To: Deirdre Morris, Vermont Public Utility Commission

From: Rick Weston, Chair, CHS Technical Advisory Group

Date: 17 September 2024

Opinion Dynamics Responses 2 October 2024 in blue

Re: CHS Measure Characterizations—Questions from the TAG for Opinion Dynamics

Last week, an ad hoc subgroup of the Clean Heat Standard (CHS) Technical Advisory Group (TAG) met to discuss two recent submissions from Opinion Dynamics (OD, the PUC’s consultant on clean heat measure characterizations): OD’s 29 August memo with “Draft Vermont Clean Heat Standard Lifecycle Emissions Rate Schedule” and OD’s 9 September “Draft Vermont Clean Heat Standard Fuel Measure Characterizations”. This memo catalogues (from my notes of the meeting) an initial, but by no means comprehensive, set of questions that TAG members have about these documents. I’m sending them along now to help OD prepare for its discussion with the TAG this coming Thursday, 19 September.

CHS Lifecycle Emissions Rate Schedule

* Why are avoided methane emissions excluded?
  + 30 VSA Section 8127(g)(2) states: “For each fuel pathway, the schedule shall account for greenhouse gas emissions from biogenic and geologic sources, including fugitive emissions and loss of stored carbon. . .”.

We had lengthy discussions internally about whether to include counterfactual scenarios (i.e., avoided emissions) in the reported carbon intensity values. We landed on excluding them for several reasons. First, the carbon intensity that we reported in the schedule represent the realized emissions of a fuel, i.e., the emissions that occur as a result of a fuels pathway and combustion. Second, inclusion of counterfactual scenarios may result in negative carbon intensities, suggesting that use of some fuels will result in carbon removal/sequestration from the atmosphere. Third, there are numerous counterfactual scenarios that may occur (e.g., natural gas flaring or unabated release at a landfill) with varying impact on carbon intensities, and which scenario is more likely is not always evident. Lastly, inclusion of counterfactual scenarios may result in further restriction of qualifying biofuels, because CI's will not only be tied to the fuel production pathway, but also the upstream counterfactual scenario. We've viewed the CHS like any other TRM, in that it is intended for ease of use, replicability, and transparency. Increased complexity may detriment one or more of the benefits of a TRM.

However, we understand that some members of the TAG feel that this was an inappropriate choice. We agree that legislation indicates that carbon intensity values should include avoided methane emissions where possible. We are in the process of revising our analysis to determine the appropriate counterfactual scenario or blend of multiple for each measure where it applies.

* + Will they be included in the final report and will they be differentiated by type (e.g., landfill, dairy, etc.)?

We will embed counterfactual scenarios into the carbon intensity values for the fuels presented in our schedule, which will differentiate the values by the existing pathways we have analyzed (including animal waste and landfill gas).

* Is there a detailed workbook that provides underlying assumptions, formulas, etc. that underpin the emissions rate schedule?

With these comment responses, we have also shared the GREET1\_2023rev1 and GREET2\_2023 models from which we have developed the CI's. As we've previously shared, we are following ANR's ESLCA approach, so ours has a similar structure and includes a table presenting GREET modifications for VT.

* In certain instances, OD assigns carbon intensities (CIs) that differ from those used by NV5 for its potential study:
  + Renewable diesel, biodiesel, biomethane, and landfill gas differ from those of NV5. Where there are negative values, the differences are significant.
  + What are the reasons for these differences? Please provide any source documentation used for the carbon intensities.

We've seen the NV5 results as well and observed similar differences in CIs. We haven't reviewed the details of the NV5 analysis so we can't speak definitively to the source of the differences, but we suspect that the differences are likely due to our choice to exclude counterfactuals and land use changes from our analysis.

* Table 1:
  + There are no nitrogen oxides shown for hydrogen combustion. This seems odd. Does it not produce any?

Thank you for this comment. We reviewed several sources (e.g., peer reviewed journal articles and government resources) and recognize that high-temperature combustion of H2 does lead to NOx production, with over 80% of the emission in the form of nitric oxide (NO). NO is a precursor emission, which is not included in emissions inventories. H2 combustion does not produce nitrous oxide (N2O), which we are characterizing emission from in our schedule. In GREET, we see an emission rate for NOx of 60g/MMBtu of fuel, but 0g of N2O/MMBtu, suggesting alignment between GREET and the resources we reviewed, i.e., hydrogen combustion does not produce significant N2O emissions.

* OD did not recognize upstream land-use impacts from the production of certain biofuels. Why not? Should they be accounted for? Is there a question of “additionality” in agricultural associated with Vermont’s demand for crop-based fuels?

As we worked within GREET to account for LUCs, we determined that GREET is inconsistent how these impacts are accounted. For example, LUC impacts associated with soybeans include explicit input parameters, while other crop-based feedstocks do not. This resulted in additional challenges for proper accounting on top of issues like additionality. Lastly, our aim with the CHS is to produce a replicable and transparent resource that is easy to use. To achieve this, we made assumptions and simplifications to ensure that future revisions could replicate our numbers while also advancing its content. We appreciate the TAG’s comments on LUCs; we don’t believe that it is inappropriate to include LUCs, but at this time we don’t see a pathway to including them in our carbon intensity values.

* “Step-downs” in carbon intensities in 2030 and 2050:
  + OD assumes that the CIs of biofuels drops in 2030 and stays flat until 2049. Is this a reasonable assumption? The legislation says that the PUC will “publish the rate at which carbon intensity values shall decrease annually for liquid and gaseous clean heat measures. . .” (8127(f)(2). Should the CIs decline during this period?

As discussed in our presentation on 9/19, we feel that any decisions around the rate of decrease in carbon intensity values for clean fuels is a policy choice that should be made by the PUC with input from the TAG. None of our work has intended to provide input on this question.

Draft Vermont Clean Heat Standard Fuel Measure Characterizations

* OD assumes that biomethane and other feedstocks sourced outside the United States will not be eligible as clean heat measures (page 6). Why? The legislation does not impose geographic limitations on sources of clean fuels.

In general, limitations in measure characterizations reflect two factors.

1. Specific to this question, the measure characterizations are used in concert with the available emissions schedule and therefore must reflect the details of that schedule. Our modeled carbon intensity values for biomethane and other fuels developed from biological feedstocks reflect certain choices we made in our analysis, in that we leverage ANL's staff's knowledge and national perspective on fuel pathways and feedstocks through GREET. For biofuels, current pathways are predominately within the US (60% of feedstocks come from Midwest). Biofuels imported from outside the US may potentially have different production pathways, which may have different CIs than what we developed. Therefore, we limited the measure characterization to cover only feedstocks sourced in the United States. This does not necessarily mean to imply that clean heat measures developed from feedstocks from outside the US are fundamentally unacceptable in the CHS, but instead that they are not currently characterized by our analysis.
2. When developing prescriptive measure characterizations, it is our experience that best practice is to define the measure eligibility as narrowly as possible to ensure that unintended consequences are not realized. As we have discussed earlier in our work, presumably “custom” measures outside of the current CHS TRM characterizations will be acceptable with a certain degree of enhanced rigor and verification.

* Why is biomethane assumed to be delivered only through pipelines (pp. 6-7)?

We viewed biomethane as a drop-in fuel for natural gas, which is delivered through pipelines. The measure characterization assumes that biomethane will be blended into existing natural gas pipeline networks. Per the above response, we defined this narrowly based on how we assumed the fuel would be used. However, the choice of delivery does not materially affect the measure characterization, so if the TAG has specific suggestions, we can certainly revise the characterization to allow for biomethane that reaches its enduse via other transportation methods.

* Renewable propane is not characterized? Why not? It’s an eligible measure, is it not?

Per our discussion on our 9/19 call, we did not develop a measure characterization for renewable propane because we did not produce carbon intensity values for renewable propane, and without carbon intensity values the measure characterization is not useful. As discussed in our emissions schedule memo, we did not develop carbon intensity values for renewable propane because the analytical method we selected for assessment of upstream emissions (GREET) does not have a method for directly calculating renewable propane emissions.

However, this is not intended to imply that renewable propane should not be eligible for the CHS. We do believe the inclusion of renewable propane in the CHS as an eligible measure would be reasonable if an analytic basis to substantiate Vermont-specific emissions for the fuel could be identified. There are a couple of paths forward we see here.

1) We could wait until further national research and tools become available. For example, the DOE released an RFI in August around renewable propane that may lead to additional information. We also imagine that ANL may consider adding renewable propane methods to GREET, though we are not aware of a specific plan to do so at this time.

2) If the PUC and TAG feel that an CI value for renewable propane is necessary now, the only straightforward path we see to doing so is adopting a CI value from the West Coast (the VFDA, for example, identified CIs from the California LCFS and the Oregon Clean Fuels Program) and applying some type of adjustment to account for differentials in travel distances for fuel delivery between the West Coast and Vermont. This would differ from the approach we are applying for other fuels.

Since our 9/19 call, we have discussed this approach with the PUC and agreed that we will characterize renewable propane.

* Biomethane used to produce electricity is not recognized as a clean fuel measure (p. 7). Why not? Should it be? Should biomethane as a material feedstock in an industrial facility be an eligible clean heat measure (p. 7)?

Our understanding of Act 18 is that it defines the CHS as applicable to the "Residential, Commercial, and Industrial Fuel Use" sector in the Vermont Greenhouse Gas Inventory only. As we understand it, fuel used to produce electricity would be included in the Electricity sector of the inventory and therefore is not eligible for the CHS. We are less certain with respect to feedstocks, but we made the assumption that feedstocks would be captured under the Industrial Processes section of the inventory and similarly therefore would not be eligible. Do any TAG members or the PUC understand Act 18 otherwise? With respect to the inventory, would it be possible for ANR to share whether we have interpreted categorizations correctly?"

* Are there any feedstocks not listed in the legislation that should be included as clean fuel measures?

We shared our list of candidate fuel pathways as part of the measure list and received only a handful of comments and suggestions, all of which we believe we have addressed (most notably the comments around renewable propane and ensuring we added biodiesel from wastes and residues. Happy to take any additional thoughts TAG might have but will have to discuss next steps if additional identified pathways are identified with the PUC.

* Why is only renewable diesel delivered by truck considered eligible?

Similar to biomethane, we viewed biodiesel as a drop-in replacement fuel for fuel oil #2, which we understand is delivered by truck to homes and businesses. We are not aware of other delivery mechanisms for renewable diesel. If there are other delivery methods, we can include those in the CHS. The delivery method factors into transmission and distribution emissions, which are minimal.

* Wood:
  + Why are only firewood production pathways in the Northeast eligible for this measure?

Per our discussion on 9/19 and responses above, we wanted to narrowly define these pathways to ensure that our analysis was applicable.

* + Is the assumption that the emissions associated with the delivery of wood fuels is equivalent to that of fuel oil and propane reasonable, in given the differences in distances travelled?

As we have previously shared in TAG deliverables, we followed the lead of the ESLCA for wood fuels, which contained information and assumptions for the electricity generation and RCI sectors. We had no reason to believe those assumptions or data were inaccurate.

We assume that travel distances for all delivered fuels from distributors to end users are similar and differences in the resulting emissions are negligible in comparison with each other. Therefore, the assumption made in the CHS is partly for simplification and ease of use of the TRM.