U.S. Department of Energy
Advanced Research Projects Agency – Energy

Request for Information (RFI)
DE-FOA-0002263 on

Rapid Encapsulation of Pipelines Avoiding Intensive Replacement (REPAIR)

Objective:
The Advanced Research Projects Agency –Energy (ARPA-E) in the U.S. Department of Energy is seeking comments on a **draft** technical section for a possible future program solicitation, which focuses on the suite of technologies required to rehabilitate cast iron, wrought iron, and bare steel natural gas distribution pipes by creating a new pipe inside the old pipe. The new pipe will meet utilities' and regulatory agencies' requirements, have a minimum life of 50 years, and have sufficient material properties to operate throughout its service life without reliance on the exterior pipe. ARPA-E seeks input from experts in the fields of pipeline testing, advanced coating materials, biomimetic materials, smart materials (e.g., self-healing, or self-monitoring), robotic coating deposition tools, material inspection techniques, pipeline mapping tools, 3-D data visualization and data management, control and systems engineering, and gas pipeline operation; as well as service providers who replace, inspect, and locate natural gas utility pipelines.

Please carefully review the REQUEST FOR INFORMATION GUIDELINES below and note in particular: the information you provide will be used by ARPA-E solely for program planning, without attribution. **THIS IS A REQUEST FOR INFORMATION ONLY. THIS NOTICE DOES NOT CONSTITUTE A FUNDING OPPORTUNITY ANNOUNCEMENT (FOA). NO FOA EXISTS AT THIS TIME. Respondents shall not include any information in their response to this RFI that might be considered proprietary or confidential.**

Purpose and Need for Information:
The purpose of this RFI is solely to solicit input for ARPA-E consideration, to inform the possible formulation of future programs intended to help create transformative technology to rehabilitate cast iron, wrought iron, and bare steel natural gas distribution pipes by crafting new pipes inside pre-existing pipes. ARPA-E will not provide funding or compensation for any information submitted in response to this RFI, and ARPA-E may use information submitted to this RFI without any attribution to the source. This RFI provides the broad research community with an opportunity to contribute views and opinions regarding the rehabilitation of legacy natural gas pipelines.

This RFI previews only the **draft** technical section for a possible future program solicitation. If respondents are interested in other sections, including general format and requirements of an

ARPA-E FOA, please visit https://arpa-e-foa.energy.gov/ . DE-FOA-0002212: BREAKTHROUGHS ENABLING THERMONUCLEAR-FUSION ENERGY (BETHE) is a sample FOA to reference. A few common sections include but are not limited to:

- III.A: ELIGIBLE APPLICANTS (e.g. foreign entities)
- III.B: COST-SHARING
- IV.C: CONTENT AND FORM OF FULL APPLICATIONS
- VI.C: REPORTING (e.g. cost)
- VIII.B: GOVERNMENT RIGHTS IN SUBJECT INVENTIONS
- VIII.C: RIGHTS IN TECHNICAL DATA

REQUEST FOR INFORMATION GUIDELINES:

A summary of RFI responses will be presented by Program Director Jack Lewnard on January 22, 2020 at ARPA-E's REPAIR Industry Day. Individuals interested in attending Industry Day please indicate so in RFI response for more information.

ARPA-E may contact respondents to request clarification or seek additional information relevant to this RFI. All responses provided will be considered, but ARPA-E will not respond to individual submissions. **Respondents shall not include any information in the response to this RFI that might be considered proprietary or confidential.**

Responses to this RFI should be submitted in PDF format to the email address ARPA-E-RFI@hq.doe.gov by **5:00 PM Eastern Time on January 20, 2020**. Emails should conform to the following guidelines:

- Please insert "Responses for REPAIR" in the subject line of your email, and include your name, title, organization, type of organization (e.g. university, non-governmental organization, small business, large business, federally funded research and development center (FFRDC), government-owned/government-operated (GOGO), etc.), email address, telephone number, and area of expertise in the body of your email.
- Responses to this RFI are limited to no more than 5 pages in length (12 point font size).
- Respondents are strongly encouraged to include preliminary results, data, and figures that describe their potential methodologies.

Questions: ARPA-E encourages responses that address any subset of the following questions and encourages the inclusion of references to important supplementary information.

1. The target pipeline diameter is 10 inches and larger. Please comment on ability to develop robotic coating deposition and inspection tools for smaller diameter pipes.

2. Task 1 identifies a preliminary list of testing for "pipe in pipe". Please comment on the suitability of the list and other potential tests ARPA-E should include.

3. The legacy pipelines are made from cast/wrought iron, and bare (uncoated) steel. Please comment:

    a. on the ability of a single coating, or family of coatings to be suitable for both types of pipes
    b. on the ability of pipe inspection technologies to be suitable for both types of pipes

4. Component developers need to collaborate with system integrators to demonstrate integrated products. Advanced materials, robotics, and inspection tools must be tailored to work together. ARPA-E is recommending component developers and system integrators form teams to produce integrated systems. ARPA-E is interested in alternative approaches that will lead to the demonstration of integrated systems at the end of the program. For example, is it better to form teams at the start, so components are developed concurrently; or delay team formation to allow component developers maximum flexibility in optimizing their technologies?

5. Task 6 seeks to develop 3D maps that incorporate data from REPAIR processes as well as utility data such as leak reports. Utilities are increasing the use of GIS-enabled databases for managing operations data. Are there preferred platforms for data storage/management in order to integrate coating data, inspection data, and mapping data? Should the FOA specify data format(s)?

6. Any other issues, questions, or feedback regarding the draft FOA

ATTACHMENT A

Draft of Technical Section for Rapid Encapsulation of Pipelines Avoiding Intensive Replacement (REPAIR)

A. Program Overview

1. Summary

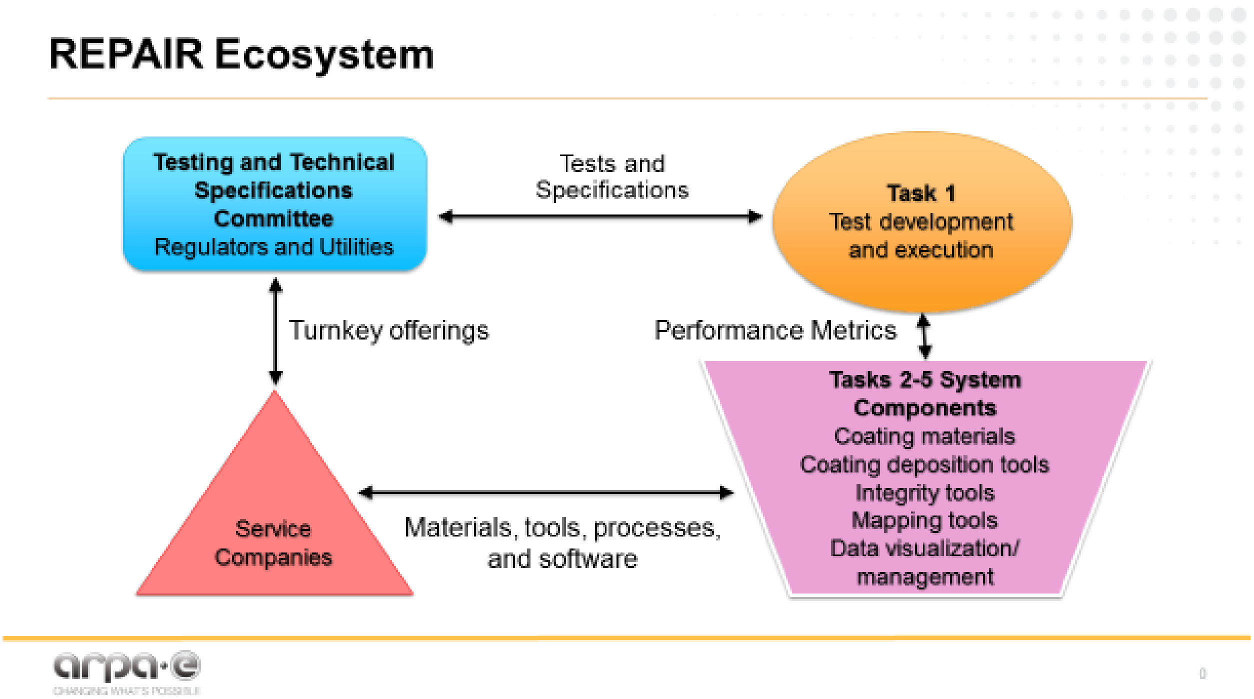
REPAIR seeks to develop the suite of technologies required to rehabilitate cast iron, wrought iron, and bare steel natural gas distribution pipes by creating a new pipe inside the old pipe. The new pipe will meet utilities' and regulatory agencies' requirements, have a minimum life of 50 years, and have sufficient material properties to operate throughout its service life without reliance on the exterior pipe. Today, older gas distribution pipes are typically excavated and replaced, with costs ranging from $1 to $10 million per mile.

REPAIR will advance the state of gas distribution pipelines by incorporating smart functionality into structural coating materials and developing new integrity/inspection tools. It will also create 3D maps that integrate geospatial data for integrity and leak testing, coating deposition data, and location data for pipes and adjacent underground infrastructure. The cost target is $1 million per mile, including gas service disruption costs.

Gas distribution pipes are regulated by the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) as well as state regulatory agencies. Consequently the suite of technologies developed under REPAIR will ultimately need regulatory approval consistent with 49 Code of Federal Regulations Parts 192. In parallel with this FOA, ARPA-E will establish a Testing and Technical Specifications Committee (TTSC) to advise ARPA-E and facilitate regulatory approval for the technologies and cost recovery for the rehabilitation process. The TTSC will include PHMSA; state regulators and their association, the National Association of Pipeline State Regulators (NAPSR); representatives of ASTM F17; gas utilities; and ARPA-E.

The REPAIR program will require coordination among multiple stakeholders, and collaboration within research programs, to achieve commercial success. Figure 1 summarizes the REPAIR ecosystem, the FOA tasks, and the path to market. The TSSC will provide inputs to ARPA-E regarding test methods and specifications that regulators and utilities will require REPAIR technologies to demonstrate. In Task 1 these requirements are reduced to specific tests and performance metrics for the "pipe in pipe". Tasks 2-5 address the individual system components: coating materials, coating deposition tools, integrity/inspection tools, and mapping tools, respectively. The FOA breaks out discreet tasks for each system component, given the technical specialization for each area. However, it is essential that these components be integrated to create comprehensive service offerings. As shown in Figure 1, utilities typically execute turn-key contracts with service companies when rehabilitating pipelines. Consequently Applicants for Tasks 2-5 will need to describe their plans for integrating their products into comprehensive service offerings, through partnering or other commercialization plans.

Figure 1 Repair Ecosystem, FOA Tasks, and Path to Market



2. Background

Natural gas is an abundant domestic energy resource that benefits the US economy. Shale gas production increased by a factor of 15 between 2007 and 2017.[1] The "shale revolution" has increased domestic gas production by 50%.[2] Today natural gas provides 31% of US primary energy and supplies record gas exports.[3] US gas prices are among the lowest in the developed world,[4] providing a competitive advantage.

More than 1,400 gas utilities provide natural gas service to 75 million residential and 5 million commercial customers[5] through a network of 1.2 million miles (1.9 million km) of distribution mains and 900,000 miles (1.4 million km) of service lines.[6] Gas utilities began operations in the

---

[1] EIA Shale gas production, https://www.eia.gov/dnav/ng/hist/res_epg0_r5302_nus_bcfa.htm
[2] EIA dry gas production, https://www.eia.gov/dnav/ng/hist/n9070us2a.htm
[3] EIA Annual Energy Outlook 2019 with projections to 2050, https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf
[4] International Gas Union Wholesale Gas Price Survey 2019
[5] Energy Information Administration. "Distribution of Natural Gas: The Final Step in the Transmission Process." 2008
[6] Department of Transportation, Pipeline and Hazardous Materials Safety Administration. "Annual Report Mileage for Gas Distribution Systems." July 1, 2014

US in the early 1800s. Cast iron, and later wrought iron, was used in construction of the early gas distribution grid. Approximately 60,000 miles (96,000 km) of cast and wrought iron pipe were installed, which will be collectively called cast iron in this document. Cast iron pipes operate at low pressures, typically below 3 psi (20 kPa) and always below 36 psi (250 kPa).

Steel pipe began replacing cast iron in the 1930s. These early steel lines did not have a protective coating or cathodic protection, and are referred to as bare steel. Approximately 100,000 miles (160,000 km) of bare steel was installed in gas distribution systems. DOT banned the use of bare steel for new gas distribution pipes after July 31, 1971.[7] Bare steel distribution pipes typically operate below 60 psi (450 kPa), although some may operate at up to 200 psi (1,400 kPa).

Cast iron and bare steel pipes, collectively referred to as legacy pipes, account for 3% of the 2 million miles (3 million km) of utility pipes. However, they have a disproportionate impact on leaks[8]and failures.[9] Many studies have investigated methane leaks from gas distribution systems, using top down and bottom up methods. DOE[8] and the EPA Gas Star program lists several reports.[10] While the magnitude of leaks is debated, there is consensus that distribution systems with legacy pipes have higher leak rates. Methane leaks and pipe failures create operating risk and legal liability for utilities; negatively impact the financial performance of system owners; and are a cost burden to gas consumers.[11] Cast iron pipes are held together by mechanical joints which are prone to leaking. The material is brittle, and can fail, typically as circumferential cracks. Bare steel pipes are prone to pitting and general corrosion/wall loss.

Over the last several decades the Federal government has taken several actions to track, and promote replacement, of these legacy cast iron and bare steel pipes. State regulators and utilities have developed accelerated pipeline replacement programs, and have removed more than half of the legacy pipes. The 2015 Quadrennial Review previously highlighted the need to address the legacy pipe problem.[12] Per Figure 2 below, there are still approximately 20,000 miles of cast iron and 40,000 miles of bare steel pipes in the PHMSA inventory of gas utility pipelines.[9,13]

---

[7] U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, "Fact Sheet: Cathodic Protection," http://primis.phmsa.dot.gov/comm/FactSheets/FSCathodicProtection.htm

[8] Natural Gas Infrastructure Modernization Programs at Local Distribution Companies: Key Issues and Considerations, Office of Energy Policy and Systems Analysis, US DOE January, 2017

[9] PHMSA Cast and Wrought Iron Inventory https://www.phmsa.dot.gov/data-and-statistics/pipeline-replacement/cast-and-wrought-iron-inventory

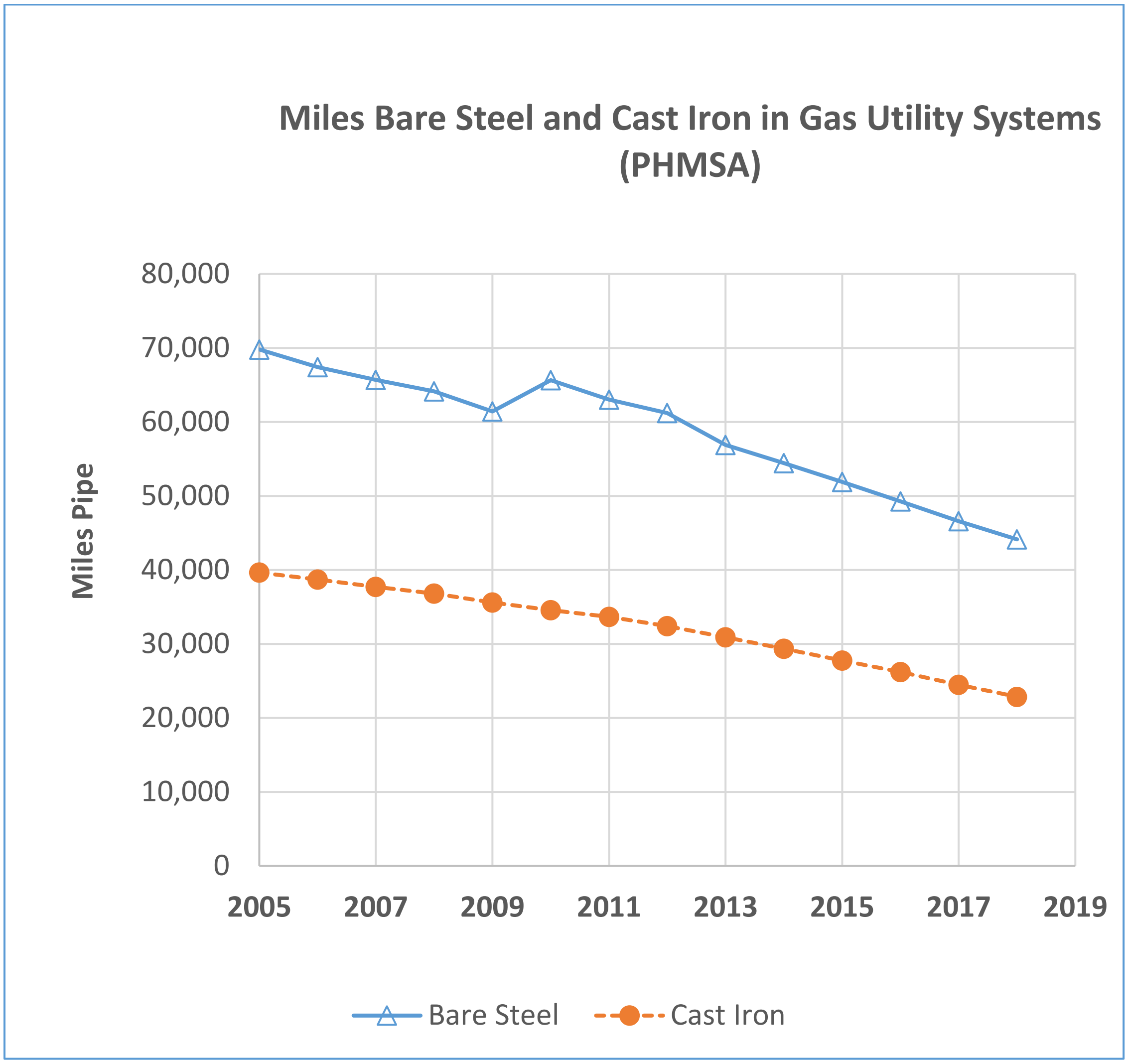
[10] EPA Gas Star Program https://www.epa.gov/natural-gas-star-program/reports-and-technical-resources#emissions

[11] Natural Gas Infrastructure Modernization Programs at Local Distribution Companies: Key Issues and Considerations, Office of Energy Policy and Systems Analysis, US DOE January, 2017

[12]Chapter 2 INCREASING THE RESILIENCE, RELIABILITY, SAFETY, AND ASSET SECURITY OF TS&D INFRASTRUCTURE, QER Report: Energy Transmission, Storage, and Distribution Infrastructure | April 2015

[13] PHMSA Bare Steel Inventory https://www.phmsa.dot.gov/data-and-statistics/pipeline-replacement/bare-steel-inventory

Figure 2 Miles of Legacy Gas Distribution Pipe[9,13]



The current approach for addressing legacy pipes is to excavate and replace the pipes, typically with high density polyethylene pipe. The cost to replace legacy pipes ranges from $1-10 million per mile, depending on the location of the pipes (rural vs urban), the degree of complexity of the excavation, such as congestion due to adjacent underground infrastructure, and the costs for restoring roads.

The costs to replace legacy pipes are passed through to gas customers. These costs are capitalized, and included in the utility's rate base. Public utility commissions typically approve multi-year to multi-decade pipeline replacement programs to moderate rate increases. However, replacement programs using current practices and costs could make natural gas unaffordable for some utility customers. In 2013 the American Gas Associated (AGA) estimated replacement costs for cast iron pipes to range from $600 to $16,000 per customer, depending on system size and customer count.[14] People's Gas in Chicago recently filed an update with their commission, noting costs to replace cast iron pipes has increased from an estimated $1 billion to $10 billion, with the potential to raise gas rates significantly.[15] The 2013 AGA report estimated the cost to replace cast iron gas pipes in the US at $82 billion in 2013. We have not found an industry-wide estimate for bare steel replacement costs, which have more than twice the mileage of cast iron pipes.

Legacy pipe materials are also found in gas gathering systems. Gathering systems connect wells to gas processing plants or gas transmission pipelines. Gas utilities began building out gathering systems around 1900, when some utilities owned wells, gathering, and distribution systems. The utilities connected customers to gathering systems, particularly in rural areas. Some of these gathering systems were subsequently sold to third parties. In other cases independently owned gathering systems provide gas supply to utility customers. Although mileage of legacy material in gathering systems is not tracked by PHMSA, these older gathering systems share many features with older gas distribution systems: they typically operate at low pressure, and may contain legacy materials. The Appalachian Basin is an example. Today there are thousands of miles of older gathering systems, some with relatively high leak rates. One example is in the filings by Columbia Gas Transmission.[16] Another example is discussed in filings by Peoples Gas of Pennsylvania. Although gathering accounts for less than 15% of their pipeline mileage, it accounts for more than 60% of their methane losses, with a loss rate of 9.5%. Recent filings with the Pennsylvania Public Utilities Commission indicate some gathering pipes will ultimately be abandoned.[17] It is possible other older gathering systems could be abandoned, requiring customers to switch to more expensive energy sources and forcing oil and gas wells to be abandoned. The technologies developed during REPAIR will be applicable to legacy materials in gathering systems.

REPAIR seeks to reduce the costs for pipeline replacement programs by reducing costs for excavation and restoration. Most of the costs for replacing pipes is associated with excavation and restoration, as opposed to the cost of the pipe itself. REPAIR seeks to eliminate the highest cost components, excavation and restoration, by rehabilitating pipes without their removal.

REPAIR also seeks to minimize gas service disruption costs. Utilities incur costs whenever gas service is disrupted. Disruptions result in additional operations tasks, such as venting and purging gas lines taken out of service; providing temporary gas service to customers; and/or interrupting and then restarting gas service. There are many operations that could disrupt gas service, such as the need to take pipes offline to access pipes, clean pipes, operate tools, or retrieve tools. Cleaning has additional cost implications, including disposal costs and possible environmental inspections, particularly for legacy pipes that were exposed to manufactured

[14] https://www.aga.org/sites/default/files/managing_the_nations_cast_iron_inventory.pdf
[15] Crain's Business Daily, Peoples Gas blows the pipe-replacement budget again, February 27, 2019
[16] Columbia Gas Transmission, LLC, Docket No. RP15-555-Compliance Report on the Status of Ongoing Efforts to Reduce LAUF.
[17] PENNSYLVANIA PUBLIC UTILITY COMMISSION Docket No. R-2018-3006818

gas. Applicants will need to specify number and duration of gas service disruption for their processes. Disruption costs will be included in the techno-economic evaluation of proposed processes.

In addition to reducing costs, REPAIR seeks to provide new functionality and data for rehabilitated pipes. Coating materials will incorporate "smart" features. New integrity/inspection tools will assess pre- and post-coated pipes, and can be incorporated into integrity management programs. New mapping tools will create 3D maps for rehabilitated mains and locate other pipeline components such as laterals, service lines, and elbows that are connected to the mains. The tools will also locate adjacent underground infrastructure. These maps will incorporate leak data, integrity/inspection data, coating parameters and allow material traceability. This information will allow utilities to plan and prioritize rehabilitation projects, track changes that impact pipeline integrity, and create accurate records for material traceability and locations of rehabilitated pipes. In the past, gas utilities needed to replace pipes that failed prematurely due to material defects (for example, Aldyl-A and polybutylene plastic pipe), in some cases with limited data on the locations of defective materials. REPAIR maps will allow utilities to track material lot number and coating parameters by location, as well as integrity/inspection data. This location-rich data will allow utilities to forecast potential integrity issues, and provide precise locations if intervention is required.

Enhanced pipe location data will also reduce third party damage. The Common Ground Alliance (CGA) linked improperly located or undetected subsurface utilities to 1,906 injuries, 421 fatalities, and $1.7 billion in damages during the last 20 years.[18] The report noted that deficiencies in pipeline locating practices were responsible for 21% of excavation damage to natural gas distribution pipelines in California. Gas utilities and regulators continue to seek better hardware and software tools for pipeline mapping, inspection, and data management. A recent CGA report highlights many issues regarding locating, mapping, and data integration that REPAIR will address.[19]

Developing the suite of technologies required for pipeline rehabilitation will improve operations and maintenance for gas utilities, reduce costs for gas customers, and allow the US to retain its natural gas cost advantage. These rehabilitation technologies may also create an opportunity for US companies to serve international markets. For example, in 2013 the UK still had over 50,000 miles (80,000 km) of cast iron pipe in high consequence areas which were

[18] Common Ground Alliance, Damage Incident Reporting Tool Report 2015, https://commongroundalliance.com/sites/default/files/publications/DIRT_Analysis_and_Recommendations_2015_Report_Final.pdf

[19] Common Ground Alliance Technology Advancements & Gaps in Underground Safety, March 2018 https://commongroundalliance.com/sites/default/files/publications/Annual%20Technology%20Report%2017_02.27.18_FINAL.pdf

targeted for replacement by 2032.[20] MarcoGas reports that cast iron accounts for 2.5% of EU gas distribution pipes, about twice the percentage of cast iron in the US distribution system.[21]

B. Metrics and Benefits

REPAIR will focus on distribution mains, the larger diameter pipes that feed smaller laterals and service lines. The PHMSA database, based on PHMSA Form 7100.1-1, indicates there are approximately 2000 miles (3200 km) of cast iron mains with 10 inch (250 cm) or larger diameter. Bare steel mileage/diameter information is not included in the PHMSA database, but we estimate a comparable mileage for larger-diameter pipe. ARPA-E will work with the TSSC to provide more detailed mileage/diameter data for cast iron and bare steel pipes.

The goal of the REPAIR program is to develop technologies to rehabilitate gas distribution mains at a cost of $1 million per mile, including gas service disruption costs.

The Preliminary Economic Model in Section E outlines inputs for the economic assessment of system components. Applicants are given broad discretion in choosing coating material, coating deposition tools, integrity/inspection tools, and mapping tools. However, these components must form the basis for an integrated turn-key solution. As discussed in Section D, components will be evaluated for technical and economic performance in an integrated test at the end of the program.

Applicants may elect to have their components operate on live pipes, or require gas service to be disrupted during part or all of their operations. Applicants must quantify the number and duration of gas service disruption(s) required for their components in the Preliminary Economic Spreadsheet.

The goal of the REPAIR program to achieve rehabilitation at a cost of $1 million per mile comes with a constraint. The technologies developed in REPAIR must meet utilities' and regulatory agencies' requirements in order to be deployed and achieve real-world impact. As mentioned above, the TSSC will provide inputs to ARPA-E regarding test methods and specifications. Initial requirements are discussed in Task 1 below. ARPA-E will work with the TSSC to ensure REPAIR targets are consistent with meet utilities' and regulatory agencies' requirements and regulatory approval processes.

Repair will create several benefits:

- Accelerate legacy pipeline replacement while reducing cost.

---

[20] Energy UK Gas Retail Group Study into the effect of shrinkage on domestic customers Final Report https://gasgov-mst-files.s3.eu-west-1.amazonaws.com/s3fs-public/ggf/Energy%20UK%20GRG%20shrinkage%20study%20FINAL.pdf

[21] Marcogaz "SURVEY METHANE EMISSIONS FOR GAS DISTRIBUTION IN EUROPE, update 2017"

- Advance the state of art for gas distribution pipelines by deploying smart materials and new integrity/inspection tools with real-time data processing.
- Produce 3D maps and data management/visualization tools that integrate geospatial data for leak testing, integrity/inspection data, coating deposition data, and locations of pipes and adjacent underground infrastructure.
- Facilitate approval by utilities and regulatory agencies by engaging these stakeholders throughout the project.

C. Program Tasks

ARPA-E is open to all rehabilitation technologies that meet the $1million/mile metric discussed above. Target pipelines are 10-inch (250 cm) and larger diameter gas distribution mains made of cast iron or bare steel. As noted above, ARPA-E will work with the TSSC to provide more detailed mileage/diameter data for cast iron and bare steel pipes. REPAIR has multiple tasks, each of which requires diverse technical skills. Applicants may respond to an individual task or multiple tasks. ARPA-E encourages diverse teams for all tasks. As noted above, Applicants will need to address plans for integrating system components into comprehensive offerings.

The tasks are:

- Tasks 1 -Testing models/protocols/hardware
- Tasks 2-5 System component development and system integration:
    - Task 2 - Structural coating materials
    - Task 3 - Coating deposition tools
    - Task 4 - Coating integrity/inspection tools
    - Task 5 - Integrated Task 2, 3, and 4 Pipe Tests
- Task 6 - 3D mapping hardware, data management, and data visualization

Detailed descriptions for each task are in the sections below.

Task 1. “Pipe in Pipe” Testing and Analysis

Regulations and codes and standards document test methods, test rigs, and performance targets for polyethylene and steel pipes used to replace legacy pipes in gas distribution systems. There are no comparable regulations or standards for a “coated” pipe in pipe. Task 1 addresses this gap. Applicants for Task 1 will be providing testing services to Applicants for Tasks 2, 3, and 4. To avoid conflict of interest, Applicants for Task 1 will not be allowed to propose work on Tasks 2-5.

Task 1.1 Define failure modes and establish the performance criteria for “pipe in pipe” with cast iron and bare steel pipes

In order to validate a 50-year life, we need to define the failure modes for cast iron and bare steel pipes that have an internal structural coating. We anticipate the Testing Applicants will conduct literature reviews for related technologies (pipeline liners, pipeline coatings, composite pipes, etc.), and collaborate with ARPA-E and the TTSC to identify the potential failure modes, which may differ for cast iron and bare steel. A preliminary list of failure mechanisms is listed below, based on prior experience with cure in place pipeline liners (CIPP liners):

- Deflection (lateral deformation), due to undermining, frost heave, ground subsidence, possibly earthquakes (i.e., liquefaction, lateral spreading).
- Axial deformation (axial displacement), due to thermal expansion/contraction, adjacent construction activity, and possibly earthquakes (i.e., transient wave propagation, permanent deformation from lateral spreading or landsliding)
- Vibrational loads, due to overhead traffic, which may cause fatigue failure
- Bonding/de-bonding at coating/pipe interface, due to differences in the thermal expansion of metal and coating or mechanical loads. Debonding could result in gas pockets at the composite/pipe interface, which may cause damage to the coating if the pipe is rapidly depressurized. Note that debonding may be advantageous in responding to some mechanical loads.
- Compatibility with current and future gas compositions with regard to corrosion and permeability, especially for hydrogen
- Cross-section ovalisation – this maybe critical for low modulus coatings
- Bends, tees, valves, and service connections - The presence of pipe fixtures and service connections may create stress concentrations and localized failures, in conjunction with the above failure mechanisms.

Task 1.2 Modelling failure modes, identification of critical physical properties, and development of test methods

Each failure mechanism will be modelled, for two purposes:

- Translate the failure modes into predictive models to estimate the required structural coating material properties, particularly for failure mechanisms that may require long-duration testing.
- Develop test methods, including inputs on quality control statistics, for each failure mechanism. Address potential issues for testing failure mechanisms that are difficult to reproduce, or require accelerated testing.

These models are intended to use fundamental principles to relate critical mechanical properties of the structural coating and pipe to the failure mechanism for each failure mode. Parametric investigations using a range of input values (pipe size, materials, coating thickness, material properties) will be used to develop approximate correlations between failure modes and critical physical properties for different types of pipes and coatings (material and thickness). These correlations will be communicated to system component development teams to inform their research.

Applicants will need to provide test rigs suitable for large-scale testing failure mechanisms for coated “pipe in pipe”. We anticipate 10- to 20-inch (250-500 cm) pipe diameters, and 3 to 20 feet (1-6 meter) lengths for most tests.

Models, test methods, and test equipment will be “calibrated” using known materials (i.e. cast iron, steel, and composite pipes) to assess how well the models and test methods correlate with prior art. Test methods and equipment development will follow ASTM and/or ISO 17025 practices and incorporate any existing/available protocols (domestic or international), since regulatory approval is ultimately required.

Task 1.3 Pipe testing and correlations for failure mechanisms

The pipe testing facility(ies) will test coated pipe-in-pipe samples fabricated by system integrators from Task 5 “Integrated Task 2, 3, 4 Pipe Tests” per below. The pipe tests will use methods approved from Task 1.2. ARPA-E anticipates that system component developers (Applicants for Tasks 2-4) and system integrators (Applicants for Task 5) will conduct many screening tests on sample coupons and test pipes before submitting “pipe-in-pipe” samples from Task 5. Once their processes are sufficiently developed, system integrators will submit “pipe in pipe” samples from Task 5 for testing under Task 1.3.

ARPA-E will work with Applicants for Task 1 to establish a testing schedule and budget. ARPA-E will allocate test times to system integrators in Task 5. The system integrators are expected to stay within their test budgets and schedules.

Test results will be communicated to system integrators and component developers as testing progresses, with go/no-go criteria established at each stage. Final reports will be communicated within 4 weeks of completing a test. The test results will be compared to model calculations to refine models, develop correlations/extrapolations, and modify test methods, if required. System integrators and component developers have the right to witness all testing involving their technologies. System integrators will be responsible for any post-testing materials/failure analysis they elect to perform, and disposing all test samples.

Task 2. Smart Coating Materials

REPAIR seeks to rehabilitate legacy pipes by applying a structural coating the inside of the legacy pipe. Success requires identifying suitable coating materials (Task 2), developing a coating deposition tool to apply the coating (Task 3), and verifying the coating integrity (Task 4). Although Tasks 2, 3, and 4 are distinct technology development efforts, all three tasks need to be integrated and demonstrated in Task 5, “Integrated Task 2, 3, 4 Pipe Test”. The later-stage milestones reflect the combined performance of the coating, deposition tools, and integrity/inspection tools in Task 5. Consequently ARPA-E expects Applicants for Task 2 to address how they intend to collaborate with coating deposition tool teams in Task 3 and integrity/inspection tool teams in Task 4, as well as a system integrator in Task 5.

Materials are expected to be consistent with the intent of CFR 192 Subpart B – Materials. Applicants need to address material traceability throughout the coating process. Note that PHMSA forbids the use of rework or regrind materials for plastic pipe. Applicants proposing to use recycled materials, such as reclaimed composite fibers, need to address quality control metrics and supply chain issues.

ARPA-E prefers coating materials that minimize impacts on gas pipeline operations. However, if technology requires gas service disruption, applicants must quantify the number and duration of disruption(s) to gas service required for their coating materials. Examples of disruptions include the need to take pipes offline for cleaning, such as blasting or reaming; deposition methods that generate particles or aerosols that might migrate and foul gas equipment such as meters, regulators, or burners; and formulations that use solvents or generate by-products in concentrations high enough to impact gas operations or downstream gas equipment.

Applicants need to address cleaning requirements. Many coating systems have been formulated to work under more extreme conditions than expected for this project. For example, coatings that adhere and cure under water, in the presence of dirt.[22] The primary reason for cleaning is to obtain bonding between the coating and the surface. However, an objective of REPAIR is that the "pipe in pipe" be able to provide service for 50 years without relying on the original pipe. There are some indications that strong bonding may not be required, and could be disadvantageous in some failure modes.

Several structural coating technologies are commercially available to repair gas, water, or sewer pipelines. Structural coatings for gas pipelines have generally used fiber composites, given their high specific strength and stiffness; resistance to damage by fatigue loading; light weight; and resistance to corrosion. Cure in place pipeline liners (CIPP liners) typically use glass or aramid fibers with thermoset materials such as epoxy and polyurethane.

Applicants are expected to address estimated coating thickness for proposed materials. The coating layer will decrease the diameter of the original pipe, potentially reducing its delivery capacity. This effect can be minimized by using thin coatings of composite materials with robust mechanical properties. For example, Sirimanna[23] showed that a 5 mm coating of E-glass/epoxy composite material could compensate for 40% wall loss in a 168 mm pipe operating at 18,500 kPa. Given the much lower operating pressures for legacy gas distribution pipes (cast iron pipes < 250 kPa, bare steel <1,400 kPa), it appears that high-strength coating materials could rehabilitate pipes with minimal impact on inner diameter and hence delivery capacity.

[22] https://www.wessex-resins.com/applications/specialist-underwater-epoxies

[23] Sirimanna, et al. ANALYSIS OF INTERNAL BONDED FIBRE REINFORCED COMPOSITE REPAIR SYSTEMS FOR CORRODED STEEL PIPELINES, *Fourth Asia-Pacific Conference on FRP in Structures (APFIS 2013) 11-13 December 2013, Melbourne, Australia*

Applicants are expected to incorporate smart features into the coating, which will provide enhanced functionality compared to polyethylene pipes typically used in replacement projects. Smart features can also reduce the risk of premature failure, which is heightened given the 50 year life expectancy for the rehabilitated pipe. Examples of smart features include:

- Self-healing (autogenous): Examples include autonomous and non-autonomous embedded microcapsules that release reagents in response to mechanical damage, and shape-memory enhanced self-healing, which may require an external force such as heating to restore performance.
- Passive and active health monitoring: There are multiple options for incorporating sensing mechanisms into the coating structure. Examples include microcapsules which release agents when subjected to stress/strain; digital image correlation, which measures the relative displacements of a random pattern of markers; embedded optical fiber; and piezoelectric transducers, such as Macro-Fiber Composite (MFC) transducers.

As part of the coating screening process, each Applicant will be expected to perform their own lab-based performance tests consistent with the failure mechanisms identified in Task 1. These results, and post-mortem failure analysis, will be incorporated into the defect detection criteria for Task 4.2 for the Applicant's proposed coating materials.

Applicants may propose any structural coating material (including coatings with no fibers) that meet the criteria listed below:

- Material(s) can be deposited by a coating deposition tool from Task 3 in a cast iron or bare steel pipe
- Achieve the performance specifications set by the TTSC, including minimum 50 year life as determined by tests from Task 1
- Incorporates smart features, including self-healing and health monitoring
- Compatible with standard gas operations and maintenance (O&M) practices, such as connecting new services to mains while pipes are live
- No hazardous materials or personnel exposure issues during subsequent O&M activities
- Compatible with current and future gas compositions, especially high hydrogen content gas
- Optionally able to re-coat pipe, if necessary

Task 3. Coating deposition tool

As noted above, ARPA-E expects Task 3 Applicants to address how they intend to collaborate with teams developing coating materials and integrity/inspection tools, as well as a system integrator in Task 5.

There are several techniques for depositing structural coatings, such as spraying, casting, and printing/additive manufacturing, each of which has specific operating requirements and ranges.[24] All of these are used commercially in a wide range of industries. Critical issues include linear speed, deposition rate, uniformity of coating thickness, and impact on gas service during coating operations.

ARPA-E prefers coating deposition tools that minimize impacts on gas pipeline operations. However, if technology requires gas service disruption applicants must quantify the number and duration of disruption(s) to gas service. Examples include downtime for excavating access points; tapping pipes; inserting and removing the deposition tool; and operating the tool. Applicants must estimate the projected cross-sectional area of their tool, and assess whether it will impair gas delivery.

Applicants must provide the target operating ranges for their deposition tools. Parameters include the linear speed of the tool in a straight pipe, viscosity and density ranges for coating materials, and maximum coating thickness per pass.

The coating tool will require access to the interior of the pipe. The range of the deposition tool will determine the number of access points. Applicants must specify the expected maximum travel distance between access points for a straight pipe. Applicants also need to specify excavation and pipe tapping requirements, and whether tapping and operations can be conducted on live pipes.

Applicants must specify if the deposition tool needs to be tethered for power, communications, and material supply. Applicants must address drag forces and traction for the deposition tool. If the deposition tools needs to use enhanced normal forces to overcome drag forces, Applicants need to provide a range for the normal forces. Applicants must also describe how they will retrieve a non-responsive coating tool from a gas pipe.

The coating deposition tool will record operating parameters, quality control metrics, and material traceability by location, with location precision within 10 cm over its operating range. As an option, the coating tool could use the in-pipe mapping tool developed in Task 6.1.

Task 4. Pipe Integrity/Inspection Tool

As noted above, ARPA-E expects Task 4 Applicants to address how they intend to collaborate with teams developing coating materials and coating deposition tools, as well as a system integrator in Task 5.

Integrity/inspection tools are needed to assess the legacy pipes prior to coating, and assess the coating after deposition. Task 4 Applicants are encouraged to collaborate with Task 2

---

[24] Fiber-Reinforced Polymer Composites: Manufacturing Properties Applications, Polymers-11-01667

Applicants to screen and select the optimal inspection technique(s) for specific coating materials or optionally a range of materials. Ideally the same techniques and tools can be used for pre- and post-coating inspections, implying the inspection technique can "see" through the coating. ARPA-E anticipates different techniques and tools may be required for cast iron and bare steel pipes.

Applicants must provide the target operating ranges for their integrity/inspection tools. Parameters include the linear speed of the tool in a straight pipe and expected maximum travel distance between access points for a straight pipe. Applicants also need to specify excavation and pipe tapping requirements, and whether tapping and operations can be conducted on live pipes. Ideally the integrity/inspection tool will use the same access points as the coating deposition tool.

Applicants must specify if the integrity/inspection tool needs to be tethered for power and communications. Applicants must address drag forces and traction for the integrity/inspection tool. If the integrity/inspection tool needs to use enhanced normal forces to overcome drag forces, Applicants need to provide a range for the normal forces. Applicants must also describe how they will retrieve a non-responsive tool from a gas pipe.

The integrity/inspection will record data by location, with location precision within 10 cm over its operating range. The tool needs to be able to record locations within 10 cm over its operating range. As an option, the coating tool can integrate the in-pipe mapping tool developed in Task 6.1 so that mapping is coincident with pre-coating inspection.

ARPA-E prefers integrity/inspection tools that minimize impacts on gas pipeline operations. However, if technology requires gas service disruption applicants must quantify the number and duration of disruption(s) to gas service. Examples include downtime for excavating access points; tapping pipes; cleaning pipes prior to inspection; inserting and removing the integrity/inspection tool; and operating the tool. Applicants must estimate the projected cross-sectional area of their tool, and assess whether it will impair gas delivery.

Task 4.1 Pre-coating integrity/inspection measurements

The pre-coating inspection will assess the initial condition of the pipe. It must include a video camera.

Some key issues for pre-coating inspection:

- Identify any gross features that could hinder pipe rehabilitation, including obstructions such as debris, liquids, pipe joints, tight bends, reducers, valves, etc.
- Identify pipe defects that would limit the operation of the coating deposition tool, including cracks, excessive corrosion, dents, etc.
- Provide real-time information with data visualization for operators.

There are several commercially available techniques for assessing cast iron and bare steel pipes, such as calipers, which measure diameter and detect gross defects; ultrasonics (UT), which can detect weld discontinuities and general corrosion; and magnetic flux leakage (MFL), which can detect cracks, severe pitting, and general corrosion/wall loss. All three techniques require tools to have contact with the pipe wall, which can be problematic for pipe with no or only minimal cleaning. UT or MFL tools may experience poor signals due to dirt, and/or damage to the detectors/magnets due to roughness or tuberculation. Consequently Applicants proposing to use tools that contact the pipe wall will need to address performance and durability for pipes with minimal cleaning.

Alternatively, Applicants can propose non-contact inspection techniques. Several non-contact inspection techniques are commercially available for cast iron and bare steel pipes, such as Electromagnetic Acoustic Transmitter (EMAT), using Lamb, Shear, and Longitudinal waves; Remote Field Electromagnetic Technique (RFET); and Large Standoff Magnetometry (LSM), which inspects pipes from the surface.

The pipeline rehabilitation operation needs timely information on the pipe condition. Consequently, the inspection technique(s) will include software that can analyze inspection data and provide results within 48 hours. The inspection report needs to identify location and characteristics of all anomalies.

Applicants may propose any contact or non-contact technique, or combination of techniques, that meet the criteria listed below:

- Detect general corrosion > 10% wall thickness
- Detect pits longer than 20 mm and deeper than 40% wall thickness on the inner diameter of the pipe
- Detect pits longer than 25 mm and deeper than 40% wall thickness on the outer diameter of the pipe
- Detect circumferential cracks deeper than 40% wall thickness
- Detect longitudinal cracks deeper than 20% wall thickness
- Detect graphitization >10% wall thickness (cast iron)
- Location accuracy within 10 cm over operating range
- Data analysis within 48 hours

Task 4.2 Post-coating integrity/inspection tool

The post-coating inspection tool has the same requirements as above, plus requirements to assess the integrity of the coating. Potential defects include holidays (areas with no coating); thickness variations, especially sagging across the perimeter; voids, especially at the pipe wall; delamination and cracks; and incomplete curing.

Defect detection requirements are typically determined from damage tolerance analysis. This analysis assumes defects are present, and grow with time. Residual strength can be calculated from defect size, and consequently can be predicted based on defect growth rates. The residual strength must match the highest load over the expected life of the coating. These loads are determined from failure mechanisms identified in Task 1. Defect growth rates and residual strength will be established during performance testing in Task 2. Consequently it is imperative that Applicants for Task 4 collaborate with Applicants for Task 2.

Many contact and non-contact integrity tests are commercially available for coating materials anticipated for REPAIR. Not all techniques have been demonstrated for operation inside a pipe. Examples include:

- Ultrasonic testing (UT), which measures thickness and can detect cracks, delaminations, shrinkage cavities, pores, and debonding. 2-D images can be created form multiple A-scans or phased arrays.
- Acoustic Emission Technique (AET), which detects matrix cracking, delamination, debonding, and fiber fracture in composite materials
- Thermography, with many variants, including optically stimulated thermography, ultrasonic stimulated thermography, eddy current stimulated thermography, and microwave thermography

Applicants may propose any coating integrity test method, or a combination of test methods. The test method must be able to meet the criteria for Task 4.1, including 48-hr turn-around time for data analysis, and ability to operate in live pipes. In addition, the Applicants must be able to demonstrate that the testing tools can detect flaws consistent with damage tolerance analysis. We anticipate that Applicants will be running tests on lab-scale samples generated from performance tests in Task 2 to define minimum flaw detection limits for the integrity test methods.

Task 5. Integrated Task 2, 3, 4 Pipe Tests

Tasks 2-4 are focused on the development of the components for REPAIR. However, commercial success requires system integrators to develop “turnkey” offerings for gas utilities. Consequently, system integrators are required for Task 5. ARPA-E will assess the success of REPAIR based on the performance of integrated systems against the tests approved by the TSSC in Task 1.2, and conducted in Task 1.3. Applicants for Task 5 will be responsible for selecting and integrating their system components. The final tests will be run on a 10- to 20-inch diameter segment of field pipe removed from service. Applicants will demonstrate pre-coating inspection, coating deposition, and post-coating inspection to verify coating integrity. If the coating does not pass the post-coating inspection, Applicants can propose to recoat the segment of pipe or repeat the process on a different segment of pipe. Pipe sample(s) will be submitted for testing per Task 1.3. System integrators will be responsible for post-testing analysis and disposal of all samples.

Task 6. Pipeline mapping, coating/integrity/leak detection data integration, and data management/visualization

The objective of Task 6 is to create 3D maps of the rehabilitated gas mains, pipeline components, and adjacent underground infrastructure. These maps will also incorporate data from leak reports, integrity/inspection tools, and coating deposition tools. These 3D maps support REPAIR efforts and utility O&M work. Objectives include:

- Location coordinates for the pipeline main targeted for rehabilitation, and other pipeline components connected to the main such as laterals, service lines, and elbows, to an accuracy of 10 cm in each of the X, Y, and Z coordinates and at a depth of up to 3 meters. Also locate valves, reducers, or foreign objects that may impede rehabilitation tools. 3D maps of these features will support pipeline replacement planning. Accurate 3D maps can also be incorporated into "Call-811 before-you dig" programs and support efforts to minimize third party damage.
- Location coordinates for other adjacent underground infrastructure, such as water, sewer, and electrical conduits within 60 cm of main, to an accuracy of 10 cm in each of the X, Y, and Z coordinates and at a depth of up to 3 meters. Locating adjacent infrastructure will facilitate planning to access mains and replace other pipeline components, as required.
- Incorporate locations for leaks, anomalies, and integrity/inspection results so utilities can prioritize mains targeted for REPAIR technologies. The data will also allow utilities to visualize changes in pipeline integrity with time, and support predictive maintenance programs.
- Provide location records for material traceability and structural coating QA/QC data so utilities can take proper action in the future if problems emerge with the coating materials or process.

Applicants can propose in-pipe or surface-based pipe mapping technologies, or a combination of technologies. ARPA-E will work with the TSSC to identify suitable locations for testing pipe mapping tools. Options include test loops and field tests with well-characterized sites.

Task 6.1 In-pipe mapping

Pipe mapping LIDAR, combined with inertial navigation system, is used extensively on the surface to create detailed 3-D maps of infrastructure. Several teams in the DARPA Subterranean (SubT) project have proposed to incorporate LIDAR with crawlers to map underground structures such as caves and tunnels.[25] LIDAR will give accurate measurements for

[25] https://www.darpa.mil/program/darpa-subterranean-challenge

the mains and other pipeline components. However, it will not detect adjacent underground infrastructure.

Ideally in-pipe mapping tools would be deployed on the coating robot and/or inspection robot from Tasks 3 and 4. If a separate tool will be used to carry the mapping tool, Applicants must provide the target operating ranges for their in-pipe mapping tools. Parameters include the linear speed of the tool in a straight pipe and expected maximum travel distance between access points for a straight pipe. Applicants also need to specify excavation and pipe tapping requirements, and whether tapping and operations can be conducted on live pipes. Ideally the integrity/inspection tool will use the same access points as the coating deposition tools and integrity/inspection tools.

Applicants must specify if the in-pipe mapping tool needs to be tethered for power and communications, and address drag forces. Applicants must also describe how they will retrieve a non-responsive tool from a gas pipe.

ARPA-E prefers mapping tools that minimize impacts on gas pipeline operations. However, if technology requires disruption applicants must quantify the number and duration of disruption(s) to gas service. Examples include downtime for excavating access points; tapping pipes; cleaning pipes prior to inspection; inserting and removing the integrity/inspection tool; and operating the tool. Applicants must estimate the projected cross-sectional area of their tool, and assess whether it will impair gas delivery.

Task 6.2 Surface mapping

Several underground technologies have been investigated by the gas industry to detect adjacent infrastructure, primarily to locate pipes and prevent cross-bores.[26] Examples include:

- Electromagnetic induction, developed by DOD for detecting buried unexploded ordinance and improvised explosive devices. Electromagnetic induction technology has the potential to be able to determine pipe size, material of construction, and detect general corrosion. This technique only works on metal-containing objects.[27]
- Large Standoff Magnetometry (LSM), mentioned in Task 4. Capable of providing 3D maps as well as stress measurements. This technique only works on metal-containing objects.[28]

---

[26] New Technologies Build on Current Success for Utility Location and Cross Bore Elimination, http://crossboresafety.org/documents/New%20Technologies%20Build%20on%20Current%20Success%20for%20Utility%20Location%20and%20Cross%20Bore%20Elimination%20-%20Mark%20Wallbom%20May%202010.pdf

[27] Review of Magnetic Modeling for UXO and Applications to Small Items and Close Distances, JEEG, June 2012, Volume 17, Issue 2, pp. 53–73

[28] Jarram, P. (2016, June 14). NACE Corrosion 2016 - Final Paper - Remote Measurement of Stress in Carbon Steel Pipelines – Developments in Remote Magnetic Monitoring. NACE International.

- Ground penetrating radar, which can detect metallic and non-metallic subsurface objects. The EU ORFEUS project highlights recent advances.[29] Tools are commercially available, but with limitations related to pavement/asphalt cover, soil type, and sensitivity to detecting pipes parallel vs crossing the plane of inspection. Varying the frequency can change sensitivity, but typically with a trade-off on detection depth.

Applicants must provide the target operating ranges for their surface mapping tools. Parameters include the linear speed of the tool in a straight line and per-pass detection width. Applicants should address ability to detect metallic and non-metallic objects, sensitivity to object orientation, and interferences from surface materials such as asphalt and concrete.

Task 6.3 Coating/integrity/leak detection data integration, and data management/visualization

Gas utilities use GIS-enabled enterprise systems for tracking pipeline locations and attributes. REPAIR processes (e.g. inspections, coating, mapping) will generate large data sets that need to be compatible with GIS-enabled enterprise systems used by gas utilities. Given the large data sets, real-time data visualization will be required to support real-time decisions in the field as mapping, coating, and inspection processes are underway. The goal of this task is to create a unified data management tool that can integrate all REPAIR information into the 3D pipeline maps, and provide an interface that allows users to manage and visualize the data in real time.

D. Preliminary Milestones and Technical Requirements by Task

Task 1.1 Define failure modes and establish the performance criteria for "pipe in pipe" with cast iron and bare steel pipes

- Provide a comprehensive list of failure mechanisms relevant to coated "pipe in pipe" operations for gas distribution to ARPA-E and the TTSC within the first 3 months of the program.
- Quarterly updates on failure mechanisms, as required

Task 1.2 Modelling failure modes, identification of critical physical properties, and development of test methods

- Initial screening models for each failure mechanism within the first 6 months of the program, and fundamental models (material and interaction models) for each failure mechanism within the first 12 months of the program
- Initial ranges for mechanical properties within the first 6 months. Quarterly updates on coating mechanical properties, based on advances in models and testing.

[29] http://www.orfeus-project.eu/publications/deliverable_D15.pdf

- Test protocols consistent with requirements to achieve ultimate approval by ASTM F17 or similar codes and standards organization.
- Test hardware functioning within the first 6 months, and all testing hardware calibrated using known materials within the first 12 months.

Task 1.3 Pipe testing and correlations for failure mechanisms for samples from Task 5

- Complete all tests within the allotted time, budget, and quality metrics
- Quarterly updates for model updates, test modification, and correlations

Tasks 2-5 System Component Development and System Integration

Although Tasks 2, 3 and 4 are distinct technology development efforts, all three tasks need to be integrated and demonstrated in Task 5, final testing on field pipe removed from service. Consequently milestones for these tasks are linked, as shown in the following table. ARPA-E anticipates that coating materials, coating deposition tools, and integrity/inspection techniques may only work in narrow combinations. ARPA-E recommends system component Applicants to identify partners with compatible technology platforms.

The test environment moves progressively from lab to field pipe for each task. ARPA-E will collaborate with the TSSC to provide pipe samples removed from the field.

- 12 months: Prototype proof of concept on a flat surface or pipe segment.
- 18 months: Sequential testing of coating material, coating deposition, and integrity/inspection technique on a flat surface or pipe segment.
- 24 month test: Sequential testing of coating, coating deposition tool, and integrity/inspection tool in a lab-based test in a pipe segment. Verify performance using Task 1 test methods at the lab scale.
- 32 month test: Integrated Performance testing of components from Tasks 2, 3, and 4 using the methods and equipment of Tasks 1.2 and 1.3 in a field pipe removed from service by end of the program. The performance test will include the coating material, the coating deposition tool, and the integrity/inspection tool chosen for that material. The coating must pass the criteria set by the integrity/inspection tool, and meet the performance specifications as determined by tests from Task 1. The costs for coating material, deposition tool, and integrity/inspection tool must be consistent with a deployed cost of $1 million per mile, including gas service disruption costs.

Table 1 Milestones for Tasks 2 - 6

Task	**12 month** **Bench testing**	**18 month** **Bench testing**	**24 month** **Lab-based pipe test**	**32 month** **Performance testing in a field pipe**
2. Coating Materials	Down-select candidate coating materials that meet mechanical requirements per Task 1 modelling	Performance tests and post-mortem testing to support minimum flaw detection criteria	REQUIRED	per Task 5
3. Deposition tool	Operate tool at the target linear speed with simulated drag forces. Not necessary to have a functioning coating device	Operate tool with required thickness using material from Task 2, and record location, coating operating parameters, and materials	REQUIRED	per Task 5
4. Integrity/ Inspection tool	Meet section 4.1 criteria, except 48 hour data analysis.	Meet section 4.1 criteria, except 48 hour data analysis. Measure thickness and detect cracks, delaminations, shrinkage cavities, pores, and debonding	REQUIRED	per Task 5
5. Integrated Task 2, 3, 4 Pipe Test			Preliminary identification of all system components	Pass Task 1.3 tests in a 10- to 20-inch diameter field pipe

			and positive pipe test results in lab environment	removed from service
6. Mapping tools and data integration		Meet section 6 criteria for 3-D map of pipes in a lab or simulated environment	Meet section 6 criteria for 3-D map of pipes, other pipeline components, and adjacent infrastructure in a test loop or well-characterized field site	Demonstrate real-time 3D maps that incorporate data from integrity/inspection tool and coating deposition tool used in Task 5

E. Preliminary Economic Model

The Preliminary Economic Model below is intended to provide guidance on the $1 million per mile cost metric. The input values are for example only. This example assumes no disruption of gas service. ARPA-E will collaborate with utility representatives to provide guidance on gas disruption costs.

Preliminary Economic Model

Summary

Total cost	($/km)	$	708,426
Total cost	($/mile)	$	1,140,783

Coating Material Costs

Material Cost	($/kg)	4
Pipe inner diameter	(in)	12
Coating thickness	(cm)	0.75
Coating density	(g/cm3)	2
Coating cost	($/km)	574,243

Tools Cost

	Units	Deposition Tool	Integrity/Inspection Tool	Mapping Tools	Notes
CAPEX	($)	$ 1,500,000	$ 1,000,000	$ 250,000	Assume mapping tools mounted on coating and integrity/inspection tool
Annual return on CAPEX	(%)	20%	20%	20%	
Useful life	(yrs)	5	5	5	
Annual return for tool CAPEX	($)	$501,570	$334,380	$83,595	
OPEX					
Crew (assume 24X7 operation)	people	5	5	5	24X7 may not be required
Fully burdended labor rate, including alocation for trucks and tools	$/year	$ 125,000	$ 125,000	$ 125,000	
Back office support	$/year	$ 250,000	$ 250,000	$ 250,000	data analysis, overhead
Annual labor costs		$875,000	$875,000	$875,000	
T&L	$/-person-da	$200	$200	$200	
T&L	$/yr	$146,000	$146,000	$146,000	on road durnig utilization
Maintenance	% of CAPEX	6%	6%	6%	
Mobilization/demobilizaton time	weeks	2	1	1	not used in calc since utilization is low
Utilization	% of year	40%	40%	40%	
Speed	m/hr	20	50	100	
Number passes/segment		1	2	3	Assume 1 pass for coating, 2 passes for pre- and post coating for integrity tool, multiple passes for mapping tool
km/yr		70	70	70	distance set by slowest tool
Bi-directional operating range	(m)	1000	1000	1000	
Number access points per year		70	70	70	
Cost per access point (assumes tools can share access points)	($)	$75,000	$0	$0	Assume tools share common access point
Number disruptions to gas serivce per segment					
Duration disruption per segment	(hr)				
Cost of disruption per segment	($)				TSSC to advise
Total annual cost	($/yr)	$6,868,570	$1,415,380	$1,119,595	
Total Annual Costs	($/km)	$98,010	$20,197	$15,976	
Hours gas service disruption	(hr)	0	0	0	By applicant
Cost gas disruption	($/yr)				By utility

F. Applications Specifically Not of Interest

The following types of applications will be deemed nonresponsive and will not be reviewed or considered:

- Applications that were already submitted to pending ARPA-E FOAs.
- Applications that are not scientifically distinct from applications submitted to pending ARPA-E FOAs.
- Applications for basic research aimed at discovery and fundamental knowledge generation.
- Applications for large-scale demonstration projects of existing technologies.
- Applications for proposed technologies that represent incremental improvements to existing technologies, including CIPP liners, slip liners, and external pipe wraps.
- Applications for proposed technologies that are not based on sound scientific principles (e.g., violates a law of thermodynamics).
- Applications that do not address at least one of ARPA-E's Mission Areas
- Applications for proposed technologies that are not transformational.
- Applications for proposed technologies that do not have the potential to become disruptive in nature. Technologies must be scalable such that they could be disruptive with sufficient technical progress.
- Applications that are not scientifically distinct from existing funded activities supported elsewhere, including within the Department of Energy.
- Applications that propose the following:
    - Development of components (coatings, inspection tools, robots, etc.) without addressing how these will be integrated into an operating system
    - Approaches that require extensive excavation, especially at intervals less than 200 m apart
    - Approaches that use non-structural coatings
    - Approaches that address leaks, but do not create a new pipe with a 50 year life
    - Approaches that require extensive downtime for gas pipes, for example for cleaning, coating deposition, curing, etc.