BEAT
Berkshire Environmental
ACTION TEAM
20 Chapel St., Pittsfield, MA 01201
413-464-9402 • www.thebeatnews.org
no fracked gas in mass.com
Protect Our Common Wealth
A Program of Berkshire Environmental Action Team
Working with you to protect
the environment for wildlife

September 18, 2020

Sharon Weber
Massachusetts Department of Environmental Protection
1 Winter Street
Boston, MA 02108

Submitted via email: climate.strategies@mass.gov

Program review of the 310 CMR 7.73: *Reducing Methane Emissions from Natural Gas Distribution Mains and Services* regulation

Dear Ms. Weber,

Thank you for the opportunity to submit our comments on the program review of the ***Reducing Methane Emissions from Natural Gas Distribution Mains and Services*** regulation. Please accept these comments from Berkshire Environmental Action Team (BEAT) and it's No Fracked Gas in Mass program. BEAT works to protect the environment for wildlife in support of the natural world that sustains us all. No Fracked Gas in Mass works to stop the expansion of fossil fuel infrastructure in the Northeast states and to promote energy efficiency and sustainable, renewable sources of energy and local, permanent jobs in a clean energy economy.

In answer to questions asked by DEP at the Stakeholder Meeting:

- ***Should the decreasing annual emissions limits be extended beyond 2020?***

Yes. With even the LDC spokesperson agreeing at the stakeholder meeting, continuing decreasing the annual emissions limits should be the bare minimum baseline scenario. If anything there should be a steeper rate of incremental decrease in emissions each year while we phase out fossil fuels to comply with our state's 2050 Decarbonization goals[1].

[1] "Determination of Statewide Emissions Limit for 2050," Karen Theoharidies, Executive Office of Energy and Environmental Affairs. April 20, 2020
https://www.mass.gov/doc/final-signed-letter-of-determination-for-2050-emissions-limit/download

- ***What are the most appropriate emission factors or other metrics to determine emission limits and evaluate progress?***

The current method is to only count known leaks from specific utility-identified self-reported locations. As stated in the Stakeholder Meeting, all methane detected should be counted, regardless of whether the source is identified or not[2].

We would also like to see the DEP using the 20-year calculations of methane impact instead of the 100-year. It has been scientifically proven that methane is most active in the atmosphere for the first 20 years[3]. It is also during these next 10 years before 2030 that the IPCC says we need to lower our GHG emissions to below pre-industrial levels to avoid a global temperature increase of 1.5°C and its effects of climate change[4].

Using the 100-year calculations for methane's CO2 equivalency paints an inaccurate picture of its impact during this crucial decade. As we observe worsening conditions from climate change happen worldwide before our eyes[5], it is irresponsible to continue using an inaccurately moderate factor to calculate the impact of our state's methane emissions.

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[2] Recommendation made by Zeyneb Magavi of HEET, DEP Stakeholder Meeting, September 10, 2020.

[3] "Radiative forcing of carbon dioxide, methane, and nitrous oxide: A significant revision of the methane radiative forcing" M. Etminan, G. Myhre, E. J. Highwood, K. P. Shine, December 27, 2016
https://agupubs.onlinelibrary.wiley.com/doi/full/10.1002/2016GL071930

[4] "Global Warming of 1.5°C: *an IPCC special report on the impacts of global warming of 1.5 °C", International Panel on Climate Change. October 8, 2018.*
https://www.ipcc.ch/site/assets/uploads/sites/2/2019/06/SR15_Full_Report_High_Res.pdf

[5] "The analysis found that wildfires and their compounding effects have intensified in recent years — and there's little sign things will improve. The last 10 years have shattered records. 2020 tops them all." The worst fire season ever. Again. By Priya Krishnakumar and Swetha Kannan, Los Angeles Times, September 15, 2020.
https://www.latimes.com/projects/california-fires-damage-climate-change-analysis/

"Scientists say that climate change, which has also contributed to the wildfires on the West Coast, helped intensify a storm that is unleashing a deluge in Florida, Alabama and Mississippi. Climate change has made hurricanes wetter and slower, scientists have found. Recent research suggests that global warming — specifically in the Arctic, which is warming much more rapidly than other regions — is playing a role in weakening atmospheric circulation and thus potentially affecting hurricane speed." Hurricane Sally Is a Slow-Moving Threat. Climate Change Might Be Why. By Richard Fausset, Rick Rojas and Henry Fountain, New York Times, September 15, 2020.
https://www.nytimes.com/2020/09/15/us/hurricane-sally.html

"A big chunk of ice has broken away from the Arctic's largest remaining ice shelf - 79N, or Nioghalvfjerdsfjorden - in north-east Greenland. The ejected section covers about 110 square km; satellite imagery shows it to have shattered into many small pieces. The loss is further evidence say scientists of the rapid climate changes taking place in Greenland. July witnessed another large ice shelf structure in the Arctic lose significant area. This was Milne Ice Shelf on the northern margin of Canada's Ellesmere Island." Climate change: Warmth shatters section of Greenland ice shelf, By Jonathan Amos BBC Science Correspondent, September 14, 2020.
https://www.bbc.com/news/science-environment-54127279

PLAN FOR TRANSITION AWAY FROM FOSSIL FUEL BUSINESS MODELS

The DEP has failed to take the most impactful method of methane reduction into account - a rapid transition away from use of natural gas. Attorney General Maura Healey, in order to make sure the Commonwealth is able to comply with it's own 2050 net-zero greenhouse gas emissions goals, has demanded that the DPU investigate plans for local gas distribution companies (LDCs), to transition away from fossil fuel business models[6].

It is alarming to see that one of the set-asides is for "Greater distribution system growth than anticipated" when we should not be adding any additional sources of GHG to our statewide budget. It is counter to our state law, mandated by the Global Warming Solutions Act and our 2050 Roadmap to Decarbonization[7].

- ***Are there practical, economically feasible technologies to detect and quantify gas leaks?*** *Are DPU's 3/22/2019 regulation 220 CMR 114 Uniform Natural Gas Leaks Classification (which details technologies to detect and quantify the areal extent of gas leaks) and 12/27/2019 regulation 220 CMR 115 Uniform Reporting of Lost and Unaccounted-for [LAUF] Gas (which quantifies LAUF components) sufficient?*

Self-reporting via the Annual Service Quality Report as required in 220 CMR 144[8] is insufficient. Acceptance of utility self-reporting as the only method of measurement is fraught with potential for under-reporting or wholesale failure to report certain leaks if not in the interest of our investor-owned utilities.

As stated by Audrey Schulman of The Home Energy Efficiency Team (HEET), current calculations are currently more fair to the utilities than to the climate. Reporting needs to come from non-utility sources as well. As science gets better, we should be allowed to re-petition to change methodologies to keep up with new methods.

BEAT would like to see DEP take the lead as a true regulatory agency with the ability to conduct regular measurements of methane in proximity to infrastructure in the state. Agency-conducted measurements should be available whenever leaks are suspected as

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[6] "The Office of the Attorney General ("AGO"), pursuant to G.L. c. 164, §§ 76, 105A; G.L. c. 12, §§ 11E, 10; and the AGO's common law authority to act in the public interest, respectfully requests that the Department of Public Utilities (the "Department") initiate an investigation to assess the future of local gas distribution company ("LDC") operations and planning in light of the Commonwealth's legally binding statewide limit of net-zero greenhouse gas ("GHG") emissions by 2050." Petition of the Office of the Attorney General Requesting an Investigation into the impact on the continuing business operations of local gas distribution companies as the Commonwealth achieves its 2050 Climate Limits, June 4, 2020. https://www.mass.gov/doc/dpu-gas-petition/download

[7] "Determination of Statewide Emissions Limit for 2050," Karen Theoharidies, Executive Office of Energy and Environmental Affairs. April 20, 2020
https://www.mass.gov/doc/final-signed-letter-of-determination-for-2050-emissions-limit/download

[8] "220 CMR 114.00: UNIFORM NATURAL GAS LEAKS CLASSIFICATION, Section 114.08: Reporting Requirements," Page 4 https://www.mass.gov/doc/220-cmr-114-uniform-natural-gas-leaks-classification/download

well as follow-up testing to reported leaks and random atmospheric testing near gas infrastructure.

It would be advisable to work in close collaboration with HEET and other similarly qualified non-profit organizations, either in using their extensive data or in learning their detection and mapping techniques.

REFORM TO ENERGY EFFICIENCY PROGRAMS

A key component to reducing demand on existing systems is maximizing energy efficiency. Our state's energy efficiency programs need to be removed from the control of for-profit utility companies. For the same reason that reliance on utility self-reporting of leaks is fraught with potential for under-reporting, energy efficiency goals and administration need to be in the hands of non-profit-making entities. Selling energy and overseeing its conservation are goals at cross-purposes with each other. Recent investigations have shown that the natural gas industry is investing in anti-electrification marketing[9], when strategic electrification supported by a transition of the grid to 100% non-combustion renewable supply is crucial in meeting our climate goals..

Programs need to streamline weatherization and electrification processes and include increased state benefits for pre-weatherization barrier remediation for low to middle income (LMI) households. As the Mass Save program stands now, the process can be time consuming and confusing to residents with lower English proficiency or LMI households with multiple jobs and inadequate time to invest in completing all the steps necessary to navigate the system. Yet these are often the homes in most need of energy efficiency upgrades[10].

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[9] *"Gas industry trade associations are spending large sums, some of it taxpayer dollars, on public relations (PR) campaigns, astroturfing and front groups to oppose initiatives aimed at curbing direct gas use. … including astroturfing, cynical marketing campaigns targeted at millennials, coordination with climate denier organizations …" "Unplugged: How the Gas Industry Is Fighting Efforts to Electrify Buildings" By Dana Drugmand, DeSmog Blog, July 28, 2020*
https://www.desmogblog.com/2020/07/22/unplugged-how-gas-industry-fighting-efforts-electrify-buildings

[10] *Low-income households carry a larger burden for energy costs, typically spending 16.3% of their total annual income versus 3.5% for other households (2014 ORNL study). Often, they must cut back on healthcare, medicine, groceries, and childcare to pay their energy bills. Weatherization returns $2.78 in non-energy benefits for every $1.00 invested in the Program (National Evaluation). Non-energy benefits represent tremendous benefits for families whose homes receive weatherization services. After weatherization, families have homes that are more livable, resulting in fewer missed days of work (i.e. sick days, doctor visits), and decreased out of- pocket medical expenses by an average of $514. The total health and household-related benefits for each unit is $14,148 (National Evaluation)". Weatherization Works! US Department of Energy. June 2019*
https://www.energy.gov/sites/prod/files/2019/07/f64/WAP-Fact-Sheet-2019.pdf

In summation:

- BEAT would like to see DEP continue decreasing annual allowed emissions, though at a more rapid pace to keep up with state mandates for GHG reduction goals

- BEAT would like to see DEP take on methane monitoring in collaboration with experienced non-profit organizations, to reduce reliance on utility self-reporting of gas leaks, along with the ability for the public to petition for re-evaluation of methods as science in the field continues to improve

- BEAT would like to see the elimination of a set-aside for “Greater distribution system growth than anticipated”, and an enforcement of our state climate laws by not allowing ANY distribution system growth, in fact, shrinking the distribution system instead. DEP should be advising the DPU to not permit any new fossil fuel infrastructure, in keeping with our 2050 Decarbonization Roadmap.

- BEAT would like to see increased interest from DEP in streamlining energy efficiency efforts in the state as a means to reduce downstream emissions and pressures on existing LDC systems.

Respectfully submitted,

Jane Winn, Executive Director
Berkshire Environmental Action Team

Rosemary Wessel, Program Director
No Fracked Gas in Mass, A Program of Berkshire Environmental Action Team

Cc:
Kathleen Theoharides, Secretary of Energy and Environmental Affairs
Attorney General Maura Healey
Charles Baker, Governor of the Commonwealth of Massachusetts

September 18, 2020

To: climate.strategies@state.ma.us
Attn: Sharon Weber, MassDEP
Re: Comments on Regulation 310 CMR 7.73 Reducing Methane Emissions

These comments are submitted by Maryann Sargent and Steven Wofsy from Harvard University and Lucy Hutyra from Boston University in support of the review of regulation 310 CMR 7.73 Reducing Methane Emissions from Natural Gas Distribution Mains and Services.

What is the best estimate of methane emissions from Natural Gas infrastructure in Massachusetts?

Methane emissions from natural gas infrastructure can be estimated by either "bottom-up" or "top-down" methods, which are complementary to each other. In bottom-up methods used in many inventories, leaks are measured for a sample of pipeline types, meters, appliances, etc., and multiplied by the total miles of pipeline, number of meters, or household appliances to determine total emissions. One challenge in using bottom-up inventories is the "fat tail" distribution problem; typically a large portion of the methane emitted is from a small number of pipes/meters/appliances that have much larger emissions than the average. If the sample tested for leaks does not contain a representative number of strong emitters, the total emissions can be biased low. Another potential problem is sources or sectors missing from the inventory.

Top-down methods quantify emissions based on the methane concentration measured in the atmosphere along with wind data and meteorological models to provide an integrated assessment of emissions from a region. Unlike bottom-up methods, they have quantifiable uncertainties and the ability to apply a consistent methodology over time for the detection of trends.

Top-down studies of urban natural gas emissions across 6 U.S. cities have all shown significantly higher NG emissions (2-6 fold higher) than bottom-up inventories[1] [2] [3] [4]. The top-down measurements capture all emissions in the city, including end-user losses of gas not included in the DEP inventory. This consistency across cities with different topography, wind patterns, and model frameworks carried out by different research groups provides confidence that there are very likely large missing sources of emissions in bottom-up methane inventories.

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[1] Plant, G., et al. (2019). Large fugitive methane emissions from urban centers along the U.S. East Coast. *Geophys. Res. Lett., 46*, 8500–8507. https://doi.org/10.1029/2019GL082635
[2] Lamb, B. K. et al. (2016). Direct and Indirect Measurements and Modeling of Methane Emissions in Indianapolis, Indiana. *Environ. Sci. Technol.* 2016, 50, 16, 8910–8917.
[3] Wunch, D., et al. (2016). Quantifying the loss of processed natural gas within California's South Coast Air Basin using long-term measurements of ethane and methane. *Atmos. Chem. Phys., 16*, 14091–14105, 2016.
[4] Ren, X., et al. (2018). Methane emissions from the Baltimore-Washington area based on airborne observations: Comparison to emissions inventories. Journal of Geophysical Research: Atmospheres, 123, 8869–8882. https://doi.org/10.1029/2018JD028851

Natural gas emissions from Boston urban Region

Our groups maintain a network of 5 spectrometers located on tall buildings in Boston and towers outside the city which have continuously measured atmospheric methane since 2012. McKain et al. used our model-measurement framework to assess top-down natural gas emissions from the Boston area from 2012-2013 and found a loss rate of 2.7 ± 0.6% from natural gas infrastructure and all other sources[5]. This loss rate is ~2.5 times higher than the leak rate based on DEP emissions published in 2013. However, the DEP has since updated its emission factors, leading to lower estimated emissions from NG infrastructure. Using the latest reported DEP emissions, the loss rate of 2.7% from McKain et al. is ~6 times higher than the DEP estimated bottom-up loss rate.

This year, the McKain et al. study was extended to analyze NG emissions from the Boston area from 2012-2019 using updated models and meteorological products[6]. We found an average loss rate of 2.5 ± 0.5% over the 7-year period, with no statistically significant trend in loss rate over that time. The loss rate remains ~6 times higher than the reported DEP loss rate as recently as 2019.

Thank you for this opportunity to speak on these important topics to reduce methane emissions as part of our goal to reduce all greenhouse gas emissions in Massachusetts.

Respectfully submitted,

Maryann Sargent, Steven Wofsy, and Lucy Hutyra

Harvard University
20 Oxford St.
Cambridge, MA 02138
(617) 495-4566

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[5] McKain, K. et al. (2015). Methane emissions from natural gas infrastructure and use in the urban region of Boston, Massachusetts. *Proceedings of the National Academy of Sciences, 112 (7)* 1941-1946.
[6] Sargent, M. et al. (2020). A 7-yr Top-Down Analysis of Methane Emissions from Natural Gas Infrastructure in the Boston Urban Region. American Meteorological Society Annual Meeting. Boston, MA. January, 2020

MOTHERS OUT FRONT
MOBILIZING FOR A LIVABLE CLIMATE

September 18th 2020

To: climate.strategies@state.ma.us
Attn: Sharon Weber, Mass DEP
Re: Comments on Regulation 310 CMR 7.73 Reducing Methane Emissions

Mothers Out Front Cambridge endorses both the Sierra Club / Gas Leaks Allies letters of September 18th 2020, and the HEET letter of September 18th 2020 and requests that the DEP take the recommendations in those letters into serious consideration.

Respectfully submitted,

Sharon de Vos
Kristine Jelstrup
Mothers Out Front Cambridge
sharondevos@gmail.com

Boston University

Department of Earth and Environment
685 Commonwealth Avenue
Boston, Massachusetts 02215–1401

To: climate.strategies@state.ma.us
September 18, 2020
Attn: Sharon Weber, MassDEP
Re: Comments on Regulation 310 CMR 7.73 Reducing Methane Emissions

Dear Director Weber,

These written comments are submitted on my own behalf in support of the review of regulation 310 CMR 7.73 Reducing Methane Emissions from Natural Gas Distribution Mains and Services. I am writing using my professional affiliation at Boston University, but my comments reflect my professional opinions alone and do not necessarily reflect opinions of Boston University.

I am writing first to endorse the comments of my fellow Gas Leak Allies members, including David Zeek of the Massachusetts Sierra Club, and Audrey Schulman and Zeyneb Magavi of HEET. Broadly speaking, these comments urge DEP to be consistent over time in how it estimates fugitive methane emissions, and to take into account the most recent and emerging science, including top-down estimates which reflect more of the process chain, even if we are not yet certain where a portion of the emissions are originating.

Secondly, I strongly urge the DEP to take seriously and act on the issue of meter error, both at the city gates, and by strategically sub-sampling from among the hundreds of thousands of end-use meters. In the joint DPU-DEP public meetings last year, I was surprised at both the level of ignorance (I'm not using that term pejoratively) and the apparent lack of interest in the literal foundation upon which our accurate accounting for gas delivery and use depends: measurement. The observation that in some years lost and unaccounted for gas can even be negative indicates the large need to better constrain this "black box" of uncertainty. Meter error quantification is arguably the lowest-hanging fruit in reducing the uncertainty in lost and unaccounted for gas.

A program of error quantification of meter error is likely to be one of the most cost-effective and practicable ways to make progress on reducing uncertainty in the total lost and unaccounted for gas. By better constraining meter error, the leak rate will be more accurately determined. In this regard, meter manufacturer error specifications on paper are insufficient; these are typical error estimates, but when a pallet full of meters are delivered, there is no guarantee on the distribution of errors among meters. Good scientific practice would entail an efficient and effective program of calibration checks and error estimates on a statistical subset of end-use meters, that can be used to assess meter error in the overall population of meters.

Respectfully submitted,

Nathan Phillips, Professor
617-997-1057; nathan@bu.edu

September 18, 2020

SUBMITTED VIA EMAIL TO CLIMATE.STRATEGIES@MASS.GOV

Sharon Weber
Massachusetts Department of Environmental Protection
1 Winter Street
Boston, MA 02108

Re: Comment of Environmental Defense Fund on the Massachusetts Department of Environmental Protection's Program Review of 310 CMR 7.73, Reducing Methane Emissions from Natural Gas Distribution Mains and Services

Dear Ms. Weber:

Environmental Defense Fund ("EDF") respectfully submits this comment to the Massachusetts Department of Environmental Protection ("MassDEP"), in the matter of its Program Review of 310 CMR 7.73, Reducing Methane Emissions from Natural Gas Distribution Mains and Services ("Gas Distribution Methane Standard"). Massachusetts is a national leader on climate action, and this comment details a key opportunity for MassDEP to continue that leadership in its oversight of methane emissions from the gas distribution system. MassDEP should require the use of advanced leak detection technology and data analytics ("ALD+") as a feasible technology to detect and quantify gas leaks. In particular, this comment explains that (1) MassDEP should continue its Gas Distribution Methane standard to comply with Massachusetts' ambitious climate policies; (2) ALD+ is an effective, available tool that gas utilities should incorporate into their operations to track and reduce methane leaks with greater accuracy than traditional technologies; and (3) gas utilities across the country use ALD+ for this purpose.

I. The Gas Distribution Methane Standard (310 CMR 7.73) was Created to Address Methane Emissions from the Natural Gas Sector, and MassDEP Must Continue the Program to Fulfill Its Statutory Obligation

The Massachusetts Global Warming Solutions Act ("Act"), which became law in 2008, mandates that the Commonwealth of Massachusetts adopt measures to reduce statewide greenhouse gas ("GHG") emissions by 25% by 2020 and 80% by 2050, from a 1990 baseline.[1] Governor Baker recently enhanced the state's ambitious climate target, committing to achieve net-zero GHG emissions by 2050.[2] The Act requires that MassDEP promulgate regulations to establish "declining annual aggregate emission limits" for sources and source categories of GHG emissions.[3] Additionally, the Act specifically recognizes methane as a contributor to climate change.[4] Methane is a potent greenhouse gas that causes 84 times as much global warming as the equivalent amount of carbon dioxide over a twenty-year horizon.[5]

In 2016, the Massachusetts Supreme Court held that the existing MassDEP standards failed to satisfy the requirements of the Global Warming Solutions Act, and that the Act requires MassDEP to promulgate annually-declining volumetric limits for sources of GHG emissions.[6] Later that year, Governor Baker issued an Executive Order requiring MassDEP, in relevant part, to issue regulations establishing GHG emission limits for the natural gas distribution system.[7] The Executive Order sought to ensure that MassDEP fulfilled its obligations under the Act to establish declining GHG emission limits for various sources.

MassDEP acted accordingly and promulgated new GHG emission standards in 2017, including 310 CMR 7.73, Reducing Methane Emissions from Natural Gas Distribution Mains and Services (hereinafter referred to as the "Gas Distribution Methane Standard").[8] The stated purpose of the Gas Distribution Methane Standard is to contribute to the achievement of the GHG emission reduction goals of the Global Warming Solutions Act, by reducing methane emissions from the

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1 MASS. GEN. LAWS ch. 21N, §§ 3-4 (2019); An Act Establishing the Global Warming Solutions Act, 2008 Mass. Acts Ch. 298, Bill No. S2540 (approved Aug. 7, 2008).

2 Massachusetts Executive Office of Energy and Environmental Affairs, Determination of Statewide Emissions Limit for 2020 (Apr. 22, 2020), https://www.mass.gov/doc/final-signed-letter-of-determination-for-2050-emissions-limit (setting a legally binding statewide limit of net zero greenhouse gas emissions by 2050, defined as 85 percent below 1990 levels); Governor Baker, State of the State Address (Jan. 21, 2021), https://www.mass.gov/news/governor-baker-delivers-2020-state-of-the-commonwealth-address (committing to achieving net-zero greenhouse gas emissions by 2050).

3 MASS. GEN. LAWS ch. 21N, § 3(d).

4 *Id.* ch. 21N, § 1.

5 IPCC, 2013: *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.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press.

6 *Kain v. Mass. Dep't of Envtl. Prot.*, 49 N.E.3d 1124, 1142 (Mass. 2016).

7 Governor Charles Baker, Executive Order No. 569, Establishing an Integrated Climate Change Strategy for the Commonwealth (Sept. 16, 2016), https://www.mass.gov/doc/executive-order-569-mass-register-1323/download.

8 310 CMR 7.73 (issued July 27, 2017).

natural gas distribution system.[9] The Standard established annually declining limits on methane emissions for six major gas distribution utilities in Massachusetts for the 2018-2020 period.[10]

As recently explained by the Massachusetts Office of the Attorney General, "this suite of legislative, judicial, executive, and agency action evinces a strong, central policy goal—across Administrations spanning over a decade—to make the changes necessary to achieve net-zero carbon emissions in the Commonwealth."[11]

MassDEP is currently undertaking the required Program Review of the Gas Distribution Methane Standard, which must be completed by December 31, 2020.[12] The review aims "to determine whether the program should be amended or extended" and to "evaluate whether to require the use of feasible technologies to detect and quantify gas leaks."[13]

MassDEP should extend the Gas Distribution Methane standard beyond 2020, with emission limits that continue to decline year-over-year. As the Massachusetts Supreme Court explained, the Global Warming Solutions Act requires the MassDEP to issue standards "that address multiple sources or categories of sources of emissions, impose a limit on emissions that may be released, limit the aggregate emissions released from each group of regulated sources or categories of sources, set emissions limits for each year, and set limits that decline on an annual basis."[14] In issuing the Gas Distribution Methane Standard, MassDEP took action to fulfill this statutory obligation. MassDEP was correct in its decision to focus on natural gas distribution systems as a source of GHG emissions, because gas leaks are a historically underestimated source of methane, a highly potent contributor to climate change. MassDEP must continue to fulfill its statutory obligation by extending the Gas Distribution Methane Standard.

II. ALD+ Can Detect and Quantify Methane Emissions with Greater Accuracy than Traditional Survey Methods

Natural gas leakage is widespread and is responsible for a significant volume of methane emissions. Academic findings have demonstrated that observed methane emissions from cities—particularly East Coast cities with older gas distribution systems—are about twice that reported

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9 *See* 310 CMR 7.73(1).

10 310 CMR 7.73(4). The methane emissions limits are expressed in carbon dioxide equivalent ("CO2e").

11 Mass. Office of the Attorney General, Petition Requesting an Investigation at p7, Mass. DPU Docket 20-80 (June 4, 2020).

12 *See* MassDEP Presentation: 310 CMR 7.73 Program Review (Sept. 10, 2020), https://www.mass.gov/doc/presentation-310-cmr-773-program-overview/download.

13 310 CMR 7.73(9).

14 *Kain v. Mass. Dep't of Envtl. Prot.*, 49 N.E.3d 1124, 1136 (Mass. 2016).

in the U.S. Environmental Protection Agency inventory.[15] Furthermore, peer-reviewed studies have shown that utilities using traditional survey methods were able to locate fewer gas leaks than were found using advanced leak detection technology and data analytics ("ALD+").[16] Thus, natural gas utilities are likely to have more leaks, and are emitting significantly more methane from their systems, than is being reported to the U.S. EPA and other agencies.

The Gas Distribution Methane Standard issued by MassDEP in 2017 is an important step towards reducing methane emissions from gas utility systems: establishing an obligation for individual utilities to reduce their fugitive emissions and an annual reporting system to track progress.[17] But MassDEP should continue to expand and improve this program to ensure greater methane emission reductions in future years. In considering changes to the program, MassDEP asks "Are there practical, economically feasible technologies to detect and quantify gas leaks?"[18] The answer is yes. ALD+ is an available, effective, and economically feasible technology that can identify additional and different leaks from traditional survey methods, and MassDEP should require the use of ALD+ by Massachusetts gas utilities.

A. Capabilities and Attributes of ALD+

Advanced leak detection technology uses highly sensitive sensors—with detection capabilities 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 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 leak grade (e.g. Type 1, 2, 2A, or 3).[19] ALD+, and the analytics and visualizations that can be developed using these methods, can provide more accurate and useful tools in a gas utility's efforts to track and reduce methane emissions from its distribution system and improve prioritization of leak repairs and leak-prone pipe replacement.

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15 G. Plant et al., Large Fugitive Methane Emissions from Urban Centers Along the U.S. East Coast, Geophysical Research Letters (July 2019), https://agupubs.onlinelibrary.wiley.com/doi/abs/10.1029/2019GL082635.

16 Weller, Zachary et al., *Vehicle Based Methane Surveys for Finding Natural Gas Leaks and Estimating their Size: Validation and Uncertainty*, Environmental Science & Technology, 2018, 52, 20, 11922–11930, https://pubs.acs.org/doi/10.1021/acs.est.8b03135.

17 310 CMR 7.73(4), (5).

18 MassDEP, Presentation: 310 CMR 7.73 Program Review at Slide 5 (Sept. 10, 2020), https://www.mass.gov/doc/presentation-310-cmr-773-program-overview/download.

19 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., *An open source algorithm to detect natural gas leaks from mobile methane survey data*. Plos One, 14(2), e0212287 (2019), https://doi.org/10.1371/journal.pone.0212287.

ALD+ is typically able to find many more leaks than traditional technologies. A 2018 peer-reviewed study found that utility crews locate only 35% of the pipeline leaks found using traditional technologies in comparison to using ALD+.[20] Two studies by the utility Pacific Gas and Electric Company ("PG&E") similarly found a fraction of "false negatives" where leaks exist and are detected by ALD+ but are not found using traditional survey methods.[21] Thus, combining ALD+ with traditional leak surveys can offer utilities unique insight into their systems that is not possible using only traditional leak survey methods.

ALD+ 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 time). Leak flow rate data derived from ALD+ can provide a real-time estimate of a gas utility's fugitive methane emissions, and the utility can reduce emissions more rapidly by targeting large, super-emitting leaks identified by the ALD+ survey and analysis. Peer-reviewed studies estimate, based on aggregated leak flow rate data, that methane emissions from the gas distribution system could by reduced by 50% by repairing only the largest 20% of leaks.[22]

Gas utilities in Massachusetts could deploy periodic, systemwide ALD+ surveys to establish an emissions baseline and track progress toward reducing emissions by remediating leaks. This would result in measurable outcomes that allow utilities to receive credit for actions they take to reduce emissions sooner. Using ALD+ to estimate a baseline systemwide leak flow rate could result in a higher estimate of methane emissions than Massachusetts utilities are currently reporting. This can and should be viewed as an opportunity to pick low-hanging fruit to reduce GHG emissions, because it allows utilities to identify and prioritize areas (i.e., super-emitting leaks) where they can cost-effectively mitigate GHG emissions using proven technologies and methods. Furthermore, integration of ALD+ into the Gas Distribution Methane Standard will allow for greater transparency, providing MassDEP with helpful, real-time data to track emissions and achieved reductions on a regular basis.

ALD+ is an economically feasible technology for gas utilities, as evidenced by the multiple examples of gas utilities that have incorporated ALD+ into their operations, *see infra* Part III.

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20 Weller, Zachary et al., *Vehicle Based Methane Surveys for Finding Natural Gas Leaks and Estimating their Size: Validation and Uncertainty*, Environmental Science & Technology, 2018, 52, 20, 11922–11930, https://pubs.acs.org/doi/10.1021/acs.est.8b03135. 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.

21 *See* Kerans, Mike, Picarro Surveyor Leak Detection Study – Sacramento Side-by-Side Study (2012); Clark, Timothy, Picarro Surveyor Leak Detection Study – Diablo Side-by-Side Study (2012); Press Release: New Independent Research Reveals Picarro Surveyor as Benchmark Solution in Natural Gas Leak Detection, Picarro (Feb. 5, 2013), https://www.picarro.com/company/press-releases/2013/new-independent-research-reveals-picarro-surveyortm-benchmark-solution.

22 Von Fischer, J., et al., *Rapid, Vehicle-Based Identification of Location and Magnitude of Urban Natural Gas Pipeline Leaks*, Environmental Science & Technology, 51(7), 4091–4099 (2017), https://doi.org/10.1021/acs.est.6b06095.

Two ALD+ service providers, Picarro and ABB Inc.-Los Gatos, have provided helpful information about the cost of ALD+ and the potential for cost-savings for individual gas utilities. For example, Picarro estimates the cost of conducting an ALD+ survey to be approximately $105 per mile of distribution main.[23] In providing a detailed cost schedule for surveying 2,000 miles of infrastructure for People's Gas Light Company in Chicago, Picarro estimated the total cost to be $312,940, or about $156 per mile.[24]

Incorporating ALD+ into MassDEP's Gas Distribution Methane Standard would improve the accuracy of the emission data reported and allow gas utilities in Massachusetts to achieve greater reductions in methane emissions.

B. Additional Context

Continuing to reduce methane emissions from the natural gas distribution system is necessary to assist in meeting Massachusetts' ambitious climate goal to achieve net-zero GHG emissions by 2050. As shown in the chart below, gas distribution companies in Massachusetts have a significant number of miles of leak-prone distribution pipelines in their systems, particularly cast iron. Cast iron, unprotected bare steel, copper, and ductile iron pipeline materials are particularly prone to leaks,[25] and thus represent a more significant emissions concern than other types of pipeline materials. This data further supports the continued need and importance of MassDEP's Gas Distribution Methane Standard.

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[23] 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, at p3 (2017).

[24] *Id.* at Appendix 2, Cost Schedule.

[25] U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, *Report on State-level Policies That Encourage or Present Barriers to the Repair and Replacement of Leaking Natural Gas Pipelines* (Aug. 2017), https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/news/18356/statebarrierstorepairreplaceleakingnatgaspipelinesaug2017.pdf; American Gas Foundation & Yardley Associates, *Gas Distribution Infrastructure: Pipeline Replacement and Upgrades - Cost Recovery Issues and Approaches* (July 2012), https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/07-2012%20Gas%20Distribution%20Infrastructure%20-%20Pipeline%20Replacement%20and%20Upgrades.pdf.

Top Ten States by Miles of Leak Prone Mains[26]

	Unprotected Bare Steel	Cast Iron	Ductile Iron	Copper	**Total Leak Prone Pipe**	Total miles
U.S. Total	33,336	22,861	513	13	**56,722**	1,305,025
PA	5,932	2,525	170	2	**8,629**	48,335
NY	4,972	3,175	-	0	**8,147**	49,307
OH	6,197	197	1	1	**6,396**	58,759
NJ	550	3,911	24	1	**4,486**	35,007
TX	3,905	466	-	-	**4,371**	107,799
MA	1,146	2,925	1	0	**4,073**	21,714
CA	3,244	58	-	0	**3,302**	106,806
MI	352	2,389	-	-	**2,742**	59,731
WV	2,546	12	-	-	**2,557**	10,961
IL	28	1,152	205	-	**1,385**	62,168

Most gas utilities estimate the GHG emissions on their 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.[27] The EPA emission 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 relied on traditional leak detection technology that finds far fewer leaks than ALD+.[28] EDF recognizes that the Gas Distribution Methane standard and the MassDEP GHG emissions inventory use distinct sets of emission factors—although some of those emission factors may be derived from EPA Subpart W.[29] Peer-reviewed studies and state regulators in other jurisdictions,

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26 U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, 2018 Gas Distribution Annual Report Data (retrieved 2019), https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.

27 40 C.F.R. Part 98, Subpart W, Table W-7 (detailing the emission factors equations to be used for different types of petroleum and gas systems).

28 *See* U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2018, Chapter 3: Energy, at 3-88 (Apr. 2020), https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2018.

29 *See* 310 CMR 7.73(5)(b)(8); MassDEP, Statewide Greenhouse Gas Emissions Level: 1990 Baseline and 2020 Business As Usual Projection Update at p18 (July 2016), https://www.mass.gov/doc/statewide-greenhouse-gas-ghg-emissions-baseline-projection-update-including-appendices-a-b/download ("Prior to this inventory update, the emission factors used to estimate this sector's emissions from pipelines and services were those found in EPA's SGIT. This

however, have observed that it is challenging for emission factors to capture the methane emissions associated with super-emitting leaks: "[A] small number of emission sources, so-called 'super-emitters,' account for the majority of emissions across the NG supply chain. Observing these rare but large sources is an important part of accurately characterizing emissions factors, and as a result, a large sample size is paramount for estimating emissions rates and total emissions."[30]

III. Gas Utilities Around the Country Have Deployed ALD+ to Detect and Quantify Methane Emissions.

Utilities across the United States are incorporating ALD+ into their operations, and ALD+ is being used in at least seven countries and on four continents worldwide.[31] ALD+ delivers significant environmental benefits, financial savings that can benefit ratepayers, improved safety, and other system-wide benefits. Major gas utilities including PSE&G, New Jersey's oldest and largest utility,[32] Elizabethtown Gas in New Jersey,[33] National Grid in New York,[34] CenterPoint

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inventory update uses a combination of emission factors from SGIT, from an ICF report for the Massachusetts Department of Public Utilities, and from an April 2015 study that measured equipment emissions to estimate current emission factors.").

30 Weller et al., *A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems*, Environmental Science & Technology, 2020, 54, 8958−8967 (June 2020), https://pubs.acs.org/doi/10.1021/acs.est.0c00437; *see also* NYSERDA, *New York State Oil and Gas Sector Methane Emissions Inventory*, Final Report No. 19-36, at p132 (July 2019), https://www.nyserda.ny.gov/About/Publications/EA-Reports-and-Studies/Greenhouse-Gas-Inventory ("High-emitting sources have been widely observed and described in the literature along all stages of the upstream, midstream, and downstream process, with a small number of sites or facilities contributing a majority of regional emissions in many instances. However, given the unknown distribution of high-emitting sources in New York State, it is challenging to apply statistical methods to estimate the likelihood of high-emitting sources.").

31 Aaron Van Pelt, Picarro, Inc., Presentation: Picarro Natural Gas Network Management Solution, Pipeline Safety Trust Conference, New Orleans, LA (Nov. 7, 2019), http://pstrust.org/wp-content/uploads/2019/11/Picarro-Pipeline-Safety-Trust-11-7-19.pdf.

32 *See* EDF, Collaboration with PSE&G: Data helps prioritize gas line replacement, https://www.edf.org/climate/methanemaps/pseg-collaboration (last accessed Sept. 17, 2020).

33 *See* Elizabethtown Gas Company, Semi-Annual Status Report, Attachment D: Methane Leak Survey Report, filed in NY BPU Docket No. GR18101197 (Feb. 18, 2020).

34 *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) (proposing 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). This rate case is ongoing.

Energy in Texas and Minnesota,[35] and Pacific Gas and Electric ("PG&E") in California[36] have recognized these and incorporated ALD+ into their operations.

PSE&G first adopted ALD+ as part of a 2015 settlement with EDF, approved by the New Jersey Board of Public Utilities.[37] The utility agreed to consider data on the volume of leaked methane emissions, in conjunction with other relevant factors, to identify pipes that are most in need of replacement as part of a three-year $905 million pipe replacement program.[38] PSE&G achieved an 83% reduction in methane emissions one-third of the time faster than in a business as usual scenario by incorporating ALD+ in the prioritization of approximately 175 miles of pipeline main replacements.[39] This difference is noteworthy considering that the typical cost to replace one mile of gas line on PSE&G's system is $1.5 to $2.0 million.

PSE&G built upon these efforts in the second phase of its gas system modernization program, committing to contract with a third party vendor to conduct an ALD+ survey in 2018 on 280 miles of leak prone pipeline.[40] The leak survey data was used to generate an "Estimated Flow Rate per Mile (Liter/min/mile)," and PSE&G then developed a ranking threshold which is being used to prioritize grids for replacement in subsequent program years.[41] In a Methane Leak Surveying Report filed about the program, PSE&G reports: "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

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

36 PG&E, Press Release: New PG&E Fleet Inspects One Million Homes and Businesses Using Super-Sensitive Gas-Detecting Technology (Sept. 2, 2016), https://www.pge.com/en/about/newsroom/newsdetails/index.page?title=20160902_new_pge_fleet_inspects_one_million_homes_and_businesses__using_super-sensitive_gas-detecting_technology.

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

38 EDF, Collaboration with PSE&G: Data helps prioritize gas line replacement, https://www.edf.org/climate/methanemaps/pseg-collaboration (last accessed Sept. 17, 2020).

39 Palacios, V., George, S. R., von Fischer, J. C., & Mohlin, K., *Integrating Leak Quantification into Natural Gas Utility Operations*. Public Utilities Fortnightly (May 2017).

40 *In the Matter of the Petition of Public Service Electric and Gas Company for Approval of the Next Phase of the Gas System Modernization Program and Associated Cost Recovery Mechanism*, BPU Docket No. GR17070776, Stipulation of Settlement and Agreement at p24 (Apr. 18, 2018). The BPU approved this settlement in a June 1, 2018 order.

41 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 (filed Feb. 28, 2020 by PSE&G).

of belowground leaks through changes to construction priorities based on these methane maps and associated data."[42]

PG&E in California has integrated ALD+ into its operations with a Super Emitter program that seeks to identify the largest leaks on its system (responsible for the most methane emissions) and address those leaks quickly to maximize emissions reductions. PG&E—working with ALD+ service provider Picarro—uses a statistical model to prioritize geographic plats based on a likelihood of finding the most leaks, allowing PG&E to increase the number of leaks found by 15% to 80% while surveying 25% to 50% fewer services.[43] In 2018, PG&E identified and repaired 220 Super Emitter leaks, estimating that the program achieved an emissions reduction of 90 Mscf (million standard cubic feet) for 2018 and is expected to result in further emissions reductions in the future.[44]

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 GHG emissions from leaks in their system, a figure that is incorporated into their annual greenhouse gas emissions inventory.[45] PG&E's use of ALD+ is in compliance with the best practices and reporting requirements approved by the California Public Utilities Commission as part of a Natural Gas Leak Abatement Program aimed at reducing methane emissions from the natural gas distribution sector, in support of California's goal to reduce methane emissions 40% below 2013 levels by 2030.[46] 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.

CenterPoint Energy in Texas and Minnesota has thoroughly integrated ALD+ into its operations, piloting the technology in 2013 and testing and phasing ALD+ into its operations in 2016.[47] 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.[48] By 2018,

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42 *Id.* at p11.

43 François Rongere, PG&E, Presentation: Risk Based Leak Surveys (Oct. 2019).

44 Pacific Gas and Electric Company, Natural Gas Leakage Abatement Report, California Public Utilities Commission Rulemaking 15-01-008, at 9 (June 17, 2019).

45 François Rongere, PG&E, Presentation: Risk Based Leak Surveys (Oct. 2019).

46 California Public Utilities Commission, Decision 17-06-015, *Decision Approving Natural Gas Leak Abatement Program Consistent with Senate Bill 1371*, Rulemaking 15-01-008 (June 15, 2017).

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

48 Centers, Tal, & Brad Coppedge, Picarro Leak Surveyor (2015), https://southerngas.org/component/content/article/102-corporateservices/committees/1027-pipeline-safety-council; *see also* Centers, Tal & Mark Menzie, Presentation: Advanced Leak Detection Technology Implementation Planning (May 21, 2015), https://slideplayer.com/slide/16333053/.

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 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 leak surveys."[49] 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."[50]

IV. Conclusion

It is necessary that MassDEP continue to require declining volumetric reductions in GHG emissions from the natural gas distribution sector, in order to assist in achieving the state's mandate of net-zero GHG emissions by 2050, and in order to fulfill its obligations under the Global Warming Solutions Act to address GHG emissions from various source categories. ALD+ is an accepted and effective technology that can detect more gas leaks and quantify the methane emissions associated with those leaks. MassDEP should require the use of ALD+ as a feasible technology to detect and quantify gas leaks. EDF looks forward to participating in the MassDEP's Program Review for the Gas Distribution Methane standard in order to share information about how ALD+ can further improve the program to achieve greater reductions in methane emissions from the natural gas distribution system.

Dated: September 18, 2020

<u>/s/ Erin Murphy</u>
Erin Murphy
Attorney, Energy Markets and Utility Regulation
Environmental Defense Fund
1875 Connecticut Avenue NW, Suite 600
Washington, DC 20009
emurphy@edf.org
202-572-3525

Natalie Karas
Senior Director and Lead Counsel, Energy
Environmental Defense Fund
1875 Connecticut Avenue NW, Suite 600
Washington, DC 20009
nkaras@edf.org

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

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

EVERSOURCE ENERGY

247 Station Dr,
Westwood, MA 02090

Columbia Gas of Massachusetts
A NiSource Company

4 Technology Drive, Suite 250
Westborough, Massachusetts

September 18, 2020

VIA ELECTRONIC MAIL

Ms. Sharon Weber
Massachusetts Department of Environmental Protection
1 Winter Street
Boston, MA 02108

Re: 310 CMR 7.73 Program Review – Initial Comments of NSTAR Gas Company d/b/a Eversource Energy and Bay State Gas Company d/b/a Columbia Gas of Massachusetts

Ms. Weber:

On August 26, 2020, the Massachusetts Department of Environmental Protection ("MassDEP") issued a Notice of Public Stakeholder Meeting (the "Notice") that it was conducting a program review (the "Program Review") of 310 CMR 7.73: Reducing Methane Emissions from Natural Gas Distribution Mains and Services. Pursuant to the Notice and consistent with 310 C.M.R. §7.73(9), the Program Review will focus on the requirements of 310 CMR 7.73 to determine whether the program should be amended or extended, shall evaluate whether to require the use of feasible technologies to detect and quantify gas leaks, and include any other information relevant to the Program Review.

NSTAR Gas Company d/b/a Eversource Energy ("NSTAR Gas") and Bay State Gas Company d/b/a Columbia Gas of Massachusetts ("BSG," together with NSTAR Gas, the "Companies") are filing joint initial comments with the other Massachusetts Local Distribution Companies. The Companies, however, offer these separate joint comments in recognition of their unique circumstances due to the acquisition of the business of BSG by Eversource Energy, and the settlement agreement entered into by BSG, and its holding company parent, NiSource Inc., Eversource Gas Company of Massachusetts ("EGMA")[1] and its holding company parent,

[1] Following approval and close of the transaction, BSG will operate as EGMA, with BSG no longer doing business in Massachusetts.

Eversource Energy, the Massachusetts Attorney General's Office, the Massachusetts Department of Energy Resources, and the Low-Income Weatherization and Fuel Assistance Program Network (the "Settlement Agreement") with regard to the proposed sale by NiSource and BSG, and acquisition by Eversource Energy, of the business of BSG.[2]

The Companies stress that at this time it is not appropriate for MassDEP to combine NSTAR Gas' and BSG's annual methane emissions limits into a single limit as proposed on Page 8 of MassDEP's PowerPoint presentation for the Program Review. First, the acquisition of the business of BSG by Eversource Energy has not yet been approved by the Department of Public Utilities and may not be finalized by the time MassDEP promulgates its proposed changes to 310 CMR 7.73. Unless and until the Department of Public Utilities approves the acquisition and the transaction closes, NSTAR Gas and BSG remain separate operating companies owned by two separate and distinct parent companies, with no legal, operational or other relationship that would allow for the combination of their individual methane emissions limits.

As you discussed with Nancy Kaplan and Tracy Gionfriddo of Eversource, and assuming Department of Public Utilities approval of the Eversource Energy acquisition of the business of BSG, NSTAR Gas and EGMA will remain as two separate and distinct legal entities. Following the transaction close, NSTAR Gas and EGMA will continue to: (1) utilize separate operator identification numbers for purposes of reporting to the Pipeline and Hazardous Materials Safety Administration ("PHMSA"); and (2) make separate filings to the Department of Public Utilities, the United States Environmental Protection Agency ("USEPA") and the MassDEP.

NSTAR Gas and EGMA will continue to develop, track and implement separate, stand-alone Gas System Enhancement Program ("GSEP") Plans tailored to their specific leak prone assets. Both NSTAR Gas and EGMA will still be required to submit their individual annual GSEP Plans to the Department of Public Utilities for its review and approval consistent with the provisions of G.L. c. 164, §145. Therefore, as previously discussed, the limits, as well as other requirements, should be kept separate, consistent with the provisions of 310 C.M.R. §§ 7.73(1) and 7.73(4)(a).[3]

Additionally, requiring the Companies to be subject to a combined annual methane emissions limit could place undue burdens on the Companies and their respective GSEP plans and could result in NSTAR Gas and/or EGMA being subject to penalties under 310 C.M.R. §7.73(8) due to factors outside of their control. Under § 2.2.3 of the Settlement Agreement, EGMA "*shall*

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[2] Both the Proposed Acquisition and Settlement Agreement are currently pending approval before the Department of Public Utilities in Joint Petition of Eversource Energy, NiSource Inc., Eversource Gas Company of Massachusetts, and Bay State Gas Company d/b/a Columbia Gas of Massachusetts for approval by the Department of Public Utilities of Purchase and Sale of Assets, D.P.U. 20-59.

[3] 310 C.M.R. § 7.73(2) defines a Gas Operator as "every Massachusetts gas operator with a Gas System Enhancement Plan approved by the Massachusetts Department of Public Utilities (DPU) pursuant to M.G.L. c. 164, §145 as of August 11, 2017." 310 C.M.R. § 7.73(4)(a), entitled Individual Operator Limits, sets out individual methane emissions limits for each of the Gas Operators in Massachusetts, i.e., those local gas distribution companies having GSEP Plans, and requires each named Gas Operator to ensure that the annual CH_4 emissions from all of its active mains and services do not exceed the limits set out in 310 C.M.R. § 7.73(4)(a).

limit GSEP replacement work to no more than 45 miles per year on average over the four years, 2021-2024."[4] Emphasis added. As always, both companies will prioritize GSEP work from a safety / risk standpoint, which may result in an adjustment up or down. The EGMA annual mileage limitation could burden the NSTAR Gas GSEP with the obligation to make up for any shortfall on the EGMA distribution system through increased replacement of leak-prone infrastructure under the NSTAR Gas GSEP. NSTAR Gas designs its annual GSEP projects to ensure that they are undertaken safely and efficiently utilizing available resources. Conversely, if NSTAR Gas were to experience a shortfall, EGMA would be prevented, pursuant to the Settlement Agreement, from taking steps to make up that shortfall through additional leak-prone infrastructure replacement under its GSEP.

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Thank you for your attention to this matter. As discussed in your meeting with Eversource representatives and summarized above, separate methane emissions limits for NSTAR Gas and EGMA are an appropriate approach to ensure compliance with the provisions of 310 C.M.R. 7.73. The Companies appreciate MassDEP's consideration of these initial comments and look forward to further participation and comments on any proposed regulation amendments to 310 CMR 7.73.

Very truly yours,

Catherine Finneran
Vice President, Sustainability and Environmental Affairs – Eversource Energy

Shaela McNulty Collins
Director, Regulatory Policy – Columbia Gas of Massachusetts

[4] Any calculation of EGMA's annual methane emissions limits must be based on the 45-mile/year average limit to EGMA's GSEP activities for 2021 through 2024. Failure to incorporate this limitation would subject EGMA to penalties under 310 C.M.R. §7.73(8) without the ability to take any steps to avoid those penalties by increasing the replacement of leak-prone infrastructure in a given year.

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September 18, 2020

To: climate.strategies@state.ma.us
Attn: Sharon Weber, MassDEP
Re: Comments on Regulation 310 CMR 7.73 Reducing Methane Emissions

These written comments are submitted on behalf of HEET in support of the review of regulation 310 CMR 7.73 Reducing Methane Emissions from Natural Gas Distribution Mains and Services.

Overall comments
We are a science based organization, so our comments reflect a science based perspective, and we attempt to prioritize the use of the latest peer-reviewed scientific knowledge as well as appropriate measurement and data where and when available.

Context
As such, we will first comment on the larger context of this regulation, as we see it as relevant to the review. Our two points regarding context are:

1. **Accuracy of Global Warming Impact:** As the intent of this regulation is to adhere to the mandate of the Global Warming Solutions Act, we believe it is important that the estimations of methane (CH_4) emissions from the natural gas distribution system produced by this regulation should be reported with scientifically accurate global warming potentials. CH_4 dissipates more rapidly than CO_2, producing its warming impact primarily within the first 20 years of being emitted. Therefore the scientifically accurate global warming potential for the 20 year timeframe is 84-86x CO_2, as published by the Intergovernmental Panel on Climate Change (IPCC). Additionally, the next 20 years are a critical period for addressing climate change. Therefore the 20 year timeframe is not only scientifically accurate but is the most relevant for our Commonwealth.

   Therefore we recommend that the DEP report all emissions outcomes from this regulation with both the EPA's currently used 25x factor for consistency across agencies, AND additionally, the more scientifically accurate IPCC 20 year factor in order to increase accuracy, transparency and understanding for the public and decision makers.

2. **Top-Down Emissions of Unburned Natural Gas are Measured in MA:** As the intent of this regulation is to address the methane emissions from our gas distribution industry, it is important to acknowledge what is known and unknown regarding these emissions. The Commonwealth is lucky enough to have premier research institutions directly and continuously measuring methane from unburned natural gas emissions in the air above our state. In 2015, McKain et al.[1] was published, and used ethane as a chemical marker to separate natural gas from other sources of

[1] McKain et al, Methane emissions from natural gas infrastructure and use in the urban region of Boston, Massachusetts. PNAS February 17, 2015 112 (7) 1941-1946; https://doi.org/10.1073/pnas.1416261112

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methane such as cows or compost, etc. This publication reported that the amount of unburned natural gas released into the atmosphere over the course of a year was roughly equal to 2.7% of all the natural gas brought into the Commonwealth. This amount of gas is much, much higher than the bottom up estimation reported by our natural gas companies to the EPA, and to the DEP, through the current emissions estimation methods. The difference between the top down measurement and the bottom up estimate is a mystery which our organization and allies have been attempting to solve since.

The scientists, including Dr. Steven Wofsy of Harvard University and Dr. Lucy Hutyra of Boston University, continue to directly measure unburned natural gas using the same method and the amount emitted reportedly remains similar each year. Other research confirms that the unburned natural gas leaked is higher than reported, see Plant et al.[2] in 2019. We suggest that it is necessary to acknowledge these directly measured top down gas numbers, and the missing pieces of information they represent, as we evaluate this regulation. Are we undercounting gas leaks? Is this gas coming from behind the meter? Is there some other unaccounted for source?

HEET therefore recommends that the DEP report these direct measures in addition to the estimated emissions, thus increasing transparency and knowledge. Let's state what we know and also what we do not yet know, or, what the Commonwealth can regulate and what the Commonwealth may yet have the opportunity to regulate in the future.

We recommend that the Department create a program to measure and monitor methane in the atmosphere, collaborating with these scientists, to determine whether Massachusetts is reducing methane emissions in line with our goals under the Global Warming Solutions Act.

We further recommend that the amount of methane measured annually by this ongoing research be added to the state's GHG inventory. By subtracting from it all the bottom up estimation of methane that you list in the inventory, this will identify the remaining quantity as an amount with an unknown source. Just because we don't know where it's coming from doesn't mean it's not there. Its existence in the inventory will give researchers, industry, and policy makers a greater opportunity to address it.

Response to Questions from the Department:

Should the decreasing annual emissions limits be extended beyond 2020?

Yes, decreasing annual emissions limits should be extended for as long as the state uses natural gas. The emissions factors should continue to be revisited every 3 years. Shifting from an estimation based on Gas System Enhancement Plan (GSEP) pipe to an estimation based on reported leaks extends the potential for annual emissions limits past the expected GSEP completion in the 2030s.

[2] 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, 8500–8507. https://doi.org/10.1029/2019GL082635

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What are the most appropriate emission factors or other metrics to determine emission limits and evaluate progress?

In terms of *emissions factors*, we recommend you update the factors from those based on Lamb et al.[3] to be based instead on a 2020 Envir. Science & Technology paper by Weller, Hamburg and von Fischer.[4] This research evaluated 4,000 leaks, and is the newest research available with the largest number of leaks studied. Furthermore, this emissions factor includes the superemitter leaks, defined as those 7% of leaks on the heavy-tail of the leak flux distribution. (Hendrick et al. 2016[5] established this distribution in a study directly measuring Boston gas leaks and these larger leaks are referred to in regulation as 'significant environmental leaks' or SEIs.)

The Weller publication also includes *activity factors*. However we recommend you use the HEET calculator (or "alternative fugitive emissions method") to determine leaked gas emissions from distribution system pipes. The DPU piloted this method this year when calculating lost and unaccounted for gas (or "LAUF"). While the utilities do not tend to report the number of leaks that the Weller study's activity factor suggests, we still believe the appropriate method is to prioritize direct measurement and observation over estimation. Why?

Because the method of using miles of GSEP pipe replaced as a proxy for leak and emissions reduction has not worked. Despite increasing pipe replacement annually, the number of leaks reported has not fallen. So, while our state 'sees' falling emissions from the gas system, the number of leaks reported remains the same and the directly measured emissions in our atmosphere also remain the same.

By using an emissions factor per leak, we both connect our emissions estimation to observed reality on the ground in our state, and by using utility-specific info we reflect real utility effort and success in emissions reduction.

We also recommend you include the new DPU LAUF measurements and calculations for venting, purging and external damage emissions as part of the leaked gas total.

Finally, in updating the emissions factors, we suggest that the Department avoid misleading representation of emissions change over time due to a shift in methodology. Retroactively applying the improved factors and methods to previous years will ensure this does not happen.

Are there practical, economically feasible technologies to detect and quantify gas leaks?

For leak detection, the most exciting current technology option is a mobile survey with a cavity ring down spectrometer (CRDS). The CRDS can be driven down the road to detect gas, with

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[3] Lamb et al, Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States. Environ. Sci. Technol. 2015, 49, 8, 5161-5169. https://doi.org/10.1021/es505116p

[4]Weller, Z., Hamburg, S., and von Fischer, J., A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems. *Environ. Sci. Technol.* 2020, 54, 14, 8958–8967. https://doi.org/10.1021/acs.est.0c00437

[5] Hendrick et al., Fugitive Methane Emissions from leak-prone natural gas distribution infrastructure in urban environments. *Environ. Pollution* 2016

algorithms adjusting for wind and car speed and direction. This technology is very accurate at the detection of leaks, but less effective for the quantification of emissions. The challenge for the CRDS quantification of leaks is distance, as the same size leak on a service line far from the road will appear to have a smaller volume than a similar leak directly under the car. We fully support the use of this technology to rapidly detect gas leaks on the distribution system.

However, given the cost of the CRDS and lack of specificity for emissions quantification, we suggest that the best and most cost effective proxy method for quantification we know is the leak extent method, based on HEET's Large Volume Leak Study[6]. This is the method currently adopted by the DPU for the identification of G3SEI (Grade 3 Significant Environmental Impact) leaks. A gas leak under the ground rises through the soil. If it's a high volume gas leak, the gas is going to spread further, saturating a larger surface area. The utilities can and are currently finding the perimeter of that gas-saturated surface area and then measuring the surface area. The initial threshold set for categorizing a G3SEI is a surface area over 2,000 sq ft, however the threshold will likely need adjustment as more data is accumulated.

Finally, we would like to suggest that in any evaluation of leak identification and quantification, the Department consider the sensitivity of the equipment. A leak of 400 ppm is detectable with a CRDS and not detected by standard Combustible Gas Indicators (CGI) used by many utilities. The latter instruments are designed to quickly assess explosion risk, not emissions, thus they focus on the lower explosive limit (LEL) of methane, not the presence of methane emissions.

Does the petition process need any changes?

We suggest that this field is rapidly evolving and much remains unknown, and therefore new science or technology should be able to trigger a petition for re-evaluation by stakeholders. If no evaluation is triggered by new science or technology, then the standard reevaluation should continue to occur on a 3 year cycle.

We greatly appreciate your careful consideration and attention to the regulation of methane emissions in our state. We see methane as a hopefully powerful and rapid lever to address our greenhouse gas emissions.

Respectfully submitted,

Audrey Schulman
Co-executive Director

Zeynep Magavi
Co-executive Director

[6] Magavi, Z. "Identifying and Rank-Ordering Large Volume Leaks in the Underground Natural Gas Distribution System of Massachusetts", Thesis, 2018 http://nrs.harvard.edu/urn-3:HUL.InstRepos:37945149

KEEGAN WERLIN LLP

ATTORNEYS AT LAW
99 HIGH STREET, Suite 2900
BOSTON, MASSACHUSETTS 02110

(617) 951-1400

TELECOPIER:
(617) 951-1354

September 18, 2020

VIA ELECTRONIC MAIL

Ms. Sharon Weber
Massachusetts Department of Environmental Protection
1 Winter Street
Boston, MA 02108

Re: 310 CMR 7.73 Program Review – Initial Comments of the Massachusetts Local Distribution Companies

Ms. Weber:

On August 26, 2020, the Massachusetts Department of Environmental Protection ("MassDEP") issued a Notice of Public Stakeholder Meeting (the "Notice") that it was conducting a program review (the "Program Review") of 310 CMR § 7.73: Reducing Methane Emissions from Natural Gas Distribution Mains and Services. Pursuant to the Notice and consistent with 310 C.M.R. §7.73(9), the Program Review will focus on the requirements of 310 CMR §7.73 to determine whether the program should be amended or extended, shall evaluate whether to require the use of feasible technologies to detect and quantify gas leaks, and include any other information relevant to the Program Review. NSTAR Gas Company d/b/a Eversource Energy, Boston Gas Company and former Colonial Gas Company each d/b/a National Grid, Bay State Gas Company d/b/a Columbia Gas of Massachusetts, Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty, The Berkshire Gas Company, and Fitchburg Gas and Electric Light Company d/b/a Unitil (collectively the "Local Distribution Companies" or "LDCs") offer the following initial comments on the Program Review.

In keeping with the Commonwealth's energy policies, the LDCs have been and plan to continue to substantially reduce greenhouse gas ("GHG") emissions. Annual data demonstrates that emissions from natural gas systems are on the decline and below 1990 levels. As noted in the 2015 Update to the Clean Energy and Climate Plan ("2015 CECP Update"), there has been a 62 percent reduction of natural gas system GHG emissions, which far exceeds the 2020 reductions contemplated by the Global Warming Solutions Act ("GWSA"). 2015 CECP Update at 5 and Figure 2. Additionally, Appendix A is a series of tables filed by the LDCs as part of their five-year Gas System Enhancement Program ("GSEP") Plan Reports to the Department of Public Utilities in October 2018. Appendix A demonstrates substantial progress, both in the aggregate and for individual LDCs, in achieving emissions reductions through (1) replacing leak-prone mains and services, and (2) eliminating gas leaks through GSEP work.

The LDCs' planned leak-prone infrastructure replacement will continue to achieve emissions reductions. Each of the LDCs have implemented GSEP Plans, pursuant to authorization granted by the Department of Public Utilities since January 1, 2015, to accelerate the replacement of aging and leak-prone natural gas pipeline infrastructure pursuant to G.L. c. 164, § 145. The LDCs' GSEPs further the achievement of the goals of the GWSA because reduction of GHG emissions is an important result of the GSEPs.[1] The LDCs' continuing implementation of their GSEPs will result in increasing GHG emissions reductions on an annual basis in a cost- and resource- efficient manner.

The LDCs continue to balance efforts to maximize environmental benefits through their respective GSEPs with their paramount commitment to provide safe and reliable service to their customers. The LDCs have an immutable public service obligation to provide safe and reliable service to their customers at a reasonable cost. NSTAR Gas Company, D.P.U. 14-150, at 307 (2015); New England Gas Company, D.P.U. 10-114, at 76 (2011), citing Report to the Legislature Re: Maintenance and Repair Standards for Distribution Systems of Investor-Owned Gas and Electric Distribution Companies, D.P.U. 08-78, at 4 (2009); Incentive Regulation, D.P.U. 94-158, at 3 (1995). Regulations affecting the LDC distribution systems must be grounded in this fundamental principle. A hallmark of reasonable and effective regulations is the recognition of the need to balance competing, yet complementary, obligations and abilities. The LDCs look forward to continuing to work with the MassDEP to ensure that the appropriate balance is struck and that the LDCs are empowered to continue to implement their GSEPs in a manner that ensures the replacement of leak-prone infrastructure is accelerated in a safe, efficient manner that also maximizes the environmental benefits inherent in the GSEPs.

I. The MassDEP Should Extend the Decreasing Annual Emissions Limits Beyond 2020.

The Program Review Notice requests input on whether MassDEP should extend its current requirement for decreasing annual emissions limits beyond 2020. As outlined below, MassDEP should, and in fact must, extend these decreasing annual emissions limits. Currently, 310 CMR § 7.73, at Tables 1 through 7, provide for the Maximum Annual CH_4 Emission Limits for each of the LDCs, and in the aggregate, for each of the calendar years 2018 through 2020. The Maximum Annual CH_4 Emissions Limits decrease year over year.

The Massachusetts Supreme Judicial Court's ("SJC") decision in Kane v. Dep't of Environmental Protection, 474 Mass. 278, 290 (2016) requires the MassDEP to "set actual limits for sources or categories that emit greenhouse gases through the promulgation of regulations" and that it "is apparent from the plain language of the statute that the aggregate emissions limits for

1 See 2015 CECP Update at 105-106 (discussing LDC infrastructure replacement plans).

each regulated source of category of sources must decline on an annual basis." The SJC therefore concluded:

> …that the plain language of § 3 (d) requires the department to promulgate regulations that address multiple sources or categories of sources of emissions, impose a limit on emissions that may be released, limit the aggregate emissions released from each group of regulated sources or categories of sources, set emissions limits for each year, and set limits that decline on an annual basis.

Kane, 474 Mass. at 292. Based on the plain language of the Kane decision, the MassDEP must continue the decreasing annual emissions limits beyond 2020.

However, the MassDEP should refine the manner in which it calculates the annual limits, including the data set used to calculate the limits. Currently, the MassDEP uses the five-year listing of potential GSEP projects that each LDC files with its annual GSEP Plans ("GSEP Appendices") to establish the annual emission limits and appears to propose to continue relying on the GSEP Appendices going forward (see Program Review PowerPoint at 8; 310 CMR § 7.73, Tables 1 through 6). Reliance on the GSEP Appendices is not an appropriate methodology to use going forward. The LDCs' GSEP Appendices represent the universe of jobs that could be drawn from during a given GSEP Investment Year, not necessarily the jobs that will occur. Given emergent issues that arise on the LDCs' distribution systems and requisite re-prioritization of jobs year over year, the GSEP Appendices do not provide the most accurate estimate of annual replacements/retirements under the LDCs' respective GSEPs.

Rather than base the annual emission limits on the LDCs' GSEP, the LDCs recommend that MassDEP set an annual emission limit each year based on an LDC's annual October GSEP filing and establish a deadband percentage.[2] If an LDC's methane reduction based on its leak-prone infrastructure replacement in a given year falls within the deadband, as demonstrated in their Annual Pipeline and Hazardous Materials Safety Administration ("PHMSA") Report, then, for purposes of the MassDEP regulations, the LDC has met its declining emissions target. If an LDC falls above the deadband, it would need to petition to access the set aside set out in 310 C.M.R. § 7.73(4)(c).

Under this proposal, MassDEP would set an LDC's annual emission limit each year, as opposed to forecasting the limit for multiple years and including those forecasts in the regulations. This position complies with Kane, as it will result in annual emissions reductions. The Department of Public Utilities has found that the intent of the Legislature in enacting G.L. c. 164, § 145 was to accelerate the repair or replacement of aging or leaking natural gas infrastructure (in the interest of public safety and to reduce lost and unaccounted for natural gas). NSTAR Gas Company d/b/a Eversource Energy, D.P.U. 18-GSEP-06, at 27 (2019). If a GSEP plan complies with G.L. c. 164, § 145, and the Department determines that it reasonably accelerates eligible

[2] The LDCs are currently reviewing operational data to determine an appropriate deadband percentage and will supplement these comments with a description of that calculation by September 25, 2020.

infrastructure replacement and provides benefits to customers, the Department must preliminarily accept the plan either in whole or in part. G.L. c. 164, § 145(e). Thus, given that each LDC must file an annual GSEP that accelerates the replacement/retirement of leak-prone infrastructure on its distribution system, there will be a corresponding reduction in methane emissions as the LDC accelerates replacement/retirement and reconfigures the material composition of its distribution system.

The LDCs' proposal also provides for more achievable goals through closely tracking an LDCs' GSEP work rather than relying on forecasted GSEP work that will necessarily be impacted by a multitude of factors, many of which are outside of the LDCs' control. The current COVID-19 pandemic and its impact on the LDCS' GSEPs is a perfect example of outside factors that are beyond the LDCs' control that will impact their replacement progress and compliance with 310 C.M.R. § 7.73.

II. The Appropriate Size and Role of the Emissions Set Aside

As discussed above, the LDCs recommend that MassDEP set their annual emissions limits each year based on the LDCs' annual October GSEP filing including an appropriately calculated deadband percent. This proposal will help alleviate several challenges with the current emissions set aside process.

Forecasted annual limits, such as those currently in use in 310 CMR § 7.73 Tables 1 through 7, present a challenge that can result in multiple set aside petitions. The forecasted annual limits also fail to capture the necessarily flexible nature of an LDC's GSEP. First, if an LDC falls behind in its GSEP replacement efforts in one year, this shortfall compounds year-over-year, resulting in an LDC playing "catch-up" and having to file annual petitions to access the set aside amount in order to remain in compliance with 310 C.M.R. §7.73. This results in an inefficient process requiring multiple set-aside petitions, as well as the related MassDEP review of and decision on the petition. Second, the forecasted annual limits developed in year one for years two, three and four do not and cannot capture circumstances that impact the LDCs' GSEPs, including but not limited to: (1) emergent issues; (2) reprioritization of projects; (3) LDC construction of projects prioritized due to safety/risk that do not result in a significant amount of retirement of leak-prone infrastructure; (4) the impact of weather; and (5) delays encountered due to site conditions and municipal permitting processes. Failing to account for these emergent issues, all of which are undertaken consistent with the directives of Section 145 and the Department of Public Utilities' precedent concerning flexibility around adjustments to annual replacements/retirements, by promulgating rigid forecasted annual limits leads to multiple set aside petitions to account for these variations in annual replacements/retirements.

In order to mitigate the current inefficiencies in the set aside petition process, the LDCs propose the modification outlined in Section II that MassDEP set an LDC's emissions cap each year based on the LDC's annual October GSEP filing with a deadband. This process would provide for a potential of only <u>one</u> set aside petition per LDC per year, and only if the LDC failed to fall within the deadband percentage, which obviates the need for multiple set aside petitions in a given year, consistent with the sentiment expressed by MassDEP at its September 10, 2020 stakeholder meeting on this matter (see also Program Review PowerPoint at 13). It also provides for the flexibility to account for emergent issues, reprioritization of projects, concentration on critical projects that do not result in a significant amount of retirement, etc., by setting an annual emissions cap amount based on an LDC's most current GSEP, as opposed to forecasting the required emissions reductions for multiple future years.

The timing for submittal of a set-aside petition could also be streamlined. The LDCs recommend that the set-aside petition be due for the previous calendar year by April 15th, submitted with the annual report to MassDEP for the prior calendar year. This one due date will eliminate the need for multiple petitions to be filed at three different points during the year (*i.e.*, 30 days after a GSEP order, after a GREC order, or after the close of the calendar year).

In addition to the proposal described above, the impact of the COVID-19 pandemic has demonstrated that the set aside process must also account for *force majeure* events outside of the LDCs' control. Since the onset of the COVID-19 pandemic, the LDCs have largely been prevented from doing service tie overs, which require a technician to enter a customer's home. In turn, this prevents main retirement, since old, leak-prone main cannot be retired until all services are tied over to new plastic main. This will likely have an impact on the LDCs' achievement of leak-prone replacement for 2020 and is likely to have an impact in 2021 in the event that the Commonwealth and/or municipalities continue to restrict service tie-overs given that the pandemic is not abating. The LDCs will be incorporating the potential impact of the COVID-19 pandemic restrictions into their 2021 GSEPs, to be filed October 31, 2020. Thus, this impact should be reflected in the 2021 annual emissions limits under 310 C.M.R. §7.73.

In the current regulations there is no exemption or accounting for the impact of *force majeure* events. COVID-19 shows the need to have such an exemption, or at least the need to maintain the option to file for an adjustment following the close of the year as set out in 310 C.M.R. §7.73(4)(c)(4)(c).

III. The Most Appropriate Emissions Factors

A. The USEPA GHGI Factors for Mains and Services are the Most Appropriate Emissions Factor.

Currently, the MassDEP uses the emissions factors based on the *Lamb et al.* study ("Lamb Study") which informed the GHGI emission factors set out in 310 CMR § 7.73, at Table 9, to develop each LDC's annual Methane Emissions Limit by multiplying the emissions factor for each material type by the miles of main and number of services of each material type on an LDC's distribution system. This provides for a clear and thoroughly vetted approach in measuring emissions and more importantly provides a benchmark for reductions in emissions each year as the LDC's progress in its respective GSEP programs and the material composition of its distribution system changes over time.

MassDEP should continue to utilize this approach as it is the only acceptable method of calculating emissions that allows for benchmarking that is generally within the LDCs' control (*i.e.*, is less susceptible to outside factors such as weather or damage). MassDEP currently called attention to this during the September 10, 2020 stakeholder meeting on the program review, and no public comments provided at the time, or alternative proposals for calculating methane emissions, provided a clear or articulated method to benchmark reductions in methane year over year.[3] As explained in these initial comments, because the LDCs are subject to financial penalties for noncompliance, and because the MassDEP is required to set annual limits that result in measurable reductions in methane emissions, MassDEP should continue its approach to apply an emissions factor to the material composition of an LDC's system in order to develop an annual emissions limit.

While the LDCs support MassDEP's continued use of the above-described method for calculating an emissions limit, the factors currently listed in Table 9 are outdated, and should be replaced with the United States Environmental Protection Agency's ("USEPA") Greenhouse Gas Inventory ("GHGI") Factors for natural gas distribution mains and services Table 3.6-2, excerpted below:

USEPA GHGI Table 3.6-2 – Average CH4 Emissions Factors

Mains - Cast Iron	1,157.3
Mains - Unprotected steel	861.3
Mains - Protected steel	96.7
Mains - Plastic	28.8
Services - Unprotected steel	14.5
Services Protected steel	1.3
Services - Plastic	0.3
Services - Copper	4.9

Units are kg/mile for mains and kg/service for services

The GHGI emission factors outlined above are publicly reviewed each year and updated, as necessary. It is USEPA's standard process to update GHGI emission factors when relevant new and improved data are available, and in recent years, as improved data have become available, USEPA has updated methods and data sources for calculating greenhouse gas emissions for several sources in the natural gas sector. In contrast, the current emissions factors outlined in 310 CMR § 7.73 at Table 9 are based on a 2015 study and have not been updated in the intervening years to be aligned with how USEPA applied the results of the 2015 Lamb Study.

During the September 10, 2020 stakeholder meeting hosted by the MassDEP, certain commenters raised the possibility of using the *Weller et al.* 2020 study ("Weller Study") to evince new methane emissions factors. Based on the findings contained in the M.J. Bradley & Associates and CMR Summary and Review papers analyzing the Weller study, provided as Appendix B and

[3] While at least one commenter discussed the idea of developing an LDC-specific emissions factor, they did not explain how MassDEP would go about developing or verifying such factors, or how such factors could be implemented in a timely manner consistent with MassDEP's statutory and regulatory obligations to complete its Program Review.

Appendix C, respectively, the MassDEP should not utilize these factors. First, the Weller Study was meant to be a scientific assessment and not supersede the USEPA methodology utilized in the GHGI factors. Second, there were various methodological issues with the Weller Study render it inappropriate for utilization as the basis for MassDEP's emissions factors. For instance, the Weller Study used a Google car in four urban areas and combined the data gathered by the Google car with geographic information system ("GIS") data to determine material types and categorize leak source. The Weller Study did not include the age of the infrastructure material, nor did it incorporate vintage plastic infrastructure into its analysis. Additionally, the Weller Study did not verify the material of any mains. The data was extrapolated nationally, and some correction factors were applied. Data that should have been counted as outliers were also included. For example, the one leak found on plastic was caused by a dig-in, which should have been removed from the study as an outlier. However, given the small sample size of the Weller Study, this leak was included in the overall analysis and contributed to the study's conclusions. Additionally, the Weller Study does not isolate general atmospheric methane (e.g., from sewers) and remove it from the study's conclusions. The Weller Study has not been generally accepted as accurate or conclusive, thus rendering it inappropriate for use in the context of 310 CMR § 7.73.

In contrast, the Lamb Study, which is the basis for the GHGI factors, does not suffer from these fundamental flaws. The Lamb Study utilizes data from all over the United States. Additionally, the Lamb Study accounted for outliers, such as general atmospheric methane, in its ultimate findings. Given these flaws and the fact that the LDCs are subject to monetary penalties under 310 CMR § 7.73, itis not appropriate to apply the Weller Study findings or data nationally, and MassDEP should not do so here.

While the current factors have served an appropriate purpose for the years 2018 through 2020, and at the time they were adopted codified the best-available leak rate and leak incidence information, this is no longer the case. Consistent with the LDCs' proposal in Section II of these initial comments, the LDCs recommend that when setting the annual emissions limits each year, the MassDEP base the limit on the most-currently available GHGI Factors.

Using the most current USEPA GHGI Factors for distribution mains and services, in conjunction with the LDCs' proposed methodology for calculating an emissions limit will ensure that each year the LDCs' emissions cap and reductions goals are based on the best available information.

B. Technologies to Detect and Quantify Gas Leaks Are Not an Appropriate Metric for the 310 CMR § 7.73 Process.

Given their collective expertise and knowledge of their distribution systems, the LDCs are leaders when it comes to reviewing and evaluating new and proven technologies for detecting and eliminating natural gas leaks and enhancing safe and reliable service to their customers. However, there are no practical, feasible technologies to detect and quantify gas leaks from the LDCs' distribution system in a manner that provides for meaningful benchmarking and evaluation.

First, the LDCs question the efficacy of methods for quantifying and measuring methane leaks on their distribution systems, such as the Picarro Surveyor for Natural Gas Leaks, as these methods have not definitively shown that they can accurately distinguish between ambient methane and methane attributable to the natural gas distribution system. While the Companies are engaged with Picarro and other stakeholders on evaluating these technologies, there is simply insufficient scientific support for using such technologies to set benchmark goals for reducing natural gas leaks.

Second, the MassDEP's regulations call for the imposition of penalties on LDCs that are found to be out of compliance with 310 C.M.R. § 7.73:

> (a) If a gas operator exceeds the Maximum Annual CH Emission limits set forth in the applicable table provided in 310 CMR § 7.73(4)(a), any such excess emissions shall be deemed to be a release of air pollutants into the environment without the authorization or approval of the Department, and shall be presumed to constitute a significant impact to public health, welfare, safety, and the environment.
>
> (b) The Department shall enforce the requirements of 310 CMR § 7.73 in accordance with applicable federal and Massachusetts law, including but not limited to M.G.L. c. 21A, § 16, 310 CMR 5.00: Administrative Penalty, M.G.L. c. 111, § 2C, §§ 142 A through 142M; and M.G.L. c. 21N, § 7(d).

310 CMR § 7.73(8). These statutes and regulations allow MassDEP to enforce significant monetary penalties against the LDCs should the LDCs exceed their maximum annual methane emissions. Under the current regulations, and under the methodologies proposed by the LDCs in these initial comments, the LDCs are largely in control of their annual methane emissions and reductions year over year, since the maximum allowable amounts are based on each LDC's GSEP.

In contrast, the use of technology, or of a methodology for calculating methane emissions based on actual leaks, does not provide the LDCs sufficient control or a meaningful method of reducing and eliminating leaks year over year such that they could be penalized financially for failing to meet the emissions limits set out in 310 C.M.R. § 7.73. Technology or methodologies that attempt to quantify leaks can provide a snapshot of methane emissions at a moment in time on a distribution system, but they do not provide a manner in which those leaks can be eliminated or reduced year over year. The LDCs do not have control over leakage rates year over year due to weather impacts on cast iron mains and bell joints, construction dig ins, and other factors, whereas the LDCs do have, to a much greater extent, control over main replacement.

Given the possibility of financial penalties, MassDEP must utilize a clear, well vetted, and acceptable method for developing benchmarks for year over year reductions in emissions that are within the LDCs' relative control. The use of technology or methodologies to calculate emissions based on leaks provide only a snapshot in time of the distribution system, and do not provide a method for extrapolating that measurement into a forecast of annual emissions limits.

Accordingly, MassDEP should continue to base the LDCs' annual emissions limits on a combination of pipe replacement and pipe material leak rate.

IV. Need for Additional Process

As noted at the September 10, 2020 public hearing, MassDEP is required to hold an additional public hearing and allow for additional written comments following its publication pf proposed revised 310 CMR § 7.73 regulations. Given the potential for the imposition of financial penalties on LDCs that fail to meet methane reductions set out in 310 CMR § 7.73, the LDCs are pleased that the MassDEP has committed to additional process prior to the finalization of revised 310 CMR § 7.73 regulations. The LDCs appreciate the opportunity to provide additional insight, clarity, and information on these important regulations.

###

Thank you for your attention to this matter. The LDCs appreciate MassDEP's consideration of these initial comments and look forward to further participation and comments on any proposed regulation amendments to 310 CMR § 7.73.

Very truly yours,

NSTAR GAS COMPANY d/b/a EVERSOURCE ENERGY

By its Attorneys,

Danielle C. Winter

Danielle C. Winter, Esq.
Keegan Werlin, LLP
99 High Street, Suite 2900
Boston, MA 02110
(617) 951-1400
dwinter@keeganwerlin.com

Nancy Kaplan

Nancy Kaplan, Esq.
Senior Counsel
Eversource Energy
800 Boylston Street, 17th Floor
Boston, MA 02199
(617) 424-2128 (office)
(617) 424-2733 (fax)
nancy.kaplan@eversource.com

-and-

BAY STATE GAS COMPANY d/b/a COLUMBIA GAS OF MASSACHUSETTS,

By its Attorneys,

Kenneth W. Christman

____
Kenneth W. Christman, Esq.
NiSource Corporate Services Company
121 Champion Way, Suite 100
Canonsburg, PA. 15317
Telephone: (724) 416-6315
E-Mail: kchrist@nisource.com

-and-

Brendan P. Vaughan

____
Brendan P. Vaughan
Keegan Werlin LLP
99 High Street, Suite 2900
Boston, Massachusetts 02110
(617) 951-1400
bvaughan@keeganwerlin.com

BOSTON GAS COMPANY and FORMER COLONIAL GAS COMPANY, each d/b/a NATIONAL GRID,

By its Attorney,

Andrea G Keeffe

____
Andre Keeffe, Esq.
Senior Counsel
National Grid USA Service Company, Inc.
40 Sylvan Road
Waltham MA 02451
781.907.2123
andrea.keeffe@nationalgrid.com

LIBERTY UTILITIES (NEW ENGLAND NATURAL GAS COMPANY) CORP. d/b/a LIBERTY,

By its Attorney,

R. J. Ritchie

____
Ronald J. Ritchie, Esq.
Liberty Utilities
36 Fifth Street
Fall River, MA 02721
TEL: (774) 627-2910

FITCHBURY GAS & ELECTRIC COMPANY d/b/a UNITIL,

By its Attorney,

Carleton B. Simpson

____

Carleton Simpson, Esq.
Regulatory Counsel
Unitil Service Corp
6 Liberty Lane West
Hampton, NH 03842
(603) 379-3848

THE BERKSHIRE GAS COMPANY,

By its Attorney,

____

Leonard Rodriguez, Esq.
General Counsel
The Berkshire Gas Company
115 Cheshire Road
Pittsfield, MA 01201
Leonard.Rodriguez@avangrid.com
203.499.2113

	GSEP Pace of Replacement				
	2015	**2016**	**2017**	**Projected 2018**	**Cumulative Under GSEP**
Miles of Leak-Prone Main Replaced	222	248	284	165	919
Number of Services Replaced or Retired	15,998	17,531	19,331	6,919	60,704

Number of Gas Leaks Eliminated Under GSEP (2015-2017)	
LDC	**Leaks Eliminated**
Berkshire Gas	630
Boston Gas	490[1]
Colonial Gas	107[2]
Columbia Gas	1,337
NSTAR Gas	361
Liberty	329
Unitil	45
Massachusetts Total	**3,299**

1 Estimated based on prior year LPP inventory leak repair rate times number of abandonment miles.
2 Estimated based on prior year LPP inventory leak repair rate times number of abandonment miles.

Projected Methane Emissions Reductions Through GSEP		
GSEP 5-Year Milestone	**Total Program Mileage to be Replaced**	**Reduction in CO_{2e}** ***(Metric Tonnes)***
5	1,223	29,264
10	1,458	37,478
15	1,309	32,164
20	1,101	27,538
25	655	20,042
TOTAL	**5,746**	**146,486**

Table 1: Berkshire Gas Company

Table 1A

The Berkshire Gas Company
Replacement Progress – Leak-Prone Infrastructure

				GSEP Pace of Replacement			
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018** ***Projected***
Miles of Leak-Prone Main Replaced	4.7	5.8	5.7	8.3	8.2	10.3	7.2
Number of Services Replaced or Retired	368	411	249	325	438	378	363

Table 1B

The Berkshire Gas Company
Number of Gas Leaks Eliminated Under GSEP
(2015-2017)

Year	**Leaks Eliminated**
2014-2017	630

Table 1C

The Berkshire Gas Company
Projected Methane Emissions Reductions Through GSEP[3]

GSEP 5-Year Milestone	**Total Program Mileage to be Replaced**	**Reduction in CO_{2e}** ***(Metric Tonnes)***
5	81	228
10	52	143
15	27	72
20	n/a	n/a
25	n/a	n/a
TOTAL	**160**	**443**

[3] Reduction in CO_{2e} results from the replacement of both main segments and services. In this chart, the LDCs have presented miles of main only because main replacements are the primary target of the GSEP program, and therefore, the primary milestone for achievement.

Table 2 and 3: National Grid/Boston Gas Company and Colonial Gas Company

Table 2A

National Grid/Boston Gas Company
Replacement Progress – Leak-Prone Infrastructure

				GSEP Pace of Replacement			
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018** ***Projected***
Miles of Leak-Prone Main Replaced	93	89	79	92	107	115	49
Number of Services Replaced or Retired	8,827	7,711	7,327	7,051	7,788	9,260	TBD

Table 2B

National Grid/Boston Gas Company
Number of Gas Leaks Eliminated Under GSEP
(2015-2017)

Year	Leaks Eliminated[4]
2015	141
2016	183
2017	166
Total	**490**

4 Estimated based on prior year LPP inventory leak repair rate times number of abandonment miles.

Table 2C

National Grid/Boston Gas Company
Projected Methane Emissions Reductions Through GSEP[5]

GSEP 5-Year Milestone	Total Program Mileage to be Replaced	Reduction in CO_{2e} *(Metric Tonnes)*
5	474	11,580
10	601	15,096
15	715	18,153
20	828	21,022
25	482	16,325
TOTAL	**3,100**	**82,177**

Table 3A

National Grid/Colonial Gas Company
Replacement Progress – Leak-Prone Infrastructure

				GSEP Pace of Replacement			
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018** ***Projected***
Miles of Leak-Prone Main Replaced	54	47	46	34	38	44	23
Number of Services Replaced or Retired	3,368	2,908	2,844	2,166	2,331	2,792	TBD

5 Reduction in CO_{2e} results from the replacement of both main segments and services. In this chart, the LDCs have presented miles of main only because main replacements are the primary target of the GSEP program, and therefore, the primary milestone for achievement.

Table 3B **National Grid/Colonial Gas Company** **Number of Gas Leaks Eliminated Under GSEP** **(2015-2017)**	
Year	**Leaks Eliminated**[6]
2015	28
2016	50
2017	29
Total	**107**

Table 3C **National Grid/Colonial Gas Company** **Project Projected Methane Emissions Reductions Through GSEP**[7]		
GSEP 5-Year Milestone	**Total Program Mileage to be Replaced**	**Reduction in CO_{2e}** ***(Metric Tonnes)***
5	173	3,810
10	104	3,039
15	22	542
20	0	0
25	0	0
TOTAL	**299**	**7,391**

---

[6] Estimated based on prior year LPP inventory leak repair rate times number of abandonment miles.

[7] Reduction in CO_{2e} results from the replacement of both main segments and services. In this chart, the LDCs have presented miles of main only because main replacements are the primary target of the GSEP program, and therefore, the primary milestone for achievement.

Table 4: Bay State Gas Company d/b/a Columbia Gas of Massachusetts

Table 4A

Columbia Gas Company
Replacement Progress – Leak-Prone Infrastructure

				GSEP Pace of Replacement			
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018** ***Projected***
Miles of Leak-Prone Main Replaced	42.8	40.5	41.2	42.5	44.5	53.2	18.5[8]
Number of Services Replaced or Retired	2,257	1,991	3,027	3,141	3,883	3,595	2,389

Table 4B

Columbia Gas Company
Number of Gas Leaks Eliminated Under GSEP
(2015-2017)

Year	Leaks Eliminated
2015	514
2016	434
2017	389
System Total	**1,337**

[8] The 2018 Year-to-Date Construction Forecast is an estimate of actual program performance based on current performance and judgment regarding performance against the program. The forecast is contingent upon executing the program completely without any obstacles adversely affecting execution, such as weather, municipality construction moratoriums, excavating conditions, permitting issues, availability of construction resources, etc. Actual results are not available until all receivable, payable and property accounts and records are fully reconciled and booked in preparation for the 2018 GREC filing to be filed May 1, 2019.

Table 4C **Columbia Gas Company** **Projected Methane Emissions Reductions Through GSEP[9]**		
GSEP 5-Year Milestone	**Total Program Mileage to be Replaced**	**Reduction in CO_{2e}** ***(Metric Tonnes)***
5	210.0	7,179
10	365.3	11,748
15	209.7	6,295
20	0	0
25	0	0
TOTAL	**785**	**25,222**

[9] Reduction in CO_{2e} results from the replacement of both main segments and services. In this chart, the LDCs have presented miles of main only because main replacements are the primary target of the GSEP program, and therefore, the primary milestone for achievement.

Table 5: NSTAR Gas Company d/b/a Eversource Energy

Table 5A

Eversource/NSTAR Gas Company
Replacement Progress – Leak-Prone Infrastructure

				GSEP Pace of Replacement			
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018 *Projected***
Miles of Leak-Prone Main Replaced	20	23	19	31	38	41	45
Number of Services Replaced or Retired	2,113	2,443	1,302	2,369	2,006	2,038	3,000

Table 5B

Eversource/NSTAR Gas Company
Number of Gas Leaks Eliminated Under GSEP
(2015-2017)

District	**Leaks Eliminated**
Somerville	47
Hyde Park	53
Southboro	101
Worcester	22
Plymouth	1
New Bedford	137
System Total	**361**

Table 5C **Eversource/NSTAR Gas Company** **Projected Methane Emissions Reductions Through GSEP[10]**		
GSEP 5-Year Milestone	**Total Program Mileage to be Replaced**	**Reduction in CO_{2e}** ***(Metric Tonnes)***
5	200	4,843
10	250	6,016
15	250	5,664
20	235	5,385
25	173	3,717
TOTAL	**1,108**	**25,625**

10 Reduction in CO_{2e} results from the replacement of both main segments and services. In this chart, the LDCs have presented miles of main only because main replacements are the primary target of the GSEP program, and therefore, the primary milestone for achievement.

Table 6: Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty

Table 6A

Liberty
Replacement Progress – Leak-Prone Infrastructure

				GSEP Pace of Replacement			
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018 *Projected***
Miles of Leak-Prone Main Replaced	6.88	6.28	9.12	9.28	8.05	13.84	17.93
Number of Services Replaced or Retired	473	517	731	619	843	878	887

Table 6B

Liberty
Number of Gas Leaks Eliminated Under GSEP
(2015-2017)

District	Leaks Eliminated
Fall River	206
Somerset	65
Swansea	25
Westport	16
North Attleboro	1
Plainville	16
System Total	**329**

Table 6C Liberty Projected Methane Emissions Reductions Through GSEP[11]		
GSEP 5-Year Milestone	**Total Program Mileage to be Replaced**	**Reduction in CO_{2e} *(Metric Tonnes)***
5	62.21	897
10	70.00	889
15	70.00	908
20	22.264	601
25	0	0
TOTAL	**224.474**	**3,295**

[11] Reduction in CO_{2e} results from the replacement of both main segments and services. In this chart, the LDCs have presented miles of main only because main replacements are the primary target of the GSEP program, and therefore, the primary milestone for achievement.

Table 7: Fitchburg Gas & Electric Light Company d/b/a Unitil

Table 7A

Unitil/Fitchburg Gas & Electric Light Company
Replacement Progress – Leak-Prone Infrastructure

				GSEP Pace of Replacement			
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018** ***Projected***
Miles of Leak-Prone Main Retired	3.04	4.33	5.67	4.74	4.01	6.51	3.93
Number of Services Replaced or Retired	303	398	405	327	242	390	280

Table 7B

Unitil/Fitchburg Gas & Electric Light Company
Number of Gas Leaks Eliminated Under GSEP
(2015-2017)

System Total	**Leaks Eliminated**
	45

Table 7C **Unitil/Fitchburg Gas & Electric Light Company Project Projected Methane Emissions Reductions Through GSEP**[12]		
GSEP 5-Year Milestone	**Total Program Mileage to be Replaced**	**Reduction in CO_{2e}** ***(Metric Tonnes)***
5	22.71	726.8
10	15.83	547.2
15	15.75	529.8
20	15.75	529.8
25	0	0
TOTAL	**70**	**2,334**

[12] Reduction in CO_{2e} results from the replacement of both main segments and services. In this chart, the LDCs have presented miles of main only because main replacements are the primary target of the GSEP program, and therefore, the primary milestone for achievement.

	GSEP Pace of Replacement				
	2015	**2016**	**2017**	**Projected 2018**	**Cumulative Under GSEP**
Miles of Leak-Prone Main Replaced	222	248	284	165	919
Number of Services Replaced or Retired	15,998	17,531	19,331	6,919	60,704

Table 8B

Consolidated LDCs
Number of Gas Leaks Eliminated Under GSEP
(2015-2017)

LDC	**Leaks Eliminated**
Berkshire Gas	630
Boston Gas	490[13]
Colonial Gas	107[14]
Columbia Gas	1,337
NSTAR Gas	361
Liberty	329
Unitil	45
Massachusetts Total	**3,299**

13 Estimated based on prior year LPP inventory leak repair rate times number of abandonment miles.
14 Estimated based on prior year LPP inventory leak repair rate times number of abandonment miles.

Table 8C Consolidated LDCs Projected Methane Emissions Reductions Through GSEP		
GSEP 5-Year Milestone	**Total Program Mileage to be Replaced**	**Reduction in CO_{2e} *(Metric Tonnes)***
5	1,223	29,264
10	1,458	37,478
15	1,309	32,164
20	1,101	27,538
25	655	20,042
TOTAL	**5,746**	**146,486**

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an ERM Group company

CONCORD, MA — WASHINGTON, DC

47 Junction Square Drive
Concord, MA 01742

978-369-5533
www.mjbradley.com

MJB&A Summary ■ August 14, 2020

Study Quantifies Methane Leakage from Distribution Mains using Advanced Mobile Leak Detection

A June 2020 study, *A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems*, by researchers at Colorado State University and the Environmental Defense Fund (EDF) ("Weller et al.")[1] presents new data on methane leakage from natural gas distribution mains. The authors used data from advanced mobile leak detection (AMLD) surveys – vehicle-mounted methane detectors – taken across four urban areas as well as pipeline data from the Pipeline and Hazardous Materials Safety Administration (PHMSA) and local utilities to develop new activity and emissions factors for distribution mains.[2] Overall, the study finds that the activity and emissions factors developed in a previous EDF-sponsored study ("Lamb et al.")[3] and currently used in EPA's Greenhouse Gas (GHG) Inventory underestimate actual methane emissions. If the new activity and emissions factors are extrapolated to the national level, total methane emissions from distribution mains are 4.8 times greater than the estimate in EPA's annual GHG Inventory.

Background

There have been significant efforts to better understand and quantify methane emissions from the natural gas supply chain in recent years. In the natural gas distribution segment, the assumptions used to estimate methane emissions were, until recently, based on a 1996 study by the Gas Research Institute and EPA (GRI/EPA) that used 1992 data. In 2015, a new study by Lamb et al. was published with data based on direct measurements of methane emissions from underground mains and services and other sources in the natural gas distribution system. The activity factors (leaks/mile) and emissions factors (g CH_4/minute/leak) developed from these data were overall substantially lower that those from the GRI/EPA study and suggested that EPA's annual GHG Inventory was significantly overestimating distribution segment methane emissions.

In response to the new data, in 2016 EPA updated the GHG Inventory methodology to include the emissions factors from Lamb et al. for specific distribution sources, including mains. The new emissions factors for mains were applied to all years from 2011 forward; the original GRI/EPA factors were maintained for 1990 through 1992, and emissions factors were calculated using linear interpolation between the old and new factors for the

[1] Weller, Zachary D., Hamburg, Steven P., and von Fischer, Joseph P. "A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems," *Environmental Science & Technology*, June 10, 2020. Available at: https://pubs.acs.org/doi/abs/10.1021/acs.est.0c00437.
[2] The locations were not disclosed to protect the identities of the participating utilities.
[3] Lamb, Brian K. et al. "Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States," *Environmental Science & Technology*, March 31, 2015. Available at: https://pubs.acs.org/doi/10.1021/es505116p.

intermediate years. The leaks per mile assumptions for each pipeline material were not updated and the original GRI/EPA activity factors remain in effect.

While the GHG Inventory methodology was updated, EPA's Greenhouse Gas Reporting Program (GHGRP) continues to use the GRI/EPA emissions factors for distribution sources. Unlike the GHG Inventory, revisions to the GHGRP require a formal rulemaking process. EPA is expected to propose updating the GHGRP with the lower Lamb et al. emissions factors, but the timing of this rulemaking is uncertain. This most recent study by Weller et al. suggests that the Lamb et al. emissions factors may underestimate actual emissions.

Activity Factors, Emissions Factors, and Inventory

The terms activity factory, emissions factor, and inventory have different meanings in the academic studies and EPA's GHG inventory programs. In the studies, activity factors refer to the number of leaks per mile of pipeline. The studies use emissions factor or leak rate to describe the amount of methane emitted over a given period of time for an individual leak, presented here in grams per minute. The studies define inventory as miles of pipeline. EPA activity factors are pipeline mileage, the same thing referred to as inventory in the studies. The metric for EPA pipeline emissions factors is kilograms methane per mile per year. This unit is derived from the emissions factors and activity factors used by the studies (grams per minute per leak and leaks per mile allow calculation of kilograms per mile per year).

Methodology

Researchers used three data components to calculate new distribution main activity and emissions factors and to estimate national emissions. First, AMLD survey and gas utility inventory data were used to develop average leaks per mile activity factors for pipe of different age and material. Next, data from the AMLD surveys was also used to develop average emission factors (g CH_4/min/leak) for each pipeline material, after individual AMLD measurements were corrected using three data validation methods.

Finally, to estimate total annual emissions nationally, PHMSA inventory data were extrapolated to estimate the total national mileage of mains by material and age. The new activity and emission factors were then applied to the PHMSA inventory data to estimate the total number of annual leaks nationally for pipelines of each material, and to estimate total annual emissions.

To integrate different pipeline classifications across data sets, researchers included certain types of mains in other categories (e.g. copper main mileage is included in bare steel mileage). Details on the report's statistical methods can be found in a separate supporting information document.[4]

Leaks per Mile

To develop estimates of the number of leaks per mile of distribution main, researchers combined data from the mobile leak surveys with gas utility GIS data that included pipeline location, material, and age. Across the four regions, roughly 5,800 miles of mains were surveyed at least twice; for a pipe section to be included the mobile leak detector had to come within 70 meters of the pipe location. Methane detected within 40 meters of a recorded pipeline was recorded as a pipeline leak indication. This resulted in a total of 4,220 leak indications. This

[4] Weller et al. "Supporting Information for a National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems." *Environmental Science & Technology*, June 10, 2020. Available at: https://pubs.acs.org/doi/10.1021/acs.est.0c00437?goto=supporting-info.

information was used to estimate the number of leaks per mile as a function of pipe material and age. The report authors assumed that the number of false negatives (undetected leaks) was equal to the number of false positives (detected leaks from non-natural gas sources), and that the leak per mile estimate therefore provides a reasonable approximation of actual leaks per mile.

Leak Rate

The AMLD data was collected by vehicle-mounted Picarro, Los Gatos, or LiCor methane detection devices. Advanced algorithms were used to calculate leak rates. Unlike the data used by Lamb et al., methane leak rates were not directly measured in this study. However, three methane quantification methods were used to validate the leak rates calculated by the mobile surveys. This information was used to correct the leak rates for each of the 4,220 leak indications and develop average emissions factors for each pipeline material. However, there is large variation around the mean, contributing to a wide range for estimated average emissions factors for each type of distribution main. Overall, the AMLD methodology overestimated leak rates compared to the validation methodologies, with a mean correction of 0.6 gram methane per minute. The difference was larger for smaller leaks, meaning AMLD was able to more accurately quantify large leak rates.

National Leak Count Estimate

The AMLD activity factors and PHMSA inventory data were used to estimate the total count of annual distribution main leaks in the U.S. The PHMSA data includes summary information on total mileage by pipeline type and total mileage by age; breakdowns of mileage for each material type by age are not provided. For example, total bare steel mileage of all ages and total mileage of all pipes installed 2010-2019 are provided, but not the mileage of bare steel installed 2010-2019. Using these known constraints and several assumptions, researchers randomly and uniformly sampled the possible distribution of main mileage for each material for each age bracket (defined as decades) 100 times. Multiplying the mean of these estimates for each material/age category by the estimated leak per mile activity factor and then summing these results by pipeline material yields an estimate of total U.S. leaks by material. Given the range of results from the random sampling of miles for each material/age combination and uncertainty associated with the leaks per mile estimate, there is a wide range of uncertainty associated with estimated total leak counts.

Findings

The report found that distribution mains have higher activity factors (average leaks per mile) and higher methane emissions factors (g/min/leak) compared to the Lamb et al. study. When scaled to the national level, these assumptions generate an estimate that is 4.8 times higher than EPA's estimate of methane emissions from distribution mains.

Activity Factors

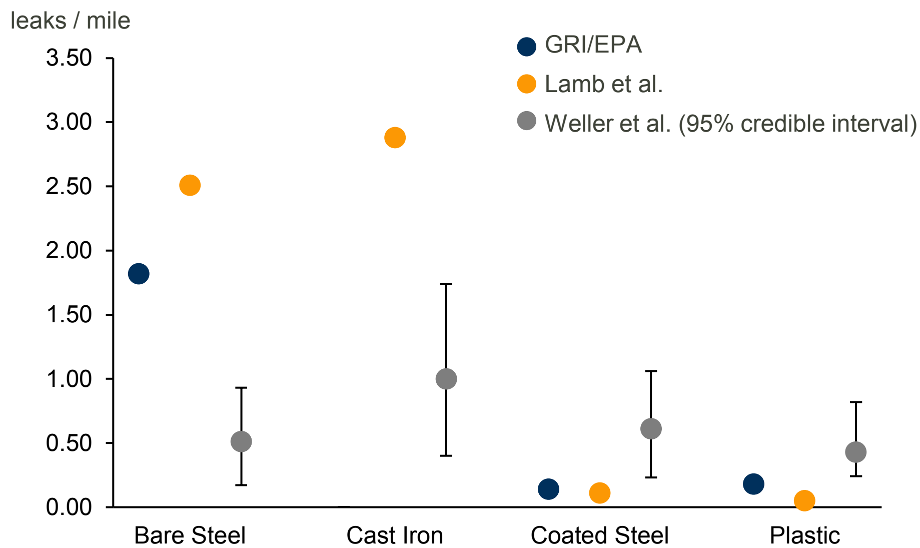
The report estimates that distribution main methane activity factors (leaks per mile) are higher than those developed by Lamb et al. and currently used in EPA's GHG Inventory, with some variation by pipeline material type. Table 1 presents estimated total U.S. leaks and leaks per mile by pipeline material for the new study, Lamb et al. (2015), and the 1996 GRI/EPA study. Figure 1 provides a visual representation of the different activity factors. Note that these activity factors are not comparable to those in the GHG Inventory – the numbers below represent leaks per mile and total leaks whereas the GHG Inventory uses pipeline mileage as an activity factor. As shown, the new study found bare steel and cast iron mains to have a lower occurrence of leaks per mile compared to Lamb et al. However, estimates of leaks per mile are significantly higher for coated steel and plastic mains. The researchers attribute the lower activity factors in the Lamb et al. study to the fact that it used leaks already known to utilities and assumed that those leaks accounted for 85 percent of total leaks. In contrast, the new study calculated leak counts based on leak indications from the mobile surveys.

Table 1: Distribution Main Methane Activity Factors Across Three Studies

Pipeline Material	Study					
	GRI / EPA		Lamb et al.		Weller et al.*	
	Total U.S Leaks (thousands)	Leaks/Mile	Total U.S Leaks (thousands)	Leaks/Mile	Total U.S Leaks (thousands)	Leaks/Mile
Bare (Unprotected) Steel	174.7	1.82	130.3	2.51	23.7 (7.9-43.0)	0.51 (0.17, 0.93)
Cast Iron	N/A	N/A	81.6	2.88	25.2 (9.9-43.5)	1.00 (0.40, 1.74)
Coated (Protected) Steel	68.3	0.14	55.4	0.11	296.0 (111.0-513.5)	0.61 (0.23, 1.06)
Plastic	49.2	0.18	32.3	0.05	314.1 (122.8-547.0)	0.43 (0.24, 0.82)

** Parentheses for total leaks represent 95 percent credible interval. Parentheses for leaks/mile represent the upper and lower estimates*

Figure 1. Distribution Main Methane Activity Factors Across Three Studies



Note: The GRI/EPA study did not include an estimate of leaks/mile for cast iron mains

The analysis of pipeline leaks by age and material found that across all materials, the number of leaks per mile increased with age. The rate at which leaks increased over time were similar for cast iron, coated steel, and plastic; bare steel exhibited a faster increase in leaks per mile as mains aged. Additionally, certain bare steel had lower leak indicator rates than coated steel of the same vintage. The researchers also explored the impact of main diameter and pressure but found that they had no meaningful impact on the number of leaks per mile.

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Emissions Factors

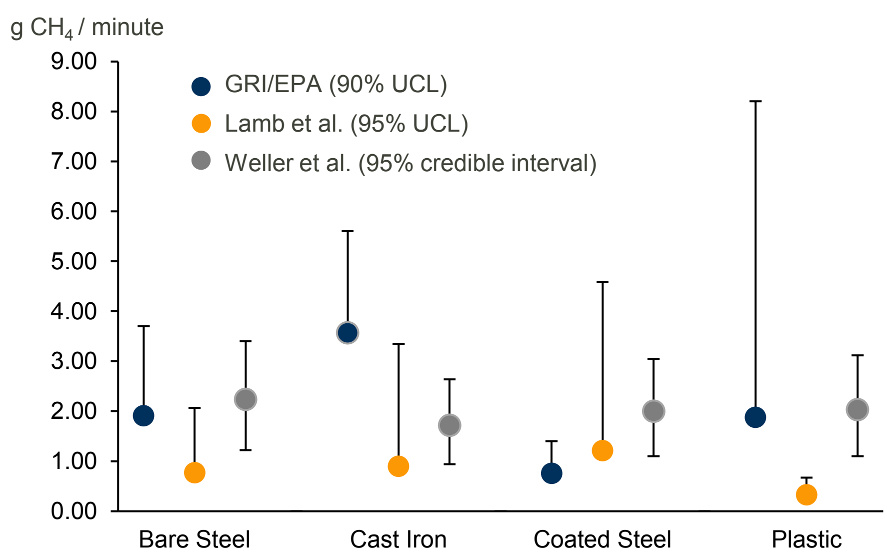
The average emissions factors calculated in the study are greater than those from Lamb et al. for all four pipeline materials and the authors note that their results show better agreement with the emission rates developed by the GRI/EPA study. Table 2 shows the mean methane emissions factors from the three studies. Note that these rates are denominated in grams methane per minute; the GHG Inventory uses kilograms methane per mile. Figure 2 shows the emissions factors with reported uncertainty ranges.

Table 2. Distribution Main Methane Emissions Factors Across Three Studies (g CH_4/minute)

Pipeline Material	Study		
	GRI / EPA	Lamb et al.	Weller et al.
Bare (Unprotected) Steel	1.91 (20)	0.77 (74)	2.24 (826)
Cast Iron	3.57 (21)	0.90 (14)	1.72 (1,664)
Coated (Protected) Steel	0.76 (17)	1.21 (31)	2.00 (911)
Plastic	1.88 (6)	0.33 (23)	2.03 (819)

Note: sample sizes for each study are shown in parentheses

Figure 2. Distribution Main Methane Emissions Factors Across Three Studies



As noted above, there is uncertainty in the estimated emissions factors due to uncertainty in the ability of the leak validation to fully correct for the rates calculated by AMLD, as well as the wide range of emission rates observed for each pipeline material. Pipeline material was found to be the primary driver of emission factors and pipeline age, diameter, and pressure were not found to have meaningful effects.

Overall, the new emissions factors are 3.2 times greater than those developed by Lamb et al. The researchers hypothesize that their higher rates are the result of a larger sample size (shown in parentheses in Table 2), which better captures the impact of a small number of “super-emitting” sources that are responsible for a disproportionate percentage of emissions. In this case, removing the highest emitting three percent of leaks from the data set reduces estimated emissions factors by 25 percent. Looking at gross emissions, an estimated 40 percent of total methane detected by the AMLD surveys was attributable to eight percent of the leaks.

National Emissions Estimate

When the study's findings are scaled to calculate national methane emissions from distribution mains, the mean estimate is 690 kilotons of methane. This is approximately 4.8 times greater than EPA's estimate of 143 kilotons for 2017 methane emissions from distribution mains, as published in the 2019 GHG Inventory. This estimate is roughly three times greater than EPA's estimate of emissions from both mains and services, suggesting that even if methane from some service leaks was captured by the AMLD surveys, it would not have a significant impact on the difference between the EPA and study estimates. Looking at the entire distribution segment, substituting the study's estimate of emissions from mains with EPA's would approximately double the segment's 2017 methane emissions. The researchers also ran sensitivity analysis to account for the possibility that large leaks may be repaired quickly and thus not emit methane for a full year. When leaks greater than 50 liters methane per minute were excluded, the mean national estimate was 550 kilotons, still 3.85 times greater than the EPA estimate.

It is important to note that the methodology used to scale national emissions did not involve simply multiplying the mean emissions factors for each pipeline material by their respective activity factors. Instead, the authors sampled their calculated estimates of pipeline mileage by material and age and applied the range of calculated emissions factors for each material. The national estimate is the mean of these outputs. This methodology accounts for the uncertainty in each component of the equation.

Contacts

For more information on this topic, please contact:

Pye Russell
Consultant
prussell@mjbradley.com
(978) 369-5533

Brian Jones
Senior Vice President
bjones@mjbradley.com
(978) 369-5533

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CMR Summary and Review – Weller et al. 2020

Executive Summary

In collaboration with Environmental Defense Fund, Colorado State University (CSU) published a paper to report the findings of a distribution system leak survey study using an "advanced mobile leak detection platform" (AMLD). The authors calculated methane emissions using leak rate estimates measured with the AMLD and pipeline GIS information provided by local utilities for four urban areas. They found that leakiness of pipes (number of leaks per mile of main) increased with pipe age and varied across pipe materials, with cast iron and, surprisingly, coated steel having a high number of leaks per mile. By extrapolating the results to the national scale, they estimated that methane emissions from pipeline mains on distribution systems were approximately 5x higher than the current EPA GHGI estimate. The implication of the calculated emission increase, if scaled nationally, could mean that methane emissions from local distribution systems are 7.6% of U.S. total methane natural gas system emissions, rather than the currently reported 3.4%. Unfortunately, however, there are several limitations of the study, including –

- Data extrapolated from four cities to nationwide.
- Did not consider rural and suburban areas.
- High uncertainty in the AMLD system quantification (2 – 3 orders of magnitude difference in flow rates between prediction and actual methods).
- Minimal verification of leak locations or emission rates.
- Authors assume that an indication within 40 meters of a pipeline is a leak associated with the pipeline without a consideration for wind direction.
- Did not determine true false positive rate. Any indication further than 40 m from a pipe was considered a false positive.
- Assumed false negative rate was equal to false positive rate to avoid calculation of a correction for the data.
- No material verification so cannot draw conclusions on material type emission rates.
- Study indicates that coated steel had more leaks per mile than bare steel. This is not explained and does not make sense.

- Pipes surveyed were older than national average ages of pipe. Have 25% of pipes older than 79 years, national average is 4%.
- Extremely different emission rates and leaks per mile than found in Lamb et al. 2015.

Limited data

The data collection methods are described in an earlier paper from this study (Weller et al. 2018). The instruments used in the research were Picarro CH_4 analyzers installed in three Google Street View (GSV) cars and a functionally similar Los Gatos CH_4 analyzer installed in a fourth car. The areas surveyed were not disclosed to comply with nondisclosure agreements with local gas distribution companies that shared GIS information. The research team collected data from a total of 8900 miles of roadways that were driven at least two or more times.

It is important to note that the research team collected data from 4 urban areas, approximately 8900 miles of roadways or 5900 miles of pipe mains, which was then extrapolated to the national scale. Performing the extrapolation can include a large amount of bias as the obtained data were only from a small number of urban areas with unknown geographic locations. Suburban or rural areas could potentially see a lower number of leaks per mile of pipe due to a lower density of other underground installations which could affect the integrity of gas pipelines. Additionally, considering that each region/utility has different practices on leak survey, leak repair, pipe replacement, the extrapolation of four urban areas to the national scale is likely to include a high degree of uncertainty. As a suggestion for future research to minimize uncertainty, the authors could expand the study to include more cities, suburban, and rural areas in a diversified geographic region.

High Uncertainty of Measurements

National methane emissions estimations were based on the multiplication of three variables: miles of pipe (activity data), number of leaks per mile of pipe (activity factors), and mean emissions per leak (emission factors). Miles of pipe data was obtained from PHMSA pipeline infrastructure information; number of leaks per mile of pipe was derived from the surveys with AMLD; the emission rates per leak were estimated using the AMLD system. It is not clear when the surveys were conducted but was likely prior to 2018.

The highest uncertainty in the data comes from the emissions rate estimate provided by the AMLD system. For this study, leak size was estimated based on an empirical calibration model of relationship between CH_4 enhancement and known emission rates. However, many variables and factors could affect the accuracy of the estimation including multiple emitting sources in an area, unknown distance of the emission source from the vehicle, changing atmospheric conditions.

To establish certainty in the estimation method, the authors conducted in-field validation studies comparing the AMLD estimates with traditional techniques such as tracer-ratio method, enclosure method, and controlled metered releases. They found positive bias in leak size estimation for the AMLD emissions estimate as shown in Figure 1. As emission values increased, the AMLD system did a better job of estimating the emission rate compared to when emission rates were lower, which is expected. The mean difference between mobile and validation emission rates was low but as seen in the logarithmic plot, which has a different scale on the x-axis and y-axis, the variability in actual emission rate for a given estimate can vary by 2 to 3 orders of magnitude.

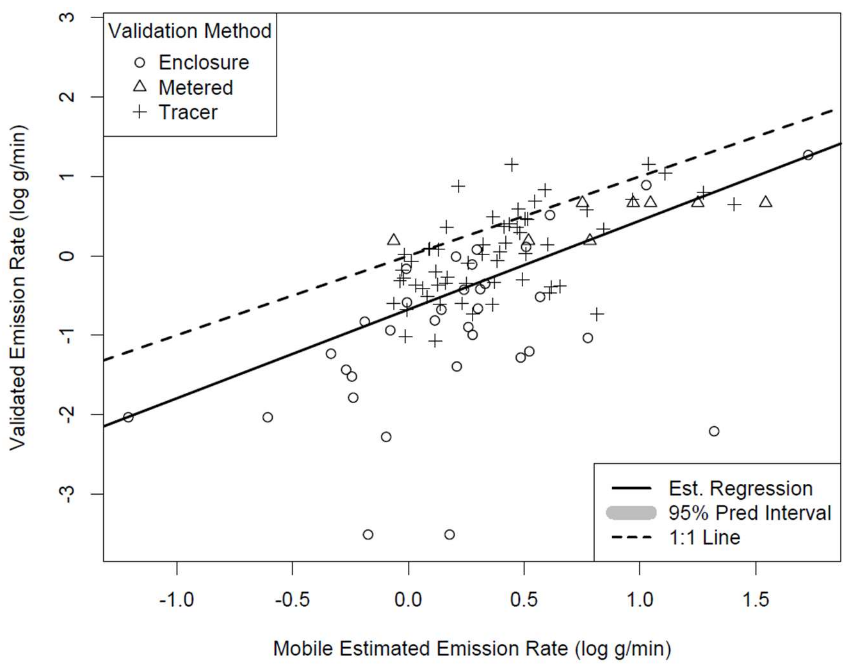

Figure 1. Regression of AMLD estimated emission rate with actual validated emission rates reported in the paper – different scales are used for the two axes. Three different leak emission validation methods were compared with the AMLD emission estimates.

Minimal Verification

Based on previous experience, mobile methane emissions studies without validation measurements on each of the leak indication found are subject to errors from false positives (false indications) and false negatives (missed leaks). In this study, the authors assume that if a methane indication was within 40 meters of a pipe (based on GIS data), then the indication was characterized as a pipeline leak. This raises questions as 1) the wind direction at the location was not considered, 2) the distance of 40 meters was extremely generous considering there could be obstructions (e.g. trees, buildings, fences) between the leak location and the car. It is highly unlikely that the mobile platform could pick up a small- or medium-sized leak 40 meters from a pipe in an urban environment with unknown wind direction. Further, the authors assumed that the false negative rate was similar to the false positive rate (24% based on the extreme case of an earlier study) which was very high and did not align with their argument that a highly sensitive instrument was used for survey.

This study considered four pipeline material types: bare steel, cast iron, coated steel, and plastic, in line with other past studies on distribution system emissions. Other material types were aggregated into the four categories. For example, copper was included within the bare steel and rarer types of iron pipe, such as ductile iron, were grouped within the cast iron category. Other remaining types were classified under coated steel. Due to the lack of availability of cathodic protection information, no distinction was made between protected or unprotected steel pipe. The material distribution of pipeline surveyed was 21% bare steel, 21% case iron, 22% coated steel, and 36% plastic.

Compared with the national distribution, the pipelines surveyed in this study contained older pipes. Approximately 25% of the pipes in this study were categorized as older than 79 years while the national distribution (2017 PHMSA data) reported 4% of mains as older than 79 years. The authors noted that the difference between national distribution and survey distribution is accounted for in the analysis, but detailed explanation is omitted from the main report (the supporting information document is still not available online at the time this report is written).

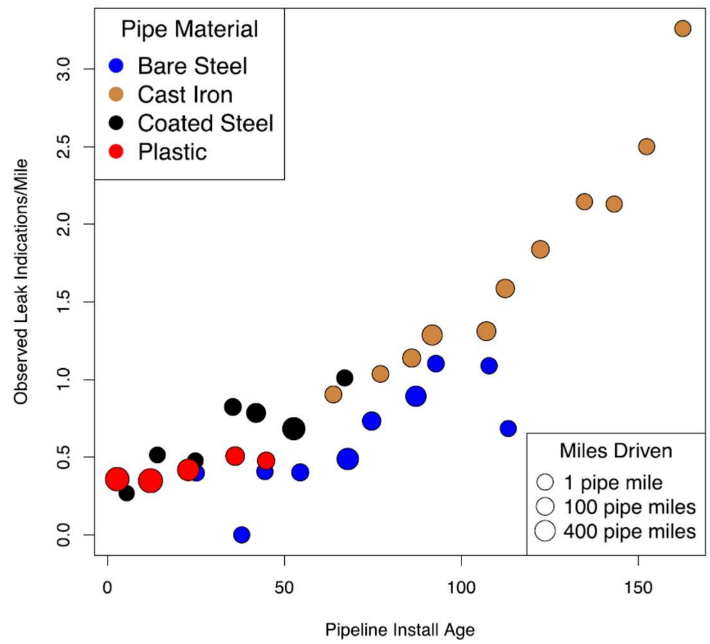

Figure 2. Leak indications per mile of main driven in four urban areas. Each point represents the observed number of leaks per mile for a specific pipeline material and age group.

It is clear from Figure 2 that the interaction of pipeline age and material is an important predictor of leak activity. It is not surprising that the leakiness of pipelines (number of leak indications/mile) increases with pipeline age as shown by the positive slope in Figure 2. It is also reasonable to see cast iron having the most leak indications per mile while plastic has the fewest leak indications per mile. However, a counter-intuitive observation is that coated steel seemed to have a higher number of leak indications per mile than bare steel of the same age (between 20 to 65 years old). The authors did not provide an explanation on why this was the case, offering only the trend as an observation. This could indicate that the lack of verification was influencing the observations.

Differences from Lamb et al. 2015

This study found a higher number of leaks per mile of pipe compared to the EPA/GRI 1990s study and the more recent study on the distribution system conducted by Lamb et al. in the early 2010s (Lamb et al. 2015). The leaks per mile estimates for bare steel and cast iron were much smaller (1/5 and 1/3, respectively) than those given in Lamb 2015 but the estimates for coated steel and plastic were much greater (5.5x and 8.5x greater, respectively). The authors of this study believed that their numbers were higher because the Lamb et al. 2015 study only surveyed leaks that were already known to the utility, either from mandated survey or odor complaint calls. EPA/GRI 1992 and Lamb et al. 2015 both assumed that 85% of the leaks are known by the utilities. This study did not make any assumptions on utilities' find rate and instead assumed that the leak indications found by the mobile platform were actual "leaks". Further, the AMLD system, which used sensitive methane analyzers on vehicles coupled with data processing algorithms, was assumed to have greater success in finding leaks compared to conventional technology and was the reason for the higher number of leaks found.

Study	**Lamb 2015**		**GRI/EPA 1992**		**This Study**	
Material	Equiv Leaks (thousands)	Equiv Leaks Per Mile	Equiv Leaks (thousands)	Equiv Leaks Per Mile	Leaks (thousands) (95% Cr Int)	Leaks Per Mile
Bare (Unprotected) Steel	130.3	2.51	174.7	1.82	23.7 (7.9-43.0)	0.51 (0.17, 0.93)
Cast Iron	81.6	2.88	n/a	n/a	25.2 (9.9-43.5)	1.00 (0.40, 1.74)
Coated (Protected) Steel	55.4	0.11	68.3	0.14	296.0 (111.0-513.5)	0.61 (0.23, 1.06)
Plastic	32.2	0.05	49.2	0.18	314.1 (122.8-547.0)	0.43 (0.17, 0.74)
Total	299.6	0.23	292.2	0.35*	659.1 (310.0-1,061.1)	0.51 (0.24, 0.82)

Table 1. Comparisons of estimates of total number of leaks and leaks per mile of main for this study and two previous studies.

Extrapolating to the national scale, this study estimated a total of 659,000 leaks on main pipelines with a 95% credible interval of 310,000 to 1.06 million leaks. Dividing the number of leaks by total miles of mains provided an estimated 0.51 leaks per main mile with a 95% credible interval of 0.24 to 0.82 leaks per mile. Note the large range in the values provided which arguably should be higher given the high degree of uncertainty in extrapolating a small dataset to a much larger scale.

This study also generated greater emission factor estimates compared to the EPA/GRI 1992 (1.4x greater, on average) and Lamb 2015 studies (3.2x greater, on average). The authors believed that past studies had not characterized the upper tail of leak emission rates very well due to limited sample size (number of leaks surveyed). Consequently, they considered large sample sizes to be critical to capture some of the large sources, the so-called "super-emitters".

Another finding of this study was that, unlike number of leaks per mile, leak emission rates were not very dependent on pipeline age, diameter, pressure. Additionally, the emission factor estimates of this study did not vary much across material types, in sharp contrast with the findings in the Lamb 2015 study where plastic mains tended to give out the lowest emission rates. Most of the emission factors estimated by Lamb et al. 2015 were smaller than the 95% bounds provided in this study, highlighting the differences between the two studies. The authors hypothesize that the larger emission factor estimates of this study arose from the larger sample size, which better characterized distribution of leak emission rates, especially the upper tail of the distribution (i.e. the rare large leaks).

Material	**EPA/GRI 1992* (g/min)** Estimate (90% UCL)	**Lamb 2015 (g/min)** Estimate (95% UCL)	**This Study (g/min)** Estimate (95% cr int)
Bare (Unprotected) Steel	1.91 (3.70) n = 20	0.77 (2.07) n=74	2.24 (1.22, 3.40) n = 826
Cast Iron	3.57 (5.60) n = 21	0.90 (3.35) n = 14	1.72 (0.94, 2.64) n = 1664
Coated (Protected) Steel	0.76 (1.40) n = 17	1.21 (4.59) n = 31	2.00 (1.10, 3.05) n = 911
Plastic	1.88 (8.20) n = 6	0.33 (0.67) n = 23	2.03 (1.10, 3.12) n = 819
Total	n = 64	n = 142	n = 4220

Table 2. Estimated emission factors in g/min from the study compared to EPA/GRI 1992 and Lamb et al. 2015 studies.

Even though the number of samples in this study was much higher than the previous two, the uncertainty of the measurements in this study was likely much higher because direct measurements used in previous studies had lower uncertainty than the mobile measurements employed by this study. To elaborate, the AMLD system or the mobile survey method estimated the emission rate based on remote concentration measurements while not knowing the location of the leak source and had to use a physical model to characterize the movement of the plume based on atmospheric conditions to predict the original leak rate at the source. In contrast, the direct measurement method collects data close or at the leak source, eliminating the intermediate step of interpreting the leak rate at the source location, and making this method less prone to variability caused by atmospheric conditions.

The authors also noted that the lack of distinction between mains and services could be a source of uncertainty. Leaks on mains could have a larger emission rate than leaks on services and lumping the two together could result in an overestimate of emissions. Due to limited availability of GIS data for service lines in the areas surveyed, this study linked all leak indications observed to main lines only.

As a key message of the study, the authors recommend that system operators focus on addressing and repairing the largest leaks in combination with targeting pipeline replacement on the oldest and leakiest sections of pipe to achieve large reductions in methane emissions from natural gas mains.

References

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Center for Methane Research

1700 S. Mount Prospect Rd.
Des Plaines, Illinois 60018
gti.energy

KEEGAN WERLIN LLP

ATTORNEYS AT LAW
99 HIGH STREET, SUITE 2900
BOSTON, MASSACHUSETTS 02110
(617) 951-1400

TELECOPIER:
(617) 951-1354

September 25, 2020

VIA ELECTRONIC MAIL

Ms. Sharon Weber
Massachusetts Department of Environmental Protection
1 Winter Street
Boston, MA 02108

Re: 310 CMR 7.73 Program Review – Initial Comments of the Massachusetts Local Distribution Companies

Ms. Weber:

On August 26, 2020, the Massachusetts Department of Environmental Protection ("MassDEP") issued a Notice of Public Stakeholder Meeting (the "Notice") that it was conducting a program review (the "Program Review") of 310 CMR § 7.73: Reducing Methane Emissions from Natural Gas Distribution Mains and Services. Pursuant to the Notice and consistent with 310 C.M.R. §7.73(9), the Program Review will focus on the requirements of 310 CMR §7.73 to determine whether the program should be amended or extended, shall evaluate whether to require the use of feasible technologies to detect and quantify gas leaks, and include any other information relevant to the Program Review. On September 18, 2020, consistent with the Notice, NSTAR Gas Company d/b/a Eversource Energy, Boston Gas Company and former Colonial Gas Company each d/b/a National Grid, Bay State Gas Company d/b/a Columbia Gas of Massachusetts, Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty, The Berkshire Gas Company, and Fitchburg Gas and Electric Light Company d/b/a Unitil (collectively the "Local Distribution Companies" or "LDCs") submitted initial comments on the Program Review, including a commitment to provide additional information on their proposal that the MassDEP adopt a deadband in determining compliance with the annual methane emissions limits.

The LDCs recommend that the MassDEP adopt an LDC-specific deadband based on the average variance plus one standard deviation of the LDC's emissions reductions using actual emissions data for 2018 through 2020 for CY2021 performance. For each subsequent performance year, the prior years' performance data will be added to the average variance and standard deviation calculation until 10 years of data is available (i.e., for CY2023 performance, the average variance and standard deviation calculation would be based on 2018 through 2022 data). This method is consistent with the process used by the Massachusetts Department of Public Utilities in developing benchmarks and penalty thresholds for the metrics in the LDCs' annual service quality filings.[1] Both the annual variance and the standard deviation components of the proposal have been included in the LDCs' proposal as a conservative and discrete means of addressing factors, such as emergent issues, weather and delays encountered due to site conditions and municipal permitting processes, that will impact leak-prone infrastructure replacement in a given Gas System Enhancement Program ("GSEP") Investment Year and the corresponding emissions reductions without requiring an LDC to file multiple petitions to access the emissions set-aside consistent with the requirement of 310 C.M.R. §7.73(4). An illustrative calculation of the deadband is shown in the table below.

	Original Emissions Reduction Target	Actual Emissions Reductions	Difference	Percentage
2018	2,158 MT CO2e	2,075 MT CO2e	(83) MT CO2e	-3.8%
2019	2,064 MT CO2e	1,946 MT CO2e	(118) MT CO2e	-5.7%
2020 projected	1,981 MT CO2e	1,890 MT CO2e	(91) MT CO2e	-4.6%
Average				-4.7%
Standard Deviation				**0.94%**
Deadband = Average + Standard Deviation				**5.64%**

As long as an LDC achieves less than or equal to the emissions target plus the average variance plus one standard deviation, it would fall within the deadband. Thus, no set-aside petition would be required, nor would the LDC be subject to potential penalties. This proposal provides both predictability and certainty for the MassDEP and LDCs, while ensuring that the Kain mandates are preserved. Additionally, the MassDEP will be able to review the operation of the deadband mechanism during its next Program Review.

Under the LDCs' proposal, each LDC will provide the MassDEP with the pertinent information in the table above in November of each year so that the MassDEP can calculate and publish the individual LDC emissions limits for the following year. The November filing will

[1] Alternatively, the average variance could be calculated on a three-year rolling basis, although this method would not provide as large of a data set capturing the actual variances experienced by the LDCs, which could impact the accuracy of the average variance calculation.

utilize the information each LDC filed with the Massachusetts Department of Public Utilities in its annual October GSEP filing, as well as projected information to calculate the deadband. Each April, utilizing the information each LDC files with the U.S. Department of Transportation ("USDOT"), the LDCs will file updated deadband calculations using actual information and notify the MassDEP as to their performance under the previous year's emissions caps. In the April filings, the LDCs will either (1) demonstrate that they were within the updated deadband or (2) file a petition for a set-aside consistent with the requirements of 310 C.M.R. §7.73(4). The LDCs will provide estimated 2020 data, as actual data will not be available prior to spring of 2021.

Use of a deadband based on an average variance and standard deviation of an LDC's historical methane emissions reduction performance provides a statistically consistent and mathematically sound method that allows flexibility for the LDCs to achieve methane emissions reductions while eliminating the duplicative and administratively burdensome process of filing for multiple set asides each year. Additionally, and equally as important, the LDCs' proposal meets the requirements of the Kain decision by enabling the MassDEP to develop and publish annually declining emissions limits for each LDC consistent with the provisions of 310 C.M.R. §7.73.

###

Thank you for your attention to this matter. The LDCs appreciate MassDEP's consideration of this additional information and look forward to further participation and comments on any proposed regulation amendments to 310 CMR § 7.73.

Very truly yours,

NSTAR GAS COMPANY d/b/a EVERSOURCE ENERGY

By its Attorneys,

Danielle C. Winter

Danielle C. Winter, Esq.
Keegan Werlin, LLP
99 High Street, Suite 2900
Boston, MA 02110
(617) 951-1400
dwinter@keeganwerlin.com
-and-

Nancy Kaplan

Nancy Kaplan, Esq.
Senior Counsel
Eversource Energy
800 Boylston Street, 17th Floor
Boston, MA 02199
(617) 424-2128 (office)
(617) 424-2733 (fax)
nancy.kaplan@eversource.com

BAY STATE GAS COMPANY d/b/a COLUMBIA GAS OF MASSACHUSETTS,

By its Attorneys,

Kenneth W. Christman

Kenneth W. Christman, Esq.
NiSource Corporate Services Company
121 Champion Way, Suite 100
Canonsburg, PA. 15317
Telephone: (724) 416-6315
E-Mail: kchrist@nisource.com

-and-

Brendan P. Vaughan

Brendan P. Vaughan
Keegan Werlin LLP
99 High Street, Suite 2900
Boston, Massachusetts 02110
(617) 951-1400
bvaughan@keeganwerlin.com

BOSTON GAS COMPANY and FORMER COLONIAL GAS COMPANY, each d/b/a NATIONAL GRID,

By its Attorney,

Andre Keeffe, Esq.
Senior Counsel
National Grid USA Service Company, Inc.
40 Sylvan Road
Waltham MA 02451
781.907.2123
andrea.keeffe@nationalgrid.com

LIBERTY UTILITIES (NEW ENGLAND NATURAL GAS COMPANY) CORP. d/b/a LIBERTY,

By its Attorney,

Ronald J. Ritchie, Esq.
Liberty Utilities
36 Fifth Street
Fall River, MA 02721
TEL: (774) 627-2910

FITCHBURY GAS & ELECTRIC COMPANY d/b/a UNITIL,

By its Attorney,

Carleton Simpson, Esq.
Regulatory Counsel
Unitil Service Corp
6 Liberty Lane West
Hampton, NH 03842
(603) 379-3848

THE BERKSHIRE GAS COMPANY,

By its Attorney,

Leonard Rodriguez, Esq.
General Counsel
The Berkshire Gas Company
115 Cheshire Road
Pittsfield, MA 01201
Leonard.Rodriguez@avangrid.com
203.499.2113

MASSACHUSETTS SIERRA CLUB

GAS LEAKS ALLIES

Date: September 18, 2020

To: climate.strategies@state.ma.us
Attn: Sharon Weber, MassDEP
Re: Comments on Regulation 310 CMR 7.73 Reducing Methane Emissions

Thank you for the opportunity to speak at the public hearing on September 10 on potential changes to the Department of Environmental Protection (the Department) regulation 310 CMR 7.73 Reducing Methane Emissions from Natural Gas Distribution Mains and Services. My comments respond to your investigative questions, which are in **bold** font in this letter, and to a broader perspective that I hope the department will take to address methane as an important greenhouse gas for Massachusetts.

These comments are submitted on behalf of the Massachusetts Chapter of the Sierra Club and the Gas Leaks Allies in support of the Department's review of regulation 310 CMR 7.73 Reducing Methane Emissions from Natural Gas Distribution Mains and Services.

The Sierra Club is the oldest and largest non-profit, non-partisan environmental organization in the country with close to three million members and supporters nationwide. The Massachusetts Chapter of the Sierra Club represents over 130,000 members and supporters throughout the state. We fight for clean energy, clean air, clean water, the preservation of the Commonwealth's natural spaces, and environmentally and economically healthy, vibrant and sustainable communities.

The Gas Leaks Allies is a coalition of more than 25 organizations and researchers focused on reducing methane emissions from the natural gas distribution system in Massachusetts while transitioning to fossil fuel free energy sources. Our unconventional, interdisciplinary collaboration of scientists, gas experts, activists, and concerned citizens is finding solutions for the problems caused by aging, leaking pipes buried in our neighborhoods. In all of our work, we address multiple issues with leaking gas—public safety, costs to consumers, health impacts, loss of trees, and the outsized damage of methane to our climate.

Should the decreasing annual emissions limits be extended beyond 2020?
Decreasing annual emissions limits should be extended beyond 2020 to, at least, the end of the Gas Safety Enhancement Program (GSEP). The emissions factors should be revisited periodically, perhaps every 3-5 years, to adjust for progress – or lack of progress – in reducing the number of gas leaks.

What are the most appropriate emission factors or other metrics to determine emission limits and evaluate progress?

- Are there practical, economically feasible technologies to detect and quantify gas leaks?
- Are DPU's 3/22/2019 regulation 220 CMR 114 *Uniform Natural Gas Leaks Classification* (which details technologies to detect and quantify the areal extent of gas leaks) and 12/27/2019 regulation 220 CMR 115 *Uniform Reporting of Lost and Unaccounted-for [LAUF] Gas* (which quantifies LAUF components) sufficient?

Recent studies have validated the volume of methane emissions from gas distribution pipes on a per leak basis. However, the natural gas distribution system in Massachusetts has more leaks for a given length of pipe than was assumed in the 2015 study[1] at Washington State University that yielded the emissions factors that are currently being used for the 7.73 methane emissions reduction regulation. The department should adopt new emissions factors based on our own observed leak count per length of pipe and pipe material yielding a new effective emissions factor per length of pipe of a given material. The Home Energy Efficiency Team (HEET) has developed a calculator for this purpose. It was proposed to the Department of Public Utilities and tested by the gas companies as part of the development of DPU's regulation 220 CMR 115 on LAUF. This factor can be tailored to the actual leak data from each gas LDC. It can also be updated periodically if we see the leak counts coming down. This approach is similar to the alternative fugitive emissions method used for DPU's LAUF regulation 220 CMR 115 but simplified and with variations for pipe material and LDC-specific leak data.

Adopting these new emissions factors works well with the approach that the Department has already been using to predict emissions reductions. Whether based on projections for pipe replacements under the GSEP or other inputs, the same methods for projections would work with the revised emissions factors.

The leak detection and measurement rules in DPU's 220 CMR 114 are sufficient for the purpose of providing the leak counts including the identification of G3SEI leaks.

Showing progress from the 1990 greenhouse gas inventory baseline.
An analysis will be required to appropriately compare the new emissions results to earlier results all the way back to 1990 to demonstrate progress toward the goals of the Global Warming Solutions Act.

This was not done appropriately at the time new emissions factors were adopted in 2015. The effect of the change then was a dramatic reduction in the calculated emissions from the natural gas infrastructure as illustrated in the 2015 update to the "Massachusetts Clean Energy and Climate Plan" in Figure 11, Historical and projected emissions (MMTCO2e) from leaks in the natural gas distribution system. The change in calculation of emissions then skewed the results. In moving from one set of emissions factors to another, the apparent change was dramatic and suggested that there had been a huge reduction in methane emissions in Massachusetts, enough to satisfy almost the entire 80% reduction goals for 2050. Now is the time to correct the record.

[1] Lamb et al. Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States. *Environmental Science & Technology* 2015 *49* (8), 5161-5169 DOI: 10.1021/es505116p

Finally, from a broader perspective and unrelated to this regulation, a discrepancy remains between the methane emissions associated with the gas distribution system and methane measured in the air. The difference was apparent from a 2015 Harvard University and Boston University study[2] which found that emissions from natural gas were two to three times larger than predicted by existing inventory methods and industry reports. Similar results have been reported in research since then, and other studies[3] [4] have noted a significantly higher level of methane emissions associated with natural gas in urban areas than would be predicted by leakage from the distribution system.

These findings suggest that there are other, significant sources of methane emissions in the urban environment, and that these other sources are independent of the natural gas distribution system. A likely possibility is leaks "behind the meter" such as leaks from gas pipes inside buildings or unburned natural gas/methane released when gas stoves, furnaces, or other appliances cycle on and off.

As this regulation 310 CMR 7.73 and DPU's related 220 CMR 115 bring finer scrutiny and management to the emissions from the gas distribution system, let's ensure that we are spending our energies to make a real difference in the contribution that methane makes to greenhouse gas emissions.

Proposals currently before the Massachusetts legislature may add some direct methane emissions from sources that are not associated with natural gas at all, like agricultural sources.

It may very well be that these other sources of methane are too many or too small for the Department to regulate. Nevertheless, it is important for the Department to determine what these other sources of methane emissions are and how they contribute to methane as a fraction of our greenhouse gases inventory.

We recommend that the Department undertake a program to measure and monitor methane in the atmosphere to determine whether Massachusetts is truly reducing methane emissions in line with our goals under the Global Warming Solutions Act.

Unfortunately, methane that does not leak from the distribution system is burned releasing another greenhouse gas, carbon dioxide. Ultimately, the answer to reducing methane emissions is also part of the answer to reducing all emissions from the burning of fossil fuels. That is to reduce the use of fossil fuels in Massachusetts for heating and for generation of electricity.

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Thank you for this opportunity to speak on these important topics to reduce methane emissions as part of our goal to reduce all greenhouse gas emissions in Massachusetts.

Respectfully submitted,

David A. Zeek
Sierra Club, Massachusetts Chapter
50 Federal Street, 3rd Floor
Boston MA 02110
(617) 423-5775

To: climate.strategies@state.ma.us September 18, 2020
Attn: Sharon Weber, MassDEP
Re: Comments on Regulation 310 CMR 7.73 Reducing Methane Emissions

These written comments are submitted on behalf of Mothers Out Front Gas Leak Task Force in support of the review of regulation 310 CMR 7.73 Reducing Methane Emissions from Natural Gas Distribution Mains and Services.

Overall comments

Mothers Out Front is an organization of volunteer advocates who believe that it is our moral responsibility to act swiftly to avert the worst impacts of climate change for the sake of all children and grandchildren. We believe that our children deserve a livable climate and this belief is central to all of our work. In order to address the climate impact of our energy use, accurate and scientific measurement of atmospheric methane is critical and our government should strive to report data that is as close to actual leaked methane as possible. We write in support of the comments of HEET and of the Sierra Club. These two organizations have developed significant scientific expertise in this field and unlike the gas industry, do not have a financial stake in the issue.

We also support HEET's recommendation regarding the Global Warming Potential factor and that the DEP report all emissions outcomes from this regulation with **both** the EPA's currently used 25x factor for consistency across agencies, **AND** additionally, the more scientifically accurate IPCC 20 year factor in order to increase accuracy, transparency and understanding for the public and decision makers.

Should the decreasing annual emissions limits be extended beyond 2020?

We strongly support extending the decreasing annual emissions limits beyond 2020.

What are the most appropriate emission factors or other metrics to determine emission limits and evaluate progress?

The DEP should use measurement and data when available. We therefore fully support HEET's recommendation to use the number of leaks reported by the MA utility companies, instead of the use of estimation of numbers of leaks based on miles of leak prone pipe. We also support using the Weller 2020 paper to update emissions factors as it uses a heavy tail distribution that includes the Grade 3 SEI category representing super-emitting gas leaks.

Are there practical, economically feasible technologies to detect and quantify gas leaks?
We recommend a reassessment of the best available technologies on a regular basis. Currently, we recommend the use of leak extent as a low cost proxy for volume of leaked gas. MA utilities are currently using this on Grade 3 leaks and could collect data for other grades as well.

Are DPU's 3/22/2019 regulation 220 CMR 114 Uniform Natural Gas Leaks Classification (which details technologies to detect and quantify the areal extent of gas leaks) and 12/27/2019 regulation 220 CMR 115 Uniform Reporting of Lost and Unaccounted-for [LAUF] Gas (which quantifies LAUF components) sufficient?

220 CMR 115, if it includes the leak based emissions calculator, is sufficient given existing limitations in their estimation of LAUF. 220 CMR 114 is problematic in its permitting the use of barhole % gas as an indicator of leak flux, which is inadequate technology, however no major utilities are currently using that method.

Does the petition process in 310 CMR 7.73(4)(c) need any changes?
We suggest that this field is rapidly evolving and much remains unknown, and therefore new science or technology should be able to trigger a petition for re-evaluation by stakeholders. If no evaluation is triggered by new science or technology, then the standard reevaluation should continue to occur on a 3 year cycle.

Respectfully submitted,

Claire Corcoran
clairecorcoran@me.com

On Behalf of Mothers Out Front Gas Leaks Task Force