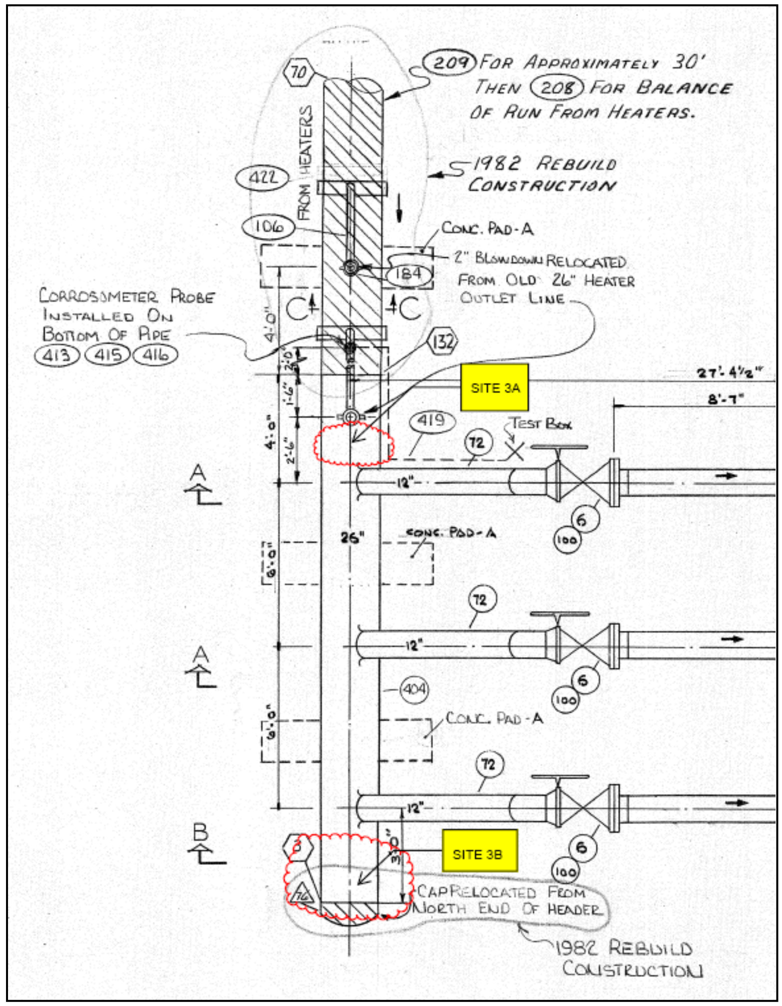


Figure 29**. Meter Run Headers.**

Figure 30**. Dig Site #3A** **Dig Site #3B.**

Figure 31**. 3A (far side) and 3B (closest). Note two heaters in the background (from dig site #2).**

Guided Wave Results

Dig Site 3A - PE

Pipe: 26" 3A IH-M Run
Site: Consumers Energy
Location: Shop Weld +20ft 5inch
Size: 26 inch

Tested: 23 Aug 2006 08:08
Tested by: David Alleyne[GUL]

Ring: R2B24(703)
Config: 11.2FR, T(0,1)
Calibration: Automatic (1132.49 mV)
Version: 3.92, Wavemaker G312

Client: Consumers Energy
Procedure: GU 1.1

General Notes: TP 17 test location 3A. The attenuation at this location is higher than expected; this was interpreted to be caused by internal deposits in the pipe. There are no reflections interpreted to be from corrosion above the call level.

Feature	Location	ECL	Class	Notes
+F1	2'5"	-	Vent	Visible
+F2	7'1"	-	Branch	
+F3	13'0"	-	Branch	Visible
+F4	19'0"	-	Branch	
+F5	20'5"	-	Weld	
+F6	22'6"	-	Flange	Capped end of the pipe
-F1	**-0'1"**	**4**	**Minor**	**The small reflections have been interpreted to be caused by the internal condition at the location**
-F2	-4'0"	-	Earth	Ground entry position

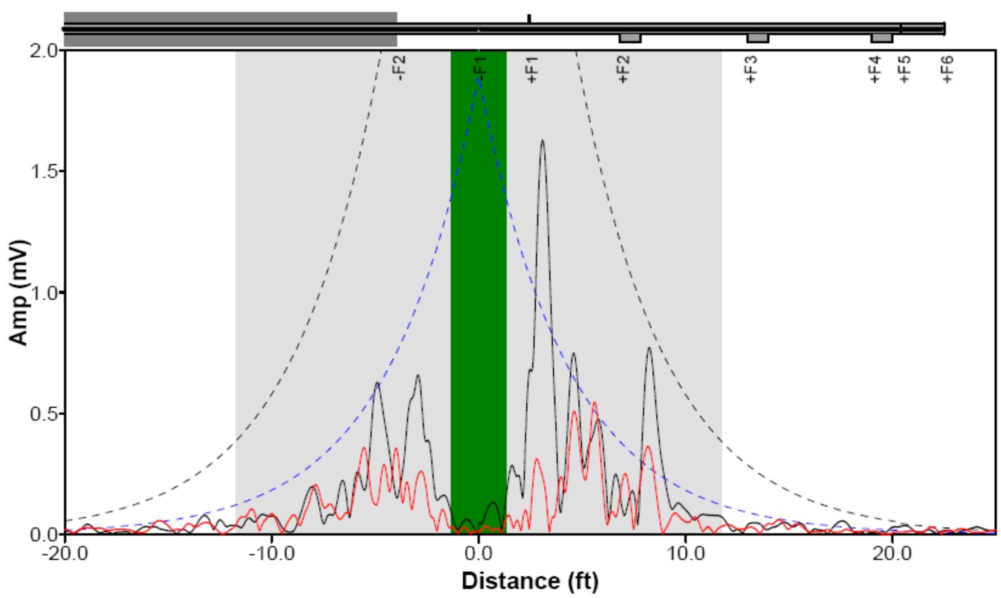


Figure 32**. Dig Site 3A - PE.**

Dig Site 3B - PE

Pipe:	26" 3B IH-M Run	Ring:	R2B24(703)
Site:	Consumers Energy	Config:	11.0FR, T(0,1)
Location:	Shop Weld +20ft 5inch	Calibration:	Automatic (587.469 mV)
Size:	26 inch	Version:	3.92, Wavemaker G312
Tested:	23 Aug 2006 08:48	Client:	Consumers Energy
Tested by:	David Alleyne[GUL]	Procedure:	GU 1.1

General Notes: TP 18 test location 3B, 26" Inlet Header to Meter Run. The attenuation at this location is higher than expected; this could be caused by internal deposits in the pipe. There are no reflections interpreted to be from corrosion above the call level.

Feature	Location	ECL	Class	Notes
-F3	-16'6"	-	Vent	Visible
-F2	-12'1"	-	Branch	
-F1	-6'0"	-	Branch	Visible
+F2	0'1"	-	Branch	
+F3	1'4"	-	Weld	Reference shop weld
+F1	**0'0"**	**5**	**Minor**	**The small reflections have been interpreted to be caused by the internal condition at the location running for the entire test range**
+F4	3'1"	-	Flange	Capped end of pipe
-F4	-23'0"	-	Earth	Approximate entry location into the ground

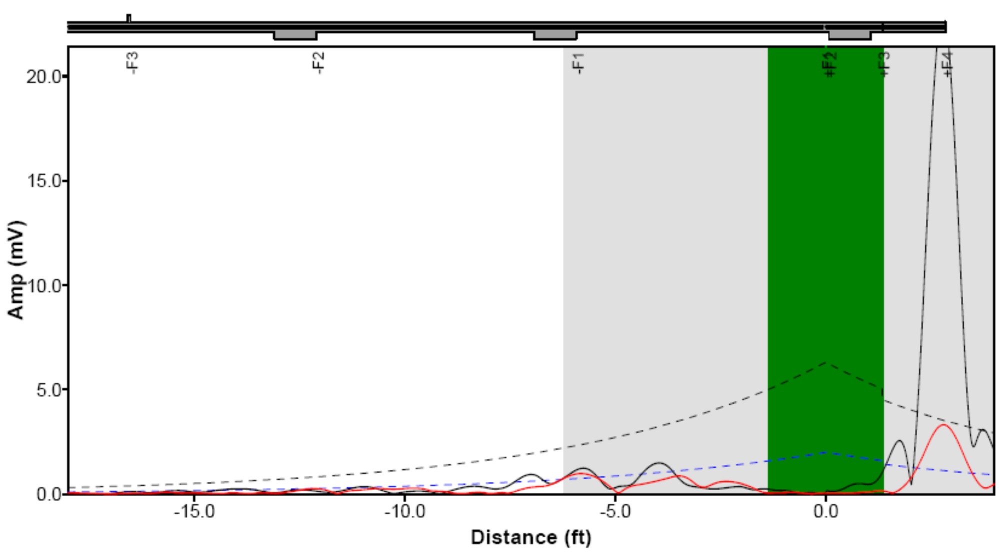


Figure 33. Dig Site 3B - PE.

Summary of GW

Reflections at dig site 3A - attenuation at this location was higher than expected; this was interpreted to be caused by internal deposits in the pipe. There are no reflections interpreted to be from corrosion above the call level. Category 3 Call with Medium Confidence.

Reflections at dig site 3B - 26" Inlet Header to Meter Run. The attenuation at this location is higher than expected; this could be caused by internal deposits in the pipe. There are no reflections interpreted to be from corrosion above the call level. Category 3 Call with Medium Confidence.

Radiography

Figure 34**. Area 3B (South Stub).**

Six circumferential RT images were taken at the cap weld (yellow arrow). The 12:00 position of the weld and CW direction are noted in the photograph. No density changes consistent with the presence of localized corrosion were visible; however, internal solid material could be seen in the images and was later confirmed visually when the cap was removed.

Figure 35**. Area 3B (South Meter Run Riser).**

A single RT image at the 06:00 position was produced. The Lo position is shown marked on the pipe with the CW arrow direction. No density changes consistent with the presence of localized corrosion were visible. View is looking to the north.

The Area 3B south stub and Area 15 were also radiographed circumferentially. Radiographs taken in this area are 4.5" x 17" and were run circumferentially along the cap girthweld. The intent of those radiographs was to determine the amount of solids present internally in the pipe.

<u>Direct Exam Visual Pipe and Coating Inspection</u>

Pipe at 3A was 0.720" wall, pipe at 3B was 0.469" wall. Buried in clay soil with 3 ft depth of cover.

Coating: Both 3A and 3B were coated with Coal Tar with repairs using Tapecoat 20 with primer. Good bonding and smooth appearance.

No external corrosion noted.

Figure 36. East end of meter run and meter header solids.

Stub and riser at the South end of the inlet to the meter run – Inspection by the GUL unit indicated the piping to be significantly blocked.

- Lab radio-graphed both the stub and primary riser and determined them to be totally filled and 75% filled respectively.
- End cap at the end of the meter header removed and was seen to be significantly plugged with solids.

Dig Site: **#4 & #12 - Inlet Header to Regulator Station**

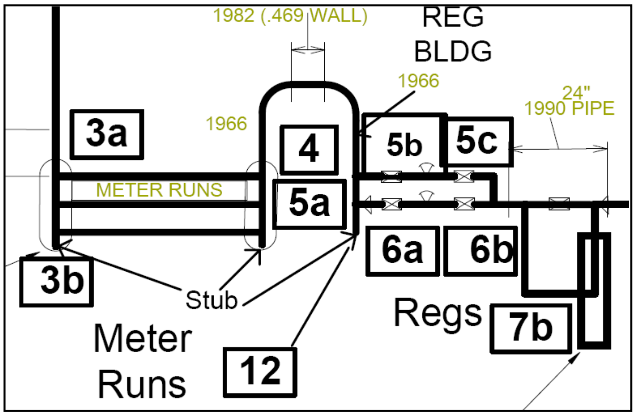


Figure 37. Inlet Header to Regulator Station Schematic and Photos.

Guided Wave Results

Dig Site 4 - PE

Pipe: 26" 4 IH-R Station
Site: Consumers Energy
Location: Shop Weld +7inch
Size: 26 inch

Tested: 22 Aug 2006 14:53
Tested by: David Alleyne[GUL]

Ring: R2B24(703)
Config: 14.8FR, T(0,1)
Calibration: Automatic (435.102 mV)
Version: 3.92, Wavemaker G312

Client: Consumers Energy
Procedure: GU 1.1

General Notes: TP 16 26inch pipe at location 4. Limited test range and sensitivity because of the large features close to the ring, however there are no reflections interpreted to be from corrosion above the call level. An increased level of the general indications has been interpreted to be mainly from a combination of external changes due to the coating and ground conditions. All visible features have not been marked in the results.

Feature	Location	ECL	Class	Notes
+F1	3'4"	-	Y	Branch to 5A, B and C test locations
+F3	11'5"	750	Weld	
+F2	8'3"	-	Y	Branch to 6A and B test locations
+F4	11'5"	-	Flange	
-F1	-2'5"	-	Pull Bend	Measured start of bend. Slight increase in non-symmetry
-F2	**-6'0"**	**60**	**Minor**	**Partially non-symmetric reflections from this section of the pipe, at some locations the amplitudes of the reflections are increased**
-F3	-7'7"	-	Entrance	Approximate ground entry location

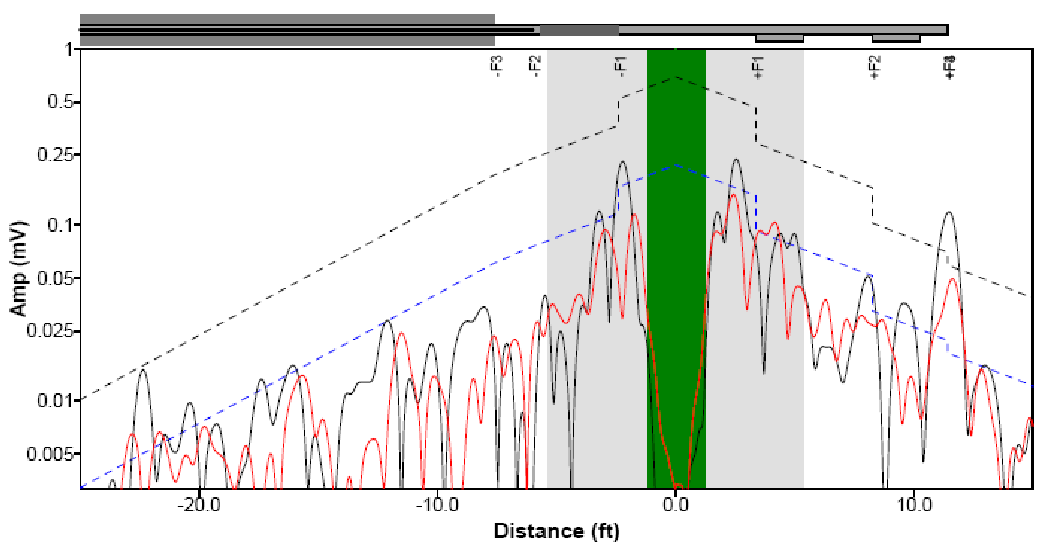


Figure 38. Dig Site 4 - PE.

Dig Site 12 - PE

Pipe:	26" 12 IH-R Station	Ring:	R2B24(703)
Site:	Consumers Energy	Config:	13.6FR, T(0,1)
Location:	Shop Weld -6ft 9inch	Calibration:	Automatic (329.225 mV)
Size:	26 inch	Version:	3.92, Wavemaker G312
Tested:	22 Aug 2006 14:34	Client:	Consumers Energy
Tested by:	David Alleyne[GUL]	Procedure:	GU 1.1

General Notes: TP 15 Test at location 12. There are no reflections interpreted to be from corrosion above the call level. The Tee branch pipes of the 12" pipes that run into the regulator building are between the welds marked. The Tee fittings have reduced the data Signal-to-noise at this location and only larger defects could be found. There are no indications interpreted to be from corrosion above 10% cross-sectional at this position.

Feature	Location	ECL	Class	Notes
+F1	4'1"	-	Flange	Capped end of the pipe
-F1	-2'4"	-	Weld	Visible
-F3	-5'0"	-	Y	Tee - 12" pipe into the regulator building. The increase signal levels are du to reflections and transmission in the closely spaced features
-F2	-3'1"	-	Y	Tee - 12" pipe into the regulator building
-F4	-7'0"	-	Weld	Shop weld with a high level of non-symmetry (amplitude of red curve)
-F5	-15'0"	-	Entrance	Approximate ground entry position
-F6	**-18'4"**	**5**	**Minor**	**Non-symmetric reflections in this area**
-F7	-23'6"	5	-	Partially symmetric reflection

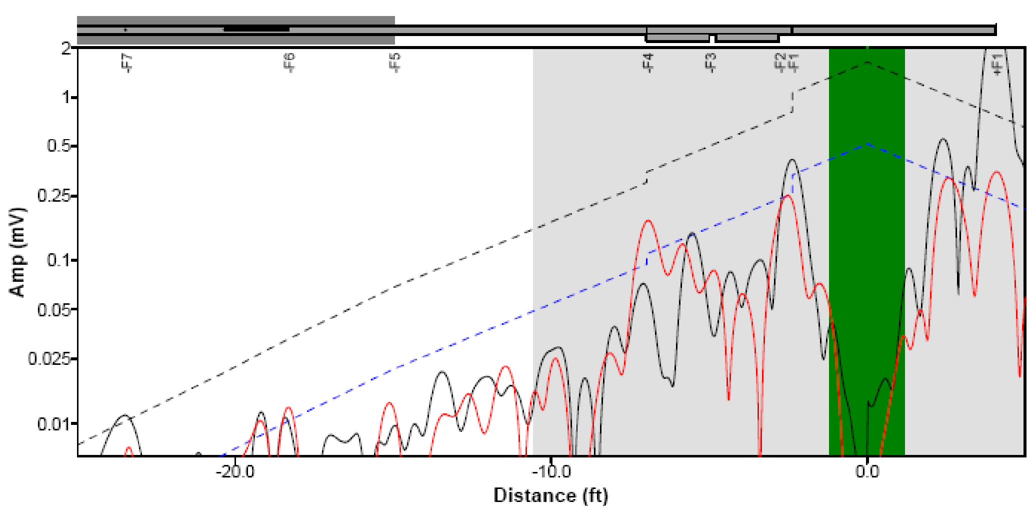


Figure 39. **Dig Site 12 - PE.**

Summary of GW

Reflections at dig site 4 - Limited test range and sensitivity because of the large features close to the ring, however there are no reflections interpreted to be from corrosion above the call level. An increased level of the general indications has been interpreted to be mainly from a combination of external changes due to the coating and ground conditions. Category 3 Call with Medium Confidence.

Reflections at dig site 12 - There are no reflections interpreted to be from corrosion above the call level but the Tee fittings have reduced the data Signal-to-noise at this location. Category 3 Call with Medium Confidence.

Radiography

None.

Direct Exam Visual Pipe and Coating Inspection

Pipe at 4 and 12 was 0.475" wall. Buried in sandy clay soil with 32" depth of cover.

Coating: Both 4 and 12 were coated with Coal Tar (80 mils thick) with good bonding and smooth appearance.

No external corrosion noted.

Operator: Consumers Energy
Case Study: Red Run City Gate 8/21/2006

Dig Site: #5 a, b, c - North Meter Run

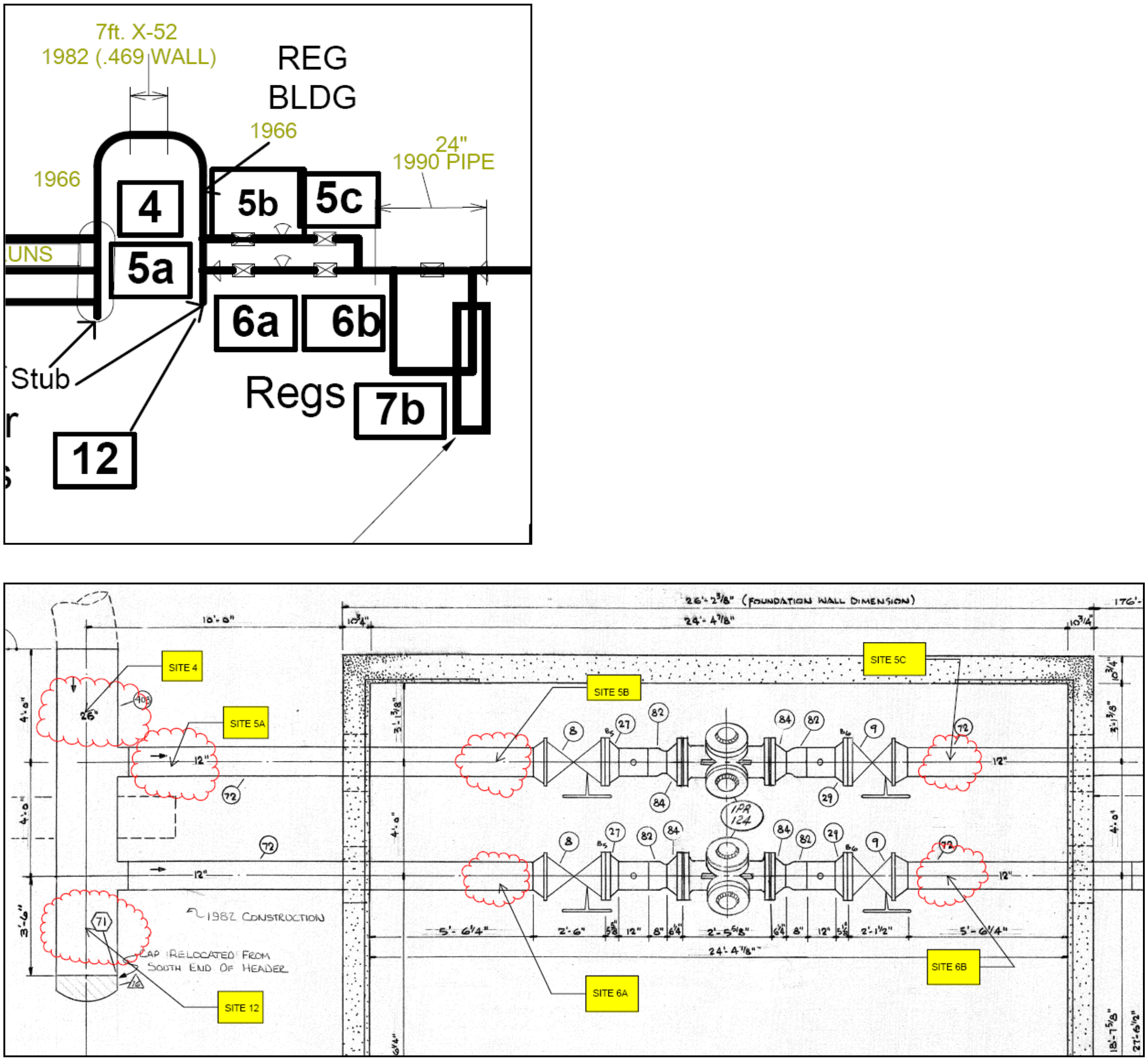


Figure 40. **North Meter Run.**

Figure 41**. Site 5A** **Both Regulator Runs.**

Figure 42**. High Pressure Side (Site #5 is behind #6) and 5B.**

Figure 43**. Site 5C.** **Site 6B.**

Guided Wave Results

Dig Site 5A - 5B PC

Pipe:	12" 5AB Reg Building	Ring:	R2B12PE(30)
Site:	Consumers Energy	Config:	4.0FR, T(0,1)
Location:	T Into 26" pipe +6ft 3inch to Reg B	Calibration:	Automatic (907.919 mV)
Size:	12 inch	Version:	3.92, Wavemaker G312
Tested:	24 Aug 2006 08:18	Client:	Consumers Energy
Tested by:	David Alleyne[GUL]	Procedure:	GU 1.1

General Notes: TP 23 Pitch Catch configuration test between Locations 5A and 5B. This result shows the direct transmission between the transducer either side of the regulator wall and link seal.

Feature	Location	ECL	Class	Notes
+F1	13'1"	-	Flange	Directly transmitted signal through the link seal in the regulator building wall. The measured attenuation is about -2dB/ft for this location and there is no measurable evidence of corrosion above the call level

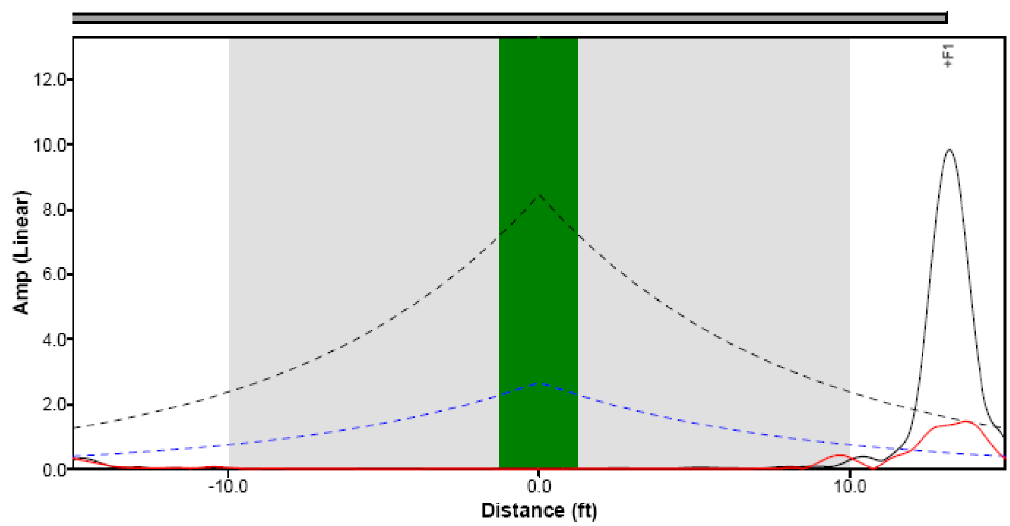


Figure 44**. Dig Sites 5A-5B - PC.**

Dig Site 5A - 5B - PC

Pipe:	12" 5B Reg Building	Ring:	R2B12PE(285)-Circum
Site:	Consumers Energy	Config:	8.2FR, T(0,1)
Location:	Link Seal wall +5' 61/2"	Calibration:	Automatic (231.556 mV)
Size:	12 inch	Version:	3.92, Wavemaker G312
Tested:	Aug 21 2006 13:18	Client:	Consumers Energy
Tested by:	David Alleyne[GUL]	Procedure:	GU 1.1

General Notes: TP 9 test location 5B. There are no reflections from changes above the reportable call level and the tests from location 5A from the outside of the wall provide further confirmation. The pitch-catch configuration allows for the clear identification of features in the near zone close to the transducer ring. In this test the reflection from the vent at -1' 4" from the ring is fully resolved. (Compare with the results from TP 8, #2520.)

Feature	Location	ECL	Length	Class	Notes
+F1	2'7"	-	0	Flange	
-F2	-3'6"	-	0	Weld	Visible
-F1	-1'4"	-	0	Vent	Visible
-F3	**-5'6"**	**-**	**~**	**Sleeve**	**The reflections from the area of the entrance are predicted to be generated by the tight link seal between the sleeve and the pipe.**
-F4	-8'5"	-	0	Weld	Reflections from within the buried section of the pipe outside the wall. Predicted not to be from corrosion

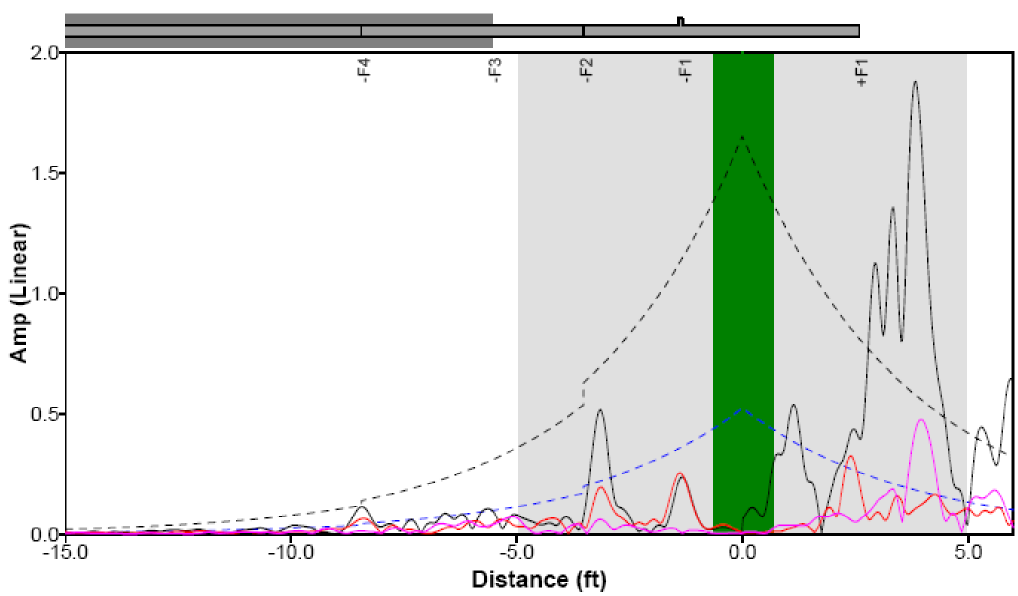


Figure 45**. Dig Sites 5A-5B - PC.**

Dig Site 5B PE

Pipe: 12" 5B Reg Building	Ring: R2B12(285)-Circum
Site: Consumers Energy	Config: 7.2FR, T(0,1)
Location: Link Seal wall +5' 61/2"	Calibration: Automatic (195.2 mV)
Size: 12 inch	Version: 3.92, Wavemaker G312
Tested: Aug 21 2006 13:16	Client: Consumers Energy
Tested by: David Alleyne[GUL]	Procedure: GU 1.1

General Notes: TP 8 test location 5B from the inside of the Regulator building in the station. No reflection above the call level interpreted to be from significant corrosion.

Feature	Location	ECL	Length	Class	Notes
+F1	2'7"	-	0	Flange	
-F2	-3'6"	-	0	Weld	Visible
-F1	-1'4"	-	0	Vent	Visible but the reflection is within the partial dead-zone near field area
-F3	**-5'6"**	**-**	**~**	**Sleeve**	**Link seal at the sleeve entrance to the wall of the building. The reflections are predicted to be caused by the tight contact between the pipe and the seal.**
-F4	-8'9"	-	0	Weld	Small reflections from the buried section of the pipe before the T into the 26" pipe. Interpreted not to be from corrosion.

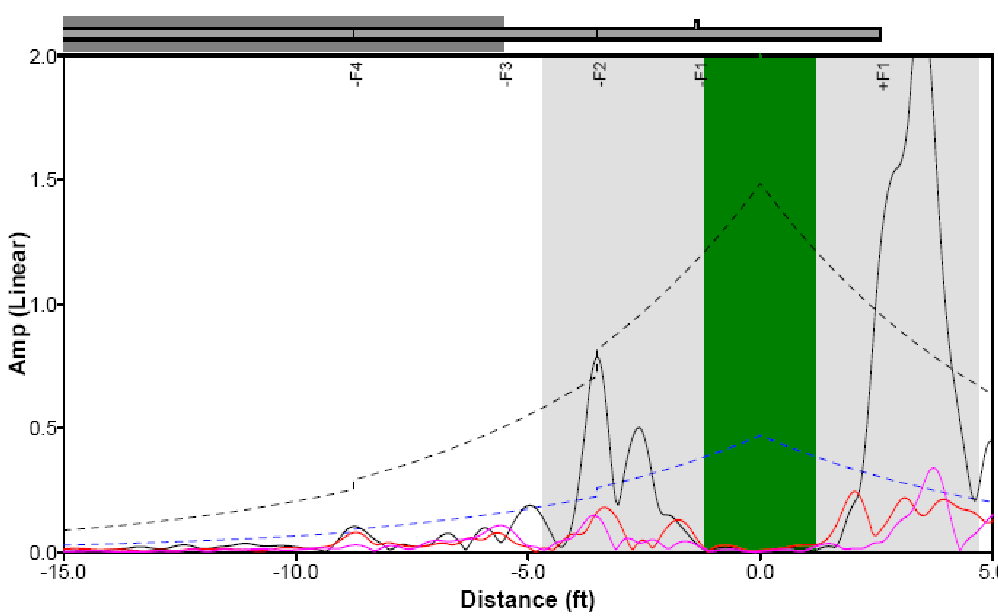


Figure 46. **Dig Site 5B - PE.**

Dig Site 5C PE

Pipe: 12" 5C Reg Building	Ring: R2B12(285)-Circum
Site: Consumers Energy	Config: 6.2FR, T(0,1)
Location: Link Seal wall +5' 10"	Calibration: Automatic (213.046 mV)
Size: 12 inch	Version: 3.92, Wavemaker G312
Tested: Aug 21 2006 12:20	Client: Consumers Energy
Tested by: David Alleyne[GUL]	Procedure: GU 1.1

General Notes: TP 6 Test location 5C from inside the regulator building. There is a localized reflection from the link seal in the wall which is of concern. The +F3 reflection is from an area of corrosion, this could not be verified. The predicted severity is in the range 15-40% at the bottom area of the pipe. The minor corrosion at the bottom of the pipe has an area where the amplitude of the reflections is increased. This is about at 6ft from the ring and is the location of the maximum wall loss, which was verified at the time of the test.

Feature	Location	ECL	Length	Class	Notes
+F1	**0'1"**	**5**	**7**	**Minor**	**Reflections from minor corrosion and pitting running at the bottom of the pipe**
+F2	6'1"	-	~	Sleeve	Link seal between sleeve and pipe
+F3	**6'**	**15**	**1**	**Medium**	**An area just inside the sleeve with increased localized reflection.**
+F4	6'0"	-	0.9	Wall	Wall of the regulator building
+F5	8'2"	-	0	Weld	Reflection from buried feature outside the building
+F6	9'1"	-	0	Weld	
-F1	-2'5"	-	0	Flange	

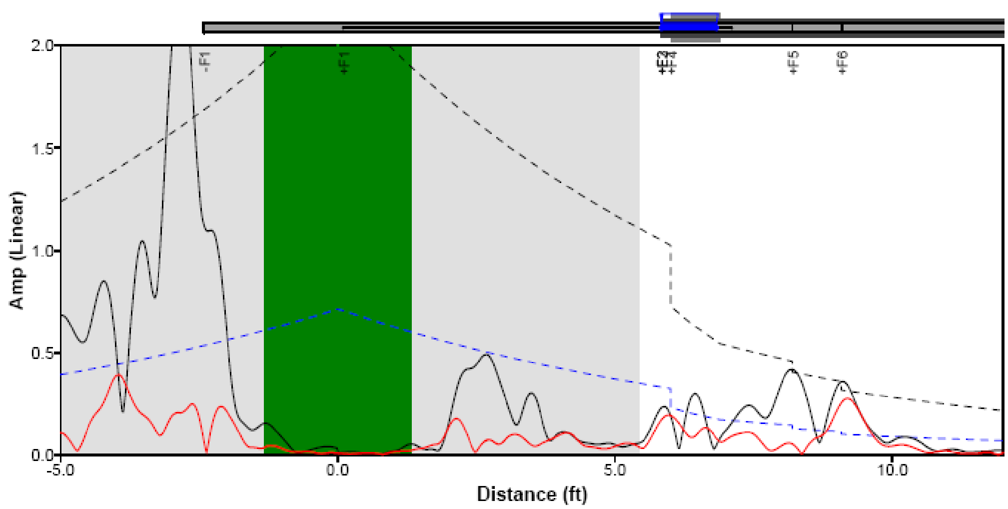
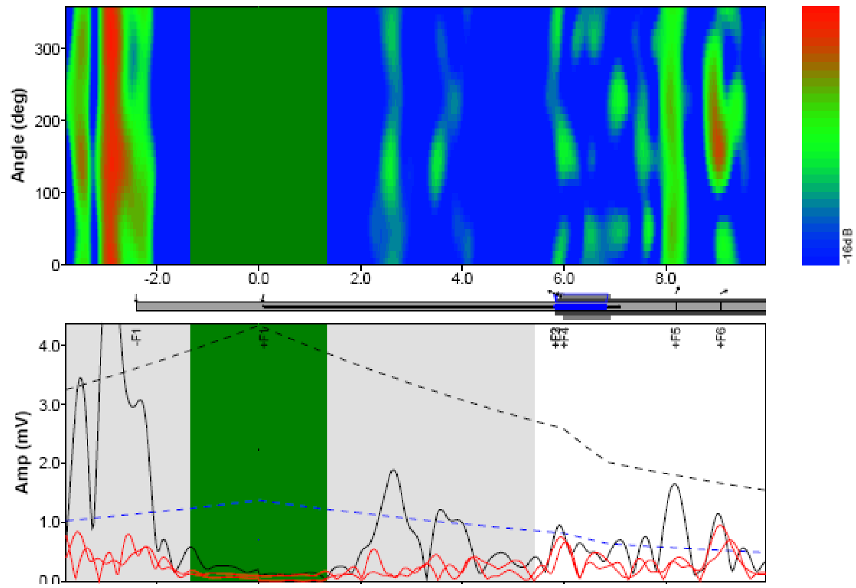


Figure 47. **Dig Site 5C - PE.**

Dig Site 5C - PC



C-Scan focused presentation of the result at TP6 (5C). The reflections from the Link seal area are localized towards the bottom of the pipe (at an angle of about 160° - 240°). In particular the reflection at the entrance is concentrated and could be visually seen to be corrosion

Figure 48**. Dig Site 5C- PC.**

Dig Site 5C - PC

Pipe: 12" 5C Reg Building	Ring: R2B12PE(285)-Circum
Site: Consumers Energy	Config: 5.4FR, T(0,1)
Location: Link Seal wall +5' 10"	Calibration: Automatic (260.642 mV)
Size: 12 inch (0.375 in)	Version: 3.92, Wavemaker G312
Tested: Aug 21 2006 12:40	Client: Consumers Energy
Tested by: David Alleyne[GUL]	Procedure: GU 1.1

General Notes: TP 7 Pitch Catch measurement at location 5C and is a confirmation test of the amplitude of the reflections from the area of the wall. This has been predicted to be from corrosion classified as Cat 2 (wall loss likely to be in the range 20-40%). The deepest measured wall loss was confirmed using a pit gauge to be about 0.13" wall loss at the position of the maximum amplitude of the reflection marked

Feature	Location	ECL	Length	Class	Notes
+F1	**0'0"**	**3**	**7**	**Minor**	**Reflection from changes from the bottom of the pipe (corrosion)**
+F3	6'1"	-	~	Sleeve	Link seal
+F4	8'1"	-	0	Weld	Reflection from buried feature
+F2	**5'8"**	**16**	**1**	**Medium**	
-F1	-2'5"	-	0	Flange	

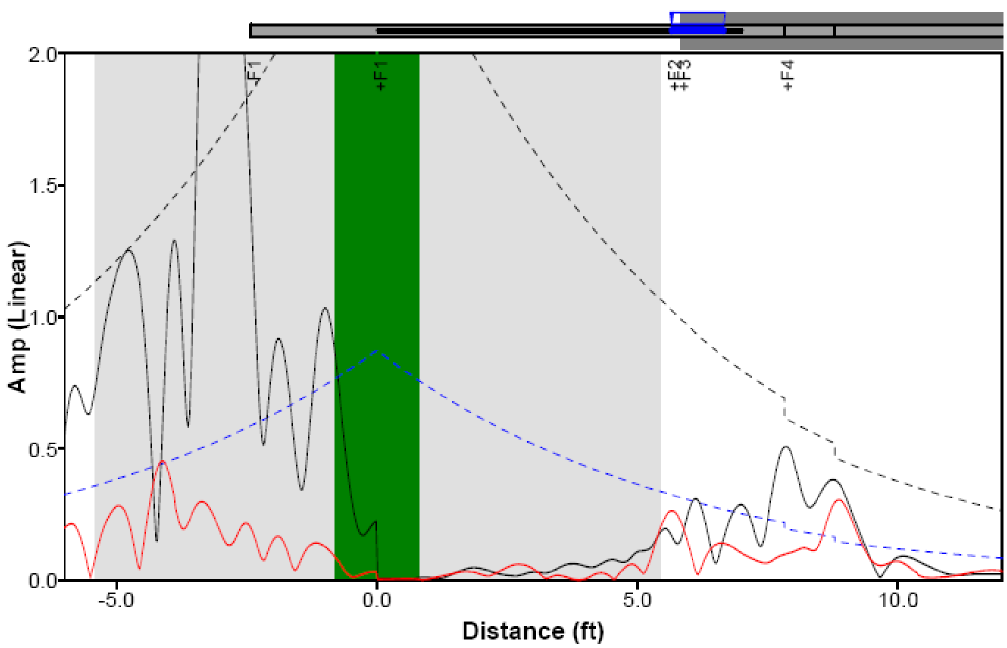


Figure 49**. Dig Site 5C- PC.**

Summary of GW

Dig sites #5A and 5B - PC between these two sites shows the direct transmission between the transducer either side of the regulator wall and link seal. The attenuation was calculated at about -2dB/ft. There are no reflections from changes above the reportable call level and the tests from location 5A from the outside of the wall provide further confirmation. The pitch-catch configuration allows for the clear identification of features in the near zone close to the transducer ring. In this test the reflection from the vent at -1′ 4″ from the ring is fully resolved. Compares well with the results from Dig site #5B from the inside of the Regulator building in the station. No reflection above the call level interpreted to be from significant corrosion.

Dig Site #5C - From inside the regulator building. There is a localized reflection from the link seal in the wall which is of concern but could not be verified. The predicted severity is in the range 15-40% at the bottom area of the pipe. The minor corrosion at the bottom of the pipe has an area where the amplitude of the reflections is increased about 6ft from the ring (right at the wall penetration downstream of #5C) and is the location of the maximum wall loss. The wall loss at the Link Seal area is predicted to be in the 20-40% range.

Radiography

5A (southeast stub) a single RT image at the 0600 position was produced. No density changes consistent with the presence of localized corrosion were visible.

Figure 50. **Area 5A (Southeast Stub).**

A single RT image at the 06:00 position was produced. No density changes consistent with the presence of localized corrosion were visible.

Direct Exam Visual Pipe and Coating Inspection

Pipe in regulator building was all 0.375" wall. All high pressure and low pressure pipe runs penetrate 10 ¾" thick concrete walls.

Coating: was liquid, non-epoxy based paint. Paint was peeling off bottom of low pressure side piping.

Figure 51. Low pressure side (5C) of North Regulator Run.

Distribution outlets (5C and 6B) in the basement of the Regulation Bldg had some significant corrosion adjacent to the wall which is cased with a link seal insulator.

- Pitting was observed at the 6:00 position (bottom of pipe). Guided Wave testing with the GUL G-3 picked up this anomalous condition, though exact pitting depths could not be determined.
- Visual inspection indicated general corrosion with an isolated 1.5 in. long area of pitting (0.100" to 0.130") extended to within approx. 3 inches of the wall. The corrosion is atmospheric in nature and possibly occurred from wet-dry cycling of the outlet piping in conjunction with poor coating. The piping is 12 inch, grade B, 0.375" wall.

- ASME B-31-G mod. was performed and indicted the piping safe to remain in place. This area is adjacent to the wall and has a casing with link seal thru the penetration.
- Data obtained from defect assessment on the basement side as discussed in the previous bullets was used to provide calibration of GUL unit allowing evaluation of waveforms <u>within</u> the casing. Corrosion in the casing was no more severe than that found in the basement and piping was safe to remain in place.

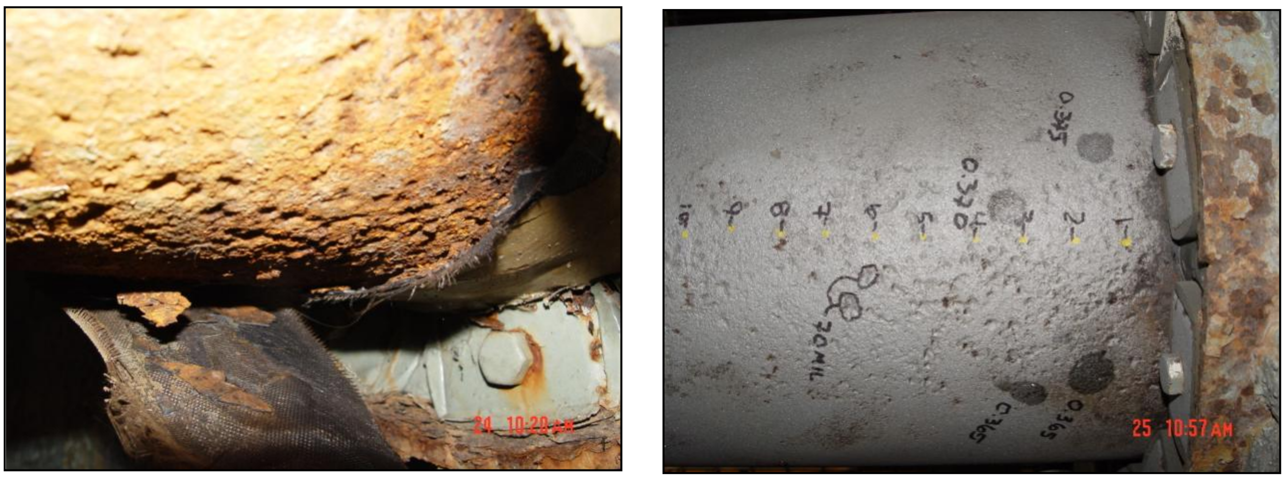
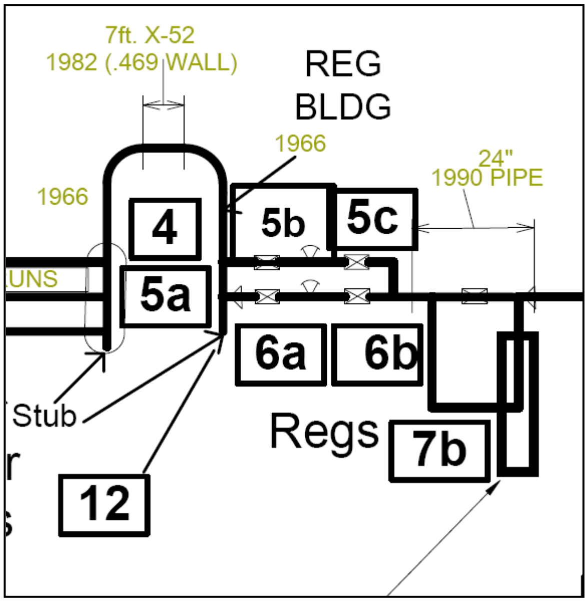


Figure 52. Significant External Corrosion under coating along 5C run before grit blasting (left image) and after grit blasting (right image).

Dig Site: #6 a, b - South Meter Run



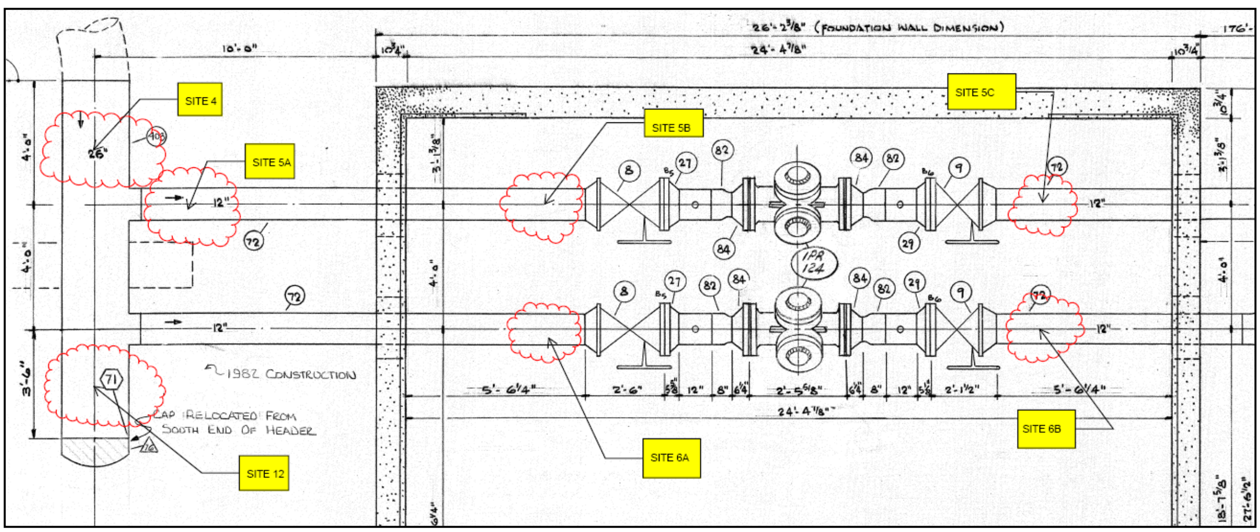


Figure 53. South Meter Run.

Figure 54**. High Pressure Side (Site #5 is behind #6) and low pressure side.**

Figure 55**. Site 6A**

Site 6B.

Guided Wave Results

Dig Site 6A - PE

Pipe:	12" 6A Reg Building	Ring:	R2B12(285)-Circum
Site:	Consumers Energy	Config:	6.0FR, T(0,1)
Location:	Link Seal inner wall -5ft	Calibration:	Automatic (319.45 mV)
Size:	12 inch (0.375 in)	Version:	3.92, Wavemaker G312
Tested:	Aug 21 2006 08:54	Client:	Consumers Energy
Tested by:	David Alleyne[GUL]	Procedure:	GU 1.1

General Notes: TP 1 test location 6A in the Regulator building at the Red Run Regulator Station in Warren. There are reflections from the pipe at the seal location within the wall penetration area. These reflections are above the reportable call level but have been interpreted to be from the seal contact with the pipe. None of the reflections have been interpreted to be from corrosion above the call level.

Feature	Location	ECL	Length	Class	Notes
+F1	3'2"	-	0	Flange	
-F1	-1'9"	-	0	Vent	Visible
-F2	-3'5"	-	0	Weld	
-F3	-5'7"	-	~	Sleeve	Link seal between seal and pipe. The reflections are from the tightness of the seal onto the pipe
-F4	-5'7"	-	0.9	Wall	The pipe is bitumen coated and buried after the wall
-F5	-5'8"	15	3	Cat 1 & 2	Reflections interpreted to be mainly caused by the link seal tightness and changes to the coating and buried conditions in this area.

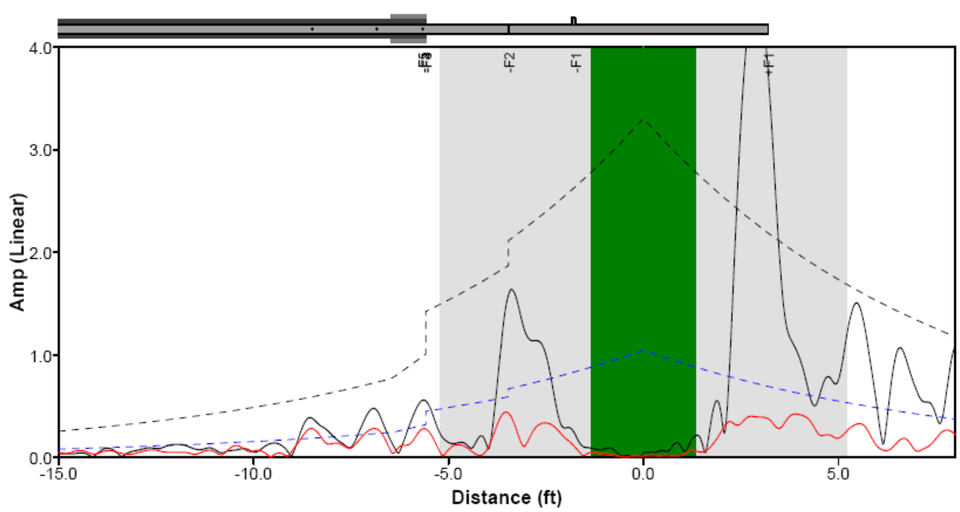


Figure 56. Dig Site 6A - PE.

Dig Site 6B - PE

Pipe:	12" 6B Reg Building	Ring:	R2B12(285)-Circum
Site:	Consumers Energy	Config:	6.6FR, T(0,1)
Location:	Link Seal in wall +5' 9"	Calibration:	Automatic (244.99 mV)
Size:	12 inch (0.375 in)	Version:	3.92, Wavemaker G312
Tested:	Aug 21 2006 12:18	Client:	Consumers Energy
Tested by:	David Alleyne[GUL]	Procedure:	GU 1.1

General Notes: TP 5 test from location 6B inside the regulator building at the Consumer Energy Red Run Station in Warren. There is corrosion running along the bottom of the pipe between the valve and the link seal. The reflection from +F3 is an area with increased corrosion; this was verified after the pipe was cleaned. The maximum wall loss measured by a pit gauge was 0.130". The amplitude of the reflection from F3 is about 16% change in cross section. The reflections from within the link seal are smaller than this so no corrosion deeper than that at +F3 is predicted from the wall area (assuming no localized isolated pit is present).

Feature	Location	ECL	Length	Class	Notes
+F1	**0'1"**	**5**	**7**	**Minor**	**Reflections from this area due to minor changes (visible corrosion at the bottom of the pipe**
+F2	4'1"	20	0	Weld	
+F3	**5'5"**	**16**	**0**	**Medium**	**The defective area is predicted to extend over about 50% of the circumference of the pipe. This would give an average wall loss of about 32%**
+F4	5'9"	-	~	Sleeve	
+F5	8'7"	-	0	Weld	Reflection from reducer fitting
-F1	-2'6"	-	0	Flange	

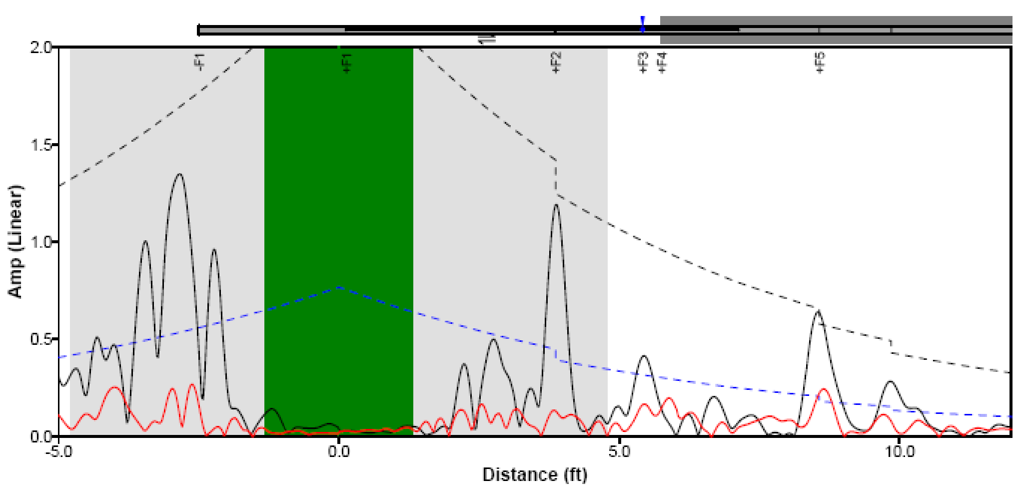
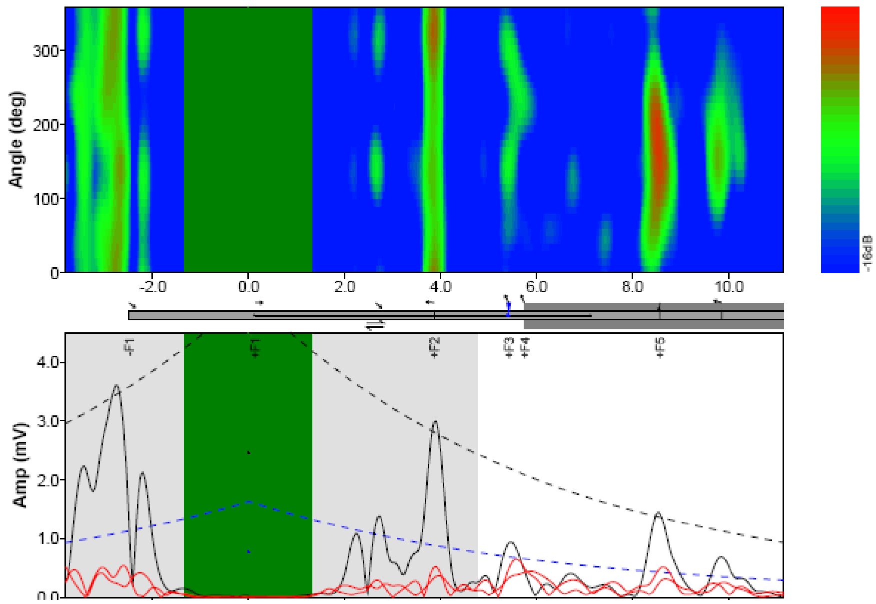


Figure 57. **Dig Site 6B - PE.**

Dig Site 6B - PE C-Scan



C-Scan focused presentation of the result at TP5 (6B). The reflections from the area just before the Link seal are localized towards the bottom of the pipe (at an angle of about 180° - 240°). In particular the reflection at about 5ft 6inch from the transducer ring is concentrated and was confirmed corrosion (see report sheet for details

Figure 58**. Dig Site 6B - PE C-Scan.**

Summary of GW

Test location 6A in the Regulator building at the Red Run Regulator Station in Warren. There are reflections from the pipe at the seal location within the wall penetration area. These reflections are above the reportable call level but have been interpreted to be mainly from the seal contact with the pipe and changes to the coating and buried condition. None of the reflections have been interpreted to be from corrosion with wall loss greater than 30% depth.

TP 5 test from location 6B inside the regulator building at the Consumer Energy Red Run Station in Warren. There is corrosion running along the bottom of the pipe between the valve and the link seal and an area with increased corrosion; this was verified after the pipe was cleaned. The maximum wall loss measured by a pit gauge was 0.130”. The amplitude of the reflection from F3 is about 16% change in cross section. The reflections from within the link seal are smaller than this so no corrosion deeper than that at +F3 is predicted from the wall area (assuming no localized isolated pit is present).

Radiography

(a)


(b)

Figure 59. Radiography of Site 6B.

Outer diameter corrosion was verified visually on the bottom as marked with black marker as seen in (b). The Lo position for radiographic images was on the girthweld at the 06:00 position (yellow arrow). Radiographs of the pipe to determine presence and extent of ID corrosion were inconclusive. No other RT inspections were performed on this pipe. Both (a) and (b) views are looking east.

Direct Exam Visual Pipe and Coating Inspection

Pipe in regulator building was all 0.375" wall. All high pressure and low pressure pipe runs penetrate 10 ¾" thick concrete walls.

Coating: was liquid, non-epoxy based paint. Paint was peeling off bottom of low pressure side piping. Significant external corrosion noted at wall penetration of 6B at the 6:00 position.

Figure 60. **Low pressure side (6B) of South Regulator Run.**

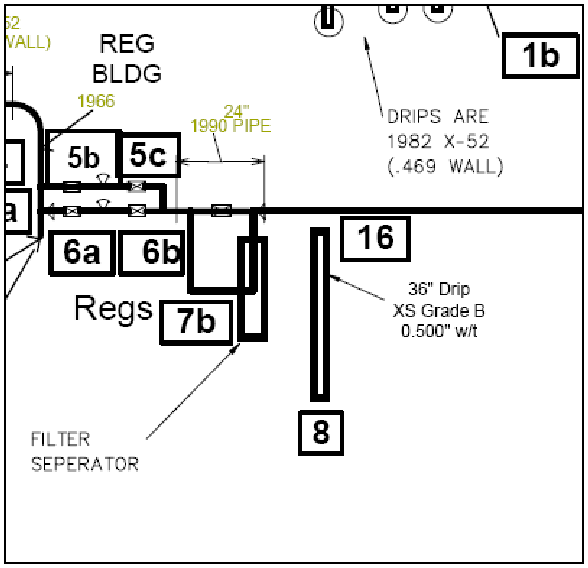
Distribution outlets (5C and 6B) in the basement of the Regulation Bldg had some significant corrosion adjacent to the wall which is cased with a link seal insulator.

- Pitting was observed at the 6:00 position (bottom of pipe). Guided Wave testing with the GUL G-3 picked up this anomalous condition, though exact pitting depths could not be determined.
- Visual inspection indicated general corrosion with an isolated 1.5 in. long area of pitting (0.100" to 0.130") extended to within approx. 3 inches of the wall. The corrosion is atmospheric in nature and possibly occurred from wet-dry cycling of the outlet piping in conjunction with poor coating. The piping is 12 inch, grade B, 0.375" wall.
- ASME B-31-G mod. was performed and indicted the piping safe to remain in place. This area is adjacent to the wall and has a casing with link seal thru the penetration.
- Data obtained from defect assessment on the basement side as discussed in the previous bullets was used to provide calibration of GUL unit allowing

evaluation of waveforms within the casing. Corrosion in the casing was no more severe than that found in the basement and piping was safe to remain in place.

Figure 61**. Significant External Corrosion under coating along 6B run.**

Dig Site: #7b - Filter-Separator Station (cancelled #7a due to unsupported wall adjacent to site)



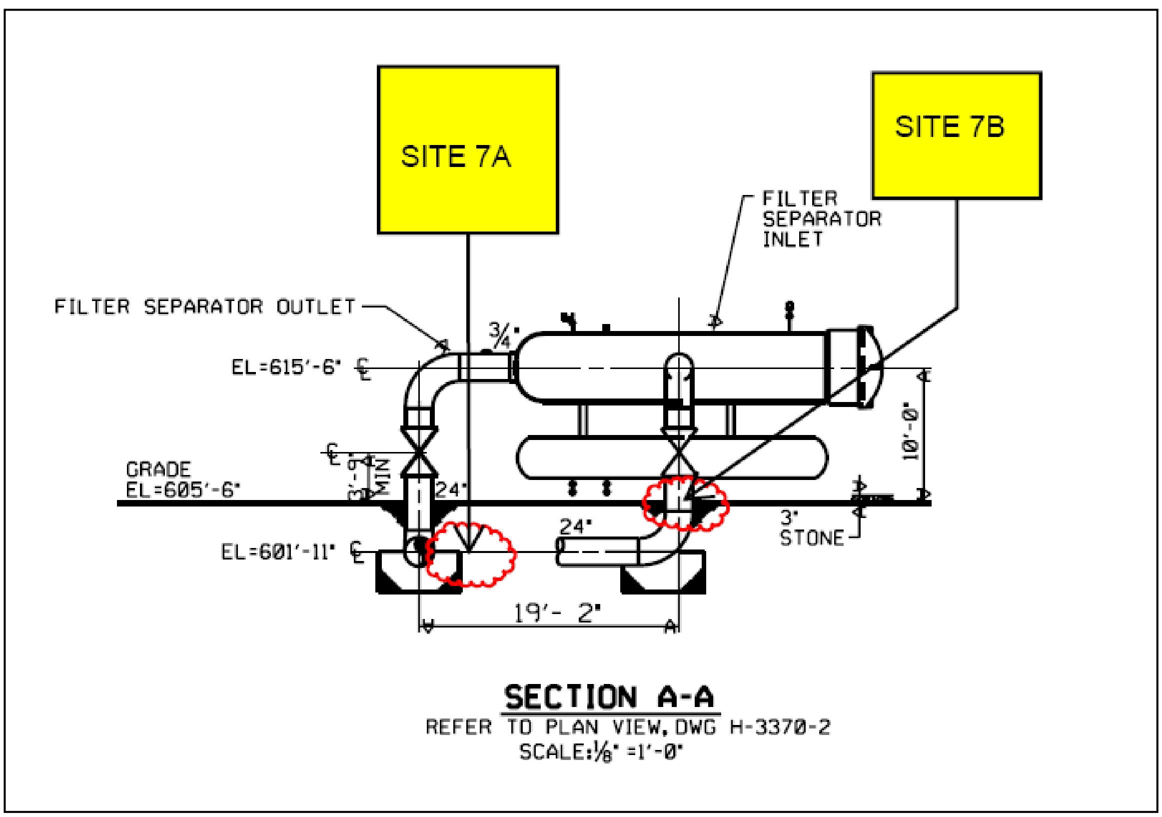


Figure 62**. Filter-Separator Station.**

Figure 63**. Filter Separator Inlet.**

Guided Wave Results

Dig Site 7B - PE

Pipe:	24" 7B F S Station	Ring:	R2B24(703)-Circum
Site:	Consumers Energy	Config:	9.2FR, T(0,1)
Location:	Ground position -1ft 8”	Calibration:	Automatic (370.848 mV)
Size:	24 inch	Version:	3.92, Wavemaker G312
Tested:	Aug 22 2006 13:38	Client:	Consumers Energy
Tested by:	David Alleyne[GUL]	Procedure:	GU 1.1

General Notes: TP 14 test location 7B. There are no reflections that have been interpreted to be from corrosion above the call level.

Feature	Location	ECL	Length	Class	Notes
-F2	-2'4"	-	0	1D Bend	
-F1	-1'8"	-	~	Earth	Ground entry
-F3	-22'0"	-	0	Bend	
+F1	0'4"	-	0	T	Weld to the valve fitting

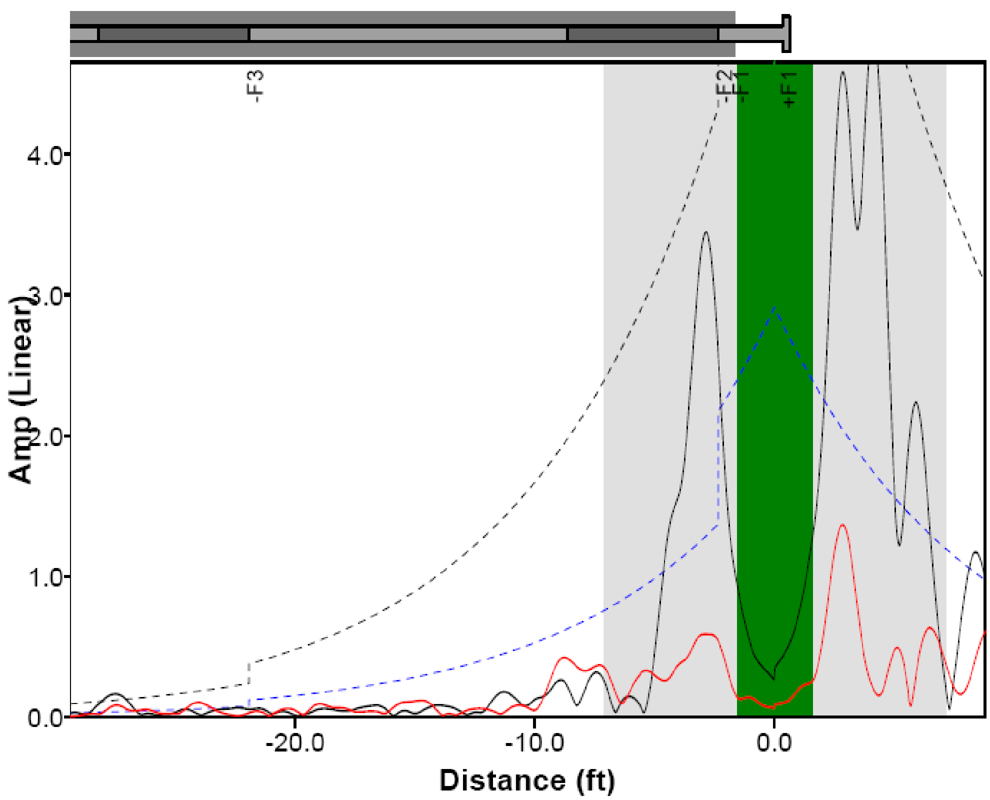


Figure 64. **Dig Site 7B - PE.**

Summary of GW

Test location 7B. There are no reflections that have been interpreted to be from corrosion above the call level.

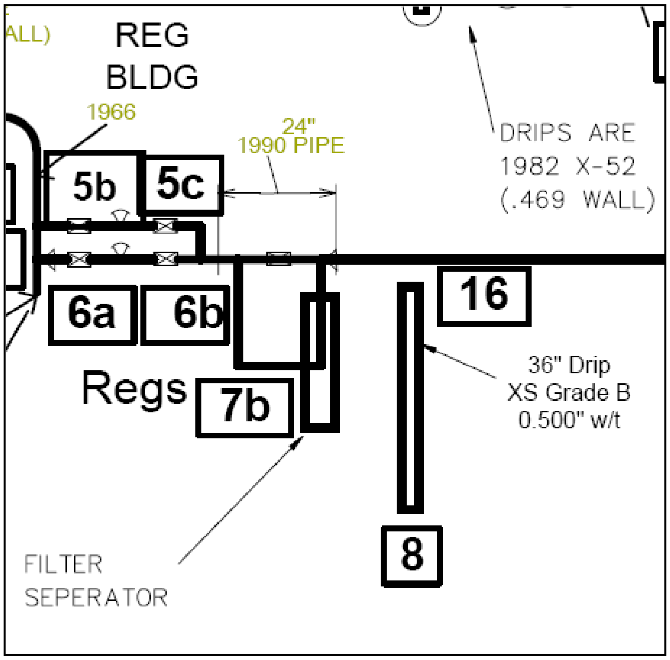
Radiography

None.

Direct Exam Visual Pipe and Coating Inspection

Above ground portion of piping showed no signs of corrosion. Paint in excellent condition.

Dig Site: ***#8 - Slop Tank (Dig Site #16 was radiography only)***



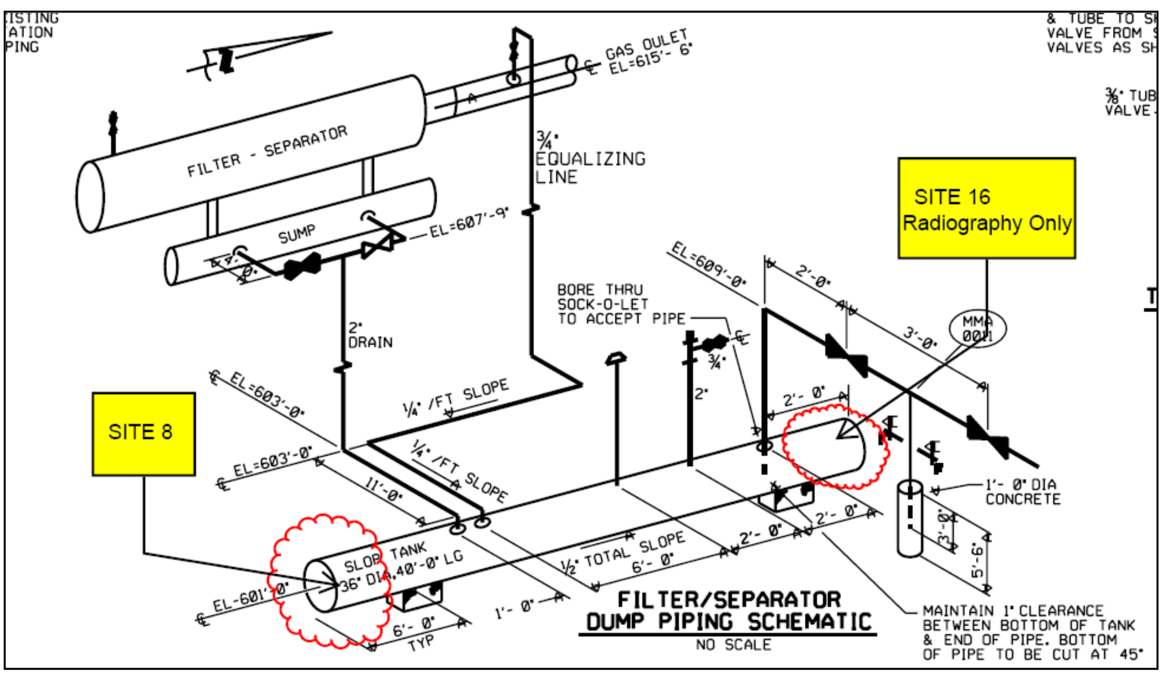


Figure 65. **Slop Tank.**

Figure 66**. South end of Slop Tank.**

Guided Wave Results

Dig Site 8 - PE

Pipe: 36" 8
Site: Consumers Energy
Location: End -2ft 5inch
Size: 36 inch

Ring: R2B36(679)
Config: 17.6FR, T(0,1)
Calibration: Automatic (568.324 mV)
Version: 3.92, Wavemaker G312
GPS: 82°59.6228'W, 42°32.7834'N

Tested: 23 Aug 2006 12:00
Tested by: David Alleyne[GUL]

Client: Consumers Energy
Procedure: GU 1.1

General Notes: TP 19 test location 8 on the 36" pipe, the attenuation at this location is a little higher than expected and this is interpreted to mainly due to the effect of the soil and the coating on the pipe. There are no reflections interpreted to be from corrosion above the call level.

Feature	Location	ECL	Class	Notes
-F1	-3'8"	-	Flange	
+F1	3'2"	-	Entrance	Approximate ground entry location
+F2	17'2"	-	Weld	Symmetric reflection

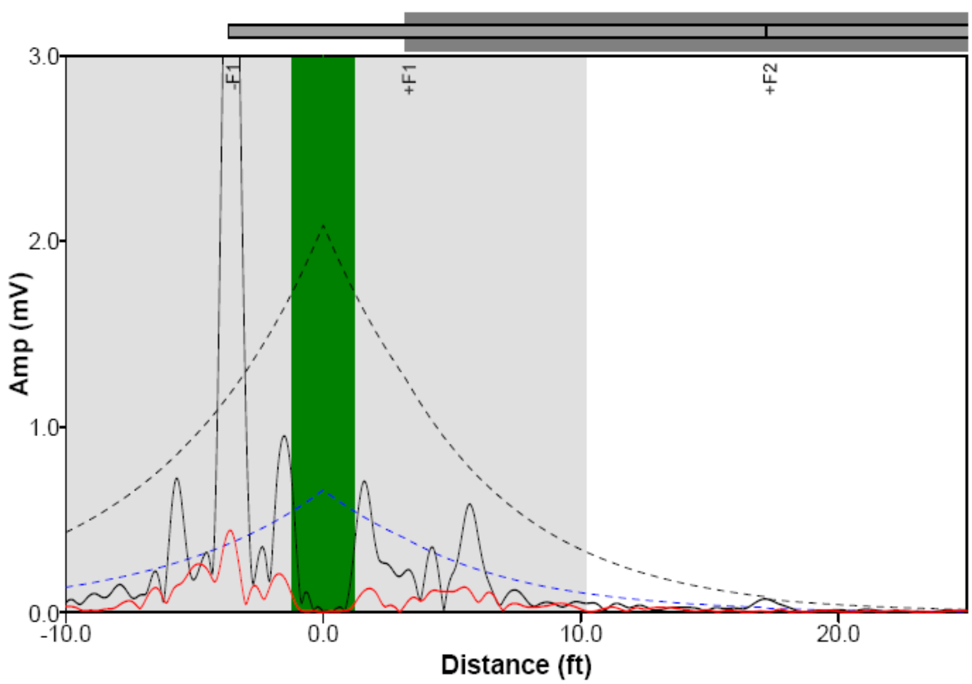


Figure 67. **Dig Site 8 - PE.**

Dig Site 8 - PE (retest)

Pipe:	36" 8	Ring:	R2B36(679)
Site:	Consumers Energy	Config:	14.4FR, T(0,1)
Location:	End -2ft 5inch	Calibration:	Automatic (1346.17 mV)
Size:	36 inch (12.7 mm)	Version:	3.92, Wavemaker G312
Tested:	25 Aug 2006 08:07	Client:	Consumers Energy
Tested by:	David Alleyne[GUL]	Procedure:	GU 1.1

General Notes: TP 28 a retest of the drip 8 from near the dome end at a low sensitivity to maximize the test range. The attenuation at this location is high and is interpreted to be mainly caused by the effect of the coating and soil on the pipe. There may also be some internal deposits that have increased the attenuation. There are no reflections interpreted to be from significant corrosion well above the higher call level.

Feature	Location	ECL	Class	Notes
+F1	3'7"	-	Flange	
-F1	-0'5"	-	Bitumen	
-F2	-1'7"	-	Earth	Ground entry position
-F3	-5'5"	-	Mirror	
-F4	-17'2"	-	Weld	Symmetric reflection
-F5	-39'6"	-	Flange	Estimated position of the end of the drip (from above ground measurements)

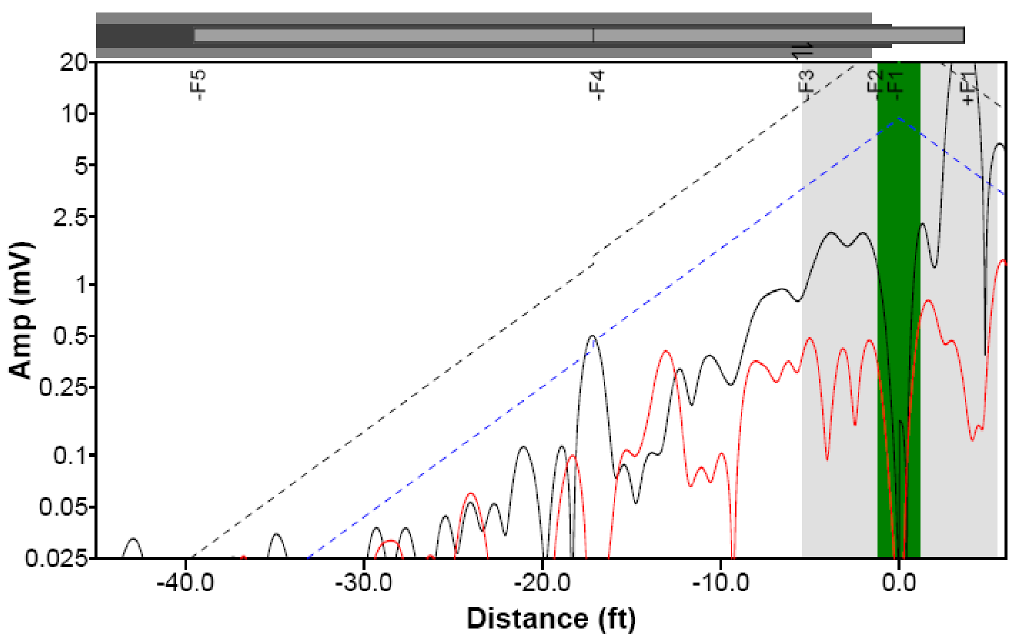


Figure 68**. Dig Site 8 - PE (retest).**

Summary of GW

Test location 8 on the 36" pipe, the attenuation at this location is a little higher than expected and this is interpreted to mainly due to the effect of the soil and the coating on the pipe. There are no reflections interpreted to be from corrosion above the call level.

A retest of location 8 was completed of the drip from near the dome end at a low sensitivity to maximize the test range. The attenuation is high and is interpreted to be mainly caused by the effect of the coating and soil on the pipe. There may also be some internal deposits, but there are no reflections interpreted to be from significant corrosion above the higher call level.

Radiography

Report Pending

Direct Exam Visual Pipe and Coating Inspection

Wall thickness of 0.50", Coating was hot applied tape.

For all exposed (above ground) sections the tank coating and metal O.D. were in good condition. No signs of coating or metal degradation.

Dig Site: #9 a, b, c & 13 - South Side of Total Station Bypass

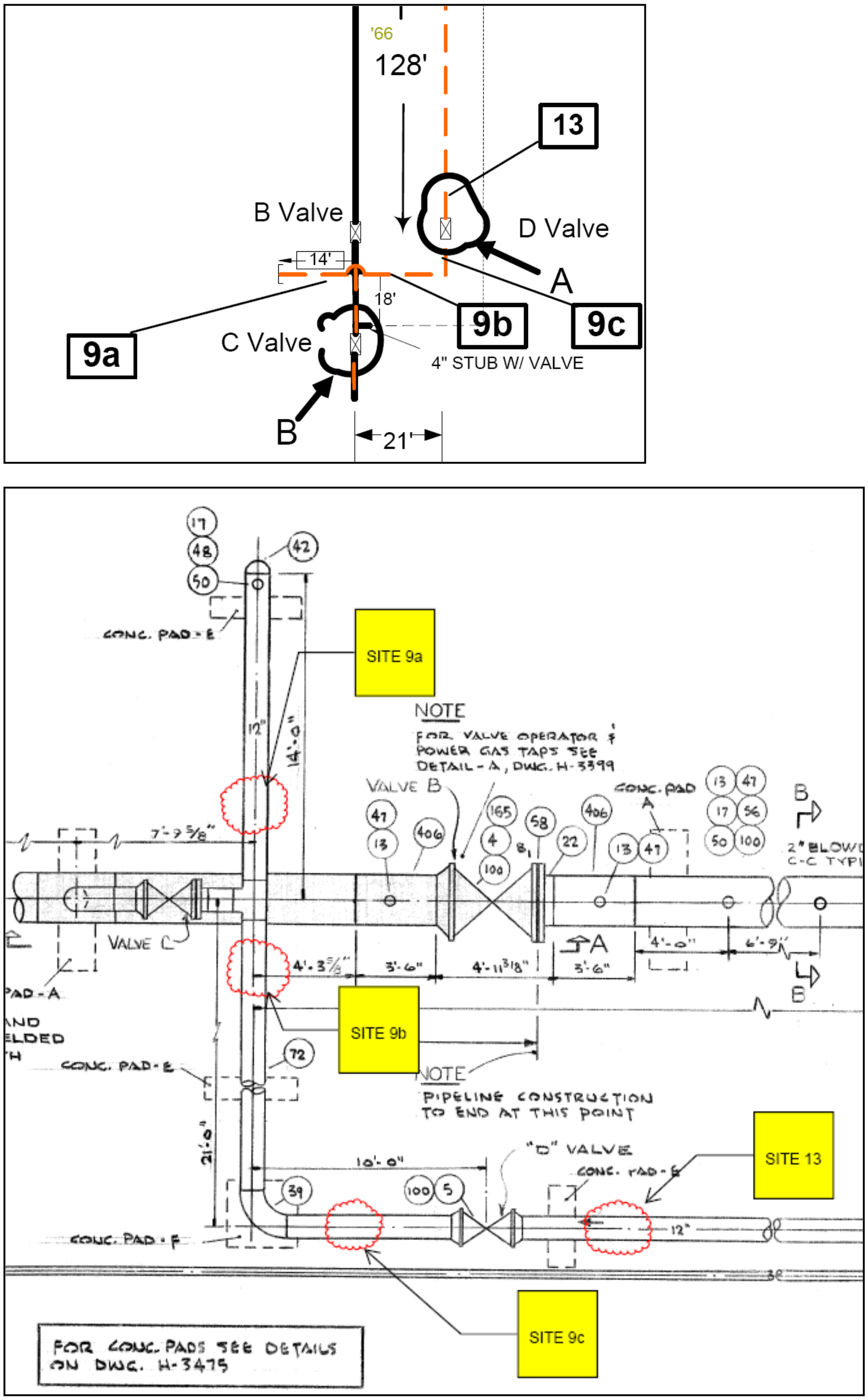


Figure 69. **South Side of Total Station Bypass.**

Figure 70**. Dig Site 9a - Station Bypass West of Valve-C.**

Figure 71**. Dig Site 9b - Station Bypass East of Valve-C.**

Figure 72**. Dig Site 9c - Station Bypass South of Valve-D.**

Figure 73**. Dig Site 13 - Station Bypass North of Valve-D.**

Dig Site 9A - PE

Pipe:	12" 9A	Ring:	R2B12(285)
Site:	Consumers Energy	Config:	4.0FR, T(0,1)
Location:	Pit 3 location 9A Center	Calibration:	Automatic (674.586 mV)
Size:	12 inch	Version:	3.92, Wavemaker G312
Tested:	24 Aug 2006 13:33	Client:	Consumers Energy
Tested by:	David Alleyne[GUL]	Procedure:	GU 1.1

General Notes: TP 27 Test location 9A within a pit on the side end of the station by-pass. A number of large reflectors close to the ring have complicated the interpretation if data fro this test position and have contributed to a very limited test range. The reverberations and echoes from within the branch fitting have reduced the test sensitivity.

Feature	Location	ECL	Class	Notes
-F1	-5'0"	-	Y	Visible branch
+F1	2'6"	-	Entrance	Ground entry
+F2	10'9"	-	Flange	The end reflection is small because of the buried condition and the bitumen coating. At the lower frequencies the attenuation is lower and this reflection is larger but the near field and dead-zone are very large
-F2	-8'7"	-	Entrance	

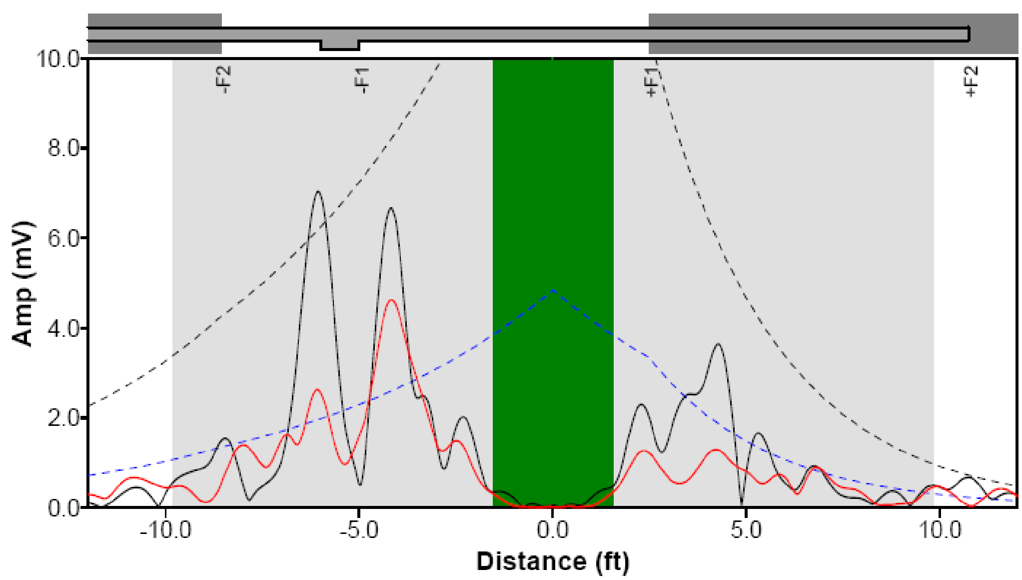


Figure 74. Dig Site 9A - PE.

Pipe: 12" 9B	Ring: R2B12(285)
Site: Consumers Energy	Config: 4.8FR, T(0,1)
Location: Pit 3 location 9B Center	Calibration: Automatic (431.115 mV)
Size: 12 inch	Version: 3.92, Wavemaker G312
	GPS: 82°59.5473'W, 42°32.7943'N
Tested: 24 Aug 2006 13:14	Client: Consumers Energy
Tested by: David Alleyne[GUL]	Procedure: GU 1.1

General Notes: TP 26 Test location 9B on the side end of the station by-pass. A number of large reflectors close to the ring have complicated the interpretation if data fro this test position and have contributed to a very limited test range. The reverberations and echoes from within the branch fitting have reduced the test sensitivity.

Feature	Location	ECL	Class	Notes
+F1	1'6"	-	Y	
+F2	9'0"	-	Entrance	Approximate position of ground entry
-F1	-2'0"	-	Entrance	Approximate position of ground entry
-F2	-18'0"	-	Bend	Estimated position of the bend

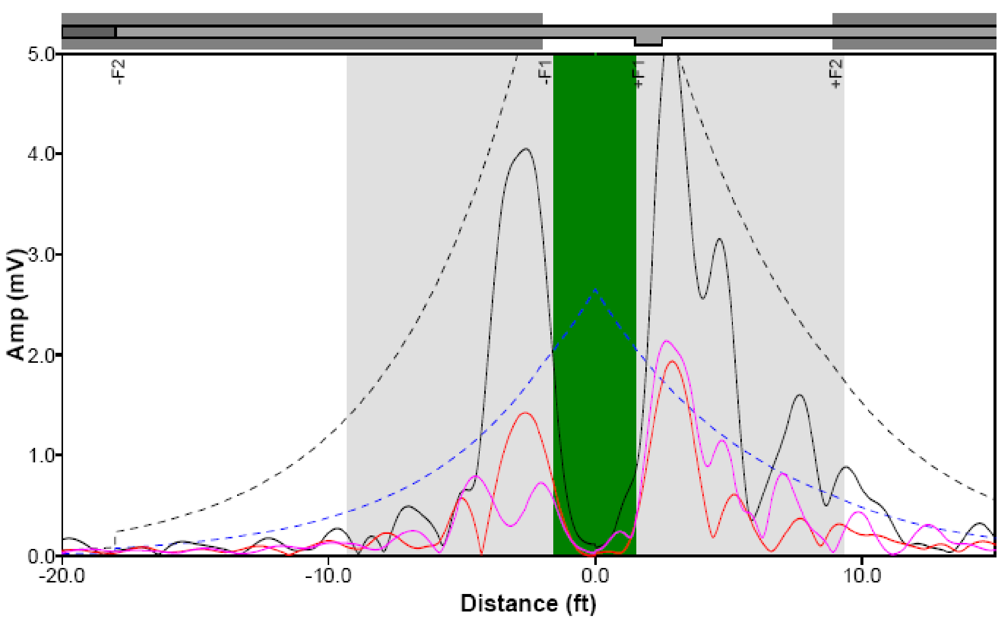


Figure 75**. Dig Site 9B - PE.**

Dig Site 9C - PE

Pipe:	12" 9C	Ring:	R2B12(285)
Site:	Consumers Energy	Config:	6.0FR, T(0,1)
Location:	Pit 3 location 9C Center	Calibration:	Automatic (555.388 mV)
Size:	12 inch (9.52454 mm)	Version:	3.92, Wavemaker G312
Tested:	24 Aug 2006 12:36	Client:	Consumers Energy
Tested by:	David Alleyne[GUL]	Procedure:	GU 1.1

General Notes: TP 25 test location 9C with a pit at the south end of the station by-pass. There are no reflections that have been interpreted to be from corrosion above the call level.

Feature	Location	ECL	Class	Notes
+F1	2'6"	-	Y	
+F2	3'6"	-	Bitumen	
+F3	3'8"	-	Earth	Ground entry
+F4	7'1"	-	1D Bend	High level of non-symmetry in this weld reflection of the bend, this is probably due to the non-symmetry caused by transmission through the welded valve fitting
-F1	-2'0"	-	T	welded in valve at TDC of pipe and a 6"

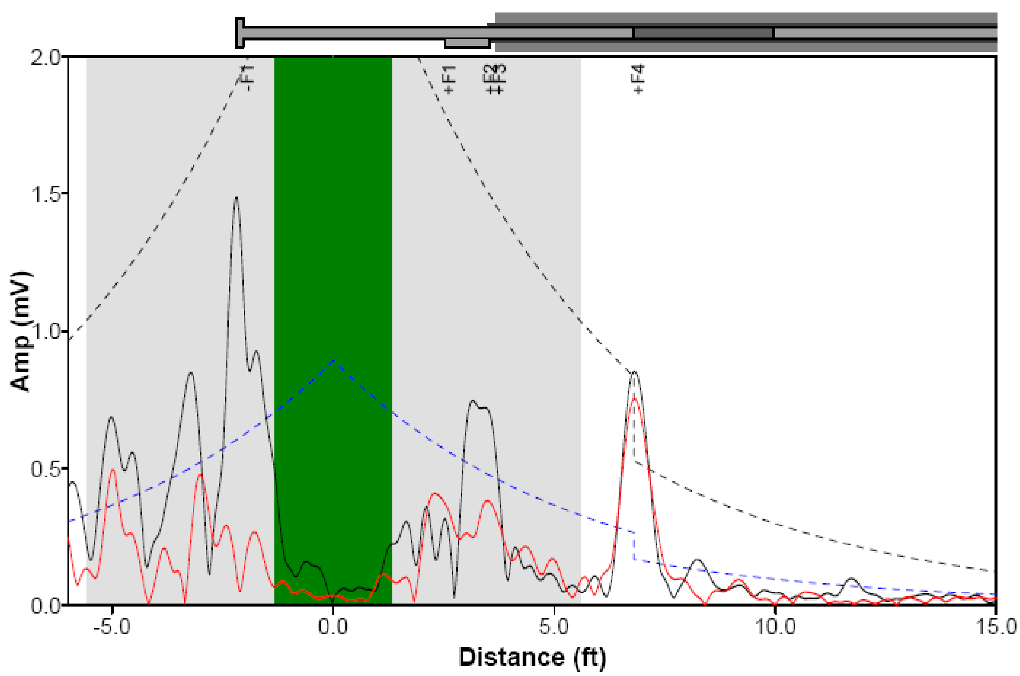


Figure 76. **Dig Site 9C - PE.**

Dig Site 13 - PE

Pipe:	12" 13	Ring:	R2B12(285)
Site:	Consumers Energy	Config:	6.4FR, T(0,1)
Location:	Pit 3 location 13 Center	Calibration:	Automatic (797.602 mV)
Size:	12 inch (9.525 mm)	Version:	3.92, Wavemaker G312
		GPS:	82°59.5473'W, 42°32.7943'N
Tested:	24 Aug 2006 12:27	Client:	Consumers Energy
Tested by:	David Alleyne[GUL]	Procedure:	GU 1.1

General Notes: TP 24 test location 13 within a fenced area at the south side of the total station by-pass. There are no reflections above the call level interpreted to be from significant corrosion.

Feature	Location	ECL	Class	Notes
+F1	7'8"	-	Y	Visible and measure vertical vent to Valve
+F2	11'9"	-	Earth	Ground entry
-F1	-0'6"	-	Bitumen	
-F2	-3'0"	-	Earth	Ground entry reflection
-F3	-45'0"	-	Weld	Symmetric reflection interpreted to be from a weld
-F4	-59'6"	8	Minor	Symmetric indication from the end of the test range area, which is not interpreted to be from a welded feature or corrosion.

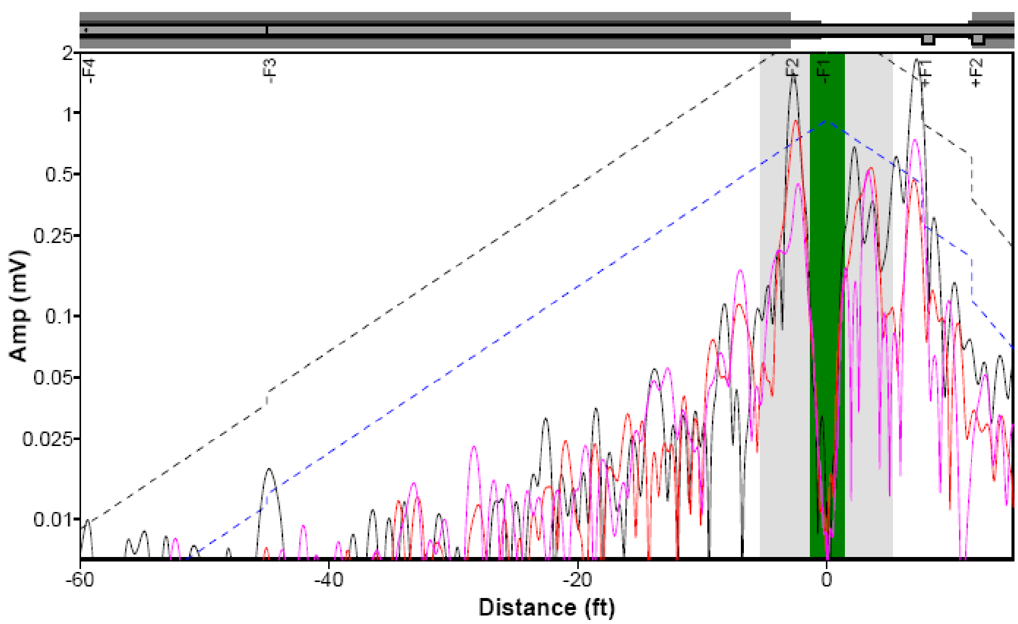


Figure 77. **Dig Site 13 - PE.**

Summary of GW

Test location 9A within the pit on the side end of the station by-pass. A number of large reflectors close to the ring have complicated the interpretation if data from this test position and have contributed to a very limited test range.

Test location 9B on the side end of the station by-pass. A number of large reflectors close to the ring have complicated the interpretation of data from this test position and have contributed to a very limited test range and the reverberations and echoes from within the branch fitting have reduced the test sensitivity.

Test location 9C with a pit at the south end of the station by-pass. There are no reflections that have been interpreted to be from corrosion above the call level.

Test location 13 within a fenced area at the south side of the total station by-pass. There are no reflections above the call level interpreted to be from significant corrosion. The reported test range was 60ft in each direction from the ring.

Radiography

Figure 78**. Areas 9A and 9B.**

A single RT image at the 06:00 position was produced for pipe at Areas 9A (yellow arrow) and 9B (green arrow) on both sides of the tee. No density changes consistent with the presence of localized corrosion were visible. View is looking southwest.

Figure 79**. Area 13.**

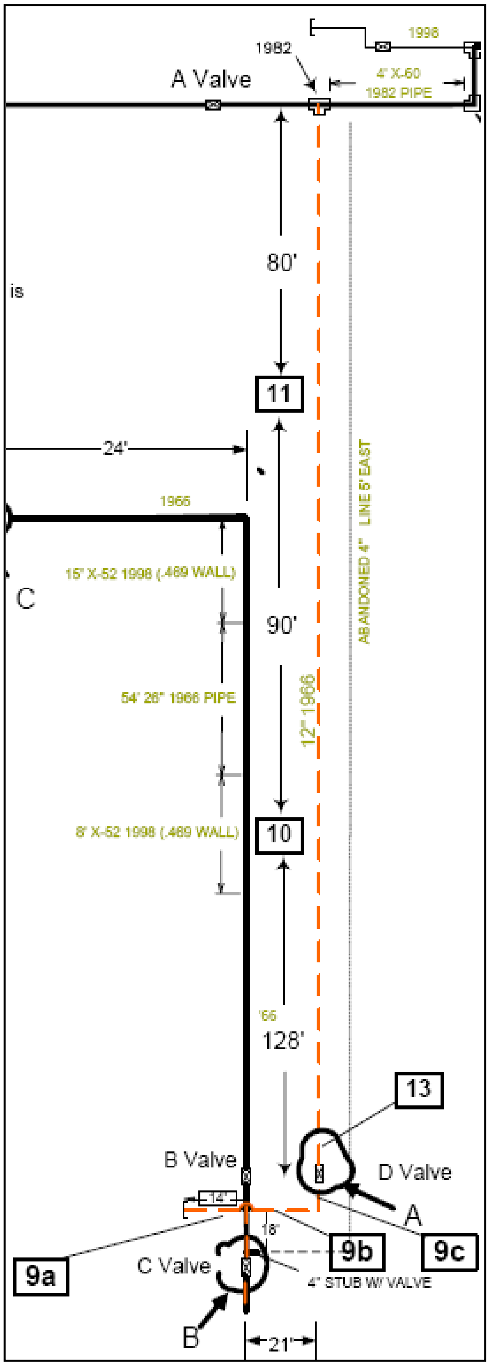
A single RT image at the 06:00 position was produced. No density changes consistent with the presence of localized corrosion were visible. View is looking south.

Direct Exam Visual Pipe and Coating Inspection

Coal tar with hot applied tape, all in smooth/good condition. No external corrosion noted.

Operator:	Consumers Energy
Case Study:	Red Run City Gate 8/21/2006

Dig Site: ***#10 and #11 - 12" Total Station Bypass***



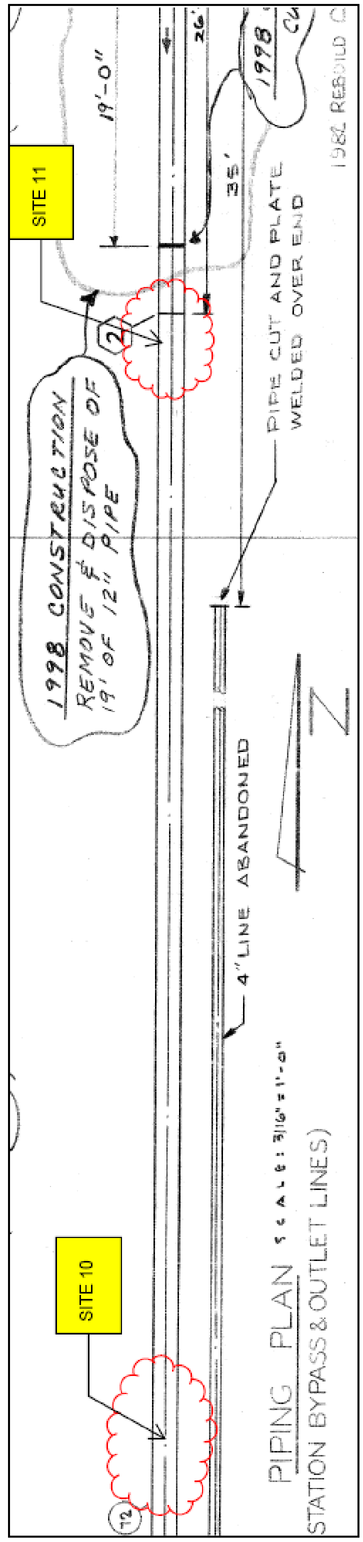


Figure 80. **Total Station Bypass.**

Figure 81**. Dig Site #10.**

Figure 82**. Dig Site #11.**

Guided Wave Results

Dig Site 10 - PE

Pipe:	12 " 10	Ring:	R2B12(285)
Site:	Consumers Energy	Config:	1.4FR, T(0,1)
Location:	Pit 2 location 10 Center	Calibration:	Automatic (1134.54 mV)
Size:	12 inch	Version:	3.92, Wavemaker G312
Tested:	23 Aug 2006 14:37	Client:	Consumers Energy
Tested by:	David Alleyne[GUL]	Procedure:	GU 1.1

General Notes: TP 21 test location 10, the increased attenuation at this location is caused by the external coating (bitumen and the soil (thick clay like) surround the pipe. There are numerous reflections from variations in the coating and contact condition with the ground and none have been interpreted to be from corrosion above the call level. The large dead-zone and near field area was inspected using data from higher frequencies (not shown).

Feature	Location	ECL	Class	Notes
+F2	6'0"	-	Earth	Ground entry
+F1	1'5"	-	Bitumen	
-F1	-0'6"	-	Bitumen	Start of coating
-F2	-5'0"	-	Earth	
-F3	-23'1"	-	Weld	Symmetric reflection consistent with estimated weld position (very frequency sensitive amplitude)

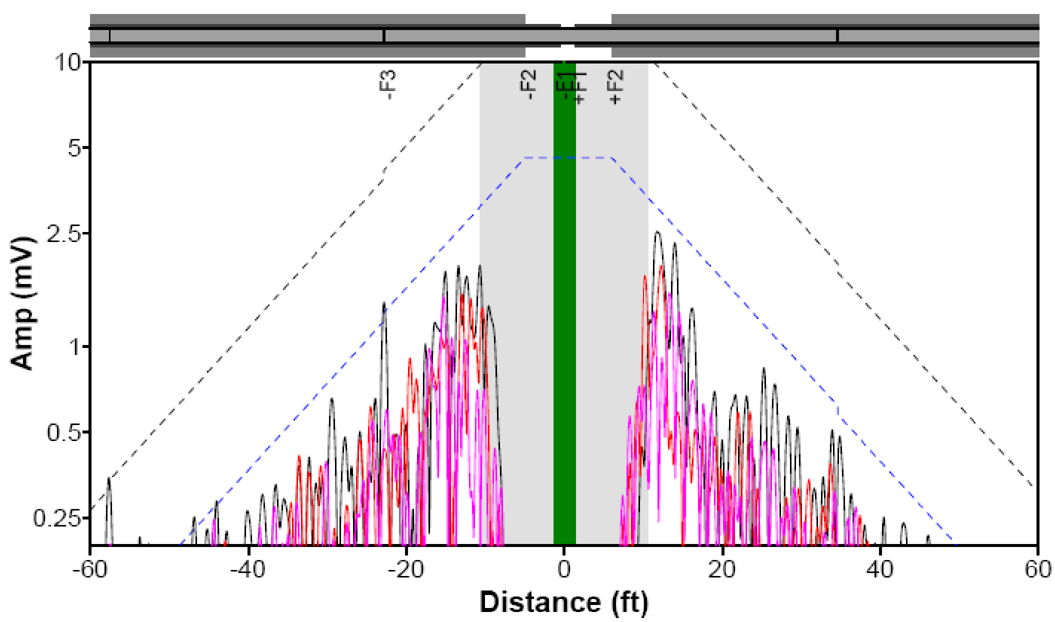


Figure 83. **Dig Site 10 - PE.**

Dig Site 11 - PC

Pipe: 12 " 11	Ring: R2B12(285)
Site: Consumers Energy	Config: 5.6FR, T(0,1)
Location: Pit 1 location 11 Center	Calibration: Automatic (899.995 mV)
Size: 12 inch (9.52454 mm)	Version: 3.92, Wavemaker G312
	GPS: 82°59.6228'W, 42°32.7834'N
Tested: 23 Aug 2006 13:47	Client: Consumers Energy
Tested by: David Alleyne[GUL]	Procedure: GU 1.1

General Notes: TP 20 test location 11 the increased attenuation at this location is caused by the external coating (bitumen and the soil (thick clay like) surround the pipe. There are numerous reflections from variations in the coating and contact condition with the ground and none have been interpreted to be from corrosion above the call level.

Feature	Location	ECL	Class	Notes
+F4	53'0"	-	Weld	Increase in symmetric indication
+F3	**10'3"**	**-**	**Weld**	**Large non-symmetry in weld reflection. Interpreted to be mainly caused by mis-alignments.**
+F2	4'1"	-	Entrance	Ground entry
+F1	0'1"	6	Minor	Small reflections form the entire extent of the pipe inspected, which have been interpreted to be caused by changes to the coating and ground contact condition
-F1	-0'8"	-	Entrance	Start of bitumen coating
-F2	-31'4"	-	Weld	Increase in symmetric indication

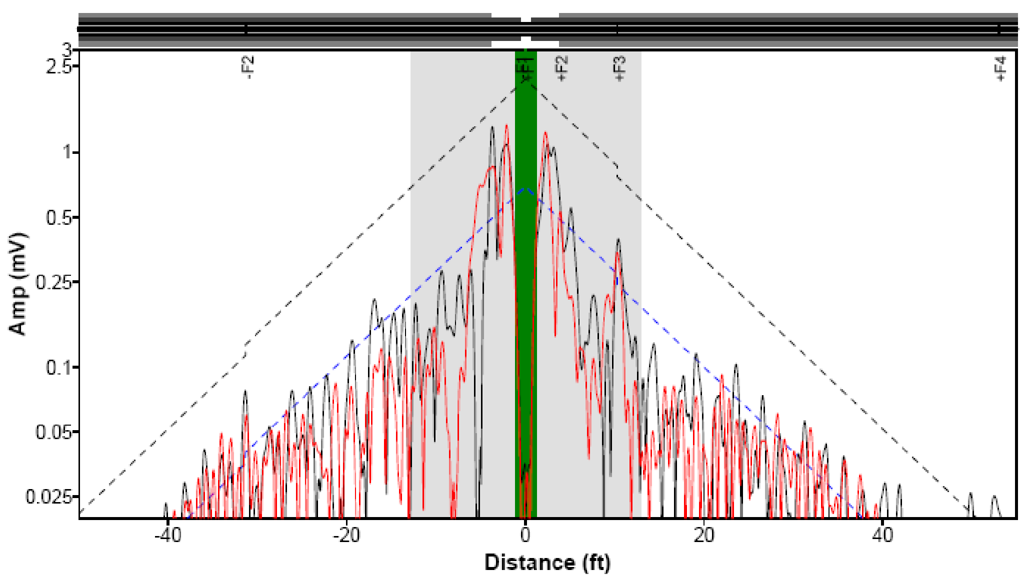


Figure 84. **Dig Site 11 - PC.**

Summary of GW

Test location 10, the increased attenuation at this location is caused by the external coating (bitumen and the soil (thick clay like) surround the pipe. There are reflections from variations in the coating and contact condition with the ground but none have been interpreted to be from corrosion above the call level. The reported test range was 60ft in each direction from the ring.

Test location 11 the increased attenuation at this location is caused by the external coating (bitumen and the soil (thick clay like) surround the pipe. There are numerous reflections from variations in the coating and contact condition with the ground and none have been interpreted to be from corrosion above the call level. Reported test range at 10% call level 50ft in each direction from the ring. A test range of up to 75ft in each direction was reviewed but beyond about 50ft the detection threshold would have to be increased to about 15% of the cross section for reliable detection.

Radiography

Figure 85. **Area 10.**

A single RT image at the 06:00 position was produced. No density changes consistent with the presence of localized corrosion were visible. View is looking to the east.

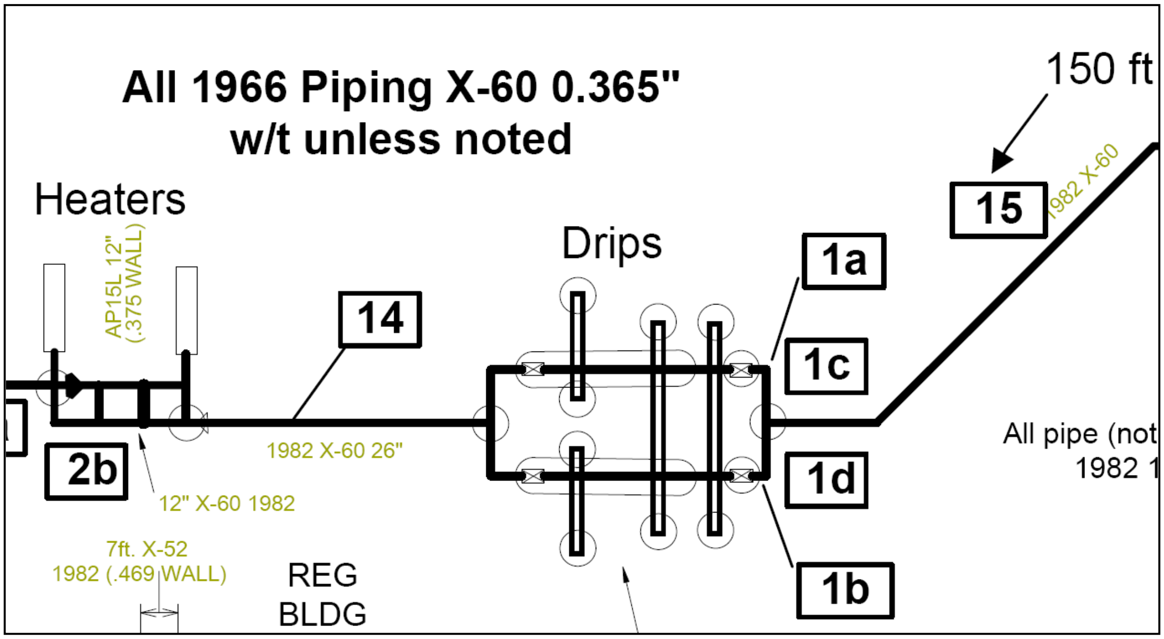
Direct Exam Visual Pipe and Coating Inspection

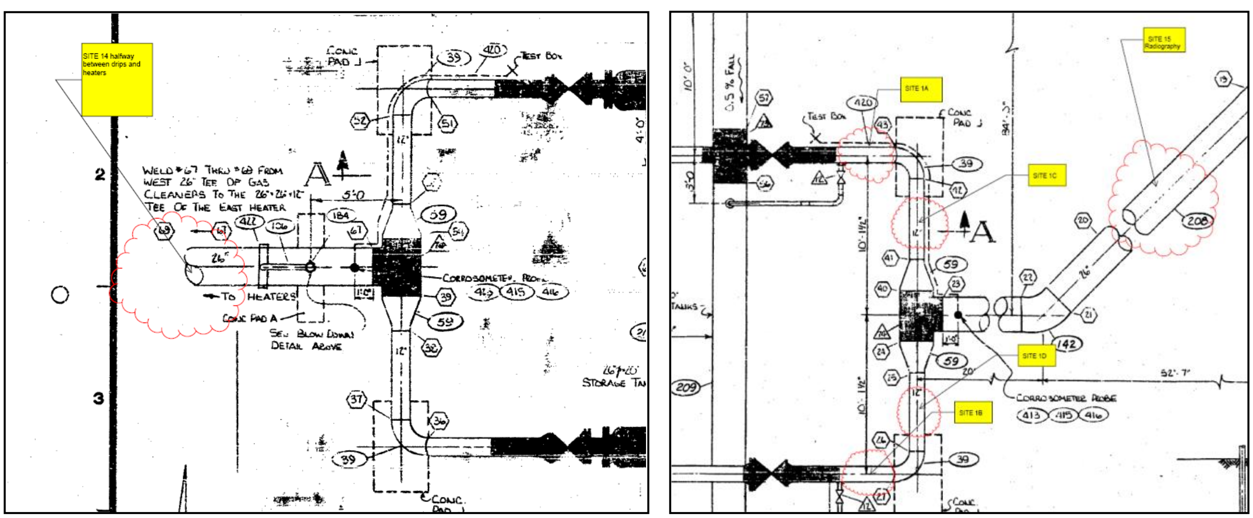
Coal Tar in smooth, good condition.

12" diameter, 0.375" wall thickness.

No signs of external corrosion.

Dig Site: #14 and 15 - Radiography of Piping on the West and East Side of the Drip Run





(a) (b)

Figure 86. **Dig Site #14 (a) on West side of drip run halfway to heaters, and Dig Site #15 (b) on East side of drip runs (150 ft West of Valve A).**

Guided Wave Results

Not done.

Radiography

Figure 87. **Dig Site #14.**

Density changes in the pipe bottom consistent with localized corrosion were present on the radiographs at the pipe bottom. Ultrasonic testing (Porta-Scans) of the pipe bottom was initiated. The figure above shows the locations of the four pipe scans in relation to the girthweld (green arrow). The locations of the scans are shown with the arrows pointing at a dashed line drawn at the 3:00 o'clock position. The pipe was scanned at the 5:30 to 6:30 positions. View is looking south.

Porta-Scans on Dig #14

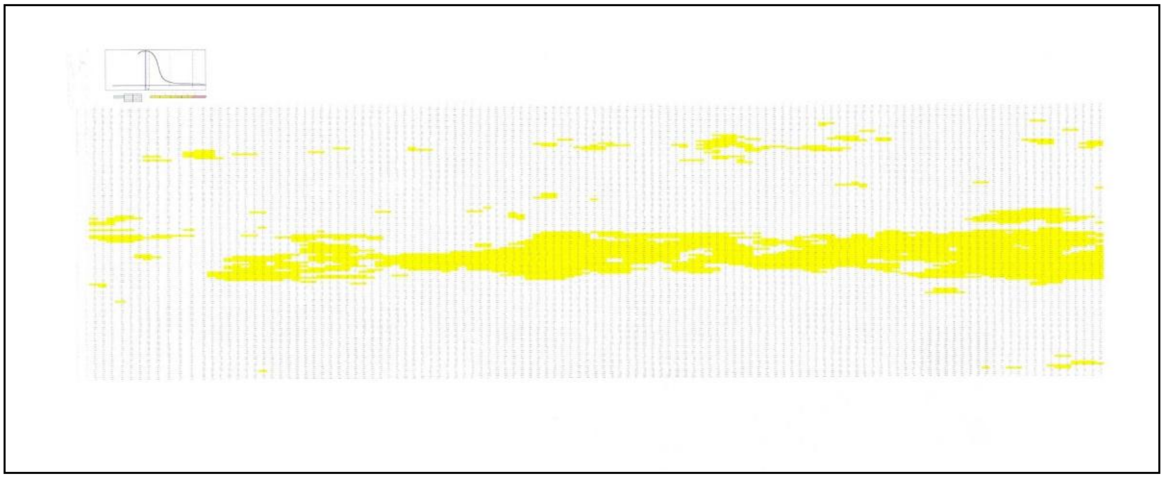


Figure 88. **Scan 1: Lo+5.75".**

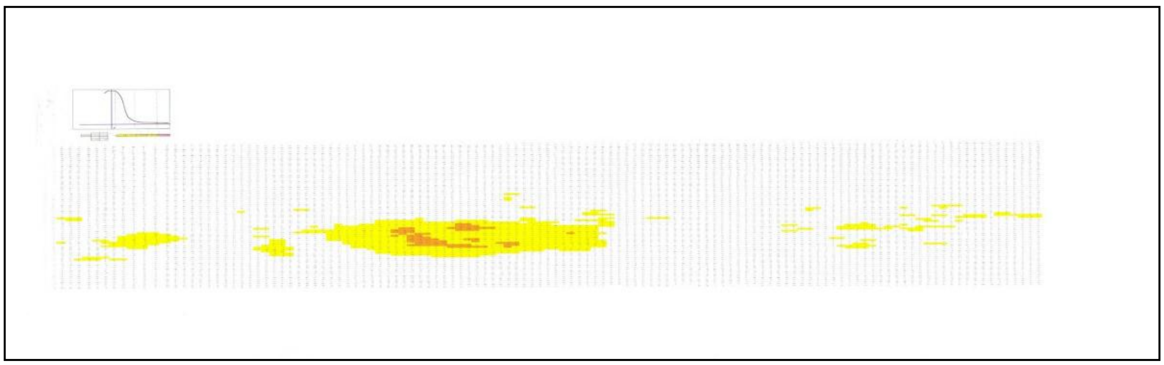


Figure 89. **Scan 2: Lo+16.75".**

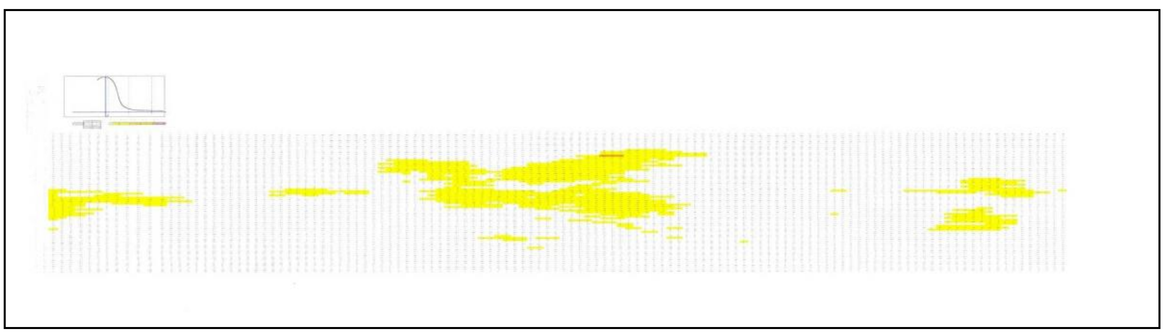


Figure 90. **Scan 3: Lo+27.75".**

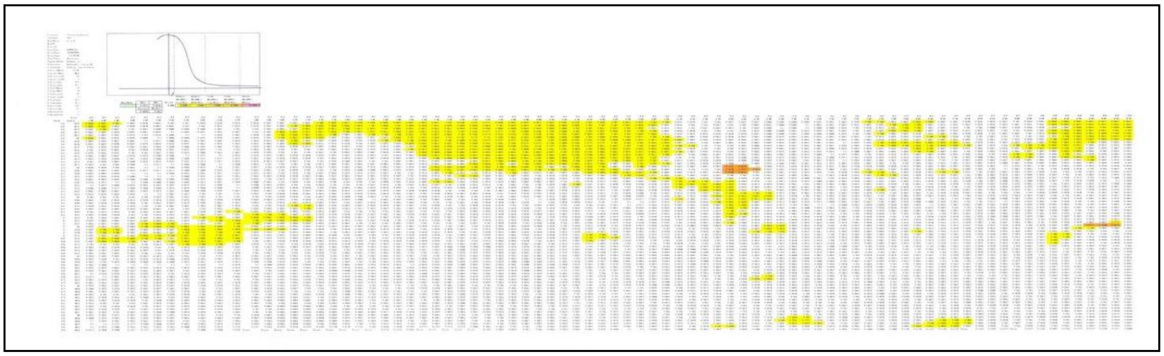


Figure 91**. Scan 4: Lo-1.75".**

Figure 92**. Dig Site #15.**

The Lo is shown by the yellow arrow. A girthweld is located 12 inches east of the Lo position. Radiographs determined the presence of sludge at a level from the 4:30 to the 6:45 position at the pipe ID. Long seams were found at the 9:30 region west of the girthweld and at the 12:30 position east of the girthweld.

Minor Density changes in the pipe bottom consistent with localized corrosion were present on the radiographs. Ultrasonic inspection was conducted manually on those three areas: at the

6:30 position for Lo+35.5" and Lo+39.5" and at the 5:30 position at Lo+39.5". The lowest wall thickness reading was 0.373 inches at the Lo+39.5", 5:30 position. The average wall thickness measured in the surrounding area was 0.383" which translates to a minimum wall loss percentage of 2.6% for the area inspected. Clockwise is going west. View is looking to the north.

Direct Exam Visual Pipe and Coating Inspection

Dig Site #14 - Visual Inspection showed no external corrosion with coal tar coating in good condition. Pipe was 26" diameter, 0.375" wall, X-60, 1982.

Summary of All Direct Exam Results

Distribution outlets in the basement of the Regulation Bldg had some significant corrosion adjacent to the wall which is cased with a link seal insulator.

- Pitting was observed at the 6:00 position. Guided Wave testing with the GUL G-3 picked up this anomalous condition, though exact pitting depths could not be determined.
- Visual inspection indicated general corrosion with an isolated 1.5 in. long area of pitting (0.100" to 0.130") extended to within approx. 3 inches of the wall. The corrosion is atmospheric in nature and possibly occurred from wet-dry cycling of the outlet piping in conjunction with poor coating. The piping is 12 inch, grade B, 0.375" wall.
- ASME B31G was performed and indicted the piping safe to remain in place. This area is adjacent to the wall and has a casing with link seal thru the penetration.
- Data obtained from defect assessment on the basement side as discussed in the previous bullets was used to provide calibration of GUL unit allowing evaluation of waveforms within the casing. Corrosion in the casing was no more severe than that found in the basement and piping was safe to remain in place. Direct Exam Results (Cont.)

Stub and riser at the South end of the inlet to the meter run:

- Inspection by the GUL unit indicated the piping to be significantly blocked.
- Lab radio-graphed both the stub and primary riser and determined them to be totally filled and 75% filled respectively.
- End cap at the end of the meter header removed and was seen to be significantly plugged with solids.
- Inspection revealed minor general corrosion in the header. A significant amount of solids existed beyond what could be removed. Several cuts were made to facilitate cleaning and inspection of piping between the outlet of the heater and the meter header. Upon cleaning, the pipe was seen to be internally coated (flow improver) and had significant pitting in the 6:00 range, particularly at the elbow.
- A total of approximately 85 ft. of piping was replaced between the heater outlet and the meter run header. The tie-in, located approx 6 ft west of the heater valve was partially

filled with solids. It was cleaned and inspected and seen to be not internally coated with only minor general corrosion.

Additional Inspections

- A total of eight sections were added to inspect for internal corrosion prospects.
- A "sag" (i.e., designed pipe bend) was identified during the assessment of the inlet tee. Radiographic inspection indicated several areas of localized internal corrosion. Ultrasonic testing was performed and revealed only negligible corrosion.
- One dig remains which is located at the low end of the distribution log. While excavating the area soil was observed to contain drip oil and is believed to have a leak present on either the drip log or associated piping. The log as been bypassed and replaced with a temporary log until a final determination can be made.

ECDA Digs A, B and C

- No external corrosion was observed.
- The two largest indications (Digs A and B) located at C and D Valves were both uncoated and showed no signs of corrosion. This condition likely goes back to original construction.
- Dig C, which was in the vicinity of a spool piece installed in 1982 had coating holidays, along with disbondment located at the transition into original 1966 coatings. The total spool was exposed and had calcareous deposits and no evidence of corrosion.

Conclusions/Observations

- 27 Pipe Segments assessed (and 16 separate excavations)
- All corrosion found by GWUT was confirmed
- There were no negative false calls by GWUT, i.e. no corrosion was found by other inspections.
- The anomalies that were ≥ 5% Cross Sectional Area (CSA) were dug up, had their coating removed, and the subsequent pits were physically measured (both length and depth with an engineering ruler and a pit gauge).
- The pit dimensions were input into ASME B31G criteria at the test pressure for the class location. All the pits passed this criteria for failure at the test pressure for their respective class location.
- Additionally (and more conservatively), all the defects also met the ASME B31G criteria for a pressure (greater than the pressure test pressure) that would have resulted in a hoop stress equal to 100% SMYS (P=2St/D), i.e. they met (passed) the standard ASME B31G criteria. This also follows from the fact that the Class 1, 2, 3, and 4 Test Pressures (used in this case) were all below the pressure required to achieve 100% SMYS pipe wall stress.
- Include drip logs in work scope for reassessment

- Labor (excavation, sand blast, recoat, etc.)
  - Four Man Crew at 7 days = 28 man-days
- Inspection & Testing
  - GUL on site 5 days
  - NDT Lab personnel on site 5 days
- Pre-Assessments
  - 4 weeks –Engineering staff
- Overall the exercise is quite costly.

Guided Wave Performance Summary

Table 1. Guided Wave Performance Matrix

Dig Site	GWUT Anomalies	X-Ray Anomalies	PortaScan Anomalies	Direct Exam Findings	Comments
1 a	None	Not Done	Not Done	No Corrosion	
1 b	None	Not Done	Not Done	No Corrosion	
1 c	None	Not Done	Not Done	No Corrosion	
1 d	None	None	Not Done	No Corrosion	
2 a	None	None	Not Done	No Corrosion	
2 b	None	None	10% at 6 o'clock	No Corrosion	MPI showed no cracking
2 c	Not Done	Light	Not Done	No Corrosion	Dug up and found internal pitting
3 a	None	Not Done	Not Done	No Corrosion	GWUT Detected Solids Inside
3 b	None	Detected Internal Solids	Not Done	No Corrosion	GWUT Detected Solids Inside
4	None	Not Done	Not Done	No Corrosion	
12	None	Not Done	Not Done	No Corrosion	
5 a	None	None	Not Done	No Corrosion	
5 b	None	Not Done	Not Done	No Corrosion	
5 c	20-40% Wall Loss at 6 o'clock	Not Done	Not Done	26-35% Wall Loss at 6 o'clock	
6 a	None	None	Not Done	No Corrosion	
6 b	20-40% Wall Loss at 6 o'clock	Inconclusive	Not Done	26-35% Wall Loss at 6 o'clock	Deepest corrosion of case study 0.130"
7 b	None	None	Not Done	No Corrosion	
8	None	Report Pending	Not Done	No Corrosion	
9 a	None	None	Not Done	No Corrosion	Limited range due to proximity of fittings
9 b	None	None	Not Done	No Corrosion	Limited range due to proximity of fittings
9 c	None	None	Not Done	No Corrosion	Limited range due to proximity of fittings
10	None	None	Not Done	No Corrosion	
11	None	None	Not Done	No Corrosion	
13	None	None	Not Done	No Corrosion	
14	Not Done	Localized Corrosion at 6 o'clock	Localized Corrosion at 6 o'clock	No Corrosion	
15	Not Done	Sludge and Minor Localized Corrosion at 6 o'clock	Not Done	No Corrosion	Direct UT (thickness gauge) indicated 3% wall loss at 6 o'clock

Notes:
All corrosion found by GWUT was confirmed
No false calls no corrosion found by other inspections that was missed by GWUT

Results and Discussion - Bare Pipe Segment

Equitrans Bare Pipe Segment - Line H-152 Background Information

- 16” diameter bare steel pipe installed in 1952.
- Grade B line approximately 0.312 wall thick - MAOP 500 psig, typical operating pressure 300-350 psig.
- Buried in 3 - 5 feet of loamy soil, with some shale present.
- Rectified distributed anodes installed in late 1970's.
- Conducted CIS on/instant off/native and depolarized line with side drain readings.
- Collected soil resistivities.
- <u>Case Study Included:</u>

  > Broke up the 420 foot case study segment into five dig sites (0 East of Parking Lot (PL), and 1,2,3, and 4 all West of PL).

  > *Pipe-to-Soil Voltage Readings:*
  (a) 2003 CIS data (On and Instant Off)
  (b) 2006 CIS data (On and Instant Off) with Soil Resistivity
  (c) 2006 Native (depolarized) line with *side-drain (cell-to-cell)* readings, i.e. hot-spot surveys in the native condition to look for anodic areas.

  > Used *Guided Wave* to asses pipe (Guided Ultrasonics, Ltd. G-3 Unit):
  (a) Torsional Waves at standard and low frequencies
  (b) Longitudinal Waves at standard and low frequencies
  (c) Traditional single-ring pulse-echo
  (d) Two-ring (same bell hole) pitch-catch
  (e) Two-ring (adjacent bell holes) transmission pitch-catch.

  > *Magnetic Tomography* Evaluation (Transkor-USA, Inc.)

  > Validated findings with *100% visual direct examinations* with *sand blasting*, *UT spot checks*, and Weld *Radiography*.

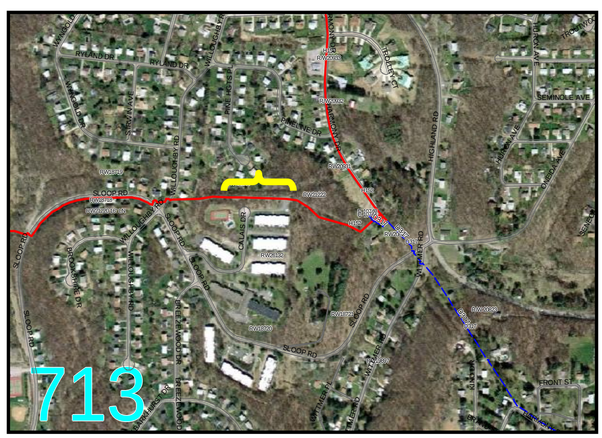


Figure 93. **Pittsburg Greater Area.** **Sat. image of 420ft segment (yellow).**

gti

General Description/Overview

- Broke up the 420 foot case study segment into five dig sites (0 east of PL, and 1,2,3, and 4 all west of PL).

Schematic of Line H-152 test segment (with Dig and Inspection Sites #0 to #4)

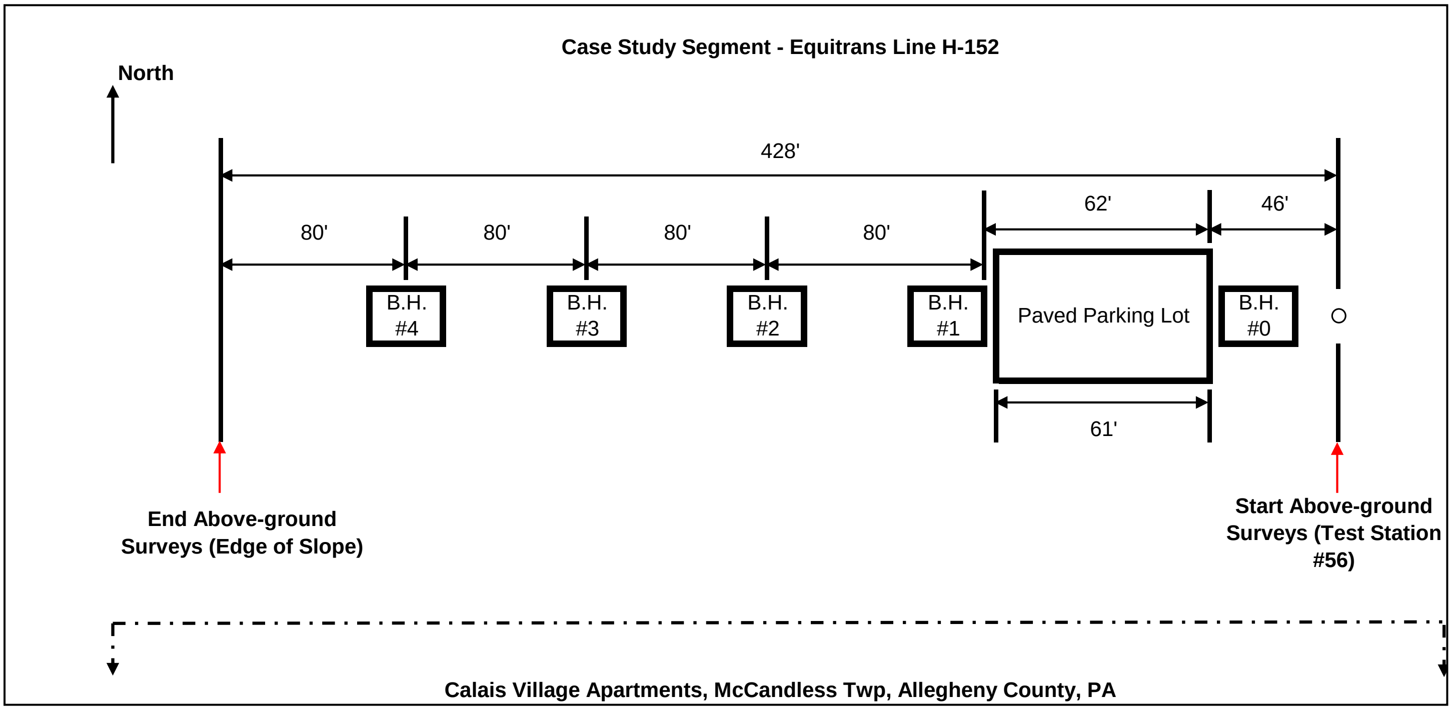


Figure 94**. Schematic of Line H-152 test segment.**

Site Background

- Bare Pipe segments were believed to be difficult to assess due to the reduced number of assessment tools that can be used. Since there is no coating, one cannot use tools that rely on detecting coating holidays, e.g., Pipeline Current Mapper (PCM), A-Frame Voltage Gradient (ACVG), and Direct Current Voltage Gradient (DCVG) instruments.

ECDA Pre-Assessment

- Drawings along with other records were assembled and reviewed for content and pertinence.
- 2003 CIS readings (on/instant off) indicated no abnormal conditions, see two figures directly below - 2006 soil resistivity data and pipe depth readings (plotted on 2003 CIS figures).

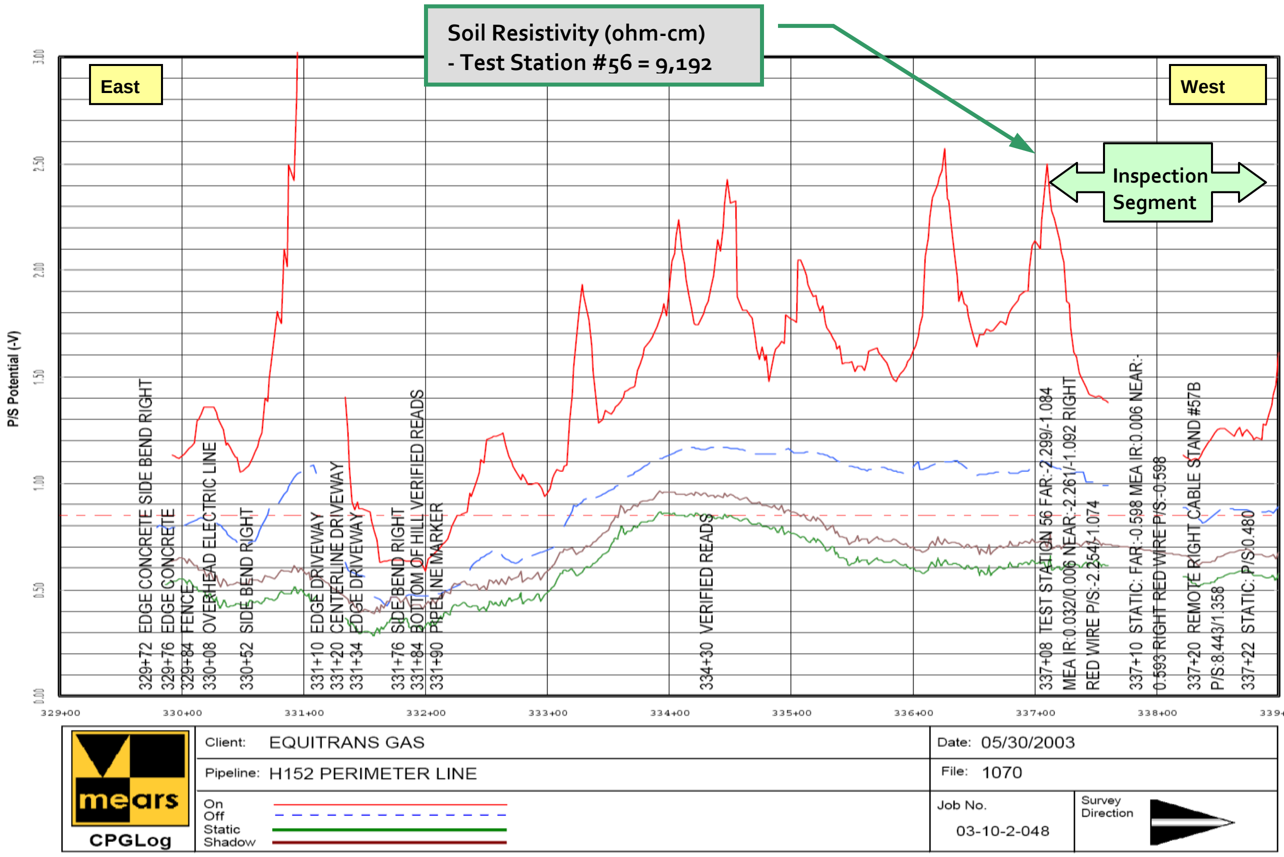


Figure 95. **ECDA Pre-Assessment Plot 1.**

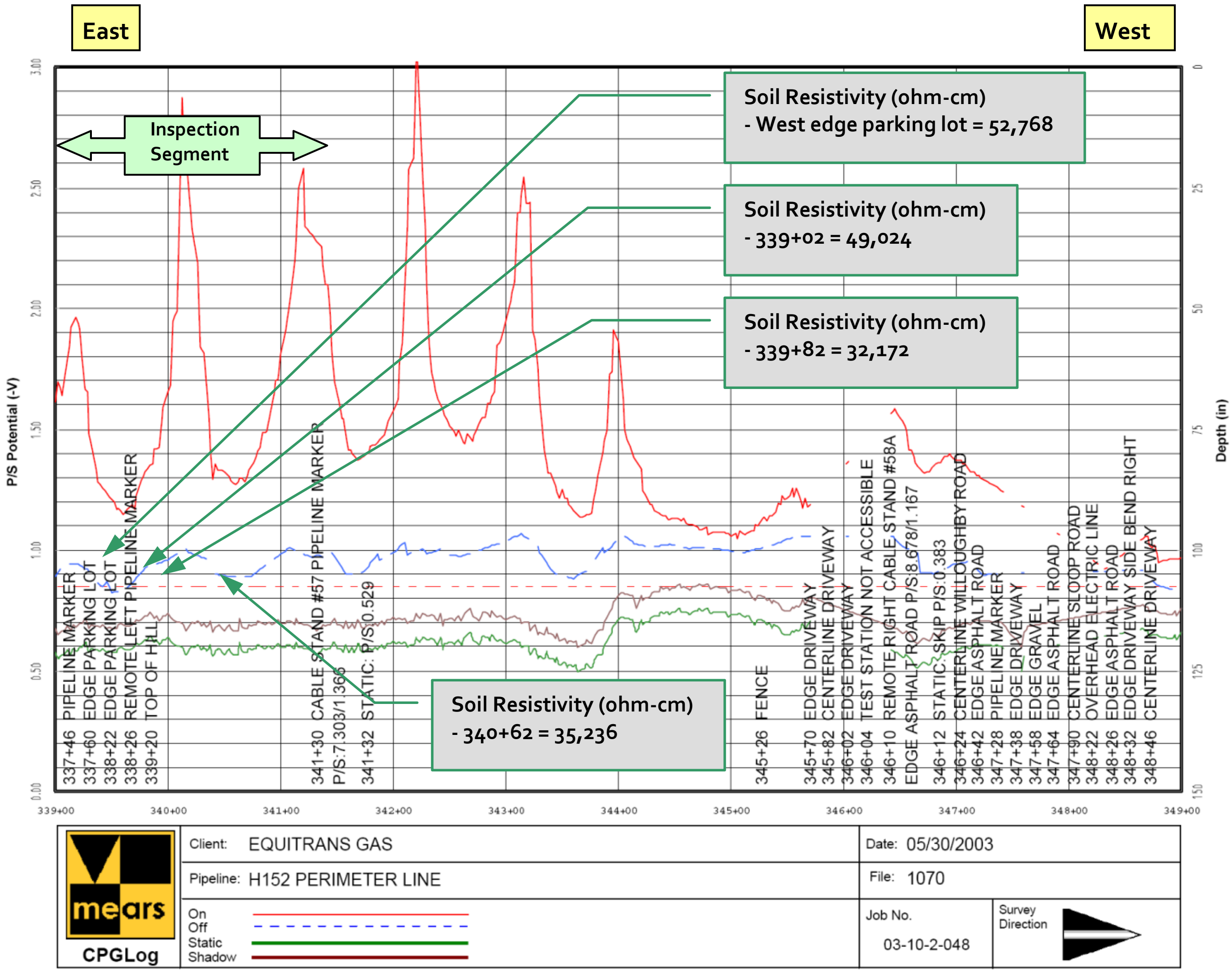


Figure 96. ECDA Pre-Assessment Plot #2.

ECDA Indirect Inspection

- In 2006 Equitrans performed (plots are below):
  - > CIS on/instant off potential surveys
  - > Depolarized (native) potential surveys (w/time)
  - > Side drain ("hot spot") potential surveys after the line was at the native potential.

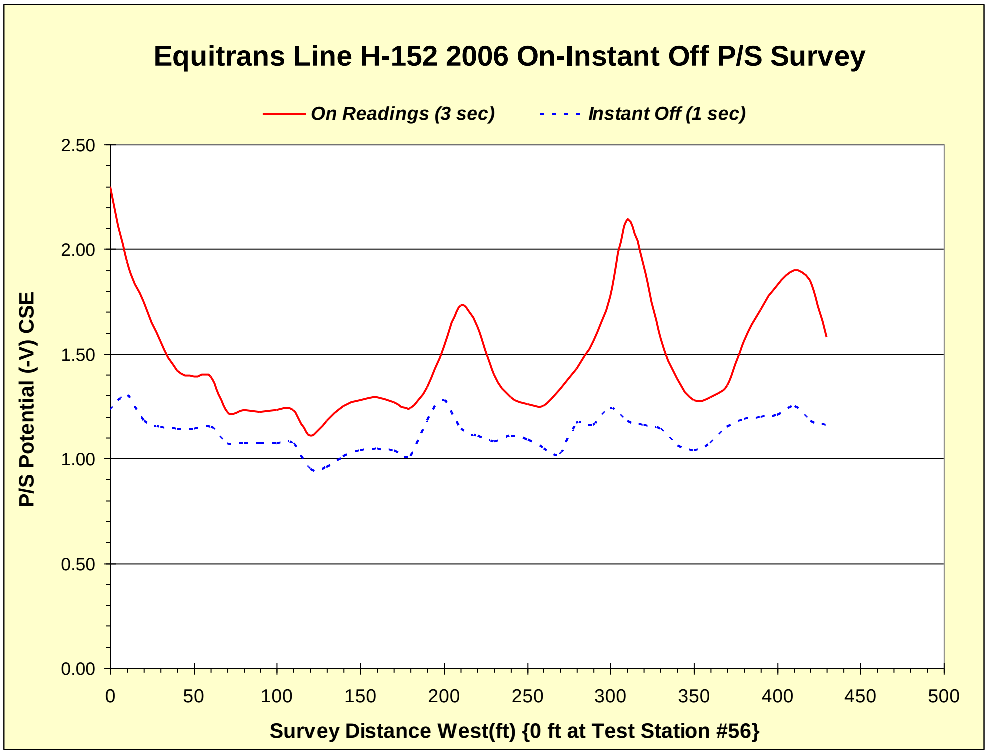
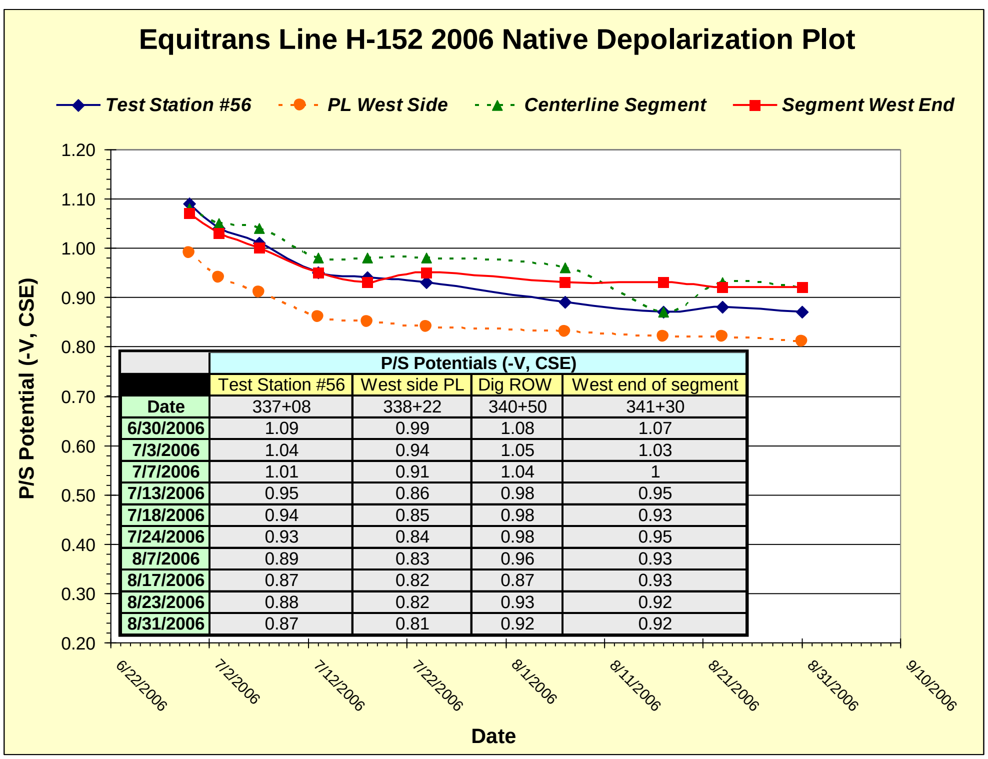
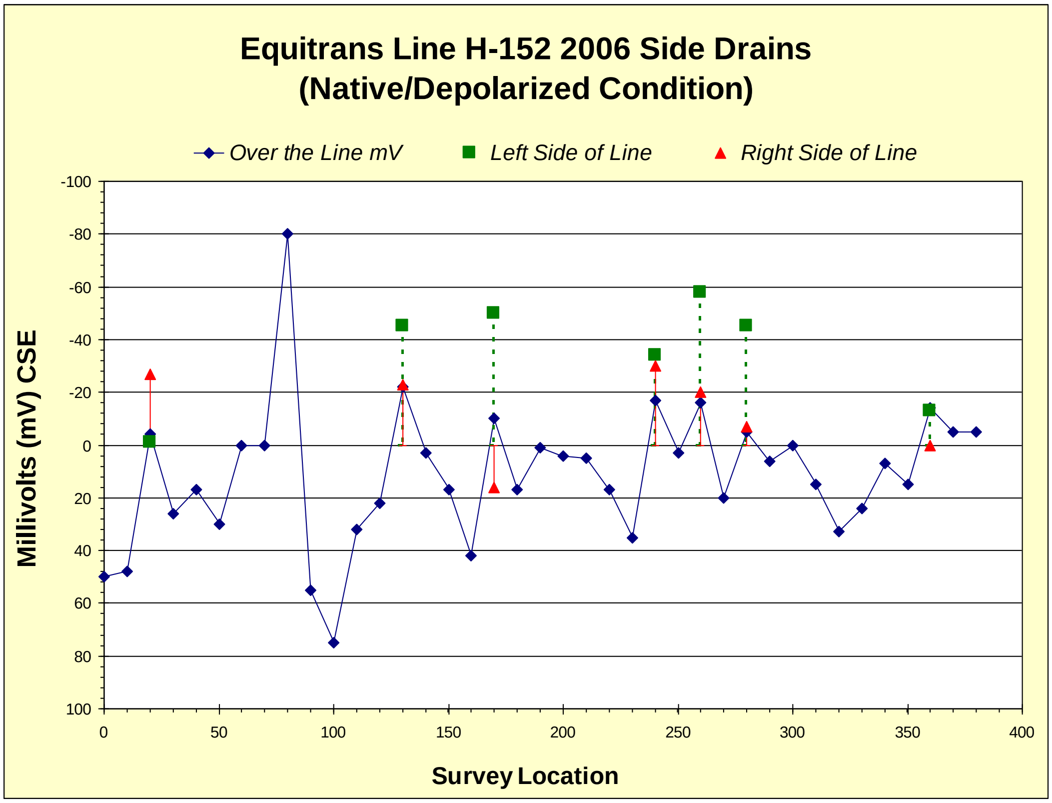


Figure 97**. On-Instant Off P/S Survey.**



	P/S Potentials (-V, CSE)			
	Test Station #56	West side PL	Dig ROW	West end of segment
Date	337+08	338+22	340+50	341+30
6/30/2006	1.09	0.99	1.08	1.07
7/3/2006	1.04	0.94	1.05	1.03
7/7/2006	1.01	0.91	1.04	1
7/13/2006	0.95	0.86	0.98	0.95
7/18/2006	0.94	0.85	0.98	0.93
7/24/2006	0.93	0.84	0.98	0.95
8/7/2006	0.89	0.83	0.96	0.93
8/17/2006	0.87	0.82	0.87	0.93
8/23/2006	0.88	0.82	0.93	0.92
8/31/2006	0.87	0.81	0.92	0.92

Figure 98**. Native Depolarization Plot.**



Notes:

- Side drain readings are recorded when the over-the-line survey switches from positive to negative readings (with the "common/black" electrode trailing in the direction of survey).
- An area is considered anodic (i.e., a hot spot that is potentially corroding) when in the native condition, both the readings on the left and the right are positive with respect to the over-the-line location (the site of the common/black electrode).

Figure 99. Side Drains (Native/Depolarized Condition).

Results of Indirect Inspections

- CIS P/S were all above 850mV criteria and showed no abnormalities.
- Depolarized side-drain readings showed no "hot spots" (anodic areas).
- Soil resistivity was typically ~ 40,000 ohm-cm through the 420 foot segment.
- Pipe cover was ~ 3-5 ft of loamy soil.

Direct Exam Dig Schedule

- All 420 feet of pipe was excavated, cut into sections, and transported to a pipe yard where they were cleaned, followed by 100% visual exam and UT spot checks.

Operator:	Equitrans
Case Study:	Line H-152 Sept. 2006
Dig Site:	**#0 - Down slope (~20 degree angle) directly East of paved parking lot**

Dig Site: #0

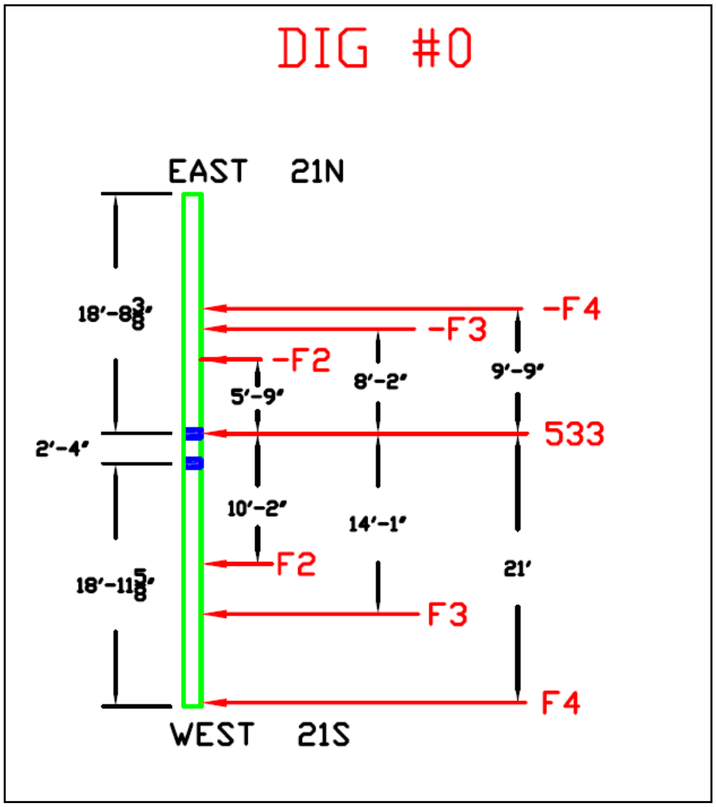


Figure 100**. Equitrans Drawing of Dig Site #0.**

Dig Site #0 overview.

Guided Wave Results

At this location (just to the west to pipe marker 56 at position 337+08), the pipe was inclined at about a 20 degree angle (West side higher). There was little evidence of corrosion product (probably due to the angle and the well drained soil), however the mineral deposits were present as they were in the other locations. Approximately 15 feet was inspected on each side of the pit. No areas of concern were identified.

Test ID: G308#3354	Result: OK
Pipe: H152	Ring: R2B16(533)
Site: GTI	Config: 11.0FR, T(0,1)
Location: BellHole0	Calibration: Automatic (234.645 mV)
Size: 16 inch	Version: 3.92, Wavemaker G308
Tested: 6 Sept 2006 16:36	Client: GTI
Tested by: Brian Pavlakovic[GUL]	Procedure: GU 2.0

General Notes: Please also see notes with the unrolled pipe display.

Feature	Location	Length	Class	Notes
+F1	4'4"	~	Earth	
+F2	10'2"	0	Weld	Likely weld showing some non-symmetry
+F3	14'1"	3	Cat 3	
+F4	21'0"	0	Weld	
-F1	-3'0"	~	Earth	End of the pit towards test station 56
-F2	-5'9"	0.75	Cat 3	Concentrated indication of corrosion (or possibly cad weld for CP protection)
-F3	-8'2"	0	Weld	(Assumed)
-F4	-9'9"	1	Cat 3	Or area of thicker deposits

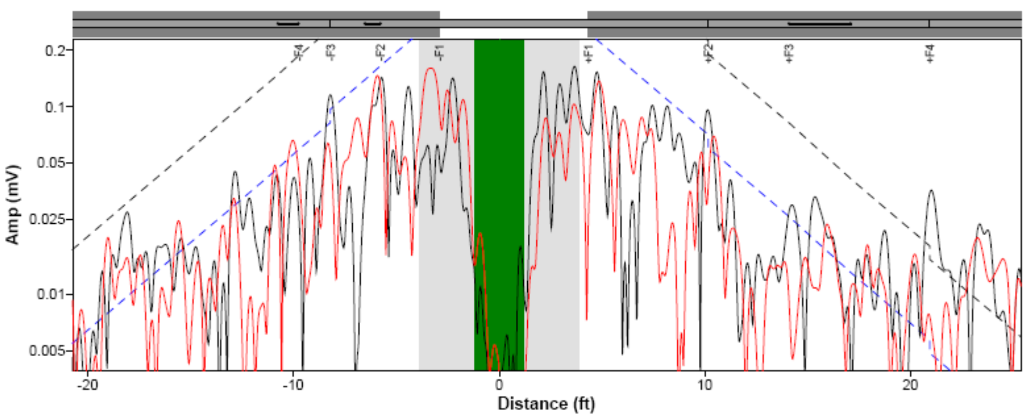


Figure 101**. Pulse-Echo Torsional Scan (high frequency) of Dig Site #0.**

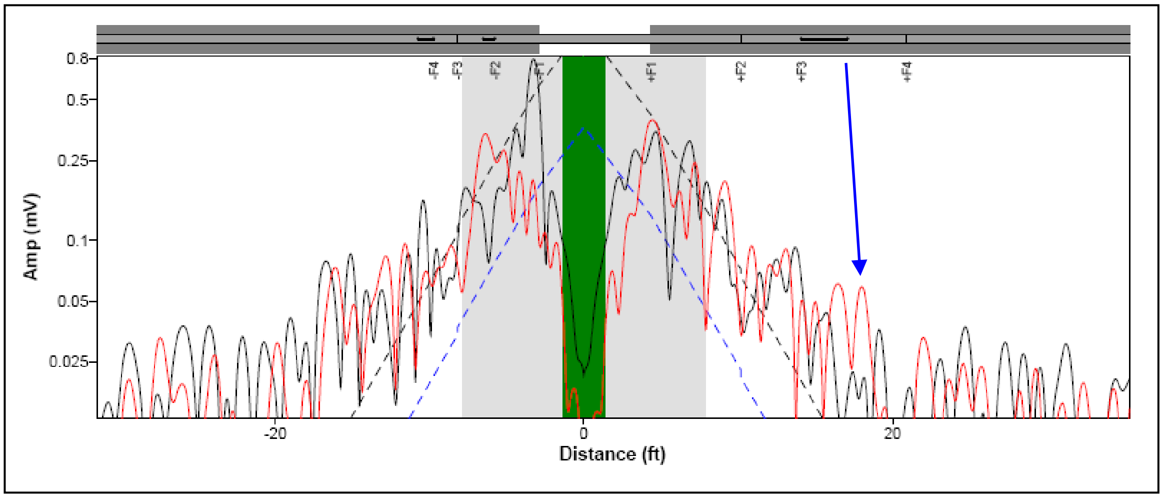


Figure 102**. Pulse-Echo Torsional Scan (low frequency) of Dig Site #0.**

The results at a lower frequency regime are similar, but are more affected by the reflections from the contact with the surrounding earth:

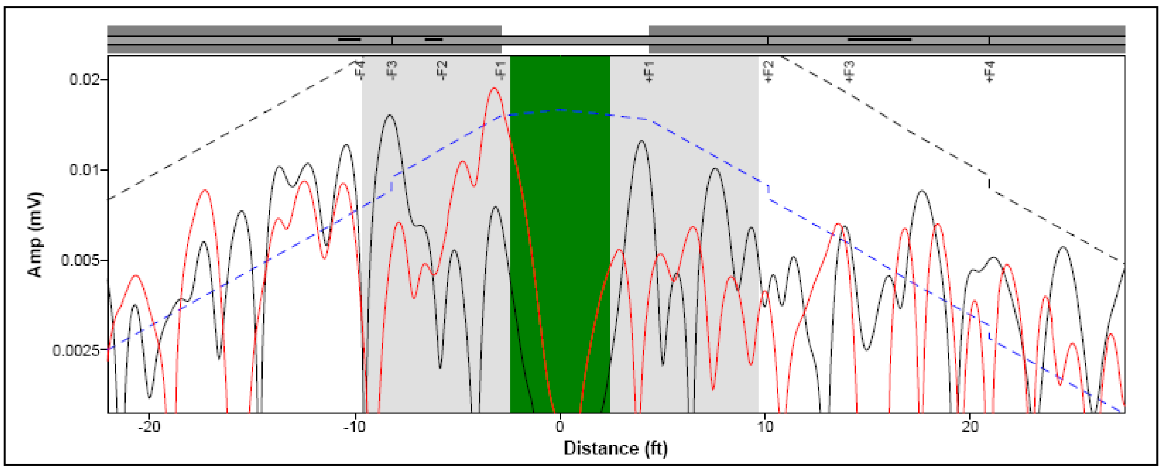


Figure 103**. Pulse-Echo Longitudinal Scan (low frequency) of Dig Site #0.**

The longitudinal mode results do not add much more information:

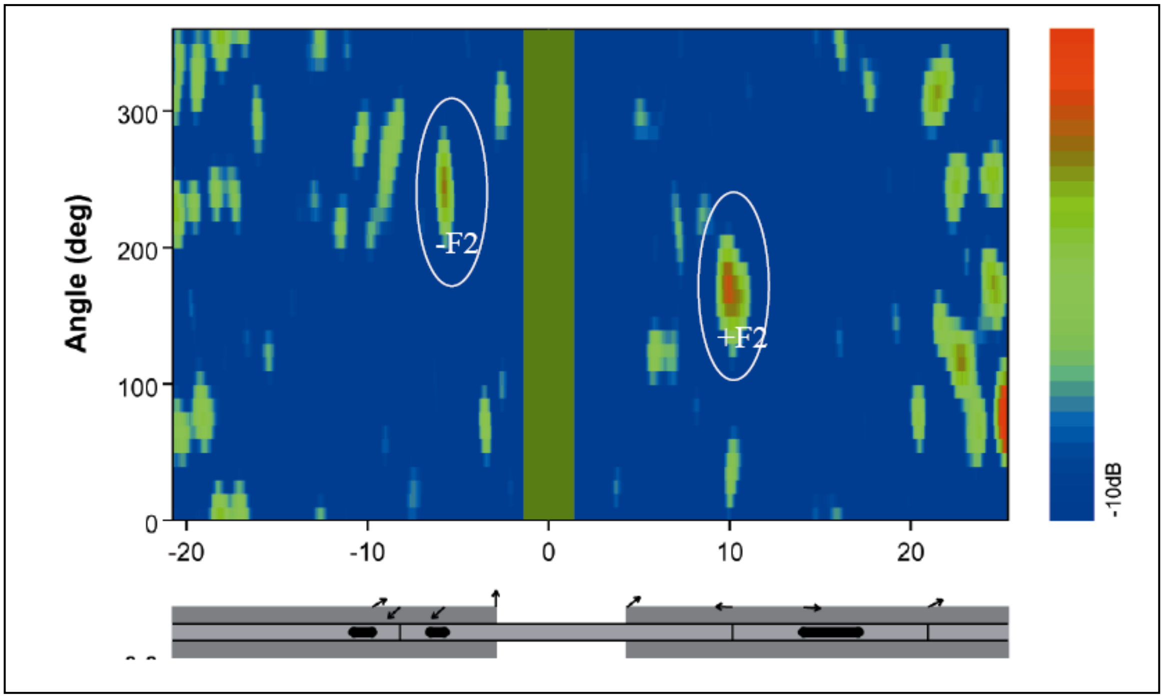


Figure 104**. Pulse-Echo C- Scan of Dig Site #0.**

The unrolled pipe display (C-Scan) shown in the figure above, highlights some areas of interest that were confirmed by radiographic inspection of the 1952 welds were considered to be sub-quality by today's (modern) standards. The following defects were reported (inadequate penetration, burn through, slag inclusions and lines, external undercut, porosity, gas pockets, and concave crowns). These areas, which show a more concentrated cross section change include:

- (-F2) The area 5 ft to the east of the ring, on the north side (about 250 degrees) was below call out level and due to mineral deposits, no corrosion was found during direct exam.
- (-F3) Assumed weld was confirmed upon excavation.
- (-F4) Assumed feature due to deposit (not corrosion) confirmed.

Figure 105**. Dig site #0: -F4, -F3, & -F2 locations.**

- (+F2) The marked weld 10 feet to the west of the ring, which shows a stronger reflection from the bottom of the pipe than the top.
- (+F3) Called out as a Cat 3 feature, confirmed as 1" long, 80 mil deep pit cluster 17" west of the +F3 start position. Feature on pipe lines up with maximum ECL peak with lack of symmetry.

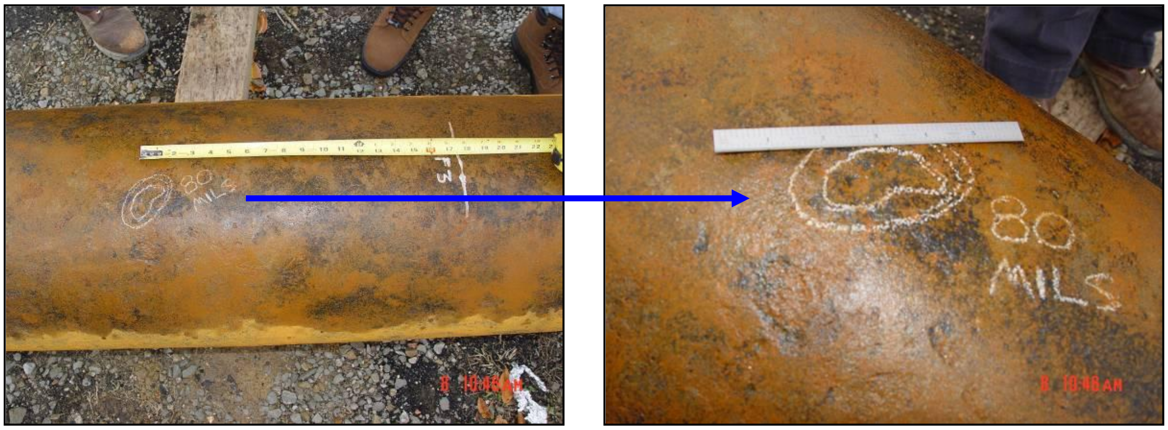


Figure 106. Pictures of feature (80 mil deep pit cluster, 1 inch long) that lined up with the maximum non-symmetric second peak for +F3.

Dig Site: #1

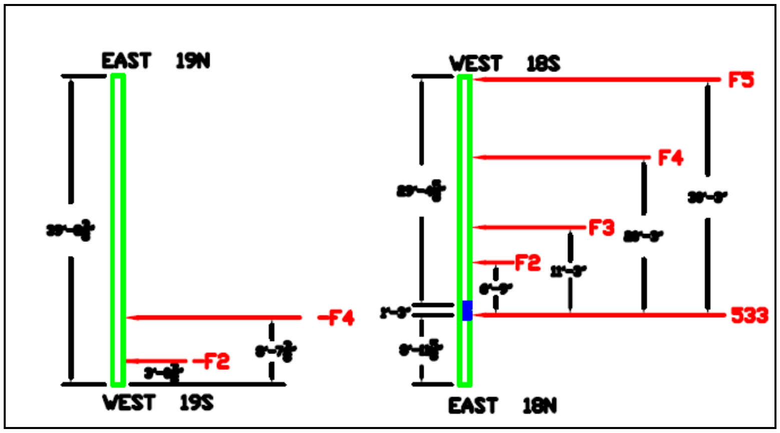


Figure 107**. Equitrans Drawing of Dig Site #1.**

Figure 108**. Dig Site #1 - just west of the paved parking lot.**

Guided Wave Results

This bell hole was located just to the West of the West edge of the paved area (the zero reference point at line position 338+22). Several areas of minor concern were identified, but no areas of major concern.

Test ID:	G308#3298	Result:	Minor concern
Pipe:	H152	Ring:	R2B16(533)
Site:	GTI	Config:	9.6FR, T(0,1)
Location:	BellHole1	Calibration:	Automatic (289.589 mV)
Size:	16 inch	Version:	3.92, Wavemaker G308
Tested:	6 Sept 2006 12:39	Client:	GTI
Tested by:	Brian Pavlakovic[GUL]	Procedure:	GU 2.0

General Notes:

Feature	Location	Length	Class	Notes
-F1	-5'4"	~	Earth	
-F3	-12'2"	~	Entrance	
-F2	-12'0"	1.5	Cat 3	
-F4 -F5	-17'7"	0	Weld	Mitred weld under the paved area with minor corrosion before it (on the bottom of the pipe)
+F1	4'0"	~	Earth	
+F2	6'9"	1.5	Cat 2	Strong concentrated reflection from the bottom of the pipe (and slightly South)
+F3	11'3"	1.5	Cat 1	Smaller reflection (possibly deposits?) on the South bottom side of the pipe.
+F4	20'3"	0.75	Cat 2	Signal to noise is degraded at this point so reliability beyond here is low.
+F5	30'3"	5	Cat 2	
+F6	31'0"	0	Weld	To the west of the ring (Towards BH 2)

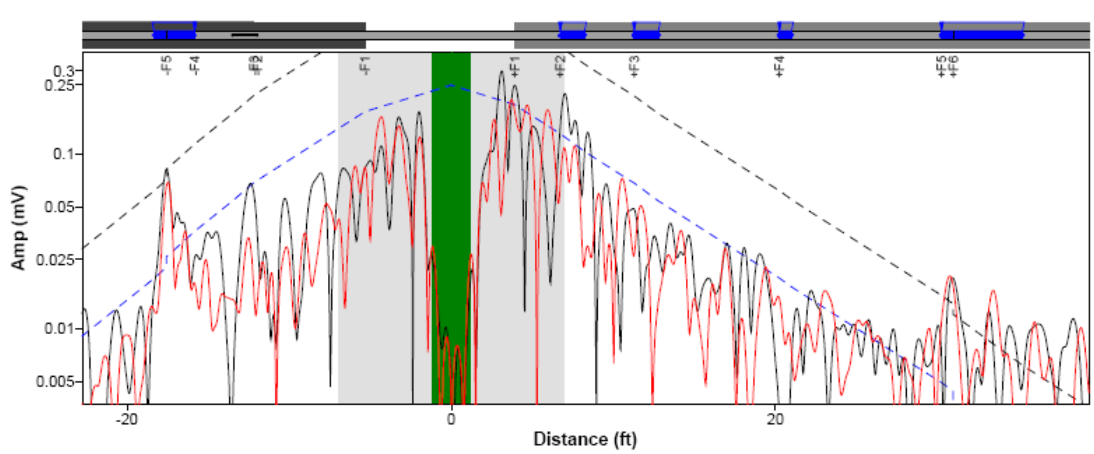


Figure 109**. Pulse-Echo Torsional Scan of Dig Site #1.**

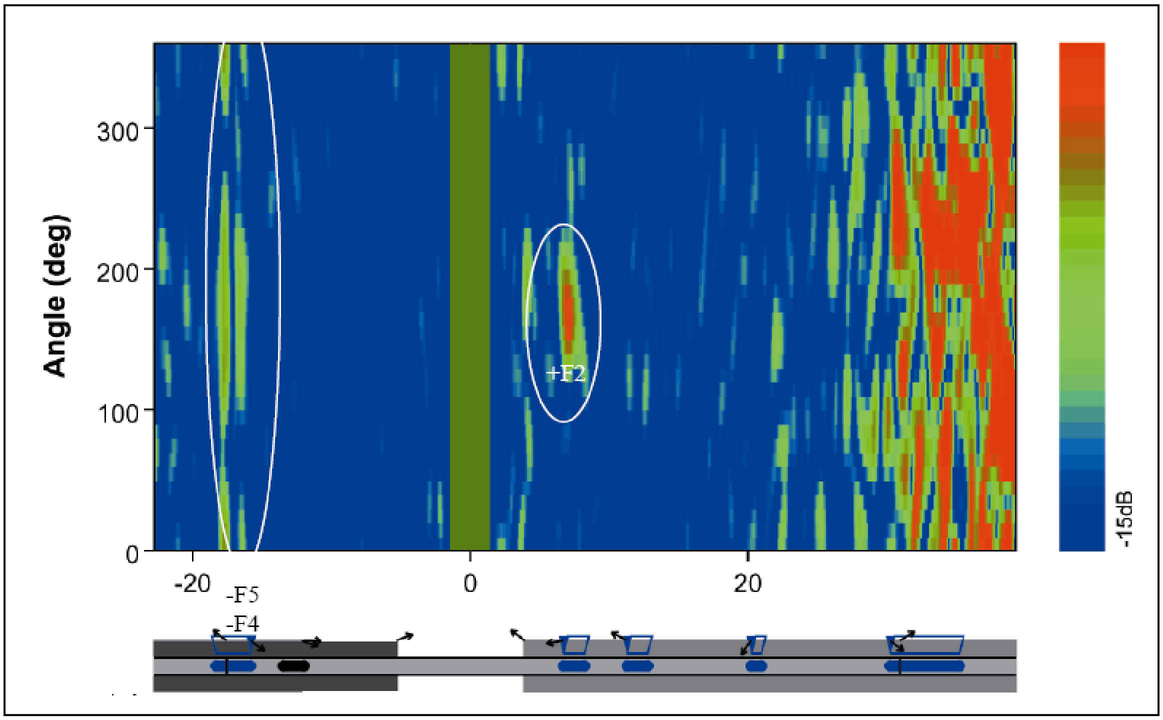


Figure 110**. Pulse-Echo C- Scan of Dig Site #1.**

- (+F2) Cat 2 strong reflection along bottom of pipe was confirmed as leafing corrosion along the bottom of pipe that extended into the earth to the West (all along the 6 o'clock position), see picture below.

Figure 111**. Dig site #1: Location just East of +F2, corrosion continued to the West as the earth was dug back.**

- (+F3) Cat 1 possible deposits. No corrosion was found only deposits.

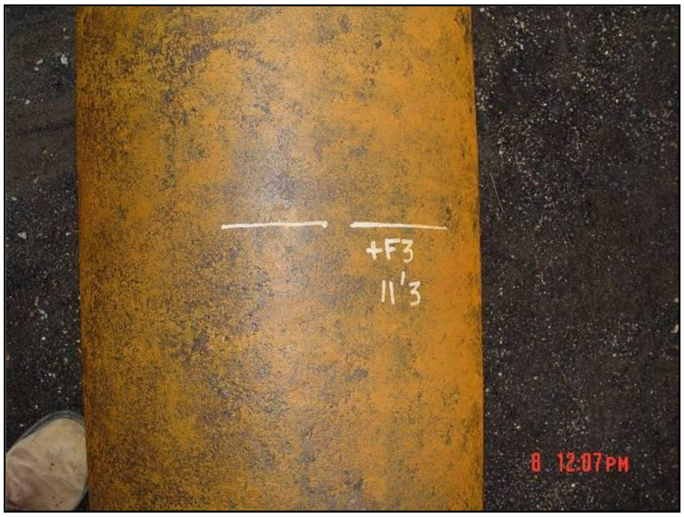


Figure 112**. Picture of pipe at location of +F3 - no corrosion was found only deposits before cleaning.**

- (+F5) Cat 2 feature just West of weld (+F6) corresponded to large area of 40-50 mil deep pitting along bottom the pipe, see pictures below. This area corresponds to the red features in the C-Scan.

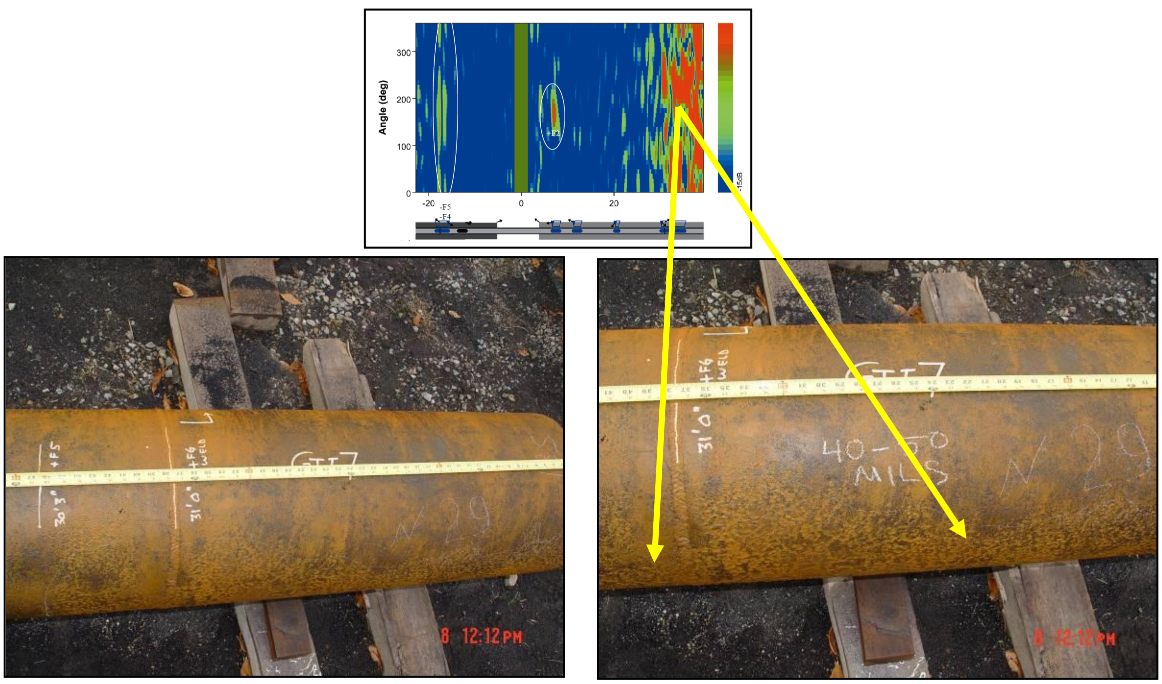


Figure 113**. Picture of (+F5) Cat 2 feature just West of weld (+F6) corresponded to large area of 40-50 mil deep pitting along bottom the pipe, see pictures below. This area corresponds to the red features in the C-Scan.**

- (-F4 & -F5) Called out as a weld with possible mitre bend/joint. Confirmed as marginal weld with the following defects (inadequate penetration, burn through, slag inclusions and lines, external undercut, porosity, gas pockets, and concave crowns).

Figure 114. Picture of -F4/-F5 showing weld confirmed by radiography to have multiple defects.

- (-F2) Called out as Cat 3, no defects were noted on visual exam, possible mineral deposits contributed to the minor reflection.

Operator: Equitrans
Case Study: Line H-152 Sept. 2006
Dig Site: **#2**

Dig Site: #2

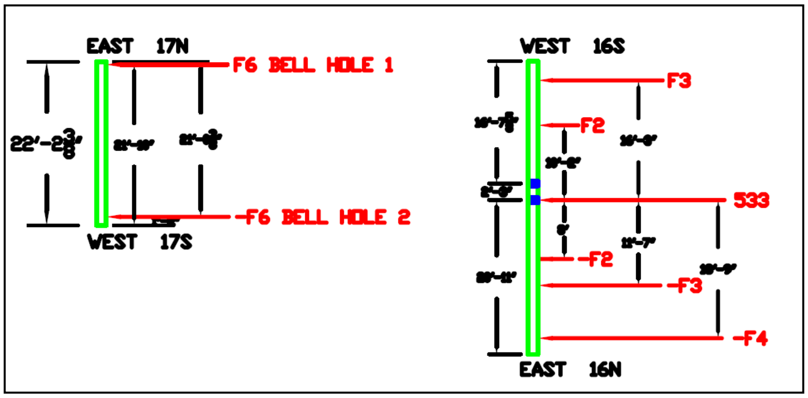


Figure 115**. Equitrans Dig Site #2 Drawing and Photo.**

Guided Wave Results

This bell holes was placed approximately 80 feet to the west of the bell hole 1. Upon observing the highly asymmetric echo at - 8 feet, that section of covering was removed revealing a weld that showed no outward signs of asymmetry. This weld raises major concerns and it is recommended that it is investigated in detail. A few other areas of interest have been marked. Approximately 25 feet has been inspected on either side of the ring with low confidence.

Test ID:	G308#3335	Result:	Concern
Pipe:	H152	Ring:	R2B16(533)-Circum-35mm
Site:	GTI	Config:	9.4FR, T(0,1)
Location:	BellHole2	Calibration:	Automatic (305.742 mV)
Size:	16 inch	Version:	3.92, Wavemaker G308
Tested:	6 Sept 2006 15:07	Client:	GTI
Tested by:	Brian Pavlakovic[GUL]	Procedure:	GU 2.0

General Notes:

Feature	Location	Length	Class	Notes
+F1	6'3"	~	Earth	
+F2	10'2"	0.5	Cat 3	Minor – bottom south
+F3	16'3"	2	Cat 3	Minor – variety of distributions around circumference, which could indicate that they were due to deposits.
-F1	-7'8"	~	Earth	
-F2	-8'0"	0	Weld	Highly suspicious weld (Suspect major flaw on South side of pipe – apparent lack of cross section change at the 90 degree position)
-F3	-11'7"	1	Cat 2	
-F4 -F5	-18'9"	0	Weld	Another suspicious weld
-F6	-22'1"	0.75	Cat 1	This is either an isolated area of increased wall loss or (more likely) the attachment point for an asymmetric feature (such as a CP point) – Located on the top north side of the pipe.

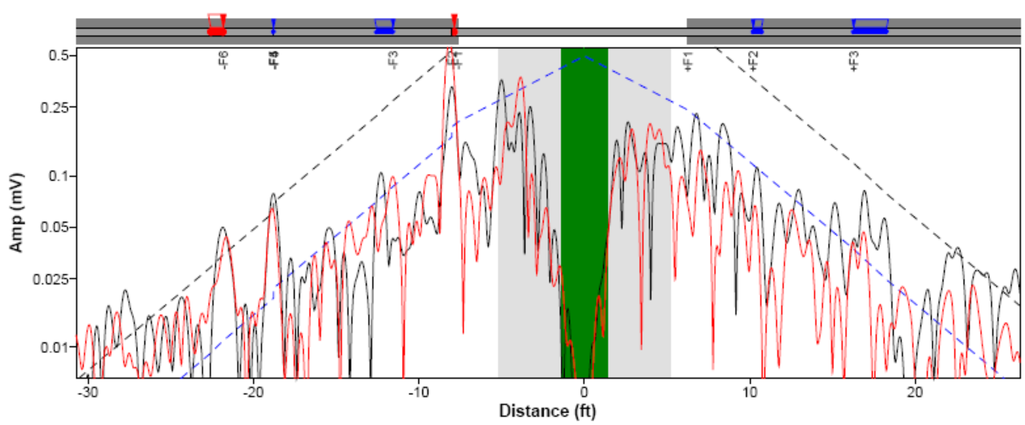


Figure 116**. Pulse-echo Torsional Scan of Dig Site #2.**

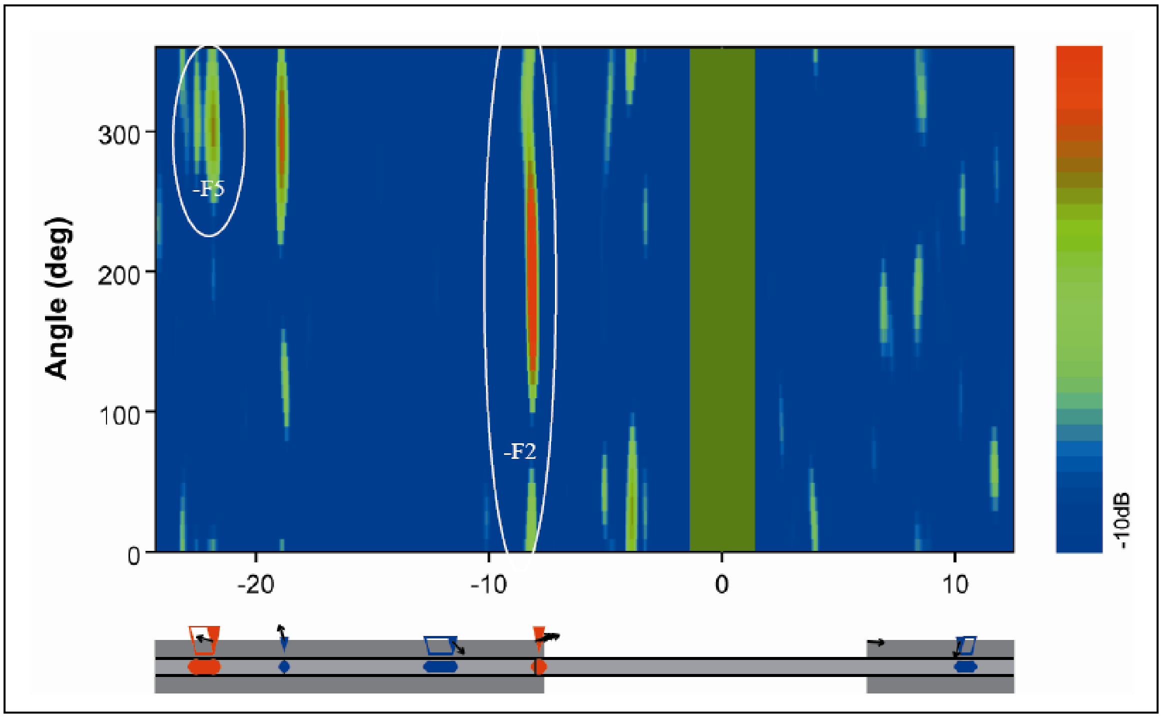


Figure 117**. The unwrapped pipe result of G308#3335 (from bell hole 2), showing the circumferential concentration of the feature at -22 feet (-F5) and the 'missing' part of the reflection from the suspicious weld at -8 fee t (-F2).**

- (+F2) & (+F3) were called out as minor Cat 3 indications. This entire pipe joint had minor pitting (~20 mils) over most of the surface.
- (-F2) & (-F4) welds were called out as highly suspicious and were confirmed as marginal welds with the following defects (inadequate penetration, burn through, slag inclusions and lines, external undercut, porosity, gas pockets, and concave crowns).
- (-F3) & (-F6) Were called out as Cat 2 and Cat 1 features respectively. Both areas had no significant corrosion and were probably due to the mineral deposits.

Figure 118**. Dig site #2 showing location -F6.**

Dig Site: #3

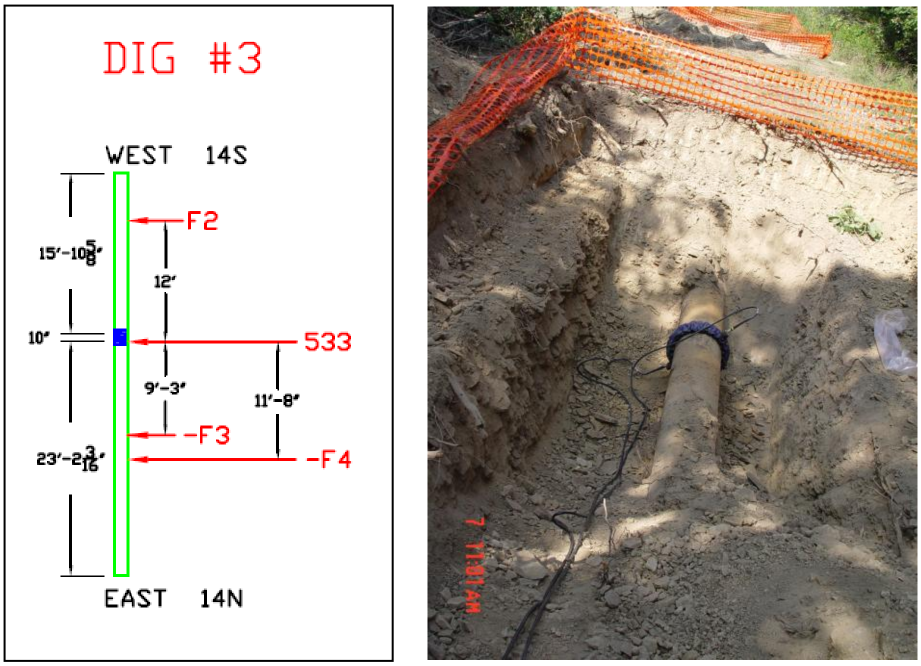


Figure 119**. Equitrans Drawing of Dig Site #3 and picture of site.**

<u>Guided Wave Results</u>

The results from bell hole 3 (approximately 80 feet to the west of bell hole 2) are unremarkable. No areas of major concern were identified. Approximately 15 feet was inspected on either side of the bell hole with low confidence.

Test ID:	G308#3341	Result:	OK
Pipe:	H152	Ring:	R2B16(533)
Site:	GTI	Config:	9.8FR, T(0,1)
Location:	BellHole3	Calibration:	Automatic (150.367 mV)
Size:	16 inch	Version:	3.92, Wavemaker G308
Tested:	6 Sept 2006 15:32	Client:	GTI
Tested by:	Brian Pavlakovic[GUL]	Procedure:	GU 2.0

General Notes:

Feature	Location	Length	Class	Notes
+F1	4'0"	~	Earth	
+F2	12'0"	0	Cat 2	Concentrated reflection on the bottom north side of the pipe.
-F1	-3'1"	~	Earth	Initial contact of earth with bottom of pipe
-F2	-6'1"	~	Earth	Entrance of full pipe into the earth
-F3	-9'3"	0	Weld	
-F4	-11'8"	1.5	Cat 2	Area of reflections of no particular circumferential orientation – could be caused by noise of deposits.

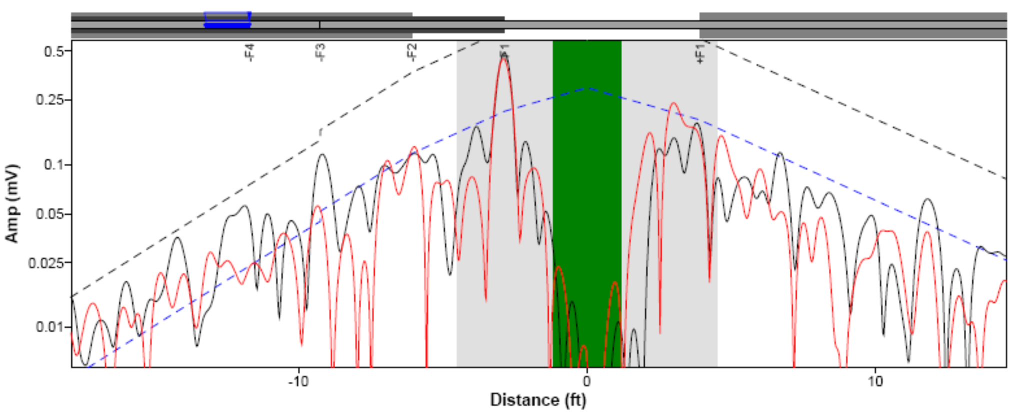


Figure 120**. Dig Site #3: Pulse-Echo Torsional Scan.**

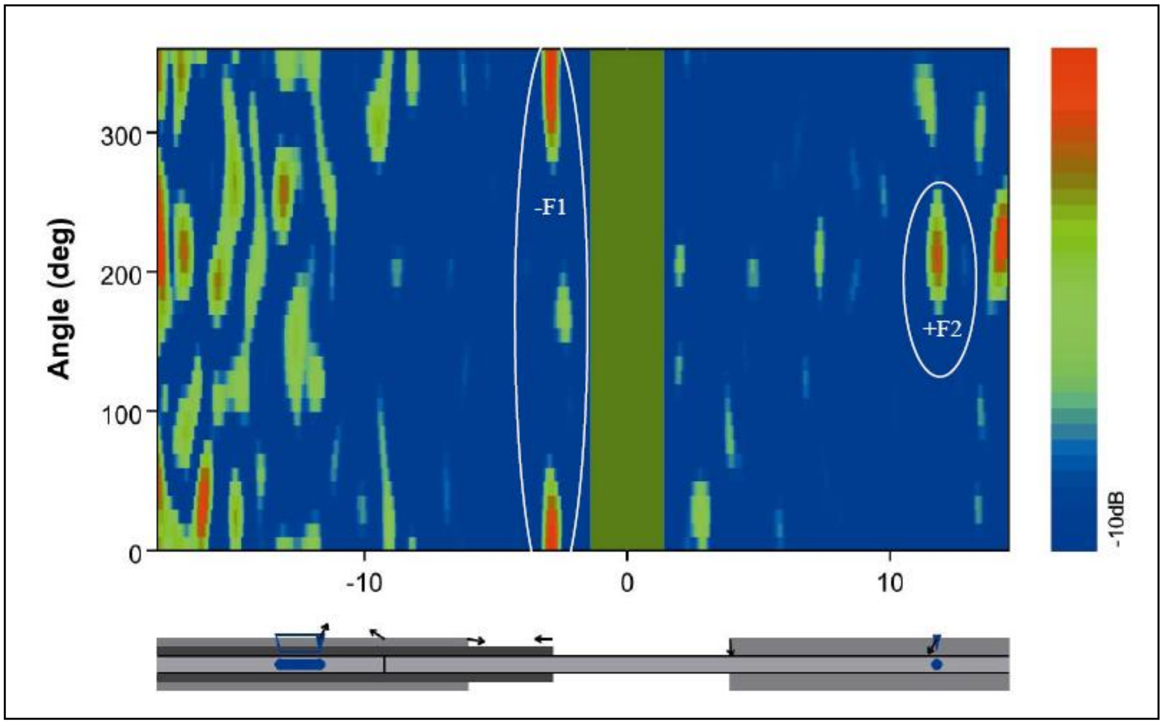


Figure 121**. The unrolled pipe display shows that the ground entrance consists primarily of reflections from the top and the bottom of the pipe, which matches the actual geometry. The concentrated nature of the reflection at +12 feet shows up more clearly in this display than in the traditional A-scan display.**

Figure 122**. Dig Site #3: typical pipe condition showing a weld.**

Operator:	Equitrans
Case Study:	Line H-152 Sept. 2006
Dig Site:	**#4**

Dig Site: ***#4***

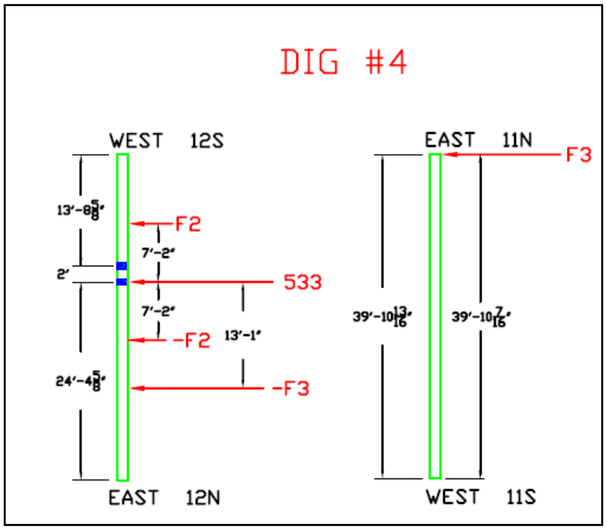


Figure 123**. Equitrans Drawing of Dig Site #4. Picture of Dig Site #4.**

Figure 124**. Shale around pipe at dig site #4.**

Guided Wave Results

The results from bell hole 4 (on the west end of the inspected region) indicate several areas of symmetric contact, but no areas of major concern. The inspection range was approximately 15 feet in either direction with low confidence in the results.

Test ID:	G308#3353	Result:	OK
Pipe:	H152	Ring:	R2B16(533)
Site:	GTI	Config:	10.0FR, T(0,1)
Location:	BellHole4	Calibration:	Automatic (137.566 mV)
Size:	16 inch	Version:	3.92, Wavemaker G308
Tested:	6 Sept 2006 16:24	Client:	GTI
Tested by:	Brian Pavlakovic[GUL]	Procedure:	GU 2.0

General Notes:

Feature	Location	Length	Class	Notes
+F1	4'8"	~	Earth	
+F2	7'2"	0	Weld	Strong weld reflection showing some non-symmetry.
+F3	15'9"	0	Weld	Weak weld reflection – low confidence in call
-F1	-5'4"	~	Earth	
-F2	-7'2"	0	Unknown	Believed to be an artifact of the contact between the pipe and the surrounding earth.
-F3	-13'1"	0	Unknown	

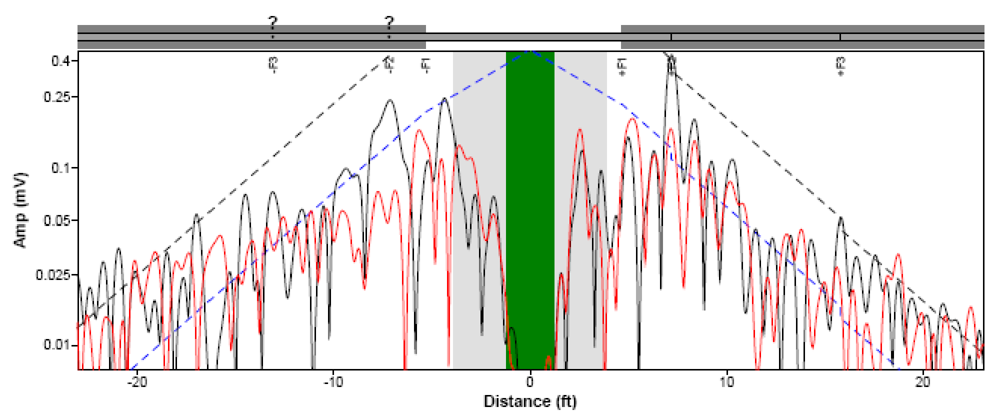


Figure 125**. Dig Site #4: Pulse-Echo Torsional Scan.**

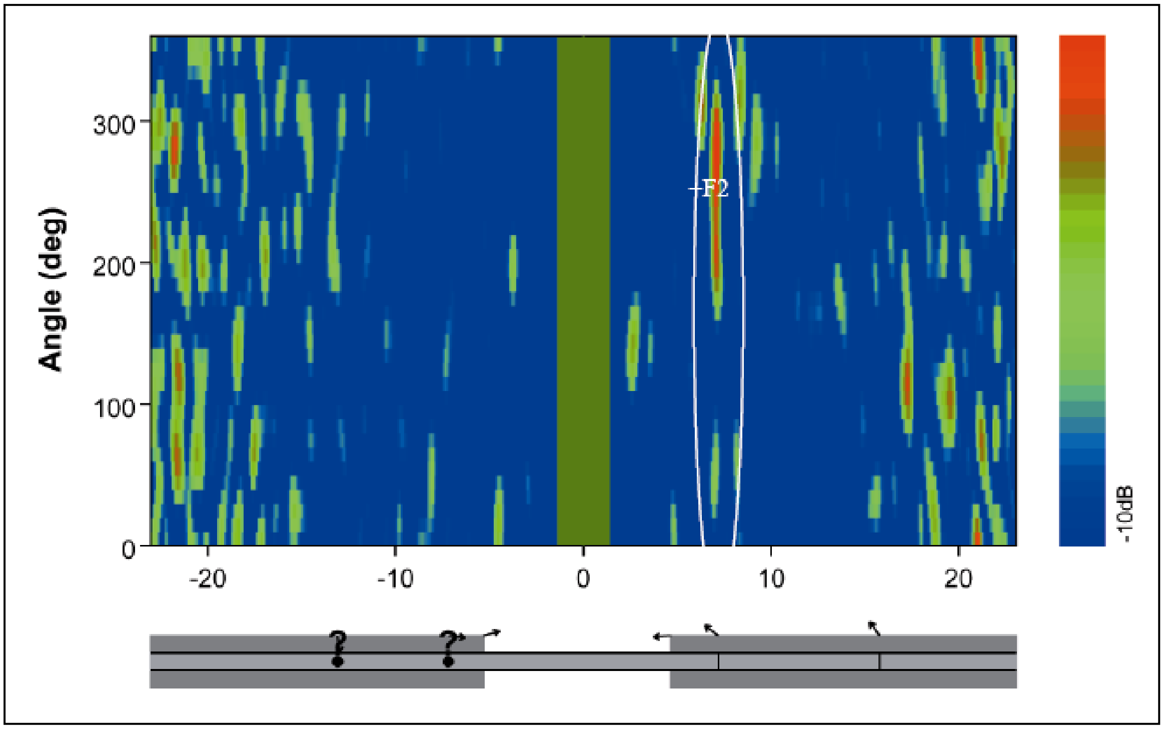


Figure 126**. Unrolled pipe display for the Bell Hole 4 (Test G308#3353). +F2.**

Figure 127**. Dig Site #4: typical pipe condition showing a weld.**

Guided Wave Performance Summary

Guided Wave Performance Summary						
Line	**Dig Site**	**GWUT Anomalies**	**Non-contact Magnetometric Inspection Transcor-USA**	**CIS & Side Drain Anomalies**	**Direct Exam Findings**	**Comments**
line H-152	0	Pitch Catch no call outs +F3 possible Cat 3 -F2 possible corrosion -F3 assumed a weld -F4 possible deposits Pulse-Echo - no calls C Scan plot indicated some welds of concern Pulse Echo Torsional - no calls	no significant corrosion was detected throughout the survey length	all above -0.850mV no side drainhot spots soil resistivity ~40kΩ	Confirmed GWUT +F3 was a pit cluster 0.080" deep about 1 inch long -F2 was a deposit -F3 confirmed weld -F4 was a deposit	Little evidence of corrosion in the 30 foot excavation, well drained soils with mineral deposits present Approximately 15 ft either side was inspected
	1	NA	highest risk location turned out to be insignificant	all above -0.850mV no side drainhot spots soil resistivity ~40kΩ	-F2 was a deposit no corrosision -F4 & -F5 miter joint with poor visual appearance no corrosion +F2 was exfoliant corrosion along 6 o'clock +F3 deposit no corrosion +F5 light pitting area 0.040" to 0.050" deep	Little evidence of corrosion Approximately 25 ft either side was inspected
	2	+F2 Cat 3 minor on bottom +F3 Cat 3 possible deposits -F2 weld of concern -F4 weld of concern -F6 possible attachment	reported all segments for this case study to be "acceptable or good" pipe, i.e. they did not recommend immediate investigation	all above -0.850mV no side drainhot spots soil resistivity ~40kΩ	+F2 & F3 were minor pitting 0.020" over most of the surface -F2 & -F4 were welds with poor visual appearences -F3 & -F6 were deposits no corrosion	Upon observing the highly asymmetric echo at - 8 feet, that section of covering was removed revealing a weld that showed no outward signs of asymmetry. This weld raises major concerns and further investigation was recommended. Approximately 25 feet has been inspected on either side of the ring with low confidence
	3	Pulse echo Torsional & C scan +F2 Cat 2 concentrated reflection on bottom -F4 Cat 2 possible corrosion or deposits	NA	all above -0.850mV no side drainhot spots soil resistivity ~40kΩ	no corrosion just deposits	Unremarkable results in bell hole 3. Approximately 15 ft either side was inspected
	4	Pulse echo Torsional & C scan +F2 weld showing nonsymetry +F3 weak reflection -F2 unknown	NA	all above -0.850mV no side drainhot spots soil resistivity ~40kΩ	+F2 was a weld -F2 may have been shale rocks	No areas of major concern Approximately 15 ft either side was inspected
	• All minor corrosion (i.e., everything found easily passed ASME B31G, the equivalent of a Hydrotest) called out by GWUT was confirmed by visual examination. There were no false positive calls. • No false negative calls were noted. • Everything passed the equivalent of a Hydrotest • Results of radiographic inspection of the 1952 welds noted in the GWUT inspection reported them as sub-quality by today's (modern) standards					

This summary was prepared based on the anomaly rating and characterization methodology that was developed by Trankor-K Company. MTM rating approach takes into account the combined effect of adjacent anomalies and stress-strained condition of the pipeline. The below summary highlights the findings based on the conducted MTM inspection for the same section of pipeline (H-152) that was inspected by GWUT and 100% visual exam after excavation.

The section of pipeline with coordinates 1873' through 2264' (where GTI study was conducted using alternate inspection method) was considered in "acceptable" condition. Corrosion defects that exceed 50% of pipe wall loss were not revealed. The largest wall loss was predicted within anomaly # 28 (30% to 37%). The inspection did not predict/indicate any defective welds. Upon excavation and visual inspection, no defects were identified in the area of any of the anomalies #27 through #33).

Table 2. Summary Table of Magnetometric Inspections

Above Ground Marker Information					*Anomaly Information*										
Marker Location from Point 0, ft	Description	Notes	GPS-Coordinates		Anomaly #	Corrosion Prediction Rating	Metal Condition Rating	Integral Risk Factor F	Clock Position	Start, ft	End, ft	Length, ft	Distance from previous marker, ft	Distance from next marker, ft
			Longitude	Latitude										
			W80°03'176"	N40°34'119"	27	2	2	0.30737	8 h 12 m	1917.66	1922.52	4.86	43.44	-2.19
			W80°03'176"	N40°34'119"	28	2	2	0.53895	7 h 43 m	1923.34	1926.70	3.35	49.11	1.98
	Parking Lot	Start	W80°03'177"	N40°34'119"										
1924.71	Parking Lot	End	W80°03'197"	N40°34'120"										
1977.25			W80°03'209"	N40°34'119"	29	3	3	0.67340	10 h 47 m	2025.47	2026.02	0.55	48.23	-198.39
			W80°03'209"	N40°34'119"	30	2	3	1.00000	6 h 29 m	2026.35	2027.66	1.31	49.10	-196.75
			W80°03'213"	N40°34'119"	31	3	3	0.58729	6 h 47 m	2042.23	2045.86	3.63	64.98	-178.55
2224.41	Top of the Hill	Start of decline	W80°03'258"	N40°34'119"										
			W80°03'266"	N40°34'119"	32	3	3	0.60447	8 h 8 m	2258.46	2260.79	2.33	34.05	-1.71
			W80°03'267"	N40°34'119"	33	3	3	0.67340	4 h 4 m	2261.06	2261.88	0.82	36.65	-0.61

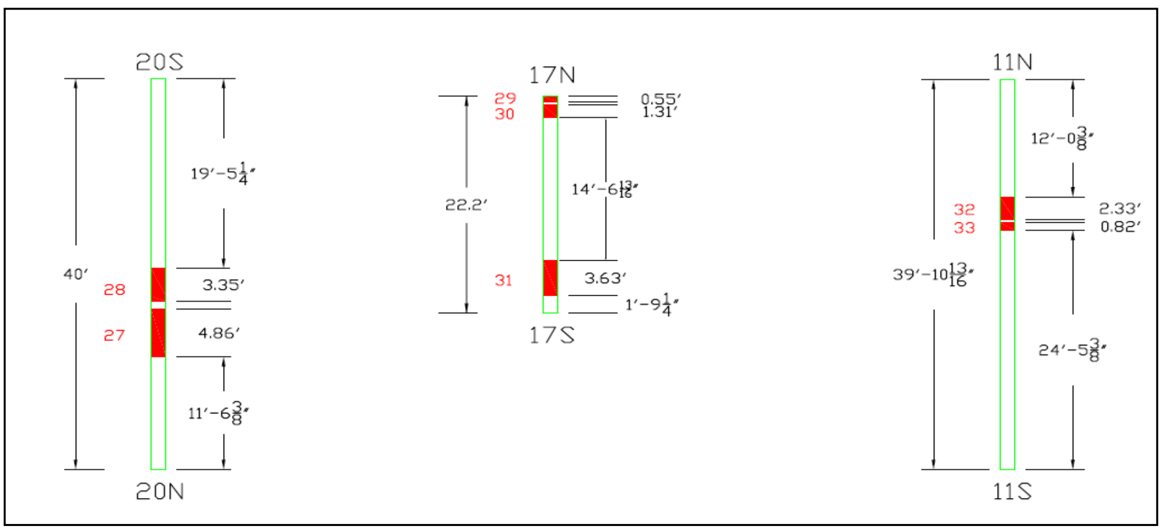


Figure 128**. Transkor-USA, Inc. MTM Indications #27 through #33.**

A set of pictures for the pipe segment that contained anomalies #27 & #28 are shown below. No significant corrosion was found.

Figure 129**. Pipe joint '20' conditions. No defects were observed on direct exam and during UT direct wall measurements.**

Conclusions/Observations

- No false negative calls were noted.
- The anomalies that were ≥ 5% Cross Sectional Area (CSA) were dug up, had their coating removed, and the subsequent pits were physically measured (both length and depth with an engineering ruler and a pit gauge).
- The pit dimensions were input into ASME B31G criteria at the test pressure for the class location. All the pits passed this criteria for failure at the test pressure for their respective class location.
- Additionally (and more conservatively), all the defects also met the ASME B31G criteria for a pressure (greater than the pressure test pressure) that would have resulted in a hoop stress equal to 100% SMYS (P=2St/D), i.e. they met (passed) the standard ASME B31G criteria. This also follows from the fact that the Class 1, 2, 3, and 4 Test Pressures (used in this case) were all below the pressure required to achieve 100% SMYS pipe wall stress.
- There were no false positive calls.
- Everything passed the equivalent of a Hydrotest in the class location using ASME B31G.
- GWUT called out several of the welds as "highly suspicious".
  - *Results of radiographic inspection of the 1952 welds reported them as sub-quality by today's (modern) standards.*
  - *These welds were reported to contain: inadequate penetration, burn through, slag inclusions and lines, external undercut, porosity, gas pockets, and concave crowns.*
- Transkor-USA inspection reported all segments for this case study to be "acceptable or good" pipe, i.e. they did not recommend immediate investigation.

Results and Discussion - Cased Pipe Segments

PG&E Line L132-200C Background Information

- Line L132-200C Segment - 300 foot casing below an expressway
- Pipe installed 1948, and replaced by 24.00" diameter, 0.375" wall, Grade x60, with a 400 psi MAOP, coated with hot applied asphalt in 1985. The 30" diameter casing was not coated. The casing was installed in 1959 when the expressway was built. Initial testing with PCM and P/S and C/S voltage measurements indicate a possible short between the carrier pipe and the casing. The PCM plot of the multiple measurements is plotted in the indirect assessment section.
- This 30 foot casing crossing below highway 101, was not coated.
- There are three dig sites;
  - > Dig #1 is about 80 ft west of the highway near the elbow in Figure 1,
  - > Dig #2 exposes the casing as it emerges from under the west edge of the freeway
  - > Dig #3 will be opened on the east edge of the freeway to expose the other end of the cased pipe segment,
- Conduct a pitch catch between Dig #1 and Dig #2 before removing about 75 feet of casing
- Conduct a tethered pig run in 2007 to inspect the 125 ft of cased pipe under the freeway [this was since cancelled by the operator].

The site is quite congested as can be seen from the Figure 130 below.

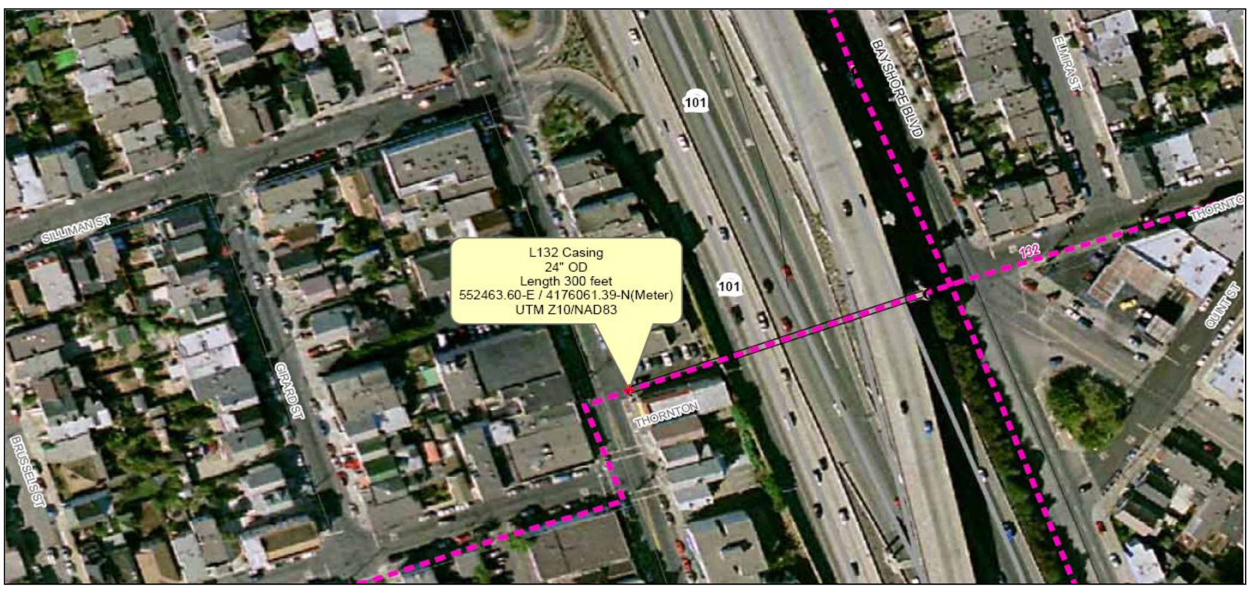


Figure 130. This is an aerial image showing the L300/200C pipe line in pink as it goes under the highway.

There were two excavations on the west side of the freeway and a third on the east side. Dig #1 was farthest to the west, approximately 13ft deep and near the elbow in the figure above. Dig #2 was 80 ft east of Dig #1 at the edge of the free way (HWY 101) and it was also about 13 ft deep. Dig #3 was on the east side of the freeway and was about 7 ft deep. The 30" diameter casing is not coated and the casing is not filled with a corrosion mitigation material and is vented. The only possible paths for water intrusion were through the end seals. Casing sections were removed in all three digs to give the GWUT tools access to the pipeline. Figure 131 is a side view schematic of the dig site.

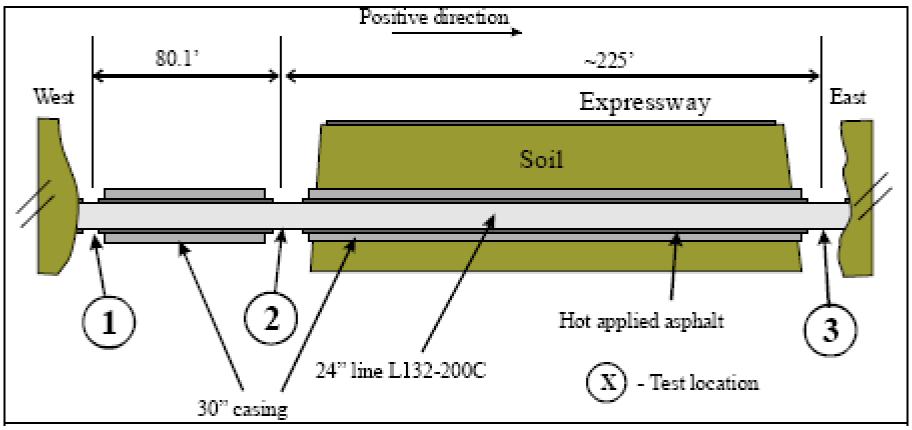


Figure 131. Schematic of the dig site.

The following figures show the congestion and general layout on the surface around the three dig sites in "China Town".

(a)

(b)

Figure 132. (a) Dig Site #1 Showing shopping area at end of lane, (b) Dig Site #2 with #1 in background.

(a) (b)

Figure 133. (a) Dig Site #1 with #2 at backhoe and then the freeway behind both, (b) Dig site #3 far side of Hwy 101.

(a) (b)

Figure 134. (a) Dig Site #1 about 13 feet deep lowering the Teletest belt and then (b) it's installation. Note the thickness of the well bonded coating on the pipe at the edge of the cut casing. The corrugated steel shoring is the west wall of the dig.

(a)

(b)

Figure 135. (a & b) Dig site #2 showing pipe emerging from under the freeway at the east end of the dig. The casing with notch can be seen in the right hand image next to the GUL ring.

(a)

(b)

Figure 136. (a & b) Casing in Dig #2 as it emerges from under west side of Hwy 101. No damage to coating/pipe was noted.

(a) (b)

Figure 137. (a) The west side of Dig #3 showing the vent from the casing, (b) then the coating, and the carrier pipe.

ECDA Pre-Assessment

The segments successfully past hydro-tests in 1984, 1986-1989, 2001.

The impressed current was acceptable and all indications were above 0.850 mV 'on'. The soils found previously found in these sections were clay, sand and adobe. There was no indication of increasing rectifier currents and in fact they were very Low. Historically these currents were less than one Ampere per rectifier. The coatings on the pipe line were indicated as "Tape", "XTRUPL", "FBE", and "HAA" on the *as builts*.

CIS and DCVG were not possible to assess the pipe in the casing so PCM techniques were used first and the GWUT as the complementary assessment.

Results of Indirect Inspections

ECDA Indirect Inspection

The following inspections were conducted on this cased crossing, Guided Wave, Pipeline Current Mapper (PCM) and PCM/A-frame which indicated a possible short, see Figure 138.

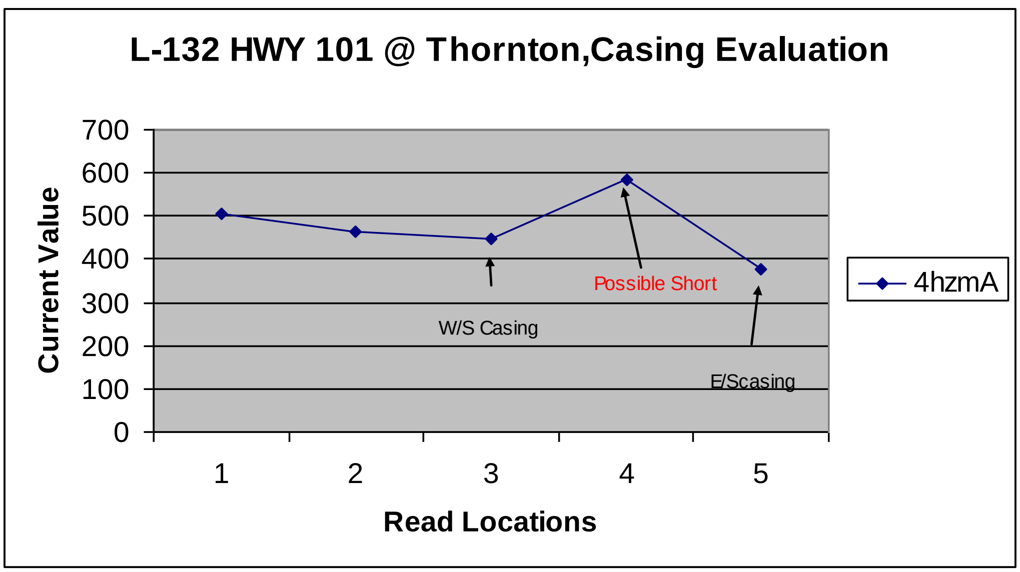


Figure 138. PCM readings either side of the casing under the freeway.

Guided Wave Inspection

The first line (L132-200C) is coated with hot applied asphalt that was first installed in 1948. An uncoated 30" casing was subsequently installed in 1959 beneath a 225 foot wide expressway when it was built. A total of three dig sites were arranged to gain access to the pipe. Two sites, approximately 75 feet apart and 20 feet beneath street level are located at the western edge of the expressway; while one other site is located at the eastern edge of the expressway. At these locations, small sections of the casing and asphalt coating were removed to expose the pipe surface. A schematic diagram showing the locations of the three dig sites for line L132-200C is illustrated in Figure 139.

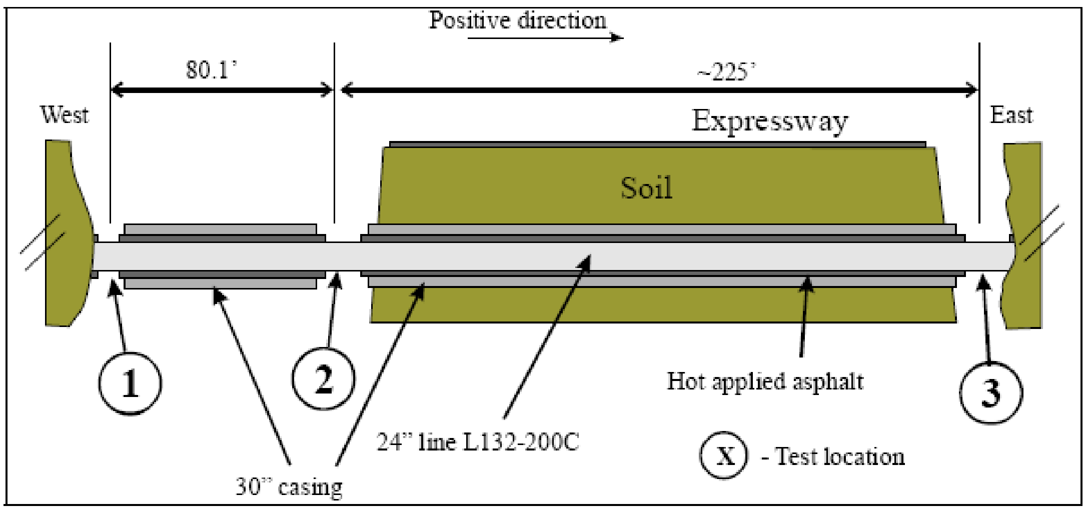


Figure 139. Indicates the dig locations.

Inspection techniques (configurations)

Pulse echo configuration: This is currently the conventional testing configuration for guided wave inspections where the signal is sent and received from the same transduction ring. The benefit of this configuration is that only one position of the pipe surface is required for mounting the transduction ring and only minimum number of transducers is needed. However, the disadvantage is that any echoes would have to pass through the length of the pipe twice before being sensed by the transduction ring. Additionally the dead-zone/near field mechanisms associated to this technique restricts inspections in the close range. This could result in poor signal to noise ratio especially where signals are heavily attenuated, for example, due to the thick coating or buried conditions on the pipe.

Pitch catch configuration: This was used between dig #1 and #2. In this configuration, two transduction rings are mounted along the same pipe at certain known distance apart where the signal sent from one transduction ring is picked up by the other. Although more preparation is needed for this configuration, it allows operators to accurately determine the decay rate of the signal along the pipe via direct through transmission measurement; consequently allowing the more accurate prediction of the attenuation to determine the DAC setting, see Figure 140.

Figure 140. Pitch-Catch between Dig #1 in the foreground and Dig #2 by the track hoe.

Focusing configuration: This is the latest development in the guided wave technology. The technique uses a specially designed ring and software, operating in pulse echo configuration to resolve the circumferential distribution of the energy precisely at any one given position within the testing range. The result of this configuration helps operators to pin-point both the circumferential and axial locations of a defect. This also allows for better and more accurate classification of defects that are found. Normally the most important parameter for classification is the maximum defect depth.

Line L132-200C Segment

A small section of the hot applied asphalt (approximately 25" wide) was removed from the pipe surface that was subsequently cleaned for the mounting of the transduction ring. The general condition of the exposed pipe surface was found to be very good; no corrosion or localized pitting was observed on the surface as a result of strong cathodic protection used in the past. The average wall thickness was measured to be 0.283" while the coating is typically 0.4"-0.5" thick at locations immediately next to each test point. This gives the coating to wall thickness ratio (t_c/t_p) of 1.77.

The coating appeared to be reasonably uniform and there was no sign of any delamination. However, the guided wave was damped significantly as it propagates along the pipe which suggested that the usually thick layer of coating is well bonded to the pipe along the entire length. Furthermore the attenuation properties of the coating are strongly related to the effectiveness of it to keep air and other elements from the pipe surface. This was the major reason for the shorter than expected test range seen in the results. The signals typically decay at a rate greater than 4dB/m or 1.22dB/ft along this cased section of the line. This value was confirmed later by the pitch-catch measurement.

Moreover, the attenuation in the direct soil buried section is expected to be even greater. An overview of the pipe condition is shown in Figure 141. In all cases, positive direction is taken towards east for all locations.

Figure 141. An overview of the testing configuration for line L132-200C.

__Pitch-catch result (from Location 2 to Location 1)__

In the pulse-echo configuration, the decay rate of the signal is typically calibrated using a series of reflectors with which the percentage of reflection amplitude is known. However this may not be possible when the test range is limited by heavy attenuation. To measure the signal decay rate accurately, a pitch-catch (through-transmission) measurement can be performed between two test locations along the pipe. In this case, a pitch-catch measurement was performed between *Location 1* and *Location 2* to establish the attenuation in Line L132-200C; the distance between the two locations was measured, using a tape measure, to be 80ft. The result file is shown below in Figure 142 where it can be seen that a single peak corresponding to the transmitted signal appears at half of the actual distance. This is because the transmitted signal is only required to travel once between the two locations. Using the 100% (Distance Amplitude Correction) DAC in the result, the attenuation was measured to be 4.3dB/m or 1.31dB/ft. This result has proven to be extremely useful when setting the decay rate for the pulse-echo results later.

Pipe:	24" 132-200C	**Coating:**	
Site:	GTI/PG&E	**Contents:**	
Location:	soil entrance +47inch	**Supports:**	
Size:	24 inch	**Corrosion:**	
Tested:	3 Oct 2006 19:16 (GMT)	**Ring:**	R2B24PE(703)-Circum-
Tested by:	Jimmy Fong[GUL]	**Config:**	50mm
Client:	PG&E	**Calibration:**	9.6FR, T(0,1)
Procedure:	GU 1.1	**Version:**	Automatic (3363.98 mV) 3.92, Wavemaker G308

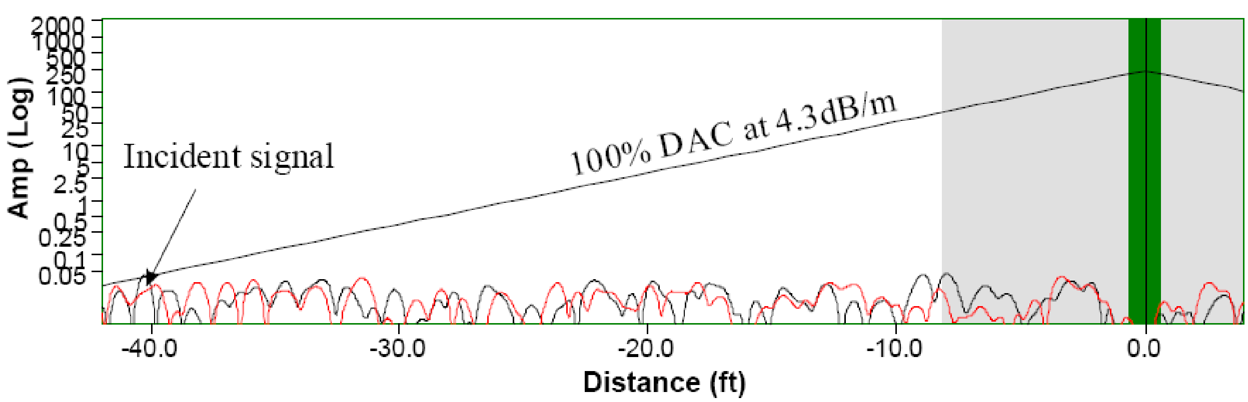


Figure 142. General Notes: pitch catch TP2 to TP1. Separation between two locations is 80ft.

Pulse-echo result

<u>Dig #1 (as marked in Figure 10)</u>

This dig site is approximately 84 feet west of the west edge of the expressway. The result indicates that the pipe enters the soil at -51" and immediately followed by a bend after that in the negative direction. With the desired sensitivity, the range included the pipe beyond 30ft from the transduction ring, however the sensitivity of this data was poor and confidence is limited. Only very large defects could be found with low confidence. For this reason, approximately 30 feet in the positive direction and 15 feet in the negative direction were interpreted. Within this range, several locations of very minor indication were identified but there are no medium and major concerns (see Figure 143 and Figure 144 below).

Pipe:	24" 132-200C	**Coating:**	Bitumen,Sleeve,Ground
Site:	GTI/PG&E	**Contents:**	Gas
Location:	wrapping +14inch	**Supports:**	Sliding
Size:	24 inch	**Corrosion:**	None
Tested:	3 Oct 2006 21:38 (GMT)	**Ring:**	R2B24(767)-Circum-50mm
Tested by:	Jimmy Fong[GUL]	**Config:**	8.8FR, T(0,1)
Client:	PG&E	**Calibration:**	Automatic (2421.17 mV)
Procedure:	GU 1.1	**Version:**	3.92, Wavemaker G308

Figure 143. General Notes: Dig #1 (85 feet west of the west edge of expressway) focusing 24" ring.

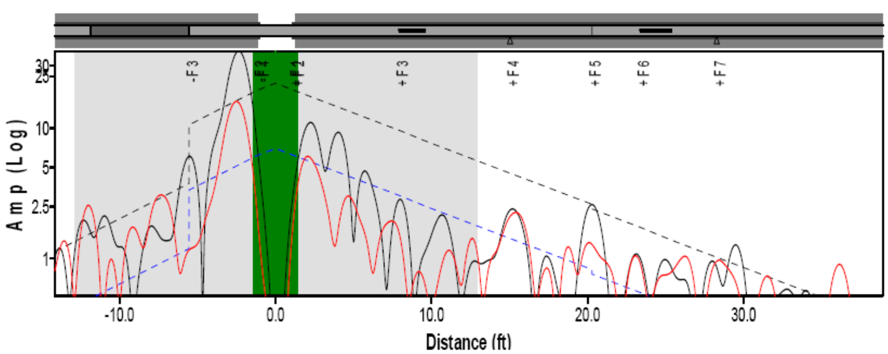


Figure 144. Location #1 with range limited to approximately +30ft and -10ft from the transducer ring placement.

Dig #2 (as marked in Figure 10)

This test location was placed approximately 80.1 feet in the positive direction of the Location 1, and is direct next to the west edge of the expressway. A 3 ft section of coating was removed to allow the transduction ring to be mounted. The casing was found to be off-centered compared to the carrying pipe in the positive direction as shown in Figure 145; this creates a pressure load at the contact point from which corrosion is likely to develop. The test range is 30 ft in both directions for the reasons mentioned for the Location 1.

Due to the absorbing effect of the thick coating, the signal amplitudes become highly sensitive to the change of frequency; and therefore not all the corresponding signals of the marked feature locations are shown in the result below. There are two area of concern at approximately +15ft and -17ft as indicated in the result; both locations have been interpreted to be from a change in the pipe condition. Mostly, the interpretation was of little change greater than normal variations to the pipe wall and coating thickness. Although there are some indications beyond 30 feet in the positive direction, the interpretation was done with low confidence due to poor signal quality in this area, see Figure 146.

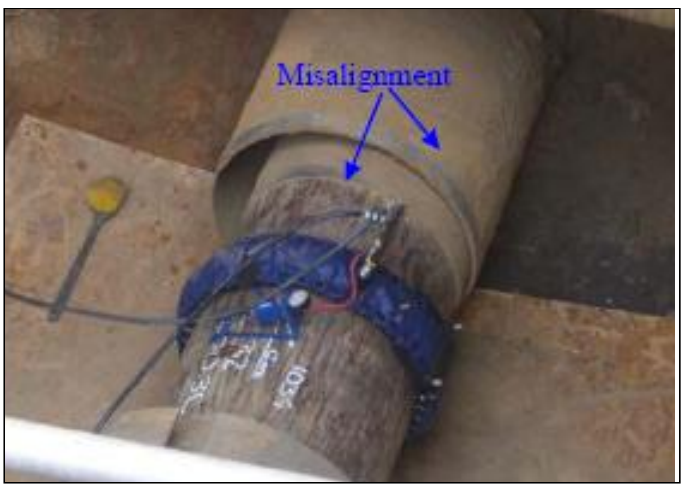


Figure 145. A view of Dig #2, showing the orientation of the 30"casing pipe and the 24" pipe.

Pipe:	24" 132-200C	**Coating:**	Bitumen,Sleeve,Ground
Site:	GTI/PG&E	**Contents:**	Gas
Location:	soil entrance +47inch	**Supports:**	Sliding
Size:	24 inch	**Corrosion:**	None
Tested:	3 Oct 2006 20:44 (GMT)	**Ring:**	R2B24(767)-Circum-50mm
Tested by:	Jimmy Fong[GUL]	**Config:**	11.0FR, T(0,1)
Client:	PG&E	**Calibration:**	Automatic (5327.03 mV)
Procedure:	GU 1.1	**Version:**	3.92, Wavemaker G308

General Notes: focusing ring 24", Location number 2

Feature	Location	Size (mV)	ECL	Class	Notes
-F1	-2'0"	2.61	-	Bitumen	Beginning of the Bitumen wrap
+F1	1'0"	1.94	-	Bitumen	Beginning of the Bitumen wrap
+F2	1'4"	2.26	-	Sleeve	Sleeve slightly off-centre
+F4	4'0"	3.05	-	Earth	Sleeve directly buried in soil
+F3	3'7"	2.66	-	Support	contact with casing pipe
+F5	9'1"	1.25	-	Weld	
+F6	12'0"	1.8	-	Support	asymmetric signal
+F7	15'4"	0.758	10	Cat 3	general wall loss of less than 10% wall loss, or can be due to general manufacturing variation.
+F9	44'0"	0.105	-	Weld	
-F2	-2'0"	3.32	-	Sleeve	Beginning of the sleeve
-F3	-15'8"	0.405	9	Cat 3	general wall loss of less than 10% wall loss

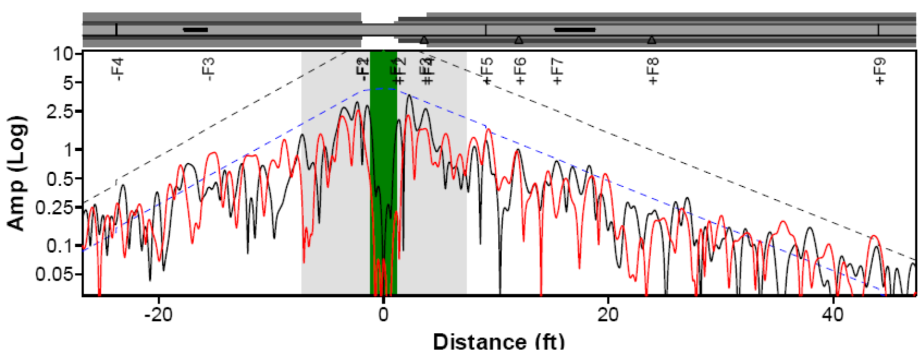


Figure 146. Location #2 with range limited to approximately +45ft and -25ft from the transducer ring placement.

<u>Dig #3 (as marked in Figure 10)</u>

This test location is placed at the *east* side of the expressway, approximately 225 feet east of Location 2. The testing conditions at this location are similar to those of the Dig Locations 1 and 2, typically with high level of attenuation. The overall inspection range is approximately 55 feet, and there is no area reportable concern within this range.

Pipe:	24" 132-200C	**Coating:**	Bitumen,Sleeve,Ground
Site:	GTI/PG&E	**Contents:**	Gas
Location:	entrance 5ft	**Supports:**	Sliding
Size:	24 inch	**Corrosion:**	None
Tested:	3 Oct 2006 22:28 (GMT)	**Ring:**	R2B24(767)-Circum-50mm
Tested by:	Jimmy Fong[GUL]	**Config:**	11.2FR, T(0,1)
Client:	PG&E	**Calibration:**	Automatic (6716.91 mV)
Procedure:	GU 1.1	**Version:**	3.92, Wavemaker G308

General Notes: Test Location #3. East of the Expressway.

Feature	Location	Size (mV)	ECL	Class	Notes
-F3	-12'2"	2.35	-	Weld	
-F2	-2'6"	25	-	Sleeve	
-F1	-2'0"	25	-	Bitumen	Beginning of the tar coating
+F3	23'3"	0.531	-	Weld	
+F4	27'3"	0.28	14	Cat 3	beyond inspection range and therefore has low confidence
+F2	5'0"	7.37	-	Earth	directly earth buried
+F1	2'3"	37.3	-	Bitumen	Beginning of the tar coating

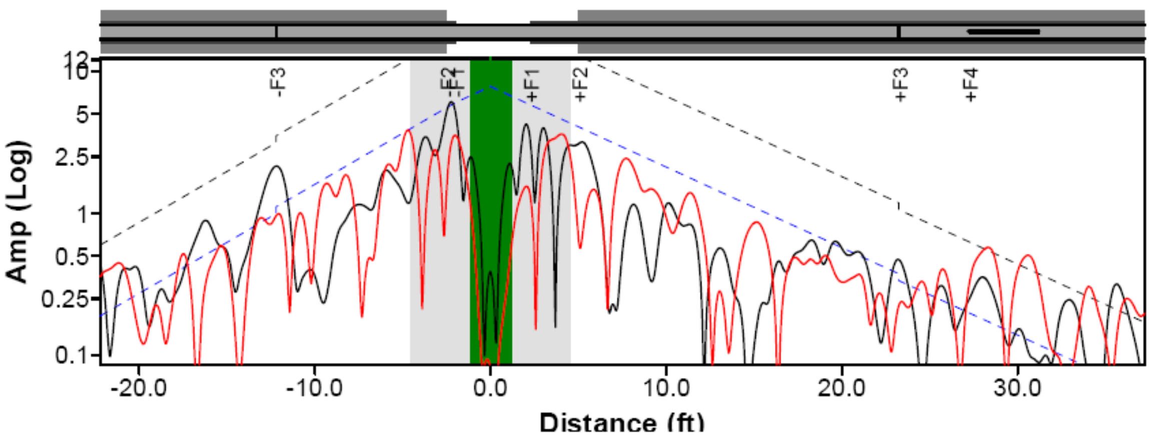


Figure 147. Dig Location #3 with range limited to approximately +35ft and -20ft from the transducer ring placement.

Direct Exam Dig Schedule

The plan was to excavate the entire section between Dig #1 and Dig #2 and remove the casing for direct examination. Mears Corporation conducted the visual examination after washing the pipe.

(a) (b)

Figure 148. Casing removed, coating removed, and pipe being washed for visual inspection.

Figure 149. Pipe ready for sand blasting before second inspection.

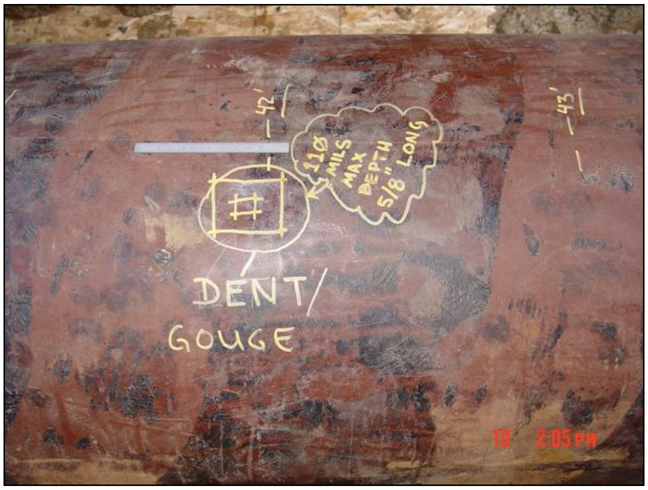


Figure 150. Dent with no corrosion observed at +42ft reference. Notice the good prime coat adherence.

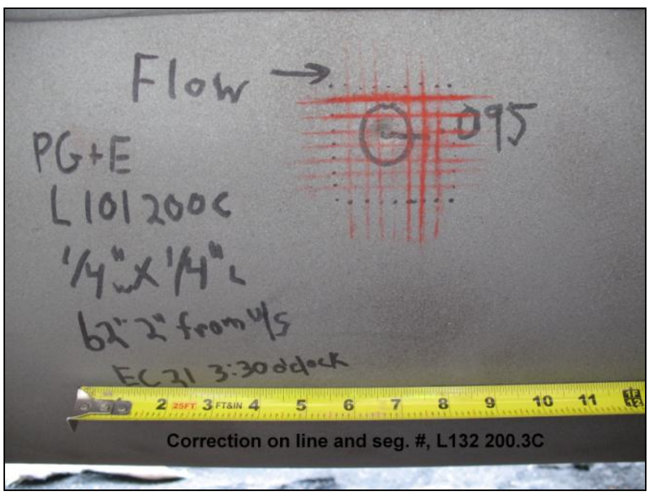
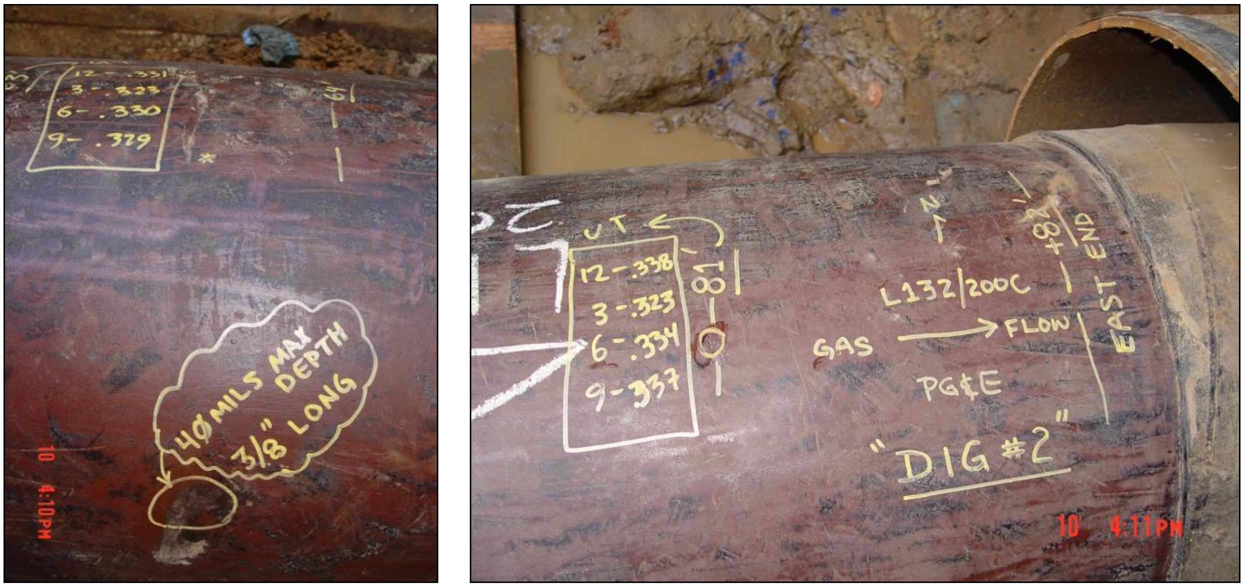


Figure 151. After sand blasting, dent classified to be "corrosion" at its center by third party, however there was no evidence of "corrosion" when visually examined.

	0	0	0	0	0			
	0	5	65	2	0			
	0	18	45	4	0		95	
	0	0	2	0	0			
		0	0	0				

Figure 152. Grid Map in ¼" squares indicating depth of wall loss (in mils) as corrosion.



(a) (b)

Figure 153. (a) Corrosion observed at reference +69 ft (west to east +), (b) East end at casing showing wall thicknesses.

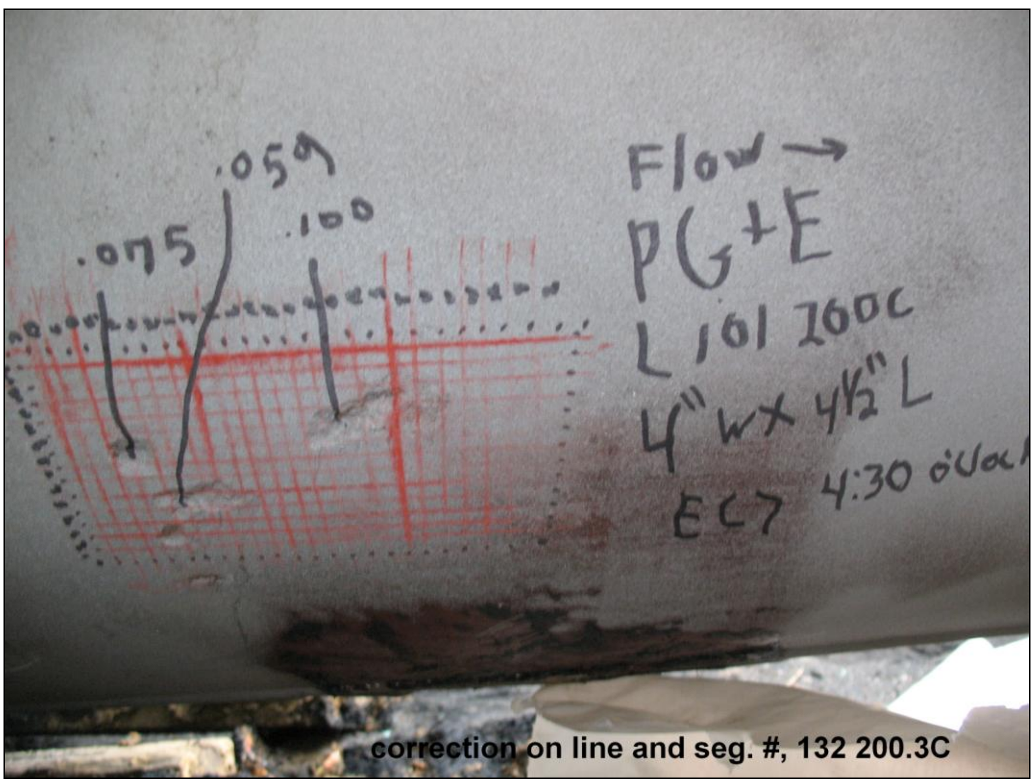


Figure 154. Sand blasted surface with grid markings and maximum depths at +69 ft (the grid map for these features in shown in the next Figure).

3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
															0	0	0		
															0	5	0	0	0
											0	0	0	0	39	51	8	4	0
	0	0	0	0							0	8	10	32	41	13	15	13	0
	0	10	3	0							0	30	71	100	2	9	0	0	0
	0	50	51	0							0	0	0	15	0	0	0		
	0	23	11	0	0	0	0						0	0	0				
	0	0	0	0	0	3	0	0											
		0	9	23	49	35	13	0											
		0	0	4	0	0	0	0											
		0	9	0	0														
		0	39	0															
		0	0	0															

Figure 155. Grid map of features shown in the previous Figure. The ¼" squares indicate the depth of wall loss (in mils) at +69ft.

Dig Site: ***#132-200 - #1***

Wall thickness at dig site #1 next to the location of the GUL belt:

Table 3. Pipe Wall Thickness Measurements at Dig Site #1

line 132	200	C	dig #1	nominal	min
center of 80' 8"			top	0.306	0.290
			bottom	0.303	0.292
			north	0.303	0.291
			south	0.303	0.291
east			top	0.292	0.270
			bottom	0.295	0.272
			north	0.295	0.272
			south	0.297	0.273

Operator:	PG&E
Case Study:	Line L101 - 140

Dig Sites: ***#4 Line L101 – 140 either side of an abandoned railway spur***

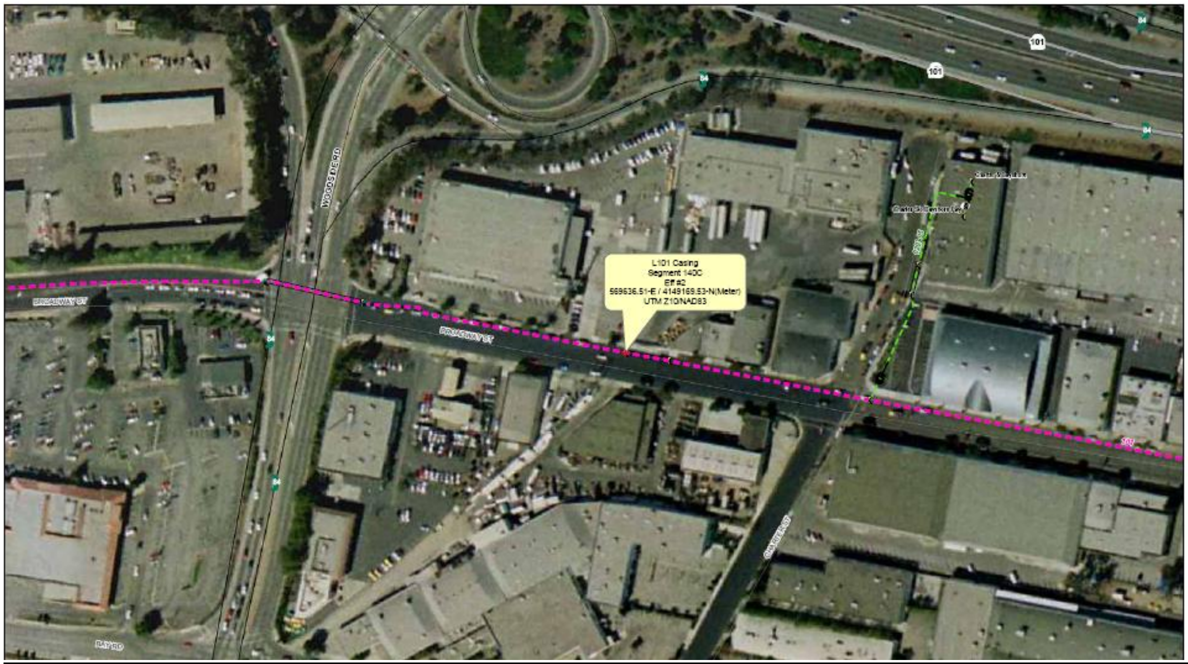


Figure 156. Line L101 – 140 either side of an abandoned railway spur.

<u>L101 Segment 140C California Gas Transmission</u>

Line L101-140C – The pipe line segment has a 76 foot casing under abandoned and removed rail line: The line was installed in 1985, and is 24.00" diameter, coated with extruded Polyken PE backed mastic tape wrap. The 30" diameter casing is not coated and the casing is not filled with a corrosion mitigation material, and is vented. The only possible path for water intrusion is through the end seals.

1) L101-140C was planned to have two (2) dig sites to attach the G-3 transducer collar to, one on each side of the casing. It was planned to be able to do pitch-catch (in addition to pulse echo at each site) across the casing and expect to need about 125 feet of umbilical cord to do this.

The entire casing was to be removed the following week for direct examination/validation.

Figure 157. Dig site 4 showing light industry with dig site 5 in the background.

Figure 158. Dig site 4 showing depth of about seven feet.

Figure 159. Dig site 4 showing GUL belt location.

Figure 160. Casing at 12 o’clock showing space band and spacer.

Figure 161. Casing edge at 6 o'clock showing some calcareous like deposit on the casing.

Figure 162. Cleaned pipe at end of casing.

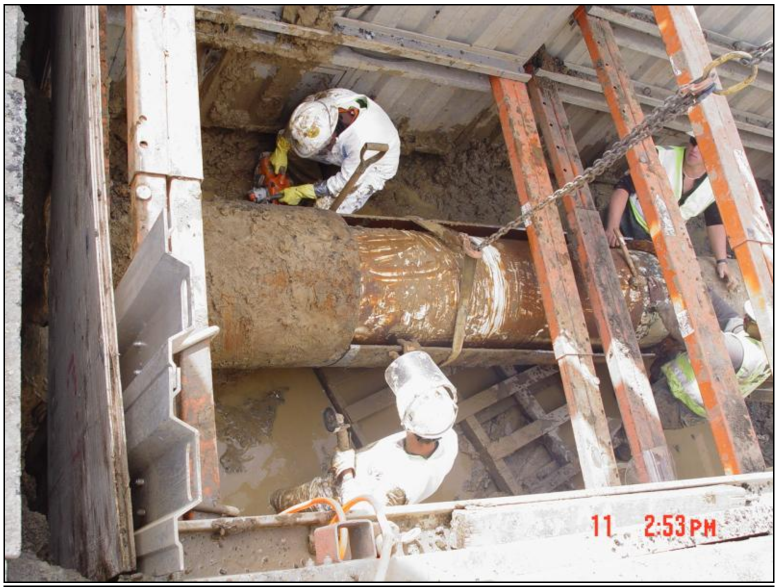


Figure 163. Abrasive technique for cutting the casing from the pipe.

Figure 164. Seal after casing removal.

Figure 165. Pipe showing well adhering coating before final cleaning.

Figure 166. Line after casing removal and direct inspection shows wall thickness measurements and the end of the remaining casing.

Guided Wave Results - Line L101-140C Segment

Although the coating is thin, the attenuation was measured at -0.9dB/ft, this is somewhat higher than expected for this kind of wrapping; The increase in attenuation may be associated with the condition of pipe surface(s) and or the properties of the uniform coating. Nevertheless the general signal quality is much better than those obtained from Line L132-200C. This average wall thickness of this pipe was measured to be 0.375” which give tc/tp ratio of less than 1. There are no large reflection that were interpreted to be corrosion above the reportable level but there are a number of reflections from within the sleeve from welds and supports.

Within the inspection range there were eight reflections interpreted to be from welds, this is higher than normally, suggesting that smaller pipe sections are used. In particular within 10ft of the ring location there are three welds in close proximity (within 16ft), including one small 2 feet pipe section.

Pipe:	24" L101-140C	**Coating:**	Bitumen,Sleeve,Ground
Site:	GTI/PG&E	**Contents:**	Gas
Location:	entrance -32inch	**Supports:**	None
Size:	24 inch (9.52499 mm)	**Corrosion:**	None
Tested:	4 Oct 2006 00:31 (GMT)	**Ring:**	R2B24(767)-Circum-35mm
Tested by:	Jimmy Fong[GUL]	**Config:**	12.2FR, T(0,1)
Client:	PG&E	**Calibration:**	Automatic (2806.51 mV)
Procedure:	GU 1.1	**Version:**	3.92, Wavemaker G308

Feature	Location	Size (mV)	ECL	Class	Notes
-F1	-2'8"	2.61	-	Bitumen	Starting of the bitumen wrapping
-F2	-5'3"	0.93	-	Earth	Entrance to the earth bury section
+F2	2'8"	2.73	-	Sleeve	Entrance to the casing
+F1	2'2"	1.72	-	Bitumen	Starting of the bitumen wrapping
+F4	7'0"	16	-	Weld	Symmetric signal - typically weld feature however a slight higher level of red is observed around the weld.
+F3	4'1"	2.2	5	Minor	Small non-symmetric indications in this area
+F5	27'9"	0.168	-	Weld	Symmetric signal - typically weld feature
+F6	47'4"	0.146	-	Weld	Symmetric signal - typically weld feature
+F7	68'1"	0.034	-	Weld	Symmetric signal - typically weld feature
-F3	-7'4"	21.9	-	Weld	Symmetric signal - typically weld feature
-F4	-9'5"	18.1	-	Weld	Symmetric signal - typically weld feature
-F5	-21'1"	1.28	-	Weld	Symmetric signal - typically weld feature

Figure 167. General Notes: Test location #4.

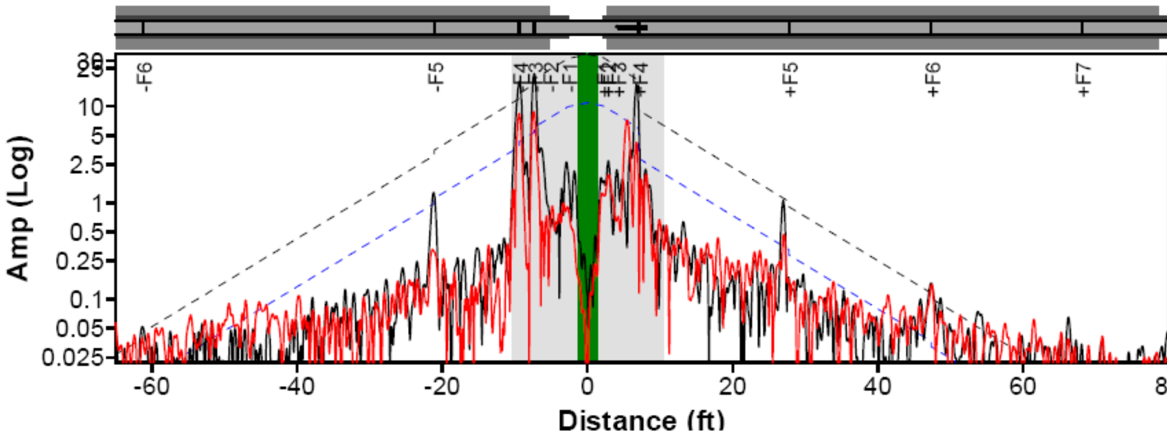


Figure 168. Guided Wave Scan for Line L101-140C Segment.

Operator:	PG&E
Case Study:	L101-140C Oct/07
Dig Site:	***#5 (other end of the casing – cancelled due to safety concerns)***

Line L101-140C was coated with extruded Polyken PE backed mastic tape wrap. The section of interest is a length within a 76 foot of a 30″ casing that was installed in 1985 under an abandoned and removed rail line. Two dig sites were initially planned on each side of the casing.

However, due to excess amount of water found in the dig site west of the casing (site #5), regrettably only the eastern site was accessible for carrying out the guided wave inspection.

Guided Wave Performance Summary

Guided Wave Performance Summary					
Line	**Dig Site**	**GWUT Anomalies**	**ECDA Anomalies**	**Direct Exam Findings**	**Comments**
Line L132-200C	1	Pitch-Catch identified several locations of very minor indication. Tech Corr found no indications.	The impressed current was acceptable and all indications were above 0.850 mV on. The soils found previously found in these sections were clay, sand and adobe. There was no indication of increasing rectifier currents and in fact they were very Low. Historically these currents were less than 1 Ampere per rectifier. Initial testing with PCM and P/S and C/S voltage measurements indicate a possible short between the carrier pipe and the casing.	@ +42' dent with third party measuring a 0.095" deep area @+69 corrosion 0.100" deep and others in area	range limited to approximately +30ft and -10ft from the transducer ring placement
	2	Pulse Echo with focusing - two areas of concern at approximately +15ft and 17ft. +F7 Cat 3 general wall loss. -F3 Cat 3 general wall loss. TechCorr found no indications.			range limited to approximately +45ft and -25ft from the transducer ring placement
	3	Pulse Echo +F4 Cat 3 TechCorr found no indications		couldn't dig	range limited to approximately +45ft and -25ft from the transducer ring placement
Line L132-200	1	+F4 weld with suspicion +F5 minor indications TechCorr found no indications	The impressed current was acceptable and all indications were above 0.850 mV on. The soils found previously found in these sections were clay, sand and adobe. There was no indication of increasing rectifier currents and in fact they were very Low. Historically these currents were less than 1 Ampere per rectifier.	no corrosion found under the section of removed casing further excavation was not safe	range limited to approximately +40ft and -40ft from the transducer ring placement

Comments on additional inspection reports for Dig Sites #1 - #4

Additional inspection reporting (from Structural Integrity Services and TechCorr Corp.) details were obtained from PG&E. These two additional service providers reinforced the previously reported data.

The two casing sites where GTI witnessed the GUL - GWUT process in one or more bell holes, were:

1. Line 101 400C the cased but now abandoned rail crossing
2. Line 132-200, two sections of the casing running under Highway #101 at Thornton Rd. one 80 foot in the alley and the 200 foot length under #101.

Location 1 - Casing segment under the abandoned rail line (Line 101- SEG 140C)

Both the TechCorr and Structural Integrity Services (SIS) inspections were done from the west excavation.

Structural Integrity Services - indicated possible corrosion and suggested monitoring. SIS suggested the GWUT trace described one anomaly located about a fifteen inches inside the casing. The east end bell hole, about 70 feet away started to cave in and undermine the street so this location was not excavated further. No confirmatory digs were done.

Further casing removal was not possible and therefore verification was not possible.

TechCorr - report indicated no significant indications.

Location 2 - 80 foot casing under the alley & 220 foot casing under highway 101 (Line L132 SEG 200.3C)

Structural Integrity Reports

Thornton Rd and Highway #101 (80 foot segment) Inspection 132-200.3C, positive direction always east (photographs confirm the orientation is with the gas flow direction).

<u>80 foot casing under the alley</u> L132 SEG 200.3C (80 ft segment)

Shot 1035 - West of 101 shoot east under highway and west towards end of casing.

Shot 1033 - West of 101 at Thornton St shoot east through casing in alley past cut in casing for GWUT access and then under highway 101 (page).

Neither inspection direction had indications that would require investigation.

- Signal trace from the west, shot 1033, indicates welds at 12′, 34′, 51′ & 67′ into the casing from the GWUT unit and about 12′ from the east end but the signal was insufficient to detect corrosion.
- Shot 1036 from the east side of 101 saw the same welds 34′, 51′, & 67′ from the west GWUT location.

Casing in the alley was removed and 2 minor corrosion defects were found by Mears, the first at 42 feet from the end was a dent/gouge estimated at 0.110" deep by 0.630" long and corrosion at 68½ ft was 0.04" deep by 0.375" long. Neither was determined to be significant but was buffed out and recoated before the pipeline was backfilled.

<u>220 foot casing under highway</u> 101 L132 SEG200.3c(220 ft segment) package.pdf
Inspection 132 200 3C
Thornton Rd and Highway #101 (200 foot segment)

Shot 1037 - East of 101 shoot west under highway
Shot 1036 - East of 101 shoot west under highway but next to casing and seal
Shot 1035 - West of 101 shoot east under highway (page indicates shot 1034 was invalid)

- Signal trace from the east (1036 or 1037) saw welds at 13′8″ and 38′3″ from the east end.
- Signal trace from the west 1035 saw welds at 8′9″, 28′4″ and 50′1″ from the west end, therefore the 100foot length in the middle was not inspected.

Inspection sensitivity was insufficient to inspect the full length of the casing. No indications were found and no remediation recommended.

TechCorr Reports

Found no significant indications either in the <u>80 foot casing</u> and were unable to inspect over the full length of the <u>220 ft casing</u> due to the heavy corrosion protection coating.

Casing under highway #101 was left undisturbed, therefore no validation was possible.

Recommendations – *Both Techcorr and SIS* should add the shot numbers or some other location correlating information on each of their GWUT summary pages (these pages show GWUT signal amplitude vs distance). It is difficult to determine the sensor location and inspection orientation without some common reference that helps tie together the various reporting pages. Normal pipeline conventions such as downstream being positive values help but are not indicated and it is easy to make mistakes.

Quantitative Range Summary of the Overall R&D Project Case Studies

GW Range vs. Pipe Diameter

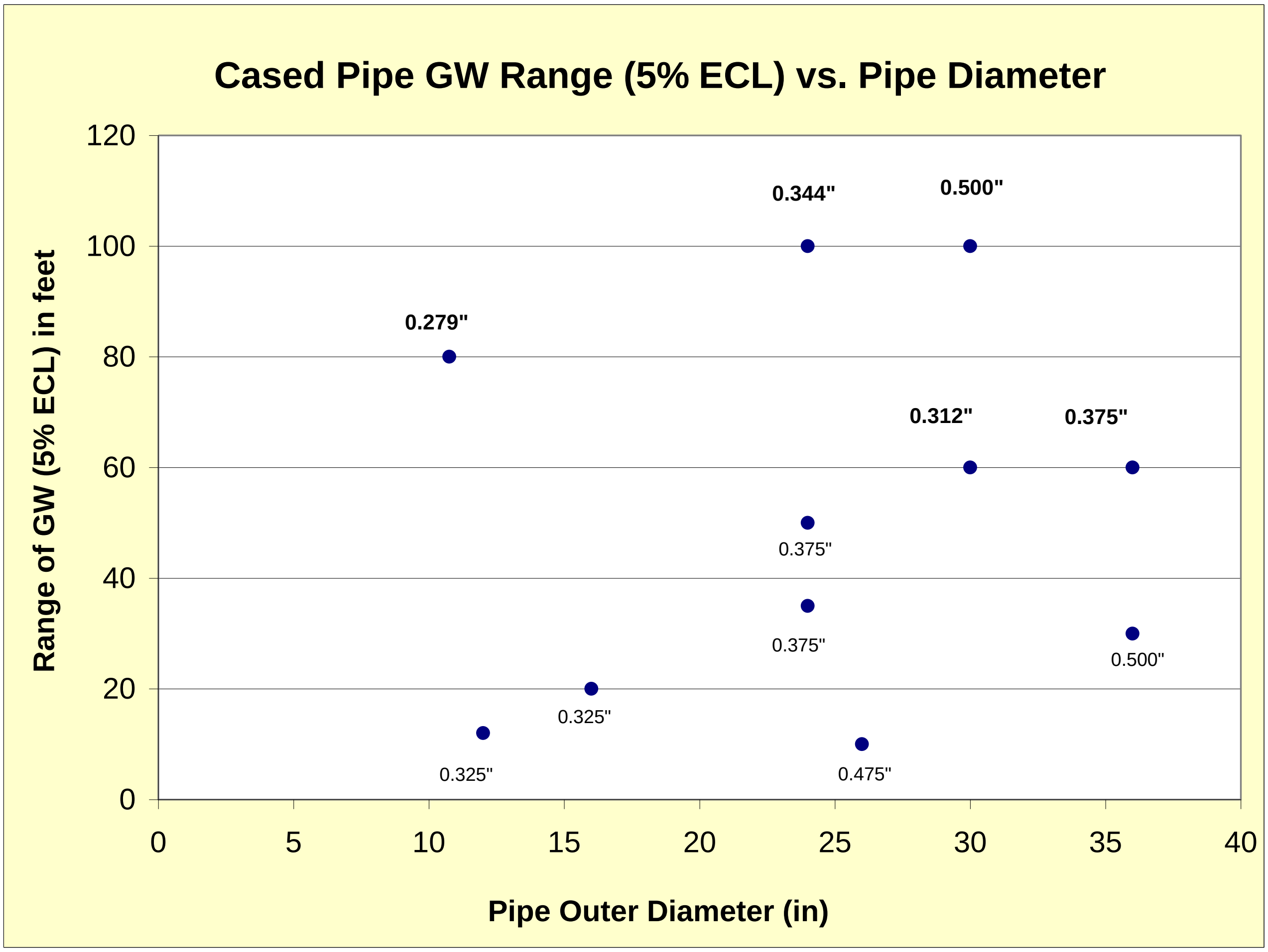


Figure 169. GW Range vs. Pipe Diameter - No direct correlation observed. The coating and other factors contribute to dampening. However essentially the larger diameter pipe with thicker walls seem to help increase the range.

GW Range vs. Wall Area

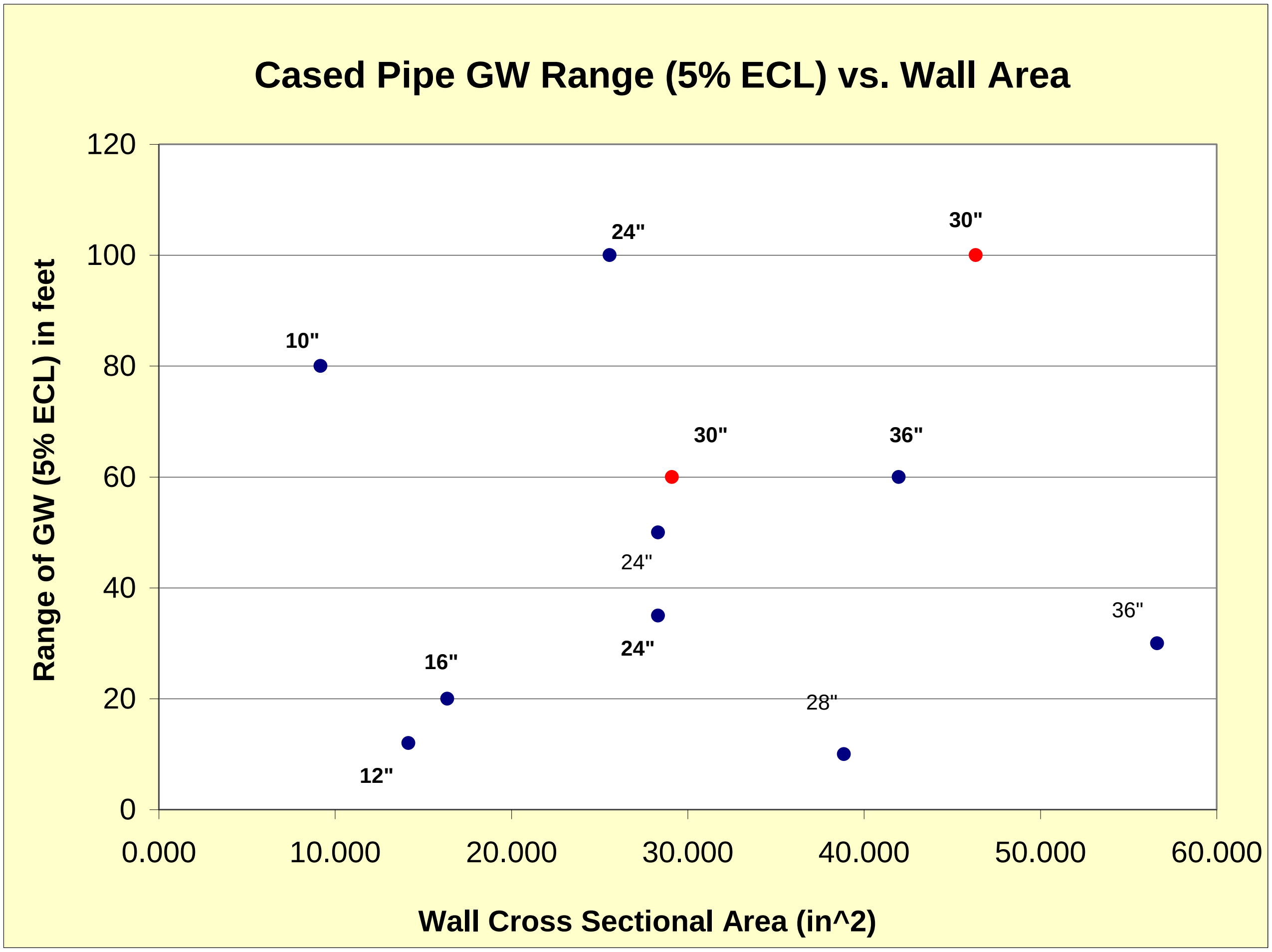


Figure 170. GW Range vs. Wall Area - again there is little correlation with the cross sectional area. The coating, annular contents, and other factors provide the greatest dampening and set the actual range. In general larger pipe have heavier wall which in turn appears to help increase the range.

Cased vs. Buried GW Range in One Direction (broken out by coating type)

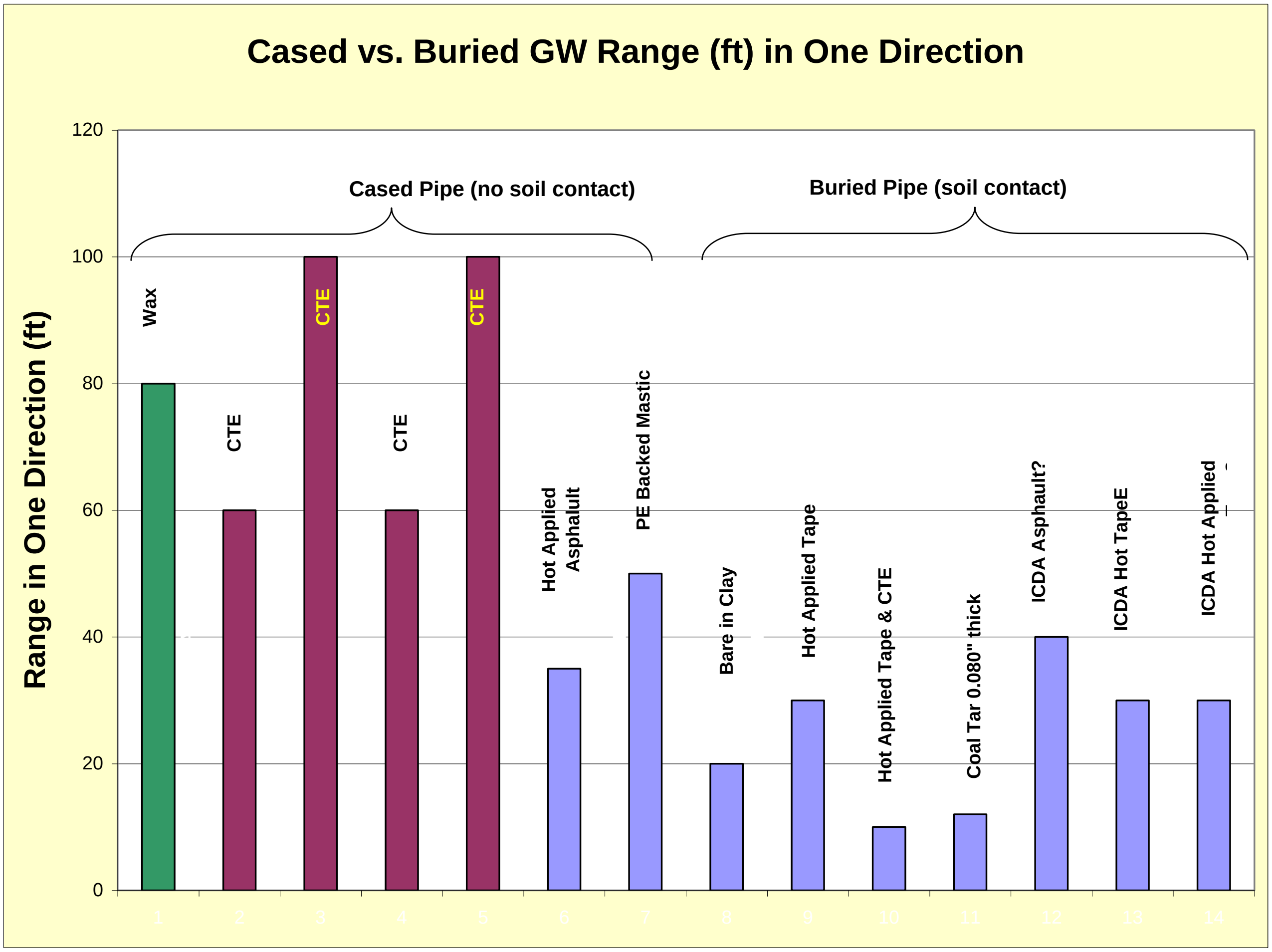


Figure 171. Cased vs. Buried GW Range in One Direction (broken out by coating type) - this arrangement better shows the dampening effects of different coatings. Note that the bare pipe example was dampened by the clay around it. Inspection distances are best determined in the field. The range can vary from a quarter joint (e.g., 10 ft) to almost 2.5 joints (100 ft) in these examples.

Summary Histograms of Guided Wave Inspections of Eighteen (18) Case Study Sites

Summary of Histogram Trends

This section contains diagrams that give an idea of the size and shape of the corrosion that was found in dozens of excavations conducted at eighteen (18) case study sites. It should be noted that when corrosion was found inside and outside of the cased sections that it was all relatively small in size and did not require repair. The pipe could be safely recoated and put back into service in all cases. It is clear from the results as a whole and the results contained in the "hydrostatic equivalent" section of this document that the GWUT tools performed somewhat conservatively.

These pit geometries were directly measured once the coating was removed and the surface cleaned. GWUT only indicated the possibility of corrosion was present or not.

Detected Pit Volume Histogram

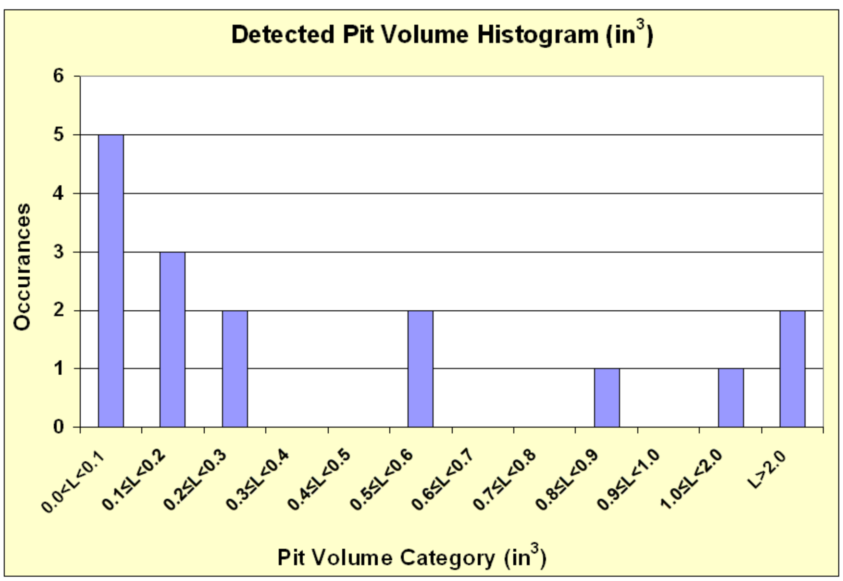


Figure 172. Pit Volume - note that none of these categories are "resolvable" by GWUT yet it predicted the presence of the pits (based on signal-to-noise ratio).

Detected Pit Area Histogram

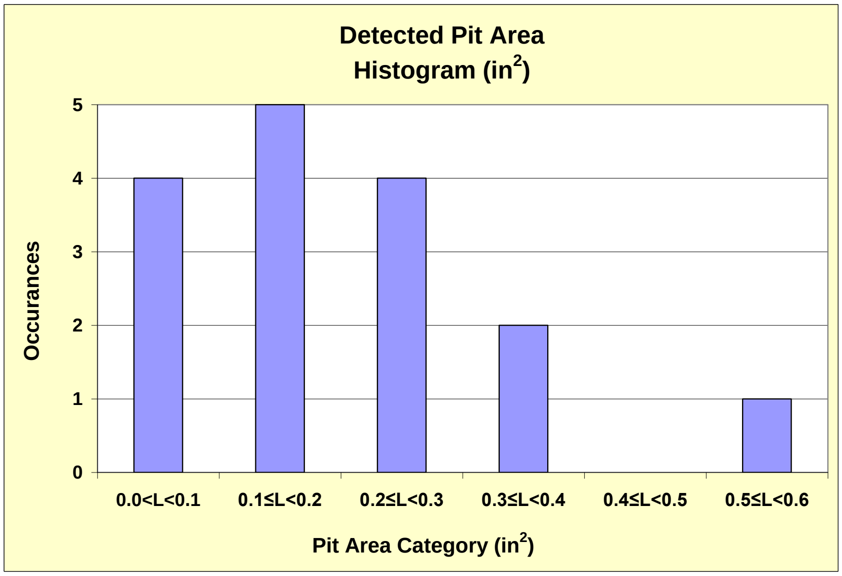


Figure 173. Detected Pit Area - again all categories are less than the typical GWUT wave length yet the pits were predicted.

Detected Pit Length Histogram

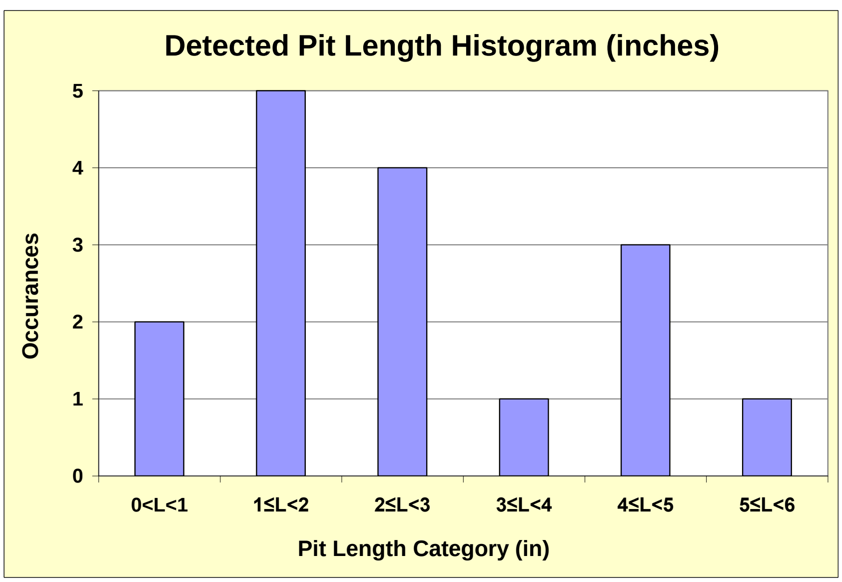


Figure 174. GWUT doesn't actually measure length. Rather the amplitude (over some distance) can indicate if the corrosion area is short medium or longer in length. These show the actual lengths of the indications after excavation, cleaning and measurement.

GWUT reacts well to a "flat" (i.e. normal) sound reflector. For instance, in several digs the old welds on the bare pipe exhibited that the reflection was not even for all 360 degrees. These were called out for additional consideration. When these welds were X-rayed, they were found to have enough lack of fusion and other welding defects that would be considered repairs if made to today's quality requirements.

Detected Pit Width Histogram

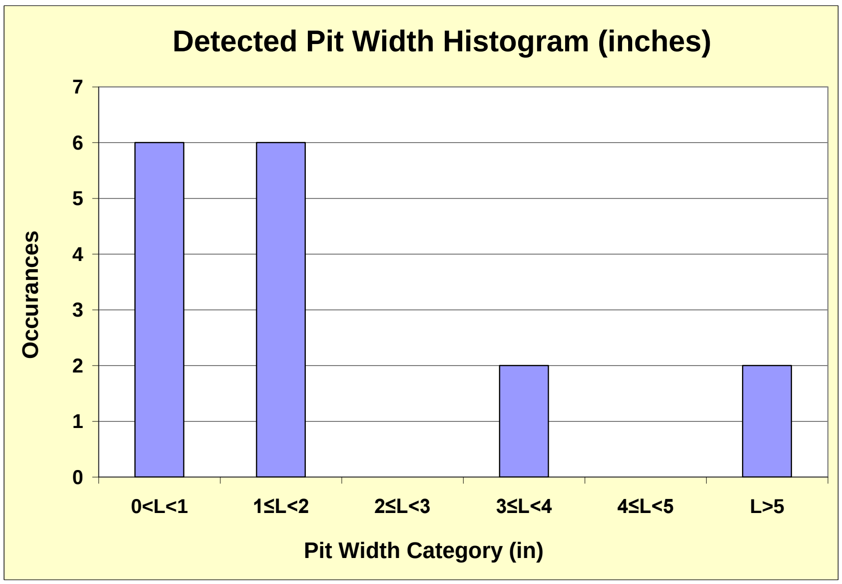


Figure 175. Detected Pit Width - axial width cannot be indicated by GWUT, however the new detection software makes it possible to predict if the corrosion lies in one or more quadrants. In a 24" pipe this width would be around 15 inches.

Detected Pit Depth Histogram

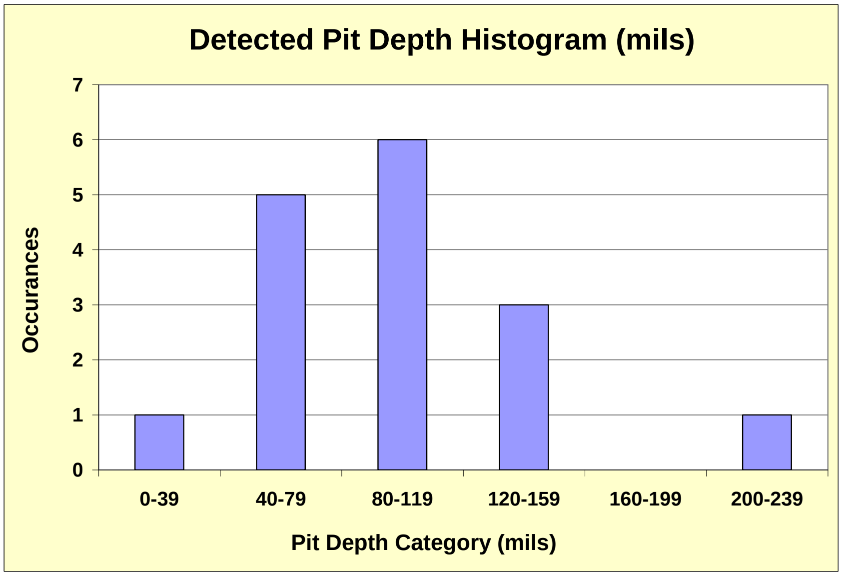


Figure 176. Detected Pit Depth - GWUT was able to find all the deep corrosion. None of these defects failed ASME B31G criteria and therefore all are "monitored" defects that will survive a hydrotest (explained in detail later in the hydrotest equivalency section of this report).

As noted earlier, these depths are much smaller than the associated sound wavelength - so while resolution is impossible, detection is normal.

GW Reliability Based on 100% Validated GW Indications from 18 Case Studies

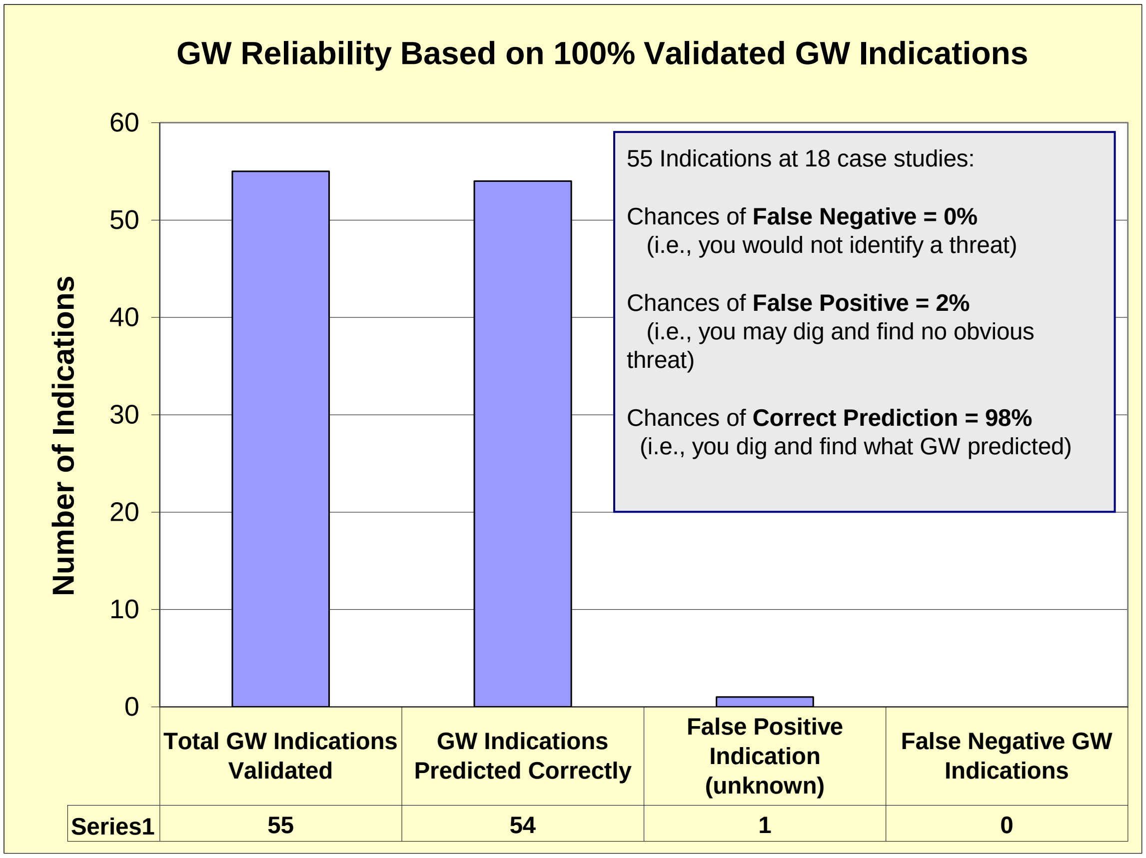


Figure 177. Guided Wave reliability based on 100% validated GW indications (18 case studies - 55 indications; all pipe was uncovered; coating was removed to get to bare metal; further inspection beyond visual was done as necessary, e.g. X-Ray, PortaScan UT, etc.). Note: the lack of any false negatives *includes* all the length of pipe inspected and is a very encouraging result in itself.

The above histograms confirm that GWUT produced very good reliability numbers even though the cases all had very small corrosion damage or none at all. When the casing and coatings were removed, the GWUT operator successfully called all the predictions. No corrosion was found that was not predicted, however one location had corrosion less severe than the prediction, confirming that the tool signals (when interpreted by the current service providers) are basically conservative.

Guided Wave Ultrasonic Testing Background, Technical Explanation, and Field Implementation Protocol to Assist Operators

I. BACKGROUND AND TECHNICAL EXPLANATION

1. Comparison to "Simple" Ultrasonic Technique to Spot Measure Wall Thickness

GWUT is somewhat similar to a simple ultrasonic probe/test used to check wall thickness, or if angled, to look for cracks or other sound reflectors especially in welds.

1.1. The piezoelectric crystal receives a large controlled voltage pulse which expands the crystal, driving a sound pulse into the steel. The crystal then becomes a receiver. The sound pulse travels through the steel, is reflected by the other face and returns to the originating crystal. The sound pulse slightly contracts the crystal which is detected as a voltage spike by the electronics.

1.2. The wall thickness is the time of flight from the signal generation to the signal return divided by the speed of sound and next by two since the sound travels first to the far wall and then returns back along the same distance.

1.3. There is a limit to how short an inspection interval/distance can be inspected because there is a time interval between the crystal acting as a sender and the crystal converting to a receiver. During this transition time, detection is not possible and this is called the dead zone.

2. Guided Wave Ultrasonic Testing (GWUT) Basic Explanation

GWUT is similar to measuring the wall thickness but operates at much lower frequency, 15-50 kHz vs. 2.5-5.0 MHz.

2.1. A ring of sound generators/detectors is placed around the pipe once the surface has been cleaned (thick coatings need to be removed), so that it will couple to the surface.

2.2. The sensors can be simultaneously pulsed causing a ring of sound to travel *longitudinally* down the pipe in both directions or the sensors can be programmed to fire in a regular order to drive a *torsional* wave down the pipe in both directions.

2.3. *Piezoelectric*, magnetic or laser techniques can be used to generate the sound pulse in the pipe. The same kinds of sensors are switched to detection mode to listen for return sound signals.

2.4. A short region, either side of the transceiver collar, is named the *dead zone* and cannot be inspected because the sensors can either be sending or receiving but not both simultaneously.

2.5. The region just adjacent to the dead zone is called the *near zone* and signals in this region are difficult to interpret because the amplitude is not steady. The ring of sensors need to be place far enough from the inspection region to ensure measurements are not required in the dead or near zones.

2.6. Various features reflect sound at different levels. For example, the sound traveling down the pipe can be reflected up to 100% by a flange, whereas welds reflect about 25% of the magnitude.

2.7. The detectors have two sets of sensors at a known spacing. The returning (reflected) sound waves trigger a signal in each sensor ring. The electronics interpret which side of the collar the reflection originated from. The *time of flight* (TOF) divided by two and the speed of sound in the pipe allow calculation of the distance from the collar to the anomaly/feature that reflected the sound.

2.8. Welds, fittings, clamps, in-casing centering cradles, spacers, and support shoes, have characteristic signals. The location of the welds and other construction features can be verified from drawings and used to "field verify" the equipment range of detection at a specified S/N ratio.

2.9. Validation/calibration of the return weld *distance amplitude curve* (DAC) is simpler if a weld cap is exposed. See the following sections for further explanation.

3. GWUT Use for Challenging Inspections

Currently, the guided wave ultrasonic testing (GWUT) inspection process can confirm that the inspected section of a pipeline is free from *significant* wall loss. GWUT may be able to ensure that no defects, that could rupture the pipe segment, are present. This ultrasonic technique is especially useful when pipe is inaccessible or difficult to expose because it is under a crossing or inside a casing. Supplemental leak surveying may help to detect *pinhole* leaks if they occur.

The currently accepted integrity assessments per Part 192, Subpart 'O', are Direct Assessment (DA) which includes ECDA, ICDA, and SCC (see NACE SP 0502, 0206, and 0102); In-line Inspection (ILI), see API 1163 and NACE SP0102, pressure testing (see API 1110), or other technology. These integrity assessment processes ensure the pressure containing capability of the pipe, including those that are cased. If ECDA, ICDA or SCC assessments are not feasible, the chosen alternative integrity assessment should be conducted in a timely fashion so as to have this substitute integrity assessment completed before the original integrity assessment period has expired.

As a standalone technology ("other technology"), GWUT would have to provide equivalent integrity assessment confidence to its users as ILI, DA, or Pressure Test. The detection capability of GWUT cannot be compared to the current ILI technology or the inspection methods employed by Direct Assessment.   Each of these techniques uses different principles of physics.

Even by varying the amplitude, frequency, and direction of the signal travel and the analytical resolution and differentiation of the reflected signals, GWUT can only detect relatively large reflectors, has difficulty determining if the anomaly is internal or external, and has limited sizing ability.

If appropriate, it would eventually be desired to have GWUT accepted as a standalone integrity assessment technology equivalent to at least pressure testing. GWUT can be used as a standalone method for regulated pipelines provided the *PHMSA GWUT "18- Point Checklist" [see Appendix I]* is followed and there is no objection prior to its use under the "other technology" notification process. In the near future, GWUT may be validated as having the capability to identify anomalies that would fail a pressure test (there are current research projects/plans to substantiate this claim).

Any direct visual inspection of the surface requires the operator to excavate, clean, and perform hands on measurements. If the carrier pipe is inside a casing, then the operator would normally be required to take the pipe out of service, cut, extract, and then clean and perform a visual inspection of the area(s) of concern. GWUT would minimize any loss of service caused by line shut down.

4. Stress Corrosion Cracking and 3rd Party Mechanical Damage

To date, neither 3rd party mechanical damage nor SCC has been successfully detected by GWUT (assuming the typical wall loss for these types of features is under 5% Cross Sectional Area - CSA).   Both threats generally produce signals that are below the detection level of the equipment, i.e. GWUT inspection should be used to detect external and internal corrosion.

5. GWUT Use as "Go/No-Go" Decision

Integrity is assured if there are no unidentified anomalies that exceed the agreed "defect" threshold values as set out in the service provider's protocol and agreed to by the operator in the service contract as a specification. For regulated pipelines, the *PHMSA GWUT "18-Point Checklist"* guidance has a maximum defect size of 5% CSA. Guidance for qualifying the different tools and operating personnel in the service provider's protocol can be found in the *PHMSA GWUT "18-Point Checklist"* and appropriate international operator qualification standards for individual tools.

Anomalies that exceed an agreed upon threshold as specified in the service contract, and that cannot be explained as benign from preassessment data, need further investigation. This investigation may be an alternate inspection technique such as exposing the pipe to conduct a visual inspection or could be one of conducting pressure testing or ILI inspection. These are the only two other alternate integrity assessment options if the Direct Assessment methodology being conducted cannot be achieved.

6. Standards Under Development Related to GWUT

Recommendations related to the qualification of equipment, personnel and inspection procedures are discussed in this document. In the future, new standards may be developed to address these and other items related to GWUT. Additional helpful guidance can be found in API 1163 for ILI equipment and ASNT ILI PQ 2005 for personnel.

7. Current Equipment, Software and Inspectors

All the tools provide similar detection capabilities.

7.1. The most recent GWUT tools are the G-3 for GUL and Rev. 3 for Teletest.

7.2. The newest tools and techniques are more automated than previous versions so the inspection is more rapid and the inspector can concentrate on interpretation rather than cross checks for improved performance. These most recent versions incorporate automatic calibration and self-checking features vs. the earlier versions that relied upon manual calibration and checking.

7.3. Prior versions can be used, if the inspector uses the protocols developed for the same generation of tool and is supported with documentation.

7.4. The service provider must show that the equipment and personal are currently qualified in accordance with *PHMSA's GWUT "18-Point Checklist"*.

7.4.1. For third generation equipment: The operating inspector/technician must be First Level, with appropriate manufacturer training for pipelines and cased crossings, while lead inspector must qualify to Senior Level or equivalent (as noted above, this is due to increased automation, i.e. the newer versions relax the need for the previous highest level of competence on the equipment operator level).

7.4.2. For older generation equipment: One needs a Senior Level operating inspector/technician.

8. Distance Amplitude Curve and Welds

The most convenient and accurate way to calculate a proper *DAC* is through the use of an exposed cap/girth weld on the pipe of interest. As previously noted, a series of girth welds will be displayed on the screen as successive reflections of decreasing amplitude.

8.1. The inspection system software can "fit" a line (DAC) to the weld peaks. This is a line of equal reflection, i.e. the welds all have the same cross sectional area reflection. This is the preferred method to generate the DAC curve versus using statistical (typical average) data from previous inspections (this may warrant/justify the extension of the bell hole to expose a girth weld for this purpose).

8.2. The display can convert the curve from an exponential decay (linear-linear plot) to a straight line decrease (via a linear-log plot). The decay line will change slope as the pipe attenuation changes from air to coated pipe in the excavation and then to coated pipe as it passes into the soil at the end of the ditch. These changes in slope represent changes in the attenuation of the sound signal due to "leaking" of the signal into the adjacent coating and soil.

9. Reflection Sensitivity as the Anomaly Threshold

9.1. *Sensitivity* is defined as the ability to identify a reflection of a specified cross sectional change (i.e. CSA).

9.2. *Anomaly (Indication) Threshold* is a fixed percentage of CSA (i.e. it is set equal to the sensitivity) of the reflected energy and is physically represented by a curve on the GWUT output plot. The anomaly threshold is typically 5% CSA. For regulated transmission pipelines 5% CSA is the minimum *PHMSA GWUT "18-Point Checklist"* threshold for no objection to a GWUT assessment. This threshold criteria for fabricated and unknown reflectors should be written into the contract or contained in the pipeline company's (operator's) procedures.

9.3. *Anomaly Threshold Curve(s)* is a parallel, amplitude shifted DAC. The procedure to choose this threshold, and how it relates to the S/N ratio of the specific pipe segment, should be written into the service contract or contained in the pipeline company's (operator's) procedures.

9.4. The magnitude of reflected sound for identical features will decrease with increasing distance from the sensor ring, however the anomaly threshold curve represents a constant cross sectional area reflection amplitude for features along the inspection distance.

9.5. A higher anomaly threshold curve above 5% CSA (say 7% CSA) would allow more pipe length to be inspected before "disappearing" below the combined background noise. Conversely a smaller anomaly threshold curve threshold, say 3% CSA, will reduce the length of pipe that can be inspected because it will intersect the background noise level in a shorter distance. Also, an increasing anomaly threshold curve (such as above 5% CSA) results in increasingly less accurate results of wall thickness loss and length at the far end of the inspection distance.

9.6. Note that there is a trade-off between useful inspection distances and the agreed anomaly threshold curve. Smaller inspection anomaly threshold curves result in shorter useful inspection ranges.

9.7. *Longitudinal waves* interact with the interior liquid content of a pipe due to the fact that liquids are incompressible and therefore want to attenuate the sound wave energy in the axial direction along the pipe. The *torsional wave* form takes advantage of the fact that liquids have no shear strength and therefore there is no coupling (and related attenuation) of the torsional wave from the pipe surface to the liquid contained within it.

9.8. Changing the Threshold Value. Any change from the contract specification must be technically justified within the report by the service provider and agreed to by the operator.

9.9. All the unidentified anomalies that exceed the stated threshold must be investigated, especially those of larger magnitude as specified in the contract (also see Appendix A - PHMSA Checklist).

9.10. Current R&D has focused on:

- Injecting more energy to increase the inspection distance
- Sensor refinement to improve the return signal quality
- Software improvements to focus signals toward specific locations along/around the pipe inspection surface
- Software improvements to calculate and plot topographical C-Scan images of signal reflectors.

10. Defining the Useful Inspection Range

The *signal strength amplitude* (S) must be at least double (2X) the *background noise* (N) over the distance of interest, i.e. one must achieve a S/N ratio of at least "2". The amplitude of the *background noise* is related to the:

- *Electronic noise* (from amplification, i.e. this noise is always present)
- *Intermittent low level reflections* from differences in the coating adhesion, as well as pipe surface roughness.

Threshold amplitude curves (e.g. 5% CSA = sensitivity) must also exceed the level of the background noise by at least a minimum of 2 times. This detection threshold will set the limits of the *useful inspection* distance away from the collar. *Smaller %CSA thresholds provide a shorter useful range but better identification certainty*.

The operator needs to confirm that the full length of the pipe section of interest (the useful inspection range) is adequately covered. In the report the service provider must technically demonstrate to the operator that the entire length of pipe section of interest was inspected and those anomalies that exceeded the *inspection threshold* specified are called out. The report should show the actual inspection distance from each of the collar locations and clearly label the *dead* and *near zones*. The range can be extended by using two bell holes and inspecting the pipe between the two excavations.

Typically the *useful range* of GWUT tools (either upstream or downstream) from the sensor location, can vary depending on:

- Coating thickness and material - Coal tars, asphalt, mastics, waxes, and other soft, pliable, and thick coatings, severely limit the detection range, typically to less than 40 feet in either direction from the collar
- Adjacent soil types and related compaction levels
- Presence of bends, clamps, and the other mechanical connections (originally fabricated into the pipe section) that dampen the signal.

11. As Built Drawings

As built drawings are frequently used to identify structures/features such as: welds, taps, tees, centering cradles, support shoes, spacers, corrosion probes, weld-o-lets, and other construction details. Unidentified reflectors above the anomaly threshold curve require further analysis to provide positive identification. Since GWUT is generally used to evaluate the surfaces of inaccessible pipes, the discovery of a significant unknown reflection necessitates additional excavation(s) and in the worst case removal of the pipe and/or casing for visual confirmation.

12. Casings Considerations to Achieve Full Coverage

Pipe in confined or inaccessible locations, such as cased road crossings may exceed the inspection distance of the GWUT equipment. Excavating at each end of the confined pipe allows inspection from both ends which taken together may provide 100% useful inspection coverage.

The inspector must demonstrate that the pipe length under the end seals, as well as the full interior length, has been inspected. This may require extending the bell hole to allow moving the collar back and forth to find alternate locations in the excavation which can remove the normal inspection uncertainties in the *dead zone* and the *near zone* or *near field zone*.

As mentioned earlier, the bell hole sometimes contains an exposed weld that can be measured and used to help calibrate the equipment on site. The sensor collar can be moved to ensure the weld is out of the dead and near zones. Likewise, the ring can be moved away from the casing ends to ensure they do not fall into the dead and near zones.

The end seal does not interfere with the accuracy of the inspection but may have a dampening effect on the inspection range. Historically, the vast majority of corrosion on the carrier pipe is located at the seals, generally within (inside of) the last three or four feet of the ends of the casing - the proper inspection of this area is critical to the continued integrity of the pipeline. Operators should remove the end seal from the casing at all ends to facilitate limited visual inspection. Water and debris can collect at the low point and cause electrolytic coupling.

Venting (of casings) can also be a source of moisture and debris. Condensation of water vapor within the vent pipe can lead to corrosion of its (the vent pipe) interior surface. The subsequent corrosion product debris (and condensed moisture) can fall into the annular space between the casing and the carrier pipe. The buildup of this debris, typically near the casing ends, can possibly lead to a electrical coupling (short) situation.

Operators should observe and collect the corrosion data, if found, under the end seal and process the data to verify the results of the inspection were correct.

13. Evaluation of Anomalies

Currently available GWUT systems present information that allows the inspector to determine how "localized" the feature of interest is around the circumference of the pipe. For example, it may aid the inspector in determining if the wall loss is from general (spread out/shallow and wide) corrosion or localized (narrow and deep) corrosion in one spot along the circumference.

The manufacturer may have proprietary software to help identify and characterize unknown reflectors. The operator needs to discuss these techniques with the service provider ahead of time and add realistic performance requirements to the contract before starting any work.

The current technology cannot determine if the reflector is on the interior surface or external surface.

II. GWUT FIELD IMPLEMENTATION PROTOCOL (TO ASSIST OPERATORS)

1. Reference or Update Existing Company Standard Operating Procedures (SOPs)

Review SOPs for adequate content, i.e. do not reinvent the wheel and it is desirable to reference existing procedures instead of generating duplicates that require their own separate updating and feedback.

2. Use of GWUT for Transmission Pipe Inspection

Operators must notify PHMSA if they plan to use GWUT. See, FAQ#198 (on http://primis.phmsa.dot.gov web site).

2.1. *Complementary* use is not considered "other technology" by the CFR and does not require notification prior to use. For example, using GW <u>to replace</u> visual inspection after using DCVG or PCM on an uncased pipeline and CIS data is complementary.

2.2. GWUT can be used as a *stand-alone* method for regulated pipelines provided the *PHMSA GWUT "18- Point Checklist"* is followed and there is no objection prior to its use under the "other technology" notification process per §192.921(a)(4).

2.3. Work is still required to improve the ability of GWUT to dimension defects and the physics are such that the GWUT technology may never approach the resolution expected for high resolution ILI tools.

3. Draft/Execute a Contract with a 3rd party service provider of GWUT Inspection Services

3.1. <u>Cost and payment terms</u> should be agreed upon early is typically broken out on a daily or ½ day basis. Agreement as to the number of locations that will be tested per ½ day or full day is helpful.

3.1.1. A ½ day for set-up and ½ day for demobilization is typically common.

3.2. Anticipated <u>schedule</u>

3.2.1. Set target dates of inspection - coordinate with internal gas control, maintenance, permits, engineering, inspection, QC groups to ensure dates will work with all groups and operational restrictions. Excavation procedures may sometimes require some internal pressure changes depending on operating procedures.

3.2.2. It can be beneficial to "build in" an adequate number of "rain days" based on the season/climatology data available.

3.2.3. Agree upon a maximum time limit from completion of guided wave testing in the field to the delivery of signed inspection report(s).

3.3. Agree on preliminary and in-the-ditch diagnostic requirements and performance requirements such as establishing the weld DAC and anomaly threshold curve.

3.4. Agree on responsible party for the validation of results at each inspection location and how all unidentified anomalies that exceed the agreed anomaly threshold curve will be located, classified and confirmed (see Sections A&B of this document for more information).

3.5. Agree upon contents of Final Inspection Report, e.g. anomaly threshold curve, format (Excel, pdf, Word, paper copies), prioritized dig site recommendations, etc.

3.6. Drug Tests (DOT) Use standard operating practice, request test data from 3rd party service provider if available, otherwise make plans to collect sample, etc. as required by the appropriate SOP.

3.7. Insurance Certification - Obtain/confirm insurance certificate from 3rd party service provider is sufficient per company policy. It is best to do this early and require receipt prior to inspection as part of terms and conditions.

3.8. Obtain Qualification Documents/Certifications Ensure that the 3rd Party inspector will present copies of the calibration and qualification certificates for both the equipment and inspectors when they first arrive on site and then ensure copies are attached to the first field report. [see section below for details]:

3.8.1. Tool Capability - Tool calibration and resolution (i.e., what reflection magnitude, quadrant location, orientation, and types of reflectors can they find). Each reflector type shall have a range of confidence.

3.8.2. People - Qualifications of actual people (inspectors) who will run and interpret the results of a job.

3.8.3. Procedures and Experience - Copies (non-confidential) of 3rd party service provider's operating procedures to run the equipment. This should also include the agreed upon procedures for "call-outs" and recommendations for Abnormal Operating Conditions (AOC's).

3.9. Health and Safety Plan - State in the contract the requirements for the 3rd party service provider to attend operator training before inspection set-up or work.

3.10. Establish Confidentiality Agreement

3.11. Logistics - Provide the service provider with a recommendation(s) for:

3.11.1. Airport to fly into

3.11.2. Local Hotel (closest to job site)

3.11.3. Rental vehicle options

3.11.4. Map to the job site and company field office with address and phone numbers.

3.11.5. Exchange lists of 3rd party service provider and operator *cell* phone numbers

4. Guided Wave (3rd Party Service Provider) Tools and Equipment

4.1. Guidance can be found in the Service Provider Requirements section of this document and also in *API 1163, "In-Line Inspection Systems Qualification Standard"*. The following are typical considerations for inclusion in the contract:

4.1.1. Current/Valid Equipment Calibrations

4.1.2. Flexibility with Inspection Parameters Selected (e.g., ultrasonic frequency range, amplitude, input voltage range, and mode - torsional and/or longitudinal).

4.1.3. Discuss possible/expected signal-to-noise ratios and attenuation rates as a function of coating, coating condition and other significant variables.

4.1.4. Correctly Sized and Spaced System Components and Dimensions

- Correct collar diameter for pipe O.D.
- Sensor type
- Sensor spacing

- Single or Dual Sensors (e.g., pulse echo vs. pitch-catch)

4.1.5. Analysis Algorithms (e.g., steps used in preprocessing, classification, and characterization of signals).

4.2. Condition

4.2.1. Ensure equipment is in acceptable operating condition prior to arrival at job site.

4.2.2. Bring spares of critical components that may fail.

4.2.3. Make diagnostic tests of signal generator unit, collar, and sensors before performing first test.

5. Guided Wave (3rd Party Service Provider) Qualifications of Personnel Performing Tasks- 49 CFR 192.801, 803, 805:

5.1. <u>Pipeline Operators</u> - Verify *operator* employees are qualified according to company procedures (e.g., an SDO standard or company SOP/Operator Qualification).

5.2. <u>Individual GWUT Inspectors</u> (part of Contract Requirement, see above) – Guidance can be found in section the Service Provider Requirements section of this document *and also ASTM ILI OP 2005 and in API 1163.* Provide documentation for each person's qualification process (certification) that the following items were addressed and permanently recorded:

5.2.1. Tasks qualified to perform according to their employer’s SOP.

5.2.2. Evaluation Method (e.g., oral board, case study, written and practical exams, etc.)

6. Guided Wave (3rd Party Service Provider) - Procedures

The service provider shall provide the operator with a written performance specification for the inspection. This procedure should include:

6.1. All of the parameters used for the analysis

6.2. The equipment which is going to be used

6.3. The actions followed to ensure that the equipment is working

6.4. A list of prior and working information considered a minimum for the Service Provider to perform the testing and analysis.

6.5. Based on the service providers' review of the pipeline to be inspected and existing conditions, the service provider shall state whether the chosen guided wave ultrasonic inspection system will have sufficient performance in that pipeline, under the existing operating conditions to meet the expectations of the operator.

6.6. The operator should provide the service provider (for review) with the regulations that the pipeline segment is regulated under. For pipelines regulated under the Code of Federal Regulations (49 CFR) §192 and §195 the *PHMSA GWUT "18-Point Checklist"* should be provided.

7. Operator Pipe History (Preassessment) - General

Provide maximum information to 3rd party service provider to aid in guided wave data analysis and screening. The following information is taken from the ECDA and ICDA Data Element Tables (DET):

- Pipeline name and/or number (identification)
- Material and grade
- Diameter
- Wall thickness
- Year manufactured
- Year installed
- Seam type
- Externally and/or internally bare or coated
- Mainline and field coating types
- Repair coatings
- Expected coating conditions
- Route maps and elevation data
- Aerial photos
- Construction practices
- Drawings or locations of fittings, valves, inputs and outputs, and drips.
- Drawings or locations of bends (miter and wrinkle)
- Depth of cover
- ROW paved or unpaved; land use
- Soil characteristics; freezing issues
- Drainage and topography
- CP system

- Pipe operating temperature
- Operating stress levels
- Internal coupons or probes
- Gas flow rate and direction
- Solid scales or sludges present
- Pipe inspection reports & repair history records
- Leak and rupture history
- Hydro-test dates
- DA tool inspection results - CIS, ILI, DCVG, ACVG, PCM, etc.
- Pipe data thickness, diameter, grade, etc....

8. Operator Pipe History (Preassessment) - Casings

It is advisable that the operator collect the following information before beginning the job and provide this information to the 3rd party service provider as soon as possible:

- Annular space filling (e.g. wax, air, water, etc.)
- Presence and design of end seals
- Presence and design of external structural supports
- Presence and design of centering cradles (aka, spacers or centralizers).

8.1. Indication if prior inspections suggested that the carrier pipe is mechanically shorted or electrically coupled to the casing.

8.2. It is suggested to gain access at the lower end first. If electrolyte is present the water should run out of the casing when the seals are opened.

9. Operator - Safety

9.1. Ensure 3rd party service provider is given proper safety briefing.

9.2. Site safety

- shoring
- pumping
- environmental (e.g., chemical contamination site), Personal Protective Equipment (PPE)
- Emergency procedures

9.3. Review company's abnormal operating procedures [e.g., 49 CFR 192.605(c) or applicable regulator code].

10. Operator - Pick Inspection Sites by priority

An operator must identify and evaluate all potential threats to the pipeline segment (e.g., see 49CFR §192.917 for High Consequence Areas (HCAs). GWUT is an evaluation of potential threats for internal and external corrosion.

10.1. Site accessibility may be an issue for selection.

10.2. Look upstream and downstream, etc.

10.3. Lead time for permits and clearing of Right-of-Way (ROW) for BOTH the known holes required for guided wave transducer placement AND anticipated validation excavations (for indications or check of non-indications) and possible repairs.

10.4. Lead time for shoring should be included. Have the appropriate type of shoring for the soil conditions, as well as extra shoring available if the excavation needs to be lengthened and /or widened during the inspection.

10.5. Consider inviting Federal and State inspectors present for early inspections (OPS/DOT and State PSC, etc.).

10.6. Consider inviting other/sister LDC's as learning experience.

11. Operator - Prepare Excavation Site

11.1. Excavation should be as close as practical to the end of the casing to ensure the maximum inspection length within the casing. However one must balance this by ensuring that the dead and near field zones lie outside the cased (inspected) length.

11.2. If this is a long inspection distance and the far end is a predicted location for "water hold-up" (or other critical feature) consider access to both ends to inspect from both directions. This is especially important if a casing or crossing is longer that the expected valid inspection range based on the interaction between the anomaly threshold curve and background noise (see Section B for more details).

11.3. Median access is generally difficult to arrange if access to one side only allows partial inspection. Historically corrosion is located within the first several feet of the ends of the casing (see *PHMSA GWUT "18 Point Checklist"*).

11.4. Excavation size needs to be big enough for two people to fit in the hole and install a transducer ring. Soil under the pipe needs to be excavated to ensure there is at least one foot clearance below the bottom of the pipe. The coating and corrosion products generally need to be removed to ensure there is bare pipe under the coil sensors. Excessive corrosion can lead to errors in interpretation.

11.5. Have drainage and pump systems ready with a back-up plan if a pump fails. Commence pumping so site is dry for inspection.

11.6. To maximize the guided wave inspection time, the coating should be assessed per the ECDA Direct Exam Protocol (e.g., coating thickness around the pipe, etc.) and then removed prior to the arrival of the 3rd party service provider. A long length of coating removal is unnecessary. It is recommended that the Operator agree with the Service Provider on the location(s) where it is best to remove the coating. Sometimes to inspect the pipe inside a barrier it is necessary to conduct two inspections. One inspection is done farther away to ensure the inaccessible region does not fall within the dead and near zones and a second inspection is done adjacent to the barrier (e.g., end seal, wall penetration, etc.) to improve the inspection behind the barrier.

11.7. Since the guided wave technique inspects in BOTH directions simultaneously, one should be prepared to excavate in EITHER direction if an indication warrants this.

11.8. If at all possible, use an exposed girth weld(s) to improve the weld DAC and subsequent anomaly threshold curve, and reference all measurements and especially indications to the open girth weld. This will also help with integrating the drawing information.

12. Operator - Ensure there is an agreed upon, written procedure for the response actions for anomalies:

Establish a criteria for a callout level from the anomaly threshold curve amplitude and directionality indications, e.g. if there is a reflection greater than or equal to 5% cross sectional loss (i.e., anomaly threshold curve is set at 5%), then either explain from pre-assessment data (e.g., fitting location) or excavate and visually examine and measure.

Regulated pipelines should be inspected and evaluated in accordance with the PHMSA go/no-go criteria of the GWUT "18-Point Checklist" (also see table directly below).

<table>
<tr><th colspan="4">Required Pipeline Response (from Appendix A - PHMSA GWUT Checklist)</th></tr>
<tr><th>GWUT Criterion</th><th>Less than 30%</th><th>Over 30 to 50% SMYS</th><th>Over 50% SMYS</th></tr>
<tr><td rowspan="4">Over 5% CSA and identified for examination</td><td>Interval < 12 month</td><td>Interval < 6 months</td><td>Interval < 6 month</td></tr>
<tr><td>Leak survey once/month</td><td>Leak survey once/month</td><td>Reduce to 80% MOP@Discovery</td></tr>
<tr><td rowspan="2">Direct Examination</td><td>Direct Examination ~</td><td rowspan="2">Direct Examination ~</td></tr>
<tr><td>MOP < psi@discovery</td></tr>
</table>

Be prepared to pull pipe and/or casing for visual inspection. In this case be ready with:

- Parts and equipment on hand - new pipe, clock springs, sleeves, etc.
- Qualified people ready to install or repair section
- Recoat material and surface preparation equipment ready
- Sufficient, appropriate, and approved backfill material on hand.

13. Inspector - Run the guided wave test.

Follow the manufacturer's procedures. Observe safe excavation practices, especially while climbing in and out of the site. Some sites require a hot work permit and since the equipment is not explosion proof a gas analysis will be required before the coil and related cables are lowered by rope into the bell hole. Ensure all cables and coil fasteners are installed correctly and tight so the belt when pressurized does not hurt the inspector. It is recommended that the wall thickness around the circumference of the pipe be verified.

14. Inspector and Operator - Review Preliminary Results While Still in the Ditch

14.1. Ensure 3rd party service provider immediately informs operator of any *abnormal operating conditions* (AOC's). The inspector usually runs several different inspection sets to ensure the ends of the ditch, known fittings, and all welds are identified and these location are typed directly onto the screen locations. Ensure the DAC is fitted correctly and then ensure the inspection distance will be sufficient. Change the frequency when probing any unidentified reflectors to help resolve what these might be if not on the as built drawings.

14.2. Ensure 3rd party service provider immediately informs operator of any indications close to the edge of the excavation allowing the operator the option to immediately extend the excavation to expose and inspect them. Validation improves the inspection for the inaccessible pipe.

15. Inspector and Operator - Receive Inspection Report which includes (at a minimum, see contract section):

15.1. Integrate all inspection indications and pipeline features whether or not they were on the as built drawings, to a common reference such as a sketch or image on the inspection report.

15.2. Recognized limitations of specific inspection results

15.3. Summarize indications which fall into the agreed severity classes and other indications as features. Provide photographic evidence if possible. Write all the dig and defect related info on the pipe so these are visible in the photographs.

15.4. Recommend follow-up activities at the dig sites if any.

16. Operator - must confirm Inspection Report Results

One may need to re-prioritize the remaining inspection digs based on new findings, operating constraints, and level of risk (safety, environmental, operational, continuity of delivery, etc.).

17. Operator - Management of Change

If the SOPs of either the operator or the service provider cannot be followed for any reason, then these deviation(s) must be documented following the operator's management of change process which may include the following:

- Reason for change
- Authority for approving changes
- Analysis of implications
- Acquisition of required work permits
- Documentation
- Communication of change to affected parties
- Time limitations
- Qualification of staff
- Date and signature of the most responsible supervisor or manager.

For further guidance on Management of Change see, *ASME B31.8S, "Managing System Integrity of Gas Pipelines".*

18. Operator - Records of Inspection

18.1. Minimum record keeping-requirements shall be documented. These records shall include not only the inspection data related to the pipeline, but shall also include records pertaining to the setup of the equipment, personnel involved in the performance of the inspection and analysis of data, and a record of the inspection equipment used for the inspection.

18.2. Records shall be maintained to the level that will allow the recreation of the system set up for inspection system verification and validation purposes. Additional information may also be maintained as part of the inspection record as determined between service providers and the pipeline operator.

18.3. Inspection records shall be retained for a time period no less than that required for legal or regulatory purposes. Adequate measures shall be taken to protect the records from loss or damage.

18.4. When developing storage and regeneration procedures for inspection data, changes in data collection technology should be considered.

19. Lead Inspector Requirements (from the Service Provider)

19.1. The lead inspector must have successfully met or shown to exceed the equivalent of a First Level qualification with specialized transmission pipeline external and internal corrosion detection training from the GWUT equipment manufacturer and preferably hold a Senior Level qualification requirement (see *PHMSA's GWUT "18-Point Checklist"*). The preferred methodology follows:

Sections 20 to 26 present helpful qualification (people and tool) and inspection information. However, "***regulated pipelines" should be inspected and evaluated in accordance with the PHMSA go/no-go criteria of the GWUT "18-Point Checklist"***

20. The <u>GWUT Inspector</u> Qualification should incorporate the following chapters and ideas:

20.1. <u>Scope</u>: This standard operating practice must establish the minimum requirements for the qualification and certification of those operators whose job is to use and interpret the results of the GWUT, and who are required to have a specialized knowledge of pipeline operations, regulatory requirements and industry standards. The qualification and certification of these personnel should be the responsibility of their employer.

20.2. Applicable <u>References</u>

20.3. <u>Definitions</u>

20.4. Written Practice: The employer needs to have a written practice on file for the control and administration of the GWUT personnel training, examination and certification. This practice must describe the different levels of responsibility, and lay out the minimum requirements for entry into each level. It needs to be periodically reviewed and approved by designated and responsible managers.

20.5. Levels of Qualification: *Generally* there are four levels of qualification:

- Trainee – no independent work, no reporting, no interpreting
- Level 1 (First Level) – entry and simple independent work, limited reporting and training under the direction of a Level II or III
- Level II (Senior Level) – limited responsibility for reporting and simple interpretation with limited supervision, and independent work
- Level III (Train the Trainer, i.e. above Senior) – overall responsibility

The individuals have different responsibilities for establishing techniques and procedures, interpretation of codes and standards, review of customer requirements, data analysis, final report writing, review of subordinate's work, and training of subordinates.

20.6. Education Training and Experience Requirements: *Generally* the higher levels require increasingly more rigorous effort such as:

	Training	Experience	Formal Education
Trainee	Introductory	none	High school
Level I	Basic	>1/2 yrs	High school
Level II	Advanced	About 2 yrs	High school
Level III	Additional physics practice and theory	About 5 yrs	Community College or better

The experience and training requirements are cumulative experience relative to site-specific conditions. The employer must record and retain the employee's records to maintain company compliance.

20.7. Training Programs: These can use outside training services or be generated in-house by the employer. The employer is responsible to ensure the training meets the requirements of the written practice.

20.8. Examinations: The employer shall administer and grade the training whether it be oral, practice, or written. These numerical results must be kept in the employee's record and in a central record. The employer must provide periodic vision examinations including color blindness and record the results with the employees training and experience records.

20.9. Certification: The certification is based on records of education, training, experience and examination and shall be administered by a suitable employee delegated by management (Level III). If outside organizations are used the designated employee is responsible to ensure compliance to the written practice.

20.10. Technical Performance Evaluation: In addition to period re-evaluations by examination, the employer may require a recertification program at any time were the employee must demonstrate they have maintained their level of training and application of the practical art.

20.11. Interrupted Service: If the employee was reassigned to other tasks and is asked to become an inspector again, the employer can re-administer the examinations to re-certify the employee.

20.12. Recertification: The written practice shall specify the maximum period between re-evaluation and this could be by documented review or reexaminations.

20.13. Termination of Certification: Certification is revoked if the individual fails to re-qualify or if terminated.

20.14. Reinstatement of certification: Previously certified individual maybe reinstated to their former level without re-examination if termination was less than 6 months, the employer holds certification, and the employees certification did not terminate in the interim.

20.15. Regulated Pipelines: 49CFR §192 and §195 - For regulated pipeline segments the *PHMSA GWUT "18-Point Checklist"* gives guidance on service provider training

21. Lead Inspector (usually a service provider) is Responsible for All Aspects of the Inspection:

21.1. Understanding the basic technology to direct employees and conduct educational discussions with the operating company project manager.

21.2. Provide an overview of the technology, operating principles, specific details such as frequencies, software algorithms, distance accuracy, anomaly identification and classification, tolerance in opinions expressed.

21.3. Provide records that trace the ownership and the type, model, calibrations, and validated detection performance of the equipment package including software, to ensure compliance with the conditions set out in the contract, substitutions must be agreed in advance.

21.4. Ensure that the whole team is employer-certified and these are recorded.

21.5. Work with the operator's project manager to understand the peculiarities of the system being inspected, especially the placement of welds, supports and other construction details which may not be exposed for visual verification.

21.6. The lead inspector will present copies of the certifications and qualifications of both the equipment and employees to the operator's project manager before entering the site.

21.7. Plan, conduct, coordinate, manage and report all aspects of the inspection and support opinions expressed.

21.8. Deliver a summary report before leaving the site and the detailed report within the timelines agreed in the contract.

22. <u>Lead Inspector</u> (usually a service provider) *in-the-ditch* Inspection Requirements:

22.1. The lead inspector is responsible to have all the equipment and helpers on site ready to work at the previously agreed time. This includes critical inspection and safety equipment spares.

22.2. In the ditch equipment to measure wall thickness, provide equipment diagnostics and the determination of a local DAC to meet performance requirements set out in the contract.

22.3. Validation of the DAC using exposed and unexposed welds and other feature locations contained on the drawings when possible.

22.4. Inspection of the pipe volume from two or more locations (if required to avoid inspections falling in dead and near zones).

22.5. Presentation of a preliminary report listing all the anomalies that exceed the threshold DAC.

22.6. Work with the operator project manager to identify all anomalies.

22.7. Confirm, and then deliver, a preliminary report that identifies the location of all unidentified anomalies that exceed the criteria with an estimate of the size and probable origin of each unknown before leaving the inspection site.

22.8. Cleanup, responsibly dispose of garbage, repack, and then remove all equipment and personal effects from the site.

23. <u>GWUT</u> <u>Tool Qualifications</u> by the Manufacturer

This standard operations practice should incorporate the following ideas:

23.1. Scope: This standard practice must establish the minimum requirements for the qualification and certification of the guided wave equipment. The qualification and certification of the equipment should be the responsibility of the manufacturer. In addition:

- The manufacturers and service providers must make clear, uniform, and verifiable statements so as not to oversell the actual equipment performance.
- The equipment must be capable to complete the job contracted.
- The equipment must operate properly for the job specifications.
- All procedures are to be followed before during and after inspection.
- Anomalies are to be described using a common nomenclature.
- The reported data and inspection results provide expected accuracy and quality in a consistent format.

This describes both existing and developing equipment for inspection of onshore and offshore gas and hazardous liquid transmission lines. This standard is an umbrella document that sets performance based expectations for the procedures, the equipment with software and the personnel that must operate them and interpret the results.

23.2. Applicable References

23.3. Definitions and Terms

23.4. System Qualification Process – The tool shall be sufficient for the proposed inspection, and the characteristics of the expected anomalies and features to be detected and sized and the required accuracies set out before hand in the contract between the service provider and the operator. Standard manufacturer practices shall be followed to calibrate before transport to the site, for diagnostics prior to each inspection, for data recording and presentation, and for data analysis especially if done automatically. Each inspection shall be validated before full analysis. The report shall be delivered in a timely fashion and in a consistent format.

23.5. Personnel Qualification - Personnel shall be qualified according to the previous section.

23.6. System Selection: The choice of the system with the accompanying procedures must be suitable for the inspections. Newer technology may be considered when appropriate.

The service provider must confirm that the equipment is suitable for the inspection. The S/N threshold levels, probability of detection (POD) and the classification of anomalies for mitigation or repair must be discussed and agreements written into the contract prior to inspection.

23.7. Performance Specifications – If performance specifications may not be met in the field due to insufficient S/N ratios at longer distances from the collar, or other reasons then the operator is to be notified immediately.

23.8. Documentation: The equipment should maintain an electronic record of the measurements and interpretation. The inspector must record all physical measurements, with photographic support to support later interpretation of marginal response signals.

23.9. System Results Verification: The data should be consistent with historical records or investigate why there are differences. Operator excavations and all measurements taken to verify detected anomalies shall be recorded and copies sent to the inspector to enable updating of the interpretations.

23.10. Reporting Requirements: These shall be standard and recorded in the contract prior to initiation of any inspection. They shall describe the date, location, equipment manufacturer, model, serial numbers of all parts, most recent calibration results, field diagnostics, sensor readings and interpretations. Similarly the operator shall identify the date, location, component identification, plus the excavation data, coating condition with report, diameter, wall, grade, date of installation etc The inspector needs to classify each indication as feature, imperfection, or a defect and these defects as a low medium or high concern.

23.11. Quality Management System: The quality management system shall ensure consistent products and services are being delivered, that these are being properly controlled to prevent delivery of unsatisfactory services, and that adequate measures are in place to ensure that the services provided continue to meet the needs of the operator. This shall apply to all activities involved in the design testing, field operations, data analysis, and support services that specifically relate to the GWUT inspection tool as covered in this document. They should consider including:

- Limitations and Scope
    - Quality Management to meet Safety, Regulatory and Environmental requirements
    - Set the Requirement to Review the project prior to initiation, during, and after for compliance
    - Establish Communications and Interfaces to resolve issues in a timely fashion

- Quality System Documentation
    - Procedures and Work Instructions must be set ahead of time by the service provider and operator and maintained or written reasons provided for deviations
    - Record Keeping
    - Document and Revision Control must be maintained for all documents
    - Design Change Control and ensure modifications are communicated in a timely fashion
- Quality Control
    - Personnel Qualifications maintained for the service provider and operators
    - Calibration and Standardization records current and available
    - Traceability through records and on equipment
- Continuous Improvement
    - Process Measurement of change by previously agreed measures of change
    - Corrective and Preventative Action if actions fall outside agreed limits
- Quality System Review
    - Periodic Internal Audit
    - External Audit

24. Operator Project Manager Qualification Requirements

The project manager must meet company operator qualification requirements according to the appropriate SOP. This could be:

- Senior specialist or engineer with project management skills
- Five or more years operational experience and formal training on the procedures
- Successfully met manufacturer's or service providers training requirement for external and internal corrosion on transmission pipelines

25. Operator Project Manager is Responsible for All Aspects of the Project:

- Understand the basic technology to lead discussions with service providers.
- Help negotiate the service contract for most appropriate equipment and software.
- Plan, conduct, coordinate, and managing all aspects of the project, this includes arranging for permits, safety meetings and backup safety gear, instructing the service providers so they meet company safety expectations, having on hand, or nearby, all the permits materials and skills to replace or repair any pipe that fails the defect criteria.
- Assemble all the necessary construction, historical performance, and current drawings of the pipe and related assemblies to share with the service provider and to have as reference material on site.

- Ensure both the service provider and company employees and equipment comply with internal and external procedures and expectations. Confirm records that trace the ownership and the type, model, calibrations, and validated detection performance of the equipment package including software, to ensure compliance with the conditions set out in the contract, substitution is not allowed unless agreed in writing before the contractor shows up on site.
- Review preliminary results for obvious errors or inconsistencies, all details, opinions, and supporting explanations while the inspection is being conducted or before the service provider leaves the site.
- Remind the service provider of impending reporting deadlines to ensure timely revisions of integrity plans.
- Conduct remaining life estimation to confirm that the interval until the next integrity assessment remains valid for the pipeline region.
- Review, and annually, update company standard operating practices based on practical experiences.

26. <u>Operator</u> in the Ditch Inspection Requirements:

- Prepare the excavation and ensure all people can work safely.
- Provide power, ditch drainage control, and cover in inclement weather.
- Ensure that the pipe surface is cleaned and correctly prepared for the equipment.
- Check the paperwork which shows the qualification of the equipment and equipment operators meet internal and external standards.
- Check that the equipment was recently calibrated, is complete and has been shown to work correctly.
- Check that the equipment verification of the DAC used exposed and known welds and was conducted by the service provider prior to the actual inspection. Verify that the equipment range was adequate to inspect 100% of the desired pipe segment.
- Review all results to verify opinions expressed by the service provider.
- Confirm that the inspection(s) covered 100% of the length of the pipe segment and that the pipe is free of reflections that meet or exceed the contract specified defect threshold.
- Work with the service provider to determine if the unidentified indications require an immediate or scheduled response.

- Be prepared to document exceptions if, in the opinion of the service provider's lead inspector and the project manager, an alternative approach to quantifying unidentified anomalies is needed.
- Schedule all recoating, repair, or replacement actions before leaving the site.
- If the GWUT failed to provide 100% inspection then the project manager must make the pipe accessible to a visual inspection of the pipeline segment or arrange to conduct one alternate integrity assessment technique such as either ILI or pressure testing. These alternatives will need to occur within the periodic re-verification window for the pipe not inspected.
- Written and oral communications inside the company will require a timely report for each site which may be updated when the service provider submits their final report.

END

Equivalency of GWUT to Pressure Testing - Review/Analysis of White Paper

This section is the deliverable for the additional scope of work requested by DOT/PHMSA in accordance with DTPH56-06-T-0001, Modification 0001 dated August 28, 2007.

A summary of this section:

Accuracy of predictions versus direct examinations

- Review a select subset of GWUT data collected from various test locations (field trials with 100% direct exam validation digs) and analyze the data to spot-test the acceptability of the tool "The Equivalency of GWUT to Pressure Testing" [white paper to be provided by the COTR] to detect indications that would fail under a hydrotest (failure pressure ratio of 1.25 for Class 1 locations) for integrity assessment.
- The selected Guided Wave inspection data will be input into the referenced model (DOT Provided white paper attached as Appendix A of this report) and then compared with the actual direct exam measurements input into ASME B31G Manual for Determining the Remaining Strength of Corroded Pipelines a Supplement to ASME B31 Code for Pressure Piping.
- Results of this comparison will be reported to DOT/PHMSA COTR.

Results and Discussion

Method of Analysis/Comparison

The subject white paper, "The Equivalency of GWUT to Pressure Testing for INGAA Rev. 11, 07-07-16" was reviewed at PHMSA's request.

For the purposes of this review, GTI used ASME B31G "Manual for Determining the Remaining Strength of Corroded Pipelines" to compare verified field data and Guided Wave inspection predictions (this is a conservative approach). The subject white paper uses the "Modified" ASME B31G Equation.

Figures 5-7 of the white paper plot Total Length (in) vs. Pressure (psi) and run a series of curves for different d/t%'s (i.e., pit depths, d, as a percentage of wall thickness, t). They also overlay the 1.25 MAOP Test Pressure (TP) curve for a Class 1 pressure test and the 4% and 5% Cross Sectional Area (CSA) plots manufactured from geometric assumptions about the pit geometries. The format of these plots does not lend itself to the clear understanding/comparison of:

- The predicted features (Constant %CSA) as a function of d/t% and length to actual corrosion defect data points (from excavated and measured corrosion pits).
- The clear plotting and understanding of the "Failure Pressure", Pf (which is independent of the class location and reduced MAOP).
- The comparison of the "Safe Pressure", Ps to the Pf where the Ps is calculated for the same pipe configuration (Grade, Diameter, and Wall Thickness) for a Pressure Test in all four class locations.
- The comparison of the (d/t%, Defect Length) contour for a constant CSA vs. the Ps for each TP condition, as well as the (d/t%, Defect Length) of the actual corrosion defects from validation digs identified by GWUT.

Because of this, GTI plotted the information of interest in a different way:

- Plots now have Corrosion Defect Length (in) along the x-axis and d/t% (corrosion max depth/wall thickness) along the y-axis.
- Curves are plotted for Pf and Ps (for a particular Class Location and Test Pressure).
- Actual corrosion defects from validation digs are plotted as points and constant CSA contours/curves are also plotted for comparison purposes.

- Three additional plots were constructed to show the Pf and Ps for standard operations (not under a pressure test) in Class 1, as well as two different CSA contours above and below the 5% CSA curve.

Explanation of Figures 1-8 (see Section 4 - Figures)

Two pipe sections were plotted up:

- 24" diameter, API 5L X52, 0.344" wall (Figure 178 to Figure 181), and
- 30" diameter, API 5L X42, 0.312" wall (Figure 182 to Figure 185).

Figure 178 to Figure 181 are plotted with the Ps calculated for Class 1 to Class 4 pressure tests (hydro tests) respectively. Seven independent corrosion defects (actual excavations and direct exams for 100% validations of GWUT inspections on the same) for this configuration of pipe are also plotted as blue squares.

Figure 182 to Figure 185 are plotted with the Ps calculated for Class 1 to Class 4 pressure tests (hydro tests) respectively. Five independent corrosion defects (actual excavations and direct exams for 100% validations of GWUT inspections on the same) for this configuration of pipe are also plotted as blue squares.

In all the figures the **red curve** is the B31G *Failure Pressure*, Pf, i.e. if one raised (set) pressure to produce a stress of 100% SMYS (in the pipe wall), see ASME B31G paragraph 1.6a for reference. The red curve traces out what combination of pit depth (d/t%) and associated maximum length in the axial direction would result in the failure when the pressure is set to achieve 100%SMYS (P = 2St/D), where S = SMYS, t = pipe thickness, and D = pipe diameter. Note that for all the red curves, the design factor is set to 1.0 since physical pipe failure is not dependent on what class location the pipe resides in. The plot is bounded by 80% on the d/t% (y axis) as B31G is bounded by the same.

In all the figures the **green curve** is the B31 Safe Pressure for a pressure test, Ps, and is calculated the same way as the Pf except the design factor (F) is now set to 0.72, 0.60, 0.50, and 0.40 for Class 1, 2, 3, and 4 respectively and the test pressure (TP) is set by SMYS x F x 1.25 for Class 1 & 2 or SMYS x F x 1.5 for Class 3 & 4. Note that the TP could be set (in accordance with *ASME B31.8S Managing System Integrity of Gas Pipelines* Table 3) to MAOP x 1.39, 1.40, 1.70, 2.2, 2.8, and 3.3 as appropriate. These could then be plotted out as additional green Ps curves for these TPs. However, the red Pf curve would still be the same.

In all the figures the **blue squares** are the actual defects identified by guided wave as indications that should be dug up, investigated, and sized. Note that for both the 24" and 30" pipe sizes, all twelve of the defects were below and to the left of the red Pf curve, i.e. they "passed" the ASME B31G criteria. Similarly, all the defects were below and to the left of all the green Ps (for the associated TPs) and 5% constant CSA curves.

In all the figures the **purple curve** is a plot of a constant cross sectional area (CSA). In **Figure** 178 to **Figure** 185 these curves are set to 5% CSA and are fixed. The shape of the curve is a function of the pipe diameter, wall thickness (both of which determine cross sectional area) and the relationship between d/t% and defect length (in the radial direction). Since in this case the radial length is part of the calculation (and not the axial length for Pf, Ps, and actual corrosion pits) one must assume a relationship between the radial length of the pit and the axial length to plot the curve on the same plot as the other data. In the white paper it was assumed that the pit is a "box" with one side (depth) set to the pit depth (d) and the other two sides (radial and axial) equal and set to maintain a constant 5% CSA as d and d/t% range from 0% to 80%. From this assumption one can then calculate the axial length from the assumed d/t%. This assumption turns out to be a key item when one compares the constant CSA plots to the actual pit depths and length identified by GWUT and will be discussed in the next section.

Figure 186 is different than the first eight figures in that it is a simple representation of the same 24" pipe operating in a Class 1 location with F = 0.72 and MAOP = 2StF/D or 1073 psi in this case. Here the Ps and Pf curves overlap as one would expect. ASME B31G is designed so that at a calculated MAOP, if one meets the Ps criteria, one will "pass" or not exceed the Pf when pressure is raised to generate a stress in the pipe wall equal to 100% SMYS.

To show how the %CSA curve changes when one selects different constant areas **Figure** 178 was re-plotted with a %CSA set to 2% for **Figure** 187 and a %CSA set to 10% for **Figure** 188. These will be explained in the next section.

1. For the first eight figures, the green Ps curve (related to the appropriate pressure test and class location) always allows larger defects (i.e., the curve is above and to the right) than the red Pf curve. This is because the design factor for both situations is set to F = 1.0, but for the pressure tests presented, the input pressure is always less (e.g., 0.9x, 0.75x, or 0.6x) than the pressure to achieve a stress in the pipe of 100% SMYS.

2. The actual pits found by GWUT (with no false negatives or positives after 100% direct examination) all fall below and to the left of the Pf and Ps (pressure test) curves.

3. These same, measured corrosion pits also fall below and to the left of the 5% CSA curve.

4. For the 24" diameter pipe:
    a. Class 1 Pressure Test - the 5% CSA curve is above and to the right of the Ps curve if the defect is ≥ 10.5" long (which corresponds to 36% d/t depth).
        i. If one were to set the CSA to 2% (see **Figure** 187) the associated CSA curve would be below the Ps curve for the pressure test and nearly overlay the Pf curve.
        ii. If one were to set the CSA to 10% (see **Figure** 188) the associated CSA curve would be above and to the right of the Ps curve for the pressure test.
    b. Class 2 & 3 - This cut-off shifts to 4.9" long and 76% d/t.
    c. Class 4 - The 5% CSA is always below and to the left of the Ps curve. The CSA curve truncates at about 4.7" since it is at 80% d/t.

5. For the 30" diameter pipe:
    a. Class 1 Pressure Test - the 5% CSA curve is above and to the right of the Ps if the defect is ≥ 13.8" long (which corresponds to 34% d/t depth).
    b. Class 2 & 3 - This cut-off shifts to 6.8" long and 68% d/t.
    c. Class 4 - The 5% CSA is always below and to the left of the Ps curve. The CSA curve truncates at about 5.8" since it is at 80% d/t.

In all cases, GWUT successfully called out defects that were less severe than the 5% CSA "criteria" curve (with associated geometric assumptions). The anomalies that were ≥ 5% Cross Sectional Area (CSA) were dug up, had their coating removed, and the subsequent pits were physically measured (both length and depth with an engineering ruler and a pit gauge). The pit dimensions were input into ASME B31G criteria at the test pressure for the class location. All the pits passed this criteria for *failure* <u>at</u> the test pressure for their respective class location.

Additionally (and more conservatively), all the defects *also* met the ASME B31G criteria for a pressure (greater than the pressure test pressure) that would have resulted in a hoop stress equal to 100% SMYS (P=2St/D), i.e. they met (passed) the standard ASME B31G criteria. This also follows from the fact that the Class 1, 2, 3, and 4 Test Pressures (used in this case) were all below the pressure required to achieve 100% SMYS pipe wall stress.

Although the 2% CSA curve constructed with the stated geometric assumptions tracks well with Pf, it is unrealistic to use this low cut-off in the field where it will currently limit the longitudinal length of the associated GWUT plot to very short distances. The 10% cut off has been shown in the field to be too high to catch defects that would have exceeded the Pf (again based on ASME B31G criteria).

It is clear from this comparison to actual data that more refinement is needed to link the %CSA cutoff criteria accurately to the defects that GWUT was successful at identifying as needing further investigation. A larger data set of GWUT inspected/predicted indications with the associated direct examination measurements is needed to refine these relationships.

Specifically, there are several items that need more investigation to help refine this analysis:

- What is the axial resolution of the GWUT plots?
- What axial length (to each side of the spatial point) is the data averaged over to provide the absolute reflection at that location.
- How is the %CSA calculated with GWUT, and more importantly, how do you relate (geometrically) for a variety of situations the radial length back into the axial length of reflections so the GWUT indications can be used to get a coarse depth and the axial length of defects (i.e., sizing). This can then be used as a go/no-go with an associated criteria such as ASME B31G. With enough data

analysis, a properly constructed and validated CSA% curve would provide this cut off point for future inspections.

CLASS 1 HYDRO Comparison - - 24" diameter; X52 Grade Pipe, 0.344" thick wall

	B31G Part 4		SMYS =	1490.667		
	0.125	d = depth	P = 2StFT/D =	1490.667	psi	
	24	D = nominal diameter	MAOP if less =	1490.667	psi	
Set F to 1 for Hydro Calc	1	F = design factor	A = 0.893 L/(Dt)^0.5 =	1.554	1.554	adjusted
	5	L = length	Pprime	1430		
	52,000	SMYS = yield	Pprime if A>4 then	1044	adjusted	
	0.344	t = nominal wall thickness	*design factor = 0.72*	*1073*	CL 1	
	1.0	T = temperature factor	*design factor = 0.60*	*894*	CL 2	
CL 1 Hydro Pressure = SMYS x 0.72 x 1.25	1341.6		*design factor = 0.50*	*745*	CL 3	
	25.94	Pipe area	*design factor = 0.40*	*596*	CL 4	

Dt		8.256
D/t		69.76744
root Dt		2.873
d/t		0.363
safe	constant	0.818182
failure	constant	0.909091

A calc	A adjusted	DEFECT length in	Folius factor M	DEFECT length in	Safe Pressure 1491 MAOP	DEFECTS Actually Dug	Estimated Equivalent CSA	Failure Pressure
							5%	
0.155	0.155	0.5	0.988141	0.5	142%		754%	134%
0.210	0.210	0.675	0.978696	0.675	137%	19%	559%	124%
0.233	0.233	0.75	0.973893	0.75	134%	30%	503%	119%
0.311	0.311	1	0.954944	1	125%	55%	377%	103%
0.466	0.466	1.5	0.906351	1.5	106%	26%	251%	77%
0.544	0.544	1.75	0.878476	1.75	97%	28%	215%	68%
0.622	0.622	2	0.849301	2	89%		188%	60%
0.932	0.932	3	0.731407	3	68%		126%	41%
1.243	1.243	4	0.626784	4	56%	18%	94%	32%
1.476	1.476	4.75	0.560832	4.75	50%	10%	79%	28%
1.554	1.554	5	0.541153	5	49%		75%	27%
1.865	1.865	6	0.472601	6	44%		63%	24%
2.176	2.176	7	0.41765	7	41%		54%	22%
2.486	2.486	8	0.373151	8	39%		47%	21%
2.797	2.797	9	0.336645	9	38%		42%	20%
3.108	3.108	10	0.306296	10	36%		38%	19%
3.729	3.729	12	0.258986	12	35%		31%	18%
4.351	4.000	14	0.242536	14	34%		27%	17%
4.973	4.000	16	0.242536	16	34%		24%	17%
5.594	4.000	18	0.242536	18	34%		21%	17%
6.216	4.000	20	0.242536	20	34%		19%	17%
6.837	4.000	22	0.242536	22	34%		17%	17%
7.459	4.000	24	0.242536	24	34%		16%	17%

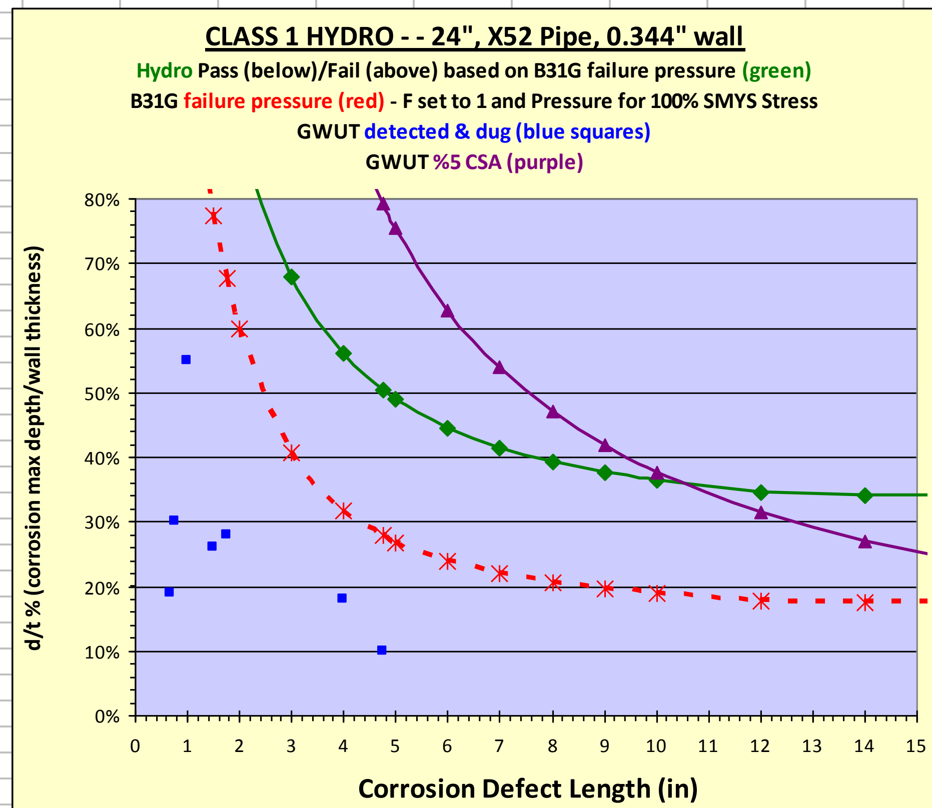


Figure 178. **CLASS 1 HYDRO Comparison - - 24" diameter; X52 Grade Pipe, 0.344" thick wall (5% CSA).**

CLASS 2 HYDRO Comparison - - 24" diameter; X52 Grade Pipe, 0.344" thick wall

		B31G Part 4
	0.125	d = depth
	24	D = nominal diameter
Set F to 1 for Hydro Calc	1	F = design factor
	5	L = length
	52,000	SMYS = yield
	0.344	t = nominal wall thickness
	1.0	T = temperature factor
CL 2 Hydro Pressure = SMYS x 0.60 x 1.25	1118	
	25.94	Pipe area

SMYS =	1490.667		
P = 2StFT/D =	1490.667	psi	
MAOP if less =	1490.667	psi	
A = 0.893 L/(Dt)^0.5 =	1.554	1.554	adjusted
Pprime	1430		
Pprime if A>4 then	1044	adjusted	
design factor = 0.72	*1073*	CL 1	
design factor = 0.60	*894*	CL 2	
design factor = 0.50	*745*	CL 3	
design factor = 0.40	*596*	CL 4	

	Dt	8.256
	D/t	69.76744
	root Dt	2.873
	d/t	0.363
safe	constant	0.681818
failure	constant	0.909091

A calc	A adjusted	DEFECT length in	Folius factor M	DEFECT length in	Safe Pressure 1491 MAOP	DEFECTS Actually Dug	Estimated Equivalent CSA	Failure Pressure
							5%	
0.155	0.155	0.5	0.988141	0.5	146%		754%	134%
0.210	0.210	0.675	0.978696	0.675	143%	19%	559%	124%
0.233	0.233	0.75	0.973893	0.75	142%	30%	503%	119%
0.311	0.311	1	0.954944	1	137%	55%	377%	103%
0.466	0.466	1.5	0.906351	1.5	125%	26%	251%	77%
0.544	0.544	1.75	0.878476	1.75	119%	28%	215%	68%
0.622	0.622	2	0.849301	2	113%		188%	60%
0.932	0.932	3	0.731407	3	95%		126%	41%
1.243	1.243	4	0.626784	4	83%	18%	94%	32%
1.476	1.476	4.75	0.560832	4.75	77%	10%	79%	28%
1.554	1.554	5	0.541153	5	76%		75%	27%
1.865	1.865	6	0.472601	6	70%		63%	24%
2.176	2.176	7	0.41765	7	67%		54%	22%
2.486	2.486	8	0.373151	8	64%		47%	21%
2.797	2.797	9	0.336645	9	62%		42%	20%
3.108	3.108	10	0.306296	10	60%		38%	19%
3.729	3.729	12	0.258986	12	58%		31%	18%
4.351	4.000	14	0.242536	14	57%		27%	17%
4.973	4.000	16	0.242536	16	57%		24%	17%
5.594	4.000	18	0.242536	18	57%		21%	17%
6.216	4.000	20	0.242536	20	57%		19%	17%
6.837	4.000	22	0.242536	22	57%		17%	17%
7.459	4.000	24	0.242536	24	57%		16%	17%

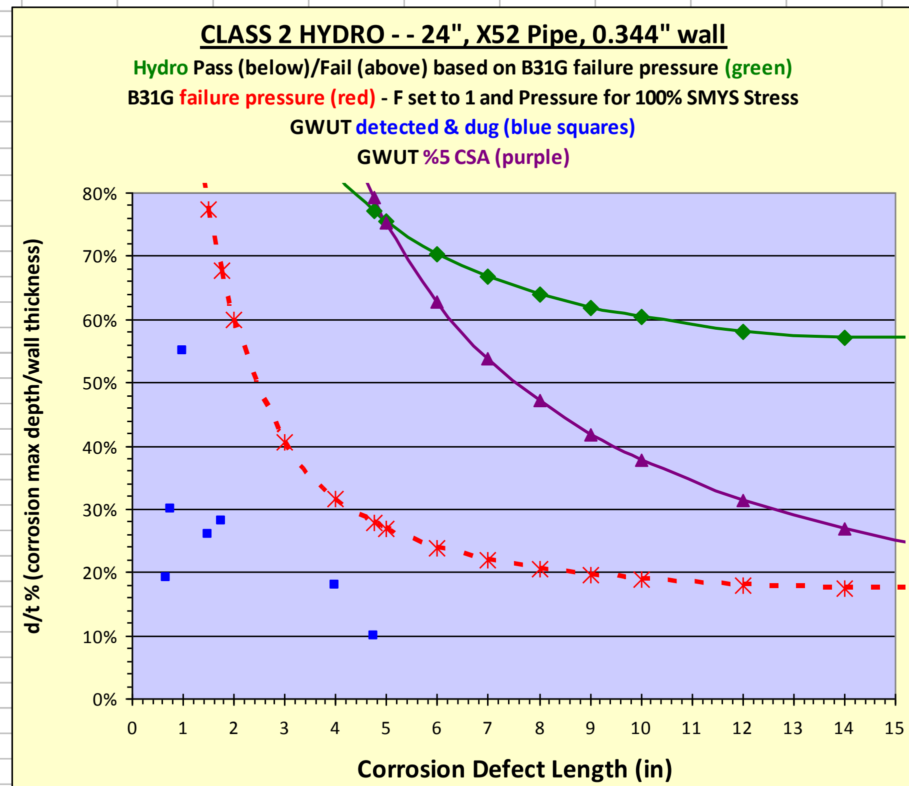


Figure 179. **CLASS 2 HYDRO Comparison - - 24" diameter; X52 Grade Pipe, 0.344" thick wall (5% CSA).**

CLASS 3 HYDRO Comparison - - 24" diameter; X52 Grade Pipe, 0.344" thick wall

	B31G Part 4	
	0.125	d = depth
	24	D = nominal diameter
Set F to 1 for Hydro Calc	1	F = design factor
	5	L = length
	52,000	SMYS = yield
	0.344	t = nominal wall thickness
	1.0	T = temperature factor
CL 3 Hydro Pressure = SMYS x 0.50 x 1.50	1118	
	25.94	Pipe area

SMYS =	1490.667		
P = 2StFT/D =	1490.667	psi	
MAOP if less =	1490.667	psi	
A = 0.893 L/(Dt)^0.5 =	1.554	1.554	adjusted
Pprime	1430		
Pprime if A>4 then	1044	adjusted	
design factor = 0.72	*1073*	CL 1	
design factor = 0.60	*894*	CL 2	
design factor = 0.50	*745*	CL 3	
design factor = 0.40	*596*	CL 4	

	Dt	8.256
	D/t	69.76744
	root Dt	2.873
	d/t	0.363
safe	constant	0.681818
failure	constant	0.909091

A calc	A adjusted	DEFECT length in	Folius factor M	DEFECT length in	Safe Pressure 1491 MAOP	DEFECTS Actually Dug	Estimated Equivalent CSA	Failure Pressure
							5%	
0.155	0.155	0.5	0.988141	0.5	146%		754%	134%
0.210	0.210	0.675	0.978696	0.675	143%	19%	559%	124%
0.233	0.233	0.75	0.973893	0.75	142%	30%	503%	119%
0.311	0.311	1	0.954944	1	137%	55%	377%	103%
0.466	0.466	1.5	0.906351	1.5	125%	26%	251%	77%
0.544	0.544	1.75	0.878476	1.75	119%	28%	215%	68%
0.622	0.622	2	0.849301	2	113%		188%	60%
0.932	0.932	3	0.731407	3	95%		126%	41%
1.243	1.243	4	0.626784	4	83%	18%	94%	32%
1.476	1.476	4.75	0.560832	4.75	77%	10%	79%	28%
1.554	1.554	5	0.541153	5	76%		75%	27%
1.865	1.865	6	0.472601	6	70%		63%	24%
2.176	2.176	7	0.41765	7	67%		54%	22%
2.486	2.486	8	0.373151	8	64%		47%	21%
2.797	2.797	9	0.336645	9	62%		42%	20%
3.108	3.108	10	0.306296	10	60%		38%	19%
3.729	3.729	12	0.258986	12	58%		31%	18%
4.351	4.000	14	0.242536	14	57%		27%	17%
4.973	4.000	16	0.242536	16	57%		24%	17%
5.594	4.000	18	0.242536	18	57%		21%	17%
6.216	4.000	20	0.242536	20	57%		19%	17%
6.837	4.000	22	0.242536	22	57%		17%	17%
7.459	4.000	24	0.242536	24	57%		16%	17%

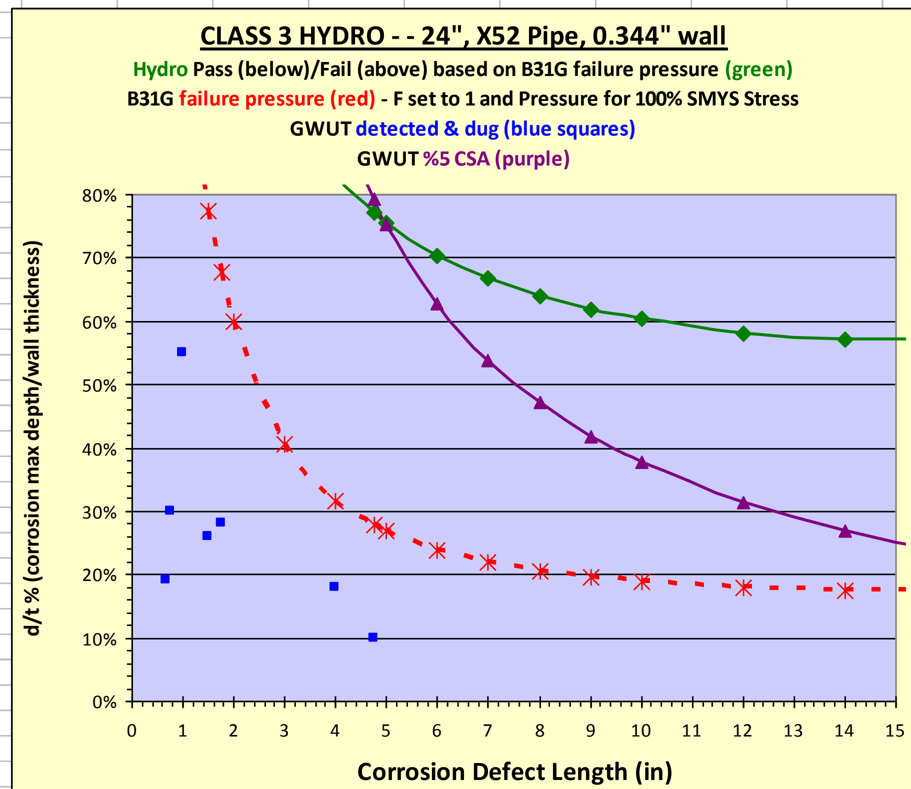


Figure 180. **CLASS 3 HYDRO Comparison - - 24" diameter; X52 Grade Pipe, 0.344" thick wall (5% CSA).**

CLASS 4 HYDRO Comparison - - 24" diameter; X52 Grade Pipe, 0.344" thick wall

	B31G Part 4			
	0.125	d = depth		
	24	D = nominal diameter		
Set F to 1 for Hydro Calc	1	F = design factor		
	5	L = length		
	52,000	SMYS = yield		
	0.344	t = nominal wall thickness		
	1.0	T = temperature factor		
CL 4 Hydro Pressure = SMYS x 0.40 x 1.50	894.4			
	25.94	Pipe area		

SMYS =	1490.667		
P = 2StFT/D =	1490.667	psi	
MAOP if less =	1490.667	psi	
A = 0.893 L/(Dt)^0.5 =	1.554	1.554	adjusted
Pprime	1430		
Pprime if A>4 then	1044	adjusted	
design factor = 0.72	*1073*	CL 1	
design factor = 0.60	*894*	CL 2	
design factor = 0.50	*745*	CL 3	
design factor = 0.40	*596*	CL 4	

	Dt	8.256
	D/t	69.76744
	root Dt	2.873
	d/t	0.363
safe	constant	0.545455
failure	constant	0.909091

A calc	A adjusted	DEFECT length in	Folius factor M	DEFECT length in	Safe Pressure 1491 MAOP	DEFECTS Actually Dug	Estimated Equivalent CSA	Failure Pressure
							5%	
0.155	0.155	0.5	0.988141	0.5	148%		754%	134%
0.210	0.210	0.675	0.978696	0.675	146%	19%	559%	124%
0.233	0.233	0.75	0.973893	0.75	145%	30%	503%	119%
0.311	0.311	1	0.954944	1	142%	55%	377%	103%
0.466	0.466	1.5	0.906351	1.5	135%	26%	251%	77%
0.544	0.544	1.75	0.878476	1.75	131%	28%	215%	68%
0.622	0.622	2	0.849301	2	127%		188%	60%
0.932	0.932	3	0.731407	3	113%		126%	41%
1.243	1.243	4	0.626784	4	104%	18%	94%	32%
1.476	1.476	4.75	0.560832	4.75	98%	10%	79%	28%
1.554	1.554	5	0.541153	5	97%		75%	27%
1.865	1.865	6	0.472601	6	92%		63%	24%
2.176	2.176	7	0.41765	7	88%		54%	22%
2.486	2.486	8	0.373151	8	86%		47%	21%
2.797	2.797	9	0.336645	9	84%		42%	20%
3.108	3.108	10	0.306296	10	82%		38%	19%
3.729	3.729	12	0.258986	12	79%		31%	18%
4.351	4.000	14	0.242536	14	79%		27%	17%
4.973	4.000	16	0.242536	16	79%		24%	17%
5.594	4.000	18	0.242536	18	79%		21%	17%
6.216	4.000	20	0.242536	20	79%		19%	17%
6.837	4.000	22	0.242536	22	79%		17%	17%
7.459	4.000	24	0.242536	24	79%		16%	17%

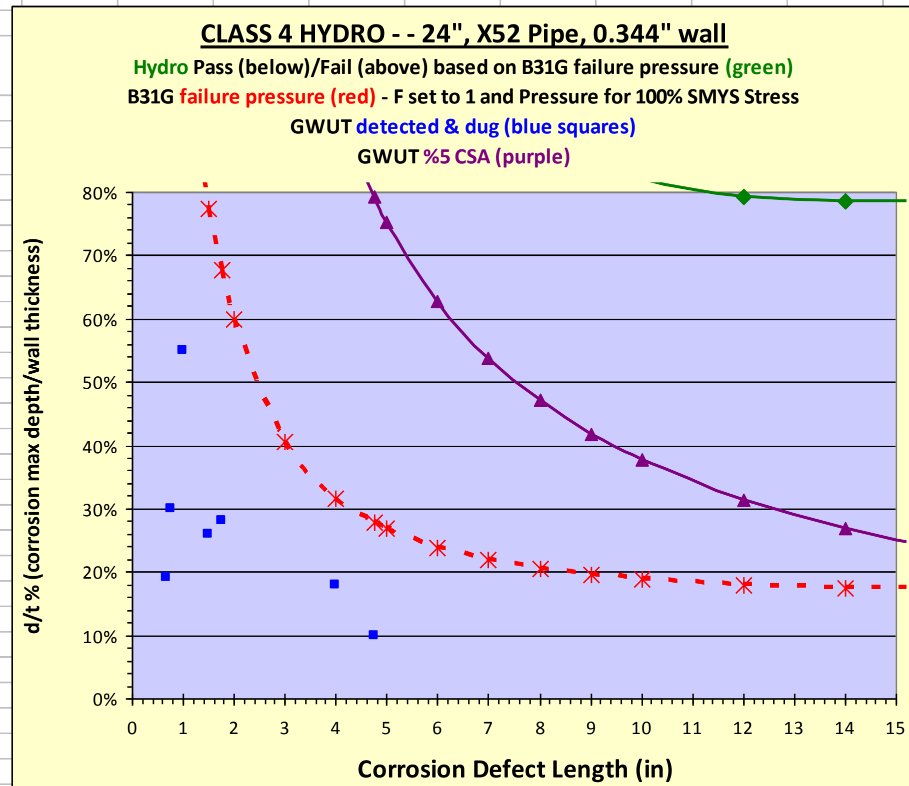


Figure 181. CLASS 4 HYDRO Comparison - - 24" diameter; X52 Grade Pipe, 0.344" thick wall (5% CSA).

CLASS 1 HYDRO Comparison - - 30" diameter; X42 Grade Pipe, 0.312" thick wall

	B31G Part 4	
	0.200	d = depth
	30	D = nominal diameter
Set F to 1 for Hydro Calc	1	F = design factor
	5	L = length
	42,000	SMYS = yield
	0.312	t = nominal wall thickness
	1.0	T = temperature factor
CL 1 Hydro Pressure = SMYS x 0.72 x 1.25	786.24	
	29.41	Pipe area

SMYS =	873.6		
P = 2StFT/D =	873.6	psi	
MAOP if less =	873.6	psi	
A = 0.893 L/(Dt)^0.5 =	1.459	1.459	adjusted
Pprime	726		
Pprime if A>4 then	345	adjusted	
design factor = 0.72	*629*	CL 1	
design factor = 0.60	*524*	CL 2	
design factor = 0.50	*437*	CL 3	
design factor = 0.40	*349*	CL 4	

	Dt	9.36
	D/t	96.15385
	root Dt	3.059
	d/t	0.641
safe	constant	0.818182
failure	constant	0.909091

A calc	A adjusted	DEFECT length in	Folius factor M	DEFECT length in	Safe Pressure 874 MAOP	DEFECTS Actually Dug	Estimated Equivalent CSA 5%	Failure Pressure
0.146	0.146	**0.5**	0.989517	**0.5**	**143%**		**942%**	**136%**
0.197	0.197	**0.675**	0.981138	**0.675**	**138%**		**698%**	**126%**
0.219	0.219	**0.75**	0.976866	**0.75**	**136%**		**628%**	**122%**
0.292	0.292	**1**	0.959943	**1**	**127%**	**29%**	**471%**	**107%**
0.438	0.438	**1.5**	0.916047	**1.5**	**109%**	**37%**	**314%**	**82%**
0.511	0.511	**1.75**	0.890547	**1.75**	**100%**		**269%**	**72%**
0.584	0.584	**2**	0.863614	**2**	**93%**	**38%**	**236%**	**63%**
0.876	0.876	**3**	0.752331	**3**	**71%**		**157%**	**43%**
1.168	1.168	**4**	0.650509	**4**	**58%**	**16%**	**118%**	**33%**
1.313	1.313	**4.5**	0.605755	**4.5**	**54%**	**16%**	**105%**	**30%**
1.459	1.459	**5**	0.565239	**5**	**51%**		**94%**	**28%**
1.751	1.751	**6**	0.495858	**6**	**46%**		**79%**	**25%**
2.043	2.043	**7**	0.439601	**7**	**43%**		**67%**	**23%**
2.335	2.335	**8**	0.393669	**8**	**40%**		**59%**	**21%**
2.627	2.627	**9**	0.355761	**9**	**38%**		**52%**	**20%**
2.919	2.919	**10**	0.324106	**10**	**37%**		**47%**	**19%**
3.503	3.503	**12**	0.27453	**12**	**35%**		**39%**	**18%**
4.086	4.000	**14**	0.242536	**14**	**34%**		**34%**	**17%**
4.670	4.000	**16**	0.242536	**16**	**34%**		**29%**	**17%**
5.254	4.000	**18**	0.242536	**18**	**34%**		**26%**	**17%**
5.838	4.000	**20**	0.242536	**20**	**34%**		**24%**	**17%**
6.421	4.000	**22**	0.242536	**22**	**34%**		**21%**	**17%**
7.005	4.000	**24**	0.242536	**24**	**34%**		**20%**	**17%**

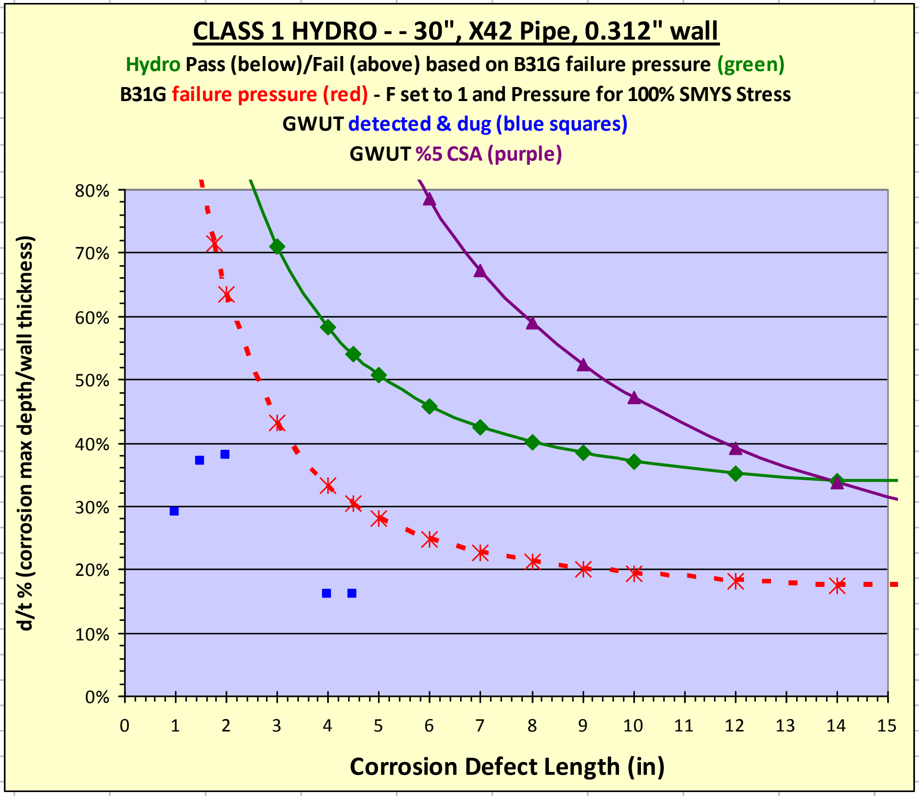


Figure 182. **CLASS 1 HYDRO Comparison - - 30" diameter; X42 Grade Pipe, 0.312" thick wall.**

CLASS 2 HYDRO Comparison - - 30" diameter; X42 Grade Pipe, 0.312" thick wall

		B31G Part 4	
	0.200	d = depth	
	30	D = nominal diameter	
Set F to 1 for Hydro Calc	1	F = design factor	
	5	L = length	
	42,000	SMYS = yield	
	0.312	t = nominal wall thickness	
	1.0	T = temperature factor	
CL 2 Hydro Pressure = SMYS x 0.60 x 1.25	655.2		
	29.41	Pipe area	

SMYS =	873.6		
P = 2StFT/D =	873.6	psi	
MAOP if less =	873.6	psi	
A = 0.893 L/(Dt)^0.5 =	1.459	1.459	adjusted
Pprime	726		
Pprime if A>4 then	345	adjusted	
design factor = 0.72	*629*	CL 1	
design factor = 0.60	*524*	CL 2	
design factor = 0.50	*437*	CL 3	
design factor = 0.40	*349*	CL 4	

	Dt	9.36
	D/t	96.15385
	root Dt	3.059
	d/t	0.641
safe	constant	0.681818
failure	constant	0.909091

A calc	A adjusted	DEFECT length in	Folius factor M	DEFECT length in	Safe Pressure 874 MAOP	DEFECTS Actually Dug	Estimated Equivalent CSA	Failure Pressure
							5%	
0.146	0.146	0.5	0.989517	0.5	147%		942%	136%
0.197	0.197	0.675	0.981138	0.675	144%		698%	126%
0.219	0.219	0.75	0.976866	0.75	143%		628%	122%
0.292	0.292	1	0.959943	1	138%	29%	471%	107%
0.438	0.438	1.5	0.916047	1.5	127%	37%	314%	82%
0.511	0.511	1.75	0.890547	1.75	122%		269%	72%
0.584	0.584	2	0.863614	2	116%	38%	236%	63%
0.876	0.876	3	0.752331	3	98%		157%	43%
1.168	1.168	4	0.650509	4	86%	16%	118%	33%
1.313	1.313	4.5	0.605755	4.5	81%	16%	105%	30%
1.459	1.459	5	0.565239	5	78%		94%	28%
1.751	1.751	6	0.495858	6	72%		79%	25%
2.043	2.043	7	0.439601	7	68%		67%	23%
2.335	2.335	8	0.393669	8	65%		59%	21%
2.627	2.627	9	0.355761	9	63%		52%	20%
2.919	2.919	10	0.324106	10	61%		47%	19%
3.503	3.503	12	0.27453	12	59%		39%	18%
4.086	4.000	14	0.242536	14	57%		34%	17%
4.670	4.000	16	0.242536	16	57%		29%	17%
5.254	4.000	18	0.242536	18	57%		26%	17%
5.838	4.000	20	0.242536	20	57%		24%	17%
6.421	4.000	22	0.242536	22	57%		21%	17%
7.005	4.000	24	0.242536	24	57%		20%	17%

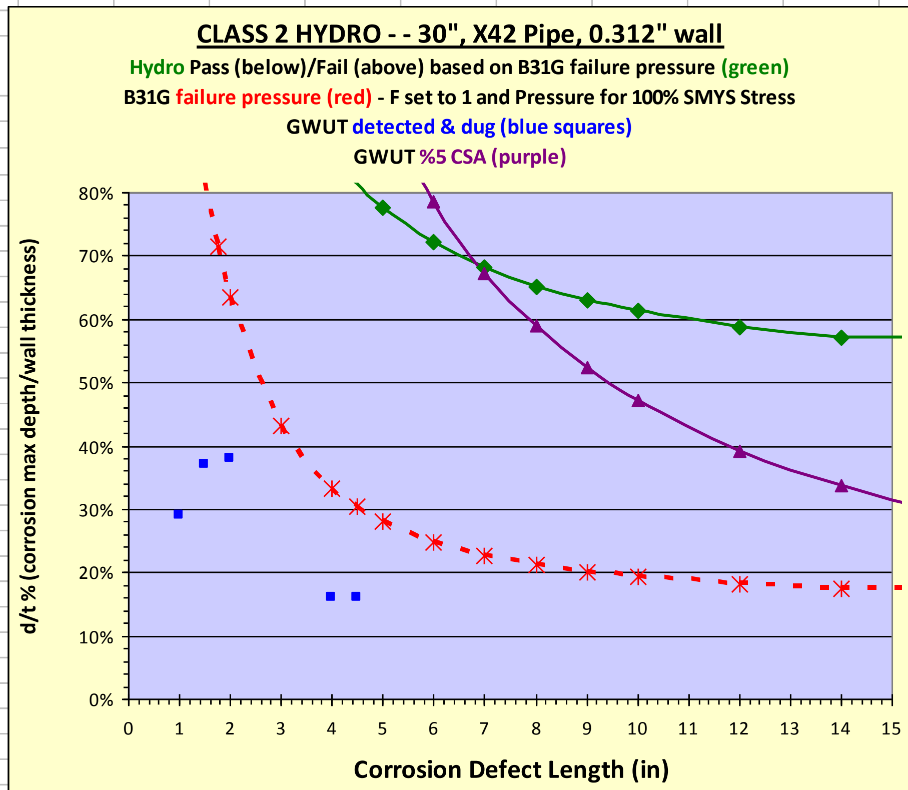


Figure 183. **CLASS 2 HYDRO Comparison - - 30" diameter; X42 Grade Pipe, 0.312" thick wall.**

CLASS 3 HYDRO Comparison - - 30" diameter; X42 Grade Pipe, 0.312" thick wall

B31G Part 4

Set F to 1 for Hydro Calc		
	0.200	d = depth
	30	D = nominal diameter
Set F to 1 for Hydro Calc	1	F = design factor
	5	L = length
	42,000	SMYS = yield
	0.312	t = nominal wall thickness
	1.0	T = temperature factor
CL 3 Hydro Pressure = SMYS x 0.50 x 1.50	655.2	
	29.41	Pipe area

SMYS =	873.6	
P = 2StFT/D =	873.6	psi
MAOP if less =	873.6	psi
A = 0.893 L/(Dt)^0.5 =	1.459	1.459 adjusted
Pprime	726	
Pprime if A>4 then	345	adjusted
design factor = 0.72	*629*	CL 1
design factor = 0.60	*524*	CL 2
design factor = 0.50	*437*	CL 3
design factor = 0.40	*349*	CL 4

Dt	9.36
D/t	96.15385
root Dt	3.059
d/t	0.641

safe	constant	0.681818
failure	constant	0.909091

A calc	A adjusted	DEFECT length in	Folius factor M	DEFECT length in	Safe Pressure 874 MAOP	DEFECTS Actually Dug	Estimated Equivalent CSA 5%	Failure Pressure
0.146	0.146	0.5	0.989517	0.5	147%		942%	136%
0.197	0.197	0.675	0.981138	0.675	144%		698%	126%
0.219	0.219	0.75	0.976866	0.75	143%		628%	122%
0.292	0.292	1	0.959943	1	138%	29%	471%	107%
0.438	0.438	1.5	0.916047	1.5	127%	37%	314%	82%
0.511	0.511	1.75	0.890547	1.75	122%		269%	72%
0.584	0.584	2	0.863614	2	116%	38%	236%	63%
0.876	0.876	3	0.752331	3	98%		157%	43%
1.168	1.168	4	0.650509	4	86%	16%	118%	33%
1.313	1.313	4.5	0.605755	4.5	81%	16%	105%	30%
1.459	1.459	5	0.565239	5	78%		94%	28%
1.751	1.751	6	0.495858	6	72%		79%	25%
2.043	2.043	7	0.439601	7	68%		67%	23%
2.335	2.335	8	0.393669	8	65%		59%	21%
2.627	2.627	9	0.355761	9	63%		52%	20%
2.919	2.919	10	0.324106	10	61%		47%	19%
3.503	3.503	12	0.27453	12	59%		39%	18%
4.086	4.000	14	0.242536	14	57%		34%	17%
4.670	4.000	16	0.242536	16	57%		29%	17%
5.254	4.000	18	0.242536	18	57%		26%	17%
5.838	4.000	20	0.242536	20	57%		24%	17%
6.421	4.000	22	0.242536	22	57%		21%	17%
7.005	4.000	24	0.242536	24	57%		20%	17%

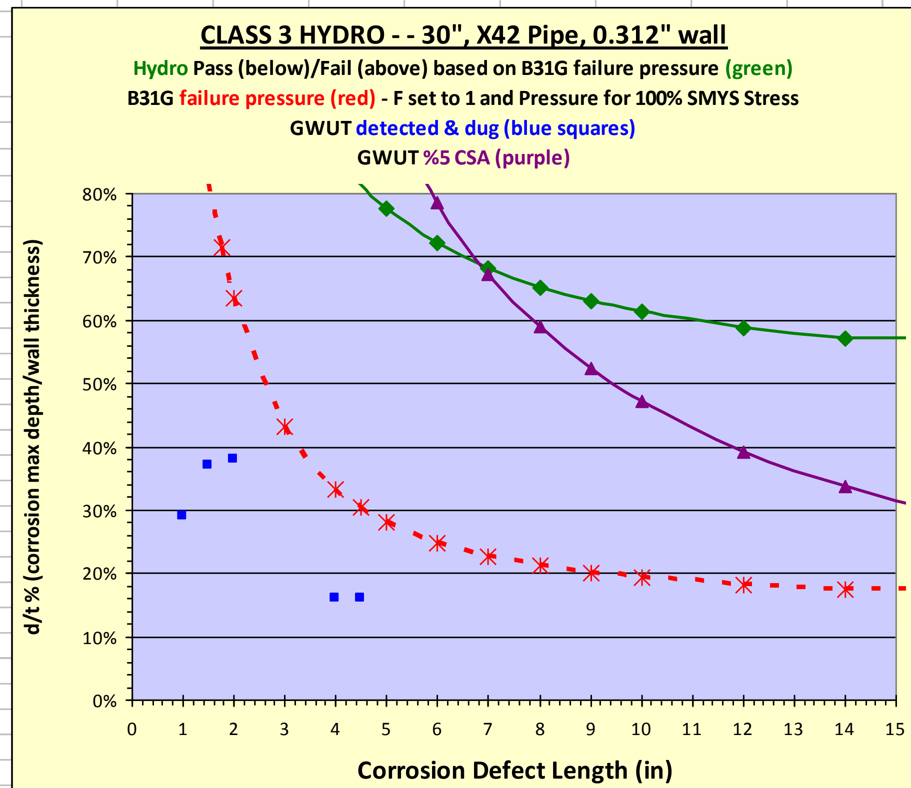


Figure 184. CLASS 3 HYDRO Comparison - - 30" diameter; X42 Grade Pipe, 0.312" thick wall.

CLASS 4 HYDRO Comparison - - 30" diameter; X42 Grade Pipe, 0.312" thick wall

		B31G Part 4	
	0.200	d = depth	
	30	D = nominal diameter	
Set F to 1 for Hydro Calc	1	F = design factor	
	5	L = length	
	42,000	SMYS = yield	
	0.312	t = nominal wall thickness	
	1.0	T = temperature factor	
CL 4 Hydro Pressure = SMYS x 0.40 x 1.50	524.16		
	29.41	Pipe area	

SMYS =	873.6		
P = 2StFT/D =	873.6	psi	
MAOP if less =	873.6	psi	
A = 0.893 L/(Dt)^0.5 =	1.459	1.459	adjusted
Pprime	726		
Pprime if A>4 then	345	adjusted	
design factor = 0.72	*629*	CL 1	
design factor = 0.60	*524*	CL 2	
design factor = 0.50	*437*	CL 3	
design factor = 0.40	*349*	CL 4	

Dt		9.36
D/t		96.15385
root Dt		3.059
d/t		0.641
safe	constant	0.545455
failure	constant	0.909091

A calc	A adjusted	DEFECT length in	Folius factor M	DEFECT length in	Safe Pressure 874 MAOP	DEFECTS Actually Dug	Estimated Equivalent CSA	Failure Pressure
							5%	
0.146	0.146	0.5	0.989517	0.5	148%		942%	136%
0.197	0.197	0.675	0.981138	0.675	147%		698%	126%
0.219	0.219	0.75	0.976866	0.75	146%		628%	122%
0.292	0.292	1	0.959943	1	143%	29%	471%	107%
0.438	0.438	1.5	0.916047	1.5	136%	37%	314%	82%
0.511	0.511	1.75	0.890547	1.75	133%		269%	72%
0.584	0.584	2	0.863614	2	129%	38%	236%	63%
0.876	0.876	3	0.752331	3	116%		157%	43%
1.168	1.168	4	0.650509	4	106%	16%	118%	33%
1.313	1.313	4.5	0.605755	4.5	102%	16%	105%	30%
1.459	1.459	5	0.565239	5	99%		94%	28%
1.751	1.751	6	0.495858	6	93%		79%	25%
2.043	2.043	7	0.439601	7	90%		67%	23%
2.335	2.335	8	0.393669	8	87%		59%	21%
2.627	2.627	9	0.355761	9	85%		52%	20%
2.919	2.919	10	0.324106	10	83%		47%	19%
3.503	3.503	12	0.27453	12	80%		39%	18%
4.086	4.000	14	0.242536	14	79%		34%	17%
4.670	4.000	16	0.242536	16	79%		29%	17%
5.254	4.000	18	0.242536	18	79%		26%	17%
5.838	4.000	20	0.242536	20	79%		24%	17%
6.421	4.000	22	0.242536	22	79%		21%	17%
7.005	4.000	24	0.242536	24	79%		20%	17%

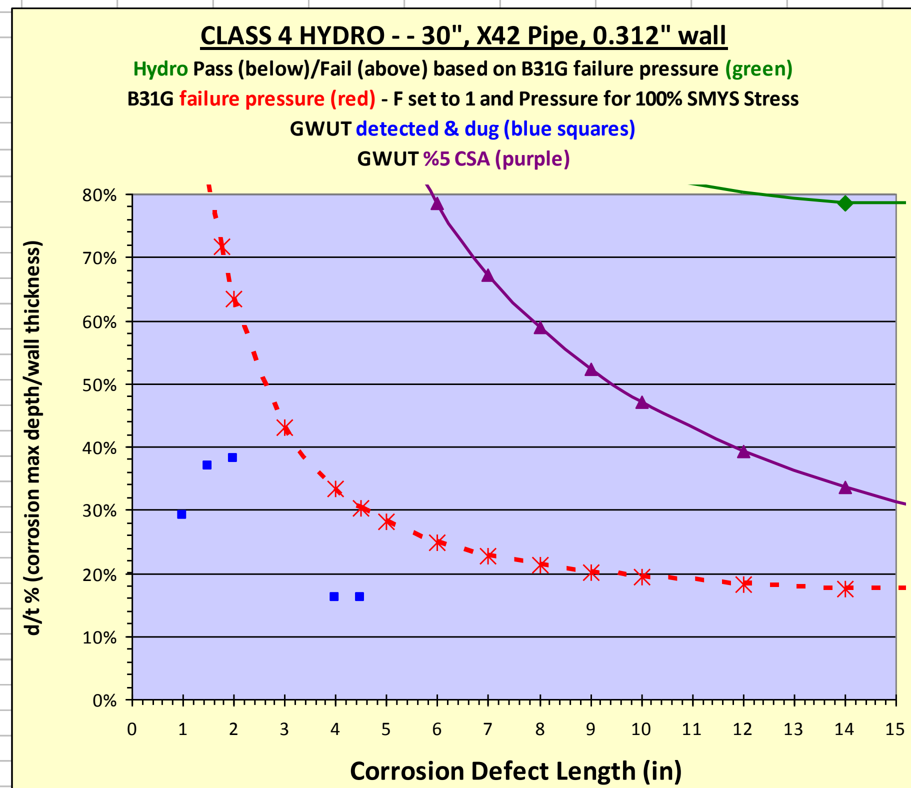


Figure 185. **CLASS 4 HYDRO Comparison - - 30" diameter; X42 Grade Pipe, 0.312" thick wall.**

CLASS 1 with F = 0.72 & P=2StF/D - - 24" diameter; X52 Grade Pipe, 0.344" thick wall

	B31G Part 4	
	0.125	d = depth
	24	D = nominal diameter
Set F to 0.72 for CL 1	0.72	F = design factor
	5	L = length
	52,000	SMYS = yield
	0.344	t = nominal wall thickness
	1.0	T = temperature factor
	1073.28	
	25.94	Pipe area

SMYS =	1490.667		
P = 2StFT/D =	1073.28	psi	
MAOP if less =	1073.28	psi	
A = 0.893 L/(Dt)^0.5 =	1.554	1.554	adjusted
Pprime	1030		
Pprime if A>4 then	752	adjusted	
design factor = 0.72	*1073*	CL 1	
design factor = 0.60	*894*	CL 2	
design factor = 0.50	*745*	CL 3	
design factor = 0.40	*596*	CL 4	

	Dt	8.256
	D/t	69.76744
	root Dt	2.873
	d/t	0.363
safe	constant	0.909091
failure	constant	0.909091

A calc	A adjusted	DEFECT length in	Folius factor M	DEFECT length in	**Safe Pressure 1073 MAOP**	**DEFECTS Actually Dug**	**Estimated Equivalent CSA**	**Failure Pressure**
							5%	
0.155	0.155	**0.5**	0.988141	**0.5**	**134%**		**754%**	**134%**
0.210	0.210	**0.675**	0.978696	**0.675**	**124%**	**19%**	**559%**	**124%**
0.233	0.233	**0.75**	0.973893	**0.75**	**119%**	**30%**	**503%**	**119%**
0.311	0.311	**1**	0.954944	**1**	**103%**	**55%**	**377%**	**103%**
0.466	0.466	**1.5**	0.906351	**1.5**	**77%**	**26%**	**251%**	**77%**
0.544	0.544	**1.75**	0.878476	**1.75**	**68%**	**28%**	**215%**	**68%**
0.622	0.622	**2**	0.849301	**2**	**60%**		**188%**	**60%**
0.932	0.932	**3**	0.731407	**3**	**41%**		**126%**	**41%**
1.243	1.243	**4**	0.626784	**4**	**32%**	**18%**	**94%**	**32%**
1.476	1.476	**4.75**	0.560832	**4.75**	**28%**	**10%**	**79%**	**28%**
1.554	1.554	**5**	0.541153	**5**	**27%**		**75%**	**27%**
1.865	1.865	**6**	0.472601	**6**	**24%**		**63%**	**24%**
2.176	2.176	**7**	0.41765	**7**	**22%**		**54%**	**22%**
2.486	2.486	**8**	0.373151	**8**	**21%**		**47%**	**21%**
2.797	2.797	**9**	0.336645	**9**	**20%**		**42%**	**20%**
3.108	3.108	**10**	0.306296	**10**	**19%**		**38%**	**19%**
3.729	3.729	**12**	0.258986	**12**	**18%**		**31%**	**18%**
4.351	4.000	**14**	0.242536	**14**	**17%**		**27%**	**17%**
4.973	4.000	**16**	0.242536	**16**	**17%**		**24%**	**17%**
5.594	4.000	**18**	0.242536	**18**	**17%**		**21%**	**17%**
6.216	4.000	**20**	0.242536	**20**	**17%**		**19%**	**17%**
6.837	4.000	**22**	0.242536	**22**	**17%**		**17%**	**17%**
7.459	4.000	**24**	0.242536	**24**	**17%**		**16%**	**17%**

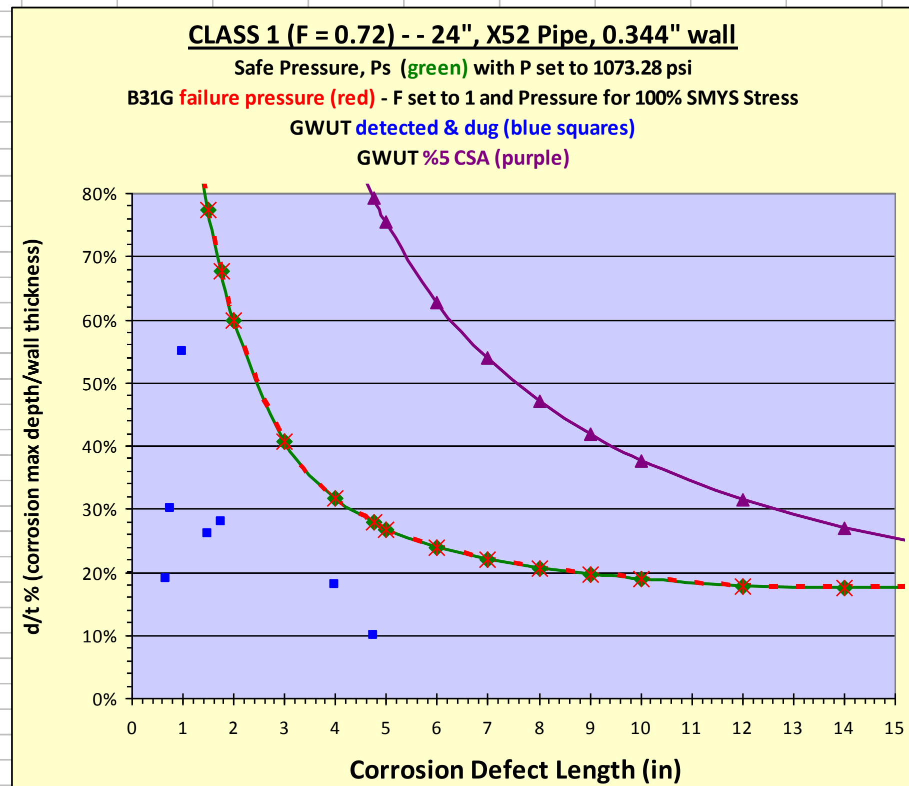


Figure 186. **CLASS 1 Standard Operations (F = 0.72) - - 24" diameter; X52 Grade Pipe, 0.344" thick wall (5% CSA).**

CLASS 1 HYDRO Comparison - - 24" diameter; X52 Grade Pipe, 0.344" thick wall

	B31G Part 4	
	0.125	d = depth
	24	D = nominal diameter
Set F to 1 for Hydro Calc	1	F = design factor
	5	L = length
	52,000	SMYS = yield
	0.344	t = nominal wall thickness
	1.0	T = temperature factor
CL 1 Hydro Pressure = SMYS x 0.72 x 1.25	1341.6	
	25.94	Pipe area

SMYS =	1490.667		
P = 2StFT/D =	1490.667	psi	
MAOP if less =	1490.667	psi	
A = 0.893 L/(Dt)^0.5 =	1.554	1.554	adjusted
Pprime	1430		
Pprime if A>4 then	1044	adjusted	
design factor = 0.72	*1073*	CL 1	
design factor = 0.60	*894*	CL 2	
design factor = 0.50	*745*	CL 3	
design factor = 0.40	*596*	CL 4	

	Dt	8.256
	D/t	69.76744
	root Dt	2.873
	d/t	0.363
safe	constant	0.818182
failure	constant	0.909091

A calc	A adjusted	DEFECT length in	Folius factor M	DEFECT length in	Safe Pressure 1491 MAOP	DEFECTS Actually Dug	Estimated Equivalent CSA	Failure Pressure
							2%	
0.155	0.155	0.5	0.988141	0.5	142%		302%	134%
0.210	0.210	0.675	0.978696	0.675	137%	19%	223%	124%
0.233	0.233	0.75	0.973893	0.75	134%	30%	201%	119%
0.311	0.311	1	0.954944	1	125%	55%	151%	103%
0.466	0.466	1.5	0.906351	1.5	106%	26%	101%	77%
0.544	0.544	1.75	0.878476	1.75	97%	28%	86%	68%
0.622	0.622	2	0.849301	2	89%		75%	60%
0.932	0.932	3	0.731407	3	68%		50%	41%
1.243	1.243	4	0.626784	4	56%	18%	38%	32%
1.476	1.476	4.75	0.560832	4.75	50%	10%	32%	28%
1.554	1.554	5	0.541153	5	49%		30%	27%
1.865	1.865	6	0.472601	6	44%		25%	24%
2.176	2.176	7	0.41765	7	41%		22%	22%
2.486	2.486	8	0.373151	8	39%		19%	21%
2.797	2.797	9	0.336645	9	38%		17%	20%
3.108	3.108	10	0.306296	10	36%		15%	19%
3.729	3.729	12	0.258986	12	35%		13%	18%
4.351	4.000	14	0.242536	14	34%		11%	17%
4.973	4.000	16	0.242536	16	34%		9%	17%
5.594	4.000	18	0.242536	18	34%		8%	17%
6.216	4.000	20	0.242536	20	34%		8%	17%
6.837	4.000	22	0.242536	22	34%		7%	17%
7.459	4.000	24	0.242536	24	34%		6%	17%

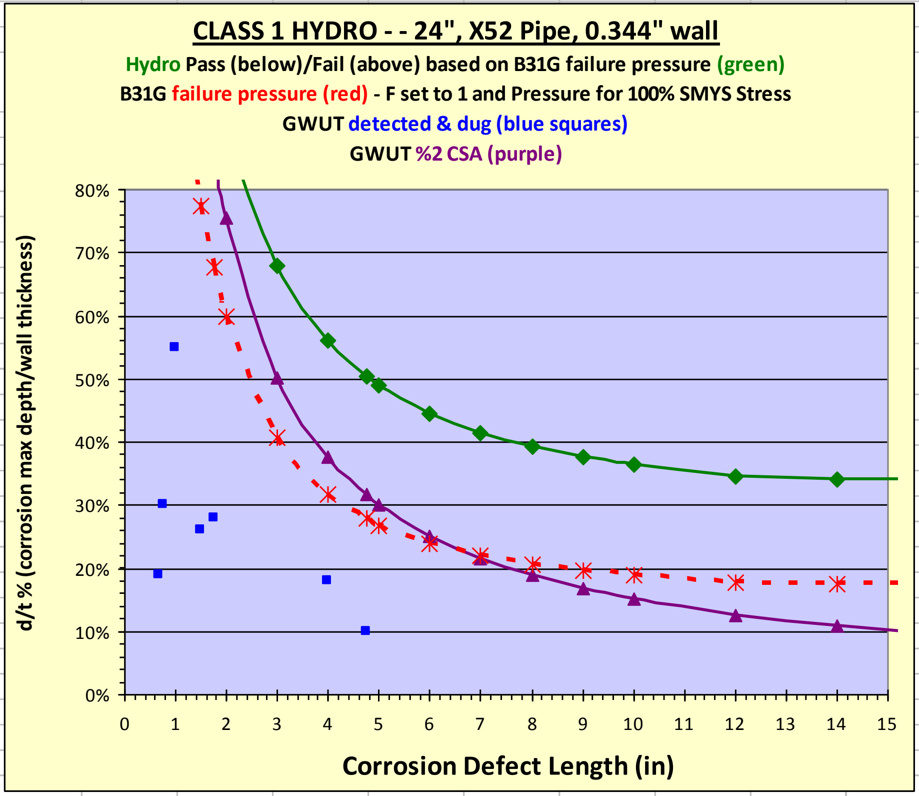


Figure 187. **CLASS 1 HYDRO Comparison - - 24" diameter; X52 Grade Pipe, 0.344" thick wall (2% CSA).**

CLASS 1 HYDRO Comparison - - 24" diameter; X52 Grade Pipe, 0.344" thick wall

	B31G Part 4	
	0.125	d = depth
	24	D = nominal diameter
Set F to 1 for Hydro Calc	1	F = design factor
	5	L = length
	52,000	SMYS = yield
	0.344	t = nominal wall thickness
	1.0	T = temperature factor
CL 1 Hydro Pressure = SMYS x 0.72 x 1.25	1341.6	
	25.94	Pipe area

SMYS =	1490.667		
P = 2StFT/D =	1490.667	psi	
MAOP if less =	1490.667	psi	
A = 0.893 L/(Dt)^0.5 =	1.554	1.554	adjusted
Pprime	1430		
Pprime if A>4 then	1044	adjusted	
design factor = 0.72	*1073*	CL 1	
design factor = 0.60	*894*	CL 2	
design factor = 0.50	*745*	CL 3	
design factor = 0.40	*596*	CL 4	

	Dt	8.256
	D/t	69.76744
	root Dt	2.873
	d/t	0.363
safe	constant	0.818182
failure	constant	0.909091

A calc	A adjusted	DEFECT length in	Folius factor M	DEFECT length in	Safe Pressure 1491 MAOP	DEFECTS Actually Dug	Estimated Equivalent CSA	Failure Pressure
							10%	
0.155	0.155	0.5	0.988141	0.5	142%		1508%	134%
0.210	0.210	0.675	0.978696	0.675	137%	19%	1117%	124%
0.233	0.233	0.75	0.973893	0.75	134%	30%	1005%	119%
0.311	0.311	1	0.954944	1	125%	55%	754%	103%
0.466	0.466	1.5	0.906351	1.5	106%	26%	503%	77%
0.544	0.544	1.75	0.878476	1.75	97%	28%	431%	68%
0.622	0.622	2	0.849301	2	89%		377%	60%
0.932	0.932	3	0.731407	3	68%		251%	41%
1.243	1.243	4	0.626784	4	56%	18%	188%	32%
1.476	1.476	4.75	0.560832	4.75	50%	10%	159%	28%
1.554	1.554	5	0.541153	5	49%		151%	27%
1.865	1.865	6	0.472601	6	44%		126%	24%
2.176	2.176	7	0.41765	7	41%		108%	22%
2.486	2.486	8	0.373151	8	39%		94%	21%
2.797	2.797	9	0.336645	9	38%		84%	20%
3.108	3.108	10	0.306296	10	36%		75%	19%
3.729	3.729	12	0.258986	12	35%		63%	18%
4.351	4.000	14	0.242536	14	34%		54%	17%
4.973	4.000	16	0.242536	16	34%		47%	17%
5.594	4.000	18	0.242536	18	34%		42%	17%
6.216	4.000	20	0.242536	20	34%		38%	17%
6.837	4.000	22	0.242536	22	34%		34%	17%
7.459	4.000	24	0.242536	24	34%		31%	17%

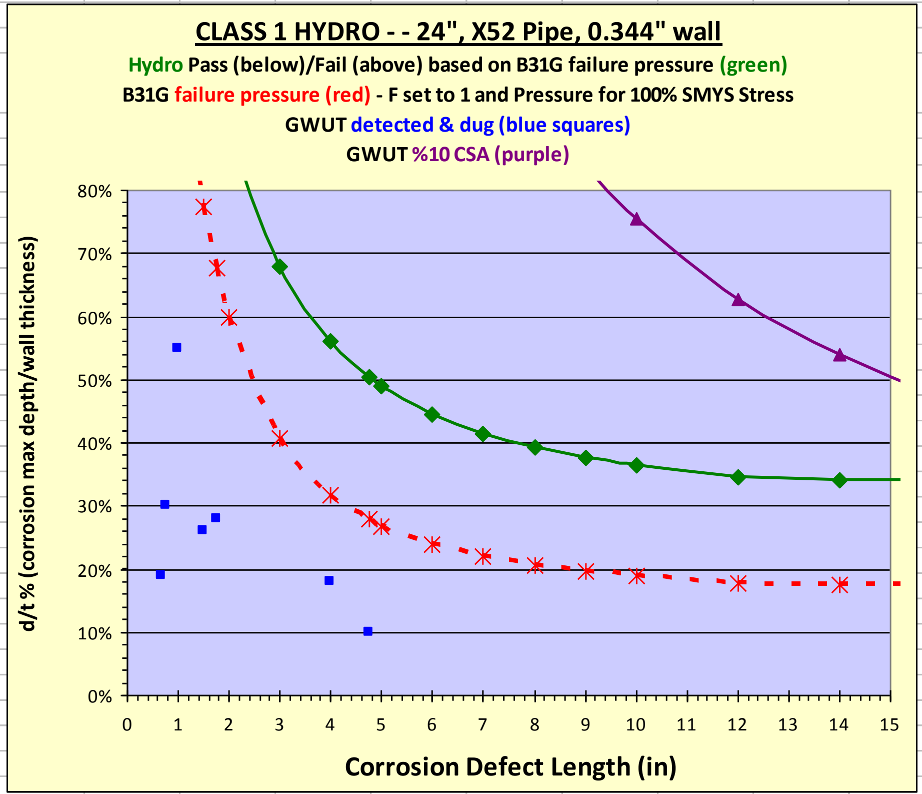


Figure 188. CLASS 1 HYDRO Comparison - - 24" diameter; X52 Grade Pipe, 0.344" thick wall (10% CSA).

Project Conclusions

The *project stakeholder group* agreed to and volunteered the following three high priority situations to focus on for potential case studies:

- *Multiple Pipes (Structures) in Congested Right of Way*
- *Bare Pipe Segments*
- *Cased Crossings*

The following tools were used during the integrity assessments performed during this project: GWUT (GUL and Teletest): torsional and longitudinal signals, pitch-catch and pulse-echo, C-scan, and multiple frequency ranges; magnetic tomography inspection; visual inspection; manual and Porta-Scan UT; radiography (X-ray); Magnetic Particle Inspection (MPI); Close Interval Surveys (CIS); Direct Current Voltage Gradient (DCVG); Pipeline Current Mapper (PCM), native potential and side-drain surveys; soil resistivity.

These three situations resulted in 30 excavations for GWUT application and when combined with the in kind data, included a total of approximately 100 dig sites with fifty-five confirmed (a 100% validation) indications for analysis.

All validated data was collected, analyzed, and summarized in graphical form, which included: inspection ranges, confirmed defect sizes (depth, length, width, and volume) as well as probabilities of detection (both false/true positives and negatives).

All the lessons learned from this project were compiled and are presented as a, *"Guided Wave Ultrasonic Testing Background, Technical Explanation, and Field Implementation Protocol to Assist Operators"*.

The capability and reliability of GWUT technology for integrity assessment for the chosen challenging situations was demonstrated as part of the DA process when following the included protocol.

For Multiple Pipes (structures) in Congested ROW Situations:

- *ECDA* standard tools worked well in open areas where interferences did not preclude the use of CIS, DCVG, and PCM as validated by 100% excavation with visual inspection & pit gauge and magnetic particle inspection.
- *ICDA* standard tools were effective at determining pipeline integrity as validated by X-ray and Porta-Scan UT.

- *GWUT* was very effective when standard DA tools could not be used. GWUT also identified the presence of sludge and deposits in pipe sections.

For the Bare Pipe Situations:

- *CIS* coupled with *Native Potential Surveys and Side-Drain Surveys* (aka Hot Spot Surveys) worked well and predicted areas of potential past corrosion.
- *GWUT* had a relatively short range due to the very adherent and "plastic" clay soil.
- *Magnetic Tomography* did not correlate well (false positive indications) for corrosion but did locate a wrinkle bend type feature outside of the GWUT inspected section.

For Cased Pipe Situations:

- GWUT correlated with the direct exam findings.
- For thick, pliable, well adhered asphalt coatings, the GWUT range was severely restricted.
- PCM inspections

General GWUT Findings:

- GWUT reliability from 55 indications at 18 case study sites resulted in no false negatives, 1 false positive, and a 98% chance of correct prediction.
- Depending on coating type and soil conditions, the inspection range varied from 10ft on the low side to greater than 100ft on the high side (this is with a 5% CSA threshold).
- Torsional waves tended to provide a better resolution vs. longitudinal waves.
- Longitudinal waves tended to provide the longest range, although at a lower frequency and resolution.
- A multitude of frequencies was necessary to differentiate spacers from anomalies.
- C-Scan images were very helpful at determining the extent and radial distribution of anomalies.
- GWUT was efficient at finding asymmetric weld geometries (verified by X-ray inspection).

GTI also conducted a feasibility analysis (at PHMSA's request) using a subset of the validated data. GWUT successfully called out defects that were ≤ 5% Cross Sectional Area (CSA) "criteria" curve. The anomalies that were ≥ 5% Cross Sectional Area (CSA) were dug up, had their coating removed, and the subsequent pits were physically measured (both length and depth with an engineering ruler and a pit gauge). The pit dimensions were input into ASME B31G criteria at the test pressure for the class location. All the pits passed this criteria for failure at the test pressure for their respective class location. Additionally (and more conservatively), all the defects *also* met the ASME B31G criteria for a pressure (greater than the pressure test pressure) that would have resulted in a hoop stress equal to 100% SMYS (P=2St/D), i.e. they met (passed) the standard ASME B31G criteria. This also follows from the fact that the Class 1, 2, 3, and 4 Test Pressures (used in this case) were all below the pressure required to achieve 100% SMYS pipe wall stress.

It was also clear from the feasibility analysis that (1) more field data with validation excavations and (2) possible analytical refinements are needed to link the %CSA cutoff criteria accurately to the defects that GWUT was successful at identifying.

In addition to the body of this report and the brief summary above, the conclusions from the in kind data sets (for ECDA tool performance in challenging situations) are as follows:

- *DCVG* had a finer location resolution than PCM, e.g. inches versus feet and located coating defects that were the size of a pinhole to 300 in^2 within 1-3 inches of their actual location.

- *CIS* located defects less precisely than DCVG, but correlated well with the excavated location; and correctly differentiated between locations with little or no cathodic protection and those that were well protected. CIS also greatly assisted in setting overall classifications and prioritizations.

- *Cell-to-cell and side-drain* (hot spot surveys) appeared to correlate well with corrosion found on bare pipe

- *PCM* worked well in indicating general regions of coating defects or large holidays (4 in^2) on well coated pipe. If the pipe had large and long holidays along the bottom, PCM did not isolate the indication.

- *PCM A-Frame* worked well at locating isolated, small defects and found a defect under an asphalt driveway. Comparable to DCVG in ability to locate small coating holidays if one already knows their general location.

To help move these project results into general use, contact with the appropriate SDO committees (e.g., ASME and NACE) has been initiated. These results and recommendations will be presented to the applicable Standards Development Organizations (SDOs) to ensure timely implementation of research benefits -- improved safety, ability to assess pipeline segments that have no alternate method available (i.e., expand DA applicability), and increased knowledge of the DA method that incorporates GWUT.

Recommended Next Steps

As a next step (i.e., follow on research efforts to this project), one suggestion would be to analyze a larger data set of GWUT inspected/predicted indications with the associated direct examination measurements. If one could demonstrate that GWUT finds defects that would pass a pressure test (and therefore substantiating that GWUT will find all larger defects than these) it would facilitate the acceptance of GWUT as an acceptable *stand-alone* inspection technique.

A final deliverable from such and effort could be the development a methodology to serve as the basis for a GWUT standard (from an SDO) and the validated supporting data.

Respectfully Submitted,

Daniel A. Ersoy, GTI

Appendix I - Guided Wave UT Target Items for Go-No Go Procedures [PHMSA 18-Points]

Source: http://primis.phmsa.dot.gov/gasimp/docs/GuidedWaveCheckList110107.pdf

Guided Wave UT Target Items for Go-No Go Procedures

These target items are for guidance only and do not require that notifications contain only this material. Where operators have alternatives to this guidance, it is suggested that they include it along with any justification in their notification. PHMSA will review each notification on the merits of the individual submittal.

1. Generation of Equipment and Software

The generation of both the equipment and the computer software is critical to the success of the inspection. Both major equipment vendors are on version 3. Prior versions may be used but require operator specific training and procedures for the earlier versions to achieve manually what later versions can do automatically. A Senior Level GWUT Equipment Operator is required for all equipment and software versions, non-automated, prior to version 3 or First Level GWUT Equipment Operator with experience and training in use of the equipment/software version may be used with oversight by a Senior Level GWUT Equipment operator of all procedures used and interpretation of data prior to completing evaluation of data. Automatic diagnostics, etc., may improve the efficiency of the test and reduce the time taken to collect data, but will not affect the sensitivity or ability to detect defects. This allows the operator to focus on the interpretation of the data rather than the mechanics of the inspection.

2. Inspection Range

The inspection range and sensitivity are set by the signal to noise (S/N) ratio but must still keep the maximum threshold sensitivity at 5% cross sectional area (CSA). Any signal that has an amplitude that is about twice the noise level can be reliably interpreted. The greater the S/N ratio the easier it is to identify and interpret signals from small changes. The signal to noise ratio is dependent on several variables such as, surface roughness, coating, coating condition, associated pipe fittings (T's, elbows, flanges), soil compaction, and environment. Each of these affects the propagation of sound waves and influences the range of the test. It may be necessary to inspect from both ends of the pipeline segment to achieve a full inspection. In general the maximum inspection range can approach 60 to 100 feet depending on field conditions for a 5% CSA.

3. Achieving a complete inspection of the pipe

To ensure that the entire pipeline segment is assessed there should be at least a 2 to 1 signal to noise ratio for the required wall loss anomalies to be detected, across the entire pipeline segment that is inspected. This may require multiple GWUT shots. Double ended inspections are expected. These two inspections are to be overlaid to show the minimum 2 to 1 S/N ratio is met in the middle. If possible, show the same near or midpoint feature (if present) from both sides and show an approximate 5% distance overlap.

4. Sensitivity

Sensitivity is defined as the ability to identify a reflection of a specified cross sectional change. The signal to noise ratio determines the detectability at a certain distance and thus sets the range. A sensitivity of 5% of the cross sectional area (CSA) must be achieved. By achieving a 5% sensitivity at the maximum inspection range, a greater sensitivity may be achieved on the segment at locations closer to the inspection equipment. The minimum sensitivity achieved must be able to identify the smallest defects that will fail by rupturing in a hydrostatic test. The locations and estimated CSA of all metal loss features in excess of the detection threshold shall be determined and reported. The use of GWUT in the "Go-No Go" mode requires that all indications (wall loss anomalies) above the testing threshold (5% of CSA sensitivity) be directly examined (or replaced) prior to completing the integrity assessment on the cased carrier pipe.

5. Frequency

The frequencies used for the inspections must be in the range specified by the manufacturer of the equipment. A sufficient number of frequencies (at least 3) need to be run for each shot as to determine the best frequency for characterizing indications. The frequencies or range of frequencies needs to be documented. Different frequencies do not change axial position or clock position. If only a single frequency is selected certain defects may not be detected.

6. Signal or Wave Type – torsional and longitudinal

Most GWUT equipment can provide both torsional and longitudinal signals. Although the use of torsional waves may produce the best results, longitudinal waves may also be considered. Where only one wave type is available, it must be torsional. Documentation of the wave type must be provided. Torsional waves do not couple well with liquids, therefore if liquid is in or around the pipe segment then the operator must consider the use of torsional waves.

7. Distance Amplitude Correction (DAC) curve is required for each inspection

Setting the DAC curve is an important step in establishing the effective range of a GWUT test and must be performed for each inspection. The DAC takes into account coating, pipe diameter, pipe wall and environmental conditions at the assessment location. DAC curves provide a means for evaluating the cross sectional area change of reflections at various distances in the test range by assessing signal to noise ratio. A DAC curve is a means of taking apparent attenuation into account along the time base of a test signal. It is a line of equal sensitivity along the trace which allows the amplitudes of signals at different axial distances from the collar to be compared.

8. Dead Zone

The Dead Zone is adjacent to the collar. GWUT uses pulse echo testing. The transmitted signal blinds the received signal, thus reducing the ability to obtain reproducible results. Therefore it can be determined from the length of the transmission pulse and the recovery time of the receiver circuits once the transmission burst has ceased. Inspection procedures need to account for the dead zone. The length of the dead zone must be documented for each inspection. Different inspections can yield different dead zones. If one is assessing cased crossings, the collar must be placed such that the dead zone does not extend into the casing, because a majority of indications in casings are typically located within the first few feet. A properly trained service provider can identify and report the dead zone. To properly assess the dead zone the service provider can move the collar and conduct an additional inspection of the dead zone. An alternate method of obtaining valid readings in the dead is to use B-scan ultrasonic equipment and visual examination of the external surface. It is recognized that not all manufacturers differentiate between the dead zone and the near field/zone.

9. Near Field Effects

The near field is the region beyond the dead zone where the receiving amplifiers are ramping up in power and thus is the region before the wave is established properly. This is not a function of the waveform but rather it is a function of the pulse echo collection method and is affected by pipe geometry. Classification is difficult in the near field due to reduced amplitude. Inspection procedures need to account for the near field. The length of the near field must be documented for each inspection. To properly assess the near field, the collar must be placed such that the near field does not extend into the casing, because a majority of indications in casings are typically located within the first few feet. A properly trained service provider can identify and report the near field. To properly assess the near field the service provider can move the collar and conduct an additional inspection of the near field. An alternate method of obtaining valid readings in the near field is to use B-scan ultrasonic equipment and visual examination of the external surface.

10. Coating type

GWUT inspections that have been conducted on pipe coated with coal tar enamel, FBE, wax, extruded coatings, and some with girth welds coated with tape or shrink sleeves, which have not affected results. Coatings can have the effect of attenuating the signal. Their thickness and condition are the primary factors that affect the rate of signal attenuation. Due to their variability, coatings make it difficult to predict the effective inspection distance. Several coating types may affect the GWUT results to the point that they may reduce the expected inspection distance. For example, concrete coated pipe may be problematic when well bonded due to the attenuation effects. If an inspection is done and the required sensitivity is not achieved for the entire length of the cased pipe, then the use of GWUT is not feasible and another type of assessment method must be utilized.

11. End Seal

The end seal does not interfere with the accuracy of the GWUT inspection but may have a dampening effect on the range. The vast majority of indications on carrier pipes in casings occur in the first several feet and this area is critical to the integrity of the pipeline. Operators will remove the end seal from the casing at each GWUT test location to facilitate limited visual inspection. Water and debris can collect at the low point and cause electrolytic shorts. Venting can also be a source of moisture and debris, and are typically located near the casing ends. Operators will be required to observe and collect the corrosion data, if found, under the end seal and process the data to verify the GWUT was correct.

12. Weld Calibration – welds are used to set DAC curve

Accessible welds, along or outside the pipe segment to be inspected, are used in setting the DAC curve. A weld(s) in the access hole (secondary area) is an alternative to set the DAC curve. In order to use these welds in the secondary area, sufficient distance must be allowed to account for the dead zone and near field. Having a weld, in the near field or dead zone, between the transducer collar and the calibration weld is not permitted. If the coating is removed from the weld prior to the inspection then the expected attenuation has been changed. A conservative estimate of the predicted amplitude for the weld is 25% CSA (cross sectional area) and can be used if welds are not accessible or version 3 software is being used. Calibrations (setting of the DAC curve) should be on pipe with similar properties such as wall thickness and coating. If the actual cap height is different from the assumed cap height, the estimated CSA may be inaccurate and adjustments to the DAC curve maybe required. Alternative means of calibration can be used if justified by sound engineering analysis and evaluation.

13. Validation of Operator Training

In the absence of an industry standard for certifying GWUT service providers, pipeline operators must require all guided wave service providers to have equipment specific training and experience for First Level and Senior Level GWUT Equipment Operators which include:

1. equipment operation,
2. field data collection, and
3. data interpretation on cased and buried pipe.

A Senior Level GWUT Equipment Operator with pipeline specific experience must provide oversight and approve the final reports of a First Level GWUT Equipment Operator. A Senior Level GWUT Equipment Operator must have additional training and experience beyond that required for the field data collection level operator, First Level GWUT Equipment Operator. This additional training must be specific to cased and buried pipe, and there must be a quality control program which conforms to Section 12 of ASME B31.8S.

Guided Wave Training and Experience Minimums – for First Level and Senior Level GWUT Equipment Operators

- Equipment Manufacturer's minimum qualification for equipment operation and data collection with specific endorsements for casings and buried pipe
- Training, qualification and experience in testing procedures and frequency determination
- Training, qualification and experience in conversion of guided wave data into pipe features and estimated metal loss (estimated cross-sectional area loss and circumferential extent)
- Equipment Manufacturer's minimum qualification with specific endorsements for data interpretation of anomaly features for pipe within casings and buried pipe – applicable for Senior Level GWUT Equipment Operator.

14. Equipment – should be traceable from vendor to contractor.

The equipment and software must be readily traceable back to the manufacturer. The version of the GWUT software used and the serial number of the other equipment such as collars, cables, etc., must be traceable and documented in the report. Only individuals who have been qualified by the manufacturer or an independently assessed evaluation procedure similar to ISO 9712 (Sections: 5 Responsibilities; 6 Levels of Qualification; 7 Eligibility; and 10 Certification), as specified above, shall operate the equipment.

15. Calibration, Onsite – diagnostic test on site and system check on site.

The equipment must have been calibrated per the equipment manufacturer's requirements and specifications for both performance and time between calibrations prior to being shipped to the service provider. A diagnostic check and system check shall be performed on-site and each time the equipment is relocated. Where on site diagnostics show some discrepancies with the manufacturer's requirements and specifications, the testing shall cease until the equipment can be restored to manufacturer's specifications.

16. Use on shorted (either direct or electrolytic) casings

Shorted casings may not interfere with GWUT assessments. Guided waves are stress waves or mechanical vibrations in the pipe wall. They are not effectively coupled to and hence should not be affected by the electro-magnetic waves. There may be a reflection if the casing and pipe are in direct contact with high contact force, which may affect the GWUT results, but this can and should be addressed with procedures for any heavily loaded support. Shorted casings may not interfere with the GWUT signal to noise ratio and subsequent results. If GWUT Service Operators see any evidence of interference other than some slight dampening of the GWUT signal from the shorted casing, it must be cleared to use GWUT. All indications (wall loss anomalies) below the testing threshold (5% of CSA sensitivity) meeting the GWUT "Go-No Go, 18 Point Checklist" criteria, provided that there is no interference or masking of these indications (wall loss anomalies) if the indications are in the area of the short, do not need to be directly examined. All shorted casings found while conducting GWUT inspections must be addressed by the operator's SOPs and are not to be considered part of a GWUT procedure.

17. Direct examination of all indications above the testing threshold is required.

The use of GWUT in the "Go-No Go" mode requires that all indications (wall loss anomalies) above the testing threshold (5% of CSA sensitivity) be directly examined (or replaced) prior to completing the integrity assessment on the cased carrier pipe. If this can not be accomplished then the use of GWUT is not considered feasible and alternative methods of assessment (such as hydrostatic pressure tests or ILI) must be utilized.

18. Timing of direct examinations of indications above the testing threshold.

All indications (wall loss anomalies) that are identified above the threshold must be scheduled for direct examination. Under a prescriptive plan for these indications, the maximum time frame for each is 6 months for those pipelines operating at greater than 30% SMYS and 12 months for those operating at or below 30% SMYS. For those locations where the operating pressure is greater than 50% SMYS, the pressure must be reduced to 80% of the operating pressure at the time the indication is "discovered" by the GWUT. For those locations where the operating pressure is greater than 30% and less than or equal to 50% SMYS, then the operating pressure shall not exceed the operating pressure at the time of the "discovery" of the indication and the monthly leak survey shall be performed until the indication is directly examined. For those locations where the operating pressure is less than or equal to 30% of SMYS, the casings must be leak surveyed once a month until the indication is directly examined.

	Required Pipeline Response		
GWUT Criterion	**Less than 30%**	**Over 30 to 50% SMYS**	**Over 50% SMYS**
Over 5% CSA and identified for examination	Interval < 12 month	Interval < 6 months	Interval < 6 month
	Leak survey once /month	Direct Examination +	Direct Examination +
	Direct Examination	MOP < psi @ discovery	Reduce to 80% MOP @ Discovery
		Leak survey once /month	