Exhibit No:	
Issue:	**Safety Basis for Replacement Programs, Cost Comparisons, Replacement of Initially Installed Bare Steel.**
Witness:	**Craig R. Hoeferlin**
Type of Exhibit:	**Direct Testimony**
Sponsoring Party:	**Spire Missouri Inc.**
Case Nos.:	**GO-2019-0356, GO-2019-0357**
Date Prepared:	**September 27, 2019**

SPIRE MISSOURI INC.

File Nos. GO-2019-0356, GO-2019-0357

DIRECT TESTIMONY

OF

CRAIG R. HOEFERLIN

September 2019

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DIRECT TESTIMONY OF CRAIG R. HOEFERLIN

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Craig R. Hoeferlin, and my business address is 700 Market Street, St. Louis, Missouri, 63101.

Q. WHAT IS YOUR PRESENT POSITION?

A. I am presently employed by Spire Missouri ("Spire Missouri" or "Company") as Vice President – Operations Services.

Q. PLEASE STATE HOW LONG YOU HAVE HELD YOUR POSITION AND BRIEFLY DESCRIBE YOUR RESPONSIBILITIES.

A. I was appointed to my current position on April 1, 2012. In this capacity, I oversee various operational functions for the Company, including engineering, pipeline safety and replacement programs, environmental compliance, operations training, GIS and system planning, damage prevention, right of way, standards and testing, and employee safety departments.

Q. PLEASE DESCRIBE YOUR EXPERIENCE WITH SPIRE MISSOURI PRIOR TO ASSUMING YOUR CURRENT POSITION.

A. I have been continuously employed by Spire Missouri since June 1984. Prior to my current position, I held a variety of positions in the Engineering, Gas Supply and Control, and Construction and Maintenance Departments.

Q. WHAT OTHER EXPERIENCE DO YOU HAVE WITH REGARDS TO PIPELINE OPERATIONS AND SAFETY?

A. I am a past chair and current member of the Operating Section Managing Committee for the American Gas Association. In this capacity, I interact with the Federal Pipeline and

Hazardous Materials Administration (PHMSA) as well as the staff of the National Transportation Safety Board (NTSB). I am also a board member of the Common Ground Alliance (CGA) representing the natural gas distribution industry. The CGA is a national organization committed to preventing damage to underground infrastructure. Finally, I am a past president and current member of the Missouri One Call System's (MOCS) Board of Directors.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I received a Bachelor of Science Degree in Chemical Engineering in 1984 from the University of Missouri-Columbia.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes, I have. I previously submitted testimony in Case Nos. GR-98-374, GR-99-315, GR-2001-629, GR-2013-0171, GO-2016-0332, GO-2016-0333, GO-2017-0201, GO-2017-0202, GM-2017-0018, GO-2018-0309, and GO-2018-0310.

I. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my direct testimony is threefold. First, I will address and support certain findings of fact contained in the Commission's Report and Order in Case Nos. GO-2019-0115 and GO-2019-0116 ("2019 cases") as they pertain to this filing regarding the replacement of bare steel and cast-iron infrastructure. I will also continue to expand on information provided by the Company in prior ISRS cases on the requirements established and positions taken by national and state regulators related to pipeline safety, specifically the replacement of bare steel and cast-iron infrastructure. Second, I will describe the new analysis that we have performed to show how the costs of the Company's systematic replacement of these facilities, which includes the replacement of certain plastic components, has and will continue to save its customers money compared to the piecemeal replacement approach previously followed by the Company. Finally, I will address certain concerns that have been raised by the Office of the Public Counsel ("OPC") regarding the Company's replacement of certain steel mains that were initially installed without cathodic protection but had such protection added at a later date.

II. SAFETY RATIONALE FOR REPLACEMENT PROGRAMS

A. THE 2019 ORDER

Q. HAVE YOU REVIEWED THE COMMISSION'S REPORT AND ORDER IN THE 2019 SPIRE MISSOURI ISRS CASES?

A. Yes, I have.

Q. DID THE COMMISSION'S REPORT AND ORDER CONTAIN DESCRIPTIONS OF THE TYPE OF RISKS ASSOCIATED WITH BARE STEEL AND CAST IRON INFRASTRUCTURE?

A. Yes. The Commission stated in its Report and Order at Findings of Fact 24 And 25 that "cast iron pipes are unsafe to use because they tend to graphitize, making the pipe brittle and subject to cracking and leaking." The Commission also acknowledged that the cast iron pipes that are being replaced are sixty to one-hundred years old. Regarding steel infrastructure, the Commission found that steel "that is not cathodically protected corrodes relatively quickly and needs to be replaced" as the "corrosion diminishes wall thickness which causes the possibility of leaks."

Q. AFTER CONSIDERING THESE RISKS, WHAT DID THE COMMISSION CONCLUDE REGARDING BARE STEEL AND CAST IRON PIPES?

A. The Commission determined at Finding of Fact 26 of its Report and Order that the cast iron and bare steel pipe being replaced as part of Spire's replacement programs is in a "worn out or deteriorated state."

Q. HAS THE COMMISSION MADE SIMILAR STATEMENTS IN PRIOR SPIRE ISRS CASES?

A. Yes. In its September 20, 2018 Report and Order in Case Nos. GO-2018-0309 and GO-2018-0310, the Commission stated at p. 13 that "the Commission concludes that the cast iron and steel pipes were replaced to comply with state or federal safety requirements and were worn out or deteriorated, so they are eligible for cost recovery under ISRS." The Commission also described the risks associated with these types of pipe in terms similar to its language in the 2019 cases, including cracking, leaking, and corrosion.

Q. IN THE 2019 CASES, SPIRE MISSOURI WITNESS ROB C. ATKINSON TESTIFIED AT HEARING THAT HE HAD NEVER ENCOUNTERED A CAST IRON OR BARE STEEL PIPE DUG UP THAT WAS NOT IN SOME SORT OF DETERIORATED STATE. DO YOU SHARE THIS OPINION?

A. Yes. Based on my decades of experience, I would fully endorse and affirm the comments made by Mr. Atkinson during the 2019 cases.

Q. DOES THE NATURAL GAS INDUSTRY AND THE SCIENTIFIC COMMUNITY SHARE YOURS' AND MR. ATKINSON'S OPINION ON CAST IRON AND BARE STEEL PIPE?

A. Yes. It has been widely accepted by leading industry experts and organizations, as well as, the scientific community that there are significant risks associated with cast iron and bare steel infrastructure and that there is an acute need to implement aggressive programs to remove this pipe from service.

Q. ARE YOU SPONSORING ANY ADDITIONAL EVIDENCE ON THE RISKS OF CAST IRON AND BARE STEEL PIPE?

A. Yes. Attached to my testimony as Schedule CRH-5 are a sample of photographs illustrating the types of pipe the Company is targeting and taking out of service with its replacement programs. These images clearly demonstrate the worn out and deteriorated condition of Spire Missouri's cast iron and bare steel pipe and the need for this pipe to be removed from service. I will also be sponsoring representative physical specimens of such facilities for Commission review at the evidentiary hearing in these cases.

Q. HAVE THE PROBLEMATIC CHARACTERISTICS OF CAST IRON AND BARE STEEL PIPE BEEN RECOGNIZED FOR SOME TIME?

A. Yes, while there has certainly been an increased focus in more recent years on eliminating cast iron and bare steel pipe given some of the very serious incidents that have occurred involving such facilities, it is important to recognize that the problematic characteristics of these facilities, as outlined by the PSC in recent Orders, has been known for some time. In fact, Spire Missouri's predecessor, Laclede Gas Company, began replacing certain cast iron and bare steel pipes in the 1950's because of the concerns that existed even then over these characteristics. Clearly, the fact that such facilities pose special risks is not a new or recently discovered phenomenon.

B. COMPLIANCE WITH FEDERAL AND STATE SAFETY REQUIREMENTS

Federal Requirements

Q. PLEASE EXPLAIN THE FEDERAL REGULATIONS SPIRE MISSOURI IS SUBJECT TO REGARDING ITS DISTRIBUTION INFRASTRUCTURE.

A. The Natural Gas Pipeline Safety Act of 1968 authorized the Federal Department of Transportation ("DOT") to implement regulations that established pipeline safety requirements for pipeline operators that transport natural gas and other fuels. The DOT rules found at 49 Code of Federal Regulations Part 192 ("Part 192") became effective in 1971 and established minimum safety requirements for pipeline operators that operate natural gas transmission or distribution systems. These regulations established a variety of requirements related to pipeline system components. As part of the 2002 Pipeline Safety Improvement Act, Part 192 was updated to include new requirements related to gas transmission pipelines. The 2006 Pipeline Inspection, Protection, Enforcement, and Safety Act resulted in additional changes to Part 192, including the requirement of the Company to develop and implement a Distribution Integrity Management Program ("DIMP"). Consistent with this mandate, which has been incorporated in the Commission's own safety rule, Spire Missouri's DIMP Plan identifies and prioritizes the risks to the Company's pipeline system. Cast iron and bare steel rank ashigh risk in the plan, due to the high likelihood of leaks and breaks associated with these types of pipe material. The Commission's Gas Safety Staff is responsible for enforcing these regulations.

Q. HAVE THESE FEDERAL SAFETY OFFICIALS ACTIVELY ENCOURAGED GAS UTILITIES LIKE SPIRE MISSOURI TO REPLACE CAST IRON AND BARE STEEL FACILITIES?

A. Yes, they have. Following several tragic incidents in 2010 and 2011, the Secretary of the Department of Transportation, Ray LaHood, sent letters to Governors of each state inviting them and others to a DOT Pipeline Safety Forum at DOT's Washington headquarters to address these issues. A copy of these letters is attached to my testimony as CRH-1. I attended and participated in this forum. Similarly, a letter was sent to utility commissioners urging them to review their State's replacement plans (for cast iron and bare steel specifically) and "consider what would be necessary to accelerate these plans." (March 31, 2011 letter from Cynthia Quarterman, PHMSA Administrator). The stated goal of the DOT's April 2011 Pipeline Safety Forum was "accelerating the rehabilitation, repair, and replacement of critical pipeline infrastructure with known integrity risks."

In December 2011, PHMSA issued a White Paper that reviewed the programs available in various states "to support efforts to accelerate the repair, rehabilitation and replacement of high-risk infrastructure in pipeline systems…" PHMSA looked favorably upon Missouri's ISRS Statute as one of the programs available to protect the public "by ensuring the prompt rehabilitation, repair, or replacement of high-risk gas distribution infrastructure." PHMSA further urged State commissions to "accelerate the repair, rehabilitation, and replacement of high-risk pipeline infrastructure." (PHMSA White Paper, p. 17). A copy of this white paper is attached to my testimony as Schedule CRH-2. In March 2012, PHMSA issued an Advisory Bulletin to gas operators and state pipeline safety representatives on Cast Iron Pipe. The Bulletin urged pipeline operators, like Spire Missouri, to conduct a comprehensive review of their cast iron distribution pipelines and replacement programs, and accelerate the pipeline repair, rehabilitation, and replacement of high risk pipelines. The Bulletin also requested that agencies consider enhancements to cast iron replacement plans and programs. A copy of the March 2012 PHMSA Advisory Bulletin is attached as Schedule CRH-3.

<u>Missouri Requirements</u>

Q. HAS THE MISSOURI COMMISSION ESTABLISHED RULES REGARDING THE REPLACEMENT OF CAST IRON AND STEEL PIPES?

A. Yes. The Commission has determined that public safety requires replacement programs for certain facilities, most notably programs for the replacement of cast iron and unprotected steel facilities – the very programs whose costs are included in the Company's request in these proceedings. The requirement for Spire Missouri to develop and implement such replacement programs can be found at 22 CSR 4240-40.030(15)(D)&(E) of the Commission's gas safety rules – provisions that were implemented by the Commission following a number of fatal natural gas explosions that occurred in Missouri in the late 80's.

Q. PLEASE EXPLAIN ANY ADDITIONAL REQUIREMENTS REFLECTED IN THE COMMISSION'S GAS SAFETY RULES.

A. Additional Missouri requirements are reflected at 22 CSR 4240-40.030(17), which require that natural gas facility operators like Spire Missouri develop and implement system integrity plans. In addition to mandating that operators develop processes for assessing the risks from leaks and other failures on their system, the rules also require that they "[i]dentify and implement measures to address [such] risks" and [d]etermine and implement measures designed to reduce the risks from failure of its gas distribution pipeline." 20 CSR 4240-40.030(17)(D).4

Q. HAS THE COMMISSION PREVIOUSLY ISSUED STATEMENTS REGARDING THE REPLACEMENT OF CAST IRON AND BARE STEEL INFRASTRUCTURE?

A. Yes. In April 2011, the Commission issued a Pipeline Safety Program Report which stated the following:

> "Review of the integrity of older cast iron and steel natural gas pipeline facilities needs to be completed with the possible goal of initiating specific long-term replacement programs to eliminate significant mileage each year. Currently, there are cast iron natural gas pipelines in service in Missouri that were installed well over 100 years ago. Two Missouri natural gas operators have a combined total of over 1,200 miles of cast iron in their distribution systems. The recommendation is for Staff to have meetings with the utilities that have these facilities and discuss the issue of systematic replacement of the aging infrastructure and the impact on rates. There are integrity issues, maintenance issues, service reliability issues and rate issues involved. The issues are related to safety, but there is also a policy decision that needs to be evaluated to determine the implications of continuing to have cast iron piping in distribution systems 30 years or 40 years from now. There should also be a discussion as to how much it will cost to initiate replacement programs for a specified number of years, and the rate implications of such programs. If the current annual replacement rate for cast iron pipelines (the average over the last three calendar years has been approximately 15 miles annually) continues, it would take over 80 years to replace the cast iron pipelines in Missouri, which could result in cast iron piping that is over 200 years old carrying natural gas. Also, older steel pipelines have been involved in the two recent incidents in Missouri. The age of the steel pipeline, by itself, may not be a determining factor. The age, as well as other integrity factors would need to be included in the review. (Page 26)

A copy of the Commission's Pipeline Safety Program Report is attached as Schedule CRH-4.

Q. HAS THE MISSOURI PUBLIC SERVICE COMMISSION GAS SAFETY STAFF MADE ANY RECOMMENDATIONS ON SPIRE MISSOURI'S REPLACEMENT PROGRAMS?

A. The Commission's Gas Safety Staff is continually aware of the ongoing pipe replacement work being performed by Spire Missouri. To my knowledge, the Commission's Gas Safety Staff has never raised any concerns with the pace or nature of this work.

Q. HOW DOES THE COMPANY COMPLY WITH THE APPLICABLE FEDERAL AND STATE SAFETY REQUIREMENTS?

A. The Company has always had a statutory duty to provide safe and adequate services and facilities, and it views its replacement programs as providing a cost-effective way of complying with this fundamental requirement.

Q. DO THE COMPANY'S REPLACEMENT PROGRAMS, AS CURRENTLY CONDUCTED, PERMIT THE COMPANY TO COMPLY WITH THE ABOVE-MENTIONED SAFETY REQUIREMENTS IN A COST-EFFECTIVE WAY?

A. Absolutely. Our systematic replacement programs are a critical component of our compliance with these requirements to identify and implement measures to reduce the risks resulting from leaks and other potential failures of Spire Missouri's gas distribution facilities. The Company cites these programs as measures that have been taken to comply with these requirements. An evaluation of leaks and other data shows that they have been very effective in reducing the number of leaks experienced by the Company. In short, the Company's implementation of its replacement programs has permitted it to comply more effectively with the safety requirements that are designed to protect the health and welfare of the Company's customers and the public generally and help prevent horrific incidents like those experienced in 2011.

C. REGULATORY OVERSIGHT OF REPLACEMENT PROGRAMS

Q. DO YOU BELIEVE THAT THE STAFF OF THIS COMMISSION HAS EXERCISED AN ADEQUATE LEVEL OF REGULATORY OVERSIGHT REGARDING THE COMPANY'S REPLACEMENT PROGRAMS AND HOW THEY ARE CURRENTLY CONDUCTED?

A. Without question I do. I know from personal experience that the Commission's Safety Staff is actively and routinely involved in assessing the Company's compliance with various safety requirements, including those relating to the structure and nature of its replacement programs. Among other things, these activities include field audits, the review of annual reports prepared and submitted by the Company and, where appropriate, the submission of data requests or other requests for information. The Safety Staff is also familiar with every major incident involving the Company's facilities and will propose various measures for preventing such incidents in the future. As previously mentioned, I have never heard any member of the Commission's Safety Staff express any reservations about the pace or structure of the Company's replacement programs. In fact, the Staff continues to express strong support for how the Company has carried out these programs.

Q. IN ADDITION TO THE COMMISSION'S SAFETY STAFF HAS THE COMMISSION ITSELF ALSO PROVIDED REGULATORY OVERSIGHT OF THE COMPANY'S REPLACEMENT PROGRAMS?

A. Yes. In September 2012, I represented the Company in presenting details regarding the nature, pace and structure of its replacement programs directly to the Commission at its agenda meeting. In acquiring Missouri Gas Energy ("MGE") in 2013, the Company also advised the Commission, Staff, OPC and other parties of its intent to accelerate the replacement programs of MGE as it recently had for Laclede Gas. The Company's follow-through on that commitment was also prominently addressed by its main policy witness in Spire Missouri's most recent rate proceedings, Case Nos. GR-2017-0215 and 0216. Although I am aware that an extraordinary number of issues were tried in that proceeding, I am unaware of any stakeholder who expressed any concerns or made any recommendations that the Company should change the pace of these replacement programs. In addition, since 2014, the Company has given annual presentations to the Staff and OPC regarding Spire Missouri's 1 and 3-year plans for carrying out these programs.

Q. ARE THERE OTHER VENUES WHERE THE COMMISSION ITSELF HAS EXERCISED REGULATORY OVERSIGHT?

A. Yes. Every time the Company makes a filing to increase its ISRS charges, filings which frequently occur twice a year, it provides detailed data regarding the cost, progress and results of its various safety programs. Among other key data, this includes the footage of mains and services replaced or retired, the footage of newly installed facilities, and the costs incurred to carry out such activities. The Company also provides a specific identification of the safety rules, mandated public improvement requirements or other circumstances that make these costs eligible for ISRS recovery. The Commission Staff audits each of the Company's ISRS filings, requests additional data, and issues a recommendation. Other parties, like OPC, have also participated in these cases and made their own recommendations. In the end, the Commission considers all this information, conducts any necessary hearings, and issues a Report and Order approving the Company's ISRS charges, with any adjustments the Commission believes are appropriate. The prudence of the Company's replacement programs and associated costs is also subject to review in subsequent rate case proceedings. As noted, there have been no disputes as to the prudence of these costs – just whether there should be an adjustment for the replacement of plastic facilities. Given this level of regulatory involvement, I strongly believe that the pace, scope and nature of the Company's replacement programs has been subject to a degree of regulatory oversight that far exceeds any replacement program previously undertaken by the Company.

III. COST RATIONALE FOR PROGRAM IMPLEMENTATION

Q. YOU PREVIOUSLY STATED THAT THE COMPANY'S SYSTEMATIC APPROACH TO REPLACING THESE FACILITIES HAS BEEN A COST-EFFECTIVE WAY OF COMPLYING WITH ITS SAFETY OBLIGATIONS. HAS THE COMPANY'S REPLACEMENT RATHER THAN RESUSE OF PLASTIC FACILITIES UNDER THIS SYSTEMATIC APPROACH INCREASED THE COST OF ITS REPLACEMENT PROGRAMS?

A. No. The Company's replacement rather than reuse of plastic components has actually served to reduce rather than increase its ISRS costs.

Q. HOW HAS THE COMPANY PREVIOUSLY ATTEMPTED TO DEMONSTRATE THE ACTUAL COST IMPACT OF ITS SYSTEMATIC PROGRAM?

A. In prior ISRS proceedings the Company conducted a number of engineering/cost analyses of its ISRS projects to determine what the actual impact of replacing rather than reusing plastic components would be on its ISRS costs and charges. This effort culminated in the Company's last ISRS proceeding with the preparation and submission of over 509 engineering/cost studies covering every ISRS project included in the Company ISRS filing. The Company and Commission Staff believed that these studies were responsive to guidance that had previously been given by the Commission on what information would be necessary to support the Company's position that any costs attributable to the replacement of plastic components were either non-existent or had already been excluded. The Commission, however, found that these studies did not demonstrate the actual cost impact of replacing rather than reusing plastic because they did not use the correct basis of comparison.

Q. WHAT BASIS OF COMPARISON DID THE COMMISSION FIND WOULD BE APPROPRIATE TO PROVE THAT THE REPLACEMENT RATHER THAN REUSE OF PLASTIC COMPONENTS DID NOT INCREASE ISRS COSTS?

A. The Commission did not identify any specific basis of comparison in its Report and Order. But in a concurring opinion on the issue, Commissioner Hall, who voted in the majority on the Report and Order, stated that the proper basis of comparison under the Western District's remand order would have been to "compare the cost of (A) systematic redesign (replacement of worn out or deteriorated cast iron/bare steel and the plastic) versus (C) patchwork replacement of only the worn out or deteriorated cast iron and bare steel." According to Commissioner Hall, if that comparison showed it was more expensive to re-use the plastic (C > A), then there would be no incremental cost to replace the plastic, and nothing to subtract from the total project cost."

Q. WHAT IS YOUR UNDERSTANDING OF THE TERM "PATCHWORK" REPLACEMENT?

A. Prior to accelerating its replacement programs in response to the factors I previously discussed, the Company had followed a "patchwork" or "piecemeal" replacement approach where it would only replace those portions of facilities that were already exhibiting a level of leaks or other conditions that made more immediate repair or replacement necessary. There were two major shortcomings, however, in this piecemeal approach. First, it resulted in a distribution system that was less than ideal from a safety and integrity standpoint. Replacing isolated segments of pipe necessarily required that pipes with different materials (i.e. plastic versus cast iron or steel) be joined together at multiple locations. The combination of multiple joints and material variations results in a greater risk of leakage than having an unbroken run of pipe with uniform materials. Second, the piecemeal approach is an expensive way of maintaining a system over the long haul. In effect, the piecemeal approach would preclude the Company from reducing the size of the piping being installed, since the new pipe would need to match the larger size of the pipe being patched. This size factor, as well as the need to prevent water-retaining dips in the piping, would also preclude the use of more efficient boring techniques for installing the pipe and require instead that pipe be direct buried. In addition, while a piecemeal replacement on a segment of main may, on a one-time basis, be somewhat less expensive than replacing the entire pipe all at once under the systematic approach, over time crews would need to be repeatedly re-assembled and sent to work on the same main to replace other portions that develop leaks in the future – costs that would be avoided by the systematic approach. And despite these added costs, the main would ultimately need to be replaced anyway.

Q. DID THE COMPANY ATTEMPT TO ANALYZE THE RELATIVE COSTS OF THE SYSTEMATIC VERSUS PIECEMEAL APPROACH?

A. Yes. We randomly selected 10 ISRS projects to evaluate, 5 on the Spire East side and 5 on the Spire West side. We then compared the actual cost of replacement under the Company systematic approach for these projects to the costs that would be incurred under the piecemeal approach. As shown by the table presented below, in all instances the cost of replacement under the systematic approach, which also included the replacement of plastic components where necessary, was significantly less than the costs that would be incurred under a piecemeal approach. In fact, the piecemeal approach was more expensive than the systematic approach by 11% to 198% depending on the specific characteristics of the project being evaluated.

Overall vs. Piecemeal

MoEast

WO	Description	Overall Cost	Piecemeal Cost	% Difference
901314	Central West End 2D	$ 462,053	$ 1,098,364	238%
901962	Delmar - Vandeventer to Sarah Mandated	$ 183,013	$ 525,706	287%
902261	Lynch & Missouri 1A	$ 329,072	$ 719,027	219%
901622	Marconi & Shaw 1H	$ 490,590	$ 654,749	133%
902586	Dunnica- Alexander to Gravois - Mandated Section 453	$ 151,446	$ 323,567	214%
901238	Pagedale 2B	$ 289,365	$ 441,209	152%
901299	Wellston 3I	$ 431,016	$ 828,636	192%

MoWest

WO	Description	Overall Cost	Piecemeal Cost	% Difference
802271	17th & Oakland Strategic Phase B (MPL) - Magnolia River GPS	$ 322,055	$ 560,065	174%
800132	FY16 Strategic Grid MGE - Belton Phase 2D - IUI	$ 165,421	$ 413,213	250%
800497	63rd and 55th Street- Cast Iron Main replacemnet Phase 1B	$ 355,686	$ 1,061,562	298%
801873	Replacement due to CP at Canterbury in Joplin - SPIRE - Smith	$ 151,026	$ 211,666	140%
802458	Meadowlake Terr & State Line Road Strategic Grid Replacement (IUI)	$ 409,349	$ 453,024	111%

Q. ARE THESE RESULTS REASONABLY REPRESENTATIVE OF THE RELATIVE SYSTEMATIC VERSUS PIECEMEAL COSTS THAT WOULD BE INCURRED ON OTHER ISRS PROJECTS?

A. Yes. Most of the same cost-related factors would apply to other ISRS projects as well and while the relative cost advantage of the systematic approach would be greater in some instances and less in others, the systematic approach would be less expensive in nearly all instances. And on a cumulative basis, the cost advantage of the systematic approach would be overwhelmingly positive.

Q. DOES YOUR ANALYSIS REFLECT ALL OF THE COST ADVANTAGES OF THE SYSTEMATIC APPROACH?

A. No. In addition to the cost impacts identified in the comparative analyses, employing a piecemeal approach would essentially require that the Company maintain a low-pressure distribution system in those parts of Spire East and Spire West service territories where these systems have historically existed. Such a result would have both an adverse cost as well as an adverse safety impact. On the cost side, all of the efficiencies gained from moving to an intermediate system would be lost. For example, instead of reducing the number of regulator stations serving Spire's East Side distribution system from over 130 to just 6, the Company would have had to maintain the far larger number of stations with all of the added capital investment and operational expenses required to keep them operating safely. As previously mentioned, the Company would have to continue utilizing a low pressure system, which would require the use and replacement of much larger diameter pipe. This would result in additional excavation costs and disruptions to neighborhoods as it would severely limit the Company's ability to use more efficient boring techniques, which would also result in additional excavation costs. At the same time, meters have to continue to be maintained on the inside of customers' homes and business, a result that is less than ideal from both a safety and customer convenience standpoint. I haven't tried to estimate with precision what the additional costs to consumers would be from following this piecemeal approach, but I am confident it would be in the tens of millions of dollars.

Q. IN YOUR VIEW, WHAT DOES THIS COMPARATIVE COST ANALYSIS OF THE SYSTEMATIC VERSUS PIECEMEAL APPROACH SUGGEST IN TERMS

OF THE COST OF REPLACING RATHER THAN REUSING PLASTIC AS PART OF THE COMPANY'S CAST IRON AND STEEL MAIN REPLACEMENT PROGRAMS?

A. I sincerely believe that the 509 engineering/cost studies we performed and presented in our last ISRS cases conclusively demonstrated either (a) that there were no incremental costs associated with replacing rather than reusing plastic for the vast majority of ISRS projects and (b) that in those small number of cases where there were incremental costs, such costs had been excluded from the ISRS costs the Company was seeking to recover. The comparative analysis suggested by Commissioner Hall and presented here, looks at the issue in a somewhat different way. But in the end, it reaffirms with even added force the conclusion that the replacement of plastic components as part of the Company's cast iron and bare steel replacement programs has served to reduce the costs and charges paid by customers through the ISRS.

IV. REPLACEMENT OF STEEL MAINS INITIALLY INSTALLED ON AN UNPROTECTED BASIS

Q. WHAT IS YOUR UNDERSTANDING OF OPC'S POSITION REGARDING THE COMPANY'S REPLACEMENT OF BARE STEEL PIPE THAT HAS BEEN PLACED UNDER CATHODIC PROTECTION?

A. OPC witness Robinett observes that as part of its replacement programs the Company has been replacing steel piping even though they have been placed under cathodic protection in the past. Because of this he suggests, that there is neither a governmental mandate nor a safety justification for replacing such facilities and that the associated costs should therefore be excluded from the ISRS.

Q. DO YOU DISAGREE WITH OPC'S ASSERTIONS IN THIS REGARD?

A. Yes, I emphatically disagree. I believe OPC's position reflects a fundamental misunderstanding of the operational history and characteristics of these facilities as well as the safety considerations that mandate their replacement.

Q. IS THE COMPANY'S REPLACEMENT OF ITS STEEL FACILITIES THAT WERE SUBSEQUENTLY PLACED UNDER CATHODIC PROTECTION A NEW DEVELOPMENT?

A. No. The Company has been replacing these facilities at Spire West for nearly two decades and has included the replacement costs in multiple ISRS cases. At no time over this period has OPC or any other party raised a concern about the ISRS eligibility of these costs. Accordingly, the only thing new about this issue, is OPC's new found concern that such costs are suddenly ineligible for inclusion in the Company's ISRS.

Q. DO THE COMMISSION'S SAFETY RULES REQUIRE THAT GAS UTILITIES LIKE THE COMPANY HAVE PROGRAMS TO ADDRESS UNPROTECTED OR "BARE" PIPELINE FACILITIES?

A. Yes. Under Section (15) (E) of the Commission's safety rules (*see* 22 CSR 4240-40.030(15)(E)), gas utilities are required to have programs in place to address unprotected steel mains and other facilities.

Q. WHY ARE SPECIAL MEASURES REQUIRED TO ADDRESS SUCH FACILITIES?

A. As I discussed earlier in my testimony, and as the Commission found in our last ISRS cases, special measures are required because steel pipe that has not been placed under cathodic protection "corrodes relatively quickly and needs to be replaced" as the "corrosion diminishes wall thickness which causes the possibility of leaks."

Q. WHAT PROGRAM MEASURES DOES SECTION (15)(e) PROVIDE FOR ADDRESSING THESE CORROSION PROBLEMS ASSOCIATED WITH BARE STEEL PIPING?

A. The Rule mentions both replacement and applying cathodic protection as measures that can be implemented to help mitigate the impact of corrosion on such facilities.

Q. ARE THESE MEASURES MUTUALLY EXCLUSIVE OR CAN THEY BE USED IN COMBINATION WITH EACH OTHER?

A. Replacement of a bare steel facility is obviously a permanent solution that eliminates the need to apply cathodic protection. The application of cathodic protection, however, does not eliminate the need to eventually replace the steel piping, particularly given the historical circumstances surrounding the steel mains being replaced by Spire West.

Q. WHAT ARE THOSE HISTORICAL CIRCUMSTANCES?

A. At the time the Commission adopted Rule (15)(E) nearly thirty years ago, Spire West's steel mains had already been in the ground and operating for over 3 decades, with many more than 40 or 50 years old at the time. Throughout this period, these facilities had no cathodic protection and therefore were susceptible to the same degree of corrosion as any other bare steel facility.

Q. DID THE APPLICATION OF CATHODIC PROTECTION IN RESPONSE TO THE COMMISSION'S ADOPTION OF RULE (15)(E) DO ANYTHING TO ADDRESS WHATEVER CORROSION MAY HAVE ALREADY OCCURRED ON THESE FACILITIES?

A. No. While the application of cathodic protection would help slow the development of corrosion on these facilities, it did nothing to mitigate or repair corrosion that had already occurred.

Q. SO WHY WAS CATHODIC PROTECTION INSTALLED ON THESE FACILITIES?

A. Given the huge quantity of bare steel facilities that MGE had in its distribution system, it would have been impractical to replace all or even most of these facilities in a relatively short period of time. In light of this reality, application of cathodic protection on these facilities was necessary to slow the progression of corrosion on these facilities pending their eventual replacement. At no point, however, was the application of cathodic protection considered a permanent fix for the problem or a long-term substitute for replacement.

Q. DID REGULATORS IN MISSOURI RECOGNIZE THAT THESE PREVIOUSLY BARE STEEL FACILITIES WOULD STILL NEED TO BE REPLACED DESPITE THE APPLICATION OF CATHODIC PROTECTION?

A. Yes. Approximately ten years after the Commission adopted Rule (15)(E), MGE, in consultation with the Commission safety staff, updated its approach for complying with the Rule. As reflected in the record of Case No. GO-2002-50, the parties agreed and the Commission approved a provision under which MGE was required to replace a minimum of 5 miles of its protected bare steel mains each year. In its recommendation endorsing this minimum replacement obligation, the Commission safety staff explained why such action was necessary, stating, in part, that "these bare steel mains were not cathodically protected for many years following installation", that "a large number of leaks have accumulated on these mains" and that "a replacement program is needed." The recommendation to begin the replacement of such facilities was of course fully authorized by Rule (15)(E) as a measure complying with the mandate to address such facilities.

Q. DID THE TERMINOLOGY USED BY THE COMMISSION TO DESCRIBE THESE FACILITIES CONVEY THAT THEY STILL QUALIFIED AS BARE STEEL FACILITIES DESPITE HAVING BEEN PLACED UNDER CATHODIC PROTECTION?

A. Yes, the Commission repeatedly referred to these facilities as protected <u>bare</u> steel facilities, a term that signifies that the cathodic protection that had been applied to such facilities did not eliminate the essential characteristics of bare steel facilities.

Q. HAVE THERE BEEN OTHER INSTANCES WHERE THE COMMISSION SAFETY STAFF EMPHASIZED THE NEED TO REPLACE THESE BARE STEEL LINES THAT HAVE BEEN SUBSEQUENTLY PLACED UNDER CATHODIC PROTECTION?

A. Yes. At the time, Spire Missouri/Laclede Gas was in the process of acquiring MGE in 2013, the Commission safety staff made a special effort to ensure that we were fully aware of the quantity of bare steel facilities that had been placed under cathodic protection in MGE's distribution system and the need to replace such facilities. The Commission's safety staff has also raised this concern in connection with its annual safety audits of Spire Missouri.

Q. IN YOUR EXPERIENCE, HAS THE NEED TO REPLACE CATHODICALLY PROTECTED STEEL FACILITIES THAT WERE INITIALLY INSTALLED WITHOUT SUCH PROTECTION BEEN RECOGNIZED BY OTHER UTILITIES AND REGULATORS OUTSIDE OF MISSOURI?

A. Yes. Based on my participation in the Operating Section Managing Committee for the American Gas Association as well as other industry groups, I have had an opportunity to interact with a large number of industry officials with responsibility for the safe operation of natural gas distribution systems. As I noted earlier in my testimony, this participation has also afforded me the opportunity to interact with officials from the PHMSA, as well as the staff of the NTSB. Based on these interactions, I can state without qualification that there is a widely-held consensus among industry professionals that facilities initially installed on an unprotected basis still need to be replaced on an aggressive basis regardless of whether they have been cathodically protected in the meantime. In fact, the same considerations I previously mentioned as warranting the accelerated replacement of cast iron and bare steel also apply to these facilities.

Q. IS THERE ANY OTHER EVIDENCE OF THIS CONSENSUS AMONG INDUSTRY OFFICIALS RESPONSIBLE FOR THE SAFE OPERATION OF NATURAL GAS DISTRIBUTION SYSTEMS REGARDING THE NEED TO REPLACE BARE STEEL MAINS UNDER CATHODIC PROTECTION AT AN ACCELERATED RATE?

A. Yes. I have reviewed the information from the USDOT Annual Reports for Gas Distribution Systems found on PHMSA's website. This information clearly shows that other natural distribution operators outside of Missouri have in fact been replacing bare steel mains under cathodic protection at an accelerated rate over the last several years. Notably, PHMSA's website reflects recent (2018) leak incidents involving the very facilities the Company is replacing, including one in Spire West's service territory where corrosion on a cathodically protected bare steel main (1929 vintage) resulted in a leak and two in Spire East's service area where fractures on large LP cast iron mains resulted in a leak.

Q. DO YOU EXPECT THIS TREND TO CONTINUE ON A NATIONAL LEVEL?

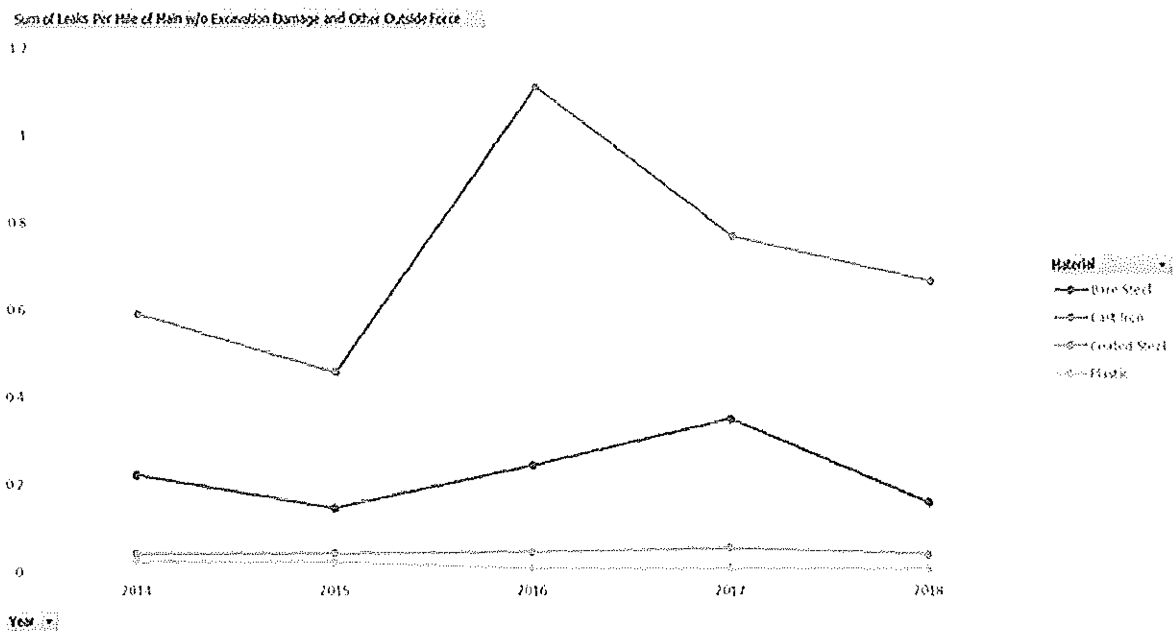
A. Yes, based on my conversations with other industry officials.

Q. DOES OTHER DATA ALSO SUPPORT THE ACCELERATED REPLACEMENT OF BARE STEEL FACILITIES THAT HAVE BEEN PLACED UNDER CATHODIC PROTECTION AT SPIRE WEST?

A. Yes. Although Spire West's DIMP plan does not rank the risks posed by bare steel facilities that have been placed under cathodic protection as high as those associated with the Company's cast iron facilities, leak data shows that there is a higher overall leak rate on the bare steel mains that have been placed under cathodic protection than other facilities.

Q. WHY IS THIS?

A. One indication of risk is the propensity of certain facilities to experience leaks since it is escaping gas that can ultimately lead to the kind of catastrophic events that have propelled the accelerated replacement of cast iron and bare steel facilities over the past several years. Prior to its efforts to replace its bare steel facilities that have been placed under cathodic protection such facilities had a leakage rate that was some 30 to 40 times higher than the rate for the Companies plastic facilities. Due in part to those replacement efforts, the leakage rate for such facilities has declined but as shown in the graph below, this rate is still some 10 times higher than the rate for plastic facilities. Absent the Company's current replacement efforts, it can be expected that the leakage rate for these facilities would rise again above the comparatively elevated level that exists today.



Q. ARE YOU AWARE OF ANY ADDITIONAL INFORMATION OR GUIDANCE GIVEN BY PHMSA ON REPLACEMENT OF BARE STEEL MAINS THAT HAVE BEEN PLACED UNDER CATHODIC PROTECTION?

A. Yes. On the PHMSA website under Pipeline Replacement Updates, the following information is provided:

> "Uncoated steel natural gas and hazardous liquids pipelines are also known as bare steel pipelines. While many of these pipelines have been taken out of service, and no longer transport these commodities to customers, some of them continue to operate today. The typical age and the lack of a protective outer coating have to be considered by the pipeline operators, and this may lead to accelerated replacement or rehabilitation of bare steel pipelines."

Q. IS THERE ADDITIONAL INFORMATION ON THE WEBSITE?

A. Yes. The website goes on to state:

> "The lack of an outer coating, which helps to protect the steel from the environment, makes a high level of protection from corrosion, and careful assessment, necessary. This typical protection is referred to as cathodic protection. Methods used to determine the effectiveness of cathodic protection on bare steel pipelines focus on identifying larger corrosion cells, called "hot spots". However, small, localized corrosion areas, receiving insufficient cathodic protection, are difficult to identify and can lead to integrity issues."

Q. HOW WOULD YOU INTERPRET THIS INFORMATION?

A. The reference to "small, localized corrosion areas, receiving insufficient cathodic protection, are difficult to identify and can lead to integrity issues" reinforces the need to eventually replace the steel piping, particularly given the historical circumstance surrounding the steel. Again, placing bare steel under cathodic protection, particularly after it was installed 30 to 50 years prior to the cathodic protection is not a permanent fix for the problem or a long-term substitute for replacement.

Q. HAS THE PACE OF THE COMPANY'S REPLACEMENT PROGRAM FOR BARE STEEL FACILITIES SUBSEQUENTLY PLACED UNDER CATHODIC PROTECTION INTERFERED WITH THE PACE OF ITS REPLACEMENT PROGRAM FOR CAST IRON FACILITIES THAT ARE RANKED HIGHER IN ITS DIMP?

A. No. Every component of the Company's various replacement programs is sequenced based on an evaluation of risks, operational realities affecting when and at what pace certain facilities in certain areas can be efficiently replaced and other factors. These factors are all taken into consideration of Spire's Master Replacement Plan for Missouri West for determining what facilities are replaced, when and at what pace. Because of these considerations, the division of resources between cast iron and steel that has been placed under cathodic protection is amply justified by these sound and prudent planning strategies.

Q. **DOES THIS COMPLETE YOUR DIRECT TESTIMONY?**

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Spire Missouri Inc. to Change its Infrastructure System Replacement Surcharge in its Spire Missouri East Service Territory	)	**File No. GO-2019-0356**
In the Matter of the Application of Spire Missouri Inc. to Change its Infrastructure System Replacement Surcharge in its Spire Missouri West Service Territory	)	**File No. GO-2019-0357**

<u>AFFIDAVIT</u>

STATE OF MISSOURI)
) SS.
CITY OF ST. LOUIS)

Craig R. Hoeferlin, of lawful age, being first duly sworn, deposes and states:

1. My name is Craig R. Hoeferlin. I am the Vice President – Operations Services for Spire Missouri Inc. My business address is 700 Market St., St. Louis, Missouri, 63101.

2. Attached hereto and made a part hereof for all purposes is my direct testimony on behalf of Spire Missouri Inc.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct to the best of my knowledge and belief.

Craig R. Hoeferlin
Craig R. Hoeferlin

Subscribed and sworn to before me this 27th day of September 2019.

TOD J. FAGAN
NOTARY PUBLIC - NOTARY SEAL
STATE OF MISSOURI
ST. LOUIS COUNTY
MY COMMISSION EXPIRES: FEBRUARY 27, 2022
COMMISSION #14398406

Tod J Fagan
Notary Public

THE SECRETARY OF TRANSPORTATION
WASHINGTON, D.C. 20590

March 28, 2011

The Honorable Robert Bentley
Governor of Alabama
Montgomery, AL 36130

Dear Governor Bentley:

Recent pipeline failures around the country have elevated concerns about pipeline safety. Neighborhoods in Allentown, Pennsylvania, and San Bruno, California, were rocked by fatal explosions caused by natural gas pipeline failures. These tragic events took lives, shook communities, and raised serious questions about the safety of some of our aging pipeline infrastructure.

These and other recent pipeline incidents, such as the one last summer in Marshall, Michigan, causing a large oil spill into sensitive waters, underscore the need to develop a comprehensive solution that will prevent accidents like these from recurring. The U.S. Department of Transportation (DOT) will host a Pipeline Safety Forum on these issues on April 18 in Washington, DC, and I invite you or your representative(s) to participate. This forum will bring together key stakeholders, including pipeline companies, State and Federal agencies, technical experts, public safety advocates, and the public, to tackle these issues head-on and discuss workable solutions. You or your representative(s) may RSVP for the Pipeline Safety Forum at pipelineforum@dot.gov.

We appreciate your State's partnership on pipeline safety inspection and enforcement. In 2009, the Pipeline and Hazardous Materials Safety Administration provided the majority of the funding for your pipeline safety program, trained your State's inspectors alongside our own, and worked with them to enforce your State pipeline safety laws.

Now, we want to partner with you again to ensure that all pipeline companies in your State, both public and private, are correctly analyzing the risks to their pipeline systems and using the appropriate assessment technologies. Your pipeline safety staff can help make this happen. We ask you to urge your staff to encourage companies and the State utility commission to accelerate pipeline repair, rehabilitation, and replacement programs for systems whose integrity cannot be positively confirmed. This is one of the best ways to help protect your citizens from accidents like those in Allentown, Marshall, and San Bruno.

In addition, there are several other actions you could take to prevent other types of pipeline accidents in your State. These include the following:

Issue a Proclamation on Safe Digging Month. You can help raise awareness about the importance of calling before you dig by issuing a State proclamation and holding a public awareness event. As you may know, April is National Safe Digging Month, and DOT will be highlighting our *811 Safe Digging Initiative*. Since establishing the 811 number in 2007 and raising awareness among excavators and do-it-yourselfers alike of the importance of calling 811 before digging, the number of gas distribution leaks caused by excavation damage has dropped by more than 45 percent. Even with this progress, excavation damage remains the number one cause of pipeline failures causing serious injuries and deaths. Your State proclamation will help raise awareness about this critical safety issue.

Enforce One-Call Laws. One of the critical components of a strong damage prevention program is fair and effective enforcement of the one-call laws. Governors play a vital role in supporting improved pipeline safety and a sound infrastructure, and we encourage your support for improvements in one-call laws and programs. Effective damage prevention laws are characterized by few or no exemptions from participation in the safe digging process, balanced enforcement that holds all parties accountable, and clearly defined responsibilities.

Encourage Better Land Use and Development. Another important damage prevention initiative is aimed at helping your cities and towns make better decisions about land use and development around existing pipelines. We have published a report on suggested practices and model legislation to help town planners and local officials coordinate with pipeline companies to ensure the safety of people and the environment. This report, called the Pipeline Informed Planning Alliance Report, can be found on our Web site at http://www.phmsa.dot.gov. Please help us by referring land use planners in your State to this report so they can make informed decisions about the best use of land near pipelines transporting natural gas or hazardous liquids.

I look forward to working with you on this critical safety issue. If the Office of the Secretary or DOT's Pipeline and Hazardous Material Safety Administration can be of any assistance to you, please contact Administrator Cynthia L. Quarterman at 202-366-4831.

Sincerely yours,

Ray LaHood

U.S. Department
of Transportation

**Pipeline and Hazardous
Materials Safety
Administration**

Administrator

1200 New Jersey Avenue SE
Washington, DC 20590

DEC 19 '11

Mr. Tony Clark
Chairman of the Board and President
National Association of Regulatory Utility Commissioners
1101 Vermont Avenue, NW
Suite 200
Washington, DC 20005

Ms. Collette Honorable
Chair, NARUC Pipeline Safety Task Force
National Association of Regulatory Utility Commissioners
1101 Vermont Avenue, NW
Suite 200
Washington, DC 20005

Dear Mr. Clark and Ms. Honorable:

As U.S. Department of Transportation (DOT) and the National Association of Regulatory Utility Commissioners (NARUC) continue to support efforts to accelerate the repair, rehabilitation, and replacement of high-risk infrastructure in pipeline systems, we appreciate the NARUC's continued diligence in promoting rate mechanisms that will encourage and will enable pipeline operators to take reasonable measures to repair, rehabilitate or replace high-risk gas pipeline infrastructure. We have prepared, and attached, a white paper on state pipeline infrastructure replacement programs in the hope that you will share it with your members as a resource for encouraging more States to adopt alternative or more flexible rate mechanisms that will facilitate the replacement or repair of high-risk pipelines.

As you know, the Pipeline and Hazardous Materials Safety Administration (PHMSA) has regulatory authority in regard to the safety of our nation's pipelines. PHMSA, however, does not have the authority to determine the routing, rates, or other terms and conditions of service for gas pipelines. The Federal Energy Regulatory Commission makes these determinations for interstate gas pipelines, and the State public utility commissions you represent typically do the same for intrastate gas pipelines. Most State commissions are also responsible for oversight of intrastate pipeline safety through certifications or agreements with PHMSA.

Many State public utility commissions have encouraged the timely repair, rehabilitation, and replacement of high-risk gas pipeline infrastructure through special rate mechanisms. Some legislatures have also provided their State public utility commissions with specific statutory authority to approve such programs for intrastate gas lines. A comprehensive list of these programs is available at http://opsweb.phmsa.dot.gov/pipelineforum/pipeline-systems/state-pipeline-system/state-replacement-programs/.

We believe that the timely repair, rehabilitation, and replacement of high-risk gas pipeline infrastructure are critical to ensuring public safety. A series of recent gas pipeline accidents, including the September 9, 2010 San Bruno, California accident, the January 19, 2011 Philadelphia, Pennsylvania accident, and the February 10, 2011 accident, show the terrible loss of life and property that can occur without adequate attention to the integrity of pipeline infrastructure.

PHMSA believes that an effective program for ensuring the timely rehabilitation, repair, or replacement of high-risk gas pipelines might have helped prevent these accidents. Accordingly, we recommend that State public utility commissions consider accelerating work on the following kinds of high-risk intrastate gas infrastructure in the future:

- Cast iron gas mains, which can be prone to failure as a result of graphitization or brittleness;
- Plastic pipe manufactured in the 1960s to the early 1980s, which is susceptible to premature failures as a result of brittle-like cracking;
- Mechanical couplings used for joining and pressure sealing pipe, which are prone to failure under certain conditions;
- Bare steel pipe without adequate corrosion control (i.e., cathodic protection or coating);
- Copper piping;
- Older pipe, if it is vulnerable to failure from time-dependent forces, such as corrosion, stress corrosion cracking, settlement, or cyclic fatigue factor; and
- Pipelines with inadequate construction records or assessment results to verify their integrity.

PHMSA requests your support in ensuring that State commissions implement effective programs for the timely repair, replacement, and rehabilitation of high-risk gas pipeline infrastructure.

I look forward to continuing to work with the NARUC on pipeline safety and welcome any thoughts that you have on the issues discussed in this letter. Please send your response to Jeffrey Wiese, Associate Administrator for Pipeline Safety, or to contact me if you have any questions or concerns.

Regards,

Cynthia L. Quarterman

Enclosure: White Paper

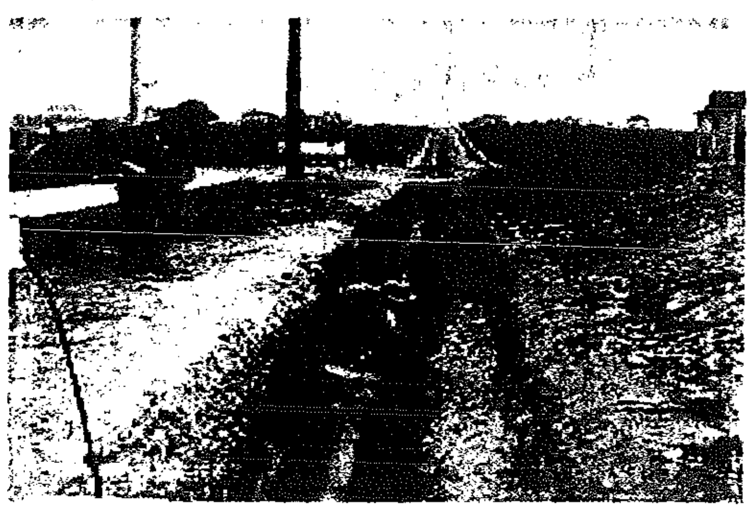
UNITED STATES DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

White Paper on State Pipeline Infrastructure Replacement Programs

Prepared for

National Association of Regulatory Commissioners

December 2011



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Introduction

Under the leadership of Transportation Secretary Ray LaHood and Administrator Cynthia Quarterman, the Pipeline and Hazardous Materials Safety Administration (PHMSA) has issued a Call to Action with the goal of accelerating the rehabilitation, repair, and replacement of high-risk pipeline infrastructure. This effort comes on the heels of several high profile pipeline accidents, including two recent gas distribution line explosions in Pennsylvania that resulted in multiple deaths.

As part of Secretary LaHood's Call to Action, PHMSA has prepared this white paper to urge State public utility commissions to expand the use of pipeline infrastructure replacement programs. It includes an overview of natural gas ratemaking, a discussion of the need to take prompt action to remediate high-risk pipeline infrastructure, and a description of the various State programs that are being used for that purpose.

Executive Summary

Public safety requires prompt action to repair, remediate, and replace high-risk gas pipeline infrastructure, including cast iron mains, certain vintages of plastic pipe and mechanical coupling installations, bare steel pipe without adequate corrosion control, and copper piping. Several recent gas pipeline accidents show the terrible consequences that can occur if such action is not taken.

The Federal Energy Regulatory Commission establishes rates for interstate natural gas pipeline service under the "just and reasonable" standard provided in the Natural Gas Act of 1938. State public utility commissions (and in some cases local authorities) establish rates for intrastate natural gas pipeline service. While based on State and local laws, those determinations are generally made on the basis of a formula that is similar to the "just and reasonable" standard.

Pipeline infrastructure replacement programs for gas distribution systems exist in nearly 30 States. Some State Public utility commissions have used their traditional ratemaking authority to approve these programs, the terms and conditions of which are established under a generally applicable statutory provision. Other State public utility commissions have specific authority to approve such programs. The terms, conditions, and cost recovery mechanisms of these programs vary by statute. Whether as part of the traditional ratemaking process or in a separate proceeding, PHMSA is encouraging the States to accelerate the remediation of high-risk gas pipeline infrastructure.

PHMSA intends to focus on this issue in implementing the new Gas Distribution Pipeline Integrity Management Program Rule and as part of the annual certification process for State pipeline safety programs. PHMSA is also willing to provide other assistance to State public utility commissions who are seeking to establish or improve programs for the repair, rehabilitation, and replacement of high-risk pipeline infrastructure.

I. General Ratemaking Principles

Federal Ratemaking

The Federal Energy Regulatory Commission (FERC) regulates the interstate sale and transportation of natural gas under the Natural Gas Act of 1938 (NGA). The NGA imposes a "just and reasonable" requirement on the rates charged for interstate pipeline services, a standard that requires FERC to consider both the interests of pipeline operators and ratepayers. FERC utilizes varying ratemaking methodologies to meet the "just and reasonable" standard, such as selective discounting, market-based rates, and negotiated rates. However, the underlying premise that ratemaking should be based on the cost of providing service remains a strong principle in rate-making proceedings. Accordingly, cost-of-service ratemaking is the primary method that FERC uses to establish rates.

Cost-of-service ratemaking bases rates on the cost of service and affords the pipeline a reasonable rate of return. The Cost-of-Service:

> Includes the product of the pipeline's Rate Base (which is the pipeline's investment) and the Overall Rate of Return, plus its Operation and Maintenance Expenses (O&M), Administrative and General Expenses (A&G), Depreciation Expense, Non-Income Taxes and Income Taxes, less Revenue Credits.

In this equation, the Rate Base captures the total amount invested in the pipeline and is used to calculate the permissible return on investment. The Overall Rate of Return is a product of the pipeline's capitalization ratio, the cost of debt, and the rate of return that is allowed on the pipeline's equity. Total cost-of-service captures the amount of rate revenue that a pipeline company must charge in order to maintain profitability and remain an attractive prospect for future investment.

FERC applies cost-of-service and other rate methodologies in rate proceedings to set initial rates for new or expanding pipelines, increase rates for existing pipelines, and require prospective changes to existing rates. Applications to establish new or expanded pipeline service must be approved by FERC and are required to meet a "public convenience and necessity" standard. In a certificate proceeding, FERC authorizes initial rates that remain in effect until a further rate proceeding is held. In a general Section 4 rate case, a pipeline files to increase rates and is required to prove that its proposal is "just and reasonable." Alternatively, in a Section 5 rate proceeding, FERC may require prospective rate changes, if it is determined that a pipeline's rates no longer meet the "just and reasonable" standard.[1]

State Ratemaking

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[1] Cost-of-Service Rates Manual, Federal Energy Regulatory Commission, June 1999.

State public utility commission (PUCs) regulate the intrastate sale of natural gas, which includes establishing rates for the end user. State PUCs evaluate ratemaking proposals according to a variety of legislative mandates, policy objectives, and consumer interests, but have traditionally set rates according to the "just and reasonable" standard. As articulated by the National Regulatory Research Institute, these rates share four general characteristics. First, rates are reflective of "an efficient or prudent utility" and, therefore, do not include those costs that a utility could eliminate without impairing efficiency or profitability. Second, rates incorporate the natural consequences of a utility's provision of service at different levels and to different classes of customers. Third, rates are set at a level that provides the utility with an acceptable return to ensure that it remains an attractive candidate for new capital investment. Lastly, the utility's provision of service should be nondiscriminatory. Within these general principles, the States use varying methods to establish rates, some of which are outlined below.

Rates for Investor-Owned Local Gas Distribution Companies

Local distribution companies are privately-owned utilities and are required to provide distribution of natural gas to any customer within its geographic franchise area upon reasonable request. These utilities own the natural gas being distributed for their "sales customers" and get paid a fee for the distribution service. Local distribution companies do not earn any money from the sale of the natural gas itself, whether the utility owns the natural gas or transports it on behalf of the customer. The companies simply pass the cost of the gas straight through to the customer. Customers who have purchased their natural gas from a third party supplier or market and wish the distribution company to transport the gas to their business or home, commonly referred to as "transportation customers," pay a fee for the transport of natural gas over the local distribution company's pipeline.

State PUCs regulate the rates, terms, and conditions of service for investor-owned natural gas distribution systems. Local agencies generally perform that regulatory function for publicly-owned distribution utilities. These State and local authorities are also responsible for ensuring that the operation of these utilities serves the public interest. In some cases, that may require prohibiting a utility from turning off a residential customer's gas service for nonpayment during cold weather, asking for safety-driven changes beyond those required by the Federal and State safety regulators, or requiring utilities to offer energy conservation programs.

Natural gas utilities are required to post the rates, terms, and other conditions of service with their State PUCs, and customers must pay the posted rates to obtain the applicable service. Utilities also have information on file with State PUCs on the current "purchased gas adjustment charge." These charges account for market-driven changes in the price the utility pays for the gas supplied to its customers.

Rates for Publicly-Owned Local Gas Utility Systems

Publicly-owned gas utility systems are non-profit enterprises that are owned by the citizens they serve. They include municipal gas distribution systems, public utility districts, county districts, and other public agencies that have natural gas distribution facilities. These utilities own the natural gas that is provided to their customers and charge a fee for the distribution service. Publicly-owned utilities also pass through and recover the cost of acquiring the natural gas that is distributed.

Unlike privately-owned pipeline systems, most State PUCs do not establish rates for publicly-owned gas distribution systems. That function is typically performed by a local body, like a city or county council or utility board. There is no requirement that the rate charged by the utility be based on the cost of service, and the utility may charge whatever rate is established by its governing body.

Rates for publicly-owned utilities do not include costs for return on investment or profit, and any necessary capital is raised by issuing bonds. Customers of municipal utilities pay the purchased gas adjustment charge for the amount of gas the utility distributes during the billing period. Rate changes must be approved by the city council or the utility board.

II. Need for Repair, Rehabilitation, and Replacement of High-Risk Gas Pipeline Infrastructure

The safety of natural gas distribution systems has improved significantly since the enactment of the Natural Gas Pipeline Safety Act of 1968, which provided DOT with the authority to establish safety standards for natural gas systems. A number of serious incidents in natural gas distribution systems, however, still occur each year, and many of those incidents are caused by failures of high-risk pipeline infrastructure. Thus, there is a need to improve pipeline safety by repairing, rehabilitating and replacing high risk pipe.

High-risk pipeline infrastructure is piping or equipment that is no longer fit for service. As discussed below, that lack of fitness can be the product of a variety of factors.

- Cast iron gas mains and service lines can be prone to failure as a result of graphitization or brittleness. The installation of cast iron pipe dates to the 1830s, and remained prevalent until the post-World War II period. Many major urban areas, including Philadelphia, PA; Boston, MA; Baltimore, MD; Washington, DC; Detroit, MI; Chicago, IL; and San Francisco, CA, still have cast iron pipe in their natural gas distribution systems.[2]

- Certain vintages of plastic pipe are susceptible to premature failures as a result of brittle-like cracking. In April 1998, the National Transportation Safety Board (NTSB) released a Special Investigation Report on Brittle-Like Cracking in Plastic Pipe for Gas Service. NTSB found that the long-term strength and resistance of plastic pipe to brittle-like cracking may have been overrated for much of the plastic pipe manufactured and installed from the 1960s through the early 1980s. The NTSB

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[2] http://opsweb.phmsa.dot.gov/pipelineforum/reports-and-research/cast-iron-pipeline/

also found that any potential public safety hazards from these failures are likely to be limited to locations where stress intensification exists. In response to the NTSB report and subsequent investigations, PHMSA issued four advisory bulletins on the susceptibility of certain kinds of older plastic pipe to brittle-like cracking.[3]

- Mechanical coupling installations are devices that are used for the joining and pressure sealing of two pieces of pipe. These devices are prone to failure under certain conditions. In March 2008, PHMSA issued an Advisory Bulletin (ADB) on the use of mechanical couplings in natural gas distribution systems. The ADB noted that these devices are more likely to fail when there is inadequate restraint for the potential stresses on the two pipes, when the couplings are incorrectly installed or supported, or when components experience age-related deterioration. The ADB also noted that inadequate leak surveys can fail to detect a coupling in need of repair and lead to more serious incidents.[4]

- Pipelines lacking adequate construction records or assessment results to verify their integrity. In January 2011, PHMSA issued an ADB on the need to use traceable, verifiable, and complete records in establishing the maximum allowable operating pressures and developing and implementing integrity management programs for natural gas pipelines. The ADB responded to an NTSB recommendation, which resulted from its investigation of the September 2010 intrastate natural gas transmission line rupture in San Bruno, California, which is discussed below.

- Other kinds of pipe installations, including bare steel pipe without adequate corrosion control (i.e., cathodic protection or coating) and copper piping, are also more susceptible to failure.

- Age of pipe should be considered in determining whether pipeline infrastructure is vulnerable to failure from time-dependent forces, like corrosion, stress corrosion cracking, settlement, or cyclic fatigue.

Several recent gas pipeline accidents show the grave consequences that can occur if high-risk gas pipeline infrastructure is not properly repaired, rehabilitated, or replaced. For example,

- On September 9, 2010, an intrastate natural gas transmission line ruptured in San Bruno, California. The ensuing explosion and fire resulted in 8 fatalities, multiple injuries, and destroyed 38 homes. NTSB has released a final report on the cause of the accident and concluded that the failure was the result of an improperly-welded section of pipe that had been installed in 1956 and never subjected to hydrostatic pressure testing.

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[3] 72 FR 51301.

[4] 73 FR 11695.

- On January 19, 2011, a natural gas explosion and fire in a natural gas distribution system killed one person and injured five others in Philadelphia, Pennsylvania. The cause of the accident remains under investigation, but preliminary reports indicate that the source of the gas leak was a 12-inch cast iron gas main installed in the 1920s.

- On February 10, 2011, another natural gas explosion and fire in a natural gas distribution system killed five people and destroyed several homes in Allentown, Pennsylvania. The cause of the accident remains under investigation, but preliminary reports indicate that the source of the gas leak was an 83-year-old, 12-inch cast iron gas main.

Recognizing that prompt action to replace these high-risk gas pipelines might have prevented each of these accidents, Transportation Secretary Ray LaHood issued a Call to Action in April 2009 encouraging the States to expand and accelerate the use of such programs.[5] Twenty-two States responded to the Secretary's initiative by providing PHMSA with information on their efforts to remediate high-risk pipeline infrastructure.

After reviewing that information and performing additional research, PHMSA decided to prepare the following overview of the State pipeline infrastructure replacement programs. PHMSA urges the appropriate regulatory authorities will use this information to accelerate their efforts to repair, rehabilitate, and replace high-risk gas pipeline infrastructure in their jurisdictions. In addition to the analysis provided below, a comprehensive list of all of these programs is included in Appendix I.

III. Using Traditional Ratemaking Authority to Establish Infrastructure Replacement Programs

Several state public utility commissions have used their traditional ratemaking authority to approve pipeline infrastructure replacement programs. The examples discussed below show how that authority can be used to ensure the timely repair, rehabilitation, and replacement of high-risk pipeline infrastructure without additional legislation.

New Jersey

Originally established in 1911 as the Department of Public Utilities, the mission of the New Jersey Board of Public Utilities (BPU) is "[t]o ensure the provision of safe, adequate and proper utility and regulated service at reasonable rates, while enhancing the quality of life for the citizens of New Jersey and performing these public duties with integrity, responsiveness and efficiency."[6] The Division of Energy is responsible for regulating the State's four natural gas

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[5] http://opsweb.phmsa.dot.gov/pipelineforum/

[6] http://www.nj.gov/bpu/about/index.html.

service providers: Elizabethtown Gas, New Jersey Natural Gas (NJNG), PSE&G, and South Jersey Gas.[7]

As part of then-Governor Jon Corzine's economic stimulus plan, BPU approved accelerated pipeline infrastructure replacement programs using its plenary authority to require or enable natural gas companies to provide safe, adequate, and proper service to its customer.[8] In a December 22, 2009 provisional order, BPU approved Elizabethtown Gas's petition to implement a Utility Enhancement Infrastructure Rider (i.e., a rate increase to allow for an accelerated recovery of the costs associated with performing certain gas-distribution infrastructure related projects). The list of qualifying projects included the replacement of 29 miles of 10- and 12-inch and 41.9 miles of 4-inch cast iron gas mains; the installation of 6 miles of 8-inch main and 20 miles of 12-inch main in certain locations. In a subsequent filing, Elizabethtown petitioned BPU to approve an additional rate increase to cover greater-than-anticipated costs for each of these projects.[9]

Likewise, in an April 29, 2009 order, BPU approved NJNG's petition to implement an Accelerated Infrastructure Investment Program (AIIP), i.e., a rate increase to allow for an accelerated recovery of the costs associated with performing 14 infrastructure projects. In a March 30, 2011, BPU approved NJNG's petition to add 9 additional projects to the AIIP. The total anticipated cost for these projects is approximately 130 million dollars.[10]

Kentucky

Created in 1934, the Kentucky Public Service Commission (KPSC) is a three member administrative body with authority to regulate investor-owned natural gas companies. KPSC does not regulate natural gas utilities subject to the control of cities or political subdivisions, or those served by the Tennessee Valley Authority.[11]

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[7] http://www.state.nj.us/bpu/index.shtml

[8] Specifically, § 48: 2-23 states:

The board may, after public hearing, upon notice, by order in writing, require any public utility to furnish safe, adequate and proper service, including furnishing and performance of service in a manner that tends to conserve and preserve the quality of the environment and prevent the pollution of the waters, land and air of this State, and including furnishing and performance of service in a manner which preserves and protects the water quality of a public water supply, and to maintain its property and equipment in such condition as to enable it to do so.

The board may, pending any such proceeding, require any public utility to continue to furnish service and to maintain its property and equipment in such condition as to enable it to do so.

[9] *See* http://www.elizabethtowngas.com/Universal/RatesandTariff/RegulatoryInformation.aspx

[10] *See* http://www.njng.com/regulatory/filings.asp

[11] http://psc.ky.gov/

In a January 31, 2002 order, KPSC approved a petition filed by Duke Energy Kentucky, Inc. (Duke) for approval of an Accelerated Main Replacement Program (AMRP) Rider, which was designed to allow Duke to reduce the time for replacing its cast iron and bare steel mains from 15 years to 10 years. The Kentucky Attorney General appealed that order, arguing that KPSC lacked the authority to approve such a program outside of the confines of a general rate case. The Kentucky Supreme Court later ruled that KPSC had the power to approve the AMRP Rider under its plenary authority to ensure that rates are "fair, just and reasonable."[12]

Indiana

Established in the early 20^{th} century, the Indiana Regulatory Utility Commission (IRUC) is comprised of five Commissioners who are appointed by the Governor to staggered four-year terms. The Gas Division is responsible for regulating the rates and terms and conditions of service for intrastate gas utilities.[13]

IRUC uses a deferred accounting alternative to allow eligible infrastructure investment costs to be diverted to a special deferred account. In the next rate case, the costs are amortized, recovered in rates, and the balance in the special deferred account is either reduced or eliminated. Gas utilities must establish, through the ratemaking proceeding, that all infrastructure investment costs in such accounts are properly accounted for. The assets in these deferred accounts may accrue interest, which isamortized and recoverable. The amount and type of infrastructure costs may be limited and are subject to state approval.

IRUC has approved Vectren Corporation's program to target 90 miles of pipeline replacements per year, as part of a broader, 20-year effort to replace 1,700 miles of aging bare steel and cast iron mains in Indiana and Ohio.[14]

IV. <u>Using Specific Ratemaking Authority to Establish Infrastructure Replacement Programs</u>

Several states have provided their public utility commissions with specific statutory authority to approve pipeline infrastructure replacement programs. Some states, like Missouri, Kansas, and Nebraska, have enacted statutes with detailed eligibility requirements and cost-recovery formulas. Other states, like Ohio, have adopted statutes that provide their commissions with far more flexibility and discretion. Still other states, like Texas and Virginia, fall somewhere in between.

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[12] *Kentucky Public Service Commission v. Commonwealth of Kentucky*, 324 S.W.3d 373 (KY 2010).

[13] http://www.in.gov/iurc/

[14] *http://www.enengineering.com/pdf/p&gj4_05.pdf.*

Infrastructure Replacement Surcharge: Missouri, Kansas, and Nebraska

Missouri, Kansas, and Nebraska have adopted statutes that authorize the approval of infrastructure replacement surcharges. Local distribution companies are allowed to charge current customers for the cost of replacing existing infrastructure through the performance of certain projects. A specific formula is provided for determining the permissible amount of the surcharge; procedural requirements are also included to facilitate commission review and approval.

Missouri and Kansas

Established in 1913, the Missouri Public Service Commission (MPSC) regulates local gas distribution companies and is composed of five commissioners who are appointed by the governor.[15] Founded two decades later, the Kansas Corporation Commission (KCC) regulates natural gas companies and is composed of three commissioners who are appointed by the Governor for 4-year terms with the approval of the Senate.[16]

On July 9, 2003, the Missouri General Assembly enacted a statute allowing gas corporations to petition MPSC for approval of an infrastructure system replacement surcharge (ISRS) as of August 28, 2003. Using Missouri's ISRS statute as a model, the Kansas Legislature enacted the Gas Safety and Reliability Act (GSRA) three years later, on April 12, 2006. The GSRA provided that as of July 1, 2006, a natural gas public utility could petition the KCC to establish or change gas system reliability surcharge (GSRS) rate schedules.

These two statutes are similar in many respects and include provisions that define the kinds of gas utility projects which are eligible for a cost recovery surcharge, establish a formula for determining and limiting the amount of that surcharge, and prescribe the procedural requirements that must be met before a surcharge can be imposed.

Both statutes generally limit eligible infrastructure system replacements to gas utility plant projects that:

- Do not increase revenues by directly connecting the infrastructure replacement to new customers;
- Are in service and used and useful;
- Were not included in the gas corporation's rate base in its most recent general rate case; and
- Replace, or extend the useful life of an existing infrastructure.

The statutes also list the kinds of "gas utility plant projects" that are eligible for the surcharge:

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[15] http://psc.mo.gov/

[16] http://www.kcc.state.ks.us/index.htm

- Mains, valves, service lines, regulator stations, vaults, and other pipeline system components installed to comply with State or Federal safety requirements as replacements for existing facilities that are in deteriorated condition;

- Main relining projects, service line insertion projects, joint encapsulation projects, and other similar projects extending the useful life, or enhancing the integrity of pipeline system components for compliance with State or Federal safety requirements; and

- Facility relocations as a result of construction or improvement of a highway, road, street, public way, or other public work by or on behalf of the United States, the State (or political subdivision thereof), or another entity having the power of eminent domain provided that the costs related to such projects have not been reimbursed to the gas corporation.

The two statutes also prescribe a formula for determining the maximum amount and duration of the surcharge:

- MPSC and KCC cannot approve a surcharge that produces a total annualized surcharge revenue below the lesser of $1,000,000 or 1/2 percent of the gas company's base revenue level or exceeds 10 percent of the base revenue approved at the gas company's most recent general rate proceeding.

- A surcharge cannot be approved for a gas company that has not had a general rate proceeding decided or dismissed within a certain number of months (the past 36 months for Missouri and the past 60 months for Kansas), unless the gas company has filed for one or is the subject of a new proceeding.[17]

Finally, there are also procedural requirements that must be met to authorize the surcharge:

- Gas companies that petition MPSC or KCC for a surcharge must submit a proposed ISRS or GSRS and supporting documentation.

- MPSC and KCC must publish notice of that filing, and their respective staffs are required to confirm underlying costs and submit a report within 60 days.

- MPSC and KCC may hold a hearing on the petition but must issue an order that is effective no later than 120 days after the filing.

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[17] As originally enacted, the GSRA prohibited a utility from collecting a GSRS for any period exceeding 60 months unless a filing had been made or was subject to a new proceeding. However, on April 13, 2011, the Kansas Legislature amended the GSRA to allow the KCC, on motion from a natural gas public utility, to extend that 60-month deadline for up to 12 months.

- A gas company cannot effectuate a change in its rates more often than twice every 12 months.

Nebraska

The Nebraska Public Service Commission (NPSC) regulates the rates and quality of service for investor-owned natural gas public utilities and is composed of five elected commissioners who serve 6-year terms.[18] On August 30, 2009, the Nebraska legislature enacted a statute allowing a jurisdictional utility to file an application and proposed rate schedule with NPSC to establish or change "infrastructure system replacement cost recovery charge rate schedules." Through this process, utilities may request an adjustment of their rates to recover costs for eligible infrastructure system replacements. Nebraska's legislation is largely bifurcated: utilities are treated differently depending on whether or not their prior rate filings were subject to negotiation.

NPSC is specifically disallowed from approving rate schedules that produce total annualized infrastructure system cost recovery charge revenue either:

- Below the lesser of one million dollars or one-half percent of the utility's base revenue level, as approved by the commission in the most recent general rate proceeding; or

- Exceeding ten percent of the utility's base revenue level, as approved by the commission in the most recent general rate proceeding.

Furthermore, NPSC cannot approve any rate schedules for a utility that has not had a general rate proceeding decided or dismissed by order within the 60 months immediately preceding the application for a infrastructure system replacement cost recovery charge. Utilities cannot collect a recovery rate for a period exceeding 60 months after the initial approval, unless that utility has filed for or is the subject of a new general rate proceeding within the 60-month period. (The rate may be collected until the effective date of a new rate schedule established as a result of a new general rate proceeding or until the rate proceeding is otherwise decided or dismissed by issuance of a commission order without new rates being established).

Two processes exist for establishing or changing a rate schedule. If the utility's last general rate filing was not subject to negotiation, the utility must submit to NPSC:

- A list of eligible projects;

- A description of the projects;

- The location of the projects;

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[18] http://www.psc.state.ne.us/index.htm

- The purpose of the projects;
- The dates construction began and ended;
- The total expenses for each project at completion; and
- The extent to which such expenses are eligible for inclusion in the calculation of the infrastructure system replacement cost recovery charge.

After the public advocate conducts an examination of this information to verify the underlying costs, NPSC must require a report on this examination to be prepared and filed not later than 60 days after the application. NPSC must hold a hearing on the application and issue an order that is effective not later than 120 days after the application is filed (there is a good-cause 30-day extension). If NPSC finds that an application complies with the applicable requirements, an order is issued authorizing the utility to recover appropriate pretax revenue. Utilities may apply for a change in any infrastructure system replacement cost no more than once in any 12-month period.

If a utility's last general rate filing was subject to negotiation, it must submit to NPSC the schedules, supporting documentation, and a written notice for each city that will be affected by the charge. The notice must identify the cities that will be affected by the filing and copies must be provided to each such city. Affected cities have 30 days from that filing to adopt a resolution of intent to negotiate a charge rate with the utility. A copy of the resolution in support, or a resolution of rejection, of the offer to negotiate must be provided to the utility and NPSC within seven days of adoption.

If NPSC receives timely resolutions from cities that represent more than 50 percent of the ratepayers within the affected cities, to negotiate a recovery rate with the utility, the commission will certify the case for negotiation and will take no action until the negotiation period has expired. If agreement is reached, it must be put in writing and filed with the commission, which then must enter an order either approving or rejecting the rate within 30 days of the filing of the agreement. If agreement is not reached, the affected cities and the utility must submit all documentation within 14 days after the commission receives notice that the negotiations have failed. A hearing must be held not later than 35 days after the receipt of this report. If the commission receives resolutions from cities representing more than 50 percent of ratepayers that expressly reject negotiations, the rate review proceeds immediately.

Interim Rate Adjustment: Texas and Virginia

Texas

Established in 1891, the Texas Railroad Commission (TRC) has primary regulatory authority over various aspects of the oil and natural gas industry. The Gas Services Division regulates the day-to-day activities of approximately 200 natural gas utilities and is responsible for ensuring that a continuous, safe supply of natural gas is available to local consumers at the lowest, reasonable price. TRC has exclusive authority over the rates and terms of service for gas utilities in unincorporated areas and original jurisdiction over utilities at a city gate. TRC is composed of three members who are elected to serve 6-year terms.[19]

On May 16, 2003, the Texas Legislature enacted the Gas Reliability Infrastructure Program (GRIP) statute, which allows gas utilities to recover a return on capital expenditures made during the interim period between general rate cases.[20] Specifically, a gas utility may file a tariff or rate schedule with TRC providing for an interim rate adjustment within two years of the utility's last general rate case. That tariff or rate schedule must be filed at least 60 days before the proposed implementation date of the new rates. During that 60-day period, implementation of the new rates may be suspended by the TRC or an affected municipality for up to 45 days.

The allowable amount of the interim rate adjustment is based on values associated with the utility's return on investment, depreciation expenses, ad valorem taxes, revenue-related taxes, and incremental federal income taxes. The reasonableness and prudence of the investments recovered by an interim rate adjustment is subject to review in the utility's next general rate case. Until the TRC issues a final order approving the interim rate adjustment in that rate case, all amounts collected under the tariff or rate schedule before the filing of that rate case are subject to refund (including with interest, if appropriate). Any utility that implements an interim rate adjustment is required to file a general rate case no later than 180 days after the fifth anniversary of the date its interim rate became effective. The regulatory authority itself may also initiate a rate case at any time to review the reasonableness of the utility's rates.

It should also be noted that TRC has issued regulations mandating the removal, rehabilitation, or replacement of gas distribution pipeline facilities as part of their state pipeline safety program.[21] That includes requirements for the removal of compression couplings and, more recently, for the submission of a written risk-based program, by August 1, 2011, for the removal or replacement of all other distribution facilities.

<u>Virginia</u>

Established in 1902, the Virginia State Corporation Commission (VSCC) is composed of three commissioners who are elected by the General Assembly for 6-year terms. Its Division of Energy Regulation is responsible for providing assistance in regulating investor-owned natural gas utilities.[22]

On April 11, 2010, the SAVE Act (Steps to Advance Virginia's Energy Plan) was enacted, authorizing certain natural gas utilities to petition the State Corporation Commission

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[19] http://www.rrc.state.tx.us/

[20] Tex. Util.Code Ann. § 104.301.

[21] http://info.sos.state.tx.us/pls/pub/readtac$ext.ViewTAC?tac_view=5&ti=16&pt=1&ch=8&sch=C&rl=Y

[22] http://www.scc.virginia.gov/pue/index.aspx

(SCC) for a separate rider ("SAVE rider"), allowing for the recovery of certain costs associated with eligible infrastructure replacement projects. While utilities are still required to apply for the SAVE rider, the statute places restrictions on the VSCC approval process, ostensibly to wall off this process from traditional ratemaking.

Under the Act, an eligible "natural gas utility" is any investor-owned public service company that furnishes natural gas service to the public. Natural gas utilities may apply for "eligible infrastructure replacement" projects that:

- Enhance safety or reliability by reducing system integrity risks associated with customer outages, corrosion, equipment failures, material failures, natural forces, or other outside force damage;
- Do not increase revenues by directly connecting the infrastructure replacement to new customers;
- Reduce or have the potential to avoid greenhouse gas emissions; and
- Are not included in the natural gas utility's rate base in its most recent rate case or in the rate base filed with a performance based regulation plan.

Specifically, eligible "natural gas utility facility replacement projects" are intended to replace storage, peak shaving, transmission or distribution facilities used in the delivery of natural gas, or supplemental or substitute forms of gas sources by a natural gas utility. The act specifically delineates recoverable costs, including return on investment, depreciation, property taxes, and carrying costs of the eligible infrastructure replacement projects.

In order to qualify for the SAVE rider, utilities must file a petition with VSCC to establish a plan, which must include a completion timeline, a schedule of cost recovery, and a certification that the plan is "prudent and reasonable." Prior to approval, VSCC must provide notice and an opportunity for a hearing on the plan. SAVE plans must be approved or denied within 180 days; in the case of a denial, VSCC must specifically detail the reasons for the denial and the utility may refile, without prejudice, an amended plan within 60 days, at which point the Commission has an additional 60 days to approve or deny. VSCC is specifically prohibited from requiring the filing of rate case schedules in conjunction with the consideration of a SAVE plan. In addition, no other revenue requirement or ratemaking issues may be examined in conjunction with the consideration of an application filed pursuant to the SAVE Act.

At the end of each 12-month period that a SAVE rider is in effect, the utility must reconcile the difference between the eligible replacement costs and the amounts recovered under the SAVE rider. This reconciliation provides the basis for an adjustment to the SAVE rider, which VSCC must approve or deny within 90 days, whether it is an additional recovery or a refund. Finally, the Act states that this rider is in addition to all other costs that a utility is permitted to recover and cannot be considered as an offset to other VSCC-approved cost of service or revenue requirements. In addition, the rider cannot be included in the computation of a performance based regulation plan revenue-sharing mechanism.

In summary, the Virginia SAVE Act:

- Uses a rider for the recovery of certain eligible infrastructure costs;
- Uses a statutorily prescribed process that is separated from the ratemaking process;
- Includes an amendment process to incorporate increased project costs, but also requires refunds;
- Requires approval or denial within specific timeframe; and
- Restricts VSCC from considering any costs that the utilities are already allowed to recover in the consideration of whether a utility should be able to recover infrastructure costs.

Alternative Rate Plan: Ohio

Established in 1913, the Public Utilities Commission of Ohio (PUCO) regulates various public utilities in Ohio, including more than two dozen natural gas companies. Those companies provide gas service to more than 3 million users and operate a network of approximately 54,000 miles of regulated distribution lines. PUCO is composed of 5 commissioners who are appointed by the Governor for 5 year terms.[23]

Ohio Chapter 4901: 1-19 governs the filing and consideration of an alternative rate case by a natural gas company. Alternative rate plans may include automatic adjustments based on a specified index or changes in a specified cost. In its "alternative rate plan filing," the applicant must notify the commission and the consumer services department of its intent to file at least 30 days prior to the expected date of filing. The application (sample is included in rule appendix) must include the proposed rates, a summary of the proposed plan, a comparison of the typical "before" and "after" customer bill, and any waiver requests. In addition, the applicant must fully justify any proposal to deviate from the traditional rate of return regulation, including the rationale for the alternative plan, including "how it better matches actual experience of performance of the company in terms of costs and quality of service to its regulated customers."

PUCO may grant alternative rate regulation on the basis of this application. However, PUCO may subsequently determine that the natural gas company is not in substantial compliance with state policy, or on the motion of an adversely affected party, abrogate any order when (1) the commission determines that the findings are no longer valid and that modification or abrogation is in the public interest; and (2) the modification or abrogation is not made more than eight years after the effective date of the order, unless the affected natural gas company consents.

California

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[23] http://www.puco.ohio.gov/puco/

The California Public Utilities Commission (CPUC) is responsible for regulating intrastate natural gas pipelines in the State of California, except for municipal gas systems.[24] CPUC is composed of five commissioners who are appointed by the Governor.

On October 7, 2011, the Governor approved a package of pipeline safety bills with several new mandates for gas pipeline operators and CPUC. The relevant provisions include:

- Requiring operators of intrastate gas transmission lines to prepare and submit to CPUC a plan for pressure testing each line segment and to replace each segment that is not tested. Plans must include a timeline for completing all testing and replacements as soon as practicable with interim safety measures during implementation. Where warranted, segments must also be capable of accommodating inline inspection devices.

- Requiring gas pipeline operators to submit to CPUC for approval a plan for the safe and reliable operation of their gas pipeline facilities. Plans must be consistent with Federal pipeline safety laws and must address specific criteria, including: minimizing hazards and systemic risks; identifying safety-related systems that may be deployed; patrolling and inspecting for leaks; responding to reports of leaks; determining MAOP; ensuring qualified and adequately-sized workforce; and meeting applicable pipeline safety standards.

- Requiring gas pipeline operators to report to CPUC twice per year on the strategic planning and decisionmaking approach that is used to determine and rank pipeline safety, integrity, reliability, operations and maintenance activities, and inspections.

- Establishing that is the policy of the State and CPUC for each gas pipeline operator to place safety as its top priority. CPUC must take reasonable and appropriate action to carry out this policy, including through ratemaking.

- Requiring gas pipeline operators who recover expenses for integrity management program and related pipeline maintenance and repairs to have a balancing account, with any unspent money being returned to ratepayers at the end of each rate cycle.

In a June 2011 order, CPUC had previously used its general authority to require operators of intrastate natural gas transmission lines to submit comprehensive pressure testing implementation plans. The purpose of these plans is to achieve the orderly and cost effective replacement or testing of all natural gas transmission lines in the State. The plans permit the use of alternatives that achieve the same standard of safety, but must include a prioritized schedule based on risk assessment and maintaining service reliability, as well as cost estimates with proposed ratemaking. The plans also address the retrofitting of pipelines to accommodate the use of in-line inspection tools and, where appropriate, automated or remotely controlled shut off valves.

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[24] CA PUB UTIL §§ 2101 *et seq.*, 4351-61, 4451-64.

V. CONCLUSIONS

Nearly 30 State public utility commissions have established pipeline infrastructure replacement programs as part of the ratemaking process. These programs play a vital role in protecting the public by ensuring the prompt rehabilitation, repair, or replacement of high-risk gas distribution infrastructure.

Several state public utility commissions, including those in New Jersey, Kentucky, and Indiana, have used their traditional ratemaking authority to approve such programs. Other States, like Missouri, Kansas, and Nebraska, have provided their public utility commissions with specific statutory authority to approve pipeline infrastructure replacement programs based on detailed eligibility requirements and cost-recovery formulas. Ohio has a statute in place that provides its commission with far more flexibility and discretion. California recently enacted a statutory scheme requiring the implementation of a comprehensive program for pressure testing and replacement of gas pipelines.

Whether as part of the traditional ratemaking process or in a separate proceeding, PHMSA urges State public utility commissions to accelerate the repair, rehabilitation, and replacement of high-risk pipeline infrastructure. The recent pipeline accidents in San Bruno, Philadelphia, and Allentown show the tremendous cost in terms of fatalities, injuries, and property damage that can result in the absence of such action.

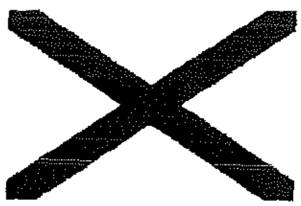
PHMSA is focused on this issue in implementing its integrity management requirements for natural gas transmission and distribution lines and as part of the state certification process. PHMSA is willing to provide assistance to State public utility commissions who are seeking to establish or improve programs for the repair, rehabilitation, and replacement of high risk pipeline infrastructure. Such assistance could include offering testimony at legislative hearings or in state proceedings, providing technical expertise in identifying high-risk pipeline infrastructure, and ensuring that state pipeline safety regulators are effectively implementing the integrity management requirements for natural gas transmission and distribution lines.

Appendix I:

Additional Information on State Pipeline Infrastructure Replacement Programs

Hyperlinks Confirmed as of Date of Publication and Available for Use in Electronic Version Only

Alabama



STATE AUTHORITY: Alabama Public Service Commission

PROGRAM: Rate Stabilization and Equalization Plan

PARTICIPANTS: Mobile Gas

Alabama Gas

Arkansas

STATE AUTHORITY: Arkansas Public Service Commission

PROGRAM: Main Replacement Program Rider

PARTICIPANTS: CenterPoint Energy

California

STATE AUTHORITY: California Public Utilities Commission

PROGRAM: Comprehensive Implementation Plan

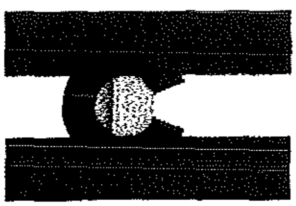
PARTICIPANT: San Diego Gas and Electric

PROGRAM: Pipeline Safety Enhancement Plan

PARTICIPANTS: Southern California Gas

Pacific Gas & Electric

Colorado



STATE AUTHORITY: Colorado Public Service Commission

PROGRAM: Pending

PARTICIPANT: Colorado Public Service Company

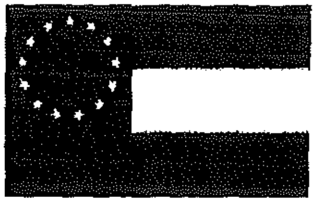
District of Columbia

STATE AUTHORITY: District of Columbia Public Service Commission

PROGRAM: Pending

PARTICIPANT: Washington Gas

Georgia



STATE AUTHORITY: Georgia Public Service Commission

PROGRAM: Pipeline Replacement Program

PARTICIPANT: Atlanta Gas Light

PROGRAM: Pipeline Replacement Surcharge

PARTICIPANT: Atmos Energy

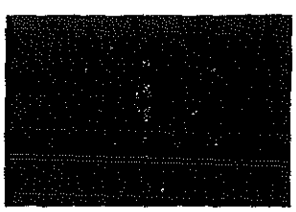
Illinois

STATE AUTHORITY: Illinois Commerce Commission

PROGRAM: Infrastructure Cost Recovery Rider

PARTICIPANT: Integrys Peoples Gas

Indiana



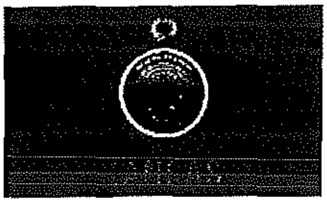
STATE AUTHORITY: Indiana Utility Regulatory Commission, Gas Division

PROGRAM: Pipeline Safety Adjustment

PARTICIPANT: Vectren Energy Delivery of Indiana, Inc.

Vectren South – SICEGO

Kansas



STATE AUTHORITY: Kansas Corporation Commission

PROGRAM: Accelerated Pipeline Replacement Rider

PARTICIPANT: Black Hills Energy

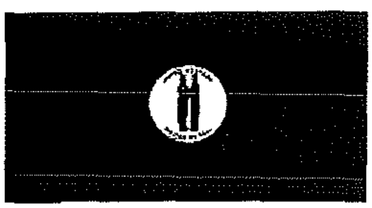
PROGRAM: Gas System Reliability Surcharge Rider

PARTICIPANT: Kansas Gas Service

Atmos Energy

LAWS: Gas Safety and Reliability Policy Act

Kentucky



STATE AUTHORITY: Kentucky Public Service Commission

PROGRAM: Accelerated Main Replacement Program Rider

PARTICIPANT: Columbia Gas Kentucky

PROGRAM: Pipeline Replacement Program

PARTICIPANT: Delta Natural Gas

PROGRAM: Accelerated Main Replacement Program

PARTICIPANT: Duke Energy Kentucky

PROGRAM: Pipeline Replacement Program Rider

PARTICIPANT: Atmos Energy

LAWS: KRS 278.509

Louisiana

STATE AUTHORITY: Louisiana Public Service Commission

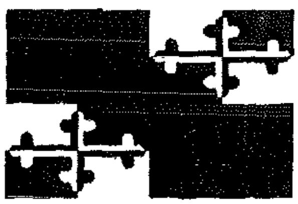
PROGRAM: Rate Stabilization Tariffs

PARTICIPANTS: Atmos Energy – LA

Entergy

CenterPoint Energy

Maryland



STATE AUTHORITY: Maryland Public Service Commission

PROGRAM: Pending

PARTICIPANTS: Washington Gas

Massachusetts

STATE AUTHORITY: Massachusetts Department of Public Utilities, Pipeline Engineering and Safety Division

PROGRAM: Targeted Infrastructure Reinvestment Factor

PARTICIPANTS: Columbia Gas Massachusetts

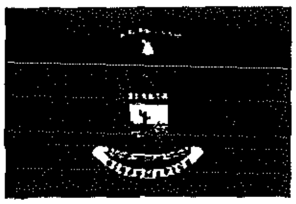
National Grid Massachusetts

New England Gas

PROGRAM: Pending

PARTICIPATNT: Fitchburg Gas and Electric

Michigan

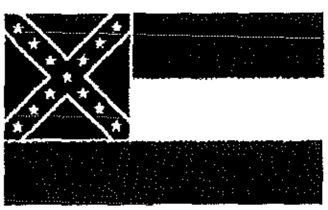


STATE AUTHORITY: Michigan Public Service Commission

PROGRAM: Main Replacement Program Rider

PARTICIPANT: SEMCO Energy

Mississippi



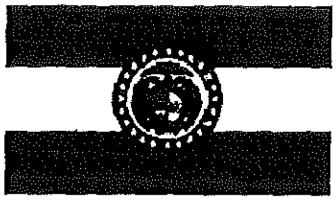
STATE AUTHORITY: Mississippi Public Service Commission

PROGRAM: Rate Stabilization Tariffs

PARTICIPANTS: Atmos Energy – MS

CenterPoint Energy

Missouri



STATE AUTHORITY: Missouri Public Service Commission

PROGRAM: Infrastructure System Replacement Surcharge

PARTICIPANTS: Ameren Missouri

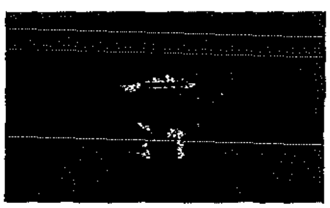
Laclede Gas

Missouri Gas Energy

Atmos Energy - MO

LAWS: MO ST 393.1009 *et seq.*

Nebraska



STATE AUTHORITY: Nebraska Public Service Commission

PROGRAM: Infrastructure System Replacement Cost Recovery Charge

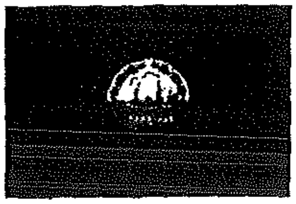
PARTICIPANT: Black Hills Energy

LAWS: NE ST 66-1865

NE ST 66-1866

NE ST 66-1867

New Hampshire

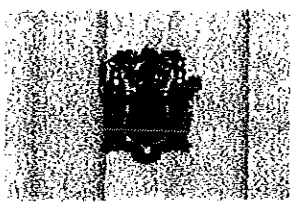


STATE AUTHORITY: New Hampshire Public Utilities Commission

PROGRAM: Cast Iron Bare Steel Replacement Program

PARTICIPANT: National Grid Energy North

New Jersey



STATE AUTHORITY: New Jersey Board of Public Utilities

PROGRAM: Utility Enhancement Infrastructure Rider

PARTICIPANT: Elizabethtown Gas

PROGRAM: Accelerated Infrastructure Investment Program

PARTICIPANT: New Jersey Natural Gas

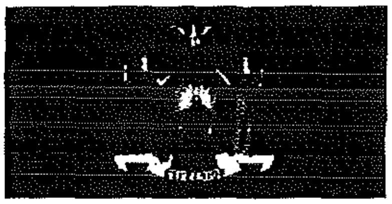
PROGRAM: Capital Adjustment Charge

PARTICIPANT: Public Service Electric and Gas

PROGRAM: Capital Investment Recovery Tracker

PARTICIPANT: South Jersey Gas

New York

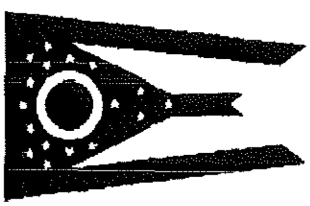


STATE AUTHORITY: New York State Public Service Commission

PROGRAM: LIMITED INFRASTRUCTURE REPLACEMENT

PARTICIPANTS: National Grid Long Island, Niagara Mohawk, and NYC
Corning Natural Gas

Ohio



STATE AUTHORITY: Ohio Public Utility Commission

PROGRAM: Infrastructure Replacement Program

PARTICIPANTS: Columbia Gas Ohio

PROGRAM: Pipeline Infrastructure Replacement Cost Recovery Charge

PARTICIPANT: Dominion East Ohio

PROGRAM: Accelerated Main Replacement Program Rider

PARTICIPANT: Duke Energy Ohio

PROGRAM: Distribution Replacement Rider

PARTICIPANT: Vectren Energy Delivery of Ohio, Inc.

Oklahoma

STATE AUTHORITY: Oklahoma Corporation Commission

PROGRAM: Rate Stabilization Tariffs

PARTICIPANTS: Oklahoma Natural Gas

CenterPoint Energy

Oregon

STATE AUTHORITY: Oregon Public Utility Commission

PROGRAM: Replacement Projects

PARTICIPANT: Avista Corp

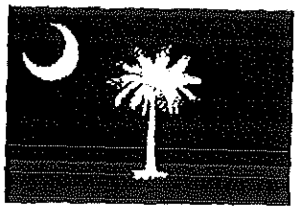
Rhode Island

STATE AUTHORITY: Rhode Island Public Utilities Commission

PROGRAM: Capital Expenditure Tracker Factor, Accelerated Replacement Program

PARTICIPANT: National Grid Narragansett Gas

South Carolina



STATE AUTHORITY: South Carolina Office of Regulatory Staff

PROGRAM: Rate Stabilization Tariff

PARTICIPANTS: Piedmont Natural Gas

South Carolina Electric and Gas

Texas

STATE AUTHORITY: Texas Railroad Commission

PROGRAM: Gas Reliability Infrastructure Program

PARTICIPANTS: CenterPoint Energy

Atmos Energy – TX

Texas Gas Service

PROGRAM: Rate Stabilization Tariffs

PARTICIPANTS: Atmos Energy – TX

CenterPoint Energy

LAWS: Tex. Util.Code § 104.301

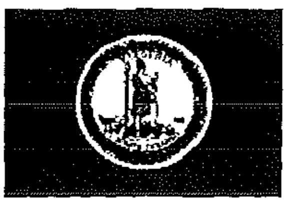
Utah

STATE AUTHORITY: Utah Public Service Commission

PROGRAM: Infrastructure Rate Adjustment Tracker

PARTICIPANT: Questar Gas

Virginia



STATE AUTHORITY: Virginia State Corporation Commission

PROGRAM: Pending

PARTICIPANT: Washington Gas

LAWS: SAVE Act

consecutive years of data, comparing the experiences of drivers in the first 2 years with their experiences in the final year.

Applying principles from these studies to the past 3-year record of the twelve applicants, two of the drivers were involved in crashes and none were convicted of moving violations in a CMV. All the applicants achieved a record of safety while driving with their vision impairment, demonstrating the likelihood that they have adapted their driving skills to accommodate their condition. As the applicants' ample driving histories with their vision deficiencies are good predictors of future performance, FMCSA concludes their ability to drive safely can be projected into the future.

We believe that the applicants' intrastate driving experience and history provide an adequate basis for predicting their ability to drive safely in interstate commerce. Intrastate driving, like interstate operations, involves substantial driving on highways on the interstate system and on other roads built to interstate standards. Moreover, driving in congested urban areas exposes the driver to more pedestrian and vehicular traffic than exists on interstate highways. Faster reaction to traffic and traffic signals is generally required because distances between them are more compact. These conditions tax visual capacity and driver response just as intensely as interstate driving conditions. The veteran drivers in this proceeding have operated CMVs safely under those conditions for at least 3 years, most for much longer. Their experience and driving records lead us to believe that each applicant is capable of operating in interstate commerce as safely as he/she has been performing in intrastate commerce. Consequently, FMCSA finds that exempting these applicants from the vision requirement in 49 CFR 391.41(b)(10) is likely to achieve a level of safety equal to that existing without the exemption. For this reason, the Agency is granting the exemptions for the 2-year period allowed by 49 U.S.C. 31136(e) and 31315 to the twelve applicants listed in the notice of February 6, 2012 (77 FR 5874).

We recognize that the vision of an applicant may change and affect his/her ability to operate a CMV as safely as in the past. As a condition of the exemption, therefore, FMCSA will impose requirements on the twelve individuals consistent with the grandfathering provisions applied to drivers who participated in the Agency's vision waiver program.

Those requirements are found at 49 CFR 391.64(b) and include the following: (1) That each individual be physically examined every year (a) by an ophthalmologist or optometrist who attests that the vision in the better eye continues to meet the requirement in 49 CFR 391.41(b)(10) and (b) by a medical examiner who attests that the individual is otherwise physically qualified under 49 CFR 391.41; (2) that each individual provide a copy of the ophthalmologist's or optometrist's report to the medical examiner at the time of the annual medical examination; and (3) that each individual provide a copy of the annual medical certification to the employer for retention in the driver's qualification file, or keep a copy in his/her driver's qualification file if he/she is self-employed. The driver must have a copy of the certification when driving, for presentation to a duly authorized Federal, State, or local enforcement official.

Discussion of Comments

FMCSA received no comments in this proceeding.

Conclusion

Based upon its evaluation of the twelve exemption applications, FMCSA exempts Eugenio V. Bermudez (MA), John A. Carroll, Jr. (AL), Mark W. Crocker (TN), Johnny Dillard (SC), Keith J. Haaf (VA), Edward M. Jurek (NY), Allen J. Kunze (ND), Jack W. Murphy, Jr. (OH), Mark A. Smalls (GA), Glenn R. Theis (MN), Peter A. Troyan (MI) and Gary Vines (AL) from the vision requirement in 49 CFR 391.41(b)(10), subject to the requirements cited above (49 CFR 391.64(b)).

In accordance with 49 U.S.C. 31136(e) and 31315, each exemption will be valid for 2 years unless revoked earlier by FMCSA. The exemption will be revoked if: (1) The person fails to comply with the terms and conditions of the exemption; (2) the exemption has resulted in a lower level of safety than was maintained before it was granted; or (3) continuation of the exemption would not be consistent with the goals and objectives of 49 U.S.C. 31136 and 31315.

If the exemption is still effective at the end of the 2-year period, the person may apply to FMCSA for a renewal under procedures in effect at that time.

Issued on: March 9, 2012.

Larry W. Minor,

Associate Administrator for Policy.

[FR Doc. 2012–7084 Filed 3–22–12; 8:45 am]

BILLING CODE 4910–EX–P

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

[Docket No. PHMSA–2012–0039]

Pipeline Safety: Cast Iron Pipe (Supplementary Advisory Bulletin)

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), DOT.

ACTION: Notice; Issuance of Advisory Bulletin.

SUMMARY: PHMSA is issuing an advisory bulletin to owners and operators of natural gas cast iron distribution pipelines and state pipeline safety representatives. Recent deadly explosions in Philadelphia and Allentown, Pennsylvania involving cast iron pipelines installed in 1942 and 1928, respectively, gained national attention and highlight the need for continued safety improvements to aging gas pipeline systems. This bulletin is an update of two prior Alert Notices (ALN–91–02; October 11, 1991 and ALN–92–02; June 26, 1992) covering the continued use of cast iron pipe in natural gas distribution pipeline systems. This advisory bulletin reiterates two prior Alert Notices which remain relevant, urges owners and operators to conduct a comprehensive review of their cast iron distribution pipelines and replacement programs and accelerate pipeline repair, rehabilitation and replacement of high-risk pipelines, requests state agencies to consider enhancements to cast iron replacement plans and programs, and alerts owners and operators of the pipeline safety requirements for the investigation of failures. In addition, the latest survey and reporting requirements of cast iron pipelines required by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 are included for information.

ADDRESSES: This document can be viewed on the Office of Pipeline Safety home page at: *http://ops.dot.gov.*

FOR FURTHER INFORMATION CONTACT: Jeff Gilliam, Director, Engineering and Research, 202–366–0568 or by email at *Jeffery.Gilliam@dot.gov.*

SUPPLEMENTARY INFORMATION:

I. Background

On January 18, 2011, an explosion and fire caused the death of one gas utility employee and injuries to several other people while gas utility crews were responding to a natural gas leak in Philadelphia, PA. A preliminary investigation found a circumferential break on a 12-inch cast iron distribution main that was installed in 1942, and was operating at 17 pounds per square inch gauge (psig) pressure at the time of incident. An investigation continues toward finding the cause.

On February 9, 2011, five people lost their lives and a number of homes were destroyed and other properties impacted by an explosion and subsequent fire in Allentown, PA. A preliminary investigation found a crack in a 12-inch cast iron natural gas distribution main that was installed in 1928, and was operating at less than 1 psig at the time of incident. The crack was located below grade near the destroyed homes. An investigation continues toward finding the cause.

Alert Notice (ALN–91–02)

On October 11, 1991, PHMSA's predecessor agency, the Research and Special Programs Administration (RSPA), issued Pipeline Safety Alert Notice (ALN–91–02) alerting pipeline operators of National Transportation Safety Board recommendation P–91–12 in response to the August 1990 explosion and fire in Allentown, PA, caused by a crack in a 4-inch cast iron gas main. The recommendation stated:

"Require each gas operator to implement a program, based on factors such as age, pipe diameter, operating pressure, soil corrosiveness, existing graphitic damage, leak history, burial depth, and external loading, to identify and replace in a planned, timely manner cast iron piping systems that may threaten public safety."

The Alert Notice informed distribution pipeline operators with cast iron pipe of the following:

—The Gas Piping Technology Committee developed guide material to assist them in developing procedures for determining the serviceability of the cast iron pipe and to identify the cast iron pipe segments that may need replacement.
—Computer programs are commercially available that can be used to develop a systematic replacement program for cast iron pipe.
—Pipeline safety regulations require that cast iron pipe on which general graphitization is found to a degree where a fracture might result must be replaced. In addition, the regulations require that cast iron pipe that is excavated must be protected against damage. An operator's compliance with the above guidelines and code requirements can be enhanced by incorporating all of the operator's cast iron responsibilities in an effective cast iron management program that is designed to identify and replace or remove from service cast iron pipe that may threaten the public.

Alert Notice (ALN–92–02)

On June 26, 1992, RSPA issued a Pipeline Safety Alert Notice (ALN–92–02) as a Supplementary Alert Notice to the 1991 Alert Notice. The Supplementary Alert Notice reminded pipeline operators of the requirement at 49 CFR 192.613 that each operator have a procedure for continuing surveillance of its pipeline facilities to identify problems and take appropriate action concerning failures, leakage, history, corrosion, and other unusual operating and maintenance conditions. This procedure should also include surveillance of cast iron to identify problems and to take appropriate action concerning graphitization.

II. Advisory Bulletin (ADB–2012–05)

To: Each Owner and Operator of a Natural Gas Cast Iron Distribution Pipeline Facility and State Pipeline Safety Representatives.

Subject: Cast Iron Pipe (Supplementary Advisory Bulletin).

Purpose: To Address Continued Concerns Rising Out of Recent Cast Iron Incidents.

Advisory:

On October 11, 1991, Alert Notice (ALN–91–02) was issued reminding all operators of natural gas distribution systems to have a program to identify and replace cast iron piping systems that may threaten public safety. RSPA also informed operators of guidelines and computer programs that were available to help operators determine the serviceability of cast iron pipe and schedule its replacement or retirement. On June 26, 1992, Alert Notice (ALN–92–02) was issued informing pipeline operators that § 192.613 required each operator to have a procedure for continuing surveillance of its pipeline facilities to identify problems and take appropriate action concerning failures, leakage, history, corrosion, and other unusual operating and maintenance conditions. This procedure should also include surveillance of cast iron to identify problems and to take appropriate action concerning graphitization. The two Alert Notices remain relevant, and reaffirm the need for operators of gas cast iron distribution systems to maintain an effective cast iron management program.

PHMSA urges owners and operators to conduct a comprehensive review of their cast iron distribution pipeline systems and replacement programs and to accelerate pipeline repair, rehabilitation, and replacement of aging and high-risk pipe. Recent incidents, such as the deadly explosions in Philadelphia and Allentown, Pennsylvania involving cast iron pipe failures, have focused attention on our Nation's aging pipeline infrastructure and underline the importance of having valid methods for evaluating the integrity of pipelines to better ensure public safety. PHMSA recommends owners and operators of natural gas cast iron pipelines assure their replacement program models are based on relevant risk factors.

In addition, PHMSA reminds owners and operators of cast iron distribution pipelines of their responsibility for the investigation of all failures and that each operator must establish procedures for analyzing incidents and failures, including laboratory examination of failed pipe segments and equipment, where appropriate, for the purpose of determining the causes of the failure and minimizing the possibility of a recurrence [192.617]. Owners and operators are required to review pipeline records, validate safe pipeline operating pressure levels and accelerate repairs and replacement where improvements in safety are necessary. The Distribution Integrity Management Program (DIMP) requires natural gas distribution companies to develop and implement DIMP for the pipelines they own, operate or maintain.

PHMSA is asking owners and operators of cast iron distribution pipelines and state pipeline safety representatives to consider the following where improvements in safety are necessary:

—Request, review and monitor operator cast iron replacement plans and programs, actively encourage operators to develop and continually update and follow their plans, and consider establishment of mandated replacement programs.
—Establish accelerated leakage survey frequencies or leak testing considering results from failure investigations and environmental risk factors.
—Focus pipeline safety efforts on identifying the highest risk pipe.
—Use rate adjustments and flexible rate recovery mechanisms to incentivize pipeline rehabilitation, repair and replacement programs.
—Strengthen pipeline safety inspections, accident investigations and enforcement actions.
—Install interior/home methane gas alarms.

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, was signed into law (Pub. L. 112–90) on January 3, 2012. Section 7 of the new law requires the U.S. Department of Transportation to measure every two years the progress that owners and operators of pipeline facilities have made in adopting and implementing their plans for the safe management and replacement of cast iron gas pipelines. Additionally, not later than December 31, 2013, the Secretary of Transportation must submit to Congress a report that — (1) Identifies the total mileage of cast iron gas pipelines in the United States; and (2) evaluates the progress that owners and operators of pipeline facilities have made in implementing their plans for the safe management and replacement of cast iron gas pipelines.

PHMSA is committed to working with owners and operators of natural gas cast iron distribution pipelines and state pipeline safety representatives to ensure our Nation's pipeline infrastructure is safe and well-maintained.

Issued in Washington, DC, on March 20, 2012.

Jeffrey D. Wiese,

Associate Administrator for Pipeline Safety.

[FR Doc. 2012–7060 Filed 3–22–12; 8:45 am]

BILLING CODE 4910–60–P

DEPARTMENT OF TRANSPORTATION

Surface Transportation Board

[Docket No. FD 35605]

RailAmerica, Inc., Palm Beach Rail Holding, Inc., RailAmerica Transportation Corp., RailTex, Inc., Fortress Investment Group, LLC, and RR Acquisition Holding, LLC—Control Exemption—Wellsboro & Corning Railroad, LLC

RailAmerica, Inc. (RailAmerica), Palm Beach Rail Holding, Inc. (Palm Beach), RailAmerica Transportation Corp. (RTC), RailTex, Inc. (RailTex), Fortress Investment Group, LLC (Fortress), and RR Acquisition Holding, LLC (RR Acquisition) (collectively, RailAmerica *et al.*), have filed a verified notice of exemption to acquire indirect control of the Wellsboro & Corning Railroad, LLC (W&C), a Class III rail carrier, through the acquisition of control of TransRail Holdings, LLC (TransRail), the parent of W&C, by RailTex.

The proposed transaction is scheduled to be consummated on or after April 7, 2012 (30 days after the notice of exemption was filed).

W&C acquired the assets of the Wellsboro & Corning Railroad Co.[1] W&C owns and operates 35.5 miles of track between Wellsboro, PA., milepost 109.90, and Erwin, N.Y., milepost 74.70, in Tioga County, PA., and Steuben County, N.Y. W&C interchanges traffic with the Norfolk Southern Railway Company and the Canadian Pacific Railway Company.

According to the verified notice of exemption, RailTex entered a Unit Purchase Agreement dated January 31, 2012 (the Agreement), with (1) TransRail, (2) Industrial Waste Group, LLC (IWG), (3) Wellsboro & Corning Railroad Co., and (4) A. Thomas Myles III, A. Thomas Myles IV, and William Myles (the MG Principals). The MG Principals own TransRail, and TransRail owns W&C and the successor to IWG. Under the Agreement, RailTex will acquire 100% of the Class A Common Units of TransRail, giving RailTex a 70% ownership interest in TransRail and control of W&C through TransRail.

The MG Principals will retain the Class B Common Units of TransRail, thereby retaining a 30% interest in TransRail, though they will not retain control or the power to control W&C.

Fortress' noncarrier affiliate, RR Acquisition, currently owns about 60% of the publicly traded shares and controls the noncarrier RailAmerica, which directly controls the noncarrier Palm Beach, which directly controls the noncarrier RTC.

RailAmerica states that it controls the following Class III rail carriers: (1) Alabama & Gulf Coast Railway LLC; (2) Arizona & California Railroad Company; (3) Bauxite & Northern Railway Company; (4) California Northern Railroad Company; (5) Cascade and Columbia River Railroad Company; (6) Central Oregon & Pacific Railroad, Inc.; (7) The Central Railroad Company of Indiana; (8) Central Railroad Company of Indianapolis; (9) Connecticut Southern Railroad, Inc.; (10) Conecuh Valley Railway, LLC; (11) Dallas, Garland & Northeastern Railroad, Inc.; (12) Delphos Terminal Railroad Company, Inc.; (13) Eastern Alabama Railway, LLC; (14) Huron & Eastern Railway Company, Inc.; (15) Indiana & Ohio Railway Company; (16) Indiana Southern Railroad, LLC; (17) Kiamichi Railroad Company, LLC; (18) Kyle Railroad Company; (19) The Massena Terminal Railroad Company; (20) Mid-Michigan Railroad, Inc.; (21) Missouri & Northern Arkansas Railroad Company, Inc.; (22) New England Central Railroad, Inc.; (23) North Carolina & Virginia Railroad Company, LLC; (24) Otter Tail Valley Railroad Company, Inc.; (25) Point Comfort & Northern Railway Company; (26) Puget Sound & Pacific Railroad; (27) Rockdale, Sandow & Southern Railroad Company; (28) San Diego & Imperial Valley Railroad Company, Inc.; (29) San Joaquin Valley Railroad Company; (30) South Carolina Central Railroad Company, LLC; (31) Three Notch Railway, LLC; (32) Toledo, Peoria & Western Railway Corporation; (33) Ventura County Railroad Corp.; and (34) Wiregrass Central Railway, LLC.[2]

Further, Fortress, on behalf of other equity funds managed by it and its affiliates, directly controls the noncarrier FECR Rail LLC, which directly controls FEC Rail Corp., which directly controls Florida East Coast Railway, LLC, a Class II rail carrier.

RailAmerica et al. states that: (1) W&C does not connect with any of RailAmerica's subsidiary railroads; (2) the proposed transaction is not part of a series of anticipated transactions to connect W&C and any of RailAmerica's subsidiary railroads; and (3) the proposed transaction does not involve a Class I rail carrier. The proposed transaction is therefore exempt from the prior approval requirements of 49 U.S.C. 11323 pursuant to 49 CFR 1180.2(d)(2).

Under 49 U.S.C. 10502(g), the Board may not use its exemption authority to relieve a rail carrier of its statutory obligation to protect the interests of its employees. Because the transaction involves the control of one or more Class III rail carriers and one Class II rail carrier, the transaction is subject to the labor protective requirements of 49 U.S.C. 11326(b) and *Wisconsin Central Ltd.—Acquisition Exemption—Lines of Union Pacific Railroad*, 2 S.T.B. 218 (1997).

If the verified notice contains false or misleading information, the exemption is void *ab initio*. Petitions to revoke the exemption under 49 U.S.C. 10502(d) may be filed at any time. The filing of a petition to revoke will not automatically stay the effectiveness of the exemption. Petitions to stay must be filed by March 30, 2012 (at least seven days before the exemption becomes effective).

An original and ten copies of all pleadings, referring to Docket No. FD 35605 must be filed with the Surface Transportation Board, 395 E Street SW., Washington, DC 20423–0001. In addition, a copy of each pleading must be served on: Louis E. Gitomer, 600 Baltimore Avenue, Suite 301, Towson, MD 21204.

Board decisions and notices are available on our Web site at *www.stb.dot.gov.*

Decided: March 20, 2012.

By the Board, Rachel D. Campbell, Director, Office of Proceedings.

Raina S. White,

Clearance Clerk.

[FR Doc. 2012–7054 Filed 3–22–12; 8:45 am]

BILLING CODE 4915–01–P

[1] *Wellsboro & Corning R.R.—Acquis. & Operation Exemption—Wellsboro & Corning R.R.*, FD 35595 (STB served Feb. 22, 2012).

[2] On February 3, 2012, in Docket No. FD 35602, RailAmerica et al. filed a petition for exemption from the prior approval requirements of 49 U.S.C. 11323–25 to acquire control of Marquette Rail, LLC, a Class III rail carrier. The Board issued a notice on February 28, 2012, instituting an exemption proceeding pursuant to 49 U.S.C. 10502(b).

DEPARTMENT OF TRANSPORTATION

Surface Transportation Board

[Docket No. EP 290 (Sub-No. 5) (2012–2)]

Quarterly Rail Cost Adjustment Factor

AGENCY: Surface Transportation Board, Department of Transportation.

ACTION: Approval of rail cost adjustment factor.

Commissioners
KEVIN GUNN
Chairman
ROBERT M. CLAYTON III
JEFF DAVIS
TERRY M. JARRETT
ROBERT S. KENNEY

Missouri Public Service Commission

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ROBERT SCHALLENBERG
Director, Utility Services
NATELLE DIETRICH
Director, Utility Operations
STEVEN C. REED
Secretary/General Counsel
KEVIN A. THOMPSON
Chief Staff Counsel

April 12, 2011

Ms. Cynthia L. Quarterman
Administrator
U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration
1200 New Jersey Avenue, S.E.
Washington, D.C. 20590

Dear Ms. Quarterman:

This letter is in response to your March 31, 2011 letter. The Missouri Public Service Commission (MOPSC) significantly enhanced its pipeline safety regulations in December 1989. These enhancements included requirements for operators to establish prioritized replacement programs for unprotected steel mains, cast iron mains, unprotected steel service lines and unprotected steel yard lines. These replacement programs have eliminated substantial amounts of piping with integrity issues and we believe these replacement programs and enhanced requirements have paid tremendous safety dividends over the years. We share your concern for piping whose integrity is still questionable and would like to share with you how far the MOPSC has come in approximately 20 years.

Due to seven natural gas incidents that occurred in Missouri and Kansas in the winter of 1988/1989, which resulted in six fatalities, over a dozen injuries and at least seven structures being destroyed, the Commission took the initiative to develop significant revisions to the Missouri pipeline safety regulations. These new regulations became effective on December 15, 1989. Missouri's regulations on gas safety standards can be found at 4 CSR 240-40.030. The significant changes included:

- Requiring operators to address specific activities in the utilities' operation and maintenance (O&M) plans, and requiring operator personnel to review the plans.

- Requiring the training of operation/maintenance/emergency response personnel, and requiring successful demonstration that all such personnel possess the knowledge and skills needed to perform the assigned tasks (including review of O&M plans).
- Requiring leak detection surveys (with an instrument) on a more frequent basis - 1 year for all unprotected steel transmission pipelines, mains, service lines, and yard lines and 3 years for all other materials.
- Implementing systematic replacement programs and more frequent leak surveys pertaining to non-cathodically protected steel service lines and yard lines.
- Implementing systematic replacement programs (that must be approved by the Commission) for cast iron (CI) mains.
- Implementing systematic replacement and/or cathodic protection programs (that must be approved by the Commission) for non-cathodically protected steel mains.
- Prohibiting the installation of ***customer-owned*** service lines and yard lines.
- Requiring tests/checks of customer's facilities before initiation of service.
- Increasing the requirements for excavator notification to prevent damage to pipelines and for public education to enhance the recognition of and response to natural gas leaks.
- Requiring that all newly installed service regulators have full over-pressure protection.

These revisions to the Commission's gas pipeline safety regulations promoted increased safety on several fronts. First, programs were established to identify existing facilities that were considered as posing a potential safety risk (certain unprotected steel mains, certain cast iron mains, and non-cathodically protected steel service lines and steel yard lines) and to eliminate those facilities in those areas that presented the greatest potential for hazard first. Second, the preparation of a thorough, comprehensive operation and maintenance plan for each operator, coupled with required training of operations personnel, created a better trained workforce. Third, more frequent leak surveys were required to be conducted (with instruments) to enable operators to detect natural gas leaks before they become hazardous. This, in turn, can reduce the potential for problems/errors and enable operators to better identify potential problems on the system and correct them before hazardous situations occur.

The Commission's Pipeline Replacement Programs

Investor-owned and municipally-owned natural gas systems have been required by Missouri PSC regulations for approximately 20 years to accelerate leak surveys and prioritize replacement for piping that has the greatest potential for hazard (integrity issues). The operators must:

- Conduct annual leak surveys and replace unprotected (not protected from corrosion) steel service lines and yard lines.

- Replace cast iron pipelines in those areas that present the greatest potential for hazard in an expedited manner.
- Replace/cathodically protect unprotected steel transmission lines, feeder lines and mains in those areas that present the greatest potential for hazard in an expedited manner.

Results of the Commission's Pipeline Replacement Programs

- Almost 1,100 miles of cast iron mains have been eliminated, leaving approximately 1,200 miles to be replaced.
- Almost 1,100 miles of unprotected steel mains have been eliminated (replaced or protected), leaving approximately 10 miles to be replaced.
- Almost 300,000 unprotected steel service lines and yard lines have been eliminated, leaving approximately 33,150 unprotected steel service lines to be replaced.

Pursuant to previous Commission orders the remaining unprotected steel mains are required to be replaced by 2014 and the remaining unprotected steel service lines are required to be replaced by 2020.

Additional Replacement Programs Required by the Commission

In addition to the regulatory requirements for unprotected steel and cast iron pipelines noted above, the Commission's on-going inspection and investigation activities have identified other specific materials that could present integrity issues, so accelerated leak surveys and replacements were ordered by the Commission, including:

- Annual leak surveys and prioritized replacement of soft copper service lines (Laclede Gas Company...GO-99-155 and GS-2008-0038). The program resulted in over 80,000 soft copper service lines being replaced. The soft copper service line replacement program will be completed in 2011.
- Accelerated leak survey frequency over, and prioritized replacement of, identified older vintage plastic pipe (City Utilities of Springfield...GS-2004-0257). Current on-going program requires annual leak surveys over identified piping and replacement of at least six miles of identified plastic main annually.

Discussions on Aging Infrastructure

The Commission Staff recently recommended a review of the integrity of older cast iron and steel natural gas pipeline facilities in Missouri with the possible goal of initiating specific long-term replacement programs to eliminate significant mileage each year. The Staff has recommended meetings/roundtables with the utilities that have these facilities to discuss the issue of systematic replacement of the aging infrastructure and the impact on rates. There are integrity issues, maintenance issues, service reliability issues and rate issues involved. The issues are not entirely related to safety, but there are also policy decisions that need to be evaluated to determine the implications of continuing to have certain steel piping and cast iron piping in distribution systems 30 years, 40 years or 80 years from now. The Commission will be considering this recommendation in the next few weeks.

The MOPSC has a strong pipeline safety enforcement program and the partnership with PHMSA is an important part of this program. Please feel free to contact the MOPSC if you have questions or concerns.

Sincerely,

Kevin D. [signature]

Kevin Gunn, Chairman
Missouri Public Service Commission

THE MISSOURI PUBLIC SERVICE COMMISSION

PIPELINE SAFETY PROGRAM

REPORT

April 2011

Table of Contents

THE MISSOURI PUBLIC SERVICE COMMISSION
PIPELINE SAFETY PROGRAM

I. EXECUTIVE SUMMARY

This report provides a summary of the Gas Safety Program in Missouri as administered by the Missouri Public Service Commission (Commission). In addition to summarizing the normal activities performed by the Commission's Gas Safety/Engineering Staff (Staff), this report discusses pipeline replacement programs, federal and state safety regulations, and the Commission's enhanced inspection efforts. This report concludes with recommendations to improve the Gas Safety Program in Missouri.

For Calendar Year 2010, Staff conducted 65 comprehensive office and field inspections in jurisdictional systems/inspection units. In addition, some Commissioners, Commission management personnel and Staff participated in special, comprehensive leak surveys in random areas of five of the jurisdictional systems. The surveys found minor above-ground leaks and one non-hazardous underground leak.

Staff filed two motions to establish cases for investigation of gas safety incidents. The first, File No. GS-2011-0245 (established February 3, 2011), was filed in response to a reportable incident[1] that occurred on January 8, 2011, in Pine Lawn, Missouri, an area served by Laclede Gas Company of St. Louis. The second, File No. GS-2011-0248 (established February 7, 2011), was filed in response to a reportable incident that occurred on February 2, 2011, in Kansas City, Missouri, an area served by Missouri Gas Energy. Staff continues its investigation of both incidents.

As explained in more detail throughout the report, Staff makes the following recommendations or observations for improvements to the Gas Safety Program in Missouri.

a. Staff will continue to monitor local distribution companies' (LDCs) and municipal systems' implementation of, and compliance with, the U.S. Department of Transportation – Pipeline and Hazardous Materials Safety Administration Transmission Pipelines Integrity Management Program (Gas IM).

[1] Missouri Reportable Incident is an event that involves a release of gas and involves a death; a personal injury involving medical care administered in an emergency room or health care facility, whether inpatient or outpatient, beyond initial treatment and prompt release after evaluation by a health care professional; or estimated property damage, including cost of gas lost, to the gas operator or others, or both, of ten thousand dollars ($10,000) or more; or an event that is significant, in the judgment of the operator, even though it did not meet the above criteria. (See 4 CSR 240-40.020(4)(A) "Missouri Reporting Requirements")

b. Staff will evaluate operator plans that will be developed and implemented pursuant to the U.S. Department of Transportation – Pipeline Hazardous Materials Safety Administration Distribution Integrity Management Program (DIMP). Once implemented, Staff will continue to monitor the plans, review operations and applicability during inspections and make recommendations for changes in areas that need improvement.

c. Staff recommends the Commission introduce proposed excavation damage prevention legislation to make revisions to Chapter 319 to add provisions related to Commission investigation of possible violations by gas corporations, gas pipelines and municipal gas systems subject to the Commission's jurisdiction for safety purposes and to improve damage notification and reporting efforts.

d. Staff recommends the Commission promulgate rulemakings to adopt amendments to the Federal Pipeline Safety Regulations; require "real-time" reporting of each known "damage event"; require quarterly reporting of excavation notices received from the notification center; require implementation of performance measures applicable to all persons that perform underground facility marking; and require the implementation of quality assurance programs.

e. Reevaluate replacement programs and review older vintage cast iron, natural gas pipeline facilities with the possible goal of initiating specific long-term replacement programs.

f. Create an educational brochure or consumer bill of rights for landowners with property near high consequence area pipelines.

II. PROGRAM OVERVIEW

The Commission has jurisdiction over all intrastate gas pipeline[2] operators in Missouri, which include four intrastate transmission pipelines, seven investor-owned natural gas distribution utilities (six of which also have intrastate transmission pipelines and all of which have multiple operating districts/inspection units), forty-two municipally-owned natural gas distribution systems, one gas distribution system owned and operated by a private company on a Department of Defense facility at Fort Leonard Wood, and three pipeline systems that supply landfill gas (LFG) directly to customers that include a high school, a correctional facility gas-fired electric generation turbine and a large industrial customer. In total, the intrastate gas pipeline operators have 105 "inspection units" for purposes of the natural gas pipeline safety program's annual comprehensive inspection program which include:

[2] "Intrastate gas pipeline" is a pipeline that operates within the State of Missouri borders and links the interstate natural gas pipeline network to local markets (LDCs and municipals).

- 26,682 miles of distribution main
- 693 miles of transmission lines
- 1,505,795 service lines

The Commission does not have jurisdiction over interstate natural gas transmission pipelines[3] or hazardous liquid pipelines. At the end of calendar year 2009, there were 3,858 miles of interstate gas transmission pipelines and 4,800 miles of interstate hazardous liquid pipelines in Missouri.[4] Safety jurisdiction of these pipelines is regulated by the U. S. Department of Transportation - Pipeline and Hazardous Materials Safety Administration (PHMSA).

The Commission's natural gas pipeline safety program is carried out under a cooperative agreement with U. S. Department of Transportation – Pipeline and Hazardous Materials Safety Administration (PHMSA). By participating in the cooperative agreement with PHMSA, the Commission receives grant funding for a significant portion of the Commission's natural gas pipeline safety program expenditures. For instance, the Commission was reimbursed for approximately 40% of costs in Calendar Year 2007 ($285,438) and Calendar Year 2008 ($313,807). Congress appropriated additional funding for the PHMSA pipeline safety grant program, and in Calendar Year 2009 the Commission was reimbursed for almost 70% ($607,271) of the Commission's natural gas pipeline safety program expenditures.

As a part of the natural gas pipeline safety program, the Commission has adopted the applicable federal pipeline safety regulations, including 49 CFR Part 192 that makes up the "minimum" federal safety standards applicable to natural gas pipelines. Additionally, the Commission's gas pipeline safety program undergoes an annual inspection by PHMSA personnel to ensure that the program is being operated in accordance with the federal/state cooperative agreement.

The Commission's gas pipeline safety program is carried out by the Gas Safety/Engineering Section (Gas Safety Section) of the Utility Operations Division's Energy Department. Staff are primarily involved in an on-going field inspection program consisting

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3 "Interstate natural gas transmission pipelines" transport processed natural gas from processing plants in producing regions to areas with natural gas requirements. The pipeline network extends across the country, and is considered the "highway" of natural gas transmission. Natural gas is transported through interstate pipelines at high pressures from 200 to 1500 pounds per square inch (psi).

4 According to information on the PHMSA website.

of comprehensive code compliance inspections of the jurisdictional operators. In addition, Staff conducts operation and maintenance compliance inspections, follow-up inspections, construction inspections and gas incident investigations. Staff also conducts safety-related consumer complaint investigations on an "as needed" basis. The Gas Safety Section consists of eight inspectors and a program manager. All nine of these positions are dedicated 100 percent to the gas pipeline safety program.

In Calendar Year 2009, Staff personnel conducted 75 individual comprehensive annual inspections which included all units of investor-owned utilities and municipal utilities. In addition to the comprehensive inspections, pipeline construction inspections and incident investigations were also conducted. Approximately 650 total Staff field days were spent on these inspections in Calendar Year 2009.

For Calendar Year 2010, Staff conducted approximately 74 comprehensive inspections, as well as follow-up inspections, construction inspections and special leak survey investigations. These inspections/investigations have resulted in Staff being out of the office over 630 days, with about one-third of those days being spent "in the field" physically inspecting pipeline facilities, conducting construction inspections, and verifying leak surveys and leak investigations.

The on-going comprehensive field inspection program is carried out according to an inspection priority list that is updated on an annual basis. The inspection "priorities" are primarily determined by the amount of time that has passed since the last inspection; however, consideration is given to the operator's competence and code compliance history, which could move the operator up on the priority list. The goal of the program is to conduct a comprehensive office and field inspection in each of the jurisdictional systems/inspection units every year.

Staff reports are written subsequent to each gas safety inspection, incident investigation and complaint investigation. Field notes, completed checklists and pertinent operator records are also maintained for these activities. In the event of a gas safety incident, Staff typically files a motion to establish a case for the investigation of the incident. The order opening case directs Staff to complete its investigation within 120 days of the date on which the case is established; however, depending on the circumstances, additional time may be needed. Two such cases were recently filed with the Commission.

1) File No. GS-2011-0245 – Staff filed a motion to establish a case for investigation of a reportable incident that occurred on January 8, 2011, in Pine Lawn, Missouri, an area served by Laclede Gas Company. Staff's initial investigation indicates that natural gas was released from a circumferential fracture in a 2-inch diameter steel main, migrated into the sanitary system and through the soil, and accumulated in the house at 3810 Council Grove Avenue. An explosion and flash fire resulted, causing extensive damage to the property.
2) File No. GS-2011-0248 – Staff filed a motion to establish a case for investigation of a reportable incident that occurred on February 2, 2011, in Kansas City, Missouri, an area served by Missouri Gas Energy. Staff's initial investigation indicates that natural gas was released from a fractured underground transmission line. A passer-by observed the gas, at a pressure of about 220 psig, blowing dirt from above the buried line. There was no fire or explosion.

Probable violations of Commission pipeline safety regulations discovered by Staff during its normal course of business are reported to the operators, who are then responsible for implementing appropriate corrective actions. Staff monitors operators to determine corrective actions are taken in a timely manner. If an operator does not take sufficient corrective action in a reasonable time period, Staff may file a formal complaint with the Commission to resolve the matter. Such complaints generally include a request for a Commission order directing the operator to comply with the rule(s) in question, as well as requesting authority to seek civil penalties from the operator in an appropriate circuit court.

Formal training of Staff is accomplished through attendance at all applicable PHMSA Office of Training and Qualification courses, as well as attendance at numerous other pipeline safety related seminars and/or short courses.

Commission-sponsored public safety education programs, coordinated by Staff, consist of state-wide press releases pertaining to consumer safety tips and radio messages promoting damage prevention efforts and referencing a gas safety website (mosafegas.com).

Staff participates in operator training by presenting seminars in cooperation with the Missouri Association of Natural Gas Operators (MANGO) and the Missouri Association of Municipal Utilities. PHMSA Office of Training and Qualification personnel attend the annual operator training seminars that are hosted by Staff and MANGO.

III. THE COMMISSION'S PIPELINE SAFETY REGULATIONS EXCEED NATIONAL STANDARDS

A. History of Revisions to Missouri's Pipeline Safety Regulations

Due to seven natural gas incidents that occurred in Missouri and Kansas in the winter of 1988/1989, which resulted in six fatalities, over a dozen injuries and at least seven structures being destroyed, the Commission took the initiative to develop significant revisions to the Missouri pipeline safety regulations. These new regulations made Missouri's rules more stringent than the applicable Federal regulations, and became effective on December 15, 1989. Missouri's regulations on gas safety standards can be found at 4 CSR 240-40.030. The significant changes included:

- Requiring operators to address specific activities in the utilities' operation and maintenance (O&M) plans, and requiring operator personnel to review the plans.
- Requiring the training of operation/maintenance/emergency response personnel, and requiring successful demonstration that all such personnel possess the knowledge and skills needed to perform the assigned tasks (including review of O&M plans).
- Requiring leak detection surveys (with an instrument) on a more frequent basis.
- Implementing systematic replacement programs and more frequent leak surveys pertaining to non-cathodically protected steel service lines and yard lines.
- Implementing systematic replacement programs (that must be approved by the Commission) for cast iron (CI) mains.
- Implementing systematic replacement and/or cathodic protection programs (that must be approved by the Commission) for non-cathodically protected steel mains.
- Prohibiting the installation of ***customer-owned*** service lines and yard lines.
- Requiring tests/checks of customer's facilities before initiation of service.
- Increasing the requirements for excavator notification to prevent damage to pipelines and for public education to enhance the recognition of and response to natural gas leaks.
- Requiring that all newly installed service regulators have full over-pressure protection.

These revisions to the Commission's gas pipeline safety regulations promoted increased safety on several fronts. First, programs were established to identify existing facilities that were considered as posing a potential safety risk (certain unprotected steel mains, certain cast iron mains, and non-cathodically protected steel service lines and steel yard lines) and to eliminate those facilities in those areas that presented the greatest potential for hazard first. Second, the preparation of a thorough, comprehensive operation and maintenance plan for each operator, coupled with required training of operations personnel, created a better trained workforce. Third, more frequent leak surveys were required to be conducted (with instruments) to enable operators to detect natural gas leaks before they become hazardous. This, in turn, can reduce the potential for problems/errors and enable operators to better identify potential problems on the system and correct them before hazardous situations occur.

Section 4 CSR 240-40.030(14) prescribes the procedure for the investigation and classification of gas leaks and for scheduling the repair of these leaks. Whenever the operator conducts work on a customer's premise for any type of customer gas service order or call, including all premise odor calls, tests of the subsurface atmosphere must be made.

Class 1 leak is a gas leak which, due to its location and/or magnitude, constitutes an immediate hazard to a building and/or the general public. It shall require immediate corrective action which shall provide for public safety and protect property. Examples of class 1 leaks are: a gas fire, flash or explosion; broken gas facilities; or blowing gas in a populated area. In other words, class 1 leaks could occur from excavator damage to natural gas pipelines or when gas enters a building from company-owned piping.

Class 2 leak is a leak that does not constitute an immediate hazard to a building or to the general public, but is of a nature requiring action as soon as possible. The leak of this classification must be rechecked every fifteen (15) days, until repaired, to determine that no immediate hazard exists. Examples of a Class 2 leak include natural gas leaking underground within five feet of a building or small amounts of natural gas detected in a sanitary sewer.

A follow-up leak investigation shall be conducted immediately after the repair of each Class 1 or Class 2 leak, and continue, as necessary, to determine the effectiveness of the repair and to assure all hazardous leaks in the affected area are corrected.

Class 3 leak is a leak that does not constitute a hazard to property or to the general public but is of a nature requiring routine actions. These leaks must be repaired within five years and be rechecked twice per calendar year, not to exceed six and one-half months, until repaired or until the facility is replaced. A Class 3 leak is any reading of fifty percent or less gas-in-air located between five and fifteen feet from a building Examples of a Class 3 leak include an underground natural gas leak that is located near the street.

Class 4 leak is a confined or localized leak which is completely non-hazardous. No further action is required. An example of a Class 4 leak would be a small amount of natural gas leaking on a shut-off valve in a valve box located near the street.

B. The Commission's Pipeline Replacement Programs

Investor-owned and municipally-owned natural gas systems have been required for over 20 years to accelerate leak surveys and prioritize replacement for piping that has the greatest potential for hazard (integrity issues)[5]. The operators must:

- Conduct annual leak surveys and replace unprotected (not protected from corrosion) steel service lines and yard lines.
- Replace cast iron pipelines in those areas that present the greatest potential for hazard in an expedited manner.
- Replace/cathodically protect unprotected steel transmission lines, feeder lines and mains in those areas that present the greatest potential for hazard in an expedited manner.

1. Results of the Commission's Pipeline Replacement Programs[6]

- Almost 1,100 miles of cast iron mains were eliminated, leaving approximately 1,200 miles to be replaced.
- Almost 1,100 miles of unprotected steel mains were eliminated (replaced or protected), leaving approximately 10 miles to be replaced.
- Almost 300,000 unprotected steel service lines and yard lines were eliminated, leaving approximately 33,150 lines to be replaced.

Pursuant to previous Commission orders, the remaining unprotected steel mains are required to be replaced by 2014 and the remaining unprotected steel service lines are required to be replaced by 2020. There is no requirement to eliminate cast iron mains; however, approximately 15 miles of cast iron main is being eliminated annually state-wide. Please see Staff Recommendation number 4 (Discussions on Aging Infrastructure) on page 26 for further information on addressing cast iron main replacement.

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[5] In 1989, problems on copper service lines had not been identified and there was not a regulation for replacement. Later, after incidents, copper service lines were required to be replaced, but were not part of replacement programs in the PSC Regulations. See section titled Additional Replacement Programs Required by the Commission for discussion on Laclede's copper service line replacement program.

[6] Information from DOT-PHMSA Annual Reports

C. Additional Replacement Programs Required by the Commission

In addition to the regulatory requirements for unprotected steel and cast iron noted above, the Commission's on-going inspection and investigation activities have identified other specific materials that could present integrity issues, so accelerated leak surveys and replacements were ordered by the Commission, including:

- Annual leak surveys and prioritized replacement of soft copper service lines (Laclede Gas Company...File Nos. GO-99-155 and GS-2008-0038). The program resulted in over 80,000 soft copper service lines being replaced. All known soft copper service lines will be replaced in 2011[7].
- Accelerated leak surveys over, and prioritized replacement of, identified older vintage plastic pipe (City Utilities of Springfield...File No. GS-2004-0257). Current on-going program requires annual leak surveys over identified piping and replacement of at least six miles of identified plastic main annually. This will result in indentified, older-vintage plastic pipe being eliminated in approximately 8 – 9 years.

IV. ANNUAL OPERATOR INSPECTION PROCEDURES

Staff conducts annual inspections on all units of investor-owned utilities and on municipal utilities. During these inspections, the records of natural gas operators are reviewed by Staff to verify compliance with pipeline safety regulations. The operators' facilities are also checked to verify information contained in the records. Near the end of each calendar year, Staff compiles a list of inspections to be conducted in the upcoming calendar year. During the actual inspection, the operator's records are reviewed and analyzed for compliance with the Commission's regulations. Staff follows an inspection checklist covering all phases of the operator's operation, maintenance, and emergency response functions, which includes review of proper installation of pipeline marker signs; steel welding qualifications; plastic joining qualifications; installation of excess flow valves; monitoring of corrosion control requirements; pressure testing of pipeline installations; liaison conducted with fire/police/other public officials; operator training requirements; natural gas educational/awareness programs implemented; odor intensity records; patrols of transmission pipelines, leak surveys, regulator station inspections; inspection of critical valves; immediate investigation and proper classification of any leak/odor call; proper monitoring of "active"

[7] NOTE: At this time there are 4 locations where records indicate a copper service line existed, but there are no buildings at these locations. Pursuant to the Commission's February 4, 2011 order in File No. GS-2008-0038, Laclede will conduct annual leak surveys in the general area of the locations until such time it determines the location and proper abandonment of the service lines.

leaks; timely repair of "active" leaks; accuracy of leak detection equipment; records indicating personnel were drug tested; and other records. To verify the accuracy and integrity of the operator's records, Staff also conducts a field investigation as part of the annual inspection. During the field investigation Staff selects facilities at random or based on Staff's decision that further on-site inspection was indicated. The facilities covered during the field inspection include regulator stations, essential valves, corrosion control levels, construction activities, location of line markers, meter-sets, odorant levels, and leak classifications.

V. THE COMMISSION'S ENHANCED INSPECTION PROGRAM

To further investigate and evaluate potential gas safety issues and the processes used to verify information from the operator, members of the Commission envisioned a proactive measure that would give Commission personnel the opportunity to have a more in-depth review of the companies' procedures and gauge the effectiveness of their safety programs. The Chairman[8] asked the operators to comply with a request to conduct special leak surveys over specified areas of several natural gas distribution companies' facilities.

The companies have established leak survey procedures and employees are required to follow operator training requirements. The special, comprehensive leak surveys were a proactive performance measure to verify the leak survey procedures, the ability of the employees performing the leak surveys, and the integrity of the distribution system.

The special leak surveys were coordinated as described below.

- The Chairman and Staff selected a random area of an operator's distribution system to be leak surveyed.
- The Chairman and Staff selected a date the leak survey was to be conducted.
- The Chairman notified the operator approximately five days before the date selected for the survey and instructed the operator on the specific details of the leak survey.
- The Pipeline Safety Regulations require leak detection instruments to be checked for accuracy according to the manufacturer's recommendations or at least once each calendar month. In addition to the required checks, Staff traveled to the operator's office on the day of the leak survey (prior to the start of the special leak survey) and observed the calibration/accuracy checks of leak survey instruments that were to be used during the leak surveys.

[8] For purposes of this report "Chairman" refers to Commissioner Robert M. Clayton, III, Chairman at the time of the report activities and preparation.

- Commission personnel then accompanied operator leak survey personnel and monitored the actual leak survey of all the company-owned natural gas facilities in the selected area.

The leak surveys over company-owned underground facilities also included checks of all of the above-ground piping comprising the meter-set and nearby accessible customer-owned fuel line piping going into the structure. Checks were also made at locations, such as checking the atmosphere in gas, electric, telephone and sewer manholes, telephone pedestals, gas and water valve boxes, water meter wells, cracks in pavement and sidewalks, the base of street signs and other locations that could provide a path for natural gas to migrate to the surface.

Special, comprehensive leak surveys were conducted over facilities of the following natural gas operators.

- AmerenUE (now Ameren Missouri) facilities in Center, MO
- Laclede Gas Company facilities in St. Peters/St. Charles, MO
- Missouri Gas Energy facilities in Kansas City, MO
- Empire District Gas Company facilities in Sedalia, MO
- Atmos Energy facilities in Hannibal, MO

A. Summary of Special Comprehensive Leak Surveys

1. AmerenUE Natural Gas Facilities in Center, MO...July 14, 2010

AmerenUE conducted a leak survey of its natural gas distribution system (mains and service lines) for the entire town of Center, MO and the high pressure feeder line serving the town from the take-point with the interstate transmission pipeline (Panhandle Eastern Pipe Line). The company used personnel and leak detection equipment from its Jefferson City, Wentzville, Columbia, Boonville, Moberly and Mexico offices to perform the leak survey.

Commission personnel monitoring the survey included the Chairman, the Chairman's Chief of Staff, the General Counsel, the Director of Utility Operations, the Manager of the Engineering and Management Services Department, and eight members of the Gas Safety Staff. The survey was also monitored by independent third parties.

Prior to traveling to Center, Staff went to the Jefferson City, Wentzville and Mexico AmerenUE offices to witness accuracy checks of the various leak detection instruments to be used for the survey.

Flame ionization (FI) detectors were checked using gas at a known concentration of 50 parts-per-million (ppm) methane. The Combustible Gas Indicators (CGIs) were checked using gas of known 100% methane concentration and at a second range using gas of known 2.5% methane concentration.

AmerenUE divided its distribution system into ten map grids and assigned a company employee to leak survey each grid of the distribution system and assigned two employees to the feeder line to perform the leak survey. Staff accompanied eight AmerenUE leak surveyors for the duration of the leak survey in the distribution system and Commission management personnel randomly spot checked the various surveys.

The leak survey was performed using FI detectors. Where the FI detectors indicated the possible presence of combustible gas coming from an underground source during the leak survey, AmerenUE used Combustible Gas Indicators (CGIs) to sample the subsurface atmosphere to confirm the presence of natural gas and to classify the leaks in accordance with Missouri Pipeline Safety Regulation, 4 CSR 240-40.030(14). For indications of a potential leak on above-ground piping, such as at customer meter-set piping, AmerenUE used the FI detectors or a soap solution to confirm the location of the leak.

During the leak survey over all of AmerenUE's natural gas facilities in Center, four very small natural gas thread leaks were found on company-owned, above-ground, meter-set piping and one on above-ground, customer-owned piping. All of these small outside leaks were repaired on July 14, 2010, by tightening fittings.

There were three locations where indications of a combustible gas were detectable with a CGI (two underground and one in a sewer manhole). Further investigations were made at the three locations. Those subsequent investigations (excavations at two locations and continued monitoring at the third location) found there were no longer indications of a combustible gas and therefore there was no natural gas leakage at these locations. Follow-up investigations found no indications of combustible gas at the locations.

2. <u>Laclede Gas Company Natural Gas Facilities in St. Peters/St. Charles, MO…October 7, 2010</u>

Staff traveled to Laclede Gas Company's North District Office in Berkeley to witness the accuracy checks of leak detection instruments to be used during the special leak survey in the St. Peters/St. Charles area. Four different types of leak detection instruments were utilized during the inspection. The following list describes the instruments that were used. Laclede personnel and equipment from the North, South and Central Districts were used to conduct the special leak survey.

1) Flame ionization units. There were a total of 18 FI units tested with gas containing 50 parts per million of methane. The instrument was set to sound an alarm and display a full scale reading at 50 ppm.
2) Mobile optical methane detector. Staff witnessed the start-up/calibration sequence to check the accuracy of the optical methane detectors (OMDs) on two mobile leak detection units. These units first display the "normal" occurring level of ppm of methane (which was approximately 10 ppm). Then the instrument is set 10 ppm above that level to give an alarm if methane at a level of 10 ppm above the normal background is detected.
3) Remote methane leak detector. Staff witnessed the start-up/calibration sequence to check the accuracy of the remote methane leak detector (RMLD) unit that was used to detect leakage over the transmission line crossing Interstate 70 and locations where heavy vegetation prevented walking over the line. The RMLD was set to detect a trace amount of natural gas in the form of a gas plume. The RMLD displayed single digit numbers when in the normal survey mode and would display double digit numbers if gas was detected. During the start-up/calibration sequence, the RMLD displayed double digit numbers indicating the detection of gas from the built-in test gas cell.
4) Combustible gas indicator. The fourth type of instrument that may be used in a leak survey is the CGI which is used to classify a leak when the instruments above detect a combustible gas. These instruments are set in a "cradle" and an accuracy/calibration test is run with gas having a known concentration. These tests are conducted monthly and were conducted at the end of September 2010 and/or the first of October 2010. After these monthly tests, all of the testing "cradles" were removed and Laclede was in the process of upgrading them. Laclede was not able to conduct accuracy/calibration checks on these instruments the day of the special leak survey because of the transition to the upgraded testing equipment that was not yet installed.

Following the accuracy checks, Laclede and Commission personnel met at a staging area located in the area selected for the leak survey. There were nine Gas Safety Staff, two Commissioners, the Utility Operations Division Director and numerous Laclede personnel. Commission personnel were "paired up" with Laclede leak survey personnel to: observe the operation of the mobile OMD leak survey; observe the use of the RMLD instrument; accompany Laclede personnel on the walking leak survey over the service lines; and accompany Laclede personnel on the walking leak survey over the mains and transmission pipeline that the mobile truck was not able to cover.

Laclede printed out maps of the area selected for the leak survey. Transmission lines and mains that could be surveyed by the mobile leak detection trucks were identified, as well as the transmission lines and mains that would require a walking survey or use of the RMLD. Service line cards were printed out for each address served by natural gas in the selected area. These service line cards had been "packaged" together in geographic areas and given to the Laclede personnel for the walking leak survey.

Laclede completed a leak survey and patrol over steel supply feeder (SF) mains. These mains, by definition, are treated as transmission lines in the Commission's gas safety program. The leak survey was performed using a combination of equipment. Transmission lines that are accessible from the roadway were leak surveyed using a truck mounted with OMD equipment. Portions of the mains that are not accessible from the roadway were leak surveyed by walking personnel using FI units. Any areas that cannot be driven or walked over were leak surveyed using a handheld RMLD. No leaks were found and no other items requiring follow-up or remedial action were reported.

Laclede completed the leak surveys over all the distribution mains in this area. Distribution mains that are accessible from the roadway were leak surveyed using a truck mounted with OMD equipment. Portions of the mains that are not accessible from the roadway were leak surveyed by walking personnel using FI units. Highway crossings were leak surveyed using the RMLD. No leaks were found during these leak surveys.

There were a total of 767 service lines that were leak surveyed in the leak survey area selected. These served a mixture of residential, commercial, and light industrial accounts. The service lines were either plastic or steel piping. The leak surveys were completed by walking over the service line locations using FI equipment. No underground leaks were found during the special leak survey.

The FI units detect methane at 50 PPM. Due to this sensitivity, a number of indications were found on above-ground meter-set piping. One small leak was found on the customer's above-ground fuel line and the valve on the fuel line was closed and a yellow caution tag was left on the customer's door. There were over 40 locations on company-owned, meter-set piping where small, above-ground leaks were found. These indications were small localized or confined leaks, were considered non-hazardous and were classified as

Class 4 Leaks[9] for which no remedial action is required. A total of nine Class 4 Leaks were at locations such as pressure regulators or public locations where the leak is likely to be reported as a nuisance. In these cases, Laclede's practice is to request service technicians be scheduled to perform remedial action. All other Class 4 Leaks found on company-owned piping during this special leak survey were repaired by the end of the day on October 8, 2010.

3. Missouri Gas Energy in Kansas City, MO...October 28, 2010

On Thursday, October 28, 2010, four Staff traveled to MGE's Central District Office in Kansas City to witness the accuracy checks of leak detection instruments to be used during the special leak survey in the Kansas City area. Two different types of leak detection instruments were utilized during the inspection.

1) Flame ionization units (FI). There were a total of seven FI units tested. One FI unit was used in a mobile leak survey truck for surveying over mains and one FI unit was used by an MGE crew to follow-up on any leak detected by the mobile FI unit. The remaining five units were used by the walking surveyors over service lines. The test was conducted by placing the probe of the instrument in a stream of gas containing 50 ppm of methane. The instrument was set to sound an alarm and display a full scale reading at 50 ppm. These instruments are normally tested monthly and were tested again prior to the leak survey. All but one of the instruments alarmed and displayed a full scale reading during the test. The failed unit was replaced with a unit that tested accurately with 50 ppm test gas.
2) Combustible gas indicator. The second type of instrument that may be used in a leak survey is the combustible gas indicator (CGI) that is used to classify a leak when the instrument above indicates combustible gas is detected. There were a total of seven CGIs tested. One CGI was kept with the mobile leak survey truck and one CGI was used by an MGE crew to follow-up on any leak detected by the mobile truck. The remaining five CGIs were kept with the walking surveyors to follow-up on any leaks they may have detected with their FI unit over the service lines. These instruments were checked for accuracy with known concentrations of test gas. The Lower Explosive Limit (LEL) scale of the instruments was tested with a known concentration of 2.5 percent methane and the 100 percent scale of the instruments was tested with a known concentration of 100 percent methane. These tests are normally conducted monthly and were conducted again prior to the leak survey. All of the CGI units tested accurately with the known concentrations of test gas.

Following the accuracy checks noted above, numerous MGE personnel and the four Staff members proceeded to a staging area located in the area selected for the leak survey. At

[9] Class 4 leak is a confined or localized leak which is completely non-hazardous. No further action is required.

the staging area, Staff was joined by the Utility Operations Division Director and the Chairman.

Four MGE employees conducted the walking leak survey in the area specified, one MGE employee drove the mobile leak survey truck, one MGE employee trailed the mobile truck conducting leak surveys over mains the mobile truck could not reach, and a MGE foreman participated to oversee the work performed on the special leak survey.

Staff members were "paired up" with MGE leak survey personnel to: observe the operation of the mobile leak survey truck, accompany MGE personnel on the walking survey over the service lines and accompany MGE personnel on the walking survey over the mains that the mobile truck was not able to cover. MGE management personnel accompanied MGE leak survey personnel and Staff on the special leak survey. The Chairman also observed the special leak survey process.

Prior to the special leak survey, MGE personnel printed Service Line Survey sheets, copied information for any active Class 3 Leaks[10] and sent the information with the mobile truck, and printed maps for each of the survey groups and pressure system maps.

In the area selected there was cast iron main, protected bare steel main, protected coated steel main, polyethylene mains, and approximately 305 service lines (protected steel and polyethylene). There were four active underground Class 3 Leaks that were checked and detected in the area during the special leak survey. One additional underground Class 3 Leak was found and classified during the survey. In addition, one above-ground Class 4 Leak was found on meter-set piping.

MGE indicated that the five Class 3 underground leaks (four active leaks and one new leak) will have follow-up leak investigations performed, and repairs completed, as required by 4 CSR 240-40.030(14)(C). The one above-ground leak on meter-set piping was repaired the day of the survey by rebuilding the meter-set piping.

[10] Class 3 leak is a leak that does not constitute a hazard to property or to the general public but is of a nature requiring routine actions. These leaks must be repaired within five (5) years and be rechecked twice per calendar year, not to exceed six and one-half (6½) months, until repaired or until the facility is replaced.

4. Empire District Gas Company Natural Gas Facilities in Sedalia, MO...November 11, 2010

Six Staff members traveled to the Empire District Gas office in Sedalia, Missouri to witness the accuracy checks of leak detection instruments to be used during the special leak survey in the Sedalia area. Two different types of leak detection instruments were utilized during the inspection.

1) Flame ionization units (FI). There were a total of three FI units tested. All three units were used by the walking surveyors over service lines and mains. The test was conducted by placing the probe of the instrument in a stream of gas containing 50 ppm of methane. The instrument was set to sound an alarm and display a full scale reading at 50 ppm. These instruments are normally tested monthly and were tested again prior to the leak survey.
2) Combustible gas indicator. The second type of instrument that may be used in a leak survey is the CGI that is used to classify a leak when the instrument above indicates combustible gas is detected. There were a total of three CGI's tested. One unit was unable to be calibrated correctly on the 100 percent scale, and it was not used for the survey. The other two were used with walking surveyors to follow-up on any leaks they may have detected with their FI unit over the service lines or mains. These instruments were checked for accuracy with known concentrations of test gas. The LEL scale of the instruments was tested with a known concentration of 2.5 percent methane and the 100 percent scale of the instruments was tested with a known concentration of 100 percent methane. These tests are normally conducted monthly and were conducted again prior to the leak survey. All of the CGI units that were used during the survey tested accurately with the known concentrations of test gas.

Two Staff members, including the Director of Utility Operations, accompanied each of the Empire leak survey personnel conducting the walking leak survey. During the special leak survey, three Empire employees accompanied by Staff leak surveyed a mostly residential area of Empire's gas distribution system in Sedalia. The survey took approximately four hours and covered over two miles of main and 153 service lines. No underground leaks were found during this survey. Small thread leaks were found on above-ground meter-set piping at two individual residences and two commercial locations. The simple repairs required at these meter-sets were completed November 15, 2010.

5. Atmos Energy Natural Gas Facilities in Hannibal, MO...November 22, 2010

Two Staff members and the Utility Operations Division Director traveled to the Atmos Energy office in Hannibal, Missouri to witness the accuracy checks of leak detection instruments to be used during the special leak survey in the Hannibal area. Staff members were joined at the Atmos office by the Commission Chairman. Two different types of leak detection instruments were utilized during the inspection.

1) Flame ionization units. There were a total of two FI units tested. The two units were used by the walking surveyors over service lines and mains. The tests were conducted by placing the probe of the instrument in a stream of gas containing 50 ppm of methane. The instrument was set to sound an alarm and display a full scale reading at 50 ppm. These instruments are normally tested monthly and were tested again prior to the leak survey.
2) Combustible gas indicator. The second type of instrument that may be used in a leak survey is the CGI that is used to classify a leak when the instrument above indicates combustible gas is detected. The two units were used with walking surveyors to follow-up on any leaks they may have detected with their FI unit over the service lines or mains. The LEL scale of the instruments was tested with a known concentration of 2.5 percent methane and the 100 percent scale of the instruments was tested with a known concentration of 100 percent methane. These tests are conducted monthly.

Following the accuracy checks, Staff and the Utility Operations Division Director were "paired up" with Atmos leak survey personnel to accompany them on the walking survey over the mains and service lines in the selected leak survey area. Atmos management personnel and the Chairman also participated in the leak survey. Atmos personnel had previously printed maps of the area in Hannibal that was selected for the special leak survey and divided the work between two crews.

No underground leaks were found during the special leak survey. There were five small above-ground leaks found on company-owned meter-set piping. Atmos personnel were able to tighten fittings and fix one of the leaks on company-owned piping during the leak survey. Atmos indicates that the four remaining above-ground leaks that were found have also been repaired. The special leak survey covered approximately 3,600 feet of main and 110 service lines. All the mains and service lines in the area surveyed were constructed of polyethylene pipe.

B. Conclusions as a Result of the Commission's Enhanced Inspection Program

During the special leak surveys over the AmerenUE, Laclede, MGE, Empire and Atmos facilities, there were minor above-ground leaks and one non-hazardous underground leak that had not been previously classified by the utility. In the areas surveyed, Staff found nothing that would not have been expected under normal operations. Although facilities appeared satisfactory at the time of inspection, that is not an indication that leaks will not occur in the future or in other locations. Therefore, Staff will incorporate accompanying leak survey personnel on random leak surveys into its annual inspection process.

VI. ADDITIONAL PIPELINE SAFETY REGULATIONS AND EFFORTS

The U. S. DOT-PHMSA has issued Federal Pipeline Safety integrity management regulations to address the integrity of transmission and distribution pipelines. Those programs are described more fully below.

A. Gas Transmission Pipeline Integrity Management Program (Gas IM)11

Transmission pipelines are defined as pipelines that operate at pressures that are equal to or greater than 20 percent of the pressure that would cause the pipeline to yield.

The Gas IM Rule specifies how pipeline operators must identify, prioritize, assess, evaluate, repair and validate the integrity of gas transmission pipelines that could, in the event of a leak or failure, affect High Consequence Areas (HCAs) within the United States. HCAs include certain populated and occupied areas such as neighborhoods, hospitals and shopping areas in close proximity to gas transmission pipelines. The Gas IM regulations and the Commission have placed a high priority on the integrity of gas transmission pipelines in HCAs since a leak or failure in these areas has the potential of impacting a large number of individuals, structures and resources.

The objective of the Gas IM Regulation is to improve pipeline safety through:

- Accelerating the integrity assessment of pipelines in High Consequence Areas;
- Improving integrity management systems within companies;
- Improving the government's role in reviewing the adequacy of integrity programs and plans; and
- Providing increased public assurance in pipeline safety.

Pursuant to the Gas IM Regulation, operators must:

- Provide enhanced protection for defined High Consequence Areas.
- Develop a written Integrity Management Plan for its Integrity Management Program.
- Implement an Integrity Management Program that includes, among other things:
    - Identification of all high consequence areas

[11] Gas Transmission Pipeline Integrity Management Rule (49 CFR Part 192, Subpart O) is incorporated by reference in 4 CSR 240-40.030(16)

- Baseline Assessment Plan (50% was to be completed by 2007, remaining assessment must be completed by December 17, 2012).
- Identification of threats and action taken to address threats.
- Provisions for remediating conditions found during integrity assessments.
- A process for continual evaluation, assessment and preventive measures.

Gas transmission pipeline operators are required to submit semi-annual performance measure reports on their Integrity Management programs, and annual reports on their pipeline infrastructure. PHMSA uses these reports – due at the end of February/August and March 15 respectively – to monitor industry progress in complying with requirements of the Gas IM Rule, to prioritize regulatory inspections, and to respond to inquiries about PHMSA's oversight program. Staff reviews these reports.

These performance measure reports provide information pertaining to operators' Integrity Management Programs, including the amounts of miles inspected and assessed, the operator's repair activities addressing time-sensitive conditions, and the numbers and types of incidents, leaks, and failures occurring in HCA segments of their pipelines.

According to the Calendar Year 2009 report:

- There are 693 miles of natural gas transmission pipelines in Missouri.
- There were 3 leaks on Missouri transmission pipelines in Calendar Year 2009.
- Approximately 80 percent of the required Gas IM assessments have been completed, so operator assessments are ahead of schedule.

B. Distribution Integrity Management Program (DIMP)

PHMSA promulgated a DIMP rule[12] to address lines not included in the Gas IM.

The Distribution Integrity regulations aim to assure pipeline integrity and improve the safety record for the transportation of energy products. Significant differences in system design and local conditions affecting distribution pipeline safety preclude applying the same tools and management practices as were used for transmission pipeline systems. Following a joint effort involving PHMSA, the gas distribution industry, representatives of the public, and the National Association of Pipeline Safety Representatives to explore potential approaches, PHMSA took a slightly different approach for distribution integrity management.

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[12] This final rule amended the Federal Pipeline Safety Regulations to require operators of gas distribution pipelines to develop and implement integrity management programs. The final rule was effective February 2, 2010. (See: 74 FR 63906)

Operators are required to identify and implement measures to reduce risk of failure of their gas distribution pipeline. They must measure performance, monitor results, and evaluate effectiveness including the following metrics:

1. Number of hazardous leaks either eliminated or repaired categorized by cause
2. Number of excavation damages
3. Number of excavation tickets (based on One-Call tickets)
4. Total number of leaks eliminated or repaired, categorized by cause.
5. Number of hazardous leaks eliminated or repaired categorized by material
6. Any additional measures the operator determines are needed to evaluate the effectiveness of the operator's program in controlling each identified threat.

The first four metrics must be reported by the operator to the state pipeline safety authority if a state exercises jurisdiction over the pipeline and to PHMSA.

The regulation requires operators, such as natural gas distribution companies, to develop and implement a written distribution integrity management program plan by August 2, 2011. The DIMP set out the following requirements:

- The operators must demonstrate knowledge of the applicable gas distribution system.
- The operators must identify threats to each gas distribution pipeline.
- The operators must evaluate and rank risks associated with distribution pipelines.
- The operators must identify and implement measures to address risks.
- The operators must measure performance, monitor results, and evaluate effectiveness.
- The operators must perform periodic evaluations of the plan and make improvements as needed.
- The operators must report results on an annual basis to the Commission and the DOT-PHMSA.

Staff will evaluate the DIMP plans, monitor them for reasonableness and accuracy, review operations and applicability during inspections, and make recommendations for changes in areas that need improvement.

C. The Pipeline Inspection, Protection, Enforcement and Safety (PIPES) Act

In 2006, Congress passed the PIPES Act[13], which prescribed nine program elements (9 Elements) that reflect processes and attributes characteristic of comprehensive and effective damage prevention programs based on actions taken in those states with effective damage prevention programs that have successfully reduced the number of damages to underground facilities. The PIPES Act noted that an effective damage prevention program includes:

1. Participation by operators, excavators and other stakeholders in the development and implementation of effective communications from receipt of an excavation notification to successful completion of the excavation.
2. A process for fostering and ensuring the support and partnership of all stakeholders.
3. A process for fostering and ensuring active participation by all stakeholders in public education efforts.
4. A process for reviewing the adequacy of a pipeline operator's internal performance measures and quality assurance programs regarding persons performing locating services.
5. Participation by all stakeholders in the development and implementation of effective employee training.
6. A process for resolving disputes that defines the state authority's role as a partner and facilitator to resolve issues.
7. Enforcement of state damage prevention laws and regulations and the use of civil penalties for violations.
8. A process for fostering and promoting the use of, by all stakeholders, improving technologies that may enhance communications, underground pipeline locating capability and gathering and analyzing information about the accuracy and effectiveness of locating programs.
9. A process for review and analysis of the effectiveness of each program element, including a means for implementing improvements.

In addition to the above 9 Elements, a key aspect of a successful damage prevention program is the collection and analysis of data related to the number and causes of excavation-related damages to underground facilities, with the analysis of the data being used as the basis for enhancements to the overall program, particularly in the areas of educational and enforcement efforts related to the program.

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[13] Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006. Public Law 109-469. 109th Congress. 49 USC 60101. December 29, 2006.

1. Commission Damage Prevention Efforts

In September 2009, Staff presented the Commission with a whitepaper[14] discussing the PIPES Act and discussing changes that might be needed to improve Missouri's damage prevention program. The paper summarized recommended actions, including:

- Place a greater emphasis on damage prevention efforts within Staff for all utilities regulated by the Commission.
- Plan, schedule and conduct stakeholder roundtables/workshops.
- Require reporting of all third-party excavation damages for all underground facility and the creation of a database to store/analyze the data.
- Draft legislation to revise Chapter 319 based primarily on the concepts contained in the 9 Elements, as deemed appropriate and necessary.

As a result of the PIPES Act, and the Commission's concern about the number of excavation damages to natural gas pipelines and other jurisdictional underground facilities[15], the Commission authorized Staff to pursue its recommendations.

Staff has been working with interested stakeholders on draft, proposed legislation to modify the Missouri Damage Prevention Act consistent with the PIPES Act. In October 2009, the Commission established File No. GW-2010-0120 to seek stakeholder input on the draft legislation. This working docket contains background information, drafts of proposed legislation to revise Chapter 319, stakeholder comments in response to the draft legislation and information about roundtables that were held to further discuss various drafts and

[14] See: Motion to Open Repository Docket, Distribution Packet re Proposed Changes to Chapter 319. Docket No. GW-2010-0120. Commission's Electronic Filing and Information System (EFIS) at http://pscprodweb/mpsc/. October 14, 2009.

[15] Each year numerous underground utility facilities are damaged by excavations ranging from homeowner landscaping projects to highway/road construction projects. Damages can cause loss of utility service, can cause significant damage, or can cause injury or death. Damages to underground facilities are considered very serious. Statistics for damages to underground facilities in Missouri include:

- Average number of third-party excavation damages reported for PSC regulated natural gas pipeline systems:
    - Calendar Year 2006 through Calendar Year 2010 – 2,498 annually (about 210 damages/month)
- Average number of third-party excavation damages reported for all PSC regulated underground facility owners (gas, electric, water/sewer and telecommunications):
    - Calendar Year 2006 through Calendar Year 2008 – 11,882 annually (about 1,000 damages/month)

proposals. Roundtables were conducted on October 21, 2009, March 9, 2010, and December 6, 2010, to solicit stakeholder input and were webcast to reach as broad an audience as possible. Consensus was reached on some areas of the proposed legislation, but there were other areas where consensus was not possible. Specific recommendations related to the legislation are discussed below.

2. Grants to Assist Missouri's Damage Prevention Efforts

For the last three years, the Commission has been awarded One Call Grants to enhance public education/awareness about excavation damage prevention in general, and specifically the "Call Before You Dig" message. The education/awareness effort is a radio campaign with excavation safety messages broadcast on radio stations across the state. These radio messages educate the general public and excavators about excavation damage prevention requirements and the importance of calling 1-800-DIG-RITE or "811" before beginning any excavation project. In conjunction with this radio education/awareness project, www.mosafegas.com was developed to provide a resource where consumers can find more information about gas safety and excavation damage prevention.

In September 2010, the Commission applied for a State Damage Prevention Grant to fund a Damage Prevention & Excavation Safety Summit. The plan for the summit is to:

- Provide more than 50 hours of educational instruction designed to familiarize attendees with legally required activities, industry standards and best practices, and pertinent theories to proactively avoid damages.
- Raise awareness of the current state of utility damages and encourage summit participants to implement practices to reduce damages and to educate colleagues, customers, and the general public on the importance of damage avoidance.
- Provide a mechanism for the review and input of the proposed revisions to Missouri Statutes regarding underground utility safety.

VII. STAFF RECOMMENDATIONS TO IMPROVE THE GAS SAFETY PROGRAM IN MISSOURI

As highlighted throughout this Report, the Commission has made several changes to its Gas Safety Program to improve the integrity and safety of gas pipelines in Missouri. For instance, the Commission has directed LDCs to replace various lines and mains and has increased the requirements contained in its pipeline safety rules. However, in an effort to remain proactive, the Commission periodically reviews its current efforts and considers changes to its Gas Safety Program to ensure continued improvement. As part of that effort, the Gas Safety Staff makes the following recommendations for enhancements to the Gas Safety Program.

A. Introduce proposed excavation damage prevention legislation that will make revisions to Chapter 319.

The proposed legislation would support damage prevention by developing a program that incorporates the nine elements of excavation damage prevention outlined in the PIPES Act of 2006. To enhance Missouri's program, the proposed legislation would include provisions related to enforcement efforts and Commission investigation of possible violation by gas corporations, gas pipelines and municipal gas systems subject to the Commission's safety jurisdiction and adds provisions authorizing underground facility owners, excavators and the notification center to submit information to the Commission supporting the investigations. The legislation would also include reporting requirements and would establish requirements pertaining to underground facility locating performance measures and quality assurance programs. A copy of Staff's most recent draft revisions to Chapter 319 are attached as Attachment 1.

B. Promulgate rulemakings to enhance Missouri's gas safety program

a. Commission Adoption of Amendments to the Federal Pipeline Safety Regulations

- Promulgate a rulemaking that will adopt the Federal Annual/Incident Reporting requirements, Distribution Integrity Management Regulation, Control Room Management requirements, and several other amendments to the Federal Pipeline Safety Regulations into the Commission's Pipeline Safety Regulations.

b. Revisions to the Commission's Pipeline Safety Regulations

- Require quarterly reporting to the MoPSC Gas Safety Staff of locations were multiple publicly-reported leak/odor calls have originated from the same location/address.

- Require natural gas operators to report when they are aware that a person required medical attention as a result of the release of natural gas from operator facilities.
- Reduce the time period to repair Class 3 leaks.

C. <u>If damage prevention legislation is not pursued, promulgate rules applicable to Commission-jurisdictional underground facilities owners</u>

a. Require "real-time" reporting of each known "damage event" to a Damage Information Reporting Tool (DIRT) database, a virtual, private database to be established by the Commission with the Common Ground Alliance (Missouri Virtual Private DIRT);

b. Require quarterly reporting of the number and type of excavation notices received from the notification center to the DIRT database established with the Common Ground Alliance (Missouri Virtual Private DIRT);

c. Require the implementation of performance measures applicable to all persons that perform underground facility marking for facility owners;

d. Require the implementation of quality assurance programs to ensure the facility marking performance measures are being met.

D. <u>Discussions on Aging Infrastructure</u>

a. Review of the integrity of older cast iron and steel natural gas pipeline facilities needs to be completed with the possible goal of initiating specific long-term replacement programs to eliminate significant mileage each year. Currently, there are cast iron natural gas pipelines in service in Missouri that were installed well over 100 years ago. Two Missouri natural gas operators have a combined total of over 1,200 miles of cast iron in their distribution systems. The recommendation is for Staff to have meetings with the utilities that have these facilities and discuss the issue of systematic replacement of the aging infrastructure and the impact on rates. There are integrity issues, maintenance issues, service reliability issues and rate issues involved. The issues are related to safety, but there is also a policy decision that needs to be evaluated to determine the implications of continuing to have cast iron piping in distribution systems 30 years or 40 years from now. There should also be a discussion as to how much it will cost to initiate replacement programs for a specified number of years, and the rate implications of such programs. If the current annual replacement rate for cast iron pipelines (the average over the last three calendar years has been approximately 15 miles annually) continues, it would take over 80 years to replace the cast iron pipelines in Missouri, which could result in cast iron piping that is over 200 years old carrying natural gas. Also, older steel pipelines have been involved in the two recent incidents in Missouri. The age of the steel pipeline, by itself, may not be a determining factor. The age, as well as other integrity factors would need to be included in the review.

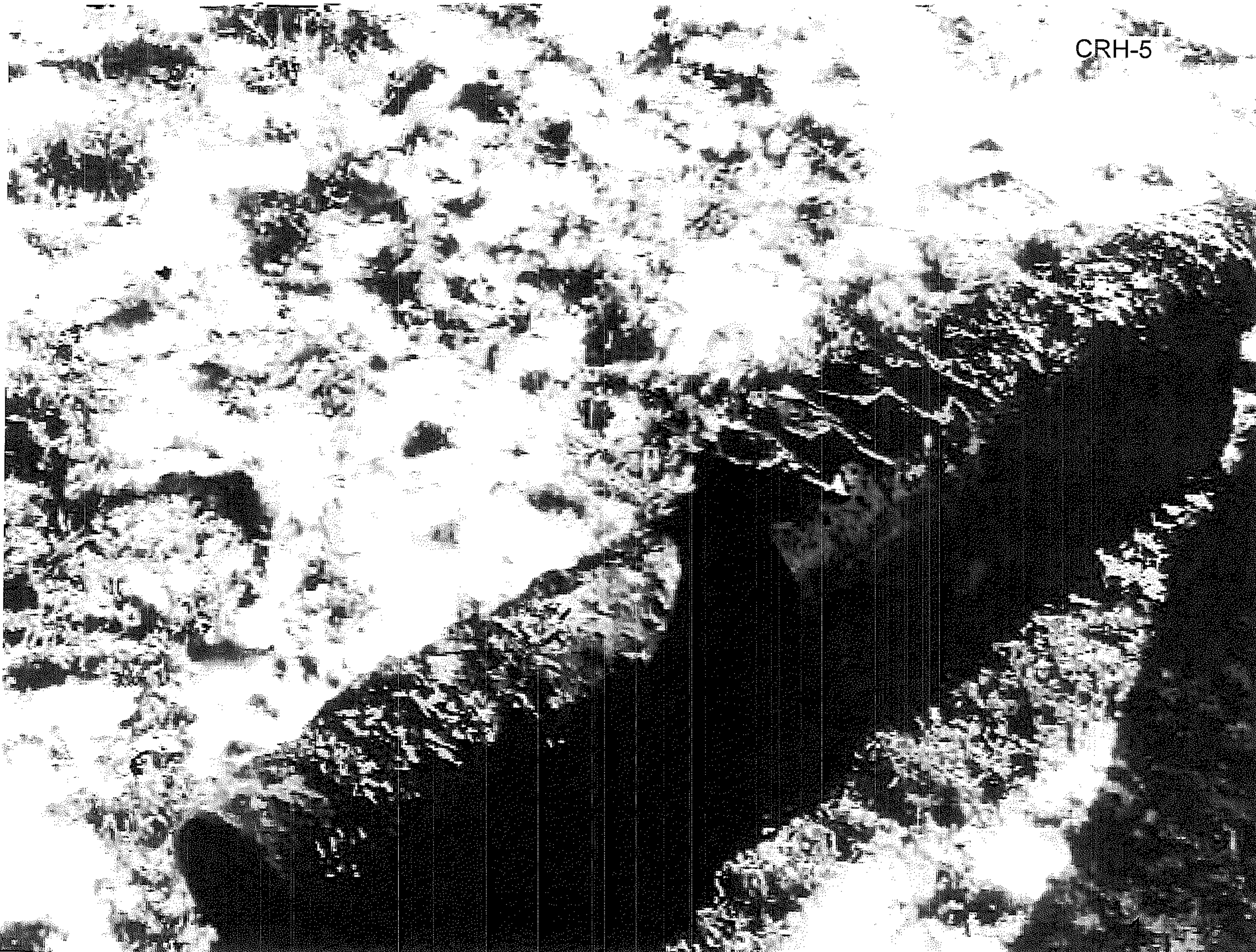
E. **Create an educational brochure or consumer bill of rights for landowners with property near high consequence area[16] pipelines.**

VIII. CONCLUSION

The Commission believes that safety is its highest priority in protecting citizens from hazardous conditions. Major constructive changes in Missouri pipeline safety occurred in the 1990s, which have dramatically improved safety conditions. Additionally, state statutes have been amended modestly increasing the Commission's penalty authority for violations. Because of this work in the past, Missouri is a much safer place. Recent surprise leak survey inspections in the past year have confirmed the integrity of Missouri natural gas transmission and distribution systems.

However, no regulator can rest on past efforts and the Commission believes more can be done to continue improving our natural gas delivery system. Many improvements require increased investment and deeper scrutiny. The Commission will consider and potentially pursue staff's recommendations and closely monitor required utility filings. While the Commission believes Missouri customers are safe from natural gas incidents, it will pursue all cost effective measures by utilities to help make systems even safer. The Commission thanks its staff for its efforts and looks forward to the work that lies ahead.

[16] For definition of high consequence area, see discussion at VI.A, page 26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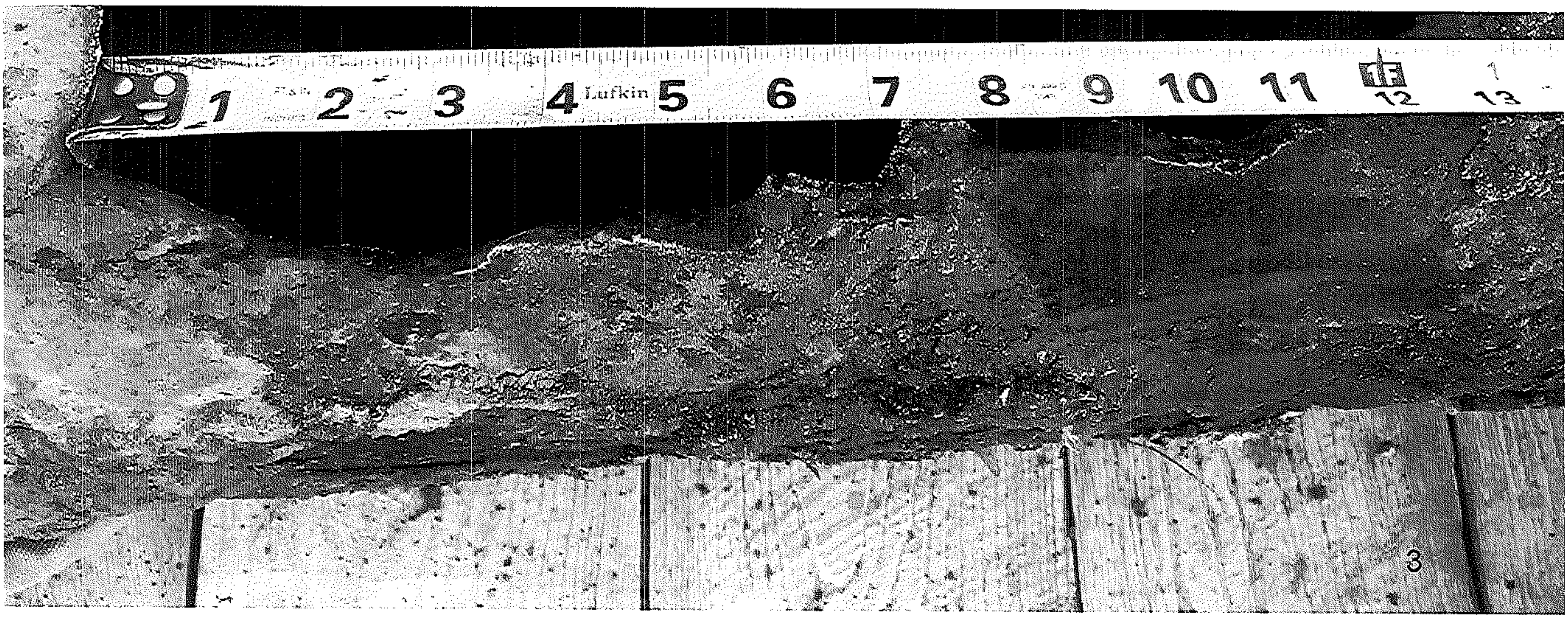
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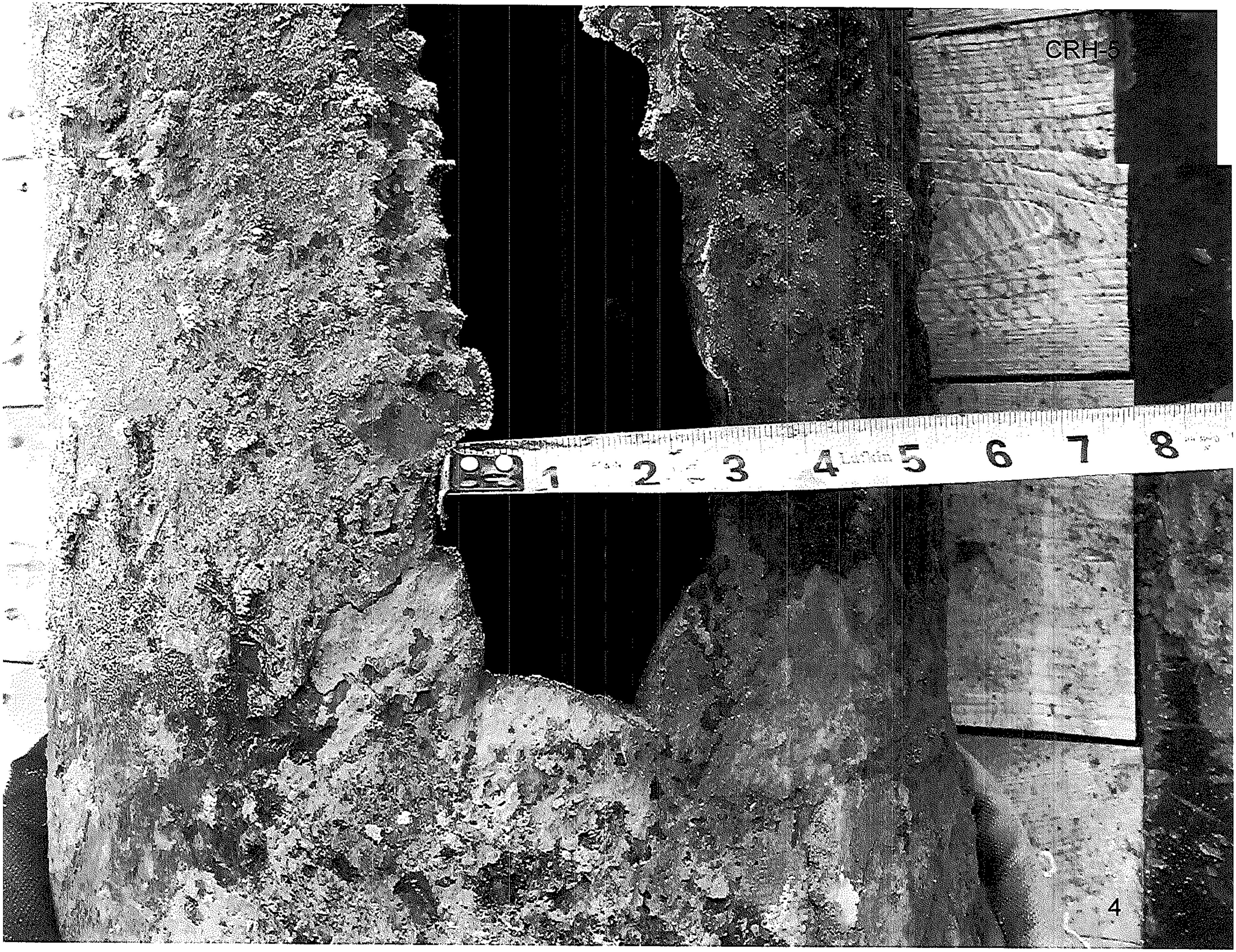
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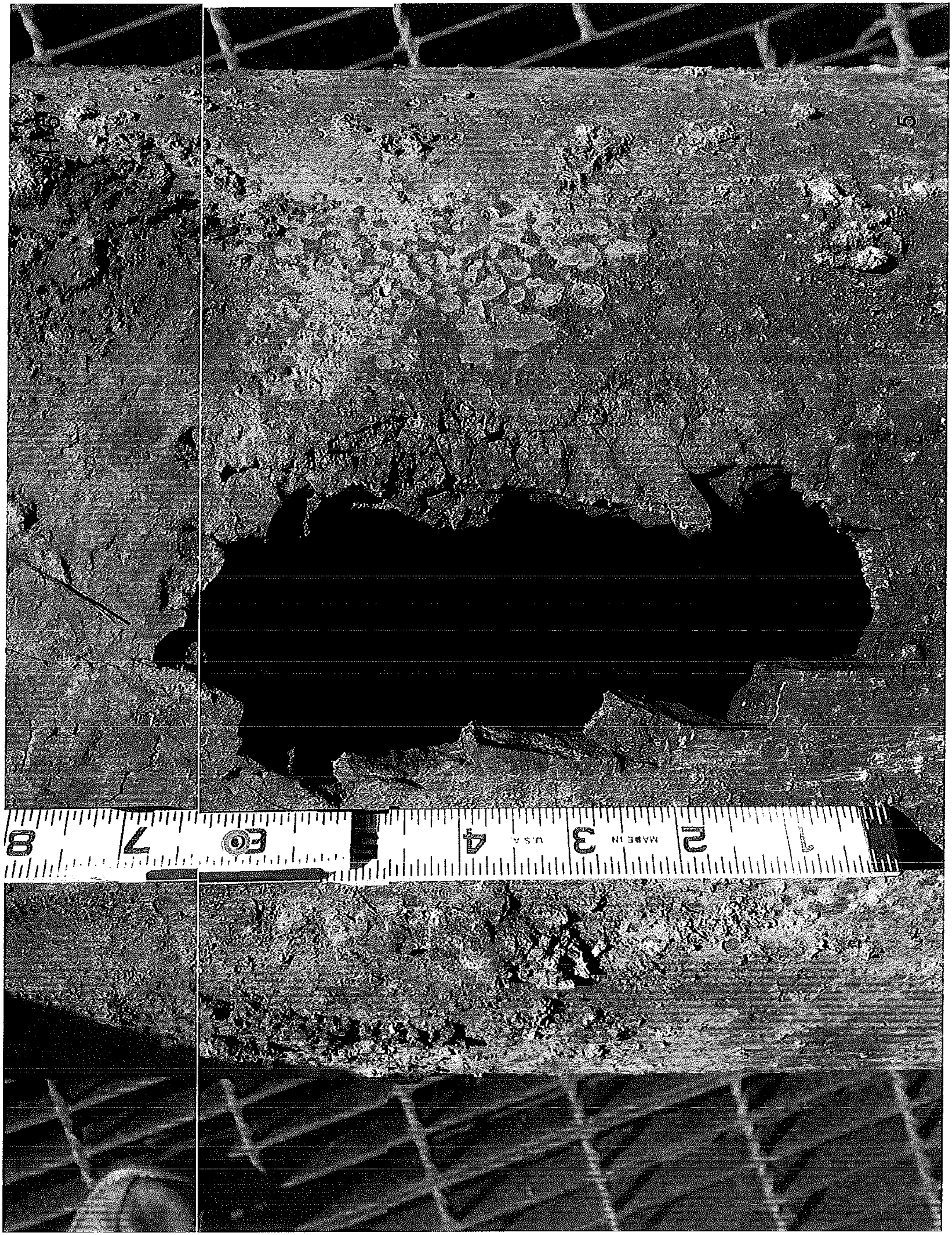

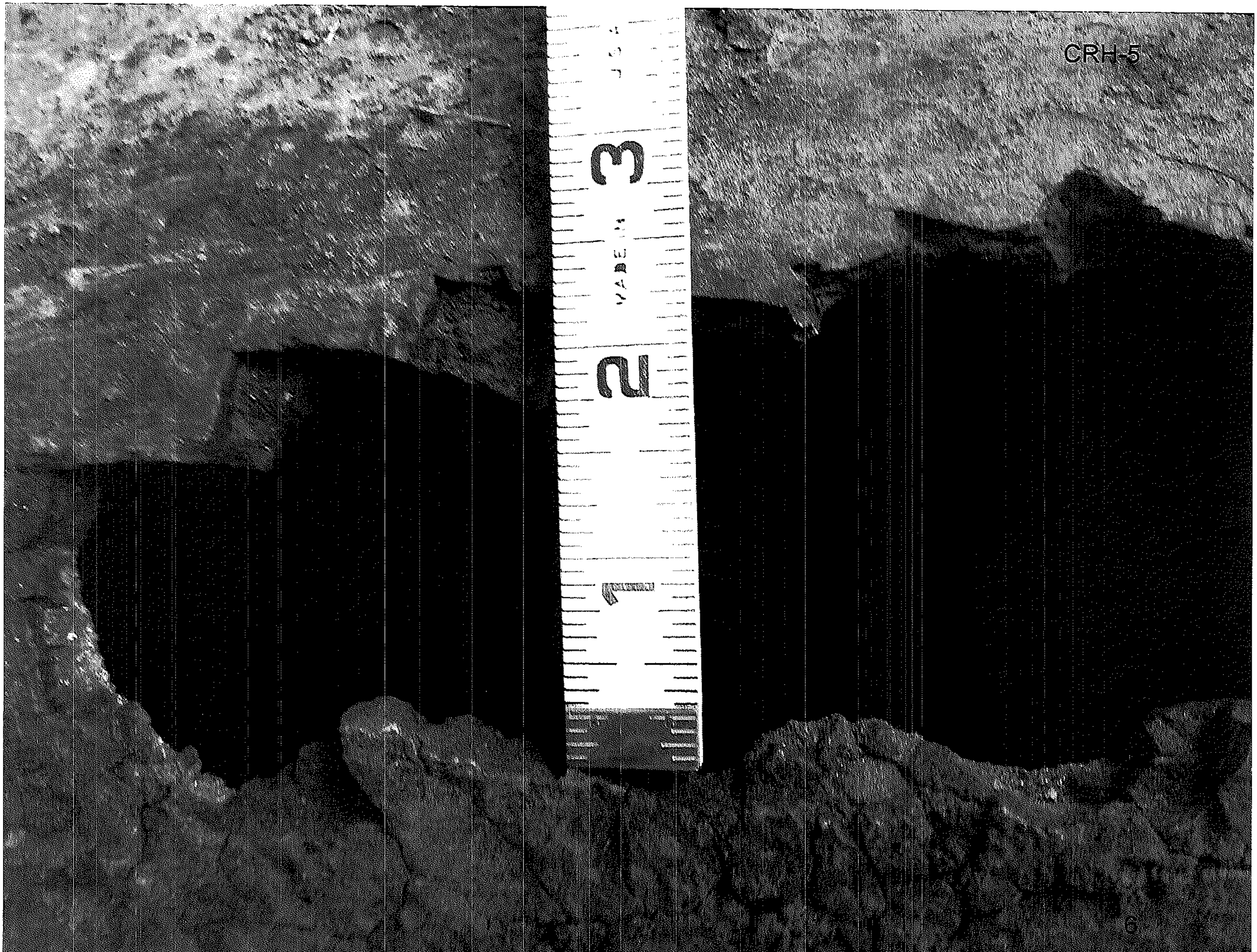
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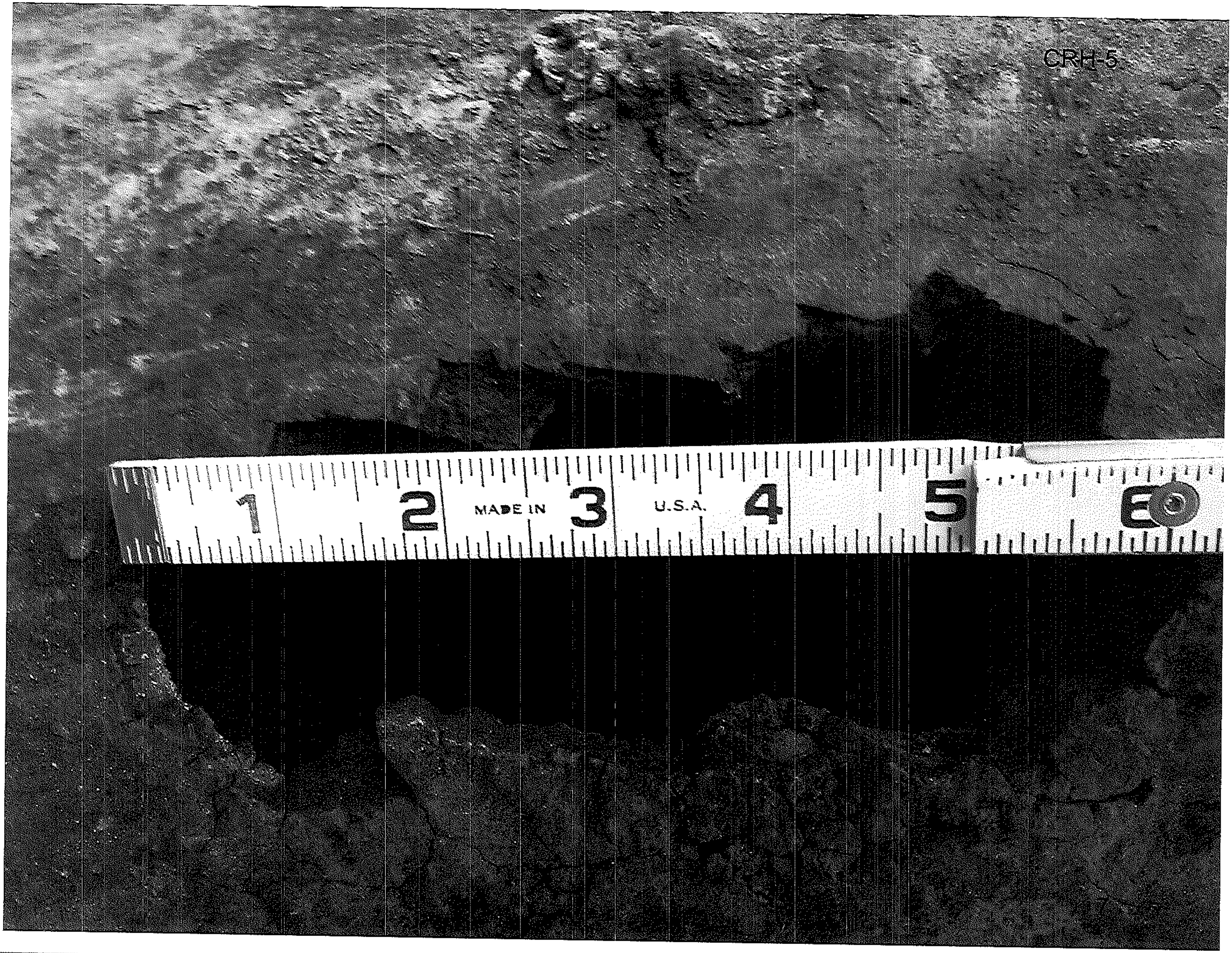
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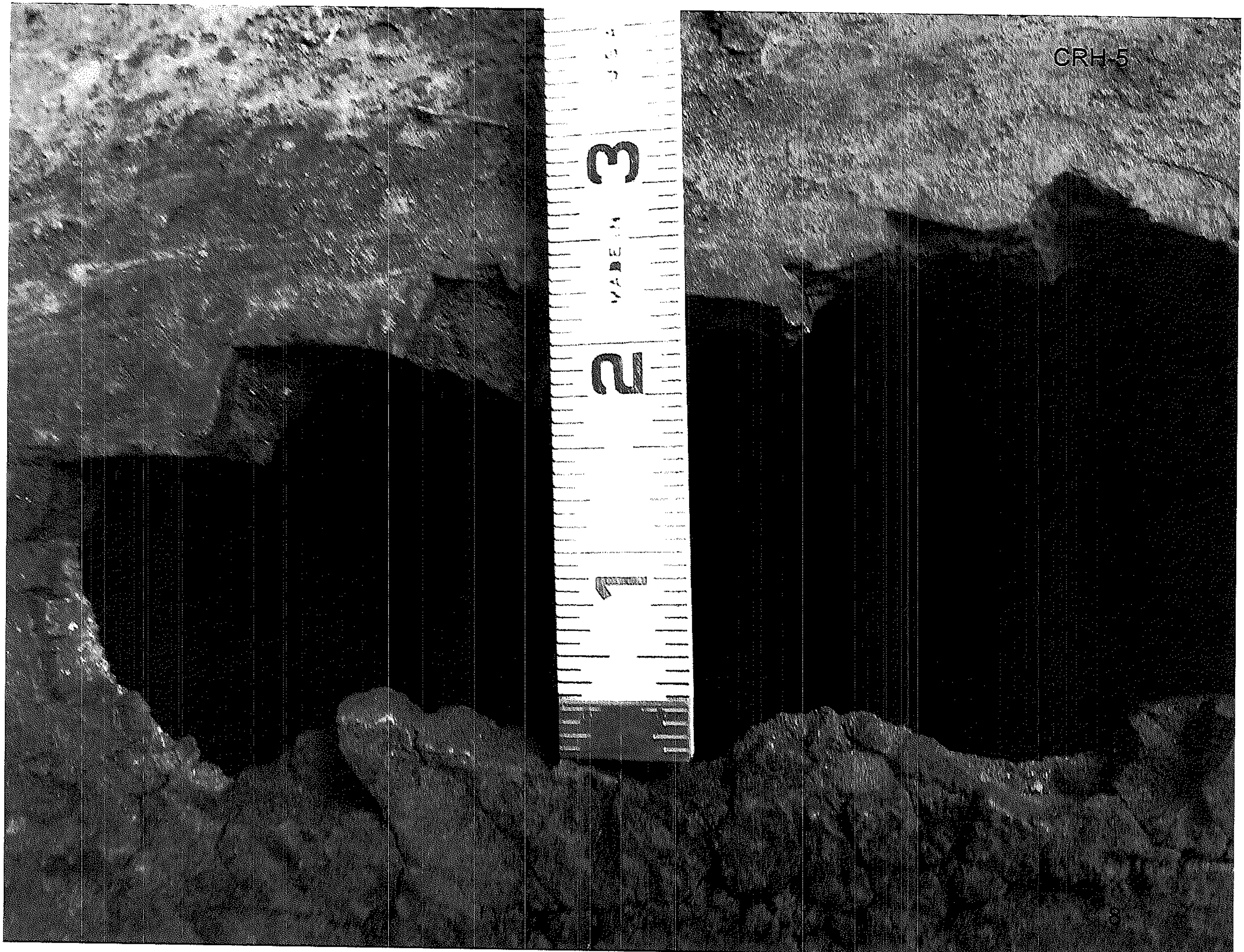
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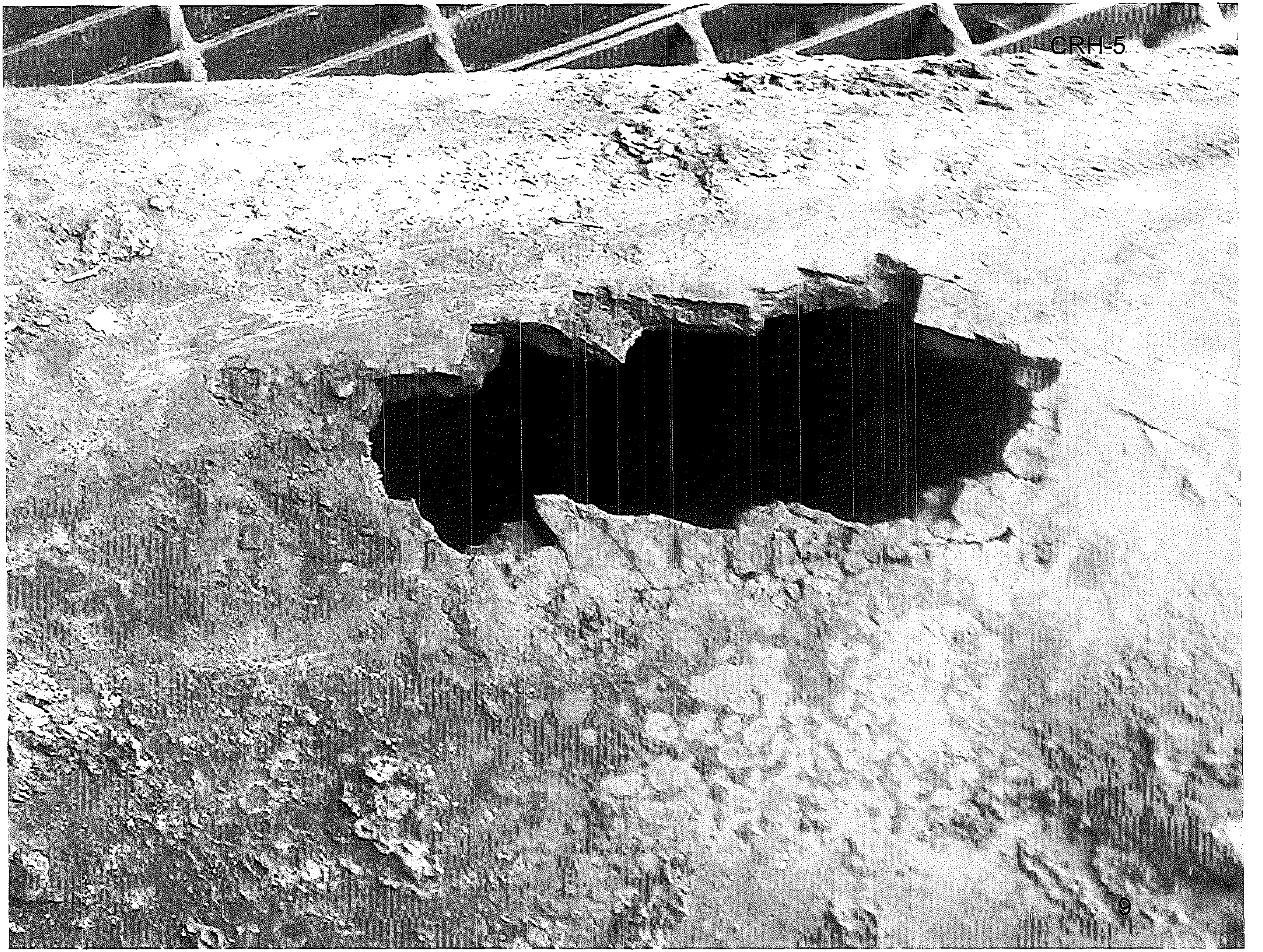
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