Internal Corrosion Control: A Regulatory Requirements Adequacy Review

As Required by Pub. L. No. 109-468
The Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006

The **U.S. Department of Transportation**
Pipeline and Hazardous Materials Safety Administration

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1 Executive Summary

In enacting the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (PIPES), the U.S. Congress directed the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA), in consultation with the Technical Hazardous Liquid Pipeline Safety Standards Committee and other appropriate entities, to review the internal corrosion control regulations set forth in subpart H of part 195 of title 49 of the Code of Federal Regulations. The mandate was to determine if such regulations currently are adequate to ensure that the pipeline facilities subject to such regulations will not present a hazard to public safety or the environment and to submit a report containing the results of the review. PHMSA believes the emphasis of this review should be the protection of pipeline facilities that could affect areas outside of the "high consequence areas," which are currently covered by integrity management requirements. PHMSA may modify the regulations referred to if necessary and appropriate.

Accomplishment of Review

In response to this mandate, PHMSA conducted a thorough review of the federal pipeline safety internal corrosion control regulations, accident history, our research findings, and activities in consensus standards organizations. As part of the process, we briefed our Technical Hazardous Liquid Pipeline Safety Standards Committee in July 2007. In August 2007, as a follow up to the meeting, we published a briefing on key points from our review in the *Federal Register* for public comment. We received valuable input in response to our request and have included a summary of key stakeholder observations in this report.

Currently, in subpart H of part 195, hazardous liquid pipeline operators are required to determine the corrosivity of the product being transported with periodic sampling and analysis to identify the risk of internal corrosion. If pipeline operators determine there is a risk for internal corrosion, operators must develop and implement a plan to mitigate the potential effects of internal corrosion. Pipeline operators are required to monitor the effectiveness of the internal corrosion mitigation program, and must re-evaluate and adjust accordingly to mitigate risk if there is a product change or indication of internal corrosion.

For many years, PHMSA has directed a multi-faceted set of initiatives to reduce the risk of internal corrosion in hazardous liquid pipelines. We define internal corrosion as a chemical attack on the interior surface of steel pipelines from the commodities, and contaminants in those commodities, being transported through the pipeline. Internal corrosion is manageable, not preventable. Our efforts span investing in research and development; actively engaging in the development of national consensus standards; increasing PHMSA staff capabilities; and developing more robust pipeline operator oversight and enforcement programs. We have retained several highly-qualified corrosion subject matter experts on staff, and they have participated in the development and revision of national corrosion standards and best practices for several years.

Learning from Research, Inspections and Investigations

Since 2002, PHMSA has invested over $3.5 million in research and development projects to support the development of technology, standards, and increase general knowledge of internal corrosion control risks and risk detection, prevention, and mitigation practices. We have co-funded with the pipeline industry and technology companies 16 projects related to internal corrosion since 2002. These projects are resulting in improved methods of internal corrosion prediction, detection and mitigation. Three of these projects have transferred improvements to market. Guided wave and in-line inspection service providers have benefited from these technology studies, with advancement possible in characterizing defects and increasing the probability of the detection of defects. As part of our multi-year research and development plan, PHMSA expects to initiate several important new projects to advance internal corrosion standards and technology in 2008.

Through our investigations and studies, we better understand the various factors which contribute to the onset of internal corrosion and influence the rate at which corrosion attacks the pipe wall. Low velocity of the fluid stream, low points in the pipeline profile, removal of solids, use of corrosion inhibitors, presence of other products like water and other corrosive material can all influence the rate of corrosion. We know that even small changes in these parameters can affect the rate of internal corrosion considerably.

Our national inspection programs, including our integrity management program, better informed by these studies, have brought special oversight focus on the threat of internal corrosion for at least the past five years. Where a spill could affect HCAs, operators are required to assess the effectiveness of their internal corrosion mitigation program through the use of internal line inspection tools and/or other methods such as direct assessment, done at a minimum of every five years. Requiring internal corrosion control outside HCAs is based on available risk data. PHMSA could, and previously has, required pipeline operators to employ the same or similar integrity management practices vis-à-vis corrosion outside HCAs where a spill could have an adverse impact on safety or the environment. PHMSA has issued violations and directive orders to pipeline operators who were not adequately implementing our regulatory requirements, both in and outside HCAs. PHMSA also has conducted accident investigations on major pipeline failures in which we identified the root cause as internal corrosion. As a result of these investigations, PHMSA has required some operators to implement a more stringent internal corrosion control system to maintain pipeline integrity. To further strengthen our inspection program, we are developing a more integrated, holistic evaluation of an operator's program that is better informed with data to focus on specific pipeline threats like internal corrosion that will be implemented in 2009.

Working with National Consensus Standards Organizations

PHMSA provides the findings of our research, inspections and investigations to national consensus standards organizations, like the National Association of Corrosion Engineers (NACE). NACE is the primary standards development organization in this area. Currently, our projects are directly contributing to standards for the direct assessment of wet and dry gas internal corrosion and we expect work in the future to move to direct assessment of internal corrosion in liquid pipelines. The American Society of Mechanical Engineers may consider revision of its standards based on these studies and investigations.

In addition to the NACE work under development on direct assessment, PHMSA has reviewed NACE's "Control of Internal Corrosion Steel Pipelines and Piping Systems," and a recommended practice, "Preparation, Installation, Analysis and Interpretation of Corrosion Coupons in Oilfield Operation." These provide best practices, currently not detailed in our regulation, for internal corrosion control as well as the placement, analysis, and review of corrosion coupons. Another standard, "Determining Corrosive Properties of Cargoes in Petroleum Product Pipelines," currently under revision, is expected to help provide operators with methodology to determine if corrosive properties exist in the products transported. It is PHMSA's practice to incorporate consensus standards at the earliest practicable date to the extent that we believe they are useful or necessary to guide operators' decision making processes.

Findings

Our review of the Federal pipeline safety internal corrosion control regulations for hazardous liquid pipelines indicates that our existing standards to protect against internal corrosion are generally sufficient to allow PHMSA to achieve safety and environmental protection goals. PHMSA believes that the existing performance-based internal corrosion rules provide us sufficient opportunity to determine that pipeline operators establish adequate prevention and mitigation programs to control for the risks of internal corrosion in their hazardous liquid pipelines. Where necessary, our existing regulations allow us the latitude in our oversight to direct changes to operator programs and pursue possible enforcement cases if a pipeline operator's program is inadequate from a safety and/or environmental protection standpoint.

PHMSA does believe, however, that there may be additional opportunities to reduce risk outside HCAs by providing further detail that operators may need to adequately determine the corrosivity of transported hazardous liquids, and to mitigate the circumstances contributing to corrosion. This detail could be provided through our incorporation of existing and developing NACE standards, but requires further evaluation.

As this work progresses, we will have improved methods for integrating physical pipeline characteristics and operating history with data from multiple field examinations and pipe surface evaluations to better validate the assessment process. The result will be a better predictive capability to manage internal corrosion that can be applied by operators as risk based, data driven process, appropriately applicable on a prioritized basis from high consequence to lesser consequences areas. In the future, there may be more of a need for operator consideration of these factors in operations where production has decreased over time, resulting in reduced flow through the pipeline. The transportation of new commodities such as ethanol could also warrant the need to consider more closely corrosion detection and mitigation practices.

In summary, PHMSA is, considering a range of near- and long-term steps to further reduce the risk of internal corrosion in hazardous liquid pipelines. We are considering 1) issuing an advisory bulletin to all hazardous liquid operators reinforcing the need for rigorous evaluation of the corrosivity of their transported products and potential contaminants in such products; 2) holding a national workshop to more fully develop a public record on the need for making regulatory improvements; and 3) depending on the outcome of the workshop, incorporating new national consensus standards into our regulations. The advisory bulletin would provide clarification to industry on how to correctly determine the threat of internal corrosion, components of integrity management best practices for internal corrosion control, and the proper use and interpretation of industry standards.

PHMSA also has promulgated final rules adding significant new protections to prevent the risk of internal corrosion failures in previously unregulated low-stress pipelines. These pipelines, previously unregulated because of their relatively low risk, will now be required to comply with the internal corrosion control regulations already in place for higher stress hazardous liquid pipelines. PHMSA believes we are seeing clear signs of success with our increased inspection and enforcement programs for hazardous liquid pipelines, and we expect to see similar results with low stress pipelines.

2 Introduction

Everyday, millions of Americans depend upon the safe, environmentally sound, and reliable transportation of oil and gas through pipelines. The energy transportation pipeline network of the United States consists of well over two million miles of pipelines. Pipelines are historically a very safe means of transporting large quantities of oil, natural gas, fuels, and other hazardous materials, and the long-term safety and environmental consequence trends are positive.

Over 165,000 miles of this system regularly transports regulated hazardous liquids. The nationwide risks of transportation of these inherently hazardous liquids, particularly relative to alternative modes of transportation, are quite low and clearly seem to be lessening. Since 2002, accidents in the hazardous liquid transportation system have resulted in an annual average of two pipeline accidents causing an injury or fatality, and 132 otherwise reportable pipeline accidents. Of these accidents, internal corrosion was not identified as the root cause of any fatality or injury, but it has been tied to an annual average of 13 reportable accidents. These internal corrosion accidents annually generate a gross loss of product of approximately 12,000 barrels of product, and result in an average $2 million in property damage (two-thirds of which is to pipeline operator property and equipment). Removal of three much larger-than-normal accidents from the comparison during this same interval, however, reduces the average gross loss of product to about 3,100 barrels per year. It should be noted that while the estimates are not precise, nearly 90 percent of gross lost product is reported to be eventually recovered.

The risk of internal corrosion in hazardous liquid pipelines varies greatly in relationship to the type of products (and their purity) being transported, the environmental conditions the pipeline is subjected to, and the quality of the management system employed by the pipeline operator to identify, assess, mitigate, or repair threats to pipeline integrity. Prevention of internal corrosion is a continuous cycle that must regularly be re-evaluated by pipeline operators. The first step in identifying the risk of internal corrosion is to rigorously determine the potential corrosivity of the product, as well as potential contaminants, being transported. This is done through periodic product quality sampling and continuous operational monitoring. To be effective, the risk analysis clearly should take into account the potential affects of upsets and other abnormal operations, and the pipeline system elevation profile. If the risk for internal corrosion is identified, the operator must develop and implement a plan to mitigate its potential effects on system integrity.

Among the many possible mitigations an operator can choose, depending on the unique circumstances of their system, are the use of specific chemical corrosion inhibitors to coat and protect pipe walls and regular cleaning pig runs at predetermined intervals to remove sediment and clean the pipe wall to maximize inhibitor effectiveness. To monitor the effectiveness of the internal corrosion mitigation program, pipeline operators use pipeline coupons inside the pipeline. These coupons are exposed to the full product stream and are reviewed at regular intervals to monitor for signs of corrosion. Effectiveness of an internal corrosion mitigation program can also be assessed through the use of internal line inspection tools and/or other methods such as direct assessment typically done every 3-7 years. If at any point the pipeline operator finds a change in product or indication of internal corrosion, the program should be re-evaluated and adjusted to more effectively mitigate the risk. Pipeline operators must regularly monitor for the presence of internal corrosion by inspecting the internal pipe wall surfaces whenever any pipe is removed for any reason. Presence of internal corrosion found during these inspections is a clear sign that a wider assessment must be done and that additional mitigations are likely necessary.

A reliable internal corrosion prevention system can reduce and prevent leaks that could result in safety, environmental, and economic consequences and will increase the life of pipeline system and ensure long term pipeline reliability.

3 Regulatory Requirements

The Federal pipeline safety regulations located in 49 CFR 195.579 (Subpart H – Corrosion Control) address all potential threats from corrosion in hazardous liquid pipelines. Among other things, these rules require pipeline operators transporting hazardous liquid or carbon dioxide to investigate the corrosive effect of the hazardous liquid or carbon dioxide being shipped in their pipeline. If the operator determines that the transportation of the product carried is not corrosive, the operator is not required to take special steps to mitigate internal corrosion. If, however, the operator determines the product being transported has the potential for a corrosive effect on the pipeline, the operator must take adequate steps to mitigate internal corrosion.

The regulations do not prescribe specific steps that an operator must take to mitigate internal corrosion. However, if the operator chooses to mitigate corrosion through the use of corrosion inhibitors, the regulation specifies that the operator must:

1. Use a sufficient quantity of inhibitor;
2. Use coupons or other monitoring equipment to determine the effectiveness of the inhibitor; and
3. Examine the coupons or other monitoring equipment at prescribed intervals.

In addition, when the operator removes pipe from a pipeline, the operator must inspect the internal surface of the pipe for evidence of corrosion. If internal corrosion is found requiring corrective action under 49 CFR 195.585, the operator must investigate beyond the removed section of pipe (by visual examination, indirect method, or both) to investigate the potential for additional corrosion requiring remedial action beyond that found in the vicinity of the removed pipe.

Special provisions exist for certain new tank bottom linings installed in aboveground breakout tanks. Except under limited circumstances, after October 2, 2000, when an operator installs a tank bottom lining in an aboveground breakout tank built to specific

American Petroleum Institute (API) Specifications or Standards, the operator must install the lining in accordance with API Recommended Practice 652.

PHMSA's integrity management program regulations, found in 49 CFR 195.452, add additional protections if a pipeline failure could affect a high consequence area (HCA). An HCA is defined as a high population area, other populated area, commercially navigable waterway, or unusually sensitive environmental area, including a sole source drinking water supply,. If a spill from a pipeline could affect these areas, the operator must rigorously identify all threats to the pipeline, including the threat of internal corrosion. The operator must have a continual process of evaluation and assessment to maintain integrity. The operator must also evaluate the need for additional preventive and mitigative measures to address the threats.

Building upon lessons learned from the few serious internal corrosion pipeline failures that have occurred, and research, inspection and investigation described in the next section of this report, PHMSA finalized new regulations in to extend regulatory protections, including those of corrosion control, to previously unregulated low-stress hazardous liquid pipelines that could affect HCAs. Additional protections for other low-stress lines will be proposed in a subsequent "Phase 2" rulemaking.

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(HCAs), including highly populated areas, commercially navigable waterways and unusually environmentally sensitive areas, operators are required to assess the effectiveness of their internal corrosion mitigation program through the use of internal line inspection tools and/or other methods such as direct assessment, done at a minimum of every 5 years. Requiring internal corrosion control outside HCAs is based on available risk data. PHMSA could, and previously has, required pipeline operators to employ the same or similar integrity management practices vis-a-vis corrosion outside HCAs where a spill could have an adverse impact on safety or the environment. PHMSA has issued violations and directive orders to pipeline operators who were not adequately implementing our regulatory requirements, both in HCAs and outside HCAs. PHMSA also has conducted accident investigations on major pipeline failures in which we identified the root cause as internal corrosion. As a result of these investigations, PHMSA has required some operators to implement a more stringent internal corrosion control system to maintain pipeline integrity. To further strengthen its inspection program, we are developing a more integrated, holistic evaluation of an operator's program that is better informed with data to focus on specific pipeline threats like internal corrosion.

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4 Technical Hazardous Liquid Pipeline Safety Standards Committee Briefing Paper and Stakeholder Comments

On July 24, 2007, PHMSA consulted with its Technical Hazardous Liquid Pipeline Safety Standards Committee (THLPSSC) to discuss the adequacy of existing regulations pertaining to the protection of hazardous liquid pipelines from the threat of internal corrosion. A briefing paper was prepared to facilitate the discussions with THLPSSC. The briefing paper was subsequently published in the *Federal Register* (72 FR 51303), and comments were solicited from other stakeholders. PHMSA received comments from the following stakeholders: American Petroleum Institute (API) and Association of Oil Pipe Lines (AOPL), NACE International (NACE) and Accufacts, Inc. (Accufacts).

API/AOPL jointly commented that existing corrosion control regulations were adequate to address the threat of internal corrosion to hazardous liquid pipelines. In support of its position, API/AOPL pointed out that the ongoing integrity assessments and reassessments of high consequence areas (HCAs) provide the opportunity to analyze corrosion data and look for trends and lessons learned. API/AOPL also indicated that the integrity assessments also result in the assessment of a large amount of pipeline outside HCAs as an adjunct of the assessments conducted in HCAs. With regard to forthcoming regulations supported by API/AOPL, rural gathering and low-stress lines will be required to address corrosion threats to the integrity of the pipe in the same manner as "high stress" transmission pipelines that could affect HCAs and should yield similar results in the reduction of releases related to corrosion, including internal corrosion, on these newly regulated lines. API/AOPL concluded that PHMSA should allow the current regulations to work before considering additional requirements, and stated that it would be helpful for PHMSA to sponsor workshops aimed at increasing operator knowledge of industry practices and standards for internal corrosion and their correct application.

NACE commented on the considerable research done over years that led to the development of a number of industry standards, including NACE International standards, which serve to reduce the impact of internal corrosion on pipelines. In addition, this research led to development of the NACE *Internal Corrosion for Pipelines* training and certification course. NACE recommended that PHMSA closely review current industry standards and training programs prior to developing any new regulations and suggested that PHMSA adopt these standards to address any inadequacies that may exist. NACE encouraged PHMSA to consider holding best practices workshops to assist in the dissemination of this knowledge.

NACE also included the following comments:

- The definition of "inhibitors" needs to be expanded to include oxygen scavengers and biocides.
- Guidance on corrosivity tests (NACE T~OI72-2001) should be provided.
- Corrosion monitoring techniques should be expanded to include not only coupons but also bacteria cultures, linear polarization probes, corrosometers, deposit analysis from pig cleanings.

- Emphasis should be placed on the data covering types, injection rates, and amount of chemicals used.
- Information on optimal locations for coupons should also be given (water phase location, deadlegs, change in diameter, change in direction of fluid flow, etc.).
- If corrosion coupons are used, data such as corrosion rate and appearance of the coupon (uniform attack, pitting, localized corrosion under coupon washer, edge corrosion, etc.) should be noted.
- Precautions for installing/removing coupons to prevent any erroneous measurements should be given. No direct contact between human hands and coupon surface should occur to prevent greases or salts from adhering to the coupon.
- There should be mention of the need to analyze deposits on the coupons for information concerning carbon dioxide corrosion, and hydrogen sulfide corrosion.
- If a segment of pipe is removed, the depth of pits present should be used to help determine the pitting rate.
- A standard that needs to be developed is one addressing the internal corrosion mitigation using maintenance pigging.

Finally, Accufacts commented that the improper reliance on corrosion inhibitor injection is indicative of very poor risk management pipeline practices. Given the serious nature of recent internal corrosion pipeline failures indicating important breakdowns in internal corrosion control programs, Accufacts recommended several regulatory changes be implemented to ensure that pipelines maintain prudent corrosion control programs and avoid future pipeline failures. Accufacts made the following comments and suggests the following changes to the corrosion control regulations:

- Caution on the weaknesses of corrosion inhibitor/coupon programs to address selective corrosion.
- Require a documented system analysis confirming that the operator has properly analyzed the pipeline for possible selective corrosion precursors and identified possible sites of selective internal corrosion risks, including monitoring for liquid changes that might increase this risk.
- If such precursors are indicated, where possible, operators should incorporate a cleaning pig program which includes analysis of removed material for signs of corrosive constituents or selective corrosion products to gauge an internal corrosion program's effectiveness.
- For pipelines, or portions of pipelines, that cannot accommodate, or be reached by cleaning pigs, operators should provide additional monitoring, mitigation, and documentation for hot zone segments identified.

Accufacts commented that for systems at risk for selective internal corrosion, a periodic cleaning pig program is highly advised and should serve as a primary tool used, – in addition to inhibitors, - to prevent internal corrosion.

The PHMSA briefing paper, *Federal Register* notice, and stakeholder responses can be found at:

http://www.regulations.gov/fdmspublic/component/main?main=DocketDetail&d=PHMSA-2007-28993.

5 Subject Matter Expert Review

PHMSA actively polled its senior corrosion experts, and other subject matter experts, to obtain detailed feedback on the internal corrosion control regulations in 49 CFR 195. All experts we consulted agree that internal corrosion is a complex threat, and difficult for both operators and regulators to deal with effectively. Many technical factors interrelate in complex ways to affect the likelihood, location, and/or aggressiveness of internal corrosion such as:

- Type of commodity;
- Flow rate;
- Operating pressure;
- Topography;
- Level of foreign material present such as sand, silt, water, or other;
- Amount of sulphur, salts, acids, or other corrosive material present;
- Presence of microbes;
- Temperature;
- Pipe configuration, design and material specifications; and
- Operating conditions.

Most experts we consulted agree that existing regulations that explicitly address the threat of internal corrosion should be performance-based, rather than prescriptive. PHMSA's regulations require operators to evaluate whether it is transporting a hazardous liquid that would corrode the pipeline and, if so, take adequate steps to mitigate the corrosion threat. The pipeline operator must determine if the product they transport is corrosive. If the operator erroneously determines the fluid is not corrosive, the operator may also err in not taking the necessary steps to manage the internal corrosion threat. Although the base commodity may not be corrosive, all hazardous liquids regulated under Part 195 can be corrosive during some phase of the production, refining, or transportation processes. The only step that separates the corrosive materials from the pipeline is the production/refining process. Production/ refining processes are not 100 percent reliable and can have upset conditions. During those upset conditions, corrosive materials can be introduced into the pipeline and could create a corrosive condition.

Pipeline operators who previously concluded an internal corrosion control program was not needed should critically re-analyze operating conditions and internal corrosion risk factors and periodically monitor, or otherwise reconfirm, that the pipeline is free of corrosive materials. Operators should perform a periodic system analysis, and document the results, confirming that they properly analyzed the pipeline for possible internal corrosion precursors. In addition, operators should also conduct periodic monitoring for changes that might increase this risk and identify possible sites of selective internal corrosion risks.

In addition, hazardous liquid pipeline operator integrity management programs are required to take the following steps as part of the operator's internal corrosion program:

- Examine and record corrosion data;
- Demonstrate an understanding of the risk of internal corrosion;
- Identify the locations of greatest risk;
- Conduct integrity assessments that will effectively discover pipeline defects caused by internal corrosion;
- Promptly repair or remediate discovered defects;
- Identify the root cause of discovered internal corrosion defects; and
- Identify the need for additional or different preventive and mitigative measures.

6 Findings

In conducting the Congressionally mandated review of its internal corrosion control regulatory framework, PHMSA has found our regulatory framework generally sound. Through our review of the internal corrosion control regulations for hazardous liquid pipelines. PHMSA finds that the existing performance-based rules provide adequate opportunity for us to require operators to establish adequate prevention and mitigation programs for internal corrosion control. These regulations also allow us the latitude to direct changes to operator programs and pursue possible enforcement cases if a pipeline operator's program is inadequate to ensure safety, environmental protection, and reliability.

For many years PHMSA has taken a broad range of steps to mitigate the potential frequency and consequence of pipeline failures from all causes – including those caused by internal corrosion, and we will continue to do so. We believe that good results have been achieved, and that the investments that have been made and continue to be made will help drive the relatively low risk of internal corrosion even further downward.

...

PHMSA has invested, and will continue to invest staff time and financial research resources into improving the standards and technology used to identify, assess, and prevent internal corrosion. Our senior corrosion staff continues to participate in national consensus standards development and improvement. In addition, PHMSA provides internal corrosion control training for all Federal and state inspectors at our training facility in Oklahoma City, Oklahoma, as part of our program to improve the overall effectiveness of our inspection and enforcement programs.

Through this review, however, we did identify several near-term and long-term actions that we believe should be taken to enhance the attention hazardous liquid pipeline operators give to the risks of internal corrosion. In the near-term, we plan to issue an advisory bulletin to the regulated industry alerting them to proper risk identification for products they ship in their pipelines. Next, we plan to convene all stakeholders – public and industry – to evaluate opportunities for use of improved best practices, and consider the merits of existing or developing national consensus standards. Finally, if warranted from these earlier steps, PHMSA will revise its current corrosion control regulations to include lessons learned. PHMSA is particularly interested in evaluating several national consensus standards that, if incorporated into our regulatory program for corrosion control, could improve the effectiveness of pipeline operators' initial determinations of the corrosivity of the products they ship – the most important step in the operator's continuous corrosion control program.

Appendix

PHMSA Pipeline Safety Research

Internal Corrosion (since 2002)

No.	Goal	Pipeline Type	Project ID	Contractor	Project Title	PHMSA	Co-Share	Pct Cmpl
1.	Safety	HazLiq GasTrans Dist-Steel	DTR57-06-C-10004	Intelligent Automation, Inc.	*"In-Line Nondestructive Inspection of Mechanical Defects in Pipelines with Shear Horizontal Wave EMAT"*	$100,000	SBIR	100
2.	Safety	HazLiq	DTRS56-05-T-0005	CC Technologies, Inc.	*"Development of ICDA for Liquid Petroleum Pipelines"*	$182,636	$315,114	100
3.	Safety	HazLiq GasTrans	DTPH56-05-T-0005	Shell Global Solutions (US) Inc.	*"Cathodic Protection Current Mapping In-Line Inspection Technology"*	$401,000	$450,000	100
4.	Safety	HazLiq GasTrans	DTPH56-05-T-0003	Electricore, Inc.	*"Assessment of Older Corroded Pipelines with Reduced Toughness and Ductility"*	$141,654	$100,000	100
5.	Safety	HazLiq GasTrans Dist-Steel	DTRS56-03-T-0014	Battelle Memorial Institute	*"Corrosion Assessment Criteria: Rationalizing Their Use Applied to Early vs. Modern Pipelines"*	$196,000	$221,000	100
6.	Safety	HazLiq GasTrans Dist-Steel	DTRS56-03-T-0013	Southwest Research Institute	*"High-power, Long-range, Guided-wave Inspection of Pipelines"*	$272,420	$332,935	100
7.	Safety	HazLiq GasTrans	DTRS56-03-T-0006	FINO AG, Hildersheil Germany	*"NoPig Metal-Loss Detection System for Non-Piggable Pipelines"*	$387,818	$340,000	100
8.	Safety	HazLiq GasTrans Dist-Steel	DTRS56-03-T-0004	CC Technologies, Inc.	*"High CP Potential Effects on Pipelines"*	$80,000	$80,000	100
9.	Safety	HazLiq GasTrans Dist-Steel	DTRS56-02-T-0007	PetroChem Inspection Services	*"Enhancement of the Long-Range Ultrasonic method for the Detection of Degradation in Buried, Unpiggable Pipelines"*	$655,564	$633,325	100
10.	Safety	HazLiq GasTrans Dist-Steel	DTRS56-02-T-0004	Southwest Research Institute	*"Baseline Study of Alternative In-Line Inspection Vehicles"*	$40,000	$40,000	100

No.	Goal	Pipeline Type	Project ID	Contractor	Project Title	PHMSA	Co-Share	Pct Cmpl
11.	Safety	HazLiq GasTrans Dist-Steel	DTRS56-02-T-0003	Southwest Research Institute	*"Feasibility of In-Line Stress Measurement by Continuous Barkhausen Method"*	$80,000	$80,000	100
12.	Safety	HazLiq GasTrans Dist-Steel	DTRS56-04-T-0008	Olympus NDT Canada	*"Stage 2 Phased Array Wheel Probe for In-Line Inspection"*	$161,000	$160,000	95
13.	Safety	HazLiq GasTrans Dist-Steel	DTRS56-04-T-0002	Southwest Research Institute	*"Determining Integrity Reassessment Intervals Through Corrosion Rate Modeling And Monitoring"*	$350,000	$350,000	92
14.	Safety	HazLiq GasTrans Dist-Steel	DTRS56-05-T-0003	Battelle Memorial Institute	*"Model Modules to Assist Assessing and Controlling Stress Corrosion Cracking (SCC)"*	$365,887	$700,000	86
15.	Safety	HazLiq GasTrans	DTPH56-06-T-000008	Acellent Technologies, Inc.	*"Real-time Active Pipeline Integrity Detection (RAPID) system for Direct Assessment of Corrosion in Pipelines"*	$67,202	$67,816	61
16.	Safety	HazLiq GasTrans	DTPH56-05-T-0001	Electricore, Inc.	*"Understanding Magnetic Flux Leakage (MFL) Signals from Mechanical Damage in Pipelines"*	$111,770	$109,770	56
					Totals:	**$3,592,951**	**$3,979,960**	