PROCEEDING ON MOTION OF THE COMMISSION AS TO THE RATES, CHARGES, RULES AND REGULATIONS OF NIAGARA MOHAWK POWER CORPORATION FOR ELECTRIC AND GAS SERVICE

Testimony and Attachments of:
Simi Rose George

August 25, 2017

Submitted to:
New York State Public Service Commission
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Before the New York State Public Service Commission

Direct Testimony

of

Simi Rose George

August 25, 2017

I. INTRODUCTION & QUALIFICATIONS

Q. Please state your name, title, and business address. By whom are you employed and in what capacity?

A. My name is Simi Rose George. My title is Manager, Energy Markets Policy, U.S. Climate and Energy at Environmental Defense Fund ("EDF"). My business address is 123 Mission Street, San Francisco, California, 94105.

Q. On whose behalf are you submitting testimony in this proceeding?

A. I am submitting this testimony on behalf of EDF.

Q. Have you previously testified before this Commission or other regulatory agencies?

A. Yes. I provided testimony before this Commission on behalf of EDF in Cases 16-G-0058 and 16-G-0059. I also submitted testimony on behalf of EDF before the Pennsylvania Public Service Commission in Docket P-2015-2501500.

Q. Please provide a summary of your education and experience.

A. I have been employed at EDF since 2014. At EDF, I manage several initiatives demonstrating the benefits of, and creating pathways for, the adoption of new and beneficial technologies providing data and analytics that enhance the design and implementation of gas distribution system modernization efforts. I also serve as EDF's lead representative in stakeholder processes managed by the California Independent System Operator, advocating for gas and electric market refinements to advance the economically and environmentally efficient integration of clean, flexible resources on the grid. Prior to joining EDF, I worked with the London offices of two international law firms where I advised multinational clients on cross-border investments and other projects, with an emphasis on the energy and infrastructure sectors. I hold a master's degree in Public Administration/International Development from the John F. Kennedy School of Government, Harvard University, and a bachelor's degree in arts and a law degree from the National Law School of India University. More information is included in my resume which is attached as Attachment_ (SRG-1).

II. SUMMARY

Q. Please provide a summary of your testimony.

A. My testimony first comments on the Company's proposed accelerated pipe replacement and leak management efforts, and the potential benefits to customers and the environment associated with the use of new technological solutions (including advanced leak detection and leak quantification methods) in designing and implementing leak repair and pipe replacement activities. Based on this analysis, I support the Company's investments to replace LPP but recommend that it be required to integrate leak quantification methods into its decision-making in prioritizing LPP replacement and leak repair efforts.

In order to create transparency around the Company's efforts to develop these capabilities, I recommend that the Company be required to file publicly accessible annual reports during the rate period documenting progress towards meeting this requirement, and its efforts to keep pace with improvements in leak quantification technology during the rate period.

My testimony also supports the Company's proposed non-pipe alternative pilots, but recommends that a robust set of metrics be developed in this proceeding to allow for the transparent evaluation of these projects. The Company should be required to submit quarterly reports in this docket during the rate period detailing its progress under each metric.

My testimony does not support the proposed changes to the Company's Neighborhood Expansion program based on the lack of data at this time. These changes should not be approved absent an economic analysis of the benefits and costs (including environmental costs) of traditional natural gas expansion relative to non-pipe alternatives. In this context, my testimony notes the growing disconnect between New York's climate policy goals and current Commission policy fostering gas service expansion and infrastructure deployment.

Q. Are you providing any appendices or attachments to your testimony?

A. Yes, I have the following attachments.

Attachment_(SRG-1): Resume of Simi Rose George

Attachment_(SRG- 2): Sample leak map reflecting spatially attributed leak flow rate data

Attachment_(SRG-3): Palacios et al., "Integrating Leak Quantification into Natural Gas Utility Operations," *Public Utilities Quarterly*, May 2017.

Attachment_(SRG-4): Company's response to EDF Data Request No. EDF-4-NK-1 dated July 31, 2017.

III. <u>THE COMPANY'S PROPOSED ACCELERATED PIPE REPLACEMENT AND LEAK REPAIR EFFORTS</u>

Q. Please summarize your understanding of the Company's proposed leak prone pipe ("LPP") replacement efforts.

A. At the close of 2016, the Company had close to 700 miles of LPP on its system. The Company proposes to retire a minimum of 150 miles of LPP aggregated over the Rate Year and Data Years. The Company also proposes a Gas Safety and Reliability Surcharge and an incentive structure to further accelerate its LPP replacement efforts beyond annual LPP replacement targets.[1] Under the Company's proposal, all LPP will be eliminated by 2030, well ahead of the Commission's stated objective of retiring all LPP by CY 2035, as expressed in Case 15-G-0151.

The Company also proposes an incentive linked to its ability to cost-effectively retire LPP. Specifically, the Company proposes to earn a positive revenue adjustment of up to ten basis points for reductions in unit costs.[2] Additionally, the Company recommends a performance metric linked to reductions in its backlog of workable leaks in addition to total leaks.[3]

[1] Testimony of the Gas Safety Panel, Book 5, at pp. 24-25.
[2] *Id.* at p. 26.
[3] *Id.* at p. 31.

Q. What is your assessment of the leak-proneness of the Company's distribution system?

A. Cast iron and unprotected steel, which constitute most of the LPP on the Company's system[4], are known to be high-risk pipe.[5] In view of these risks, the Pipeline and Hazardous Materials Safety Administration ("PHMSA") introduced requirements in the early 1970s requiring buried or submerged steel pipeline to be protected against external corrosion. Because these requirements do not apply to pipelines installed pre-1971, they continue to corrode and must therefore be replaced.[6]

As part of a collaborative project with Google Earth Outreach and Colorado State University, discussed in greater detail in a later section of this testimony, EDF has gathered a vast dataset on leaks from gas utility systems across the country. Analysis of this data reflects a positive correlation between corrosion-prone gas infrastructure and leak rate.[7] The same pattern is reflected in data relating to the Company's distribution system. While the Company's LPP inventory represents only 8% of its distribution system, it is responsible for 87% of leak repairs, excluding excavation damages.[8] Similarly, the Company reports that the current leak rate for all distribution pipe is 0.07 leaks per mile whereas the corresponding figure for LPP is over ten times as high.[9]

The challenges associated with LPP will become more pressing as the Company's distribution system continues to age. This is not only a public safety issue, but also an important economic issue, given the large volumes of natural gas being released into the atmosphere, the costs of which are borne by ratepayers. Additionally, this is harmful to the climate because methane,

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[4] Testimony of the Gas Infrastructure and Operations Panel, Book 8, at p. 18. See also Exhibit GIOP-4, at p. 11.

[5] For instance, PHMSA has recognized the heightened risk of failure associated with cast iron pipelines, on account of the degrading nature of iron alloys, age of such pipelines and pipe joint design. Relative to unprotected steel, cast iron is more susceptible to main breaks leading to the leakage of large volumes of gas, whereas unprotected steel is more likely to develop slow leaks that can be detected over time. See generally Pennsylvania PUC Staff Report, "Inquiry into Philadelphia Gas Works' Pipeline Replacement Program", April 21, 2015, retrieved from http://www.puc.pa.gov/NaturalGas/pdf/PGW_Staff_Report_042115.pdf, at pp. 15-16.

[6] *Ibid.*

[7] von Fischer et al., "Rapid, Vehicle-Based Identification of Location and Magnitude of Urban Natural Gas Pipeline Leaks", *Environ. Sci. Technol.*, 51 (7), 2017, pp 4091–4099.

[8] *Supra* note 4, at p. 19.

[9] *Ibid.*

which makes up about 90% of pipeline quality natural gas[10], is a powerful greenhouse gas, more than 84 times more potent than carbon dioxide over a 20-year timeframe.[11] Methane is also an ozone smog precursor.[12] Although it is a short-lived climate pollutant, methane can cause significant environmental harm because of its potency as a greenhouse gas.

The estimate for the social cost of methane used by federal agencies to evaluate the climate impacts of new rulemakings is $1,000/ton of methane.[13] This estimate translates into social damages of $17 per thousand cubic feet (Mcf) of natural gas leaked and hence each reduced Mcf of gas leaked to the atmosphere spares society as much in climate change-related damages.[14]

Q. Please comment on the Company's LPP replacement and overall leak reduction efforts.

A. Through its proposed accelerated replacement efforts, the Company expects to eliminate all LPP on its system by 2030.[15] New York has one of the highest volumes of LPP in the country. It is second only to Pennsylvania by a small margin[16] in terms of aggregate mileage of cast iron and unprotected steel.

The Company's proposed accelerated pipe replacement efforts are necessary and appropriate. These efforts not only advance the Commission's goal of replacing all LPP in New York by 2035[17], but are also consistent with the standard adopted by key federal agencies on the issue of aging natural gas pipeline infrastructure. For instance, in 2011, the U.S. Department of Transportation ("DOT") and PHMSA jointly issued a Call to Action to accelerate the repair and

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[10] Demirbas, "Natural Gas", *Methane Gas Hydrate*, 2010, at p. 47, retrieved from. http://doi.org/10.1007/978-1-84882-872-8.
[11] IPCC, *Working Group I Contribution to the IPCC Fifth Assessment Report Climate Change 2013: The Physical Science Basis*, 2013, retrieved from http://www.ipcc.ch/report/ar5/wg1/#.Ut_4FxDna00.
[12] Fiore et al., "Linking Ozone Pollution and Climate Change: The Case for Controlling Methane", *Geophysical Research Letters*, 29 (19), 2002 at pp. 2–5.
[13] U.S. Government Interagency Working Group on Social Cost of Greenhouse Gases, "Addendum to Technical Support Document on Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866: Application of the Methodology to Estimate the Social Cost of Methane and the Social Cost of Nitrous Oxide", August 2016.
[14] Attachment_(SRG-3), at p. 4.
[15] *Supra* note 4, at p. 18.
[16] PHMSA, "Pipeline Mileage and Facilities", 2016, retrieved from https://www.phmsa.dot.gov/pipeline/library/data-stats/pipelinemileagefacilities.
[17] Case 15-G-0151.

replacement of cast iron and bare steel pipelines. According to PHMSA data, at least 21 states have completely eliminated cast or wrought iron natural gas distribution lines within their borders.[18]

Significant public safety, ratepayer and environmental benefits can be gained from thoughtfully designed, economically efficient, and well-executed pipeline replacement projects. As noted by the U.S. Department of Energy in the Quadrennial Energy Review released in April 2015, the replacement of leak-prone pipelines enhances safety by reducing the risk of main breaks and pipe failure, and reduces harmful methane emissions.[19] Pipeline replacement programs also advance ratepayers' interests by reducing the amount of natural gas leaked into the atmosphere and the need for future leak maintenance and repair.

IV. DESIGN AND IMPLEMENTATION OF THE COMPANY'S PIPE REPLACEMENT AND LEAK REPAIR EFFORTS

Q. Please explain relevant aspects of the prevailing utility and regulatory context as it relates to the use of advanced leak detection technology and leak quantification methods by utilities.

A. ***Utility context:*** Since the 2011 PHMSA/DOT Call to Action to accelerate the repair, rehabilitation, and replacement of the highest-risk pipeline infrastructure, sophisticated technologies allowing for the collection of previously unavailable data on utility asset conditions have emerged. Utilities are beginning to employ such data to supplement existing information on asset risks, and thereby design and target system modernization and maintenance efforts more effectively.

Gas utilities are beginning to move beyond regulatory compliance towards proactive asset risk and integrity management in response to a number of factors, including regulatory advancements, and an increased focus on pipeline safety.[20]

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[18] PHMSA, "Cast and Wrought Iron Inventory", retrieved from https://opsweb.phmsa.dot.gov/pipeline_replacement/cast_iron_inventory.asp.

[19] Department of Energy, "Quadrennial Energy Review: Energy Transmission, Storage, And Distribution Infrastructure", 2015, retrieved from http://energy.gov/epsa/downloads/quadrennial-energyreview-full-report, at p. 2-18.

[20] PricewaterhouseCoopers, "A new view on pipeline risks: How spatial analytics can empower asset management for gas utility companies", April 2016, retrieved from https://www.pwc.com/us/en/power-and-utilities/publications/assets/pwc_gas_pipeline_spatial_analytics_april_2016.pdf.

Advanced leak detection and quantification methods have significant ratepayer, environmental and system-wide benefits. In order to demonstrate these benefits and create pathways for the adoption of such advanced technologies by utilities, EDF has worked with a number of major utilities including New Jersey's oldest and largest utility, Public Service Electric and Gas ("PSE&G"), as well as Consolidated Edison ("Con Edison") and National Grid in New York, as described in further detail below.

Regulatory/Policy context: Under federal rules establishing integrity management requirements for gas distribution pipeline systems (the "Distribution Integrity Management Program for Natural Gas Distribution Sector" or "DIMP"), operators are required to develop and implement a distribution integrity management program. While the rules do not explicitly require utilities to quantify leaks, they state that (a) pipeline operators must consider all reasonably available information to identify threats to pipeline integrity and (b) the number and severity of leaks can be important information in evaluating the risk posed by a pipeline in a given location. Operators are required to consider the following categories of threats to each gas distribution pipeline: corrosion, natural forces, excavation damage, other outside force damage, material or welds, equipment failure, incorrect operations, and other concerns that could threaten the integrity of its pipeline. Sources of data may include, but importantly, are not limited to, incident and leak history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, and excavation damage experience.

With technology evolving to make leak quantification methods commercially available, and PHMSA rules requiring operators to consider all relevant data points in identifying threats to pipeline integrity, it is clear that the prevailing regulatory framework not only allows for newly available data such as spatially referenced leak flow rate data to be considered in evaluating threats to pipeline integrity, but in fact, underscores the need to do so.

Regulatory agencies in major states are now engaging on questions relating to the reduction of methane emissions from the gas distribution sector which can be addressed using leak quantification methods.

The California Public Utilities Commission issued a proposed decision in May 2017[21] in a natural gas leak abatement rulemaking required by SB 1371, a pioneering California state statute which emphasized the need for rules to minimize methane emissions from the gas distribution sector. If implemented, the proposed decision would require California's gas utilities to employ best practices such as the use of enhanced methane detection practices (e.g., mobile methane detection and/or aerial leak detection) to minimize methane emissions.[22] The proposed decision also specifies other best practices that utilities shall be required to comply with such as developing methodologies for improved quantification of leaks; geographic evaluation and tracking of leaks from gas distribution systems; employing leak detection technology capable of transferring leak data to a central database in order to provide data for leak maps; and making geographic leak maps publicly available.[23]

Along similar lines, based on requirements established by Massachusetts state statute, the Massachusetts Department of Public Utilities has initiated a rulemaking[24] to classify gas leaks from the distribution system to advance the identification and repair of environmentally significant leaks. Among other things, this rulemaking will consider a proposed methodology for classifying non-hazardous Grade 3 leaks as "environmentally significant" – these questions relate directly to the value and benefits of leak quantification methods by gas utilities.

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[21] Proposed Decision Approving Natural Gas Leak Abatement Program Consistent With Senate Bill 1371, R15-01-008, May 15, 2017, retrieved from http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M190/K738/190738162.PDF.
[22] *Id.* at pp. 79-80.
[23] *Ibid.*
[24] Investigation of the Department of Public Utilities, on its own motion, instituting a rulemaking pursuant to the G.L. c. 164, § 144, G.L. c. 30A, § 2; and 220 C.M.R. § 2.00 et seq., establishing requirements for Uniform Natural Gas Leaks Classification, Docket No. DPU 16-31.

V. BENEFITS OF INTEGRATING ADVANCED LEAK DETECTION AND LEAK QUANTIFICATION METHODS INTO UTILITY LEAK REPAIR AND PIPE REPLACEMENT PROJECTS

Q. Please describe EDF's engagement with utilities on the integration of advanced leak detection technology and leak quantification methodology into utilities' pipe replacement and leak repair programs.

A. In collaboration with Google Earth Outreach, Colorado State University, and various natural gas utilities, EDF is managing a project that uses Google Street View cars equipped with methane concentration analyzers to quantify methane leaks from distribution pipelines. The goals of this project are to demonstrate the benefits of state-of-the-art technological solutions, create pathways for the integration of leak quantification and advanced leak detection technology into utility operations, and to enhance transparency with respect to utilities' leak abatement efforts by publishing online maps showing the location and size of leaks in utilities' distribution systems. These maps have been referenced in the U.S. Department of Energy's Quadrennial Energy Review released in April 2015.[25]

In November 2015, the New Jersey Board of Public Utilities ("BPU") approved a settlement agreement among PSE&G, EDF and other stakeholders relating to a proceeding initiated by PSE&G, in which the company sought approval for an accelerated pipe replacement program.[26] As part of this settlement, PSE&G received BPU approval to implement a $905 million pipe replacement program. Under the terms of this settlement, after taking into account safety considerations, PSE&G is required to consider data gathered by EDF on leak flow rate, i.e. the volume of methane emissions leaked from its pipes, in conjunction with other relevant factors, to identify those that are most in need of replacement.

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[25] *Supra* note 19, at p. 2-20.

[26] Decision and Order of the New Jersey Board of Public Utilities In The Matter Of Public Service Electric And Gas Company for Approval of a Gas System Modernization Program and Associated Cost Recovery Mechanism, Docket No. GR15030272, November 16, 2015, retrieved from http://www.nj.gov/bpu/pdf/boardorders/2015/20151120/11-16-15-2F.pdf.

In collaboration with PSE&G, EDF gathered leak flow rate data for sections of the utility's infrastructure targeted for replacement through a mobile leak survey using Google Street View cars that were specially outfitted with methane sensors. PSE&G shared information with EDF on the location and type of its pipelines, enabling the collection of leak flow rate data that could be spatially attributed to specific pipes targeted for replacement. PSE&G used this leak flow rate data to prioritize its pipeline replacement efforts after considering safety factors.[27] The methodology used by PSE&G to integrate leak flow rate data into its pipe replacement prioritization scheme is described in a white paper titled "Integrating Leak Quantification into Natural Gas Utility Operations," that I co-authored with colleagues at EDF and researchers at Colorado State University. This paper was published in Public Utilities Fortnightly in May 2017, and is included as Attachment_(SRG-3) to this testimony. This analysis demonstrates that by using leak flow rates for prioritization, PSE&G achieved an 83% reduction of methane emissions early on by replacing one-third fewer miles of gas lines than that needed to achieve the same result under a business as usual scenario.[28] This difference is noteworthy considering that the typical cost to replace one mile of gas line on PSE&G's system is $1.5 to $2 million.

Recognizing the value of leak quantification methods in terms of enhancing operational safety, reducing methane emissions, and advancing ratepayer interests, utilities are taking steps towards integrating these methods into their operations. EDF is currently collaborating with KeySpan Gas East Corporation d/b/a National Grid ("KEDLI") and the Brooklyn Union Gas Company d/b/a National Grid ("KEDNY"), both subsidiaries of National Grid USA ("National Grid"), on a suite of pilot projects in National Grid's service territory in Long Island, NY, leveraging these new technological capabilities, as envisioned in settlement agreements approved

[27] Johnson, "Utilities must reduce methane leaks from natural gas pipelines, says new bill", February 5, 2016, retrieved from http://www.njspotlight.com/stories/16/02/04/utilities-must-clamp-down-on-methane-leaks-from-natural-gas-pipelines-says-new-bill/.
[28] See Attachment_(SRG-3). Further information about this analysis can be accessed at https://www.edf.org/climate/methanemaps/pseg-collaboration.

by the Commission in Cases 16-G-0059 and 16-G-0058 (collectively, the "2016 KEDNY and KEDLI Rate Cases"). The settlement agreement provides that leak flow rate data gathered as part of these projects will be used by National Grid to enhance leak repair and LPP replacement efforts in its Long Island service territory, and that the companies shall develop the means to quantify leak flow rate from their systems in order to better prioritize their leak repair and LPP replacement projects on an ongoing basis. It is anticipated that the pilot projects in Long Island will create pathways for the integration of the underlying advanced leak detection and quantification methods into the companies' regular operations. These efforts advanced by other National Grid companies can serve as a helpful foundational basis for the Company to integrate similar capabilities into its operations on a long term basis.

Following its 2013 rate case, Con Edison along with other parties, including state and city agencies as well as EDF and other NGOs, formed a collaborative to consider methane leak reduction opportunities. This collaborative has since developed a project to test leak quantification methods with the objective of identifying a method for the quantification of leaks on Con Edison's system to allow for leak repair activities to be prioritized using leak flow rate alongwith other factors. EDF and Con Edison recently completed a collaborative pilot project to quantify gas leaked from Con Edison's non-hazardous Type 3 leak backlog and develop a prioritization scheme for the repair of those leaks.[29] Under this project, researchers from Colorado State University surveyed hundreds of leaks constituting Con Edison's Type 3 leak backlog using advanced leak detection technology, and separated these leaks into "small," "medium," and "large" categories based on leak flow rate data gathered using leak quantification methods, to allow the company to prioritize the repair of its largest leaks. In order to facilitate this survey, Con Edison provided EDF with

[29] See generally Con Edison, "Con Edison steps up gas safety patrols, studying new ways to quantify methane emissions, accelerate gas main replacement", December 17, 2014, retrieved from https://www.coned.com/en/about-con-edison/media/news/20141204/safety-quantify-emissions-gas-replacement.

information on the location of its Type 3 leaks, including information on underground infrastructure locations, under the terms of a non-disclosure agreement.

Con Edison prioritized the repair of Type 3 leaks based on leak flow rate, thereby locking in methane emission reductions earlier than might have been possible under a business as usual scenario. The company has since received Commission approval to acquire and test advanced leak detection equipment on its system.

Q. How can data gathered using advanced leak detection and quantification methods assist the Commission and the Company in assessing the extent of need for, and benefits of, proposed system modernization and leak abatement projects?

A. Along with other public utility commissions around the country, this Commission is tasked with the challenge of balancing ratepayer interests in keeping natural gas rates stable and affordable, and utility and broader public safety interests in addressing gas infrastructure modernization and maintenance needs. The evaluation of proposed pipeline replacement programs by state regulatory entities necessitates a robust cost-benefit analysis, requiring careful scrutiny of all available information.

New data such as that made available through commercially available state-of-the-art leak detection and leak quantification methods can assist utilities and the Commission in addressing this challenge by offering more granular and detailed information on the leakiness of natural gas systems than has ever been previously available. Spatially-attributed leak data developed by connecting leak flow rates with information on the nature and location of the associated utility infrastructure can aid in effective and transparent decision making, offering significant benefits to utilities and regulatory agencies. For instance, such data can help characterize the condition of pipeline systems, and highlight where the need for leak repair and pipeline replacement programs are greatest. It can also improve the design and implementation of such programs by allowing utilities to prioritize, for repair or replacement, sections of their infrastructure with the largest leaks or the highest leak density (i.e. leaks per mile of pipeline), where appropriate, after taking safety considerations into account. Attachment_(SRG-2) contains a sample leak map developed by EDF and Colorado State University, based on randomly generated data, reflecting the type of visual tool that can be developed using advanced leak detection and leak quantification methods.

Similar leak maps were developed by EDF and Colorado State University as part of the PSE&G-EDF pilot project by overlaying PSE&G's infrastructure maps over leak maps reflecting the location and relative size of leaks on the company's system. This approach allows utilities to develop an actionable, visual tool reflecting areas of their infrastructure that are in particular need of replacement or repair efforts.

By comparing "before" and "after" scenarios, reflecting reductions in volumes of leaked gas achieved through the implementation of such programs, utilities, the Commission, and other stakeholders can evaluate the effectiveness of pipe replacement and leak repair efforts in reducing system-wide leaks.

From a longer term perspective, there is potential for data gathered using these methodologies to be used to supplement utility hazard ranking algorithms, to order to enhance the foundational basis of utility efforts to identify sections of infrastructure that are most in need of replacement/repair. Many major utilities use proxy variables for leak flow rate (e.g., a combination of pipe diameter and pressure) in their hazard ranking models to get a broad understanding of the volume of leaking gas that could accumulate in an enclosed space, which is a necessary parameter to include in risk assessments. Using actual, measured leak flow rate instead of estimates generated using proxy variables will enhance the overall efficacy and accuracy of these models. Measured leak rates that can be geographically attributed to infrastructure allow a more direct risk assessment than is possible using proxy variables, and can therefore serve as a valuable parameter in main replacement prioritization.

Q. Please outline the benefits of leak quantification and advanced leak detection methods.

A. Leak data gathered by EDF using mobile leak survey techniques suggests that the majority of methane emissions from natural gas distribution systems are attributable to a relatively small number of large leaks. This finding is supported by multiple independent sources. For instance, a 2014 Stanford University study noted, based on many independent experiments, that a small number of large leaks are responsible for a disproportionately large fraction of the leakage from natural gas systems.[30]

Using leak quantification technology, the Company can identify and address the largest leaks on its system as part of pipeline replacement and leak repair programs, after addressing those leaks/pipelines that pose a safety risk, thereby facilitating cost effective leak abatement and infrastructure improvement.

Ratepayers and society as a whole stand to benefit from this approach. First, the larger reductions in lost gas that such prioritization schemes can achieve translates into savings for ratepayers who generally pay both for gas delivered as well as gas lost on the pipeline system. Leak quantification can be used to prioritize non-hazardous leaks for repair, thus improving cost-effectiveness by capturing the highest volumes of gas per dollar spent on leak repair.

Finally, there are societal benefits associated with reducing the amount of gas leaked given the environmental risks associated with methane emissions. Because of the climate impacts, methane emissions come with a cost to society.[31] As noted above, federal agencies have estimated that the social cost of methane is $1,000/ton.[32] The Commission has previously considered the costs of climate change, which are currently external to the costs of natural gas, in an order establishing the benefit cost analysis framework for the Reforming the Energy Vision proceeding.[33]

Similarly, there are benefits associated with the use of advanced leak detection technology, which is more sensitive than traditional leak detection equipment and is therefore capable of finding

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[31] *Supra* note 11.
[32] *Supra* note 13.
[33] State of New York Public Service Commission, Proceeding on Motion of the Commission in regard to Reforming the Energy Vision, Case 14-M-0101, January 21, 2016.

more leaks. A growing number of utilities are adopting or exploring the adoption of such new and advanced leak detection equipment.

In California, Pacific Gas & Electric Co. ("PG&E") has integrated advanced leak detection technology into its operations, and is exploring the integration of leak quantification technology into its leak management efforts.[34] PG&E notes that the advanced methane detectors that it currently uses, which are manufactured by a California based company, Picarro, finds many more leaks than traditional leak survey instruments.[35]

CenterPoint Energy, which operates gas distribution systems in Arkansas, Louisiana, Minnesota, Mississippi, Oklahoma and Texas, uses advanced leak detection technology for leak surveying in Arkansas and Minnesota.[36] Centerpoint Energy has conducted pilots in Houston and Minneapolis to evaluate the performance of Picarro's advanced methane detectors compared to current leak detection equipment—both pilots reported more than 5 fold improvements in leak find rate.[37] The company reports several benefits linked to use of such advanced leak detection technology resulting from an improvement in the ability to detect leaks, including improved safety of the gas distribution system, reduction of natural gas emissions, and overall improvements in leak management.[38]

The California Public Utilities Commission reports that California utilities reported a 21% increase in the number of leaks detected from 2013 to 2014, due partly to the use of advanced leak

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[34] See generally Pacific Gas & Electric, "PG&E Launches Next Phase of its Industry-Leading Gas Leak Management Strategy", January 26, 2015, retrieved from http://www.pge.com/en/about/newsroom/newsdetails/index.page?title=20150126_pge_launches_next_phase_of_its_industry-leading_gas_leak_management_strategy.

[35] Pacific Gas & Electric Company, Prepared Testimony Exhibit (PG&E-3) on Gas Distribution, Chapter 6C (Leak Management), 2017 General Rate Case, Case No. A.15-09-001, at p. 6-4.

[36] See generally Docket No. 15-098-U, Arkansas Public Service Commission and Docket No. GR-15-424, Minnesota Public Utilities Commission.

[37] CenterPoint Energy, "Picarro Leak Surveyor: A Step Change in Leak Detection Capability", July 2015, retrieved from https://southerngas.org/images/PSC_Tal_Centers.pdf.

[38] Direct Testimony of Talmage Centers on Integrity Management Program, Minnesota Public Utilities Commission Docket No. GR-15-424, at p. 48.

detection technologies being employed.[39] As utilities start adopting more sensitive surveying equipment, leak backlogs are likely to grow, increasing the need for, and benefits of, prioritizing leak abatement activities by considering leak flow rate. PG&E, for instance, plans to test this technology for the purposes of quantifying the volume of fugitive emissions associated with its facilities, recognizing that this would improve site efficiency and safety, minimize losses and reduce greenhouse gas emissions.[40]

A 2016 report by PricewaterhouseCoopers which discusses the benefits of using new data analytics for improved utility asset management, and opportunities to integrate data gathered using cutting edge technologies, such as mobile leak detection technology, into utilities' risk management efforts[41] includes a case study relating to a major gas distribution utility which sought to optimize its prioritization of capital replacement projects. The company used data gathered using mobile leak detection technology along with historical data to develop a predictive leak model. For a $15 million asset portfolio, this effort led to the following outcomes: an estimated 3.9 times more leaks avoided, 3.6 times greater leaks/mile replaced and 4.1 times more O&M cost savings for the same capital investment.[42] This is a powerful example of the significant benefits to utilities from using data that can now be gathered using cutting edge technologies to enhance their asset management efforts.

Q. Please outline potential opportunities to integrate leak quantification methods into the Company's operations in the context of its proposal in this case.

A. While the Company's proposed use of residential methane detectors to facilitate early detection of gas leaks, and changes to its LPP retirement algorithm to include Type 3 leaks and service leaks

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[39] Mrowka et al., "Analysis of the Utilities' May 15th, 2015, Methane Leak and Emissions Reports Required by Senate Bill (SB) 1371 (Leno) and Rulemaking (R.) 15-01-008", 2016.

[40] Pacific Gas & Electric Company, Prepared Testimony Exhibit (PG&E-3) on Gas Distribution, Chapter 9 (Gas Operations Technology), 2017 General Rate Case, Case No. A.15-09-001, at p. 9-24.

[41] *Supra* note 20, at p. 6.

[42] *Ibid.*

are positive steps, there remains significant unexplored potential for leak quantification methods to be leveraged in order to reduce methane emissions from its system.

The proposed Gas Business Enablement ("GBE") program, aimed at enhancing the Company's existing operational and risk analytics processes, presents a unique opportunity for the Company to explore the integration of advanced leak detection and quantification capabilities into its operations. The Company's objective of ensuring that GBE investments drive "continuous improvement in regulatory compliance and transparency with *more complete data capture and reporting*"[43] can be advanced in a significant way using advanced leak detection and quantification methods.

The Company notes that the GBE Program will allow for GIS with accurate foundation maps, available with mobile functionality, and an Asset Investment Planning and Management software application to perform asset condition assessment and risk ranking/prioritization of asset replacement.[44] As explained in an earlier section of this testimony, leak quantification methods can provide information around the leakiness of underground pipe infrastructure, thereby serving as a critical data point in the assessment of asset condition, and ultimately, infrastructure risk ranking and prioritization of LPP replacement. Integrating leak flow rate data gathered using leak quantification methods into the Company's Asset Investment Planning and Management tool can, therefore, enhance the overall functionality and quality of asset condition assessment produced by this tool, beyond the improvements contemplated under the GBE program.

Q. What are your recommendations in relation to the implementation of the Company's LPP replacement efforts?

A. Generally, EDF supports the levels of investment proposed by the Company to replace LPP but recommends that in terms of implementation, the Company be required to integrate advanced leak quantification methods into its operations as detailed below. By way of background, the settlement

[43] *Supra* note 4, at p. 90.
[44] *Id.* at p. 91.

agreement adopted by this Commission in the 2016 KEDNY and KEDLI Rate Cases provided that both KEDLI and KEDNY shall "utilize internal personnel or a qualified contractor to develop the means to quantify emission flow rate data on an ongoing basis", that both companies "prioritize the highest emitting leaks when repairing [Type 3] leaks" and consider leak flow rate as a factor in prioritizing LPP removal. As noted above, EDF is currently working with KEDLI and KEDNY on a series of pilot projects which are intended to serve as a foundation for the integration of leak flow rate methods into the companies' operations at scale.

Given this background, I recommend that the Company be required to develop, by July 1, 2018, the means to quantify leak flow rate data using leak quantification methods on an ongoing basis by utilizing internal personnel or a qualified contractor. Further, I recommend that in each Data Year, the Company be required to (a) use leak flow rate data, gathered in this way, to identify and prioritize the highest emitting leaks when repairing all Type 3 leaks on its system and (b) to use leak flow rate data as a factor in prioritizing LPP removal.

In order to create transparency around the Company's efforts to develop these capabilities, I recommend that the Company be required to file publicly accessible annual reports with the Commission by the end of the Rate Year and each Data Year, documenting progress towards meeting each of these requirements, including, but not limited to, identifying and contracting with a service provider for the provision of advanced leak detection and leak quantification services; hiring/training personnel to use these technologies; operational and technical changes to integrate leak flow rate data into the Company's operations.

To the extent that leak quantification methods advance during the rate period, the Company should be required to ensure that its own practices advance along with such improvements. As part of the aforementioned annual reports, the Company should be required to document the extent to which leak quantification methods have advanced during the rate period and its own efforts to keep pace with such improvements.

Focusing on the largest leaks or leakiest pipeline segments first, after addressing those that pose a safety threat, will benefit ratepayers by reducing the amount of lost gas, and will also offer environmental benefits, as discussed above. From a longer term perspective, this will enhance the foundational basis of the Company's system modernization and maintenance efforts.

VI. ANALYZING THE COMPANY'S GAS EXPANSION AND NON-PIPE ALTERNATIVE PROPOSALS IN AN EVOLVING REGULATORY AND LEGAL CONTEXT

Q. Are there other proposals of the Company which you would like to address?

A. Yes, I would like to address the Company's proposed changes to its existing Neighborhood Expansion program as well as its proposal to test two non-pipe alternatives: a geothermal project and a voluntary demand response program to provide incentives to commercial firm gas customers who agree in advance to permit the Company to reduce their gas usage during period of peak demand.

Q. Please comment on the regulatory context in which gas service expansion and infrastructure decisions are considered in New York.

A. The Commission has several, decades-old policies regarding natural gas service expansion and infrastructure deployment. Taken together, these policy prescriptions consider gas service expansion and infrastructure deployment without taking the availability of alternatives into account. For example, the Company currently designs its gas supply plans based on frameworks issued in the late 1990s—the Commission's Policy Statements in Case 97-G-1380 and Case 97-G-0600.[45] In addition, a 2012 Order to examine the policies regarding the expansion of natural gas service notes that expansion into new natural gas franchise territories is covered by a Commission Policy Statement issued in 1989.[46]

[45] Direct Testimony of Elizabeth D. Arangio at p. 11.
[46] Proceeding on Motion of the Commission to Examine Policies Regarding the Expansion of Natural Gas Service, Order Instituting Proceeding and Establishing Further Procedures, Case No. 12-G-0297, November 30, 2012.

Q. Has there been a change in circumstances since these Policy Statements were issued?

A. Yes. These Policy Statements were issued at a time when natural gas was viewed as a cost-effective and cleaner alternative to other fossil fuels that residential and commercial customers were reliant on. Since then, New York's climate policy has evolved in a way that appears to be increasingly out of sync with the Commission's policy framework relating to gas service expansion. New York is a leader on environmental issues, having committed to reducing greenhouse gas emissions 80% below 2005 levels by 2050. The state's Clean Energy Standard provides that half its electricity will come from renewables by 2030. Governor Andrew Cuomo's methane reduction plan, released in May 2017, directs state agencies to develop policies to minimize methane emissions from the oil and gas sector and beyond. The conflict between New York's climate policy goals and its policy framework incentivizing gas service expansion and infrastructure needs to be addressed by the Commission. Specifically, policy incentives for gas service expansion and related infrastructure investments must be revisited for New York to achieve its ambitious climate goals. The Commission must consider this evolving regulatory and legal context as it addresses the specific proposals by the Company in this case.

Q. Please comment on the Company's proposed changes to its Neighborhood Expansion program.

A. The Company proposes several changes to its existing Neighborhood Expansion program, which is aimed at facilitating the expansion of gas service via main extension into new neighborhoods. Specifically, it proposes to increase the annual target for main installations from 14,000 to 16,000 feet, and to increase the annual service target by 20% from 100 to 120 new customers.[47] In order to effectuate these changes, the Company proposes to lower the customer density threshold to qualify projects from eight to seven customers per 500 feet, and to decrease the secured commitment for project commencement from 60% to 50% of the tariff entitlement.[48]

[47] Testimony of the Gas Customer Panel at p. 18.
[48] *Id.* at pp. 18-19.

Q. Has the Company provided a sufficient rationale for these proposed changes?

A. Based on the information available at this time, there does not appear to be a sufficient basis for the Commission to approve these proposed changes. As shown in Attachment_(SRG-4) to my testimony, the Company has not yet performed an economic analysis comparing the benefits and costs of gas service expansion under its Neighborhood Expansion program relative to non-pipe alternatives.

Q. What do you recommend to the Commission on this issue?

A. The Company's proposed changes to its Neighborhood Expansion program should not be approved absent an economic analysis of the benefits and costs (including environmental costs) of traditional natural gas service expansion relative to alternatives. For example, the Company notes that geothermal heating as a non-pipe alternative offers potentially greater economic and environmental benefits over fuels in areas without gas service or subject to system constraints.[49] New gas expansion incentives should not be granted absent a demonstration of the true costs and benefits of such expansion compared to alternatives.

Q. Please provide an overview of the Company's non-pipe alternative pilot projects.

A. The Company proposes to test two non-pipe alternatives: (a) a geothermal project, and (b) a commercial demand response project.

(a) Geothermal project: In collaboration with the New York State Energy Research and Development Authority, the Company proposes to evaluate geothermal technology at customers' premises using an underwater heat exchanger combined with advanced solar hot water panels that will be installed and owned by the Company.[50]

(b) Commercial demand response: The Company proposes to implement a voluntary demand response program to provide incentives to commercial firm gas customers who agree in advance to permit the Company to reduce their gas usage during periods of peak demand. The program targets

[49] *Id.* at p. 6.
[50] *Id.* at pp. 5-7.

an average 25% reduction in gas usage for each participating customer, in order to achieve the objective of 1% reduction in winter peak gas demand on the East Gate.[51]

Q. What proposed changes do you recommend to the Company's non-pipe alternative pilot projects?

A. The Company's efforts to identify and consider non-pipeline alternatives are commendable. Generally, EDF supports the non-pipe alternative pilot projects proposed by the Company. A robust reporting framework and a set of metrics should be developed as part of this proceeding. Regarding the geothermal pilot project, metrics should be created to (a) evaluate implementation progress relative to pre-established project milestones in order to ensure timely project completion; (b) measure the effectiveness of the geothermal technology; (c) account for the benefits to customers and the system as a whole; and (d) outline how the project can be incorporated into the Company's future system planning efforts and service offerings.

Regarding the gas demand response pilot project, metrics should be created to (a) evaluate implementation progress relative to pre-established project milestones in order to ensure timely project completion; (b) measure the effectiveness of the technology and devices enabling gas usage reductions; (c) determine whether the average targeted 25% reduction in gas usage for each participating customer was met; and (d) measure customer satisfaction.

These metrics will help ensure that customers capture the value of the Company's proposed non-pipe pilot projects. Once a set of metrics has been finalized, the Commission should require that the Company submit publicly accessible quarterly reports in this docket detailing its progress under each metric.

[51] *Id.* at pp. 7-9.

VII. CONCLUSION

Q. Please summarize your recommendations and conclusions.

A. Based on my review of testimony submitted on behalf of the Company, my conclusions and recommendations are as follows:

(1) The Company's proposed accelerated pipe replacement efforts are necessary and appropriate.

(2) The Company should be required to develop, by July 1, 2018, the means to quantify leak flow rate data using leak quantification methods on an ongoing basis by utilizing internal personnel or a qualified contractor.

(3) In each Data Year, the Company should be required to use leak flow rate data gathered in the manner described in (2) above to prioritize the highest emitting leaks when repairing Type 3 leaks, and as a factor in prioritizing LPP removal.

(4) The Company should be required to ensure that its own leak quantification practices advance along with any improvements to leak quantification methods during the rate period.

(5) The Company should be required to file publicly accessible annual reports with the Commission by the end of the Rate Year and each Data Year, documenting progress towards meeting the goals set out in (2) and (3) above. The Company should be required to document its efforts to ensure that its own leak quantification practices advance along with any improvements to leak quantification methods during the rate period in these reports, consistent with (4) above.

(6) Changes to the Neighborhood Expansion program, including gas service expansion incentives, should not be approved without a reasonable economic analysis that favorably compares the benefits and costs of gas service expansion relative to non-pipe alternatives.

(7) The Commission should approve the non-pipe alternative pilot projects proposed by the Company, and institute a robust set of metrics as proposed in this testimony to allow for the transparent evaluation of these projects. The Company should be required to submit publicly

accessible quarterly reports in this docket during the rate period detailing its progress under each metric to allow for transparent evaluation of the results of these projects.

Q. Does this conclude your testimony?

A. Yes.

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Professional Experience
2014-

ENVIRONMENTAL DEFENSE FUND — San Francisco, CA
Manager, Energy Markets Policy (2017- present)
Manager, Natural Gas Distribution Regulation (2015-2017)
Clean Energy Research Intern (Fall 2014)

Utility Regulation

- Lead EDF's advocacy efforts on reduction of methane emissions from downstream gas sector, including convening team of policy experts & defining strategic goals
- Serve as expert witness in regulatory proceedings before state utility commissions
- Manage EDF's interventions in regulatory proceedings before state utility commissions by providing policy expertise & strategic inputs
- Negotiate settlement discussions in regulatory proceedings before New York and New Jersey state utility commissions leading to settlement agreements advancing EDF's policy objectives
- Manage utility/regulatory engagement and strategy development for EDF-Google Earth Outreach methane mapping project
- Supervise senior analysts and interns on multiple research projects

Gas & Electric Market Design

- Serve as lead EDF representative at California ISO (CAISO), setting strategic direction, identifying opportunities for engagement, analyzing CAISO proposals, developing EDF's position, participating in stakeholder meetings, and drafting comments
- Develop and maintain strategically beneficial relationships with CAISO, state regulatory entities, market participants and other stakeholders
- Contribute to thought leadership on gas-electric coordination/ market design issues through blog posts and research projects

2010 –12

LINKLATERS LLP — London, UK
Associate, Corporate M&A

- Managed legal risk analysis team, analyzed legal issues and communicated legal advice to British Petroleum on $7.2 bn acquisition of Indian natural gas blocks (largest foreign direct investment into India)
- Crafted legal strategy for financial messaging service provider, SWIFT's joint venture with Indian banks to develop India's first financial messaging platform
- Negotiated Citibank's sale of UK consumer loans portfolio & managed deal execution in coordination with in-house team at Citibank

2008 –10

CLIFFORD CHANCE LLP — London, UK
Foreign Qualified Lawyer (Energy & Infrastructure focus)

- Developed legal agreements for €6.4 bn financing of Nord Stream gas pipeline connecting Russia and Germany
- Analyzed regulatory issues and conducted legal risk analysis on various mergers, acquisitions and project finance transactions (e.g. Standard Chartered Bank's financing of energy projects, Ghana; merger of T-Mobile UK and Orange UK)
- Conducted legal research and developed written arguments to support successful defense of a European state in Energy Charter Treaty dispute

Education 2012–14	**HARVARD UNIVERSITY, John F. Kennedy School of Government (HKS)** **Master in Public Administration in International Development (MPA/ID)** • Honorable Mention Award awarded to best capstone policy research papers • HKS Graduation Speaker, 2014 (represented MPA/ID Class of 2014)	Cambridge, MA
2003–08	**NATIONAL LAW SCHOOL OF INDIA UNIVERSITY** **Bachelor of Arts, Bachelor of Laws (Honors)** • Foreign exchange student, National University of Singapore • Law Clerk to Justice Dalveer Bhandari, Supreme Court of India	Bangalore, India

Presentations

"A Scale Differentiated Framework to Reward Rooftop Solar", National Renewable Energy Laboratory, (2015)

Select Publications

Co-author, "Integrating Leak Quantification into Natural Gas Utility Operations", Public Utilities Fortnightly, May 2017

Co-author, "System reliability and environment to be helped by non-event demand response", Natural Gas & Electricity 32/11, June 2016

"New Study Highlights Need for California Market Refinements", February 2017, EDF Energy Exchange Blog

"EDF Methane Mapping Partnerships Accelerate Technological Advances in Gas Utility Sector", January 2017, EDF Energy Exchange Blog

Published Interviews

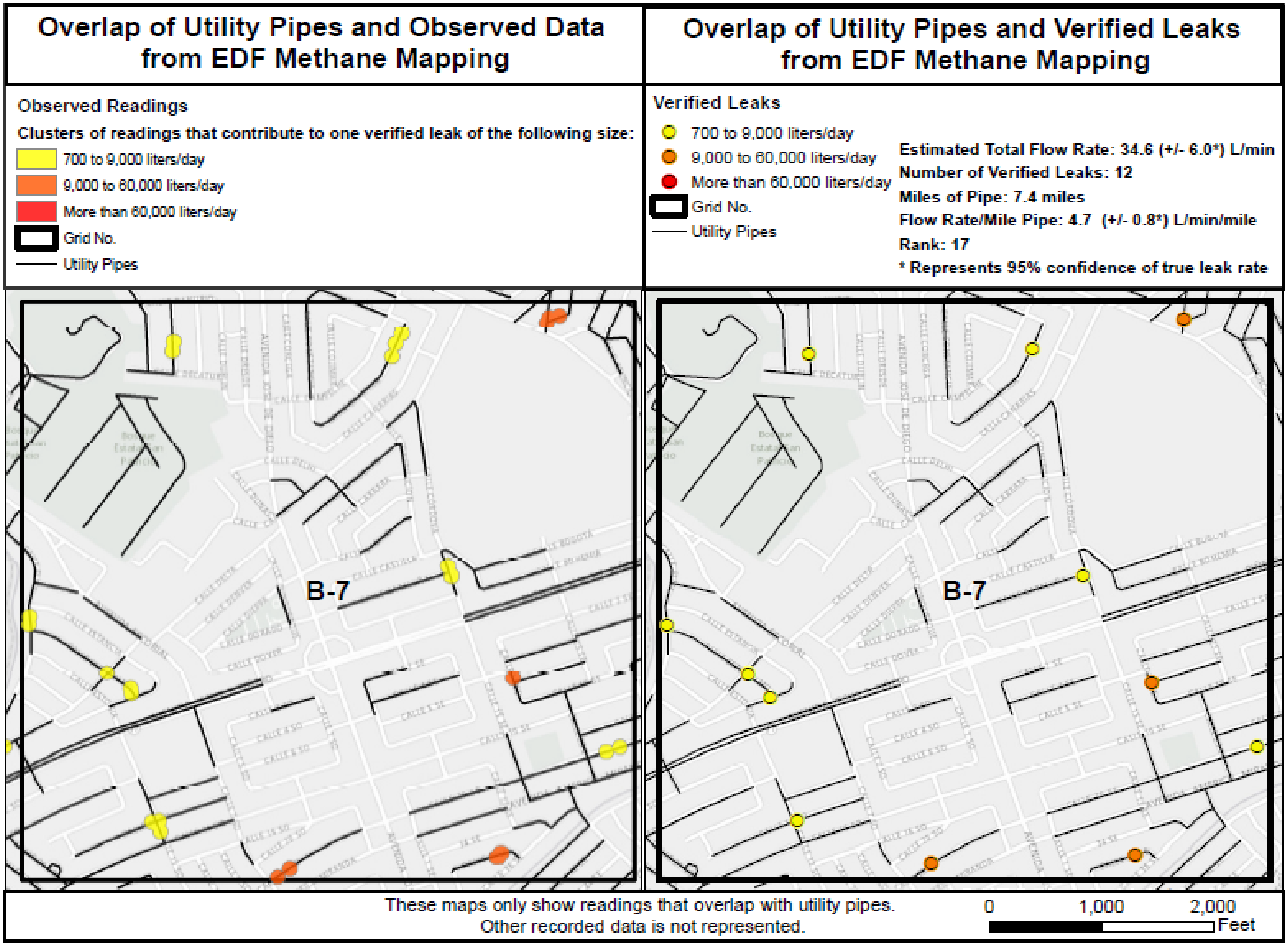
Judith Mernit, "With New Tools, A Focus on Urban Methane Leaks", Yale Environment e360, 2016

Testimony

Testimony submitted on behalf of EDF before the New York Public Service Commission in Cases 16-G-0058 and 16-G-0059 (May 2016)

Testimony submitted on behalf of EDF before the Pennsylvania Public Service Commission in Docket P-2015-2501500 (October 2015)

Sample Leak Map Reflecting Spatially Attributed Leak Flow Rate Data



Integrating Leak Quantification into Natural Gas Utility Operations

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May 2017

Abstract

Natural gas utilities can incorporate leak flow rate data into existing pipeline replacement and leak repair prioritization frameworks to more rapidly and efficiently reduce leakage on their system. Leak distributions typically demonstrate a "fat-tail," where a few, large leaks are responsible for the majority of lost gas volumes. Through ranking and ordering leak flow rate data, utilities can identify a subset of the largest leaks to repair or the leakiest pipelines to replace, and capture more gas per dollar spent on leak repair or pipeline replacement. This benefits ratepayers, who pay for the cost of lost gas, and also carries broader environmental and societal benefits.

1. Introduction

Studies of natural gas distribution pipeline leaks indicate that a relatively small subset of leaks is responsible for a disproportionate share of total observed emissions (Brandt et al., 2016; Lamb et al., 2015; Hendrick et al., 2016; von Fischer et al., 2017). Even though natural gas distribution utilities must expeditiously repair hazardous leaks, many large leaks can persist for months or years prior to repair because the standard used to grade a leak's risk generally places greater weight on the proximity to structures than to leak size. Recently, mobile monitoring has been used to detect the presence of underground pipeline leaks and estimate their size (von Fischer et al., 2017). If utilities used such leak quantification systems to prioritize abatement of the largest non-hazardous leaks, after taking safety into account, the climate benefits of leak repair and pipe replacement programs could be enhanced. By eliminating more natural gas losses per dollar spent on leak repair and pipeline replacement, leak quantification also helps constrain ratepayer costs.

Information on the size of leaks can also help utilities to verify and validate the need for leak repair and pipe replacement programs and allow regulatory agencies responsible for authorizing utility leak abatement projects to better assess the need for such efforts. In addition, leak quantification can improve project management by allowing utilities and public utility commissions to evaluate the progress of leak repair and pipeline replacement programs by considering the reduction in volumes of leaked gas achieved through implementation of such programs. This paper describes the implications of integrating leak quantification into utilities' regular leak operations and explores potential frameworks for implementation based on currently employed utility practices.

2. Leak Repair and Pipeline Replacement Programs: Current Regulatory Framework and Utility Practice

Natural gas leaks and leak-prone infrastructure impose costs and pose safety risks to society. Natural gas leaks are also harmful to the climate and environment because they consist primarily of methane, a potent short-lived climate pollutant and an ozone smog precursor. Traditionally, local gas distribution utilities focus their repair programs on finding, assessing, and repairing leaks in their infrastructure to prevent explosions. The occurrence of pipeline leaks is influenced by the following factors (U.S. Department of Transportation, 2011; American Gas Foundation and Yardley Associates, 2012):

- Exposure to extreme weather (e.g. temperature, moisture),
- Corrodible or brittle pipeline materials (cast iron, bare steel, copper, and certain vintage plastic pipes),
- Age,
- High occurrence of joints,
- Material or weld failures,
- Location of pipeline in the vicinity of excavation, or
- Areas where soil is unstable (e.g. earthquake-prone areas, karst-prone systems or in shrink/swell soils).

The Pipeline and Hazardous Materials Safety Administration (PHMSA) rules require operators to annually report data on the number of leaks repaired and the number of known leaks remaining on their system at the end of each year, but do not require operators to quantify leak volume (49 C.F.R. §191.11 and Form PHMSA F 7100.1-1).

PHMSA also offers non-binding guidance to operators on how to grade leaks based on safety risk, thereby establishing leak repair priority, and assisting operators in complying with federal safety rules that require them to "evaluate and rank risk" posed by their distribution pipeline systems (49 C.F.R. § 192.1007). Some states have incorporated or adapted PHMSA's leak grading guidance into their rules and statutes (NAPSR, 2013). The grading categories are based solely on an evaluation of the risk to persons or property and primarily considers proximity to building envelopes (PHMSA, 2000). Moreover, some researchers have observed the size, or leak flow rate, of grade one (i.e. "immediately" hazardous) leaks to be no different from other grades of leaks (Hendrick et al., 2016). Under the existing regulatory framework, utilities are generally not required to repair non-hazardous leaks (i.e. leaks that are not immediately hazardous) within a specific timeframe. As a result, non-hazardous leaks may continue unabated for long periods, in some cases decades,[1] thereby wasting a valuable resource and hurting the economic interests of ratepayers, who bear the costs of leaked gas.

[1] Two jurisdictions in the U.S., California and Massachusetts, require gas distribution utilities to report leak inventories with relevant characteristics. Leak data made available through the California Public Utilities Commission R. 15-01-008 – Natural Gas Leakage Abatement Rulemaking indicates that as of May 22, 2015, there were some leaks discovered in the 1990s that still had not been scheduled for repair.

PHMSA guidance on leak grading suggests comparing the concentration of gas in air around the leak to the lower explosive limit (LEL) of natural gas. [2] However, methane concentrations in air (e.g. parts per million) in and around a leak are not necessarily proportional to the rate at which gas is being lost (i.e. flow rate, typically measured in standard cubic feet per hour). Current utility practices, therefore, are insufficient for: (1) prioritizing leak repair using flow rate, or (2) verifying the effectiveness of leak repair and pipeline replacement initiatives at reducing system-wide losses of methane from natural gas.

It is important to distinguish between leak repairs, which occur on a regular basis and are paid for through operation and maintenance budgets, and pipeline replacements. On average leak repairs cost from $2,000 to $7,000 per leak (Aubuchon and Hibbard, 2013; Pacific Gas and Electric Company, 2015a). Considering that utilities are required to repair hazardous leaks immediately while non-hazardous leaks can persist for longer periods of time, leak quantification can be used to prioritize non-hazardous leaks for repair, thus improving cost-effectiveness by capturing the highest volumes of gas per dollar spent on leak repair without negatively impacting safety.

Similarly, leak quantification can be used to prioritize pipelines for replacement. Pipeline replacement can cost between $900,000 and $3 million per mile of pipe depending on a variety of factors (Aubuchon and Hibbard, 2013; Anderson et al., 2014). Utilities across the country are looking to replace many, if not most, of the 70,000 miles of leak-prone distribution pipes still in operation in the U.S. over the next two decades at an estimated cost of $270 billion (U.S. Department of Energy, 2015).[3]

The size of these investments underscores the need to thoughtfully design and execute these programs. In order to prioritize leak repair and pipe replacement programs, many utilities use hazard assessment algorithms to estimate the relative safety risk posed by leaks on their system, considering factors such as pipe material, environmental conditions, leak history, etc. After hazard assessment data is considered, leak flow rate data provides additional information that can be considered in prioritizing leak repair and pipeline replacement activities, and by so doing optimize the benefits of both operating and capital expenses.[4] Typical utility practices do not include leak flow rate assessments and therefore do not allow for this kind of improved prioritization.

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[2] The PHMSA guidance document, “Gas Leakage Control Guidelines for Petroleum Gas Systems,” gives several examples of a Grade 1 leak:

- *Any leak which, in the judgment of operating personnel at the scene, is regarded as an immediate hazard*
- *Escaping gas that has ignited*
- *Any reading of 80% LEL or greater in a confined space*
- *Any reading of 80% LEL or greater in small substructures (other than gas associated substructures) from which gas would likely migrate to the outside wall of a building*

[3] The estimated 70,000 miles of leak-prone pipe includes cast iron, unprotected bare steel, copper, ductile iron, and “other,” as listed in PHMSA 2015 Annual Distribution Data. Cost estimates provided from the U.S. Department of Energy (2015) may be based on older mileage values, and it is unclear which materials are included in the U.S. Department of Energy’s estimate.

[4] The availability of additional data points indicating the character of pipeline infrastructure is naturally useful for the purposes of integrity management as well. Utilities may find that it is beneficial to integrate leak flow rate values into hazard assessments.

3. Benefits of Using Leak Quantification

In 2011, PHMSA issued a "Call to Action" to state pipeline regulatory agencies, pipeline operators, and technical and subject matter experts after a series of natural gas distribution pipeline explosions. Recognizing the safety risks associated with cast iron gas mains, PHMSA urged state agencies to facilitate accelerated pipeline replacement programs for cast iron and other high-risk pipeline segments (U.S. Department of Transportation, 2011). Accelerated pipeline replacement programs are necessary from a safety standpoint, but also carry significant ratepayer and environmental implications.

With advanced leak detection technology and leak quantification, a utility can quickly and comprehensively assess the leakiness of its infrastructure with geospatial awareness. Using leak flow volume to further prioritize leak repair and pipeline replacement programs, once safety considerations have been taken into account, offers benefits to both ratepayers and society as a whole. First, the larger reductions in lost gas that leak prioritization can achieve translates into savings for ratepayers who generally pay both for gas delivered as well as gas lost on the pipeline system, which is considered an accepted cost of service (Webb, 2015). Second, there are societal benefits from reducing the amount of gas leaked because natural gas is composed primarily of methane,[5] a powerful short-lived climate forcer 84 times more potent than carbon dioxide over a 20-year time horizon (IPCC, 2013).

Researchers have estimated the social costs of greenhouse gas emissions by considering their effect on the climate and subsequent impacts such as changes in agricultural productivity, heat-related illness, and property damages from increased flood risk. The social cost of methane is a monetized value of the damages occurring as the result of an additional unit of methane emissions. Specifically, it represents society's aggregate willingness to pay to avoid the future impacts of one additional unit of methane emitted into the atmosphere in a particular year (Martens et al., 2014). Estimates of the social cost of methane can be used in a cost-benefit analysis of proposed regulations or projects with an impact on methane emissions. That is, the social cost of methane can be used to assess the benefits to society of a leak repair or a pipeline replacement program. The estimate for the social cost of methane used by federal agencies to value the climate impacts of new rulemakings is $1000/ton of methane (Interagency Working Group on Social Cost of Greenhouse Gases, 2016).[6] This estimate translates into social damages of $17 per thousand cubic feet (Mcf) of natural gas leaked and hence each reduced Mcf of gas leaked to the atmosphere spares society as much in climate change-related damages.[7]

4. Using Leak Quantification to Prioritize Pipe Replacement and Leak Repair

Studies show that distributions of leaks often exhibit a "fat-tail," where a small number of large leaks, often referred to as superemitters, account for the majority of measured gas losses in a sample (Brandt et al., 2016; Lamb et al., 2015; von Fischer et al., 2017). Leak quantification can help utilities facilitate cost-effective design and implementation of leak repair and pipe replacement programs by allowing for

[5] On average, pipeline-quality natural gas is composed of over 90% methane by volume (Demirbas, 2010).
[6] This specific estimate refers to the damages associated with a ton of methane emitted in 2015 monetized in 2007 dollars. The current value therefore would be higher when adjusted for inflation. The value is also higher for emissions in later years because future emissions are expected to produce larger incremental damages (see Interagency Working Group on Social Cost of Greenhouse Gases, 2016).
[7] Assuming a mass of 19,200 g/Mcf natural gas, and a methane share of 78.8% per mass unit of natural gas. This estimate is in $2007 for one Mcf of natural gas leaked in 2015.

prioritization of the highest-emitting leaks or pipe segments, as the case may be. The methodology also allows public utility commissions to consider the need for, and progress of, the planned program.

4.1 Information that improves efficiency

Utilities are starting to adopt the use of advanced leak detection equipment capable of finding more leaks more rapidly. For example, the California Public Utilities Commission reports that utilities experienced a 21% increase in the number of leaks detected from 2013 to 2014, due partly to the use of advanced leak detection technologies (Mrowka et al., 2016). Additionally, the use of advanced leak detection technology has been shown to reduce the time needed to complete a leak survey, have a longer-distance field of view for detecting leaks, and can be used overnight when atmospheric conditions are more stable (Clark et al., 2012).

Applied efficiently, advanced leak detection technology can be used to obtain (on a continuous basis) leak information sufficient for determining the most hazardous and/or largest emitting leaks that in turn can be prioritized for remediation. Rather than continuing the paradigm that leaks are found and remediated one at a time, industry and regulators can foster innovative strategies that involve obtaining leak survey information as the first step, and application of advanced analytics as a second step, in order to prioritize remediation of the most hazardous and largest leaks.

4.2 Leak repair and pipe replacement prioritization methodology

One key consideration in employing leak quantification methodologies to leak repair programs is how to systematically translate a database of measured leak flow rates into a prioritized list. This consideration is equally applicable to pipe replacement programs, where the corresponding challenge is to prioritize pipeline segments for replacement. In providing the data necessary, the primary emphasis should not be on the accuracy of individual leak measurements, but rather on the precision of the characterization of the leaks, the ability to provide a prioritized list and a cost-effective path to reducing leak volumes.

A cumulative distribution, ordering leaks by size, is a useful tool to determine the relative priority of leaks for repair, which is made possible with the use of sufficiently precise leak quantification methodologies. A cumulative distribution can both help identify the largest leaks, and determine their relative contribution to overall leakage.

As shown in Figure 1 (A), the flow rate of leaks can vary significantly. When ranked from largest to smallest as shown in Figure 1 (B), the relative importance of different leaks is transparent and the relative contribution of each leak to overall leak flow rate is easily quantified (Figure 1 [C]). The cumulative distribution is created by integrating the ranked distribution in Figure 1 (B) from left to right. The first data point from the left on the X-axis in the CD plot is the leak determined to have the largest leak volume, the second point is the cumulative leak flow rate of the top two leaks, the third point is the sum of leak flow rates of the top three leaks, and so on. Thus, the last data point is the sum of leak flow rates of all known leaks. This distribution is then normalized to 1 (or 100% in Figure 1 [C]) so that we can readily consider the relative contribution of a certain number of leaks to the total system-wide leakage.

While this discussion focuses on the particular context of leak repair, a similar analytical approach can be applied to prioritize pipeline segments for replacement (see Appendix).

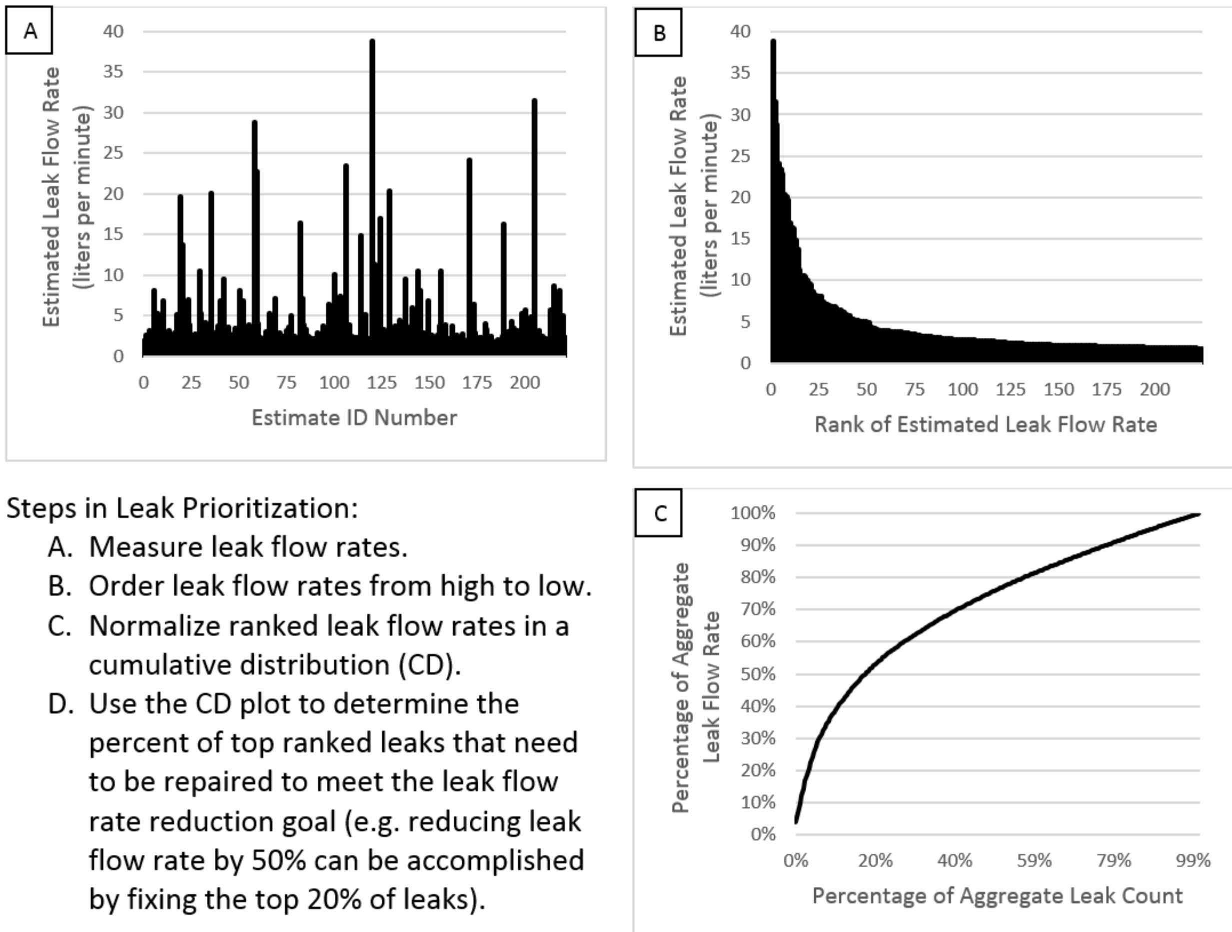

Figure 1 An example step-by-step model depicts how to construct a cumulative distribution curve for the purpose of leak prioritization, using data collected by EDF in Syracuse, NY.

In the near term, leak quantification can help utilities reduce the volumes of gas lost through leakage, and thereby save ratepayers money and reduce methane emissions, by enabling the prioritization of both leak repair and leak-prone pipeline replacement projects based on leak flow rate. In the longer term, as leak quantification methodologies become more sophisticated, utilities will be able to easily quantify leak rates for their entire system, measuring progress in reducing emissions.

In the context of leak repair programs, leak volume may be considered to prioritize the repair of non-hazardous leaks, with the utility addressing larger leaks first. Similarly, in the context of leak-prone pipe replacement, a utility may prioritize the leakiest pipeline segments on its system for replacement first. In either case, as discussed below, utilities are starting to recognize the benefits of a “bundling” or “grid-based” approach whereby leaks or pipeline segments in a given geographic area are bundled together for repair or replacement, as the case may be, in order to allow for efficient use of time and resources (Clark et al., 2012).

5. Case Studies: Applying Leak Quantification Data to Utility Operations

Using leak data collected by Environmental Defense Fund (EDF), Public Service Gas & Electric (PSE&G), New Jersey’s largest utility, is applying a spatially-attributed grid-based method to prioritize pipe segments for replacement. This effort is part of a large-scale $905 million pipe replacement program that was recently approved by the New Jersey Board of Public Utilities (Public Service Electric and Gas, 2012). The methodology developed by EDF in collaboration with PSE&G is discussed below.

First, PSE&G's distribution system was plotted using geographic information systems (GIS) divided into roughly equally sized polygons of one square mile. Using its Hazard Risk Index Model, PSE&G ranked grids for pipeline replacement based on the hazard index per mile of cast iron pipes in each grid, which is calculated based on an assessment of safety risk factors.[8] The hazard index per mile for each grid for which EDF quantified leak flow rate is depicted in Table 1 of the Appendix.

Next, using a Google Street View car equipped with methane detection equipment and geographic positioning systems (GPS), EDF surveyed 30 grids targeted for pipe replacement based on their ranking by the Hazard Risk Index Model. A leak quantification algorithm developed by Colorado State University was applied to the resulting data such that the leak flow rate for each leak observed was calculated (von Fischer et al., 2017). Flow rates for all leaks detected in a given grid were then summed and averaged over the number of miles of pipe in each grid to arrive at the estimated leak flow rate per mile of pipe in each grid. The resulting normalized metric resulted in a ranking of grids by their leak flow rate per mile of pipe (Table 1 of the Appendix).

This methodology was used to develop spatially attributed leak data for each grid cell (Figure 2),[9] presenting a visual depiction of the relative size, frequency, and location of leaks in each grid cell, and attributing each leak to particular segments of utility infrastructure. This information when sorted by comparable Hazard Risk Index results, used in making the initial prioritization of the grids, allowed PSE&G to prioritize grids for pipeline replacement. Specifically, for grids with comparable hazard ranks, the overall leak flow rate/mile of pipe was considered to identify and prioritize the leakier grids for replacement.

PSE&G's approach allowed it to focus its expenditures and resources on the leakiest pipeline segments and also recover the largest volume of usable natural gas per section of pipeline replaced. An analysis of emission reductions from PSE&G's final prioritized grid replacement strategy indicated that PSE&G was able to control 83% of the measured leak flow rate by replacing 58% of the pipeline mileage in measured grids (Appendix, Table 1 at grid 2B-42). In the business-as-usual case, PSE&G would have needed to replace 99% of the pipeline mileage in the surveyed grids to reach the same level of emission reductions (Appendix, Table 2 at grid 2C-43). Therefore, PSE&G achieved an 83% reduction in leak flow rate by replacing approximately one-third fewer miles of pipe than would have been necessary to achieve the same level of emission reductions if they had not used leak flow rate data. All of the pipes

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[8] PSE&G conducts an annual study using this model to evaluate each cast iron main segment that has had a break, to rank each segment for replacement based on a combination of break history and environmental factors. Each geographic grid is ranked by adding the hazard indexes for individual pipe segments within the geographic grid and dividing them by the total miles of utilization pressure cast iron (UPCI) in the grid, arriving at a hazard index per mile for each geographic grid. Using the hazard index per mile results, grids were ranked by highest to lowest and then placed into A, B, C, and D priority grid categories.

[9] PSE&G's infrastructure data is protected under a non-disclosure agreement, and is not shown here. However, an example of the grid method, using fictitious data, is provided in Figure 2.

targeted for replacement will eventually be replaced, but emission reductions were achieved sooner than they would have been in a business-as-usual scenario.

Cast iron pipelines make up roughly 4% of pipelines nationwide. The avoided leak rates assumed here are based on roughly 9% of cast iron pipeline mileage having been prioritized for replacement out of the PSE&G miles where leak flow rates were quantified. In the case of PSE&G, those 9% of cast iron pipeline miles were equivalent to 37% of the estimated leak flow rate. Let us assume that utilities across the nation find and replace superemitting pipeline segments in a similar proportion to PSE&G — that is, where the prioritized grids represent 37% of the measured emissions and 9% of the pipeline miles. If this is possible, then 37% of emissions would be reduced by prioritizing 9% of nationwide cast iron pipeline miles, or roughly 2,500 miles. Reducing 37% of national cast iron pipeline emissions would be equal to reductions of 600,000 Mcf/year (+/- 70,000 Mcf/year).[10] This would have the same climate impact as taking 200,000 passenger vehicles off the road each year (+/-24,000 passenger vehicles).[11]

There are of course, uncertainties in the proportional presence of superemitting pipeline segments, the actual leak flow rates of those segments, and whether superemitting pipeline segments would be coincidentally classified as hazardous, regardless of leak flow rate. Even in PSE&G's system, the frequency of superemitters is unknown on a system-wide basis, because only some areas were surveyed, and because little is known about the "birth rate" of superemitters on a system. Nonetheless, these results from PSE&G indicate that there are likely to be sizeable benefits of leak quantification and prioritization for the climate and ratepayers.

PSE&G is already beginning to capture the benefits of prioritizing high-emitting (or "superemitting") grids for replacement. If other utilities find and prioritize superemitting pipeline segments or leaks at a similar rate nationwide, significant climate benefits could be achieved earlier than might otherwise be possible under a business as usual efforts.

As mentioned above, the grid approach can also be used to prioritize geographic zones not only for pipeline replacement, but also for leak repair. In 2015, Consolidated Edison of New York (CECONY) had the highest percentage of leak prone pipeline mains out of any utility in New York.[12] Just as PSE&G is using leak quantification to prioritize pipeline segments for replacement, CECONY recently completed a pilot program in collaboration with EDF to prioritize the utility's non-hazardous leaks for repair (Environmental Defense Fund and Consolidated Edison Company of New York, 2016). CECONY provided EDF with location and infrastructure information for its non-hazardous leak backlog. EDF surveyed the areas indicated by CECONY and quantified these leaks. CECONY will rank and prioritize leaks for repair based on the emissions flow volume. Preliminary results show that more than half of the emissions identified through our survey efforts could be eliminated by addressing the largest 18% of the leaks.

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[10] This estimate only includes the removal of cast iron pipelines. The calculation of potential reductions of national cast iron pipeline emissions is derived by multiplying the average emission factor of 60.1 Mcf/mile/year for cast iron by the total miles of cast iron in the nation and multiplying that product by 37%. The estimate does not account for the added potential emissions of plastic mains — the most likely replacement material — which have an estimated average emission factor of 0.5 Mcf/mile/year (Lamb et al., 2015; U.S. Environmental Protection Agency, 2016).

[11] Assuming a 20-year Global Warming Potential of 84 for methane.

[12] "Leak prone pipeline mains" includes miles of unprotected bare steel mains and cast iron mains.

By enabling the ranking of the leakiest pipeline segments and individual leaks, leak quantification can help utilities decide where to repair leaks or replace pipelines when comparing sections of infrastructure with comparable risk rankings, thereby balancing safety and efficiency considerations. This approach, now pioneered by two major utilities, presents significant safety, capital efficiency, ratepayer, and environmental benefits, and is ready for adoption by other utilities.

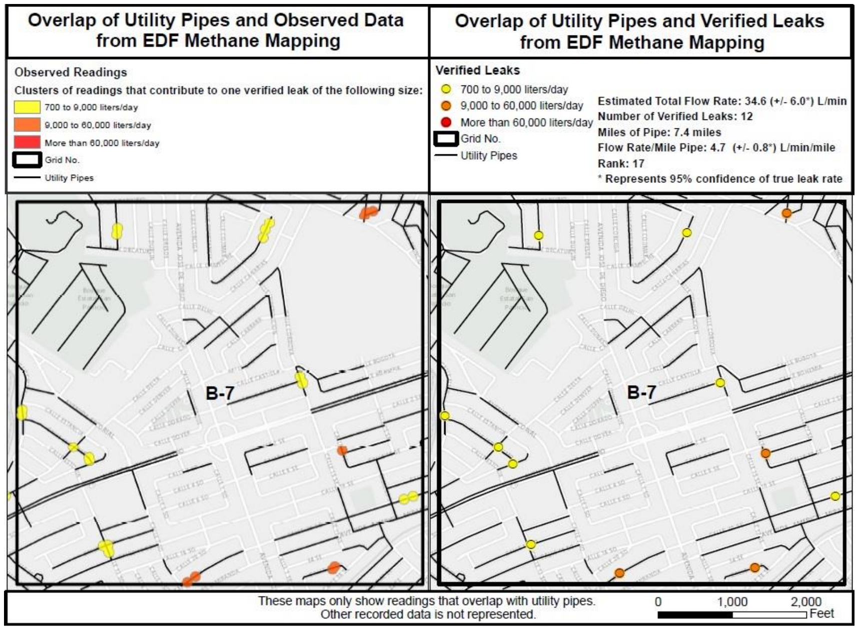

Figure 2 This simulated depiction of leaks in one grid cell of a utility's pipeline system demonstrates how overlapping observed readings are treated as individual "verified leaks," attributable to pipeline infrastructure. The result of such spatial attribution is a visual depiction of the relative size, frequency, and location of leaks in each grid cell.

6. Opportunities for Further Methodological Improvements

Leak quantification methodologies offers utilities an opportunity to use leak quantification to establish a baseline system-wide leak flow rate for their entire distribution system and measure progress in reducing emissions over time. Applied in this manner, quantification would be informative when considering major pipeline repair or replacement initiatives, allowing regulators and other stakeholders to assess the effectiveness of leak repair and pipe replacement programs in a transparent, measurable way.

Currently, utilities are building out and integrating advanced leak detection technology and spatial analysis into their routine pipeline safety and inspection programs. The federal rules establishing integrity management requirements for gas distribution pipeline systems ("Distribution Integrity Management Program for Natural Gas Distribution Sector") came into effect in 2011 (49 C.F.R. §192 [2009]). Under those rules, operators are required to develop and implement a distribution integrity management program. While the rules do not explicitly require utilities to quantify leaks, they state that: (1) pipeline operators must consider all reasonably available information to identify threats to pipeline integrity, and (2) the number and severity of leaks can be important information in evaluating the risk posed by a pipeline in a given location (49 C.F.R. §192.1007 [2009]). Under the rules, operators are required to consider the following categories of threats to each gas distribution pipeline: corrosion, natural forces, excavation damage, other outside force damage, material or welds, equipment failure, incorrect operations, and other concerns that could threaten the integrity of its pipeline. Sources of data may include, but importantly, are not limited to: incident and leak history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, and excavation damage experience.

With technology available that makes leak quantification methods commercially available and viable, and PHMSA rules requiring operators to consider all relevant data in identifying threats to pipeline integrity, it is clear that the prevailing regulatory framework not only allows for leak flow rate to be considered in evaluating threats to pipeline integrity, but in fact, underscores the need to do so.

Some utilities, in addition to those described above, are already making use of leak quantification technology for this purpose. In California, Pacific Gas & Electric Co. (PG&E) is exploring how to integrate leak quantification technology into its leak management efforts (Pacific Gas and Electric Company, 2015b; Pacific Gas and Electric Company, 2012). This includes collecting leak data in a format that supports predictive analytics for assessing and mitigating risks to PG&E's infrastructure. CenterPoint Energy has also begun pilot testing advanced leak detection technology in Houston, Texas, and Minneapolis, Minnesota (Centers and Coppedge, 2015). The company has implemented a phased deployment strategy to evaluate and use advanced leak detection technology for leak surveys, and integrated the resulting data into leak prediction models that rely on spatial analytics. A collaborative, utility-led effort exploring leak quantification methods is also underway.[13]

A recent report by researchers at PricewaterhouseCoopers discusses the benefits of using spatial analytics to predict when and where pipeline leaks will occur (Wei et al., 2016). The authors describe how using quantitative failure history data, customer calls, and condition assessments can enable utilities to transparently manage their system, reduce human error, and cost-effectively improve decision-making (Wei et al., 2016). Traditional risk assessment has relied heavily on subject-matter experts who may use subjective data to make decisions about prioritizing risk mitigation actions. The report proposes that integrating spatial analytics with condition assessment data can allow operators to obtain a quantitative snapshot of asset risks in near real-time to inform investment planning and pipeline replacement project prioritization. The report further indicates that advanced leak detection technology can be used to provide data on leak density that can be integrated into a predictive model of leaks, further enabling capital prioritization. Such an approach can lead to efficiency and cost savings. For example, a case study presented in the report found that the client's quantitative spatial analytics model "delivered an estimated 3.9 times more leaks avoided, 3.6 times greater leaks/mile replaced, and 4.1 times more O&M (operations and maintenance) expense cost savings for the same capital investment" (Wei et al., 2016).

7. Conclusion

Quantifying and ranking leak flow rates for prioritization of leak repair and pipe replacement programs makes it possible to achieve larger reductions in gas lost for the same amount of time and resources, resulting in more cost-effective leak repair and pipeline replacement programs. As demonstrated by PSE&G's successful use of new practices to prioritize a large-scale pipe replacement program, leak

[13] i.e. NYSEARCH. 2014. "Technology Evaluation and Test Program For Quantifying Methane Emissions Related to Non-Hazardous Leaks." https://www.nysearch.org/tech_briefs/TechBrief_Methane-Emissions-Quantification.pdf

quantification technologies and methodologies can currently be deployed to prioritize leak repair and pipeline replacement programs. Using leak quantification allows for more robust leak prioritization, which helps to improve safety, minimize waste of natural gas, and reduce greenhouse gas emissions. Moving forward leak quantification will allow utilities to establish a baseline of system leaks that can provide an improved mechanism for comparing pre- and post-repair/pipe replacement outcomes to evaluate the success of such programs.

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Appendix A: Emission Reduction Analysis

EDF quantified leak flow rates in 30 grids that PSE&G had designated as needing pipeline replacement. PSE&G replaced pipes in the most hazardous grids first, then used leak flow rate as an additional layer for prioritizing pipes for replacement in grids with lower, but comparable hazard indexes. This appendix describes the estimated emissions impact of this prioritization scheme.

The goal of this analysis was to quantify the amount of avoided methane emissions resulting from EDF's methane mapping activities in PSE&G's system, particularly with respect to pipeline grids that were prioritized for replacement as a result of having leak flow rate data available.

To determine this impact, leak flow rate reduced per replacement effort was considered. This includes an analysis of the percent of leak flow rate avoided under each scenario (i.e. business as usual or prioritized based on leak flow rate) and a comparison to the percent of mileage replaced under each scenario. This would give a comparison of the relative leak flow rate reduced per mile of expenditures, rather than a direct estimate of the leak flow rate reduced over time. Calculating the leak flow rate reduced over time was not possible, because we did not have data demonstrating when each grid would have undergone replacement in a business-as-usual scenario.

A.1 Procedures

PSE&G indicated that any grid with a hazard index per mile (HI/mi) greater than 25 would hold the highest priority for replacement (Table 1; grids shaded in orange). Where HI/mi was comparable (between 25 and 10 HI/mi), leak flow rate data was used to help sub-prioritize the grids by leak flow rate normalized by the number of miles in each grid. This parameter was expressed as liters per minute per mile (L/min/mi). In the datasheet, grids that met the above criteria and were prioritized based on leak flow rate were shaded in green. Three grids were prioritized this way.

The first step in determining the amount of avoided methane emissions was to sort all of the grids in order of final ranking (Table 1). Next, the cumulative percent of leak flow rate (L/min) and the cumulative percent of mileage for each successive grid was calculated (see far right columns). Finally, the same calculations were made ordering the grids by "GSMP UPCI Grid Rank" to represent the business-as-usual case (Table 2).[14] These calculations allow a demonstration of the leak flow rate avoided for each successive replacement effort, and allow a comparison between the business-as-usual case and the final ranking that includes leak flow rate.

A.2 Calculating uncertainty

Researchers at Colorado State University calculated a measure of uncertainty for the flow rate (L/min) and flow rate per mile (L/min/mi) in each grid. The measure of uncertainty, or confidence interval, was based on two times the standard deviation, which was calculated as 60% of the flow rate divided by the square root of the number of verified leaks found in each grid. Within this confidence interval, the flow rate range is expected to be true 95% of the time. In calculating a confidence interval for a select number of grids, the measure of uncertainty was summed for the total estimated flow rate (L/min) in the selected grids.

[14] GSMP stands for "Gas System Modernization Program." UPCI stands for "Utilization Pressure Cast Iron."

A.3 Avoided leak flow rate by mileage replaced

Three grids (2B-42, 2L-43, and 2C-43) met PSE&G's criteria for prioritization based on leak flow rate, and had not already been prioritized based on the hazard index. Three other grids (2A-48, 2K-44, and 2A-45) had a flow rate of greater than 10 L/min/mi, but were already prioritized based on hazard index. The green shaded grids that were prioritized based on leak flow rate, rather than hazard index, add up to a flow rate (L/min) of 37% of the total flow rate. Table 1 shows the grids in order of final ranking and demonstrates the leak reductions that could be achieved through prioritization of each successive grid, as well as the corresponding percentage of pipeline miles that had to be replaced to reach each successive leak flow rate reduction.

The grids were replaced in order of final ranking, with the orange-shaded grids having been replaced first. The total emissions reduced are calculated as a cumulative percentage from the time that the first grid (2A-48) undergoes pipeline replacement, until the last-ranked green-shaded grid (2B-42) undergoes pipeline replacement. By the time pipeline replacement takes place in all three green-shaded grids with an HI/mi less than 25, the total flow rate reduced is 83% (Table 1 at grid 2B-42). This flow rate reduction was achieved through replacing less than 60% of the surveyed pipeline mileage (Table 1 at grid 2B-42).

In this prioritization, 11 grids out of 30 (Table 1, grids 1Y-48 to 2D-53) were ranked as a lower priority than the three non-hazardous, green-shaded grids. If the business-as-usual ranking based only on hazard is considered (Table 2), the three green-shaded grids would have been prioritized lower, and all but three grids out of 30 (Table 2, grids 2B-42 to 2D-53) would need to be replaced to reach the same level of avoided emissions (83%) that came as a result of prioritization based on leak flow rate. In the business-as-usual prioritization, by the time a flow rate reduction of at least 83% would have been achieved, 99% of the pipeline miles would have to have been replaced (Table 2 at grid 2C-43).

Grid	Miles of UPCI Pipe in Grid	Total Estimated Flow Rate (L/min)	Estimated Flow Rate per Mile (L/min/mi)	Hazard Index per Mile (HI/mi)	GSMP UPCI Grid Rank	Rank by Estimated Flow Rate per Mile	Final Ranking	Cumulative Percent of Miles	Cumulative Percent of Total Estimated Flow rate (L/Min)
2A-48	1.07	16.08	15.03	54.9381	1	19	1	1%	1%
1Z-47	7.49	52.46	7.00	25.9084	15	10	2	5%	4%
2L-57	4.21	9.15	2.18	45.3544	2	24	3	7%	5%
2K-57	4.23	2.33	0.55	27.8521	11	25	4	10%	5%
2L-58	1.77	1.93	1.09	27.7219	12	27	5	11%	5%
2K-45	5.49	51.03	9.30	37.2695	3	9	6	14%	8%
2K-44	3.43	119.20	34.75	36.7325	5	5	7	16%	15%
2B-46	2.54	10.19	4.01	36.1869	6	23	8	17%	15%
2A-45	2.25	329.34	146.37	28.0060	10	1	9	19%	34%
2K-55	12.89	24.85	1.93	32.5147	7	17	10	26%	36%
2L-55	10.64	20.65	1.94	20.8300	28	14	11	32%	37%
2J-51	9.34	36.13	3.87	29.1177	8	11	12	37%	39%
2H-50	5.75	34.58	6.01	24.7551	17	12	13	41%	41%
2D-58	2.87	9.94	3.46	28.1752	9	20	14	42%	42%
2C-43	6.91	426.80	61.77	19.6449	39	2	15	46%	66%
2L-43	7.41	189.20	25.53	23.6801	20	3	16	50%	77%
2L-51	8.05	68.93	8.56	24.1780	18	4	17	55%	81%
2H-45	4.28	11.95	2.79	24.1516	19	22	18	57%	82%
2B-42	1.09	15.81	14.50	20.6577	32	16	19	58%	83%
1Y-48	4.14	23.29	5.63	23.3831	22	18	20	60%	84%
1V-50	8.2	58.26	7.10	22.2527	23	6	21	65%	88%
1V-49	2.52	1.98	0.79	20.6865	29	26	22	67%	88%
2P-53	1	0.00	0.00	22.0075	24	28	23	67%	88%
2J-52	8.95	50.98	5.70	20.6443	33	8	24	72%	91%
2G-51	10.38	28.43	2.74	20.4184	34	15	25	78%	92%
1T-60	1.97	0.00	0.00	20.3291	35	29	26	79%	92%
2 E-43	4.18	22.97	5.50	20.1753	36	13	27	82%	94%
2N-44	14.21	94.22	6.63	19.8060	37	7	28	90%	99%
2J-53	12.49	14.88	1.19	19.0926	42	21	29	97%	100%
2D-53	4.88	0.00	0.00	19.0639	44	30	30	100%	100%

Table 1 Grids in order of final ranking. Grids with flow rates shaded in green were prioritized based on leak rate. Grids with hazard index shaded in orange were replaced based on hazard index. Final ranking incorporates both hazard and flow rate. An additional 22 grids scheduled for replacement where leak flow rates were not quantified are not included in this table.

Grid	Miles of UPCI Pipe in Grid	Total Estimated Flow Rate (L/min)	Estimated Flow Rate per Mile (L/min/mi)	Hazard Index per Mile (HI/mi)	GSMP UPCI Grid Rank	Rank by Estimated Flow Rate per Mile	Final Ranking	Cumulative Percent of Miles	Cumulative Percent of Total Estimated Flow Rate (L/min)
2A-48	1.07	16.08	15.03	54.9381	1	5	1	1%	1%
2L-57	4.21	9.15	2.18	45.3544	2	21	3	3%	1%
2K-45	5.49	51.03	9.30	37.2695	3	7	6	6%	4%
2K-44	3.43	119.2	34.75	36.7325	5	3	7	8%	11%
2B-46	2.54	10.19	4.01	36.1869	6	16	8	10%	12%
2K-55	12.89	24.85	1.93	32.5147	7	23	10	17%	13%
2J-51	9.34	36.13	3.87	29.1177	8	17	12	22%	15%
2D-58	2.87	9.94	3.46	28.1752	9	18	14	24%	16%
2A-45	2.25	329.34	146.37	28.0060	10	1	9	25%	35%
2K-57	4.23	2.33	0.55	27.8521	11	27	4	28%	35%
2L-58	1.77	1.93	1.09	27.7219	12	25	5	29%	35%
1Z-47	7.49	52.46	7.00	25.9084	15	10	2	33%	38%
2H-50	5.75	34.58	6.01	24.7551	17	12	13	36%	40%
2L-51	8.05	68.93	8.56	24.1780	18	8	17	41%	44%
2H-45	4.28	11.95	2.79	24.1516	19	19	18	43%	45%
2L-43	7.41	189.2	25.53	23.6801	20	4	16	47%	56%
1Y-48	4.14	23.29	5.63	23.3831	22	14	20	50%	57%
1V-50	8.2	58.26	7.10	22.2527	23	9	21	55%	61%
2P-53	1	0	0.00	22.0075	24	28	23	55%	61%
2L-55	10.64	20.65	1.94	20.8300	28	22	11	61%	62%
1V-49	2.52	1.98	0.79	20.6865	29	26	22	63%	62%
2B-42	1.09	15.81	14.50	20.6577	32	6	19	63%	63%
2J-52	8.95	50.98	5.7	20.6443	33	13	24	68%	66%
2G-51	10.38	28.43	2.74	20.4184	34	20	25	74%	68%
1T-60	1.97	0	0	20.3291	35	29	26	75%	68%
2 E-43	4.18	22.97	5.50	20.1753	36	15	27	78%	69%
2N-44	14.21	94.22	6.63	19.8060	37	11	28	86%	74%
2C-43	6.91	426.8	61.77	19.6449	39	2	15	90%	99%
2J-53	12.49	14.88	1.19	19.0926	42	24	29	97%	100%
2D-53	4.88	0	0	19.0639	44	30	30	100%	100%

Table 2 The business-as-usual ranking, with grids in order of hazard index per mile (GSMP UPCI Grid Rank).

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Date of Request: August 7 2017
Due Date: August 17, 2017

EDF Request No. EDF-4 NK-1
NMPC Req. No. NM-1537

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Case No. 17-E-0238 and 17-G-0239 –
Niagara Mohawk Power Corporation d/b/a National Grid – Electric and Gas Rates

Request for Information

FROM: Environmental Defense Fund, Natalie Karas

TO: National Grid, Gas Customer Panel

SUBJECT: ***GAS CUSTOMER AND SHARED SERVICES PANEL***

Request:

1. Refer to the Company's response to EDF-3-NK-5, part c, which provides, "The non-pipe gas proposal is for projects that are not near gas main and generally are uneconomic to pursue by traditional or NEP gas expansion criteria."

   a. Please define, with supporting documents as appropriate, "traditional criteria."

   b. Has the Company performed an economic analysis comparing the costs of gas expansion under its Neighborhood Expansion Program versus non-pipe proposals? If yes, please provide that analysis.

Response:

a. The traditional method is to use standard tariff allowances of one hundred feet of main and one hundred feet of service for heat customers, and a total of one hundred feet for non-heat customers. Specifically, Rules 10.1.4 – 10.1.5 of Niagara Mohawk's Gas Tariff P.S.C 219 states:

   10.1.4 Residential Applicant – Non-Heating: If an applicant requests residential non-heating service, the Company shall furnish, place and construct all mains, service lines, service connections and appurtenant facilities necessary to render the service requested. The cost and expense which the Company must bear shall include:

   10.1.4.1 The material and installation costs relating to up to 100 feet of main and service line combined, service connections and appurtenant facilities, but not less than 100 feet of main (if necessary) plus the length of service line necessary to reach the edge of the public right-of-way.

10.1.4.1.1 The service line will be measured from the centerline of the public right-of-way (or the main, if it is closer to the customer and development will be limited to one side of the right-of-way for at least 10 years).

10.1.4.2 The amounts legally imposed by governmental authorities for obtaining required work permits and for repairing or replacing disturbed pavement.

10.1.5 Residential Heating Applicant: If an applicant requests residential heating service, the Company shall furnish, place and construct all mains, service lines, service connections and appurtenant facilities necessary to render the service requested. The cost and expense which the Company must bear shall include:

10.1.5.1 The material and installation costs relating to:

10.1.5.1.1 Up to 100 feet of main and appurtenant facilities, and

10.1.5.1.2 Up to 100 feet of service line measured from the centerline of the public right-of-way (or the main if it is closer to the customer and development will be limited to one side of the right-of-way for at least 10 years), service connections and appurtenant facilities; but not less than the length of service line necessary to reach the edge of the public right-of-way; and

10.1.5.2 The amounts legally imposed by governmental authorities for obtaining required work permits and for repairing or replacing disturbed pavement.

b. No analysis has been performed comparing the Neighborhood Expansion Program verses non-pipe proposals.

Name of Respondent:	Date of Reply:
Glynn Matthews	August 11, 2017