Memorandum

TO: CAITLIN PEALE SLOAN, CONSERVATION LAW FOUNDATION

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DATE: MAY 5, 2022

RE: DOCKET 20-80: PROPOSED "COMMON REGULATORY FRAMEWORK"

The Massachusetts gas local distribution companies (LDCs) filed a proposed "Common Regulatory Framework and Overview of Net Zero Enablement Plans" (CRF) in Department of Public Utilities Docket 20-80 on March 18, 2022.[1] In this memo, the Synapse authors analyze the CRF in the context of the analysis developed and presented by E3 and ScottMadden (the LDCs' Consultants) in this docket, the state's 2050 Roadmap and interim Clean Energy and Climate Plan for 2030 (Interim CECP), and our work around North America on issues closely related to the issues being discussed in Docket 20-80.

The memo addresses three interrelated issues in the context of the CRF. First, we discuss the relationship between the CRF and utility stranded cost risk. In particular, the CRF does not explicitly address the LDCs' Gas Safety Enhancement Program (GSEP) investments in the context of changes in how the gas system is used. Second, we examine the risk of customer-owned stranded assets if changes in the gas system drive early replacement of gas-consuming equipment and appliances, and the role of the CRF in shifting utility programs to reduce this risk. We close the memo by discussing the CRF's approach to non-fossil gases in the LDCs' pipelines, as well as procurement strategies and the emissions resulting from use of those gases.

[1] This memo focuses particularly on the Overview of Regulatory Proposals on pages 16-17 of the CRF filing.

Summary of Recommendations

Utility stranded asset risk

- The DPU should initiate a prompt review of the GSEP program to determine if its current approach and regulatory structure is well aligned with cost-effective achievement of state policy.
- The DPU should require that depreciation rates reflect the utilization of different assets with different lifetimes, and should not delay in requiring development of the necessary data to differentiate assets by utilization and rate class.

Customer stranded asset risk

- The DPU and program administrators should emphasize building shell improvements and electrification in expanded efficiency programs.
- The DPU should exclude efficient gas equipemnt from any list of eligible measures, or equivalent guidance
- The LDCs should pilot targeted electrification programs and heat pump technologies that could meet hard-to-decarbonize applications.
- The LDCs should target efficiency and electrification programs towards (1) high-consumption households and (2) low-income households.

Non-fossil gases

- The DPU should not make long-term commitments to non-fossil gas implementation and infrastructure based on the state's current inventory treatment of biomethane and other non-fossil gases.
- Any LDC pilots should be designed to address different questions than pilots conducted in other jurisdictions, and have clearly defined research objectives, timeframes, and budgets.
- The DPU should ensure that any LDC marketing of non-fossil gases is focused on hard-to-electrify end uses that have sophisticated customers able to understand their choices and risks within the larger energy transition.

Stranded asset risk and infrastructure investments

In the utility context, stranded assets are assets that cease to be used and useful before they are fully depreciated. The CRF's regulatory recommendations address stranded asset risk in two items within its section titled "Manage gas infrastructure investments and cost recovery." First, the CRF includes a recommendation to "Develop framework to examine and implement opportunities to minimize or avoid gas infrastructure projects through utilization of decarbonized technologies and strategies, while maintain [sic] safety and reliability." The section concludes with a recommendation to "Align gas infrastructure cost recovery and utilization." Together, these recommendations address two ways to avoid or minimize stranded assets: by minimizing gas infrastructure projects (and thereby reducing the supply of assets that could become stranded, especially given the long lives of many LDC assets), and by recovering the capital invested in the assets before they cease to be used and useful.

One approach to stranded assets would be to leave them purely as a risk to utility shareholders. However, in practice regulators tend to establish structures or change processes in order to allow utilities to recover their investments in assets for which the investment was prudent at the time it was made. This means that stranded assets reflect investments made with some kind of regulatory approval are very likely to be recovered from ratepayers in some fashion—therefore ratepayers should be concerned with how the costs of these assets are treated. The present GSEP structure likely provides enough regulatory approval that ratepayers, rather than shareholders, will be responsible for cost recovery. The combination of the state's net zero commitments and the analysis conducted for this docket present an opportunity to establish a clear new paradigm for pipeline investments, including GSEP.

GSEP increases stranded cost risk

While the CRF recommendations explicitly address the question of investment standards for serving new customers, they do not directly address GSEP or pipeline replacement. This choice is surprising, given that GSEP represents a large portion of the LDCs' projected capital investments in the next few years. The LDCs propose to spend more than $1.8 million per day on GSEP investments in 2022, with amounts growing in future years.

To illustrate the impact of today's GSEP investments on long-term stranded cost risk, we evaluated the rate base impact of $681 million in GSEP investment in 2022, assuming an 80-year asset life, a 60 percent salvage cost,[2] and Eversource NSTAR's capital structure. In this case, in 2050 the utilities would still have both $166 million of rate base from this investment and a $409 million salvage obligation. Even if the state decided to allow the utility to abandon GSEP assets in place, almost a quarter of the investment made this year will still be at risk of stranding in 2050. Each year's GSEP investment will add more to the remaining rate base in 2050.

[2] 80-year service life and 60 percent salvage cost are the assumptions for mains in Eversource NSTAR Gas's depreciation study filed in DPU docket 19-120, Exhibit ES-JJS-2.

Given this pace of investment and its long-lasting implications, the DPU should initiate a prompt review of the GSEP program to determine if its current approach and regulatory structure is well aligned with cost-effective achievement of state policy.

Cost-effectiveness of GSEP

The purpose of GSEP is "in the interest of public safety and reducing lost and unaccounted for natural gas through a reduction in natural gas system leaks."[3] While the utilities have taken the approach of meeting these objectives through pipeline replacement, the law does not limit their plans to this approach. The DPU should take this occasion to conduct a review of the cost-effectiveness of the traditional GSEP approach against other means of meeting these objectives. For example, another approach that would have comparable or better impact on public safety and leak reduction would be the electrification of customers served by leak-prone pipe, coupled with safely abandoning the pipe in accordance with federal regulations. Our initial analysis shows that the electrification approach could be substantially lower cost, while simultaneously advancing the state's emission-reduction goals and the objectives of the Clean Energy and Climate Plan.

According to the LDCs' filed plans for GSEP in 2022, as summarized in the appendices to the LDC Consultants' reports in this docket, the GSEP program costs an average of $2.67 million per mile ($506 per foot) of leak-prone main replaced. This cost also includes the cost of replacing leak-prone service lines associated with these mains; the LDCs have an average of about 80 service lines per mile. Using the leak emission rates for different materials that are codified in 310 Mass. Reg. 7.73, replacing cast-iron pipe with plastic pipe reduces emissions by 28.4 metric tons of CO_2-equivalent (CO_2e) emissions per year. Replacing 80 service lines in that mile would reduce CO_2e emissions by a further 9.9 metric tons per year. This means that the GSEP program reduces annual emissions by 38.3 metric tons per year for an investment of $2.67 million, or a cost rate of $69,602 to reduce recurring annual emissions by one metric ton. This calculation uses only the upfront cost of the GSEP investments, rather than the actual ratepayer costs after accounting for the cost of capital, taxes, and ongoing operations and maintenance cost for the pipe, which together would more than double the cost that ratepayers actually incur.

Examining the electrification approach to leak elimination, we calculate the emissions reduction per home that is fully electrified, if it is electrified in the context of pipeline retirement. That is, if the homes served by a given main were electrified, and the main and services retired, what emission reductions would occur, and what would be the break-even cost worth paying for these reductions relative to pipeline replacement? Retiring cast-iron main reduces emissions by 28.7 metric tons CO_2e/year per mile, or about 360 kg/year per service. Retiring an unprotected steel service line adds 130 kg per year to this

[3] An Act Relative to Natural Gas Leaks, 2014. https://malegislature.gov/Laws/SessionLaws/Acts/2014/Chapter149.

(per 310 Mass. Reg. 7.73), plus another 128 kg from the meter,[4] for a combined reduction of about 620 kg per service per year.

Emissions from on-site gas use average about 4.1 metric tons per household in Massachusetts (based on 777 therms/year of gas consumption[5]). We assume that the gas was burned at an average efficiency of about 80 percent (reflecting a blend of uses dominated by space heating, where the most common furnace and boiler efficiency is 80 percent), and the customers' energy service needs are instead met by electric equipment with an average efficiency of 200 percent (which is a conservative assumption relative to the equipment efficiencies used in the LDC consultant reports). Using New England's current marginal electric sector emissions rate of 719 pounds per MWh, the household's electric consumption would increase emissions by about 2.5 metric tons per year, so the household's combustion-based emissions would fall by about 1.6 metric tons per year.[6] Adding this to the household's portion of eliminated methane leakage, the emissions reduction from this approach would be about 1.8 metric tons per household per year. As the electric grid's emissions fall, the emissions benefit would increase further.

To compare electrification and pipeline retirement with GSEP, we must estimate the cost to produce the ongoing reduction of 1.8 metric tons per year. While we do not necessarily agree with their assumptions, particularly regarding the cost of heat pump systems if deployed in a mature market, the LDC Consultants assume that replacing all gas appliances and equipment in a Massachusetts home with efficient electric alternatives would cost about $20,000. They also estimate that an "efficient" level building shell retrofit (deeper than that achieved with Mass Save today) would add about $9,000 for a 1,500 square foot home, for a total of about $30,000 to transform the emissions and comfort of an average home. GSEP costs about $35,000 per service (including both service and main replacement), so main and service abandonment (or potentially even removal) could surely be accomplished for this much or less. This indicates that a conservative estimate of the per-household cost to reduce emissions by 1.8 metric tons per year using this approach would be about $65,000. For the $2.67 million GSEP budget, such an approach could reduce recurring emissions by 74 metric tons per year, or almost double the reductions achieved through the GSEP approach.

We conclude that this initial, high-level analysis indicates that an approach to meeting the statutory goals of "public safety and reducing lost and unaccounted for natural gas through a reduction in natural

[4] Meter emission rates from U.S. Environmental Protection Agency. *Annex 3.6: Methodology for Estimating CH_4, CO_2, and N_2O Emissions from Natural Gas Systems (xlsx)*. Available via https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2019-ghg.

[5] 2019 data from U.S. Energy Information Administration. "Number of Natural Gas Consumers" accessed at https://www.eia.gov/dnav/ng/ng_cons_num_a_EPG0_VN3_Count_a.htm and "Natural Gas Consumption by End Use" accessed at https://www.eia.gov/dnav/ng/ng_cons_sum_a_EPG0_vrs_mmcf_a.htm. Used 2019 data because 2020 customer count data are anomalously higher than 2019 and earlier year data.

[6] 4.1 minus 2.5 equals 1.6.

gas system leaks" could be met more cost-effectively through an electrification and retirement-based approach than through the pipeline replacement-based approach that the utilities currently use.

Depreciation

While eliminating unnecessary and cost-ineffective utility investment can limit stranded costs, changing depreciation rates can further mitigate or even eliminate this concern. The LDCs' proposed CRF suggests "align[ing] gas infrastructure cost recovery and utilization," which is a promising method to change depreciation. In order to illustrate the importance of addressing depreciation rates promptly, we used our model of the finances of Eversource NSTAR Gas to calculate the total system cost and rate impact of two hypothetical cases. In the first case, depreciation rates are set in 2023 at a level that would fully depreciate the utility's assets by 2050 (that is, leaving a rate base of zero[7]). In the second case, depreciation rates remain at their current levels for five years, until 2028, and then are adjusted to the level that would leave a rate base of zero in 2050. In both cases we assume gas consumption and number of customers fall roughly in line with the state's 2050 Roadmap, and that GSEP pipeline replacement is transitioned to geo-targeted electrification beginning in 2023.

In the prompt-action case, average delivery rates increase by about 22 percent (or 10 cents per therm) between 2022 and 2023, and the present value of total delivery system costs between 2022 and 2050 is $3.89 billion (at a 3 percent discount rate). In contrast, in the delayed-action case, average delivery rates increase by 29 percent (or 17 cents per therm) between 2027 and 2028,[8] and the present value of total system costs between 2022 and 2050 is $4.04 billion. The difference in present value cost between these two cases is about $500 per customer. Comparable calculations for other Massachusetts gas utilities would yield similar results. Eversource NSTAR Gas represents about 18 percent of Massachusetts retail gas sales, so the total savings from prompt action on depreciation may be approximately $800 million, present value. This shows that prompt action on depreciation rates both reduces rate shock and saves ratepayers money.

In reality, depreciation rates would not be set in the manner used for our illustration, because the DPU should require that they reflect the utilization of different assets with different lifetimes. For example, if the utility retains a long-term business model providing non-fossil gas to industrial customers, the assets used for that purpose would have lower depreciation rates. Developing the depreciation framework and data structures necessary to differentiate assets by rate class and utilization would require substantial effort, and that effort should also begin promptly. Delays in considering and implementing these approaches would increase the risk of rate shock when they are implemented and would likely result in misallocation of depreciation costs between rate classes until the approaches are implemented.

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[7] For simplicity, this analysis assumes that assets can be abandoned in place, so there are no residual salvage costs.

[8] The increase measured in cents per therm is proportionally larger in the 2028 case because in this case sales declines have already driven the delivery rate up 18 cents (or about 40 percent) from today's levels by 2027. Rates are higher if the GSEP program continues as usual.

Reducing customer stranded asset risk

Meeting the Commonwealth's 2050 climate goals means that there is a risk that new gas-consuming systems (especially space heating) installed today or for the next several years may become stranded assets for customers. Customers with new gas equipment or appliances may not be able to use such assets in the future as such assets could prevent the state and the gas LDCs from meeting the climate target, or customers may find them very expensive to operate due to gas rate increases. Customers may therefore need to replace those new gas systems with electric systems (e.g., heat pumps) before the end of their engineering lives, which will impose additional, unnecessary costs to consumers. Thus, the gas LDCs must implement a variety of programs and strategies now to avoid promoting the installation of new gas equipment and shift their funding to the promotion of electrification from gas equipment and appliances as much as possible.

As we discussed above, the CRF includes a recommendation to "[d]evelop framework to examine and implement opportunities to minimize or avoid gas infrastructure projects through utilization of decarbonized technologies and strategies, while maintain safety and reliability" under the recommendation #4 "Manage gas infrastructure investments and cost recovery." This recommendation focuses on gas infrastructure investments and cost recovery. When considering the CRF and next steps in this docket, the DPU should explicitly include the issue of customer stranded asset risk within its efficiency program approach or otherwise establish a framework to mitigate customer stranded asset risks.

Another relevant recommendation is the recommendation #5 "evaluate and enable customer affordability" (CRF, p. 16). In this recommendation category, the CRF recommends the development of a framework to quantify and evaluate transition costs for customers, especially low-income and those in environmental justice communities. The customer stranded cost issue is currently not included in this recommendation; when the DPU considers these issues it should be added.

The CRF contains several recommendations that help avoid customer stranded asset risks. We discuss those recommendations below.

CRF recommendation #1 ("Support customer adoption and conversion to electrified/decarbonized heating technologies") includes (a) increase funding of energy efficiency programs, (b) enhance energy efficiency measures, and (c) evaluate alternative funding mechanisms. Energy efficiency measures must be an integral element of building decarbonization. In particular, building shell improvements are important to support heating electrification as they allow the size and cost of space heating measures to be reduced. They will also improve the resiliency of buildings during cold snaps and make the growth of electrification more manageable, especially for the distribution grid.

However, while energy efficiency is a key component of decarbonization, we reiterate that utility support for gas equipment efficiency measures increases customer risk. The CRF's proposed "Net Zero Enablement Plan Model Tariff" includes a list of eligible measure types that includes efficient gas equipment.[9] We strongly recommend the DPU exclude efficient gas equipment from any list of eligible measures (or equivalent guidance). Massachusetts ratepayers are asked to pay substantial amounts to support utility energy efficiency programs, on the basis that those investments are prudent uses of their funds to save money and meet state policy objectives. Ratepayer support is, however, limited. Targeting funds toward the most impactful purposes, such as electrification and building shell improvements, rather than supporting potentially stranded gas equipment, would demonstrate care and respect for ratepayers' contributions.

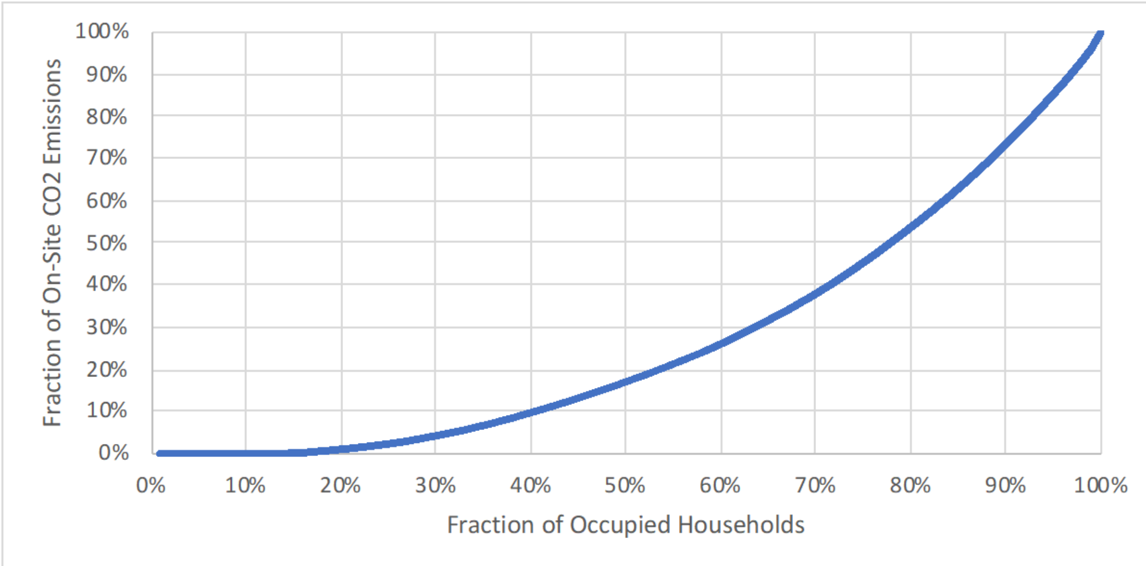
CRF recommendation #3 ("Pilot and deploy innovative electrification and decarbonized technologies") is another key productive recommendation, with respect to electrification technologies. While most heat pumps are mature technologies, certain applications of heat pumps such as geotargeted electrification using heat pumps and district geothermal systems are worth piloting from either a programmatic or technological perspective. The CRF notes that the LDC Consultants recommended that "several decarbonization technologies are worth further research and development to better understand their costs and resource potential, including hybrid system operation pilots and programs, targeted electrification to enable decommissioning of gas distribution assets, networked geothermal systems and renewable hydrogen" (CRF, p. 4). Like the LDC Consultants, we recommend the LDCs pilot targeted electrification to enable decommissioning of gas distribution assets and networked geothermal systems. Further, we recommend that the LDCs explore piloting certain heat pump technologies (e.g., 120-volt-based compact heat pumps and industrial heat pumps) that can address hard-to-decarbonize building segments.

Finally, while the CRF recommendations do not address programmatic design elements for energy efficiency or electrification programs, we note that there is one important program delivery approach that we recommend all LDCs adopt. Specifically, we recommend that for residential building electrification, the gas LDCs target the households with higher gas consumption while making sure that they also provide adequate incentives and program support for low-income customers to switch to efficient electrification measures.

Targeting high gas consumption customers will benefit the gas LDCs and the ratepayers as a whole for a number of reasons. First of all, the gas LDCs can reduce more gas use and GHG emissions at lower costs by targeting high-usage customers. Our review of heating fuel usage data from U.S. Energy Information Administration (EIA) residential and commercial building energy consumption surveys, along with Boston's building emissions disclosure data, reveals that 22 percent of Massachusetts homes emit half of the state's residential GHG emissions from on-site fuel combustion, and one-quarter of commercial floor space is responsible for between two-thirds and three-quarters of non-electric emissions.

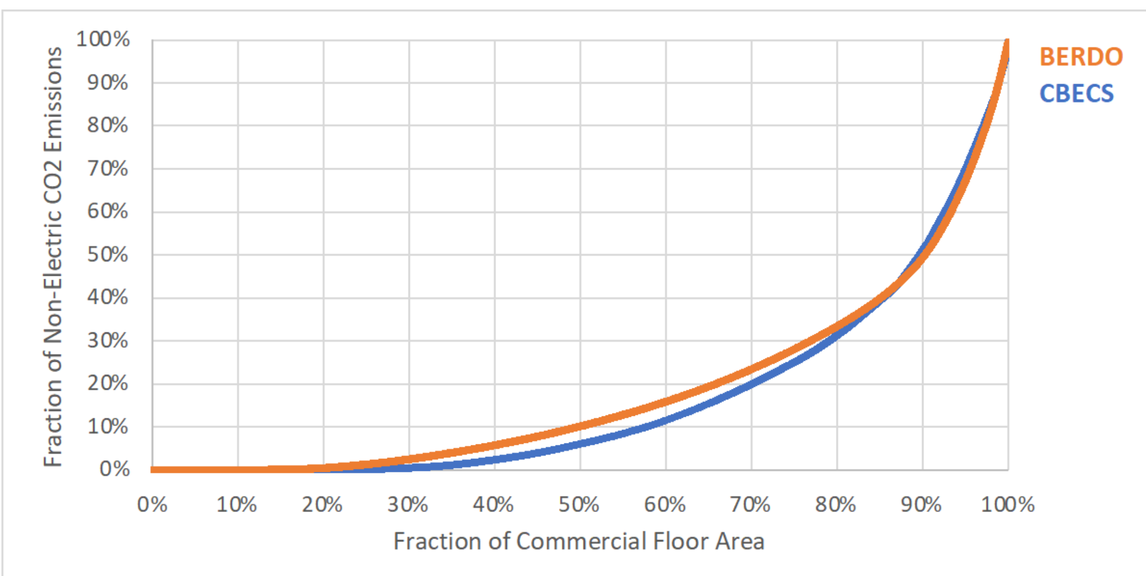
[9] Massachusetts Natural Gas Local Distribution Companies. March 18, 2022. *Common Regulatory Framework and Overview of Net Zero Enablement Plans*. Appendix A, Page 1 of 7. Filed in Massachusetts DPU Docket 20-80.

Figure 1. Estimated cumulative distribution of Massachusetts on-site residential CO_2 emissions versus cumulative occupied households



Source: Synapse analysis of data from EIA RECS.

Figure 2. Estimated cumulative distribution of Massachusetts on-site commercial CO_2 emissions versus cumulative square footage



Source: Synapse analysis of data from EIA CBECS and Boston BERDO.

LDCs can take advantage of the wide disparity in gas consumption to achieve greater emission reductions more rapidly. The LDCs have customer-level consumption data that would allow them to identify and target these high-use customers. The programmatic incentive amount per customer typically does not differ greatly among customers. Thus, the LDCs can achieve a greater amount of savings at the same or similar program costs by targeting high-consumption customers. This approach is consistent with the LDCs' efficiency performance incentives. Under the 2022–2024 energy efficiency program framework, the gas LDCs are eligible to receive program performance incentives based on the total benefits they achieve from space heating electrification from gas equipment. Additional advantages of this approach include: (a) there is no performance incentive cap specific to electrification measures, while there is a 125 percent cap (% of the target benefits) on the total performance incentive at the program portfolio level; (b) the incentive payout rate for electrification measures from gas is 55 percent higher than the payout rate for standard gas efficiency measures.[10] Therefore, the LDCs should be able to increase their performance incentive rewards by targeting high gas usage customers for their electrification measures.

In addition to targeting high-usage customers, we also strongly recommend that the gas LDCs make sure to promote building electrification for low-income customers for the following two reasons: (1) low-income customers are likely to be the last customers who remain on the gas system because they may not be able to easily afford to fully electrify their end-uses, or they may not control their building systems because they are renters; and (2) an approach that only targets large-usage customers could otherwise leave out many low-income customers from electrification efforts because their gas usage may be less than average (as it is more likely that they live in multifamily buildings that have low energy usage per unit).

Non-fossil gas options

In its GHG inventories, the State of Massachusetts assumes that biomethane is a net zero-emission fuel at combustion, and the LDC Consultants have adopted this assumption.[11] (The inventory would account for gas leakage within the state.) This approach is not unanimously adopted. For example, New York's inventory approach accounts for CO_2 emissions from the combustion of non-fossil gas as equivalent to emissions from fossil gas; the difference comes in treatment of non-combustion emission factors.[12] California's Low Carbon Fuel Standard makes explicit distinctions between the GHG impacts of different types of non-fossil fuels.[13] The DPU should carefully consider whether to make long-term commitments in infrastructure and policy based on Massachusetts's current approach. On April 29, 2022, Undersecretary Judy Chang stated to the GWSA Implementation Advisory Council that the updated CECP will include an action item to update emissions accounting for methane emissions.

[10] Mass Save. 2021. *Massachusetts Joint State Wide Electric and Gas Three-Year Energy Efficiency Plan – 2022-2024*. Exh. 1, App. A at 29. Available at: https://ma-eeac.org/plans-updates/.

[11] E3 and ScottMadden. *The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals Independent Consultant Report – DRAFT Part I: Technical Analysis of Decarbonization Pathways ("Part I")*. Page 48.

[12] New York State Climate Action Council. July 22, 2021. *Meeting 13*. Available at https://climate.ny.gov/-/media/Migrated/CLCPA/Files/2021-07-22-CAC-Meeting-Presentation.pdf. Slide 26.

[13] California Air Resources Board. "LCFS Pathway Certified Carbon Intensities." Available at https://ww2.arb.ca.gov/resources/documents/lcfs-pathway-certified-carbon-intensities.

In order for a non-fossil gas to be a net-zero-emission (or negative emission) fuel, the emissions from its production would have to be negative, to cancel out the emissions from its combustion. The typical story is that there is a biological process that would ordinarily result in the emission of a methane molecule (such as the decomposition of animal waste). By capturing that molecule, a "negative emission" has occurred. When that molecule is burned and turns into CO_2, that creates emissions. If the combined lifecycle emissions are zero or negative, then the gas is claimed to be zero- or negative-emission. In practice, the lifecycle of a non-fossil gas molecule is more complex. Engineered anaerobic digestion of animal or food wastes results in substantially more methane production than would have occurred had the waste decomposed in a field or landfill, so not all methane produced is "negative emission." If any of this produced methane leaks, it raises the overall level of emissions.

If producers across the Northeast or further afield are making biomethane or other non-fossil gases for use in homes in Massachusetts and businesses, it is reasonable to consider what climate impact those processes are having on the state's behalf. From a GHG accounting standpoint, the jurisdiction that hosts the agricultural facility may count the negative emissions from methane capture as an offsetting term in its own pursuit of net zero emissions. If Massachusetts then counts the resulting gas as low emission, the negative emissions are being counted twice. Relying on other states to not claim negative emissions from their non-fossil gas production, in order to claim that burning the resulting gases does not contribute to Massachusetts's GHG inventory, introduces substantial risk into the state's pursuit of legislatively mandated net zero emissions. If Massachusetts plans to count on the agricultural and land-use sectors as a source of negative emissions to offset continued combustion, it would be wise to assume that other states will do the same.

Many assessments of non-fossil gases show that their lifecycle emissions have a non-zero GHG impact and should be considered accordingly. The following table shows the impact of the non-fossil gas options that have been proposed by the LDC Consultants. Emissions factors from ICF (developed for Washington Gas Light in Maryland, Washington, DC, and Virginia) and the California Air Resources Board are in alignment that the top three most available renewable fuel sources that the LDC Consultants have proposed will have positive lifecycle carbon emissions. The DPU should not assume that non-fossil gas is either carbon neutral or widely available for use in Massachusetts.

These emissions intensity numbers are likely underestimates of true greenhouse gas impacts because upstream leakage during renewable natural gas (RNG) production and distribution will release methane. The GHGs released through leakage may also cancel out any GHG benefits relative to natural digestion.

Table 1. Estimated resource potential and emissions impact of RNG sources

Type of Non-Fossil Gas	Conversion process	Resource Potential, Optimistic	Resource Potential, Conservative	Emissions Intensity, ICF (gCO_2e/MJ)	Emissions Intensity, CARB (gCO_2e/MJ)
Landfill gas	Anaerobic digestion	17 TBTU	10 TBTU	18–26	70
Municipal solid waste	Gasification	15 TBTU	0 TBTU	25–55	45
Forest residues	Gasification	13 TBTU	0 TBTU	25–55	45
Animal manure	Anaerobic digestion	9 TBTU	5 TBTU	-404 – -294	-150
Wastewater	Anaerobic digestion	1 TBTU	1 TBTU	18–26	45

Sources: For resource potential, E3 and ScottMadden. The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals Independent Consultant Report – DRAFT Part I: Technical Analysis of Decarbonization Pathways ("Part I"). Page 48. For emissions, ICF. Study on the Use of Renewable Natural Gas in the Greater Washington DC Metro Area. Table 40. Available at https://washingtongasdcclimatebusinessplan.com/wp-content/uploads/2020/04/200316-WGL-RNG-Report-FINAL.pdf. California Air Resource Board. Table 8. Temporary Pathways for Fuels with Indeterminate CIs. Available at: https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/ca-greet/temp.pdf.

In our earlier analysis during the LDC Consultants' stakeholder process, Synapse examined the impact of including non-zero GHG emissions from non-fossil gases on meeting the state's GHG requirements in 2050. That analysis was filed as part of the LDC Consultants' stakeholder report and can be found on page 86 (of 362) in Appendix K to that report.[14] In summary, we derived that the additional lifecycle emissions shown in Table 1 are not counted in the LDC Consultants' reports.

Table 2. Estimated unaccounted-for lifecycle emissions from "renewable gas"

Scenario	Additional Renewable Gas Emissions (MMT of CO2e in 2050)	Percent increase in emissions over the 2050 requirement of 9.5 MMT
Efficient Gas	3.8	40%
Hybrid Elec.	1.3	13%
Low Elec.	1.7	18%
Networked Geo.	1.6	17%
Targeted Elec.	1.1	12%
High Elec.	0.3	3%
Interim 2030 CECP	0.3	3%
100% Gas Decomm.	0.1	1%

[14] Available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/14772390.

As this table shows, accounting for these additional emissions would result in substantial exceedances over the 90 percent emissions reduction requirement for 2050, unless they are countered by further emission reductions, at additional cost. Scenarios that utilize more low-carbon gas have more lifecycle emissions, and therefore greater cost to mitigate those emissions. Additional emissions reductions will be relatively expensive to achieve, since lower-cost options have already been adopted as part of the underlying scenarios. If we assume an incremental cost of $400 per metric ton, these costs could add an incremental $400 million per year or more to the cost of even moderate-renewable-gas scenarios relative to high-electrification scenarios.[15]

In the CRF, the LDCs also noted the possibility of piloting research and development programs for innovative electrification and decarbonized technologies, such as renewable gas. For biomethane gas, this technology is mature and does not warrant additional pilot studies in Massachusetts. As the state's utilities are already proposing to procure RNG for their portfolios, it appears further research is unnecessary. Green hydrogen production and blending are at an earlier stage of technology readiness. However, as R&D and pilot programs on hydrogen are being implemented elsewhere, we believe that Massachusetts does not need to spend additional funding to repeat the same types of studies and can instead use the lessons learned in other jurisdictions.

If the utilities and DPU believe that pilot studies are essential, the DPU must establish a clear research objective alongside a strict timeframe and budget for the research to ensure that the findings are released within a reasonable amount of time and without excessive costs. In New York City, National Grid has been conducting its pilot study on a wastewater digestor for eight years. National Grid documents from New York showed that the estimated budget for the project in 2012 was $14.6 million and has grown to $47.8 million as of February 2021.[16] Precautions should be taken to ensure that pilot studies conducted in Massachusetts avoid the same pitfalls. Ultimately, it will be better in the long run if LDCs delay long-lived commitments into non-fossil gas infrastructure to allow more time to learn from other jurisdictions around the nation.

The CRF recommends that LDCs provide customers with options to purchase non-fossil gas from the LDCs and third parties. These recommendations create the prospect of monopoly utilities marketing non-fossil gas supply options with a message of environmental benefits, alongside marketing for energy efficiency and other programs. The DPU should be skeptical about the benefits of such marketing for advancing state policy, for two primary reasons.

First, as discussed above, the environmental benefits of non-fossil gases are not well established, if they exist at all, and depend on details regarding gas provenance and transportation that are difficult to convey in public-facing marketing materials. To provide an example, consider the sale of non-fossil gases

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[15] For example, the annual unaccounted-for emissions are 1.3 MMT CO2e in 2050 in the Hybrid scenario and 0.3 MMT in the Interim 2030 CECP scenario. The incremental 1.0 MMT per year times $400 per ton equals $400 million per year.

[16] Maldonado, Samantha. "Newtown Creek Plant Burns Off Valuable Methane Daily as Waste Recycle Project Lags." *The City.* April 2022. Available at: https://www.thecity.nyc/2022/4/15/23026137/newtown-creek-plant-burns-methane-waste-recycle-lags.

that receive certification in the form of a renewable identification number (RIN) for transportation fuels or California's Low-Carbon Fuel Standard compliance certificates. These certifications are valuable to entities other than Massachusetts ratepayers (e.g., transportation fuel companies, particularly those in California) and ratepayer costs would be reduced if the certifications were sold. However, once the certifications are separated from the fuel, no other entity along the supply and delivery chain can claim those environmental characteristics. Even if all certifications are retained, the blend of fuels provided and how they are procured and transported could provide a shifting and uncertain foundation for customer understanding.

Second, the economic impact of non-fossil gases on customer bills is likely to be negative. Non-fossil gas costs more than fossil gas, so customers who choose the fuel will immediately face higher bills. But more important, because it raises the prospect of lock-in and stranded costs, is the impact of non-fossil gas marketing on customer equipment choices. If customers choose gas appliances because they believe they will be able to cost-effectively transition to a net-zero-emission future through the purchase of non-fossil gas, these customers risk being locked in to using gas as delivery rates rise (driven by GSEP costs, absent a different approach, and by reductions in sales volumes). They will likely face substantially higher costs than they expected.

To mitigate these risks, the DPU should ensure that any LDC forays into non-fossil gas procurement and marketing are focused on hard-to-electrify end uses, such as industrial processes, district heating, or combined heat and power. These end uses typically correspond to sophisticated customers able to understand their choices and risks within the larger energy transition.