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December 7, 2018

VIA ELECTRONIC FILING

Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission
of the District of Columbia
1325 "G" Street, N.W., 8th Floor
Washington, D.C. 20005

Re: Formal Case No. 1115
[Washington Gas's Application for Approval of PROJECT*pipes* 2 Plan]

Dear Ms. Westbrook-Sedgwick:

Transmitted for filing is Washington Gas Light Company's ("Company") Application for Approval of PROJECT*pipes* 2 Plan, along with the supporting testimony and accompanying exhibits of Company Witnesses Wayne A. Jacas (Exh. WG (A)), Aaron C. Stuber (Exh. WG (B)), and R. Andrew Lawson (Exh. WG (C)).

Please do not hesitate to contact me if you have questions regarding this matter.

Sincerely,

Cathy Thurston-Seignious
Supervisor, Administrative and
Associate General Counsel

pc: Per Certificate of Service

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

FORMAL CASE NO. 1115

IN THE MATTER OF THE APPLICATION OF WASHINGTON GAS LIGHT COMPANY
FOR APPROVAL OF A REVISED ACCELERATED PIPE
REPLACEMENT PROGRAM

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(WITNESSES JACAS, STUBER, AND LAWSON)

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DATED: DECEMBER 7, 2018

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APPLICATION

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

IN THE MATTER OF APPLICATION OF WASHINGTON GAS LIGHT COMPANY FOR APPROVAL OF A REVISED ACCELERATED PIPE REPLACEMENT PROGRAM	)	Formal Case No. 1115

WASHINGTON GAS LIGHT COMPANY'S
<u>APPLICATION FOR APPROVAL OF PROJECTPIPES 2 PLAN</u>

By Public Service Commission of the District of Columbia ("Commission") Order No. 17431, issued in Formal Case Nos. 1093 and 1115, the Commission granted approval, in part and subject to certain conditions, of the first five (5) years of Washington Gas Light Company's ("Washington Gas" or "Company") proposed 40-year Revised Accelerated Pipe Replacement Plan ("Revised Plan" or "PIPES 1 Plan").[1] The Commission stated in the Order that it "anticipate[s] approving the remainder of the Revised Plan in additional 5-year segments, with the Company requesting our approval for each segment separately."[2] Washington Gas hereby submits for approval its PROJECT*pipes* 2 Plan ("PIPES 2 Plan"), as well as authorization to recover the costs associated with the PIPES 2 Plan through the approved PROJECT*pipes* surcharge mechanism. To allow the continuous progression of PROJECT*pipes*, and to ensure the continued availability of

[1] Formal Case Nos. 1093 and 1115, Order No. 17431 (March 31, 2014).
[2] Order No. 17431 at 32.

contractor resources needed to perform the work under this program, Washington Gas requests approval of the PIPES 2 Plan and surcharge mechanism in advance of the expiration of the current PIPES 1 Plan, *i.e.*, by September 30, 2019.

I. BACKGROUND

By Order No. 17602, the Commission granted final approval of the Company's Revised Plan[3] and subsequently approved the Unanimous Agreement of Stipulation and Full Settlement, filed in this case on December 10, 2014, which, *inter alia*, authorized the implementation of a surcharge mechanism to recover the costs associated with the Revised Plan ("Settlement Agreement").[4] Through a series of orders, the Commission clarified issues related to the Revised Plan, such as the requirements under the PROJECT*pipes* Customer Education Program, and imposed additional obligations, including detailed reporting requirements.[5] The Company has complied with all of the Commission's prior directives and has provided the requisite information pertaining to the management and operation of the program. With few exceptions, under the PIPES 2 Plan, the Company seeks to continue the performance of the PROJECT*pipes* program under the terms and conditions approved by the Commission in this proceeding.

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[3] Formal Case No. 1115, Order No. 17602 (August 21, 2014).
[4] Formal Case No. 1115, Order No. 17789 at 37 (January 29, 2015).
[5] *See* Order No. 17789; Order No. 17885; Order No. 17983 (September 25, 2015); Order No. 18720 (July 14, 2016); Order No. 18503 (August 23, 2016); Order No. 18566 (October 12, 2016); Order No. 18815 (June 23, 2017); Order No. 19088 (September 7, 2017); Order No. 19153 (October 23, 2017); Order No. 19194 (November 30, 2017); and Order No. 19323 (April 18, 2018).

II. DISCUSSION

PROJECT*pipes* has proven to be an effective program designed to enhance the safety and improve the reliability of Washington Gas's natural gas delivery system by accelerating the replacement of relatively higher-risk natural gas facilities which serve the Company's District of Columbia customers. Under the PIPES 1 Plan, as of September 30, 2018, the Company retired or remediated approximately 12.8 miles of main and 2,959 services. By this filing, Washington Gas proposes to implement the next five (5) years of PROJECT*pipes*, to continue enhancements of its system. The selection of pipe to be replaced is based on various factors, including assessed risk identified through the Company's Distribution Integrity Management Program ("DIMP")[6] and Transmission Integrity Management Program ("TIMP").[7] The PIPES 2 Plan offers a number of benefits to customers and the environment, as described in the supporting testimony of Company Witnesses Wayne A. Jacas and Aaron C. Stuber.

The PIPES 2 Plan will further the Company's efforts to address relatively higher-risk pipe associated with an aging infrastructure by replacing pipe materials and components, as well as adding new features to enhance the safety of the system. Approval of the PIPES 2 Plan will allow the Company to continue to modernize its system at an accelerated pace for the benefit of Washington Gas customers and the general public.

A. Description of PIPES 2 Plan

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[6] Company Witness Jacas provides the policy and operational support for the proposed distribution pipe replacement programs.
[7] The Direct Testimony of Company Witness Stuber provides detail and support for the proposed transmission pipe replacement programs under the PIPES 2 Plan.

The PIPES 2 Plan covers the period October 1, 2019 through December 31, 2024 and consists of 13 programs, *i.e.,* eight (8) distribution replacement programs and five (5) transmission replacement programs, at an estimated total cost of $305.3 million. The distribution programs under the plan are as follows:

- **Program 1** – Bare Steel Main and Services (including Contingent Main and Affected Services
- **Program 2** – Unprotected Wrapped Steel Main and Services (including Contingent Main and Affected Services)
- **Program 3** Vintage Mechanically Coupled Main and Services (including Contingent Main and Affected Services)
- **Program 4** – Cast Iron Main (including Contingent Main and Affected Services)
- **Program 5** – Copper Services
- **Program 6** – Distribution Gauge Lines
- **Program 7** – Regulator Station Enhancements
- **Program 8** – Low-Pressure Service Replacements/Transfers

In addition, the Company is proposing the following transmission replacement programs:

- **Program 1** – Transmission and High-Pressure Pipe Replacement
- **Program 2** – Remote Control Valve Installation
- **Program 3** – Transmission and High-Pressure Block Valve Replacement
- **Program 4** – Transmission and High-Pressure Valve Riser Replacement
- **Program 5** – Replacement of Components of DOT Transmission and High-Pressure Pipes to Enable the Use of In-Line Inspection Tools.

All of these programs are described in detail and fully supported in the accompanying testimony of Company Witnesses Jacas and Stuber. With the approval of the PIPES 2 Plan, Washington Gas intends to replace 22 miles of main and replace or changeover 8,274 services in its distribution system over the five-year period of the plan, at a total estimated cost of $277.1 million. For the transmission programs, Washington Gas has budgeted $28.2 million for the five-year plan for the District of Columbia allocated portion of the total cost for these projects.

B. Surcharge Mechanism

The Company seeks to continue recovery of the costs associated with the PIPES 2 Plan through the PROJECT*pipes* surcharge mechanism previously approved by the Commission in this proceeding.[8] As discussed in further detail in the testimony of Company Witness R. Andrew Lawson, this cost recovery mechanism has a reconciliation component to adjust for any over- or under-collection of revenues from the surcharge to ensure that customers pay the actual costs incurred by Washington Gas in the performance of the program. The calculation of the Year 6 rider is included in the supporting testimony of Company Witness Lawson, as well as proposed tariff revisions.[9] Unless otherwise amended by the Commission, the Company will continue to follow the terms and conditions

[8] However, in accordance with Commitment 72 in Appendix A of Order No. 19396 issued by the Commission in Formal Case No. 1142, "excess costs" as defined in the commitment shall not be recovered through the surcharge mechanism, but rather will be subject to a prudence review in the Company's next base rate case.

[9] Year 6 covers the period October 1, 2019 – December 31, 2020, in consideration of the Company's transition to a calendar year fiscal year. Each subsequent calendar year will encompass a plan year.

set forth in Section 1 of the Settlement Agreement governing the surcharge mechanism, as well as any related Commission-directed requirements.[10]

C. Annual Project Lists

Pursuant to Order No. 17789, and consistent with the Settlement Agreement, on July 31st of each year under the plan, Washington Gas must file a new project list to include the proposed list of pipe replacement projects for the upcoming construction year, consistent with the requirements set forth in Order No. 17431, as amended by the Commission.[11] As determined by the Commission in Paragraph 68 of Order No. 17431 for the PIPES 1 Plan, projects that are included on an annual project list and qualify for funding under the surcharge must meet the following criteria:

1. The project is started on or after June 1, 2014;[12]
2. Project assets are not included in the Company's rate base in its most recent rate case;
3. The Project does not increase revenues by directly connecting the infrastructure replacement to new customers; and
4. The Project is needed to reduce risk and enhance safety by replacing aging corroded or leaking cast iron mains, bare and/or unprotected

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[10] *See* Settlement Agreement at 4-6.

[11] Order No. 17431 at 34. The Commission required the annual project lists to include (1) project description; (2) location; (3) estimated costs; (4) type of infrastructure being replaced (*i.e.*, material type); (5) the risk assessment for the project, including where applicable the current Optimain score, leak rates, or other factors that were considered in the risk assessment; (6) the estimated start date and completion date, by month and year; and (7) the reason for the replacement. The Commission subsequently adopted certain amendments related to the annual project lists for purposes of consistency with the Settlement Agreement. *See* Order No. 17789 at 33-34.

[12] The Commission modified this requirement to reflect expenses incurred on or after June 1, 2014. Formal Case No. 1115, Order No. 17500 at 8 (May 30, 2014).

steel mains and services, and black plastic service in the distribution system.[13]

For transmission programs, the same criteria should apply, with some modification to Criterion No. 4, to recognize the differences between distribution and transmission facilities, as discussed in the testimony of Company Witness Stuber.

For the Year 6 Annual Project List, Washington Gas will file the initial Annual Project List by June 1, 2019 and the final Annual Project List by July 31, 2019. In consideration of the Company's planned change in its fiscal year to a calendar year, Washington Gas is proposing to change the filing dates of the annual project lists. Specifically, beginning with the Year 7 Annual Project List and throughout the PIPES 2 Plan, the Company proposes to file the initial annual project lists by September 1 and the final annual project lists by November 1 of each year, in accordance with the criteria set forth above and as provided in the Settlement Agreement. The Company would follow the same timeline to file the non-APRP proposed budget referenced in the Settlement Agreement.[14] If no objection is lodged for a project on an annual project list, the projects will be deemed approved by the Commission and the associated costs will be included in the rate calculations to be effective on October 1, 2019, for Year 6, and January 1 of each year thereafter, beginning with Year 7 of the PIPES 2 Plan.

The Company reserves the right to modify its project lists, as set forth in Order No. 17500.[15] Specifically, Washington Gas may adjust up to two (2) projects each year on its annual project list by up to $1 million per project, provided the

[13] Order No. 17431 at 33. The Commission later approved the inclusion of copper services in this criterion. *See* Order No.17500 at 12. Additional material types may be included, if approved by the Commission for the PIPES 2 Plan.
[14] Settlement Agreement at 7-8.
[15] Order No. 17500 at 13.

Company submits written advance notice and details of the revisions to Commission Staff and the parties in this case. If modifications are needed to more than two (2) projects and/or exceed $1 million per project, Washington Gas will file a request for approval of the changes, including a detailed explanation for the changes and cost estimates. Parties will have an opportunity to file comments on these additional modifications, and the Commission will conduct an expedited review of the filings. The Company will continue to follow the time frames and procedures for discovery on the annual project lists, as provided under Section 2 of the Settlement Agreement and Order No. 17602, as amended in Order No. 17789.[16]

Unless otherwise amended by the Commission, the Company will follow the terms and conditions set forth in Section 2 of the Settlement Agreement governing annual project lists, as well as any related Commission decisions.[17]

D. Annual Audit

In Order No. 17431, the Commission required that an annual audit be conducted of the Company's program and expenditures to ensure (1) the work is being performed timely, and (2) that costs are being fairly and accurately recorded.[18] The Commission expanded the scope of the audit in Order No. 17789 stating, "The focus of the audit is to assure that the project costs being recovered through the [surcharge] mechanism are prudent and accurate, that the APRP projects that were completed are timely, consistent with the Annual Project List submitted by WGL and includes projects from Programs 1, 2 and 4 that meet the

[16] Order No. 17602 at 52-53 and Order No. 17789 at 33-34. *See also* Settlement Agreement at 6-10.
[17] Settlement Agreement at 6-10.
[18] Order No. 17431 at 36.

four requirements set forth in Paragraph 68 of Order No. 17431."[19] By Order No. 17885, the Commission clarified the type of audit to be performed under the PIPES Plan.[20] Washington Gas will continue to comply with the Commission's audit requirements under the PIPES 2 Plan.

E. Reporting Requirements

Under the Settlement Agreement, Washington Gas agreed to annually file a Financial Reconciliation Report and a Completed Projects Reconciliation Report to evaluate the progress of the program and assess compliance with requirements.[21] Additional reporting requirements were directed by the Commission in subsequent Orders.[22] For example, by Order No. 19194, the Commission authorized Washington Gas to recover the costs associated with the conversion of low-pressure to medium-pressure mains and the opportunistic conversion of low-pressure service lines to medium-pressure service lines in the PROJECT*pipes* surcharge and directed the Company to provide documentation for its low-to-medium pressure conversion program and plans in its annual Completed Projects Reconciliation Report.[23] Washington Gas will comply with these reporting requirements but proposes some modifications, as discussed herein and in the testimony of Company Witness Jacas.

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[19] Order No. 17789 at 31. The Commission provided additional insight on the parameters of the annual audit, including the option for Washington Gas to use the same independent contractor for the first five (5) years of the program. Order No. 17789 at 30-32.
[20] Order No. 17885 at 14-21.
[21] Settlement Agreement at 10-12.
[22] Order No. 18503 at 59-61; *See also* Order No. 19153 (October 23, 2017) and Order No. 19194 (November 30, 2017).
[23] Formal Case No. 1115, Order No. 19194 at 9 (November 30, 2017).

In light of the proposed change in the plan years, beginning with Year 6 of the PIPES 2 Plan, the Company proposes to file both the Completed Projects Reconciliation Report and the Financial Reconciliation Report, by March 31 of each year. Comments and reply comments on these reports would be due on April 30 and May 15, respectively. The Reconciliation Factor will be added to or subtracted from the Current Factor in the June billing cycle. Washington Gas proposes that the Current Factor will go into effect during the January billing period, unless otherwise ordered by the Commission.

F. Customer Education Plan

Per Order No. 17789, the Commission set parameters for a Customer Education Plan for PROJECT*pipes*, which were later modified by Order Nos. 17885 and 17983.[24] Washington Gas has implemented a robust Customer Education Plan and continues to work cooperatively with Commission Staff and the Office of the People's Counsel for the District of Columbia on this effort. The Company will continue its Customer Education Plan under the PIPES 2 Plan in compliance with these requirements.

[24] Order No. 17789 at 34-36; Order No. 17885 at 24-26; and Order No. 17983 at 2-3 (September 25, 2015).

G. Construction Drawings

Pursuant to Order No. 17789, the Company must file with the Commission final construction drawings for each project on an annual project list throughout the duration of PROJECT*pipes*, within 10 days of the completion of the drawings.[25] Washington Gas will continue to comply with this requirement under the PIPES 2 Plan.

H. Cost-Benefit Analysis

Pursuant to the Unanimous Agreement of Stipulation and Full Settlement approved by the Commission in Formal Case No. 1142, Commitment No. 54, Washington Gas is to file the results of a cost/benefit analysis, performed by a third-party consultant, of the acceleration of PROJECT*pipes* and minimization of future leaks that addresses Grade 1 leaks not caused by excavation damage, for consideration in the examination of the next five (5) years of PROJECT*pipes*.[26] Washington Gas has issued a Request for Proposal to conduct the cost/benefit analysis and is engaged in the bid/review process; however, the study is not expected to be concluded until April of 2019. Upon completion of the study, Washington Gas will file the study results for consideration in this proceeding, as well as supplemental testimony addressing the impact of the study results on the Company's PIPES 2 Plan.

[25] Order No. 17789 at 33.
[26] Formal Case No. 1142, Order No. 19396, Appendix A at 21 (June 29, 2018).

III. PROPOSED PROCEDURAL SCHEDULE

Provided below is Washington Gas's proposed procedural schedule for the Commission's examination of the PIPES 2 Plan. This schedule is designed to allow sufficient time for the completion of the cost/benefit analysis discussed above prior to the parties' submission of testimony and issuance of a Commission order in advance of the expiration of the current PIPES 1 Plan.

PROPOSED PROCEDURAL SCHEDULE

1	WG Application and Supporting Testimony	December 7, 2018
2	Deadline for Data Requests on Application and Supporting Testimony	February 27, 2019
3	Cost/Benefit Analysis Filed	April 12, 2019
4	WG Supplemental Testimony	April 26, 2019
5	Deadline for Data Requests on Supplemental Testimony	May 3, 2019
6	Direct Testimony and Exhibits of OPC and Intervenors	May 31, 2019
7	Deadline for Data Requests on OPC and Intervenors' Direct Testimony	June 7, 2019
8	Rebuttal Testimony and Exhibits by All Parties	June 28, 2019
9	Deadline for Data Requests on Rebuttal Testimony	July 3, 2019
10	All Responses to Data Requests on Rebuttal Testimony	July 10, 2019
11	Evidentiary Hearings	July 11 and 12, 2019
12	Motions to Correct Transcript and Corrected Final List of Cross-Examination Exhibits	July 16, 2019
13	All Initial Post-Hearing Briefs	July 19, 2019
14	All Reply Briefs	July 31, 2019
15	Expected Commission Decision	September 30, 2019

Unless otherwise noted on this Procedural Schedule, responses to data requests, follow-up data requests and follow-up data responses will be provided within the timeframes provided in the Commission's regulations.

IV. CONCLUSION

For all of the reasons discussed herein, Washington Gas respectfully requests that the Commission approve (1) the Company's PIPES 2 Plan, as described herein and in the supporting testimony attached hereto; (2) the associated surcharge mechanism supported by accompanying testimony; and (3) the proposed procedural schedule for this proceeding as set forth herein.

Respectfully submitted,

Cathy [signature]

CATHY THURSTON-SEIGNIOUS
Supervisor, Administrative and
Associate General Counsel

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(202) 624-6105

Dated: December 7, 2018

WITNESS JACAS
EXHIBIT WG (A)

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE
DISTRICT OF COLUMBIA

IN THE MATTER OF APPLICATION OF WASHINGTON GAS LIGHT COMPANY FOR APPROVAL OF A REVISED ACCELERATED PIPE REPLACEMENT PROGRAM	FORMAL CASE NO. 1115

WASHINGTON GAS LIGHT COMPANY
District of Columbia

DIRECT TESTIMONY OF WAYNE A. JACAS
Exhibit WG (A)
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Exhibits

WASHINGTON GAS LIGHT COMPANY

DISTRICT OF COLUMBIA

DIRECT TESTIMONY OF WAYNE A. JACAS

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

A. My name is Wayne A. Jacas, and I am the Director of Construction Program Strategy and Management at Washington Gas Light Company ("Washington Gas" or "Company"). My business address is 6801 Industrial Road, Springfield, VA 22151.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY TO THE PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA ("COMMISSION") OR ANY OTHER PUBLIC UTILITY COMMISSION?

A. I have not provided testimony before the Commission; however, I have appeared before the Maryland Public Service Commission ("Maryland Commission") regarding the Company's accelerated pipe replacement program. Specifically, in Case No. 9486, I testified regarding Washington Gas's second Strategic Infrastructure Development and Enhancement ("STRIDE 2") Plan. In addition, I have addressed the Maryland Commission at Administrative Meetings considering various aspects of the Company's STRIDE program.

I. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science degree in Civil Engineering from North Carolina State University and a Master's Certificate in Project Management from

Villanova University. I am a certified Project Management Professional. I have 16 years of engineering, construction and operations experience, with 11 of those years in the natural gas industry. Prior to joining Washington Gas in 2017, I worked for North Carolina Department of Transportation, Atlanta Gas Light, Virginia Natural Gas, and Columbia Pipeline Group. My specific areas of natural gas experience have been in gas distribution, transmission, and compression. I am currently the Director of the Company's Construction Program Strategy and Management Department, and responsible for the program management including governance and reporting of the Company's Accelerated Pipe Replacement Programs.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony, with accompanying exhibits, is to describe what has been accomplished by Washington Gas during the first five years of the PROJECT*pipes* Program ("PIPES 1" or the "PIPES 1 Plan"), to explain what Washington Gas plans to accomplish under its second five-year PROJECT*pipes* Program ("PIPES 2" or the "PIPES 2 Plan"), to provide details and justification for the Company's PIPES 2 Plan, and to recommend that the Commission approve Washington Gas's PIPES 2 Plan. Under PIPES 2, Washington Gas will continue to replace relatively higher risk infrastructure at an accelerated pace through its proposal to increase total expenditures from approximately $110 million under the current five-year PIPES 1 Plan to approximately $305.3 million over the next five years. This PIPES 2 Plan demonstrates the Company's continued commitment to proactively enhancing safety and improving reliability of its infrastructure, consistent with Order Nos. 17431, 17602 and 17789,[1] and responds to the federal government's "Call to Action" for accelerated efforts to replace aging gas infrastructure, discussed further below. In addition, under PIPES 2, District of Columbia customers will continue to receive both economic and environmental benefits, which I will describe later in my testimony.

III. IDENTIFICATION OF EXHIBITS

Q. DO YOU SPONSOR ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes, I sponsor six (6) exhibits. Exhibit WG (A)-1 is a National Association of Regulatory Utility Commissioners ("NARUC") resolution concerning accelerated gas infrastructure replacements and associated rate recovery mechanisms. Exhibit WG (A)-2 includes the proposed PIPES 2 Plan scope, cost estimate, and timeline for implementation of the proposed distribution programs. Exhibit WG (A)-2 also provides the supporting information and justification for the selection of distribution replacement programs for PIPES 2. Exhibit WG (A)-3 is the American Association of Cost Engineers International ("AACE") Cost Estimate Classification System. Exhibit WG (A)-4 is the economic study conducted by NERA Consulting. Exhibit WG (A)-5 is the American Gas Association ("AGA") State Infrastructure Replacement Activity published on December 19, 2016. Exhibit WG (A)-6 is the White Paper on State Pipeline Infrastructure Replacement Programs prepared for NARUC by the

[1] Formal Case Nos. 1093 and 1115, Order No. 17431 (March 31, 2014); Formal Case No. 1115, Order No. 17602 (August 21, 2014); and Formal Case No. 1115, Order No. 17789 (January 29, 2015).

Department of Transportation ("DOT") Pipeline and Hazardous Materials Safety Administration ("PHMSA").

IV. BACKGROUND

Q. PLEASE EXPLAIN THE BACKGROUND FOR THE PROJECTPIPES PROGRAM.

A. By Order No. 17431, the Commission approved the Company's Revised Accelerated Pipe Replacement Plan ("Revised Plan"), filed on August 15, 2013, in Formal Case No. 1093, subject to certain conditions provided in the Order. Having satisfied the Commission's conditions, Washington Gas was granted final approval of the Revised Plan in Order No. 17602. Under the Revised Plan, for the first five years of the program, Washington Gas designed projects to replace relatively higher-risk (1) bare and/or unprotected steel services; (2) bare and/or targeted unprotected steel main and affected services; and (3) cast iron main and affected services.[2] The Company further agreed to include the top three Optimain projects on its annual project lists.[3] On January 29, 2015, by Order No. 17789, the Commission approved the Unanimous Agreement of Stipulation and Full Settlement filed in this proceeding, wherein the Company was authorized to implement a surcharge mechanism to recover the costs of the program ("Settlement Agreement").[4]

V. THE CURRENT PIPES 1 PLAN AND SUPPORT FOR THE PIPES 2 PLAN

Q. DOES WASHINGTON GAS CURRENTLY HAVE A PROJECTpipes PLAN IN PLACE?

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[2] Order No. 17431 at 32.
[3] Order No. 17602 at 50.
[4] Order No. 17789 at 37.

A. Yes. Washington Gas has a current, Commission-approved PIPES 1 Plan that has been in place since 2014. PIPES 1 covers the first five years of a 40-year accelerated replacement program. The Company has been executing this phase of its PROJECT*pipes* Plan for more than four years. Each year the Company has provided reports on program progress to the Commission pursuant to reporting requirements established by the Settlement Agreement. The Company's current PIPES 1 Plan consists of the following programs set forth in Table 1 below:

Table 1: Washington Gas's Current PIPES 1 Programs

Program Number	Program Description
1	Bare and/ or Unprotected Steel Service Replacement
2	Bare and/ or Targeted Unprotected Steel Main Replacement and affected services
4	Cast Iron Main Replacement and affected services

Q. WHAT HAS THE COMPANY ACCOMPLISHED UNDER THE PIPES 1 PROGRAM TO DATE?

A. The Company's PIPES 1 Plan has enhanced the safety and improved the reliability of the Company's District of Columbia distribution system, by replacing the relatively higher risk facilities as identified through annual project lists approved by the Commission. This work has been completed at a total cost of $78.1 million through September 30, 2018. Through that same date, the Company spent approximately 54% of its PIPES 1 budget on qualified, diverse vendors which includes Minority Business Enterprises, Women Business Enterprises and Service Disabled Veteran Business Enterprises. Table 2 below sets forth the PIPES 1 Plan accomplishments and costs by program. The shaded boxes are not applicable to the corresponding program.

Table 2: PROJECT*pipes* Accomplishments Years 1-4					
Program	**Description**	**Number of Services**	**Miles of Main Installed**	**Miles of Main Replaced/ Remediated**	**Charges ($M)**
1	Bare and/or Unprotected Steel Service Replacement	1,317			$14.7
2	Bare and/or Targeted Unprotected Steel Main and Affected Services	392	4.9	4.1	$19.0
4	Cast Iron Main and Affected Services	1,250	10.6	8.7	$44.4
Total		2,959	15.5	12.8	$78.1

Q. HAS ALL WORK PROPOSED BY THE COMPANY UNDER ITS CURRENT FIVE-YEAR PIPES 1 PLAN BEEN COMPLETED?

A. No. As of September 30, 2018, the Company has spent a total of $78.1 million on current PIPES 1 programs. The Company plans to spend the remaining balance (that is, up to the Commission-approved budget cap of $110 million) on Commission-approved projects prior to the close of the surcharge period, which concludes on September 30, 2019. As of September 30, 2018, Washington Gas has retired/remediated approximately 12.8 miles of gas main and 2,959 gas services under its current PIPES 1 Plan. The Company will continue to work on projects that have been approved by the Commission on annual project lists.

Q. WHAT BENEFITS HAS THE PIPES 1 PROGRAM PROVIDED TO THE COMPANY'S DISTRICT OF COLUMBIA CUSTOMERS?

A. The Company's accelerated replacement work conducted through its PIPES 1 program benefits District of Columbia customers through enhanced safety and improved reliability of Washington Gas's gas distribution system, consistent with the Company's Revised Plan approved by Commission Order No. 17602 and the Settlement Agreement.

Q. HAVE THERE BEEN ADDITIONAL BENEFITS FROM THE COMPANY'S PIPES 1 WORK?

A. Yes. Through its completion of PIPES 1 work and consistent with the Commission's findings in Formal Case No. 1137 that the Company's measures and methodologies regarding leak mitigation conform to industry and regulatory standards, Washington Gas has reduced greenhouse gases ("GHGs") released from its District of Columbia distribution system by an estimated cumulative reduction total of 5,674 metric tons of carbon dioxide (or CO2 equivalent) and estimated total equivalents cars removed from the road of 1,214, as well as enhanced safety with the installation of 1,677 Excess Flow Valves ("EFVs"). Under the PIPES 1 Plan, the Company is also using new marking technology and updated as-builts and has improved reliability through uprating low-pressure systems which can reduce water infiltration into pipelines causing outages.

In addition, the Company's current PIPES 1 Plan has created a substantial number of jobs in the District of Columbia and achieved substantial economic benefits for the District of Columbia. According to the Analysis of Economic Benefits prepared by NERA Economic Consulting and attached as Exhibit WG (A)-4, for the PIPES 1 spending period (2014-2019), an estimated 616 full-time jobs will be created, the total value of the industry output will be $95,078,026, employee compensation is estimated at $38,880,488, and Gross Domestic Product ("GDP") in the District of Columbia is estimated at $57,579,451.

Q. IS THE COMPANY'S DISTRIBUTION SYSTEM CURRENTLY SAFE?

A. Yes. Washington Gas operates and maintains its system in full compliance with all federal, state and local regulations.

Q. GIVEN THAT THE COMPANY'S DISTRIBUTION SYSTEM IS ALREADY SAFE, AND MEETS OR EXCEEDS FEDERAL SAFETY GUIDELINES, WHAT IS THE BENEFIT OF THE COMPANY'S PROPOSED PIPES 2 PLAN?

A. Safety is the number one priority for Washington Gas. Commission approval of the PIPES 2 Plan will provide the Company with the financial and regulatory certainty necessary to replace relatively higher risk pipe earlier than it could be replaced if the Company were limited to recovering related costs using the traditional base rate case process. While under either scenario the Company will maintain and operate a safe and reliable system, with the approval of PIPES 2, the Company can replace eligible infrastructure in 40 years rather than 100 years or more under its traditional replacement programs. Commission approval of PIPES 2 will ensure that Washington Gas will accelerate its pipe replacement activity that focuses on reducing risk and enhancing reliability for its Washington, D.C. piping system.

Q. WOULD COMMISSION APPROVAL OF WASHINGTON GAS'S PIPES 2 PLAN SUPPORT ANY FEDERAL OR OTHER POLICIES?

A. Yes. The DOT PHMSA issued in March 2011 a "Call to Action" urging the acceleration of efforts to replace aging gas system infrastructure. As part of the "Call to Action," federal officials encouraged legislators and state regulators to adopt and approve special rate mechanisms to allow for accelerated infrastructure replacement of gas system materials such as Cast Iron and Bare Steel (materials which PHMSA identified). By approving Washington Gas's PIPES 2 Plan, the Commission would further support PHMSA's Call to Action.

Additionally, in July 2013, NARUC passed a resolution entitled Resolution Encouraging Natural Gas Line Investment and the Expedited Replacement of High-Risk Distribution Mains and Service Lines (the "NARUC Resolution"), which called on state regulatory commissions "to consider sensible programs aimed at replacing the most vulnerable pipelines as quickly as possible along with the adoption of rate recovery mechanisms that reflect the financial realities of the particular utility in question" and "to explore, examine, and consider adopting alternative rate recovery mechanisms as necessary to accelerate the modernization, replacement, and expansion of the nation's natural gas pipeline systems . . ."[5] In approving Washington Gas's PIPES 2 Plan, the Commission would support NARUC's policy position as described in the NARUC Resolution.

As of December 2016, the American Gas Association ("AGA") has identified 41 states plus the District of Columbia, thus far, which have approved

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[5] *See* attached Exhibit WG (A)-1.

innovative cost recovery mechanisms for accelerated infrastructure replacement.[6] Thus, the District of Columbia is squarely among the mainstream of jurisdictions for incenting utilities to address aging infrastructure in a comprehensive and timely manner to enhance safety and improve reliability of distribution systems.

PIPES 2 is a critical tool in the Company's efforts to reduce pipeline integrity risk. The United States Department of Transportation Code of Federal Regulations 49 Part 192 ("DOT 192"), Subpart P (Gas Distribution Pipeline Integrity Management) requires gas companies to have a Distribution Integrity Management Program ("DIMP") Plan. A DIMP Plan is performance-based, using metrics to drive overall performance improvement. The purpose of a DIMP Plan is to enhance the safety of distribution piping infrastructure by identifying, evaluating, and prioritizing pipeline integrity risk and to propose actions to reduce risk. In addition, Subpart O of DOT 192 (Gas Transmission Pipeline Integrity) requires gas companies to have a Transmission Integrity Management Program ("TIMP") Plan. This is a prescriptive-based plan that utilizes risk modeling and pipeline assessments to identify and lower the risks of transmission infrastructure. The Company operates and maintains its gas transmission and distribution piping systems in full compliance with DOT 192 and the District regulations. This includes materials standards, engineering and design, construction, and operations and maintenance activities. Programs are developed to mitigate the risk identified in the DIMP and TIMP Plans. The

[6] *See* attached Exhibit WG (A)-5.

Company proposes PIPES 2 to continue its efforts to reduce pipeline integrity risk.

Q. HOW WILL PIPES 2 PROVIDE CONSTRUCTION EMPLOYMENT BENEFITS IN THE DISTRICT OF COLUMBIA?

A. Washington Gas has maintained an annual average of 11 qualified contractor crews working on accelerated pipeline replacements in the District of Columbia. Commission approval of Washington Gas's PIPES 2 Plan will allow the Company to continue the accelerated pace of replacing targeted infrastructure while continuing to provide a predictable and consistent flow of work for a defined period to qualified resources. Timely approval of the PIPES 2 Plan will allow the Company to reduce the risk of valuable trained and qualified resources leaving to pursue more stable projects in the region or outside of the District of Columbia and retain the qualified resources for this accelerated replacement work.

VI. WASHINGTON GAS'S PIPES 2 PLAN

Q. PLEASE GIVE A BRIEF SUMMARY OF THE COMPANY'S PROPOSED PLAN.

A. PIPES 2 is a broad outline containing programs targeting, on an accelerated basis, replacement of at-risk infrastructure in the Company's distribution and transmission systems along with a timeline for completion of all projects under each program and the estimated cost of each program. As stated above, my testimony will address details and justification for acceleration of distribution facilities replacement programs included in the PIPES 2. Company Witness Stuber will address the details and justification for acceleration of transmission facilities replacement programs included in PIPES 2. Company Witness Lawson will address the PROJECT*pipes* surcharge, specifically how the Current Factor for the PROJECT*pipes* surcharge for the fifteen months ended December 31, 2020 ("Plan Year 6") will be calculated and implemented.

As in PIPES 1, in PIPES 2 the Company will identify relatively higher-risk natural gas distribution pipe based on various factors, including assessed risk, as identified through the Company's DIMP Plan. The Company seeks to continue replacing relatively higher risk pipe on an accelerated basis and recover the associated costs through a surcharge mechanism as previously approved by the Commission.

The proposed PIPES 2 Plan for the next five years totals $305.3 million, which includes $277.1 million for distribution plant replacement and $28.2 million for transmission plant projects. Washington Gas's PIPES 2 Plan, which is attached to my testimony as Exhibit WG (A)-2, involves the replacement of targeted infrastructure on the Company's natural gas distribution system. Company Witness Stuber describes proposed transmission improvements under PIPES 2. Based on current risk assessment, the distribution and transmission budget will be invested across the District system programs as detailed in Table 3 and Table 4 below.

The Company anticipates that the annual investment for each of the programs indicated may vary based upon changes in schedules and priorities due to risk profiles, operational conditions and/or opportunities for construction efficiency. However, the current budget for each program provides strategic direction for allocating PIPES 2 resources on a long-term basis. Year-to-year project selections will be developed based on both short and long-term considerations and will be presented to the Commission annually for review and approval following the existing process already approved by the Commission.

The Company's PIPES 2 Plan consists of eight (8) distribution programs and five (5) transmission programs designed to enhance the safety and reliability of Washington Gas's distribution and transmission systems serving its District of Columbia customers, while also reducing GHG emissions related to aging infrastructure. Specifically, for the distribution system, the Company proposes to replace approximately 22 miles of main and replace/changeover 8,274 services over a five-year plan period (October 1, 2019 through December 31, 2024).[7] The Company's PIPES 2 distribution and transmission programs are listed in Table 3 and Table 4 below. Washington Gas will prioritize the selection and timing of replacing specific types of facilities within these categories, based on their relative risk, direct field observations, work by others, and the Company's ability to gain construction efficiencies.

Table 3: Washington Gas's PIPES 2 Distribution Programs

Program Number	Program Description	Program Budget ($M)
1	Bare Steel Main and Services (including Contingent Main[8] and Affected Services[9])	$ 162.9
2	Unprotected Wrapped Steel Main and Services (including Contingent Main and Affected Services)	$ 17.6
3	Vintage Mechanically Coupled Main and Services (including Contingent Main and Affected Services)	$ 38.6

[7] The first year of PIPES 2 will be 15 months (October 1, 2019 to December 31, 2020).
[8] As described in Exhibit WG (A)-2, Contingent Main reflects instances where non-program specific main (i.e., Black Plastic, Protected Wrapped Steel, etc.) materials are encompassed within the bounds of program eligible materials and logically group with program eligible main for replacement.
[9] As described in WG (A)-2, Affected services (i.e., Black Plastic, Vintage Mechanically Coupled Pipe, Protected Wrapped Steel, Copper, etc.) will be replaced when exposed and connected to a portion of main in a program.

4	Cast Iron Main (including Contingent Main and Affected Services)	$ 29.5
5	Copper Services	$ 10.2
6	Distribution Gauge Lines	$ 2.3
7	Regulator Station Enhancements	$ 6.3
8	Low-Pressure Service Replacements/ Transfers	$ 9.7

Table 4: Washington Gas's PIPES 2 Transmission Programs

Program Number	Program Description	Program Budget ($M)
1	Transmission and High-Pressure Pipe Replacement	$ 18.4
2	Remote Control Valves	$ 2.8
3	Transmission and High-Pressure Block Valve Replacement	$ 1.1
4	Transmission and High-Pressure Valve Riser Replacement	$ 0.1
5	Replacement of Components of DOT Transmission and High-Pressure Pipes to Enable the Use of In-line Inspection Tools	$ 5.8

Q. WHY IS WASHINGTON GAS SEEKING APPROVAL OF THE NEXT PHASE OF ITS PROJECTPIPES PLAN AND AN ACCOMPANYING COST RECOVERY MECHANISM?

A. In the Company's Revised Plan, it sought Commission approval of the first five years of a 40-year accelerated pipe replacement program. Washington Gas's current PIPES 1 Plan has allowed the Company to accelerate the pace of eligible infrastructure replacement, resulting in the replacement of more natural gas system facilities in a shorter period than would have otherwise occurred under normal replacement. The Company proposes the next phase of its PROJECT*pipes* plan, which I will describe in further detail below, to continue its efforts to enhance safety and improve reliability of the Company's distribution and transmission systems. The proposed scope and investment of the

Company's transmission system program is described separately by Company Witness Stuber.

PIPES 1 will conclude on September 30, 2019, though Commission-approved work from PIPES 1 remains. In order to maintain the critically important continuity of work and contractor availability, the Company is submitting its PIPE 2 application at the beginning of the fifth year of its PIPES 1 Plan to allow sufficient time for an Order to be issued in 2019 prior to the conclusion of PIPES 1. As noted, the timely approval of PIPES 2 will ensure the continuity between both plans and assist the Company in retaining and securing additional contractor resources to continue PROJECT*pipes* work.

Q. WHY IS WASHINGTON GAS TARGETING THE DISTRIBUTION SYSTEM FACILITIES LISTED ABOVE FOR REPLACEMENT IN THE PIPES 2 PLAN?

A. As mentioned above, relatively higher risk pipe will be identified through the Company's DIMP Plan, which is a required plan under federal law.[10] PIPES 2 will allow the Company to continue its accelerated replacement activities consistent with federal law and the Company's DIMP Plan.

Consistent with the approach in our prior filings in Formal Case No. 1115, and as explained in Exhibit WG (A)-2, the Company analyzed the updated leak and maintenance history of its main and service pipes by material type for the period of January 2013 to February 2018. The Company's analysis of this data was used to determine the population of main and service pipes to be replaced in PIPES 2. Additionally, the separation of the original Program 1 (Bare and/or Unprotected Steel Services) and Program 2 (Bare and/or Targeted Unprotected

[10] *See* Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 § 9, 49 U.S.C. § 60109 (2006); 49 CFR Part 192 Subpart P.

Steel Main with Affected Services) into two (2) unique programs will allow the Company to maintain the accelerated pace of replacement of its Bare Steel Main and Services which has the higher leak rates among the programs. The analysis and additional considerations for safety enhancements have also led Washington Gas to develop five new distinct programs to proactively enhance safety and improve the reliability of its distribution system in the District.

Q. YOU INDICATED THE RELATIVELY HIGHER RISK PIPE WOULD BE SELECTED BASED ON LEAK RATES AS IDENTIFIED THROUGH THE DIMP. CAN YOU PLEASE PROVIDE DATA TO SUPPORT THESE SELECTIONS?

A. Yes. The information provided in this testimony and more specifically in Exhibit WG (A)-2 details the rationale behind the Company's determination to establish the PIPES 2 distribution programs as listed in Table 3.

The Bare Steel Main and Services replacement program (Program 1, includes Affected Services and Contingent Main) leak analysis shows a leak rate of 9.9 leaks per mile for main and a leak rate of 6.3 leaks per 100 service segments, and this population is risk-ranked as highest among all the Company's main and service programs. The current leak rate represents a marked increase over the 1.97 leaks per mile of main and 2.67 leaks per 100 service segments (Combined Bare and/or Unprotected Steel Service Replacement Leak Rate) reported in Company Witness Townsend's testimony in the Company's initial application filed in Formal Case No. 1093, due to aging infrastructure that has yet to be replaced. It is not practical to protect bare steel main and services from corrosion, as this bare steel piping will continue to deteriorate over time, likely leading to higher leak rates in the future.

Replacements will be made using modern polyethylene (PE) pipe which has a historical leak rate of almost zero, excluding leaks related to excavation damages which are addressed in the Company's robust damage prevention program outside of PROJECT*pipes*.

Based on the current leak rates, Washington Gas has included all Unprotected Steel Main and Services replacements (Program 2). Program 2 will include Affected Services and Contingent Main. The leak analysis shows a leak rate of 2.8 leaks per mile of main and 2.9 leaks per 100 service segments, and this population is risk-ranked fourth (4th) among the main programs and third (3rd) among the services programs. The current leak rate represents a marked increase over the 0.49 leaks per mile of main and 2.67 leaks per 100 service segments (Combined Bare and/or Unprotected Steel Service Replacement Leak Rate) reported in Witness Townsend's testimony in Formal Case No. 1093, due to aging infrastructure that has yet to be replaced.

The Company has added a Vintage Mechanically Coupled ("VMC") Main and Services replacement program (Program 3), which includes Affected Services and Contingent Main, to cover the remaining pipe after the Company's completion of targeted pipe in Formal Case No. 1027. VMC is considered steel main or services two-inches or smaller installed between 1952-1956 and 1962-1965. The leak analysis shows a leak rate of 5.2 leaks per mile of main and 5 leaks per 100 service segments. This population is risk-ranked second (2nd) among the main and service programs. Under the settlement agreement approved in Formal Case No. 1027,[11] the Company agreed to replace or

[11] GT97-3, GT06-1 and Formal Case No. 1027 – Joint Motion for Approval of Unanimous Agreement of Stipulation and Full Settlement and Waiver of Commission Rule 130.12 (October 2, 2009).

encapsulate approximately 3.7 miles of main and 495 services on an annual basis over the seven years of the program. This equates to approximately 26 miles of main and 3,465 services replaced or remediated. The proposed Program 3 under PIPES 2 would replace the remaining units that were not a part of the Formal Case No. 1027 settlement agreement.

The Cast Iron Main and Affected Service replacement program (Program 4), now includes Contingent Main in PIPES 2. The leak analysis shows a leak rate of 4 leaks per mile of main, and this population is risk-ranked third (3rd) among the main programs. The current leak rate represents a marked increase over the 1.37 leaks per mile of main reported in Witness Townsend's testimony in Formal Case No. 1093, due to aging infrastructure that has yet to be replaced. This is consistent with the PHMSA White Paper findings that high-risk cast iron mains "can be prone to failure as a result of graphitization or brittleness" and that the District is an urban area which still has cast iron piping.[12]

All copper services (Program 5) will be targeted in PIPES 2, which have a current leak rate of 2.0 leaks per 100 service segments. Program 5 is risk-ranked 4th among the Company's service programs. Program 5 will not include services replaced as part of main replacements in other programs. Under PIPES 1, the Commission included copper services as a material type eligible for recovery under the program.[13]

Washington Gas is proposing a Distribution Gauge Lines replacement program (Program 6). This program is focusing on Pre-1972 steel critical

[12] *See* attached Exhibit WG (A)-6.
[13] Formal Case No. 1115, Order No. 17500 at 12 (May 30, 2014).

valves.[14] Currently, approximately 80% of gauge line leaks on gauge lines occur on pre-1972 facilities. The Company has identified 107 corrosion leaks out of 150 total leaks on valves from years 2013 thru 2018. The replacement of gauge lines will enhance safety to the Company's distribution system and improve reliability to pressure-monitoring facilities.

The Company is proposing a Regulator Station Enhancement program (Program 7) to further reduce the risks of over pressurization of the low-pressure ("LP") distribution system in the District. Program 7 will capitalize on lessons learned from our review of a recent over-pressurization incident in Massachusetts and consist of the replacement of bypass valves at regulator stations that divide differing Maximum Allowable Operating Pressure ("MAOP") systems (or, in some cases add an additional valve) and relocating LP regulator station control lines into existing vaults where most of these regulators are located. The replacement or addition of bypass valves and the relocation of control lines into vaults will further enhance the safety, reduce the risks of over-pressurization, and improve the reliability of the LP system in the District.

Finally, Washington Gas is proposing a Low-Pressure Service Replacement program (Program 8) to enhance the safety and improve reliability of its distribution system in the District. Program 8 is focused on transferring and upgrading existing LP service lines from the LP system to the Medium Pressure ("MP") system where these services are near MP mains. Program 8 will reduce the risk of LP customers' exposure to over-pressurization incidents and provide the added benefits of enhanced safety features that come with

[14] Critical valves are used to control or shut off the flow of gas to an area during an emergency. The area controlled by critical valves is designated as a safety sector.

having MP facilities (*i.e.*, house regulator with an internal pressure relief, improving service lines from the LP main to MP main, EFV, improved locatability, improved reliability from water outages, reducing the consequences if over-pressurization were to occur).

Q. DOES THE COMPANY PROPOSE TO REPLACE THE TOP 3 OPTIMAIN PROJECTS UNDER THE PIPES 2 PLAN?

A. Washington Gas believes that working through projects initiated as the result of risk analysis, based on the risk reduced per dollar spend metric, is the most effective method for prioritizing projects and maximizes the amount of risk removed in the District for a given funding level. Such a metric would consider all Optimain projects, including the Top 3, but would not dictate that the Top 3 Optimain projects be undertaken unless their risk reduced per dollar spent supports undertaking the project at that time.

Q. WHAT IMPACT WILL THE PIPES 2 PLAN REPLACEMENTS HAVE ON LEAK RATES?

A. The Company will continue to track the number of gas leaks on its piping system. Although year-to-year variations may arise due to continued aging infrastructure, the leak rate (excluding leaks from third-party excavation damages) for pipe replaced will begin to approach zero, as previously mentioned. However, it is critical to note that the remaining pipe will continue to age and the leak rate on the remaining targeted pipe can be expected to increase until replaced. Put simply, the Company's distribution system continues to age, and the Company expects the leak rate for both targeted and non-targeted pipe to increase as a result. Thus, the overall leak rate may continue to increase until the cumulative amount of pipe replaced via PROJECTpipes offsets the impact of the remaining pipe on the leak rate level.

Q. WILL THE COMPANY CONTINUE TO REPLACE PIPING THROUGH NORMAL REPLACEMENTS?

A. Yes. The Company will continue to replace piping through normal replacements for emergency or expedited field operations originated work, Advance of Pavement and District Department of Transportation ("DDOT") required replacements, as well as non-recoverable facilities determined by annual Optimain rankings. PIPES 2 accelerates the replacement of relatively higher risk pipe as identified annually by Optimain and is therefore incremental to normal replacements. The overall goal of PIPES 2 is to proactively replace relatively higher risk pipe on an expedited basis.

Q. DO THE DISTRIBUTION INFRASTRUCTURE REPLACEMENTS INCLUDED IN THE COMPANY'S PIPES 2 PLAN IMPROVE PUBLIC SAFETY OR INFRASTRUCTURE RELIABILITY?

A. Yes. All of the Company's proposed replacements for PIPES 2 reduce potential leaks, enhance safety (*e.g.*, EFVs, new marking technology, updated as-builting, moving inside meters outside, *etc.*), improve reliability (*e.g.*, uprating low-pressure systems which can reduce water infiltration into pipelines causing outages, *etc.*), and reduce the relative risk of over-pressurization of the Company's distribution system.

Q. IN ADDITION TO SAFETY AND RELIABILITY, WHAT OTHER BENEFITS WILL BE ACHIEVED AS A RESULT OF THE PIPES 2 PLAN?

A. There are several benefits that will be achieved. First, as part of service replacements, inside meters will be moved outside where feasible, thereby providing the Company with direct access to the meter without the need for the customer to be present and eliminating the inconvenience of providing access for routine maintenance. Relocating meters also allows fire departments and Company personnel to shut off gas to the property from the outside quickly in the case of an emergency. Costs associated with meter moves are not recovered through PROJECTpipes, but through the normal ratemaking process.

Second, when a direct replacement of main is performed, where feasible, the new main will be installed inside of the roadway curb instead of in the street. This allows the gas pipeline to be moved away from other utility infrastructure in the street, such as water and sewer lines, reducing the possibility of future excavation damage. Traffic inconvenience will also be minimized for any future maintenance requirements.

Third, where feasible, the Company will be upgrading low-pressure systems to medium-pressure. In this process of upgrading low-pressure systems to medium-pressure, the Company will not increase revenues by directly connecting the infrastructure replacement to new customers.[15]

The upgrading of low-pressure systems will also eliminate the required maintenance to pump out and properly dispose of water and other liquids collected in the piping system drips, as well as eliminate the quarterly lab testing of liquids collected, providing both cost savings and environmental benefits. In addition, upgrading low-pressure systems to medium-pressure will provide customers the opportunity to install high-efficiency appliances, such as tankless water heaters, that cannot operate with low-pressure deliveries. Besides the

[15] Order No. 17431 at 33.

environmental benefits from the improved efficiencies, customers will realize a cost savings due to the reduced gas consumption. Another advantage of medium-pressure deliveries is the opportunity to install gas-fired backup generators that may require the higher delivery pressure. Customers will thus be able to enhance the reliability of electric use by having greater access to gas fired backup generators. Again, as noted above, this activity is not intended to increase revenues by directly connecting the infrastructure replacement to new customers.[16]

Q. DO THE PROPOSED REPLACEMENTS IN THE COMPANY'S PIPES 2 PLAN PROVIDE ADDITIONAL CUSTOMER BENEFITS?

A. Yes. The Company projects that PIPES 2 will reduce GHGs released from its distribution system by an estimated cumulative reduction total of 1,134,197 metric tons of carbon dioxide (or CO2 equivalent) and estimated total equivalents cars removed from the road over the program duration of 242,869.

In addition, the Company anticipates that PIPES 2 will continue to provide significant economic benefits to the District of Columbia economy. Specifically, according to the Analysis of Economic Benefits attached as Exhibit WG (A)-4, for the PIPES 2 planned spending period (2020-2024) an estimated 1,708 full-time jobs will be created, the total value of the industry output will be $263,643,497, employee compensation is estimated at $107,680,535, and GDP in the District of Columbia is estimated at $159,483,161.

Q. PLEASE DISCUSS THE PLANNED REPLACEMENT PROJECTS INCLUDED IN WASHINGTON GAS'S PIPES 2 PLAN.

[16] Order No. 17431 at 33.

A. The Company evaluates its distribution system risk annually utilizing the most current information. Therefore, it is difficult to estimate in detail an annual list of projects more than a year in advance. The Company will develop and file annual project lists with the Commission as agreed upon in PIPES 1.

Q. HOW DOES THE PIPES 2 PLAN SUPPLEMENT THE COMPANY'S OBLIGATIONS UNDER DOT 49 CFR PART 192?

A. The Company operates and maintains its gas distribution piping system in accordance with DOT 192 regulations. DOT 192 includes rules relating to materials standards, engineering and design, construction, operations and maintenance activities, as well as newer pipeline integrity rules such as DIMP. In addition to complying with the applicable standards, PIPES 2 addresses many of the risks associated with operating an aging infrastructure by installing modern pipe materials and components, as well as adding safety features not previously required or available when the distribution system was originally constructed.

By replacing infrastructure having the highest relative leak rates, PIPES 2 is a proactive approach designed to enhance pipeline, customer and public safety, which aligns with DOT regulations. By eliminating this pipe and reducing the related leak risk, the Company's risk management will be narrowed primarily to preventing third-party excavation damages. The Company currently addresses third-party excavation damage risk through a robust Damage Prevention Program that includes damage prevention education, training and outreach programs. Moreover, as the Commission recently approved in Formal Case No. 1142, Washington Gas has committed to a new public safety program focused on preventing third-party excavation damages.[17] This will be accomplished by increasing staffing and resources in two primary areas: a) Excavator Engagement and Training; and b) Customer and Community Engagement, Education and Outreach. Thus, the PIPES 2 focus on replacing relatively higher-risk pipe complements the Company's commitment to reducing third-party excavation damages.

Q. HOW WILL MAIN PROJECTS BE SELECTED FOR REPLACEMENT UNDER THE PIPES 2 PLAN?

A. Main projects will be initially identified by the Optimain risk assessment tool. Washington Gas will review the risk profile of all main projects within PIPES 2. The Company will identify and prioritize those projects with higher relative risk scores. However, because the risk scores are calculated without considering relative economics and operational considerations, the Company will also target those projects that optimize reductions in risk on a risk reduced per dollar basis. The result will be to address risk through a combined approach to enhance safety and improve reliability.

The Optimain calculation of the risk priority score is based on the probability of a leak occurring (*i.e.*, the historic leak rate by material type, vintage, and pressure) multiplied by the consequence of a leak. This "consequence" factor includes, but is not limited to, pipe-related factors such as pipe size, material, pressure, vintage, proximity of the pipe from buildings, and building classification/Places of Public Assembly, as well as specifics concerning individual leaks such as location and type, pipe material where the

[17] Formal Case No. 1142, Order No. 19396, Appendix A at 4 (June 29, 2018).

leak occurred, soil type and cover information. In fact, as many as 82 factors can be utilized in the Optimain calculation. The calculation also includes subject matter expert inputs, further demonstrating the level of complexity that underlies the plan's prioritization determination.

Finally, to take advantage of construction and operational efficiencies and related cost savings, the Company anticipates that PIPES 2 expenditures will be directed to replace certain main and service piping across programs, notwithstanding their relative risk profiles. These selected pipes may be replaced earlier than otherwise anticipated, to realize these efficiencies and cost savings, in conjunction with other PIPES 2 Plan replacement activities, DDOT or roadway improvement projects and other utilities' projects. As a result, the Company will limit traffic disruptions, reduce public parking inconveniences, and lower paving restoration costs. In addition, projects will be selected due to other operational considerations and field assessments.

Q. HOW WILL SERVICE-ONLY PROJECTS BE SELECTED FOR REPLACEMENT UNDER THE PIPES 2 PLAN?

A. To maximize the construction efficiency of replacing bare steel, VMC, unprotected wrapped steel, and copper services within the District of Columbia's distribution system, the Company will use a few key factors in prioritizing the replacement of such services. The majority of the services will be replaced in conjunction with main replacement projects or DDOT roadway improvement projects and other utilities' projects. Services not being replaced in conjunction with these types of projects will be grouped geographically by the Company's quad map area. The historical leak rates will be determined for each quad map area, and the quads will be ranked from highest leak rates to lowest with leaks by 100 service segments for each material type. Additionally, with a reduction to the risks associated with over-pressurization of the Company's distribution system, a low-pressure service replacement program (Program 8) is proposed. Services within this program will be ranked based on consequences of failure considerations. Low-pressure services within 40 feet of an existing non-eligible medium-pressure main will be targeted and converted to medium-pressure. Facility type along with estimates of the maximum occupancy totals, based on the structure use, for each low-pressure service will be used for prioritization. Additionally, to minimize customer inconvenience and to ultimately retire sections of low-pressure main, the Company will convert multiple low-pressure services in a block into a single project where possible for efficiency. The intent is to remediate the targeted low-pressure services concurrently while reducing exposure to the greatest number of building occupants.

VII. PIPES 2 COST ESTIMATION AND MANAGEMENT

Q. PLEASE EXPLAIN HOW THE COMPANY ESTIMATED PROJECT COSTS UNDER ITS CURRENT PLAN.

A. Under its current PIPES 1 Plan, the Company generated and presented three unique estimates. First, the Company estimated the total costs and total duration of each individual program. Second, the Company estimated the costs for the first five years of the program, $110 million. Third, the Company created an annual project list with specific project estimates. These estimates were derived using historic average costs from all similar past construction work (normal and accelerated replacement). The Company chose this approach because it is consistent with the budget cost methodology Washington Gas has historically used with respect to regular infrastructure replacements.

In the development of its cost estimates, the Company utilized different internal data sources to construct cost estimates, including its Work Management Information System ("WMIS") and Powerplant[18] system. Washington Gas extracted direct contractor charges from WMIS. Paving, Other Direct Costs, and Allocations are extracted from Powerplant. The Paving and Other Direct Costs were calculated as percentages of the contractor charges. Applying the percentages to the WMIS average costs resulted in fully loaded unit costs for main and services. Main costs were expressed as cost per foot of main. Service Costs were expressed as cost per service. All Unit costs were expressed on an individual program basis. This average costing methodology provided a one size fits all approach to estimating of main and services in the PIPES 1 Plan that resulted in variances, which are expected using this methodology, against individual project actual costs.

Q. HOW HAS THE COMPANY CHANGED ITS COST ESTIMATION TECHNIQUE SINCE ITS INITIAL PIPES 1 PLAN BEGAN?

A. Currently, the Commission requires Washington Gas to perform project specific AACE Class 3 estimates for all projects included on each PIPES 1 annual project list. The Company submitted Class 3 estimates for its Year 4 and Year 5 Project Lists. The Company is tracking and assessing its cost performance against the Class 3 estimates as projects close. The Company will evaluate this data to determine whether Class 3 estimates are the most

[18] PowerPlant serves as the Company's facility tracking system and functions as the property accounting sub-ledger. It is also the principal source of financial information regarding the Washington Gas facility base.

appropriate basis for forming initial control estimates against which all actual costs and resources will be monitored.

Washington Gas acknowledges that per Merger Commitment 72 in Formal Case 1142, the Company will not be allowed to recover any replacement/remediation expenditures for completed program work incurred post-Merger Close (Fiscal Year 2019 and beyond) in the surcharge tracker mechanism that exceed 120 percent of the rolling two-year annual average program cost (calculated from program years 2017 and 2018) of the per unit and per program material replacement/remediation cost, referred to as "excess costs;" provided, for cast iron replacement/remediation costs, "excess costs" shall be defined as costs above 120% of the Class 3 estimates for such projects until Washington Gas has sufficient data to establish average costs of cast iron replacements/remediation by pipe diameter.[19]

Q. HAS THE COMPANY IDENTIFIED PARTICULAR COST DRIVERS THAT EXPLAIN THE VARIANCES YOU MENTION?

A. Yes. The Company has learned a great deal about external cost drivers through its experience during the first four years of its PIPES 1 Program. For example, in evaluating the original PIPES 1 Plan cost escalations, the Company identified the following cost drivers: 1) increasing paving and restoration requirements; 2) increasing traffic control requirements; 3) increasing resultant spoils, backfill and trucking use; 4) increased requirements for saw cutting and pavement breakage; 5) additional fees for permitting and other activities; 6) increased design drawing requirements; and 7) increased restrictions on work

[19] Order No. 19396, Appendix A at 26 - 27 (Commitment 72).

hours, which has reduced productivity. Additionally, the Company continues to experience cost escalations associated with the growing demand for qualified underground contractor crews to perform work on accelerated infrastructure replacement programs, as well as the overall effort to coordinate projects with external parties.

Q. WHAT PERCENTAGE OF THE VARIANCES DO THESE DRIVERS ACCOUNT FOR?

A. It is difficult to state with certainty what percentage of the variances can be attributed to the cost drivers, due to the evolving jurisdictional requirements. However, the Company believes that the cost drivers identified above, along with general cost inflation, which was not reflected in the original program estimates, have contributed to the variances the Company has experienced in the implementation of its initial PIPES 1 Plan.

Q. WHAT STEPS HAS THE COMPANY TAKEN TO CONTROL COSTS UNDER ITS INITIAL PIPES 1 PLAN?

A. The Company has relied on two key processes to manage construction costs under its initial PIPES 1 Plan. First, Washington Gas has relied on contractors for pipeline construction and replacement services. Washington Gas has, to date, entered into multi-year, alliance-type construction contracts with three diverse pipeline contractors through competitive bidding, and negotiated unit pricing (per foot or a lump sum) to obtain the most competitive unit prices in the market from qualified contractors. Each of the unit-based contracts includes very specific per unit prices for various units of work completed as part of a project.

Second, Company management personnel review and approve all units that are necessary and appropriate for each project prior to payment. Washington Gas's management personnel provide oversight for all work that is performed on the Company's system. This oversight not only promotes safe, quality installations, but also provides thorough oversight of all proposed field design changes and any associated pay items required to complete the work on each project. Company management personnel provide oversight of the pipeline contractors to ensure installation of the facilities per required specifications, including contract pricing schedules and definitions.

These two processes, working together, ensure that expenditures are necessary and prudent and follow contract pricing.

Q. IF THE COMPANY SPENDS BELOW THE ANNUAL PIPES 2 BUDGET FOR A PROJECT YEAR, DOES THE COMPANY INTEND TO DEPLOY THE UNUSED FUNDS IN THE FOLLOWING PROGRAM YEAR?

A. Yes. When the Commission approves an annual project list submitted by the Company, it approves both the proposed work on that list and the associated cost estimates. The Company anticipates that similar to PIPES 1, in PIPES 2 it will encounter instances in which actual costs for units completed may be less than what was estimated, resulting in unused funds. Also, the Company may not be able to complete all projects on a project list in the relevant year due to factors outside of the Company's control, which would also result in unused funds. Both scenarios, which might result in unused funds, may apply to projects that span two (2) years, referred to as "phased projects." Accordingly, the Company plans to carry forward unused dollars to complete work previously approved by the Commission on a project list. Furthermore, if unused dollars continue to remain, the Company will continue to manage PIPES 2 at a program level and consider additional PIPES 2 projects that will enhance the safety and improve reliability of its distribution system in the District. The Company believes this approach is consistent with maximizing the risk reduced per dollar spent.

Q. WHAT HAS THE COMPANY DONE TO ADVANCE THE MANAGEMENT OF ITS PROJECTPIPES PROGRAM?

A. The Company has created a Construction Program Strategy and Management ("CPSM") department that is dedicated to the overall management of its Accelerated Replacement Programs. The CPSM group has the support of the leadership team and has worked diligently to ensure replacement projects get the attention required to eradicate higher-risk pipe.

Q. WHAT ARE THE ROLES AND RESPONSIBILITIES OF CPSM?

A. CPSM is responsible for providing program governance to ensure regulatory compliance and strategic alignment, preparing program performance reporting, managing program audit processes and responses, facilitating the preparation and coordination of testimony reviews, and developing new programs consistent with the Washington Gas DIMP Plan.

Q. HOW DOES CPSM BENEFIT THE PROJECTPIPES PROGRAM?

A. The CPSM team provides a dedicated focus on the PROJECTpipes program management, which includes governance and the tracking and reporting of execution against the plan, program costs, and project closeout.

Q. WHAT TYPE OF IMPROVEMENTS HAS CPSM IMPLEMENTED?

A. In addition to facilitating the Company's enhancement of its cost estimation method, CPSM facilitates a monthly variance meeting to enhance tracking and identification of factors impacting project scope, schedule and cost.

CPSM also develops monthly dashboards and presentations for executive review, reporting on PROJECTpipes progress as expressed in units completed and dollars spent.

Q. HAS THE COMPANY MADE ANY CHANGES TO ENHANCE THE CLOSING OUT OF PROJECTS?

A. In 2017, the Company began generating Business Case Authorization ("BCA")[20] closeout reports, at least monthly, to be reviewed by responsible departments. The purpose of the BCA closeout reports is to identify issues impacting the closure of BCAs and reduce the duration of the BCA closure process for PROJECTpipes BCAs. The Company continues to review and closely monitor the closure process for each PROJECTpipes BCA, thereby continuing to improve its BCA closure process.

VIII. PIPES 2 REPORTING

Q. HOW WILL THE COMMISSION TRACK THE COMPANY'S PROGRESS IN REPLACING PIPE UNDER THE PIPES 2 PLAN?

A. Washington Gas proposes to continue to file all reports consistent with what the Commission has required of the Company with respect to its PIPES 1 Plan, and consistent with Merger Commitments in Formal Case No. 1142.[21] The Company will continue to file annual Financial Reconciliation Reports and Completed Projects Reconciliation Reports, which are subject to review and

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[20] A Business Case Authorization includes the entire scope of a particular project, including all design, construction, restoration and accounting work.

[21] Order No. 19396, Appendix A at 20, 26, and 28 (Commitments 53, 72, and 74).

comments by the parties in this case, and the Quarterly PROJECTpipes Community Liaison Report.

Q. DOES THE COMPANY PROPOSE ANY CHANGES FROM ITS CURRENT PIPES 1 REPORTING REQUIREMENTS TO BE APPLIED TO PIPES 2?

A. Yes. First, the Company proposes that the first year of its PIPES 2 Plan run from October 1, 2019, to December 31, 2020, for purposes of administrative efficiency and ease of reporting as the Company shifts to operating on a calendar versus fiscal year basis. Thereafter, PIPES 2 Plan Years 2-5 will begin January 1, 2021, and end December 31, 2024.

Second, the Company proposes that both the Financial and Completed Projects Reconciliation Reports be due at the end of March in the following project year, instead of the month of December in the project year as currently required. This modification will allow time for more accurate data capture of spend and units completed, which will more appropriately reflect the Company's progress in its prior year of work.

For the Year 6 Annual Project List, the Company will file the initial Annual Project List by June 1, 2019 and the final Annual Project List by July 31, 2019. In consideration of the Company's planned change from fiscal year to a calendar year, Washington Gas is proposing to change the filing dates of the annual project lists. Specifically, beginning with the Year 7 Annual Project List and throughout the PIPES 2 Plan, the Company proposes to file the initial annual project lists by September 1 and the final project lists by November 1 of each year.

Finally, the Company will continue to comply with current requirements pertaining to program audits, the Customer Education Plan, and the filing of construction drawings.

IX. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND PROVIDE YOUR RECOMMENDATION TO THE COMMISSION.

A. Washington Gas is seeking Commission approval of its PIPES 2 Plan. I have noted in my testimony the Company's accomplishments under its current PIPES 1 Plan which are aligned with PHMSA's "Call to Action" and the NARUC Resolution regarding accelerated pipe replacement. Under its PIPES 2 Plan the Company will continue to enhance the safety and improve reliability of its gas system while providing additional benefits to the District's economy and environment. Lastly, during the execution of its PIPES 2 Plan, the Company will continue to inform the Commission of its accelerated replacement efforts by continuing to meet all reporting obligations.

Q. DOES THAT COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

WITNESS JACAS
EXHIBIT WG (A)-1

EXHIBITS

Resolution Encouraging Natural Gas Line Investment and the Expedited Replacement of High-Risk Distribution Mains and Service Lines

WHEREAS, NARUC and its members have long focused on pipeline safety, led by the Committee on Gas, established in 1964, the Staff Subcommittee on Pipeline Safety, the Task Force on Pipeline Safety, and the newly created Subcommittee on Pipeline Safety; *and*

WHEREAS, NARUC enjoys a close working relationship with the National Association of Pipeline Safety Representatives (NAPSR), a national organization representing the State pipeline inspection workforce throughout the country; *and*

WHEREAS, NAPSR in November 2011 released an exhaustive compendium of State pipeline safety programs which exceed the minimum federal standards States must meet in order to receive funding from the U.S. Pipeline and Hazardous Materials Safety Administration (PHMSA); *and*

WHEREAS, NARUC and the Committee on Gas maintain a strong cooperative partnership with PHMSA, which is essential to ensure State and federal safety regulators work closely on pipeline safety; *and*

WHEREAS, More than two million miles of natural gas distribution pipelines crisscross the United States, connecting homes and businesses with one of America's most important energy resources. These pipelines are the safest, most reliable and cost-effective way to transport this essential fuel across the country; *and*

WHEREAS, The safe and reliable delivery of natural gas to homes and businesses and its use in providing new products and services is vital to the U.S. and of paramount importance to members of NARUC; *and*

WHEREAS, By law, the utilities are charged with knowing the location, material, age and condition of their systems. Developing essential data to evaluate the integrity of the systems is the foundation for any determination over what regulators need to fund in rates, as well as what rate recovery methodology best suits a particular case; *and*

WHEREAS, Many States and distribution utilities are undergoing significant pipeline replacement programs to replace aging pipe; *and*

WHEREAS, Many distribution companies are being proactive about replacing their aging pipelines through a risk-based approach focusing on prioritizing safety, asset replacement, and rate impact; *and*

WHEREAS, Alternative rate-recovery mechanisms may help expedite the replacement and expansion of the pipeline systems by promoting more timely rate recovery for investments in infrastructure, safety and reliability; *and*

WHEREAS, Alternative rate recovery mechanisms may help eliminate near-term financial barriers of traditional ratemaking policies such as "regulatory lag" and promote access to lower-cost capital; *and*

WHEREAS, The adoption of alternative rate policies may be very effective for advancing critical safety and reliability infrastructure upgrades, *and*

WHEREAS, Notwithstanding the positive advances in innovative ratemaking and proactive remediation by many distribution companies, utility management bears ultimate responsibility for their respective systems and should seek to work, in ways permissible under their respective State rules and law, collaboratively with Commissioners and/or Commission staff to prioritize asset replacement based upon asset risk, available technology, public safety risk, rate impact, *and*

WHEREAS, Ensuring pipeline safety is about more than just replacement and cost recovery. It is also about effective communication, enforcement, risk sharing, and establishing a long range strategic plan that ensures a safe and reliable gas pipeline system; *and*

WHEREAS, As evidenced in the NAPSR 2011 Compendium, State commissions and inspectors are best suited to determine how best to finance system improvements because each State is different and the needs and financial circumstances of each utility system are unique; *now, therefore be it*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners, convened at the 2013 Summer Committee Meetings, in Denver, Colorado, 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 that reflect the financial realities of the particular utility in question; *and be it further*

RESOLVED, That State commissions should explore, examine, and consider adopting alternative rate recovery mechanisms as necessary to accelerate the modernization, replacement and expansion of the nation's natural gas pipeline systems, *and be it further*

RESOLVED, That NARUC encourages its members to reach out to PHMSA, NAPSR, industry, State and local officials, and the general public about pipeline safety and replacement programs.

Sponsored by the Committee on Gas and the Committee on Critical Infrastructure
Adopted by the NARUC Board of Directors July24, 2013

WITNESS JACAS
EXHIBIT WG (A)-2

Washington Gas's Proposed PROJECTpipes 2 Plan: Distribution Replacements

Introduction

Washington Gas Light Company ("Washington Gas" or "the Company") is proposing the next five-year portion (referred to as "PIPES 2" or the "PIPES 2 Plan") of its originally estimated 40-year PROJECTpipes plan for the Commission's consideration. The purpose of this exhibit is to provide the analysis supporting years six through ten of the distribution system programs proposed in the Company's PIPES 2 Application. The Company's PIPES 2 Plan, including the corresponding investment amounts for each distribution program is described in this document. PIPES 2 will enable the Company to continue and further accelerate the proactive replacement of relatively higher risk piping in its District of Columbia service territory to enhance the safety and improve reliability of its distribution system. The proposed scope and investment of the Company's PIPES 2 transmission system programs are described separately by Company Witness Stuber.

This document includes the source of data, assumptions, and calculations made for the supporting analysis for distribution system PIPES 2 Plan programs. The leak rates for services and main pipe are shown on Tables 1 and 2 and in Figures 1 through 6. The estimated timeline for completion of each of the programs and the projected scope and costs of each program for the next five years are shown in Table 3. The estimated reductions in greenhouse gas emissions are shown on Table 4.

The PIPES 2 Plan

Washington Gas proposes the PIPES 2 Plan for eligible infrastructure replacements consistent with the approach in the prior filings in Formal Case No. 1115. The Company analyzed the updated leak and maintenance history of its main and service pipes by material type for the period of January 2013 to February 2018. The Company's analysis of this data was used to reaffirm or update the population of main and service pipes to be replaced in PIPES 2. Additionally, Washington Gas proposes the separation of the original Program 1 (Bare and/or Unprotected Steel Services) and Program 2 (Bare and/or Targeted Unprotected Steel Main with Affected Services) into two (2) unique programs that will allow the Company to maintain the accelerated pace of replacement of its Bare Steel Main and Services which has the highest leak rates among the programs. The analysis has also led Washington Gas to develop five new distinct programs to proactively enhance safety and improve the reliability of its distribution system in the District.

Each of the program-specific tables shown below present the miles of main, including "contingent main", number of services, planned duration, estimated average unit costs in 2020 dollars, and the anticipated 5-year investment with an average annual inflation rate of 3%.

The Company is seeking approval to continue the next 5 years of the program, the PIPES 2 Plan. The overall remaining duration of the Company's PROJECTpipes plan is 35 years, consistent with the originally estimated 40 years. The table below shows durations by program presented in the original filings as compared to this filing.

Comparison Of Program Durations		
Program	Original Duration (Years)	Proposed Filing Duration (Years)
Program 1: Bare and Unprotected Services	15	
Program 1: Bare Steel Services and Main (including Contingent Main and Affected Services)	Revised	10
Program 2: Bare and Targeted Unprotected Wrapped Steel Main Replacement and Affected Services	15	
Program 2: Unprotected Wrapped Steel Services and Main (including Contingent Main and Affected Services)	Revised	35
Program 3: Vintage Mechanically Coupled Wrapped Steel Services and Main (including Contingent Main and Affected Services)	New	10
Program 4: Cast Iron Main Replacement (including Contingent Main and Affected Services)	40	35
Program 5: Copper Services	New	35
Program 6: Critical Valve Gauge Line Replacement	New	10

Program 7: Regulator Station Enhancement	New	10
Program 8: Low Pressure Service Replacement	New	10

Currently, the overall PROJECTpipes plan is anticipated to be completed by 2054, which is consistent with the Company's original filing. As the table above shows, the duration for Program 1, Bare Steel Services and Main (including Contingent Main and Affected Services) and Program 3, Vintage Mechanically Coupled Wrapped Steel Services and Main (including Contingent Main and Affected Services), are both 10 years in order to support the front-ended replacement of these relatively higher risk segments of pipe from the distribution system. The Company prioritizes these programs of Bare Steel and Mechanically Coupled Steel Pipe by dedicating 73% of the proposed next 5 years of resources focused on programs 1 and 3 as shown in Table 3. The duration of Program 2, Unprotected Wrapped Steel Services and Main (including Contingent Main and Affected Services), is extended to 35 years to reflect both the relatively lower leak rates and the expansion of the program to include all unprotected wrapped steel. The duration of Program 4, Cast Iron Main Replacement (including Contingent Main and Affected Services), is unchanged and reflects the relatively lower leak rates and the overall scope of the population. The duration of program 5 reflects the fact that Copper Services have the 4th highest leak rate of services behind Bare Steel and Vintage Mechanically Coupled Wrapped Steel. The duration of program 6 reflects the individual relative risk not measured in typical leak-based metrics, which is described more fully below. The duration of programs 7 and 8 reflect the relative reduced risk associated with over pressurization of the distribution system not measured in typical leak-based metrics which is described more fully below. The duration of all of the programs, including the new programs, remain within the originally estimated planned total duration of 40 years.

The Company evaluates the risk prioritization of materials to determine its set of targeted materials and then evaluates the targeted materials to determine the duration of each program. The planned duration of each program is presented in Table 3.

The proposed PIPES 2 distribution system programs are described below, including remaining units, projected unit costs, and the total projected 5-year spend for which the Company is seeking approval. All remaining miles of main, service replacements, and service changeovers were extracted from the Company's GE Smallworld system as of July 2018. Miles of main are based on the lengths of main segments recorded. This information may change depending on ongoing data review and Quality Assurance/Quality Control and will be reflected in the Company's filings of annual project lists. The number of service replacements and transfers are based on the number of unique service tees. A single service tee can have multiple service segments. However, it is the Company's policy to replace existing services with a full-length single service segment. Therefore, when estimating the number of services to be replaced it is appropriate to count service tees.

In addition to the targeted relatively higher risk main pipe, the Company has also projected the units for "contingent main." "Contingent main" reflects instances where non-program specific main (*i.e.* Black Plastic, Protected Wrapped Steel, etc.) materials are encompassed within the bounds of program eligible materials and logically group with program eligible main for replacement. Inclusion of the costs associated with replacing these mains with polyethylene is requested because of associated construction efficiencies. Moreover, it will avoid creating separate cathodic protection areas and/or low-pressure regulator stations and legacy low-pressure systems, which could often result if these pipes are not replaced at the same time. Overall, Contingent main is projected to be approximately 4% of the total miles of main to be replaced in PROJECT*pipes*.

Also, to remain in compliance with current Washington Gas policy, affected services (*i.e.* Black Plastic, Vintage Mechanically Coupled, Protected Wrapped Steel, Copper service, etc.) will be replaced when exposed and connected to a portion of main in a program. Costs associated with the replacement of affected services will be included in the respective program costs.

For each of the eight PIPES 2 programs, program-specific tables are shown below which present the miles of main including contingent, number of services, other units, planned duration, estimated average unit costs in 2020 dollars, and the anticipated 5-year investment with an average annual cost escalation rate of 3%.

<u>Program Units and Costs</u>

- Program 1 - Bare Steel Main and Service Replacement (including Contingent Main and Affected Services)
  - Estimated remaining duration: 10 Years.
  - Washington Gas has updated the cost of replacement and program duration based on enhanced cost estimation methods:
    - Average costs for service replacement are a blended rate of projected costs based on historical actuals reflecting based on length and size of service.
    - Main unit costs are a blended rate of projected costs based on historical actuals reflecting based size of main pipe.
    - Unit prices have been escalated by 3% annually to reflect cost escalations.

- Consistent with current leak data as shown in Table 1 and Table 2: Service Leaks by Material (Jan 2013- Feb 2018), this program has one of the shortest remaining durations of all of the programs, as can be seen in Table 3: Cost by Year.
- Leaks on Bare Steel pipe accounted for 27% of the Grade 1 leaks[1].
- This also includes replacement and inclusion for cost recovery under this program any services that are branched from any existing Bare Steel services which are replaced
- The proposed units to be completed are presented below:

Program 1: Bare Steel Main and Service Replacement including Contingent Main and Affected Services (Proposed Filing)	
Remaining Miles of Main as of July 2018	22.1
Contingent Miles of Main as of July 2018	1.9
Remaining Services to be Replaced including Affected Services	9,295
Remaining Services to be changed over	1,113
Remaining Duration (Years)	10
Average Cost per Service without Main Replacement (2020 $s)	$21,172
Average Cost per Service with Main Replacement (2020 $s)	$7,349

[1] Leak history timeframe of January 2013-February 2018.

Average Cost per Change over (2020 $s)	$2,797
Average Cost per foot of Main (2020 $s)	$1,116
5-Year Projected Spend	$162.9 M

- Program 2 - Unprotected Wrapped Steel Main and Service Replacement (including Contingent Main and Affected Services)
  - Estimated remaining duration: 35 years
  - Washington Gas has updated the cost of replacements and program duration based on enhanced cost estimation methods:
    - Average costs for service replacement are a blended rate of projected costs based on historical actuals reflecting based on length and size of service.
    - Main unit costs are a blended rate of projected costs based on historical actuals reflecting based size of main pipe.
    - Unit prices have been escalated by 3% annually to reflect cost escalations.
  - Consistent with current leak data as shown by Table 1 and Table 2, this program is comparatively lower priority as can be seen in Table 3: Cost by Year.
  - Leaks on Unprotected Wrapped Steel pipe accounted for 17% of the Grade 1 leaks.
  - This also includes replacement and inclusion for cost recovery under this program any services that are branched from any existing Unprotected Wrapped Steel services which are replaced
  - The proposed units to be completed are presented below.

Program 2: Unprotected Wrapped Steel Main and Services including Contingent Main and Affected Services (Proposed Filing)	
Remaining Miles of Main as of July 2018	55.3
Contingent Miles of Main as of July 2018	4.4
Remaining Services to be Replaced	4,733

including Affected Services	
Remaining Services to be changed over	1,658
Remaining Duration (Years)	35
Average Cost per Service without Main Replacement (2020 $s)	$21,172
Average Cost per Service with Main Replacement (2020 $s)	$7,349
Average Cost per Change over (2020 $s)	$2,797
Average Cost per foot of Main (2020 $s)	$1,116
5-Year Projected Spend	$17.6 M

- Program 3 – Vintage Mechanically Coupled Pipe Wrapped Steel Main and Service (vintages 1952-1956 and 1962-1965) Replacement (including Contingent Main and Affected Services)
  - Estimated remaining duration: 10 years.
  - Washington Gas has updated the cost of replacements and program duration based on enhanced cost estimation methods:
    - Average costs for service replacement are a blended rate of projected costs based on historical actuals reflecting based on length and size of service.
    - Main unit costs are a blended rate of projected costs based on historical actuals reflecting based size of main pipe.
    - Unit prices have been escalated by 3% annually to reflect cost escalations.
  - Consistent with current leak data as shown by Table 1: Service Leaks by Material (Jan 2013- Feb 2018) and Table 2: Main Leaks by Material, this program is a priority as can be seen in Table 3: Cost by Year.
  - Leaks on Vintage Mechanically Coupled Wrapped Steel Pipe accounted for 6% of the Grade 1 leaks.
  - This also includes replacement and inclusion for cost recovery under this program any services that are branched from any existing Vintage Mechanically Coupled Wrapped Steel services which are replaced
  - The proposed units to be completed are presented below:

Program 3: Vintage Mechanically Coupled Main and Service including Contingent Main and Affected Services (Proposed Filing)	
Remaining Miles of Main as of July 2018	11.0
Contingent Miles of Main as of July 2018	3.2
Remaining Services to be Replaced including Affected Services	1,498
Remaining Services to be changed over	634
Remaining Duration (Years)	10
Average Cost per Service without Main Replacement (2020 $s)	$21,172
Average Cost per Service with Main Replacement (2020 $s)	$7,349
Average Cost per Change over (2020 $s)	$2,797
Average Cost per foot of Main (2020 $s)	$725
5-Year Projected Spend	$38.6 M

- Program 4- Cast Iron Main Replacement and Affected Services (including Contingent Main and Affected Services)
    - Estimated remaining duration: 35 years.
    - Washington Gas has updated the cost of replacement and program duration for all cast iron mains and the associated contingent mains based on enhanced cost estimation methods:
        - Average costs for service replacement are a blended rate of projected costs based on historical actuals reflecting based on length and size of service.
        - Main unit costs are a blended rate of projected costs based on historical actuals reflecting based size of main pipe.
        - Unit prices have been escalated by 3% annually to reflect cost escalations.
    - Consistent with current leak data shown in Table 2: Main Leaks by Material, cast iron main remains a priority but is relatively lower in order as compared to other PIPES 2 Programs.

- This also includes replacement and inclusion for cost recovery under this program any services that are branched from any affected services which are replaced
- Leaks on Cast Iron Main accounted for 22% of the Grade 1 leaks.
- The proposed units to be completed are presented below:

Program 4- Cast Iron Main Replacement including Contingent Main and Affected Services (Proposed Filing)	
Remaining Miles of Main as of July 2018	413.2
Contingent Miles of Main as of July 2018	9.7
Remaining Services to be Replaced including Affected Services	12,234
Remaining Services to be changed over	29,484
Remaining Duration (Years)	35
Average Cost per Service with Main Replacement (2020 $s)	$8,492
Average Cost per Change over (2020 $s)	$4,468
Average Cost per foot of Main (2020 $s)	$1,457
5-Year Projected Spend	$29.5 M

- Program 5- Copper Service Replacement
  - Estimated remaining duration: 35 years.
  - Washington Gas has updated the cost of replacements and program duration based on enhanced cost estimation methods:
    - Average costs for service replacement are a blended rate of projected costs based on historical actuals reflecting based on length and size of service.
    - Main unit costs are a blended rate of projected costs based on historical actuals reflecting based size of main pipe.
    - Unit prices have been escalated by 3% annually to reflect cost escalations.

- This also includes replacement and inclusion for cost recovery under this program any copper services which experience active leaks during the program period, regardless of quad.
- This also includes replacement and inclusion for cost recovery under this program any services that are branched from any existing copper services which are replaced.
- Leaks on Copper Service accounted for 8% of the Grade 1 service leaks.
- The proposed units to be completed are presented below:

Program 5- Copper Services (Proposed Filing)	
Remaining Services to be Replaced as of July 2018	6,072
Remaining Duration (Years)	35
Average Cost per Service (2020 $s)	$21,172
5-Year Projected Spend	$10.2 M

- Program 6- Distribution Gauge Lines
  - Estimated remaining duration: 10 years.
  - Washington Gas is targeting the replacement of 532 steel Gauge Lines on critical valves[2].
  - Approximately 80% of gauge line leaks on gauge lines occur on pre-1972 facilities.
  - The Company has identified 107 corrosion leaks out of 150 total leaks on valves from years 2013 thru 2018.

[2] Critical valves are used to control or shut off the flow of gas to an area during an emergency. The area controlled by critical valves is designated as a safety sector.

  - Annual inspection data will be used to determine the priority of replacement.
  - The proposed units to be completed are presented below:

Program 6- Distribution Gauge Lines (Proposed Filing)	
Critical Valves with Steel Gauge Lines to be replaced	532
Remaining Duration (Years)	10
Average Cost per Valve (2020 $s)	$9,000
5-Year Projected Spend	$2.3 M

- Program 7- Regulator Station Enhancements
  - Estimated remaining duration: 10 years.
  - Washington Gas has projected the cost of replacement and program duration for regulator stations based upon prior similar construction efforts.
  - The Company has a total of 91 low pressure regulator stations in the District of Columbia
  - Replace bypass valves at regulator stations that divide differing Maximum Allowable Operating Pressure (MAOP) systems (or, in some cases add an additional valve) and relocating LP regulator station control lines into existing vaults where most of these regulators are located.
  - The relative reduce risk associated with over pressurization of the distribution system is not measured in typical leak-based metrics.
  - Regulator Stations will be prioritized based on consequences of failure considerations, including but not limited to miles of main and/or the number of services fed by the regulator station, and operational considerations.
  - The proposed units to be completed are presented below:

Program 7- Regulator Station Enhancements (Proposed Filing)

Regulator Stations	91
Remaining Duration (Years)	10
Average Cost per Regulator Station	$250,000
5-Year Projected Spend	$6.3 M

- Program 8 – Low Pressure Service Replacements.
  - Estimated remaining duration: 10 years.
  - Washington Gas has estimated the cost replacement / change over based on the costs used to estimate Program 1.
  - This program will reduce Low Pressure ("LP") customers' to over-pressurization incidents and provide the added benefits of enhanced safety features that come with having Medium Pressure facilities (i.e., house regulator with an internal pressure relief, improving service lines from the LP main to MP main, EFV, improved locatability, improved reliability from water outages, reducing the consequences if over-pressurization were to occur).
  - Services within this program will be prioritized based on consequences of failure considerations. Consequences will be calculated based in part on nearby facility types along with estimates of the maximum occupancy totals, and the structure use.
  - Low pressure services that are near to an existing non-eligible medium pressure main will be targeted and converted to medium pressure.
  - This also includes replacement and inclusion for cost recovery under this program any services that are branched from any affected services which are replaced
- The proposed units to be completed are presented below:

Program 8 - Low Pressure Service Replacements (Proposed Filing)

Remaining Services to be Replaced and connected to Medium Pressure	1,293
Remaining Services to be changed over to Medium Pressure	2,293
Remaining Duration (Years)	10
Average Cost per Service (2020 $s)	$21,172
Average Cost per Change over (2020 $s)	$2,797
5-Year Projected Spend	$9.7 M

In sum, the Company is requesting the approval of PIPES 2 for the next 5 years of the program (2020-2024) in the amount of $305.3 million, which includes $277.1 million for distribution replacements and $28.2 million for transmission replacements (*see* Witness Stuber Testimony and Exhibit WG (B)-1). This amount, which includes an annual inflation over the 5-year period of 3%, is intended to be invested across the distribution system programs as follows given the Company's current risk assessment:

- $162.9 million for Program 1 projects;
- $14.0 million for Program 2 projects;
- $38.6 million for Program 3 projects;
- $29.5 million for Program 4 projects;
- $10.2 million for Program 5 projects;
- $2.3 million for Program 6 projects;
- $6.3 million for Program 7 projects; and
- $9.7 million for Program 8 projects.

The Company anticipates that the annual spend on each of the programs may vary each year based on changes in schedules and priorities due to changing risk profiles, operational conditions and/or opportunities for construction efficiency. The Company will continue to provide annual updates on the PIPES 2 Plan, by program, in its annual reporting. Table 3 shows the expected duration of each program and the projected investment for the next 5 years.

Data Sources and Collection

Washington Gas utilized data obtained from the Company's GE Smallworld system, Asset Manager system, and Work Management Information System ("WMIS"). All three systems were used to gather leak data. Smallworld was also utilized to identify the total known population of main and services. The current population of mains and services was extracted on July 2018. This information may change depending on ongoing data QA/QC and will be reflected in the Company's filings of annual project lists. Washington Gas is committed to improving processes including the review and maintenance of our records. These on-going record research activities could result in the populations presented being updated as needed.

Both WMS and Smallworld were used to collect pipe attributes, such as length, size, material, system pressure, year of installation, as well as the geographical information (quad map, county and state) where the pipe is located. The following information and analysis is developed from and supported by these systems and their associated data.

Service Pipe Information Gathering/Results and Analysis

Consistent with the approach in prior PROJECTpipes filings, Washington Gas obtained the leak and maintenance history of service pipe by material type for the updated period of January 2013 to February 2018 (*see* Table 1). The leaks presented in Table 1 meet the federal Department of Transportation ("DOT") categorization of the targeted threats of Corrosion Failure, Pipe Weld or Joint Failure and Equipment Failure. The DOT categories of Natural Force Damage, Excavation Damage, Other Outside Force Damage, Incorrect Operations, and Other Cause have been excluded in the analysis as these categories do not directly reflect the actual condition or performance of the pipe. WMS and Smallworld were used to develop the following data on service pipes in the District of Columbia distribution system.

The results have been "unitized" on a leaks per 100 service segments basis in order to make a comparison of the service performance by materials. Table 1 shows that the top four materials ranked by leaks per 100 service segments are Bare Steel, Vintage Mechanically Coupled, Unprotected Wrapped Steel, and Copper. In fact, these four material types accounted for approximately 79% of all service leaks and represent 24% of the service segments. These material types are addressed for replacement in Programs 1, 2, 3, 4 and 5 either specifically or as affected services.

TABLE 1 SERVICE LEAKS BY MATERIAL Jan 2013-Feb 2018
(EXCLUDING THIRD PARTY DAMAGE, OPERATIONS AND OTHER)

Service Material	Number of Service Segments	Number of Leaks	Leaks per 100 Service Segments	Rank
Bare Steel	9,198	580	6.3	1
Vintage Mechanically Coupled	1,255	63	5.0	2
Unprotected Wrapped Steel	14,373	413	2.9	3
Copper	13,174	266	2.0	4
Protected Wrapped Steel	3,960	69	1.7	5
Black Plastic	7,832	67	0.9	6
Plastic	110,876	205	0.2	7

Figures 1 and 2 show the number of leaks per 100 service segments that occurred by material type from January 2013 to February 2018. This data shows that for the period between January 2013 and February 2018, the Bare Steel, Unprotected Wrapped Steel services, Vintage Mechanically Coupled Wrapped Steel ("VMC"), and Copper have elevated leak rates as compared to the other materials. These results are consistent with the Company's DIMP Plan. As such, the Company is continuing to focus on the replacement of these materials through its current accelerated replacement program and proposed PIPES 2 Plan.

In summary, based upon the analysis of the leak history of services in the District of Columbia over the period January 2013 to February 2018, the Company's proposed PIPES 2 Plan for distribution system facilities replacements is targeting the appropriate service materials. The planned replacement is consistent with the Company's DIMP Plan. The replacement of these services with polyethylene service pipe also offers a lasting means of reducing greenhouse gas emissions and improving reliability.

Main Pipe Information Gathering/Results and Analysis

Consistent with the approach in prior filings, Washington Gas reviewed the leak and maintenance history of main pipe by material type for the updated period of January 2013 to February 2018 (See Table 2). The leaks presented in Table 2 meet the DOT categorization of the targeted threats of Corrosion Failure, Pipe Weld or Joint Failure and Equipment Failure. The DOT categories of Natural Force Damage, Excavation Damage, Other Outside Force Damage, Incorrect Operations, and

Other Cause have been excluded in the analysis as these categories do not directly reflect the actual condition or performance of the pipe.

TABLE 2 MAIN LEAKS BY MATERIAL Jan 2013-Feb 2018
(EXCLUDING THIRD PARTY DAMAGE, OPERATIONS AND OTHER)

Main Material	Miles of Main	Number of Leaks	Leaks per Miles of Main	Rank
Bare Steel	23	230	9.9	1
Vintage Mech. Coupling	23[3]	119	5.2	2
Cast Iron	413	1,645	4.0	3
Unprotected Wrapped Steel	56	158	2.8	4
Protected Wrapped	296	180	0.6	5
Plastic	405	67	0.2	6

The results shown in Table 2 are "unitized" on leaks per mile of main basis in order to make a comparison of the main pipe performance by materials. Table 2 shows that the top materials ranked by leaks per mile of main are Bare Steel, Vintage Mechanically Coupled Wrapped Steel, Cast Iron, and Unprotected Wrapped Steel. In fact, these material types accounted for approximately 90% of all leaks on main pipe but make up only 42% of the total main pipe. Program 1 addresses all Bare Steel main with affected services and contingent mains. Program 3 addresses all Vintage Mechanically Coupled main with affected services and contingent mains. Program 4 addresses all Cast Iron with affected services and contingent mains. Program 2 addresses all Unprotected Wrapped Steel main with affected services and contingent mains.

Figure 3 emphasizes that replacing Bare Steel, Vintage Mechanically Coupled Steel, Cast Iron main, and Unprotected Wrapped Steel with polyethylene pipe also offers a lasting means of reducing greenhouse gas emissions and improving reliability.

[3] The VMC mileage used to calculate the leak rate includes encapsulated/remediated pipe. The Company is only proposing to replace the miles in Program 3.

In summary, based upon the analysis of the leak history of active mains in the District of Columbia over the period January 2013 to February 2018, the Company's proposed PIPES 2 Plan for distribution main facilities replacements is targeting the appropriate main materials and/or subsets. The planned replacement is consistent with the Company's DIMP plan. The Company proposes to continue these replacement programs accordingly.

Table 3: PIPES COSTS AND UNITS BY YEAR

Program	Total Submission	Remaining Duration	2020	2021	2022	2023	2024	5-Year Total
			$45.4	**$54.1**	**$56.9**	**$55.7**	**$61.4**	**$277.1**
1	Bare Steel Main and Services	10	$26.1	$31.9	$33.5	$35.2	$36.2	**$162.9**
2	Unprotected W/S Main and Services	35	$3.3	$3.4	$3.5	$3.6	$3.7	**$17.6**
3	VMC Mains and Services	10	$6.2	$7.5	$8.0	$8.3	$8.5	**$38.6**
4	Cast Iron Main	35	$4.7	$5.9	$6.1	$6.3	$6.5	**$29.5**
5	Copper Services	35	$1.9	$2.0	$2.0	$2.1	$2.2	**$10.2**
6	Distribution Gauge Lines	10	$0.4	$0.5	$0.5	$0.5	$0.5	**$2.3**
7	Reg Station Enhancements	10	$1.0	$1.0	$1.3	$1.4	$1.5	**$6.3**
8	LP service Replacement	10	$1.8	$1.9	$1.9	$2.0	$2.1	**$9.7**

Total Units replaced / remediated	2020	2021	2022	2023	2024	5-Year Total
Services Replaced	1,137	1,300	1,320	1,339	1,347	**6,443**
Service Transferred	335	370	374	376	376	**1,831**
Miles of Main	3.8	4.4	4.5	4.6	4.6	**21.9**
Gauge Lines	45	50	50	50	50	**245**
Regulator Stations	4	4	5	5	6	**24**

Table 4: GREENHOUSE GAS REDUCTIONS FROM PIPES 2

System Improvement Projects - Replacement			Quantity	Units	Program's Duration	Average GHG Reduction Per Program Year (mT/yr)[1]	Total GHG Reduction (mTons)	Total Cumulative GHG Reductions (mTons)	Total Equivalent Cars removed from the Road Over Program's Duration	Total Equivalent Cars removed from the Road (average per year)[1]
Program 1: Bare Steel Main and Services	**Main Replacements**	**Affected Service Replacements**								
	Bare / Unprotected Steel Main		22	Miles	10	100	997	5481	1,174	117
	Protected Wrapped Steel Main		1	Miles	10	-1	(6)	-32	-7	-1
	Plastic		1	Miles	10	0	-		0	0
		Copper Service	224	# of Services	10	3	26	145	31	3
		Black Plastic Service	1,236	# of Services	10	0	-		0	0
		Protected Wrapped Steel Service	202	# of Services	10	2	16	89	19	2
		Bare and/or Unprotected Steel Service	8,746	# of Services	10	711	7,108	39091	8,371	837
Program 2: Unprotected W/S Main and Services	**Main Replacements**	**Affected Service Replacements**								
	Bare / Unprotected Steel Main		55	Miles	35	71	2,494	44884	9,611	275
	Protected Wrapped Steel Main		2	Miles	35	-0.40	(14)	-253	-54	-2
	Plastic		2	Miles	35	0	-		0	0
		Copper Service	451	# of Services	35	2	53	954	204	6
		Black Plastic Service	1,795	# of Services	35	0	-		0	0
		Protected Wrapped Steel Service	29	# of Services	35	0.07	2	42	9	0
		Bare and/or Unprotected Steel Service	4,115	# of Services	35	96	3,344	60194	12,890	368
Program 3: Mechanically Coupled Pipe Main and Service (vintages 1952-1956 and 1962-1965) Replacement	**Main Replacements**	**Affected Service Replacements**								
	Protected Wrapped Steel Main		14	Miles	10	-9	(88)	-481	-103	-10
	Plastic		1	Miles	10	0	-		0	0
		Copper Service	244	# of Services	10	3	29	158	34	3
		Black Plastic Service	676	# of Services	10	0	-		0	0
		Protected Steel Service	1,188	# of Services	10	10	95	523	112	11
		Bare and/or Unprotected Steel Service	24	# of Services	10	2	20	107	23	2

Table 4: GREENHOUSE GAS REDUCTIONS FROM PIPES 2 (Continued)

	Main Replacements	Affected Service Replacements						
Program 4: Cast Iron Main Replacement	Cast Iron Main		413	Miles	35	857,836	183,691	5,248
	Protected Steel Main		6	Miles	35	(679)	(145)	(4)
	Plastic		4	Miles	35		-	-
		Copper Service	2,822	# of Services	35	5,968	1,278	37
		Black Plastic Service	31,729	# of Services	35		-	-
		Protected Steel Service	93	# of Services	35	134	29	1
		Bare and/or Unprotected Steel Service	7,074	# of Services	35	103,477	22,158	633
Program 5: Copper Service Replacements	Service Replacements							
	Copper Service		6,072	# of Services	35	12,840	2,749	79
Program 9: LP Service Replacements	Service Replacements							
	Bare and/or Unprotected Steel Service		796	# of Services	10	3,558	761	76
	Copper Service		198	# of Services	10	128	27	3
	Protected Steel Service		78		10	34	7	1
	Black Plastic Service		2,514	# of Services	10		-	-
						1,134,197	242,869	7,686

[1] Uniform distribution is assumed throughout the life of the plan.

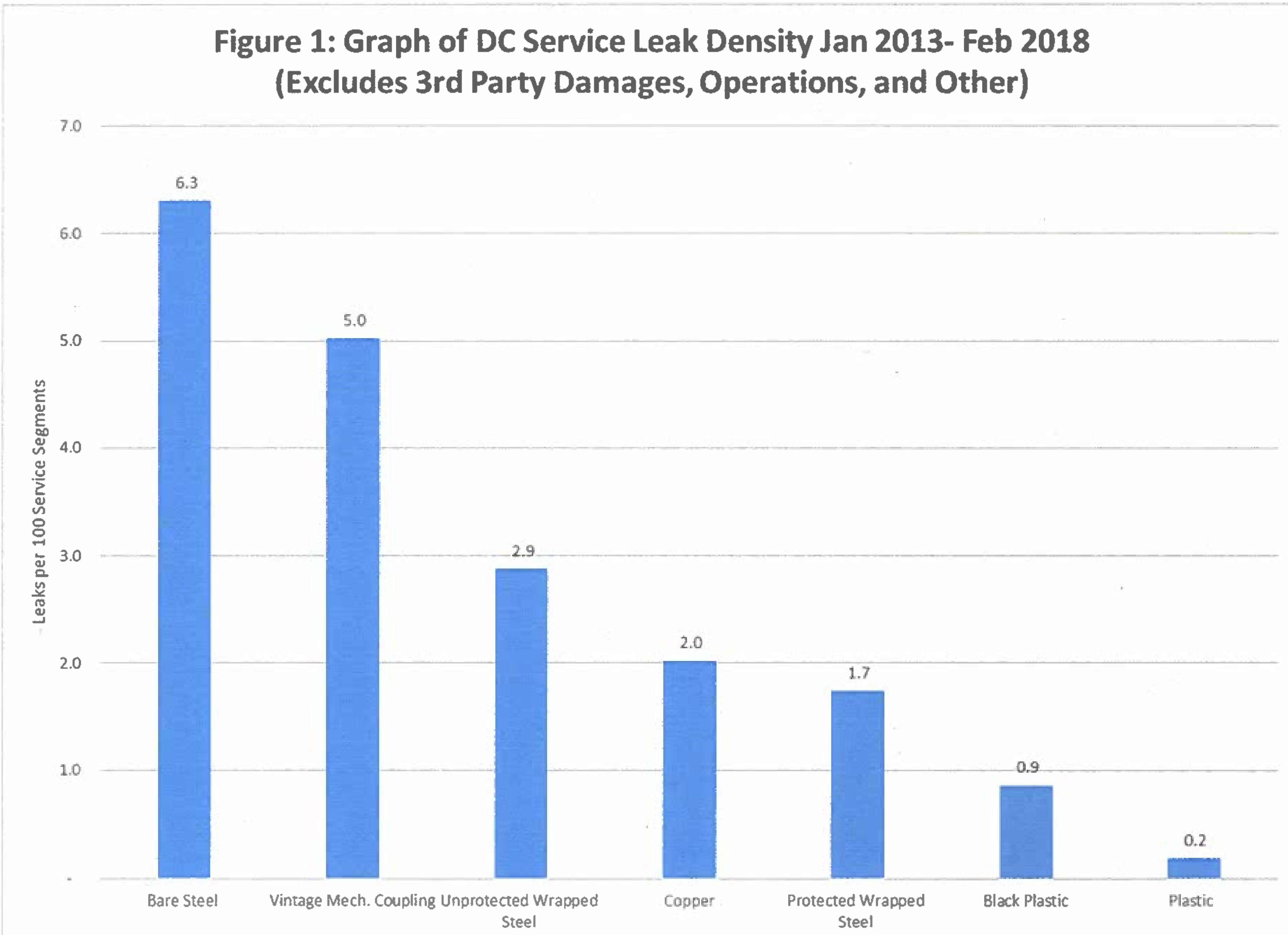


Figure 1: Graph of DC Service Leak Density Jan 2013- Feb 2018
(Excludes 3rd Party Damages, Operations, and Other)
Leaks per 100 Service Segments
7.0
6.0
5.0
4.0
3.0
2.0
1.0
6.3
5.0
2.9
2.0
1.7
0.9
0.2
Bare Steel
Vintage Mech. Coupling Unprotected Wrapped Steel
Copper
Protected Wrapped Steel
Black Plastic
Plastic

Figure 2: DC Service Leak Density and Service Segments Jan 2013-Feb 2018 (Excludes 3rd Party Damages, Operations and Other)

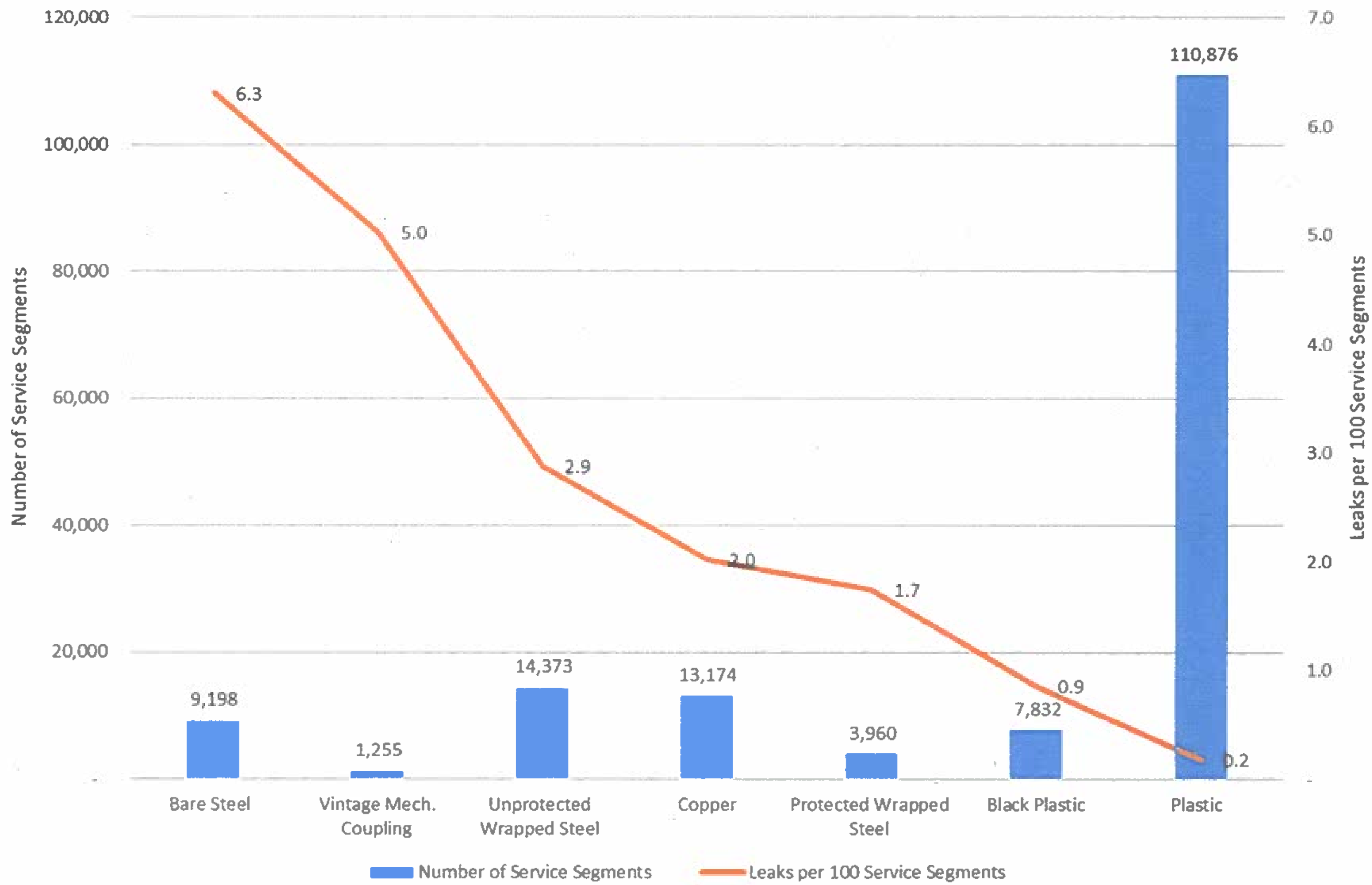


Figure 3: DC Service Leaks per 100 Segments and per Year Jan 2013-Feb 2018 (Excludes 3rd PARTY DAMAGE, OPERATIONS AND OTHER)

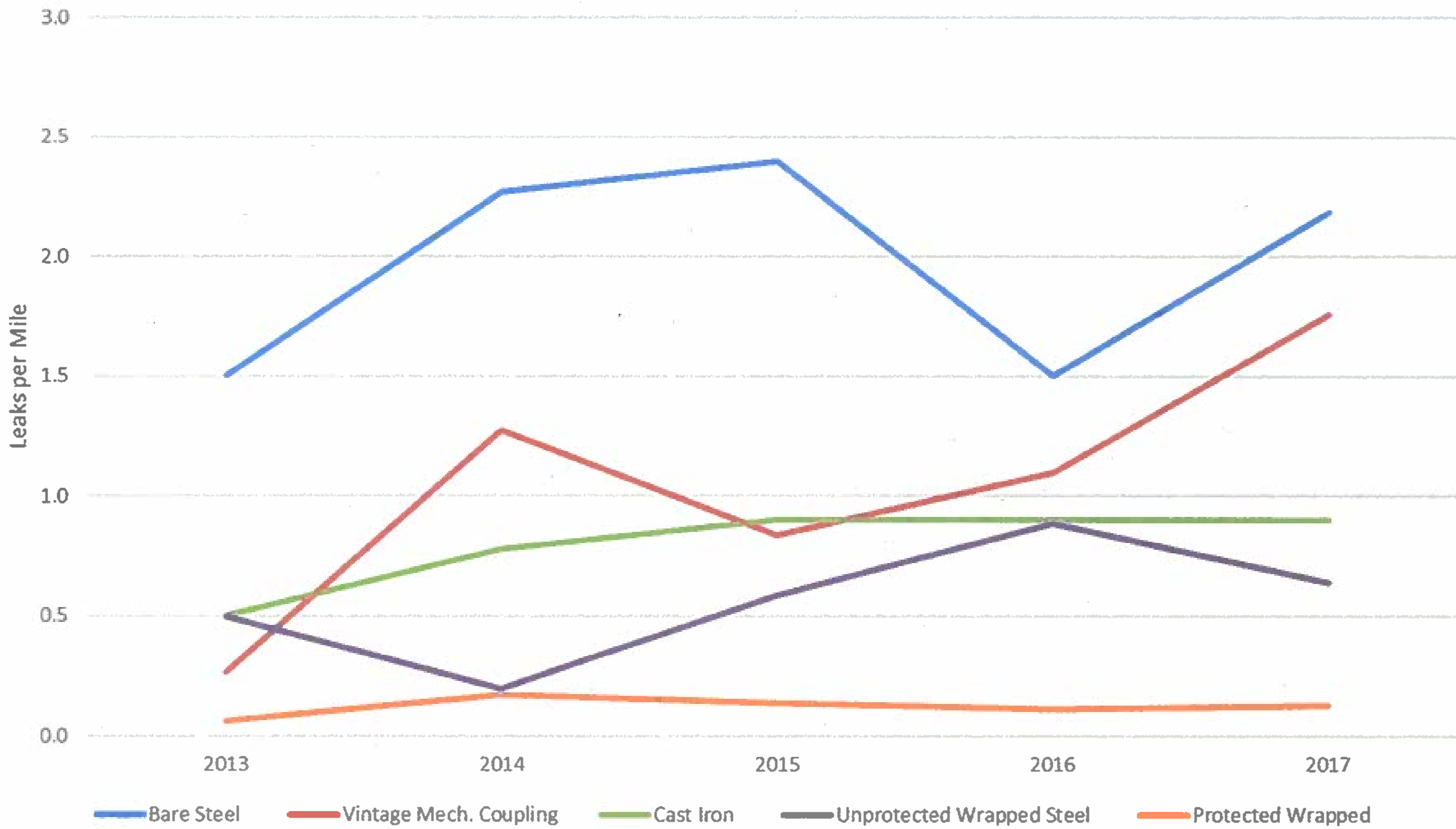


Figure 4: Graph of DC Main Leak Density Jan 2013- Feb 2018 (Excludes 3rd Party Damages, Operations, and Other)

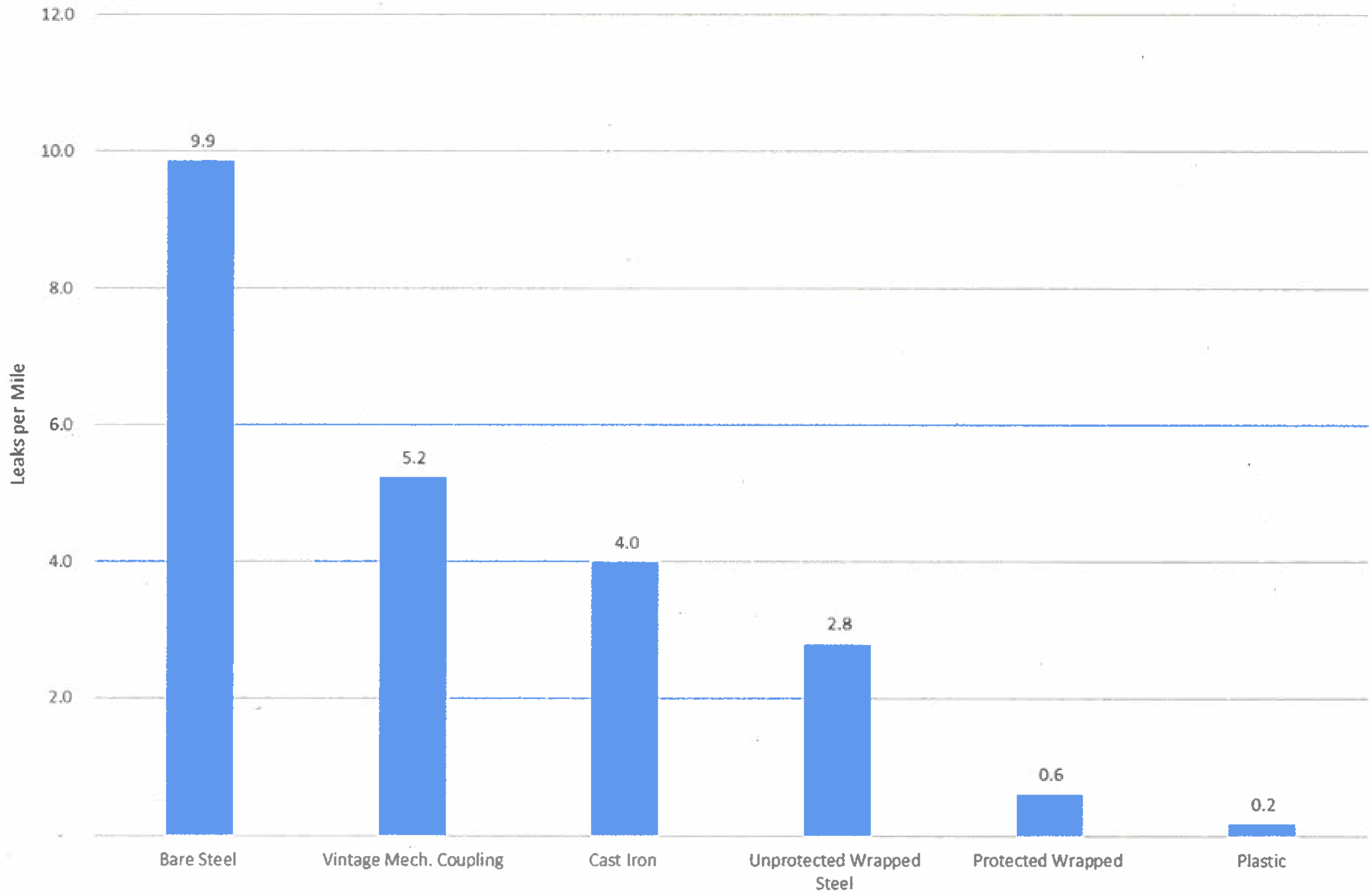


Figure 5: DC Main Leaks per Mile and Miles of Main Jan 2013-Feb 2018 (Excludes 3rd PARTY DAMAGE, OPERATIONS AND OTHER)

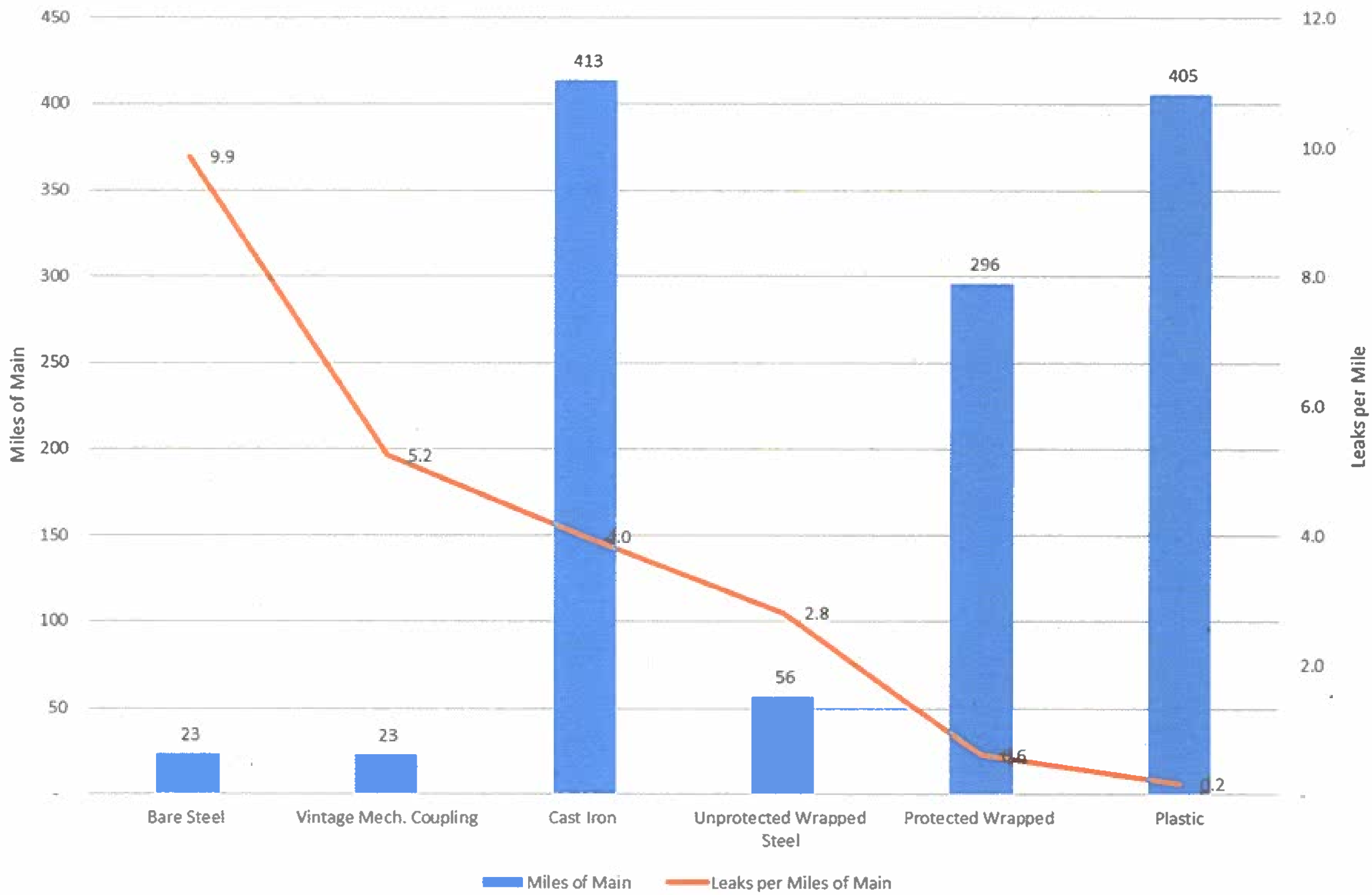
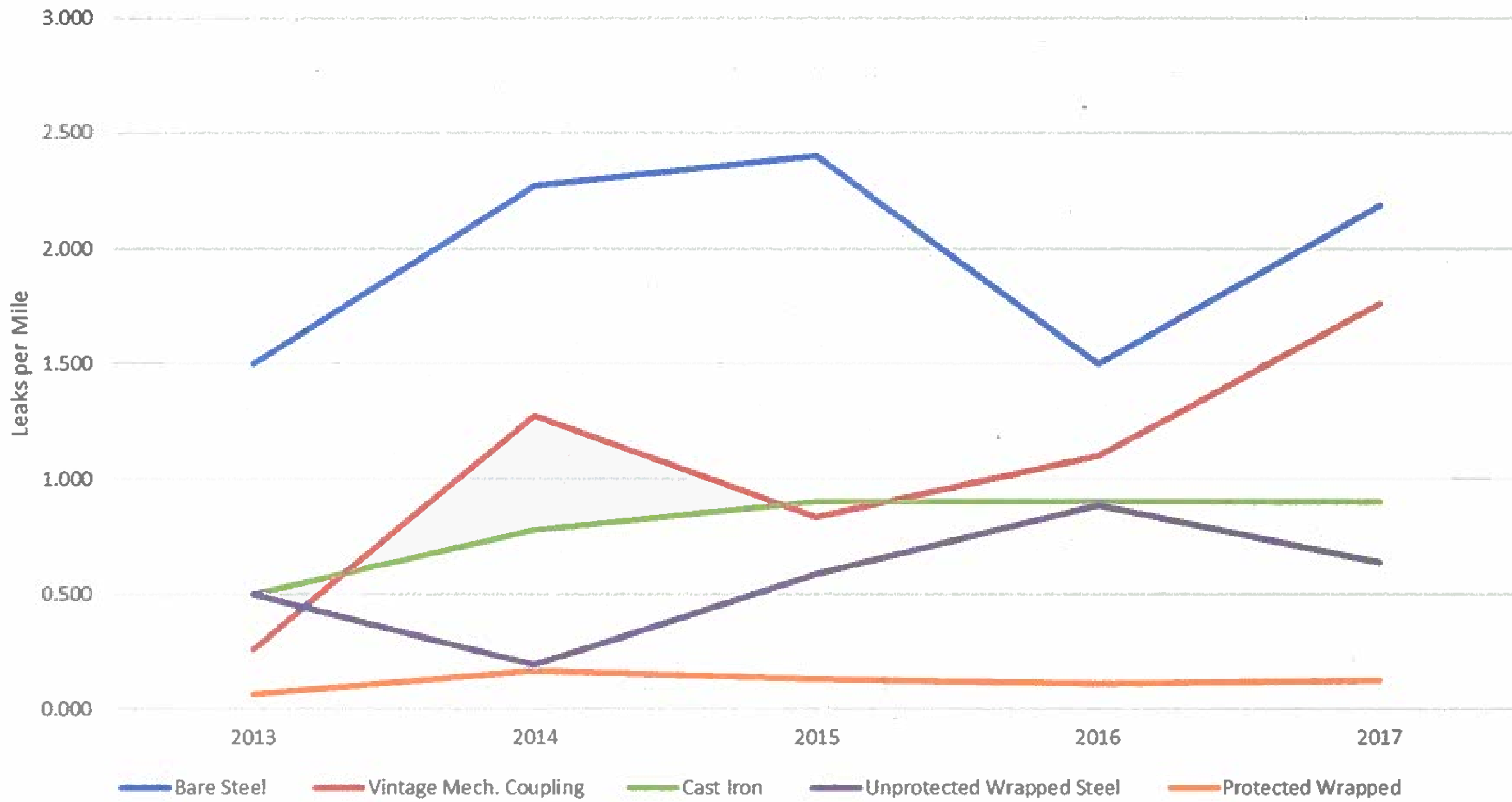


Figure 6: DC Main Leaks per Mile and per Year Jan 2013-Feb 2018
(Excludes 3rd PARTY DAMAGE, OPERATIONS AND OTHER)



AACE INTERNATIONAL RECOMMENDED PRACTICE

18R-97

COST ESTIMATE CLASSIFICATION SYSTEM – AS APPLIED IN ENGINEERING, PROCUREMENT, AND CONSTRUCTION FOR THE PROCESS INDUSTRIES

aace International
The Authority for Total Cost Management®

AACE International Recommended Practice No. 18R-97

COST ESTIMATE CLASSIFICATION SYSTEM – AS APPLIED IN ENGINEERING, PROCUREMENT, AND CONSTRUCTION FOR THE PROCESS INDUSTRIES

TCM Framework: 7.3 – Cost Estimating and Budgeting

Rev. March 1, 2016

Note: As AACE International Recommended Practices evolve over time, please refer to www.aacei.org for the latest revisions.

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COST ESTIMATE CLASSIFICATION SYSTEM – AS APPLIED IN ENGINEERING, PROCUREMENT, AND CONSTRUCTION FOR THE PROCESS INDUSTRIES

TCM Framework: 7.3 – Cost Estimating and Budgeting

March 1, 2016

PURPOSE

As a recommended practice of AACE International, the *Cost Estimate Classification System* provides guidelines for applying the general principles of estimate classification to project cost estimates (i.e., cost estimates that are used to evaluate, approve, and/or fund projects). The *Cost Estimate Classification System* maps the phases and stages of project cost estimating together with a generic project scope definition maturity and quality matrix, which can be applied across a wide variety of process industries.

This addendum to the generic recommended practice (17R-97) provides guidelines for applying the principles of estimate classification specifically to project estimates for engineering, procurement, and construction (EPC) work for the process industries. This addendum supplements the generic recommended practice by providing:

- A section that further defines classification concepts as they apply to the process industries.
- A chart that maps the extent and maturity of estimate input information (project definition deliverables) against the class of estimate.

As with the generic recommended practice, the intent of this addendum is to improve communications among all of the stakeholders involved with preparing, evaluating, and using project cost estimates specifically for the process industries.

The overall purpose of this recommended practice is to provide the process industry with a project definition deliverable maturity matrix that is not provided in 17R-97. It also provides an approximate representation of the relationship of specific design input data and design deliverable maturity to the estimate accuracy and methodology used to produce the cost estimate. The estimate accuracy range is driven by many other variables and risks, so the maturity and quality of the scope definition available at the time of the estimate is not the sole determinate of accuracy; risk analysis is required for that purpose.

This document is intended to provide a guideline, not a standard. It is understood that each enterprise may have its own project and estimating processes and terminology, and may classify estimates in particular ways. This guideline provides a generic and generally acceptable classification system for process industries that can be used as a basis to compare against. This addendum should allow each user to better assess, define, and communicate their own processes and standards in the light of generally-accepted cost engineering practice.

INTRODUCTION

For the purposes of this addendum, the term "process industries" is assumed to include firms involved with the manufacturing and production of chemicals, petrochemicals, and hydrocarbon processing. The common thread among these industries (for the purpose of estimate classification) is their reliance on process flow diagrams (PFDs) and piping and instrument diagrams (P&IDs) as primary scope defining documents. These documents are key deliverables in determining the degree of project definition, and thus the extent and maturity of estimate input information.

Estimates for process facilities center on mechanical and chemical process equipment, and they have significant amounts of piping, instrumentation, and process controls involved. As such, this addendum may apply to portions of other industries, such as pharmaceutical, utility, water treatment, metallurgical, converting, and similar industries.

This addendum specifically does not address cost estimate classification in non-process industries such as commercial building construction, environmental remediation, transportation infrastructure, hydropower, "dry" processes such as assembly and manufacturing, "soft asset" production such as software development, and similar industries. It also does not specifically address estimates for the exploration, production, or transportation of mining or hydrocarbon materials, although it may apply to some of the intermediate processing steps in these systems.

The cost estimates covered by this addendum are for engineering, procurement, and construction (EPC) work only. It does not cover estimates for the products manufactured by the process facilities, or for research and development work in support of the process industries. This guideline does not cover the significant building construction that may be a part of process plants.

This guideline reflects generally-accepted cost engineering practices. This RP was based upon the practices of a wide range of companies in the process industries from around the world, as well as published references and standards. Company and public standards were solicited and reviewed, and the practices were found to have significant commonalities. These classifications are also supported by empirical process industry research of systemic risks and their correlation with cost growth and schedule slip[8].

COST ESTIMATE CLASSIFICATION MATRIX FOR THE PROCESS INDUSTRIES

A purpose of cost estimate classification is to align the estimating process with project stage-gate scope development and decision making processes.

Table 1 provides a summary of the characteristics of the five estimate classes. The maturity level of project definition is the sole determining (i.e., primary) characteristic of class. In Table 1, the maturity is roughly indicated by a percentage of complete definition; however, it is the maturity of the defining deliverables that is the determinant, not the percent. The specific deliverables, and their maturity or status are provided in Table 3. The other characteristics are secondary and are generally correlated with the maturity level of project definition deliverables, as discussed in the generic RP [2]. The post sanction classes (Class 1 and 2) are only indirectly covered where new funding is indicated. Again, the characteristics are typical and may vary depending on the circumstances.

March 1, 2016

	Primary Characteristic	*Secondary Characteristic*		
ESTIMATE CLASS	**MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgment, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%

Table 1 – Cost Estimate Classification Matrix for Process Industries

This matrix and guideline outline an estimate classification system that is specific to the process industries. Refer to the generic estimate classification RP[1] for a general matrix that is non-industry specific, or to other addendums for guidelines that will provide more detailed information for application in other specific industries. These will provide additional information, particularly the project definition deliverable maturity matrix which determines the class in those particular industries.

Table 1 illustrates typical ranges of accuracy ranges that are associated with the process industries. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically to achieve a 50% probability of project overrun versus underrun) for given scope. Depending on the technical and project deliverables (and other variables) and risks associated with each estimate, the accuracy range for any particular estimate is expected to fall into the ranges identified (although extreme risks can lead to wider ranges).

In addition to the degree of project definition, estimate accuracy is also driven by other systemic risks such as:

- Level of non-familiar technology in the project.
- Complexity of the project.
- Quality of reference cost estimating data.
- Quality of assumptions used in preparing the estimate.
- Experience and skill level of the estimator.
- Estimating techniques employed.
- Time and level of effort budgeted to prepare the estimate.
- Unique/remote nature of project locations and the lack of reference data for these locations.
- The accuracy of the composition of the input and output process streams.

Systemic risks such as these are often the primary driver of accuracy, especially during the early stages of project definition. As project definition progresses, project-specific risks (e.g. risk events) become more prevalent and also drive the accuracy range[3]. Another concern in estimates is potential pressure for a predetermined value that may result in a biased estimate. The goal should be to always have an unbiased and objective estimate. The stated estimate ranges are dependent on this premise and a realistic view of the project.

Failure to appropriately address systemic risks (e.g. technical complexity) during risk analysis impacts the resulting probability distribution of the estimate costs, and therefore the interpretation of estimate accuracy.

Another way to look at the variability associated with estimate accuracy ranges is shown in Figure 1. Depending upon the technical complexity of the project, the availability of appropriate cost reference information, the degree of project definition, and the inclusion of appropriate contingency determination, a typical Class 5 estimate for a process industry project may have an accuracy range as broad as -50% to +100%, or as narrow as -20% to +30%.

Figure 1 also illustrates that the estimating accuracy ranges overlap the estimate classes. There are cases where a Class 5 estimate for a particular project may be as accurate as a Class 3 estimate for a different project. For example, similar accuracy ranges may occur if the Class 5 estimate of one project that is based on a repeat project with good cost history and data and, whereas the Class 3 estimate for another is for a project involving new technology. It is for this reason that Table 1 provides ranges of accuracy range values. This allows application of the specific circumstances inherent in a project, and an industry sector, to provide realistic estimate class accuracy range percentages. While a target range may be expected of a particular estimate, the accuracy range is determined through risk analysis of the specific project and is never pre-determined. AACE has recommended practices that address contingency determination and risk analysis methods.

If contingency has been addressed appropriately, approximately 80% of projects should fall within the ranges shown in Figure 1. However, this does not preclude a specific actual project result from falling inside or outside of the bands shown in Figure 1 indicating the expected accuracy ranges.

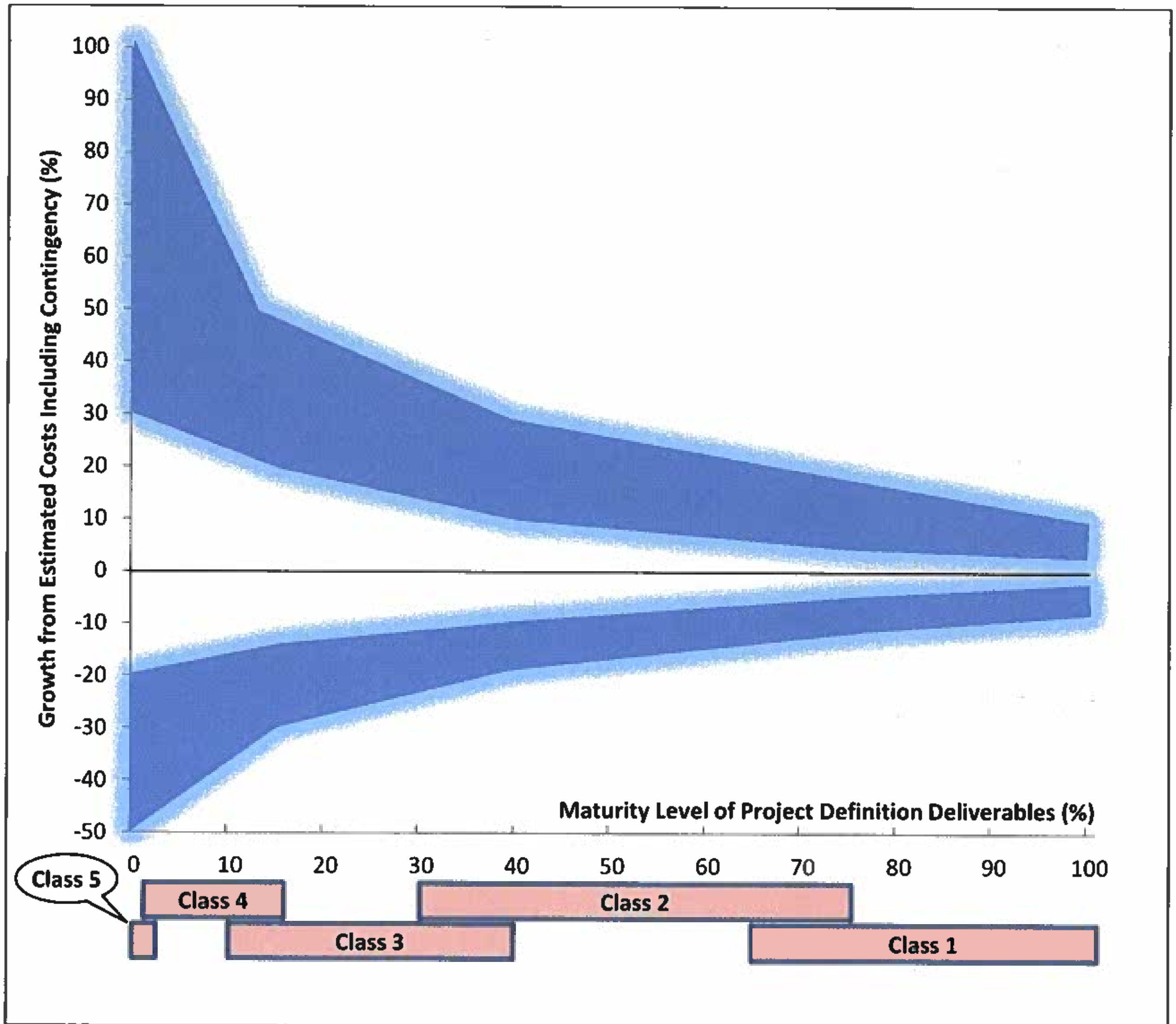

Figure 1 – Example of the Variability in Accuracy Ranges for a Process Industry Estimate

DETERMINATION OF THE COST ESTIMATE CLASS

The cost estimator makes the determination of the estimate class based upon the maturity level of project definition based on the status of specific key planning and design deliverables. The percent design completion may be correlated with the status, but the percentage should not be used as the estimate class determinant. While the determination of the status (and hence the estimate class) is somewhat subjective, having standards for the design input data, completeness and quality of the design deliverables will serve to make the determination more objective.

CHARACTERISTICS OF THE ESTIMATE CLASSES

The following tables (2a through 2e) provide detailed descriptions of the five estimate classifications as applied in the process industries. They are presented in the order of least-defined estimates to the most-defined estimates. These descriptions include brief discussions of each of the estimate characteristics that define an estimate class.

For each table, the following information is provided:

- **Description:** A short description of the class of estimate, including a brief listing of the expected estimate inputs based on the maturity level of project definition deliverables.
- **Maturity Level of Project Definition Deliverables Required (Primary Characteristic):** Describes a particularly key deliverable and a typical target status in stage-gate decision processes, plus an indication of approximate percent of full definition of project and technical deliverables. For the process industries, this correlates with the percent of engineering and design complete.
- **End Usage (Secondary Characteristic):** A short discussion of the possible end usage of this class of estimate.
- **Estimating Methodology (Secondary Characteristic):** A listing of the possible estimating methods that may be employed to develop an estimate of this class.
- **Expected Accuracy Range (Secondary Characteristic):** Typical variation in low and high ranges after the application of contingency (to achieve a 50% probability of project overrun versus underrun). Typically, this represents about 80% confidence level that the actual cost will fall within the bounds of the low and high ranges. The estimate confidence level or accuracy range is driven by the reliability of the scope information available at the time of the estimate in addition to the other variables and risk identified above.
- **Alternate Estimate Names, Terms, Expressions, Synonyms:** This section provides other commonly used names that an estimate of this class might be known by. These alternate names are not endorsed by this recommended practice. The user is cautioned that an alternative name may not always be correlated with the class of estimate as identified in Tables 2a-2e.

CLASS 5 ESTIMATE	
Description: Class 5 estimates are generally prepared based on very limited information, and subsequently have wide accuracy ranges. As such, some companies and organizations have elected to determine that due to the inherent inaccuracies, such estimates cannot be classified in a conventional and systematic manner. Class 5 estimates, due to the requirements of end use, may be prepared within a very limited amount of time and with little effort expended—sometimes requiring less than an hour to prepare. Often, little more than proposed plant type, location, and capacity are known at the time of estimate preparation. **Maturity Level of Project Definition Deliverables:** Key deliverable and target status: Block flow diagram agreed by key stakeholders. List of key design basis assumptions. 0% to 2% of full project definition. **End Usage:** Class 5 estimates are prepared for any number of strategic business planning purposes, such as but not limited to market studies, assessment of initial viability, evaluation of alternate schemes, project screening, project location studies, evaluation of resource needs and budgeting, long-range capital planning, etc.	**Estimating Methodology:** Class 5 estimates generally use stochastic estimating methods such as cost/capacity curves and factors, scale of operations factors, Lang factors, Hand factors, Chilton factors, Peters-Timmerhaus factors, Guthrie factors, and other parametric and modeling techniques. **Expected Accuracy Range:** Typical accuracy ranges for Class 5 estimates are -20% to -50% on the low side, and +30% to +100% on the high side, depending on the technological complexity of the project, appropriate reference information and other risks (after inclusion of an appropriate contingency determination). Ranges could exceed those shown if there are unusual risks. **Alternate Estimate Names, Terms, Expressions, Synonyms:** Ratio, ballpark, blue sky, seat-of-pants, ROM, idea study, prospect estimate, concession license estimate, guesstimate, rule-of-thumb.

Table 2a – Class 5 Estimate

CLASS 4 ESTIMATE	
Description: Class 4 estimates are generally prepared based on limited information and subsequently have fairly wide accuracy ranges. They are typically used for project screening, determination of feasibility, concept evaluation, and preliminary budget approval. Typically, engineering is from 1% to 15% complete, and would comprise at a minimum the following: plant capacity, block schematics, indicated layout, process flow diagrams (PFDs) for main process systems, and preliminary engineered process and utility equipment lists. **Maturity Level of Project Definition Deliverables:** Key deliverable and target status: Process flow diagrams (PFDs) issued for design. 1% to 15% of full project definition. **End Usage:** Class 4 estimates are prepared for a number of purposes, such as but not limited to, detailed strategic planning, business development, project screening at more developed stages, alternative scheme analysis, confirmation of economic and/or technical feasibility, and preliminary budget approval or approval to proceed to next stage.	**Estimating Methodology:** Class 4 estimates generally use factored estimating methods such as equipment factors, Lang factors, Hand factors, Chilton factors, Peters-Timmerhaus factors, Guthrie factors, the Miller method, gross unit costs/ratios, and other parametric and modeling techniques. **Expected Accuracy Range:** Typical accuracy ranges for Class 4 estimates are -15% to -30% on the low side, and +20% to +50% on the high side, depending on the technological complexity of the project, appropriate reference information, and other risks (after inclusion of an appropriate contingency determination). Ranges could exceed those shown if there are unusual risks. **Alternate Estimate Names, Terms, Expressions, Synonyms:** Screening, top-down, feasibility (pre-feasibility for metals processes), authorization, factored, pre-design, pre-study.

Table 2b – Class 4 Estimate

CLASS 3 ESTIMATE	
Description: Class 3 estimates are generally prepared to form the basis for budget authorization, appropriation, and/or funding. As such, they typically form the initial control estimate against which all actual costs and resources will be monitored. Typically, engineering is from 10% to 40% complete, and would comprise at a minimum the following: process flow diagrams, utility flow diagrams, preliminary piping and instrument diagrams, plot plan, developed layout drawings, and essentially complete engineered process and utility equipment lists. Remedial action plan resulting from HAZOPs is identified. **Maturity Level of Project Definition Deliverables:** Key deliverable and target status: Piping and instrumentation diagrams (P&IDs) issued for design. 10% to 40% of full project definition. **End Usage:** Class 3 estimates are typically prepared to support full project funding requests, and become the first of the project phase control estimates against which all actual costs and resources will be monitored for variations to the budget. They are used as the project budget until replaced by more detailed estimates. In many owner organizations, a Class 3 estimate is often the last estimate required and could very well form the only basis for cost/schedule control.	**Estimating Methodology:** Class 3 estimates generally involve more deterministic estimating methods than conceptual methods. They usually involve predominant use of unit cost line items, although these may be at an assembly level of detail rather than individual components. Factoring methods may be used to estimate less-significant areas of the project. **Expected Accuracy Range:** Typical accuracy ranges for Class 3 estimates are -10% to -20% on the low side, and +10% to +30% on the high side, depending on the technological complexity of the project, appropriate reference information, and other risks (after inclusion of an appropriate contingency determination). Ranges could exceed those shown if there are unusual risks. **Alternate Estimate Names, Terms, Expressions, Synonyms:** Budget, scope, sanction, semi-detailed, authorization, preliminary control, concept study, feasibility (for metals processes) development, basic engineering phase estimate, target estimate.

Table 2c – Class 3 Estimate

CLASS 2 ESTIMATE

Description:
Class 2 estimates are generally prepared to form a detailed contractor control baseline (and update the owner control baseline) against which all project work is monitored in terms of cost and progress control. For contractors, this class of estimate is often used as the bid estimate to establish contract value. Typically, engineering is from 30% to 75% complete, and would comprise at a minimum the following: process flow diagrams, utility flow diagrams, piping and instrument diagrams, heat and material balances, final plot plan, final layout drawings, complete engineered process and utility equipment lists, single line diagrams for electrical, electrical equipment and motor schedules, vendor quotations, detailed project execution plans, resourcing and work force plans, etc.

Maturity Level of Project Definition Deliverables:
Key deliverable and target status: All specifications and datasheets complete including for instrumentation. 30% to 75% of full project definition.

End Usage:
Class 2 estimates are typically prepared as the detailed contractor control baseline (and update to the owner control baseline) against which all actual costs and resources will now be monitored for variations to the budget, and form a part of the change management program. Some organizations may choose to make funding decisions based on a Class 2 estimate.

Estimating Methodology:
Class 2 estimates generally involve a high degree of deterministic estimating methods. Class 2 estimates are prepared in great detail, and often involve tens of thousands of unit cost line items. For those areas of the project still undefined, an assumed level of detail takeoff (forced detail) may be developed to use as line items in the estimate instead of relying on factoring methods.

Expected Accuracy Range:
Typical accuracy ranges for Class 2 estimates are
-5% to -15% on the low side, and +5% to +20% on the high side, depending on the technological complexity of the project, appropriate reference information, and other risks (after inclusion of an appropriate contingency determination). Ranges could exceed those shown if there are unusual risks.

Alternate Estimate Names, Terms, Expressions, Synonyms:
Detailed control, forced detail, execution phase, master control, engineering, bid, tender, change order estimate.

Table 2d – Class 2 Estimate

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CLASS 1 ESTIMATE	
Description: Class 1 estimates are generally prepared for discrete parts or sections of the total project rather than generating this level of detail for the entire project. The parts of the project estimated at this level of detail will typically be used by subcontractors for bids, or by owners for check estimates. The updated estimate is often referred to as the current control estimate and becomes the new baseline for cost/schedule control of the project. Class 1 estimates may be prepared for parts of the project to comprise a fair price estimate or bid check estimate to compare against a contractor's bid estimate, or to evaluate/dispute claims. Typically, overall engineering is from 65% to 100% complete (some parts or packages may be complete and others not), and would comprise virtually all engineering and design documentation of the project, and complete project execution and commissioning plans. **Maturity Level of Project Definition Deliverables:** Key deliverable and target status: All deliverables in the maturity matrix complete. 65% to 100% of full project definition. **End Usage:** Generally, owners and EPC contractors use Class 1 estimates to support their change management process. They may be used to evaluate bid checking, to support vendor/contractor negotiations, or for claim evaluations and dispute resolution. Construction contractors may prepare Class 1 estimates to support their bidding and to act as their final control baseline against which all actual costs and resources will now be monitored for variations to their bid. During construction, Class 1 estimates may be prepared to support change management.	**Estimating Methodology:** Class 1 estimates generally involve the highest degree of deterministic estimating methods, and require a great amount of effort. Class 1 estimates are prepared in great detail, and thus are usually performed on only the most important or critical areas of the project. All items in the estimate are usually unit cost line items based on actual design quantities. **Expected Accuracy Range:** Typical accuracy ranges for Class 1 estimates are -3% to -10% on the low side, and +3% to +15% on the high side, depending on the technological complexity of the project, appropriate reference information, and other risks (after inclusion of an appropriate contingency determination). Ranges could exceed those shown if there are unusual risks. **Alternate Estimate Names, Terms, Expressions, Synonyms:** Full detail, release, fall-out, tender, firm price, bottoms-up, final, detailed control, forced detail, execution phase, master control, fair price, definitive, change order estimate.

Table 2e – Class 1 Estimate

ESTIMATE INPUT CHECKLIST AND MATURITY MATRIX

Table 3 maps the extent and maturity of estimate input information (deliverables) against the five estimate classification levels. This is a checklist of basic deliverables found in common practice in the process industries. The maturity level is an approximation of the completion status of the deliverable. The completion is indicated by the following descriptors:

General Project Data:

- **Not Required:** May not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- **Preliminary**: Project definition has begun, and progressed to at least an intermediate level of completion. Review and approvals for its current status has occurred.
- **Defined**: Project definition is advanced and reviews have been conducted. Development may be near completion with the exception of final approvals.

Engineering Deliverables:

- **Not Required (NR)**: Deliverable may not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- **Started (S):** Work on the deliverable has begun. Development is typically limited to sketches, rough outlines, or similar levels of early completion.
- **Preliminary (P):** Work on the deliverable is advanced. Interim, cross-functional reviews have usually been conducted. Development may be near completion except for final reviews and approvals.
- **Complete (C):** The deliverable has been reviewed and approved as appropriate.

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	ESTIMATE CLASSIFICATION				
	CLASS 5	**CLASS 4**	**CLASS 3**	**CLASS 2**	**CLASS 1**
MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES	**0% to 2%**	**1% to 15%**	**10% to 40%**	**30% to 75%**	**65% to 100%**
General Project Data:					
Project Scope Description	Preliminary	Preliminary	Defined	Defined	Defined
Plant Production/Facility Capacity	Preliminary	Preliminary	Defined	Defined	Defined
Plant Location	Preliminary	Preliminary	Defined	Defined	Defined
Soils & Hydrology	Not Required	Preliminary	Defined	Defined	Defined
Integrated Project Plan	Not Required	Preliminary	Defined	Defined	Defined
Project Master Schedule	Not Required	Preliminary	Defined	Defined	Defined
Escalation Strategy	Not Required	Preliminary	Defined	Defined	Defined
Work Breakdown Structure	Not Required	Preliminary	Defined	Defined	Defined
Project Code of Accounts	Not Required	Preliminary	Defined	Defined	Defined
Contracting Strategy	Not Required	Preliminary	Defined	Defined	Defined
Engineering Deliverables:					
Block Flow Diagrams	S/P	P/C	C	C	C
Plot Plans	NR	S/P	C	C	C
Process Flow Diagrams (PFDs)	NR	P/C	C	C	C
Utility Flow Diagrams (UFDs)	NR	S/P	C	C	C
Piping & Instrument Diagrams (P&IDs)	NR	S/P	C	C	C
Heat & Material Balances	NR	P/C	C	C	C
Process Equipment List	NR	S/P	C	C	C
Utility Equipment List	NR	S/P	C	C	C
Electrical One-Line Drawings	NR	S/P	C	C	C
Design Specifications & Datasheets	NR	S/P	C	C	C
General Equipment Arrangement Drawings	NR	S	C	C	C
Spare Parts Listings	NR	NR	P	P	C
Mechanical Discipline Drawings	NR	NR	S/P	P/C	C
Electrical Discipline Drawings	NR	NR	S/P	P/C	C
Instrumentation/Control System Discipline Drawings	NR	NR	S/P	P/C	C
Civil/Structural/Site Discipline Drawings	NR	NR	S/P	P/C	C

Table 3 – Estimate Input Checklist and Maturity Matrix (Primary Classification Determinate)

March 1, 2016

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EXHIBIT WG (A)-4

Analysis of Economic Benefits

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November 20, 2018

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1. INTRODUCTION

NERA Economic Consulting (NERA) was retained by Washington Gas ("WGL" hereafter) to conduct an analysis of the economic benefits of PROJECT*pipes* ("the Project") on the District of Columbia economy that will result from replacing relatively higher risk natural gas pipeline infrastructure. WGL has replaced pipelines for the past 4 years (June 2014-September 2018), and will complete its fifth year September 2019. Spending for the first five years of the Project (2014-2019) will be an estimated $110 million.[1] WGL plans to continue to replace higher risk natural gas pipelines over the next 5 years (2020-2024), during which total spending is projected to approximate $305 million.

The execution of PROJECTpipes benefits the economy of the District of Columbia from the investment completed to date and "planned" spending by Washington Gas through 2024. In addition, the spending during the construction of PROJECTpipes will provide economic benefits to the District of Columbia in terms of job creation, labor income, Gross Domestic Product (GDP), and tax revenues. The estimate of the economic benefits resulting from the construction of PROJECTpipes to the District of Columbia is the subject of this report.

NERA has conducted an analysis of the economic benefits associated with the construction of PROJECTpipes for the District of Columbia for the 2014-2019 and 2020-2024 time-periods. The economic benefits reported include full-time equivalent (FTE) employment, labor income, GDP, and total economic output.

The modeling framework calculates the direct, indirect, and induced economic impacts resulting from the construction of PROJECTpipes. Direct impacts are the additional economic activities that are directly paid for by the construction dollars. To the extent that these funds are spent on goods and services provided by local businesses, they produce benefits to the local economy. Indirect impacts result from the secondary business-to-business transactions required to produce the directly consumed goods and services (*e.g.*, increased output from the business providing intermediate inputs). Induced impacts are the impacts derived from spending on goods and services by people working to satisfy the direct and indirect effects (*e.g.*, increased household spending resulting from higher personal income).

The following sections of the report provide (1) background to economic benefits analyses and (2) the results of the economic benefits analysis of PROJECT*pipes* to the District of Columbia. In addition, the Appendix provides background information on the modeling assumptions, impact analysis methodology specific to this study and the IMPLAN model used for the analysis.

Table 1-1 reports[2] the key findings of the study, which include the estimated total economic benefits from PROJECT*pipes* to the District of Columbia economy that will result from the replacement of the relatively higher risk natural gas pipelines over the 2014-2019 and 2020-2024 period. Specifically, the table reports the FTE Employment, labor income, and GDP, expected to be generated as a result of PROJECTpipes. FTE Employment benefits is estimated as 616 for WGL's 2014-2019 spending period and 1,708 for WGL's 2020-2024 "planned" spending period. Output benefits represents the total value of the industry output, which is estimated as $95,078,026 for WGL's 2014-2019 spending period and $263,643,497 for WGL's 2020-2024 "planned" spending period in the District of Columbia. Employee compensation is estimated as $38,880,488 for WGL's 2014-2019 spending period and $107,680,535 for WGL's 2020-2024 "planned" spending period. GDP in the District of Columbia is estimated as $57,579,451 for WGL's 2014-2019 spending period and $159,483,161 for WGL's 2020-2024 "planned" spending period.

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[1] The spending estimate of $110 million represents the WGL's total spending for the 2014-2019 construction period. This figure is expressed in 2018 dollars and is calculated as the total spending within each fiscal year from June 2014 through September 2019.

[2] Each of the reported economic benefits are described in Section 3.

Table 1-1 demonstrates the significant economic benefits to the District of Columbia economy that will result from PROJECT*pipes* and the associated spending directed to businesses located in the District of Columbia

Table 1-1. Summary Results – Estimated Total Economic Benefits from Natural Gas Pipeline Investment Project (2014-2019 and 2020-2024)[3]

Project Spending Period	Employment	Output	Employee Compensation	GDP
2014-2019	616	$95,078,026	$38,880,488	$57,579,451
2020-2024	1,708	$263,643,497	$107,680,535	$159,483,161

[3] Impacts are reported in 2018 dollars. FTE Employment refers to Full Time Equivalent Employment and reflects part-time and full-time annual average jobs converted to full-time equivalent jobs.

2. GENERAL BACKGROUND OF ECONOMIC BENEFITS ANALYSIS

The development of energy infrastructure, such as PROJECTpipes, results in an increase in economic activity associated with purchasing manufactured products and professional services required to construct the facilities. This benefits local and regional economies, such as the District of Columbia, in many ways. The increase in economic activity, which is also referred to as economic benefits, represents positive contributions to the economy. The most common type of economic impact quantified is employment-related benefits, such as jobs. The private investment in the local economy associated with the development of new energy infrastructure, such as PROJECTpipes, provides job-related economic benefits to the regional economies, including additional benefits associated with the quality of the jobs PROJECTpipes generates.

The second frequently referenced economic benefits statistic is gross domestic product ("GDP"), which is also referred to as value added. GDP represents an aggregate measure of economic activity resulting from a Project in a particular geographic region.[4] GDP consists of locally earned wages, interest, rents, and profits associated with producing the output of the region. Other economic benefit statistics include additional tax revenues from PROJECTpipes, which provides government agencies with increased revenues, and, in turn, higher fiscal budgets, to fund ongoing operations and economic initiatives. Generally, the economic activities from an energy infrastructure project create positive ripple effects through many economic sectors of a particular region as well as inter regional economic activity. The ripple effect occurs because diverse industries are interdependent.

First, an economic event, such as the construction of PROJECTpipes, will create expenditures or production changes and therefore generate economic benefits. For PROJECTpipes, the direct spending occurs because WGL purchases construction and other professional services, equipment, and other supplies from businesses located in the District of Columbia to construct the transmission and substation facilities. These economic activities create "direct economic benefits."

Second, as a result of PROJECTpipes, the professionals, material, and equipment suppliers hired by WGL, in turn, must purchase goods and services to produce their own goods and services, many of which may also be supplied by local businesses. This creates economic activity resulting from subsequent rounds of business-spending entities indirectly involved in PROJECTpipes arising from inter-industry linkages. For example, a local business supplying WGL with excavation, demolition, and other construction-related services will need to purchase input materials, such as tools and other equipment and supplies, that enhance the economic activity of other businesses, indirectly, which provides extra benefits to the economy. These benefits are referred to as "indirect economic benefits."

In addition, "induced economic benefits" to the economy result from additional spending on general discretionary items that arise from the higher wages and personal income earned by local workers in the direct and indirect industries that received additional business activity from PROJECTpipes. When local workers receive additional disposable income (which will occur from PROJECTpipes), an increase in discretionary spending on merchandise (*e.g.*, clothes and electronics) and services (*e.g.*, entertainment activities including dinners) occurs. This ripple effect rests on the assumption that consumers spend, and do not use labor income gains solely for personal savings. Therefore, the resulting effect is that the local economy receives an induced economic benefit.

The overall economic impact arising from the construction and operation of a proposed energy infrastructure project equals the sum of its direct, indirect, and induced impacts. For new energy infrastructure projects, economic impact analyses are frequently completed for the construction phase of PROJECTpipes and the ongoing operational phase of PROJECTpipes. For PROJECTpipes, my analysis addresses only the economic benefits from the design and construction phase.

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[4] For the purposes of this report, GDP refers to the local contribution to national GDP that results from PROJECT*pipes* and the spending in the District of Columbia.

3. RESULTS OF ECONOMIC BENEFITS ANALYSIS

The economic benefits analysis relies on IMPLAN, an economic modeling and software data package.[5] As discussed in Appendix C, IMPLAN is widely used by government agencies, companies, academics, and others to evaluate the economic impacts of different activities, including for government agencies of the District of Columbia.[6]

The IMPLAN model predicts significant economic benefits to the District of Columbia economies from the construction of PROJECTpipes and the associated spending directed to businesses located in the District of Columbia.[7] The tables in this section of the report provide summary-level and detailed reporting of the estimated economic benefit statistics resulting from PROJECTpipes.

- Full Time Equivalent (FTE) employment represents reflects part-time and full-time annual average jobs converted to full-time equivalent jobs. IMPLAN predicts that the private investment from PROJECTpipes will result in FTE jobs as a result of the construction.

- Output represents IMPLAN's predicted total economic impact by adding the direct, indirect, and induced impacts on local industries plus the final users of the region's goods and services. Final users of goods and services include government, physical investment, household consumption, and exports minus imports (a second approach for measuring the region's aggregate economic activity).

- Labor income represents IMPLAN's prediction of before-tax income earned from producing the region's output.

- Gross Domestic Project (GDP or Value Added) is one often used approach to estimate the region's aggregate economic activity. GDP consists of locally earned wages, interest, rents, and profits associated with producing the region's output.

Table 3-1 and Table 3-2 report the economic benefit statistics estimated for PROJECTpipes as the total Output economic benefits estimated to occur in the District of Columbia as a result of the increased economic activity of PROJECTpipes. In summary, the two most frequently referenced economic benefit statistics include FTE employment and GDP. As shown in Table 3-1, the construction of PROJECTpipes is anticipated to result in 616 FTE jobs and $57,579,451in GDP to the District of Columbia economy over the construction period (2014-2019). As shown in Table 3-12, the construction of PROJECTpipes is anticipated to result in 1,708 FTE jobs and $159,483,161 in GDP to the District of Columbia economy over the construction period (2020-2024).

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[5] IMPLAN Group LLC, 16740 Birkdale Commons Pkwy, Suite 212, Huntersville, NC 28078 www.implan.com.

[6] For example, within the District of Columbia, the Mayor's Power Line Undergrounding Task Force, Metropolitan Washington Airports Authority, and DC Office of Motion Picture and Television Development have relied upon IMPLAN. Within Maryland, the Maryland Department of Commerce and the Maryland Transit Administration have used IMPLAN. See Appendix A for additional details.

[7] The IMPLAN modeling applied the entire spending for PROJECTpipes into a single year, whereas the dollars will be spread over the period, which is a common practice for economic impacts studies conducted for proposed energy infrastructure projects to provide an estimate of cumulative economic benefits.

Table 3-1. Estimated Total Economic Benefits from Construction Spending (2014-2019)[8]

Type	Direct	Indirect	Induced	Total
Employment	445	83	88	616
Output	$73,000,000	$12,217,747	$9,860,279	$95,078,026
Employee Compensation	$29,389,610.06	$5,536,814.12	$3,954,064.32	$38,880,488.49
GDP	$42,611,841	$8,506,505	$6,461,105	$57,579,451

Note: Adjusted for price inflation from 2016$ to 2018$, using gross domestic product chain-type price index for industry obtained from Bureau of Economic Analysis.

Table 3-2. Estimated Total Economic Benefits from "Planned" Construction Spending (2020-2024)[9]

Type	Direct	Indirect	Induced	Total
Employment	1,233	231	244	1,708
Output	$202,360,079	$33,938,074	$27,345,343	$263,643,497
Employee Compensation	$81,320,913	$15,393,914	$10,965,708	$107,680,535
GDP	$117,932,772	$23,631,843	$17,918,546	$159,483,161

Note: Adjusted for price inflation from 2016$ to 2018$, using gross domestic product chain-type price index for industry obtained from Bureau of Economic Analysis.

Table 3-2 also reports the subcomponents of the economic benefits statistics, including the direct, indirect, and induced economic benefits. The direct-effect employment data is generated by IMPLAN from the construction spending associated with PROJECTpipes and represents the total FTE employment. FTE employment figures represent the estimated number of employees across the construction period (2014-2019). Direct FTE employment includes the internal employees, who are employed in both the field and professional levels across a variety of functions, and the contractor employees, who are mostly employed in construction and engineering roles. Indirect employment includes the regional supply chain that provides materials and services to WGL and its contractors. Induced contributions are the results of employees spending their incomes in the local economy.

PROJECTpipes economic benefits analysis is conservative because the District of Columbia regional economics were modeled as separate geographic regions, even though these economies operate within the larger Washington Metropolitan area. To the extent that additional spending in Maryland creates additional economic activity in the District of Columbia or additional spending in the District of Columbia increases economic activity in Maryland, these additional economic benefits are not captured in the single state study area results.

In addition, as discussed above, these economic benefit results are conservative as other spending is expected to occur in the Washington Metropolitan region (*i.e.*, Virginia and Maryland) as well as other U.S. locations. This additional spending in other regions will provide a positive economic impact (direct, indirect, and induced benefits) to those regions, and, in turn, will create economic benefits in the Washington Metropolitan area and the broader U.S. economy. PROJECTpipes has been implemented for the past 5 years (2014-2018) and planned to continue over the next 6 years (2020-2024). The following discussion centers on the economic benefits that arise from PROJECTpipes during each Phase.

[8] Impacts are reported in 2018 dollars. FTE Employment refers to Full Time Equivalent Employment and reflects part-time and full-time annual average jobs converted to full-time equivalent jobs. The FTE employment as well as the other economic benefits statistics are reported for the entire time period modeled for the duration of the construction. Reliance on FTE employment economic benefits across the time period modeled representing the construction period is common practice and convention in economic benefits studies.

[9] Impacts are reported in 2018 dollars. FTE Employment refers to Full Time Equivalent Employment and reflects part-time and full-time annual average jobs converted to full-time equivalent jobs.

Overall, the economic benefits of PROJECTpipes enhance the District of Columbia regional economies over the next decade, enabling WGL to operate effectively, efficiently, and reliably while continuing to contribute to the regional economy.

APPENDIX A: DETAILED IMPACT ANALYSIS RESULTS

Table A-1: Detailed Employment Impacts of Natural Gas Pipeline Project Spending (2014-2019)

Description	Direct Effect	Indirect Effect	Induced Effect	Total Effect
Other nonresidential structures	303	53	64	420
Maintenance and repair of highways, streets, bridges, and tunnels	80	13	11	103
Architectural, engineering, and related services	29	12	9	50
All other miscellaneous manufacturing	17	3	2	22
Building material and garden equipment and supplies stores	16	2	2	21
Insurance agencies, brokerages, and related activities	2	1	1	3
Marketing research and all other miscellaneous professional, scientific, and technical services	1	0	1	2
Business and professional associations	1	0	0	1
Pipeline transportation	0	0	0	0
Wired telecommunications carriers	0	0	0	0
Transit and ground passenger transportation	0	0	0	0
Facilities support services	0	0	0	0
Employment and payroll of state govt, non-education	-	-	-	-
Accounting, tax preparation, bookkeeping, and payroll services	(6)	(1)	(2)	(8)
Total	445	83	88	616

Table A-2: Detailed Output Impacts of Natural Gas Pipeline Project Spending (2014-2019)

Description	Direct Effect	Indirect Effect	Induced Effect	Total Effect
Other nonresidential structures	46,608,878	6,018,049	5,944,230	58,571,157
Maintenance and repair of highways, streets, bridges, and tunnels	13,694,741	2,620,719	1,774,788	18,090,249
Architectural, engineering, and related services	6,695,911	2,075,380	1,509,790	10,281,081
All other miscellaneous manufacturing	3,092,583	746,800	278,600	4,117,982
Building material and garden equipment and supplies stores	2,697,517	568,785	386,748	3,653,050
Insurance agencies, brokerages, and related activities	806,568	237,311	99,629	1,143,508
Marketing research and all other miscellaneous professional, scientific, and technical services	228,079	29,512	105,215	362,806
Business and professional associations	175,304	21,022	27,132	223,458
Pipeline transportation	38,668	830	889	40,387
Wired telecommunications carriers	4,582	1,045	270	5,897
Facilities support services	57	19	7	84
Transit and ground passenger transportation	23	9	4	36
Employment and payroll of state govt, non-education	-	-	-	-
Accounting, tax preparation, bookkeeping, and payroll services	(1,042,910)	(101,735)	(267,023)	(1,411,668)
Total	73,000,000	12,217,747	9,860,279	95,078,026

Table A-3: Detailed GDP Impacts of Natural Gas Pipeline Project Spending (2014-2019)

Description	Direct Effect	Indirect Effect	Induced Effect	Total Effect
Other nonresidential structures	27,592,377	4,150,802	3,894,850	35,638,030
Maintenance and repair of highways, streets, bridges, and tunnels	7,453,380	1,788,577	1,163,112	10,405,069
Architectural, engineering, and related services	4,347,692	1,512,674	989,558	6,849,924
Building material and garden equipment and supplies stores	2,046,002	400,660	253,262	2,699,924
All other miscellaneous manufacturing	1,113,928	516,251	182,513	1,812,692
Insurance agencies, brokerages, and related activities	604,551	173,062	65,242	842,854
Marketing research and all other miscellaneous professional, scientific, and technical services	194,441	20,995	69,096	284,532
Business and professional associations	148,934	14,442	17,766	181,142
Pipeline transportation	36,848	573	582	38,003
Wired telecommunications carriers	3,418	722	177	4,317
Facilities support services	29	13	5	47
Transit and ground passenger transportation	10	6	2	19
Employment and payroll of state govt, non-education	-	-	-	-
Accounting, tax preparation, bookkeeping, and payroll services	(929,770)	(72,272)	(175,060)	(1,177,101)
Total	42,611,841	8,506,505	6,461,105	57,579,451

Table A-4: Detailed Employment Impacts of Natural Gas Pipeline "Planned" Project Spending (2020-2024)

Description	Direct Effect	Indirect Effect	Induced Effect	Total Effect
Other nonresidential structures	841	146	178	1,166
Maintenance and repair of highways, streets, bridges, and tunnels	223	36	30	289
Architectural, engineering, and related services	83	33	26	142
All other miscellaneous manufacturing	49	8	5	61
Building material and garden equipment and supplies stores	44	6	6	56
Insurance agencies, brokerages, and related activities	6	2	2	10
Marketing research and all other miscellaneous professional, scientific, and technical services	3	0	2	6
Pipeline transportation	0	0	0	0
Wired telecommunications carriers	0	0	0	0
Facilities support services	0	0	0	0
Employment and payroll of state govt, non-education	-	-	-	-
Business and professional associations	-	-	-	-
Transit and ground passenger transportation	-	-	-	-
Accounting, tax preparation, bookkeeping, and payroll services	(16)	(2)	(5)	(22)
Total	1,233	231	244	1,708

Table A-5: Detailed Output Impacts of Natural Gas Pipeline "Planned" Project Spending (2020-2024)

Description	Direct Effect	Indirect Effect	Induced Effect	Total Effect
Other nonresidential structures	129,332,703	16,699,192	16,494,353	162,526,248
Maintenance and repair of highways, streets, bridges, and tunnels	38,311,463	7,331,544	4,965,026	50,608,033
Architectural, engineering, and related services	18,909,896	5,861,072	4,263,793	29,034,761
All other miscellaneous manufacturing	8,584,644	2,073,028	773,360	11,431,032
Building material and garden equipment and supplies stores	7,126,318	1,502,619	1,021,713	9,650,650
Insurance agencies, brokerages, and related activities	2,274,895	669,328	281,001	3,225,224
Marketing research and all other miscellaneous professional, scientific, and technical services	644,267	83,363	297,205	1,024,836
Pipeline transportation	109,245	2,346	2,511	114,103
Wired telecommunications carriers	12,945	2,952	762	16,659
Facilities support services	162	55	20	236
Employment and payroll of state govt, non-education	-	-	-	-
Business and professional associations	-	-	-	-
Transit and ground passenger transportation	-	-	-	-
Accounting, tax preparation, bookkeeping, and payroll services	(2,946,458)	(287,426)	(754,401)	(3,988,285)
Total	202,360,079	33,938,074	27,345,343	263,643,497

Table A-6: Detailed GDP Impacts of Natural Gas Pipeline "Planned" Project Spending (2020-2024)

Description	Direct Effect	Indirect Effect	Induced Effect	Total Effect
Other nonresidential structures	76,564,742	11,517,859	10,807,630	98,890,231
Maintenance and repair of highways, streets, bridges, and tunnels	20,851,061	5,003,600	3,253,843	29,108,504
Architectural, engineering, and related services	12,278,299	4,271,938	2,794,607	19,344,843
Building material and garden equipment and supplies stores	5,405,141	1,058,465	669,068	7,132,675
All other miscellaneous manufacturing	3,092,133	1,433,050	506,634	5,031,818
Insurance agencies, brokerages, and related activities	1,705,114	488,114	184,013	2,377,241
Marketing research and all other miscellaneous professional, scientific, and technical services	549,248	59,304	195,178	803,731
Pipeline transportation	104,104	1,618	1,645	107,367
Wired telecommunications carriers	9,657	2,039	499	12,195
Facilities support services	83	38	13	134
Employment and payroll of state govt, non-education	-	-	-	-
Business and professional associations	-	-	-	-
Transit and ground passenger transportation	-	-	-	-
Accounting, tax preparation, bookkeeping, and payroll services	(2,626,811)	(204,184)	(494,584)	(3,325,579)
Total	117,932,772	23,631,843	17,918,546	159,483,161

APPENDIX B: ECONOMIC BENEFITS MODELING

Assumptions and Methodology

In order to conduct the economic benefits analyses, WGL provided NERA with the current expenditure estimates for PROJECTpipes. Specifically, WGL provided estimated spending on manufactured products and purchased services expected to be made locally to commercial businesses that operate within the District of Columbia.[10] PROJECTpipes spending estimates are based on WGL's historical and "planned" spending patterns made to local businesses for the replacement of higher risk natural gas pipelines.

A high-level summary of the total expenditures for WGL's Natural Gas Pipeline Investment Project Capital Grid Project is presented in Table B-1, below. As Table B-1 shows, the estimated spending of PROJECTpipes is approximately $110 million (in 2018 dollars) between 2014 and 2019. Of the $110 million, $66 million represents spending on vendors (including vendors within and outside of District of Columbia), while the remaining $43 million is assumed to be WGL's overhead. Of the $66 million, $38 million (approximately 56% of total spending on vendors and 34% of total spending on PROJECTpipes) represents spending directed to businesses located in the District of Columbia, while the remaining approximately $29 million represents spending directed to businesses not located in the District of Columbia, which includes substantial purchases for specialized equipment that cannot be purchased in the District of Columbia, as discussed below.[11]

Table B-1. WGL's Natural Gas Pipeline Investment Estimated Total Spending (2018$)[12]

Spending Period	Allocations	Contractor Costs	Material	Other Direct[13]	Paving	Grand Total
2014-2019	$15,111,217	$77,019,624	$3,462,942	$235,450	$14,170,767	**$110,000,000**
2020-2024	$42,692,634	$213,463,172	$9,148,422	$0	$39,643,160	**$304,947,388**

Note: For the total spending values are calculated as the sum of spending for each fiscal year within the spending period. The historical spending period 2014-2019 begins on June 1, 2014 and ends on September 1, 2019. The future spending period 2020-2024 begins on January 1, 2020 and ends on December 31, 2024.

Due to the specialized nature of the equipment required for the WGL system, certain manufactured products are not able to be purchased from businesses located in the District of Columbia regions and therefore do not contribute to these local economies. For example, a portion of the underground gas distribution, pipeline is not manufactured in the Washington Metropolitan area.

The spending estimate of $304 million represents WGL's total "planned" spending for the 2020-2024 construction period. Using the historical vendor spending patterns, NERA adjusted the spending on the construction of other new nonresidential structures assuming that the share of spending within the District of Columbia is 56%.[14]

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[10] WGL reported expenditure estimates by the specific manufactured product and services categories that are used by IMPLAN's industry classifications in order to determine the impact of aggregate spending for each industry within the regional economy.

[11] 34% = $37,566,503 / $110,000,000

[12] The total Project is estimated to cost approximately $110 million over the 2014-2019 period. After the adjustments for the local purchases, the total Project estimated cost approximately $71 million for reliance on the IMPLAN economic benefits analysis. Based on the data provided by the WGL,the historical spending period 2014-2019 begins on June 1, 2014 and ends on September 1, 2019.

[13] In future spending, WGL did not have any "planned" spending on "Other Direct" category therefore, the value is equal to $0.

[14] The spending estimate of $304 million represents WGL's total "planned" spending for the 2020-2024 construction period in 2018$s and are used because the economic model functions in real dollars (i.e., nets out effects of inflation).

This analysis has modeled the District of Columbia as a separate geographic region, even though these economies operate within the Washington Metropolitan area.

Further, to the extent that WGL purchases manufactured products and services in other nearby regions (such as Virginia and Maryland) or other U.S. locations, the study understates the economic benefits of PROJECTpipes to the broader Washington Metropolitan area and the overall U.S. economy.

APPENDIX C: IMPLAN MODEL

IMPLAN Model Background

As discussed above, the economic benefits analysis relies on IMPLAN, an economic modeling and software data package.[15] IMPLAN is widely used by government agencies, companies, academics, and others to evaluate the economic impacts of different activities, including for government agencies of the District of Columbia. For example, within the District of Columbia, the Mayor's Power Line Undergrounding Task Force[16], the Metropolitan Washington Airports Authority[17], the District of Columbia Office of Motion Picture and Television Development[18] sponsored studies utilizing IMPLAN. Within Maryland, the Maryland Department of Commerce[19] and the Maryland Transit Administration[20] sponsored studies utilizing IMPLAN.

IMPLAN is an input-output model that mathematically represents a region's economy to predict the effect of changes in one industry on other, related industries. Input-output modeling is widely used to predict the effects of a large series of complicated economic transactions. The IMPLAN database contains economic statistics organized by county, state, and zip code. This granularity of input data enables more accurate predictions by using data that is specific to each region, instead of using estimates from national averages.[21] These statistics are used to measure the effect of a specific project or other economic event on a regional or local economy.

IMPLAN's set of databases and algorithms are operated by a software package that enables specific data inputs under review (*i.e.*, PROJECT*pipes*'s estimated construction costs) to be specifically analyzed. In turn, IMPLAN uses two primary systems to predict economic impacts. First, the social accounting system

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[15] IMPLAN Group LLC, 16740 Birkdale Commons Pkwy, Suite 212, Huntersville, NC 28078. www.implan.com.

[16] Report prepared by Mayor's Power Line Undergrounding Task Force, "Findings and Recommendations" (October 2013), available at: https://oca.dc.gov/sites/default/files/dc/sites/oca/page_content/attachments/Power%20Line%20Undergrounding%20-%20Task%20Force%20Report.pdf

[17] Report prepared for Metropolitan Washington Airports Authority by the Louis Berger Group, Inc., "Technical Report: Economic Impact Study - 2009" (October 2010), available at: http://www.mwaa.com/sites/default/files/2009_economic_impact_study.pdf

[18] Report prepared for the DC Office of Motion Picture and Television Development by ECONorthwest, "An Analysis of the Entertainment and Media Industry in Washington, D.C." (July 2013), available at: http://www.dcfpi.org/wp-content/uploads/2013/09/ECONorthwest-Study.pdf

[19] Report prepared for the Maryland Department of Commerce," The Effect of Federal Employment & Spending in Maryland, February 2012, available at: http://commerce.maryland.gov/Documents/ResearchDocument/FederalFacilitiesAdvisoryBoardFederalImpactReport.pdf

[20] Report prepared for the Maryland Transit Administration Baltimore Development Corporation – The Economic Impact of the North Avenue Rising Proposed Infrastructure Improvements 2016, available at: https://mta.maryland.gov/sites/default/files/Appendix%20C-%20Economic%20Impact%20Analysis.pdf

[21] IMPLAN data files use various federal government data sources, including but not limited to: U.S. Bureau of Economic Analysis Benchmark I/O Accounts of the U.S.; U.S. Bureau of Economic Analysis Output Estimates; U.S. Bureau of Economic Analysis REIS Program; U.S. Bureau of Labor Statistics County Employment and Wages (CEW) Program; U.S. Bureau of Labor Statistics Consumer Expenditure Survey; U.S. Census Bureau County Business Patterns; U.S. Census Bureau Decennial Census and Population Surveys; U.S. Census Bureau Economic Censuses and Surveys; and U.S. Department of Agriculture Crop and Livestock Statistics. See www.implan.com.

describes transactions between producers and intermediate and final consumers. As described by IMPLAN, the social accounting matrix "includes all commodity flows, not only purchases and production of sales of commodities, but transfer payments to and from institutions."[22] The second system is a multiplier model. Multipliers describe the impact of a change. For example, an employment multiplier of 1.9 would suggest for every 10 employees hired in the given industry, 9 additional jobs would be added to the given economic region.

Use of both the social accounting and multiplier systems provides a clear picture of the economy in any given region. The economy's reaction to a defined event, such as the construction of PROJECTpipes, can then be modeled. This economic benefits analysis of PROJECTpipes utilizes construction cost data provided by WGL. WGL's construction cost data was assigned to IMPLAN economic sectors (*i.e.*, industries) for use in the economic benefits analysis. The construction cost data only includes spending on materials and services expected to occur to vendors located in Maryland and District of Columbia regional economy. Therefore, expenditures were excluded when information from WGL indicated that materials or supplies would be purchased outside of Maryland and District of Columbia and delivered to the region to construct PROJECTpipes. IMPLAN then uses well-established patterns of economic activity based on historical data from within the District of Columbia to track where the direct expenditures flow in the District of Columbia economy.

This approach to quantifying economic benefits based on WG's anticipated local spending to the District of Columbia region based on its supply chain is a rigorous approach that provides a realistic estimate of the potential economic benefits from PROJECTpipes.

To the extent that WGL ultimately purchases more material and services in the District of Columbia than initially estimated, the economic benefits results are likely understated. The economic benefits analysis of PROJECTpipes includes the direct, indirect, and induced effects. The overall economic impact arising from the construction of PROJECTpipes equals the sum of its direct, indirect, and induced effects.

[22] IMPLAN User's Guide, Analysis Guide, Data Guide, MIG, Minnesota IMPLAN Group, 1999-2004, p. 74.

WITNESS JACAS
EXHIBIT WG (A)-5

American Gas Association

12/19/2016

State Infrastructure Replacement Activity

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.	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)

	• 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: o 1) Bare steel mains; o 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 o 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.	
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. • In April 2017, the Arizona Corporation Commission adopted a gas rate settlement for Southwest Gas Holdings. A provision of the settlement agreement included the implementation of a Vintage Steel Pipe (VSP) replacement program in order to improve safe and reliable operation of the Company's system. The annual adjustment surcharge for the VSP will be capped at $0.015 per therm per year, and shall apply to all recorded full margin therms sold. The effective period for replacements under the VSP program will be until the effective period of new permanent rates approved by the Commission in the Company's next general rate case application, unless otherwise extended by the Commission. • Also as part of the April 2017 settlement agreement, Southwest Gas will be allowed to expand its Customer Owned Yard Line (COYL) program. The Company will work with Staff to develop a plan for the COYL program, to include revised annual reports. The annual rate adjustment for the COYL program surcharge will continue to be capped at $01.01 per therm per year, and shall apply to recorded full margin therms sold.	Docket No. G-01551A-10-0458 (Southwest Gas) Docket No. G-01151A-16-0107 (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	Docket No. 10AL-963G Docket No. 15AL-0135G (Xcel) 15AL-0299G (Atmos)

	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 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. • Eversource Energy is investing $50 million in Connecticut for gas line improvement projects this 2017. These investments are intended to modernize the company's natural gas distribution system.	Docket No13-06-08 Docket No 10-12-02 (Yankee Gas)
Delaware	• During its 2017 session, the Delaware State Legislature considered a bill that allow for the implementation of an interim rate mechanism—distribution system improvement charge (DSIC)—in order to replace infrastructure that has reached its useful service life or otherwise extend or modify existing distribution facilities in order to eliminate conditions which negatively impact the quality and reliability of service to the customer. • By way of background, the General Assembly had previously enacted a law to provide an efficient interim	SB 80/ SS 1

	rate mechanism to foster investments in needed infrastructure improvements for water utilities, including those mandated by government agencies. This bill extends the same provisions to electric and natural gas utilities. • The legislation was introduced in May 2017 and was carried over into the 2018 legislative session. On March 3, 2018, the bill passed the Senate. On May 9, 2018, the bill was reported out of committee and into the House. On June 6, 2018, the bill passed the House with amendments and was sent to the Senate for concurrence.	
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	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

	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.	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 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.	Docket Nos. 8516 & 29950 (Approving Georgia STRIDE Program) Docket No. 12509-U (Atmos – now Liberty)

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	Natural Gas Consumer, Safety and Reliability Act (Passed by legislature 5/28/13, Signed by Governor Quinn 7/5/13, Public Act 98-0057) Case Number: 14-0292 Nicor Gas Case Number 14-0573 Ameren Illinois QIP

	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.	
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, 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.	Indiana SB 560 (Became Public Law No. 133-2013 on 5/1/2013) 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	Docket No. RMU-2011-0002 (October 2011)

	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. 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 was approved on June 18, 2015. • 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. • As an update, in 2017 the Kansas State Legislature passed S 279, an act relating to the gas safety reliability surcharge. Notably, the language was amended to strike	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

	references in infrastructure "replacements" and replace it with infrastructure system "investments."	
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 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.	CenterPoint Rider RSP Docket U-32987 (Atmos) U-32682 (Entergy Gulf States)
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 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	Maryland SB 8 (Enrolled 5/2/2013, MD Chapter No. 161) Case No. 9331 Case No. 9332 Case No. 9335

	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: o 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 o 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 o 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: o Civil penalties for violations of federal pipeline safety regulations; o Uniform natural gas leak classification for all gas companies; o Grade 1 leaks defined as representing an existing or probably hazard to persons or property and requiring immediate action; o 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; o Grad 3 leaks defined as non-hazardous to persons or property and can be reasonably expected to remain non-hazardous; Requires	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

	utilities to reevaluate during scheduled surveys or within 12 months until the main is replaced;
	o Prioritization of pipeline repairs in school zones
	o Cost recovery for eligible infrastructure replacement programs;
	o Eligible plans shall include, but not be limited to, the following:
	    o 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
	    o Anticipated timeline for the completion of each project—timelines should include a target end date of either not more than 20 years or a 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.
	
	• Eversource Energy is investing $65 million in Massachusetts for gas line improvement projects this 2017. These investments are intended to modernize the company's natural gas distribution system.	

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 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:	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)

	- 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; - spend on average approximately $10.1 million annually for a total of $50.5 million on main replacement for 2016 through 2020; - 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 - 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	Minnesota H.F. 279 (As enrolled, 5/23/2013) Docket No. 14-336 (Xcel)

	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.
	
	• 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.	CenterPoint RRA Plan Docket No. 2015-UN-049 (Atmos SIP)

	• 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: o A rigorous annual review of Atmos Energy's proposed system integrity projects for the next fiscal year and annual rate impact, including o Project spending o Project objective and regulatory requirement being met o Start and completion dates o Historical spending analysis o Project analysis including safety benefit/alternatives considered/engineering support o Annual summary of operational metrics/savings/safety reports o A rolling five-year capital spending plan update including estimated rate impacts o Rate recovery though a combination of fixed and volumetric rates o Estimated impact of the first year of implementation (begins November 2016) is $0.85/month per residential customer	
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 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.	Missouri Statute 393.1009-1015 Missouri SB 240 (Final Passage on 5/9/13; Governor Nixon vetoed this legislation on 7/9/13)

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,	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 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 ◦ 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, 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 ◦ 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. ◦ 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	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)

	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-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 (SMART) 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:
	    o All remaining cast iron and unprotected bare steel mains and associated services;
	    o The most leak prone coated steel mains that are 2" in diameter or less and associated services; and
	    o 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	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)

	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 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
		Docket No. 15-G-0284 (RGE and NYSEG)
		
		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)
		
		Docket No. C-16-G-0257 (National Fuel Gas Distribution)

	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 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 was accepted on November 16, 2016. • In its January 29, 2016 rate filing for its Brooklyn and Long Island service territories (BUG 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, BUG 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. • On December 15, 2016, the New York Public Service Commission (PSC) approved a three-year joint proposal (JP) for National Grid in the above-referenced matter which establishes a Gas Safety and Reliability Surcharge (GSRS) allowing the companies to recover (1) a return on investment, depreciation expense, and O&M expense for disconnects and reconnects of service lines with respect to incremental Leak Prone Pipe (LPP) replacements above the levels funded in base rates; (2) the cost to repair up to 250 incremental system leaks a year in excess of their applicable leak reduction targets; and (3) any positive revenue adjustments earned for LPP productivity, LPP removals and leak repairs. • For each mile of LPP removed above the levels funded in base rates, the GSRS will allow the companies to recover the associated revenue requirement calculated as the lesser of the Companies' average capital and O&M replacement cost per mile of LPP in the Rate Year, or 102% of the capital and O&M unit cost allowances for LPP replacement in the Rate Year. The GSRS will be a per therm surcharge that will appear on a GSRS Statement to be filed with the PSC annually on March 15th. The GSRS would be collected in the delivery rate adjustment (DRA), and would be reconciled annually and included in the DRA from firm sales and firm	

	transportation customers beginning April 1st of the following Rate Year. • Additionally, under the approved JP, BUG will be subject to minimum LPP removal targets of 50 miles in Calendar Year (CY) 2017, 55 miles in CY 2018, or a cumulative three-year total of 180 miles by the end of CY 2019. KGE will be subject to minimum LPP removal targets of 105 miles in CY 2017, 125 miles in CY 2018, or a cumulative three-year total of 405 miles by the end of CY 2019. The removal targets in the Joint Proposal represent a compromise between the slightly lower levels generally proposed by the companies and the slightly higher levels generally proposed by Staff. • In January 2017, Assemblyman Rodriguez (D) introduced AB 656. The bill requires gas corporations to file a plan with the PSC addressing aging or leaking pipelines within their service territory and outlining plans for the replacement of such pipelines. Further, it requires gas corporations to file with the commission a plan to address aging or leaking pipelines within its respective territory in the interest of public safety and reducing lost and unaccounted for gas through a reduction in gas leaks; Requires plans be filed no later than October 31, 2018. • In January 2017, Assemblyman Dinowitz (D) introduced AB 2320. The bill requires gas corporations to file a gas safety report on or before March 15 annually; The department shall review reports to monitor gas corporations' pipeline replacement projects and all other activities related to providing safe and reliable gas service; Reports shall include a thorough description and explanation of the strategic planning and decision-making methodology used to determine and prioritize pipeline replacement projects, a description of operation and maintenance activities, a description of inspections of transmission and distribution lines, and any other information as required by the department; Reports shall also include information that indicates whether replacement projects were completed by its own employees or by outside contractors • In April 2017, the New York Public Service Commission authorized National Fuel Gas Distribution a $5.9 gas distribution rate increase premised on a 8.7% ROE. In its initial filing, National Fuel proposed that it be provided a system upgrade and modernization tracking mechanism. The Company justified its inclusion as allowing for the efficient recovery of carrying costs associated with the replacement of Leak Prone Pipe (LPP) above the targeted amounts planned for replacement. The Company proposed a 200 basis point repeating, cumulative positive incentive to accelerate its LPP replacement. • Staff supported the company's request for a surcharge, but maintained that it should cover only those costs specific to LPP replacement. In this manner, the surcharge would be consistent with surcharges provided to other LDCs in accord with Commission Policy. Staff	

	also proposed that the surcharge would sunset after three years, be limited to the forecast unit cost per mile and include a positive incentive limited to 10 basis points per year for incremental LPP beyond 105 miles. The Company refuted some of the Staff's modifications, claiming that some of the limitations were not consistent with the Commission's policy of replacing LPP as quickly as practicable. • In its final order, the Commission adopted a LPP tracking mechanism limited to incremental LPP costs that reflect the approved pre-tax rate of return, depreciation rates, property tax rates and uncollectible rates. The surcharge will be available for recovery of the Company's LPP costs for a period of three years or until modified by the Commission.	
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. • On October 28, 2016, the North Carolina Utilities Commission (NCUC) adopted an amended stipulation which authorized Public Service Company of North Carolina (PSNC) an Integrity Management Tracker,	NC H 119 (Signed by Governor 5/17/13) Docket No. G-9, Sub 631 (Piedmont) Senate Bill 434 (died)

	which will allow PSNC to recover integrity management plant investment net of excluded costs. The NCUC defined excluded costs as the portion of capital expenditures related to system enhancement and system strengthening of a capital project that results in more volumes, higher pressure, or larger pipe sizes. At the time of PSNC's next general rate case proceeding, all prudently incurred Integrity Management Plant Investment associated with this Rider will be included in base rates and the excluded costs will be eligible for inclusion in recoverable rate base.	
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. • 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.	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) Case No 11-5515-GA-ALT (Columbia Gas) Case No. 11-3238-GA-RDR (Dominion) 15-0362-GA-ALT (Dominion)

	• 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.	
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	Docket No. UG-201 (Avista) Docket No. UG-177 (NW Natural) UM 1722 (PUC Investigation Into Recovery of Safety Costs)

	Program, the Transmission Integrity 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.	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)

	• 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. • 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: o 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; o Deploy automated meter reading technology; o Undertake various upgrades and improvements to M&R stations and related M&R equipment; o 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	Public Chapter No. 245 (HB 191) Docket No. 1400146 (Atmos Energy)

	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.	
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. • In 2013, the three-year Infrastructure Replacement Adjustment mechanism was expanded and continued as a pilot program until the next general rate case, when it again will be reviewed.	Docket No. 09-057-16 Docket No. 13-057-05
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.	Code of Virginia: 56-603, 56-604 (Implementation of SAVE Act) PUE-2010-000871 (Washington Gas) PUE-2012-00096 (Washington Gas)

	• 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.
	
	• 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.
	
	    o 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.
	
	    o 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.
	
	    o 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
		PUE-2015-00017
		(Washington Gas)
		
		PUE-2012-00012
		(Virginia Natural Gas)
		
		PUE-2011-00049
		(Columbia Gas of Virginia)

	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.	
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. • 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.	Docket No. PG-120715 (12/31/2012)
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	SB 390 Docket No. 15-0003-G-42T (Mountaineer Gas) Docket No. 15-1600-G-390P (Dominion Hope)

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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.

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<td>Docket No. 15-1256-G-390P (Mountaineer IREP)</td>
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	• 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 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, 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 Dth 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.	DOCKET NO. 30003-66-GA-15

U.S. Department
of Transportation

**Pipeline and Hazardous
Materials Safety
Administration**

Administrator

1200 New Jersey Avenue SE
Washington, DC 20590

DEC 19

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

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

Dear Mr. Clark and Ms. Honorable:

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

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

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

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

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

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

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

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

Regards,

Cynthia L. Quarterman

Enclosure: White Paper

UNITED STATES DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

White Paper on State Pipeline Infrastructure Replacement Programs

Prepared for

National Association of Regulatory Commissioners

December 2011

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Introduction

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

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

Executive Summary

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

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

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

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

I. General Ratemaking Principles

Federal Ratemaking

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

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

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

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

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

State Ratemaking

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

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

Rates for Investor-Owned Local Gas Distribution Companies

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

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

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

Rates for Publicly-Owned Local Gas Utility Systems

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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[3] 72 FR 51301.

[4] 73 FR 11695.

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

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

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

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

III. <u>Using Traditional Ratemaking Authority to Establish Infrastructure Replacement Programs</u>

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

New Jersey

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

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

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

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

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

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

Kentucky

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

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

[8] Specifically, § 48: 2-23 states:

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

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

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

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

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

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

Indiana

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

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

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

IV. Using Specific Ratemaking Authority to Establish Infrastructure Replacement Programs

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

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

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

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

Infrastructure Replacement Surcharge: Missouri, Kansas, and Nebraska

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

Missouri and Kansas

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Nebraska

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

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

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

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

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

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

- A list of eligible projects;

- A description of the projects;

- The location of the projects;

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

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

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

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

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

Interim Rate Adjustment: Texas and Virginia

<u>Texas</u>

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

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

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

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

Virginia

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

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

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

[20] Tex. Util.Code Ann. § 104.301.

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

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

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

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

- Enhance safety or reliability by reducing system integrity risks associated with customer outages, corrosion, equipment failures, material failures, natural forces, or other outside force damage;

- Do not increase revenues by directly connecting the infrastructure replacement to new customers;

- Reduce or have the potential to avoid greenhouse gas emissions; and

- Are not included in the natural gas utility's rate base in its most recent rate case or in the rate base filed with a performance based regulation plan.

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

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

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

In summary, the Virginia SAVE Act:

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

Alternative Rate Plan: Ohio

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

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

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

California

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

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

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

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

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

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

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

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

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

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

V. CONCLUSIONS

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

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

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

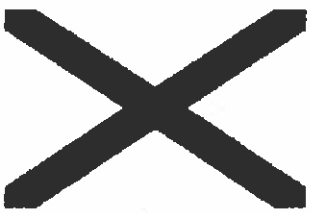
PHMSA is focused on this issue in implementing its integrity management requirements for natural gas transmission and distribution lines and as part of the state certification process. PHMSA is willing to provide assistance to State public utility commissions who are seeking to establish or improve programs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

Appendix I:

Additional Information on State Pipeline Infrastructure Replacement Programs

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

Alabama



STATE AUTHORITY: Alabama Public Service Commission

PROGRAM: Rate Stabilization and Equalization Plan

PARTICIPANTS: Mobile Gas

Alabama Gas

Arkansas

STATE AUTHORITY: Arkansas Public Service Commission

PROGRAM: Main Replacement Program Rider

PARTICIPANTS: CenterPoint Energy

California

STATE AUTHORITY: California Public Utilities Commission

PROGRAM: Comprehensive Implementation Plan

PARTICIPANT: San Diego Gas and Electric

PROGRAM: Pipeline Safety Enhancement Plan

PARTICIPANTS: Southern California Gas

Pacific Gas & Electric

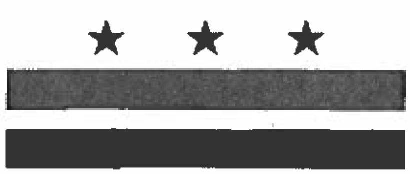
Colorado

STATE AUTHORITY: Colorado Public Service Commission

PROGRAM: Pending

PARTICIPANT: Colorado Public Service Company

District of Columbia



STATE AUTHORITY: District of Columbia Public Service Commission

PROGRAM: Pending

PARTICIPANT: Washington Gas

Georgia

STATE AUTHORITY: Georgia Public Service Commission

PROGRAM: Pipeline Replacement Program

PARTICIPANT: Atlanta Gas Light

PROGRAM: Pipeline Replacement Surcharge

PARTICIPANT: Atmos Energy

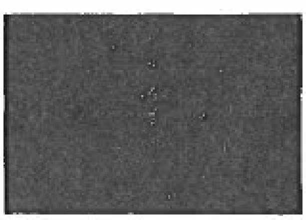
Illinois

STATE AUTHORITY: Illinois Commerce Commission

PROGRAM: Infrastructure Cost Recovery Rider

PARTICIPANT: Integrys Peoples Gas

Indiana



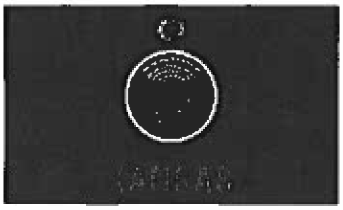
STATE AUTHORITY: Indiana Utility Regulatory Commission, Gas Division

PROGRAM: Pipeline Safety Adjustment

PARTICIPANT: Vectren Energy Delivery of Indiana, Inc.

Vectren South – SICEGO

Kansas



STATE AUTHORITY: Kansas Corporation Commission

PROGRAM: Accelerated Pipeline Replacement Rider

PARTICIPANT: Black Hills Energy

PROGRAM: Gas System Reliability Surcharge Rider

PARTICIPANT: Kansas Gas Service

Atmos Energy

LAWS: Gas Safety and Reliability Policy Act

Kentucky

STATE AUTHORITY: Kentucky Public Service Commission

PROGRAM: Accelerated Main Replacement Program Rider

PARTICIPANT: Columbia Gas Kentucky

PROGRAM: Pipeline Replacement Program

PARTICIPANT: Delta Natural Gas

PROGRAM: Accelerated Main Replacement Program

PARTICIPANT: Duke Energy Kentucky

PROGRAM: Pipeline Replacement Program Rider

PARTICIPANT: Atmos Energy

LAWS: KRS 278.509

Louisiana

STATE AUTHORITY: Louisiana Public Service Commission

PROGRAM: Rate Stabilization Tariffs

PARTICIPANTS: Atmos Energy – LA

Entergy

CenterPoint Energy

Maryland

STATE AUTHORITY: Maryland Public Service Commission

PROGRAM: Pending

PARTICIPANTS: Washington Gas

Massachusetts

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

PROGRAM: Targeted Infrastructure Reinvestment Factor

PARTICIPANTS: Columbia Gas Massachusetts

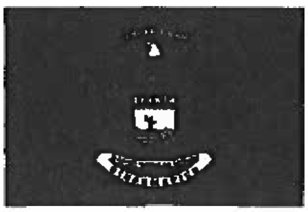
National Grid Massachusetts

New England Gas

PROGRAM: Pending

PARTICIPATNT: Fitchburg Gas and Electric

Michigan

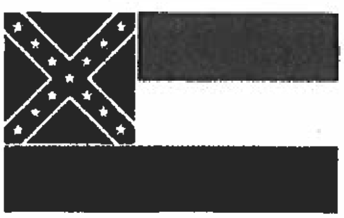


STATE AUTHORITY: Michigan Public Service Commission

PROGRAM: Main Replacement Program Rider

PARTICIPANT: SEMCO Energy

Mississippi



STATE AUTHORITY: Mississippi Public Service Commission

PROGRAM: Rate Stabilization Tariffs

PARTICIPANTS: Atmos Energy – MS

CenterPoint Energy

Missouri

STATE AUTHORITY: Missouri Public Service Commission

PROGRAM: Infrastructure System Replacement Surcharge

PARTICIPANTS: Ameren Missouri

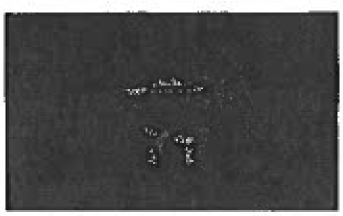
Laclede Gas

Missouri Gas Energy

Atmos Energy - MO

LAWS: MO ST 393.1009 *et seq.*

Nebraska



STATE AUTHORITY: Nebraska Public Service Commission

PROGRAM: Infrastructure System Replacement Cost Recovery Charge

PARTICIPANT: Black Hills Energy

LAWS: NE ST 66-1865

NE ST 66-1866

NE ST 66-1867

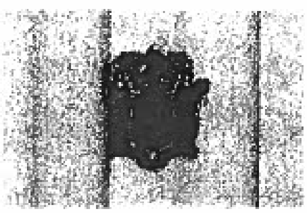
New Hampshire

STATE AUTHORITY: New Hampshire Public Utilities Commission

PROGRAM: Cast Iron Bare Steel Replacement Program

PARTICIPANT: National Grid Energy North

New Jersey



STATE AUTHORITY: New Jersey Board of Public Utilities

PROGRAM: Utility Enhancement Infrastructure Rider

PARTICIPANT: Elizabethtown Gas

PROGRAM: Accelerated Infrastructure Investment Program

PARTICIPANT: New Jersey Natural Gas

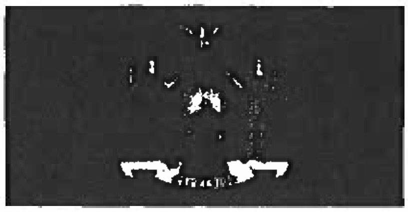
PROGRAM: Capital Adjustment Charge

PARTICIPANT: Public Service Electric and Gas

PROGRAM: Capital Investment Recovery Tracker

PARTICIPANT: South Jersey Gas

New York

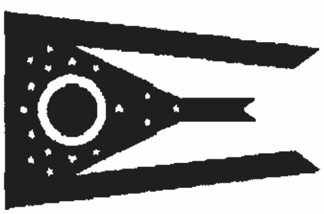


STATE AUTHORITY: New York State Public Service Commission

PROGRAM: LIMITED INFRASTRUCTURE REPLACEMENT

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

Ohio



STATE AUTHORITY: Ohio Public Utility Commission

PROGRAM: Infrastructure Replacement Program

PARTICIPANTS: Columbia Gas Ohio

PROGRAM: Pipeline Infrastructure Replacement Cost Recovery Charge

PARTICIPANT: Dominion East Ohio

PROGRAM: Accelerated Main Replacement Program Rider

PARTICIPANT: Duke Energy Ohio

PROGRAM: Distribution Replacement Rider

PARTICIPANT: Vectren Energy Delivery of Ohio, Inc.

Oklahoma

STATE AUTHORITY: Oklahoma Corporation Commission

PROGRAM: Rate Stabilization Tariffs

PARTICIPANTS: Oklahoma Natural Gas

CenterPoint Energy

Oregon

STATE AUTHORITY: Oregon Public Utility Commission

PROGRAM: Replacement Projects

PARTICIPANT: Avista Corp

Rhode Island

STATE AUTHORITY: Rhode Island Public Utilities Commission

PROGRAM: Capital Expenditure Tracker Factor, Accelerated Replacement Program

PARTICIPANT: National Grid Narragansett Gas

South Carolina

STATE AUTHORITY: South Carolina Office of Regulatory Staff

PROGRAM: Rate Stabilization Tariff

PARTICIPANTS: Piedmont Natural Gas

South Carolina Electric and Gas

Texas

STATE AUTHORITY: Texas Railroad Commission

PROGRAM: Gas Reliability Infrastructure Program

PARTICIPANTS: CenterPoint Energy

Atmos Energy – TX

Texas Gas Service

PROGRAM: Rate Stabilization Tariffs

PARTICIPANTS: Atmos Energy – TX

CenterPoint Energy

LAWS: Tex. Util.Code § 104.301

Utah

STATE AUTHORITY: Utah Public Service Commission

PROGRAM: Infrastructure Rate Adjustment Tracker

PARTICIPANT: Questar Gas

Virginia

STATE AUTHORITY: Virginia State Corporation Commission

PROGRAM: Pending

PARTICIPANT: Washington Gas

LAWS: SAVE Act

VERIFICATION

COUNTY OF FAIRFAX)
) SS:
COMMONWEALTH OF VIRGINIA)

WAYNE A. JACAS, being first duly sworn, deposes and says that he is the WAYNE A. JACAS whose Testimony accompanies this Verification; that such testimony was prepared by him or under his supervision; that he is familiar with the contents thereof; that the facts set forth therein are true and correct to the best of his knowledge, information and belief; and that he does adopt the same as true as his sworn testimony in this proceeding.

JESSICA T HERAS
NOTARY PUBLIC
REGISTRATION # 7348912
COMMONWEALTH OF VIRGINIA
MY COMMISSION EXPIRES
MAY 31, 2022

WAYNE A. JACAS

Subscribed and sworn to before me this 19th day of November 2018.

NOTARY PUBLIC

WITNESS STUBER
EXHIBIT WG (B)

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE
DISTRICT OF COLUMBIA

IN THE MATTER OF APPLICATION OF WASHINGTON GAS LIGHT COMPANY FOR APPROVAL OF A REVISED ACCELERATED PIPE REPLACEMENT PROGRAM	FORMAL CASE NO. 1115

WASHINGTON GAS LIGHT COMPANY
District of Columbia

DIRECT TESTIMONY OF AARON C. STUBER
Exhibit WG (B)
(Page 1 of 1)

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Exhibits

EXHIBIT WG (B)

WASHINGTON GAS LIGHT COMPANY
DISTRICT OF COLUMBIA
<u>DIRECT TESTIMONY OF AARON C. STUBER</u>

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

A. My name is Aaron C. Stuber and I am Director of Technical Engineering Services at Washington Gas Light Company ("Washington Gas" or "Company"). My business address is 6801 Industrial Road, Springfield, VA 22151.

I. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science degree in Chemical Engineering from the University of Tulsa and am a Professional Engineer in the states of Oklahoma, Virginia and Maryland. In addition, I am a Project Management Professional. I have more than 23 years of engineering, construction, operations and environmental experience in the natural gas industry, 17 of which are with Washington Gas. My experience with Washington Gas includes various positions of increasing responsibilities within Corporate Engineering. Prior to my employment with Washington Gas, I was employed by Domain Engineering as a Senior Process Engineer and CETCON as an Environmental Specialist.

Q. HAVE YOU SUBMITTED TESTIMONY IN PROCEEDINGS BEFORE REGULATORY COMMISSIONS?

A. Yes. I have previously submitted testimony to the Maryland Public Service Commission ("Maryland Commission") in Case No. 9335, when the Company sought and received approval for its Maryland "STRIDE" ("Strategic Infrastructure Development and Enhancement") Plan. In addition, I submitted testimony to the Maryland Commission in Case No. 9486, where the Company is seeking to extend its Maryland "STRIDE" Plan (this case is currently pending before the Commission). I have also appeared several times before the Maryland Commission during Administrative Meetings in support of various "STRIDE" filings. In addition, I have submitted testimony to the Virginia State Corporation Commission in PUE-2015-00017 and PUE-2017-00102, when the Company sought and received approval for its Virginia "SAVE" ("Steps to Advance Virginia's Energy") Plan.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of this Direct Testimony, with an accompanying exhibit, is to provide details and justification for acceleration of transmission facilities replacement programs included in the Company's second five-year PROJECT*pipes* Program (which the Company refers to as "PIPES 2" or "PIPES 2 Plan") and to recommend that the Commission approve Washington Gas's PIPES 2 Plan.

Q. PLEASE BRIEFLY SUMMARIZE YOUR DIRECT TESTIMONY.

A. The Company is proposing to add a transmission component to its PIPES 2 Plan, consisting of five distinct replacement programs, which are described below and detailed in the exhibit attached to my Direct Testimony.

III. IDENTIFICATION OF EXHIBITS

Q. DO YOU SPONSOR ANY EXHIBITS?

A. Yes, Exhibit WG (B)-1 provides the supporting information for the new transmission programs discussed below.

IV. TRANSMISSION FACILITIES REPLACEMENT PROGRAMS

Q. SHOULD TRANSMISSION FACILITIES BE CONSIDERED ELIGIBLE INFRASTRUCTURE REPLACEMENTS UNDER THE PIPES 2 PLAN?

A. Yes. All of the facilities included in the proposed transmission programs under the PIPES 2 Plan were selected for replacement to reduce risk and enhance the safety and reliability of the Company's transmission system which serves District of Columbia customers.

Q. IS THE INCLUSION OF TRANSMISSION FACILITIES IN PIPES 2 CONSISTENT WITH THE ELIGIBILITY CRITERIA THAT THE COMMISSION ESTABLISHED IN APPROVING THE FIRST FIVE YEARS OF PROJECTPIPES ("PIPES 1")?

A. With some modification to Criterion No. 4 to reflect the difference in distribution and transmission facilities (noted below), the inclusion of transmission facilities for PIPES 2 is consistent with the following Commission-approved eligibility criteria from PIPES 1[1]:

1. Expenses incurred on or after June 1, 2014;
2. Project assets are not included in the Company's rate base in its most recent rate case;

[1] Formal Case Nos 1093 and 1115, Order No.17431 at 33 (March 31, 2014), as amended by Order No. 17500 at 8 and 12 (May 30, 2014).

3. The Project does not increase revenues by directly connecting the infrastructure replacement to new customers; and
4. The Project is needed to reduce risk and enhance safety.

Criterion No. 4 for PIPES 1 reads as follows: "The Project is needed to reduce risk and enhance safety by replacing aging corroded or leaking cast iron mains, bare and/or unprotected steel mains and services, and black plastic service in the distribution system."[2] The Company proposes to modify Criterion No. 4, as noted above, because the only distinction between distribution and transmission facilities is with respect to function, *i.e.*, transmission plant is not distribution plant and some of the physical materials are the same or different. However, these are minor distinctions given the overall Commission policy goal to reduce risk and enhance safety through accelerated infrastructure replacement. Moreover, the inclusion of transmission facilities reduces risk and enhances safety by installing remote controlled valves and replacing: high-risk pipeline segments, pipeline components that have aged and are difficult to operate, and pipeline components that will enable the use of a better, more sophisticated transmission pipeline assessment method.

Q. HAVE TRANSMISSION FACILITIES BEEN INCLUDED IN THE COMPANY'S ACCELERATED PIPE REPLACEMENT PROGRAMS IN VIRGINIA AND MARYLAND?

A. Yes, transmission facilities have been included and approved in the Company's accelerated pipe replacement programs in both Virginia and

[2] Order No.17431 at 33.

Maryland. Based on the Company's experience and analysis identifying suitable transmission facilities for replacement, and inclusion in Virginia and Maryland accelerated replacement programs, the Company has identified transmission facilities for inclusion in the PIPES 2 Plan. This inclusion will reduce risk and enhance safety and reliability, as described in more detail in both my testimony below and the accompanying exhibit, and should be approved by the Commission.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF THE COMPANY'S PROPOSED PROGRAMS RELATED TO THE FACILITIES REPLACEMENT PROJECTS ON THE COMPANY'S TRANSMISSION SYSTEM.

A. The Company is proposing to include the following five separate programs related to enhancing safety on its transmission system in its PIPES 2 Plan. The rationale and support for selecting these transmission replacement programs are detailed in Exhibit WG (B)-1, included with this Direct Testimony.

- Transmission Program 1 – U.S. Department of Transportation ("DOT") Transmission and High-Pressure Pipe Replacement which will focus on the replacement of transmission and high-pressure pipe;
- Transmission Program 2 – Remote Control Valve ("RCV") Installation, which will involve the installation of new or retrofit of existing valves to be operated remotely in case of emergency to enhance safety;
- Transmission Program 3 – DOT Transmission and High-Pressure Block Valve Replacement, which will involve the replacement of transmission or high-pressure valves that are used, in cases of emergency, to safely control/eliminate pressure to specific areas as required and used to reduce pressure allowing a variety of construction activities to occur;

- Transmission Program 4 – DOT Transmission and High-Pressure Valve Riser Replacement, which will replace transmission and high-pressure gauge lines that are installed to monitor the pressures on the transmission system when operating the valves and grease lines that are used to lubricate the valves; and
- Transmission Program 5 – Replacement of Components of DOT Transmission and High-Pressure Pipes to Enable the Use of In-line Inspection ("ILI") Tools. This program will focus on the replacement of non-piggable[3] components of pipelines. The ILI capability will identify areas where corrosion or pipe defects exist.

Q. WILL DISTRICT OF COLUMBIA CUSTOMERS BE RESPONSIBLE FOR THE ENTIRETY OF THE ESTIMATED COSTS DESCRIBED IN THIS TESTIMONY?

A. No. The Company's transmission and high-pressure system, which consists of 49 distinct "strips," is designed to support the entirety of the Washington Gas operating system. The overwhelming majority of these transmission pipeline strips provide service and support to the Company's entire system, and therefore, the cost of designing, installing and maintaining these strips is allocated to customers in Maryland, Virginia and the District of Columbia. As discussed in Witness Lawson's testimony, the Company's District of Columbia jurisdiction is allocated approximately 17% of these costs, which is based on the average of Peak Day and Annual Normal Weather Therm Sales.

[3] A piggable pipeline is a pipeline that is designed to allow a standard in-line inspection tool to negotiate it, which normally requires a constant bore, sufficiently long radius bends and traps to launch and receive the pigs.

Some of the Company's transmission system contains pipelines known as "spur lines," which support a specific jurisdiction of the Company's system. The natural gas delivered through these spur lines does not cross into other jurisdictions. Because these spur lines support a specific jurisdiction of the Company's system, the cost of installing and maintaining these pipelines are directly assigned to the jurisdiction in which they are located.

As discussed below, with respect to the five proposed PIPES 2 Plan transmission programs, whether there will be a District of Columbia jurisdictional allocation of costs, or a direct assignment of costs to the District of Columbia customers, will depend on the nature of the transmission plant included in the project. In this filing, all the identified transmission projects are located on the interconnected transmission and are considered allocable.

Q. PLEASE GIVE A BRIEF SUMMARY OF TRANSMISSION PROGRAM 1 – DOT TRANSMISSION AND HIGH-PRESSURE PIPE REPLACEMENT.

A. There are approximately 674 miles (177 miles DOT transmission and 497 miles high-pressure) of coated and protected steel transmission mains active in Washington Gas's service territory. Approximately 58% of these mains were installed from 1940 to 1979. Due to their age, as well as safety and supply reliability considerations, Washington Gas proposes to replace certain higher risk pipe in the transmission system. This program is described in detail in Exhibit WG (B)-1.

The Company proposes to spend approximately $109.1 million on this program through 2024. Because transmission and high-pressure pipelines are categorized as allocable transmission plant, District of Columbia customers will only be responsible for the District of Columbia allocated portion of the projects as described by Company Witness Lawson. The District of Columbia allocated share of the transmission and high-pressure program is approximately $18.4 million of transmission plant.

Q. PLEASE GIVE A BRIEF SUMMARY OF TRANSMISSION PROGRAM 2 – REMOTE CONTROL VALVE INSTALLATION.

A. RCVs allow for remote operation of valves located on the transmission system to be operated by a qualified technician from a remote location. The RCV PIPES 2 Plan program allows Washington Gas to shut off critical valves around the system from the Gas Control room in the Company's Springfield Center in case of an emergency. For example, in the case of a pipeline rupture, the use of RCVs would enable Washington Gas to more quickly isolate high-risk pipe segments and shut off gas flow. These segments were selected based on an engineering analysis that involved a risk-based evaluation of pipeline segments that operate at pressures that produce a ≥25% specified minimum yield strength ("SMYS") on the pipe and are located in high consequence areas ("HCAs") and Class 3 and 4 locations as defined in §192.5 and §192.903 of the DOT regulations.

The estimated budget for 2020 through 2024 for RCV installation is approximately $16.3 million. Because RCVs are categorized as allocable transmission plant, District of Columbia customers will only be responsible for the District of Columbia allocated portion of the cost, as described by Company Witness Lawson. The District of Columbia allocated share of the RCV program is approximately $2.8 million of transmission plant.

Q. PLEASE GIVE A BRIEF SUMMARY OF TRANSMISSION PROGRAM 3 – DOT TRANSMISSION AND HIGH-PRESSURE BLOCK VALVES.

A. There are over 1,100 transmission and high-pressure valves in the Company's system, which are inspected, internally lubricated, cleaned, and tested annually, in accordance with Company operations and maintenance ("O&M") procedures. However, due to their age, certain valves have become increasingly difficult to operate. The Company has compiled a list of valves that are difficult to operate, and/or not able to provide positive shutoff, and has initiated a multi-year replacement program for these valves.

The estimated budget for 2020 through 2024 for the replacement of block valves is approximately $6.4 million. Because block valves are categorized as allocable transmission plant, District of Columbia customers will only be responsible for the District of Columbia allocated portion of the costs, as described by Company Witness Lawson. The District of Columbia allocated share of the block valve replacement program is approximately $1.1 million of transmission plant.

Over the longer term, and subject to approval in future PROJECT*pipes* Plans, the Company plans to continue the block valve replacement program beyond the timeframe of PIPES 2 as the valves continue to age.

Q. PLEASE DESCRIBE TRANSMISSION PROGRAM 4 – RISER REPLACEMENT FOR DOT TRANSMISSION AND HIGH-PRESSURE VALVES.

A. Transmission and high-pressure valves are equipped with steel gauge risers and grease risers that are prone to corrosion. Washington Gas proposes to proactively replace these risers. The pressure gauge risers are located both upstream and downstream of a mainline valve and are used to monitor pipeline pressure during normal mainline valve maintenance and construction activities as well as for emergency conditions when pressure and/or flow must be controlled or throttled. The grease risers are located on the valve body and are used to internally lubricate the valve during annual maintenance. Through this PIPES 2 program, Washington Gas seeks to proactively replace both gauge and grease risers that have corroded in order to prevent high-pressure gas from leaking.

These risers are wrapped ¾" steel pipe that are accessible via a below-grade valve box and are continuously exposed to moisture. As risers are not completely buried, they cannot be cathodically protected. Also, many of these valves are located in streets and highways and are impacted by road salt. Under these conditions, valve risers begin to corrode and over time need to be replaced. The Company proposes to continue to proactively replace these risers before they leak and possibly create an emergency situation that increases response and remediation time and, more importantly, risk to the public, as well as responding Company employees. Also, leaks attributed to corroded valve risers can negatively impact the greenhouse gas ("GHG") affect.

The estimated budget for 2020 through 2024 for valve risers is approximately $722,000. Because valve risers are categorized as allocable transmission plant, District of Columbia customers will only be responsible for the District of Columbia allocated portion of the costs, as described by Company Witness Lawson. The District of Columbia allocated share of the valve riser program is approximately $122,000 of transmission plant.

Q. PLEASE DESCRIBE TRANSMISSION PROGRAM 5 – REPLACEMENT OF COMPONENTS OF DOT TRANSMISSION AND HIGH-PRESSURE PIPES TO ENABLE THE USE OF IN-LINE INSPECTION TOOLS.

A. The Code of Federal Regulations ("CFR"), 192 Subpart O, requires a pipeline operator to assess the integrity of its transmission pipelines every seven years. The Company currently meets this requirement by conducting External Corrosion Direct Assessments ("ECDA") in its HCAs on the majority of its transmission pipelines. Running ILI tools internally through these pipelines will allow the Company to identify more potential integrity issues such as corrosion, dents and manufacturing defects. These pipelines contain some appurtenances including valves that are not full port and certain fittings, such as short radius elbows and large diameter non-barred tees that do not allow an ILI tool to pass through the pipeline. The Company proposes to replace these appurtenances to enhance safety by reducing system integrity risks. In addition, pig launchers and receivers will be installed so that the ILI tools can be inserted into and retrieved from the pipeline.

This transmission program is an infrastructure replacement program which directly impacts and enhances the safety and integrity of the system by identifying areas where corrosion or pipe defects exist so that they can be remediated when warranted. In addition, the remediation of corrosion or pipe defects reduces the potential for GHG emissions due to leaks, which could be considerable due to the high operating pressures of high-pressure and transmission pipe.

The estimated budget for 2020 through 2024 for the replacement of non-piggable pipeline components is $34.5 million. Because replacing non-piggable components on pipelines is categorized as allocable transmission plant, District of Columbia customers will only be responsible for the District of Columbia allocated portion of the costs, as described by Company Witness Lawson. The District of Columbia allocated share of the ILI program is $5.8 million of transmission plant.

Q. WILL THE WORK PERFORMED UNDER THE PROPOSED PROGRAMS BE PERFORMED BY THE EXISTING WORKFORCE?

A. The work under the five transmission and high-pressure programs will be performed by the Company's steel alliance contractors, which are able to add crews as necessary to accommodate the proposed programs. When additional crews are required, there is potential for creating new jobs in the District of Columbia to perform this work.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

WITNESS STUBER
EXHIBIT WG (B)-1

WASHINGTON GAS'S PIPES 2 PLAN FOR TRANSMISSION FACILITIES REPLACEMENT

Background:

The purpose of this report is to provide details on the five transmission system PIPES 2 programs proposed by Washington Gas. These programs are:

- Program 1 – U.S. Department of Transportation ("DOT") Transmission and High-Pressure Pipe Replacement
- Program 2 – Remote Control Valve Installation
- Program 3 – DOT Transmission and High-Pressure Block Valve Replacement
- Program 4 – DOT Transmission and High-Pressure Valve Riser Replacement
- Program 5 – Replacement of Components of DOT Transmission and High-Pressure Pipes to Enable the Use of In-line Inspection ("ILI") Tools

PROGRAM 1 – DOT Transmission and High-Pressure Pipe Replacement

Introduction:

There are approximately 674 miles (177 miles DOT transmission and 497 miles high pressure) of coated and protected steel mains that make up the transmission system delivering gas throughout the Company's service territory. As part of the Company's Transmission Integrity Management Program ("TIMP") and consistent with the Pipeline and Hazardous Materials Safety Administration's ("PHMSA") recommendations for maximum allowable operating pressure ("MAOP") verification, Washington Gas extensively reviewed and collected data for the Company's DOT transmission[1] and high-pressure[2] pipelines. The documents that were reviewed included, but were not limited to, original installation records, or "as-builts," pipeline procurement records, field notes, historical memos, prior studies of the transmission system, pressure test records, up-

[1] DOT transmission pipe is pipe with MAOP equal to or greater than 20 percent of specified minimum yield strength ("SMYS")

[2] High-pressure pipeline is defined as having MAOP greater than 60 pounds per square inch (psig) and less than 20 percent SMYS.

rating records, laboratory reports, x-ray records and project binders. The review was conducted to understand the original installation parameters of the DOT transmission and high-pressure pipelines that constitute the transmission mainlines and laterals. Washington Gas refers to the mainlines of the transmission and high-pressure system as "strips." There are currently 49 distinct strips throughout Washington Gas's system. The strips are comprised of sections of both DOT transmission and high-pressure mains.

The majority of these strips support the entire Washington Gas system and all costs associated with operating and maintaining these strips are allocated to customers in three jurisdictions served by Washington Gas: Virginia, Maryland and the District of Columbia. As discussed in Witness Lawson's testimony, the Company's District of Columbia jurisdiction is allocated approximately 17% of these costs, which is based on the average of Peak Day and Annual Normal Weather Therm Sales. Some transmission strips only provide natural gas to a specific jurisdiction surrounding their physical location and are known as "spur lines." These spur lines do not support the entirety of the Washington Gas system and all costs associated with operating and maintaining these pipes are directly assigned to the jurisdiction in which they are located.

Based on the Company's review of its DOT transmission and high-pressure pipelines, at this time there are two transmission strips identified for continued full or partial replacement. The Company anticipates identifying additional strips for replacement in the future as a result of the implementation of proposed new PHMSA regulations, integrity management assessments and continued MAOP records review for those pipelines. The projects identified for this program are described below.

1. Strip 1

The Strip 1 mainline runs within the Virginia Department of Transportation ("VDOT") right-of-ways from western Fairfax County (near Dranesville), through Falls Church, to eastern Fairfax County (near Seven Corners) along Leesburg Pike (Route 7) and Arlington Boulevard (Route 50). The Strip 1 mainline is a DOT transmission and high-pressure pipeline, which includes 16-inch and some 24-inch diameter lines, was constructed in 1948 with welded joints and mechanically (Dresser style) coupled joints.

The majority (approximately 95%) of the materials used for construction of this line were low frequency electric resistance welded ("ERW") pipe.[3] The pipeline has 325 and 260 psig MAOPs that are separated by a pressure reducing station. These MAOPs produce a specified minimum yield strength ("SMYS") ranging from 11% to 29% and were established via the "grandfather clause" (49 CFR §192.619(c)). Over the years, Washington Gas has upgraded the Strip 1 pipeline, including the installation of weld-over sleeves on the Dresser couplings for reinforcement. In addition, portions of the mainline have been up-rated four times in order to increase the capacity of the pipeline.

Because this pipeline is the oldest transmission line in the Company's system, the majority of its MAOP was determined pursuant to a section of 49 CFR §192.619(c) of the DOT regulations that provides for establishing MAOP by relying on previous operating history and does not provide a stated safety factor between the current MAOP and the highest test pressure as required by other sections in this subpart.

The Company cannot conduct a hydro test to requalify this line in order to establish a safety factor because of the possibility of water leaking past the Dresser couplings and into the weld-over sleeves. Any water that might leak into the weld-over sleeve would not be able to be detected and removed, causing corrosion concerns. In addition, there are risks associated with hydro testing a 69 year old pipeline, like the Strip 1 mainline, which includes many taps and spurs connected to regulator stations feeding distribution systems. Additionally, conducting a hydro test in a heavily traveled thoroughfare such as along Route 7 could pose a potential public risk, and therefore is not preferred.

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[3] According to PHMSA's "Fact Sheet: Pipe Manufacturing Process": "Electric resistance welded (ERW) pipe is manufactured by cold-forming a sheet of steel into a cylindrical shape. Current is then passed between the two edges of the steel to heat the steel to a point at which the edges are forced together to form a bond without the use of welding filler material. Initially this manufacturing process used low frequency A.C. current to heat the edges. This low frequency process was used from the 1920's until 1970. In 1970, the low frequency process was superseded by a high frequency ERW process which produced a higher quality weld. Over time, the welds of low frequency ERW pipe was found to be susceptible to selective seam corrosion, hook cracks, and inadequate bonding of the seams, so low frequency ERW is no longer used to manufacture pipe. The high frequency process is still being used to manufacture pipe for use in new pipeline construction." *See*, http://primis.phmsa.dot.gov/comm/FactSheets/FSPipeManufacturingProcess.htm

The low frequency ERW pipe that makes up Strip 1 is considered an inferior quality pipe by PHMSA. Washington Gas assigns the second highest contribution to the pipe manufacturing threat in the TIMP risk model for this seam type (lap welded pipe has the highest contribution). The combination of a higher manufacturing risk factor, along with the lack of a pressure test that gives this pipeline an adequate safety factor and the construction methodology of using reinforced Dresser couplings, elevates this segment as one of the top priorities for pipe replacement.

Based on its TIMP review, the Company has identified a portion of the Strip 1 pipeline for accelerated replacement for the PIPES 2 Plan proposed in this Application. It consists of approximately 6.5 miles of 16-inch and 24-inch diameter sections located in Leesburg Pike (Route 7), running from Tyco Road to the Company's Dranesville Gate Station (near Bishopsgate Way) and is within a very heavily traveled part of the Leesburg Pike in Fairfax County, Virginia.

The Strip 1 project proposed for replacement in this proceeding is a distinct project that has been selected for accelerated replacement in this PIPES 2 Plan because of its location, condition and regulatory requirements.

Replacing the 6.5 mile section of pipe in Leesburg Pike between Tyco Road and Dranesville Gate Station is the best and most feasible solution to address concerns about age, the inferior manufacturing process for low frequency ERW pipe, construction methodology, and inadequate pressure test. The Company proposes to replace this section of the Strip 1 mainline with a 24-inch diameter line with a MAOP of 325 psig, including inlets to existing regulating equipment. Replacing this pipeline with a size less than 24-inch would be imprudent given that the 16-inch portions of the pipeline were installed nearly 70 years ago. The existing pipeline that will be replaced will be abandoned as part of this project.

Construction is in progress and is expected to be completed in 2023. The replacement schedule coincides with VDOT's project to widen Leesburg Pipe between Jarrett Valley Drive and Reston Ave. (VDOT's road widening project begins 0.5 miles west of the start of the Company's pipe replacement project). VDOT expects to start its road widening project in 2018 and complete the project in 2024. The new Strip 1 pipeline will be designed to be in the VDOT road and right-of-way areas. This is a heavily traveled thoroughfare in Fairfax County which will require extensive traffic control measures to be installed, some of which must be dismantled each day of construction. As a result, Washington Gas expects to install approximately 40 feet of new main per week per crew.

For years 2020 through 2023 the Company expects to spend $101.4 million for this project of which $17.1 million would be allocated to the District of Columbia.

2. Strip 6

The Strip 6 mainline runs within VDOT right-of-ways from eastern Fairfax County (near Seven Corners) along Arlington Boulevard (Route 50), through Rosslyn and across the Key Bridge into Washington, DC. Strip 6, a DOT transmission and high-pressure pipeline, consists of 16" and 24" pipe and was constructed in 1948 and 1951. The project involves replacing approximately 2,500 linear feet of 16-inch-diameter steel DOT transmission pipeline, running along Arlington Blvd (or Route 50), from the Company's Rosslyn Pressure Reducing Station to south of the N. Rhodes Street overpass.

The pipeline has 260 and 215 psig MAOPs that are separated by a pressure reducing station. These MAOPs produce a SMYS ranging from 8% to 24%. Multiple pipe samples from Strip 6 were taken by Washington Gas to establish the location of installed lap welded pipe. Lab results from analysis of the pipe indicate that a portion of Strip 6 was constructed with low yield strength (28,000 psi) lap welded pipe[4]. In the section of pipe with a 215 psig MAOP, this change in pipe material from what was thought to be installed increases the SMYS on the pipe from 13% to 18%. The 215 psig MAOP for the 2,500 foot segment to be replaced was determined pursuant to 49 CFR §192.557 of the

[4] According to PHMSA's "Fact Sheet: Pipe Manufacturing Process": "In the lap welding process, steel was heated in a furnace and then rolled into the shape of a cylinder. The edges of the steel plate were then "scarfed." Scarfing involves overlaying the inner edge of the steel plate, and the tapered edge of the opposite side of the plate. The seam was then welded using a welding ball, and the heated pipe was passed between rollers which forced the seam together to create a bond. The welds produced by lap welding are not as reliable as those created using more modern methods. The American Society of Mechanical Engineers (ASME) has developed an equation for calculating the allowable operating pressure of pipe, based on the type of manufacturing process. This equation includes a variable known as a "joint factor", which is based on the type of weld used to create the seam of the pipe." *See*, http://primis.phmsa.dot.gov/comm/FactSheets/FSPipeManufacturingProcess.htm

DOT regulations that allows for up-rating of steel pipelines to a pressure that produces a hoop stress of less than 30% of SMYS. This methodology does not include a pressure test safety factor as prescribed by 49 CFR §192.619 of the DOT regulations. Washington Gas proposes replacing the lap welded pipe, which is the highest contribution to the pipe manufacturing threat in the TIMP risk model. Moreover, the existing pipe is of a lower grade than the pipe that Washington Gas has historically installed and is also considered an inferior quality pipe by PHMSA. In 49 CFR §192.113 of the DOT regulations, lap welded pipe is assigned a 0.8 joint factor in the pipe design equation. The majority of other pipe seam types are 1.0 joint factor. The acceptable design pressure is lowered for joint factors that are less than 1.0. Hydro testing a 67-year-old pipeline like Strip 6 is not preferred due to the potential public risk posed by a pressure test in a crowded thoroughfare such as along Arlington Blvd.

The proposed construction area is located both in the travel lanes of Route 50 and alongside the highway right-of-way and will involve interrupting the west bound lanes of Route 50 at times. This section of Route 50 has a high vehicular volume that will require extensive traffic control measures to be installed and dismantled each day of construction. Because this is a main commuter artery into the District of Columbia, it is anticipated that work in Route 50 will be restricted to night hours which will reduce the efficiency of the work crews. To reduce these challenges, Washington Gas is coordinating with Arlington County to use a vacant property at the intersection of Route 50 and Fairfax Drive to directionally drill the majority of the new pipeline. This would allow the majority of the pipeline to be installed in an existing utility corridor and eliminate the challenges of working under bridges and in Route 50. The only anticipated work in Route 50 for the drill project would be the eastern tie-in location, which would require the pipeline to cross the road. It is estimated that the project could be completed between January and November. The construction period for work in the road for this project is limited to April 2 through October 31 because the VDOT limits the use of steel plates in the road from November 1 through April 1. A portion of the new pipeline is designed to be located in Route 50 and the right-of-way areas and would require steel plates to be used during non-construction periods of the day for safety.

The replacement of this segment on Strip 6 is planned to start in 2020 and is estimated to take approximately 1 year to complete and cost approximately $7.7 million of which $1.3 million would be allocated to the District of Columbia.

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Program 2 – Remote Control Valve Installation

Introduction:

Remote Control Valves ("RCVs") allow for valves located on the transmission system to be operated by a qualified employee from a remote location. For Washington Gas, this remote location is Gas Control at the Springfield Center.

49 CFR §192.935 requires the pipeline operator to take additional measures to prevent or mitigate the consequences of pipeline failures. A risk analysis to address the use of RCVs is discussed in 49 CFR §192.935(c). The Washington Gas TIMP had an independent third-party conduct a risk-based engineering study to ascertain the need for and identification of appropriate locations of RCVs in the transmission system. Based on this analysis, and with additional Company analysis, Washington Gas identified potential locations to install new RCVs or to retrofit existing valves to be operated remotely in case of a pipeline emergency.

The addition of RCVs is a preventative and mitigative measure that directly impacts and enhances system safety and integrity. The RCVs will allow Washington Gas to shut off critical valves around the system from Gas Control in case of an emergency. A pipeline rupture would be considered an emergency, and without the use of RCVs, there would likely be greater greenhouse gas ("GHG") emissions if the valves used to isolate the rupture required manual closing. The congested traffic in the metro Washington, DC and surrounding areas at times impedes timely access to pipeline equipment. RCVs would enable Washington Gas to more quickly isolate high risk segments in the event of a pipeline incident. Safety of the public will be enhanced with a shorter isolation time which will help minimize potential consequences and allow emergency responders quicker access to the affected area.

The addition of these valves will improve overall system safety, especially for critical and sensitive locations within the metro Washington, DC area. In addition, the shorter isolation time of a pipeline failure also reduces the potential for the emission of GHGs which would be considerable due to the high operating pressures of this transmission pipe.

This program will accelerate the installation of RCVs. The installation of each RCV will occur over a two-year time period, with the easement being obtained in the first year and construction occurring during the second year. The Company proposes to install 4 RCVs starting in 2020 through 2024 at a total cost of approximately $16.3 million of which $2.8 million would be allocated to the District of Columbia. The locations and estimated costs of the 4 valves identified are listed below in Table 1.

Table 1 – Remote Control Valves Planned for Installation

Strip	Location	Valve Name / Number	Estimated Start Date	Estimated Completion Date	Estimated Cost
14	MD	Valve 2	January 2019	December 2020	$4,461,000
14	MD	Valve 5	January 2020	December 2021	$4,489,000
2	VA	Valve 18	January 2021	December 2022	$4,625,000
15	MD	Valve 13	January 2022	December 2023	$4,962,000

Note: 1.) The installation of the RCV located on Strip 14, Valve 2 will occur over a 2-year period. Only the charges that occur after October 2019 will be included in the PIPES 2 surcharge.
2.) The estimated completion date is the pipe completion date. Full project close-out and cost recordation is expected 6 months from this date.

Program 3 – DOT Transmission and High-Pressure Block Valve Replacement

Introduction:

Transmission and high-pressure block valves are located throughout the Washington Gas DOT transmission and high-pressure system, as required by CFR 192. They can be used, in cases of emergency, to safely control/eliminate pressure to specific areas, as required. They are also used to reduce pressure to allow for a variety of construction activities to occur. Installation dates of transmission valves range from the 1940's to present. There are over 1,100 transmission and high-pressure valves in the system.

Transmission valves are inspected, lubricated, and tested annually. However, due to age of service, certain valves have become increasingly difficult to operate. With the excessive force required to operate these valves there is a high risk that the valve could break and become inoperable. Table 2 below lists the 9 valves that are currently identified as difficult to operate (although in the future, this program may also include valves that are not able to provide a positive shutoff). These valves are gear-operated or quarter-turn plug valves that were installed in the 1940's, 1950's and 1960's and are reaching the end of their useful life.

The valve replacement program directly impacts and enhances safety and integrity of the system by allowing a segment of pipe to be isolated in the event of a pipeline incident. In addition, the replacement of difficult to operate valves has the potential to reduce emission of GHGs which would be considerable due to the high operating pressures of this transmission pipe by allowing for the isolation of shorter segments of pipe via properly functioning valves.

This program will accelerate the replacement of transmission and high-pressure block valves. The block valve replacement program is expected to continue for a minimum of 7 years and will cost approximately $8.3 million. In addition, the Company expects to identify additional valves in the future that will require replacement. The Company expects to spend approximately $6.4 million on this program through 2024 of which $1.1 million would be allocated to the District of Columbia.

Table 2 – Block Valve Planned Replacements

Valve/Strip Number	Mainline or Spur	Location State / Quad	Installation Year	Valve Type	Estimated Start Date	Estimated Completion Date	Estimated Cost
13 Strip 1	M	VA / T004SW	1948	Gear / Plug	January 2020	December 2020	$1,601,000
1 Strip 6	M	VA / T004SW	1948	Gear / Plug	January 2020	December 2020	
1 Strip 5	M	VA / T004SW	1947	Gear / Plug	January 2020	December 2020	
2 Strip 6	M	VA / Q004SW	1948	Gear / Plug	January 2021	December 2021	$1,017,000
6 Strip 13	M	MD / Q028NW	1955	Gear / Plug	January 2022	December 2022	$1,049,000
12 Strip 6	M	VA / J002NW	1951	Gear / Plug	January 2023	December 2023	$1,752,000
6 Strip 4	M	VA / V017SW	1956	Gear / Plug	January 2024	December 2024	$949,000
7 Strip 4	M	VA / U017SW	1956	Gear / Plug	January 2025	December 2025	$976,000
9 Strip 4	M	VA / Q016SW	1957	Gear / Plug	January 2026	December 2026	$994,000

Note: 1.) The estimated completion date is the pipe completion date. Full project close-out and cost recordation is expected 6 months from this date.

Program 4 - DOT Transmission and High-Pressure Valve Riser Replacement:

Introduction:

Transmission and high-pressure valves are located throughout the Washington Gas DOT transmission and high-pressure system, as required by CFR 192. They are equipped with a ¾" wrapped steel pressure gauge riser on either side, and ¾" wrapped steel grease risers. The pressure gauge risers are used for installing one up-stream and one downstream pressure gauge when the valves are operated. These gauges enable pressures to be monitored while the valve is being used for reducing pressure during an emergency or a downstream tie in. The pressure gauge risers operate at the same pressure as the transmission line at all times. The grease risers are used to lubricate the DOT transmission and high-pressure valves during annual maintenance.

Table 3 lists 4 transmission valves that are currently identified as having corrosion issues with these risers. Each year, upon inspection, additional valve risers are identified as needing to be replaced. Most of these facilities are in the street and subject to the effects of road salt. These risers are inspected annually during valve maintenance to assess their condition. Repair of leaking risers may result in a pressure reduction in the transmission pipeline, which, depending on the time of year and location, could adversely impact the Company's ability to serve customers. Washington Gas proposes a proactive replacement of corroded risers under controlled conditions which would not impact service to customers. A prioritized list of these facilities has been compiled and a multi-year replacement program is planned.

The Transmission and High-Pressure Valve Riser Replacement Program directly impacts and enhances transmission system safety and integrity, eliminating them as a future source of a high-pressure gas leaks and GHG emissions.

This program will accelerate the replacement of transmission and high-pressure valve risers and is expected to continue for a minimum of 5 years. For the 4 locations identified, the program will cost approximately $272,000 over 2 years of which $46,000 would be allocated to the District of Columbia. The Company anticipates identifying additional valve risers in need of replacement during this 5-year period. $150,000 has been budged each year, for years 2022 through 2024, for projects that have not yet been identified. For these additional projects, $76,000 would be allocated to the District of Columbia.

Table 3 – Valve Riser Replacements

Mainline or Spur	LOCATION State/Quad	STRIP #	VALVE #	Estimated Start Date	Estimated Completion Date	Estimated Cost
M	DC / B002SE3	23	9	January 2020	December 2020	$84,000
M	VA / O004SW	6	2	January 2020	December 2020	$58,000
M	MD / AP002SE	24	9	January 2021	December 2021	$74,000
M	MD / Q027SE	9	18	January 2021	December 2021	$56,000

Notes: 1.) The estimated completion date is the pipe completion date. Full project close-out and cost recordation is expected 6 months from this date.

Program 5 – Replacement of Components of DOT Transmission and High-Pressure Pipes to Enable the Use of In-line Inspection ("ILI") Tools

Introduction:

Washington Gas proposes this transmission system replacement program to replace components of DOT transmission and high-pressure pipes to enable the use of ILI tools (see Figure 1). Assessment of pipelines using these tools will help the Company to better address threats, such as external corrosion, and other pipeline defects, which can negatively impact pipeline integrity. CFR 192 Subpart O requires pipeline operators to assess the integrity of its transmission pipelines every seven years. The Company currently meets this requirement by conducting Direct Assessments ("DA"), specifically External Corrosion Direct Assessment ("ECDA") in its High Consequence Areas ("HCAs") on 85% of its transmission pipelines. ECDA is an integrity assessment method intended to identify areas that have a high likelihood of external corrosion. However, this method does not identify all areas on the pipe where corrosion may be occurring.

ILI is a methodology that can detect the presence, location and magnitude of corrosion or other pipe defects that may exist and is more comprehensive than an ECDA assessment. Some ILI tools are also capable of examining the pipe for other features such as dents or cracks. Unfortunately, ILI tools are unable to pass through some appurtenances of the pipe, for example, valves that are not full port (such as plug or reduced port valves), and certain pipe fittings such as short radius elbows and large diameter non-barred tees. These valves and fittings that are located on a pipeline need to be replaced to allow the use of ILI tools (that is, to make them "piggable"[5]). In addition, launchers and receivers (see Figure 2) need to be installed to insert and remove the ILI tool from the pipeline.

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[5] A piggable pipeline is a pipeline that is designed to allow a standard in-line inspection tool to negotiate it, which normally requires a constant bore, sufficiently long radius bends and traps to launch and receive the pigs.

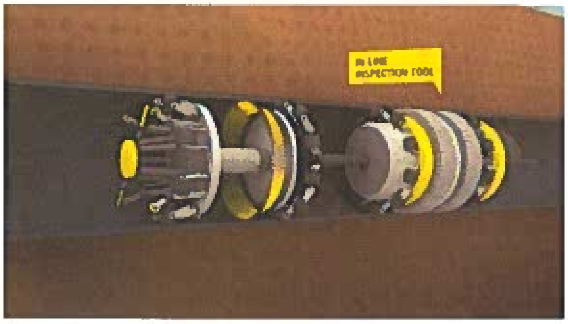

Figure 1 – Example of an in-line inspection tool in the pipe

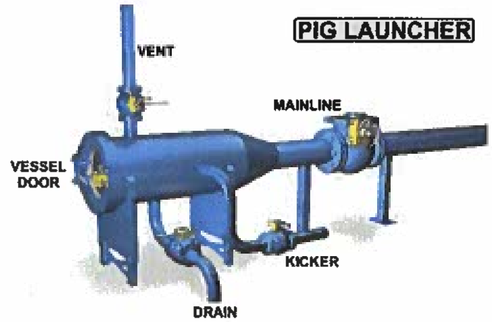

Figure 2 – Example of a pig launcher

As seen in Table 4 below, ILI is a better assessment method and can identify 6 of 9 threats to transmission pipe while ECDA can only identify 1 of 9 threats.

Table 4

Assessment Method	Construction Defects	Manufacturing Defects	Internal Corrosion	Equipment Failure	External Corrosion	Stress Corrosion Cracking	Weather and Outside Force	3rd Party Damage	Incorrect Operations
ECDA	No	No	No	NA	Yes	No	No	No	No
ILI	Yes	Yes	Yes	NA	Yes	Yes	No	Yes	No

Due to recent incidents on gas transmission pipelines, in 2015, the National Transportation Safety Board ("NTSB") made the following pipeline "safety recommendations" to PHMSA:

- P-15-18 – Require all gas transmission ("GT") pipelines to be piggable by either reconfiguring the pipeline to accommodate ILI tools or through using new technology that permits the inspection of previously uninspectable pipelines; priority should be given to the highest-risk GT pipelines considering age, pressure, diameter, and class location (supersedes P-11-17)
- P-15-20 – Identify all operational complications that limit the use of inline inspection (ILI) tools in piggable pipelines, develop methods to eliminate the operational complications, and require operators to use these methods to increase the use of ILI tools
- P-15-21 – Develop and implement a plan for eliminating the use of Direct Assessment ("DA") as the sole integrity assessment method for GT pipelines

In March 2016 PHMSA issued a Notice of Proposed Rulemaking ("NPRM") which emphasizes the use of ILI. It is clear that PHMSA views ILI as a better assessment method than ECDA. The proposed rule (49 CFR §192.921(a)(6)), as written, only allows ECDA as an assessment method if the pipeline is not capable of inspection by ILI tools. In addition, the NTSB has identified that 68% of intrastate pipelines are piggable.[6] Only 15% of the Company's transmission pipelines are currently piggable.

The Company has prioritized the replacement of non-piggable components on Strips 24, 14 and 15 as discussed in the following sections. The integrity of these pipelines would benefit from future assessments using an ILI.

Proposed Projects for Transmission Program 5

1. Strip 24

Strip 24 mainline runs from Brandywine, Maryland along Rte. 301 to Central Avenue. Along Central Avenue and up the CSX right-of-way to near Bowie, Maryland. It is a DOT transmission pipeline which is made up of 14.6 miles of 12-inch pipe and 9.4 miles of 16" pipe. The pipeline was constructed in the late 1960s and the early 1990s. The earlier vintage pipe was coated with coal tar (a legacy coating) while the more recent pipe was coated with Pritec (a newer high-performance coating).

A baseline assessment of Strip 24 occurred in 2016. The mainline pipe was assessed using the ECDA assessment method while the cased pipe segments were assessed using a robotic Pipetel ILI tool.[7] It was discovered that in areas where the ECDA and ILI assessments overlapped, the ILI picked up moderate to severe corrosion where there were no indications from the ECDA assessment. Subsequent exploratory evaluation of field applied coal tar coating at pipe joints found that it was disbonding in some locations and shielding the pipe from cathodic protection as well as inhibiting indications from being detected during the ECDA assessment. Since it was discovered

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[6] NTSB Safety Study, PB2015-102735, *Integrity Management of Gas Transmission Pipelines in High Consequence Areas*, page 57.

[7] The Pipetel ILI tool is a self-propelled, remotely controlled, battery operated ILI tool that has limited rangeability of 1,500 to 2,000 feet. The tool is limited to portions of the pipeline that are free from unpiggable obstructions.

that some of the pipe examined had more significant corrosion than indications from the ECDA suggested, it was determined that ILI would be a more appropriate assessment method for portions of Strip 24 that have field applied coal tar coating. As a result of this finding, Washington Gas will be working to make the section of Strip 24 that was coated with coal tar piggable before its next planned assessment in 2022. This segment of pipe is approximately 11.8 miles long. It begins near the intersection of Rte. 301 and Rte. 4 and ends near Bowie, Maryland just south of Annapolis Road. The newer sections of pipe that are coated with Pritec will not be made piggable at this time and will continue to be assessed by ECDA.

The replacement of non-piggable components will allow for a free-swimming pig to pass through the pipeline and will include the installation of a launcher and receiver for inserting and removing the ILI tool from the pipeline. A free-swimming pig moves through the pipe due to differential pressure in lieu of a battery operated robotic ILI, which has limited travel distance. The replacement of components to enable ILI tools on Strip 24 is a multiyear project that will begin in 2019 and is planned for completion in 2021.

2. Strips 14 and 15

Strips 14 and 15 are a continuous segment of pipe that begins in Rockville, Maryland that runs through various private rights-of-way and easements to I-495 and River Road and then down River Road to Washington, DC and into Georgetown. Strips 14 and 15 are both DOT transmission pipelines that are 24" in diameter. Strip 14 was constructed in 1965 and is 10.6 miles in length. Strip 15 was constructed in 1962 and is 9.5 miles in length.

Strips 14 and 15 pass through many densely-populated areas and are classified as HCAs. Over 50% of Strip 14 is located within an HCA and almost all of Strip 15 is located within an HCA. In addition, there were two leaks on Strip 15 in Washington, DC that were attributed to external corrosion, resulting in it having a high threat of external corrosion. In terms of reliability, a service interruption on either Strip 14 or 15 would have a high outage consequence for the Washington, DC metro area.

The replacement of non-piggable components will allow for a free-swimming pig to pass through the pipeline and will include the installation of a launcher and receiver for inserting an ILI tool into and removing it from the pipeline. The replacement of components to enable ILI tools on Strips 14 and 15 is a multiyear project that is planned to begin in 2022 and continue beyond 2024.

The Company proposes to replace components on portions of Strips 24, 14 and 15 in order to enable pigging, and estimates investing approximately $34.5 million on this program between 2020 and 2024 of which $5.8 million would be allocated to Washington, DC. These costs are identified in Table 5.

Table 5 – Pipelines Identified for Replacing Components to Enable ILI Tools

Strip Number	State	Location	Retrofit	Planned Remediation Years	Estimated Cost
24	MD	Prince Georges County	Replace Plug Valves and Unpiggable Fittings	2020, 2021	$10,978,000
14/15	MD/DC	Montgomery County and DC	Replace Plug Valves and Unpiggable Fittings	2022, 2023, 2024, 2025	$32,112,000

This transmission program is an eligible infrastructure replacement program which reduces risk and directly impacts and enhances the safety and integrity of the system by identifying areas where corrosion or pipe defects exist so that they can be remediated when warranted. In addition, the remediation of corrosion or pipe defects reduces the potential for GHG emissions due to leaks, which could be considerable due to the high operating pressures of high-pressure and transmission pipe.

Conclusion/Summary:

Based on the analysis described above, Washington Gas proposes five PIPES 2 infrastructure replacement programs targeting safety and risk lowering improvements to the Company's transmission assets. The replacement of the vintage DOT transmission and high-pressure pipelines, the installation of RCVs, the replacement of aging DOT transmission and high-pressure block valves, the replacement of valve gauge and grease risers and the replacement of components of DOT transmission and high-pressure pipes to enable the use of in-line inspection tools will, or have the potential to reduce GHG emissions, and to enhance transmission system safety and reliability and will reduce transmission system risk. The replacement of the vintage DOT transmission and high-pressure pipelines and the installation of RCVs as well as replacement of DOT transmission and high-pressure block valves, DOT transmission and high-pressure valve riser replacement and the replacement of components of DOT transmission and high-pressure pipes to enable the use of in-line inspection tools are not being installed to extend the facilities to serve new customers and will not result in increased revenues.

Transmission Allocable - PIPES 2 Plan

Year	2019 (Oct-Dec)	2020	2021	2022	2023	2024	5-Year Total
Program							
Program 1 - Transmission and High Pressure Replacement	$3,902,000	$ 35,017,000	$ 30,329,000	$22,771,000	$17,109,000	$0	$109,128,000
Program 2 - Remote Control Valves	$0	$3,900,000	$4,102,000	$4,222,000	$4,098,000	$0	$16,322,000
Program 3 - Transmission and High Pressure Block Valve Replacement	$0	$1,600,000	$1,017,000	$1,049,000	$1,751,000	$949,000	$6,366,000
Program 4 - Transmission and High Pressure Valve Riser Replacement	$0	$142,000	$130,000	$150,000	$150,000	$150,000	$722,000
Program 5 - Replacement of Components of DOT Transmission and High Pressure Pipes to enable the use of In-line Inspection (ILI) Tools	$0	$5,364,000	$5,614,000	$6,806,000	$7,490,000	$9,272,000	$34,546,000
Grand Total	**$3,902,000**	**$46,023,000**	**$41,192,000**	**$34,998,000**	**$30,598,000**	**$10,371,000**	**$167,084,000**
DC Jurisdictional Allocation	16.890%	16.890%	16.890%	16.890%	16.890%	16.890%	16.890%
Total DC Transmission Expenditures	**$659,000**	**$7,773,000**	**$6,957,000**	**$5,911,000**	**$5,168,000**	**$1,752,000**	**$28,220,000**

VERIFICATION

COUNTY OF FAIRFAX)
) SS:
COMMONWEALTH OF VIRGINIA)

AARON C. STUBER, being first duly sworn, deposes and says that he is the AARON C. STUBER whose Testimony accompanies this Verification; that such testimony was prepared by him or under his supervision; that he is familiar with the contents thereof; that the facts set forth therein are true and correct to the best of his knowledge, information and belief; and that he does adopt the same as true as his sworn testimony in this proceeding.

AARON C. STUBER

Subscribed and sworn to before me this 5th day of November 2018.

Tammi Lachelle Corbin
NOTARY PUBLIC

TAMMI LACHELLE CORBIN
NOTARY PUBLIC
REG. # 7729319
MY COMMISSION EXPIRES
1/31/2021
COMMONWEALTH OF VIRGINIA

WITNESS LAWSON
EXHIBIT WG (C)

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE
DISTRICT OF COLUMBIA

IN THE MATTER OF APPLICATION OF WASHINGTON GAS LIGHT COMPANY FOR APPROVAL OF A REVISED ACCELERATED PIPE REPLACEMENT PROGRAM	FORMAL CASE NO. 1115

WASHINGTON GAS LIGHT COMPANY
District of Columbia

DIRECT TESTIMONY OF R. ANDREW LAWSON
Exhibit WG (C)
(Page 1 of 1)

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Exhibits

WASHINGTON GAS LIGHT COMPANY

DISTRICT OF COLUMBIA

DIRECT TESTIMONY OF R. ANDREW LAWSON

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

A. My name is R. Andrew Lawson. I am employed as Regulatory Affairs Manager at Washington Gas Light Company ("Washington Gas" or "Company"), 6801 Industrial Road, Springfield, Virginia, 22151.

I. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science degree in Economics from Mary Washington College in Fredericksburg, Virginia.

I joined the Staff of the Maryland Public Service Commission as a Regulatory Economist in 2004. I began my employment with Washington Gas in 2006. From 2006 to 2008, I worked in the Rates Department of Washington Gas primarily on commodity pricing and Purchased Gas Charge issues. In 2008, I joined the Regulatory Affairs Department, working primarily on all regulatory issues in the Commonwealth of Virginia. I was promoted to Project Manager – Strategic Initiatives in the Company's Sales and Economic Development Department in June 2015. I assumed my current position in Regulatory Affairs in January 2016.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA ("COMMISSION") OR ANY OTHER STATE COMMISSION?

A. I testified before the Commission in Formal Case No. 1137. I have sponsored testimony before the Virginia State Corporation Commission and on several occasions before the Maryland Public Service Commission concerning various electric, gas, and water issues during my employment with the Maryland Public Service Commission.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support the Company's request for continuation of the surcharge for PROJECT*pipes* ("PIPES 2 Surcharge") to recover eligible infrastructure replacement costs (consistent with the Unanimous Agreement of Stipulation and Full Settlement approved in Formal Case No. 1115)[1] for the second phase of the Company's PROJECT*pipes* Plan ("PIPES 2 Plan"). I explain how the Current Factor for the PIPES 2 Plan for the fifteen months ended December 31, 2020 ("Plan Year 6") will be calculated and implemented. The calculated Current Factor is based on costs associated with replacements from October 1, 2019 through December 31, 2020.

III. IDENTIFICATION OF EXHIBITS

Q. DO YOU SPONSOR ANY EXHIBITS IN YOUR TESTIMONY?

A. Yes. I sponsor three exhibits. Exhibit WG (C)-1 provides the calculation of the PIPES 2 "Current Factor" (described in Section IV below) for Plan Year 6,

[1] Formal Case No. 1115, *In the Matter of the Application of Washington Gas Light Company for Approval of a Revised Accelerated Pipe Replacement Program,* Joint Motion for Approval of Unanimous Agreement of Stipulation and Full Settlement filed December 10, 2014.

the first year of the PIPES 2 Plan. Exhibit WG (C)-2 provides preliminary bill impact calculations for proposed expenditures in Plan Years 7-10, which will be based on the twelve months ended December of each year. Exhibit WG (C)-3 includes tariff revisions related to the PIPES 2 Plan.

IV. PIPES 2 SURCHARGE

Q. PLEASE EXPLAIN THE COMPANY'S PIPES 2 COST RECOVERY PROPOSAL.

A. Washington Gas proposes to continue PROJECT*pipes* for Years 6-10, as described in its PIPES 2 Plan filing, that will allow cost recovery for certain infrastructure improvement costs. I will explain how the PIPES 2 Surcharge will be calculated and implemented. I also support the tariff revisions relating to the PIPES 2 Plan.

Q. PLEASE DESCRIBE THE PIPES 2 SURCHARGE.

A. The PIPES 2 Surcharge, reflected in the Company's tariff as the APRP Adjustment, is a billing adjustment computed on an annual basis that creates a volumetric charge to be billed to customers on a monthly basis. The PIPES 2 Surcharge amount is shown as a separate line item on customers' bills.

Q. HOW IS THE PIPES 2 SURCHARGE DETERMINED?

A. The PIPES 2 Surcharge is determined by conducting a series of calculations and using a cost of service methodology utilized in Company rate cases. First, as shown in the testimony and exhibits of Company Witnesses Wayne Jacas and Aaron Stuber, the Company has determined an annual level of facility replacement costs, for eligible infrastructure replacements. Each year an annual level of costs will be incurred by the Company over a 12-month period.

The exception to this is Plan Year 6, where it is necessary to compute the level of costs for the fifteen-month period from October 2019 through December 2020.[2] The level of plant incurred for each plan year is shown in Company Witness Jacas's Exhibit WG (A)-2 and Company Witness Stuber's Exhibit WG (B)-1. The annual level of plant will be converted to an average rate base amount before calculating the costs to be included in the PIPES 2 Surcharge. In addition, the average rate base will be reduced for Reserve for Depreciation and Accumulated Deferred Income Tax, as shown on Exhibit WG (C)-1, Page 2. The resulting computation serves as the basis upon which the Company proposes to compute the return on investment described further below.

Each of the items to be included in the PIPES 2 Surcharge is discussed below:

1. Return on the Investment - The Company will apply the cost of capital as determined in the Company's most recent base rate case (currently Formal Case No. 1137) to the average level of plant expenditures shown in Exhibit WG (A)-2 and Exhibit WG (B)-1, as adjusted and described above for the Reserve for Depreciation and Accumulated Deferred Income Taxes, to calculate a return on the plant. For Plan Year 6 the Return on Investment for the fifteen-month period is calculated by converting Annual Return on Investment to a monthly basis (7.57% divided by 12) and applying that monthly return to the net rate base amount calculated above on a monthly basis. The sum of these

[2] Company Witness Jacas explains the Company's rationale for aligning PROJECT*pipes* plan years to the calendar year.

monthly returns provides the Return on Investment for the fifteen-month period.

2. Revenue Conversion Factor - A Revenue Conversion factor, including an allowance for income taxes and bad debt expense, will be applied to the eligible infrastructure replacement costs. The Revenue Conversion factor is based on the level of bad debt expense reflected in the Company's most recent base rate case (currently Formal Case No. 1137).

3. Depreciation - The Company will calculate a return of the eligible infrastructure replacement plant by using currently approved depreciation rates from the most recent depreciation study and applying those rates to the expected average plant balance during the year, net of retired plant, to capture depreciation costs for the period. For Plan Year 6, the annual depreciation rates will be converted to monthly depreciation rates (annual depreciation rate divided by twelve) and applied to the depreciable plant additions for each month of the fifteen-month period. This calculation is shown on Exhibit WG (C)-1, Page 5.

4. Carrying Costs - Carrying costs on the over-or-under recovery of the actual eligible infrastructure replacement costs will be calculated at the end of a twelve-month period. The calculation will determine the over- or under-recovered amount at the end of each month. Each monthly amount will apply the over- or under-recovery to the cost of capital. For Plan Year 6, carrying costs on the over-or-under recovered amount will be calculated at the end of the fifteen-month period.

In the final step, the total calculated eligible infrastructure replacement cost is divided by estimated throughput to arrive at a "per therm" factor by customer class multiplied by customer usage and included in the separate customer bill line item shown on bills. For Plan Year 6, the estimated costs for the fifteen-month period October 2019 - December 2020, will be divided by estimated throughput for the same fifteen-month period to arrive at a "per therm" factor.

Q. PLEASE EXPLAIN HOW THE PIPES 2 SURCHARGE WILL BE CALCULATED DIFFERENTLY IN ORDER TO MOVE THE COMPANY'S PROJECTPIPES PLAN YEARS TO A CALENDAR YEAR BASIS.

A. Company Witness Jacas discusses the Company's plans and rationale for moving the Company's plan years from the twelve months ended September 30 of each year to a calendar year basis ending in December. In order to accommodate that plan year change, the calculation of the PIPES 2 Surcharge must be altered for Plan Year 6. To accomplish this, I have calculated an estimated revenue requirement for the fifteen-month period October 2019-December 2020 as explained above. In subsequent periods, the revenue requirements and reconciliation periods will be calculated annually on a calendar year basis ending in December of each year.

Q. PLEASE EXPLAIN THE "CURRENT FACTOR" AND "FINANCIAL RECONCILIATION FACTOR" THAT ARE SHOWN IN GENERAL SERVICE PROVISION (GSP) NO. 28.

A. The Current Factor is an annual factor that collects the expected costs over a twelve-month calendar period ending in December. The workpapers for the proposed Current Factor for the PIPES 2 Surcharge for Plan Year 6 are shown in Exhibit WG (C)-1. The Reconciliation Factor is calculated by comparing the actual collections of the Current Factor to the actual eligible infrastructure replacement costs incurred. A Reconciliation Factor will be computed at the conclusion of each annual Plan Year by comparing actual collections of the Current Factor through the PIPES 2 Surcharge with actual eligible infrastructure replacement costs. The calculated under- or over-collection will be divided by the current estimated annual throughput to create the Reconciliation Factor to be added to or subtracted from the Current Factor.

Q. HOW DOES THE COMPANY PROPOSE TO ALLOCATE TRANSMISSION COSTS AMONG ALL JURISDICTIONS?

The proposed transmission-related projects described in the Direct Testimony of Witness Stuber replace transmission plant that supports the Company's entire operating system, not simply the jurisdiction in which the plant is located. As a result, a portion of these costs must be allocated among each of the Company's jurisdictions, consistent with the methodology in Company rate cases.

In this proceeding, the Company proposes to allocate common transmission plant consistent with its approach in general rate proceedings. That approach is to allocate costs based on an average of Peak Day and Annual Normal Weather Therm Sales. Exhibit WG (C)-1, Page 10, is excerpted from the Company's most recent base rate case (Formal Case No. 1137) and supports the allocation factor of approximately 17% (16.89%) used in this proceeding.

Q. PLEASE EXPLAIN HOW THE ALLOCATION OF PLANT REPLACEMENT COSTS TO CUSTOMER RATE SCHEDULES IS ACCOMPLISHED.

A. As shown on Exhibit WG (C)-1, Page 1, Plan Year 6 plant replacement costs have been allocated by rate schedule based on net rate base in the Class Cost of Service Study filed in Formal Case No. 1137 (Exhibit WG (C)-1, Page 9). This allocation methodology is consistent with the allocation methodology used in the initial phase of PROJECT*pipes*.

Q. PLEASE EXPLAIN WHAT IS SHOWN IN EXHIBIT WG (C)-2.

A. Exhibit WG (C)-2, Page 1, provides an estimate of the PIPES 2 Surcharge impact for the Years 2021-2024 based on the proposed expenditures in this proceeding and also an estimated bill impact for each of those years. Exhibit WG (C)-2, Page 2 provides a bill comparison over time, comparing estimated average bills for 2007, 2018 and 2024 (including the bill impact of the proposed PIPES 2 expenditures).

Q. PLEASE EXPLAIN THE TARIFF CHANGES SHOWN IN EXHIBIT WG (C)-3.

A. The tariff changes in Exhibit WG (C)-3 amend the existing language in General Service Provision ("GSP") No. 28 to revise filing dates and plan year periods to reflect the Company's proposal to adjust its plan years to a calendar year basis. Specifically, in addition to those revised filing dates discussed by Witness Jacas, the Company proposes to file its proposed PIPES 2 Surcharge Current Factor on November 1 of each year concurrent with the Company's submission of its Final Project List.

One additional change has been made to clarify that the PIPES 2 Surcharge, as shown in GSP No. 28 as the APRP Adjustment, is applicable to customers served under Rate Schedule No. 7. Rate Schedule No. 7 currently contains language stating that customers served under that rate schedule are subject to the PIPES 2 Surcharge. The proposed tariff change creates consistency between the two sections of the tariff.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

WITNESS LAWSON
EXHIBIT WG (C)-1

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA
CALCULATION OF PIPES 2 SURCHARGE - PLAN YEAR 6

Line No.	Description				OCT 2019 - DEC 2020
1	Plant additions (Page 2 of 10)				$89,574,239
2	Rate of Return on Investment (Page 2 and 3 of 10)				$8,052,099
3	Revenue Conversion Factor (Page 4 of 10)	Ln 2 * 1.404408			$11,308,432
4	Depreciation (Pages 5,6 and 7 of 10)			$	2,922,963
5	Interest Synchronization (Page 7 of 10)			$	(811,761)
6	Carrying Cost a/				n/a
7	TOTAL COSTS	Lines 3+4+5+6			$13,419,634
8	ALLOCATION b/		%		
9	Residential		62.23%		$8,351,038
10	Commercial & Industrial		20.74%		$2,783,232
11	Group-Metered Apartments		8.31%		$1,115,172
12	Interruptible		8.72%		$1,170,192
			100.00%		$13,419,634
13	BUDGETED THERMS c/				
14	Residential				125,407,000
15	Commercial & Industrial				107,015,000
16	Group-Metered Apartments				39,774,000
17	Interruptible				79,831,000
					352,027,000
18	CURRENT FACTOR				
19	Residential			$	0.0666
20	Commercial & Industrial			$	0.0260
21	Group-Metered Apartments			$	0.0280
22	Interruptible			$	0.0147

a/ Amount to be determined when annual reconciliation performed
b/ Based on net rate base in Class Cost of Service Study in Case No. 1137 (Page 9 of 10).
c/ Based on budgeted normal weather therms for October 2019-December 2020.(Page 8 of 10)

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA
PIPES 2 EXPENDITURES FOR YEAR SIX (OCTOBER 2019 - DECEMBER 2020)

	Distribution Services	Distribution Mains	Tranmission Mains	Total	Cummulative	Average Rate Base	Average Depreciation Reserve	Accuumulated Deferred Income Tax	Net Rate Base	Return On Net Rate Base
	A	B	C	D	E	F	G	H	I	J
Oct 15-Sept 19				$95,449,069			$2,754,543	$ (25,262,988)	$ 67,431,538	
Oct-19	$ 1,569,012	$ 1,467,288	$ 562,133	$ 3,598,433	$99,047,502	$ 97,248,285	$ 2,908,391	$ (26,251,710)	$ 68,088,185	$ 429,604
Nov-19	$ 1,569,012	$ 1,467,288	$ 562,133	$ 3,598,433	$102,645,935	$ 100,846,718	$ 3,067,607	$ (27,240,431)	$ 70,538,680	$ 445,065
Dec-19	$ 1,569,012	$ 1,467,288	$ 562,133	$ 3,598,433	$106,244,368	$ 104,445,151	$ 3,232,192	$ (28,229,153)	$ 72,983,807	$ 460,493
Jan-20	$ 1,569,012	$ 1,467,288	$ 562,133	$ 3,598,433	$109,842,801	$ 108,043,584	$ 3,402,145	$ (29,217,874)	$ 75,423,565	$ 475,887
Feb-20	$ 1,569,012	$ 1,467,288	$ 562,133	$ 3,598,433	$113,441,234	$ 111,642,017	$ 3,577,467	$ (30,206,596)	$ 77,857,954	$ 491,247
Mar-20	$ 1,569,012	$ 1,467,288	$ 562,133	$ 3,598,433	$117,039,667	$ 115,240,450	$ 3,758,158	$ (31,195,317)	$ 80,286,975	$ 506,572
Apr-20	$ 1,569,012	$ 1,467,288	$ 562,133	$ 3,598,433	$120,638,100	$ 118,838,883	$ 3,944,218	$ (32,184,039)	$ 82,710,627	$ 521,865
May-20	$ 1,569,012	$ 1,467,288	$ 562,133	$ 3,598,433	$124,236,533	$ 122,437,316	$ 4,135,646	$ (33,172,760)	$ 85,128,910	$ 537,123
Jun-20	$ 1,569,012	$ 1,467,288	$ 562,133	$ 3,598,433	$127,834,966	$ 126,035,749	$ 4,332,442	$ (34,161,482)	$ 87,541,825	$ 552,347
Jul-20	$ 1,569,012	$ 1,467,288	$ 562,133	$ 3,598,433	$131,433,399	$ 129,634,182	$ 4,534,608	$ (35,150,203)	$ 89,949,371	$ 567,538
Aug-20	$ 1,569,012	$ 1,467,288	$ 562,133	$ 3,598,433	$135,031,832	$ 133,232,615	$ 4,742,142	$ (36,138,925)	$ 92,351,549	$ 582,694
Sep-20	$ 1,569,012	$ 1,467,288	$ 562,133	$ 3,598,433	$138,630,265	$ 136,831,048	$ 4,955,044	$ (37,127,646)	$ 94,748,358	$ 597,817
Oct-20	$ 1,569,012	$ 1,467,288	$ 562,133	$ 3,598,433	$142,228,698	$ 140,429,481	$ 5,173,316	$ (38,116,368)	$ 97,139,798	$ 612,906
Nov-20	$ 1,569,012	$ 1,467,288	$ 562,133	$ 3,598,433	$145,827,131	$ 144,027,914	$ 5,396,955	$ (39,105,089)	$ 99,525,870	$ 627,961
Dec-20	$ 1,569,012	$ 1,467,288	$ 562,133	$ 3,598,433	$149,425,564	$ 147,626,347	$ 5,625,964	$ (40,093,811)	$ 101,906,573	$ 642,982
	$ 23,535,180	$ 22,009,315	$ 8,432,000	$ 149,425,564		$ 128,800,588	$ 4,369,389	$ (34,856,959)	$ 89,574,239	$ 8,052,099

Washington Gas Light Company
Utility Cost of Capital
District of Columbia

Twelve Months Ended September 30, 2015

Formal Case No. 1137

Description	Capital Structure Ratio	Cost	Return
A	B	C	D = B * C
Short Term Debt	3.090%	1.06%	0.033%
Long-Term Debt	39.660%	5.83%	2.312%
Preferred Stock	1.550%	4.79%	0.074%
Common Equity	55.700%	9.25%	5.152%
Total			7.57%

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA
REVENUE CONVERSION FACTOR

Ln. No.	Description	Reference	Amount
A	B	C	D
1	State Tax Rate	Statutory	8.250%
2	Federal Tax Rate	Statutory	21.00%
3	Federal Tax Rate Net of State Taxes	=Ln. No. 2*(1-Ln. No.1)	19.27%
4	Composite Tax Rate	=Ln. No.1 + 3	27.518%
5	Compliment of Composite Tax Rate	=1-Ln. No.4	72.483%
6	Revenue Gross Up, Excluding Uncollectible Accounts	=1/Ln. No.5	1.379643
7	Uncollectible Rate	Case No. 1137	1.7950%
8	Uncollectible Conversion Factor	=Ln. No.6 X Ln.No. 7	0.024765
9	Revenue Conversation Factor	=Ln No.6 + 8	1.404408

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA
ANNUAL PLANT BALANCES AND DEPRECIATION EXPENSE

	PLANT EXPENDITURES				DEPRECIATION EXPENSE						
	Distribution Services	Distribution Mains	Transmission Mains	Total Plant	Distribution Services	Distribution Mains	Transmission Mains	Total Depr. Exp. b/	Monthly Depreciation	Accumulated Depreciation	Deferred Income tax
	A	B	C	D	E	F	G	H	I	J	K
Depreciation Rates a/					2.40%	2.07%	1.13%				
Oct 15-Sept 19 c/				$95,449,069					$148,479	$ 2,754,543	($25,262,988)
Oct-19	$1,569,012	$1,467,288	$562,133	$3,598,433	$3,138	$2,531	$529	$5,369	$153,848	$ 2,908,391	$ (26,251,710)
Nov-19	$1,569,012	$1,467,288	$562,133	$3,598,433	$3,138	$2,531	$529	$5,369	$159,216	$ 3,067,607	$ (27,240,431)
Dec-19	$1,569,012	$1,467,288	$562,133	$3,598,433	$3,138	$2,531	$529	$5,369	$164,585	$ 3,232,192	$ (28,229,153)
Jan-20	$1,569,012	$1,467,288	$562,133	$3,598,433	$3,138	$2,531	$529	$5,369	$169,954	$ 3,402,145	$ (29,217,874)
Feb-20	$1,569,012	$1,467,288	$562,133	$3,598,433	$3,138	$2,531	$529	$5,369	$175,322	$ 3,577,467	$ (30,206,596)
Mar-20	$1,569,012	$1,467,288	$562,133	$3,598,433	$3,138	$2,531	$529	$5,369	$180,691	$ 3,758,158	$ (31,195,317)
Apr-20	$1,569,012	$1,467,288	$562,133	$3,598,433	$3,138	$2,531	$529	$5,369	$186,059	$ 3,944,218	$ (32,184,039)
May-20	$1,569,012	$1,467,288	$562,133	$3,598,433	$3,138	$2,531	$529	$5,369	$191,428	$ 4,135,646	$ (33,172,760)
Jun-20	$1,569,012	$1,467,288	$562,133	$3,598,433	$3,138	$2,531	$529	$5,369	$196,797	$ 4,332,442	$ (34,161,482)
Jul-20	$1,569,012	$1,467,288	$562,133	$3,598,433	$3,138	$2,531	$529	$5,369	$202,165	$ 4,534,608	$ (35,150,203)
Aug-20	$1,569,012	$1,467,288	$562,133	$3,598,433	$3,138	$2,531	$529	$5,369	$207,534	$ 4,742,142	$ (36,138,925)
Sep-20	$1,569,012	$1,467,288	$562,133	$3,598,433	$3,138	$2,531	$529	$5,369	$212,903	$ 4,955,044	$ (37,127,646)
Oct-20	$1,569,012	$1,467,288	$562,133	$3,598,433	$3,138	$2,531	$529	$5,369	$218,271	$ 5,173,316	$ (38,116,368)
Nov-20	$1,569,012	$1,467,288	$562,133	$3,598,433	$3,138	$2,531	$529	$5,369	$223,640	$ 5,396,955	$ (39,105,089)
Dec-20	$1,569,012	$1,467,288	$562,133	$3,598,433	$3,138	$2,531	$529	$5,369	$229,008	$ 5,625,964	$ (40,093,811)
	$23,535,180	$22,009,315	$8,432,000	$149,425,564				$80,529	$2,871,421		

a/ Based on Commission rates approved in Formal Case No. 1137.
b/ Total Depreciation has been reduced by 5.3% to reflect the cost of retired plant
c/ Starting balances represent balances from Company Current Factor Filing in FC1115, as revised on September 14, 2018

E. Annual Depreciation Rates[1019]

FO 1137 Commission [illegible]
Attachment [illegible]
Page 1 of 2

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA Statement A
Comparison of Current and SFAS 143 Accrual Rates
Current: VG Procedure / RL Technique
Updated: VG Procedure / RL Technique
Accretion Rate: 3.32 Percent

Account Description	Current Investment	Current Net Salvage	Current Total	SFAS 143 Investment	SFAS 143 Net Salvage	SFAS 143 Total
A	B	C	D=B+C	E	F	G=E+F
STORAGE AND PROCESSING PLANT						
Allocated Property						
361.00 Structures and Improvements						
Maryland (Rockville)	2.75%	0.69%	3.44%	2.39%	0.76%	3.15%
Virginia (Ravensworth)	2.63%	0.51%	3.14%	2.47%	0.40%	2.87%
Total Account 361.00	2.69%	0.71%	3.40%	[illegible]	0.63%	3.05%
362.00 Gas Holders						
Maryland (Rockville)	1.67%	0.56%	2.23%	1.69%	0.67%	2.36%
Virginia (Ravensworth)	1.76%	0.31%	2.06%	1.79%	0.34%	2.13%
Total Account 362.00	1.70%	[illegible]	2.17%	[illegible]	0.47%	2.20%
363.50 Other Equipment						
Maryland (Rockville)	2.59%		2.59%	6.37%	0.11%	6.48%
Virginia (Ravensworth)	-0.57%	6.10%	5.53%	1.97%	1.54%	3.51%
Total Account 363.50	2.09%	1.45%	3.53%	4.59%	0.45%	5.00%
Total Allocated Property	1.87%	0.57%	2.44%	2.02%	0.50%	2.52%
Total Storage and Processing Plant	1.87%	0.57%	2.44%	2.02%	0.50%	2.52%
TRANSMISSION PLANT						
Assigned Property						
365.20 Rights of Way						
366.00 Meas. and Reg. Station Structures						
367.10 Mains - Steel	1.02%	0.15%	1.17%	0.50%	0.10%	0.60%
369.00 Measuring and Regulating Equipment	1.91%	0.21%	2.12%	1.09%	0.20%	1.29%
Total Assigned Property	1.50%	0.16%	1.65%	0.82%	0.15%	0.97%
Allocated Property						
365.20 Rights of Way						
District	1.76%		1.76%	0.33%		0.33%
Maryland	1.58%		1.58%	1.60%		1.60%
Virginia	1.29%		1.19%	1.16%		1.16%
Total Account 365.20	1.55%		1.55%	[illegible]		1.45%
366.00 Meas. and Reg. Station Structures						
Maryland	1.95%		1.98%	0.33%	1.24%	1.57%
Virginia	2.04%	0.20%	2.24%	1.33%	0.02%	1.35%
Total Account 366.00	2.01%	0.12%	2.13%	1.00%	0.41%	1.44%
367.10 Mains - Steel						
District	0.98%	0.16%	1.13%	1.05%	0.10%	1.15%
Maryland	1.06%		1.66%	1.44%	-0.03%	1.41%
Virginia	1.54%	0.25%	1.79%	1.47%	0.10%	1.57%
Total Account 367.10	1.50%	0.11%	1.61%	1.42%	0.03%	1.45%
369.00 Measuring and Regulating Equipment						
District	1.67%	0.21%	1.88%	-0.18%	0.20%	0.02%
Maryland	1.92%	0.29%	2.21%	0.29%	2.40%	2.69%
Virginia	1.61%	0.45%	2.06%	0.66%		0.66%
Total Account 369.00	1.92%	0.25%	2.17%	0.36%	1.66%	2.02%
Total Allocated Property	1.63%	0.18%	1.81%	1.07%	0.56%	1.63%
Total Transmission Plant	1.61%	0.18%	1.79%	1.03%	0.60%	1.63%
DISTRIBUTION PLANT						
Assigned Property						
375.00 Structures and Improvements						
376.10 Mains - Steel	1.28%	0.37%	1.65%	0.87%	0.39%	1.26%
376.20 Mains - Plastic	1.61%	0.46%	2.07%	1.53%	0.57%	2.10%
376.30 Mains - Cast Iron	0.47%	1.16%	1.63%	-1.78%	1.14%	-0.64%
376.40 Mains - Copper						
377.00 Compressor Station Equipment						
378.00 Measuring and Regulating Equipment	1.19%	0.11%	1.30%	1.08%	0.11%	1.19%
380.10 Services - Steel	1.57%	1.63%	3.20%	1.16%	0.91%	2.08%
380.20 Services - Plastic	1.82%	0.58%	2.40%	1.42%	0.73%	2.15%
380.30 Services - Copper	1.07%	1.40%	2.47%	-1.89%	1.46%	-0.40%

1019 The following tables are from Commission Exhibit No. 9 (WGL's Response to Commission Data Requests, Question No. 4-1.)

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA
INTEREST SYNCHRONIZATION AND DEPRECIATION

CALCULATION OF INTEREST SYNCHRONIZATION

		YEAR 6
1	Plant Additions	$89,574,239
2	Debt Return %	0.02345
3	Line 1 *Line 2	$2,100,516
4	Tax Rate	$0.27518
5	Line 3 * Line 4	$578,009
6	Revenue Conversion Factor	$1.404408
7	Line 5 * Line 6	($811,761)

CALCULATION OF DEPRECIATION w/ REVENUE CONVERSION FACTOR

		YEAR 6
8	Depreciation Amount (Workpaper 3)	$ 2,871,421
9	Tax Rate Compliment	0.72483
10	Line 8 * Line 9	$2,081,278
11	Revenue Conversion Factor	$1.404408
12	Line 10 * Line 11	$2,922,963

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA
BUDGET THROUGHPUT THERMS
Fifteen Months Commencing October 2019 - December 2020

Line No.	Description	Oct 2019	Nov 2019	Dec 2019	Jan 2020	Feb 2020	Mar 2020	Apr 2020	May 2020	Jun 2020	July 2020	Aug 2020	Sep 2020	Oct 2020	Nov 2020	Dec 2020	Total
1	BUDGET THERM SALES - CYCLE																
2	D.C. - Firm Sales - Res	2,755,000	6,259,000	11,353,000	17,800,000	15,880,000	14,034,000	9,139,000	4,095,000	2,362,000	1,593,000	1,588,000	1,588,000	2,766,000	6,272,000	11,370,000	108,854,000
3	D.C. - Firm Sales - C&I	1,651,000	1,843,000	4,349,000	5,563,000	5,478,000	4,940,000	3,644,000	2,152,000	1,650,000	1,593,000	1,575,000	1,608,000	1,737,000	1,929,000	4,508,000	44,220,000
4	D.C. - Firm Sales - GMA	385,000	888,000	1,493,000	1,909,000	1,870,000	1,642,000	1,217,000	656,000	382,000	372,000	366,000	364,000	385,000	889,000	1,494,000	14,312,000
5	Total D.C. Firm Sales	4,791,000	8,990,000	17,195,000	25,272,000	23,228,000	20,616,000	14,000,000	6,903,000	4,394,000	3,558,000	3,529,000	3,560,000	4,888,000	9,090,000	17,372,000	167,386,000
6	BUDGET DELIVERY THERMS - CYCLE																
7	D.C. - Firm Delivery - Res	418,000	951,000	1,728,000	2,710,000	2,417,000	2,136,000	1,390,000	622,000	358,000	241,000	240,000	240,000	419,000	953,000	1,730,000	16,553,000
8	D.C. - Firm Delivery - C&I	2,329,000	2,593,000	6,193,000	7,931,000	7,815,000	7,042,000	5,185,000	3,045,000	2,326,000	2,249,000	2,225,000	2,271,000	2,452,000	2,718,000	6,421,000	62,795,000
9	D.C. - Firm Delivery - GMA	658,000	1,579,000	2,678,000	3,433,000	3,361,000	2,949,000	2,185,000	1,147,000	649,000	643,000	631,000	628,000	659,000	1,581,000	2,681,000	25,462,000
10	Total D.C. Firm Delivery	3,405,000	5,123,000	10,599,000	14,074,000	13,593,000	12,127,000	8,760,000	4,814,000	3,333,000	3,133,000	3,096,000	3,139,000	3,530,000	5,252,000	10,832,000	104,810,000
11	D.C. - Interruptible Delivery	3,239,000	6,338,000	8,652,000	10,208,000	8,559,000	8,822,000	4,912,000	3,199,000	2,432,000	2,047,000	1,901,000	2,375,000	2,867,000	5,957,000	8,323,000	79,831,000
12	BUDGET THERM SALES - CYCLE																
	D.C. - Firm Total - Res	3,173,000	7,210,000	13,081,000	20,510,000	18,297,000	16,170,000	10,529,000	4,717,000	2,720,000	1,834,000	1,828,000	1,828,000	3,185,000	7,225,000	13,100,000	125,407,000
	D.C. - Firm Total - C&I	3,980,000	4,436,000	10,542,000	13,494,000	13,293,000	11,982,000	8,829,000	5,197,000	3,976,000	3,842,000	3,800,000	3,879,000	4,189,000	4,647,000	10,929,000	107,015,000
	D.C. - Firm Total - GMA	1,043,000	2,467,000	4,171,000	5,342,000	5,231,000	4,591,000	3,402,000	1,803,000	1,031,000	1,015,000	997,000	992,000	1,044,000	2,470,000	4,175,000	39,774,000
	Total D.C. Firm Total	8,196,000	14,113,000	27,794,000	39,346,000	36,821,000	32,743,000	22,760,000	11,717,000	7,727,000	6,691,000	6,625,000	6,699,000	8,418,000	14,342,000	28,204,000	272,196,000

Washington Gas Light Company
District of Columbia Division Proforma Class Cost of Service Study
Income Statement Summary

Twelve Months Ended September 30, 2015 - Average Rate Base

	Description	Reference — Sc-Pg-Ln	Reference — Allocator	District of Columbia Rate Making Total	RES-HTG/CLG	RES-NON H/C-MA	RES-NON H/C-OTH	C&I H/C < 3075	C&I H/C > 3075	C&I NON H/C	GMA H/C < 3075	GMA H/C > 3075	GMA NON H/C	NON FIRM
	A	B	C	F	G	H	I	J	K	L	M	N	O	P
1	Operating Revenues	RV 1 35		$ 154,242,733	$ 73,313,997	$ 1,270,052	$ 1,318,589	$ 9,202,199	$ 33,958,583	$ 7,735,276	$ 851,484	$ 15,258,503	$ 2,489,430	$ 11,877,84
2	Operating Expenses													
3	Gas Purchased	EX 2 45		$ 0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Operation - Other than Gas Purchased			60,682,174	38,104,787	1,454,502	1,142,157	1,881,450	7,157,319	1,428,182	191,383	3,332,010	549,922	5,340,44
5	Maintenance	EX 4 22		14,223,885	9,485,174	185,931	303,371	483,182	1,690,160	341,509	35,768	798,225	132,882	857,68
6	Depreciation	EX 6 21		15,517,901	9,235,608	200,648	298,113	533,483	2,312,298	414,242	48,725	1,082,928	168,028	1,215,80
7	Amortization of Capitalized Software	AL 6 30	O&M Adjusted	2,849,984	1,781,850	75,789	53,857	80,893	287,583	56,325	7,920	126,726	21,838	178,88
8	Amortization of Chalk Point / MD Post 1989 Inter	AL 5 3	Net_Rate_Base	-	-	-	-	-	-	-	-	-	-	
9	Amortization of General Plant	AL 5 3	Net_Rate_Base	1,100,353	650,117	14,689	20,682	37,198	182,889	28,148	3,483	78,571	11,288	85,88
10	Amortization of Unrecovered Plant Loss Chillum	AL 5 3	Total_Weather_All_NW	150,411	89,554	244	978	5,184	30,542	2,436	787	14,811	1,251	25,64
11	Interest on Customer Deposits	RV 1 5	Gas_Sales_Ex_Non_Firm	59,601	30,746	508	548	2,572	14,171	3,186	380	6,468	1,841	
12	Interest on Supplier Refunds	AL 1 5	Annual_Firm_NW	-	-	-	-	-	-	-	-	-	-	
13	General Taxes	EX 8 24		44,044,516	15,384,422	139,885	277,407	1,407,220	8,426,422	1,812,677	187,649	3,687,115	580,882	12,670,73
14	Other Income Taxes		Tax_Factor	(1,579,614)	557,686	117,557	119,461	(225,742)	(1,831,192)	(476,080)	(50,041)	(808,767)	(130,073)	1,145,54
15	Expenses Before Federal Income Taxes	= Ln 2 > Ln 14		$ 136,789,822	$ 76,278,931	$ 2,178,653	$ 2,216,653	$ 4,195,510	$ 18,230,299	$ 3,710,695	$ 425,880	$ 8,208,097	$ 1,346,287	$ 20,878,61
16	Federal Income Taxes		Tax_Factor	$ (4,745,542)	$ 1,876,451	$ 353,170	$ 358,889	$ (878,182)	$ (5,501,343)	$ (1,430,200)	$ (150,335)	$ (2,423,723)	$ (390,772)	$ 3,441,50
17	Investment Tax Credit Adjustments		Tax_Factor	(264,990)	82,557	19,721	20,040	(37,870)	(307,180)	(79,862)	(8,396)	(135,340)	(21,821)	192,17
18	Deferred Income Taxes		Tax_Factor	11,048,111	(3,900,623)	(822,217)	(838,531)	1,578,878	12,807,693	3,329,654	349,996	5,842,677	909,757	(8,012,16
19	Loss-Disposition of Utility Plant			-										
20	Total Operating Expenses	= Ln 16 > Ln 19		$ 142,807,402	$ 73,147,416	$ 1,730,328	$ 1,760,052	$ 5,058,345	$ 25,229,459	$ 5,530,287	$ 617,258	$ 11,391,711	$ 1,842,431	$ 16,500,11
21	Net Operating Income	= Ln 1 > Ln 20		$ 11,435,331	$ 166,581	$ (460,276)	$ (441,463)	$ 1,143,835	$ 8,727,127	$ 2,204,989	$ 234,207	$ 3,864,792	$ 617,999	$ (4,622,47
22	Net Income Adjustments													
23	AFUDC	AL 5 3	Net_Rate_Base	$ 110,661	$ 65,345	$ 1,408	$ 2,077	$ 3,739	$ 16,373	$ 2,833	$ 350	$ 7,696	$ 1,148	$ 9,53
24	Donations - Net of Tax													
25	LCP Equity Accrual		Tot_Dist_Plnt	-	-	-	-	-	-	-	-	-	-	-
26	Net Operating Income - Adjusted			$ 11,545,992	$ 231,926	$ (458,810)	$ (439,387)	$ 1,147,599	$ 8,743,500	$ 2,207,823	$ 234,557	$ 3,872,489	$ 619,145	$ (4,612,94
27	Net Rate Base	RB 1 23		$ 261,882,302	$ 154,594,684	$ 3,466,026	$ 4,910,422	$ 8,848,022	$ 38,765,464	$ 6,701,820	$ 829,102	$ 18,223,989	$ 2,710,449	$ 22,832,3
28	Return Earned	= Ln 26 / Ln 27		4.41%	0.15%	-13.24%	-8.95%	12.97%	22.55%	32.94%	28.29%	21.25%	22.84%	

L-1)

Washington G[illegible]ht Company
Allocation Factors Base[illegible] Normal Weather Study

Twelve Months Ended September 2015 - Average

Description	Sc-Pg-Ln (Reference)	Allocator (Reference)	WG	DC	MD	VA	DC	MD	VA
A	B	C	D	E	F	G	H	I	J
1 Firm Annual Weather Gas									
2 TOTAL FIRM WEATHER GAS - NW	NW Study	Firm_Weather_NW	992,859,488	157,482 574	420,485,726	414,891,188	0.158615	0 423510	0 417875
3 TOTAL FIRM THERM SALES - NW	NW Study	Annual_ Firm_NW	1,412,692,822	222 384,780	608,345,699	581,962,342	0.157419	0.430628	0.411953
4 TOTAL FIRM THERM SALES - NW(sales only)		Annual_ Firm_Sales_NW	881,798,947	138,148,309	337,828,596	405,822,043	0.156666	0 383113	0.460221
5 Non-Firm Annual Weather Gas									
6 June Sales	Financial Stmt.		15,746,659	4,929,972	7,009,517	3,807,171			
7 July Sales	Financial Stmt.		14,935,002	4,620,003	6,823,859	3,491,141			
8 Aug. Sales	Financial Stmt.		15,098,239	4,526,325	7,031,280	3,540,634			
9 Total Summer Usage	=7+8+9		45,779,901	14,076,300	20,864,655	10,838,946			
10 Annualization Factor	Constant		4	4	4	4			
11 Annualized Summer Usage	=10*11		183,119,602	56,305,199	83,458,620	43,355,783			
12 Watergate Usage	Financial Stmt.		1 024,221	1,024,221					
13 Calculated Base Usage	=12+13		184,143,823	57,329,420	83,458,620	43,355,783			
14 Actual Usage	NW Study		269,846,750	90,011,016	117,653,395	62,182,340			
15 Weather Usage	=15-14		85,702,927	32,681,596	34,194,775	18,826,556			
16 Total Interruptible Therm Sales - NW			246,743,342	87,275,395	102,215,503	57,252,444			
17 Weather Gas Interruptible - NW			66,817,657	29,150,113	21,631,482	16,036,062			
18 TOTAL FIRM THERM SALES - NW(Delivery only)		Annual_Firm_Delivery_NW	512,114,782	84,236,472	251,738,011	176,140,299	0.164487	0.491566	0.343947
19 TOTAL ALL WEATHER GAS	=2+18	Total_Weather_All_NW	1,059,677,145	186,632,687	442,117,208	430,927,250	0.176122	0.417219	0.406659
20 TOTAL ANNUAL THERM SALES	=4+17	Annual_Total_NW	1,659,436,164	309,660,175	710,561,203	639,214,786	0.186606	0.428194	0.385200
21 Deductions for Pipeline :									
22 Propane Holding		Annual_Prop_Hold						0.000000	0 000000
23 Propane Gasified		Firm_Weather_NW							
24 Total Pipeline Deductions	=22+23								
25 ANNUAL THERMS ADJUSTED	=20-25	Pipeline_NW	1,659,436,164	309,660,175	710,561,203	639,214,786	0.186606	0.428194	0.385200
26 FIRM ANNUAL PIPELINE	=4-25	Firm_Pipe_ Ann_ Adj	1,412,692,822	222,384,780	608,345,699	581,962,342	0 157419	0.430628	0.411953
27 FIRM ANNUAL PIPELINE(Sales only)	=4-25	Firm_Pipe_ Ann_Sales_ Adj	881,798,947	138,148,309	337,828,596	405,822,043	0.156666	0 383113	0 460221
28 Peak Day Therm Sales- Normal Weather									
29 Weather Gas	NW Study	Peak_Day _Weather	15,694,510	2,370,607	6,750,070	6,573,833	0.151047	0.430091	0.418862
30 Base Gas	NW Study	Peak_Day_Base	1,065,340	164,968	478,975	421,397	0 154850	0.449588	0.395552
31 Total Peak Day Therms	=31+32	Peak_Day_Total	16,759,850	2,535,575	7,229,045	6,995,230	0.151289	0 431331	0 417380
32 PEAK DAY AND ANNUAL SALES	=20+33/2	Comp_Peak_ Ann_NW					0 168947	0.429763	0 401290
33 TOTAL WINTER THERMS (NOV-APR)	NW Study	Wintr_Pipe_NW	1,294,032,462	236,166,578	550,137,200	507,728,684	0.182504	0 425134	0 392362

Exhibit WG (D[illegible]
Page 34 of 67 (A

WITNESS LAWSON
EXHIBIT WG (C)-2

2021 - 2024 PROJECT*pipes* 2 Bill Impact Estimate

Line No.	Description			2021		2022		2023		2024
1	Plant additions (page 2)		$	60,061,649	$	103,351,204	$	146,954,533	$	189,753,196
2	Return on Plant	Line 1 * 7.57%	$	4,547,524	$	7,825,161	$	11,126,555	$	14,367,025
3	Revenue Conversion Factor	Line 2 * 1.404408	$	6,386,579	$	10,989,718	$	15,626,223	$	20,177,164
4	Depreciation a/		$	1,575,459	$	2,820,513	$	4,110,952	$	5,424,679
5	Interest Synchronization		$	(544,305)	$	(936,614)	$	(1,331,767)	$	(1,719,627)
6	TOTAL COSTS		$	7,417,733	$	12,873,617	$	18,405,408	$	23,882,217
7	ALLOCATION a/	%								
8	Residential	62.23%	$	4,616,055	$	8,011,252	$	11,453,685	$	14,861,903
9	Commercial & Industrial	20.74%	$	1,538,438	$	2,669,988	$	3,817,282	$	4,953,172
10	Group-Metered Apartments	8.31%	$	616,414	$	1,069,798	$	1,529,489	$	1,984,612
11	Interruptible	8.72%	$	646,826	$	1,122,579	$	1,604,952	$	2,082,529
12		100.00%	$	7,417,733	$	12,873,617	$	18,405,408	$	23,882,217
13	BUDGETED THERMS b/									
14	Residential			102,452,715		102,964,979		103,479,803		103,997,202
15	Commercial & Industrial			88,497,285		88,939,771		89,384,470		89,831,393
16	Group-Metered Apartments			32,253,465		32,414,732		32,576,806		32,739,690
17	Interruptible			61,910,010		62,219,560		62,530,658		62,843,311
18	CURRENT FACTOR									
19	Residential		$	0.0451	$	0.0778	$	0.1107	$	0.1429
20	Commercial & Industrial		$	0.0174	$	0.0300	$	0.0427	$	0.0551
21	Group-Metered Apartments		$	0.0191	$	0.0330	$	0.0470	$	0.0606
22	Interruptible		$	0.0104	$	0.0180	$	0.0257	$	0.0331

ESTIMATED AVERAGE INCREMENTAL BILL IMPACT FOR PROJECTpipes 2

	Class	Avg Annual Usage		2021		2022		2023		2024
23	Residential	735	$	33.12	$	57.19	$	81.35	$	105.04
24	Commercial & Industrial	9,157	$	159.19	$	274.89	$	391.06	$	504.90
25	Group-Metered Apartments	13,318	$	254.53	$	439.54	$	625.28	$	807.31
26	Interruptible	587,420	$	6,137.27	$	10,598.36	$	15,077.09	$	19,466.18

a/ Based on net rate base in Class Cost of Service Study in Case No. 1137 (Page 9 of 9).
b/ The budgeted therms for Calendar Year 2020 estimating annual throughput growth of 0.5% annually

Washington Gas Light Company

District of Columbia

Heating Customers

	2007				2018				2024			
	Annual Bill				Annual Bill				Annual Bill a/			
		Non-gas				Non-gas				Non-gas		
	Commodity	Fixed	Distribution	Total	Commodity	Fixed	Distribution	Total	Commodity	Fixed	Distribution	Total
Residential	$ 793.50	$ 94.20	$ 316.62	$ 1,204.32	$ 337.88	$ 157.20	$ 383.89	$ 878.97	$ 337.88	$ 157.20	$ 488.93	$ 984.01
Commercial & Industrial	$ 7,649.42	$ 204.07	$ 2,969.43	$ 10,822.92	$ 4,256.96	$ 451.38	$ 4,382.16	$ 9,090.50	$ 4,256.96	$ 451.38	$ 4,887.06	$ 9,595.40
Group Metered Apartments	$ 11,976.16	$ 270.20	$ 4,556.04	$ 16,802.40	$ 6,166.13	$ 575.66	$ 6,343.14	$ 13,084.93	$ 6,166.13	$ 575.66	$ 7,150.45	$ 13,892.24
Interruptible	$ -	$ 750.60	239,532.70	$ 240,283.30	$ -	$ 1,200.00	$182,183.17	$ 183,383.17	$ -	$ 1,200.00	$ 202,849.35	$ 204,049.35

a/ 2018 rates with estimated average 2024 bill impact by customer class from Exhibit WG (C)-3, Page 1 added to Distribution costs

WITNESS LAWSON
EXHIBIT WG (C)-3

Formal Case No. 1115

Exhibit WG (C)-3

Proposed Tariff Pages (Legislative Version)

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA
P.S.C. of D.C. No. 3
Sixth ~~Fifth~~ Revised Page No. 63
Superseding Fifth ~~Fourth~~ Revised Page No. 63

GENERAL SERVICE PROVISIONS (continued)

28. ACCELERATED PIPE REPLACEMENT PLAN (APRP) ADJUSTMENT

I. PROVISION FOR ADJUSTMENT

The monthly Distribution Charges billed under the Company's Rate Schedule Nos. 1, 1A, 2, 2A, 3, 3A, 6 and ~~6~~7 shall be subject to an adjustment which is called an Accelerated Pipe Replacement Plan (APRP) Adjustment.

II. APPLICATION

A. The APRP Adjustment shall be applied monthly and comprise: (a) a "current factor", as determined in III. A. below, and (b) a "reconciliation factor", as determined in III. B. below. The APRP charge shall be shown as a separate line item on customer bills.

III. COMPUTATION

A. Current Factor

The current factor, calculated to the nearest .01¢ per therm, shall be computed and filed annually by dividing the respective total amount allocated (as hereinafter defined) by the estimated total throughput for the applicable year customer class. The new factor will become effective each January~~October~~ billing cycle. Eligible infrastructure replacement plant is defined as plant expenditures that are part of the approved APRP plan but not reflected in base rates.

The amount to be charged to each customer shall be determined as follows:

1. The amount to be recovered will include the costs related to the eligible infrastructure replacement plant approved by the Commission.
2. The amount will include both a return of the expenditures as stated in III.A.1. and a return on the expenditures for the coming year.
3. The return of the expenditures will be computed by using the then-currently approved depreciation rates from the most recent depreciation study and apply those rates to the expected average plant balance, net of retired plant, during the year to capture depreciation costs for the period.
4. The return on the expenditures will be calculated by applying the then-currently approved cost of capital as determined in the Company's last base rate case to the average level of eligible plant replacement plan, as adjusted for the reserve on depreciation and accumulated deferred income taxes, to calculate a return on the plant.
5. A revenue conversion factor, including an allowance for income taxes and bad debt expense, shall be applied to the return on the expenditures calculated in Section III.A above.

ISSUED: ~~January 8, 2015~~ December 7, 2018
Effective for service rendered on and after ~~June 1, 2014~~ October 1, 2019
~~Roberta W. Sims~~ John D. O'Brien– Executive Vice President, Strategy ~~Rates and Regulatory~~ & Public Affairs

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA
P.S.C. of D.C. No. 3
Fifth ~~Fourth~~ Revised Page No. 64
Superseding Fourth ~~Third~~ Revised Page No. 64

GENERAL SERVICE PROVISIONS (continued)

28. ACCELERATED PIPE REPLACEMENT PLAN ADJUSTMENT (Continued)

6. Carrying costs on the over-or-under recovery of the eligible plant replacement costs will be calculated at the end of the twelve-month period. The calculation will determine the over-or-under recovered amount at the end of each month. Each monthly amount of the over-or-under recovery will be multiplied by the cost of capital.

7. The total recovery amount as described in Sections III.A.1 through A.6 above will be divided by estimated throughput to arrive at a "per therm" factor by customer class multiplied by customer usage and included in the separate customer bill line item shown on bills.

B. Financial Reconciliation Factor

A reconciliation factor shall be computed at the conclusion of each annual period of the APRP Adjustment by comparing actual collections of the current factor through the APRP Adjustment with actual eligible infrastructure replacement costs. The calculated under-or-over collection shall be divided by the current estimated annual throughput to create the reconciliation factor to be added or subtracted from the current factor. Any adjustment to costs based upon the completed projects reconciliation shall be reflected in the next annual Financial Reconciliation Factor filing.

C. Completed Projects Reconciliation

On or before March ~~December~~ 31st of each year of the Five-Year Approved Plan, the Company shall file a Completed Projects Reconciliation Report, which will include estimated and actual spend for each APRP project completed during the prior Plan year (~~October~~January 1 – ~~September 30~~ December 31). Actual spend for each project shall be defined to include direct capital expenditures and project total capital expenditures, each of which shall be shown separately.

IV. FILING

The Company shall provide the Commission Staff, OPC, AOBA and other interested parties with a copy of the annual computation of the current APRP factor by November 1st ~~July 31st~~ of each year for implementation in the January ~~October~~ billing cycle. The Financial Reconciliation Factor will be filed by March ~~December~~ 31st of each year with implementation in the June ~~March~~ billing cycle.

ISSUED: ~~January 8, 2015~~ December 7, 2018
Effective for service rendered on and after ~~June 1, 2014~~ October 1, 2019
~~Roberta W. Sims~~ John D. O'Brien – Executive Vice President, Strategy ~~Rates and Regulatory~~ & Public Affairs

Formal Case No. 1115

Exhibit WG (C)-3

Proposed Tariff Pages (Clean Version)

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA
P.S.C. of D.C. No. 3
Sixth Revised Page No. 63
Superseding Fifth Revised Page No. 63

GENERAL SERVICE PROVISIONS (continued)

28. ACCELERATED PIPE REPLACEMENT PLAN (APRP) ADJUSTMENT

II. PROVISION FOR ADJUSTMENT

The monthly Distribution Charges billed under the Company's Rate Schedule Nos. 1, 1A, 2, 2A, 3, 3A, 6 and 7 shall be subject to an adjustment which is called an Accelerated Pipe Replacement Plan (APRP) Adjustment.

II. APPLICATION

B. The APRP Adjustment shall be applied monthly and comprise: (a) a "current factor", as determined in III. A. below, and (b) a "reconciliation factor", as determined in III. B. below. The APRP charge shall be shown as a separate line item on customer bills.

III. COMPUTATION

A. Current Factor

The current factor, calculated to the nearest .01¢ per therm, shall be computed and filed annually by dividing the respective total amount allocated (as hereinafter defined) by the estimated total throughput for the applicable year customer class. The new factor will become effective each January billing cycle. Eligible infrastructure replacement plant is defined as plant expenditures that are part of the approved APRP plan but not reflected in base rates.

The amount to be charged to each customer shall be determined as follows:

5. The amount to be recovered will include the costs related to the eligible infrastructure replacement plant approved by the Commission.

6. The amount will include both a return of the expenditures as stated in III.A.1. and a return on the expenditures for the coming year.

7. The return of the expenditures will be computed by using the then-currently approved depreciation rates from the most recent depreciation study and apply those rates to the expected average plant balance, net of retired plant, during the year to capture depreciation costs for the period.

8. The return on the expenditures will be calculated by applying the then-currently approved cost of capital as determined in the Company's last base rate case to the average level of eligible plant replacement plan, as adjusted for the reserve on depreciation and accumulated deferred income taxes, to calculate a return on the plant.

5. A revenue conversion factor, including an allowance for income taxes and bad debt expense, shall be applied to the return on the expenditures calculated in Section III.A above.

ISSUED: December 7, 2018
Effective for service rendered on and after October 1, 2019
John D. O'Brien– Executive Vice President, Strategy & Public Affairs

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA
P.S.C. of D.C. No. 3
Fifth Revised Page No. 64
Superseding Fourth Revised Page No. 64

GENERAL SERVICE PROVISIONS (continued)

28. ACCELERATED PIPE REPLACEMENT PLAN ADJUSTMENT (Continued)

6. Carrying costs on the over-or-under recovery of the eligible plant replacement costs will be calculated at the end of the twelve-month period. The calculation will determine the over-or-under recovered amount at the end of each month. Each monthly amount of the over-or-under recovery will be multiplied by the cost of capital.

7. The total recovery amount as described in Sections III.A.1 through A.6 above will be divided by estimated throughput to arrive at a "per therm" factor by customer class multiplied by customer usage and included in the separate customer bill line item shown on bills.

B. Financial Reconciliation Factor

A reconciliation factor shall be computed at the conclusion of each annual period of the APRP Adjustment by comparing actual collections of the current factor through the APRP Adjustment with actual eligible infrastructure replacement costs. The calculated under-or-over collection shall be divided by the current estimated annual throughput to create the reconciliation factor to be added or subtracted from the current factor. Any adjustment to costs based upon the completed projects reconciliation shall be reflected in the next annual Financial Reconciliation Factor filing.

C. Completed Projects Reconciliation

On or before March 31st of each year of the Five-Year Approved Plan, the Company shall file a Completed Projects Reconciliation Report, which will include estimated and actual spend for each APRP project completed during the prior Plan year (January 1 – December 31). Actual spend for each project shall be defined to include direct capital expenditures and project total capital expenditures, each of which shall be shown separately.

IV. FILING

The Company shall provide the Commission Staff, OPC, AOBA and other interested parties with a copy of the annual computation of the current APRP factor by November 1st of each year for implementation in the January billing cycle. The Financial Reconciliation Factor will be filed by March 31st of each year with implementation in the June billing cycle.

ISSUED: December 7, 2018
Effective for service rendered on and after October 1, 2019
John D. O'Brien – Executive Vice President, Strategy & Public Affairs

VERIFICATION

COUNTY OF FAIRFAX)
) SS:
COMMONWEALTH OF VIRGINIA)

R. ANDREW LAWSON, being first duly sworn, deposes and says that he is the R. ANDREW LAWSON whose Testimony accompanies this Verification; that such testimony was prepared by him or under his supervision; that he is familiar with the contents thereof; that the facts set forth therein are true and correct to the best of his knowledge, information and belief; and that he does adopt the same as true as his sworn testimony in this proceeding.

JESSICA T HERAS
NOTARY PUBLIC
REGISTRATION # 7348912
COMMONWEALTH OF VIRGINIA
MY COMMISSION EXPIRES
MAY 31, 2022

R. ANDREW LAWSON

Subscribed and sworn to before me this 5th day of November 2018.

NOTARY PUBLIC

CERTIFICATE OF SERVICE

I, the undersigned counsel, hereby certify that on this 7th day of December 2018, I caused copies of the foregoing to be hand-delivered, mailed, postage-prepaid, or electronically delivered to the following:

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