Advancing the Clean Energy Future

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November 11, 2022

Connecticut Department of Energy and Environmental Protection
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To Whom It May Concern:

Acadia Center appreciates the opportunity to submit written comments related to Technical Session 6: Alternative Fuels associated with the development of Connecticut's Comprehensive Energy Strategy (CES).

Acadia Center is a non-profit research and advocacy organization committed to advancing the clean energy future by offering real-world solutions to the climate crisis. Acadia Center tackles complex problems, identifies clear recommendations for reforms, and advocates for policy changes that support a low-carbon economy across the Northeast. Acadia Center identifies regional, state, and local improvements that will dramatically reduce carbon pollution and improve quality of life throughout the Northeast.

Acadia Center respectfully submits the following comments:

## Summary of Key Topics Discussed in Comments:

- Alternative fuels (hydrogen, biofuels, synthetic fuels) are and will continue to be limited resources that should be deployed in the sectors of the economy that are most challenging to electrify. These sectors do not include residential and commercial buildings or light-duty transportation, but do include high heat industrial processes, long- and medium-haul aviation, cargo ships, and long-haul heavy-duty trucks.

- Direct electrification of the buildings and light-duty transportation sectors is significantly more efficient than the use of hydrogen in these same sectors from both an energy efficiency perspective and a renewable energy siting/land use perspective.

- The use of alternative fuels in sectors of the Connecticut economy that are relatively easy to electrify directly makes it harder for states with disproportionate concentrations of the hardest-to-electrify sectors to achieve economy-wide decarbonization.

- To play any significant role in decarbonization of the building sector in Connecticut, a significant portion of the hydrogen and biofuels used in Connecticut would need to be imported from outside of the region. As a result, decarbonization strategies including electrification, energy efficiency, and local renewable energy deployment result in more positive local economic impact and job creation.

- A clean heating standard is preferable to a blending mandate assuming that certain policy guardrails are in place, including accurate lifecycle GHG accounting for biofuels and caps on biofuel use. A clean heating standard should only be explored once Connecticut has undertaken a rigorous study on the future of the gas distribution system and committed to a clear path forward for the gas distribution system that aligns with state decarbonization targets.

- All biofuels produced using energy crop feedstocks should be restricted. Biofuels not derived from energy crops should be evaluated on a case-by-case basis considering the lifecycle GHG emissions associated with the specific fuel production pathway.

- The GHG accounting methodology in Connecticut needs to be completely overhauled to account for lifecycle GHG emissions associated with biofuels.

- When discussing biofuel policy options, it's critical to separate 1) Policies that marginally reduce GHG emissions in the short/medium-term and 2) Policies that set Connecticut on the most cost-effective trajectory towards economy-wide net zero emissions. Biofuel policies that are effective in achieving the first goal often directly conflict with the second goal.

## Question 1: Which alternative fuels are likely to be limited by the availability of affordable and sustainable feedstocks over the next 30 years? Why?

All alternative fuels are likely to be limited by the availability of affordable and sustainable feedstocks. Alternative fuels are fundamentally limited in supply.

- Biofuels are limited by the amount of sustainable forms of feedstocks available to produce biofuels.
- Hydrogen is limited by the sheer amount of land it would require to site the wind and solar generation that would be required to produce green hydrogen at scale.
- Synthetic fuels are limited by the sheer cost of fuel production and the opportunity costs associated with using captured carbon to produce synthetic fuels versus using the same captured carbon to produce negative emissions.

As an example, let's look specifically at biomethane (often referred to as "renewable natural gas" or RNG). The limited amount of biogas available is a major impediment to RNG playing any meaningful role in displacing FNG use in buildings. In 2017 in the U.S., if all uncontrolled $CH_4$ emissions from biogenic sources that could reasonably be captured were used to produce RNG, it would result in enough RNG to displace under 1% of total 2017 U.S. FNG consumption or about 3.6% of U.S. residential and commercial buildings FNG consumption.[1]

Studies considering a future expanded market for RNG have reached similar conclusions. The American Gas Foundation (AGF) commissioned ICF to examine the potential for expanding RNG production potential over the next 20 years while considering constraints including feedstock accessibility and the economics of production. The "high

[1] Grubert, 2020. "At scale, renewable natural gas systems could be climate intensive: the influence of methane feedstock and leakage rates" https://iopscience.iop.org/article/10.1088/1748-9326/ab9335

resource potential scenario", concluded that by 2040 biogas produced by landfills, animal manure, wastewater, and food waste facilities would have the potential to produce 1,425 trillion British thermal units (tBTU) of RNG per year, equivalent to only 4.5% of total U.S. FNG consumption in 2020 or 17.5% of U.S. residential and commercial buildings FNG consumption.[2] The same scenario found that by 2040 thermal gasification of agricultural residues and forestry and forest product residues[3] (both highly controversial forms of biogas production for various reasons) had the potential to produce 876 tBTU per year, equivalent to 2.8% of total current U.S. FNG consumption or 10.8% of U.S. residential and commercial buildings consumption.[4] Combined, this high-end projection of RNG potential from upgrading biogas and biomass gasification amounts to 7.3% of total U.S. FNG consumption and 28.3% of U.S. residential and commercial buildings consumption. The same study found that RNG would also be extremely expensive to produce. For example, as production of RNG scaled up in the study, the cost or producing RNG via biomass gasification ranged from $27/MMBtu to $31/MMBtu, approximately 13 to 15 times the average cost of FNG in 2020.[5]

It's important to note that these "high resource potential" estimates from the AGF/ICF study assumed that a very high percentage of all potential biomass feedstocks in the U.S. would be used to produce RNG for pipeline injection, including over 60% of biogas from landfills, 60% of biogas from animal manure, 60% of forest and forestry product, and 70% of biogas from food waste. Allocating well over half the nation's limited supply of biomass feedstocks to pipeline RNG production comes with a significant opportunity cost: Less biomass available to produce low-carbon fuels for decarbonizing industry, chemical production, transportation, and power generation.

### Question 2: Which alternative fuels are likely to be limited due to infrastructure costs over the next 30 years? Why?

Green hydrogen production via electrolysis requires an enormous amount of renewable energy, largely attributable to the inherent inefficiencies associated with the electrolysis process. Meeting just half of existing U.S. hydrogen needs using only renewable electricity sources would require two-thirds of all the renewable energy generated in the U.S. in 2019 to be devoted to hydrogen production.[6]

Many advocates for hydrogen blending in the gas distribution system envision a not-too-distant future in which abundant excess renewable electricity on the grid, available at times when electricity generation exceeds electricity demand, can be used to produce hydrogen via electrolysis. While this is certainly one potential use of renewable electricity generation that would otherwise be curtailed, it's difficult to envision a scenario in which the scale of excess renewable generation is enough to produce enough electrolyzed hydrogen to both decarbonize hard-to-electrify sectors (e.g., industry, shipping, etc.) and space and water heating in buildings.

[2] American Gas Foundation, "Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment", 2019. https://gasfoundation.org/2019/12/18/renewable-sources-of-natural-gas/

[3] The study also estimated 837.6 tBtus of RNG produced via gasification of energy crops in this scenario

[4] Calculated using outputs from the AGF/ICF foundation paired with EIA data.

[5] EIA "Henry Hub Natural Gas Spot Market" https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm

[6] Estimate assumes an electrolysis efficiency rate of 52- 60 kWh per kilogram of hydrogen production

There are and will continue to be many competing end-uses for the renewable electricity that green hydrogen electrolysis production is reliant on. Significant amounts of additional renewable electricity are needed to eliminate our current reliance on fossil electricity generation and even more renewable electricity will be needed as large portions of the transportation and building sectors move towards decarbonization via electrification. See the response directly below to Question 4 for more details on this topic.

### Question 4: What sectors or end uses should be prioritized for the use of alternative fuels? Why?

Alternative fuels are and will be limited in supply for a variety of reasons: lack of sustainable biomass feedstocks, high costs of production, limited land availability to produce hydrogen via electrolysis at scale, etc. For this reason, when considering the end uses that are most appropriate for deploying the inherently limited supplies of alternative fuels, it's essential to lean on economy-wide decarbonization modeling to understand the tradeoffs between the use of alternative fuels versus the most likely alternative (in most cases direct electrification) for a particular end use.

The Massachusetts 2050 Decarbonization Roadmap ("MA Roadmap") study is an example of a quantitative modeling study from a bordering state that could provide valuable insights as Connecticut considers the most reasonable way to deploy alternative fuels.[7] Completed in late 2020, the MA Roadmap involved a rigorous modeling process to chart the most cost-effective pathways and strategies to achieving the state's net zero by 2050 target. The study's "All Options" pathway specifically answered the question: "*Under the most likely assumptions, what is the least-cost deployment of energy system technologies that achieve deep decarbonization?"* Key findings from this "All Options" pathways analysis included:

1. **Electrification is the most cost-effective path to building decarbonization:** Widespread electrification of buildings, primarily using highly efficient heat pumps, was found to be the least-cost strategy. The "All Options" pathway calls for electrification of over 90% of residential space heating, 95% of residential water heating, and 95% of commercial heating, water heating, and cooking by 2050.[8]

2. **There is no cost-effective role for "alternative fuels" in buildings.** The study found that widespread adoption of electrification paired with increased energy efficiency measures are a lower cost decarbonization strategy in buildings than the use of alternative fuels, including renewable natural gas (RNG), biodiesel, hydrogen, and synthetic natural gas (SNG). In the "All Options" pathway, none of these alternative fuels are used in residential and commercial buildings, as these supply-constrained fuels were found to be most efficiently used in decarbonizing the most difficult-to-electrify portions of the transportation and industrial

[7] Massachusetts 2050 Decarbonization Roadmap. https://www.mass.gov/info-details/ma-decarbonization-roadmap#final-reports-

[8] Massachusetts 2050 Decarbonization Roadmap: Buildings Sector Report, page 5 https://www.mass.gov/doc/building-sector-technical-report/download

sectors.[9]

3. **Electrification is the most cost-effective path to decarbonize transportation.** Due to comparatively low cost and high drive-train efficiency of battery electric vehicles (BEVs) compared to alternatives including hydrogen fuel cell electric vehicles (FCEVs), the "All Options" pathway found that BEVs made up 95% of the light-duty fleet and 50-60% of medium/heavy-duty fleet by 2050. While converting approximately 20-30% of the medium/heavy-duty vehicle fleet to FCEVs by 2050 was found to be cost effective, the study found no cost-effective role for hydrogen in decarbonizing passenger car and light-duty truck fleets.[10]

The Princeton Net-Zero America (NZA) Project is another well respected quantitative modeling study that Acadia Center thinks could provide valuable insights as Connecticut considers the most reasonable way to deploy alternative fuels. While the study is at a national scale, many of the key takeaways from the modeling can help to inform state-level decarbonization pathway decision making. Similar to the MA Roadmap, Princeton's study found overwhelmingly that the most cost-effective end use of green hydrogen was in hard-to-electrify portions of the industrial and transportation sectors.

**None of the five decarbonization pathways in the study found that it was cost-effective to use hydrogen or RNG in residential and commercial buildings.**[11] The study also found that the two pathways with the lowest energy system costs over the next 30 years were the "High Electrification" and "High Electrification, Renewables Constrained" pathways. Both of these pathways assumed "aggressive end-use electrification" with electricity accounting for 85%-90% of total energy consumption in residential and commercial buildings.[12] These lowest costs scenarios also assumed that 97% of light-duty autos, 94% of light-duty trucks, 72% of medium-duty trucks, and 57% of heavy-duty trucks would be BEVs by 2050. The role of HFCEVs was projected to be nonexistent in light-duty autos and trucks and only accounted for 17% of medium-duty trucks in 2050. **Heavy-duty trucks were the only vehicle type where hydrogen played a significant role, with about 38% of heavy-duty trucks projected to be HFCEVs by 2050.** [13]

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[9] Massachusetts 2050 Decarbonization Roadmap: Energy Pathways to Deep Decarbonization, page 35 https://www.mass.gov/doc/energy-pathways-for-deep-decarbonization-report/download

[10] Massachusetts 2050 Decarbonization Roadmap: Transportation Sector Report, page 13 https://www.mass.gov/doc/transportation-sector-technical-report/download

[11] Princeton University Net-Zero America Potential Pathways, Infrastructure, and Impacts Final Report. Slides 30-33. https://netzeroamerica.princeton.edu/the-report

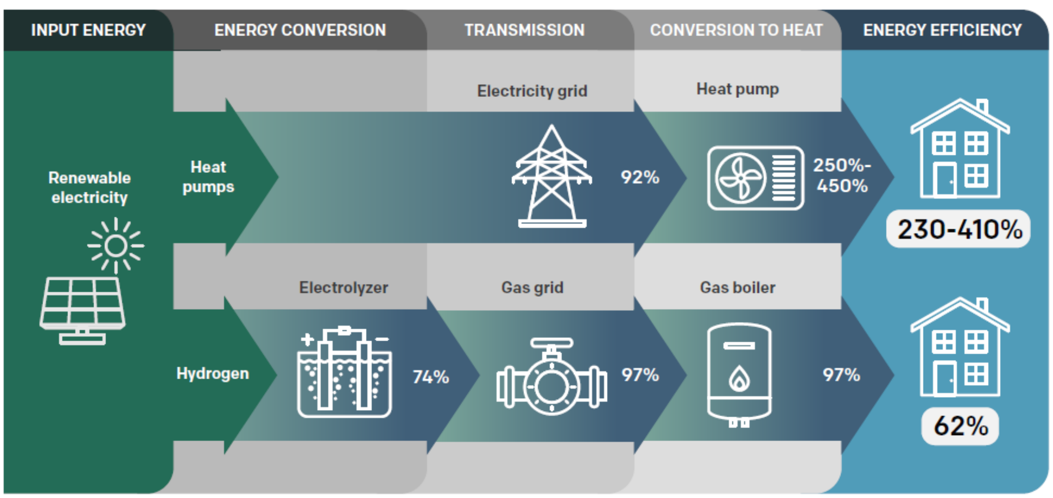
[12] Princeton University Net-Zero America Potential Pathways, Infrastructure, and Impacts Final Report. Slides 57 & 63. https://netzeroamerica.princeton.edu/the-report

[13] Princeton University Net-Zero America Potential Pathways, Infrastructure, and Impacts Final Report. Slide 46. https://netzeroamerica.princeton.edu/the-report

In the DOE's Billion Ton Study, the lifecycle GHG benefits for four potential end uses for biomass were analyzed: Ethanol, jet fuel, biopower, and biochemicals.[14] Using biomass feedstocks to produce RNG for pipeline injection or biodiesel for use in residential and commercial heating *was not investigated or discussed*, presumably because the authors viewed both as lower priority end uses of limited biomass feedstocks.

With regard to hydrogen, specifically, one of the key reasons that neither the MA Roadmap nor Princeton NZA studies found it cost-effective to use hydrogen to decarbonize buildings was that "directly" electrifying buildings, opposed to using that same electricity to produce green hydrogen, is significantly more energy efficient. For example, a study from the Fraunhofer Institute for Energy Economics found that compared to using electric air source heat pumps for heating buildings, relying on a hydrogen-based, low temperature heating system uses 500-600% more electricity.[15] The U.K.'s Climate Change Committee estimated that using renewable electricity to heat buildings using heat pumps has an overall efficiency between 230-410%. In contrast, using that same renewable electricity to produce hydrogen via electrolysis, transport the gas through the hydrogen distribution system, and eventually combust the hydrogen in a boiler to heat buildings has an overall efficiency of approximately 62%.[16]

Comparison of Efficiencies for Hydrogen and Heat Pumps in Homes[17]




[14] DOE 2016 Billion Ton Study, Volume, 2 Chapter 4, Figure 4.20 https://www.energy.gov/sites/default/files/2017/02/f34/2016_billion_ton_report_volume_2_chapter_4.pdf

[15] Norman Gerhardt et al., Fraunhofer Institute for Energy Economics, Hydrogen in the Energy System of the Future: Focus on Heat in Buildings, at 5 (May 2020) ("Fraunhofer Institute 2020") https://www.iee.fraunhofer.de/content/dam/iee/energiesystemtechnik/en/documents/Studies-Reports/FraunhoferIEE_Study_H2_Heat_in_Buildings_final_EN_20200619.pdf.

[16] Committee on Climate Change (CCC) "Hydrogen in a low-carbon economy" https://www.theccc.org.uk/publication/hydrogen-in-a-low-carbon-economy/

[17] Image from Earthjustice's "Reclaiming Hydrogen for a Renewable Future" report, 2021. https://earthjustice.org/features/green-hydrogen-renewable-zero-emission Underlying data in figure from Committee on Climate Change (CCC) "Hydrogen in a low-carbon economy" report https://www.theccc.org.uk/publication/hydrogen-in-a-low-carbon-economy/

Any R&D efforts or infrastructure investments related to the development of alternative fuels should be focused on hard-to-electrify sectors of Connecticut's economy including high heat industrial processes, long- and medium-haul aviation, cargo ships, and long-haul heavy-duty trucks. Given the challenges of directly electrifying these particular sectors, as demonstrated in the MA Roadmap and Princeton Net Zero America analysis, it would be prudent for states, including Connecticut, to support research and development projects aimed at expanding production and lowering the production cost of alternative fuels, including green hydrogen, but it is essential that regulations be put in place ensuring that these public funds will not support investments investigating or expanding the role of these fuels in residential and commercial buildings or passenger vehicles. **Both investments and policies must be limited to supporting decarbonization of the hardest-to-electrify sectors.**

**Using hydrogen and biofuels in buildings in Connecticut directly makes it harder for states with disproportionately high concentrations of hard-to-electrify sectors to decarbonize.** For example, states like Connecticut, with relatively little heavy industry, using supply-constrained green hydrogen and biofuels for space heating in residential and commercial buildings directly inhibits the ability of industry-heavy states to achieve economy wide-decarbonization. To illustrate this point, consider the state of Louisiana. Louisiana has a population of 4.65 million people, about 30% higher than the population of Connecticut. However, industrial sector GHG emissions in Louisiana are over 65 times higher than industrial sector emissions in Connecticut.[18] **Put another way, industrial sector emissions alone in Louisiana in 2018 were over 2.9x higher than the entire state of Connecticut's emissions from all sectors in the same year.**[19] States with heavy concentrations of industry, like Louisiana, already face the most challenging path to achieving decarbonization without states with relatively light concentrations of industry, like Connecticut, competing for alternative fuels to use in a sector (e.g. buildings) that is relatively easy to decarbonize through electrification. **Connecticut has a moral imperative to ensure that the path it pursues to achieve net-zero emissions does not directly conflict with the efforts of other states (and in the bigger picture, the country) to achieve net-zero emissions and decisions regarding the appropriate use of these fuels in the state should accurately reflect this imperative.**

Who will benefit if the Connecticut achieves net zero emissions by 2050 but in doing so directly makes it harder for other states, regions, and countries to achieve net zero emissions? The answer is nobody.

## Question 5: Specific to transportation, which vehicle types and vehicle classes are the best candidates for alternative fuel use in the near term?

Please see the above response to Question 4. For on-road vehicles – certain medium-duty and heavy-duty vehicles (particularly those used in long-haul applications) are the only vehicle types where alternative fuels should be considered. Investment and policies aimed at promoting adoption of HFCEV medium- and heavy-duty trucks should proceed with caution. It's unclear which technology (BEV or HFCEVs) will ultimately "win out" in these vehicle

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[18] U.S. Energy Information Administration, "Energy-Related CO2 Emission Data Tables" Table 4 https://www.eia.gov/environment/emissions/state/

[19] Connecticut Greenhouse Gas Reduction Progress Reports https://portal.ct.gov/DEEP/Climate-Change/CT-Greenhouse-Gas-Inventory-Reports

categories.[20] For all other vehicle types, direct electrification makes more sense form every possible angle – cost, energy efficiency, existing market share, and overall technical feasibility.

### Question 6: How should alternative fuels be utilized to complement Connecticut's existing light-duty and medium- and heavy-duty vehicle electrification commitments?

Please see the above response to Question 4. Alternative fuels should not be utilized to complement Connecticut's existing light-duty and medium-duty vehicle electrification commitments. Investment and policies aimed at promoting adoption of HFCEV medium and heavy-duty trucks should proceed with caution. It's unclear which technology (BEV or HFCEVs) will ultimately "win out" in these vehicle categories.

### Question 8: How can state government help prepare Connecticut's workforce for wider use of alternative fuels and for potential reductions in liquid and gaseous fuel use in Connecticut?

Expanded use of alternative fuels does not necessarily result in expanded local jobs or increase local economic activity. Take, for example, the findings from two recent studies in Massachusetts – the Massachusetts Decarbonization Roadmap and the Massachusetts D.P.U. 20-80 Independent Consultant Report. The Massachusetts Decarbonization Roadmap Study found that pathways that invested in local energy resources, including renewable electricity generation and energy efficiency, created more jobs and demonstrated greater economic benefits by keeping money local in comparison to the pathways more reliant on imported energy, including alternative fuels. For example, the "All Options" pathway from the Roadmap (which emphasized deep electrification and broad renewable electricity buildout) had 17% higher economic "output" (the broadest measure of economic activity) in Massachusetts per dollar invested than the "Pipeline Gas" pathway (which relied heavily on imported alternative fuels).[21,22]

In contrast, in the D.P.U. 20-80 analysis, quantifying the local economic and jobs impact of various scenarios was deemed out of scope in the consultant's analysis. This is extremely problematic when you step back and think through some of the economic ramifications of the various scenarios posed in the 20-80 Independent Consultant Report. **Scenarios in that analysis that relied heavily on hydrogen, including the Efficient Gas and Hybrid Electrification scenarios, are assumed to import all hydrogen from Pennsylvania.** Importing hydrogen from Pennsylvania was found to be the most cost-effective option, largely because Massachusetts, and New England more broadly, do not have naturally occurring, cost-effective geological features (e.g. salt caverns) capable of storing hydrogen.[23] In the consultant's analysis, hydrogen production in Pennsylvania was assumed to entail large investments in hydrogen electrolyzers in Pennsylvania, dedicated on-shore wind capacity in Pennsylvania to power

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[20] NREL Decarbonizing Medium- & Heavy-Duty On-Road Vehicles: Zero Emission Vehicles Cost Analysis. See slide 22. https://www.nrel.gov/docs/fy22osti/82081.pdf

[21] Massachusetts Decarbonization Roadmap, Economic and Health Impacts Report, Table 3, page 13 https://www.mass.gov/doc/economics-and-health-impacts-report/download

[22] It's worth noting that the "Pipeline Gas" pathway in the MA Roadmap made much more significant investments in energy efficiency upgrades than the "Hybrid Electrification" scenario evaluated by E3.

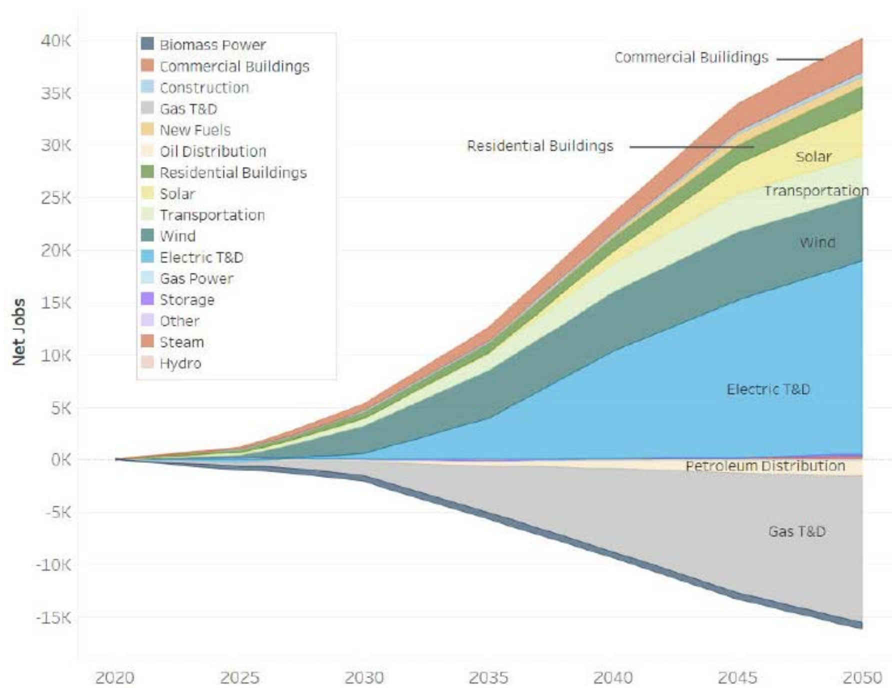
[23] Independent Consultant Report, Appendix 1, page 18 https://thefutureofgas.com/content/downloads/2022-03-21/3.18.22%20-%20Independent%20Consultant%20Report%20-%20Appendix%201%20(Modeling%20Methodology).pdf

those electrolyzers, underground storage in Pennsylvania, and a 400-mile hydrogen pipeline from Pennsylvania to New England. In other words, it would create many jobs in Pennsylvania, but very few in New England.

Sending money and jobs out of state was also a staple of scenarios in the 20-80 analysis, including the Efficient Gas and Hybrid Electrification scenarios, that rely heavily on RNG. **The consultant's model assumed the vast majority of RNG consumed in Massachusetts was imported from outside of New England.** This is largely result of biomass resource availability in New England being, on a per capita basis, about 25% that of the national average according to the consultant's analysis (0.63 dry tons per person per year in New England vs. 2.47 nationally).[24] In summary, in the 20-80 analysis, a reliance on both hydrogen and RNG means sending large amount of ratepayer dollars and job out of state. The same dilemma holds true for Connecticut.

Alternatively, 20-80 scenarios like High Electrification, Networked Geothermal, and 100% Gas Decommissioning, do a better job of keeping money local by investing more aggressively in energy efficiency, local renewable electricity generation, and electricity system transmission and distribution buildout. The job-creation benefits of MA Roadmap's "All Options" pathway, which relies heavily on building electrification, are demonstrated below.

Net Change in Directly Created Jobs by Year for the Massachusetts Decarbonization Roadmap All Options Pathway[25]




[24] Independent Consultant Report, Appendix 1, page 16 https://thefutureofgas.com/content/downloads/2022-03-21/3.18.22%20-%20Independent%20Consultant%20Report%20-%20Appendix%201%20(Modeling%20Methodology).pdf
[25] Massachusetts Decarbonization Roadmap, Economic and Health Impacts Report, Figure 7, page 14 https://www.mass.gov/doc/economics-and-health-impacts-report/download

It's also worth noting that the Hybrid Electrification scenario touted in the 20-80 analysis as being the most cost effective assumes the least substantial investment in building shell retrofits of any scenario investigated by the consultants.[26] With that assumption comes fewer jobs in the local energy efficiency industry. The downside of this approach – fewer local jobs making our buildings more efficient – just simply isn't captured in the 20-80 analysis. Scenarios that place a larger emphasis on the utilization of heat pumps also leverage locally available resources, heat in the local air and ground, and renewable energy gathered from the sun and wind for usable energy.

### Question 10a: Under PA 21-181, the minimum proportion of LCBs blended into heating oil distributed in Connecticut is to be 50 percent by 2035. Is this technically realistic? Is it environmentally responsible?

It's not environmentally responsible for two critical reasons discussed in more detail in other parts of these comments, that are briefly summarized below:

- Using the nation's limited supply of sustainable biomass feedstocks for the production of a fuel to be used in a sector the economy that is relatively easy to electrify (residential and commercial space and water heating) comes with a massive opportunity cost. It fundamentally makes it harder for the state, region, and country to decarbonize the sectors of the economy that are most challenging to electrify using those same limited sustainable biomass feedstock resources.

- What is the end game? Even if one is under the impression that a 100% blend of biodiesel is eventually technically achievable in residential and commercial space heating equipment (there is little evidence to support this claim), once lifecycle GHG emissions associated with biofuels are taken into account, it quickly becomes apparent that this strategy would only marginally reduce GHG emissions in the residential and commercial space heating sector. This strategy simply doesn't align with achieving net zero GHG emissions by 2050. It's a dead-end solution and the state shouldn't be investing limited resources (time, public capital, private capital, staff bandwidth) into dead end solutions. The state should be investing limited resources into solutions (like electrification paired with energy efficiency) that actually put the state on a course to achieving carbon neutrality.

### Question 10b: Should the minimum percentage of LCB ultimately go beyond fifty percent? If so, how far and in what time frame?

No. PA 21-181 blending requirements of 50 percent by 2035 are already a massive mistake when you consider the lifecycle emissions associated with biofuels, the opportunity cost associated with using biofuels to decarbonize a sector of the economy that is relatively easy to electrify, the high costs and limited supply of biofuels in the medium-to long-term, and the fact that biofuel blending is not compatible with actually achieving net zero emissions at state level. Expanding the LCB requirements beyond 50% would simply be doubling down on an already flawed decision.

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[26] Independent Consultant Report, Appendix 1, page 7, Table 1. https://thefutureofgas.com/content/downloads/2022-03-21/3.18.22%20-%20Independent%20Consultant%20Report%20-%20Appendix%201%20(Modeling%20Methodology).pdf

### Question 10 c: Would a low-carbon fuel standard be more efficient than a blending mandate?

Generally speaking, yes, Acadia Center thinks that a "clean heat standard" (e.g., similar to the one recently proposed in Vermont[27]) is a significantly better policy mechanism, *if designed correctly,* for decarbonizing the building sector than a blending mandate. The specifics related to how the clean heat standard is designed are *absolutely critical* to the success of the standard. Specifically, Acadia has two major concerns with the version of the clean heat standard proposed in Vermont.

Concern #1: A clean heat standard actually has to get the lifecycle GHG accounting for biofuels right to be effective. The Clean Heat Standard, as proposed in Vermont, didn't specify the exact lifecycle GHG accounting methodology that would be used, but the existing models used for lifecycle accounting of biofuels are so fundamentally flawed that they can't be relied upon for guiding sound clean heating policy. For example, Argonne National Laboratory's GREET Model is one of the more widely used lifecycle accounting models currently used to estimate lifecycle emissions associated with biofuels. The California Low Carbon Fuels Standard (LCFS) relies on a version of GREET to inform their policy. However, as expressed in a recent letter from Jeremey Martin at the Union of Concerned Scientists to the California Air Resources Board, there are massive holes in the GHG accounting logic used in both the LCFS and, in turn, GREET. One of the core problems with the LCFS is that it uses venting of methane at the site of production (landfill, wastewater treatment facility, livestock facility, etc.), rather than flaring, as the baseline for which all biofuels are compared against. In other words, the default assumption for biofuels is often that, absent the LCFS policy, methane generated at factory farms would be directly vented to the atmosphere (the worst possible result from a GHG perspective) rather than flared on site (a much better GHG outcome because it converts methane to carbon dioxide). This dramatically overestimates the GHG benefits of biofuels in many instances. Some select quotes from the UCS research help to demonstrate these concerns that Acadia Center shares:

*"Furthermore, this study illustrates that the **negative emissions associated with use of anaerobic manure digestion** are at least in part an **artifact of accounting choices** that increase the revenue particularly to large dairy operations. These include the policy of considering manure to be a true waste from an LCA standpoint even where it accounts for a significant portion of total revenue, and the base-case assumption of uncontrolled methane release."*[28]

*"Methodologically, the **extremely large negative carbon intensity (CI) values for manure biomethane are the result of several assumptions and judgements made by CARB in the life-cycle analysis that bear reconsideration**. In particular, CARB should revisit the assumption that the methane from manure lagoons is purely a waste product with no value that would be **emitted into the atmosphere absent the LCFS support** for use as a transportation fuel."*[29]

*"**Farms could be required to flare rather than vent biogas generated by manure as a baseline**. This would have a*

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[27] Energy Action Network Vermont "The Clean Heat Standard: Whitepaper" https://www.eanvt.org/chs-whitepaper/

[28] Union of Concerned Scientists, Quantification of Dairy Farm Subsidies Under California's Low Carbon Fuel Standard, page 19. https://www.arb.ca.gov/lists/com-attach/24-lcfs-wkshp-dec21-ws-AHVSN1MhVlpXNQRl.pdf

[29] Union of Concerned Scientists, Quantification of Dairy Farm Subsidies Under California's Low Carbon Fuel Standard, page i. https://www.arb.ca.gov/lists/com-attach/24-lcfs-wkshp-dec21-ws-AHVSN1MhVlpXNQRl.pdf

*similar impact to the option above, since it would mean the carbon intensity of generated electricity would be close to zero rather than significantly negative."*[30]

While the focus of the UCS comments is on biomethane, specifically, these concerns extend to various forms of biofuels, including biodiesel produced under various pathways. There is no easy solution to this biofuels lifecycle accounting issue. At the moment, incorporating biofuels into any clean heat standard in a responsible manner is extremely challenging due to the critical flaws with the current lifecycle accounting methodologies commonly employed. We need better lifecycle accounting before we start enacting these policies. Using bad lifecycle accounting approaches that overemphasize the GHG reduction potential of biofuel is extremely problematic.

Concern #2: Given the huge concerns with accurate lifecycle accounting of biofuels and the massive opportunity cost of using biofuels in a sector of the economy that is relatively easy to electrify (residential and commercial heating), the only responsible policy response is to put caps on the amount of biofuels that can participate in a clean heat standard. The Vermont example referenced above currently lacks these caps. One could imagine a tweak to the Vermont policy that essentially makes the cap on the amount of alternative fuels eligible under a clean heat standard equal to the heat demand that cannot be easily met via electrification (e.g. heat demand from industrial customers requiring high heat applications). This type of policy guardrail would prevent biofuels being irresponsibly used in sectors of the economy where electrification is clearly a better option.

Concern #3: A clean heat standard can't be deployed as a policy fix in a vacuum. It should only be deployed once the state has undertaken a rigorous study on the future of the gas distribution system, as Massachusetts has already done and Rhode Island is currently doing, and is ready to chart a clear policy path forward to address the future of the gas system. To minimize future stranded costs, minimize overall system cost and minimize costs to ratepayers, it's critical to have clear direction on the future of the gas system prior to deploying a "let the market decide" clean heat standard. Without first considering the future of the gas system, a clean heat standard could result in heavy investment in hydrogen and RNG to be blended into the gas distribution system with no real consideration of strategies for minimizing stranded asset costs, the financial risks associated with continued investment into gas system infrastructure, or the long-term pathway for fully decarbonizing the gas distribution system. This would be a disastrous policy result and can be avoided by first fully evaluating the long-term future of the gas distribution system.

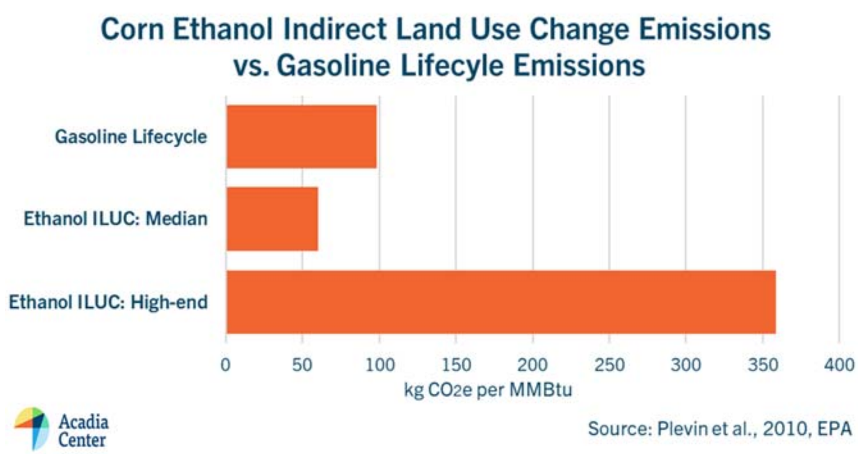
### Question 10 d: Should feedstocks used in producing biodiesel sold in Connecticut be restricted? If so, what feedstocks should be avoided, and why?

Yes, any biodiesel derived from energy crops should be avoided in Connecticut. Even some biodiesel not derived from energy crops should be restricted if the lifecycle GHG emissions associated with production of that fuel surpass a certain threshold. This logic should extend to all biofuels – not just biodiesel.

Energy crops, or crops grown solely for the purpose of energy production, are the most problematic biofuel feedstocks for a number of reasons, including the net GHG implications of indirect land use changes (ILUC). Because of the

[30] Union of Concerned Scientists, Quantification of Dairy Farm Subsidies Under California's Low Carbon Fuel Standard, page 19 https://www.arb.ca.gov/lists/com-attach/24-lcfs-wkshp-dec21-ws-AHVSN1MhVlpXNQRl.pdf

problematic nature of biofuels derived from energy crops, any policy promoting the use of biofuels in Connecticut must make it clear that biofuels derived from energy crops are explicitly prohibited, regardless of the end use application of those biofuels. ILUC associated with energy crop production make it particularly challenging to quantify the life cycle GHG emissions impact of biofuels derived from these feedstocks. ILUC are the unintended consequence of the expansion of croplands for biofuels to meet increased global demand for biofuels. The U.S. is one of the world's largest agricultural exporters and shifting land in the U.S. from agricultural food production to energy crop production can have ripple effects across the globe that result in a net increase in GHG emissions.




The complexities of these ripple effects result in wide ranges of uncertainty when attempting to quantify emissions from ILUC associated with biofuels. For example, ILUC emissions associated with US corn ethanol expansion during the 2000s were estimated to fall in the range of 10.5 to 358.6 kg CO2e per million Btu (MMBtu), with a median emission factor between 58.0 and 62.2 kg CO2e per MMBtu.[31] To put those numbers in perspective, as shown in the figure to the right, the median ethanol emission factor from that study is about 60% of the EPA's life cycle emission factor for conventional gasoline and the high-end ethanol emission factor estimate is over 3.6 times higher than the emission factor for conventional gasoline.[32] The U.S. Department of Energy's Billion-Ton Report – which is one of the most comprehensive studies calculating potential biomass supply in the United States and the associated environmental impacts – conducted analysis assessing the GHG impacts of scenarios with expanded biofuels production but did not attempt to quantify the GHG impacts of ILUC, highlighting the extreme level of uncertainty surround the topic.[33]

One of the most widely cited sources on the GHG emission reduction benefits of biodiesel is from Argonne National Lab, but the study openly acknowledges that the GHG impacts of land use changes are so complicated that they just simply ignore them in the analysis: "*Note that this study does not consider potential land use changes. Increased $CO_2$ emissions from potential land use changes are an input option in GREET, but it was not used in the current analysis*

[31] Plevin, et al., 2010. "Greenhouse Gas Emissions from Biofuels' Indirect Land Use Change Are Uncertain but May Be Much Greater than Previously Estimated " https://pubs.acs.org/doi/abs/10.1021/es101946t

[32] EPA "Lifecycle Greenhouse Gas Results" www.epa.gov/fuels-registration-reporting-and-compliance-help/lifecycle-greenhouse-gas-results

[33] DOE 2016 Billion-Ton Report www.energy.gov/eere/bioenergy/2016-billion-ton-report

*since* ***reliable data on potential land use changes induced by soybean-based fuel production are not available.***"[34] This is extremely concerning, considering that soybean oil accounts for over 60% of the biodiesel currently produced in the U.S.[35] .

Even more concerning is that there are troubling links between expanded biodiesel production in the U.S. and the expansion of palm oil plantations in Indonesia and Malaysia, a major driver of deforestation and global land use emissions.[36] EPA lifecycle GHG emissions analysis, which attempts to account for indirect land use changes (to a debatable level of accuracy), highlights that biodiesel is far from carbon neutral. For example, biodiesel derived from soybean oil and canola oil is estimated to have 56% and 50% lower lifecycle emissions, respectively, than conventional diesel. Some forms of biodiesel, like biodiesel derived from palm oil, only reduce lifecycle emissions of conventional diesel by 17% according to the EPA data.[37] However, it's critical to note that trying to peg the emissions reduction potential of biodiesel, or any biofuel, to a single number masks the extreme uncertainty in emissions resulting from ILUC discussed above.

### Question 10 f: In conducting the state greenhouse gas inventory under the Global Warming Solutions Act (Public Act 08-98), DEEP currently subscribes to an international accounting norm under which primary greenhouse gas emissions associated with combustion of virgin biofuel are not counted in the jurisdiction where the fuel is combusted unless that is also the jurisdiction where the feedstock was grown. Are this norm and this practice adequate from a global climate perspective?

The greenhouse gas accounting for biofuels needs to be completely revamped to account for lifecycle GHG impacts of biofuels. One of the key limitations of the CT Inventory is that it largely treats biogenic emissions as an informational item and almost entirely ignores the impact of biogenic emissions on overall statewide emissions totals. Currently, only $CH_4$ and $N_2O$ GHG emissions resulting from combustion of biogas are captured in the "non-biogenic" portion of the CT Inventory. These $CH_4$ and $N_2O$ emissions represent a small fraction of total biofuel combustion emissions and an even smaller fraction of the total net GHG emissions resulting from the biofuel supply chain (including production, processing, and transmission). This accounting of biofuels is gross simplification of a complex issue, particularly in instances where biofuels are derived from energy crops and in instances where emissions are released while producing, processing, and transporting biomethane.

Because the use of biofuels is likely to increase in coming years, it underscores the importance of accurate GHG accounting for these fuels. **Acadia Center recommends that Connecticut establish GHG accounting principles that clearly assert that 1) Biogenic emissions should impact total reported emissions in the CT Inventory and 2)**

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[34] Argonne National Laboratory "Life-Cycle Assessment of Energy and Greenhous Gas Effects of Soybean-derived Biodiesel and Renewable Fuels", 2008. Page 4. https://greet.es.anl.gov/files/e5b5zeb7

[35] EIA "Monthly Biodiesel Production Report" Table 3. https://www.eia.gov/biofuels/biodiesel/production/table3.pdf

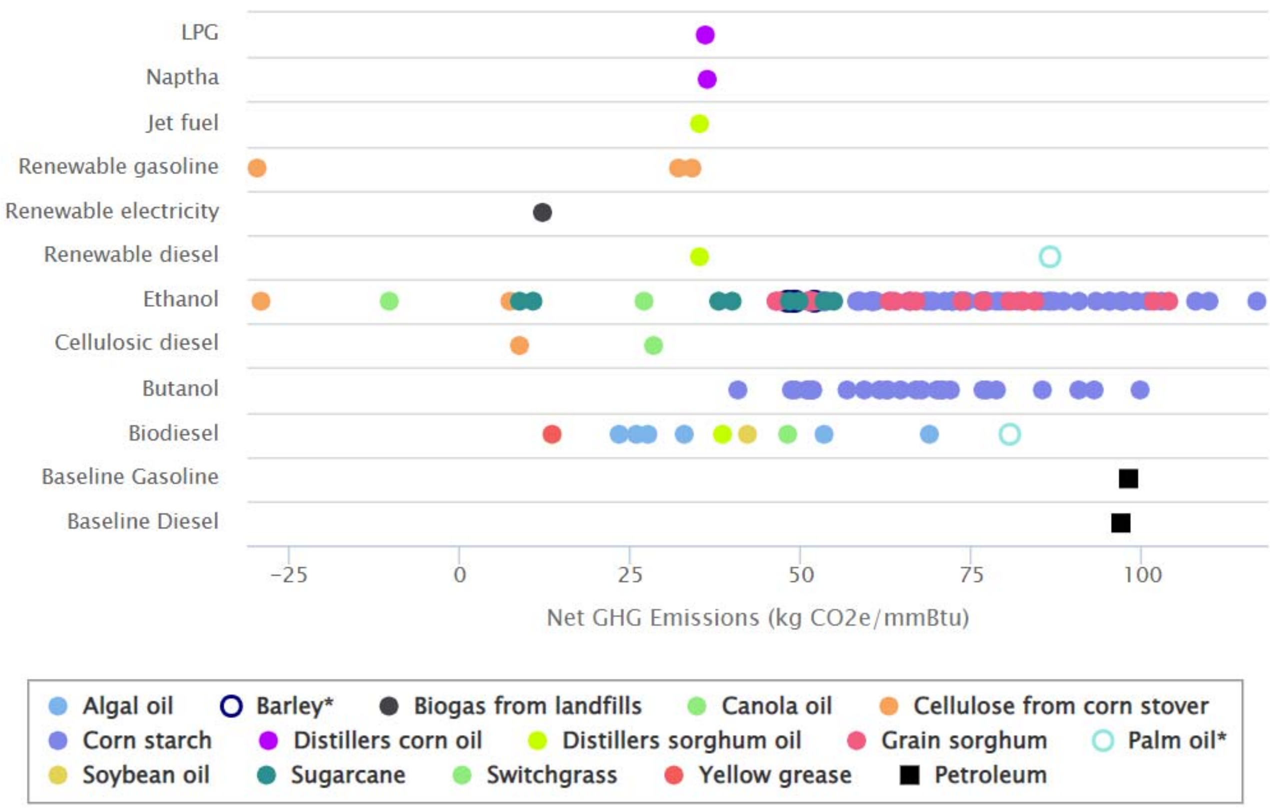
[36] Union of Concerned Scientists "Everything You Ever Wanted to Know About Biodiesel", 2016. https://blog.ucsusa.org/jeremy-martin/all-about-biodiesel/

[37] EPA "Lifecycle Greenhouse Gas Results" www.epa.gov/fuels-registration-reporting-and-compliance-help/lifecycle-greenhouse-gas-results

Biogenic emissions from biofuels need to be measured against the counterfactual (e.g., not intentionally producing biogas in the first place or diverting biogas from flaring to produce biomethane). These accounting practices are critical to establish now given the increasing interest in biofuels as a potential decarbonization strategy.

EPA's Renewable Fuel Standard provides a demonstration of the wide variance in lifecycle GHG emissions from biofuels (see figure below).[38] The EPA analyses examined the production of a number of different types of biofuels using various feedstocks. The results vary considerably, but the overwhelming majority of biofuels show some level of positive net GHG emissions, with some biofuels exceeding the lifecycle emissions of conventional fossil fuels like gasoline and diesel.

EPA Renewable Fuel Standard Program Lifecycle GHG Emissions by Feedstock and Fuel Type[39]




[38] EPA "Lifecycle Greenhouse Gas Results" https://www.epa.gov/fuels-registration-reporting-and-compliance-help/lifecycle-greenhouse-gas-results
[39] EPA "Lifecycle Greenhouse Gas Results" https://www.epa.gov/fuels-registration-reporting-and-compliance-help/lifecycle-greenhouse-gas-results

This issue of lifecycle GHG emissions from biofuels gets thornier in the particular case of RNG, where methane leaks along the entire RNG supply chain pose massive GHG concerns. When analyzing the GHG impacts of RNG, it's important to consider the two general categories of RNG: 1) RNG derived from "intentionally produced" methane and 2) RNG derived from "waste methane".

An example of "intentionally produced methane" is converting agricultural residues (e.g., corn stalks remaining after harvest) to methane through a process known as gasification, and an example of "waste methane" is methane released by a landfill as organic material decays. The "Hybrid Electrification" scenario in MA DPU 20-80, as an example, relied on both categories of RNG despite numerous requests from stakeholders to not consider the use inclusion of "intentionally produced methane" pathways.

As Dr. Emily Grubert, Associate Professor of Sustainable Energy Policy at Notre Dame, points out in her research, we know that RNG systems leak methane, just like natural gas systems, only potentially at even higher rates. **When we *intentionally* produce methane, *any* methane leaks along the RNG supply chain result in a net increase in GHG emissions.**[40] In other words, if our goal is to minimize GHG emissions, we shouldn't be intentionally producing *any* methane that we know will leak.

**For RNG produced using "waste methane", claims of GHG-neutrality are based on a flawed comparison against the worst possible alternative – that is, allowing methane released from sites like landfills to go directly into the atmosphere. That is unlikely to occur in a setting where GHG emissions are regulated, however, as the best option from a GHG perspective, by a wide margin, is to capture the biogas and combust it in a combined heat and power facility that produces both electricity and useful heat.** This on-site combustion efficiently converts methane to $CO_2$ (a far less potent GHG), while simultaneously avoiding downstream methane emissions associated with upgrading, transporting, and distributing RNG. It also has the critical benefit of serving as a "firm" electricity generation resource to complement a future grid with a high penetration of intermittent renewable electricity resources.

If combined heat and power at a particular site is not a viable option, even just burning the methane on site (a process known as flaring) is better from a GHG perspective than RNG production because it avoids downstream methane leaks along the RNG supply chain, as research by Dr. Grubert highlights.[41] For RNG produced form waste methane to actually be beneficial from a GHG perspective, leak rates along the supply chain would need to be about 1%, but we know they're much higher than that – typically ranging from 2.8% to 4.8% but observed to be as high as 15.8%.[42]

The consultant's report in MA DPU 20-80 openly acknowledges that treating RNG as emissions-neutral is problematic:

*"In this Study, the Consultants have assumed that renewable fuels have a net-zero GHG impact, consistent with the Massachusetts GHG inventory. This contrasts to other states, such as New York, that have adopted a lifecycle*

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[40] Emily Grubert 2020 Environ. Res. Lett. 15 084041 https://iopscience.iop.org/article/10.1088/1748-9326/ab9335

[41] Ibid.

[42] Ibid.

*approach to accounting GHG impacts of renewable fuels.* ***The Consultants recognize that treating renewable fuels as having net-zero emissions is a simplification of the complex carbon flux associated with these fuels****, as is further detailed in Appendix 1. As such, pathways that rely more heavily on renewable fuels bears the risks related to GHG accounting methods changing over time."*[43]

*"As a result,* ***treating renewable fuels as having net-zero carbon emissions may overestimate their decarbonization potential****, especially considering that emissions accounting frameworks in the Commonwealth may evolve.* ***Such an overestimation increases the risk of not meeting the Commonwealth's decarbonization goals****, especially under those economy-wide transitions that rely on high levels of renewable fuels, such as the Efficient Gas Equipment pathway."*[44]

Despite this acknowledgement in the report, the consultants ignored multiple requests from stakeholders to consider lifecycle GHG emissions from RNG in their modeling. They also ignored requests from stakeholders to address three other critical assumptions: 1) Accounting for out-of-state emissions associated with fuel production, 2) Using updating AR5 GWP values and 3) Estimating methane leaks in the gas distribution system based on the most recent and accurate data available. The fact that the consultant's analysis in DPU 20-80 just repeated the same mistakes as the MA GHG Inventory without even conducting any sort of sensitivity analysis brings into question the validity of the overall modeling outputs, and the regulatory proposals based upon them. Connecticut can and should do better when it comes to considering the GHG emissions associated with biofuels.

### Question 10i: What environmental side effects of biofuel combustion and biofuel reliance should DEEP take into account as it develops regulations regarding LCBs blended in heating oil?

These topics have been addressed in sections above, but to summarize:

- Lifecycle GHG emissions associated with the production of biofuels are not currently accounted for in Connecticut's GHG Inventory. Two major areas of concern related to lifecycle GHG emissions for biofuels are 1) Methane leaks along the RNG supply chain and 2) Indirect land use change emissions associated with energy crop biofuel production.
- The opportunity cost of using limited, sustainable biomass feedstocks to produce fuels in an effort to decarbonize a sector (residential and commercial heating) that is relatively easy to electrify. This will directly

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[43] Energy and Environmental Economics Inc. (E3) The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals Independent Consultant Report DRAFT, at 48 (2022)https://thefutureofgas.com/content/downloads/2.15.22%20-%20DRAFT%20Independent%20Consultant%20Technical%20Report%20-%20Part%20I%20(Decarbonization%20Pathways).pdf

[44] Energy and Environmental Economics Inc. (E3) The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals Independent Consultant Report DRAFT, at 184 (2022) https://thefutureofgas.com/content/downloads/2.15.22%20-%20DRAFT%20Independent%20Consultant%20Technical%20Report%20-%20Part%20I%20(Decarbonization%20Pathways).pdf

make it more challenging to electrify sectors of the economy more challenging to electrify on a statewide, regional, and national scale.

- DEEP should be asking itself the following questions as it relates to reliance on biofuels. How does accelerated biofuel blending actually move the state closer to achieving net zero GHG emissions by 2050? The strategy may marginally reduce GHG emissions associated with the building sector in the short/medium-term, but is it actually part of a wholistic, cost-effective approach to achieving economy-wide net zero emissions? Will reliance on biofuels delay the development of policy and the deployment of capital that is necessary to support deployment of the technologies (e.g., electrification, energy efficiency) in the building sector at the scale and speed needed to set Connecticut on the most cost-effective path to economy-wide net zero emissions?

### Question 10j: Does reliance on LCB blended in heating fuel create an inadvertent risk of prolonging the use of petroleum in Connecticut?

Yes. It sends a clear signal to the market that heating oil is here to stay rather than shifting the focus as quickly as possible to the solutions like electrification, paired with aggressive energy efficiency, that present the most cost-effective path to decarbonization of the building sector. While the infrastructure required to deliver heating fuels pose less of a stranded asset risk than the gas distribution system as we move towards a decarbonized future, pushing increasing blending rates of biodiesel via policy nonetheless could lead to significant stranded asset risks as consumers invest in long-lasting end uses appliances to handle increasing blends of biodiesel. Redirecting those investments as quickly as possible towards electrification is absolutely essential if Connecticut hopes to minimize the system level costs associated with the transition to net zero emissions.

## Conclusion

Acadia Center thanks DEEP for their work in developing the CES, and we look forward to opportunities to remain engaged as the development of the CES progresses.

Sincerely,

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