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November 12, 2020

Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission of the District of Columbia
1325 G Street NW, Suite 800
Washington, DC 20005

Re: Formal Case No. 1162, In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges for Gas Service

Dear Ms. Westbrook-Sedgwick:

Enclosed for filing in the above-referenced proceeding, please find the errata to the direct testimony of Virginia Palacios on behalf of Environmental Defense Fund. The errata filing contains no changes to the body of the testimony, but appends an affidavit completed by Ms. Palacios to ensure compliance with D.C.M.R. 15-133.4. If there are any questions regarding this matter, please contact me at 202-572-3525.

Sincerely,

Erin Murphy
Environmental Defense Fund
1875 Connecticut Ave. NW, Suite 600
Washington, DC 20009
202-572-3525
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Enclosure

cc: Parties of Record
Formal Case No. 1162

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

IN THE MATTER OF THE APPLICATION	**)**	
OF WASHINGTON GAS LIGHT COMPANY	**)**	
FOR AUTHORITY TO INCREASE	**)**	**Formal Case No. 1162**
EXISTING RATES AND CHARGES FOR	**)**	
GAS SERVICE	**)**	

DIRECT TESTIMONY

OF

VIRGINIA PALACIOS

ON BEHALF OF

ENVIRONMENTAL DEFENSE FUND

Exhibit EDF(A)

Dated: July 31, 2020

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I. Introduction and Qualifications

Q. Please state your name, title, and business address.

A. My name is Virginia Palacios. I am a Principal at VP Environmental, LLC, and my business address is P.O. Box 27, Encinal, Texas 78019.

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

A. I hold a Master of Environmental Management degree from Duke University and a Bachelor of Science degree in Aeronautical Science from Embry-Riddle Aeronautical University. I am currently a Principal at VP Environmental, LLC. From 2017-2018, I was the State and Local Policy Manager at South-central Partnership for Energy Efficiency as a Resource, where I managed a collaborative effort between investor-owned electric utilities and stakeholders interested in improving the achievements of energy efficiency programs in Texas.

In all, I have nine years of experience working on issues relating to the natural gas sector. In my role as Principal of VP Environmental, LLC, I lead the development of policy solutions to mitigate methane emissions in the natural gas distribution sector in various states through the U.S. Previously, as a Senior Research Analyst at EDF, I provided technical expertise on scientific and regulatory concepts related to local distribution pipeline safety, lost and unaccounted for gas, and quantification of methane emissions from local distribution system pipelines. I also analyzed quantitative and geospatial data related to methane leakage in the natural gas sector.

In my prior position as a Research Analyst at EDF, I investigated local, state, and federal rules related to local distribution pipeline safety and lost and unaccounted for gas, and developed an understanding of how methane emissions from local distribution system pipelines can be quantified. Some of my work, which involved geospatial attribution of methane emissions data, was published in two peer-reviewed articles.[1]

When I began working for EDF as a Research Associate, I conducted regulatory comparisons and data analysis related to the oil and gas industry, with a particular focus on federal and state regulations on distribution system integrity management, SCADA leak detection systems, cost recovery mechanisms, lost and unaccounted for gas, and pipeline mileage and leakage data provided in Pipeline and Hazardous Materials Safety Administration ("PHMSA") Annual Distribution System reports. I co-authored a paper titled "Integrating Leak Quantification into Natural Gas Utility Operations," which was published in Public Utilities Fortnightly in May 2017, provided as Exhibit EDF(A)-3 to this testimony. Additionally, I have had the opportunity to participate in field research comparing several leak quantification methodologies. I have also met with advanced leak detection technology service providers and reviewed information supporting the technical basis for the services they offer. As part of numerous regulatory proceedings, I have reviewed and analyzed several utilities' gas infrastructure programs. Please refer to Exhibit EDF(A)-1 for my complete resume.

Q. Have you previously filed testimony before regulatory or legislative bodies?

A. Yes. I submitted testimony to the Public Service Commission of the District of Columbia ("PSC" or "Commission") in Formal Case No. 1154 on behalf of Environmental Defense Fund. I submitted testimony to the New Jersey Board of Public Utilities ("BPU") in Docket

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1 Lyon, D., et al. (2015). Constructing a Spatially Resolved Methane Emission Inventory for the Barnett Shale Region. Environmental Science and Technology (http://doi.org/10.1021/es506359c); and Zavala-Araiza, D., et al. (2015). Towards a Functional Definition of Methane Super-Emitters: Application to Natural Gas Production Sites. Environmental Science and Technology (http://doi.org/10.1021/acs.est.5b00133).

No. GR17070776 and the New York Public Service Commission ("NYPSC") in Case Nos. 16-G-0061 and 19-G-0066. In Illinois Commerce Commission Docket No. 16-0376 I submitted, on behalf of the Citizens Utility Board, Direct Testimony in 2016, Direct Testimony on Reopening in 2017, and Rebuttal Testimony on Reopening. Please refer to Exhibit EDF(A)-2 for a detailed listing of my testimonies.

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

A. I am submitting this testimony on behalf of the Environmental Defense Fund ("EDF").

Q. Was your testimony prepared by you or under your supervision?

A Yes.

II. <u>Purpose of Testimony and Recommendations</u>

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present information and recommendations to improve Washington Gas Light Company's ("WGL" or "Company") rate application, with a specific focus on the proposed leak repair activities, in order to advance the District of Columbia's ("District" or "DC") climate policies to reduce greenhouse gas emissions. The Company has the opportunity in this proceeding to meaningfully expand the use of ALD+ on its system in order to fully realize the benefits the technology can provide. My recommendations in this proceeding are designed in tandem with my testimony in the PROJECTpipes "PIPES 2" proceeding, Formal Case No. 1154, which details how the Company should use advanced leak detection and leak quantification methods ("ALD+")

to prioritize leak-prone pipe replacements to maximize greenhouse gas ("GHG") emissions reductions and safety.[2]

Q. Please provide a summary of your testimony and recommendations.

A. I recommend that WGL employ ALD+ on a systemwide basis to prioritize leak repairs based on leak flow rate data, after considering safety factors, in order to improve cost-effectiveness, improve safety, and reduce greenhouse gas emissions.[3] The resulting data will assist the Company with quantifying greenhouse gas emissions on its system and reducing emissions quickly and cost-effectively in support of the District's climate policies. Furthermore, data associated with ALD+ will allow the Company to address its Grade 2 and Grade 3 leak backlog. Along these lines, I recommend the Commission revisit the structure of the leak reduction metrics required by Merger Commitments 55 and 73.

I also recommend that the Commission require WGL to submit annual reports on the progress of the Company's proposed implementation of ALD+, which would present additional information beyond the reporting requirements I detailed in Formal Case No. 1154. I next explain how ALD+ works and the potential benefits to the Company, customers, and the environment associated with the use of ALD+ in designing and

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[2] *See* Testimony of Virginia Palacios on behalf of Environmental Defense Fund, Exhibit EDF(A), F.C. 1154 (June 15, 2020).

[3] My recommendations specific to the Company's accelerated pipeline replacement programs are detailed in my testimony filed in Formal Case No. 1154, which addresses phase 2 of the PROJECTpipes program. However, because a systemwide ALD+ survey could be funded in part through base rates, I am also submitting testimony in this proceeding.

implementing leak repair and pipe replacement activities.[4, 5] Finally, I explain the benefits of incorporating ALD+ into utility operations, and provide examples of other utilities that have integrated ALD+ into their operations and recognized these benefits.

Q. Are you providing any exhibits to your testimony?

A. Yes. I am attaching the following exhibits to my testimony:

- Exhibit EDF(A)-1: Resume
- Exhibit EDF(A)-2: List of Expert Testimony of Virginia Palacios
- Exhibit EDF(A)-3: "Integrating Leak Quantification into Natural Gas Utility Operations," Public Utilities Fortnightly (May 2017)
- Exhibit EDF(A)-4: Response of ABB Inc. ("ABB") – Los Gatos Research to Letter of Inquiry Dated May 9, 2017 from the Citizen's Utility Board submitted in Illinois Commerce Commission Docket No. 16-0376
- Exhibit EDF(A)-5: Response of Picarro, Inc. ("Picarro") to Letter of Inquiry Dated May 9, 2017 from the Citizen's Utility Board submitted in Illinois Commerce Commission Docket No. 16-0376
- Exhibit EDF(A)-6: Lost Gas Calculations Worksheet

[4] By advanced leak detection technology, I am referring to high sensitivity (i.e. measuring methane concentrations in parts per billion and collecting data points at a rate of at least twice per second) methane detectors mounted on vehicles equipped with Global Positioning Systems ("GPS") that collect latitude and longitude coordinates at the same time as methane concentration data is being collected.

[5] "Leak quantification methods" refers to the advanced analytics or algorithms that utilize data acquired from advanced leak detection technology to estimate the methane flow rate (e.g. in liters per minute) that can be attributed to a leak indication. Thus, throughout my testimony "ALD+" refers to the combination of ALD technology and quantification methods.

- Exhibit EDF(A)-7: Aaron Van Pelt, Picarro, Presentation: Picarro Natural Gas Network Management Solution (Nov. 2019).
- Exhibit EDF(A)-8: François Rongere, PG&E, Presentation: Risk Based Leak Surveys (Oct. 2019).
- Exhibit EDF(A)-9: Elizabethtown Stipulation of Settlement; New Jersey Board of Public Utilities Docket No. GR18101197
- Exhibit EDF(A)-10: Picarro Emissions Quantification Results Final Report in Support of the Methane Leak Surveying Report for the Public Service Electric and Gas Company ("PSE&G") Gas System Modernization Program ("GSMP") II Program
- Exhibit EDF(A)-11: PSE&G Presentation "Replacement Main Prioritization: A Practical Application of Using Risk and Methane Emissions" (May 2, 2019)
- Exhibit EDF(A)-12: Proposed Components of WGL Systemwide Methane Leak Surveying Report
- Exhibit EDF(A)-13: Washington Gas Light & AltaGas, Climate Business Plan (Mar. 2020)

III. Climate Commitments Adopted by the District of Columbia and Washington Gas

Q. Please explain the connection between achieving the District of Columbia's climate goals and reducing natural gas leaks.

A. The principal component of natural gas is methane, a potent greenhouse gas known to trap 84 times more heat than carbon dioxide over the first 20 years it is released into the atmosphere.[6] Methane is a significant contributor to climate change, and recent academic research indicates that in U.S. cities, methane emissions due to natural gas leakage are about double what is reported in the Environmental Protection Agency's emissions inventory.[7] Academic research has shown that utilities using traditional survey methods were able to locate fewer gas leaks than were found using advanced leak detection.[8] Thus, natural gas utilities such as WGL likely have more leaks, and are emitting significantly more methane from their systems, than is being reported.

Q. Has the District of Columbia committed to act on climate change?

A. Yes. As detailed in its Climate and Energy Action Plan, the District of Columbia government has committed to reduce greenhouse gas ("GHG") emissions at least 50% by 2032 (below 2006 levels), and to make Washington, DC carbon neutral and climate resilient by 2050.[9] These commitments are further affirmed in the CleanEnergy DC

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6 Myhre, G.; Shindell, D.; BrÂŐon, F.-M.; Collins, W.; Fuglestvedt, J.; Huang, J.; Koch, D.; Lamarque, J.-F.; Lee, D.; Mendoza, B.; Nakajima, T.; Robock, A.; G. Stephens, T. T.; Zhang, H. In Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change; Stocker, T., Qin, D., Plattner, G., Tignor, M., Allen, S., Boschung, J., Nauels, A., Xia, Y., Bex, B., Midgley, B., Eds.; Cambridge University Press, 2013.

7 Plant, G., Kort, E. A., Floerchinger, C., Gvakharia, A., Vimont, I., & Sweeney, C. (2019). Large Fugitive Methane Emissions From Urban Centers Along the U.S. East Coast. Geophysical Research Letters, 46(14), 8500–8507. https://doi.org/10.1029/2019GL082635.

8 Weller, Zachary *et al.*, Vehicle Based Methane Surveys for Finding Natural Gas Leaks and Estimating their Size: Validation and Uncertainty, Environmental Science and Technology (2018).

9 Clean Energy DC, The District of Columbia Climate and Energy Action Plan, at Executive Summary page v (Aug. 2018), https://doee.dc.gov/sites/default/files/dc/sites/ddoe/page_content/attachments/Clean%20Energy%20DC%20-%20Full%20Report_0.pdf; Office of the Mayor of DC, Press Release: Mayor Bowser Commits to Make Washington, DC Carbon-Neutral and Climate Resilient by 2050 (Dec. 4, 2017), https://mayor.dc.gov/release/mayor-bowser-commits-make-washington-dc-carbon-neutral-and-climate-resilient-2050.

Omnibus Amendment Act, which requires that the Commission consider the District's climate commitments while "supervising and regulating utility or energy companies."[10] The D.C. Climate and Energy Action Plan specifically states that "natural gas is a major source of methane emissions, which increase global warming much more significantly than carbon dioxide, potentially accelerating the onset of major climate change impacts."[11]

Q. Has the Company committed to act on climate change and reduce its methane emissions?

A. Yes. The Company has committed to reduce its GHG emissions by 50% by 2032 and achieve carbon neutrality by 2050, in alignment with DC's climate goals.[12] The Company identified a pathway to achieve these targets in its Climate Business Plan issued in March 2020.[13] The Company includes the transmission and distribution sector as one of the three prongs central to the Climate Business Plan, acknowledging that improved leak identification and repair, and accelerated replacement of leak-prone pipe, will reduce greenhouse gas emissions in its service territory.[14] The Company has acknowledged that adoption of ALD+ will assist the company in reducing GHG emissions sooner, in support of the District's climate policies.[15]

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[10] D.C. Law 22-257, CleanEnergy DC Omnibus Amendment Act of 2018, Section 103 (effective date Mar. 22, 2019) (amending D.C. Code § 34-808.02) (emphasis added), https://code.dccouncil.us/dc/council/laws/22-257.html.

[11] Clean Energy DC, The District of Columbia Climate and Energy Action Plan, at 24 (Aug. 2018).

[12] Exhibit EDF(A)-13: Washington Gas & AltaGas. (March 16, 2020). Natural Gas and its Contribution to a Low Carbon Future - Climate Business Plan for Washington, D.C. ("Climate Business Plan") p. 2.

[13] *Id.*

[14] Exhibit EDF(A)-13, Climate Business Plan at 15-16.

[15] *Id*. at 4, 16.

In this proceeding, the Company states that its rate application addresses the District of Columbia's climate commitments because its gas leak repair activities contribute to reducing methane leaks.[16]

IV. Considerations to Improve WGL's Use of Advanced Leak Detection and Compliance with the DC Climate Goals

Q. How can advanced leak detection technology be used to improve the Company's estimates of avoided GHG emissions?

A. The Company has acknowledged that using ALD+ will assist the company in reducing methane emissions on its system, in support of the District's greenhouse gas policies.[17] Leak flow rate data derived using ALD+ provides a real-time estimate of the company's actual emissions.

Currently, the Company estimates greenhouse gas emissions on its system using the EPA Subpart W emission factors, which are emissions estimates per mile of pipeline main, by material (e.g. cast iron, plastic, etc.), averaged from samples taken in limited studies across the entire nation.[18] Using the EPA's emissions accounting method is less than optimal and is not the most accurate method available in this context. The EPA emission factors were developed using leak inventories that were established using traditional leak detection technology that finds far fewer leaks than ALD+. Additionally, some studies that were used to revise the most recent EPA emissions factors quantified

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[16] Supplemental Direct Testimony of Melissa Adams, Exhibit WG(L), pp3-4 (May 15, 2020).

[17] Formal Case No. 1154, Supplemental Direct Testimony of Stephen J. Price. Exhibit WG (D). p. 4, lines 10 – 12 and 18 – 20.

[18] Exhibit EDF(A)-13, Climate Business Plan at 15.

flow rates only for non-hazardous leaks, which may have presented bias toward leaks with lower flow rates.[19] Furthermore, studies using data from aerial surveys have indicated that the EPA inventory may be only be identifying half of the actual emissions from the natural gas supply chain.[20] The Company is likely underestimating emissions by relying on the EPA's method for estimating systemwide emissions.

Using company-specific data from a systemwide ALD+ leak survey to establish an emissions baseline and track progress toward reducing emissions will result in measurable outcomes that allow the Company to take credit for actions it takes to reduce emissions sooner. To the extent that using ALD+ to estimate a baseline systemwide leak flow rate results in a higher estimate of emissions than is derived using the EPA method, this can and should be viewed as an opportunity to pick low-hanging fruit to reduce GHG emissions, because it allows the Company to identify more areas where it can cost-effectively mitigate GHG emissions using proven technologies and methods. Furthermore, this would allow for transparency that would provide the Commission helpful information to track reductions on a regular basis.

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[19] U.S. Environmental Protection Agency. (2016). Inventory of U.S. Greenhouse Gas Emissions and Sinks: Revisions to Natural Gas Distribution Emissions. Retrieved from https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/Final_Revision_NG_Distribution_Emissions_2016-04-14.pdf.

[20] Plant, G., Kort, E. A., Floerchinger, C., Gvakharia, A., Vimont, I., & Sweeney, C. (2019). Large Fugitive Methane Emissions From Urban Centers Along the U.S. East Coast. Geophysical Research Letters, 46(14), 8500–8507. https://doi.org/10.1029/2019GL082635

Q. How can the Company's plans to integrate advanced leak detection into its operations be improved?

A. As I note above, WGL has included ALD+ in its proposal for PIPES 2 (as Program 9) and in its Climate Business Plan. [21] Although the Company's commitment to using ALD+ is an important first step, I suggest improvements to ensure that the resources invested in ALD+ are used to maximum effect. The Company should institute a holistic, systemwide program implementing ALD+ for use in leak repair, pipe replacement prioritization, and calculating a systemwide emissions baseline and reporting reductions. The Company should fund its systemwide ALD+ program through its rate case—in support of its leak repair program and systemwide emissions analysis; and through PIPES 2—in support of its pipe replacement prioritization efforts.

Conducting a systemwide leak survey would allow the Company to find large leaks that may not have been previously identified through traditional leak survey methods. In conjunction with a program designed to address Grade 2 and Grade 3 leaks, WGL can apply the results of the ALD+ survey to reprioritize mains for replacement based on leak density (e.g., leaks per mile) and leak flow rate data.[22] WGL can use information from an ALD+ survey to more quickly repair the leaks responsible for the greatest volume of methane emissions, and thus reduce emissions from its distribution system and quantify the achieved emission reductions. The use of leak information from a systemwide ALD+ survey need not interfere with WGL's PIPES 2 program, and in fact could improve the

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[21] Formal Case No. 1154, Jacas Supplemental Direct Testimony, p.3 lines 9 – 10; Exhibit EDF(A)-13, Climate Business Plan p. 16-17.

[22] *See* Formal Case No. 1154, Testimony of Virginia Palacios, Exhibit EDF(A) at p. 9 – 12. (June 15, 2020).

prioritization of those projects as well. As explained in testimony filed on behalf of EDF in Formal Case 1154 regarding the Company's PIPES 2 proposal, conducting an ALD+ survey on approximately 5 miles of main at a time during varying years of PIPES 2, which is what the Company proposes,[23] would be significantly less impactful than other options.[24]

Q. How else will ALD+ improve the Company's operations?

A. ALD+ data can provide additional datapoints relevant to addressing leak backlogs and greenhouse gas emissions, including:

1. Identification of additional leaks not found using traditional survey methods: Leaks can be "bundled" and repaired on a shorter timeframe using a method similar to PG&E's "Super Crew" approach.[25] These data can help identify areas with high leak density that could merit more significant treatment than leak repair, such as prioritization for pipeline replacement or pipeline retirement through a Non-Pipeline Alternative program, if the Company were to develop such a program.

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[23] *See* Formal Case No. 1154, Exhibit WG (2A)-1 at p18, Table 3 (proposing to replace between 4.5 and 5.6 miles of main per year during 2020-2025); Supplemental Direct Testimony of Stephen J. Price, Exhibit WG (D), p. 6, lines 1-5 (proposing to conduct an ALD+ survey during each year of PIPES 2 only of the Programs 2, 3, and 4 (main and service replacements) projects planned for that year that are available for reprioritization).

[24] Formal Case No. 1154, Testimony of Virginia Palacios, Exhibit EDF(A) at p. 30 – 33 (June 15, 2020).

[25] PG&E. (2016). 2016 Gas Safety Plan. p. 33. Retrieved from: http://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=390621. Also findable at: https://www.pge.com/en_US/safety/gas-safety/safety-initiatives/pipeline-safety/pipeline-safety.page.

2. Information on leak flow rates can enable the company to prioritize leak repairs in areas with higher leak flow rates, reducing greenhouse gas emissions faster and capturing the monetary savings of reducing lost gas.

There are various ways that a systemwide ALD+ survey of WGL's service territory in the District could be conducted and analyzed. WGL reported 1,223.24 miles of main in its D.C. territory in its annual distribution report to PHMSA for the year 2019.[26] Across approximately 1,198 miles of that service territory—everything except the 25 miles of mains designated for replacement during PIPES 2—WGL could use the systemwide survey results to better assess leak density and identify the highest-emitting leaks.

In its Grade 2 and Grade 3 leak repair program, the Company can identify areas of their system where pipeline replacements are not planned imminently—i.e., within the next 12 months—and prioritize zones for leak repair based on leak flow rate. And the additional leak data could be incorporated into the Company's DIMP, identifying new areas of the Company's system where accelerated pipeline replacement (or pipeline retirement through a Non-Pipeline Alternative program, if the Company were to develop such a program) may be more efficient than individual leak repair. Within PROJECTpipes, project areas can be sub-prioritized by leak flow rate, after risk rankings and safety factors are taken into account, as explained in my testimony in that proceeding.

I recommend that the Company conduct systemwide leak surveys on a regular, periodic basis—e.g., every two years—to continuously identify new leaks and continue to track GHG emissions on its system. This recommendation is aligned with the DC

[26] PHMSA. July 1, 2020. Gas Distribution Annual Data - 2010 to present. Accessed on July 22, 2020. Retrieved from: https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.

Department of Energy and Environment's recommendation to the Commission that GHG emissions from the natural gas distribution system be quantified and tracked.[27]

Q. Why is it important for the Company to conduct a systemwide ALD+ survey to best prioritize zones for leak repair?

A. Emission reductions achieved using ALD+ are primarily time dependent. The opportunity for optimizing emission reductions lies in earlier repairs of the highest-emitting leaks, as well as earlier replacement of the leakiest mains. Surveying only Grade 2 leaks which are likely to be repaired within six months, or a more limited universe of planned pipe replacements at a time will likely result in only a few months' worth of emission reductions and will be limited to a very small proportion of the systemwide leak population and overall methane emissions.

The Company's limited proposal for the use of ALD+, as detailed in its Climate Business Plan and PIPES 2 testimony, could result in WGL conducting advanced leak detection surveys of fewer than five miles of pipe at a time, in a given year, which would provide the Company with very limited opportunities for emission reductions. The Company's proposed approach is not optimal. Instead, the Company should incorporate ALD+ more fully into its operations, so that leak flow rate information can be collected and used to improve leak repair efforts as well as its accelerated pipe replacement program.

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[27] *See* G.D. 2019-04-M, *In the Matter of the Implementation of the 2019 Clean Energy DC Omnibus Act Compliance Requirements*, Comments by the Department of Energy and Environment on behalf of the District of Columbia Government in Response to the Public Service Commission's Notice of Inquiry at p5 (Nov. 12, 2019); *id.* at p14 ("DOEE believes that the Commission should track reductions in GHG emissions and provide a progress report at an appropriate interval. Further, the Commission should determine, at least every 5 years, whether sufficient progress is being made to achieve the reduction targets and propose remedies or corrective action where needed.").

A systemwide ALD+ survey would provide the greatest opportunities for emission reductions.

Q. How should the Company report on its use of ALD+?

A. The Company should report on its progress with the implementation of ALD+ and its achievements in reducing GHG emissions on its system to the Commission, the District Government, and the public. The Company should complete and file with the Commission an annual, public Systemwide Methane Leak Surveying Report detailing its findings and progress in implementing ALD+ technology and utilizing the associated data to improve risk assessment and reduce methane emissions. The annual report will be a resource to track the Company's progress in decreasing leaks, reducing greenhouse gas emissions, and improving safety. The annual report should be detailed and consistent to allow the Commission and stakeholders to track the Company's progress in its integration of ALD+ into its operations, and should contain the information detailed in Exhibit EDF(A)-12. In testimony in the PIPES 2 proceeding, I propose that the Company should file an annual PIPES 2 Methane Leak Surveying Report.[28] The systemwide Methane Leak Surveying report described here could include and encompass the information WGL would report on within the PIPES 2 program, but would be broader given that it would address the Company's systemwide operations.[29]

[28] Formal Case No. 1154, Testimony of Virginia Palacios, Exhibit EDF(A)-12 (June 15, 2020).

[29] Exhibit EDF(A)-12 contains suggestions for the report's requirements.

V. Recommendations to Improve WGL's Leak Repair Metric and Proposed Efforts to Reduce Methane Emissions

Q. Please summarize your understanding of the Company's proposed leak repair efforts.

A. In its rate application, WGL allocates $22.2 million for leak repair expenses in the District of Columbia in the test year.[30] WGL describes "leak response costs" and "regulatory requirements" as reasons that WGL is experiencing a deficiency in net operating income that creates a need for increased revenue and rates.[31] WGL further states that its rate case "directly addresses" the District's public climate commitments "through the Company's activity to address methane leaks in the District."[32]

The Company does not propose to incorporate ALD+ into its leak repair efforts. The Company, however, is proposing an expansion of PIPES 2—the second five-year period in the Company's proposed 40-year Revised Accelerated Pipe Replacement Plan, also referred to as PROJECT*pipes*—to include a pilot project using ALD+.[33] The Company included its plans to use ALD+ in PROJECT*pipes* in its Climate Business Plan, as part of its long-term strategy to reduce methane emissions and combat climate change.[34] The Company is proposing to spend $2 million on ALD+ over a five-year period,[35] and has

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30 Supplemental Direct Testimony of Robert E. Tuoriniemi, Exhibit WG (2D), at p. 43 (May 15, 2020).

31 Direct Testimony of Robert E. Tuoriniemi, Exhibit WG (D), at p. 6 (Jan. 13, 2020).

32 Supplemental Direct Testimony of Melissa Adams, Exhibit WG (L), at p. 3-4 (May 15, 2020).

33 Formal Case No. 1154, Supplemental Direct Testimony of Stephen J. Price, Exhibit WG(D), p. 3, lines 8 – 12.

34 Exhibit EDF(A)-13, Climate Business Plan at 16.

35 Formal Case No. 1154, Exhibit WG (2A)-1, p12.

proposed that the duration of ALD+ use extend past the pilot phase, for the remaining 35 years of PROJECT*pipes*.[36]

Q. Please explain the Company's current leak reduction metrics, and the Company's progress to date in reporting and compliance with the metrics.

A. As part of the merger agreement between WGL and AltaGas, the Company agreed to Merger Commitment 73, which establishes a five-year leak reduction target for the Company's Grade 2 leaks during 2019 through 2023.[37] The Company is committed to reduce its Grade 2 leaks reported to PHMSA on an annual percentage basis below its 2017 annual level, achieving 10% below the 2017 level by 2023. If the Company fails to meet an annual leak reduction target it must make a compliance payment ranging from $535,000 to $3,510,995.[38] The Company filed its first report detailing its progress with Merger Commitment 73 in May 2020, stating that the Company failed to meet its target for calendar year 2019 of a 2% reduction from 2017 levels of Grade 2 leaks reported.[39] In subsequent filings in July 2020, the Company reported that it made a non-compliance payment of $535,000 pursuant to Merger Commitment 73.[40]

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36 Formal Case No. 1154, Exhibit WG (2A)-1, pp2-3.

37 DC PSC, F.C. 1142, *In the Matter of the Merge of AltaGas and WGL Holdings, Inc.*, Order 19396, Appendix A at p27, Merger Commitment #73.

38 Matrix of Commitment From ALTAGAS/WGLH Merger. FC 1142-2018-G-428 Order No. 19396 Attachment B. (July 10, 2020). P. 26 of 29. https://dcpsc.org/PSCDC/media/PDFFiles/HotTopics/FC1142AltaGasWGLHMergerMatrixPublic.pdf

39 F.C. 1142, Washington Gas Light Company - Commitment No. 73 – Compliance Filing (May 15, 2020).

40 F.C. 1142, Washington Gas Light Company, Commitment No. 73 – Notice of Compliance (July 21, 2020); F.C. 1142, Washington Gas Light Company, Commitment No. 73 – Notice of Compliance (July 23, 2020).

Furthermore, as a part of Merger Commitment 55, WGL must reduce its Grade 2 leak backlog to 35 leaks or less each calendar year starting no later than 2021.[41] WGL reported 149 "known system leaks at end of year scheduled for repair" in their PHMSA annual distribution report for 2019.[42]

Q. Please explain your understanding of the Company's definition of Grade 1, Grade 2, and Grade 3 leaks.

A. Grade 1 leaks are hazardous leaks that require immediate repair by definition.[43] Whereas Grade 2 and Grade 3 leaks are not immediately hazardous and can be repaired on different timeframes.[44] According to Witness Price, "if not repaired before 6 months, a Grade 2 leak must be re-inspected at no less than 6-month intervals to confirm its non-hazardous nature."[45] Typically, Grade 3 leaks are non-hazardous, are monitored at regular intervals and are not scheduled for repair.

Q. Why should the Commission revisit the structure of the leak reduction metrics?

A. The leak reduction metrics should be revisited and improved, so that the Company is rewarded for identifying all leaks on its system and repairing them promptly, not penalized for finding more leaks and potentially increasing its repair backlog.

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41 Matrix of Commitment From ALTAGAS/WGLH Merger. FC 1142-2018-G-428 Order No. 19396 Attachment B. (July 10, 2020). P. 20 of 29. https://dcpsc.org/PSCDC/media/PDFFiles/HotTopics/FC1142AltaGasWGLHMergerMatrixPublic.pdf

42 PHMSA. July 1, 2020. Gas Distribution Annual Data - 2010 to present. Accessed on July 22, 2020. Retrieved from: https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids

43 Supplemental Direct Testimony. Witness Price. p. 5, lines 1 – 7. May 15, 2020.

44 *Id.*

45 Supplemental Direct Testimony. Witness Price. p. 5, lines 4 - 6. May 15, 2020.

Currently, the Company is required to reduce the number of Grade 2 leaks in its backlog to a specified target within no more than 3 years (Merger Commitment 55). Furthermore, the Company is rewarded—or at least, avoids being penalized—for reporting a lower number of Grade 2 leaks (Merger Commitment 73) each year. These metrics discourage the Company from discovering unknown leaks.

As I discuss below, ALD+ is typically able to identify many more leaks than traditional technologies. Thus, the Company may be disincentivized from using ALD+, which could be expected to find more leaks on its system. Although the benefits of ALD+ may not have been known to the Company at the time of the merger agreement, ALD+ is a scientifically and commercially established technology. The Commission should establish a leak metric that incentivizes the Company to identify and repair the maximum number of leaks. In addition to utilizing a metric based on the number of leak reductions from accurate system-wide leak survey counts using ALD+, the Commission should also implement a metric based on the percentage of methane emissions reductions, as measured by leak volume.

Q. What revisions to the leak reduction metric would you recommend?

A. I recommend that WGL first complete a methane leak survey of its entire service territory using advanced leak detection technology. Using the information gathered from this initial survey, WGL could establish a system-wide baseline leak flow rate. Next, a volumetric leak reduction target could be established as WGL's leak abatement incentive. For example, in order to receive its annual maximum positive incentive, the Company could be required to achieve a 50% emissions reduction in no more than four years, which studies have shown can be accomplished through abatement of approximately the largest 20% of leaks in its non-hazardous leak inventory.[46] This objective could be met through a combination of pipeline replacement and leak repairs, allowing the utility to optimize its approach to leak mitigation through pipeline replacements when necessary.

Q. Please explain why you are recommending a period of no more than four years for the Company to achieve a 50% emissions reduction?

A. I am recommending that the Company achieve a 50% emissions reduction in no more than four years for two reasons: first, the current, estimated rate of advanced leak detection technology surveying is such that a system-wide survey could take approximately six months to complete over WGL's 1,200 miles of gas main;[47] and second, in recognition of the time that may be required for the Company to integrate leak flow rate information into its geospatial information systems, reprioritize pipeline replacement and leak repair plans, and conduct the necessary repairs and replacements needed to achieve these reductions.

Q. How would this revised leak reduction metric and approach help to reduce the number of Grade 2 leaks in the Company's system, while achieving safety and climate goals?

A. Addressing Grade 3 leaks early on is one way to avoid the progression of Grade 3 leaks into Grade 2 leaks. Leaks are primarily graded using two factors: concentration of gas in

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[46] Fischer, J. von, Cooley, D., Chamberlain, S., Gaylord, A., Griebenow, C., Hamburg, S., Ham, J. (2017). Rapid, Vehicle-Based Identification of Location and Magnitude of Urban Natural Gas Pipeline Leaks. Environmental Science & Technology, 51(7), 4091–4099. https://doi.org/10.1021/acs.est.6b06095.

[47] WGL reported 1,215.89 miles of main in its D.C. territory in its annual distribution report to PHMSA for the year 2018. Picarro, an ALD+ service provider, reports that their survey method averages more than 3,000 miles of main per year. *See* Exhibit EDF(A)-5, Response of Picarro to Letter of Inquiry Dated May 9, 2017 from the Citizen's Utility Board submitted in Illinois Commerce Commission Docket No. 16-0376).

air, and proximity to buildings or populated areas.[48] In some cases, Grade 3 leaks may be in unpopulated areas. And in other cases, Grade 3 leaks may simply have a low enough concentration reading that they are categorized as non-hazardous.

Concentration readings and leak flow rates are not correlated. Grade 3 leaks are typically not required to be scheduled for repair,[49] and because of this they can leak large amounts of gas over multiple years. Instead, Grade 3 leaks are monitored until they are regraded or no gas is detected, though some states require Grade 3 leaks to be repaired within 36 months.[50] Washington, D.C. does not define leak grades in regulations, nor does it require leaks to be repaired within a certain timeframe by grade.[51]

Prioritizing repair of Grade 3 leaks allows utilities to not only achieve the economic benefits of reducing lost gas, but also proactively addresses leaks before they could become Grade 2 leaks that add to the backlog or become hazardous Grade 1 leaks. Thus, prioritizing Grade 3 leak repairs would improve the safety of a utility's gas distribution system while maximizing methane emission reductions.

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[48] PHMSA. (2000). Gas Leakage Control Guidelines for Petroleum Gas Systems.

[49] For example, New York (16 CRR-NY 255.817) and New Hampshire (New Hampshire Code of Administrative Rules Chapter 500 Part Puc 508.04(l)).

[50] *See*, *e.g.*, Texas Administrative Code Title 16, Part 1, Chapter 8, Subchapter C, Rule § 8.207.

[51] *See* 15 DCMR §§ 2300-2399.

VI. The Mechanics, Benefits, and Cost Effectiveness of Advanced Leak Detection Technology and Data Analytics (ALD+)

Q. Please explain how advanced leak detection technology and analytics (ALD+) operate and can reduce emissions from the gas system.

A. Advanced leak detection technology involves the use of sensitive sensors (e.g. methane sensors with detection limits on the order of parts per billion) installed on vehicles to collect emissions data such as methane and ethane while driving selected survey routes and collecting GPS and wind data. The emissions data are then analyzed using algorithms to draw out key leak information such as estimated leak flow rate (e.g. liters per minute), leak density (e.g. leaks per mile), and probable grade (e.g. Grade 1, 2, or 3).[52] Advanced leak detection technologies and leak quantification methodologies, and the analytics and visualizations that can be developed using these methods, can provide more accurate and useful tools in the Company's efforts to reduce methane emissions from its distribution system and improve prioritization of leak repairs and leak-prone pipe replacement.

Utility estimates of leak size have typically been made using best available estimates of pipeline type, diameter, pressure, and historical leak data. However, this method has limitations; traditional leak surveys can miss up to 66% of leaks compared to ALD+, rely on dated and sometimes incomplete records, and may not provide spatially-attributed information that can be easily linked to infrastructure asset maps.[53]

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[52] For a publicly available description of an algorithm for developing leak indications using data from mobile methane surveys, see Weller, Z. D., Yang, D. K., & von Fischer, J. C. (2019). An open source algorithm to detect natural gas leaks from mobile methane survey data. Plos One, 14(2), e0212287. https://doi.org/10.1371/journal.pone.0212287.

[53] Picarro. 2016. "Pipeline Replacement and Emissions Reduction." Santa Clara, CA. http://naturalgas.picarro.com/support/library/documents/pipeline-replacement-and-emissions-reduction-using-picarro-emissions.

Q. How does advanced leak detection technology compare to traditional technologies?

A. Advanced leak detection is typically able to find many more leaks than traditional technologies. A peer reviewed 2018 Colorado State University ("CSU") study found that utility crews locate only 35% of the pipeline leaks found using traditional technologies in comparison to using advanced leak detection technology.[54] Advanced leak detection technology is helping utilities to find more gradable and hazardous leaks (e.g., requiring abatement due to safety) than they were able to detect using traditional technologies.[55] Combining advanced leak detection technology with traditional leak surveys offers utilities unique insight into their systems that is not possible using only traditional leak survey methods. Advanced leak detection technology often finds different subsets of leaks than traditional survey methods,[56] suggesting that advanced leak detection technology can support a company's existing datasets by providing up to date information about otherwise undiscovered leaks in a system.

Advanced leak detection technology not only offers a better understanding of leak density (leaks per mile), but also can be used to estimate leak flow rate (volume lost over

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[54] Weller, Zachary *et al.*, Vehicle Based Methane Surveys for Finding Natural Gas Leaks and Estimating their Size: Validation and Uncertainty, Environmental Science and Technology (2018). If this detection rate is applied at the national scale, then the national inventory for the number of pipeline leaks in natural gas distribution infrastructure would increase by a factor of 2.4. *Id.* at 11925.

[55] Redding Sr., Stephen M., and Brenda Glaze. 2015. "Revolutionising Leak Management." In World Gas Conference. 2015. Paris, France.

[56] Weller, Z. D., Roscioli, J. R., Daube, W. C., Lamb, B. K., Ferrara, T. W., Brewer, P. E., & Von Fischer, J. C. (2018). Vehicle-Based Methane Surveys for Finding Natural Gas Leaks and Estimating Their Size: Validation and Uncertainty. Environmental Science and Technology, 52, 11922–11930. research-article. https://doi.org/10.1021/acs.est.8b03135.

time).[57] Both leak density and leak flow rate are valuable parameters to be considered in pipeline replacement prioritization, particularly to cost-effectively reduce the volume of leaked and emitted methane. Traditional leak detection technologies are only able to collect data on the concentration of gas in air for a particular leak, and are not capable of estimating leak flow rates. Therefore, ALD+ provides different, important information, that has not previously been widely available.[58]

Q. How can the use of advanced leak detection technology and leak quantification methodologies reduce methane emissions while ensuring that ratepayer funding is deployed efficiently?

A. Fischer et al. (2017) aggregated leak flow rate data collected in several locations in the northeast and Midwest, and estimated that on average "cutting emissions in half could be accomplished by repairing the largest 20% of leaks."[59] This is further demonstrated by the following leak distribution curve,[60] which shows that, among the leaks studied, using

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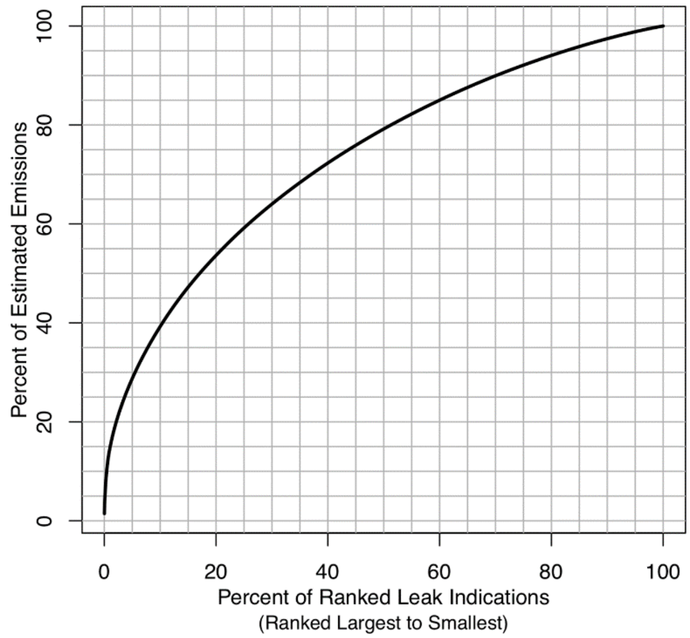
57 Utilities typically use the term "leak rate" to discuss leaks per mile. Because "leak flow rate" appears similar to "leak rate," I use a different term throughout this document to refer to leaks per mile: "leak density."

58 A variety of technologies exist in non-mobile platforms that allow users to estimate leak flow rates, however, most of these are much more time consuming and expensive to use than ALD+ and they are unable to provide improved rates of leak detection, which is an important feature of ALD+.

59 Fischer, J. von, Cooley, D., Chamberlain, S., Gaylord, A., Griebenow, C., Hamburg, S., Ham, J. (2017). Rapid, Vehicle-Based Identification of Location and Magnitude of Urban Natural Gas Pipeline Leaks. *Environmental Science & Technology*, *51*(7), 4091–4099. https://doi.org/10.1021/acs.est.6b06095.

60 Weller, Z. D., Yang, D. K., & von Fischer, J. C. (2019). "Cumulative emissions curve from the estimated sizes of 6125 leak indications. The cumulative emissions curve indicates that largest 20% of leaks account for approximately 54% of total emissions."

ALD+ to prioritize the repair the top 20% of leaks could reduce distribution system emissions by 54%:



By conducting a systemwide leak survey and prioritizing its leak repairs and a selection of pipelines for replacement using leak flow rate data from ALD+, WGL could achieve similar significant emissions reductions faster in its distribution system for the benefit of both ratepayers and the environment.

Q. Can you provide an example of a utility that saw benefits from considering leak size a factor when selecting backlog leaks for repair?

A. Consolidated Edison of New York ("Con Edison"), EDF, and EDF's collaborators at Colorado State University ("CSU") conducted a pilot program in 2016 to survey Con Edison's backlog of Grade 3 leaks (i.e. non-hazardous, and typically categorized as leaks to be reevaluated during the next required leakage survey or annually) and characterize the leaks by size (i.e. flow rate). Con Edison used these data to prioritize the repair of the

Grade 3 leaks with the highest leak flow rates. That is, the Company considered leak size as a factor when selecting backlog leaks for rapid repair.

This prioritization of the highest-emitting non-hazardous leaks represented an estimated reduction in nearly twice the amount of methane emissions compared to a business-as-usual scenario. EDF estimated that Con Edison reduced about 30% of the total emissions from surveyed areas. If Con Edison had used a random prioritization method, they would have reduced just 15% of the total emissions, or only half as many emissions as were reduced using EDF's ranking information. These results and an interactive map showing the leak locations are available on EDF's website.[61]

Q. Please describe how analytic tools enhance the utility of data collected by advanced leak detection technology.

A. In a recent publication, Weller, Yang, and Fischer (2019) of CSU describe how ALD+ can "translat[e] raw survey data into actionable information about natural gas leaks."[62] The publication presents an advanced statistical analysis of over 6,100 leak indications collected from 15 cities; an improved ALD+ open-source algorithm allowing for ALD+ to deliver better source attribution; leak flow rate quantification; leak locating; a more complete survey of otherwise undiscovered leaks; leak grade probability; and "flute" maps, which depict areas where multiple leak indications are observed in close proximity along

[61] Environmental Defense Fund. Innovative collaboration fixes non-hazardous leaks faster. Retrieved from: https://www.edf.org/climate/methanemaps/con-edison. Accessed on: July 27, 2020.

[62] Weller, Z. D., Yang, D. K., & von Fischer, J. C. (2019). An open source algorithm to detect natural gas leaks from mobile methane survey data. *Plos One*, *14*(2), e0212287. https://doi.org/10.1371/journal.pone.0212287.

a pipeline path.[63] The application of advanced leak detection technology and analytics can assist utilities in improving the cost-effectiveness of leak repair and pipeline replacement projects while maximizing volumetric leak reductions.

ALD+ can be used to "prioritize each leak indication by the likelihood that it corresponds to a hazardous leak,"[64] so that utilities can prioritize leak investigations in a way that cost-effectively mitigates risk by maximizing the number of hazardous leaks found per effort spent investigating leaks. By studying plume characteristics, ALD+ software can provide an indication of the potential for leak expressions to migrate into an enclosed area. Some ALD+ providers are using this information to estimate the probability of a leak indication representing an immediate hazard. Such a strategy would improve the utility's performance at reducing the greatest number of hazardous leaks per dollar spent on investigations.

Q. Please comment on how data from advanced leak detection technology can lead to improved prioritization and scheduling of leak repair programs.

A. Data generated by ALD+ can be used to estimate the relative size of leaks, or leak flow rate. Additionally, the sensitivity of ALD+ often results in finding many more leak indications than would be possible using only traditional leak survey technology.

Leak size data can allow the company to prioritize areas of their system for rapid leak repair based on leak flow rates, resulting in more significant reductions in methane emissions and lost gas. As leak flow rates change with replacement levels each year, and

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63 *Id.*

64 Picarro. 2016. "The Transition to Smart Gas Distribution." Santa Clara, CA. http://naturalgas.picarro.com/sites/default/files/2017-04/Picarro%20Analytics.pdf.

new data is added, the quads can be easily reassessed with advanced leak detection technology and analytics. The Company could incorporate that new data to reprioritize leak repairs or replacement scheduling based on efficiency and risk reduction goals, thereby ensuring that the schedule of main replacements is consistently optimized.

For example, Pacific Gas and Electric Company ("PG&E") in California began integrating ALD+ into its standard leak management operating model in 2015. PG&E has been using ALD+ with a "Super Crew" model since 2016 to conduct leak surveys over a wider area and repair hazardous and non-hazardous leaks more quickly. In the Super Crew model, PG&E conducts an ALD+ survey over their system, "performing what would traditionally be multiple weeks of leak survey in one week."[65] All hazardous leaks are then repaired immediately, and schedulable non-hazardous leaks are bundled and repaired within 90 days. PG&E has stated that "having all the work required in an area at one time provides opportunity to bundle work locations and effectively maximize the utilization of resources."[66]

Relying on historical datasets that use only traditional leak detection methods is very likely to result in less accurate pipeline replacement prioritization. Historical leak data should be supplemented with more robust and up to date data provided by advanced leak detection technology and analytics to improve utility decision-making for spending

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[65] PG&E. (2016). 2016 Gas Safety Plan. p. 33. Retrieved from: http://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=390621.

[66] PG&E. (2020). 2020 Gas Safety Plan – Public version. p. 53. Retrieved from: https://www.pge.com/pge_global/common/pdfs/safety/gas-safety/safety-initiatives/pipeline-safety/2020GasSafetyReport.pdf.

customer funds and ensure that replacement activities prioritize the pipelines with the greatest need for replacement.

Q. What are the cost savings that advanced leak detection technology and leak quantification potentially offer to a utility?

A. Advanced leak detection technology service providers describe a wide variety of use cases for advanced leak detection technology and leak quantification.[67] PG&E in California has reported that using ALD+ for compliance leak surveying has allowed them to survey over 100,000 additional services and associated main per year at a forecasted cost savings of $1.6 million over traditional survey methods.[68]

Considering these additional use cases, benefits are significantly greater when using ALD+ holistically in comparison to what can be realized through only applying ALD+ to the management of a pipe replacement program. Currently the Company has only proposed a very limited application of ALD+ to its pipe replacement program, in its Climate Business Plan and in the Pipes 2 proceeding.[69] A more robust application of ALD+ would lead to a commensurate increase in benefits.

Potential cost savings can be found through:

- Capturing gas through identification and remediation of high volume leaks
- Reducing risk through replacement of pipe segments with high leak density (leaks per mile)

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67 *See* Exhibit EDF(A)-4 and Exhibit EDF(A)-5.

68 PG&E's 2020 Leak Abatement Compliance Plan (Attachment 1 to 2020 Gas Safety Plan). 3/16/2020. Page ATCH 1-26. Retrieved from: https://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=598545.

69 Exhibit EDF(A)-13, Climate Business Plan at 14-17; F.C. 1154, Supplemental Direct Testimony of Stephen J. Price. p. 4-6.

- Reducing risk through auditing a walking survey[70]
- Responding to fewer odor calls
- More quickly locating hard-to-find leaks
- Conducting rapid post-emergency survey
- Finding leaks during post-construction quality control
- Real-time source attribution, if using methane/ethane sampling
- Verifying quality of a system prior to asset acquisition

Q. Can you detail an example to demonstrate the magnitude of potential cost savings from using advanced leak detection technology and leak quantification?

A. Although it is difficult to specifically quantify these benefits until a system-wide leak survey with ALD+ is completed, a simple analysis of one category can help to show the order of magnitude of potential cost savings from using advanced leak detection technology and leak quantification. One of the fundamental cost savings offered by advanced leak detection technology and leak quantification is in the form of reduced gas loss from the system. Using a few assumptions, we can estimate potential savings from employing advanced leak detection technology and leak quantification to prioritize a combination of project areas for leak repair or pipeline replacement. The calculations described below are detailed in Exhibit EDF(A)-6.

[70] Advanced leak detection technology can be used to survey an area after a walking survey has taken place, identifying leak indications that may not have been detected in a walking survey. Using leak grade probability software in conjunction with advanced leak detection technology can help to identify priority leak indications that deserve to be revisited.

In 2018, WGL's Natural Gas Deliveries, reported on Energy Information Administration ("EIA") Form 176, were approximately 30.2 billion cubic feet.[71] Meanwhile, the Company's reported "Losses from Leaks Volume" represented about 4.4% of Natural Gas Deliveries. The method of estimating losses from leaks is not clearly defined by the EIA, nor is the method of estimation reported by operators. For the sake of being conservative, I assume that WGL's rate of losses from leaks is 2.2%. The price of gas delivered to residential consumers was $11.78 per thousand cubic feet, and residential customers made up 75.6% of the Company's sales. The commercial price was $10.42 per thousand cubic feet, and commercial customers made up 21.7% of the Company's sales.[72] The value of WGL's 2018 lost gas was nearly $7.4 million. Therefore, if ALD+ could be used to prioritize leak repairs and pipeline replacements for the pipes representing the top 25% of losses from leaks,[73] the Company could save over $1.8 million in only the first year those leaks are stopped. This may represent a conservative estimate of savings if the Company's actual leak rate is closer to 4.4%. Additionally, the savings of multiple years of gas that would otherwise be lost are benefits that compound for ratepayers. Achieving this level of savings would likely require a system-wide leak survey.

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[71] U.S. Energy Information Administration. September 2018. Natural Gas Annual Respondent Query System (EIA-176 Data through 2018). Retrieved from: https://www.eia.gov/naturalgas/ngqs/#?year1=2018&year2=2018&company=Name

[72] U.S. Energy Information Administration. May 29, 2020. District of Columbia Natural Gas Prices. Retrieved from: https://www.eia.gov/dnav/ng/ng_pri_sum_dcu_SDC_a.htm.

[73] Assuming the leak rate is 2.2%, or half of what was actually reported to the EIA.

Q. Can the metrics associated with advanced leak detection technology and analytics provide useful information for regulators, the Company, and ratepayers?

A. Data collected using ALD+ can provide useful input to assist WGL, ratepayers, and the Commission in evaluating the efficacy of the Company's leak repair efforts, as well as its pipeline replacement program. Having data on leak flow rates that is spatially attributed results in metrics that can be verified, as ALD+ can provide insightful performance analysis. By supplying spatially attributed data that can be used to report on meaningful evaluation metrics, ALD+ can improve the information stakeholders and the Commission use to evaluate WGL's leak repair efforts, as well as its pipeline replacement program. Specifically, information including leak flow rate data and leak frequency can be used to evaluate the pace at which risk is mitigated, and whether the scheduling of leak repairs and pipe replacement has been prioritized in a way that optimizes risk mitigation, and allows for replacement program progress to be tracked and assessed frequently and easily.

Furthermore, under the CleanEnergy DC Omnibus Act, the Commission must consider the District's climate commitments and the effect of a given proposal on GHG emissions in its oversight of WGL.[74] ALD+ will yield actionable data on methane emissions, allowing WGL to receive credit for emissions reductions achieved and ensuring accountability before the Commission, D.C. Government, and other stakeholders.

[74] D.C. Law 22-257, CleanEnergy DC Omnibus Amendment Act of 2018, Section 103 (effective date Mar. 22, 2019) (amending D.C. Code § 34-808.02) (emphasis added), https://code.dccouncil.us/dc/council/laws/22-257.html.

Q. How can advanced leak detection technology and leak quantification provide meaningful information for assessing the risk that will allow WGL to make appropriate adjustments in prioritizing leak repairs, as well as pipeline replacements?

A. Advanced leak detection technology and leak quantification can provide data that is relevant to predictive risk models, which would integrate well with the Company's rankings identified by its Distribution Integrity Management Program model, Optimain.[75] Through capturing the current state of the system in each quad with ALD+, the Company can determine the number of leaks per mile in each quad and the leak flow rate per mile in each quad. Using these two data points and Optimain risk modeling, the Company can assess the known magnitude of leak densities (i.e. leaks per mile) over time, and can assess the known magnitude of leak flow rates per mile (i.e. liters per minute per mile) over time. Having data on additional leaks found using ALD+, the Company can make more efficient decisions about where to deploy leak repair crews to address non-hazardous leaks and which areas are more suitable for pipeline replacement based on leak density. When considered along with traditional metrics, leak flow rates per mile can also be a valuable factor in risk assessment. In this testimony, I propose that WGL include another metric in their reporting, the percent of total leak flow rate reduced per year over the percent of pipeline miles replaced per year.

Considering leak flow rate in leak repair and pipeline replacement scheduling can help WGL capture greater volumes of gas earlier in its leak repair and pipeline replacement programs —reducing methane emissions, improving efficiency, and benefiting ratepayers.

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[75] *See* Jacas Direct Testimony. December 7, 2018. p. 21.

Empirical research has shown that leak flow rates per mile are not necessarily correlated to leak densities,[76, 77, 78] indicating that a utility could reduce large numbers of leaks without achieving comparable reductions in overall leak flow rates. It is beneficial to remediate leaks with higher flow rates more quickly so that greater volumes of potentially lost gas will be captured earlier on in the program. Because leak flow rate is an indicator of the overall volume of gas lost from a system, a prioritization ranking that includes leak flow rate at a relatively high weight will result in leak repair and pipeline replacement programs that reduce lost gas and methane emissions sooner.

VII. Use and Integration of ALD+ by Other Utilities

Q. Please explain how other utilities are using advanced leak detection technology and data analytics.

A. Utilities across the United States are incorporating advanced leak detection technology and analytics into their operations, and ALD+ is being used in at least seven countries and four continents worldwide.[79] Additionally, advanced leak detection is currently used by utilities for compliance leak surveys in at least eight U.S. states.[80]

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76 Fischer et al. (2017).

77 Brandt, A. R., Heath, G. A., & Cooley, D. (2016). Methane leaks from natural gas systems follow extreme distributions. *Environmental Science & Technology*, acs.est.6b04303. https://doi.org/10.1021/acs.est.6b04303

78 Hendrick, M. F., Ackley, R., Sanaie-Movahed, B., Tang, X., & Phillips, N. G. (2016). Fugitive methane emissions from leak-prone natural gas distribution infrastructure in urban environments. *Environmental Pollution*, *213*, 710–716. https://doi.org/10.1016/j.envpol.2016.01.094.

79 Exhibit EDF(A)-7: Van Pelt, A. (2019). Picarro Natural Gas Network Management Solution. In Pipeline Safety Trust. New Orleans, Louisiana. Retrieved from http://pstrust.org/wp-content/uploads/2019/11/Picarro-Pipeline-Safety-Trust-11-7-19.pdf.

80 *Id.*

Utilities are employing ALD+ data to supplement existing information on asset risks, and thereby design and target system modernization and maintenance efforts more effectively. Gas utilities are now moving 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.[81] Advanced leak detection and quantification methods have significant ratepayer, environmental and system-wide benefits, as I detail below. A number of major utilities including PSE&G, New Jersey's oldest and largest utility, Elizabethtown Gas in New Jersey, National Grid in New York, CenterPoint Energy in Texas and Minnesota, and Pacific Gas and Electric in California have recognized the benefits of these methods and created pathways for the adoption of such advanced technologies.

Q. How have other utilities used advanced leak detection technology and analytics to optimize leak surveying and track methane emissions reductions on their system?

A. The California Public Utilities Commission approved best practices and reporting requirements for a Natural Gas Leak Abatement Program to reduce methane emissions from the natural gas distribution sector. These include "twenty-six mandatory best practices for minimizing methane emissions pertaining to policies and procedures, recordkeeping, training, experienced trained personnel, leak detection, leak repair, and leak prevention," in support of California's goal to reduce methane emissions 40% below 2013 levels by 2030.[82]

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[81] PricewaterhouseCoopers (2016).

[82] California Public Utilities Commission. Decision 17-06-015. June 15, 2017.

PG&E is complying with these best practices by using advanced leak detection technology to better predict areas of its system where the frequency of below-ground leaks is likely to be higher.[83] PG&E first began using Picarro's mobile ALD+ system in compliance surveys in 2014, finding it to be ten times faster than walking surveys.[84] PG&E has integrated its ALD+ data analysis into its DIMP "Likelihood of Failure" ("LoF") model, which the utility uses to assess risk and prioritize its repair and replacement activities.[85]

PG&E has developed statistical models to identify geographic areas or "plats" in its system that warrant more frequent surveys.[86] The models are also being used to establish the order in which plats should be surveyed, based on the likelihood of finding the most leaks earlier in the survey. To test this methodology, PG&E ranked its plats by number of leaks, and plotted them along a cumulative distribution curve to depict a "perfect ranking."[87] In the "perfect ranking" scenario, the plats with the highest number of leaks per number of services would be driven first. Thirty-seven percent of the plats did not have any leaks, demonstrating that a typical scenario where plats are surveyed at random would likely result in inefficient surveying expenditures that find fewer leaks per service driven.

After testing the various several statistical models, PG&E found that a Forest-based regression model results in a prioritization ranking that is closest to the "perfect ranking."[88]

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83 Exhibit EDF(A)-8, François Rongere, PG&E, Presentation: Risk Based Leak Surveys, at Slide 18 (Oct. 2019)

84 *Id.* at Slide 11.

85 *Id.* at Slide 5.

86 *Id.* at Slide 18.

87 *Id.* at Slide 4.

88 *Id.* at Slide 17.

By focusing surveys on plats that are likely to contain more leaks, PG&E can increase the number of leaks found by 15% to 80% while surveying 25% to 50% fewer services. PG&E is also incorporating these statistical models into an analysis of the number of unknown leaks in their system, which they plan to use to estimate total greenhouse gas emissions from leaks in their system, a figure that is incorporated into their annual greenhouse gas emissions inventory.[89]

ALD+ allows PG&E not only to optimize efficiency in its leak survey process, but also to find and remediate more leaks sooner, thereby reducing risk, cost, and emissions.

Q. Please provide an example of a utility integrating advanced leak detection, data analytics and leak quantification into its operations.

A. CenterPoint Energy began piloting ALD+ technology in 2013, and began testing and phasing ALD+ into their operations in 2016.[90] The company conducted pilots in Houston and Minneapolis and reported that both pilots saw improvements in leak find rates five times greater than traditional methods.[91] By 2018, CenterPoint had fully integrated Picarro units into its operations, boasting a fleet of 16 surveyor units to conduct leak surveys and identify high-emitting leaks for repair. CenterPoint has stated that its use of ALD+ allows for "[n]ear real-time tracking of the leak survey results and natural gas system assets surveyed in the geographic information system, replacing manual tracking of completed

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89 *Id.* at Slide 18.

90 CenterPoint Energy. (2018). Shared Impact - 2018 Corporate Responsibility Report. Retrieved from https://investors.centerpointenergy.com/static-files/82c57a89-1fc3-43af-ac9e-9cabfb21f070.

91 Centers, Tal, and Brad Coppedge. 2015. "Picarro Leak Surveyor." Retrieved from: https://southerngas.org/component/content/article/102-corporateservices/committees/1027-pipeline-safety-council.

leak surveys."[92] CenterPoint Energy recently noted: "By incorporating EQ [Picarro's Emissions Quantification] technology, we expect to enhance the ability to select and design pipe replacements that deliver increased value in safety and emission reductions."[93]

Q. Have utilities that have integrated advanced leak detection technology acknowledged the safety and environmental benefits such technology provides?

A. Yes. Among other utilities previously noted, National Grid in New York has acknowledged these benefits.

Recognizing the value of leak quantification methods in terms of enhancing operational safety, reducing methane emissions, and advancing ratepayer interests, 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, agreed in a 2016 settlement to launch a suite of ALD+ projects in Long Island, New York. The settlement states that "KEDNY will utilize internal personnel or a qualified contractor to develop the means to quantify emission flow rate data on an ongoing basis."[94] The settlement agreement provides that National Grid will use leak flow rate data gathered as part of these projects to enhance leak repair and pipe replacement efforts in its Long Island service territory, and that the companies shall develop the means to quantify leak flow rate

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92 CenterPoint Energy. (2018). Shared Impact - 2018 Corporate Responsibility Report. Page 26. Retrieved from https://investors.centerpointenergy.com/static-files/82c57a89-1fc3-43af-ac9e-9cabfb21f070.

93 CenterPoint Energy. (2018). Shared Impact - 2018 Corporate Responsibility Report. Page 26. Retrieved from https://investors.centerpointenergy.com/static-files/82c57a89-1fc3-43af-ac9e-9cabfb21f070.

94 *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of KeySpan Gas East Corporation d/b/a National Grid for Gas Service*, Case No. 16-G-0058 *et al.*, page 51, section 8.2.2 (Sep. 7, 2016).

from their systems in order to better prioritize their leak repair and LPP replacement projects on an ongoing basis. Niagara Mohawk, National Grid's upstate New York utility, built upon these efforts in a January 19, 2018 Joint Proposal. That settlement obligates Niagara Mohawk to continue to "develop a methodology for assessing leak size and volume using leak quantification methods" and consider "best practices for identifying and abating high volume leaks."[95]

In the pending KEDNY/KEDLI rate case, National Grid has proposed an Enhanced High Emitter Methane Detection Program to conduct ALD surveys in previously-identified vulnerable areas so that the utilities can identify, quantify, and repair high-emitting leaks more quickly; and National Grid proposes to consider further "expanded application" of advanced leak detection.[96]

VIII. Conclusion

Q. Based on these observations, what do you recommend?

A. I recommend that WGL integrate advanced leak detection technology and leak quantification methods into its operations as detailed above, with a goal of conducting regular systemwide leak surveys; and that the Company incorporate leak flow rate data derived using these technologies into its leak repair program on an ongoing basis. I recommend that the Commission allow cost recovery of a systemwide ALD+ leak survey

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[95] *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Gas Service*, Case No. 17-G-0239 *et al.*, Joint Proposal at page 42, Section 7.6 (January 19, 2018).

[96] *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of The Brooklyn Union Gas Company d/b/a National Grid NY for Gas Service*, Case 19-G-0309, National Grid Gas Safety Panel Direct Testimony at 45-46 (Apr. 2019). This rate case is ongoing.

in base rates. I further recommend that the Commission revisit the structure of the leak reduction metrics required by Merger Commitments 55 and 73. Rather than requiring the Company to report fewer Grade 2 leaks repaired and limiting the number of leaks remaining in the backlog each year, the metric should require the Company to achieve a 50% reduction in methane emissions from non-hazardous leaks in no more than four years which, would require abatement of approximately the largest 20% of leaks in its non-hazardous leak inventory. This objective could be met through a combination of pipeline replacement and leak repairs.

Q. Does this conclude your testimony?

A. Yes.

Exhibit EDF(A)-1:

Resume of Virginia Palacios

VIRGINIA E. PALACIOS

(512) 791-1973
virginia@vpenv.com

P.O. Box 27
Encinal, Texas 78019

EDUCATION

MASTER OF ENVIRONMENTAL MANAGEMENT

Duke University – Durham, NC - May 2012

Concentration: Global Environmental Change

Relevant coursework: Energy and Ecology, Natural Resources Economics, Climate Change Economics, Human Health and Ecological Risk Assessment

BACHELOR OF SCIENCE IN AERONAUTICAL SCIENCE

Embry-Riddle Aeronautical University – Daytona Beach, FL - May 2007

Commercial pilot, airplane single- and multi-engine land, instrument-rated

Relevant coursework: Physics I and II, Calculus I, Meteorology I and II

WORK EXPERIENCE

PRINCIPAL

VP Environmental, LLC – Encinal, TX – May 2019 to present

Lead the development of policy solutions to mitigate methane emissions in the natural gas distribution pipeline sector in various states throughout the U.S.

SENIOR ENVIRONMENTAL SCIENTIST

Glenrose Engineering – Austin, TX – Mar. 2019 to Feb. 2020

Conduct geospatial analysis and use modeling tools provided by the City of Austin to estimate potential pollutant loads into the Edwards Aquifer.

INDEPENDENT CONSULTANT

Self-employed – Oct. 2017 to Apr. 2019

Advise on strategic considerations for projects aimed at reducing methane leakage and risks from natural gas distribution systems.

Write testimony for regulatory proceedings explaining how to use methane leakage data to achieve cost-savings and greenhouse gas emission reductions.

STATE AND LOCAL POLICY MANAGER

South-central Partnership for Energy Efficiency as a Resource (SPEER)
Austin, TX – Oct. 2017 to Oct. 2018

Managed collaborative group of investor-owned utilities and stakeholders to discuss expanding utility energy efficiency programs in Texas.

Shared expertise on energy efficiency in buildings as a member of the Energy and Buildings Working Group for the City of San Antonio's Climate Action Plan.

SENIOR RESEARCH ANALYST

Environmental Defense Fund (EDF) - Austin, TX - Apr. 2016 to Oct. 2017

Provided technical expertise on scientific and regulatory concepts related to local distribution pipeline safety and methane emission quantification.

Compared state and federal regulations on local distribution pipeline safety.

Solved complex analytical problems using geospatial analysis.

RESEARCH ANALYST
Environmental Defense Fund (EDF) - Austin, TX – Apr. 2014 to Apr. 2016
Investigated local, state, and federal rules related to distribution pipeline safety.
Analyzed data related to environmental impacts of oil and gas development.

RESEARCH ASSOCIATE
Environmental Defense Fund (EDF) - Austin, TX – Jul. 2012 to Apr. 2014
Wrote reports on distribution system leak detection technology and regulations.
Researched distribution system integrity management and leakage.
Analyzed data on distribution system material mileage and leak frequencies.

RESEARCH AND CAMPAIGN ASSOCIATE
Rio Grande International Study Center - Laredo, TX - May 2011 to Aug. 2011
Organized expert panels to provide public opportunities to learn about potential environmental impacts of oil and gas development.
Drafted letters and other documents to establish public positions of coalition.

PUBLICATIONS

Palacios, Virginia, Simi R George, Joseph C von Fischer, and Kristina Mohlin. (2017). Integrating Leak Quantification into Natural Gas Utility Operations. *Public Utilities Fortnightly, May.*

Lyon, D., Zavala-Araiza, D., Alvarez, R., Harriss, R., Palacios, V., Lan, X., … Hamburg, S. (2015). Constructing a Spatially Resolved Methane Emission Inventory for the Barnett Shale Region. *Environmental Science and Technology.*

Zavala-Araiza, D., Lyon, D., Alvarez, R., Palacios, V., Lan, X., Talbot, R., & Hamburg, S. (2015). Towards a Functional Definition of Methane Super-Emitters: Application to Natural Gas Production Sites. *Environmental Science and Technology.*

Palacios, V. (2012). Baseline groundwater quality testing needs in the Eagle Ford Shale region. *Duke University.*

CONFERENCES

Palacios, V. (2018). Moderator: Restructuring Investor-owned Utility Programs for Maximum Impacts Panel. *SPEER Summit.* Austin, Texas.

Palacios, V. (2014). Environmental Perspective on Methane Emissions and EDF Research Program Overview. In *Government/Industry Pipeline R&D Forum - Leak Detection/Fugitive Methane Working Group*. Rosemont, IL: U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration. https://primis.phmsa.dot.gov/rd/mtg_080614.htm

ARTICLES

Palacios, V. (2016). PSE&G and EDF "Google It." Energize | A PSEG Blog.

Palacios, V., and Simi Rose George. (2016). Managing Methane: New Jersey's Largest Utility Using Better Data for Better Decisions. *EDF Energy Exchange.*

Palacios, V., and Holly Pearen. (2016). New Technologies Deliver Data That Can Make Gas Pipelines Safer. *EDF Energy Exchange.*

Exhibit EDF(A)-2:

List of Expert Testimony of Virginia Palacios

List of Expert Testimony of Virginia E. Palacios

Name of Case	Jurisdiction	Docket Number	Date
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Gas Service	State of New York Public Service Commission	16-G-0061	May 27, 2016 (Direct Testimony)
Investigation of the cost, scope, schedule and other issues related to the Peoples Gas Light and Coke Company's natural gas system modernization program and the establishment of Program policies and practices pursuant to Sections 8-501	Illinois Commerce Commission	16-0376	October 11, 2016 (Direct Testimony) June 14, 2017 (Direct Testimony on Reopening) July 18, 2017 (Rebuttal Testimony on Reopening)
I/M/O Public Service Electric and Gas Company For Approval Of The Next Phase of the Gas System Modernization Program And Associated Cost Recovery Mechanism	New Jersey Board of Public Utilities	GR17070776	January 19, 2018 (Direct Testimony)
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company for Gas Service	State of New York Public Service Commission	19-G-0066	November 4, 2019 (Direct Testimony)
Application of Washington Gas Light Company for Approval of PROJECTpipes2 Plan	Public Service Commission of the District of Columbia	1154	June 15, 2020 (Direct Testimony)

Exhibit EDF(A)-3:

"Integrating Leak Quantification into Natural Gas Utility Operations"
Public Utilities Fortnightly (May 2017)

Integrating Leak Quantification into Natural Gas Utility Operations

Virginia Palacios, Senior Research Analyst, Environmental Defense Fund
Simi R. George, Manager of Natural Gas Distribution Regulation, Environmental Defense Fund
Joseph C. von Fischer, Associate Professor at Colorado State University
Kristina Mohlin, Senior Economist, Environmental Defense Fund

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

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[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).

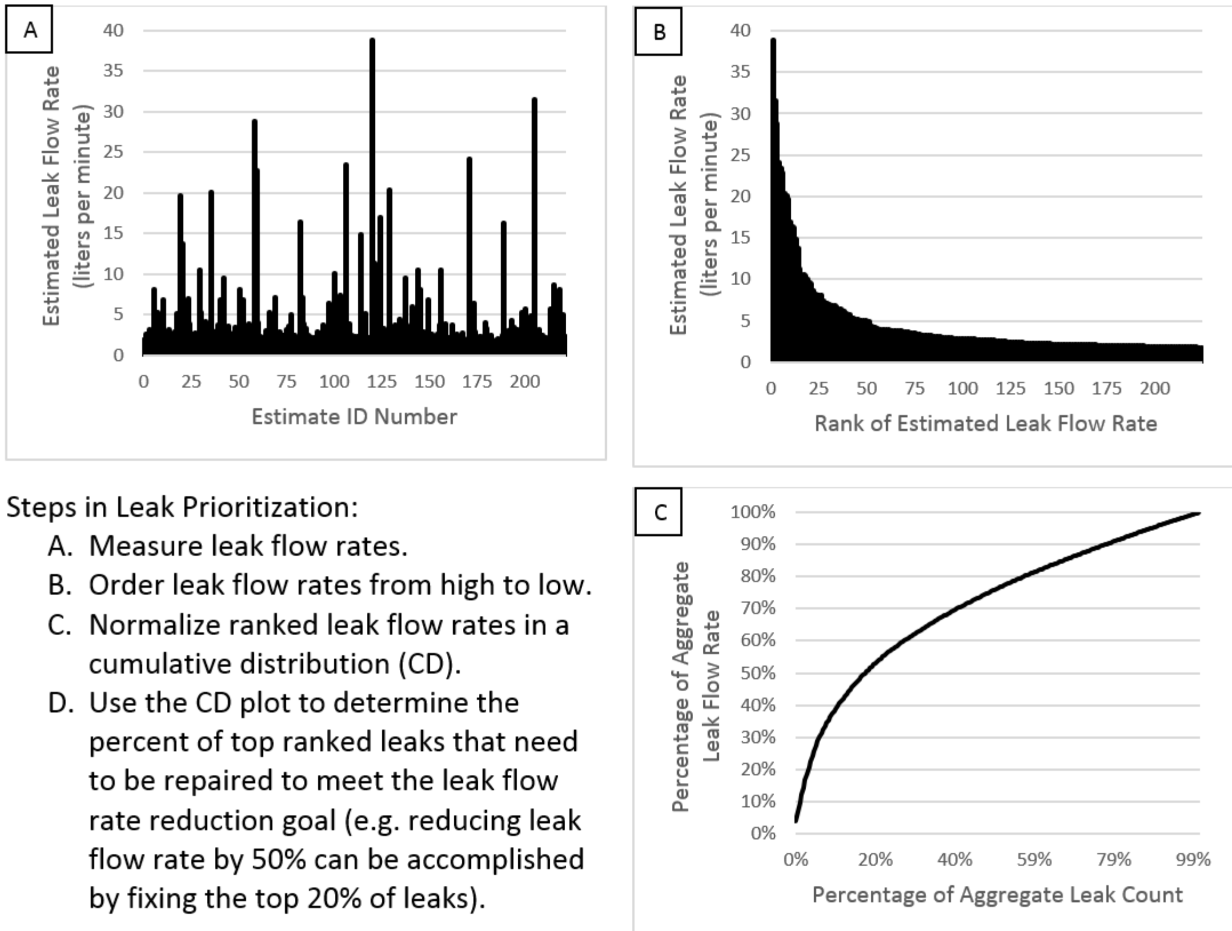

Figure 1 An example step-by-step model depicts how to construct a cumulative distribution curve for the purpose of leak prioritization, using data collected by EDF in Syracuse, NY.

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

[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.

[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.

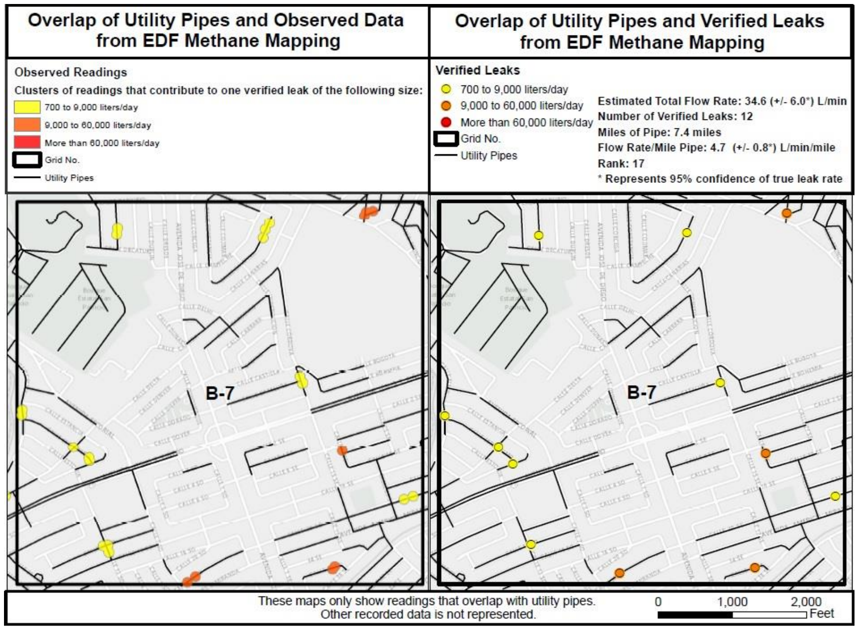

Figure 2 This simulated depiction of leaks in one grid cell of a utility's pipeline system demonstrates how overlapping observed readings are treated as individual "verified leaks," attributable to pipeline infrastructure. The result of such spatial attribution is a visual depiction of the relative size,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

Acknowledgements

The authors wish to thank Rob Roscioli, Ramon Alvarez, Steven Hamburg, and David Lyon for their feedback and guidance in developing this work.

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.

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[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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Exhibit EDF(A)-4:

ABB Inc.-Los Gatos Research's Response to Letter of Inquiry Dated May 9, 2017 from the Citizen's Utility Board

Submitted in Illinois Commerce Commission Docket No. 16-0376

(June 12, 2017)

RESPONSE OF ABB INC. - LOS GATOS RESEARCH TO LETTER OF INQUIRY DATED MAY 9, 2017 FROM THE CITIZEN'S UTILITY BOARD

12 June 2017

1. Introduction to ABB-LGR

ABB, a global leader in electric power and automation with over 135,000 employees and offices in over 100 countries, acquired Los Gatos Research (LGR) in October 2013 to fill a technology gap in its portfolio of analyzers. LGR provides analyzers and services to a wide range of customers needing real-time measurement of trace gases and isotopes for research and environmental monitoring, industrial processes and gas leak detection. LGR's instruments have been deployed by scientists for acquiring the most accurate measurements possible on all seven continents, in unmanned aerial vehicles, in mobile laboratories, on research and commercial aircraft, and in undersea vehicles.

ABB-LGR's novel, innovative and patented laser-based analyzer technology is based on Off-Axis Integrated Cavity Output Spectroscopy (OA-ICOS) that has a substantially higher sensitivity, precision and accuracy than other traditional sampling and laser-based technologies.

2. Leak Detection Capabilities

2.1 Type of Sensors

- **Methane only**
- **Methane and Ethane**

ABB sells (laser-based) analyzers capable of simultaneously reporting methane and ethane while driving. Unlike older technology, these new analyzers report methane and ethane with single-digit ppb sensitivity every second. ABB also sells man-portable, battery-powered analyzers for reporting methane with single-digit ppb (part-per-billion) sensitivity while walking. These portable units bridge the gap that exists between advanced mobile leak detection (ppb detection) and conventional handheld detection (ppm or part-per-million detection).

2.2 Sensitivity (lowest/highest detection level)

Our Mobile Gas Leak Detection system is capable of reporting methane with a precision below 1 ppb and ethane concentrations below 10 ppb. While these levels are more than sufficient to detect gas pipeline leaks 100 meters (or further) away, we are developing next-generation analyzers that will be 100x more sensitive.

The highest detection levels for these two different analyzers can be as high as several percent methane. ABB's analyzers are unique in advanced leak detection solutions because of the large measurement dynamic range.

However, please note that ABB also produces other laser analyzers for measuring natural gas purity than allows quantification of levels to 100% methane.

ABB

2.3 Underlying technology

ABB's underlying technology is patented and based on a laser absorption spectroscopy technique called Off-axis ICOS, the latest generation of the cavity enhanced absorption spectroscopy methods.

LGR, which was acquired in 2013 by ABB, invented cavity ringdown spectroscopy (CRDS) and all the major cavity enhanced spectroscopy techniques, including off-axis ICOS, the fourth-generation of these techniques, which LGR patented. This unique perspective gives us the ability to discuss various laser-based techniques with authority and experience.

Off-axis ICOS is superior to conventional cavity ringdown spectroscopy in several ways, including, but not limited to, the following:

1. highest reliability
2. most robust to harsh environments (vibration, extreme temperature, etc.)
3. simplest to service
4. widest dynamic range
5. unsurpassed sensitivity
6. fastest time response

Details regarding each of these attributes is provided below.

2.4 Type of survey using sensor technology

ABB sells a comprehensive solution for Mobile (Gas Leak Detection) surveys that measure, quantify and locate leak locations on Google Earth maps in real time. This technology can be attached to and installed in a wide variety of new or used vehicles including automobiles, SUVs, trucks and UTVs that the customer presently owns, and consists of:

1. Patented gas analyzer (19" wide, 7" height, 24" deep) and proprietary computational software

platform for measuring methane and ethane simultaneously and displaying likely leak locations on Google Earth maps or other GIS platform.

2. GPS antenna (on the roof) and GPS receiver (included inside the analyzer)

3. sonic anemometer (located on the roof) for measuring wind velocity while the vehicle is either stationery or moving

4. vacuum pump for pulling the sampled air from an inlet located below the front bumper to and through the analyzer which is typically located in the trunk.

Installation and full commissioning of the entire system (in the customer's vehicle) takes less than one day.

To compliment the vehicle-based system, which provides the likely areas in which the leak originates, ABB also sells a lightweight, battery-powered, purse-size methane analyzer to quickly perform the investigation or "pinpointing" of leak indications. This 'microportable' methane analyzer, based on the same patented technology as the vehicle-based system, employs a smartphone or tablet as the User Interface. Importantly, this analyzer allow users to bridge the sensitivity gap between ppb sensitivities of advanced mobile leak detection systems and ppm sensitivity of conventional handheld detectors. The matched sensitivity dramatically decreases the time required to investigate leak indications and preliminary testing indicates the time to find goes from 30-45 min with conventional equipment to 10-15 min with ABB's portable unit.

2.5 Cost of sensors/hardware

LGR offers two purchase models for utilities interested in deploying Advanced Leak Detection Technology and analytics, rental or purchase.

Interested customers can evaluate ABB's Mobile Gas Leak Detection system for extended periods at very small rental rates of approximately $5000/week. Moreover, the rental fees can be applied towards the purchase price of the system.

The retail price for the new Mobile Gas Leak Detection solution capable of providing surveys that measure, quantify and locate leak locations on Google Earth maps in real time, sells for between $250k-$300k (hardware costs only) and does not include the vehicle.

After purchasing the system, the owner possesses and owns all the data reported by the analyzer. ABB does not sell the data back to the customer nor does ABB charge for generation of reports. Also, since the customer owns, and does not lease, the system, the equipment can be depreciated as a capital expense.

2.6 Software costs

ABB charges an annual license fee to maintain and enhance the software, provide support, and to effectively provide an evergreen software package that continuously provides new features and capabilities, in response to customer needs. ABB offers this for $45k, although the costs can be differently amortized depending on customer needs.

2.7 Estimated annual O&M costs

The operations and maintenance costs of the mobile system, excluding the vehicle, are small (typically less than $1500/year), and include re-building vacuum pumps, cleaning optics, if needed.

2.8 Cost of transport method

This is simply the cost of driving the vehicle in which the Mobile system installed and includes gas, maintenance, and driver costs. There is no need for purchasing a new vehicle for this application. In fact, utilities such as Pacific Gas and Electric, Atmos Energy, Sempra Energy, Google, Enbridge Gas, generally incorporate the system into existing (i.e. used) fleet vehicles.

2.9 Staffing requirements

After only a few days of training, virtually anyone can drive the car and operate the technology to find leaks. Aside from the power switch, the system is fully controlled with the intuitive software interface.

2.10 Product certification

The product passes all FDA and CE requirements.

2.11 GIS/geographic/mapping capabilities

The system offers several methods of viewing and analyzing the reported leak indications.

- The in-vehicle UI plots all the results on Google Maps (default or satellite view) in real-time. Leak indications can be clicked to raise additional information about gas concentration, location and time of find.

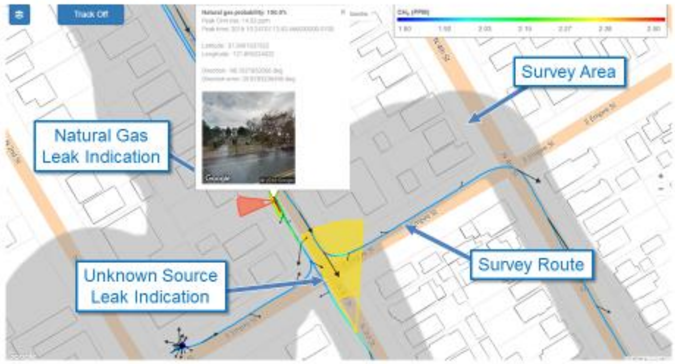
- The automatically generated report includes a KML/KMZ output of all the recorded data, including drive path with color coded methane concentration, wind velocity, estimated survey area and leak indications. All of this data can be view interactively in Google Earth.

- Finally, the report also includes KML/KMZ in individual layers that can be imported into common GIS tools such as ArcGIS and Smallworld for further analysis and comparison to utility data.

Additionally, the in-vehicle UI allows users to import utility assets for viewing in real-time. This permits users to overlay and compare the locations of mains and services with the leak indications found by the vehicle.

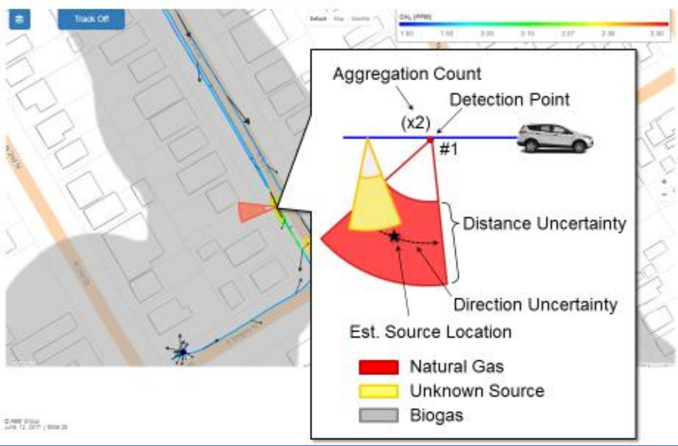
Some examples of User Interface screens presented while driving allows users to see survey routes, surveyed areas and leak indications:

User Interface
Map Display

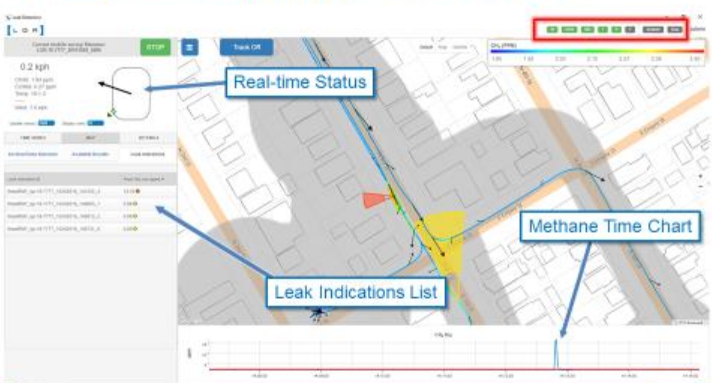


Graphically displays survey route, survey area and leak indications

User Interface
Leak Indication Anatomy



User Interface
Measured Data and Automated Alarms



Power and productivity for a better world™ ABB

2.12 Unique capabilities of service/product offered, relative to competitors

The ABB Ability Mobile Gas Leak Detection system is based on ABB's *patented* Off-axis ICOS technology. Off-axis ICOS is superior to conventional mobile leak detection systems and cavity ringdown spectroscopy in practically every performance metric, including, but not limited to:

- **Speed of response**
  The mobile system provides a 5-Hz data rate to allow spatially resolved measurements even while driving at highway speeds (i.e. to 65 miles/hour). The microportable methane analyzer reports data at a 10 Hz data rate (and with ppb sensitivity) for similar reasons while walking. Conventional methods based on walking report data at speeds of about 1-2 miles/hour and often lack a digital record.

- **Accuracy**
  Unlike other analyzers based on older cavity based methods, these novel laser-based analyzers provide measurements that are inherently accurate because they record "fully resolved" (i.e. detailed) absorption spectra (that are displayed on screen to the user).

- **Precision**
  ABB analyzers report data with single parts per billion precision for measurements of methane and ethane. Based on field trials conducted by large utilities, this allows users to find leaks far from the source very quickly and reliably – 5 to 10 times faster than conventional legacy methods, which must be close to the leak and only report methane or total hydrocarbons, and thus get confused between natural gas leaks and other methane sources.

- **Measurement dynamic range**
  ABB reports natural gas concentrations at both extremely low concentrations with parts per billion sensitivity and precision but also reports high concentrations of methane to well over 1% in air. This large dynamic range gives users the ability to accurately detect leaks both from far away as well as nearby – i.e., there is no saturation when large leaks are detected as with cavity ringdown based advanced leak detection.

- **Overall robustness/ruggedness**
  Unlike older methods like CRDS, ABB's technology does not require extraordinary thermal control and nanometer alignment tolerances to operate. As a result, ABB analyzers can easily operate anywhere and over a far wider temperature range (0 to 45 C) compared with CRDS, which is constrained by much narrower mechanical tolerances.

- **Simplicity of service**
  Unlike older methods like CRDS, ABB's technology does not require extraordinary thermal control and nanometer alignment tolerances to operate. As a result, ABB analyzers can be easily serviced in the field – even cavity mirrors -- in the unlikely event that this is necessary. This reduces total cost of ownership and maximizes total measurement time.

- **Cost to own**

Due to higher reliability, simplicity and ruggedness, ABB technology is simpler to build and service, which leads to greater uptime, far lower purchase price (cf. $1.4 million or more for cavity ringdown systems), and easily the lowest maintenance costs. Finally, we expect the equipment to easily last for more than ten years, so the annual cost to operate the system is very low.

- **Cost to operate**
  Since the customer owns the equipment, after purchasing the system, the only annual costs are software licensing. Since ABB does not lease the solution, the customer can depreciate the capital equipment and thus reduce annual costs even further. Maintenance and service costs are typically less than $1500/year primarily for rebuilding the vacuum pump, changing particle filters, and possibly cleaning mirrors.

  In addition, ABB's mapping capability provides detailed geospatial maps of likely leak locations based on proprietary algorithms that have been proven for accuracy and reliability by numerous gas utility operators.

- **Data ownership**
  Unlike other laser-based companies that only lease their solutions, ABB sells the entire package to the customer. Thus, the customer owns and has immediate and direct access to all data recorded by the system.

  In brief, ABB's system provides users with unsurpassed capabilities at a price that is 5-10 times less on an annual basis than competitive (and less capable) systems based on conventional CRDS laser methods.

3. Leak Quantification Capabilities

3.1 What analytics packages does your company offer that are capable of quantifying leaks?

3.2 What is the cost of the quantification package?
ABB includes leak quantification metrics with the annual software licensing fee (at no additional cost). These metrics utilize evolving proprietary models that incorporate the measured data recorded by the system.

To maximize public safety and accelerate the development and testing of advanced leak quantification models, ABB collaborates openly with scientists and engineers from universities, industry and advocacy groups.

4. Operationalization and Integration

ABB's Mobile Gas Leak Detection Systems have been integrated into the operations of several major gas utilities throughout the US and Canada, and many other utilities will evaluate our systems within the next several months.

These systems provide utilities quantitative information that is available in easily read (i.e. in nonproprietary) data formats and maps of leak locations and relative sizes continuously while driving.

ABB has a long-standing tradition of collaborating with leading academic, governmental and industrial researchers worldwide through local and corporate research initiatives. We continue this practice of open collaboration for the development of the Mobile Leak Detection solution in order to refine this product quickly and most efficiently.

Exhibit EDF(A)-5:

Picarro, Inc. Response to Letter of Inquiry Dated May 9, 2017 from the Citizen's Utility Board

Submitted in Illinois Commerce Commission Docket No. 16-0376

PICARRO

RESPONSE OF PICARRO, INC. to
LETTER OF INQUIRY DATED MAY 9, 2017 FROM THE CITIZEN'S UTILITY BOARD

Introduction to Picarro
Founded in 1998, Picarro is a leading provider of hardware and analytics solutions to measure greenhouse gas (GHG) concentrations, trace gases and stable isotopes across many scientific applications and industrial markets. The company holds over 50 patents, some exclusively licensed from Stanford University and has a global headquarters, R&D, manufacturing in Silicon Valley, California with offices in Europe & Asia with 145 employees, 35 PhDs and over 3,000 Picarro instruments deployed in 60+ countries world-wide.

Cavity Ring-Down Spectroscopy
Our patented Cavity Ring-Down Spectroscopy (CRDS) is at the heart of all Picarro instruments and solutions, enabling the detection of target molecules at part per billion, or better, resolution.

Natural Gas Solutions
Picarro is the industry leader in analytics-driven leak detection and quantification solutions, enabling our energy customers to increase capital efficiency while simultaneously improving the safety of their infrastructure.

Picarro helps utilities reduce O&M costs in their leak survey and repair budgets while also reducing risk. The Picarro mobile detection system coupled with customized data analytics produces leak indications ranked by potential risk. This lets utilities focus on the most important leaks without increasing leak backlogs. Picarro's Risk Ranking Analytics enables utilities to maximize the yield of important leaks per leak found. This maximizes the safety impact per dollar of expense. The analytics can also calculate emissions on pipe segments to aid in prioritization of pipe replacement for DIMP.

Picarro's vehicles conduct multiple patrols through a natural gas infrastructure, collecting methane plume data and sending it to the Picarro cloud – driving becomes simply data collection. Leak managers then run Picarro's Risk Ranking Analytics, transforming the data into actionable results for leak investigators. Armed with the indications and locations that are most likely to lead to important leaks, crews maximize their impact while keeping costs and backlogs under control. This same data can be used with Picarro's Emissions Quantification Analytics, allowing leak density and aggregate emissions to be calculated on different pipe segments. The pipe segments can then be ranked by emissions or leak density, providing significant O&M cost avoidance due to avoided leaks when this ranking is used to inform capital replacement priorities.

PICARRO

Scientific Instruments
Our portfolio of Picarro gas analyzers and systems enables scientists around the world to measure GHGs, trace gases and stable isotopes found in the air we breathe, water we drink and land we harvest. The ultra-precise and easy-to-use instruments are deployed across the globe offering unmatched performance in a variety of field conditions.
Industrial Solutions
Picarro's industrial solutions range from methane detection and analytics technology for energy companies to trace gas analysis for semiconductor fabrication and pharmaceuticals isolators.

Leak Detection Capabilities

- **Type of Sensors**
  - **Methane only**
  - **Methane and Ethane**

The Picarro system consists of an analyzer that measures both methane and ethane in addition to some additional gases that aid in discriminating natural gas from other methane sources like sewers or other vehicles.

- **Sensitivity (lowest/highest detection level)**

The Picarro system detects methane with a 4ppb precision at ambient levels (roughly 0-15ppm methane concentration) and has a detection range of approximately 0-500ppm of methane in air. For comparison, 100% gas escaping from an underground leak near the vehicle is quickly diluted by the atmosphere to 10s of ppms at the point the gas enters the Picarro system's inlet.

- **Underlying technology**

The Picarro system is based on Cavity Ring Down Spectroscopy (CRDS) which is a near-infrared optical measurement technology. The Picarro system has a closed-path gas flow configuration that continuously draws air flowing from inlets on the vehicle's front bumper into the CRDS analyzer. CRDS is capable of measuring concentrations of methane at levels below one part-per-billion (ppb) in the air.

- **Type of survey using sensor technology**
  - **Mobile survey**
  - **Other**

The Picarro system is a mobile system that is typically installed in a utility's SUV, truck, car, van or equivalent.

- **Cost of sensors/hardware**
- **Software costs**

The hardware is bundled with a software license and support. The incurred cost of the entire system (hardware purchase or lease, software license and annual service and support) is approximately $105 per mile of distribution main. This assumes full utilization of the system (driving and collecting data for one standard daily shift over 250 working days per year). *Please see detailed cost information in Appendix 2 and ROI analysis in Appendix 1 of this document.*

- **Estimated annual O&M costs**

The majority of the O&M cost relates to vehicle operation and maintenance and are approximately $0.65 per mile of distribution main. This excludes the labor component to drive the vehicle. Otherwise, the maintenance costs for the system are included in the price above.

- **Cost of transport method**

The cost of transport is limited to fuel costs and is approximately $1.64 per mile of distribution main, assuming fuel is $2.50/gal.

- **Staffing requirements**
  - **new staff required**
  - **utilization of existing utility staff**

To fully utilize the Picarro system, one dedicated hourly employee is required per vehicle. This could be a contracted or current employee since no specific skills are required. To coordinate the mobile data collection and to run reports using Picarro's analytics report generation software, one employee in a functional area such as leak survey or integrity management would be utilized. For compliance leak survey or emissions quantification using Picarro, this employee would be utilized at a rate of about two (2) hours per day annually for each 3000 miles of distribution main driven by the Picarro system. Existing full time or existing contract staff that are currently used for routine compliance leak survey would be used to investigate the leak indications reported by the Picarro system. In other words, instead of conducting routine survey on the miles of distribution main and services covered by Picarro, they would instead focus just on pinpointing and grading leaks found within the leak indication areas identified by the Picarro system.

Picarro's risk ranking analytics allows utilities to concentrate their limited leak survey and repair budgets on the most important leaks. Risk ranking prioritizes the most potentially hazardous leaks and provides utilities the option to defer repair of non-hazardous leaks in favor of the higher risk leaks in their distribution system. In this way, Picarro's analytics allow mobile leak survey to be accomplished without ballooning non-hazardous leak backlogs.

- **Product certification**

The Picarro system is compliant with the following specifications, standards and regulations regarding its use in this mobile application: DOT, CSA, military MIL-STD 810F shock/vibration test standard, FCC Part15B Class A, CE: EN61326, Safety: EN61010, EN60825-1 (Class 3B laser). The product is being used for DOT Compliance Leak Survey in the following states: CA, TX, AR, MN, LA, MS by three major U.S. utilities with additional states and utilities planning to come online in 2018. The product has been tested and validated in 40 double-blind, Directed Field Trials with 25 LDCs beginning in 2011, several involving independent, third-party validation by GTI, NYSEARCH and PRCI and several natural gas utilities worldwide.

- **GIS/geographic/mapping capabilities**

The system is compatible with any utility GIS system via direct import or API and supports real-time updates and GIS visualization from utility GIS system (ESRI, SAP, GE Small World, Integraph, etc.) using a variety of file formats including GeoDB, ShapeFile, kml, etc. The GIS information is shown in a map-based user interface within the Picarro vehicle and is also viewable for live and past surveys through Picarro's web-based interface. The Picarro analytics and reporting engine produces map-based output including utility GIS information (via PDF, Shape File or via an API to a utility's GIS system). Overlaying GIS information with Picarro leak indications greatly enhances a utility's ability to locate leaks.

- **Unique capabilities of service/product offered, relative to competitors**

Multi-pass Analytics: Picarro's system combines data from multiple passes over an area, and Picarro's algorithms process these runs (often collected on different days), producing actionable results. No other available solution uses analytics to collect and combine multiple data collection runs in this way. Picarro's patented Field of View coverage area and patent-pending algorithms for leak locating, methane emissions quantification and leak indication risk-ranking all take advantage of multi-pass data collection and analytics.

Risk-Ranking and Emissions Quantification: Picarro's analytics produce leak indications that are ranked by their potential hazard and can calculate point-source methane emissions (in cubic feet per hour) and can aggregate total emissions and calculate leak density over an area or pipeline segment. There is no other available mobile solution that offers these capabilities.

Avoiding False Positive Indications: Picarro has seven independent algorithms that act to avoid false positives (and false negatives) including: discriminating between biogas and methane from gasoline and diesel vehicles using multi-gas spectroscopy and Bayesian analytics, removing redundant indications, removing false indications from natural gas vehicles, compensating for high background concentrations of methane, identifying leak indications by using plume shape analytics and identifying search areas using atmospheric and wind vectoring analytics. The removal of false positives significantly improves O&M cost efficiency during investigation of leak indications. No other available solutions have this combination of capabilities.

GIS Integration: The bi-directional integration with a utility's GIS and ERP systems described above is unique to the Picarro system.

Cloud-based Data Storage and Reporting: Picarro offers a unique cloud infrastructure for collecting, storing and visualizing data taken by one or more Picarro vehicles: This web-based platform provides the user access to the various multi-pass analytics routines and reporting engines described above. Various, customizable reports in various formats are available to the utility for download. Picarro ensures the utility has full access to the raw data produced by the Picarro hardware, available in usable *.csv format

Data Security: Picarro's system incorporates third-party audited, industry standards for backup and disaster recovery and security in the areas of information, datacenter, IT systems, cloud application and customer data. Data is encrypted and the in-vehicle computer is hardened and secure.

Support: Picarro's service offing includes on-site training, installation, guaranteed service-level support, immediate response via 24x7x365 phone support and on-demand, on-site support.

Data Quality: The Picarro system suppresses data collection if system malfunctions, drifts out of calibration, or for excessive wind conditions. The system also offers an optional inertial GPS that enables mobile survey in dense urban canyon environments where normal GPS systems fail, such as in Manhattan. These capabilities are unique to Picarro.

Field Investigation Application via Tablet or Smart Phone: Picarro's unique Mobile View application is a live, map-based tool used to investigate leak indications and catalog search results. It offers real-time GPS location and utility GIS system situational awareness for the field technician and provides a record of the walking path and survey results of ground survey crews.

Utility GIS and ERP Connectivity Options: Picarro's system has API-level interoperability with GIS and enterprise systems such as SAP for logging leak information, scheduling, etc.

- **Other relevant information relating to leak detection capabilities**

Picarro's system has been extensively tested (both in real-world and controlled settings) by dozens of utilities and multiple gas industry partners. The testing consistently shows that the Picarro system is significantly more effective than legacy methods of leak detection. The testing and validation includes metrics on leak find rate, Field of View coverage percentage, efficiency, false positives and false negatives.

Picarro's risk-ranking analytics prioritizes leak indications by potential risk, a capability that is unique in the industry. Hazardous leak plumes have unique signatures that can be measured, allowing analytics to rank indications by potential risk. By combining multiple data collection runs by multiple Picarro vehicles, Picarro's risk-ranking analytics allow utilities to maximize operational efficiency by prioritizing leak indications that are most likely to be hazardous. Addressing the highest priority leak indications retires more risk per dollar than any available survey methodology.

Leak Detection Capabilities

- **Does your leak detection equipment have the capability to detect methane, ethane, or both? Are there any other chemical constituents that your equipment detects, which would be relevant to attributing the source of methane detections? If so, please name the constituents and describe their relevance.**

The Picarro system measures and reports concentrations of methane, ethane, the ethane-to-methane ratio and the related measurement uncertainties. For any methane indication reported, it calculates and reports the confidence percentage that the indication is either natural gas, biogenic methane or methane from vehicle exhaust. These determinations are calculated based on the known ethane content in the particular utility's natural gas. This is a configurable, utility-specific parameter in the Picarro analytics. The system also compensates for the presence of H_2S, CO, N_2O, propane and higher hydrocarbons, and mercaptans in the ambient air, and measures and compensates for CO_2 and water concentration changes in the air. To accurately discriminate between natural gas and other methane sources, and to avoid false positives, the system has been designed to measure and/or compensate for these interfering gases that are often found in ambient air and is the only commercially available system that has these capabilities.

- **What is the sensitivity of the leak detection equipment (i.e. the lowest and highest calibrated levels of detection for each constituent that can be detected by the equipment)?**

The detection rages are: Methane: 0-500ppm, Ethane: 0-200ppm, All other gases (H_2S, CO, N_2O, propane and higher hydrocarbons, mercaptans, CO_2 and water) are measured and/or compensated for but not provided as calibrated outputs to the user.

- **Can the leak detection equipment be mounted to a vehicle for the purposes of detecting natural gas pipeline leaks?**

Yes, the Picarro solution is inherently mobile in design.

- **Does your company provide a vehicle with the leak detection equipment, or would a vehicle be provided by the organization that chooses to purchase the leak detection equipment?**

Picarro does not provide a vehicle. The vehicles used are typically a utility fleet vehicle or contractor's vehicle.

- **What is the cost of the leak detection technology?**

The Picarro system is offered as a bundled system including the hardware, system software, access to Picarro's web-based analytics engine, and support and maintenance. The incurred cost of the entire system (purchase or lease) is approximately $105 per mile of distribution main. *Please see detailed cost information in Appendix 2 and ROI analysis in Appendix 1 of this document.*

- **What is the cost of software that is associated with verifying the location of natural gas leaks associated with methane emission indications identified by the technology?**

The Picarro system is offered as a solution and the various elements are not priced separately. The price is inclusive of all the elements required to collect methane and atmospheric data, process and analyze it and deliver reports and other processed output.

- **What is the cost of the vehicle, if a vehicle is included with the leak detection technology system that your company offers?**

Picarro does not sell the vehicle itself and it is not included in the cost.

- **What is the estimated number of new staff required to operate the leak detection technology?**

To fully utilize the Picarro system, one dedicated hourly employee is required per vehicle. This could be a contracted or current employee since no specific skills are required. Picarro provides training to utility staff.

- **What is the estimated number of new staff required to analyze the data generated by the leak detection technology?**

To coordinate the mobile data collection and to run reports using Picarro's analytics report generation software, one employee in a functional area such as leak survey or integrity management would be utilized.

- **What is the estimated utilization of existing utility staff for the above- mentioned purposes?**

For compliance leak survey or emissions quantification using Picarro, this employee would be utilized at a rate of about two (2) hours per day annually for each 3000 miles of distribution main driven by the Picarro system. Existing full time or existing contract staff that are currently used for routine compliance leak survey would be used to investigate the leak indications reported by the Picarro system. In other words, instead of conducting routine survey on the miles of distribution main and services covered by Picarro, they would instead focus just on pinpointing and grading leaks found within the leak indication areas identified by the Picarro system.

- **Has the technology been certified for use for any particular purpose? If so, what purpose has your technology been certified for? What capability does the technology or accompanying software have to generate approximate geographic locations of leaks or the maps of the estimated field of view of areas surveyed?**

The product is being used for DOT Compliance Leak Survey in the following states: CA, TX, AR, MN, LA, MS and has been certified to do so by three major US utilities with additional states and utilities planning to come online in 2018[1].

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[1] Picarro's natural gas detection system is being used by PG&E in California and by CenterPoint Energy in Minnesota, Arkansas, Louisiana, Mississippi and Texas. Due to confidentiality reasons, Picarro is not able to disclose the specific customer in other states.

The Picarro system is specifically designed to use vehicle GPS position and wind speed and direction data to localize the point of origin of natural gas plumes and to define regions that have been surveyed by the Picarro system's Field of View. The map-based visualization capability (both live and from reports produced by the software) combines satellite and street maps with utility GIS information to provide the user with information-rich, geospatial views of potential leak locations and the Field of View.

Leak Quantification Capabilities

- **Sensors/analytics packages capable of quantifying leak flow rate**

The Picarro system includes an analytics package that takes data collected by the Picarro hardware and produces output that calculates methane emissions and leak density on point sources, areas or pipe segments and ranks them by total emissions.

- **Cost of quantification capabilities**
    - **hardware**
    - **software**
    - **services**
    - **estimated annual O&M costs**

The Picarro system is offered as a solution and the various elements are not priced separately. The price is inclusive of all the elements required to collect methane and atmospheric data, process and analyze it and deliver reports and other processed output. The incurred cost of the entire system is approximately $105 per mile of distribution main.

The majority of the O&M cost relates to vehicle operation and maintenance and are approximately $0.65 per mile of distribution main. This excludes the labor component to drive the vehicle.

- **Unique capabilities of service/analytics package offered, relative to competitors**

No other competitors offer vehicle-based emissions quantification and analytics. No other competitors offer the unique capability to combine data taken on an infrastructure over a period of time and run analytics on the combined passes to improve the accuracy of the results with each pass included in the analysis.

- **Other relevant information relating to leak quantification capabilities**

Picarro's system informs pipeline replacement decisions based on current, measured emissions data. Picarro's emissions quantification analytics uses data collected by the Picarro hardware to calculate methane emissions of individual open leaks, pipeline segments, or entire infrastructures. This allows utilities to rank pipe segments by overall emissions and prioritize pipe replacement projects – construction dollars are saved by identifying and eliminating segments with the most leaks before those leaks trigger expensive repairs. Actual emissions data and leak density also informs pipeline repair vs. replace decisions.

Leak Quantification Capabilities

- **What analytics packages does your company offer that are capable of quantifying leaks?**

The standard Picarro system includes both leak quantification and leak detection capabilities. The data collection is done with the same vehicle-based hardware. The two different applications (leak quantification and leak locating) are served by two different analytics packages that are both included in the analytics software package of standard Picarro product.

- **What is the cost of the quantification package?**

The emissions quantification analytics software is included at no additional cost in the standard Picarro product.

Leak Data Analysis Capabilities

- **Sensors/analytics capable of ranking leaks by size, spatial characteristics**

The Picarro system can measure emissions of individual or aggregate sources and rank these points or segments by leak flow rate (i.e. leak size or emissions in cubic feet per hour). Since the emissions ranking takes into account a measurement of the entire plume that could come from a point source or from a larger spatial migration pattern, the ranked emissions is reflective of the entire volume of gas escaping.

- **Cost of analytics services (disaggregated by category, to the extent possible)**

The various analytics capabilities of Picarro's system are all included in the cost of the system and are not offered individually.

Leak Analysis Capabilities

- **What analytics does your company offer that are capable of ranking leaks by order of potential hazard?**

Picarro's system has the ability to rank potential leak indications by risk (i.e. likelihood of the indication being from a grade-1 or grade-2 leak for example) based on measured characteristics of the plume. Each leak indication is assigned a percentile ranking score by the analytics according to its potential risk.

- **What is the cost of this service?**

The risk-ranking analytics software is included in the cost of the overall Picarro system and not offered as an individual module.

Operationalization and Integration

- **Specific description of how products and services can be integrated into PGL's "neighborhood method" described in Appendix A**

Please see the response below regarding integration into the neighborhood method.

- **Cost of integration (disaggregated by category, to the extent possible)**

Please see the response below regarding cost.

- **Timeline for integration, including key milestones**

Please see the response below regarding timeline.

- **Number of gas distribution companies that are currently using the product, service or technology offered**

Seven (7) major natural gas utilities around the world are currently using the Picarro system; five (5) being U.S. based (including CenterPoint Energy and PG&E) and four (4) are using it for compliance leak survey. The system has been used and evaluated by a total of 37 utilities across North America, Europe, Asia and Australia.[2]

- **Description of operations or integration with other distribution utilities**

In the utilities where the system is being used actively, the use cases include DOT compliance survey, special non-compliance survey (rapid, emergency surveys, post-construction quality control, etc.), assessment surveys to inform pipe replacement (DIMP) and source discrimination and leak pinpointing applications. Please see additional information in the response below regarding integration.

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[2] Due to confidentiality reasons, Picarro cannot disclose the names of all utilities that have used the Picarro system.

Operationalization and Integration

- **Please provide a specific description of how your company's products and services can be integrated into "neighborhood method"**

The data from Picarro's emissions quantification analytics would significantly improve the accuracy with which individual pipe segments (and entire neighborhoods) could be prioritized for repair based on potential risk. As is shown in PGL Ex. 1.1 "South Austin Gas Leak Comparison" on p. 4 of the "Appendix B – PGL initial brief" there are pipe segments in the "Before AMRP" which were replaced but which appear to have no existing leaks. It has been shown, however, that traditional survey misses typically 60% of gas leaks in an area when compared to using a Picarro system. It is therefore likely that a reliance on historical leak rates will lead to errors in prioritizing pipe segments for repair. Using the Picarro system would allow *current* emissions and leak density to be used – with a higher weighting factor than the 10% now used for historical leaks. Doing so would provide a much more accurate appraisal of the actual *current* risk of each pipe segment. Segments with no emissions (and low risks from the other weighting factors) could be removed from consideration for replacement, saving significant construction costs. A stepwise plan is described in the response below on timeline.

Data from the Picarro system can be processed using emissions quantification analytics which does not calculate individual leak indications. Instead, this analytics report mode is designed to provide a measurement of aggregate emissions over a pipe segment and an estimate of the number of leaks on that segment. Importantly, since individual leak locations are not calculated when using the Picarro system in this analytics mode, the process does not trigger the duty to investigate and repair leaks. Rather, this report provides a means by which pipe segments can be ranked by emissions and/or leak density and prioritized for repair. An example of this output is shown in the figure below.

Segment ID	Segment Rank	Emissions Rate (SCFH)	Emissions range (confidence)	Segment Length (ft)	Emissions Factor (SCFH/ft)	Estimated # of leaks	# Leaks/ft	Emissions Rate / Leak
4	1	7.0	4 – 16 SCFH (90%)	1579	0.0044	5	0.0032	1.14
1	2	5.1	2 – 8 SCFH (90%)	3090	0.0017	5	0.0016	1.0
3	3	2.4	1 – 4 SCFH (90%)	2535	0.001	4	0.0016	0.6
2	4	1.5	0.5 – 2 SCFH (60%)	2514	0.0006	1	0.0004	1.5

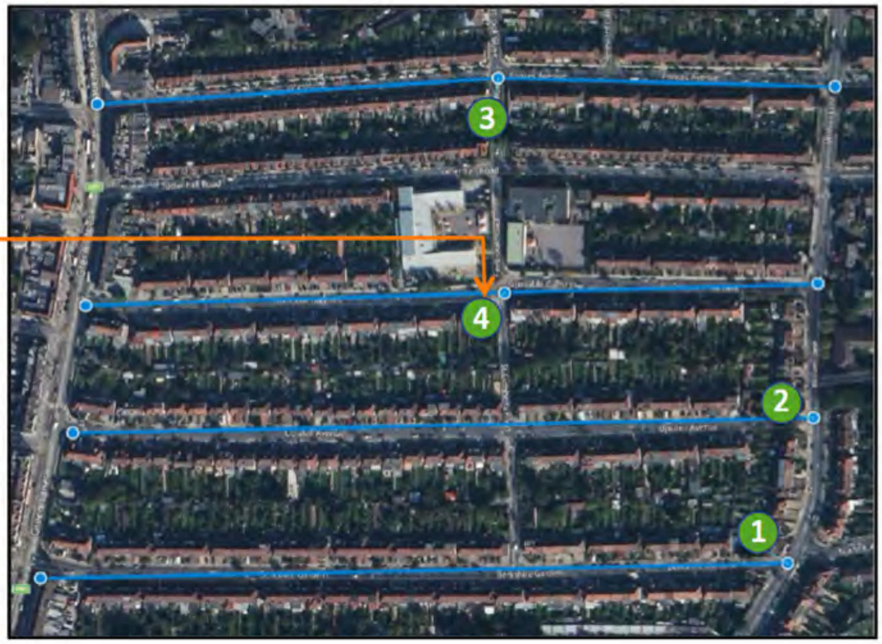

Figure 1. Picarro data processed with Picarro's Emissions Quantification Analytics to calculate emissions and leak density, allowing segments to be ranked and prioritized for replacement.

PGL also states that the "neighborhood approach" allows them to "continually evaluate" their construction priorities. The Picarro system has the ability to rapidly assess emissions and changes in leak density along leak-prone pipe in the winter months. Adding such "frost survey" data taken by the Picarro system could expose new pipe segments that should be prioritized for replacement. Picarro partnered with National Grid and GTI to study the effectiveness of this approach and concluded it was a more effective means of rapidly detecting changes in pipeline integrity under a cover of ice and snow than current practices.

- **Cost of integration**

The costs of utilizing the Picarro system for this application would be consistent with the costs described previously: $105 per mile of distribution main. *Please see detailed cost information in Appendix 2 and ROI analysis in Appendix 1 of this document.*

- **What would be the potential timeline for being able to integrate your company's products and services into the "neighborhood method?"**

Implementing Picarro to provide this informative data in the current prioritization model used by PGL could be done in a matter of a few months. A stepwise plan is detailed below:

Steps to Operationalize EQ Analytics for Optimizing Capital Pipe Replacement Decisions:

1. Identify sections of pipe that are candidates for replacement
2. Using Picarro's driving protocol, collect data on all these sections of pipe with the Emissions Quantification (EQ) mode of Picarro vehicle
   - In this mode, no leak indications are provided to the user – the system simply collects methane concentration, GPS and wind data for further processing with EQ analytics.
   - The EQ driving protocol essentially recommends six (6) or more passes at night, on at least two different nights, along street(s) near the pipe segments to be measured. Picarro's in-vehicle Field of View coverage will show if the pipelines are being sufficiently covered and measured.
3. After all data is collected, use Picarro's EQ Analytics report engine to identify the geographic location of each section that has been driven. Each section will be given an ID number by the system.
4. The report produced by EQ Analytics will rank these sections by overall emissions and provide an estimate of the total number of leaks on that section.
5. This ranking can be compared and/or used to further inform whatever current method of pipe replacement prioritization is being used. For example, PGL could assess individual pipes or an entire neighborhood and combine the resulting reports with the other data used in prioritizing pipeline replacement work.
   - EQ Analytics provides a current snapshot of the state of the infrastructure that can be superior to only using pipe type, age, pressure, historical leaks, risk etc. to prioritize replacement.
   - By selecting more leak-dense pipes for replacement than would be selected with other risk models, more O&M cost in leak repairs can be avoided. In

addition, PGL can focus on replacing the most leak-dense pipe segments first – whether on a neighborhood-by-neighborhood approach or otherwise.

- **Please describe the extent to which your company's products and services have been integrated into the operations of other distribution utilities.**

At the utilities that are using it for compliance leak survey, the Picarro system is tightly integrated with monthly GIS data input from the utility. The Picarro analytics results and leak find information from the field is tied directly into the SAP work order and data collection system at the utility. Data collection drives are scheduled by SAP over multiple days. Once complete, a utility employee runs Picarro's analytics on the collected data. This generates leak indications which are searched for leaks by utility or contract leak surveyors with the aid of Picarro's Mobile View smart phone application. Leak grade, location and other data is collected in the field and uploaded into SAP which drives leak repairs or monitor orders.

These utilities use the system for other non-compliance use cases, scheduled on an as-needed basis. Utilities not yet using the system for compliance leak survey are exclusively using the system for any number of use cases described below:

- Special Non-compliance surveys
  - Rapid, emergency survey, post-disaster evaluation (earthquakes, tornadoes, floods)
  - Surveying high-risk pipe
  - Frost survey patrols (high-frequency survey)
  - Surveying public assemblies and high-consequence areas
  - Rapid survey of areas prior to public events (NFL Super Bowl, parades, official visits etc.)
  - Pre/post building demolition
  - Identification of large lost & unaccounted for gas sources
- Emissions Quantification
  - Construction prioritization (capital main replacement)
  - Targeted emissions reduction (identification & repair of highest emitting open leaks)
  - Post-construction QC – rapid survey of new or modern infrastructure
  - Due-diligence for asset acquisition
  - Risk-based assessment surveys
  - Support DIMP initiatives and analysis (high risk pipe, business districts, annual survey)
- Special use cases
  - Pinpointing hard-to-find leaks
  - Investigation of odor complaints

- Real-time source attribution (on-site chemical analysis: is source natural gas or not?)

Please see detailed cost information in Appendix 2 and ROI analysis in Appendix 1 of this document related to the use cases described above.

The responses to this letter of inquiry were prepared by Aaron Van Pelt, Director of Product Marketing and Product Management at Picarro Inc. Mr. Van Pelt is responsible for Picarro's energy products including the leak detection and emissions quantification hardware and analytics. Mr. Van Pelt has been in various technical and business roles at Picarro since 2007 and has managed Picarro's leak detection products since their development and introduction in 2010 and has managed the multiple campaigns with utilities and product validation by third parties.

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Leak Management Cost Savings

Summer 2017

Appendix 1

Summary

This document provides detail on the return on investment of the Picarro Leak Management System applied to various use cases within Leak Management. The financial assumptions for each use case are listed and the ROI is shown on an annual and 5-year basis. Various use cases included real examples from LDCs using Picarro, and the financial model for ROI in these cases is based on the financials of these examples. In cases where an example is not cited, the estimates come from typical estimates Picarro has obtained in its discussions with current gas distribution customers.

Common uses of Picarro Surveyor

- **Regulatory compliance leak survey**
- **Special Non-compliance surveys**
  - Rapid, emergency survey, post-disaster evaluation (earthquakes, tornadoes, floods)
  - Surveying high-risk pipe
  - Frost survey patrols (high-frequency survey)
  - Surveying public assemblies and high-consequence areas
  - Rapid survey of areas prior to public events (parades, official visits etc.)
  - Pre/post building demolition
  - Identification of large lost & unaccounted for gas sources
- **Emissions Quantification**
  - Construction prioritization (capital main replacement)
  - Targeted emissions reduction (identification & repair of highest emitting open leaks)
  - Post-construction QC – rapid survey of new or modern infrastructure
  - Due-diligence for asset acquisition
  - Risk-based assessment surveys
  - Support DIMP initiatives and analysis (high risk pipe, business districts, annual survey)
- **Special use cases**
  - Pinpointing hard-to-find leaks
  - Investigation of odor complaints
  - Real-time source attribution (on-site chemical analysis: is source natural gas or not?)

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Emissions Quantification Use Cases

1. Pipeline replacement prioritization
   - Inform repair vs. replace decisions before construction
     - Avoid leak *repair* construction costs by prioritizing removal of leaky segments
   - Evaluation of high-risk pipe – DIMP

2. Fugitive emissions reporting
   - Identification of largest emitting leaks

3. Post-construction QC evaluation
   - Quality control audits of (pre/post) construction by contractors

4. Monitoring of leak rate changes over time
   - High-frequency frost survey
   - Seasonal comparison (Fall/Spring) survey to detect frost damage
   - Long-term monitoring of Grade-3 leaks in high risk areas

Cost Savings: Emissions Quantification (EQ)

- Pipeline replacement prioritization
  - EQ measures emissions *and* leak density on pipe segments
  - EQ is superior to using traditional leak history and identifies the *most* leak-dense pipe segments for replacement
  - Inform repair vs. replace decisions before construction
    - Avoid leak *repair* construction costs by prioritizing removal of segments with highest leak density

EQ Cost Savings

Total HARD cost savings			Total SOFT cost savings		
Yearly Replacement Budget	$146,720,000		**Risk Reduction:**		
Total Miles of Main	2,000		Hazardous leak find multiple	2.2	
Burdened cost of Picarro survey per mile of main	$156		Current annual risk reduced from replacement**	$537,600	
Total yearly cost to survey "Yearly Replaced Miles"*	$34,944		Annual risk reduced from replacement with EQ	$1,164,800	
Cost per Mile Replaced	$1,310,000		Five year risk reduction:	-->	**$5,824,000**
Cost per Leak	$3,000				
Yearly Replace Miles	112				
			Reduction in Odor Calls:		
Leaks/mile without EQ**	0.6		Cost of Odor Calls	$300,000	*($150/call, 1 call/mi)*
Yearly Cost Avoidance without EQ	$201,600				
			Reduction or Odor Call by replacement	28.56%	
Leaks/mile with EQ**	5.7		Reduced Cost from Odor Calls	$85,680	
Yearly Cost Avoidance EQ	**$1,880,256**				
EQ Extra Savings	$1,678,656				
Five year cost savings-->		**$8,393,280**	Five year cost savings:	-->	**$428,400**

*Assumes to prioritize the Yearly Replace Miles, that you have to drive 2x that many of miles of pipe to prioritize the sections needing replacement

**Assumes 0.6 hazardous leaks/mi (traditional), 1.3 hazardous leaks/mi (Picarro), 5.7 total leaks/mi (Picarro) from Field Trial data

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Cost Savings: Compliance Leak Survey

- Hard savings from increased efficiency with Picarro
- Soft savings from:
  - Risk reduction due to finding more hazardous leaks with Picarro
  - Reduction of penalties from losing paper survey records due to Picarro digital records

Routine Regulatory Compliance Leak Survey

Total HARD cost savings			Total SOFT cost savings		
Annual spend on leak survey	$1,800,000		Hazardous leak find multiple	2	*(x traditional, typical)*
Miles of mains surveyed annually	10000		**Risk Reduction:**		
Picarro efficiency gains	38%	*(typical)*	Current annual risk reduced from leak survey activity	$1,000,000	
Survey cost per mile	$180		Five year incremental risk reduction:	-->	**$5,000,000**
			Non-Compliance Penalties:		
Five year savings:	-->	**$3,420,000**	Cost of losing a survey record	$25,000	
			Surveys completed per year	3000	
			Risk of record loss per survey	0.10%	
			Five year risk reduction:	-->	**$375,000**

*Customers report savings from 15% to 60% over traditional survey. 38% is an average.
**Based on risk reduction at higher leak find rate
***Estimate of lost productivity and labor cost to find replicate lost records

Cost Savings: Customer Odor Calls

Investigation of Odor Complaints

Total HARD cost savings			Total SOFT cost savings		
Annual odor calls	10000	*(10k mi x 1 call/mi)*	Risk per missed hazardous leak	$8,000	
Response cost	$150	*(typical)*	No-leaks where Picarro finds a hazardous leak	16%	*(CenterPoint example)*
Picarro reduction from repeat calls	10%	*(CenterPoint example)*	Number of no-leaks	2000	
Five year savings:	-->	**$750,000**	Five year risk reduction:	-->	**$12,640,000**

- **CenterPoint Energy Example:**
  - Respond to 81k odor calls per year
  - 31% of leaks are from customer odor calls
  - In 34% of cases, technicians come back reporting no gas found
  - When they send a Picarro vehicle to a no-gas-found case, it finds gas 79% of the time
  - Of those cases, 20% are hazardous leaks
  - This means: 81k x 34% x 79% x 20% = 4,351 hazardous leaks are found that would not otherwise be found
- CenterPoint's goal to reduce the 34% NGF by half
  - Picarro would be key to quantifying & tracking
  - Could institutionalize use of Picarro for no gas found reports from odor calls
  - Expand use to construction monitoring, etc. using Picarro

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Cost Savings: Large Odor Cloud, Emergencies, Hard-to-Find Leaks

- There are several examples from current Picarro customers of these use cases

Responding to Massive False Odor Clouds

Total HARD cost savings

Large-scale false alarms per year	1	
Calls needing a response per incident	1000	
Cost per odor call response	$150	
Cost to respond with Picarro vehicle	$2,000	
Five year savings:	-->	**$740,000**

Rapid Post-Emergency Survey

Total HARD cost savings			Total SOFT cost savings		
Emergencies per year	0.3		Goodwill from gas company driving streets post-incident	$100,000	
Extra cost for emergency survey	$500,000		Five year value of goodwill	-->	**$150,000**
Five year emergency survey savings:	-->	**$750,000**			

Locating Hard-to-find Leaks

Total HARD cost savings			Total SOFT cost savings		
Overnight cost of crew	$5,000		Morale and health impact of emergency all night work	$2,000	
Avg number of nights spent in field on unfound leaks	1.5		5-year avoidance:	-->	**$195,000**
Hard to find leaks per year	20				
Amount Picarro finds before nightfall	65%				
Five year pinpointing savings:	-->	**$487,500**			

Cost Savings: Special Survey & QC after Construction

- There are several examples from current Picarro customers of these use cases

Non-Scheduled Mandated Leak Survey

Total HARD cost savings

Annual spend on non-scheduled survey	$500,000	
Efficiency savings	38%	
Five year savings:	-->	**$190,000**

- Public news report: PG&E dispatched 64 workers to a recent over-pressurization event:
  - http://www.kcra.com/article/pgande-gas-problem-prompts-concern-in-folsom/8643190
  - There is also a benefit for finding leaks faster, if they actually occurred due to the overpressure event

Post-construction Quality Control

Total HARD cost savings

Total annual repair costs	$5,000,000	
Construction jobs that will cause a problem in the next survey cycle	5%	
Five year future cost avoidance:	-->	**$1,250,000**

- Amount spent on repairing or replacing assets
- Contractors should fix problems if they are discovered quickly

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Cost Savings: Source Attribution, Auditing Traditional Survey, Asset Acquisition

- There are several examples from current Picarro customers of these use cases

Real-time Source Attribution

Total HARD cost savings			Total SOFT cost savings		
Gas samples processed per year	500		Hourly crew cost	$500	
Cost per gas sample	$100		Hours for a crew to collect a sample	2	
Cases resolved with Picarro	50%		Five year collection savings:	-->	**$1,250,000**
Five year gas sample savings:	-->	**$125,000**			

- There is also a reduction in risk from finding out faster if there is actual risk due to a gas leak

Auditing walking survey

Total HARD cost savings			Total SOFT cost savings		
Annual spend on survey	$1,000,000		Risk per missed leak	$10,000	
Improvement knowing Picarro auditing	20%		Current annual leaks found	2000	
Five year value of additional survey:	-->	**$1,000,000**	Improvement from Picarro audits	20%	
			5-year risk reduction:	-->	**$20,000,000**

- Utilities have seen an improvement in leak survey quality when traditional surveyors know they are being followed by Picarro

Due-diligence for Asset Acquisition

Total SOFT cost savings		
Gas systems purchased per five years	2	
Value of knowing if system was well maintained	$500,000	
Five year risk avoidance on acquisitions:	-->	**$1,000,000**

Cost Savings: Lost Gas & Community Outreach

- There are several examples from current Picarro customers of these use cases

Identification of Lost and Unaccounted for Gas Sources

Total HARD cost savings			Total SOFT cost savings		
Gas delivered per day (Bcf)	2.0		Social cost of carbon† per ton of CO_2	$42	(highly variable)
Cost per Mcf	$3.50		Tons of CO2 equilivent‡ per Mcf methane	0.054717	
Lost gas rate	1.50%		Carbon impact avoided over five years	-->	**$10,065,739**
Picarro leakage reduction	40%				
Five year ratepayer gas savings:	-->	**$3,832,500**			

† In the year 2020 for 3.0 percent discount rate in 2007 dollars. Source: nap.edu/read/24651
‡ Source: epa.gov/energy/ghg-equivalencies-calculator-calculations-and-references

- Helpful if companies have a target for emissions reduction
  - Can be calculated as tons of CO2 avoided as well

Community Outreach

		Total SOFT cost savings		
Public events per year	1	Goodwill from showcasing advanced utility technology	$10,000	
		Five year goodwill value:	-->	**$50,000**

  - Community outreach is worth spending money on

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Cost Schedule

In the detail that follows, costs of acquisition and operation of the Picarro system are listed per mile of distribution main and are calculated for PGL's planned 2,000 mile infrastructure. Costs are also compared to industry averages for leak management.

Item	Itemized cost	Multiplier	Subtotal
Cost of leasing the system	$105 per mile of distribution main	2,000 miles* of distribution main per year	$210,000
Vehicle operation and maintenance	$0.65 per mile of distribution main	2,000 miles of distribution main per year	$1,300
Fuel costs (SUV, Ford Escape or similar)	$1.72 per mile of distribution main	2,000 miles of distribution main per year	$3,440
Annual cost of Driver and Analyst	$49.10 per mile of distribution main	2,000 miles of distribution main per year	$98,200
		Grand Total	**$312,940**

*2000 miles of distribution main is used in this example to match PGL's total replacement project mileage.

The average cost per mile, including all expenses listed above is approximately $156.22/mile. This compares to industry ranges of $180 to over $2600 per mile[1] of main for leak survey.

Rate per mile calculations are based on the Picarro multi-pass driving protocol and current driving productivity rates of Picarro customers, one car driven 7 hours per day and 250 days per year can survey up to 3055 miles of main per year, on average, providing over >90% coverage of mains and services. Productivity for mains-only survey could be as high as 9165 miles of main annually, at a cost of $52.07 per mile of main. This compares to the industry standard[2] of 9.9 services per hour and 2.5 miles of main per hour, the productivity of which depends on mains/services density.

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[1] Pacific Gas and Electric Company 2017 General Rate Case, Exhibit (PG&E-3), Chapter 6c, Leak Management Expenses by Major Work Category. Leak survey cost per service in 2017 is projected to be $33 per service. PG&E has approximately 79 services per mile of main, yielding a leak survey cost of $2607 per mile of main including associated services and other inspection requirements. Contract leak survey can range between $180-$350 per mile of main according to estimates obtained by Picarro.

[2] *Picarro Surveyor™ Leak Detection Study Diablo Side-By-Side Study*, Timothy Clark, et al., November 2012, Pipeline Research Council International & Pacific Gas & Electric Co.

Exhibit EDF(A)-6:

Lost Gas Calculations Worksheet

Calculations

Variable		Amount	Units
Deliveries		30,159,739	Mcf
Losses from Leaks		1,316,409	Mcf
Calculated percentage		4.4%	%
Conservative percentage		2.2%	%
Conservative Volume		658,205	Mcf
District of Columbia Natural Gas % of Total Residential - Sales (%)		75.6	%
District of Columbia Price of Natural Gas Delivered to Residential Consumers (Dollars per Thousand Cubic Feet)		$11.78	$
Percent of Commercial Natural Gas Deliveries in District of Columbia Represented by the Price (%)		21.7	%
District of Columbia Price of Natural Gas Sold to Commercial Consumers (Dollars per Thousand Cubic Feet)		$10.42	$
Value of Residential Losses from leaks		$5,861,759	$
Value of Commercial Losses from leaks		$1,488,293	$
Total value of losses from leaks		7,350,051	$
Top 10% of losses from leaks	$	735,005.12	$
Top 25% of losses from leaks	$	1,837,512.79	$
Top 50% of losses from leaks	$	3,675,025.59	$

Deliveries

Area	Company	Item	2018
District of Columk	WASHINGTON GAS LIGHT COMPANY	Residential Volume	13111897
District of Columk	WASHINGTON GAS LIGHT COMPANY	Commercial Volume	16621415
District of Columk	WASHINGTON GAS LIGHT COMPANY	Vehicle Fuel Volume	426427
			30159739

Report: Natural Gas Annual Respondent Query System (EIA-176 Data through 2018)
Release Date: October 2019
Years: 2018 to 2018
Volumes in Thousand Cubic Feet, Prices in Dollars per Thousand Cubic Feet

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Data 1: District of Columbia Natural Gas Prices

Sourcekey	NA1480_SDC_3	N3050DC3	N3010DC3	NA1504_SDC_4	N3020DC3	N3020DC4	N3035DC3	N3035DC4	NA1570_SDC_3	N3045DC3
Date	**District of Columbia Natural Gas Pipeline and Distribution Use Price (Dollars per Thousand Cubic Feet)**	**Natural Gas Citygate Price in the District of Columbia (Dollars per Thousand Cubic Feet)**	**District of Columbia Price of Natural Gas Delivered to Residential Consumers (Dollars per Thousand Cubic Feet)**	**District of Columbia Natural Gas % of Total Residential - Sales (%)**	**District of Columbia Price of Natural Gas Sold to Commercial Consumers (Dollars per Thousand Cubic Feet)**	**Percent of Commercial Natural Gas Deliveries in District of Columbia Represented by the Price (%)**	**District of Columbia Natural Gas Industrial Price (Dollars per Thousand Cubic Feet)**	**Percent of Industrial Natural Gas Deliveries in District of Columbia Represented by the Price (%)**	**District of Columbia Natural Gas Vehicle Fuel Price (Dollars per Thousand Cubic Feet)**	**District of Columbia Natural Gas Price Sold to Electric Power Consumers (Dollars per Thousand Cubic Feet)**
1980			4.57		4.22					
1981			5.5		5.12					
1982	3.94		6.64		6.28					
1983	4.73		8.1		7.44					
1984	4.37		8.05		7.04					
1985	4.16		7.91		6.72					
1986	3.61		7.52		5.91					
1987	3.02		7.09		5.01					
1988	2.94		6.96		5.03					
1989	3.03		7.44	100	5.3					
1990	2.99		7.18	100	5.63	100				
1991	2.78		7.07	100	5.17	97.3				
1992	2.95		7.61	100	5.36	99				
1993	2.58		8.34	100	5.75	98				
1994	2.13		8.29	100	6.16	90.9				
1995	1.97		8.03	100	6.04	76.8			2.06	
1996	3.02		9.19	100	7.37	70.5			4.94	
1997	2.97		9.39	100	7.37	54.9		0	3.01	
1998	2.52		8.91	1	7.36	52.3		0	2.6	
1999	2.39		8.7	93.2	7.38	45.9		0	2.8	
2000	4.63		10.81	82.8	9.63	35.6		0	3.99	
2001	5.36		12.65	75.4	12.02	22.4		0	5.14	
2002			11.01	74.5	10.3	23.5		0	4.37	
2003			13.29	70.7	12.73	30.5			5.95	
2004			14.31	75.4	13.6	23.3			6.76	
2005			16.87	79.8	13.17	100		0	8.93	
2006			16.96	76.7	14.67	100		0	9.5	
2007			15.67	76.2	13.69	100		0	9.49	
2008			16.49	76.3	13.9	100		0	15.57	
2009			13.92	76.1	12.99	100		0	6.83	
2010			13.53	75.5	12.26	100		0	4.87	
2011			13.06	75	12.24	16.9		0	4.17	4.96
2012			12.1	73.9	11.19	17.9		0	9.38	
2013			12.45	75	11.64	19.1		0		
2014			13.05	73.8	12.18	19.9		0		
2015			11.98	73.3	11.07	21.4				
2016			10.9	73.2	9.88	19.5				
2017			12.53	73.9	10.87	20.1				
2018			11.78	75.6	10.42	21.7				
2019			12.84		11.36			0		

Source: EIA Natural Gas Prices
Link: https://www.eia.gov/dnav/ng/ng_pri_sum_dcu_SDC_a.htm
Release Date: 5/29/2020

Losses

Area	Company	Item	2018
District of Columb	WASHINGTON GAS LIGHT COMPANY	Losses from Leaks Volume	1,316,409

Report: Natural Gas Annual Respondent Query System (EIA-176 Data through 2018)
Release Date: October 2019
Years: 2018 to 2018
Volumes in Thousand Cubic Feet, Prices in Dollars per Thousand Cubic Feet

Exhibit EDF(A)-7:

Presentation: Picarro Natural Gas Asset Management Solution by Aaron Van Pelt, Picarro (Nov. 7, 2019)

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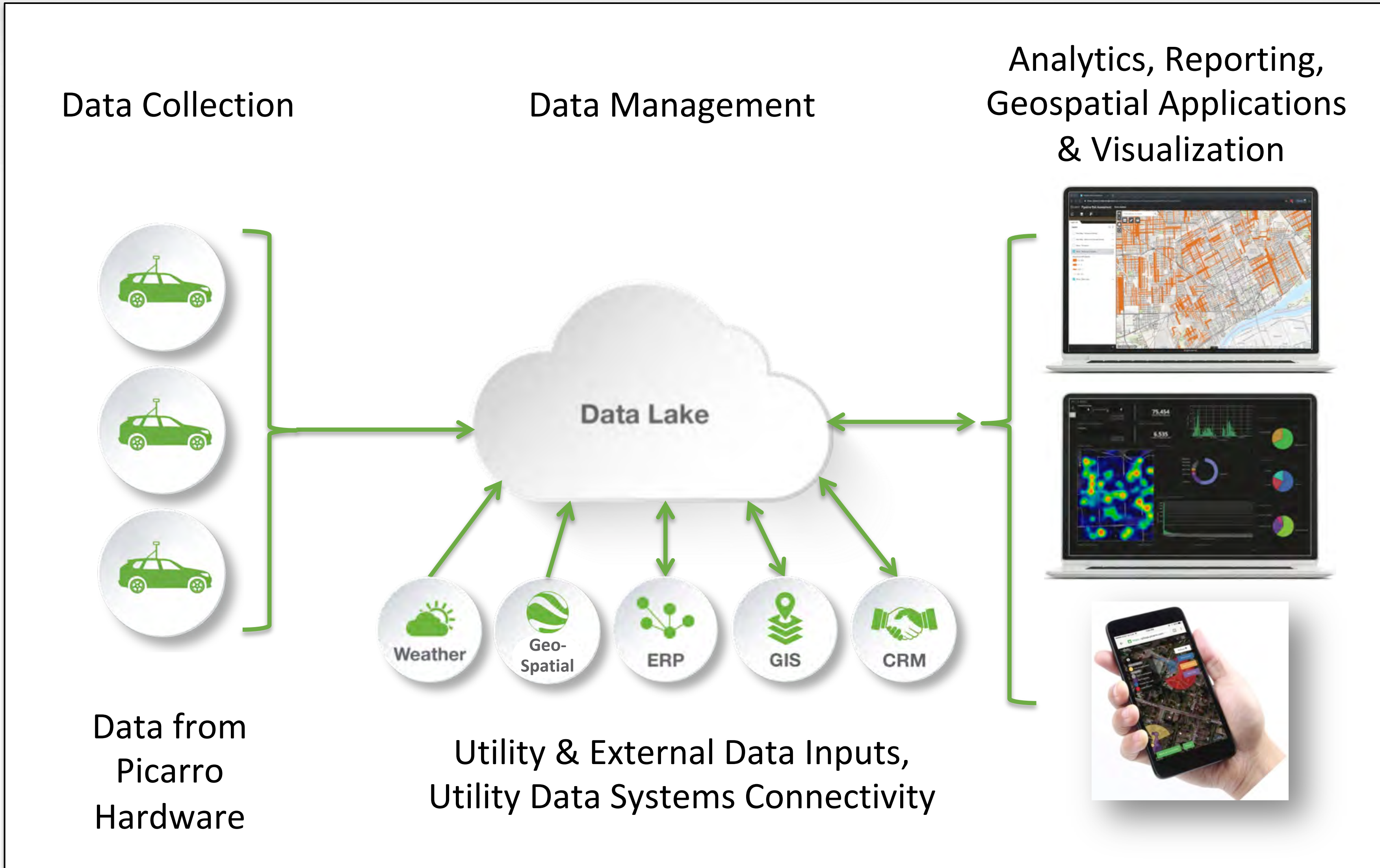
Natural Gas Asset Management Solution

Pipeline Safety Trust
November 7, 2019

Aaron Van Pelt
Vice President of Product Strategy
Picarro, Inc. Santa Clara, CA, USA

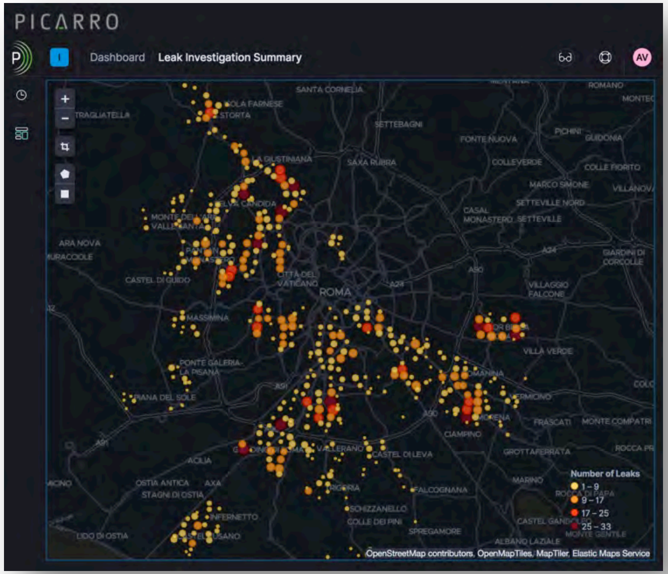
Picarro's Natural Gas Network Management Solution



Picarro’s Hardware-Enabled Data Analytics

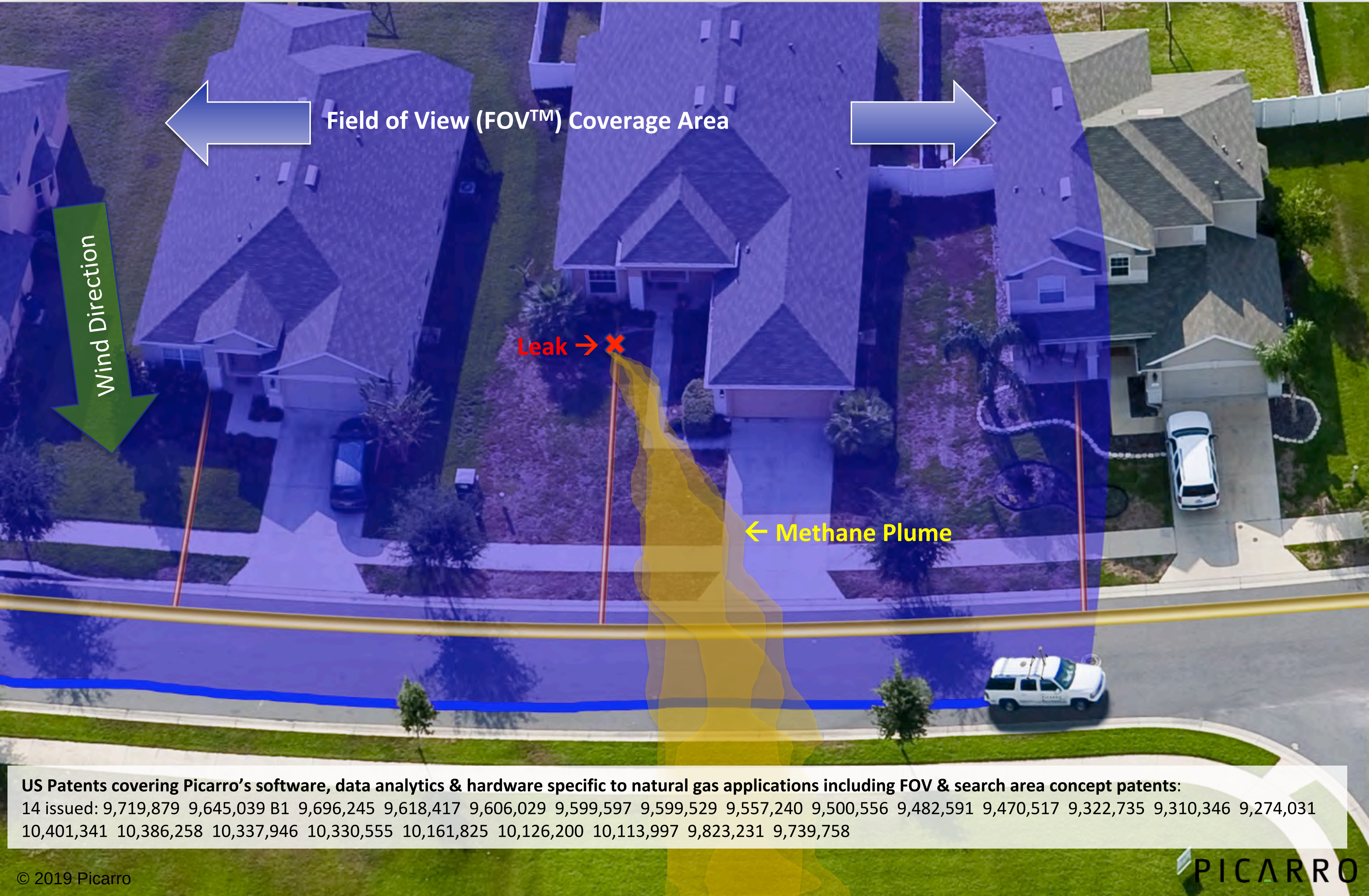
- Picarro’s advances in mobile leak detection technology allow natural gas emissions data to be collected at a speed and scale not previously possible
- Advances in “Big Data” Analytics allow better-informed conclusions to be drawn from that data and action taken
- This data can be collected once and used for multiple use cases including Leak Survey, Risk Reduction & Emission Reduction

Data Collection



Data Management, Analytics, Visualization & Reporting

Picarro's Advanced Emissions Measurement Technique



US Patents covering Picarro's software, data analytics & hardware specific to natural gas applications including FOV & search area concept patents:
14 issued: 9,719,879 9,645,039 B1 9,696,245 9,618,417 9,606,029 9,599,597 9,599,529 9,557,240 9,500,556 9,482,591 9,470,517 9,322,735 9,310,346 9,274,031 10,401,341 10,386,258 10,337,946 10,330,555 10,161,825 10,126,200 10,113,997 9,823,231 9,739,758

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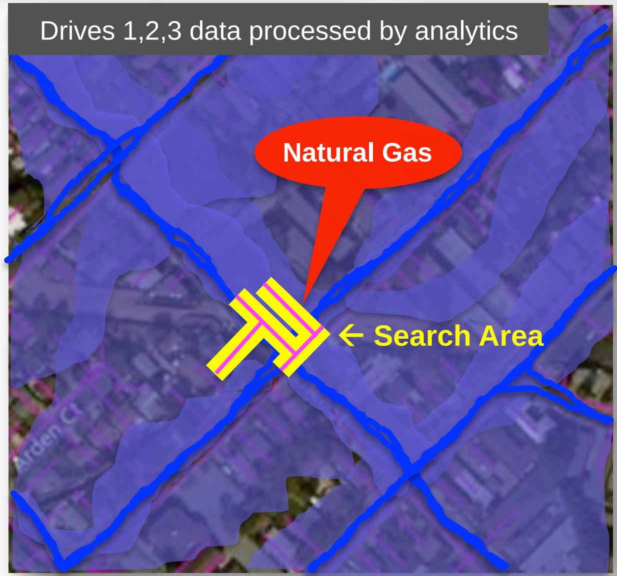
Data from multiple drives is processed by analytics to compute emission location, coverage & source attribution

Data from **multiple drives** combined and processed by **Analytics** to determine:

- Search Areas
- Source Attribution
- Field of View Coverage



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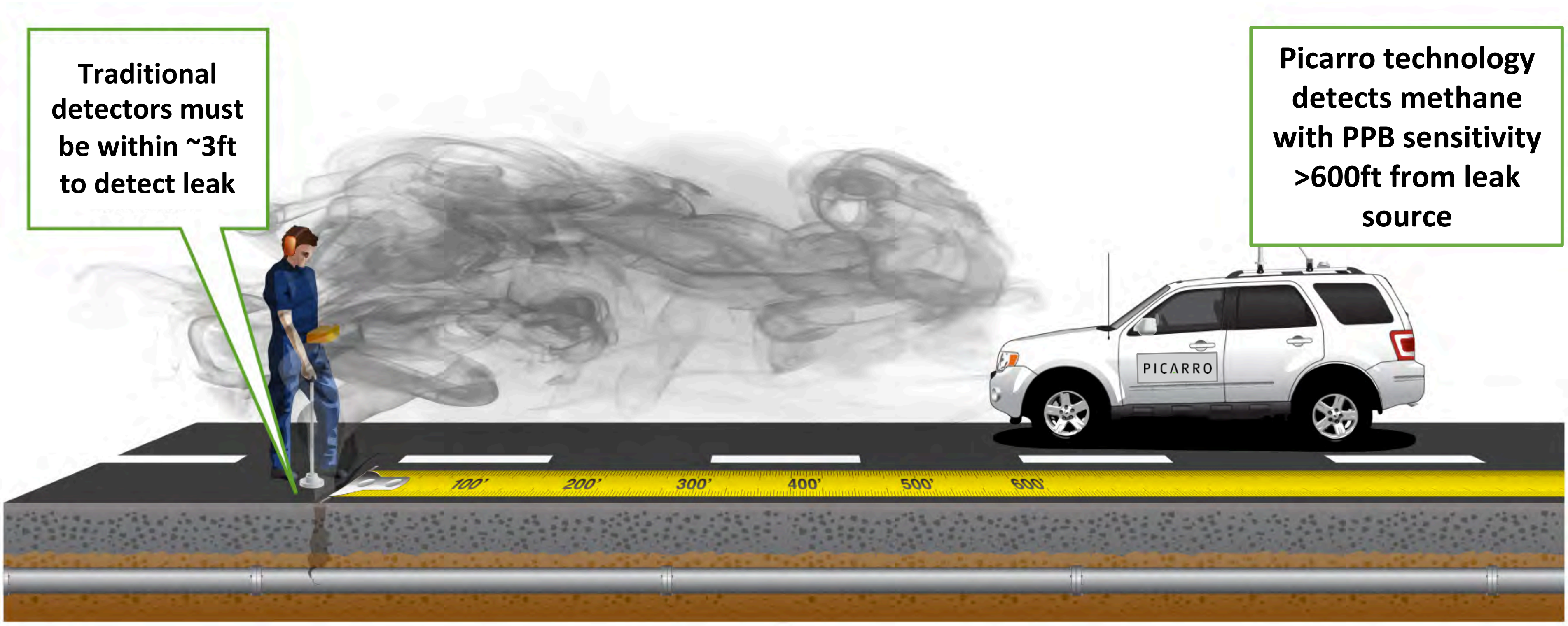
Picarro can detect distant leaks

- Traditional leak survey equipment has PPM methane sensitivity & requires the detector to be within ~3ft to detect the leak because the gas dilutes quickly in the atmosphere
- Picarro detects leaks at a larger distance (>600ft) which requires very high PPB methane sensitivity and wind direction measurements to find the leak location



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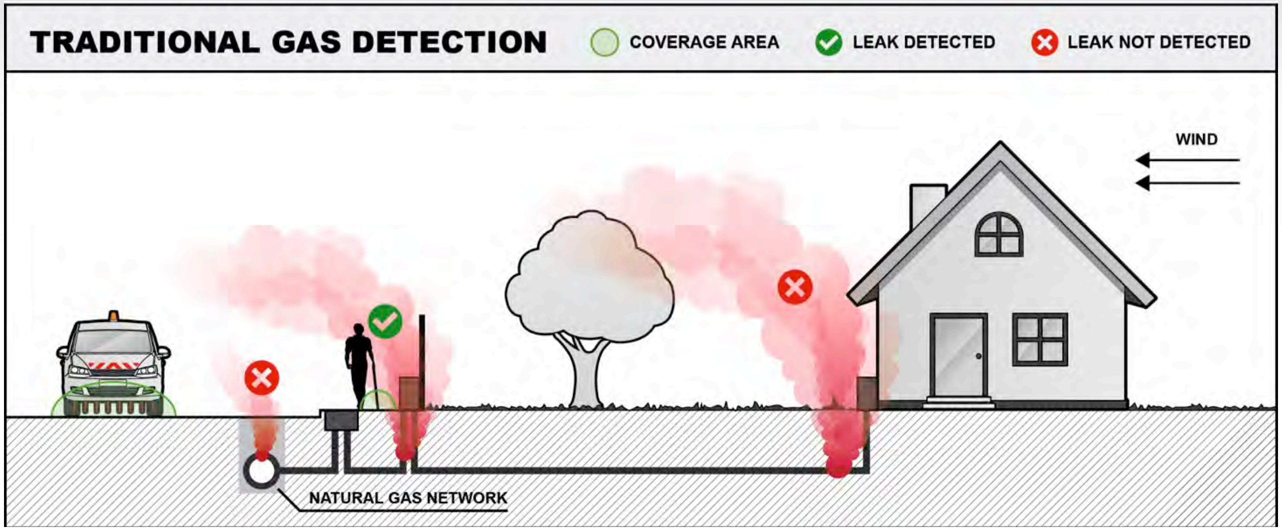
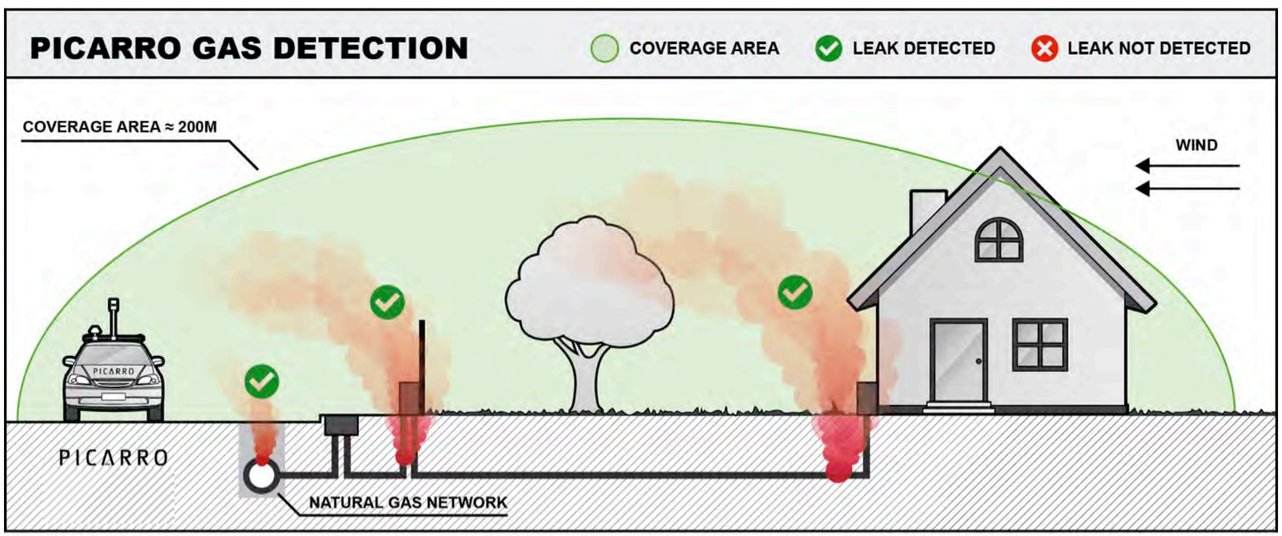
Picarro compared to traditional walking and mobile survey



Disadvantages:

- Only PPM sensitivity
- Only detects ~32% of hazardous leaks
- Limited coverage: must be directly over pipelines
- Detects only methane
- Depends on skill of technician
- Cannot use in rain/snow
- Slow walking & driving speeds



Advantages:

- PPB sensitivity
- Large coverage area
- Detects ~91% of hazardous leaks
- Detects methane & ethane: discriminates natural gas from sewer gas
- Not influenced by human error
- Detects leaks on the entire network (mains, services & meters)
- Can use in rain/snow
- Can drive at high speeds

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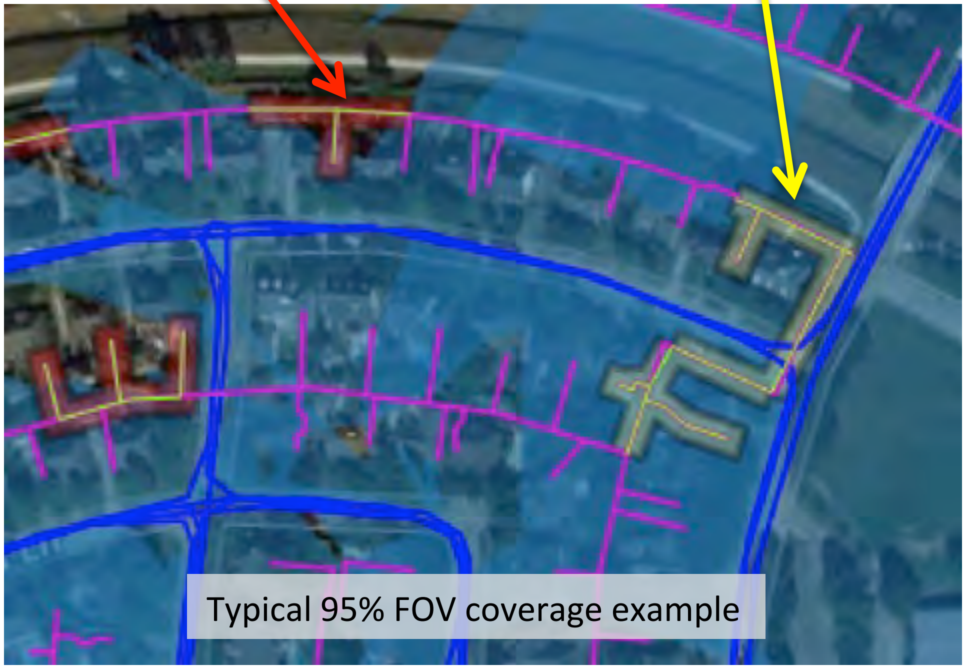
Picarro leak survey process: efficiency comparison to traditional survey

Typical leak survey results & investigation process to fully complete survey in an area

"Gap" (area not covered by Picarro FOV requiring foot survey)

Pipeline associated with a leak indication requiring investigation



95% FOV coverage → only need to walk 5% in Gap + investigate leak indications

Example area:
10 miles of main / 500 services:

- 5.7 hrs to drive
- 25 Gap services* = 1.8 hrs
- 2 leak indications /mi

@ 25 min/indication = 8.3hrs

15.8 hrs Picarro process

- vs. -

36.2 hrs traditional survey

*Typical traditional survey rate of 13.8 services/hr

PICARRO

Picarro & Traditional Leak Survey Performance Comparison

Picarro is 2x faster and 3x more effective than traditional survey

	Picarro	Traditional	Notes
Gradeable Leak Find Rate*	89%	36%	All categories of reportable leaks
Hazardous Leak Find Rate	91%	32%	Hazardous leaks defined as Grade 1, 2+, 2 or Grade A, B depending on utility grading criteria
Survey Coverage	90%	Undefined	Picarro "FOV" coverage. Traditional technologies do not calculate coverage
Survey Speed (mains)	0.45	0.22	Mains pipeline mi/hr *including* services
Survey Speed (services)	28	13	Services/hr including associated mains

- *This performance is based on data collected in 50 Field Trials conducted since 2011 with 30 utilities worldwide.*
- **100% "leak find rate" is defined as the population of all leaks in an area found by Picarro survey plus all leaks found by traditional survey.*
- *Anonymized, detailed results data on each of these 50 trials is available upon request.*

PICARRO

Deployment Summary

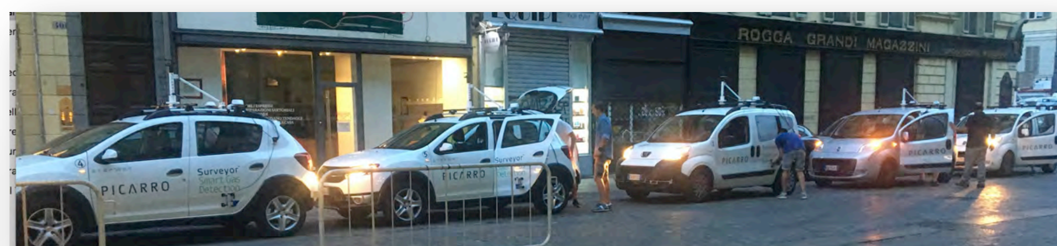
- 18 natural gas operators in 7 countries use the Picarro solution (as of 11/2019)
  - U.S., Canada, Australia, Italy, France, Switzerland, Japan
  - 11 LDCs are using it for compliance leak survey
  - 7 LDCs are U.S. based
- Picarro used for U.S. DOT Compliance Leak Survey in 8 states
  - CA, TX, AR, MN, LA, OK, MS, AL
  - by 3 major U.S. utilities (Centerpoint, PG&E, Atmos)
  - Centerpoint & PG&E used Picarro for ~100% of their 2018 compliance survey
- Picarro solution has been tested & validated in 53 double-blind, Directed Field Trials with 33 gas operators across North America, Europe, Asia and Australia since 2011, several involving independent, third-party validation
- Further evaluated in 20 additional field demonstrations by 14 additional gas operators worldwide

PICARRO

Picarro's Predictive Analytics Using Machine Learning

- **Data collected by Picarro systems worldwide to date:**
  - 63,000 hours (7.2 years or 30 person-years) of active driving data collection
  - 1.2 billion time-series measurements (10 years equivalent)
  - 3.6 million leak indications
  - Accruing data today at a rate of 30,000 hours/year & accelerating
- **Customer validation datasets:**
  - 100,000's of graded leaks to validate analytics & feed machine learning algorithms
  - GIS pipeline data & risk (DIMP) models

No other such dataset exists at this scale



Use Cases

Data can be collected once and used for multiple applications

Descriptive Analytics

Compliance Leak Survey

Non-Compliance

- Construction QC
- Pre-Construction
- Leak Pinpointing
- Post-Disaster
- Frost Patrol
- Pre-Event
- Source Discrimination
- Auditing Survey
- System Assessment

Diagnostic Analytics

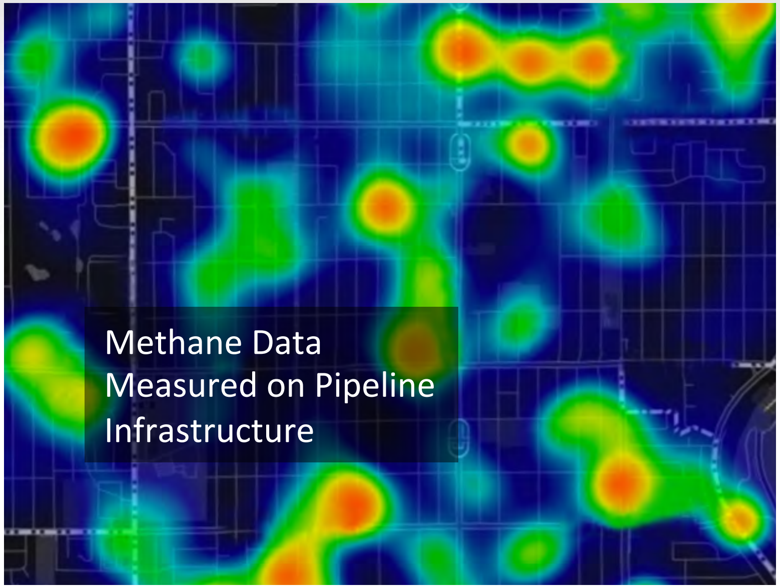
- Construction Prioritization
- Emissions Quantification
- System Risk Reduction (DIMP)
- Leak Risk Ranking (CH_4)

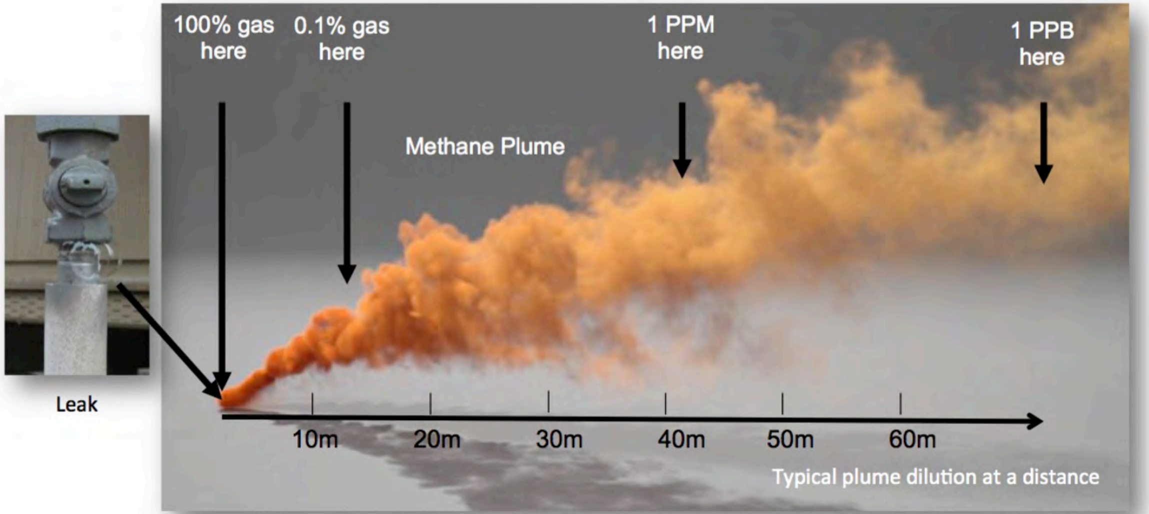
Predictive Analytics

Budget & Risk Forecasting

Using methane data for applications beyond leak survey

- Measuring methane data provides a "live" snapshot of the current condition of pipelines
- There are qualities of methane plumes (shape/size/ flow rate, etc.) that we can measure that correlate to the risk, size and type of the leak that created the plume
- Using Picarro methane data and analytics, leak density and emissions are measured along pipe segments
- The methane data is not used to identify individual leaks as in the leak survey application

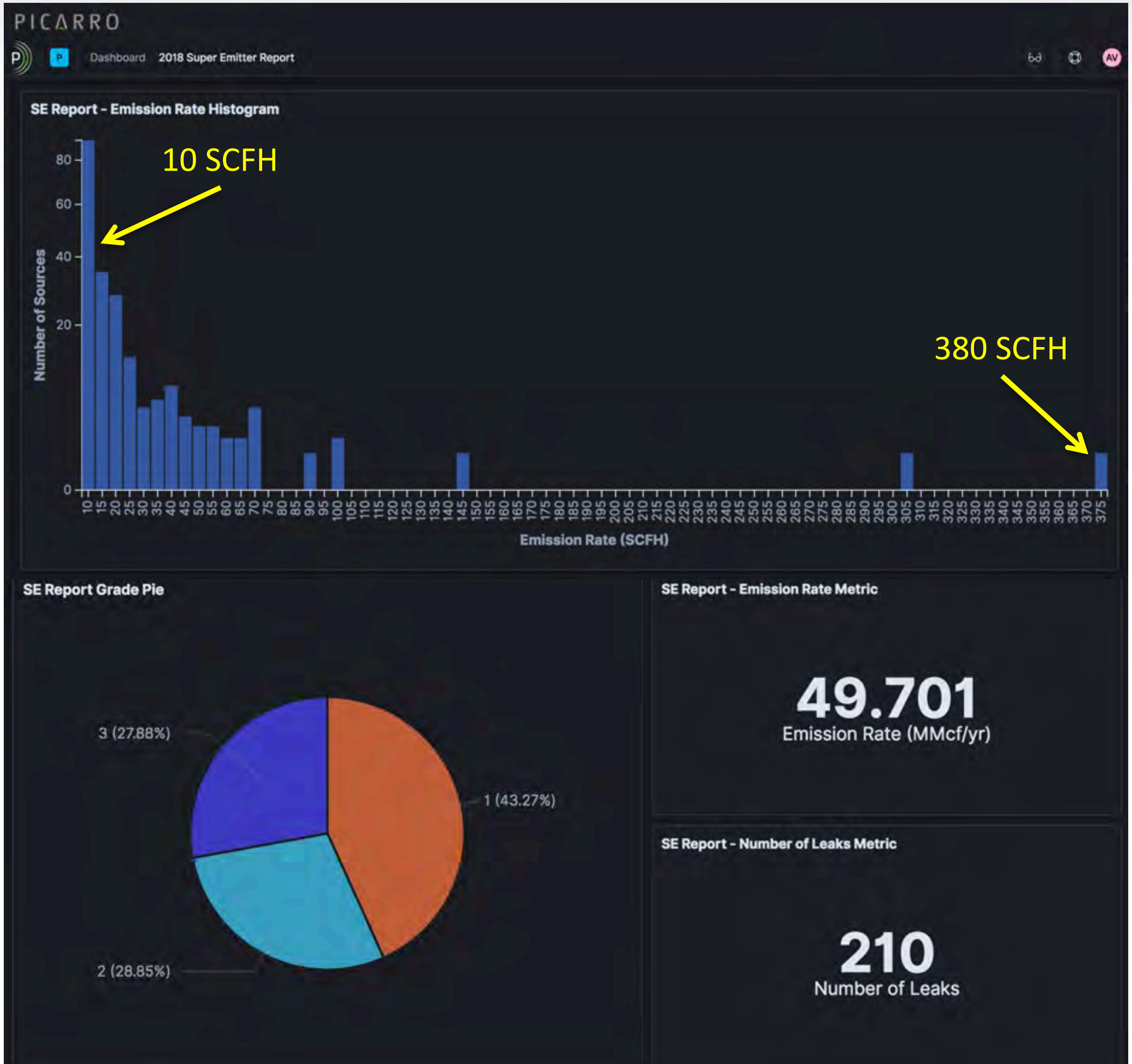




PICARRO

Emissions Quantification & Reduction at Scale

Picarro Emissions Quantification Analytics Dashboard



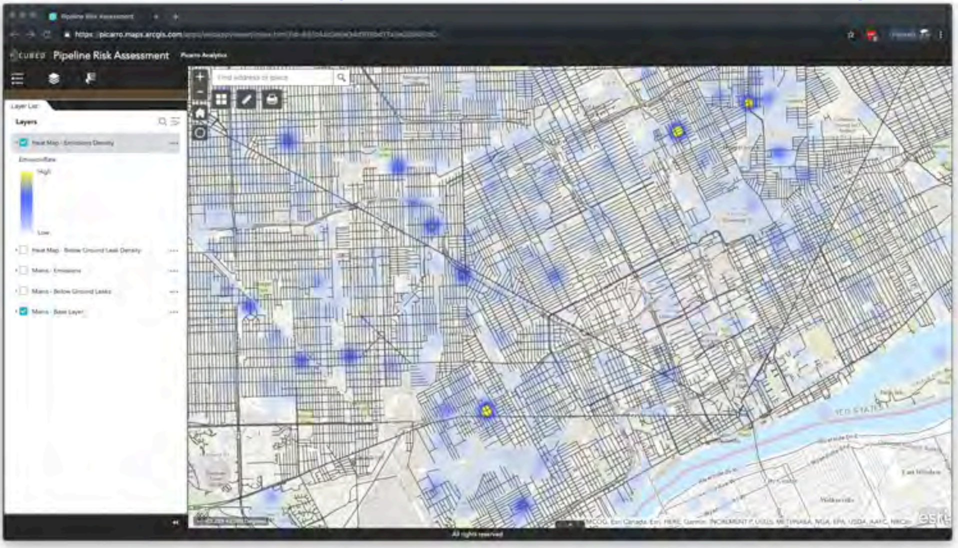
- **PG&E 2018 Program to Identify Highest-Emitting Leaks for Prioritized Repair**
- Picarro data collection on nearly entire PG&E gas distribution system in 2018:
  - Surveyed 1/3 of system for compliance & collected methane data on 2/3 of system for emissions only
- Identified 210 leaks of ≥10 SCFH accounting for 49.7 MMcf/yr of estimated emissions
- Highest-emitting leaks prioritized for repair to take advantage of reduction in emissions
- Only 210 leaks account for 32% of PG&E's total distribution system emissions as measured by Picarro on assets covered by Picarro
- 74 Grade-1 leaks remediated through the 2/3 non-compliance, emissions-only effort

Emissions quantification & estimation of leak density

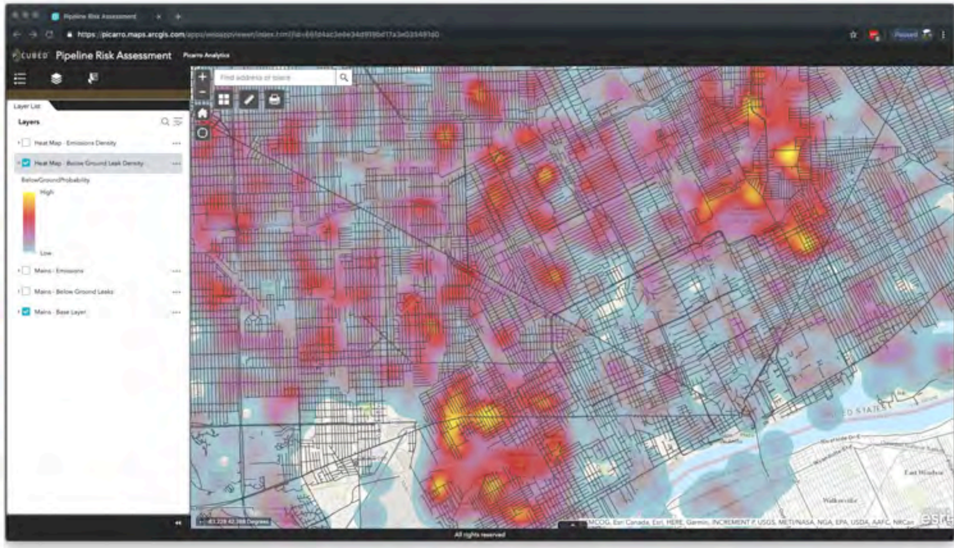
- Using methane data, analytics estimate leak density and measures emissions of pipe segments rather than identifying individual leaks
- Significant O&M (2-3x) cost avoidance by identifying pipe segments with highest leak density for capital replacement
- Better informs targeted emissions & risk reduction programs

Pipe replacement optimization enabled by Picarro's emissions quantification & analytics

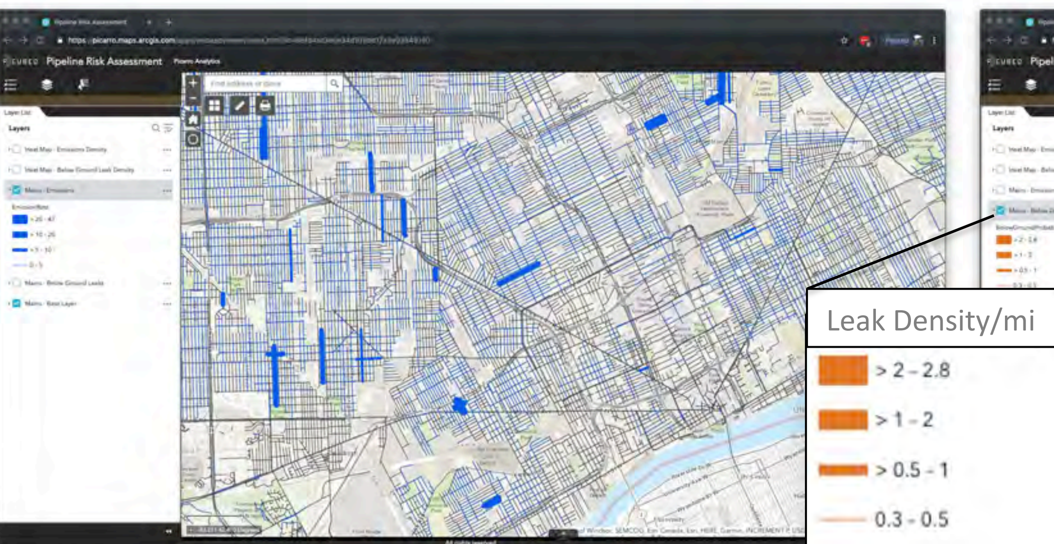
Heat Map View – Emissions Density



Heat Map View – Below-Ground Leak Density



Mains View – Emissions



Mains View – Below-Ground Leaks

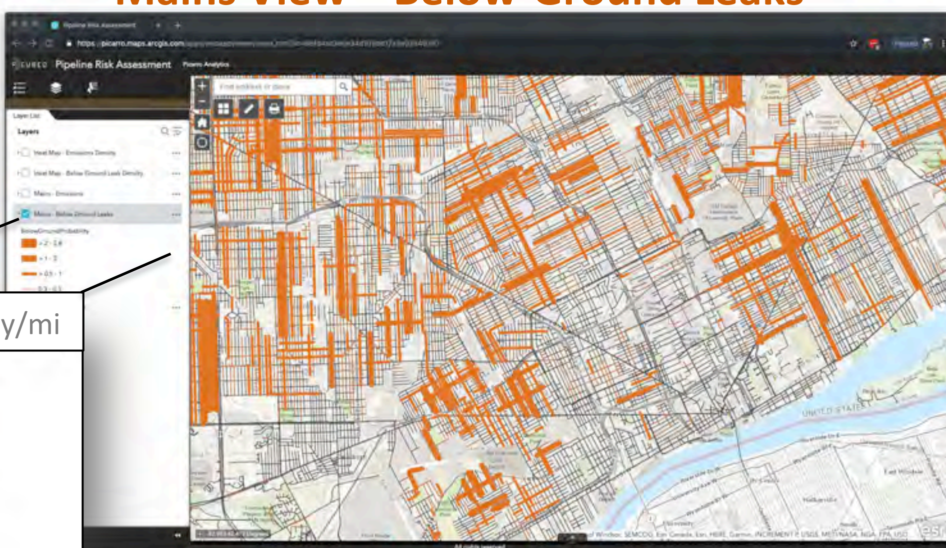


Exhibit EDF(A)-8:

Presentation: Risk Based Leak Surveys (Oct. 2019)

by François Rongere, PG&E

Risk Based Leak Surveys (BP#16)

Using analytics and monitoring to optimize the leak survey process

François Rongere

October 2019

Together, Building
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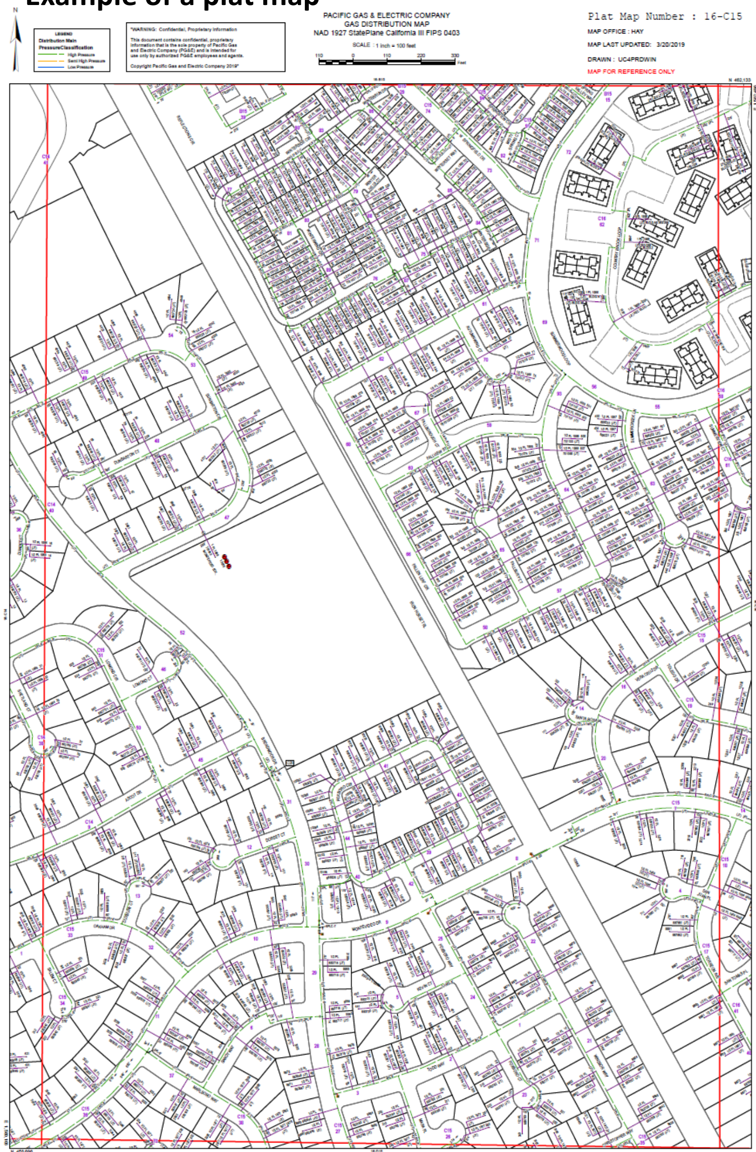
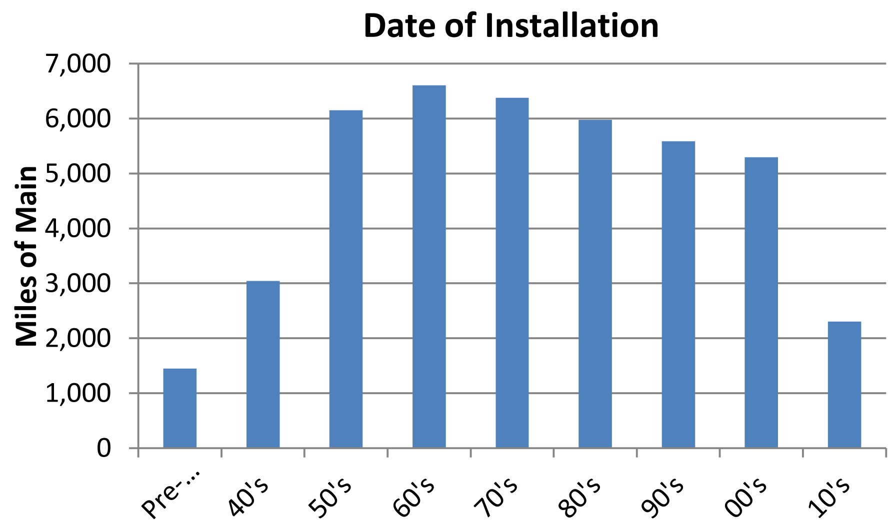
The Distribution System at PG&E

Example of a plat map



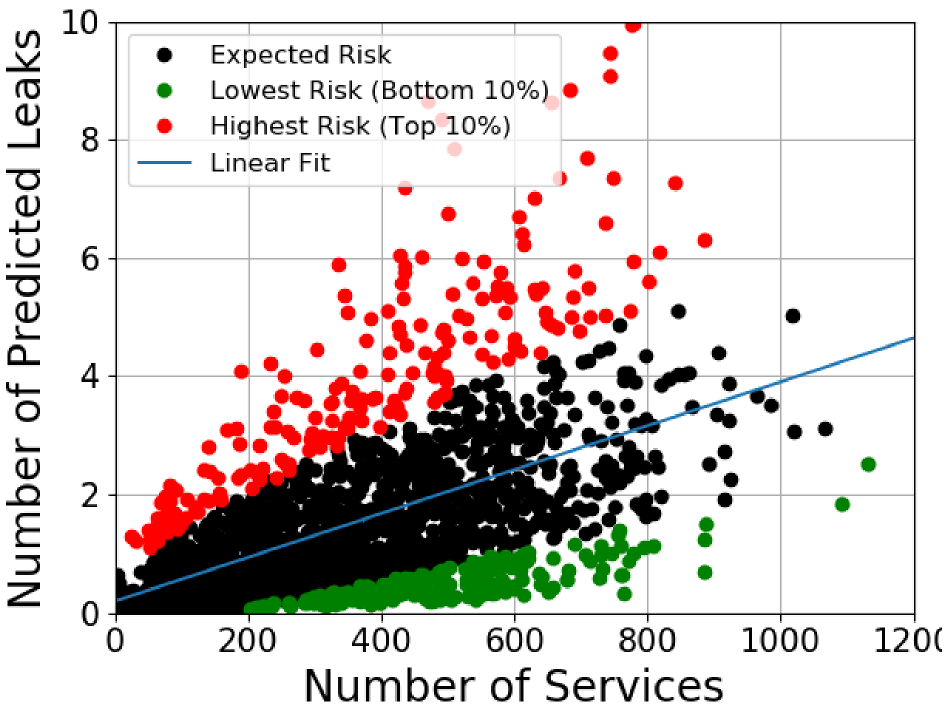
Material	Main (Miles)	Services (Miles)
Plastic	22,926	22,543
Protected Steel	17,818	10,781
Unprotected Steel	259	100
Copper	-	6



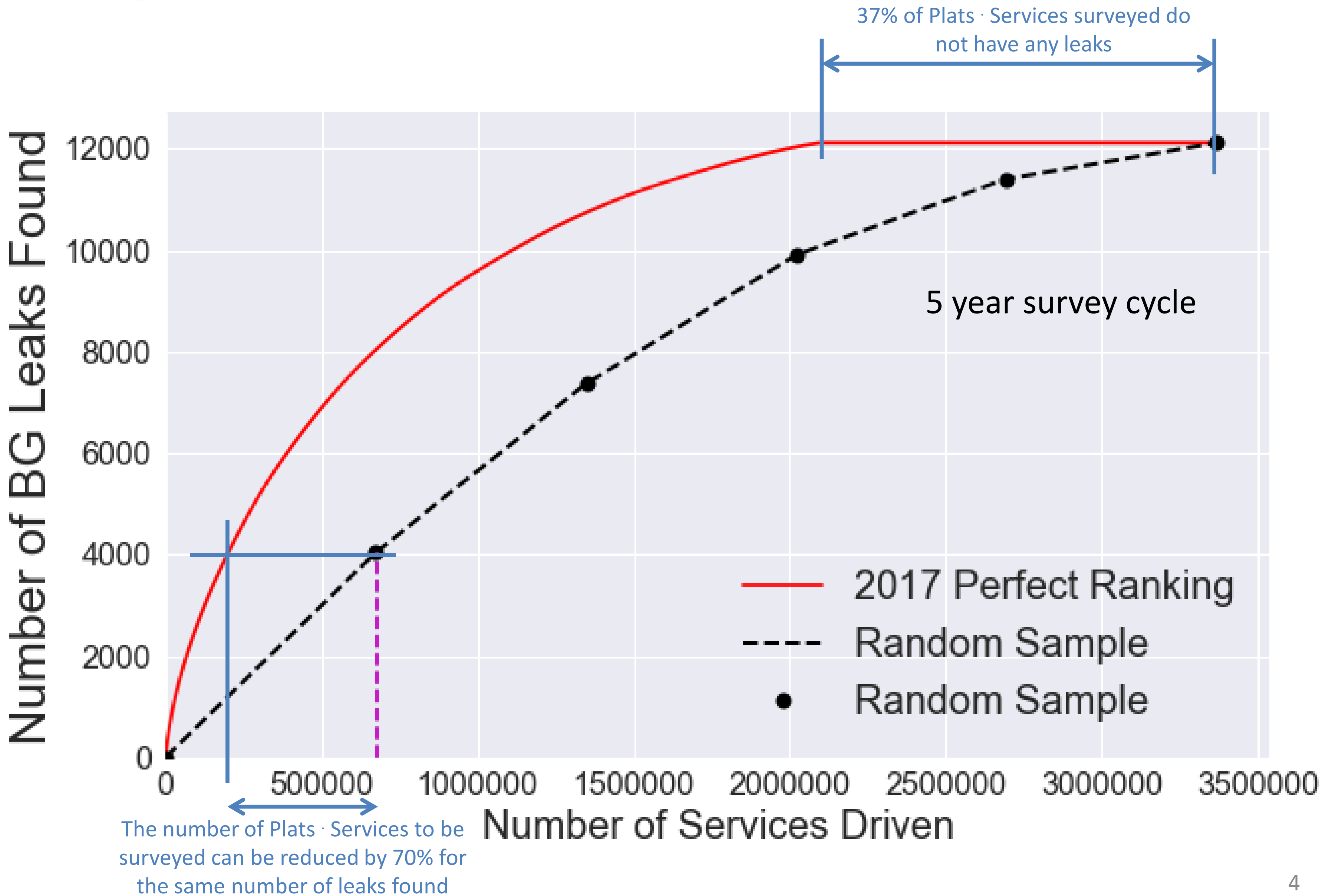
Objective

- Prioritize the plats to be surveyed in order to optimize the number of leaks found, minimize the time leaks stay open and reduce emission.

Distribution of leaks found per plat (2017)



The Potential of prioritization



The DIMP risk model

- The DIMP Likelihood of Failure (LoF) model estimates the likelihood of a leak for each segment of the Distribution System considering the following Threats and Sub-Threats:

Threat	Sub-Threats
Corrosion	Atmospheric, External, Internal
Excavation Damage	Excavation, Mismark, No Call, Other Damage Prevention, Unlocatable
Equipment Failure	Malfunction
Incorrect Operations	Construction Defect, Incorrect Operations, Crossbore
Material/Weld	Compression Coupling, Metallic Failure, Weld Failure, Fusion Failure, Plastic Failure
Natural Forces	Earth Movement, Flooding, Lightning, Earthquake, Roots, Other
Outside Forces	3rd Party, Electrical Facilities, Fire/Explosion, Previously Damaged, Rodent, Vandalism, Vehicle
Other	Pipe Dope, Other

Likelihood of Failure

- Three contributions to LoF are considered:

1. **District Baseline (BL):** Leak data averaged over the past five years per each sub-threat aggregated by district.

$$LoF_{BL} = \frac{Sub - Threat\ Leak\ Count}{I \cdot Asset\ Mileage\ in\ District} \quad [Leak \cdot Mile^{-1} \cdot Year^{-1}]$$

2. **Observed Leak Score (OLS):** Leak data averaged over the past five years per each sub-threat aggregated by Segment.

$$LoF_{OLS} = \frac{Sub - Threat\ Leak\ Count}{I \cdot Length\ of\ Segment} \quad [Leak \cdot Mile^{-1} \cdot Year^{-1}]$$

3. **Supplemental (SUPP):** Estimates based on data other than historical leak. Examples include an asset’s proximity to seismic hazards, Aldyl-A vintage, FEMA flood zones, regions of unstable soil, and observations collected from Field Reviews.

Likelihood of Failure

- The LoF for each sub-threat for each segment is calculated as a combination of the three contributions described earlier:

$$LoF_{Segment,Sub-threat} = \sum_{i} w_i \cdot LoF_i \quad i \in \{BL, OLS, SUPP\}$$

Weighting factors w_i are specific of each sub-threat and each asset type.

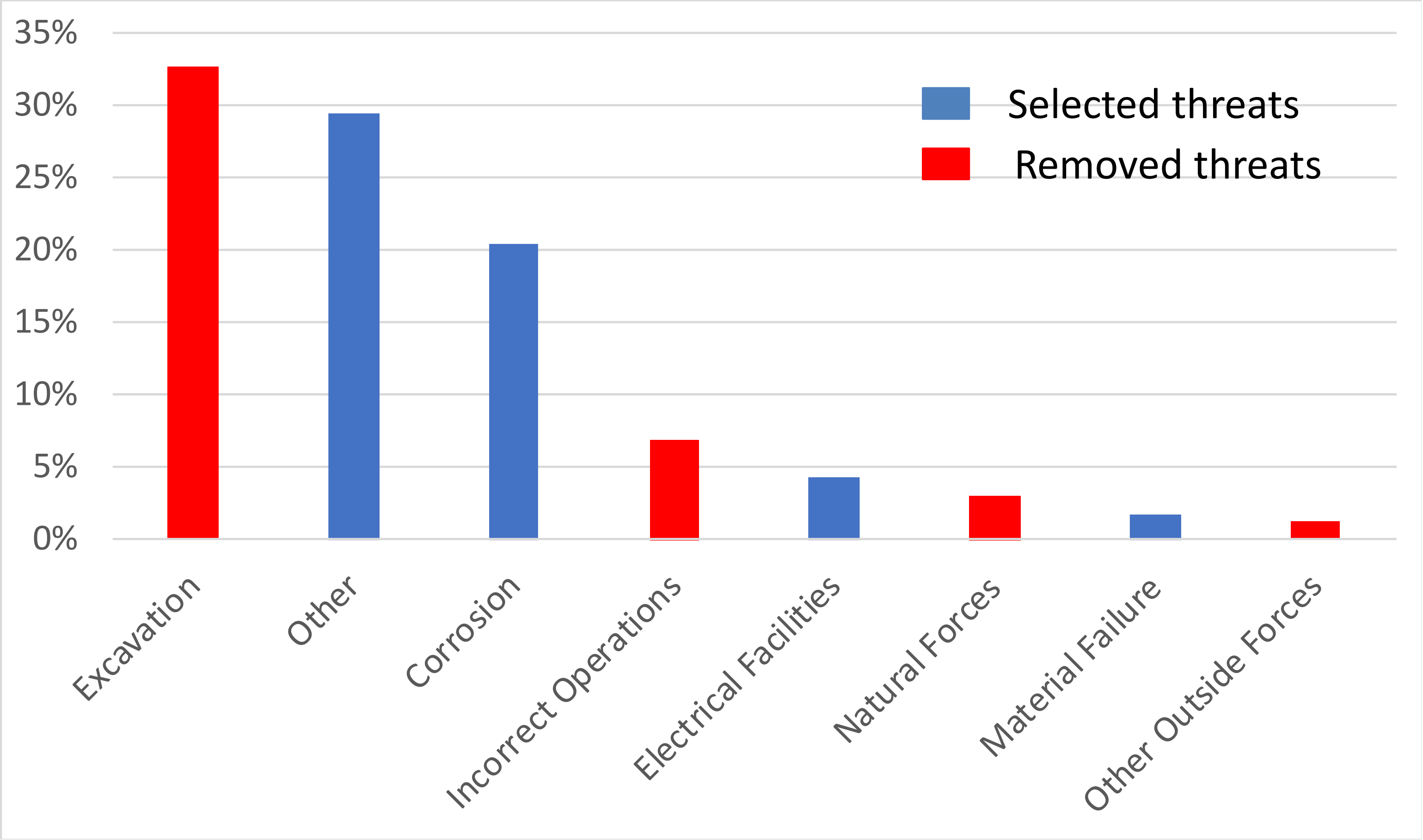
- The LoF for a given segment is:

$$LoF_{Segment,Sub-threat} = \sum_{Sub-threat} LoF_{Segment,Sub-threat} \cdot Length$$

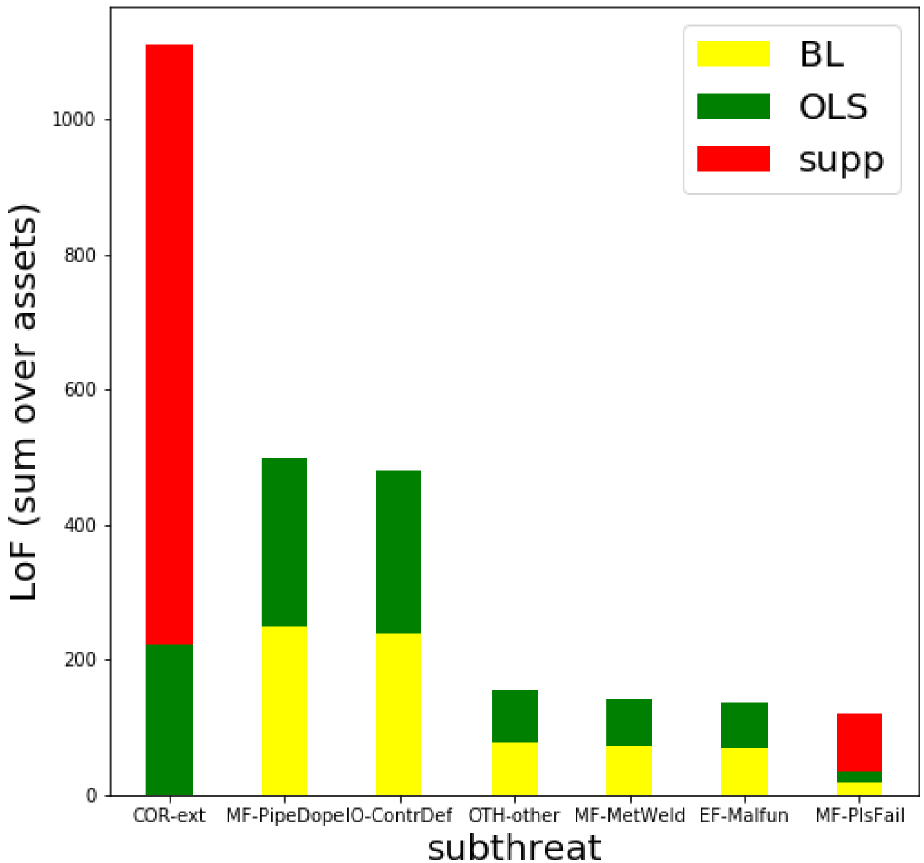
$$[Leak \cdot Year^{-1}]$$

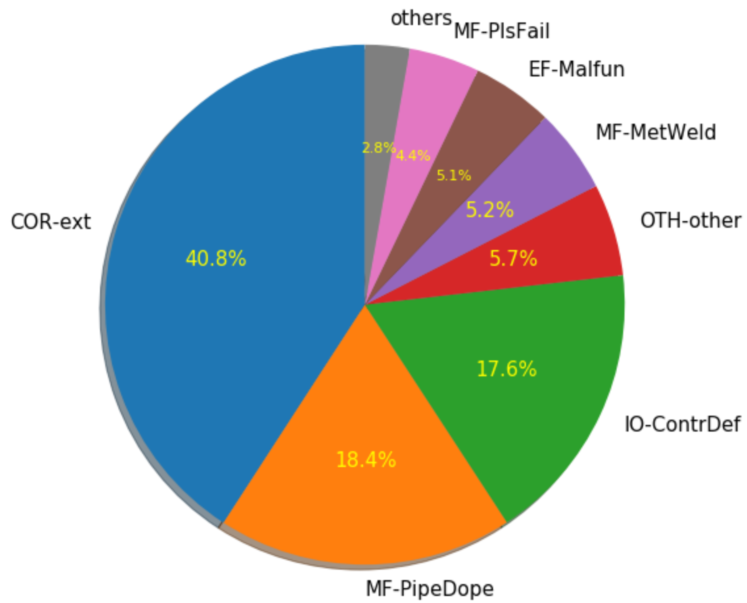
Selected Threats

- For the purpose of forecasting leaks found during surveys, the threats with high call-in rates are removed:



Results for Selected Threats





<u>Sub-threat Key</u>

COR-ext = external corrosion

MF-PipeDope = material failure from pipe dope

IO-ContDef = incorrect operations, construction defect

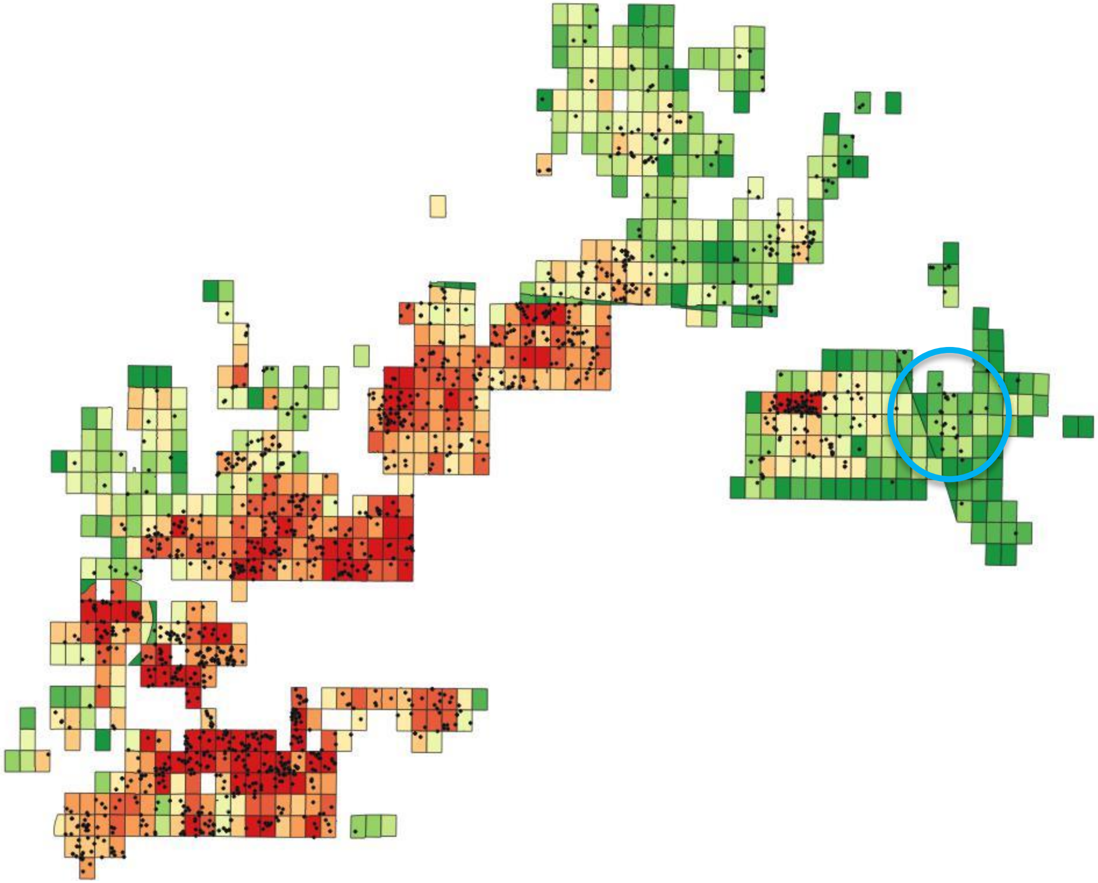
MF-MetWeld = material failure, metallic weld

EF-Malfun = equipment failure, malfunction

MF-PlsFail = material failure, plastic failure

Mapping of Likelihood of Failure

- LoF aggregated by plat established with pre-2016 data are shown with the locations of below-ground leaks found through compliance survey in 2017



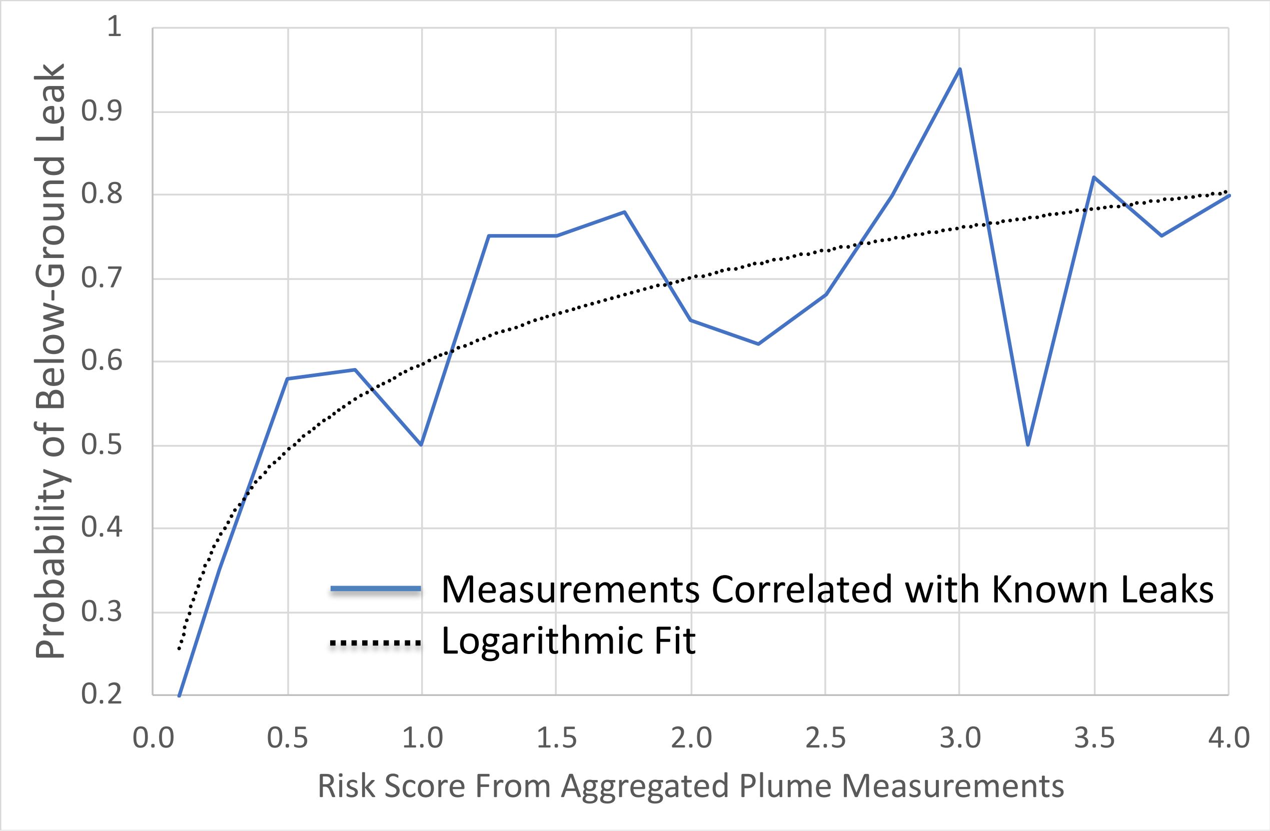
Mobile Methane Detection System

- PG&E introduced Picarro's mobile detection system for its compliance survey in 2014

- Mobile monitoring is typically 10 times faster than walking surveys

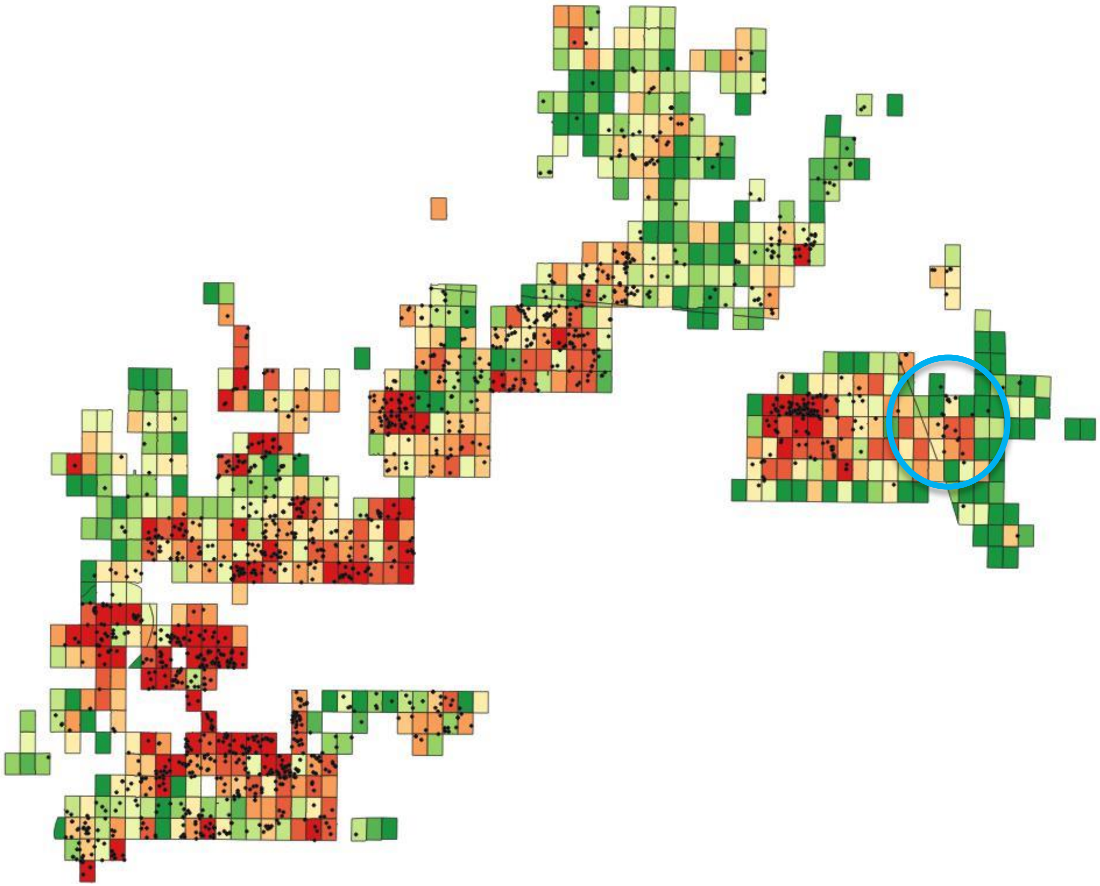
Leak – Mobile Monitoring Model

- For each location of enhanced methane concentration, a probability of Below Ground leak is calculated using a combination of concentration, size, plume shapes, and number of detections over multiple passes



Mapping of Leak Probability

- Leak estimates using mobile monitoring data are shown with the locations of below-ground leaks found through compliance survey in 2017



Merging the two models

- We tested three approaches fitted on 2017 and 2018 leak data:
  - Linear regression

$$Nb\ of\ predicted\ leaks = a \cdot P_{BG} + b \cdot LoF + c$$

  - Bayesian optimization
  - Random Forest optimization

$$P\langle A_i | B_j \cap C_k \rangle \sim P\langle B_j \cap C_k | A_i \rangle \cdot P\langle A_i \rangle$$

Where A_i: the number of leak on the plat is i

B_j: the predicted number of leak on the plat by DIMP is j

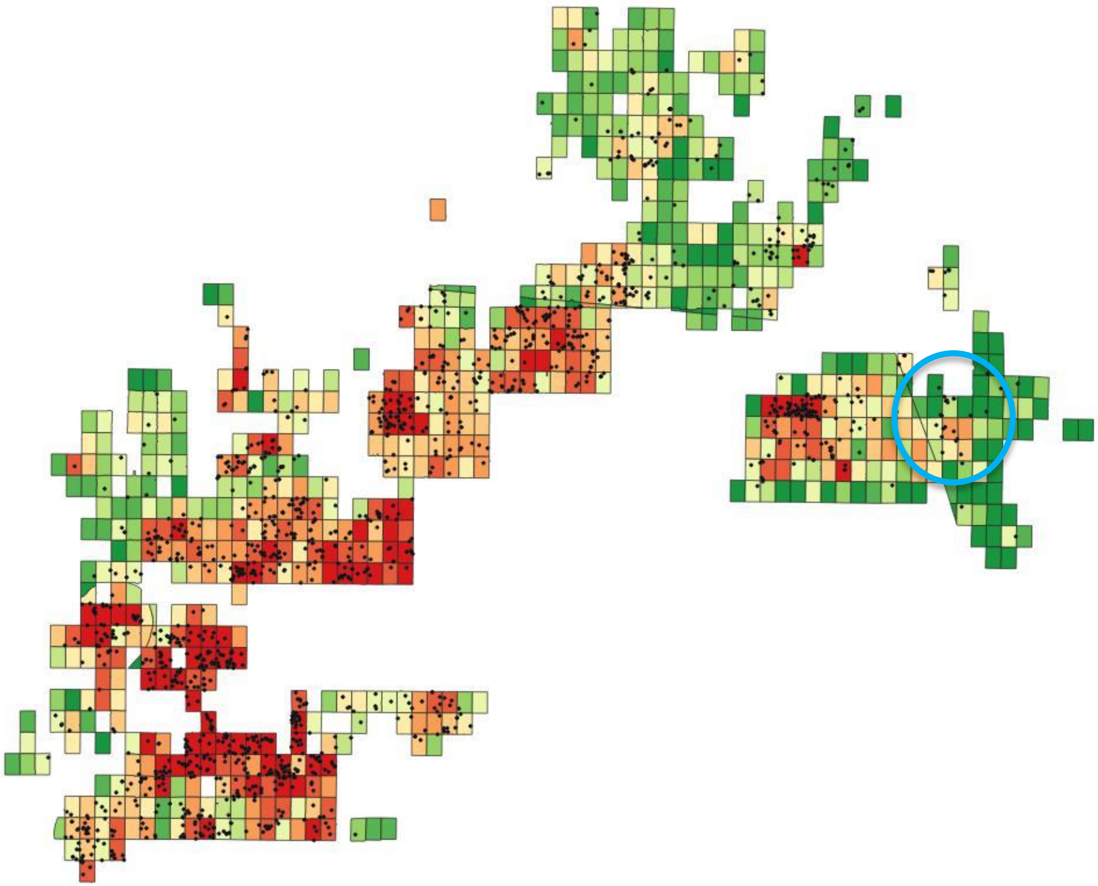
C_k: the predicted number of leak on the plat by Monitoring is k

$Nb\ of\ predicted\ leaks = i$ such as $P\langle A_i | B_j \cap C_k \rangle$ is maximum

The Random Forest optimization performed the best

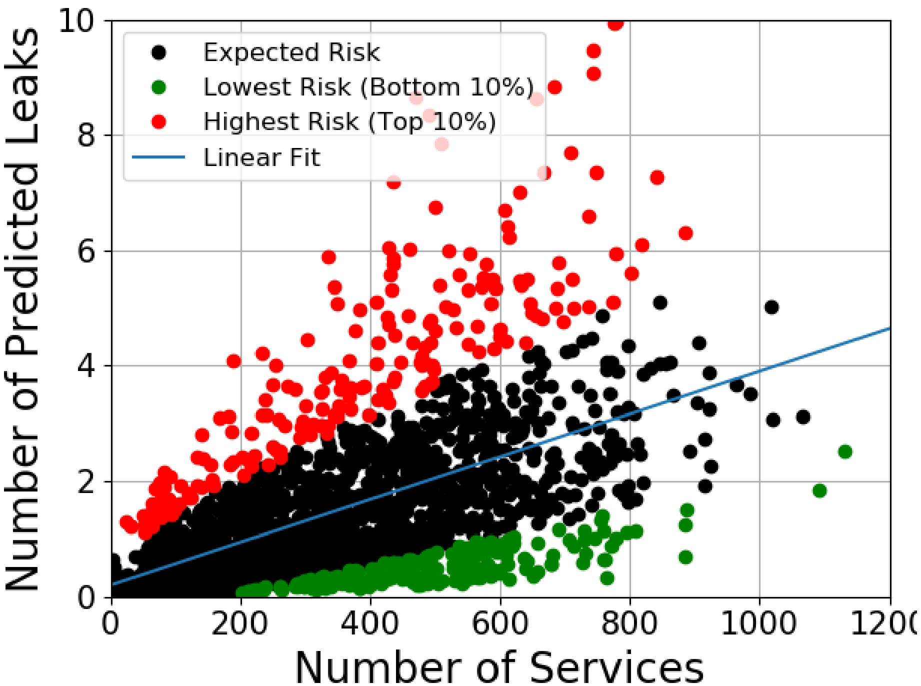
Merging the models

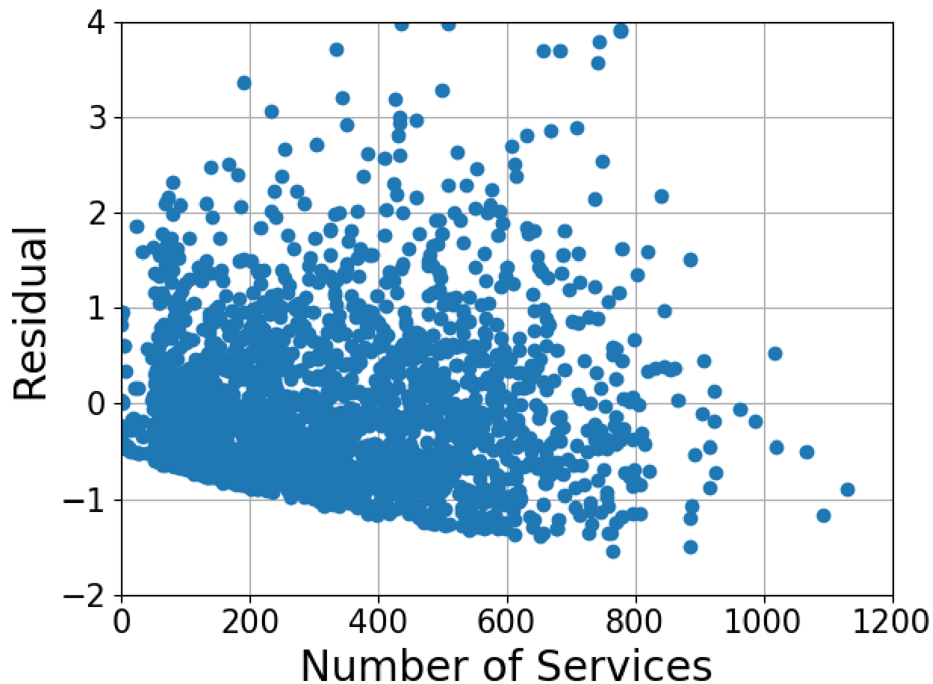
- Leak estimates using Bayesian optimization are shown with with the locations of below-ground leaks found through compliance survey in 2017



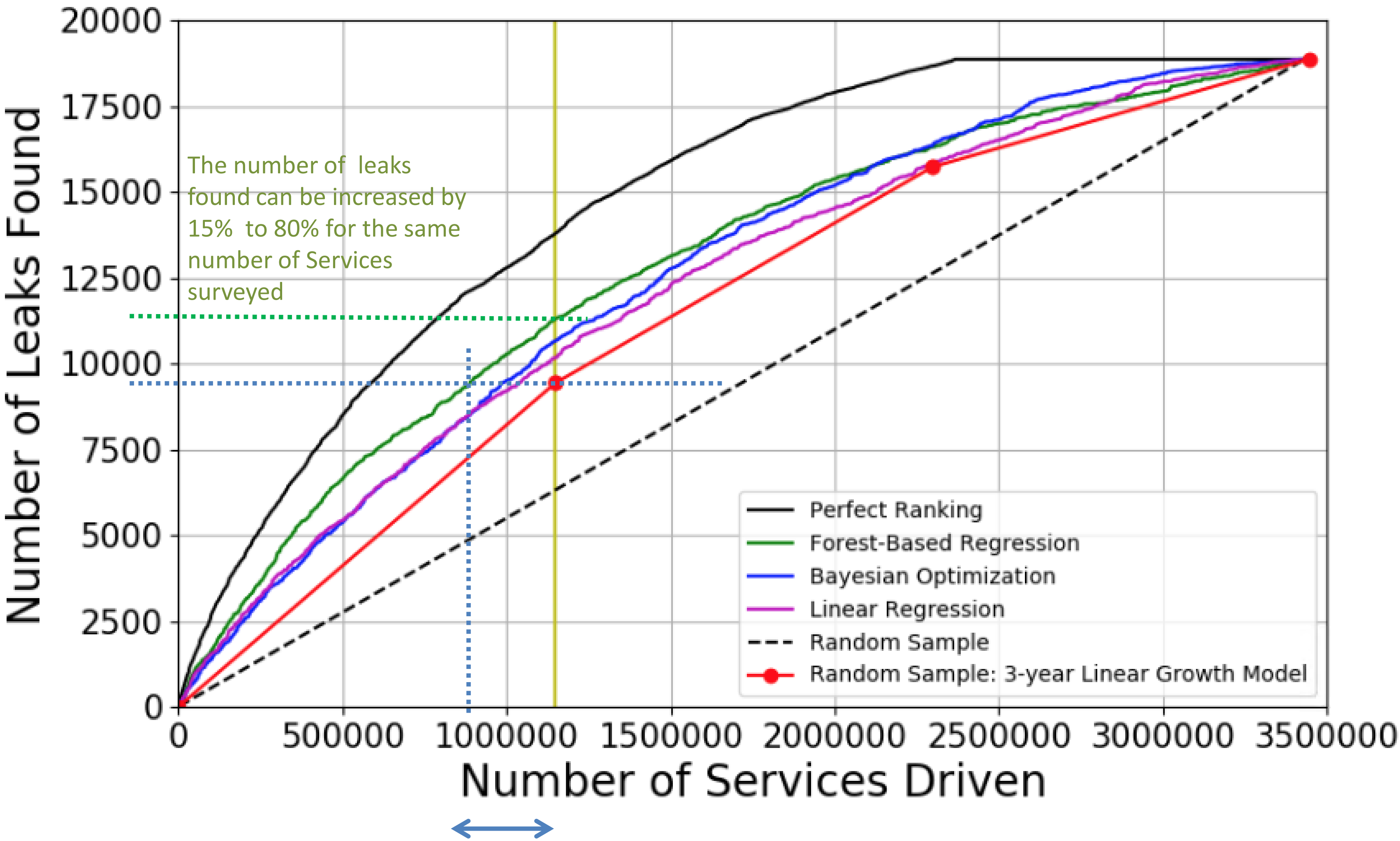
Ranking Plats by leak probability

- Larger plats have a higher probability of leaks but they are longer to survey therefore the optimization must be done on the residual variance to the linear fit





Results



The number of Services to be surveyed can be reduced by 25% to 50% for the same number of leaks found

Implementation

- Calculate the predicted numbers of found leaks with the existing list of plats.
- Keep the plats surveyed 4 years ago in the list: keeping 5 years as the back stop of time between surveys
- Restack the plats prioritizing the ones with the higher residual variance to find the same number of leaks
- Calculate the number of unknown leaks using the model adjusted from observations

Thank you

François Rongere
fxrg@pge.com

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Exhibit EDF(A)-9:

Elizabethtown Gas Company Stipulation of Settlement,
New Jersey Board of Public Utilities Docket No. GR18101197
(May 29, 2019)

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF ELIZABETHTOWN GAS COMPANY TO IMPLEMENT AN INFRASTRUCTURE INVESTMENT PROGRAM ("IIP") AND ASSOCIATED RECOVERY MECHANISM PURSUANT TO N.J.S.A. 48:2-21 AND N.J.A.C. 14:3-2A	**BPU DOCKET NO. GR18101197** **STIPULATION OF SETTLEMENT**

APPEARANCES:

Deborah M. Franco, Esq., Regulatory Affairs Counsel, SJI Utilities, Inc., on behalf of Elizabethtown Gas Company

Brian O. Lipman, Esq., Litigation Manager, **Felicia Thomas-Friel, Esq.** Managing Attorney Gas, Division of Rate Counsel, and **Maura Caroselli, Esq.**, Assistant Deputy Rate Counsel, on behalf of the Division of Rate Counsel (**Stefanie A. Brand, Director**, Division of Rate Counsel)

Patricia Krogman, Deputy Attorney General on behalf of the Staff of the New Jersey Board of Public Utilities (Gurbir S. Grewal, Attorney General of New Jersey)

Martin C. Rothfelder, Esq., Rothfelder Stern, L.L.C., on behalf of Intervenor Environmental Defense Fund

Steven S. Goldenberg, Esq., Giordano, Halleran & Ciesla, and **Paul Forshay, Esq.**, Eversheds Sutherland (US) LLP, on behalf of Intervenor New Jersey Large Energy Users Coalition

Phillip J. Passanante, Esq., Assistant General Counsel on behalf of Participant, Atlantic City Electric Company

TO THE HONORABLE NEW JERSEY BOARD OF PUBLIC UTILITIES:

BACKGROUND

On October 29, 2018, Elizabethtown Gas Company ("Elizabethtown" or "Company") filed a petition (the "Petition") with the New Jersey Board of Public Utilities ("Board") seeking approval for an infrastructure investment program ("IIP"), including an associated cost recovery mechanism pursuant to N.J.S.A. 48:2-21 and N.J.A.C. 14:3-2A.1 *et seq.* and any other provision applicable by the Board. As reflected in the Petition, Elizabethtown sought authority for a five (5) year, $518 million IIP. Of this amount, Elizabethtown proposed to recover $466 million under the IIP cost recovery mechanism, with the remaining amount of $52 million (10% of the total IIP expenditures) allocated as base spend to be recovered in a subsequent base rate case filing in accordance with N.J.A.C. 14:3-2A.

The Company's proposed IIP included the following projects: (i) the replacement and retirement of approximately 309[1] miles of the Company's vintage mains and services in its distribution system, including cast iron, ductile iron, bare steel, copper and certain vintage plastic mains; (ii) the relocation of approximately 44,000 inside meter sets to outside; (iii) the installation of excess flow valves ("EFVs") on new service lines; (iv) the retirement of approximately 100 district regulators that would no longer be needed once the existing low pressure system is upgraded; and (v) the conversion of five (5) master metered complexes to individually metered apartments within those facilities. According to the Petition, the benefits of the proposed IIP included enhancing the safety and reliability of the Company's gas distribution system, reducing greenhouse gas emissions, and supporting economic development and employment in New Jersey.

PROCEDURAL HISTORY

By order dated December 18, 2018, the Board retained this matter, and pursuant to N.J.S.A. 48:2-32, designated Commissioner Upendra J. Chivukula as the Presiding Officer. The Board further directed that motions to intervene or participate be filed by January 8, 2019. Motions to intervene were filed on behalf of the Environmental Defense Fund ("EDF") and the

[1] Testimony of Michael Scacifero at page 10 stated, "While the Company is proposing to install approximately 309 miles of new main in the initial five-year program, the Company proposes to retire approximately 364 miles. The difference of new main versus retired main is due to the fact that certain areas of the Company's distribution system have existing redundant mains."

New Jersey Large Energy Users Coalition ("NJLEUC"). A motion for admission *pro hac vice* by Paul Forshay accompanied the NLEUC motion to intervene. A motion to participate was filed on behalf of Atlantic City Electric Company ("ACE"). The Company did not oppose the granting of any of the motions.[2] In a Prehearing Order dated March 18, 2019, Commissioner Chivukula approved a procedural schedule and granted the motions to intervene filed on behalf of NJLEUC and EDF, the motion to participate filed on behalf of ACE, and the motion for admission *pro hac vice*.

Notices of this proceeding, including the dates of the public hearings, were placed in newspapers having circulation within Elizabethtown's service territory, and served on the county executives and clerks of all municipalities in the Company's service territory. Public hearings were held in Union, New Jersey on March 19, 2019 and Flemington, New Jersey on March 20, 2019. No members of the public submitted written comments or appeared at the hearings.

At the request of the parties, Commissioner Chivukula modified the procedural schedule to permit additional time for settlement discussions, and ultimately suspended the procedural schedule.

Extensive discovery was conducted and several settlement discussions were held. As a result, the Company, Board Staff ("Staff"), the New Jersey Division of Rate Counsel ("Rate Counsel"), EDF and NJLEUC (collectively the "Signatory Parties" and each a "Signatory Party") reached an amicable resolution of all matters set forth in this Stipulation. Specifically, the Signatory Parties hereby STIPULATE AND AGREE to the following:

[2] Elizabethtown's original opposition to EDF's motion to intervene was subsequently withdrawn.

STIPULATED MATTERS

IIP Investments

1. Elizabethtown may implement the IIP pursuant to the terms of N.J.A.C. 14:3-2A.1 *et seq*., subject to the terms of this Stipulation. The Company's IIP will include accelerated capital investment in Elizabethtown's gas distribution system and a related cost recovery mechanism ("IIP Cost Recovery Mechanism"), as described herein. In addition, this Stipulation includes Baseline Capital Spending amounts (defined below in paragraph 7) to be made by the Company and recovered in the ordinary course through base rates as described below.

2. The IIP shall consist of the capital investment of up to $300 million, excluding the Baseline Capital Spending amounts (defined below in paragraph 7), and Allowance for Funds Used During Construction ("AFUDC") ("IIP Capital Investment Cap") in the Company's gas distribution system over the five (5) year period beginning July 1, 2019 through June 30, 2024. The capital investments may be recovered through the IIP Cost Recovery Mechanism permitted pursuant to N.J.A.C. 14:3-2A.6.

3. The IIP Capital Investment Cap of $300 million is derived by applying a cost per mile cap of $1.2 million per mile to an IIP mileage cap of 250 miles over the five (5) year IIP term. The Signatory Parties agree that the projects to be recovered through the IIP Cost Recovery Mechanism consist of the replacement of up to 250 miles of cast iron and bare steel mains and related services, as well as the installation of EFVs on new service lines ("IIP Projects"). These projects are intended to enhance distribution system safety and reliability to the benefit of Elizabethtown's customers, to help support the environment, and to facilitate economic development and employment in New Jersey. The IIP Projects and amounts are incremental to the Company's normal capital spending budget.

4. Capital investments for the replacement of vintage plastic mains and related services, relocation of meters and labor costs associated with the relocations from an inside to outside location, retirement of district regulators, and conversion of master metered complexes to individually metered apartments are not eligible for recovery under the IIP Cost Recovery Mechanism ("Excluded Investments"). Such Excluded Investments will be credited toward the Baseline Capital Spending amounts defined in paragraph 7 provided below. The parties understand and agree that in no event will the Company be entitled to recovery for any investments in customer-owned property in connection with the conversion of master-metered complexes to individual metering. Elizabethtown will coordinate with master meter complex owners in an effort to help facilitate a conversion of such complexes over the term of the IIP to the extent feasible.

5. Costs recoverable under the IIP Cost Recovery Mechanism shall not exceed $1.2 million per mile. Costs incurred by the Company in excess of $1.2 million per mile ("Costs In Excess of $1.2 million/mile") will be credited toward the Baseline Capital Spending requirement set forth in paragraph 7 of this Stipulation as provided below. Recovery of costs in excess of $1.2 million per mile may be sought through a base rate case.

6. The Signatory Parties recognize that the initiatives included in the IIP are significant in scale and scope, and that flexibility in budgeting the IIP is appropriate. Accordingly, consistent with the provisions of N.J.A.C. 14:3-2A.4(f), year-to-year variations in the IIP approved annual budget of up to 10% shall be permitted, provided that the total IIP budget is not exceeded. To the extent that year-to-year variations in the IIP budget exceed the 10% variation level, Elizabethtown shall seek Board approval of any amount in excess of 10%.

Baseline Capital Spending

7. In addition to the IIP expenditures described in paragraphs one (1) through six (6) above, over the five (5) year IIP investment period July 1, 2019 through June 30, 2024, the Company agrees to maintain Baseline Capital Spending amounts consisting of: (i) a Total Capital Baseline Spend and (b) an IIP Baseline Spend as defined below. Elizabethtown shall seek recovery of the Baseline Capital Spending amounts in a base rate case subject to N.J.A.C. 14:3-2A.1 et seq. Elizabethtown may request, and the Board may consider, an exception from the Baseline Capital Spending requirements contained herein based on extraordinary circumstances, including, but not limited to, extreme weather, labor disputes, acts of war or terrorism, and/or other *force majeure* circumstances.

8. The Total Capital Baseline Spend will be equal to an average annual amount of $79 million per IIP year or $395 million over the five (5)-year IIP investment period beginning July 1, 2019 through June 30, 2024. The specific capital investments made by the Company as part of the Total Capital Baseline Spend are within the discretion of Elizabethtown and shall include all capital expenditures, including, but not limited to, Excluded Investments and Costs In Excess of $1.2 million/mile. New business expenditures included in the Total Capital Baseline Spend shall not exceed $10 million per IIP year. The Total Capital Baseline Spend shall not include expenditures associated with the IIP Baseline Spend.

9. The IIP Baseline Spend will be equal to $6 million per IIP year or $30 million over the five (5) year IIP investment period beginning July 1, 2019 through June 30, 2024. The IIP Baseline Spend will consist of expenditures on projects similar to those eligible for recovery under the IIP Cost Recovery Mechanism.

Term

10. The IIP five (5) year investment period shall commence on July 1, 2019 and end on June 30, 2024. The Company may include IIP non-construction expenditures, such as planning and engineering of IIP projects incurred as of July 1, 2019 in revenue requirements associated with IIP projects for the first year of the IIP from July 1, 2019 to June 30, 2020. The Company shall have the option of seeking Board approval to extend the Program beyond the term provided herein.

Prioritization of Projects

11. IIP Projects will be prioritized utilizing Elizabethtown's Distribution Integrity Management Plan ("DIMP"), which is a risk-based process followed by the Company. In prioritizing IIP Projects, Elizabethtown will integrate advanced leak detection ("ALD") technology information and methane emission flow rates, as appropriate, and consider additional factors such as construction, efficiencies, logistics and other risk factors within Elizabethtown's discretion, including the prioritization ranking methodology within the Company's DIMP. If construction, logistics and/or other issues on a project area (*i.e.* municipal/county paving costs, traffic control, etc.) make work within that project area impossible, impracticable, and/or significantly more expensive, Elizabethtown may postpone that project and proceed to work on subsequent prioritized projects. Elizabethtown may resume work on a postponed project after resolution of the issues with the project area. IIP investments in years two (2) through five (5) of the IIP shall be subject to completion of a methane leak survey for Elizabethtown's targeted IIP miles using ALD technology. The survey will be completed six months after the effective date of the Board Order approving this program. All costs incurred by Elizabethtown in connection with methane leak surveying using ALD technology will be recovered through the IIP Cost

Recovery Mechanism, and shall be in addition to the $300 million recovered through the IIP Cost Recovery Mechanism. Elizabethtown will report on the above-referenced methane leak survey activity as set forth in paragraph 22 below.

Leak Metrics

12. The Company will reduce its year-end open leak inventory by one (1) percent for each year of the IIP, except under extraordinary circumstances, including, but not limited to, extreme weather, labor disputes, acts of war or terrorism, and/or other *force majeure* circumstances. This open leak reduction metric includes all post-approval open leaks subject to a cap for each year of the Program. The cap for the first year following the date of Board approval is set at the average number of year-end open leaks the Company has experienced during the past five (5) calendar years. Thereafter, the cap will be reduced by one (1) percent for each of the remaining four (4) years of the IIP as follows:

Year	**Year End Open Leaks**
2015	3,933
2016	3,190
2017	3,531
2018	4,330
2019	nnnn (open leaks as of May 1, 2019: 2,146)
5-Year Average	xxx

Year	**Year End Open Leaks**
2020	xxx
2021	xxx – 1%
2022	xxx – 2%

2023	xxx – 3%
2024	xxx – 4%

13. If Elizabethtown fails to meet the leak reduction target in 2020, it will notify Board Staff, Rate Counsel, and all Signatory Parties, and schedule a conference to discuss within thirty (30) days of Elizabethtown's determination that it failed to meet such target. If the Company fails to reduce the leak target in any year thereafter, the Company shall achieve compliance with this obligation without seeking cost recovery from ratepayers for any expenditures incurred for this purpose. Elizabethtown may request, and the Board may consider, an exception from the requirements of this paragraph based upon extraordinary circumstances, such as extreme weather, labor disputes, acts of war or terrorism, and/or other *force majeure* circumstances.

Cost Recovery

14. The Signatory Parties agree that Elizabethtown shall be permitted to recover the revenue requirement associated with a maximum of $300 million in IIP investments, plus AFUDC, through the IIP Cost Recovery Mechanism as described below and in Appendix B, in accordance with a separate clause in the Company's tariff to be included with the Company's annual cost recovery filings, a sample of which is set forth in Appendix C. The prudency of the IIP Projects will be reviewed by the Board in the Company's subsequent base rate proceedings. The Company will file a base rate case no later than June 30, 2024. If the costs for IIP Projects exceed the amount allowable under the IIP, the Signatory Parties agree that Elizabethtown may seek recovery of those additional costs, not subject to recovery in the IIP Cost Recovery Mechanism, in a subsequent base rate case.

15. The Company may seek cost recovery for completed IIP Projects in accordance with the annual cost recovery filing schedule and rate effective dates contained in Appendix B. The cost recovery filing requirements are set out in N.J.A.C. 14:3-2A.1 *et seq*., with Minimum Filing Requirements contained in Exhibit D. Consistent with the requirement contained in N.J.A.C. 14:3-2A.6(b), Elizabethtown will make annual filings to recover IIP costs when eligible in-service amounts exceed 10% of the total proposed program spending, except however, given the nature of the work, the Signatory Parties recognize that the April 2025 filing may be less than 10% of total program spending as it will reflect residual spending associated with restoration work occurring after June 30, 2024.

16. As reflected in Appendix B, the costs to be included in rates shall include the following: depreciation expense providing for the recovery of the invested capital over its useful book life, and a return on the net investment, which will be calculated as the gross investment, plus AFUDC, less depreciation expense and deferred income taxes. The return on this net investment shall be calculated utilizing the Weighted Average Cost of Capital ("WACC") approved in the Company's 2016 base rate case in Docket No. GR16090826 ("2016 Base Rate Case"), adjusted for subsequent tax rate changes associated with the Tax Cuts and Jobs Act of 2017. The WACC is 6.707% (6.063% after-tax), which is based on a return on equity ("ROE") of 9.60% and an equity component of 46%. Any change in the WACC authorized by the Board in a subsequent base rate case will be reflected in the subsequent monthly revenue requirement calculations. The revenue requirement will also utilize a revenue factor of 1.40828098 to reflect State and Federal income taxes, as well as the costs associated with Board and Rate Counsel's annual assessments and uncollectibles. The Company will apply the revenue

factor applied in the 2016 Base Rate Case. Any future changes to the revenue factor will be reflected in the subsequent monthly revenue requirement calculations.

17. As reflected in Appendix B, the IIP Cost Recovery Mechanism revenue requirement will be reduced by an operations and maintenance ("O&M") credit of $90,000 per year, or prorated annual amount where applicable, to reflect an O&M savings associated with leak repair on facilities replaced in connection with the IIP.

18. Cost recovery under the IIP is contingent on an earnings test. If the product of the calculation set forth in N.J.A.C. 14:3-2A.6(h) exceeds the Company's most recently approved ROE by fifty (50) basis points or more, cost recovery under the IIP shall not be allowed for the applicable filing period pursuant to N.J.A.C. 14:3-2A.6(i).

Rates and Rate Design

19. There is no rate impact on customers at this time from the IIP. The Company will allocate the total revenue requirement to each firm customer class and firm special contract customers based on the level of distribution revenues from the rate design approved in the 2016 Base Rate Case. A volumetric distribution charge will be determined for each class utilizing the billing determinants used to set rates in the Company's most recent base rate case. The Margin Revenue Factor set forth in the Company's Weather Normalization Clause tariff will be revised to reflect the IIP annual rate adjustments authorized by this Stipulation. To the extent a rate design methodology that differs from the rate design methodology used to set base rates in the 2016 Base Rate Case is adopted, then that rate design shall be utilized for the IIP Cost Recovery Mechanism in IIP filings subsequent to the adoption of such methodology.

Monitor

20. Within six (6) months of a final BPU Order in this proceeding, Elizabethtown, following consultation with Board Staff and Rate Counsel, will retain an independent monitor to review and report to Board Staff and Rate Counsel the information contained in N.J.A.C. 14:3-2A.5(c)(2) which provides as follows: (i) the effectiveness of IIP investments in meeting project objectives; (ii) the cost-effectiveness and efficiency of investments; (iii) the appropriateness of cost assignments; and (iv) any other information required by the Board. Independent monitor expenses shall be capitalized to the extent consistent with Generally Accepted Accounting Principles ("GAAP") and shall be in addition to the $300 million recovered through the IIP Cost Recovery Mechanism.

Reporting Requirements

21. The Company agrees to file a semi-annual status reports with the Board, and provide copies to Board Staff, Rate Counsel, and all Signatory Parties, for project management and oversight purposes. The semi-annual status reports shall contain the following requirements consistent with N.J.A.C. 14:3- 2A.5(e):

(a) Forecasted and actual costs of the IIP for the applicable reporting period, and for the IIP to date, where IIP projects are identified by major category;

(b) Estimated total quantity of work completed under the IIP identified by major category. In the event that the work cannot be quantified, major tasks completed shall be provided;

(c) Estimated completion dates for the IIP as a whole;

(d) Anticipated changes to IIP projects, if any;

(e) Actual capital expenditures made by Elizabethtown in the normal course of business on similar projects, identified by major category; and

(f) Any other performance metrics concerning the IIP required by the Board.

22. In addition to information set forth above, the semi-annual status report shall include the methane leak survey information contained in Appendix A.

Miscellaneous

23. All appendices referenced in and attached to this Stipulation are incorporated by reference herein as if set forth in the body of this Stipulation.

24. This Stipulation will become effective in accordance with N.J.S.A. 48:2-40.

25. This Stipulation is intended to be accepted and approved in its entirety. In the event any particular aspect of this Stipulation is not accepted and approved in its entirety by the Board, then any Signatory Party aggrieved thereby shall not be bound to proceed with this Stipulation, and shall have the right to litigate all issues addressed herein to a conclusion. In the event this Stipulation is not adopted in its entirety by the Board in an Order in this matter, then any Signatory Party hereto is free to pursue legal remedies with respect to all issues addressed in this Stipulation as though this Stipulation had not been signed.

26. It is the intent of the Signatory Parties that the provisions hereof be approved by the Board, as appropriate, as being in the public interest. The Signatory Parties further agree that this Stipulation be binding on them for all purposes herein. It is understood and agreed by the Signatory Parties that this Stipulation represents a negotiated agreement and, except as otherwise

expressly provided herein, is intended to be binding only in this proceeding and only as to the matters specifically addressed herein.

27. This Stipulation may be executed in as many counterparts as there are Signatory Parties of this Stipulation, each of which counterparts shall be an original, but all of which shall constitute one and the same instrument.

WHEREFORE, the Signatory Parties hereto do respectfully submit this Stipulation and request that the Board issue a Decision and Order approving it in its entirety, in accordance with the terms hereof.

ELIZABETHTOWN GAS COMPANY

By: ______________________
Deborah M. Franco, Esq.
Regulatory Affairs Counsel

STEFANIE A. BRAND, DIRECTOR
NEW JERSEY DIVISION OF
RATE COUNSEL

By: ______________________
Felicia Thomas-Friel, Esq.
Managing Attorney - Gas

GURBIR S. GREWAL
ATTORNEY GENERAL OF
NEW JERSEY
Attorney for the Staff of the
New Jersey Board of Public Utilities

By: ______________________
Patricia Krogman
Deputy Attorney General

ENVIRONMENTAL DEFENSE FUND

By: ______________________
Martin C. Rothfelder, Esq.
Rothfelder Stern, L.L.C.

NEW JERSEY LARGE ENERGY
USERS GROUP

By: ______________________
Stephen S. Goldenberg, Esq.
Giordano, Halleran & Ciesla

Dated: May 29, 2019

Exhibit EDF(A)-10:

Picarro Emissions Quantification Results Final Report

in Support of the Methane Leak Surveying Report for the PSE&G Gas System Modernization Program ("GSMP") II Program

Submitted to New Jersey BPU by PSE&G (Feb. 28, 2020)

Danielle Lopez
Associate Counsel—Regulatory

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PSEG Services Corporation

February 28, 2020

VIA ELECTRONIC and FIRST-CLASS MAIL
Aida Camacho-Welch, Secretary
Board of Public Utilities
44 South Clinton Avenue, 3rd Flr.
P.O. Box 350
Trenton, New Jersey 08625-0350

Re: PSE&G GAS SYSTEM MODERNIZATION PROGRAM II
Methane Leak Surveying Report

Dear Secretary Camacho-Welch:

Enclosed for filing are copies of the confidential and redacted public versions of Public Service Electric & Gas Company's (PSE&G's) Methane Leak Surveying Report for March 1, 2020 on its Gas System Modernization Program II (GSMP II or the Program).

GSMP II was approved by a Board Order dated May 22, 2018 in BPU Docket No. GR17070776. That Order adopted a Stipulation pursuant to which PSE&G is operating the Program. This Report is filed pursuant to Attachment D of that Stipulation.

As indicated previously, the Report contains proprietary, commercially sensitive information and portions of the Report are entitled to confidential treatment pursuant to Board regulations set forth at N.J.A.C. 14:1-12. Accordingly, PSE&G requests that the Board grant the redacted portions of the Report confidential treatment in accordance with those regulations, and that the redacted portions of the Report not be subject to public disclosure. In support of this request PSE&G submits the Affidavit of Wade Miller. Public Service is also serving Rate Counsel with the public and confidential versions of the Report and with Mr. Miller's Affidavit. By copy of this letter, it is respectfully requested that Rate Counsel maintain the confidentiality of this material as well.

Note that the electronic submission of this material includes only the public version of the Report and Mr. Miller's Affidavit; the confidential Report is being provided via regular mail.

Very truly yours,

Danielle Lopez

cc: Stefanie Brand
Paul Flanagan
Grace Strom Power
Stacy Peterson
Brian Lipman
Felicia Thomas-Friel
Karen Forbes
Matko Illic
Caroline Vachier
Mary Barber
Naim Jonathan Peress

Picarro Emissions Quantification Results Final Report

in Support of the Methane Leak Surveying Report for the PSE&G GSMP II Program

Prepared by Picarro, Inc.

December 14, 2018

Introduction

Picarro has completed mobile methane emissions measurements for use in the next phase of PSE&G's Gas System Modernization Program (GSMP II). Methane data was gathered along approximately 280 miles of Utilization Pressure Cast Iron ("UPCI") gas mains contained in 44 map grids. The replacement of mains within GSMP II will follow the prioritization based on the grid-based Leak Hazard Indices developed by PSE&G, and the Picarro methane emissions results will be used as a sub-prioritization metric within that framework. Including methane emission rate (volumetric flow rate) as part of the replacement prioritization process may result in the reduction of natural gas emissions and reduce the environmental impacts of such emissions. This document describes the measurement campaign results, data collection methodology, protocol and validation as well as details about Picarro's hardware, software and data analytics platform used to gather and process the data.

Picarro System Hardware

Picarro's mobile natural gas leak detection system is driven through a natural gas distribution infrastructure gathering methane, wind, atmospheric and GPS data which is later processed by Picarro's algorithms to detect and localize leaks and calculate methane emission rates. The Picarro hardware consists of the following elements (shown in figure 1 below) forming a completely integrated solution mounted in a vehicle:

- A parts-per-billion sensitivity gas analyzer based on Cavity Ring Down Spectroscopy (CRDS) measuring atmospheric gas composition and other tracers such as ethane
- An anemometer mounted on a mast for detecting wind speed, direction and wind variability
- Two antennas on the vehicle roof, one for the 4G wireless connectivity and one for sub-meter GPS vehicle positioning
- A 4G wireless router enabling the internet connection and data transmission to and from the Picarro Cloud and WiFi connection to the in-vehicle tablet

- A tablet computer which allows the operation and visualization of the system and data
- A supporting equipment module containing pumps, a backup battery, GPS receiver and various power supplies and gas handling equipment
- A gas inlet system mounted on the front of the vehicle

Air is continuously collected on the front of the vehicle routed to the gas analyzer via tubing. The entire system and accessories are directly connected to the vehicle battery.

Figure1. Picarro System Hardware.

Picarro Software & Data Analytics

The Picarro system identifies the characteristic signature of natural gas leaks by analyzing the methane plumes as they propagate in the atmosphere and intersect with the path of the vehicle. The system also measures atmospheric and meteorological conditions and uses algorithms to identify the origin and degree of hazard of the natural gas leak indication while virtually eliminating indications triggered on other non-natural gas sources of methane.

The most powerful feature of the Picarro system is its ability to combine information from multiple measurement sessions over a region, taking advantage of varying atmospheric conditions (wind direction, wind speed, atmospheric stability), to produce aggregated survey results over a certain period of time. This unique capability increases territory coverage with successive passes by the vehicle and allows statistics to be built up on location and risk for every leak indication. Reports and other data outputs can be generated from this processed data specific to the intended use case – leak survey, forecasting, targeted emissions reduction, risk management, etc.

Picarro's Emissions Quantification Analytics is one of the analytical models that generates outputs and reports that can be applied to data taken by the Picarro vehicle. After multiple passes are driven in an area of interest where the vehicle path intersects methane plumes typically multiple times, the analytics process the data using four basic steps:

1. Calculate the emission rate from individual methane plume detections. Here, the methane concentration is represented as a function of distance along the vehicle's path and that "line integral" is evaluated, as described below, to calculate the flow (emission) rate.
2. Geographically associate (cluster) these detections to identify emission source locations.
3. Calculate "average" emission rate of each cluster using individual detections using a Bayesian framework.
4. Aggregate sources (clusters) over areas (grids) or pipe segments and sum emissions from individual sources to determine total emission rate and uncertainty.

The methane flow rate Q is derived from the volumetric flux equation which uses a "Mobile Flux Plane" measurement as input:

$$Q = u \iint [C(y,z) - Co] \, dy \ \ dz$$

where $C(y,z)$ is the concentration at each measurement point of the cross-sectional area of the plume (the vehicle samples the concentration along a line through this plume in the y direction and the plume is assumed to be homogenous in concentration across this surface), C_0 is the background methane concentration, u is the mean wind speed (the wind is measured by the anemometer on the vehicle and is assumed to be roughly vertically constant over the size of the plume; the height of the plume is inferred from its measured width in the y direction). In standard engineering terminology the flux plane method is analogous to a control volume approach for quantifying gas flow rates. The vehicle drives downwind of the leak and captures methane emissions over a control surface along the vehicle's path. The inflow condition for the control volume is determined from highly sensitive measurements of the background methane concentration. The Picarro methane emission rate measurement system is consistent with the provisional EPA test method OTM 33 for gas leak detection and emissions quantification (EPA, 2014). For plume intersections where the angle of the wind is too shallow (i.e. the wind is along the direction of vehicle travel and the plume is propagating parallel or nearly parallel to the vehicle path) the wind direction data allows these plumes to be excluded from the analysis since their line integrals are not meaningful in this instance).

The power of the flux plane method for natural gas leak rate quantification is the simplicity of the approach. A prediction of emission rate is made directly by multiplying the measured crosswind concentration profile by the measured wind speed. Accurate emissions estimates are achieved through a combination of enhanced spatial resolution of the concentration profile, accurate measurements and models of the instantaneous vertical wind speed gradient, and averaging of multiple plume transects downwind of the leak. The fast response time (4 Hz) of the Picarro methane gas analyzer provides high spatial resolution in the crosswind direction. This produces a high-resolution concentration map without loss of spatial information content.

Comparison to Traditional Survey Equipment and Methods

The Picarro system takes methane data at a speed and scale not possible with traditional instrumentation, eliminating human bias and operator error associated with these legacy methods. It has been shown in over 60 field studies to consistently identify an average of *three times* as many gradeable leaks (and a three times more hazardous leaks) as compared to traditional survey equipment and methods. In comparison to traditional leak survey equipment, the Picarro hardware is 1000 times more sensitive, with the ability to detect methane and ethane at better than one part-per-*billion* (traditional systems have only 1-part-per-*million* methane sensitivity and do not use ethane to remove false positive leak indications from biogenic methane sources (sewer, etc.) as the Picarro system does. The system can take data at vehicle speeds over 40mph and in rain and snow conditions. The system's reliance on the wind enables it to sense leaks without driving directly over the gas main, and the analytics can rank methane plumes according to their potential hazard, emission rate and likelihood of emanating from an aboveground or belowground leak.

Comparing the Picarro system and analytics to other mobile methane detection technologies (including that which was used during the methane mapping done for GSMP I), there are some key technological advantages of the Picarro system which result in even higher-quality methane quantification results than were achieved for GSMP I.

The key advantage of the Picarro system and methodology is its use of wind information to both localize emission points and calculate emission rates. The use of wind information to calculate emission rates is critical to obtaining accurate results. The Picarro system also has a high collection rate and gas sampling rate so that gas plumes are measured with very high spatial resolution, resulting in high precision emissions quantification. Picarro's six-pass, two-night protocol results in high leak detection rates and high-precision emissions measurements. Picarro's analytics further improve these results by identifying and rejecting false-positive indications. Picarro's analytics can also statistically differentiate between aboveground and belowground leaks and therefore preferentially aggregates plumes judged to be coming from belowground leaks for emissions quantification (i.e. it will preferentially exclude aboveground leak plumes from the emissions calculations).

Data Collection Methodology & Protocol

Picarro's Advanced Leak Detection technique utilizes the wind to bring methane plumes to Picarro's vehicle-based methane and atmospheric sensing platform. Picarro's data collection methodology is based on the ability of Picarro system to detect methane emissions below as well as at some distance away from the vehicle when the methane emission point is upwind of the vehicle. The reach of Picarro's Field of View coverage area is calculated at each point along the vehicle path to provide a documented record of survey coverage. This concept is shown in figure 2 below.

There are qualities of methane plumes that the system measures (size, emissions, concentration, ethane content, etc.) that allow analytics to predict the location and relative risk of the leak indication (i.e. if it is likely originating from a hazardous leak or not). Leak Indication Search Area (LISA) markers are computed for each potential leak to aid crews in pinpointing leaks for repair.

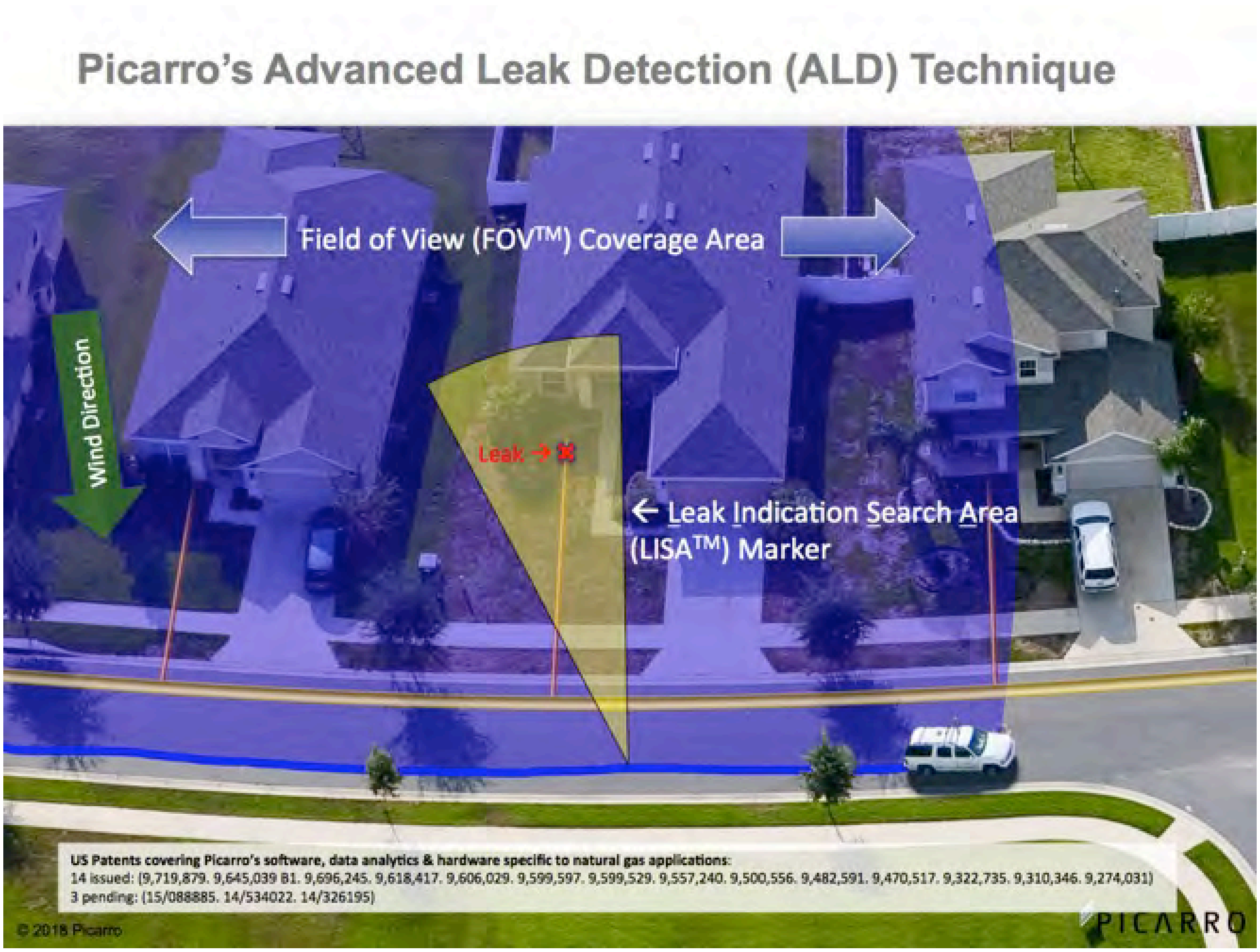


Figure 2. Picarro ALD technique concept.

Picarro collected data on PSE&G UPCI mains sections using a standard "three-drives" protocol that prescribes that each street along which mains were located be driven twice (one pass on each side of the street) and that this be repeated three times on at least two different nights (so that either two or four passes were completed on one night) between sunset and sunrise. This results in six passes per street along the defined sections of main. Data is taken at night to maximize plume detectability and minimize measurement noise due to higher atmospheric turbulence that is present during the day. Nighttime survey also avoids traffic that disturbs plumes.

The reasons for multiple passes over multiple nights is to collect data in a variety of wind conditions (multiple wind directions) to achieve complete Field of View coverage of the mains. Multiple passes also ensures the leak detection rate is >95% since the single-pass detection for a given leak is generally only 25-35% and the detection probability scales as the probability of independent events, reaching >95% for these belowground leaks that are generally near the vehicle. An example of one night's driving on a grid is shown below in figure 3.

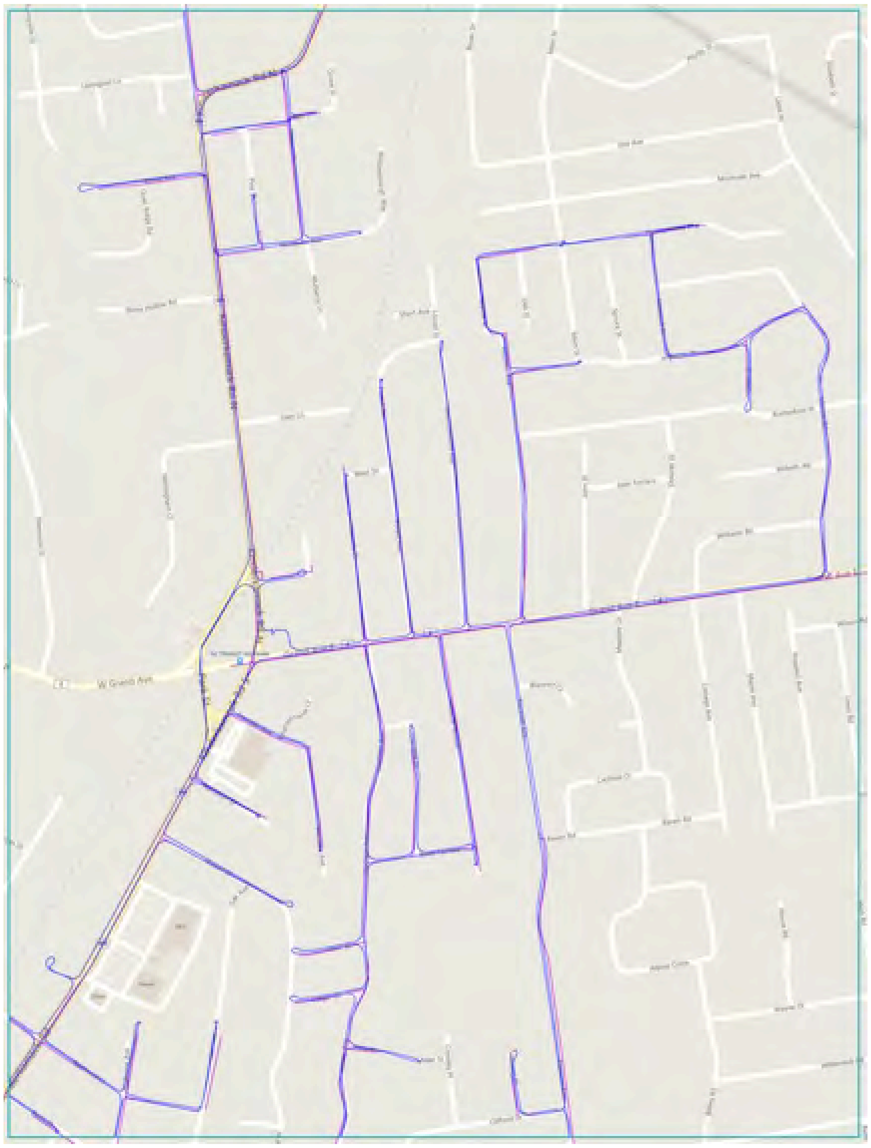


Figure 3. Driving example during one night (two passes per street). Vehicle breadcrumb (blue), UPCI mains (magenta).

Picarro provided a driver and vehicle outfitted with the Picarro equipment to accomplish this task, during the period from 10/23/18 through 11/27/18. PSE&G provided to Picarro shape files (for importation into Picarro's analytics platform) defining: 1) the 44 grid boundaries and 2) the sections of mains to be measured. Using the GIS data, the driver was able to visually identify specific streets to drive and capture data on and those to avoid. During post processing, only emissions that were measured along the sections of mains defined in the GIS were reported – any other data not associated with these mains was excluded and not processed. The system also automatically suspends data collection when the vehicle traverses outside a grid boundary.

PSE&G Results & Discussion

The complete set of tabulated numerical results is in Appendix I, and geographical methane maps for each grid along with summary statistics for each grid are presented in Appendix II).

In figure 4 below, various metrics are plotted against the total emissions per grid. For each grid, the number of measured emissions clusters and the estimated number of belowground leaks (as determined by Picarro's analytics) are plotted versus total grid emissions. Similarly, the emission rate per mile for each grid is plotted versus total grid emissions.

There is generally – but not always – a correlation between these metrics and total grid emissions. The fact that there are large departures from a perfect correlation shows that it would not be possible to accurately predict total grid emissions (nor leaks per mile) based on a "representative" per-mile emission rate (which might be inferred from pipe age, type, etc.) using an inventory approach. In other words, the emission rates and locations must be measured and mapped. With methane maps and their aggregated emissions data, however, it is possible to make accurate, surgical construction decisions at the grid or individual pipeline section level as desired.

It interesting to note that in the comparison of the number of emission clusters below (red squares) to the total grid emissions, the trend is linear up to about 20 liters/minute and then becomes nearly flat. The interpretation of this result – which has been observed in the study[1] of natural gas distribution system emissions previously – is that, a very few number of so-called "super emitters" (i.e. the largest emitting sources) are responsible for a significant fraction of the overall emissions. Here we see examples of where the number of clusters hardly changes, but the overall grid emissions more than doubles.

[1] Lamb BK, Edburg SL, Ferrara TW, Howard T, Harrison MR, Kolb CE, Townsend-Small A, Dyck W, Possolo A, Whetstone JR, 2015, Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States, *Environmental Science and Technology* 49, 5161-5169.

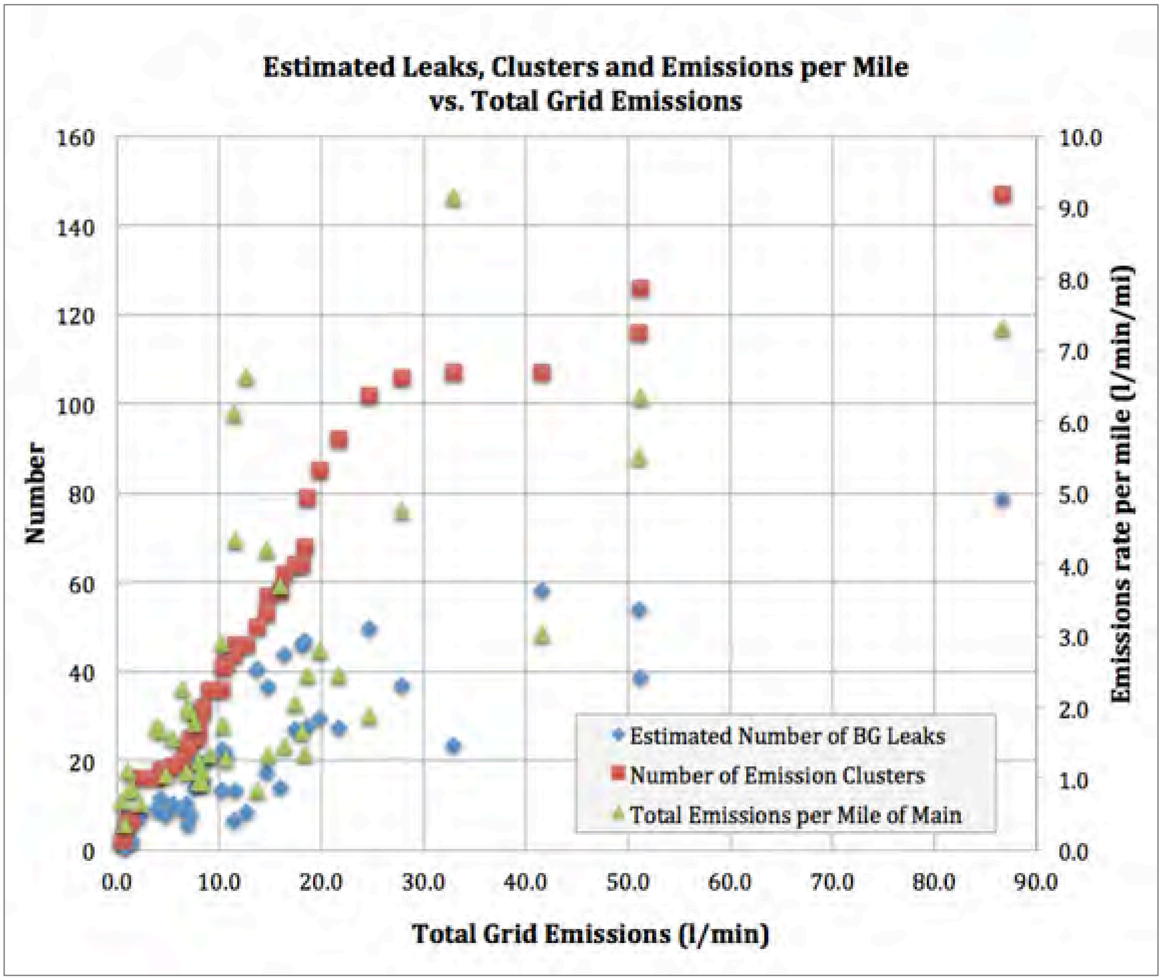


Figure 4. Comparison of total emission rate to per-mile emission rate and per-mile leak number estimation derived from methane mapping data.

The following data is summarized in Appendix 1 for each grid:

- Grid ID
- Miles of UPCI pipe in grid
- Total estimated flow rate (emission rate) (liters/minute)
- Estimated flow rate per mile (liters/minute/mile)
- Rank by total flow rate
- Rank by flow rate per mile
- Total number of emissions clusters within grid
- Total estimated belowground leaks on UPCI mains within grid

The following metrics will be provided or determined by PSE&G after combining the methane emissions results with the existing grid ranking information:

- Hazard Index per mile
- GSMP II UPCI Grid Rank
- Ranked Year of Construction using methane flow rate data
- Planned Year of Construction
- Description of factors contributing to grid bypass decisions (if Planned Year of Construction does not match Ranked Year of Construction)

Summary of PSE&G GSMP II Methane Mapping Project

Some key figures of merit from the data collection and analysis has shown the following summary statistics from the 44 grids:

- Highest emitting grid: 86.6 l/min
- Lowest emitting grid: 0.6 l/min
- Mean grid emissions: 15.3 l/min
- Median grid emissions: 10.5 l/min

The statistics for the emission rate per mile of main were:

- Highest: 9.2 l/min/mi
- Lowest: 0.4 l/min/mi
- Mean: 2.5 l/min/mi
- Median: 1.7 l/min/mi

- Although the total grid emissions trends essentially with the per-mile emission rate, there are exceptions to that trend, also evidenced by visual comparison of the methane maps – there are large variations in both per-mile leak density as well as variability of over two orders of magnitude in leak rates.

- This variability shows the power of the methane mapping technique for providing additional granularity that can be used to maximize methane emissions reductions and/or maximize remediation of the maximum number of belowground leaks through changes to construction priorities based on these methane maps and associated data.

Appendix I: Tabulated Data on GSMP II Grids

Table 1. Detailed statistics for all 44 grids sorted by Grid Rank by Total Grid Emissions. Emissions estimates have a quoted confidence level of 80% (i.e. 10-90% of the distribution). The error estimates are non-symmetric (e.g. Grid 2C-44 has a total grid emission of 86.6 (+23.0 / -15.1) l/min). The terms “flow rate”, “emissions” and “emission rate” are synonymous. Mileage is always in terms of miles of UPCI mains.

Grid ID	UPCI Main Pipe Length (mi)	Grid Rank by Total Grid Emissions	Grid Rank by Total Emissions per Mile	Total Grid Emissions (l/min)	Total Emissions Upper Error Bar (l/min)	Total Emissions Lower Error Bar (l/min)	Estimated Number of Belowground Leaks	Number of Emission Clusters	Total Emissions per Mile of Main	Total Emissions per Main Mile, Upper Error Bar (l/min/mi)	Total Emissions per Main Mile, Lower Error Bar (l/min/mi)
2C-44	11.8	1	2	86.6	23.0	15.1	79	147	7.3	1.3	1.9
2H-48	8.1	2	4	51.2	21.6	12.4	39	126	6.4	1.5	2.7
4E-13	9.3	3	6	51.0	7.8	5.2	54	116	5.5	0.6	0.8
1Y-49	13.7	4	11	41.6	6.9	4.7	58	107	3.0	0.3	0.5
2P-51	3.6	5	1	33.0	8.2	5.7	23	107	9.2	1.6	2.3
2R-42	5.9	6	7	27.9	6.5	4.4	37	106	4.8	0.7	1.1
2J-54	13.1	7	20	24.7	3.5	2.3	50	102	1.9	0.2	0.3
2J-46	8.9	8	14	21.8	6.3	4.0	27	92	2.5	0.4	0.7
2J-50	7.1	9	13	19.9	4.2	2.9	29	85	2.8	0.4	0.6
3D-38	7.6	10	15	18.6	4.6	3.0	28	79	2.5	0.4	0.6
1Z-54	13.7	11	28	18.4	2.5	1.7	47	68	1.3	0.1	0.2
3E-37	10.9	12	25	18.1	2.7	1.8	46	64	1.7	0.2	0.2
2L-56	8.5	13	17	17.5	3.3	2.2	27	64	2.1	0.3	0.4
3E-35	11.2	14	27	16.4	2.6	1.7	44	62	1.5	0.2	0.2
2K-54	4.3	15	10	15.9	8.6	5.7	14	58	3.7	1.3	2.0
2J-55	11.1	16	30	14.9	2.4	1.6	36	57	1.3	0.1	0.2
2K-43	3.5	17	9	14.6	4.0	2.9	17	53	4.2	0.8	1.2

2F-53	16.4	18	40	13.7	2.4	1.6	41	50	0.8	0.1	0.1
2R-48	1.9	19	3	12.6	3.9	2.9	9	46	6.6	1.5	2.1
2Y-48	2.7	20	8	11.6	4.4	3.0	13	46	4.3	1.1	1.7
1U-51	1.9	21	5	11.4	9.8	5.5	7	44	6.1	2.9	5.2
2F-48	8.4	22	31	10.7	2.0	1.5	21	42	1.3	0.2	0.2
3F-36	5.9	23	22	10.4	3.0	1.8	23	41	1.8	0.3	0.5
3J-49	3.6	24	12	10.3	3.2	2.1	13	36	2.9	0.6	0.9
2A-02N	6.8	25	29	9.1	1.7	1.2	20	36	1.3	0.2	0.3
1V-59	9.0	26	38	8.3	2.5	1.8	16	32	0.9	0.2	0.3
3B-44	7.5	27	34	8.2	2.1	1.3	16	31	1.1	0.2	0.3
2A-58	8.4	28	37	8.0	2.0	1.3	20	29	1.0	0.2	0.2
2B-59	6.5	29	32	8.0	1.9	1.2	19	26	1.2	0.2	0.3
2N-54	4.3	30	21	7.6	1.8	1.2	14	25	1.8	0.3	0.4
2G-57	3.7	31	19	7.2	2.9	2.0	8	25	2.0	0.5	0.8
2Y-41	3.5	32	18	6.9	6.0	3.9	6	23	2.0	1.1	1.7
3D-45	6.3	33	35	6.8	2.6	1.6	10	23	1.1	0.3	0.4
2P-54	2.8	34	16	6.3	1.8	1.2	9	20	2.3	0.4	0.6
1T-57	3.5	35	26	5.4	1.9	1.2	10	19	1.6	0.3	0.5
3G-47	4.5	36	36	4.7	1.7	1.3	8	18	1.1	0.3	0.4
2C-45	2.6	37	24	4.3	1.1	0.7	12	18	1.7	0.3	0.4
2C-60	2.3	38	23	3.9	1.0	0.7	9	16	1.7	0.3	0.4
3E-30	3.4	39	43	2.2	0.9	0.6	8	16	0.6	0.2	0.3
2C-02N	1.7	40	39	1.5	1.5	0.9	2	7	0.9	0.5	0.8
3F-48	1.5	41	41	1.2	0.6	0.4	3	7	0.8	0.3	0.4
2L-52	1.0	42	33	1.1	0.8	0.5	2	6	1.1	0.5	0.8
3E-48	2.1	43	44	0.8	1.0	0.5	1	3	0.4	0.3	0.5
2C-48	0.8	44	42	0.6	0.2	0.2	2	2	0.7	0.2	0.3

Appendix II: Methane Emissions Maps on GSMP II Grids

In the following pages, methane heat maps are shown for each of the 44 grids along with summary information for each grid. Figure 5 shows these grids on a map.

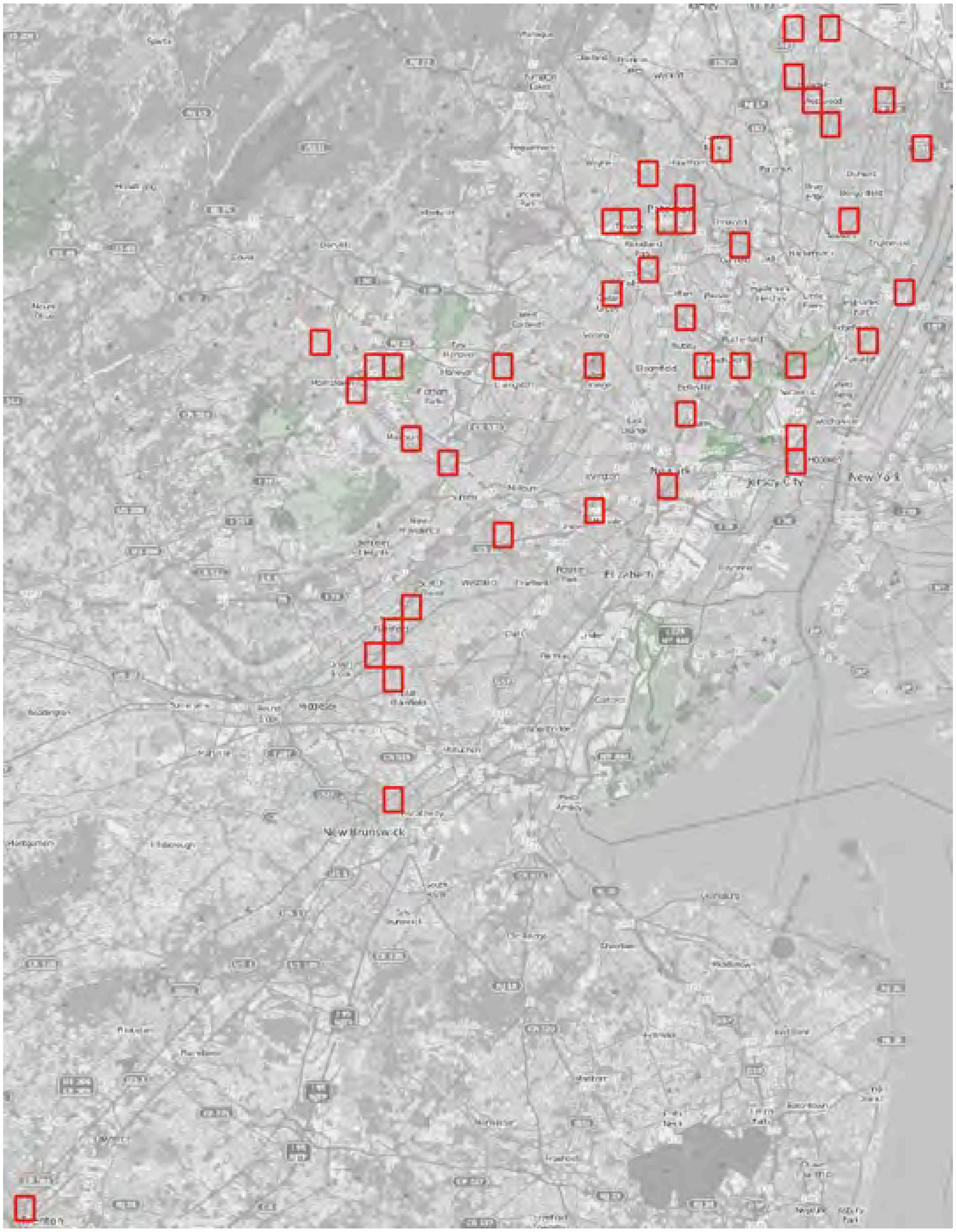
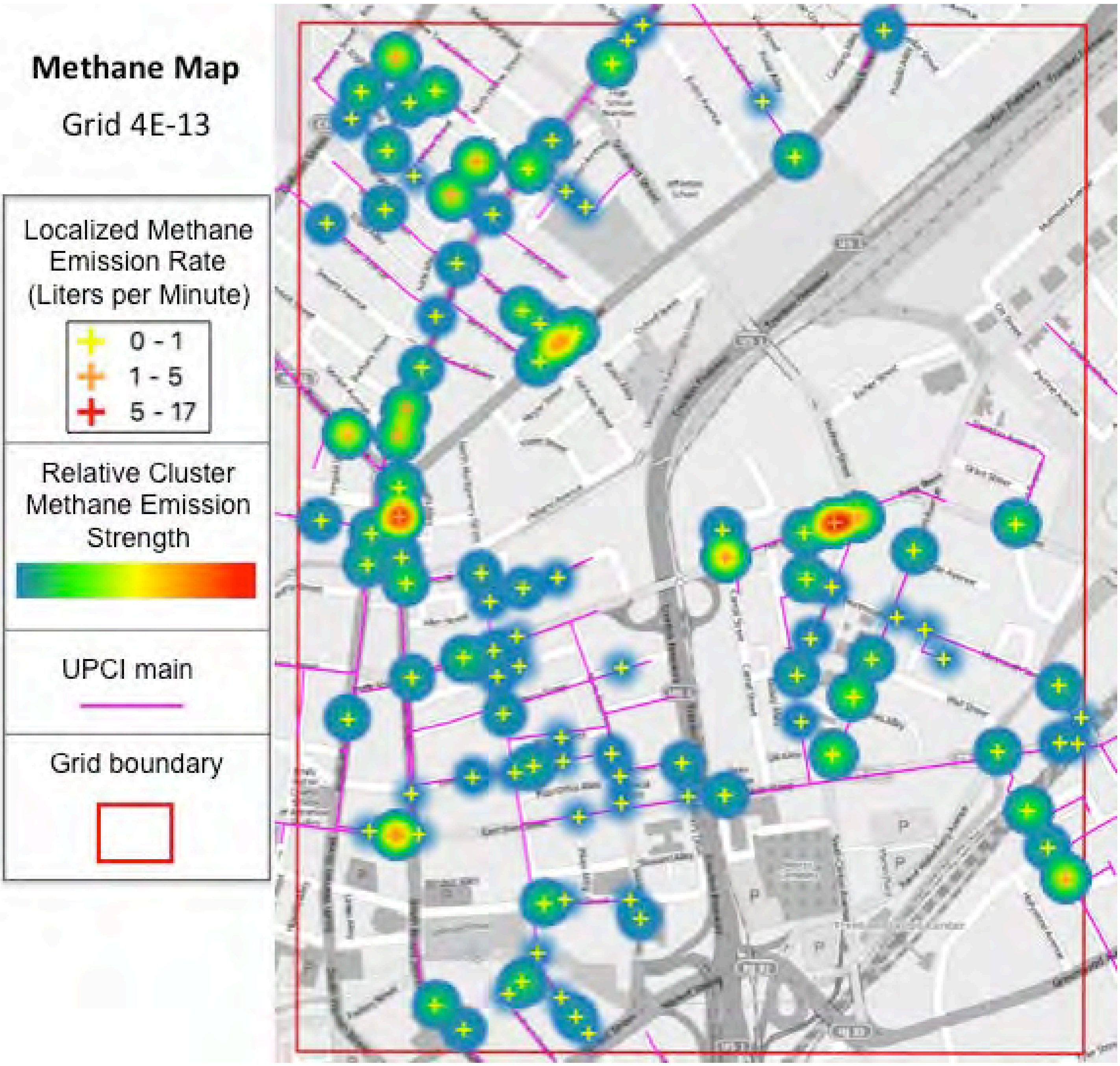


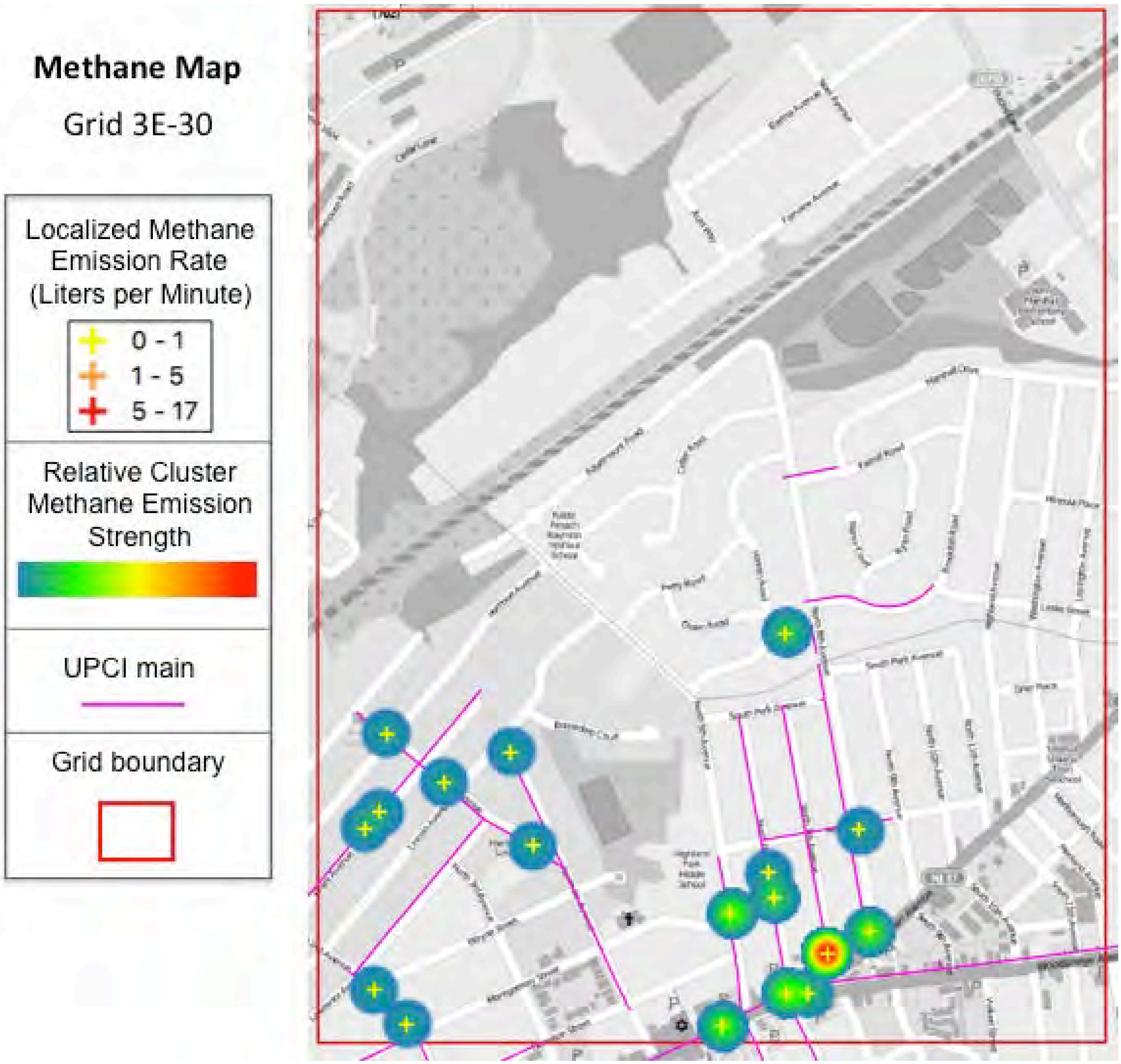
Figure 5. Relative locations of the 44 grids.

PICARRO


Methane Map
Grid 4E-13
Localized Methane Emission Rate (Liters per Minute)
0 - 1
1 - 5
5 - 17
Relative Cluster Methane Emission Strength
UPCI main
Grid boundary

Methane Map

Grid 3E-30



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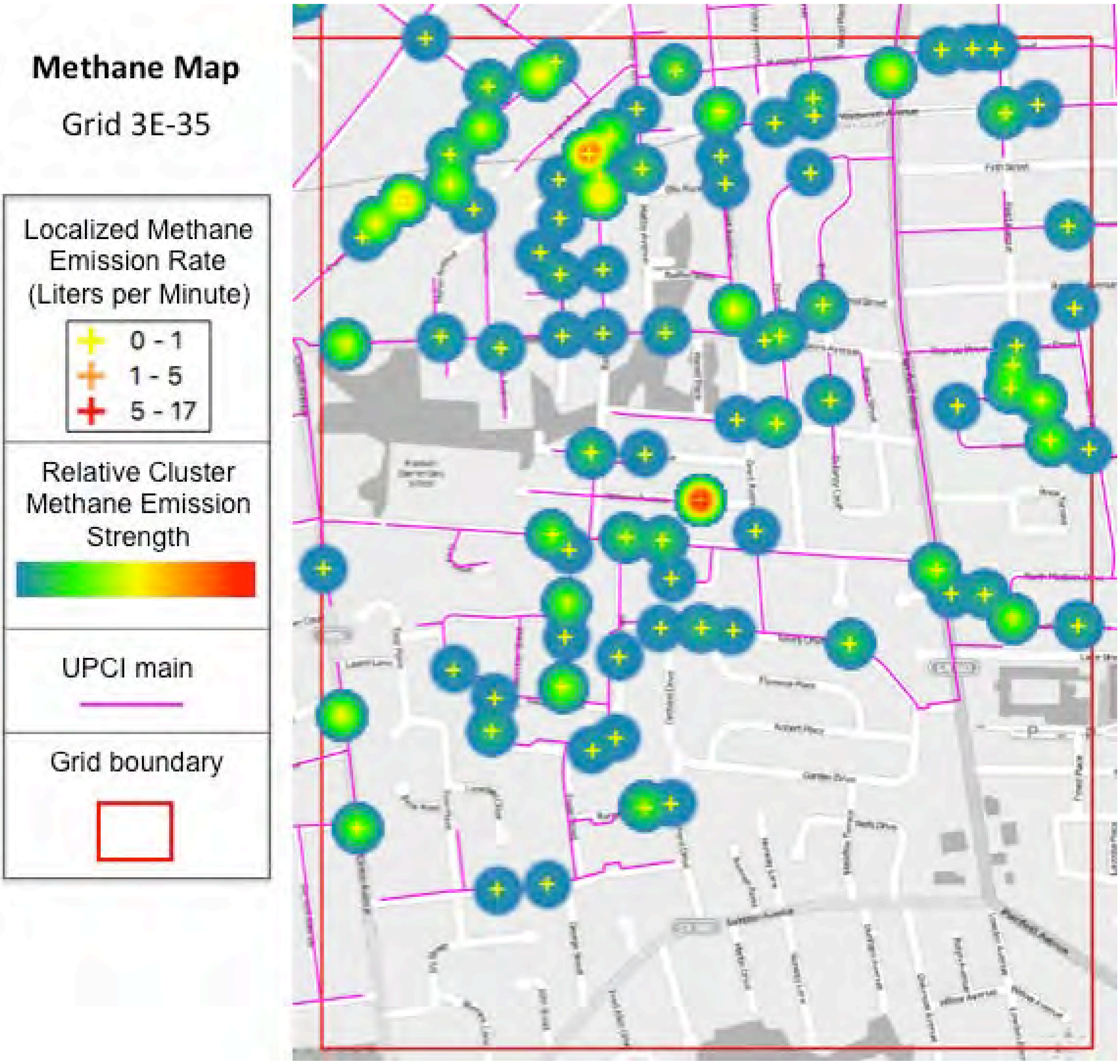
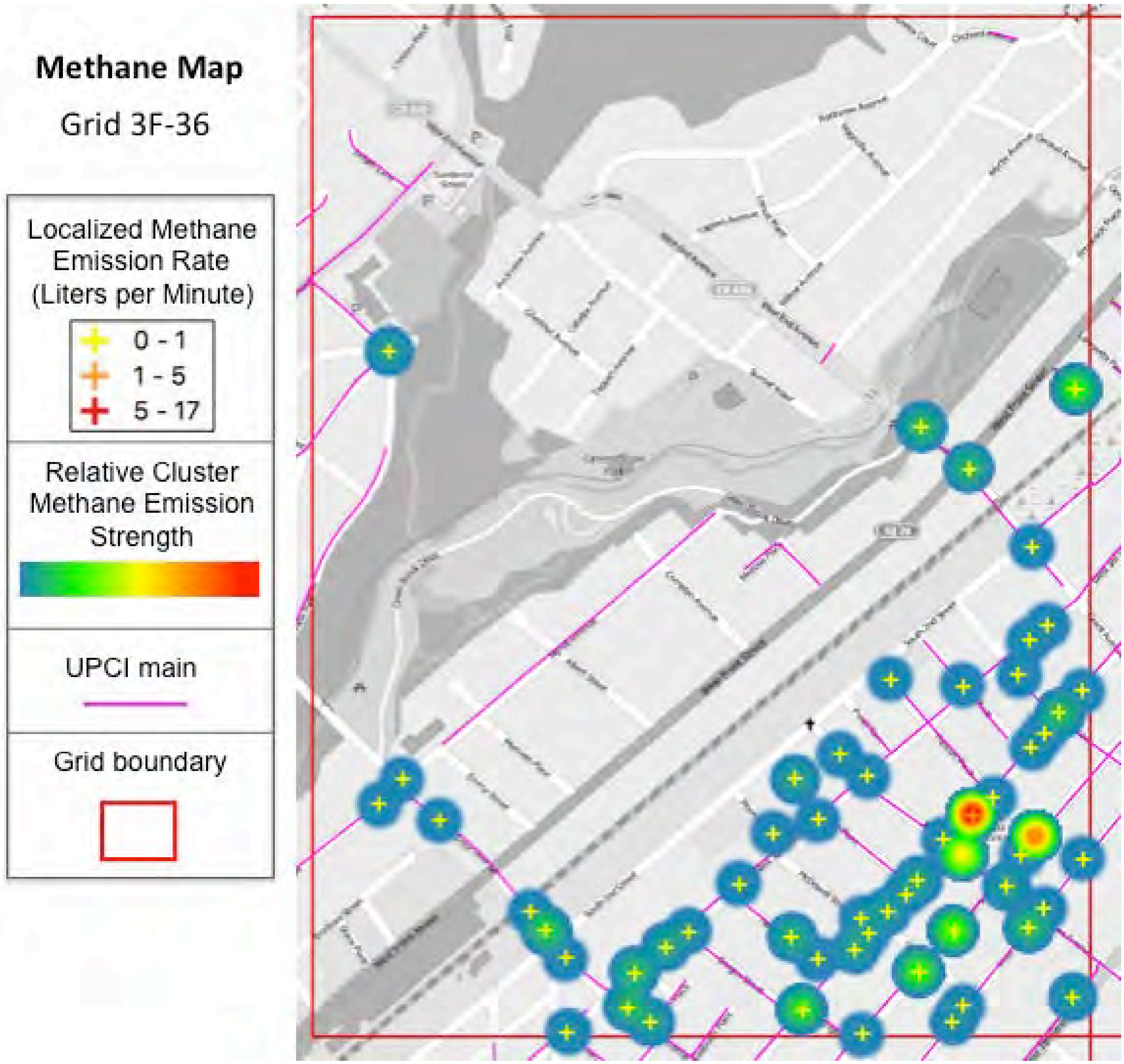

Methane Map
Grid 3E-35
Localized Methane Emission Rate (Liters per Minute)
0 - 1
1 - 5
5 - 17
Relative Cluster Methane Emission Strength
UPCI main
Grid boundary

PICARRO


Methane Map
Grid 3F-36
Localized Methane Emission Rate (Liters per Minute)
0 - 1
1 - 5
5 - 17
Relative Cluster Methane Emission Strength
UPCI main
Grid boundary

Methane Map

Grid 3E-37

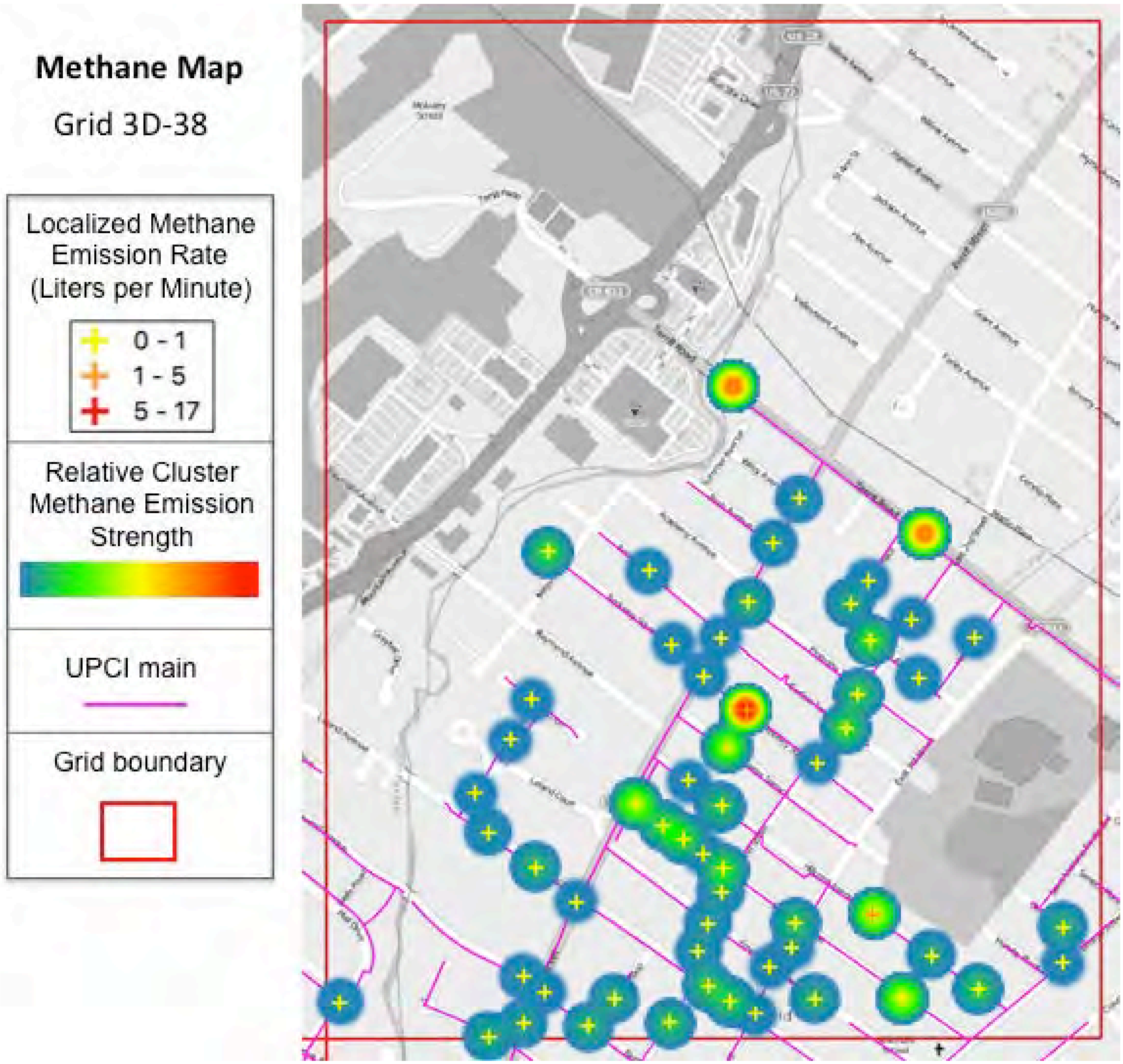
Localized Methane Emission Rate (Liters per Minute)

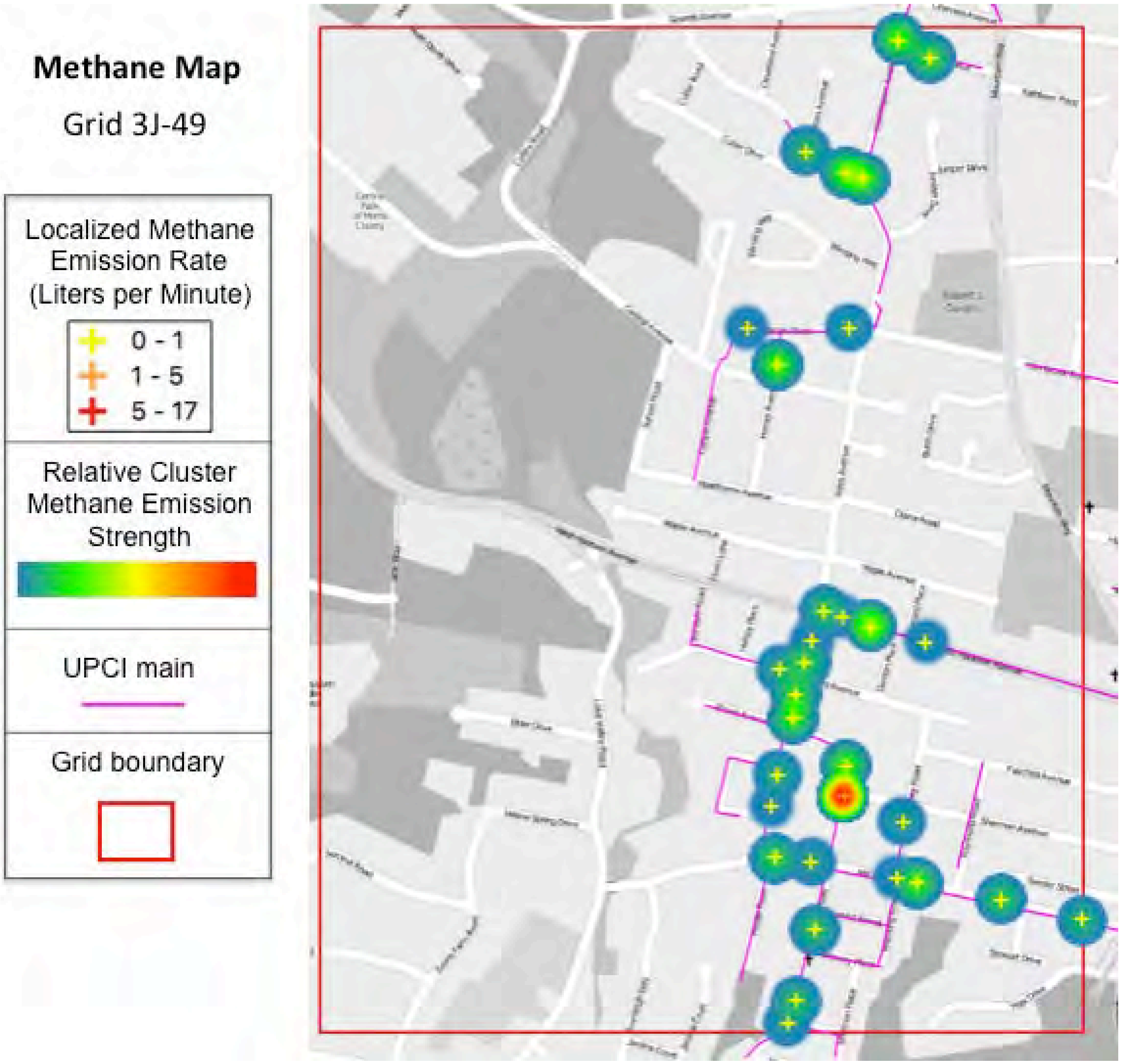
0 - 1
1 - 5
5 - 17

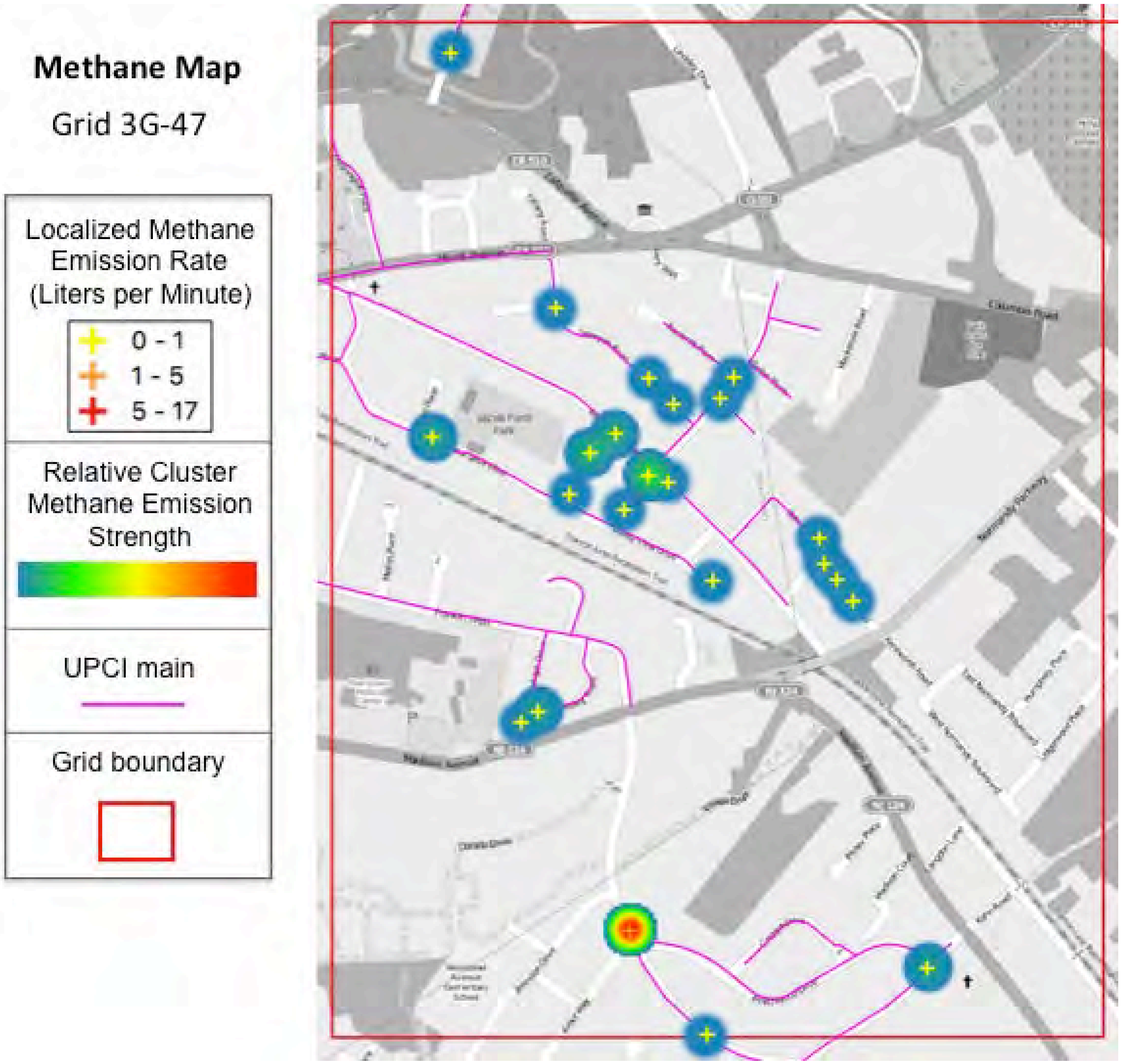
Relative Cluster Methane Emission Strength

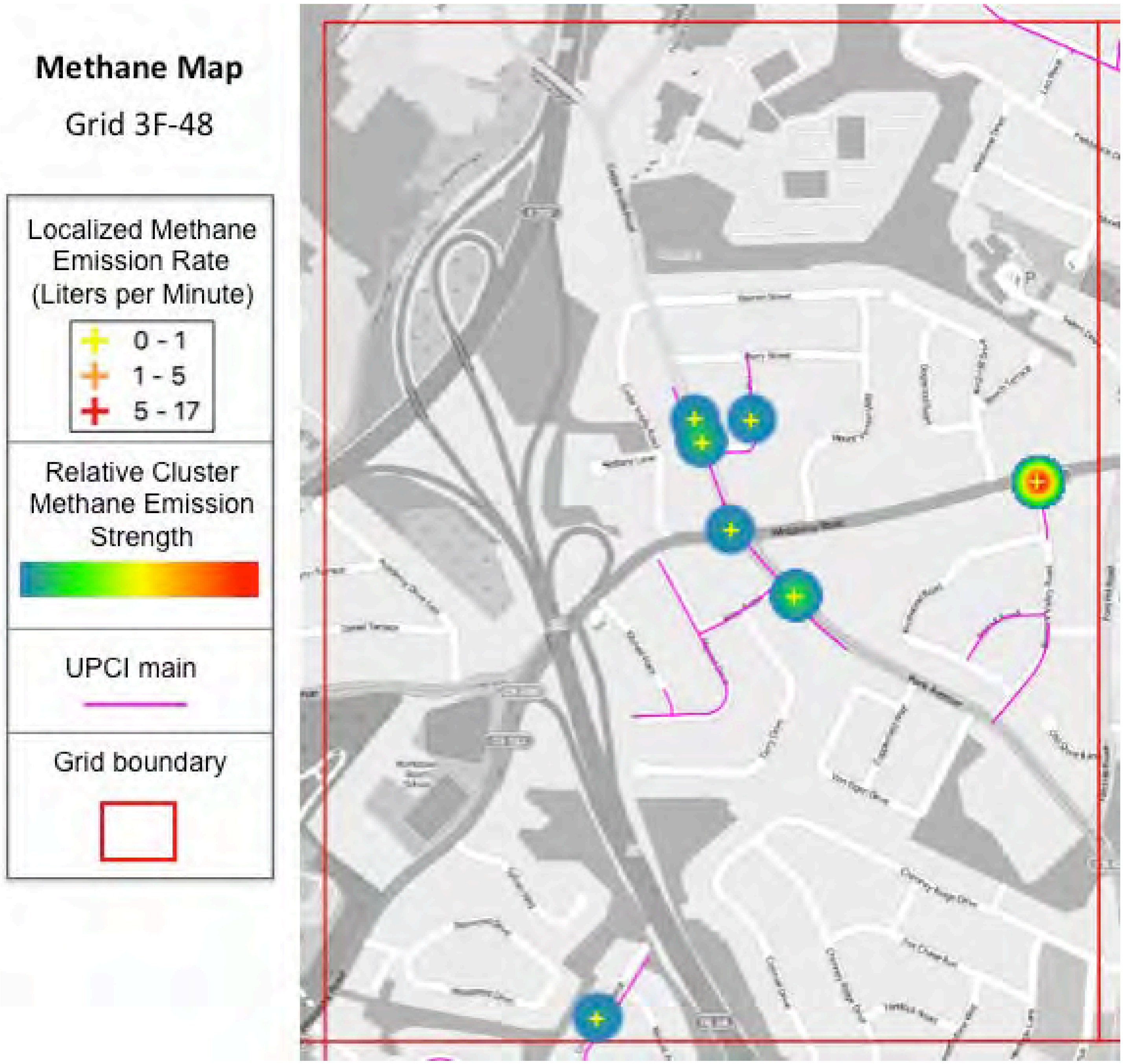
UPCI main

Grid boundary

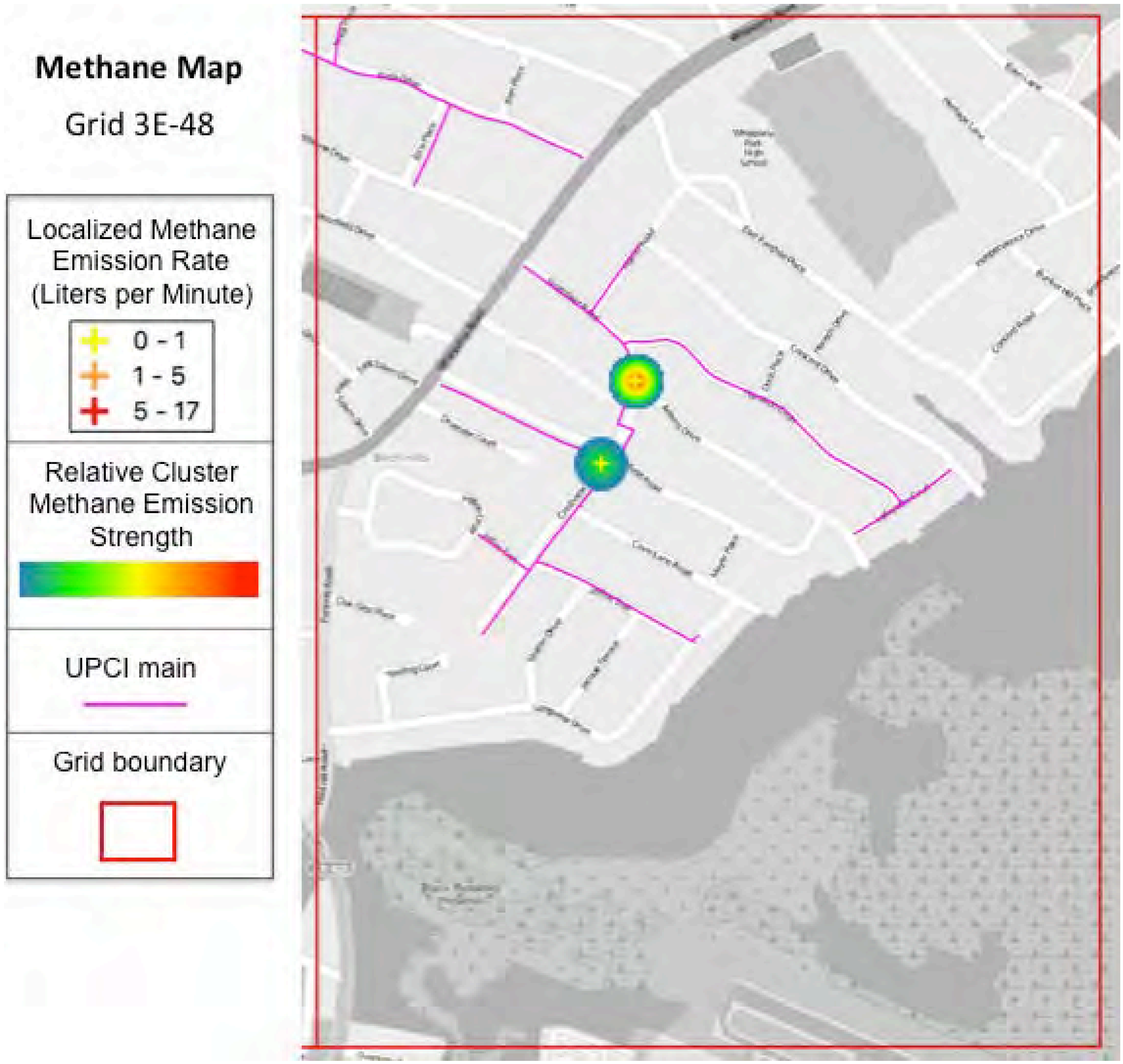

Methane Map
Grid 3D-38
Localized Methane Emission Rate (Liters per Minute)
0 - 1
1 - 5
5 - 17
Relative Cluster Methane Emission Strength
UPCI main
Grid boundary

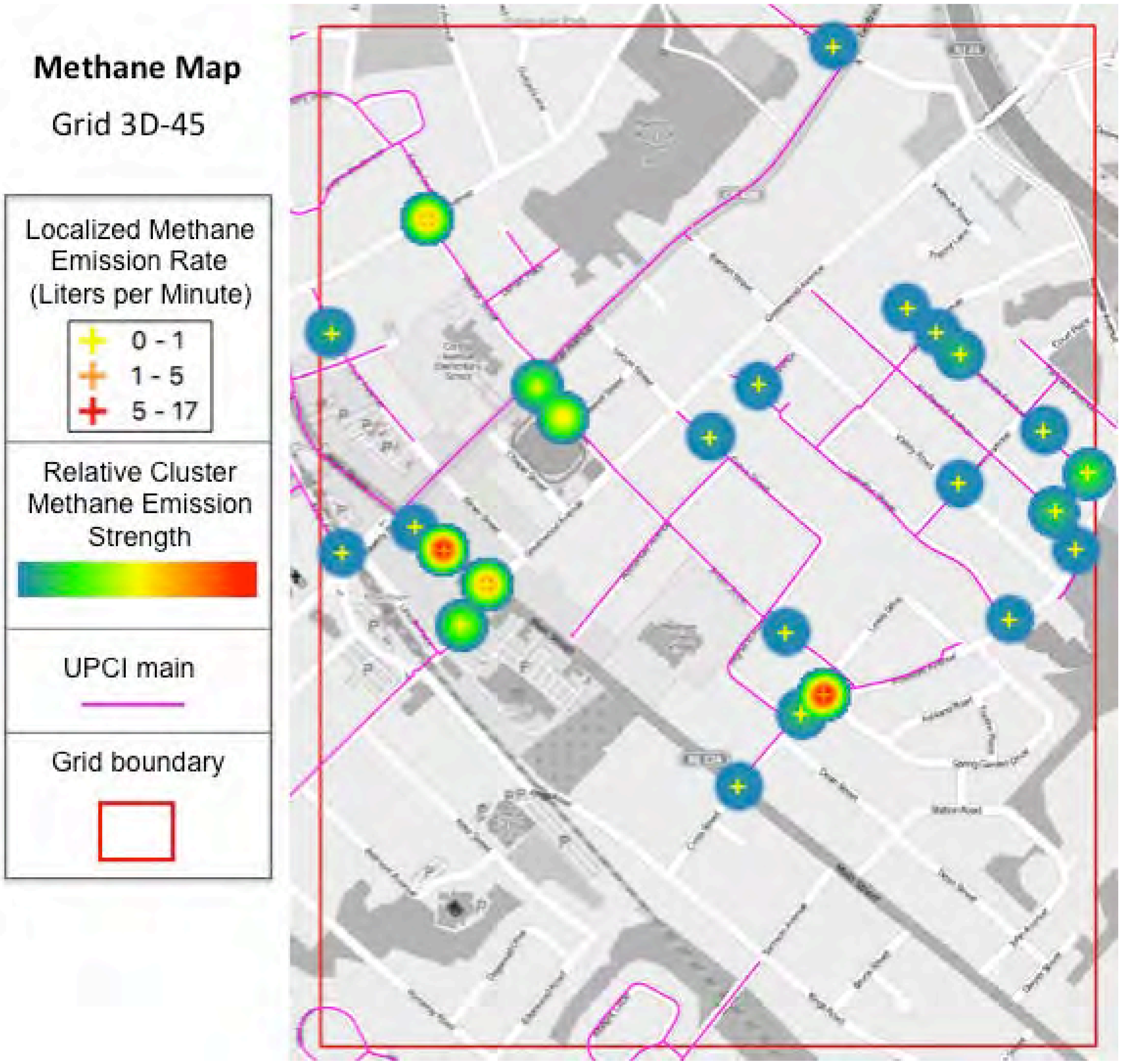

Methane Map
Grid 3J-49
Localized Methane Emission Rate (Liters per Minute)
0 - 1
1 - 5
5 - 17
Relative Cluster Methane Emission Strength
UPCI main
Grid boundary


Methane Map
Grid 3G-47
Localized Methane Emission Rate (Liters per Minute)
0 - 1
1 - 5
5 - 17
Relative Cluster Methane Emission Strength
UPCI main
Grid boundary

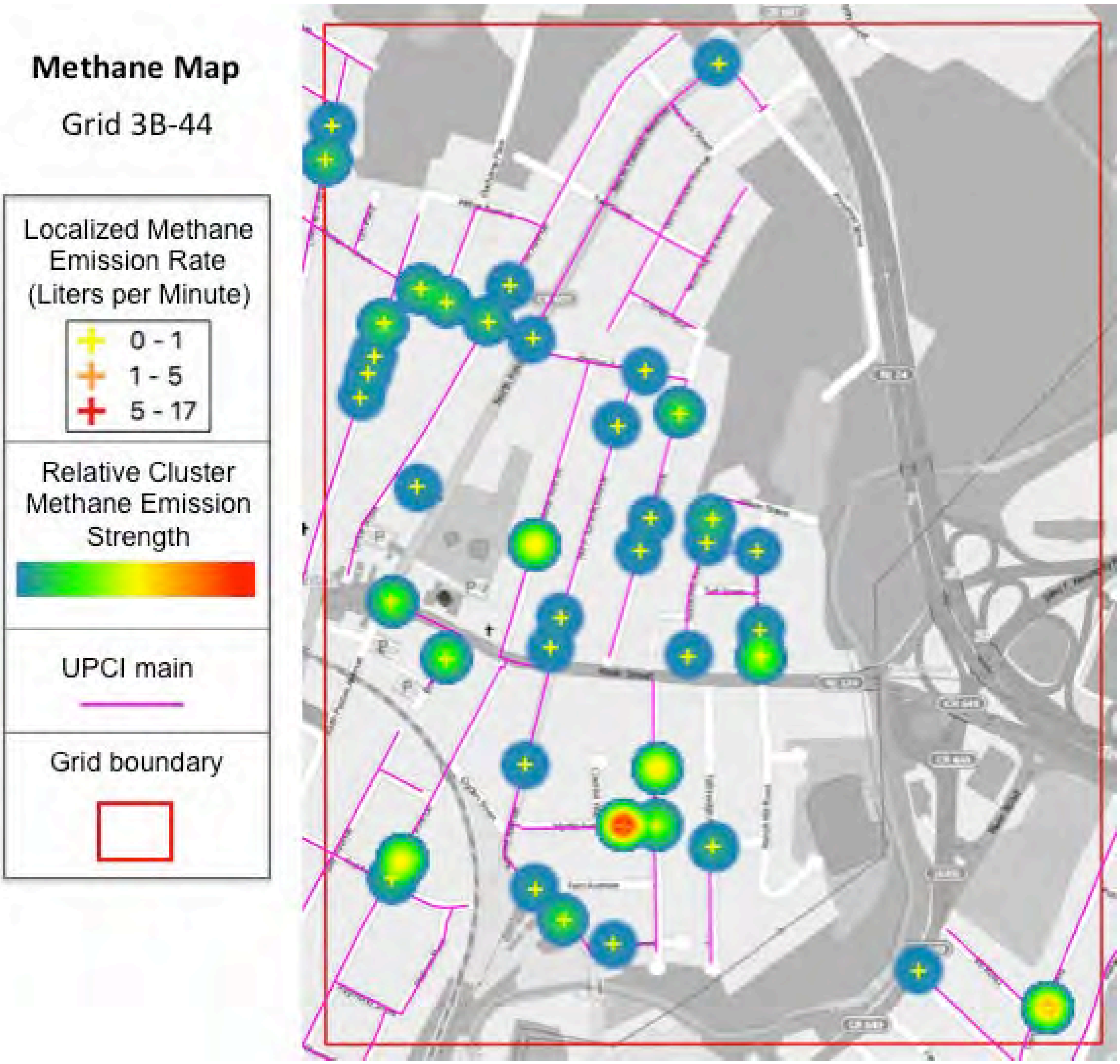

Methane Map
Grid 3F-48
Localized Methane Emission Rate (Liters per Minute)
0 - 1
1 - 5
5 - 17
Relative Cluster Methane Emission Strength
UPCI main
Grid boundary

PICARRO


Methane Map
Grid 3E-48
Localized Methane Emission Rate (Liters per Minute)
0 - 1
1 - 5
5 - 17
Relative Cluster Methane Emission Strength
UPCI main
Grid boundary


Methane Map
Grid 3D-45
Localized Methane Emission Rate (Liters per Minute)
0 - 1
1 - 5
5 - 17
Relative Cluster Methane Emission Strength
UPCI main
Grid boundary

PICARRO


Methane Map
Grid 3B-44
Localized Methane Emission Rate (Liters per Minute)
0 - 1
1 - 5
5 - 17
Relative Cluster Methane Emission Strength
UPCI main
Grid boundary

Methane Map

Grid 2Y-41

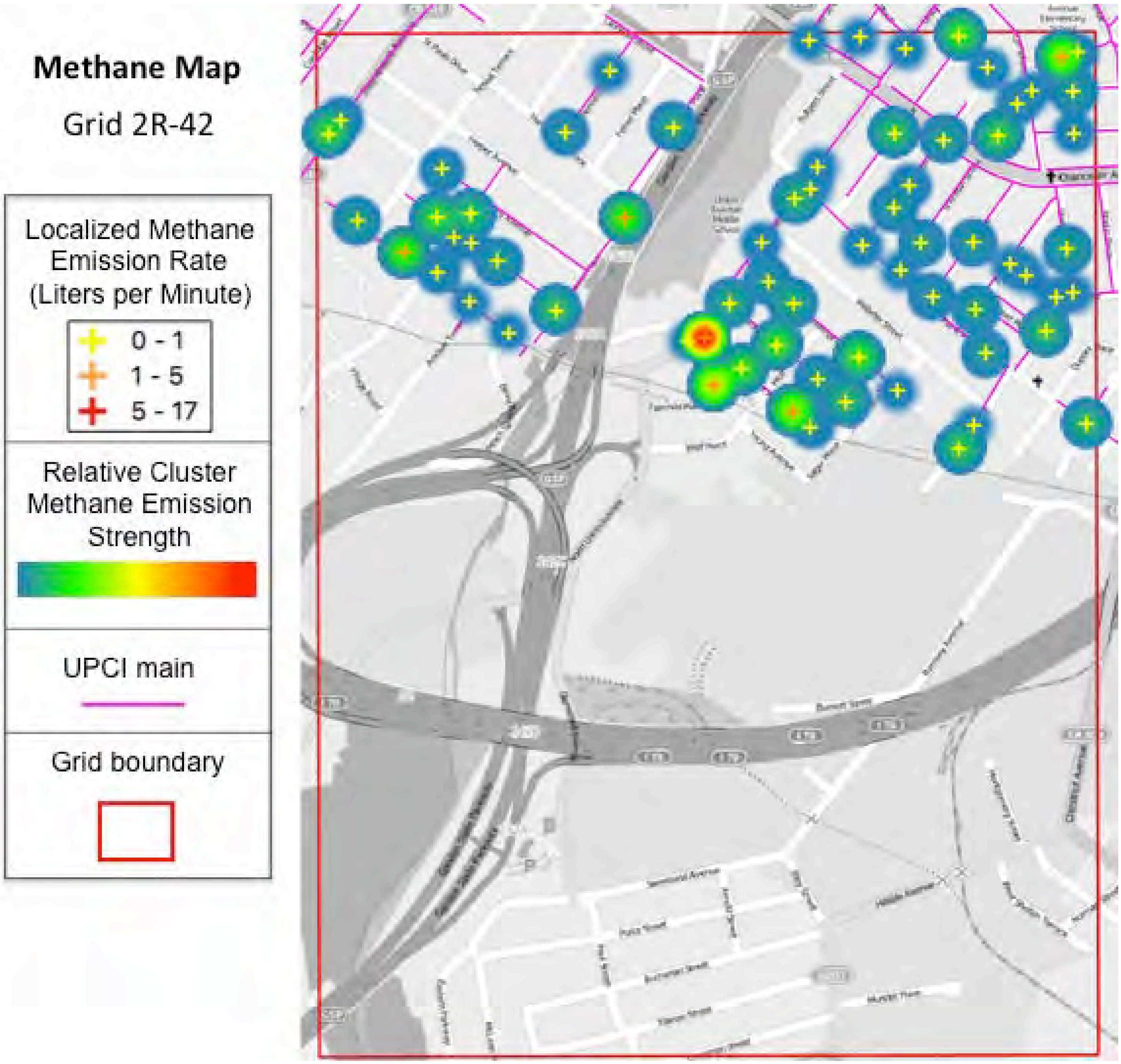
Localized Methane Emission Rate (Liters per Minute)

- 0 - 1
- 1 - 5
- 5 - 17

Relative Cluster Methane Emission Strength

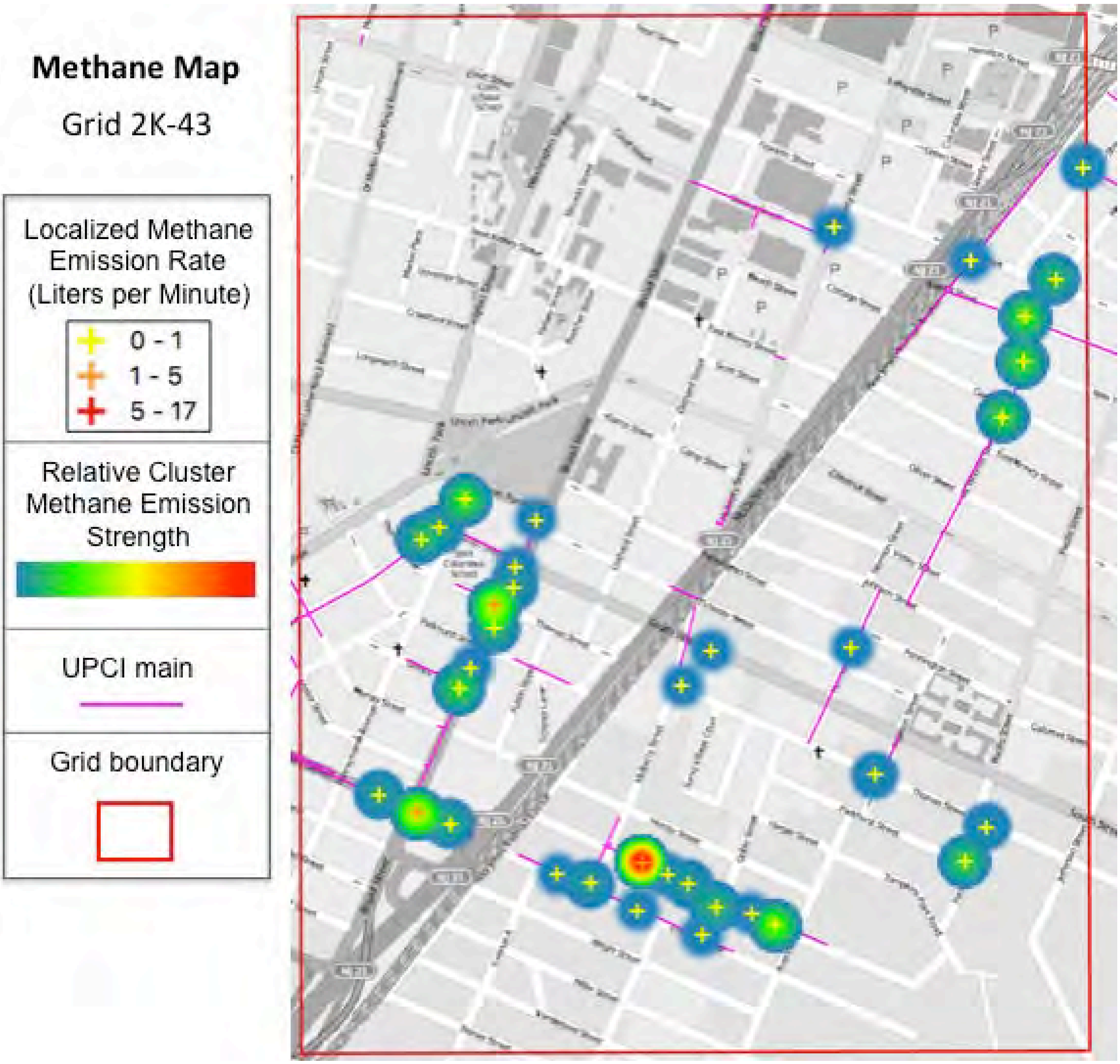
UPCI main

Grid boundary


Methane Map
Grid 2R-42
Localized Methane Emission Rate (Liters per Minute)
0 - 1
1 - 5
5 - 17
Relative Cluster Methane Emission Strength
UPCI main
Grid boundary

Methane Map

Grid 2K-43



PICARRO

Methane Map

Grid 2C-44

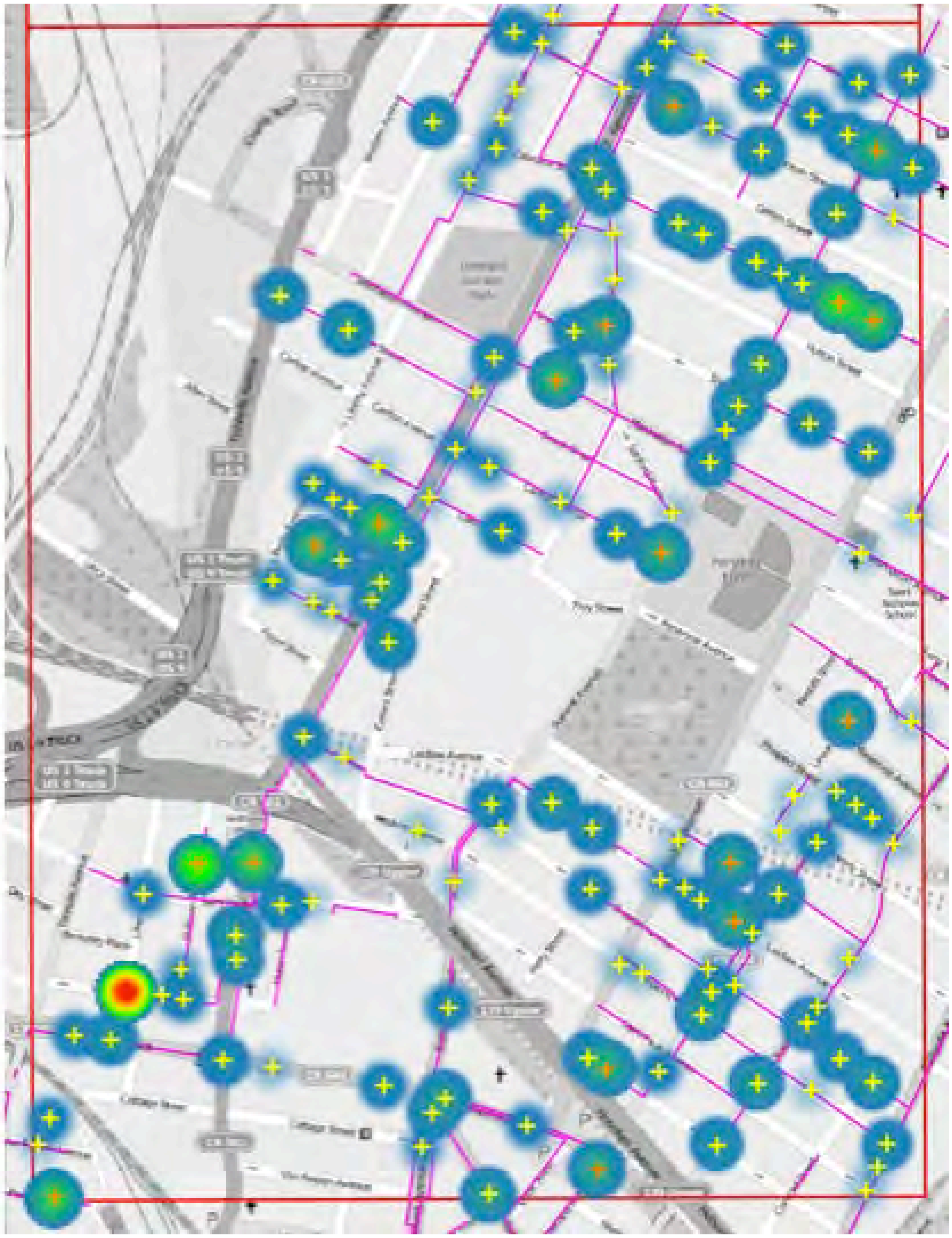
Localized Methane Emission Rate (Liters per Minute)

- 0 - 1
- 1 - 5
- 5 - 17

Relative Cluster Methane Emission Strength

UPCI main

Grid boundary



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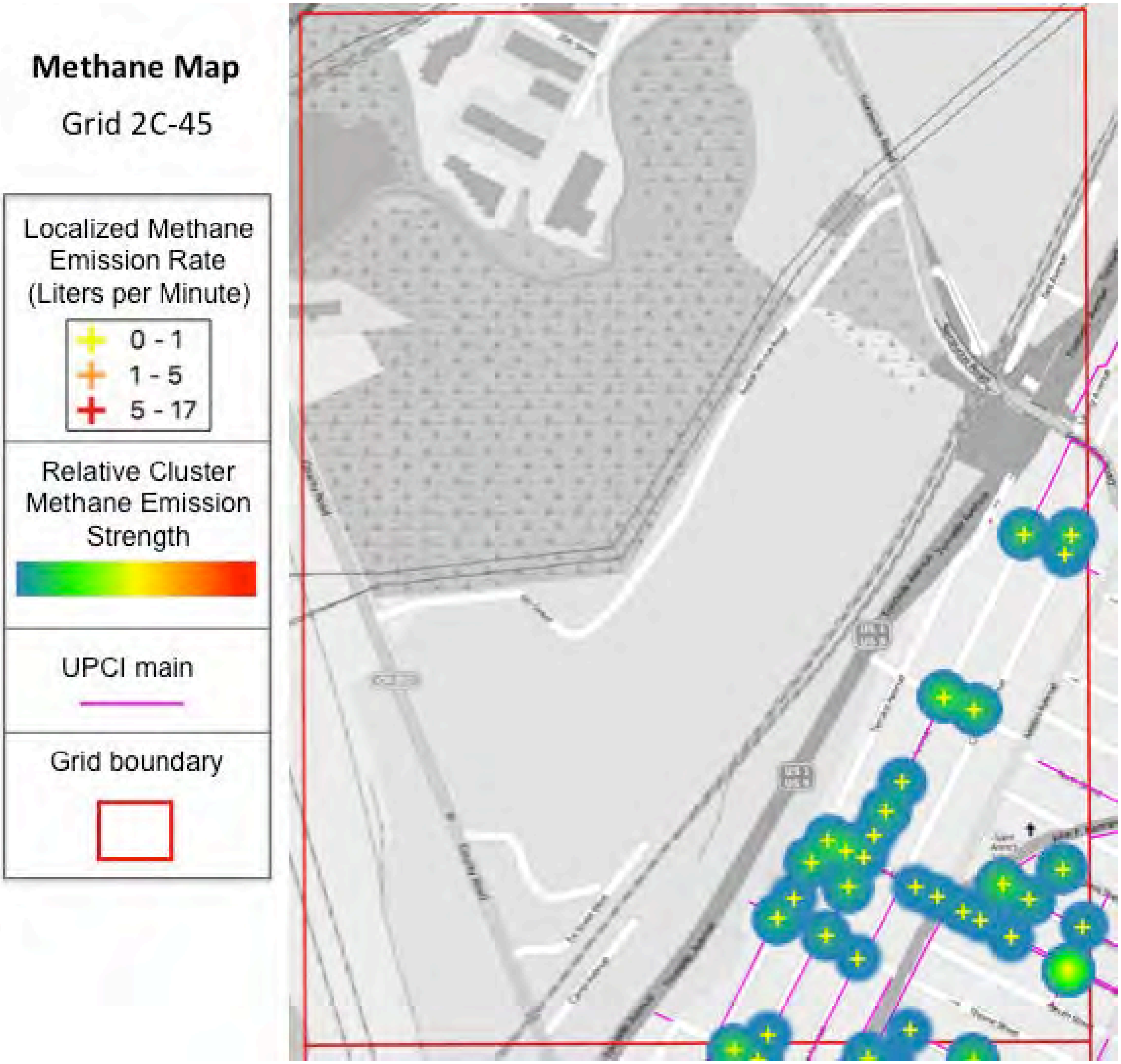
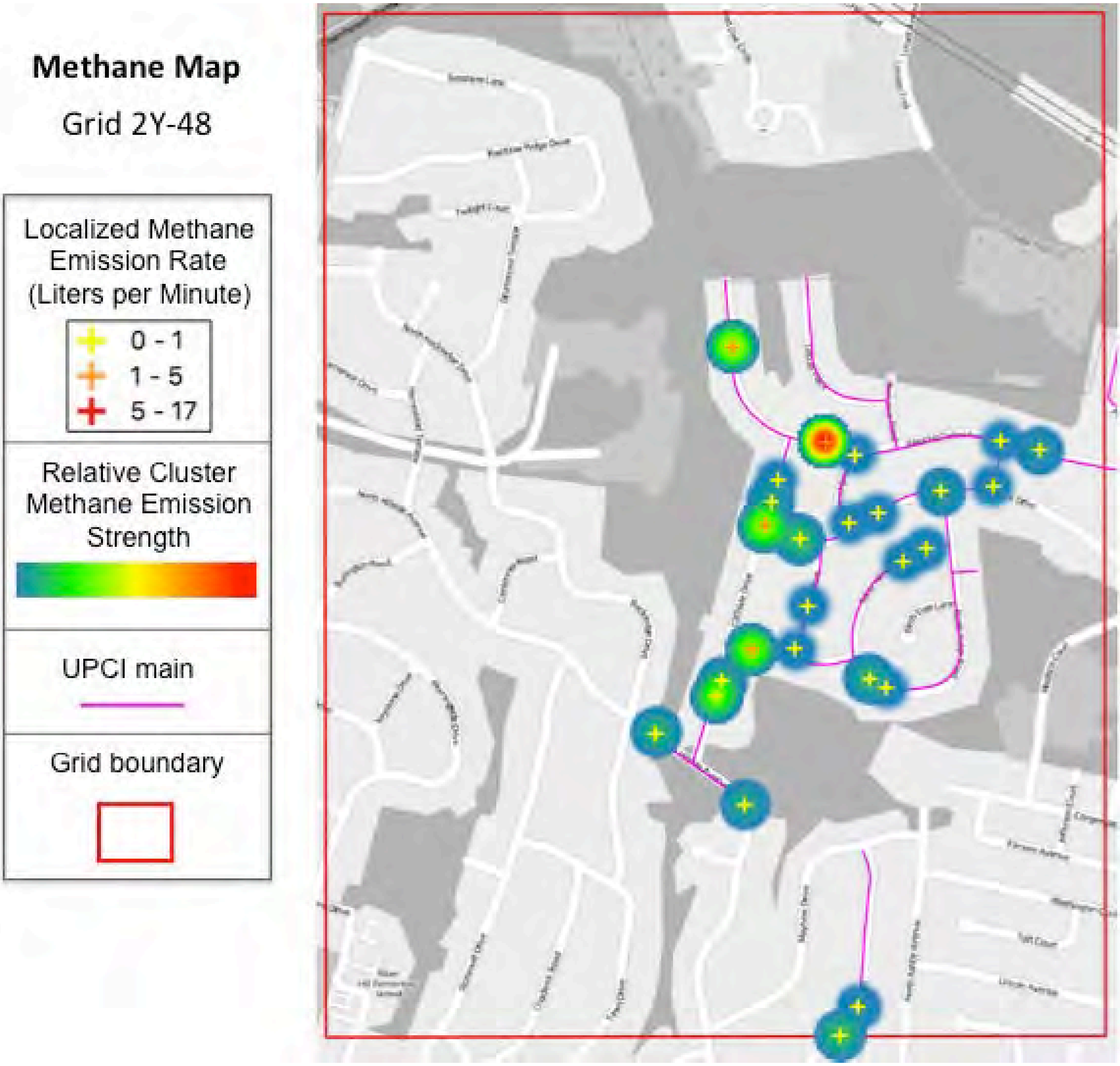
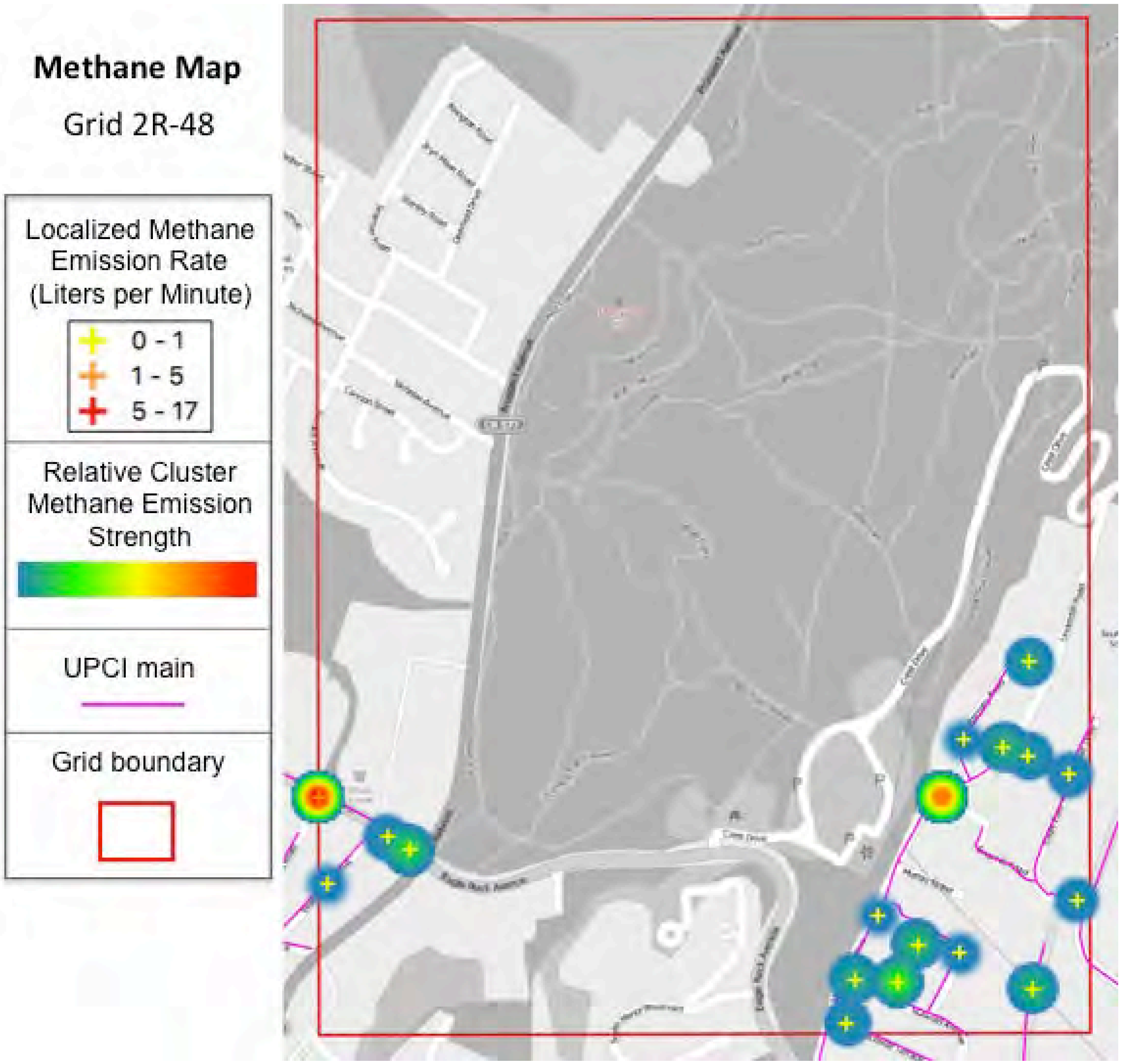
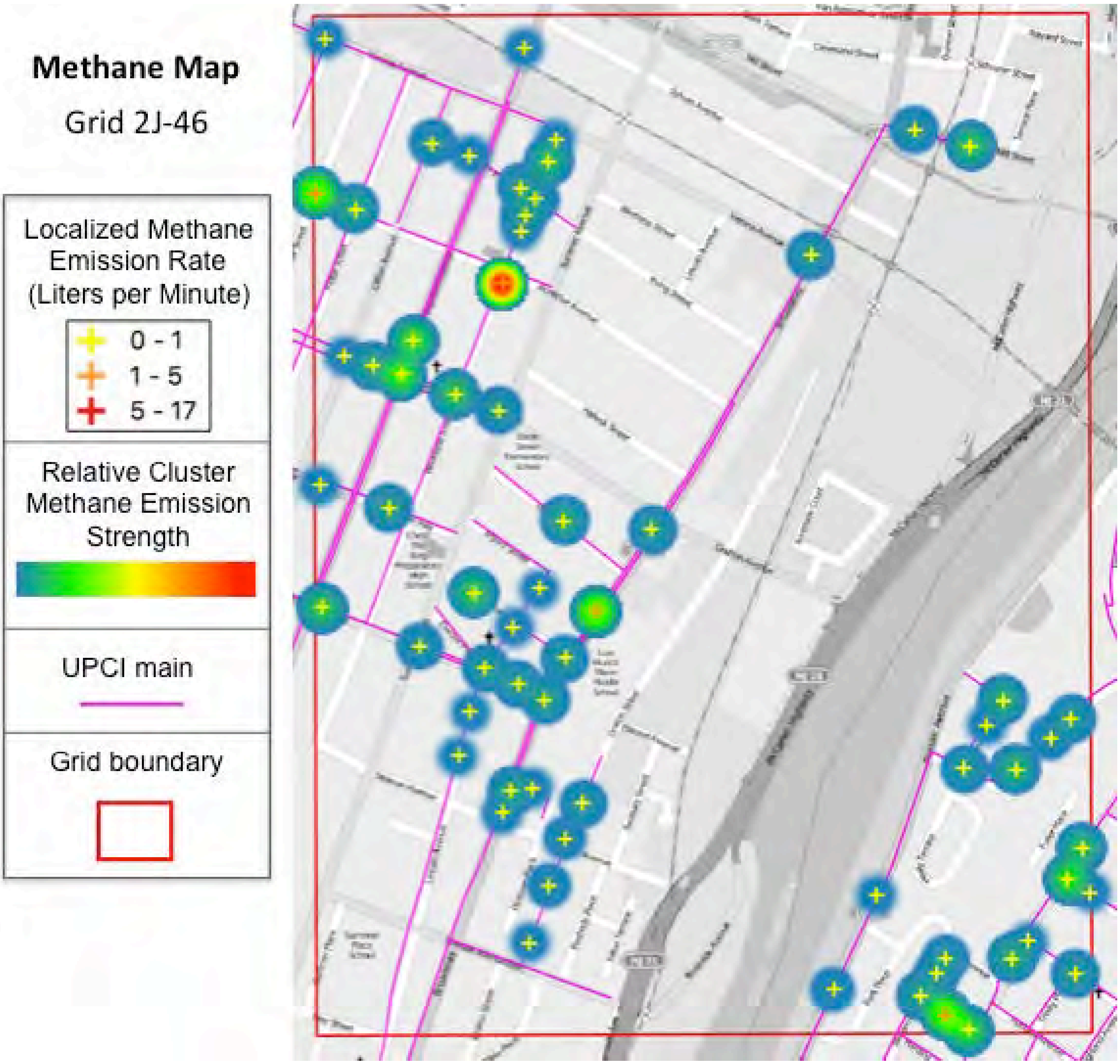

Methane Map
Grid 2C-45
Localized Methane Emission Rate (Liters per Minute)
0 - 1
1 - 5
5 - 17
Relative Cluster Methane Emission Strength
UPCI main
Grid boundary


Methane Map
Grid 2Y-48
Localized Methane Emission Rate (Liters per Minute)
0 - 1
1 - 5
5 - 17
Relative Cluster Methane Emission Strength
UPCI main
Grid boundary


Methane Map
Grid 2R-48
Localized Methane Emission Rate (Liters per Minute)
0 - 1
1 - 5
5 - 17
Relative Cluster Methane Emission Strength
UPCI main
Grid boundary

PICARRO


Methane Map
Grid 2J-46
Localized Methane Emission Rate (Liters per Minute)
0 - 1
1 - 5
5 - 17
Relative Cluster Methane Emission Strength
UPCI main
Grid boundary

Methane Map

Grid 2C-48

Localized Methane Emission Rate (Liters per Minute)

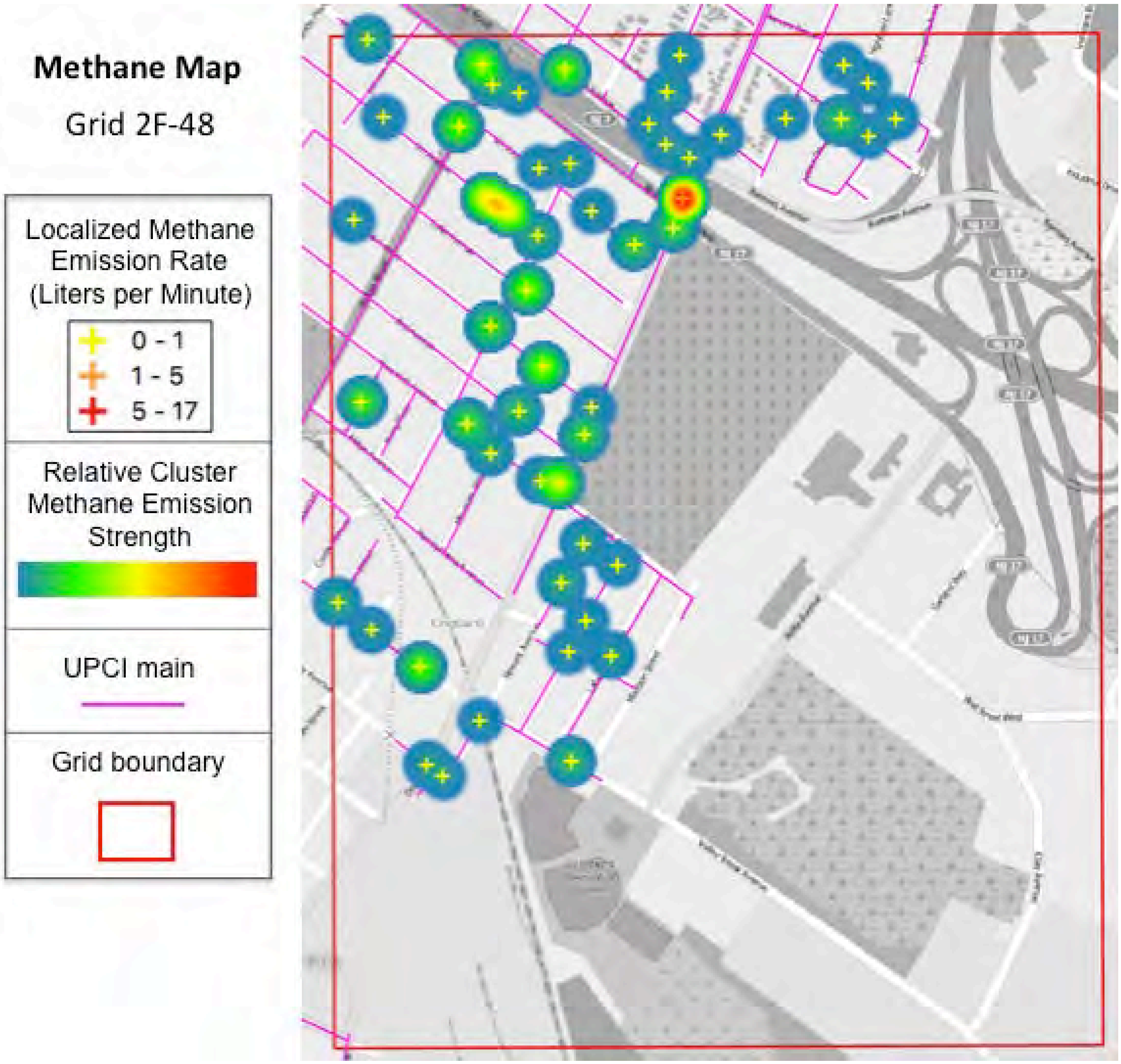
0 - 1
1 - 5
5 - 17

Relative Cluster Methane Emission Strength

UPCI main

Grid boundary

PICARRO


Methane Map
Grid 2F-48
Localized Methane Emission Rate (Liters per Minute)
0 - 1
1 - 5
5 - 17
Relative Cluster Methane Emission Strength
UPCI main
Grid boundary

PICARRO

Methane Map

Grid 2H-48

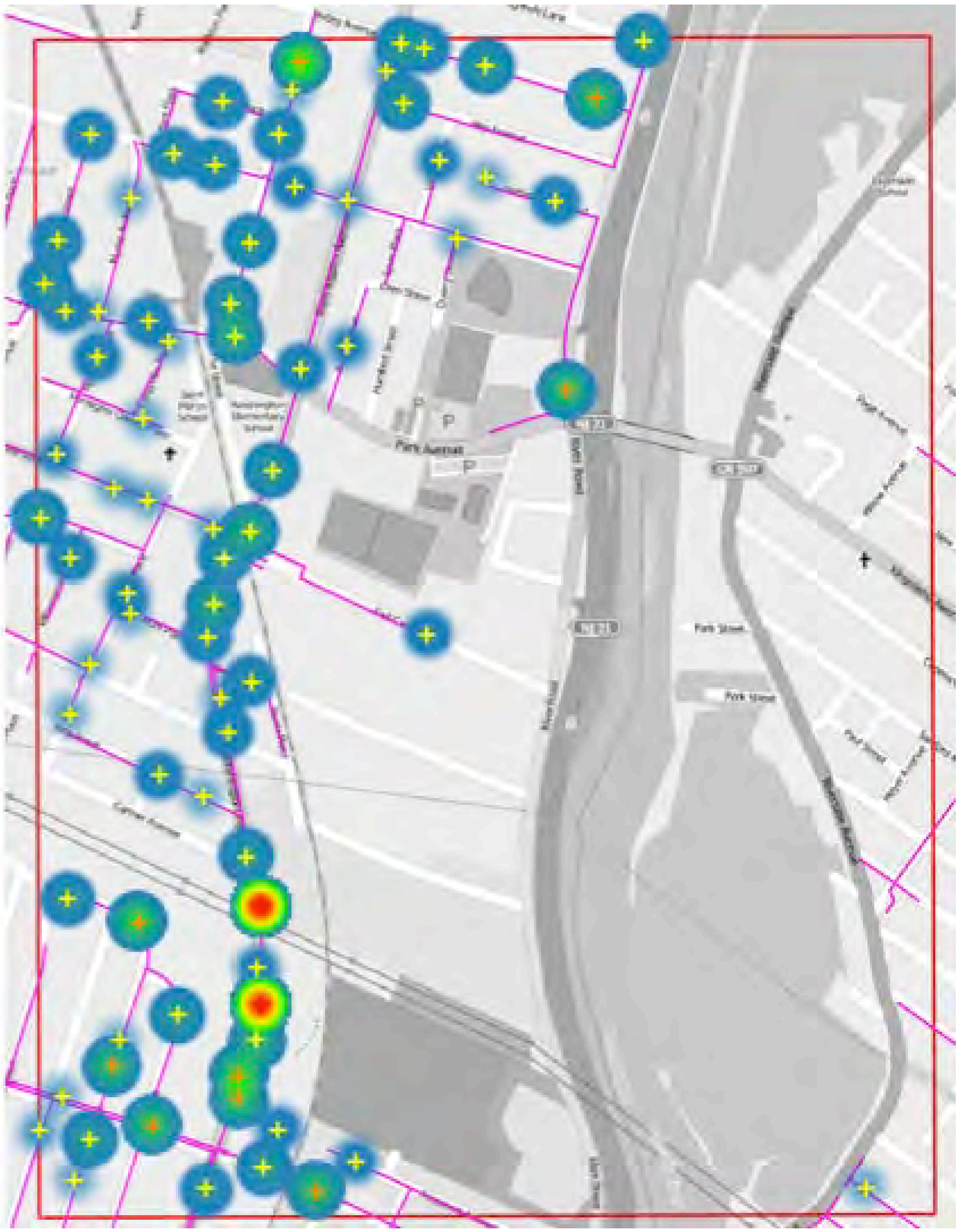
Localized Methane Emission Rate (Liters per Minute)

- 0 - 1
- 1 - 5
- 5 - 17

Relative Cluster Methane Emission Strength

UPCI main

Grid boundary



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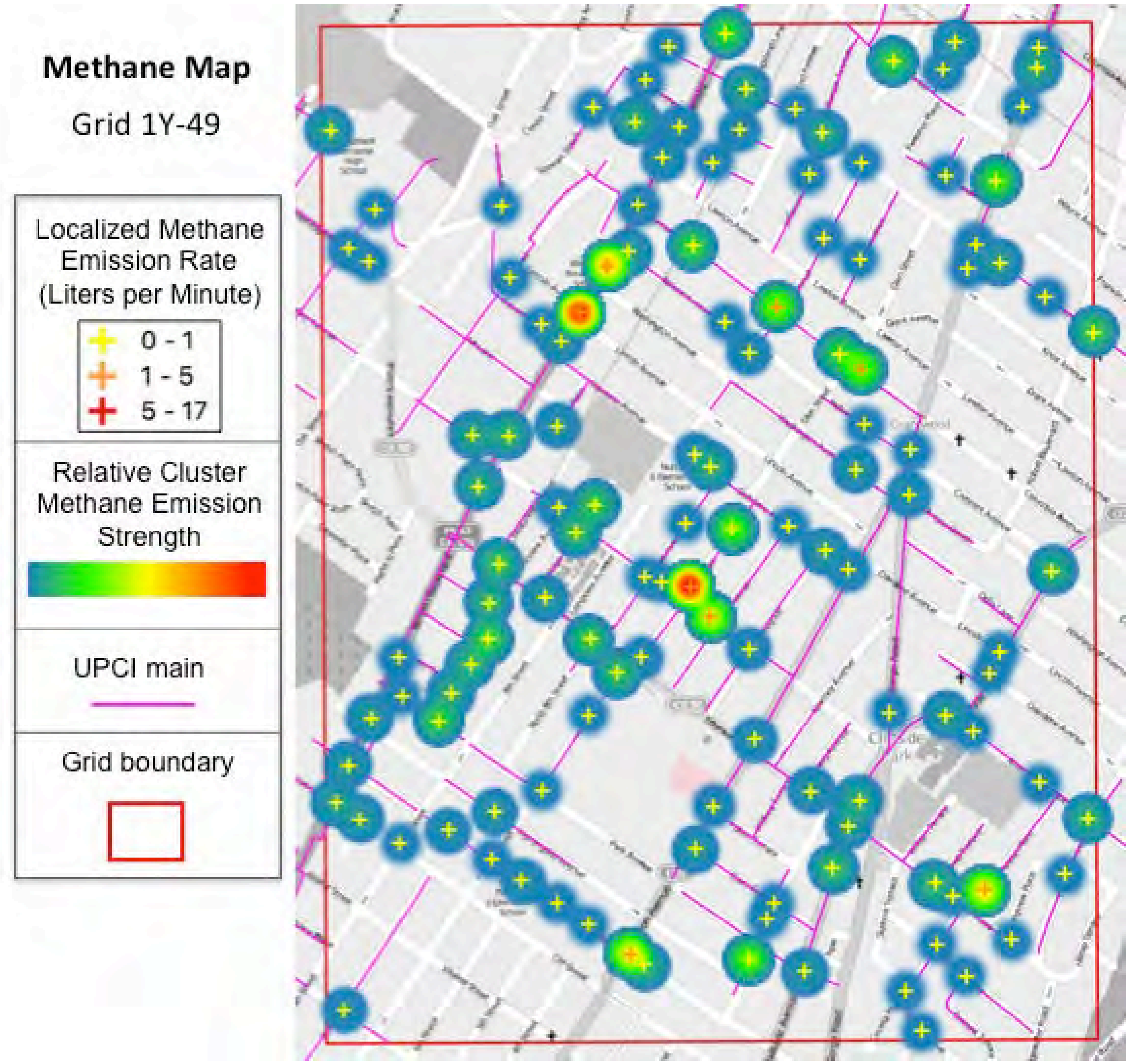
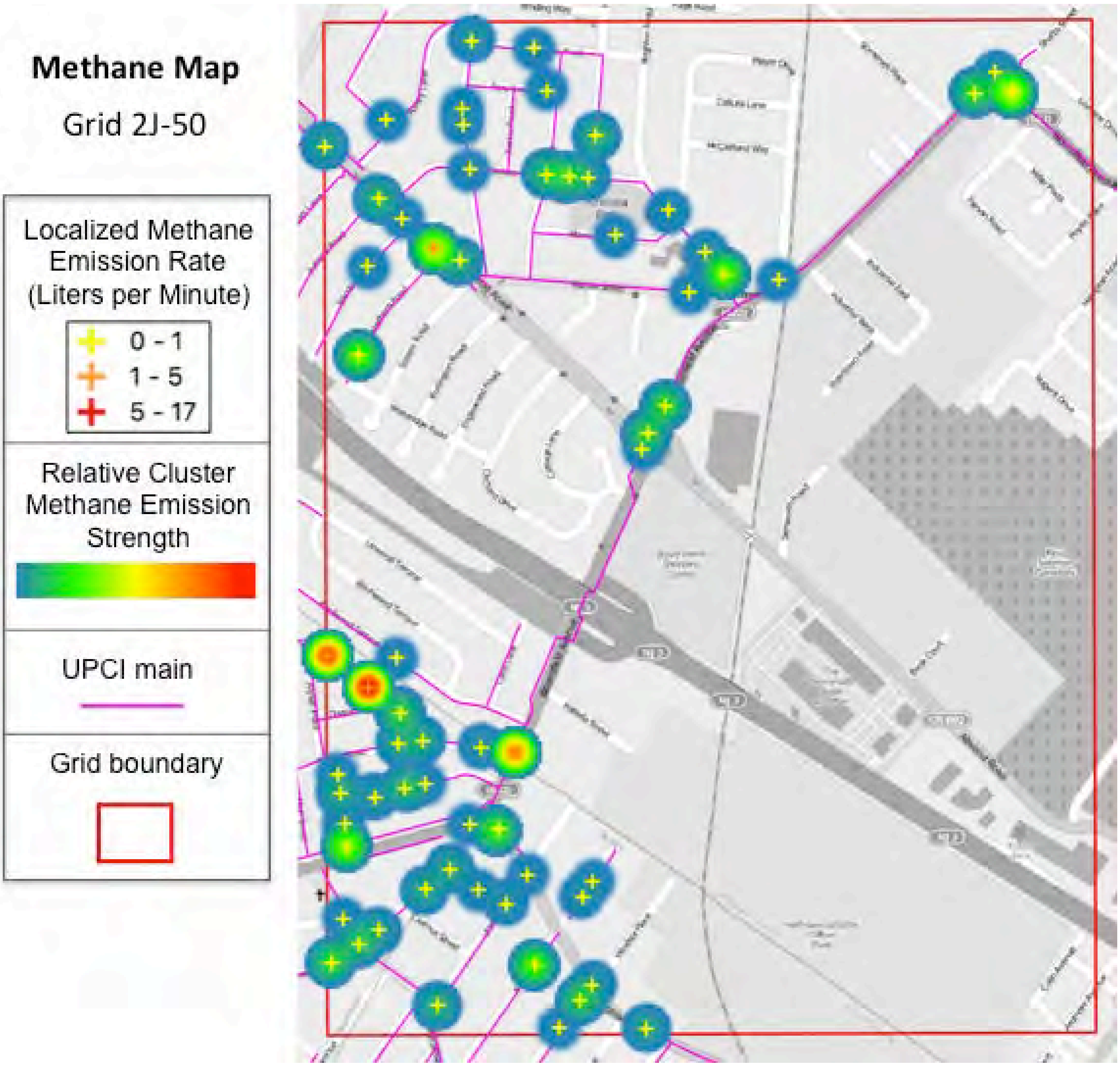
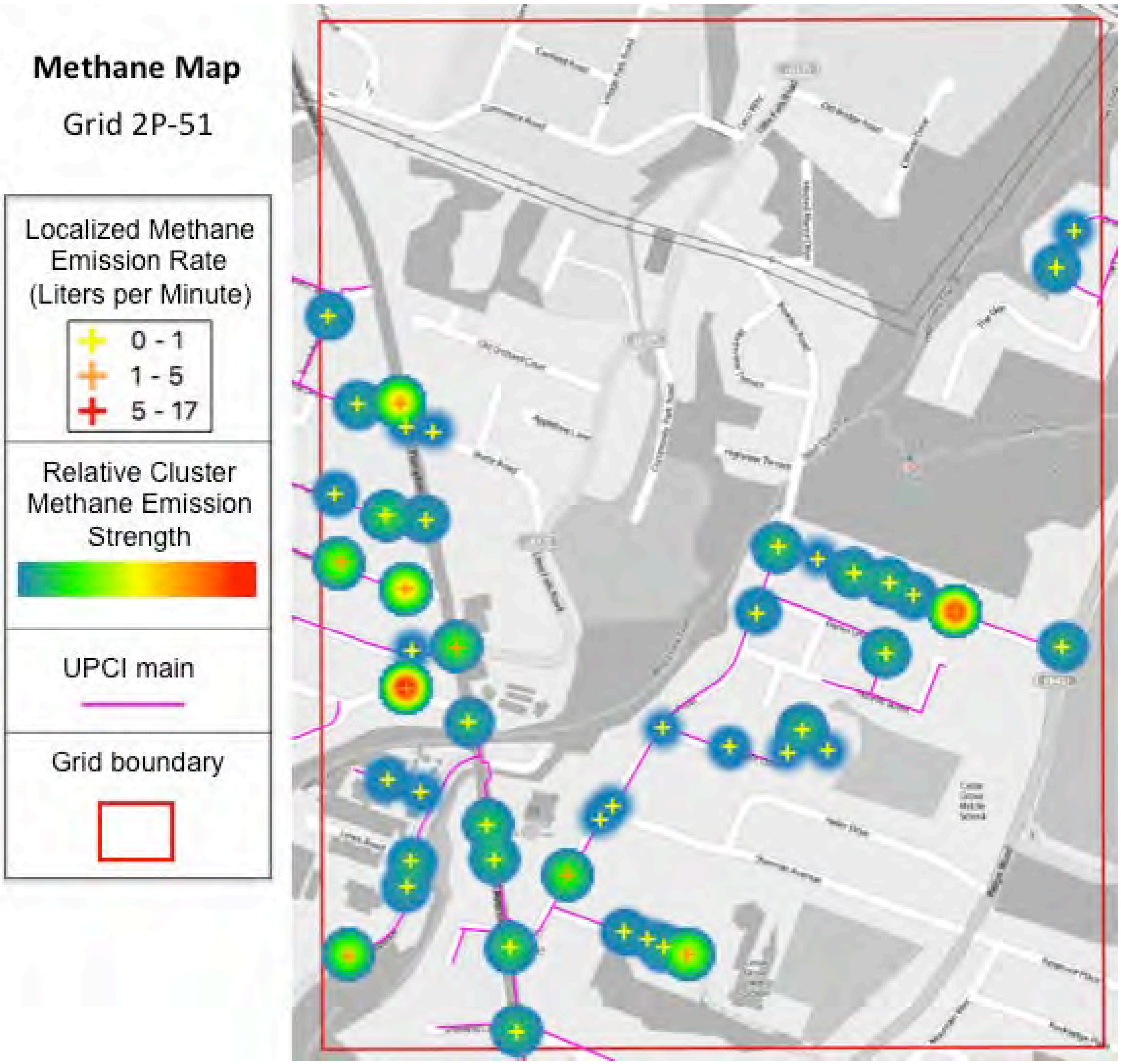

Methane Map
Grid 1Y-49
Localized Methane Emission Rate (Liters per Minute)
0 - 1
1 - 5
5 - 17
Relative Cluster Methane Emission Strength
UPCI main
Grid boundary

PICARRO


Methane Map
Grid 2J-50
Localized Methane Emission Rate (Liters per Minute)
0 - 1
1 - 5
5 - 17
Relative Cluster Methane Emission Strength
UPCI main
Grid boundary


Methane Map
Grid 2P-51
Localized Methane Emission Rate (Liters per Minute)
0 - 1
1 - 5
5 - 17
Relative Cluster Methane Emission Strength
UPCI main
Grid boundary

Methane Map

Grid 2L-52

Localized Methane Emission Rate (Liters per Minute)

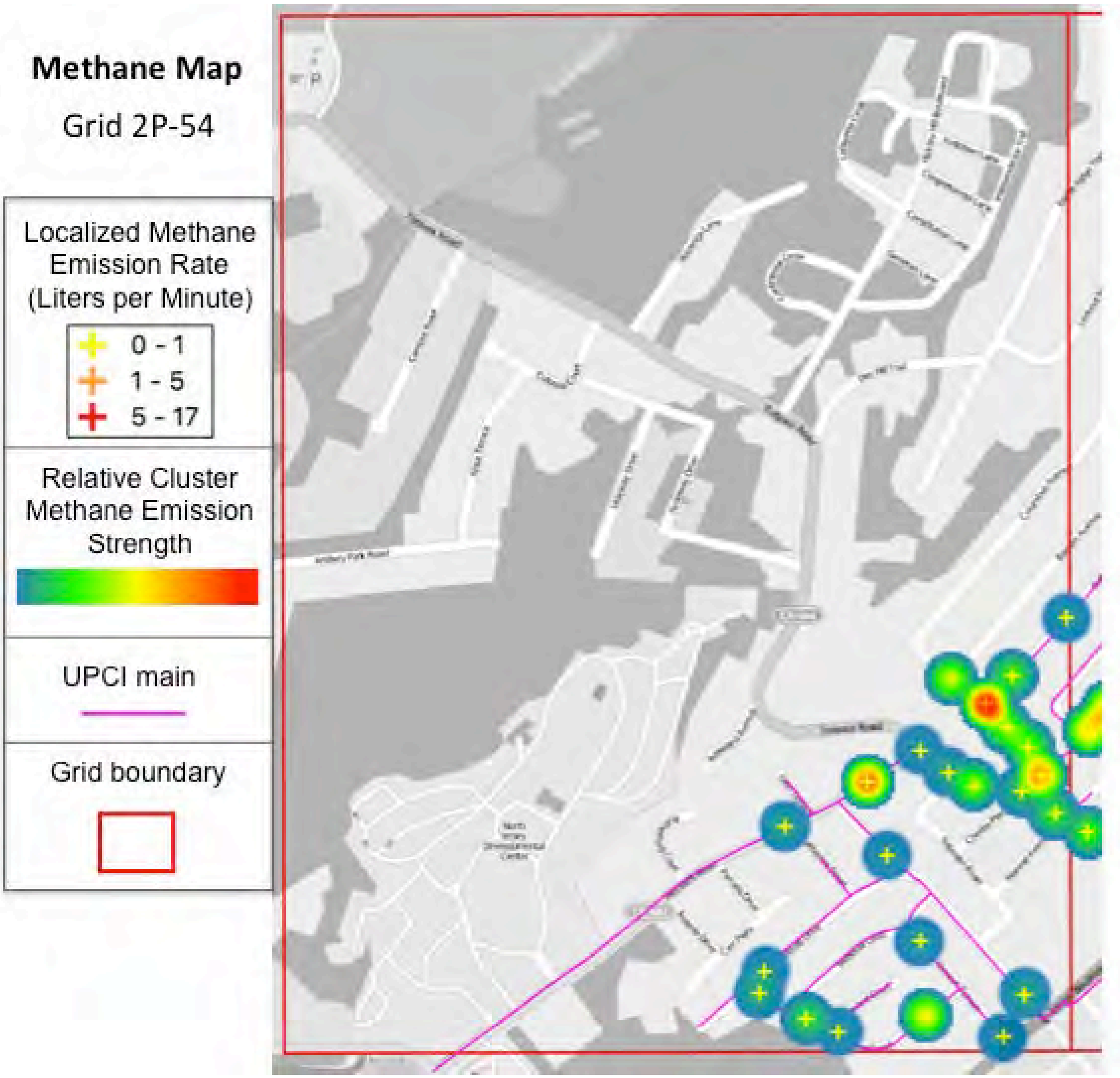
- 0 - 1
- 1 - 5
- 5 - 17

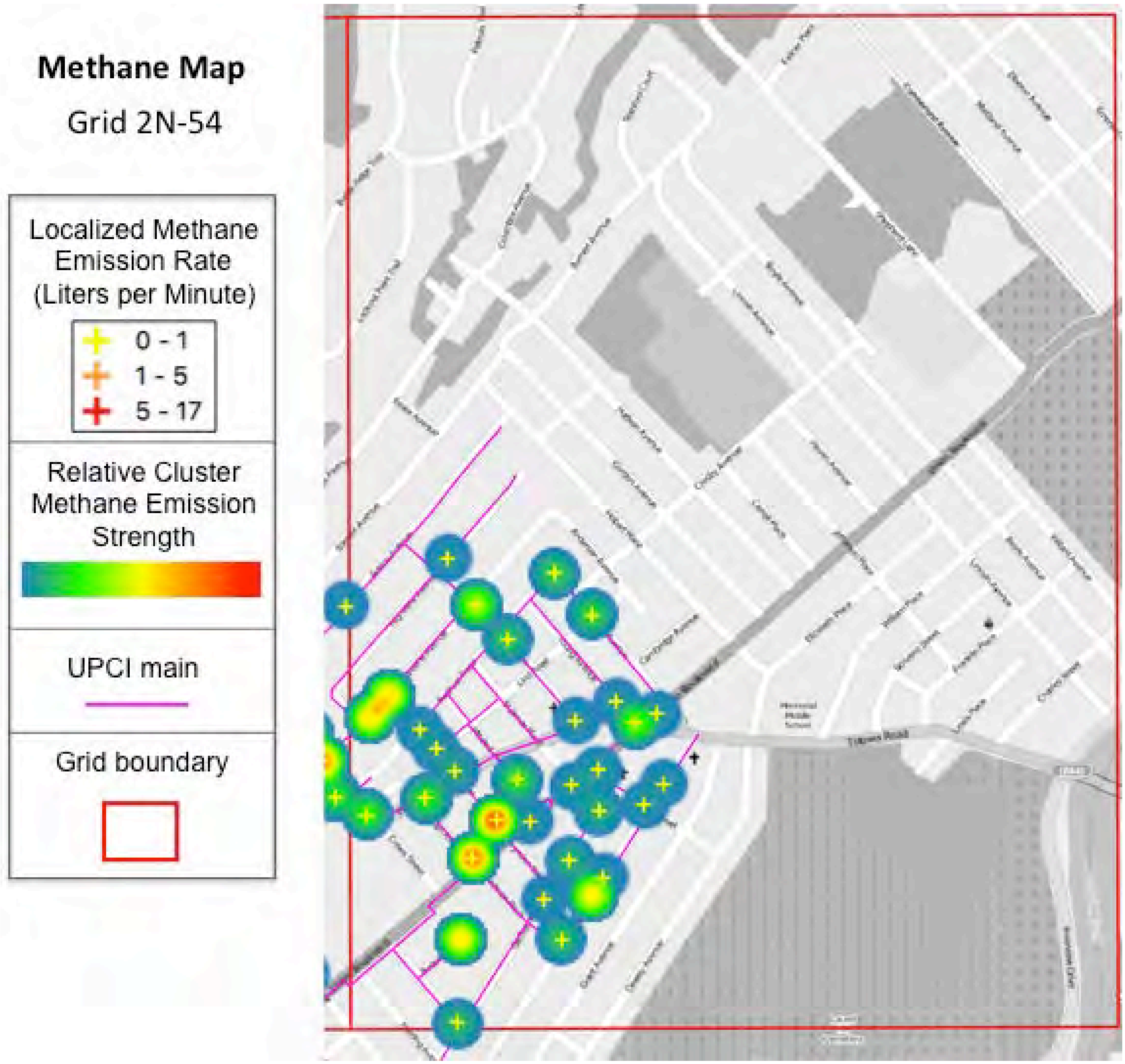
Relative Cluster Methane Emission Strength

UPCI main

Grid boundary

PICARRO


Methane Map
Grid 2P-54
Localized Methane Emission Rate (Liters per Minute)
0 - 1
1 - 5
5 - 17
Relative Cluster Methane Emission Strength
UPCI main
Grid boundary


Methane Map
Grid 2N-54
Localized Methane Emission Rate (Liters per Minute)
0 - 1
1 - 5
5 - 17
Relative Cluster Methane Emission Strength
UPCI main
Grid boundary

PICARRO

Methane Map

Grid 2K-54

Localized Methane Emission Rate (Liters per Minute)

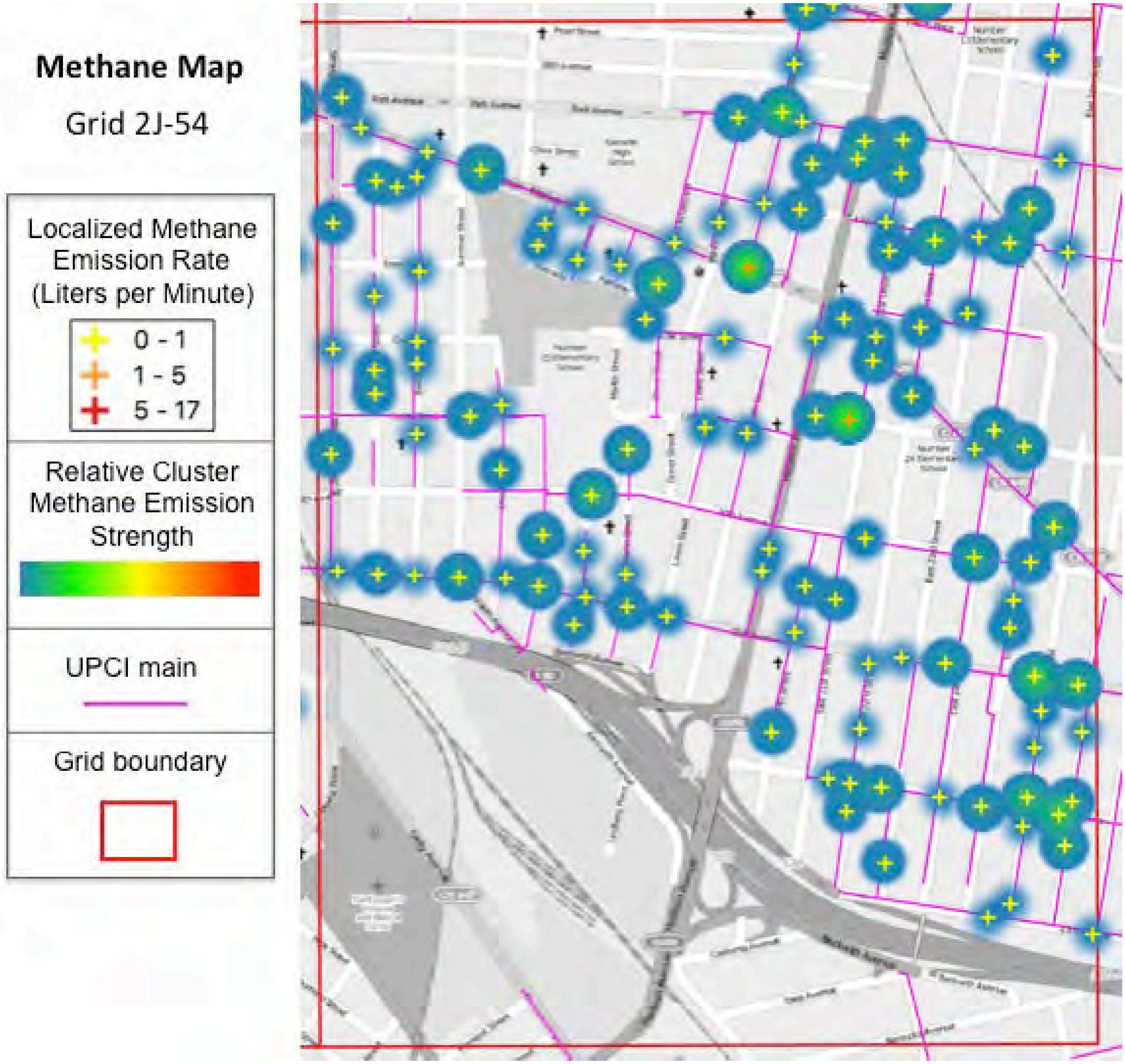
- 0 - 1
- 1 - 5
- 5 - 17

Relative Cluster Methane Emission Strength

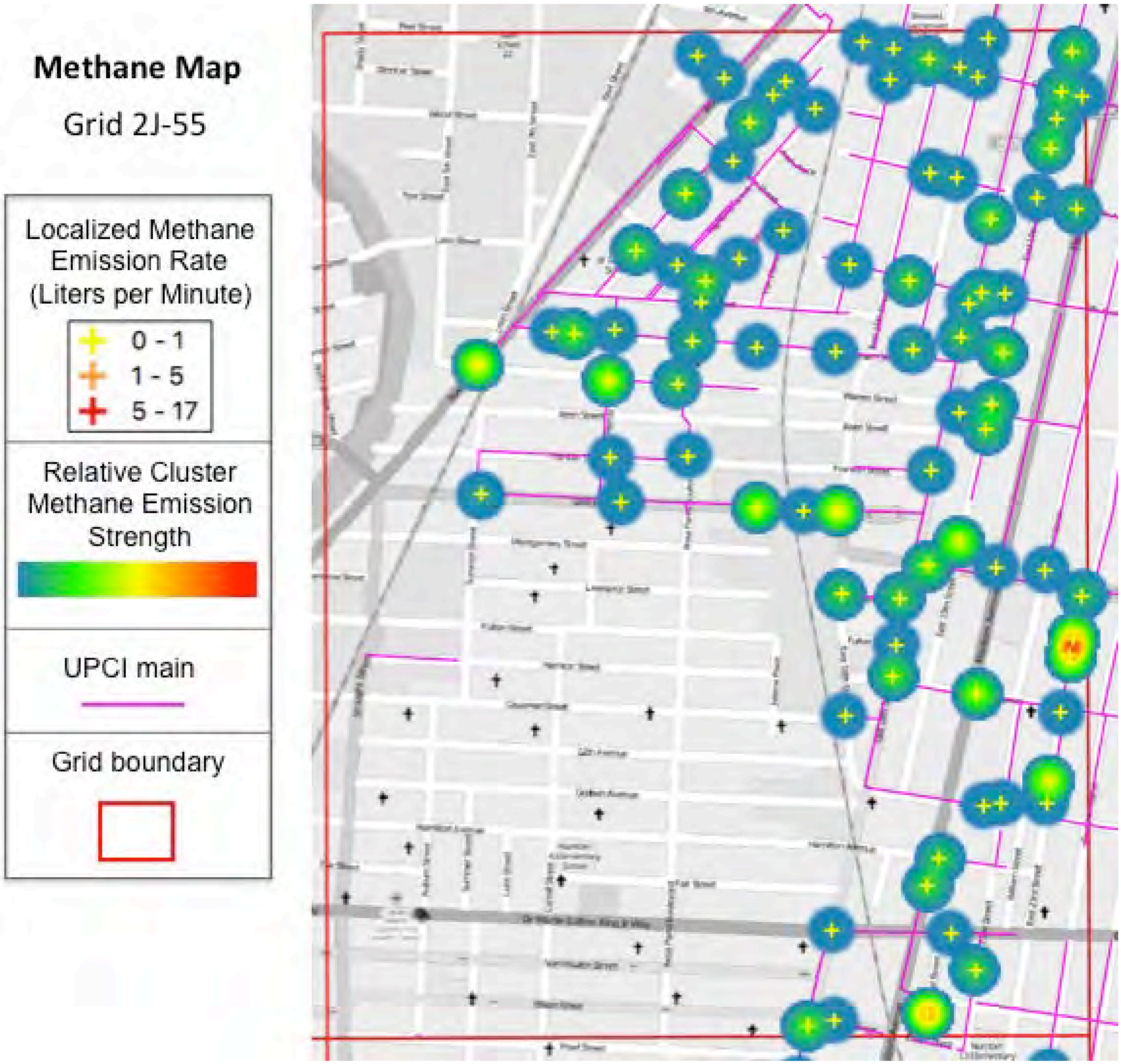
UPCI main

Grid boundary

PICARRO


Methane Map
Grid 2J-54
Localized Methane Emission Rate (Liters per Minute)
0 - 1
1 - 5
5 - 17
Relative Cluster Methane Emission Strength
UPCI main
Grid boundary

PICARRO


Methane Map
Grid 2J-55
Localized Methane Emission Rate (Liters per Minute)
0 - 1
1 - 5
5 - 17
Relative Cluster Methane Emission Strength
UPCI main
Grid boundary

PICARRO

Methane Map

Grid 2F-53

Localized Methane Emission Rate (Liters per Minute) 0 - 1 1 - 5 5 - 17
Relative Cluster Methane Emission Strength
UPCI main
Grid boundary

Methane Map

Grid 1U-51

Localized Methane Emission Rate (Liters per Minute)

- 0 - 1
- 1 - 5
- 5 - 17

Relative Cluster Methane Emission Strength

UPCI main

Grid boundary

PICARRO

Methane Map

Grid 2L-56

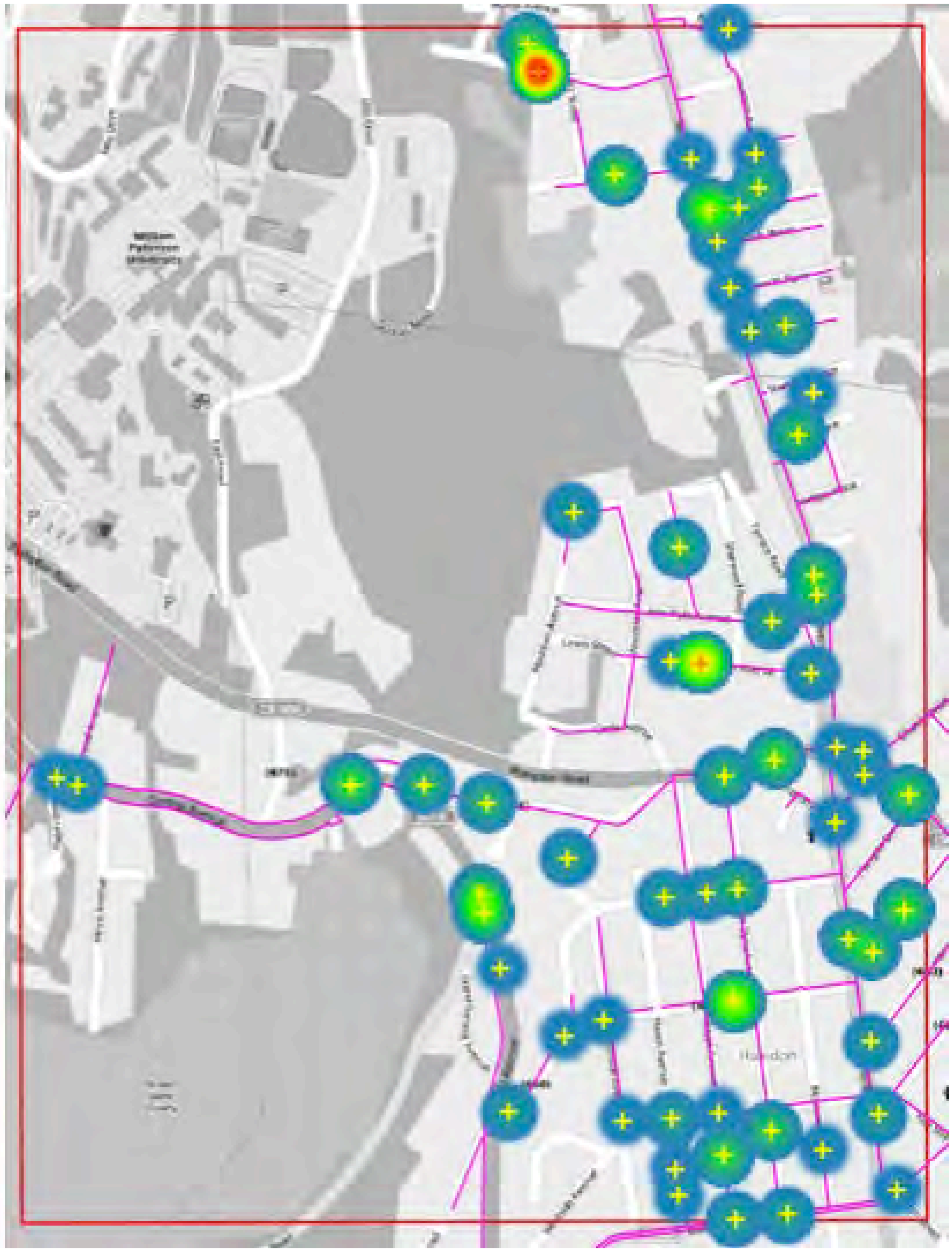
Localized Methane Emission Rate (Liters per Minute)

- 0 - 1
- 1 - 5
- 5 - 17

Relative Cluster Methane Emission Strength

UPCI main

Grid boundary



PICARRO

Methane Map

Grid 2G-57

Localized Methane Emission Rate (Liters per Minute)

- 0 - 1
- 1 - 5
- 5 - 17

Relative Cluster Methane Emission Strength

UPCI main

Grid boundary

Methane Map

Grid 1Z-54

Localized Methane Emission Rate (Liters per Minute)

0 - 1

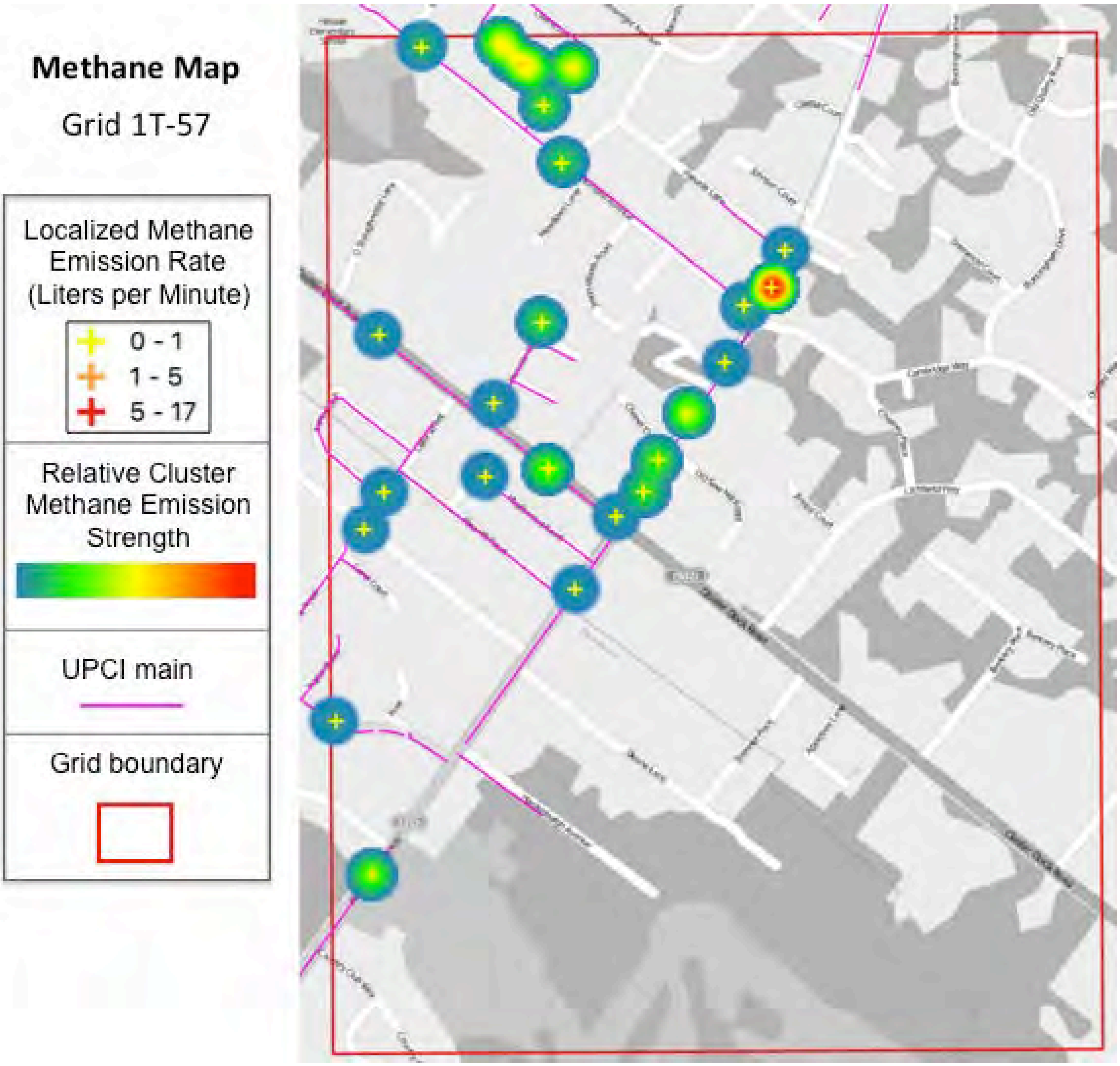
1 - 5

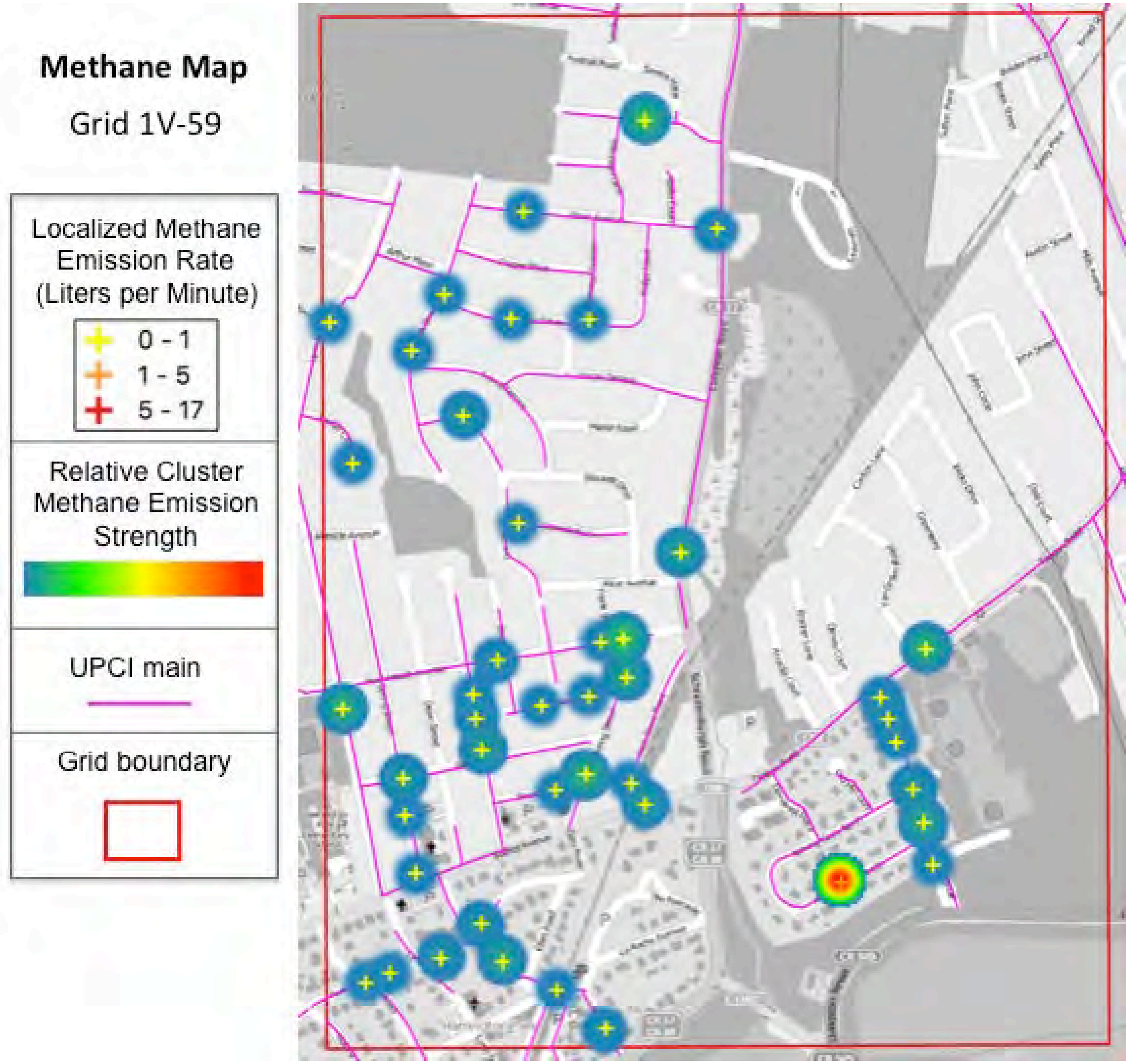
5 - 17

Relative Cluster Methane Emission Strength

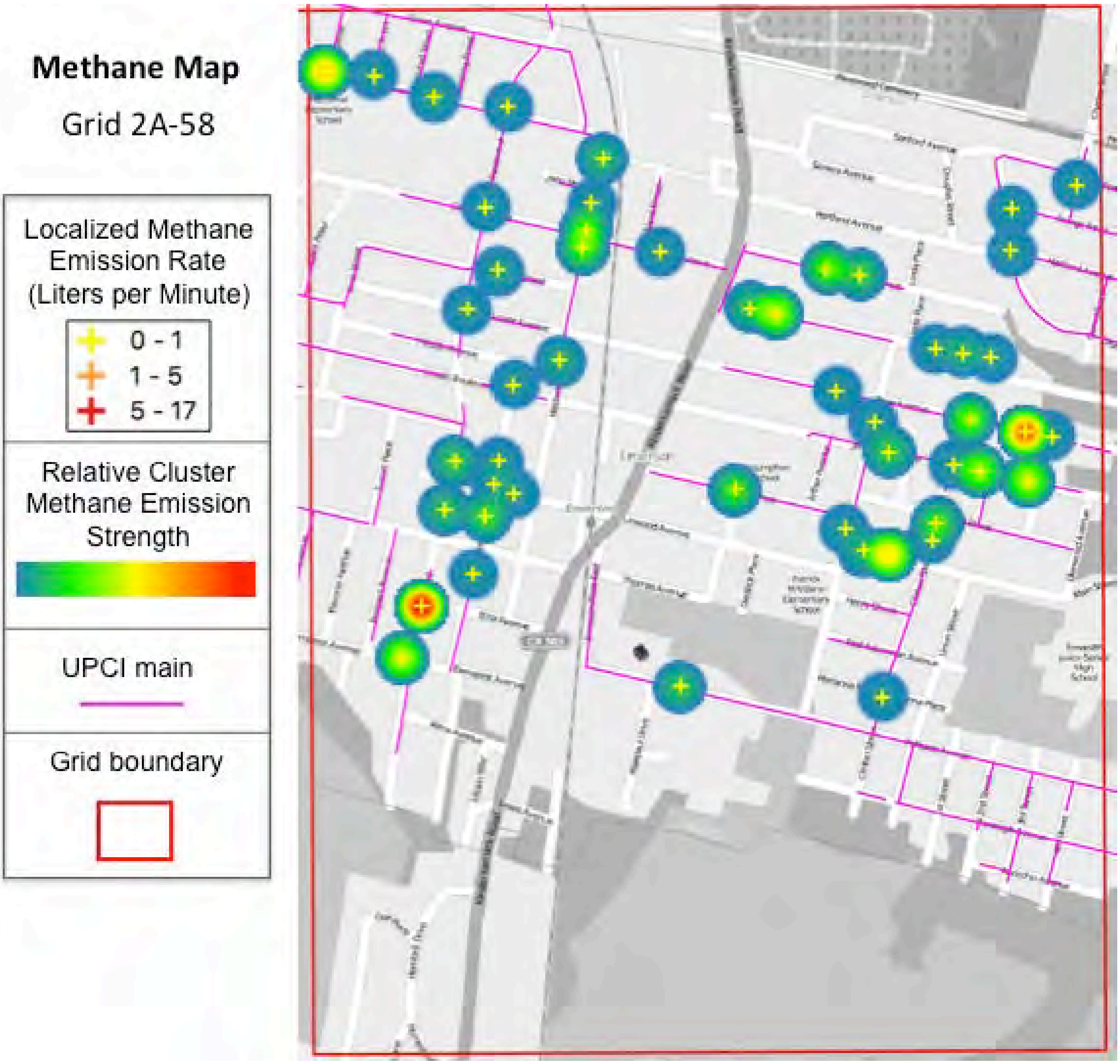
UPCI main

Grid boundary

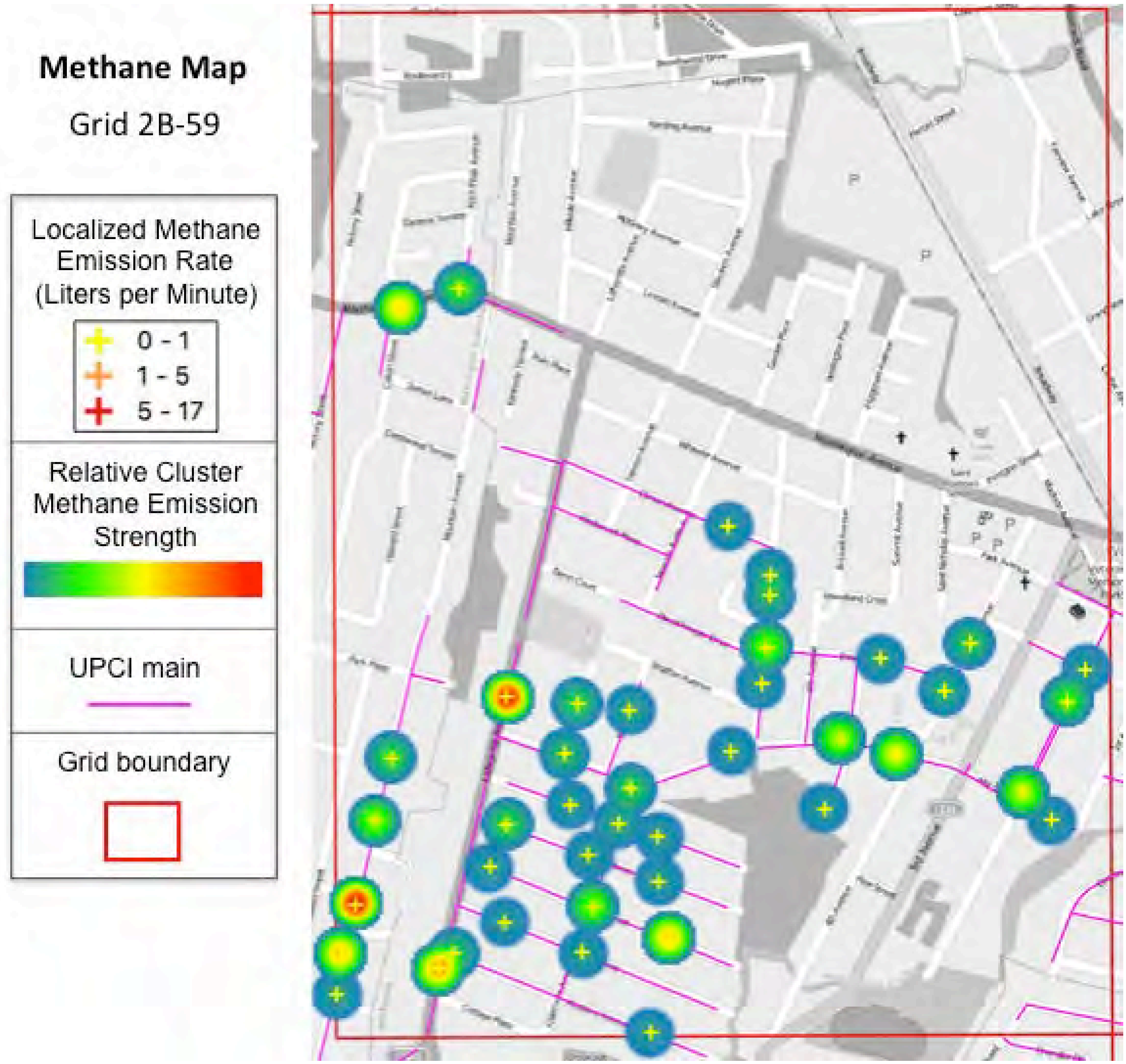

Methane Map
Grid 1T-57
Localized Methane Emission Rate (Liters per Minute)
0 - 1
1 - 5
5 - 17
Relative Cluster Methane Emission Strength
UPCI main
Grid boundary


Methane Map
Grid 1V-59
Localized Methane Emission Rate (Liters per Minute)
0 - 1
1 - 5
5 - 17
Relative Cluster Methane Emission Strength
UPCI main
Grid boundary

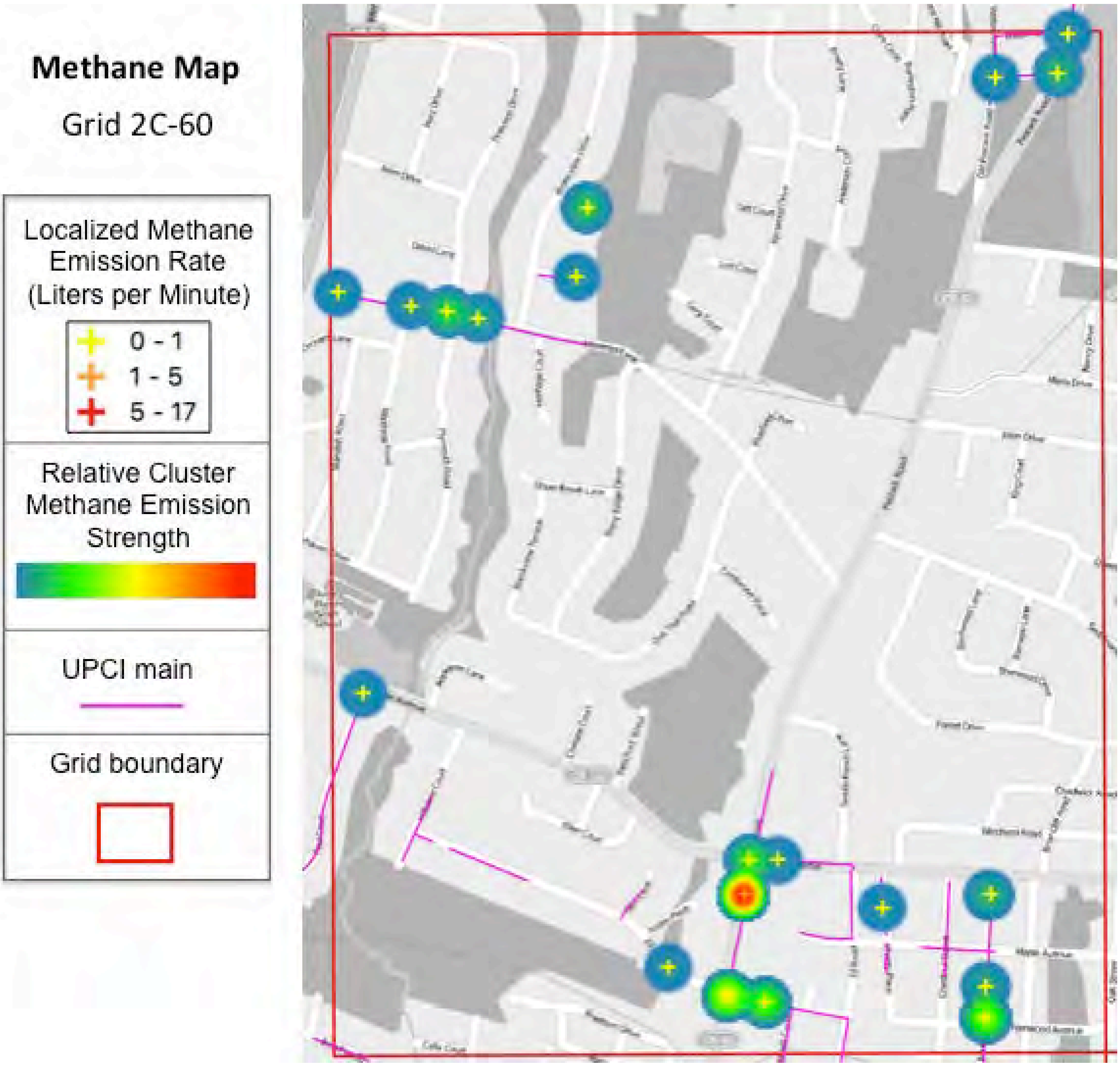
PICARRO


Methane Map
Grid 2A-58
Localized Methane Emission Rate (Liters per Minute)
0 - 1
1 - 5
5 - 17
Relative Cluster Methane Emission Strength
UPCI main
Grid boundary

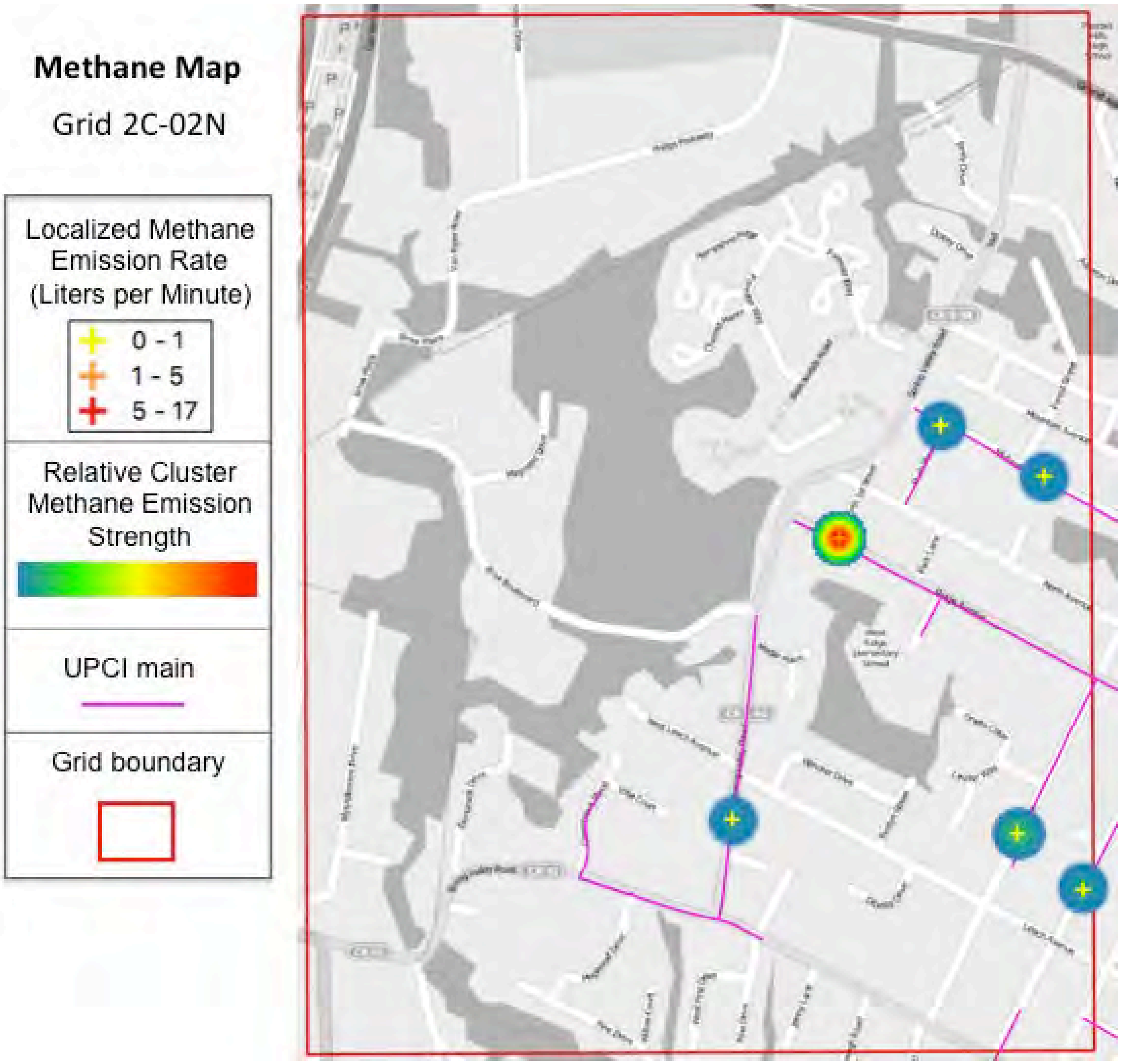
PICARRO


Methane Map
Grid 2B-59
Localized Methane Emission Rate (Liters per Minute)
0 - 1
1 - 5
5 - 17
Relative Cluster Methane Emission Strength
UPCI main
Grid boundary

PICARRO


Methane Map
Grid 2C-60
Localized Methane Emission Rate (Liters per Minute)
0 - 1
1 - 5
5 - 17
Relative Cluster Methane Emission Strength
UPCI main
Grid boundary

PICARRO


Methane Map
Grid 2C-02N
Localized Methane Emission Rate (Liters per Minute)
0 - 1
1 - 5
5 - 17
Relative Cluster Methane Emission Strength
UPCI main
Grid boundary

Methane Map

Grid 2A-02N

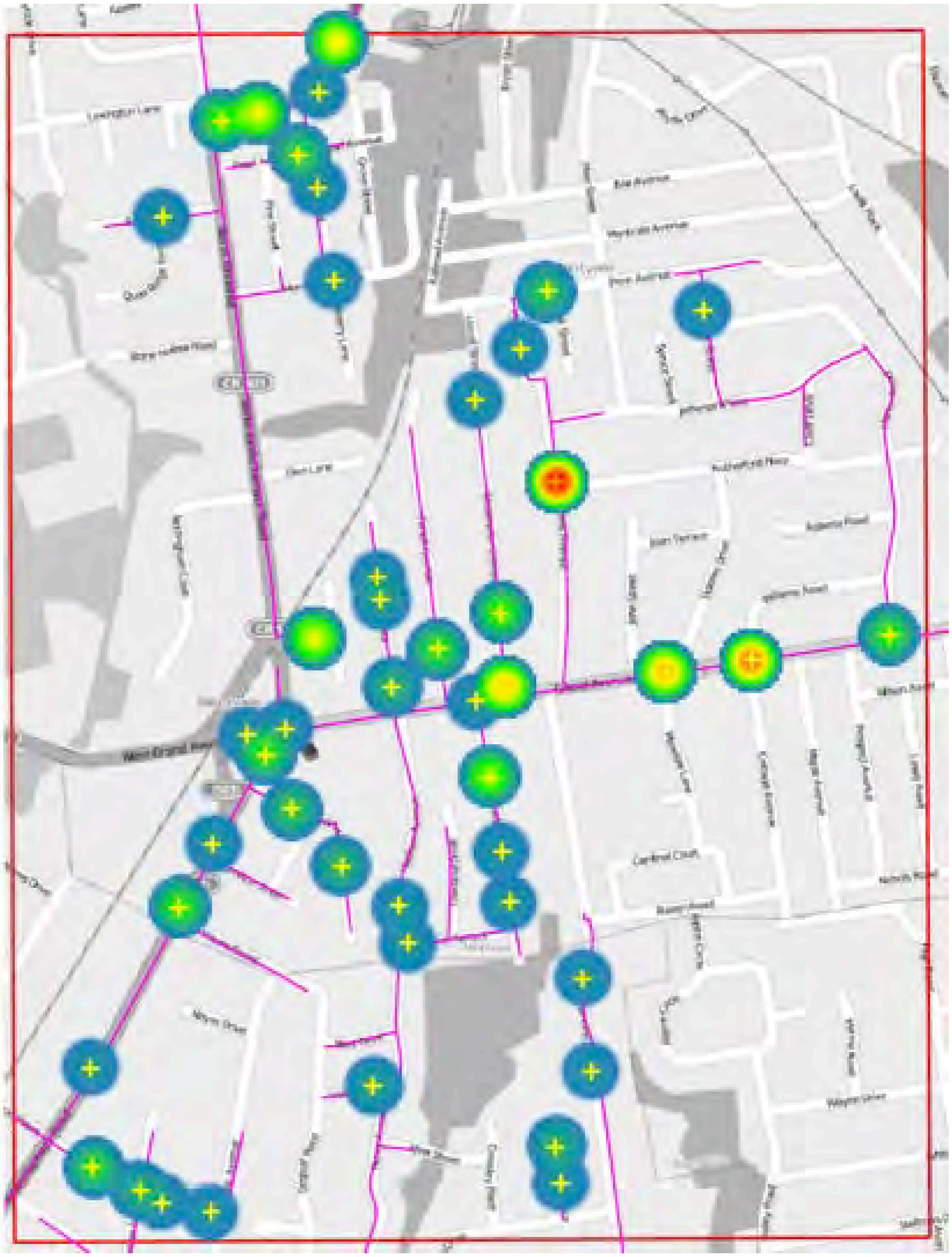
Localized Methane Emission Rate (Liters per Minute)

- 0 - 1
- 1 - 5
- 5 - 17

Relative Cluster Methane Emission Strength

UPCI main

Grid boundary



GSMP II UPCI Grid Ranking

A grid ranking process has been developed based on the Company's Hazard Risk Index Model. The approach is similar to the hazard ranking method used in GSMP I. PSE&G targets the replacement of its riskiest gas assets through the use of a ranking methodology that prioritizes main segments with the highest risk, through the use of the Hazard Index. The Hazard Index is based on a predictive model constructed from leak history "environmental factors" that include: building setback, number of underground utilities, demographic area (urban, suburban, rural), building types (industrial, commercial, or residential), and asset information (pipe diameter, operating pressure). Through the "weighted leak history" factor, past main breaks are considered and weighted based on how recently they occurred. Each map grid is evaluated by adding the hazard indexes for the individual utilization pressure segments within the grid and dividing them by the total miles of utilization pressure cast iron in the grid, arriving at a hazard index per mile for each map grid. Consistent with the hazard index per mile results, grids are ranked by highest to lowest and then placed into A, B, C and D priority grids categories. Grids with a Hazard Score over 15 are treated as the highest priority (A). B grids have a score between 15 and 10, C grids have a score between 10 and 5 and D grids have a score lower than 5.

Per the GSMP II Stipulation, PSE&G retained the services of Picarro to conduct and complete a methane leak survey of approximately 280 miles of UPCI located within the highest ranked B grids during the Fall of 2018. The 280 miles of main correlated to 44 grids that were surveyed. Consistent with the approach for GSMP I, an "Estimated Flow Rate per Mile (Liters/minute/mile)" was determined for each of the surveyed grids. Once the results for the 44 grids were determined, a discussion between PSE&G and the Environmental Defense Fund (EDF) occurred on Dec 4th 2019 to determine a threshold for accelerating the subset of B grids with significant methane emissions. A value of 4.5 L/min/mi was agreed to verbally at this time. Having not received additional feedback from the EDF, PSE&G moved forward with this value to sub-prioritize the surveyed grids. Per the stipulation, these grids were ranked as the highest priority work after the A grids. Planning discussions with municipalities occurred for all grids accelerated by the methane mapping survey. In a few isolated cases, factors like project feasibility, cost and construction efficiency altered the outlined prioritization and has been documented.

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Exhibit EDF(A)-11:

PSE&G Presentation: "Replacement Main Prioritization: A Practical Application of Using Risk and Methane Emissions"

(May 2, 2019)

Replacement Main Prioritization

A Practical Application of Using Risk and Methane Emissions

MAY 2, 2019

WADE MILLER, PE- DIRECTOR OF GAS TRANSMISSION & DISTRIBUTION ENGINEERING
ANDREW ARGESKI, PE- GAS PLANNING & DESIGN MANAGER

We have the energy to make things work ... for you.

PSEG
We make things work for you.

Getting to know PSE&G

- 6th Highest Gas Utility in US sales
- Serves 10 of the top 15 cities in NJ
- ~2,400 employees
- 12 District Headquarters
- 17,955 miles of gas distribution main
- 57 miles of gas transmission main
- 1.2 million gas services
- 1.8 million gas customers
- Sales volume growth: 1% per year

What is the Gas System Modernization Program (GSMP)?

- Accelerated cast iron and unprotected steel main and service replacement program
- Upgrades legacy low (utilization) pressure systems to medium pressure
- Relocates inside meter sets to outside
- Installs excess flow valve (EFV) safety devices
- Supports DOT focus on replacing the highest risk, most leak prone facilities

Continued replacement at these levels would take 25 years to replace/rehabilitate all the cast iron and unprotected steel

Gas System Modernization Program

- PSE&G currently operates and maintains over 4,400 miles of cast iron and unprotected steel gas distribution main.
- The program provides for investment and clause recovery of Utilization Pressure Cast Iron (UPCI) and Unprotected Steel replacement main, services, and associated uprating of plastic and protected steel in targeted areas
  - GSMP I started in 2016 (3 year term - $900M)
  - GSMP II started in 2019 (5 year term – $1.9B)
- Stipulated Base CapEx spend requirement associated with the program approval
  - Includes High Pressure Cast Iron (HPCI), UPCI, unprotected steel main and service replacement
  - Includes program and stipulated base inside meter set relocations
- Total ~170 miles of main replacement per year in Program and Stipulated Base
- The first two approvals are the beginning phases of a long-term 25 year replacement strategy for cast iron and unprotected steel mains
- Benefits:
  - Methane emission reduction is estimated at 30,000 metric tons of CO2 equivalent per year*
  - Medium pressure system allows usage of high efficiency appliances by customers
  - Includes installation of excess flow valve safety devices where applicable

* EPA SUBPART W METHODOLOGY.

GSMP Stipulation

The replacement of mains in the Program shall follow the prioritization based on the grid based Leak Hazard Indices developed by PSE&G using its Hazard Assessment model.

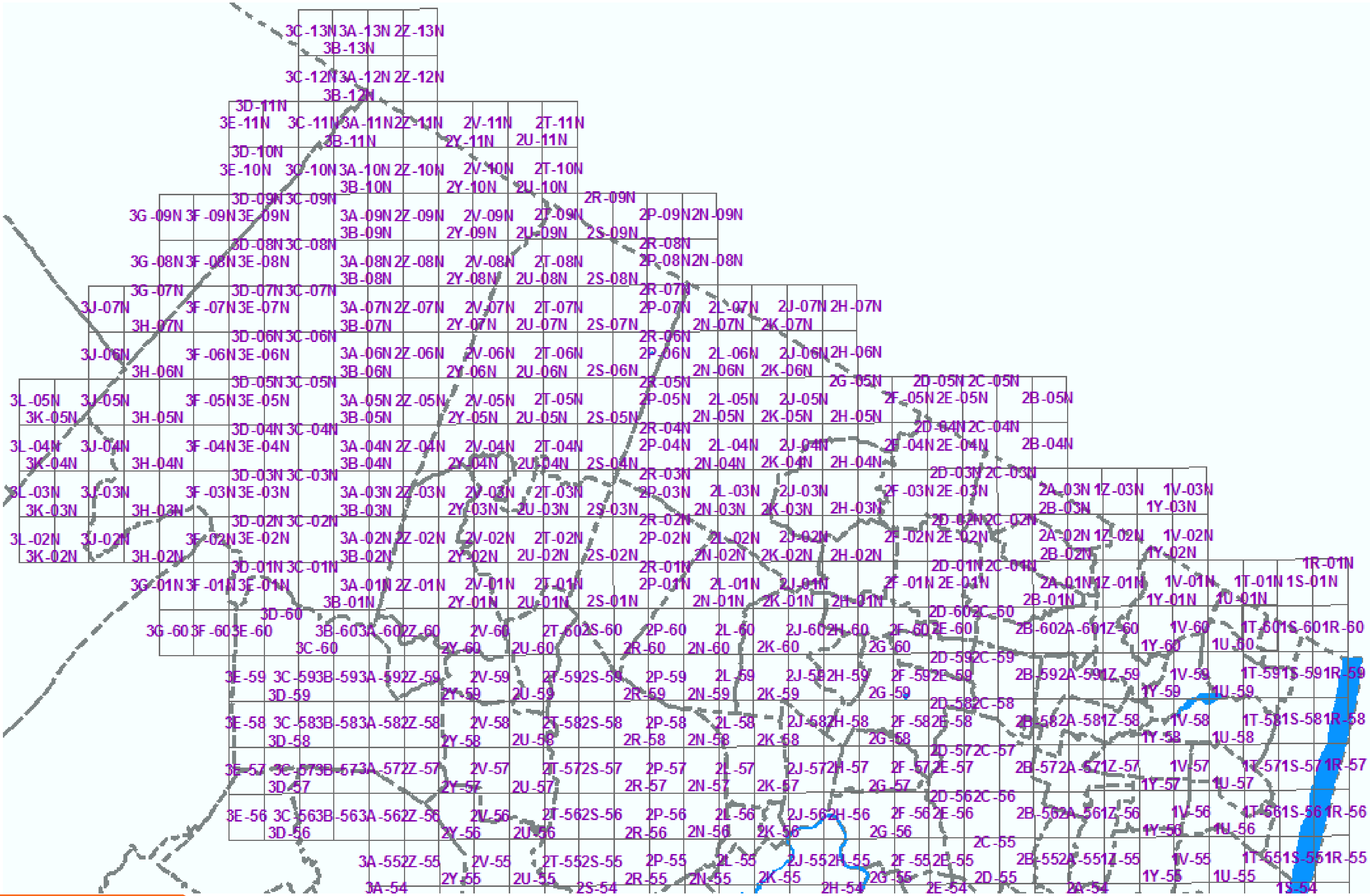
"...Recognizing that considering methane emission flow volume (i.e., emission size) as part of prioritization will reduce the amount of natural gas lost from emissions to the benefit of customers, and reduce the environmental impacts of such emissions, the Signatories agree that for grids with comparable Hazard Index/Mile, available methane emissions survey data estimating flow volumes, as prepared by the Environmental Defense Fund using Program plans, system information and maps provided by PSE&G, will be used, as appropriate, in sub-prioritizing replacement activities…"

Accelerated UP Cast Iron (UPCI) Replacement

- Goal - Replace priority areas most efficiently
  - Highest potential hazard
  - Contiguous area for construction efficiency

- Map grid system utilized
  - 1 square mile area
  - 1 – 20 miles of low pressure cast iron per grid
  - Similar environmental conditions

PSE&G Grid Mapping System



Prioritization of UPCI Replacement Main

- Hazard Index (HI) rankings used to express and compare relative hazard for main segments having a history of breaks.

- Factors used in the calculation
  - Hazard Index = Weighted Break History (WBH) x Environmental Index (E)

  - WBH = The sum of the factors multiplied by the number of annual break repairs for each period (factors higher for recent breaks)

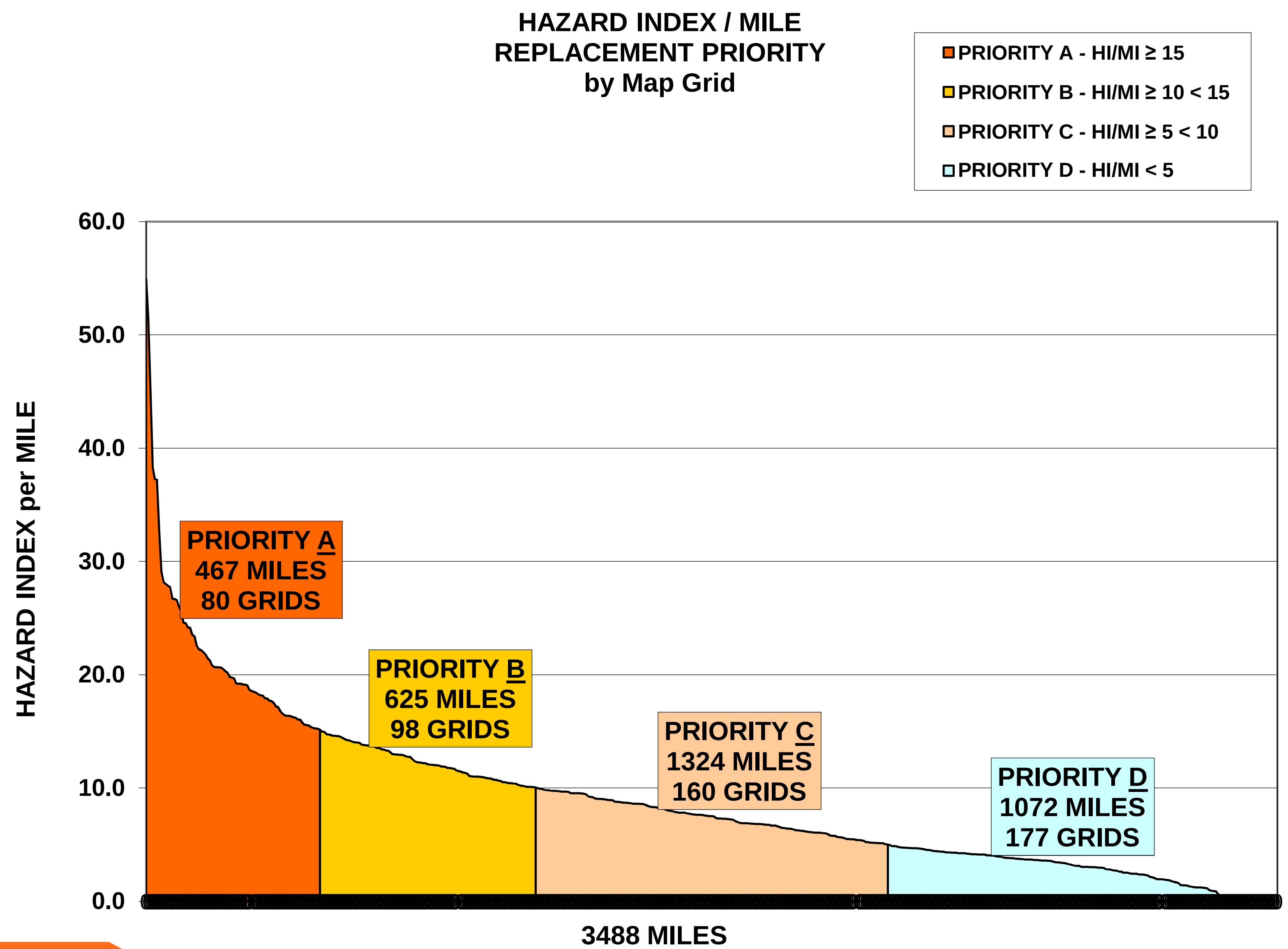
  - Environmental Index evaluates the environmental conditions at the main segment location that may affect the relative hazard of a break and is based upon the following factors
    - Building Density
    - Operating Pressure
    - Building Occupancy
    - Underground Utility
    - Building Set-back
    - Nominal Pipe Size

- Mileage is based upon total low pressure cast iron mileage in grid

Prioritization of UPCI Replacement Main (cont'd)

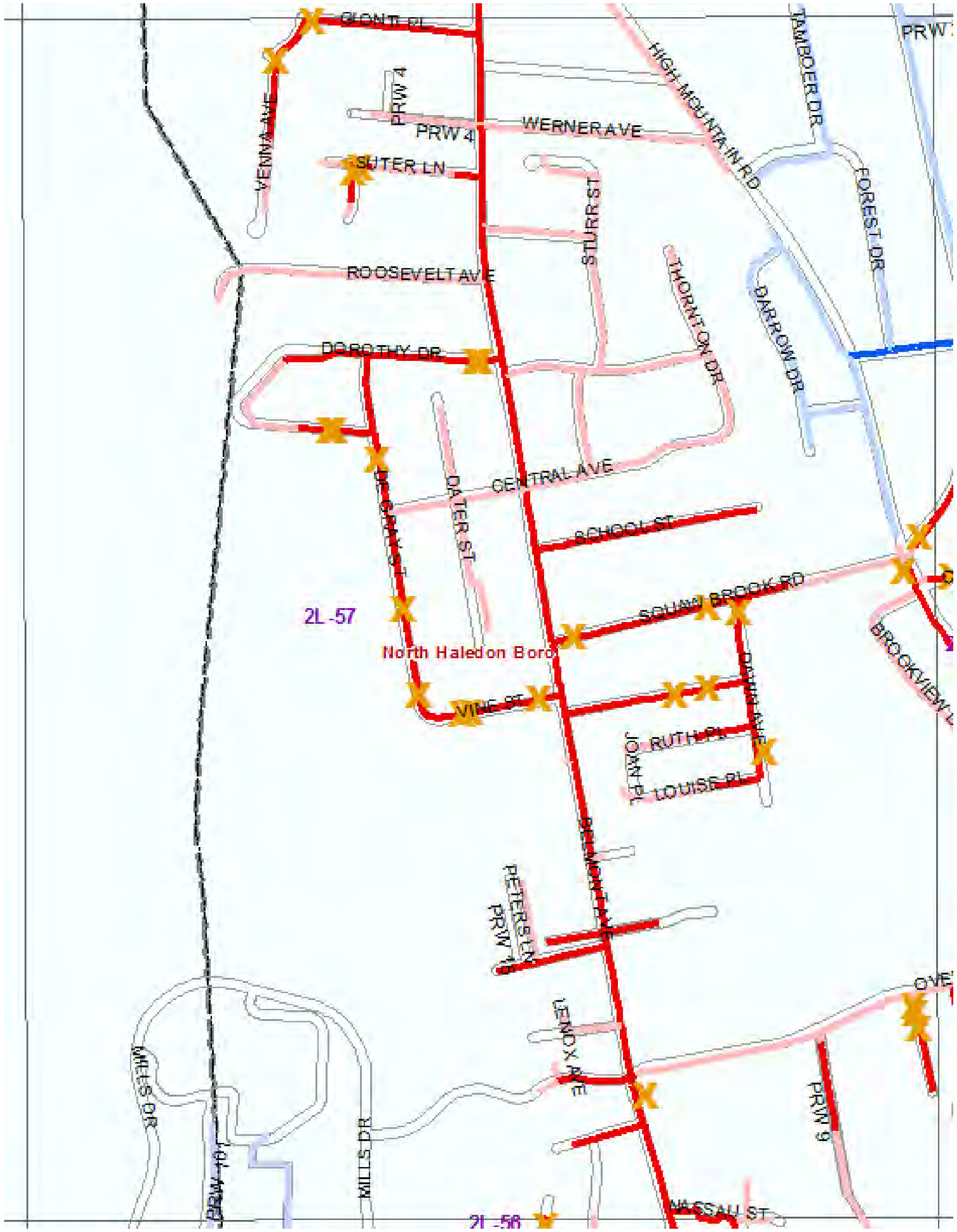
- Mains with break history - Hazard Index
- Individual segments within a grid are summed to obtain total hazard index for the grid
- Miles of UPCI main in grid are summed
- Hazard score divided by miles gives HI/Mi score
- Map Grids ranked by HI/Mi

GSMP I - UP Cast Iron Main Prioritization



Grid 2L-57 (Rank 2)
UP CI = 3.8 miles
HI/MI = 45.4

- UP Cast Iron
- EP Cast Iron
- UP Plastic and Steel
- EP Plastic and Steel
- Regulator
- CI Break



Hazard Index – Grid 2L - 57

District	Street	Municipality	Install Year	Main Size	Main Type	Pressure	Segment Length	B	P	O	U	S	Last Repair Date	Number of Breaks	WBH	BPOU/S	Env Index E	Hazard Index	Wall Map Grid
DGOK	VINE ST	Haledon Boro	1900	6	CI	UP	700	4	1	4	2	1.5	1/8/2014	3	12	21	2.3012	27.615	2L-57
DGOK	DE ROON AVE	Haledon Boro	1900	4	CI	UP	458	8	1	4	3	1	4/4/2012	3	9	96	3.0307	27.2765	2L-57
DGOK	MORNINGSIDE AVE	North Haledon Boro	1953	4	CI	UP	929	8	1	4	3	1	1/28/2013	2	8	96	3.0307	24.2458	2L-57
DGOK	BELMONT AVE	North Haledon Boro	1927	8	CI	UP	460	8	1	15	4	1	11/6/2013	1	5	480	4.5596	22.7982	2L-57
DGOK	DE GRAY ST	Haledon Boro	1955	6	CI	UP	1037	4	1	4	3	1.5	2/14/2013	2	7	32	2.5705	17.9933	2L-57
DGOK	DAWN AVE	Haledon Boro	1951	6	CI	UP	426	8	1	4	3	1	1/14/2011	1	3	96	3.3	9.8999	2L-57
DGOK	GIONTI PL	North Haledon Boro	1928	6	CI	UP	885	4	1	4	2	3	2/11/2014	1	5	11	1.841	9.205	2L-57
DGOK	SQUAW BROOK RD	North Haledon Boro	1937	6	CI	UP	962	4	1	4	3	1	1/12/2009	2	2	48	2.8397	5.6794	2L-57
DGOK	MEADOW PL	North Haledon Boro	1954	4	CI	UP	187	4	1	4	4	1	2/22/2010	1	2	64	2.7615	5.523	2L-57
DGOK	DOROTHY DR	North Haledon Boro	1964	4	CI	UP	276	4	1	4	3	1	3/25/1999	2	2	48	2.5705	5.141	2L-57
DGOK	HIGH MOUNTAIN RD	North Haledon Boro	1900	8	CI	UP	109	2	1	4	3	1.5	12/30/2010	1	2	16	2.3012	4.6025	2L-57
DGOK	SUTER LN	North Haledon Boro	1954	4	CI	UP	93	4	1	4	1	1.5	2/20/2010	1	2	11	1.5718	3.1435	2L-57
DGOK	DAWN AVE	North Haledon Boro	1951	6	CI	UP	267	4	1	4	3	1	12/8/2003	1	1	48	2.8397	2.8397	2L-57
DGOK	DOROTHY DR	North Haledon Boro	1957	6	CI	UP	682	2	1	4	2	3	1/8/2001	2	2	5	1.3807	2.7615	2L-57
DGOK	VENNA AVE	Haledon Boro	1929	6	CI	UP	325	2	1	4	2	3	2/2/2009	1	1	5	1.3807	1.3807	2L-57
																Total Hazard Score		170.1051	
																Total CI Miles in Grid		3.75	
																Hazard Index Per Mile		45.36	

Top 20 Hazard Index/Mile

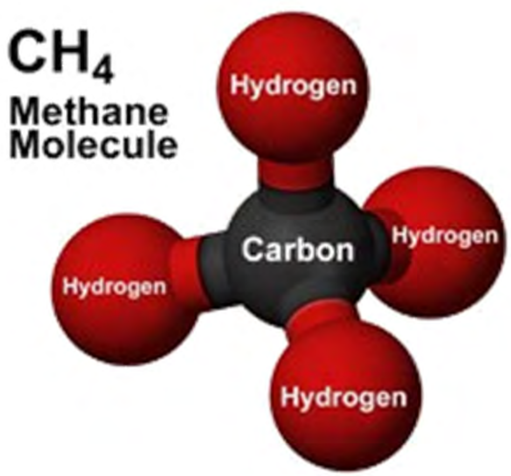
UPCI GRID	UPCI MILES	2014 HAZARD INDEX	HAZARD INDEX/MILE	HI/MILE RANK
2A-48	1.0	55.0970	54.9	1
2L-57	3.7	170.2419	45.4	2
2K-45	5.0	185.4933	37.3	3
2Z-41	1.2	43.9937	37.2	4
2K-44	3.0	109.7977	36.7	5
2B-46	2.9	103.7972	36.2	6
2K-55	11.1	360.4543	32.5	7
2J-51	10.1	294.1113	29.1	8
2D-58	3.1	87.5603	28.2	9
2A-45	2.4	66.1032	28.0	10
2K-57	4.1	115.1842	27.9	11
2L-58	1.7	48.0314	27.7	12
3D-46	2.1	55.6910	26.6	13
3J-50	1.4	37.6969	26.0	14
1Z-47	7.7	200.3936	25.9	15
3C-25	1.4	35.9431	25.6	16
2H-50	6.6	162.3633	24.8	17
2L-51	8.1	194.9827	24.2	18
2H-45	3.6	87.6968	24.2	19
2L-43	7.1	167.2065	23.6	20

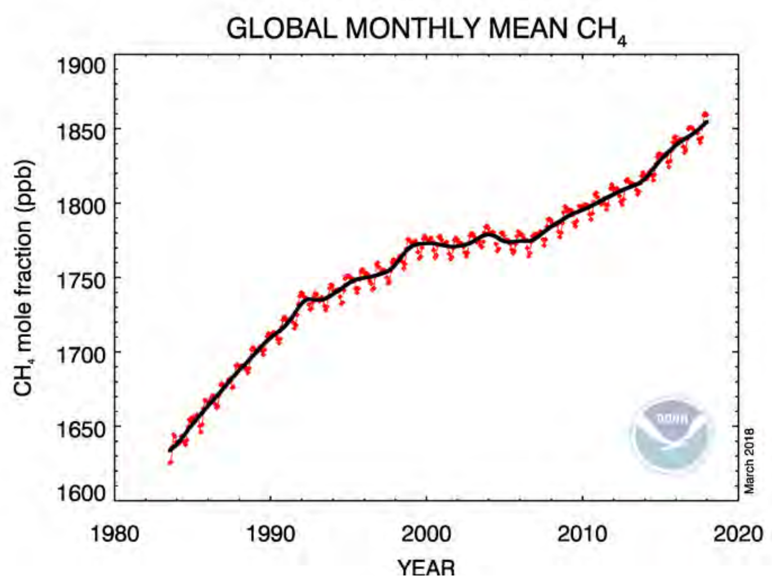
Methane as a Greenhouse Gas

- Methane has 84 times the warming effect of carbon dioxide over a 20 year period
- EDF estimates that about 25% of the manmade global warming we're experiencing today is caused by methane emissions

Typical Composition of Natural Gas

Methane	CH_4	70-90%
Ethane	C_2H_6	0-20%
Propane	C_3H_8	
Butane	C_4H_{10}	
Carbon Dioxide	CO_2	0-8%
Oxygen	O_2	0-0.2%
Nitrogen	N_2	0-5%
Hydrogen sulphide	H_2S	0-5%
Rare gases	A, He, Ne, Xe	trace





Working with the EDF

- In advance of GSMP I, PSE&G engaged the Environmental Defense Fund (EDF) to quantify methane emissions in our service territory to consider in the prioritization of the work
- Mapping was performed over a six month period
- Study was done at no cost to PSE&G
- PSE&G followed the EDF equipment with its own optical methane leakmobile to compare data

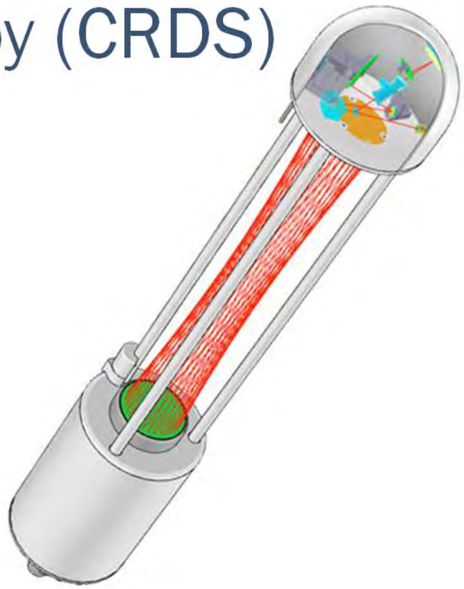
EDF
ENVIRONMENTAL DEFENSE FUND®
Finding the ways that work

EDF Overview - Continued

- The EDF partnered with Google and Colorado State University on a nationwide program to detect and map methane leaks from natural gas distribution systems
- A Google street-view car, equipped with state of the art methane and meteorological sensors, was driven repeatedly along streets with natural gas pipelines to map emissions
- Urban areas have been mapped across the country (Birmingham, Boston, Burlington, Chicago, Dallas, Indianapolis, Jacksonville, Los Angeles, Mesa, Pittsburgh, Staten Island, and Syracuse)
- The same technology used to map these cities was also used for the PSE&G project

What Technology Was Used?

- Advanced GPS technology and anemometer
- Open path, Cavity Ring-Down Spectroscopy (CRDS) LiCor analyzer



- High data collection rate
- No pumps (closed path CRDS)
- The longer the laser path, the better the sensitivity in detecting molecular signatures
- Equipment uses a series of mirrors within the sample cavity to reflect the laser path from a distance of 25 cm to over 20 km

Methane Quantification Data

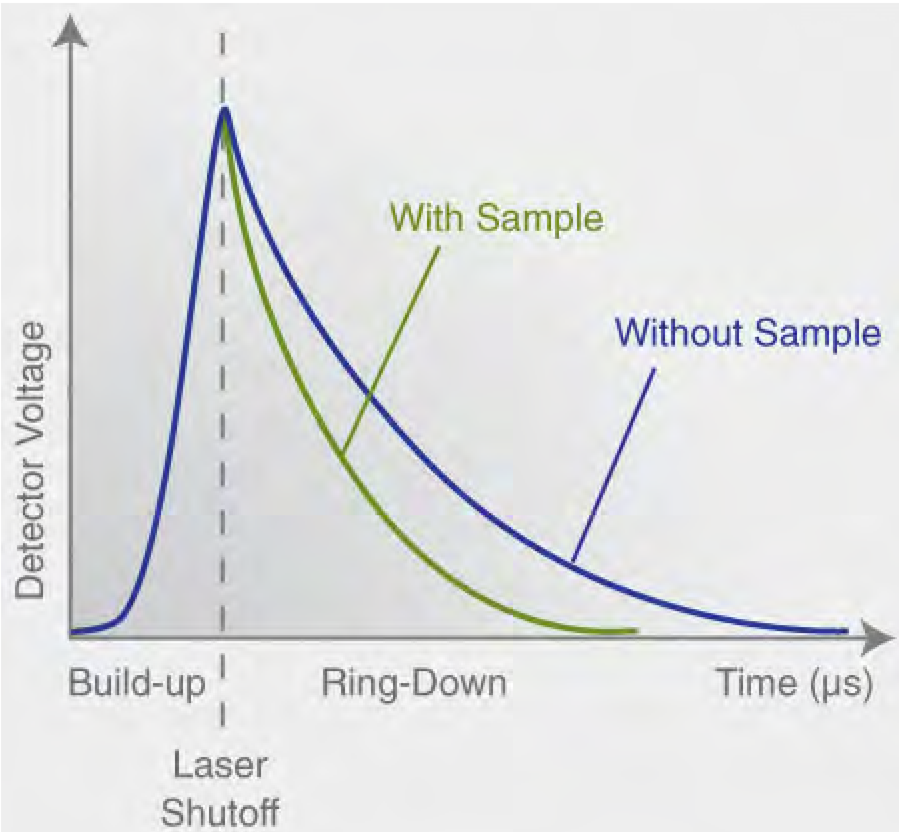


Fig 1. Ring Down Graph. Adapted from Picarro. Retrieved from Picarro.com

- Different gases absorb light (laser) at specific rates
- Normal atmospheric air has a certain decay pattern as the laser fades inside the sample chamber (blue graph)
- When a gas like methane is in the sample, it absorbs light at a different decay rate than the control (green graph)
- The laser wavelength and difference in decay rates is used to quantify methane by analyzing the sample data stream through a series of algorithms
- Wind and precipitation are factors in sampling

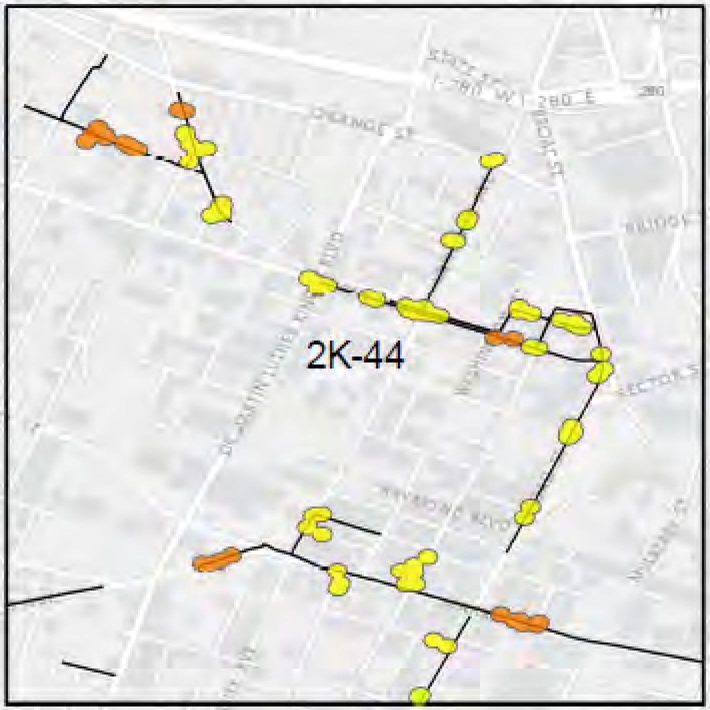
Readings vs Indications

Overlap of UPCI Pipes and Observed Data from EDF Methane Mapping

New Jersey: Observed Readings

Clusters of readings that contribute to one verified leak of the following size:

- 700 to 9,000 liters/day
- 9,000 to 60,000 liters/day
- More than 60,000 liters/day
- PSEG UPCI Pipes
- PSEG Map Grid

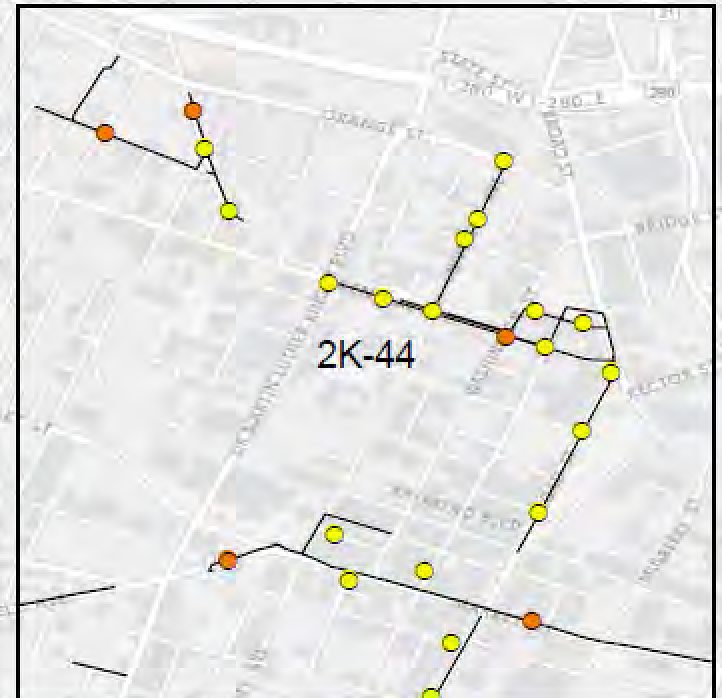


Overlap of UPCI Pipes and Verified Leaks from EDF Methane Mapping

New Jersey: Verified Leaks

- 700 to 9,000 liters/day
- 9,000 to 60,000 liters/day
- More than 60,000 liters/day
- PSEG UPCI Pipes
- PSEG Map Grid

Estimated Total Flow Rate: 119 (+/- 15*) L/min
Number of Verified Leaks: 24
Miles of UPCI: 3.4 miles
Flow Rate/Mile UPCI: 34.8 (+/- 4.3*) L/min/mile
Rank:4
*** Represents 95% confidence of true leak rate**



These maps only show readings that potentially overlap with utility UPCI pipes. Other recorded EDF data is not represented.

0 500 1,000 2,000 Feet

PSEG

Using the Results in GSMP I

- Hazard Index per Mile (HI/Mi) still primary risk ranking tool
- Any grid with HI/Mi > 25 is highest priority
- Where HI/Mi is comparable (< 25), EDF data used to help **sub-prioritize** by leak rate of liters per minute per mile of UPCI pipe in the grid (L/Min/Mi)
    - Grids with outlying leak rates of >10 L/Min/Mi take highest priority
    - Grids with leak rates of <10 L/Min/Mi as well as non-surveyed grids take secondary priority
- Grids are evaluated for construction efficiencies and logistics as well as permitting and municipality conflicts prior to setting the final prioritization
- Results reviewed with EDF and submitted to the NJ Board of Public Utilities

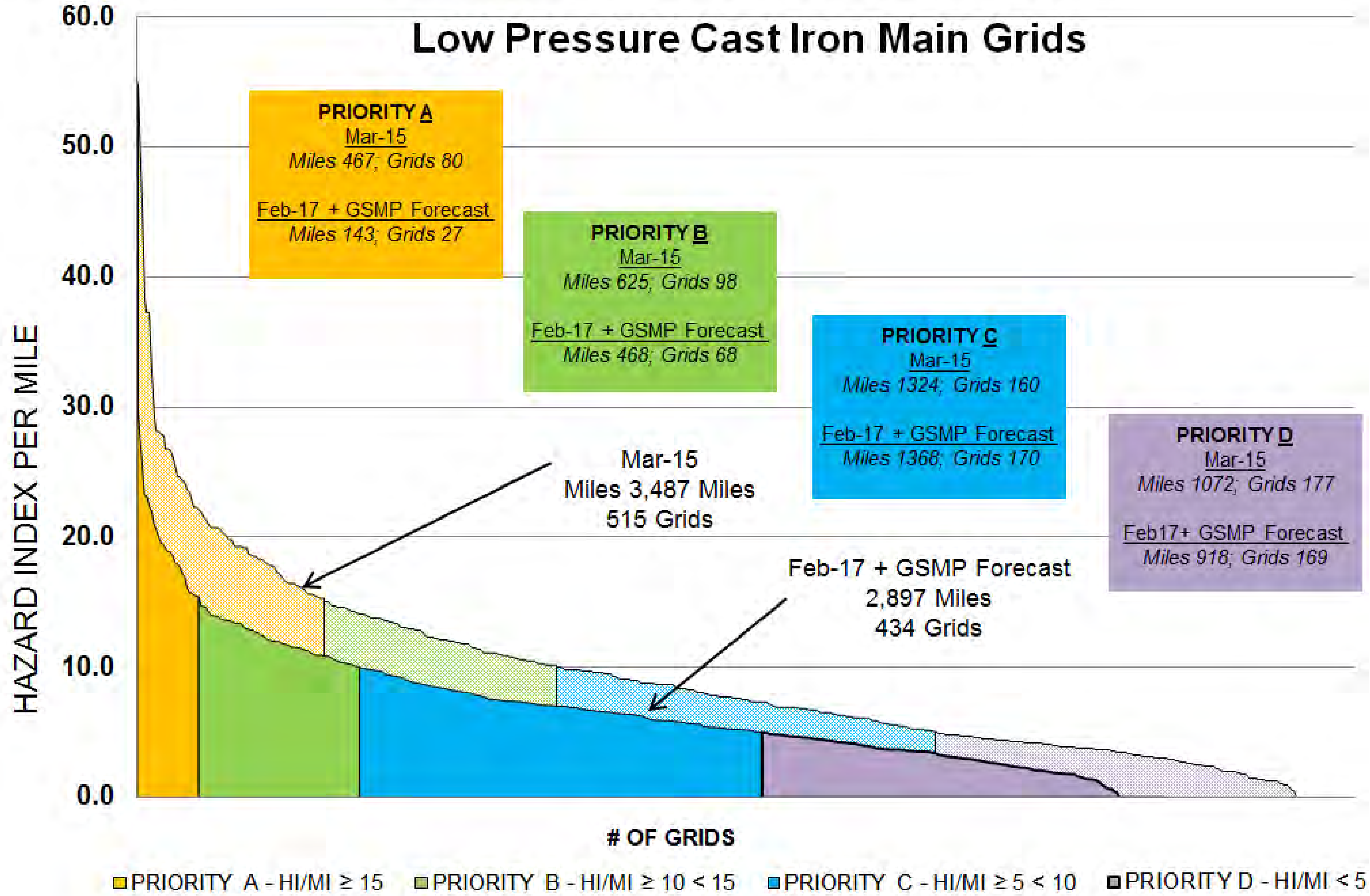
Reduction in Emissions

- Outlier grids (>10 L/min/mi) were looked to be moved up in schedule where possible
- Mains retired earlier than originally planned stop emitting methane faster
- By accelerating high emissions grids, PSE&G was able to reduce total grid emissions by 83% early in the program.
- To achieve the same emissions reductions, 35% less main abandonments were needed vs if PSE&G followed strictly by hazard ranking.
- The accelerated grids the company prioritized for upgrades accounted for more than 37% of the emissions but only 9% of the mileage on which leak rates were measured.

Continuing the Program into GSMP II

- GSMP II filed in 2017 and approved in Spring 2018 as a five year extension
- Hazard Index and methane mapping to be used again to prioritize grids
- Picarro was chosen to map 44 "B Grids" of similar HI/mi that covered the 280 miles agreed to in the stipulation

Reduction in Risk and Methane Mapping

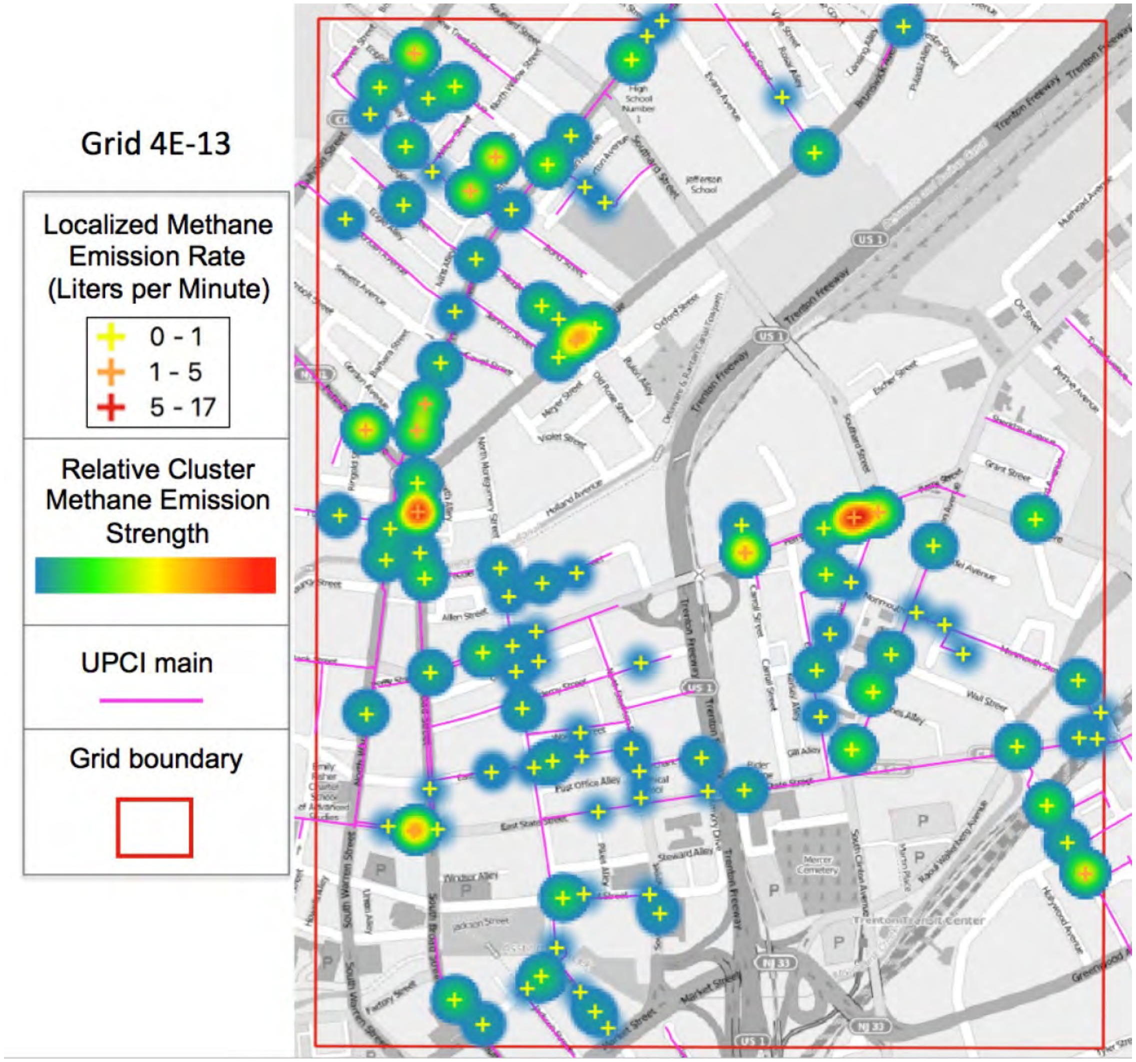


Continuing to address the highest hazard main segments

PSEG

Methane Quantification Survey

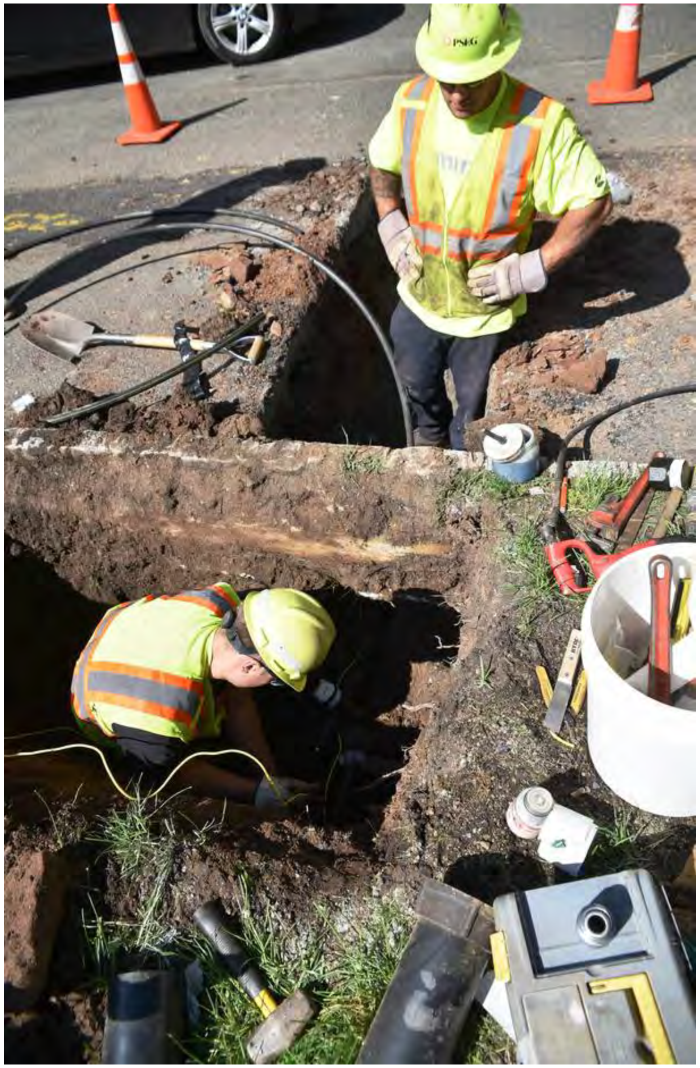
- Areas require 3 passes on each side of the street for proper sampling (95% statistical confidence interval)
- Indications are run through an algorithm with wind, vehicle speed, ethane content and other factors, leak rates are determined
- Heat maps can show areas of high emissions and calculated leak rates



Using GSMP II Results

- Discussion with EDF after data collected to set prioritization
- Threshold of 4.5 L/min/mi used for accelerating grids that were surveyed (down from 10 L/min/mi in GSMP I)
- 6 grids accelerated
- If retired sooner than “as is” plan, they account for 41% of the methane loss in only 16% of the grids surveyed
- Construction beginning in Spring of 2019

Key Takeaways



- Hazard Ranking and safety are highest priority
  - Hazard Rank and Leak Volume do not necessarily correlate
- Methane Emissions sub prioritization useful for areas of relatively equal hazard
  - Better for the environment
  - Less chance of non-hazardous leaks getting worse
  - Fewer potential customer calls/complaints
- Other LDC's and PUC's continue to discuss best applications for the technology's use

Questions?

Exhibit EDF(A)-12:

EDF Proposal for WGL Systemwide Methane Leak Surveying Report

EDF Proposal
WGL Systemwide Methane Leak Surveying Report

Annually, the Company shall complete and file with the Commission in Formal Case No. 1162 a Systemwide Methane Leak Surveying Report detailing its findings and progress in implementing advanced leak detection technology and analytics ("ALD+") and utilizing the associated data to improve risk assessment and reduce methane emissions. The annual report will be made public and distributed to the rate case parties, and the report will serve as a resource to track the Company's progress in decreasing leaks, reducing greenhouse gas emissions, and improving safety. To the extent any of the information is already included in the Company's PIPES 2 Methane Leak Surveying Report, the Company may include a cross-reference to the Pipes 2 Report. The Systemwide Methane Leak Surveying Reports issued by the Company shall include the following information:

a. An explanation of the ALD technology and leak quantification methods used, including description of equipment, software, sensor sensitivity and capabilities relative to equipment and technology traditionally used by Washington Gas for these purposes, and service provider.

b. A description of methodology used to integrate leak flow rate data into the Company's prioritization framework, as an additional factor to supplement risk-based rankings.

c. A description of the miles of pipe surveyed during the year, and a description of the Company's plans for surveying during the subsequent year. Recognizing that the Company might not conduct a systemwide survey every year, the report should explain when the systemwide survey was completed—either during the current year or in a previous year—and when the next systemwide survey is planned. If the Company designates geographic zones to plan its leak survey and repairs, those should be explained and depicted on a map in the report.

d. Depiction of results, *i.e.*, a table with the leak indication IDs, and associated information for each leak indication, including:

   - Leak indication ID number, GPS coordinates for location of leak indication, and District of Columbia ward where leak indication is located (and, if the Company establishes geographic zones to plan its leak survey and repairs, that zone should be stated);
   - Date the leak indication was discovered;
   - Date the leak indication was graded, if applicable;
   - Leak grade or a clear indication that the leak has not yet been graded, if applicable;
   - Date the leak is scheduled for repair, and the date the leak was actually repaired;
   - Specify which leaks were prioritized for repair based on leak flow rate;
   - Estimated leak flow rate (e.g. liters per minute or standard cubic feet per hour);
   - If the Company could not locate a leak corresponding with a leak indication, that should be noted; and,

- If a leak indication is within a PROJECT*pipes* project area, identify the project area ID number.

e. An annual systemwide greenhouse gas (GHG) emissions baseline. This baseline will report the systemwide emissions as surveyed, before leak repairs or pipe replacements were undertaken. The baseline can be calculated using the leak flow rate.

f. An estimate of the total annual GHG emissions reductions achieved via leak repair, as well as estimates of the individual GHG emissions reductions achieved for each leak repaired during the year.

The Company will undertake the Systemwide Methane Leak Survey in furtherance of the District of Columbia's climate action commitments, most recently codified by the Clean Energy DC Omnibus Amendment Act of 2018. The Company will make the Systemwide Methane Leak Surveying Report available to the D.C. Department of Energy and Environment for use in the District's emissions inventory.

Exhibit EDF(A)-13:

Washington Gas & AltaGas

Natural Gas and its Contribution to a Low Carbon Future: Climate Business Plan (Mar. 2020)

VENABLE LLP

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March 16, 2020

VIA ELECTRONIC MAIL AND E-FILING

Ms. Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission of the District of Columbia
1325 G Street, NW, Suite 800
Washington, DC 20005

Re: Formal Case No. 1142
[In the Matter of the Merger of AltaGas Ltd. and WGL Holdings, Inc.]

Dear Ms. Westbrook-Sedgwick:

Enclosed for filing please find the Climate Business Plan for Washington, D.C. (the "Climate Business Plan"), submitted in compliance with Term No. 79 of the Settlement Agreement in this proceeding. The Climate Business Plan includes as Appendix D the Renewable Natural Gas Study performed in compliance with Term No. 6 of the Settlement Agreement.

If you have questions regarding this matter, please feel free to contact me.

Respectfully submitted,

MAUpadhyaya

Moxila A. Upadhyaya
Counsel for AltaGas Ltd.

Copy to: Certificate of Service
Christopher S. Gunderson, Esq.
J. Joseph Curran, III, Esq.

Natural Gas and its Contribution to a Low Carbon Future

Climate Business Plan for Washington, D.C.

Washington Gas
A WGL Company

AltaGas

MARCH 2020

Forward Looking Statement

This Climate Business Plan, prepared solely for the Company's operations in the District of Columbia, contains forward-looking statements, which are subject to the inherent uncertainties in predicting future results and conditions. Such statements are based on our current expectations as of the date we filed this business plan, and we do not undertake to update or revise such forward-looking statements, except as may be required by law. Statements contained in this business plan concerning expectations, beliefs, plans, objectives, goals, strategies, expenditures, recovery of expenditures, future environmental matters, regulatory and legislative proposals, future events or performance and underlying assumptions and other statements that are other than statements of historical fact are "forward-looking statements." Forward-looking statements are based on management's beliefs and assumptions based on information available at the time the statement is made and can often be identified by terms and phrases that include "anticipate," "believe," "intend," "estimate," "expect," "continue," "should," "could," "may," "plan," "project," "predict," "will," "potential," "forecast," "target," "guidance," "outlook" or other similar terminology. The Company believes that it has chosen these assumptions or bases in good faith and that they are reasonable. However, actual results almost always vary from assumed facts or bases, and the differences between actual results and assumed facts or bases can be material, depending on the circumstances. Important factors that could cause actual results to differ materially from those projected in the business plan include (but are not limited to), changes in United States and District of Columbia laws and regulation, the inability to timely recover costs through utility rate proceedings, the impact of future legal proceedings, competitive pressures, compliance costs, changes in the structure of capital and/or energy markets, technological advancements and advances in new technologies, changes in consumer preferences, the availability of alternative or lower-priced energy options, access to capital, and existing and future environmental requirements, including those related to potential, anticipated or known impacts of climate change. You should not place undue reliance on forward-looking statements.

Table of Contents

A Message from our President and Chief Executive Officer

Delivering on Our Commitment to Help DC and the World Meet Future Climate Goals

When AltaGas acquired Washington Gas, we committed to continue our history of proven energy innovation by providing the District of Columbia with a long-term business plan that can contribute to the District achieving its climate goals. As a trusted energy partner to the District for over 170 years, we set out to develop a blueprint detailing how we, as a newly combined company, can help the District reach its goal to cut greenhouse gas emissions (GHG) in half by 2032 and become carbon neutral by 2050. We are proud to submit the following plan in furtherance of that commitment.

BUILDING ON A LEGACY OF CLIMATE REDUCTION: IN OUR OWN OPERATIONS AND FOR CUSTOMERS

The Climate Business Plan builds on our record of achievement and our companies' collective determination to address climate change. AltaGas, and its subsidiary, Washington Gas, share a legacy of leadership and innovation. Both companies have excelled in bringing new clean energy sources to customers. AltaGas built and operated the first wind generation facility in British Columbia, the 102 MW Bear Mountain Wind Park, and the impressive Northeast Hydro run-of-the-river hydroelectric generation facilities in British Columbia. We are also helping to reduce emissions globally by shipping propane to Asia that displaces emissions from burning coal, oil and wood. It is estimated that our Ridley Island Propane Export Terminal will help avoid emissions on an annual basis that exceed the total annual emissions attributed to natural gas use in Washington, D.C. Closer to home, WGL Energy was among the first companies to provide wind power to retail electric customers. WGL is also a leading first-mover company in the installation of solar in the mid-Atlantic region. In DC alone we developed 68 distributed generation solar projects which generate 15,150 MW-hours annually, reducing local GHG emissions for years to come.

DELIVERING BOLD INNOVATION TO EMPOWER THE DISTRICT'S CARBON-NEUTRAL FUTURE

We are confident that our Climate Business Plan provides a sensible path forward. Collaborating with the District to implement the steps toward decarbonization gives us the opportunity to continue to leverage our resilient, vast and established energy delivery and storage system to reduce emissions while providing affordable and reliable energy. Our Plan promotes customer energy efficiency and savings, builds and maintains a modern infrastructure for today and tomorrow, and introduces carbon-free fuels, such as renewable natural gas (RNG) and hydrogen.

Looking 30 years into the future means that we have to do our best to anticipate what's ahead. While many factors are unknowable over that long timeframe, there are emerging, disruptive and breakthrough technologies that are showing tremendous promise and are expected to impact everything from sourcing (including renewable natural gas and hydrogen) to distribution, to how effectively we use energy in the future. The Plan includes investing in, and piloting, some of these emerging technologies that will maintain and enhance the District's position as responsible climate leaders.

We look forward to productive discussions and closely collaborating with the District to create policies and regulations to meet the District's climate targets, while continuing to provide essential energy in a cost-effective manner to the people, businesses and institutions that call the District of Columbia home.

Sincerely,

Randy Crawford
President and Chief Executive Officer

Plan Overview: Empowering the District to Meet Carbon Neutral Status by 2050

BRINGING IN A NEW ERA OF CLEANER ENERGY TO THE NATION'S CAPITAL

AltaGas Ltd., with its subsidiary Washington Gas Light Company (Washington Gas), is proud to submit a comprehensive Climate Business Plan (the Plan) designed to serve as a bold blueprint to achieve carbon neutrality in support of the District of Columbia's long-term climate goals. The Plan achieves **a 50 percent greenhouse gas (GHG) emissions reduction associated with the use of natural gas by 2032 and 100 percent carbon neutrality associated with the use of natural gas by 2050.**

The core tenets of the Plan's three-pronged approach will maximize energy efficiency programs as well as leverage our existing, vast and reliable energy infrastructure system to deliver not only natural gas but also forward-looking fuel sources like biogas and 'green' hydrogen as part of a broader portfolio mix of energy supply. Importantly, the cost to implement the **plan saves an estimated $2.7 billion** as compared to approaches that rely solely on electrification, while enhancing the reliability of energy to the District's energy consumers.

The Plan is not only a part of AltaGas' commitment made with the Public Service Commission of the District of Columbia (DC PSC) during its proceedings to approve AltaGas' acquisition of Washington Gas in July 2018, but continues to demonstrate our long-standing efforts to address the issue of climate change.

A FUEL NEUTRAL DECARBONIZATION APPROACH MEETS GOALS, IS COST EFFECTIVE AND FLEXIBLE FOR THE FUTURE

Over the last year, AltaGas has engaged in extensive and thorough research, leveraged its own decades of energy expertise and enlisted the respected consulting firm ICF Resources, LLC (ICF), to assess an optimal path forward for the District and its residents. AltaGas has determined that **Fuel Neutral Decarbonization** is the right choice for the District to meet its Climate Goals.

Among its many benefits, a Fuel Neutral Decarbonization strategy provides the desired GHG emission reductions at a fraction (59 percent) of the cost of full electrification, while maintaining energy reliability for District residents, businesses, government agencies, and visitors. In addition, it preserves customer choice, empowering all energy consumers in the District to select an energy source most suited to their needs.

**FUEL NEUTRAL DECARBONIZATION –
THE RIGHT APPROACH TO ACHIEVE OUR CLIMATE GOALS**

- Achieves the District's 2050 carbon neutrality goals and saves residents and businesses $2.7 billion relative to meeting the goals primarily through electrification
- Preserves customer choice, secures energy reliability, and enhances resiliency in the face of increasing climate-related weather variability

THREE BUILDING BLOCKS OF 2050 NATURAL GAS DECARBONIZATION

Action in three key areas – **End Use, Transmission and Distribution, and Sourcing and Supply** – will lead to the success of Fuel Neutral Decarbonization by embracing new emerging technologies, as well as energy innovations – such as the promise of green hydrogen and renewable natural gas – that use the reliable energy delivery infrastructure system already in place across the District. Other important benefits include stabilized costs, resiliency and reliability, and energy storage, as compared to alternative scenarios that were studied but come with higher cost, more risk and uncertainty.

End Use – Providing practical energy efficiency solutions to our customers. The cleanest and lowest cost energy is that which is not used. Increasing energy efficiency is the first step to reduce energy use and the associated GHG emissions. The Plan highlights the many methods to reduce use and improve efficiency.

Transmission and Distribution – Continue to reinforce and strengthen our infrastructure and advanced leak detection to reduce leaks and fugitive methane emissions. Fugitive methane emissions, attributable to pipeline transmission and distribution, account for the smallest source of emissions relating to natural gas. However, their community impacts – including odor, noise and disruptions during repairs, planned construction, and proactive pipeline replacement programs – make them the most visible to people living in our communities.

Sourcing and Supply - Decarbonize the energy supply delivered. There are two ways to reduce emissions associated with natural gas supply. The first is through introducing low/no carbon non-fossil-based gases into the natural gas delivery system and the second is avoiding methane emissions from the upstream extraction of natural gas.

Building Blocks of Decarbonization

End Use	Transmission and Distribution	Sourcing and Supply
Energy Efficiency ▪ Expand DCSEU programs ▪ Develop Washington Gas programs that support – Behavioral demand reductions – High-efficiency appliances – Building envelope upgrades – Gas heat pumps – Demand response internet of things automation – CHP deployments ▪ Electric/Gas Hybrid Heating – Explore approaches, such as Energy-As-A-Service, to ease financial burden – Reduce economic disincentives through decoupling/revenue normalization adjustment adoption – Accelerate advanced technology development/adoption via partnerships and pilots with National Labs/original equipment manufacturers	▪ Prioritize Accelerated Pipeline Replacement Programs projects based on GHG emissions using data analytics ▪ Promote advanced leak detection and enhanced response solutions ▪ Recover gas during maintenance, repair and replacement projects using drawdown compressors ▪ Evaluate the efficacy of several promising airborne and vehicle-based methane detection systems	▪ Certified Gas – Low cost emissions reduction – Ready now strategy ~ 1–2% reduction – Pending study with Rocky Mountain Institute to validate emissions reductions ▪ RNG – Facilitate development of and access to non-fossil supply (13% by 2032; 58% by 2050) – Purchase/distribute RNG and other zero carbon fuels including biogas, power-to-gas, and green hydrogen ▪ Seek regulatory cost recovery – Socialize cost across customer base – Encourage marketers to provide additional opt-in RNG offering

THE CRITICAL ROLE OF INNOVATIVE LOW/NO CARBON FUELS - RENEWABLE NATURAL GAS AND GREEN HYDROGEN

Two non-fossil-based gases – RNG and green hydrogen – are included in the Climate Business Plan due to their strong emissions reduction potential and compatibility with existing pipeline infrastructure and customer end-use equipment and appliances. They also require no action on the part of customers to implement and bring to scale.

RNG – can be introduced and provide emissions reductions without requiring upgraded or new equipment by the end-user. RNG is developed from biomass, waste, or other renewable resources and is a pipeline-quality gas that is fully interchangeable with conventional natural gas. It is carbon neutral, extremely versatile and fully compatible with the U.S. pipeline infrastructure.

Green Hydrogen – a carbon-free fuel that emits no GHG emissions, is made with renewable energy and stored in a tank until needed. The technology to produce clean hydrogen from water and electricity has been commercially available for more than 50 years and there are many initiatives underway to advance this technology. As renewables increasingly come on line as a source for electricity, the viability of using this energy as a source for generating the hydrogen becomes increasingly attractive. Green hydrogen can be produced from “curtailed” electricity – that which is not needed on the grid and would otherwise be wasted – or through dedicated renewable installations.

BENEFITS OF A FUEL NEUTRAL DECARBONIZATION APPROACH

Stabilizing Cost – A diversified energy portfolio helps stabilize costs. Diversification provides a ‘hedge’ against price increases and volatility from competition for projected escalation in demand for renewable electricity supply and renewable energy credits (REC), as well as protection against unknown costs of electric utility system distribution and transmission upgrades.

Resiliency and Reliability – Energy resiliency and reliability are enhanced by leveraging the 99.9 percent reliability of the natural gas delivery system. Additionally, multiple energy sources and distribution networks incorporated within the Fuel Neutral Decarbonization approach provide an inherent redundancy of energy supply, reducing the District's risk exposure to disruptions in energy delivery from weather or other events.

Providing Energy Storage – Long-term energy storage is enabled for the District to support its peak energy needs which occur during the winter months. Washington Gas's existing system stores energy for months (up to years) at a time and demonstrates how natural gas provides high capacity, long duration and long discharge seasonal energy storage that can provide backup power when intermittent renewables such as solar and wind energy are not generating.

NATURAL GAS IS A FOUNDATIONAL FUEL THAT CAN HELP US ACHIEVE OUR CLIMATE GOALS

> Because natural gas is warm and quickly responsive, it is the preferred method of heating and cooking for 165,000 District residences and businesses. It is over **99 percent reliable** and **affordable,** costing **$879** less per year than a comparable home using electricity for heating, hot water, cooking and clothes drying.[1] According to the 2017 emissions inventory, natural gas use, primarily in the residential and non-residential buildings sectors, provided more energy but accounted for less emissions than other sources — accounting for about 17.7 percent of the District's 2017 GHG emissions while delivering 27.1 percent of the energy used. Comparatively, electricity provided 46.7 percent of the energy but accounted for 55.1 percent of the GHG emissions.

ACHIEVING OUR TARGETS BY 2050

The figure below illustrates the projected GHG emissions reductions associated with measures proposed in the Plan. The figure includes the forecast reductions by category relative to the 2006 baseline. It also recognizes natural gas emissions reductions already realized since 2006, as reflected by the District's most recent GHG emissions inventory[2].

CLIMATE BUSINESS PLAN (2020-2050)		2032	2050
TOTAL End-Use REDUCTIONS	• Energy Efficiency (including Behavioral Programs and Gas Heat Pumps) • CHP and Distributed Energy Systems • Dual Fuel Systems (Hybrid Heating) • Emerging Technology and Offsets	12%	36%
TOTAL Distribution REDUCTIONS	• Second phase of PROJECT*pipes* • Advanced leak detection and response • Third-party damage prevention	2%	4%
TOTAL Sourcing and Supply REDUCTIONS	• Certified Gas Production (of geologic gas) and Transmission • Renewable Natural Gas (RNG) • Power-to-Gas and Hydrogen	13%	31%
	SUB-TOTAL of Climate Business Plan REDUCTIONS	27%	71%
	Net EMISSIONS REDUCTION from natural gas achieved between 2006 - 2017	27%	27%
	Net CHANGES in business as usual emissions after 2017	-3%	2%
TOTAL REDUCTION in GHG Emissions against Business as Usual		**50%**	**100%**

Note: numbers do not sum due to rounding

1 http://playbook.aga.org/#p=8

2 https://doee.dc.gov/service/greenhouse-gas-inventories

AltaGas and Washington Gas share a long legacy of leadership and innovation, and of excelling when it comes to bringing new clean energy sources to customers. For example, AltaGas built the first fully-operational wind park in British Columbia (B.C.), the 102-megawatt (MW) Bear Mountain Wind Park, that is located near Dawson Creek, and the Northeast Hydro run-of-the-river hydroelectric generation facilities in British Columbia. Today it delivers enough electricity to power most of B.C.'s South Peace region. WGL is a leading, first-mover company in the installation of solar in the mid-Atlantic region. In DC alone, WGL Energy developed 68 distributed generation solar projects which produce 15,150 megawatt-hours annually, reducing local GHG emissions for years to come. In addition, AltaGas is working to reduce emissions globally by shipping propane that displaces emissions from higher emitting fuels, resulting in annual emissions avoided that are greater than the total emissions attributed to natural gas use in the District's entire 2017 GHG inventory.

Washington Gas has a demonstrated commitment to reducing GHG emissions and addressing climate change in its own operations. In 2011, four years prior to the Paris Agreement, the company set 2020 targets for GHG emissions reductions for its fleet and facilities as well as to reduce the carbon intensity of the gas it delivers. The Company exceeded those goals in 2016. Washington Gas then announced new, updated targets for 2025—carbon neutrality for Washington Gas fleet and facilities by 2025 and a 38 percent reduction in fugitive carbon intensity per delivered therm of natural gas. These targets put the Company on track to meet the "2 degrees Celsius" scenario that reflected the guidance from the Intergovernmental Panel on Climate Change (IPCC) in support of the 2015 Paris Agreement as being necessary to avoid the most damaging impacts of climate change.

A FLEXIBLE FRAMEWORK ACHIEVES GOALS OVER THE NEXT 30 YEARS

On the road to 2050, AltaGas and Washington Gas have pledged to work closely with the District's leadership, its community and influencers to drive sustained and positive change by significantly reducing GHG emissions, protecting the environment and improving how District residents, businesses, and visitors enjoy their everyday life experiences. The Plan will further distinguish the District as a leader in climate change among major cities across the nation.

With proper regulatory and legislative support, the companies are poised to partner with the District, so it is positioned to achieve its climate goals by:

- Implementing the "ready now" actions with specific targeted reductions — like those offered by the application of efficiency measures aimed at reducing energy use, as well as the decarbonization of Washington Gas' gas supply through the use of renewable energy sources.
- Engaging in forward looking, emerging technologies and pilots to support the development of highly promising new areas like green hydrogen (zero/negative carbon) and direct air carbon capture, as well as re-use technologies that enable the District to cost-effectively leverage the highly reliable, existing energy delivery infrastructure system that currently serves residents and businesses across the District.

> As we plan for the future we must take into consideration the important role that energy plays in our lives. Energy is a necessity. Energy provides the pathway to a more sustainable economy, helps eradicate poverty, combats climate change, generates advancements in health, education, food and water quality and is a critical building block for economic development, competitiveness and quality of life.[3]
>
> In creating the Plan, AltaGas recognizes that envisioning 30 years into the future represents the challenges of projecting the evolution of science and technology and the likelihood that there may well be revolutionary advances that could render today's thinking obsolete. It is in this spirit that the Plan is offered to provide a responsible and effective path forward. It will evolve over the coming decades to ensure a brighter, cleaner energy future that draws on an energy innovation vision, abundant resources and extensive carbon emissions reduction expertise.

3 Researchers including Amulya Reddy, Valclav Smil, and P.M Dekker et al. have studied the relationship between per capita energy use and a variety of basic quality of life measures. They have found a correlation between energy use and life expectancy, literacy, education, GDP, and access to clean water. As well as declines in infant and maternal mortality rates.

Climate Business Plan

Introduction

AltaGas' principal subsidiary in the District, Washington Gas, has developed the Plan in fulfillment of AltaGas Merger Commitment DC 79 (the Commitment) and as a continuing demonstration of its long-standing efforts to address the serious issue of climate change. AltaGas committed to submit a "long-term business plan on how it can evolve its business model to support and serve the District's 2050 climate goals (e.g. providing innovative and new services and products instead of relying only on selling natural gas)."

The Commitment consists of two elements. This Plan represents fulfillment of the first element. The second element will involve regular updates and dialogue with stakeholders through bi-annual public meetings.

The Plan recognizes the scientific consensus that human activity — primarily GHG emissions from industrialization and the conversion of land for agriculture and development — is contributing to changes in the global climate including changing weather patterns, rising sea levels and more extreme weather events. The companies understand that climate change necessitates the evolution of how we provide essential energy solutions to our customers and presents us with the opportunity to develop new ways to serve the community while reducing the impact on the environment.

The Plan that AltaGas has developed provides a conceptual framework that, with proper regulatory and legislative support, evolves our business model in and for the District to meet the District's Climate Goals, achieving both a 50 percent GHG emissions reduction associated with natural gas use by 2032 and carbon neutrality by 2050 compared with baseline GHG emissions in 2006. In drafting the Plan, AltaGas recognizes that extrapolating 30 years into the future represents a significant challenge due to the number of unknown and unknowable variables, such as the exact timing for the development and adoption of new technologies.

As the future unfolds it is more than likely that revisions will need to be made, so that the District (and AltaGas) can adapt our efforts. Despite these caveats, based on what we know today, the Plan as outlined achieves the GHG emissions reduction targets and is the lowest cost pathway to the 2050 GHG emission reduction target. The Plan offers significant additional benefits including greater resilience, safeguards against service interruptions and preservation of customer choice.

To inform the Plan, AltaGas engaged ICF to develop and model a variety of scenarios to evaluate the effectiveness and implications of different approaches to meet the District's 2032 and 2050 GHG emission reduction targets. ICF has extensive experience evaluating natural gas and power markets, helping natural gas and electric utilities assess business opportunities and risks, and supporting corporate entities and governmental agencies with the development of energy and environmental policy initiatives.

The scenarios evaluated in the development of the Plan also incorporated findings from a separate study that assessed the potential for renewable natural gas (RNG)[4] to contribute to the achievement of the District's climate goals. The study evaluated environmental benefits, economic viability, and operating and regulatory challenges and solutions relating to the introduction of RNG in the DC metro region.

The outputs of the scenario models demonstrated that a **Fuel Neutral Decarbonization**[5] approach provides the most affordable and flexible framework for meeting the District's climate goals through expeditious measures that also meet the District's needs for safe and reliable energy.

A Fuel Neutral Decarbonization approach is also most compatible with the seven key factors identified in the DC PSC's Vision for modernizing the District's energy delivery system; namely that it be: (1) sustainable[6], (2) well-planned, (3) safe and reliable, (4) secure, (5) affordable, (6) interactive, and (7) non-discriminatory.[7] To ensure further alignment with the needs and desires of District stakeholders, the company is conducting ongoing stakeholder outreach, including meetings and surveys, to solicit their input and inclusion in the ongoing process.

The Plan, developed based on the Fuel Neutral Decarbonization scenario, contains recommendations to reduce GHG emissions from **(a) end-use; (b) transmission and distribution; and (c) sourcing and supply.**

4 RNG is a pipeline compatible gaseous fuel derived from biogenic or other renewable sources that has lower or negative lifecycle carbon dioxide equivalent emissions than geological natural gas.

5 Fuel Neutral Decarbonization is a non-prescriptive, multi-fuel approach that sets priorities based on GHG emissions reductions potential in the short, medium and long term.

6 The Notice of Inquiry (November 25, 2019) GD2019-04-M, In the Matter of the Implementation of the 2019 Clean Energy Omnibus Act Compliance requirements states; "Under the factor of "sustainable," the Commission made it clear that it will focus on: (1) Environmental Protection, including protecting the District's natural resources and assisting the District Government in reaching its Clean Energy DC goals by fostering the use of more efficient energy and renewable energy sources, distributed energy resource ("DER") technologies, and controllable demand alternatives to reduce GHG emissions and overall energy consumption; (2) Economic Growth; and (3) Social Equity, including positively impacting the daily lives of District residents and strengthening community involvement in reaching environmental protection and economic growth goals related to modernizing the District's energy delivery system."

7 https://dcpsc.org/CMSPages/GetFile.aspx?guid=068d9b90-cb2d-4844-ab23-b94842588d13

The figure below illustrates the projected GHG emissions reductions associated with measures proposed in the Plan. The figure includes the forecast reductions by category. It also recognizes natural gas emissions reductions already realized since 2006, as reflected by the District's most recent emissions inventory.[8]

Summary Estimated Climate Business Plan Emissions Reductions	2032	2050
1) End-Use	12%	36%
2) Distribution and Transmission	2%	4%
3) Sourcing and Supply	13%	31%
Total Climate Business Plan Emissions Reductions	**27%**	**71%**
+ Net emissions reduction from natural gas achieved 2006 - 2017	27%	27%
+ Net change in Business As Usual emissions after 2017	-3%	2%
= Total Reduction in GHG Emissions against Business as Usual	**50%**	**100%**

Numbers do not sum due to rounding

> The gas-related proposals set forth in this Plan – which depend upon supportive policy and regulations – will enable the District to exceed its 50 percent 2032 GHG emissions reduction target ahead of schedule – a critical achievement due to the urgency of climate action.[9]

Climate Business Plan: A Sensible, Cost Effective GHG Emissions Reduction Pathway

The successful track record established by Washington Gas to reduce GHG emissions in the District demonstrates that Washington Gas is a preferred energy partner that will continue to help the District lower its GHG emissions and meet its 2050 climate goals by bringing innovation to what we deliver, how we deliver and the business model that pays for our service.

> While the mandated 100 percent renewable portfolio standard (RPS) will help the District meet the 2032 50 percent emissions reduction target, implementing the Plan will lead to even greater reductions, sooner, which the recent Intergovernmental Panel on Climate Change (IPCC) Special Report on Global Warming tells us is necessary to avoid the worst impacts of climate change. Furthermore, early approval and implementation of the Plan will enhance the opportunity to meet the 2050 carbon neutral target at the lowest cost.

The Plan identifies specific measures that, if and when fully implemented with supportive government policy and regulatory certainty, offer GHG emissions reductions to meet the District's climate goals.

Based on a **Fuel Neutral Decarbonization approach**, AltaGas and Washington Gas, with the assistance of ICF, evaluated the emissions reduction potential for a number of measures organized by:

1. **End Use** - *Providing practical energy efficiency solutions to our customers*

   The cleanest and lowest cost energy is that which is not used. Increasing energy efficiency is the first step to reduce energy use and the associated GHG emissions.

2. **Transmission and Distribution** – *Continue to reinforce and strengthen our infrastructure and advanced leak detection to reduce leaks and fugitive emissions*

   Fugitive methane emissions attributable to pipeline transmission and distribution account for the smallest source of emissions relating to natural gas.

8 https://doee.dc.gov/service/greenhouse-gas-inventories

9 The reductions associated with the implementation of the DC Omnibus Clean Energy Act mandates the use of 100% renewable electricity by 2032, achieving the District's interim goals. Washington Gas' proposals will accelerate the path to the achievement of carbon neutrality.

3. **Sourcing and Supply** - *Decarbonize the energy supply delivered*
   There are two ways to reduce emissions associated with natural gas supply. The first is through introducing low/no carbon non-fossil-based gases into the natural gas delivery system and the second is avoiding methane emissions from the upstream extraction of fossil natural gas.

The following table summarizes the Plan's proposed GHG emissions reduction measures and the expected GHG emissions reductions for 2032 and 2050.

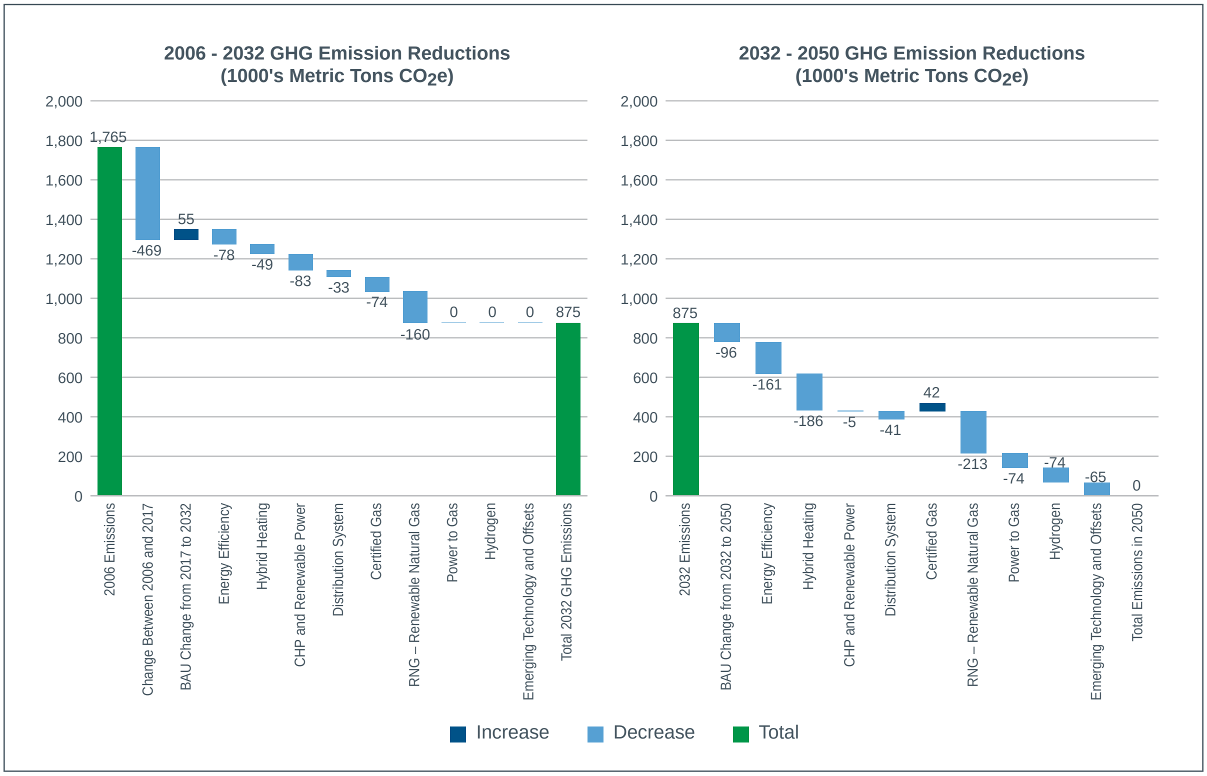
Detailed Estimated Climate Business Plan Emissions Reductions*	2032	2050
1) End-Use		
Energy Efficiency (including Behavioral Programs and Gas Heat Pumps)	4%	14%
CHP and Distributed Energy Systems	5%	5%
Dual Fuel Systems (Hybrid Heating)	3%	13%
Emerging Technology and Offsets	0%	4%
Total End-Use Reductions	**12%**	**36%**
2) Transmission and Distribution		
Distribution (Emissions reductions including second phase of PROJECT*pipes*)	2%	4%
Total Transmission and Distribution Reductions	**2%**	**4%**
3) Sourcing and Supply		
Certified Gas Production (of geological gas) and Transmission	4%	2%
Renewable Natural Gas (RNG)	9%	21%
Power-to-Gas and Green Hydrogen	0%	8%
Total Sourcing and Supply Reductions	**13%**	**31%**
Total Climate Business Plan Emissions Reductions	**27%**	**71%**
+ Net emissions reduction from natural gas achieved 2006 - 2017	27%	27%
+ Net change in Business as Usual emissions after 2017	-3%	2%
= Total Reduction in GHG Emissions against Business as Usual*	**50%**	**100%**

*Numbers do not sum due to rounding

Emissions Reduction Measures in 2032 and 2050

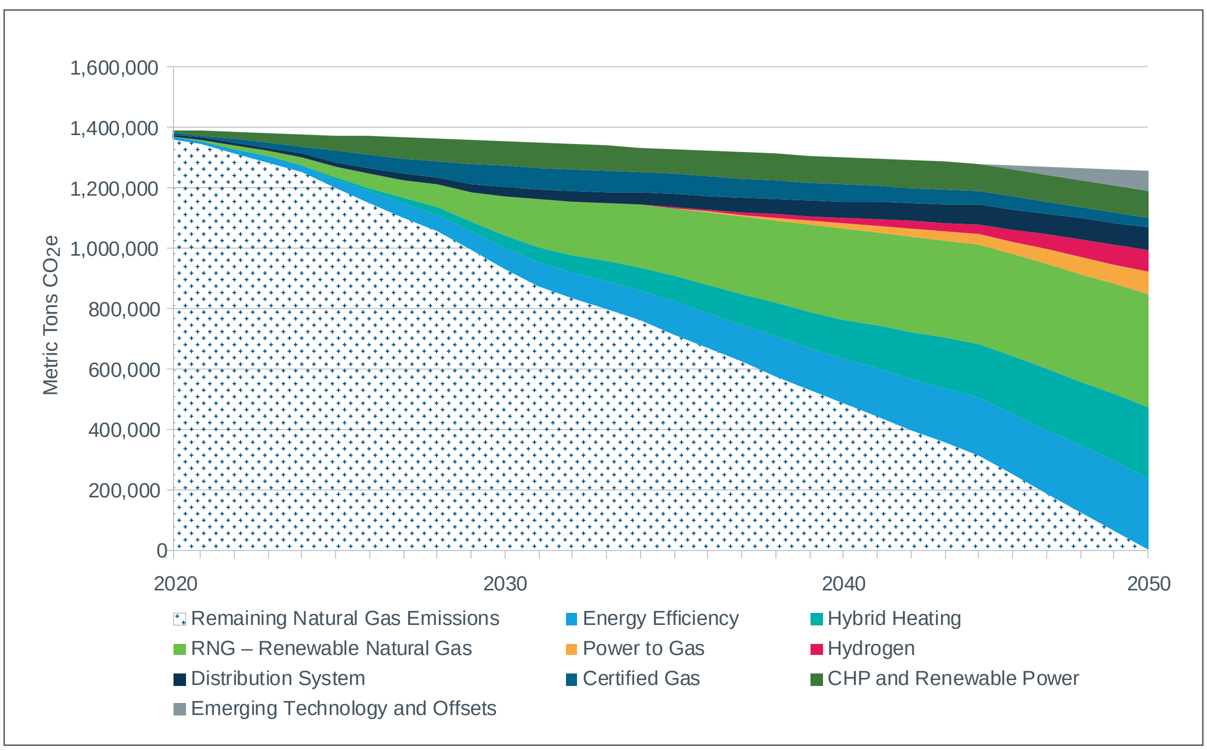
The figure below illustrates how the above proposed measures are expected to achieve emissions reductions at target dates 2032 and 2050, respectively. The GHG emissions reductions align with the District's overall targets, so that by 2032 GHG emissions associated with natural gas will be reduced 50 percent.

Natural Gas Emission Reduction Measures in the WGL Climate Business Plan at 2032 and 2050



Emissions Reductions Over Time

The figure below offers a visual representation of the relative emissions reduction contributions of the various measures over time.



Over the next 30 years, there are likely to be major new technology developments that will increase the ability and reduce the costs of eliminating GHG emissions. That is why investment in research and development and pilot programs are included in the Plan. As the District takes an aggressive approach to reducing GHG emissions, it is critical that the options for new technologies are not foreclosed but are rather supported, and that new technologies that help energy to remain affordable and reliable are encouraged as part of the low carbon future.

End Use: Energy Efficiency and Beyond

Enables us to achieve

12%

toward the 2032 50 percent GHG reduction target

Enables us to achieve

36%

toward the 2050 50 percent GHG reduction target

Promoting energy efficiency measures is one of the best (cleanest, least expensive) approaches to GHG emissions reductions. It avoids the need for new energy infrastructure, promotes conservation of our natural resources, lowers customer bills and creates jobs. Energy efficiency is 'by far' the largest source of jobs in the energy sector, including construction, production/manufacturing, installation, maintenance and repair.[10]

Today, programs that promote natural gas energy efficiency in the District are exclusively carried out by the DCSEU. DCSEU provides rebates to homeowners for the installation of energy-efficient equipment. Increasing the number and types of energy efficiency programs holds tremendous value.

To deliver this value to our customers, Washington Gas is participating in the Commission's Formal Case No. 1160 Working Group dedicated to establishing utility-led energy efficiency programs that are not duplicative of those now offered by the DCSEU.[11]

Washington Gas believes that more can be done through complementary programs that empower customers to make intelligent and informed decisions to reduce their energy use. The programs include ideas such as the introduction of additional initiatives to enhance the installation of energy efficiency equipment and building envelope measures, new behavioral programs, and new demand response programs that leverage smart thermostats and the Internet of Things (IOT) potential to automate and use data to maximize efficient uses of energy.

With supportive government policies and a constructive regulatory framework, the Plan anticipates the adoption of several promising and proven energy efficiency measures including, but not limited to, those detailed below.

ENERGY EFFICIENCY — BEHAVIORAL PROGRAMS

Empowering People to Save Energy and Reduce GHG Emissions

The "home energy report program" is a behavioral program that assesses how the energy performance of a customer's home compares with peers residing in similar homes. This assessment has been proven to induce changes in customer behavior which could lead to energy savings of between 0.5 to 2 percent[12]. In preparing the Plan, we have conservatively estimated savings of 0.85 percent per customer participating in the program, which is consistent with the savings reported for the Washington Gas 2019 EmPOWER Maryland Report. Savings are achieved through the adoption of good conservation habits in setting point thermostat temperature, reducing hot water use, and promoting do-it-yourself low-cost conservation measures such as the installation of window wrapping or water aerators. Typical reports include energy conservation tips and recommendations, as well as cross promotions of other utility programs. The programs can be augmented over time by adding enhancements

10 https://www.ase.org/sites/ase.org/files/the_jobs_opportunity_of_energy_efficiency_-_alliance_to_save_energy_-_fact_sheet_final.pdf

11 In addition, as a condition of the merger between Washington Gas and AltaGas, AltaGas agreed to provide $4.2 million for energy efficiency and energy conservation initiatives with a primary focus on assisting low and limited-income residents who are living in affordable multifamily units. The cost cannot and will not be recovered in rates. On February 5, 2019, Washington Gas made compliance filing indicating the company has chosen VEIC https://www.veic.org/ as the administrator.

12 Mazur-Stommen, S., & Farley, K. (2013). Behavior Change Programs: Status and Impact. ACEEE Report Number B132. Retrieved from http://www.aceee.org/research-report/b132

like gamification features. The behavioral programs would be based on an opt-out approach in order to maximize participation. Reports can be delivered both on paper and by email. Program effectiveness would be measured based on a billing analysis. The best outcomes are achieved when programs provide customers with both gas and electric energy information. These programs educate customers about the value of energy efficiency and are an entry point for promoting more aggressive energy efficiency programs. The Plan uses a penetration rate for behavioral programs of 53 percent of residential meters by 2032 and 71 percent of meters by 2050.

ENERGY EFFICIENCY — EQUIPMENT & BUILDING UPGRADES

High Efficiency Appliances and Equipment Guarantee GHG Emissions Reductions

The Plan includes Commission-approved utility programs that enable energy efficiency upgrades in 26 percent of buildings using natural gas by 2032, and 66 percent of the buildings using natural gas in the District by 2050.

These upgrades are expected to result in at least a 24 percent reduction in energy use for heating and hot water, primarily by replacing lower efficiency appliances/systems with higher efficiency appliances/systems and installing basic enhancements to building envelopes. The building envelope upgrades are limited to low cost measures that reduce energy consumption by 2 percent per building, and do not include deep building retrofits due to the cost of the more aggressive building envelope measures.

Several of the most promising new and emerging technologies in the Plan are described below.

ENERGY EFFICIENCY — COMBINED HEAT AND POWER

CHP also called “cogeneration” is an energy efficient technology that generates electricity and captures the heat that would otherwise be wasted to provide useful thermal energy—such as steam or hot water—that can be used for space heating, cooling, domestic hot water and industrial processes. CHP can be located at an individual facility or building or be a district energy system or utility resource. CHP is typically located at facilities where there is a need for both electricity and thermal energy.

The CHP system’s thermal output displaces the fuel otherwise consumed in an on-site boiler, and the electric output displaces fuel generated by central station power plants. Moreover, the CHP system’s electric output also avoids the loss of electric energy that occurs during transmission and distribution. CHP installations offer enhanced reliability and resilience because both heat and power are generated on-site.

According to ICF’s analysis, CHP will continue to reduce the total GHG emissions associated with energy use in the District through at least 2050, providing important reductions needed to meet the District’s 2032 and 2050 GHG emissions targets. CHP is expected to reduce overall GHG emissions because it will continue to displace fossil fuel power generation in PJM, without changing the amount of renewable power generation attributed to the District. As long as fossil fuel generation in PJM provides the marginal source of electric generation, natural gas CHP systems will always result in fewer emissions than separate heat and grid power. While CHP installations in the District will lead to increased consumption of natural gas in the District, the reduction in GHG emissions from power generation in PJM will more than offset the emissions from the natural gas consumed in the CHP units.

Today there are natural gas-powered CHPs at the U.S. Capitol Power Plant, GSA’s Central Heating and Refrigeration Plant, the U.S. Department of the Interior, Boland Trane (multi-family building), Carrollsburg Condominiums, George Washington University, the British Embassy and the National Archives Buildings. Additional CHPs at the Walter E. Washington Convention Center and the Blue Plains Advanced Wastewater Treatment Plant are fueled by waste and biomass respectively.[13]

CHP installations can also be paired with rooftop solar photovoltaic and other technologies in a resilient microgrid configuration that offer deeper GHG emission reductions than a standalone CHP system. Use of RNG in CHP systems would lead to further reductions in GHG emissions and would achieve net negative emissions.

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13 https://doe.icfwebservices.com/chpdb/state/DC

ICF projects a theoretical potential of more than 750 appropriate sites for CHP in the District, which could provide 912 MW of electrical generation. Based on their calculations, penetration of CHP units in the District could grow to 12 units per year by 2026 and remain stable through 2034. Starting in 2035, the rate of CHP installations is projected to start a gradual decline, due to the GHG emissions reduction potential and the declining availability of cost-effective site opportunities.

CASE STUDY | LESSONS FROM HURRICANE SANDY

When Hurricane Sandy hit in October 2012 eight million customers across 21 states lost power for days and even weeks. Ironically, many buildings outfitted with solar arrays stayed dark because they were permanently connected to the grid and had to be shut down.[14]

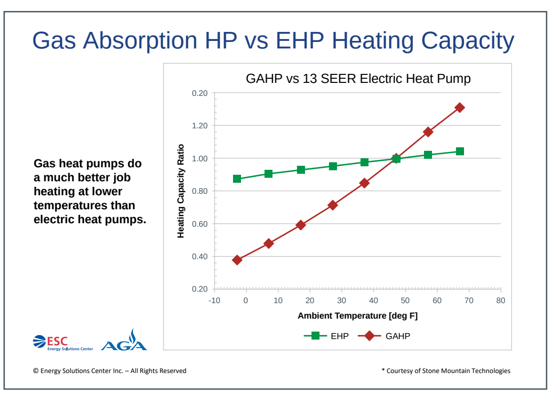
Co-op City with 60,000 residents, more than 14,000 apartment units, 35 high rise buildings, seven clusters of townhouses, eight parking garages, three shopping centers, a high school, two middle schools and three grade schools never lost power thanks to a 40-megawatt combined heat and power (CHP) plant that uses natural gas to provide both heat and power. Similarly, the 22 buildings connected to New York University's cogen plant continued to have power, heat and hot water leading the Environmental Defense Fund (EDF) to conclude:

"Sandy taught us lessons not only about what couldn't withstand the storm, but what did work and why."[15]

ENERGY EFFICIENCY

GAS HEAT PUMPS

Gas heat pumps are an emerging technology solution that, like electric heat pumps, collect heat from external sources – air, water, and geothermal sources – and transfer it for use inside the building. The efficiency measures for this technology (coefficient of performance or COP)[16] range from 1.4 to 1.5, whereas today's conventional high-efficiency natural gas furnaces have an effective COP of 0.90 to 0.98. This results in a 30-50 percent reduction in energy use when compared to today's already highly efficient natural gas furnaces. Like an electric heat pump, these devices will also provide hot weather cooling. Gas heat pumps offer certain benefits not provided by electric heat pumps. For example, gas heat pumps are more effective at delivering heat at lower temperatures and do not require an additional fuel source or technology during cold weather snaps. In addition, many of these devices are being developed to be self-powered and will not be dependent on an electrical source of energy, offering far greater resilience and reliability in the face of severe weather events and energy interruptions.



Gas Heat Pumps are making inroads in commercial and multi-family settings and are being readied for piloting and deployment in the residential sector. There are several key players already in the marketplace, including Stone Mountain Technologies, BoostHeat, Thermolift and Robur. Many of these companies are developing their technology in collaboration with commercial manufacturers and Department of Energy (DOE) national labs.

With supportive government policy and regulatory framework, ICF assumed the inclusion of gas heat pumps for both residential and commercial buildings within the equipment and building upgrade program. The Plan assumes a penetration rate of 2.3 percent of residential and commercial meters per year after the program ramp up in 2023.

Due to their high efficiency and promising commercialization pathway, the Plan projects gas heat pumps will first start to have an impact in 2026, and then grow steadily through 2050.

ICF assumed that between 2026 and 2040, 50 percent of the projected efficiency upgrades include conversion to a gas-fired heat pump with a COP of 1.4 for space heating. After 2040, all of the upgrades include gas-fired heat pumps with a COP of 1.4. The Plan anticipates that 38 percent of residential and commercial buildings will adopt gas heat pumps by 2050.

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14 What New York's Sandy successes can teach us about resiliency https://www.greenbiz.com/blog/2013/01/14/New-York-Sandy-resiliency

15 https://www.edf.org/blog/2013/10/29/two-technologies-literally-shone-during-sandys-darkest-hours

16 COP - the ratio of Energy Output to the Energy Input

ENERGY EFFICIENCY

HYBRID HEATING

The Plan also includes greater use of hybrid heating systems designed to combine an electric heat pump with a natural gas furnace. The heat pump operates during most of the year and displaces about 60 percent of the annual natural gas demand for the consumer. However, the natural gas furnace operates during the coldest days reducing the need for additional and costly investments in the electric grid which would be required under the policy-driven electrification scenario. The Plan anticipates that 40 percent of residential and 20 percent of commercial buildings now exclusively heated with natural gas will become dual fuel hybrid heating systems by 2050.

Hybrid heating systems have a slower rate of adoption in the Plan due to their higher upfront costs. However, with the appropriate policy and regulatory support, we believe that they have a role in reducing GHG emissions associated with end use. On that basis, the Plan uses a conservative rate for high-efficiency equipment turnover and replacement in the analysis. Washington Gas recognizes that open and collaborative dialogue with multiple stakeholders is necessary to facilitate this element of the Plan.

Facilitating Transition to High-Efficiency Equipment

There are multiple pathways to encourage customers to adopt high-efficiency equipment ranging from traditional utility appliance incentives to more innovative financing arrangements such as Energy as a Service that can serve as accelerators, facilitating faster adoption of ultra-high-efficiency appliances and equipment by reducing customers' upfront costs. As an example, under the Energy as a Service model, energy service providers will own and maintain the equipment; and customers will pay fees to the energy service provider based on their energy savings pursuant to energy service agreements signed between the parties. Washington Gas will explore the feasibility of creating new partnerships to facilitate this.

A November 2019 survey of Housing Association of Nonprofit Developers (HAND) members revealed that cost of implementation was the highest concern and that 83 percent would like equipment rebates to cover upfront costs."[17]

Transmission and Distribution

Enables us to achieve

2%

toward the 2032 50 percent GHG reduction target

Enables us to achieve

4%

toward the 2050 50 percent GHG reduction target

Based on the 2017 District GHG emissions inventory, fugitive methane emissions from the distribution and delivery of natural gas represent less than a quarter of one percent of emissions in the District. Reducing transmission and distribution emissions offers multiple benefits: (a) enhanced safety and reliability; (b) reduced methane emissions associated with climate change, and (c) conservation of our natural resources.

DISTRIBUTION

MODERNIZING OUR INFRASTRUCTURE

In the United States, natural gas infrastructure includes 2.5 million miles of underground pipelines made of different materials, with GHG emissions factors assigned by the U.S. Environmental Protection Agency (EPA), based on material type (see below). Replacing pipes with those that have a lower GHG emission factor (e.g. removing cast iron or unprotected steel and replacing with plastic) reduces the release of these fugitive methane emissions while significantly enhancing safety and reliability.

17 Results from Washington Gas survey of HAND members, November 2019

Methane is emitted from a variety of sources, both natural and man-made. The EPA reports that 75 percent of US methane emissions came from agriculture, landfills, mining and other sources – with only 25 percent attributable to natural gas use. In 2017, 165.6 MMT CO_2e of methane associated with natural gas use were emitted into the atmosphere. Those emissions have decreased by 27.5 MMT CO_2e (14.2 percent) since 1990.[18] Since 1990, GHG emissions from cast iron pipelines have declined 58 percent and unprotected steel have declined by 50 percent as they have been replaced with modern plastic pipelines with lower emissions factors.

Emission Factor by Type of Pipeline Material

Pipeline Type/Material	Equipment Leak Emission Factor
Mains – Unprotected Steel	110 Mcf/mile/year
Mains – Protected Steel	3.07 Mcf/mile/year
Mains – Plastic	9.91 Mcf/mile/year
Mains – Cast Iron	239 Mcf/mile/year
Services – Unprotected Steel	1.70 Mcf/service/year
Services – Protected Steel	0.18 Mcf/service/year
Services – Plastic	0.01 Mcf/service/year
Services – Copper	0.25 Mcf/service/year

Washington Gas reports annual data to the EPA that identifies changes in the types of pipeline material used on our system. The report applies EPA emissions factors for each type of pipe material to calculate the GHG emissions associated with system changes and replacements. Washington Gas also publicly reports progress in emissions reductions on its website https://sustainability.wglholdings.com/results-reports/ and through industry sites.[19]

Accelerated pipeline replacement programs are designed and intended to ensure system integrity by replacing older pipelines with new and modern materials, promoting safety and system reliability. As an ancillary benefit, they also reduce GHG emissions associated with natural gas throughout our operating territory. Between 2008 and 2017, Washington Gas' pipeline replacement work in the District resulted in an eight percent GHG emissions reduction (see case study below). In the District reductions have come from two programs: FC 1027 and PROJECT*pipes*. The continuation of these efforts, as detailed in our PROJECT*pipes* 2 filing now pending before the DC PSC, is expected to further reduce the District's GHG emissions and enhance the safety and reliability of the gas distribution system. Modernizing our energy infrastructure today also prepares us for the future – enabling the system integrity needed to deliver tomorrow's low/no carbon fuels like RNG and green hydrogen.

CASE STUDY | INFRASTRUCTURE MODERNIZATION REDUCES EMISSIONS

Based on our annual GHG inventory and reporting, between 2008 and 2017 Washington Gas replacement programs have reduced absolute emissions from our distribution system in the District by 8 percent and a significant portion of that reduction came from reducing fugitive methane emissions from pipelines.

Washington Gas' accelerated pipeline replacement work in the District includes the remediation of 41 miles of main and 4,644 service lines.

- Through FC 1027 we replaced 27 miles of main and 1,605 services.
- Our progress on PROJECT*pipes* since June 2014 includes successfully replacing approximately 14.2 miles of pipe and 3,039 service lines.
- Through our proposed continuation of PROJECT*pipes*, currently before the DC PSC for consideration, we estimate an additional total cumulative reduction of 973,968 tons of CO_2e by 2050 by replacing/remediating 458 miles of main and 59,741 service lines.

18 EPA, 2019, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2017 https://www.epa.gov/sites/production/files/2019-04/documents/us-ghg-inventory-2019-main-text.pdf (ES-15)

19 See https://www.aga.org/policy/natural-gas-esgsustainability/

DISTRIBUTION

LEAK DETECTION AND ENHANCED RESPONSE

Other efforts that modernize the Washington Gas system include the use of new technologies to monitor and check for leaks. Whether deployed on trucks, drones, and airplanes, new and promising technologies for finding natural gas leaks swiftly and cheaply offer the possibility of quicker detection and faster response to methane leaks. While still in development, many of the technologies have demonstrated strong potential.

Inexpensive detectors combined with focused use of optical gas imaging systems could pay for themselves by reducing losses of natural gas.

Washington Gas' leak survey technicians and our contractors primarily use Heath Remote Methane Leak Detectors to find leak indications. These units use Tunable Diode Laser Absorption Spectroscopy (TDLAS) for the detection method and can sense indications as small as 5 PPM-M. Once a leak indication is found, a Bascom-Turner Rover is used to further assess the indication and grade the leak. Following this assessment, the leak repair is prioritized per company protocols.[20] Washington Gas' Leak Survey team is planning to begin refreshing its population of Remote Mobile Leak Detectors. Several units which use TDLAS, from multiple manufacturers, are being tested.

Washington Gas will work to include leak volume quantification analyses, utilizing where it can, and survey processes, including alternative advanced leak detection (ALD) technologies (on a pilot basis), as part of its approved list of pipe replacement project prioritization criteria. In addition, the Company will continue to refine, or contract for the use of advanced data analytics in analyzing and projecting leaks on its piping assets, with a focus on developing better predictability of future leak occurrences. The goal of this program is to utilize better analytics and machine learning to reduce/avoid leaks at a faster rate through pipe replacement.

With respect to its PROJECT*pipes* 2 and 3 program, the company intends to pursue the following measures subject to DC PSC approval and cost recovery:

1. For PROJECT*pipes* 2 service only projects, Washington Gas will determine a list of services scheduled for replacement in the upcoming PROJECT*pipes* 2 construction year, currently based on a service leaks per quad ranking. Once the list is developed and approved, Washington Gas will leak survey the services scheduled for that year to determine if any are currently leaking. All leaking services will be replaced as a priority over non-leaking services where feasible.
2. Main and service replacement projects will be prioritized utilizing Washington Gas's Distribution Integrity Management Program (DIMP) and risk modeling tool or through an Advanced Data Analytics program. Through the term of PROJECT*pipes* 2, when prioritizing Program 2 and 3 main replacement projects, Washington Gas will integrate ALD based methane quantity information, as appropriate and based on the limits and availability of the ALD technology, in addition to the consideration of additional factors such as construction efficiencies, logistics, coordination with other construction activities (AOP, DC PLUG, DC GRID, and other utility and road-based construction projects), and other risk factors
within Washington Gas's discretion, including the prioritization ranking methodology used by the Company in support of its DIMP.
3. The Company will endeavor to implement leak flow rate data from the ALD survey as a factor in prioritizing those pipeline replacement projects previously selected for the upcoming PIPES construction year, as determined in accordance with the PROJECT*pipes* 2 Program. Washington Gas' consideration of leak flow rate will be secondary to safety considerations.
4. For the PROJECT*pipes* 2 construction year, leak flow rate per mile will be used to sub-prioritize among project areas selected with comparable risk ranks. Project areas with higher leak flow rates per mile will be prioritized sooner than other project areas that have a comparable risk ranking but a lower leak flow rate subject to permit and crew constraints.
5. In advance of the agreed upon termination of the PROJECT*pipes* 2 Program, Washington Gas will provide to DC PSC staff and intervenors a written evaluation of the use of ALD survey technologies as a factor in selecting and prioritizing accelerated pipeline replacement. The written evaluation will include Washington Gas' assessment of the impact of ALD technologies on the nature and extent of GHG emissions reductions achieved within PROJECT*pipes* 2, including whether Washington Gas recommends the continued use of such technologies in proposed subsequent accelerated pipe replacement renewal programs.

20 Washington Gas' standing requirement is to repair Grade 1 leaks immediately. Our average time of repair of Grade 2 leaks is under three months, well faster than the industry safety standard (12-15 months with monitoring) for that level of leak. These practices continually seek to reduce the number and the duration of emitting leaks in the District.

In addition, Washington Gas will continue evaluating the efficacy of several promising systems that are available today including:

- Airborne - LiDAR system capable of rapid, simultaneous, and precise 3D topography and methane concentration measurements.
- Mobile - The Picarro system[21] combines multiple individual surveys, increasing leak location accuracy and false positive rejection. Inertial GPS ensures accurate location information in dense urban environments and provides record of walking path and survey results to ground survey crews. It prioritizes leak indications by potential risk and is able to reduce false positives by distinguishing between natural gas and biogas and vehicle exhaust.

CASE STUDY | DRAWDOWN COMPRESSORS

Washington Gas is piloting the use of Drawdown Compressor technology to recover gas in infrastructure during maintenance and replacement projects in order to avoid atmospheric venting. The first drawdown operation was performed in October 2017 and to date, Washington Gas has redirected approximately **754,000** SCF back into its system. We are evaluating the use of drawdown compressors on a variety of pressures and project types to fully understand the operation and capacity of the equipment.

Thus far, the use of drawdown compressors has been best suited for medium scale projects. We are in the process of developing our own compressor technology that would be suitable to address small-scale recovery projects. Washington Gas is currently developing the appropriate training modules, emission reduction tracking mechanisms, and equipment selection strategies to support deployment. Implementation of a full drawdown compressor program is planned for 2020.

DISTRIBUTION

THIRD PARTY DAMAGE PREVENTION

Washington Gas encourages and supports third-party damage prevention programs, including MISS UTILITY as well as contractor training programs for all contractors working in our area of operations, not just our own contractors, to prevent accidental damages and the concomitant release of methane when they are digging in proximity to pipelines.

MISS UTILITY is the free service that people can call prior to digging that notifies member utilities, including Washington Gas, to mark the approximate locations of underground utility lines with high-visibility safety paint and/or flags. Washington Gas promotes this on its website, phone hold messages, signage, service vehicles, and through advertising.

The company also hosts Damage Prevention Workshops that focus on how to improve safety and lower the number and duration of third-party damages as well as reducing the amount of natural gas released.

Sourcing and Supply

Enables us to achieve

13%

toward the 2032 50 percent GHG reduction target

Enables us to achieve

31%

toward the 2050 50 percent GHG reduction target

21 https://naturalgas.picarro.com/support/library/documents/picarro_solution_brief_whitepaper

There are two ways to reduce GHG emissions associated with natural gas supply:

1. Through the injection of non-fossil, renewable gases into the natural gas delivery system
2. By avoiding methane emissions from the upstream extraction of fossil natural gas.

For each of these options the factors to consider are:

- Location – with preference given to sources within or near Washington Gas' service territory
- Availability of supply to meet demand
- Proximity to existing natural gas delivery infrastructure
- Cost

Assuming supportive government policies and regulatory framework are in place to promote low-carbon gas supply, the Plan calls for the phased introduction of non-fossil-based gases that are expected to achieve the emissions reductions summarized below.

Low Carbon Fuel Source Volumes

YEAR	Total BCF	RNG BCF	% System RNG	P2G+ Green Hydrogen BCF	Total Low-Carbon Gas BCF	Percent of Low-Carbon Gas
2018	24.41	-	0%	-	-	0%
2025	24.22	0.48	2%	-	0.48	2%
2032	23.20	3.00	13%	-	3.00	13%
2050	**17.02**	**7.00**	**41%**	**2.80**	**9.80**	**58%**

HIGHLIGHTS:

Blending renewable fuels with fossil fuels or substituting them altogether is a proven path for creating low-carbon fuels.

The principal benefits to the District are:

- Limited additional investment in the electrical or natural gas distribution systems
- Does not require customers/end users to purchase new or different equipment
- The lowest-priced clean fuels for industry, transportation and the individual consumers
- New industries with permanent jobs

SOURCING AND SUPPLY

RENEWABLE NATURAL GAS

As defined by The American Gas Association; "Renewable natural gas (RNG) is derived from biomass or other renewable resources and is a pipeline-quality gas that is fully interchangeable with conventional natural gas." RNG is carbon neutral, extremely versatile and fully compatible with the U.S. pipeline infrastructure. It can be directly used in homes and businesses, in manufacturing and heavy industries and also for electricity production and as an alternative fuel for transportation. One of the most attractive features of RNG is that it can be introduced and provide emissions reductions without necessitating upgraded or new equipment by the end-user. Because of these benefits, RNG is a key element in the Plan.

AltaGas commissioned ICF to engage in a separate study of the potential for RNG to decarbonize Washington Gas' fuel supply in the District, including an assessment of supply availability and accessibility in fulfillment of Merger Commitment #6. The study found that ample supplies could be available for delivery by Washington Gas. Outputs of this study were integrated into the Plan's scenario modeling.

Assuming the enactment of supportive policy and regulatory framework, Washington Gas (and our third-party suppliers) can purchase RNG and other low carbon fuel specifically for delivery to District customers. The Plan calls for increasing volumes of RNG to be delivered through a combination of local, regional and national supply sourcing in staggered, stair-stepped amounts with varying contract durations.

For more information see Appendix D: Renewable Gas Study

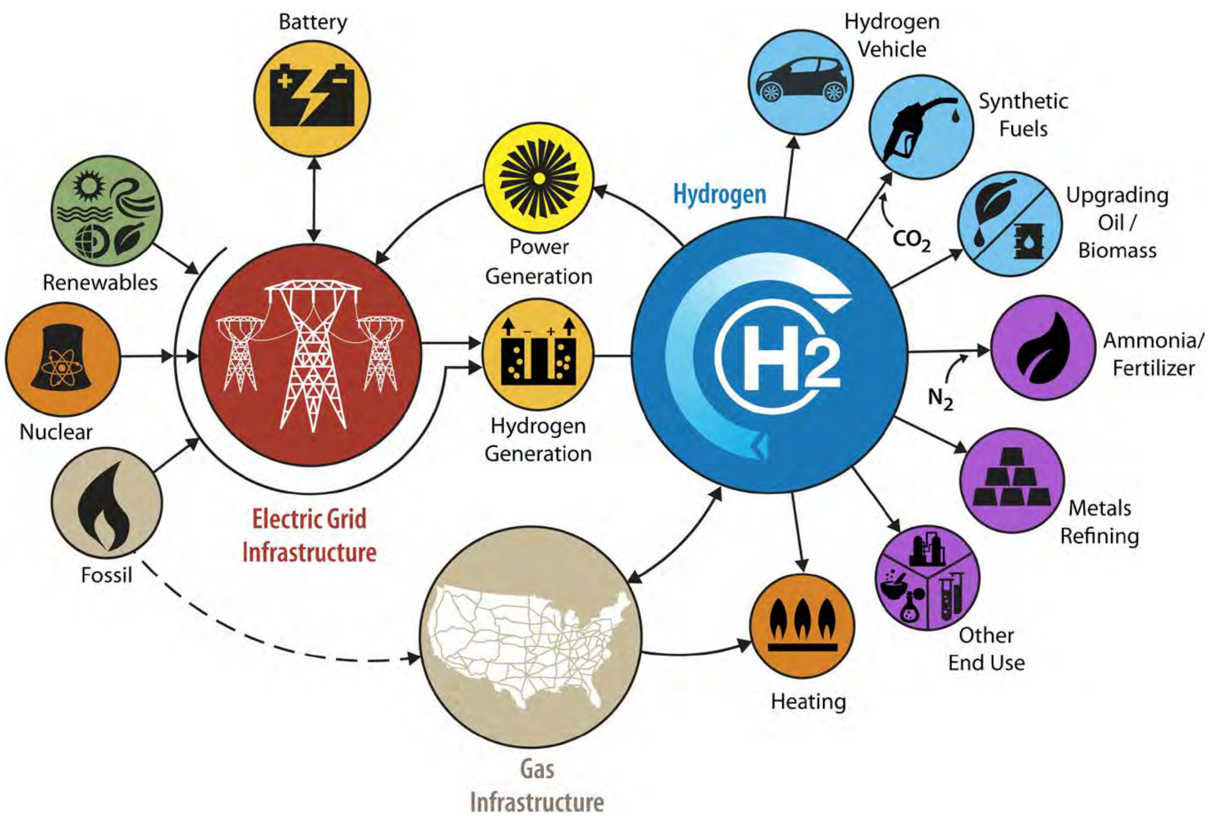
SOURCING AND SUPPLY

POWER-TO-GAS AND GREEN HYDROGEN

Power-to-Gas (P2G) is another renewable gas supply source. P2G is a promising and growing energy technology that converts electricity to a gaseous fuel effectively storing excess electricity in gas form rather than in conventional batteries. P2G has two distinct advantages over batteries for storing energy, including storing energy from excess renewable sources: i) unlike today's limited capacity batteries, nearly unlimited amounts of electricity can be easily stored for very long periods of time, and ii) fuel from P2G can be stored and used with existing infrastructure.[22] When the electricity is generated by renewable resources, such as wind and solar, then the resulting gas is considered carbon neutral.

The key process in P2G is the production of green hydrogen from renewably generated electricity by means of electrolysis which uses electricity to split water into hydrogen and oxygen.[23] This green hydrogen conversion method is not new, and there are three electrolysis technologies with different efficiencies and in different stages of development and implementation. This can be a particularly attractive option when the electricity is generated from wind, solar or hydro-electric plants when they are producing more power than is needed and must otherwise be curtailed. Alternatively, dedicated renewable electricity installations may be used to produce a firm supply of green hydrogen. This green hydrogen can be blended into the natural gas system directly, reducing the carbon intensity of the gas as well as providing a higher temperature at combustion which reduces the amount of gas needed to provide the same amount of heat.

Combining this green hydrogen with carbon dioxide (ideally carbon from captured emissions, for example from a brewery or other processing facility) produces methane that can be directly fed into the natural gas system. Fuel produced in this manner will be carbon neutral and may even be considered carbon negative.



Source: https://www.energy.gov/eere/fuelcells/h2scale

22 Lawrence Livermore Natural Labs https://www.llnl.gov/news/using-microbes-convert-co2-natural-gas

23 Hydrogen can be produced by the electrolysis of water (using an electric current to break water into its component elements of hydrogen and oxygen). When this electric current is produced by a renewable source (e.g. solar, wind or other renewable sources), the hydrogen is known as green hydrogen. https://www.geopura.com/blog/why-we-should-start-using-green-hydrogen-in-2019/

THE BENEFITS OF HYDROGEN

Hydrogen allows energy from renewables to be stored in a tank for use at a later date, time and place. That is very different from the usual output of a wind turbine or a solar array, which must be transmitted and used immediately. Its flexibility as either a fuel or a storage medium is similar to petroleum, with none of the fossil fuel deficiencies. Long duration, even seasonal storage, has been the holy grail sought by the renewables industry. Since hydrogen can be made from renewables and stored in a tank, it serves as:

- A carbon-free fuel that emits no GHG emissions
- An enabling technology to deal with the intermittency of renewables
- A long-duration storage solution[24]

The technology to produce clean hydrogen from water and electricity has been commercially available for more than 50 years. As renewables increasingly come on line as a source for electricity, the idea of using them as a source for generating the hydrogen becomes increasingly attractive. P2G technologies are showing tremendous promise as demonstrated by several facilities operating in Europe (e.g. Audi's 6-MW P2G facility in Germany), Japan and a SoCalGas® partnership with the National Fuel Cell Research Center (NFCRC) at the University of California at Irvine (UCI) that launched the first U.S. P2G project. A second project with UCI, a simulation of the campus microgrid, showed that P2G could increase their use of renewable power from 3.5 percent to 35 percent.

Currently electolyzers are expensive but are expected to come down in price, especially as states like New Jersey are investing heavily in integrating green hydrogen into their power mix. A key inflection point for P2G is anticipated beginning around 2020 "as costs reach parity in more areas" according to Navigant Consulting.[25] Reflecting this reality, the Plan assumes that with supportive government policies, Power-to-Gas pilot programs will begin in 2035, and then grow steadily through 2050.

It remains to be determined whether these technologies can produce low carbon/no carbon gas at a lower price than RNG. If they do not, it is expected there is sufficient RNG available to take the place of P2G and green hydrogen blending in the scenarios used to develop the Plan.

SOURCING AND SUPPLY

CERTIFIED NATURAL GAS

Efforts to reduce methane emissions during the sourcing of traditional natural gas are also underway. The most practical near-term option is to arrange physical procurement of certified natural gas via third parties. Several third-party companies apply certification criteria to specific wells and/or producing regions. The criteria are tiered depending upon how sustainable the practices are, with higher levels being modestly more expensive. Longer-term efforts are underway to identify and separate the environmental attributes associated with certain gas producers on a nation-wide basis. This effort would use "Big Data" and ultimately separate the attribute from the physical gas so that they could be acquired and/or traded on exchanges, like RECs or Renewable Identification Numbers (RINs).

Certified gas is very inexpensive. Based on our discussions with providers/deal makers, we estimate a per annum cost of $27,000 to $270,000 based on the procurement of 20 percent of sales gas volume for today's residential District customers. Since the procurement of natural gas represents the largest expenditure by the Washington Gas, exercising our buying power to drive emissions reduction in the natural gas value chain is an effective, sustainable strategy to help reduce GHG emissions. Washington Gas is currently in talks to collaborate with the Rocky Mountain Institute and others to more clearly quantify GHG emissions reductions from gas supply produced by best practice companies. With the necessary government policy and regulatory support, certified natural gas can be blended into existing gas supply and is expected to result in a 1 – 2 percent GHG emissions reduction.

24 https://www.forbes.com/sites/patsapinsley/2020/02/11/its-time-to-talk-hydrogen/#4552c8d0470b

25 The Future of Power-to-Gas Couldn't Be Brighter https://www.renewableenergyworld.com/2018/02/20/the-future-of-power-to-gas-couldn-t-be-brighter/#gref

How the Plan Was Developed

The Plan is designed to reduce GHG emissions throughout the natural gas value chain – from end use to distribution and sourcing. The Plan mirrors the District's climate goals by achieving a 50 percent reduction in GHG emissions associated with natural gas by 2032 and carbon neutrality by 2050 when compared with GHG emissions in base year 2006. In addition, some of the actions outlined in the Plan will help reduce emissions in other sectors (such as reducing emissions produced by transportation and electricity generation).

AltaGas selected ICF, a consulting firm recognized for its leadership in energy and climate change policy, research, and technical analysis, to assist with the development of the Plan.

The Plan was informed by, and based on, the desire to develop a framework that will accommodate changes to market and policy realities, such as in the District's climate goals, energy needs, and economic growth, as well as technologies and innovations that are anticipated to be refined and/or developed over the next 30 years. The Plan was developed to recognize and optimize the following considerations:

- Ensuring public safety, resilience and reliability by protecting against interruptions in energy delivery and use from weather-related and other disruptions;
- Evaluating the GHG emissions reduction potential of various approaches as well as associated cost per ton of carbon abated ($/$CO_2$e ton);
- Moderating the impact on customer cost, including up-front capital costs (i.e. for new equipment) and monthly energy costs, particularly for lower-income households;
- Preserving energy availability during both normal and peak demand conditions;
- Leveraging existing assets to their fullest potential;
- Sequencing actions based on technology and regulatory maturity;
- Pursuing a non-prescriptive approach that maximizes opportunities presented by innovations, technological advances and scientific understanding; and
- Implementing a regulatory framework and policy that facilitates and incents emission reduction measures.

Four different energy scenarios were modeled and evaluated to compare and contrast their ability to achieve the District's climate goals. All the scenarios considered reflect the District's requirement to have 100 percent of the District's electricity usage come from renewable generation by 2032.[26]

Scenario 1, **Business as Usual (BAU)**, is used as a reference case against which to compare all other scenarios. Based on the 100 percent renewable portfolio standard (RPS), GHG emission reductions in 2032 and 2050 are approximately 73 percent to 75 percent relative to 2006.

Scenario 2, **Partial Decarbonization**, uses BAU case as its foundation, with additional penetration of EVs, increased energy efficiency and modest decarbonization of gas supply including introduction of RNG and certified gas. It achieves additional GHG emissions reductions (82 percent) associated with those actions by 2050.

Scenario 3, **Policy-Driven Electrification**, uses the BAU case as its foundation, reaches net zero carbon emissions in the District in 2050 by requiring existing homes and businesses using natural gas to convert to electricity and banning natural gas for all new construction. It also reflects aggressive market penetration of electric vehicles and relies on a small volume of carbon offsets.

Scenario 4, **Fuel Neutral Decarbonization**, uses the BAU case as its foundation, reaches net zero carbon emissions in the District in 2050 by including significant actions to decarbonize the natural gas supply through the introduction of RNG, certified gas, and green hydrogen. As described in the preceding sections, it leverages expected improvements in technologies, aggressive energy efficiency programming for residential and commercial buildings, as well as hybridized dual fuel approaches. It also includes aggressive market penetration of electric vehicles and relies on a small volume of carbon offsets.

26 A more complete list of detailed assumptions (including discount rates) can be found in the ICF Technical Analysis Executive Summary which is appended to this Plan (Appendix E).

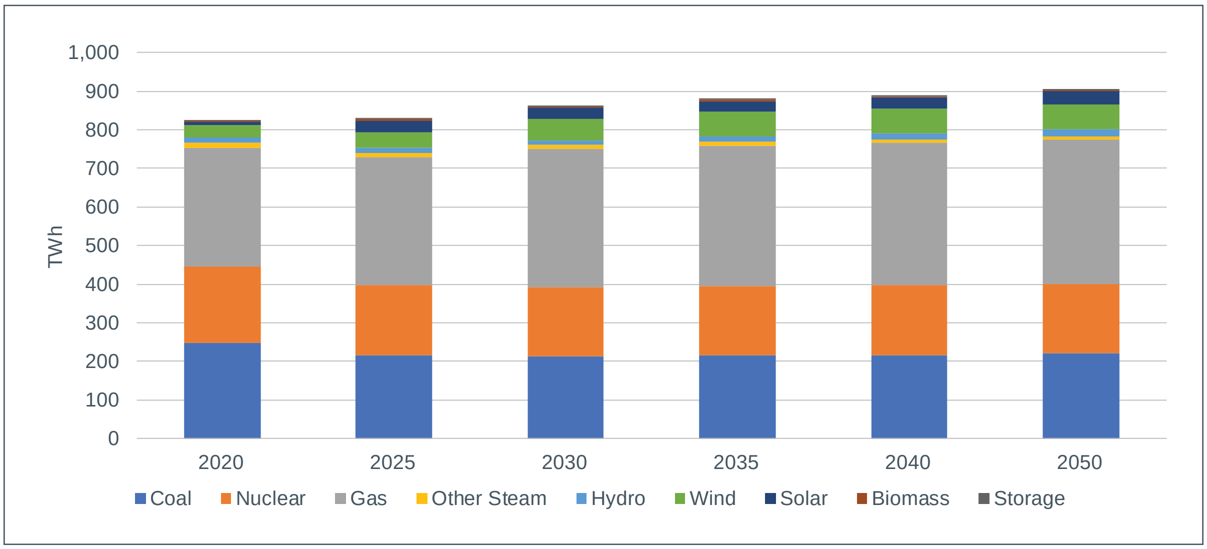
Overview of Energy in the District

The District of Columbia occupies ~68 square miles, is home to over 700,000 people, and more than 20,000 business and 300,000 housing units.[27] The District consumes 11.3 TWh of electric power and 101 BCf of natural gas and 2,400 MBarrels of petroleum products annually[28]. The District imports nearly all of its energy except for 1.3 percent of the electric generation from rooftop solar[29] and biomethane[30]. WGL Holdings, Inc. (WGL) helped seed some of this generation through initiatives that included the installation of 68 solar projects.

About 60 percent of the energy used in the District is consumed by the commercial sector, which includes the many federal buildings, museums, and universities that are a large part of the city's economic activity. The District of Columbia receives nearly all its electricity from power plants in other states through the distribution system of the local electric utility, which receives power via PJM interconnection that manages electricity transmission on the regional power grid for the District and all or part of 13 states.[31]

PJM is the federally regulated regional transmission system operator that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District.[32] While the District is but a small fraction of the total demand served by the greater PJM interconnection network (approximately 1.5%) the overall demand from other jurisdictions within PJM will have a significant impact on the cost of electricity for the District. As the figure below illustrates, though PJM is forecasting substantial growth in wind and solar generating mix (5 percent of 2020 generation and 11 percent of 2050 generation assuming business as usual), it remains a small portion of the overall electric generating capacity.

PJM Generation Mix 2020 - 2050



Source: PJM Projection

The District of Columbia receives its natural gas via Washington Gas' local distribution system, which, in turn, obtains the natural gas via interstate pipelines. The natural gas interstate transmission pipeline systems allow for the seamless movement of natural gas across the country, connecting sources of supply and storage to large industrial users and local distribution companies (LDCs) who, in turn, deliver energy to residential and commercial customers. The US DOT PHMSA Office of Pipeline Safety regulates the safety of construction, operation and maintenance of interstate transmission pipeline systems, while the Federal Energy Regulatory Commission (FERC) regulates the transmission and sale of natural gas for resale in interstate commerce. The District of Columbia Public Service Commission oversees Washington Gas rates and other local operational matters.

27 https://www.census.gov/quickfacts/DC

28 https://www.energy.gov/sites/prod/files/2016/09/f33/DC_Energy%20Sector%20Risk%20Profile.pdf

29 The District generates 0.071 TWh of electric power from small scale solar, 0.057 TWh from biomass and 0.023 TWh from natural gas, representing 1.3% of total electric consumed 11.358 TWh https://www.energy.gov/sites/prod/files/2016/09/f33/DC_Energy%20Sector%20Risk%20Profile.pdf

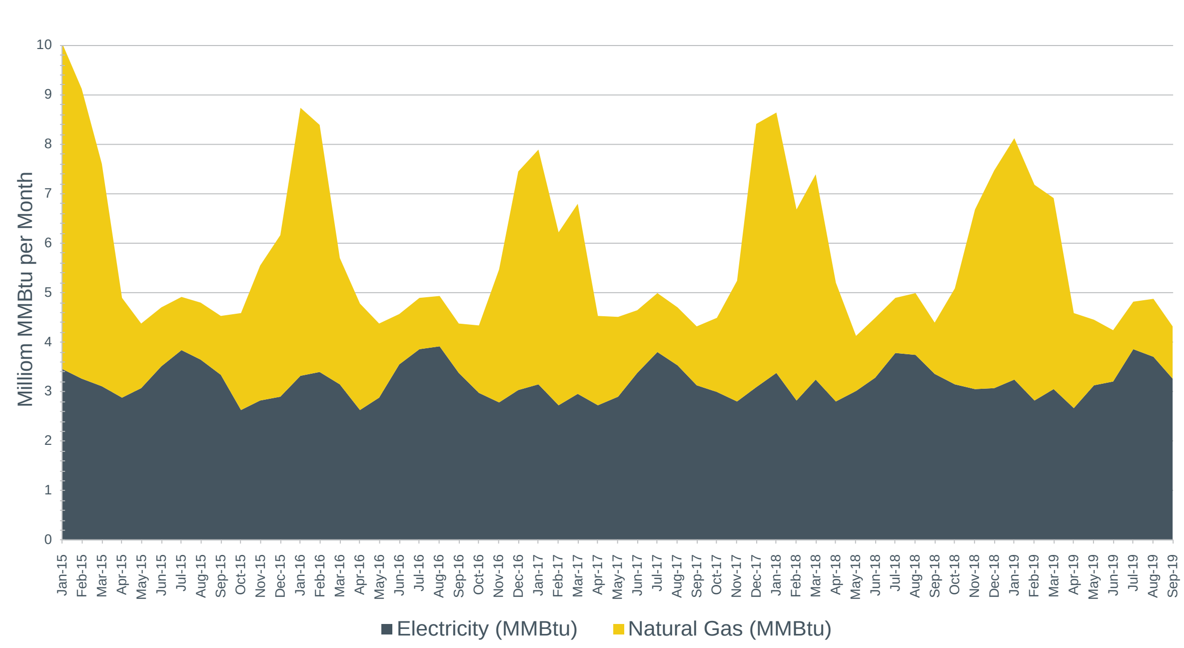
30 https://www.dcwater.com/sites/default/files/Blue_Plains_Plant_brochure.pdf

31 https://www.eia.gov/state/analysis.php?sid=DC

32 https://www.pjm.com/about-pjm/who-we-are.aspx

The District of Columbia's energy consumption is highly seasonal, with peak energy consumed occurring in the winter months.

Monthly Natural Gas and Electricity Energy Consumption in the District of Columbia



Source: US Energy Information Administration

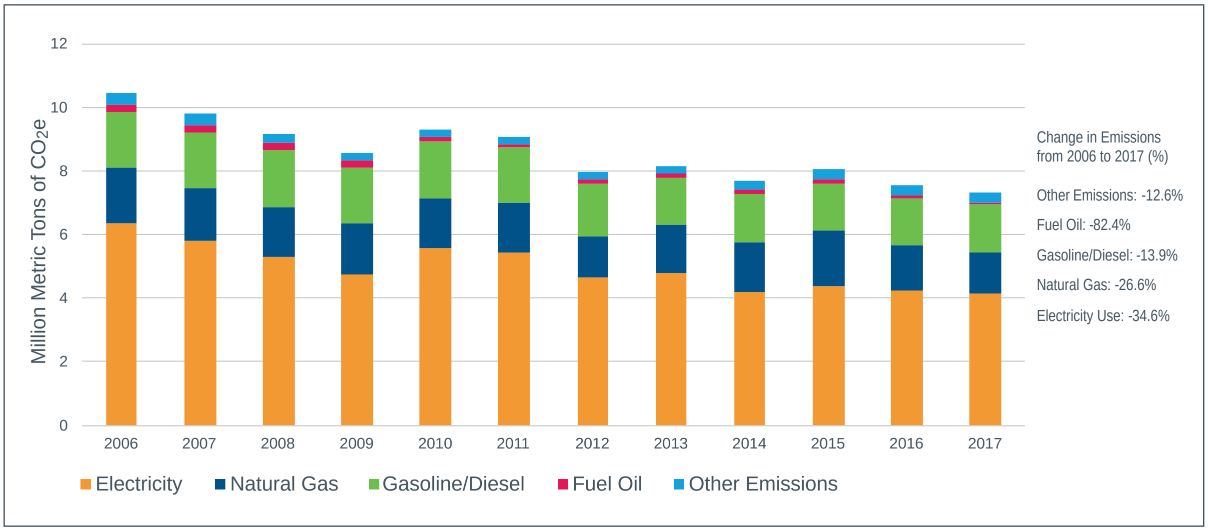
In 2017 the District was named the first Leadership in Energy and Environmental Design (LEED) Platinum City in the world; and boasts the most LEED Certified buildings and the most LEED space per resident, according to the US Green Building Council. With 30 percent of all points allocated to building energy efficiency[33], LEED has a strong emphasis on energy and the associated impacts, giving extra points for advanced energy metering and demand response. Many of these buildings depend on high-efficiency natural gas equipment for LEED eligibility. Natural gas systems that earn LEED certification Rating System Points include: high efficiency boilers, furnaces, and water heaters; high efficiency energy recovery systems; high efficiency food service equipment; and desiccant regeneration systems.

STRONG EMISSIONS REDUCTIONS SINCE 2006; MORE REMAINS TO BE DONE

The use of clean efficient natural gas has well positioned the District to meet its GHG emissions reduction targets. GHG emissions from the direct use of natural gas have declined 26.6 percent. In addition, the increased use of natural gas, replacing coal, for electricity generation has been a key driver of the 34.6 percent GHG emissions reduction since 2006. Similarly, AltaGas is leveraging its Canadian midstream and export capabilities to support the transition from high carbon fuels like coal and oil to lower carbon natural gas and natural gas liquids (NGLs) throughout Asia, which accounts for a third of global GHG emissions.

33 https://www.usgbc.org/articles/how-leed-saves-energy

Historical District of Columbia GHG Emissions by Fuel Type



From 2006 to 2017, the District reduced citywide emissions by 30 percent, achieving almost 60 percent of its 2032 goal.

The District's most recent – 2017 – GHG emissions inventory reported the following sectoral GHG emissions:

- The power sector accounted for the majority of emissions (55 percent of total emissions) attributed to the District of Columbia, including 42.5 percent in non-residential buildings, 8.9 percent in residential buildings, and 3.8 percent in other applications.
- According to the District's Clean Energy Plan[34] the rising use of natural gas for electric generation has been the key factor in the District's reduction in electricity carbon intensity, along with the growth of renewable electric generation. GHG emissions associated with electricity – primarily due to natural gas replacing coal generation - have declined by 34.6 percent since 2006.

As the figure below illustrates, today no other energy source matches the high energy/low GHG ratio (1.53) that natural gas provides.

Comparison of Fuel Source Energy Content and GHG Emissions

Energy Sources and Associated GHG Emissions	Energy Consumption (Billion kBtu's)	GHG Emissions ($MTCO_2e$)	Energy Consumption (Percent)	GHG Emissions (Percent)	Energy to Emissions Ratio
Natural Gas					
Residential	13.44	714,776	16.0%	9.8%	- - - -
Non-Residential / Other	9.25	491,790	11.0%	6.7%	- - - -
Natural Gas Distribution	- - - -	**89,447**	**0.0%**	**1.2%**	- - - -
Total Natural Gas	**22.69**	**1,296,013**	**27.1%**	**17.7%**	**1.53**
Electricity					
Residential	6.40	648,697	7.6%	8.9%	- - - -
Non-Residential / Other	32.73	3,388,270	39.1%	46.2%	- - - -
Total Electricity[35]	**39.13**	**4,036,967**	**46.7%**	**55.1%**	**0.85**
Fuel Oil and Kerosene	**0.57**	**470,159**	**0.7%**	**6.4%**	**0.11**
Gasoline and Diesel Transportation	**21.35**	**1,525,832**	**25.5%**	**20.8%**	**1.22**
Total	**83.75**	**7,328,971**	**100.0%**	**100.0%**	

34 Clean Energy DC – August 2018, p. 24

35 Electricity grid losses and emissions are based on eGRID data

Natural Gas: More Energy/Fewer Emissions

Natural gas provides critical energy to key sectors that drive the District economy including the federal government, technology, construction, international business, and hospitality. For more than 170 years, energy provided by Washington Gas has been an integral part of the District's energy portfolio. Today natural gas provides low carbon energy to fuel highly efficient thermal applications including heating and hot water for residential and commercial buildings, as well as cooking for families and restaurants, etc. Washington Gas also fuels 461 District buses[36] with compressed natural gas, producing virtually no particulates and approximately 25 percent fewer GHG emissions than conventional diesel buses.

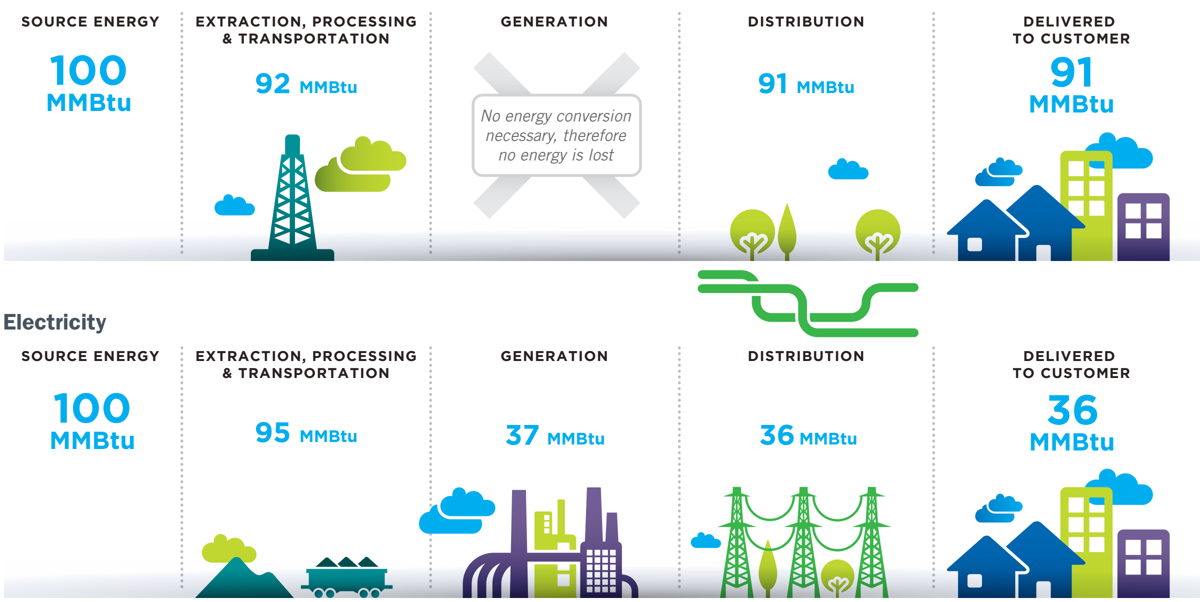
In 2017
Natural Gas provided
27%
of the energy used

While emitting
18%
of the District's emissions

According to the 2017 emissions inventory natural gas use, primarily in the residential and non-residential buildings sectors, accounted for about 17.7 percent of the District's 2017 GHG emissions, with 9.8 percent attributable to the residential sector, 4.9 percent to non-residential buildings, 1.8 percent from WMATA and other applications, and 1.2 percent from natural gas distribution system emissions.[37]

Because natural gas is warm and quickly responsive, it is the preferred method of heating and cooking for 165,000 district residences and businesses. It is over **99 percent reliable** and **affordable,** costing $879 less than a comparable home using electricity for heating, hot water, cooking and clothes drying.[38] It is also **highly efficient**, with 91 percent of the energy value delivered, compared to only 36 percent for electricity, as the following diagram illustrates.[39]

Natural Gas – Delivering 2.5 Times More Energy Than Electricity



Natural gas delivers more than 90 percent of the energy from the source to the customer's doorstep. Conversely, 64 percent of the energy used to generate electricity is 'lost' and therefore wasted.

36 https://www.washingtongas.com/media-center/green-commute
37 https://doee.dc.gov/service/greenhouse-gas-inventories
38 http://playbook.aga.org/#p=8
39 http://playbook.aga.org/#p=50

NATURAL GAS: THE DISTRICT'S MOST CRITICAL PEAK DAY ENERGY RESOURCE

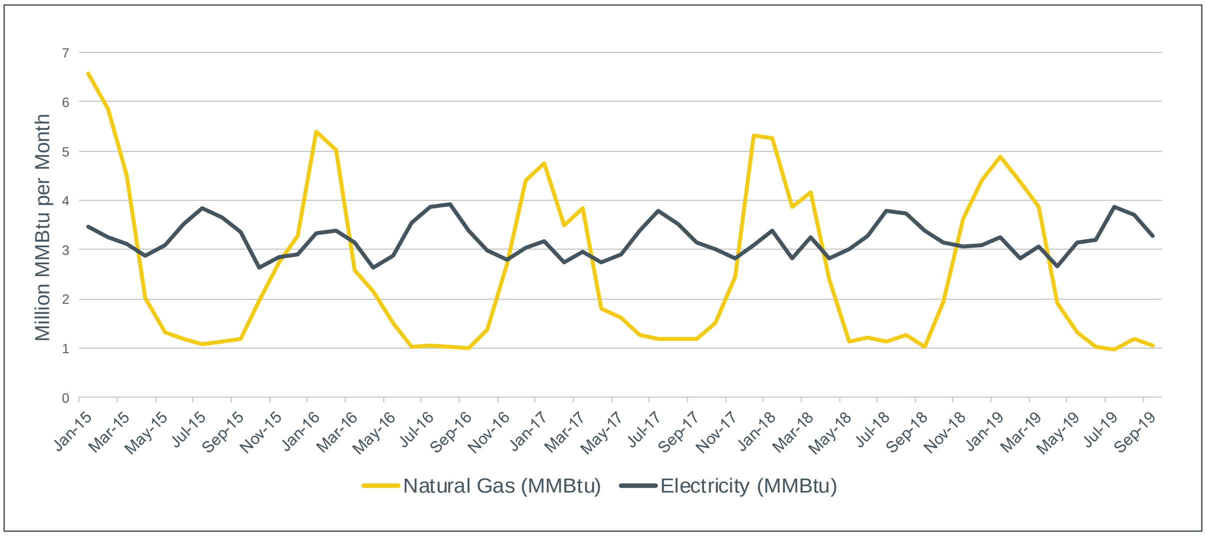
By design, the natural gas distribution system in the District is capable of delivering 61 percent more energy on a peak winter day than the electric grid is designed to deliver during a peak summer day. The natural gas distribution system is designed to deliver twice as much energy during a peak winter hour than the electric grid is capable of delivering during a peak summer hour.

Actual physical deliveries of natural gas mirror design day plans.

> Over the last five years, during high demand winter peak periods, the natural gas system delivered **60 percent more energy** to District customers than the electric grid delivered during its highest demand (summer) periods.[40]

The natural gas system also possesses unique and dynamic load following capabilities. During a typical January, the natural gas system delivers more than five times the energy as it does during the summer months, as illustrated in the following figure:

Comparative Monthly Natural Gas and Electricity Energy Consumption in the District of Columbia



AltaGas: Proven Partner in GHG Reduction

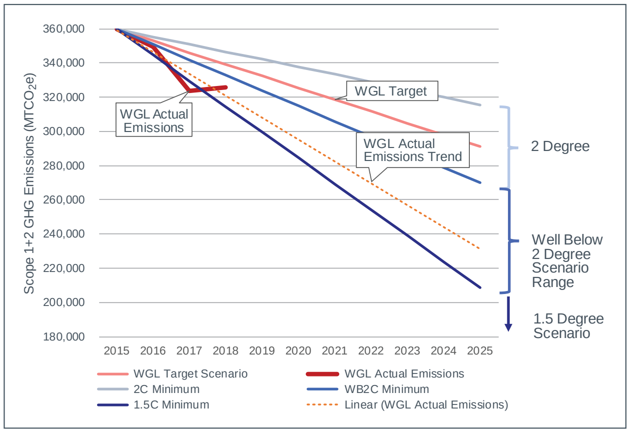
AltaGas' subsidiary, Washington Gas, has a long-demonstrated commitment to reducing GHG emissions and addressing climate change in its operations.

1. In 2011, four years prior to the Paris Agreement, the company set aggressive 2020 targets for GHG emissions reductions for its fleet and facilities as well as to reduce the carbon intensity associated with gas delivery. In 2016 Washington Gas announced it had exceeded those goals four years ahead of schedule.[41]
2. Less than a year later, it announced new, updated targets for 2025. The new targets; carbon neutrality for Washington Gas' fleet and facilities by 2025 and a 38 percent reduction in fugitive carbon intensity per delivered therm of natural gas, put the Company on track to meet the "2 degrees Celsius" scenario that reflected the guidance from the Intergovernmental Panel on Climate Change (IPCC) for the 2015 Paris Conference as being necessary to avoid the most damaging impacts of climate change.

40 January 2015 for natural gas; August 2016 for summer cooling
41 https://www.washingtongas.com/newsroom/2016/washington-gas-exceeds-carbon-reduction-goals-four

3. An analysis conducted by consulting firm WSP shows the actual Scope 1 and Scope 2 GHG emissions reductions from 2015 through 2018 on a trend line comfortably in the "well below 2 degrees" GHG emissions reductions range of 2.5 percent to 4.2 percent per year – as defined by the Science Based Target Initiative.[42]

WGL Scope 1+2 GHG Emission Reduction Analysis



4. Washington Gas has implemented energy efficiency measures that, as of 2018, have reduced its emissions more than 78 percent from its own fleet and facilities. Washington Gas has also achieved a 24 percent reduction in emissions intensity per therm of gas delivered and is on track to meet both of our targets.

5. An even more impactful contribution in the District has been the direct use of natural gas for thermal purposes. A home using natural gas for heating, cooking, hot water and clothes drying produces about half of GHG emissions than a comparable home using electricity for those same applications. It also saves the household $879 per year.[43]

CASE STUDY | 78 PERCENT EMISSIONS REDUCTION

Washington Gas has reduced emissions from its facilities and fleet by more than 78 percent since 2008. This demonstrates not only our commitment, it also serves as a local pilot and proof of concept.

With constructive stakeholder collaboration, supportive policy and regulatory certainty, Washington Gas can implement the measures proposed in the Plan and can continue to be an effective partner in achieving the District's climate goals.

The Plan once again puts AltaGas at the forefront; having taken a deep dive into the possibilities, emerging and nascent technologies and outlining the company's desire to support those innovations and to pilot/proof of concept as well as working to bring promising low-carbon opportunities to the District over the course of the next 30 years.

Policy Considerations

The Plan sets forth GHG emissions reduction measures based on their ability to meet the desired GHG emissions reductions while preserving the energy affordability and reliability Washington Gas' customers need. To implement the Plan measures in support of the DC Climate Goals, collaborative and good faith dialogue among Washington Gas, the DC PSC, policymakers and various other stakeholders will be required.

Constructive stakeholder collaboration, supportive policy and regulatory certainty facilitate investments in GHG reduction and support implementation of the measures proposed in the Plan such that Washington Gas can continue to be an effective partner in achieving the District's climate goals while maintaining its financial integrity and its ability to continue to attract capital to safely and reliably serve its customers in the District.

42 The analysis completed by WSP used the methodology prescribed by the SBTi for setting science-based targets. The Sectoral Decarbonization Approach is currently unavailable for our business sector, so WSP utilized the Absolute Contraction method using SBTi's reduction percentages required to meet the different scenarios under this methodology. WSP confirmed the reduction range required for the "Well-below 2 degree" scenario was an average reduction of 2.5 percent to 4.2 percent per year. The annual average of the total reductions in Washington Gas' emissions over the 3-year period from the end of 2015 through the end of 2018 falls in this range.

43 American Gas Association Playbook 2019 p. 8 http://playbook.aga.org/?utm_source=google&utm_medium=banner&utm_campaign=2019_AGAPlaybook&utm_term=playbook#p=8

The following section outlines policy considerations and regulatory mechanisms that are necessary to enable the implementation of GHG emissions reduction measures identified in the Plan. Washington Gas will seek consideration for the following over-arching regulatory mechanisms.

1. Decoupling rates from volumetric throughput. This will enable Washington Gas to support energy efficiency while recovering operating costs to preserve safety and reliability. Due to the aggressive efficiency measures proposed and resulting decrease in energy deliveries, such decoupling is a necessity.
2. Developing a cost recovery mechanism that would socialize the costs and benefits of gas use to all energy users. It would recoup the avoided cost of overbuilding peak electricity and associated storage from electric utilities, which is made possible by gas service. Recovery would help equitably distribute fixed costs of the natural gas system and maintain reasonable rates for gas (and electric) customers.

POLICY – END-USE

Policies to facilitate measures specifically related to energy efficiency promotion and programs as well as accelerating the deployment of high-efficiency equipment and appliances include:

1. Expanding energy efficiency programs to include best-in-class programs. These programs are described in the end use discussion. A detailed description of programs in the District, Maryland and Virginia is included as Appendix A;
2. Ensuring cost recovery and enabling utilities to earn a return on investment (ROI) for investments in next-generation end-use technology;
3. Allowing for cost recovery associated with the promotion of ready-now lower GHG emissions appliances, contractors' education, demonstration pilots, and similar items;
4. Providing deeper energy efficiency incentives for emerging technologies with very high GHG emissions reduction potential; this could include multi-fuel source, integrated whole house performance programs;
5. Initiatives to encourage the District's energy providers, including local distribution companies and others, to form working groups and create the opportunity for parties to seek a better and unbiased understanding of emerging hybrid heating technologies and an equitable pathway for implementation;
6. Utilizing accelerated recovery mechanisms to support infrastructure investment in service areas of high CHP/demand potential;
7. Promoting innovative programs such as Energy as a Service, and enabling on-bill financing mechanisms, including third party financing, to encourage adoption of technologies and equipment for energy conservation; and
8. Applying tiered performance incentives (e.g. ROI adders) to support the implementation of behavioral energy efficiency programs.

POLICY – TRANSMISSION AND DISTRIBUTION

In addition to programs currently in place, there are other policies that policymakers and the DC PSC can pursue to facilitate GHG emissions reduction during the transmission and delivery of natural gas, including:

1. Approval for PROJECT*pipes* 2 (currently under consideration);
2. Cost recovery for investments in new detection equipment and personnel and/or pilot project participation;
3. Approvals necessary to deploy advanced leak detection technologies; and
4. Built-in incentives for performance that reward timely deployment and results.

POLICY – SOURCING AND SUPPLY

The development of RNG production sources for national, regional and local supply scenarios in the greater Washington, D.C. metropolitan region are all contingent upon Washington Gas being able to gain approval of some kind of legislative and/or regulatory structure that will include a timely cost recovery mechanism for Washington Gas.

This policy structure should address the following key areas of cost recovery:

1. Allow for long-term supply contracts for acquisition of low-GHG emissions gases including certified natural gas, RNG, P2G, Green Hydrogen, with an agreed upon volumes, durations and pricing;
2. Allocate incremental cost of low carbon gas supply to all customers in the District;
3. Rate base and approve return for investments in interconnection facilities and equipment to facilitate access to low carbon gas supplies needed to meet gas quality specifications and standards (odorization, metering, gas chronometers, emergency shut off valves, etc.);
4. Rate base of investment in larger facilities such as pipelines and low carbon gas production, supply facilities and recovery of pipeline capacity costs that would support and facilitate the development and access to RNG and other low carbon supply;
5. Enable investments associated with the development and deployment of next-generation technologies, including pilot programs and funding research [e.g. via Gas Technology Institute (GTI) or other associations] and other initiatives;
6. Developing regulatory framework and policy to enable third party retailers to provide additional quantities of low/no carbon gas supply to customers, including;
   a. Allowing incremental volumes of low carbon gas supply as a percentage of third-party marketer supply in set tranches over time from now until the year 2050; and
   b. Require third-party retailers to report to Washington Gas annual sales volume and environmental attributes of all low carbon gas sold and delivered to Washington Gas customers.

The significant reductions in GHG emissions available through the utilization of low carbon fuel supply are predicated upon the timely approval of supportive policy. Because the regulatory process in the District lacks a suspension statute, achieving regulatory certainty is a significant consideration. In some instances, it may be desirable for authorization related to cost recovery to be legislatively enacted. Because of the investment levels and project timelines required to support RNG and green hydrogen sourcing development, clarity regarding regulatory policy is critical.

CONCLUSIONS:

1. The Climate Business Plan, guided by a Fuel Neutral scenario, provides a pathway to meet the District's Climate Goals for $2.7 billion less than alternatives being proposed.
2. The Plan demonstrates that natural gas CAN be decarbonized; and natural gas infrastructure is tremendously valuable resource that can be leveraged to deliver and store – low/no/negative carbon fuel.
3. Washington Gas has earned an established reputation as a trusted partner, responsibly managing a set of valuable community assets; with history of proactive leadership in achieving GHG emissions reductions.
4. With the necessary policy changes and supportive regulatory framework to facilitate GHG emissions reductions, Washington Gas can enable cost-effective and deep GHG emissions reductions that support the achievement of the District's climate goals while preserving access to affordable, resilient and reliable energy.

Glossary of Terms

Biogas – is a type of biofuel that is naturally produced from the decomposition of organic waste. When organic matter, such as food scraps and animal waste, break down in an anaerobic environment (an environment without any oxygen) they release a blend of gases, primarily methane and carbon dioxide. Biogas from wetlands, for example, is a source of GHG emissions. Capturing these emissions at their source and using them to displace/replace fossil natural gas is often considered 'carbon neutral' or even 'carbon negative' because the emissions associated with its combustion are far lower than what naturally occurs.

British Thermal Units (Btus) - a measurement of the amount of heat required to raise the temperature of one pound of water by one-degree Fahrenheit.

Carbon dioxide equivalent (CO_2e) – standard unit for measuring carbon footprints. The idea is to express the impact of each different greenhouse gas in terms of the amount of CO_2 that would create the same amount of warming, allowing for direct comparison between the warming potential of different emissions.

Carbon Neutral – also called carbon neutrality – is a term used to describe the action of organizations, businesses and individuals taking action to remove as much carbon dioxide from the atmosphere as each put in to it. The overall goal of carbon neutrality is to achieve a zero-carbon footprint.

Carbon Intensity (CI) - the amount of carbon by weight emitted per unit of energy consumed. A common measure of carbon intensity is weight of carbon per British thermal unit (Btu) of energy.

Combined Heat & Power (CHP) – also called "cogeneration" CHP describes the concurrent production of electricity or mechanical power and useful thermal energy (heating and/or cooling) from a single source of energy.

Distributed Generation – when power is generated at or near the point of consumption/use.

Electrolyzer – device that use an electric current to provide the energy that splits a water molecule (H_2O) into hydrogen (H_2) and oxygen (O_2).

Fossil Gas – natural gas formed from buried combustible geologic deposits of organic materials from decayed plants and animals that have been exposed to heat and pressure in the earth's crust over hundreds of millions of years.

Greenhouse Gas (GHG) – A greenhouse gas is a gas that absorbs and emits radiant energy within the thermal infrared range. Greenhouse gases cause the greenhouse effect. The primary greenhouse gases in Earth's atmosphere are water vapor (H_2O), carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and ozone (O_3).

Paris Agreement – the 2015 multi-national agreement to combat climate change and to accelerate and intensify the actions and investments needed for a sustainable low carbon future. Its central aim is to strengthen the global response to the threat of climate change by keeping a global temperature rise this century well below 2 degrees Celsius above pre-industrial levels and to pursue efforts to limit the temperature increase even further to 1.5 degrees Celsius.

Power to Gas (P2G) – Technology that utilizes electrical power to split water into hydrogen and oxygen by means of electrolysis. Can be injected into the natural gas system as hydrogen or combined with carbon dioxide and be converted into methane for injection or use as transportation fuel. Particularly attractive option when green hydrogen is generated by electricity generated from wind, solar or hydro power.

Renewable Natural Gas (RNG) – Renewable Natural Gas – Pipeline compatible gaseous fuel derived from biogenic or other renewable sources that has lower lifecycle carbon dioxide equivalent (CO_2e) emissions than geological natural gas.

Scope 1 emissions – direct emissions released from on-site fossil fuel combustion and fleet fuel consumption.

Scope 2 emissions - indirect emissions from sources that are owned or controlled by the organization. Includes emissions that result from the generation of electricity, heat or steam purchased by the company from a utility provider.

Scope 3 emissions – indirect emissions from sources not owned or directly controlled by but related to the company activities such as employee travel and commuting. Scope 3 also includes emissions associated with customers. Some Scope 3 emissions can also result from transportation and distribution (T&D) losses associated with purchased electricity.

Therms – a measurement of the amount of heat energy in natural gas, equal to 100,000 BTUs.

List of Acronyms

Acronym	Description
EIA	Energy Information Administration
BAU	Business as Usual
CHP	Combined Heat and Power
CO_2	Carbon Dioxide (CO2e) – Carbon dioxide equivalent
COP	Coefficient of Performance
DCSEU	DC Sustainable Energy Utility
DOE	Department of Energy
DOEE	District of Columbia Department of Energy & Environment
EaaS	Energy-as-a-Service
EPA	Environmental Protection Agency
EV	Electric Vehicles
GHG	Greenhouse Gas
ICF	ICF Resources, LLC
NHTSA	National Highway Traffic Safety Administration
P2G	Power-to-Gas
RECs	Renewable Energy Credits
RNG	Renewable Natural Gas
RPS	Renewable Portfolio Standard
WGL	WGL Holdings, Inc.
WMATA	Washington Metropolitan Area Transit Authority

Appendices

Appendix A: Energy Efficiency Programs Gap Analysis

WGL offers several programs that cross the jurisdictional boundaries. These include:

1. **Master Meter Conversion program:**[44] This program offers the ability to convert large residential buildings from a single meter to individual customer meters. This is a measure that can facilitate greater "ownership" of energy efficiency measures.
2. **8A Housing Program:**[45] WGL provides technical expertise to work with low-income buildings to provide energy efficiency natural gas options, including design in pre-construction as well as retrofits of existing businesses.

DISTRICT OF COLUMBIA PROGRAMS

The DCSEU, which is funded by Washington Gas and Pepco ratepayers, runs energy efficiency programs in Washington, DC. The DCSEU provides energy conservation tips and conducts home energy audits. For its residential customers, DCSEU offers rebates for a wide variety of appliances, including smart thermostats, water heaters, heating appliances, and air conditioners. In 2018, the DCSEU participated in a residential heat pump study and worked with participating customers to optimize energy efficiency via smart thermostats with its Seasonal Savings program. For its commercial and industrial customers, the DCSEU offers rebates for efficient lighting, heating equipment, water coolers, and other appliances.

Table 1. DC WGL Rebates[46 47]

Appliance Type	Eligible Equipment	Efficiency Requirement	Rebate
Space Heating	Furnace	ENERGY STAR certified and minimum 94% AFUE	$500
Space Heating	Boiler Tier 1	ENERGY STAR certified and minimum 90% AFUE	$500
Space Heating	Boiler Tier 2	ENERGY STAR certified and minimum 95% AFUE	$750
Space Heating	Boiler Reset Controls	N/A	$250
Water Heating	Storage Water Heater	ENERGY STAR certified and minimum UEF 0.64	$100
Water Heating	Light Duty Storage Water Heater	ENERGY STAR certified and minimum UEF 0.80	$500
Water Heating	Tankless Water Heater	ENERGY STAR certified and minimum UEF 0.92	$300
Appliance	Gas Clothes Dryer	ENERGY STAR Certified	$50
HVAC	Condensing Boiler	75-225 kBtu/hr. and minimum 90% AFUE	$2.50 kBtu/hr.
HVAC	Condensing Furnace	<225 kBtu/hr. and minimum 95% AFUE	$2.75 kBtu/hr.

44 https://www.washingtongas.com/media-center/programs-and-solutions-master-meter-conversion
45 https://www.washingtongas.com/media-center/programs-and-solutions-8a-housing
46 https://www.washingtongas.com/home-owners/savings/rebates#washington,-d.c.
47 https://www.dcseu.com/

VIRGINIA PROGRAMS

There are limited direct customer incentives from WGL in Virginia. Those are detailed in Table 2 below.

Table 2. Virginia WGL Rebates[48]

Appliance Type	Eligible Equipment	Efficiency Requirement	Rebate
Space Heating	Furnace	ENERGY STAR certified and minimum 90% AFUE	$300
Thermostat	Wi-Fi-enabled thermostats	Wi-Fi-enabled	$50
Commercial rebates to offset first-cost equipment costs of up to $12,500 for small and medium sized businesses			

Other Virginia programs include:

Virginia DEQ:[49] There are several programs directly offered by the Virginia Department of Environmental Quality. These include incentives for energy efficiency, renewable energy, alternative fuels, and weatherization programs.

The Virginia Commercial Rebate program was designed to specifically target small businesses in the Washington Gas service areas of Virginia. Virginia business owners are eligible to receive rebates on high-efficiency natural gas furnaces and WIFI-Enabled smart thermostats.[50]

MARYLAND PROGRAMS

WGL offers high-efficiency natural gas equipment rebates for Home Heating, Home Appliances and Water Heating. Table 3 shows rebates that WGL offers to natural gas consumers in Maryland.

Table 3. Maryland WGL Rebates[51]

Appliance Type	Eligible Equipment	Efficiency Requirement	Rebate
Space Heating	Furnace Tier 1	ENERGY STAR certified and minimum 92% AFUE	$300
Space Heating	Furnace Tier 2	ENERGY STAR certified and minimum 95.1% AFUE	$400
Space Heating	Boiler Tier 1	ENERGY STAR certified	$400
Space Heating	Boiler Tier 2	ENERGY STAR certified and minimum 95% AFUE	$700
Space Heating	Boiler Reset Controls	N/A	$300
Appliance	Gas Clothes Dryer	ENERGY STAR Certified	$50
Water Heating	Storage Water Heater Tier 1	ENERGY STAR certified	$100
Water Heating	Storage Water Heater Tier 2	ENERGY STAR certified and minimum UEF 0.69	$150
Water Heating	Tankless Water Heater Tier 1	ENERGY STAR certified	$350
Water Heating	Tankless Water Heater Tier 2	ENERGY STAR certified and minimum UEF 0.89	$400
Commercial rebates to offset first-cost equipment costs of up to $12,500 for small and medium sized businesses.			

Within Maryland, there are also multiple programs available directly through **EMPOWER Maryland**, including energy efficiency and renewable energy programs.[52] There are also separate incentives offered for residential customers, businesses, and for the transportation sector.

48 https://www.washingtongas.com/home-owners/savings/rebates#virginia
49 https://www.deq.virginia.gov/Programs/PollutionPrevention/VirginiaInformationSourceforEnergy/FinancialIncentives.aspx
50 https://www.washingtongas.com/home-owners/savings/rebates#virginia
51 https://www.washingtongas.com/home-owners/savings/rebates#maryland
52 https://energy.maryland.gov/Pages/Facts/empower.aspx

Appendix B: Megatrends and Implications for the District

Affordability

While public support is strong and growing for actions that address climate change and reduce GHG emissions[53] a large number of customers are either unwilling or unable to pay premiums for 'greener' goods and services. Upwards of 70 percent of consumers indicate that they would pay an additional 5 percent for a green product if it met the same performance standards as a non-green alternative. But as the premium increases, the willingness to pay falls rapidly. Less than 10 percent of consumers said they would choose green products if the premium rose to 25 percent."[54]

More importantly, a significant number of people are unable to pay significantly more for their energy. According to a report prepared for the Department of Energy & Environment in September 2018:

> "About one quarter (27 percent) of the population in the District of Columbia is income-eligible for the Low-Income Housing Energy Assistance Program (LIHEAP). More than half of these low-income households (51 percent) use natural gas as their main heating fuel, while 44 percent rely on electric."

Increasing Frequency and Severity of Weather Events - Underscores Importance of a Diverse and Reliable Energy Portfolio

Scientists link rising global temperatures to an increased number and severity of storms around the world. Most models agree that climate change through the 21st century is likely to increase the average intensity and rainfall rates of hurricanes in the Atlantic and other basins.

In the District, Kate Johnson, climate chief with the District Department of Energy and Environment, says this research shows the District is going to be "warmer, it's going to be wetter, and it's going to be wilder in terms of our weather."

The average duration of electric power outages almost doubled between 2016 and 2017, according to an analysis from the U.S. Energy Information Administration (EIA), with major storms blamed for the longer interruptions. EIA data shows electric customers in the United States experienced power outages of an average of 7.8 hours in 2017, compared with just over 4 hours in 2016. (The overall analysis does not include the massive, extended power outage that struck Puerto Rico following Hurricane Maria.)

Though an underground initiative is underway in the District, the electrical grid is largely still above ground and therefore more susceptible to damage due to weather and weather-related incidents (such as high winds, downed trees, the formation of ice on power lines, etc.).

A prolonged loss of power is no longer just an inconvenience, it brings normal life to a standstill. But there are solutions.

Pacific Gas & Electric (PG&E)'s 'public safety shutdowns' in 2019 that have left millions of customers in the dark for days on multiple occasions demonstrate both the vulnerability of relying on non-redundant energy systems and also that financial integrity of the utility is essential in order to maintain safety and reliability.

Washington-area residents remember the June 2012 derecho that brought intense winds and rain to our region, knocking out power for more than a million residents.

It is important to note that according to NOAA, the most common natural hazard in the District is Thunderstorm & Lightning and the second-most common is Winter Storm & Extreme Cold.[55] [56] The electric grid is far more vulnerable to both of these weather conditions than is the natural gas delivery system.

With the increasing number and severity of weather events, the ability of natural gas to address and mitigate the vulnerability of our energy infrastructure becomes an important consideration.

53 https://earth.stanford.edu/news/public-support-climate-policy-remains-strong#gs.7a2du2
54 https://www.mckinsey.com/business-functions/sustainability/our-insights/how-much-will-consumers-pay-to-go-green
55 https://www.ncdc.noaa.gov/data-access/severe-weather
56 https://www.nerc.com/pa/rrm/ea/Pages/EA-Program.aspx

CASE STUDY | CARROLLSBURG CONDOMINIUM

In Southwest Washington, DC the Carrollsburg Condominium is an example of resilient and efficient use of energy. With new windows, a highly-advanced building automation system, and the District's first natural gas powered microturbine Combined Heat and Power plant which creates electricity for the property's North and East High-Rise Towers and recovers waste heat to warm water, heat, and cool the 11-acre campus. In addition to resiliency benefits, the property has realized well over $1,000,000 dollars in energy and operational savings from the upgrades and serves as a model for other buildings and campuses throughout the Region.

Aside from natural disasters, our energy delivery systems **must** be designed and built to meet 'peak load' days when energy usage increases substantially, whether it is during heat waves or cold spells. During the peak heating (often the coldest) days of the year, Washington Gas reliably delivers 150 percent of the energy delivered during summertime's peak cooling days. If Policy-Driven Electrification were to be pursued, the grid's capability would need to increase by 50 percent, at substantial cost.

CONCLUSION:

Maintaining our current integrated (multiple sources) energy system is essential to allow a smooth, affordable and reliable transition to a clean energy future.

Cold Weather Vulnerability

The issues of both affordability and reliability are paramount as demographic trends project a larger and increasingly vulnerable population.

The Urban Institute projects that Washington metropolitan area's population is expected to grow by at least 2 million by 2030 with 15.3 percent of the population being 65 years and older, about twice the current rate of 7.7 percent.[57]

US Census data for 2018 shows that approximately 17 percent of District residents over 65 live below the poverty line in the District.[58]

Older adults are particularly affected by energy poverty and cold weather, according to the National Institute of Health (NIH). For an older person, a body temperature of 95°F or lower can cause many health problems, such as a heart attack, kidney problems, liver damage, or worse. Even mildly cool homes with temperatures from 60 to 65 degrees can trigger hypothermia in older people.[59]

The Centers for Disease Control and Prevention (CDC) found: "cold-related deaths are more prevalent than heat related[60].

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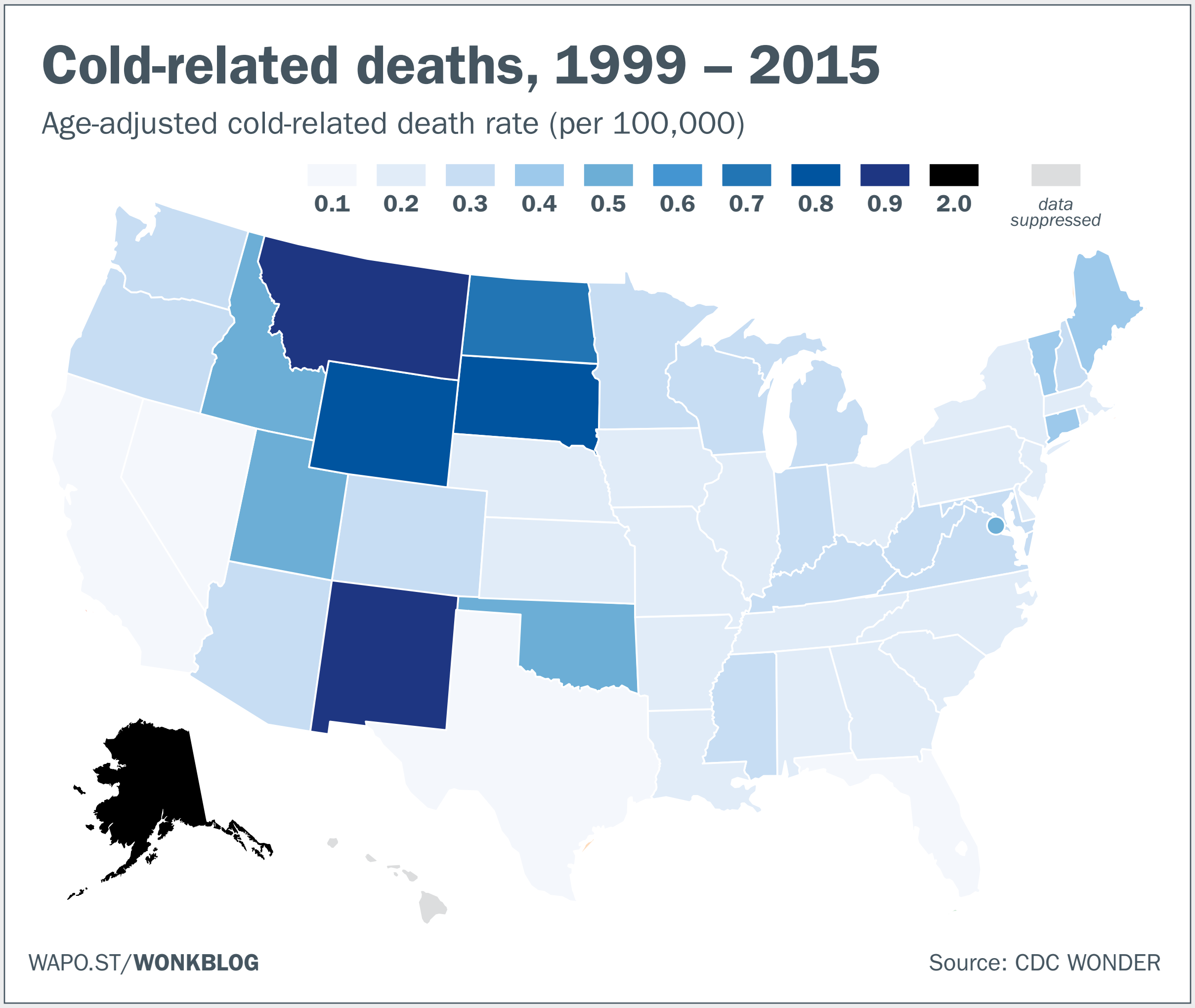
57 https://www.washingtonian.com/2015/01/22/washington-area-population-expected-to-increase-by-more-than-2-million-by-2030/

58 https://censusreporter.org/profiles/16000US1150000-washington-dc/

59 https://www.nih.gov/news-events/news-releases/hypothermia-cold-weather-risk-older-people

60 https://www.washingtonpost.com/news/wonk/wp/2016/12/17/cold-temperatures-kill-more-americans-than-hot-ones-cdc-data-show/



As this December 2016 Washington Post figure shows[61], this problem is more acute in Washington, DC than the mid-Atlantic region in general, with an adjusted per-capita death rate more associated with Idaho, Utah and Oklahoma than neighboring states.

CONCLUSION:

Washington, D.C. will need to accommodate and meet the energy needs of an additional 70,000 people and a growing number (and proportion) of elderly residents who are more susceptible to cold-weather-related maladies. Ensuring access to affordable, reliable, clean energy is an imperative.

NATURAL GAS AND RENEWABLE ELECTRICITY ROLES EXPANDING THROUGH 2050

Intermittent Power Sources Require Backup and Storage

As natural gas, wind and solar continue to replace coal for electrical power generation, the 'grid' will continue to get cleaner. This trend is anticipated to continue so that by 2050 renewably generated electricity serves almost a third of demand. However, because renewables are an intermittent source of power, other electrical prime movers like natural gas fired plants – or energy storage – will be required to meet 24 x 7 on demand power needs. While multiple energy storage technologies exist, battery storage is the technology most widely contemplated for our region.

PJM, a regional transmission organization located in 13 eastern states (including the states adjacent to DC that supply the city's electricity - Pennsylvania, West Virginia, Ohio and Illinois), has the most large-scale battery installations, with a storage capacity of **278 MW at the end of 2017**. The second biggest owner of large-scale battery capacity is California's ISO (CAISO) with a total storage capacity of 130MW.

The need for high-capacity, long-duration and long-discharge storage will be a limiting factor to the reliance upon wind and solar generated electricity, due to inherent intermittency of those sources. Limits for storage include technological limitations, resources and space required for installation.

Technological Limits

Batteries offer limited duration discharge, meaning that longer periods without generation require multiple numbers of batteries to provide power during intermittent periods when power is not being generated. For example, without backup generation, to provide enough power during two or three cloudy or windless days will require an unrealistic level of battery storage (see below) to meet the demand for the entire period of time.[62]

	Max Power Rating (MW)	Discharge Time	Max cycles or lifetime	Energy density (watt-hour per liter)	Efficiency
Pumped hydro	3,000	4h – 16h	30 – 60 years	0.2 – 2	70 – 85%
Compressed air	1,000	2h – 30h	20 – 40 years	2 – 6	40 – 70%
Molten salt (thermal)	150	hours	30 years	70 – 210	80 – 90%
Li-ion battery	100	1 min – 8h	1,000 – 10,000	200 – 400	85 – 95%
Lead-acid battery	100	1 min – 8h	6 – 40 years	50 – 80	80 – 90%
Flow battery	100	hours	12,000 – 14,000	20 – 70	60 – 85%
Green Hydrogen	100	mins – week	5 – 30 years	600 (at 200bar)	25 – 45%
Flywheel	20	secs - mins	20,000 – 100,000	20 – 80	70 – 95%

By December 2017, there was approximately 708 MW of large-scale battery storage operational in the U.S. energy grid.

Most of the battery storage projects are for short-term energy storage and are not built to replace the traditional grid. Most of these facilities use lithium-ion batteries, which provide enough energy to shore up the electric grid for approximately four hours or less. These facilities are used for grid reliability, to integrate renewables into the grid, and to provide relief to the energy grid during peak hours.[63] They are not sufficient to protect against large scale interruptions or to maintain service during extended outages.

Resource Limits

Global demand for Lithium, a key component material of today's batteries, is expected to rise at least 300 percent in the next 10 to 15 years, in large part because sales of electric vehicles are expected to increase dramatically.[64] The increase in lithium production required to meet demand is staggering, compared to the current global market for lithium. Future pricing estimates are adding two new global markets—electric vehicles and large-scale battery storage.

62 Environmental and Energy Study Institute, Storage Fact Sheet 2019 https://www.eesi.org/papers/view/energy-storage-2019

63 Environmental and Energy Study Institute, 2019, Fact Sheet: Energy Storage (2019) https://www.eesi.org/papers/view/energy-storage-2019

64 Science News, 2019, The search for new geologic sources of lithium could power a clean future https://www.sciencenews.org/article/search-new-geologic-sources-lithium-could-power-clean-future

This has resulted in increasing competition, and prices, for Lithium; a trend that is expected to continue through 2024.[65 66] In addition, sourcing is a concern as the US has very few Lithium resources itself and will have to rely on the primary sources of Lithium (Australia, Chile, China, Argentina, and Zimbabwe). One need only recall the Oil Embargo of the 1970s to appreciate how a lack of energy independence presents an economic and potential natural security vulnerability.

Space Limits

Just as solar panels require space, so too would battery storage facilities. A state-of-the-art Lithium battery the size of the US Capitol building would be necessary just to support the District's peak electricity demand for 2 and a half hours. For average (non-peak) electrical load, the battery would supply ~4.5 hours of the electricity that the District requires. And the cost of that battery would be approximately $3 billion.

Solution: Natural Gas Pipelines Provide Ready-Now Energy Storage

In contrast, while largely invisible to the public (because they are underground) the existing gas pipelines in place today store hundreds of terawatt hours[67] of energy for indefinite periods of time and it is available at a moment's notice. Furthermore, if that gas were to be produced using P2G to generate green hydrogen, combined with sequestered carbon from other emissions sources and/or RNG, that energy would be carbon neutral.

CONCLUSION:

- One third of electrical power generation is projected to be sourced from intermittent renewables by 2050.[68]
- Battery technology will help manage and balance short-duration intermittency, however huge backup power generation will be required, most of which is forecast to be gas-fired.[69]
- Increased demand on the grid (such as for vehicle electrification or the potential displacement of natural gas) will require a massive increase in electrical generation and storage, at a higher carbon intensity and GHG emissions than the direct use of natural gas for heating, cooking, hot water and clothes drying. In addition, advancements in renewable natural gas provide promise of even lower emissions for these applications.

Transportation Emissions Are Regulated by the Federal Government and are Therefore Difficult to address at the local level

Despite the fact that transportation is the second-largest contributor to the District's GHG emissions, Clean Energy DC acknowledges that this will be a difficult sector to impact;

"Data indicates that 70% of vehicles are on the road for at least 15 years[70], and "the District Government has few policy tools to encourage an electric car purchase."[71]

The city has chosen to shift focus onto other sources of emissions to affect reductions. Vehicle electrification can yield important and relatively lower cost emisions reductions than electrifying residential and commercial buildings.

65 Oil And Gas Investments, 2017, Lithium Prices To Stay High To 2024–UBS https://oilandgas-investments.com/2017/top-stories/lithium-prices-to-stay-high-to-2024-ubs/
66 https://1reddrop.com/2018/06/07/tesla-panasonic-lead-ev-battery-cost-race-cutting-cobalt/lithium-carbonate-battery-grade-cost/
67 https://www.energycentral.com/c/ec/power-gas-enables-massive-energy-storage
68 EIA, Annual Energy Outlook 2019 with Projections to 2050
69 PJM projection- ICF
70 National Highway Traffic Safety Administration, http://www-nrd.nhtsa.dot.gov/Pubs/809952.pdf
71 Clean Energy DC – August 2018, page xii

Appendix C: Scenarios Evaluated for Emissions Reductions

Pillars of the Plan

The Plan was informed by, and based on, the desire to develop a framework that will accommodate changes to market and policy realities, such as in the District's climate goals, energy needs, and growth, as well as emerging technologies and innovations that will be refined and/or developed over the course of the next 30 years. As noted, the Plan supports and aligns with the seven factors articulated in the DC PSC Vision for modernizing the district's energy delivery system and in support of the Omnibus Clean Energy Act, namely that the energy systems be: (1) sustainable – including three sub-factors environmental protection, economic growth and social equity (2) well-planned, (3) safe and reliable, (4) secure, (5) affordable, (6) interactive, and (7) non-discriminatory. The figure below shows how the key criteria of the Plan align with the seven factors:

Critical Alignment with DC PSC Factors for a Modernizing Energy Delivery System

	Public Service Commission Factors						
The Plan was developed to recognize and optimize the following considerations	Sustainable	Well-planned	Safe & Reliable	Secure	Affordable	Interactive	Non-discriminatory
Ensuring public safety, resilience and reliability by protecting against service interruptions from weather and other disruptions	■	■	■	■	■		■
Evaluating GHG emissions reduction potential of various approaches as well as associated cost per ton of carbon abated	■	■			■	■	■
Moderating impact on customer cost, including up-front and monthly energy costs, particularly for lower-income households	■	■			■	■	■
Preserving energy availability during both normal and peak demand conditions	■	■	■	■		■	■
Leveraging existing assets to their fullest potential	■	■	■	■	■		
Sequencing actions based program and regulatory maturity	■	■			■	■	
Pursuing non-prescriptive approach which allows opportunities presented by future innovations and technological advances	■	■		■	■	■	■
Implementing a regulatory framework and policy that facilitates and incents strategies and tactics to reduce emissions	■	■	■	■		■	■

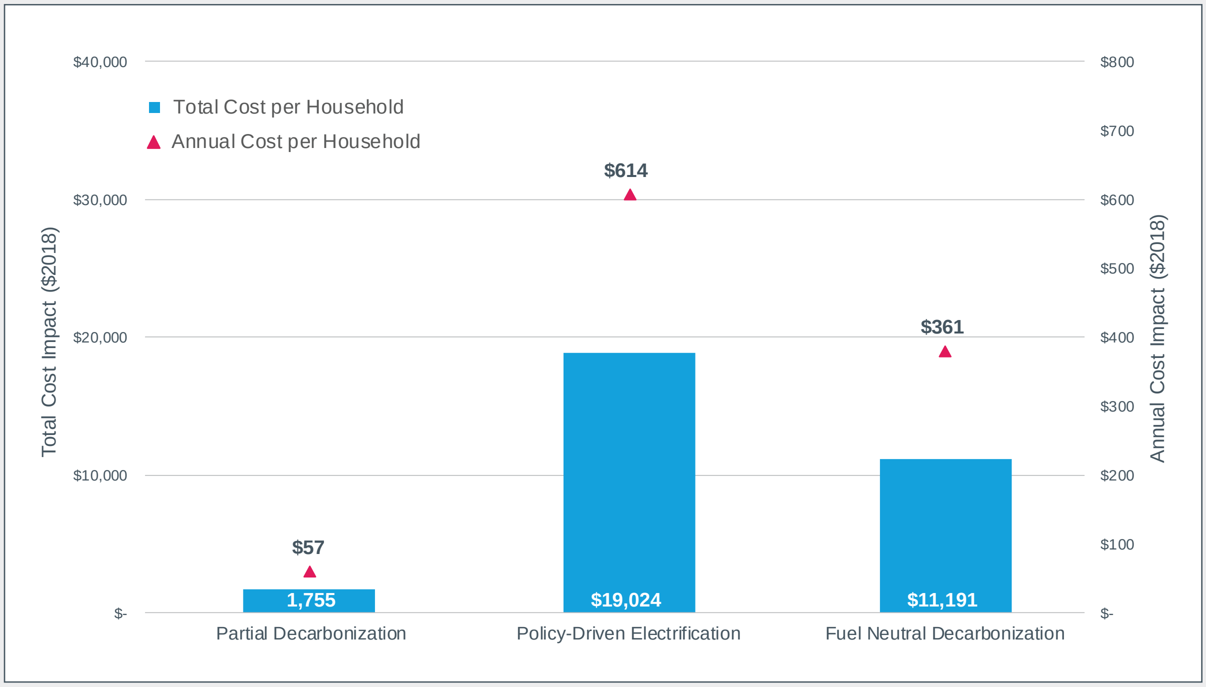
Washington Gas incorporated the above considerations as it examined and evaluated the effectiveness, comparative costs and timeframes associated with the four different energy scenarios to inform our Plan to support the achievement of the District's decarbonization and climate goals.

The following figure provides a comparative summary of the four scenarios, including their foundational assumptions, each scenario's respective potential to achieve the District's GHG emissions reduction targets, as well as the estimated cumulative costs (as related to the Business as Usual scenario) that would be incurred.

Summary of Scenarios, Benefits and Costs

	2050 GHG reduction since 2006	Additional cumulative cost (above BAU)
Business as Usual (Reference Case) Based on the 100 percent renewable portfolio standard (RPS)	**75%**	**–**
Partial Decarbonization BAU plus: ▪ moderate market penetration of EVs ▪ increased energy efficiency ▪ modest decarbonization of gas supply including introduction of RNG and certified gas	**82%**	**$603 Million**
Policy-Driven Electrification BAU plus: ▪ requires homes and businesses using natural gas to convert to electricity ▪ electrification of all new construction ▪ aggressive market penetration of electric vehicles ▪ small volume of offsets (not included in costs)	**100%**	**$6.5 Billion**
Fuel Neutral Decarbonization BAU plus: ▪ aggressive energy efficiency programming including gas heat pumps ▪ moderate introduction of dual fuel heating systems ▪ substantial decarbonization of gas supply introduction of renewable natural gas, certified gas, and green hydrogen ▪ leverages new and emerging technologies ▪ aggressive market penetration of electric vehicles ▪ small volume of offsets (not included in costs)	**100%**	**$3.8 Billion**

Cumulative and Annual Cost of Scenarios per District Household Compared to BAU



The scenarios make very conservative assumptions when estimating future electricity costs, in part because some of the required information was not available to ICF. ICF believes these costs could be very significant because of the electrification of space heating in the Policy-Driven Electrification Case is likely to cause a 50 percent increase in peak demand.[72] An ICF analysis, based on data from a DCSEU study, estimates the costs of meeting a 50 percent increase in peak demand is an additional $0.3 billion per year in costs.[73]

Likewise, this scenario did not consider the cost impacts of future demands for growing renewable electricity. For example, as more jurisdictions adopt or increase RPS targets the price of today's energy credits which are bought by the incumbent utility to meet the District's RPS requirements are likely to double.

> ICF analysis did not include an estimate of the increase in the District's electricity distribution, and transmission costs. The information required to make such an assessment is not public; it is only available to the electric utility.

The Lowest Cost Option to Meet Emission Targets

The fuel neutral decarbonization pathway achieves the desired emissions reductions for $2.7 Billion less than the overall total cost of Policy-Driven Electrification.

72 This is conservative because the Policy-Driven Electrification scenario assumed that practically no EV charging would occur during the system peak. One estimate indicates that full electrification would not only shift the peak power demand from summer to winter but could also double peak electricity demand. Rocky Mountain Institute, New Jersey Integrated Energy Plan, Public Webinar, November 1 2019, page 23. Full electrification of heating and transportation. ICF's estimate is 50 percent but contains conservative transportation assumptions.

73 TetraTech. (2017). *Evaluation of the District of Columbia Sustainable Energy Utility - FY2016 Annual Evaluation Report for the Performance Benchmarks (Final Draft)*. Madison, WI, USA. See page 31, and 33. The DCSEU uses this study in determining the amount of cost that every KW of demand avoided saves annually– i.e. the distribution and transmission capacity cost is $257/KW-year ($231/kw year for distribution and $27/kw year for transmission). The $0.3 billion per year assumes the reverse is true, namely that adding to peak electricity demand also increases costs.

ADDITIONAL IMPORTANT BENEFITS OF FUEL NEUTRAL APPROACH

Stabilizing Costs

Fuel neutral decarbonization helps to stabilize costs via a diversified energy portfolio. A diversified energy portfolio provides a 'hedge' against price increases and volatility from competition for projected escalation in demand for renewable electricity supply and RECs as well as protection against unknown costs of distribution and transmission upgrades. A diverse low-carbon fuel portfolio can reduce the demand for electricity, thereby lessening the potential of multiple jurisdictions to get into bidding wars for a scarce commodity.

> A November 2019 survey of HAND members revealed that more than three quarters (77 percent) currently rely on natural gas in their projects. More than half (54 percent) reported that they are familiar with DC's climate goals to reduce emissions in half by 2032, for the District's electricity supply to be 100 percent renewable by 2032 and for the District to be carbon neutral by 2050. When asked to rank concerns, **83 percent** of respondents cited the cost of Implementation as their greatest concern.

Resiliency and Reliability

The Fuel Neutral Decarbonization approach enhances energy resiliency and reliability for the District by leveraging the 99.9 percent reliability of the natural gas delivery system. Additionally, multiple energy sources and distribution networks incorporated within the Fuel Neutral Decarbonization approach provide an inherent redundancy of energy supply to the District, reducing the District's risk exposure to disruptions in energy delivery from weather or other events.

Resiliency is a matter that the District of Columbia seeks to quantify as a benefit in its proceedings to establish assessment metrics and factors relating to the implementation of the 2019 DC Clean Energy Omnibus Act[74].

The Washington DC Energy Risk Profile[75] lists winter storms, thunderstorms and extreme cold as the leading causes of interruptions in electrical power service with the DOEE finding that the District can anticipate an increasing frequency and intensity of these events.[76] Electric power interruptions range from modest events impacting several hundred for a few hours to severe events like the June 2012 derecho that left hundreds of thousands without power for extended periods. Electric only customers are more likely to lose heating than customers who also use natural gas, due to the underground nature of natural gas infrastructure.

During the winter months the need for heat can often become a matter of health and well-being and even life and death – particularly for the vulnerable elderly and lower-income populations.[77] [78] Energy security is becoming an issue of increasing concern for the District as the mean age of city residents continues to rise.[79]

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74 Comments to this NOI submitted on November 12, 2019, by the District of Columbia Department of Energy and the Environment, recommend the establishment of benefit-cost test that accounts for the cost of resiliency. P.3. See also Comments to this NOI submitted on November 12, 2019 by the Department of Energy and Environment, P. 14-17, In the Matter of the Implementation of the 2019 Clean Energy DC Omnibus Act Compliance Requirements, Matter No. GD-2019-04-m. See also, "First Report from the Commission on Climate Change and Resiliency. First Report to the District of Columbia October 15, 2019".

75 https://www.energy.gov/sites/prod/files/2016/09/f33/DC_Energy%20Sector%20Risk%20Profile.pdf

76 The 2015 report: Climate Change Projections for the District of Columbia https://doee.dc.gov/sites/default/files/dc/sites/ddoe/publication/attachments/Attachment%201%20.ARC_.Report_07-10-2015.pdf

77 https://www.nih.gov/news-events/news-releases/hypothermia-cold-weather-risk-older-people

78 https://www.washingtonpost.com/news/wonk/wp/2016/12/17/cold-temperatures-kill-more-americans-than-hot-ones-cdc-data-show/

79 See Appendix B: Megatrends and Implications for the District

Providing Energy Storage

The Fuel Neutral Decarbonization approach enables long-term energy storage for the District to support peak winter energy needs. Washington Gas's existing system stores energy for months (up to years) at a time. In contrast, state-of-the-art batteries, such as Lithium Ion and flow batteries, can provide a few hours of backup power when intermittent renewables such as solar and wind energy are not generating. However, cost and space considerations limit the practicality of these batteries to be used to store large amounts of energy for extended periods. The existing natural gas pipeline network and associated underground storage facilities already provide a high-capacity, long duration and long-discharge seasonal energy storages, storing sufficient energy to meet the District's peak energy requirements in the winter months.

The results of the scenario analysis present a compelling case that Fuel Neutral Decarbonization is the best path to emission reduction. It provides the desired GHG emission reductions at a fraction (59 percent) of the cost of electrification, while maintaining energy reliability for District residents, businesses, government agencies, and others. In addition to achieving energy affordability and reliability, it also preserves customer choice.

Appendix D: Renewable Natural Gas Study

<< provided as a separate attachment >>

Study on the Use of Biofuels (Renewable Natural Gas) in the Greater Washington, D.C. Metropolitan Area

March 2020

Submitted to:
Washington Gas Light Company
1000 Maine Avenue SW
Washington, DC 20080

Submitted by:
ICF Resources, L.L.C.
9300 Lee Highway
Fairfax, VA 22031

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Executive Summary

This study was commissioned and completed to fulfill AltaGas Merger Commitment No. 6, as stipulated in Formal Case No. 1142 (Order No. 19396) of the Public Service Commission of the District of Columbia (D.C.)[1] and AltaGas Merger Commitment No. 5, as stipulated in Formal Case No. 9449 (Order No. 88631) of the Public Service Commission of Maryland.[2] To achieve this, ICF characterizes the technical and economic potential for renewable natural gas (RNG) as a greenhouse gas (GHG) emission reduction strategy, with particular focus on local or regional resources in the Greater Washington, D.C. metropolitan area. Further, the study seeks to support AltaGas' efforts to improve understanding of the extent to which delivering RNG to all sectors of the regional economy can contribute to broader GHG emission reduction initiatives.

Washington Gas Light Company (WG) is the largest natural gas local distribution company serving the Greater Washington, D.C. metropolitan area, distributing natural gas to nearly 1.2 million customers. To serve these 1.2 million customer meters, WG has an annual throughput of roughly 165 trillion British thermal units per year (tBtu/y), with WG sales representing over half that volume, and the remainder met by third-party suppliers.

Washington, D.C., Maryland, and Virginia have made climate and clean energy commitments that will play critical roles in determining the pace of GHG emission reductions in each jurisdiction and that will directly impact the natural gas system. Natural gas use in various economic sectors makes up approximately 10% of the GHG emissions in the Greater Washington, D.C. metropolitan area. As such, it is critically important that stakeholders have a clear understanding of the potential role of RNG as a strategy to reduce GHG emissions.

RNG is derived from biomass or other renewable resources and is a pipeline-quality gas that is fully interchangeable with conventional natural gas. As RNG is a "drop-in" replacement for natural gas, it can be safely employed in any end use typically fueled by natural gas, including electricity production, heating and cooling, industrial applications, and transportation. Today, about 50 tBtu per year of RNG from landfills, dairy digesters, and water resource recovery facilities (WRRFs) is injected into pipelines, with production growing year-on-year.

Methodology

To achieve the study's objective, ICF sought to address several questions, including:

- How much RNG is potentially available in the near- to long-term future?
- What is the cost-effectiveness of RNG as a GHG mitigation strategy?
- What are the potential economic and environmental impacts of deploying RNG to help meet decarbonization objectives in the Greater Washington, D.C. metropolitan area?
- What are the key opportunities for and challenges inhibiting RNG deployment?

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[1] Public Service Commission of the District of Columbia, 2019. https://dcpsc.org/Newsroom/HotTopics/AltaGas-WGL-Holdings-Merger-Commitments-Tracking-M.aspx
[2] Public Service Commission of Maryland, 2018. https://www.psc.state.md.us/wp-content/uploads/Order-No.-88631-Case-No.-9449-AltaGas-WGL-Merger-Order.pdf

As a starting point, ICF applied the approach used in our recent American Gas Foundation assessment of the national supply and emission reduction potential of RNG,[3] but with an additional and detailed focus on regional and local RNG resources relevant to the Greater Washington, D.C. metropolitan area.

ICF developed three resource potential scenarios by considering RNG production from nine feedstocks and three production technologies. The feedstocks include landfill gas, animal manure, WRRFs, food waste, agricultural residues, forestry and forest product residues, energy crops, the use of renewable electricity, and the nonbiogenic fraction of municipal solid waste (MSW). These feedstocks were assumed to be processed using one of three technologies to produce RNG: anaerobic digesters, thermal gasification systems and power-to-gas (P2G) in combination with a methanation system.

RNG Potential and Costs

ICF developed three RNG production scenarios: Conservative Low, Achievable, and Aggressive High, varying both the assumed utilization of existing resources as well as the rate of project development required to deploy RNG at the volumes presented. ICF estimates that the resource potential scenarios will yield between 1,890 tBtu/y and 7,160 tBtu/y of RNG production by 2040. For comparison, the United States consumed approximately 17,500 tBtu of natural gas in 2018 in the residential, commercial, transportation, and industrial sectors.

In other words, using ICF's balanced assumptions regarding feedstock utilization and technology deployment in the Achievable scenario, there is enough national RNG production potential to displace upward of 25% of total natural gas consumption in direct use applications today. This does not include any potential reductions attributable to conservation or efficiency measures, nor does it account for the higher volumes in the Aggressive High scenario, which could displace upward of 40% of the conventional natural gas consumption in direct uses domestically today. Relative to the Greater Washington, D.C. metropolitan area, local RNG resources could displace up to 33% of natural gas consumption in the Achievable scenario, without accessing any potential RNG resources from outside the immediate region.

ICF developed assumptions for the capital expenditures and operational costs for RNG production from the various feedstock and technology pairings examined. ICF characterizes costs based on a series of assumptions regarding production facility size, gas conditioning and upgrading costs, compression, and interconnect for pipeline injection. The table below summarizes the estimated cost ranges for each RNG feedstock and technology.

[3] ICF, 2019. Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment, https://www.gasfoundation.org/2019/12/18/renewable-sources-of-natural-gas/

Summary of Estimated Cost Ranges by Feedstock Type

	Feedstock	Cost Range ($/MMBtu)
Anaerobic Digestion	Landfill Gas	$7.10 – $19.00
	Animal Manure	$18.40 – $32.60
	Water Resource Recovery Facilities	$7.40 – $26.10
	Food Waste	$19.40 – $28.30
Thermal Gasification	Agricultural Residues	$18.30 – $27.40
	Forestry and Forest Residues	$17.30 – $29.20
	Energy Crops	$18.30 – $31.20
	Municipal Solid Waste	$17.30 – $44.20

GHG Emission Reductions from RNG

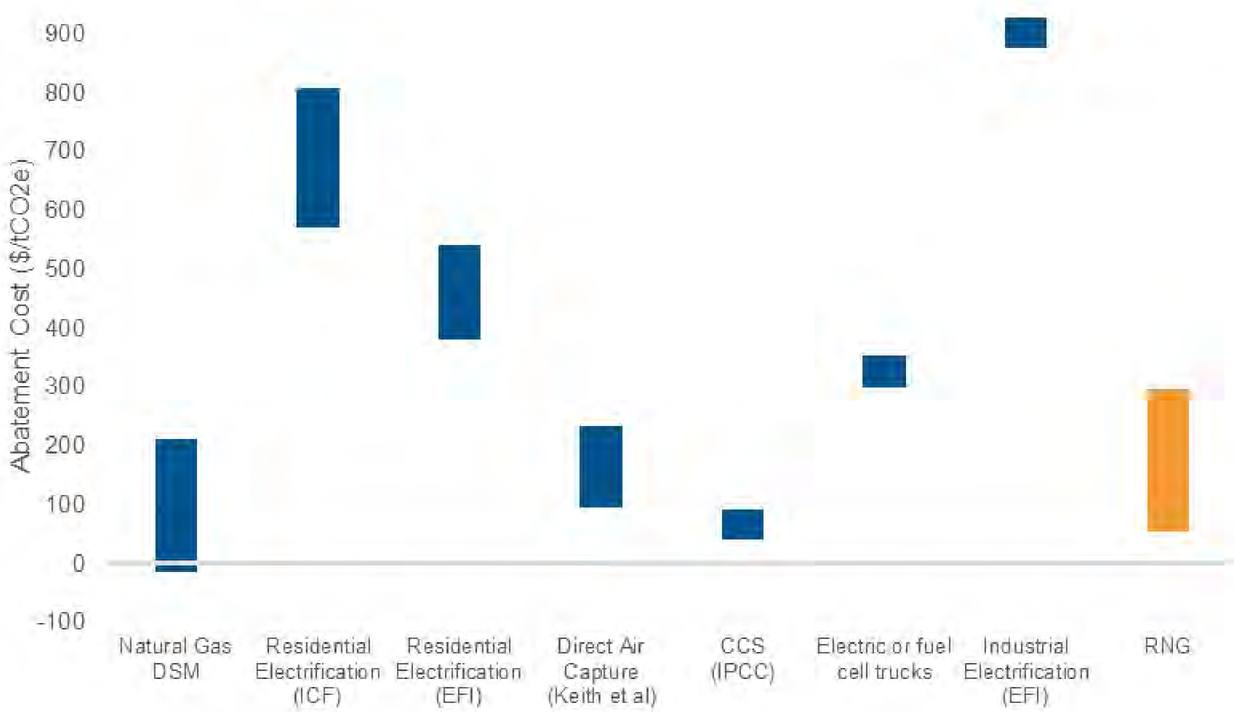
RNG represents a valuable renewable energy source with a low or net negative carbon intensity depending on the feedstock. The GHG emission accounting methodology has a significant impact on how carbon intensities for RNG are estimated, with a lifecycle approach reflecting the full emission reduction potential, such as including credit for avoided methane emissions.

ICF estimates that locally in the Greater Washington, DC. metropolitan area, 0.5 to 2.3 million metric tons (MMT) of GHG emissions could be reduced per year by 2040, and 13 to 44 MMT could be reduced in the South Atlantic region via the deployment of RNG based on the Conservative Low to Aggressive High scenarios. At the national level, 100 to 380 MMT of GHG emissions could be reduced per year by 2040. For comparison, D.C.'s total direct GHG emissions in 2017 were 7.3 MMT, while Greater Washington, D.C. metropolitan area's population-weighted share of Maryland and Virginia GHG emissions were 34 and 59 MMT in 2017 and 2015, respectively.

RNG can play an important and cost-effective role to achieve aggressive decarbonization objectives over the long-term future, with ICF estimating GHG emission reductions at a cost of $55 to $295 per ton of carbon dioxide equivalent (tCO_2e). RNG is more expensive than its fossil counterpart, but in a decarbonization framework the proper comparison for RNG is to other abatement measures that are viewed as long-term strategies to reduce GHG emissions.

In this context, RNG is a cost-competitive option. The figure below shows a comparison of selected measures across various key studies for specific abatement measures that are likely to be required for economy-wide decarbonization by the 2050 timeframe, including natural gas demand side management (DSM), electrification of certain end uses (including buildings and in the industrial sectors), direct air capture (whereby CO_2 is captured directly from the air and a concentrated stream is sequestered or used for beneficial purposes), carbon capture and storage (CCS), battery electric trucks (including fuel cell drivetrains), and RNG (from this study).

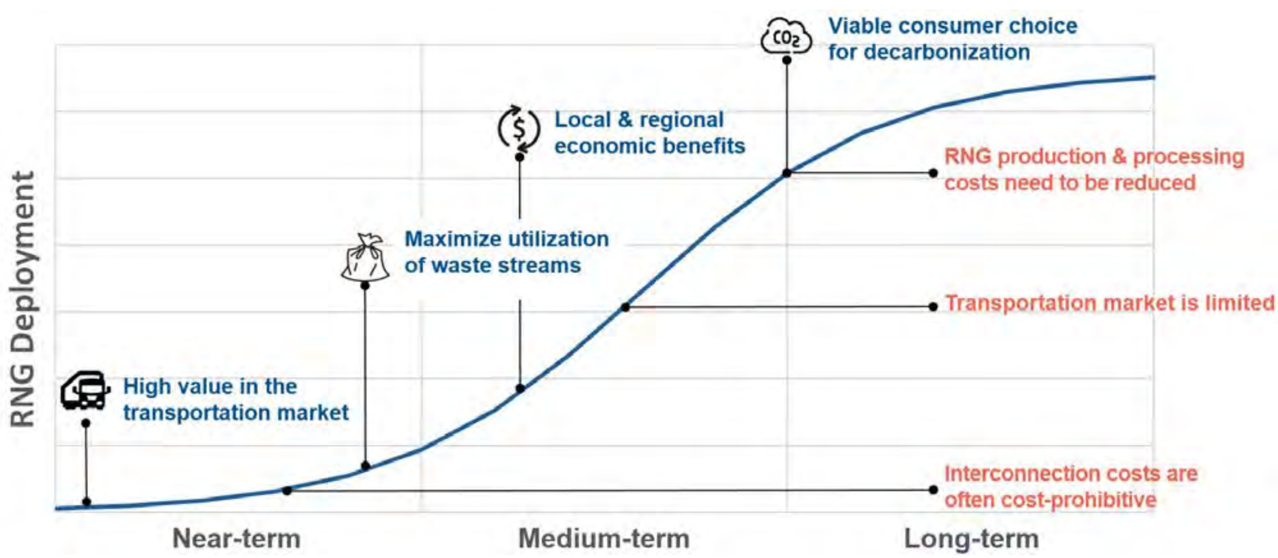
Full GHG Abatement Cost Ranges, Selected Measures, \$/tCO_2e



Opportunities and Challenges

The figure below illustrates a subset of ICF's key findings across the technical, market, and regulatory and policy aspects of RNG deployment, including both **opportunities** and **challenges** envisioned along an illustrative RNG production potential curve. The table that follows the figure provides more detail regarding the opportunities and challenges for each key aspect of RNG deployment.

Overview of RNG Opportunities and Challenges



RNG Deployment	Opportunities	Challenges
Technical	▪ RNG is available today and is a valuable renewable resource with carbon-neutral, and in some cases carbon-negative, characteristics. ▪ RNG utilizes the same existing infrastructure as fossil natural gas. ▪ The long-term potential for RNG is linked in part to P2G and hydrogen.	▪ The technical potential for RNG production has been constrained to some extent by old policies. ▪ Location, accessibility, and competition of feedstocks will constrain RNG production potential. ▪ P2G and hydrogen technology will require significant cost reductions. ▪ Seasonal variability in systemwide demand will require the RNG production market to adapt.
Market	▪ RNG has high value in the transportation sector, which can be replicated in other end uses. ▪ RNG can deliver cost-effective GHG emission reduction measures for deep decarbonization. ▪ RNG helps maximize the utilization of evolving waste streams. ▪ RNG markets are evolving to thermal use by utilities and other sustainability goals. ▪ RNG helps give suppliers and consumers a viable decarbonization option in a changing market and policy environment.	▪ RNG markets beyond transportation fuel are nascent. ▪ RNG production and processing costs need to be reduced to improve cost-competitiveness. ▪ Limited availability of qualified and experienced RNG developers to expand RNG production in the near term. ▪ RNG costs more than conventional natural gas, when environmental benefits are not valued appropriately. ▪ Interconnection costs for RNG suppliers and developers can be prohibitively high.
Regulatory	▪ Introduction of standardized conditioning and interconnection tariffs. ▪ Legislation and regulations for both mandatory and voluntary RNG programs has emerged. ▪ Transportation policies currently favor RNG over fossil natural gas. ▪ RNG can help achieve aggressive decarbonization policies. ▪ Complementary policies could facilitate RNG feedstock collection (e.g., waste diversion and management). ▪ A robust regulatory framework will encourage deployment of RNG.	▪ The policy pathway promoting RNG in market segments other than transportation is unclear and not uniform. ▪ Some policymakers are singularly focused on electrification and unaware of the costs and benefits of RNG. ▪ Gas utilities are just beginning to gain cost recovery mechanisms for RNG procurement and investments. ▪ Gas safety, reliability, and quality rules and requirements need to be updated in line with current science/evidence.

Recommendations

ICF developed a series of recommendations that are presented across three areas:

- **Strategic direction** for policymakers and industry stakeholders;
- **Market approaches** that will help to advance RNG deployment; and
- **Regulatory actions** that will help to bring near- and long-term certainty needed to realize the potential for RNG as a cost-effective strategy for decarbonization.

Together, these three areas encompass the suite of actions that will help to realize the opportunities and overcome the challenges for RNG deployment in the Greater Washington, D.C. metropolitan area outlined in the previous table.

Strategic Direction for Policymakers and Stakeholders

ICF recommends developing a strategic roadmap for regional policymakers and stakeholders guided by the following vision statement and based on a set of clear principles:

Vision Statement: *The Greater Washington, D.C. metropolitan area will maximize RNG throughput as a decarbonization strategy while maintaining the safety, reliability, and affordability of gas services.*

Principles:

- Produce and deliver RNG safely and cost-effectively to participants and end-use customers.
- Contribute to broader regional GHG emission reduction objectives.
- Implement a flexible regulatory and legislative structure that values RNG deployment.
- Engage proactively with key stakeholders through the implementation of the RNG strategy.

The roadmap can be implemented through aggressive but attainable RNG throughput targets. The Greater Washington, D.C. metropolitan area can achieve up to 5%, 15%, and 20% RNG throughput by 2025, 2030, and 2035, respectively. ICF's scenario analysis of RNG potential supports the volumes required to achieve these targets.

The strategic roadmap should also have a keen focus on reshaping the policy conversation at all levels to ensure that regulators and policymakers include RNG in federal and state programs that provide support to clean energy development. This includes the broad range of support currently afforded to renewable electricity, including research and development support (e.g., grants), as well as incentives for investment in clean energy commercial deployment in all sectors (e.g., investment tax credits).

Market Approaches to Spur RNG Deployment

- **Develop interconnection standards for RNG projects.** ICF recommends that gas utility stakeholders work closely with project developers to focus on interconnection. A consistent approach to evaluate RNG quality and constituent composition will facilitate the broader acceptance of different RNG feedstocks and encourage the development of RNG as a source for pipeline throughput and larger sources of demand (e.g., thermal use applications).
- **Deploy RNG into the transportation market.** The transportation sector is a natural fit for the near-term focus of RNG deployment in the region: the combination of higher conventional energy costs and existing incentives makes for a clear opportunity. The market

for RNG as a transportation fuel in the Greater Washington, D.C. metropolitan area should take advantage of other market forces, notably that California's market for natural gas as a transportation fuel is nearly saturated with RNG.

- **Establish common tracking across RNG markets**. A system to track and verify RNG in thermal use applications (i.e., outside of transportation and electricity sectors that currently have tracking systems in place) will become increasingly important as multiple sectors and regions seek to deploy RNG across various end uses, particularly for the multiple jurisdictions in the Greater Washington, D.C. metropolitan area.

Regulatory Approaches to Support RNG Deployment

ICF recommends a regulatory approach that stages potential RNG programs over the near-, mid-, and long-term horizons in an effort to reconcile conflicting requirements.

- **Develop pilot or voluntary RNG procurement programs.** ICF recommends a near-term regulatory approach that supports voluntary purchase of RNG through gas utility service providers to help foster market growth, improve customer awareness, and satisfy nascent demand.
- **Expand RNG in the transportation sector through infrastructure investments.** ICF recommends an innovative regulatory structure whereby utilities are able to invest in NGV fueling infrastructure, offer beneficial and attractive tariffs to CNG users, and partner with key stakeholders to deploy CNG in key vehicle market segments.
- **Implement a broad and stable policy framework such as a Renewable Gas Standard.** ICF recommends that the region adopt a Renewable Gas Standard (RGS). This is the most robust policy structure, and it will help drive consistent demand in a diverse set of end uses, and assist the market to transition from a near-term focus on the transportation sector to a mid- to long-term focus on stationary uses in thermal applications. The RGS will act as a utility procurement mechanism, thereby providing supply and price certainty without disrupting the success and market participation in existing programs driving existing RNG deployment.

1. Introduction

ICF was engaged by Washington Gas Light Company (WG) to fulfill AltaGas Merger Commitment No. 6, as stipulated in Formal Case No. 1142 (Order No. 19396) of the Public Service Commission of the District of Columbia (D.C.)[4] and AltaGas Merger Commitment No. 5, as stipulated in Formal Case No. 9449 (Order No. 88631) of the Public Service Commission of Maryland:[5]

> "AltaGas will provide $450,000 to fund a study to assess the development of renewable (bio) gas facilities in the Greater Washington, D.C. metropolitan area. The study will assess the potential environmental benefits of repurposing locally sourced waste streams into pipeline quality renewable gas, compressed natural gas and/or liquefied natural gas that can be used for carbon neutral vehicle fueling and onsite energy production. The study will evaluate the economic viability, identify operating challenges and solutions, and offer recommendations relating to regulatory and market approaches that can facilitate the utilization of renewable sources to support the achievement of local, state, and regional climate and energy plans. This study will be a single study funded by AltaGas with respect to all of the Washington Gas service territories and will be commenced within one year after Merger Close. Neither AltaGas nor any AltaGas affiliate will perform the study. The costs of this study shall not be recovered through Washington Gas's utility rates."

The primary objective of this study is to characterize the technical and economic potential for renewable natural gas (RNG) as a greenhouse gas (GHG) emission reduction strategy, with particular focus on local or regional resources in the Greater Washington, D.C. metropolitan area. Further, the study includes a series of deliverables that support AltaGas' efforts to improve understanding of the extent to which delivering RNG to all sectors of the regional economy can contribute to broader GHG emission reduction initiatives.

Greater Washington, D.C. Metropolitan Area

The Greater Washington, D.C. metropolitan area had a population of over six million people in 2018,[6] making it the sixth largest metropolitan area in the United States and the largest metropolitan area in the Census Bureau's South Atlantic division.[7] The metropolitan area includes all of D.C., as well as parts of Maryland, Virginia, and West Virginia, covering 24 counties, cities and districts. [8]

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[4] D.C. Public Service Commission, 2019. https://dcpsc.org/Newsroom/HotTopics/AltaGas-WGL-Holdings-Merger-Commitments-Tracking-M.aspx

[5] Public Service Commission of Maryland, 2018. https://www.psc.state.md.us/wp-content/uploads/Order-No.-88631-Case-No.-9449-AltaGas-WGL-Merger-Order.pdf

[6] US Census Bureau, 2019. https://www.census.gov/data/tables/time-series/demo/popest/2010s-counties-total.html

[7] US Census Bureau, 2019. https://www.census.gov/programs-surveys/metro-micro.html

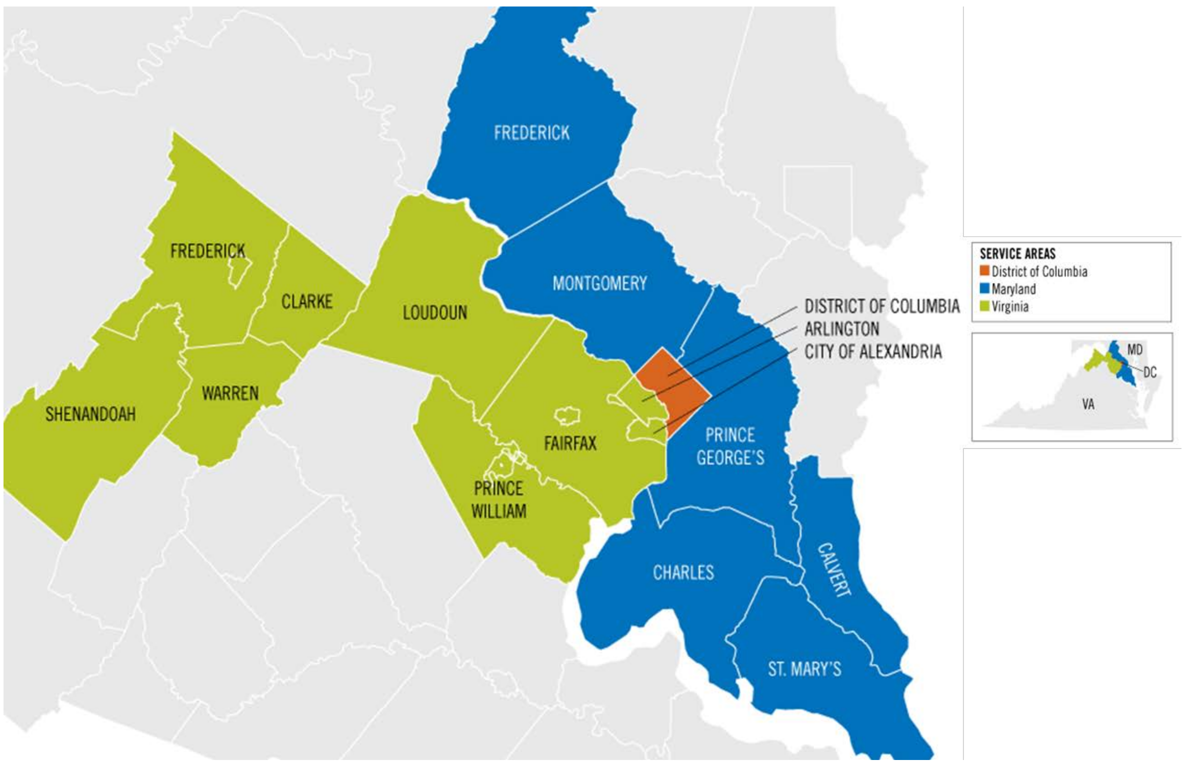
[8] US Census Bureau, 2019. https://www2.census.gov/geo/maps/metroarea/us_wall/Sep2018/CBSA_WallMap_Sep2018.pdf?#

The Greater Washington, D.C. metropolitan area has three major airports, four rail transit systems and over 10 bus transit systems; and it is home to numerous Fortune 500 companies, including AES Corporation, Capital One, Lockheed Martin and General Dynamics. The region is served by multiple electric and natural gas utilities, including WG, Pepco, Dominion and Columbia Gas of Virginia.

Washington Gas Light Company

WG is the largest natural gas local distribution company in the Greater Washington, D.C. metropolitan area, distributing natural gas to nearly 1.2 million customers in a service territory that covers areas of Washington, D.C., Maryland, and Virginia (see Figure 1).

Figure 1. WG Service Territory[9]



To serve these 1.2 million customer meters, WG has an annual throughput of roughly 165 trillion British thermal units per year (tBtu/y), with WG sales representing over half that volume. WG's natural gas system sees a significant winter peak, largely driven by space heating demand during the winter months.

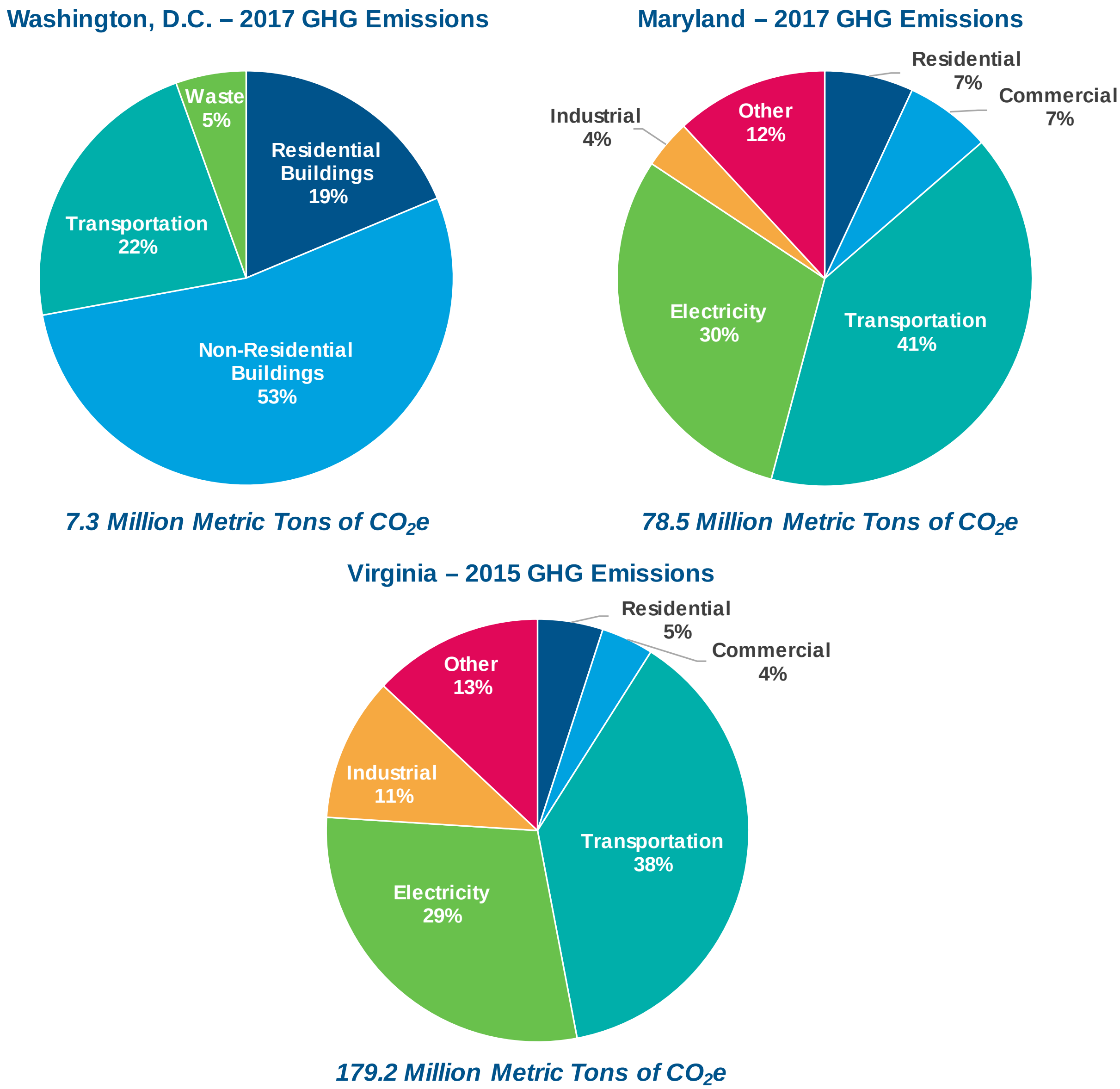
Greenhouse Gas Emissions

The share of GHG emissions for each major emitting sector for Washington, D.C., Maryland, and Virginia is shown in Figure 2. In Maryland and Virginia, the transportation and power sectors account for the majority of GHG emissions. This is also true for D.C., although it is not clear from Figure 2. There is almost no direct power generation in Washington, D.C.; however

[9] https://www.washingtongas.com/builders-contractors/contractor-services/service-territory

the indirect emissions associated with electricity generation accounted for 60% of the total GHG emissions attributed to D.C. in 2017.[10] The emissions from the generation of the electricity used in D.C. are assigned to the end-use sector using the electricity. In 2017, electricity accounted for 76% of GHG emissions in the residential and nonresidential buildings sectors in D.C., while natural gas accounted for 23% and fuel oil 1% of GHG emissions.

Figure 2. Share of GHG Emissions for Washington, D.C., Maryland and Virginia by Sector[11]



[10] Since 2013, emissions from power generation in the PJM have declined due to a reduction in coal generation and growth in natural gas generation in the region.
[11] Sources: D.C. Department of Energy and Environment, 2019, GHG Emission Inventory, https://doee.dc.gov/service/greenhouse-gas-inventories; Maryland MDE, 2019, GHG Emission Inventory, https://mde.state.md.us/programs/Air/ClimateChange/Documents/2017%20GHG%20Inventory/MD2017PeriodicGHGInventory.pdf; Virginia DEQ, 2017.

There are key differences between Maryland, Virginia, and D.C. related to emission trends and large emitting sectors. D.C. has the highest share of emissions from the building sector—primarily due to the emissions generated from electricity used in the buildings. The transportation sector accounts for 22% of D.C.'s emissions, a lower than average share when compared to regional and national emission levels. This lower share is a result of the smaller geographic area of D.C. and the high levels of public transportation usage in the Greater Washington, D.C. metropolitan area. In contrast, the share of transportation sector emissions is 41% in Maryland and 38% in Virginia, more in line with national averages.

Climate Policies

In recent years, climate policies have shifted from a national approach to local and regional approaches. In parallel with this geographic trend, there has also been a shift in the types of policies that are being proposed for reducing GHG emissions. National policies were broadly focused on regulation of GHG emissions in the power sector and direct fuel efficiency targets in transportation. There is a much larger degree of variation in approaches at the regional level toward emission reductions measures, although there is a broader national trend toward economy-wide decarbonization. Washington, D.C., Maryland, and Virginia have all made commitments to climate and clean energy goals that will play critical roles in determining the pace of GHG emission reductions in each jurisdiction, and will directly impact WG's natural gas system.

In D.C., there is a goal for 50% GHG emission reductions by 2032, carbon neutral transportation by 2045, and an economy-wide carbon neutrality goal by 2050. In Maryland, there is a goal for 40% GHG emission reductions by 2030 and a carbon neutral goal by 2050. Finally, in Virginia, there is a goal to cut carbon dioxide (CO_2) power plant emissions by 30% by 2030, and also an Executive Order to make 30% of energy production come from renewable resources by 2030 and for 100% of electricity to be produced from carbon-free sources by 2050.

The call for long-term, low-carbon targets will increasingly impact gas utility operations and the role that these companies will be asked to perform in meeting state and local GHG emission reduction targets. Many natural gas distribution companies continue to focus on ways that they can contribute to meeting these goals.

Natural gas utilities have a number of approaches to pursue as part of decarbonization strategies that help meet GHG emission targets. These measures focus on reducing consumer fossil fuel usage (including energy-efficiency measures and fugitive emissions reduction efforts) as well as applying new technologies such as hybrid heating systems or other approaches. However, increasing attention is being given to RNG as a cost effective and impactful option to reduce GHG emissions significantly from natural gas consumption, while maintaining the benefits of the natural gas system.

Renewable Natural Gas

RNG is derived from biomass or other renewable resources, and is a pipeline-quality gas that is fully interchangeable with conventional natural gas. As a point of reference, the American Gas Association (AGA) defines RNG as:[12]

> *Pipeline-compatible gaseous fuel derived from biogenic or other renewable sources that has lower lifecycle carbon dioxide equivalent (CO_2e) emissions than geological natural gas.* [13]

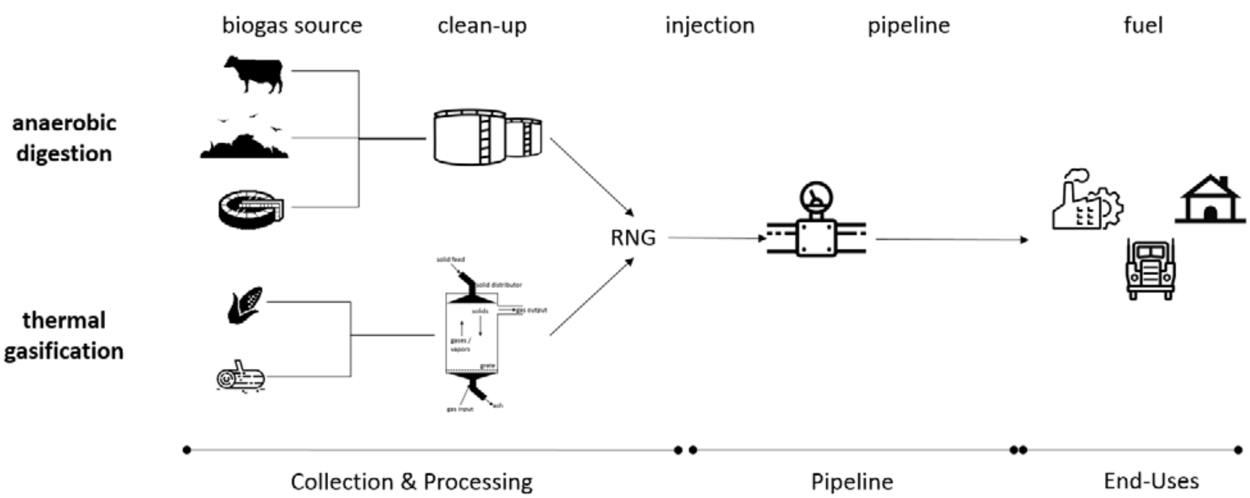
The following subsections introduce the RNG production technologies and corresponding feedstocks. Consistent with the approach undertaken in our recent American Gas Foundation assessment of the national supply and emission reduction potential of RNG, ICF assessed the production potential for renewable gas in two categories:[14]

- RNG from renewable feedstocks using anaerobic digestion and thermal gasification.
- RNG produced via combination of power-to-gas (P2G) and methanation.

For each resource and production technology pairing, ICF estimated the production cost and corresponding range of GHG emissions.

RNG is produced over a series of steps (see Figure 3): collection of a feedstock, delivery to a processing facility for biomass-to-gas conversion, gas conditioning, compression, and injection into the pipeline. ICF considered three production technologies: anaerobic digestion, thermal gasification, and P2G combined with methanation.

Figure 3. RNG Production Process via Anaerobic Digestion and Thermal Gasification



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[12] AGA, 2019. RNG: Opportunity for Innovation at Natural Gas Utilities, https://pubs.naruc.org/pub/73453B6B-A25A-6AC4-BDFC-C709B202C819

[13] ICF notes that this is a useful definition, but excludes RNG produced from the thermal gasification of the nonbiogenic fraction of municipal solid waste (MSW). In most cases, however, the thermal gasification of the nonbiogenic fraction of MSW will yield lower CO_2e emissions than geological natural gas. As a result, MSW is included as an RNG resource in this study.

[14] ICF, 2019. Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment, https://www.gasfoundation.org/2019/12/18/renewable-sources-of-natural-gas/

Anaerobic Digestion

The most common way to produce RNG today is via anaerobic digestion, whereby microorganisms break down organic material in an environment without oxygen. For example, National Grid's New York City Newtown Creek RNG demonstration project will be one of the first anaerobic digestion facilities in the United States that directly injects RNG into a local distribution system using biogas generated from a water and food waste facility.[15]

The four key processes in anaerobic digestion are:

- Hydrolysis
- Acidogenesis
- Acetogenesis
- Methanogenesis

Hydrolysis is the process whereby longer-chain organic polymers are broken down into shorter-chain molecules like sugars, amino acids, and fatty acids that are available to other bacteria. Acidogenesis is the biological fermentation of the remaining components by bacteria, yielding volatile fatty acids, ammonia, carbon dioxide, hydrogen sulfide, and other byproducts. Acetogenesis of the remaining simple molecules yields acetic acid, carbon dioxide, and hydrogen. Lastly, methanogens use the intermediate products from hydrolysis, acidogenesis, and acetogenesis to produce methane, carbon dioxide, and water, where the majority of the biogas is emitted from anaerobic digestion systems.

The process for RNG production generally takes place in a controlled environment referred to as a digester or reactor. When organic waste, biosolids, or livestock manure is introduced to the digester, the material is broken down over time (e.g., days) by microorganisms and the gaseous products of that process contain a large fraction of methane and carbon dioxide. The biogas requires capture and then subsequent conditioning and upgrade before pipeline injection. The conditioning and upgrading help to remove any contaminants and other trace constituents, including siloxanes, sulfides and nitrogen, that cannot be injected into common carrier pipelines, and increase the heating value of the gas for injection.

Thermal Gasification

Biomass-like agricultural residues, forestry and forest produce residues, and energy crops have high energy content and are ideal candidates for thermal gasification. The thermal gasification of biomass to produce RNG occurs over a series of steps:

- Feedstock pre-processing in preparation for thermal gasification (not in all cases).
- Gasification, which generates synthetic gas (syngas) consisting of hydrogen and carbon monoxide (CO).
- Filtration and purification, where the syngas is further upgraded by filtration to remove remaining excess dust generated during gasification and other purification processes to remove potential contaminants like hydrogen sulfide and carbon dioxide.
- Methanation, where the upgraded syngas is converted to methane and dried prior to pipeline injection.

[15] National Grid, 2019. https://www9.nationalgridus.com/non_html/NG_renewable_WP.pdf

While biomass gasification technology is at an early stage of commercialization, the gasification and purification steps remain challenging. The gasification process typically yields a residual tar, which can foul downstream equipment. Furthermore, the presence of tar effectively precludes the use of a commercialized methanation unit. The high cost of conditioning the syngas in the presence of these tars has limited the potential for thermal gasification of biomass. For instance, in 1998, Tom Reed concluded that after "two decades" of experience in biomass gasification, "'tars' can be considered the Achilles heel of biomass gasification."[16] Over the last several years, however, a few commercialized technologies have been deployed to increase syngas quantity and prevent the fouling of other equipment by removing the residual tar before methanation. There are a handful of technology providers in this space, including Haldor Topsoe's tar-reforming catalyst. Frontline Bioenergy takes a slightly different approach and has patented a process producing tar-free syngas (referred to as TarFreeGas™).

ICF notes that biomass (particularly agricultural residues) is often added to anaerobic digesters to increase gas production (by improving carbon-to-nitrogen ratios, especially in animal manure digesters). It is conceivable that some of the feedstocks considered here could be used in anaerobic digesters. For simplicity, ICF did not consider any multi-feedstock applications in our assessment; however, it is important to recognize that the RNG production market will continue to include mixed feedstock processing in a manner that is cost-effective.

Power-to-Gas/Methanation

P2G is a form of energy technology that converts electricity to a gaseous fuel. Electricity is used to split water into hydrogen and oxygen, and the hydrogen can be further processed to produce methane. If the electricity is sourced from renewable resources, such as wind and solar, then the resulting fuels are carbon neutral. The key process in P2G is the production of hydrogen from renewably generated electricity by means of electrolysis. This hydrogen conversion method is not new, and there are three electrolysis technologies with different efficiencies and in different stages of development and implementation:

- Alkaline electrolysis, where two electrodes operate in a liquid alkaline solution,
- Proton exchange membrane electrolysis, where a solid membrane conducts protons and separates gases in a fuel cell, and
- Solid oxide electrolysis, a fuel cell that uses a solid oxide at high temperatures.

The hydrogen produced from P2G is a highly flexible energy product that can be:

- Stored as hydrogen and used to generate electricity at a later time using fuel cells or conventional generating technologies,
- Injected as hydrogen into the natural gas system, where it augments the natural gas supply, and
- Converted to methane and injected into the natural gas system.

The last option, methanation, involves combining hydrogen with renewably sourced CO_2 and converting the two gases into methane. The methane produced is RNG, and is a clean alternative to conventional fossil natural gas, as it can displace fossil natural gas for combustion

[16] NREL, Biomass Gasifier "Tars": Their Nature, Formation, and Conversion, November 1998, NREL/TP-570-25357. Available online at https://www.nrel.gov/docs/fy99osti/25357.pdf.

in buildings, vehicles, and electricity generation. Methanation avoids the cost and inefficiency associated with hydrogen storage and creates more flexibility in the end use through the natural gas system. The P2G RNG conversion process can also be coordinated with conventional biomass-based RNG production by using the surplus CO_2 in biogas to produce the methane, creating a productive use for the CO_2.

RNG Feedstocks

RNG can be produced from a variety of renewable feedstocks, as described in Table 1.

Table 1. RNG Feedstock Types

Feedstock for RNG		Description
Anaerobic Digestion	Landfill gas (LFG)	A mix of gases, including methane (40–60%), produced by the anaerobic digestion of organic waste in landfills.
	Animal manure	Manure produced by livestock, including dairy cows, beef cattle, swine, sheep, goats, poultry, and horses.
	Water Resource Recovery Facilities (WRRF)	Wastewater consists of waste liquids and solids from household, commercial, and industrial water use; in the processing of wastewater, a sludge is produced, which serves as the feedstock for RNG.
	Food waste	Commercial food waste, including from food processors, grocery stores, cafeterias, and restaurants, as well as residential food waste, typically collected as part of waste diversion programs.
Thermal Gasification	Agricultural residue	The material left in the field, orchard, vineyard, or other agricultural setting after a crop has been harvested. Inclusive of unusable portion of crop, stalks, stems, leaves, branches, and seed pods.
	Forestry and forest product residue	Biomass generated from logging, forest and fire management activities, and milling. Inclusive of logging residues, forest thinnings, and mill residues. Also materials from public forestlands, but not specially designated forests (e.g., roadless areas, national parks, wilderness areas).
	Energy crops	Inclusive of perennial grasses, trees, and annual crops that can be grown to supply large volumes of uniform and consistent feedstocks for energy production.
	Municipal solid waste (MSW) [17]	Refers to the nonbiogenic fraction of waste that would be landfilled after diversion of other waste products (e.g., food waste or other organics), including construction and demolition debris and plastics.
P2G	Renewable electricity	Renewable electricity (presumably excess generation) serves as feedstock for P2G technologies. P2G produces hydrogen, which can be used as a form of energy storage, injected into the natural gas system, or converted to methane (RNG).

[17] ICF notes that the nonbiogenic fraction of MSW does not satisfy the American Gas Association's definition of RNG; however, this feedstock was included in the analysis. The results associated with RNG potential from this nonbiogenic fraction of MSW are called out separately throughout the report.

RNG Policy Environment

At both the national and state levels, policy and regulatory frameworks for RNG are developing, albeit inconsistently: RNG producers and consumers often face multiple overlaying policies and regulations that both promote RNG production (or elements thereof) and consumption and create barriers to RNG use.

Current policies direct RNG consumption into the transportation sector, and to a lesser extent for on-site electricity generation. At the national level, the Federal Renewable Fuel Standard (RFS) provides financial incentive for RNG as a transportation fuel, while state programs such as California's Low Carbon Fuel Standard (LCFS) and Oregon's Clean Fuels Program (CFP) provide additional incentives for RNG consumption. In addition, there is growing interest from policymakers in other jurisdictions such as New York, Washington, and Colorado to implement LCFS-type programs that would incentivize RNG consumption in transportation markets.

In parallel to the incentives for RNG use in the transportation sector, Renewable Portfolio Standards (RPS) reward biogas combustion to generate on-site electricity as a source of compliance. Methane from landfill and wastewater treatment plants are eligible and participate in the RPSs in D.C. and Maryland.

Other policies are developing to support the potential growth of RNG beyond the transportation sector and on-site electricity generation, including programs that facilitate methane capture from feedstock sites and mandate waste diversion and collection. Jurisdictions and individual utilities are also pursuing regulatory initiatives that support the development of RNG, including voluntary tariffs and procurement programs, and RNG conditioning and interconnection tariffs (Section 6).

The limited policy structure in place today that supports RNG development, primarily as a transportation fuel, has already spurred considerable investment. Since 2015, RNG for pipeline injection has grown at a compound annual growth rate of about 30%, and ICF forecasts that this growth rate will increase slightly in the next two to four years. Despite these impressive gains, ICF considers the current policy structure inadequate to support the level of RNG production that is needed for it to contribute more meaningfully to decarbonization policies. In fact, there are regulations and market structures that hinder RNG production, including limited support for research and development, deficient cost-recovery mechanisms for utility investments in RNG, restrictive or time-consuming pipeline interconnection requirements, and decarbonization policies focused on technology rather than cost (e.g., fuel switching). In particular, the policies that focus on a specific technology as opposed to taking a technology-neutral approach to decarbonization inhibit RNG development. Instead, a technology-neutral approach would promote the utilization of the best technology for each application as determined by a thorough analysis, including elements such as cost, reliability, and resilience.

Even with the success of RNG in the transportation fuels market, the programs in place today do not provide the overall price and supply certainty that is required for larger volumes of RNG to be deployed. Furthermore, many policymakers and stakeholders do not recognize RNG's broader prospects as a strategy to reduce GHG emissions, most notably those related to the potential supply and corresponding cost of developing those resources.

Policies related to building decarbonization often narrowly focus on electrification, rather than on a broader approach that prioritizes least cost emission reductions over specific technologies. For example, there is a growing trend for local governments—such as various cities in California and Massachusetts—to ban natural gas hookups and equipment in new buildings.[18] There are many opportunities to expand the use of RNG to all sectors of the economy, but one of the limiting factors is that decision-makers do not have adequate access to updated and reliable information regarding the resource potential, technology advancement, and costs of RNG.

[18] City of Berkeley, 2019. https://www.cityofberkeley.info/.../2019-07-09_Item_21_Adopt_an_Ordinance_adding_a_new.aspx; Town of Brookline, 2019. https://www.brooklinema.gov/DocumentCenter/View/20101/Sustainable-Bldgs-WA-plus-Explanation-as-submitted?bidId=

2. RNG Resource Assessment

Key Takeaways

ICF estimates that there sufficient RNG feedstock resources are available at a local, regional, and national level for both near-term and long-term deployment of RNG to help decarbonize the natural gas system and contribute to the aggressive climate commitments in the region.

ICF anticipates that there is enough RNG production potential to displace upward of 25% of total natural gas consumption in direct uses today. This percentage does not include any potential reductions attributable to conservation or efficiency measures, nor does it account for RNG volumes available if fewer conservative assumptions are applied.

Assessment Methodology

The resource assessment methodology is based on the primary objective: to characterize the technical and economic potential for RNG as a cost-effective and impactful strategy to reduce GHG emissions from the natural gas system, with particular focus on local or regional resources in the Greater Washington, D.C. metropolitan area. The resource assessment is broken down into two areas: production technologies and feedstocks, outlined in Section 1.

ICF used a mix of existing studies, government data, and industry resources to estimate the current and future supply of the feedstocks. The table below summarizes some of the resources that ICF drew from to complete our resource assessment, broken down by RNG feedstock:

Table 2. Illustrative List of Data Sources for RNG Feedstock Assessment

Feedstock for RNG	Potential Resources for Assessment	
LFG	▪ U.S. EPA Landfill Methane Outreach Program	
Animal manure	▪ AgStar Project Database	▪ USDA Livestock Inventory (Cattle, Swine, etc.)
WRRFs	▪ U.S. EPA	▪ Water Environment Federation
Food waste	▪ U.S. DOE 2016 Billion Ton Report	▪ Bioenergy Knowledge Discovery Framework
Agricultural residue	▪ U.S. DOE 2016 Billion Ton Report	▪ Bioenergy Knowledge Discovery Framework
Forestry and forest product residue	▪ U.S. DOE 2016 Billion Ton Report	▪ Bioenergy Knowledge Discovery Framework
Energy crops	▪ U.S. DOE 2016 Billion Ton Report	▪ Bioenergy Knowledge Discovery Framework
MSW	▪ U.S. EPA	▪ Waste Business Journal

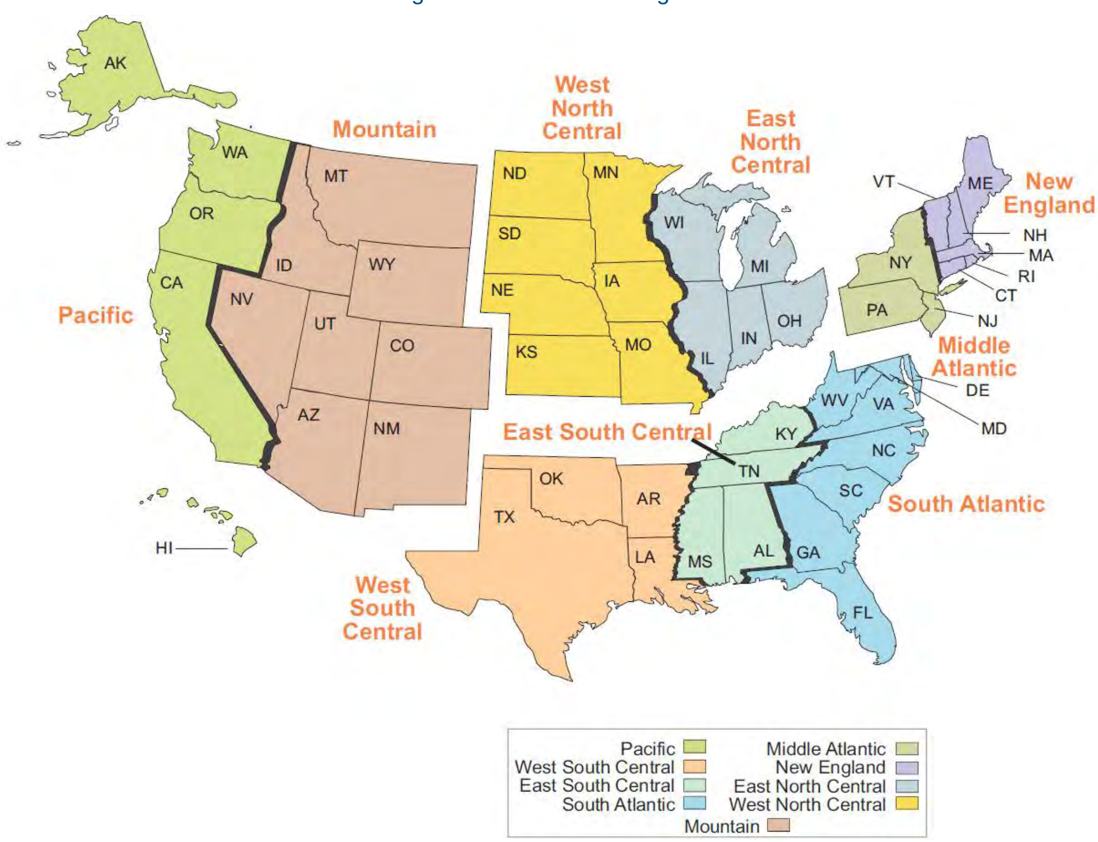
RNG potential is based on an assessment of resource availability—in a competitive market, that resource availability is a function of multiple factors, including but not limited to demand, feedstock costs, technological development, and the policies in place that might support RNG project development. ICF assessed the RNG resource potential of the different feedstocks that could be realized, given the necessary market considerations (without explicitly defining what those are), and then captured the corresponding costs and GHG emission reductions associated with these production estimates.

For the RNG market more broadly, ICF assumed that the market would grow at a compound annual growth rate slightly higher than we have seen over the last five years—a rate of about 35%.[19] ICF applied a logistic function to model the growth potential of the RNG production, whereby the initial stage of growth is approximated as an exponential, and thereafter growth slows to a linear rate and then approaches a plateau (or limited to no growth) at maturity.

Geographies

We present RNG potential at the local, regional, and national levels. The local level is defined as WG's service territory and is referred to as the Greater Washington, D.C. metropolitan area. The regional level is based on the U.S. Energy Information Administration's (EIA) South Atlantic Census region, shown below. The South Atlantic Census region incorporates all of the Greater Washington, D.C. metropolitan area, with a natural gas consumption level broadly analogous to the natural gas consumption in WG's current long-haul supply and distribution systems. The national level includes all regions other than the South Atlantic Census region.

Figure 4. EIA Census Regions



[19] ICF estimates that there were about 17.5 trillion Btu (tBtu) of RNG produced for pipeline injection in 2016 and that there will be about 50 tBtu of RNG produced for pipeline injection in 2020—this yields a compound annual growth rate of about 30%.

Scenarios

ICF developed three scenarios for each feedstock—with variations among conservative, balanced, and aggressive assumptions regarding utilization of the feedstock.

- **Conservative Low** represents a low level of feedstock utilization, with utilization levels depending on feedstock, with a range from 25% to 40% for feedstocks that were converted to RNG using anaerobic digestion technologies. The utilization rates of feedstocks for thermal gasification in the Conservative Low scenario ranged from 25% to 50%.
- **Achievable** represents balanced assumptions regarding feedstock utilization, with a range from 50% to 80% for feedstocks that were converted to RNG using anaerobic digestion technologies. The utilization rates of feedstocks for thermal gasification in the Achievable scenario ranged from 50% to 75%. This scenario reflects a plausible resource potential where feedstocks are more efficiently utilized and where there is a more favorable policy and regulatory environment that would deliver RNG resources greater than in the Conservative Low scenario.
- **Aggressive High** represents higher levels of utilization closer to the technical potential of RNG feedstock. Utilization levels vary by feedstock, with a range from 85% to 95% for feedstocks that were converted to RNG using anaerobic digestion technologies. The utilization rates of feedstocks for thermal gasification in the Aggressive High scenario ranged from 80% to 90%. It is worth noting that this scenario does not represent a maximum achievable or technical potential scenario.

In the following sub-sections, ICF outlines the potential for RNG for pipeline injection, broken down by the feedstocks presented previously and considering the potential for RNG growth over time, with 2040 being the final year in the analysis. ICF presents the Conservative Low, Achievable, and Aggressive High RNG production scenarios, varying both the assumed utilization of existing resources as well as the rate of project development required to deploy RNG at the volumes presented.

Summary of RNG Potential by Geography

The following subsections summarize the RNG potential for each feedstock and production technology by geography of interest.

Greater Washington, D.C. RNG Resource Potential

Table 3 includes estimates for the Greater Washington, D.C. metropolitan area's RNG potential in the Conservative Low, Achievable, and Aggressive High scenarios. The table shows the development potential of each feedstock in 2040, reported in units of trillion Btu per year (tBtu/y). For reference, with total throughput in WG's natural gas system at roughly 165 tBtu/y, local RNG resources could displace up to 33% of natural gas consumption in the Achievable scenario without accessing any potential RNG resources from outside the immediate region.

Table 3. Estimated Annual RNG Production in the Greater Washington, DC Metro Area by 2040, tBtu/y

RNG Feedstock	Scenario		
	Conservative Low	Achievable	Aggressive High
LFG	7.0	17.0	24.4
WRRFs	1.2	2.5	4.6
Food Waste	0.3	6.2	7.8
MSW (nonbiogenic)	5.3	29.8	43.5
Total	**13.8**	**55.5**	**80.3**

The Greater Washington, D.C. metropolitan area's RNG resources are focused on waste in an urbanized region, including landfills, WRRFs, food waste, and MSW. Conversely, the local area is resource-limited for specific feedstocks—such as animal manure, agricultural residues, forestry and forest product residues, and energy crops—because it is a predominantly urbanized area. Despite the lack of these resources locally, the local area's access to waste from landfills, wastewater, the potential for diverted food waste, and MSW streams can still provide a significant amount of RNG as part of a broader decarbonization focus.

South Atlantic Regional RNG Resource Potential

Figures 5–7 illustrate ICF's South Atlantic Regional estimates for the Conservative Low, Achievable and Aggressive High potential scenarios. The figures show the development potential of each feedstock out to 2040, reported in units of trillion Btu per year (tBtu/y).

Figure 5. Estimated Annual RNG Production South Atlantic, Conservative Low Scenario, tBtu/y

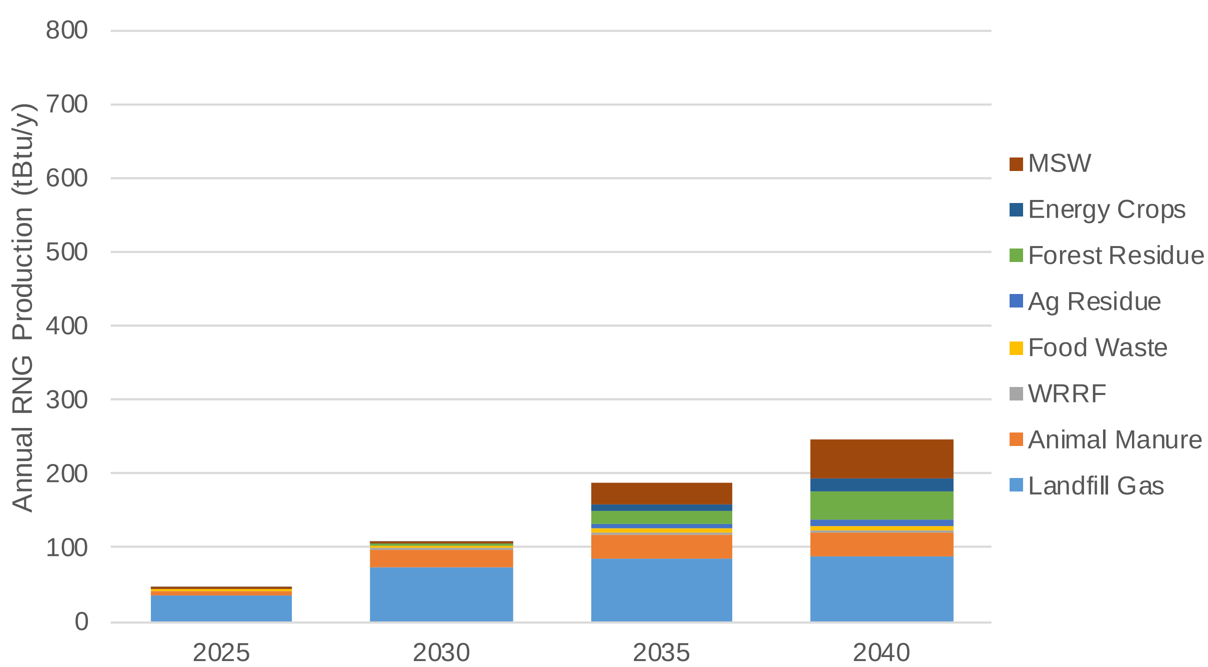


Figure 6. Estimated Annual RNG Production South Atlantic, Achievable Scenario, tBtu/y

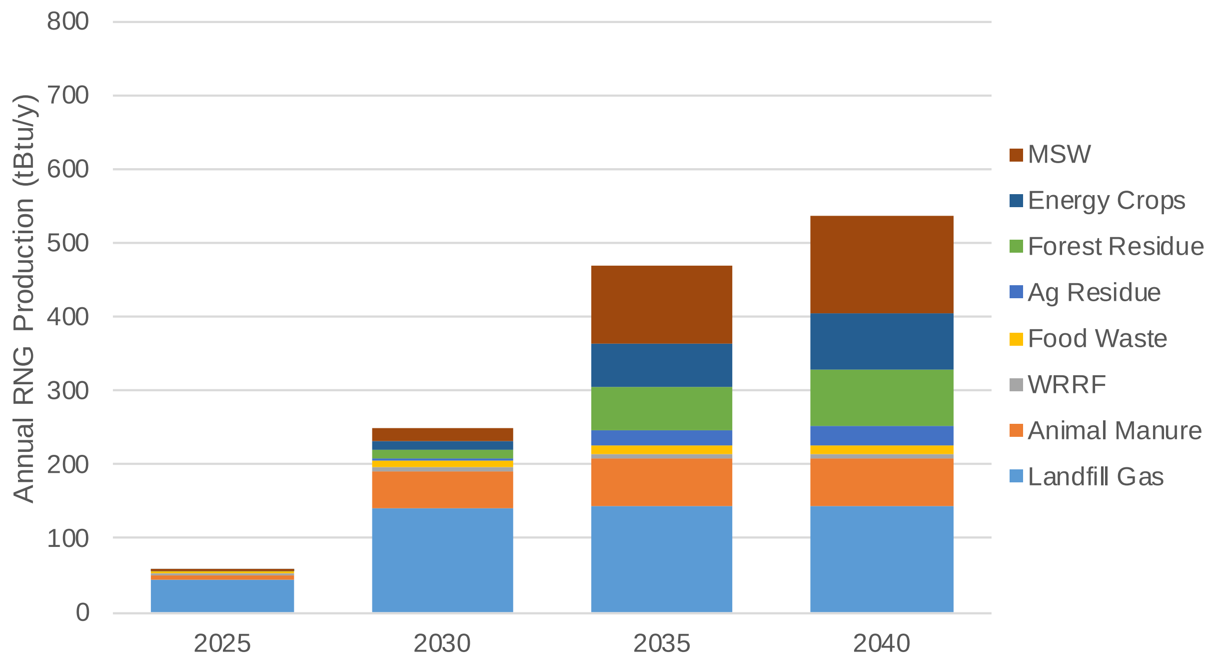
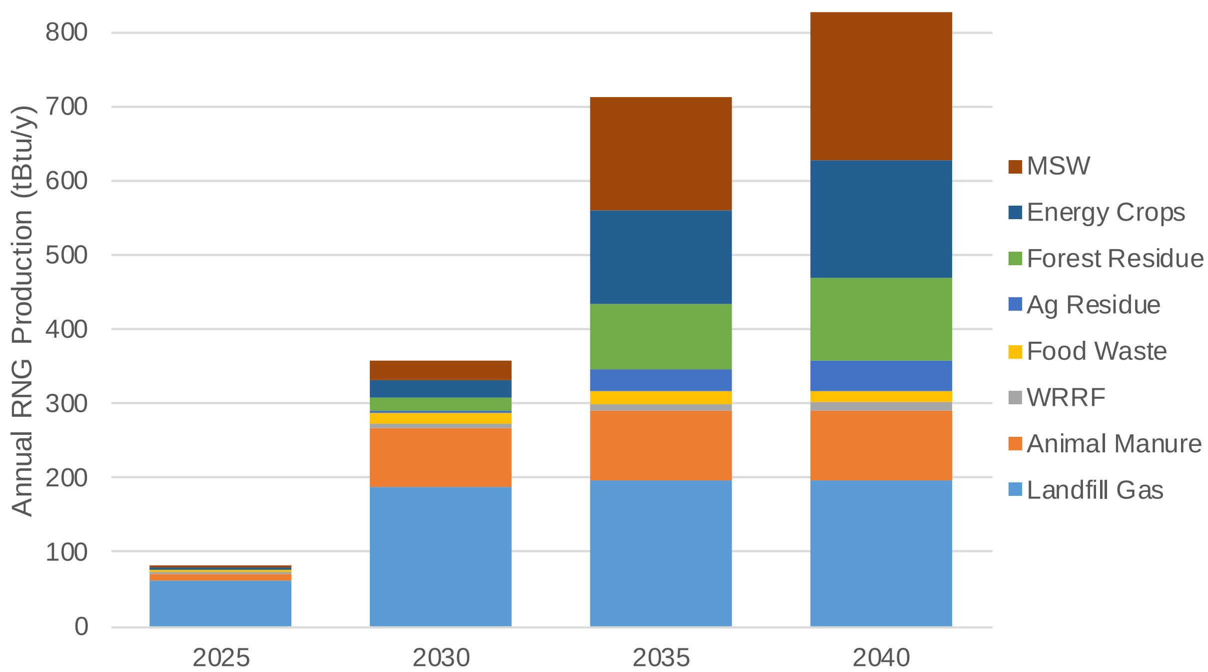


Figure 7. Estimated Annual RNG Production South Atlantic, Aggressive High Scenario, tBtu/y



National RNG Resource Potential

Figures 8–10 illustrate ICF's national estimates for the Conservative Low, Achievable, and Aggressive High potential scenarios. The figures show the development potential of each feedstock out to 2040, reported in units of tBtu/y.

Figure 8. Estimated National Annual RNG Production, Conservative Low Scenario, tBtu/y

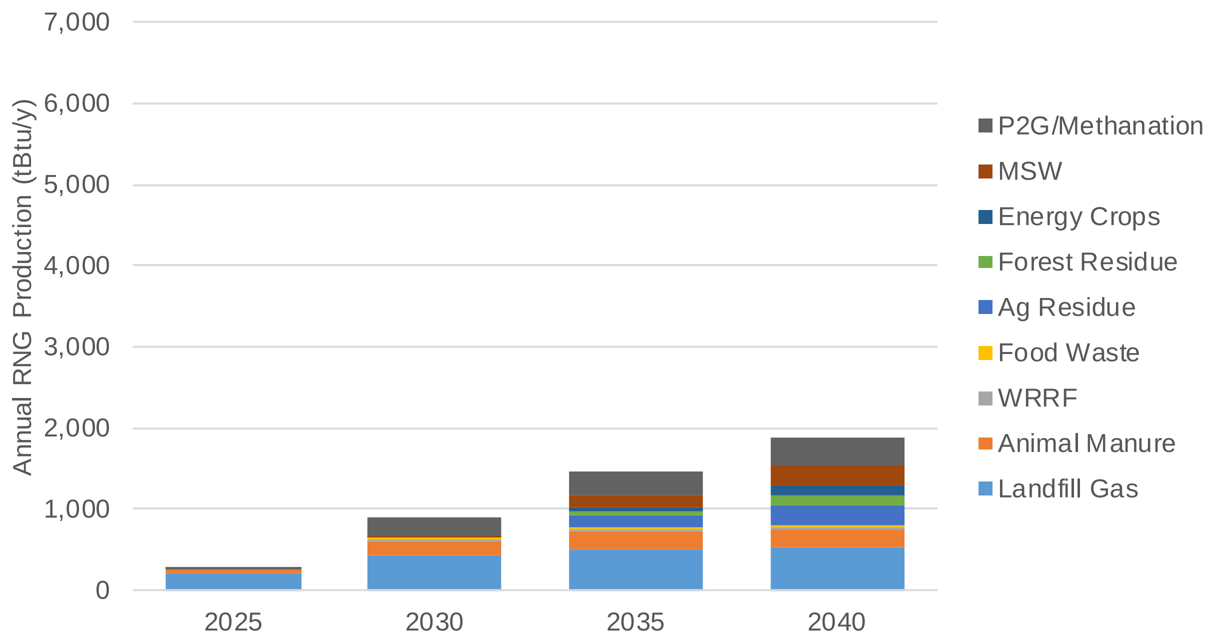


Figure 9. Estimated National Annual RNG Production, Achievable Scenario, tBtu/y

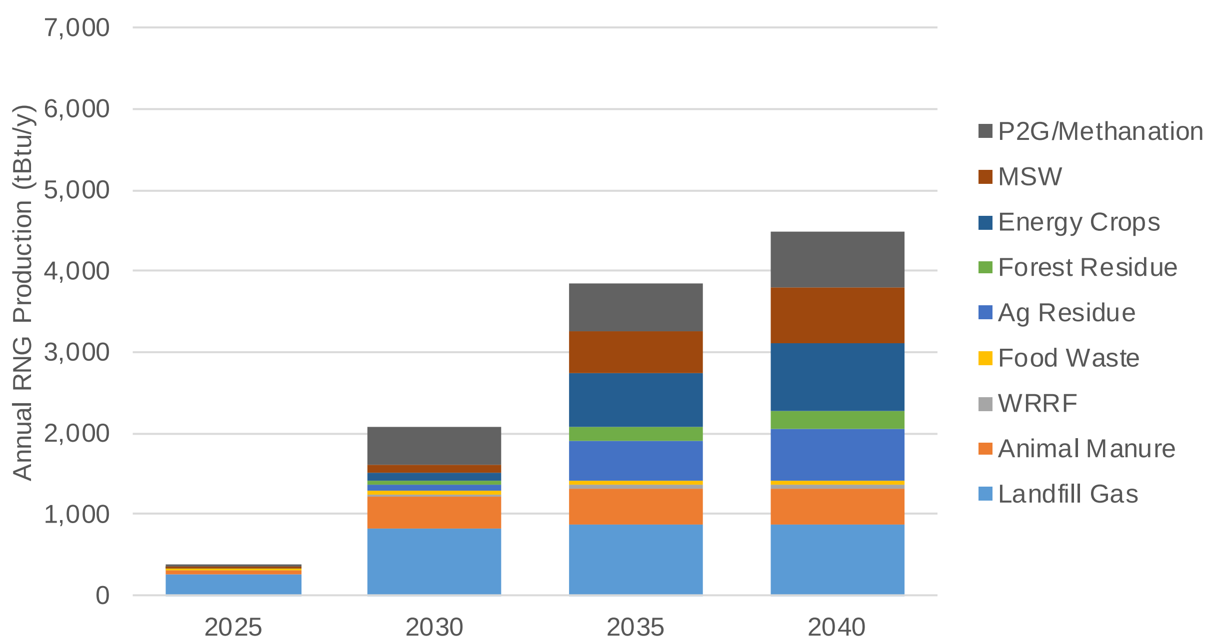
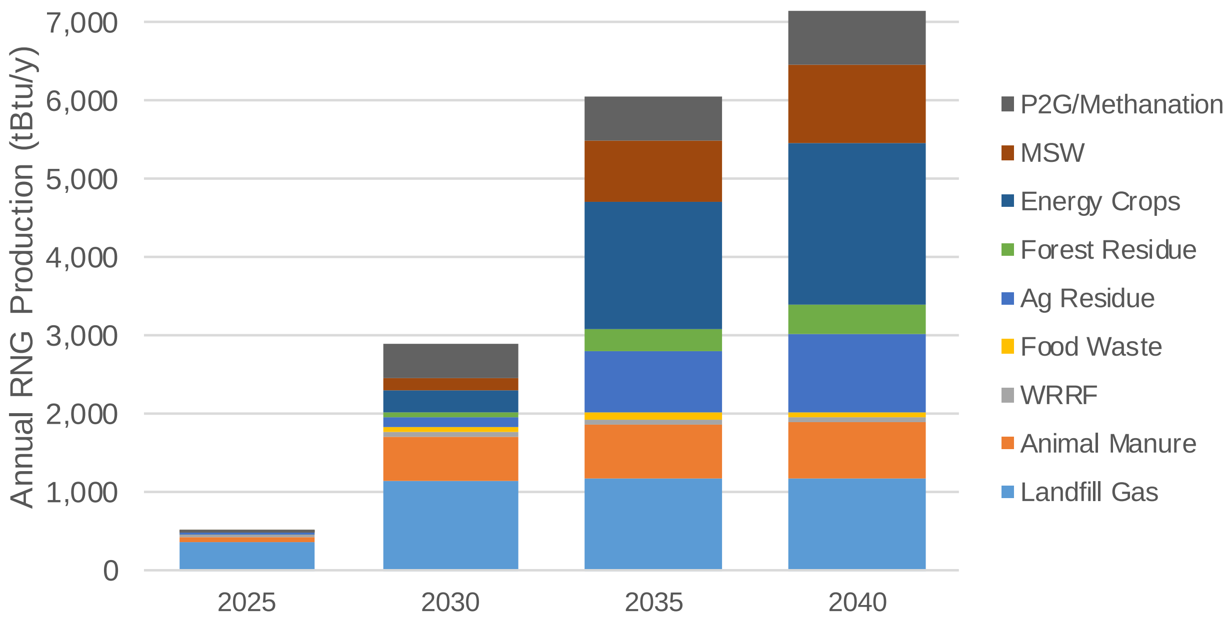


Figure 10. Estimated National Annual RNG Production, Aggressive High Scenario, tBtu/y



ICF estimates that the resource potential scenarios will yield between 1,890 tBtu/y and 7,160 tBtu/y of RNG production by 2040. For the sake of comparison, the United States consumed approximately 17,500 tBtu of natural gas in 2018 in the residential, commercial, transportation, and industrial sectors.[20]

In other words, using ICF's balanced assumptions regarding feedstock utilization and technology deployment in the Achievable scenario, there is enough RNG production potential to displace upward of 25% of total natural gas consumption in direct uses today. This percentage does not include any potential reductions attributable to conservation or efficiency measures, nor does it account for the higher volumes in the Aggressive High scenario, which could displace upward of 40% of the conventional natural gas consumption domestically today. Relative to WG, local RNG resources could displace up to 33% of direct use natural gas consumption in the Achievable scenario, without accessing any potential RNG resources from outside the immediate region.

[20] Based on data reported by the Energy Information Administration, available online at https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm.

Summary of RNG Potential by Scenario

Conservative Low Scenario

Table 4 below summarizes ICF's resource assessment for the Conservative Low RNG production potential scenario, reported in units of tBtu per year for local-, regional-, and national-level resources.

Table 4. Conservative Low RNG Production Potential Across Multiple Geographies, tBtu/y

RNG Feedstock		Geography		
		Greater D.C.	Regional	National
Anaerobic Digestion	Landfill Gas	7.0	88	528
	Animal Manure	--	32	231
	WRRFs	1.2	3	24
	Food Waste	0.3	6	29
Thermal Gasification	Agricultural Residue	--	10	255
	Forestry and Forest Product Residue	--	38	109
	Energy Crops	--	18	123
	Municipal Solid Waste	5.3	57	256
	Total	**13.8**	**252**	**1,556**

Achievable Scenario

Table 5 summarizes ICF's resource assessment for the Achievable RNG production potential scenario, reported in units of tBtu per year for local-, regional-, and national-level resources.

Table 5. Achievable RNG Production Potential Across Multiple Geographies, tBtu/y

RNG Feedstock		Geography		
		Greater D.C.	Regional	National
Anaerobic Digestion	Landfill Gas	17.0	145	866
	Animal Manure	--	63	462
	WRRFs	2.5	5	34
	Food Waste	6.2	13	64
Thermal Gasification	Agricultural Residue	--	27	641
	Forestry and Forest Product Residue	--	75	236
	Energy Crops	--	77	838
	Municipal Solid Waste	29.8	136	695
	Total	**55.5**	**542**	**3,834**

Aggressive High Scenario

Table 6 summarizes ICF's resource assessment for the Aggressive High RNG production potential scenario, reported in units of tBtu per year for local-, regional-, and national-level resources.

Table 6. Aggressive High RNG Production Potential Across Multiple Geographies, tBtu/y

RNG Feedstock		Geography		
		Greater D.C.	Regional	National
Anaerobic Digestion	Landfill Gas	24.4	197	1,195
	Animal Manure	--	95	694
	WRRFs	4.6	9	62
	Food Waste	7.8	17	82
Thermal Gasification	Agricultural Residue	--	40	1,019
	Forestry and Forest Product Residue	--	113	381
	Energy Crops	--	163	2,093
	Municipal Solid Waste	43.5	200	1,019
	Total	**80.3**	**833**	**6,544**

RNG: Anaerobic Digestion of Biogenic or Renewable Resources

Landfill Gas

The Resource Conservation and Recovery Act of 1976 (RCRA, 1976) sets criteria under which landfills can accept municipal solid waste and nonhazardous industrial solid waste. Furthermore, RCRA prohibits open dumping of waste, and hazardous waste is managed from the time of its creation to the time of its disposal. Landfill gas (LFG) is captured from the anaerobic digestion of biogenic waste in landfills and produces a mix of gases, including methane, with a methane content generally ranging from 45% to 60%. The landfill itself acts as the digester tank—a closed volume that becomes devoid of oxygen over time, leading to favorable conditions for certain micro-organisms to break down biogenic materials.

The composition of LFG is dependent on the materials in the landfill, and other factors, but is typically made up of methane, CO_2, nitrogen (N_2), hydrogen, CO, oxygen (O_2), sulfides (e.g., hydrogen sulfide or H_2S), ammonia, and trace elements like amines, sulfurous compounds, and siloxanes. RNG production from LFG requires advanced treatment and upgrading of the biogas via removal of CO_2, H_2S, siloxanes, N_2, and O_2 to achieve a high-energy (Btu) content gas for pipeline injection. Table 7 summarizes landfill gas constituents, the typical concentration ranges in LFG, and commonly deployed upgrading technologies in use today.

Table 7. Landfill Gas Constituents and Corresponding Upgrading Technologies

LFG Constituent	Typical Concentration Range	Upgrading Technology for Removal
Carbon dioxide, CO_2	40% – 60%	▪ High-selectivity membrane separation ▪ Pressure swing adsorption (PSA) systems ▪ Water scrubbing systems ▪ Amine scrubbing systems
Hydrogen sulfide, H_2S	0 – 1%	▪ Solid chemical scavenging ▪ Liquid chemical scavenging ▪ Solvent adsorption ▪ Chemical oxidation-reduction
Siloxanes	<0.1%	▪ Non-regenerative adsorption ▪ Regenerative adsorption
Nitrogen, N_2 Oxygen, O_2	2% – 5% 0.1% – 1%	▪ PSA systems ▪ Catalytic removal (O_2 only)

To develop the RNG potential from LFG, ICF extracted data from the Landfill Methane Outreach Program (LMOP) administered by the U.S. Environmental Protection Agency (EPA)—which included more than 2,000 landfills. Due to the minimal and declining methane production of waste after 25 years in landfills, ICF considered only landfills that are either open or were closed post-2000. This reduced the number of landfills included in our analysis to just over 1,500.

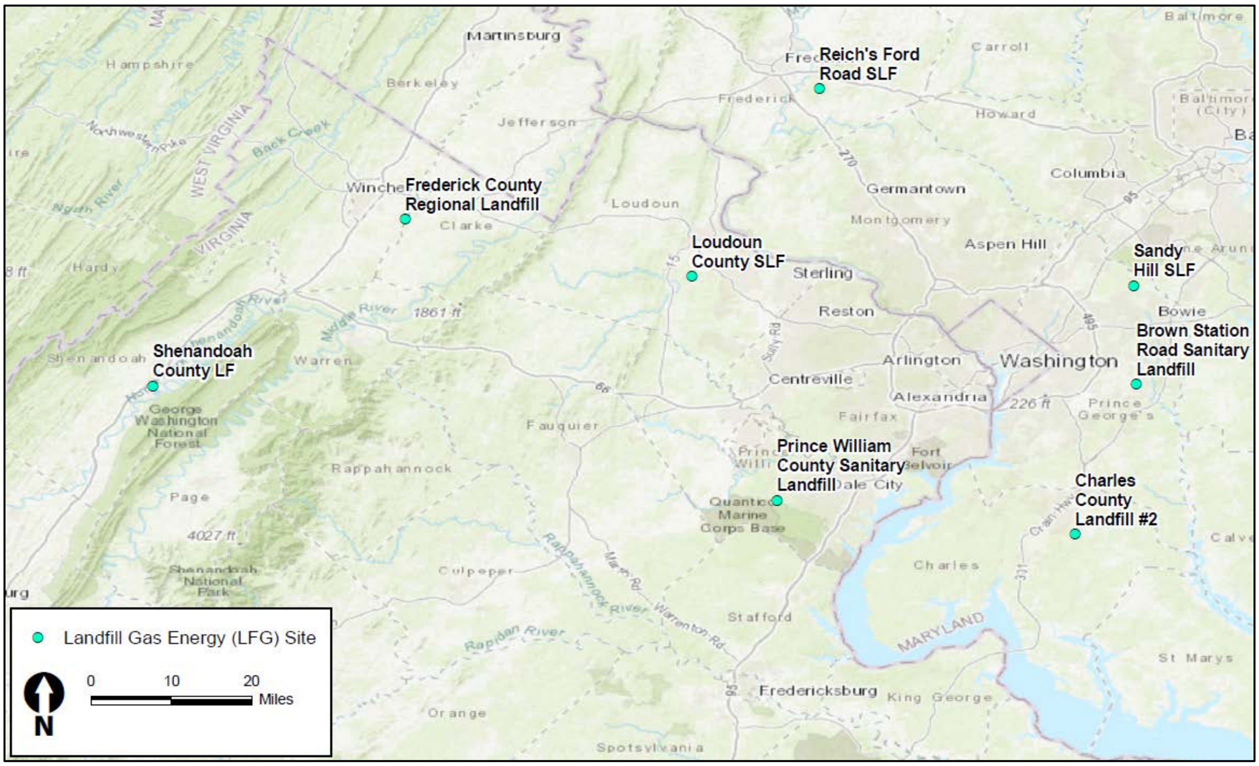
EPA's LMOP database shows that there are about 620 operational LFG to energy projects nationwide; however, only 60 (10%) of them produce RNG, and only 52 of those actually inject RNG into the pipeline. Most of the projects capture LFG and combust it in reciprocating engines to make electricity (72%) or have a direct use (18%) for the energy (e.g., thermal use on-site).

Moreover, the EPA currently estimates that there are 480 candidate landfills that could capture LFG for use as energy—EPA characterizes candidate landfills as those that are accepting waste or have been closed for five years or less, have at least one million tons of waste-in-place (WIP), and do not have operational, under-construction, or planned projects. Candidate landfills can also be designated based on actual interest by the site.

Local Landfills as an RNG Resource

Figure 11 shows the eight large landfills in WG's service territory that have more than one million tons of WIP.

Figure 11. Locations of Significant Landfills in the Greater Washington, D.C. Metropolitan Area



Of the eight landfills, five have LFG-to-energy operations, while the other three fall into EPA's candidate landfill category (see Table 8). If the LFG feedstock potential in WG's service territory is fully realized, the three candidate landfills could deliver up to 1 tBtu/y of RNG, while the remaining five LFG-to-energy facilities can deliver close to 5 tBtu/y of RNG into the natural gas pipeline system.

Table 8. Landfills in WG Service Territory

Name	LFG Generated (tBtu/y)	LFG Collection	Notes
Brown Station Rd (Calvert)	1.73	Yes	LFG-to-energy facility
Charles County #2	0.30	No	EPA candidate
Frederick County Regional	0.56	Yes	LFG-to-energy facility
Loudoun County	0.40	Yes	EPA candidate
Prince William County	1.10	Yes	LFG-to-energy facility
Reich's Ford Road (Frederick)	0.58	Yes	LFG-to-energy facility
Sandy Hill (Prince George's)	0.89	Yes	LFG-to-energy facility
Shenandoah County	0.28	Yes	EPA candidate
Total Potential	**5.84**		

Regional and National Landfills as an RNG Resource

The table below includes the number of landfills considered in each Census region.

Table 9. Number of Candidate Landfills by Census Region[21]

Landfill Status	South Atlantic	New England	Mid-Atlantic	East North Central	West North Central	East South Central	West South Central	Mountain	Pacific	National
Closed post-2000	**54**	33	16	51	21	19	25	24	58	**301**
Open	**221**	25	79	173	121	107	160	162	166	**1,214**
Total	**275**	58	95	224	142	126	185	186	224	**1,515**

[21] Based on data from the Landfill Methane Outreach Program at the EPA (updated February 2019).

Table 10 includes LFG-to-energy projects and candidate landfills broken down by Census region.

Table 10. LFG-to-Energy Projects and Candidate Landfills by Census Region[22]

Project Type	South Atlantic	New England	Mid-Atlantic	East North Central	West North Central	East South Central	West South Central	Mountain	Pacific	National
Electricity	**101**	28	64	105	23	20	19	18	71	**449**
Direct	**31**	1	12	26	17	6	10	1	5	**109**
RNG	**4**	1	9	13	5	4	19	1	4	**60**
Candidate Landfills	**88**	8	14	62	46	60	95	57	43	**473**

ICF developed assumptions for the resource potentials for RNG production at landfills in the three scenarios, considering the potential at LFG facilities with collection systems in place, LFG facilities without collection systems in place, and at candidate landfills identified by the EPA.

- In the Conservative Low scenario, ICF assumed that RNG could be produced at 40% of the LFG facilities that have collection systems in place, 30% of the LFG facilities that do not have collections systems in place, and at 50% of the candidate landfills.
- In the Achievable scenario, ICF assumed that RNG could be produced at 65% of the LFG facilities that have collection systems in place, 60% of the LFG facilities that do not have collections systems in place, and at 80% of the candidate landfills.
- In the Aggressive High scenario, ICF assumed that RNG could be produced at 95% of the LFG facilities that have collection systems in place, 85% of the LFG facilities that do not have collections systems in place, and at 90% of the candidate landfills.

To estimate the amount of RNG that could be injected from LFG projects, ICF used outputs from the LandGEM model—which is an automated tool with a Microsoft Excel interface developed by the EPA to estimate the emissions rates for landfill gas and methane based on user inputs including WIP, facility location and climate conditions, and waste received per year. The estimated LFG output was estimated on a facility-by-facility basis. About 1,150 facilities reported methane content; for the facilities for which no data were reported, ICF assumed the median methane content of 49.6%.

[22] Based on data from the Landfill Methane Outreach Program at the EPA (updated February 2019).

Figures 12–14 show the Conservative Low, Achievable, and Aggressive High RNG resource potential from LFG between 2025 and 2040. Table 11 includes the total annual RNG production potential (in units of tBtu/y) for 2040 in the scenarios.

Figure 12. RNG Production Potential from Landfill Gas, Conservative Low Scenario, tBtu/y

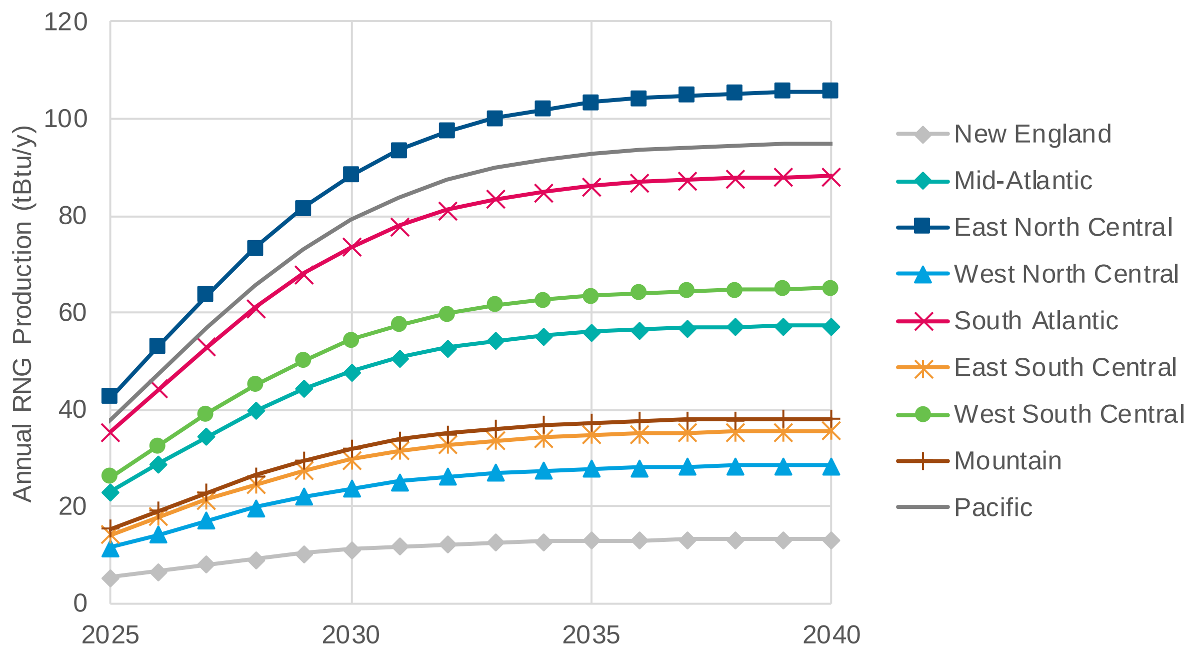


Figure 13. RNG Production Potential from Landfill Gas, Achievable Scenario, tBtu/y

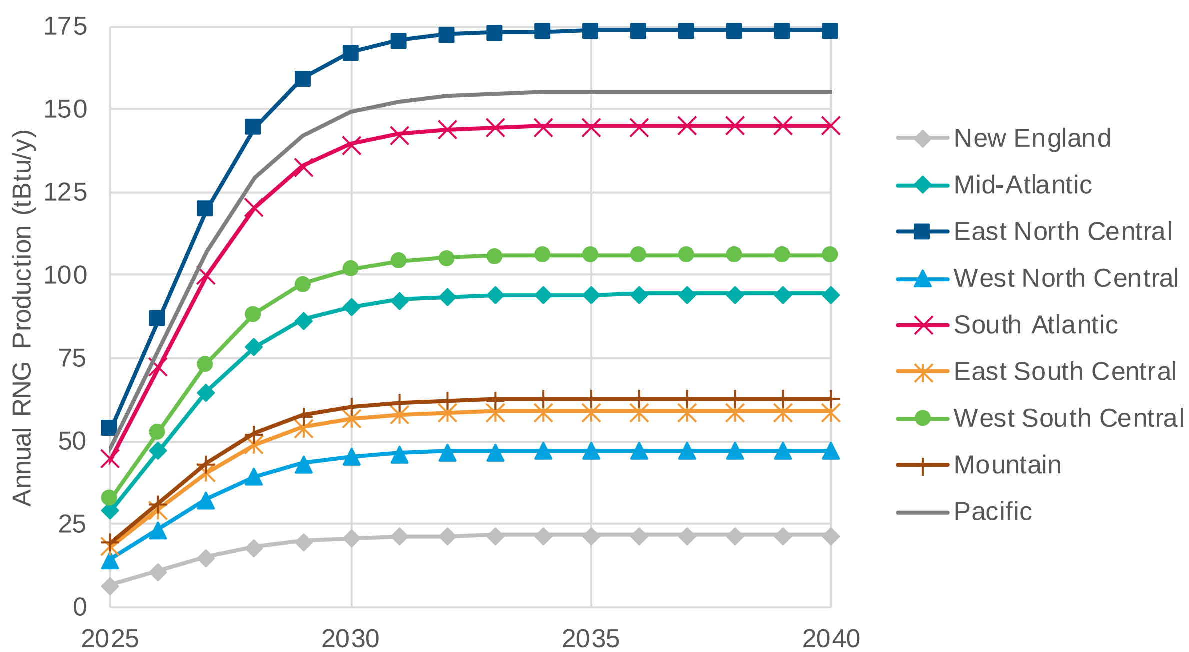
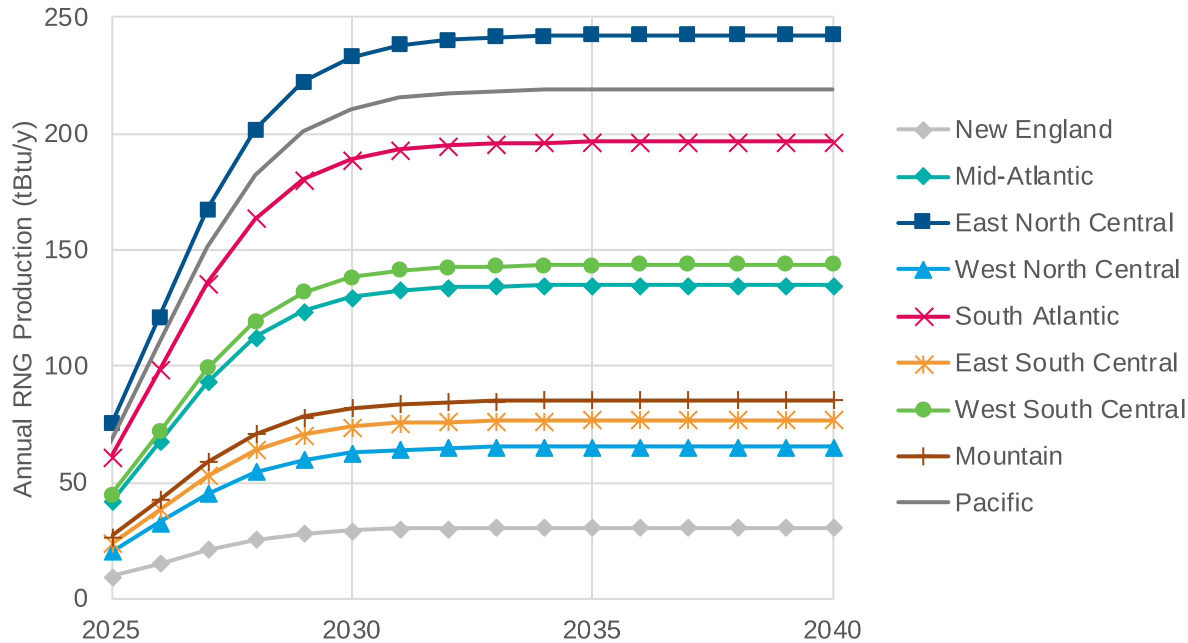


Figure 14. RNG Production Potential from Landfill Gas, Aggressive High Scenario, tBtu/y



As shown in Table 11, ICF estimates that 145 tBtu/y of RNG could be produced from LFG facilities in the South Atlantic Census region by 2040 in the Achievable scenario. At a national level, this increases to 866 tBtu/y of RNG by 2040 in the Achievable scenario, rising to 1,195 tBtu/y in the Aggressive High scenario.

Table 11. Annual RNG Potential from Landfills in 2040, tBtu/y

RNG Potential Scenario	RNG Potential from Landfills, tBtu/y									
	South Atlantic	New England	Mid-Atlantic	East North Central	West North Central	East South Central	West South Central	Mountain	Pacific	National
Conservative	**88.4**	13.3	57.5	106.2	28.6	35.7	65.3	36.2	95.2	**528.4**
Achievable	**145.0**	21.7	94.3	173.8	47.3	59.1	106.2	62.9	155.2	**865.6**
Aggressive	**196.5**	30.4	134.9	242.5	65.3	76.7	143.6	85.3	219.4	**1,194.6**

Animal Manure

Animal manure as an RNG feedstock is produced from the manure generated by livestock, including dairy cows, beef cattle, swine, sheep, goats, poultry, and horses. The EPA lists a variety of benefits associated with the anaerobic digestion of animal manure at farms as an alternative to traditional manure management systems, including but not limited to:[23]

- Diversifying farm revenue: the biogas produced from the digesters has the highest potential value. But digesters can also provide revenue streams via “tipping fees” from non-farm organic waste streams that are diverted to the digesters, organic nutrients from the digestion

[23] More information available online at https://www.epa.gov/agstar/benefits-anaerobic-digestion.

of animal manure, and displacement of animal bedding or peat moss by using digested solids.

- Conservation of agricultural land: digesters can help to improve soil health by converting the nutrients in manure to a more accessible form for plants to use and help protect the local water resources by reducing nutrient run-off and destroying pathogens.
- Promoting energy independence: the RNG produced can reduce on-farm energy needs or provide energy via pipeline injection for use in other applications, thereby displacing fossil or geological natural gas.
- Bolstering farm-community relationships: digesters help to reduce odors from livestock manure, improve growth prospects by minimizing potential negative impacts of farm operations on local communities, and help forge connections between farmers and the local community through environmental and energy stewardship.

The main components of anaerobic digestion of manure include manure collection, the digester, effluent storage (e.g., a tank or lagoon), and gas handling equipment. A variety of livestock manure processing systems are employed at farms today, including plug-flow or mixed plug-flow digesters, complete-mixed digesters, covered lagoons, fixed-film digesters, sequencing-batch reactors, and induced-blanked digesters. Most dairy manure projects today use the plug-flow or mixed plug-flow digesters.

ICF considered animal manure from a variety of animal populations, including beef and dairy cows, broiler chickens, layer chickens, turkeys, and swine. Animal populations were derived from the United States Department of Agriculture's (USDA) National Agricultural Statistics Service. ICF used information provided from the most recent census year (2017) and extracted total animal populations on a state-by-state basis.

ICF estimated the total amount of animal manure produced based on the animal population, the total wet manure produced per animal, an assumed moisture content, and the energy content of the dried manure. The values in Table 12 are taken from a California Energy Commission report prepared by the California Biomass Collaborative.[24]

Table 12. Key Parameters for Animal Manure Resource RNG Potential

Animal Type	Total Wet Manure (lb/animal/day)	Moisture Content (% wet basis)	Higher Heating Value (HHV) (Btu/lb, dry basis)	Technical Availability Factors
Dairy Cow	140	87	7,308	0.50
Beef Cow	125	88	7,414	0.20
Swine	10	91	6,839	0.20
Poultry, Layer Chickens	0.20	75	6,663	0.50
Poultry, Broiler Chickens	0.22	75	6,839	0.50
Poultry, Turkeys	0.58	74	6,727	0.50

[24] Williams, R. B., B. M. Jenkins and S. Kaffka (California Biomass Collaborative). 2015. An Assessment of Biomass Resources in California, 2013 – DRAFT. Contractor Report to the California Energy Commission. PIER Contract 500-11-020. Available online here.

The EPA AgStar database indicates that there are nearly 250 operational digesters at farms—more than 90% of which produce electricity or use the biogas for cogeneration. Only five of the projects (2%) currently inject gas into the pipeline.

Local, Regional, and National Sources of Animal Manure as an RNG Resource
Although there is only one small-scale animal manure digester operational in the Greater Washington, D.C. metropolitan area, with the resultant biogas consumed on site, there are other animal manure feedstock sources in the regions in proximity of the Greater Washington, D.C. metropolitan area. For example, there are currently more than 30 digesters operational or under construction in Pennsylvania, and another 11 in North Carolina as of late 2019. Also relevant to the development of animal manure RNG in the region is the joint venture between Dominion Energy and Smithfield Foods, which is set to become the largest RNG producer in the United States, with animal manure-based RNG projects in development or proposed in North Carolina, Virginia, and Utah, with plans to expand to California and Arizona.

Figures 15 and 16 show the operational digesters in the region, while

Table 13 provides a summary of the types of projects by Census Region.

Figure 15. AgStar Projects in Surrounding Greater Washington, D.C. Metropolitan Area (North)

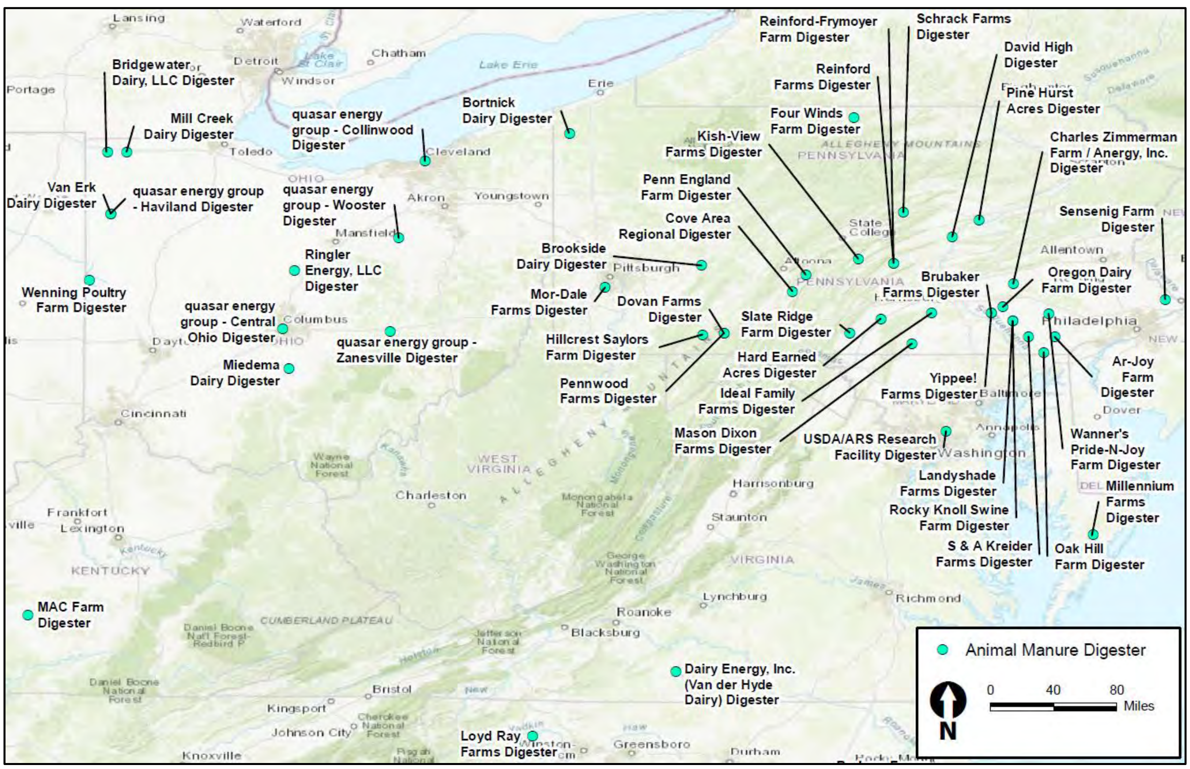


Figure 16. AgStar Project in Surrounding Greater Washington, D.C. Metropolitan Area (South)

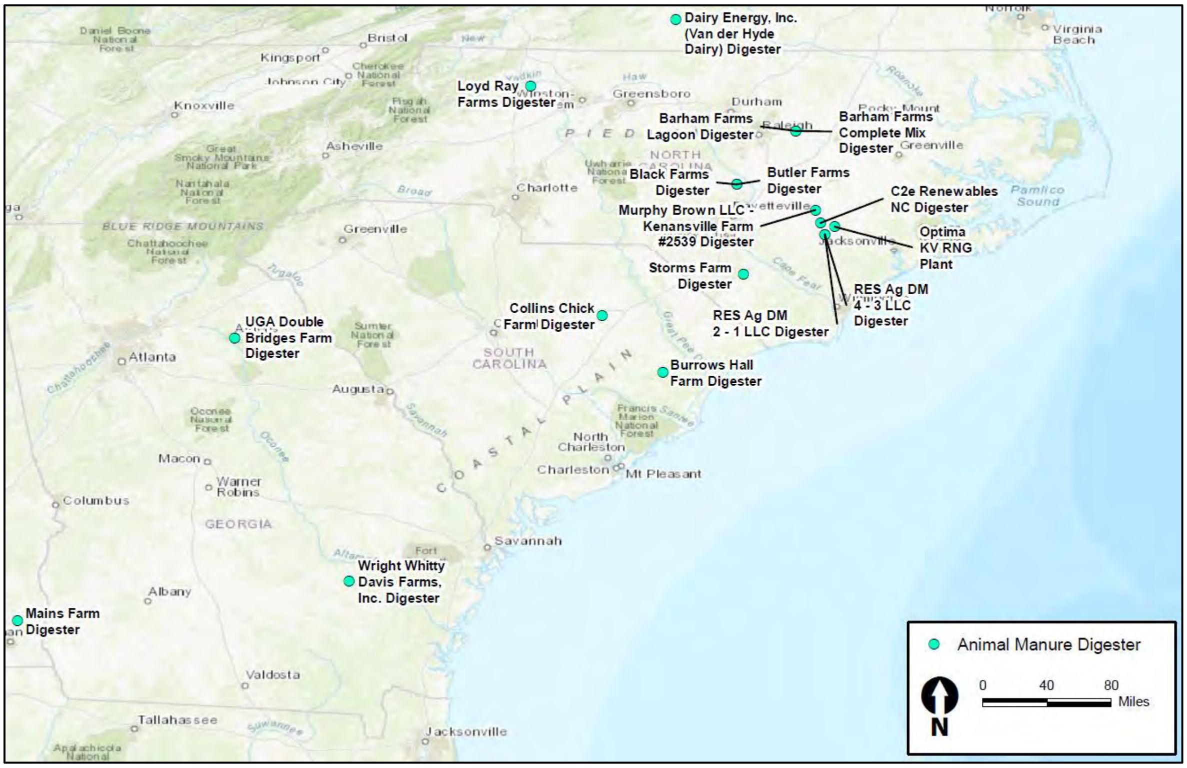


Table 13. Summary of AgStar Projects Using Anaerobic Digestion Systems, by Census Region

AgStar Projects	South Atlantic	New England	Mid-Atlantic	East North Central	West North Central	East South Central	West South Central	Mountain	Pacific	National
Project Status										
Operational	**20**	22	62	69	16	5	4	16	34	**238**
Construction	**2**	2	3	3	7	--	--	3	14	**34**
Project Type										
Electricity/Cogen	**19**	22	57	64	10	5	3	15	34	**229**
Flared	**--**	--	8	10	6	--	2	2		**28**
Pipeline	**1**	--	--	--	3	--	--	--	1	**5**
Animal Type										
Dairy	**6**	22	55	61	8	1	--	11	34	**198**
Swine	**12**	--	4	2	7	1	4	5	--	**35**
Poultry	**2**	--	1	1	--	3	--	--	--	**7**
Multiple	**--**	--	2	5	1	--	--	--	--	**8**

ICF developed the following assumptions for resource potentials for RNG production from the anaerobic digestion of animal manure in the three scenarios.

- In the Conservative Low scenario, ICF assumed that RNG could be produced from 30% of the animal manure, after accounting for the technical availability factor.
- In the Achievable scenario, ICF assumed that RNG could be produced from 60% of the animal manure, after accounting for the technical availability factor.
- In the Aggressive High scenario, ICF assumed that RNG could be produced from 90% of the animal manure, after accounting for the technical availability factor.

Figures 17–19 below show the Conservative Low, Achievable and Aggressive High resource potential from animal manure between 2025 and 2040. The table that follows includes the total annual RNG production potential (in units of tBtu/y) for 2040 in the scenarios.

Figure 17. RNG Production Potential from Animal Manure, Conservative Low Scenario, tBtu/y

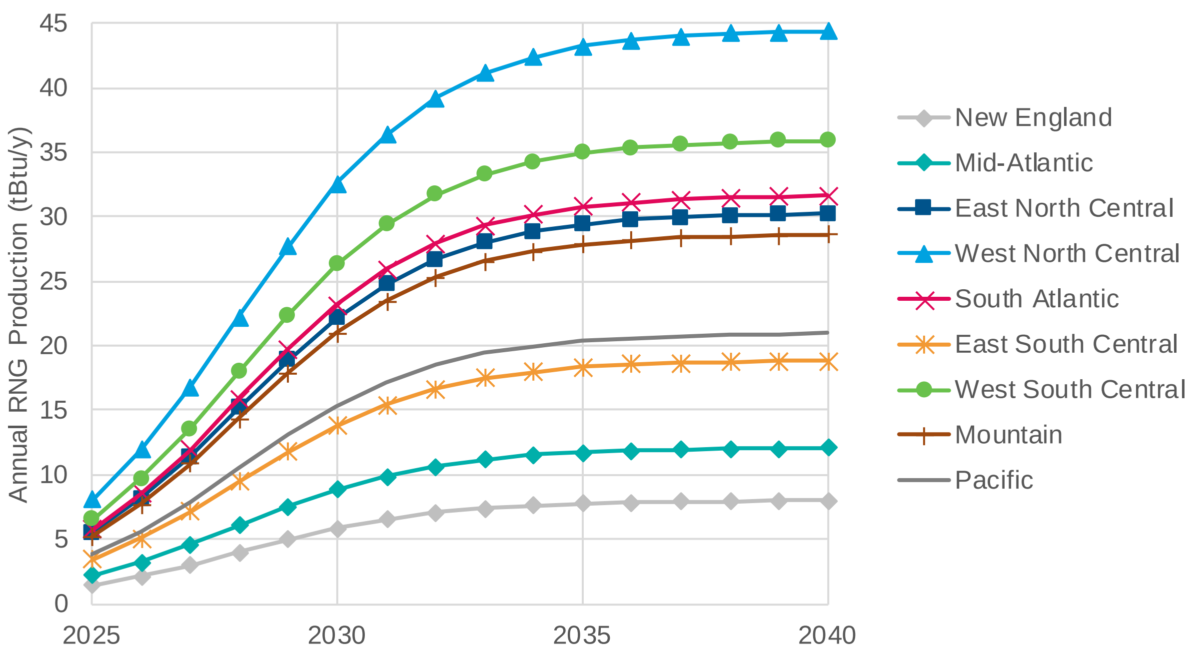


Figure 18. RNG Production Potential from Animal Manure, Achievable Scenario, tBtu/y

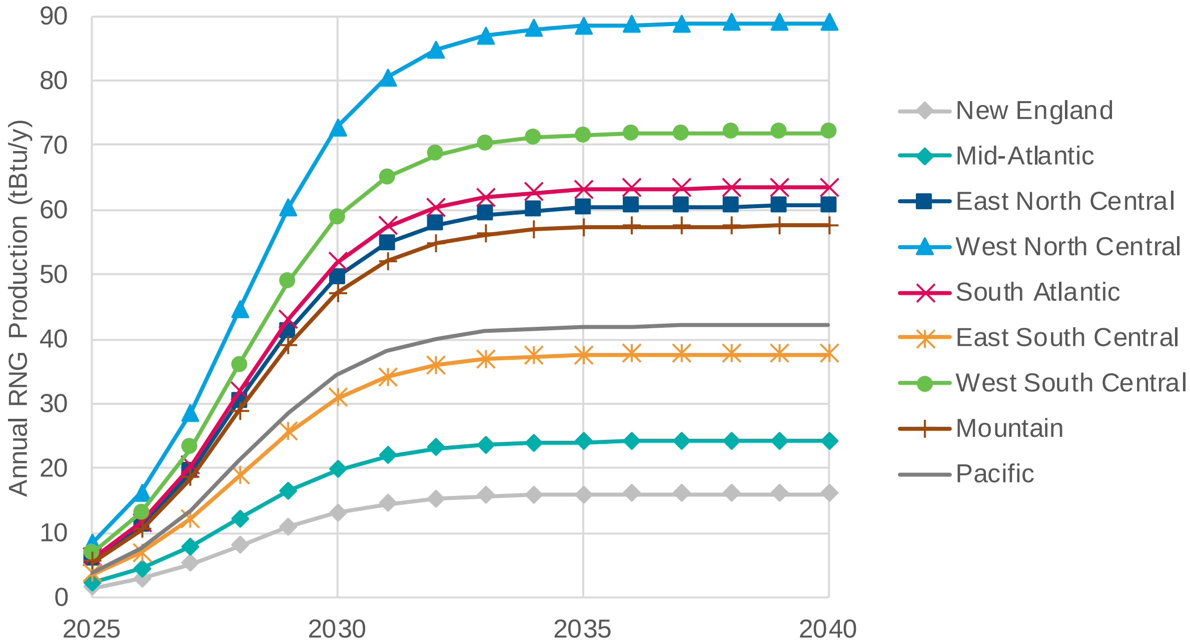


Figure 19. RNG Production Potential from Animal Manure, Aggressive High Scenario, tBtu/y

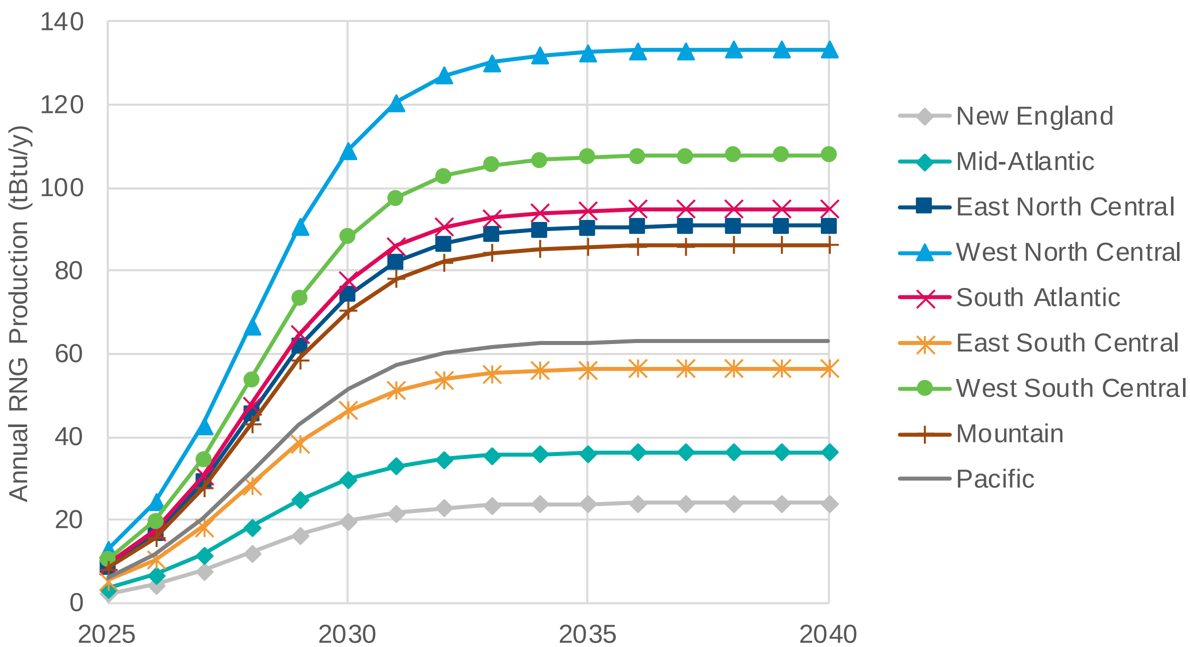


Table 14 shows that in the Achievable scenario, ICF estimates that up to 63 tBtu/y of RNG from animal manure could be produced in the South Atlantic Census region by 2040. This increases to 462 tBtu/y of RNG nationally, rising to 694 tBtu/y in the Aggressive High scenario.

Table 14. Annual RNG Production Potential from Animal Manure in 2040, tBtu/y

RNG Potential Scenario	RNG Potential from Animal Manure, tBtu/y									
	South Atlantic	New England	Mid-Atlantic	East North Central	West North Central	East South Central	West South Central	Mountain	Pacific	National
Conservative	**31.7**	8.0	12.1	30.3	44.5	18.9	36.0	28.7	21.0	**231.2**
Achievable	**63.4**	16.0	24.2	60.6	88.9	37.7	71.9	57.5	42.1	**462.3**
Aggressive	**95.0**	24.0	36.3	90.9	133.4	56.6	107.9	86.2	63.1	**693.5**

Water Resource Recovery Facilities

Wastewater is created from residences and commercial or industrial facilities, and it consists primarily of waste liquids and solids from household water usage, commercial water usage, or industrial processes. Depending on the architecture of the sewer system and local regulation, it may also contain storm water from roofs, streets, or other runoff areas. The contents of the wastewater may include anything that is expelled (legally or not) from a household and enters the drains. If storm water is included in the wastewater sewer flow, it may also contain components collected during runoff: soil, metals, organic compounds, animal waste, oils, and solid debris such as leaves and branches.

Processing of the influent to a large water resource recovery facility (WRRF) is composed typically of four stages: pre-treatment, primary, secondary, and tertiary treatments. These stages consist of mechanical, biological, and sometimes chemical processing.

- Pretreatment removes all the materials that can be easily collected from the raw wastewater that may otherwise damage or clog pumps or piping used in treatment processes.
- In the primary treatment stage, the wastewater flows into large tanks or settling bins, thereby allowing sludge to settle while fats, oils, or greases rise to the surface.
- The secondary treatment stage is designed to degrade the biological content of the wastewater and sludge, and is typically done using water-borne micro-organisms in a managed system.
- The tertiary treatment stage prepares the treated effluent for discharge into another ecosystem, and often uses chemical or physical processes to disinfect the water.

The treated sludge from the WRRF can be landfilled, and during processing it can be treated via anaerobic digestion, thereby producing methane that can be used for beneficial use with the appropriate capture and conditioning systems put in place.

ICF reviewed more than 14,500 wastewater treatment facilities surveyed as part of the Clean Watersheds Needs Survey (CWNS) conducted in 2012 by the EPA, an assessment of capital investment needed for wastewater collection and treatment facilities to meet the water quality goals of the Clean Water Act. ICF further distinguished between facilities based on location and facility size as a measure of average flow (in units of million gallons per day, MGD). ICF also reviewed more than 1,200 facilities that are reported to have anaerobic digesters in place, as reported by the Water Environment Federation.

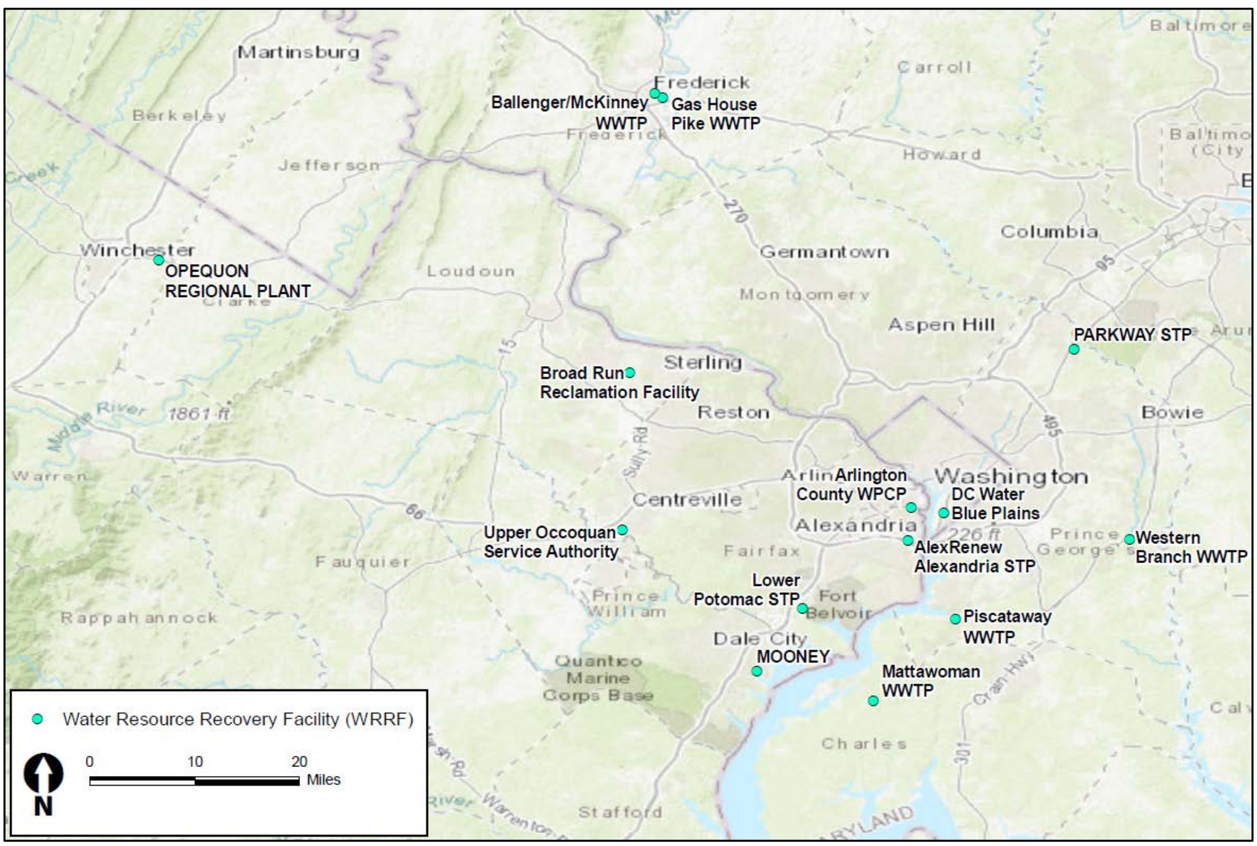
Local WRRFs as an RNG Resource

There are four WRRF facilities in the Greater Washington, D.C. metropolitan area that have anaerobic digestion (AD) systems, with a total flow of 460 MGD. DC Water's Blue Plains Advanced Wastewater Treatment Plant makes up 80% of this flow, with Alexandria City's AlexRenew WRRF and the Upper Occoquan Service Authority's WRRF making up another 18% of this flow (see "Spotlight" box for more detail on the Blue Plains facility).

There are 10 other WRRFs in the Greater Washington, D.C. metropolitan area that have high flow but do not yet have an AD system. These include WSSC's Piscataway WRRF, Arlington's Water Pollution Control Plant, and Fairfax County's Lorton WRRF, which have a combined flow of over 120 MGD.

Figure 20 shows the large WRRFs in the Greater Washington, D.C. metropolitan area, while Table 15 provides more detail on existing flows and RNG potential based on facility capacity.

Figure 20. Significant WRRFs in Greater Washington, D.C. Metropolitan Area



SPOTLIGHT: DC Water Blue Plains

DC Water's Blue Plains Advanced Wastewater Treatment Plant in Washington, D.C. is the largest WRRF of its type in the world. The facility treats close to 300 million gallons of wastewater per day and has the potential capacity for significantly higher peak flows, at over 1 billion gallons per day. Wastewater flows are from D.C., Maryland, and Virginia, including Montgomery and Prince George's Counties in Maryland, and Fairfax and Loudoun Counties in Virginia.

Figure 21. DC Water Blue Plains Service Area[25]

In 2015, an AD system was installed at the facility, converting more than half the organic matter to methane for onsite electricity generation and consumption. DC Water is currently assessing opportunities to expand methane production at the facility, and potentially produce pipeline-quality RNG and interconnect with the natural gas system. With successful injection into the gas system, this RNG would displace more carbon-intensive fossil natural gas, delivering GHG emission reduction benefits for the region. The RNG would also potentially generate valuable environmental commodities if used in the transportation sector.

WG is working with DC Water on engineering configurations at the interconnection and gas quality requirements.

[25] DC Water, 2019. https://www.dcwater.com/sites/default/files/Blue_Plains_Plant_brochure.pdf

Table 15. WRRFs in WG Service Territory with Flow Greater Than 3.3 MGD

Name	County	Existing Flow (MGD)	Max. RNG Potential (tBtu/y)	AD System
DC Water Blue Plains	D.C.	370	0.95	Yes
Upper Occoquan WRRF	Prince William	45	0.14	Yes
AlexRenew STP	Alexandria	37	0.15	Yes
Lower Potomac STP	Fairfax	28	0.17	No
Arlington WPCP	Arlington	22	0.10	No
WSSC Piscataway WRRF	Prince George's	19	0.08	No
Western Branch WWTP	Prince George's	18	0.08	No
Broad Run Reclamation Facility	Loudoun	11	0.06	No
Mattawoman WWTP	Charles	8	0.06	No
Gas House Pike WWTP	Frederick (MD)	7	0.02	Yes
H.L. Mooney Advanced Water Reclamation Facility	Prince William	6	0.06	No
Parkway Wastewater TP	Prince George's	6	0.02	No
Opequon Regional Plant	Frederick (VA)	5	0.02	No
Ballenger/McKinney WWTP	Frederick (MD)	4	0.02	No
Total		**585**	**1.9**	

Regional and National WRRFs as an RNG Resource

Tables 16 and 17 summarize the key data points from the survey of WRRFs in the United States, broken down by Census Region.

Table 16. Number of WRRFs by Census Region[26]

Facility Size (MGD)	South Atlantic	New England	Mid-Atlantic	East North Central	West North Central	East South Central	West South Central	Mountain	Pacific	National
<0.02	**94**	33	70	169	581	46	127	107	32	**1,259**
0.02-0.07	**222**	58	255	495	1,125	191	362	263	137	**3,108**
0.07-0.18	**291**	83	289	607	602	224	380	217	145	**2,838**
0.18-1.00	**569**	176	555	838	552	391	459	308	293	**4,141**
1.01-3.30	**267**	109	234	324	160	177	178	126	162	**1,737**
3.31-7.25	**137**	46	91	122	53	68	88	39	78	**722**
7.26-34.05	**112**	35	67	116	36	30	58	36	88	**578**
34.05+	**21**	5	30	23	9	8	15	7	24	**142**

[26] Based on data from CNWS 2015.

Table 17. Total Flow of WRRFs by Census Region, MGD[27]

Facility Size (MGD)	South Atlantic	New England	Mid-Atlantic	East North Central	West North Central	East South Central	West South Central	Mountain	Pacific	National
<0.02	**1**	0	1	2	6	0	1	1	0	**13**
0.02-0.07	**9**	2	10	20	40	8	14	10	5	**118**
0.07-0.18	**33**	9	33	68	66	26	42	24	16	**316**
0.18-1.00	**261**	84	255	380	228	170	201	139	135	**1,854**
1.01-3.30	**511**	201	440	632	292	338	323	238	304	**3,279**
3.31-7.25	**678**	231	461	576	259	323	439	198	394	**3,560**
7.26-34.05	**1,645**	535	1,009	1,734	569	424	863	552	1,320	**8,652**
34.05+	**1,686**	494	3,438	2,839	717	536	1,086	586	2,580	**13,961**
Total	**4,824**	1,556	5,647	6,251	2,177	1,825	2,969	1,748	4,754	**31,753**

Table 16 shows that about 90% of the facilities in the database used by ICF have a flow rate of less than 3.30 MGD, representing just under 20% of the total flow of wastewater into WRRFs. The 142 facilities with a flow greater than 34 MGD represent nearly 45% of the entire flow into WRRFs. Table 18 shows the distribution of the more than 1,250 WRRFs with installed AD systems.

Table 18. WRRFs with Anaerobic Digesters, by Census Region[28]

	South Atlantic	New England	Mid-Atlantic	East North Central	West North Central	East South Central	West South Central	Mountain	Pacific	National
AD Facilities	**133**	34	231	309	125	47	74	82	233	**1,268**

The three tables above illustrate the opportunities and challenges associated with deploying AD systems at WRRFs: while fewer than 10% of WRRFs have an AD system, they tend to be the larger systems, representing the bulk of wastewater treated at facilities. Most of these facilities have AD systems in place and are capturing biogas for on-site electricity production rather than for pipeline injection. With an effective policy and regulatory framework, these facilities present a near-term opportunity for RNG to be directed into the pipeline, rather than for on-site electricity production, as shown by DC Water's Blue Plains facility. The database of RNG-producing facilities maintained by the Coalition for Renewable Natural Gas indicates that there are only 12 operational WRRFs using AD systems to capture and subsequently inject RNG into the pipeline, five WRRFs with AD systems under substantial development, and another five WRRFs with AD systems under construction.

[27] Based on data from CNWS 2015.
[28] Based on data from the Water Environment Federation.

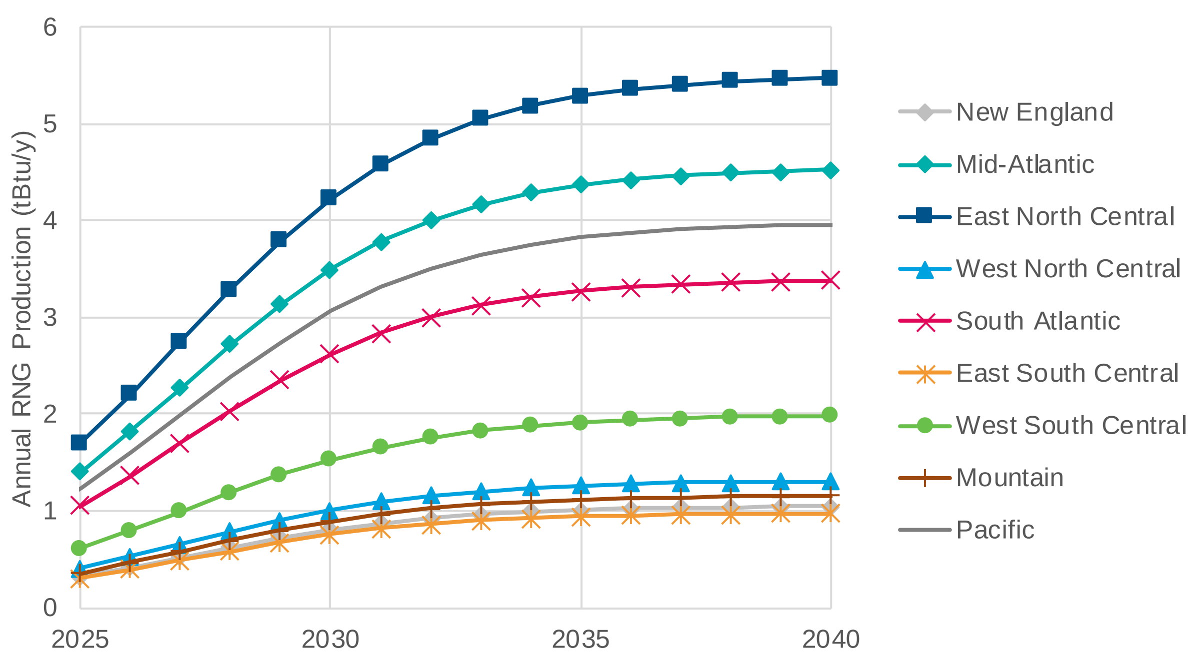
ICF developed the following assumptions for the resource potentials for RNG production at WRRFs in the three scenarios:

- In the Conservative Low scenario, ICF assumed that RNG could be produced at 30% of the facilities with a capacity greater than 7.25 MGD.
- In the Achievable scenario, ICF assumed that RNG could be produced at 50% of the facilities with a capacity greater than 3.3 MGD.
- In the Aggressive High scenario, ICF assumed that RNG could be produced at 90% of the facilities with a capacity greater than 3.3 MGD.

To estimate the amount of RNG produced from wastewater at WRRFs, ICF used data reported by the EPA,[29] a study of WRRFs in New York State,[30] and previous work published by AGF.[31] ICF used an average energy yield of 7.0 MMBtu/MG of wastewater. For the maximum achievable resource, ICF used all of the wastewater flow reported at the more than 14,500 facilities in the database.

Figures 22–24 show the Conservative Low, Achievable, and Aggressive High RNG resource potential from WRRFs between 2025 and 2040. Table 19 includes the total annual RNG production potential (in units of tBtu/y) for 2040 in the three scenarios.

Figure 22. RNG Production Potential from WRRFs, Conservative Low Scenario, tBtu/y



[29] EPA, Opportunities for Combined Heat and Power at Wastewater Treatment Facilities, October 2011. Available online here.

[30] Wightman, J. and Woodbury, P., Current and Potential Methane Production for Electricity and Heat from New York State Wastewater Treatment Plants, New York State Water Resources Institute at Cornell University. Available online here.

[31] AGF, The Potential for Renewable Gas: Biogas Derived from Biomass Feedstocks and Upgraded to Pipeline Quality, September 2011.

Figure 23. RNG Production Potential from WRRFs, Achievable Resource Scenario, in tBtu/y

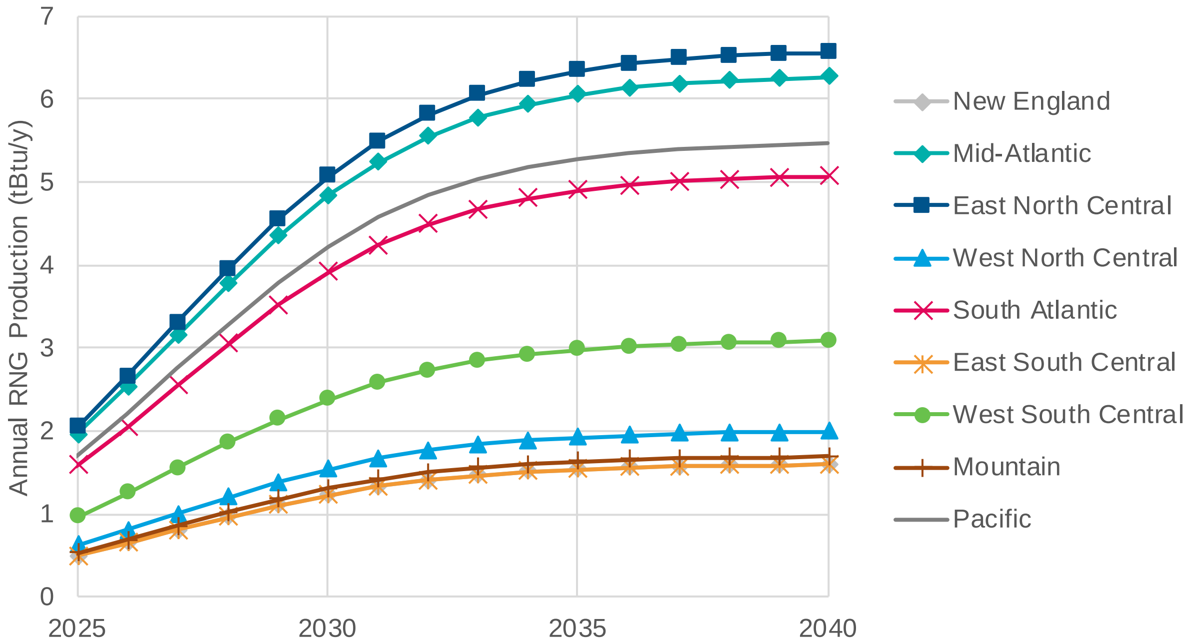


Figure 24. RNG Production Potential from WRRFs, Aggressive High Resource Scenario, in tBtu/y

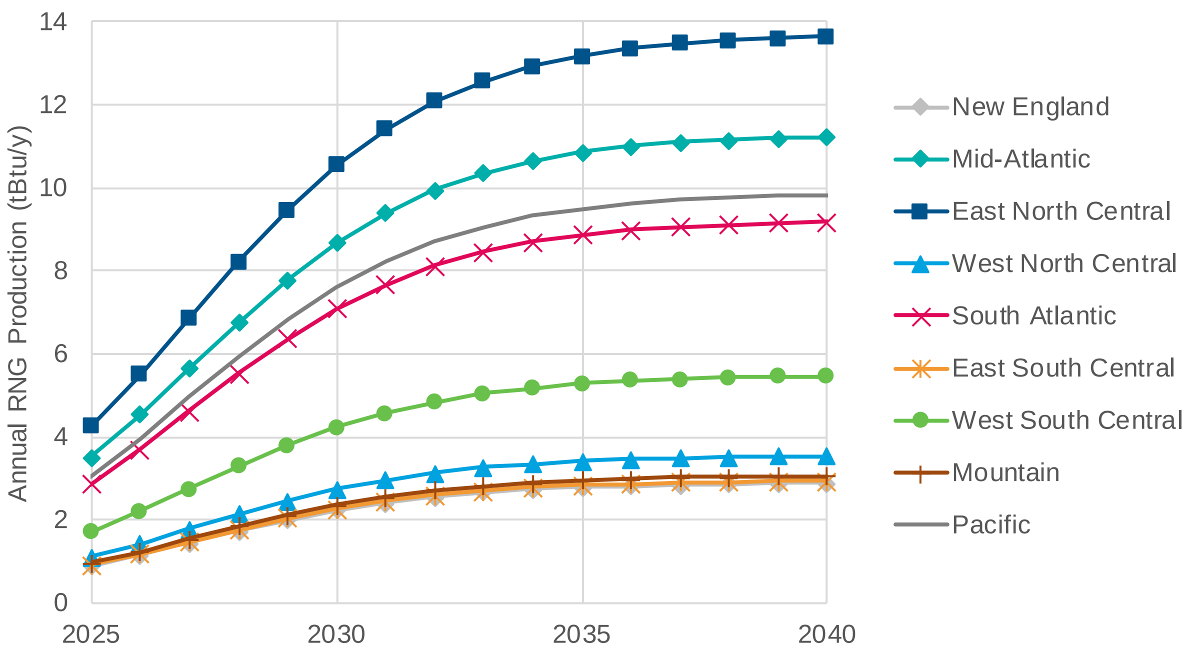


Table 19. Annual RNG Production Potential from WRRFs in 2040, tBtu/y

RNG Potential Scenario	RNG Potential from WRRFs, tBtu/y									
	South Atlantic	New England	Mid-Atlantic	East North Central	West North Central	East South Central	West South Central	Mountain	Pacific	National
Conservative	**3.4**	1.1	4.5	5.5	1.3	1.0	2.0	1.2	4.0	**24.0**
Achievable	**5.1**	1.6	6.3	7.6	2.0	1.6	3.1	1.7	5.5	**34.5**
Aggressive	**9.2**	2.9	11.3	13.7	3.6	2.9	5.5	3.1	9.9	**62.1**

For the South Atlantic Census region, ICF estimates that 5 tBtu/y of RNG could be produced from WRRFs in the Achievable scenario, which would require the installation of AD systems at approximately 180 facilities. On a national scale, this estimate increases to 34 tBtu/y of RNG that could be produced from WRRFs in the Achievable scenario, rising to 62 tBtu/y in the Aggressive High scenario. To achieve this level of RNG production from WRRFs, ICF estimates that 1,450 facilities would need to install AD systems in the Achievable scenario.

Food Waste

Food waste is a major component of MSW—accounting for about 15% of MSW streams. More than 75% of food waste is landfilled. Food waste can be diverted from landfills to a composting or processing facility where it can be treated in an anaerobic digester. ICF limited our consideration to the potential for utilizing the food waste that is currently landfilled as a feedstock for RNG production via AD, thereby excluding the 25% of food waste that is recycled or directed to waste-to-energy facilities.

ICF extracted information from the U.S. Department of Energy's (DOE) Bioenergy Knowledge Discovery Framework (KDF), which includes information collected as part of DOE's Billion Ton Report (updated in 2016). The Bioenergy KDF includes food waste at tipping fee price points ranging from $70/ton to $100/ton, with higher tipping fees leading to increased feedstock availability. ICF assumed a high heating value of 12.04 MMBtu/ton (dry). Note that the values from the Bioenergy KDF are reported in dry tons, so the moisture content of the food waste has already been accounted for in DOE's resource assessment.

ICF developed the following assumptions for the RNG production potential from food waste in the three scenarios:

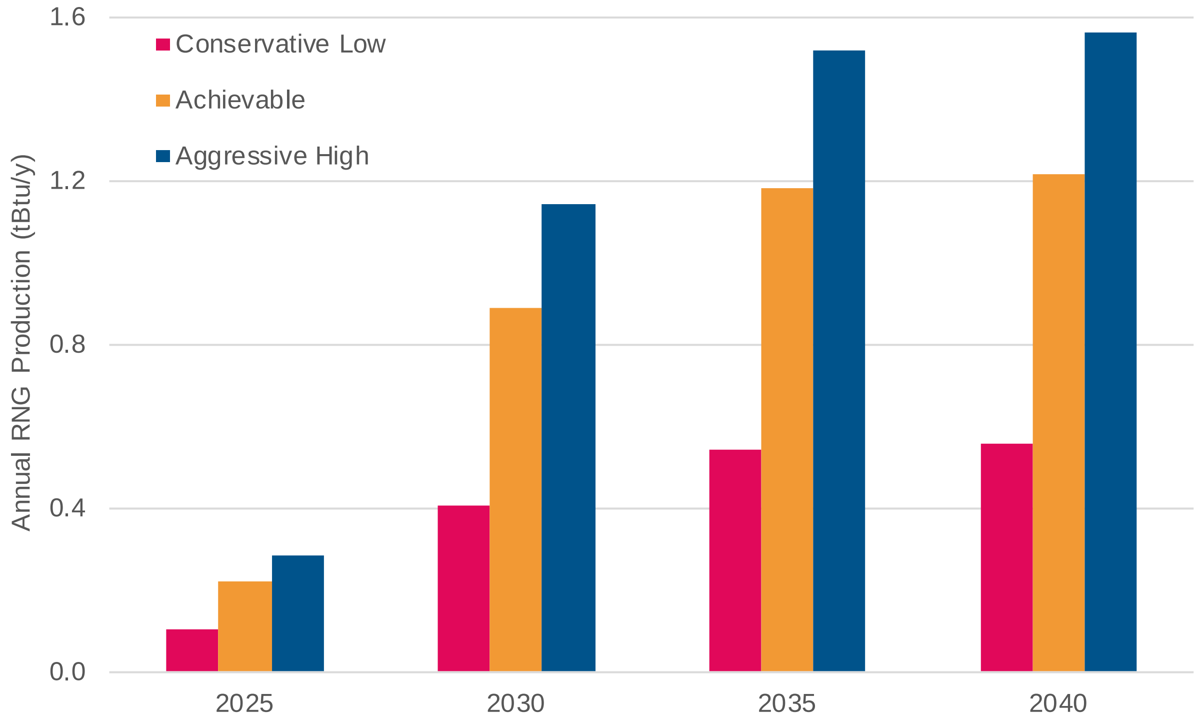
- In the Conservative Low scenario, ICF assumed that 40% of the food waste available at $70/dry ton would be diverted to AD systems.
- In the Achievable scenario, ICF assumed that 70% of the food waste available at $100/dry ton would be diverted to AD systems.
- In the Aggressive High scenario, ICF assumed that 90% of the food waste available at $100/dry ton would be diverted to AD systems.

As food waste is generated from population centers and typically diverted at waste transfer stations rather than delivered to landfills, it is challenging to identify specific facilities or projects in the region that will generate RNG from food waste. However, food waste can potentially utilize existing or future AD systems at LFG and WRRF facilities, as outlined in the previous sections. Adoption of new and expanded waste diversion mandates by municipalities in the Greater Washington, D.C. metropolitan area could spur the development of RNG production from food waste. For example, Sustainable DC's 2.0 Plan identified the need for a new organic waste processing facility to capture diverted food and other waste streams in the region.[32]

Local Sources of Food Waste as an RNG Resource

Figure 25 shows the RNG production potential from food waste in the Greater Washington, D.C. metropolitan area, for the three scenarios out to 2040. These estimates are based on a population-weighted proportion of regional food waste figures.

Figure 25. RNG Potential from Food Waste in Greater Washington, D.C. Metropolitan Area, tBtu/y



[32] Sustainable DC, 2019. Sustainable DC 2.0 Plan, http://www.sustainabledc.org/wp-content/uploads/2019/04/sdc-2.0-Edits-V5_web.pdf

Regional and National Source of Food Waste as an RNG Resource

Figures 26–28 show the Conservative Low, Achievable, and Aggressive High RNG resource potential scenarios from the anaerobic digestion of food waste between 2025 and 2040, broken down by Census Region. Table 20 includes the total annual RNG production potential (in units of tBtu/y) for 2040 for the three scenarios.

Figure 26. RNG Production Potential from Food Waste, Conservative Low Resource Scenario, in tBtu/y

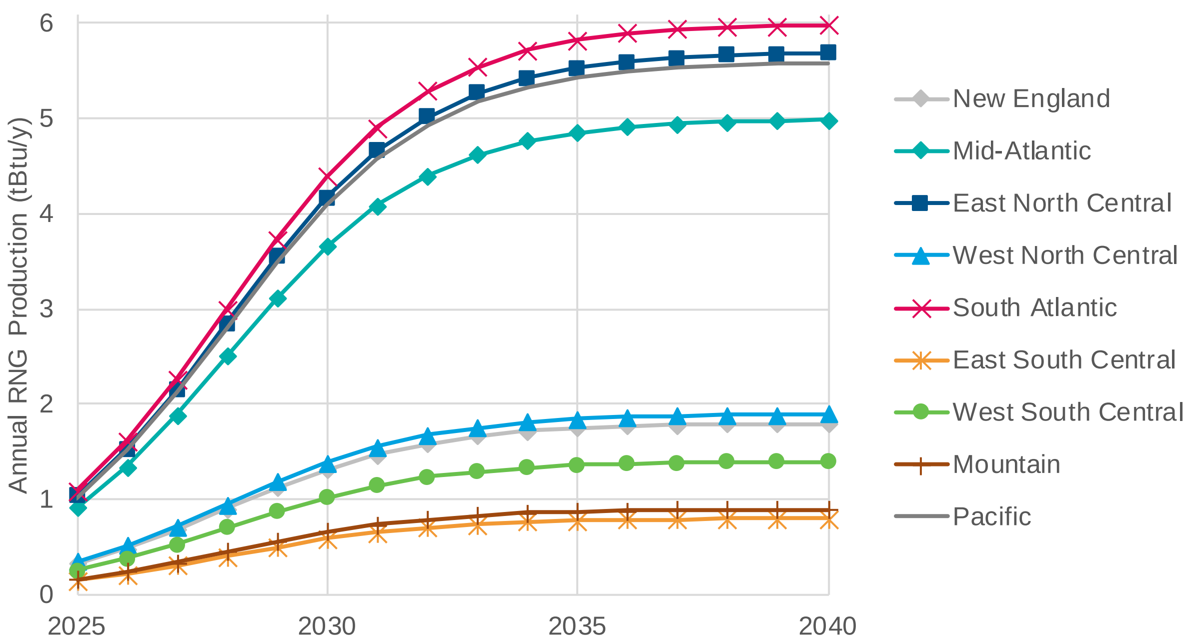


Figure 27. RNG Production Potential from Food Waste, Achievable Resource Scenario, in tBtu/y

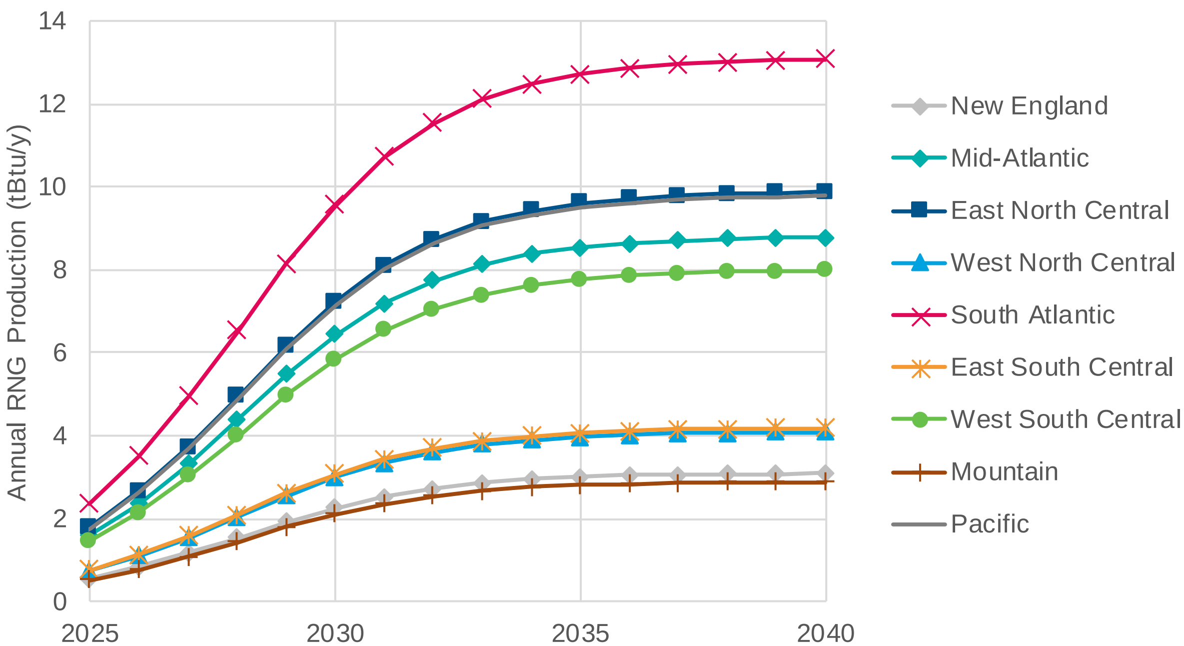


Figure 28. RNG Production Potential from Food Waste, Aggressive High Resource Scenario, in tBtu/y

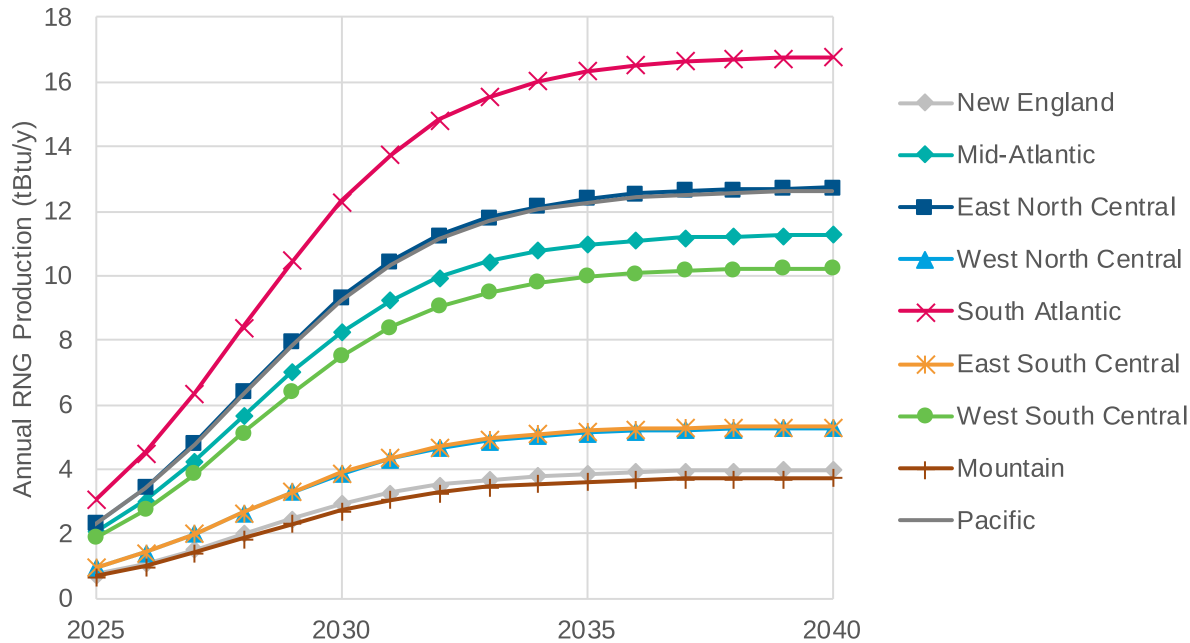


Table 20. Annual RNG Production Potential from Food Waste in 2040, tBtu/y

RNG Potential Scenario	RNG Potential from Food Waste, tBtu/y									
	South Atlantic	New England	Mid-Atlantic	East North Central	West North Central	East South Central	West South Central	Mountain	Pacific	National
Conservative	**6.0**	1.8	5.0	5.7	1.9	0.8	1.4	0.9	5.6	**29.1**
Achievable	**13.1**	3.1	8.8	9.9	4.1	4.2	8.0	2.9	9.8	**63.9**
Aggressive	**16.8**	4.0	11.3	12.8	5.3	5.3	10.3	3.7	12.6	**82.2**

ICF estimates that 13 tBtu/y of RNG could be produced by 2040 in the South Atlantic Census region in the Achievable scenario from food waste diverted to anaerobic digesters. At the national level, this increases to 64 tBtu/y of RNG, rising to 82 tBtu/y in the Aggressive High scenario.

RNG: Thermal Gasification of Biogenic or Renewable Resources

The biomass feedstocks for RNG production potential via thermal gasification include agricultural residues, forestry and forest product residues, energy crops, and the nonbiogenic fraction of MSW. With the exception of MSW, the densely populated Greater Washington, D.C. metropolitan area has limited availability of feedstocks for thermal gasification. However, there is significant potential regionally and nationally—there is nothing inherently limiting about the availability of these feedstocks for RNG production and subsequent delivery to WG's system. There is only limited local production potential from biomass feedstocks given the region's population density. Ultimately, RNG production should be considered no different from conventional natural gas production areas, whereby a robust pipeline infrastructure enables transmission and distribution of natural gas efficiently from various sources.

Agricultural Residues

Agricultural residues include the material left in the field, orchard, vineyard, or other agricultural setting after a crop has been harvested. More specifically, this resource is inclusive of the unusable portion of crop, stalks, stems, leaves, branches, and seed pods. Agricultural residues (and sometimes crops) are often added to anaerobic digesters.

ICF extracted information from the DOE Bioenergy KDF, including the following agricultural residues: wheat straw, corn stover, sorghum stubble, oat straw, barley straw, citrus residues, non-citrus residues, tree nut residues, sugarcane trash, cotton gin trash, cotton residue, rice hulls, sugarcane bagasse, and rice straw. ICF extracted data from the Bioenergy KDF at three price points: \$30/ton, \$50/ton and \$100/ton. Table 21 lists the energy content on a higher heating value (HHV) basis for the various agricultural residues included in the analysis. The energy content is based on values reported by the California Biomass Collaborative. To estimate the RNG production potential, ICF assumed a 65% efficiency for thermal gasification systems.

Table 21. Heating Values for Agricultural Residues

MSW Component	Btu/lb, dry	MMBtu/ton, dry
Wheat straw	7,527	15.054
Corn stover	7,587	15.174
Sorghum stubble	6,620	13.240
Oats straw	7,308	14.616
Barley straw	7,441	14.882
Citrus residues	8,597	17.194
Non-citrus residues	7,738	15.476
Tree nut residues	8,597	17.194
Sugarcane trash	7,738	15.476
Cotton gin trash	7,058	14.116
Cotton residue	7,849	15.698
Rice hulls	6,998	13.996
Sugarcane bagasse	7,738	15.476
Rice straw	6,998	13.996

ICF developed the following assumptions for the RNG production potential from agricultural residues in the three scenarios.

- In the Conservative Low scenario, ICF assumed that 20% of the agricultural residues available at $50/dry ton would be diverted to thermal gasification systems.
- In the Achievable scenario, ICF assumed that 50% of the agricultural residues available at $50/dry ton would be diverted to thermal gasification systems.
- In the Aggressive High scenario, ICF assumed that 80% of the agricultural residues available at $50/dry ton would be diverted to thermal gasification systems.

Figures 29–31 show the Conservative Low, Achievable and Aggressive High RNG resource potential scenarios from the thermal gasification of agricultural residues between 2025 and 2040. Table 22 includes the total annual RNG production potential (in units of tBtu/y) for 2040 for the three scenarios.

Figure 29. RNG Production Potential from Agricultural Residue, Conservative Low Scenario, in tBtu/y

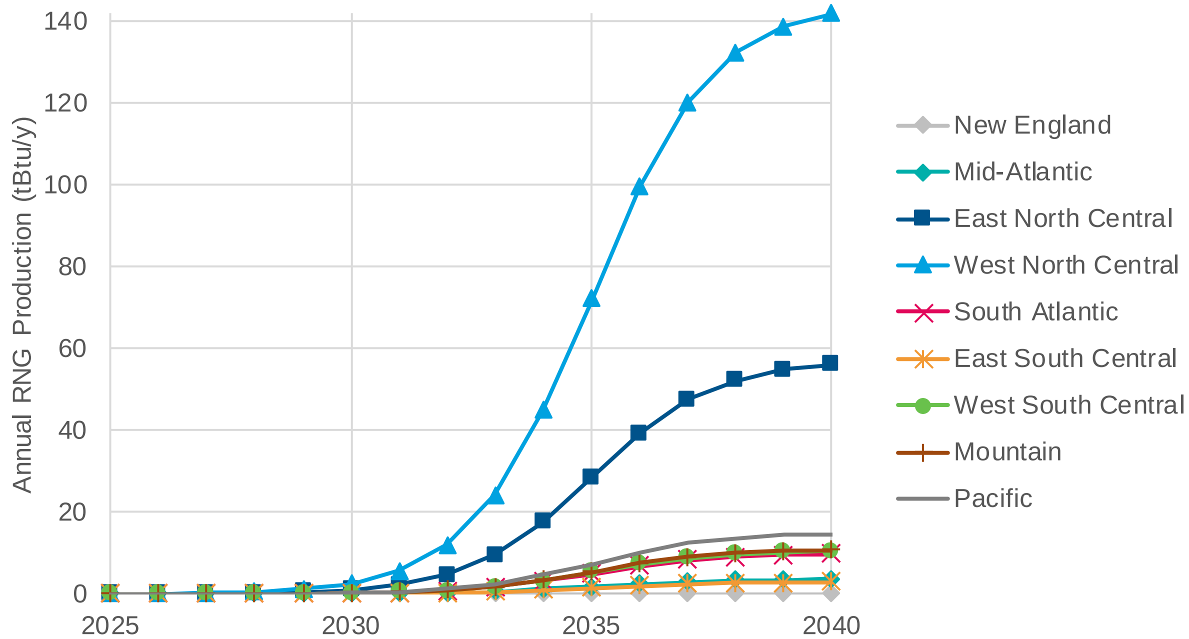


Figure 30. RNG Production Potential from Agricultural Residue, Achievable Scenario, in tBtu/y

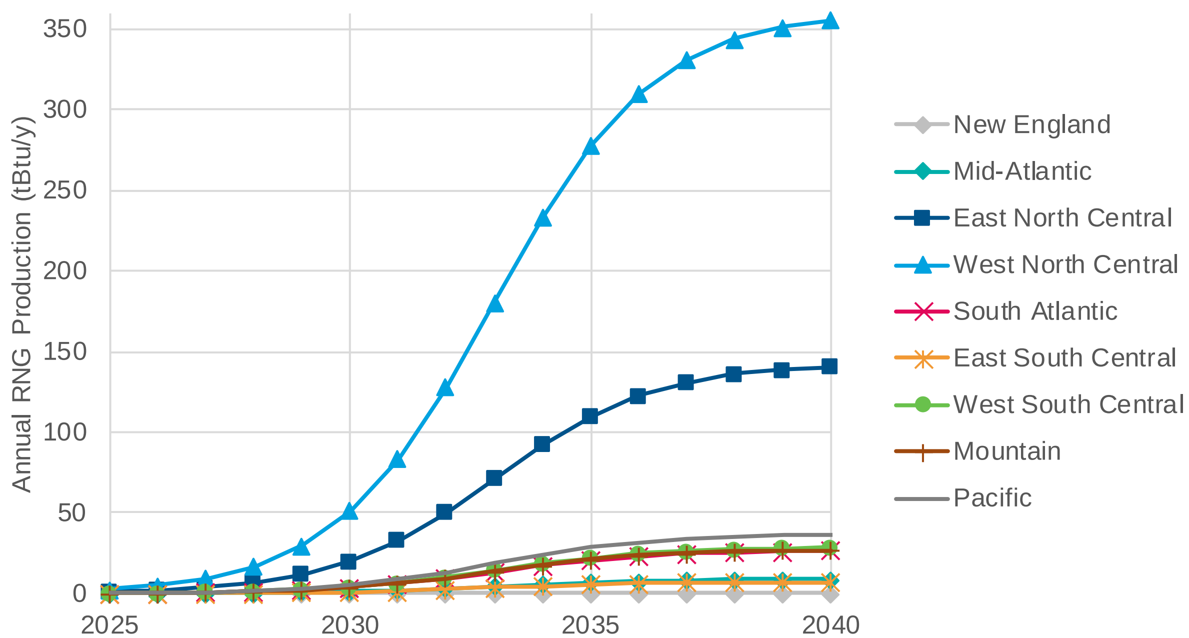


Figure 31. RNG Production Potential from Agricultural Residue, Aggressive High Scenario, in tBtu/y

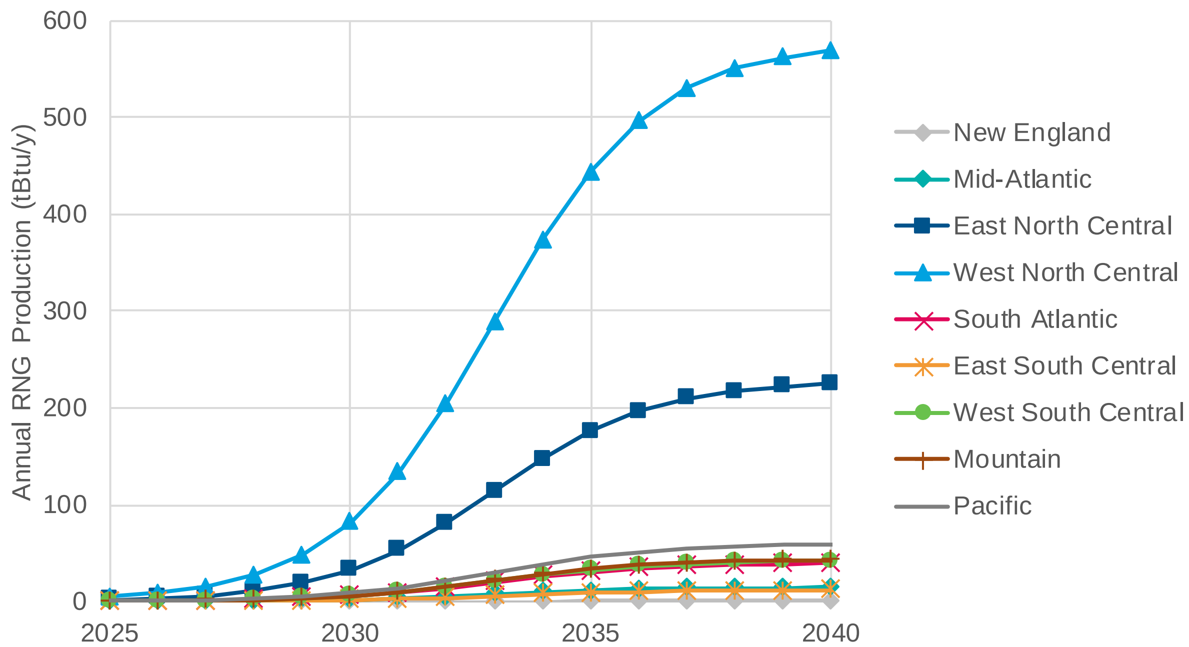


Table 22. Annual RNG Production Potential from Agricultural Residues in 2040, tBtu/y

RNG Potential Scenario	RNG Potential from Agricultural Residue, tBtu/y									
	South Atlantic	New England	Mid-Atlantic	East North Central	West North Central	East South Central	West South Central	Mountain	Pacific	National
Conservative	**10.0**	0.0	3.7	57.0	144.4	2.9	10.7	10.9	14.9	**254.6**
Achievable	**26.9**	0.1	9.2	142.6	361.0	7.3	28.8	27.3	37.3	**640.5**
Aggressive	**40.1**	0.2	14.8	228.2	577.7	11.6	42.7	43.7	59.7	**1,018.5**

ICF estimates that 27 tBtu/y of RNG could be produced by 2040 in the Achievable scenario from the thermal gasification of agricultural residues in the South Atlantic Census region. Nationally, this agricultural residue estimate increases to 641 tBtu/y of RNG by 2040 in the Achievable scenario and rises to 1,019 tBtu/y in the Aggressive High scenario.

Forestry and Forest Product Residues

Forestry and forest product residues include biomass generated from logging, forest and fire management activities, and milling. Logging residues (e.g., bark, stems, leaves, branches), forest thinnings (e.g., removal of small trees to reduce fire danger), and mill residues (e.g., slabs, edgings, trimmings, sawdust) are also considered in the analysis. This includes materials from public forestlands (e.g., state, federal), but not specially designated forests (e.g., roadless areas, national parks, wilderness areas) and includes sustainable harvesting criteria as described in the DOE Billion Ton Update. The updated DOE Billion Ton study was altered to include additional sustainability criteria. Some of the changes included: [33]

- Alterations to the biomass retention levels by slope class (e.g., slopes with between 40% and 80% grade included 40% biomass left on-site, compared to the standard 30%).
- Removal of reserved (e.g., wild and scenic rivers, wilderness areas, U.S. Forest Service special interest areas, national parks) and roadless designated forestlands, forests on steep slopes and in wetland areas (e.g., stream management zones), and sites requiring cable systems.
- Assumptions only reflect thinnings for over-stocked stands and do not include removals greater than the anticipated forest growth in a state.
- No road building greater than 0.5 miles.

These additional sustainability criteria provide a more realistic assessment of available forestland than other studies. ICF extracted information from the DOE Bioenergy KDF, which includes information on forest residues such as thinnings, mill residues, and different residues from woods (e.g., mixedwood, hardwood, and softwood). ICF extracted data from the Bioenergy KDF at three price points: $30/ton, $60/ton, and $100/ton. Table 23 lists the energy content on an HHV basis for the various forest and forest product residue elements considered in the analysis. To estimate the RNG production potential, ICF assumed a 65% efficiency for thermal gasification systems.

Table 23. Heating Values for Forestry and Forest Product Residues

Forestry and Forest Product	Btu/lb, dry	MMBtu/ton, dry
Other forest residue	8,597	17.19
Other forest thinnings	9,027	18.05
Primary mill residue	8,597	17.19
Secondary mill residue	8,597	17.19
Mixedwood, residue	6,500	13.00
Hardwood, lowland, residue		
Hardwood, upland, residue		
Softwood, natural, residue		
Softwood, planted, residue		

ICF developed the following assumptions for the RNG production potential from forest residues in the three scenarios:

- In the Conservative Low scenario, ICF assumed that 30% of the forest and forestry product residues available at $30/dry ton would be diverted to thermal gasification systems.
- In the Achievable scenario, ICF assumed that 60% of the forest and forestry product residues available at $60/dry ton would be diverted to thermal gasification systems.

[33] Bryce Stokes, DOE, "2011 Billion Ton Update – Assumptions and Implications Involving Forest Resources," September 29, 2011, http://web.ornl.gov/sci/ees/cbes/workshops/Stokes_B.pdf.

- In the Aggressive High scenario, ICF assumed that 90% of the forest and forestry product residues available at $100/dry ton would be diverted to thermal gasification systems.

Figures 32–34 show the RNG resource potential from the thermal gasification of forestry and forest product residues between 2025 and 2040 in the Conservative Low, Achievable and Aggressive High scenarios. Table 24 includes the total annual RNG production potential (in units of tBtu/y) for 2040 in the three scenarios.

Figure 32. RNG Potential from Forestry & Forest Products Residue, Conservative Low Scenario, tBtu/y

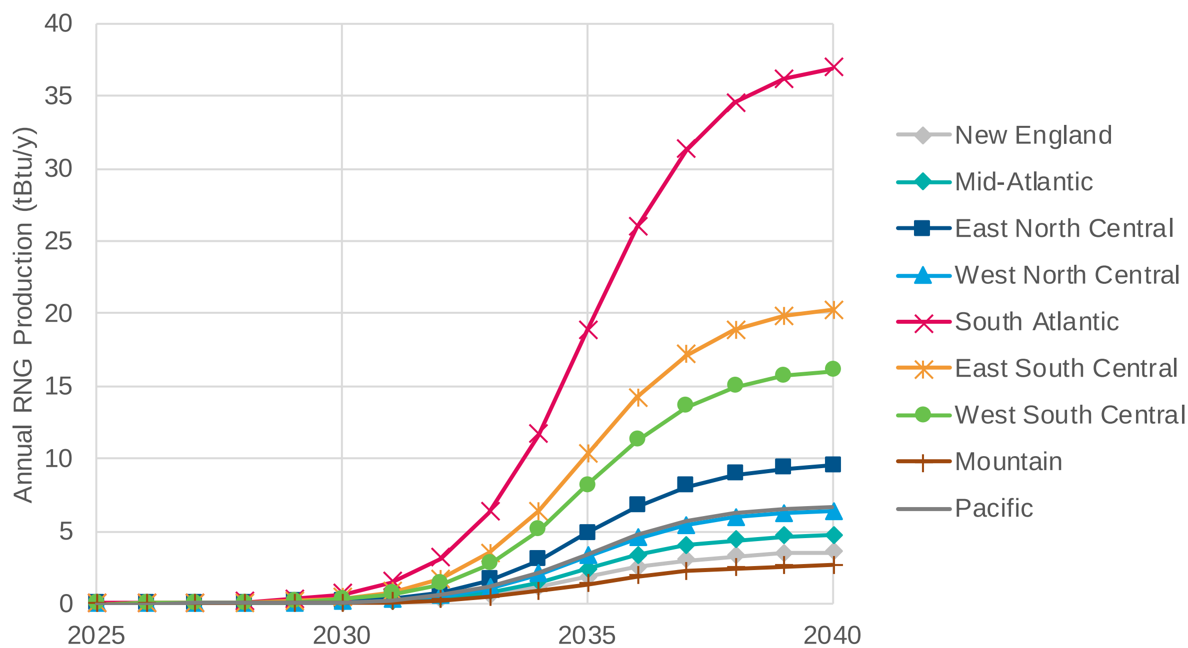


Figure 33. RNG Potential from Forestry & Forest Product Residue, Achievable Scenario, tBtu/y

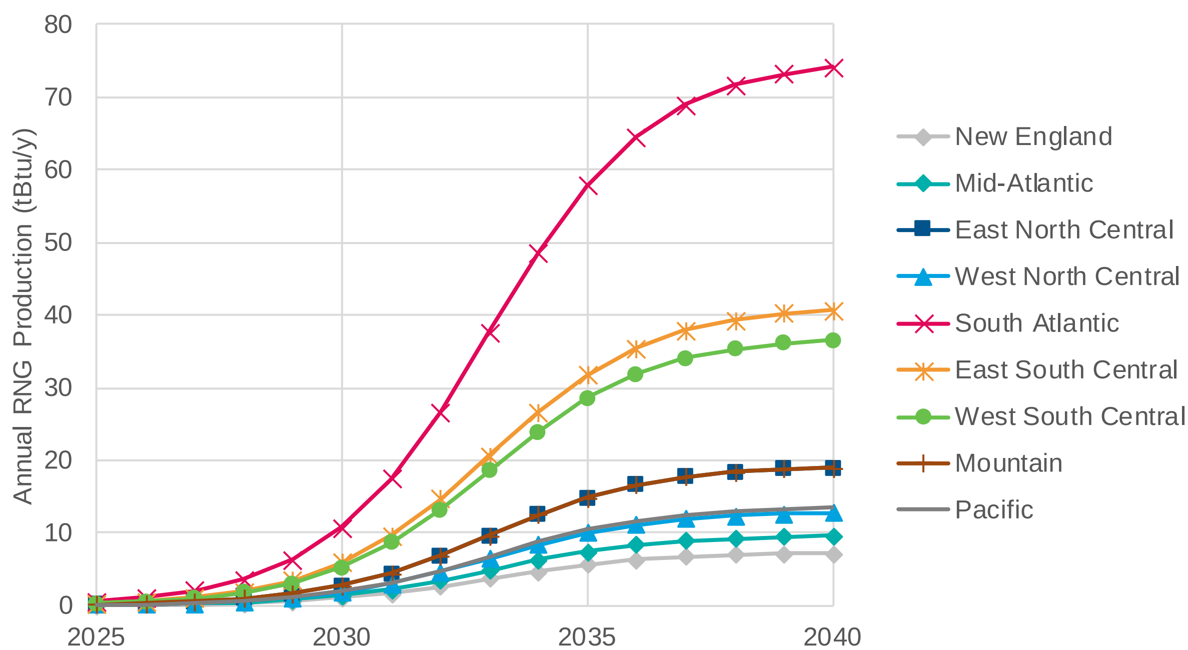


Figure 34. RNG Potential from Forestry & Forest Product Residue, Aggressive High Scenario, tBtu/y

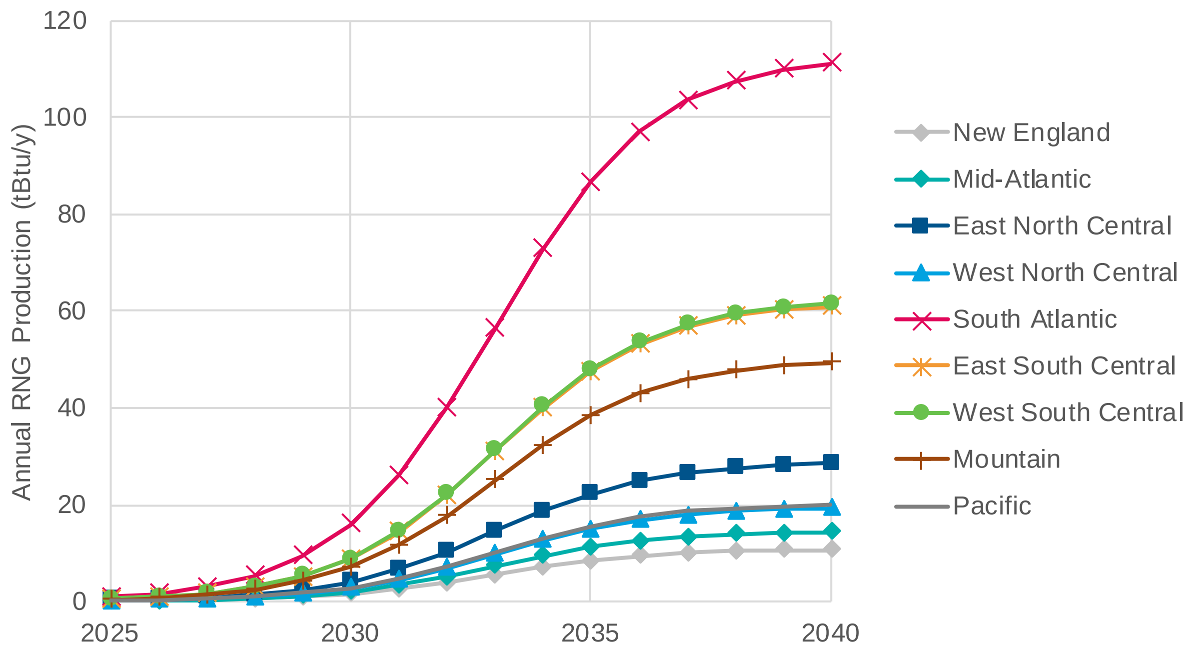


Table 24. Annual RNG Production Potential from Forestry and Forest Product Residues, tBtu/y

RNG Potential Scenario	RNG Potential from Forestry and Forest Product Residues, tBtu/y									
	South Atlantic	New England	Mid-Atlantic	East North Central	West North Central	East South Central	West South Central	Mountain	Pacific	National
Conservative	**37.6**	3.6	4.8	9.7	6.5	20.6	16.3	2.7	6.8	**108.6**
Achievable	**75.2**	7.3	9.7	19.3	13.0	41.3	37.1	19.3	13.6	**235.8**
Aggressive	**112.9**	10.9	14.5	29.0	19.5	61.9	62.4	50.0	20.3	**381.4**

ICF estimates that in the Achievable scenario, 75 tBtu/y of RNG could be produced by 2040 in the South Atlantic Census region from the thermal gasification of forest and forestry product residues. This rises to 236 tBtu/y of RNG at the national level by 2040, increasing to 381 tBtu/y in the Aggressive High scenario.

Energy Crops

Energy crops are inclusive of perennial grasses, trees, and some annual crops that can be grown specifically to supply large volumes of uniform, consistent quality feedstocks for energy production. ICF extracted data from the Bioenergy KDF at three price points: $50/ton, $70/ton, and $100/ton. Table 25 lists the energy content on an HHV basis for the various energy crops included in the analysis. To estimate the RNG production potential, ICF assumed a 65% efficiency for thermal gasification systems. This factor is based in part on the 2011 AGF Report on RNG, indicating a range of thermal gasification efficiencies in the range of 60% to 70%, depending upon the configuration and process conditions. The report authors also used a conversion efficiency of 65% in their assessment. More recently, GTI estimated the potential for

RNG from the thermal gasification of wood waste in California and assumed a conversion efficiency of 60%.[34]

Table 25. Heating Values for Energy Crops

Energy Crop	Btu/lb, dry	MMBtu/ton, dry
Willow	8,550	17.10
Poplar	7,775	15.55
Switchgrass	7,929	15.86
Miscanthus	7,900	15.80
Biomass sorghum	7,240	14.48
Pine	6,210	12.42
Eucalyptus	6,185	12.37
Energy cane	7,900	15.80

ICF developed assumptions for the RNG production potential from energy crops for the three scenarios:

- In the Conservative Low scenario, ICF assumed that 50% of the energy crops available at $50/dry ton would be diverted to thermal gasification systems.
- In the Achievable scenario, ICF assumed that 50% of the energy crops available at $70/dry ton would be diverted to thermal gasification systems.
- In the Aggressive High scenario, ICF assumed that 70% of the energy crops available at $100/dry ton would be diverted to thermal gasification systems.

Figures 35–37 show the RNG resource potential from the thermal gasification of energy crops between 2025 and 2040 in the Conservative Low, Achievable and Aggressive High scenarios. Table 26 includes the total annual RNG production potential (in units of tBtu/y) for 2040 for the three scenarios.

[34] GTI, Low-Carbon Renewable Natural Gas from Wood Wastes, February 2019, available online at https://www.gti.energy/wp-content/uploads/2019/02/Low-Carbon-Renewable-Natural-Gas-RNG-from-Wood-Wastes-Final-Report-Feb2019.pdf

Figure 35. RNG Production Potential from Energy Crops, Conservative Low Scenario, in tBtu/y

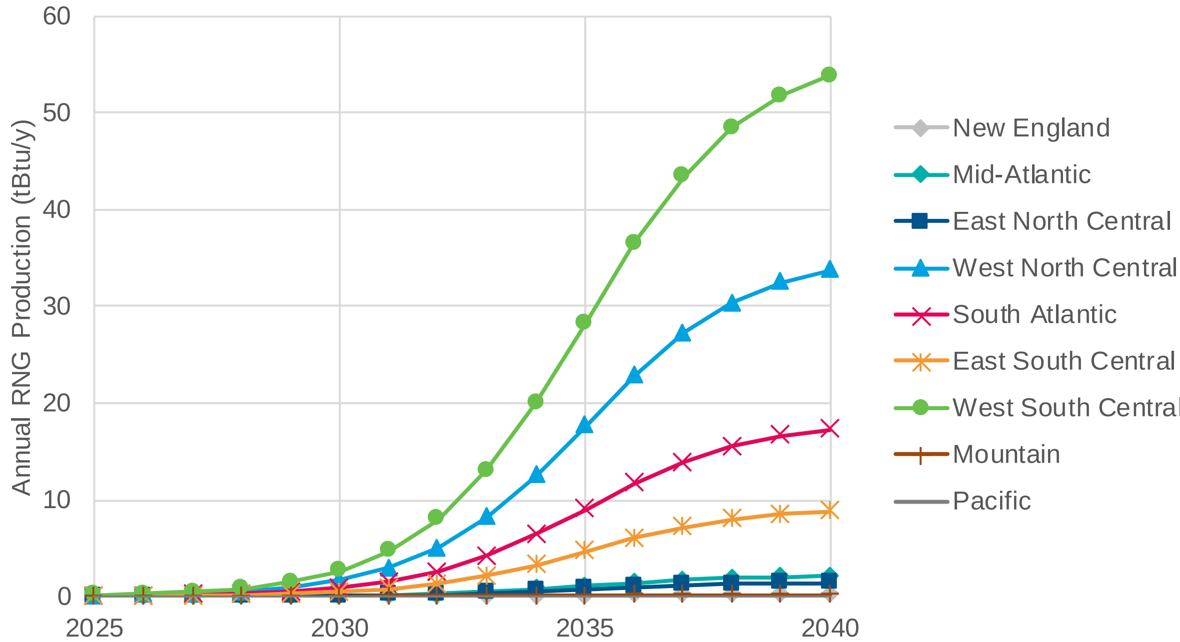


Figure 36. RNG Production Potential from Energy Crops, Achievable Scenario, in tBtu/y

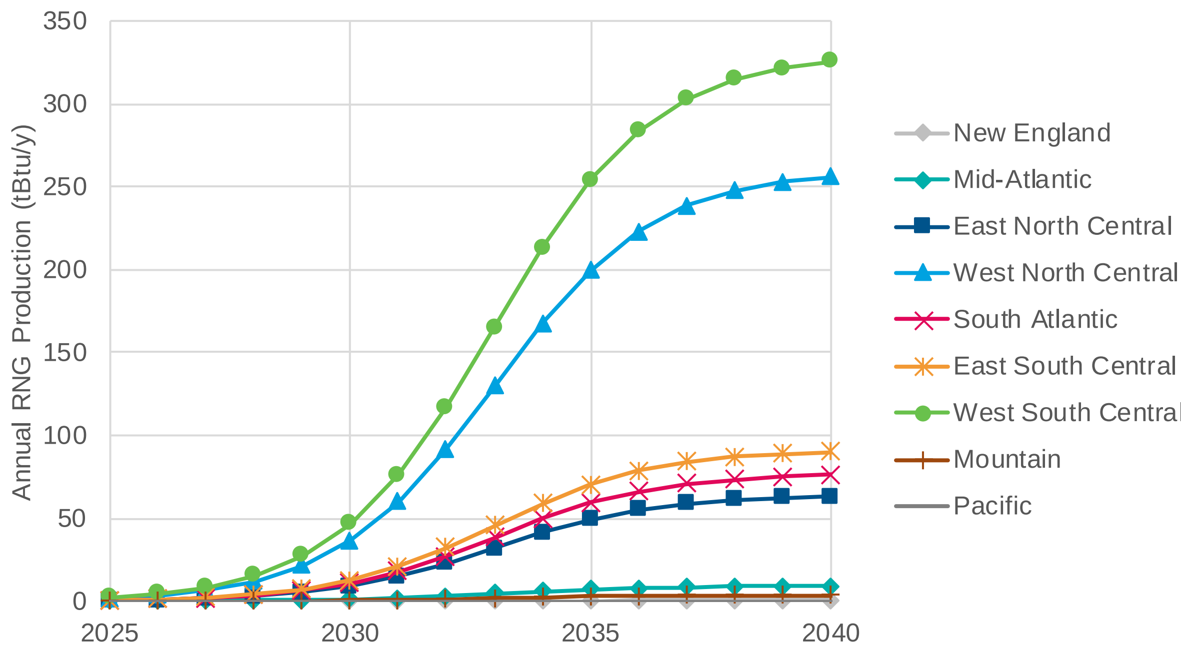


Figure 37. RNG Production Potential from Energy Crops, Aggressive High Scenario, in tBtu/y

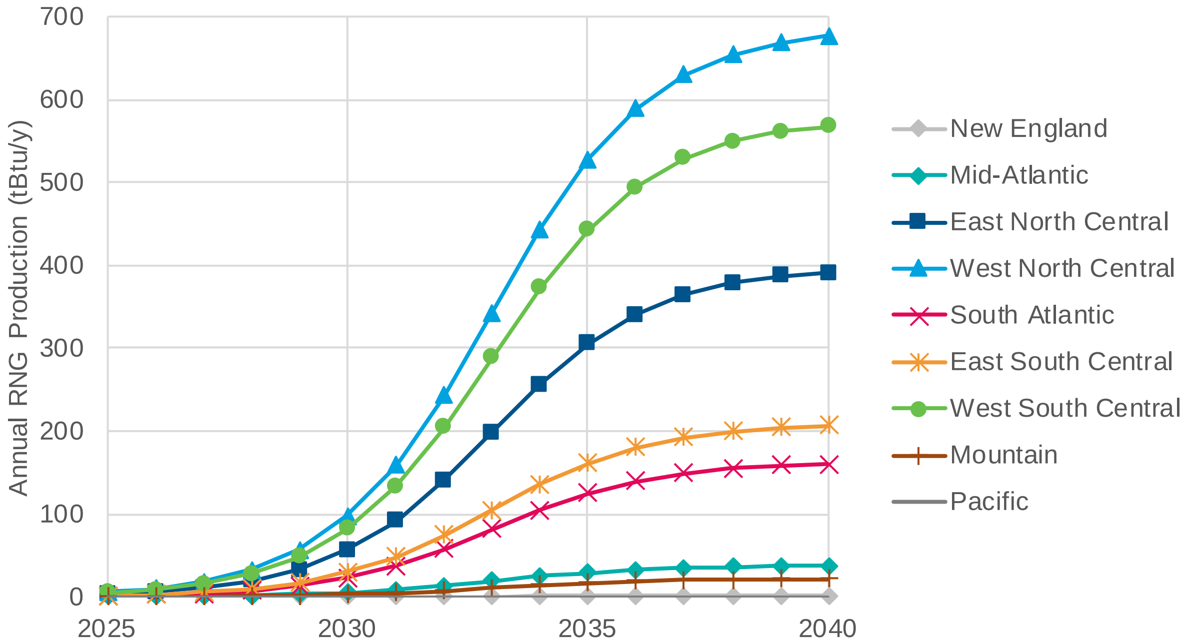


Table 26. Annual RNG Production Potential from Energy Crops, tBtu/y

RNG Potential Scenario	RNG Potential from Energy Crops, tBtu/y									
	South Atlantic	New England	Mid-Atlantic	East North Central	West North Central	East South Central	West South Central	Mountain	Pacific	National
Conservative	**18.1**	0.2	2.2	1.5	35.4	9.3	56.5	0.2	0.0	**123.4**
Achievable	**77.3**	0.5	9.4	64.4	260.0	91.6	330.5	3.9	0.0	**837.6**
Aggressive	**162.5**	1.4	38.4	397.0	686.2	209.6	576.2	22.2	0.0	**2,093.4**

ICF estimates in the Achievable scenario that 77 tBtu/y of RNG could be produced by 2040 in the South Atlantic Census region from the thermal gasification of energy crops. At the national level, this estimate increases to 838 tBtu/y of RNG that could be produced from energy crops, rising to 2,093 tBtu/y in the Aggressive High scenario.

Municipal Solid Waste

MSW represents the trash and various items that household, commercial, and industrial consumers throw away—including materials such as glass, construction and demolition (C&D) debris, food waste, paper and paperboard, plastics, rubber and leather, textiles, wood, and yard trimmings. About 25% of MSW is currently recycled, 9% is composted, and 13% is combusted for energy recovery, with the roughly 50% balance landfilled.

ICF limited our consideration to the potential for utilizing MSW that is currently landfilled as a feedstock for thermal gasification; this excludes MSW that is recycled or directed to waste-to-energy facilities. With a more supportive policy and regulatory framework, MSW waste-to-energy facilities in the region could present a near-term opportunity for RNG to be processed and directed into the pipeline, such as at Covanta's Alexandria/Arlington, Fairfax, and Dickerson waste-to-energy facilities. ICF also excluded food waste from consideration in this sub-section, and opted to consider feedstock as a separate resource for AD systems.

ICF extracted information from the DOE's Bioenergy KDF, which includes information collected as part of DOE's Billion Ton Report (updated in 2016). The Bioenergy KDF includes the following waste residues: C&D debris, paper and paperboard, plastics, rubber and leather, textiles, wood, yard trimmings, and other. ICF extracted data from the Bioenergy KDF at two price points: $30/ton and $100/ton. Table 27 lists the energy content on an HHV basis for the various components of MSW. To estimate the RNG production potential, ICF assumed a 65% efficiency for thermal gasification systems.

Table 27. Heating Values for MSW Components

MSW Component	Btu/lb, dry	MMBtu/ton, dry
CD waste	6,788	13.58
Other	5,600	11.20
Paper and paperboard	7,642	15.28
Plastics	19,200	38.40
Rubber and leather	11,300	22.60
Textiles	8,000	16.00
MSW wood	8,304	16.61
Yard trimmings	6,448	12.90

ICF developed assumptions for the RNG production potential from MSW for the three scenarios:

- In the Conservative Low scenario, ICF assumed that 30% of the nonbiogenic fraction of MSW available at $30/dry ton from the Bioenergy KDF for relevant waste residues in MSW could be gasified. ICF notes that at the price of $30/ton, DOE reports no MSW wood or yard trimmings.
- In the Achievable scenario, ICF assumed that 60% of the nonbiogenic fraction of MSW available at $100/dry ton from the Bioenergy KDF for the CD waste, other, paper and paperboard, plastics, rubber and lather, and textiles waste could be gasified, and that 75% of the MSW wood and yard trimmings could be gasified.
- In the Aggressive High scenario, ICF assumed that 90% of the nonbiogenic fraction of MSW available at $100/dry ton from the Bioenergy KDF for the CD waste, other, paper and paperboard, plastics, rubber and lather, and textiles waste could be gasified, and that 90% of the MSW wood and yard trimmings could be gasified.

Figures 38–40 show the RNG resource potential from the thermal gasification of MSW between 2025 and 2040 in the Conservative Low, Achievable and Aggressive High scenarios. Table 28 includes the total annual RNG production potential (in units of tBtu/y) for 2040 for the three scenarios.

Figure 38. RNG Production Potential from MSW, Conservative Low Scenario, in tBtu/y

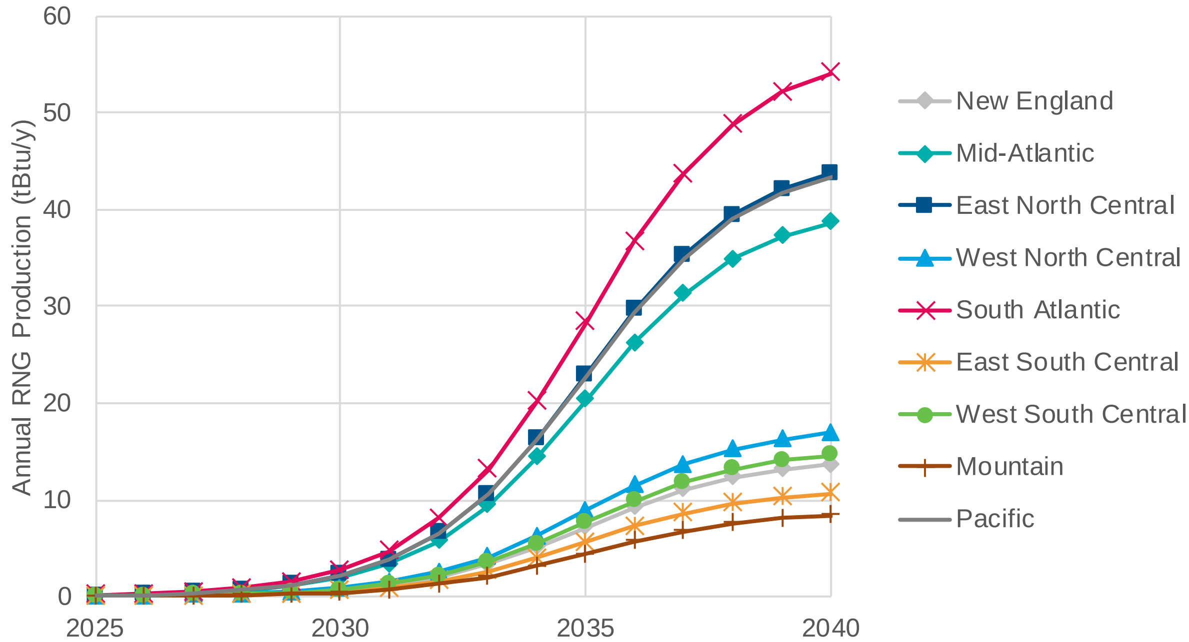


Figure 39. RNG Production Potential from MSW, Achievable Scenario, in tBtu/y

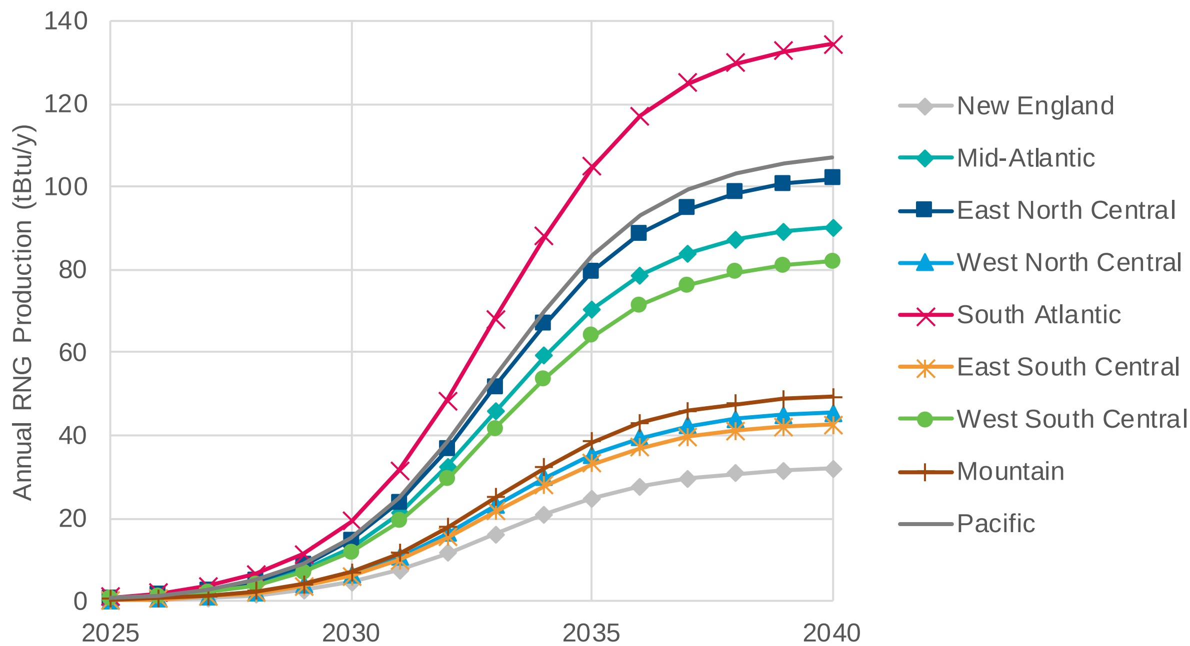


Figure 40. RNG Production Potential from MSW, Aggressive High Scenario, in tBtu/y

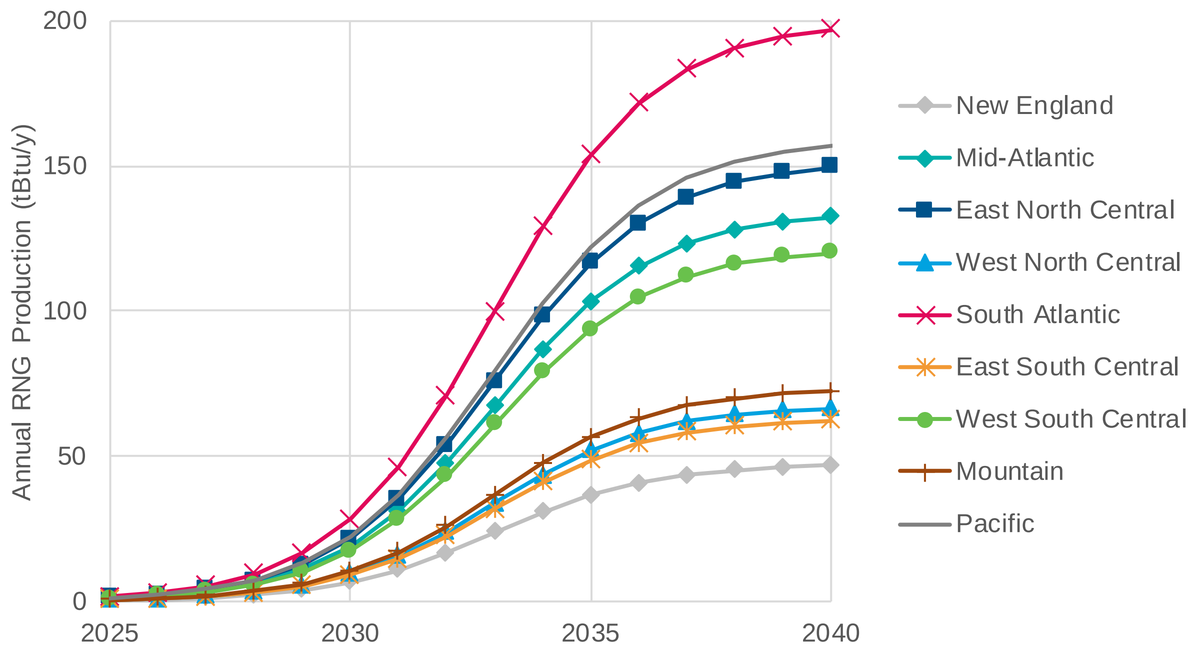


Table 28. Annual RNG Production Potential from MSW, tBtu/y

RNG Potential Scenario	RNG Potential from Nonbiogenic MSW, tBtu/y									
	South Atlantic	New England	Mid-Atlantic	East North Central	West North Central	East South Central	West South Central	Mountain	Pacific	National
Conservative	**56.9**	14.4	40.6	45.9	17.7	11.2	15.3	8.8	45.4	**256.2**
Achievable	**136.3**	32.4	91.6	103.4	46.1	43.2	83.2	50.1	108.5	**694.8**
Aggressive	**199.8**	47.5	134.3	151.6	67.6	63.4	122.0	73.5	159.0	**1,018.7**

As shown in Table 28, ICF estimates in the Achievable scenario that 136 tBtu/y of RNG could be produced from nonbiogenic MSW through thermal gasification by 2040 in the South Atlantic Census region. At the national level this estimate increases to 695 tBtu/y of RNG from nonbiogenic MSW, rising to 1,019 tBtu/y in the Aggressive High scenario.

RNG from P2G and Methanation

A critical advantage of P2G is that the RNG produced is a highly flexible and interchangeable carbon neutral fuel. With a storage and infrastructure system already established, RNG from P2G can be produced and stored over the long term, allowing for deployment during peak demand periods in the energy system. RNG from P2G also utilizes the highly reliable and efficient existing natural gas transmission and distribution infrastructure, the upfront costs of which have already been incurred.

The flexibility of hydrogen provides advantages beyond being an input to methanation for RNG. Hydrogen can be mixed directly with natural gas in pipeline systems, up to certain recommended blending proportions, and used in place of natural gas in some applications. In addition, currently, most commercially produced hydrogen is derived from conventional natural gas and does not have the environmental benefits of carbon neutral hydrogen produced from P2G.

Whether hydrogen or methane is the final product, P2G offers the potential to produce carbon neutral fuels from sustainable resources and leverage existing natural gas infrastructure for long-term and large-scale storage. Competing electric energy storage options, including batteries and pumped hydro storage, are expensive as a long-term energy storage option and can be more expensive than P2G storage. P2G also offers other benefits, such as a fully dispatchable load capable of supplying grid balancing or ancillary services.

P2G discussions often focus on the role and scale of excess (curtailed) renewable electricity as the source for hydrogen and RNG production. The issue of curtailed renewable electricity is a complicated one, and P2G systems are likely to use curtailed electricity in the near term as a transitional approach to develop cost-effective P2G systems. However, for hydrogen and RNG to be produced at meaningful quantities, dedicated renewable electricity generation is likely to be needed. This is particularly the case if P2G will be a key driver for emission reductions in the natural gas system and form part of deep decarbonization strategies.

ICF estimated the potential for P2G to contribute toward RNG production over a series of steps consistent with the approach taken in our recent American Gas Foundation assessment of the national supply and emission reduction potential of RNG, but tailored to reflect the specific policy environment of the Greater Washington, D.C. metropolitan area.[35] First, ICF utilized our Integrated Planning Model (IPM®), which provides true integration of wholesale power, system reliability, environmental constraints, fuel choice, transmission, capacity expansion, and all key operational elements of generators on the power grid in a linear optimization framework. The model utilizes a Windows™-based database platform and interface that captures a detailed representation of every electric boiler and generator in the power market being modeled. The fundamental logic behind the model determines the least-cost means of meeting electric generation energy and capacity requirements while complying with specified constraints, including air pollution regulations, transmission constraints, and plant-specific operational constraints.

ICF used the IPM platform to develop a supply-cost curve for renewable electricity from 2025 to 2040. We did this over a series of steps. Firstly, the model was constrained by all finalized and on-the-books state-level Renewable Portfolio Standards (RPS) and Clean Energy Standard (CES) policies and regional carbon markets. The model does not explicitly capture renewable targets announced by municipalities and corporate actors. The RPS demand modeled represents a floor on incremental renewable demand, since the model conducts capacity expansion based on relative economics. To the extent that renewable energy is cost-competitive relative to other technology types, the model will choose to build renewable energy, even in excess of modeled targets.

[35] ICF, 2019. Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment, https://www.gasfoundation.org/2019/12/18/renewable-sources-of-natural-gas/

Table 29 shows the share of generation represented by renewable resources for each region (note that the regions in IPM are distinguished by independent system operator [ISO], regional transmission organization [RTO], reliability council, etc. and are not consistent with the U.S. Census Regions that have been employed elsewhere in the study). The table also includes the share of electricity generation that is attributable to solar and wind.

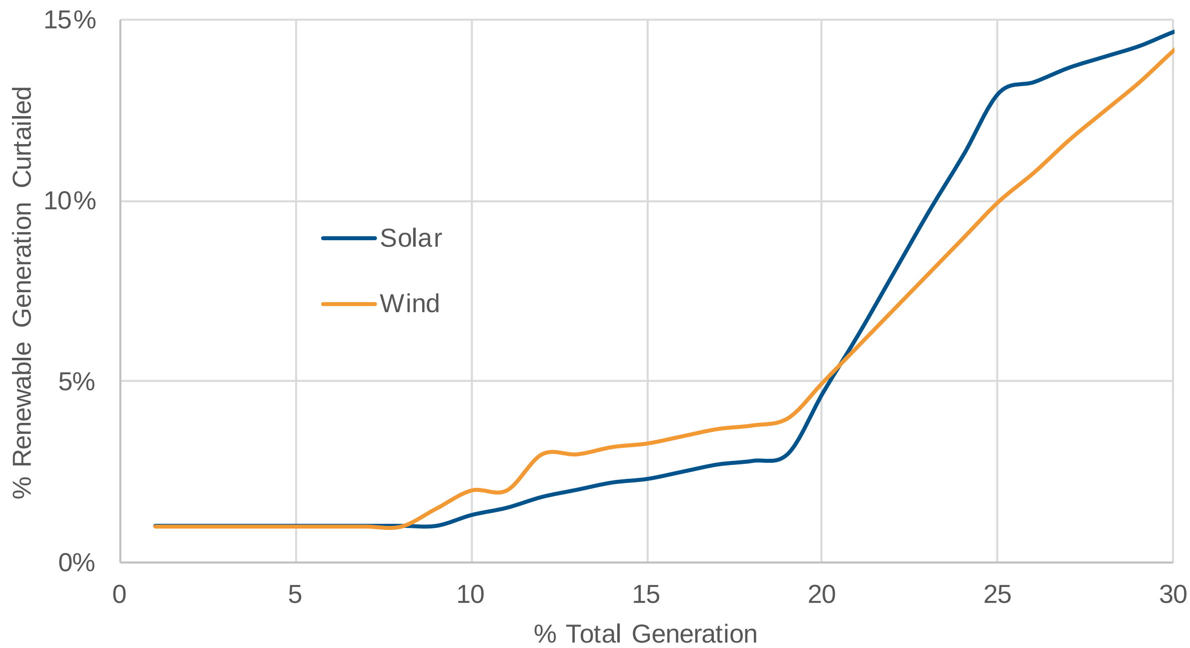
Table 29. Renewable Share of Electricity Generation in RPS-Compliant Run Using IPM

Region	Renewable Share of Electricity Generation			Renewable Share: Solar and Wind		
	2030	2035	2040	2030	2035	2040
US	27%	28%	29%	20%	20%	21%
Non-CA WECC	45%	45%	47%	19%	20%	22%
CAISO	70%	69%	73%	49%	49%	56%
SPP	46%	45%	44%	42%	41%	40%
MISO	28%	29%	31%	24%	25%	25%
SERC	8%	8%	10%	4%	4%	4%
ERCOT	30%	27%	25%	29%	27%	25%
ISONE	44%	47%	49%	30%	34%	36%
NYISO	50%	51%	60%	29%	31%	39%
PJM	13%	14%	14%	11%	12%	12%
FRCC	12%	12%	12%	11%	11%	11%

ICF also implemented, as an input to the IPM platform, an assumption regarding the rate of curtailed renewable electricity, differentiated between solar and wind, and the percent of total electricity generation that the renewable resource represents.

As shown in Figure 41, ICF assumed an increasing curtailment rate as the share of renewable generation increased. In other words, the input assumes that when solar and wind electricity generation represent about 20% of total electricity generation, about 5% of the electricity is curtailed. ICF reviewed the current frequency of curtailment events in each region (at the daily time scale) and assumed that the frequency would be similar moving forward.

Figure 41. Assumed Curtailment Rates as a Function of Renewable Electricity Penetration



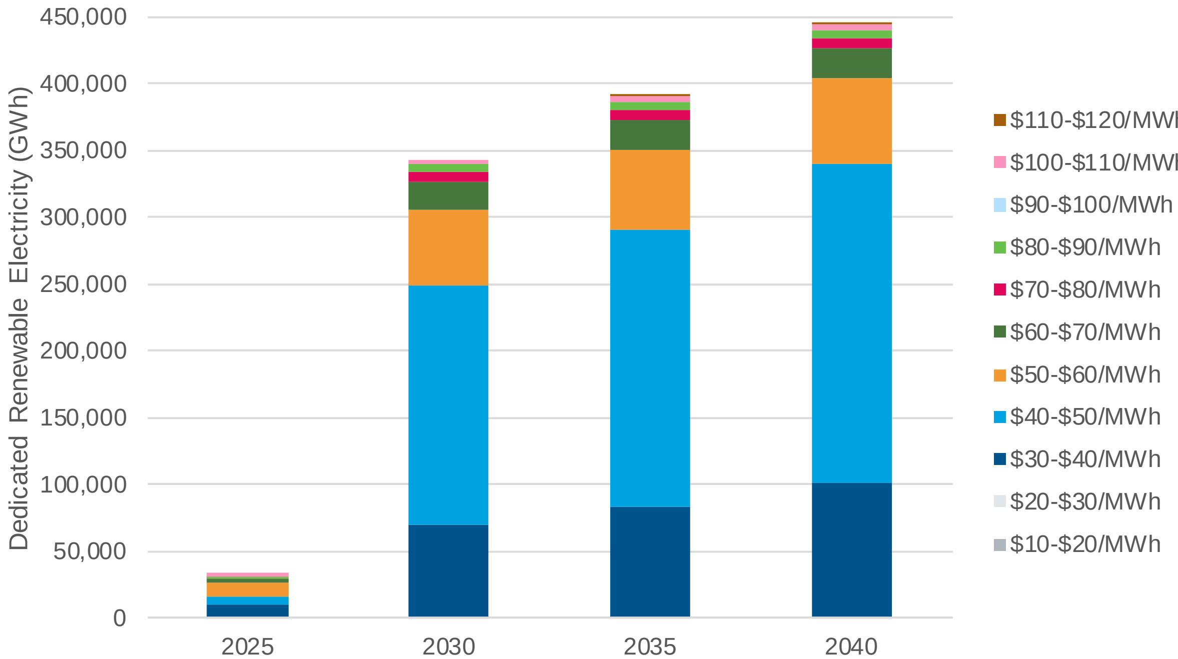
ICF notes that this is likely an over-simplification of curtailment, especially given the interest of regulators to start to impose more stringent RPS or CES policies and energy-efficiency measures, thereby possibly increasing curtailment considerably. Table 30 includes the estimated curtailed renewable electricity generation (reported in units of GWh) available from 2025 to 2040.

Table 30. Estimated Curtailed Renewable Electricity Generation, 2025–2040 in Units of GWh

Region	Estimated Curtailed Renewable Electricity, GWh			
	2025	2030	2035	2040
US	**458.5**	**505.7**	**491.3**	**499.4**
Non-CA WECC	20.7	22.3	22.6	22.9
CAISO	98.3	164.4	170.7	177.3
SPP	164.3	164.6	164.6	164.6
MISO	53.4	44.2	44.7	45.3
SERC	2.9	3.4	3.4	3.4
ERCOT	108.1	88.9	67.6	67.6
ISONE	1.1	1.9	2.4	3.0
NYISO	2.4	2.8	2.8	2.8
PJM	6.9	7.4	7.4	7.4
FRCC	0.4	5.9	5.1	5.1

In the last step of the analysis using the IPM platform, ICF made a simple calculation. We developed a supply-cost curve for renewable electricity generation by extracting the total consumption of renewable electricity (in GWh) by region in 2025, 2030, 2035, and 2040, assuming all RPS and CES policies are achieved on time. ICF then determined what the corresponding levelized cost of energy (LCOE) in $10/MWh increments up to $110/MWh would be to deploy the same number of generating assets to produce the same amount of renewable electricity. ICF used those estimates, as shown in Figure 42, to develop an outlook for P2G using dedicated renewable electricity generation.

Figure 42. Supply-Cost Curve for Dedicated Renewable Electricity for P2G Systems, 2025–2040

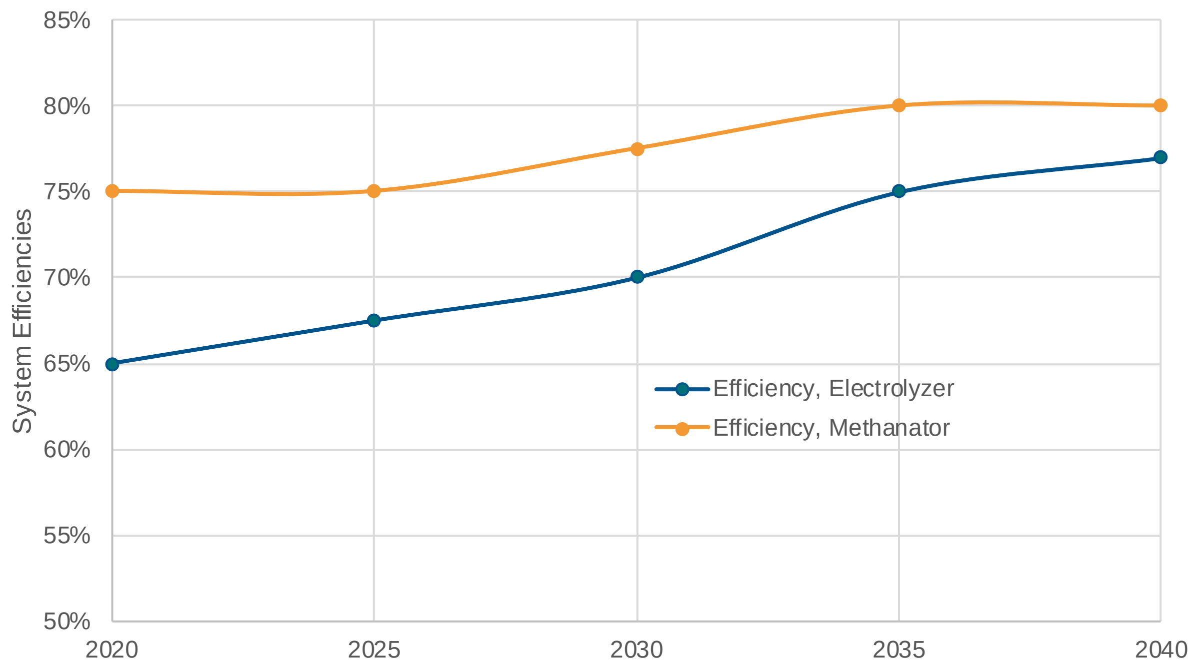


Based on the curtailed electricity estimates and the supply-cost curve constructed for dedicated renewable electricity generation, ICF determined how much hydrogen and methane could be produced using P2G/methanation systems. We assumed a capacity factor of 5% to 10% for curtailed renewable electricity generation and 50% to 80% for dedicated renewable electricity generation. The energy price in each scenario was based on the LCOE supply curve for renewable electricity generation.

ICF limited our considerations for the low resource potential for RNG derived from P2G and methanation to the curtailed renewable electricity generation available and dedicated renewable electricity generation that is estimated to be available at an LCOE less than $50/MWh. In the high resource potential scenario, we included curtailed renewable electricity generation and dedicated renewable electricity generation that is estimated to be available at an LCOE less than $60/MWh.

ICF assumed that all of the renewable electricity would be available to an electrolyzer to produce hydrogen. Furthermore, ICF assumed the co-location of a methanation unit. Figure 43 includes the assumed conversion efficiencies for hydrogen production from an electrolyzer (blue) and for the methanation reaction to produce RNG for injection (orange).

Figure 43. Assumed Efficiency for Electrolysis and Methanation, 2020–2040



These assumptions yield the resource potential listed in Table 31, which also includes the hydrogen produced in the first step using P2G. The low and the high resource potential estimates are presented assuming capacity factors of 5% and 10% for systems using curtailed electricity and capacity factors of 50% and 80% for systems using dedicated renewable electricity generation.

Table 31. 2025-2040 Annual Hydrogen and RNG Production from Renewable Electricity P2G, tBtu/y

Resource: Curtailment & Dedicated RE Generation	Capacity Factors		2025	2030	2035	2040
	Curtailed	Dedicated				
Hydrogen						
Low	5%	50%	11.5	297.1	372.2	447.1
	10%	80%	18.4	475.3	595.6	715.4
High	5%	50%	11.5	364.6	448.7	530.2
	10%	80%	18.4	583.4	718.0	848.3
Max	10%	95%	93.2	935.7	1,064.0	1,210.5
RNG						
Low	5%	50%	8.6	230.2	297.8	357.7
	10%	80%	13.8	368.4	476.5	572.3
High	5%	50%	8.6	282.5	359.0	424.1
	10%	80%	13.8	452.1	574.4	678.7
Max	10%	95%	74.5	748.5	851.2	968.4

3. Cost Assessment

Key Takeaways

ICF reports that RNG will be available from various feedstocks in the range of $7/MMBtu to $44/MMBtu. Anaerobic digestion feedstocks, notably from LFG and WRRF, are more cost-effective in the near term. RNG from thermal gasification feedstocks are more expensive, largely reflecting the immature state of thermal gasification as a technology, and the associated uncertainties around cost and feedstock availability.

RNG is more expensive than its fossil counterpart; however, in a decarbonization framework, the proper comparison for RNG is to other abatement measures that are viewed as long-term strategies to reduce GHG emissions (discussed in more detail in Section 4). In addition, ICF anticipates that over time there will be increasing opportunities for cost reductions as RNG technologies mature and the market expands.

Cost Methodology

ICF developed assumptions for the capital expenditures and operational costs for RNG production from the various feedstock and technology pairings outlined previously. ICF characterizes costs based on a series of assumptions regarding the production facility sizes (as measured by gas throughput in units of standard cubic feet per minute [SCFM]), gas upgrading and conditioning and upgrading costs (depending on the type of technology used, the contaminant loadings, etc.), compression, and interconnect for pipeline injection. We also include operational costs for each technology type. Table 32 outlines some ICF's baseline assumptions that we employ in our RNG costing model.

Table 32. Illustrative ICF RNG Cost Assumptions

Cost Parameter	ICF Cost Assumptions
Facility Sizing	▪ Differentiate by feedstock and technology type: anaerobic digestion and thermal gasification. ▪ Prioritize larger facilities to the extent feasible, but driven by resource estimate.
Gas Conditioning and Upgrade	▪ Vary by feedstock type and technology required.
Compression	▪ Capital costs for compressing the conditioned/upgraded gas for pipeline injection.
Operational Costs	▪ Costs for each equipment type—digesters, conditioning equipment, collection equipment, and compressors—as well as utility charges for estimated electricity consumption.
Feedstock	▪ Feedstock costs (for thermal gasification), ranging from $30 to $100 per dry ton.
Financing	▪ Financing costs, including carrying costs of capital (assuming a 60/40 debt/equity ratio and an interest rate of 7%), an expected rate of return on investment (set at 10%), and a 15-year repayment period.

Cost Parameter	ICF Cost Assumptions
Delivery	▪ Cost of delivering the biogas at a price of $1.20/MMBtu. This cost is in line with financing, constructing, and maintaining a pipeline of about 1 mile in length. The costs of delivering the same volumes of biogas that require pipeline construction greater than 1 mile will increase, depending on feedstock/technology type, with a typical range of $1–$5/MMBtu.
Project Lifetimes	▪ 20 years. The levelized cost of gas was calculated based on the initial capital costs in Year 1, annual operational costs discounted at an annual rate of 5% over 20 years, and biogas production discounted at an annual rate of 5% for 20 years.

ICF notes that our cost estimates are not intended to replicate a developer's estimate when deploying a project. For instance, ICF recognizes that the cost category "conditioning and upgrading" actually represents an array of decisions that a project developer would have to make with respect to CO_2 removal, H_2S removal, siloxane removal, N_2/O_2 rejection, deployment of a thermal oxidizer, etc.

In addition, these cost estimates do not reflect the potential value of the environmental attributes associated with RNG, nor the current markets and policies that provide credit for these environmental attributes. While this section focuses purely on the costs associated with the production of RNG, Sections 4 and 5 discuss in more detail the market prices for RNG and the associated value of the environmental characteristics of RNG.

Furthermore, we understand that project developers have reported a wide range of interconnection costs, with numbers as low as $200,000 reported in some states, and as high as $9 million in other states. We appreciate the variance between projects, including those that use anaerobic digestion, thermal gasification, or P2G technologies, and our supply-cost curves are meant to be illustrative, rather than deterministic. This is especially true of our outlook to 2040—we have not included significant cost reductions that might occur as a result of a rapidly growing RNG market or sought to capture a technological breakthrough or breakthroughs. We have made some assumptions in line with those in the publicly available literature regarding potential decreases in the costs of P2G systems; however, for anaerobic digestion and thermal gasification systems we have focused on projects that have reasonable scale, representative capital expenditures, and reasonable operations and maintenance estimates.

To some extent, ICF's cost modeling does presume changes in the underlying structure of project financing, which is currently linked inextricably to revenue sharing associated with environmental commodities in the federal Renewable Fuel Standard market and California's LCFS market. Our project financing assumptions likely have a lower return than investors may be expecting in the market today; however, our cost assessment seeks to represent a more mature market to the extent feasible, whereby upward of 1,000-4,500 tBtu per year of RNG is being produced. In that regard, we implicitly assume that contractual arrangements are likely considerably different and local/regional challenges with respect to RNG pipeline injection have been overcome.

Table 33 provides a summary of the different cost ranges for each RNG feedstock and technology.

Table 33. Summary of Cost Ranges by Feedstock Type

	Feedstock	Cost Range ($/MMBtu)
Anaerobic Digestion	Landfill Gas	$7.10 – $19.00
	Animal Manure	$18.40 – $32.60
	Water Resource Recovery Facilities	$7.40 – $26.10
	Food Waste	$19.40 – $28.30
Thermal Gasification	Agricultural Residues	$18.30 – $27.40
	Forestry and Forest Residues	$17.30 – $29.20
	Energy Crops	$18.30 – $31.20
	Municipal Solid Waste	$17.30 – $44.20

RNG from Anaerobic Digestion

Landfill Gas

ICF developed assumptions for each region by distinguishing between four types of landfills: candidate landfills[36] without collection systems in place, candidate landfills with collection systems in place, landfills[37] without collection systems in place, and landfills with collections systems in place.[38] For each region, ICF further characterized the number of landfills across these four types of landfills, distinguishing facilities by estimated biogas throughput (reported in units of SCFM of biogas).

For utility costs, ICF assumed 25 kWh per MMBtu of RNG injected and 6% of geological or fossil natural gas used in processing. Electricity costs and delivered natural gas costs were reflective of industrial rates reported at the state level by the EIA.

[36] The EPA characterizes candidate landfills as one that is accepting waste or has been closed for five years or less, has at least one million tons of WIP, and does not have an operational, under-construction, or planned project. Candidate landfills can also be designated based on actual interest by the site.
[37] Excluding those that are designated as candidate landfills.
[38] Landfills that are currently producing RNG for pipeline injection are included here.

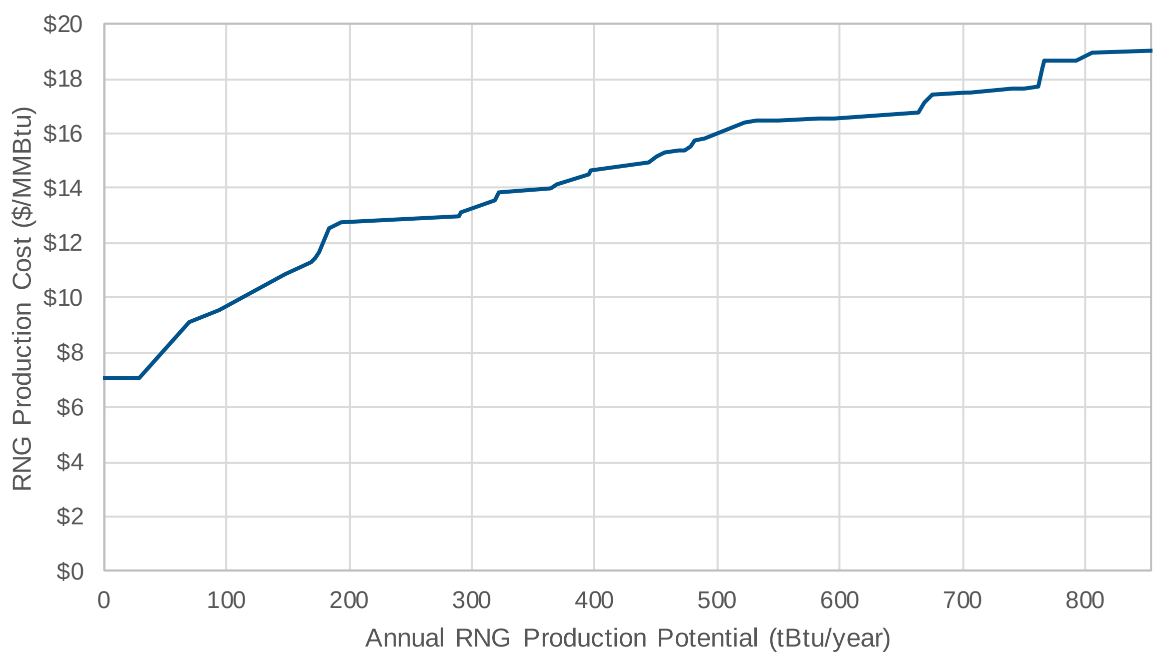
Table 34 summarizes the key parameters that ICF employed in our cost analysis of LFG.

Table 34. Cost Consideration in Levelized Cost of Gas Analysis for RNG from Landfill Gas

Factor	Cost Elements Considered	Costs
Performance	▪ Capacity factor	▪ 95%
Installation Costs	▪ Construction / Engineering ▪ Owner's cost	▪ 25% of uninstalled costs of equipment ▪ 10% of uninstalled costs of equipment
Gas Upgrading	▪ CO_2 separation ▪ H_2S removal ▪ N_2/O_2 removal	▪ $2.3 to $7.0 million, depending on facility ▪ $0.3 to $1.0 million, depending on facility ▪ $1.0 to $2.5 million, depending on facility
Utility Costs	▪ Electricity: 25 kWh/MMBtu ▪ Natural Gas: 6% of product	▪ 4.6–13.7 ¢/kWh; average of 6.5 ¢/kWh for region ▪ $3.00–$8.25/MMBtu; average of $4.75/MMBtu for region
Operations & Maintenance	▪ 1 FTE for maintenance ▪ Miscellany	▪ 10% of installed capital costs
For Injection	▪ Interconnect ▪ Pipeline ▪ Compressor	▪ $2 million ▪ $1.5 million ▪ $0.2–$0.5 million
Financial Parameters	▪ Rate of return ▪ Discount rate	▪ 10% ▪ 7%

Figure 44 includes ICF's estimates for the RNG from landfill gas supply curve.

Figure 44. Supply-Cost Curve for RNG from Landfill Gas, $/MMBtu vs tBtu



ICF reports a range of costs for RNG from LFG at $7.1/MMBtu to $19.0/MMBtu.

Animal Manure

ICF developed assumptions for each region by distinguishing between animal manure projects, based on a combination of the size of the farms and assumptions that certain areas would need to aggregate or cluster resources to achieve the economies of scale necessary to warrant an RNG project. There is some uncertainty associated with this approach because an explicit geospatial analysis was not conducted; however, ICF did account for considerable costs in the operational budget for each facility assuming that aggregating animal manure would potentially be expensive.

Table 35 includes the main assumptions used to estimate the cost of producing RNG from animal manure.

Table 35. Cost Consideration in Levelized Cost of Gas Analysis for RNG from Animal Manure

Factor	Cost Elements Considered	Costs
Performance	▪ Capacity factor	▪ 95%
Installation Costs	▪ Construction / Engineering ▪ Owner's cost	▪ 25% of uninstalled costs of equipment ▪ 10% of uninstalled costs of equipment
Gas Upgrading	▪ CO_2 separation ▪ H_2S removal ▪ N_2/O_2 removal	▪ $2.3 to $7.0 million, depending on facility ▪ $0.3 to $1.0 million, depending on facility ▪ $1.0 to $2.5 million, depending on facility
Utility Costs	▪ Electricity: 30 kWh/MMBtu ▪ Natural Gas: 6% of product	▪ 4.6–13.7 ¢/kWh; average of 6.5 ¢/kWh for region ▪ $3.00–$8.25/MMBtu; average of $4.75/MMBtu for region
Operations & Maintenance	▪ 1 FTE for maintenance ▪ Miscellany	▪ 15% of installed capital costs
For Injection	▪ Interconnect ▪ Pipeline ▪ Compressor	▪ $2.0 million ▪ $1.5 million ▪ $0.2–$0.5 million
Other	▪ Value of digestate ▪ Tipping fee	▪ Valued for dairy at about $100/cow/y ▪ Excluded from analysis
Financial Parameters	▪ Rate of return ▪ Discount rate	▪ 10% ▪ 7%

ICF reports a range of costs for RNG from animal manure at $18.4/MMBtu to $32.6/MMBtu.

Water Resource Recovery Facilities

ICF developed assumptions for each region by distinguishing between WRRFs based on the throughput of the facilities. The table below includes the main assumptions used to estimate the cost of producing RNG at WRRFs.

Table 36. Cost Consideration in Levelized Cost of Gas Analysis for RNG from WRRFs

Factor	Cost Elements Considered	Costs
Performance	▪ Capacity factor	▪ 95%
Installation Costs	▪ Construction / Engineering ▪ Owner's cost	▪ 25% of uninstalled costs of equipment ▪ 10% of uninstalled costs of equipment
Gas Upgrading	▪ CO_2 separation ▪ H_2S removal ▪ N_2/O_2 removal	▪ $2.3 to $7.0 million, depending on facility ▪ $0.3 to $1.0 million, depending on facility ▪ $1.0 to $2.5 million, depending on facility
Utility Costs	▪ Electricity: 26 kWh/MMBtu ▪ Natural Gas: 6% of product	▪ 4.6–13.7 ¢/kWh; average of 6.5 ¢/kWh for region ▪ $3.00–$8.25/MMBtu; average of $4.75/MMBtu for region
Operations & Maintenance	▪ 1 FTE for maintenance ▪ Miscellany	▪ 10% of installed capital costs
For Injection	▪ Interconnect ▪ Pipeline ▪ Compressor	▪ $2.0 million ▪ $1.5 million ▪ $0.2–$0.5 million
Financial Parameters	▪ Rate of return ▪ Discount rate	▪ 10% ▪ 7%

ICF reports an estimated cost of RNG from WRRFs of $7.4/MMBtu to $26.1/MMBtu.

Food Waste

ICF made the simplifying assumption that food waste processing facilities would be purpose-built and be capable of processing 60,000 tons of waste per year. ICF estimates that these facilities would produce about 500 SCFM of biogas for conditioning and upgrading before pipeline injection. In addition to the other costs included in other anaerobic digestion systems, we also included assumptions about the cost of collecting food waste and processing it accordingly (see Table 37).

Table 37. Cost Consideration in Levelized Cost of Gas Analysis for RNG from Food Waste Digesters

Factor	Cost Elements Considered	Costs
Performance	▪ Capacity factor ▪ Processing capability	▪ 95% ▪ 60,000 tons per year
Dedicated Equipment	▪ Organics processing ▪ Digester	▪ $10.0 million ▪ $12.0 million
Installation Costs	▪ Construction / Engineering ▪ Owner's cost	▪ 25% of uninstalled costs of equipment ▪ 10% of uninstalled costs of equipment
Gas Upgrading	▪ CO_2 separation ▪ H_2S removal ▪ N_2/O_2 removal	▪ $2.3 to $7.0 million, depending on facility ▪ $0.3 million ▪ $1.0 million
Utility Costs	▪ Electricity: 28 kWh/MMBtu ▪ Natural Gas: 5% of product	▪ 4.6–13.7 ¢/kWh; average of 6.5 ¢/kWh for region ▪ $3.00–$8.25/MMBtu; average of $4.75/MMBtu for region
Operations & Maintenance	▪ 1.5 FTE for maintenance ▪ Miscellany	▪ 15% of installed capital costs
Other	▪ Tipping fees	▪ Varied by region; used weighted average of $49.07 (see Table 38)
For Injection	▪ Interconnect ▪ Pipeline ▪ Compressor	▪ $2.0 million ▪ $1.5 million ▪ $0.2–$0.5 million
Financial Parameters	▪ Rate of return ▪ Discount rate	▪ 10% ▪ 7%

ICF assumed that food waste facilities would be able to offset costs with tipping fees. ICF used values presented by an analysis of municipal solid waste landfills by Environmental Research & Education Foundation (EREF). The tipping fees reported by EREF for 2018 are shown in Table 38.

Table 38. Average Tipping Fee by Region ($/ton of MSW unless otherwise noted)[39]

Region	Tipping Fee
Greater Washington, D.C Area	
Frederick County, MD[40]	$69
Frederick County, MD (Food Waste, Separated)[41]	$50
Montgomery County LF, MD[42]	$60
Charles County LF, MD[43]	$75
Brown Station SLF, Prince George's County, MD[44]	$59
Frederick County Regional Landfill, VA[45]	$50
Loudoun County SLF, VA[46]	$62
Shenandoah County LF, VA[47]	$45
Regional	
Maryland, statewide average	$68.57
Virginia, statewide average	$52.22
Northeast: CT, DE, ME, MD, MA, NH, NJ, NY, PA, RI, VA, WV	$67.39
Rest of U.S.	
Pacific: AK, AZ, CA, HI, ID, NV, OR, WA	$68.46
Midwest: IL, IN, IA, KS, MI, MN, MO, NE, OH, OH, WI	$46.89
Mountains / Plains: CO, MT, ND, SD, UT, WY	$43.57
Southeast: AL, FL, GA, KY, MS, NC, SC, TN	$43.32
South Central: AR, LA, NM, OK, TX	$34.80
National Average	***$55.11***

The values listed in Table 38 are generally the fees associated with tipping municipal solid waste—the tipping fees for construction and debris tend to be higher because the materials take up more space in landfills. The only data point for tipping fees for food waste is for the Frederick County landfill in Maryland, which shows a tipping fee of $50/ton for food waste compared to

[39] Environmental Research & Education Foundation, Analysis of MSW Landfill Tipping Fees–April 2019. Retrieved from www.erefdn.org.
[40] Frederick County, available online at https://frederickcountymd.gov/535/Fees-Payment-Options.
[41] Ibid.
[42] Montgomery County, Maryland, available online at https://www.montgomerycountymd.gov/SWS/Resources/Files/swc/swc-rate-detail.pdf.
[43] Charles County Landfill, https://www.charlescountymd.gov/sites/default/files/pw/FY20%20Landfill%20Fees.pdf.
[44] Prince George's County, MD, https://www.princegeorgescountymd.gov/615/Brown-Station-Road-Sanitary-Landfill.
[45] Frederick County, VA. https://www.fcva.us/departments/public-works/landfill-and-solid-waste#tipping.
[46] Loudoun County, VA, https://www.loudoun.gov/landfill.
[47] Shenandoah County, VA, https://shenandoahcountyva.us/landfill/landfill-fees/.

$69/ton for MSW. ICF notes, however, that the $50/ton reported by Frederick County is for residential customers; they do not list a comparable fee for commercial customers. ICF developed our cost estimates assuming that anaerobic digesters discounted the tipping fee for food waste compared to MSW landfills by 20%.

ICF reports an estimated cost of RNG from food waste of $19.4/MMBtu to $28.3/MMBtu.

RNG from Thermal Gasification

ICF used similar assumptions across the thermal gasification of feedstocks, including agricultural residue, forestry residue, energy crops, and MSW.[48] There is considerable uncertainty around the costs for thermal gasification of feedstocks, as the technology has only been deployed at pilot scale to date or in the advanced stages of demonstration at pilot scale. This is in stark contrast to the anaerobic digestion technologies considered previously. ICF reports here on a range of facilities processing different volumes of feedstock (in units of tons per day, or tpd) that we employed for conducting the cost analysis.

Table 39. Thermal Gasification Cost Assumptions

Factor	Cost Elements Considered	Costs
Performance	▪ Capacity factor ▪ Processing capability	▪ 90% ▪ 1,000–2,000 tpd
Dedicated Equipment & Installation Costs	▪ Feedstock handling (drying, storage) ▪ Gasifier ▪ CO_2 removal ▪ Syngas reformer ▪ Methanation ▪ Other (cooling tower, water treatment) ▪ Miscellany (site work, etc.) ▪ Construction / Engineering	▪ $20–22 million ▪ $60 million ▪ $25 million ▪ $10 million ▪ $20 million ▪ $10 million ▪ All-in: $335 million for 1,000 tpd
Utility Costs	▪ Electricity: 30 kWh/MMBtu ▪ Natural Gas: 6% of product	▪ 4.6–13.7 ¢/kWh ▪ $3.00–$8.25/MMBtu
Operations & Maintenance	▪ Feedstock ▪ 3 FTE for maintenance ▪ Miscellany: water sourcing, treatment/disposal	▪ $30–$100/dry ton ▪ 12% of installed capital costs
For Injection	▪ Interconnect ▪ Pipeline ▪ Compressor	▪ $2.0 million ▪ $1.5 million ▪ $0.2–$0.5 million
Financial Parameters	▪ Rate of return ▪ Discount rate	▪ 10% ▪ 7%

[48] Note that MSW here refers to the non-organic, nonbiogenic fraction of the MSW stream, which is assumed to be a mix of, including, but not limited to construction and demolition debris, plastics, rubber and leather, etc.

ICF applied these estimates across each of the four feedstocks, their corresponding feedstock cost estimates, and assumed that the smaller facilities processing 1,000 tons per day would represent 50% of the processing capacity, and that the larger facilities processing 2,000 tons per day would represent the other 50% of the processing capacity. The number of facilities built in each region was constrained by the resource assessment.

ICF reports an estimated levelized costs of RNG from thermal gasification as follows:

- Agricultural residues: $18.3/MMBtu to $27.4/MMBtu
- Forestry and forest residues: $17.3/MMBtu to $29.2/MMBtu
- Energy crops: $18.3/MMBtu to $31.2/MMBtu
- MSW: $17.3/MMBtu to $44.2/MMBtu

RNG from Power-to-Gas/Methanation

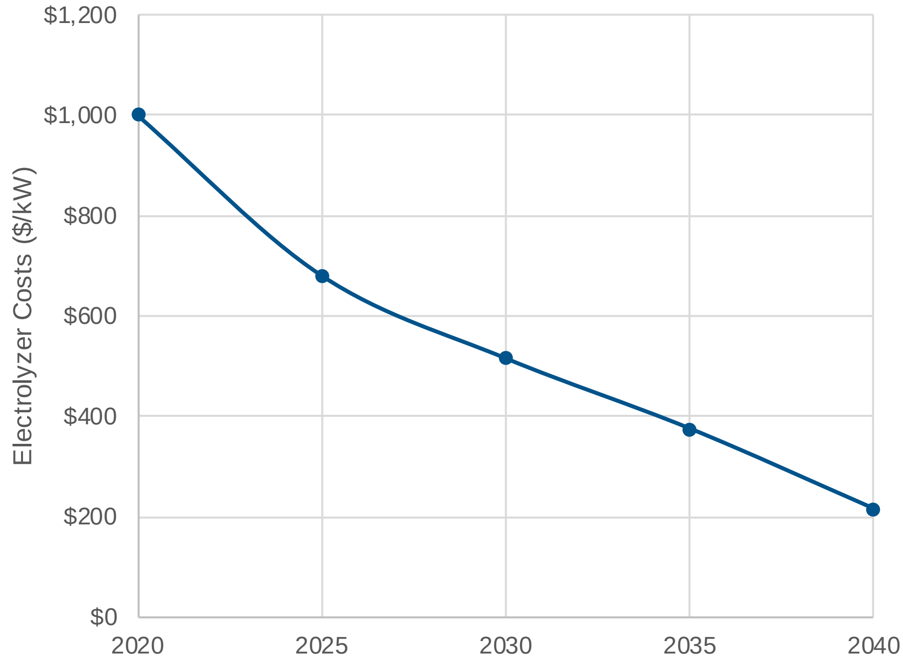
ICF developed the levelized cost of energy for P2G systems using a combination of an electrolyzer and a methanator to produce RNG for pipeline injection. The main cost considerations include the installed cost of electrolyzers on a dollar per kW basis ($/kW), the installed cost of a methanation system on a $/kW basis, the cost of RNG compression and interconnect for pipeline injection, and the cost of electricity used to run the P2G system. ICF also estimated the operations and maintenance (O&M) costs of both the electrolyzer and the methanator. ICF notes that we assume that the renewable electricity is dedicated to the P2G system and co-located, thereby reducing other electricity costs (e.g., transmission and distribution) considerably. ICF did not quantify:

- The costs of CO_2 that would be required for the methanation reaction; the underlying assumption is that the cost of CO_2 would be a marginal contributor to the overall cost of the system, and that it would be available at a low cost (e.g., less than $30 per ton).
- The costs of a heat sink for the waste heat generated from the methanation reaction, or the corresponding benefits of repurposing this heat.

The graph below illustrates ICF's assumptions regarding the installed costs of electrolyzers; we assumed that the resource base for electrolyzers would be some blend of proton exchange membrane (PEM), alkaline systems, and solid oxide systems. Rather than be deterministic about which technology will be the preferred technology, we present the cost as a blended average of the $/kW installed. This is based on ICF's review of literature and review of assumptions developed by UC Irvine.[49]

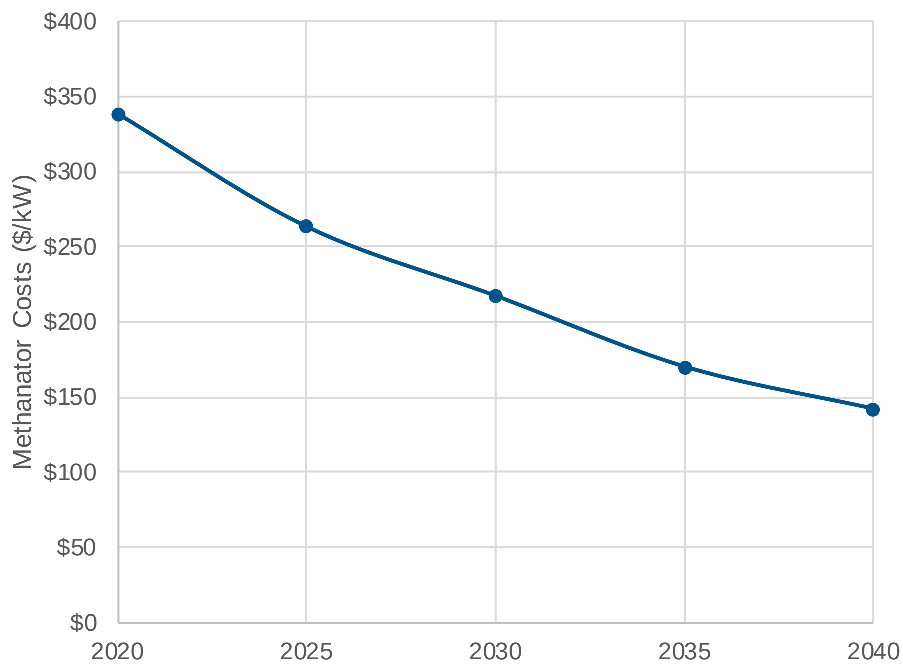
[49] Draft Results: Future of Natural Gas Distribution in California, CEC Staff Workshop for CEC PIER-16-011, June 6, 2019, available online at https://ww2.energy.ca.gov/research/notices/2019-06-06_workshop/2019-06-06_Future_of_Gas_Distribution.pdf.

Figure 45. Installed Capacity Cost of Electrolyzers, $/kW, 2020–2040



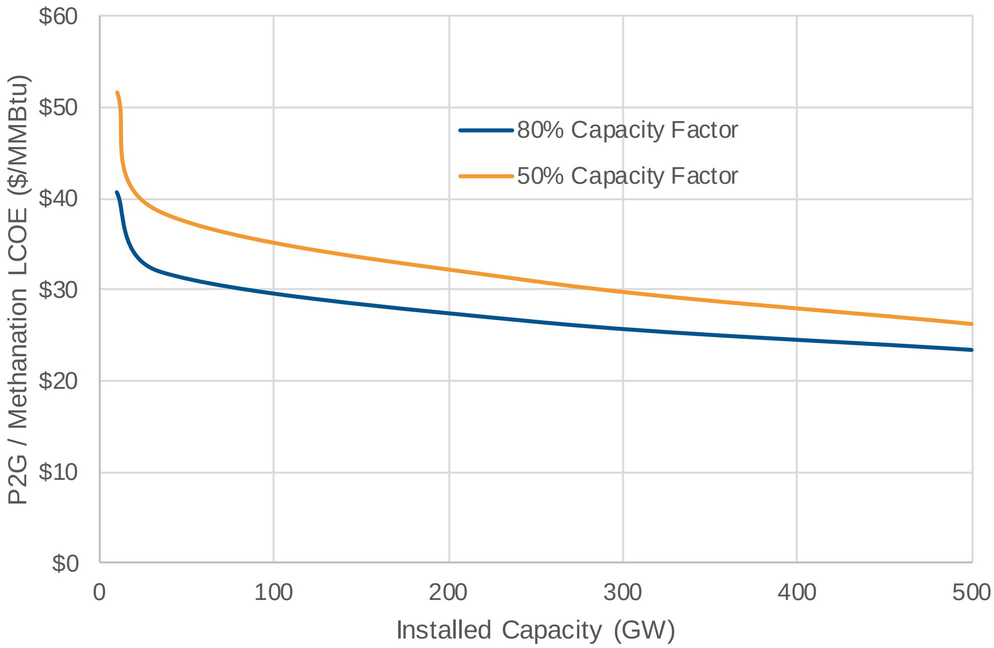
ICF assumed a decreasing cost of Methanation technology consistent with Figure 46, presented in units of $/kW.

Figure 46. Installed Capacity Cost of Methanator, $/kW, 2020–2040



ICF developed our cost estimates assuming a 50 MW system for P2G co-located with methanation capabilities, and included the costs of compression for pipeline injection, interconnection costs, and pipeline costs. We assumed an electricity cost of $42/MWh based on the supply curve for dedicated renewables that we developed using IPM. We assumed operational costs of 10% and 7% of capex, respectively for the electrolyzer and the methanator, and we assumed operational costs of 5% of capex for pipeline and interconnect systems. Figure 47 shows the decreasing LCOE for RNG from P2G systems using these baseline level assumptions; the blue line shows the costs assuming a 50% capacity factor for the system and the orange line shows the costs assuming an 80% capacity factor for the system.

Figure 47. Estimated RNG Costs from P2G/Methanation as a Function of Installed Capacity, $/MMBtu



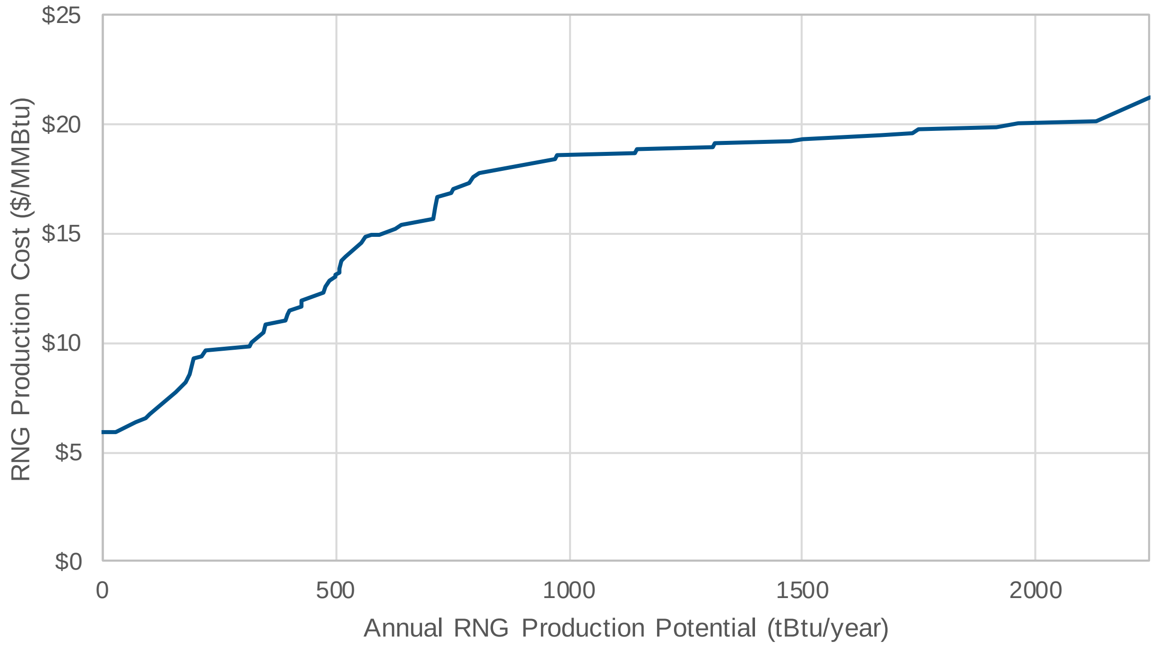
Combined Supply Curves

ICF developed a supply-cost curve (shown in Figure 48) based on a combination of a) the supply estimates included previously, and b) ICF's bottom-up cost estimates to produce RNG. For each feedstock, ICF calculates the levelized cost of energy (LCOE) by incorporating the capital expenditures from equipment, operations and maintenance (O&M), and financing.[50]

ICF estimates that more than half of the RNG production potential in the Achievable scenario would be available at less than $20/MMBtu, as shown Figure 48. Generally speaking, ICF finds the front end of the supply curve to be landfill gas projects and WRRFs that are poised to move toward RNG production. As the estimated costs move to higher costs, the supply curve includes some of the larger animal manure projects and the well-positioned food waste projects. The tail end of the curve, showing the upward slope to the right, captures the first tranche of thermal gasification projects that we assume will just start to break that $20/MMBtu level by 2040.

[50] Financing costs are inclusive of factors such as interest rate for financing, typical debt/equity ratios for new projects, and an assumed return on equity.

Figure 48. Combined RNG Supply-Cost Curve, Less Than $20/MMBtu in 2040



RNG Pricing

The RNG production costs outlined previously are illustrative and provide context for RNG as a mitigation strategy and how its introduction might impact costs in the natural gas system. It is important to note, however, that technology breakthroughs and greater RNG deployment could reduce the costs presented by ICF. Apart from cost-reduction considerations, there is another major factor associated with understanding RNG deployment: the price of RNG.

Today, the RNG market is largely driven by contracts that are dependent on the value of environmental commodities generated, assuming, as in most cases for RNG for pipeline injection today, that the fuel ends up in a transportation application. In other words, there is no real reference market price for RNG today as there are for other commodities.

The challenge that utilities and other stakeholders will face is the transitional period during which the market will evolve from shorter-term contracts linked to the price of environmental commodities to longer-term, fixed-price contracts. In other words, the market lacks liquidity and price discovery. As the market becomes more liquid and price discovery improves, there is potential for market swings and uncertainty. This process will occur naturally as the transportation market becomes saturated with RNG and other policies that support RNG production come into play; however, the transition itself may be bumpy.

In principle, the RNG price should reflect the marginal cost of RNG production on the system. However, differences in incentives across various end uses have the potential to skew this fundamental relationship. ICF believes that the near-term RNG price will reflect investors' risk appetites. More specifically, ICF posits that the RNG price will reflect the value of a long-term, fixed-price agreement compared to the discounted value of short-term gains realized from potentially valuable environmental commodities.

On a simplified basis, the current market value of RNG in the transportation sector (based on D3 RIN pricing) is at least \$20/MMBtu, with at least another \$8–\$10/MMBtu available if the RNG can be directed to California or Oregon. This should not be misconstrued as an RNG price. If that were the case, then market actors outside of the transportation sector would have to pay a price upward of \$30/MMBtu.

However, this price is out of line with the production costs of some RNG accessible to the Greater Washington, D.C. metropolitan area. ICF estimates that in the next 2–4 years, RNG pricing will be available on a fixed-price, long-term basis in the range of \$9–\$15/MMBtu. In some cases, this may include the option for additional revenue sharing between counterparties linked to potential environmental commodities.

ICF also estimates that policies incentivizing RNG consumption outside the transportation sector will help yield overall cost reductions, but that the marginal cost of production will increase as more RNG is needed in the system to comply with various commitments. ICF estimates that the mid-term RNG pricing (in 5–10 years) will be available on a fixed-price, long-term basis in the range of \$8–\$19/MMBtu and will become less dependent on the share of environmental commodities.

RNG pricing post-2030 will be dependent on a variety of market developments that are difficult to forecast—most notably the increased use of RNG outside of the transportation sector. If robust policies are put into place (as discussed in more detail in Sections 6 and 7), then ICF believes that market conditions will support downward pressure on RNG pricing post-2030.

4. GHG Accounting and Cost-Effectiveness

Key Takeaways

RNG represents a valuable and underutilized renewable energy source with a low or net negative carbon intensity, depending on the feedstock. The GHG emission accounting method and scope employed can have a significant impact on how carbon intensities for RNG are reported and estimated. For some feedstocks, applying the lifecycle emission accounting framework captures the full benefit of RNG's emission reduction potential, such as reflecting avoided methane emissions.

RNG can make a significant contribution to the long-term GHG emission reduction objectives in the Greater Washington, D.C. Metropolitan area. When applying a combustion accounting framework, ICF estimates that in the South Atlantic region, 13 to 44 MMT of GHG emissions could be reduced per year in 2040 through the deployment of RNG based on the Conservative Low and Aggressive High scenarios. For abatement cost estimates, RNG at under $7/MMBtu is equivalent to about $55–$60/tCO$_2$e, while RNG at $20/MMBtu has an estimated cost-effectiveness of about $300/tCO$_2$e.

In many instances, policymakers, corporations and RNG stakeholders may not be recognizing the complete benefits of RNG due to a limited assessment and reporting scope. In addition, the cost-effectiveness of RNG as an emission reduction measure is generally underestimated and underappreciated, particularly in comparison to other mitigation approaches over the long term and in a deep decarbonization policy environment.

GHG Accounting Framework and Methodology

The GHG emissions of RNG, typically called a carbon intensity (e.g., grams of CO_2 equivalents per MJ of fuel), varies primarily based on the source of the fuel (i.e., feedstock), but can be impacted by other factors such as production efficiency and location as well as transmission distances. The assessment method and scope can also have a significant impact on how RNG carbon intensities and emissions are estimated and reported. This section provides a summary of commonly used GHG emission accounting methods and how they relate to the GHG emission profiles of RNG production and consumption.

Overview of Accounting Methods

GHG emission accounting for a given source of emissions relies on the application of an emission factor to activity data. In the example below, we use an emission factor for California's average electricity mix to determine the annual GHG emissions associated with an average household's electricity consumption using data from the EPA[51] and EIA:[52]

$$240\ \frac{g\ CO_2e}{kWh} \times 6{,}800\ \frac{kWh}{house} = 1.6 \times 10^6\ \frac{g\ CO_2e}{house}$$

Emissions accounting becomes more complex when an assessment scope includes a diverse set of sources. This is most often seen in GHG emission inventories for agencies, corporations, and jurisdictions (e.g., community, city, county, state, country) where entities must account for a wide range of sectors (e.g., transportation, energy, agriculture). Each sector has an array of emissions sources with unique variations in emission factors, activity data, and other aspects to consider.

GHG emission profiles can be complex for specific products or resources, when a scope may consider elements outside of product use, such as emissions from supply chains, co-products, and disposal. For example, California's LCFS relies on a lifecycle assessment approach for estimating carbon intensities of transportation fuels. As a result, LCFS emissions for a specific transportation fuel pathway include all emission sources in the fuel lifecycle from resource extraction to final consumption in a vehicle.

Lifecycle Assessment

California's LCFS, consumption-based inventories, and GHG Protocol's Scope 3 include all GHG emissions from a product or resource's lifecycle. This relies on an approach called lifecycle assessment (LCA). LCA allows for a holistic GHG accounting approach that considers all lifecycle aspects from raw resource extraction to final disposal (i.e., "cradle to grave"). For RNG and transportation fuels, Argonne National Laboratories' GHGs, Regulated Emissions, and Energy Use in Transportation (GREET) model is the most commonly relied on resource.

GHG emission accounting for inventories typically relies on guidance from the Intergovernmental Panel on Climate Change (IPCC) developed in 2006.[53] The IPCC provides guidance for different levels of detail depending on the availability of data and capacity of the inventory team for all sectors typically considered in a GHG inventory. GHG emission reporting programs that address a specific sector or subsector, like the LCFS, may have unique guidelines that diverge from IPCC and typical inventories in accounting methods.

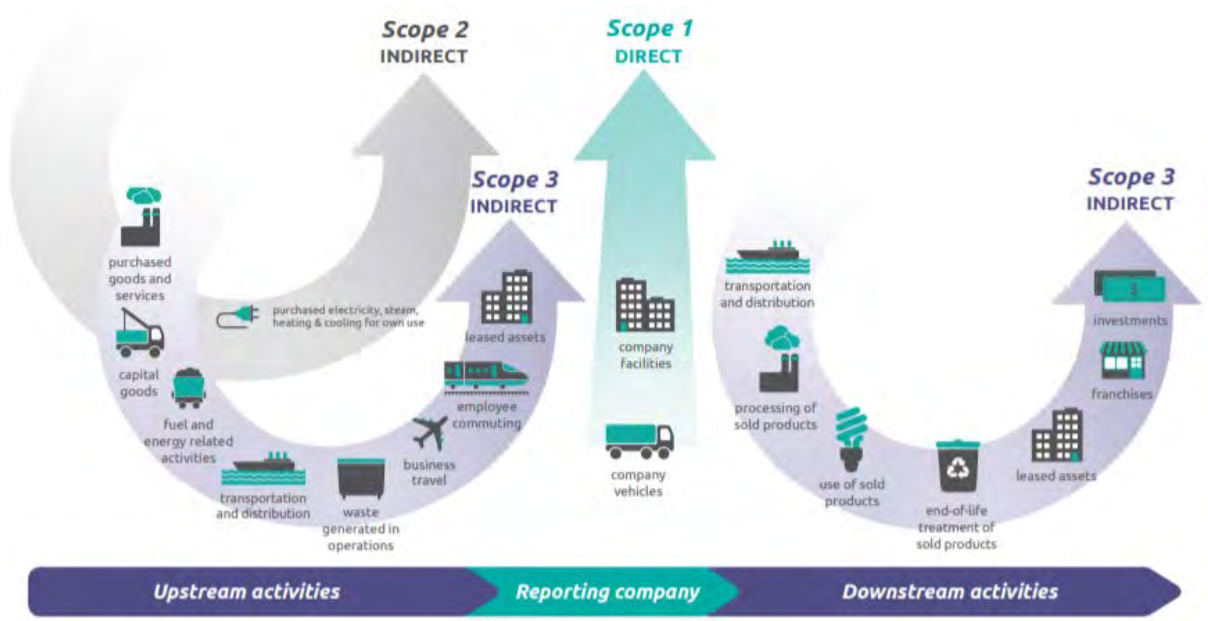
[51] US EPA. 2018. eGRID. Available at: https://www.epa.gov/energy/emissions-generation-resource-integrated-database-egrid.
[52] US EIA. 2009. Household Energy Use in California. Available at: https://www.eia.gov/consumption/residential/reports/2009/state_briefs/pdf/ca.pdf.
[53] IPCC. 2006. 2006 IPCC Guidelines for National Greenhouse Gas Inventories. Available at: https://www.ipcc-nggip.iges.or.jp/public/2006gl/.

Greenhouse Gas Protocol

The GHG Protocol is a commonly used set of reporting standards developed by the World Resources Institute and the World Business Council for Sustainable Development. A GHG Protocol-based approach is most common with corporations, but still incorporates many of the same sources and emission factors used by jurisdictions and public agencies.

The GHG Protocol uses "Scope" levels to define the different sources and activity data included within an assessment. Instead of thinking in terms of geographic or sector-based boundaries, the Protocol groups emissions in direct and indirect categories through these Scopes. Figure 49 shows how the Protocol groups these emission sources by Scopes, and how they relate to an organization's operations.

Figure 49. Scopes for Categorizing Emissions Under the 2019 GHG Protocol



Organizations most often may limit their assessment to Scope 1 and 2 emissions, which includes directly controlled assets. Scope 3 emissions reflect a lifecycle assessment approach that includes supply chain activities and associated, but not directly controlled, organizations.

There is often confusion about who can claim and monetize the environmental benefits of RNG production and consumption across various stakeholders and GHG reporting structures. For example, a corporation based in California buys RNG from a fuel distributor to fuel their fleet of shuttle buses. The RNG was produced out of state and transported and sold in California to take advantage of the LCFS credit program. The value of the LCFS credits are owned and monetized by the various actors within the fuel production supply chain. However, the corporation purchasing the RNG as an end user can still factor in the fuel's low carbon intensity into their corporate emissions accounting by including the volumes purchased in their Scope 1 emissions.

RNG and GHG Accounting

There are two broad methodologies to account for the GHG emissions from RNG: a combustion accounting framework or a lifecycle accounting framework. A combustion GHG accounting framework is the standard approach for most volumetric GHG targets, inventories and mitigation measures (e.g. carbon taxes, cap-and-trade programs and RPS programs) as they are more closely tied to a particular jurisdiction—where the emissions physically occur.

Figure 50 details the differences between the two accounting frameworks relative to RNG production.

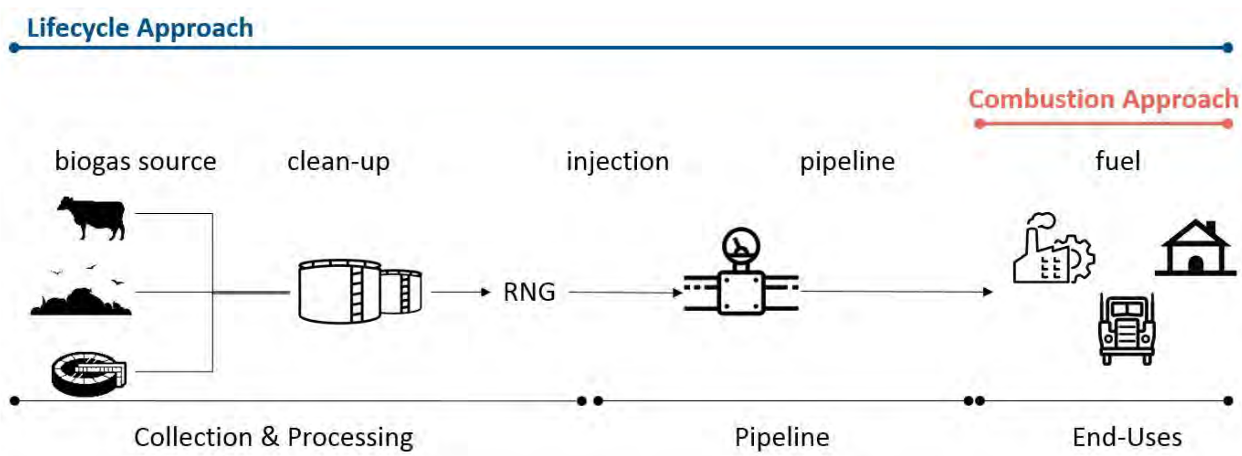
Accounting for Biogenic Emissions

IPCC guidelines state that CO_2 emissions from biogenic fuel sources (e.g., biogas- or biomass-based RNG) should not be included when accounting for emissions in combustion; only CH_4 and N_2O are included.

This is to avoid any upstream "double counting" of CO_2 emissions that occur in the agricultural or land use sectors per IPCC guidance. Other approaches exclude biogenic CO_2 in combustion as it is assumed that the CO_2 sequestered by the biomass during its lifetime offsets combustion CO_2 emissions.

This method of excluding biogenic CO_2 is still commonly practiced for RNG users and producers. For example, LA Metro did not include CO_2 emissions in the combustion of RNG in the agency's most recent CAAP.

Figure 50. GHG Accounting Frameworks for RNG Production



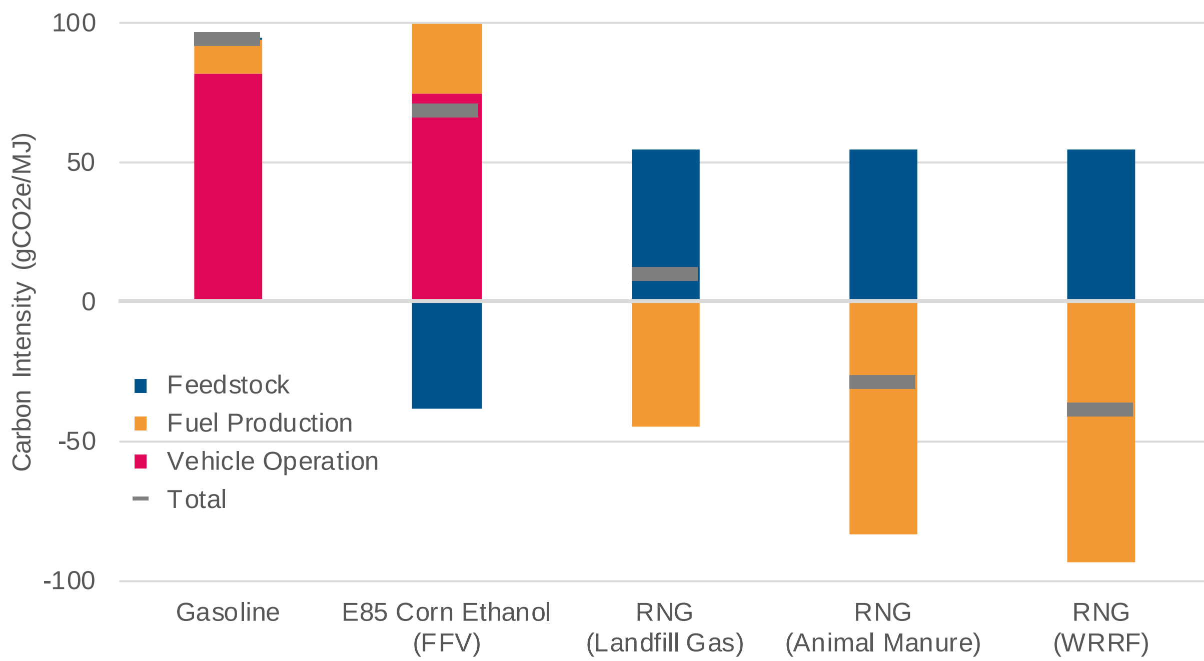
Using the combustion framework, the CO_2 emissions from the combustion of biogenic renewable fuels are considered zero, or carbon neutral. In other words, RNG has a carbon intensity of zero. This includes RNG from any biogenic feedstock, including landfill gas, animal manure, and food waste. Upstream emissions, whether positive (electricity emissions associated with biogas processing) or negative (avoided methane emissions), are not included. RNG procurement strategies do not necessarily need to differentiate RNG by lifecycle carbon intensity, given that RNG in a combustion accounting approach is zero-rated and carbon neutral.

When using a lifecycle accounting methodology RNG's carbon intensity (i.e., GHG emissions per unit of energy) varies substantially between feedstocks and production methods. Carbon intensities can also vary by the location of production and how the fuel is transported and distributed. The GHG accounting methods and scopes previously discussed dictate which of RNG's lifecycle elements are included as a carbon intensity in emissions reporting.

Variations in Production

Figure 51 shows how these different lifecycle elements contribute to RNG's overall carbon intensity for a selection of RNG sources using Argonne's GREET model[54]: landfill gas, animal waste AD, wastewater sludge AD, and MSW AD. We have also included corn ethanol (E85 blend) and gasoline as reference points. Note that in the GREET model, the original sourcing of RNG is considered "fuel production" and not feedstock operations.

Figure 51. Summary of Carbon Intensities for Transportation Fuels Across Lifecycle Stages[55]



The biggest variations in RNG production come from the associated emissions credits from the different RNG sources. For landfill gas, animal waste, and wastewater sources, GREET assigns a significant credit for the reduction in vented and flared methane that would have occurred in absence of the production of RNG.

Depending on the reporting standard and scope, different credits may be included or excluded. The California LCFS has a similar scope in accounting for credits as the GREET results shown above. Other programs or jurisdictional inventories may exclude these credits or incorporate them into other emission sectors.

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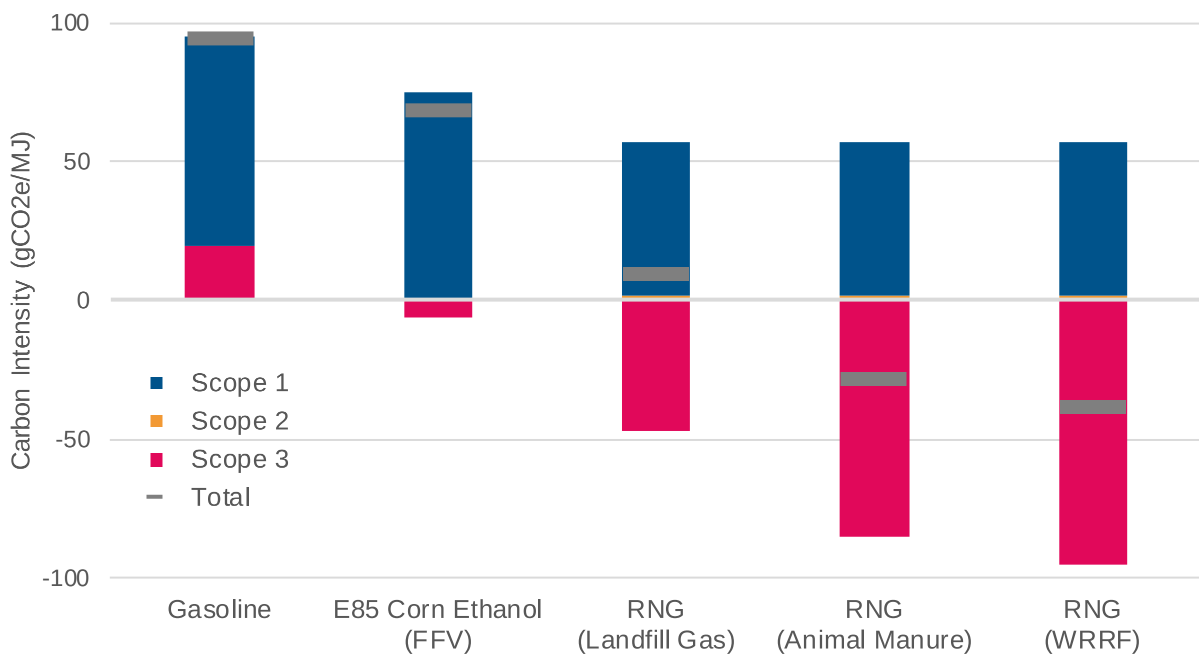
[54] Argonne National Laboratory, 2019. Available at: https://greet.es.anl.gov/
[55] Ibid.

Variations Based on Accounting Method

Figure 52 shows the same GREET results from Figure 51 grouped into the GHG Protocol Scopes. Scope 1 is limited to the tailpipe emissions and Scope 3 includes all aspects of feedstock and fuel production activities. For RNG we have grouped the compression of gas before use into Scope 2, assuming electricity is used in compression.

Figure 52. RNG Lifecycle Carbon Intensity by Different GHG Protocol Scopes Using GREET Results[56]



Many organizations, jurisdictions, and corporations may limit their emissions reporting to just Scope 1 and Scope 2 emissions, which reflect a production or activity-based accounting approach. Some programs, like the LCFS, include all GHG Protocol Scopes with its lifecycle assessment approach. This means that if Scope 3 or lifecycle emission are excluded in reporting, the potential emission benefits of RNG will not be attributed to that reporting organization. A jurisdiction or organization using a consumption-based approach, or including Scope 3 emissions, would report a lower or negative carbon intensity for RNG, depending on the feedstock.

For example, the Los Angeles County Metropolitan Transportation Authority (LA Metro) is working to shift its entire directly operated bus fleet to RNG as soon as possible. Many of the potential RNG feedstocks that LA Metro may use have a negative carbon intensity under the emissions scope of the LCFS (e.g., animal waste, wastewater anaerobic digestion pathways). However, LA Metro's recent Climate Action and Adaptation Plan[57] included only Scope 1 and 2 emissions, which meant that RNG had net positive emissions from compression and combustion regardless of the feedstock.

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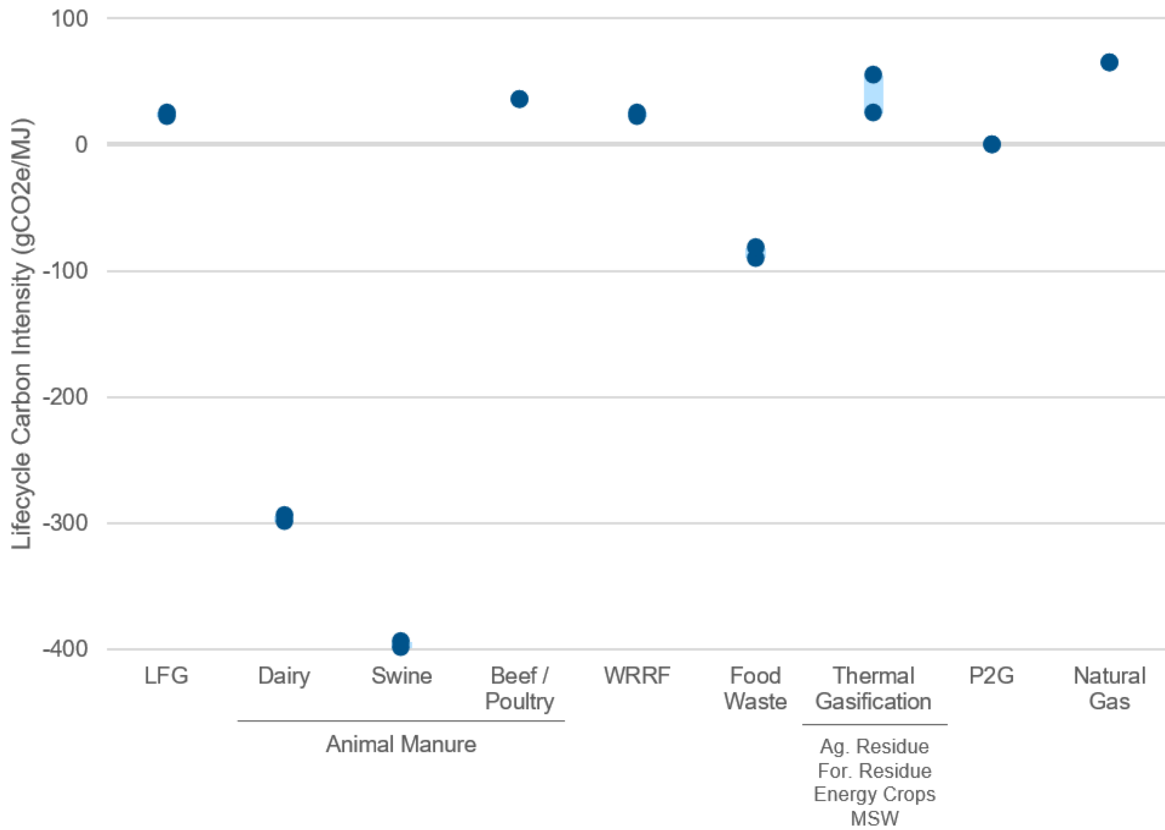
[56] GHG Protocol, 2019. Guidance. Available at: https://ghgprotocol.org/guidance-0
[57] LA Metro, 2019 https://media.metro.net/projects_studies/sustainability/images/Climate_Action_Plan.pdf

Approach to RNG GHG Emission Factors

As noted in more detail in the previous sub-section, the GHG emissions associated with the production of RNG vary depending on a number of factors including the feedstock type, collection and processing practices, and the type and efficiency of biogas upgrading. For the purposes of this report, ICF determined the lifecycle carbon intensity (CI) of RNG up to the point of pipeline injection. This includes feedstock transport and handling, gas processing, and any credits for the reduction of flaring or venting methane that would have occurred in absence of the RNG fuel production.

Figure 53 and Table 40 present ranges of lifecycle CIs for different RNG feedstocks up to the point of pipeline injection. These estimates are primarily based on a combination of Argonne National Laboratory's GREET model, California Air Resources Board's modified California GREET model,[58] and ICF analysis.

Figure 53. Lifecycle GHG Emission Factor Ranges for RNG Feedstocks, South Atlantic Region



[58] ARB, 2019. https://ww3.arb.ca.gov/fuels/lcfs/ca-greet/ca-greet.htm

Table 40. Lifecycle GHG Emission Factor Ranges for RNG Feedstocks by Region, gCO_2e/MJ

Fuel	New England	Mid-Atlantic	East North Central	West North Central	East South Central	West South Central	Mountain	Pacific
LFG	18 – 26	15 – 21	28 – 34	28 – 32	26 – 28	26 – 31	21 – 32	13 – 29
Animal Manure								
Dairy	-304 – -294	-308 – -300	-292 – -285	-292 – -286	-294 – -292	-294 – -288	-300 – -286	-310 – -290
Swine	-404 – -394	-408 – -400	-392 – -385	-392 – -386	-394 – -392	-394 – -388	-400 – -386	-410 – -390
Beef/Poultry	36 – 36	31 – 31	46 – 46	44 – 44	38 – 38	42 – 42	44 – 44	41 – 41
WRRF	18 – 26	15 – 21	28 – 34	28 – 32	26 – 28	26 – 31	21 – 32	13 – 29
Food Waste	-97 – -82	-104 – -91	-79 – -68	-79 – -70	-83 – -79	-83 – -73	-91 – -70	-108 – -76
Agricultural Res.	25 – 55	25 – 55	25 – 55	25 – 55	25 – 55	25 – 55	25 – 55	25 – 55
Forestry Res.	25 – 55	25 – 55	25 – 55	25 – 55	25 – 55	25 – 55	25 – 55	25 – 55
Energy Crops	25 – 55	25 – 55	25 – 55	25 – 55	25 – 55	25 – 55	25 – 55	25 – 55
MSW	25 – 55	25 – 55	25 – 55	25 – 55	25 – 55	25 – 55	25 – 55	25 – 55
P2G	0	0	0	0	0	0	0	0
Natural Gas	65	65	65	65	65	65	65	65

ICF notes the following about these emission factors:

- The lowest carbon intensities are from feedstocks that prevent the release of fugitive methane, such as the collection and processing of dairy cow manure.
- RNG from WRRFs has the same CI range as landfill gas because both feedstocks start with raw biogas that is processed by the same type of gas upgrading equipment.
- Agricultural residue, energy crops, forestry products and forestry residues, as well as MSW all have the same CI range based on the thermal gasification process required to create biogas from woody biomass. This is an energy-intensive process, but inclusion of renewables and co-produced electricity on-site can reduce the emissions impact of gas production.

After the point of injection, RNG is transported through pipelines for distribution to end users. The CI of pipeline transmission depends on the distance between the gas upgrading facility and end use. The GREET model applies 5.8 grams of CO_2e per MMBtu-mile of gas transported as the pipeline transmissions CI factor. If the gas will be used in the transportation sector, and therefore requires compression, another 3–4 gCO_2e is added onto the CI. For reference, the tailpipe emissions of use in a heavy-duty truck are around 60 gCO_2e/MJ.

GHG Cost-Effectiveness

The GHG cost-effectiveness is reported on a dollar-per-ton basis and is calculated as the difference between the emissions attributable to RNG and fossil natural gas. For this report, ICF followed IPCC guidelines and does not include biogenic emissions of CO_2 from RNG. The cost-effectiveness calculation is simply as follows:

$$\Delta(RNG_{cost}, Fossil\ NG_{cost})\Big/_{0.05306\ MT\ CO_{2e}}$$

where the RNG_{cost} is simply the cost from the estimates reported previously. For the purposes of this report, we use a fossil natural gas price equal to the average Henry Hub spot price reported by the EIA in the 2019 Annual Energy Outlook, calculated as $3.89/MMBtu.

In other words, the front end of the supply-cost curve is showing RNG of just under $7/MMBtu, which is equivalent to about $55–$60/tCO_2e. As the estimated RNG cost increases to $20/MMBtu, we report an estimated cost-effectiveness of about $300/t$CO_2$e. This range in cost for RNG can be converted to provide an equivalent range for the cost-effectiveness of RNG for GHG emission reductions, in dollars per ton of carbon dioxide equivalent.

Estimating the cost-effectiveness of different GHG emission reduction measures is challenging and results can vary significantly across temporal and geographic considerations. Figure 54 shows a comparison of selected measures across various key studies for specific abatement measures that are likely to be required for economy-wide decarbonization in the 2050 timeframe, including natural gas demand side management (DSM), electrification of certain end uses (including buildings and in the industrial sectors),[59,60] direct air capture (whereby CO_2 is captured directly from the air and a concentrated stream is sequestered or used for beneficial purposes),[61] carbon capture and storage,[62] battery electric trucks (including fuel cell drivetrains),[63] and RNG (from this study).

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[59] Energy Futures Initiative, 2019. Optionality, Flexibility & Innovation: Pathways for Deep Decarbonization in California.

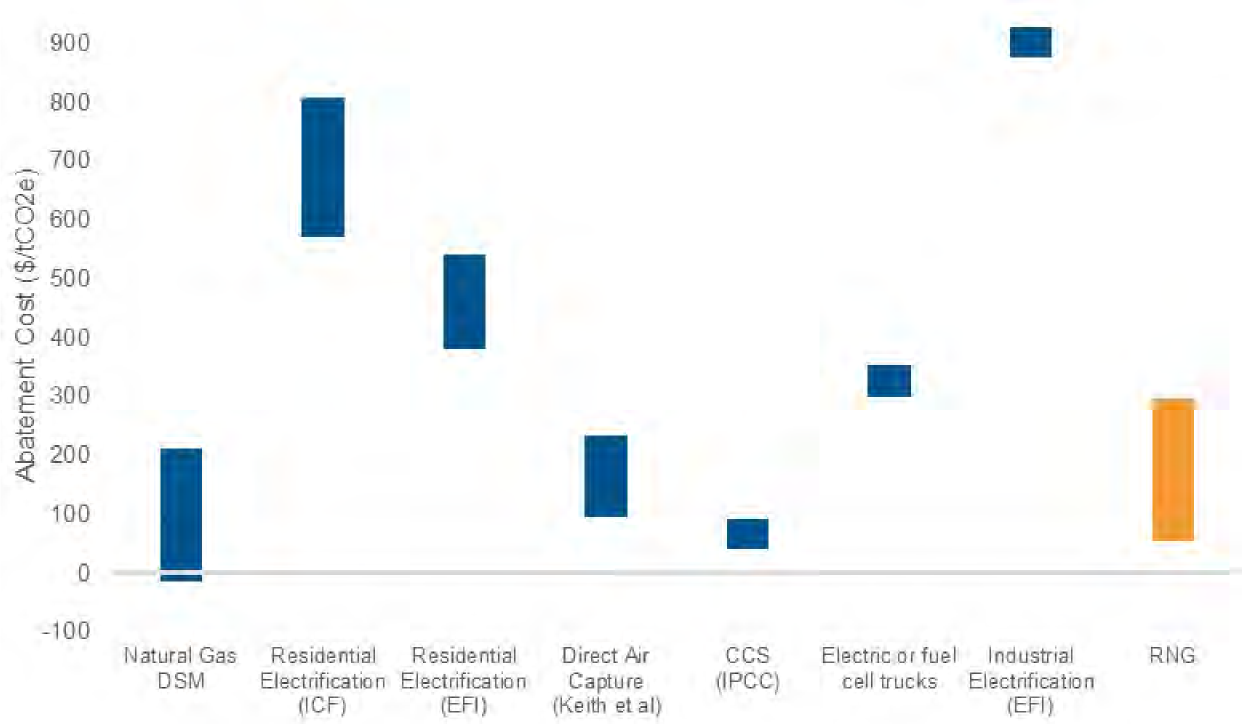
[60] ICF, 2018, Implications of Policy-Driven Residential Electrification, https://www.aga.org/globalassets/research--insights/reports/AGA_Study_On_Residential_Electrification.

[61] Keith, DW; Holmes, G; St Angelo D; Heidel, K; A Process for Capturing CO2 from the Atmosphere, *Joule*, 2 (8), p1573-1594. https://doi.org/10.1016/j.joule.2018.05.006

[62] IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage. Prepared by Working Group III of the Intergovernmental Panel on Climate Change [Metz, B., O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp.

[63] E3, 2018. Deep Decarbonization in a High Renewables Future, https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization_in_a_High_Renewables_Future_CEC-500-2018-012-1.pdf

Figure 54. GHG Abatement Costs, Selected Measures, \$/tCO_2e[64]



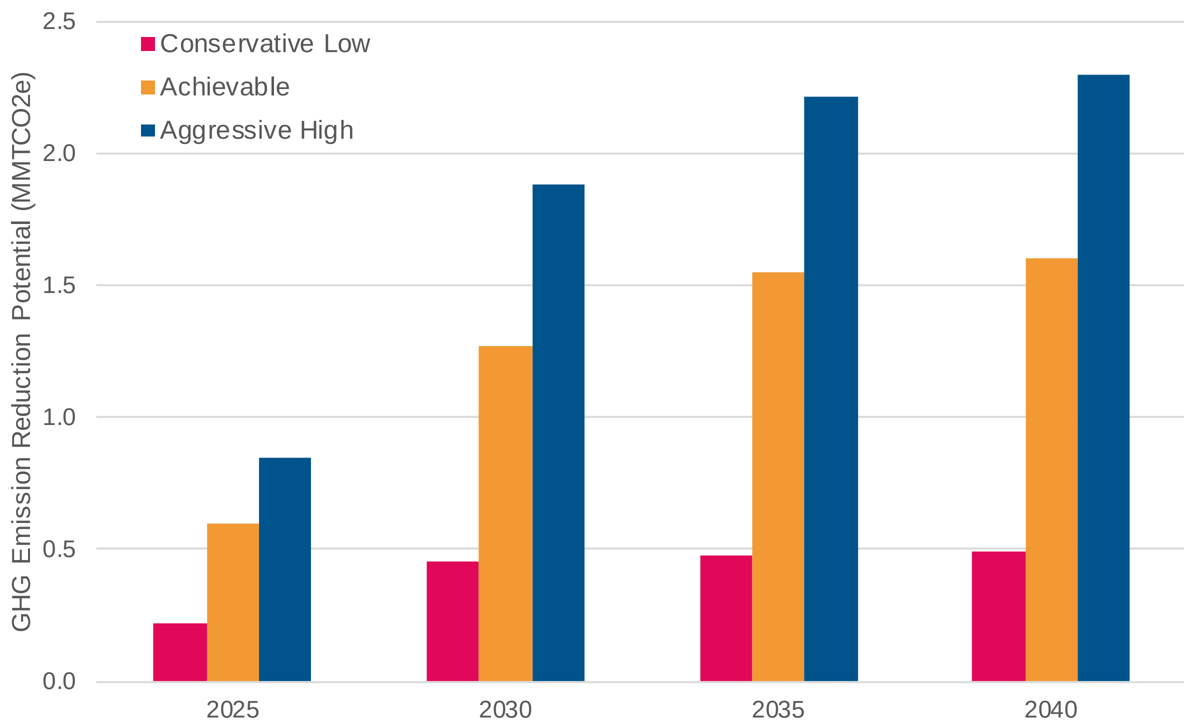
64 Energy Futures Initiative, 2019. Optionality, Flexibility & Innovation: Pathways for Deep Decarbonization in California, https://static1.squarespace.com/static/58ec123cb3db2bd94e057628/t/5ced6fc515fcc0b190b60cd2/1559064542876/EFI_CA_Decarbonization_Full.pdf; E3, 2018. Deep Decarbonization in a High Renewables Future, https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization_in_a_High_Renewables_Future_CEC-500-2018-012-1.pdf

GHG Emissions from RNG Resource Assessment

ICF applied the emission factors from the aforementioned “combustion approach” to estimate the GHG reduction potential across each of the RNG potential scenarios for the Greater Washington, D.C. metropolitan area, the South Atlantic Census region, and nationally, as reported previously in Section 2.

Figures 55, 56 and 57 show the range of GHG emission reductions using a combustion accounting framework, in units of million metric tons of CO_2e ($MMTCO_2e$).

Figure 55. Greater Washington, D.C. RNG Emission Reduction Potential by Scenario, $MMTCO_2e$



ICF estimates that in the Greater Washington, D.C. metropolitan area, 0.5 to 2.3 $MMTCO_2e$ of emissions could be reduced per year by 2040 through the deployment of RNG based on the Conservative Low to Aggressive High Scenarios. ICF estimates that 13 to 44 $MMTCO_2e$ and 100 to 380 $MMTCO_2e$ of emissions could be reduced per year by 2040 in the South Atlantic Region and nationwide, respectively, through the deployment of RNG based on the Conservative Low to Aggressive High Scenarios.

By way of comparison, Washington, D.C.’s total direct GHG emissions in 2017 were 7.3 $MMTCO_2e$,[65] while Greater Washington, D.C. metropolitan area’s population-weighted share of Maryland and Virginia GHG emissions were 34 and 59 $MMTCO_2e$ in 2017 and 2015, respectively.[66]

[65] Washington, D.C. GHG Inventory, 2019. https://doee.dc.gov/service/greenhouse-gas-inventories
[66] Maryland Department of the Environment and Virginia Department of Environmental Quality.

Figure 56. South Atlantic RNG Emission Reduction Potential by Scenario, $MMTCO_2e$

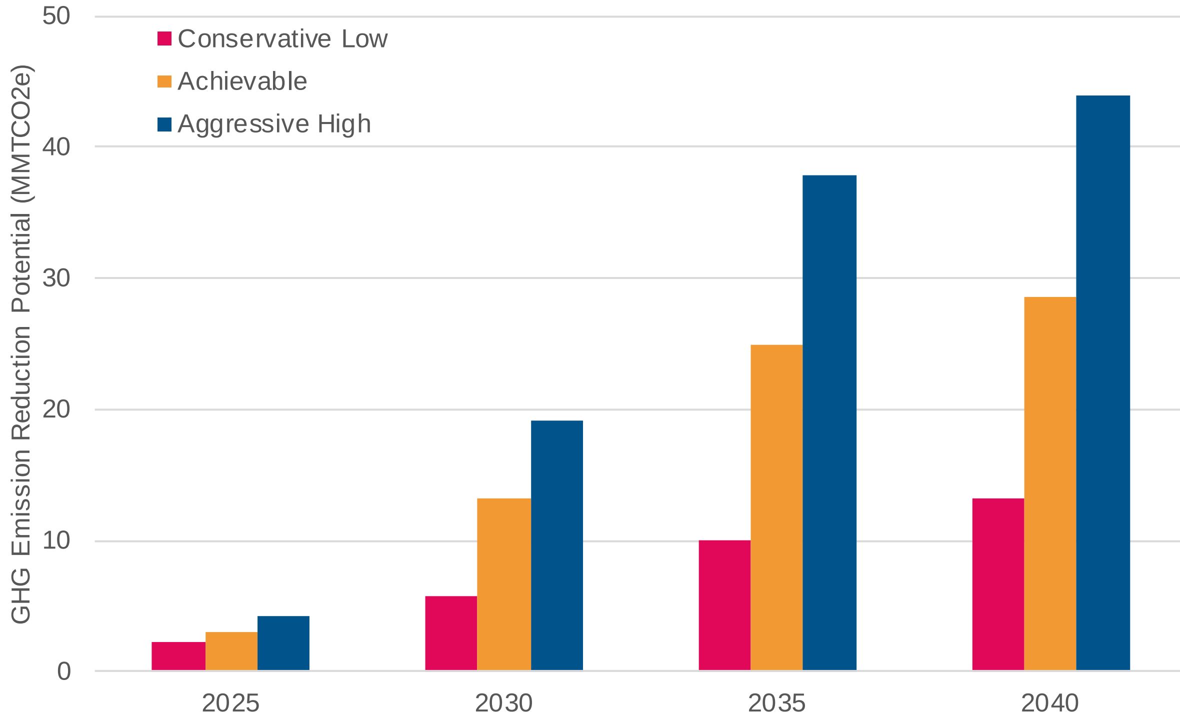
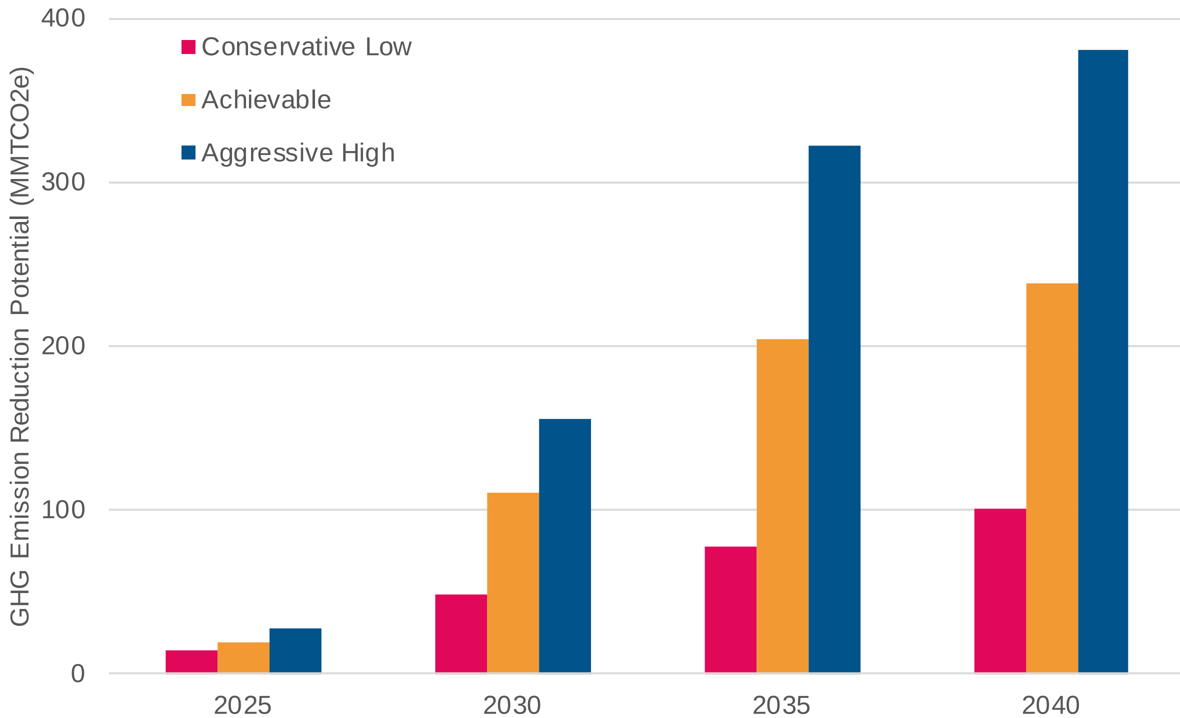


Figure 57. National RNG Emission Reduction Potential by Scenario, $MMTCO_2e$



5. Economic and Market Analyses

Key Takeaways

Historically, anaerobic digestion-based RNG feedstocks have been combusted on-site to generate electricity to comply with various RPS programs nationwide. However, current policies such as the Federal RFS and state LCFS programs favor the direction of RNG consumption into the transportation sector with substantial environmental crediting incentives. Natural gas vehicles (NGVs) can be fueled with RNG with no changes to equipment or performance, with RNG production for use as a transportation fuel increasing nearly six-fold in the last five years

As currently constructed, this policy framework does not encourage RNG use in stationary thermal use applications, such as for building heating and cooling. However, there is growing interest from some policymakers, gas utilities, and industry stakeholders to grow the production of RNG for pipeline injection and stationary end-use consumption. With appropriate incentives that fully capture the environmental benefits of RNG, the end use demand for RNG from stationary thermal applications is substantial, in contrast to the limited demand in the transportation sector.

Assessment of End-Use Markets

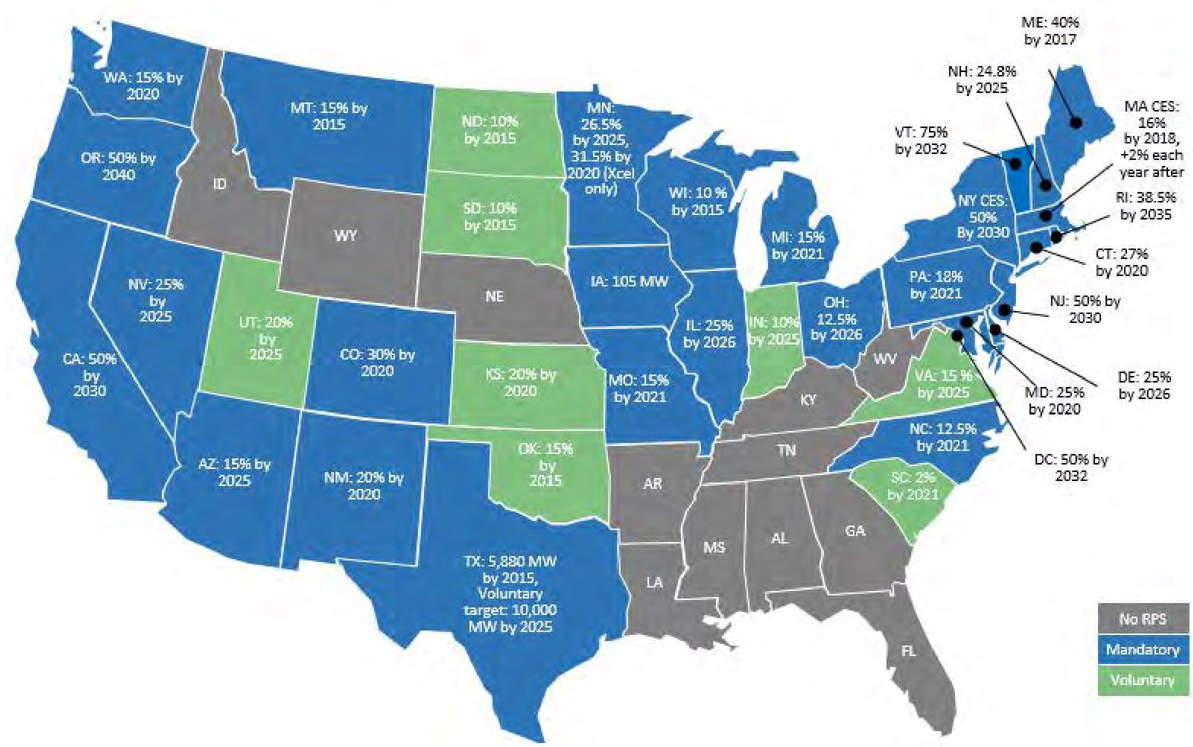
RNG is a pipeline-quality gas that is fully interchangeable with conventional natural gas. As RNG is a “drop-in” replacement for natural gas, it can be safely employed in any end use typically fueled by natural gas, including electricity production, heating and cooling, commercial and industrial applications, and as a transportation fuel. This section discusses the use of RNG for electricity generation, in the transportation market, and for pipeline injection. Interest in RNG has increased considerably over the last several years, especially for use in the transportation sector.

Electricity Generation

Before the recent movement of RNG into the transportation sector, most biogas has been combusted on-site to generate electricity. The renewable electricity is typically used to comply with a Renewable Portfolio Standard (RPS), which requires a certain share of all final end user electricity consumption to come from eligible renewable generation technologies. Twenty-nine states and D.C. have passed mandatory renewable generation requirements or goals and eight more have passed voluntary standards or goals. Most of these programs include landfill gas as an eligible renewable resource, while some also include wastewater treatment plants and anaerobic digestion. Figure 58 shows the RPS requirements across the United States.

The design of each RPS requirement varies by target and timing, type of renewable generation allowed, geographic scope within which a generator might be eligible to meet the standard, enforcement mechanisms, and escape clauses. State RPS programs face a number of near-term changes, two of the largest being the availability of federal tax incentives, namely the Investment Tax Credit and the Production Tax Credit.

Figure 58. Renewable Portfolio Standards



Load-serving entities (LSEs) demonstrate compliance with a state's RPS by retiring Renewable Energy Credits (RECs). One REC is equal to one megawatt-hour of eligible renewable energy generation. RECs can be embedded in contracts for renewable energy or purchased on the open market. If an LSE is unable to acquire the necessary number of RECs, it will have to pay a penalty fee as set by the state. These fees, known as Alternative Compliance Payments (ACPs), act as a ceiling on REC prices.

The history of RECs in the renewable electricity market provides valuable lessons for RNG deployment. Stakeholders contemplated the concept of RECs as California considered an RPS in the mid-1990s, and this continued as multiple utilities and states advanced renewable electricity initiatives. The first retail REC product was sold in 1998.[67] REC markets helped to foster and stimulate growth of renewable power markets, as shown in Figure 59. By 2008, just five years after NREL started tracking renewable power markets in 2003, it was reported that REC markets accounted for nearly 65% of the annual renewable electricity consumed, which was three to four times greater than what was being consumed in utility green pricing programs or in competitive markets. Furthermore, this growth was occurring as the market continued to expand at a compound annual growth rate of 45%.[68,69]

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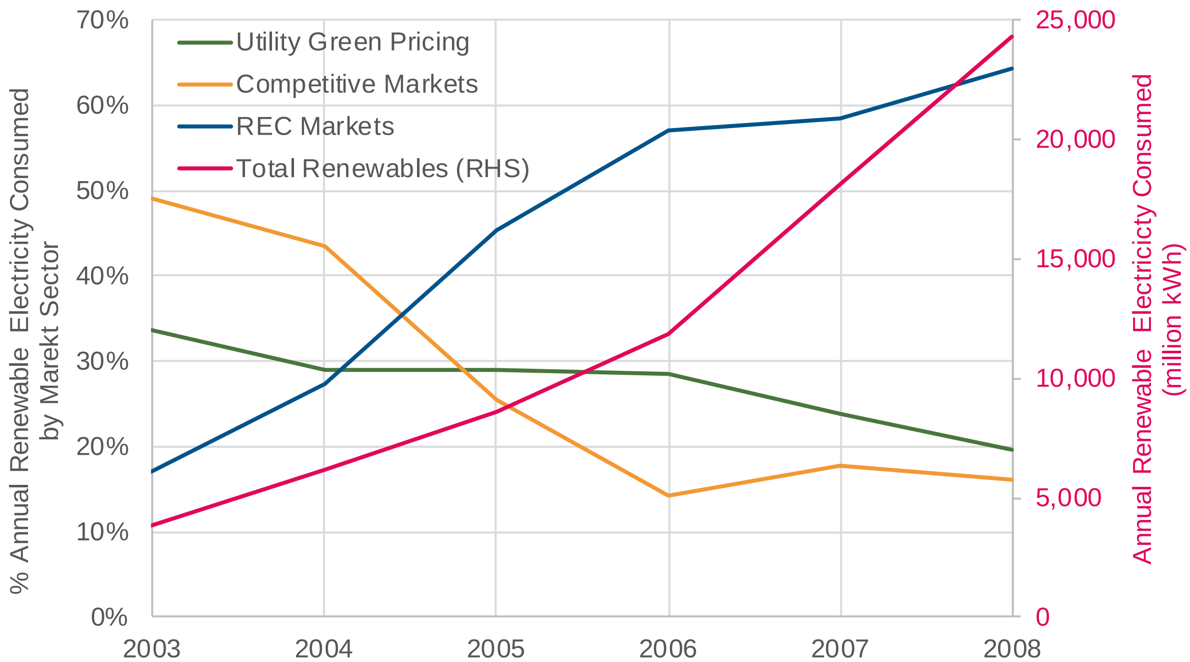
[67] NREL, Emerging Markets for Renewable Energy Certificates: Opportunities and Challenges, January 2005, NREL/TP-620-37388. https://www.nrel.gov/docs/fy05osti/37388.pdf
[68] NREL, Green Power Marketing in the United States: A Status Report (Tenth Edition), December 2007, NREL/TLP-670-42502, https://www.nrel.gov/docs/fy08osti/42502.pdf.
[69] NREL, Green Power Marketing in the United States: A Status Report (2008 Data), September 2009, NREL/TLP-6A2-46851, https://www.nrel.gov/docs/fy08osti/42502.pdf.

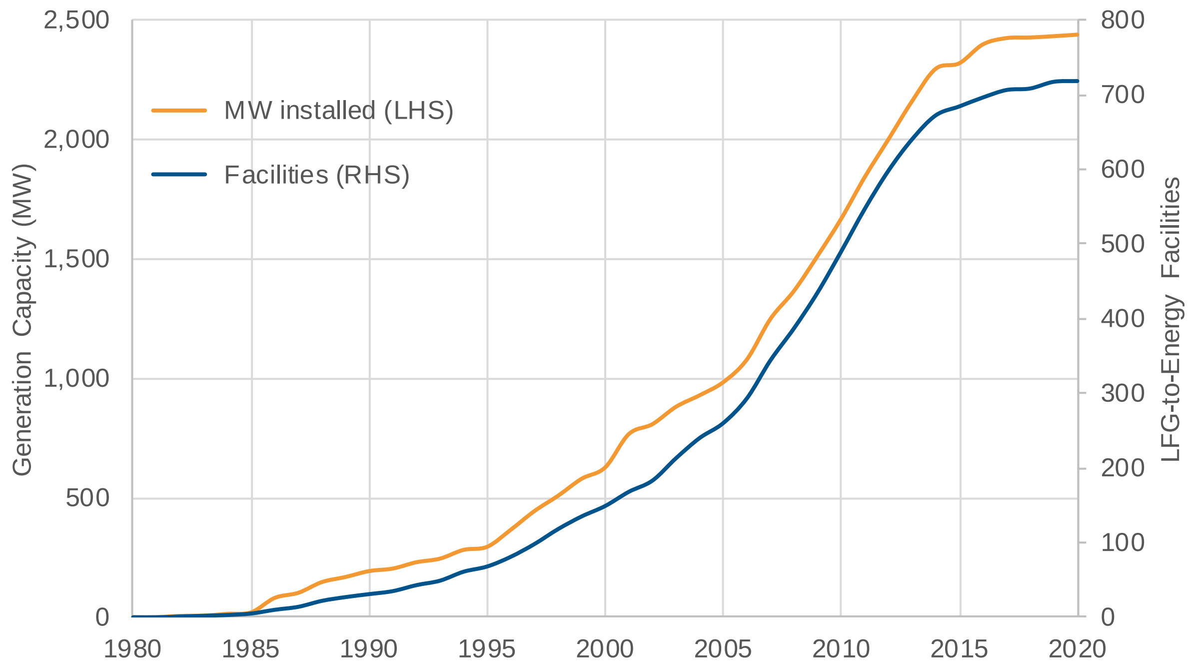
Figure 59. Percent and Total Renewable Electricity Consumption by Market Sector, 2003–2008



A primary feature of RPS policies is the segmentation of the renewable requirements into “Tiers” or “Classes.” These Classes are differentiated by eligibility criteria, which may include technology type, geography, or vintage. RPS Classes may also represent “carve-out” requirements, which require that a subset of the overall RPS target come from a specific technology, such as Landfill Gas or Anaerobic Digestion.

Landfill gas plays a substantive role in many RPS programs. The EPA database of Landfill Gas Energy Projects indicates that there are currently more than 450 operational LFG-to-electricity projects with a capacity exceeding 2,000 MW—see Figure 60. There has been a noticeable decrease in the rate of installed capacity and facilities since 2014. For instance, for the years 2005–2014, an average of 26 new facilities were brought online annually with installed capacity of 318 MW annually. This has decreased to just 4–5 facilities annually over the last four years, with an installed capacity of just 25 MW annually. This is likely due to the availability of RINs and, to a lesser extent, LCFS credits. ICF anticipates this trend to continue plateauing for LFG-to-electricity projects as investors seek out higher value in the LCFS and RIN markets.

Figure 60. Facilities and Installed Capacity of LFG-to-Electricity Facilities[70]



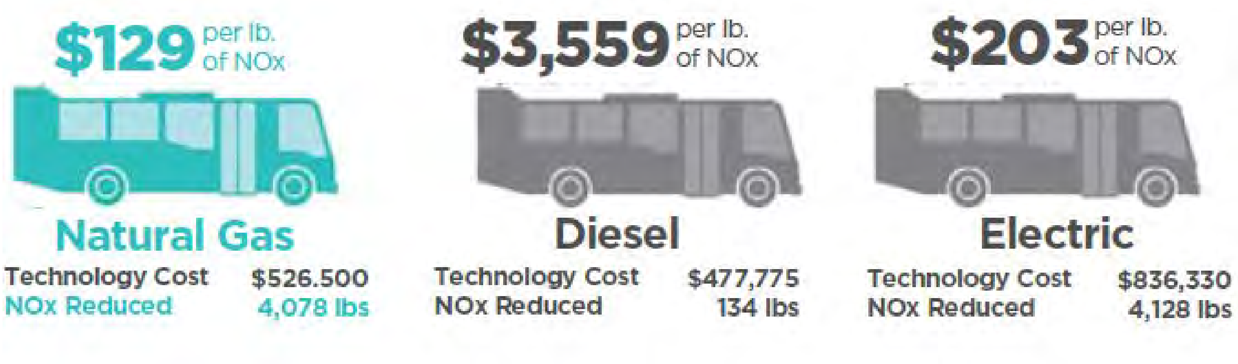
Transportation

NGVs consume natural gas as compressed natural gas (CNG) or liquefied natural gas (LNG). Natural gas as a transportation fuel is primarily used in transit buses and fleet applications (including refuse haulers and over-the-road trucks), with over 175,000 NGVs on U.S. roads today. The more recent expansion of natural gas use in transportation is typically linked to goods movement and regional or short haul applications operating at or near port facilities.

NGVs are the most cost-effective vehicle technology to reduce local air pollutants and smog from heavy-duty trucks and buses. The latest commercially available natural gas engines are 90% cleaner than the EPA's current NOx emissions requirement, and 90% cleaner than the cleanest diesel engine.[71] Figure 61 shows NGV America's comparison of NOx emission reduction costs over the lifetime of different bus technologies and fuels.[72]

[70] ICF Analysis of LMOP Database.
[71] EPA and California Air Resources Board, 2018.
[72] NGV America, 2019. NGV Transit Buses, https://www.ngvamerica.org/wp-content/uploads/2018/12/NGV-VW-Transit-Buses.pdf

Figure 61. Comparison of NOx Emission Reduction Costs by Vehicle Technology



In addition, NGVs can be fueled with RNG with no changes to equipment or adverse impacts on performance. Over the last five years, RNG production for use as a transportation fuel has increased nearly six-fold, with a third of all NGV fuel use relying on RNG in 2018.[73] This rise in RNG consumption in NGVs has been largely driven by the environmental crediting incentives provided by the federal RFS and carbon constraining policies like California's LCFS and Oregon's CFP, discussed in more detail below.

RFS Program and RIN Prices

The RFS program sets volumetric targets for blending biofuels into transportation fuels across the entire United States—compliance is tracked through the production and retirement of Renewable Identification Numbers (RINs).[74] In most cases, a RIN is generally reported as an ethanol gallon equivalent. In 2013, the EPA determined that RNG qualified as an eligible fuel and could generate 'D3' RINs, with landfill RNG qualifying after meeting cellulosic content and GHG reduction thresholds. This led to a rapid expansion of RNG projects for pipeline injection and subsequent RNG use as a transportation fuel in NGVs.

In 2017, nearly 300 million RINs were generated by RNG projects domestically, with the RINs valued at approximately $2.50–$3.00 each, the equivalent of $29–$35/MMBtu of RNG. In 2018, these RINs traded lower along with other categories of RINs, but remained more resilient than other categories with a range of $2.00–$2.60 per RIN ($23–$30/MMBtu).

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[73] NGV America, 2019. https://www.ngvamerica.org/wp-content/uploads/2019/04/RNG-Driving-Down-Emissions.pdf

[74] The RFS has four nested categories of fuels: renewable biofuels, advanced biofuels, biomass-based diesel and cellulosic biofuels, which are each represented by a different RIN type. RINs are the tradeable commodity in the RFS, with most RINs equivalent to one gallon of ethanol. RNG is eligible to generate D3 RINs, representing the cellulosic biofuel category, with one MMBtu of RNG equivalent to 11.67 gallons of ethanol (or RINs) based on energy density.

In 2019, the D3 RIN price was at historically low levels, around $0.60 per RIN, equivalent to roughly $7/MMBtu. ICF analysis for 2020 suggests that D3 RIN prices should increase to around $1.80–$2.00, based on RFS program fundamentals that reflect supply and demand for D3 RINs, gasoline pricing, and RNG production economics. However, as the EPA under the current administration has increasingly exempted volumes from the federal RFS, the D3 RIN price had collapsed.[75]

ICF modeled a D3 RIN price forecast based on three scenarios:

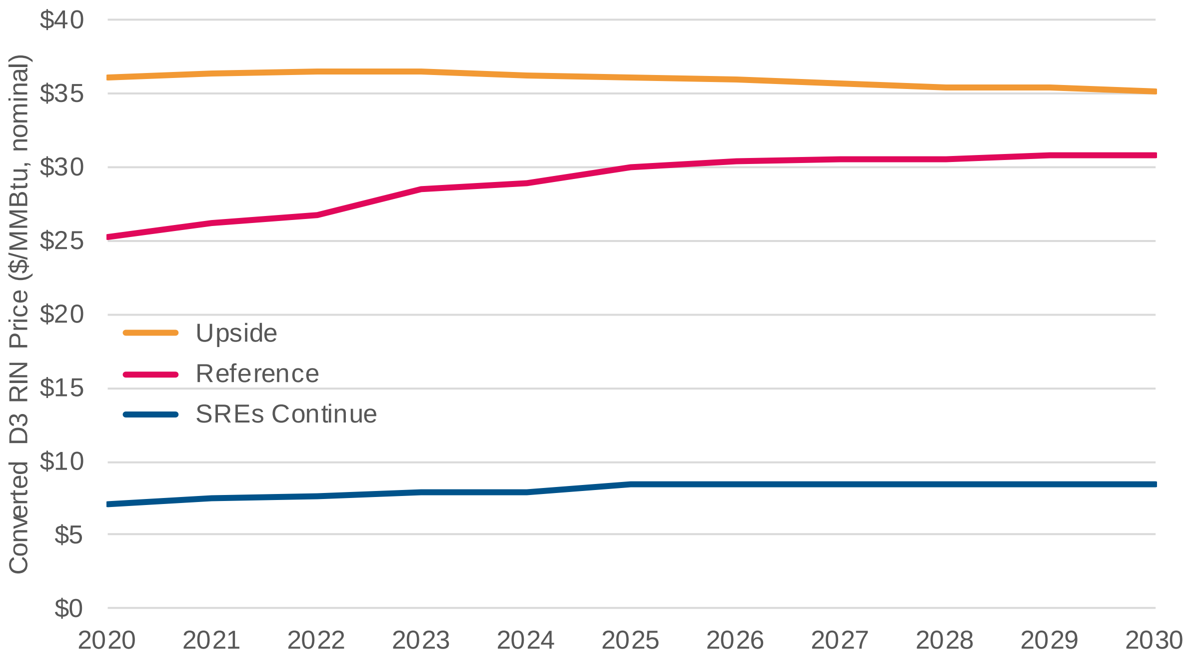
- The **SREs Continue Case** includes assumptions that the EPA under the current administration will continue to issue SREs at a rate similar to what has been observed over the last 2–3 years, with about 10% of the RVOs exempted as a result of EPA granting hardship waivers.
- In the **Reference Case**, ICF's modeling reflects internal estimates for gasoline pricing to estimate the value of the cellulosic waiver credit (CWC) annually (adjusted for inflation, per the regulation), the anticipated outcome of using biodiesel as the marginal unit of compliance—including factoring in limitations on cheaper imports from Argentina and Indonesia—and we estimate a likely discount of D3 RIN pricing relative to the sum of the CWC and the D5 RIN price.
- In the **Upside Case**, ICF assumed that RNG production economics would drive D3 RIN pricing as the marginal unit of compliance in the absence of a CWC. This assumption is a proxy for a more conservative set of RVOs being established moving forward as part of a programmatic reset. Note that in a reset scenario, in which EPA revises the cellulosic biofuel targets to a lower level, EPA will no longer need to use its Cellulosic Waiver authority, and thus will not issue CWCs. CWCs act as a floor on prices. With the cap removed, D3 RINs will price to the marginal unit of production. ICF assumes that RVOs will still increase with supply (consistent with legal interpretation of the RFS[76]), thereby linking D3 RIN pricing to the marginal unit of RNG supply. In our modeling, these economics are driven by a combination of liquid cellulosic biofuel production and RNG production from the anaerobic digestion of animal manure. In either case, the production economics drive RIN pricing higher.

Figure 62 includes the forecasted pricing for D3 RINs to 2030 for the three cases considered outlined above. These forecasts are reflected as annual averages, and do not necessarily account for the price variation that might be observed throughout a given year.

[75] Small refiners (i.e., those with an average annual crude oil input less than 75,000 barrels per day) are allowed to petition the U.S. EPA for an economic hardship waiver from their obligations under the federal RFS—these are referred to as small refinery exemptions (SREs). The rate of SREs submitted and granted have more than quadrupled under the Trump Administration, undercutting the renewable volume obligations (RVO) annually by about 10%. As a result of these exemptions, the D3 RIN market has been significantly over-supplied, and prices have collapsed.

[76] In 2015, the Court of Appeals for the District of Columbia ruled that the so-called "inadequate domestic supply" provision in the Energy and Information Security Act "does not allow EPA to consider the volume of renewable fuel that is available to ultimate consumers or the demand-side constraints that affect the consumption of renewable fuel by consumers."

Figure 62. Forecasted D3 RIN Pricing, 2019–2030, $/D3 RIN, nominal[77]



California LCFS Program and Credit Prices

In California, carbon emissions are constrained based on a combination of California's Cap-and-Trade program and complementary measures, such as the LCFS program. The LCFS program targets the GHG emissions from transportation fuels. Low carbon fuels—such as ethanol, biodiesel, renewable diesel, and RNG—that are deployed in California have the potential to earn LCFS credits in the state-level LCFS program as well as RINs in the federal RFS program. Fuel providers are able to generate value in both the LCFS and the RFS programs by rule. The programs are implemented by tracking two different environmental attributes: the state-level LCFS program enables fuel providers to monetize the GHG reductions attributable to the fuel, whereas the federal-level RFS program monetizes the volumetric unit of the renewable fuel. This ability to "stack" environmental credits has led to significant increases in the volume of biodiesel, renewable diesel, and RNG consumption in California.

ICF estimates that 65–70% of the 30–35 BCF (390–450 million diesel gallons) of RNG produced in 2018 was delivered to California, generating both the RINs and the LCFS credits. In 2017, LCFS credits traded for $60–$115/ton, which was equivalent to about $3–$6/MMBtu of RNG from landfills, and $20–38 for animal manure (dairy) RNG. In 2018, prices rose past $150 per ton, and traded up into the low $190s per ton. More recently, throughout 2019 and into 2020, LCFS credits have consistently traded above $190/ton.

Through the end of 2019, the LCFS market operated with a soft cap of $200/ton in 2016 dollars (annually adjusted based on the Consumer Price Index, CPI), which was linked to the Credit Clearance Market. ICF generally considered this a soft cap as there was no language in the regulation that precluded parties from buying credits at a value higher than the $200/ton cap (when adjusted for inflation). Rather, the $200/ton was used as the maximum price that parties

[77] Note: D3 RIN price in dollars per gallon of ethanol converted to dollars per MMBtu.

can set when selling credits into the Clearance Market. Because the Credit Clearance Market exposed regulated parties as not being able to fulfill their credit obligations in the program, ICF considered it likely that some parties would have preferred to avoid the public process that defined the Clearance Market and pay a premium in a bilateral transaction.

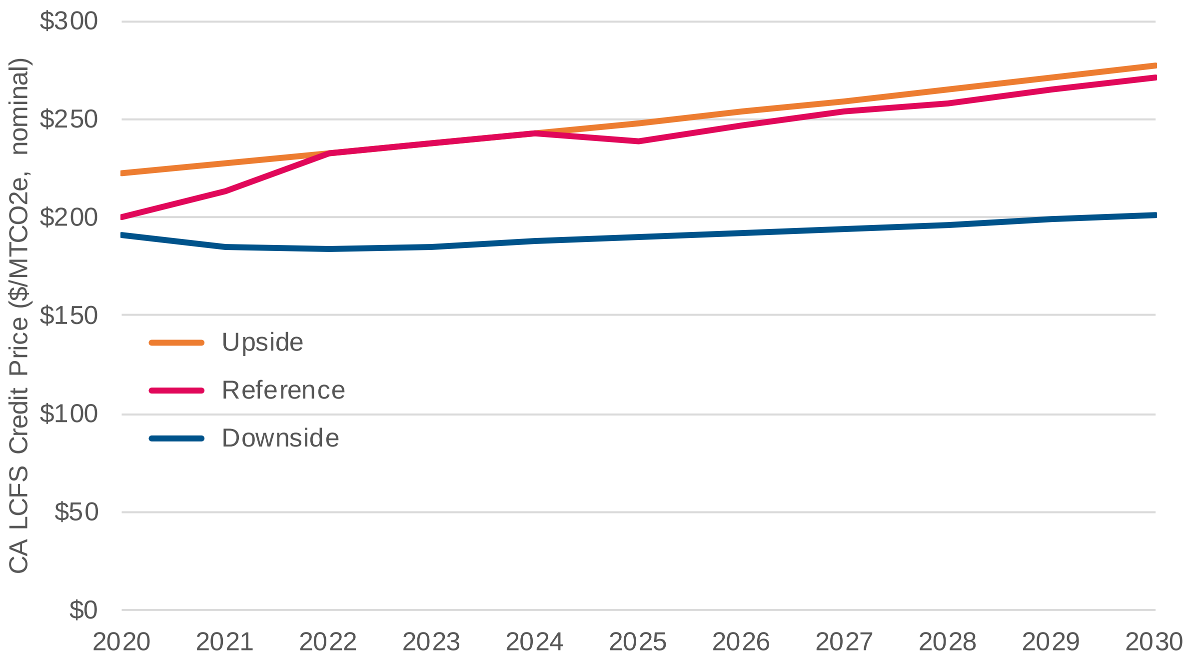
In late 2019, however, CARB considered and adopted a maximum tradeable price for LCFS credits equivalent to the value of credits established in the Credit Clearance Market—equal to $200/ton in 2016 dollars and adjusted for inflation. This went into effect January 1, 2020. This change has transitioned the program to a hard cap. In ICF's view, there are limited ways that regulated parties could avoid the hard cap and pay a higher price—ICF anticipates that this would require paying a higher price on the physical fuel (e.g., ethanol) being purchased by a regulated party. ICF considers this possible, but unlikely given the risk of drawing the ire of CARB for circumventing the intended cap on credit prices.

ICF conducts forecasting of California LCFS credit prices using an optimization model that considers compliance strategies based on parameters including alternative fuel production costs, fuel supply chains (to California), interactions between programs, alternative fuel pricing, gasoline and diesel pricing, and GHG abatement potential. To do the price forecasting, ICF modeled three cases:

- **Reference Case:** reflects best estimates of the supply, demand, costs, and corresponding constraints of the various compliance pathways in the LCFS program.
- **Upside Case:** assumed more constrained availability of liquid fuels, slower transition to electrification in the light-duty sector, and modest expansion of natural gas as a transportation fuel.
- **Downside Case:** higher penetration of low carbon fuels in the biofuel blending and vehicle replacement buckets. This scenario is designed to represent lower-cost biofuel blending, a faster transition to transportation electrification, and has higher penetration of natural gas as a transportation fuel, which decreases credit prices.

Figure 63 summarizes the derived LCFS credit prices for the various scenarios considered in this analysis. As noted for ICF's RIN forecasts, these forecasts are reflected as annual averages, and do not necessarily account for the price variation that might be observed throughout a given year.

Figure 63. Forecasted CA LCFS Credit Prices, 2019–2030, \$/MTCO$_2$e, Nominal



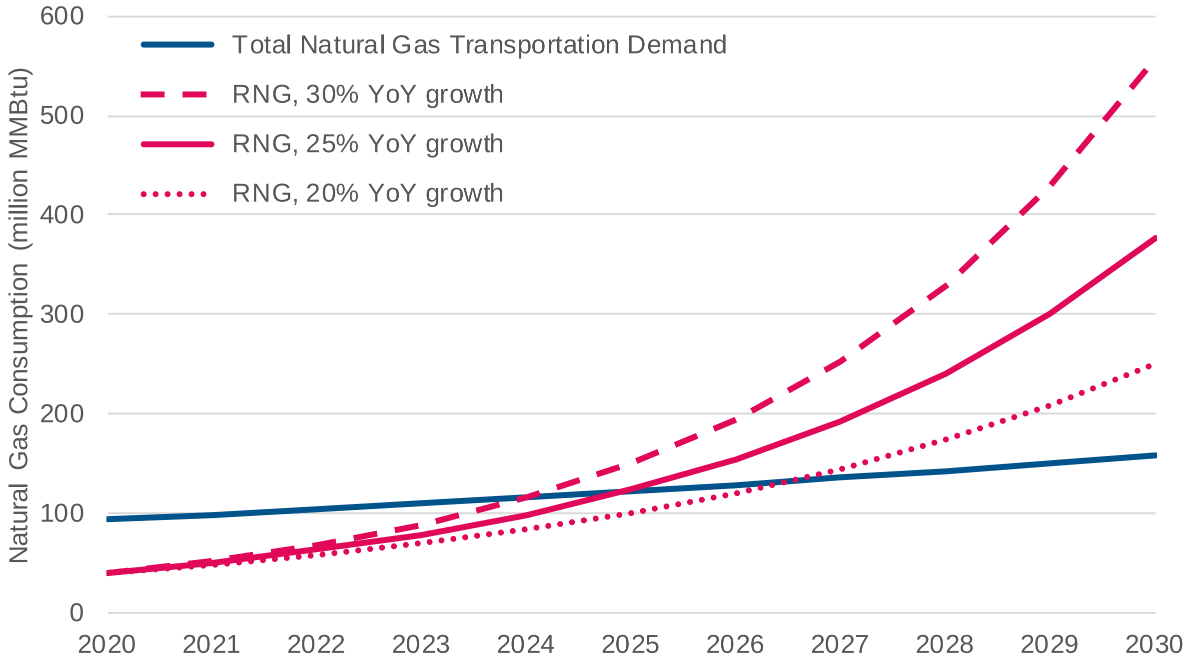
RNG Consumption in Transportation

The chart below shows ICF's estimates for total natural gas consumption as a transportation fuel in the U.S. and forecasted RNG production capacity. These estimates are based on a combination of national-level data from the EIA, California-specific data reported via the LCFS program, and ICF's analysis of potential RNG projects. In this scenario, we assume a growth rate of natural gas at about 5% year-over-year out to 2030. For RNG, we show year-over-year growth between 20% and 30% out to 2030.

Figure 64 helps demonstrate the potential for suturing the demand for natural gas as a transportation fuel with RNG production in the 2024–2027 timeline. This rising RNG consumption in the transportation sector is shown by the largest RNG procurement agreement between Clean Energy and logistics company UPS, where UPS will fuel its CNG vehicle fleet with RNG.[78]

[78] GreenBiz, 2019. 'UPS to buy huge amount of renewable natural gas to power its truck fleet', https://www.greenbiz.com/article/ups-buy-huge-amount-renewable-natural-gas-power-its-truck-fleet

Figure 64. Natural Gas as a Transportation Fuel



Most of the RNG that is currently delivered to and dispensed in California is derived from landfills. ICF anticipates a shift towards lower carbon intensity RNG from feedstocks such as the anaerobic digestion of animal manure and digesters deployed at WRRFs. Over time, these lower-carbon sources will likely displace higher-carbon intensity RNG from landfills. The role of RNG post-2020 in the LCFS program will be determined by the market for NGVs. If steps are taken to foster adoption of NGVs, particularly in the heavy-duty sector(s), then this will be less of an issue. The introduction of the low-NOx engine (currently available as 9L, 12L, and 6.7L engines) from Cummins may help jumpstart the market, especially with a near-term focus on NOx reductions in the South Coast Air Basin, which is in severe non-attainment for ozone standards.

In an RNG transportation saturation scenario, there are many outcomes—we consider two. In one case, a share of the RIN price would have to be dedicated to inducing demand; in another case, the RIN price would have to go up to reflect the higher cost of dispensing a marginal unit of natural gas (rather than just displacing the fueling of fossil natural gas with renewable natural gas). In other words, there is some cost associated with getting additional supply on the system, and that can come out of either existing RIN pricing or increasing RIN pricing to account for that. To summarize, ICF anticipates that for RNG in the transportation sector to continue growing, market actors must be savvier with respect to pricing the fuel more competitively.

Transportation Demand in the Greater Washington, D.C. Metropolitan Area
Based on vehicle registration from IHS Markit, there are nearly 1,600 CNG vehicles in the Greater Washington, D.C. metropolitan area—including D.C. and surrounding nine counties. Roughly 90% of the vehicles are registered in D.C. (65%), Montgomery County (15%), and Fairfax County (10%). Furthermore, nearly 70% of the CNG vehicles are Class 8 heavy-duty vehicles—primarily transit buses, some refuse hauler fleets, and some heavy-duty trucks.

Table 41. Fleets in Different Vocations Using CNG[79]

Fleets Using CNG	No. of Vehicles	Vocation	Est Annual CNG Consumption (M DGE)
Arlington Regional Transit (updated to 2019 data)	72	Transit & Shuttle	0.70
DC Government	7	Refuse	<0.1
	119	Fleet	
Montgomery County	102	Transit	0.27
Smithsonian	7	Fleet (LD)	<0.1
WG (updated to 2019 data)	131	Dedicated	0.14
	160	Bi-fuel	
Washington Metropolitan Area Transit Authority (WMATA)	461	Transit	4.6

The fleets in Table 41 account for more than 60% of the estimated CNG vehicles in the study area, and about 60% of the estimated 9.1 million diesel gallon equivalents of CNG consumed. The remaining share of CNG vehicles are largely from public and private fleets in the region, including logistics companies.

Figure 65 outlines the fleet make-up of NGVs registered in the Greater Washington, D.C. metropolitan area—including the total number of vehicles registered from each model year (MY) 1992 to 2019. The blue dots represent all CNG vehicles and the orange crosses show the Class 8 heavy-duty CNG vehicles registered in each MY. ICF makes the following observations:

- From 2010 to 2015, CNG vehicle population growth was slow, and was driven largely by light-duty vehicles. This is consistent with other regions that showed low rates of growth in new vehicle sales for fleet applications during this timeframe, as many fleets opted to get more mileage out of existing vehicles as they emerged from the Great Recession.
- As light-duty fleet sales slowed and Honda exited the light-duty CNG vehicle market in 2015, a new trend has emerged from 2016 to the present: Class 8 CNG vehicles are driving growth. Fifty percent of the CNG vehicles on the road are MY 2010 or later, and two-thirds of those are Class 8.
- The shift over the last five years has been even more pronounced: a third of the CNG vehicles on the road are MY 2015 or later, and nearly 85% of those are Class 8 NGVs.
- ICF assumes that most of this recent growth is driven by CNG transit bus purchases and refuse hauler fleet purchases.

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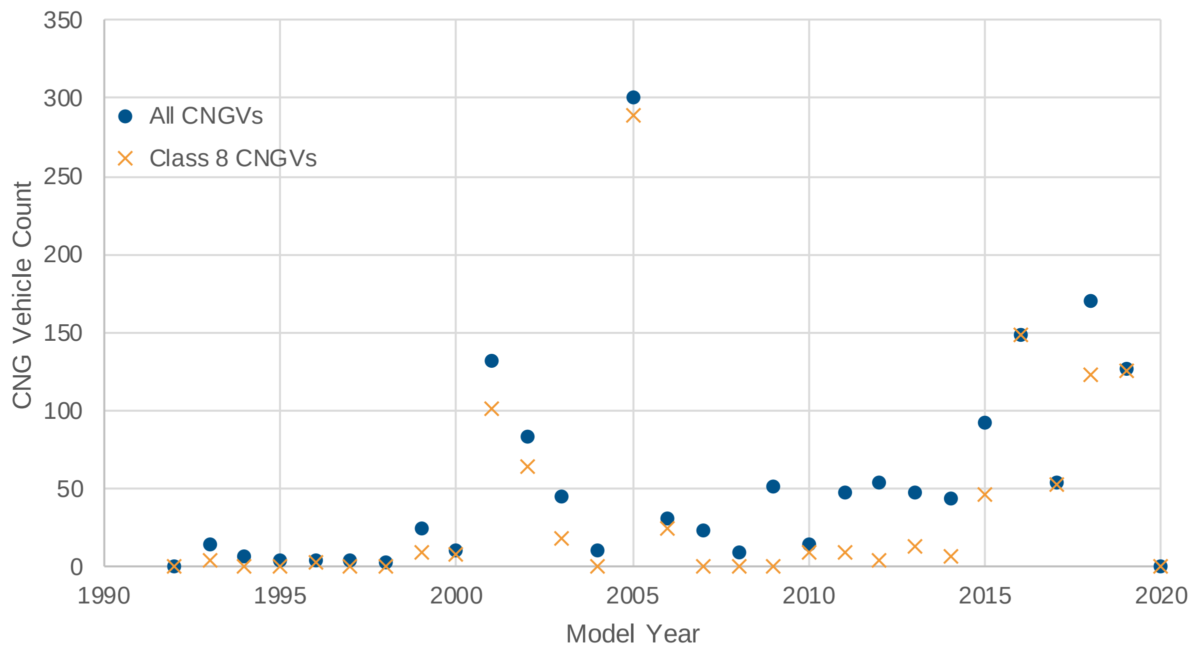
[79] DOE 2017, Greater Washington Region Clean Cities Coalition, 2017 Transportation Technology Deployment Report. Available online at http://www.gwrccc.org/uploads/1/1/9/3/119314124/clean_cities_2017_annual_report_-_dc_-_greater_washington_region_clean_cities_coalition_-_expanded_edition.pdf. Data from 2016 unless otherwise indicated in the table.

- For example, WMATA has a demonstrated commitment to CNG vehicles as part of their overall portfolio, further expanding their CNG vehicle fleet through an order for an additional 75 CNG buses in September 2019.[80]

Figure 65. CNG Vehicle Counts by Model Year in Study Area[81]



Despite its modest demand for natural gas as a transportation fuel, RNG consumption in the transportation sector in the Greater Washington, D.C. metropolitan area appears limited, but with potential for immediate growth. In contrast to other parts of the country, notably California, there is little to no RNG transportation consumption in the region and significant immediate potential for natural gas transportation demand to be supplied by RNG.

ICF estimates that transportation natural gas consumption in the Greater Washington, D.C. metropolitan area is currently about 1.25 bcf per year, and using EIA's 2019 Annual Energy Outlook (AEO), is forecast to grow to over 1.7 bcf by 2030 and nearly 3 bcf in 2050, applying the AEO average annual growth rate of 2.7%.[82] ICF developed a more aggressive growth scenario to reflect the immediate potential of natural gas use in transportation if appropriate policy incentives are implemented and near-term adoption barriers are overcome. In this scenario the growth rate is 5.4% per year out to 2030 and then reduced to 2.7% out to 2050 to moderate year-on-year total growth and reflect the ultimately limited nature of transportation use over the long-term. In this scenario regional transportation demand for natural gas grows to 2.3 bcf in 2030 and 4 bcf in 2050 (see Figure 66–67 and Tables 42–43).

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[80] NGT News, 2019. 'WMATA Places Hefty CNG Bus Order', https://ngtnews.com/washingtons-wmata-places-hefty-cng-bus-order
[81] Based on ICF analysis of vehicle registration data from IHS Markit.
[82] EIA AEO 2019, https://www.eia.gov/outlooks/aeo/

Figure 66. Transportation Natural Gas Demand Moderate Forecast, Greater D.C. Region, tBtu

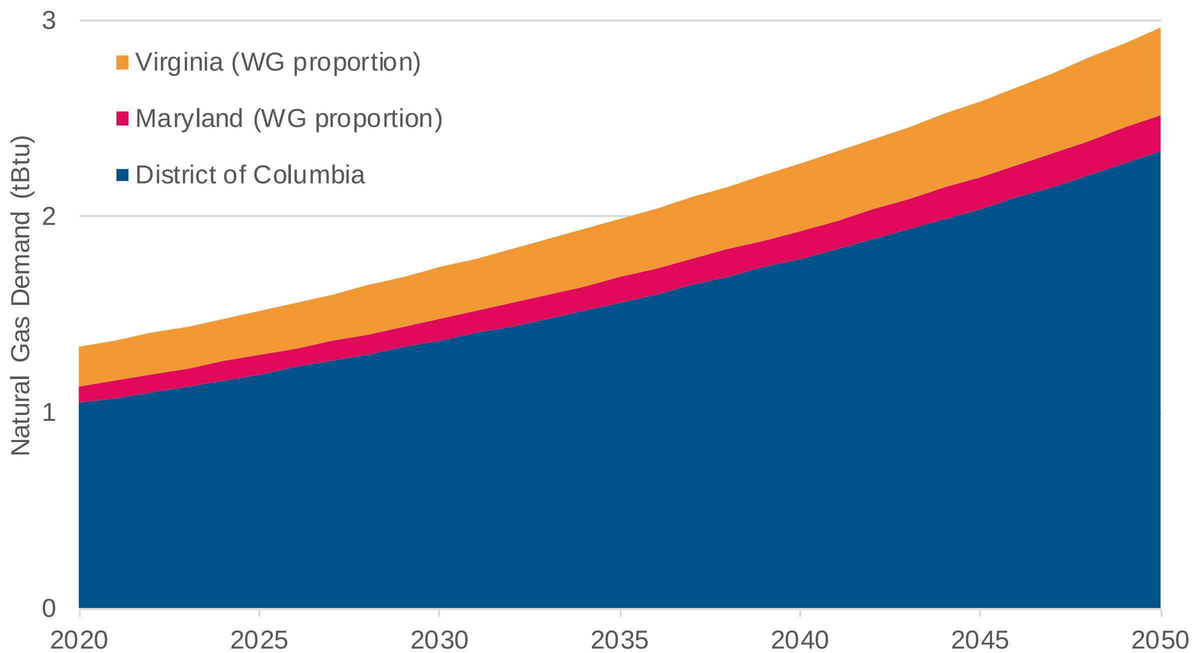


Table 42. Transportation Natural Gas Consumption Moderate Forecast, Dth/day

Dth/day	2020	2030	2040	2050
Greater Washington DC metro	**3,620**	**4,730**	**6,170**	**8,050**
D.C.	2,850	3,720	4,850	6,330
Maryland	230	300	390	510
Virginia	540	710	920	1,200

Figure 67. Transportation Natural Gas Demand Aggressive Forecast, Greater D.C. Region, tBtu

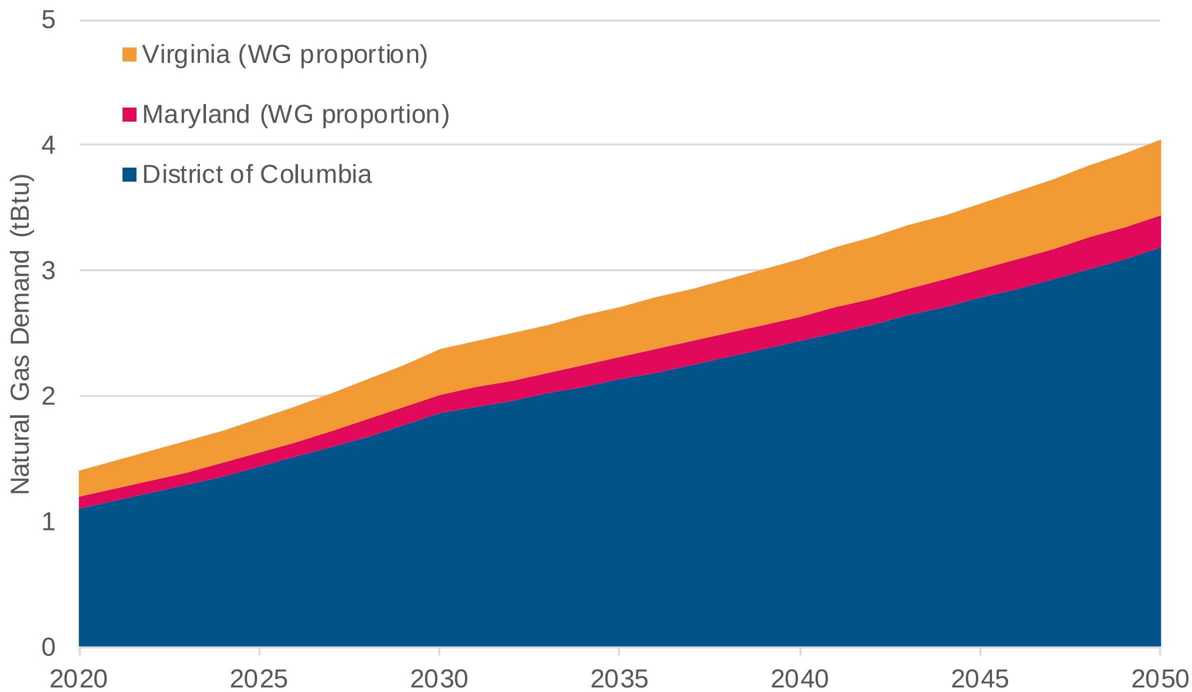


Table 43. Transportation Natural Gas Consumption Aggressive Forecast, Dth/day

Dth/day	2020	2030	2040	2050
Greater Washington DC metro	**3,810**	**6,450**	**8,420**	**10,990**
D.C.	3,000	5,080	6,630	8,650
Maryland	240	410	540	700
Virginia	570	960	1,260	1,640

The transportation sector remains an area of untapped demand for RNG in the Greater Washington, D.C. metropolitan area, and a viable near-term opportunity to direct relatively cost-effective RNG supply. The region is home to operators of large and small NGV fleets, including WMATA, Montgomery County Transit Services, and Arlington Regional Transit, which could provide feasible starting points to drive RNG demand.

SPOTLIGHT: RNG in Heavy-Duty Vehicles

Heavy-duty vehicles, including trucks, buses, and refuse haulers, powered by diesel account for a significant share of GHG emissions in the Greater Washington, D.C. metropolitan area. Furthermore, heavy-duty vehicles like single line-haul trucks can emit more NOx per than 100 cars per mile traveled.

RNG in heavy-duty vehicles has the potential to reduce GHG emissions, and when coupled with the newest natural gas engine technology it can also help achieve drastic reductions in NOx emissions.

Heavy-duty trucks, transit buses, and refuse haulers running on fossil-based CNG reduce GHG emissions by about 10–20% compared to their diesel counterparts. The introduction of RNG amplifies these emission reductions by four to five times (on a direct GHG emission accounting basis; see Figure 50).

For every 1,000 heavy-duty natural gas vehicles powered by RNG that displace diesel consumption in the Greater Washington, D.C. metropolitan area, ICF estimates GHG emission reductions of 20,000–25,000 MT CO_2e. And when coupled with the newer natural gas engine technology that is commercially available today, RNG in heavy-duty vehicles can also help deliver drastic NOx reductions compared to their diesel counterparts.

Pipeline (Stationary)

Lastly and crucially for long-term decarbonization strategies, RNG is also a drop-in replacement for pipeline natural gas used in stationary applications, such as for heating and cooling, and commercial and industrial applications. As currently constructed, the policy framework does not encourage RNG use in these stationary applications, instead directing RNG consumption to the transportation and electricity generation sectors.

However, there is growing interest from some policymakers and industry stakeholders to grow the production of RNG for pipeline injection and stationary end-use consumption. With deep decarbonization goals becoming more prevalent, the ability to use an existing energy system to deliver significant emission reductions is highly valuable. RNG as a decarbonization approach for stationary energy applications provides two critical advantages relative to other measures:

- Utilizes existing natural gas transmission and distribution infrastructure, which is highly reliable and efficient, and already paid for; and
- Allows for the use of the same consumer equipment as conventional gas (e.g., furnaces, stoves), avoiding expensive retrofits and upgrades required for fuel-switching.

There is growing activity outside the transportation sector, and in particular the construct of the LCFS program, where so much attention is paid today. Southern California Gas Company (SoCalGas) announced that they intend to have 5% RNG on their system by 2022 and 20% by 2030. SoCalGas is also seeking approval to allow customers to purchase RNG as part of a voluntary RNG tariff program. Despite the challenges of its bankruptcy, Pacific Gas & Electric is close to announcing a more nuanced approached to its RNG strategy.

Momentum for RNG is not just in California where carbon-constraining policies are the most restrictive in the United States. Gas utilities and local distribution companies (LDCs) are either volunteering or being forced to take a closer look at RNG across the country, with growing interest in the Greater Washington, D.C. metropolitan area:

- Approved in 2017, Vermont Gas offers a voluntary RNG tariff program, providing retail gas customers the opportunity to purchase RNG in amounts proportionate to their monthly requirements.
- Consolidated Edison is very focused on RNG for pipeline injection as part of its consideration for the future of heating.
- National Grid's New York City Newtown Creek RNG demonstration project will be one of the first facilities in the U.S. that directly injects RNG into a local distribution system using biogas generated from a water and food waste facility.
- The joint venture between Dominion Energy and Smithfield Foods is set to become the largest RNG producer in the U.S., developing animal manure-based RNG in North Carolina, Virginia, and Utah, with plans to expand to California and Arizona.

Driven by corporate sustainability goals and customer preferences, a growing number of large end users of natural gas are looking into RNG as an option to reduce GHG emissions. Global cosmetics manufacturer L'Oréal uses RNG from a nearby landfill facility at its plant in Kentucky. L'Oréal's long-term purchase commitment for the RNG was a key underwriting component that led to the financing of the LFG project.

In ICF's view, the renewed focus on pipeline injection and consumption of RNG by utilities, LDCs, and large end users is an overwhelmingly positive signal for the RNG developer community. While there is clearly a near-term focus on reaping the benefits of credits generated in the LCFS program and RINs in the RFS program, the long-term potential for increased volumes of RNG outside the transportation sector is considerably more robust than many stakeholders may realize. With appropriate incentives that fully capture the environmental benefits of RNG, the end-use demand for RNG from stationary applications is substantial, in contrast to the limited demand in the transportation sector.

SPOTLIGHT: Anaerobic Digester Project Development

The RNG production potential for the Greater Washington, D.C. metropolitan area is real and there are significant near-term opportunities that could be pursued. However, these resources must be converted to RNG for pipeline injection. ICF summarizes the process for bringing projects online in three simplified steps: site identification, project due diligence and financing, and project development and execution.

1. **Site identification**. This is the biggest challenge in the RNG market for projects today. In the case of landfills, the site needs to have a variety of characteristics to produce RNG. These include technological considerations like ensuring that the LFG has high energy content (e.g., methane concentration) and that the LFG capture management system is modernized to deliver consistent volumes, and market considerations such as ensuring that the facility can be converted to a pipeline injection project without negatively impacting existing agreements. The highest priority for developers for non-LFG projects, like WRRFs and animal manure for RNG, is for projects to already have a digester in place, for example, for biogas to electricity or some other on-site application. These are the most cost-effective facilities in place. In all cases, the proximity to common carrier pipelines is critical. Most of the stakeholders with whom ICF has spoken have indicated a 6-9 month timeframe for site identification.
2. **Project due diligence and project financing**. After identifying a site, the next critical step is to engage in project due diligence and secure financing. This involves a variety of parties and approaches, which can include a combination of debt or equity financing, depending on the project. At this stage, project developers often conduct a preliminary carbon intensity analysis to estimate potential revenue from the facility if they are able to deliver the gas to a transportation application (ideally in California to maximize revenue). Project developers and their partners also conduct a valuation of the RNG production asset, including the various revenue streams (e.g., environmental commodities like RINs and LCFS credits), and costs (e.g., operating the upgrading and conditioning equipment). ICF estimates this part of the process will take 6-9 months.
3. **Project development and execution**. The timeline for project development and execution depends significantly on site-specific considerations. ICF generally estimates that this process will take 12-20 months, indicative of the time between project financing secured and RNG injected into the pipeline.

ICF estimates that LFG projects have about a 6-24 month timeline, depending on site-specific considerations. However, we estimate that non-LFG projects have about a 24-month timeline from the point of executing an agreement with a viable site to the point of injecting gas. And we assume that the site identification and partnering aspect on the front end is at least a 6-month process, assuming that a facility has a digester in place. ICF notes that for projects without a digester in place, the project lifetime will likely increase by another 6-24 months, depending on construction requirements.

Relevant to the above spotlight, there are several projects in the Greater Washington, D.C. area that have advanced towards RNG for injection. For instance:

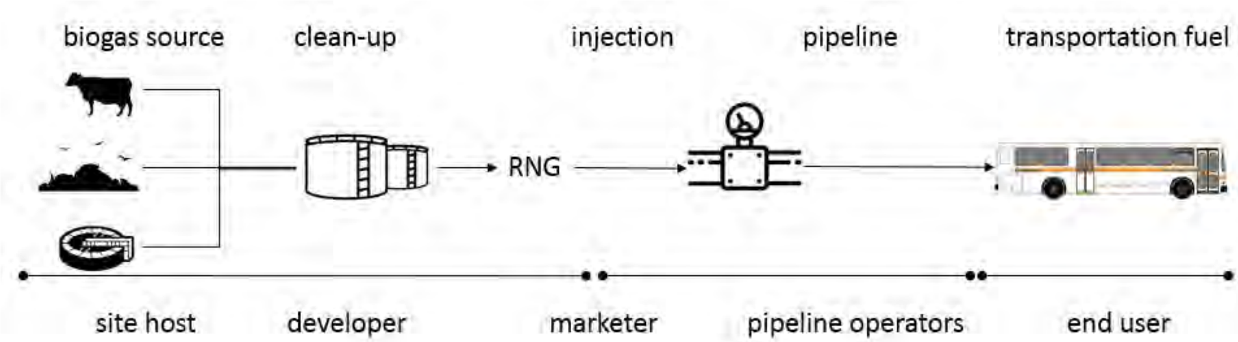
- DC Water issued a Request for Proposal in February 2019 to select a technical and commercial partner for the purposes of initially materializing a program to realize the full value of RNG resources, as well as the full portfolio of energy-related business opportunities to bring value to D.C. and its stakeholders. The project is primarily focused on producing pipeline-quality RNG and maximizing the value of that injected gas through transportation end-uses.
- The WSSC Piscataway WRRF has an RNG project in the design phase, which involves aggregating waste from five existing treatment plants. In its first phase, WSSC is focused on design and early construction (including the demolition of existing on-site facilities and relocation of existing utilities). WSSC report that Phase Two is expected to advance in 2020, and that the entire project should be complete and operational in late 2021.

There are a variety of project structures that could be pursued to deploy RNG produced in the Greater Washington, D.C. metropolitan area. Generally speaking, the key parties include:

- Site host or operator (e.g., a landfill, WRRF, or farmer)
- Developer or technology provider
- Project financing
- LDC, utility or marketer to transport the gas
- End user

Figure 68 highlights these various stakeholders, with the end user being a transportation fuel application for illustrative purposes.

Figure 68. Market Participants in the RNG Supply Chain



The revenue associated with these projects can conceivably be split between the site host, developer, marketer, and end user to ensure that each party shares in the value of the delivered RNG. At the same time, the utility that moves the RNG along its system to an end user in its service territory can benefit from reduced GHG emissions.

Interconnection and Gas Quality

For RNG to be suitable for introduction into the natural gas pipeline network, the initial raw biogas must be adequately processed to meet gas quality and end-use application standards. At a high level, this typically involves concentrating the methane content and removing any problematic constituents.

While RNG is fundamentally interchangeable with conventional natural gas, different RNG feedstocks pose different challenges for gas quality and composition. For example, raw (unprocessed) biogas from a landfill facility is different than biogas from a dairy digester. Biogas constituents of concern vary by feedstock and conversion technology, and testing requirements need to be aligned to optimize results and processing requirements. Gas quality standards and constituents for testing consideration include those listed in Table 44. Acceptable gas quality terms for normal operations will depend on a variety of factors, including the dilution of RNG when injected into the system and the feedstock type. Table 44 shows an example of acceptable limits.

Table 44. Illustrative Gas Quality Considerations for RNG Injection

Gas Quality Term	Generally Acceptable Limit
Hydrogen content	
Heating value	$\geq$ 960 Btu/SCF
Wobbe Number	
Dew point temperature	
Sulfur, including dimethyl sulfide and hydrogen sulfide	Total S: $\leq$ 20 grains/CCF H_2S: $\leq$ 0.25 grains/CCF
Carbon Dioxide, CO_2	$\leq$ 3.0%, by volume
Nitrogen, N_2	$\leq$ 4.0%, by volume
Oxygen, O_2	$\leq$ 0.4%, by volume
Ammonia	< 0.001%, by volume
Volatile and semi-volatile organics	
Siloxanes	< 1 mg/m^3
Pesticides	
Temperature	32 to 140 °F
Moisture	< 7 lb/MMSCF

Each element has a differing impact on gas quality and safety, interchangeability, end-use reliability and pipeline integrity. If a constituent is not reasonably expected to be found above background levels at the point of interconnect for the RNG, then testing may not be necessary. An additional challenge is that while some constituents may not present a problem in isolation, the interaction between different constituents could result in negative impacts on the pipeline or end-use applications.

Substantial research, testing and analysis has been done to better understand the composition of raw biogas from different feedstocks compared to traditional pipeline-quality natural gas delivered into the natural gas system. In parallel, significant technology advancements have been achieved in processing and treating raw biogas to address trace constituents and the concerns of pipeline operators and end users.

For example, at the direction of the California Public Utilities Commission, the California Council on Science and Technology (CCST) assessed acceptable heating values and maximum siloxane specifications for RNG. CCST found that keeping the current minimum Wobbe Number requirement for RNG while relaxing the heating value specification to a level near 970 Btu/scf would not likely impact safety or equipment reliability. In relation to siloxanes, the CCST found that some RNG feedstocks are very unlikely to harbor siloxanes (e.g. dairy waste, agricultural residues or forestry residues), and less stringent monitoring requirements would be needed. The CCST also recommended a comprehensive research program to understand the operational, health, and safety consequences of various concentrations of siloxanes, due to inconclusive evidence for other RNG feedstocks.[83]

However, the lack of a consistent approach to evaluate RNG quality and constituent composition remains a challenge to the broader acceptance of different RNG feedstocks and inhibits the development of RNG as a source for pipeline throughput. The industry is still learning about RNG and the impact on pipeline infrastructure and end use, and it is in the industry's best interest to continue research, collaboration, and dissemination of biogas processing and RNG pipeline injection experience, particularly as more RNG facilities come online.

An evidence-based, common-sense framework is needed to assess the composition and interchangeability of RNG with conventional natural gas supplies and pipeline requirements. As currently constructed, the processes, requirements, and agreements that facilitate the pipeline connection of RNG projects are not uniform, resulting in commercial and technical uncertainties for stakeholders that limit the efficiency and, potentially, the viability of different RNG projects.

Instead, a consistent and impartial approach to assess the commercial and technical potential of each project is required to encourage the introduction of RNG from a range of biomass feedstocks, without compromising the safety or reliability of the pipeline or end-use applications. In addition, a uniform approach would provide greater certainty for all parties regarding safety, reliability, and interchangeability.

The Role of RNG in Decarbonization

Objectives of Climate Business Plan Analysis

In parallel to this study on the use of RNG in the Greater Washington, D.C. area, ICF was engaged by WG to develop alternative scenarios to evaluate the effectiveness and implications of different approaches to meet D.C.'s 2032 and 2050 emission reduction targets. To do this, ICF conducted scenario modeling that informed the Climate Business Plan that WG is developing, which examines the effectiveness, comparative costs, and timeframes associated with four different energy scenarios.

As part of this exercise, the objective of ICF's scenario modeling is to characterize a low-carbon energy future for the Greater Washington, D.C. metropolitan area, with a critical focus on the role of natural gas in meeting energy commitments in a decarbonized economy. More specifically, ICF's scenario modeling assesses the following key issues:

[83] CCST, 2018. Biomethane in California Common Carrier Pipelines: Assessing Heating Value and Maximum Siloxane Specifications, https://ccst.us/reports/biomethane/.

- **The Role of RNG**: The RNG results include the anticipated use of RNG in various sectors, with a focus on transportation and pipeline injection for space heating or other end uses. The results extend beyond the Greater Washington, D.C. metropolitan area to the regional and national level to address the costs and emissions associated with the sources of RNG.
- **Natural Gas Emissions**: Evaluation of natural gas supply options for reducing GHG emissions from the end use of natural gas based on publicly available information.
- **Impact on Peak Electric Load**: One of the major cost drivers of decarbonization efforts is expected to be the need to expand the electric grid to serve the incremental electric load. Currently, this region is a summer peaking electric system. At least initially, conversion of space heating load from fossil fuels to electricity will be able to use existing capacity on the electricity grid without incurring the need to build new peak period capacity. However, after a significant share of space heating is converted, the electric grid shifts from summer peaking to winter peaking, which will likely require major new investments in power generation capacity.
- **Change in Consumer Energy Costs**: The changes in consumer energy costs considered changes in consumption for electricity, natural gas, fuel oil, and transportation fuels due to improvements in energy efficiency and from conversion of fossil fuel applications to electricity.
- **Building Stock Conversion Costs**: Improvements to energy efficiency and conversions from fossil fuel to electricity in existing building stock have different costs based on the type and age of the building and the type and age of the heating system and other appliances. ICF used detailed Census data to disaggregate the building stock by type and age of the building and the heating system when estimating the costs of converting the buildings to electricity.
- **Power Sector Impacts**: The power sector results were extended beyond these jurisdictions to the regional and national level to address the costs and emissions associated with the sources of electric power.

Investments in RNG

Over the last 20 years, a variety of investments in biogas capture systems have been made that have helped the market to its level of maturation today. That said, the RNG market has traditionally been focused on small-scale biogas capture systems at landfills, WRRFs, and animal manure digester systems, with most of those facilities producing electricity. As RNG became eligible for valuable D3 RIN generation (as discussed previously), investors largely focused on diverting existing biogas-to-electricity generation systems to biogas-to-RNG pipeline injection projects. As noted previously, the number of projects domestically injecting RNG into the pipeline is rapidly approaching 100, marking impressive and positive growth over the last 5 to 7 years.

The most telling and positive trend from ICF's perspective over the last 2-3 years has been an increase in and the shift in the types of investors engaged in this market, with notable and established infrastructure investors and renewable energy funds dedicating significant resources and attention to RNG investments. Some of the highlighted investments over the last several years include the following:

- **DTE Biomass Energy** broke ground on its first dairy digester cluster in Wisconsin in 2018 and started producing RNG in September 2019; the indications are that DTE Biomass Energy has at least another five additional dairy projects moving forward. DTE Biomass Energy already operates 21 landfill gas projects, and five of those produce RNG.
- **Generate Capital** in San Francisco has made significant investments in RNG, including acquisition of AMP Americas, LLC and its entities that produce RNG at the Fair Oaks Farms dairy (ampRenew, LLC and RDF Indiana Holdings, LLC).[84]
- **Dominion Energy and Smithfield Foods** have committed to investing up to $500 million through 2028 via their Align Renewable Natural Gas joint venture—including projects in North Carolina, Virginia, Utah, Arizona, and California.
- **Chevron** is working with California Bioenergy LLC (CalBio) to produce RNG from dairy digesters in California, including commitments to fund as many as 18 digesters across clusters in California's dairy-producing counties, including Tulare, Kern, and Kings.
- **BP** acquired Clean Energy's RNG business in 2017, and has been working to expand the company's existing RNG footprint over the last three years.
- Other established players in the landfill gas market, such as **Fortistar, US Gain,** and **Aria Energy**, have expanded their portfolio, and broadened their footprint into other RNG production areas, including RNG from animal manure digesters. These longer-standing players are joined by newer players in the RNG space such as **Brightmark Energy** and **Ultra Capital**, as well as investors that have been active in other renewable energy sectors but are new to RNG, like **Iogen** and **Air Liquide**.

The changes in the diversity of investors, and most notably the combination of existing and new investors, in the RNG market over just the past 2–3 years portend rapid changes to the availability of RNG in multiple applications.

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[84] Federal Trade Commission, https://www.ftc.gov/enforcement/premerger-notification-program/early-termination-notices/20191221.

6. Opportunities and Challenges

Key Takeaways

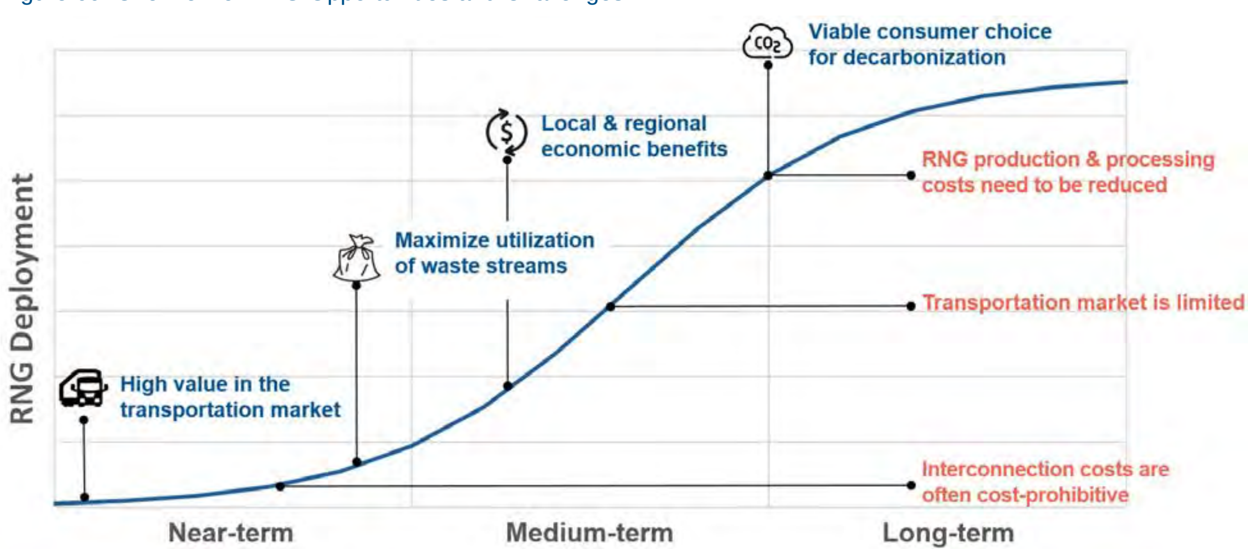
There are multiple opportunities and challenges for the wide-scale deployment of RNG. The physical and environmental characteristics of RNG make for substantial development potential, particularly in relation to the ambitious climate policies in the region. However, challenges remain, including limited capacity in current end-use markets and high pipeline interconnection costs.

These challenges are far from insurmountable with the right direction and leadership from policymakers and industry stakeholders. Some challenges can be overcome in the near-term future, such as a supportive regulatory framework for broad end-use consumption and cost recovery mechanisms for interconnection, while others will be mitigated in the longer term through increased and varied deployment of RNG, including through reduced technology and project costs.

Overview

In this section, ICF considers the highest-value opportunities and the corresponding challenges to realizing the potential of these opportunities in the RNG market. While the technical, market, and regulatory drivers for RNG are inextricably linked, we have distinguished between the key opportunities and challenges across these three broad areas. Figure 69 illustrates a subset of ICF's key findings across the technical, market, and regulatory/policy aspects of RNG deployment, including both **opportunities** and **challenges** envisioned along an illustrative RNG production potential curve.

Figure 69. Overview of RNG Opportunities and Challenges



Technical

The technical potential for RNG over the next five to seven years is constrained primarily by regulatory and market constraints, rather than technical ones. In large part, this is attributable to the fact that there are multiple feedstocks that can be converted to RNG using anaerobic digestion—this is a mature technology. Moving past 2025 and into a post-2030 reality, however, the technical potential for RNG will be constrained by the ability to expand beyond anaerobic digestion of feedstocks like landfill gas, animal manure, WRRFs, and food waste, and into technologies like thermal gasification and P2G. While both thermal gasification and P2G are viable technologies, they would likely be considered in pre-commercial stages or very early commercial deployment. The transition to these types of technologies increases RNG production potential substantially, and can help drive down the long-term costs of RNG.

Opportunities

- **RNG is a valuable renewable resource with carbon neutral (and in some cases, carbon-negative) characteristics.** The GHG benefits of RNG are clear: emissions from RNG are lower than fossil or geological natural gas across the board. When paired with conservation and efficiency improvements, the introduction of RNG has the potential to significantly reduce GHG emissions from the natural gas system and form part of a cost-effective deep decarbonization strategy. Furthermore, these emission reductions are supported by policies that can improve waste management (e.g., landfill diversion), improve utilization of agricultural and forestry products, and generate additional revenue streams for some vulnerable parts of the economy.
- **RNG utilizes the same existing infrastructure as fossil or geological natural gas.** When conditioned and upgraded to pipeline specifications, RNG can use the same extensive system of pipelines for the transmission and distribution of natural gas. Improved and continuous monitoring of potential harmful constituents from RNG production can decrease the technical risks of contamination in the pipeline.
- **The long-term potential for RNG is linked in part to P2G and hydrogen**, which have the potential to increase the flexibility of the natural gas system as a long-term energy storage technology. RNG from anaerobic digestion and thermal gasification make up the majority of production potential considered in this study. However, it is important to note that there is a significant and important role for P2G and hydrogen, driven by the rapid decrease of renewable electricity costs, the need to identify productive uses for CO_2 rather than treating it as a pollutant, and the potential for decreases in electrolyzer costs.

Challenges

- **The technical potential for RNG production is currently constrained to some extent by old policies.** Biogas was originally linked to electricity projects that favored renewable electricity generation, on-site co-generation, and other projects. While this demand for renewable electricity helped to spur investments in landfill gas projects and smaller projects at dairy farms, it has led to the unintended consequence of limiting the near-term potential for production and pipeline injection of RNG.
- **Feedstock location and accessibility will constrain RNG production potential.** The location and availability of RNG feedstocks is mismatched with traditional demand centers for natural gas consumption. For example, many feedstocks are available in predominantly

rural areas whereas demand is focused in urban centers. Some of these feedstocks may be difficult to access, or may require substantial (and in some cases impractical) investments in infrastructure. This issue is similar to challenges around location-constrained resources for renewable electricity generation.

- **Competition for feedstocks will constrain RNG production potential.** There is a diverse array of feedstocks available for RNG production, yet accessing some of those feedstocks can be difficult or prohibitive. Furthermore, as waste diversion policies improve over time, and decarbonization efforts presumably expand in different regions, biogenic and biomass feedstocks will have increasing value, thereby increasing competition for various energy production processes, including for gaseous fuels (i.e., RNG), liquid fuels (e.g., liquid biofuels like renewable diesel), and for renewable electricity. Technological advances in each of these markets will help determine the appropriate use of each feedstock, while the availability of that feedstock will still be constrained by other factors, including the rate of waste produced, agricultural outputs, and forestry outputs.
- **Gas quality and gas composition for RNG remains an engineering concern.** There is no existing standard for RNG gas quality and gas composition, and with limited operational data, some concerns remain regarding RNG injection into a pipeline system.
- **P2G technology will require significant cost reductions.** While P2G holds significant promise, the long-term viability of the technology will require significant near-term deployment of electrolyzers to help drive the necessary cost reductions for the technology to be cost-competitive in a post-2030 market that is increasingly focused on decarbonization. Potential cost reductions for P2G could replicate the trends displayed by other low carbon technologies, such as renewable electricity, with the appropriate and immediate policy and regulatory support.
- **Seasonal variability in the region's natural gas systemwide demand will require the RNG production market to adapt.** As noted previously, Greater Washington, D.C. metropolitan area's natural gas system sees a significant winter peak, largely driven by space heating demand. There is a six-fold difference in natural gas demand on the region's system between winter and summer months, and RNG production facilities do not have the same variability. Current RNG contractual structures are driven by natural gas demand as a transportation fuel, and are not designed to accommodate the type of system variation required for space heating applications. As the RNG market evolves and matures, ICF anticipates that this issue can be solved through book-and-claim accounting, storage, and other considerations. However, as the RNG market transitions from transportation fuel use to more diverse end uses on the natural gas system, there will be growing pains.

Market

There are more than 85 projects producing RNG for pipeline injection today, compared to less than a half-dozen in 2010. In Section 2, ICF provided an outline of RNG potential for pipeline injection, broken down by feedstocks and production technologies. Based on this untapped potential, the RNG market is poised for substantial growth with ICF estimating that as many as 100 new RNG projects will be developed by 2023. The following section outlines the most significant opportunities driving the RNG market, and the most significant challenges that must be overcome.

Opportunities

- **RNG has high value in the transportation sector.** Natural gas consumption as a transportation fuel is modest in the Greater Washington, D.C. metropolitan area; however, there are clear incentives to deploy RNG into the transportation sector, and saturation in other state-level markets will make it increasingly favorable for fleets and other entities to dispense RNG for use as a transportation fuel in that area.
- **RNG can deliver cost-effective GHG emission reductions for deep decarbonization.** RNG is a cost-effective GHG emission reduction measure, and relative to other GHG mitigation measures, RNG can play an important role in helping to achieve aggressive decarbonization out to 2050.
- **RNG helps maximize the utilization of evolving waste streams.** The anaerobic digestion of biomass, including at landfills and WRRFs, helps maximize the use of waste. With growing urban populations and more pressure for landfill diversion, the anaerobic digestion of food waste and thermal gasification of MSW, for instance, has the potential to continue to increase the utilization of waste streams as renewable energy resources.
- **RNG markets are evolving to reflect utilities and corporations with climate and sustainability goals.** There is increasing activity and interest in RNG outside of the transportation sector, and also beyond jurisdictions where carbon constraining policies are influential. Driven by corporate sustainability goals and customer preferences, an increasing number of utilities and large end users of natural gas are looking into RNG as an option to reduce GHG emissions, exemplified by the actions of SoCalGas, Vermont Gas, L'Oréal, and others in the RNG market.
- **RNG helps give suppliers and consumers a viable decarbonization option in an evolving market and policy environment.** There is a growing trend for utilities and large industrial consumers to adopt ambitious decarbonization measures, while small consumers are increasingly aware of their carbon footprint and looking for ways to reduce emissions. In this environment, the introduction of RNG has the potential to provide suppliers and end-use customers with a viable choice toward a balanced energy future that delivers safe and reliable energy, while also reducing GHG emissions, and in a manner that is more cost-effective and equitable than outright bans or restrictive mandates on natural gas use, as recently seen in California at the local level.

Challenges

- **RNG markets beyond transportation fuel are nascent.** The long-term growth potential for RNG is dependent on transitioning to end uses other than transportation. The near-term market potential for RNG deployment in WG's service territory will help the region satisfy proof of principle, and bolster stakeholder confidence in the ability of RNG to deliver cost-effective GHG emission reductions. However, absent some other markets for RNG consumption, production investments will stall and it will plateau.
- **RNG production and processing costs need to be reduced to improve cost-competitiveness.** The market for RNG will expand beyond the transportation sector through improved technology and complementary policies. However, technology and overall production costs need to decrease over time to maintain competitiveness.
- **RNG is not explicitly included in LDC tariffs governing gas procurement.** LDCs may be required to procure natural gas on a least-cost basis, or least-cost with consideration for

peaking/reliability sources. Given that RNG is likely to exceed the market cost of conventional natural gas, and absent an RNG procurement mandate, it may be necessary to include RNG within LDC tariffs as another legitimate source option that is subject to standard prudent procurement requirements.

- **Limited availability of qualified and experienced RNG developers to expand RNG production in the near-term.** With growing interest in RNG projects, particularly to capture near-term value in the transportation market, there is a lack of experienced project developers (perceived or real) to meet this demand. This issue will ameliorate over time, as the industry expands and project developers gain more experience on RNG projects.
- **RNG costs more than conventional natural gas, when environmental benefits are not valued appropriately.** The capital expenditures and operational costs associated with RNG production are higher than the commodity price for conventional natural gas, greatly restricting the potential for RNG production and consumption. However, the costs of RNG should not be compared directly with conventional natural gas without reflecting the significant GHG emission reduction benefits of RNG. For example, with the environmental attributes valued under the LCFS, RNG is a cost-effective transportation fuel relative to diesel and conventional natural gas.
- **Interconnection costs for RNG suppliers and developers can be prohibitively high.** Interconnection serves a vital role in an RNG project—it is the point at which gas quality is monitored, prevents non-compliant gas from entering the system, and meters the RNG injected. On a project-lifetime basis, interconnection costs are generally small as the cost is amortized, for instance, over a 10- to 20-year project lifetime. However, meeting interconnection costs can be a challenge for project developers.

  There is no “right cost” associated with interconnection. Instead, gas utilities need to work with regulators and project developers to ensure safety and reliability are maintained on the system, and that utilities can recover the costs associated with the system requirement.

  Utilities, along with regulators, have strategic roles to work with potential RNG suppliers and project developers to:

  (i) Research and evaluate suitable site locations;
  (ii) Determine pipeline interconnection distances and pathways;
  (iii) Develop engineering designs and configurations;
  (iv) Determine appropriate flows and pressures; and
  (v) Conduct initial project cost estimates.

Regulatory and Policy

The aforementioned regulatory and policy incentives for the use of RNG as a transportation fuel have helped spur substantial investment in new RNG projects nationwide. However, the demand for RNG as a transportation fuel is limited and tied to the growth of NGVs. Therefore, a regulatory and policy structure that supports the cost-effective use of pipeline-injected RNG as a GHG mitigation strategy is paramount to the long-term success for RNG.

Today, a handful of state-level policies are in place that are helping to shape the outlook for RNG beyond transportation. Table 45 provides information on these policies, including the state in which the bill was enacted, a bill summary, and key programmatic components such as supply, production or interconnection, cost recovery for gas utilities, and end-user benefits.

Table 45. Summary of State Laws Enacted to Support RNG

State / Bill	Brief Description	Supply	Production / Interconnection	Cost Recovery	End-User Benefit
Oregon SB 98	Allows natural gas utility to make "qualified investments" and procure RNG from 3rd parties to meet portfolio targets for the percentage of gas purchased for distribution to retail customers.	Establishes large/small RNG programs and to make "qualified investments" and procure RNG from 3rd parties to meet portfolio targets for the percentage of gas purchased for distribution to retail natural gas customers.	RNG infrastructure means all equipment and facilities for the production, processing, pipeline interconnection, and distribution.	PUC shall adopt rules establishing a process for utilities to fully recover costs. Cost of capital established by PUC from most recent rate case. Affiliates not prohibited from making a capital investment in a biogas production project. Restricted from making additional qualified investments without the approval of the PUC if the program annual costs exceed 5% of the utility's total revenue requirement in an individual year.	Reduced emissions. RNG portfolio ranging from 5% between 2020 and 2024 to 30% between 2045 and 2050.
Washington HB 1257	Required each gas company to offer by tariff a voluntary renewable natural gas service available to all customers.	To replace any portion of the natural gas that would otherwise be provided by the gas company. Customer charge for an RNG program may not exceed 5% of the amount charged to retail customers for natural gas.	No Reference	No Reference	Commission must assess whether the gas companies are on track to meet a proportional share of the state's GHG reduction goal.

State / Bill	Brief Description	Supply	Production / Interconnection	Cost Recovery	End-User Benefit
Nevada SB 154	Authorized natural gas utilities to engage in RNG activities and to recover the reasonable and prudent costs of such activities, including the purchased of and production of RNG.	Requires a public utility to "attempt" to incorporate RNG into its gas supply portfolio. Gas which is produced by processing biogas or by converting electric energy generated using renewable energy into storable or injectable gas fuel in a process commonly known as power-to-gas or electrolysis.	Activities which may be approved: contracting with a producer of RNG to build and operate an RNG facility; extending the transmission or distribution system to interconnect with an RNG facility; purchasing gas that is produced from an RNG facility whether the gas has environmental attributes or not.	Utility applies to the Commission for approval of a reasonable and prudent RNG activity that will be used and useful. Must meet one or more: the reduction or avoidance of pollution or GHG; the reduction or avoidance of any pollutants that could impact waters in the state; the alleviation of a local nuisance within the state associated with the emission of odors.	Sell gas from RNG facility directly to the customer. Providing customers with the option to purchase gas produced from an RNG facility with or without environmental attributes. Utility shall attempt to incorporate RNG in its gas supply portfolio: By 2025, not less than 1% of the total amount of gas sold; by 2030, not less than 2%; by 2035, not less than 3%.
California SB 1440	Requires the CPUC to establish biomethane procurement goals or targets on natural gas IOUs to further decarbonize the state's natural gas sector. Stipulates that the goals and targets need to be a cost-effective means of achieving reductions in short-lived climate pollutants and other GHG emission reductions.	In consultation with the State Air Resources Board, the Commission would consider adopting specific biomethane procurement targets or goals for each gas corporation so that each gas corporation procures a proportionate share of biomethane annually.	To be eligible, the biomethane needs to be delivered through a common carrier pipeline that physically flows within California, or toward the end user in California for which the biomethane was produced. Currently, CA has a 50% by 2050 RPS. Under the RPS, utilities are authorized to meet the requirements using biogas from eligible renewable sources through the state's Bioenergy Market Adjusting Tariff (BioMAT) program.	The bill would require the PUC, if the PUC adopts those targets or goals, to take certain actions in regard to the development of the targets or goals and the procurement of the biomethane to meet those targets or goals.	A limited biomethane procurement program would help the state reduce methane and ensure that California's climate policies are met.

State / Bill	Brief Description	Supply	Production / Interconnection	Cost Recovery	End-User Benefit
California AB 1900	Established a program beginning in 2015 that provided $40M for RNG interconnection infrastructure. The bill was intended to address the barriers to allowing RNG to be injected into pipelines and break down barriers to using instate RNG—all while ensuring the supply was non-hazardous to human health.	The bill required the California EPA to compile a list of constituents of concern that could pose risks to human health and that are found in biogas at concentrations that significantly exceed the concentrations of those constituents in natural gas.	A part of this bill would require the PUC to adopt standards to ensure pipeline integrity and safety. The PUC would also adopt pipeline access rules to ensure nondiscriminatory access to all pipeline systems for physically interconnecting with the gas pipeline system and effectuating the delivery of gas.	No reference.	As a health safety initiative, the bill required the PUC to specify the maximum amount of vinyl chloride that may be found in landfill gas.
Utah HB 107	Authorizes gas utilities to establish natural gas clean air programs that promote sustainability through increasing the use of renewable natural gas if those programs are deemed to be in the public interest.	In determining whether a project is in the public interest, the Public Service Commission (PSC) shall consider to what extent the use of renewable natural gas is facilitated or expanded by the proposed project; potential air quality improvements associated with the proposed project; whether the proposed project could be provided by the private sector or would be viable without the proposed incentives; whether any proposed incentives were offered to all similarly situated potential partners and recipients; and potential benefits to ratepayers.	No reference.	The PSC may authorize large-scale utilities to allocate up to $10M annually to a specific sustainable transportation and energy plan. Elements include an economic development incentive rate; R&D of efficiency technologies; acquisition of non-residential natural gas infrastructure behind the utility's meter; the development of communities that can reduce GHG and NOx emissions; a natural gas renewable energy project; a commercial line extension program; or any other technology program. Electric utilities were previously authorized to have similar programs. If the PSC finds that a gas	Reduction of greenhouse gases and NOx emissions.

State / Bill	Brief Description	Supply	Production / Interconnection	Cost Recovery	End-User Benefit
				corporation's request for an NGV rate/clean air programs is less than the full cost of service, remaining costs may be spread to other customers. A previous statute authorizes recovery of expenditures for the construction, operation, and maintenance of natural gas fueling stations and related facilities.	
Vermont PUC Docket# 8667	VT Public Utility Commission authorized a renewable natural gas program for the sale of RNG to customers on a voluntary basis and optional RNG tariff service.	Vermont Gas stated they were seeking to source RNG from landfill gas projects.	Supply from Lincoln and landfill gas projects outside Vermont would be received through the Trans-Canada Pipeline system.	Requires Vermont Gas to file a formal tariff including proposed rates once it has procured RNG in sufficient amounts for estimated customer demand. Adder price for each scf of RNG will be equal to the average RNG commodity cost to VGS less the average commodity cost of natural gas. Also, if Vermont Gas' RNG supply exceeds customer demand, they must first seek to sell the excess at wholesale, and if necessary may seek to flow any remaining inventory amounts through a rate case as part of its cost of service.	Successful implementation can help meet the State's renewable energy policy objectives. Assessment of the voluntary program will assist in determining the feasibility of incorporating RNG as a portion of Vermont Gas' supply mix in the future.

Opportunities

An existing suite of regulatory initiatives and policies could help support RNG deployment in the near- to long-term future. These include conditioning and interconnection tariffs, voluntary offerings paid by customers, and a renewable gas standard. These opportunities are summarized here:

- **Conditioning and Interconnection Tariffs.** As outlined in Section 3, the costs of biogas conditioning and upgrading can be expensive; similarly, interconnection costs can be prohibitive for some project developers. These costs are the primary capital outlays at the outset of a project and have a material impact on the ability of projects to get financed. Under a tariff structure, the producer can avoid the significant upfront capital costs that can often impede project development. Conditioning and interconnection tariffs allow utilities or LDCs to build and operate the upgrading and interconnection facilities, while recovering capital and operation and maintenance costs from the project developer at a pre-determined rate. Examples of where this has been done include:
  - SoCalGas has a biogas conditioning and interconnection tariff; it "is an optional tariff service for customers that allows SoCalGas to plan, design, procure, construct, own, operate and maintain biogas conditioning and upgrading equipment on customer premises."[85]
  - TECO Peoples Gas in Florida had a tariff for biogas conditioning and upgrading approved in December 2017, and have since made modifications to the tariff to accommodate the receipt of RNG from biogas producers and an updated rate schedule for conditioning services.[86]
  - Southwest Gas Company (SWGC) in Arizona has a biogas services tariff enabling them to enter into a service agreement with a biogas or RNG producer, and includes requirements for access to the production facilities, interconnection facilities, and gas quality testing facilities.[87]
- **Emergence of legislation and regulations for both mandatory and voluntary programs.** Utilities may offer opt-in voluntary programs to customers to help reduce the environmental impact of their energy supply. This is more common for electric utilities, however, similar programs can be developed for gas utilities and RNG consumption. Examples of voluntary programs include:
  - Vermont Gas has had a voluntary program in place since 2018 for various blends of RNG. Vermont Gas customers consume about 6 BCF of RNG, which is sourced from Canada.[88]
  - In early 2019, SoCalGas and San Diego Gas & Electric (SDG&E) submitted a proposal to the CPUC to offer a voluntary RNG Tariff program to their residential, small

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[85] SoCalGas, information retrieved from https://www.socalgas.com/for-your-business/power-generation/biogas-conditioning-upgrading.
[86] TECO Peoples, tariff is available online at https://www.peoplesgas.com/files/tariff/tariffsection7.pdf.
[87] SWGC, Schedule No. G-65, Biogas and Renewable Natural Gas Services , available online at https://www.swgas.com/1409197529940/G-65-RNG-02262018.pdf.
[88] More information is available online at https://www.vermontgas.com/renewablenaturalgas/.

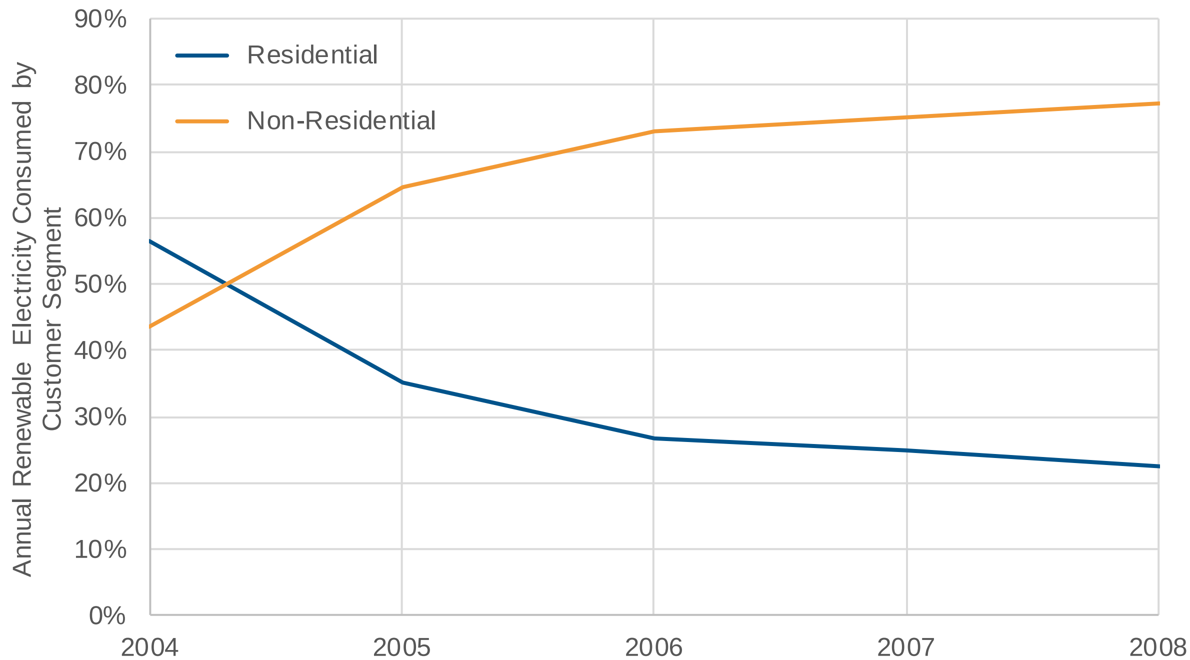
commercial, and industrial customers. SoCalGas and SDG&E have proposed to recoup program costs through rates charged to program participants.

– National Grid proposed a Green Gas Tariff offering in April 2019 that will enable its customers to voluntarily purchase RNG to meet all or a portion of their energy needs. National Grid designed the tariff with four tiers, providing consumers with multiple options regarding the extent to which they want to green their gas.

– Fortis BC, the main gas utility in the Canadian Province of British Columbia, has had a voluntary RNG tariff program since 2011, which has spurred RNG production in the region.[89]

Voluntary markets were critical to the initial growth of renewable electricity, as residential and non-residential customers helped grow demand considerably in the early years of renewable electricity development (see Figure 70).[90,91]

Figure 70. Percent Annual Renewable Electricity Consumption by Customer Segment, 2004–2008



Renewable electricity accounts for more than 20% of today's total electricity generation. However, less than 15 years ago, renewable electricity accounted for less than 1% of total electricity generation as voluntary renewable electricity programs started in earnest. This nascent growth helped achieve some cost reductions, raise consumer awareness, and spur action by non-residential customers. Furthermore, it helped to demonstrate the

[89] Fortis BC, 2020. https://www.fortisbc.com/services/sustainable-energy-options/renewable-natural-gas
[90] NREL, Green Power Marketing in the United States: A Status Report (Tenth Edition), December 2007, NREL/TLP-670-42502, https://www.nrel.gov/docs/fy08osti/42502.pdf.
[91] NREL, Green Power Marketing in the United States: A Status Report (2008 Data), September 2009, NREL/TLP-6A2-46851, https://www.nrel.gov/docs/fy08osti/42502.pdf.

demand for renewable products, and served as the launching point for more structured regulatory action via renewable portfolio standards.

Renewable Gas Standard (RGS):

The principles of an RGS are straightforward and mimic RPS programs, a common policy tool to introduce a renewable energy procurement requirement for electricity providers. In other words, an RGS would require RNG to be delivered and measured against some benchmark, such as a carbon-based reduction or volumetric target. There are a variety of approaches to RGS implementation, including:

– A free-market approach whereby a procurement target is established and the market simply responds to the price signal according to the supply-cost curve for RNG production.

– A feed-in tariff, or standard offer contracts, would provide clear, reliable pricing for RNG producers. Although this approach provides a clear signal to help producers finance renewable gas projects, without distinguishing between feedstocks, a feed-in tariff has the potential to favor low-cost producers without recognizing the cost-effectiveness of GHG emission reductions.

– The RGS could take on a performance-based approach structure like the LCFS program in California, requiring a percent reduction in the carbon intensity of natural gas by some date. Similarly, the RGS could take on a structure that requires a percent volume target by some date (different from an absolute volumetric target, as is prescribed in the federal RFS program).

– The coverage of an RGS would not necessarily be limited to just utilities and LDCs, but also encompass all suppliers of natural gas, including third-party suppliers such as natural gas marketers, similar to the broad coverage of RPS programs relative to electric load serving entities.

There are two additional aspects of an RGS that ICF considers critical: 1) tracking and verifying progress toward achieving an RGS and 2) understanding the tradeoffs of various performance-based approaches.

– **Thermal RECs to track and verify RNG**. With increased interest in voluntary and compulsory regulations and policies in place supporting the use of RNG, the market for tracking and verifying RNG has advanced rapidly. This will be critical in light of the potential for an RGS. Renewable electricity markets rely on various bodies to track and verify RECs, the primary regulatory currency for RPS programs.

  There is no analogous tracking system for RNG today, however, market actors are advancing the concept rapidly to help grow the market for RNG consumption outside of the transportation sector. The Midwest Renewable Energy Tracking System (M-RETS) has been trialing a thermal REC system since July 2019, which includes RNG used in stationary applications such as building heating and cooling. The intent is to provide the same verification and price transparency to the RNG market as exists in the renewable electricity market.

– **Understanding performance-based approach tradeoffs: volumetric vs carbon intensity targets.** ICF originally researched and wrote about this issue in 2017.[92] A performance-based approach should, in principle, provide clear signals to regulated parties and investors regarding the timeline required to achieve program targets, whether it be a carbon intensity target or volumetric target.

  The downside of a carbon intensity target is that it may introduce undue complexity to the RGS. For instance, consider the boundary conditions of the lifecycle GHG assessment of dairy digester gas. Without regulations in place to capture and burn the methane that is released, the gas receives a lower carbon intensity for being credited with the avoided emissions from *venting* methane. Landfill gas, on the other hand, being regulated and required to be captured and burned, receives a lower carbon intensity for being credited with the avoided emissions from *flaring* methane. The difference in the GHG benefit of avoided methane venting versus avoided methane flaring is tremendous: in the case of the former, you are avoiding methane emissions at a 100-year global warming potential of 25, whereas in the latter you are avoiding carbon dioxide emissions with a global warming potential of 1. Furthermore, if complementary regulations are enacted that improve waste (or manure) management, these could impact the carbon intensity of the RNG, simply by changing the boundary conditions of the analysis.

  Another consideration related to a carbon intensity-based approach is the potential for the intent of the program to be expanded unexpectedly to include upstream emission reductions; e.g., methane leaks in the natural gas pipeline. This could provide additional compliance opportunities for utilities that produce additional GHG benefits, but may detract from the intent of stimulating RNG development. Additionally, and similar to the example above, other regulations and programs that address these system improvements could complicate the benefit calculation, creating moving targets and challenging utilities' assessments of investment value for different compliance pathways.

Apart from the regulatory and policy opportunities outlined above, there are several other key opportunities in the RNG space:

- **Transportation policies currently favor RNG over fossil natural gas.** Despite depressed pricing in the federal RFS program, the environmental commodities generated from the use of RNG as a transportation fuel still generates value upward of $7/MMBtu. Complementary policies, such as a low carbon fuel standard, can be enacted to support RNG use in the Greater Washington, D.C. metropolitan area to further decarbonize the transportation sector immediately.
- **RNG can help achieve aggressive decarbonization policies.** RNG can play an important and cost-effective role in achieving aggressive decarbonization by 2032 and 2050.
- **Complementary policies could facilitate RNG feedstock collection (e.g., waste diversion and management).** The RNG industry could benefit considerably from complementary policies that help improve the accessibility of feedstocks while improving project development economics. This includes regulations or policies that encourage

[92] ICF White Paper, Design Principles for a Renewable Gas Standard, 2017.

methane capture, encourage waste diversion and waste utilization, forest management and thinning requirements, etc.

- **A robust RNG regulatory framework will encourage deployment of RNG.** When developing the programs and policies that reduce GHG emissions and help meet aggressive deep decarbonization objectives, policymakers and regulators should consider RNG as a cost-effective alternative and adopt policies to encourage customers and utilities to adopt RNG.

Challenges

- **The pathway for policies and incentives promoting RNG in market segments other than transportation is unclear and not uniform.** Current programs in place do not provide the price and supply certainty that is required for larger volumes of RNG to be deployed, beyond the success of RNG in the transportation fuels market. While voluntary commitments and other drivers may help to increase RNG consumption in non-transportation market segments, the potential for RNG is intrinsically constrained without a strong policy signal in place. Furthermore, the programs that have been proposed or even promulgated are generally lacking or insufficient, and do not recognize or credit the environmental benefits of RNG in a manner that is consistent with the long-term potential of the technology.
- **Some policymakers are singularly focused on electrification and unaware of the cost-effectiveness and other benefits of RNG.** In many policymaking environments today, the path to 2050 is viewed as electrification or bust. There are dubious claims about the supply and cost of RNG that are dismissive at worst, and pessimistic at best. This reinforces the underlying narrative that the best and only path to a decarbonized economy relies on rapid electrification of end uses paired with renewable electricity generation. This study is not intended, and makes no effort, to refute the viability of electrifying various end uses, while increasing amounts of renewable electricity. Instead, this study highlights the fact that the current policy environment creates a situation where RNG production as a viable, large-scale and cost-effective GHG mitigation strategy is potentially marginalized without proper investigation.
- **The applicability of RNG must be considered within existing customer choice programs.** The effectiveness of RNG procurement may be undercut by LDCs if the higher incremental costs are avoided through suppliers in customer choice programs who rely on traditional sourced and lower-cost supply. Regulators and policymakers may need to consider policy constructs that encourage or require all suppliers to procure RNG, or all customers to be allocated the costs of RNG, in order to promote effectiveness.
- **Gas utilities are just beginning to gain cost-recovery mechanisms for RNG procurement and investments.** The rapid expansion of RNG production over the last several years has been impressive; however, the industry will face limits as technical and market constraints limit market participants. Faced with varying pressures to decarbonize, utilities need cost-recovery mechanisms for RNG procurement or investments.

  In particular, natural gas utilities will need a regulatory structure that provides cost recovery for the incremental costs of RNG, interconnection facilities and equipment for RNG to comply with gas quality specifications and standards, and investment in larger facilities such as pipelines and premium gas production, supply facilities, and pipeline capacity costs that would support and facilitate the development of RNG.

- **Gas safety, reliability and quality rules and requirements need to be updated to align with current science/evidence.** The safety and reliability of the natural gas transmission and distribution network of pipelines is paramount to utility operations. Gas quality requirements and standards serve as an important reminder of this. However, it is important that gas quality rules and requirements reflect current science and evidence regarding RNG systems, and their ability to deliver a safe and reliable product. Pilot projects and demonstration programs provide opportunities for additional evidence on the impact of RNG systems, which can be used to update gas rules and requirements accordingly.

7. Recommendations to Deploy RNG

Key Takeaways

Although natural gas has played an important role over the last decade in GHG emission reductions by replacing coal-fired generation, it is still a significant contributor to GHG emissions in the Greater Washington, D.C. metropolitan area, contributing approximately 10% of regional GHG emissions (including a population-weighted share of natural gas consumption in Maryland and Virginia). Washington, D.C., Maryland, and Virginia have all made climate and clean energy commitments that will play critical roles in determining the pace of GHG emission reductions in each jurisdiction and will directly impact the natural gas system.

Stakeholders in the gas supply and distribution industry in the region, including gas utilities, should expect to play a proactive and positive role in supporting the Greater Washington, D.C. metropolitan area's various GHG emission reduction goals and delivering emission reductions from the natural gas system. To be a partner in meeting these climate objectives, gas utilities and associated stakeholders will need a sustainable and innovative business model that helps decarbonize the natural gas system. In parallel, regulators and policymakers must develop innovative approaches that enable the market for RNG to flourish and take full advantage of the full suite of cost-effective decarbonization strategies.

ICF's recommendations to support RNG deployment are structured in three parts:

1. ***Strategic direction for policymakers and industry stakeholders***
2. ***Market approaches***
3. ***Regulatory actions***

Deploying RNG in the Greater Washington, D.C. Area

ICF envisions a strategic roadmap to deploy RNG across the components outlined in Figure 71.

Figure 71. RNG Strategic Roadmap

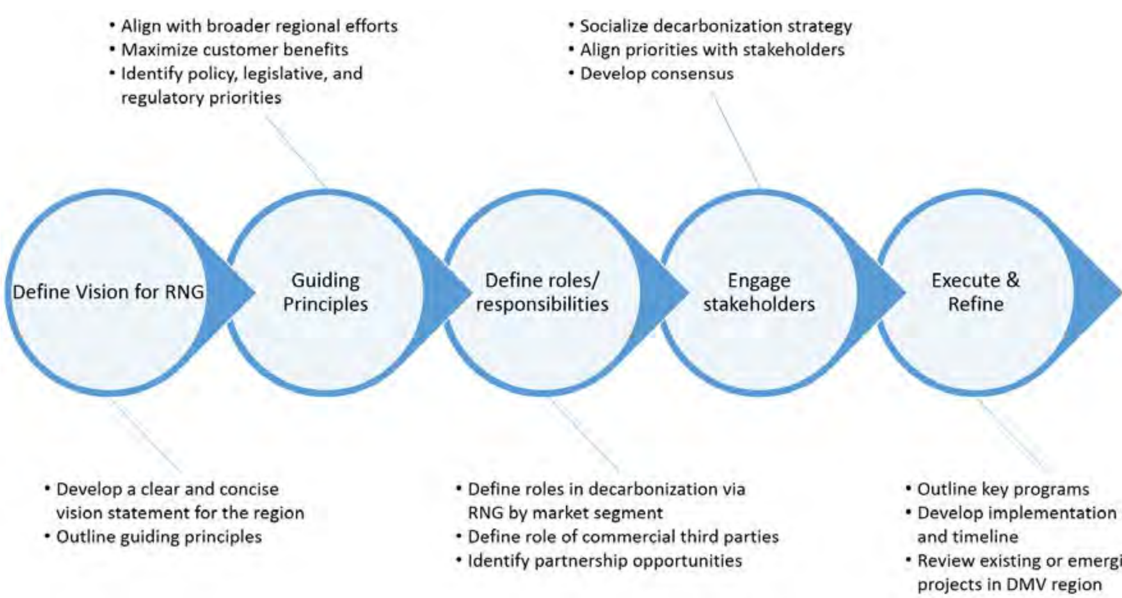


Figure 71 illustrates the Strategic Roadmap process that ICF recommends, including developing a vision statement and guiding principles, defining roles and responsibilities, engaging stakeholders, and executing the plan. ICF notes that the roadmap is portrayed in a linear fashion only for the sake of simplicity. There is nothing about the roadmap or the process that is inherently deterministic. Rather, the roadmap for the region will have to advance iteratively driven by the changing landscape.

The RNG Strategic Roadmap should be socialized across all key stakeholders—with a focus on regulated parties (e.g., gas utilities), key third parties, regulators, and policymakers. The roadmap should also be updated as decarbonization efforts are advanced in earnest across the region.

ICF's overview of the Strategic Roadmap to deploy RNG in the Greater Washington, D.C., metropolitan area is focused on the vision and guiding principles outlined in Figure 71. In the sections that follow, ICF reviews market and regulatory actions that can be taken to deploy RNG. These actions largely (but not exclusively) address the other aspects of the roadmap, including the roles and responsibilities of different stakeholders, how to engage different stakeholders, and execution of various projects to deploy RNG.

As part of this Strategic Roadmap, natural gas industry stakeholders should not just focus on RNG-specific regulations and policies, but adopt a broader perspective and push for the inclusion of RNG in relevant federal and state mechanisms that support clean energy and decarbonization in general. Clean energy grant programs, tax credits, and research and development funding should reflect the critical role that RNG can play in deep decarbonization efforts. For example, RNG investments should receive similar investment tax credits or production tax credits as those currently or previously afforded to renewable electricity generation via wind or solar resources. Similarly, RNG paired with low NOx engines for trucks and buses can help achieve the NOx reduction targets sought through the administration of funds from the Volkswagen settlement and other DOE grants, and help to achieve valuable GHG emission reductions.

A Vision for RNG Deployment

The potential for RNG in the region is clear: many stakeholders are positioned to take immediate action to facilitate the necessary development of RNG consumption in the region and should be guided by the following vision statement:

> ***Vision Statement:*** *The Greater Washington, D.C. metropolitan area will maximize RNG throughput as a decarbonization strategy while maintaining the safety, reliability, and affordability of gas services.*

This vision can be implemented through aggressive but attainable RNG throughput targets as outlined below. The Greater Washington, D.C. metropolitan area (including supply to D.C., and parts of Maryland and Virginia) can potentially achieve:

- Up to 5% RNG throughput by 2025,
- Up to 15% RNG throughput by 2030, and
- Up to 20% RNG throughput by 2035.

ICF's analysis of RNG potential at the local, regional, and national level supports the RNG volumes required to achieve these targets. The market- and regulatory-focused efforts that are required to help achieve these targets are discussed in more detail below.

Guiding Principles

To achieve the vision statement objective and throughput targets outlined above, the Greater Washington, D.C. metropolitan area will need to be guided by a set of consistent and clear principles:

- ***Produce and deliver RNG safely and cost-effectively to participants and end-use customers.*** There is growing interest in RNG from consumers, especially in the commercial and industrial sectors. It is imperative that customers across the region know that market actors are delivering a safe product that helps to cost-effectively reduce the environmental footprint of natural gas operations.
- ***Contribute to broader regional GHG emission reduction objectives.*** The RNG strategy must align with the region's broader objectives with respect to GHG emission reductions.
- ***Pursue a flexible regulatory and legislative structure that values RNG deployment appropriately***. The region should seek to develop and support a regulatory and legislative structure that provides sufficient flexibility to achieve cost-effective GHG emission reductions while maintaining safety and reliability. This economy-wide structure should also be balanced and not focused on particular technologies or fuels, given the uncertainties and long timeframes needed to achieve deep decarbonization goals.
- ***Proactively engage with key stakeholders throughout the implementation of the RNG strategy.*** RNG deployment requires close coordination between regulators and stakeholders like gas utilities, LDCs, and investors. Similarly, an effective engagement strategy is needed with potential RNG suppliers (locally and regionally), potential end users in targeted segments (e.g., RNG in transit buses at WMATA), and key industry groups (e.g., AGA, Coalition for Renewable Natural Gas).

Market-Based Approaches to RNG Deployment

ICF has focused on three areas for RNG deployment with respect to market-based approaches, including a pragmatic near-term approach to develop interconnection standards for RNG projects, deploy RNG in the transportation sector, and to work as part of a broader coalition to establish common tracking and verification of RNG attributes across end uses and markets.

Market-based approaches in these areas would address some of the technical, market and regulatory challenges discussed in this report, notably:

- Maximized and immediate deployment of RNG to cost-effective end uses;
- Development of a framework to facilitate broader and long-term RNG deployment;
- Enhanced market certainty and transparency through a tracking and verification framework;
- Clarity related to interconnection costs and gas quality requirements; and
- Cost reductions, technology developments, and efficiency improvements up and down the supply chain driven by increased industry experience with, and number of, RNG projects.

Develop Interconnection Standards for RNG Projects

ICF recommends that gas utility stakeholders work closely with project developers to focus on interconnection standards. As currently constructed, the processes, requirements, and agreements that facilitate the pipeline connection of RNG projects are not uniform, resulting in commercial and technical uncertainties for stakeholders (particularly project developers) that limit the efficiency and, potentially, the viability of different RNG projects. The process of developing interconnect standards does not need to reinvent the wheel; rather, local and regional stakeholders should build upon work done by peers across the country (including in the Northeast and West Coast) to review gas quality minimum standards, monitoring requirements, and other critical components of interconnection.

Ultimately, local and regional stakeholders will need to develop a consistent and impartial approach to assess the commercial and technical potential of each project to encourage the introduction of RNG from a range of feedstocks, without compromising the safety or reliability of the pipeline or end-use applications. A uniform approach will provide greater certainty for all parties regarding safety, reliability, and interchangeability, and lay the groundwork for expanding RNG consumption into larger and more diverse markets and end uses over the long-term future.

Deploy RNG into the Transportation Market

The transportation sector is a natural fit for the near-term focus of RNG deployment in the region: the combination of higher conventional energy costs and existing incentives makes for a clear opportunity.

Despite its modest demand for natural gas as a transportation fuel, RNG consumption in the transportation sector in the Greater Washington, D.C. metropolitan area has potential for immediate growth. In contrast to other parts of the country, there is currently minimal RNG transportation consumption in the region and significant immediate potential for natural gas transportation demand to be supplied by RNG.

ICF estimates that natural gas transportation consumption in the Greater Washington, D.C. metropolitan area is currently about 1.25 bcf per year and is poised for optimistic growth of between 3% and 5%, with potential for more growth depending on market and regulatory incentives. There are opportunities for expanding natural gas consumption in the medium- and heavy-duty vehicle market segments, thereby acting as a conduit for increased RNG deployment. The combination of the total cost of ownership for NGVs and the fueling infrastructure requirements remains a challenge to higher volumes. However, the appropriate combination of policy and market incentives can induce additional growth in NGVs. The regulatory considerations regarding NGV deployment are outlined in the following sub-section.

The market for RNG as a transportation fuel in the region should take advantage of other market forces, notably that California's market for natural gas as a transportation fuel is nearly saturated with RNG. Furthermore, the EPA continues to increase the mandated volumetric consumption of transportation biofuels like RNG—meaning that suppliers will be seeking to find markets other than California to maximize value. This will require closer coordination amongst market actors, including project developers and suppliers, gas utilities (to distribute the gas), natural gas station owners, and natural gas fleets.

Establish Common Tracking Across RNG Markets

There is increasing interest in RNG deployment across multiple markets. Most RNG today is used either in the transportation sector (typically via pipeline injection) or combusted to make renewable electricity. In both cases, these markets have tracking and verification through RINs in the federal RFS and RECs in renewable energy markets, respectively. RNG use outside of these markets, however, is not subject to tracking or verification.

Although there is no analogous tracking system for RNG today, market actors are advancing the concept rapidly to help grow the market for RNG consumption outside of the transportation sector. As noted previously, the Midwest Renewable Energy Tracking System (M-RETS) has been trialing a thermal REC system since July 2019 with the intent of providing the same verification and price transparency to the RNG market as exists in the renewable electricity market.

Tracking will become increasingly important as numerous sectors and regions seek to deploy RNG, and RNG markets expand into multiple and broader end uses over the medium- and long-term. Tracking and verification through certification provides market certainty and can also help assure that markets and credits remain fungible. This will be particularly important for stakeholders in the Greater Washington, D.C. metropolitan area because of the multiple jurisdictions in play, including in D.C., Maryland, and Virginia.

Regulatory Approaches to RNG Deployment

Supportive government policies and regulatory certainty are needed to encourage the long-term adoption of RNG as a decarbonized fuel beyond current uses in the transportation sector, namely into stationary thermal use applications, such as building heating and cooling. A supportive regulatory framework would allow for the recovery of cost in procuring RNG, update gas rule requirements, reflect the cost-effectiveness of RNG as a decarbonization strategy relative to other measures, and capitalize on complementary measures. This type of regulatory framework would address many of the challenges discussed in this report, including:

- Capitalize on and expand current cost-effective end uses;
- Expand markets beyond current RNG end uses;
- Maximize RNG feedstock production through complementary measures;
- Provide necessary competition for various RNG feedstocks;
- Facilitate opportunities for cost reductions and technology development, including for P2G;
- Ensure the costs and benefits of RNG are appropriately shared by RNG market participants and energy consumers;
- Financially reward the significant environmental value of RNG; and
- Recognize and reflect the critical role RNG can play in decarbonizing the natural gas system, and the energy system as a whole, over the long-term.

ICF recommends a regulatory approach that stages potential RNG programs in the near-, mid-, and long-term horizons in an effort to reconcile conflicting requirements. In general, regulators (e.g., utility commissions) tend to prefer piloting new customer programs when customer interest, cost assumptions, and the utility's execution capabilities are unconfirmed. This particularly applies to RNG programs because of the emerging aspects of the technology. Pilot programs are especially pertinent for the development of P2G projects, given the nascent stage of technology development and the uncertain costs associated with P2G.

Utility commissions and ratepayer advocates' concerns, usually driven by prudence and the need to limit or mitigate the risk for costly stranded assets, may not align with a utility's desire to launch broad market transformation efforts. In addition, transitioning from pilots to larger-scale initiatives may involve additional regulatory review, and this has the potential to create a transition period that disrupts progress toward broader RNG deployment by creating delays. Further, these transitions may have a dampening effect on the market as customers delay further RNG investments until new utility programs become available.

Pilot or Voluntary RNG Procurement Programs

As noted previously in Section 6, utilities can offer opt-in voluntary programs to customers to help reduce the environmental impact of their energy supply. This is more common for electric utilities; however, similar programs can be developed for gas utilities and RNG consumption. ICF recommends a near-term regulatory approach that supports voluntary purchase of RNG through gas utility service providers to help foster market growth, improve customer awareness, and to satisfy nascent demand.

Vermont has already approved a voluntary tariff and utilities in New York and California have filed proposals for approval of voluntary RNG tariffs. ICF recommends policymakers and regulators move rapidly to encourage gas utilities in the Greater Washington, D.C. metropolitan area to file voluntary tariffs for RNG deployment, thereby sending a clear and immediate signal to the investor community that the region seeks to be at the forefront of RNG deployment. Voluntary procurement programs will also lay a foundation for establishing RNG demand in end uses beyond the transportation sector.

Expand RNG in Transportation through Infrastructure Investments

As noted in the previous section regarding market-based approaches to deploy RNG, the transportation sector is a clear near-term opportunity for regional RNG deployment. However, the long-term opportunity for RNG in the transportation sector is limited because of low demand growth for natural gas as a transportation fuel. The GHG emission reduction benefits and ancillary air quality benefits of deploying low NOx-emitting trucks presents a unique opportunity for the region. The regulatory market for decarbonizing the transportation sector has favored liquid biofuels at the federal level (via the RFS) and transportation electrification (via the federal tax credit for electric vehicles), with less incentives for natural gas as a transportation fuel.

ICF recommends an innovative regulatory structure to enable utilities to invest and recover costs in fueling infrastructure, offer beneficial and attractive tariffs to CNG users, and partner with key stakeholders to deploy CNG in key vehicle market segments. ICF envisions a regulatory structure analogous to the make-ready approach popularized by transportation electrification assessments whereby the utility helps to defray the costs of deploying fueling infrastructure, but site hosts retain ownership and are responsible for interfacing with the consumer.

Similarly, just as electric utilities are increasingly seeking to offer attractive time-of-use pricing for electric vehicle drivers or design demand response programs that incentivize consumers to charge their electric vehicles at certain times of day, ICF foresees attractive CNG tariffs with provisions requiring a minimal throughput of RNG (e.g., as a percent of total flow). Lastly, ICF recommends that gas utility service providers be afforded the opportunity to partner strategically with third-party fuel providers. Furthermore, ICF recommends a regulatory approach that enables tracking and verification of RNG throughput at CNG stations and enables regulators to impose penalties when minimum RNG throughput targets are not met.

Implementing a Renewable Gas Standard

The RNG market is poised to evolve rapidly over the next three to five years beyond voluntary tariffs and transportation sector demand, and shift into broader stationary end uses. However, in the absence of clearer policy action, RNG deployment has the potential to stall in the same way that emerging renewable energy markets did before RPS programs became more ubiquitous.

Furthermore, the RNG industry faces a difficult transition over the next several years as the transportation sector is increasingly saturated with RNG, and project developers look for new markets and end uses to maximize the value of their project. This transition will be bumpy, and will change the underlying structure of RNG markets in ways that are not entirely understood today. However, the experience of the renewable electricity sector, discussed above, should prove analogous to the opportunities and potential of RNG markets.

In order to smooth the transition to greater RNG deployment over the mid-term future and to achieve the deployment contemplated in the scenarios that ICF developed, an effective and practical policy framework that is conducive for RNG consumption in multiple end uses beyond transportation is required. At a high level, this equates to a regulatory and legislative structure that provides sufficient flexibility to achieve cost-effective GHG emission reductions, and where RNG is viewed as a critical part of broader decarbonization efforts. In this respect, the region's objective would be:

> *A policy structure that drives consistent demand through a utility procurement mechanism that provides supply and price certainty without disrupting the success and market participation in current programs driving existing RNG deployment.*

A well-designed RGS would meet the above objective and provide access to sustainable and considerable end-use markets outside of the transportation sector. Although there are different policy approaches available, a utility procurement mechanism would drive consistent demand for lowest-cost RNG based on market principles, and provide a robust cost recovery mechanism for utilities. A key advantage of an RGS over other measures, including voluntary programs, is that RGS coverage would not be limited to utilities and LDCs, but also include third-party suppliers such as natural gas marketers, similar to the operation of RPS programs. Over the past five years, different advocacy groups across the U.S. have discussed the concept of an RGS as a procurement policy.

The principles of an RGS are straightforward and mimic renewable portfolio standards. It is important to note that any RNG procurement program would not exist in a vacuum. There is limited, but existing, participation in the RNG market, and there are other goals that must be addressed, including promoting in-state or regional economic development, addressing environmental equity considerations, and reducing short-lived climate pollutants. Any RGS design should be complementary to other programs currently driving RNG development and flexible enough to enable market innovation that will maximize benefits and minimize costs.

As summarized previously, ICF considers three different approaches towards implementing an RGS:

- **Free market approach**. The free market approach suggests that a procurement target is established, and the market simply responds to the price signal according to a supply-cost curve (e.g., see Figure 48). ICF notes that while this approach will incentivize lowest-cost resources (likely landfill gas), a slightly more prescriptive design could enable more across-the-board RNG deployment and help achieve other priorities (e.g., in-state economic development) and deployment (e.g., more diverse feedstock supply).
- **Feed-in tariff**. A feed-in tariff, or standard offer contracts, would provide clear, reliable pricing for RNG producers. Although this approach provides a clear signal to help producers finance renewable gas projects, without distinguishing between feedstocks, a feed-in tariff has the potential to favor low-cost producers without recognizing the cost-effectiveness of GHG emission reductions.

  For instance, to incentivize higher-cost pathways, the feed-in tariff would need to be set at a level that would yield considerable windfall profits to lower-cost pathways (e.g., landfill gas). Some markets have included a degradation mechanism for feed-in tariffs to encourage technology cost reductions; however, it is unclear to what extent a simple degradation mechanism could be effective considering the cost disparities expected for different sources of RNG (see Table 33), which may also have varying levels of technology maturity and cost-reduction pathways.
- **Performance-based approach**. The RGS could take on a structure that requires a percent volume target by some date (different from an absolute volumetric target, as is prescribed in the federal RFS program). Similarly, an RGS could take on a structure like California's LCFS program, requiring a percent reduction in the carbon intensity of natural gas by some date.
  - Carbon intensity targets and percent volume targets should, in principle, provide clear signals to regulated parties and investors regarding the timeline required to achieve program targets.
  - The downside of a carbon intensity target is that it may introduce undue complexity to the RGS. For instance, consider the boundary conditions of the lifecycle GHG assessment of dairy digester gas. Without regulations in place to capture and burn the methane that is released, the gas receives a lower carbon intensity for being credited with the avoided emissions from *venting* methane. Landfill gas, on the other hand, being regulated and required to be captured and burned, receives a lower carbon intensity for being credited with the avoided emissions from *flaring* methane. The difference in the GHG benefit of avoided methane venting versus avoided methane flaring is significant: In the case of the former, avoided vented methane emissions have a global warming potential of 25, whereas in the latter, you are avoiding carbon dioxide emissions with a global warming potential of 1. In addition, new regulations can inadvertently change the boundary conditions of the analysis.

- Another consideration related to a carbon intensity-based approach is the potential for the intent of the program to be expanded unexpectedly to include upstream emission reductions, such as methane leaks in the natural gas pipeline. This could provide additional compliance opportunities for utilities that produce additional GHG benefits, but may detract from the intent of stimulating RNG development. Additionally, and similar to the example above, other regulations and programs that address these system improvements could complicate the benefit calculation, creating moving targets and challenging utilities' assessments of investment value for different compliance pathways.

Ultimately, ICF recommends an RGS taking on a hybrid of these approaches with the primary objective of accelerating market development of RNG through supply and price certainty. Despite the success of RNG deployment in the transportation sector, there is still unrealized investment and growth in the sector because of uncertainty linked to existing regulatory programs.

As noted previously, there is clearly a high value proposition for RNG used as a transportation fuel. This value can be leveraged by an RGS to maximize benefits and minimize ratepayer costs, while helping to serve as a diversification strategy for the RNG market. An RGS can provide investors, developers, and utilities with the policy certainty they seek to cost-effectively contribute to decarbonization efforts. The RGS also has the potential to help maintain and build upon the success of the programs that have enabled rapid growth in the RNG market over the last five years.

8. Conclusions

There has been rapid growth in the deployment of RNG projects across the United States over the last five years, with annual growth rates of RNG available for pipeline injection exceeding 25% per year. This rapid growth in the deployment of RNG projects focused on pipeline injection is bolstered by a diverse set of available feedstocks and technologies that can be used to produce RNG.

ICF estimates that there are and will be sufficient RNG feedstock resources at a local, regional, and national level available for both near-term and long-term deployment of RNG to help decarbonize the natural gas system and contribute to the aggressive climate commitments in the Greater Washington D.C. metropolitan area. More specifically, ICF anticipates that there is enough RNG production potential to displace upwards of 25% of total natural gas consumption in direct use applications today. This does not include any potential reductions attributable to conservation or efficiency measures, nor does it account for RNG volumes available if fewer conservative assumptions are applied.

RNG represents a valuable and underutilized renewable energy source with a low or net negative carbon intensity, depending on the feedstock. The GHG emission accounting method and scope employed can have a significant impact on how carbon intensities for RNG are reported and estimated. For some feedstocks, applying the lifecycle emission accounting framework captures the full benefit of RNG's emission reduction potential, such as reflecting avoided methane emissions. RNG can make a significant contribution to the long-term GHG emission reduction objectives in the Greater Washington, D.C. Metropolitan area. When applying a combustion accounting framework, ICF estimates that in the South Atlantic region, 13 to 44 MMT of GHG emissions could be reduced per year by 2040 through the deployment of RNG based on the Conservative Low to Aggressive High scenarios.

In relation to cost, ICF reports that RNG will be available from various feedstocks in the range of $7/MMBtu to $44/MMBtu. ICF anticipates that over time there will be increasing opportunities for cost reductions as RNG production technologies mature, access to feedstocks improves, and the market expands. Anaerobic digestion feedstocks, notably from LFG and WRRF, are and will remain more cost-effective in the near-term. RNG from thermal gasification feedstocks are more expensive, largely reflecting the emerging potential of thermal gasification as a technology, and the associated uncertainties around cost and feedstock availability.

Although RNG is more expensive than its fossil counterpart, in a decarbonization framework the proper comparison for RNG is to other GHG abatement measures that are viewed as long-term strategies to reduce GHG emissions. For abatement cost estimates, RNG at or near $7/MMBtu is equivalent to about $55–$60/tCO_2e, while RNG at $20/MMBtu has an estimated cost-effectiveness of about $300/t$CO_2$e.

In many instances, policymakers, corporations and RNG stakeholders may not be recognizing the complete benefits of RNG due to a limited assessment and reporting scope. In addition, the cost-effectiveness of RNG as an emission reduction measure is generally underestimated and underappreciated, particularly in comparison to other more costly mitigation approaches over the long-term.

The policy framework in place today does not encourage RNG use in stationary thermal use applications, such as for building heating and cooling. However, there is growing interest from some policymakers, gas utilities, and industry stakeholders to grow the production of RNG for pipeline injection and stationary end use consumption. With appropriate incentives that fully capture the environmental benefits of RNG, the end-use demand for RNG from stationary thermal applications is substantial, in contrast to the limited demand in the transportation sector.

There are multiple opportunities and challenges for the wide scale deployment of RNG. A supportive regulatory framework for broad end-use consumption and cost recovery mechanisms for interconnection challenges can help mitigate near-term challenges, while helping the market realize existing opportunities. These near-term actions will help realize the long-term opportunity of increased and varied deployment of RNG via reduced technology and project costs.

Industry stakeholders should expect to play a proactive and positive role in supporting the Greater Washington, D.C. metropolitan area’s various GHG emission reduction goals. In parallel, regulators and policymakers must develop innovative approaches that enable the market for RNG to flourish and take full advantage of the full suite of cost-effective decarbonization strategies.

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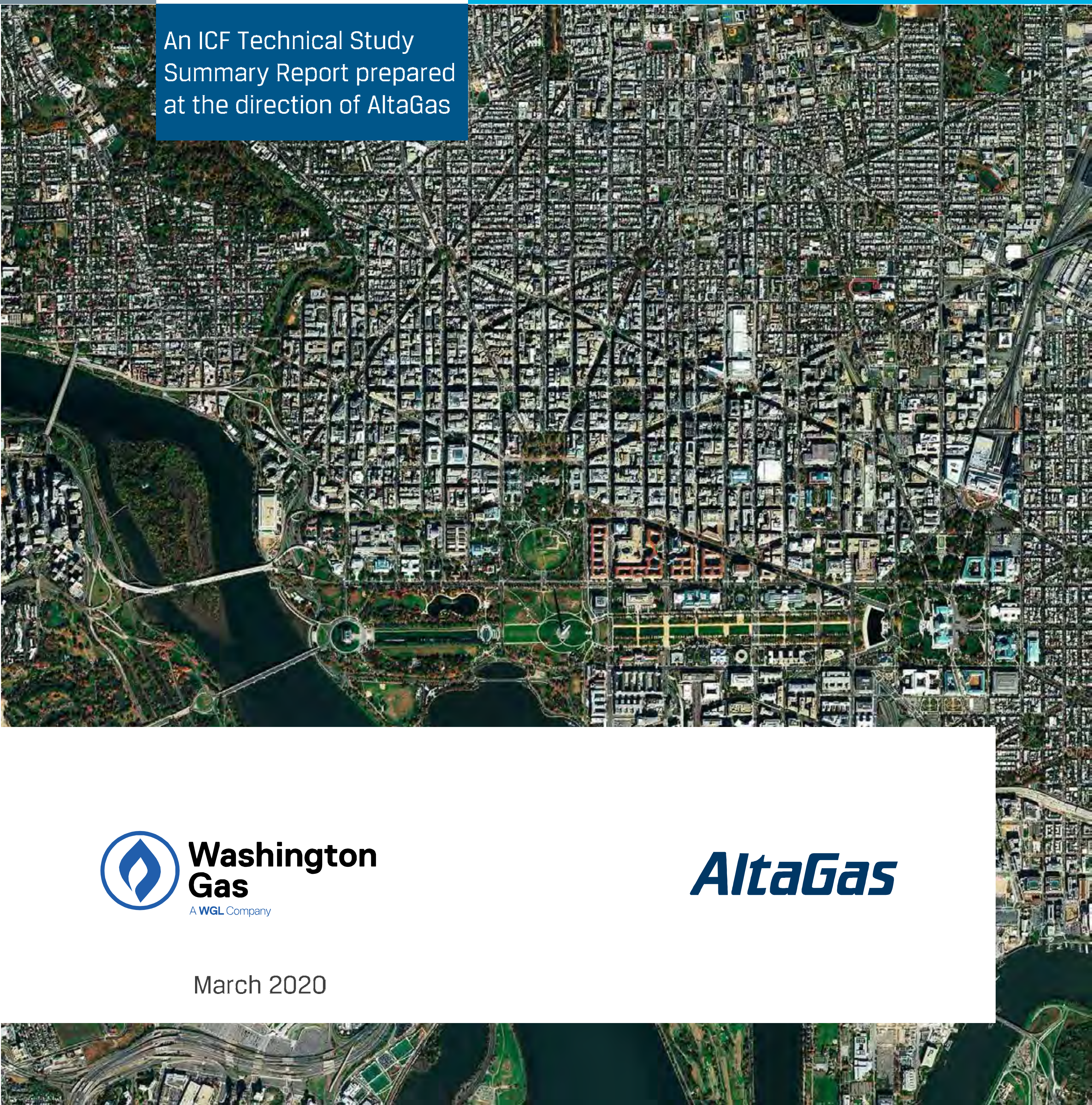
Appendix E: ICF Technical Study Summary

<< provided as a separate attachment >>

Opportunities for Evolving the Natural Gas Distribution Business to Support the District of Columbia's Climate Goals

An ICF Technical Study Summary Report prepared at the direction of AltaGas



Washington Gas
A WGL Company

AltaGas

March 2020

IMPORTANT NOTICE

This report was prepared for AltaGas, Ltd. (AltaGas) by ICF Resources LLC (ICF). AltaGas defined the cases to be evaluated and reviewed the overall methodology and major assumptions.

This report and information and statements herein are based in whole or in part on information obtained from various sources:

- The Energy Information Administration's Annual Energy Outlook 2019 Reference Case, including its energy prices, energy consumption trends, energy-sector emissions, and power generation capacity and dispatch projections, was used as the starting point for the analysis described in this report.
- The study is based on public data on energy costs, costs of customer conversions to electricity, technology cost trends, and ICF modeling and analysis tools used to analyze the costs and emissions impacts for each study case.

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List of Acronyms

Acronym	Description
EIA AEO	Energy Information Administration's Annual Energy Outlook
BAU	Business as Usual
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
COP	Coefficient of Performance
DGE	Diesel Gallon Equivalent
DOE	Department of Energy
EPA	Environmental Protection Agency
EV	Electric Vehicles
GHG	Greenhouse Gas
HDVs	Heavy-Duty Vehicles
ICF	ICF Resources LLC
IPM®	ICF's Integrated Planning Model
LDVs	Light-Duty Vehicles
NREL	National Renewable Energy Laboratory
P2G	Power-to-Gas
PJM	Pennsylvania, Jersey, and Maryland
R&D	Research and Development
RECs	Renewable Energy Credits
RNG	Renewable Natural Gas
RPS	Renewable Portfolio Standard
SEU	Sustainable Energy Utility
TOU	Time-of-Use
WGL	Washington Gas Light Company

Technical Study Summary

1 Introduction

The District of Columbia has made a strong commitment to the development and implementation of a sustainable energy future. The District of Columbia's public commitment to reduce greenhouse gas (GHG) emissions includes a 50% reduction relative to 2006 levels by 2032 and reaching carbon neutrality by 2050. The most recent legislation addressing this topic, the Clean Energy D.C. Omnibus Act of 2018[1], increases the mandate for renewable electricity use in the District by 2032 from 50% to 100%, and requires that all public transportation and privately-owned fleet vehicles be carbon neutral by 2045. Along with the focus on GHG emissions reductions, the District of Columbia sustainability plan also focuses on equity, including actions intended to help residents find opportunities to reduce their utility bills and increase access to affordable housing. While many of the elements needed to meet these objectives - including the commitment to 100% renewable portfolio standard (RPS) - have been determined, the full plan to meet these objectives is still under development.

At the request of AltaGas, ICF conducted a study of alternative approaches to emission reduction strategies for the District of Columbia to meet these commitments. The study started with the premise that the District would meet or exceed its 50% emissions reduction goal by 2032 and would meet its goal of carbon neutral emissions by 2050. AltaGas requested that the study ensure that both the overall GHG emissions reductions and the emissions reductions associated with the use of the Washington Gas natural gas distribution system meet these objectives. In developing its recommendations, AltaGas also asked ICF to think beyond the limitations of existing regulatory structures and traditional fossil-based gases and services.

The primary goals of this study were to:

1) Determine whether emissions from the natural gas system in the District of Columbia could reasonably be reduced consistent with the District's emissions reduction goals.
2) Understand the costs, uncertainties, and tradeoffs associated with meeting the District energy objectives based on different implementation pathways.
3) Identify the appropriate role for the Washington Gas natural gas distribution system in the District of Columbia's low carbon future.

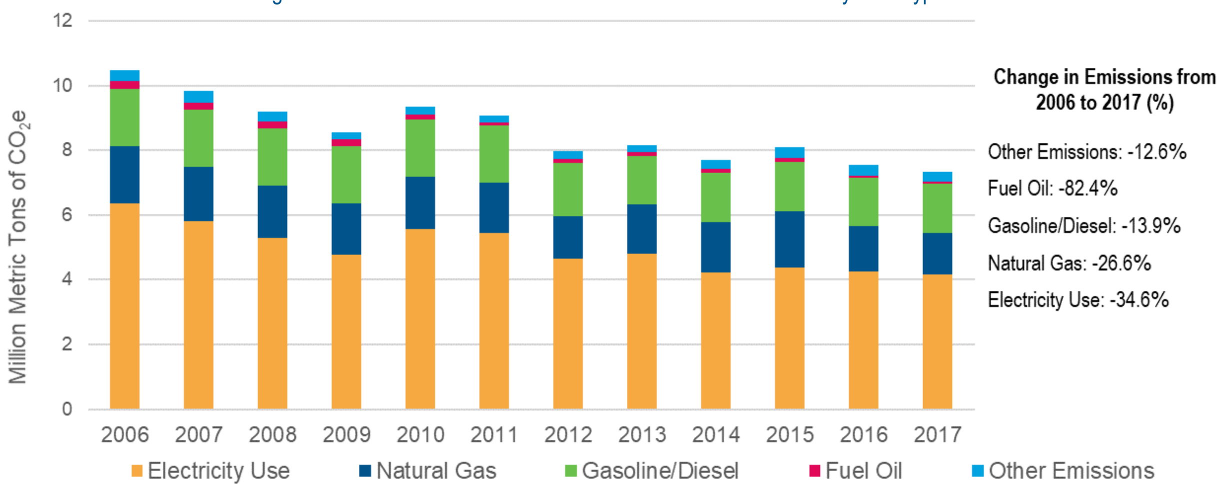
This study was not designed, or intended, to address all the potential issues or alternatives to meeting the District of Columbia policy objectives, nor the region-wide issues and implications of emission reduction policies. The study did not attempt to optimize costs or find the most efficient emissions reduction strategy. Instead, the study was designed to highlight different emissions reduction approaches and strategies capable of meeting the District of Columbia policy objectives and to identify the potential trade-offs, costs, and equity implications of the different approaches.

[1] Sustainable D.C. 2.0 Plan. http://www.sustainabledc.org/wp-content/uploads/2019/04/sdc-2.0-Edits-V4_web.pdf. The 2020 RPS is 20%. There is also a solar carve-out of 1.7% which increases over time.

2 District of Columbia Emissions Profile and Targets

The 2017 District of Columbia District-wide GHG Emissions Inventory shows that the District is on track to significantly outperform the 2032 goal set by the District of Columbia Clean Energy Act.[2] Figure 1 shows total District of Columbia emissions for each year from 2006, the reference year, through 2017, the last year data was available by sector for the District of Columbia. In 2017, overall GHG emissions reported in the emissions inventory were down by 30% relative to 2006 levels and natural gas emissions reported in the District of Columbia GHG Emissions Inventory were down by 26.6% relative to 2006 levels.

Figure 1. Historical District of Columbia GHG Emissions Breakout by Fuel Type



Source: District of Columbia Department of Energy and Environment

The reductions in emissions to date have occurred primarily due to the shift in power generation away from coal toward natural gas in response to lower natural gas prices,[3] District of Columbia implementation of the renewable portfolio standard for electricity supply, and national trends, including lower electricity demand growth, federal fuel efficiency standards, and growth in renewable power generation.

In 2017, emissions from natural gas use were the smallest of the three major emissions sectors and resulted in the lowest emissions per unit of energy:

- **Electricity -** The generation of electric power consumed in the District of Columbia accounted for about 47% of the 83.8 billion kBTUs of energy consumed and 55% of total GHG emissions attributed to the District of Columbia. The emissions attributed to electricity consumption included 42% in non-residential buildings, 9% in residential buildings, and 4% in other applications.

[2] https://doee.dc.gov/service/greenhouse-gas-inventories
[3] CO_2 emissions per unit of input fuel energy or kwh of output are less for natural gas generation than coal generation. Natural gas CO_2 emissions are approximately 45% lower per unit of energy than coal and gas generation on average requires less input energy per unit of output than coal generation.

- **Transportation -** Fossil fuel (gasoline and diesel fuel) use in the transportation sector accounted for approximately 25% of energy use and about 21% of total GHG emissions attributed to the District of Columbia.
- **Natural Gas -** Natural gas use, primarily in the residential and non-residential building sectors accounted for about 27% of the 83.8 billion kBtus of energy used during 2017 in the District of Columbia and 18% of the emissions attributed to the District of Columbia.
  - The emissions associated with natural gas use in the District are primarily the result of use in the District's residential sector; which accounted for 55% of the emissions attributed to natural gas or 10% of the total GHG emissions attributed to the District.
  - Nearly all the remainder is attributed to use in non-residential buildings; this sector accounted for 28% of the emissions attributed to gas or 5% of the District's total emissions.
  - Overall, the residential and commercial buildings sectors accounted for 83% of the natural gas emissions and 15% of the total emissions in the District of Columbia.
  - The remaining 17% of natural gas emissions (and 3% of total emissions) is associated with natural gas used by the GSA (including buildings), and with fugitive emissions attributed to the natural gas distribution system.

The District of Columbia will need to reduce emissions by an additional 20%, relative to 2006, between 2017 and 2032 to meet the 2032 target. By 2032, the emissions attributed to the generation of the electricity consumed in the District are expected to decline to zero due to the 100% RPS standard set by the District of Columbia 2018 Energy Omnibus Act. The elimination of emissions attributed to electricity will reduce overall District GHG emissions by about 61% relative to 2006 levels, well below the 2032 policy target, even prior to consideration of additional policies beyond the power sector. However, actions taken prior to 2032 in the other sectors are necessary to facilitate timely and cost-effective achievement of the 2050 policy target.

By 2032, current District of Columbia energy policy related to renewable electricity is expected to result in a reduction in overall GHG emissions attributed to the District of Columbia to about 27% of 2006 levels (a 73% reduction), before consideration of further reductions in emissions from fossil fuel use, including natural gas used in the buildings sector, and gasoline and distillate fuel in the transportation sector.

Further reductions in emissions from the transportation sector and buildings sector will be needed to meet the 2050 objective of carbon neutrality. In the transportation sector, most users of gasoline and diesel will need to convert to electricity and other low carbon fuels such as Renewable Natural Gas (RNG), hydrogen, or biodiesel. In certain applications, the transportation sector emissions likely will need to be met by a modest amount of carbon emissions offsets. In the buildings sector, owners and end users will need to make additional reductions in energy consumption, and in the carbon content of the energy consumed; users will also be required to decrease energy use in both residential and non-residential buildings.

3 Opportunities to Reduce Emissions Attributed to the Natural Gas Distribution System

ICF reviewed the current natural gas markets in the District of Columbia to determine whether GHG emissions attributed to the natural gas distribution system in the District could be reduced consistent with the District of Columbia climate change policy while leveraging the value and usefulness of the natural gas distribution system in the District. The ICF analysis considered a range of opportunities for reducing GHG emissions attributed to the use of natural gas and the natural gas distribution system in the District, including:

- Improvements in energy efficiency for current and new natural gas consumers.
- Penetration of new end-user technologies designed to reduce energy consumption and emissions, including natural gas heat pumps, hybrid electric heat pump / natural gas furnace space heating systems, as well as Combined Heat and Power (CHP) units to provide space and water heating in commercial and industrial buildings.
- Reductions in the carbon content of the gases distributed by the Washington Gas distribution system, including Renewable Natural Gas (RNG), green hydrogen, and power-to-gas options.
- Reductions in methane emissions associated with the production, transportation, and distribution of the natural gas consumed in the District of Columbia.

Overall, ICF determined that a reasonable mix of these actions would result in reductions in GHG emissions attributed to the natural gas distribution system consistent with the District of Columbia climate change objectives with a modest (less than 4%) contribution from emerging technologies, further adoption of measures already included in the Climate Business Plan, or carbon offsets.

The net contributions from each of these components are shown in Figure 2 and Table 1. The major components are summarized below.

Figure 2. Emission Reductions Attributable to Natural Gas Sector

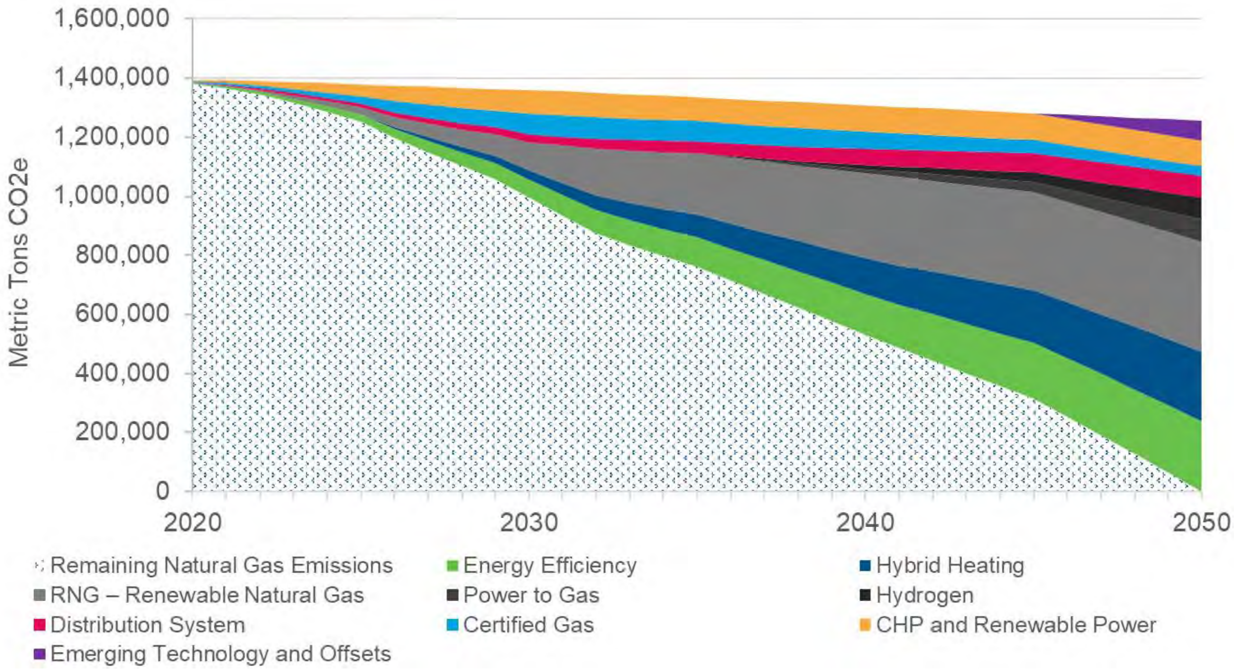


Table 1: 2050 Natural Gas Emission Reductions by Measure

Category / Measure	Annual Emissions (1000's of Metric Tons CO2e)	% of 2006 Levels
2006 Natural Gas GHG Emissions	**1,765**	**100.0%**
Change Between 2006 and 2017	-469	-26.6%
BAU Change Between 2017 and 2050	-41	-2.3%
Energy Efficiency	-239	-13.6%
Hybrid Heating	-235	-13.3%
CHP and Renewable Power	-88	-5.0%
Distribution System	-74	-4.2%
Certified Gas	-31	-1.8%
RNG	-372	-21.1%
Power to Gas	-74	-4.2%
Green Hydrogen	-74	-4.2%
Emerging Technology and Offsets	-65	-3.7%
2050 Natural Gas GHG Emissions	**0**	**0.0%**

Reductions in End-Use Energy Demand

Behavioral Demand Reductions: Behavioral demand reduction programs are a widely accepted approach to reducing natural gas consumption, and have been implemented by Washington Gas in Maryland, and by other natural gas utilities in other jurisdictions. The ICF analysis reflects implementation of aggressive behavioral demand reduction programs in the District of Columbia.

Building and Appliance Energy Efficiency: Improvements in energy efficiency, including improvements in building envelope efficiency and appliance efficiency provide significant opportunities for reducing emissions and will be required to meet the District of Columbia climate change objectives. The ICF analysis is based on implementation of utility-sponsored energy efficiency upgrades reaching 26% of buildings using natural gas by 2032 and 65% of the buildings using natural gas in the District by 2050. Each installation includes an upgrade to appliances and basic envelope upgrades. The building envelope upgrades do not include deep building retrofits due to the high cost of the more aggressive building envelope measures.

Gas-Fired Heat Pumps: Natural gas heat pumps represent a technology in the early stages of commercialization that is expected to be widely available before 2025. Gas-Fired heat pumps use thermal energy to drive a refrigeration cycle to provide space heating and cooling. Like the electric heat pump, a gas heat pump has an efficiency of more than 100%. Between 2026 and 2039, 50% of the energy efficiency upgrades include conversion to a gas-fired heat pump. After 2040, all of the upgrades include a gas-fired heat pump. The programs are expected to address both residential and commercial buildings.

Hybrid Heating Programs: In order to reduce carbon emissions associated with natural gas consumption, ICF has included consumer adoption of hybrid heating systems designed to combine an electric heat pump with a natural gas furnace. The heat pump operates during most of the year and displaces about 85% of the space heating natural gas demand and about 60% of the total annual natural gas demand for the consumer. However, the natural gas furnace operates during the coldest days reducing the need for additional investments in the electric grid once the electric grid peaks during the winter.

Combined Heat and Power (CHP) Programs: CHP installations increase the overall efficiency of energy use in the District. While CHP units increase the amount of natural gas consumed and the emissions from natural gas consumption, the installations also reduce electricity imports, and electricity production in the region where the District of Columbia sources its electricity supply. CHP reduces electricity production and associated emissions from the incremental sources of power generation in the PJM. The mix of marginal power in the PJM is expected to include coal power plants and natural gas combined cycle facilities. Although coal's share is projected to continue to decline over time due to economic and environmental regulatory factors. As a result, the net emissions reductions associated with CHP units decline over time. After 2032, CHP use is expected to reduce emissions primarily from combined cycle natural gas facilities.

AltaGas Renewable Power Investments: AltaGas has committed to developing renewable power as part of the merger agreement between AltaGas and the D.C. PSC. The emissions reductions associated with these investments have been included as an offset to emissions from the Washington Gas distribution system.

Decarbonization of Natural Gas Supply

Renewable Natural Gas (RNG): RNG represents a significant opportunity to reduce the GHG emissions associated with the use of natural gas. In order to meet the District of Columbia GHG emissions reduction targets, ICF has included 3 BCF of RNG in the 2032 natural gas supply portfolio and 7 BCF of RNG in the 2050 natural gas supply portfolio. At these volumes, RNG is expected to cost an average of about $10 per MMBtu more than the cost of conventional natural gas (about $15 per MMBtu in total). Although more expensive than fossil natural gas, using RNG and existing distribution infrastructure is expected to enable a more cost-effective decarbonization pathway than the electrification of many thermal end uses.

RNG from different feedstocks have different levels of GHG emissions reduction, including net negative impacts on GHG emissions from certain feedstocks. ICF has used the simplifying assumption that on balance, RNG will be carbon neutral. RNG is operationally indistinguishable from conventional sources of natural gas.

Power-to-Gas: New technologies are also under development to produce low carbon gas that would be delivered using the Washington Gas natural gas distribution system. These include power-to-gas technologies designed to use renewable electricity to generate 'green' methane from hydrogen. Power-to-gas technologies can provide low carbon methane to the gas distribution system that is operationally indistinguishable from conventional sources of natural gas.

Power-to-gas will need to be cost competitive with other sources of RNG before becoming a significant source of energy. If the costs of this technology are higher than the cost of RNG, RNG would be expected to displace these sources in the market and in the Climate Business Plan.

Green Hydrogen: Hydrogen, which can be produced from renewable electricity, can also be directly injected into the natural gas distribution system. Small amounts of hydrogen can be mixed with methane without significantly impacting system operations. The percentage of hydrogen that can be added to a methane-based gas distribution system depends on the specific system and is subject to ongoing research.

Green hydrogen will need to be cost competitive with sources of RNG before becoming a significant source of energy. If the costs of these technologies are higher than the cost of RNG, RNG would be expected to displace these sources in the market.

Certified Gas Purchases: Currently, about 1% to 1.5% of natural gas produced is emitted to the atmosphere during the production, processing, and transportation of natural gas. However, because methane has an emission factor that is 28 to 36 times the GWP of CO_2, it is important to focus on this reduction.[4] These volumes have dropped dramatically in the last 10 years due to changes in natural gas production regulations and industry practices, however, significant reductions in emissions remain possible. Current efforts by the natural gas industry to reduce emissions include certification of gas produced using industry best practices to reduce emissions. Purchasing of certified gas has the potential to reduce in upstream natural gas GHG emissions (both methane and carbon) by as much as 60% to 80% relative to current average levels. These reductions can be achieved at reasonable costs and represent one of the least expensive approaches to reducing GHG emissions.

Certified Clean Transportation: Transportation of natural gas involves much lower emissions than production and processing. However, further reductions in emissions from gas transportation are feasible at relatively modest costs.

Distribution Pipe Emissions: The 2017 District of Columbia Emissions Inventory indicates that Washington Gas distribution pipe emissions accounted for 7.4% of the GHG emissions attributed to natural gas in 2017. Washington Gas has committed to reducing this value based on investments in system integrity management. ICF has assumed that Washington Gas will be able to reduce methane emissions associated with its distribution system by 80% per unit of throughput by 2050 based on these investments.

Emerging Technologies and Offsets

The decarbonization pathway for the natural gas sector presented here included a modest (e.g. 4%) contribution from emerging technologies and other emissions offsets. There are additional technology options, both currently available and under development, that could close this gap without the use of offsets. At this point it is difficult to predict which of these options will be best placed to meet the remaining gap towards 2050 targets, but some of the options for additional contributions include:

- Future technologies currently under development, such as direct air capture and conversion of carbon dioxide (CO_2) to liquid and gaseous fuels
- Deep building envelope energy efficiency retrofits if cost effective
- Additional contributions from other existing measures, such as increased RNG, green hydrogen, or CHP penetration

The potential for additional contributions from these sources will depend in part on reductions in technology costs, particularly for emerging technologies such as green hydrogen production where projections of future costs vary widely.

[4] EPA, 2019, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2017, https://www.epa.gov/sites/production/files/2019-04/documents/us-ghg-inventory-2019-main-text.pdf. The emissions factor is dependent on the time frame of the calculation. The EPA emissions factor is based on 100 year impact. Over a shorter time period, the emissions factor would be higher.

4 Comparison of Alternative Approaches to Meeting the District of Columbia's Climate Change Objectives

This study evaluated the costs and GHG emissions for four separate, comprehensive, and internally consistent cases representing alternative futures for District of Columbia energy demand and emissions. All four cases rely on energy prices from the Energy Information Administration's Annual Energy Outlook 2019 (EIA AEO 2019) Reference Case. All cases assume a 100% RPS by 2032. All of the cases meet the 2032 objective of a 50% reduction in emissions by 2032. The first two cases (the Business as Usual Case and Partial Decarbonization Case) do not sufficiently decrease emissions to meet the 2050 carbon neutral emissions target. The third and fourth cases (the Policy-Driven Electrification Case and the Fuel Neutral Decarbonization Case) both result in enough emission reductions to meet the 2050 carbon neutral emissions target, but with very different approaches and costs. The four cases are summarized below:

Case 1: Business as Usual ("BAU") Case: This case reflects the expected market conditions in the absence of new efforts to limit GHG emissions in the District of Columbia. The BAU Case assumes moderate growth in the number of natural gas meters, as well as a continuation of historical natural gas efficiency trends. Total emission reductions in the District of Columbia in 2032 and 2050 are approximately 73% and 75% relative to 2006, respectively. This is primarily because of the assumed 100% RPS. The Business as Usual Case represents the baseline for the cost and environmental outcomes of the other three cases.

Case 2: Partial Decarbonization Case: This case starts with the BAU and adds a series of lower cost decarbonization options, including increases in energy efficiency in buildings, gas heat pumps, moderate electrification of the transportation sector, and low-cost RNG supply volumes (10% of 2050 gas demand met with RNG). In this case, emission reductions in 2032 and 2050 are approximately 76% and 82% relative to 2006, respectively. While this case does not reach the 2050 policy goal of zero net carbon emissions, it achieves a significant share of the total objective at a much lower cost than the carbon neutral scenarios.

Case 3: Policy-Driven Electrification Case: This case reaches carbon neutral emissions in the District of Columbia by 2050 based on aggressive electrification of energy demand, including energy demand in the transportation and buildings sectors. The Policy-Driven Electrification Case includes the following:

- Conversion of 96% of residential and commercial buildings from direct use fossil fuels to all-electric energy use.[5] By 2050, 158,630 residential natural gas customers and 9,670 commercial customers are converted to all electric appliances.

[5] Converting all existing buildings to electric space heating will be a significant challenge, and the 4% of buildings continuing to use natural gas in this case in 2050 is representative of uncertainty in how some buildings can be converted (i.e. space constrained historic buildings with hydronic systems).

- Aggressive market penetration of Electric Vehicles (EVs). By 2050, 59% of the light duty vehicle fleet and 32% of the medium- and heavy-duty vehicle fleets operating in the District of Columbia are EVs or plug-in hybrids. EVs will represent 58% of total vehicle sales in 2050. Owners of EVs are assumed to charge during off-peak periods in order to avoid increases in peak electricity demand.[6]

The 7.0% remaining emissions in 2050, relative to 2006, from the buildings, transportation, and other sectors, are assumed to be addressed through the implementation of emerging technologies and the use of carbon emissions offsets if needed.

Case 4: Fuel Neutral Decarbonization Case: This case reaches carbon neutral emissions in the District of Columbia in 2050 based on an approach that leverages the existing natural gas distribution infrastructure in the building sector and includes decarbonization of the natural gas supply. The case has the same transportation sector assumptions as Case 3. The case includes a 50% reduction in emissions associated with natural gas use in the District relative to 2006 by 2032, and a 96% reduction in emissions associated with the use of natural gas emissions from 2006 levels by 2050. The final 4% of emissions attributable to natural gas in 2050 will be addressed through the implementation of emerging technologies and the modest use of emissions offsets if needed. The proposed Climate Business Plan is based on this case. The basic assumptions in this case include:

- Aggressive energy efficiency programs reach 65% of natural gas customers by 2050, resulting in high efficiency furnaces and gas heat pumps, as well as high efficiency gas water heaters and moderate building shell improvements.
- By 2050, 40% of residential and 20% of commercial natural gas customers use supplemental hybrid electric heat pump/natural gas furnace systems, using renewable power for most of the year, and natural gas to meet heating needs on the coldest days.
- CHP in the District of Columbia is used to reduce carbon emissions from power generation outside of the District of Columbia.
- By 2050, 58% of the remaining gas demand is met with low carbon gas, including RNG, Power-to-Gas, and green hydrogen.

As stated above, while emissions related to natural gas use drop by over 96%, city-wide emissions drop by 93.5%. The 6.5% of remaining overall District emissions in 2050, relative to 2006, from the buildings, transportation, and other sectors, are assumed to be addressed through the implementation of emerging technologies and the use of carbon emissions offsets if needed.

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[6] Due to the ICF assumption that all vehicle charging will occur during off-peak periods, it is likely that the increase in peak demand for electricity due to vehicle electrification will be greater than accounted for in this study, leading to higher electrification costs.

Table 2 provides an overview of key parameters for each case in 2050.

Table 2: 2050 Overview of the Study Cases

Sector	Business as Usual (BAU)	Partial Decarbonization	Policy-Driven Electrification	Fuel Neutral Decarbonization
Power	100% RPS by 2032 (100% emissions reduction by 2032) in all Cases			
Transportation	• LDV sales: 14% electric, 3% plug-in hybrid • MDV sales: 2% electric Achieves a 39% emission reduction from 2006 levels	• 2050 LDV sales: 37% electric, 12% plug-in hybrid • 2050 MDV/HDV/Bus sales: 25% electric Achieves a 51% emission reduction from 2006 levels	• 2050 LDV sales: 60% electric, 20% plug-in hybrid • 2050 MDV/HDV/Bus sales: 50% electric Achieves a 69% emission reduction from 2006 levels	
Buildings (Natural Gas)	• Res / Com customer natural efficiency improvements: growth: -0.6% / -0.3% per year (total of -11% / -6% vs. 2017) • Res / Com customer growth: 0.1% / 0.03% per year (total of +10% / +1% vs. 2017) Achieves a 40% emission reduction from 2006 levels	• Increased energy efficiency • Gas Heat Pumps: 16% of customers • Low Carbon Gas (RNG): 10% of supply / 2 Bcf • 80% fugitive emission reductions (per unit of throughput) • Certified gas Achieves a 55% carbon emission reduction from 2006 levels by 2050	• 96% of natural gas customers converted to electricity using efficient air-source heat pumps • Natural gas throughput reduced by 92% Achieves a 94% carbon emissions reduction from 2006 levels by 2050	• Increased energy efficiency • Gas Heat Pumps: 38% of customers • Hybrid Heating: 40% of residential and 20% of commercial customers • Low Carbon Gas (RNG, P2G, Hydrogen): 58% of supply / 9.8 Bcf • 120 MW CHP + 10 MW Solar • 80% fugitive emission reductions (per unit of throughput) • Certified gas Achieves a 97% carbon emissions reduction from natural gas from 2006 levels by 2050
Waste / Water / Other	Unchanged	50% emission reduction from 2006 levels assumed	80% emission reduction from 2006 levels assumed	
	Total Offsets Required (Million Metric Tons of CO_2e)		**-0.73 (7.0%)**	**-0.69 (6.5%)**

Key Methodologies and Assumptions

For each case, costs were calculated based on installed costs of equipment conversions and operating costs, including annual fuel use and maintenance. Key costs for each sector include:

- **Buildings Sector:** Consumer energy purchases, appliance capital and installation costs, energy efficiency programs implementation costs, and the cost premium for low carbon fuels.
- **Transportation Sector:** Fuel costs, operating and maintenance costs, vehicle purchase costs and electric charging infrastructure costs.
- **Power Sector:** Total power system costs, including new generation capacity additions and fuel costs, in PJM in response to changes in power load and policy in the District.[7]

Where possible, the study used projections of technology cost and performance from credible outside sources, including from the National Renewable Energy Laboratory (NREL), Gabel & Associates, Edison Electric Institute, California Air Resource Board, and other public studies.

The study did not consider, except as noted, recovery of any cost of service on the gas system[8] that would not be recovered based on existing rates , or the incremental electric transmission and distribution system costs above the level supported by current electricity rates. Nonetheless, there are reasons why these costs may be significant, especially in the Policy-Driven Electrification Case, and therefore, they should be studied further before a decision to pursue electrification (see later discussion). Other costs that have not been fully accounted for in this study that should be considered before determining a decarbonization roadmap include the cost of decreased reliability and resiliency on the power grid, natural gas system decommissioning costs, and final customer transition costs.

The impacts of policies in other nearby jurisdictions should also be considered. ICF has assumed that other states in the region meet current RPS and other policy requirements, but do not implement more aggressive RPS, climate change or electrification policies. The District of Columbia represents only approximately 1.5% of the total electricity demand in the PJM, and alternative state policies have the potential to fundamentally change power markets in the District. ***More aggressive RPS or climate change policies in the PJM likely would lead to a substantial increase in power costs associated with decarbonization, especially in the Policy-Driven Electrification Case, which has the highest volume of power consumed.*** More aggressive electrification in PJM would also diminish the seasonal diversity benefits the District would receive if the District becomes a winter peaking utility as other parts of PJM also switch from summer peaking to winter peaking. More aggressive electrification could also diminish the reliability benefits of solar power which is less effective at producing energy during the winter peak power demand period thereby further increasing costs of power.

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[7] We have not included the costs of expanding the power grid (i.e. the wires or networks) in the District of Columbia or in PJM in response to load growth resulting from implementation of climate change policy.
[8] For example, in the Policy-Driven Electrification Case, sales volumes on the Washington Gas distribution system decrease to about 8% of current levels by 2050, which would be expected to lead to consideration of a potential decision to shut down the natural gas distribution system. However, the legacy costs and most of the incremental maintenance and safety capital costs associated with maintaining a safe and reliable natural gas distribution system would still need to be recovered during this period. This would lead to higher rates for the remaining customers on the Washington Gas system, and/or require other actions.

Comparison of Alternative Approaches to Decarbonization

Figure 3 compares the GHG emissions from the BAU Case to the emissions in cases 2, 3, and 4. In the BAU Case emissions decrease to 27% of 2006 levels (a 73% reduction) by 2032 and to 25% of 2006 levels by 2050 (a 75% reduction). The reductions occur primarily due to the 100% RPS. In Case 2, the Partial Decarbonization Case, emissions decrease to 24% of 2006 levels by 2032 (a 76% reduction), and to 18% of 2006 levels by 2050 (an 82% reduction). Thus, Case 2 achieves part, but not all of the District's 2050 goal of carbon neutrality. In Cases 3 and 4, the Policy-Driven Electrification and Fuel Neutral Decarbonization Cases, by 2032, emissions decrease to roughly 20% of 2006 levels (80% reduction), and by 2050, emissions decline by 100% (including offsets).

Figure 3. District of Columbia GHG Emissions by Year and Case

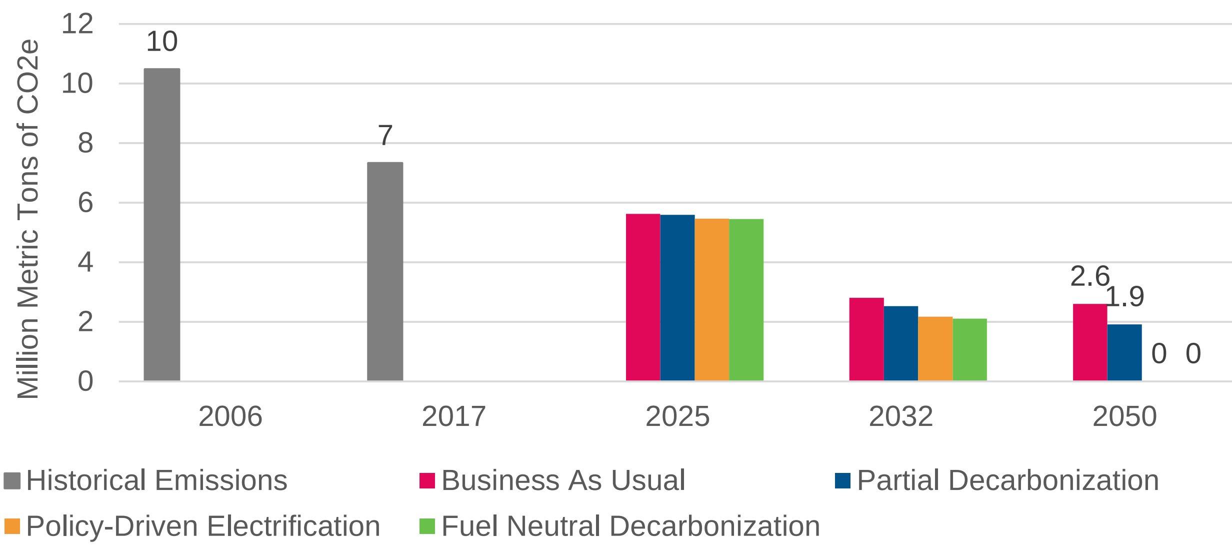

Figure 4 illustrates the cumulative direct cost impacts of the three decarbonization cases relative to the BAU Case, between 2020 and 2050, in real 2018 dollars. The policies from the Partial Decarbonization Case (Case 2) are projected to have a direct cost of about $603 million relative to the Business as Usual Case (Case 1); these policies result in a reduction of GHG emissions of approximately 82% by 2050 relative to 2006. The Policy-Driven Electrification Case is projected to have direct costs to energy consumers of $6.5 billion[9] while achieving 100% emissions reduction by 2050. The Fuel Neutral Decarbonization Case also decreases emissions 100% by 2050, but is projected to have direct costs to energy consumers of $3.8 billion.[10] This is a savings of $2.7 billion or 41% relative to the Policy-Driven Electrification Case. The Policy-Driven Electrification Case costs 70% more than the Fuel Neutral Decarbonization Case for the same emissions result. The reduction in cost relative to the Policy-Driven Electrification Case is

[9] Not including costs for offsets required for the last 7.0% of overall District emissions in 2050.
[10] Not including costs for offsets required for the last 6.5% of overall District emissions in 2050.

primarily due to the retention of natural gas deliveries, which reduce incremental power grid costs and allow for a more cost-effective mix of building decarbonization options.

Figure 4. Impact on District Wide Energy Costs by Sector from 2020 to 2050[11]

	Sector			
Case Name	Transportation	Power	Buildings	Total
BAU	0	0	0	0
Partial Decarbonization	377	137	89	603
Policy-Driven Electrification	350	2,382	3,799	6,532
Fuel Neutral Decarbonization	350	576	2,916	3,843

The cost increases for power are largest in the Policy-Driven Electrification Case. By 2050, the District's peak electricity demand increases 50% and electrical energy demand increases approximately 22% compared to the BAU Case. The increase in electricity demand from the District from 2020 to 2050 results in an increase in PJM power generation costs of about $2.4 billion. Power sector cost increases are driven by the cost of incremental electricity requirements to accommodate the electrification of buildings and the transportation sector.

The direct cost impacts are significant when allocated on a per household basis, as shown in Figure 5. In the Policy-Driven Electrification Case, the increase in direct costs is $19,024 over 31 years, or $614 annually, for the average District of Columbia household. In contrast, in the Fuel Neutral Decarbonization Case the increase in average per household costs is $11,191, or approximately $361 per year.[12] These costs do not include the incremental costs of meeting the 100% RPS since these costs are included in the BAU Case, or any required electricity distribution and transmission costs, which are expected to be substantial but are beyond the scope of this study. They also do not include the costs of any necessary rate increases required to recover the cost of service on the gas distribution system, the cost of any stranded assets on the gas distribution system, the potential costs of decommissioning the gas distribution system or the costs of transitioning the last natural gas customers off the gas distribution system.

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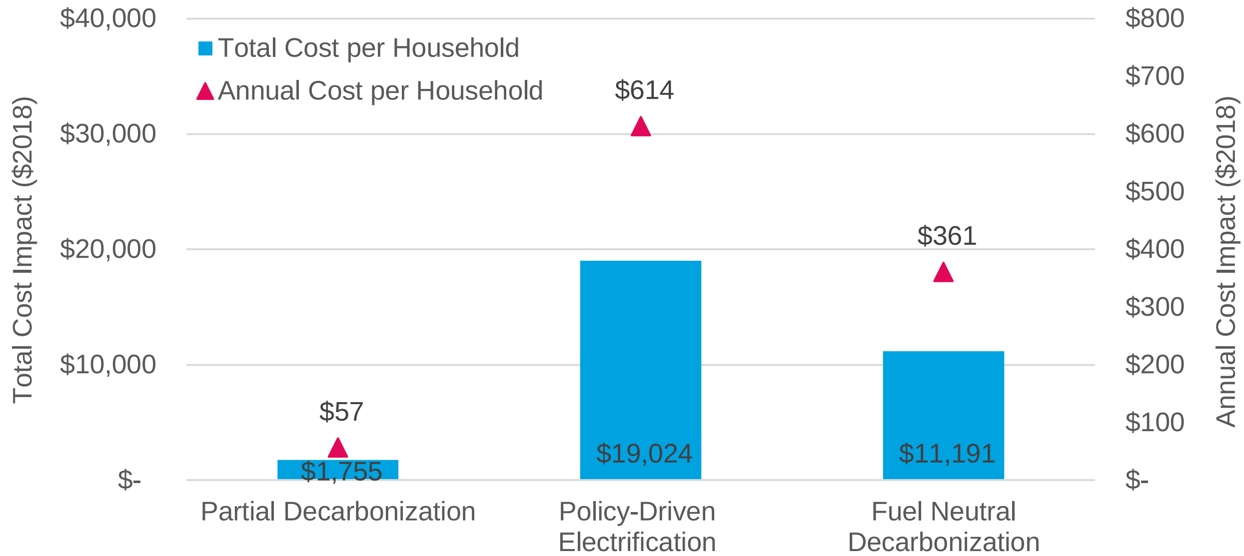
[11] The Transportation sector uses the same costs for both the Policy-Driven Electrification and Fuel Neutral cases. There are two Transportation sector cost scenarios, a base-case cost for electric vehicle and a low-case cost for electric vehicles. Transportation sector costs shown in the figure use the base-case costs for electric vehicles.

[12] Calculated based on 343,356 households, an average of a 2020 to 2050 forecast for the District.

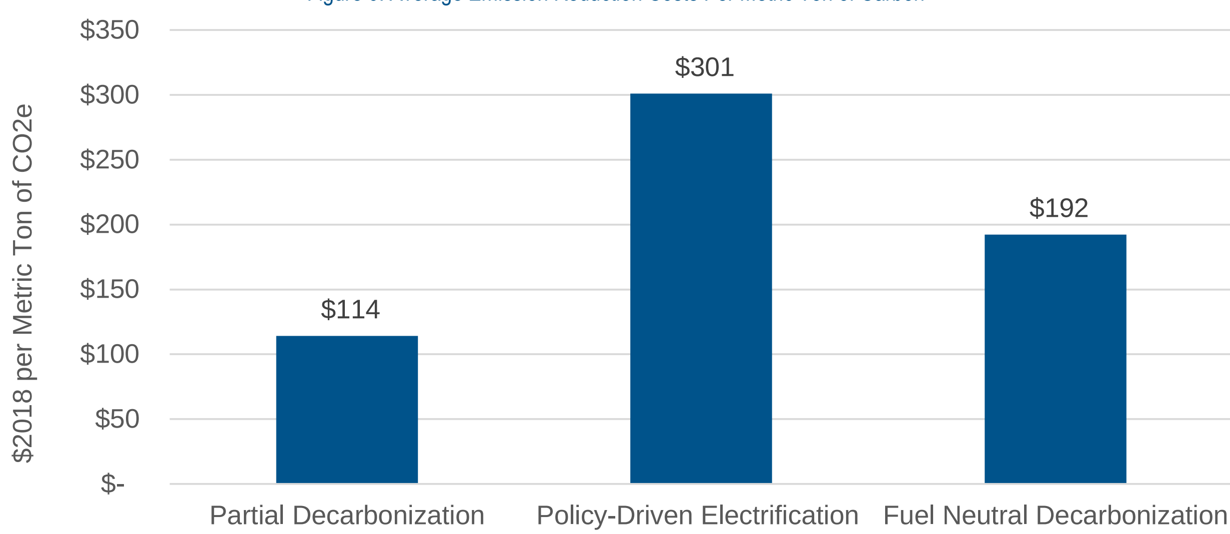
Figure 5. Comparison of Per-Household Costs by Case for the District



The average costs, in $2018 dollars per metric ton of emission reductions, for each of the three decarbonization cases, incremental to the BAU, are shown in Figure 6. The costs per ton of emissions reduction are:

- $114 / metric ton CO_2e in the Partial Decarbonization Case
- $301 / metric ton CO_2e In the Policy-Driven Electric Case, and
  $192 / metric ton CO_2e in the Fuel Neutral Decarbonization Case.

Figure 6. Average Emission Reduction Costs Per Metric Ton of Carbon[13]



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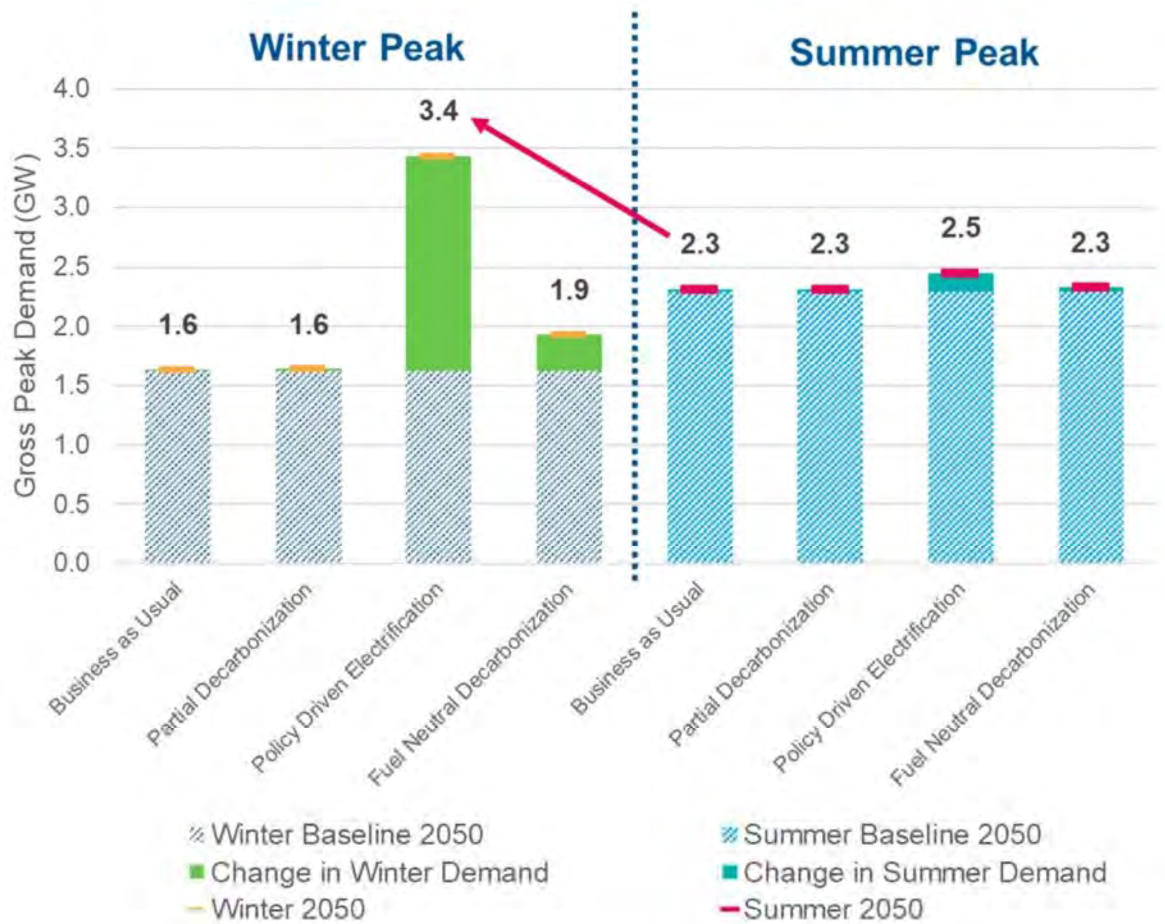
[13] The cost of emission reductions is calculated based on the change in costs and emissions from the Business as Usual case on an annual basis from 2020 to 2050 using a 5% discount rate back to 2018. Note incremental costs – i.e. the costs of going from 82% (partial decarbonization) to 100% reduction - are much higher.

Figure 7 shows the impacts to summer and winter peak electricity demand in the District. In the Policy-Driven Electrification Case, the District's peak electricity demand shifts from the summer to the winter and increases by about 50% relative to the BAU Case.[14] The increase in peak is important because peak demand generally drives infrastructure investment requirements.

Figure 7. Change in District Summer and Winter Peak Electricity Demand Requirements



The current power grid is designed to meet a summer peak demand, including reliance on solar power during peak summer periods. As a result, the shift to a winter peak is likely to lead to a decrease in system reliability and resiliency. In addition, in the Policy-Driven Electrification Case, the District would be switching from a combination of two energy delivery systems to a single energy system to support space heating; from natural gas and electricity to electricity only, reducing the resiliency of the system. The costs of addressing the decrease in reliability and resiliency are not included in the reported costs for each Case.

Table 3 shows the impacts on the District's gas throughput as percentage reduction relative to 2018 levels. By 2050, the Policy-Driven Electrification Case causes a very large decrease in overall throughput on the gas distribution system (92% reduction). This degree of throughput

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[14] This is a conservative estimate because in this analysis, EVs are assumed to charge during off-peak periods, when in fact the charging patterns could coincide to a degree with the electrical peak.

decline would need to lead to consideration of a shutdown of the gas delivery system. This in turn would result in very large stranded costs compared to the Fuel Neutral Decarbonization Case, adverse reliability consequences, and incurrence of additional customer transition costs and system decommissioning costs.

By 2050, the Fuel Neutral Decarbonization Case results in a much smaller decline in throughput on the gas distribution system relative to the Policy-Driven Electrification Case (30% versus 92%). The Fuel Neutral Decarbonization case achieves a slightly greater degree of decarbonization than the Policy-Driven Electrification Case by decarbonizing the remaining gas supply through the use of RNG, green hydrogen, and Power-to-Gas, along with other emissions reductions attributed to the natural gas distributed on the Washington Gas distribution system.

Table 3: Reduction in District Annual Gas Throughput (% Reduction from 2018)

Year	BAU	Partial Decarbonization	Policy-Driven Electrification	Fuel Neutral Decarbonization
2032	3%	7%	31%	5%
2050	10%	23%	92%	30%

Summary of Case Results

The results from the study confirm that there are multiple approaches capable of meeting District of Columbia GHG emissions reduction targets for 2050, based on the technology cost and penetration rate assumptions in each case. The analysis also confirms that emissions from the natural gas system in the District of Columbia could reasonably be reduced consistent with the District's emissions reduction goals, and indicate a key role for the Washington Gas distribution system in the District of Columbia's low carbon future by controlling costs and augmenting reliability.

The study results also highlight the significant differences in the costs of alternative approaches to reducing carbon emissions in the District:

- *Case 2: District of Columbia Partial Decarbonization Case -* The Partial Decarbonization Case achieves 82% of the District's 2050 emission reduction targets with an average incremental annual cost of $57 per household between 2020 and 2050, primarily by implementing a 100% RPS for power purchases (common to all cases), increased building energy efficiency, use of gas heat pumps, inclusion of around 10% RNG in the natural gas supply, and increasing penetration of electric vehicles.
- Case 3: District of Columbia Policy-Driven Electrification Case - The Policy-Driven Electrification Case achieves 100% of the District's GHG goals for 2050 by forcing the electrification of fossil fuel use in the buildings sector as well as in the transportation sector. The electrification of building's space heating load requires significant expansion in power generation and potentially other electric infrastructure (e.g. distribution systems), resulting in an increase in average annual costs of $614 per household between 2020 and 2050, before consideration of the full cost of power sector distribution

and transmission system expansion, costs of carbon offsets, and other transition costs for gas distribution customers.

- Case 4: District of Columbia Fuel Neutral Decarbonization Case - The Fuel Neutral Decarbonization Case also achieves 100% the District's GHG goals using a mixture of energy efficiency, gas heat pumps, hybrid heating systems, CHP, vehicle electrification, low carbon fuels (58% of natural gas supply from RNG, P2G, and green hydrogen), and new technology. This approach to meeting the District's GHG goals will have an average annual cost of $361 per household between 2020 and 2050, well below Case 3.

These cases illustrate the ability to achieve most of the District's decarbonization goals, at a modest cost increment to BAU Case costs, but highlight the significant costs associated with reaching a carbon neutral solution:

- Comparing Case 2 to the BAU: the Partial Decarbonization Case achieves an additional 7% reduction in 2006 emission levels, relative to the BAU Case, at an incremental cost of $0.6 billion.
- Comparing Case 3 to Case 2: the Policy-Driven Electrification Case achieves an additional 11% reduction in 2006 emission levels, relative to the Partial Decarbonization Case, at an incremental cost of $5.9 billion.[15,16]
- Comparing Case 4 to Case 2: the Fuel Neutral Decarbonization Case achieves an additional 12% reduction in 2006 emission levels, relative to the Partial Decarbonization Case, at an incremental cost of $3.2 billion.[16]

These cases also illustrate the impact of the approach to meeting the carbon neutral policy object on overall costs. The last 11% to 12% of the reductions are approximately 73% more costly in Policy-Driven Electrification Case relative to the Fuel Neutral Decarbonization Case – i.e. $5.9 versus $3.2 billion. The higher costs of the Policy-Driven Electrification Case are driven primarily by the costs associated with the electrification of space and water heating in the buildings sector.

[15] Before consideration of the full cost of power sector distribution and transmission system expansion, costs of carbon offsets, and other transition costs for gas distribution customers.
[16] These incremental costs and incremental percentage emission reductions show the difference between Cases 3 / 4 and Case 2. The full 2050 emissions reductions for both Cases 3 and 4, relative to the BAU Case, would be 18% (before offsets). The values exclude the cost and emission reductions of offsets required for carbon neutrality in both cases.

5 Importance of Energy System Resiliency and Reliability During the Transition to a Low Carbon Economy

Large scale electrification of the energy system has the potential to adversely impact the overall energy system reliability and resiliency, and this impact needs to be considered when determining the focus and magnitude of electrification efforts. The District of Columbia currently has three major energy delivery systems, electricity, natural gas and oil. In 2017, the electric grid provided about 47% of the energy consumed in the District, the natural gas distribution system provided about 27% of the energy consumed, and gasoline and diesel fuel for transportation provided most of the remaining 25% of energy consumed.

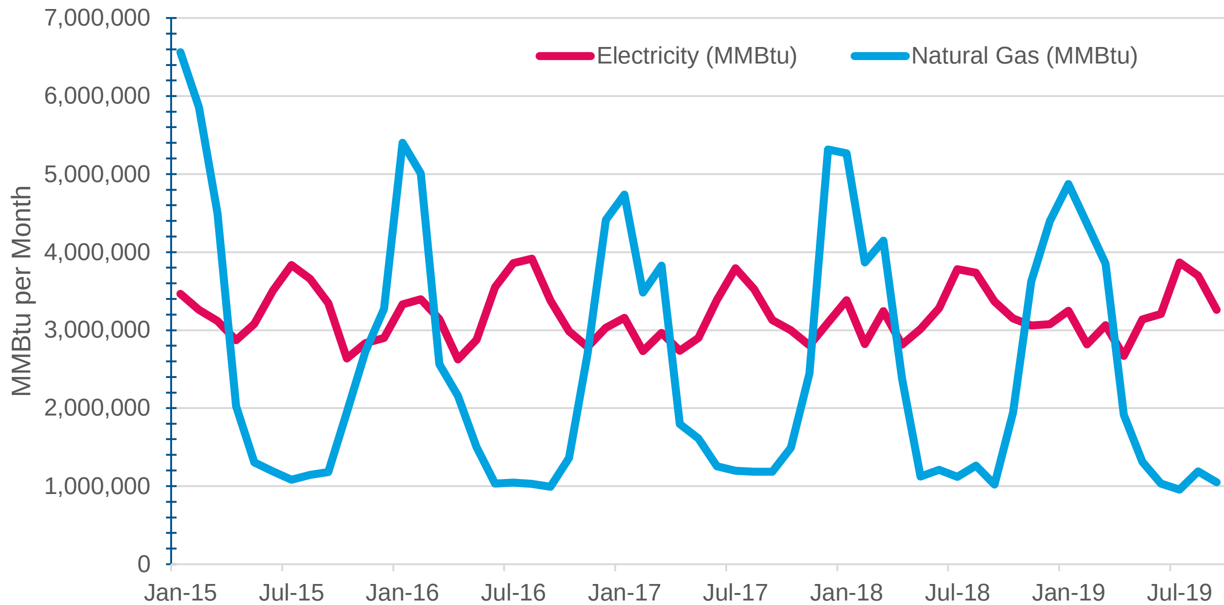
The natural gas system currently plays a very large role in winter energy system reliability in the District. Over the last four full years for which data is available (2015 – 2018), the Washington Gas natural gas distribution system in the District of Columbia has delivered about 75% of the total energy delivered by the electric grid.[17] However, the distribution of energy deliveries over the year varies widely by season. The natural gas system is winter peaking, while the electric grid is summer peaking, and natural gas deliveries are much peakier than electricity deliveries. The U.S. DOE Energy Information Agency (EIA) reports natural gas and electricity consumption in the District of Columbia by month. This data, converted to MMBtu/Month for both fuels, is shown in Figure 8 below. The winter peak for space heating load on the natural gas grid is much larger than the summer peak for air conditioning on the electric grid. Over the last four full years for which data is available, the amount of energy (Btus) delivered during the peak winter month by the natural gas distribution system has averaged 38% higher than the amount of energy delivered by the electric grid during the peak summer month in each year.

While the consumption data shown in Figure 8 illustrates the comparative energy deliveries between the two sources of energy on a monthly basis, it does not illustrate the full disparity in the infrastructure requirements. The natural gas system in the District of Columbia is designed to meet demand under design winter day conditions. The most recent WGL 10K reports a WGL system wide design day for Fiscal 2019 of 21 million therms, or 2.1 TBtu, of which 14.86%, or 0.312 TBtu is allocated to the District of Columbia. The electric grid is designed to meet the peak instantaneous requirements, measured in kW. ICF estimates the peak kW requirement for the District of Columbia to be about 2.3 GW in 2019.

Based on these system design characteristics, the natural gas distribution system in the District is designed to deliver 69% ***more*** energy on a peak winter day than the electric grid is designed to deliver during peak summer conditions.[18] This disparity increases when considering the design characteristics of the gas and electric systems. During a peak hour, the natural gas distribution system would be capable of delivering more than twice the amount of energy that the electric grid would be capable of delivering.

[17] Based on U.S. DOE Energy Information Agency (EIA) data on natural gas and electricity consumption in the District of Columbia from January 2015 through December 2018.
[18] Based on the simplifying assumption that peak electric load would continue for a 24-hour period.

Figure 8. Natural Gas and Electricity Consumption in the District of Columbia



The case where District policy prioritizes electrification over the use of gas in buildings and fossil fuels in the transportation sector reduces these three energy delivery systems into one single fuel energy system, significantly reducing the energy system redundancy. This approach assumes that the transformation of the District's energy supply infrastructure is feasible and does not require fundamental rethinking of District energy resiliency and reliability. While this study is not intended to provide a full assessment of the reliability and resiliency issues associated with such a concentration of the energy system, it is important to highlight the general implications. These include:

- An increase in the reliance on the electric grid is likely to lead to a significant increase in the costs of electricity:
    - The electrification of space heating is expected to cause the electrical distribution system to switch from a summer to a winter peaking system, leading to a large increase in the annual District of Columbia peak electricity demand. ICF estimates that, conservatively, this is likely to exceed a 50% increase in peak period requirements.[19]

[19] One estimate from a reputable environmental organization indicates that full electrification would not only shift the peak power demand from summer to winter but could also double peak electricity demand. *Rocky Mountain Institute, New Jersey Integrated Energy Plan, Public Webinar, November 1 2019, page 23. Full electrification of heating and transportation.* ICF's estimate from this study is 50% but contains conservative assumptions that cause the increase to be low – i.e. lower than expected transportation demand during peak periods, since ICF assumed that almost no EV charging occurs during the peak electricity demand period, as well as no change in reserve margin to address increased resiliency and reliability concerns on a winter peaking system highly reliant on renewable power sources.

- The large increase in peak electricity demand in the District would likely require massive changes in the electricity distribution, transmission, and generation infrastructure supporting the city, especially distribution. ICF did not evaluate the full increase in transmission and distribution costs in part because the required information is not public. However, there are reasons to believe it is likely these costs are large. The District's Sustainable Energy Utility evaluation assumes that lowering peak demand saves transmission and distribution costs of $258/kW per year; 90% of these costs are distribution costs.[20] If $258/kW is applied to the conservative projection of increased peak demand in 2050 of 50%, this would add approximately $0.3 billion per year in costs. This would be equivalent to approximately $2.8 billion in cumulative costs from 2032 to 2050, thereby increasing Case 3 (Policy-Driven Electrification) costs to over $9.3 billion from $6.5 billion. If added, it would make the Policy-Driven Electrification Case 144% more costly than the Fuel Neutral Case, versus the 70% shown in the main study results.

  ICF did not include an estimate of the full increase in electricity distribution, and transmission costs. However, the District should study further potential cost increases and overall feasibility before a decision to pursue major electrification policies.

- It will be challenging and expensive to make the power system as resilient during winter storms, or other contingencies, as the combination of the power and natural gas delivery systems is now. The natural gas system is entirely underground, and not subject to the same risks as electrical infrastructure during winter conditions, especially extreme winter storms. An attempt to increase peak winter resiliency in a power-only system would likely involve higher power reserve margins than currently employed, greater undergrounding, added requirements for local sourcing of power generation, and additional resiliency of power transmission and distribution systems, including possibly a local grid or micro-grid capable of independent operation. None of these costs are included in this analysis.

  Resiliency refers to events that are not likely but have large impacts. Resiliency is already a matter of concern to the District, including the ability to function during major winter storms, and as the nation's capital, maintain both critical federal and local government services. Currently, the District of Columbia is seeking to quantify resiliency benefits.[21]

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[20] TetraTech. (2017). *Evaluation of the District of Columbia Sustainable Energy Utility - FY2016 Annual Evaluation Report for the Performance Benchmarks (Final Draft)*. Madison, WI, USA. See page 31, and 33. The DC SEU uses this study in determining the amount of cost that every kW of demand avoided saves annually– i.e. the distribution and transmission capacity cost is $257/kW-year ($231/kw year for distribution and $27/kW year for transmission). The $0.3 billion per year assumes the reverse is true, namely that adding to peak electricity demand also increases costs.

[21] Comments to Notice Of Inquiry (NOI) submitted on November 12, 2019, by the District of Columbia Department of Energy and the Environment, recommend the establishment of benefit-cost test that

Overall, replacing the energy system reliability and resiliency provided by the natural gas distribution system would be an extremely challenging and uncertain process, especially if the broader power grid in the regions around the District of Columbia adopt RPS policies similar to the District's. This study did not attempt to quantify these challenges.

Importance of a Diversified Technology Approach

A diversified energy system also reduces the risks associated with the long-term uncertainty in the costs of Renewable Energy Credits (RECs) and other costs associated with the target of 100% renewable electricity sourcing. The District's 100% RPS by 2032 is higher than any other state in the region and well above the PJM average RPS. If the level of the grid wide RPS requirements outside of the District increases, the costs of the RECs to District consumers are likely to increase as well. This is in part because the same amount of capital will be required for renewables that are increasingly devoted to displacing peaking fossil generation with lower per kW emissions leading to expected increases in the $/ton and $/MWh premium.[22] Currently, the District has first mover advantage to lock in low cost renewable options.[23] Over time, if grid-wide RPS or electrification levels increase, the costs of incremental REC and electrification options could be much higher. If this happens, a diversified set of decarbonization options could be especially preferred.

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accounts for the cost of resiliency, on page 3, see also pages 14-17, In the Matter of the Implementation of the 2019 Clean Energy DC Omnibus Act Compliance Requirements, Matter No. GD-2019-04-m. See also, "First Report from the Commission on Climate Change and Resiliency. First Report to the District of Columbia October 15, 2019".

[22] Another related phenomenon is the increasing cost of storage as the amount of storage capacity required increases. As the capacity of storage increases as a share of total capacity, it must be able to operate more hours to accommodate the loss of fossil thermal generation and to accommodate prolonged lack of intermittent output.

[23] The level of federal subsidies has also been decreasing and is scheduled to further decrease, increasing the advantage of near-term reductions.

6 Rate Impacts and Other Transition Costs

The cost estimates for the different decarbonization cases shown above reflect many of the incremental costs associated with implementation of the different approaches to reducing GHG emissions. However, the incremental costs included in the ICF analysis are not the only cost increases that consumers should expect to pay as part of the decarbonization efforts. Consumers are also likely to pay higher rates for both electricity and natural gas due to "sunk" cost allocations that are not reflected in the ICF analysis of incremental production costs.

Natural Gas Distribution System Rate Increases

On the natural gas side, per therm distribution rates have been held constant throughout the analysis. However, as natural gas throughput declines relative to the BAU case, distribution rates will need to increase in order to recover the utility cost of service. We have not increased natural distribution rates to reflect this increase since the costs behind the increase are sunk and would not be considered incremental.

The reduction in throughput associated with each of the decarbonization cases will lead to an under-recovery of natural gas distribution system cost of service under the current rate structure. Under current District of Columbia utility regulatory policies, natural gas distribution rates would need to be increased to allow the utility to recover these costs.

Since the Policy-Driven Electrification Case leads to a much larger decline in system throughput than the Fuel Neutral Case, the under-recovery of the cost of service is much larger. Absent any change to the regulatory framework under which utilities recover their cost of service, ICF has estimated the under-recovery of utility cost of service for the Policy-Driven Electrification Case to be about $1 billion higher than in the Fuel Neutral Case, for the period from 2020 through 2050.

In addition, the Policy-Driven Electrification Case is likely to lead to the shut-down and decommissioning of the natural gas distribution system, leading to significant stranded assets and unrecovered ratebase for the gas distribution system that would need to be recovered. [24] If stranded costs are added to give a measure of the incremental challenges of Policy-Driven Electrification Case over the Fuel Neutral Decarbonization Case, recognizing the difference in the type of costs, the Policy-Driven Electrification Case could become more than twice as costly as the Fuel Neutral Decarbonization Case.

Electricity Distribution System Rate Impacts

On the electricity side, the growth in load combined with the shift from a summer peaking utility system to a winter peaking utility system, as well as with the need to address the reliability and resilience issues discussed previously, is expected to lead to significant new investments in the electricity distribution system in the District. The analysis partially considered the impact of the

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[24] A full transition away from the gas distribution system would also require additional customer transition costs for the 4% of customers remaining on the system in 2050. These customers are expected to include the most difficult and expensive customers to transition away from natural gas.

growth in power load on distribution costs by using existing retail power rates to assess the cost impact to consumers of increasing electricity consumption; so utility revenue increases as throughput increases. However, we do not expect that the increase in revenue at current retail rates will be sufficient to fund the necessary power grid upgrades.

While a realistic assessment of these costs should be a critical input when evaluating the alternative approaches to decarbonization, estimating the costs associated with this type of growth in the power grid was beyond the scope of the ICF analysis.

7 Study Implications

Overall, ICF's analysis of alternative approaches to reaching carbon neutrality in the District of Columbia supports the implementation of a fuel neutral approach to decarbonizing the building sector instead of an aggressive policy-driven electrification approach. The fuel neutral approach provides greater long-term flexibility, as well as holding down the costs of decarbonization, including costs[25] associated with;

- Power generation, transmission, and distribution.
- Consumer energy purchases and building retrofits.
- Natural gas system decommissioning.
- Stranded assets on the natural gas distribution system.
- Reliability and resiliency of the overall energy system.

The key implications of the ICF study are summarized below:

1) ***A significant share of the District of Columbia's long-term energy and emissions reduction goals can be achieved reliably and at a modest incremental cost to current policy proposals.***

The Business As Usual Case, including the currently proposed 100% RPS, in combination with current energy efficiency trends and modest vehicle electrification that is likely to occur based on vehicle economics, will lead to emissions reductions of about 73% by 2032 and about 75% by 2050, relative to 2006 emissions, without incurring major energy infrastructure reliability or resiliency risks.[26]

The Partial Decarbonization Case, builds off the BAU and adds a series of lower-cost decarbonization options, including further transportation electrification, increased building energy efficiency, gas heat pumps, and modest RNG supply volumes, and will lead to emissions reductions of about 79% by 2032 and about 82% by 2050, relative to 2006 emissions, at a modest incremental cost to District of Columbia consumers, again without incurring major energy infrastructure reliability or resiliency risks.

As a result, special attention to affordability and to the resiliency and reliability of the energy system in the District of Columbia is critical when planning for 2032 to 2050. The last 18% of the emission reductions needed to reach the carbon neutral policy objective will account for the vast majority of the total incremental compliance costs.

2) ***Reaching the carbon neutral emissions goal by 2050 will require a reshaping of almost all aspects of energy use within the District.***

Changes in consumer energy consumption patterns, including reductions in vehicle miles traveled, time of use energy rates, changes in building codes and permitting practices to discourage energy demand, and other policies designed to reduce energy consumption by

[25] The ICF study cost analysis includes the costs associated with the first two of these cost components.
[26] A region-wide 100% RPS standard would result in potential region-wide electric power grid resiliency risks.

changing consumer behavior are likely to be necessary to meet the District of Columbia climate change policy objectives. These changes are likely to significantly increase the total cost of energy in the District of Columbia, particularly in the buildings sector.

3) ***Greenhouse gas emissions attributed to natural gas delivered by the Washington Gas distribution system can be reduced by 50% relative to the 2006 District of Columbia emissions inventory by 2032 and to carbon neutral emissions by 2050 without eliminating the usefulness of the Washington Gas distribution system.***

ICF's analysis indicates that Washington Gas and District of Columbia consumers can reduce the GHG emissions associated with the use of the natural gas distribution system to meet the District of Columbia climate objectives, based on a combination of programs designed to:

- Reduce energy demand, including energy efficiency, implementation of new natural gas technologies including gas heat pumps, hybrid natural gas furnaces/electric heat pumps, and CHP.
- Decarbonize natural gas supply, including replacement of conventional natural gas with RNG and green (made from renewable power) hydrogen.
- Reduced methane leaks and fugitive emissions throughout the natural gas production, transportation, and distribution system through pipeline modernization, advanced leak detection and remediation, and upstream best practices.

This would enable Washington Gas to deliver energy through the current distribution system consistent with a carbon neutral emissions policy by 2050.

4) ***The cost of reaching carbon neutral emissions in the buildings sector by decarbonizing the existing Washington Gas natural gas distribution system will be significantly lower than the cost of reaching the same level of GHG emissions by electrifying building sector energy requirements and increasing the purchases of renewable power.***

The ICF study results suggest a multi-sector electrification strategy reliant on achieving high electrification penetration levels in the buildings sector is a more expensive emissions reduction strategy than one based on allowing consumer fuel choice in buildings.

- Reducing emissions in the buildings sector through a Policy-Driven Electrification approach results in both the largest expansion of the electric grid and the corresponding elimination of consumer energy choice.
- Across decarbonization cases, power sector costs account for a large share of the total costs to consumers, reflecting the transformational nature of the change needed from this sector to meet emissions reduction targets.

5) *Reliance on electrification of the building sector to meet the 2050 emissions goal could sacrifice the reliability and resiliency of the energy system in the District of Columbia.*

Reliance on electrification of the building system to meet 2050 emissions goals will result in the need to significantly expand the current electric grid to meet peak winter space heating requirements and would eliminate the redundancy, reliability and resilience associated with reliance on two major energy delivery systems (gas and electric) to meet peak winter load.

In addition, to date no one in North America has attempted to convert a major metropolitan energy system away from natural gas to renewable power. Currently, there is no established pathway to achieve the same reliability and resiliency of two energy delivery systems to meet winter peak space heating requirements using only the electric grid without significant increases in energy costs.

6) *An inflexible emissions reduction strategy that is reliant on achieving high consumer adoption and the penetration of new technologies is likely to result in higher costs*

An approach to reducing emissions in the building sector that focuses primarily on electrification of fossil fuel demand, such as the Policy-Driven Electrification Case, is likely to result in a costly emissions reduction strategy that would commit the District to an inflexible emission reduction approach, with limited ability to adapt to new technologies and approaches in the future. This type of approach is also contingent on achieving high penetration rates of new electric technologies and the large-scale conversion of appliances in existing buildings, despite the lack of experience with the implementation of these types of transformational policies on the scale that would be necessary.

- This approach results in an expensive expansion of energy storage and generation requirements in the PJM, while future cost estimates and emission reductions are contingent on the assumption that electric technology performance improves relative to fossil-fuel based appliances which now provide significantly greater efficiency in hot water and space heating.
- It will take multiple decades for the building stock to turn over. Converting a majority of existing buildings from natural gas or fuel oil to electric heating systems, which is needed to achieve the emission reduction targets in Policy-Driven Electrification Case, is a large, and expensive logistical challenge given the heterogeneous nature of the District's building stock.

7) *The decline in throughput on the natural gas system in both the Fuel Neutral and Policy-Driven Electrification cases will require changes in rates and rate structures to assure recovery of the full cost of service, and in the Policy-Driven Electrification case to address stranded assets and system transition costs.*

Without changes in gas system rates and cost recovery practices, ICF estimates that Washington Gas is likely to under recover the non-gas cost of service for the period between 2020 and 2050 in both the Fuel Neutral Decarbonization and Policy-Driven Electrification Cases due to the decline in natural gas throughput. The necessary changes could include decoupling of throughput from cost recovery, restructuring of rates to reduce cost recovery related to throughput. The changes could also include cost sharing with the electricity customers when Washington Gas programs increase costs to gas consumers while reducing the cost impacts of decarbonization on electricity customers. The under recovery of the cost of service in the Policy-Driven Electrification Case would add an additional one billion dollars to the cost difference relative to the Fuel Neutral Decarbonization Case.

The Policy-Driven Electrification Case is also likely to lead to the termination of service on the gas distribution system in the District. ICF estimates that this would lead to additional customer transition costs of around $800 million or more to convert the last remaining customers to electricity, and would lead to stranded assets of around $1.5 to $2.1 billion in unrecovered rate base in 2050, as well as distribution system decommissioning costs that have not been estimated. These costs can be avoided if the natural gas distribution system remains used and useful.

8) Alternative approaches to decarbonization are likely to have significantly different impacts on different customer groups, resulting in equity concerns.

Reaching the carbon neutral emissions target by 2050 will result in significant increases in the cost of energy services to buildings sector consumers, and particularly to current Washington Gas customers. These costs will include both the increase in costs to the electricity sector that will be spread over all energy consumers, as well as the costs of reducing buildings sector emissions from the use of natural gas. The cost of reducing emissions from buildings sector natural gas use will fall primarily on current Washington Gas customers, particularly the lower income customers in older buildings that will be harder to update, leading to significant equity concerns with an approach that requires electrification of most of the building stock in the District.

Regardless of the approach taken to decarbonization, these customers will see potentially significant cost increases. However, the cost impacts on these customers in the Fuel Neutral Decarbonization Case will be significantly lower than in the Policy-Driven Electrification Case.

9) An adaptive and flexible approach to decarbonization provides market participants with more options to reduce emissions and to reduce costs

While certain approaches to reducing carbon emissions, including promotion of energy efficiency and renewable power and partial conversion of the transportation sector to electricity will clearly play significant roles in climate change policy, in many areas it is still unclear which technologies and approaches are likely to result in the most cost-effective long-term emissions reduction approaches.

- The utilization of multiple emissions reduction pathways and technologies, such as the approach reflected in the Fuel Neutral Decarbonization Case, can result in lower costs to consumers through improvements in overall energy efficiency, the utilization of current infrastructure, and consequently the avoidance of expensive investments in new power sector infrastructure investments.

- The emissions reduction approach that will best meet the District of Columbia climate objectives is likely to change over time and should be able to consider future regulatory structures, market developments, consumer behaviors, and technology innovations.

10) There is likely to be a role for new and developing technologies to reduce future emissions

Low-carbon fuel technologies, including currently available technologies such as renewable natural gas appear capable of playing a significant role in meeting emerging GHG emissions reductions targets, and, if promoted and developed, can provide a ceiling on the cost of reaching District of Columbia's policy objectives. These technologies are expected to be available at costs equivalent to or lower than the cost of electrification of some fossil fuel end uses.

In addition, technologies currently under development including green hydrogen, as well as direct air capture and conversion of carbon dioxide (CO_2) to liquid and gaseous fuels, and power-to-gas (P2G) technologies, and other emerging technologies are likely to be developed and to become capable of contributing to reducing GHG emissions over time.

Energy policy should be designed to promote the development of these technologies, rather than closing off the development opportunities for these technologies. In the absence of such new technology developments, further adoption of measures already included in the Fuel Neutral Decarbonization Case could also take a larger role to meeting emission reduction targets.

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BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

IN THE MATTER OF THE APPLICATION OF WASHINGTON GAS LIGHT COMPANY FOR AUTHORITY TO INCREASE EXISTING RATES AND CHARGES FOR GAS SERVICE	)))))	**Formal Case No. 1162**

AFFIDAVIT OF VIRGINIA PALACIOS

I, Virginia Palacios, declare under penalty of perjury that the foregoing testimony and exhibits, originally filed on July 31, 2020, were prepared by me or under my direct supervision; and that the contents therein are true and correct to the best of my knowledge, information, and belief.

Virginia E. Palacios

Virginia Palacios

November 10, 2020

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I hereby certify that on this 12th day of November 2020, copies of the foregoing were electronically delivered to the following parties of record:

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