November 21, 2022

Sent via email to: DEEP.EnergyBureau@ct.gov

Connecticut Department of Energy and Environmental Protection
Bureau of Energy and Technology Policy
10 Franklin Square
New Britain, CT 06051

Re: Environmental Advocates' Written Comments for 2022 CES Technical Session 6 – Alternative Fuels

Dear Bureau of Energy and Technology Policy,

Thank you for the opportunity to submit comments for the 2022 Comprehensive Energy Strategy (CES) Technical Session 6. Conservation Law Foundation, Save the Sound, Sierra Club, the Nature Conservancy in Connecticut, Eastern CT Green Action, and People's Action for Clean Energy are public interest organizations that are working to align Connecticut's energy policies with the state's statutory climate commitments and decarbonize the electric sector, transportation sector, and buildings sector, which are the three major sources of Connecticut's greenhouse gas (GHG) emissions. We appreciate the opportunity to provide these joint comments and look forward to engaging further in development of the 2022 CES.

As a preliminary matter, the undersigned organizations urge DEEP to further increase opportunities for meaningful public engagement in the CES. Holding the technical sessions online and posting the slides and recordings on DEEP's website is extremely helpful in making these materials more widely available to interested members of the public. However, we are concerned that DEEP has not been posting these materials promptly.[1] They should be posted on DEEP's website as soon as possible following the technical sessions, ideally within the next 1-2 business days. Many, if not most, interested participants cannot devote a full day (or in this case, two consecutive days), to attending technical sessions, even professionals who work on energy issues full-time. Members of the public who are interested in energy issues but do not work in the field may not be able to attend any of the sessions live during regular business hours.

With only a two-week public comment period for Technical Sessions #5 and #6, for which DEEP requested input on over fifteen complex and highly technical questions, there is limited opportunity to provide meaningful public comment. For those who were unable to view the technical sessions live, every day that the slides and recordings remain unavailable further shortens the public comment period and makes it harder for people to comment. Even those who viewed the technical sessions live would benefit from having prompt access to the slides and recordings, as reviewing these materials can help inform public comments. For all of these reasons, DEEP must prioritize posting the slides and recordings promptly following CES

[1] The slides and recordings for Technical Sessions #5 and #6 were posted on November 10, one week after Technical Session #5 (held November 3) and six days after Technical Session #6 (held November 4).

technical sessions. If posting the materials promptly is not possible for some reason, DEEP should extend the public comment period so it starts when the materials are posted.

At a recent meeting of the Governor's Council on Climate Change (GC3) Mitigation Strategies Working Group, which was held on November 7, 2022, DEEP requested input from participants on how to make the CES more accessible and equitable.[2] We recommend that DEEP continue holding CES technical sessions during regular business hours since these sessions are targeted to energy professionals, but DEEP should post the slides and recordings immediately following the technical sessions so anyone can view them on demand. As discussed above, this would facilitate more meaningful opportunities for public engagement in the CES.

In addition to the technical sessions, we encourage DEEP to work on an outreach strategy to engage the broader public in the CES, including environmental justice advocates and residents of environmental justice communities. The Public Utilities Regulatory Authority (PURA) is already trying to increase opportunities for community engagement by holding listening sessions, posting explainer videos, and publishing a newsletter,[3] with a focus on using accessible language and explaining why the public should care. DEEP should speak with PURA's staff to learn more about their approach to public engagement and find out what has been effective. DEEP should also actively solicit further public input on how to effectively engage the public in the CES. In addition to seeking input from potentially interested groups like the GC3, the CEEJAC, and CES participants, DEEP should also reach out to the public more broadly. Meeting people where they are (*e.g.* at local community meetings, places of worship, schools, *etc.*) is one approach that DEEP should use to reach a broader audience. In addition, DEEP should provide funding to support meaningful engagement from environmental justice residents and groups who are interested in the CES (and other proceedings) but may not otherwise be able to participate.

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

a. Renewable natural gas (RNG)

There is a limited supply of refined biogas (often referred to as "renewable" natural gas, or RNG) available for use in Connecticut, and availability is unlikely to increase due to limited supply and due to demand from competing hard-to-electrify sectors in which RNG will be critical. New England has minimal biogas potential. Five of the six New England states, including Connecticut, rank among the twelve states with the least biogas potential.[4] Massachusetts also has limited biogas potential,[5] with one study finding that Massachusetts'

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[2] In addition to requesting input from the GC3, the CEEJAC, and other potentially interested groups, DEEP should also request input directly from participants in the CES, as these stakeholders likely have the greatest familiarity with the proceeding and may have valuable ideas to contribute.

[3] Public Utilities Regulatory Authority, *PURA Releases Debut Public Engagement Newsletter* (Oct. 4, 2022), https://portal.ct.gov/PURA/Press-Releases/2022/PURA-Releases-Debut-Public-Engagement-Newsletter.

[4] National Renewable Energy Laboratory (NREL), *Biogas Potential in the United States*, 3 (Oct. 2013), https://www.nrel.gov/docs/fy14osti/60178.pdf.

[5] *Id.*

annual RNG potential could displace just 10% of its fossil gas demand.[6] Nationally, it is estimated that biogas potential could replace just 5% of fossil gas consumption in the electric sector.[7] Other studies estimate that RNG could meet around 12%[8] or 14%[9] percent of the United States' total gas demand in a high resource potential scenario, with estimates of environmentally sound biogas being as low as 2-5%.[10] In Technical Session #6, Mike Henchen of RMI noted that "RNG potential estimates in Connecticut are just 2-4% of statewide gas demand and 6-12% of buildings demand."[11] Moreover, only 40% of the state's RNG potential could be met through anaerobic digestion—with thermal gasification from various sources, mostly municipal solid waste, accounting for the other 60%.[12] This is deeply concerning from a climate perspective because thermal gasification involves creating new methane, which can then leak and contribute to climate change. There are also serious environmental and environmental justice concerns associated with gasification.

b. Green hydrogen

There is a great deal of interest in the potential for "green" hydrogen[13] as a long-term decarbonization strategy in selected circumstances, most notably hard-to-decarbonize sectors like high-heat industrial processes. However, hydrogen is not a viable pathway to decarbonization for end uses that can be electrified directly, including buildings and most forms of transportation. It is far more efficient and cost-effective to use electricity directly (*e.g.*, to power electric vehicles and electric heat pumps) rather than using it to produce green hydrogen.[14]

"Green" hydrogen is produced using only renewable energy sources to power the electrolysis of water. Currently, electrolysis of water accounts for less than 0.1% of hydrogen

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[6] National Grid, *Renewable Gas - Vision for a Sustainable Gas Network*, 2 (2010), https://www9.nationalgridus.com/non_html/NG_renewable_WP.pdf.

[7] National Renewable Energy Laboratory (NREL), *Biogas Potential in the United States*, 3 (Oct. 2013), https://www.nrel.gov/docs/fy14osti/60178.pdf.

[8] The American Gas Foundation found that in a "high resource potential scenario", 4,510 trillion Btus of RNG would be available in 2040. American Gas Foundation, *Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment*, 2 (2019), https://gasfoundation.org/2019/12/18/renewable-sources-of-natural-gas/. Assuming, as reported by the EIA, the US used 31.5 quadrillion btus of gas in 2020, that amounts to about 12% of current US gas demand. U.S. Energy Information Administration. *Natural Gas Explained*, https://www.eia.gov/energyexplained/natural-gas/use-of-natural-gas.php.

[9] Philip Sheehy *et al.*, *Exploring renewable natural gas as a decarbonization strategy* (2021) https://www.icf.com/insights/energy/renewable-natural-gas-decarbonization-strategy.

[10] Natural Resources Defense Council, *A Pipe Dream or Climate Solution? The Opportunities and Limits of Biogas and Synthetic Gas to Replace Fossil Gas*, 5 (2020), https://www.nrdc.org/resources/pipe-dream-or-climate-solution.

[11] Mike Henchen, RMI, *Low Carbon Fuels' Limited Role in Building Decarbonization*, Slide 55 (Nov. 4, 2022), https://portal.ct.gov/-/media/DEEP/energy/ConserLoadMgmt/Master-Slide-Deck_TM-6_Alt-Fuels_PM.pdf.

[12] *Id.*

[13] Connecticut should limit its support of hydrogen to green hydrogen only. The state should not support increased deployment of hydrogen that is produced using fossil fuels (*e.g.*, via steam methane reformation), including "blue" hydrogen production methods that utilize carbon capture and storage, because these production methods generate significant GHG emissions and are not consistent with the state's climate targets under the GWSA.

[14] Cara Bottorff, Sierra Club, *Challenges with Alternative Fuels and Strategies for Optimal Use*, Slide 63 (labeled Page 65) (Nov. 4, 2022), https://portal.ct.gov/-/media/DEEP/energy/ConserLoadMgmt/Master-Slide-Deck_TM-6_Alt-Fuels_PM.pdf (estimating that "Green hydrogen is 20-40% less efficient than using renewables directly").

production.[15] Globally, less than 0.02% is produced from electrolysis powered purely by renewable electricity."[16] And while production of green hydrogen is likely to increase significantly in coming years, the availability of renewable resources needed to produce green hydrogen will remain a limiting factor. Currently, fossil gas generates 53% of electricity in the New England regional grid.[17] Renewable generation and storage dominate the interconnection queue,[18] but there are questions about how quickly these resources can be integrated into the grid due to factors that are hindering the urgently needed expansion of transmission infrastructure and market reforms that would accelerate the deployment of renewables in the region.

Decarbonizing the grid while maintaining reliability and keeping up with increased electricity demand is already a major challenge. Using electricity to produce green hydrogen would further increase demand and make it harder for New England states to decarbonize the grid and meet their state climate goals. The Massachusetts 2050 Energy Pathways Report found that green hydrogen is unlikely to scale until there are sufficient surplus quantities of renewable electricity for cost-effective production, which the report projected would occur in the 2040s at the earliest.[19] And even in such a scenario, the report found that green hydrogen was likely to be cost-effective only in difficult-to-electrify sectors, with electrification still being more cost-effective in the buildings sector.[20]

c. Biofuels

As jurisdictions continue efforts to address climate change and decarbonize their economies, growing demand for biofuels and the resulting rise in prices for biofuel feedstocks is placing increased pressure on farmers to divert feedstock crops from use as a food source to biofuels.[21] This includes diverting existing soy, corn, and canola crops to biofuels, as well as devoting acreage formerly used for corn to soybeans.

However, we have seen limits to the ability of biofuel feedstocks to keep pace with demand. Even as soybean oil prices hit record prices this year, roughly tripling over the past two years,[22] competing market pressures driven by geopolitical conflicts in eastern Europe have resulted in a significant supply shortage of soybean oil for both consumption and combustion.[23]

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[15] International Energy Agency, *The Future of Hydrogen: Seizing Today's Opportunities*, 42 (2019), https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf.

[16] Sara Gersen & Sasan Saadat, Earthjustice, *Reclaiming Hydrogen for a Renewable Future*, 7 (Aug. 2021), https://earthjustice.org/sites/default/files/files/hydrogen_earthjustice_2021.pdf.

[17] ISO-New England, *Resource Mix*, https://www.iso-ne.com/about/key-stats/resource-mix.

[18] ISO-New England, *Generator Interconnection Queue*, https://irtt.iso-ne.com/reports/external.

[19] Buildings Sector Report: A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study, 5 (2020), https://www.mass.gov/doc/building-sector-technical-report/download.

[20] *Id.* at 103.

[21] We note that this comes at a time when the world's population has just surpassed 8 billion. By 2050, the world's population is expected to be nearly 10 billion. UNCTAD, "Now 8 billion and counting: where the world's population has grown most and why that matters" (Nov. 15, 2022), https://unctad.org/data-visualization/now-8-billion-and-counting-where-worlds-population-has-grown-most-and-why#:~:text=According%20to%20UN%20estimates%2C%20the,one%20third%2C%20or%202.1%20billion.

[22] Matthew Sedacca, The Counter, *How war, weather, and Covid-19 are rekindling the food vs. fuel debate* (Mar. 31, 2022), https://thecounter.org/ukraine-biden-oil-us-reserves-biofuel-rfs-ethanol-soybean/.

[23] Nelson Low, Institutional Investor, *Edible Oils are Facing a Supply Crunch* (Aug. 8, 2022), https://www.institutionalinvestor.com/article/b1z5xhxrzdgld4/edible-oils-are-facing-a-supply-crunch.

Unpredictable weather, such as droughts, can also limit the availability of feedstocks. Demand for edible oils that serve as biofuel feedstock is anticipated to grow at a compound rate of 7.6% over the next seven years, placing further supply pressure on the market.[24]

2. **Which alternative fuels are likely to be limited due to infrastructure costs over the next 30 years? Why?**

a. Renewable natural gas (RNG)

RNG is expensive to produce or procure, and its consumer price is approximately three times the price of fossil gas.[25] The infrastructure costs associated with RNG are substantial and huge investments would be needed to ramp up supply, which is limited (see response to Question 1(a), *supra*). All three of New England's current RNG projects had high startup costs,[26] and new facilities would likely face steep cost hurdles as well.

The production and procurement costs for RNG vary widely. It costs between $3.00 and $30.00 per MMBtu to produce RNG.[27] At its cheapest, RNG production can cost less than fossil gas, which ranges from $2.52 to $4.37 per MMBtu.[28] However, RNG production estimates often exclude the cost of removing siloxanes from RNG produced with consumer waste, so lower costs may not be feasible.[29] Importing RNG is also costly: imported RNG costs between $12 and $25 per Mcf, while imported fossil gas costs $3 per Mcf.[30] If Connecticut increases its use of RNG, it would be costly whether the gas is produced in-state or imported from elsewhere.

RNG mostly consists of methane and is just as harmful from a climate perspective as fossil gas when it leaks into the atmosphere. For this reason, leak prevention is critical to ensure that any increased use of RNG results in emissions reductions. Preventing such leakage would lead to more infrastructure costs, such as replacing leaky pipelines and upgrading equipment.

b. Green hydrogen

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[24] *Id.*

[25] Programs Manual – Vermont Gas Systems, 10 (Aug. 20, 2019), https://www.vermontgas.com/wp-content/uploads/2018/09/VGS-RNG-Manual-Final-V-1.01.pdf.

[26] University of New Hampshire, *Cogeneration and EcoLine*, https://www.unh.edu/sustainability/operations/energy/ecoline (landfill RNG project cost $49 million); Elizabeth Gribkoff, VT Digger, *Partners Hail Groundbreaking of Salisbury Biodigester* (Aug. 20, 2019) https://vtdigger.org/2019/08/20/partners-hail-groundbreaking-of-salisbury-biodigester/ (Goodrich Farm project cost $20 million); Summit Natural Gas Maine, *Summit Announces Renewable Natural Gas Initiative*, (May 23, 2019), https://summitnaturalgasmaine.com/SummitAnnouncesRenewableNaturalGasInitiative (Summit Maine project projected to cost $20 million).

[27] Rebecca Gasper & Tim Searchinger, World Resources Institute, *The Production and Use of Waste-Derived Renewable Natural Gas as a Climate Strategy in the United States*, 24 (Apr. 2018), https://www.wri.org/publication/renewable-natural-gas.

[28] *Id.* at 23.

[29] Gregory Von Wald *et al.*, *Biomethane in California Common Carrier Pipelines: Assessing Heating Value and Maximum Siloxane Specifications*, 70 (June 2018), https://ccst.us/wp-content/uploads/2018biomethane.pdf.

[30] Vermont Public Service Board, Docket No. 8667, Petition of Vermont Gas Systems, Prefiled Testimony of Thomas Murray on Behalf of Vermont Gas Systems, 8-9:21-1 (Oct. 23, 2015).

There are significant safety and infrastructure concerns associated with hydrogen due to its higher flammability and leakage rates.[31] Upgrading existing gas infrastructure and appliances to safely transport and use hydrogen in the building sector would require enormous investments, which do not make economic sense given the need to prioritize hydrogen for hard-to-decarbonize applications. While costs are likely to decline over time given the substantial investment in green hydrogen production and deployment, such a massive overhaul of existing infrastructure would take many years, at a time when emissions reductions must be achieved as quickly as possible. Use of green hydrogen in the building sector does not make sense from a cost perspective and would not reduce emissions at the speed and scope needed to meet state climate goals.

Hydrogen can cause pipe embrittlement and cannot safely be transported through many existing gas pipelines.[32] While estimates may vary by distribution system, hydrogen cannot be blended into the gas distribution system at high volumes. An empirical study of hydrogen blending conducted this year by the California Public Utilities Commission found that a "systemwide blending injection scenario becomes concerning as hydrogen blending approaches 5% by volume."[33] In Connecticut, over 50% of gas mains are made of steel or iron, which cannot be used to transport a high level of hydrogen.[34] Upgrading or replacing these pipelines so they could be safely used for hydrogen would be enormously expensive: "[b]uilding a hydrogen pipeline can cost up to 68% more per mile than a conventional fossil gas pipeline."[35] Using truck or rail transport would also be expensive because hydrogen must be highly compressed, making these options realistic only for smaller volumes of hydrogen.[36]

In addition, there are limits on how much hydrogen can be used in home appliances like furnaces and boilers. Appliances that were designed for methane gas cannot safely accommodate a high level of hydrogen.[37] Most equipment can only use a blend of up to 25% hydrogen.[38] Such a low level of hydrogen blending has limited emissions benefits (even assuming green hydrogen is used), because the remaining 75% of fuel would still be methane. Replacing the equipment so it can accommodate higher levels of hydrogen would be more costly than simply switching to an electric heat pump because there are so many associated infrastructure upgrades needed to safely transport and use high levels of hydrogen to heat buildings. And, as Mike Henchen of RMI noted during Technical Session #6, using hydrogen to heat buildings "would require significantly more

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[31] Sara Gersen & Sasan Saadat, Earthjustice, *Reclaiming Hydrogen for a Renewable Future*, 19 (Aug. 2021), https://earthjustice.org/sites/default/files/files/hydrogen_earthjustice_2021.pdf.
[32] *Id.*
[33] California Public Utilities Commission, Rulemaking No. R.13-02-008, Hydrogen Blending Impacts Study: Final Report (July 18, 2022).
[34] Mike Henchen, RMI, *Low Carbon Fuels' Limited Role in Building Decarbonization*, Slide 53 (Nov. 4, 2022), https://portal.ct.gov/-/media/DEEP/energy/ConserLoadMgmt/Master-Slide-Deck_TM-6_Alt-Fuels_PM.pdf.
[35] Sara Gersen & Sasan Saadat, Earthjustice, *Reclaiming Hydrogen for a Renewable Future*, 19 (Aug. 2021), https://earthjustice.org/sites/default/files/files/hydrogen_earthjustice_2021.pdf (citing Julien Dumoulin-Smith et al., US Alternative Energy, Bank of America, at 4 (June 28, 2021).
[36] *Id.*
[37] *Id.* at 27; Jairo Duran, *Safety Issues to Consider When Blending Hydrogen with Natural Gas* (Feb. 17, 2021), https://processecology.com/articles/safety-issues-to-consider-when-blending-hydrogen-with-natural-gas.
[38] Jeff St. John, Green Tech Media, *Green Hydrogen in Natural Gas Pipelines: Decarbonization Solution or Pipe Dream?* (Nov. 30, 2020), https://www.greentechmedia.com/articles/read/green-hydrogen-in-natural-gas-pipelines-decarbonization-solution-or-pipe-dream.

energy input than heating with an electric heat pump" because producing green hydrogen and using it for heating is much less efficient than using electricity directly.[39]

3. What other factors (beyond feedstocks and infrastructure) may limit the availability of affordable alternative fuel supplies during the next 30 years? Why?

Market demand will influence the availability of alternative fuel supplies in Connecticut in the coming decades. For example, the European Union has been a substantial market for U.S. produced biomass, and this demand has led to increased biomass production in the United States, notably in the southeast.[40] As market demand shifts within the U.S. and internationally, this will impact the availability and cost of alternative fuels in Connecticut and the northeast.

Evolving understanding of the GHG emissions and environmental impacts associated with alternative fuels may lead jurisdictions to stop supporting these fuels. Such policy changes would affect the availability and cost of alternative fuels. For example, Massachusetts recently revised its Renewable Portfolio Standard (RPS) to disqualify biomass facilities that are located in environmental justice communities or operate at less than 60% efficiency.[41]

Connecticut should revise its RPS so biomass no longer qualifies as a renewable resource. Continued inclusion of biomass under the RPS is at odds with state climate goals because the production and use of biomass generates substantial emissions and environmental harms. Notably, the Connecticut RPS directly supports the continued operation of two biomass facilities in Vermont, one of which is located between two environmental justice communities and negatively impacts the health and wellbeing of residents. These facilities would likely become uneconomic and stop operating if they became ineligible for renewable energy certificates under the Connecticut RPS. Continued support of biomass under the RPS is inconsistent with Connecticut's climate goals and its stated commitment to equity and environmental justice.

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

As several speakers discussed during the panel on strategies for optimal use of alternative fuels, alternative fuels should be limited to hard-to-decarbonize applications that cannot easily or cost-effectively be electrified. Tessa Weiss of RMI explained, "Direct electrification should be prioritized [over alternative fuels] whenever possible—it is more efficient, cheaper, and can bring human health and broader environmental benefits."[42]

Appropriate end uses for hydrogen are currently an important subject of discussion at the Connecticut hydrogen task force, which has a working group focused on this topic. The working

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[39] Mike Henchen, RMI, *Low Carbon Fuels' Limited Role in Building Decarbonization*, Slide 51 (Nov. 4, 2022), https://portal.ct.gov/-/media/DEEP/energy/ConserLoadMgmt/Master-Slide-Deck_TM-6_Alt-Fuels_PM.pdf.

[40] Saul Elbein, Vox, *Europe's renewable energy policy is built on burning American trees* (Mar. 4, 2019), https://www.vox.com/science-and-health/2019/3/4/18216045/renewable-energy-wood-pellets-biomass.

[41] Massachusetts Department of Energy Resources, *2019 RPS Class I & II Rulemaking*, https://www.mass.gov/service-details/2019-rps-class-i-ii-rulemaking.

[42] Tessa Weiss, RMI, *Why Prioritize Low Carbon Fuels for Industry and Heavy Transport?*, Slide 127 (Nov. 4, 2022), https://portal.ct.gov/-/media/DEEP/energy/ConserLoadMgmt/Master-Slide-Deck_TM-6_Alt-Fuels_PM.pdf.

group's draft list of the **lowest**-priority applications for hydrogen includes "hydrogen blending [in existing gas infrastructure to heat buildings] for residential and commercial customers, commuter [transit] buses, heavy duty trucks with lower daily driving ranges, privately-owned light-duty vehicles, low-heat industrial processes, and short-haul aviation."[43] We agree that these are low-value applications for green hydrogen and Connecticut should not pursue them.

High priority applications for green hydrogen include high-heat industrial processes, aviation, maritime, and long-haul trucking (see response to Question #5, *infra*).[44] Given the early stage of green hydrogen deployment and pending processes at the state and regional level (*i.e.*, the Connecticut Hydrogen Task Force and the northeast regional hydrogen hub proposal), it is premature for Connecticut to establish specific policies related to these high priority applications in the 2022 CES. The CES should identify likely high priority applications for green hydrogen and discuss how ongoing processes and developments at the state, regional, national, and international levels will inform the state's approach to hydrogen policy.

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

As discussed at Technical Session #6, hydrogen makes the most sense for long-haul heavy duty trucks (Class 8). These trucks are the heaviest class of vehicle and cannot easily be electrified because they would require such large batteries (which are also heavy) and because their long travel routes and strict schedules are less amenable to regular charging patterns than most other types of vehicles,[45] including school buses, transit buses, most other medium-and heavy-duty vehicles, and light-duty vehicles.

Coordinated deployment of hydrogen fueling stations for heavy duty trucks along Connecticut's existing alternative fuel corridors (and potentially other routes as needed) could help accelerate a shift away from diesel trucks. Policies that will accelerate a transition to clean trucks, most notably California's Advanced Clean Trucks Rule (ACT), will be critical to speed up the adoption of both electric and hydrogen fuel cell trucks. Notably, New York, New Jersey, and Massachusetts have already adopted the ACT, Vermont is on the cusp of doing so, and Connecticut is expected to adopt the rule in 2023. Connecticut should coordinate with these neighboring states and others in the region on developing the infrastructure needed to accommodate increasing numbers of electric trucks and hydrogen fuel cell trucks. Establishing an adequate supply of green hydrogen will be critical to ensure that increased deployment of hydrogen fuel cell trucks (and other uses of hydrogen) results in emissions reductions. This

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[43] Connecticut Hydrogen Task Force Meeting Presentation, Working Group Updates, Slide 28 (Nov. 8. 2022), https://www.ctgreenbank.com/wp-content/uploads/2022/11/SA-22-8_Hydrogen-Power-Study-Task-Force_110822.pdf.

[44] *Id.*, *see also* Tessa Weiss, RMI, *Why Prioritize Low Carbon Fuels for Industry and Heavy Transport?*, Slide 131 (Nov. 4, 2022), https://portal.ct.gov/-/media/DEEP/energy/ConserLoadMgmt/Master-Slide-Deck_TM-6_Alt-Fuels_PM.pdf.

[45] *See, e.g.*, Bernd Heid, Christopher Martens, & Markus Wilthaner, McKinsey & Company, *Unlocking hydrogen's power for long-haul freight transport* (Aug. 2, 2022), https://www.mckinsey.com/capabilities/operations/our-insights/global-infrastructure-initiative/voices/unlocking-hydrogens-power-for-long-haul-freight-transport.

consideration should be a central component of the northeastern states' regional hydrogen hub proposal and their hydrogen policies.

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

As discussed in response to Question #5, *supra*, hydrogen makes sense as a transportation fuel in the limited context of heavy duty long-haul trucking. Other types of alternative fuels are not a viable decarbonization strategy for vehicles because electrification is much more efficient and cost-effective. Connecticut should remain focused on electrifying the transportation sector and should not support or invest in alternative fuels for vehicles other than green hydrogen for heavy duty long-haul trucking.

7. What should DEEP regard as best practices for the production, delivery, storage, and use of alternative fuels? Where are these best practices in effect?

Best practices for the production, delivery, storage, and use of green hydrogen are still in development.[46] Given the safety concerns associated with hydrogen transport and use, following best practices will be critical to minimize the chances of explosions and other safety risks.

Methane-based biofuels, such as biogas and RNG, also present significant risks of leaking methane, a greenhouse gas that is more than 80 times more potent than carbon dioxide when it remains in the atmosphere. The production, storage, and transport of biogas and RNG is associated with substantial methane leaks.[47]

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?

This question implicitly assumes that Connecticut will be using alternative fuels more widely in the future. This assumption is problematic. Some increase does appear likely given the state's interest in the deployment of green hydrogen and current state law requiring biofuels to be blended with heating oil. However, there are significant challenges associated with scaling up the use of alternative fuels, including high costs and substantial infrastructure changes. Most notably from a climate perspective, alternative fuels can result in substantial GHG emissions depending on the method of production and the end use of these fuels, and they could prolong Connecticut's reliance on fossil fuels like natural gas and heating oil. For these reasons, discussed throughout these comments and during Technical Session #6, Connecticut should strategically plan for the increased use of alternative fuels only in circumstances where those fuels are the best means of decarbonizing specific end uses, such as hard-to-decarbonize sectors like aviation and high-heat industrial processes.

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[46] U.S. Dept. of Energy, Hydrogen and Fuel Cell Technologies Office, *Regulations, Guidelines, and Codes and Standards*, https://www.energy.gov/eere/fuelcells/regulations-guidelines-and-codes-and-standards.

[47] Bakkaloglu *et al*, *Methane Emissions Along Biomethane and Biogas Supply Chains Are Underestimated*, 5 One Earth 724-736 (2022); Emily Grubert, *At Scale, Renewable Natural Gas Systems Could be Climate Intensive: the Influence of Methane Feedstock and Leakage Rates,* Environ. Res. Lett. 15 (2020).

Connecticut must develop a plan for a managed transition away from "liquid and gaseous fuel" in alignment with state climate targets. "Potential reductions" will not be enough: the state must dramatically reduce its reliance on fossil gas and petroleum oil. Simply supplementing or attempting to replace these fossil fuels with alternative fuels like RNG and biofuels will not achieve the level of emissions reductions that are required under the GWSA.

Workforce development opportunities should be established that will help facilitate an equitable transition to a clean energy economy. To that end, Connecticut should focus on creating opportunities for populations that face systemic discrimination and/or are underrepresented in the workforce, including women, minorities, and formerly incarcerated individuals. Career pathways should be made available to people who currently work in the fossil fuel industry, such as heating oil dealers, gas station owners, and contractors who install gas or oil heating equipment. These people have strong incentives to oppose a transition away from fossil fuels, so policies that realign their incentives with Connecticut's climate and energy policies would be helpful.

9. Can alternative fuels help to insulate Connecticut from volatility in the global petroleum markets? If so, how?

Biofuels, like fossil fuels, are commodities that are subject to commodity market fluctuations and volatility.[48] Relying on imported biofuels would subject Connecticut to biofuel market volatility. Moreover, there is limited potential for alternative fuels in the buildings sector to insulate Connecticut from global fossil oil market volatility. Blending biofuels with petroleum heating oil does little to reduce the state's dependence on heating oil because the blending rate is so low, at just 5% biofuel and **95%** heating oil. It is unlikely that the percentage of biofuel will exceed the percentage of heating oil within the next 10-15 years, given numerous infrastructure and cost constraints associated with increased deployment of biofuels. In addition, the state's biofuel blending law contemplates no more than a 50-50 blend by 2035. Finally, the amount of oil used to heat buildings in Connecticut is vanishingly small compared to overall oil demand, since oil is mostly used for transportation and industrial uses.[49] Even a 100% biofuel mandate (eliminating the use of heating oil in Connecticut) would not insulate the state from volatility in global oil markets.

In the light-duty transportation sector, there is little opportunity for alternative fuels to insulate Connecticut from volatility in the global oil market. Current blending requirements for ethanol have not provided this insulating effect. Hydrogen will play a role in decarbonizing the transportation sector, but its application for light-duty vehicles is limited and the penetration of hydrogen fuel cell vehicles is so low (and expected to remain low) that any insulating effects are speculative at best. Utilizing hydrogen for certain harder to electrify applications, like long-haul trucking, would help reduce Connecticut's reliance on diesel, but would not make a substantial dent in the state's overall oil demand.

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[48] Paul Wightman et al, Global Feedstock Volatility Intensifies for Biofuels, CME Group (May 10, 2021), https://www.cmegroup.com/education/articles-and-reports/global-feedstock-volatility-intensifies-for-biofuels.html.
[49] U.S. Energy Information Administration, *Oil and petroleum products explained: use of oil*, https://www.eia.gov/energyexplained/oil-and-petroleum-products/use-of-oil.php.

Electrification, which is the most efficient and cost-effective strategy to decarbonize the transportation and building sectors, also has the greatest potential to insulate Connecticut from volatility in the global oil market. Oil currently accounts for just 0.2% of electric generation in the region, though its use can temporarily be much higher during times of peak demand.[50] As New England continues decarbonizing the electric sector and replacing oil and gas generation with renewables and storage, the region will become increasingly energy independent. Wind, solar, and battery storage already dominate the ISO-New England interconnection queue.[51] These energy resources, along with complementary energy efficiency and demand response measures, can all be produced in the region. In contrast, oil and gas are volatile international commodities that must be imported from outside New England. The widespread electrification of buildings and transportation has enormous potential to reduce Connecticut's reliance on foreign oil and insulate the state from volatility in global oil markets. Alternative fuels do not.

10. Questions regarding "low-carbon biofuels" (LCBs) such as biodiesel:

a. 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?

Under Connecticut's current blending mandate, heating oil sold in the state must contain 5% biofuel.[52] The minimum percentage of biofuel increases to 10% in 2025, 15% in 2030, 20% in 2034, and 50% in 2035.[53] The 50% blending mandate is not environmentally responsible, nor is it technically realistic.

As explained further in response to Question 10(j), *infra*, the blending mandate risks prolonging Connecticut's reliance on heating oil. Extending the use of emissions intensive fossil fuels is inconsistent with the state's climate targets under the GWSA. Further, as several speakers discussed during Technical Session #6, biofuels themselves are not climate neutral. At the point of combustion, biofuels emit approximately the same amount of carbon dioxide as their fossil fuel counterparts, and there are emissions associated with biofuel production and transport. If demand for biofuels increases, more nonagricultural land would be converted to grow biofuel feedstocks. Such land use changes are already a significant source of GHG emissions.

As discussed further in response to Question 10(g), *infra*, it probably is not technically feasible to achieve a 50% biofuel blend without replacing current oil-burning appliances, some of which would have to be replaced before the end of their useful lives. This would be expensive and would further prolong the use of heating oil in Connecticut. Any new oil-burning furnace or boiler that is installed is likely to continue operating for the rest of its useful life (10-15 years, or even 20 years in some circumstances) and generating GHG emissions that will make it harder for Connecticut to meet state climate goals.

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[50] ISO-New England, *Resource Mix*, https://www.iso-ne.com/about/key-stats/resource-mix.

[51] ISO-New England, *Generator Interconnection Queue*, https://irtt.iso-ne.com/reports/external; *see also* ISO-New England, *A queue and a curve: Signs in New England of a greener grid this Earth Day* (Apr. 22, 2021), https://isonewswire.com/2021/04/22/a-queue-and-a-curve-signs-in-new-england-of-a-greener-grid-this-earth-day/.

[52] Conn. Gen. Stat. Sec. 16a-21b(b).

[53] *Id.*

The feasibility of the timeline required under this statute is also questionable. The 2034 blending requirement is 20%, which more than doubles to a 50% requirement the following year. Even if the 20% requirement is met, which is theoretically possible using current infrastructure, it is unlikely that all oil burning appliances remaining in the state could be replaced or upgraded in a single year so they could burn a 50% biofuel blend starting in 2035. Even if this is doable, it would be costly from both a financial perspective and a climate perspective.

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

Connecticut should not require biofuel blends that exceed 50% if this would require oil burning appliances to be replaced, because replacing these appliances would be costly and would prolong the state's reliance on heating oil. As discussed elsewhere in these comments, it is likely that a 50% blend (or greater) would require current equipment to be replaced.

c. Would a low-carbon fuel standard be more efficient than a blending mandate?

As explained elsewhere in these comments, the biofuel blending mandate is a poorly designed policy to reduce emissions from the thermal sector, and Connecticut should consider repealing or at least substantially modifying this policy. Alternative policies to reduce emissions from the thermal sector in line with the state's binding climate targets should be considered in the 2022 CES.

A low-carbon fuel standard (LCFS) is probably not the most efficient policy option to address thermal sector emissions in Connecticut. LCFSs in other jurisdictions focus on reducing emissions from the transportation sector, which raises substantially different considerations than the buildings sector. Designing a Connecticut LCFS aimed at reducing emissions from buildings would be challenging from both a technical and policy perspective, which would likely delay program implementation. The challenges associated with this approach make it a less viable option for reducing Connecticut's building sector emissions, at least in the near term.

A clean heat standard is a related option that Connecticut should consider. A clean heat standard takes aspects of a LCFS and uses them to create a performance standard (*e.g.*, tradeable credits associated with GHG reductions) in the thermal sector. There are substantial risks with this approach, however. A poorly designed clean heat standard could incentivize increased use of alternative fuels that do not reduce emissions, slowing down the state's progress in decarbonizing the buildings sector. DEEP should hold a technical session and solicit comments on developing a clean heat standard for Connecticut that is explicitly aligned with state climate targets and that would effectively reduce emissions.

Accurate GHG emissions accounting is critical to ensure that a clean heat standard results in actual and verifiable emissions reductions. Faulty accounting could overstate GHG reductions and might lead to *increased* emissions in some circumstances. This raises some considerations that Connecticut would have to address before a clean heat standard could be implemented.

First, biofuels that are combusted in Connecticut's thermal sector are assumed to be zero carbon in the state's GHG inventory, even though there are CO_2 emissions associated with these fuels. That means, for example, that every gallon of biodiesel that replaces a gallon of fossil diesel will look like it has reduced CO_2 emissions 100%, when that is not actually true. To prevent this, Connecticut would have to more accurately account for biogenic emissions in the state's GHG inventory. Without such reforms, a clean heat standard would make it look like GHG emissions were decreasing dramatically in the thermal sector, when in fact the reductions were more modest.

Second, a reliable GHG lifecycle tool is necessary to accurately determine clean heat credits. The credits would be determined by subtracting the lifecycle GHG emissions associated with a clean heat measure (*e.g.*, a biofuel[54] or the electricity used to operate a heat pump) from the lifecycle GHG emissions of the fossil fuel the clean heat measure is replacing. The larger the difference, the more credits would be awarded. An accurate GHG lifecycle analysis is critical to ensure that clean heat credits reflect actual emissions reductions.

There are also real concerns about using a lifecycle measure to assign credit values to alternative fuels specifically. Those concerns include: (1) promoting the creation of methane that would not otherwise exist but for the increased demand for RNG under the clean heat standard and the RNG subsidy created by clean heat credits; (2) promoting deforestation and grassland conversion to create additional biofuel croplands, thereby releasing stored carbon; (3) converting food crops (*e.g.*, soy and corn) into biofuel crops, which can increase food prices and disproportionately impact low-income people; and (4) increasing air and water pollution because of the need for additional fertilizers and the resultant runoff pollution.

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

Yes, Connecticut should consider restricting the sale of biodiesel based on the feedstock that was used to produce it. The feedstock is one of the most important factors determining the emissions intensity of biofuels on a lifecycle basis. For example, used cooking oil and similar commodities are waste products and may reduce emissions when used as a feedstock for biofuels.[55] However, as a waste by-product this feedstock is not sensitive to increased biofuel demand, so additional feedstocks would likely need to be utilized once demand for biofuels passes a certain threshold. Using land to grow biofuel crops like soybeans is more emissions

[54] Because biofuels have approximately the same GHG emissions as fossil fuels at the point of combustion, a reliable lifecycle measure would have to demonstrate that biofuels produce fewer emissions than fossil fuels for them to be eligible for clean heat credits.

[55] But in terms of enforcement, used cooking oil [UCO] currently poses a problem. As the European Commission has noted, "it is relatively easy to artificially modify vegetable oil to make it indistinguishable from genuine UCO." CE Delft, *Used Cooking Oil (UCO) as biofuel feedstock in the EU*, Transport & Environment (December 2020), https://www.transportenvironment.org/wp-content/uploads/2021/07/CE_Delft__200247_UCO_as_biofuel_feedstock_in_EU_FINAL%20-%20v5_0.pdf. When UCO prices are higher than prices for virgin oil, suppliers are incentivized to commit fraud, and challenges with traceability and transparency compound the problem. *See* Sarantis Michalopoulos, *Industry source: one third of used cooking oil in Europe is fraudulent*, Euractiv (26 June 2019), https://www.euractiv.com/section/agrifuels/news/industry-source-one-third-of-used-cooking-oil-in-europe-is-fraudulent/.

intensive than using waste products as a biofuel feedstock,[56] as Tim Searchinger explained in his presentation at Technical Session #6.[57]

Connecticut should not allow biodiesel produced from feedstocks with high lifecycle GHG emissions to be sold in the state. The threshold would need to be determined after a robust public process in which DEEP: (1) assesses available data on feedstock emissions intensity and environmental impacts, and (2) considers how other jurisdictions address the issue. For example, California, Washington, and Oregon, which have a low carbon fuel standard, already assess the emissions intensity of various feedstocks, and Europe is planning to phase out certain types of feedstocks for biofuels.[58] Connecticut should learn from these jurisdictions in developing an approach to minimize the emissions and environmental impacts of biofuel feedstocks.

e. The statute defines eligible biofuels as those "meeting the standards for advanced biofuels under the federal Renewable Fuel Standard Program, requiring a fifty per cent reduction in lifecycle greenhouse gas emissions..." Is qualification under the Renewable Fuel Standard Program an adequate basis for biofuels sold in Connecticut?

No, qualification under the federal Renewable Fuel Standard (RFS) is not an adequate standard for biofuels sold in Connecticut. Direct and indirect induced land use-change is a significant factor impacting the sustainability and lifecycle GHG emissions of biofuels.[59] While the RFS recognizes the impact that land use conversion has on the calculation of emissions from the use of biofuels,[60] the RFS does not require biofuel producers to demonstrate that their feedstock does not cause direct land-use changes.[61] In contrast, the European Union's renewable energy directive (RED) (which, *inter alia*, prohibits the use of biofuels derived from crops grown on land that was forested in 2008) does require biofuel producers to demonstrate that the feedstock was not produced on land that recently stored significant amounts of carbon.[62]

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[56] Oregon Department of Environmental Quality, *Oregon Clean Fuels Program: Program Review*, 11 (Feb. 1, 2022), https://www.oregon.gov/deq/ghgp/Documents/CFP-ProgramReview.pdf.
[57] Tim Searchinger, *Bioenergy*, Slide 24 (Nov. 4, 2022), https://portal.ct.gov/-/media/DEEP/energy/ConserLoadMgmt/Master-Slide-Deck_TM-6_Alt-Fuels_PM.pdf.
[58] The EU's Renewable Energy Directive II will phase out feedstocks with a high risk of indirect land-use change (e.g. palm) by 2030. *See* Stephanie Searle & Jacopo Giuntoli, *Analysis of high and low indirect land-use change definitions in European Union renewable fuel policy*, The International Council on Clean Transportation (February 2018), https://theicct.org/sites/default/files/publications/High_low_ILUC_risk_EU_20181115.pdf. Similarly, several European countries (France, Belgium, Denmark, and the Netherlands) have already moved to phase out palm and soybean oil as feedstocks for biofuels, at least in the transport sector. Brussels Times, *Belgium to ban soy and palm oil in biofuels from 2022* (Apr. 12, 2021), https://www.brusselstimes.com/164687/belgium-to-ban-soy-and-palm-oil-in-biofuels-from-2022-environment-climate-zakia-khattabi-sustainability-amsterdam-declatation-partnership.
[59] *See* Stephanie Searle, The International Council on Clean Transportation, *How rapeseed and soy biodiesel drive oil palm expansion* (July 2017), https://theicct.org/wp-content/uploads/2021/06/Oil-palm-expansion_ICCT-Briefing_27072017_vF.pdf; Searle & Giuntoli, *supra* note 56.
[60] *See, e.g.*, definition of "Renewable biomass" at 40 C.F.R. § 80.1401 (2022).
[61] The International Council on Clean Transportation, *A Comparison of Induced Land-Use Change Emissions Estimates from Energy Crops* 9 (February 2018), https://theicct.org/wp-content/uploads/2021/06/ILUC-energy-crops_ICCT-White-Paper_06022018_vF1.pdf.
[62] *Id*. at 8-9.

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?

As Professor Tim Searchinger described during his presentation at Technical Session #6, this accounting practice is *only* effective from a global perspective, and only if GHG emissions are properly accounted for where the biofuel feedstock is grown. Under this practice, emissions are counted once where a feedstock is grown and harvested, but not again when the feedstock is burned as a biofuel. This avoids double counting emissions *at the global level*. However, this accounting practice is deeply problematic on the level of individual jurisdictions.

This accounting practice enables jurisdictions that burn, but do not grow, biofuels to disclaim any responsibility for the emissions that occur at the point of combustion. The burning jurisdiction can claim that the biofuels have net-zero emissions, but this is only accurate (1) from a global perspective, and (2) *if the growing jurisdiction properly accounts for emissions* from growing the feedstock, plus the upstream emissions that result from producing, refining, and transporting the biofuel. If a jurisdiction where a biofuel feedstock is grown does not factor in the opportunity cost of land used for biofuel crops, for example, then total emissions are *not* accounted for, and the burning jurisdiction cannot accurately claim that the biofuels have net-zero emissions.

In most instances, the growing jurisdiction probably is not properly accounting for the emissions associated with growing the biofuel, or the other upstream emissions from producing and transporting the biofuel, and the burning jurisdiction has zero incentive to determine whether these emissions are being counted. They can simply point to the international norm and claim that burning biofuels results in no net emissions. Through this faulty accounting, jurisdictions that burn biofuels can appear to greatly reduce their carbon footprint while making no substantial emissions reductions.[63] To avoid falling into this trap, Connecticut should include the emissions from burning biofuels in its GHG inventory *unless* the best available information indicates that the emissions from growing, refining, and transporting the biofuels have already been properly counted by the jurisdiction where they were grown.

g. Does incorporation of biodiesel in heating fuel have the potential to negatively impact components of older or new heating oil combustion systems (e.g., tanks, burners, gaskets)? What level of biodiesel blending do new system component warranties commonly cover? Are system warranties expected to change in the next 5 to 10 years?

This hinges on the percentage of biodiesel in the blend. Right now, biodiesel/heating oil mixes at the B5 level are commonly used across New England, including Connecticut. But as the

[63] Further, this accounting failure likely induces a greater reliance on biofuels at the expense of truly zero-emissions resources, effectively increasing localized air pollution impacts due to the increased combustion of these fuels.

U.S. Energy Information Administration observes, "Biodiesel is a good solvent that can degrade rubber in fuel lines and loosen or dissolve varnish and sediments in petroleum diesel fuel tanks, pipelines, and in engine fuel systems, which can clog engine fuel filters."[64] As the proportion of blended biodiesel increases, additional mechanical problems may arise. Brookhaven National Laboratory's survey of the use of B20 to B100 blends as heating oil enumerates some of these potential complications—such as malfunctioning flame sensors in biodiesel blends greater than 50% (which requires recalibration), and how degraded biodiesel (which is highly acidic) has the potential to damage the oil pump shaft seal.[65] However, issues like malfunctioning flame sensors at a 50% blend are largely academic at the moment, given existing infrastructure impediments to biodiesel blends above 20% and the fact that ASTM Standard Specification for Fuel Oils D396 heating oil specification limits biodiesel blends to 20% in most situations.[66]

From a warranty perspective, many manufacturers exclude biodiesel blends greater than 20%. The dominant oil burner pump manufacturer is Suntec Industries, which in 2014 held "an estimated 90% market share."[67] As of 2020, Suntec's current Warranty and Returned Goods Policy reads in relevant part: "Biodiesel acts as solvent and may entrain deposits and residues of the tank or the pipes, which will end up in the pump. Some mechanical components may get stuck and the warranty of B20 pump would not apply in this case. No warranty applies if [a] pump is operated with blends higher than B20 or non ASTM fuels."[68] As another example, the burner manufacturer RW Beckett Corp. specifies that "damages caused by fuel are not covered by this warranty" but notes that "[p]roducts marked as B20 compliant may additionally be used with ASTM D396 Grade B6-B20 biodiesel."[69]

h. Is gelling of biodiesel in outdoor fuel tanks during cold weather an issue that should be addressed in regulating the use of LCBs?

Yes. Because biodiesel gels at higher temperatures than petroleum diesel, it struggles to perform effectively in cold weather conditions. As the National Oilheat Research Alliance Technology Conference observed, "B100 freezes at 25 to 35 F, and blends of biodiesel and diesel fuel exhibit higher cloud and pour points compared to diesel or heating oil alone. Mixing with kerosene has a positive impact on cold weather properties and it is common practice to transport biodiesel as a 50:50 blend with kerosene in the wintertime. Most cold flow additives tend to work only on the petroleum portion of blends and not at all on B100."[70]

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[64] U.S. Energy Information Administration, *Biodiesel, renewable diesel, and other biofuels*, https://www.eia.gov/energyexplained/biofuels/biodiesel-rd-other-use-supply.php.
[65] U.S. Department of Energy Office of Scientific and Technical Information, *B20 to B100 Blends as Heating Fuels*, https://www.osti.gov/biblio/1526692.
[66] US Department of Energy Alternative Fuels Data Center, *Biodiesel Codes, Standards, and Safety*, https://afdc.energy.gov/fuels/biodiesel_codes.html.
[67] U.S. Department of Energy Office of Scientific and Technical Information, *B20 to B100 Blends as Heating Fuels*, https://www.osti.gov/biblio/1526692.
[68] Suntec, *Warranty and Returned Goods Policy*, https://www.suntec.fr/wp-content/uploads/2018/12/US-SUNTEC-Warranty-and-Returned-Goods-Nov-10-2020.pdf
[69] Beckett Corporation, *Limited Warranty For Beckett Products*, https://www.beckettcorp.com/support/warranty/#originalburnercomponents.
[70] Mcdonald, R J. *Proceedings of the 2001 National Oilheat Research Alliance Technology Conference Held at Brookhaven National Laboratory*, Upton, N.Y., April 30 - May 1, 2001. United States: N. P., 2001. Web. Doi:10.2172/780685.

For this reason, the U.S. Energy Information Administration recommends against storing biodiesel in regular petroleum liquids tanks.[71] While performance can be improved by keeping the fuel warm—for instance, by employing insulating measures around the tank/fuel filter or by using chemical additives to increase cold flow, there is no "one-size-fits-all" approach.[72] The effectiveness of additives varies depending on the type of additive and the type of biodiesel feedstock. As one journal article in the RSA (Royal Society of Chemistry) Advances noted, "a specific method or additive that can improve cold flow behavior of all types of biodiesel is not available."[73]

i. 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?

At the point of combustion, biofuels produce similar levels of GHG emissions and other pollutants as their fossil fuel counterparts. And because current biofuel blends used for home heating are mostly distillate fuel oil by volume, combustion of these fuel blends continues to present significant localized health risks. Any regulations addressing biofuels should limit these emissions as much as possible to prevent adverse effects on human health and the climate. Other environmental impacts of biofuels that DEEP should take into account include land use changes (the conversion of forested land and other nonagricultural lands to grow biofuel crops), habitat destruction, the inputs needed to grow biofuels (such as fertilizer, which can contaminate water and contribute to toxic algal blooms), and the emissions and other impacts associated with producing, harvesting, refining, and transporting the biofuels.

Because most biofuels are produced outside of Connecticut, it is unclear how much the state can limit the negative impacts associated with these fuels. Regulations could minimize the emissions and other impacts that occur at the point of combustion, but it would be much harder for DEEP to influence impacts occurring outside the state. Eliminating the problematic 50% biofuel blending requirement, which would reduce demand for biofuels in Connecticut, is another pathway that could indirectly reduce the negative impacts of biofuels both within and outside the state. Additionally, this would avoid the need for investments that extend the state's reliance on fossil fuels, such as furnace upgrades necessary to accommodate high biofuel blends. These furnace upgrades would effectively delay adoption of cleaner, less polluting alternatives such as heat pumps.

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

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[71] U.S. Energy Information Administration, *Biodiesel, renewable diesel, and other biofuels*, https://www.eia.gov/energyexplained/biofuels/biodiesel-rd-other-use-supply.php.

[72] eXtension Farm Energy, *Biodiesel Cloud Point and Cold Weather Issues*, https://farm-energy.extension.org/biodiesel-cloud-point-and-cold-weather-issues/#:~:text=In%20cold%20climates%2C%20it%20can,from%20which%20it%20is%20made.

[73] Monirul et al., 2015, *A comprehensive review on biodiesel cold flow properties and oxidation stability along with their improvement processes*, RSC Adv., 5 (105) (2015), pp. 86631-86655

Yes, blending biofuels with heating oil clearly creates a risk of prolonging Connecticut's reliance on heating oil, especially if this approach is supported by state policies like the current blending mandate and/or is seen as a solution to reduce emissions from the buildings sector.

As discussed at Technical Session #6, most heating oil is currently blended with only 5% biofuel, while petroleum heating oil makes up the remaining 95% of the blend. Under the current blending mandate, the percentage of biofuel must increase to 10% in 2025, 15% in 2030, 20% in 2034, and 50% in 2035.[74] Twelve years from now, petroleum heating oil would still account for 80% of the blend. If the 2035 target is achieved—which is highly questionable, as discussed in response to question 10(a), *supra*—petroleum heating oil would still be half of the blend.

This ongoing reliance on heating oil is shortsighted and inconsistent with Connecticut's binding climate targets under the GWSA. The state should implement policies that proactively phase out fossil fuels *and* alternative fuels for home heating, not incentivize the ongoing use of fossil fuels by requiring them to be supplemented with limited quantities of alternative fuels.

Oil dealers are already using the current biofuel blending requirement to their advantage, claiming that they are selling an environmentally friendly product that will help combat climate change.[75] These claims are misleading and can easily confuse consumers, who are more likely to continue using heating oil if they think it is environmentally responsible. This will only make it harder for Connecticut to phase out heating oil and decarbonize the buildings sector.

k. In 2050, what proportion of Connecticut's space heating load should be satisfied with petroleum heating oil blended with LCB?

Connecticut must plan for space heating load in 2050 that is consistent with the state's GHG reduction requirements under the GWSA: by 2050, emissions must be at least 80% below 2001 levels.[76] Some building sector emissions would still be permissible under the current 2050 target if all sectors are to achieve the same level of emissions reduction; however, given that space heating is effectively decarbonized through electrification, it may make sense to capitalize on emissions reductions from this low-hanging fruit and reserve the remaining emissions allowance in 2050 for harder to decarbonize sectors. Updated modeling is needed to calculate the level of emissions from the buildings sector that would be consistent with the 2050 target and feasible pathways to reach that target. Further, as discussed below, Connecticut should adopt a net zero target for 2050 which would further encourage decarbonization in the buildings sector and would necessarily eliminate space heating load satisfied with petroleum heating oil and biofuel blends.

DEEP should coordinate with the GC3 and consultants as needed to update the state's GHG modeling and determine the level of emissions reductions that are necessary to meet state climate goals on a sector-specific basis. For the buildings sector, electrification and efficiency

[74] Conn. Gen. Stat. Sec. 16a-21b(b).
[75] *See, e.g.*, Chris Herb, CT Mirror, *Bioheat fuel is the best way to lower carbon emissions today* (Feb. 16, 2022), https://ctmirror.org/2022/02/16/bioheat-fuel-is-the-best-way-to-lower-carbon-emissions-today/ (opinion piece published in CT Viewpoints).
[76] Conn. Gen. Stat. 22a-200a(a)(3).

measures will be key to reducing emissions. Reliance on fossil fuels (gas and heating oil) and biofuels must decline, but the relative reduction for each fuel type will vary depending on that fuel's emissions intensity and the state's policy priorities. For example, Connecticut might reasonably prioritize the most cost-effective heating conversions that reduce emissions.

Under a net zero 2050 target, Connecticut could not have *any* space heating load that uses petroleum heating oil blended with biofuels.[77] Increasingly, state and national governments and companies have adopted 2050 net zero targets,[78] and Connecticut should likewise update its GHG emissions reduction targets in line with the growing international consensus that achieving net zero emissions by 2050 is necessary to avert the most disastrous impacts of climate change.[79] In the 2022 CES, Connecticut should commit to a goal of eliminating the use of heating oil blended with biofuels for space heating by 2050.

Respectfully submitted,

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[77] Under a net zero target, some level of offsets would likely be necessary to zero out any remaining emissions. However, offsets remain controversial and their use should be limited to the most difficult to decarbonize sectors. Since the buildings sector can be fully decarbonized through electrification, energy efficiency improvements, and related measures that are already available, Connecticut should plan to decarbonize the buildings sector without resorting to the use of offsets.

[78] International Energy Agency, *Net Zero by 2050: A Roadmap for the Global Energy Secto*r, 32-36 (Oct. 2021), https://iea.blob.core.windows.net/assets/deebef5d-0c34-4539-9d0c-10b13d840027/NetZeroby2050-ARoadmapfortheGlobalEnergySector_CORR.pdf.

[79] *See* IPCC, 2021: Summary for Policymakers. In: *Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change* [Masson-Delmotte, V., P. Zhai, A. Pirani, S. L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M. I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J. B. R. Matthews, T. K. Maycock, T. Waterfield, O. Yelekçi, R. Yu and B. Zhou (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 3−32, doi:10.1017/9781009157896.001, https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_SPM.pdf.

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