Final Report

ENERGY REDUCTION USING EPOXY COATINGS FOR SEALING LEAKING COMPRESSED AIR SYSTEMS

Energy and Water Project
EW 201517

September 21, 2018

Gary Anguiano, P.E.
Itzel Godinez, Ph.D.
Mark Foreman
Hunter Spence
James Pilkington
Andy Vasquez

Naval Facilities Engineering and Expeditionary Warfare Center

REPORT DOCUMENTATION PAGE (SF 298)

Form Approved OMB No. 0704-0811

1. REPORT DATE *(DD-MM-YYYY)*
09-20-2018

2. REPORT TYPE
ESTCP Final Report

3. DATES COVERED *(From – To)*
March 2016 – September 2017

4. TITLE AND SUBTITLE
ENERGY REDUCTION USING EPOXY COATINGS FOR SEALING LEAKING COMPRESSED AIR SYSTMS

5a. CONTRACT NUMBER

5b. GRANT NUMBER

5c. PROGRAM ELEMENT NUMBER

5d. PROJECT NUMBER
EW-201517

5e. TASK NUMBER

5f. WORK UNIT NUMBER

6. AUTHOR(S)
Gary Anguiano, NAVFAC EXWC
Itzel Godinez, Ph.D.
Mark Foreman
Hunter Spence
James Pilkington

7. PERFORMING ORGANIZATION NAME(S) AND ADDRESSES
Naval Facilities Engineering and Expeditionary Warfare Center
1000 23rd Ave
Port Hueneme, CA 93043

8. PERFORMING ORGANIZATION REPORT NUMBER
EW-201517

9. SPONSORING/MONITORING AGENCY NAME(S) AND ADDRESS(ES)
Environmental Security Technology Certification Program
4800 Mark Center Drive, Suite 17D08,
Alexandria, VA 22350-3605

10. SPONSOR/MONITORS ACRONYM(S)
ESTCP

11. SPONSOR/MONITOR'S REPORT NUMBER(S)
EW-201517

12. DISTRIBUTION/AVAILABILITY STATEMENT
Distribution A: Public release, Unlimited

13. SUPPLEMENTARY NOTES

14. ABSTRACT
Air distribution pipeline leaks are common place at DoD intermediate and depot level maintenance facilities, and if resolved can improve system operational performance and reduce lifecycle energy costs. Facility managers in many cases can easily fix common aboveground leaks with conventional practices given adequate resources. However, some leaks are difficult and expensive to repair, particularly those in inaccessible locations where piping runs beneath slabs, roadways, etc. The project objectives were to validate epoxy coating technology as a means to seal leaks in these challenging circumstances. The technology was demonstrated on abandoned below slab steel pipeline located at Construction Equipment Department, Naval Base Ventura County, CA.

15. SUBJECT TERMS
Compressed Air System Energy Reduction; Epoxy Coating; Leaky Pipes

16. SECURITY CLASSIFICATION OF: a. REPORT	b. ABSTRACT	c. THIS PAGE	17. LIMITATION OF ABSTRACT	18.NUMBER OF PAGES	19a. NAME OF RESPONSIBLE PERSON
Unclass	Unclass	Unclass	Unclass	174	Gary Anguiano
					19b. TELEPHONE NUMBER *(include area code)* (805) 982-1302

Disclaimer

This publication is intended to be informational and does not indicate endorsement of a particular product(s) or technology by the Department of Defense or NAVFAC, nor should the contents be construed as reflecting the official policy or position of any of those Agencies. Mention of specific product names, vendors or source of information, trademarks, or manufacturers is for informational purposes only and does not constitute or imply an endorsement, recommendation, or favoring by the Department of Defense or NAVFAC. Although every attempt is made to provide reliable and accurate information, the authors of this publication do not warrant or otherwise represent in any way the accuracy, adequacy, efficiency, or applicability of any product or technology discussed or mentioned herein, including the suitability of any product or technology for a particular purpose.

Acknowledgment

This work was supported by the U.S. Department of Defense Environmental Security Technology Certification Program (ESTCP) under Project Number 201517. The Naval Facilities, Engineering and Expeditionary Warfare Center (EXWC) would like to thank ESTCP-Energy and Water Program Manager Mr. Tim Tetreault, CEM, and Dr. James Galvin (former Program Manager) for their leadership during the project execution. We are also thankful for the technical and administrative support from Mr. Travis Michalke, Ms. Sarah Medepalli and Mr. Charles Purcell.

The project team would like to thank Joseph Paris from the Construction Equipment Department, Naval Base Ventura for hosting the field demonstration.

Abstract

Introduction and Objective: Leaks are common on compressed air lines in maintenance facilities and are often left unrepaired until they negatively impact downstream operations. A common response to a substantially leaky compressed air system is to provide additional compressor capacity to meet end user flow and pressure requirements, which increases energy consumption. Leaking compressed air lines represent wasted energy that should be addressed to reduce energy costs at Department of Defense (DoD) installations.

Engineers from the Naval Facilities Engineering and Expeditionary Warfare Center (NAVFAC EXWC) investigated the use of epoxy coatings to seal leaks on compressed air lines. The team focused on pipelines found in inaccessible areas such as those underground that are costly to repair with conventional techniques (requiring demolition, excavation and reconstruction). In particular, the team demonstrated the epoxy technology on two recently abandoned below grade steel pipelines (1-1/2 and 4-inch diameter) located at Naval Base Ventura County in California. The lines served three maintenance buildings, but were recently abandoned due to extensive leakage, requiring that each building operate its own respective air compressor. If corrected with the epoxy technology, the lines could be recommissioned, which would allow one air compressor to service three maintenance buildings in lieu of the three air compressors currently being used.

Specific project objectives were established to measure the epoxy coating's ability to seal leaks in-situ, to reduce energy losses, and to improve operational performance. The results of the demonstration were mixed. The larger 4-inch line was successfully coated and recommissioned while the 1-1/2-inch line proved to be too corroded for repair with epoxy and remains abandoned.

Technology Description: The technology consists of a two-part epoxy coating that is introduced into the pipeline using low pressure compressed air to uniformly coat the inner wall of the leaking pipe. It was originally developed to extend the service life of new wastewater pipelines installed on Navy ships. The following steps are used in the deployment of the technology on compressed air systems: 1) Conduct leak audit to identify large pipe breaches 2) repair large pipe breaches and remove sensitive equipment (i.e., flow meters, filters), 3) Create access points to inspect pipe condition for follow-on application of the epoxy, 4) Remove moisture with heated air and use abrasive media to remove surface rust, which creates an interior surface texture for proper coating adhesion, 5) Apply epoxy using low-pressure heated air, and 6) Allow epoxy to cure and return pipeline back to service.

Performance and Cost Assessment: Performance objectives were established to validate the epoxy coating's ability to effectively seal leaks in a timely manner. The two primary performance objectives included: 1) Static pressure tests requiring > 90% reduction in pressure loss over a baseline measurement with minimal negative side effects on line performance; and 2) Coating installation period of less than 72 hours to avoid operational disruption.

The results of the pressure variation tests were varied. The 90% reduction in air loss was not achieved on the 1-1/2-inch diameter pipe due to significant wall degradation caused by corrosion (major leaks were found) that likely worsened during the abrasive surface preparation step. The 90% reduction in air loss was achieved on the 4-inch diameter pipe (over 50 years of prior service life). Due to the extra time used to resolve the major leaks in the 1-1/2-inch pipeline, the 72 hour time limit for both pipelines was not met.

The return on investment (ROI) of the technology was evaluated for the following three scenarios:

- Scenario 1: Represents military activities that simply add more compressors to ensure adequate air supply is available to end users. Results: The ROI was calculated at 2 years. The major benefits include: 1) Annual energy savings realized by reducing the number of air compressor used; 2) Annual energy savings from reduced air leakage; and 3) Improved service life of compressors with deferred capital cost by avoiding acquisition of additional compressors.
- Scenario 2: Represents military activities that do nothing to address leaks, operate at high leakage rate, and are marginally able to provide adequate air supply to end users. Results: The ROI was calculated at 12 years. The major cost benefits are derived by: 1) Annual energy saving from reduced air leakage; and 2) Improved compressor efficiency and service life.
- Scenario 3: Represents military activities comparing the cost of installing new pipelines through traditional methods to address substantially leaking in underground compressed air pipelines. Results: The ROI for scenario 3 was calculated at 17 years. Assuming the annual energy savings and the ability to operate with one compressor as equitable, the cost benefit is derived from the difference in capital cost.

Implementation Issues: The application of the epoxy coating technology at Naval Base Ventura County provided mixed results. The full scale demonstration on two separate underground pipelines exposed the inherent risk associated with the technology, as the pipe wall thickness (maximum limit of < 40% degraded) cannot be accurately assessed with existing inspection technologies prior to applying the epoxy coating. Large breaches in the pipe wall greater than a 1/16-inch wide cannot be repaired using the epoxy coating process.

The demonstration revealed that pipe conditions can vary considerably within a length of pipe, and when significant corrosion is encountered, it may likely point to multiple and significant breaches, which result in a higher risk for epoxy failure at normal operating pressure. Technology shortfalls were also identified with pipeline camera inspection equipment, as the smallest camera head was unable to navigate through multiple pipe fittings in series, and the resultant visual inspection was unable to identify large breaches that were possibly masked by extensive corrosion. Additional research should be conducted to identify cost effective alternatives to existing camera pipeline inspection equipment.

Static pressure and pressure drop tests may be the most pragmatic approach to assessing relative pipe conditions and whether a pipeline is a good candidate for epoxy repair applications. NAVFAC EXWC recommends that the epoxy coating technology be used primarily as a preventative maintenance measure to extend the service life of aging compressed air systems that do not have significant indicators of corrosion as indicated by static pressure leak tests.

Publications: Mr. Gary Anguiano, Dr. Itzel Godinez, Mr. Mark Foreman, Mr. James Pilkington, and Mr. Andy Vasquez, 2018, Energy Reduction using Epoxy Coatings to Seal Compressed Air Lines, Military Engineer, 2019 (estimated).

EXECUTIVE SUMMARY

Introduction

From March 2016 to September 2017, the Environmental Security Technology Certification Program (ESTCP) funded the Naval Facilities Engineering and Expeditionary Warfare Center (NAVFAC EXWC) to demonstrate an in-situ pipe rehabilitation epoxy coating technology that seals pipeline distribution system leaks in compressed air systems. Air distribution pipeline leaks are common place at intermediate and depot level maintenance facilities, and if resolved can improve system operational performance and reduce lifecycle energy costs. The application of epoxy coating on compressed air distribution systems is a new use of an existing technology that was originally developed for corrosion control on carriers' copper-nickel wastewater pipelines, and can facilitate more efficient air management of Department of Defense (DoD) compressed air systems.

Leak management of compressed air systems at DoD maintenance facilities is often neglected due to mission essential operational and funding requirements taking priority. One symptom of a leaky system is continuous compressor cycling (i.e., on and off) under light or no load conditions, and degraded downstream pressure and airflow. The cost of compressed air leaks can be significant due to 1) Facilities procuring larger (or additional) air compressors to compensate for leaks, 2) Compressors having shortened service life due to extended load up time to make up for the lost air and increased maintenance cycles, and 3) Leaks degrading mission capability. Some pipeline distribution system leaks are difficult and expensive to repair, particularly those in inaccessible locations where piping runs beneath slabs, roadways, through walls, or if located in areas that first require abatement of hazardous material. It is under these circumstances that the application of the epoxy coating technology is thought to be most appropriate and cost effective.

In February 2016 NAVFAC EXWC constructed a bench scale testbed to assess the technology's ability to seal simulated pinhole, threaded fitting, and soldered fitting leaks. Favorable results from the bench scale tests prompted the decision to proceed with a full scale demonstration of the technology.

In September of 2017 NAVFAC EXWC and Nu Flow Inc. collaborated to demonstrate the epoxy coating technology on two recently abandoned underground pipelines located at the Naval Base Ventura County Construction Equipment Department (NBVC CED). The underground steel pipelines consisted of approximately 140 feet of 1-1/2 inch diameter pipe, and 420 feet of 4-inch diameter pipe. The compressed air distribution pipelines were likely installed in 1952 and are fairly representative (i.e., 60+ years) of other DoD compressed air systems. The full scale demonstration provided a low risk opportunity to evaluate the epoxy coating sealing performance under actual field conditions without significantly risking NBVC CED equipment or operations.

Objective

The project objectives were to reduce energy losses associated with the operation of compressed air systems, validate the epoxy coating's ability to seal leaks common to compressed air distribution pipelines, and increase the system service life of existing compressed air systems via a robust epoxy coating that prevents future corrosion.

Technology Descriptions

Unlike conventional pipe repair and replacement options that may require significant demolition and downtime, the epoxy coating technology can be managed to minimize the duration of operational disruption (≤ 72 hours) where the technology is to be applied. The application of the epoxy coating technology involves the following steps:

1) System analysis to identify the current leaks and confirm system layout;
2) Repair of major leaks and removal of sensitive equipment as appropriate;
3) Drying of the system with dried compressed air;
4) Rust and scale removal with an abrasive garnet sprayed through the system;
5) System cleaning by blowing dry compressed air through pipelines;
6) Distribution of epoxy using compressed air flow to form an epoxy pipe coating;
7) Curing of the epoxy with warm compressed air;
8) System testing to ensure that the system is functioning as intended.

Figure 1 illustrates steps 4), 6) and 7) of the application process. Figure 2 shows images of the pre and post epoxy coating application process at NBVC CED.

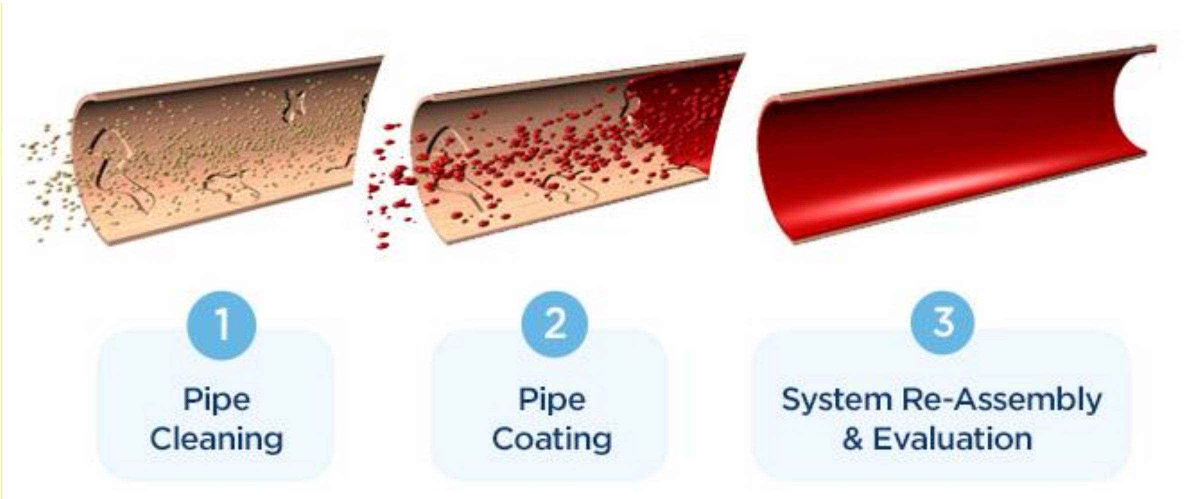


Figure 1: Depiction of the Epoxy Coating Process (Courtesy of Nu Flow)

Figure 2: Uncoated Pipe and Epoxy Coated Pipe at NBVC CED, Port Hueneme, CA

Performance Assessment

Performance objectives with specific success criteria metrics were established to determine the success of the full scale demonstration and validate the epoxy coating technology with a primary focus on sealing leaks. The two primary performance objectives were; 1) static pressure tests requiring > 90% reduction in pressure loss over a baseline measurement with minimal negative side effects (i.e., <20% reduction of internal pipe cross section area due to epoxy pooling); and 2) a coating installation efficiency of less than 72 hours to avoid operational disruption.

The demonstration performance objectives yielded the following results:

- **Coating installation efficiency: Success criteria not achieved.** The total combined duration for the epoxy coating application process from mobilization to demobilization for the 1-1/2 inch and 4 inch diameter pipes was greater than 72 hours. However, it should be noted that excessive time was taken attempting to epoxy coat the 1-1/2 inch pipeline that was later determined to have two holes greater than 1/2 inch in diameter. The performance objective would have been met had each pipe segment been independently evaluated.

- **Pressure variation (pre- and post-coating): Success criteria not achieved**. The results of the pressure variation tests were mixed. The > 90% reduction in air loss was not achieved on the 1-1/2 inch diameter pipe due to major leaks that worsened during the coating application process. The 90% reduction in air loss was achieved on the 4" diameter pipe. However, it should be noted that baseline static pressure tests on the 4" diameter pipeline showed that the pipeline was not appreciably leaking. The decision to proceed with epoxy coating of the 4" diameter pipeline was made in an attempt to further evaluate the pros and cons of the epoxy application process in a full scale application.

- **Coating thickness and uniformity: Success criteria not achieved.** The 4" diameter pipeline met the thickness and uniformity criteria. The 1-1/2 inch pipeline did not meet the thickness and uniformity criteria due to substantial corrosion in the pipe. Camera inspection of the 4” diameter pipeline showed negligible pooling within the pipe.

Cost Assessment

The team developed cost models to assess return on investment (ROI) of the technology to three alternative scenarios. NBVC CED was chosen as the economic case study because it is a fairly representative site having buried steel pipelines (over 60 years old) with leak issues similar to those found at many other DoD installations. The cost models use local utility rates, include the cost to repair a major leak, conducting underground pipeline camera inspections, and applying the epoxy coating to an underground compressed air pipeline. The models were prepared in Microsoft Excel and are generic so they can be used at other DoD activities with similar issues.

The three scenarios evaluated are:

- **Scenario 1:** Represents military activities that simply add more compressors to ensure adequate air supply is available to end users in lieu of fixing leaky compressed air system pipelines.

- **Scenario 2:** Represents military activities that do nothing to address leaky compressed air systems pipelines, operate at high leakage rate, and are just marginally able to provide adequate air supply to end users.

- **Scenario 3:** Represents military activities comparing the cost of installing new pipelines through traditional methods to address substantially leaking underground compressed air distribution pipelines thought to be beyond repair. The model uses the 2012 pipeline construction report – $200,000 per inch-mile for estimating new pipeline cost (e.g., the cost to install a mile of 1-inch diameter pipe would be $200,000).

Facility pipeline characteristics including length, diameter, layout (the number of branches), accessibility, and overall condition are all important factors that impact the technology’s ROI. For NBVC CED the cost of the epoxy application was $38,000, which was approximately $45 per foot. However, according to Nu Flow, epoxy application costs can vary dramatically at other sites ranging from $35 -$200 per foot based on the complexity and size of a given compressed air system. Hence, it is recommended that Nu flow or other epoxy contractors be contacted to provide an estimate on application cost for accuracy of the models.

The common costs for each of the three models at NBVC CED included the epoxy application expense of $38,000, conventional repair of one large pipeline breach at $5,000, the site preparation cost at $3,500 for pipe condition assessment, and an estimated compressor replacement cost of $72,000 for a 125 horsepower rotary screw air compressor.

Scenario 1: The ROI for the epoxy application at NBVC CED was calculated at 2 years. The major cost benefits of the epoxy technology were: 1) annual energy savings from operating with one air compressor instead of two; 2) the annual energy savings from reduced air leakage; and 3) deferred capital cost of buying a new compressor by operating with minimal air leaks (i.e., extended service life).

Scenario 2: The ROI for the epoxy application at NBVC CED was calculated at 12 years. The major cost benefits are derived by: 1) the annual energy saving from reduced air leakage; and 2) the tangible benefit of improved compressor efficiency and improved service life (i.e., efficient duty cycle, reduced compressor maintenance and reduced workload). Scenario 2 conservatively assumes a 5 year reduction in compressor service life (i.e., from 25 to 20 years).

Scenario 3: The ROI for scenario 3 was calculated at 17 years. This scenario represents the cost of installing a new pipeline and looks at a timeframe of 25 years which is the estimated service life of utilities. Assuming the annual energy savings and the ability to operate with one compressor as equitable, the cost benefit is derived from the difference in capital cost. When normalizing the cost of epoxy application and the cost of installing a new pipeline over 25 years, the cost avoidance would be $2,179 per year by using the epoxy coating.

Implementation Issues

The full scale demonstration at NBVC CED showed there is inherent risk associated with applying the epoxy coating on pipelines where pipe condition cannot be accurately assessed. Nu flow recommends fixing major leaks and replacing pipe sections with less than 60% wall thickness prior to applying the coating. However, ascertaining pipe wall thickness in the field proved problematic. The team discovered technology shortfalls with visual pipeline camera inspection to identify pipeline condition, as the camera head was not able to navigate through most of the pipe network due to physical constraints. Where the pipeline camera was able to navigate, two large breaches (subsequently found during the application process) were not readily seen and possibly masked by extensive tuberculation (corrosion). It was also determined that conventional wall thickness technology using ultrasonic or X-ray practices would have similar issues, and more importantly be cost prohibitive. Preliminary estimates to measure wall thickness throughout the underground compressed air pipeline at NBVC CED with ultrasonic technology was estimated at over $40,000 and would have taken longer than a week to perform.

Isolating pipe segments by closing valves and conducting static pressure and pressure drop tests may be the most pragmatic approach to assessing relative pipe conditions. A pipe segment which cannot be brought up to pressure likely has too large of a leak to be filled by epoxy. A pipeline that does come up to pressure but then drops to zero within 10 minutes (after isolation by closing valves) may also have a leak too large to be filled with epoxy. Additionally, the operations of existing pipeline valves should be inspected to assure a proper seal prior to conducting pressure tests. New leak free valves were required at NBVC CED to allow for a more accurate assessment of the pipeline condition. The 1-1/2-inch diameter pipeline was not a good candidate for a successful epoxy application, as the pipe was unable to maintain 100 psi during baseline tests and had significant pressure drop. The epoxy coating procedure was nevertheless conducted on the below grade pipeline to better understand if the soil immediately surrounding the leaking pipeline was dense enough to act as a backing in conjunction with a larger application of epoxy.

Follow-up forensic study of the 1-1/2-inch diameter line at the rupture point showed large voids in the soil (approximately 1 cubic foot) that were lined with epoxy. In addition, large vanes of epoxy were found following the path of air to the surface. The 1-1/2-inch diameter pipeline repair and accompanying forensic study showed that the pipe breaches were on the top of the pipe, the outer protective coating was damaged, and that corrosion primarily thinned out the walls where the coating was removed. Pipe wall thickness was intact outside of the corroded areas.

The epoxy application on the 4-inch diameter pipeline was successful with minimal pressure loss.

The CED demonstration results revealed that pipe conditions vary considerably, and when significant tuberculation is encountered, it may likely point to multiple and significant breaches, which result in a high risk for pressure test failure. Pipelines with minimal leakage as seen with the 4-inch diameter pipe are a lower risk.

The team recommends that the epoxy coating technology be used primarily as a preventative maintenance measure to extend the service life of existing pipelines that do not already have significant indicators of corrosion. As previously stated, static pressure and pressure drop tests may be the most pragmatic approach to assessing relative pipe conditions.

Future research efforts in below ground compressed air pipeline repair should focus on low cost methods to identify accurate air leak locations, pipe breaches, and the associated void spaces created by underground leaks where conventional repair, in-pipe restoration techniques or excavation may be required.

Lessons learned

The following lessons were learned from the demonstration:

- The added time and costs associated with identifying pipeline location, validating pipe wall integrity, static pressure tests, and fixing substantial leaks must be addressed prior to the application of the epoxy coating technology.
- Camera inspection prior to epoxy application may not adequately identify small breaches or holes within the pipe system. In addition, introducing a camera into an uncoated underground pipeline has challenges such as inability to pass through short sweep 90˚elbows, pushing the camera through multiple 90˚elbows and moving the camera in small diameter pipes. Manipulating long camera cord lengths necessary to traverse long distances also presents challenges.
- Leakage through existing compressed air system valves complicates the leak detection process. Valves should be inspected and exercised regularly, and repairs made if they do not provide a leak free seal.
- Road or pavement construction repairs conducted near existing underground compressed air pipelines should take special care not to damage existing pipelines (e.g., outer wrap or coating) or other utilities, as small ruptures can contribute to accelerated corrosion. If

contact is made with the outer wrap or coating of any existing pipeline or utility, repairs should be conducted prior to the soil compaction and re-pavement.

Table of Contents

Appendices

Figures

Tables

Abbreviations and Acronyms

bgs	below ground surface
CAS	compressed air system
CED	Construction Equipment Division
CFM	cubic feet per minute
CHT	collection, hold, and transfer
DoD	Department of Defense
DOE	Department of Energy
DON	Department of the Navy
EPCA	Energy Policy and Conservation Act
ESTCP	Environmental Security Technology Certification Program
EXWC	Engineering and Expeditionary Warfare Center
FS	Field Site
GIS	geographic information system
hp	horsepower
IPC	International Plumbing Code
IRC	International Residential Code
Kwh	Kilowatt Hour
NAS	Naval Air Station
NAVFAC	Naval Facilities Engineering Command
NBVC	Naval Base Ventura County
NEPA	Naval Environmental Policy Act
NRL	Naval Research Laboratory
Nu Flow	Nu Flow Technologies
POC	point of contact
psi	pounds per square inch
ROI	return on investment

1.0 INTRODUCTION

From March 2016 to September 2017, the U.S. Department of Defense (DoD) Environmental Security Technology Certification Program (ESTCP) funded the Naval Facilities Engineering and Expeditionary Warfare Center (NAVFAC EXWC) to demonstrate an “in-pipe” epoxy coating technology to seal leaking compressed air pipe systems. The application of an epoxy coating (also referred to as a lining) on compressed pipelines is a new use for an existing technology that was originally developed for corrosion control on ship wastewater pipelines. The demonstration was conducted at Naval Base Ventura County (NBVC), Port Hueneme California.

The demonstration goals were to reduce energy costs at industrial facilities by validating the coating’s ability to seal leaks common to compressed air pipe systems, to facilitate more efficient air management of DoD compressed air systems, and increase system service life via a robust epoxy barrier that prevents future pipeline corrosion. The technology, if determined successful, would be appropriate for many DoD compressed air systems, especially those that are leaking within inaccessible locations and thus costly to repair/replace, or pipelines leaking to the extent that they are disrupting mission operations.

In February 2016 and April 2017, NAVFAC EXWC collaborated with Nu Flow to demonstrate the epoxy coating technology on bench scale test beds constructed with simulated pipeline leaks to validate the coating’s ability to seal leaky threaded fittings, soldered joints, and various size pinhole leaks. The bench scale testing showed that the epoxy coating technology could effectively seal some of these types of leaks. Bench scale testing is discussed in Section 2.2.2, and results are provided in Appendix B.

In September of 2017, NAVFAC EXWC and Nu Flow conducted full scale field demonstration tests on a recently abandoned underground pipelines located at the Construction Equipment Division (CED) on NBVC. The underground pipelines consisted of approximately 140 feet of 1-1/2-inch diameter pipe, and 420 feet of 4-inch diameter pipe. The full scale demonstration provided a low risk opportunity to evaluate the epoxy coating sealing performance under actual field conditions without significantly risking CED equipment or operations.

The pipelines were abandoned in-place in 2016 due to excessive air leaks and their inability to provide adequate air flow to meet CED requirements at three maintenance buildings (813, 815, and 1497). NBVC Public Works Department was reluctant to invest in replacing or repairing the pipelines, as it would have required extensive excavation and cause disruption of facility operations at a high cost. The facility instead opted to procure additional compressors and to operate one at each building in lieu of repairing the pipelines. An in-situ successful application of the epoxy coating technology would allow the pipelines to be re-commissioned, thus allowing the dual air compressor in Building 1497 to supply air to Buildings 813 and 815. Building 1497 has a dual lead and lag air compressor system that can effectively supply all three buildings.

Results from the full scale demonstration show the primary performance objective for sealing leaks was not achieved on the smaller pipeline. A forensic investigation to determine the failure mechanism of the smaller pipe revealed that the pipe had large breaches beyond what the epoxy coating would be expected to seal. The details and lessons learned from the forensic study are provided in Appendix C. The epoxy coating on the larger abandoned pipe was successful, and the line is now considered operational.

1.1 BACKGROUND

The DoD has the opportunity to reduce energy costs at industrial facilities by reducing leakage from compressed air systems. Leaking systems are ubiquitous at intermediate and depot level maintenance facilities and leak management is often neglected due to mission essential operational and funding requirements taking priority. Facility managers in many cases can easily fix common aboveground leaks with conventional practices given adequate resources. However, some leaks are difficult and expensive to repair, particularly those in inaccessible locations where piping runs beneath slabs, roadways, through walls, or if located in areas that first require abatement of hazardous material. Often these leaks are left unrepaired until they have significant negative impact on downstream operations or create a safety (noise) hazard. In many instances managers simply buy additional or larger air compressors rather than dealing with the leaks loss so they can maintain adequate pressure and airflow to end users.

Statistics from the Department of Energy (DOE) and the Compressed Air Challenge (which consists of a consortium of industrial users, manufacturers, energy efficiency organizations, etc.) indicate that compressed air systems found at an average industrial facility typically have 20% to 30% air leakage if the plant manager has taken no recent actions to correct deficiencies (DOE, 2003). In addition, a survey by DOE's Office of Industrial Technologies noted that 57% of facilities have taken no action on leak management during the past two years (DOE, 2003). It is suspected that many DoD industrial facilities trend in the same manner. Maintenance facilities that have light compressed air usage or relatively long runs between connection points are expected to have higher leakage rates (i.e., as a percent of total demand) than manufacturing facilities that use air for a large number of processes on a near constant basis.

Estimates by the Compressed Air Challenge indicate that the total cost of 100 pounds per square inch (psi) of compressed air ranges between $0.18 and $0.32 per 1,000 cubic feet of air. At an average value of $0.24 per 1,000 cubic feet of air, it is estimated that annual leakage costs based on 8,500 hours of operation at 100 psi for 1/16- to 1/2-inch diameter equivalent hole-size ranges from $800 to $51,000.

Studies by the Compressed Air Challenge and leak audits conducted by EXWC at four DoD industrial activities have shown that pervasive problem areas for leaks on compressed air systems are at hose couplings (quick disconnects), valves, fittings, regulators, and pipe joints. The noise generated by the leaks can be readily heard during non-operational hours or identified during operational hours with ultrasonic leak detection tools. In many cases, facility managers can easily identify and correct these leaks with a vigilant leak management/maintenance program. However, some leaks are not readily corrected and are often ignored until they severely impair downstream operational performance. A symptom of a leaky system is continuous compressor cycling (i.e., on and off) under light or no load conditions, and degraded downstream pressure. Some of the leaks are often found in hard to access areas such as under roadways, concrete slabs, inside crawl spaces, utility vaults, inside walls, or in areas that require abatement of hazardous materials. In some cases, eliminating those difficult to reach leaks would require excessive downtime of the compressor system that could have negative impact on mission capability. The cost, the disruption of nearby operations, and the length of time to repair these leaks often results in non-action.

Leaks in compressed pipelines can lead to other negative side effects including a need for oversized compressors and corresponding ancillary equipment capacity, increased maintenance cost, and excess pressure requirement or load on supply equipment that decreases compressor service life.

The current approach for compressed air system leakage is to repair leaking components and fittings when:

1) System operations become severely impaired;
2) The compressor is continuously cycling on and off under light loads;
3) The noise from larger leaks creates a noise hazard within the workspace.

Perceived smaller leaks on threaded and mechanical fittings are usually tolerated or ignored, as mission essential work requirements take priority. Leaks from both above and below ground piping are also ignored until complaints are made about degraded performance on downstream system operation. To further complicate matters, facility managers have little incentive to repair known leaks when their shop does not directly pay electrical utility costs and the energy savings are less obvious because they have no direct impact on their budget.

Nu Flow epoxy coating system is designed for in situ pipe rehabilitation to coat the inner pipe wall and extend system life by providing a robust barrier to corrosion. The epoxy technology was originally developed and jointly patented by the Department of the Navy (DON) and Nu Flow for copper nickel pipeline found on carriers. Nu Flow has utilized epoxy for coating restoration in liquid piping systems for hospitals, laboratories, and other Navy ships. Unlike conventional pipe repair and replacement options, the epoxy pipe coating can be managed to minimize operational disruption of the infrastructure where the process is to take place. The coating process involves:

1) System analysis to identify the current leaks and confirm system layout;
2) Repair of major leaks and removal of sensitive equipment as appropriate;
3) Drying of the system with dried compressed air;
4) Rust and scale removal with an abrasive garnet sprayed through the system;
5) System cleaning by blowing dry compressed air through pipelines;
6) Distribution of epoxy using compressed air flow to form an epoxy pipe lining;
7) Curing of the epoxy with warm compressed air;
8) System testing to ensure that the system is functioning as intended.

The entire process in many cases has shown to take only a fraction of the time compared to traditional reconstruction methods. The epoxy liner system has a projected life expectancy of over 50 years.

The epoxy lining process offers the potential benefits of directly reducing energy consumption by eliminating or reducing the size of existing leaks and providing a smooth liner for protecting against pit corrosion and emergent leaks. Eliminating or otherwise reducing leaks improves service life of the air compressor by reducing on and off cycling and ensuring a more reliable air source for air-operated equipment. For leaky pipelines in inaccessible areas, the liner can extend the life of the pipe and eliminates the need for costly and timely repairs and/or replacement, usually requiring large areas to be excavated and potentially disrupting the Facility's mission. As a result, the epoxy lining process has the potential to result in a lower life-cycle energy cost and a reduced environmental footprint in contrast to conventional approaches.

1.2 OBJECTIVE OF THE DEMONSTRATION

The objective of this project is to reduce energy losses associated with compressed air systems at DOD industrial sites. Accordingly the team focused on validating the ability of the epoxy coating to seal the interior of compressed air distribution pipeline systems to eliminate/minimize leaks thereby reducing energy losses.

The primary quantitative performance objective established for the field demonstration effort was to validate how well the coating technology seals inaccessible below grade compressed air distribution lines with known leaks by performing a baseline measurement tracking pressure loss over a specified time period. This was accomplished by isolating the below ground section of pipe with new ball valves (leak free) and measuring the pressure drop before and after treatment for a given time period. Secondary objectives were to qualitatively inspect the coverage and uniformity of the internal pipe circumference and measure the system downtime necessary to mobilize, apply the coating, and demobilize from the site. The ability to seal pinhole leaks up to 1/4 inch and leaks at threaded/brazed/welded joints were quantitatively validated with the test beds prior to the proposed field test, as it was not practical to conduct field examination on an operational site without destructive testing. Performance objectives and results from bench-scale controlled testing are provided in Appendix B.

As part of this project, the team collaborated with energy professionals specializing in compressed air systems, and DoD energy/facility managers to perform leak assessment audits at several DoD sites. The goal was to better understand current compressed air system conditions and operational parameters to better evaluate the epoxy coating technology and determine how to implement the technology DoD wide.

In general, Facility managers have limited resources, manpower, time and tools to keep their air distribution system at optimum efficiency. Although not required, optimizing a compressor distribution system after years of neglect (due to limited funding and competing priorities) is thought to be best assessed by a trained energy/compressor system professional followed by a leak control program managed by a vigilant facility manager. Due to the different levels of priority for an often underfunded utility and the lack of a standard DoD guidance for leak control it was envisioned that the DoD would benefit with a simplified leak control guidance document. Accordingly, a simplified leak assessment protocol found in Appendix D was compiled for those activities without a defined leak assessment program to help them improve overall compressed air energy efficiency. In addition, the protocol would help managers identify when the epoxy technology makes sense to use. The protocol leverages CAS guidance documents, and the lessons learned from the leak assessment audits. The protocol along with lessons learned in the demonstration should provide basic information to DoD facility/energy managers to meet the intent of the executive orders described below.

1.3 REGULATORY DRIVERS

DoD Directive 4180.01, dated 16 April 2014, established DoD energy policy and guidance and assigned responsibilities for energy planning, use, and management for the DoD. The policy mandates improving the following:

1) Energy performance of weapons systems, platforms, equipment, products, and their modifications;
2) Installations, including both enduring and non-enduring locations;
3) Military forces.

Title III of the Energy Policy and Conservation Act (EPCA), 42 U.S.C. 6291, et seq., sets forth a variety of provisions designed to improve the energy efficiency of products and commercial equipment.

The energy saving activities for this demonstration are aligned with the following Executive Orders (EO):

1) EO 13514 "Federal Leadership in Environmental, Energy, and Economic Performance" recognizes and supports the need for energy conservation efforts by federal agencies. This order sets sustainability goals for federal agencies and focuses on making improvements in their environmental, energy, and economic performance. It requires federal agencies to set greenhouse gas emission reduction targets; increase energy efficiency, reduce fleet petroleum consumption; conserve water; reduce waste; support sustainable communities; and leverage federal purchasing power to promote environmentally responsible products and technologies. The Executive Order seeks to conserve and protect resources through efficiency and reuse.

2) EO 13693 (March 25, 2015 expands on EO13514) "Planning for Federal Sustainability in the Next Decade" stipulates that federal agencies must conduct their environmental, transportation, and energy-related activities in an environmentally, economically, and fiscally sound manner. To improve environmental performance and Federal sustainability, priority should first be placed on energy use. The technology used in this demonstration also supports meeting Section 3 "Sustainability Goals for Agencies" which calls to reduce building energy intensity by 2.5 percent annually through FY 2015, compared to a baseline year of FY 2015.

2.0 TECHNOLOGY DESCRIPTION

2.1 TECHNOLOGY OVERVIEW

The technology consists of the pneumatic application of a two-part epoxy lining for pipes designed to improve pipe flow and extend system life by preventing pipe corrosion. One component of the epoxy is comprised of a liquid epoxy resin, red iron oxide as a colorant, and hydrophobic fumed silica to give body and resistance to flow. The other component is a curing agent. The components are mixed and the epoxy is applied pneumatically to the interior of pipes using hot dry compressed air.

2.2 TECHNOLOGY DEVELOPMENT

2.2.1 NRL DEVELOPMENT AND COMMERCIALIZATION

The Naval Research Laboratory (NRL) and Nu Flow originally developed the chemically resistant two-part epoxy lining, known as "NRL Series 4 linings", in the 1990s to solve corrosion problems on wastewater lines aboard aircraft carriers. The technology is considered mature for use in water distribution systems and is described in detail in the document "Epoxy Linings for Shipboard Piping Systems (Brady et al., 1994). A few of the diverse water applications where the technology has been successfully demonstrated include:

- Collection, hold, and transfer (CHT) systems rehabilitation for the DON aircraft carrier fleet. The CHT system, which is the waste drain system for the vessels, is located throughout the carrier. CHT pipelines range from 4 to 6 inches in diameter and average 1,200 feet in length.
- Heating system rehabilitation at National Aeronautics and Space Administration's Goddard Space Flight Center
- Roof-drain rehabilitation at the U.S. Naval Academy Chapel and Eisenhower Executive Office Building
- Fire suppression line rehabilitation at Naval Base San Diego Fire Training Center and Army Fort Drum 10th Mountain Division aircraft hangar.

The commercially available Nu Flow 7000 Epoxy Coating System is reportedly applicable to the rehabilitation of pipes ranging from 1/2 inch to 12 inches in diameter, and for metallic pipe materials including galvanized steel, cast/black iron, copper, and lead. Unlike conventional external pipe repair or major pipe replacement options, the epoxy coating process can be implemented with minimal operational disruption of the affected infrastructure. The technology is thought to be most cost effective on pipelines that are difficult to access (e.g., behind walls, along the ceiling in high bay hangars, or underground) but is used in readily accessible pipes as well, particularly in highly corrosive mediums.

Although well documented for its ability to provide a corrosion barrier on water/wastewater lines, limited information is available on the technology maturity for application with compressed air systems. However, Nu Flow reports that the epoxy lining technology is appropriate for the pipe material found in compressed air systems. The company has successfully demonstrated the process on a compressed air system at Naval Air Station (NAS) North Island in San Diego, California, where more than 1,300 feet of 6-inch-diameter steel pipe located approximately 4 feet under a concrete runway were coated. Figure 1 depicts before and after pictures of a section of the pipe that was coated at NAS North Island.

Figure 1. Uncoated and Epoxy Coated Pipe at NAS North Island, California

The procedure to perform pipe rehabilitation using the epoxy technology consists of the following steps:

1) Performing system analysis to identify the current leaks and confirm pipe distribution layout[1];
2) Repairing any major leaks and removing sensitive equipment as appropriate[2];
3) Drying the system with dried compressed air;
4) Removing rust and scale with an abrasive garnet sprayed through the system;
5) Cleaning the distribution system to remove residual garnet and other debris by blowing dry compressed air through pipelines;
6) Applying the epoxy using compressed air flow to form the lining across the entire length of the distribution system;
7) Curing the epoxy with compressed air;
8) Testing the system to ensure that it is functioning as intended.

Air is first blown through the pipe system, from each termination point, and abrasive grit is added to remove rust and other contaminants as wells as to give the inside of the pipe a rough surface referred to as an anchor tooth. A hose attached to a termination point of the pipe leads outside to a dust collector. After the pipes are cleaned, freshly-mixed epoxy is blown through the system where it starts to harden in about 20 minutes. Two to three coats can be applied in opposite directions to ensure that pinholes and "shadow" areas where the pipe changes diameters are

[1] Pipe thickness should be measured during the inspection with appropriate equipment. Pipes with less than 60% of the original wall thickness must be replaced before epoxy lining.
[2] Mechanical (flange) joints are installed where it may be necessary to open the system in the future, as this decreases the future need to cut the pipe and damage the coating.

completely covered. A stream of hot air is maintained for a period of time to dry and cure the coating thoroughly. The application process is believed to cause minimal disruption to tenants or their activities and may be used on systems with multiple bends and varying pipe diameters. Piping may be lined without major removal or disassembly and with proper execution returned to service within 48 to 72 hours. The coating reportedly has a life expectancy of at least 50 years for application in liquid distribution systems (Brady et al., 1994).

2.2.2 BENCH-SCALE TEST BEDS

Prior to the field demonstration, NAVFAC EXWC constructed two bench-scale test beds to validate the epoxy's ability to seal typical leaks on representative pipe materials and sizes found on compressed air systems, as well as to fully understand the strengths and limitations of the technology. The test beds consisted of 10 to 13 pipeline segments each with intentionally created leak points such as pinholes, loosely threaded fittings and/or ill prepared soldered joints. The pipe segments ranged from 1/2" to 2" diameter and were either galvanized steel, black iron or copper which are typical of the compressed air pipelines found on DOD installations.

The bench-scale test beds allowed us to conduct follow-up hydrostatic tests in non-operational setting that included higher than typical air working pressures and perform destructive testing to verify adhesion, coating thickness and pooling. The results from the test beds are found in Appendix B.

In summary, the epoxy coating process showed good results for sealing leaks in soldered joints, and threaded fittings. The results for filling pinholes leaks were mixed and less than expected. For one of the test beds (February 2016), the above ground 1/16" pinhole leaks were sealed. For both test beds (February 2016 and April 2018), pinhole leaks 1/8" or greater were not fully sealed and would require a backing on the pipe exterior to insure a 100% seal. Holes with a 1/4" diameter were externally taped and the epoxy coating applied. The1/4" taped and treated holes were fully sealed and pressurized to over 125 psi with no leakage or pressure drop under hydrostatic loading.

Pooling of epoxy within horizontal pipe segments at reducer fittings was a concern for the test bed on February 2016. Pooling decreases the cross sectional area and if extensive can increase energy consumption over the system lifespan through increased pipe losses. The bench-scale tests on April 2018 were conducted to address those issues. Epoxy pooling was reduced to acceptable levels for the latter test bed with a highly controlled epoxy application procedure. However, these procedures resulted in a slight decrease in performance for sealing pinhole leaks as compared to the February 2016 test bed.

2.3 POTENTIAL FUTURE APPLICATIONS AND EXPECTED BENEFITS TO THE DEPARTMENT OF DEFENSE

DoD facilities typically contain one or more compressed air distribution systems. Many of these systems are old and nearing the end of predicted service life. The epoxy coating technology is expected to be attractive at a subset of these facilities in which special conditions exist such as compressed pipelines under active flight lines and inside mission critical building; these conditions make it technically prohibitive or not cost effective to repair or replace lines using conventional methods. These facilities would potentially benefit from the application of the epoxy coating in the form of energy savings in compressed air system operation and increased system life due to prevention of internal corrosion. In addition, a smoother pipe surface interior would benefit the distribution of compressed air in remote portions of the distribution system.

2.4 ADVANTAGES AND LIMITATIONS OF THE NU FLOW EPOXY COATING SYSTEM

The advantages of the epoxy coating technology over conventional leak repair technologies and system replacement practices include:

1) Minimal disruption to building/facility occupants during epoxy application, which could require temporary relocation of occupants and temporary shutdown of critical systems.
2) The epoxy can be applied and cured within 72 hours, which is significantly shorter than the time it would take to excavate and replace some or all of the distribution piping; this is especially important at DoD facilities where pipe repair/replacement could impact mission-critical activities.
3) Application does not require significant destruction, repair and/or replacement of walls, ceilings, roads, or any other aboveground or underground structures.
4) The non-reactive coating is not susceptible to corrosion; hence, it helps to extend the life expectancy of the pipe.
5) It can result in considerable cost savings over pipe replacement depending on site-specific factors.

The limitations of the epoxy coating technology include:

1) It is not suitable for applications on gasket connections, valves, or pressure pipes that can be flexed more than 15%.
2) It is not suitable on sections of pipe in which the original pipe wall thickness is less than 60% - they should not be coated with epoxy and should be replaced.
3) Breaking threaded mechanical connections after the coating has been applied can promote delamination of the coating. (To address this issue, NuFlow recommends installing flange connections at points where the need to open or modify the system is anticipated. If the need later arises to open the system where no flange exists, piping should be cut rather than unthreaded, and a flange or “Straub” coupler installed.)
4) Labeling is required to include a warning that an epoxy coating is present and that flame or heat should not be used when repairing any part of the piping system.
5) Installation may not be a cost effective option at sites where pipes are easily accessible.
6) Characteristics/location of mainlines and laterals (i.e., size and material) must be well defined prior to epoxy application.

7) Sealing pinhole leaks is limited to 1/16" or less.
8) Abrasive blasting required to create an anchor tooth finish for adhesion may exacerbate underground pinhole leaks caused by external corrosion. Hence, these pinhole leaks must be identified, located and properly replaced prior to the application of abrasive garnet.

A related limitation is the inability to conduct camera inspections on systems with small pipe diameters, multiple elbows, and/or long pipe runs, which all impedes assessment of pipe condition and wall thickness.

3.0 PERFORMANCE OBJECTIVES

3.1 SUMMARY OF FULL SCALE PERFORMANCE OBJECTIVES

Table 1 summarizes the full scale demonstration quantitative and qualitative performance objectives and the corresponding success criteria for assessing progress towards meeting energy reduction goals. The primary success criterion was to ensure that the static pressure requirements were met for the compressed air distribution system after epoxy application. The rehabilitated air supply lines were tested after the epoxy application to evaluate whether the process meets the anticipated performance requirements as described below.

Section 5.0 provides a detailed description of the design and testing procedures used to address the performance objectives in Table 1.

Table 1. Performance Objectives

Performance Objectives	Metric	Data Requirements	Success Goal	Results
Quantitative Performance Criteria				
Lining installation efficiency (in the field)	The amount of time the system is inoperable due to the lining process	Total time (hours) to complete the lining process	Less than 72 hours from start to finish of the lining process	Not Achieved
Pressure variation before installation and after curing	Static pressure drop over time	Pipeline pressure (psi) and time (minutes)	>90% reduction of pressure loss over the baseline[1]	Not Achieved
Return on investment (ROI)	Years	Epoxy application cost	Less than 15 years	Achieved
Qualitative Performance Objectives				
Pipe properly cleaned	Level of cleaning	Photo. Captured by camera inspection.	Pipe surface free of debris, excessive rust, and liquids. The cleaned surface must be in a shiny metal state and free of all visible oil, grease, dirt, mill scale, rust and previously applied coatings with the exceptions noted below.[2]	Not Achieved
Liner thickness, uniformity and defects	Coating appearance	As determined by camera inspection. Results from test bed	Minimal pooling of epoxy at the bottom of pipe. Reduction of pipe diameter should be less than 20% based on visual observation.[3] no signs of blisters, sags, uncoated pipe, delamination, rings, or other defects.	Not Achieved
User satisfaction	Degree of satisfaction	Rating scale ranging from very dissatisfied to very satisfied. Feedback from users, lessons learned and/or other factors affecting CAS performance.	Overall satisfied to very satisfied rating achieved from end users	Achieved

1 The proposed minimum static test pressure was 100 psi. The 1-1/2-inch line was only able to achieve 70 psi due to significant leakage.

2 Per vendor specifications, evenly dispersed, very light shadows, streaks and discolorations caused by stains of mill scale, rust and old coatings may be permitted to remain on no more than 33 percent of the surface. Slight residues of rust and old coatings are permitted to be left in the craters of pits, if the original surface is pitted.

3 Data for this performance objective are considered partially qualitative as the ability to capture thickness and cross sectional data is limited to end of pipe at the access points. Thickness measurement within the pipeline would require cutting concrete and pipeline, which is not considered practical in an operational setting. Test bed data is detailed in Appendix B and provides more representative data as multiple cross sections were examined throughout the entire pipe length.

3.2 PERFORMANCE OBJECTIVES DESCRIPTIONS

This section describes the performance objectives as listed in Table 1.

3.3 LINING INSTALLATION EFFICIENCY

- Name and Definition: Lining installation efficiency (hours).
- Purpose: The lining installation efficiency requirement was set at 72 hours to minimize disruption to facility operations (weekends) and is defined as the time necessary to mobilize equipment, execute the 8 step epoxy application process, and demobilize (including cleanup). Non-epoxy coating pipe repairs identified concurrent with the lining process are not included in the 72 hour timeline as several subsequent site visits may be necessary to implement.
- Metric: Several steps were involved in the lining process as described in Sections 1 and 2. The total time in hours to complete the lining process was recorded. This included tracking and recording the hours required to complete key steps such as mobilization, site preparation (cutting into the pipe system to install coating system), cleaning/drying, epoxy application, curing, post-lining verification/inspection, bringing the compressed air system to operational status, and demobilization.
- Data: The total amount of time required to complete the lining process was recorded, as well as the duration of the key steps that are involved as described above. Any reasons or causes of significant delays were noted.
- Analytical Methodology: The total time required for the lining process was recorded by EXWC team and compared to the expected duration.
- Success Criteria: The total project duration should be less than 72 hours from start to finish of the lining process.
- Achievement: Not Achieved. The total duration from start to finish for the 1-1/2-inch and 4-inch diameter pipes was more than 72. However, it should be noted that more time was taken to try to resolve the leakage in the 1-1/2" diameter pipeline. Realistically, this pipeline would not have been epoxy treated until major breaches were corrected. The performance objective would have been met if each pipe segment were evaluated independently.

3.4 PRESSURE VARIATION

- Name and Definition: Pressure drop variation (pre- and post-lining).
- Purpose: The pressure drop performance objective was to achieve greater than 90% reduction in pressure drop with treated pipe section with reference to the baseline pressure drop measurement. Achieving this performance objective would ensure that the lining seals the leaks or otherwise reduced leak rate to an acceptable level as shown by reduced pressure drop across the pipe segment. Improved performance would ensure adequate pressure is provided for operations downstream of the treated section and concurrently minimizing wasted energy.

- Metric: The success of the lining system was measured by comparing the pressure loss of the treated pipe section to the baseline pressure loss at a starting working pressure of 100 psi.
- Data: The data collected was the drop in pressure over time. The ability of the epoxy lining once cured to reduce pressure loss over a 30-minute test duration was compared to the pre-lined pipeline. The subject pipe sections were pressurized with compressed air until it reached working pressure and then isolated with leak free ball valves. The pressure drop was measured over 30-minute intervals. This pressure drop test was conducted at baseline (e.g., pre-lining) and post-lining. Valves, couplers, and other in-line devices were used in the test and were sufficiently air tested to eliminate them as a potential source of air leakage.
- Analytical Methodology: The pressure drop (psi) across the air supply line during the 30-minute run time was calculated from the following formula:

  $$\frac{[(P_1 - P_2) / T)]_{\text{Baseline}} - [(P_1 - P_2) / T)]_{\text{Treated}}}{[(P_1 - P_2) / T)]_{\text{Baseline}}}$$

  where:

  P_1 = Pressure at beginning of test

  P_2 = Pressure at end of test

  T = Time
- Success Criteria: The success criterion is 90% reduction in air loss. After lining, the pressure drop resulting through the pipe segment should be substantially reduced.
- Achievement: Not achieved. The results of the pressure variation tests were inconclusive. The 90% reduction in air loss was not achieved in the 1-1/2-inch diameter pipe because of the major breaches. The 90% reduction in air loss was achieved on the 4-inch diameter pipe. However, it should be noted that isolation of the abandoned pipe section with leak free valves prior to the epoxy coating demonstrated that the aged pipeline was not appreciably leaking.

3.5 PIPE PROPERLY CLEANED

- Name and Definition: Pipe cleaning (qualitative).
- Purpose: The pipe surface must be adequately cleaned for the coating to properly adhere to the pipe wall.
- Metric: Cleaning was documented via visual inspection near pipe ends by field technicians.
- Data: The visual appearance of the pipe immediately prior to epoxy application was assessed.
- Analytical Methodology: A camera inspection was used to assess the visual appearance where feasible.

- Success Criteria: To ensure a proper lining application, the pipe surface must be free of debris, excessive rust, and liquids as noted above.
- Achievement: Not Achieved. A visual camera examination could not be performed on pipe end without impeding the contractor's epoxy application process. However, positive adherence of epoxy to pipe wall on the 4-inch diameter pipe was noted after curing which suggests that proper cleaning was performed. Since the 1-1/2-inch diameter underground pipeline failed the second point of the performance objective; the pipeline also did not pass the overall objective.

3.6 LINER THICKNESS AND UNIFORMITY AND DEFECTS

- Name and Definition: Liner thickness (millimeters) and uniformity.
- Purpose: The purpose of this performance objective is to validate that the epoxy can be uniformly applied throughout the pipe length to meet minimum thickness requirements while avoiding excessive pooling of epoxy. The strength and durability of the epoxy liner coating is dependent on meeting the minimum design thickness as specified by the vendor. Minor pooling of epoxy at the bottom of the pipe is acceptable. However, excess pooling of the epoxy within the pipe can reduce the cross-sectional area of the pipe, which could negatively impact pressure and air flow if excessive. Increased pressure losses can also increase energy consumption over the system lifespan.
- Metric: The liner thickness must be equal to or greater than the minimum design value across the pipe cross section. Reduction of pipe diameter should not be greater than 20% at any point along the length of the pipe.
- Data: A camera inspection was performed at accessible parts of the pipe to qualitatively evaluate the diameter along the length of the pipe with regards to excessive pooling. In addition, the liner thickness was quantitatively measured in millimeters using a caliper on extracted pipe samples installed at each of the access points. The liner thickness was measured at the 3, 6, 9, and 12 o'clock positions at each end of the pipe sample (e.g., two locations with four readings each).
- Analytical Methodology: A simple comparison of the measured liner thickness at each location was made to ensure that the minimum design thickness is met across the pipe cross section. Thickness measurements were averaged to obtain the average (mean) liner thickness and standard deviation. The average (mean) liner thickness was then compared to the vendor's specifications.
- Success Criteria: Pooling of epoxy at the bottom of the pipe must not reduce the diameter of the pipe by more than 20% as determined by camera/visual inspection. The liner thickness measured at the ends of the pipe must be equal to or greater than 0.178 mm (0.007 inch) for all pipe sizes at all measured locations on the lined pipe sample as specified by the vendor's design specifications (see Appendix E). The coating shall be smooth and exhibit an even application with no signs of blisters, sags, uncoated pipe, delamination, rings, or other defects.
- Achievement: Not Achieved. The 4-inch pipeline met the criteria but not the 1-1/2-inch pipeline.

3.7 USER SATISFACTION

- Name and Definition: Customer satisfaction with the technology is based on 1) implementation and expediency of application, 2) impact on operations (acceptable downtime), and 3) improved efficiency of a newly lined compressed air system.
- Purpose: Customer (CED facility manager and end user) satisfaction is important to follow-on implementation. A satisfied customer is likely to endorse and recommend a new technology to other potential customers considering implementation. It is important to interview the end users to note any lessons learned and/or additional factors affecting the compressed air system performance in a positive or negative manner that cannot be anticipated ahead of the field demonstration.
- Metric: The project engineers interviewed base personnel on their overall satisfaction with the operation of the compressed air system performance after the completion of the lining process.
- Data: Ratings was collected utilizing a scale ranging from very dissatisfied to very satisfied. Qualitative data was collected on any lessons learned, adverse performance issues, or improvements identified by the end users of the compressed air supply system.
- Analytical Methodology: An interview with facility manager was conducted to assess overall user satisfaction with the rehabilitated system.
- Success Criteria: Overall satisfied to very satisfied rating achieved from end users.
- Achievement: Achieved. End user was satisfied with the end results.

3.8 RETURN ON INVESTMENT

- Name and Definition: Return on Investment (ROI). The ROI was based on the cost to procure, install, operate, and maintain a second compressor to support operations in Buildings 1497 and 813. In addition, the cost to repair and/or replace the subsurface lines was compared to the epoxy lining cost (installation cost).
- Purpose: To determine if the epoxy lining technology was cost effective.
- Metric: Number of years required to achieve net positive cash flow.
- Data: The economic payback was determined by capturing direct and indirect cost data from the vendor and from estimates of the cost to procure, install, operate, and maintain a 125-horsepower (hp) rotary screw compressor, and an estimate of the cost to repair and/or place the existing compressed air distribution system lines.
- Analytical Methodology: The ROI was determined using a 4% discount rate for the life-cycle cost calculation. A 4% interest rate is approximately the long-term Government bond rate and represents the cost of alternative uses for capital investment funds. For the purposes of evaluating this performance objective, the economic payback was considered

the time period within which the discounted future savings of a project repays the initial investment costs. The calculation of payback was based on a present worth evaluation of the annual cost savings, assuming that interest was compounded continuously. The economic payback period will equal the point at which the present worth of the annual cost savings exceeds the upfront direct and indirect cost of the lining application.

- Success Criteria: The ROI should be less than or equal to 15 years. The lifetime extension afforded by lining the pipe is estimated to be a maximum of 50 years based on the vendor estimates of the design life.
- Achievement: Achieved. See next section 7.0 for full explanation.

4.0 FACILITY/SITE DESCRIPTION

The demonstration was conducted at CED, Building 813, NBVC, Port Hueneme, California.

4.1 SITE LOCATION AND OPERATIONS

NBVC is located along the Pacific coastline in Ventura County, California, adjacent to the cities of Oxnard, Port Hueneme, and Camarillo. NBVC is composed of three primary operating facilities including Port Hueneme, Point Mugu, and San Nicolas Island. The Port Hueneme area consists of approximately 4,500 acres and is the location of the field demonstration. The facility and operations are described below.

- Demonstration Site Description: The demonstration area at CED encompasses the area bordered by Buildings 813, 814, 815, and 1497.
- Key Operations: A variety of maintenance operations are performed in Buildings 813, 815, and 1497 including overhaul and maintenance of Seabee construction equipment including cranes, bulldozers, tractors and material handling equipment. Crews routinely use compressed air to perform paint removal (sand blasting), and paint operations as well as run air powered tools used in overhaul and maintenance of equipment. Table 2 describes the air compressors and receiver tanks in each of these buildings presented above.

Table 2. Existing Compressor and Receiver Tank Specifications at CED

Compressor Specifications	Blgd. 813	Blgd. 814	Blgd. 815	Blgd. 1497
Compressor Type	Reciprocating	None	Piston	Rotary Screw
Size (Hp)	125 HP	-	10 HP	125 HP
Quantity	1	0	1	2
Flow (CFM)	100	-	50	566
Working Pressure	125 psi	125 psi	125 psi	125 psi
Receiver Tank Size (gallons)	900	2100	1300	3000

- Location and Site Map: Figure 2 shows the plan view of the demonstration site relative to the locations of the abandoned underground pipelines as they connect to buildings 813, 814, 815 and 1497. The yellow line is a 4-inch diameter steel pipeline that was marked out using radio frequency (RF) technology. The red line is a 3” diameter steel pipeline connecting building 814 and 1497 that could not be verified using the RF technology but is known to exist. The team suspects that the 3” line could be partially non-metallic or simply have a non-bonded coupler in line as it could not be detected even when a current was impressed on it. EXWC cut away sections of pipe near the receiver tank to provide camera access. A contractor was hired to inspect the line with a pipeline camera but multiple back-to-back plumbing elbows preventing camera access. The red line was later identified by drawings related to the construction of Building 1497 but its accuracy could not be reasonably validated. No archived drawings were found showing the compressed pipelines connecting buildings 813, 814 or 815 nor its associated utilities. The smaller 1-1/2-inch diameter line shown in green traverses below grade from Access Point 3 near 814 to Building 815. The receiver tank at building 814 has a placard with 1952 inscribed on it. The compressed pipelines with the exception of the red line were likely installed during that same time period, circa 1952. All lines are installed approximately 2 feet below ground surface based on the output of the RF pipe locator.

Figure 2. NBVC Port Hueneme Field Demonstration Site

4.2 FACILITY/SITE CONDITIONS

Due to its age and proximity to the Pacific Ocean, (air moisture and high ground water table) much of the CED facility is in fair condition, showing considerable signs of paint wear and external corrosion. The receiver tank located near building 814 originally installed in 1952 has external rust and is in need of fresh coat of paint as shown if Figure 3. The above ground adjoining pipeline (abandoned) has also considerable external rust but appears to be serviceable. The underground pipelines connecting buildings 813, 814 and 815 are thought to be the same age as the receiver tank and are not accessible without digging. The condition of the inside of the underground lines could not be effectively ascertained in some cases due to its construction with multiple elbows and length limitations of the cameras. Where camera inspection was possible the pipeline mostly appeared to be a relatively good shape with the exception of the 1-1/2-inch pipe from 814 to 815. This pipeline had a fair amount of tuberculation. See Figures 4 and 5.

Figure 3. CED Receiver Tank near Building 814

Figure 4. Inside view of 1-½ inch diameter pipeline prior to epoxy coating

Figure 5. Inside view of 1-½-inch diameter pipeline showing severe corrosion

Building 1497, which serves as the main corrosion control facility, was installed circa1995 with new steel pipeline installed both above and below ground. It has the two large rotary screw air compressors that on most work days could support the air demand of the entire CED facility. However, within the last 5 years the underground pipelines connected the buildings were abandoned due to excessive pressure loss later discovered to be large breaches not visible due to heavy tuberculation as shown on Figures 4 and 5. CED opted to isolate the building as valves were closed and now each has their own dedicated air compressor with the exception of 814. Currently there is no operational requirement for air in this building. The isolation valve did not make a positive seal and bypass air fills the abandoned lines at pressures exceeding 75 psi.

5.0 TEST DESIGN

This section provides a detailed description of the design and testing procedures that will be used to address the performance objectives as described in Section 4.0.

Fundamental Problem: Leaking compressed air systems are common at DoD industrial facilities and are often overlooked because of operational and funding priorities. Leaks—also referred to as artificial demand—represent lost energy as compressors need to work at higher pressures and have longer "load up" run times to provide adequate supply air to downstream operations. Leaks are costly from an energy standpoint. Many leaks are readily located and fixed but some are difficult to repair, particularly those underground or within inaccessible locations. The DoD has an opportunity to reduce energy costs at industrial facilities by applying epoxy coatings to leaking pipelines in compressed air systems located in difficult to access points.

Demonstration Questions: The key demonstration questions to be answered are:

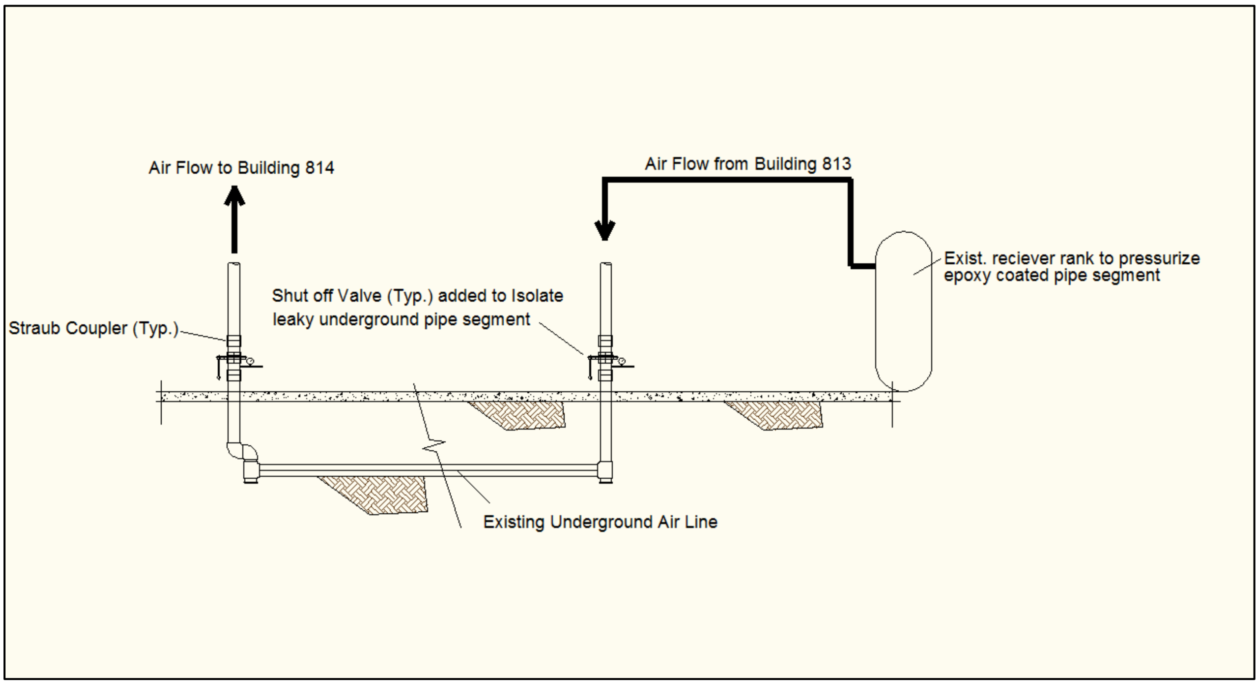
- How well does the epoxy coating technology seal leaks in inaccessible areas such as below grade compressed air pipe distribution systems?
- Does the application of epoxy negatively impact system flow or pressure? Note that excessive pooling (non-uniform epoxy coating) can adversely affect downstream pressure.
- Can the epoxy application process be performed in an expedient manner (e.g., mobilization, application, and demobilization time completed in less than 72 hours)?

5.1 CONCEPTUAL TEST DESIGN

This section provides an overview of key test variables for the field demonstration. After validating the successful performance of the epoxy coating technology during the bench-scale test beds (Appendix B), the team applied the coating technology within a representative section of NBVC CED compressed air distribution system to validate the coating's ability to meet the established technical and operational performance objectives.

- **Independent variables**: The independent variables for the field test were the initial static pressure and volumes of air that are applied to the treated and untreated pipe section. The integrity of the pipeline was evaluated on static pressure applied before and after treatment to compare pressure loss over time.
- **Dependent variables**: The dependent variable for the field test is the static pressure drop relative to a fixed timeframe. Pressure drop directly correlates to energy loss. Before and after pressure differential will be assessed.
- **Controlled variables**: The primary controlled variable is the pipeline air pressure (range of air pressure required by operations) that is applied on the treated pipeline. The fixed underground pipeline inherently is of constant pipe material, diameter and length, as well as surrounding ground temperature and moisture.

- **Hypothesis**: The hypothesis was that the epoxy coating technology can seal leaks to meet the given performance objectives (i.e., pressure drop over time) within a subsurface compressed air distribution system.
- **Test Design**: Nu Flow technicians were brought to the NBVC CED in Port Hueneme to install the epoxy lining technology. Figure 6 shows a schematic of the 4-inch compressed pipeline that was coated as part of the full-scale field demonstration. The below grade 4-inch-diameter steel pipe mainlines is 420 feet long and 1-1/2-inch-diameter steel pipe is 140 feet long. As part of the demonstration, NAVFAC EXWC performed baseline pressure drop measurements, monitored the technology installation, conducted field and laboratory testing on the lined system, and documented the results in comparison to the established performance objectives. To validate return on investment, cost data was extracted from the epoxy installation contract with Nu Flow. Resources, materials, and man-hours were tracked throughout the demonstration to validate accuracy of the cost proposed during contract negotiations and for use in the cost model in Section 7.0. Qualitative performance objectives were assessed through observations, discussion with base personnel, end user and camera inspections.



.

Figure 6. Compressed Air System Schematic for NBVC Port Hueneme

- **Test Phases**: The lining technology was field tested in the following phases:
  - **Phase Field Site (FS) 1 Baseline Data Review:** NBVC's Public Works provided geographic information system (GIS) maps, plans, and as-built drawings showing some of the pipe fittings, valves, gauges and any other essential information in targeted areas of the compressed air distribution system. Available historical records regarding pipe sizes, pipe material type, pipe condition, known air leakage issues, and repair history

were also reviewed. To the extent possible all pipe types and sizes located within the test area were verified for suitability with the vendor prior to starting the field demonstration. In addition, pre-existing data available on the compressed air distribution system equipment specifications was collected including air compressor sizing (e.g., air cubic feet per minute (CFM), maximum pressure, target operational pressure range, and energy usage (hp)). The site data was reviewed to ensure selection of an appropriate host pipe location for the field demonstration test area and collection of the needed cost data.

- **Phase FS 2 Site Preparation:** After the site location was verified, NAVFAC EXWC cut out sections of pipeline above grade to create an access for pipeline videography and subsequent application of the epoxy lining. A minimum cut out of 18 inches was required for camera insertion. EXWC installed Straub couplers at each pipe cut for reinsertion of the cut away section and to facilitate follow-on access. The selected Straub couplers were pressure rated well above the 115-psi operating range of the system. In addition, EXWC identified a major leak on an underground dead-leg pipe section. The latter was dug out and sealed with a cap.
- **Phase FS3 Lining Application:** Nu Flow conducted its lining application process in accordance with their product specifications and established field procedures (see Appendix E). The key steps in the lining process included mobilization, site preparation/cleaning, epoxy application, curing, post-lining verification/inspection, and demobilization. Nu Flow installed a sacrificial pipe section on one end point of the 1-1/2-inch pipeline so that it could be coated and evaluated. The section was 10 feet long. NAVFAC EXWC conducted camera inspections of the pipelines and documented the completeness of the cleaning process prior to the application of the epoxy coating. The team recorded the time it required for Nu Flow to accomplish each major step epoxy coating process and the total time to complete the demonstration (i.e., start to finish).
- **Phase FS 4 Lining Assessment**: After the lining application and curing were completed, NAVFAC EXWC conducted pressure field tests, captured coating thickness measurements at pipe ends, and performed camera or visual inspections to assess lining uniformity. The liner thickness at pipe ends was verified to ensure that specifications were met for the "as installed" liner.
- **Phase FS 5 Data Analysis and Reporting**: The data from the field testing was analyzed and the required reports prepared.

5.2 BASELINE CHARACTERIZATION

This section describes the baseline characterization performed to support the demonstration. The various reference conditions and cost information listed below were captured prior to validating the lining technology via field application.

- **Reference Conditions**: The following baseline data and information was collected to assess the technology's ability to meet performance objectives:
  - Unit electrical costs at installations in NBVC Port Hueneme (e.g., \$/kW-hr (kwh))

- Air compressor sizing (e.g., free flow CFM and hp) and pressure demand for compressed air system (minimum, maximum, and average). Data was collected for the compressor installed in Building 1497 as well as the compressor that would be used to supply air to Building 813 should it not be possible to adequately seal the compressed air system
- Air compressor sizing (e.g., free flow CFM and hp) and pressure demand for compressed air system (minimum, maximum, and average). Data was collected for the compressor installed in Building 1497
- Compressed air distribution system test area specifications (e.g., maps, pipe material, pipe diameter, pipe length, access points, and leakage/repair history)
- Pre-lining compressed air distribution system operations (e.g., tool usage).

- **Baseline Collection Period**: The baseline collection period was conducted over a 1 month period. See Table 3 in Section 5.4.3 for the field demonstration timeline.
- **Existing Baseline Data**: The actual cost to install the epoxy liner and estimated costs to procure, install, and operate an air compressor (125 hp) in lieu of two was used to assess cost-effectiveness and the ROI. In addition, a cost comparison was made between the epoxy lining cost and the cost to replace with new pipe construction.
- **Baseline Estimation**: The energy cost for operating the NBVC CED compressed air distribution system was compared against national averages. Local costs were used to analyze the cost-effectiveness of the technology application as it was relatively close to the national average.
- **Data Collection Equipment**: Data from the test bed was collected manually. Data was captured by visually reading instruments and documenting captured data using logbooks and log sheets. The data collection equipment used in the field included pressure gauges, an eddy current thickness tool, and in-line camera.

5.3 DESIGN AND LAYOUT OF SYSTEM COMPONENTS

The lining system components and installation process used in the demonstration are described below.

5.4 SYSTEM DESIGN

The lining system selected for this field demonstration was a two-part, mechanically mixed epoxy material. It was designed for use on metallic pipes ranging in size from 1/2 inch to 12 inches (12.7 to 305 mm) in diameter. The lining system was designed in compliance with the following codes and standards as summarized in Appendix E. Many of these design standards are for potable water applications but are listed for completeness of applications for which the Nu Flow epoxy system has been approved.

Compliance with the following codes:

- 2015, 2012 and 2009 International Plumbing Code® (IPC)
- 2015, 2012 and 2009 International Residential Code® (IRC)

Compliance with the following standards:

- LC1008-2009, Listing Criteria for Internal Epoxy Barrier Pipe Coating Material for Water Supply Systems
- IAPMO IGC 189-2008 (R2014), Internal Pipe Epoxy Barrier Coating Material for Application in Pressurized (Closed) Water Piping Systems
- ASTM D 4541-2009e1, Standard Test Method for Pull-off Strength of Coatings Using Portable Adhesion Testers
- NSF/ANSI 61-2015, Section 5, Drinking Water System Components – Health Effects
- AWWA C210-2007, Liquid-Epoxy Coating System for the Interior and Exterior of Steel Water Pipe Lines

5.5 SYSTEM DEPICTION

The lining was applied using the proprietary epoxy coating process shown Figure 4. The following key steps comprise the installation process:

1) The piping system coated was prepared by isolating it with new leak free valves. One major repair was performed upstream of the isolated section on an underground branch line that led to a battery shop. The air leak was so extensive that the air compressors would have extended duty cycles and was the primary reason the underground pipeline was abandoned. The branch line was no longer in use so the line was simply capped.
2) Each section was air dried and clean via media blasting with an abrasive garnet sprayed through the pipelines (Figure 4, Step 1). Prior to lining, it was confirmed that the pipes' cleaned surface was in a shiny metal state and free of visible oil, grease, dirt, mill scale, rust, and previously applied coatings. This step is required to ensure proper adherence of the coating. However, for this demonstration, confirmation was limited to the access points as the camera had limited reach due to pipe diameter and layout constraints.
3) The epoxy lining was applied in one end of the pipe and forced by air pressure through each section (Figure 7, Step 2). Note that the field epoxy application procedure was changed for the 1-1/2-inch pipeline, as epoxy was applied from both pipe ends to compensate for epoxy lost through a pipe breach.
4) After curing for 24 hours, each section was then pressure tested with air up to 100 psi (689.5 kPa) to verify that the pipe had no holes, cracks, or leaks.
5) The rehabilitated piping system was then re-assembled and evaluated (Figure 4, Step 3).

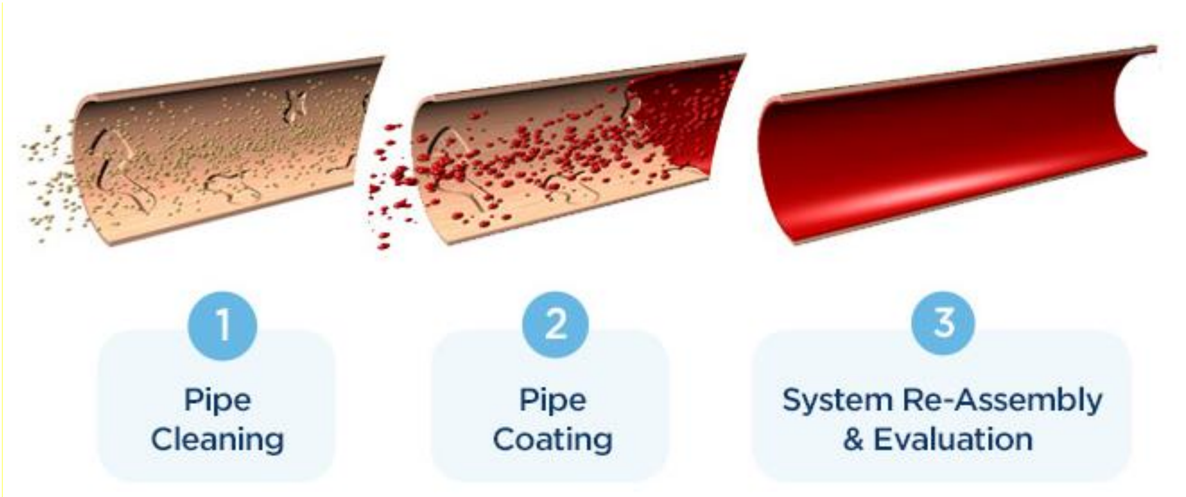


Figure 7. Depiction of the Epoxy Lining Process (Courtesy of Nu Flow)

5.6 COMPONENTS OF THE SYSTEM

The technology consisted of the pneumatic application of a two-part epoxy lining. Part A was a curing agent (68% by weight), and Part B (32% by weight) was a liquid epoxy resin with red iron oxide as a colorant, and hydrophobic fumed silica to provide body and resistance to flow. Appendix E details the Nu Flow 7000 Epoxy System lining product.

5.7 SYSTEM INTEGRATION AND CONTROLS

There were no applicable system controls.

5.8 OPERATIONAL TESTING

5.9 OPERATIONAL TESTING OF COST AND PERFORMANCE

Operational testing focused on installing the epoxy technology on the two underground pipe sections described in detail in Section 5.1, and the specific data collection parameters described in Section 5.5. Table 3 summarizes the overall activities associated with the collection of cost and performance data for the lining technology demonstration.

Table 3. Cost and Performance Information for Each Mode of Operation

Modes of Operations	Cost	Performance
Pre-Lining Assessment	Assess electrical costs for pre-existing compressed air system operations (e.g., prior to repair). Assess alternative costs to operate one compressor.	Document baseline pressure performance prior to lining.
Lining Application	Assess lining application costs per contract.	Document lining process and material properties of installed liner compared to vendor specifications.
Post-Lining Assessment	Assess electrical costs for post-lining compressed air system operations. Estimate the cost savings compared to the baseline costs above.	Document pressure performance after lining.

5.10 MODELING AND SIMULATIONS

No modeling or computer simulations were performed for the demonstration.

5.11 TIMELINE

Table 4 displays the start and end dates for operational testing activities conducted at NBVC CED. The total project duration was estimated at 15 months. The baseline data review, site preparation, and characterization took 3 months. The lining application was performed over a one week period. Performance testing assessment and forensic analysis was accomplished in three months

Table 4. Operational Testing Timeline

Project Phases	2017												2018				
	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M
Phase FS-1 Baseline Data Review				x	x	x											
Phase FS-2 Site Preparation						x	x										
Phase FS-3 Baseline Characterization							x	x									
Phase FS-4 Lining Application									x								
Phase FS-5 Lining Assessment[1]										x	x	x					
Phase FS-6 Data Analysis and Reporting											x	x	x	x	x	x	x

[1]Forensic study was performed to determine why epoxy failed to seal leak on 1-1/2-inch pipeline.

5.12 DATA COLLECTION PROTOCOL

This section focuses on data collected to assess lining performance, while the energy savings and cost information are summarized in Section 7.0. Table 5 summarizes the data collection protocol used during the field demonstration; it includes a description of the data, phase, data collector, data recording process, and the data collection frequency.

Table 5. Data Collection Protocol for the Field Demonstration

Data Description	Phase	Data Collector	Data Recording	Data Collection Frequency
Pipe materials	FS-1	EXWC	Manual	Once for the existing compressed air system.
Pipe diameters (in)	FS-1	EXWC	Manual	Once for the existing compressed air system.
Pipe lengths (ft)	FS-1	EXWC	Manual	Once for the existing compressed air system.
Minimum air pressure (psi)	FS-1	EXWC	Manual	Once for the existing compressed air system.
Maximum air pressure (psi)	FS-1	EXWC	Manual	Once for the existing compressed air system.
Average air pressure (psi)	FS-1	EXWC	Manual	Once for the existing compressed air system.
Pre-lining air pressure differential testing	FS-3	EXWC	Manual	Record pressure at time zero and at 30 minutes. Record pressure at both the inlet and outlet pressure gauges.
Pipe cleaning	FS-4	EXWC/ Nu Flow	Video	Once (View video after pipe cleaning.)
Lining installation efficiency (in field)	FS-4	EXWC	Manual	Record the time to complete each installation step and the total time of the installation.
Coating free of major defects	FS-5	EXWC	Video	Once (View video after lining.)
Post-lining air pressure differential testing	FS-5	EXWC	Manual	Record pressure at time zero at 30 minutes. Record at inlet and outlet pressure gauge.
Liner thickness at pipe ends	FS-5	EXWC	Manual	The liner thickness will be measured at the 3, 6, 9, and 12 o'clock positions at each end of the pipe ends (e.g., two locations with four readings each). Total equal to eight measurements.
Liner uniformity	FS-5	EXWC	Manual	The eight liner thickness readings noted above will be averaged to obtain the average (mean) liner thickness and standard deviation.

5.13 DATA COLLECTORS

The data collectors were members of the NAVFAC EXWC research team and Nu Flow. Table 5 summarizes who collected the data during the field demonstration. The EXWC research team was primarily responsible for documentation of the site preparation, documentation of the lining efforts, and the collection of performance and cost data. Nu Flow was responsible for documentation of the lining process following their established procedures and verifying proper site preparation, cleaning, and lining application efforts.

5.14 DATA RECORDING

Table 4 lists how data recording will occur and the planned frequency of data collection. Manual data will be recorded in a log notebook.

5.15 DATA DESCRIPTION

The data that will be collected are described in Table 4, including the applicable field phase during which it will be collected and the frequency of data collection.

5.16 DATA STORAGE AND BACKUP

NAVFAC EXWC performed systematic backups of electronic files. Logbooks were maintained, stored and secured by the NAVFAC EXWC research team during execution of the project.

5.17 DATA COLLECTION DIAGRAM

The compressed air system schematic in Figure 3 (Section 5.1) shows the location of the pressure gauges and the sample collection point for the 2, two foot long extracted pipe samples. It also shows the access points used for videography conducted after cleaning and after lining.

5.18 NON-STANDARD DATA

No unusual data collection processes were applicable for the demonstration.

5.19 SURVEY QUESTIONNAIRES

A survey was performed to gauge user satisfaction with the lining technology and subsequent compressed air distribution system performance. The survey is included in Appendix F. The questions were updated at the time of the survey based on observations and lessons learned from the field demonstration.

5.20 EQUIPMENT CALIBRATION AND DATA QUALITY ISSUES

Equipment calibration focused on insuring pressure gauges were accurate and coating thickness measurement tools were properly calibrated to measure thickness. Thickness blanks were used to calibrate thickness gauge prior to each use.

5.21 EQUIPMENT CALIBRATION

All instrumentation tools used in the field demonstration were calibrated by their respective manufacturer. The pressure gauges were checked once each day prior to performing static and/or dynamic pressure testing of the compressed air distribution system. The gauges were checked to ensure they read zero when the valve is closed and they give consistent and steady readings when the valve is opened. Two spare pressure gauges were procured and kept on site but were not needed. Micrometer and coating thickness devices was field checked with standard coupons before and after usage. Other equipment used such as the pipeline camera did not require calibration

5.22 QUALITY ASSURANCE

Quality assurance of the data collecting protocol was achieved by capturing and reviewing critical data that was manually recorded. Pipeline pressure and epoxy lining thickness are two critical manual measurements that could impact the results of the demonstration. These measurements underwent quality assurance checks as listed in Table 6.

Table 6. Quality Assurance Checks for Critical Manual Measurements

Data Collected	Frequency (No. of Readings by Primary Technician)	Second Observers Validating Collected Data (Independent Technician)	End of Day Review of Data Log (Third Team Member to Ensure Data Completeness)
Pipeline Pressure	Several readings per each 30-minute test	Yes (1 reading per test)	Yes
Lining thickness	8 measurements from the extracted pipe sample	Yes (2 readings)	Yes

6.0 PERFORMANCE ASSESSMENT

The goal of the full scale demonstration is to assess how well the epoxy coating technology seals below grade CAS distribution systems (steel pipeline) with known leaks. Secondary objectives include qualitatively inspecting the coverage and uniformity of the internal pipe circumference, and measuring the system downtime necessary to mobilize, apply the coating, and to bring the CAS back on line. The demonstration took place from 18 September 2017 through 22 September 2017 at NBVC Port Hueneme CED.

Table 7 summarizes the planned quantitative and qualitative assessment criteria for the performance objectives identified in Section 3.0. The specific assessment methodology of each performance objective and its corresponding results are discussed in the following subsections.

Table 7. Expected Performance and Performance Confirmation Methods

Performance Objective	Expected Performance	Performance Confirmation	Assessment
Lining installation efficiency	Less than 72 hours to complete installation	Complete and accurate recordkeeping	Evaluate operational downtime. Record actual time to prepare pipe, apply epoxy, cure and bring system back on line
Static pressure variation (pre- and post-epoxy lining)	>90% reduction over the baseline	Complete and accurate recordkeeping	Comparison of pre- and post-epoxy lining static pressure loss
Pipe properly cleaned	Cleaned surface must be free of all visible oil, grease, dirt, mill scale, and rust	Complete and accurate recordkeeping	Visual examination and review of video logging. (Proper cleaning and preparation validated with adhesion test conducted on pipeline from test beds)
Liner thickness, uniformity and defects	Must not reduce the pipe diameter by more than 20%. Pooled epoxy should be minimal on bottom of pipe. Smooth and even application with no signs of blisters, sags, uncoated pipe, delamination, rings, or other defects.	Complete and accurate recordkeeping	Review of video log near access points. (Liner thickness, uniformity and defects measured on test beds)
User satisfaction	Satisfied to very satisfied	Customer feedback via written questionnaire	Query users
ROI	<15 years	Complete and accurate recordkeeping	Cost comparison to baselines

6.1 LINING INSTALLATION EFFICIENCY

Installation efficiency is gauged by the amount of operational downtime that is required to apply the liner. Downtime includes the time to cut into the pipeline for access, camera inspection (accounted for separately as this would be accomplished by a third party and not performed during epoxy installation), mobilization, pipeline surface preparation, cleaning, drying, epoxy application, curing, reinstallation of pipe access segments (using Straub couplers) and demobilization. If system downtime (not including creating access) is less than or equal to 72 hours, then the performance objective is successfully met.

Table 8 provides a detailed description of the lining installation efficiencies or operational downtime as recorded by EXWC for the demonstration at CED. Actual start and end times by task were recorded in column 4. The overall cumulative downtime includes idle time between tasks and is displayed in column 6.

Table 8. Installation Efficiencies (Operational Downtime) Derived from the Demonstration

Date	Pipeline Description	Task Performed	Task Timeline	Actual Hours spent per Task	Operational Downtime (Hours)
18 September 2017	Not applicable	Mobilization- Equipment drop-off at demonstration site followed by review of safety plan and demonstration objectives	1600 – 1700	1 hour	1 hour
19 September 2017	1-1/2-inch underground pipeline between BLDG 814 and BLDG 815	Equipment set-up and site preparation for demonstration	0800 – 1020	2 hours 20 minutes	18 hours 20 minutes
		Pipe conditioning	1028 – 1057	29 minutes	18 hours 57 minutes
		Pipe blasting with abrasive garnet	1105 – 1129	24 minutes	19 hours 29 minutes
		Anchor tooth measurement at inlet (BLDG 815) and outlet (BLDG 814) of pipeline, pressure test of pipeline at 20 psi prior to coating and preparation of epoxy mixture for first coating	1130 – 1617	4 hours and 47 minutes	24 hours and 17 minutes
		Application of first epoxy coating to pipeline (coating from BLDG 815 inlet to BLDG 814 outlet)	1629 – 1800	1 hours and 31 minutes	26 hours and 0 minutes
20 September 2017	1-1/2-inch underground pipeline between BLDG 814 and BLDG 815	Equipment relocation, post-first coating pressure test, camera inspection of pipeline and preparation of epoxy mixture for second coating	0800 – 1134	3 hours and 34 minutes	43 hours and 34 min.
		Pipe conditioning and application of second epoxy coating to pipeline (coating from BLDG 814 inlet to BLDG 815 outlet)	1134 – 1310	1 hours and 36 minutes	45 hours and 10 minutes
	4-inch underground pipeline between BLDG 813 and BLDG 814	Relocating and positioning of equipment to process 4-inch underground pipeline	1400 – 1650	2 hours and 50 minutes	48 hours and 50 minutes
		Initiate pipe conditioning	1651 – 1800	1 hour and 9 minutes	50 hours and 0

Date	Pipeline Description	Task Performed	Time	Actual Hours spent per Task	Elapsed Time
21 September 2017	Not applicable	Compressor re-fueling and set-up for post-pressure test (after second and final epoxy coating) of 1-1/2-inch underground pipeline	0720 – 0840	1 hour and 20 minutes	64 hours and 40 minutes
	1-1/2-inch underground pipeline between BLDG 813 and BLDG 814	Post-pressure test (after epoxy coating) of 1-1/2-inch underground pipeline	0855 – 1005	1 hour and 10 minutes	65 hours and 5 minutes
	4-inch underground pipeline between BLDG 813 and BLDG 814	Pipe conditioning	1006 – 1035	29 minutes	65 hours and 35 minutes
		Pipe blasting with abrasive garnet	1057 – 1202	1 hour and 5 minutes	67 hours and 2 minutes
		Anchor tooth measurement at inlet (BLDG 814) and outlet (BLDG 813) of pipeline, pipe conditioning prior to coating and preparation of epoxy mixture for first coating	1301 – 1540	2 hours and 39 minutes	70 hours and 40 minutes
		Application of first epoxy coating to pipeline (coating from BLDG 814 inlet to BLDG 813 outlet)	1543 – 1630	47 minutes	71 hours and 30 minutes
22 September 2018	4-inch underground pipeline between BLDG 813 and BLDG 814	Camera inspection of pipeline through inlet and outlet, coating thickness and pipe's ID measurements and post-pressure test (after first and only epoxy coating)	0800 – 1245	4 hours and 45 minutes	92 hours and 45 minutes
		Clean up	1345 – 1530	1 hour and 45 minutes	95 hours and 30 minutes

Table 8 shows that the CAS system downtime required to epoxy coat both pipelines was 94.5 hours and the lining installation efficiency did not satisfy the 72 hours performance criteria. The problems encountered while lining the 1-1/2-inch diameter underground pipeline extended the demonstration time to more than three days.

During the first epoxy coating application to the 1-1/2-inch diameter pipeline, it was noticed that the epoxy was not reaching the pipe outlet. To verify if the latter issue was the result of the epoxy escaping through large pin-holes or pipe cracks, the pipeline was isolated and prepared for a static pressure test. The pressure test revealed that after pressurizing the pipeline to 20 psi and then cutting off the air supply with an isolation valve, the pressure within the pipeline instantly dropped to zero. The rapid pressure loss indicated that the abrasive garnet blasting process likely exacerbated the leakage problem. In an effort to verify if a second epoxy coating would seal the pipe's compromised or damaged points, a second epoxy coating was applied in the opposite direction as compared to the first coating. After allowing the second coating to cure, an additional post-lining pressure test was conducted with similar results; the 1-1/2-inch diameter pipeline could not hold any pressure once air supply was cut off.

The situation encountered with the 1-1/2-inch diameter underground pipeline suggests that prior to cleaning a pipeline by blasting it with abrasive garnet, it would be recommended to verify that the pipe wall thickness requirement holds and that there are no major breaches. Damaged sections of pipe not meeting pipe wall thickness requirements need to be replaced prior to continuing with the epoxy coating application process.

It should be noted that the 72 hour performance objective would have been met if the 4- inch diameter pipeline was treated independently from the 1-1/2-inch diameter pipeline.

6.2 PRESSURE VARIATION

Reducing leakage and corresponding pressure loss is the key feature of the lining system as it equates to reducing energy loss. Performance was assessed by comparing the pressure drop of the treated and untreated pipe segment. The underground pipe segment was pressurized with the existing air compressor and then isolated with valves. The pressure drop was measured over a time interval (e.g., 30-minutes or longer). This pressure drop test was conducted at baseline (e.g., pre-lining) and post-lining. If the pressure differential is greater than 90% reduction, then the performance objective is successfully met.

The baseline or pre-lining pressure tests for the 1-1/2-inch diameter and 4-inch diameter underground pipelines were conducted 11 – 12 September 2017. Three trials of the pre-lining pressure tests were carried out per pipeline. The post-lining pressure tests took place the day following a lining or coating application to a pipeline. Table 9 summarizes the results of the different pre and post-lining pressure tests for both underground pipelines.

Table 9. Pressure Tests Pre and Post-Lining of the 1-1/2-inch and 4-inch Underground Pipelines

		Pre-Lining					Post-Lining				
Diameter	Trial		Pressure (psi)		Time	Leakage Rate		Pressure (psi)		Time	Leakage Rate
Pipeline	No.	Date	Start	End	(min)	(psi/min)	Date	Start	End	(min)	(psi/min)
1-1/2-inch	1	9/12	110	0	11	10	9/20	40	0	0	Pipe not capable of holding pressure
	2	9/12	95	0	6	15.8					
	3	9/12	95	0	5	19					
4-inch	1	9/11	101	100	177	0.00565	9/22	40	40	158	0
	2	9/11	105	104	235	0.00426	9/25	104	104	240	0
	3	9/12	103	102	239	0.00418	9/25	104	104	240	0

Table 9 shows that the 1-1/2-inch diameter underground pipeline did not meet the pressure variance (pre- and post-lining) performance objective. As discussed in Section 6.1, the cleaning of the pipeline with abrasive garnet may have further damaged the pipe wall.

The success of the 4-inch diameter underground pipeline to hold pressure, on the other hand, should not directly qualify as successful in meeting the performance objective of the pressure variance between pre- and post-lining. The latter is due to the fact that pressure loss prior to the epoxy coating application was extremely low; the pipeline had a pre-lining pressure loss ranging from 0.00418 psi/min to 0.00565 psi/min. Once the epoxy was applied, the post-lining pressure loss was also negligible (1 psi loss after 4 days). Even though the lining resolved the minimal leakage problem in the pipeline, the leakage at the start was not sufficient to test the capability of the epoxy application process to resolve leakage problem of slight to moderate or moderate to severe concerns. In contrast, it should be noted that the abrasive blasting did not exacerbate the leakage problem as it did with the smaller pipeline.

Although the performance testing provided minimal useful data, the baseline test did highlight that the 4-inch diameter line was actually in good shape and not leaking. With this determination, EXWC was able to discover that an adjacent valve was not closing properly and was allowing air flow to pass through to a segment of pipeline that had many leaks making it difficult to accurately assess the real problem. The faulty valve and a large pipe breach near 1497 were the likely cause of abandoning the pipe segment (between buildings 813 and 1497) in the first place. Even though, the team discovered that the pipe was in good shape, it was decided it was still important to evaluate Nu Flow's full scale epoxy application process on a long length of larger diameter pipe to glean additional information and determine if the abrasive garnet step would compromise the pipe wall thickness as it had with the smaller pipeline.

6.3 PIPES PROPERLY CLEANED AND PREPARED

In order to achieve proper bonding of the epoxy lining to the pipe, it is necessary to ensure that the interior surface of the pipe is free of visible oil, grease, dirt, mill scale, rust, and that it has an adequate surface roughness finish (anchor tooth) for proper adhesion. Surface roughness is measured with a surface replica tape reader and according to instructions from NRL/MR/6120—94-7629 it should be between 2 and 3 mils throughout the pipe after blasting it with abrasive garnet. The quality of the pipe preparation is effectively demonstrated in the adhesion of the epoxy to the substrate which was demonstrated in the bench scale test beds using adhesion strength (ASTM D 4541-2009e1) and the knife delamination test.

Assessment of pipe preparation and cleanliness in the full scale field demonstration was limited to a visual examination within the pipe length, and surface roughness determination at the pipe ends (the inner pipeline assessment is not practical as it requires extensive demolition to access pipe and this action requires disrupting operations at site).

The primary assumption for this assessment is that if the same epoxy installation procedures used in the bench scale test bed are used in the field, very similar results should be observed. The assessment criteria for this objective was considered successfully met if the same test bed procedures are used and no anomalies are found:

- If the pipe ends visually appear to be in a clean state exhibiting a surface free of oil, grease, dirt, mill scale, rust and any previous coatings, then this performance objective will be achieved.
- If the interior of pipe as observed with a borescope is free of debris, then this performance objective will be achieved.
- If the pipe ends have a surface roughness between 2 to 3 mils, then the performance objectives will be achieved.

Figures 8 and 9 show pictures of the inlet and outlet ends for the 1-1/2-inch diameter and 4-inch diameter underground pipelines, respectively, post-blasting with the abrasive garnet. The pictures demonstrate that the inlet and outlet ends of the pipelines were mostly clean. In the case of the 1-1/2-inch diameter pipeline there was pipe pigmentation in some of the pictures. This may be due to the removal of heavy scale, rust and possibly corrosion from the inner wall surface. Nonetheless, the images show that the pipe's ends were clean and free of debris. Therefore, both underground pipelines exhibit good general appearance and pass point one of the present performance objective.

Figure 8. 1-1/2-inch Underground Pipeline Inlet and Outlet Ends after Abrasive Garnet

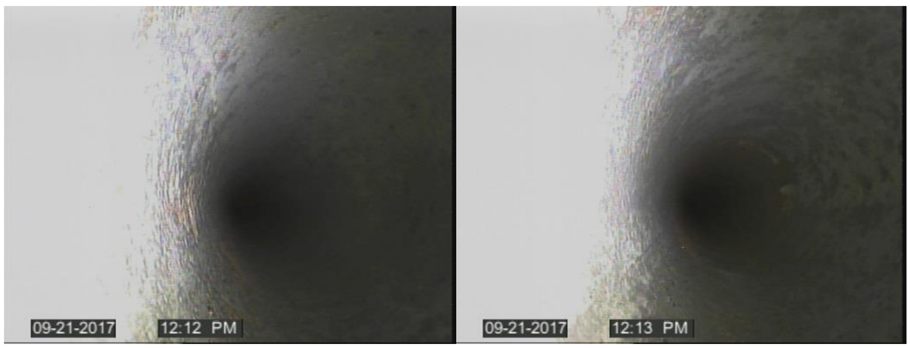


Figure 9. 4-inch Underground Pipeline Inlet and Outlet Ends after Abrasive Garnet

Figures 10 and 11 display the interior of the 1-1/2-inch diameter and 4-inch diameter underground pipelines, respectively, after the application of the abrasive garnet. The pictures of the 4-inch diameter pipeline show its interior to be extremely clean and free of debris. Hence, this pipeline passed the second point of performance criteria regarding pipe cleanliness and preparation. Conversely, the interior images of the 1-1/2-inch diameter underground pipeline depict a clean interior free of debris but with some regions of the pipe showing significant surface roughness. The latter may have the potential to compromise the epoxy coating as extreme surface roughness may interfere with the formation of a smooth and homogenous epoxy coating along the pipe. It is believed that the extreme surface roughness was the result of moderate to severe pipe corrosion resulting from pin-holes or fractures on the pipe wall allowing contact with water. The 1-1/2-inch diameter underground pipeline did not pass the second point of the present performance criteria.

Figure 10. Interior of 1-1/2-inch Underground Pipeline after Abrasive Garnet

Figure 11. Interior of 4-inch Underground Pipeline after Abrasive Garnet

Anchor tooth or surface roughness measurements at pipe ends were taken by both Nu Flow and NAVFAC EXWC. Figure 12 shows the instrument used by Nu Flow whereas Figure 13 provides images of the instrument used by NAVFAC EXWC. In theory both instruments should reflect similar values for the anchor tooth measurement derived from the same substrate. However, the anchor tooth results from the pipe ends did not indicate this was the case for both the 1-1/2-inch diameter and 4-inch diameter pipelines.

Table 10 presents the anchor tooth measurements taken at the pipe ends for the 1-1/2-inch diameter underground pipeline. Note that the anchor tooth measurements taken by the analog spring at the inlet and outlet were 3.1 and 9.9 times larger, respectively, as compared to those taken by the PosiTector. The difference in results may be attributed to human error while imprinting the anchor tooth on the surface of the pressure film. Regardless of the difference in anchor tooth measurement by instruments, both approaches show a surface roughness greater than 2 microns. The latter met the criteria established in point three of the present performance objective for the 1-1/2-inch diameter pipeline.

Figure 12. Analog Spring Micrometer

Figure 13. PosiTector RTR H by DeFelsko

Table 10. Anchor Tooth Measurements for 1-1/2-inch Diameter Underground Pipeline

		Anchor Tooth (µm)									
		Inlet (BLDG 815)					Outlet (BLDG 814)				
Group	**Instrument to Measure Anchor Tooth**	**3**	**6**	**9**	**12**	**Mean**	**3**	**6**	**9**	**12**	**Mean**
Nu Flow	**Analog Spring**	**24.5**	**24**	**23**	**25**	**24.1**	**25.5**	**25**	**25**	**23.5**	**24.8**
NAVFAC EXWC	**PosiTector RTR H (DeFelsko)**	**14.1**	**10.6**	**2.0**	**4.0**	**7.7**	**2.6**	**2.2**	**2.6**	**2.5**	**2.5**

Table 11 shows the anchor tooth measurements taken at the pipe ends for the 4-inch underground pipeline. Just as in the case for the 1-1/2-inch pipeline, the measurements taken with the analog spring for both the inlet and outlet were greater than those taken with the PosiTector. Human error can be attributed to the difference in value between recorded measurements. Nonetheless, the surface roughness measured by both instruments is greater than the recommended value presented in the NRL/MR/6120—94-7629 instruction. Hence, the 4-inch diameter pipeline also met the surface roughness criteria designated in point tree of the performance objective.

Table 11. Anchor Tooth Measurements for 4-inch Underground Pipeline

		Anchor Tooth (µm)									
		Inlet (BLDG 814)					Outlet (BLDG 813)				
Group	**Instrument to Measure Anchor Tooth**	**3**	**6**	**9**	**12**	**Mean**	**3**	**6**	**9**	**12**	**Mean**
Nu Flow	**Analog Spring**	**21.8**	**25.8**	**24**	**24.8**	**24.1**	**24**	**25**	**29**	**25.5**	**25.9**
NAVFAC EXWC	**PosiTector RTR H (DeFelsko)**	**3.6**	**4.4**	**2.9**	**4.3**	**3.8**	**3.1**	**5.5**	**6.1**	**3.2**	**4.5**

Based on the information presented above, the 4-inch underground pipeline successfully met all the criteria for the performance objective regarding cleanliness and preparation. Since the 1-1/2-inch diameter underground pipeline failed the second point of the performance objective, the pipeline also did not pass the overall objective.

6.4 LINER THICKNESS, UNIFORMITY AND DEFECTS

To minimize the reduction in cross-sectional area and ensure adequate air flow, the applied lining must be uniform, free of major defects, and not have excessive pooling. Defects and excessive pooling were assessed qualitatively through visual inspection using a borescope at the pipe access points, before and after epoxy application. Quantitative measurements were made with a caliper and coating thickness tool to assess coating uniformity at the pipe ends. Performing destructive test or using ultrasonic measurements devices to evaluate the entire pipe were not included in the scope of this effort. Since these limited points of measurements may not accurately represent the coating thickness throughout the pipe; the evaluation is considered qualitative. However, based on using the same application procedures used on the test bed pipeline, similar results for coating uniformity and thickness should be expected. Generally speaking, if the pipe ends are properly coated then similar results are expected throughout.

Assessment criteria for the field demonstration include:

- If the diameter of the pipe is not reduced by more than 20% at any location within the accessible pipe as estimated from direct measurements at pipe ends, then the coating technology assumed to have achieved the performance objective.
- If the minimum thickness of the coating as measured at the pipe ends is greater than 0.178 mm (0.007 inch) and less than 1.26 mm (0.05 inch) for all pipe sizes in the pipe ends, then the coating technology will be considered conditionally to have achieved the performance objective (with minor allowance for pooling).
- If the interior of the pipe is free of major visual defects (e.g., blisters, sags, uncoated pipe, delamination, or significant pooling of material at bottom of pipe), then the coating technology will have achieved the performance objective.

The quantitative and qualitative results presented below were collected throughout the demonstration at CED. Table 12 describes the pipe ends IDs and Table 13 presents the pipe end coating thicknesses for both the 1-1/2-inch diameter and 4-inch diameter underground pipelines respectively. Figures 14 and 15 provide camera shots inside the 1-1/2-inch diameter pipeline the day after the first and second epoxy coatings, respectively. Figure 16 presents camera shots inside the 4-inch diameter pipeline the day after its only epoxy coating application.

Table 12. IDs at Pipe Ends in Buildings 814 and 815 Pre- and Post-Epoxy Lining

Pipeline	BLDG	Before Coating (in)					After Epoxy (in)					Difference ID (in)
		A–B	B–A	C–D	D–C	Mean	A–B	B–A	C–D	D–C	Mean	
1-1/2-inch	814	1.561	1.557	1.556	1.569	1.561	1.584	1.576	1.556	1.568	1.571	-0.01
	815	1.592	1.594	1.589	1.588	1.591	1.591	1.587	1.595	1.570	1.586	0.005
4-inch	814	4.059	4.034	4.024	4.035	4.038	3.770	3.986	3.987	4.024	3.942	0.096

Table 13. Epoxy Coating Thickness at Pipe Ends in Buildings 814 and 815

Pipeline	BLDG	Coating Thickness					
		(um)					(in)
		3	6	9	12	Mean	
1-1/2-inch	814	154	204	104	243	176.3	0.00694
	815	39.7	54.7	106	32.7	58.3	0.00230
4-inch	814	148.6	167	452	422	297.4	0.0117

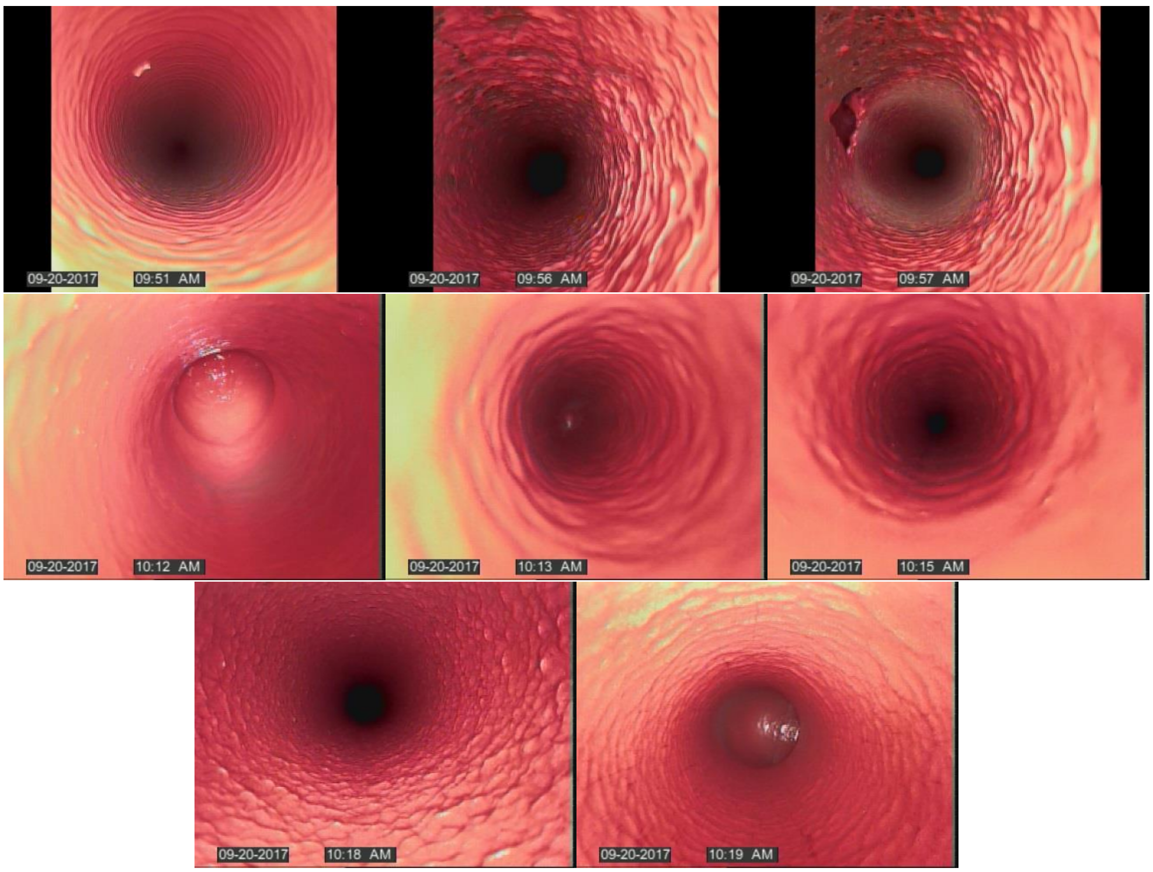


Figure 14. Inside Camera Shots of 1-1/2-inch Diameter Pipeline One Day after First Epoxy Coating

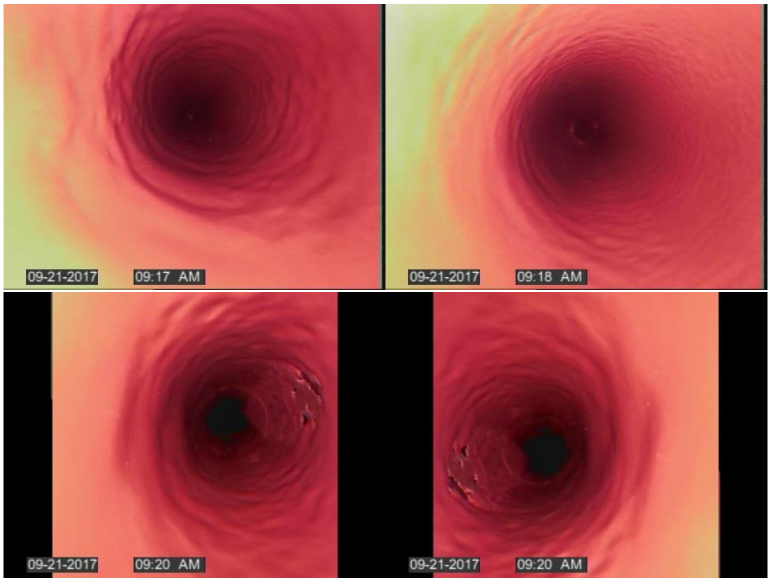


Figure 15. Inside Camera Shots of 1-1/2-inch Diameter Pipeline One Day after Second Epoxy Coating

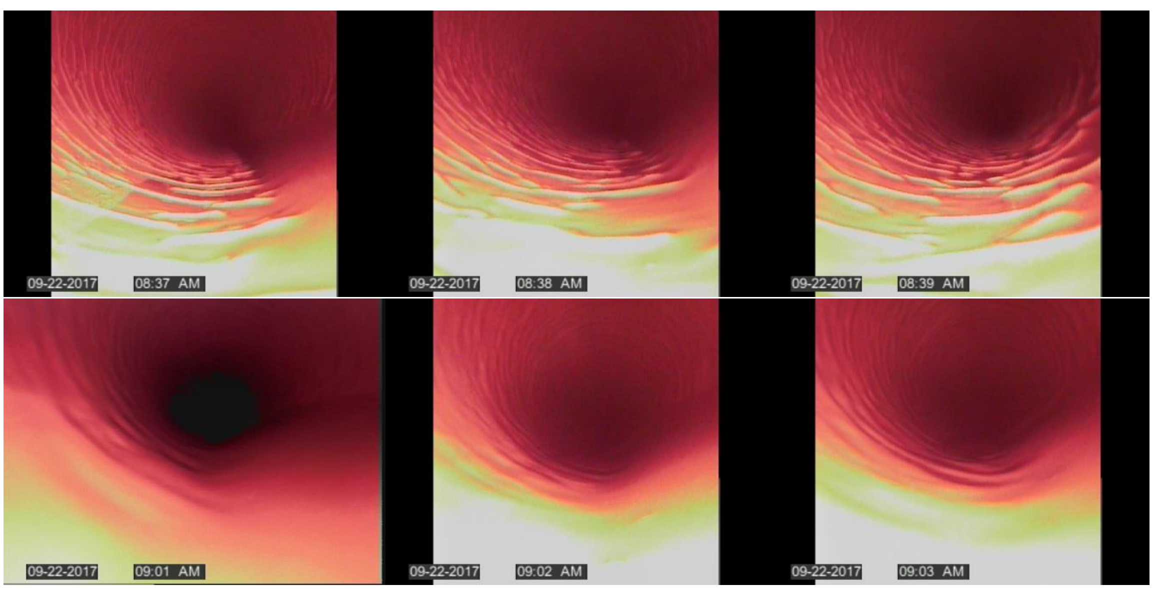


Figure 16. Inside Camera Shots of 4-inch Diameter Pipeline One Day after Epoxy Coating

The results indicate that the 1-1/2-inch diameter underground pipeline did not meet the criteria for this performance objective. After two coatings of epoxy, the images in Figure 15 still show visual defects such as delamination and blisters. The delamination and blisters are attributed to the areas of the pipeline where the abrasive garnet compromised the wall thickness resulting in the formation of large holes on the pipe. On the other hand, Table 13 shows the epoxy coating at pipe ends did not meet the requirements of having at least 0.007 in thickness. The latter point, however, can be debated because the pictures in Figure 12 seem to show that the coating thickness throughout the pipe length may indeed be greater than 0.007 in. The minimum coating thickness would not have been difficult to achieve for the 1-1/2-inch diameter pipeline since it received two coatings of epoxy. Conversely, the percent reduction of the pipe ends IDs is determined inconclusive due to not being able to quantify from the pictures if the ID of the pipeline was reduced by less than or more than 20% throughout its length. The IDs at pipe ends also show discrepancies (Table 12). The pipe end in BLDG 814 shows an increase in ID after two coatings of epoxy. This cannot be true because the epoxy coating does not enlarge the ID of a pipe.

The 4-inch diameter pipeline achieved the criteria of the performance objective. Figure 13 shows an epoxy coating free of major visual defects inside the pipeline. The results on Table 12 and Table 13 also demonstrate that the criteria for pipe ends ID and coating thickness were met.

Nonetheless, to render the epoxy coating process a success both pipelines needed to pass the criteria presented in this performance objective. Since that was not the case, the epoxy coating process did not achieve this performance objective.

6.5 USER SATISFACTION

User satisfaction is based on a number of factors including the level of disruption to facility activities during application, functionality of the system after application, and cost of the application. Assessment was qualitatively based on observations made during the lining process and feedback received from users on any additional lessons learned and/or other factors affecting compressed air system performance. Interviews were conducted using a standard questionnaire that was administered after the demonstration and are provided in Appendix F. The performance objective was considered achieved as the end user rated the epoxy application as more than satisfied.

6.6 RETURN ON INVESTMENT

Data was collected as described in Section 4.2.8 to assess the economic payback period for the liner technology. The cost effectiveness of the technology was determined based on potential capital cost savings. ROI (economic payback) was determined using a 4% discount rate for the life-cycle cost calculation. For the purposes of evaluating this performance objective, the ROI was considered the time period within which the discounted future savings of a project repays the initial investment costs. The economic payback period was equal the point at which the present worth of the annual cost savings exceeds the upfront direct and indirect cost of the lining application. The application will be considered successful if the economic payback period is less than 15 years.

The cost of the epoxy application was evaluated based on three scenarios:

- Operation of two air compressors at two buildings. The existing abandoned pipeline remains abandoned rather than being replaced or repaired.
- Operation of one compressor with use of the leaking line at two buildings (assumed 30% leak rate). No additional repairs would be made beyond any improvements resulting from this demonstration.
- Cost of replacing the existing distribution line with conventional practices and using one air compressor.

The ROI of the application of the epoxy coating was less than the 15 years cost to repair the line under the first two scenarios but not the third. The assessment is addressed in detail below.

7.0 COST ASSESSMENT

7.1 COST MODEL

The team used the cost model in Table 11 to evaluate the expected life-cycle cost benefits and economic feasibility of applying the epoxy coating on the compressed air pipelines at the NBVC CED facility. The cost model is also applicable to other DoD installations, exploring ways to reduce operation and maintenance costs by improving air compressor efficiency and saving energy using the in situ epoxy coating to restore pipeline integrity and resolve inadequate air supply issues.

Three scenarios were established to evaluate the cost feasibility of the in situ epoxy repair process:

- **Scenario 1:** Represents military activities that simply add more compressors to ensure adequate air supply to end users in lieu of fixing leaky CAS. CED opted to install separate air compressors at each maintenance building instead of repairing a line that would have allowed one compressor to service two buildings. This solution increases energy usage and maintenance requirements and increases annual operating costs.

- **Scenario 2:** Represents military activities that do nothing to address substantially leaky compressed air systems and are marginally able to maintain adequate air supply to end users. This inefficient operation scenario increases the duty cycle of the compressor, which increases maintenance costs and reduces compressor service life. At CED, for example, it was suspected that the continuous operation of an air compressor supplying air through the leaky pipe system in Building 813 led to compressor's overheating and a subsequent fire. This air compressor was less than 2 years old and was rendered a total loss.

- **Scenario 3:** Represents military activities comparing the cost of installing new pipelines through traditional methods to restoring the integrity of the existing pipelines with the epoxy coating technology. CED explored the idea of installing a new underground pipeline to allow usage of one compressor but was not able to secure approval from the Public Works Department due to competing facility requirements and high cost. The high cost is attributed to significant demolition and excavation expenses that would have been required to complete.

Scenario 1 is the primary comparison at CED while Baselines 2 and 3 are more informational. Scenario 2 highlights the cost of "doing nothing" to manage a substantially leaking pipe system. Scenario 3 highlights the cost of replacing an underground pipeline system using conventional replacement practices. For comparison, we estimated that the replacement cost for the underground pipeline at CED would be $110,000 based on the national average cost to install underground steel pipelines.

The desired outcome of the field demonstration at CED was realizing the operational, economic, and energy benefits gained if the abandoned pipe segments were adequately sealed. Sealing the pipe segments should allow the use of one compressor to satisfy air demand requirements for multiple buildings at CED. The methodology used in the cost model is general so that it can be replicated at other facilities that face similar issues.

Upon completing the demonstration, the collected data was used to validate and update the cost elements of the model, and to calculate the ROI. The primary demonstration questions to be assessed include:

- Is there a positive cost outcome for use of epoxy for leak control and energy reduction?
- Could payback be achieved in a reasonable amount of time?

Table 11. Epoxy Coating Cost Model

Cost Element	Data Tracked during the Demonstration	Value
Existing site parameter at CED NBVC Port Hueneme influencing economic viability and energy efficient design		
Electrical cost (per kwh)	Electrical billing rate taken from 2018 stabilized billing rate for NBVC	$0.17
Diameter of pipe (in.)	Measured in the field	4
Length of pipe (ft.)	Measured in the field	600
Hours of compressor operations	Estimated based on normal work year	2000
Efficiency, percent time air compressor is on	Estimated based on normal operations (2 compressors)	60
Efficiency, percent time air compressor is on	Estimated based on normal operations (1 compressors)	85
Economic Model Parameters		
Service life - conventional system (years)	Estimated at 25 years (for utilities)	25
Discount rate	As prescribed in National Institute of Standards and Technology Handbook 135	4%
Normalized time frame "X" (years)	Estimate for comparison	10
Compressor replacement frequency at 30% leak rate (years) or overhaul	Estimate based on CED[1]	20
Compressor replacement frequency at 3% leak rate (years) or overhaul	Estimate	25
Compressor replacement cost	Based on quote for 125 hp rotary screw compressor	$72,000
Epoxy application		
DPW project planning cost (Contractor hired to locate and assess condition of pipeline)	Based on actual cost to locate utilities	$3,500
Installation cost of pipe access points (two cuts per access point) and return to original configuration.	Labor hours tracked to make pipe cuts and return site to its condition prior to coating installation	$250
Cost of couplers - 2 per access point	Actual cost of coupler purchased for 4-inch diameter pipe	$480
Installation cost- mobilize equipment (includes diesel powered air compressor)	Vendor pricing for mobilization (250-mile radius). Extracted from Nu Flow cost proposal	$2,000
Installation cost to coat pipe with epoxy (lf) <4-inch diameter	Estimated at $45/ft from contract. Cost per lineal foot is variable- could range from $35 to $200 per lineal foot.	$45
Assumed leakage rate after epoxy treatment (1-3%)	Estimate based on test bed results	3%
Major Leak Repair Cost (estimate)	Estimate based on man-hours to repair large holes/ than what can be expected to seal with epoxy	$5,000
Scenario 1- Operation of two air compressors year round (status quo)		
Scenario 2- Air compressor operating at 30% leak rate		
Scenario 3- Replacing existing underground pipeline with new construction.		

7.2 DESCRIPTION OF COST ELEMENTS

7.2.1 PROJECT PLANNING

Project planning costs are often neglected in cost models as they are typically performed by general funded personnel within the Public Works Department (PWD - Planning, Environmental, and Safety Offices). For this project a nominal cost of $3,500 was included to perform specialized underground pipe locating/mapping and in-pipe camera inspection which are typically outside PWD staff capabilities but are required for informed decision making. Locating or mapping underground pipelines using ground penetrating radar and evaluating pipe conditions with internal pipeline cameras are typically performed by contractors with specialized knowledge and equipment. Prior to hiring these specialists, PWD should also budget time for their personnel to review detailed drawings, plans, and as-builts to corroborate compressed air pipe sizes, materials, layout, and compile any essential information regarding the compressed air system.

7.2.2 ELECTRICAL COST

The electrical cost associated with operating a CAS is a key parameter in determining economic feasibility of the epoxy coating technology. With compressor size, voltage, and local billings rate, energy costs can be determined. The electrical cost used in this model is the NBVC 2018 utility rate of $0.17 kwh. National electric supply rates, however, may range from $0.09 kwh to $0.32 kwh depending on geographical location.

7.2.3 EPOXY INSTALLATION COST

The epoxy coating application cost is based on the total length of pipe treated, the quantity of consumable materials required (e.g., garnet and epoxy), the number of staff needed to perform the application, and the total application time (i.e., number of days) in the field. In addition, the cost includes mobilization and demobilization of equipment and materials. Based on the total contract cost at CED, it is estimated that applying an epoxy lining on a 4-inch diameter pipe ranges from $40 to $50 per linear foot. The cost model uses $45 per linear foot.

Contractor mobilization costs including travel and shipping, which vary from site-to-site, are based on proximity to vendor facilities. These actual costs were extracted from the fixed unit cost provided in the Nu Flow contract and represent a facility within 250 miles from the vendor staging site. For other sites with varying pipelines sizes, configuration, and materials, the cost can range from $35 to over $200 per linear foot.

A preliminary site assessment by the epoxy contractor should be performed to estimate the project cost. The pipe size and length influences overall cost as long runs of large diameter pipes require more air flow (cfm) to clean the pipe surface and coat with epoxy. In general, pipes longer than 500 feet are outside the reach of Nu Flow’s equipment. Longer sections require isolation into smaller segments. The model can help explore the viability of using the epoxy over other alternatives but must be coupled with a project estimate from the epoxy contractor.

7.2.4 SITE PREPARATION COST

Site preparation costs include host facility activities to prepare the site for access. Prior to vendor mobilization, the host facility must ensure that the pipeline access areas are clean and free of debris, provide a mobilization area, and confirm that any valves or equipment used to operate the CAS are in working order. Site preparation should also include traffic control costs, if required, by the host facility. As part of site preparation, NAVFAC EXWC removed an 18" section pipe in several locations to allow for camera inspection and serve as a point to apply the epoxy coating. Couplers (Straub axial restraint couplers) were used to reconnect all access points upon work completion. For the CED demonstration, above ground pipe sections were cut which took less than 1 hour with standard pipe cutting equipment. Labor cost is estimated at $250 for pipe access and installing the couplers.

7.3 LIFE-CYCLE COSTS ESTIMATE AND TIMEFRAME

The life-cycle cost timeframe used in the model is normalized at 10 years for calculation purposes in scenario 1. Ten years is considered conservative as the epoxy coating should endure for more than 50 years.

7.4 COST DRIVERS

The cost drivers that impact the feasibility of implementing the epoxy coating technology at a given installation are site specific. The facilities pipe line characteristics including length, diameter, layout (the number of branches), accessibility, and overall condition are all important factors that weigh in on the capital cost of a project. Regions with cold temperature or high humidity regions may have a slightly higher installation cost as more time would be required to condition the pipe for optimum adhesion (i.e., heat for curing and moisture removal for adhesion). Local electrical costs factor into the lifecycle cost and impact economic viability.

7.4.1 PIPE SIZE AND LENGTH

Epoxy installation involving large pipe sizes will have substantially higher capital cost than the CED example because the amount of epoxy needed increases exponentially with pipe diameter. In general, larger diameter pipes require the use of more expensive portable air compressors and appurtenance needed to clean, dry, and heat the pipe to apply the epoxy. The length of the pipe impacts material cost as well, as long runs require larger air compressors for pipe preparation and epoxy application. Pipe segments with sub-branches (tees) will also increase installation cost, as additional hoses and connectors must be fitted to each pipe branch (with a corresponding increase in manpower needed to prepare and apply the epoxy).

7.4.2 LAYOUT

Cost to install the epoxy technology is variable depending on the many factors associated with pipe system layout. Based on discussions with Nu Flow, there is no specific methodology or equation that an end user can be given to estimate installation cost due to the wide variation in pipe layout. Nu Flow or equivalent companies require a site visit to assess pipe characteristics and local site conditions to prepare a cost estimate. From discussion, Nu Flow has had projects that when adjusted to a cost per foot basis, range from $35 per lineal foot to over $200 per lineal foot. The pipeline segments coated at CED were easy to access, and had no tee branches. The cost to apply the epoxy on the 4-inch diameter pipe segment was at the lower end of the range at $45 lineal foot.

7.4.3 PIPE CONDITION

The condition of the pipe system plays an important role in determining feasibility of the epoxy coating technology. A pipe in poor condition with a 30% leak rate has the equivalent of a 1/4" and a 1/8" diameter hole (based on air flow through an orifice) which would not likely be sealed by the epoxy. The added cost to resolve more than one or two major leaks can impact feasibility particularly on small projects. These leaks must be identified, located and repaired prior to epoxy application or as part of the application process. The cost to fully assess the conditions of a pipe other than with a pressure test can be expensive and require the system to be taken offline. The cost to make these repairs will vary from site to site. If repairs require demolition and excavation (under slabs, sidewalks, pavement) or are near other utility lines, excavation can be difficult and restoring demolished ground structure to pre-existing conditions may be cost prohibitive. Nu Flow has in-pipe spot repair techniques for 4-inch diameter pipe sizes and larger which uses an insert-able inflatable liner technology that range from $8,000 - $10,000 per repair. Underground pipelines with less than a 4-inch diameter would likely require excavation and may be cost prohibitive if static pressure test shows high leak rates.

7.4.4 ELECTRICAL COST

Electrical cost varies from $0.09 kwh to $0.32 kwh throughout the country and should be adjusted accordingly in the model based on locality. For an equivalent project, an installation in Hawaii would likely achieve a faster payback on investment than in Louisiana simply due to cost of energy; Hawaii has three times the electrical cost rate of Louisiana.

7.5 COST ANALYSES AND COMPARISON

Tables 12 through 14 summarize the three scenario models used to evaluate the economic viability of the epoxy technology. CED was chosen as the case study because it is a representative site. The site has an old steel pipeline (over 60 years old) and compressed air problems similar to many other DoD installations. Through the CED case study, the team was able to acquire actual cost data extrapolated from the epoxy installation contract, minor credit card transactions and though tracking labor hours needed to perform required tasks. The models were prepared in Microsoft Excel and can be used on similar activities to evaluate alternative solutions and help to define payback, cost avoidance, and to justify future investment in implementation of the epoxy technology or other means. Appendix G provides additional data that was used in the calculations.

Table 12 Scenario 1

Cost Element	Data Tracked during the Demonstration	Value
Existing site parameter at CED NBVC Port Hueneme influencing economic viability and energy efficient design		
Electrical cost (per kwh)	Electrical cost – NBVC 2018 stabilized billing rate	$0.17
Diameter of pipe (in.)	Measured in the field	4
Length of pipe (ft.)	Measured in the field	600
Hours of compressor operations	Estimated based on normal work year	2000
Efficiency, Percent time Air compressor is on	Estimated based on normal operations (2 compressors)	60
Efficiency, Percent time Air compressor is on	Estimated based on normal operations (1 compressors)	85
Economic Model Parameters		
Service life - conventional system (years)	Estimated at 25 years (for utilities)	25
Discount rate	As prescribed in National Institute of Standards and Technology Handbook 135	4%
Normalized time frame "X" (years)	Estimate for comparison	10
Compressor replacement frequency at 30% leak rate (years) or overhaul	Estimate based on CED[1]	20
Compressor replacement frequency at 3% leak rate (years) or overhaul	Estimate	25
Compressor replacement cost	Based on 125 hp	$72,000
Epoxy application		
DPW project planning cost (Contractor hired to locate and assess condition of pipeline)	Based on actual cost to locate utilities	$3,500
Installation cost of access points (two cuts per access point) and return to original configuration.	Labor hours tracked to make pipe cuts and return site to its condition prior to coating installation	$250
Cost of couplers - 2 per access point	Actual cost of coupler purchased for 4-inch diameter pipe	$480
Installation cost- mobilize equipment (includes diesel powered air compressor)	Vendor pricing for mobilization (250-mile radius). Extracted from Nu Flow cost proposal	$2,000
Installation cost to coat pipe with epoxy (lf) <4-inch diameter	Estimated at $45/ft from contract. Cost per lineal foot is variable- could range from $35 to $200 per lineal foot.	$45
Assumed leakage rate after epoxy treatment (1-3%)	Estimate based on test bed results	3%
Major Leak Repair Cost (estimate)	Estimate based on man-hours to repair large holes/ than what can be expected to seal with epoxy	$5,000
Scenario 1- operation of two air compressors year round (status quo)		
Air compressor horsepower- rotary screw (Building 1497)	Actual rated horsepower of compressor (used for estimating energy cost)	150
Air compressor horsepower- rotary screw (Building 813)[1]	Actual rated horsepower of compressor (used for estimating energy cost)	150
Cost of leakage at 30% (2 compressors)	Calculated for 2 air compressor	$22,798
Comparison		
Epoxy application (one time cost)	$38,230	
Epoxy application normalized over X years	$3,823	
Cost of leakage after application @ 3% loss rate (annual cost)	$582	
Cost to operate with one air compressor (at higher "on" time)	$32,326	
Total Annual Cost if pipeline is epoxy coated and CED operates with one air compressor	**$36,732**	

Scenario 1- Annual Cost-Operating two air compressors year round @ 30% leak rate	**$68,435**
Yearly cost avoidance	**$31,703**
Return on investment (years) discounted at 4%	**2.0**

Table 13 Scenario 2

Cost Element	Data Tracked during the Demonstration	Value
Existing site parameter at CED NBVC Port Hueneme influencing economic viability and energy efficient design		
Electrical cost (per kwh)	Electrical cost – NBVC 2018 stabilized billing rate	$0.17
Diameter of pipe (in.)	Measured in the field	4
Length of pipe (ft.)	Measured in the field	600
Pipe construction	Material inspected in the field	Steel
Hours of compressor operations	Estimated based on normal work year	2000
Economic Model Parameters		
Service life - conventional system (years)	Estimated at 25 years (for utilities)	25
Discount rate	As prescribed in National Institute of Standards and Technology Handbook 135	4%
Service life of epoxy (years)	Estimated provided by epoxy patent holder	50
Normalized time frame (years)	Estimate for comparison	25
Compressor replacement frequency at 30% leak rate (years) or overhaul	Estimate based on CED[1]	20
Compressor replacement frequency at 3% leak rate (years) or overhaul	Estimate	25
Compressor replacement Cost	Based on 100 hp	$50,000
Epoxy application		
DPW project planning cost (contractor hired to locate and assess condition of pipeline)	Based on actual cost to locate utilities	$3,500
Installation cost of access points (two cuts per access point) and return to original configuration.	Labor hours tracked to make pipe cuts and return site to its condition prior to coating installation	$250
Cost of couplers - 2 per access point	Actual cost of coupler purchased for 4-inch diameter pipe	$480
Installation cost- mobilize equipment (includes diesel powered air compressor used for epoxy application)	Vendor pricing for mobilization (250-mile radius). Extracted from Nu Flow cost estimate	$2,000
Installation cost to coat pipe with epoxy (lf) <4-inch diameter	Estimated at $45/ft from contract. Cost per lineal foot is variable- could range from $35 to $200 per lineal foot.	$45
Assumed leakage rate after epoxy treatment (1-3%)	Estimate based on test bed results	3%
Efficiency, Percent time Air compressor is running (improved)	Estimate	70
Major leak repair cost (estimate)	Estimate based on man-hours to repair holes larger than what can be expected with epoxy	$5,000
Scenario 2 - operation with one air compressor with 30% leak rate		
Air compressor horsepower- rotary screw (Building 1497)	Actual rated horsepower of compressor (used for estimating energy cost)	150
Cost of leakage at 30% (annual)	Calculated	$11,399
Comparison		
Epoxy application (one time cost)	$38,230	
Epoxy application normalized over 25 years	$1,529	
Cost of leakage after application @ 3% loss rate (annual cost)	$582	
Cost to operate with one air compressor (at higher "on" time)	$26,621	
Annual cost if pipeline is epoxy coated and CED operates with one air compressor	**$28,733**	

Scenario 2 - Annual cost to operate with one air compressor year round 30% leak rate (notional status quo)	**$32,326**
Yearly Cost Avoidance	**$3,593**
Return on investment (years) discounted 4%	**12**
Present worth	**$30,646.97**

Table 14. Scenario 3

Cost Element	Data Tracked during the Demonstration	Value
Existing site parameter at ED NBVC Port Hueneme influencing economic viability and energy efficient design.		
Electrical cost (per kwh)	Electrical cost – NBVC 2018 stabilized billing rate	$0.17
Diameter of pipe (in.)	Measured in the field	4
Length of pipe (ft.)	Measured in the field	600
Hours of compressor operations	Estimated based on normal work year	2000
Efficiency, percent time air compressor is running (Scenario 3 new pipe)	Estimated based on normal operations (1 compressor)	70
Efficiency, percent time Air compressor is running (epoxy coating)	Estimated based on normal operations (1 compressors)	70
Economic Model Parameters		
Service life - conventional system (years)	Estimated at 25 years (for utilities)	25
Discount rate	As prescribed in National Institute of Standards and Technology Handbook 135	4%
Service life of epoxy (years)	Estimated provided by epoxy patent holder	50
Normalized time frame (years)	Estimate for comparison	25
Compressor replacement cost	Based on 125 hp	$72,000
Epoxy application		
DPW project planning cost (contractor hired to locate and assess condition of pipeline)	Based on actual cost to locate utilities	$3,500
Installation cost of access points (two cuts per access) and return to original config.	Labor hours tracked to make pipe cuts and return site to its condition prior to coating installation	$250
Cost of couplers - 2 per access point	Actual cost of coupler purchased for 4-inch diameter pipe	$480
Installation cost- mobilize equipment (includes diesel powered air compressor used for epoxy application)	Vendor pricing for mobilization (250-mile radius). Extracted from Nu Flow cost estimate	$2,000
Installation cost to coat pipe with epoxy (lf) <4-inch diameter	Estimated at $45/ft from contract. Cost per lineal foot is variable- could range from $35 to $200 per lineal ft	$45
Assumed leakage rate after epoxy treatment (1-3%)	Estimate based on test bed results	3%
Efficiency, Percent time Air compressor is running (improved)	Estimate	70
Major leak repair cost (estimate)	Estimate based on man-hours to repair holes larger than what can be expected with epoxy	$5,000
Scenario 3 - Activity installs new underground pipeline		
2012 Ave. constr. cost - $xx per inch mile-	2012 pipeline construction report- $200,000 per inch mile	$200,000
2018 Ave. constr. cost - $xx per inch mile	2018 estimate corrected for inflation at 3%	$236,000
Cost to install	Calculation (length (mile) x diameter (in))	$107,273
Normalize over X years	Calculated (with 3% loss rate)	$4,873.33
Comparison		
Epoxy application (one time cost)	$38,230	
Epoxy application normalized over "25" years	$1,529	
Cost of leakage after application @ 3% loss rate (annual cost)	$582	

Cost to operate with one air compressor (higher efficiency)	$26,621
Total normalized cost if pipeline is epoxy coated and operate with one compressor	**$28,733**
Scenario 3 - Total normalized cost to replace existing pipeline and operate with one compressor (includes 3% leak rate)	**$31,495**
Yearly cost avoidance	**$2,762**
ROI (years) discounted 4%	**17.2**

The primary demonstration questions presented at the conclusion of Section 7.1 are assessed below according to scenario.

Scenario 1: The Nu Flow contractors successfully applied the epoxy coating to the 4-inch pipe and it can be recommissioned giving CED the ability to service two buildings with one air compressor. There was a positive outcome on the field demonstration due to the epoxy application and the repair of a major leak. The team discovered that leaks were not widespread in the underground pipelines and that malfunctioning valves and other parts of the CED pipeline network were not well understood. These factors caused the original abandonment of the pipeline. However, to follow through with the economic model the team computed the payback at 5 years based on the epoxy application expense of $38,000 and a large repair of $5,000.

Scenario 2: This Scenario evaluates activities choosing to operate with high leak rates. From an energy cost reduction standpoint alone it would take over 25 years to get payback by reducing the leak rate with epoxy. However, when considering both energy and the tangible benefit of improved compressor efficiency and service life (i.e., efficient duty cycle, reduced compressor maintenance and reduced workload), resolving leaks makes sense as payback may be achieved at 12 years. In this model, the team conservatively assumed a 5 year reduction in compressor service life (i.e., 30 to 25 years). With the high leak rate at CED, a new 100 hp air compressor was compromised in less than two years, so fixing leaks could greatly improve the payback period because of the high capital costs associated with the purchase of a new compressor.

Scenario 3: This Scenario represents the cost of installing a new pipeline to replace the abandoned pipeline and looks at a timeframe of 25 years which is the anecdotal service life of utilities. When normalizing the cost of epoxy application and the cost of installing a new pipeline over 25 years, the cost avoidance would be $2,179 per year by using the epoxy coating. The ROI was calculated at 17.2 years. It is important to note from the study that much of the existing pipelines, although in the ground for over 60 years, still held up to working test pressures and had wall thicknesses capable of several more years of service. Epoxy coating these pipes could provide substantial increase in service life.

The ROI results from scenarios 1, 2, and 3 indicate that epoxy coating may be a viable repair alternative for leaking compressed air systems. Section 8.0 further discusses the situational nature of selecting the technology for repairing compressed air system

8.0 IMPLEMENTATION ISSUES

8.1 FUTURE IMPLEMENTATION OF TECHNOLOGY AT DOD INSTALLATION

One of the facility manager's primary responsibilities at DoD industrial activities with compressed air systems is to ensure that the end users have adequate air flow and pressure to meet mission critical requirements. The facility manager has minimal incentive to interrupt operations in pursuit of reduced energy consumption through optimized air system performance objectives due to the electrical bills being paid by funding sources outside the budget of the manager's office.

However, corrective measures become a priority when end users complain of insufficient pressure or flow, loud hissing noises become a safety concern, or upon complete system failures. Corrective actions to resolve insufficient pressure or flow should begin with fixing commonplace leaks. If the latter does not solve the issues, then evaluating other repair alternatives such as partial or total system replacement, or using new techniques like the epoxy coating technology should be considered. Note that the common practice of increasing air capacity by adding air compressors is an inefficient short term fix that decreases system service life, and increases system lifecycle costs.

8.2 THE LEAK ASSESSMENT PROTOCOL

Appendix D contains a leak assessment protocol that provides guidance on how to perform a thorough review of existing compressed air systems through the use of well-defined leak management techniques. Many times compressed air systems can be returned to optimum conditions at the least possible cost.

In summary, the leak assessment protocol supports leak management goals through a five step process. Figure 1 shows the five steps of the leak assessment protocol which includes: 1) capturing flow and pressure data and determining overall site layout, 2) establishing a baseline for CAS leaks and energy usage, 3) conducting walk-through surveys, 4) implementing recommendations to resolve leaks, and 5) evaluating alternative energy conservation measures (ECMs) to resolve extensive and hard-to-reach leaks.

The full five step protocol works best if it is initially performed by a qualified specialist that is trained in compressed air and energy auditing, and the facility manager, as it does require a wide breath of knowledge in concepts such as mechanical, pneumatic, electrical, and energy, as well as familiarity with the local system. Once the initial Standard Leak Audit/Assessment is performed, the facility manager and shop personnel can continually perform walk-through surveys and make repairs to reduce energy losses while looking at alternative solutions.

The epoxy coating technology solution can be fairly expensive so it is thought best to be used to resolve leaks in the more challenging hard to reach or inaccessible pipelines. The protocol includes information for applying the epoxy coating technology based on site-specific factors, highlighting appurtenances including valves, gauges, filters etc., and other key pipe components that must be removed prior to epoxy applications.

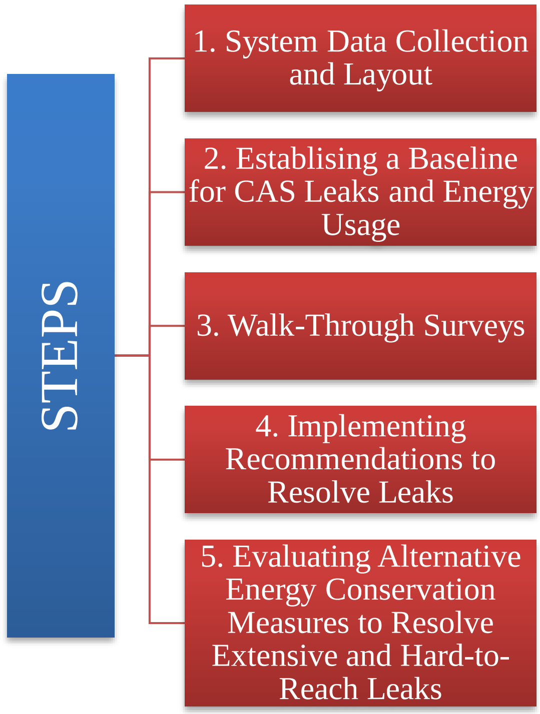


Figure 17. Leak Assessment Protocol Steps

The economic cost model found in Appendix G is a companion to the leak assessment protocol and it was prepared to help managers estimate payback periods and project economic benefits when considering the epoxy coating technology as a solution to resolve leaks in CAS.

The epoxy coating technology solution can be fairly expensive so it is thought best to be used to resolve leaks in the more challenging hard to reach or inaccessible pipelines. The protocol includes information for applying the epoxy coating technology based on site-specific factors, highlighting appurtenances including valves, gauges, filters etc., and other key pipe components that must be removed prior to epoxy applications.

8.3 END USER CONCERNS-CONDITION OF PIPE

One of the contractor's requirements for applying the epoxy coatings on any metal pipe is that the wall thickness be at least 60% intact. If the pipe's wall is not at least 60% of the original thickness, the abrasive blasting cleaning process can further deteriorate wall thickness and result in epoxy coated pipe sections with deficient wall thickness that may crack or rupture once the pipeline is pressurized. Below discusses some of the alternatives and challenges associated with condition assessment.

Camera inspection is a fairly inexpensive technique which can provide real-time images of pipe conditions. The fairly inexpensive statement holds true as long as the user has access to the proper camera. One of the limitations of camera inspection is that the camera is standard which only allows for large breaches to be properly identified; small pipe cracks, pin-holes or thinned-out wall thicknesses are difficult if not impossible to point out. Another limitation is that inline cameras cannot navigate in small diameter pipelines or in pipe sections with multiple elbows or other mechanical joint fittings

Conversely, ultrasonic pipe diagnostics uses an internal ultrasonic manipulator incorporating ultrasonic probes coupled with hi-resolution camera that allow for full pipe scans and wall thickness measurements. This technology, however, can be quite expensive. One company with the skills and equipment necessary to assess the below grade steel pipelines at CED was contacted to provide a quote for service. The quote stipulated a $10,000 per day to mobilize equipment within 200 miles of company's office, and a $14,000 per day equipment operation. The process is time consuming and it can only analyze 1 foot of pipe per hour. Hence, using this technology to assess the pipe conditions at CED would have been simply impossible because it would have taken multiple days and cost almost twice the amount of the epoxy coating application. On a different note, the ultrasonic pipe diagnostics technology is also subject to the same challenges as camera inspection, that is, inline cameras cannot navigate in small diameter pipelines or in pipe sections with multiple elbows or other mechanical joint fittings.

Pressure drop tests conducted prior to the epoxy coating process may provide an additional, cost effective alternative measure to assess pipe condition in lieu of the ultrasonic inspection technology. Bench scale tests showed that pipelines with 1/16 diameter holes were able to be sealed and hold pressure with the epoxy coating process without additional pipe repair. Pipelines with larger diameter holes were unable to be sealed by the epoxy coating process. Bench scale pressure tests also showed that pipelines with 1/16 diameter holes momentarily held pressure upon shutdown of the supply air, while the pressure instantaneously dropped to zero psi in the pipelines with larger diameter holes. The pressure test conducted on the 1-1/2-inch pipeline at CED had a rated pressure of 110 psi, but only held 70 psi and failed after 7 minutes dropping to zero psi. The limited data set from the bench scale tests (along with the 1-1/2-inch pipeline data at CED) indicate that additional investigation is required, but it is reasonable to assume that greater than 75 percent of the rated working pressure must be maintained in below grade pipelines to increase the probability that the pipe wall thickness is at least 60% intact.

Follow-up forensic study of the 1-1/2-inch diameter line at the rupture point showed large voids in the soil (approximately 1 cubic foot) that were lined with epoxy. In addition, large vanes of epoxy were found following the path of air to the surface. The 1-1/2-inch diameter pipeline repair and accompanying forensic study showed that the pipe breaches were on the top of the pipe, the outer protective coating was damaged, and that corrosion primarily thinned out the walls where the coating was removed. Pipe wall thickness was intact outside of the corroded areas.

The epoxy application on the 4-inch diameter pipeline was successful with minimal pressure loss.

The CED demonstration results revealed that pipe conditions vary considerably, and when significant tuberculation is encountered, it may likely point to multiple and significant breaches, which result in a high risk for pressure test failure. Pipelines with minimal leakage as seen with the 4-inch diameter pipe are a lower risk.

The team recommends that the epoxy coating technology be used primarily as a preventative maintenance measure to extend the service life of existing pipelines that do not already have significant indicators of corrosion. As previously stated, static pressure and pressure drop tests may be the most pragmatic approach to assessing relative pipe conditions.

Future research efforts in below ground compressed air pipeline repair should focus on low cost methods to identify accurate air leak locations, pipe breaches, and the associated void spaces created by underground leaks where conventional repair, in-pipe restoration techniques or excavation may be required.

8.4 Lessons Learned

There is inherent risk with applying the epoxy coating to pipelines where the pipe wall thickness cannot be adequately accessed at a reasonable cost. The present epoxy coating procedures recommend replacing pipe sections with less than 60% wall thickness prior to applying the coating. However, as the CED demonstration results revealed, there are likely numerous cases where finding one section of insufficient pipe wall thickness in a below grade pipeline may indicates the existence of other such sections.

Lesson learned from the demonstration include:

- Fully understanding the conditions of a pipeline can be problematic as introducing a camera into an unlined underground pipeline has challenges such as inability to pass through short sweep 90˚elbows, pushing the camera through multiple 90˚elbows and moving the camera in small diameter pipes. Handling of the camera cord length also presents a challenge. In addition, camera inspection prior to epoxy application may not be adequate for identifying existing breaches or holes that may be covered by corrosion.
- The added time and costs associated with identifying the exact location of pipelines, validating pipe wall integrity via camera inspection and fixing substantial leaks must be addressed prior to the application of the epoxy coating technology.
- Leakage through existing valves is problematic as it makes it difficult to assess where leakage is occurring. Valves should be exercised regularly and repairs made if they do not provide a leak free seal.
- Voids created by air leaks in underground pipelines can be substantial and could lead to failure of above ground pavements or structures if not properly addressed. They should be addressed as early as possible to minimize impact.
- NuFlow offers a cured-in-place pipe (CIPP) restoration process to repair pipelines with identifiable cracks or holes in an efficient alternative in contrast to traditional pipe repair and replace practices. CIPP does not require excavation in the case of underground pipelines but it does have a limitation in terms of the pipe diameter for which it can be used.

- Road or pavement construction conducted near existing underground compressed air pipelines should take special care not to damage pipelines (e.g., outer wrap or coating) as small ruptures can contribute to accelerate corrosion. If contact is made with the outer wrap or coating of a pipeline, it should be repaired prior to the soil compaction and re-pavement.
- Future research efforts in below ground compressed air pipeline repair should focus on low cost methods to identify accurate air leak locations, pipe breaches, and the associated void spaces created by underground leaks where conventional repair, in-pipe restoration techniques or excavation may be required.

9.0 REFERNENCES

Brady, R. F. Jr. and Adkins, J.D. 1994. *Epoxy Linings for Shipboard Piping Systems*. NRL Memorandum Report 6120--94-7629, September 30.

Department of Energy (DOE). 2003. Improving Compressed Air System Performance, A Sourcebook for Industry. Third edition

Moncef Krarti, XXXX Chapter 16 Energy Audits for Buildings, , University of Colorado

Mike C.J., Lin Taha, and Yezin E. Taha, Applications, Guide for Compressed Air Systems, US Army Corps of Engineers, Engineer Research and Development Center

Compressed Air Challenge, Compressed Air Systems Fact Sheet # 7, Compressed Air System Leaks,

Department of Defense, Unified Facilities Criteria (UFC), Compressed Air

Energy Management Association of New Zealand, Compressed Air Systems (CAS) Audit Standard, A Standard for the Auditing of the Energy Efficiency of Electric Motor-Powered Compressed Air Systems,

Comprehensive Compressed Air Audits: The 5-Step Process, WEBSITE

US Department of Energy, Energy Efficiency &Renewable Energy, Improving Compressed Air System Performance: A Sourcebook for Industry,

Appendix A: Points of Contact

POINT OF CONTACT Name	ORGANIZATION Name Address	Phone Fax E-mail	Role in Project
Gary Anguiano	Naval Facilities Engineering Service Center 1100 23rd Ave. Port Hueneme, CA	(805) 982-1302 (805) 982-4832 Fax Gary.anguiano@navy.mil	Principal Investigator
Itzel Godinez	Naval Facilities Engineering Service Center 1100 23rd Ave. Port Hueneme, CA	(805) 982-5864 (805) 982-4832 Fax Itzel.godinez@navy.mil	Co-Principal Investigator
Mark Foreman	Naval Facilities Engineering Service Center 1100 23rd Ave. Port Hueneme, CA	(805) 982-2644 (805) 982-4832 Fax Mark.foreman@navy.mil	Project Engineer
Andy Vasquez	Naval Facilities Engineering Service Center 1100 23rd Ave. Port Hueneme, CA	(805) 982-5228 (805) 982-4832 Fax Andy.vasquez@navy.mil	Lead Technician
Jeremy Anding	SPT (NuFlow)	(619) 275-9130 (619) 275-7110 Fax JeremyA@sptpipe.com	Epoxy Installation Contractor
Steve Mori	Aquam	(858) 967-4682 smori@aqaumcorp.com	Epoxy Application Consultant
Annette Strumpfe	US Army Civil Engineering Research Laboratory Champaign, Illinois	(217) 373-4492 (217) 373-6724 Fax Annette.l.stumpf@usace.army.mil	Army Liaison

Appendix B: Test Bed Results

Test Bed Number 1.
Air Compressor Line Epoxy Coating Demonstration Field Notes

Demonstration Site: NAVFAC EXWC, Port Hueneme, Bldg. 1100, General Use Lab (GUL)

Dates of Demonstration: 1 – 2 February 2016

Contractor: Nu Flow Technologies

EXWC Team: Gary Anguiano
Itzel Godinez
Prakash Temkar
Mark Foreman

Purpose: The purpose of this demonstration is to determine the efficacy of Nu Flow epoxy coating process in reducing simulated air leaks in various pipe materials commonly used in DoD air compressor systems.

Test Bed: The test bed consisted of various pipe configurations and simulated air leaks as described in this document.

Timeline of Events:

- The contractor mobilized all needed equipment for the Nu Flow Epoxy Coating process and arrived at site at 11:36 on 1 February 2016.
- The test bed was ready for demonstration with four simulated compressed air pipe configurations with leaks, three horizontal black-iron pipe segments with pinholes (i.e. 20 pinholes per pipe segment) of various sizes (i.e. 1/16", 1/8" and 1/4") and one horizontal black-iron segment with a 2 loose threaded fittings and a copper section with 5 welds in bad condition.
- The four compressed air pipe configurations consisted of Clear PVC, Copper, Galvanized Iron and Black Iron with pipes ranging in size from 2", 1.5", 1", 0.5" and 0.25".
- The contractor set up all the equipment necessary to apply the epoxy coatings. Main components included air compressor, abrasive pipe cleaning system (i.e. sand blaster), manifolds for delivering air, pressure gauges, dust collector, epoxy mixing system, pressure gauges.
- Contractor demonstrated the epoxy coating process and explained each step.
- The Clear PVC pipe and the Black Iron pipe were coated with epoxy on the first day of demonstration.
- The Galvanized Iron and Copper pipes were coated with epoxy on the second day. The horizontal Black Iron pipe segments were also coated on the second day.
- The demonstration was documented with photos and videos.

Epoxy Coating Process:

- The general process consisted of the following steps:
  - drying of the system with dried compressed air
  - rust and scale removal with an abrasive garnet sprayed through the system
  - system cleaning by blowing dry compressed air through pipe
  - distribution of epoxy using compressed air flow to form an epoxy pipe lining
  - curing of the epoxy with compressed air
- Air drying: The air from compressor is passed through a heater before it enters the system. The air temperature is maintained between 80° and 90° F, relative humidity is below 20% and dew point is below the humidity level. The air exhausted from the pipe system should meet the above criteria. Air drying time depends on the pipe condition as well as local weather.
- Rust and Scale Removal: The inside surface of the pipe is cleaned to remove any rust or scale by passing an abrasive material through the pipe using pulsed air pressure (80 psi). The choice of abrasive material depends on the pipe material being cleaned. The abrasive material can be granite or glass. Figure B1 displays abrasive materials.

Figure B1. Samples of Abrasive Material or Garnet.

- After the rust and scale are removed, the pipe system is flushed thoroughly using warm dry air with the same characteristics described above.
- The epoxy coating material is prepared by mixing two components is a specified ratio of 70:30. The epoxy is mixed thoroughly using hand held drill until it reaches 80° – 90° F temperature. Figure B2 shows the epoxy mixing process.

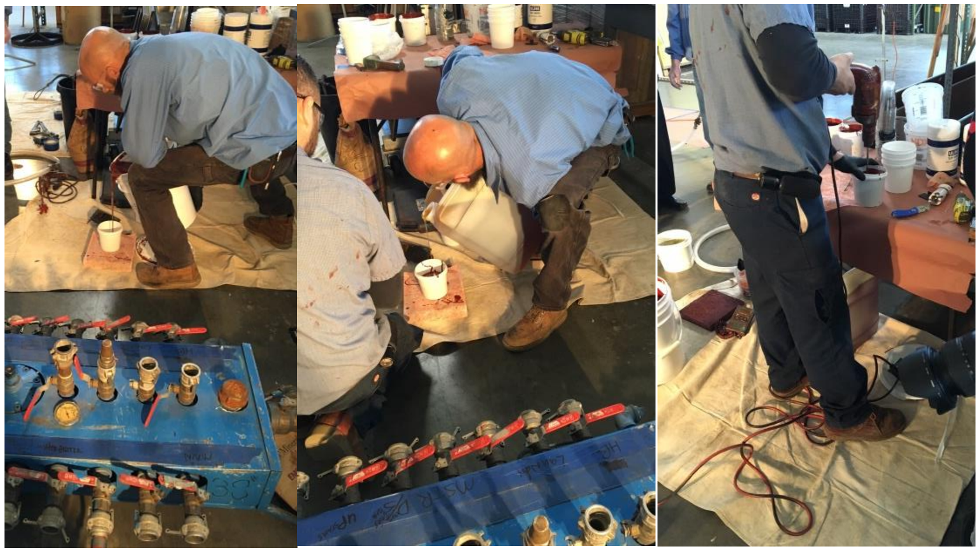


Figure B2. Process Involving Epoxy Coating Mixing.

- The epoxy is then transferred to a “shot hose”, attached to the pipe and compressed air is passed through the hose. The epoxy material then flows through the pipe coating the inside surface. The pressure in each section of the pipe is carefully balanced to ensure uniform coating as the epoxy material passes through the pipes. Figure 3 displays the coating process.

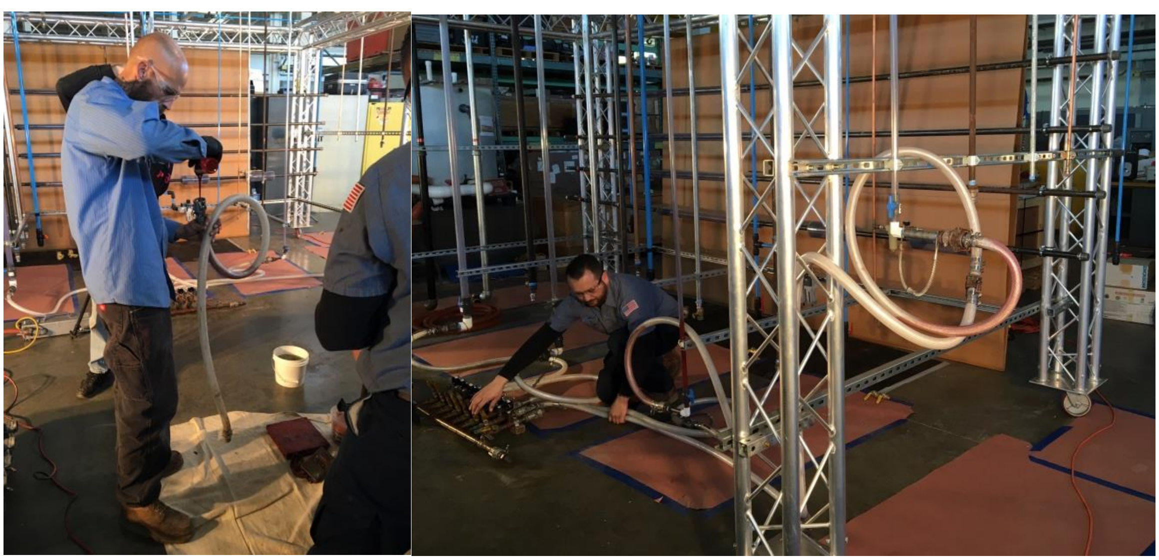


Figure B3. Epoxy Coating Application.

- The amount of epoxy material, time required to coat a given length of pipe depend upon the pipe material, pipe size and air pressure. An empirical formula, mostly based on experience, is used to determine the parameters.

- According to the Nu Flow team, the following formulas as used to estimate the amount of epoxy needed per pipe segment:

$$Pipe\ Diameter\sqrt{18\ (for\ pipe\ material\ other\ than\ copper)}$$
$$= \#\ of\ feet\ covered\ by\ 1\ lb\ of\ epoxy$$

$$Pipe\ Diameter\sqrt{24\ (for\ copper\ pipe)} = \#\ of\ feet\ covered\ by\ 1\ lb\ of\ epoxy$$

In addition, epoxy is poured into the "shot hose" in amounts of 140 ml using the measuring cup shown in Figure B4. According to the contractor, the following are estimates of how many feet of pipe 140 ml of epoxy cover:

  - 140 ml = 24 ft of 1/2" pipe
  - 140 ml = 18 ft of 3/4" pipe
  - 140 ml = 12 ft of 1" pipe

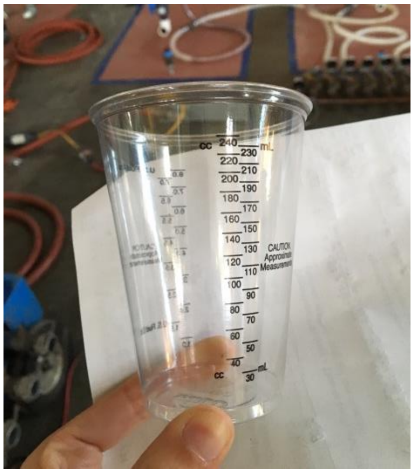


Figure B4. Standard Measuring Cup.

- The smallest pipe diameters are coated first followed by larger diameter pipes.
- The epoxy mix must be used within 40 minutes of preparation.
- After the epoxy is determined to have passed through the system, the system is capped and held under static pressure of about 5 – 15 psi to ensure the film of epoxy on the inside surface adheres completely.
- After the epoxy coating process is completed, the pipe system is cured for at least 24 hours. Curing time depends on the air temperature. Minimum of 24 hours is needed at an ideal temperature of 90° – 100° F.

<u>Observations during the Demonstration</u>:

- Heaters used for warming and drying air needed to be changed frequently.

The Clear PVC pipes were coated under lower pressure (<50 psi) compared to the other pipe materials (> 60 psi) due to potential damage to the PVC system under higher pressure. However, the clear PVC pipe provided an excellent visual on the coating process.

Test Bed Operational Efficiencies:

TASK 1: **Operational Efficiency – Expedient set-up**
(Amount of time to set-up equipment (hours))

Table B1 displays set-up times.

Table B1 – Set-Up on 1 February, 2016

START TIME	*END TIME*	*TOTAL TIME*
11:36 a.m. – getting compressor ready and start set-up of pipelines as well as end fitting to apply hot air, epoxy and pressurize pipe lines	12:15 p.m. – stopped to step out to get equipment from other truck parked outside base	39 min
12:45 p.m. – Nu Flow team came back to continue set-up	1:45 p.m. – end of set-up; Nu Flow team brings in the sand blaster unit to commence the pipe line preparation	60 min
		1 hr- 39 min

TASK 2: **Operational Efficiency – Pipe preparation**
(Amount of time to prepare pipeline (hours))

Table B2 and B3 display pipeline preparation times.

Table B2 – Pipe Segments Preparation on 1 February, 2016

Pipe Segment	Pipe Conditioning • hot compressed air to achieve 80 – 90 °F, < 20% humidity and a dew point < humidity		Total Time	Sand Blasting[1]		Total Time
	Start	End		Start	End	
Copper	1:54 p.m.	2:02 p.m.	8 min	2:03 p.m.	2:08 p.m.	5 min
Galvanized	2:11 p.m.	2:17 p.m.	6 min	2:18 p.m.	2:24 p.m.	6 min
Black Iron	2:26 p.m.	2:32 p.m.	6 min	2:32 p.m.	2:37 p.m.	5 min
PVC				Applied 10 – 15 psi of pressure and poured glass garnet to illustrate the sand blasting process to clean the inside of a pipe lines		

[1] Four cycles of sand blasting were completed per pipe segment except for PVC.

Table B3 – Pipe Segments Preparation on 2 February, 2016

Pipe Segment	Pipe Conditioning • hot compressed air to achieve 80 – 90 °F, < 20% humidity and a dew point < humidity		Total Time	Sand Blasting		Total Time
	Start	End		Start	End	
Copper Section with Bad Welding Sections and Loose Threaded Fittings	11:02 a.m.	11:06 a.m.	4 min	11:06 a.m.	11:07 a.m.[2]	1 min
20 – 1/16” Holes				11:09 a.m.	11:10 a.m.[3]	1 min
20 – 1/8” Holes				11:11 a.m.	11: 12 a.m.	1 min
20 – 1/4” Holes[4]	12:11 p.m.	12:13 p.m.	2 min	12:14 p.m.	12:16 p.m.[5]	2 min

[2] Five cycles of sand blasting were applied to the pipe line.

[3] Six cycles of sand blasting were applied to the pipe line.

[4] Different types of tape were used to cover the 10 sets of 2-holes drilled on a portion of the pipe line.

[5] Three cycles of sand blasting at 60 psi and three cycles of sand blasting at 90 psi.

<u>TASK 3</u>: **Operational Efficiency – Time to apply and cure epoxy**
(Amount of time to apply and cure (hours))

Table B4 thru B6 display the epoxy application time.

Table B4 – Epoxy Coating Procedure on 1 February, 2016

Pipe Segment	Pipe Conditioning • hot compressed air to achieve 80 – 90 °F, < 20% humidity and a dew point < humidity		Total Time	Epoxy[6] Coating Application		Total Time	Pressurize to Seal Leaks at Threaded Fittings[7]		Total Time
	Start	End		Start	End		Start	Time	
PVC				3:09 p.m.	3:37 p.m.	28 min			
Black Iron	3:41 p.m.	3:56 p.m.	15 min	3:57 p.m.	4:16 p.m.	19 min	4:16 p.m.	4:29 p.m.	13 min

[6] Epoxy is 70% red – 30% honey like material. Materials are mixed until epoxy reaches a temperature of 90 – 100 °F. It takes about 40 minutes until epoxy mixture turns hard and cannot be used anymore. At this point a new epoxy mixture must be prepared.

[7] Pipe line segment is pressurized in 3 – 4 min cycles to push epoxy through threaded fittings to seal leaks properly. Number of cycles depends on pressure drop registered on gages when end hose is removed and replaced by a cap to record pressure retention. Conversely, as the pipe segment is pressurized, additional epoxy is added through pipe lines where pressurized hot compressed air is being applied. This additional epoxy guarantees that the first two feet of pipe maintain a uniform coating and that the coating is not thinned-out as pressurized hot air enters the pipe. During this step, Black Iron was pressurized at 30 psi.

Table B5 – Epoxy Coating Procedure on 2 February, 2016

Pipe Segment	Pipe Conditioning • hot compressed air to achieve 80 – 90 °F, < 20% humidity and a dew point < humidity		Total Time	Epoxy[6] Coating Application		Total Time	Pressurize to Seal Leaks at Threaded Fittings[7]		Total Time
	Start	End		Start	End		Start	Time	
Galvanized	8:32 a.m.	9:11 a.m.	39 min[8]	9:12 a.m.	9:40 a.m.	28 min	9:40 a.m.	9:52 a.m.	12 min[9]
Copper	9:52 a.m.	10:14 a.m.	22 min	10:19 a.m.	10:38 a.m.	19 min	10:39 a.m.	10:47 a.m.	8 min[10]

[8] Nu Flow team had trouble with the heater. Heater had to be replaced and extension cord-segments were replaced by only one-long extension.

[9] Note that at locations where we noted leaks (2nd and 3rd pipe lines from left) a second round of coating was applied to make sure that leaks are properly sealed as well as to maintain a uniform epoxy coating within the first two feet of the pipe line where pressurized hot compressed air was applied.

[10] Additional epoxy was added to 2nd and 3rd pile lines (from left) which were noted as having leaks. Reference footnotes 7 and 9.

Table B6 – Epoxy Coating of Horizontal Black Iron Pipe Segments (2 February, 2016)

Pipe Segment	Pipe Conditioning • hot compressed air to achieve 80 – 90 °F, < 20% humidity and a dew point < humidity		Total Time	Epoxy Coating Application		Total Time	Pressurize to Seal Leaks at Threaded Fittings		Total Time
	Start	End		Start	End		Start	Time	
Copper Section with Bad Welding Sections and Loose Threaded Fittings	11:14 a.m.	11:25 a.m.	11 min	11:25 a.m.	11:27 a.m.[11]	2 min	11:27 a.m.	11:40 a.m.	13 min[12]
20 – 1/16” Holes	11:30 a.m.	11:35 a.m.	5 min	11:36 a.m.	11:38 a.m.[13]	2 min	11:38 a.m.	11:56 a.m.	18 min[14]
20 – 1/8” Holes	11:45 a.m.	11:54 a.m.	9 min	11:55 a.m.	11:59 a.m.[15]	4 min	11:59 a.m.	12:08 a.m.	9 min[14]
20 – 1/4” Holes	12:16 p.m.	12:29 p.m.	13 min	12:29 p.m.	12:31 p.m.[15]	2 min	12:31 p.m.	12:45 a.m.	14 min[14]

[11] Epoxy applied at 50 psi.
[12] Pressurized hot compressed air to seal leaks applied at 10 psi.
[13] Epoxy shavings added to epoxy mixture to increase the probability that 1/16” holes will be sealed properly during the coating process.
[14] Pressurized hot compressed air applied at 5 psi.
[15] Extra epoxy shavings were added to epoxy mixture to increase the probability that 1/8” and 1/4” holes will be sealed properly during the coating process. Based on results, the extra epoxy shavings did not make a difference in the case of the 1/8” holes the epoxy was splattered out.

<u>TASK 4</u>: Operational Efficiency – Time to return to operational status not including curing time

Table B7 and B8 detail the time to return to operational status.

Table B7 – Overall Time Spent on Day 1 and Day 2 of Test Bed Demonstration

START TIME	*END TIME*	*TOTAL TIME*
11:36 a.m. – start of overall process on Day 1 (1 February, 2016)	4:45 p.m. – end of day one (i.e. set-up, preparation of 4-pipe line segments up to sand blasting, and epoxy coating of PVC and Black Iron)	5 hr – 9 min
7:45 a.m. – start of overall process on Day 2 (2 February, 2016)	1:09 p.m. – end of day two (i.e. epoxy coating of Galvanized and Copper, pipeline preparation as well as epoxy coating of 4 horizontal Black Iron segments with pin-holes (1/16”, 1/8”, 1/4”) and leaking welded/threaded connections, and overall clean up)	5 hr- 24 min

Table B8 – Cleaning Up

START TIME	*END TIME*	*TOTAL TIME*
12:25 p.m. – cleaning up area to return it to original conditions (i.e. not including removing construction paper placed on floor)	1:09 p.m. – completion of cleaning and Test Bed Demonstration (epoxy must be allowed to cure for about 24 hours)	44 min

Table B9 thru B12 detail the pressure drop before and after epoxy coating for the different pipe setups.

Table B9 – Pressure Drop before Epoxy Coating Application

Pipe Configuration	Pressure Drop	Trial 1	Trial 2	Trial 3	Average
Copper	90 – 60 psi	4:52 min	4:59 min	4:48 min	4:53 min
Galvanized	91 – 70 psi	6:21 min	6:20 min	6:25 min	6:22 min
Black Iron	90 – 60 psi	4:43 min	4:42 min	4:41 min	4:42 min

Table B10 – Pressure Drop before Epoxy Coating Application

Horizontal Pipe Segment (Black Iron)	Pressure Drop	Trial 1	Trial 2	Trial 3	Average
Copper Section with Bad Welding Sections and Loose Threaded Fittings	90 – 60 psi	00:19.25 sec	00:18.80 sec	00:18.65 sec	00:18.90 sec
20 – 1/16” Holes	Holds about 20 psi but it takes less than a second to release pressure				
20 – 1/8” Holes	Does not retain pressure				
20 – 1/4” Holes	Does not retain pressure				

Table B11 – Pressure Drop after Epoxy Coating Application

Pipe Configuration	Pressure Drop	Trial 1	Trial 2	Trial 3	Average
Copper					
Galvanized	91-90 psi	3:00 min	3:00 min	3:00 min	3:00 min
Black Iron	90-88 psi	5:00 min	5:00 min		5:00 min
	90-90 psi			5:00 min	5:00 min

Table B12 – Pressure Drop after Epoxy Coating Application (Friday, February 5th, 2016)

Horizontal Pipe Segment (Black Iron)	Pressure Drop	Trial 1	Trial 2	Trial 3	Average
Copper Section with Bad Welding Sections and Loose Threaded Fittings	92 psi – 92 psi	3:00 min	3:00 min	3:00 min	3:00 min
20 – 1/16” Holes	92 psi – 92 psi	3:00 min	3:00 min	3:00 min	3:00 min
20 – 1/8” Holes	37 psi – 0 psi	00:01.13 sec	00:01.18 sec	00:01.15 sec	00:1.153 sec
20 – 1/4” Holes	92 psi – 92 psi	3:00 min	3:00 min	3:00 min	3:00 min

<u>Test Bed Characteristics</u>:
Figure B5 and B6 provide photographs of the test bed pipeline setup.

Figure B5. Front View of Test Bed.

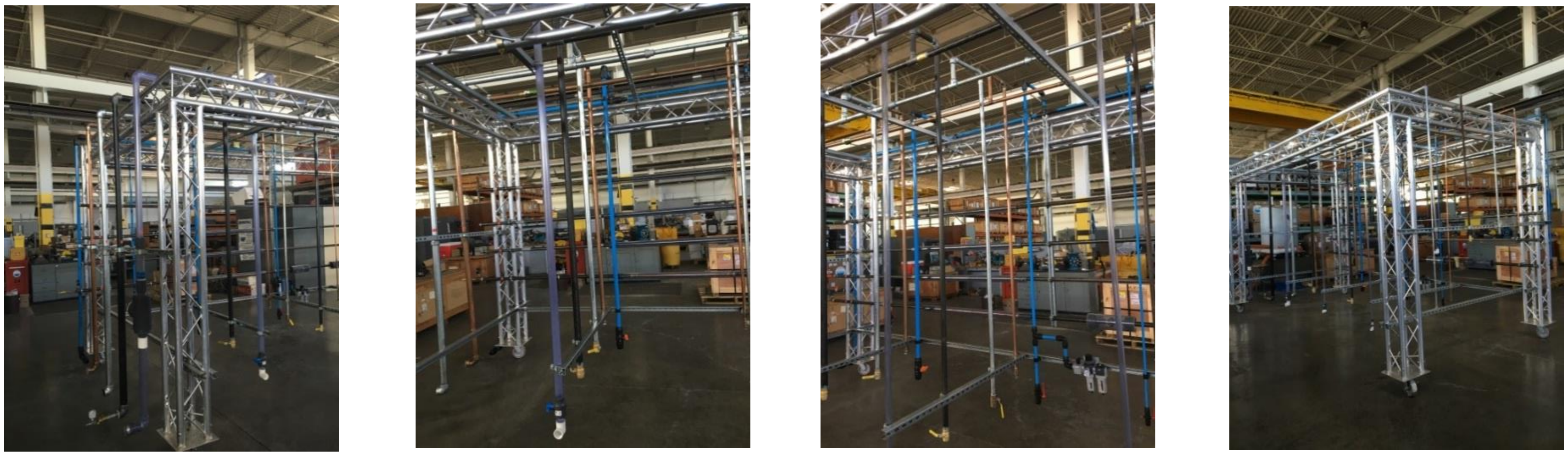


Figure B6. Left-End, Left-Mid Section, Mid-Right Section, and Right-End Views of Test Bed.

Test Bed Number 2. Evaluation of Epoxy Coating Application Process on Mock-up Compressed Air Pipeline Field Notes

Demonstration Site: NAVFAC EXWC, Port Hueneme, Bldg. 1100, General Use Lab (GUL)

Dates of Demonstration: 18 – 20 April 2017

Contractor: Nu Flow Technologies

EXWC Team: Gary Anguiano
Itzel Godinez
Andy Vasquez
James Pilkington

Purpose: A follow-on bench scale demonstration was conducted as a request by the ESTCP Committee on Energy and Water. The committee members requested this demonstration to focus on coating uniformity and pooling as a result of higher than expected pooling issues encountered on the first test bed.

Test Bed: In addition to evaluating the leaking scenarios and pipe configurations from the first test bed, the team also evaluated the ability to seal pinhole leaks in pipelines encased in soil to simulate an underground pipeline leakage, and a leaking 1" – 48' pipe segment intended to assess coating uniformity and pooling in longer pipe segments that have far apart access points such as inlet and outlet. Table B13 describes all the pipe segments included in test bed no. 2.

Table B13 – Pipe Segments of Test Bed No. 2

Pipe Segment		
No.	Material	Description
1	Black Iron	2" - 1.5" - 1.0" - 0.5"
2	Galvanized	2" - 1.5" - 1.0" - 0.5"
3	Copper	2" - 1.5" - 1.0" - 0.5"
4	Black Iron	1" HORIZONTAL (10 - 1/4" PIN-HOLES)
5	Black Iron	1" HORIZONTAL (10 - 1/8" PIN-HOLES)
6	Black Iron	1" HORIZONTAL (10 - 1/16" PIN-HOLES)
7	Black Iron	1" UNDERGROUND (6 - 1/4" PIN-HOLES)
8	Black Iron	1" UNDERGROUND (6 - 1/8" PIN-HOLES)
9	BLACK IRON	1" UNDERGROUND (6 - 1/16" PIN-HOLES)

11	Black Iron	1" ANCHOR TOOTH TEST
10	Black Iron	3" NATURAL GAS LINE
12	Black Iron	1" (48' PIPE SEGMENT)
13	Black Iron & Copper Section	1" WITH COPPER SOLDERED SECTION & TWO LOOSELY THREADED FITTINGS

Timeline of Events:

- Nu Flow arrived to the GUL at 07:30 on 18 April 2017 and at 07:45 it was ready to initiate the set-up of equipment to carry out the first day of operations on the test bed.
- Due to a problem with the main compressor, on 18 April 2017 only the following operations were possible: (1) equipment set-up; (2) pipe conditioning and garnet blasting of copper segment no. 3; and partial pipe conditioning of galvanized segment no. 2.
- On 19 April 2017 Nu Flow brought a new compressor to the site and continued with the normal operations. On this day, pipe segments 2-13 underwent pipe conditioning, and garnet blasting. In addition, all pipe segments—excluding no. 11 which was intended for measuring anchor tooth generation during garnet blasting—were applied the first coat of epoxy.
- On 20 April 2017 Nu Flow applied the second epoxy coating and concluded the test bed demonstration.

Epoxy Coating Process:

- The general process consisted of the following steps:
    - drying of the system with hot compressed air
    - rust and scale removal with an abrasive garnet sprayed through the pipeline
    - system cleaning by blowing hot compressed air through pipeline
    - distribution of epoxy using compressed air flow to form an epoxy pipe coating
    - curing of the epoxy with compressed air
- Air drying: Compressed air is passed through a heater before it enters the pipeline. The air temperature within the pipeline is maintained at > 90° F, relative humidity is below 18% and dew point is below the humidity level.
- Rust and Scale Removal: The inside surface of the pipeline is cleaned to remove any rust or scale by passing an abrasive garnet through the pipeline using pulsed air pressure; for copper a pressure of 55-60 psi is typically used whereas for black iron and galvanized metals a pressure of 75-80 psi is used. Figure B7 shows the types of abrasive garnet used for the different pipe metals incorporated in the demonstration.

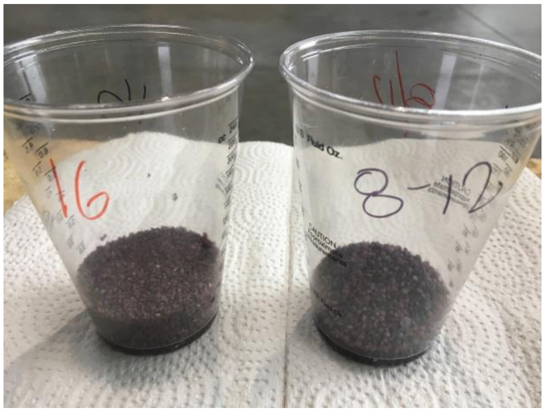


Figure B7. Garnet Used for Copper Pipe is 16 and for Galvanized and Black Iron is 8-12; The Higher The Garnet Value, The Smaller The Garnet.

- After the rust and scale are removed, the pipeline is flushed thoroughly using hot compressed air.
- The anchor tooth was measured at the end of pipeline to make sure that the garnet created the necessary roughness on the internal wall surface for the epoxy to grab onto and form a uniform coating throughout the pipeline. NRL/MR/6120—94-7629 recommends an anchor tooth of 2 to 3 mils. Nu Flow, on the other hand, typically wants to see an anchor tooth of 4 to 5 mils. Pipe segment no. 12 was used to measure the anchor tooth throughout the pipe length. Based on the instrumentation used by Nu Flow to measure anchor tooth, pipe segment no. 12 achieved an anchor tooth of more than 5 mils throughout the pipeline. Figure B8 shows the instruments used by Nu Flow to measure anchor tooth as a result of the abrasive garnet and Figure B9 presents the anchor tooth results for the different cross-sections cut away from pipe segment no. 12.

Figure B8. Instrumentation Used by Nu Flow to Measure Anchor Tooth.

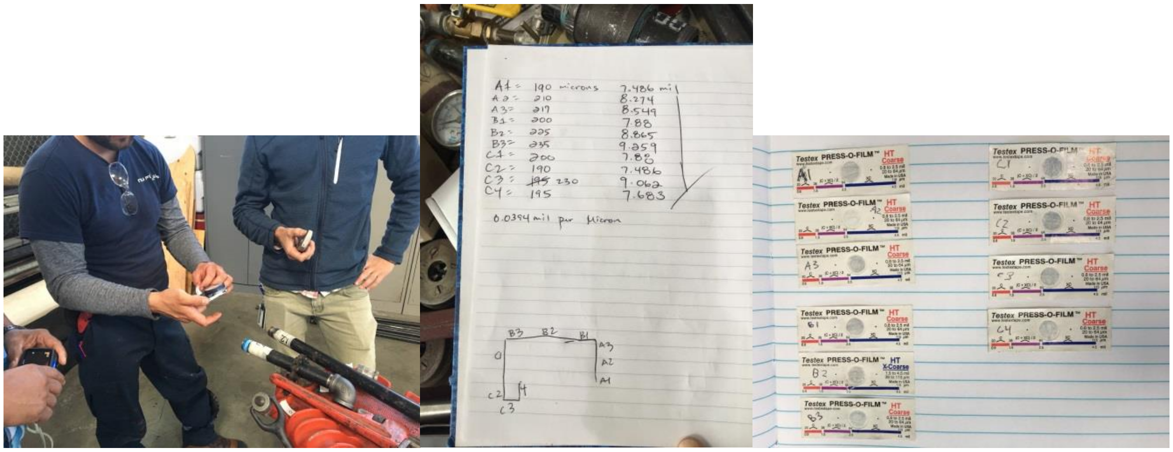


Figure B9. Anchor Tooth Measurement for Pipe Segment no. 12 Cross-Sections.

- The epoxy coating is prepared by mixing two materials in a ratio of 70:30 percent by weight. Figure B10 illustrates the preparation of a 2-lb batch of epoxy.

Figure B10. 2-lb Batch of Epoxy Mix
(70% Part A-Small Container & 30% Part B-Bucket).

Batch is mixED until its temperature reaches 95º F then it is allowed to rest for 10 min in order for the epoxy to combine properly. Additional mixing is required prior to applying epoxy to pipelines.

- The epoxy is then transferred to a “shot hose”, attached to the pipe and compressed air is passed through the hose. The epoxy material then flows through the pipe coating the inside surface. The pressure in each section of the pipe is carefully balanced to ensure uniform coating as the epoxy material passes through the pipes. Figure B11 provides a view of the “shot hose” and its assembling to one of the underground pipelines.

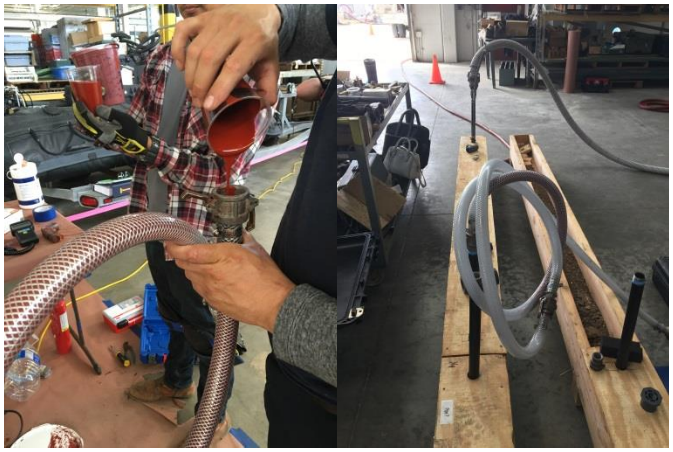


Figure B11. "Shot hose" and Assembling to An Underground Pipeline to be Epoxy Coated.

- In this test bed demonstration two coats of epoxy will be applied to each of the pipe segments. NRL/MR/6120—94-7629 recommends three coats of epoxy for shipboard piping systems; the total thickness of the epoxy coating is at least 15 mils at any point, and no more than 20 mils at any point around the circumference of the pipe (6 mils per coat average). For the test bed pipe segments two coats of epoxy will be sufficient because they represent pipelines in compressed air systems which are static and for the most part are enclosed inside buildings or underground.
- For pipe segments 1 to 3, the smallest pipe diameters will be coated first followed by larger pipe diameters.
- Table B20 to B23 presented in the Test Bed Operational Efficiencies section describe the amount of epoxy used per coat and pipe segment.
- After each epoxy coating applied to a pipe segment, time will be allocated to apply hot compressed air throughout the pipeline to initiate the curing process.
- Epoxy coatings are typically cured after hours. Curing time depends on the air temperature. Minimum of 24 hours is needed at an ideal temperature of 90° – 100° F.

<u>Observations during the Demonstration</u>:

- Second air compressor brought by Nu Flow allowed for the work to be completed on time even after delays encountered on day one of the test bed demonstration.
- During the epoxy coating application process of pipe segments 7 and 8, fine soil particles blew out of the enclosed wooden container simulating underground pipe conditions. This provided evidence that for these pipe segments, the coating process was not successful.

- During the epoxy coating application process of pipe segments 5 and 6, excessive amounts of epoxy came through the pin-holes. For pipe segment 6, this was atypical and the behavior was not observes as part of the demonstration for test bed no. 1.

Test Bed Operational Efficiencies:

Table B14 thru B19 display setup, epoxy application, and clean up times.

Table B14 – Set-Up on 18 April 2018

Start	End	Time (hr-min)
07:45 – initiate set-up of air compressor, heaters, garnet tank, hoses, table for epoxy mixing and floor covering to protect from spills.	09:52	2 hr – 7 min

The photographs in Figure B12 depict the equipment setup.

Figure B12 – Set-Up of Equipment at the GUL.

Table B15 – Pipe Segments Preparations on 18 April 2017

Pipe Segment			Pipe Conditioning				Sand Blasting			
No.	Material	Description	Start	End	Total (min)	Comments	Start	End	Total (min)	Comments
3	COPPER	2" - 1.5" - 1.0" - 0.5"	09:57	10:09	12	• Temperature > 90º F and Moisture < 18% and a dew point < humidity • Hot air at 18-24 psi	10:12	10:22	10	• Sand blast pressure < 60 psi (typically 55-60 psi) • ½" pipe 3 passes at 3-5 sec/pass • 1" pipe 3-4 passes at 3-5 sec/pass • 1.5-2" pipes 5-6 passes at 3-5 sec/pass
2	GALVANIZED	2" - 1.5" - 1.0" - 0.5"	10:23	10:34	11	• Same as No. 3	10:36	10:38	2	• Sand blast pressure 75-80 psi • Issues with compressor; it had to be turned off • Compressor could not be started again
At 11:40 Nu Flow left to get a new compressor.										

Table B16 – Pipe Segments Preparations on 19 April 2017

Pipe Segment			Pipe Conditioning				Sand Blasting			
No.	Material	Description	Start	End	Total (min)	Comments	Start	End	Total (min)	Comments
2	GALVANIZED	2" - 1.5" - 1.0" - 0.5"	07:40	07:50	10	• Same as No. 3 on Table B15	07:51	07:56	5	• Sand blast pressure 75-80 psi • 6 passes per pipe size with garnet at 3-5 sec/pass • Note that pipe is new otherwise it would need more passes per pipe size
1	BLACK IRON	2" - 1.5" - 1.0" - 0.5"	07:59	08:08	9		08:09	08:15	6	• 7-8 passes per pipe size at 3-5 sec/pass
4	BLACK IRON	1" HORIZONTAL (10 - 1/4" PIN-HOLES)	08:16	08:24	8		08:28	08:30	2	• 10 passes at 3-5 sec/pass
5	BLACK IRON	1" HORIZONTAL (10 - 1/8" PIN-HOLES)	08:31	08:36	5		08:37	08:39	2	
6	BLACK IRON	1" HORIZONTAL (10 - 1/16" PIN-HOLES)	08:39	08:45	6		08:46	08:48	2	
13	BLACK IRON & COPPER SECTION	1" WITH COPPER SOLDERED SECTION & TWO LOOSELY THREADED FITTINGS	08:49	08:56	7		08:57	08:59	2	
12	BLACK IRON	1" (48' PIPE SEGMENT)	08:59	09:08	9		09:09	09:11	2	
11	BLACK IRON	1" ANCHOR TOOTH TEST	09:12	09:16	4		09:18	09:20	2	
10	BLACK IRON	3" NATURAL GAS LINE	09:22	09:27	5		09:29	09:33	4	• 10 passes at 3-5 sec/pass in the middle • 15 passes at 3-5 sec/pass at right end
7	BLACK IRON	1" UNDERGROUND (6 - 1/4" PIN-HOLES)	09:38	09:43	5		09:43	09:45	2	• 12 passes at 3-5 sec/pass

9	BLACK IRON	1" UNDERGROUND (6 - 1/16" PIN-HOLES)	09:46	09:52	6		09:54	09:56	2	• 12 passes at 3-5 sec/pass
8	BLACK IRON	1" UNDERGROUND (6 - 1/8" PIN-HOLES)	09:56	10:05	9		10:07	10:09	2	• 12 passes at 3-5 sec/pass

Table B17 - Pipe Segment Preparation and Time to Apply 1st Coat and Start Curing Process of Epoxy on 19 April 2017

Pipe Segment			Pipe Conditioning				Epoxy Coating Application		Start of Curing Process (Hot Compressed Air)		
No.	Material	Description	Start	End	Total (min)	Comments	Total Time Per Coat (min:sec)	Comments	Start	End	Total (min)
8	BLACK IRON	1" UNDERGROUND (6 - 1/8" PIN-HOLES)	10:16	10:40	24		1:25		10:46	10:56	10
7	BLACK IRON	1" UNDERGROUND (6 - 1/4" PIN-HOLES)	10:46	10:49	3		1:45	1st Coat – 240 mL of epoxy	10:52	11:04	12
9	BLACK IRON	1" UNDERGROUND (6 - 1/16" PIN-HOLES)	10:59	11:01	2		1:30		11:05	11:14	9
13	BLACK IRON & COPPER SECTION	1" WITH COPPER SOLDERED SECTION & TWO LOOSELY THREADED FITTINGS	11:14	11:26	12		1:25	1st Coat – 180 mL of epoxy	11:30	11:39	9
6	BLACK IRON	1" HORIZONTAL (10 - 1/16" PIN-HOLES)	11:15	11:30	15		1:25	1st Coat – 200 mL of epoxy	11:34	11:45	11
5	BLACK IRON	1" HORIZONTAL (10 - 1/8" PIN-HOLES)	11:39	11:42	3		1:30		11:44	11:54	10
4	BLACK IRON	1" HORIZONTAL (10 - 1/4" PIN-HOLES)	13:05	13:26	21	• Same as No. 3 on Table B15	1:38	1st Coat – 180 mL of epoxy	13:30	13:41	11
10	BLACK IRON	3" NATURAL GAS LINE	13:30	13:40	10		1:30	1st Coat – 400 mL of epoxy	13:45	13:55	10
12	BLACK IRON	1" (48' PIPE SEGMENT)	13:45	14:00	5		5:00	1st Coat – 540 mL of epoxy (3 – 180 mL/shot) • Epoxy coating applied at 60 psi	14:07	14:29	22
3	COPPER	2" - 1.5" - 1.0" - 0.5"	14:20	14:36	16		1) 1:33 2) 1:10 3) 4:02 4) 2:40	1st Coat: 1) 1/2" Right end – 140 mL of epoxy 2) 1/2" Vertical drop down – 100 mL of epoxy	14:53	15:03	10 • Ball valve open/close 12 times and left at 45º from closed position
1	BLACK IRON	2" - 1.5" - 1.0" - 0.5"	15:06	15:17	11		1) 1:27 2) 1:20		15:32	15:42	10

							3) 4:20 4) 2:11	3) 1” Vertical drop down – 2-140 mL of epoxy 4) 1.5” Vertical drop down – 220 mL of epoxy			• Ball valve open/close 15 times and left at 45º from closed position
2	GALVANIZED	2" - 1.5" - 1.0" - 0.5"	15:44	15:47	3		1) 1:26 2) 1:27 3) 4:05 4) 2:35		16:03	16:14	11 • Ball valve open/close 15 times and left at 45º from closed position

Table B18 - Pipe Segment Preparation and Time to Apply 2nd Coat and Start Curing Process of Epoxy on 20 April 2017

Pipe Segment			Pipe Conditioning				Epoxy Coating Application		Start of Curing Process (Hot Compressed Air)		
No.	Material	Description	Start	End	Total (min)	Comments	Total Time Per Coat (min:sec)	Comments	Start	End	Total (min)
7	BLACK IRON	1" UNDERGROUND (6 - 1/4" PIN-HOLES)									
9	BLACK IRON	1" UNDERGROUND (6 - 1/16" PIN-HOLES)						2nd Coat – 180 mL of epoxy			
8	BLACK IRON	1" UNDERGROUND (6 - 1/8" PIN-HOLES)	08:17	08:19	2		1:30		08:22	08:33	11
13	BLACK IRON & COPPER SECTION	1" WITH COPPER SOLDERED SECTION & TWO LOOSELY THREADED FITTINGS	08:23	08:33	10		1:30	2nd Coat – 160 mL of epoxy	08:36	08:40	4
6	BLACK IRON	1" HORIZONTAL (10 - 1/16" PIN-HOLES)						2nd Coat – 200 mL of epoxy			
5	BLACK IRON	1" HORIZONTAL (10 - 1/8" PIN-HOLES)									
4	BLACK IRON	1" HORIZONTAL (10 - 1/4" PIN-HOLES)	08:53	09:04	11	• Same as No. 3 on Table B15	1:25	2nd Coat – 180 mL of epoxy	09:07	09:20	13
10	BLACK IRON	3" NATURAL GAS LINE	09:14	09:16	2		1) 1:25 2) 1:35	2nd Coat 1) 1 – 80 mL of epoxy through top-mid 1” pipe 2) 2 – 160 mL of epoxy	09:23	09:33	10
12	BLACK IRON	1" (48' PIPE SEGMENT)	09:23	09:37	14		3:58	2nd Coat – 480 mL of epoxy (3 – 160 mL/shot)	09:42	10:00	18
3	COPPER	2" - 1.5" - 1.0" - 0.5"	10:32	10:45	13			2nd Coat:	10:53	11:04	11

							1) 3:45 2) 2:48	1) 1” Vertical drop down – 2-180 mL of epoxy 2) 1.5” Vertical drop down – 2-140 mL of epoxy			• Ball valve open/close several times and left at 45º from closed position
2	GALVANIZED	2" - 1.5" - 1.0" - 0.5"	11:06	11:11	5		1) 3:52 2) 2:37		11:19	11:30	11 • Ball valve open/close several times and left at 45º from closed position
1	BLACK IRON	2" - 1.5" - 1.0" - 0.5"	11:31	11:37	6		1) 3:45 2) 3:15		11:46	11:56	11 • Ball valve open/close several times and left at 45º from closed position

Table B19. Clean-Up on 20 April 2017

Start	End	Time (hr-min)
11:56 – – cleaning up area to return it to original conditions	12:45 - completion of cleaning and test bed no. demonstration (epoxy must be allowed to cure for about 24 hours)	0 hr – 49 min

Figure B13 displays the locations where pipe cross sections were cut to inspect for pooling and analyze coating thickness.

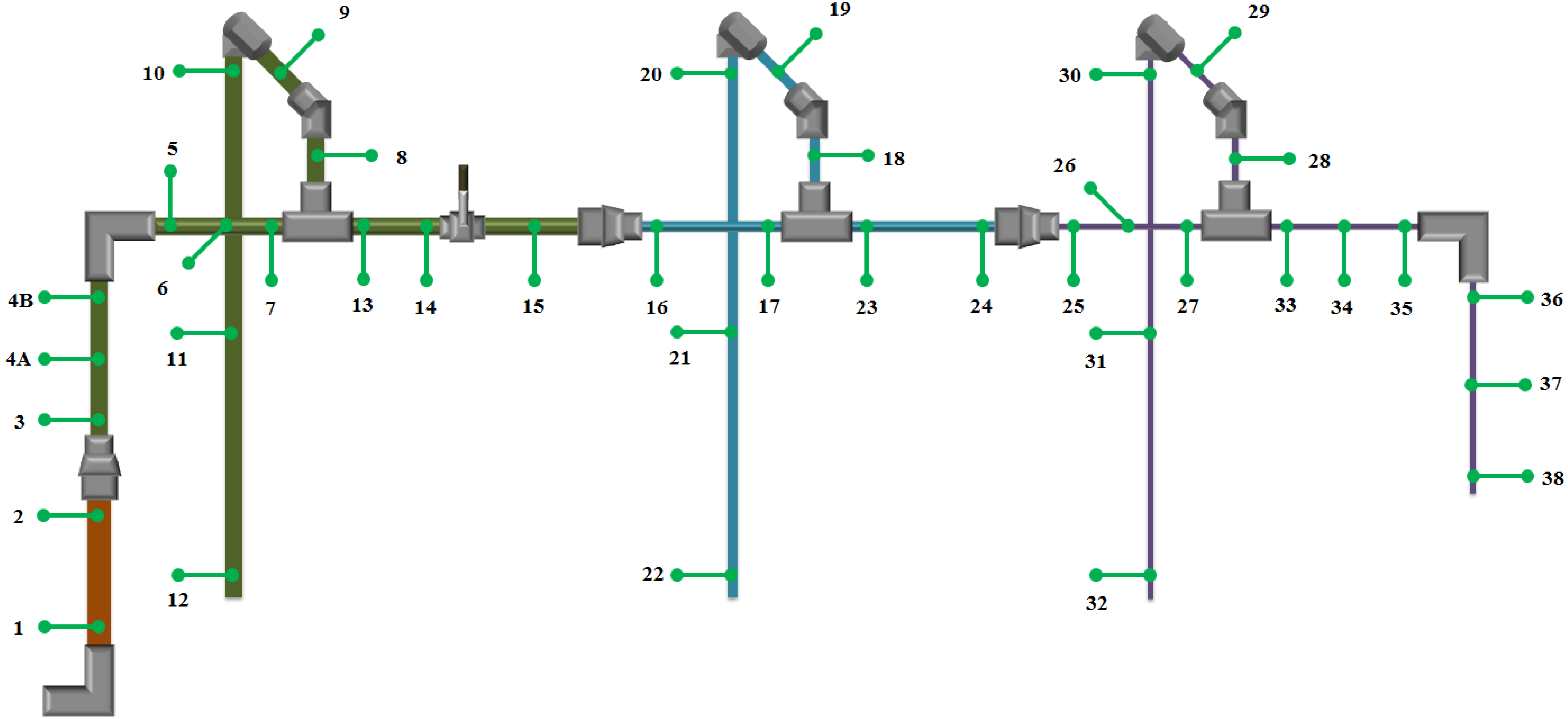


Figure B13. Pipe Diagram Illustrating Cross-Section Cut Locations.

Table B20 thru B22 detail the pooling and coating thickness analysis for the different pipe segments.

Table B20. Black Iron (Pipe Segment No. 1) Coating Thickness and Cross-Sectional Area % Reduction Due to Coating with Pooling and Not Pooling

		COATHING THICKNESS																				
		BLACK IRON							RADIUS		CROSS-SECTION AREA - NO POOLING				CROSS-SECTION - POOLING & COATING							
ACTUAL ID						MEAN COATING THICKNESS			R_{BEFORE}	R_{AFTER}	A_{BEFORE}	A_{AFTER}	DIFFERENCE		h_{BEFORE}	h_{AFTER}	θ	$A_{POOLING}$	$A_{COATING}$	A_{AFTER}	DIFFERENCE	
INCH	CUT No.	3	6	9	12	µm	MILS	INCH	INCH		$(INCH)^2$			%	INCH		RAD	$(INCH)_2$				%
2.0648	1							0.055	1.03	0.9774	3.3483	3.0010	0.1037	**10.37**								
	2	1092	1082	1069	1054	1074	42.3	0.0423	1.03	0.9901	3.3483	3.0796	0.0803	**8.03**								
1.6410	3	689	730	709	765	723	28.5	0.0285	0.82	0.7920	2.1150	1.9707	0.0682	**6.82**								
	4A	584	618	652	623	619	24.4	0.0244	0.82	0.7961	2.1150	1.9912	0.0585	**5.85**								
	4B	367	431	420	644	466	18.3	0.0183	0.82	0.8022	2.1150	2.0216	0.0442	**4.42**								
	5	371	POOLING	353	386	370	14.6	0.0146	0.82	0.8059	2.1150				0.0845	0.0699	0.8393	0.0309	0.0744	2.0097	0.0498	**4.98**
	6	267	POOLING	262	282	270	10.6	0.0106	0.82	0.8099	2.1150				0.0978	0.0871	0.9361	0.0429	0.0545	2.0176	0.0461	**4.61**
	7	428	POOLING	84.75	428	314	12.3	0.0123	0.82	0.8082	2.1150				0.0825	0.0702	0.8395	0.0311	0.0632	2.0207	0.0446	**4.46**
	8	433	POOLING	422	379	411	16.2	0.0162	0.82	0.8043	2.1150				0.0440	0.0278	0.5274	0.0078	0.0827	2.0245	0.0428	**4.28**
	9	310	POOLING	329	362	334	13.1	0.0131	0.82	0.8074	2.1150				0.1013	0.0881	0.9431	0.0436	0.0672	2.0042	0.0524	**5.24**
	10	619	799	625	628	668	26.3	0.0263	0.82	0.7942	2.1150	1.9816	0.0631	**6.31**								
	11	925	1145	979	1135	1046	41.2	0.0412	0.82	0.7793	2.1150	1.9080	0.0979	**9.79**								
	12	225	130	134	423	228	9.0	0.0090	0.82	0.8115	2.1150	2.0690	0.0218	**2.18**								
	13	297	POOLING	299	255	284	11.2	0.0112	0.82	0.8093	2.1150				0.1023	0.0911	0.9580	0.0458	0.0572	2.0120	0.0487	**4.87**
	14	216	1094	236	152	425	16.7	0.0167	0.82	0.8038	2.1150	2.0297	0.0403	**4.03**								
	15	264	POOLING	186	234	228	9.0	0.0090	0.82	0.8115	2.1150				0.1085	0.0995	1.0009	0.0523	0.0460	2.0166	0.0465	**4.65**
1.0705	16	138	1068	145	144	374	14.7	0.0147	0.54	0.5205	0.9000	0.8512	0.0542	**5.42**								
	17	38	509	55.25	219	205	8.1	0.0081	0.54	0.5272	0.9000	0.8731	0.0300	**3.00**								
	18	139	126	162	144	143	5.6	0.0056	0.54	0.5296	0.9000	0.8812	0.0209	**2.09**								
	19	95	219	128	115.75	139	5.5	0.0055	0.54	0.5298	0.9000	0.8817	0.0204	**2.04**								
	20	187	192	190	160	182	7.2	0.0072	0.54	0.5281	0.9000	0.8761	0.0266	**2.66**								
	21	166	160	172	145	161	6.3	0.0063	0.54	0.5289	0.9000	0.8789	0.0235	**2.35**								
	22	64.5	70	92.75	83.25	78	3.1	0.0031	0.54	0.5322	0.9000	0.8898	0.0114	**1.14**								
	23	140	1029	139	131	360	14.2	0.0142	0.54	0.5211	0.9000	0.8530	0.0522	**5.22**								
	24	118	POOLING	114.25	79.5	104	4.1	0.0041	0.54	0.5312	0.9000				0.1543	0.1502	1.5418	0.0765	0.0137	0.8099	0.1002	**10.02**
0.6228	25	68.25	644	114.75	59.5	222	8.7	0.0087	0.31	0.3026	0.3046	0.2878	0.0553	**5.53**								
	26	83.5	70	95	119	92	3.6	0.0036	0.31	0.3078	0.3046	0.2976	0.0231	**2.31**								
	27	84.75	37.5	324	62.5	127	5.0	0.0050	0.31	0.3064	0.3046	0.2949	0.0319	**3.19**								
	28	138	126	103.25	209	144	5.7	0.0057	0.31	0.3057	0.3046	0.2936	0.0361	**3.61**								
	29	106.5	459	92.5	95.25	188	7.4	0.0074	0.31	0.3040	0.3046	0.2903	0.0471	**4.71**								
	30	171	145	180	210	177	6.9	0.0069	0.31	0.3044	0.3046	0.2911	0.0441	**4.41**								
	31	168	144	128	184	156	6.1	0.0061	0.31	0.3052	0.3046	0.2927	0.0391	**3.91**								
	32	61.75	80.75	75.25	82.75	75	3.0	0.0030	0.31	0.3084	0.3046	0.2988	0.0189	**1.89**								
	33	218	101.75	91.5	104	129	5.1	0.0051	0.31	0.3063	0.3046	0.2948	0.0323	**3.23**								
	34	84.5	183	89.5	80.75	109	4.3	0.0043	0.31	0.3071	0.3046	0.2962	0.0275	**2.75**								
	35	85	145	72.5	78.25	95	3.7	0.0037	0.31	0.3076	0.3046	0.2973	0.0239	**2.39**								
	36	76.75	98.75	86.5	91.25	88	3.5	0.0035	0.31	0.3079	0.3046	0.2978	0.0222	**2.22**								
	37	82.5	79.75	78	78.75	80	3.1	0.0031	0.31	0.3082	0.3046	0.2985	0.0201	**2.01**								
	38	18.75	34.5	19.75	32.75	26	1.0	0.0010	0.31	0.3103	0.3046	0.3026	0.0067	**0.67**								

Table B21. Galvanized (Pipe Segment No. 2) Coating Thickness and Cross-Sectional Area % Reduction Due to Coating with Pooling and Not Pooling

COATING THICKNESS																						
		GALVANIZED							RADIUS		CROSS-SECTION AREA - NO POOLING				CROSS SECTION AREA - POOLING & COATING							
ACTUAL ID						MEAN			R_{BEFORE}	R_{AFTER}	A_{BEFORE}	A_{AFTER}	DIFFERENCE		h_{BEFORE}	h_{AFTER}	θ	$A_{POOLING}$	$A_{COATING}$	A_{AFTER}	DIFFERENCE	
INCH	CUT No.	3	6	9	12	µm	MILS	INCH	INCH		$(INCH)^2$			%	INCH		RAD	$(INCH)_2$				%
2.0220	1							0.0528	1.0110	0.9583	3.2111	2.8847	0.1016	**10.16**								
	2	993	1024	1111	1012	1035	40.7	0.0407	1.0110	0.9703	3.2111	2.9575	0.0790	**7.90**								
1.6490	3	756	693	675	712	709	27.9	0.0279	0.82	0.7966	2.1357	1.9935	0.0666	**6.66**								
	4A	589	614	589	580	593	23.3	0.0233	0.82	0.8012	2.1357	2.0164	0.0558	**5.58**								
	4B	301	713	323	344	420	16.5	0.0165	0.82	0.8080	2.1357	2.0508	0.0397	**3.97**								
	5	356	POOLING	379	347	361	14.2	0.0142	0.82	0.8103	2.1357				0.0830	0.0688	0.8301	0.0302	0.0729	2.0325	0.0483	**4.83**
	6	273	POOLING	319	269	287	11.3	0.0113	0.82	0.8132	2.1357				0.0818	0.0705	0.8386	0.0314	0.0581	2.0461	0.0419	**4.19**
	7	168	POOLING	239	842	416	16.4	0.0164	0.82	0.8081	2.1357				0.0670	0.0506	0.7116	0.0191	0.0841	2.0325	0.0483	**4.83**
	8	482	POOLING	453	470	468	18.4	0.0184	0.82	0.8061	2.1357				0.0518	0.0333	0.5770	0.0102	0.0945	2.0310	0.0490	**4.90**
	9	471	POOLING	475	497	481	18.9	0.0189	0.82	0.8056	2.1357				0.1010	0.0821	0.9106	0.0392	0.0970	1.9995	0.0638	**6.38**
	10	721	882	621	650	719	28.3	0.0283	0.82	0.7962	2.1357	1.9916	0.0674	**6.74**								
	11	1167	1068	1116	975	1082	42.6	0.0426	0.82	0.7819	2.1357	1.9208	0.1006	**10.06**								
	12	272	298	368	208	287	11.3	0.0113	0.82	0.8132	2.1357	2.0776	0.0272	**2.72**								
	13	378	POOLING	329	313	340	13.4	0.0134	0.82	0.8111	2.1357				0.0773	0.0639	0.7990	0.0271	0.0688	2.0398	0.0449	**4.49**
	14	309	POOLING	265	271	282	11.1	0.0111	0.82	0.8134	2.1357				0.0768	0.0657	0.8091	0.0283	0.0571	2.0503	0.0400	**4.00**
	15	358	POOLING	350	289	332	13.1	0.0131	0.82	0.8114	2.1357				0.2133	0.2002	1.4354	0.1464	0.0672	1.9221	0.1000	**10.00**
1.0650	16	305	193	151	156	201	7.9	0.0079	0.53	0.5246	0.8908	0.8645	0.0295	**2.95**								
	17	158	111	82	107.5	115	4.5	0.0045	0.54	0.5307	0.9000	0.8849	0.0168	**1.68**								
	18	218	178	209	193	200	7.9	0.0079	0.54	0.5274	0.9000	0.8738	0.0291	**2.91**								
	19	161	168	164	202	174	6.8	0.0068	0.54	0.5284	0.9000	0.8772	0.0254	**2.54**								
	20	244	234	248	238	241	9.5	0.0095	0.54	0.5258	0.9000	0.8684	0.0351	**3.51**								
	21	191	211	256	190	212	8.3	0.0083	0.54	0.5269	0.9000	0.8722	0.0309	**3.09**								
	22	96.75	114	154	139	126	5.0	0.0050	0.54	0.5303	0.9000	0.8834	0.0184	**1.84**								
	23	196	POOLING	209	179	195	7.7	0.0077	0.54	0.5276	0.9000				0.0470	0.0393	0.7772	0.0106	0.0256	0.8639	0.0402	**4.02**
	24	158	POOLING	207	166	177	7.0	0.0070	0.54	0.5283	0.9000				0.1220	0.1150	1.3450	0.0517	0.0233	0.8251	0.0833	**8.33**
	25	229.25	POOLING	183	121.75	178	7.0	0.0070	0.32	0.3112	0.3180				0.1210	0.1140	1.7691	0.0382	0.0139	0.2660	0.1636	**16.36**
0.6363	26	115.75	72.5	131	124.75	111	4.4	0.0044	0.32	0.3138	0.3180	0.3093	0.0273	**2.73**								
	27	46.75	45	139	68.75	75	2.9	0.0029	0.32	0.3152	0.3180	0.3122	0.0184	**1.84**								
	28	128	146	221	108	151	5.9	0.0059	0.32	0.3122	0.3180	0.3063	0.0370	**3.70**								
	29	135	321	142	158	189	7.4	0.0074	0.32	0.3107	0.3180	0.3033	0.0462	**4.62**								
	30	160	159	224	172	179	7.0	0.0070	0.32	0.3111	0.3180	0.3041	0.0437	**4.37**								
	31	203	258	241	155	214	8.4	0.0084	0.32	0.3097	0.3180	0.3014	0.0523	**5.23**								
	32	102.75	104.5	91.5	144	111	4.4	0.0044	0.32	0.3138	0.3180	0.3094	0.0272	**2.72**								
	33	133	215	151	227	182	7.1	0.0071	0.32	0.3110	0.3180	0.3039	0.0444	**4.44**								
	34	161	151	199	205	179	7.0	0.0070	0.32	0.3111	0.3180	0.3041	0.0438	**4.38**								
	35	92	113	119	128	113	4.4	0.0044	0.32	0.3137	0.3180	0.3092	0.0278	**2.78**								
	36	195	158	221	179	188	7.4	0.0074	0.32	0.3108	0.3180	0.3034	0.0460	**4.60**								
	37	254	148	149	156	177	7.0	0.0070	0.32	0.3112	0.3180	0.3043	0.0433	**4.33**								
	38	96	91.75	56.75	91.5	84	3.3	0.0033	0.32	0.3149	0.3180	0.3114	0.0207	**2.07**								

Table B22. Copper (Pipe Segment No. 3) Coating Thickness and Cross-Sectional Area % Reduction Due to Coating with Pooling and Not Pooling

COATING THICKNESS																						
		COPPER							RADIUS		CROSS-SECTION AREA - NO POOLING				CROSS SECTION AREA - POOLING & COATING							
ACTUAL ID						MEAN			R_{BEFORE}	R_{AFTER}	A_{BEFORE}	A_{AFTER}	DIFFERENCE		h_{BEFORE}	h_{AFTER}	θ	$A_{POOLING}$	$A_{COATING}$	A_{AFTER}	DIFFERENCE	
INCH	CUT No.	3	6	9	12	µm	MILS	INCH	INCH		$(INCH)^2$			%	INCH		RAD	$(INCH)_2$				%
2.0210	1							0.0300	1.0105	0.9805	3.2079	3.0203	0.0585	**5.85**								
	2							0.0273	1.0105	0.9833	3.2079	3.0372	0.0532	**5.32**								
1.5057	3	361	426	383	378	387	15.2	0.0152	0.7528	0.7376	1.7805	1.7092	0.0401	**4.01**								
	4A	367	296	258	385	327	12.9	0.0129	0.7528	0.7400	1.7805	1.7202	0.0339	**3.39**								
	4B	104	122.75	64	396	172	6.8	0.0068	0.7528	0.7461	1.7805	1.7487	0.0179	**1.79**								
	5	241	POOLING	237	213	230	9.1	0.0091	0.7528	0.7438	1.7805				0.0478	0.0387	0.6479	0.0123	0.0426	1.7256	0.0308	**3.08**
	6	209	POOLING	165	123	166	6.5	0.0065	0.7528	0.7463	1.7805				0.0705	0.0640	0.8342	0.0260	0.0307	1.7238	0.0319	**3.19**
	7	67.75	POOLING	52.25	259	126	5.0	0.0050	0.7528	0.7479	1.7805				0.0550	0.0500	0.7357	0.0181	0.0234	1.7390	0.0233	**2.33**
	8	279	POOLING	250	301	277	10.9	0.0109	0.7528	0.7419	1.7805				0.0323	0.0214	0.4810	0.0050	0.0512	1.7243	0.0316	**3.16**
	9	147.75	POOLING	223	230	200	7.9	0.0079	0.7528	0.7449	1.7805				0.0273	0.0194	0.4570	0.0044	0.0371	1.7391	0.0233	**2.33**
	10	538	558	536	656	572	22.5	0.0225	0.7528	0.7303	1.7805	1.6756	0.0589	**5.89**								
	11	474	531	516	460	495	19.5	0.0195	0.7528	0.7333	1.7805	1.6895	0.0511	**5.11**								
	12	98.75	152	136	111.5	125	4.9	0.0049	0.7528	0.7479	1.7805	1.7574	0.013	**1.30**								
	13	196	POOLING	219	204	206	8.1	0.0081	0.7528	0.7447	1.7805				0.0540	0.0459	0.7057	0.0158	0.0382	1.7265	0.0304	**3.04**
	14	139	POOLING	161	87.25	129	5.1	0.0051	0.7528	0.7478	1.7805				0.0458	0.0407	0.6626	0.0133	0.0240	1.7433	0.0209	**2.09**
	15	140	POOLING	123	104.25	122	4.8	0.0048	0.7528	0.7480	1.7805				0.1388	0.1339	1.2154	0.0778	0.0227	1.6800	0.0564	**5.64**
1.0277	16	70	500	71.25	45.25	172	6.8	0.0068	0.5138	0.5071	0.8295	0.8078	0.0261	**2.61**								
	17	46.75	347	71	87.75	138	5.4	0.0054	0.5138	0.5084	0.8295	0.812	0.0211	**2.11**								
	18	59.5	82	334	39	129	5.1	0.0051	0.5138	0.5088	0.8295	0.8132	0.0196	**1.96**								
	19	114	48	54.5	63.25	70	2.8	0.0028	0.5138	0.5111	0.8295	0.8206	0.0107	**1.07**								
	20	167	119.75	166	109	140	5.5	0.0055	0.5138	0.5083	0.8295	0.8117	0.0214	**2.14**								
	21	118	123.75	116	141.75	125	4.9	0.0049	0.5138	0.5089	0.8295	0.8137	0.019	**1.90**								
	22	42.25	65	57	68	58	2.3	0.0023	0.5138	0.5115	0.8295	0.8221	0.0089	**0.89**								
	23	118	POOLING	96.25	85.5	100	3.9	0.0039	0.5138	0.5099	0.8295				0.0445	0.0406	0.8032	0.0109	0.0127	0.8059	0.0284	**2.84**
	24	48.25	POOLING	57	33	46	1.8	0.0018	0.5138	0.5120	0.8295				0.0315	0.0297	0.6844	0.0068	0.0058	0.8168	0.0153	**1.53**
0.5533	25	195	164	158	171	172	6.8	0.0068	0.2767	0.2699	0.2405	0.2288	0.0484	**4.84**								
	26	164	159	191	179	173	6.8	0.0068	0.2767	0.2698	0.2405	0.2288	0.0487	**4.87**								
	27	175	149	145	154	156	6.1	0.0061	0.2767	0.2705	0.2405	0.2299	0.0438	**4.38**								
	28	177	170	230	177	189	7.4	0.0074	0.2767	0.2692	0.2405	0.2277	0.0529	**5.29**								
	29	173	164	219	210	192	7.5	0.0075	0.2767	0.2691	0.2405	0.2275	0.0538	**5.38**								
	30	208	214	215	221	215	8.4	0.0084	0.2767	0.2682	0.2405	0.226	0.0601	**6.01**								
	31	196	194	195	193	195	7.7	0.0077	0.2767	0.2690	0.2405	0.2273	0.0546	**5.46**								
	32	121	107	120	132	120	4.7	0.0047	0.2767	0.2719	0.2405	0.2323	0.0339	**3.39**								
	33	201	247	195	167	203	8.0	0.008	0.2767	0.2687	0.2405	0.2268	0.0568	**5.68**								
	34	200	201	171	175	187	7.4	0.0074	0.2767	0.2693	0.2405	0.2279	0.0524	**5.24**								
	35	132	146	162	150	148	5.8	0.0058	0.2767	0.2709	0.2405	0.2305	0.0415	**4.15**								
	36	170	167	159	180	169	6.7	0.0067	0.2767	0.2700	0.2405	0.229	0.0475	**4.75**								
	37	144	148	164	154	153	6.0	0.006	0.2767	0.2707	0.2405	0.2301	0.0429	**4.29**								
	38	110	128	118	119	119	4.7	0.0047	0.2767	0.2720	0.2405	0.2324	0.0335	**3.35**								

Table B23 thru B25 detail the before and after pressure test results for the various pipe segments.

Table B23. Static Pressure Tests Before and After Epoxy Coating for Pipe Segments 1-3

PIPE				STATIC PRESSURE										LEAK RATE REDUCTION
				BEFORE EPOXY COATING					AFTER EPOXY COATING					
				START	END	TIME	LEAK RATE	COMMENTS	START	END	TIME	LEAK RATE	COMMENTS	
NO.	MATERIAL	DESCRIPTION	SIMULATION	PSI		MIN	PSI/MIN		PSI		MIN	PSI/MIN		%
1	BLACK IRON	2" - 1.5" - 1.0" - 0.5"	BALL VALVE OPENED	90	10	30	2.667		100	64	30	1.200		55
			BALL VALVE CLOSED	87	36	30	1.700	LEAKS NOTED IN PIPE SEGMENTS AFTER VALVE; VALVE IS NOT WORKING PROPERLY	100	54	30	1.533		10
2	GALVANIZED	2" - 1.5" - 1.0" - 0.5"	BALL VALVE OPENED	86	3	30	2.767		100	72	30	0.933		66.3
			BALL VALVE CLOSED	90	18	30	2.400	LEAKS NOTED IN PIPE SEGMENTS AFTER VALVE; VALVE IS NOT WORKING PROPERLY	100	72	31	0.903		62.4
3	COPPER	2" - 1.5" - 1.0" - 0.5"	BALL VALVE OPENED	87	0	8.47	10.276	FLUX PASTE AND ADDITIONAL SOLDERING ADDED TO SECTIONS REVEALING EXTREME LEAKS	100	100	32	0		100
			BALL VALVE CLOSED					TEST NOT PERFORMED WITH BALL VALVE CLOSED	100	100	34	0	TO CHECK FUNTIONALITY OF VALVE CAP FROM FAR END 1/2" DROP DOWN WAS REMOVED, VALVE CLOSED AND PIPELINE PRESURIZED; UNDER THESE CONDITIONS PIPELINE COULD ONLY BE PRESSURIZED TO 40 PSI AS LONG AS CONSTANT SUPPLY OF AIR WAS APPLIED; AIR COMES OUT OF THE 1/2"	

Table B24. Static Pressure Tests Before and After Epoxy Coating for Pipe Segments 4-9

				STATIC PRESSURE										
				BEFORE EPOXY COATING					AFTER EPOXY COATING					
PIPE				START	END	TIME	LEAK RATE	COMMENTS	START	END	TIME	LEAK RATE	COMMENTS	LEAK RATE REDUCTION
NO.	MATERIAL	DESCRIPTION	SIMULATION	PSI		MIN	PSI/MIN		PSI		MIN	PSI/MIN		%
4	BLACK IRON	1" (10 - 1/4" PINEHOLES)	ABOVE GROUND					PRESSURE DID NOT HOLD	101	101	31	0	AFTER 24 HRS, ANALOG GAUGE STILL READ 101 PSI	
5	BLACK IRON	1" (10 - 1/8" PINEHOLES)	ABOVE GROUND					PRESSURE DID NOT HOLD					PIPELINE HOLDS 1 PSI AS LONG AS A CONSTANT SUPPLY OF AIR FROM COMPRESSOR IS PROVIDED; ONCE AIR SUPPLY IS CUT OFF PRESSURE DROPS TO ZERO PSI IMMEDIATELY	
6	BLACK IRON	1" (10 - 1/16" PINEHOLES)	ABOVE GROUND					PRESSURE DID NOT HOLD	44	0	0.05	880	PIPELINE HOLDS ABOUT 44 PSI AS LONG AS CONSTANT SUPPLY OF AIR FROM COMPRESSOR IS PROVIDED; ONCE AIR IS CUT OFF PRESSURE DROPS TO ZERO PSI IN 3 SEC	
7	BLACK IRON	1" (6 - 1/4" PINEHOLES)	BURIED PIPELINE					PRESSURE TEST NOT CONDUCTED PRIOR TO EPOXY COATING; ASSUMED PRESSURE COULD NOT HOLD					PIPELINE HOLDS 1 PSI AS LONG AS A CONSTANT SUPPLY OF AIR FROM COMPRESSOR IS PROVIDED; ONCE AIR SUPPLY IS CUT OFF PRESSURE DROPS TO ZERO PSI IMMEDIATELY	
8	BLACK IRON	1" (6 - 1/8" PINEHOLES)	BURIED PIPELINE					PRESSURE TEST NOT CONDUCTED PRIOR TO EPOXY COATING; ASSUMED PRESSURE COULD NOT HOLD	85	0	0.08	1020	PIPELINE HOLDS 85 PSI AS LONG AS A CONSTANT SUPPLY OF AIR FROM COMPRESSOR IS PROVIDED; ONCE AIR SUPPLY IS CUT OFF PRESSURE DROPS TO ZERO PSI IN 5 SEC	
9	BLACK IRON	1" (6 - 1/16" PINEHOLES)	BURIED PIPELINE					PRESSURE TEST NOT CONDUCTED PRIOR TO EPOXY COATING; ASSUMED PRESSURE COULD NOT HOLD	100	100	31	0		

Table B25. Static Pressure Tests Before and After Epoxy Coating for Pipe Segments 10-13

				STATIC PRESSURE										
				BEFORE EPOXY COATING					AFTER EPOXY COATING					
PIPE				START	END	TIME	LEAK RATE	COMMENTS	START	END	TIME	LEAK RATE	COMMENTS	LEAK RATE REDUCTION
NO.	MATERIAL	DESCRIPTION	SIMULATION	PSI		MIN	PSI/MIN		PSI		MIN	PSI/MIN		%
10	BLACK IRON	3" NATURAL GAS LINE						PRESSURE TEST NOT CONDUCTED PRIOR TO EPOXY COATING	100	100	30	0		
11	BLACK IRON	1" ANCHOR TOOTH TEST						PRESURE TEST DOES NOT APPLY FOR PIPELINE					PRESSURE TEST DOES NOT APPLY FOR PIPELINE	
12	BLACK IRON	1" (48' PIPE SEGMENT)		92	2	30	3.000		102	102	36	0		100
13	BLACK IRON & COPPER SECTION	1" WITH COPPER SOLDERED SECTION & TWO LOOSELY THREADED FITTINGS						PIPE SEGMENT CANNOT BE PRESSURIZED DUE TO EXTREME LEAKS	101	101	32	0	SECOND COUPLING FROM LEFT REMOVED AND REPLACED BY SHARK BITE DUE TO EXTREME LEAKING AT THAT LOCATION ONLY; PRESSURE TEST CONDUCTED WITH SHARK BITE	100

Test Bed Characteristics:

Figure B14 thru B18 provide photographs and illustrations to provide better details of the test bed.

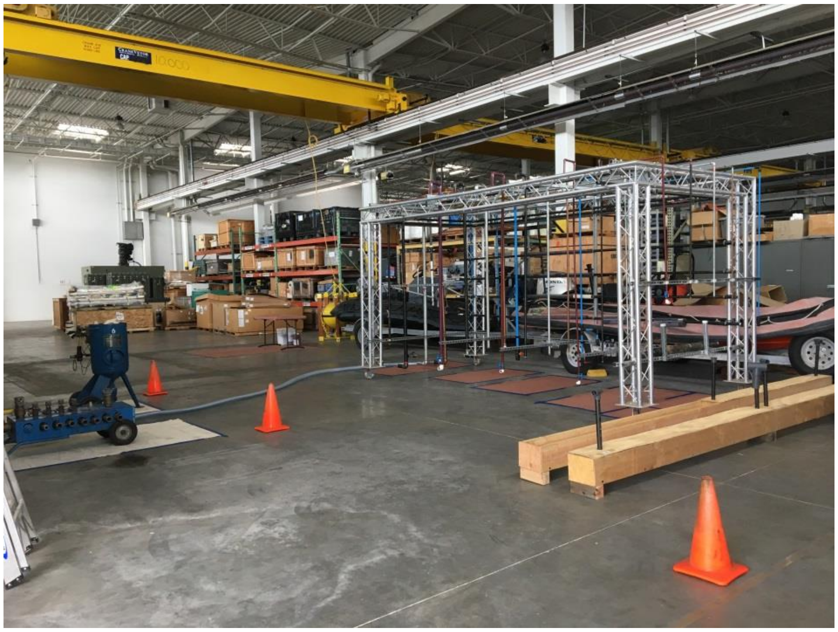


Figure B14. Test Bed and Underground Pipe Segments.

Figure B15. Close-Up of Test Bed Being Prepared for the Epoxy Application Process.

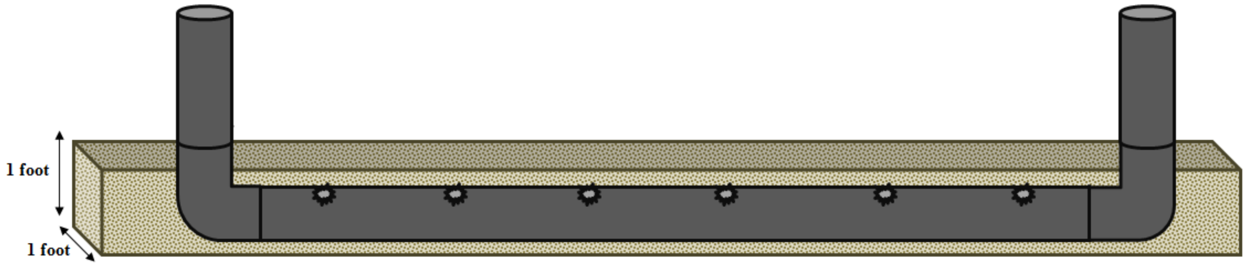


Figure B16. 1" Underground Pipeline with 6 Pin-Holes- 12 o'clock Position (3 of these underground pipelines were built for the 1/4", 1/8" and 1/16" pin-holes).

Figure B17. Underground Pipeline Segments During the Epoxy Application Process.

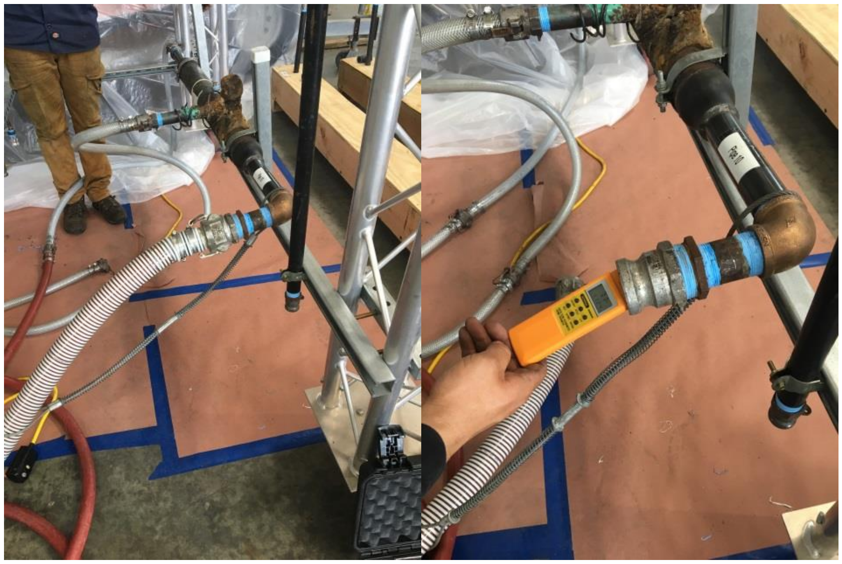


Figure B18. 3” Natural Gas Line (pipe segment no. 10 during pipe conditioning).

Appendix C: Forensic Study

Post evaluation of epoxy coating application to seal leaking underground compressed air pipeline (1 ½" diameter steel pipe) at Construction Equipment Department (CED), Naval Base Ventura County (NBVC).

Background

The existing underground pipeline at CED was abandoned in 2014 due to significant loss in pressure at the point of use. During that year the Facility Manager reported longer compressor duty cycles and visible signs of leakage (bubbling) through cracks in the surrounding paved area during rain events. To resolve the issue, Building 815 was outfitted with its own compressor. Figure D1 shows the pipeline layout.

Pipeline conditions:

- Diameter: 1 ½"
- Material: Carbon steel
- Age: Circa 60 years
- Projected depth of pipe: 24"
- Actual depth of Pipe: 24" – 40"
- Outer Coating: Yes, Mastic
- Operational Status: Offline/Abandoned circa 2014
- Total Length of pipe: Approximately 148 Feet
- Number of 90° elbows: 4 Verified by viewing camera pictures
- Number of laterals: 0
- Desired Pressure: 100 - 125 psi
- Baseline Pressure: 70 psi

Figure D1. Pipe layout between Buildings 814 and 815.

Original Hypothesis

It was originally envisioned that holes in underground pipelines (caused by corrosion) would be mostly small and surrounded by compacted soil with an associated small fillable cavity. The premise for sealing these holes was that the epoxy would fill the small cavity encased within compacted soil and ultimately serve as an external patch to the hole.

Problem Encountered

The application of the epoxy coating technology did not seal the leaks (holes) in the 1 ½” underground steel compressed air lines.

While applying the first of two required coats, Nuflow technicians quickly realized that the epoxy was not reaching/exiting the pipe outlet as expected. Nuflow technicians determined that the leak holes in the pipe were too large to fill with the epoxy. This effectively meant that the epoxy was being lost through a breach. Consequently, they projected that they would not be able to fill in the holes enough to meet the established performance objectives.

A pressure test performed after 24 hours of cure time agreed with their projection, as a pneumatic pressure test could neither reach the original baseline pressure of 70 psi nor hold any pressure once isolated. Pressure beyond 40 psi could not be achieved, and once isolated with shutoff valves the pressure dropped from 40 to 0 psi in less than 2 seconds.

Time-line:

1) Utilities mark-out by Contractor: April 19, 2017, Contractor (CPL Detection) marked out location of utilities in area of concern using radio frequency technology coupled with an electromagnetic induction clamp.
2) Baseline Pressure Pre-Test: September 12 – 15, 2017, EXWC performed a baseline pressure test and determined pressure no greater than 70 psi could be achieved with the existing air compressor (125 psi max).
3) Epoxy Application: September 19 -22, 2017, Nuflow applied the epoxy coating to the underground pipeline from Building 814 to Building 815 following their standard guidance for pipe rehabilitation.
4) Pressure Post-Test: September 25-30, 2017, EXWC performed a post pressure test and determined that epoxy coating process actually magnified the pressure loss.
5) Forensics: September 29, 2017, EXWC evaluated the use of above ground instrumentation to determine if ultrasonic equipment could be used to identify location of holes.
6) Forensic: November 15-16, 18 2017, EXWC technicians used pipeline camera to determine the location of 2 holes and found them 5 feet apart. The holes appeared greater that 1/2” in diameter. EXWC engineers exposed the compromised sections of the pipeline by excavating the existing pavement and soil. The pipeline was repaired by replacing the leaking pipe section with a new section of epoxy coated pipe.

7) Forensics: December 12, 2017, a five foot section of the compromised pipe was completely removed and inspected.

Utilities Mark-out and Pre-Pipe Inspection

A local utility company (CPL Detection) was hired to mark-out utilities on the ground surface and perform a pipeline camera inspection of the 4” and 1 ½” pipeline. CPL marked out the compressed air line with white dots in increments of approximately 25 feet. The company was not able to insert the camera head through most of the 4” diameter pipe. The initial 90 degree elbows did not permit penetration of the camera and cable, so the full scope of the internal pipe condition could not be ascertained. The 1 ½” diameter pipe was not imaged for similar reasons. A second company was contacted to conduct the pipes’ camera inspection; however, they also encountered problems getting the camera through the 90 degree elbows (Note: Several Utilities Inspection Service companies were contacted and none were equipped to perform inspections on small diameter pipelines other than very short runs).

.

EXWC did extensive research and found one special camera that could be inserted into the 1 ½” diameter pipe; the only shortcoming was that the camera’s cable had a range of 60 feet. The subject 1 ½” diameter pipeline was inspected with this camera to evaluate the conditions and check for holes/breaches. Again, due to the relatively small diameter of the pipe and the use of short sweep elbows (typical in compressed air systems), the camera’s head was not able to advance through about 40% of the pipeline’s length. As for the remaining 60%, no holes were found but there were areas encountered that had moderate to high levels of corrosion; this corrosion is typical to steel point submerged in water Figures 2D and 3D display the interior pipe condition.

Figure D2. Photo of inner pipe near one leak point and prior to epoxy application (35’ from camera’s insertion point).

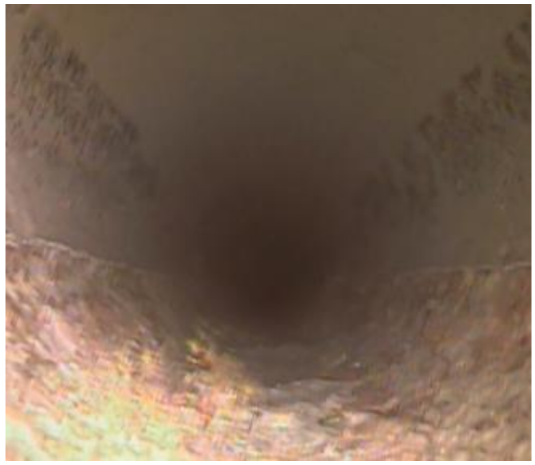


Figure D3. Photo of inner pipe near another leak point and prior to epoxy application (40' from camera's insertion point).

Baseline Pressure Pre-Test

To determine the baseline pressure drop across the pipeline (prior to application of epoxy coating), the pipe ends were configured with leak-tight shutoff valves and pressurized by EXWC to 70 psi using the compressor serving Building 1497. During the baseline test, engineers noted some dust clouds appearing at various locations above the pipeline through cracks in overlying concrete and asphalt surface. Some of the cracks were several yards away from the known location of the underground pipeline. The flow was then stopped with the existing gate valve in Building 814 and the time for the pressure to drop to zero was measured. The pressure within the pipeline dropped from 70 psi to 0 psi in approximately 5 minutes.

Epoxy Application

The epoxy application was performed by Nuflow technicians one week after the baseline pressure pre-tests were completed. The pipeline was blasted with abrasive garnet for several cycles at 800 CFM for a total of 20 minutes and dried prior to the epoxy application. After the blasting operations, the line was pressurized but could only achieve 20 psi while air was flowing. Nuflow technicians attempted to introduce the first coat of epoxy after checking the surface roughness generated by the blasting operation.. As mentioned above, the technicians became concerned with achieving the desired epoxy coating results as the epoxy did not exit the pipe end as expected. Based on the initial amount of epoxy estimated to provide a 5 mm uniform-coating, the entire length of the pipeline should have been fully coated.

Figure D4 shows the end of the pipeline after the initial amount of epoxy was applied. At that time, the entire wall surface of the pipeline should have been coated by the epoxy. Figure D4 also provides a glimpse of how the epoxy coat generates within the pipeline. Needless to say, additional epoxy was required to fully coat the pipe.

To generate a uniform coating thickness throughout the pipeline, it was determined to introduce the epoxy in opposite directions. On Day 1 of the epoxy application process, the epoxy was introduced through an inlet located in Building 815 to Building 814. On Day 2 of the process, the epoxy was introduced from Building 814 to Building 815. The first epoxy coat was allowed to cure for 24 hours before the second epoxy coat was applied.

Figure D4. Photo of pipe's end near Building 814 that should have been fully coated after applying initial amount of epoxy.

Pressure Post-Test

EXWC engineers performed a pressure test after a 24 hour cure time of the first coating. They found that the highest achievable pressure in the 1 ½" pipeline was 40 psi. After the pipeline was isolated with shutoff valves and the supply of compressed air was cut, the pressure within the pipe dropped from 40 to 0 psi in less than 2 seconds.

Forensics to Determine location of Leak(s) and Failure Mechanism

Use of Ultrasonic Leak Detection to Locate Holes

Figure D5 shows EXWC technicians using an ultrasonic leak detection sensor with a surface bridging adapter to determine if the leaks could be identified above ground. The equipment was used a few years ago with some success in a compressed air survey/audit performed at Joint Base Pearl Harbor Hickam, Hawaii. The technician using that technology did detect leaks, but they were not at the locations identified by the camera inspection. The ultrasonic leak detection sensor predicted location of the holes to be approximately 10-20 feet further away.

Figure D5: Picture of technician using ultrasonic leak detection sensor to locate holes.

Day One (November 15, 2017): Pipeline Camera Inspection

EXWC technician used a pipeline camera to pinpoint the location of two leak points. Two major holes were found with the camera. Figure D6 shows the holes, which were situated at approximately 35 and 40 feet from the entrance point located in Building 814.

Figure D6. Photo of inner pipe after application of epoxy and near leak point at 40'.

The local utility location service company (CPL Detection) hired to map the location of the 1 ½" pipeline marked its relative surface location on the ground with paint. Figure D1 shows the impressed marks suggest the pipeline ran in a slightly skewed path line from Building 814, connected to a perpendicular pipe section which subsequently connected to a perpendicular line coming from Building 815. Nonetheless, EXWC engineers suspected that the above ground markings were slightly off, as it is customary in pipe construction practices to follow perpendicular sight lines to connecting buildings. The previously mentioned marking in connection with the pipeline camera were used to identify the point above ground where leaks were located.

EXWC engineers used the pipeline camera's cable to locate one of the leaks. In summary, the camera was pushed through the inlet in Building 814 until it encountered the first 90 degree elbow some distance between Buildings 814 and 815. The cable length used up to that point was measure; from that length 24" were subtracted to compensate for the cable used to insert the camera through the inlet before reaching the underground pipeline. The remaining length was extended above ground surface starting from the inlet to estimate the point above ground for the leak

The EXWC team marked a 7'x7' area over the estimated leak location which also accounted for both line directions (straight perpendicular or angled) so that the leak would be accessible regardless of position. This area of asphalt was removed by a contractor.

The team excavated the pipe line once the asphalt was removed. Initially, shovels and pickaxes were used to loosen and remove rocks and soil down to a depth of 24" on opposite corners of the 7'x7' patch of exposed earth. When no underground pipeline was discovered it was decided to continue digging deeper. The packed earth proved to be time consuming and exhaustive work to remove with shovels and pickaxes, thus an electric impulse hammer with a wedged head was obtained to speed up the digging process.

The underground pipelines were pressurized periodically throughout the process to listen for air leaks which might hint at the actual location of the underground pipeline. The team began to find air leaking from fissures in the dirt at a depth of approximately 2.5 to 3 feet. As the team continued to dig, air leaks were discovered in different locations from different fissures, making it difficult to pinpoint the exact location of the pipeline. The leaking air seemed to have penetrated or created a network of fissures in the soil surrounding the pipeline which snaked their way to the surface. These leaks were located in the general vicinity of both holes.

It was not until a depth of 3 to 4 feet that a large air passage in the dirt was discovered. The team then focused the digging effort on this air passage in hopes of finding the underground pipeline.

Removing the soil surrounding the air passage led to the discovery of a large void in the earth above the pipeline. Figure D7 display the hole, which was estimated to be slightly larger than a cubic foot in volume. Presumably, this void was created from years of leaking compressed air which slowly stripped the soil surrounding the pipeline and pushed it through soil cracks and fissures induced by pressure as well as above ground road activity. Engineers noted that the void's outer shell was fully coated with epoxy ranging from 1/16" to ½" thick and wondered if it may have been better to use ground penetrating radar (GPR) to identify the exact location of the pipeline. Using GPR may have detected the presence of the voids and major breaches which could have been used to better select pipe repair/replacement procedures.

Figure D7. Void region in the soil above the pipeline.

Figure D8 shows the inner walls of the void were coated in large amounts of epoxy resin that had to be chipped away or broken when digging into the void. The amount of the epoxy deposited in this void seemed to be much more than the quantity originally estimated to coat the entire length of the pipeline (i.e., beginning to end). The coating was paper thin in some areas and inches thick in others. The coating seeped into pores and fissures in the dirt and between rocks to form a solid matrix of dirt, rocks, and resin in the thickest areas.

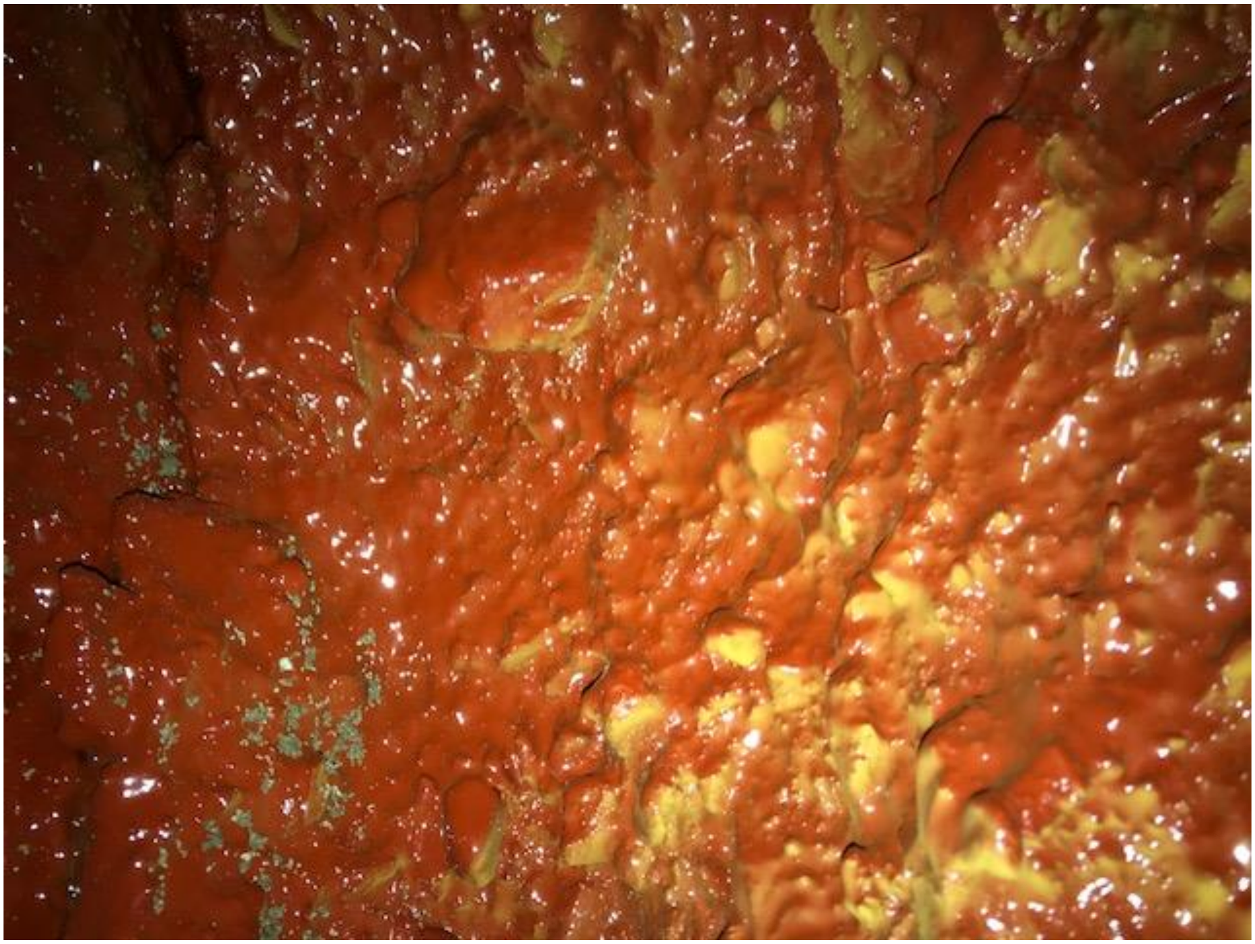


Figure D8. Hardened epoxy coating on the inner side walls of the void.

After digging out the void, the underground pipeline was discovered directly underneath. Figure D9 displays the exposed pipeline with the void and the associated leak located on the left.

Figure D9. Exposed length of underground pipeline within the 7'x7' area.

The pipeline had originally been wrapped in a protective material. However, this material was significantly deteriorated in the uncovered area. The wrap had become rough, hard, and extremely brittle. Figure D10 shows the condition of the pipeline with protective wrap. In some sections of the pipe it was difficult to differentiate the wrapping material from corrosion. Nonetheless, corrosion was prevalent on the pipe in particular in the areas surrounding the holes responsible for the leaks. In addition, loss in pipe wall thickness was exhibited around the holes. Sections of pipe around the holes were only a few millimeters thick. Both holes were located in the 12 o'clock position. The cause for the accelerated corrosion is unknown but it is suspected that previous construction/excavation in the area directly above the underground pipeline may have compromised its integrity.

Figure D10. The picture shows one the leaks that formed as a result of heavy corrosion.

The actual depth of the pipe where the excavation occurred was roughly 40” below grade. This is substantially deeper than the initial elbow fitting found in the inlet at Building 814 which had a depth of about 24”. The section of pipe excavated did not have an apparent slope and the initial visual inspection using the camera line did not give any obvious indication of a downward slope. The team assumes that the higher than expected depth is due to a gradual S-curve bend downwards from the initial elbow joint.

Figure D11 displays the exposed damaged pipe and the surrounding area which was marked with hazard cones as establish by safety regulations .

Figure D11. Excavation area marked with hazard cones for safety.

Day Two (November 16, 2017): Pipe Section Repaired and Replaced

Further excavating was necessary around the pipeline in order to have enough space to carry out the necessary pipe repairs. Most of the exposed pipeline, including both holes, were cut and removed with an angle grinder. The removed pipe section was replaced with a new galvanized pipe internally coated during the demonstration of the epoxy technology; a circular pipe saw was used to cut the equivalent length from the freshly coated pipe. Figure D12 and D13 shows that Straub couplings were used to connect the new pipeline to the existing pipeline, and the new section was wrapped in a protective tape to prevent future corrosion.

Figure D12. Pipe replacement installed and wrapped in protective tape.

Figure D13. Pipe replacement with Straub couplings wrapped in protective tape.

After completing the pipe replacement, preparations were undertaken prior to conducting a pressure test of the entire 1 ½" compressed air pipeline. The exposed pipe was covered with about 1.5' of soil to stabilize the pipeline and prevent flexion during testing which could potentially damage the pipe. As part of the pressure test, the entire 1 ½" pipeline was pressurized; an assessment of the pipe was undertaken thereafter to check that there were no leaks. The pipe replacement withheld the pressure with no signs of leakage. Nonetheless, the pressure test revealed a different leak on the north end of the 1 ½" pipeline which was much larger than any of the ones removed during the pipe replacement. The air from the new leak escaped from underneath a section of asphalt adjacent to an older excavation site covered with a newer patch of asphalt.

Since the camera revealed no previous holes in that area, the team concluded that the leak was likely from a new hole that formed during the pressure test. Because the previous 2-holes were repaired, as the pressure in the pipeline built a third hole was generated in another area where the pipe wall may have thinned out or weakened by corrosion.

As a result of these hole-incidents, it is important to emphasize that the use of epoxy coating is most effective when the wall thickness of the pipeline is at least 60% of the original. If this is not the case, the wall thickness of the pipeline may be further compromised and reduced during the epoxy application process, in particular, the abrasive blasting step. In this case, as the pressure built during testing, a new hole was generated in an area of the pipe that must have had extremely thin wall thickness. Note that wall thickness cannot be identified by camera inspections.

Figure D14 shows the 7’x7’escavated area was filled up with soil as stipulated by pavement regulations and an asphalt patch was poured on the top layer.

Figure D14. Excavated site after asphalt was poured.

Inspection of Removed Underground Pipeline with 2-Holes

Figure D15 displays the removed underground pipe section that was analyzed in terms of hole-sizes, pipe-wall thickness and epoxy coating thickness. The pipe section consisted of 2-pipe ends and 4-pipe cuts that resulted in segments A (pipe end), AB (cut), BC (cut), CD (cut), DE (cut), and E (pipe-end). A thickness gauge was used to measure the thickness of the epoxy coating and a digital caliper was used to measure the inner diameter and wall thickness of the pipe at the 3, 6, 9, and 12 o’clock positions.

Figure D15: Removed underground pipe section and labeled segments.

Figures D16 and D17 illustrate the first and second holes, respectively, in the pipe section along with their estimated sizes. The holes were noted as being in the 12 o'clock position.

Figure D16. First-hole located in section A at the 12 o'clock position.

Figure D17. Second-hole located in section E at the 12 o'clock position.

Figure D18 shows the pipe wall thickness at each one of the cuts.

Figure D18. Visual inspection of pipe thickness at each cut.

Table 1 describes the results obtained from the different measurements taken from the pipe segments.

Table 1: Epoxy coating thickness as well as inner pipe diameters and wall thicknesses.

	Coating Thickness Based on Clock Position (µm)				Pipe Inner Diameter Based on Clock Position (ID) (in)		Pipe Wall Thickness Based on Clock Position (µm)			
Section	3	6	9	12	6-12	3-9	3	6	9	12
A	671	833	577	498	1.59	1.557				
AB	543	881	642	66.8	1.527	1.575	4079.8	3868.8	29293.4	3498.2
BC	693	1135	417	216	1.519	1.559	3498	4427.6	3469.2	3721
CD	462	996	531	322	1.5	1.561	4059.2	4033.2	3152	4224.6
DE	361	966	541	305	1.522	1.569	4033.2	4164.8	3624.6	3860.6
E	160	343	107	110	1.544	1.57	3954.8	4889.4	3855.4	4030.2

The Table 1 measurements indicate that it is fair to say that the removed underground section maintained more than 60% of the original wall thickness at each one of the cuts (i.e., AB, BC, CD and DE). Hence, it is assumed that the two holes found in the pipe section were caused by accelerated-positional corrosion induced by pipe disturbances and deterioration of the pipe's original protective wrapping as well as possible water infiltration derived from multiple dig projects conducted throughout the years and after the original installation of the underground pipeline. This is evident by the ample number of asphalt patches found on the ground surface in the areas of interest.

Final Discussion

Underground pipeline disturbance due to construction has the potential to damage pipeline external wall surface and external wrapping. For example, during excavation, equipment may impact or damage the wall surface of the pipeline generating dents or indentations that may result in either pin-holes or cracks depending on the blow or pressure exercised on the wall surface. With time these pin-holes or cracks contribute in generating concentrated external and internal corrosion in underground pipelines. The latter contributes to the deterioration of the pipe's external protective wrapping and reduction of its original wall thickness. Corrosive weak points or areas of concern on a pipeline can contribute to compressed air leakage.

The observations from the pipe removal and replacement also suggest that construction conducted after an underground pipeline is originally installed can have the tendency to disturb or damage the pipeline (i.e., protective wrapping and wall thickness). Disturbance or damage to the pipe can be either through stresses generated in the pipe surroundings or unintended-direct damage to the pipe surface. Poorly guided construction projects can also generate potential cracks within the underground compacted soil and surface asphalt resulting in direct channels for water infiltration. Constant water infiltration can contribute to corrosion.

In order for the epoxy application process to be effective, the pipeline must have at least 60% of its original wall thickness. As part of the epoxy coating process, abrasive blasting must be used to clean the interior of the pipe and remove internal pipe corrosion. If the pipe's wall thickness does not have sufficient integrity/thickness to withstand the abrasive blasting, the pipe wall may be compromised and further deteriorated. This results in sensitive epoxy coated areas that may crack or blow holes once the pipe is pressurized for testing. In addition, if the pipe has existing holes or cracks that are big enough, the epoxy may not be able to patch them up.

Lessons Learned

- As a first step, it is reasonable to explore technologies that identify the location and the layout of underground pipelines. For example, ground penetrating radar may be a better way than radio frequency technology to determine the exact location of underground pipelines that do not have current or up to date drawings.
- Introducing a pipeline camera into an unlined underground compressor pipeline has many challenges including inability to pass through short sweep 90˚elbows, multiple 90˚elbows and small diameter pipe as well as length limitations.
- As learned, camera inspection prior to epoxy application may not be adequate for identifying breaches or holes (covered by corrosion) that may be present. It may be worth considering camera inspection after abrasive blasting to confirm that all holes have been identified.

- To provide a better guarantee of success in the epoxy application process, the procedure should include an analysis to confirm that the pipe to be coated is intact, has no holes, and has a minimum wall thickness of at least 60 percent of the original in all areas. Nuflow recommends analysis of pipe wall thickness prior to the application of the epoxy; however, this may not be practical or cost effective for small diameter underground compressed air pipelines or those with short sweep elbows.
- There are several companies that can perform pipe thickness analysis but in general are limited to pipes larger than 4” diameter.
- If the pipe’s wall thickness is not at least 60 % of the original, the abrasive blasting can further deteriorate the wall thickness resulting in epoxy coated pipe sections with thinned out walls that may crack or rupture once the pipeline is pressurized.
- Compressed air pipelines exhibiting big cracks or holes, as evident by camera inspection, require pipe repair and replace prior to the epoxy application process. The demonstration illustrated that big holes cannot be patched using the epoxy application process.
- Nuflow offers a cured-in-place pipe (CIPP) restoration process to repair pipelines with identifiable cracks or holes in an efficient alternative compared to traditional pipe repair and replace practices. CIPP does not require excavation in the case of underground pipelines but it may have a limitation in terms of the pipe size for which it can be used. **
- Voids created by air leaks in underground pipelines can be substantial and could lead to failure of above ground pavements or structures if not properly addressed.
- Earth construction conducted near compressed air pipelines should take special care not to damage pipeline nor its outer wrap or coating.
- One of the benefits of applying epoxy coating to the inner wall of pipeline is reduced friction as illustrated by the pipeline camera being pushed further into the pipeline than uncoated pipe.
- Future research efforts in below ground compressed air pipeline repair should focus on low cost methods to identify exact location of air leaks, breaches and the voids spaces created by underground leaks for the case where CIPP restoration or excavation might be required. **
- The added time and cost to identifying exact location of pipeline, validating pipe wall integrity via camera/technology and fixing substantial leaks must be addressed prior to epoxy application and for determining overall feasibility. **

Appendix D: Protocol

Standard Leak Assessment Protocol for Compressed Air Systems

It is estimated that compressed air system leakage wastes approximately 20-30 percent of a compressor's output [3, 7]. In Department of Defense (DoD) industrial facilities, leaks may constitute 20 percent of the production capacity of compressed air systems [3, 7]. Hence, a Standard Leak Assessment Protocol is proposed for DoD Facility and Utility managers to assist in resolving those leaks. Reducing leaks results in reduced energy consumption, increased productivity, and improved life cycle cost in compressed air systems (CAS).

Figure 1C shows the leak assessment protocol which consists of five steps including system data collection and layout, establishing a baseline for CAS leaks and energy usage, walk-through surveys, implementing recommendations to resolve leaks, and evaluating alternative energy conservation measures (ECM) to resolve extensive and hard-to-reach leaks. The full five step protocol works best if it is initially prepared by a qualified specialist that is trained in compressed air and energy auditing, and the facility manager, as it does require a wide breath of knowledge in concepts such as mechanical, pneumatic, electrical, and energy, as well as familiarity with the local system. Once the Standard Leak Assessment Protocol is established, the facility manager and shop personnel can continually perform walk-through surveys and make repairs to reduce energy losses.

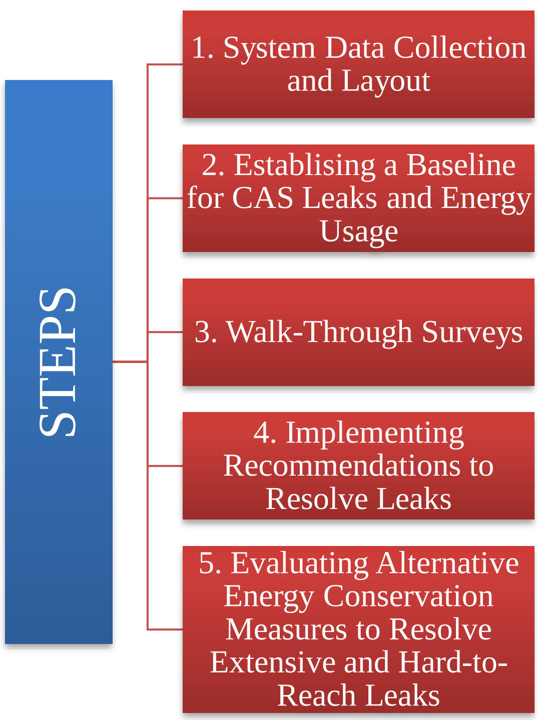


Figure 1C. Leak Assessment Protocol for CAS.

The following paragraphs describe the five-step Standard Leak Assessment Protocol for CAS in greater detail.

1.0 System Data Collection and Layout

It is critical to gather sufficient information to delineate the physical and operational characteristics of the system. Information should be collected to describe the system's environmental conditions, physical layout (e.g. original plans and specifications with subsequent modifications), parts/components (e.g. piping, storage, controls, etc.), operating data logs, recorded energy usage, duty cycles (e.g. on/off cycle, peak demand, offline periods, etc.), and present maintenance procedures [1, 6, 7]. The data collected will be used to form a preliminary assessment of the CAS and to identify potential areas of concerns regarding leaks and other energy saving opportunities. The concerns can be corroborated, discarded or redefined throughout the remaining steps of the Standard Leak Assessment Protocol.

Table 1C provides an example of a data log that can be used to collect the basic information in regards to the CAS in question.

Table 1C. CAC Schematic/Layout and General Information.*

<table>
<tr><td colspan="4">CAC Schematic/Layout</td></tr>
<tr><td colspan="4">SCHEMATIC/LAYOUT:</td></tr>
<tr><td colspan="4">MAINTENANCE INFORMATION:</td></tr>
<tr><td colspan="4">ADDITONAL NOTES:</td></tr>
<tr><td colspan="4">Pipelines and Valve/Filter Information</td></tr>
<tr><td colspan="2">Pipelines</td><td colspan="2">Valves/Filters</td></tr>
<tr><td>Material</td><td></td><td rowspan="3">Valves and Filter Types</td><td></td></tr>
<tr><td>Size Range</td><td></td><td></td></tr>
<tr><td>Joint Types</td><td></td><td></td></tr>
<tr><td>Pipe Section</td><td>Measured Pressure Losses</td><td>Valve/Filter</td><td>Measured Pressure Losses</td></tr>
<tr><td></td><td></td><td></td><td></td></tr>
<tr><td></td><td></td><td></td><td></td></tr>
<tr><td></td><td></td><td></td><td></td></tr>
<tr><td></td><td></td><td></td><td></td></tr>
<tr><td></td><td></td><td></td><td></td></tr>
<tr><td colspan="4">Air Compressor Information</td></tr>
<tr><td>Manufacturer</td><td></td><td></td><td></td></tr>
<tr><td>Model</td><td></td><td></td><td></td></tr>
<tr><td>Serial</td><td></td><td></td><td></td></tr>
<tr><td>Compressor Type</td><td></td><td></td><td></td></tr>
<tr><td>Operating Pressure Set-Points</td><td></td><td></td><td></td></tr>
<tr><td>Rated Air Flow</td><td></td><td></td><td></td></tr>
<tr><td>Rated kW</td><td></td><td></td><td></td></tr>
<tr><td>Proportion of Time On-Load</td><td></td><td></td><td></td></tr>
<tr><td>Off-Load Run Factor</td><td></td><td></td><td></td></tr>
<tr><td>Annual Run Hours</td><td></td><td></td><td></td></tr>
<tr><td>Annual Usage</td><td></td><td></td><td></td></tr>
</table>

*Table 1C was created by merging two templates provided in Reference 5.

2.0 Establishing a Baseline for CAS Leaks and Energy Usage

Baselining a CAS establishes the system's current operating conditions, determines the present operational costs, and correlates the results to the overall production levels [1, 5, 7]. As leaks are detected and repaired, a new baseline needs to be calculated. By contrasting the before and after baselines, the level of success of the leak detect and repair approach can be determined. For example, the percent reduction of the compressor's output can be computed and the latter value translates into energy savings.

There are a minimum of four measurements required to properly baseline a CAS. These include power, pressure, flow, and leak load [7]. During the collection of these measurements, it is advised to adhere to the proper safety and operational regulations particular to the facility where the CAS is located.

2.1 Power, Pressure and Flow Measurements

To obtain an accurate description of the operational characteristics and patterns of a CAS, power (amperage and voltage), pressure, and flow should be measured and recorded for a period of at least 7 to 10 days [5, 6]. The period of time must be sufficient to capture nights, weekends, and other downtimes that identify non-production demands. Table 2C describes the performance objectives of these three measurements.

Table 2C. Measurements to Baseline CAS [5, 6, 7]

Measurement	Tool	Metrics	Purpose	Calculation (If Any) or Recommended Location(s) to Record Measurement
Power	Power meter data logger	Amperage, voltage and power factor (p.f.)	To measure electricity consumption of CAS	kW* = (1.73 x volts x amps x p.f.) / 1000
Pressure	Calibrated pressure gauges or pressure loggers	psig	To provide feedback for control adjustments and determine pressure drops across equipment	• Inlet to compressor • Differential across air/lubricant separator • Pressure differentials for after-cooler, dryer, filters, long pipe segments and other critical points in the distribution system
Flow	Flow meter that accounts for mass flow; this type of meter compensates for temperature and pressure variation	cfm	To determine consumption of compressed air during a period of time that captures full range of operating requirements (e.g. shifts, non-production periods, etc.)	• Inlet of air compressor • Discharge of system prior to distribution piping

*Equation used to determine power in a three-phase meter.

2.2 Leak Load Measurement

Efficient and well maintained CAS can experience up to 10 percent air leakage [5, 7]. Any percent increase above the latter value can result in costly energy losses. Leak load measurements can be estimated using one of two methods depending on the type of controls used by the compressor. The first method is for compressors that use start/stop controls [5, 7]. This method requires calculating the average time for the compressor to undergo on-load/off-load cycles while operating at normal pressures and when the end-user equipment is turned off.

The second method is for compressors that use other control strategies and have a pressure gauge downstream of the receiver [5, 7]. This method brings the compressor to normal pressure and records the time taken by the system to drop to one-half the normal pressure; measurements should also be taken when the air-operated equipment is offline [3]. Table 3C describes both methods.

Table 3C. Computing Leak Load According to Types of Controls Used by Compressor [7]

Method	Metrics	Description	Calculation
Compressor using start/stop controls	• On-load time (T, minutes) • Off-load time (t, minutes)	• Takes a series of measurements to determine the average time to load and unload compressor • Average loading and unloading times help calculate the percent of compressed air escaping the system as a result of leaks	• Leakage (%) = [(T x 100) / (T + t)]
Compressor using other controls; pressure gauge located downstream of receiver	• Total system volume (V, ft^3) • Normal operating pressure (P_1, psig) • Lower pressure (P_2, psig) • Time for P_1 to drop to P_2 (T, minutes)	• Requires to bring the compressor to normal operating pressure conditions and determining the time that the compressor takes to drop to a lower pressure which is typically one-half of the operating pressure • Several readings should be taken to determine the average time • The equation uses a 1.25 factor to correct leaks to normal system pressure	• Leakage (cfm free air) = [V x (($P_1 – P_2$) / T) x 14.7] x 1.25

2.3 Consider Using DOE Trained AIRMaster+ Qualified Specialists to Baseline Complex CAS

Problematic multi-compressor systems supplying compressed air to two or more facilities may be best assessed by qualified specialist. There are a number of consulting firms and independent auditors that perform site audits and leak assessments to baseline CAS on DoD installations. Users must be mindful that baseline audits and leak assessments conducted by these non-government affiliated entities may differ in quality and comprehensiveness [7]. Nonetheless, the user must communicate from the beginning that the recommendations provided must be system-neutral and commercially impartial.

In selecting a qualified specialist to baseline a CAS, the user may access the website from the Department of Energy (DOE) [8, 9]. The DOE maintains a list of qualified specialists found all over the United States that are trained in using AIRMaster+. AIRMaster+ is a software tool developed by the DOE's Industrial Technologies Program (ITP) to analyze energy use and savings in industrial CAS [8, 9]. According to the DOE's AIRMaster+ fact sheet [9]:

> "AIRMaster+ provides a systematic approach to assessing the supply-side performance of compressed air systems. Using plant-specific data, the software effectively evaluates supply-side operational costs for various equipment configurations and system profiles. It provides useful estimates of the potential savings that could be gained from selected energy efficiency measures and calculates the associated simple payback periods."

As a result of the baseline audit, the trained AIRMaster+ specialist provides guidance and recommendations on energy savings opportunities as well as recommendations on new techniques and equipment to further enhance energy savings. The energy savings opportunities are derived from problems found with the CAS during the baseline audit. Example problems may include:

- Lack of maintenance
- Non-operating equipment
- Design and installation flaws
- Inadequate air storage capacity
- Excessive cycling of compressor
- Inappropriate air use
- Problems with mechanical components

- Lubricant condition
- Heat-exchange surfaces
- Effectiveness of heat-recovery
- Compressor motor and drive conditions
- Drive-belt condition and tensioning
- Cooling system operation

3.0 Walk-Through Surveys

Leaks in CAS are a major source of wasted energy. Furthermore, leaks can be attributed to critical operating malfunctions in CAS[1, 2, 5, 7]. Figure 2C shows multiple system consequences that may emanate from CAS leaks. To detect and repair leaks the user is suggested to conduct two types of surveys which include quarterly walk-through surveys and bi-annual walk-through ultrasonic leak detection surveys. In the former, the user walks closely to the CAS supply and demand piping naturally listening for leaks, whereas in the latter the user walks along the CAS supply and demand piping listening for leaks with the assistance of ultrasonic leak detection equipment.

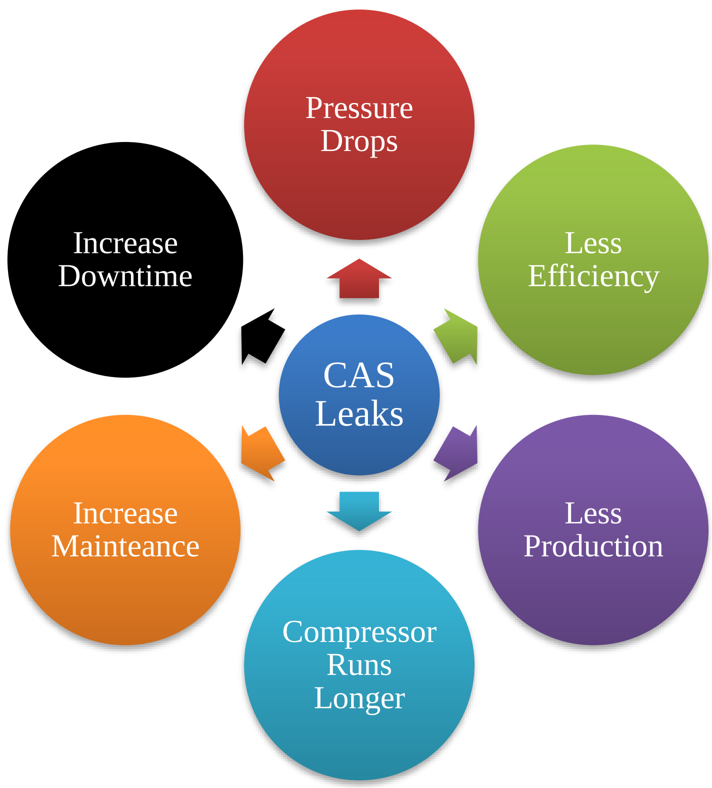


Figure 2C. Operating Malfunctions Resulting from Leaks.

Upon identifying leaks, they need to be properly tagged and recorded. As a recommendation, the user may want to keep a log book to maintain official records of the leaks found during the walk-through surveys. For each leak detected, the following information needs to be collected [5]:

- Leak description and location (Picture documentation is useful)
- Pressure at location
- Estimated leak rate
- Estimated energy cost
- Timeline to repair
- Type of repair
- Date of repair and when checked.

Figure C3 provides a sample of a tag that can be used to identify/locate leaks as well as to provide the necessary details to the personnel responsible for repairing the leak. The user should make a habit to repair the detected leaks within 7 days of discovery. Upon repair, leaks must be monitored to assure they have been completely resolved.

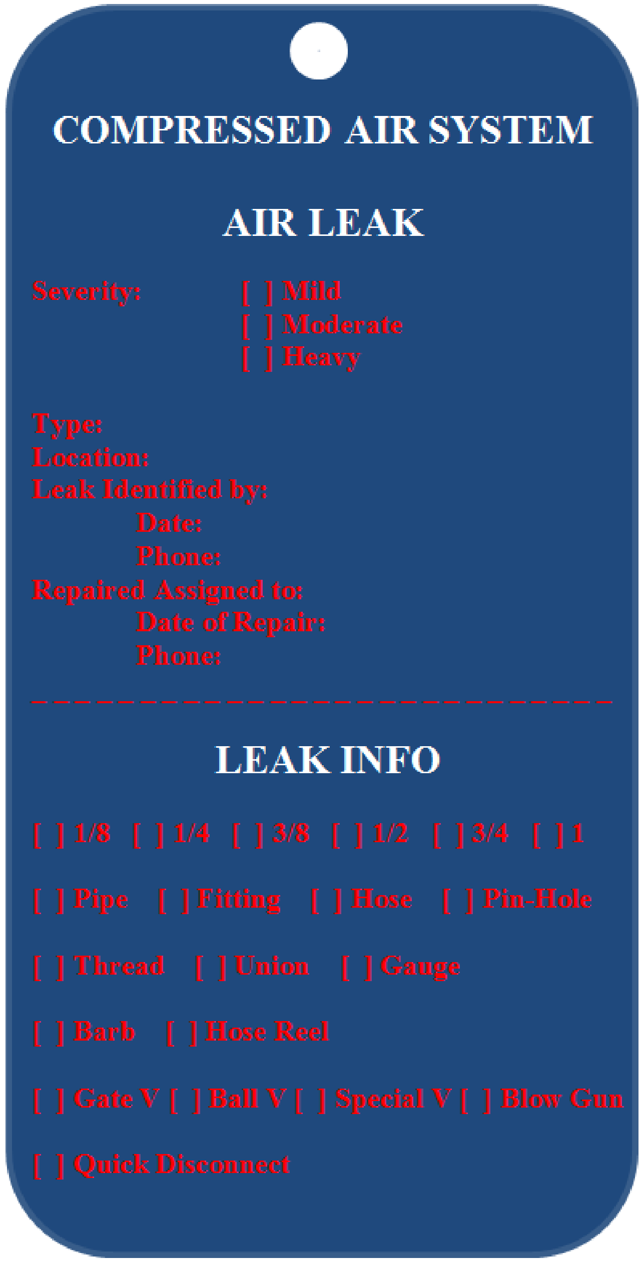


Figure C3. Sample of Leak Tag.

The walk-through surveys are crucial components of effective leak prevention programs aimed at improving the performance of CAS (e.g. efficiency, reliability, stability).

One additional thing that the user needs to keep in mind while performing the walk-through surveys is that if non-operating equipment is found, the equipment needs to be isolated from the CAS by placing a valve in the piping distribution system. Non-operating equipment can become an active source for leaks. To further prevent leaks, non-operating equipment needs to be completely separated.

3.1 Quarterly Walk-Through Survey

The user is recommended to perform the quarterly walk-through surveys during off peak hours (e.g. weekends) in order to prevent disturbance of scheduled operations. Prior to initiating the assessment, the CAS needs to be fully pressurized. Using the system plans obtained during Step 1 of the Standard Leak Assessment Protocol, the user needs to walk close to the supply and demand side piping listening for leaks; document and record any detectable leaks. Make sure to use highly visible tags to mark the leaks in order to follow-up with the necessary repairs.

Substantive leaks can be heard without the aid of specialized instruments or equipment such as ultrasonic leak detection. According to the Compressed Air Challenge, leaks of the size of 1/16 inch, 1/8 inch and 1/4 inch can result in average yearly costs of approximately $523, $2,095, and $8,382, respectively [3, 7, 10]. These values were calculated assuming constant operation of a CAS, efficient compressor, and electricity rate of $0.05 per kilowatt. The most common problem areas to review during the walk-through survey include:

- Couplings, hoses, tubes, and fittings
- Disconnects (e.g. O-rings are often missing and they are required to complete the seal)
- Filters, regulators and lubricators (FRLs) (e.g. improperly installed low first-cost FRLs often leak)
- Open condensate traps (e.g. improperly operating solenoids and dirty seals are often problem areas)
- Pipe joints (e.g. missed welds are a common problem)
- Control and shut-off valves (e.g. worn packing through the stem can cause leaks)
- Point of use devices (e.g. old or poorly maintained tools can have internal leaks)
- Flanges
- Cylinder rod packing
- Thread sealants (e.g. incorrect and/or improperly applied thread sealants may cause leaks; it is recommended to use the highest quality materials and apply them according to instructions)

Tagged leaks are recommended to be fixed within 7 days of identification. This may prevent forgetting about repairing the leaks. After repair, it is recommended to monitor leaks to make sure that they are fully resolved. Extensive leakage in threaded pipe systems may be a good candidate for alternative ECMs such as epoxy coating application.

3.2 Bi-Annual Walk-Through Ultrasonic Leak Detection Survey

The user is recommended to conduct bi-annual walk-through ultrasonic leak detection surveys to identify difficult to hear or hard to reach leaks (e.g. pipe leaks on high bays hangers). Figure C4 provides an example of some ultrasonic leak detection equipment available in the market. Just as with the quarterly surveys, the leaks detected need to be properly tagged and recorded. It is suggested that leaks be repaired within 7 days of identification. The bi-annual surveys must strive to detect all leaks that are not audible to the human ear. Hence, the bi-annual surveys serve as a complement to the quarterly surveys.

Figure C4. Ultrasonic Leak Detection Equipment.

With the use of ultrasonic leak detection, high frequency hissing sounds associated with air leaks are recognized [5, 7]. Ultrasonic leak detection equipment typically consists of directional microphones, amplifiers, and audio filters. The equipment also has visual indicators or earphones which aid in detecting leaks. While inspecting the supply and demand piping of CAS, additional accessories such as parabolic antennas can be used with ultrasonic leak detection equipment to identify leaks up to 50 feet above the shop floor. Ultrasonic detectors can be used to detect leaks during normal operating facility hours because they have the capacity to filter out noises in the audible range [7]. The cost associated with ultrasonic leak detection equipment varies by brand and vendor. However, the user may consider the investment worthwhile. In the majority of cases, users can easily and competently be trained after 15 minutes of instruction with the equipment [7]. Figure 5C shows situations in which ultrasonic leak detection equipment is being used to detect leaks in the field.

Figure 5C. Ultrasonic Leak Detection Equipment Being Used in the Field.

4.0 Implementing Recommendations to Resolve Leaks

The user is suggested to implement repairs to resolve the leaks found in Step 3 of the Standard Leak Assessment Protocol. Based on experience, joints and connections will typically be the places where leaks will occur. Repairing leaks can be as easy as tightening a connection, or as complicated as replacing pipe sections and segments due to the presence of large pinhole leaks or leaky threaded fittings. As a general practice, once all the leaks have been addressed, a new baseline for the CAS needs to be completed to determine the total energy savings accomplished by the repairs.

5.0 Evaluating Alternative ECMs to Resolve Extensive and Hard-to-Reach Leaks

Upon concluding Steps 1 through 4 of the Standard Leak Assessment Protocol, there is a chance that extensive or hard-to-reach leaks (e.g. extreme high altitude, behind walls, underground, or otherwise difficult to find/repair leaks) will remain unresolved. To address these types of leaks an alternative ECM such as epoxy coating is suggested.

Epoxy coating is an in-situ and non-invasive pipe rehabilitation technology designed to restore pipe flow and extend pipe life by preventing pipe corrosion. The epoxy was developed by the Naval Research Laboratory (NRL) with the objective to restore and protect piping in collection, holding and transfer (CHT) systems on aircraft carriers from erosion and corrosion [12]. The technology can be successfully applied to the distribution side of a CAS and is characterized by [11]:

- Rapid implementation (less than 72 hours downtime)
- Suitable for use inside buildings and underground
- Effective in bent pipes and pipes of different diameters (e.g. 1/2 inch and up to 24 inch)

- Economical compared to cost of replacing inaccessible pipe through conventional pipe repair methods
- Minimally disruptive of tenants and their activities
- Potential to reduce pipe leakage by 90%.

5.1 Epoxy Coating Application Process

Unlike conventional pipe repair and replacement options, the epoxy coating can be managed to minimize operational disruption at the facility where the process is to take place. The epoxy coating application process involves [11] the following steps:

- System analysis to identify current leaks and confirm system layout.
- Repair of major leaks and removal of sensitive equipment as appropriate.
- Drying of the system with dried compressed air: The air from compressor is passed through a heater before it enters the pipeline system. The air temperature is maintained between 80° and 90° F, relative humidity is below 20% and dew point is below the humidity level. The air exhausted from the pipe system should meet the above criteria. Air drying time depends on the pipe condition as well as local weather. Figure C6 illustrates a general schematic of the pipeline drying step.

Figure C6. Drying of Pipeline.

- Rust and scale removal with an abrasive garnet sprayed through the system: The inside surface of the pipe is cleaned to remove any rust or scale by passing an abrasive material through the pipe using pulsed air pressure. The choice of abrasive material depends on the pipe material being cleaned. The abrasive material can be granite or glass. Figure C7 depicts abrasive material cleaning the pipe, and displays different types of abrasive materials.

Figure C7. (Top) Illustration of Rust or Scale Removal; (Bottom) Samples of abrasive material or garnet.

- System cleaning by blowing dry compressed air through piping; process similar to point three above.
- Distribution of epoxy using compressed air flow to form an epoxy coating: The epoxy coating material is prepared by mixing two components is a specified ratio of 70:30. The epoxy is mixed thoroughly using hand held drill until it reaches 80° – 90° F temperature. The amount of epoxy material, time required to coat a given length of pipe depend upon the pipe material, pipe size and air pressure. Figure C8 depicts the epoxy coating application.

Figure C8. Epoxy Coating Application.

- An empirical formula, mostly based on experience, is used to determine the parameters. According to one vendor, Nu Flow Technologies, the following formulas can be used to estimate the amount of epoxy needed per pipe segment:

$$Pipe\ Diameter\sqrt{18\ (for\ pipe\ material\ other\ than\ copper)} = \#\ of\ feet\ covered\ by\ 1\ lb\ of\ epoxy$$

$$Pipe\ Diameter\sqrt{24\ (for\ copper\ pipe)} = \#\ of\ feet\ covered\ by\ 1\ lb\ of\ epoxy$$

- Curing of the epoxy with compressed air: After the epoxy coating process is completed, the pipe system is cured for at least 24 hours. Curing time depends on the air temperature.

Minimum of 24 hours is needed at an ideal temperature of 90° – 100° F. Figure 9C depicts the curing process.

Figure 9C. Final Curing of Pipeline.

- System testing to ensure that the system is functioning as intended

Notice that the first two bullets of the epoxy coating application process are achieved through Steps 1 through 4 of the Standard Leak Assessment Protocol.

It is important to note that successful application of epoxy relies on having relatively sound pipe. In general pipes with less than 60% of the original wall thickness are not good candidates and must be replaced before applying the epoxy [12]. Determination of wall thickness may require destructive exploration or use of specialized equipment such as magnetic flux leakage or other sophisticated eddy current technologies. Conversely, mechanical joints (e.g. flanges) may be installed where appropriate to open the piping distribution system for future needs. This action has the potential to reduce the need to cut the pipe and damage the coating in the future.

REFERENCES

[1] Chapter 16 Energy Audits for Buildings, Moncef Krarti, University of Colorado

[2] Applications Guide for Compressed Air Systems, Mike C.J., Lin Taha, and Yezin E. Taha, US Army Corps of Engineers, Engineer Research and Development Center

[3] Compressed Air Systems Fact Sheet # 7, Compressed Air System Leaks, Compressed Air Challenge

[4] Unified Facilities Criteria (UFC), Compressed Air, Department of Defense

[5] Compressed Air Systems (CAS) Audit Standard, A Standard for the Auditing of the Energy Efficiency of Electric Motor-Powered Compressed Air Systems, Energy Management Association of New Zealand

[6] Comprehensive Compressed Air Audits: The 5-Step Process, WEBSITE

[7] Improving Compressed Air System Performance: A Sourcebook for Industry, US Department of Energy, Energy Efficiency &Renewable Energy

[8] Qualified Specialists in Industrial Assessment Tools, US Department of Energy, Energy Efficiency & Renewable Energy

[9] AIRMaster+ Motor-Driven Systems, Technical Assistance, US Department of Energy, Energy Efficiency & Renewable Energy

[10] Compressed Air Challenge

[11] Nu Flow Technology

[12] Epoxy Lining for Shipboard Piping System NRL/MR/6120—94-7629

Appendix E: Nu Flow Epoxy System Specification

ICC EVALUATION SERVICE

Most Widely Accepted and Trusted

ICC-ES Report

ICC-ES | (800) 423-6587 | (562) 699-0543 | www.icc-es.org

PMG-1020

Reissued 12/2015

This report is subject to renewal 12/2016

EVALUATION SUBJECT:

NU FLOW POTABLE 7000 WATER PIPING EPOXY COATING SYSTEMS

DIVISION:
22 00 00—PLUMBING
SECTION:
22 11 16—DOMESTIC WATER PIPING

Report Holder:

NU FLOW TECHNOLOGIES 2000, INC.

1313 BOUNDARY ROAD SOUTH
OSHAWA, ONTARIO L1J 6Z7
CANADA

Look for the ICC-ES marks of Conformity!

ICC-ES PMG Listing

PMG-1020

Effective Date: December 2015
This listing is subject to re-examination in one year.

www.icc-es-pmg.org | (800) 423-6587 | (562) 699-0543 *A Subsidiary of the International Code Council®*

CSI: DIVISION: 22 00 00—PLUMBING
Section: 22 11 16—Domestic Water Piping

Product certification system:

The ICC-ES product certification system includes testing samples taken from the market or supplier's stock, or a combination of both, to verify compliance with applicable codes and standards. The system also involves factory inspections, and assessment and surveillance of the supplier's quality system.

Product: Nu Flow Potable 7000 Water Piping Epoxy Coating Systems—(uses epoxy to coat the interior of existing, but cleaned, galvanized steel pipe or copper rigid tube pressurized potable water supply systems)

Listee: Nu Flow Technologies 2000, Inc.
1313 Boundary Road South
Oshawa, Ontario L1J 6Z7
Canada
www.nuflowtech.com

Compliance with the following codes:

2015, 2012 and 2009 *International Plumbing Code®* (IPC)
2015, 2012 and 2009 *International Residential Code®* (IRC)

Compliance with the following standards:

LC1008-2009, Listing Criteria for Internal Epoxy Barrier Pipe Coating Material for Water Supply Systems
IAPMO IGC 189-2008 (R2014), Internal Pipe Epoxy Barrier Coating Material for Application in Pressurized (Closed) Water Piping Systems
ASTM D 4541-2009e1, Standard Test Method for Pull-off Strength of Coatings Using Portable Adhesion Testers
NSF/ANSI 61-2015, Section 5, Drinking Water System Components – Health Effects
AWWA C210-2007, Liquid-Epoxy Coating System for the Interior and Exterior of Steel Water Pipe Lines

Identification:

Nu Flow 7000 Epoxy: Each container bears a label marked Part A or Part B, with the manufacturer's name (Nu Flow Technologies), the NSF 61 designation, the name of the third-party inspection agency, and the ICC-ES PMG listing mark. Each container is stamped on the top with the date of manufacture and the batch number.

Coated Piping or Rigid Tubing: At a maximum distance of 20 feet (6096 mm) along coated pipe or tube, and at each fixture connection, a label is attached indicating the manufacturer's name (Nu Flow

Technologies), NSF-PW, the words "Attention, epoxy lined piping," the product name (Nu Flow 7000) and the ICC-ES PMG listing mark. The label includes a warning against using flame or heat when repairing any part of the piping system.

Installation:

The Nu Flow 7000 Epoxy System must be applied by authorized applicators trained by Nu Flow Technologies 2000, Inc. Existing piping or rigid tubes must be in good condition, with any cracks or leaks or visible signs of corrosion repaired. The following steps comprise the installation sequence:

1. The existing piping system is partially disassembled into separate sections, with flexible tube, valves and gasketed connections removed.
2. Each section is air-dried and sandblasted clean in accordance with the manufacturer's published instructions. The cleaned surface, when viewed without magnification, must be in a shiny metal state and free of all visible oil, grease, dirt, mill scale, rust and previously applied coatings. Evenly dispersed, very light shadows, streaks and discolorations caused by stains of mill scale, rust and old coatings may be permitted to remain on no more than 33 percent of the surface. Slight residues of rust and old coatings are permitted to be left in the craters of pits, if the original surface is pitted. Upon completion, this level of cleaning must be visually verified and recorded by the applicator.
3. Each section is then pressure-tested with air to 100 psi (689.5 kPa), to verify that the pipe has no holes, cracks or leaks.
4. Using proprietary measuring and application equipment provided by Nu Flow Technologies 2000, Inc., Nu Flow 7000 epoxy is applied in one end of a pipe or tube section and forced by air pressure through the section.
5. After drying in accordance with the manufacturer's instructions, the Nu Flow applicator then reassembles the piping system and hydrostatically pressure tests to 150 psi (1,034 kPa) in the presence of the code official or the official's designated representative.
6. In the presence of the code official or designated representative, the Nu Flow applicator then conducts a flow test to verify the minimum flow rate to each fixture in accordance with Table 604.3 of the IPC.

Models:

Nu Flow 7000 is a proprietary, two-part, mechanically mixed epoxy material that is pneumatically applied to the interior of cleaned rigid-galvanized pipe or copper tube used to convey pressurized potable water. Nu Flow 7000 is composed of a two-component epoxy (68% part A to 32% part B by weight) which meets the requirements of NSF 61, Section 5. The Nu Flow Epoxy System is recognized for application on either galvanized steel pipe or copper tube from $^{1}/_{2}$ inch to 12 inches (12.7 to 305 mm) in diameter. The installed minimum thickness of the coating must be 0.007 inch (0.178 mm) on all sizes. The average coating thickness must not exceed 0.009 inch (0.229 mm) on $^{1}/_{2}$-inch-diameter (12.7 mm) galvanized steel pipe and copper tube, or 0.05 inch (1.27 mm) on larger pipe and tube. The Nu Flow Epoxy System is not for application on gasketed connections, on valves or on flexible pressure pipe that can be flexed more than 15%.

Conditions of listing:

1. The Nu Flow 7000 system must be installed in accordance with this listing and the manufacturer's published installation instructions. In the event of a conflict, the instructions in this listing govern.
2. The existing piping system must be fabricated from rigid copper tubing or galvanized steel pipe materials in accordance with the applicable code.
3. All leaks must be repaired prior to coating in such a way so as to restore the affected sections to a code-complying condition.
4. Nu Flow 7000 is manufactured in Oshawa, Ontario, Canada, under a quality control program with annual surveillance inspections by ICC-ES.

SECTION 1: Identification of the substance/mixture and of the company/undertaking

1.1. Product identifier

Product form : Substance
CAS No : 88384-96-7
Product code : RN720

1.2. Relevant identified uses of the substance or mixture and uses advised against

Use of the substance/mixture : Additive
Adhesives: Component

1.3. Details of the supplier of the safety data sheet

Nu Flow Technologies (2000) Inc.
1313 Boundary Rd.
L1J 6Z7 Oshawa, Ontario
CANADA

Attn: Mrs. Deborah Read
Tel: 905-433-5510
Email: dread@nuflowtech.com

1.4. Emergency telephone number

Country	Organization/Company	Address	Emergency number
MEXICO	Servicio de Informacion Toxicologica Sintox	Tinoreto #32 Bllt. a Desp. Col. Nochebuena Mixcoac México, D.F.	1 800 009 2800 +52 55 5611 2634 / +52 55 5598 9095
UNITED STATES OF AMERICA	American Association of Poison Control Centers		1-800-222-1222

SECTION 2: Hazards identification

2.1. Classification of the substance or mixture

Classification (GHS-US)

Not classified

2.2. Label elements

GHS-US labeling

No labeling applicable

2.3. Other hazards

No additional information available

2.4. Unknown acute toxicity (GHS-US)

Not applicable

SECTION 3: Composition/information on ingredients

3.1. Substance

Name	Product identifier	%	Classification (GHS-US)
polyamide resin (Main constituent)	(CAS No) 88384-96-7	>= 98	Not classified

Full text of H-phrases: see section 16

3.2. Mixture

Not applicable

SECTION 4: First aid measures

4.1. Description of first aid measures

First-aid measures general : Never give anything by mouth to an unconscious person. If you feel unwell, seek medical advice (show the label where possible).

First-aid measures after inhalation : Allow victim to breathe fresh air. Allow the victim to rest.

Appendix F: User Satisfaction Survey

END USER - SATISFACTION SURVEY

ESTCP - ENERGY REDUCTION USING EPOXY COATINGS FOR SEALING LEAKING COMPRESSED AIR SYSTEMS AT CED, NBVC

Name: Joseph Paris

Date: 5/29/18

Please provide your comments and feedback to the following questions regarding the installation of epoxy to the 1.5" and 4" underground pipelines.

1. Is the 4" underground pipeline back in service?

☒ Yes

☐ No

2. If the 4" pipeline is back in service, did it allow you to configure:

☐ **a lead-lag operational approach to supply compressed air to/from Bldgs. 1357 and 813**

☒ **one compressor to supply compressed air to end users in Bldgs. 1357 and 813**

☐ **Not Applicable**

☐ **To be determined at a later date after other corrections to the air system are completed.**

Comments:

Still waiting to plumb line from 814 to 815. Able to feed 813 from 1497 with zero pressure loss.

3. If the 4" pipeline is back in service, have you quantified any energy savings or drop in energy consumption?

☐ **Yes**

☐ **No**

☒ **Not Applicable: Electrical power/Energy managed by others**

Comments:

4. Do you believe the installation of epoxy to the 1.5" and 4"underground pipelines caused minimal disruption to your daily field operations?

☒ Strongly agree
☐ Agree
☐ Neither agree nor disagree
☐ Disagree
☐ Strongly disagree

5. Are the pressure and flow conditions acceptable for the 4" pipeline after the installation of the epoxy?

☒ Strongly agree
☐ Agree
☐ Neither agree nor disagree
☐ Disagree
☐ Strongly disagree
☐ Not applicable
☐ **To be determined at a later date after other corrections to the air system are completed.**

6. Have you received any end user customer complaints regarding the post epoxy application system pressure and flow received from the 4" pipeline after epoxy installation?

☒ No
☐ Yes
☐ Not applicable
☐ **To be determined at a later date after other corrections to the air system are completed.**

If yes, please explain the types of complains received.

7. Please rate the maintenance requirements after the installation of the epoxy?

☒ None performed to date
☐ High
☐ Medium
☐ Low
☐ Not Applicable
☐ **To be determined at a later date after other corrections to the air system are completed.**

8. Pick all that applies with regards to the epoxy installation:

- ☒ **Improved my operational capability**
- ☒ **Has potential to save the DoD money**
- ☒ **Has potential to extend service life of pipeline**
- ☒ **The process was expedient**
- ☐ **The process took longer than expected**
- ☐ **Marginal value; Not worth the investment**
- ☐ **No way to tell how the epoxy installation helped**
- ☐ **I would only use the epoxy as a corrosion barrier**
- ☐ **To be determined at a later date after other corrections to the air system are completed.**

9. Pick all the lessons learn that applies with regards to the epoxy demonstration:

- ☒ **underground pipeline although old may still have structural integrity**
- ☐ **existing valves allow leakage (do not fully close)**
- ☒ **performing leak management could help overall mission**
- ☒ **having accurate drawings and maps of the compressed air system would help with leak management**
- ☒ **repairing major underground leaks may be a cost effective solution**
- ☒ **underground air leaks can create substantial voids under pavement**

10. Final thoughts on Epoxy technology: Would you recommend the installation of epoxy to resolve issues with leaking pipelines in compressed air systems or serve as a corrosion barrier

- ☒ **I would recommend the epoxy technology as a method to seal leaks**
- ☐ **I would not recommend the epoxy technology as a method to seal leaks**

- ☒ **I would recommend the epoxy technology as a barrier to future corrosion**
- ☐ **I would not recommend the epoxy technology as a barrier to future corrosion**

- ☐ **I do not have enough information to make an informed decision**

Additional Comments

Installation of the epoxy has greatly improved the operational capability of the CED compound. Working with the team improved my understanding of the airline system throughout the compound. The team was expedient and kept in constant contact with updates and problem solving.

Appendix G: Return on Investment

Baseline 1
Discounted
ROI

Years	Annual Return	Compressor Cost With Leaks	Compressor Cost Without Leaks	Present Value	Net Energy Savings	Yearly Compressor Savings	Total Net Savings
1	$31,703	$3,462	$2,769	$30,484	$30,484	$692	$31,176
2	$31,703	$3,328	$2,663	$29,311	$59,795	$666	$61,153
3	$31,703	$3,200	$2,560	$28,184	$87,979	$640	$89,977
4	$31,703	$3,077	$2,462	$27,100	$115,079	$615	$117,693
5	$31,703	$2,959	$2,367	$26,058	$141,137	$592	$144,342
6	$31,703	$2,845	$2,276	$25,055	$166,192	$569	$169,966
7	$31,703	$2,736	$2,189	$24,092	$190,284	$547	$194,605
8	$31,703	$2,630	$2,104	$23,165	$213,449	$526	$218,297

Capital Investment	$38,230
Discount Rate	0.04
Compressor Cost	$72,000
ROI (years)	2

Note:
Compressor replacement costs are normalized at a 4% rate, and divided by their operational lifetime to provide an annual compressor cost

Baseline 2 Discounted ROI

Years	Annual Return	Compressor Cost With Leaks	Compressor Cost Without Leaks	Present Value	Net Energy Savings	Yearly Compressor Savings	Total Net Savings
1	$3,593	$3,462	$2,769	$3,455	$3,455	$692	$4,147
2	$3,593	$3,328	$2,663	$3,322	$6,777	$666	$8,135
3	$3,593	$3,200	$2,560	$3,194	$9,971	$640	$11,969
4	$3,593	$3,077	$2,462	$3,071	$13,042	$615	$15,656
5	$3,593	$2,959	$2,367	$2,953	$15,995	$592	$19,201
6	$3,593	$2,845	$2,276	$2,840	$18,835	$569	$22,609
7	$3,593	$2,736	$2,189	$2,730	$21,565	$547	$25,887
8	$3,593	$2,630	$2,104	$2,625	$24,191	$526	$29,038
9	$3,593	$2,529	$2,023	$2,524	$26,715	$506	$32,068
10	$3,593	$2,432	$1,946	$2,427	$29,142	$486	$34,982
11	$3,593	$2,338	$1,871	$2,334	$31,476	$468	$37,784
12	$3,593	$2,249	$1,799	$2,244	$33,720	$450	$40,478
13	$3,593	$2,162	$1,730	$2,158	$35,878	$432	$43,068
14	$3,593	$2,079	$1,663	$2,075	$37,953	$416	$45,559
15	$3,593	$1,999	$1,599	$1,995	$39,948	$400	$47,953
16	$3,593	$6,743	$5,394	$1,918	$41,866	$1,349	$51,220

Capital Investment	38,230.
Discount Rate	0.04
Compressor Cost	72,000.
ROI (years)	12

Note: Compressor replacement cost are adjusted at a 4% rate, and divided by their operational lifetime to provide an annual
Compressor cost.

Baseline 3 ROI

Years	Annual Return	Compressor Cost With Leaks	Compressor Cost Without Leaks	Present Value	Net Energy Savings	Yearly Compressor Savings	Total Net Savings
1	$2,762	$3,462	$2,769	$2,655	$2,655	$692	$3,348
2	$2,762	$3,328	$2,663	$2,553	$5,209	$666	$6,567
3	$2,762	$3,200	$2,560	$2,455	$7,664	$640	$9,662
4	$2,762	$3,077	$2,462	$2,361	$10,025	$615	$12,638
5	$2,762	$2,959	$2,367	$2,270	$12,295	$592	$15,500
6	$2,762	$2,845	$2,276	$2,183	$14,477	$569	$18,252
7	$2,762	$2,736	$2,189	$2,099	$16,576	$547	$20,897
8	$2,762	$2,630	$2,104	$2,018	$18,594	$526	$23,441
9	$2,762	$2,529	$2,023	$1,940	$20,534	$506	$25,888
10	$2,762	$2,432	$1,946	$1,866	$22,400	$486	$28,240
11	$2,762	$2,338	$1,871	$1,794	$24,194	$468	$30,501
12	$2,762	$2,249	$1,799	$1,725	$25,919	$450	$32,676
13	$2,762	$2,162	$1,730	$1,659	$27,577	$432	$34,767
14	$2,762	$2,079	$1,663	$1,595	$29,172	$416	$36,778
15	$2,762	$1,999	$1,599	$1,533	$30,706	$400	$38,711
16	$2,762	$1,922	$1,538	$1,474	$32,180	$384	$40,570
17	$2,762	$1,848	$1,479	$1,418	$33,598	$370	$42,357
18	$2,762	$1,777	$1,422	$1,363	$34,961	$355	$44,076

Capital Investment	$38,230
Discount Rate	0.04
Compressor Cost	$72,000
ROI (years)	15

19	$2,762	$1,709	$1,367	$1,311	$36,272	$342	$45,729
20	$2,762	$1,643	$1,314	$1,260	$37,533	$329	$47,318
21	$2,762	$1,580	$1,264	$1,212	$38,744	$316	$48,845
22	$2,762	$1,519	$1,215	$1,165	$39,910	$304	$50,315
23	$2,762	$1,461	$1,168	$1,120	$41,030	$292	$51,727
24	$2,762	$1,404	$1,124	$1,077	$42,108	$281	$53,085
25	$2,762	$1,350	$1,080	$1,036	$43,144	$270	$54,392
26	$2,762	$1,298	$1,039	$996	$44,140	$260	$55,647
27	$2,762	$1,249	$999	$958	$45,098	$250	$56,855
28	$2,762	$1,201	$960	$921	$46,019	$240	$58,016
29	$2,762	$1,154	$923	$886	$46,904	$231	$59,132
30	$2,762	$1,110	$888	$851	$47,756	$222	$60,206
31	$2,762	$1,067	$854	$819	$48,574	$213	$61,238
32	$2,762	$1,026	$821	$787	$49,362	$205	$62,231

Note:
Compressor replacement costs are adjusted at a 4% rate, and divided by their operational lifetime to provide an annual compressor cost