# FINAL REPORT

# Ultrasonic Guided Wave Technology for Non-Invasive Assessment of Corrosion-Induced Damage in Piping for Pollution Prevention in DoD Fuel Storage Facilities

## ESTCP Project WP-200819

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This report summarizes the work performed in a two-phase ESTCP project to demonstrate the capabilities of commercially available ultrasonic guided wave technology for the detection, sizing, and growth monitoring of corrosion-induced defects in fuel piping. Corrosion-induced defects in long and inaccessible pipelines are a concern for the DOD because of the potential for leaks and oil spills on land and underwater. In Phase I, a pipeline was established in the facilities at the NSWCCD, incorporating welds, elbows, and hidden corrosion-induced defects to serve as a test bed for ultrasonic guided wave technology. In Phase II the technology was used to monitor a steel pipeline at the Naval Station, Norfolk, VA. using above and below ground transducers for a period of 20 months. Several locations suspected of having corrosion have not yet produced consistently increasing ultrasonic signals to warrant excavation and physical examination, an indirect indication of the efficacy of the cathodic protection system for the pipeline. It is recommended that monitoring be continued to further demonstrate this technology for future DOD and commercial use.

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| | |
|---|---|
| **BL** | Block |
| **CSAL** | Cross Sectional Area Loss |
| **CFR** | Code of Federal Regulations |
| **DAC** | Distance Amplitude Correction |
| **DESC** | Defense Energy Support Center |
| **DOD** | Department of Defense |
| **DOT** | Department of Transportation |
| **ESTCP** | Environmental Security Technology Certification Program |
| **FISC** | Fleet Industrial Supply Center |
| **NAVFAC** | Naval Facilities Engineering Command |
| **NAVSUP** | Naval Supply Systems Command |
| **NDE** | Nondestructive Evaluation |
| **NSWCCD** | Naval Surface Warfare Center, Carderock Division |
| **ONR** | Office of Naval Research |
| **OPA** | Oil Pollution Act |
| **OSHA** | **Occupational Safety and Health Administration** |
| **PIG** | Pipeline Inspection Gage and also refer to as PIGGING for internal inspection of a pipeline |
| **SBIR** | Small Business Innovative Research |
| **SEAP** | Science and Engineering Apprentice Program |
| **STTR** | Small Business Technology Transfer/Research |

**VP** Valve Pit

## ACKNOWLEDGEMENTS

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## EXECUTIVE SUMMARY

This report summarizes the work performed in a two-phase ESTCP project to demonstrate the capabilities of commercially available ultrasonic guided wave technology for the detection, sizing, and growth monitoring of corrosion-induced defects in fuel piping. Corrosion-induced defects in long and inaccessible pipelines are a concern for the DOD because of the potential for leaks and oil spills on land and underwater. In Phase I, a pipeline was established in the facilities at the NSWCCD, incorporating welds, elbows, and hidden corrosion-induced defects to serve as a test bed for ultrasonic guided wave technology. Periodic ultrasonic measurements were made to monitor the growth of these defects. Results demonstrated that a defect growth rate could be established based on ultrasonic signal characteristics and established the viability of this technology to monitor defect growth in pipelines in the field.

Based on the approach developed in Phase I, this technology was demonstrated in Phase II in a steel pipeline at Norfolk Naval Station, Norfolk, Virginia. Transducers were installed on above and below ground pipe sections of mixed 10 inch, 8 inch, and 6 inch outside diameter piping with numerous bends, welds, and reducers. Access points above ground allowed convenient monitoring of pipeline conditions over a period of 20 months. Of interest were the achievable inspection distance, the stability of signals in variable environments, defect detection, and growth tracking. It is concluded that there has not been sufficient corrosion occurring to produce a wall cross section loss exceeding 30 %, an indirect indication of the efficacy of the cathodic protection system for the pipeline. Compared to the Phase I results, the signal to noise ratio in the old pipeline in the field was larger by a factor of 4 in most locations. Several locations suspected of having corrosion have not yet produced consistently increasing ultrasonic signals to warrant excavation and physical examination. It is recommended that monitoring be continued to further demonstrate this technology for future DOD and commercial use.

# 1.0 INTRODUCTION

The Oil Pollution Act (OPA) of 1990 sets up operational and maintenance requirements for DOD and civilian fuel/oil storage and transport facilities in the U.S. Fuel/oil spills are problematic for the DOD in terms of impacts to the environment, costs in cleanup, and adverse public perceptions. Many of the negative impacts associated with fuel/oil spills could be minimized through spill prevention efforts, such as better maintenance of storage tanks and piping systems. Since pipeline problems resulting in leaks and spills can be caused by metal corrosion, devices known as maintenance pigs and smart pigs are passed through a pipeline to measure wall thickness loss and other structural anomalies. In addition, leak indicating pressure testing and excavation to expose the surface of buried pipes for visual inspection are also used. These techniques are invasive and not very effective if there are internal obstructions, external dikes, or other complex geometric features along the pipeline. Furthermore, these approaches do not provide sufficient information to predict the future health of the piping unless a failure leading to leakage has already occurred.

This report summarizes the results obtained in Phase I and II of an ESTCP supported project from 2008 through 2011. A test facility was established at NSWCCD for pipes with controlled amounts of corrosion damage. The purpose of Phase I was to establish the viability of defect growth detection and monitoring in a well controlled environment and to provide guidance for field testing in a live pipeline in Phase II. If a nondestructive technique based ultrasonic guided wave can reliably detect small defects and monitor their growth by using a small number of easily accessible sensors, contractors can be hired by all DOD fuel facilities to perform such tests according to government specifications, thereby improving the management for structural integrity of pipelines at reduced cost.

## 1.1 BACKGROUND

Corrosion in steel piping in DOD fuel storage and transport facilities can lead to fuel leaks and potentially serious spills if it is not detected to allow for timely repair. This problem is compounded by the fact that piping systems can extend for many miles, often go underground, through dikes, and road crossings, making them inaccessible for routine inspection. Current practices of inspection techniques allow seriously deficient items to be repaired or removed from service, sometimes at inconvenient times and high cost as a result of emergencies. However, none of these techniques provides sufficient information to predict the growth rate of small defects. Often, the presence of defects does not imply the end of life of the structure. As long as the changes in these defects can be monitored, it could be economical to continue using the existing structures until the point is reached when they are judged to be unsafe to be used.

In the past decade, long range ultrasonic techniques based on wave propagation through the pipe wall along the pipe axis have been developed and commercialized by a number of companies in the U.S. and abroad and are accepted by the petrochemical industry. Under favorable conditions, such techniques can provide rapid identification of corrosion-induced wall loss over long distances (typically 50-100 feet at a time). By means of signals associated with welds, pipe supports, and other material boundaries, the locations where corrosion has occurred can be identified, and detailed examination of those locations can be carried out if accessible to an inspector. Some DOD facilities have initiated such a spot checking approach.

## 1.2 OBJECTIVE OF THE DEMONSTRATION

The need for conventional, point-by-point nondestructive evaluation to supplement the long range guided wave results has significant drawbacks due to inaccessibility of the underground locations. We seek to demonstrate that ultrasonic guided wave technology can be a non-invasive, cost-effective technology that not only detects defects, but also monitors their growth rate without additional measurements. The overall objective of this ESTCP project was to demonstrate and validate this capability in the field.

Before field testing, we need to validate the concept of defect growth monitoring by ultrasonic guided wave technology when the amount of corrosion damage is systematically increasing. In Phase I, several technical issues need to be resolved, including the stability of signals over a long period of time; the effects of correlating results for sensors at different distances from a defect, and the effects of welds and elbows in the paths of the pipeline. These tests should provide quantitative measures of the range of defect sizes detectable and the rate of defect growth. The objective in Phase II is to validate these concepts in the field.

## 1.3 REGULATORY DRIVERS

The OPA (1990) established the laws governing oil spill prevention and response on both the federal and state levels. Management plans are in place at Navy fuel storage and transport facilities, in accordance with the guidelines provided by 94 CFR Chapter 195, Pipeline Safety, and Pipeline Management in High Consequence Areas. To achieve compliance, pipeline inspection is performed periodically and corrective actions are taken to prevent fuel/oil spills. Ultrasonic guided wave technology is included by the American Petroleum Institute as one of the new tools for safety inspection of a pipeline as stated in API 570 procedures.

## 2.0 DEMONSTRATION TECHNOLOGY

### 2.1 TECHNOLOGY DESCRIPTION

Conventional ultrasound technology is commonly used for nondestructive material evaluation and in the health care industry. For that reason, guided wave ultrasound is a special variant of this technology. Contrary to conventional ultrasound, which by equipment design excites wave propagation through the thickness of a material, guided wave ultrasound in a pipe propagates along the axis of the pipe over a long distance, as shown in the sketch in Figure 1. By analyzing the reflections from defects at a long distance, the location and the severity of the defects can be determined by suitable calibration techniques [1,2].

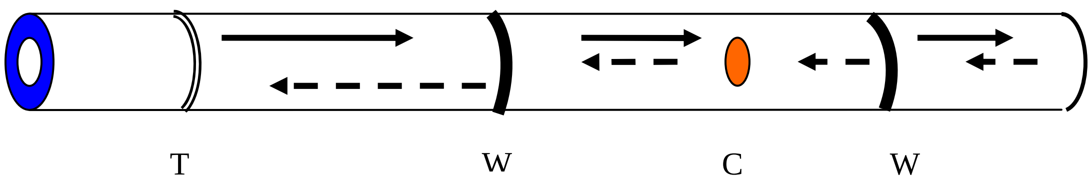



Figure 1. Sketch of ultrasonic guided wave propagation in a pipeline.
T represents the transducer for launching and receiving wave signals, W represents the welds, and C represents an area of corrosion. Right-going arrows depict waves launched by the transducer and left-going arrows depict reflections from the welds, corrosion, and the end of the pipe.

The basic science of ultrasonic guided wave propagation in pipes has been known for decades. The commercialization of techniques based on this technology was initiated by two British companies in the 1990s, followed by a number of U.S. companies using either British technology or newly invented American approaches and devices. Among others, the Office of Naval Research (ONR) supported basic research and exploratory development in this area in the 1990s, and several SBIR and STTR projects in this area were supported by the ONR and the Department of Transportation (DOT) for equipment development and to improve signal processing and interpretation.

### 2.2 TECHNOLOGY DEVELOPMENT

The practitioners of guided wave ultrasound technology in industry today fall into two distinct groups. The first group, using inexpensive magnetostrictive sensor technology patented by Southwest Research Institute, San Antonio, Texas, has transducers permanently mounted on the pipe. These transducers can be left in place for successive measurements over a long period of time (years). The second group, couples expensive, removable piezoelectric transducer arrays to a pipe every time a measurement is to be made. By re-coupling such transducers at the same locations and repeating the measurements at a later date, changes in the pipe can be monitored.

With either approach the goal is to relate the changes in the signals over time with the growth in size and severity of defects.

Prior to this ESTCP project, it was demonstrated at NSWCCD that there were significant changes in the characteristics of the ultrasonic guided wave signals as corrosion-induced wall loss progressed in a pipe. These results were limited to pipes up to 20 feet long. The tests were designed so that different amounts of corrosion occurred in different test pieces, resulting in some uncertainty in the determination of the rate of material loss due to baseline drifts. However, it was necessary to demonstrate the monitoring of material loss in a more systematic fashion to decrease such baseline drifts on pipes up to 100 feet long and on pipes with protective coatings.

While ultrasonic guided wave technology has been applied commercially in the petrochemical industry for at least ten years, the concept of pipeline condition monitoring is relatively recent. We would like to demonstrate that monitoring of corrosion-induced wall loss in piping can be achieved by simply recording the changes in ultrasonic guided wave signals periodically. A simple subtraction of the envelope of the digitally recorded waveforms should provide the means to monitor the progress of corrosion-induced material damage.

## 2.3 ADVANTAGES AND LIMITATIONS OF THE TECHNOLOGY

The maintenance for piping integrity in DOD fuel storage and transport facilities and ships is currently based on either a time-based schedule (preventive maintenance) or in response to an emergency following an incident of piping failure (corrective maintenance). While the current practice of using smart pigs for condition assessment is effective for very long pipelines, it is expensive and interrupts pipeline operations. Furthermore, results obtained by smart pigging today do not provide information on the rate of corrosion-induced wall loss in the future. Set up cost (at tens of thousands of dollars) for smart pigging is high, rendering it impractical for a short line. Also, hydrostatic tests are used frequently today (at a cost of $5K to $50K per test) to verify the structural integrity of a pipeline. Part of this test actually relies on inducing a visible controlled leak in the weak points (likely caused by corrosion) along the line, at which point repair or replacement of the weak sections is then carried out. If the technology of guided waves can be demonstrated to provide reliable information not only on sizing the defects, but also on defect growth rate, it will provide timely information to facilitate the practice of predictive maintenance in fuel facilities at low cost. In addition, many short lines can be tested in one work day by a qualified inspector at a cost of less than $2K.

Drawbacks do exist in the ultrasonic guided wave technology. First, guided waves do not propagate beyond a flange in the pipeline. The choice of access points for launching and receiving guided waves must take into account the locations of flanges, valves, elbows, and other obstructions, which sometimes prevent inspection of parts of a pipeline. Such limitations can sometimes be overcome by propagating waves in opposite directions from two ends of a pipe. The second limitation/drawback is some uncertainty in the smallest amount of corrosion-induced wall loss in a complex piping system that can be detected by the proposed monitoring techniques. Today, commercial testing services show that an averaged loss of 10% in wall cross-sectional area can be reliably detected in the field in 50-100 feet long pipes. However, the “aging” of the pipes in the field may introduce noise effects, which is likely to vary from one pipe location to another. The effect of old, unknown, and protective coatings on inspection distance is another aspect that can only be assessable by on-site measurements.

# 3.0 PERFORMANCE OBJECTIVES

Table 1. Performance Objectives

| Performance Objective | Data Requirements | Success Criteria | Results |
|---|---|---|---|
| **Quantitative Performance Objectives** | | | |
| 1. Achievable inspection distance | Pulse-echo signal traces for pipeline at start of the project | 100 feet from transducer location | In field testing, distance up to 92 feet, but most frequently at approximately 30 feet from transducer |
| 2. Stability of signal traces and durability of transducers | Location and peak height of weld signals over the course of the project | Distance and peak height reproducible to within 5% | Peak height reproducible at 30 feet to within 10% over 20 months |
| 3. Accuracy in locating defects in pipelines in a Navy fuel storage facility using ultrasonic guided wave technology | Results of visual or other conventional NDE measurement at locations identified by ultrasonic guided waves, or data provided by pigging, or by observations after underground pipes are exposed | Accuracy of locating a defect within +/- 2 feet at a distance of 50 feet from the location where ultrasonic waves are launched | Weld signal locations stationary to within +/- 2 feet at 30 feet. Physical sighting of defects not yet available |
| 4. Minimum size of detectable defect based on guided wave ultrasound | Ultrasonic signals including background noise returned from a distance of up to 50 feet | A defect with 10% cross sectional area loss (CSAL) at 50 feet is detectable | 10% CSAL at 20-30 feet |
| 5. Accuracy in sizing defects | Data on sizes of defect and the corresponding ultrasound data | Defect sizing is accurate to within a factor of 2 | Physical examination of defects not yet available |

| Performance Objective | Data Requirements | Success Criteria | Results |
|---|---|---|---|
| **Quantitative Performance Objectives (Cont'd)** | | | |
| 6. Capability for defect growth monitoring | Changes in ultrasonic signals as a function of time | Defect size increase by 10% CSAL resulted in changes in signal peak height above noise level | Consistent signal increases indicating defect growth await further monitoring; signal for 10% CSAL probably achievable at 20-30 feet |
| 7. Improved planning for maintenance activities | Data on repair activities and incidence of corrosion induced piping failures | Sufficient time (3 months or more) is provided for budgeting and planning for piping repair before any failure due to corrosion | Defect large enough to warrant repair has yet to be detected; objective to be demonstrated by additional monitoring time |
| 8. Increased efficiency in pipeline maintenance as a result of the use of ultrasonic technology | Maintenance activity records | Redistribution of the limited, invasive maintenance resources from one pipeline to another or from one part of a pipeline to another as a result of increased confidence in the conditions of the pipelines provided by ultrasonic data | Awaiting additional monitoring effort; no piping failure or leakage is observed during 20 months of monitoring |
| 9. Technology maturation | Data on the use of technology by DOD | Increase in the application of technology in DOD since the initiation of this project in 2008 | New equipment has been developed commercially and demonstrated in Navy facilities since start of this project |

Because excavation is very disruptive to site operation, we recommended to proceed only when the results of ultrasonic tests suggest the existence of defects with a CSAL of 30% or larger, in order to allow repair action to proceed well before a defect size reaching 50% CSAL which is the current commercial standard. For this reason, a suspected region would be available for visual or other inspection for damage sizing only when it reached a later stage of damage. In our plans for the field tests the relationship between the ultrasonic data and the location and sizes of small defects was intended to be an extrapolation from the results for the larger defects. This and other aspects of defect sizing will be discussed in later paragraphs.

Objective #1. Achievable inspection distance

The most attractive feature of pipe inspection using ultrasonic guided wave is the remote sensing capability. Defect information is obtained by analyzing the signal returned to a sensor placed at a long distance from the defect. Thus, the achievable inspection distance is a basic parameter of interest. Equipment must be able to provide adequate signal power to overcome signal loss due to intrinsic material attenuation, impedance mismatch at discontinuities (e.g. welds), and geometric features, such as elbows and reducers as guided waves propagates down a pipeline. This capability is affected by the effect of aging of the pipes in the field. The data required to judge whether this objective is met are the pulse-echo waveforms recorded by the transducers representing reflections from welds and flanges as a function of wave propagation distance.

Objective #2. Stability of signal traces and durability of transducers

In order to monitor the progress of corrosion induced damage in a pipeline, changes in the signals obtained by repeated measurement over the duration of this project were compared to a baseline data set. The durability and stability of the transducers would control this capability. The limits of +/- 5% set for the “Success Criteria” is based on the electronic noise associated with environmental effects on the measurement.

Objective #3. Accuracy in locating defects in pipelines in a Navy fuel storage facility using ultrasonic guided wave technology

Essentially, two pieces of information are provided by ultrasonic guided wave data. The first is the time of arrival of signals, from which the distance information for reflectors (defects) are calculated based on the known wave propagation speed. The second is the amplitude of these signals, associated with the “size’ of the reflectors that is typically represented by the peak voltage value. Material inhomogeneity as a result of aging, as well as signal noise issues will modify the shape of a signal peak, rendering some uncertainty in its exact location. It is expected that the shape of the defect would also affect the achievement of this objective. The “Success Criteria” of +/- 2 feet should be acceptable since any corrective action would require excavation over an area of at least a few feet to expose the suspected pipe section. The data required to judge whether this Objective is met includes the actual sighting and gauging of the defects when excavation is carried out, but only if the defects are at the external surface.

Objective #4. Minimum size of detectable defect based on guided wave ultrasound

The smallest defect detectable in the field will be the ones whose peak height is above noise level. The data required to judge whether these criteria are met in the field tests are the noise signal peak heights at a distance of 50 feet. A minimum size of 10% cross sectional area loss

(CSAL) at a potential error by a factor of 2 (specified in Objective #5) would still provide ample time for repair which commences when the defect reaches a size of 50% CSAL.

Objective #5. Accuracy in sizing defects

Since the action for repair relies on the severity of a defect, the accuracy in sizing is important as an objective. Current practice requires that a pipeline having a defect representing a loss of cross sectional area of 50% or higher be repaired or replaced. The locations where a defect judged by ultrasound to have a CSAL exceeding 30% will be excavated and the defect searched out. With reference to the capability to detect a defect with CSAL of 10% or larger (Performance Objective # 4), an inaccuracy by a factor of 2 in sizing would assure that a defect will be detected and sized well before it reaches a CSAL of 50%. Even if the size of a physical defect with a CSAL of 10% is underestimated by a factor of 2, its signal height would be a significant fraction of a weld signal, which should be readily detectable. Thus, a capability of ultrasound to predict the physical size of a defect to within a tolerance of 2 should be acceptable.

Objective #6. Capability for defect growth monitoring

One of the main goals of this project is to demonstrate the capability of current ultrasonic guided wave technology to monitor the changes in material conditions and to follow the increase in size and severity of corrosion damaged areas in a pipeline. In view of the requirement for pipeline repair at CSAL of 50%, this capability to detect a defect growth by 10% CSAL is deemed sufficiently conservative in providing adequate early warning against unexpected pipeline failure due to hidden corrosion.

One of the many benefits of using ultrasonic guided wave to monitor defect growth over an extended period of time is to minimize the risk of misidentifying an unknown signal peak to be associated with a corrosion-induced defect if uncoordinated measurements are made. A successful monitoring effort allows a judgment of corrosion and repair action to be based on a systematic increase in defect size and not on a one-time measurement of peak height. A systematic and consistent increase in signal above the noise signifying a defect growth by a CSAL of 10% should indicate true defect growth.

Objective #7. Improve planning for maintenance activities

Currently, the long underwater section of the pipeline between Craney Island and the shore of Norfolk is inspected internally every 5-years by pigging operations. However, the underground sections of the pipeline tested ultrasonically here are unpiggable; as a result of the existence of multiple elbows and reducers. A small portion of this part of the pipeline was pressure tested and repair activity followed before this ESTCP project was initiated. Presently, the only maintenance performed in the selected pipeline is to correct a problem upon the discovery of a fuel leak. Thus, lead time for piping repair does not exist. Furthermore, Navy management at Norfolk has a keen interest in managing maintenance activities based on the real conditions of a pipeline instead of on the time of usage. In reality, there is very little that can be done to inspect an underground, unpiggable pipeline because the excavation required prior to any sort of inspection is both costly and interruptive. If the physical conditions of a pipeline are known accurately at all times as a result of ultrasonic measurements, resources can be allocated to address the most pressing problems first. We envisioned that a lead time of 3 months or more would be achievable based on the capability for defect sizing and growth prediction based on guided wave data. This should result in a more intelligent scheduling of maintenance and repair activities.

Objective #8. Increased efficiency in pipeline maintenance as a result of the use of ultrasonic technology

This Objective is a long-term performance objective of this project. If the reliability of ultrasonic guided wave technology can be proven, valuable resources saved in a pipeline certified to be free of serious defects by ultrasound can be applied to facilitate needed maintenance in other pipelines in a site. For this reason, site management efficiency is increased when a reduction in invasive testing in one part of the site benefits the maintenance of the whole site, even though the total amount of activities for the whole site remains unchanged. Consequently, because there is no reliable and cost effective technology currently available to inspect the underground portion of this pipeline, information obtained in this project should be useful for the overall pipeline structural integrity management. In addition, the effectiveness of the existing cathodic protection system for corrosion prevention can also be checked by the ultrasonic guided wave results.

Objective #9. Technology maturation

We envision that the maturity of ultrasonic guided wave technology will be enhanced by this demonstration. We anticipate that our experience in test procedures, equipment operation, lessons learned, and other technical and management processes will bring about improvements in the application of this technology for DOD and commercial users.

# 4.0 FACILITY/SITE DESCRIPTION

## 4.1 PHASE I LABORATORY SITE

In Phase I, a pipe loop with both indoor and outdoor sections was housed in a long building for corrosion and ultrasonic guided wave experiments in the facilities at the Carderock Div., NSWC in West Bethesda, Maryland.

## 4.2 FIELD TEST SITE SELECTION

The Navy fuel facility at Norfolk Naval Station, Norfolk, Virginia was selected as the demonstration site. This site has an underground pipeline and underground storage tanks. It is part of a large Fleet Industrial Supply Center (FISC) based at Craney Island, Portsmouth, Virginia. The fuel department manager and staff are supportive of the proposed demonstration, since they are interested in new technology such as ultrasonic guided waves to identify existing areas of corrosion and other structural weakness in the inaccessible sections of the pipeline. Figure 2 shows the location of Norfolk Naval Station in the Hampton Roads area of Virginia. It is accessible by I-64, and is served conveniently by Norfolk International Airport, providing easy access by contractors and government staff.


Figure 2. Map of area around Norfolk Naval Station, Norfolk, Virginia.
The FISC Craney Island is the lower small white area in the middle of the map, across Elizabeth River from Norfolk.

### 4.2.1 Site operation

This Navy site is operated by the Naval Supply Systems Command. It supplies mainly JP-5 jet fuel for Navy aircrafts based on land and onboard ships. In addition to federal civilian employees, it is supported by on-site contractors for operations and maintenance. This includes the upkeep of valve pits that provide access to the underground pipeline.

The general layout of the pipeline where the majority of the test was performed is shown in Figure 3. The total length of the pipeline between Valve Pit (VP) 5 and VP 7 is approximately one mile. Please note, there are several abrupt bends in the pipeline between VP 5 and Block 20. The distance between each valve pit is approximately 200-400 feet, with a longer distance of approximately 2000 feet between VP 23 and VP 7. The pipeline runs underground through the Navy base from VP 7 to the underground storage tanks in Chambers Field, approximately 3 miles away. A photograph showing the outside of a typical valve pit is shown in Figure 4.

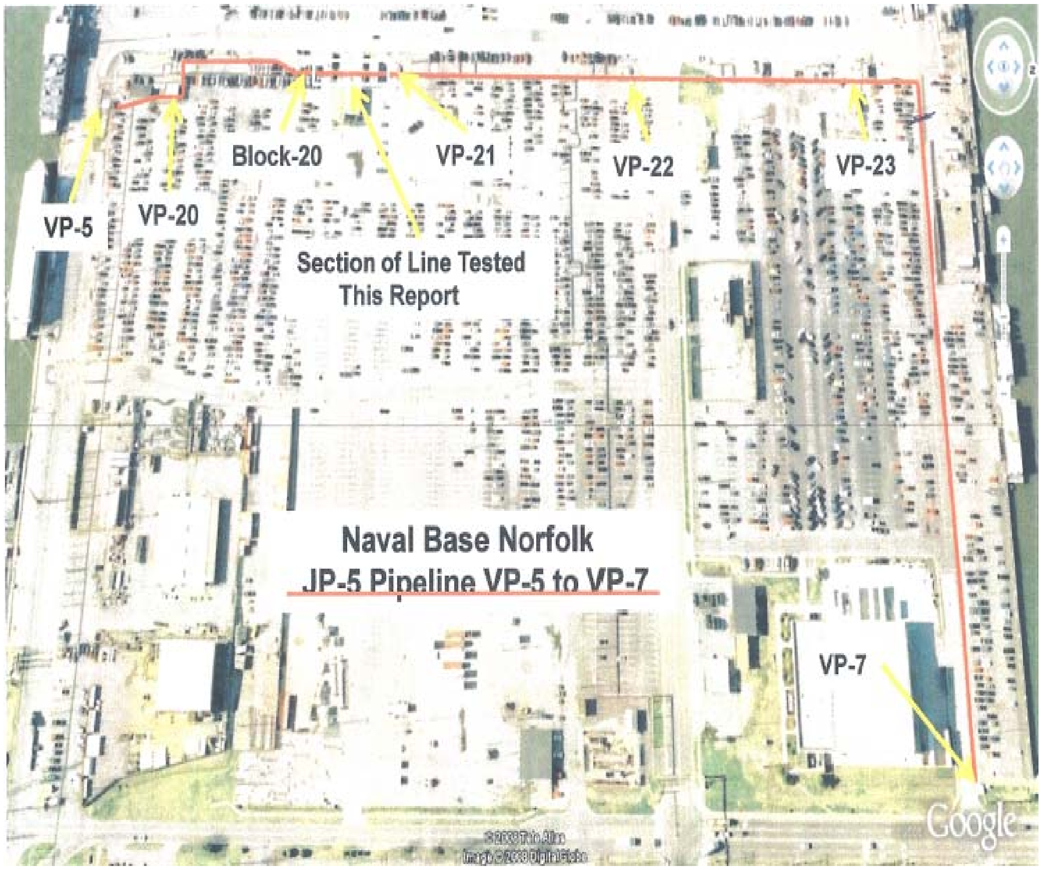



Figure 3.  JP-5 pipeline layout (shown in red) from VP5 to VP7 at Norfolk Naval Station.

Figure 4. Photograph of a valve pit along the pipeline.
The gray access hatch for human entry is located on the corrugated roof and the "access box" was mounted on the concrete wall for easy electrical connections to the transducers inside the pit.

#### 4.2.2 Site conditions

JP-5 jet fuel in storage tanks on Craney Island supplies the needs of Navy aircrafts at Naval Station Norfolk via this pipeline that runs through the Elizabeth River before reaching the shores in Norfolk, Virginia. An aerial picture of the facility in Craney Island, Virginia is shown in Figure 5. A large portion of the 4.6 miles long, underwater pipeline was pigged five years ago. A test report [3] showed the overall structural soundness, but the existence of some external and internal defects was documented in that section of the pipeline between VP 5 and the water front. Sections of the pipeline between VP 5 and VP 7 were deemed unpiggable because of the existence of internal obstructions and reducers and because of cost considerations for a relatively short line. An example of obstructions inside a valve pit is shown in Figure 6.

Figure 5. Aerial view of fuel storage tanks and pipelines in FISC Craney Island, Portsmouth, Virginia.

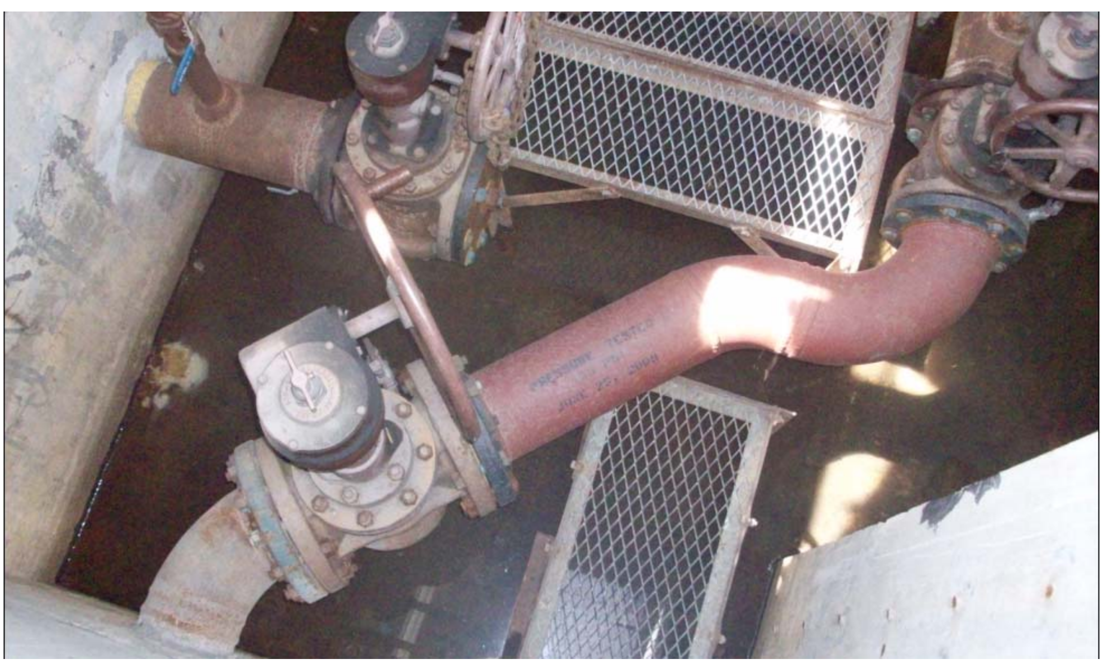


Figure 6. Pipeline accessories inside a valve pit.A section of the pipeline between Block 20 and Valve Pit 21 was replaced 4-years ago because of structural weakness as revealed by pressure testing. It has a mixture of 10 inch and 6 inch pipes connected through reducers and valves.

### 4.2.3 Site related permits and regulations

We secured the permission from the Navy site manager to conduct the proposed guided wave technology demonstration. To comply with Occupational Safety and Health Administration (OSHA) regulations workers inside valve pits completed safety training for confined space environment. Federal and state regulations require valve pits to be certified by qualified safety professionals daily before human are allowed to work inside. DOD staff and contractors have complied with the requirements that a team of 2 people should work together inside a valve pit. In addition, a third person is to be present outside on safety watch when workers are inside a pit.

## 5.0 TEST DESIGN

In Phase I, government staff controlled the corrosion experiments, including the location and severity of the defects, measured the defect characteristics, and examined, as well as analyzed the ultrasonic guided wave data provided by the inspectors. The locations of the defects were hidden from the inspectors throughout the defect growth monitoring effort to simulate the unknown conditions in the field. In Phase II, field testing at Norfolk Naval Station the existence of defects was unknown. Detailed test design is shown in later paragraphs.

The flow chart in Figure 7 depicts the overall plan for the execution of Phase I and II.

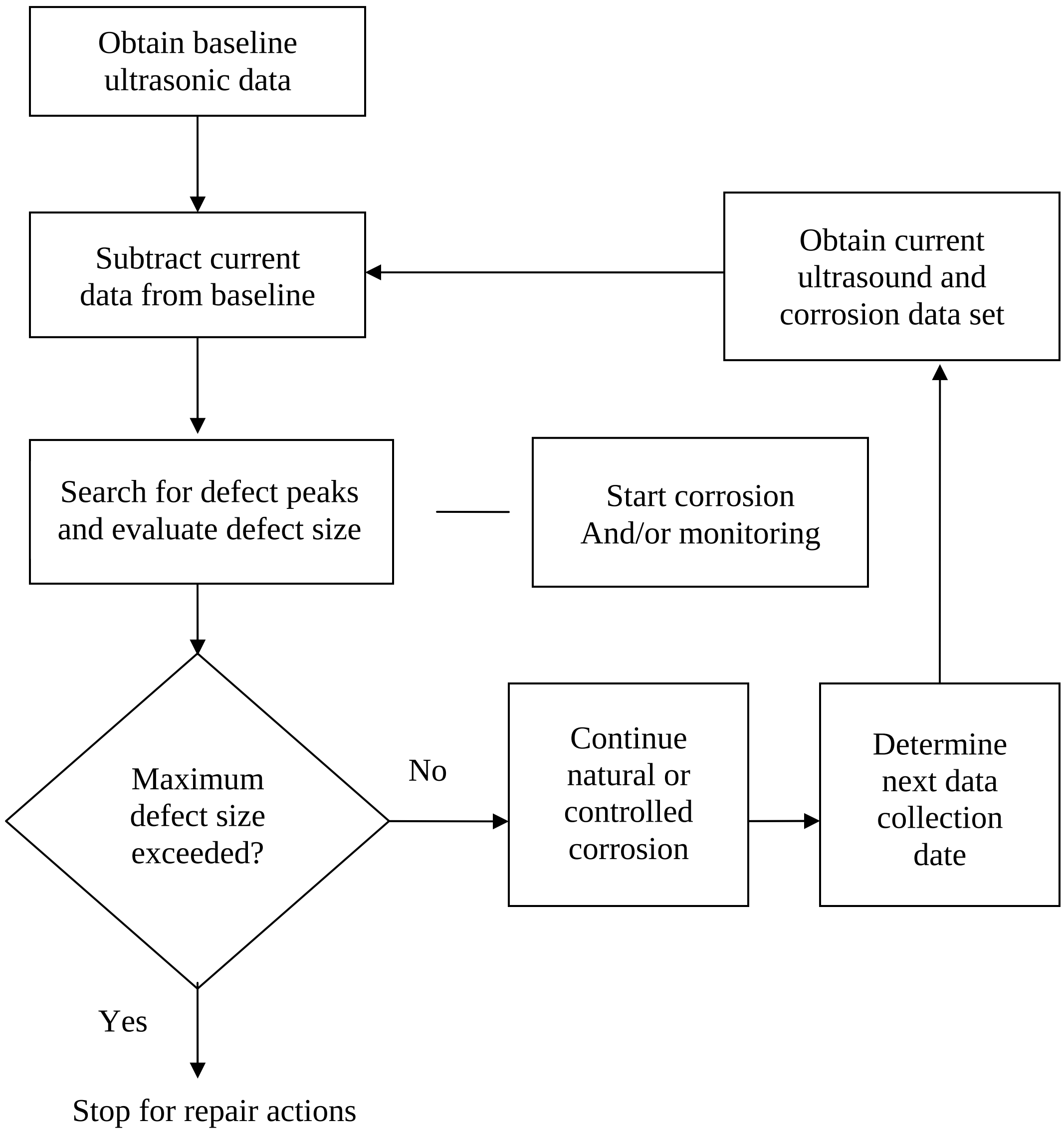



Figure 7. Flow chart for the application of ultrasonic guided wave technology for corrosion defect growth monitoring.

## 5.1 CONCEPTUAL LABORATORY TEST DESIGN (PHASE I)

Two types of pipes were tested in Phase I at NSWCCD. The first type of pipe was coated with an above-ground coating system and the second type of pipe was coated with an under-ground coating system. Both types of pipes were tested with ultrasonic guided waves to determine if the coating systems affected the signal properties.

### 5.1.1 Above-ground coating system pipes

5.1.1.1 Pipeline design and layout

The first series of pipe was 8.6 inches outside diameter (OD), 0.33 inch thick (8 inch schedule 40) steel pipe, set up as shown in Figure 8. In addition to a number of welds, we incorporated two 90 degree elbows joined by a 5 feet long pipe segment, with 75 and 25 feet long straight segments extending to the other ends. The intent was to provide sensor placement areas that allow the investigators to test their equipment in both straight and elbow contained pipe sections before reaching a defect.

The nominal 20 feet long pipe segments were coated by a 3 layer protective paint, following the Unified Facilities Guide Specification for an outdoor, above ground environment. A 20 feet segment of the pipeline was left outdoors to provide some indication of the performance of transducers left in the outdoor environment. The rest of the pipeline was housed in a long indoor space where controlled corrosion experiments and ultrasonic measurements were made. The pipeline was supported every 10 feet by pipe stands and the pipe stands were electrically isolated from the pipeline to reduce potential interference with the testing.

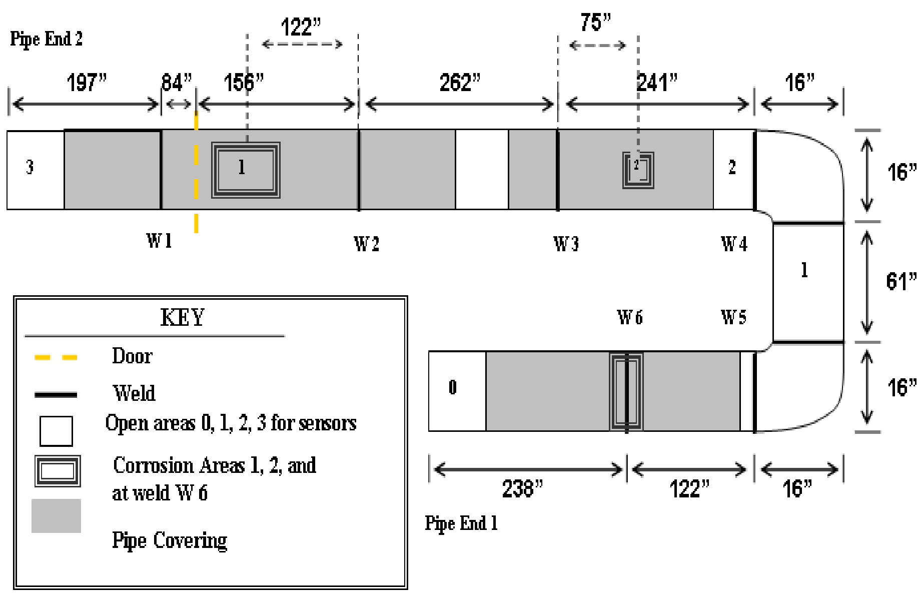



Figure 8. Location of ultrasonic measurement points and corrosion defects in the 8.6 inch diameter pipeline at NSWCCD.

5.1.1.2 Defect locations and size

Figure 8 illustrates the locations of the corrosion-induced defects. Two defects (unknown to the inspectors) were placed in the long straight sections of the pipeline. One of the defects not only increased systematically in its depth, but also along the pipe axis and along its circumference as the exposure progressed (Defect 1). The other defect was intended to be a ”small” defect (Defect 2) having a fixed lateral dimension of approximately 3 inch x 3 inch, but with increasing material loss in the thickness direction. The goal was to achieve a wall thickness loss exceeding 50% in this defect by the end of Phase I. The third defect (Defect W6) was at one of the welds, approximately 20 feet from one end of the pipeline. There has not been any report in the literature on ultrasonic guided wave responses for corrosion at a weld, even though welds are not immune to corrosion in the field. As stated earlier, the approach was to increase the severity of the corrosion defect, as measured by the change in thickness and area loss, over time.

The locations and sizes of the defects were hidden by a sheet metal cover over large portions of the pipeline, so that a true blind test could be presented to the inspectors performing the ultrasonic measurements. This approach was intended to simulate testing of unknown underground pipes in the field. The inspectors were told that defects existed in the two long, straight sections of the pipeline, and they can place sensors in the uncovered portions of the pipeline, including the 5 feet section between the two elbows. The sheet metal covers were supported by thin wood pieces resting on the pipe surface.

#### 5.1.1.3 Transducer placement

In Figure 8 regions 0, 1, 2, and 3 shows where transducers were mounted. We see that waves excited by Sensor 3 propagating in the negative direction should reach Defects 1 and 2 before reaching an elbow. Waves excited by Sensor 2 propagating in the positive direction should reach Defects 2 and 1 before it reaches the pipe end. Waves excited by Sensor 1 should see Defects 2 and 1 after crossing an elbow in the positive direction, and see the Defect W6 in the negative direction after crossing an elbow. Waves excited by Sensor 0 and propagating in the positive direction sees Defect W6 before reaching either elbow and beyond.

#### 5.1.1.4 Corrosion experiments

In order to control the extent of corrosion systematically over the course of time, we employed electrochemical means to introduce localized wall loss at selected locations in the pipeline. A photograph of the apparatus used for the corrosion experiments is shown in Figure 9. The transparent plastic tank on top of the pipe contained the electrolyte. To seal the electrolyte container to the pipe, reusable plumber's putty was used around the edges of the containers and the coating was removed from the pipe to provide an adequate seal. There were two drains in the electrolyte container on either side of the pipe to facilitate electrolyte removal. The apparatus was designed to allow continuous observation of the corrosion as it progressed and allowed convenient measurement of the wall loss by an external micrometer at various times of the experiment. The positive terminal of the power supply was connected to the pipeline and carbon rods served as the negative electrode. The carbon rods were suspended in the electrolyte during the corrosion experiments. Based on previous experience, a constant current of 10 Amps was maintained. Since the corroded surface areas varied among different defects, the current density varied amongst the defects and the time of exposure was adjusted according to the size of the intended defects. The electrolyte was a 3% salt solution using a mixture of rock salt and tap water. A combination of lacquer and duct tape was used to mask the desired corrosion areas and to prevent excessive material loss along the edges of the areas.

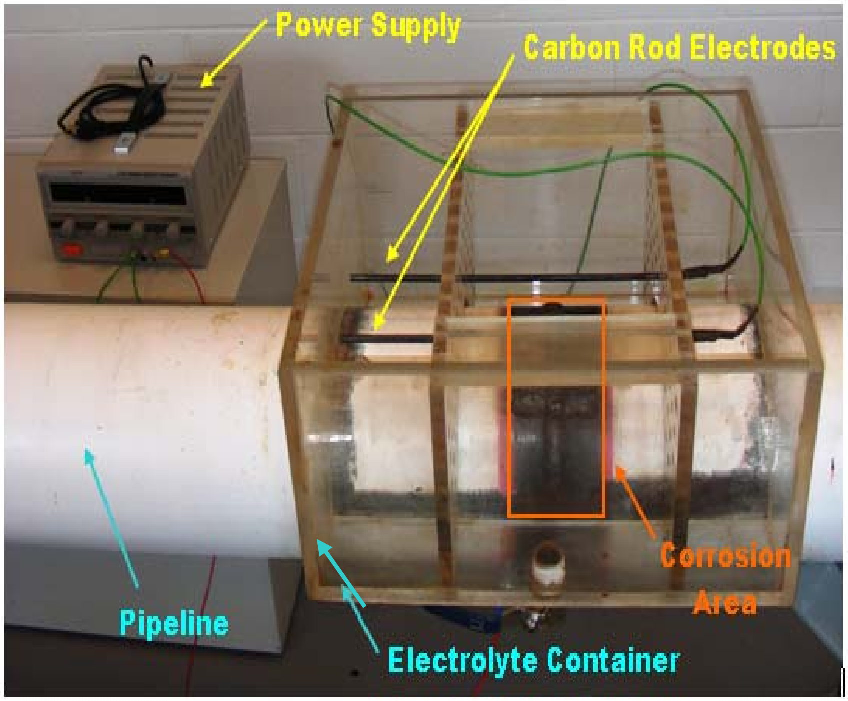



Figure 9. Corrosion apparatus for generating electrochemically controlled corrosion on the external surface of a pipe.

5.1.1.5 Transducer assemblies

A key component in the ultrasonic guided wave measurement system is the transducer to launch and receive the wave signal. The transducer based on magnetostrictive transduction principles, is shown in Figure 10. It consisted of a nickel strip, bonded to the pipe surface by room-temperature cured epoxy. Protective adhesive covers were applied onto these strips after bonding. Low profile energizing coils were wrapped around the bonded strips before additional aluminum covers were applied. The electrical leads from the coils were housed in a junction box for easy access throughout testing. Each transducer was bar-coded for easy identification.

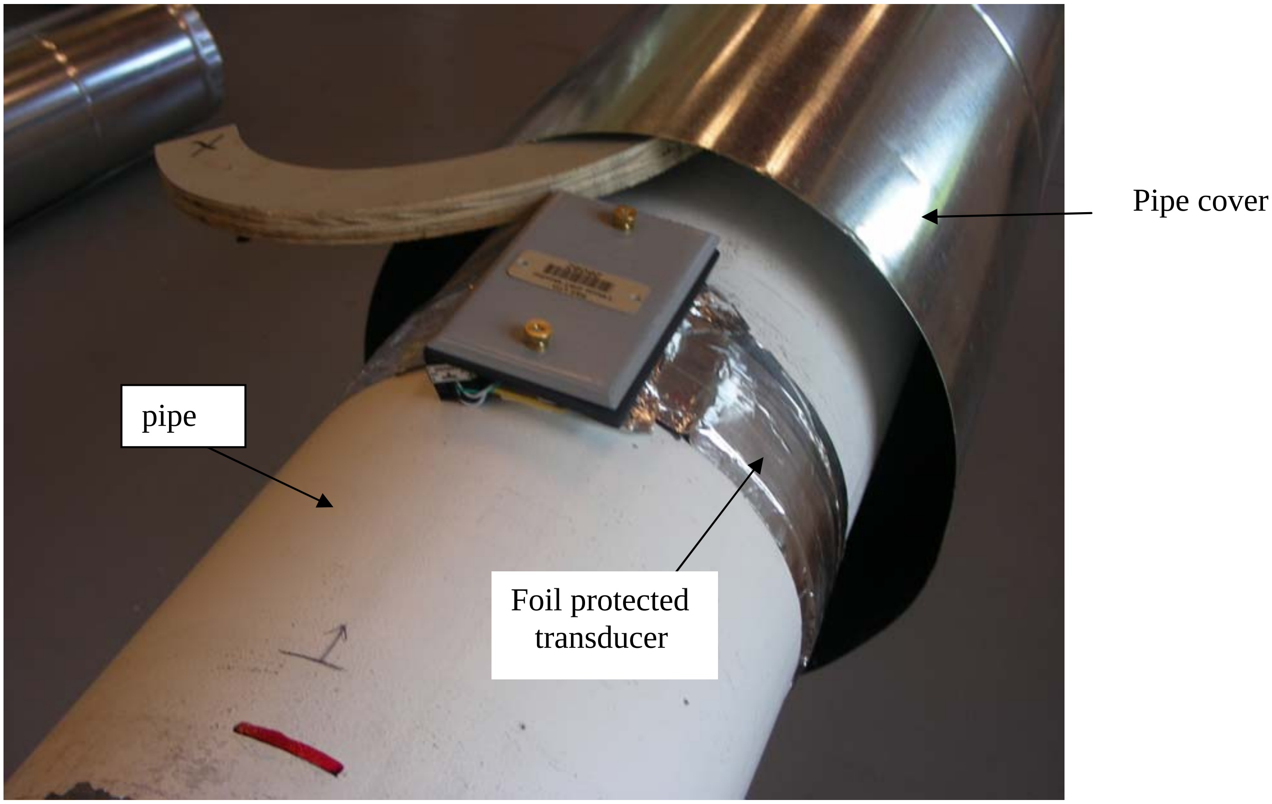



Figure 10.  Magnetostrictive transducer used by the inspectors.

5.1.1.6 Definition of cross sectional area loss (CSAL)

An important measure, widely used in the industry for characterizing the degree of corrosion damage in a pipe is the CSAL. Its definition is shown in a sketch in Figure 11. Other useful measures include the averaged depth of material loss and the total volume loss in a damaged region in the pipe wall. Signal peak height will be correlated to these quantities in later parts of this report.

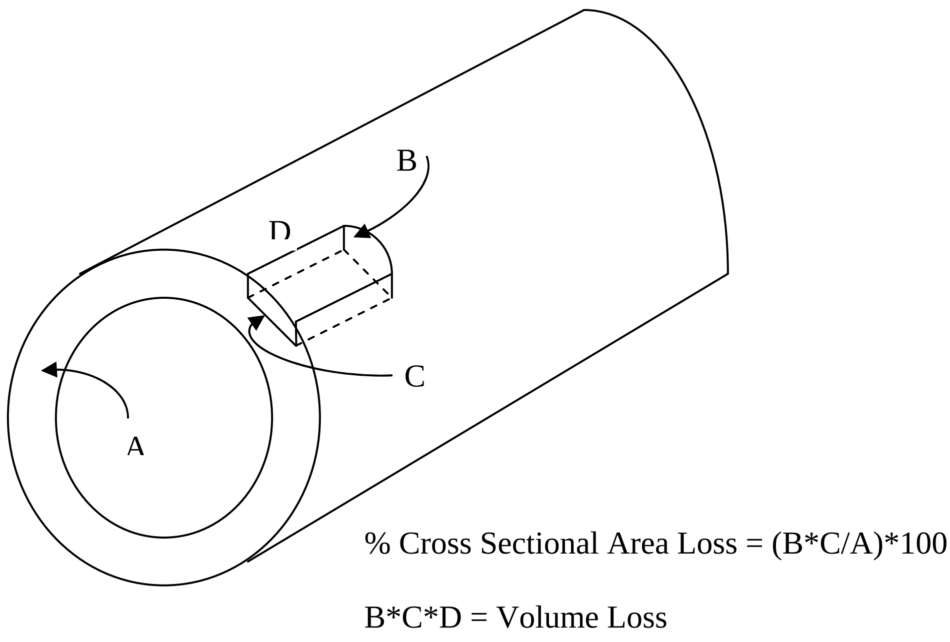



Figure 11. Definition of CSAL and Volume Loss.
A is the cross sectional area of the pipe wall, B is the average depth of corrosion, C is the length of the corroded area along the circumference of the pipe, and D is the length of the corroded area along the length of the pipe.

5.1.1.7 Measurement of averaged CSAL

A number of instruments for measuring the depth of corrosion were evaluated, including two versions of pit gauges. The equipment either had a very limited depth range, or was cumbersome to use without removing the tank holding the electrolyte on top of the pipe. We instead chose a large jaw micrometer fitted with a long arm to account for the corrosion apparatus and the outside diameter of the pipe; thus allowing for the corroded areas to be measured without removing the tank. By recording such data as corrosion progressed, the localized wall loss was calculated. Since the corrosion process was not expected to remove material uniformly over the intended area, we obtained an averaged measure of CSAL by first taking a photograph of the corrosion area and marking a large number of locations within the photograph to indicate where the micrometer readings of the wall thickness should be made as shown in Figures 12a and12b. These measurements were compared to the measured thickness of the pipe without corrosion and the corroded region was divided into segments with an average wall thickness, calculated from the measured thicknesses, associated with each segment, as shown in Figure12c. Knowing the area of each segment, the CSAL for each corrosion defect was calculated. In this manner, an average and standard deviation for CSAL was obtained for each of the defects after each stage of corrosion.

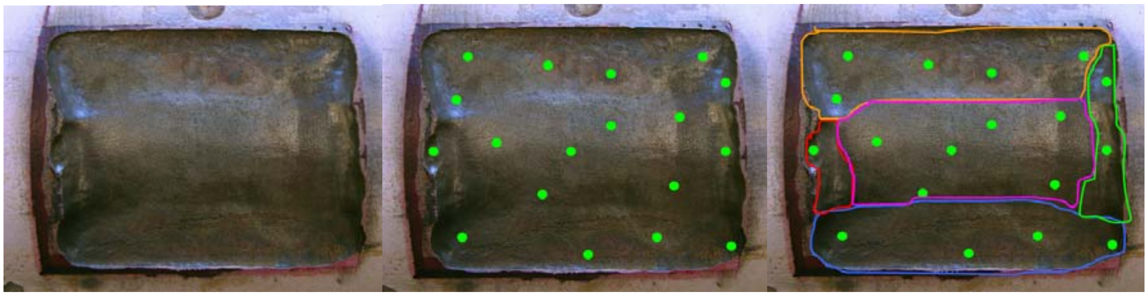



Figure 12. CSAL measurement sequence.
12a) Step 1: Photograph the corroded area.
12b) Step 2: Mark the locations for micrometer readings based on the topography of the corroded area.
12c) Step 3: Divide the corroded area into like segments and measure the segment areas.

5.1.1.8 Calibration of ultrasonic guided wave equipment

The key guided wave signal parameters used to determine the location and severity of a defect are the time of arrival, the peak height, and the shape of the signal envelope. The consistency of time measurement was checked by noting the time of wave arrival from known markers like welds and flanges. Unless a corrosion-induced defect is either initiated or is increasing in size, the ultrasonic wave form should not differ from the baseline data set. We used the height of the known markers to normalize potential fluctuations in the equipment output. For defect growth monitoring, we used a signal subtraction scheme after this amplitude normalization.

5.1.1.9 Distance Amplitude Correction (DAC) curves

The need to account for the decrease in signal amplitude as the propagation distance increases is well understood in ultrasonic bulk waves. A number of standard specimens provided by ASTM and other organizations by incorporating a drilled hole are being used today. However, the extension of this concept to guided waves in pipes is not straightforward. First, there are welds in the propagation path in a pipe. In addition to strictly distance effects, the mechanical impedance change across each of the welds must be accounted for. Second, when attempting to compare the results obtained by transducers mounted at different locations in a long pipeline, not only is the number of welds in the propagation path a factor, but the fact that the impedance across a weld may be different depending on the direction of propagation must also be accounted for. Finally, different welding processes and procedures result in variations in the size of the weld crown and the width of the weld.

5.1.1.10 Signal peak height normalization

Irregularities in the weld geometry can result in large variations in impedance across each weld. Such effects frequently result in the weld peak signal not following an exponential decay curve. In these situations, the use of a DAC curve, which is based on the concept of signal attenuation versus distance in the case of bulk waves, is not valid.

Instead of DAC curves, we normalized a defect signal peak height by scaling it against the peak height of a weld signal nearby. For comparing the signals obtained by a single transducer over the duration of these experiments, the relative change in signal height should indicate the growth of a defect. When comparing the response from different transducers for a given defect, this approach produces an error by not accounting for the distance between the defect and the weld used for this normalization and the difference in impedance across a weld from the forward and the reverse direction. We expect these differences to cause some scatter in the values for the peak height associated with a defect of a given size when looked upon by different transducers located at different locations in the pipeline. Additional discussion of our approach for signal normalization can be found in a recently published paper [4].

##### 5.1.1.11 Quality assurance sampling/consistency check

The consistency of data obtained was checked using the response from known markers and comparing the signals sensed by separate transducers propagating waves towards the marker from opposite directions. Also, it is known that each transducer can generate wave trains propagating in the forward and backward directions. Electronic designs in the measurement systems allow the selection of wave propagation in one of these directions only. However, these designs are not perfect and result in some residual power in the wave train in the unwanted direction. When interpreting the peaks in the data, care was exercised to distinguish reflections by static items like welds and growing defects in a data set, which could contain multiple reflections from both forward and backward propagating waves. The unintended wave could be particularly strong when it is reflected backward from a free end or from a flange in the pipeline.

### 5.1.2 Under-ground coating system pipes

The second type of pipe investigated in Phase I was 4.5 inches OD, 0.25 inch thick (4 inch schedule 40) steel pipes wrapped with a generic underground coating. The wrap was put on in a three step process per manufacturer's recommendation. A relatively thin coat of bitumen mastic was applied to the entire pipe surface. This layer was approximately 0.010 inches thick. The wrap was applied next. The wrap was a 0.075 inches thick, Denso 'Densyl' brand, made of a fabric tape impregnated with both wax and petroleum tar product. We used a 6 inch wide wrap with 2 inches overlap in the wrapping process. Finally, a 0.010 inch thick layer of Polyken pipe tape was put over the Denso wrap.

Ten feet long sections of these wrapped pipes were fabricated at contractor's facilities. The purpose was to evaluate the effects of these commonly used underground pipe coatings on signal attenuation to assist in the interpretation of experimental results in the field tests in Phase II. For that reason, no corrosion was introduced in these wrap pipes. In addition, an example of such a pipe ready for guided wave testing is shown in Figure 13.

Figure 13. Pipe with wrap coating on a stand ready for ultrasonic guided wave testing.

## 5.2 FIELD TEST DESIGN (PHASE II)

### 5.2.1 Conceptual test design

In the field testing, we drew upon experience gained in Phase I for ultrasonic tests in pipes undergoing controlled corrosion. Of interest in the field testing were the capabilities in defect detection, sizing, and growth monitoring, as well as the repeatability of data in changing environment, the durability of transducers, and the consistency of test results obtained by pigging (if available) and by ultrasound.

We had ultrasonic guided wave transducers permanently mounted at selected pipe sections that were either above ground or were exposed inside valve pits. These transducers were powered via extension cables by equipment that remained above ground and were accessible at convenient locations on the pit wall. These transducers were accessible for the duration of this project. In general, wave propagation in both the forward and backward directions was attempted in order to maximize the range of pipe coverage, unless the existence of a flange obstructs wave propagation along a particular direction.

Electronic equipment was energized by power sources transported in an automobile from one location to another. The ability to do monitoring without reentering the valve pits had two benefits. First, the requirements for confined space entry were met only for the baseline measurement when the transducers were installed inside the valve pits. Secondly, this eliminated the need for repeated personnel entry to valve pits which had an opening of approximately 2 by 3 feet only.

### 5.2.2 Baseline characterization

The conditions of one section of the pipeline between VP 5 and the water front were documented in a report five years ago. Some areas of corrosion were identified even though the overall structural soundness of the piggable portion of the pipeline was verified. Unfortunately, because parts of the pipeline are over 50-years old, mechanical drawings and repair history were lacking, the construction, geometric layout, and distances among segments were not precisely known. This precluded the ability to locate precisely structural markers to calibrate the ultrasonic data. Since the baseline information on the rest of the pipeline extending from VP 5 to the rest of the pipeline was unknown, the results of the initial guided wave measurements in August 2009 served as the baseline data.

### 5.2.3 Design and layout of technology

The ultrasonic guided wave measurement system started with bonding magnetostrictive metal strips to the pipe surface by room-temperature cured epoxy. This was preceded by the removal of protective coating from the pipe surface and the removal of debris and rust by hand sanding and brushing. Examples of surface conditions on an above-ground pipe section and one inside a valve pit are shown in Figure 14. Protective duct tape was applied to these strips after transducer bonding. Low profile, energizing coils were wrapped around the bonded strips before tar-based, roofing compound was applied. The electrical leads to coils were brought outside of a valve pit into an access port mounted on the external wall for easy access, as shown in Figure 15. Experience showed that a “transducer assembly” fabricated in this manner had been environmentally stable for up to 5-years in outdoor environment. Each transducer was bar-coded for easy identification.

a) 

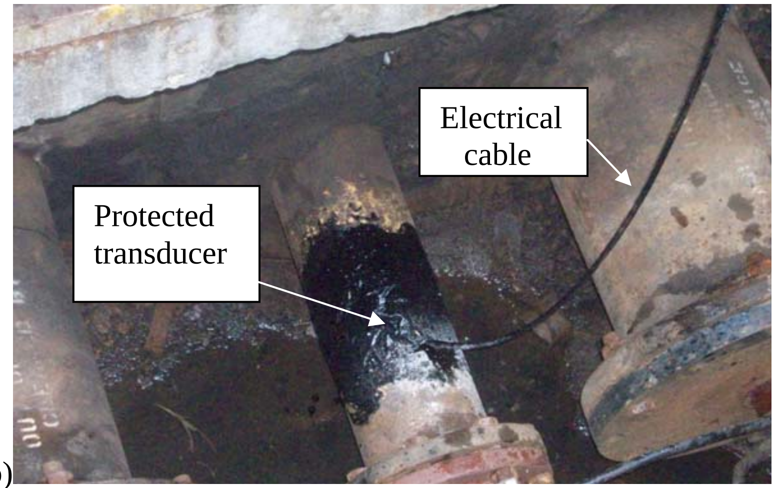
b) 


Figure 14. Surface conditions of tested pipe.
14a) Protective paint on a section of pipe to be removed prior to transducer mounting.
14b) Protective tar coating and lead wires for a transducer in the underground pipeline.


Figure 15. Access boxes for signal monitoring outside of restricted areas around VP5.

### 5.2.4 Operational testing

After baseline measurements following transducers installation in August 2009, follow up monitoring was performed in Jan 2010, Sept, 2010, and April 2011. More frequent follow up measurements would have been warranted if the initial data sets suggested the existence of significant corrosion damage in part of the pipeline. In that case, corrective maintenance activity may be recommended. Our intent was to monitor the changes in the pipeline, which would progress moderately slowly, unless the guided wave data suggested otherwise. Observations by on-site contractors were also made to assess the conditions of the electronic outlet boxes and to record water accumulation inside valve pits.

Space permitting inside the valve pits, two transducers were installed to provide wave propagation towards the forward and reverse directions from a valve pit. For the guided wave measurements, the basic electronic excitations were 4 cycles of sine waves at 32 kHz. Additional frequencies were used only if they were deemed useful to resolve uncertainties in signal interpretation. The proper functioning of the permanently mounted transducers was judged by noting the quality of signals reflected from known markers, such as welds and flanges.

### 5.2.5 Equipment calibration

The key guided wave signal parameters upon which judgment for the location and the severity of a defect is based are the time of arrival, the peak height, and the shape of the signal envelope. In the field, the consistency of time measurement was checked by noting the time of wave arrival from known markers such as welds and flanges.

Based on the results obtained in Phase I, unless a corrosion-induced defect is either initiated or is increasing in size, there should not be changes in the ultrasonic wave form from the baseline data set to another acquired at a later date. For defect growth monitoring, we used a signal subtraction scheme after amplitude normalization, as used in Phase I.

Signals obtained by redundant transducer pairs mounted adjacent to each other inside a valve pit were also used to correlate data traces. In the event one transducer was judged to be malfunctioning, the response from the other would be normalized with known markers to allow for signal subtraction against data obtained earlier by the one that failed.

# 6.0 PERFORMANCE ASSESSMENT

## 6.1 LABORATORY RESULTS (PHASE I)

### 6.1.1 Cross sectional area loss

As stated earlier, we obtained a statistical average of area loss by taking photographs of the corroded areas and identifying a large number of locations where micrometer readings should be made. These readings allowed the calculation of a good statistical average of the overall area loss at each stage of corrosion. An example of these photographs is shown in Figure 16. The area and volume loss over the course of these experiments are shown in Table 2. We achieved CSAL over 25%, a volume loss of over 18 cubic inches, and the smallest defect area was 3 inch x 3 inch.

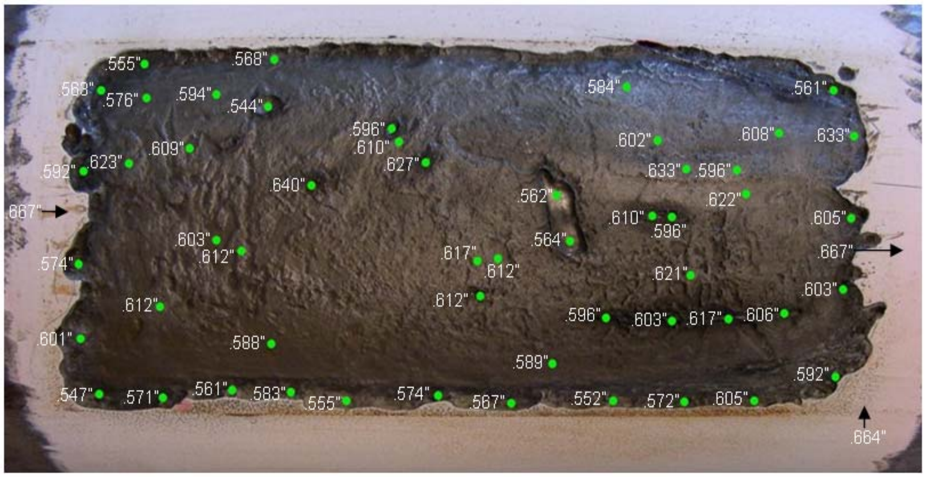



Figure 16. Annotated photograph of the Defect 1 corrosion area in Phase I.
The numbers indicate micrometer readings at the green dot locations from which wall thickness loss was calculated.

Table 2. Summary of Corrosion Defect Characteristics

| Defect | Month | Size (Circ) x (axial) in | CSAL (%)*(Ave +/- stdev) % | Wall Thickness Loss[2] (Ave +/- stdev) in | Volume Loss (Ave +/- stdev) $in^3$ |
|---|---|---|---|---|---|
| 2 | June | ~ 3 x 3 | 1.8 +/- 0.2 | 0.06 +/- 0.007 | 0.6 +/- 0.08 |
| | August | 3 x 3.5 | 3.2 +/- 0.12 | 0.09 +/- 0.006 | 0.96 +/- 0.06 |
| | September | 3 x 3.5 | 8.8 +/- 0.7 | 0.23 +/- 0.02 | 3.5 +/- 0.28 |
| | December | 4 x 4.5 | 11.6 +/- 1.7 | 0.26 +/- 0.04 | 4.7 +/- 0.7 |
| 1 | June | 5 x 11 | 3.6 +/- 0.39 | 0.06 +/- 0.007 | 3.6 +/- 0.38 |
| | August | 5 x 11 | 5.2 +/- 1.0 | 0.09 +/- 0.006 | 5.1 +/- 0.33 |
| | September | 11 x 12 | 9.4 +/- 0.5 | 0.07 +/- 0.004 | 10.3 +/- 0.55 |
| | December | 12 x 15 | 14.0 +/- 0.9 | 0.11 +/- 0.007 | 18.7 +/- 1.2 |
| W6 | June | 6 x 3.5 | 4.5 +/- 0.8 | 0.07 +/- 0.03 | 1.4 +/- 0.09 |
| | August | 6 x 3.5[1] | 12.8 +/- 6.0 | 0.2 +/- 0.1 | 4.2 +/- 0.4 |
| | September | 10.5 x 3.5[1] | 13.5 +/- 1.4 | 0.13 +/- 0.07 | 4.0 +/- 0.2 |
| | December | 12 x 4[1] | 25.0 +/- 1.2 | 0.2 +/- 0.08 | 8.8 +/- 0.3 |

Notes:
Pipe wall cross sectional area = 32.7 square inches
[1]crack developed
[2]Nominal wall thickness = 0.335 inches.
Defect 2 is 65 feet from Pipe End #2
Defect 1 is 26 feet from Pipe End #2
Defect W6 is the weld defect, 20 feet from Pipe End #1

### 6.1.2 Ultrasonic data

#### 6.1.2.1 Above-ground 8 inch pipeline in Phase I.

##### 6.1.2.1.1 Wave speed

Using the known distance between the welds in the pipeline, the wave speed for the torsional mode at 32 and 64 kHz was determined to be 1.07 x $10^4$ft/sec. This speed was used to identify the locations of defects based on the time of arrival of signal peaks in the pulse-echo ultrasonic data collected throughout the course of the experiments. The dependence of guided wave speed on frequency is governed by the theory of dispersion curves in pipes, the discussion of which can be found in the literature, but is beyond the scope of this report.

##### 6.1.2.1.2 Ultrasonic guided wave signal traces

An example of ultrasonic guided wave data showing peak height versus distance along the pipeline (see Figure 8) is shown in Figure 17. Wave propagation speed has been utilized to convert time of flight information to distance information along the pipe. In this figure, the large peaks are reflections from the welds. We note the existence of some small signal peaks with unknown origin before the initiation of corrosion that are not associated with welds. They could be caused by pipe stands, as-manufactured material anomalies, or other unknown conditions. We will come back to these points later in this report.

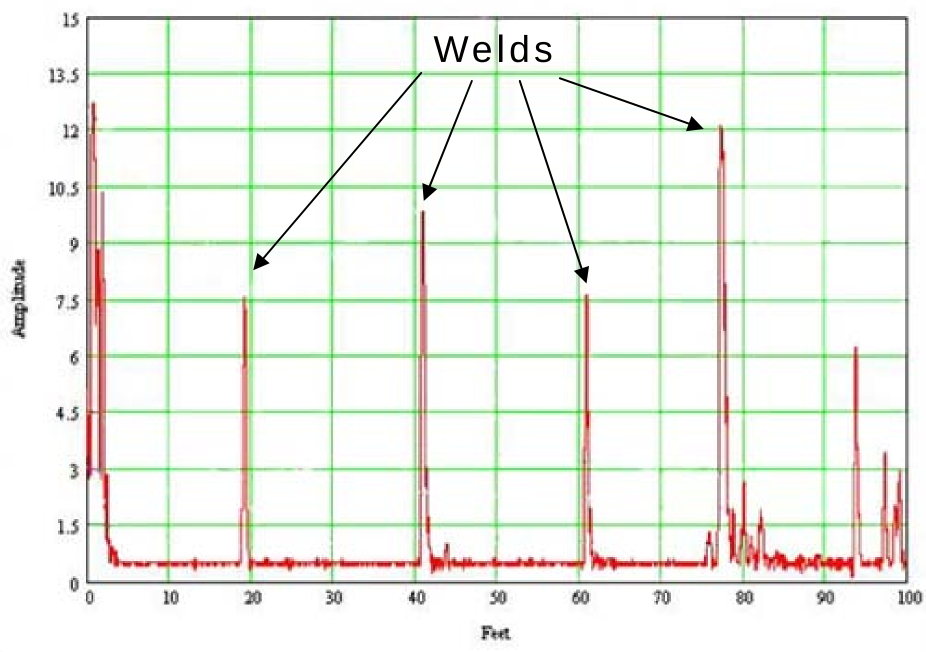



Figure 17. Example of plotted ultrasonic guided wave baseline data for the above-ground coating system pipeline at NSWCCD before corrosion was initiated.
The plot shows peaks originating from welds, approximately 20 feet apart, as sensed by a transducer mounted in location 2.

Shown in Figure 18 is the summary of the above-ground ultrasonic wave data over time as compared to the baseline with a systematic increase in defect peak height with successive stages of corrosion from a transducer placed at location 2. Waves from one transducer detect the presence of welds, elbows, and one or more defects in the guided wave propagation path. As expected, the signal height depends on the size of the defect, the distance between the transducer and the defect, and the number of welds in the wave propagation path. We note that the noise level increased in the later months as corrosion progressed, but was less than 0.1 of the weld signal height at about 80 feet.

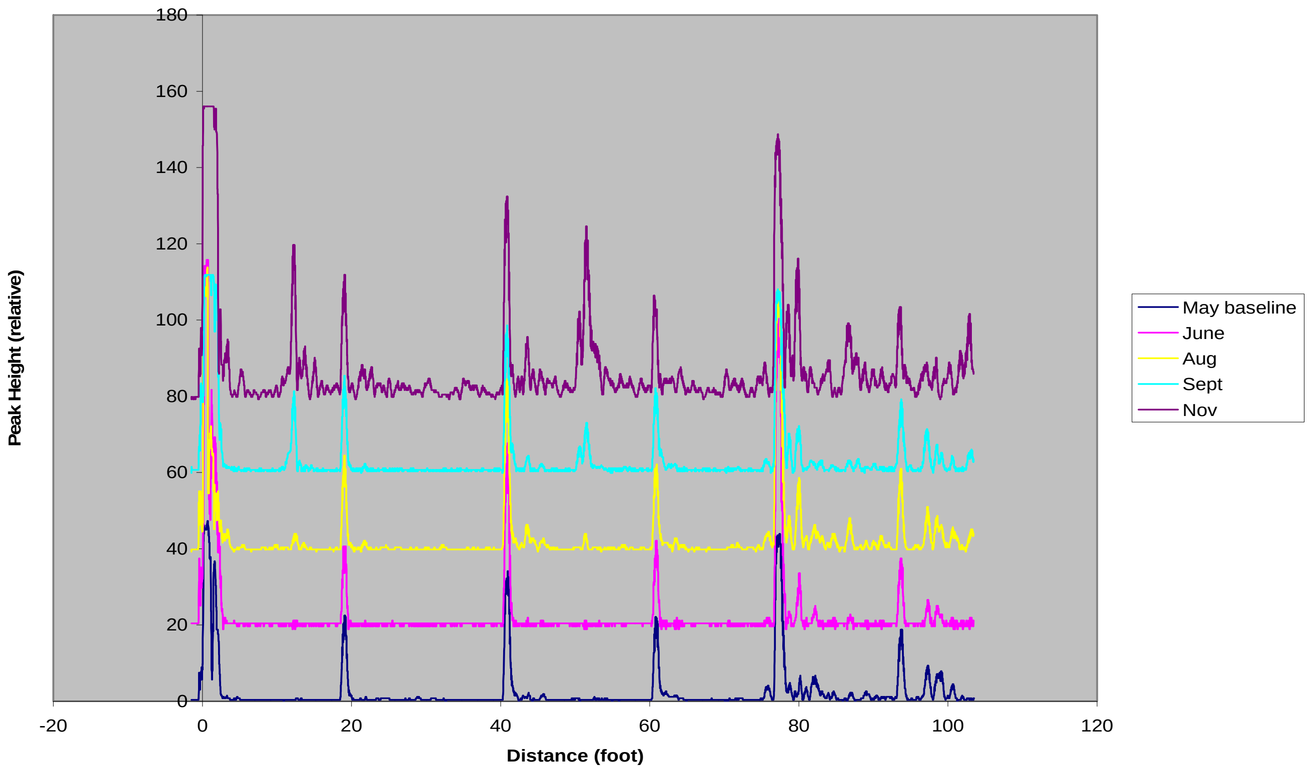



Figure 18. Systematic increases in defect detection over time as compared to the baseline. Systematic increases in peak heights for growing Defects 1 and 2 sensed by transducer at location 2. Defect 1 was located at approximately 50 feet and Defect 2 was located at approximately 12 feet. The other large peaks, approximately 20 feet apart, are from the welds in the pipeline. The baseline signal (May 2008) is blue, the June signal is pink, the August signal is yellow, the September signal is light blue, and the November signal is purple. An offset of twenty units along the vertical axis has been added to each successive trace before plotting.

Examples of the appearance of signal traces for a corroding weld (Defect W6) are shown in Figure 19.

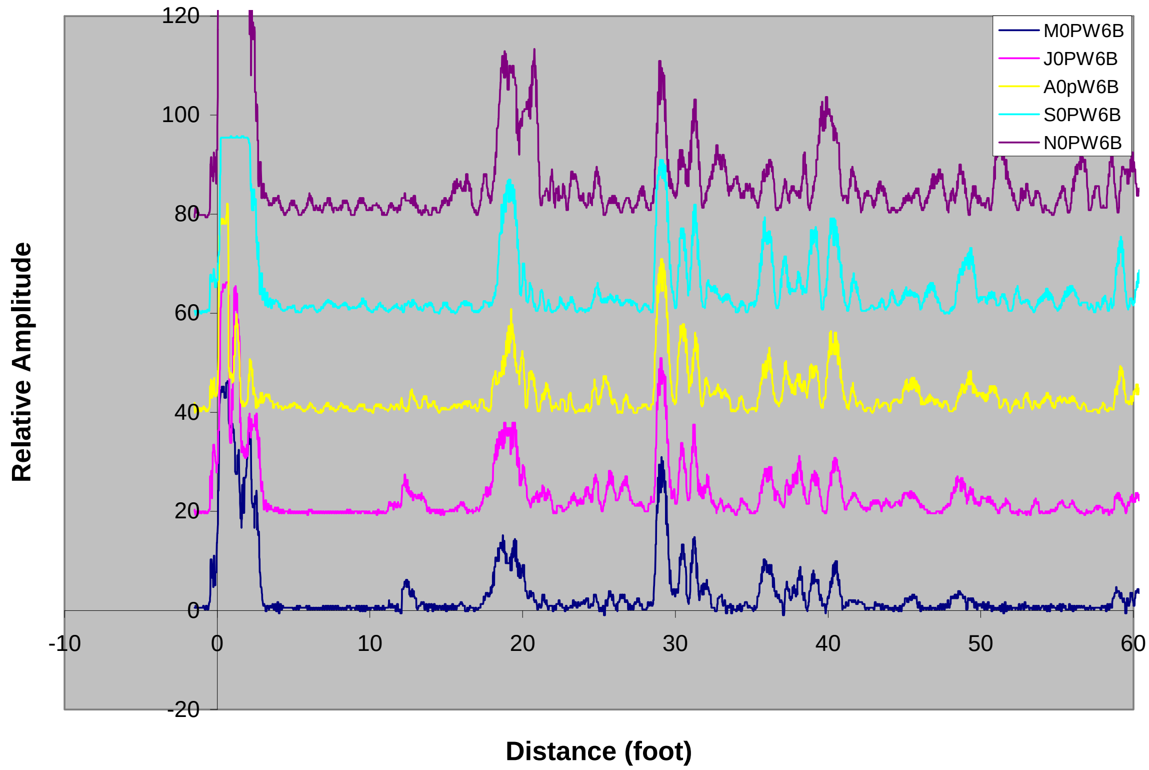



Figure 19. Systematic increases in weld defect detection over time as compared to the baseline. The transducer was at location 0, launching waves toward Defect W6. The baseline signal is blue, the June signal is pink, the August signal is yellow, the September signal is light blue, and the November signal is purple. Note the "split peak" feature associated with the corrosion around the weld. An offset of twenty units along the vertical axis has been added to each successive trace before plotting.

Shown in Figure 20 is an example of Defects 1 and 2, sensed by two sensors located in locations 1 and 2 separated by an elbow, with wave propagation in the same direction as used shown in Figure 18. The origins of the traces are shifted to match the peaks from the defects. We note that the presence of an elbow increased the noise level, but remained less than 0.2 of the weld signal height at 50 to 80 feet.

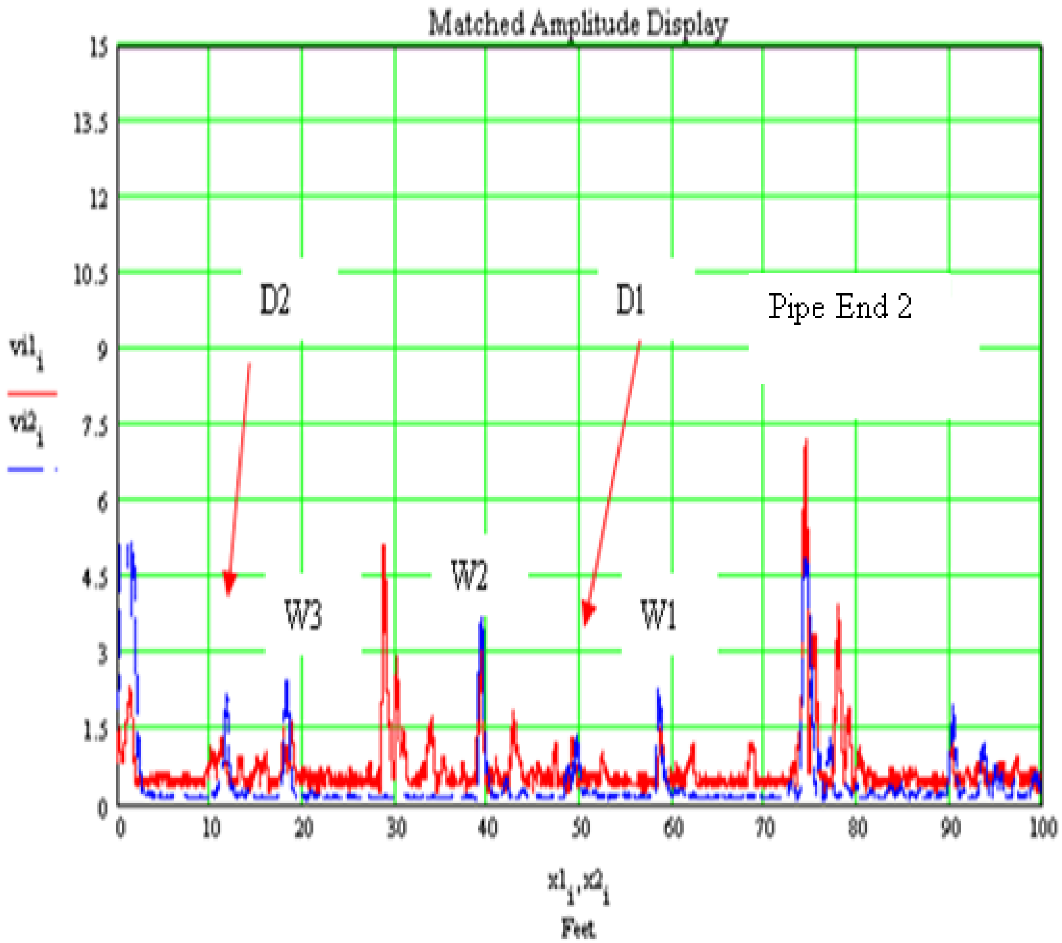



Figure 20. An example of data obtained by dual sensors generating waves propagating towards Pipe End #2 shown in Figure 8.
The red trace is from the transducer at location 1 and the blue trace is from the transducer at location 2. The origin of the trace for the sensor at location 1 is shifted to account for the sensor separation. The red arrows indicate the locations of Defects 1 & 2. The other matching peaks are from the welds in the pipeline. The large signal at ~30 feet originated from the reflection of the unwanted wave propagating from the transducer at location 1 in the reverse direction towards Pipe End #1.

6.1.2.2 Underground coating system wrapped pipe results

6.1.2.2.1 Wave speed

Comparing the time of signal arrival in a pipe before and after the wrap was applied showed that the speed of the torsional mode guided wave in the presence of the wrap was reduced by about 2 %.

6.1.2.2.2 Ultrasonic signal traces

The experiments on the wrapped pipes in Phase I was intended to provide some information on the signal attenuation in the presence of protective wrapping, typically used for underground pipes. Shown in Figure 21 are two traces, the red colored one represents data before and the blue colored one after the coating was applied. The signal for the wrapped pipe has been amplified by ten before plotting. The peaks at approximately 10, 20, and 30 feet represent the first, second, and third round trip signals returned to the transducer from the end of pipe where wrap was applied. The peaks at 7 to 8.5 feet were due to reflections from the uncoated end of the pipe where the transducer was located. In general, data on the wrapped pipes indicated that the coating introduces a signal attenuation factor of ten, and the signal to noise ratio was approximately unity after a distance of travel approached about 30 feet. The uncoated pipe had a signal to noise ration of at least 5 at the same distance.

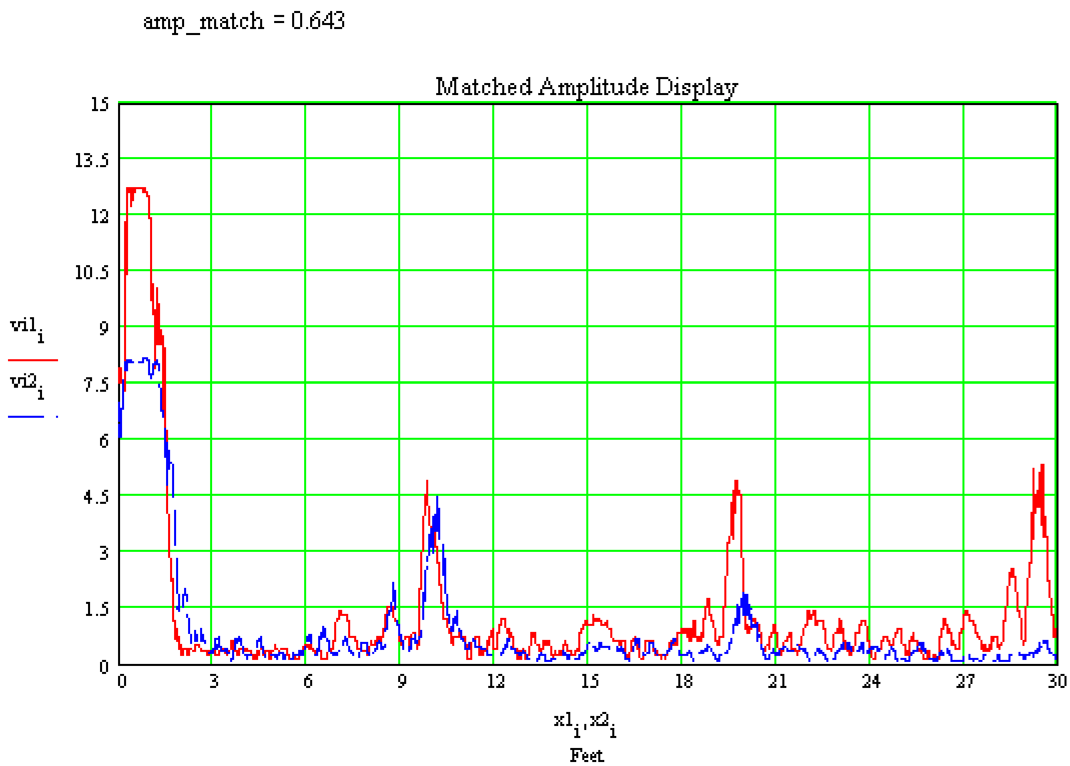



Figure 21. Signal traces for a steel pipe, 4.5 inches in diameter before (red0 and after (blue) the wrap coating was applied.
The signal for wrap pipe was amplified by factor of 10 before plotting.

6.1.3 Summary of ultrasonic results

In the following paragraphs, the findings from Phase I are briefly summarized. More details and discussions can be found in a recent publication [4]. A representative data set obtained in the tests performed on the pipeline, shown in Figure 8, is shown in Figure 22. We will discuss the source of measurement errors and statistics. The data summarizes the results for two different defects varying from approximately 3 inch x 3 inch to 12 inch x 14 inch in surface area, and from 10% to 50% in loss of wall thickness. The signal returned from these two defects was sensed by 3 different transducers, mounted at 3 different distances. The blue symbols represent the signals for a defect (3 inch x 3 inch in area) measured by transducer #2, mounted at 12 feet away from the defect. The pink symbols represent the signals for the same defect measured by transducer #3, mounted 62 feet away, with the wave propagating through several welds before reaching the defect in the opposite direction. The yellow symbols represent the signal for the larger defect (12 inch x 14 inch in area) measured by transducer #3, mounted 25 feet away. The purple symbols represent signals for the same defect measured by transducer #1, mounted 18 feet away with the wave propagating through a 90-degree elbow in the same direction as the wave propagating from transducer #2. Several observations can be made from this plot.

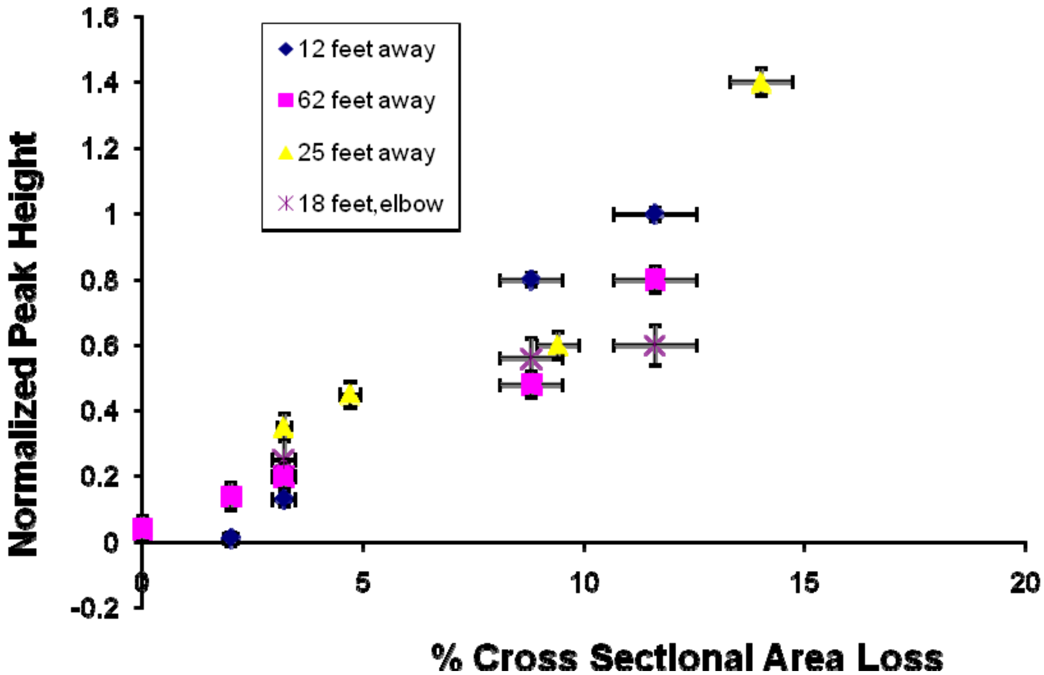



Figure 22. Ultrasonic guided wave signal peak height (relative to a weld signal) plotted against CSAL.

The signal peak height for a defect is influenced by (1) the distance between the defect and the transducer, (2) the number of welds crossed by the propagating waves, (3) the existence of elbows, (4) the asymmetry of a weld or a defect looking from opposite directions, and (5) the size of the defect. As a result of these uncontrollable factors, the peak height values for a defect of 12% CSAL, for example, could range from 0.6 to 1.0 volt, as shown in Figure 22. The same set of data showed that the range of peak heights for a defect of 9% CSAL was approximately 0.5 to 0.8 volt and for a defect of 3% CSAL, the range was 0.12 to 0.35 volt. These variations represent the range of uncertainties for sizing a defect on an absolute basis as a result of the effects of the uncontrolled variables mentioned above. The datum for a defect with 5% CSAL resulted in a signal peak height of approximately 0.4 volts.

A plot of signal peak height against the defect CSAL around Defect W6 is shown in Figure 23.

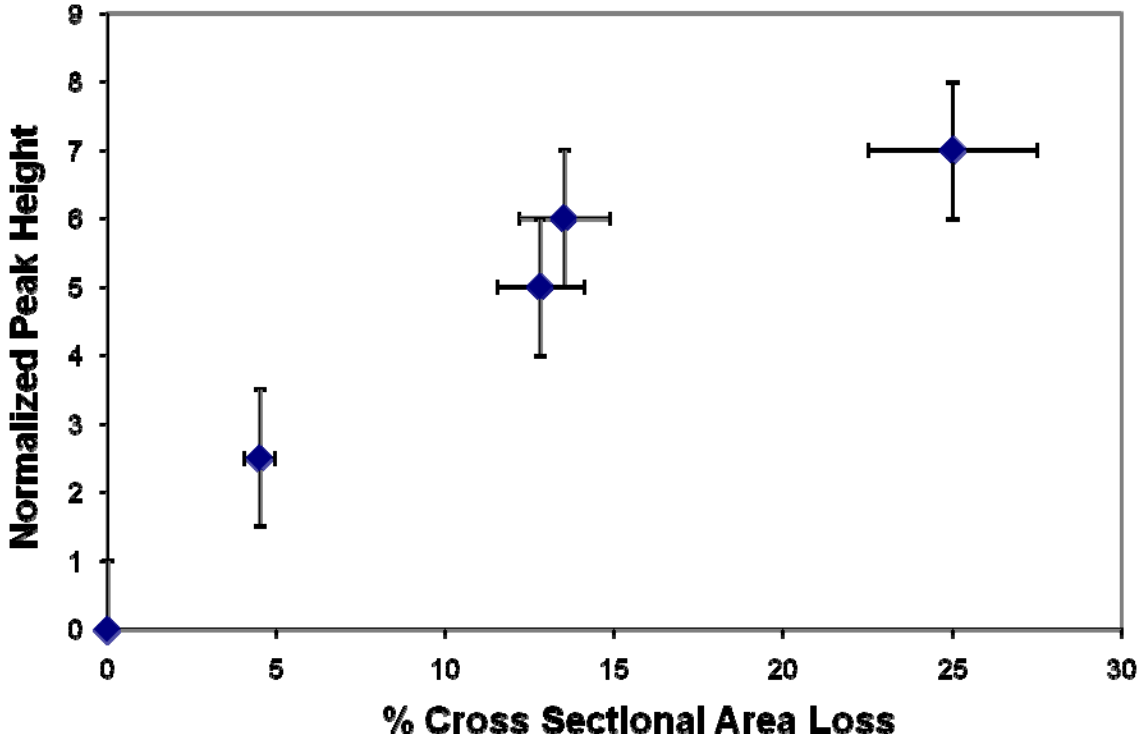



Figure 23. Plot of signal height against defect CSAL for defect W6 showing increased signal peak height for the weld signal as corrosion increased.

6.1.4 Trend lines for defect growth monitoring

Three trend lines are shown in Figure 24. The solid line is based on the data shown in Figure 22. It represents an averaged trend that provides an empirical “calibration” curve converting relative signal peak height to percentage CSAL for defects. The other two trend lines (dotted) were generated using the two subsets of data including the effects of an elbow (labeled “18 feet away” in the legend) and the ones representing the largest defects (labeled “25 feet away” in the legend). These two dotted trend lines provide the upper and lower bounds for the slope of the average trend line. Defects with 5% and 10% CSAL produced signal peak height of 0.35 and 0.65 volts, respectively, on the average trend line with uncertainties of approximately 25%. These uncertainties are the results of combining all the data obtained from different transducers, located at distances from 12 to 62 feet from the defect, the existence of a variable number of welds and an elbow, as well as defects of different area, volume, and shape.

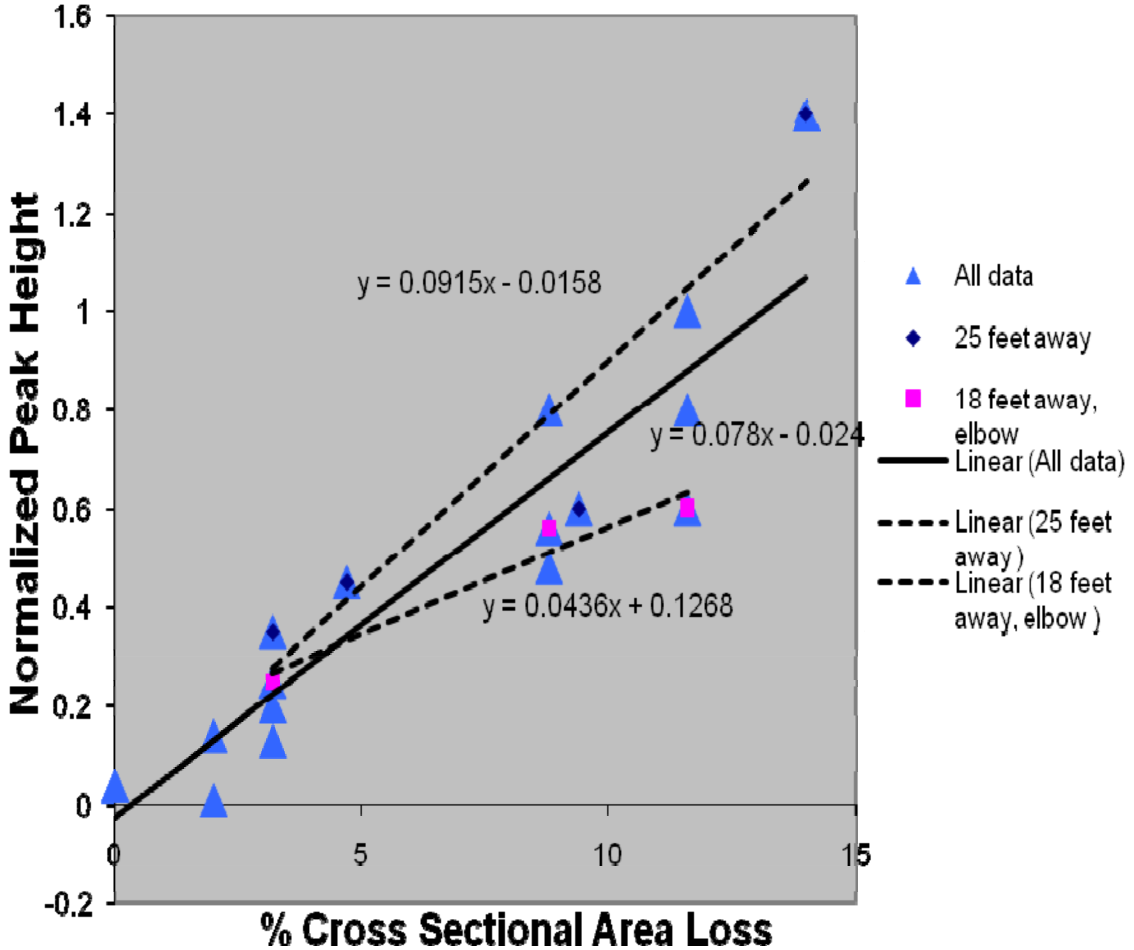



Figure 24. Trend lines for the increase in signal height as the CSAL increases for data obtained in Phase I.

If we focus our attention on the signals associated with a single transducer, as would be appropriate if we are only interested in measuring the changes of the system from a baseline condition, we realize that the slope of the trend line is mainly controlled by the variations of electronic noise and defect shape change over time. The details of the wave propagation across welds and elbows, as well as, scattering mechanisms affecting the absolute signal peak heights are less important when only signal changes are considered, since the effects of these variables (except for the size of the defect) are constant as a function of time. As shown in Figure 23, the uncertainties associated with electronic noise and defect shape were represented by the vertical (approximately 0.1 volt) and horizontal (less than 2% CSAL) error bar at each datum. For the purpose of tracking defect growth, we observed in Figure 24 that the slope of the average trend line departs from those represented by the two extremes by no more or less than a factor of 2. Additional discussions of the Phase I results can be found in a recently published paper [4].

## 6.2 FIELD TEST PERFORMANCE EVALUATION (PHASE II)

Three aspects of the pipeline at Norfolk Naval Station greatly affected the technology performance as demonstrated in the laboratory tests in Phase I. First, in the above ground, vertical pipe sections in Norfolk, where the transducer could be placed, there were usually two or more 90 degree elbows, one ahead and one behind this vertical section. These elbows were there so that the underground and the above ground parts of the pipeline could run parallel to the ground surface (see Figures 14a and 15). Because this vertical section was relatively short, the transducer had to be placed near the ground interface. Experience has shown that the formation of a uniform wave front in the guided wave at 32 kHz required a propagation distance of several feet ahead of the ground interface. This small “lead-in” distance for all the sensors most likely distorted the uniformity of the axisymmetric wave front and attenuated its intensity.
The second important aspect is that pipe sections typically have bends, elbows, valve attachments, and even flanges within the confined space of 5 to 15 feet inside the pit (see Figures 6 and 14b). These features have the following ramifications. First, guided wave cannot propagate across a flange. Its existence prevents the interrogation of the pipe in the direction away from the pit if a transducer cannot be place between the flange and the wall in the valve pit. This was the situation in valve pits, 21, 22, and 23 and thus limited wave propagation to one direction only away from the pit. Second, the characteristics of the waves in the forward and the reverse directions generated by one transducer would be very different since the complex components inside the pit strongly modified the waveform in the reverse direction. This had the consequence that attempts to compare the forward to the reverse waves to check for consistency in peak identification, as we did in Phase I was not successful due to the significant distortions in wave propagation in the reverse direction.

The third aspect is related to the proximity of the water front to most of the pipeline. This resulted in frequent and uncontrollable water saturation inside the valve pits where many of the sensors were located. This was evidenced by the existence of standing water inside these pits and by the grayish marking on the body of the pipe section and on the inside walls of the pits. The tar-based roofing compound probably did not perform as well as anticipated, resulting in deterioration of electrical performance of these sensors and the cable connections. The uncontrollable presence of water in the soil around the underground pipeline also resulted in variable mechanical loading conditions on the pipe, contributing to the instability of the signals over time. These variations would increase further if the conditions of the old protective coating reacted to water unevenly in different parts of the pipeline.

To mitigate these conditions, we used the following approach that was found useful in Phase I in analyzing signal traces in Phase II. First, we used data traces for different frequencies to help recognizing spurious peaks due to constructive interference in one particular frequency originated from multiple reflections between parts of the structures in the pipeline. If a peak appeared near the same location at a different frequency, it is more likely to be originated from a stationary weld or a defect and not by interference effects. Secondly, we looked for matching (after time shifting) of the forward and reverse traces from the same transducer. As mentioned previously, this second approach was only partially successful due to the existence of complex obstructions in the pipe segments inside valve pits.

6.2.1 Baseline data

Key to our demonstration is the comparison of the data traces from the same sensor over the monitoring periods, starting with the baseline data obtained in August 2009, followed by successive stages in January and September of 2010 and April of 2011. Some examples of the baseline traces collected in August 2009 for some of the sensors are shown in Figures 25 through 27.

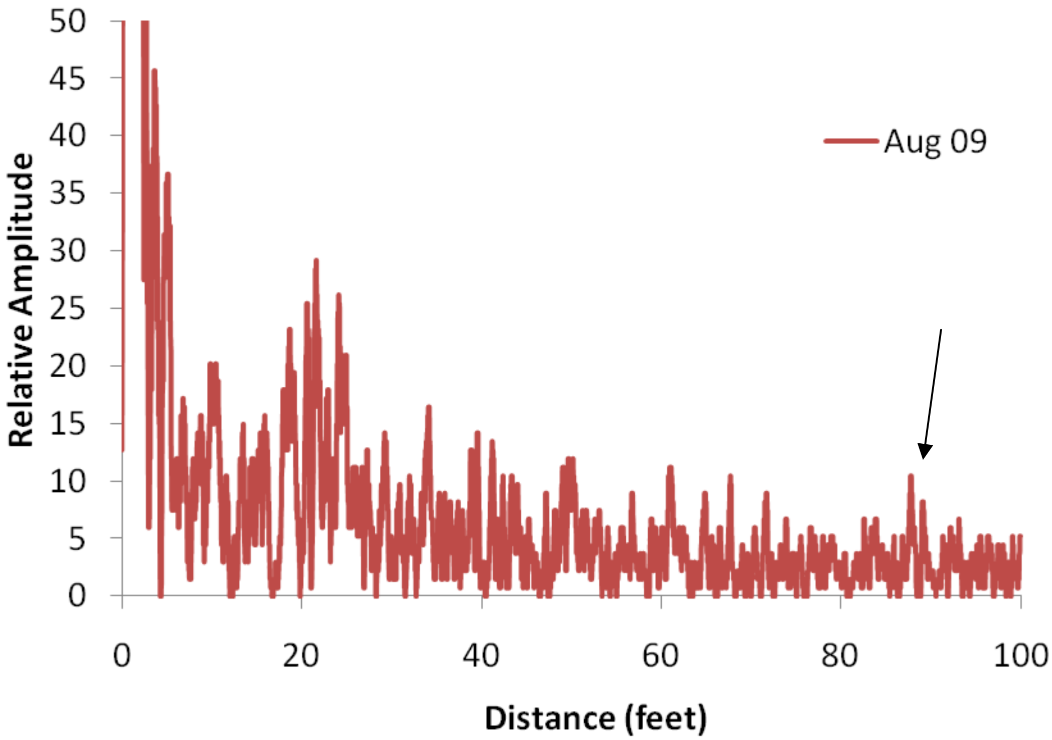



Figure 25. Signal trace at baseline obtained by sensor #22532 inside VP 21 propagating guided waves towards BL 20.

Shown in Figure 25 is the baseline trace for wave propagation from VP 21 towards BL 20. The peaks located up to 20 feet represent signals, first from the leakage of the transducer excitation, followed successively by the signals at the wall interface, and from welds and reducers along the pipeline. Of note is the pair of peaks above noise level at about 90 feet, which could be identified to originate from the region on the ground where pipe repair and replacement were made a few years back. The height of these two peaks was approximately twice as large as the noise level, which was 4 times as large as that typically observed in the laboratory tests in Phase I. We will discuss these signals further in the next section.

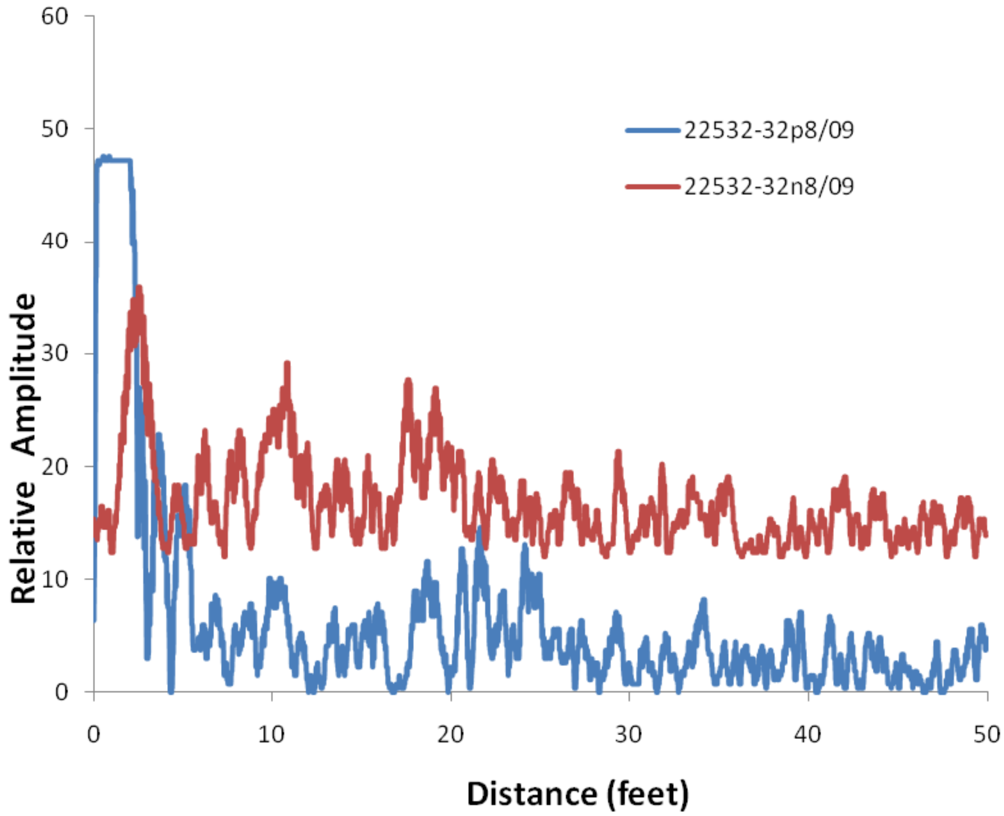



Figure 26. Comparison of forward to backward propagating waves for sensor #22532 at the baseline.
An offset of fifteen units along the vertical axis has been added to each successive trace before plotting.

Shown in Figure 26 is the the same data set as in Figure 25, but in Figure 26, both records of the forward propagating (blue) and the backward propagating (red) waves are shown. The latter was time/distance shifted to faciltate the matching of peaks. It is seen that moderately good “matching” of the peak locations from one trace to another is limited only to about 40 feet for this below-ground sensor (#22532) inside VP 21.

As shown in the pipeline layout in Figure 3, a straight line can be drawn between the entrance and exit ports between BL 20 and VP 21, VP 22, and VP 23. With few, if any, elbows attenuating the signal strength in these straight pipe sections, we anticipated the capability to detect weld signals at long distance with good signal to noise ratio. However, as shown in Figures 26 and 27 the signal strength was still low compare to noise, probably due to the small “lead-in” distance from the transducer to the valve pit wall, as discussed earlier, and the additional complication associated with the existence of unknown components such as reducers in these underground pipe sections.

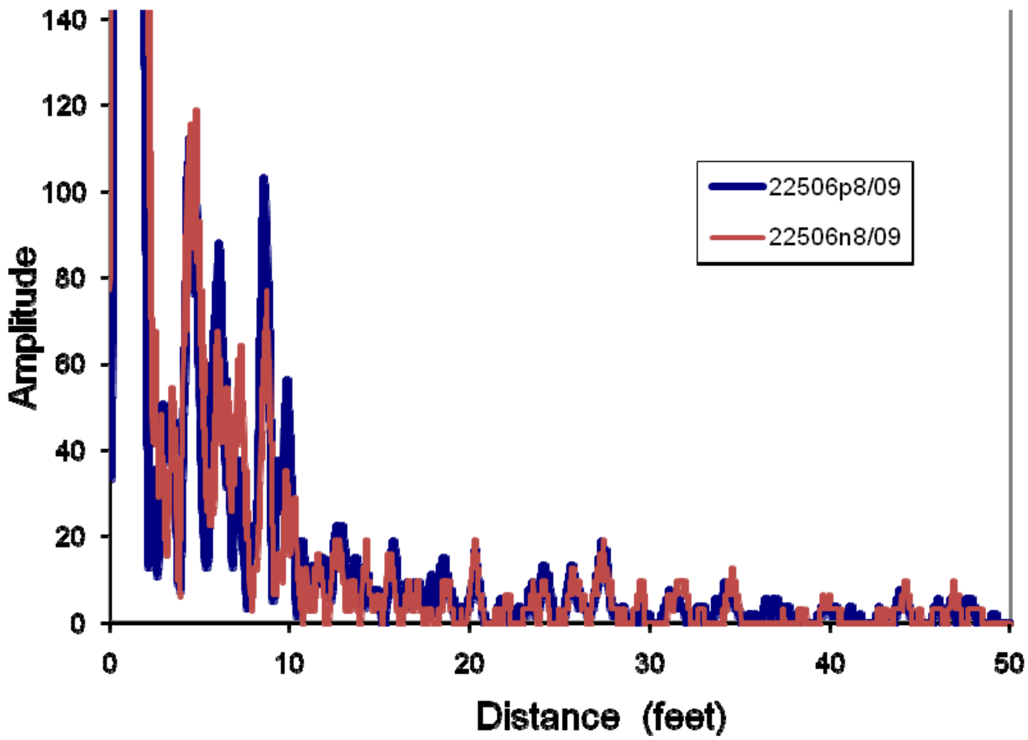



Figure 27. The matching of forward and reverse traces over a distance of 50 feet for above ground sensor #22506 in baseline testing.

In Figure 27 we display a superposition of the traces for the forward and the reverse propagating waves for an above-ground sensor #22506 after time/distance shifting to achieve peak matching. Over the distance of 50 feet, the matching appears to be very good, which gives some confidence that the peaks did not arise from superfluous multiple reflections. The two pairs of peaks up to 10 feet were associated with reflections from two 90 degree bends, which existed to allow the alignment of the pipeline between VP 5 and VP 20, as shown by the pipeline layout in Figure 3.

In general, we note that while there were apparent peaks above noise level detected at distances beyond 50 feet, most of these large peaks assumed to originate from welds and elbows were limited to distance of less than 30 feet. The identification of these signals was greatly hampered by the lack of detailed mechanical drawings for the pipeline layout.

6.2.2 Pipeline monitoring after baseline at Norfolk Naval Station

Shown in Figure 28 are traces obtained from the baseline through April 2011 for under-ground sensor #22532 with wave propagation from VP 21 towards BL 20.

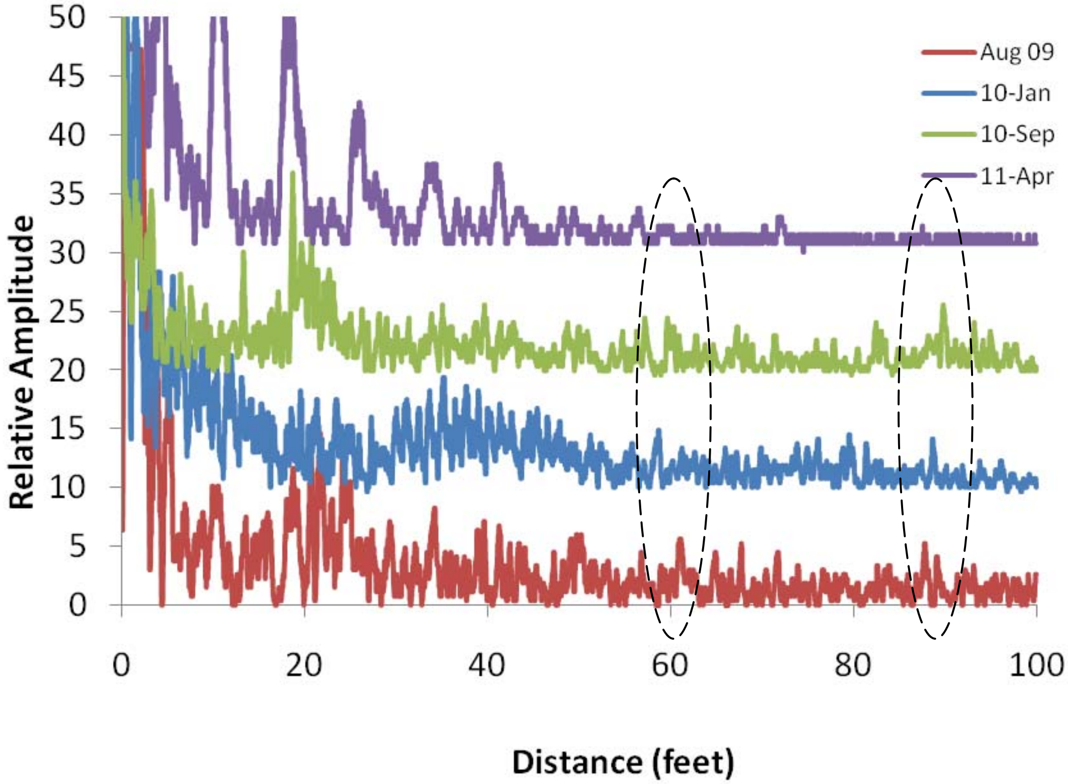



Figure 28. Monitoring changes in data sets obtained at the baseline and successive months by underground sensor #22532.
An offset of ten units along the vertical axis has been added to each successive trace before plotting.

In Figure 28, the data traces collected by an underground sensor (#22532) from the baseline in August 2009 through January 2010, September 2010, and April 2011 are stacked up (with an off-set of 10 units on the vertical axis) to facilitate a comparison of the stability in the peaks detected throughout the course of this project. In particular, the pair of peaks around 90 feet pointed at in Figure 25 appeared to be consistently located to within +/-2 feet over the course of 20 months of monitoring. A group of peaks around 60-62 feet appear to be consistently present also.

An example of the degree of reproducibility in traces obtained by an above-ground sensor (#22506) is shown in Figure 29.

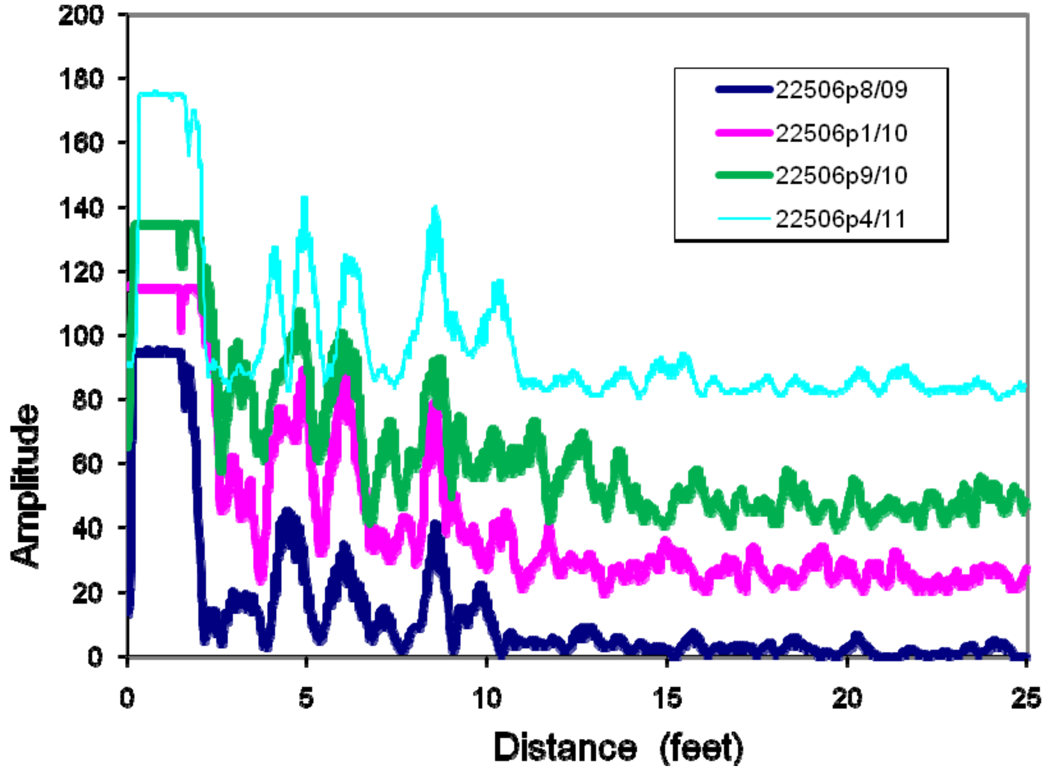



Figure 29. Monitoring changes in data sets obtained by above-ground sensor #22506 at the baseline and successive months at VP5.
An offset of twenty units along the vertical axis has been added to each successive trace before plotting.

In Figure 29, we stack up (with an off-set of 20 units along the vertical axis) the traces obtained from above-ground sensor #22506 over successive monitoring intervals starting with the baseline trace (blue) in August 2009 at the bottom and ending with the April 2011 trace (light blue) at the top. Because of the existence of two or more 90 degree bents in this section of the pipeline between VP 5 and VP 20, identifiable by the pairs of peaks between the origin and 15 feet on the x- axis, the signal to noise ratio rapidly decreased beyond 20-25 feet. It appeared that the stability of the peaks in this section of the pipeline was limited to 15 feet or less over the course of the 20 months of monitoring period.

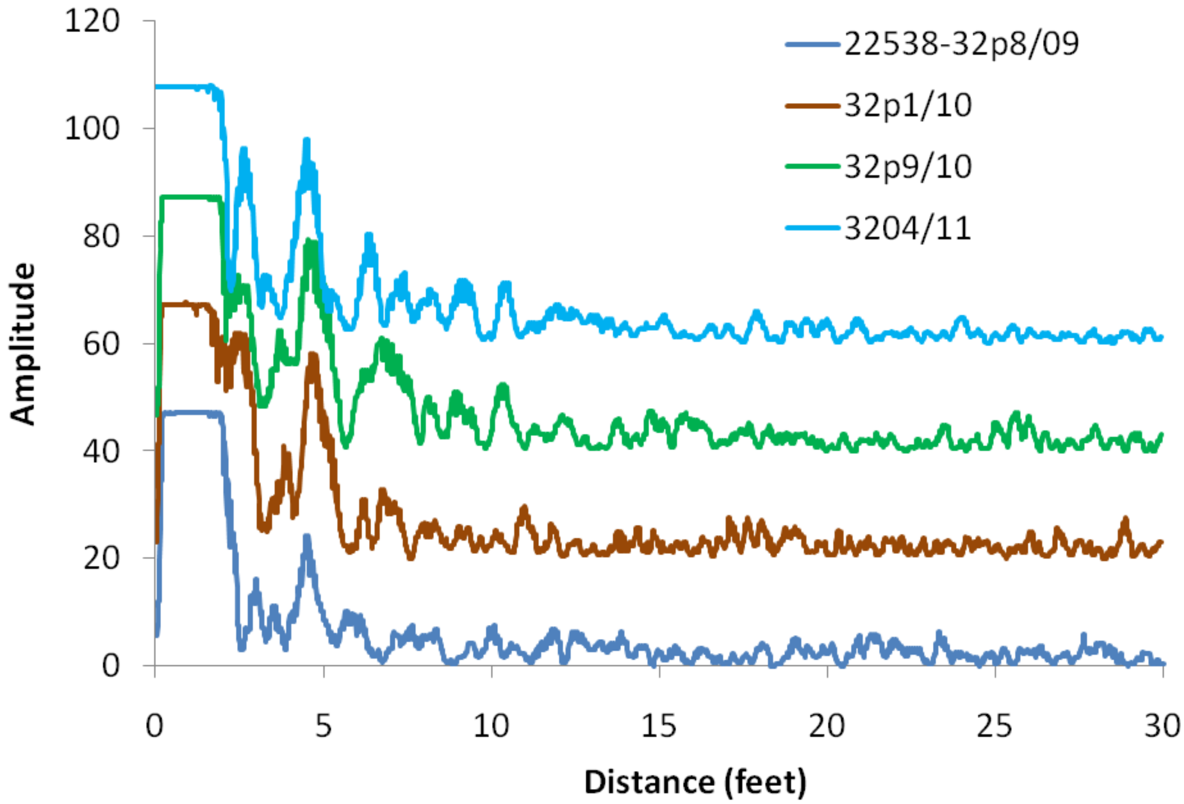



Figure 30. Monitoring changes in data sets obtained by above-ground sensor #22538 at Chambers Field over a period of 20 months.
An offset of twenty units along the vertical axis has been added to each successive trace before plotting.

In Figure 30, the traces obtained by above-ground sensor #22538 over the 4 monitoring periods (August 2009 in dark blue, January 2010 in red, September 2010 in green, and April 2011 in light blue) are stacked up (with a vertical off-set of 20 units) to facilitate a comparison. It appeared that the existence of 90 degree elbows again reduced the signal to noise ratio, so that the reproducibility of peak locations was limited to approximately 15-20 feet. The lack of detailed mechanical drawing did not allow a definitive identification for the structural components giving rise to these peaks.

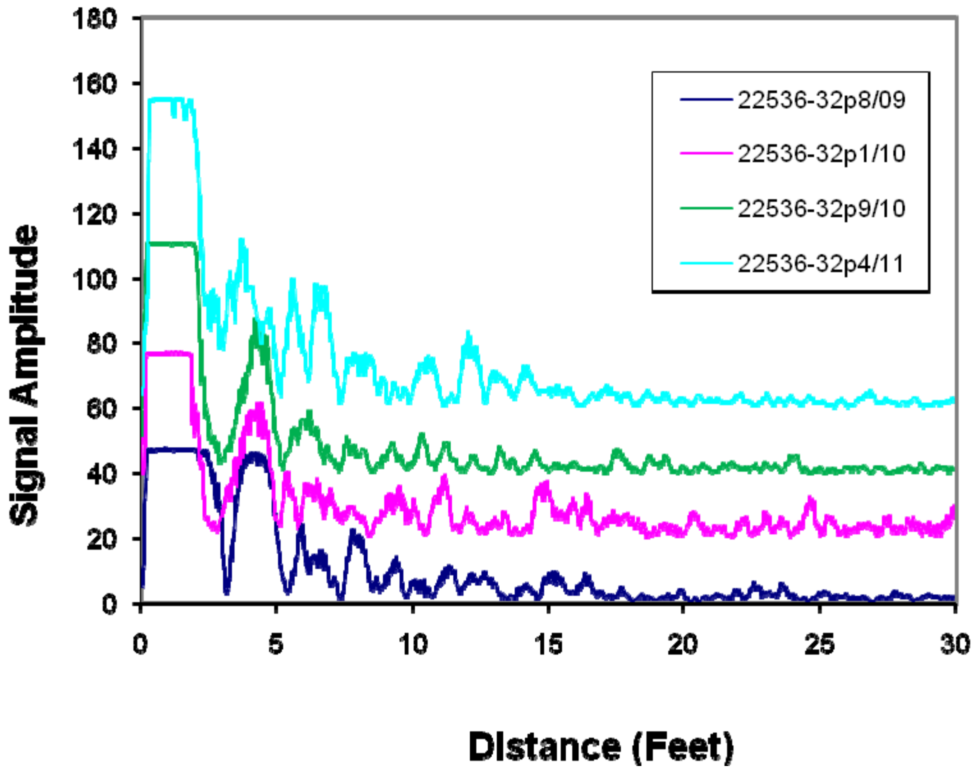



Figure 31. Monitoring changes in data sets obtained by underground sensor #22536. An offset of twenty units along the vertical axis has been added to each successive trace before plotting.

Traces in Figure 31 were obtained for an underground sensor #22536 in VP 7 over the course of the 20 months. Again, the traces (August 2009 in dark blue, January 2010 in pink, September 2010 in green, and April 2011 in light blue) are stacked up with a vertical off-set of 20 units to facilitate a comparison of the stability and reproducibility over time. It appears that the reflections from the pit wall, welds, reducers, and elbows (identifiable by the peaks up to 8 feet) limited the range of signal reproducibility to approximately 15-20 feet with an error of +/- 2 feet.

Data traces in Figure 32 are for waves propagating from VP 5 towards VP 20 from sensor #22506. Focusing on the groups of peaks around 16 feet, 35 feet, and 44 feet, we observe that the normalized peak heights at some locations (e.g. 35 feet) have not been increasing consistently or they remained relatively unchanged over the course of the monitoring effort. The locations where peak heights remained constant most likely originated from static structural features such as welds. Inconsistent changes in peak heights could be due to signal noise and/or multiple reflections unrelated to defects.

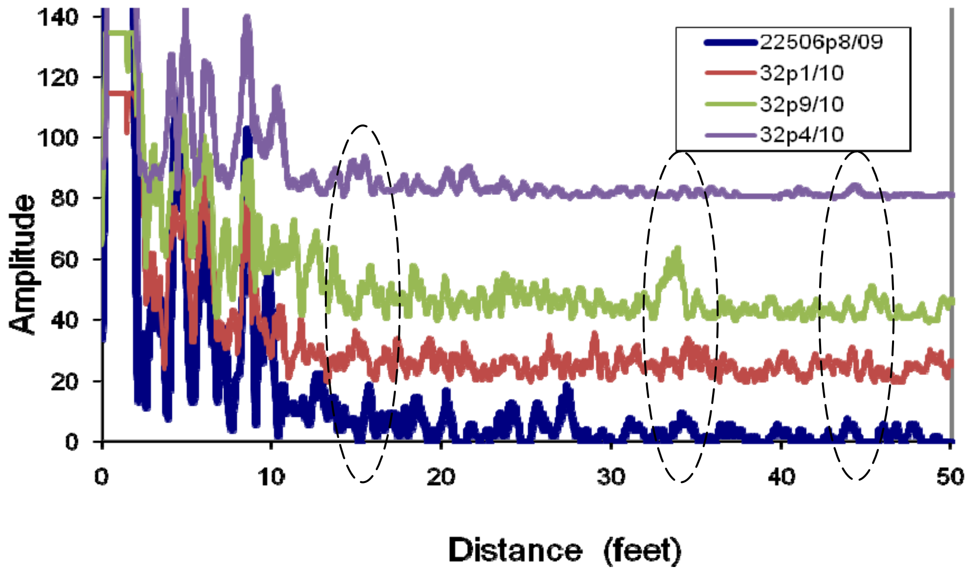



Figure 32. Monitoring signal changes in data sets obtained by above-ground sensor #22506. An offset of twenty units along the vertical axis has been added to each successive trace before plotting.

In Figure 33, the inconsistent increases in peak heights obtained by the above-ground sensor #22515 at long distance are also shown. The peak at 82 feet has not yet increased in height consistently over the course of this monitoring effort, and cannot yet be identified as an indication of defect growth at that location without additional monitoring. We also note that the overall signal strength beyond 40 feet in the trace obtained in April 2011 was much reduced from those observed in earlier traces, probably due to a deterioration in the stability of the transducer over time.

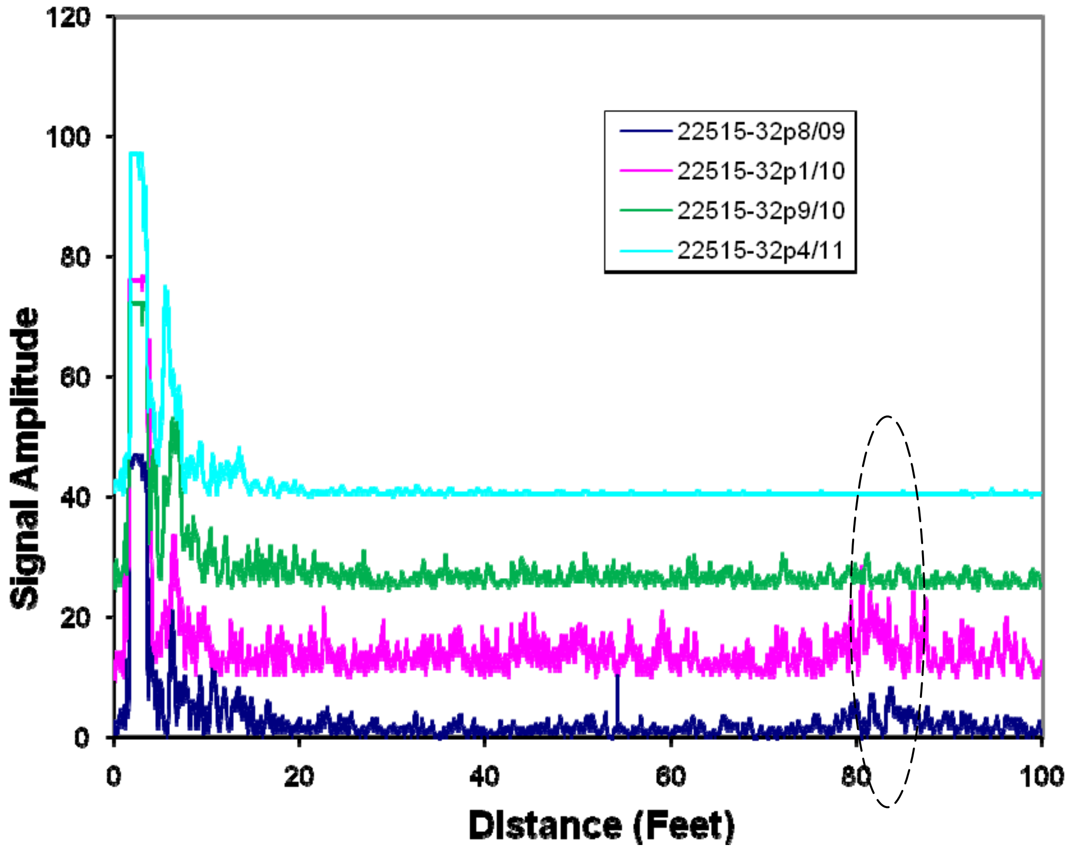



Figure 33. Monitoring changes in data sets obtained by above-ground sensor #22515. An offset of ten units along the vertical axis has been added to each successive trace before plotting.

Shown in Figures 34 and 35 are additional examples of peaks that were suspected of being caused by defect growth and were monitored in the course of this effort.

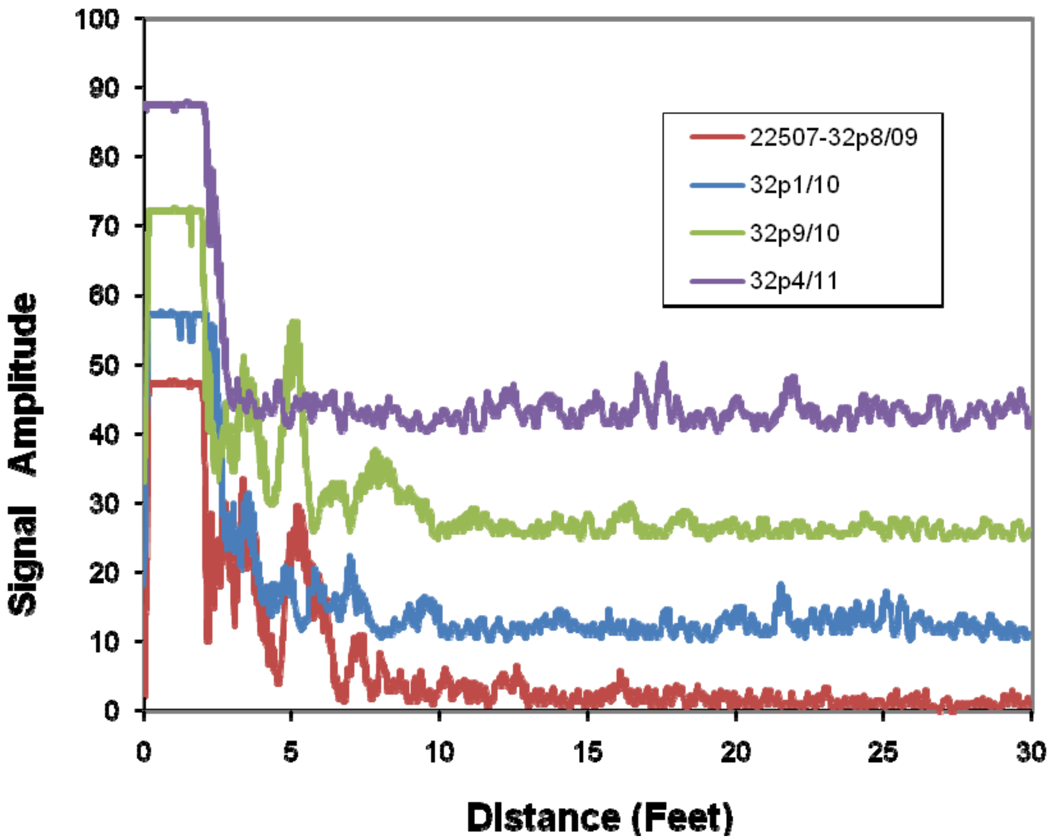



Figure 34. Monitoring changes in data sets obtained by sensor #22507.
An offset of ten units along the vertical axis has been added to each successive trace before plotting.

In Figure 34, we stack up traces (August 2009 in red, January 2010 in blue, September 2010 in green, and April 2011 in purple) obtained by a sensor #22507 propagating waves from VP 5 towards the water front, over the period of 20 months. The amplitude consistency of the traces was not good. Even though the signal to noise ratio appeared to be good in the April 2011 trace, the matching of peaks over the 4 monitoring periods was not consistent from one period to another. The group of peaks around 20-25 feet should be monitored for additional time before its origin can be identified.

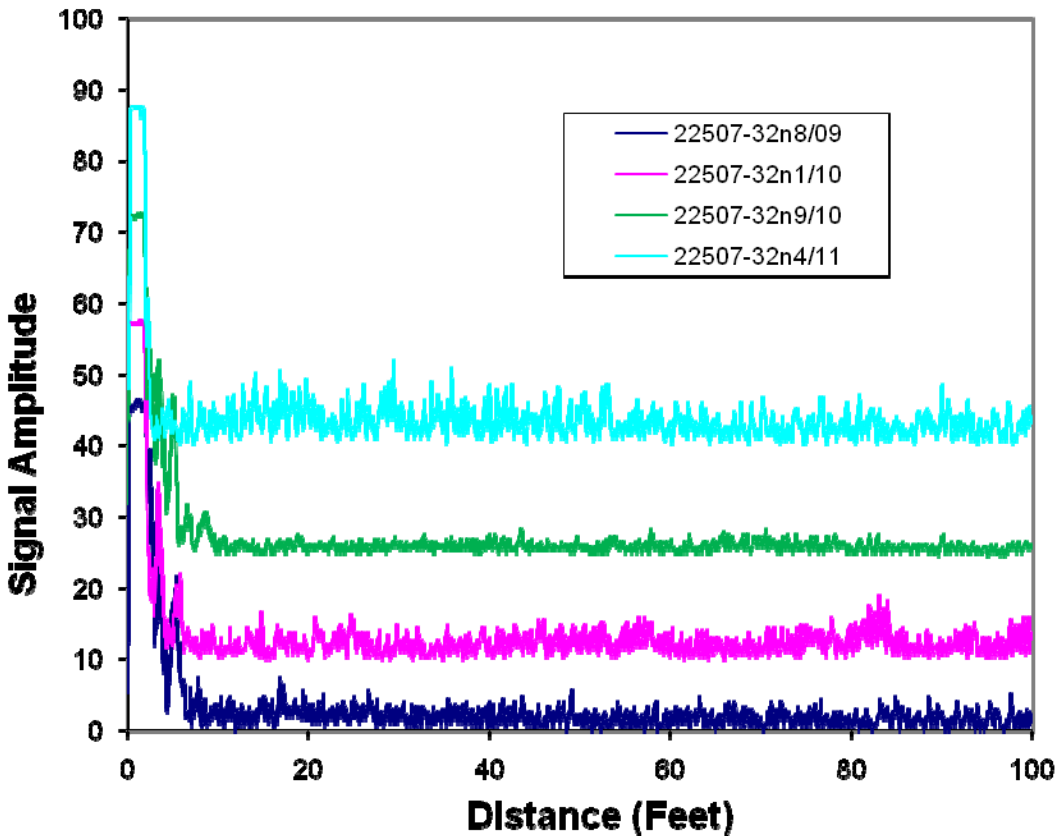



Figure 35. Monitoring changes at long distance in data sets obtained by sensor #22507. An offset of ten units along the vertical axis has been added to each successive trace before plotting.

In Figure 35 are data obtained by the same sensor as in Figure 34, but at a distance up to 100 feet. A peak detected in January 2010 (pink trace) at about 82 feet has not increased consistently in the following months to allow for a definitive identification.

We have plotted the signal amplitude at a number of locations after amplitude normalization in the data presented in Figures 32 through 35 to search for systematic increase in peak heights, following the procedure developed in Phase I. The results are shown in Figure 36. We observed that none of these peaks increased systematically in amplitude during the 20 months of monitoring. Thus, further monitoring is required to determine whether these locations have corrosion-induced defect growth.

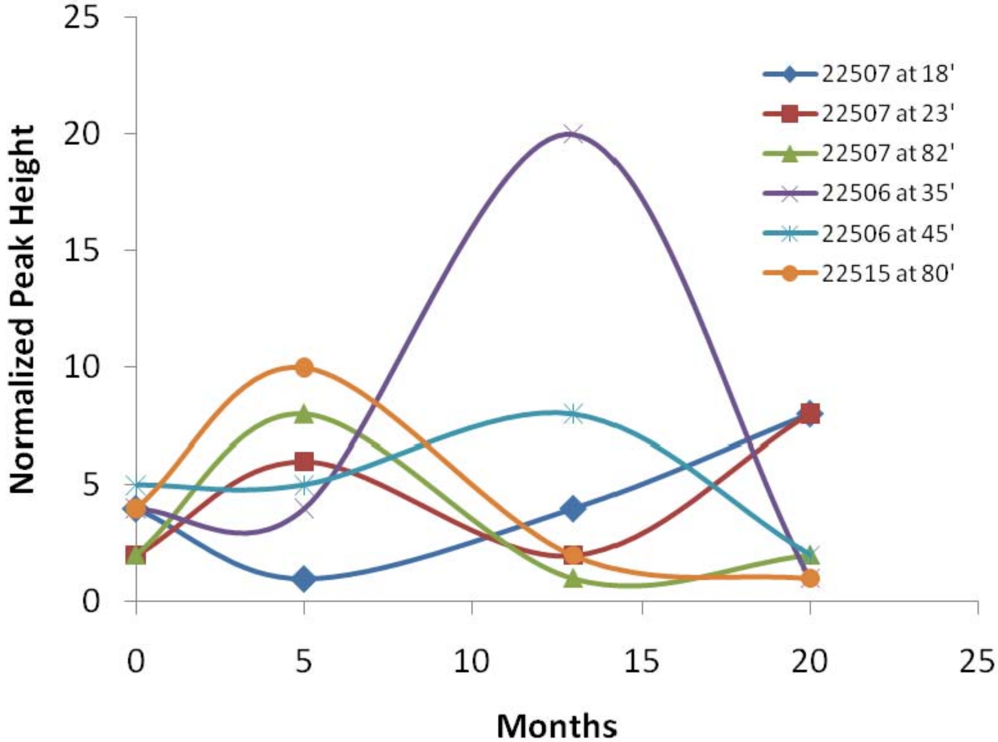



Figure 36. Changes in normalized peak height at suspected defect locations detected by three above-ground transducers.
Typical signal noise was 2 vertical units.

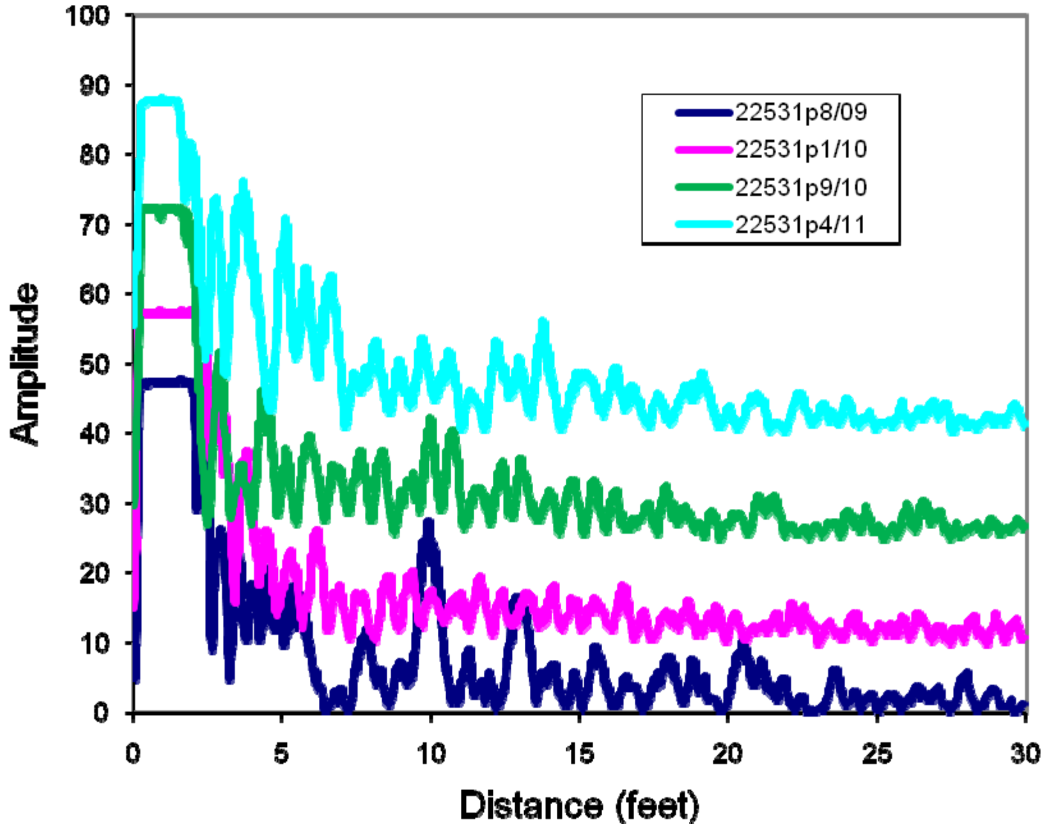



Figure 37. Changes in data sets obtained by under-ground sensor #22531 inside BL 20. An offset of fifteen units along the vertical axis has been added to each successive trace before plotting.

Figure 37 is an example of peak splitting over the course of the monitoring months. The peaks at 10 and 13 feet appeared to split in later months. Our work in Phase I suggested that such splitting was associated with corrosion around a weld. However, there is not yet consistent peak height increase in these split features. Additional monitoring is required to further identify the nature of these signals.

We note that the features in traces obtained by above-ground sensors appeared to be more reproducible than those obtained by underground sensors. While some of the peaks preserved in amplitude to a large extent, some features had changed. This is in direct contrast to the observation in the above-ground pipe in Phase I, in which a change of signal height of less than 10 percent was observed. At Norfolk Naval Station, the noise level was typically 4 times as large as that observed in the new pipeline established in Phase I. In general, weld reflections beyond 30 feet did not consistently show amplitudes above background noise level. Therefore, since the distance between valve pits is at least 100 feet, which excluded the possibility of matching the information obtained for the same segment of the pipeline using sensors in two pits propagating waves in opposite directions. This approach was successfully demonstrated in the laboratory pipelines in Phase I. More detailed comments on these points will be provided in a later section on Performance Evaluation.

### 6.2.3 Performance assessment (Phase I and II)

The overall test results of the pipeline at Norfolk Naval Station indicate that there has not been significant deterioration as a result of corrosion in the 20 months of this monitoring effort. This is consistent with the fact that there has not been any visible leakage in the pipeline over this period of time. Based on the results obtained in the laboratory and field tests completed thus far, the following is a discussion on the performance results enumerated in Table 1.

Objective #1 Result. Achievable inspection distance

Considerable variations were observed in the achievable inspection distance among different segments of a pipeline based on signal to noise considerations. In the new 8 inch line at NSWCCD with above-ground coating, the existence of two 90 degree elbows allowed a travel distance over 100 feet. In a new 4.5 inch diameter pipeline with a generic under-ground coating, data showed detectable signal above background noise at 30/40 feet, based on the analysis of multiple reflections in a ten feet long pipeline. These results were established in Phase I. Different sections of the underground fuel line at Norfolk Naval Station exhibited different signal attenuation dependent on whether multiple elbows existed and the varying noise background in each pipe segment.

Industrial experience has shown that welds in old underground pipes tend to be less reflective to ultrasonic energy, due to a combination of non-uniform deterioration of the coating and the existence of a thin, rust layer around the weld crown over time. This was the case in the pipeline in Norfolk Naval Station. The longest inspection distance of 92 feet (see Figure 28) was inferred from reflections in a straight section in the pipeline between BL20 and VP 21. By analyzing the signal peaks in Figures 27 through 35, we observed weld signals above background noise at up to approximately 30 feet. Based on these observations, the useful inspection distance in the field can only be estimated to be half of that specified in Objective #1.

However, the stability of the signals near the air/ground interface in this first 30 feet of a pipeline shown in Figures 27 through 35 is important. Because of moisture accumulation, corrosion is known to occur in this near surface region of underground pipelines making the ability to inspect in this near surface region useful.

Objective #2 Result. Stability of signal traces and durability of transducers

In Phase I, we demonstrated that the transducer performance was unaffected in the above-ground and outdoor environment over 20 months. At this point, the noise level and the conditions in the entire pipeline did not change except where controlled corrosion occurred. In contrast, the underground environment at Norfolk Naval Station was significantly different. Because of the proximity of the water front, the protected transducers were submerged in water for an unknown period of time inside the valve pits. Furthermore, the changing condition of moisture and ground loading on the pipeline would also vary in the course of the past 20 months.

These changing conditions had a significant impact on the reproducibility of the signals. As expected, signals from above ground sensors did not vary as much as from those inside the valve pits. The stability of signals was limited to below 10% at a distance of approximately 30 feet over this 20 month period.

Objective #3 Result. Accuracy in locating defects in pipelines in a Navy fuel storage facility using ultrasonic guided wave technology

We did not have mechanical drawings or the benefit of excavation to verify the accuracy of the peak location thus far at Norfolk Naval Station, since no defect exceeding a CSAL of 30% has been detected to warrant excavation and physical examination. In Phase I, the location accuracy was better than +/- 1 foot. Some peaks representing pipe features in the pipeline at Norfolk Naval Station shown in Figures 32 through 35, appeared stationary in location to within +/- 2 feet over the past 20 months.

Objective #4 Result. Minimum size of detectable defect based on guided wave ultrasound

In Phase I, a defect of 5% CSAL was detectable at 50 feet. Since no clear defects large enough were detected to warrant physical examination in the pipeline at Norfolk Naval Station, we can only estimate this capability based on the noise level and some weld peak heights at known distances. It is generally accepted that the weld signal peak height is the same as a defect at 20% CSAL. The weld signal at 92 feet in Figure 28 was approximately twice as large as the background noise. In this case, we estimate that a defect with 10% CSAL would have a signal to noise ratio of unity only. Similarly the weld signal at 20 feet in Figure 29 indicates that the effect of two 90-degree elbows has reduced this signal peak to be only twice as large as the background noise. Thus, a defect with CSAL of 10% it would have a signal to noise of unity only at this distance because of the adverse effect of the elbows. These indicate that this Objective was met in the pipeline at Norfolk Naval Station only at a distance of 20 to 30 feet.

Objective #5 Result. Accuracy in sizing defects

We do not believe that there has been a defect with a CSAL larger than 30% observed in the course of this demonstration at Norfolk Naval Station. This was the threshold at which time we proposed in the approved demo Plan to start excavation, inspection, and repair. This is consistent with the fact that no leakage of fuel has been observed on the ground. For this reason, we have no means to actually compare any ultrasonically identified defect exceeding 30% CSAL with actual defect size. This has to wait until such time that a large enough defect peak height appears in a continuation of this monitoring effort to warrant excavation and physical measurements.

Objective #6 Result. Capability for defect growth monitoring

We have not observed consistently increasing defect signal in the past 20 months in the pipeline at Norfolk Naval Station. As shown previously in Figure 36, some peaks suspected of indicating corrosion either disappeared in later months or never increased in height above the noise level to indicate true defect growth. Since each segment of the pipeline is different in mechanical construction and layout, the demonstration for defect growth monitoring requires additional monitoring time. The fact that no external leakage has been observed probably indicates that no large scale corrosion has occurred during the past 20 months when ultrasonic guided wave monitoring was in progress. However, judging by the noise level in the field, the capability to monitoring defect growth by 5% CSAL demonstrated in Phase I would likely be reduced to 10% CSAL at a distance of 20-30 feet.

Objective #7 Result. Improve planning for maintenance activities

No leak has been observed to warrant repair with a lead time of at least 3 months. Additional monitoring time is required to observe defect growth to quantify this Objective.

Objective #8 Result. Increased efficiency in pipeline maintenance as a result of the use of ultrasonic technology

No leak has been observed to warrant repair with a lead time of at least 3 months. Additional monitoring time is required to observe defect growth to quantify this Objective.

Objective #9 Result. Technology maturation

In Phase I, we established the basic potential of this technology. The tests in the field in Phase II need to be extended to provide more data before definitive conclusions can be drawn. Since the start of this project in 2008, there have been advancements in commercial equipment for guided wave testing and analysis [5]. Our experience thus far indicates that the technology can best be demonstrated in pipe segments over which the baseline weld signal over the distances of interest can be clearly identified using removable transducers, before permanently mounted sensors are installed. These weld markers would greatly facilitate the identification and location of unknown defect growth later on during the monitoring phase. In addition, the location for transducers should provide a lead-in distance of several feet ahead of the air/ground interface to improve the formation of a uniform guided wave front. This may require some excavation around the pipe before transducer installation to relocate ground interface farther away from the transducer.

Since the start of this Demonstration in 2008, ultrasonic guided wave technology has been demonstrated in underground pipelines in facilities at Marine Base Quantico, Virginia, and at Mayport Naval Station, Mayport, Florida, and on Navy ships at Northrop Grumman Newport News Ship Builders. The potential for defect growth monitoring appears promising in all of these locations.

# 7.0 COST ASSESSMENT

The ultrasonic guided wave measurements are intended to be performed by qualified contractors at DOD fuel farms and pipeline facilities using contractors owned equipment. Currently, the cost for such services is approximately $2K per inspector per work day excluding traveling cost. Because a two-person crew is required working inside valve pits, the labor cost for inspecting several pipe sections each 100 feet long should be achievable in one work day at a cost of approximately $4K. Also, because the equipment is contractor owned, there is little cost associated with hardware procurement and maintenance. Once measurement points are selected, transducers are mounted, and baseline measurements are made, the transducers will remain inactive until the next set of measurements is made months later to monitor changes in the conditions of the pipeline. Each set of such measurements will incur cost at a significantly reduced rate, since the installment of transducers inside valve pits and the service of a safety observer are not required.

The maintenance for piping integrity in DOD fuel storage and transport facilities and ships is currently based on either a time based schedule or in response to an emergency following an incident of piping failure. While the use of smart pigs for condition assessment is effective, this practice is expensive and interrupts pipeline operations. Therefore, the results obtained by smart pigging today do not provide information on the rate of corrosion induced wall loss in the future. Hydrostatic tests are used frequently today (at a cost of $5K to $50K per test) to verify the structural integrity of a pipeline. Part of the Hydrostatic test is "strength testing" which can actually cause a controlled leak in the weak points (likely caused by corrosion) in the line, allowing repair or replacement of the detected weak sections. Set up cost (at tens of thousands of dollars) for smart pigging is high, rendering it impractical for a short line. In contrast, ultrasonic guided wave testing will provide timely information on difficult-to-access piping systems at low cost, since many short lines can be tested in one work day at a cost of approximately $2K per inspector. The real return in investment would be the prevention of serious fuel spills which can cost millions of dollars for cleanup efforts.

## 7.1 COST MODEL

Table 3. Cost Model for Technology Demonstration at Norfolk Naval Station

| Cost Element | Actual Cost at Norfolk Naval Station | |
|---|---|---|
| | **Transducer installation / baseline measurement and analysis** | **Periodic monitoring and analysis after baseline tests** |
| Hardware capital costs | $2100 ($300.0 per transducer, 13 installed at 7 valve pits ) | $0 |
| Inspectors labor | $ 1200 (600/day for two inspectors) | $600 per day |
| Data Conversion/Analysis | $1000 per data collection | $1000 per data collection |
| Indirect costs (100% of labor) | $1200 ($600/day for two inspectors) | $600 per day |
| Equipment usage/maintenance | $500/trip | $500 per trip |
| Equipment shipping | $500/trip | $500 per trip |
| Travel (San Antonio, Texas to Norfolk, Virgina), time and expenses | $1000/trip for two inspectors | $1000 per trip |
| Travel per diem at Norfolk, Virginia | $640 ($160/person/day for two days) | $160 per day |
| Safety training/certificates | $1000 ($500/person/job) | $0 |
| Onsite equipment van rental | $200 ($100/day for two days) | $100 per day |
| **Facility operational costs** | | |
| Environmental safety observer/support (direct and indirect) | $800/job for transducer installation inside valve pits | $0 |
| TOTAL | $10,140 | $13,380 ($4460 per trip) |

Explanation of cost elements:

1. **Hardware Cost** is mainly the transducer assembly which, once installed, will remain attached to the selected location on the pipeline.
2. **Cost for inspectors, time, and travel and equipment use** is based on our experience at NSWCCD and at Norfolk Naval Station. The baseline measurements and transducer installation require a trip lasting for about 4 days including traveling to and from San Antonio, Texas by two qualified inspectors. Subsequent trips for monitoring potential changes in the pipeline require only one inspector and a one to two day trip, and no

transducer hardware cost is required. Excluding transducer costs, a total cost of $2K per inspector per day for inspecting several 100 feet long pipe sections is a reasonable estimate for budging purposes.
3. **Facilities and operation cost** is for one-day on-site support during transducer installation inside valve pits to be provided by another contractor in Norfolk, Virginia.

### 7.2 COST ANALYSIS AND COMPARISONS

The ultrasonic guided wave measurements are intended to be performed by qualified inspectors at DOD fuel storage and pipeline facilities using inspector owned equipment. Currently, the cost for such services is approximately $2K per inspector per work day excluding traveling cost, equipment rental, etc. Since the equipment is inspector owned, there is no cost to the Government associated with hardware procurement and maintenance. Once measurement points are selected, transducers are mounted, and the baseline measurements are made; the transducers will remain inactive until the next set of measurements is made months later to monitor potential changes in the pipeline. Each set of these subsequent measurements will cost significantly less.

## 8.0 IMPLEMENTATION ISSUES

### 8.1 ISSUES OF SCALING AND TECHNOLOGY TRANSFER

The sections of the pipeline evaluated at Norfolk Naval Station and monitored in the past 20 months are underground. The test design provided access points above ground to monitor the conditions of these pipes. The results on defect detection and growth monitoring should be applicable for similar pipelines in other DOD facilities. This technology should provide an additional tool for the management of pipeline structural integrity. It should be particularly useful for low-cost condition monitoring at selected locations, such as underground pipes at road crossings or through-tank piping on Navy ships.

Some of the Performance Objectives have not yet been met in the monitoring duration of 20 months because natural corrosion occurs slowly and since insufficient information is available on the physical construction of the different sections of the pipeline, which could have served as location and defect calibration markers. We recommend that a method to select promising locations for condition monitoring using permanent sensors in a pipeline should be preceded by a preliminary evaluation for weld signal response using re-mountable transducers. Additionally, locations where weld signals are well above noise level in the baseline would enhance the success of defect growth monitoring later on. Naturally, the more complex the pipe geometry and the longer the pipeline the more measurement stations will be required at increased cost. Extensive planning for the selection of measurement points is necessary to achieve good results. Mostly, the cost is associated with the labor hours for the testing and subsequent data analysis.

## 8.2 RECOMMENDATIONS FOR FUTURE R&D

Additional considerations on both technological and cost issues should be given to promote the implementation of this technology in the field. These issues include: (a) the effect of different protective coatings on performance, (b) the effect of soil conditions on the signal response, (c) increasing the portability of the equipment to facilitate personnel activity inside underground pits and trenches, and onboard Navy ships, and (d) consideration of the cost benefits associated with the implementation of an autonomous measurement system on a remotely located pipeline requiring minimal human supervision.

## 8.3 QUALIFYING CONTRACTOR FOR SERVICE PROCUREMENT

In order to implement the process of qualifying potential contractors to perform ultrasonic guided wave monitoring of pipelines for the Government, we suggest the following requirement: The contractor should successfully demonstrate the capability to detect and size a defect with CSAL of 10% in a 10 feet long, straight pipe with a tar-wrap coating similar to the ones used in part of our Phase I effort. A signal to noise ratio of 2 must be achieved when the location of the defect from the sensor is extrapolated from this 10 feet calibration pipe to the pipeline in the field of concern to the Agency initiating the procurement. Discussions in our published paper on extrapolating results on a pipe of simple geometry to one with complex geometry should provide additional guidance in this process.

# 9.0 REFERENCES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3. NAVFAC Contractor Report CR-08-003-E & U, Internal Inspection of 10-Inch Multi-Product Pipeline, FISC Craney Island, Virginia, July, 2008.
4. John M. Liu, Carrie E. Davis, Terri M. Regin, and Joseph Brophy, “Monitoring the Growth of Hidden Corrosion Discontinuities in a Pipeline with Complex Geometry Using Torsional Mode Ultrasonic Guided Wave,” Materials Evaluation, 69 (3), pp. 393-400, March 2011.
5. Steve E. Owens, FBS, Inc. (private communications, 2011)

# 10.0 APPENDICES

## Appendix A: Points of Contact

| POINT OF CONTACT | ORGANIZATION | PHONE<br>FAX<br>E-MAIL | ROLE IN PROJECT |
|---|---|---|---|
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## Appendix B: Materials Evaluation Article (Reference 4)

The following article (Reference 4 in this report) was published in March, 2011 issue of Materials Evaluation, an archival journal published by the American Society for Nondestructive Testing (www.asnt.org).

# Monitoring the Growth of Hidden Corrosion Discontinuities in a Pipeline with Complex Geometry Using Torsional Mode Ultrasonic Guided Wave

by John M. Liu*, Carrie E. Davis*, Terri M. Regin† and Joseph Brophy‡

ABSTRACT

The peak amplitude of the fundamental torsional mode, T(0,1), ultrasonic guided wave, excited and sensed by commercially available equipment using permanently mounted magnetostrictive transducers, was used to monitor the growth of electrochemically induced, external discontinuities in a steel pipeline (216 mm outside diameter). The pipeline was more than 30.5 m long, had multiple welds and two 90° elbows. Over the course of eight months, two discontinuities, hidden from ultrasonic testing (UT) technicians, grew systematically in both area and depth, providing the opportunity to experimentally evaluate the effects of complex geometry on signal characteristics. Corrosion around a weld was also studied. The obtained results were compared with a surface discontinuity that was unaffected by intermediate welds located between the transducer and the discontinuity. It was found that the effects of multiple welds and an elbow decreased the sensitivity for discontinuity growth monitoring by a factor of less than two. This was established by examining the scaling of discontinuity signal peak heights against a weld peak instead of using a conventional distance-amplitude-correction (DAC) curve to account for material attenuation, by comparing the signals from a discontinuity viewed along the forward and the reverse direction, and by allowing the discontinuities to change in all three dimensions in the course of this monitoring effort. This controlled study for discontinuity growth monitoring can be useful to guide efforts on discontinuity growth monitoring of complex pipelines in the field.

KEYWORDS: Ultrasonic guided waves, pipes, corrosion monitoring, discontinuity growth, effects of welds and elbows.

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## Introduction

In recent years, ultrasonic guided wave technology has progressively evolved from research laboratories to commercial applications (Alleyne and Cawley, 1997; Kwun et al., 2003; Ledesma et al., 2009; Mu et al., 2008; Rose et al., 2007). Equipment operating in the range of tens to hundreds of kilohertz (kHz) frequencies using transducers based on either piezoelectric arrays or magnetostrictive rings is currently in commercial use. Because of the potential to detect discontinuities at long distances from a single wave source, guided wave technology is being promoted as an additional tool, besides conventional nondestructive testing (NDT) methodology, to monitor the structural integrity of pipelines, particularly those in areas that are difficult to access (Liu and Davis, 2006; Liu and Nemarich, 2008). The main purpose of most applications of ultrasonic guided wave technology, however, is to screen for suspected areas, with a secondary purpose of additional and localized NDT.

There is increasing interest in using ultrasonic guided wave measurements to monitor the state of discontinuity growth, without the need to supplement these measurements by additional measuring techniques. In order to facilitate such a pipeline health monitoring concept, guided wave signal data for growing discontinuities are required.

Some previous investigations in guided wave discontinuity characterization mainly considered simple discontinuities such as saw cuts and holes in a straight pipe without welds (Demma et al., 2003; Demma et al., 2004). Corrosion-induced discontinuities, however, are not well represented by these simple discontinuities. In order to account for a decrease in signal strength with propagation distance due to material attenuation, the concept of distance-amplitude-correction (DAC) curves is used to facilitate discontinuity sizing, no matter where the discontinuity is located in the wave propagation path. However, many pipelines in the field contain multiple welds and elbows. Frequently, the signal peaks that originate from welds do not follow a well-defined exponential decay pattern on which the DAC curve is based.

The purpose of this study was to examine the effect of three factors on the establishment of a signal peak height versus discontinuity size relationship. These three factors were multiple welds in a pipeline exhibiting a non-exponential decaying DAC curve, a 90° elbow and corrosion-induced discontinuities changing in size in all three dimensions (Demma et al., 2005; Rose et al., 2005). A special case was also included in this study; a growing discontinuity that was a short distance from the transmitting and receiving transducer in a straight pipe section without a weld in the propagation. Experimental results are provided that help determine whether the growth rate of discontinuities induced by corrosion can be measured by the changes in guided wave signal data in a pipeline with complex geometry, and how much this growth rate differs from that obtained for a short pipe without welds or an elbow.

Commercially available equipment based on magnetostrictive transduction principles was used to generate and receive the axisymmetric, fundamental torsional mode, T(0,1), in the pipes and characterized the discontinuity response by the rectified signal peak height after electronic filtering (Kwun et al., 2003; Kwun et al., 2004). A simple scheme was adopted to correct for distance dependence of discontinuity peak heights, using the peak height of a weld signal either in front of or behind a discontinuity as a reference. Corrosion-induced discontinuities were introduced using electrochemical means to provide a systematic change in all three dimensions of the discontinuities. Also included are measurements of guided wave signals that originated from a corroding weld, which did not appear to have been previously reported.

## Test Design

A sketch of the pipeline is shown in Figure 1. It had an outside diameter of 216 mm with a wall thickness of 8.4 mm. The 6.1 m pipe segments were coated by a three-layer protective paint, following the U.S. Army Corps of Engineers' specification for an outdoor, above ground environment. One 6.1 m segment of the pipeline was left outdoors through the duration of this study, to provide some indication of the performance of transducers (affixed to the pipe surface by epoxy) left in the outdoor environment for a period of eight months. Note that the locations where corrosion discontinuities existed were hidden by long sheet metal covers to purposely hide the locations and number of discontinuities from those performing the testing, and thus achieve blind tests in this discontinuity growth monitoring project.

### Transducer Placement

Figure 1 shows the locations where guided wave transducers were mounted. The wave propagating direction from Pipe end 1 toward Pipe end 2 was designated to be positive. Wave propagation in the reverse direction was designated as negative. This approach included interrogating the same discontinuity by propagating guided waves toward it from opposite directions. Figure 3 includes multiple ultrasonic waveforms obtained by two transducers separated by a known distance along the pipeline. By shifting the origin of the time (distance) axis by this known separation in one of the traces,

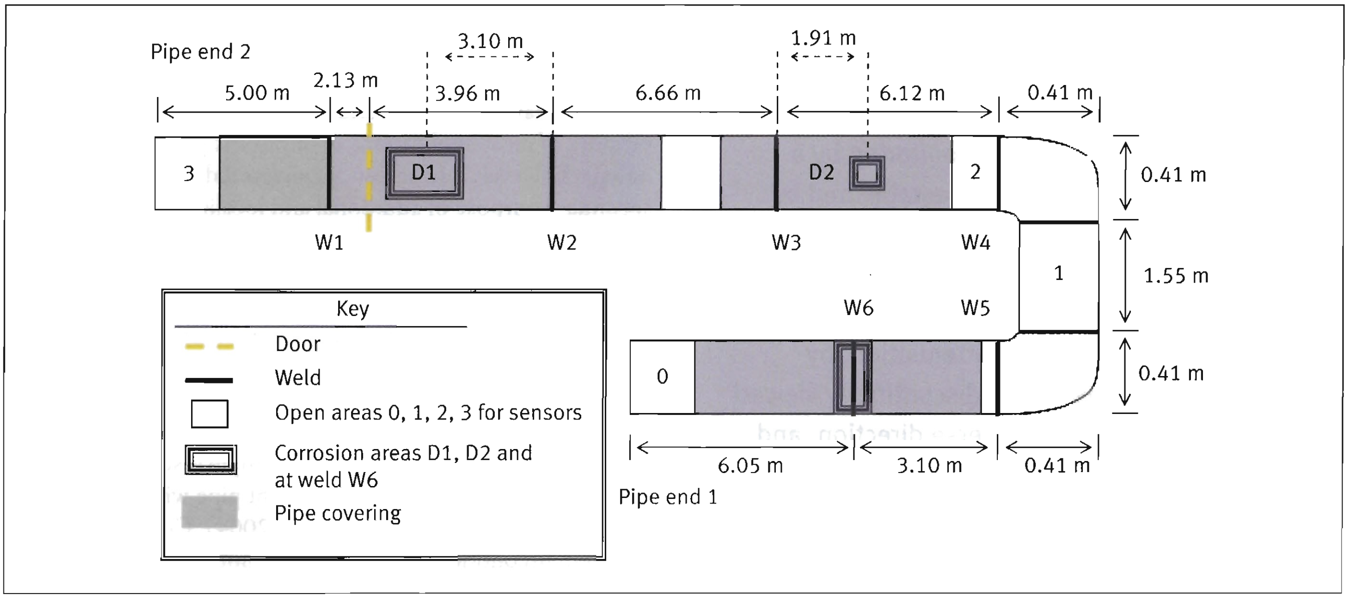


**Figure 1. Location of ultrasonic measurement points and corrosion discontinuities in the test pipeline.**

**TABLE 1**
**Summary of corrosion discontinuity characteristics**

| Discontinuity | Month | Size circ. × axial mm × mm | CSAL avg. ± st. dev. % | Wall thickness loss† avg. ± st. dev. mm | Volume loss avg. ± st. dev. $mm^3$ |
|---|---|---|---|---|---|
| D2 | June | ~76 × 76 | 1.8 ± 0.2 | 1.5 ± 0.18 | 98 ± 13 |
| D2 | August | 76 × 89 | 3.2 ± 0.12 | 2.3 ± 1.5 | 157 ± 10 |
| D2 | September | 76 × 89 | 8.8 ± 0.7 | 5.8 ± 0.5 | 574 ± 46 |
| D2 | November | 100 × 115 | 11.6 ± 1.7 | 6.6 ± 1.0 | 770 ± 115 |
| D1 | June | 127 × 280 | 3.6 ± 0.39 | 1.5 ± 0.18 | 590 ± 62 |
| D1 | August | 127 × 280 | 5.2 ± 1.0 | 2.3 ± 0.15 | 836 ± 54 |
| D1 | September | 280 × 305 | 9.4 ± 0.5 | 1.8 ± 0.1‡ | 1688 ± 90 |
| D1 | November | 305 × 380 | 14.0 ± 0.9 | 2.8 ± 0.17 | 3065 ± 197 |
| W6 | June | 150 × 89 | 4.5 ± 0.8 | 1.8 ± 0.8 | 229 ± 15 |
| W6 | August | 150 × 89* | 12.8 ± 6.0 | 5.0 ± 2.5 | 688 ± 66 |
| W6 | September | 267 × 89* | 13.5 ± 1.4 | 3.3 ± 1.8‡ | 656 ± 33 |
| W6 | November | 305 × 192* | 25.0 ± 1.2 | 5.0 ± 2.0 | 1442 ± 49 |

Notes: Pipe wall cross-sectional area = 555 $mm^2$; * = crack developed; † = nominal wall thickness = 8.5 mm.; ‡ = the thickness loss averaged over an increase in corroded area was smaller than that for the preceding month; Discontinuity 2 is 19.8 m from Pipe end 2; Discontinuity 1 is 7.9 m from Pipe end 2; Discontinuity W6 is the weld discontinuity, 6.1 m from Pipe end 1; CSAL = cross-sectional area loss; circ. = circumference; avg. = average; st. dev. = standard deviation.

the weld signals in both waveforms could be plotted to appear in an apparent fixed location on one of the distance axes. With a reversal in the direction along the distance axis, signal traces can be superimposed even if the direction of wave propagation was different.

### Distance-amplitude-correction Curves

The need to account for the decrease in signal amplitude as propagation distance increases is understood in ultrasonic bulk waves. An exponential decay of signal strength with distance is generally depicted by a DAC curve. The extension of this concept to guided wave in pipes is, however, not straightforward. First, there can be welds in the propagation path in a pipe. In addition to distance effects, the variations on the reflection energy loss across each of the welds would modify this DAC curve. Different welding processes could result in variations in the length and width of the weld crown. It was frequently observed in this study that weld peak signals did not follow an exponential decay curve. Since the intention was to compare the obtained results by transducers mounted at different locations in a long pipeline, not only was the number of welds varied, but the energy loss across each weld might have been different, depending on the direction of propagation. This made the application of a standard DAC curve impractical.

Instead of conventional DAC curves, a discontinuity signal peak height was normalized by scaling it against the peak height of a weld signal nearby. The difference in the obtained results was examined by using the signal associated with a weld either in front of or behind a discontinuity for this process. The obtained results should have provided an estimation of the error in discontinuity sizing associated with the random location of a weld with respect to a discontinuity in the field. When comparing the response from different transducers for a given discontinuity, this approach produces an error as a result of failing to account for the distance between the discontinuity and the weld, as well as the potential difference in energy loss across a weld in the forward and reverse directions.

## Results

### Wave Speed Determination

Using the known distance between the welds in the pipeline, the wave speed for the fundamental torsional mode, T(0,1), at 32 kHz was determined to be 3230 m/s. At this frequency, this mode is known to be non-dispersive (Rose, 1999).

### Cross-sectional Area Loss Measurements

Details of the corrosion experiments and the techniques for cross-sectional area loss (CSAL) measurements can be found in previous studies (Liu and Davis, 2006). The area and volume loss are shown in Table 1. CSAL was achieved over 25%, a volume loss of more than 2950 $mm^3$, and the smallest discontinuity area was approximately 76 × 76 mm.

In Table 1, D2 was designed to be a small discontinuity, in the sense that its dimensions along the circumference and axial directions were close to the wavelength (100 mm) of the torsional guided wave at 32 kHz. On the other hand, D1 was 3 to 4 wavelengths in the axial direction, and 1 to 3 wavelengths in the circumferential direction. In both discontinuities, the axial length did not exceed the length of the four-cycle wave train excited by the transducer, thereby not allowing the reflections from the leading and the trailing edge of the discontinuity to be completely separated in time to produce a double peak.

### Ultrasonic Guided Wave Signal Traces

In the following paragraphs, a summary of the data for baseline and successive stages of corrosion is shown. Signal traces are labeled in the following manner. Label M1PD2B designates a May (M), or baseline, trace that was obtained by the transducer at Location 1 (see Figure 1), exciting guided wave propagating in the positive (P) direction. The signal peak for D2 was scaled with respect to the weld signal behind (B) D2.

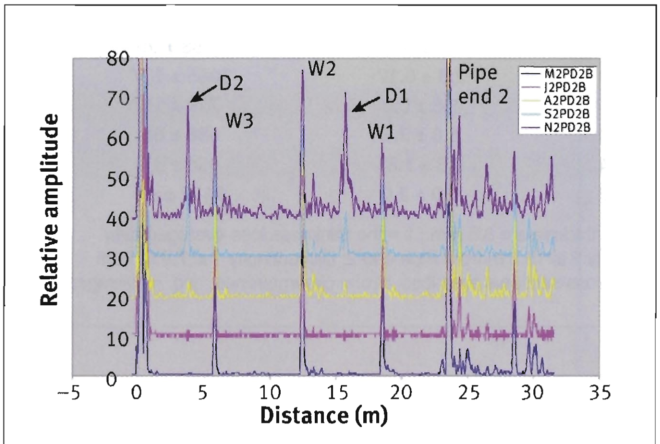


**Figure 2. Systematic increases in peak heights for growing D1 and D2 sensed by transducer at Location 2. D1 was located at approximately 15.3 m and D2 was located at approximately 3.7 m. The other large peaks, approximately 6.1 m apart, are from the welds in the pipeline. The baseline signal (May) is blue, the June signal is pink, the August signal is yellow, the September signal is light blue and the November signal is purple. An offset of 10 units along the vertical axis was added to each successive trace before plotting.**

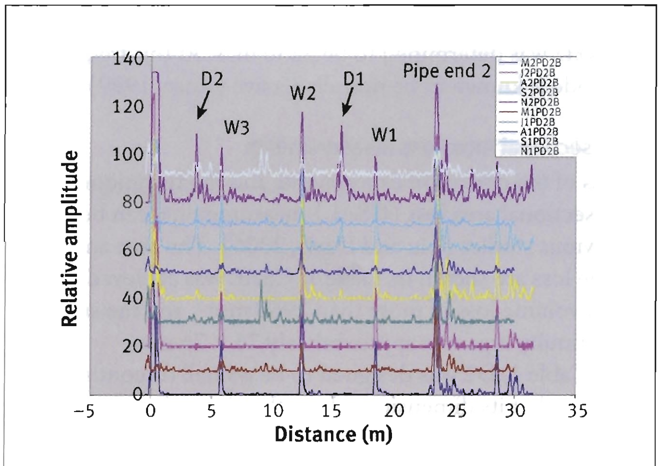


**Figure 3. Signal traces for transducers at Locations 2 and 1 (time-shifted), for waves propagating in the same positive direction towards Pipe end 2. The initial portion of the traces for the sensor at Location 1, including the effects of the elbow, was deleted to allow for the matching of peaks in the traces for both sensors. D2 was at 3.7 m and D1 was at 15.5 m. The other matching peaks originated from welds. An offset of 10 units along the vertical axis was added to each successive trace before plotting.**

Similarly, label N3ND1F represents a November (N) trace, obtained by the transducer at Location 3 (see Figure 1), exciting waves propagating in the negative (N) direction. The peak height for discontinuity D1 was also scaled with respect to the weld signal in front (F) of D1. The month in which the data trace was obtained is included, since details of the discontinuity size and shape for that month can be found in Table 1.

Examples of systematic increases in discontinuity peak height as corrosion progressed are shown in Figure 2. Here, traces obtained over the months of May, June, August, September and November were stacked up beginning with the May (baseline) trace shown at the bottom of Figure 2. In order to facilitate the examination of each trace in detail, an offset of 10 units along the vertical axis was added to each successive trace before plotting in Figure 2. The labels for the traces (such as M2PD2B for the month of May), as stated before, indicted that the transducer was at Location 2, propagating guided waves in the positive (P) direction, and the weld signal behind (B) D2 was used to normalize the peak height. It can be seen that the discontinuity signal height depends on the size of the discontinuity, the distance between the transducer and the discontinuity, and the number of welds in the wave propagation path. Note that the weld peaks did not decrease in amplitude following a well-defined exponential decay curve in this welded pipe. As previously mentioned, these measurements of peak height, originated from D2 by the transducer in Location 2, provided the simplest case of discontinuity growth monitoring in a short, straight pipe section without the interference of a weld. In Figure 2, it can be noted that the signal at approximately 13.4 m immediately behind the peak for W2 did not increase systematically throughout the course of the experiment, signifying that it did not originate from a growing corrosion discontinuity.

The signals received by the transducer located in Location 1, which was located behind a 90° elbow, were superimposed on the traces displayed in Figure 2 for the same two discontinuities, D2 and D1. The obtained traces are shown in Figure 3. Here, the origin of the traces for the transducer at Location 1 (such as M1PD2B) has been shifted to account for the distance separating the two transducers, in order to match the peaks corresponding to the welds in both sets of traces. Wave propagation was in the same positive direction for both data traces. As in Figure 2, the traces in Figure 3 were stacked upwards starting with the May (baseline) traces measured by the two transducers, followed successively by the June traces for Transducer 2 and Transducer 1, respectively, and then by the traces for the later months.

Figure 3 shows that the peak associated with D2 at 3.66 m was below noise level in the traces obtained by the transducer in Location 1 for the month of June and August, as a result of the adverse effect of the 90° elbow in front of this discontinuity. When D2 reached a CSAL of 8.8% in the month of September (see Table 1), its peak height was above noise level. Similarly, D1 was below noise level until a CSAL of 5%

was reached in the month of August. The spurious signal at approximately 9.1 m originated from the reflection of the unwanted wave propagating from the transducer at Location 1 in the reverse direction towards Pipe end 1.

In Figure 4, a comparison is made between the groups of traces obtained by transducers placed in Locations 2 and 3. The origin of the horizontal (distance) axis is defined by the location of the transducer in Location 2. Starting from the bottom, the traces for Transducers 3 and 2 were stacked up alternately, beginning with the May trace for Transducer 3. Because wave propagation was in opposite directions along the pipe, the traces for Transducer 3 are plotted from right to left along the distance axis in order to match the weld peaks. In this way, the peaks originated from D1 and D2 should appear in the same locations (approximately 3.7 and 15.5 m, respectively) among all the traces. The systematic increase in peak heights as corrosion progressed from May (baseline) through November can be seen, except for the trace for the month of June (labeled J3ND2F) obtained by Transducer 3, in which the peak for D2 was below the noise level. This shows that the signal associated with a small discontinuity in the shadow of a large discontinuity was not detectable, as a result of the distortion and energy loss caused by the presence of a large discontinuity in front of it. This distortion also increased the uncertainty in peak height measurements for D2 in the later stages of corrosion, as seen in the November trace labeled N3ND2F. Most of the welds showed a double peak feature in the wave trains detected by the transducer at Location 3. As pointed out earlier, it is believed that these peaks were due to imperfect elimination of the wave propagating in the reverse direction, which was reflected from Pipe end 2, and then superimposed on the main wave train propagating along the negative direction. The signal at 7.6 and 10.7 m, detected by the transducer in Location 3, did not systematically increase in amplitude, and was not consistent with the results obtained by the transducer in Location 2. It can be concluded that these were spurious signals unrelated to corrosion.

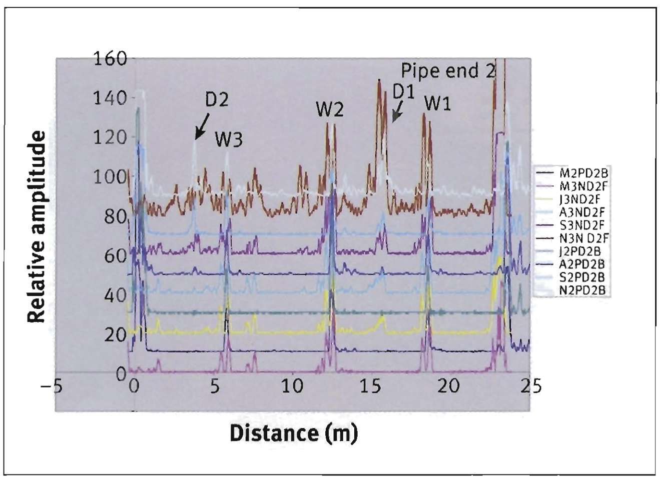


**Figure 4. Superimposed signal traces obtained by transducers at Locations 3 and 2 with the wave propagating in opposite directions. An offset of 10 units along the vertical axis was added to each successive trace before plotting.**

In Figure 5, the gradual increase in peak height is shown as corrosion damage increased at the weld W6. An offset of 20 units along the vertical axis has been added to each successive trace in Figure 5. The amount of wall loss at successive months is shown in Table 1. The peak appeared to split in the later stages of corrosion, probably as a result of the circumferential crack developing observed in the weld crown.

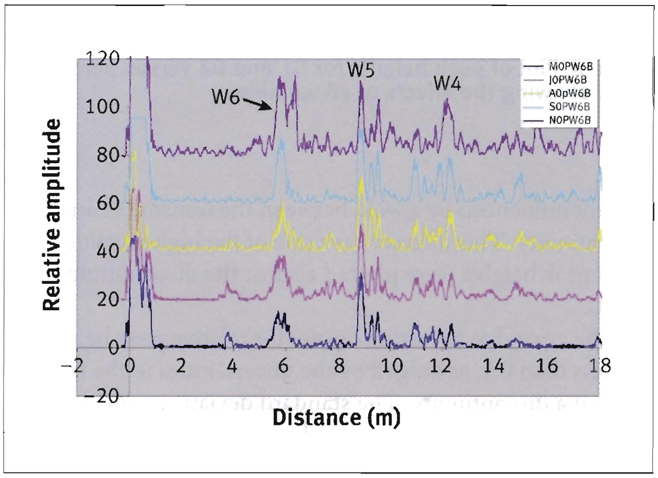


**Figure 5. Data traces showing the increase in peak height and split peak features at W6 located approximately 5.5 m from the transducer placed at Location 0. An offset of 20 units along the vertical axis was added to each successive trace in this Figure.**

### Summary of Ultrasonic Guided Wave Results

The signal peak height from each data trace was extracted and then plotted versus percent CSAL in Figure 6. The data summarize the results for D1 and D2, varying in size from approximately 76 × 76 mm to 305 × 356 mm in surface area, and from 10 to 50% in loss of wall thickness, as shown previously in Table 1. The signal returned from these two discontinuities was sensed by three different transducers, mounted at distances ranging from 3.7 to 18.9 m, and one was affected by the presence of a 90° elbow. Each of the data sets were labeled with the same system used before, except that the first letter designating the month in which the data were obtained was removed from those used in Figures 2 – 5, since each data set contains peak height information from the month of May through November.

Due to the effects of the large number of selected variables as previously discussed, there was a considerable amount of scatter in the discontinuity peak heights. These data will be discussed in some detail in the Discussion section of this paper. Worth noting now, however, is that the data set 2PD2B

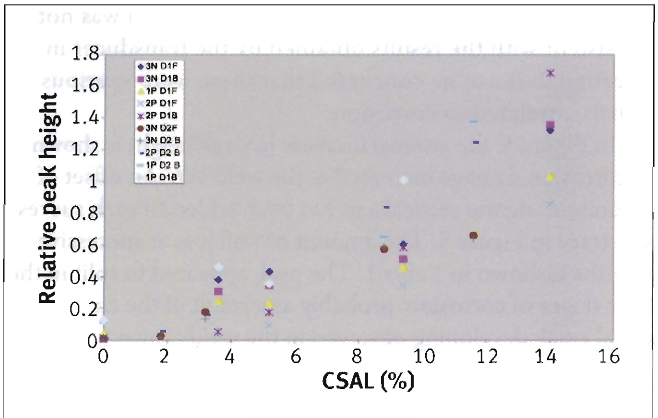


**Figure 6. Plot of peak heights for D1 and D2 versus percent CSAL, showing the effects of all variables.**

was not influenced by a weld between the transducer and the discontinuity. This data set gave one of the highest values when peak heights were plotted against the discontinuity CSAL.

The error due to intrinsic noise for relative peak height was less than 0.1, as judged by the uncertainties in the signal without a discontinuity. The standard deviations of the discontinuity CSAL shown in Table 1 indicate an uncertainty of approximately 8%. In totality, these data sets show that the signal peak height for a discontinuity is influenced by the distance between the discontinuity and the transducer, the number of welds crossed by the propagating waves, existence of elbows, and the asymmetry of a weld or a discontinuity viewed from opposite directions. Overall, the complex geometric features in the welded pipeline resulted in an error of less than a factor of 2 in the percent CSAL based on the measurement of discontinuity peak height, when comparing to the simplest case exhibited by data set 2PD2B obtained for a short pipe section without welds.

### Trend Lines for Discontinuity Growth Monitoring

Three trend lines are shown in Figure 7. The blue line was based on all data shown in Figure 6. It represents an averaged trend that provides an empirical calibration curve converting relative signal peak height to percentage CSAL for the two discontinuities. The other two trend lines were generated using data sets from one transducer producing the largest and smallest slopes. The green trend line was based on the data set 2PD2B collected by the transducer at Location 2 on D2. The straight propagation path of 3.66 m without an interfering weld resulted in a trend line with the highest slope. The data set 2PD1F included the effects of three welds and resulted in a trend line with the lowest slope. The slopes in these extremes differ by a factor of less than 2. These uncertainties are the results of combining all the data obtained from different transducers, located at a distance from 3.7 to 18.9 m from a discontinuity, the existence of variable number of welds and an elbow, and discontinuities of different area, volume and shape.

A plot of peak height versus the discontinuity CSAL around the weld, W6, including the influence of a 90° elbow is shown in Figure 8. The relative peak heights were smaller when the effect of the elbow was included (comparing the trace 0PW6B to traces 1NW6F and 1NW6B), and the fitted slope of peak height versus percent CSAL curves was slightly less than that obtained without the presence of the elbow. This is consistent with what was presented previously on the effect of an elbow on signal heights associated with D1 and D2. The large scatter in the data was probably the result of a developing crack in the weld crown midway through this monitoring study.

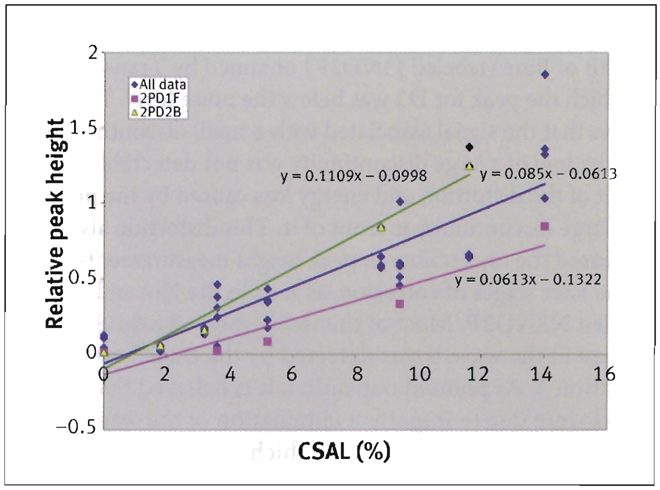


**Figure 7. Trends for the increase in signal height with respect to discontinuity CSAL, incorporating the effects of all variables considered.**

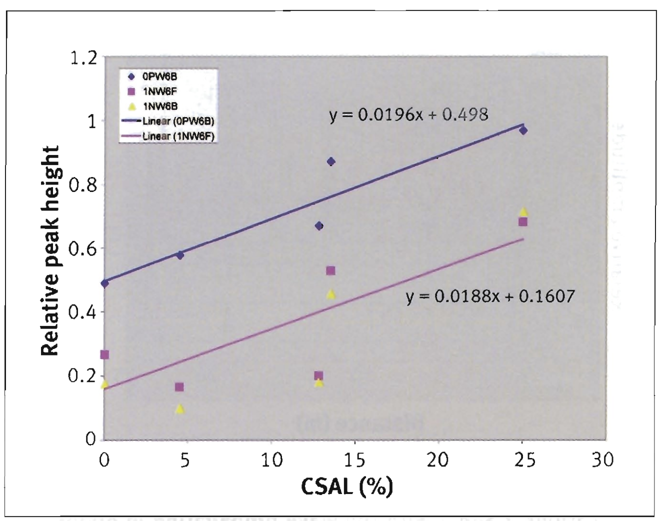


**Figure 8. Increase in signal peak height of the weld signal as corrosion increased in a pipe section with or without a 90° elbow.**

## Discussion

Based on the data presented in Figure 6, the following observations can be made. First, for the small discontinuity, D2, the difference in relative peak height was not very dependent on whether the weld peak in front of or behind it was used for normalization. This can be seen by comparing data sets 3ND2F and 3ND2B. However, for discontinuity D1, particularly when its CSAL was large, normalization against the weld behind the discontinuity usually resulted in a larger relative peak height. This was illustrated by comparing data sets 2PD1F and 2PD1B. This was caused by the energy loss of the propagating wave across the large discontinuity, resulting in an apparent smaller weld signal behind the discontinuity. This difference is seen also by comparing data sets 1PD1F and1PD1B. However, this difference was not as clearly observed when data set 3ND1F was compared to 3ND1B.

In general, using the weld signal behind a discontinuity for peak height normalization tended to overestimate the apparent discontinuity size, especially when the discontinuity was large.

In some data sets, the relative peak height for a discontinuity was smaller when the number of welds existing between the transducer and the discontinuity increased. The clearest example is given by comparing data set 2PD2B to 3ND2F, when no weld existed for the former and two existed for the latter. As previously mentioned, data set 2PD2B gave the highest values in peak height versus percent CSAL among all the data sets. Similarly, this correlation holds for data sets 2PD1F and 3ND1F. The relative peak height was lower for 2PD1F (two welds) compared to 3ND1F (one weld). This correlation was again observed when comparing 3ND1F to 3ND2F (three welds), and was also consistent with data sets 1PD1F and 1PD2B, two data sets including the effects of an elbow preceding the discontinuities. It is possible that the wave distortion resulting from propagation across multiple welds diminished the small discontinuity signal more than the larger weld signal used for peak height normalization. Also, data set 3ND1F (one weld) exhibited peak heights higher than in 2PD1B (three welds) as expected, except for the datum at 14% CSAL, at which point normalization using the weld signal behind the large discontinuity apparently compensated for the signal decrease due to the three welds in 2PD1B. Additional work may be required to clarify these points.

In general, it was observed that a large discontinuity decreased the normalized peak height for a small discontinuity existing further down the wave propagating path. Also, the presence of an elbow decreased the normalized discontinuity peak heights, as, for example, exhibited by 1PD1F. However, consistent with what was stated in the last paragraph, the expected decrease in discontinuity peak heights due to an elbow could be compensated for by choosing the weld signal behind a discontinuity for normalization. For example, most data points in 1PD1B and 1PD2B had high peak values, contrary to the expected low values due to the presence of the elbow, a result most likely due to this choice of weld peak normalization.

This work showed that CSAL as small as 5% was measurable, thereby proving sufficient time to track the discontinuity size before it increased to a size of concern. Similar results were also obtained using measurement systems based on piezoelectric array transducers (Rose et al., 2007). The rate of the signal growth with percent CSAL for localized corrosion in a weld, as shown in Figure 8, is smaller than that for the two isolated discontinuities studied in this work, probably as a result of the existence of extra material in the weld crown. However, the split peak feature of the signal at this corroding weld, probably the result of a crack developing at the weld crown, might have affected the results.

## Conclusion

The use of weld peak normalization appears to be a useful approach when an exponential decay curve for weld signals does not hold. Included for consideration were the effects of discontinuity sizes ranging from approximately 5 to 15% CSAL, the presence of an elbow and the varying 3D discontinuity geometry. This approach resulted in an averaged signal peak height versus discontinuity CSAL curve having an uncertainty factor of less than 2 in the CSAL values when compared to the results obtained in a short pipe without the presence of a weld or elbow. An uncertainty factor of 2 in tracking the change in percent CSAL may be acceptable in field testing, because corrective actions for a pipeline is usually deferred until CSAL of 50% is reached. Following this logic, a simple calibration pipe with a discontinuity could be used to establish a relationship between signal peak height and discontinuity growth rate in a pipeline with welds if a safety factor of 2 is incorporated.


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