STATE OF NORTH DAKOTA

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO., A DIVISION OF MDU RESOURCES GROUP, INC.,FOR AUTHORITY TO ESTABLISH INCREASED RATES FOR NATURAL GAS SERVICES /

Case No. PU-17-295

DIRECT TESTIMONY OF KARL R. PAVLOVIC

Submitted on Behalf of the Advocacy Staff of the North Dakota Public Service Commission

December 18, 2017

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Exhibit PSC-20 - Direct Testimony of Karl R. Pavlovic
Public Service Commission

DIRECT TESTIMONY OF

KARL R. PAVLOVIC

QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Karl Richard Pavlovic. My business address is 22 Brookes Avenue, Gaithersburg, MD 20877. I am a Senior Consultant with and the Managing Director of PCMG and Associates LLC.

Q. PLEASE DESCRIBE PCMG.

A. PCMG and Associates LLC (PCMG) is an association of experts in economics, accounting, finance, and utility regulation and policy, with over 75 years collective experience providing assistance to counsel and expert testimony regarding the regulation of electric, gas, water, and wastewater utilities. PCMG began operation on January 1, 2015. During its most recent year of operation, PCMG has provided assistance to counsel and/or testimony in regulatory proceedings before Federal Energy Regulatory Commission, the Pennsylvania Public Service Commission, the Maine Public Utilities Commission, the Massachusetts Department of Public Utilities, the New Jersey Board of Public Utilities, the Illinois Commerce Commission, the Corporation Commission of Oklahoma, and the Maryland Public Service Commission. PCMG is currently providing assistance to the Illinois Citizens Utility Board, the New Hampshire Office of Consumer Advocate, the Maine Office of the Public Advocate, the Massachusetts Office of the Attorney General, the New Jersey Division of Rate Counsel, the Oklahoma Office of Attorney General, and the Maryland Office of Peoples' Counsel.

Q. HAVE YOU PREPARED A SUMMARY OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. Attachment A to my testimony summarizes my qualifications and experience.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. Attachment A contains a complete list of my engagements as an expert and/or expert witness in matters before state and federal regulatory agencies. I have submitted testimony to the Federal Communications Commission, the Federal Energy Regulatory Commission, the Alaska Public Utilities Commission, the Alberta Utilities Commission, the Corporation Commission of the State of Kansas, the Delaware Public Service Commission, the Pennsylvania Public Service Commission, Illinois Commerce Commission, the Maryland Public Service Commission, the Massachusetts Department of Public Utilities, the North Dakota Public Service Commission, the Maine Public Utilities Commission, and the Public Service Commission of the District of Columbia.

Q. IN WHICH PROCEEDINGS HAVE YOU PREVIOUSLY APPEARED BEFORE THIS COMMISSION?

A. I appeared in Case No. PU-12-813 Application of Northern States Power Company for Authority to Increase Rates for Electric Service in North Dakota regarding cost allocation and rate design on behalf of the North Dakota Public Service Commission Staff.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS?

A. I received undergraduate and graduate degrees in Philosophy from Yale College and Purdue University. By education and professional experience I have expertise in formal and mathematical logic, statistics, economics, financial analysis, econometrics, and computer modeling. I have knowledge and experience in the areas of commercial and industrial operations in the energy, transportation, and telecommunications industries and am familiar with a wide range of experimental and investigative methods in science and engineering.

Q. PLEASE SUMMARIZE YOUR ELECTRIC AND GAS REGULATORY EXPERIENCE.

For most of my career I have performed analyses and submitted testimony regarding electric and gas utility least-cost planning, reliability, cost of service, rate design, and weather-emergency response. Specifically regarding gas regulation, I have testified on: (a) integrated resource planning, (b) cost of service and rate design, (c) accelerated infrastructure replacement programs, and (d) mergers and acquisitions.

I. PURPOSE AND ORGANIZATION

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been asked by the Commission's Advocacy Staff to examine MONTANA-DAKOTA UTILITIES' (MDU) assertions and proposals in this proceeding regarding its class cost of service studies, proposed revenue requirement distribution, and proposed rate design.

Q. HAVE YOU PREPARED ANY EXHIBITS IN SUPPORT OF YOUR RECOMMENDATIONS?

A. Yes. I have included the following four exhibits:

Exhibit No. KRP-1: "Natural Gas Infrastructure Modernization Programs at Local Distribution Companies: Key Issues and Considerations," Office of

	Energy Policy ad Systems Analysis, U.S. Department of Energy, January 2017;
Exhibit No. KRP-2:	System Safety and Integrity Program (SSIP) Estimated Investment and Revenue Requirement;
Exhibit No. KRP-3:	Statement N Rate Design: Mains Demand Cost Study and Recommended $1,998,969 Revenue Increase;
Exhibit No. KRP-4:	Statement N Rate Design: Minimum System Cost Study and Recommended $1,998,969 Revenue Increase.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into sections. In Section A, I address MDU's proposed System Safety and Integrity Program (SSIP) as presented in the direct testimony and exhibits of Nicole A. Kivisto, Patrick C. Darras, Stephanie Bosch, and Travis R. Jacobson.[1] In Section B, I address MDU's depreciation study and proposed depreciation rates as presented in the direct testimony and exhibits of Earl M Robinson.[2] In Section C, I address MDU's class cost of service study, proposed class revenue requirement, and tariff rates as presented in the direct testimony of Jordan R. Hatzenbuhler.[3] In Section D, I recalculate MDU's tariff rates consistent with the revenue requirement proposed by Advocacy Staff Witness Mugrace and my recommended revisions to MDU's class cost of service study, class revenue requirement distribution, and rates.

II. SUMMARY OF TESTIMONY AND CONCLUSIONS

[1] Kivisto Direct, page 7, line 14 to page 10, line 7; Darras Direct, page 13, line 15 to page 34, line 6; Bosch Direct, page 3, line 17 to page 7, line 6 and Exhibit Nos. SB1 and SB2; Jacobson Direct, page 23, line 13 to page 25, line 2, Statement L and Exhibit No. TRJ-3.

[2] Robinson Direct, page 11, line 3 to page 28, line 7 and Exhibit No. EMR-1 "Depreciation Report."

[3] Hatzenbuhler Direct, page 2, line 19 to page 12, line 10, Statements M and N, and Exhibit Nos. JRH-1 and JRH-2.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony finds the following.

- MDU's proposed System Safety and Integrity Program (SSIP) lacks (1) a clearly articulated plan laying out the timetable, performance metrics, and project selection process for the replacement of eligible infrastructure, (2) a well-defined cost recovery mechanism, (3) a demonstration of customer benefit, and (4) a demonstration that the program is the least-cost option for achieving that customer benefit.
- MDU has not demonstrated that its 2018 SSIP infrastructure replacement projects will replace infrastructure that is "known for higher risks as identified by the Company's Distribution Integrity Management Plan."
- The depreciation rates proposed by MDU are well supported by MDU's depreciation studies of its distribution and common plant accounts.
- If the Commission does not accept MDU's use of the minimum system approach, I recommend that MDU's demand allocator be used to allocate 100 percent of mains costs in the cost study for this proceeding
- MDU proposes to use the fair return standard to distribute the revenue requirement increase and apply the full customer cost rate design principle.

I recommend that the Commission:

- Direct MDU to remove from the 2018 Test Year in this proceeding $5,553,154 Plant in Service investment for 2018 SSIP projects;
- Accept MDU's depreciation study and proposed depreciation rates;

- Give consideration to the rate for Residential and Firm General Service customers calculated in Exhibit No. KRP-3 and Exhibit No. KRP-4.

III. DISCUSSION

A. SYSTEM SAFETY AND INTEGRITY PROGRAM (SSIP)

Q. PLEASE PROVIDE REGULATORY CONTEXT FOR MDU'S SSIP?

A. MDU's proposed System Safety and Integrity Program (SSIP) is similar in concept to infrastructure replacement programs that were first implemented on natural gas systems with cast iron, wrought iron, and non-cathodically protected steel (bare or coated) infrastructure following two catastrophic gas incidents that Ms Kivisto references in her direct testimony.[4] In some jurisdictions infrastructure replacement programs have been implemented by expanding and accelerating existing gas utility safety- related replacement programs on approval by state regulatory authorities. In most cases infrastructure replacement programs have been implemented and operate under regulations established by state regulatory authorities, often pursuant to an enacted statutory mandate.

The regulations for infrastructure replacement programs set forth (1) the specific parameters of the program and (2) the mechanism by which prudently incurred costs for used and useful facilities will be recovered. Program parameters typically specify

- the elements to be contained in the program plan,
- demonstrations required for regulatory approval of the program plan,
- criteria for eligible infrastructure under the program,
- process for selecting and scheduling,

[4] Kivisto Direct, page 8, lines 14-18.

- minimum/maximum pace of recovery on the plan,
- caps on annual investment and/or recoverable revenue, and
- performance metrics.

Recovery mechanisms define

- the components of the revenue requirement calculation for recovery of the eligible costs (rate base, expenses, taxes and return),
- the timing of recovery relative to the time of replacement,
- the true-up of actual costs to projected costs, and
- the tariff rate design and calculation.

I have attached as Exhibit No. KRP-1 a January 2017 US Department of Energy publication that provides the history and current status of accelerated replacement programs in the states that have implemented such programs.[5]

Q. WHAT ARE THE PRIMARY PURPOSES OF INFRASTRUCTURE ACCELERATED REPLACEMENT PROGRAMS?

A. The primary purposes of infrastructure replacement programs are (1) to accelerate the replacement of targeted infrastructure for safety or reliability purposes and (2) to accelerate gas utility infrastructure cost recovery outside of base rate proceedings.

Q. PLEASE PROVIDE AN OVERVIEW OF MDU'S SSIP?

A. Ms Kivisto states in her testimony that MDU's SSIP is a program to accelerate the replacement of "Early Vintage Steel Pipe, Early Vintage Plastic Pipe, Low Pressure

[5] "Natural Gas Infrastructure Modernization Programs at Local Distribution Companies: Key Issues and Considerations," Office of Energy Policy and Systems Analysis, U.S. Department of Energy, January 2017

Systems and the relocation of inside meters ... that are known for higher risks as identified by the Company's Distribution Integrity Management Plan (DIMP)."[6]

MDU's plans for implementation of the SSIP are set forth in two documents provided in response to discovery: "Low-Pressure Replacement Plan (Pre-1970)"[7] and "North Dakota Aldyl-A Replacement Project (Pre- & Post-1982)."[8]

The schedule for implementation of the two plans is:

- 2018 - projects replacing (1) low pressure steel mains and services, regulator stations and inside meters in New Salem, Taylor, Bismarck and Mandan and (2) Aldyl-A plastic mains and services, regulator stations and inside meters in Barlow, Cleveland and Eldridge at an estimated total plant in service investment of $5,557,718 and a revenue requirement of $386,787;[9]
- 2019 - unspecified projects replacing unspecified mains, services, inside meters and regulator stations at an estimated total plant in service investment of $6,000,000 and a revenue requirement of $856,289;[10]
- 2020-20?? - unspecified projects replacing unspecified mains, services, inside meters and regulator stations at an unspecified pace and an estimated total plant in service investment of $205,083,285.[11]

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6 Kivisto Direct at 8, lines 8-13.
7 Response No. 2.5 Attachment A.
8 Response No. 2.5 Attachment B.
9 Response No. 2.5 Attachment C and Exhibit No. TRJ-3, pages 4-5. See Exhibit No. KRP-2
10 Jacobson Direct, page 23, lines 13-19 and Exhibit No. TRJ-3. See Exhibit No. KRP-2.
11 Response No. 2.5 Attachment s A (.3), B(p. 5) and C and Exhibit No. TRJ-3. See Exhibit No. KRP-2.

The SSIP recovery mechanism (SSIP Program Adjustment Mechanism)[12]consists of annual filings[13] of (1) a projected revenue requirement calculation,[14] (2) a true-up calculation,[15] and (3) tariff rate adjustment charge.[16] MDU proposes to make the first annual filing in Spring 2019 covering projected 2019 projects and costs. The 2019 annual filing will include a true-up of the 2018 actual SSIP projects and costs to the projected 2018 SSIP projects and costs that are contained in the calculation of base rates in this proceeding.[17]

Q. HOW DOES MDU'S SSIP COMPARE TO INFRASTRUCTURE REPLACEMENT PROGRAMS IN OTHER JURISDICTIONS?

A. MDU's SSIP lacks (1) a clearly articulated plan laying out the timetable, performance metrics, and project selection process for the replacement of eligible infrastructure, (2) a well-defined cost recovery mechanism, (3) demonstration of customer benefit, and (4) a demonstration that the program is the least-cost option for achieving that customer benefit.

Q. WHY DO YOU SAY THAT THE SSIP LACKS A CLEARLY ARTICULATED PLAN?

A. MDU has submitted the two plan documents I referenced earlier. I will address each in turn. The SSIP's "Low-Pressure Replacement Plan (Pre-1970)"[18] consists of a single page executive summary stating broadly the safety risks addressed, maps and estimated cost summaries for each of 10 low pressure systems targeted for replacement in the plan, six-years of historical leak data for each of the 10 targeted systems, and the detailed costs used

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[12] Bosch Direct, page 4, line 9 to page 5, line14 and Exhibit No. SB-I (Rate 94).
[13] Exhibit No. SB-1, page 1, Section 2.
[14] Exhibit No. SB-1, page 1, Section 1, Jacobson Direct, page 23, line 13 to page 24, line 16, and Exhibit No. TRJ-3.
[15] Jacobson Direct, page 24, line 17 to page 25, line 2, Exhibit No. SB-1, page 1, Section 3, and Bosch Direct, page 4, lines 12-16.
[16] Bosch Direct, page, line 17 to page 5, line 14, Exhibit No. SB-1, page 1, Section 4 and page 2, Section 5, and Exhibit No. SB-2.
[17] Bosch Direct, page 6, lines 18-20.
[18] Response No. 2.5 Attachment A.

to calculate the costs for each of the 10 targeted systems. The plan contains no timetable for implementation, no project selection process, no metrics by which to measure implementation of the plan, no demonstration of the benefit to be derived, and no demonstration that the plan represents the least-cost option to achieve the benefit. The SSIP's "North Dakota Aldyl-A Replacement Project (Pre- & Post-1982)"[19] consists of a single page executive summary stating broadly the safety risks addressed, maps and estimated cost summaries for each of the 75 North Dakota Aldyl-A plastic pipe replacements targeted for replacement in the plan, a summary table of quantities and estimated costs for the 75 replacements, and the unit costs used to estimate the costs for each of the 75 replacements. As with the low pressure plan, the Aldyl-A plan contains no timetable for implementation, no project selection process, no metrics by which to measure implementation of the plan, no demonstration of the benefit to be derived, and no demonstration that the plan represents the least-cost option to achieve the benefit.

Q. THESE DEFICIENCIES NOTWITHSTANDING, IS IT POSSIBLE TO ASSESS THESE TWO PLANS BASED ON THE SSIP'S ELIGIBILITY CRITERIA?

A. Yes. The criteria of eligibility for MDU's SSIP are articulated by Ms Kivisto:[20] Early Vintage Steel Pipe, Early Vintage Plastic Pipe, Low Pressure Systems and the relocation of inside meters identified as high risk as identified by the Company's Distribution Integrity Management Plan (DIMP) and the eligibility of both the specific type and specific locations of the infrastructure targeted can be assessed as to the level of risk identified in MDU's DIMP.[21]

[19] Response No. 2.5 Attachment B.
[20] Kivisto Direct at 8, lines 8-13.
[21]

Q. HAS MDU DEMONSTRATED THAT THE TYPES OF INFRASTRUCTURE TARGETED IN MDU'S TWO REPLACEMENT PLANS ARE IDENTIFIED AS HIGH RISK BY MDU'S DIMP?

A. No. The specific types of infrastructure identified as eligible by Ms Kivisto, viz. early vintage steel pipe, early vintage plastic pipe, low pressure systems, and inside meters, are not identified or ranked as specific threat risks in MDU's DIMP.[22] As a component of its DIMP, MDU has constructed a GIS based model of its system[23] that, in addition to the location of components on the system, also includes information concerning the vintage, material type, potential threat type[24] and risk scores.[25] Regarding steel pipe, bare steel is listed as a threat and included in the model and all steel pipe, whether bare, coated or protected, is risk scored based on vintage age. Regarding plastic pipe, pre-1974 vintage Aldyl-A is listed as a threat, included in the model and risked scored based on pre- or post 1974 vintage. Regarding low pressure systems, no specific threat is listed or included in the model, but system over pressure is listed as a threat, but not included in the model due to a lack of data. Regarding meters, inside meters are listed as a threat, included in the model, and risk scored on that basis. Regarding infrastructure generally, corrosion is listed as a threat but not included in the model due to lack of data; leaks & repairs are listed as a threat, included in the model, and risk scored based on the cause of the leak with no distinctions drawn between hazardous and non-hazardous leak classes.[26]

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[22] Response Nos. 3.2 Attachment A (DIMP) and 5.6 Attachment D (DIMP App. E), page 2, Table E3.1, "MDU Threat Risk and Ranking."
[23] Response No. 3.2 Attachment A (DIMP), Section 4.2.
[24] Response No. 5.6 Attachment B (DIMP App. C), page 2, Table C4.1 Potential Threats.
[25] Response No. 5.6 Attachment C (DIMP App. D), Section 4.2.
[26] Class 1 leaks represent an existing or probable hazard to persons or property and require immediate repair; Class 2 leaks are non-hazardous at the time of detection, but require scheduled repair based on probable future hazard; Class 3 leaks are non-hazardous at the time of detection and can reasonably expected to remain non-hazardous.

Q. HAS MDU DEMONSTRATED THAT THE INFRASTRUCTURE AT THE LOCATIONS TARGETED IN MDU'S LOW PRESSURE REPLACEMENT PLAN ARE IDENTIFIED AS HIGH RISK BY MDU'S DIMP?

A. No. With regard to the Low Pressure Replacement Plan, MDU has not demonstrated that the targeted low pressure systems are high risk as a consequence of operating at low pressure. MDU has also not demonstrated that the targeted low pressure systems are at high risk due to the quantity of early vintage steel in the system or a high percentage of leaks and repairs on the pipe sections (of any material or vintage) due to corrosion or material failure. Further, the replacement of inside meters with outside meters does not require the replacement of the entire low pressure system on which the inside meters are located.

Q. HAS MDU DEMONSTRATED THAT THE INFRASTRUCTURE AT THE LOCATIONS TARGETED IN MDU'S ALDYL-A REPLACEMENT PLAN ARE IDENTIFIED AS HIGH RISK BY MDU'S DIMP?

A. No. With regard to the Aldyl-A Replacement Plan, MDU has not demonstrated that the targeted replacements are high risk. The executive summary of the plan notes that Aldyl-A pipe manufactured using certain identified resins is prone to brittle-like cracking under stress citing a 1998 NTSB Special Investigation Report and then goes on to state that MDU's model is missing material information regarding Aldyl-A and therefore the replacement plan assumes that all plastic pipe installed prior to 1988 is Aldyl-A and will be replaced.[27] As noted above, MDU's model only identifies pre-1974 vintage Aldyl-A as a threat that is risk scored. Thus, MDU is unable to identify the segments of their system that are at risk due to the composition of the pipe and instead makes a sweeping assumption as to the portions of

[27] Response No. 2.5 Attachment B, page 5.

its system that are high risk and require replacement, wholly unsupported by its risk model. Moreover, independent of pipe composition, MDU has also not demonstrated, that the targeted replacements are at high risk due to a high percentage of leaks and repairs on the pipe sections (of any material or vintage) due to material failure or any other cause.

Q. WHAT DO YOU CONCLUDE REGARDING THE TWO REPLACEMENT PLANS?

A. I conclude that both the Low Pressure Replacement Plan and the Aldyl-A Replacement Plan fail to satisfy the SSIP's eligibility criteria and should not be approved for recovery via the SSIP cost recovery mechanism.

Q. WHAT IS YOUR CONCLUSION REGARDING RECOVERY THROUGH BASE RATES OF THE COSTS OF MDU'S 2018 SSIP PROJECTS?

A. I conclude that MDU has failed to demonstrate the necessity and prudence of these projects on grounds of normal replacement, system expansion, or reliability improvement. As a consequence the costs of the 2018 projects should not be included in MDU's projected 2018 base rate revenue requirement.

B. DEPRECIATION

Q. PLEASE SUMMARIZE MDU'S DEPRECIATION PROPOSALS.

A. MDU's depreciation proposals rest upon depreciation studies of MDU gas and common plant account historical data and balances as of December 31, 2015. The depreciation study was performed using the Straight Line Method, Broad Group Procedure, and the Average Remaining Life Technique.[28] The studies' results are minor changes in most of MDU's gas

[28] Exhibit Nos. EMR-1, page 1-1 and EMR-2, page 1-1.

and common plant accounts and significant increases or decreases in the depreciation rates. In all accounts the changes in the depreciation rates are largely attributable to the Average Remaining Life (ARL) technique's adjustment for under or over funding of each account's depreciation reserve. There are no significant changes in the Average Service Lives (ASL) or Net Salvage (NS) parameters of MDU's distribution and common plant accounts.

Q. WHAT IS YOUR ASSESSMENT OF MDU'S PROPOSED DEPRECIATION RATES?

A. The parameters underlying the calculation of MDU's proposed depreciation rates (ALS, NS and ARL) are reasonably well supported by the depreciation studies' life, net salvage, and remaining life analyses.[34] I have no proposed changes to the depreciation rates.

C. COST OF SERVICE AND RATE DESIGN

Q. PLEASE SUMMARIZE MDU'S COST OF SERVICE AND RATE DESIGN PROPOSALS.

A. Based on a projected embedded class cost of service study,[35] the fair return standard of revenue requirement distribution to classes,[36] and the cost study's class customer cost results, MDU proposes the following changes in customer rates.

- Residential (Rates 60 and 90): 5.9% of the revenue increase, applied solely to the Basic Service Charge (BSC), producing a proposed Residential BSC of $0.7422/day;[37]

[34] Exhibit No. EMR-1, Sections 5 and 7; Exhibit No. EMR-2, Sections 5 and 7.
[35] Hatzenbuhler Direct, pages 2-8.
[36] Hatzenbuhler Direct, pages 9-10.
[37] Hatzenbuhler Direct, pages 10-11 and Statement N, page 4.

- Firm General (Rate 70): 5.5% of the revenue increase, distributed to the BSC and Distribution Delivery Charge (DDC), producing (1) BSCs of $0.70/day (Small) and $2.05/day (large) and (2) a DDC of $0.983/dk (Small and Large);[38]
- Small Interruptible (Rates 71 and 81): 0.0% of the revenue increase, BSC increased and DDC decreased, producing (1) a BSC of $190/month and (2) DDCs of $1.063/dk (71) and $0.668/dk (81);[39]
- Large Interruptible (Rates 82 and 85); 0.0% of the revenue increase, BSC increased and DDC decreased, producing (1) a BSC of $1500/month (82 and 85) and (2) DDCs of $0.213/dk (82 only).[40]

Q. DO YOU HAVE ANY COMMENTS ABOUT THE COST STUDY?

A. Yes. There are different methods to classify distribution of costs. MDU uses the minimum system method to classify a portion of the distribution costs to demand and a portion as customer costs. The minimum system approach is premised on a recognition that there is a minimum size pipe the Company would install to serve customers regardless of usage. The demand approach attempts to allocate based solely on usage. There are also other approaches. I am not in favor of a minimum system method. However, the use of a particular methodology is a determination of the regulatory body as to the classification of costs that results in just and reasonable rates.

Q. WHAT ARE YOUR CONCERNS REGARDING THE COST STUDY'S USE OF MINIMUM SYSTEM CLASSIFICATION?

[38] Hatzenbuhler Direct, page 11 and Statement N, page 10.
[39] Hatzenbuhler Direct, page 12 and Statement N, page 12.
[40] Hatzenbuhler Direct, page 12 and Statement N, page 15.

A. MDU uses the minimum system approach to classify 75 percent of mains costs as demand-related and 25 percent as customer related.[42] The result of this classification of mains costs is to shift a portion of mains costs that, consistent with the principle of cost causation, should be allocated to classes based on each classes' demand to allocation to classes based on each class' number of customers. It can be argued that this effectively creates a cost subsidy from the classes with large numbers of customers to the classes with lesser numbers of customers. If the Commission accepts the minimum system approach, I do not disagree with the manner in which MDU has applied it in this case, subject to the recommendations below. If the Commission determines the minimum system approach is not the appropriate method, I recommend that MDU's demand allocator be used to allocate 100 percent of mains costs in the cost study for this proceeding. This would result in the following changes in customer rates:

- Residential (Rates 60 and 90): 3.3% of the revenue increase, applied solely to the Basic Service Charge (BSC), producing a proposed Residential BSC of $0.6983/day;
- Firm General (Rate 70):9.0% of the revenue increase, distributed to the BSC and Distribution Delivery Charge (DDC), producing (1) BSCs of $0.70/day (Small) and $2.05/day (large) and (2) a DDC of $1.176/dk (Small and Large);
- Small Interruptible (Rates 71 and 81): 0.0% of the revenue increase, BSC increased and DDC decreased, producing (1) a BSC of $190/month and (2) DDCs of $1.063/dk (71) and $0.668/dk (81);

[42] Hatzenbuhler Direct, page 5, lines 7-18; Response Nos. 3.9, 5.1 and 5.2.

- Large Interruptible (Rates 82 and 85); 0.0% of the revenue increase, BSC increased and DDC decreased, producing (1) a BSC of $1500/month (82 and 85) and (2) DDCs of $0.213/dk (82 only).

Q. DO YOU HAVE ANY ADDITIONAL RECOMMENDATIONS REGARDING MDU'S CLASS RATE DESIGN?

A. MDU's proposal is to move towards full cost Basic Service Charge for each class on the basis of the class cost study's customer cost results for each class. I have no concerns regarding that rate design principle. However, the application of that principle requires accurate class cost service study customer cost results. Regardless of which approach the Commission decides in this case, I recommend the Commission direct MDU to investigate whether the use of more rigorous methodologies would produce a material improvement in the accuracy of its forecasting.

D. <u>RECOMMENDED RATES</u>

Q. HAVE YOU CALCULATED MDU RATES CONSISTENT WITH YOUR RATE DESIGN RECOMMENDATIONS AND THE REVENUE REQUIREMENT RECOMMENDED BY WTINESS MUGRACE?

A. Yes. I have recalculated those rates in Exhibit No. KRP-3. I have also recalculated rates using Witness Mugrace's recommended revenue requirement and MDU's class cost of service study results in Exhibit No. KRP-4.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

KARL RICHARD PAVLOVIC, Ph.D.

Education

Purdue University – MA and Ph.D. in Philosophy

Karl-Ruprecht Universität, Heidelberg, Germany – graduate study

Yale University – BA in Philosophy

Positions

Senior Consultant – PCMG and Associates	2015-Present
Senior Consultant – Snavely King Majoros and Associates	2010-2014
Director – FTI Consulting	2008-2010
President – DOXA, Inc	1994-2008
Partner – Snavely King and Associates	1983-1994
Assistant Professor – University of Florida-Gainesville	1978-1983

Professional Experience

Dr. Pavlovic provides clients with economic and policy analyses of commercial operations and expert testimony in support of litigation, negotiation and strategic planning. His analyses and testimony are distinguished by systematic articulation and testing of assumptions, thorough evaluation of data, innovative application of statistical tools and economic principles, and clarity and precision of presentation. In his 33 years as a consultant and expert witness, Dr. Pavlovic has provided expert testimony on the operations, costs and revenues of gas and electric utilities, the impacts of restructuring wholesale and retail electric markets, effects of mergers, the operation and competitiveness of petroleum and electric markets, the market valuation of crude oil, electric and gas reliability, and the performance of energy efficiency, renewable energy, and peak reduction programs.

Major projects directed by Dr. Pavlovic have included: analytical assistance to counsel and testimony on all aspects of the restructuring of wholesale and retail electric markets in the Eastern Interconnection; technical representation of the District of Columbia People's Counsel on DC PSC's Pepco Productivity Improvement Working Group and various PJM working groups; impact evaluation study of pilot energy efficiency and renewable energy programs in the District of Columbia; analysis of petroleum markets, expert testimony, and coordination of technical testimony in the Trans-Alaska Pipeline quality bank litigation; Independent Technical Review of the economic models used by the US Army Corps of Engineers for the Ohio River System Investment Plan; assistance to a major independent telephone company in the formulation and implementation of corporate strategic plans, applications for long-distance authority, and settlement negotiations with major domestic and foreign carriers.

By education and professional experience Dr. Pavlovic has expertise in formal and mathematical logic, statistics, economics, financial analysis, econometrics, and computer modeling.

References

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Representative Regulatory Projects and Appearances

1. In re: The Gas Company d/b/a Hawaii Gas, Application for Approval of Rate Increases and Revised Rate Schedules and Rules (2017) - (Appearance: cost of service and rate design on behalf of the Hawaii Division of Consumer Advocacy)
   HI Public Utilities Commission Docket No. 2017-0105

2. In re: Montana-Dakota Utilities Co., Application to Increase Natural Gas Rates (2017) - (Appearance: cost of service and rate design on behalf of the North Dakota Public Service Commission Staff)
   ND Public Service Commission Case No. PU-12-813

3. In re: The Application of Delmarva Power and Light Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2017) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
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Natural Gas Infrastructure Modernization Programs at Local Distribution Companies: Key Issues and Considerations

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Contents

Acronyms and Abbreviations

Acronym / Abbreviation	Stands For
AGA	American Gas Association
AR-5	IPCC Fifth Assessment Report
AR-4	IPCC Fourth Assessment Report
DIMP	Distribution Pipeline Integrity Management Plan
EDF	Environmental Defense Fund
EPA	U.S. Environmental Protection Agency
GSEP	Gas System Enhancement Plan
GPTC	Gas Piping Technology Committee
GWP	Global Warming Potential
IPCC	Intergovernmental Panel on Climate Change
LDC	Local Distribution Company
LAUF	Lost and Unaccounted for Gas
NARUC	National Association of Regulatory Utility Commissioners
NASPR	National Association of State Pipeline Regulators
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIPES	Pipeline Integrity, Protection, Enforcement, and Safety Act
PSE&G	Public Service Electric and Gas
Psig	Pounds Per Square Inch Gauge
SoCalGas	The Southern California Gas Company
UNFCCC	United Nations Framework Convention on Climate Change

1. Executive Summary

There is growing interest in natural gas system modernization among a wide range of stakeholders and many examples of progress being made. Nevertheless, many policymakers and the utilities responsible for delivering natural gas to customers broadly recognize the need to accelerate ongoing efforts to replace aging infrastructure while embracing new approaches to operations and maintenance. Based on new analysis and interviews with stakeholders directly working on these ongoing efforts, this paper highlights emerging policy trends and new developments through descriptions of select case studies.

Local gas distribution companies (LDCs) are the entities that deliver natural gas to retail customers. LDCs deliver gas to all residential gas customers, most commercial gas customers, and some industrial and power generation gas customers.[a] LDCs typically receive gas from one or more interstate or intrastate gas transmission pipelines and deliver the gas to customers through a network of gas mains (larger distribution pipelines) and service lines (the smaller pipes that connect to customer facilities). There were approximately 1,276,900 miles of LDC mains and 913,773 miles of LDC service lines in the U.S in 2015.[1] In addition, LDCs operate metering and regulating stations to measure and control the flow of gas in the system as well as customer meters to measure the gas supplied to consumers. Some LDCs also operate and maintain natural gas storage facilities, including underground reservoirs[b] and liquefied natural gas facilities. While this study focuses primarily on distribution pipeline infrastructure, many of the policy insights could apply to modernization efforts for other types of facilities operating in a rate-regulated market.

The age and type of pipeline infrastructure in service throughout LDC systems varies widely across the U.S. In some areas, portions of the natural gas distribution system can be more than 100 years old. Many LDCs have been working for decades to replace older natural gas infrastructure, as some types of older infrastructure can be leak-prone and at higher risk for failure. While maintenance, repair and replacement of these facilities has historically been driven by safety and reliability considerations, and to a lesser extent, a desire to increase system efficiency while reducing unnecessary loss of gas, more recently there has been an additional focus on the environmental impact of natural gas leaked to the atmosphere from natural gas systems. The primary component of natural gas (usually over 90% by volume) is methane, a powerful greenhouse gas (GHG) many times more potent than carbon dioxide. Natural gas distribution systems accounts for 6% of methane emissions from U.S. natural gas infrastructure.[2] Approximately 50% of these emissions are estimated to be from gas mains and services, primarily those made of cast iron and non-cathodically-protected steel.

Most of the cast iron and unprotected steel natural gas mains in the United States are in a handful of States with older distribution systems and, for safety reasons, have been the focus of repair and replacement programs for many years. Federal and State regulators have established pipeline inspection and maintenance requirements and LDCs have created risk-based pipeline replacement and maintenance programs to meet these requirements. Natural gas LDCs are regulated utilities, and as

[a] Very large customers typically receive gas directly from interstate or intrastate pipelines, bypassing the LDC.
[b] Roughly 29 percent of U.S. natural gas storage capacity in underground reservoirs is owned by LDCs.

such, they must get authorization from their regulators to undertake capital improvement programs, such as pipe repair and replacement, and are subject to cost recovery regulation. The regulators' mandate is to ensure safe, reliable operation of the utility at the lowest cost, so they must balance, safety, reliability and other benefits of infrastructure modernization investments against their cost. There is no allowance in this regulatory structure for investment in voluntary environmental measures, and even expenditures required to meet compliance with mandatory safety and environmental regulations must be approved by the utility regulators.

While there is increasing interest in accelerating replacement of cast iron and unprotected steel gas distribution pipe for safety, reliability and environmental benefits, there are a variety of barriers. For example, main replacement programs can be costly, with cost per mile to replace pipe from $1 to $5 million.[3] The relatively high cost of pipeline repair and replacement means that LDCs are unlikely or unable to undertake replacement programs without some prior guarantee of timely cost recovery. However, since costs associated with replacement programs are passed on to natural gas consumers, rate-payer impact is always a consideration, particularly for low- and fixed-income consumers. Even for LDCs that have regulatory approval to repair and replace infrastructure, a shortage of skilled labor necessary to perform the maintenance can hamper modernization programs. Finally, the current regulatory structure often does not recognize innovative technological solutions to pipeline maintenance issues, such as the use of plastic inserts inside older pipe. Moreover, since natural gas distribution lines are often buried under streets, infrastructure replacement activities are often disruptive to affected communities.

Despite the challenges, LDCs are continuing to replace and repair cast iron and unprotected steel pipe and non-pipeline facilities (e.g., regulators and meters), often with the support of State legislatures and public utility commissions. For example, most States have enacted some form of rate structure to ensure cost recovery for replacement of certain types of leak-prone natural gas pipelines. In some jurisdictions, these rate recovery mechanisms are paired with policies that require a pipeline replacement to occur on a specific timeline. In addition to complying with mandatory policies, many LDCs have been active in EPA's voluntary methane reduction program, Natural Gas STAR,[4] and some LDCs have joined industry groups, such as the Downstream Natural Gas Initiative[5] and the ONE Future Coalition,[6] to help promote infrastructure replacement policies and methane reduction activities.

Some recent State legislation is designed to spur further investment in infrastructure modernization activities. California SB 1371 requires LDCs to target pipeline and infrastructure replacement actions specifically for the purpose of improving public safety and reducing methane emission. Massachusetts Bill 4164 establishes a three-tier classification for gas leaks and sets specific timelines for full replacement of leak-prone pipe. Both the California and Massachusetts laws require submittal of LDC plans to achieve the policy goals. Oregon Senate Bill 844 establishes a program for natural gas utilities to receive cost recovery for voluntary projects that reduce greenhouse gas emissions through investments in infrastructure replacement or other means. State and federal utility and pipeline safety regulators are increasingly considering ways to account for the emissions benefits of their programs.

A variety of other stakeholders, including federal agencies and environmental groups, are helping to facilitate pipeline replacement activities. The Obama Administration initiated a Strategy to Reduce Methane Emissions, which includes several interagency efforts to reduce emissions from oil and natural gas systems more broadly, including new initiatives by the U.S. Department of Energy (DOE) and the U.S. Environmental Protection Agency (EPA)[7] that apply to distribution systems. The Administration also issued a number of policy recommendations related to natural gas infrastructure modernization in the first installment of the Quadrennial Energy Review.[8] DOE has formed a partnership with the National Association of Regulatory Utility Commissioners (NARUC) to provide technical assistance to States interested in natural gas infrastructure modernization.[9] Environmental groups are focusing on methane emissions from LDC systems and have taken action to raise awareness of the issue, highlight potential employment benefits, improve scientific knowledge, and directly intervene in utility proceedings to promote methane reduction at LDC facilities.

In sum, safety remains the primary policy driver for LDC pipeline and infrastructure repair programs. However, the significance of the methane emissions is becoming more recognized and companies, regulators, and other stakeholders are seeking ways to incorporate emission reductions into utility programs while limiting the cost to consumers.

Our analysis of existing pipeline replacement programs found that LDCs are implementing pipeline replacement acceleration programs in different ways. Some companies are taking advantage of new policies to initiate replacement programs, while other companies are updating existing replacement activities that have been ongoing for years. Experience has shown that the specific cost recovery mechanism used for a given program does not seem to strongly affect the success of that program. Some notably successful examples include several tracker-based programs in Ohio (see section 4) and Atlanta Gas Light's long-term replacement program (discussed in section 3). A combination of policies may be the most effective strategy for accelerating pipeline replacement rates; for example, coupling a dependable cost recovery mechanism with a requirement for pipeline replacement to occur on a specific timeline.

2. Introduction

Local gas distribution companies (LDCs), are the entities that deliver natural gas to retail customers. LDCs deliver gas to all residential gas customers, most commercial gas customers, and some industrial and power generation gas customers.[c] The LDCs typically receive gas from one or more interstate or intrastate gas pipelines and deliver the gas to customers through a network of gas mains (larger distribution pipelines) and service mains (the smaller pipes that connect to customer facilities).

Maintenance, repair and replacement of these facilities has historically been driven by safety and reliability considerations and to a lesser extent reduced losses of the gas commodity. Safety is the primary driver for most pipeline replacement programs in part because the costs associated with these capital improvements typically far exceed the economic value of avoiding losses of natural gas from leaking infrastructure.[10] More recently there has been an additional focus on the environmental effect of methane emissions as a greenhouse gas (GHG). LDCs, their regulators, customers, and other stakeholders have been evaluating the opportunity to accelerate repair and replacement of LDC infrastructure, especially pipelines, for safety, reliability and environmental benefits. These decisions are affected by economic, operational, and regulatory factors, some of which are changing. The U.S. Department of Energy has multiple interests related to this topic, including improving the operational efficiency of natural gas systems,[11] infrastructure modernization,[12] reducing GHG emissions, and conducting research, development and demonstration of technologies that enable leak detection and quantification.[13]

This report addresses the current state of play for these efforts through research and analysis and interviews with LDCs, State regulators, and other stakeholders. Not all States were interviewed during this analysis, and the States included were chosen based on a set of subjective criteria with the intention of making the sample of States regionally diverse and broadly representative. Chapter 3 provides information on the existing LDC infrastructure, relevant regulations and current practices. Chapter 4 identifies recent and current trends related to repair and replacement of LDC infrastructure for safety, reliability and environment. Chapter 5 includes quantitative analysis of implementation timelines for pipeline replacement programs by LDCs across the country. Chapter 6 summarizes the conclusions of the research.

3. Background

3.1. Local Natural Gas Distribution Infrastructure

Facilities owned by LDCs include metering and regulating stations that measure and control the flow of gas in the system and customer meters that measure the amount of gas supplied to consumers. Though not the focus of this study, LDCs also own underground storage facilities that account for nearly 30 percent of total U.S. capacity, transmission pipelines and compressor stations. The age and construction of LDC system infrastructures varies widely across the U.S. In some areas, portions of the distribution systems are more than 100 years old.

LDCs owned approximately 1,276,900 miles of mains and 913,773 miles of service lines in the U.S in 2015.[14] The vast majority of the pipes in natural gas local distribution networks are made of either cast iron, steel, or plastic. Small amounts of pipe are made of other materials, such as copper and ductile iron.[d] Within this broad categorization, plastic pipe can be further categorized based on the type of

[d] Ductile iron is a variety of iron that is less brittle—and less prone to cracking under stress—than traditional cast iron.

plastic, such as polyethylene (PE) or polyvinylchloride (PVC). Steel pipe can also be categorized based on whether it is covered with a corrosion-resistant coating and whether it is cathodically protected.[e] [15] Both coatings and cathodic protection reduce the likelihood that steel pipes will corrode and leak natural gas.

Figure 1 summarizes the amount of distribution mains by material in 2015. While the vast majority of the LDC system is plastic and coated steel pipe, the cast iron and unprotected steel pipes are generally older, more prone to leaks, and are the primary focus of pipe replacement programs aiming to improve the safety and reliability of local distribution systems.

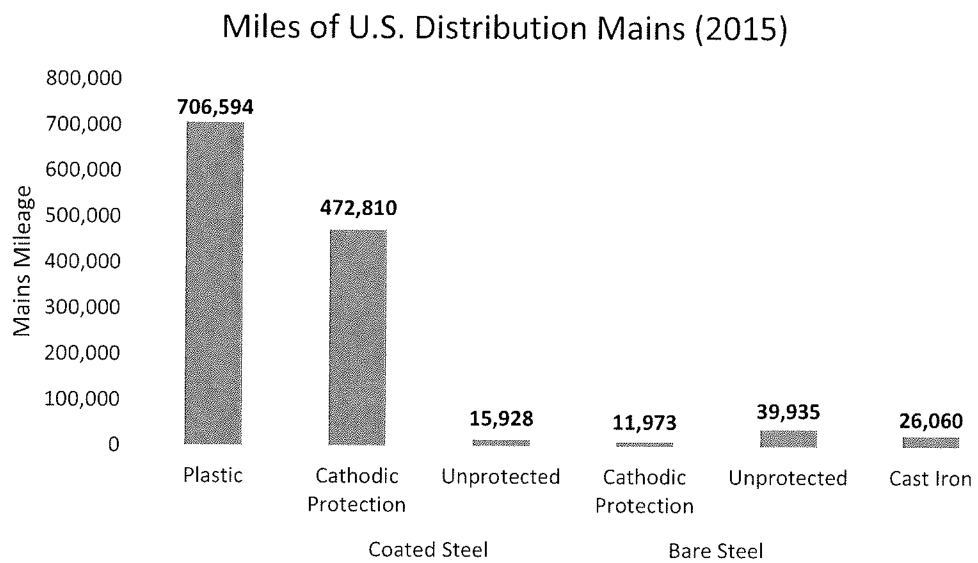

Figure 1. U.S. Distribution Main Pipeline Miles (2015)[16]

The total number of miles of cast iron and unprotected steel mains has been declining for the past three decades. As shown in Figure 2, the mileage of cast iron pipe[f] in the U.S. has declined from 53,506 miles in 1990 to about 26,060 miles in 2015, a 51% reduction. Likewise, the mileage of unprotected steel pipe has decreased from 102,342 miles to 55,863 miles, a decrease of 45%. The mileage of unprotected steel

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[e] Cathodic protection (CP) "is a technique to reduce the corrosion rate of a metal surface by making it the cathode of an electrochemical cell." Cathodic protection can be accomplished by passing a small electrical current through the metal to be protected.

[f] In this figure and throughout this paper, "cast iron pipe" refers to pipe made of cast iron that is less than 12 inches in diameter. Cast iron pipe larger than this generally has thicker walls and is less prone to catastrophic failure than cast iron pipe with smaller diameters (Downstream Initiative, personal communication). Because larger diameter cast iron pipes present less of a safety risk and can be very costly to replace, they are less likely to be targeted by the types of infrastructure replacement programs analyzed in this study. These large-diameter cast iron pipes represent a relatively small fraction of the total amount of cast iron pipe in the U.S. In 2015, there were about 1,700 miles of cast iron mains greater than 12 inches in diameter in the U.S. reported to the Pipeline and Hazardous Materials Safety Administration (PHMSA), compared to over 26,000 miles of cast iron pipe less than 12 inches in diameter. Only 15 LDCs in the U.S. reported more than 20 miles of cast iron main greater than 12 inches in diameter and only 7 LDCs reported more than 100 miles of this type of main. The preceding analysis is based on the analysis of PHMSA data in Section 4 of this document.

has remained approximately twice that of cast iron throughout this period. The reduction in mileage of cast iron and unprotected steel pipe is a result of efforts by LDCs and State regulators to encourage repair and replacement of aging infrastructure. As discussed in subsequent sections of this report, many utilities across the country have programs to replace cast iron and unprotected steel pipe. Some utilities have further accelerated those replacement efforts using a variety of funding mechanisms. Some States have also enacted legislation to facilitate or encourage upgrades to natural gas infrastructure.

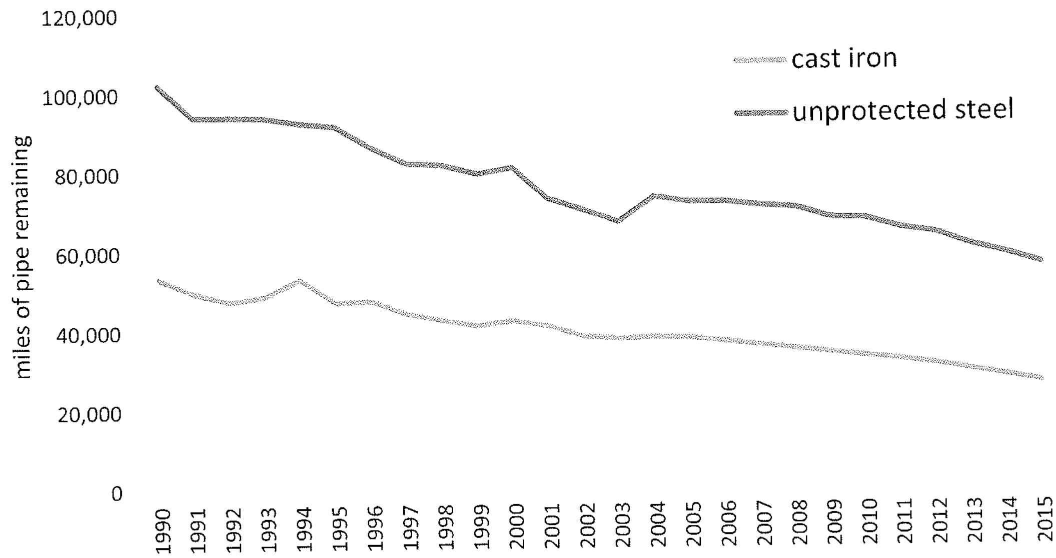

Figure 2: Miles of cast iron mains less than 12 inches in diameter and unprotected steel mains in the U.S., 1990 to 2014.

Cast iron and unprotected steel pipes are concentrated in a relatively small number of States in the U.S. (Figure 3). Four States (New Jersey, New York, Massachusetts, and Pennsylvania) account for half of all the cast iron pipe in the U.S. Similarly, four States (Ohio, Pennsylvania, California, and New York) account for half of all the unprotected steel pipe in the U.S. While some States, such as New York, have relatively large inventories of both cast iron and unprotected steel, some States with large inventories of unprotected steel pipes do not have large inventories of cast iron pipe (California, for example) and vice versa.

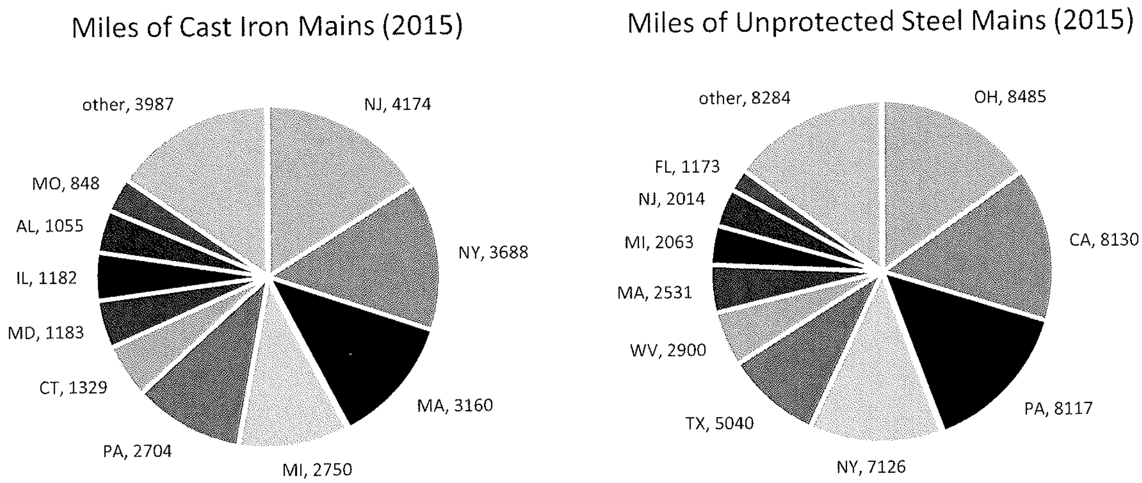

Figure 3: Distribution of cast iron (left panel) and unprotected steel (right panel) pipeline less than 12 inches in diameter by State.

3.2. Environmental Impacts

As noted above, infrastructure repair and modernization programs have historically been motivated by safety, reliability and conservation of the natural gas commodity. However, more recently leaks have become a concern due to the greenhouse warming impacts of methane, the primary component of pipeline quality natural gas[17] (95-98% by volume). Methane is a greenhouse gas (GHG) that is, pound-for-pound, more than 20 times more effective at trapping heat in the atmosphere than carbon dioxide (CO_2) over a 100 year time period.[18] Appendix A describes in greater detail how methane affects climate change.

Figure 4 shows the official estimates of methane emissions from local gas distribution networks in the context of total U.S. methane emissions. Methane emissions accounted for approximately 11% of U.S. greenhouse emissions[g] in 2014 according to the U.S. EPA.[19] The pie chart on the left shows total U.S. methane emissions by industry sector. Natural gas systems, shown in different shades of grey, contributed about one quarter of U.S. methane emissions in 2014, or nearly 3% of all U.S. GHG emissions in that year. The chart on the left also shows methane emissions by segment within the natural gas industry. The "distribution" segment, shown in light grey, includes the infrastructure networks considered in this paper and is responsible for about 6% of the methane emissions from the natural gas industry (approximately 2% of total U.S. methane emissions). Methane emissions from LDC service lines and mains account for nearly 50% of emissions from the natural gas distribution sector.

[g] The U.S. EPA Inventory of Greenhouse Gas Emissions uses a GWP of 25 for methane in compliance with inventory guidance from the UNFCCC.

The remainder of emissions are mostly attributable to venting and leaks from residential and commercial/industrial meters, metering and regulating stations[h] and mishaps (aka dig-ins).

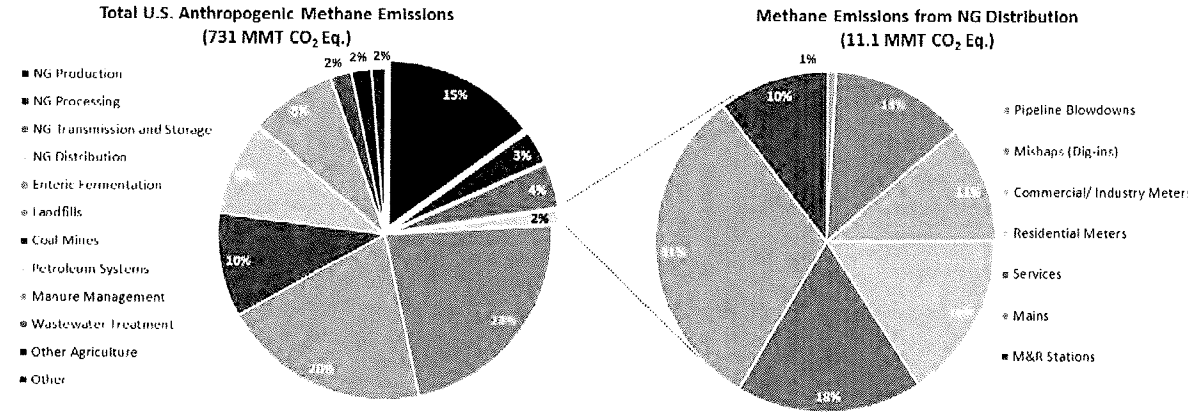

Figure 4: Breakout of U.S. and Natural Gas Distribution System Emissions, 2014 (2016 Inventory of U.S. Greenhouse Gas Emissions and Sinks).

3.3. Economic Regulation of LDCs

All residential, most commercial, and some industrial gas customers are served by a regulated natural gas LDC. Like local electricity distribution companies, gas utilities are deemed to be a "natural monopoly", i.e., it does not make sense to have multiple companies installing gas distribution networks in one city and competing with each other. Therefore, one company is given the franchise to own and operate the gas distribution system in a given area subject to rate regulation by a State agency, usually called the Public Utility Commission (PUC), Public Service Board, Department of Public Utilities, or a similar name. Pipelines are a primary asset of a natural gas LDC, along with the metering and regulating equipment that control and measure the flow of gas into, through, and out of the system. Some LDCs own thousands of miles of pipe. Since most of the remaining inventory of cast iron and unprotected steel natural gas pipelines are owned by investor-owned LDCs, interviews conducted for this study were limited to these companies, all of which are regulated by State, as opposed to municipal, PUCs.

LDCs are allowed to charge customers for the company's actual operating expenses plus a regulated rate of return on their capital investments, which, in part, allows LDCs to raise money from capital markets to invest in the infrastructure. The capital on which operators are allowed to receive a return is known as their "cost basis." A company seeking to invest in infrastructure, either to perform maintenance or to xpand their system, must get approval from State regulators to ensure that capital investments are prudent, reasonable, and useful to the consumers. Stakeholders, including consumer advocacy organizations, labor unions, and environmental groups have an opportunity to comment during these reviews. Commenters may suggest that more should be done to increase public safety or, conversely,

[h] Metering and regulating stations are facilities that regulate and measure gas flow on the LDC system. Customer meters are the meters that measure deliveries to customer facilities.

that infrastructure programs result in excessive costs to ratepayers. The State regulators also review the company's other costs for reasonableness and must review and approve how costs are recovered from customers via the rate structure. Reasonable operating costs and the cost of the gas that the company purchases and sells to customers are passed directly to customers. LDCs do not charge any fee or make any profit on the gas commodity itself, which means that gas companies cannot increase profit by reducing gas losses.

Rather, utility rate structures include an allowance for "lost and unaccounted for" (LAUF) gas. This factor accounts for losses from the system, which can result from metering error, leakage and routine venting, theft, and other factors. These losses are considered a recoverable operating cost and each LDC calculates its own specific factor, which must be reviewed and approved by the State regulator.

The primary policy goal for State economic regulators is to ensure safe, reliable service at the lowest cost to consumers. Environmental performance is typically not part of their charter except to the extent that it is required by environmental regulations. Even then, economic regulators must determine whether LDCs are complying with environmental regulations in the most prudent and cost-effective manner possible. With few exceptions (e.g., Oregon Senate Bill 844), utility regulators do not typically approve voluntary emission control actions as recoverable costs.

The rate review and rate-setting process varies by State. The process is conducted annually in some States and less frequently elsewhere. When LDCs are preparing to undertake large capital investments, they want to know how and when they will be able to recover the costs of those investments. LDCs are typically reluctant to undertake major capital projects without assurance of cost recovery. In some cases, cost recovery can occur through regular annual rate cases. In other cases, cost recovery is accomplished through a special review and rate plan (more discussion in Section 4).

3.4. Pipe Replacement Regulation and Safety Protocols

3.4.1. Federal Distribution Pipeline Integrity Management Plan (DIMP) Requirements

In 2006, the Pipeline Integrity, Protection, Enforcement, and Safety Act (PIPES) mandated that the Pipeline and Hazardous Materials Safety Administration (PHMSA) within the U.S. Department of Transportation prescribe standards for distribution pipeline integrity management programs (DIMPs). Federal DIMP rules were subsequently established under Subpart P of the U.S. Code of Federal Regulations, Title 49, Part 192 – Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards. This section states that gas distribution operators are responsible for developing and implementing a pipeline integrity management program. Per § 192.5, DIMPs must include information concerning: threat identification, risk ranking and evaluation, risk identification and measures to address risks (including an effective leak management program), and performance measurement. Operators are required to re-evaluate DIMPs at least every five years, taking into account performance measures, such as the number of leaks detected within the system. Operators are required to report a number of attributes to PHMSA annually, including the magnitude of damages caused by excavation, miles of main by type and size, the number of service lines by type and average length, and the number of leaks eliminated or repaired in that year. These data collected by PHMSA are one of the sources used in the analysis of pipeline replacement programs in Section 5 of this document.

Section 9 of the PIPES Act prescribes minimum requirements for maintenance of pipeline facilities, to be accounted for in distribution system operators' DIMPs. Two major performance-based guidelines for pipeline maintenance are listed in § 192.703:

- Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service
- Hazardous leaks must be repaired promptly. A hazardous leak is defined in Subpart P as "a leak that represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous."

Hazardous leak prevention, detection, repair, and reporting requirements are to be addressed in operators' DIMPs. It is left up to operators to further define/classify and prioritize leaks for repair. Further guidance on DIMP plans and leak repair is provided in the Gas Piping Technology Committee (GPTC) DIMP guidelines, though these are not explicitly incorporated into regulatory requirements. In the GPTC DIMP guidelines, leaks are assigned a grade from 1 (leaks requiring immediate attention) to 3 (non-hazardous leaks that are expected to remain non-hazardous). The details of the GPTC DIMP guidelines are described in Table 1.[20]

Grade	1	2	3
Definition	Leaks that require immediate repair or continuous action until conditions are no longer hazardous	Detected non-hazardous leaks which represent a future hazard and justify scheduled repair	Detected non-hazardous leaks which can be "reasonably expected to remain non-hazardous."
Recommended Action(s)	Implementation of an emergency plan and other potential measures including rerouting traffic and notifying police and fire departments	Repair of leaks within one calendar year or earlier if potential hazard is high	Re-evaluation of leaks during the next scheduled survey, or within 15 months of the data reported, until there is no longer an indication of a leak
Examples	Ignited gas or any gas concentration measured at least 80% of the lowest concentration at which combustion can occur (also known as the lower explosive limit, or LEL)	Leaks under frozen or adverse soil conditions that could migrate to the outside of a building wall and any leak resulting in gas concentration measured at 20-80% of the LEL in a confined space	Any leak resulting in gas concentration measured at less than 20% of the LEL in a confined space

Table 1 – Leak grading standards described by the Gas Piping Technology Committee Distribution Pipeline Integrity Management Program guidelines.

3.4.2. Federal Requirements for Distribution Pipeline Leak Detection Surveys

Minimum requirements for distribution system leak survey programs[i] are summarized below:

- At least once each calendar year, at intervals not exceeding 15 months, a leak survey using leak detecting equipment must be performed in business districts[j] [21] at all locations providing an opportunity to locate gas leaks (e.g. gas, electric, and water system manholes and sidewalk/pavement cracks)
- Outside of business districts, leak surveys must be performed at least every five years. For cathodically unprotected distribution lines, leak surveys must be conducted every 3 years.

[i] As outlined in § 192.5 of Title 49, Part 192 – Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, Subpart M.

[j] According to PHMSA Guidance: "A 'business district' is an area marked by a distinguishing characteristic of being used in the conducting of buying and selling commodities and service, and related transactions. A 'business district' would normally be associated with the assembly of people in shops, offices and the like in the conduct of such business."

Many LDCs implement these surveys more frequently than required. According to a report by Kiefner & Associates[22] that was commissioned by PHMSA, even though leak detection and repair programs have safety, environmental, and economic advantages, the leak detection standards for natural gas pipelines are not as comprehensive as those for hazardous liquid pipelines. As stated in the report, "while there are recommended best practices for leak detection on liquids pipelines, there are none for gas pipelines."[23] In addition, while liquids pipeline operators must install equipment to continuously monitor pipelines for leaks, gas pipeline operators are not required to do the same. Among the limitations to current requirements is that the specific timing for "prompt" repair is not clearly defined in the statute or regulations.[24]

While many gas pipelines do not have continuous leak detection systems, operators often employ other methods to maintain the safety of their systems. LDCs add mercaptans, potent odorant chemicals, to natural gas that flows through local distribution systems. This odorant can allow customers to identify gas leaks before they become hazardous. LDCs also perform regular leak detection and repair (LDAR) programs to identify and remediate potentially hazardous gas leaks.

3.4.3. State Inspection Programs

While pipeline safety programs are administered by PHMSA, the majority of the responsibilities for intrastate lines are delegated to the States. State pipeline safety personnel represent more than 75% of the combined State and Federal inspection workforce and the bulk of the safety and inspection responsibility lies at the State level. States opt into this relationship with PHMSA. If a State decides not to participate in intrastate pipeline safety inspections, PHMSA will perform the safety inspections in that State. At present, this situation applies only to Alaska and Hawaii.

Under the Pipeline Safety Act, States must receive certification from PHMSA to assume pipeline safety responsibilities within their jurisdiction. Certification is a "mutual agreement" between PHMSA and a State to take on this responsibility, and the State must agree to ensure that its pipeline operators meet the federal agency's minimum pipeline safety standards. Once certified, the State is responsible for oversight of pipelines that do not cross State boundaries (intrastate pipelines). Arizona, California, Connecticut, Iowa, Michigan, Minnesota, New York, Ohio, Washington, and Virginia also act as interstate agents on behalf of the federal government. In this role, State personnel inspect interstate pipelines and submit reports to PHMSA, which carries out compliance and enforcement action as necessary.

The general responsibilities of pipeline inspectors include inspection of safety records, facilities, construction, integrity management and other programs, and investigation of accidents. States are allowed to adopt pipeline safety regulations that are stricter than federal government regulations, and the overwhelming majority of States do have more stringent requirements.[25] These requirements are based on specific results of State inspections and increased safety expectations of the public.

Additional safety requirements have been established in many States. According to the 2013 Compendium of State Pipeline Safety Requirements and Initiatives, 45 States have "implemented at least one initiative above and beyond the minimum requirements of the Code of Federal Regulations that apply to one or more pipeline operators within their States."[26] Appendix C of this document includes more information about the types of initiatives included in the Compendium of State Pipeline Safety Requirements and Initiatives.

4. Current Trends in LDC Infrastructure Repair and Replacement

4.1. Existing Pipeline Repair and Replacement Programs

LDCs use risk assessment methodologies to prioritize their repair and maintenance programs based on safety considerations. These systems use information from LDC leak surveys and other leak reports to track and prioritize repairs according to the DIMP classifications. Grade 1 leaks are repaired immediately and Grade 2 leaks are prioritized for the second tier of repairs. Grade 3 leaks are repaired as resources become available or if they reach Grade 1 or 2 status. Most pipeline and infrastructure replacement programs are more complex and expensive and are typically classified as capital investments. They require permitting from local authorities to close and excavate streets and may need to be coordinated with city paving or other operations. These are often multi-year projects requiring long lead times for planning and design.

4.2. Barriers to Pipeline and Infrastructure Replacement

In preparing this paper, interviews were conducted with several LDCs and public utility commissions to learn more about the potential barriers to replacing cast iron and unprotected steel natural gas distribution mains. The interview participants were chosen to be regionally diverse and broadly representative of the issues companies could face in pipeline replacement. These interviews, along with other research, inform the discussion of potential barriers discussed below. Some of the issues discussed here apply to maintenance and repair of all types of LDC facilities (e.g., including metering and regulation stations) while others are specific to gas mains and service lines.

LDCs seeking to replace older infrastructure can face high costs; the cost of replacing cast iron and unprotected steel mains can range from $1 million to $5 million per mile depending on location. Costs can be a significant challenge in particular for LDCs with large inventories of cast iron or unprotected steel pipe to be replaced. Most cast iron and unprotected steel pipe is located in urban areas[27] where the cost of excavation and pipe replacement is typically higher. Factors that contribute to higher replacement costs include congestion, multiple (sometimes poorly documented) underground utilities, limited construction seasons due to weather, and high labor costs.

Since pipeline replacement costs must be approved by State regulators, large capital investment programs require a rigorous review and approval process and cost recovery may not begin until a project is constructed and in service. Cost recovery may then also be subject to retroactive review and disapproval. LDCs are typically reluctant to embark on large, long-term construction or maintenance programs without some expectation of cost recovery upon project completion or, preferably, as the program proceeds. Many States are implementing financing mechanisms that address these concerns with the goal of accelerating pipeline replacement (see section 4.3).

Due to the high cost of pipeline replacement, these programs can affect consumer rates. As a result, infrastructure replacement programs can garner scrutiny from consumer protection groups concerned about utility rates and public utility commissions. Additionally, the cost of methane leak detection and monitoring infrastructure can pose a barrier to greater deployment. However, the current low commodity price of natural gas has reduced some sensitivity to gas utility rates. All States have low-income assistance programs,[28] though these typically focus on providing consumer bill relief for costs associated with heating and cooling.

Another barrier is the lack of regulatory recognition for innovative technology solutions. Due to the high cost of pipeline excavation and replacement, there is interest in alternative technologies that can reduce natural gas losses at a lower cost and with less service disruption than can be incurred by excavating and replacing mains. For example, there are several technologies for installing plastic liners and inserts in existing pipelines, including those made of cast iron and unprotected steel.[k] [29] These technologies can be a lower-cost leak reduction option than pipeline replacement in some cases, especially for pipe that is expensive to replace because it is large or deeply buried. However, some regulators, notably PHMSA, do not recognize pipe lining as an alternative to replacement. Thus, lined cast iron pipe is considered the same as unlined pipe for reporting purposes, which limits the incentive for developing or implementing potentially effective and cost-effective alternative technologies.

Another challenge is that pipe replacement requires skilled labor from tradespeople certified for the required tasks. These resources are limited in most parts of the country. The shortage of qualified labor has been exacerbated in some areas that have a significant share of the total leak prone pipe inventory, such as the Mid-Atlantic and Northeast, as multiple States and companies are now focusing on pipeline repair and replacement. Some companies are working with local educational institutions to encourage training programs for these vocations (see examples noted below). Long-term construction program commitments can provide added support for the training and development of skilled workers.

Limited workforce capacity and training availability for Federal and state pipeline safety inspectors can also be a barrier to pipeline inspection and replacement. The Pipeline and Hazardous Materials Safety Administration's (PHMSA) Office of Pipeline Safety operates a single gas and hazardous material training facility for the entire nation, and PHMSA's certification process for state inspectors can extend up to five years.[l] According to the National Association of Regulatory Utility Commissioners (NARUC), there is currently a backlog for admission to PHMSA's state inspector training program of one to two years. In November 2015, NARUC passed a resolution urging PHMSA to establish regional pipeline safety training facilities to increase their training capacity for pipeline safety inspectors.[30]

Finally, objections to natural gas infrastructure in general can undermine efforts to make infrastructure improvements. There is growing opposition in some regions to the development or expansion of natural gas infrastructure. This is a reaction to concerns about the environmental effects of hydraulic fracturing

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[k] Liners adhere to pipes while inserts do not.
[l] For more information about PHMSA's training program for pipeline safety inspectors, see http://www.phmsa.dot.gov/pipeline/tq.

as a natural gas production technology, concerns about continued use of natural gas in a future GHG-constrained environment, and a broader focus on the transition to renewables. In some cases this can translate to objections to continued investment in natural gas systems.

4.3. Financing Mechanisms to Promote Infrastructure Repair and Replacement

Despite the challenges noted above, continued focus on safety and reliability and growing concerns over emissions are resulting in changing approaches to LDC infrastructure repair and replacement. Several of these trends are discussed below.

4.3.1. Focused Cost Recovery Treatment for Pipeline Replacement

As discussed earlier, uncertainty over cost recovery can prevent LDCs from undertaking infrastructure replacement programs. In response, some LDCs and public utility commissions have developed alternative mechanisms to finance these programs. The American Gas Association (AGA) has published a list of 40 States (plus the District of Columbia) that have specific rate structures for accelerating pipeline replacement (Appendix B). There are several characteristics of rate programs that companies and regulators indicate can encourage and facilitate pipeline and infrastructure replacement. These are described below with specific examples for each.

Certainty of Cost Recovery

Allowing LDCs to charge consumers rates that include a cost recovery formula, especially over a multi-year period, can smooth the implementation of large capital programs and provide more flexibility and leverage in procuring materials and labor contracts. Most of the rate structures in the AGA database (Appendix B) provide this kind of certainty. For example, the Arizona Corporation Commission gave Southwest Gas approval to establish the Customer Owner Yard Line (COYL) program, which is designed to survey leaks and replace service lines, also known as yard lines, which connect customer meters to mains. Under this program, Southwest Gas defers the costs associated with the COYL program and submits an annual application to the Arizona Corporation Commission "to implement a surcharge rate to recover the revenue requirement on the deferred COYL costs."[31]

Other States ensure LDC cost recovery through rate stabilization programs. The rate stabilization mechanism "decouples utility rates from natural gas throughput by adjusting rates to meet pre-established and authorized rate targets."[32] For instance, Louisiana uses a stabilization program to change the LDC's annual rates if the company incurs higher capital investment or O&M costs related to pipeline safety. At the end of each 12 month period, a decision will be made on whether the company's revenue should be increased, decreased, or left unchanged.

Cost Recovery during Construction

Some cost recovery mechanisms allow LDCs to begin recovering costs only after a project is completed. However, cost recovery during construction can be preferable for utilities, especially for multi-year projects. This type of ongoing cost recovery can be achieved through a "cost tracker" mechanism. A cost recovery tracker is a ratemaking mechanism that involves "tracking costs in a specified account[33]." This type of mechanism allows an LDC conducting a capital project to add a small amount to the amount charged for gas to "track" how much of the authorized expenditure level for that project is being spent in real time. Trackers allow for cost recovery more immediately outside of a rate case. The costs associated with the tracker are not included in utilities' base rates but are later reviewed by regulators. In the case of underspending by a utility, the tracked costs are returned to the ratepayers.[34]

A surcharge is another type of cost recovery mechanism that "allows a utility to separately charge customers for costs that would have otherwise been part of the utility's standard base rates."[35] In other words, the utility recovers the incurred costs and the surcharge shows up as an extra charge on a ratepayer's utility bill. Some surcharges are flat rates, while others change depending on usage.

For example, Rhode Island applies an infrastructure investment tracking mechanism designed to recover actual and anticipated capital investments. Another example of a program with timely cost recovery is Indiana's SB 560, which allows "a tracker for cost recovery of infrastructure upgrades and extensions," but also allows "utilities to propose a 7 year infrastructure plan to the Indiana Utility Regulatory Commission" so that the utility could "recover its investment in a timely manner through a tracker on customer's bills."[36]

In 1998, Georgia's AGL Resources started a 15-year Pipeline Replacement Program that consists of a "fixed dollar amount of expense to be recovered in rates over the remaining 7 years of the program."[37] In 2009, the Georgia Public Service Commission expanded the program so that it also includes infrastructure expansion investments. The Pipeline Replacement Program is now a part of Georgia's Strategic Infrastructure Development and Enhancement Program, which "provides a rider on customer bills that will allow AGL to recover costs associated with traditional infrastructure replacement, and infrastructure expansion related to customer growth and economic development."[38] As shown in Figure 5, AGL has been very successful at replacing aging infrastructure under this program. AGL went from replacing an average of 80 miles of unprotected steel pipeline per year between 1993 and 1998 to replacing an average of 140 miles of unprotected steel pipeline per year between 1998 and 2003. (Note: This is data from PHMSA filings. See Section 5.1 for more information about the analysis and data referenced here). AGL continued replacing cast iron pipe at a rate of approximately 30 miles per year before and after the establishment of the program in 1998. As a result of these efforts, AGL replaced all of the 1,939 miles of unprotected steel pipe that it owned in 1998 by 2013 and all 291 of the miles of cast iron pipe that it owned in 1998 by 2010. AGL is one example of an operator with substantial inventories of cast iron and unprotected steel pipe that has managed to completely replace pipes made of these materials. For comparison, the number of miles of unprotected steel pipe that AGL replaced between 1990 and 2014 (2,605 miles) ranks as the second-greatest number of miles of unprotected steel pipe replaced by any LDC in the U.S. during this period (behind only SoCal Gas). The 535 miles of cast iron pipe that AGL replaced during this period ranks as the 10th highest number of miles of cast iron pipe replaced by an LDC in the U.S. during this time period.

There are other examples of cost recovery trackers throughout the United States. Colorado uses a cost recovery tracker to recover costs of improvements in pipeline safety and compliance with federal regulations. In 2015, West Virginia passed SB 390, which allows natural gas utilities to file a multi-year plan for infrastructure replacements and upgrades, becoming the 39th State to implement an accelerated replacement program.[39]

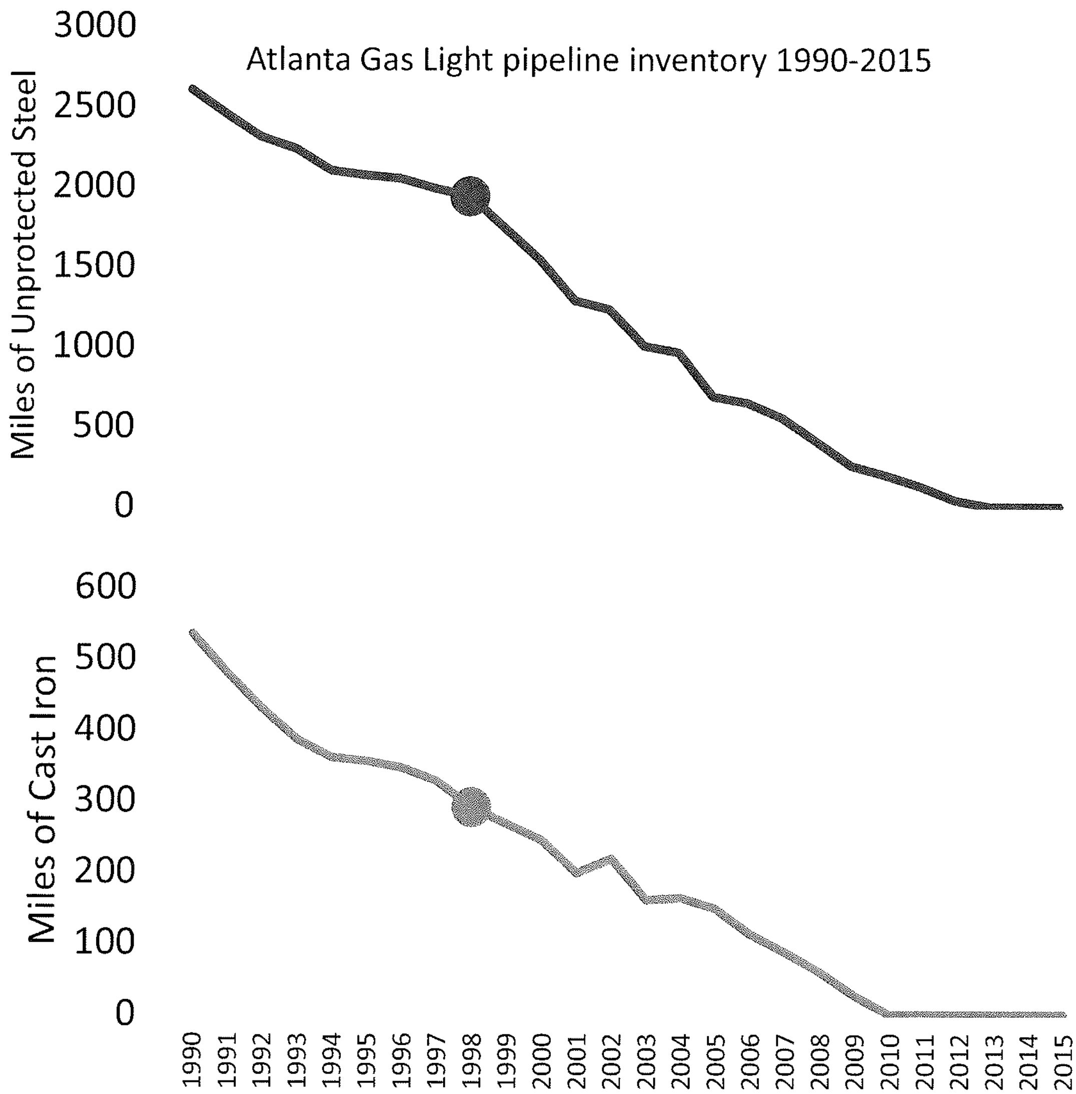

Figure 5: Atlanta Gas Light's miles of unprotected steel (red, top) and cast iron (blue, bottom) mains reported to PHMSA, 1990 – 2015. AGL initiated a successful pipeline replacement acceleration program in 1998 (large circles in each figure indicate the year in which programs were put into place). The rate of replacement of unprotected steel pipeline went from 80 miles/year before 1998 to 140 miles/year after 1998. AGL replaced all of its unprotected steel and cast iron miles of main by 2015.

Establishing Targets for Replacement

Some programs provide cost recovery for replacement based primarily on safety analysis. However, other programs include specific replacement targets, either in terms of miles of pipeline to be replaced each year or as a deadline for completing the targeted replacement. Both approaches provide certainty for companies and regulators and are becoming more common. Massachusetts Law (2014) Chapter 149 (see below) requires companies in that State to establish a plan to completely replace cast iron and unprotected steel pipe within 20 years or justify an extension. The Massachusetts program establishes an annual cost cap of 1.5% of revenue for the replacement program, though companies could request to recover costs above the cap in later years. As another example, the public utility commission in Georgia set a 10-year replacement schedule with annual mileage targets for Atlanta Gas Light in conjunction with a coordinated cost recovery plan. The combination of the replacement targets with a cost recovery plan contributed to AGL's success in accelerating pipeline replacement under the program, as discussed above.

A few States have or are considering establishing targets for infrastructure replacement that include incentives and/or penalties for meeting or missing targets. These incentives and penalties are typically implemented by varying the amount of return that LDCs can collect on projects. New York is developing a generic pipeline replacement program with a 20-year target and incentives or penalties on LDC returns for better or worse performance.[40] This is an example of an incentive mechanism in which the commission "rewards or penalizes a utility based on actual performance relative to a pre-specified benchmark."[41]

Consideration of Environmental Benefits

Most State public utility regulators only have authority to consider environmental issues in setting utility rates if LDCs are required to comply with environmental regulations. As a result, environmental impacts are rarely factored into the approval process for pipeline replacement programs by State regulators.[42] However, some States are enacting legislation that includes environmental considerations in the ratemaking process for LDCs. California SB 1371 (see below) requires the State public utility commission to convene a proceeding to address reduction of natural gas emissions from gas facilities to support achievement of the greenhouse gas reductions outlined in the California Global Warming Solutions Act of 2006. Oregon Bill 844 (see below) requires the public utility commission in that State to establish a voluntary emission reduction program for LDCs. Also, Massachusetts Department of Environmental Protection has proposed methane emissions limits and reporting requirements for gas operators as part of the state strategy to comply with the Massachusetts Global Warming Solutions Act.[43]

Figure 6 shows the States with accelerated infrastructure replacement programs. As shown in the figure, most States with such measures have implemented cost recovery tracker and surcharge programs.

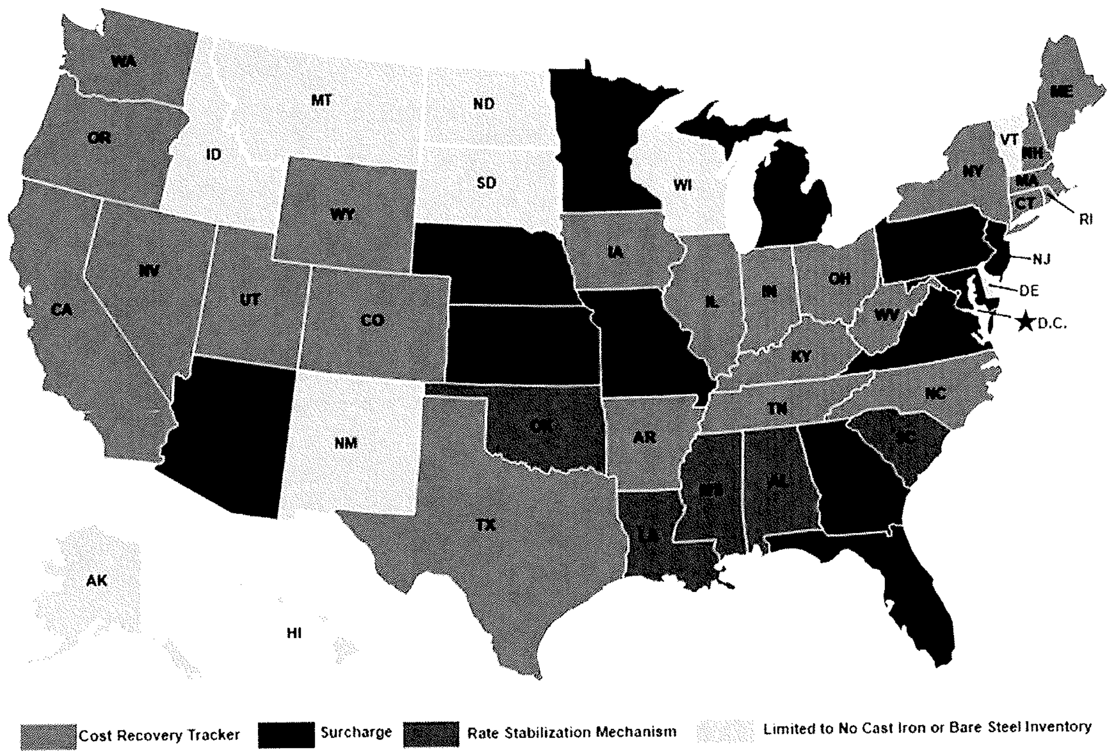

Figure 6: Cost Recovery Mechanisms use by States with Accelerated Infrastructure Replacement Programs[44]

4.4. Pipeline Modernization Efforts by Entities Other than Utilities

With the continuing focus on methane emissions by oil and gas companies, many entities are contributing to the effort to reduce methane emissions from LDCs. Some of these entities include:

4.4.1. Environmental NGOs

Several national and regional environmental non-governmental organizations have become engaged in the issue of methane emissions from LDCs. The Environmental Defense Fund (EDF) is very engaged on the broader issue of methane emissions from oil and gas operations and has sponsored several activities related to LDCs. Examples of EDF's work include a cooperative effort with Google to add mapping of methane leaks to Google maps for certain cities.[45] EDF also sponsored a measurement study on methane emissions from LDC operations.[46] This study was part of a broader effort led by EDF aimed at updating estimates of methane emissions from natural gas facilities throughout the value chain, from well-head to customer meter. EDF has also submitted comments in LDC rate cases and other PUC actions expressing support for the inclusion of methane emissions data in prioritization of pipeline repairs. For example, EDF submitted comments on the California PUC implementation of SB 1371 to this effect.[47] The Conservation Law Foundation has also been active in highlighting the methane issue and quantifying emissions from cast iron mains in Massachusetts.[48]

4.4.2. Labor Organizations

Labor organizations have also supported natural gas infrastructure replacement efforts. The BlueGreen Alliance, whose membership includes both labor and environmental organizations, has promoted pipeline replacement through analysis that highlights the employment benefits associated with these capital-intensive projects.[49] In addition, the AFL-CIO issued a policy statement in 2013 calling for accelerated investment in natural gas infrastructure, noting that "repair and buildout of the natural gas pipeline system alone has been estimated by the INGAA Foundation as likely to create, on average, 125,000 jobs a year between now and 2035."[50]

4.4.3. Regulators

In 2011, PHMSA issued a "Call to Action" for all "pipeline stakeholders, including the pipeline industry, the utility regulators, and State and federal partners,"[51] to improve the safety of the pipeline system in the United States, including those pipelines used to transport and distribute natural gas. In March 2012, PHMSA published an advisory bulletin to owners and operators of natural gas cast iron distribution pipelines and State pipeline safety representatives highlighting "the need for continued safety improvements to aging gas pipeline systems."[52] This advisory bulletin, among other points, urges owners and operators of such systems to conduct a comprehensive review of their cast iron distribution pipelines and replacement programs and to accelerate pipeline repair, rehabilitation and replacement of pipelines that are relatively likely to fail. The advisory bulletin also requests State agencies to consider enhancing cast iron main replacement plans and programs[53].

Improving the safety and reliability of LDC infrastructure continues to be a priority for State utility regulators. In July 2013, the National Association of Regulatory Utility Commissioners (NARUC), whose membership includes State utility regulators, adopted Resolution GS-1, titled "[A] Resolution Encouraging Natural Gas Line Investment and the Expedited Replacement of High-Risk Distribution Mains and Service Lines."[54] The Resolution encourages States to fully explore, examine, and implement alternative rate recovery mechanisms that will accelerate the modernization, replacement and expansion of the nation's natural gas pipeline systems. The resolution also encourages regulators and industry to consider sensible programs aimed at replacing the most vulnerable pipelines as quickly as possible along with the adoption of rate recovery mechanisms tailored to individual utilities. To further enable achievement of these goals, in February, 2016, NARUC announced that eight State Commissioners agreed to participate in the DOE-NARUC Partnership for Natural Gas Infrastructure Modernization.[55]

4.4.4. Federal Agencies

In 2014 The U.S. Department of Energy (DOE) launched the Natural Gas Infrastructure Modernization Initiative, which aims to encourage further actions by government and industry to upgrade natural gas infrastructure to improve safety and reliability, improve efficiency, reduce costs and reduce methane emissions. This initiative resulted from a series of stakeholder roundtable meetings in 2014 that were hosted by U.S. Secretary of Energy Ernest Moniz.[56] The DOE built upon the insight gained in these stakeholder roundtable meetings to create the policy recommendations to promote natural gas infrastructure modernization that were included in the Quadrennial Energy Review (QER).[57] In the first installment of the QER, which focused specifically on the transmission, storage and distribution of energy, the Administration made recommendations aiming to further improve safety and reduce leaks from natural gas distribution systems. In particular, Chapter 2 of the report the report called for DOE to establish a program to help accelerate pipeline replacement and enhance maintenance programs for natural gas distribution systems.[58]

As discussed below, the Environmental Protection Agency recently established the voluntary Methane Challenge Program.[59] The Partners in the program consist primarily of LDCs and pipeline replacement is the most common commitment made under the program.[60]

4.5. State Legislation Promoting Pipeline Replacement

While regulation of LDCs has traditionally been the purview of State utility commissions, there have been several recent State legislative efforts focusing on LDC pipeline replacement. The following sections discuss recent legislative efforts in California, Oregon, and Massachusetts that have been enacted into law. Other States with notable legislative initiatives include Illinois.[61] This Illinois Gas Pipeline Safety program applies to intrastate natural gas transmission, distribution, and gathering pipeline facilities, and the objective of the program is to ensure that these facilities comply with federal and State safety rules and regulations.

4.5.1. California SB 1371

California Senate Bill 1371 was enacted on September 21, 2014 and outlines rules and procedures "governing the operation, maintenance, repair, and replacement of commission-regulated gas pipeline facilities that are intrastate transmission and distribution lines to minimize leaks."[62] The objective of the bill is to reduce natural gas emissions from gas facilities and promote practices to support achievement of the greenhouse gas reductions outlined in the California Assembly Bill 32, the Global Warming Solutions Act of 2006. This Act aims to decrease California's GHG emissions to 1990 levels by 2020, which amounts to a 15% reduction.[63] These practices can include physical infrastructure replacement programs as well as operational improvements, such as changing leak detection and repair programs or reducing venting of blowdowns[m] during maintenance.

[m] "Blowdown" refers to a procedure in which natural gas is removed from some type of infrastructure equipment that is actively in service, including pipelines. Blowdowns are often required to remove natural gas from sections of pipelines prior to performing maintenance on those pipelines.

California Assembly Bill 32 requires each LDC in the State to file a report that summarizes the company's utility leak management practices, a list of new methane leaks identified in 2013 organized by grade (see Table 1), a list of identified leaks that are being monitored or are scheduled to be repaired, and an estimate of gas loss due to leaks.[64] In addition, the bill requires "the commission to commence a proceeding by January 15, 2015 to adopt these rules and procedures."[65] This proceeding is in progress as of the writing of this report.

California Senate Bill 1371 also changes the definition of what constitutes a gas leak in the State. Before the bill, vented emissions from leaks occurring as a result of normal operations and maintenance were considered non-hazardous. PHMSA defines a "leak" as "an unintentional escape of gas from the pipeline,"[66] and States that "a non-hazardous release that can be eliminated by lubrication, adjustment, or tightening, is not a leak." PHMSA defines a hazardous leak as one that "represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous."[67] However, SB 1371 states that the public utility commission shall "provide for the maximum technologically feasible and cost-effective avoidance, reduction, and repair of leaks and leaking components in those commission-regulated gas pipeline facilities that are intrastate transmission and distribution lines within a reasonable time after discovery."[68] Thus, SB 1371 promotes best practices to reduce leaks and decrease methane emissions.

The Southern California Gas Company (SoCalGas) has filed its initial report in compliance with the bill, laying out its current status and recent actions to reduce gas leaks. SoCalGas operates the largest natural gas distribution system in the country, which consists of more than 100,000 miles of pipeline across 20,000 square miles, serving 21 million consumers.[69] SoCalGas reduced its overall methane emissions to 0.12% of all gas delivered in 2011 by replacing the sections of pipe that were most likely to leak, according to their engineering studies.[70] Furthermore, SoCalGas is planning to publish a public map showing methane emissions from non-hazardous gas leaks. Hazardous sites are not included on the map because leaks from those sites are repaired immediately.

In general, technicians at SoCalGas conduct "four-point" inspections of all leaks that are identified, which consist of evaluating the location of a leak, the concentration of gas measured at the time of the inspection, the potential for gas buildup in the area of the leak, and the existence of an ignition source that could potentially ignite the leaking gas. Depending on the safety risk associated with each site, SoCalGas technicians can take one of the three following actions: 1) repair the leak immediately; 2) "determine the leak to be non-hazardous but in need of follow-up and repair;"[71] or 3) label the site as non-hazardous and schedule another inspection to monitor the site. Any non-hazardous site that falls under Option 2 is monitored frequently until it is repaired. In general, the repair process takes up to six months. Although federal regulations do allow gas distribution companies to monitor non-hazardous leaks without repairing them, SoCalGas designed a plan in November 2014 stating that SoCalGas will repair *all* detected leaks, regardless of whether they are hazardous or not, in line with Senate Bill No. 1371. SoCalGas expects that they will repair all non-hazardous leaks that have not yet been repaired by the end of 2018, once funding for the plan has been approved by the California Public Utilities Commission (CPUC). Pacific Gas and Electric, has launched a "super crew" program to increase their efficiency at finding and repairing leaks.[72] Under this program, a crew surveys a particular area of interest for gas leaks using sensitive leak detection equipment. A coordinated leak repair and replacement plan is then created and the materials necessary to complete the plan, such as pipe and fittings, are prepared. Finally, the materials are delivered to the area of interest and the repair and replacement program is executed. This program is more efficient than conventional leak detection and repair protocols in which leaks are identified piecemeal in general leak surveys because the focus on a particular area allows for the creation of a coordinated repair and replacement plan. PG&E estimates that this approach could reduce the number of hours spent on leak detection and repair by more than 40%.

4.5.2. Oregon Senate Bill 844 (2013)

Oregon Senate Bill 844 was passed by the Oregon State Senate on June 19, 2013, and was signed by the governor on July 1, 2013.[73] The bill requires the Oregon PUC to "establish a voluntary emission reduction program for the purposes of incentivizing public utilities that furnish natural gas to invest in projects that reduce emissions and providing benefits to customers of public utilities that furnish natural gas."[74] Any LDC completing a project under the program must file an application with the commission including information such as the projected emissions reductions from the project, the projected date on which the project will become operational, the projected amount of capital and operating costs necessary to complete and operate the project, a requested method for recovery of costs incurred and investments made, and the projected rate impact of the project.[75]

By creating a mechanism for utilities to receive cost recovery for proposed projects, this new law creates an incentive for voluntary efforts to reduce GHG emissions.

4.5.3. Massachusetts Act (2014) Chapter 149

Massachusetts Act (2014) Chapter 149 was enacted on June 26, 2014 and applies to intrastate pipelines and gathering lines. While it does not specifically focus on emissions, the bill outlines a natural gas leak classification system and a priority repair system. The three classifications for gas leaks are described in Table 1. The bill also requires gas companies to prioritize the repair of gas leaks within school zones, which are defined as areas within 50 feet of any school property.[76] In addition, LDCs in Massachusetts must annually report the location of all leaks to the Department of Public Utilities.

Gas companies may also file a Gas System Enhancement Plan (GSEP), which outlines their plan for replacing within 20 years infrastructure constructed from non-cathodically protected steel, cast iron, and wrought iron. The Department of Public Utilities is responsible for evaluating the progress and the reporting made by the gas companies towards meeting the goals outlined in their GSEPs. So far, six utilities in Massachusetts have adopted GSEPs. The details of these GSEPs are fully described in Appendix D.

4.6. Non-Pipeline Methane Reduction Activities

While the primary focus of LDCs' efforts to reduce methane emissions has been pipe repair and replacement, there are also efforts to reduce emissions from other facilities. LDCs continuously inspect and maintain the stations that meter and regulate the pressure of gas entering the distribution network. These efforts are reflected in a recent Washington State University study titled "Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States."[77] The authors of this study measured methane emissions from 13 urban distribution systems in the United States. From these measurements, the authors derive emissions estimates for these facilities based on "direct measurements at 230 underground pipeline leaks and 229 metering and regulating facilities."[78] The projected national LDC emission estimate from this report is 393 Gg[n]/year with a 95% upper confidence limit of 854 Gg/yr. This emission estimate is 36%-70% less than what was reported in the 2011 EPA Greenhouse Gas Inventory (GHGI). According to the authors, the difference between the emission estimates in the GHGI and those measured by the study is primarily due to improvements at metering and regulating stations, repair and replacement of aging pipes and service lines, upgrades in leak detection and maintenance activities, as well as different methodology between the Washington State University study and those used to construct the GHGI. Specifically, there has been "replacement and upgrades of equipment within metering and regulating facilities,"[79] in addition to about a 38% decrease in the miles of older cast iron, a 22% decrease in the miles of unprotected steel pipeline, an 8% increase in the miles of protected steel, and a 150% increase in plastic pipeline miles. Furthermore, since the 1990s when the measurements used to construct the GHGI were conducted, leak survey techniques have improved. These improvements in maintenance have contributed to decreased methane emissions at these facilities.

Many other organizations and researchers are actively working in this area. The Gas Technology Institute has undertaken a methane measurement study for LDCs and continues to pursue development and commercialization of methane reduction technologies for distribution mains and other LDC equipment. In addition, a recent Harvard study found that emissions from the Boston area are far greater than State inventory estimates would suggest, highlighting need for more research to reconcile differences between top-down and bottom-up studies.[o] Other researchers have published studies based on vehicle- mounted measurements in various cities.[80]

Recent research has also suggested that reducing methane emissions from the natural gas distribution sector is relatively expensive compared to reducing emissions from other areas of the natural gas supply chain. For example, a recent study of the cost of methane reduction measures[81] found that reducing emissions from the distribution sector had a higher cost per thousand cubic feet (Mcf) of gas reduced than measures in other industry segments. This difference is primarily due to very high capital costs for

[n] Gigagrams which is a unit of mass equal to 1,000,000,000 grams.

[o] "Bottom-up" measurements are made directly at the facility or component level, and bottom-up greenhouse gas inventories are often used to inform policy and program decisions. In contrast, "top-down" methods involve sampling methane concentrations in the atmosphere and inferring estimates of emission flux from sources using atmospheric models. Top-down methods are useful for identifying hot spot regions (where emissions are relatively higher than in surrounding areas) and validating bottom-up estimates.

pipeline replacement and relatively low baseline emissions due to existing inspection and maintenance programs. However, this study also acknowledged many health and safety co-benefits which could not be monetized, such as reductions in ground-level ozone which forms from interactions between methane and nitrogen oxides. Despite the relatively high costs, many LDCs continue to repair and replace aging infrastructure to increase the safety of the distribution system.

4.7. Voluntary LDC Programs

The EPA Natural Gas STAR program is a voluntary partnership that encourages oil and natural gas companies in all industry segments to adopt cost-effective technologies and practices that improve operational efficiency and reduce methane emissions. The Natural Gas STAR program has identified a number of emission reduction options including flexible liners that can be inserted inside existing gas mains, directed inspection and maintenance (DI&M) at surface facilities such as metering and regulating stations, and composite wraps to address pipeline defects and prevent future pipeline ruptures.[82] Many LDCs have participated in the program and demonstrated voluntary emission reductions. In 2016, the EPA established a new voluntary program, called the Methane Challenge,[83] to encourage oil and natural gas companies to adopt cost-effective technologies and practices that improve operational efficiency and reduce methane emissions.[84]

5. Quantitative Analysis of Replacement Programs

5.1. Introduction and Methodological Summary

As evidence of the widespread interest in pipeline replacement acceleration described in the previous sections of this document, 40 States and the District of Columbia have initiated some type of pipeline replacement acceleration program. A description of these programs compiled by the American Gas Association is provided in Appendix B. These programs vary widely, from the size of the operator participating in the program to the financing mechanism used to fund replacement activities (see section 3.2 for a discussion of infrastructure financing mechanisms).

This section describes results from an analysis of pipeline replacement rates – at the State and LDC level – to identify programs that have been particularly successful at increasing annual pipeline replacement rates. The goal of this analysis is to identify the elements shared by particularly successful programs to provide policy guidance and examples for LDCs and policymakers looking to establish pipeline replacement acceleration programs in the future.

The methodology used to analyze the effectiveness of pipeline replacement programs is fully described in Appendix E with a briefer description here. PHMSA data were used to construct time series of miles of cast iron and unprotected steel pipe for each LDC in the U.S. for the time period from 1990 to 2014. Pipeline replacement rates were then calculated for each LDC as the change in the annual total of each type of pipe for each operator. To enable a measure of comparability between utilities of different sizes, annual pipe replacement rates were normalized using natural gas sales data for each LDC from the U.S. Energy Information Administration (EIA). Gas sales was used to normalize replacement rates based on the simplifying assumption that companies with larger gas sales volumes also have larger distribution systems and therefore greater ability to replace more miles of pipe annually than smaller operators with less gas sales.

Replacement rates were analyzed for both cast iron and unprotected steel pipelines. In particular, this analysis examined the mileage of unprotected steel pipe, which is a combination of miles of coated and uncoated steel pipe without cathodic protection. Steel pipe was divided based on cathodic protection following the convention in the U.S. EPA's Greenhouse Gas Inventory.[p] For cast iron pipe, this analysis only considered pipe less than twelve inches in diameter. Based on interviews with companies, cast iron pipes larger than twelve inches in diameter are somewhat less likely to be targeted by replacement programs because these pipes pose a lower safety risk; the thicker walls of larger-diameter cast iron pipe generally reduce the risk of catastrophic failure relative to that for smaller-diameter cast iron pipe. Also, replacing large diameter pipe is more expensive, per mile, than replacing smaller pipe.

This analysis examined the impacts of the programs described in Appendix B on LDCs annual pipeline replacement rate. Due to data limitations, this analysis only includes consideration of those programs enacted in 2012 or earlier (at the time of writing, PHMSA's data extends only to 2015). To evaluate the effectiveness of a given program, this analysis compared the average replacement rate for the LDC participating in replacement programs for both cast iron and unprotected steel pipe in the five years immediately before that program was enacted with the average replacement rate for the five years immediately after the program was enacted. For programs enacted recently for which five years of subsequent data were not available (for a program enacted in 2012, for example), this analysis calculated the average replacement rate after program implementation using all available data from years after the program was enacted. Data for any year in which a company's pipeline replacement rate was negative (indicating an increase in pipeline mileage) was excluded from this averaging. This simple screening method was used because a LDCs' pipeline totals can sometimes increase due to acquisitions of infrastructure from other operators or because pipe is reclassified as operators gain better information about their systems.

5.2. Results

Of the 42 programs in Appendix C initiated in 2012 or earlier, 15 had a measurable positive impact on LDCs' pipeline replacement rates. These programs and a description of the effect of each are shown in Table 2. There are a number of reasons why a given acceleration program may not result in a change in pipeline replacement rates as measured by this analysis. Some companies showed evidence of continuing replacement efforts that started before a new program was initiated. In these cases, enacting a new program may be a way for LDCs to secure funding for efforts that are already underway. It is also possible that there is insufficient data to measure the impact of programs that were initiated recently, especially in 2012. Recent programs may result in long-term downward trends in cast iron and unprotected steel pipeline mileage that will appear as more data becomes available. Moreover, there are limitations to the underlying data used to conduct this analysis, as described in Appendix E.

[p] EPA uses single emissions factors for pipes with and without cathodic protection, respectively, regardless of whether those pipes have external coatings.

Despite these potential limitations, the collection of programs identified in Table 2 evidence a wide range of attributes. Pipeline replacement rates normalized by volume of gross natural gas sales per operator are shown in Figure 7. The top panel of this figure shows replacement rates for cast iron and the bottom panel shows replacement rates for unprotected steel. Each figure shows the replacement rates for the 20 LDCs with the most mileage reported in 2014 for that type of pipe as well as a few examples of LDCs that have accelerated their pipeline replacement rates. LDCs that increase replacement rates under an acceleration program are shown by dark blue before participating in the program and light blue afterwards. The shape of the symbols represents the business model of the LDCs in the figure: circles represent investor-owned utilities, triangles represent municipal utilities, and diamonds represent privately-owned utilities. Comparing results in Table 2 with the policies and programs in Appendix B indicates that no single approach to cost recovery is clearly better than other approaches for successful acceleration pipeline replacement.

Table 2: Programs that resulted in a measurable increase in LDC pipeline replacement rates for cast iron pipelines, unprotected steel pipelines or both.

State	Company	Year	Cast iron (CI) replacement after acceleration (miles/yr/bcf)	Unprotected steel (UP) replacement after acceleration (miles/yr/bcf)	Results of acceleration program for cast iron (CI) and unprotected steel (UP)
CT	Yankee Gas	2011	0.76	NA	Mid-sized company changed replacement time for CI from ~36 years to ~18 years. UP replacement to be completed in ~7 years continued.
FL	Florida Public Utilities Company	2012	NA	8.8	Smaller company reduced system replacement time for UP to 4 years (25% of total inventory every year). No CI inventory.
FL	Central Florida Gas	2012	NA	5.9	Smaller company reduced system replacement time for UP to 5 years (20% of total inventory every year). No CI inventory.
GA	AGL	1998	NA	Sales data not available	Mid-sized company greatly accelerated UP replacement, while holding CI replacement rate constant. Although CI replacement did not accelerate, rate was sufficient to remove all CI pipe by 2014.
IL	Peoples	2011	0.56	NA	Large company doubled CI replacement rate. No UP inventory.
IN	Vectren	2008	0.16	0.78	Mid-sized company reduced replacement time for CI and UP to ~10 years.

MI	Consumers Energy	2012	0.17	0.11	Mid-sized company changed replacement time for CI from ~50 years to ~14 years and reduced replacement time for UP from to ~20 years.
NJ	New Jersey Natural Gas Co	2012	0.46	0.68	Mid-sized company changed replacement time for UP from ~30 years to ~15 years and is already on track to remove all CI in next 1-2 years.
NJ	South Jersey Gas	2009	0.71	2.8	Mid-sized company changed replacement time for CI from ~50 years to ~8 years and replacement time for UP from ~30 years to ~8 years.
NY	New York State Electric and Gas	2010	NA	1.37	Mid-sized company changed replacement time for UP from ~13 years to ~4 years. No CI inventory.
OH	Columbia Gas of OH	2008	0.90	7.8	Large company reduced replacement time for CI to ~9 years and replacement time for UP from ~55 years to ~21 years.
OH	Dominion East Ohio	2011	NA	14.8	Large company reduced replacement time for UP to ~21 years. Company is on track to replace remaining ~70 miles of CI in ~14 years.
OH	Duke Energy Ohio	2000	3.4	NA	Large company increased CI replacement rate 7x in 2000 to replace nearly all mileage by 2014. On track to replace all UP mileage in ~5 years.
OH	Vectren Energy Delivery of OH	2009	10.7	17.2	Mid-sized company reduced replacement time for CI from to ~4 years and replacement time for UP from ~120 years to ~15 years
VA	Columbia Gas of VA	2011	NA	0.91	Small company changed replacement time for UP from ~36 years to ~9 years. No CI inventory.

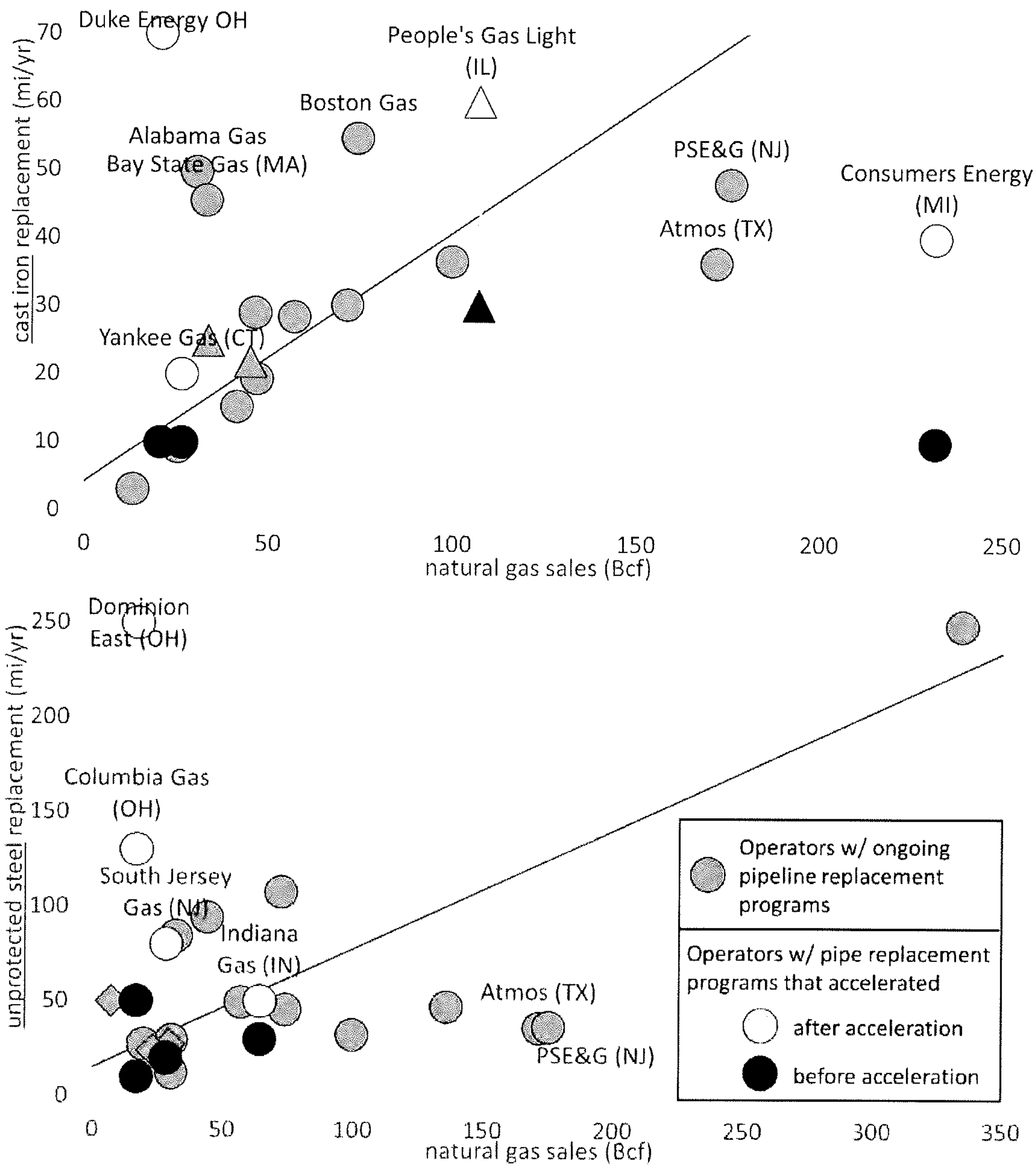

Figure 7: Pipeline replacement rates versus natural gas sales for cast iron (top) and unprotected steel pipe (bottom). Each figure shows 20 operators with the most mileage of that type of pipe reported in 2014 (blue). A least squares regression shown in red on each graph. Regressions were calculated excluding all outliers (labeled with company names). Also shown are some examples of LDCs that have accelerated their pipeline replacement rate; dark blue symbols represent LDCs before acceleration and light blue symbols show LDCs after acceleration. Pipeline acceleration examples were not included in regression calculations. Shape of symbols represent utility ownership model: circles are investor-owned, triangles are municipal, and diamonds are private.

Not surprisingly, when outliers are not considered, the companies in Figure 7 show a fairly consistent relationship between gas sales and pipeline replacement rate, particularly for cast-iron pipelines; companies with greater gas sales generally replace more miles of pipeline per year. We quantified this relationship by computing a least-square regression of the companies shown in Figure 7, excluding outliers and those with replacement programs (all LDCs excluded from the regression calculation are labeled with company name in the figure). We found that the average replacement rate amongst this group of LDCs for cast iron was 0.3 miles per year per billion cubic feet (Bcf) of gross natural gas sales. For the LDCs shown in the bottom panel of Figure 7, the average replacement rate was 0.6 miles of unprotected steel pipeline replaced per year per Bcf of sales.

More to the point of this analysis: companies with replacement rates above average appear in the upper left portion of both panels of Figure 7. For example, Boston Gas, Alabama Gas, and Bay State Gas are all replacing cast iron pipes more rapidly than other companies with comparable sales volume.

The examples of LDCs with successful replacement programs shown in Figure 7 further suggest that LDCs in a variety of circumstances can take advantage of replacement acceleration programs. For example, People's Gas Light in Illinois is a large operator that was able to accelerate its rate of cast iron pipeline replacement from below average to above average. Duke Energy in Ohio managed to greatly increase its cast iron pipeline replacement rate, despite having a relatively small volume of gas sales. For unprotected steel pipeline, both Dominion East Ohio and Columbia Gas of Ohio were able to use tracker programs to accelerate their rate of pipeline replacement well above average. Indiana Gas Company took advantage of a pipeline acceleration program to increase its rate from below average to comparable with its peers, while New Jersey Natural Gas company changed its pipeline replacement rate to be well above average.

6. Conclusions

There is growing interest amongst LDCs, utility regulators, and State legislators in reducing natural gas losses from infrastructure systems. Safety and, to a much lesser extent, reduced gas commodity losses remain the primary driver for LDCs' infrastructure replacement and repair efforts. However, most stakeholders are becoming more aware of the potential environmental benefits of reducing natural gas losses to the atmosphere. Despite the recent focus by other stakeholders, many LDCs have been pursuing replacement of leak-prone pipe for years, and some LDCs have completely removed cast iron and unprotected steel pipes from their distribution systems. As evidence, the mileage of cast iron distribution pipe in the U.S. declined by 25% between 2005 and 2014.

Barriers to LDC pipeline replacement can include cost, uncertainty of cost recovery, availability of skilled labor, ratepayer impacts, and lack of regulatory recognition for new solutions to reducing gas losses. Innovative rate recovery mechanisms are being developed that can help address some of the difficulties that LDCs can face in undertaking large capital projects. Many States have developed some form of special rate structure to support cost recovery for pipeline replacement programs. These programs help ensure timely cost recovery for LDCs, and many programs include other elements to promote infrastructure replacement, such as specific mileage targets and providing incentives and penalties based on LDCs' performance. Some programs may soon incorporate emissions-based targets. In addition to cost recovery programs, California, Oregon, Illinois and Massachusetts have passed legislation focusing on LDC infrastructure. California's and Oregon's programs directly target methane emissions while Massachusetts's is focused on replacement of all cast iron and unprotected steel pipe in LDCs' inventories by a fixed deadline.

There are myriad models for successful pipeline replacement acceleration programs. The analysis conducted for this report found that multiple rate recovery methods have been employed in successful programs. Some companies have used these pipeline replacement acceleration programs to increase existing pipeline replacement programs, while other companies have used these programs to begin replacement programs. Most LDCs have a fairly constant rate of pipeline repair per unit of gas sales (0.3 miles per year per Bcf for cast iron and 0.6 miles per year per Bcf for unprotected steel), although some companies are replacing more pipe than the average per unit of gas sales. Ultimately, a combination of policies, such as a cost recovery plan along with specific replacement targets, may be the most effective approach to accelerating pipeline replacement rates.

Appendix A: The Climate Implications of Methane Emissions

Different greenhouse gases persist in the atmosphere for different lengths of time and have different warming effects, and thus have different effects on climate change. In order to compare them, the scientific community typically uses a factor called the global warming potential (GWP), which relates each GHG's climate warming impact to that of CO_2, which is assigned a GWP of 1. The science and policy communities have historically looked to the Intergovernmental Panel on Climate Change (IPCC) assessment reports as the authoritative basis for GWP values, the most recent of which was the IPCC Fifth Assessment report (AR-5),[85] published in November 2014.

CO_2 emissions are the primary driver for climate change over the long term, due to the relatively large scale of (mostly energy-related) CO_2 emissions and their long lifetime in the atmosphere. GWP values expressed on a 100-year time horizon are used by the U.S. EPA and other federal, State, and international agencies to quantify total GHG emissions. Methane is assigned a GWP of 36 on a 100-year basis by the Fifth Assessment Report (AR-5) of the Intergovernmental Panel on Climate Change (IPCC), with the inclusion of carbon-climate feedbacks.[q] This means that one ton of methane from fossil fuel sources has the same effect as 36 tons of CO_2 over 100 years.

In order to evaluate the short-term effects of GHG emissions, the GWP is also calculated on a 20-year basis. This is useful in part because some GHGs, including methane, have a stronger climate-forcing effect but a shorter lifetime in the atmosphere than CO_2 (the atmospheric lifetime of methane is about 12 years). On a 20 year basis, the AR-5 estimates a GWP of 86 for methane.

While the AR-5 is the most recent assessment of GWP, the United Nations Framework Convention on Climate Change (UNFCCC) reporting guidelines for national inventories require the use of GWP values from the *IPCC Fourth Assessment Report* (AR-4)[86]. The 100-year GWP of methane in the AR-4 is 25 on a 100-year bases an 72 on a 20-year basis. For consistency with international reporting standards under the UNFCCC and the standards used in the EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks,* this study uses the AR-4 100 year GWP of 25 for methane except where otherwise noted.

[q] The AR-5 estimates that the 100 year GWP for methane ranges from 28 to 36.

Appendix B: Infrastructure-Related Tariff Information

Table 3: American Gas Association list of natural gas infrastructure modernization programs.

State	Activity	Relevant Documents
Alabama	• In 1995, the Alabama PSC approved the Cast Iron Main Replacement Factor as part of Mobile Gas' general rate case. The program recovers the annual revenue requirement level of depreciation, taxes and return associated with cast iron main replacements. The tracking mechanism is applied to all rate classes and is updated annually for incremental investment in cast iron main replacements. • Mobile Gas and Alabama Gas presently utilize a Rate Stabilization and Equalization Plan.	Docket No. 24794

Arkansas	• In 1988, CenterPoint received approval from the Arkansas PSC for a Gas Main Replacement Program (GMRP) which provided for a tracker to be applied to the replacement of bare steel and cast iron mains and associated services. In 1992, the program was modified to include recovery of capital investment (depreciation) and was expanded to include all cast iron gas main and related services. At that time it was also renamed the Cast Iron Main Replacement Program (CIGMRP). In 2002, the program was modified again to include bare steel and associated services, and was renamed the Main Replacement Program (MRP).
	• On July 9, 2012, in Docket No. 12-045-TF, the Arkansas PSC authorized CenterPoint Energy to include as eligible for expedited replacement steel mains that do not have a cathodic protection system (unprotected steel main) along with any associated services. These mains were deemed eligible for cost recovery under CenterPoint's Main Replacement Program Rider (Rider MRP).
	• On July 7, 2014, the Arkansas Public Service Commission adopted a settlement in SourceGas Arkansas' (SGA) base rate proceeding. The approved settlement allows SGA to implement a main replacement program (MRP) rider and an at risk meter relocation program rider. The primary purpose of the MRP Rider is to support the expedited replacement of Subject Mains and Associated Services. Eligible mains and services under the MRP are:
	  ○ 1) Bare steel mains;
	  ○ 2) Coated steel mains that are not cathodically protected; and
	  ○ 3) Mains that are the subject of an advisory issued by a federal or state agency and which the Company has determined to be in unsatisfactory condition.
	• On July 25, 2014, the Arkansas Public Service Commission adopted a settlement in Arkansas Oklahoma Gas' base rate proceeding. The approved settlement also allowed for the implementation of a system safety and enhancement rider (SSER). The SSER will provide AOG with the opportunity to earn the Commission approved rate of return on investments made in replacing aging infrastructure. The SSER is designed to prioritize the replacement of the riskiest pipe in the system each year, but at a rate which has minimal impact on customers' bills. Mains covered under the SSER are:
	  ○ 1) Bare steel mains;
	  ○ 2) Any mains associated with the replacement of low pressure systems (AOG's tariff defines a low pressure system as one that is composed of distribution mains operated at less than or equal to 12 ounces of pressure); and
	  ○ 3) Mains that are the subject of an advisory issued by a federal or Arkansas state agency and which the Company has determined to be in unsatisfactory condition.
		Dockets 06-161-U and 10-108-U (CenterPoint)
		
		Docket No. 13-079-U (SourceGas Arkansas)
		
		Docket No. 13-078-U (Arkansas Oklahoma Gas)
		
		Docket No. 12-045-TF (CenterPoint MRP)

Arizona	• In January 2012, the Arizona Corporation Commission granted Southwest Gas approval to implement a Customer Owner Yard Line (COYL) program as part of its general rate case settlement. The program is designed to facilitate leak	

	surveying and, when required, replacement of customer yard lines. The program includes a cost recovery component whereby Southwest Gas defers the actual COYL capital costs and files an annual application requesting authority from the Arizona CC to implement a per therm surcharge rate to recover the revenue requirement on the deferred COYL costs.	Docket No. G-01551A-10-0458 (Southwest Gas)
California	• In December 2010, San Diego Gas & Electric filed a request with the California PUC for a gas base rate increase. In its filing, the utility also proposes a post-test-year ratemaking mechanism for the three-year period 2013 through 2015, under which the company's revenue requirement would be adjusted to reflect increases in capital-related and other expenses. The CPUC approved the mechanism in May 2013. • In December 2010, Southern California Gas filed a request with the CPUC for a gas base rate increase. As part of that filing, the utility proposes a post-test-year ratemaking mechanism for the three year period 2013-2015, which under the company's revenue requirement would be adjusted to reflect increases in capital-related and other expenses. The company did not request specific rate increases under the mechanism. The CPUC approved the mechanism in May 2013. • As part of its 2013 GRC in California, Southwest Gas (Southwest) proposed an Infrastructure Reliability and Replacement Adjustment Mechanism (IRRAM) that is designed to facilitate and complement projects involving the enhancement and replacement of gas infrastructure. • In June of 2014, southwest received approval for an IRRAM mechanism. Southwest's approved IRRAM, applies to infrastructure replacement and other non-revenue producing infrastructure projects. The PUC will allow SWG to assess a surcharge to collect the first year IRRAM budget of $232,665 in Southern California, $48,345 in Northern California, and $58,942 in South Lake Tahoe. The first phase of this program will be limited to surveying leaks on Customer Owned Yard Lines (COYL) on school properties. • Southwest will also continue with its Early Vintage Plastic Pipe (EEVP) replacement plan, which it began in 2007. Southwest had proposed to accelerate this program in order to complete replacement of the replacement of Aldyl-A pipe by 2018, however, the Commission denied this proposal. The company will adhere to its current EEVP schedule, which is due to be completed in 2026.	A1012005 (San Diego Gas & Electric) A1012006 (Southern California Gas) A1212024 (Southwest Gas)

Colorado	• In September 2011, Public Service Company of Colorado received approval from the Colorado PUC to implement a pipeline system integrity adjustment tracker to recover costs associated with reliability improvements and compliance with certain federal safety regulations.
	• SourceGas has Rate Schedules for natural gas service that are subject to a System Safety and Integrity Rider ("SSIR") designed to collect Eligible System Safety and Integrity Costs. Eligible project cost include:
	  o Projects in accordance with Code of Federal Regulations ("CFR") Title 49 (Transportation), Part 192 (Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards), Subpart O (Gas Transmission Pipeline Integrity Management), including projects in accordance with the Company's transmission integrity management program ("TIMP") and projects in accordance with State enforcement of Subpart O and the Company's TIMP;
	  o Projects in accordance with CFR Title 49 (Transportation), Part 192 (Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards), Subpart P (Gas Distribution Pipeline Integrity Management), including projects in accordance with the Company's distribution integrity management program ("DIMP") and projects in accordance with State enforcement of Subpart P and the Company's DIMP; and
	  o Projects in accordance with final rules and regulations of the U.S. Department of Transportation's Pipeline and Hazardous Materials
		Docket No. 10AL-963G
		
		Docket No. 15AL-0135G (Xcel)
		
		15AL-0299G (Atmos)

	Safety Administration ("PHMSA") that becomes effective on or after the filing date of the application requesting approval of the SSIR. • The SSIR rate will be subject to annual changes to be effective on January 1 of each year for a period of four years from the first effective date, after which period of time the Company's SSIR Tariff will expire unless the SSIR Tariff is reinstated upon consideration of the Public Utilities Commission of the State of Colorado (the "Commission") of an application filed by the Company no later than six months prior to the expiration date. The SSIR Tariff to be applied to each Rate Schedule is as set forth on the statement of effective rates, charges and fees, Sheet Nos. 8 through 10 of the Rocky Mountain Tariff. • In its March 2015 rate filing, Xcel Energy requested (in addition to its base rate increase) a cumulative increase of $42.9 million attributable to the extension and modification of the pipeline system integrity adjustment, spread out over three years. This mechanism was extended through 2018 on January 27, 2016. • On September 23, 2015, Atmos Energy filed a settlement signed by Commission Staff, the Office of Consumer Counsel, and Energy Outreach Colorado in with the Public Utilities Commission of Colorado in which the settling parties agreed to allow Atmos to separately recover system safety integrity costs through a System Safety and Integrity Rider (SSIR). • Projects eligible for recovery through the SSIR will include high and moderate risk integrity projects that are (a) identified by the Company and approved on a preliminary basis by the Commission based on filing made on or before February 1, 2016 (for 2016 Projects) and on or before each November 1 thereafter (for 2017 and beyond Projects), (b) implemented in consultation with the Staff of the Commission and the Office of Consumer Counsel, and (c) ultimately approved for inclusion in the SSIR by the Commission through a filing made on or before February 1, 2016 (for 2016 Projects) and each November 1 thereafter (for 2017 and beyond Projects). Such SSIR Projects shall be consistent with the Company's compliance with federal and state regulatory requirements including, but not limited to, 49 CFR Part 192, final rules and regulations of the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) and the Environmental Protection Agency (EPA) that become effective on or after the effective date of the SSIR. • The SSIR will be implemented for an initial three year term, from January 1, 2016, through December 31, 2018, and will recover capital investments made between September 1, 2015, and December 31, 2018, that are associated with integrity projects. Atmos will have the right to seek an extension of the initial three-year term in a future filing. This proposal was approved on November 4, 2015.	
Connecticut	• In a June 2011 order, the Public Utilities Regulatory Authority (PURA) approved Yankee Gas' proposal to increase its capital spending on cast iron and bare steel replacement by approximately $13 million in Rate Year 1, and approximately $25 million in Rate Year2. Yankee plans to maintain this $40 million capital spending level (i.e., $15 million authorized in 06-12-02PH01 plus an incremental $25 million) in each subsequent year. The Commission found that this level of spending was reasonable to adequately provide for the integrity of Yankee's pipeline system and it anticipates that this level of replacement will reflect the improvement required by the DIMP regulations. • On January 22, 2014 the Public Utilities Regulatory Authority (PURA) approved a Distribution Integrity Management Program (DIMP) mechanism that allows recovery of the revenue requirement for main replacement activity between rate applications. Additionally, the PURA approved a schedule and budget for system integrity projects that target needed replacement of cast iron mains, bare steel mains and bare steel services.	Docket No13-06-08 Docket No 10-12-02 (Yankee Gas)

District of Columbia	• In February 2012, WGL filed a rate case with the DC PSC in which it proposed to expand its existing pipe replacement program (originally approved in 2007). In the filing, WGL proposes a 5-year accelerated pipeline replacement program and a surcharge recovery of $119 million to be invested in replacement infrastructure. The DC PSC ruled, in part, on this case in May 2013. It denied WGL's request to implement the initial 5 year phase of its Accelerated Pipeline Replacement Program. A decision on WGL's request to recover the costs of its Accelerated Pipeline Replacement Program in a Plant Recovery Adjustment was deferred until a later date. • The DC PSC conditionally approved WGL's program on March 31, 2014. WGL has since received full approval to implement the first five years of a 40-year Accelerated Pipe Replacement Plan (APRP). The APRP is designed to reduce risk and enhance safety by replacing aging, corroded or leaking pipe in the natural gas distribution system. • WGL will spend $110M during this period. The APRP is divided into multiple "programs", three of which were approved in this first phase: o $40 million to replace an undetermined number of bare and/or unprotected service replacements. o $32.5 million to replace 18 miles of bare and unprotected steel main and an undetermined number of services. o $37.5 million to replace 20 miles of cast iron mains.	Case No. 1093
Florida	• On August 14, 2012, the Florida Public Service Commission approved a Gas Reliability Infrastructure Program (GRIP) for Florida Public Utilities Company (FPU) and its partner company, Central Florida Gas (CFG). Under the program, the two providers plan to replace more than 350 miles of pipeline over the next ten years. At that time the Commission approved the same program for Chesapeake Utilities. • Also on August 14, 2012, the Florida PSC approved a GI Cast Iron/Bare Steel Replacement Rider for TECO Peoples Gas Systems. Under that program, TECO is expected to invest approximately $8 million and over the course of ten years will replace 150 miles of cast iron and 400 miles of bare steel pipeline, comprising about 4 percent of the company's system. • On September 15, 2015, the Florida Public Service Commission (PSC) issued an order approving Florida City Gas' (FCG) request to implement the Safety, Access, and Facility Enhancement (SAFE) program that is to replace aging pipes to improve system safety and reliability, FCG's SAFE program encompasses a 10-year, $105 million project that is to relocate and replace 254.3 miles of 4-inch and smaller mains and associated facilities from rear property easements to the street front. The relocation and replacement program will remove most of the utility's 61.3 miles of unprotected steel mains and improve service reliability, safety, and facility access. Expenditures for the first full calendar-year of the program will not exceed $9.5 million. • Recovery of the revenue requirement associated with the SAFE program, including a return on the investment, depreciation, ad valorem taxes, income taxes, and noticing expenses will be effectuated through a surcharge mechanism. The cost to remove the facilities identified in the SAFE program will not be recovered through the surcharge; rather, they will be recovered through the cost of removal component in FCG's existing depreciation rates.	Docket No. 120036-GU (GRIP for FPU/CFG and Chesapeake Utilities) Docket No. 110320-GI (GI Replacement Rider for TECO) Florida PSC News Release (8/14/2012) Docket No. 150116-GU Florida City Gas
Georgia	• In 1998, AGL Resources began a 15 year Pipeline Replacement Program (PRP), which, at the time, was reviewed annually by the Georgia PSC—the PSC reviewed the utility's infrastructure replacement expenses from the previous year and then approved a new surcharge amount. Later, the commission agreed to a fixed dollar amount of expense to be recovered in rates over the remaining 7 years of the program. • In 2009, the Georgia PSC approved the expanding of the PRP to include investments for infrastructure expansion. PRP is now included as part of the Strategic Infrastructure Development and Enhancement (STRIDE) Program for AGL Resources. STRIDE provides for a rider on customer bills that will allow	Docket Nos. 8516 & 29950 (Approving Georgia STRIDE Program) Docket No. 12509-U (Atmos – now Liberty)

	AGL to recover costs associated with both traditional infrastructure replacement, as well as infrastructure expansion relating to customer growth and economic development. • In 2000, Liberty Utilities (then Atmos) received approval to implement a pipe replacement surcharge for its Georgia customers. • In September of 2013, AGL received approval to replace 756 miles of vintage plastic pipe over 4 years.	
Illinois	• In May 2013, the Illinois General Assembly passed the Natural Gas Consumer, Safety and Reliability Act (SB 2266). The legislation will allow utilities to make incremental investments in infrastructure upgrades and recover those costs through a rider on customer bills. The rider/surcharge is to be regularly reviewed by the ICC. In addition, the measure requires utilities to file annual plans with the ICC detailing performance improvements and reporting on progress. Performance improvements may include decreases in time to respond to gas emergency calls and/or preventing damage caused by utility or contractor error. • The Illinois Commerce Commission has authorized a cost recovery mechanism for the work, known as the rider qualified infrastructure program, that went into effect January 1, 2014 and sunsets after 2023. The rider enables Peoples to recover its costs with only a one-month cash flow lag, eliminating the regulatory lag between rate cases, and allows the company to earn a return on investment based on the cost of capital established in the most recent rate case. • Peoples had been replacing roughly 45 miles of cast iron and ductile iron main with modern polyethylene pipes annually, but in 2011 the utility ramped up the replacement program, aiming to tackle nearly 2,000 miles of gas pipe, or 40% of the company's system, over two decades. • On April 7, 2014, Nicor Gas filed for its infrastructure replacement surcharge with the ICC. Nicor's plan calls for approximately $171 million in spending in each of the three years beginning in 2015. Entitled the Qualifying Infrastructure Plant (QIP) tariff, this surcharge will allow NICOR to replace hundreds of miles of aging distribution lines and thousands of natural gas services. The company also plans to upgrade gas transmission and storage systems and refurbish regulating stations. This application was approved on July 30, 2014. This plan will allow the company to replace approximately 125 miles of gas mains and 15,000 natural gas service lines. The following projects are eligible for recovery under the QIP: 1) Replacing cast iron main and related services; 2) Replacing non-cast iron main, which may include wrought iron, ductile iron, unprotected coated steel, unprotected bare steel, pre-1973 DuPont Aldyl "A" polyethylene, polyvinylchloride ("PVC") plastic, or other vintage materials, and related services; 3) Replacing copper services; 4) Replacing high-pressure transmission pipelines and associated facilities; and 5) Replacing and/or installing regulator stations, regulators, valves, and associated facilities. • In August of 2014, Ameren Illinois announced its plan for a 10-year, $400 million overhaul of its natural gas distribution in central and southern Illinois. When the project is completed, up to 350 miles of steel pipe will be replaced with polyethylene pipe. The project includes upgrades to 70 stations that regulate gas from interstate pipelines and adding over 450,000 'smart meters.' • On January 6, 2015, the ICC approved a QIP rider for Ameren Illinois.	<u>Natural Gas Consumer, Safety and Reliability Act</u> (Passed by legislature 5/28/13, Signed by Governor Quinn 7/5/13, Public Act 98-0057) <u>Case Number: 14-0292 Nicor Gas</u> <u>Case Number 14-0573</u> Ameren Illinois QIP
Indiana	• In 2013, the state legislature passed a bill that allowed for gas utilities to apply for a cost recovery tracker for infrastructure upgrades and extensions; under the legislation, utilities may propose a 7 year infrastructure plan to the IURC,	<u>Indiana SB 560</u> (Became Public Law No. 133-2013 on 5/1/2013)

	and, if considered reasonable, the utility may recover its investment in a timely manner through a tracker on the customer's bill. • In 2008, Indiana Gas (Vectren Corp.) received approval to implement a tracking mechanism that allows the utility to defer expenses associated with investments in infrastructure and replacement projects. • In 2006, Southern Indiana Gas and Electric Company (Vectren Corp.) received approval of a tracking mechanism for recovery of an accelerated bare steel and cast iron pipeline replacement program. • NIPSCO field its 7 year plan with the IURC on October 3, 2013. Among the projects which NIPSCO will pursue over the next seven years: installing 80 miles of transmission pipeline and adding automated valves ($280 million); eliminating bare steel gas mains and replacing them with low pressure systems ($61 million); and retrofitting lines for in-line inspection ($46 million).This plan was approved on April 30, 2014. • Vectren filed its 7 year plan with the IURC on November 26, 2013. The plan includes the replacement of 800 miles of bare steel and cast iron distribution mains with new mains in the 13,000-mile network in Vectren North, inspecting and upgrading its pipelines, and the expansion of gas delivery infrastructure to rural areas, which call for an estimated $650 million investment. The company will also replace 300 miles of bare steel and cast iron distribution mains with new mains in the 3,200-mile network of Vectren South, which call for an estimated $215 million investment. The costs will be recovered through a fixed charge to be included in residential customers' monthly bills. Gas bills will not be adjusted for these expenditures until 2015, with modest increases in adjustments up to 2021. The IURC approved this plan on August 27, 2014. • On March 30, 2016, the Indiana Utility Regulatory Commission approved gas infrastructure modernization projects representing $890 million in investments supported by recovery mechanisms for Vectren as part of the company's third update to its initial 7 year plan.	Case No. 43298 (Indiana Gas) Case No. 43112 (Southern Indiana Gas and Electric Company) Cause Number 44403 (NIPSCO) Cause number 44429 (Vectren)
Iowa	• In October 2011, the Iowa Utilities Board adopted a rule that allows the state's natural gas utilities to implement either of two types of automatic adjustment mechanisms for recovery of a limited number of capital infrastructure investments outside of a general rate case, including those that are required by government mandates or are required by state or federal pipeline safety mandates. To date no utility has implemented either of the two types of mechanisms for cost recovery. • Effective April 25, 2013, the Iowa Utilities Board has approved tariffs implementing a capital infrastructure investment automatic adjustment mechanism. • Black Hills utilizes this rider.	Docket No. RMU-2011-0002 (October 2011) Docket No. RPU 2002-0004 (April 2013)

Kansas	• In 2006, the Kansas State Legislature passed the Gas Safety and Reliability Policy Act, which approved the implementation of a gas system reliability surcharge (GSRS) between 0.5% and 10% of revenues to recover new infrastructure replacement costs not already included in rates; Atmos, Black Hills, and Kansas Gas Service utilize the surcharge. • GSRS balances are rolled into base rates in its next rate case. GSRS riders may be used for up to five years (or up to six years under certain circumstances) and the utilities must file new rate cases if their riders are to remain in place. GSRS rate changes may not be requested more frequently than every 12 months. Annualized GSRS revenues may not exceed 10% of the utility's base revenue level, as approved in its most recent rate case. GSRS rate changes are not permitted if they are less than 0.5% of the utility's base revenue level, or $1 million, whichever is lower. • On March 12, 2015, the Kansas Corporation Commission opened the General Investigation Regarding the Acceleration of Replacement of Natural Gas Pipelines Constructed of Obsolete Materials. In the Order Opening General Investigation, Staff reported that after meetings with Kansas natural gas utilities and Commission work studies, they had developed a framework with eleven parameters for a pipeline replacement program that could be uniformly applied to Kansas natural gas utilities. This proceeding is presently pending. • In its August 2015 rate filing, Atmos Energy proposed to implement a system integrity program (SIP) rider that would allow the company to accelerate the replacement of certain obsolete components of its distribution system. The SIP rider, which would be in place for a five-year pilot term and would be updated on a quarterly basis, is intended to address the "capital investment lag" associated with the GSRS and a $0.40 per customer, per month statutory cost recovery cap that applies to the GSRS. This proposal was rejected on March 17, 2016.	K.S.A 66-2201 through K.S.A 66-204 (Gas Safety Reliability Policy Act) Docket No. 16-ATMG-079-RTS (Atmos) Docket No. 15-GIMG-343-GIG
Kentucky	• In 2005, pursuant to passage of KY HB 440, Kentucky created a new section in the Kentucky Revised Code titled "Recovery of Costs for Investments in Natural Gas Pipeline Replacement Programs," which allows the commission to approve the recovery of costs for investment in natural gas pipeline replacement programs which are not recovered in the existing rates of a regulated utility; Atmos, Columbia Kentucky, Delta Natural Gas, and Duke Energy Kentucky utilize such programs.	KRS 278.509 Case No. 2009-00141 (Columbia Gas of Kentucky) Case No. 2009-00354 (Atmos) Case No. 2005-00042 (Duke Energy Kentucky) Case No. 2010-00116 (Delta Natural Gas)
Louisiana	• CenterPoint utilizes a rate stabilization program (Rider RSP) to change its rates annually to reflect higher capital investment (rate base) and higher O&M costs relating to pipeline safety and other factors. • Under this program, for each twelve month period ended June 30, a determination shall be made pursuant to this Rider RSP as to whether the Company's revenue should be increased, decreased or left unchanged. If it is determined that the revenue should be increased or decreased, the natural gas rate schedules incorporating this Rider RSP will be adjusted accordingly. • On June 6, 2014, Atmos Energy received approval to establish a regulatory asset using an accounting deferral to recover significant increases in the amount of investment made for the replacement of its aging infrastructure. The mechanism will be reviewed annually as part of the Rate Stabilization Clause (RSC) filing. • In January of 2015, Entergy Gulf States received permission to start replacing many of the old pipes that carry natural gas in Baton Rouge. In the first	CenterPoint Rider RSP Docket U-32987 (Atmos) U-32682 (Entergy Gulf States)

	phase, Entergy is replacing about 25 miles of cast iron pipe, then another two miles of bare steel, Another 72 miles of vintage plastic will be replaced in phase three. The Louisiana Public Service Commission, voted 3-1 to approve a special rider to pay for the work.	
Maine	• In 2011, the Maine Public Utilities Commission authorized Northern Utilities to implement a limited, one year, incremental step adjustment of $0.9 million effective 5/1/2012 to reflect investments made under the company's Cast Iron Replacement Program (CIRP); Initially the utility had sought a targeted infrastructure replacement adjustment (TIRA) tracker to reflect incremental CIRP investments; The Commission did not approve a permanent tracker, instead opting for the more limited mechanism for one year. • On December 17, 2013, the Maine Public Utilities Commission ("MPUC"), during its public deliberations, voted unanimously to approve a Settlement and Stipulation ("Stipulation") in Docket No. 2013-00133, the base rate proceeding for the Maine division of Northern Utilities, Inc. Unitil Corporation's natural gas distribution utility subsidiary. • The Stipulation included a Targeted Infrastructure Replacement Adjustment ("TIRA") rate mechanism, which will provide for annual adjustments to distribution base rates in future years to recover costs associated with the Unitil's investments in specified operational and safety-related infrastructure replacement and reliability upgrade projects to its natural gas distribution system. The TIRA will have an initial term of four (4) years, and applies to investments made in eligible facilities in each of the calendar years 2013, 2014, 2015, and 2016.	Docket No. 2011-92 Docket No. 2013-00133
Maryland	• On February 22, 2013, the Maryland General Assembly passed SB 8, legislation that allows a gas company to recover costs associated with infrastructure replacement projects through a gas infrastructure replacement surcharge on customer bills. The bill specifies how the pretax rate of return is calculated and adjusted and what it includes, and states that it is the intent of the General Assembly to accelerate infrastructure improvements by establishing this mechanism for gas companies to recover reasonable and prudent costs of infrastructure replacement. • As of November 7, 2013, Washington Gas Light, Baltimore Gas and Electric and Columbia Gas of Maryland had all filed for approval of their STRIDE plans with the Maryland PSC. • On January 29, 2014, The Maryland PSC approved the first phase of Baltimore Gas and Electric's (BGE) $400 million, 30-year gas STRIDE Plan. BGE's plan targets five specific areas for improvement, including bare steel mains, cast iron mains and bare steel services. It calls for the replacement of the company's 42 miles of bare steel mains within 15 years and 1,292 miles of cast iron mains within 30 years. • On January 31, The Maryland PSC the Maryland Public Service Commission (PSC) rejected Columbia Gas of Maryland's (CGM's) proposed STRIDE plan and associated rider mechanism, finding that the plan failed to meet certain statutory requirements. In addition, the PSC found that the STRIDE plan would not improve safety and reliability in the gas distribution system, because the plan "does not keep pace" with the company's current replacement rate of aging mains and services and would thus decelerate its infrastructure replacement activity. The Commission noted that it may approve a gas infrastructure replacement plan in accordance with state law if it finds the proposed investments and estimated costs of eligible projects to be: reasonable and prudent; and, designed to improve public safety or infrastructure reliability. The PSC directed CGM to submit an amended application addressing the issues within 60 days; the Commission indicated that it would consider an amended application on an expedited basis. • On May 6, 2014, the Public Service Commission of Maryland (MDPSC) issued an Order conditionally approving Washington Gas' amended accelerated pipeline replacement plan, commonly referred to as STRIDE, which will	Maryland SB 8 (Enrolled 5/2/2013, MD Chapter No. 161) Case No. 9331 Case No. 9332 Case No. 9335

	accelerate natural gas infrastructure upgrades and replacement projects. The plan will also provide current cost recovery for the company, reduce greenhouse gas emissions and costs to utility customers. Washington Gas has accepted the conditions and will be able to recover eligible infrastructure replacements costs for projects initiated after January 1, 2014, that are not included in current base rates. The STRIDE surcharge will not exceed $2.00 per month for residential customers. Washington Gas will provide the MDPSC with an updated list of planned STRIDE projects for 2014 by June 5, 2014. Audits will be performed following each program year. • On August 18, 2014 the Maryland Public Service Commission (PSC) conditionally approved Columbia Gas of Maryland's (CGM's) proposed infrastructure replacement and improvement plan (IRIP) and an associated annually-adjusted rider (IRIS). CGM accepted the conditions and the IRIS surcharge will begin recovery of the forecasted $8.9 million of eligible investment. The IRIS mechanism covers investments made from January 1st through December 31st of each year. Audits will be performed following each program year.	
Massachusetts	• Several of the state's utilities utilize a Targeted Infrastructure Reinvestment Factor (TIRF) for cost recovery of infrastructure replacement: ○ Columbia Gas of Massachusetts received approval for its TIRF in 2009. The TIRF allows for the recovery of the revenue requirement associated with bare steal capital additions for the previous calendar year ○ National Grid companies Boston Gas, Essex Gas and Colonial Gas received approval for a TIRF as part of a 2010 general rate case. The TIRFs provide for the recovery of costs associated with the accelerated replacement of gas mains and the companies are allowed to surcharge customers up to 1% of total revenue ○ New England Gas (Now Liberty Utilities) received authorization to implement a TIRF to provide recovery of incremental expenditures associated with reinforcing the system and meeting public safety goals • On February 28, 2014, the Massachusetts Department of Public Utilities issued an order in Columbia Gas of Massachusetts' (Columbia) rate case (DPU 13-75) which allowed Columbia to increase the annual cap on amounts collected under the TIRF mechanism from 1% to 3.75% of distribution revenues. • Governor Deval Patrick signed H. 4164 into law on June 26, 2014. The bill provides for the following: ○ Civil penalties for violations of federal pipeline safety regulations; ○ Uniform natural gas leak classification for all gas companies; ○ Grade 1 leaks defined as representing an existing or probably hazard to persons or property and requiring immediate action; ○ Grade 2 leaks defined as non-hazardous to persons or property at time of detecting but justifies scheduled repair based on future hazard; Requires company to replace the main within 1 year from date of leak classification; ○ Grad 3 leaks defined as non-hazardous to persons or property and can be reasonably expected to remain non-hazardous; Requires utilities to reevaluate during scheduled surveys or within 12 months until the main is replaced; ○ Prioritization of pipeline repairs in school zones ○ Cost recovery for eligible infrastructure replacement programs; ○ Eligible plans shall include, but not be limited to, the following: ○ Eligible infrastructure replacement of mains, services and meter sets composed of non-cathodically protected steel, cast iron and wrought iron prioritized to implement the federal DIMP plan annually submitted to the department ○ Anticipated timeline for the completion of each project—timelines should include a target end date of either not more than 20 years or a	Docket No. DPU 09-30 (Columbia Gas of Massachusetts) Docket No. DPU 10-55 (National Grid) Docket No. DPU 10-114 (New England Gas) Docket No. DPU 13-75 (Columbia Gas of Massachusetts) H 4164 DPU 14-130 Unitil GSEP DPU 14-131 Berkshire Gas GSEP DPU 14-132 National Grid GSEP DPU 14-133 Liberty Utilities GSEP DPU 14-134 Columbia Gas of Massachusetts GSEP DPU 14-135 NSTAR Gas GSEP

	reasonable target end date considering the allowable recovery cap established o Estimated cost of each project o Rate change requests o Customer costs/benefits under the plan o An expansion component which permits the DPU to authorize gas utilities to design and offer programs to customers which will increase the availability, affordability and feasibility of natural gas service for new customers; o A direction for the DPU to issue a report addressing the prevalence of natural gas leaks in the natural gas system including estimates for the number of Grade 1, 2 and 3 leaks and estimates for lost and unaccounted for gas and methane emissions. • Pursuant to H. 4164 (now G.L. c. 164, § 145), National Grid, Unitil, NSTAR Gas, Columbia Gas of Massachusetts, Liberty Utilities and Berkshire Gas all filed Gas System Enhancement Program Plans (GSEP) for 2015 on October 31, 2014. These plans were approved on April 30, 2015. • These plans will allow for the removal of all cast iron and bare steel mains to be eliminated in 20 years for National Grid, Unitil, Columbia Gas of Massachusetts, Liberty Utilities and Berkshire Gas and 25 years for NSTAR Gas.	
Michigan	• In January 2011, the Michigan PSC adopted a settlement that establishes a main replacement program rider. The mechanism will enable SEMCO Energy to recover the incremental capital-related costs associated with the accelerated removal and replacement of cast iron and unprotected steel service lines and mains. The program expires in 5 years unless extended by order or new rate case. • In June 2012, the Commission approved a settlement in a Consumers Energy gas rate case that will fund a main replacement program at $56 million annually until the program is reviewed and spending is reset by the Commission in a general rate proceeding. • In May 2013, the Commission approved an expanded main replacement program proposed by SEMCO Energy Gas Company that will double the amount spent annually on the program and double the miles of main replaced annually. Coupled with its existing program, SEMCO will replace 40.6 miles of high-risk main annually. This will allow SEMCO to accelerate the installation of excess flow valves at the homes of its customers, helping to protect customers in case of a service line leak. • On April 16, 2013, the Michigan PSC approved an expanded gas main replacement program (MRP) and a pipeline integrity program, and the recovery of the costs of those programs, as well as the ongoing meter move-out program, through an infrastructure recovery mechanism (IRM) for DTE Gas Company. This order allowed the company to accelerate its annual pace of main replacement from 30 miles to 66 miles per year. • On January 13, 2015, the Michigan Public Service Commission (PSC) adopted a settlement in a Consumers Energy (CE) gas base rate case. The settlement provides for an Enhanced Infrastructure Replacement Program (EIRP). The EIRP is a twenty-five year incremental investment program to upgrade natural gas infrastructure, including approximately 540 miles of cast iron pipe. The EIRP is based on transmission and distribution integrity management principles intended to eliminate cast iron pipe and other high-risk components as identified through existing federal and state code requirements. CE projects that it will spend about $75 million per year under the EIRP. • On June 3, 2015, The Michigan Public Service Commission (MPSC) approved a settlement agreement that authorized SEMCO Energy Gas Company to extend its natural gas main replacement program (MRP) and increase its MRP surcharge, effective with the next full billing cycle. The surcharge will continue	Docket No. U-16169 (SEMCO) Docket No U-16999 (DTE) Docket No. U-16855 (Consumers) Case No. U-17643 (Consumers EIRP) Case No. U-17701 (DTE) Case No. U-17824 (SEMCO)

	until the earlier of either the establishment of base rates in a future contested case addressing the MRP through self-implementation or Commission order, or May 30, 2020.
	• Under the terms of the settlement, the parties agreed that SEMCO will:
	  o continue to annually replace 26 miles of main through the MRP and 14.6 miles under the base program, for a total of 40.6 miles of main from 2016 through 2020;
	  o spend on average approximately $10.1 million annually for a total of $50.5 million on main replacement for 2016 through 2020;
	  o not file any further requests for expansion, continuation, or modification of the MRP surcharge outside of a general rate case, unless there is a change in the law addressing infrastructure replacement programs; and
	  o File an MRP planning report and MRP performance report by March 31 of each year for that year's main replacement spending.
	• On November 12, 2014, DTE Gas filed an application with the Michigan PSC to further improve the overall safety and reliability of the DTE Gas distribution system by revising its Main Replacement Program ("MRP" or "Program") to increase MRP capital expenditures by $46.9 million annually in 2016 and 2017 and increase the Infrastructure Recovery Mechanism ("IRM") surcharge to recover the capital costs associated with the Program. This program would accelerate the company's pace of replacement to approximately 120 miles per year. (Case No. Case No. U-17701).
	• On November 23, 2015, the Michigan Public Service Commission (PSC) issued a decision that modified DTE's proposal and authorized the company to expand its Main Replacement Program in 2016 by $15.6 million above the previously-approved spending levels, and to increase spending in 2017 by $31.4 million above previously-approved spending levels, contingent upon 2016 targets being met.
	• Additionally, the PSC directed its Staff to meet with DTE prior to July 1, 2016, to reassess the utility's target mileage for 2016 main replacement. In reassessing the target mileage for 2016, Staff is to consider all relevant information and documents provided by the company, the authorized increase for 2016, and the fact the utility exceeded mileage targets and completed more main replacement than expected under the current MR program to date. The PSC also determined that the parties should reassess 2017 targets in a similar manner prior to July 1, 2017, and that authorization of the 2017 spending increase is subject to reduction back to 2016 levels if 2016 targets are not substantially completed.	

Minnesota	• In May 2013, the Minnesota legislature passed an Omnibus jobs, economic development, housing, commerce and energy bill which included a rider for the recovery of gas utility infrastructure costs. Under the legislation, a gas utility may submit a gas infrastructure project plan report and a petition for cost recover. Upon receiving those items, the Minnesota Public Utilities Commission may approve a rider provided that the costs included for recovery through the rate schedule are prudently incurred and achieve gas facility improvements at the lowest reasonable and prudent cost to ratepayers. • In August of 2014, Xcel Energy stated in a regulatory filing that it intends to spend $15 million in 2015 on pipeline safety improvements, which is roughly a twofold increase over past levels. In future years, the company envisions even larger safety-related investments, peaking in 2019 at more than $50 million. Should the Minnesota Public Utilities Commission approve the 2015 investment, it would increase customers' bills 3.5 percent in January, about $2 per month for a typical customer, the company said. Future investments could bring more increases, though they would need separate regulatory approval.	Minnesota H.F. 279 (As enrolled, 5/23/2013) Docket No. 14-336 (Xcel)

	• On January 27, 2015, The Commission approved Xcel's proposed GUIC rider, rate-adjustment factors, and tariff sheets with the following modifications:
	  ○ A rate of return calculated using the capital structure and cost of debt from Xcel's electric rate case, Docket No. E-002/GR-13-868, and the cost of equity from its last natural-gas rate case, Docket No. G-002/GR-09-1153;
	  ○ A rate design that allocates the 2015 revenue requirement to Xcel's customer classes in the same manner as revenues were apportioned in the Company's February 28, 2011 compliance filing in its last natural-gas rate case; and
	  ○ An effective date of the date of this order, with final rate-adjustment factors calculated to recover the 2015 revenue requirement over the remaining months of 2015.
	• The Commission also determined that sixty days in advance of its next annual GUIC filing, Xcel shall submit information on what it believes the appropriate rate of return should be for the coming year. Lastly, in the initial filing in its next natural-gas rate case, Xcel must submit detailed schedules, any necessary supporting documentation, and an explanation of all O&M costs that were being recovered in the rider and are now included in the test year for recovery in base rates.	

Mississippi	• CenterPoint utilizes a rate stabilization mechanism (RRA Plan) to change its rates annually to reflect higher capital investment (rate base) and higher O&M costs relating to pipeline safety and other factors.
	• For each twelve-month period ending December 31, a Commission determination shall be made pursuant to this RRA Plan as to whether the Company's revenue should be increased, decreased or left unchanged.
	• On September 8, 2015, the Mississippi Public Service Commission approved a stipulation which approved Atmos Energy's proposal to establish a long term system integrity plan and accelerate an investment program to make its system safer and ensure full compliance with federal (DOT/PHMSA) pipeline safety directives.
	• The docket involved a comprehensive review of Atmos Energy's planned system integrity spending over the next 10 years and projected rate impact.
	• Among the key provisions approved:
	  ○ A rigorous annual review of Atmos Energy's proposed system integrity projects for the next fiscal year and annual rate impact, including
	  ○ Project spending
	  ○ Project objective and regulatory requirement being met
	  ○ Start and completion dates
	  ○ Historical spending analysis
	  ○ Project analysis including safety benefit/alternatives considered/engineering support
	  ○ Annual summary of operational metrics/savings/safety reports
	  ○ A rolling five-year capital spending plan update including estimated rate impacts
	  ○ Rate recovery though a combination of fixed and volumetric rates
	  ○ Estimated impact of the first year of implementation (begins November 2016) is $0.85/month per residential customer
		CenterPoint RRA Plan
		
		Docket No. 2015-UN-049
		(Atmos SIP)

Missouri	• Missouri established an Infrastructure Replacement Surcharge (ISRS) mechanism as part of a revision to Missouri Statute 393.1009-105. The ISRS allows rates of a gas utility to be adjusted twice per year to provide for the recovery of costs of eligible infrastructure replacements. Companies that utilize the ISRS must file a rate case at least every 3 years; Ameren, Liberty Utilities, Laclede and Missouri Gas Energy use an ISRS mechanism. • The Missouri Legislature had considered legislation that would modify the provisions outlined above. SB 240 would have required the PSC to specify the annual amount of net write-off incurred by a gas corporation, after which the company would be allowed to recover 90% of the increase in net write offs	Missouri Statute 393.1009-1015 Missouri SB 240 (Final Passage on 5/9/13; Governor Nixon vetoed this legislation on 7/9/13)

	from customers. The legislation would have also modified the provisions above by extending the amount of time in which a company must come in for a rate case to be eligible for the ISRS from three years to five years. It would have also increased the amount a utility may recover through ISRS from 10% of the company's base revenue level to 13%. This legislation was vetoed by Governor Nixon on July 9, 2013. • In January of 2014, Laclede Gas filed for a $7.4 million increase in its ISRS, revenues to recover investments in replacement of distribution pipelines over the previous 13 months. Laclede proposed to spend $7.1 million annually from the new charge to fund roughly 68 miles of gas main replacements. This request was approved on April 3, 2014.	
Nebraska	• In 2009, Nebraska established an Infrastructure System Replacement Surcharge (ISRS) as part of revisions to Nebraska Statutes 66-1865, 66-1866 and 66-1867. The ISRS allows the rates of a gas utility to be adjusted twice per year to provide for the recovery of costs of eligible infrastructure replacements. Companies that utilize the ISRS must file a rate case at least every 5 years. • SourceGas and Black Hills currently utilize these riders.	NRS 66-1865, 66-1866, 66-1867
Nevada	• As part of its GRC in 2011, Southwest Gas proposed a Gas Infrastructure Recovery Mechanism (GIR) that would have allowed the utility to invest in incremental non-revenue producing projects and collect on an annual basis the revenue requirement associated therewith. The GIR was not approved as part of the rate case; however, the Commission opened a rulemaking to develop regulations to facilitate the implementation of a GIR-type of recovery mechanism. Pursuant to the rulemaking, Southwest Gas is proposed a mechanism to allow the capital cost of qualifying investments to be deferred, and the associated revenue requirement recovered on an interim basis until its next general rate case. • On January 8, 2014, the Nevada Public Utilities Commission approved regulations establishing an application process for accelerated recovery of eligible costs associated with replacing natural gas pipelines to address safety and reliability concerns that are incurred by operators in between general rate cases.	Docket No. 11-03029 (2011 GRC) Docket Nos. 12-04005 and 12-02019
New Hampshire	• Energy North (now Liberty Utilities) established a Cast Iron Bare Steel (CIBS) Replacement Program as part of the National Grid/KeySpan merger settlement agreement approved by the Commission in Order No. 24,777 on July 12, 2007, in Docket No. DG 06-107. • In, 2009 National Grid (now Liberty Utilities) proposed to modify its annual CIBS rate adjustment mechanism to include public works projects and to eliminate the $0.5 million annual threshold required prior to cost recovery. In a March 2011 settlement, the New Hampshire PUC called for the CIBS rate adjustment mechanism, as it was originally structured, to remain in effect.	Docket No. DG 10-1017

New Jersey	• In 2009, the New Jersey Board of Public Utilities approved accelerated infrastructure programs for five of the seven major utilities that had filed such plans. In total, the plans provide that the utilities will invest $956 million in incremental infrastructure and energy efficiency programs over the following two years, and the costs of the various programs were to be recovered through various, separate adjustment mechanisms (see below).
	  o New Jersey Natural Gas: In 2009, New Jersey Natural Gas received approval to invest $71 million in new infrastructure and system upgrades, which it completed in 2011. In 2011, the utility was granted approval for an additional $60 million. The recovery mechanism is not a traditional tracker or surcharge—the utility is recovering the costs through adjustments to base rates
	  o Elizabethtown Gas: The utility implemented the Utilities Infrastructure Enhancement Program in 2009, which includes both the costs of replacing cast iron pipes and investments in specified new main extensions. The recovery mechanism was through a surcharge. In 2011,
		Docket No. GO09010052 (New Jersey Natural Gas)
		
		Docket No. GO09010053 (Elizabethtown Gas)
		
		Docket No. GO09010050 (PSE&G)
		
		Docket Nos GR09110907, GR10100765,

	the utility was granted approval for the extension of the program through 2012, and the recovery mechanism continued to be a surcharge until October 2011 when the surcharge rolled into base rates o PSE&G: In 2009, the utility received approval for an infrastructure investment program. The recovery mechanism, the Capital Adjustment Charge (CAC), is a deferral account that is adjusted each January based on forecasted program expenditures. o South Jersey Gas: In 2009, South Jersey Gas received approval for its Capital Investment Recovery Tracker (CIRT) mechanism. The program has gone through several revisions in the last several years (CIRT-I, CIRT-II, CIRT-III) • In October of 2012, New Jersey Natural Gas received approval from the New Jersey Board of Public Utilities (BPU) to implement its Safety Acceleration and Facility Enhancement (SAFE) program. Through SAFE, NJNG will replace 276 miles, or approximately 50 percent, of the cast iron and unprotected steel mains and associated services in its delivery system over the next four years. • In August 2013, Elizabethtown Gas received unanimous approval from the New Jersey BPU to implement its Accelerated Infrastructure Replacement (AIR) program. The agreement will enable Elizabethtown Gas to invest up to $115 million over a four-year period to enhance the safety, reliability and integrity of the utility's distribution system. Under the terms, Elizabethtown Gas will file a rate case no later than September 1, 2016 at which time the AIR program costs will be subject to review. During the AIR program, Elizabethtown Gas will accrue Allowance for Funds Used During Construction (AFUDC) related to project expenditures during the construction period, and accrue associated carrying costs from the time the project is placed in service until the time its costs are recovered through base rates. This program allows the company to replace approximately 30 miles of year of cast and bare steel mains per year. • In the aftermath of Hurricane Sandy, Public Service Electric & Gas Co (PSEG) has proposed a multi-billion dollar network hardening plan to improve resiliency and allow its electric delivery system to recover more quickly after damaging events. Had it been approved as PSEG proposed, the program, referred to as Energy Strong, would have allowed PSEG to will invest $1.1 billion into gas service system upgrades over a 10-year period to proactively protect and strengthen its systems against increasingly frequent severe weather. • On May 21, 2014 the New Jersey BPU adopted a settlement approving PSEG's Energy Strong infrastructure improvement program and related surcharge mechanisms. PSEG will improve its natural gas infrastructure over a three-year period. Under the now-approved settlement, over the next three years PSEG is to expend on natural gas investments: $350 million to replace and modernize 250 miles of low-pressure cast iron gas mains in or near flood areas and $50 million to protect five natural gas metering stations and a liquefied natural gas station affected by Hurricane Sandy or located in flood zones. • On July 23, 2014, the New Jersey Board of Public Utilities (BPU) approved New Jersey Natural Gas' (NJNG's) New Jersey Reinvestment in System Enhancements (NJ RISE) infrastructure program. The NJ RISE program is comprised of multiple investments over a five-year time frame of $102.5 million in gas distribution storm hardening and mitigation projects. The BPU also authorized an annual adjustment mechanism for this program. This mechanism covers program costs incurred through July 31, 2015. A base rate case must be filed no later than November 15, 2015. All costs incurred after July 31, 2015 will be addressed in the base rate proceeding. • Also on July 23, 2014, the BPU approved the Elizabethtown Natural Gas Distribution Utilities Reinforcement Effort (ENDURE) program, under which the company was authorized to invest approximately $15 million over a one-	GO1100632 (South Jersey Gas) PSEG Energy Strong Order Docket No. GO12070693 (Elizabethtown Gas AIR Order) Docket No. GR13090828 (New Jersey Natural Gas RISE Order) Docket No. GR13009814 (South Jersey Gas SHARP Order)

year period from January 1, 2014 to December 31, 2014 in its natural gas infrastructure to prevent damage from future major storm events, and to improve communication during and after weather-related emergencies. Elizabethtown Gas proposed to defer the costs of the program, with recovery of the ENDURE program-related deferrals to be determined in a base rate case to be filed in 2016.

- On August 20, 2014, the New Jersey Board of Public Utilities approved the South Jersey Gas's $103.5 million storm hardening and reliability program (SHARP) to improve its infrastructure in advance of significant weather events. SHARP, which is expected to be completed in the next three years, will replace roughly 93 miles of natural gas mains and approximately 11,100 associated services. Program costs will be recovered through annual adjustments to South Jersey Gas base rates on October 1st of each year of the program. There will be no immediate impact to customer bills.
- On March 2, 2015, PSE&G filed a proposal with the New Jersey Board of Public Utilities to invest $1.6 billion over the next five years to proactively modernize its gas systems. PSEG's Gas System Modernization Program would include replacing an average of approximately 160 miles of cast iron and unprotected steel gas mains, and about 11,000 unprotected steel service lines to homes and businesses per year, over the five year period of the program.
- On September 15, 2015, PSE&G announced a $905 million settlement in principle with the staff of the New Jersey Board of Public Utilities (BPU) and the New Jersey Division of Rate Counsel to expedite the replacement of aging gas pipelines. The settlement will enable the company to replace up to 510 miles of gas mains and 38,000 service lines over the three-year period.
- Under the agreement, PSE&G will earn a return on equity of 9.75 percent on $650 million of investment based on an accelerated recovery mechanism, and will seek to recover the remaining $255 million in a base rate case, to be filed no later than November 1, 2017. This agreement was approved on November 16, 2015.
- On September 23, 2015, Elizabethtown Gas Co. filed a plan a 10-year, $1.1 billion infrastructure program with the BPU. The program aims to replace 630 miles of aging cast iron, steel and copper pipelines.
- The proposed Safety, Modernization and Reliability Tariff plan intends to eliminate all aging pipelines, along with 240 regulator stations associated with the utility's low-pressure distribution system, by 2027,and also includes the installation of excess flow valves on all new service lines, and the transferring of gas meters to the outside of homes and businesses. This matter is presently pending.
- On February 29, 2016, South Jersey Gas (SJG) filed a petition with the New Jersey Board of Public Utilities seeking to continue its Accelerated Infrastructure Replacement Program (AIRP) for a period of seven years with a total program investment of $500 million. The proposed program will be referred to as AIRP II. Under the AIRP II program, SJG would continue its Distribution Integrity Management Program-based approach to addressing the most significant threats on its distribution system and would replace and retire a significant portion of the vintage and most leak prone mains and services in its distribution system. The company's targets for replacement include:
  - All remaining cast iron and unprotected bare steel mains and associated services;
  - The most leak prone coated steel mains that are 2" in diameter or less and associated services; and
  - Other pipe materials and sizes found within replacement grids that would be logical and necessary to complete the modernization of the grid
- Approval of AIRP II would enable the company to continue enhancing the reliability and safety of its gas distribution system in a cost effective manner,

	achieve increased operational efficiencies and continue the employment benefits that have been created by its previous and existing main replacements programs. SJG proposes to recover the capital investment costs and expenses of the AIRP II program through annual base rate adjustments. The company's first AIRP II rate adjustment filing would be made on April 1, 2017 and there would be no rate adjustment or customer bill impact from the AIRP II program until October 1, 2017. • On November 4, 2016, the New Jersey Board of Public Utilities issued an order approving South Jersey's AIRP II program for the next 5 years. This approval will allow the company to invest $302.5 million in its system over that period. During that period, the utility expects to be able to replace all its aging cast iron and bare steel mains with less leak-prone plastic pipelines. • On September 23, the New Jersey Board of Public Utilities (BPU) adopted a settlement in New Jersey Natural Gas Company's (NJNG) base rate case. As part of the decision, the BPU granted a five-year extension on the utility's Safety and Facilities Enhancement program (SAFE). The SAFE program is a $200 million pipeline replacement effort to modernize NJNG's distribution system. The program allows NJNG to earn an allowance on its invested capital used in construction and request rate increases for spending in annual filings. These annual filings will consider the rate impacts associated with program spending of $157.5 million over its term.	
New York	• Corning Natural Gas has had a limited pipeline replacement cost recovery mechanism since 2006. • National Grid Long Island has had a limited infrastructure replacement tracker program since 2008. The program allows the utility to track only the costs of new or replacement infrastructure that are necessitated by city and state construction projects; National Grid NYC has a similar infrastructure replacement tracker that covers only those costs that are necessitated by city and state construction projects. • National Grid (NYC) uses a risk based prioritization model to identify and rank segments of Leak Prone Pipe (LPP) to be removed from service. The Company will target LPP removal from service of 85 miles in CY 2013 and CY 2014, with a minimum of 40 miles during each calendar year, including at least 10 miles per year outside of City/State Construction-driven work. The Company will incur a negative revenue adjustment of 8 basis points should it fail to remove from service a minimum of 40 miles of LPP in each of CY 2013 and CY 2014 or a cumulative two year total of 85 miles of LPP by the end of CY 2014. • On September 10, 2010, The New York PSC approved a leak prone replacement schedule for New York State Electric and Gas (NYSEG) and Rochester Gas and Electric (RGE). The schedule requires that NYSEG replace a minimum of 24 miles of leak prone main per year and a minimum of 1200 leak prone services per year. RGE shall be required to replace 24 miles of leak prone main per year and 1000 services. • National Grid Niagara Mohawk has had a limited pipeline replacement cost recovery mechanism since 2008. The limited program was scheduled to run for 5 years. • National Grid Niagara Mohawk uses a risk based prioritization model to identify and rank segments of Leak Prone Pipe (LPP) to be removed from service. The Company will target LPP removal of 35 miles in CY13, 40 miles in CY14 and 45 miles in CY15. The Company will incur a negative revenue adjustment of 8 basis points should it fail to remove from service a minimum of 35 miles in CY13 and 35 miles in CY14 or a cumulative three-year total of 120 miles by the end of CY15. • On May 8, 2014, The New York PSC authorized a leak-prone pipe (LPP) removal plan for National Fuel Gas Distribution Corp. The Company will continue to use its risk based prioritization model to identify and rank segments of LPP to be removed from service. The Company will target	Docket No. 08-G-1137 (Corning Natural Gas) Docket No. 09-G-0716/ 09-G-0718 (NYSEG and RGE) Docket No. 06-M-0878 (National Grid Long Island, National Grid NYC, National Grid Niagara Mohawk) Docket No. 13-G-0031 (Con Ed) Docket No. 13-G-0136 National Fuel Docket No. 12-G-0202 (National Grid NIMO) Docket No. 12-G-0544 (National Grid NYC) Docket No. 14-G-0319 (Central Hudson) Docket No. 15-G-0151 (Commission Acceleration Proceeding) Docket No. 15-G-0284 (RGE and NYSEG)

	removal from service of a cumulative total of leak prone pipe of 190 miles over CY 2014 and CY 2015, with a minimum of 90 miles removed in each year. • In February 2014, the New York PSC approved a multi-year Joint Proposal (JP) that resolved all issues in Consolidated Edison's (Con Ed) gas delivery rate proceeding. The JP provided for the following gas related expenditures relating to storm hardening which will allow Con Ed to modernize its system at an accelerated pace: o Rate Year 1: $524.2 million of which $5.021 million will go toward storm hardening; o Rate Year 2: $586 million of which $36.459 million will go toward storm hardening; o Rate Year 3: $627 million of which $56.942 will go towards storm hardening • Con Ed has approximately 1,100 miles of cast iron and bare steel pipe in their inventory in the state, and they replaced approximately 13-20 miles per year over the last four years. Under the new program outlined above, the company will replace 60 miles in 2014, 65 miles in 2015, and 70 miles in 2016. • In June of 2014, National Grid petitioned the Public Service Commission to accelerate the replacement of leak prone pipe on Long Island. On December 11, 2014, The PSC ordered the company to accelerate the annual pace of this program to 77.5 miles in 2015 and 95 miles in 2016 to improve public safety and system performance. • In its 2014 rate case, Orange and Rockland proposed to expand its current gas infrastructure replacement program so as to remove a total of 100,000 feet of main annually. In order to eliminate all low pressure mains in six years, the Company proposes to replace annually a minimum of 10,000 feet of low pressure mains. Orange and Rockland also proposes to replace an additional 500 bare steel services annually, as part of the Company's ten year program to remove all bare steel services in its service territory. • On October 15, 2015 the New York Public Service Commission (PSC) adopted a multi-year Joint Proposal (JP) in Orange and Rockland Utilities' (ORU) gas rate proceeding. The approved JP establishes funding for the removal of 21 miles, 22 miles, and 23 miles of leak prone pipe in RY1, RY2, and RY3, respectively, with annual reporting by O&R on the status of its leak prone pipe replacement efforts. The JP also allows a negative revenue adjustment if the Company fails to replace at least 20 miles of leak prone pipe in any calendar year. The JP recommends a total negative revenue adjustment of up to eight basis points, rather than continuation of the current level of six basis points, which was initially recommended by Staff in its pre-filed testimony. • The approved JP also provides for an incentive mechanism for incremental replacement of leak prone pipe above the amounts provided for in base rates. This mechanism will allow for a positive revenue adjustment equivalent to two basis points for each whole incremental mile of leak prone main replaced in any calendar year above the targets provided for in base rates, up to a 10 basis point cap. ORU could recover the cumulative incremental revenue requirement for such costs through the Reliability Surcharge Mechanism, provided the company had also met its other targets for net plant under the approved agreement. • In a February 2015 Joint Proposal, Central Hudson Gas and Electric proposed a leak prone pipe replacement program that would allow for up to $1.4 million in deferred costs for every mile over 13 miles in 2016, up to $1.5 million for every mile over 14 miles in 2017, and up to $1.6 million for every mile above 15 miles in 2018. For the avoidance of doubt, the Company is expressly authorized to include Leak Prone Pipe eliminations (abandonment, disuse or any other method that terminates use of the Leak Prone Pipe while still serving the customer) in this deferral mechanism. • In the event the Company replaces or eliminates Leak Prone Pipe in excess of its mileage target in any calendar year, for each mile in excess of the	Docket No. 14-G-0494 (Orange and Rockland) Docket No. 16-G-0061 (Con Ed RSM) Docket No. 16-0059 (National Grid Brooklyn and Long Island)

	applicable target, the Company shall receive a positive revenue adjustment of 2 basis points per additional mile, capped at a maximum of 5 miles (10 basis points) per calendar year, which the Company will defer for future recovery. This proposal was approved on June 17, 2015. • On April 17, 2015, The New York PSC issued an order instituting a proceeding to implement a cost recovery mechanism to further accelerate the replacement of leak prone pipe. The Commission's stated goal will be to reduce the statewide average replacement timeline to 20 years. This matter is presently pending. • On May 20, 2015, RGE and NYSEG filed rate cases in which the combined companies proposed an acceleration of leak prone gas main removal. The Companies propose to increase the leak prone main replacement target from 24 miles in 2016 to 26 miles in 2017, and to 28 miles each year thereafter. The combined annual cost is estimated to be approximately $27 million in 2017. Based on the increased miles, the Companies estimate that it will take approximately 11 years (a two year acceleration), beginning in 2016 to replace all of their leak prone gas mains. This proposal was approved on n June 22, 2016. • In its January 29, 2016 rate filing, Con Ed proposed a Reliability Surcharge Mechanism (RSM). Under the RSM, beginning February 1, 2018, the company's Monthly Rate Adjustment would recover the cumulative net plant carrying costs and associated O&M costs for any capital expenditures associated with main replacement above the levels established in the Company's base delivery rates and installed since base rates were last reset. Carrying costs, including associated O&M costs, would be recovered through the RSM over the twelve-month period beginning February immediately following the end of each Rate Year until the Company's base delivery rates are reset. Both the allowed revenue requirement associated with the cost of main replacement as well as the targeted mileage of main replacement must be exceeded on a cumulative basis for any costs to be recovered through the RSM. • Any over- or under-collections for each period, including interest at the Commission's Other Customer Capital Rate, will be reconciled and included in a subsequent RSM. The RSM is applicable to Firm Sales Customers taking service under SC Nos. 1, 2, 3 and 13, applicable Riders and equivalent firm transportation service under SC No. 9. • ConEd's proposal also seeks to increase base gas rates by $154 million, including $77 million for infrastructure investments to support a significant acceleration of the replacement of cast iron and unprotected steel gas mains. The company is currently replacing, on average, approximately 65 miles of gas main per year. The company is proposing to ramp up that goal to 100 miles annually, reducing the time of total system replacement from over 30 years to 20 years. The proposed rate plan also would continue the company's monthly inspections of its gas delivery system. This matter is presently pending. • In its January 29, 2016 rate filing for its Brooklyn and Long Island service territories (KEDNY and KEDLI, respectively), National Grid outlined a proposal targeting the replacement of more than 300 miles of Leak Prone Pipe (LPP) over a five-year period (2017 through 2021). In recognition of the unprecedented incremental work associated with the company's accelerated main replacement targets, and to allow the company to begin recovering the actual costs of the accelerated replacement of LPP as the work is completed, the Company proposed a Gas Safety and Reliability Surcharge under which the Company would be allowed to recover a return on investment, depreciation expense and related O&M expense (i.e., disconnects and reconnects) associated with prudent investment in LPP replacement incremental to the level funded in base rates. Provided the Company exhausts its rate allowance for LPP replacements, incremental investment in LPP above the base level of 50 miles in any calendar year, in an amount not to exceed the company's	

	average cost of main replacement for comparable pipe materials, sizes, strata (e.g., pavement, grass) and working conditions, would be included in the Gas Safety and Reliability Surcharge. • Additionally, with regard to the LPP performance metric, KEDNY and KEDLI propose a negative revenue adjustment of eight pre-tax basis points if they fail to remove their Base LPP Targets of an average of 50 miles per year and 115 miles per year, respectively, over the next three years. The targets would have annual and cumulative targets similar to KEDNY's current LPP metric in Colander years (CY) 2013 and 2014. That is, KEDNY would incur a negative revenue adjustment in each year for failure to replace a minimum of 45 miles in CYs 2017 and 2018, and a minimum cumulative three-year total of 150 miles for CYs 2017 to 2019. KEDLI would incur a negative revenue adjustment in each year for failure to replace a minimum of 105 miles in CYs 2017 and 2018, and a minimum cumulative three-year total of 345 miles for CYs 2017 to 2019. Any replacement miles recovered through the Gas Safety and Reliability surcharge would not count toward the cumulative CY 2019 target. The proposal is presently pending.	
North Carolina	• In May 2013, the North Carolina General Assembly passed legislation that will authorize the NC PUC to adopt, implement, modify or eliminate a rate adjustment mechanism for natural gas local distribution company rates so that the utility can recover the prudently incurred costs associated with complying with federal gas pipeline safety requirements; Piedmont Natural Gas Company has applied for a tracker in accordance with this legislation as part of its recent rate filing. • In December of 2013, the NC PUC permitted Piedmont Natural Gas to implement an integrity management rider (IMR) that allows the company to track and recover future capital expenditures it expects to incur to comply with federal pipeline safety and integrity requirements outside of a general rate case. IMR filings are to occur annually, each November, to reflect costs incurred through the previous October, and the revised rates are to become effective the following February. • In March of 2015, Senator Robert Rucho (R) introduced Senate Bill 434, which would permit the NC PUC to adopt, implement, modify, or eliminate a rate adjustment mechanism to enable the company to recover the reasonable and prudently incurred capital investment and associated costs of complying with federal gas pipeline safety requirements, including a return based on the company's then authorized return. Costs incurred for routine maintenance, repair, and replacement of system components shall not be included in a rate adjustment mechanism authorized under this legislation. The Commission shall adopt, implement, modify, or eliminate a rate adjustment mechanism authorized under this section only upon a finding by the Commission that the mechanism is in the public interest. The Commission may eliminate or modify any rate adjustment mechanism authorized pursuant to this section upon a finding that it is not in the public interest. This bill died at the end of the legislative session.	NC H 119 (Signed by Governor 5/17/13) Docket No. G-9, Sub 631 (Piedmont) Senate Bill 434 (died)
Ohio	• In its 2008 base rate case, Columbia Gas of Ohio received approval for its Infrastructure Replacement Program (IRP) tracker. The IRP was authorized for an initial five year period, and no rate case is required. The approved 25-year plan called for $2.7 billion to replace approximately 4,100 miles of bare steel, cast and wrought iron and copper pipelines. • In 2011, in Case No. 11-55-15-ALT, the Commission approved a stipulation that Columbia may continue its Rider IRP mechanism to reflect IRP investments made through December 31, 2017. However, should Columbia file a base rate case with new rates effective before December 31, 2017, as part of any such rate case, interested parties may challenge any aspect of the IRP and the Commission may, as a result of such challenge, or on its own initiative, revise Columbia's IRP prior to December 31,2017.	Case No. 08-72-GA-AIR (Columbia Gas of Ohio) Case No. 09-458-GA-RDR (Dominion East Ohio) Case No. 01-1228-GA-AIR (Duke Energy) Case No. 07-1080-GA-AIR (Vectren Ohio)

	• This stipulation also expanded the scope of the AMRP component of Columbia's IRP to expressly include first generation plastic pipe or Aldyl-A plastic pipe when such pipe is associated with priority pipe in replacement projects. For each calendar year of the IRP, the footage of such first generation plastic pipe and Aldyl-A plastic pipe that may be included in Rider IRP may not exceed five percent of the total AMRP program footage for that same calendar year. • In its 2008 rate case, Dominion East Ohio received initial approval for its Pipeline Infrastructure Replacement (PIR) tracker program. In 2011, the utility filed a motion to modify the program due to an increase in the identified scope and in response to recent national concern about pipeline safety, which PUCO approved in August 2011. • Duke Energy has had an accelerated main replacement tracker in place since 2000. All customers, except interruptible transportation customers, are assessed a monthly charge in addition to the customer charge component of their applicable rate schedule. • In 2009, the Commission approved the establishment of a tracking mechanism for Vectren Energy Delivery of Ohio that allows the recovery of costs associated with an accelerated bare steel and cast iron pipeline replacement program. • In 2011 Dominion East Ohio (DEO) received Commission approval to further accelerate its replacement activities. PUCO authorized a modified program for another 5 years or until DEO's next rate case. This approval raised the annual adjustment cap on the company's rider mechanism. • On February 9, 2015 Dominion East Ohio filed a notice of intent for approval of an alternative rate plan which would extend and increase its investment in pipeline replacement (Docket No. 15-0362-GA-ALT). On September 15, 2016, The Public Utilities Commission of Ohio (PUCO) authorized the continuance of Dominion's pipeline infrastructure replacement program through 2021. PUCO also approved an increase in the yearly spending for the replacement program from $160 million to $180 million in 2017, $200 million in 2018, and a 3% increase per year thereafter.	Case No. 11-5515-GA-ALT (Columbia Gas) Case No. 11-3238-GA-RDR (Dominion) 15-0362-GA-ALT (Dominion)
Oklahoma	• CenterPoint utilizes a rate stabilization mechanism (Rider PBRC) to change its rates annually to reflect higher capital investment (rate base) and higher O&M costs relating to pipeline safety and other factors. • For each twelve-month period ended December 31, a Commission determination shall be made pursuant to this PBRC Plan as to whether the Company's revenue should be increased, decreased or left unchanged.	CenterPoint Rider PBRC
Oregon	• In the settlement of Avista's 2010 rate case, the Oregon Public Utility Commission provided for deferred accounting treatment for two capital additions: the second phase of the Roseburg Reinforcement Project and the Medford Integrity Management Pipe Replacement Project. A subsequent incremental rate adjustment was made on June 1, 2012 to recover the costs of the projects. • NW Natural has a tracker that recovers the cost of the acceleration of bare steel pipe replacement, transmission pipeline integrity costs and distribution pipeline integrity costs. • On October 21, 2014, NW Natural filed Advice No. 14-23 with an effective date of March 1, 2015. Subsequently, NW Natural filed on February 6, 2015, to extend the effective date to April 1, 2015. The filing requests that Northwest Natural's SIP Recovery Mechanism be extended beyond its sunset date of October 31, 2014. On March 3, 2015, NW Natural filed a supplement to Advice No. 14-23. The purpose of this supplemental filing is to add language requiring that SIP costs be subject to an earnings test. • NW Natural noted in its filing that the regulatory component of the SIP program consists of the ability to update NW Natural's rate base on an annual basis to reflect certain system safety investments. The SIP is comprised of three distinct programs: the Bare Steel Program, the Transmission Integrity	Docket No. UG-201 (Avista) Docket No. UG-177 (NW Natural) UM 1722 (PUC Investigation Into Recovery of Safety Costs)

	Management Program (TIMP), and the Distribution Integrity Management Program (DIMP). On March 10, 2015, Staff recommended that the Commission suspend Northwest Natural's Advice No. 14-23, its request to continue Schedule 177, the System Integrity Program Recovery Mechanism, and open an investigation. The Commission adopted Staff's recommendation and opened an Investigation into Recovery of Safety Costs by Natural Gas Utilities on March 25, 2015.	
Pennsylvania	• In February 2012, the Pennsylvania General Assembly passed HB 1244, legislation that amended Title 66 (Public Utilities) of the Pennsylvania Consolidated Statutes to provide an additional mechanism for distribution systems (gas, electric, water, wastewater) to recover costs related to the repair, improvement and replacement of eligible property. Under the amended law, the PA PUC may approve the establishment of a distribution system improvement charge (DSIC) to provide for the timely recovery of reasonable and prudent costs incurred by a utility to repair, improve or replace eligible infrastructure. • On March 14, 2013, The Pennsylvania Public Utility Commission approved the Distribution System Improvement Charge (DSIC) of Columbia Gas of Pennsylvania. Columbia anticipates completing the replacement of cast iron and bare steel mains in approximately 17 years, or by the end of 2029. • On April 4, 2013, The Pennsylvania Public Utility Commission approved the DSIC of Philadelphia Gas Works. PGW also received approval of its long-term infrastructure improvement plans (LTIIP) to accelerate its replacement of 8 inch and smaller cast iron main inventory (totaling 1,200 miles) by 17 years, and accelerating the replacement of all 12 inch and 30 inch high pressure cast iron main by more than 60 years. Without the LTIIP, PGW removed 18 miles of cast iron main as part of its baseline main replacement program. The approved LTIIP allows PGW to remove cast iron main from inventory at a rate of approximately 25 miles per year. • On May 9, 2013, The Pennsylvania Public Utility Commission approved the DSIC plan of PECO. • PECO will modernize all of the cast iron and bare steel mains in its gas system within approximately 34 years. This represents a significant acceleration over the 85-year replacement plan that existed prior to acceleration. All bare steel services will be modernized within 10 years versus the 22 year replacement period that existed prior to acceleration. • On May 23, 2013, The Pennsylvania Public Utility Commission approved the DSIC plans of Peoples Natural Gas and Peoples TWP. • Beginning in 2012, Peoples TWP commenced its SMP program to replace all of its unprotected bare steel and some cathodically-protected steel gas mains – a total of roughly 948 miles of pipeline – over a twenty year period, the early years of which have been described and incorporated in PTWP's LTIIP addressed in the Commission's order approving its DSIC and LTIIP. • Beginning in 2011, Peoples commenced its SMP program to replace all of its cast iron, unprotected bare steel, and some cathodically-protected steel gas mains – a total of roughly 2,300 miles of pipeline – over a twenty year period, the early years of which have been described and incorporated in Peoples' LTIIP addressed in the Commission's order approving its DSIC and LTIIP. • On July 16, 2013, The Pennsylvania Public Utility Commission approved the DSIC plan of Equitable Gas Co. • At the time of the approval of its DSIC and LTIIP, Equitable operated approximately 41 miles of cast iron distribution mainlines. In 2012, Equitable began to accelerate the replacement of small diameter cast iron. The Commission's order approving its DSIC and LTIIP will allow for the removal of all such pipe from Equitable's distribution system by 2017. During the same time period, Equitable intends to accelerate the replacement of larger diameter cast iron distribution mainline.	Pennsylvania HB 1294 (Original legislation) Pennsylvania Consolidated Statute: Title 66, Chapter 13B, Section 1353 Docket No. P-2012-2338282 (Columbia Gas of PA) Docket No. P-2013-2347340 (PECO) Docket No. P-2013-2342745 (Equitable Gas) Docket No. P-2012-2337737 (PGW) Docket No. P-2013-2344595 (Peoples TWP) Docket No. P-2013-2344596 (Peoples Natural Gas) Docket No. P-2013-2342745 (Equitable Gas) Docket No. P-2013-2398835 (UGI Utilities) Docket No. P-2013-2397056 (UGI Penn Natural Gas)

		• This LTIIP will allow Equitable to replace all small diameter (<12 in.) cast iron distribution mains (9.8 miles), 11.4 miles of large diameter (>12 in.) cast iron distribution mains, 49.7 miles of bare steel and wrought iron distribution mains and 28.7 miles of bare steel and wrought iron gathering mains through calendar year 2017. • On December 12, 2013, UGI Central Penn Gas filed for approval of a DSIC and DSIC Tariff. • On December 12, 2013, UGI Penn Natural Gas filed for approval of a DSIC and DSIC Tariff. • UGI-PNG plans to retire or replace all in-service cast iron mains over the period of 14 years and all bare steel mains over the period of 30 years beginning in March 2013. • On July 9, 2014, The Pennsylvania Public Utility Commission approved UGI Utilities Inc.'s $256 million long-term infrastructure improvement plan. UGI's five-year plan puts the utility on track to replace its cast-iron mains within 14 years and its bare-steel mains within 30 years of March 2013. As of 2013, UGI had roughly 2,118 miles of steel and 316 miles of iron distribution main, along with 603 miles of steel service lines. UGI also plans to replace gas service lines in conjunction with the mains to which they are connected, the PUC noted in a news release. • On September 11, 2014, the Pennsylvania Public Utility Commission (PUC) approved the long-term infrastructure improvement plans, or LTIIP, of UGI Penn Natural Gas Inc. (UGI-PNG) and UGI Central Penn Gas Inc. (UGI-CPG). In its order, the PUC also approved the companies' plans to implement the distribution system improvement charges, or DSIC. Under the LTIIP, each of the UGI Corp. subsidiaries are allowed to replace an average of 17 miles of pipeline per year in a five-year period. UGI-PNG plans to spend nearly $23 million per year, while UGI-CPG plans to spend almost $14 million per year, on pipeline replacements, service line improvements and safety device installations over the five-year period. • In February of 2015, PECO filed a request with the Pennsylvania Public Utility Commission (PUC) for approval to accelerate the modernization of the company's natural gas distribution system. PECO's plan would increase the company's Long-Term Infrastructure Improvement Plan from $34 million per year to $61 million per year. Under the proposed plan, replacement of natural gas main would increase from about 30 miles per year to more than 50 miles per year by 2018. Bare steel service line replacement would remain at about 4,000 lines per year. This would accelerate the replacement of existing cast iron, bare steel, wrought iron and ductile iron gas main and bare steel service line from 34 years to 22 years. This plan was approved on May 7, 2015. • On July 8, 2015 the Pennsylvania Public Utility Commission (PUC) issued orders finalizing previously approved distribution system improvement charge (DSIC) mechanisms for UGI Penn Natural Gas (UGI-PNG) Gas and UGI Central Penn Gas (UGI-CGP). • This decision relates back to the PUC's September 2014 orders approving Long Term Infrastructure Improvement Plans (LTIIPs) and related DSICs for UGI-PNG and UGI-CPG, subject to subsequent review of certain issues. Pursuant to a 2012 settlement resolving an investigation into a gas pipeline explosion in Allentown, the companies were not permitted to implement adjustments under the DSIC until April 2015. • Under its approved LTIIP, UGI-PNG is to expend roughly $23 million annually on pipeline replacements (average of 17 miles per year), service line improvements, and safety device installations over the five-year term of the plan. Additionally, UGI-CPG, the company is to expend roughly $14 million annually on pipeline replacements (average of 17 miles per year), service line improvements, and safety device installations over the five-year term of its plan.	

- On September 3, 2015, the Pennsylvania Public Utility Commission voted 5-0 to approve PECO Energy Co.'s plan to implement a distribution system improvement charge for its gas operations.
- On January 28, 2016, the Pennsylvania Public Utility Commission (PUC) voted to help Philadelphia Gas Works (PGW) fund faster pipeline replacement work. The commissioners unanimously approved an increase to the utility's distribution system improvement charge, or DSIC, raising the cap from 5% of the company's billed revenues to 7.5%. PGW will have to track and account for all its distribution system improvement charge, or DSIC, spending using a designated accounting mechanism, earmarking all unspent DSIC money for future infrastructure spending or refunds to customers, if necessary, according to the PUC decision. This increase would allow PGW to spend about $33 million annually on its main replacement program, which would cut the projected timeline to replace the company's aging gas mains to 48 years.
- On March 10, 2016, the Pennsylvania Public Utility Commission issued an order approving Peoples Natural Gas' (Peoples) Second Revised Long Term Infrastructure Improvement Plan. The newly-approved plan will allow Peoples to implement the following changes:
  - Shift its replacement focus towards urban projects in order to more effectively target pipeline replacements for higher risk projects located in the higher population areas of its system;
  - Deploy automated meter reading technology;
  - Undertake various upgrades and improvements to M&R stations and related M&R equipment;
  - Expand the replacement of bare steel and other at-risk customer-owned service lines.
- In addition, Peoples received approval to establish a Construction Division with in-house employees and construction crews that would perform 100% of capital related construction work at Peoples, the Equitable Division and its sister company – Peoples TWP, LLC. The Construction Division's scope of work will include design, planning, construction, and restoration. Peoples maintains that the move to an in-house staffed Construction Division will further improve the quality of capital work by reducing the cycle time of "planning to restoration" and improving the efficiency and operating costs of all construction activities. The transition to a full Construction Division is expected to be a two-year process that will continue through 2016.
- By the end of 2016, the Construction Division will be staffed with superintendents, managers, supervisors, technicians and engineers, as well as approximately 300 field employees that will be located throughout the company's service territories to handle all construction and restoration work. Approximately 220 of these field employees (including field inspectors) will be assigned to 45 construction crews, and the remaining field employees (approximately 80) will be responsible for restoration work. While the Construction Division employees will be dedicated to performing capital work, they will be made available, on a limited basis, to support Operations and Maintenance (O&M) work activities, such as emergencies and overtime call outs, in order to ensure that all operations activities are done in the most cost-efficient manner. Should this occur, their time would be properly tracked and charged as an O&M expense.
- On March 18, 2016 Columbia Gas of Pennsylvania (CGP) filed with the Pennsylvania Public Utility Commission (PUC) for gas distribution base rate increase. CGP indicated that the rate increase is intended to allow the company to collect the revenue requirement associated with investments made under the company's accelerated pipeline replacement program. The company expended $152 million on infrastructure investments in 2015, and estimates that is will spend $162 million on infrastructure modernization in 2016. Over the years 2016 through 2020, Columbia estimates its total capital spending will be $958 million. The filing also reflects increases in operation

	and maintenance expenses associated with the facilities upgrades. A settlement modifying the company's proposal was approved on October 27, 2016. • On June 30, 2016, The Pennsylvania Public Utility Commission (PUC) approved the modified long-term infrastructure improvement plans (LTIIPs) for Peoples Natural Gas, UGI Utilities Inc. - Gas, UGI Penn Natural Gas Inc. and Central Penn Gas Inc. • The approved, revised LTIIP for Peoples Natural Gas replaces the currently approved, separate LTIIPs of the Peoples Division and the Equitable Division (previously Equitable Gas Company) of the Peoples Natural Gas Co. Peoples' Revised LTIIP is a five-year plan that builds off of, and expands upon, the previously-approved LTIIPs for the Peoples and Equitable Divisions. Peoples has replaced all known cast iron pipelines in its system, and plans to address accelerated replacement of the 37 miles of known cast iron pipelines acquired through its formation of the Equitable Division. Peoples proposes to replace all bare steel and cast iron pipelines over an approximately 20-year period. • In its revised LTIIP, Peoples indicates it will replace all at-risk customer-owned service lines, which is an update from its original LTIIP where the company said it planned to pressure test customer-owned service lines prior to replacement. Peoples provides natural gas service to approximately 640,000 residential, commercial, and industrial customers in all or portions of 17 Southwestern Pennsylvania Counties. • In a separate action, the Commission voted to approve the modified LTIIPs for UGI Gas, UGI Penn Natural Gas and UGI Central Penn Gas. Each of the UGI Companies' modified LTIIPs are five-year plans, spanning the years 2014-2018. The LTIIPs detail accelerated infrastructure improvements that are intended to enhance system resiliency. The instant petitions do not propose to change or extend the term of the current LTIIPs. Rather, the instant petitions propose to increase the amount of infrastructure spending over that of the currently effective LTIIPs by more than 20 percent. The UGI Companies as a group propose spending more than 50 percent additional capital in the final three years of their LTIIPs compared to the original projections.	
Rhode Island	• In 2010, the Rhode Island General Assembly passed legislation to amend Chapter 39-1 of the Rhode Island General Laws to allow the Rhode Island PUC to approve revenue decoupling and infrastructure investment tracking mechanisms. • As a result of this legislation, National Grid utilizes an Infrastructure Safety and Reliability Plan (ISR) which replaced its existing Accelerated Replacement Program (ARP). This program began April 2011 and funds both replacement of leak prone mains and bare steel, high pressure services. The plan also includes funds for system reliability, mandated programs and special projects and includes a fully-reconciling rate mechanism designed to recover actual and anticipated capital investments as reflected in the approved ISR spending plan. • In its FY 2015 Gas Infrastructure Safety and Reliability Plan (ISR) (Docket No. 4474), the Commission authorized the company to target 70 miles of main per year, which would reduce the time frame for removal of leak prone pipe to approximately 20 years. The company had replaced 50 miles in FY 2014.	Rhode Island General Laws: Title 39, Chapter 39-1, Section 39-1-27.7.1 Docket No. 4474 (National Grid)
South Carolina	• In 2005, South Carolina passed the Natural Gas Rate Stabilization Act (RSA), which was designed to reduce fluctuations in customer rates by allowing for more efficient recovery of the costs regulated utilities incur in expanding, improving and maintaining natural gas service infrastructure. • In lieu of a general rate case, Piedmont Natural gas and SCE&G have filed annual base rate updates since 2005 pursuant to the RSA. The annual rate update enables the Company to earn a return on actual plant investments made thru the prior March 31st.	Natural Gas Rate Stabilization Act

Tennessee	• In April 2013, Tennessee enacted legislation which provides for alternative regulatory methods to allow for public utility rate reviews and cost recovery for investments in infrastructure replacement and expansion in lieu of a general rate case. In particular, the measure allows the Tennessee Regulatory Authority (TRA) to approve cost recovery mechanisms to recoup operational expenses and/or capital costs associated with infrastructure replacement that is necessary to comply with federal and state safety requirements and/or ensuring reliability. • Piedmont Gas utilizes this rider. • In May of 2015, Atmos Energy received approval from the Tennessee Regulatory Authority to implement an Annual Review Mechanism, which will allow the company to adjust its rates annually to reflect higher capital investment and higher O&M costs relating to infrastructure replacement and other factors.	Public Chapter No. 245 (HB 191) Docket No. 1400146 (Atmos Energy)
Texas	• In 2003, the Texas Legislature passed SB 1271 which established the Texas Gas Reliability Infrastructure Program (GRIP). • GRIP allows a gas utility that has filed a rate case within the previous two years to file a tariff or rate schedule that provides for an interim adjustment in its monthly customer charge or initial block rate in order to recover the cost of investment changes, which could include the replacement of aging infrastructure or expansion of infrastructure. • In 2011, the Texas Railroad Commission adopted a comprehensive pipeline safety rule that requires all state natural gas distribution companies to survey their pipeline distribution systems for the greatest potential threats for failure and make replacements. The rule allows for the recovery of costs of such programs via a deferral mechanism. • Atmos Energy, CenterPoint Energy and Texas Gas Service utilize portions of these mechanisms. • On August 25, 2015 the Texas Railroad Commission (RRC) adopted a settlement in CenterPoint Energy's base rate case. The agreement provides that a 10% ROE with a 54.5% equity capital structure is to be used for prospective adjustments under any interim rate adjustment mechanisms that recognize new capital investment, including the company's Gas Reliability Infrastructure Program.	Senate Bill 1271, Establishing the Gas Reliability Infrastructure Program 16 TAC Chapter 8- Pipeline Safety Regulations (2011)
Utah	• In 2010, the Utah Public Service Commission authorized Questar Gas to implement a three-year pilot Infrastructure Replacement Adjustment (IRA) mechanism to track and recover the costs associated with the replacement of high pressure natural gas feeder lines between rate cases.	Docket No. 09-057-16
Virginia	• In 2010, Virginia enacted the SAVE (Steps to Advance Virginia's Energy Plan) Act. The law allows utilities to petition the Virginia State Corporation Commission for a separate rider to recover a return on certain investments, including natural gas facility replacement projects that enhance safety and reliability, or have the potential to reduce greenhouse gas emissions by reducing system integrity risks; Atmos Energy, Columbia Gas Virginia, Virginia Natural Gas and Washington Gas utilize the rider. • On November 28, 2011, The Virginia State Corporation Commission approved the SAVE plan and rider of Columbia Gas of Virginia. The plan permits Columbia to spend $20 million each year with the flexibility to vary this amount up to 5% above or below the projected level of plan investment in any year. The approved plan runs through December 31, 2016. • On July 25, 2014 The Virginia State Corporation Commission authorized Virginia Natural Gas to recover costs associated with the replacement of up to $105 million of infrastructure during the five-year term (2012-2016) of its SAVE Plan. The Company intends to spend up to $25 million annually with the total investment over the five-year term of the SAVE Plan capped at $105 million. Costs are recovered through a rider ("Rider E" or "SAVE Rider") on customers 'bills as authorized by the SAVE Act.	Code of Virginia: 56-603, 56-604 (Implementation of SAVE Act) PUE-2010-000871 (Washington Gas) PUE-2012-00096 (Washington Gas) PUE-2015-00017 (Washington Gas) PUE-2012-00012 (Virginia Natural Gas) PUE-2011-00049

	• On February 6, 2015 Washington Gas Light Company (WGL) filed an application with the Commission for approval of amendments to its SAVE Plan, which the Commission first approved in Case No. PUE-2010-000871 ("Approved SAVE Plan") and modified in its Order Approving Amended SAVE Plan in Case No . PUE-2012-00096. In this Application for an amended SAVE Plan, WGL proposed to increase its Virginia SAVE Plan expenditures for the period January 1, 2015, to December 31, 2017 ("Period") by approximately $75.2 million, for a total of $194 .4 million for the Period, for the expansion of the scope of certain of its approved SAVE Plan programs and implementation of new programs. This plan was approved on June 5, 2015. • WGL plans to expand its pre-1975 Plastic Service Replacements program, and the Copper Service Replacement program to include all services in each of these categories. The Company also proposed to add two new distribution system replacement programs. ○ Program 8 - a Meter Set Survey and Remediation Program - will address the replacement of piping if certain conditions are discovered during the meter set survey, the replacement of shallow main that is occasionally discovered, and the replacement of gauge lines for medium pressure main-line valves. ○ Program 9 – a Meter Set Survey Technology Implementation Program - will automate the Company's manual processes by constructing- a data model and technology solution that will provide integration with a range of work management systems, document management systems, and mapping systems. ○ This filing also calls for the approval of an additional one 1 per year of bare steel replacement on top of the company's currently-approved 25 mile per year pace and .7 miles per year of cast iron replacement on top of the company's current 13.3 mile per year pace. • In December of 2015, Virginia Natural Gas asked the State Corporation Commission to approve a plan to further accelerate its replacement of aging infrastructure. Since 2012, the company has installed 155 miles of new main line and more than 9,000 new service lines to customers, replacing aging connections, and expects to finish work on another nine miles of main line and 600 service lines by the end of the year. The proposed plan aims to replace the final 23 miles of cast iron pipe in the company's system, as well as 293 miles of bare steel main. If approved, this proposal would authorize the company to invest $30 million in 2016 and $35 million a year from 2017 to 2021, up to a maximum of $210 million. • On March 17, 2016, The Virginia State Corporation Commission (SCC) approved an expansion of Virginia Natural Gas' (VNG) infrastructure modernization program. Under the newly-approved plan, VNG plans to invest $30 million in its Steps to Advance Virginia's Energy (SAVE) program in 2016 and up to $35 million annually after that to replace more than 200 miles of aging pipeline infrastructure through 2021. Since 2012, Virginia Natural Gas has invested about $82 million in replacing more than 160 miles of pipeline with modern materials. • The SCC stated that it would require VNG to provide a list of completed projects during the preceding calendar year, a list of planned projects for the current calendar year and details about what the projects address. This list is to be filed annually in January.	(Columbia Gas of Virginia)
Washington	• In December 2012, the Washington UTC issued a policy statement aiming to enhance safety and modernize and update the state's pipeline system. • In November 2013, the UTC approved the the plans of Avista Corporation, Puget Sound Energy Inc., Cascade Natural Gas Corporation and Northwest Natural Gas Company. The plans involve the replacement of hundreds of miles of older "elevated risk" pipes with plastic pipe.	Docket No. PG-120715 (12/31/2012)

	• As an incentive, the UTC permitted these utilities to recover costs annually instead of waiting for future formal rate proceedings. The companies are also required to update their modernization plans every two years.	
West Virginia	• In its January 2015 base rate filing, Mountaineer Gas proposed an infrastructure replacement program to increase reliability and enhance safety by enabling the more timely cost recovery for eligible infrastructure improvements. The proposed program would cover investments to eliminate bare steel mains and services with the highest leakage rates and other infrastructure replacements. This enhanced investment will accelerate overall safety and reliability improvements by reducing system integrity risks due to corrosion, equipment failures, material failures, and the impact of natural forces, and it will reduce customer service outages through replacement of higher-risk pipeline segments. Investment currently in rate base (or that would be included in rate base in this rate case), or that would increase revenue by directly connecting new customers to the system, would be ineligible. • The program would be funded through a rate mechanism, which would be implemented beginning on January 1, 2017, and the Company would commit to invest at least $12,800,000 in qualifying infrastructure replacement each year for the succeeding three years. The Company wishes to formalize this program under the Commission's direction and to accelerate its investment in this important component of its system. • On February 3, 2015, the West Virginia Senator Charles Trump (R) filed SB 390. This bill provides that natural gas utilities may file with the commission, an application for a multi-year comprehensive plan for infrastructure replacements, upgrades and extensions. Subject to commission review and approval, a plan may be amended and updated by the natural gas utility as circumstances warrant. • Following commission approval of its infrastructure program, a natural gas utility shall place into effect rates that include an increment that recovers the allowance for return, related income taxes, depreciation and property tax expenses associated with the natural gas utility's estimated infrastructure program investments for the upcoming year, net of contributions to recovery of those incremental costs provided by new customers served by the infrastructure program investments, if any, ("incremental cost recovery increment"). In each year subsequent to the order approving the infrastructure program and an incremental cost recovery increment, the natural gas utility shall file a petition with the commission setting forth a new proposed incremental cost recovery increment based on investments to be made in the subsequent year, plus any under-recovery or minus any over-recovery of actual incremental costs attributable to the infrastructure program investments, for the preceding year. This bill was signed into law on March 24, 2015 and will take effect on June 11, 2015. • On September 30, 2015, Dominion Hope Gas filed for approval of its Pipeline Replacement and Expansion Program (PREP). PREP is consistent with SB 390's objectives of replacing, upgrading, extending and expanding the Company's natural gas pipeline infrastructure to provide continued and enhanced, efficient, safe and reliable gas service to its current base, including to new customer bases in unserved or underserved areas of West Virginia. • PREP features two separate replacement initiatives. The first is a 50-year program to accomplish the following goals: o Replace bare steel distribution mains; o Replace unprotected, ineffectively coated steel distribution mains; o Replace unprotected bare steel services; o Enhance or upgrade system facilities; and	SB 390 Docket No. 15-0003-G-42T (Mountaineer Gas) Docket No. 15-1600-G-390P (Dominion Hope) Docket No. 15-1256-6-390P (Mountaineer IREP)

	o Replace aged gas measurement and regulation equipment • The second replacement initiative is the company's proposal to prospectively replace existing gas sales service customer' piping (CSP) if it is found to be bare steel in the course of associated mainline replacements or when the time comes in the future to replace that customer-owned CSP due to its age or condition. • Costs associated with PREP would be eligible for recovery through an annual rate surcharge. • On July 31, 2015, Mountaineer Gas Company (MGC) filed for approval of an Infrastructure Replacement and Expansion Program (IREP). On October 9, 2015, the parties in this proceeding filed a Joint Stipulation and Agreement for Settlement (Joint Stipulation). In the Joint Stipulation, the parties recommended that the Commission authorize a total 2016 revenue increase of $565,758, using the customer class allocation determined in above-referenced rate proceeding. The IREP rate component for IS and LGS customers will also be expressed as a fixed customer charge, as opposed of the volumetric calculation that MGC had proposed in its IREP Application. The parties asserted that this change would not affect other rate schedules. The parties also agreed that the IREP rate component would not apply to customers who receive service under one or more special contracts filed with the Commission. The Commission approved the Joint Stipulation on December 23, 2015. • On February 4, 2016, the West Virginia Public Service Commission approved a Joint Stipulation and Agreement for Settlement that provides for a Pipeline Replacement and Expansion Program (PREP) and a PREP cost recovery component to the base rates of Hope Gas (Dominion Hope). The Commission modified the Joint Stipulation as it relates to the filing of quarterly reports as part of a pilot program. The approved Stipulation reflects the parties' agreement to a 2016 projected PREP capital investment of approximately $20.5 million. The approved agreement allows Dominion Hope to collect a total 2016 revenue increase of $862,014 using the customer class allocations and rate of return on equity determined in Dominion Hope's last base rate proceeding. The company's initial filing separated proposed projects into 3 categories. Categories 1 and 3 were approved. • Category 1 projects -- The largest category of proposed capital investment, these projects will replace and upgrade aged infrastructure, including distribution mains, service lines and appurtenant facilities. When individual PREP projects are completed Dominion Hope will prepare a work order package that contains the same information that was approved in the Mountaineer SB 390 proceeding: the materials used (type and amount), unit prices, work force used (internal or contracted), total project cost, construction period and duration, project in-service date and related details. These packages will be available to Commission Staff and the Consumer Advocate Division for auditing purposes. • The Commission also approved the parties request for approval of a three-year pilot program in which Category 3 projects - Dominion Hope's repair, replacement and installation of customer service piping. These projects will also be included in the capital investment for PREP cost recovery. The pilot program will begin March 1, 2016, and end December 31, 2018.	
Wyoming	• On August 4, 2016, the Wyoming Public Service Commission approved a Pipeline Safety and Integrity Mechanisms (PSIM) for Black Hills Energy (BHE). The PSIM will allow BHE to recover its investment for nine specific projects utilizing the PSIM and would increase its natural gas utility revenue by $42,511 for the period of August 1, 2016, through March 31, 2017. • The PSIM is designed to recover the PSIM Revenue Requirement associated with the investments in pipeline infrastructure approved in Docket Nos. 30003-62-GA-14 and 30005-187-GA. Until such time as these infrastructure investments are included in base rates, but no later than March 31, 2021,	DOCKET NO. 30003-66-GA-15

	PSIM costs will be recovered from customers using a PSIM charge applied to all customers' monthly bills. The PSIM will be calculated annually using the actual and forecasted capital costs and operating expenses for the just ending calendar year and forecasted billing determinants by customer class, except for the calculation to be used to determine the first PSIM rates effective with usage on or after August 1, 2016. • The Company will make a PSIM filing with the Commission annually by December 31st of each year. The PSIM filings will: 1) reflect the additional investment in pipeline replacement costs that have been, or that are anticipated to be completed, during the current year; 2) true-up to actual costs the investment costs and related revenue requirement from the amount in the previous year's PSIM, and 3) true-up the revenue collected from customers to the amount, reflecting the prior year's trued-up investment. The PSIM applies to all natural gas rate schedules for all classes of service authorized by the Wyoming Public Service Commission	

Appendix C: Selected Excerpts from the Appendix in the Compendium of State Pipeline Safety Requirements and Initiatives

This appendix summarizes the types of State initiatives relating to pipeline safety (including initiatives for liquids and hazardous material pipelines) that exceed federal code.[r] There have been over 1,360 pipeline safety initiatives[87] in the 23 categories included in the figure below, including enhanced reporting, improved record keeping, use of cathodic protection, and design and installation requirements. The first number shown in each slice of the chart is the number of initiatives in that category, while the second number is the percentage of all initiatives represented by the category.

The following text is excerpted from the National Association of Regulatory Utility Commissioners' Compendium of State Pipeline Safety Requirements and Initiatives.[88] These descriptions provide more detail about the categories of pipeline replacement acceleration quantified in Section 5 of this document.

Enhanced reporting requirements include "periodic leak status reports, cast iron/bare steel replacement reporting, and approved damage prevention plans." Initiatives under "More Direct Oversight" include "more direct oversight of construction activities" or emergency procedures that "recognize sour gas safety precautions." Guidelines under "Valves" include ensuring that "emergency valves are accessible at all times" and that there are "blow-down valve requirements for mains."

"Pressure Testing" consists of "requiring pressure testing to more than 50% for certain operating pressures or a more stringent minimum and having all service lines be pressure tested to at least 90 pounds per square inch gauge (psig)." Operating pressure initiatives are "multiple pressure recording devices per system" as well as "max pressure limits on cast iron pipes." "Damage Prevention" requirements for pipeline operators include the following: the operator "can only be a member of single or specified One Call Center, must oversee all transmission line excavations and document all findings, extend training to local community colleges, pilot new technologies, and monitor all excavations of sour gas."

[r] While this figure quantifies the number of programs that have been enacted, it does not consider the efficacy of those programs.

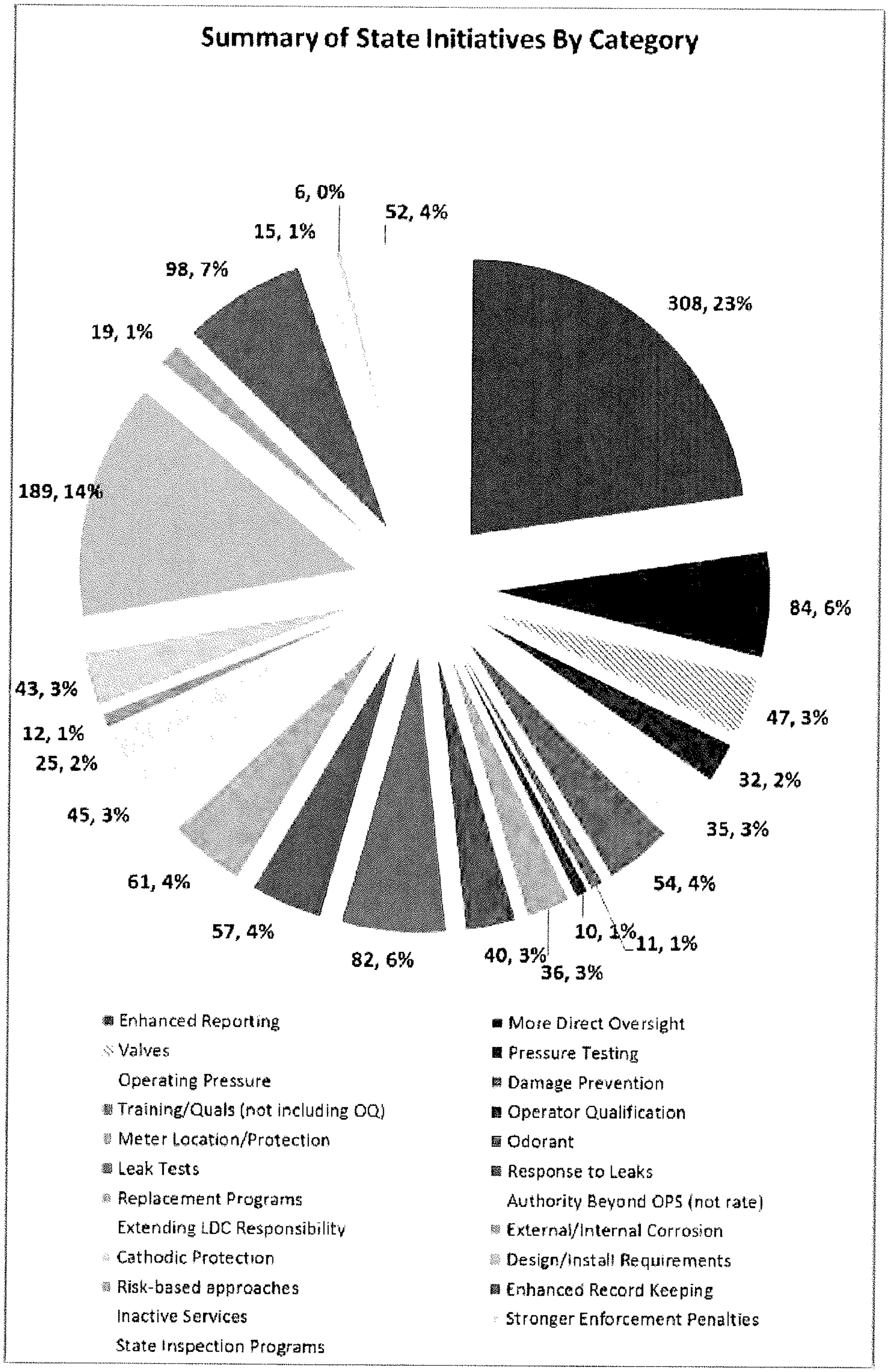

Figure 8 – Summary of State Pipeline Initiatives (includes liquids and hazardous material pipelines)[89]

Examples of "Training/Quals" initiatives include "enhanced training programs for system managers and written emergency plans," while "Operator Qualification" can be an "operator training that covers construction." "Meter Location/Protection" guidelines include the replacement of meters every 7-10 years and giving the operator responsibility of monitoring "service lines regardless of meter locations."

State pipeline recommendations for "Odorants" and "Leak Tests" are increased testing frequency of odorants and "additional surveys for public buildings and for mains on bridges." An example of a "Response to Leaks" is a "repair of leaks post survey."

A "Replacement Program" is a "mandated accelerated main replacement resulting from inadequate system pressure levels or other customer complaints or minimum wall thickness." "Authority Beyond (OPS)" is the "authority to order change in public interest, assessments, compliance with State statutes, and maintaining liaison with public works directors."

"Extending LDC Responsibility" initiatives includes "Public Awareness Plans that include messages to end use customers of customer responsibilities for downstream piping and appliances and reporting gas leaks, notifications to customers relocating within operators' districts, and requiring the operator to respond to other operator emergencies if in the same country." "External/Internal Corrosion" guidelines are "sour gas analysis and monitoring intervals," and "Cathodic Protection" includes "requirements for cathodic protection near power transmission lines and shorter intervals for cathodic protection testing."

A "Design/Install Requirement" would be an "installation requirement for plastic pipe." All plastic fitting must meet "ASTM D2513 Category 1 or the ASTM D2513 1995 edition for temperatures greater than 100 degrees." "Risk-based approaches" require operators "to perform integrity assessment of entire line section, temporary and permanent repairs based on inspections to reveal defects, gouges, dents or leaks." An example of an "Enhanced Record Keeping" is including "more stringent data elements such as test pressures, duration of strength test, date, description of facilities, retention of pressure charts, and testing services in equivalent manner as mains with associated records." "Inactive Service" would be cutting inactive services off at mains during demolition, while a "Stronger Enforcement Penalty" would be applying civil penalties "that exceed federal maximum penalty." A "State Inspection Program" can include the ability "to use outside consultants for State led inspections when necessary."

Appendix D. Massachusetts Gas System Enhancement Plans

As discussed in section 4.5.3, gas companies in Massachusetts can file a Gas System Enhancement Plan (GSEP), which outlines their plan for replacing within 20 years infrastructure constructed from non-cathodically protected steel, cast iron, and wrought iron. The Department of Public Utilities is responsible for evaluating the progress and the reporting made by the gas companies towards meeting the goals outlined in their GSEPs.

There are six Massachusetts utilities that have GSEPs:

- Bay State Gas Company
- The Berkshire Gas Company
- Liberty Utilities
- NSTAR Gas Company
- Boston Gas Company and Colonial Gas Company
- Fitchburg Gas and Electric Light Company doing business as Unitil

The GSEPs for the utilities are summarized in the following table.

Table 4 – Summary of Massachusetts GSEP Submittals

Utility Name	Description of Utility	Proposed GSEP	Estimated GSEP Cost
Bay State Gas Company	• Distributes natural gas to approximately 295,000 customers in 61 communities in three operating areas in Massachusetts: Brockton, Springfield, and Lawrence • As of December 31, 2013, they operate 4,857 miles of distribution mains and over 260,097 services • 6.1% of distribution system mains are composed of non-cathodically protected steel and 14.5% is composed of smaller diameter cast iron and wrought iron • Historically, they have replaced an average of 35 miles of leak-prone pipe/year	• Anticipates replacing 44 miles of leak-prone mains and 4,900 priority services in 2015 • Replace all infrastructure in a 20-year period: first 5 years comprising the ramp-up period, next 5 years comprising a level run-rate for replacement, and remaining 10 years comprising a ramp-down period for replacing the remaining infrastructure • During the ramp-up period, they increase the rate of leak-prone main replacement by 5 miles each year	• Total estimated 2015 GSEP capital cost is $44.26 million • Revenue requirement associated with recovery of 2015 GSEP costs beginning May 1, 2015, is $2,625,905 • Include the costs related to replacement of encroached[5] pipe
Berkshire Gas Company	• Distributes natural gas to 40,000 customers in Berkshire county and portions of Hampshire and Franklin counties • Operates 759 miles of natural gas mains and over 31,000 active services	• Replace 109 miles of leak-prone cast iron and bare steel infrastructure, starting January 1, 2015, and ending December 31, 2034 • Intends to retire about 5.5 miles of main each year	• Berkshire forecasts a revenue requirement of $226,850, but the actual amount will not be reconciled until May 1, 2016 • Proposes to include the costs related to replacement of encroached pipe

[5] Encroached pipe "includes cast iron pipe that is eight inches or smaller in diameter and has been exposed and undermined by a trench crossing the natural gas pipeline or by an adjacent, parallel excavation." Page 11: http://www.mass.gov/eea/docs/dpu/orders/14-134-bay-state-gas-gsep-order.pdf

	• 18% of system mileage consists of leak-prone mains and services • Cast iron and unprotected steel facilities account for 81 percent of their leaks in 2013 • Historically, they have replaced leak-prone mains at a rate of 3.4 to 4.4 linear miles per year	• Implement through a series of 3-year rolling plans, beginning with 2015-2017, and will then revise its GSEP after the 2015 construction season to address years 2016-2018 • on October 31 of each year, the Company will file for approval of the GSEAF (the rate that recovers the aggregate GSEP revenue requirement approved by the Department), with recovery beginning on the following May 1)	
Liberty Utilities	• Distributes to approximately 54,000 customers in the Fall River, North Attleboro, Plainville, Swansea, Somerset, and Westport communities • About 16.48% of distribution system is composed of non-cathodically protected steel mains and 20.33 percent is composed of smaller diameter cast iron and wrought iron mains • With large diameter cast iron mains included, 37.57% of the system qualifies as "leak prone." 39% of the services existing on the Company's distribution system are composed of non-cathodically protected steel	• Anticipates replacing the approximately 230 remaining miles of leak prone or "Priority Main" on the Company's system. • Work to replace that amount of Priority Main will also encompass the replacement of approximately 13,711 leak-prone services and the completion of all necessary tie-overs	• Proposes to include the costs related to the replacement of encroached pipe
NSTAR Gas Company	• Distributes natural gas to 300,000 customers in 51 communities in central and eastern Massachusetts • Owns and operates 3,213 miles of distribution mains and over 195,000 services • 23% of distribution system mains are composed of non-cathodically protected steel and wrought iron, and 12% of distribution system is composed of cast iron • Historically, NSTAR has replaced an average of 25 miles of leak-prone pipe/year	• Under the proposed GSEP, NSTAR anticipates replacing 30 miles of leak-prone mains and 2,480 associated services in 2015 • Estimates that it will require a 25-year period to replace all leak-prone infrastructure, with an anticipated replacement rate of 50 miles per year following an initial five-year ramp-up period • During the ramp-up period, the Company intends to increase the rate of leak-prone main replacement by five miles each year	• Total estimated 2015 GSEP capital cost is $42.5 million • Revenue requirement associated with recovery of 2015 GSEP costs beginning May 1, 2016, is $2,905,397 • Proposes to include the costs related to the replacement of encroached pipe
Boston Gas Company and Colonial Gas Company (each doing business as National Grid)	• Distributes natural gas to 876,000 customers in 116 cities and towns • Owns and operates 11,021 miles of distribution mains and over 720,000 services. • For Boston Gas, the Company States that 17% of distribution system mains are composed of non-cathodically protected steel and 29% of distribution system mains are composed of cast iron and wrought iron • For Colonial Gas, the Company states that 5% of distribution system	• Under the proposed GSEP, Boston Gas anticipates replacing 113 miles of leak-prone mains in 2015, increasing to 150 miles per year by 2021, and again increasing to 170 miles per year by 2023 • Colonial Gas anticipates replacing 43 miles of leak-prone mains in 2015, and decreasing to less than 30 miles in 2019 • For Boston Gas, National Grid anticipates it will take 20 years to replace all eligible leak-prone facilities	• National Grid seeks approval to collect $8,292,527 and $1,417,131 for Boston Gas and Colonial Gas, respectively, through the gas system enhancement adjustment factor ("GSEAF") effective May 1, 2015 • Proposes to include the costs related to the replacement of encroached pipe

	mains are composed of non-cathodically protected steel and 3% of distribution system mains are composed of cast iron and wrought iron • Between 2010 and 2013, Boston Gas replaced an average of 84 miles of leak-prone pipe/year, and Colonial Gas replaced an average of 39 miles of leak-prone pipe/year	• For Colonial Gas, National Grid anticipates it will take eight years to replace all eligible leak-prone facilities • Requires a ramp-up period to obtain the internal and external resources necessary to implement the Company's GSEP	
Fitchburg Gas and Electric Light Company (Unitil)	• Distributes natural gas to approximately 15,700 customers in six communities in Massachusetts • Owns and operates approximately 275 miles of distribution mains and 10,930 services • 3.48% of the Company's distribution system mains are composed of unprotected bare steel and wrought iron, and approximately 23.86 percent of its distribution system (65.54 miles) is composed of cast iron, which means that approximately 27.34 percent of the distribution system mains (75.1 miles) are composed of leak-prone materials • Historically, Unitil has replaced a minimum of two miles of leak-prone pipe/year	• Estimates that it will require a 20-year period to replace all eligible leak-prone infrastructure, with a replacement rate of 3.75 miles/year • implement the GSEP through a series of five-year rolling plans, beginning with 2015 through 2019, and revising the GSEP after the 2015 construction season to address the years 2016 through 2020, and so forth	• Total estimated 2015 GSEP capital cost is $4,216,175 • Revenue requirement associated with recovery of 2015 GSEP costs beginning May 1, 2016, is $284,456 • Proposes to include the costs related to the replacement of encroached pipe

The initial pipeline replacement progress for Massachusetts utilities with GSEP plans is shown in Table 5. The 2015 column includes actual replacement miles. The 2016 and 2017 columns are forecasts. Actual replacement miles for 2016 will be reported in the Spring of 2017.

Table 5 – Replacement Progress of Leak-Prone Mains by Massachusetts Utility, 2015-2017

Utility	GSEP Number	2015 Replacement (Actual, in miles)	2016 Replacement (Projected, miles)	2017 Replacement (Projected, miles)
Bay State	GSEP-05	42.5	49.03	52.5
Berkshire	GSEP-02	8.73	6.87	9.09
FGE (Unitil)	GSEP-01	4.74	4.65	4.92
Grid	GSEP-03	92.4	115	146
Liberty	GSEP-04	9.07	11	14.4
NSTAR	GSEP-06	30	35	40

Appendix E. Pipeline Replacement Acceleration Program Analysis Methodology

Overview

This appendix describes the methodology used to examine the pipeline replacement acceleration programs discussed in this paper. The basic steps involved in this analysis, which will be described more fully below, are:

1. Use data from the Pipeline and Hazardous Materials Safety Administration (PHMSA) to construct a time series of attributes of the systems of many natural gas distribution companies in the U.S.

2. Use records from the Energy Information Administration (EIA) to determine how much gas LDCs sold. Gas sales was used as a metric to normalize replacement rates, as companies with larger gas sales volumes may have larger distribution systems and the ability to replace more miles of pipe annually than operators with less gas sales.

3. Compare the average replacement rate in the five years immediately before and after the implementation of the pipeline replacement acceleration programs listed in the American Gas Association's State-by-State list of such programs (included as Appendix A in this document).

PHMSA database

PHMSA collects data on a variety of attributes of natural gas distribution systems, such as miles of main of various materials and number of leaks caused by various mechanisms. Data is available to the public from covering the period from 1970 to the present on PHMSA's website.[90]

Each operator that reports data to PHMSA is assigned a unique operator ID. For the purposes of this analysis, this operator ID is presumed to stable over time, i.e. a given operator is presumed to have reported under the same operator ID since its first reporting as far back as 1970. However, while operators IDs may represent the same company continuously in the PHMSA data, infrastructure assets can change hands between operators and companies can acquire other operators. While these changes are not reflected in the operator ID, we attempted to identify them as large, discontinuous jumps in the pipeline mileage reported by a particular LDC. We found these types of large jumps to be uncommon for the operators whose programs were analyzed in this study.

Starting in 2010, operators that operated in multiple States were required to submit to PHMSA separate reports for the portion of their systems in each State in which they operated. Before this time, operators could submit a single submission for their entire system if that system spanned multiple States. Because our analysis was focused on pipeline replacement acceleration programs that are initiated at the State level, we chose to follow the more modern convention in the PHMSA data. For LDCs with operations that span multiple States, we considered the operations in each State to be a separate entity with individual rates of pipeline replacement calculated for each State.

For each attribute that LDCs report to PHMSA (miles of cast iron main, for example), we created a time series of the values of that attribute by operator for all of the years for which PHMSA data is available. Because the more recent PHMSA data is generally more accurate and because all of the pipeline replacement acceleration programs analyzed in this study were enacted within the last few decades, we used only the PHMSA data from the years 1990 to 2015 in this analysis.

Gas Sales Volume Data from EIA and Data Analysis

Our analysis focused on two attributes of LDC systems: miles of cast iron main and miles of bare steel main. For each of these two attributes, we modified the data in the PHMSA database to identify our quantities of interest. We examined the mileage of unprotected steel pipe, which is a combination of miles of coated and uncoated steel pipe without cathodic protection. Steel pipe was divided based on cathodic protection following the convention in the U.S. EPA's Greenhouse Gas Inventory. EPA uses single emissions factors for pipes with and without cathodic protection, respectively, regardless of whether those pipes have external coatings. For cast iron pipe, we considered only pipe less than twelve inches in diameter. Based on conversations with members of the Downstream Initiative, cast iron pipes larger than twelve inches in diameter are less likely to be targeted by replacement programs because these pipes r pose less safety risk; the thicker walls of larger-diameter cast iron pipe generally reduce the risk of catastrophic failure relative to that for smaller-diameter cast iron pipe. Also, replacing large diameter pipe is more expensive, per mile, than replacing smaller pipe.

For both cast iron and bare steel pipeline mileage, time series of replacement rates, in miles per year, were then created for each LDC by taking the difference between reported mileage of each respective pipe type in successive years.

To evaluate the effectiveness of a given program described in Appendix A of this document, we compared the average replacement rate for the LDC participating in the program in the five years immediately before that program was enacted and the five years immediately after the program was enacted. For programs enacted recently for which five years of subsequent data were not available (for a program enacted in 2012, for example), we calculated the average replacement rate after program implementation using all available data from years after the program was enacted. Any year in which a company's pipeline replacement rate was negative (indicating an increase in pipeline mileage) was excluded from this averaging.

These replacement rates were then normalized by The Energy Information Administration records data for a number of attributes of LDCs that are not tracked by PHMSA. This data includes natural gas sales volume for each LDC by customer type (residential, commercial, and industrial). For this analysis, we normalized the replacement rate calculated above for each LDC by the gross gas sales volume for that LDC. The EIA and PHMSA databases do not share a common operator ID. Instead, records for each operator were matched between the EIA and PHMSA databases based on similarities between the names of operators in the two databases. Operator names in these two databases are not identical, which prevented automation of this task. Instead, operator names were matched by inspection.

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Case No. PU-17-295
Exhibit No. KRP-2

MDU System Safety and Integrity Program (SSIP)
Low Pressure Replacement Plan and Aldyl-A replacement Plan
Estimated Investment and Revenue Requirement (2018-2019)
(dollars)

	2018 /1	2019 /2	Plan Total /3	2020 to Completion
Plant in service				
Mains	2,886,799	3,118,800		
Services	2,666,355	2,881,200		
Total Plant in Service	5,553,154	6,000,000	216,630,000	205,076,846
Revenue Requirement				
Mains	178,930	397,246		
Services	207,857	459,043		
Total Revenue Requirement	386,787	856,289		

/1 Source: Exhibit No. TRJ-3, pages 4-5.
/2 Source: Exhibit No. TRJ-3, pages 2-3.
/3 Source: Response No. 2.5 Attachment A, page 3 and Attachment B, page 5.

MONTANA-DAKOTA UTILITIES CO.
REVENUES UNDER CURRENT AND PROPOSED RATES
GAS UTILITY - NORTH DAKOTA

	Projected 2018 1\			Total	Proposed	
Customer Class/Rate	Customers	Dk	Revenue	Total Proposed Revenue	Proposed Revenue Increase	Percent Increase
Residential - Rate 60	96,792	8,826,214	$58,201,289	$59,381,280	$1,179,991	2.0%
Firm General Service - Rate 70	15,560	8,035,663	44,071,987	44,890,629	818,642	1.9%
Air Force - Rate 64						
Firm	1	32,523	143,249	143,249	0	0.0%
Interruptible	2	457,577	1,461,611	1,461,611	0	0.0%
Total Air Force	3	490,100	1,604,860	1,604,860	0	0.0%
Small Interruptible						
Sales - Rate 71	92	572,872	2,532,810			0.0%
Transport - Rate 81	63	1,104,513	870,115			0.0%
Total Small Interruptible	155	1,677,385	3,402,925	3,402,754	(171)	0.0%
Large Interruptible						
Sales - Rate 85	0	0	0			
Transport - Rate 82	6	4,321,943	1,327,781			
Total Large Interruptible	6	4,321,943	1,327,781	1,327,920	139	0.0%
Total North Dakota	112,516	23,351,305	$108,608,842	$110,607,443	$1,998,601	1.8%

1\ Statement K, page 5.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
ALLOCATION OF REVENUES
Projected 2018

	Billing Determinants 1/					Embedded COS Before Increase 2/			Increase Required @ Overall Return		
RATE CLASS	Customers	Dk	Distribution Revenues	Fuel Revenues	Total Revenues	Operating Income	Rate Base	Rate Of Return	Operating Income	Revenues	% Increase
Residential	96,792	8,826,214	$22,762,526	$35,438,763	$58,201,289	$4,593,351	$73,207,858	6.274%	$834,205	$834,205	1.43%
Firm General Service	15,560	8,035,663	11,785,787	32,286,200	44,071,987	3,209,912	48,078,173	6.676%	580,584	$580,584	1.32%
Air Force											
Firm	1	32,523	12,800	130,449	143,249						
Interruptible	2	457,577	107,091	1,354,520	1,461,611						
Total Air Force	3	490,100	119,891	1,484,969	1,604,860	30,650	149,794	20.462%	(15,325)	($15,325)	-0.95%
Small Interruptible											
Sales	92	572,872	830,234	1,702,576	2,532,810						
Transportation	63	1,104,513	870,115	0	870,115						
Total Small IT	155	1,677,385	1,700,349	1,702,576	3,402,925	551,704	4,218,401	13.079%	(291,938)	($291,938)	-8.58%
Large Interruptible											
Sales	0	0	0	0	0						
Transportation	6	4,321,943	1,327,781	0	1,327,781						
Total Large IT	6	4,321,943	1,327,781	0	1,327,781	618,577	4,022,219	15.379%	(269,669)	($269,669)	-20.31%
MAFB Distribution 3/					0	140,712	1,223,481	11.501%	(8,359)	($8,359)	-
Total North Dakota	112,516	23,351,305	$37,696,334	$70,912,508	$108,608,842	$9,144,906	$130,899,926	6.986%	$829,498	$829,498	0.76%

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
RATE RECONCILIATION
RESIDENTIAL GAS SERVICE - RATES 60 & 90
Projected 2018

	Billing Units		Current Rate	Current Amount	Proposed Rate	Proposed Amount	Change		
Residential Rates 60 & 90									
Basic Service Charge (600)	96,516	Cust	$0.6443	$22,697,619	$0.6777	$23,874,246	$1,176,627	Per month	$20.61
Basic Service Charge (900)	276	Cust	$0.6443	64,907	$0.6777	68,271	3,364		$19.60
				22,762,526		23,942,517	1,179,991		
Distribution Charge	8,826,214	dk	0	0	0.000	0	0		
Cost of Gas (600)	8,808,050	dk	4.011	35,329,089	4.011	35,329,089	0		
Cost of Gas (900)	18,164	dk	6.038	109,674	6.038	109,674	0		
	8,826,214			$35,438,763		$35,438,763	0		
Total Revenue Rates 60 & 90				$58,201,289		$59,381,280	$1,179,991		

Total Distribution Revenues Per Design	$23,942,517
Target Distribution Revenues	23,941,838
Difference	$679

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
RESIDENTIAL GAS SERVICE - RATES 60 & 90
Projected 2018

Current Non-Gas Revenues	$22,762,526
Proposed Revenue Increase	1,179,312
Total Revenue Requirement	$23,941,838
Projected Customers	96,792
Basic Service Charge per customer	$247
Basic Service Charge per day	$0.67770

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
RATE RECONCILIATION
FIRM GENERAL GAS SERVICE - RATE 70, 72, & 92
Projected 2018

	Billing Units		Current Rate	Current Amount	Proposed Rate	Proposed Amount	Change
Firm General Rate 70							
Basic Service Chg Rates (700)	10,777	Cust	$0.67	$2,635,515	$0.70	$2,753,524	$118,009
Basic Service Chg Rates (720)	5		0.67	1,223	0.70	1,278	55
Basic Service Chg Rates (920)	68		0.67	16,629	0.70	17,374	745
Basic Service Chg Rates (701)	4,693		1.90	3,254,596	2.05	3,511,537	256,941
Basic Service Chg Rates (721)	10		1.90	6,935	2.05	7,483	548
Basic Service Chg Rates (921)	7		1.90	4,855	2.05	5,238	383
Subtotal	15,560			$5,919,753		$6,296,434	376,681
Distribution Delivery	8,035,663	Dk	0.730	5,866,034	0.785	6,307,995	441,961
Cost of Gas (700)	2,022,627		4.011	8,112,757	4.011	8,112,757	0
Cost of Gas (720)	2,437		4.119	10,038	4.119	10,038	0
Cost of Gas (920)	11,774		6.038	71,091	6.038	71,091	0
Cost of Gas (701)	5,971,314		4.011	23,950,940	4.011	23,950,940	0
Cost of Gas (721)	12,891		4.119	53,098	4.119	53,098	0
Cost of Gas (921)	14,620	Dk	6.038	88,276	6.038	88,276	0
Subtotal	8,035,663			32,286,200		32,286,200	0
Total Revenue				$44,071,987		$44,890,629	$818,642
Total Distribution Revenues Per Design				$12,604,429			
Target Distribution Revenues				12,606,556			
Difference				($2,127)			

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
FIRM GENERAL GAS SERVICE - RATE 70, 72, & 92
Projected 2018

Current Non-Gas Revenues	$11,785,787
Proposed Revenue Increase	820,769
Total Revenue Requirement	$12,606,556
Less:	
Base Service Charge Revenue	6,296,434
Remaining Revenues To Be Collected	6,310,122
Total Rates 70, 72 and 90 (Firm) Consumption	8,035,663
Distribution Delivery Charge	$0.785

MONTANA-DAKOTA UTILITIES CO.
REVENUES UNDER CURRENT AND PROPOSED RATES
GAS UTILITY - NORTH DAKOTA

	Projected 2018 1\			Total	Proposed	
Customer Class/Rate	Customers	Dk	Revenue	Proposed Revenue	Revenue Increase	Percent Increase
Residential - Rate 60	96,792	8,826,214	$58,201,289	$59,529,663	$1,328,374	2.3%
Firm General Service - Rate 70	15,560	8,035,663	44,071,987	44,745,988	674,001	1.5%
Air Force - Rate 64						
Firm	1	32,523	143,249	143,249	0	0.0%
Interruptible	2	457,577	1,461,611	1,461,611	0	0.0%
Total Air Force	3	490,100	1,604,860	1,604,860	0	0.0%
Small Interruptible						
Sales - Rate 71	92	572,872	2,532,810			0.0%
Transport - Rate 81	63	1,104,513	870,115			0.0%
Total Small Interruptible	155	1,677,385	3,402,925	3,402,754	(171)	0.0%
Large Interruptible						
Sales - Rate 85	0	0	0			
Transport - Rate 82	6	4,321,943	1,327,781			
Total Large Interruptible	6	4,321,943	1,327,781	1,327,920	139	0.0%
Total North Dakota	112,516	23,351,305	$108,608,842	$110,611,185	$2,002,343	1.8%

1\ Statement K, page 5.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
ALLOCATION OF REVENUES
Projected 2018

	Billing Determinants 1/					Embedded COS Before Increase 2/			Increase Required @ Overall Return		
RATE CLASS	Customers	Dk	Distribution Revenues	Fuel Revenues	Total Revenues	Operating Income	Rate Base	Rate Of Return	Operating Income	Revenues	% Increase
Residential	96,792	8,826,214	$22,762,526	$35,438,763	$58,201,289	$4,023,257	$81,821,272	4.917%	$891,669	$891,669	1.53%
Firm General Service	15,560	8,035,663	11,785,787	32,286,200	44,071,987	3,632,069	41,419,929	8.769%	449,935	$449,935	1.02%
Air Force											
Firm	1	32,523	12,800	130,449	143,249						
Interruptible	2	457,577	107,091	1,354,520	1,461,611						
Total Air Force	3	490,100	119,891	1,484,969	1,604,860	30,627	149,792	20.446%	(15,313)	($15,313)	-0.95%
Small Interruptible											
Sales	92	572,872	830,234	1,702,576	2,532,810						
Transportation	63	1,104,513	870,115	0	870,115						
Total Small IT	155	1,677,385	1,700,349	1,702,576	3,402,925	644,556	2,789,032	23.110%	(341,072)	($341,072)	-10.02%
Large Interruptible											
Sales	0	0	0	0	0						
Transportation	6	4,321,943	1,327,781	0	1,327,781						
Total Large IT	6	4,321,943	1,327,781	0	1,327,781	673,791	3,496,437	19.271%	(293,740)	($293,740)	-22.12%
MAFB Distribution 3/					0	140,605	1,223,463	11.492%	(8,353)	($8,353)	-
Total North Dakota	112,516	23,351,305	$37,696,334	$70,912,508	$108,608,842	$9,144,906	$130,899,926	6.986%	$683,125	$683,125	0.63%

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
RATE RECONCILIATION
RESIDENTIAL GAS SERVICE - RATES 60 & 90
Projected 2018

	Billing Units		Current Rate	Current Amount	Proposed Rate	Proposed Amount	Change		
Residential Rates 60 & 90									
Basic Service Charge (600)	96,516	Cust	$0.6443	$22,697,619	$0.6819	$24,022,205	$1,324,586	Per month	$20.74
Basic Service Charge (900)	276	Cust	$0.6443	64,907	$0.6819	68,695	3,788		$19.60
				22,762,526		24,090,900	1,328,374		
Distribution Charge	8,826,214	dk	0	0	0.000	0	0		
Cost of Gas (600)	8,808,050	dk	4 011	35,329,089	4.011	35,329,089	0		
Cost of Gas (900)	18,164	dk	6 038	109,674	6.038	109,674	0		
	8,826,214			$35,438,763		$35,438,763	0		
Total Revenue Rates 60 & 90				$58,201,289		$59,529,663	$1,328,374		

Total Distribution Revenues Per Design	$24,090,900
Target Distribution Revenues	24,091,838
Difference	($938)

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
RESIDENTIAL GAS SERVICE - RATES 60 & 90
Projected 2018

Current Non-Gas Revenues	$22,762,526
Proposed Revenue Increase	1,329,312
Total Revenue Requirement	$24,091,838
Projected Customers	96,792
Basic Service Charge per customer	$249
Basic Service Charge per day	$0.68190

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
RATE RECONCILIATION
FIRM GENERAL GAS SERVICE - RATE 70, 72, & 92
Projected 2018

	Billing Units		Current Rate	Current Amount	Proposed Rate	Proposed Amount	Change
Firm General Rate 70							
Basic Service Chg Rates (700)	10,777	Cust	$0.67	$2,635,515	$0.70	$2,753,524	$118,009
Basic Service Chg Rates (720)	5		0.67	1,223	0.70	1,278	55
Basic Service Chg Rates (920)	68		0.67	16,629	0.70	17,374	745
Basic Service Chg Rates (701)	4,693		1.90	3,254,596	2.05	3,511,537	256,941
Basic Service Chg Rates (721)	10		1.90	6,935	2.05	7,483	548
Basic Service Chg Rates (921)	7		1.90	4,855	2.05	5,238	383
Subtotal	15,560			$5,919,753		$6,296,434	376,681
Distribution Delivery	8,035,663	Dk	0.730	5,866,034	0.767	6,163,354	297,320
Cost of Gas (700)	2,022,627		4.011	8,112,757	4.011	8,112,757	0
Cost of Gas (720)	2,437		4.119	10,038	4.119	10,038	0
Cost of Gas (920)	11,774		6.038	71,091	6.038	71,091	0
Cost of Gas (701)	5,971,314		4.011	23,950,940	4.011	23,950,940	0
Cost of Gas (721)	12,891		4.119	53,098	4.119	53,098	0
Cost of Gas (921)	14,620	Dk	6.038	88,276	6.038	88,276	0
Subtotal	8,035,663			32,286,200		32,286,200	0
Total Revenue				$44,071,987		$44,745,988	$674,001
Total Distribution Revenues Per Design				$12,459,788			
Target Distribution Revenues				12,456,556			
Difference				$3,232			

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
FIRM GENERAL GAS SERVICE - RATE 70, 72, & 92
Projected 2018

Current Non-Gas Revenues	$11,785,787
Proposed Revenue Increase	670,769
Total Revenue Requirement	$12,456,556
Less:	
Base Service Charge Revenue	6,296,434
Remaining Revenues To Be Collected	6,160,122
Total Rates 70, 72 and 90 (Firm) Consumption	8,035,663
Distribution Delivery Charge	$0.767

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana Dakota Utilities, Co., a Division of MDU Resources Group, Inc. 2017 Natural Gas Rate Increase Application

Case No. PU-17-295

VERIFICATION

STATE OF Maryland)
) ss.
COUNTY OF Montgomery)

Karl Pavlovic, being first duly sworn on oath, deposes and states that he has read the testimony and exhibits submitted in the above captioned matter under his name, that they were prepared by him or under his direction, that he knows the contents thereof, and that the same are true and correct to the best of his knowledge and belief.

Karl R Pavlovic
Karl Pavlovic

Subscribed and sworn to before me this 15th day of December, 2017.

Michelle Lease
Notary Public
My Commission Expires: 3/10/21

MONTGOMERY CO. PUBLIC NOTARY MICHELLE A. LEASE MD

MICHELLE A. LEASE
NOTARY PUBLIC STATE OF MARYLAND
My Commission Expires March 10, 2021