Submitted by: International Council on Clean Transportation
November 14, 2022

Clean H2 production standard comments

1) Data and Values for Carbon Intensity

a) Many parameters that can influence the lifecycle emissions of hydrogen production may vary in real-world deployments. Assumptions that were made regarding key parameters with high variability have been described in footnotes in this document and are also itemized in the attached spreadsheet "Hydrogen Production Pathway Assumptions." Given your experience, please use the attached spreadsheet to provide your estimates for values these parameters could achieve in the next 5-10 years, along with justification.

b) Lifecycle analysis to develop the targets in this draft CHPS were developed using GREET. GREET contains default estimates of carbon intensity for parameters that are not likely to vary widely by deployments in the same region of the country (e.g., carbon intensity of regional grids, net emissions for biomass growth and production, avoided emissions from the use of waste-stream materials). In your experience, how accurate are these estimates, what are other reasonable values for these estimates and what is your justification, and/or what are the uncertainty ranges associated with these estimates?

GREET is an attributional life-cycle assessment (LCA) tool that has been adopted by international regulators, academia, and industry. Other LCA tools such as the European Joint Research Center (JRC) Well to Wheels study[1] and GHGenius exist but are not as thoroughly vetted. GREET is regularly updated to include peer-reviewed data from literature and scientific developments. Although GREET is built using standard emission factors, it allows users to vary input assumptions according to parameters such as geographic region or process efficiency rate. While these factors are not exhaustive, GREET has a feature for users to select a "user defined" input (e.g., electricity generation mix) for many parameters.

Although GREET is a comprehensive attributional LCA tool, it lacks the capability to estimate many indirect emissions impacts associated with producing transportation fuels. Importantly, this includes competing demand for electricity across the electric power and transport sectors. In the EU, Malins estimates that renewable fuels of non-biological origin (RFNBOs), a fuels classification that includes hydrogen, may have emissions up to three times that of conventional fossil alternatives due to increased

---

[1] Joint Research Centre (European Commission) et al., "JEC Well-to-Tank Report V5: JEC Well to Wheels Analysis : Well to Wheels Analysis of Future Automotive Fuels and Powertrains in the European Context" (LU: Publications Office of the European Union, 2020), https://data.europa.eu/doi/10.2760/100379.

demand for grid-average electricity across the network.[2] Project-specific CI values for electrolytic hydrogen certified under the California LCFS range between 10.51 gCO2e/MJ to 164.46 gCO2e/MJ depending on the source of electricity utilized.[3]

With the emergence of transportation fuels that use electricity as a primary process input, there is high risk for renewable electricity attributes to be claimed by multiple parties operating across different industry sectors. For example, renewable electricity generation that is required under state-level Renewable Portfolio Standard (RPS) requirements could also be claimed as a zero-carbon electricity source for green hydrogen generation. Renewable electricity diverted from the power sector is then replaced by the marginal source of electricity, and that is most often natural gas. Even under national decarbonization commitments, failing to ensure that electricity sources for hydrogen production are both renewable and additional could lead to an increase in natural gas plant capacity.[4]

Attributional LCA tools such as GREET can estimate the emissions associated with a share of renewable and grid-average electricity resulting from added transport-sector electricity demand. However, certification schemes to prevent double counting are needed to ensure that CI values are reflective of real-world conditions.

c) Are any key emission sources missing from Figure 1? If so, what are those sources? What are the carbon intensities for those sources? Please provide any available data, uncertainty estimates, and how data/measurements were taken or calculated.

d) Mitigating emissions downstream of the site of hydrogen production will require close monitoring of potential CO_2 leakage. What are best practices and technological gaps associated with long-term monitoring of CO_2 emissions from pipelines and storage facilities? What are the economic impacts of closer monitoring?

e) Atmospheric modeling simulations have estimated hydrogen's indirect climate warming impact (for example, see Paulot 2021). The estimating methods used are still in development, and efforts to improve data collection and better characterize leaks, releases, and mitigation options are ongoing. What types of data, modeling or

[2] Chris Malins, "What Does It Mean to Be a Renewable Electron?" (Washington, D.C.: International Council on Clean Transportation, December 9, 2019), https://theicct.org/publication/what-does-it-mean-to-be-a-renewable-electron/.

[3] CARB, "CA-GREET3.0 Lookup Table Pathways Technical Support Documentation," August 13, 2018.

[4] Jane O'Malley, "Drafting the Future of Clean Hydrogen: Build Back Better with an Additionality Requirement," *ICCT Staff Blog* (blog), December 8, 2021, https://theicct.org/drafting-the-future-of-clean-hydrogen-build-back-better-with-an-additionality-requirement/.

verification methods could be employed to improve effective management of this indirect impact?

f) How should the lifecycle standard within the CHPS be adapted to accommodate systems that utilize CO2, such as synthetic fuels or other uses?

The lifecycle scope outlined in Figure 1 includes emissions associated with carbon dioxide extraction and compression. Carbon dioxide can be sourced from various processes, most notably point-source capture and direct air capture (DAC). It is important that emissions credits claimed for carbon capture are attributed to a single entity (e.g., industrial producer) to avoid the risk of double counting. Adherent with the EU draft Delegated Act on Recycle Carbon Fuels, we recommend that synthetic fuel producers do not receive credit for avoided CO2 emissions as they have already been taken into account under other regulatory accounting schemes.[5]

We recommend that the CHPS require an assessment of capture efficiency rates and CO_2 storage leakage rates to quantify the full scope of emissions associated with blue hydrogen production. The source of CO_2 will influence the amount of energy required for extraction and compression, as a component of hydrogen's final CI value.

2) Methodology

a) The IPHE HPTF Working Paper (https://www.iphe.net/iphe-working-papermethodology-doc-oct-2021) identifies various generally accepted ISO frameworks for LCA (14067, 14040, 14044, 14064, and 14064) and recommends inclusion of Scope 1, Scope 2 and partial Scope 3 emissions for GHG accounting of lifecycle emissions. What are the benefits and drawbacks to using these recommended frameworks in support of the CHPS? What other frameworks or accounting methods may prove useful?

The IPHE framework is a voluntary framework that provides useful guidelines for industry stakeholders aiming to develop GHG inventories for hydrogen. The IPHE is not binding, nor does it calculate lifecycle emissions that can be assessed consistently with other fuels under existing federal clean fuels regulations. The IPHE framework also treats Scope 3 emissions as instructive rather than prescriptive and does not include them within a fuel's final carbon intensity value. This differs from federal and state

[5] European Commission, "Commission Delegated Regulation Supplementing Directive (EU) 2018/2001 of the European Parliament and of the Council by Establishing a Minimum Threshold for Greenhouse Gas Emissions Savings of Recycled Carbon Fuels and by Specifying a Methodology for Assessing Greenhouse Gas Emissions Savings from Renewable Liquid and Gaseous Transport Fuels of Non-Biological Origin and from Recycled Carbon Fuels," 2022.

regulations such as Renewable Fuel Standard and California Low Carbon Fuel Standard (LCFS) that include some indirect emissions within a fuel's final CI.

Significant reporting gaps include Section 3.3.6 on embodied emissions covering methane leakage rates. Within Section 3.3.6, guidance on upstream methane leakage is limited and the framework lacks tools for stakeholders to monitor and report methane emissions. Based on the literature, methane leakage rates associated with natural gas distribution and storage can range up to 10% while leakage rates associated with gas extraction and recovery can range up to 9%.[6] Stronger monitoring, reporting and verification (MRV) methods are needed under the CHPS to ensure that high leakage rates do not undermine the GHG emission savings of clean hydrogen. An example of stronger guidance includes a 2021 proposal released by the European Commission on economy-wide methane emission reductions. The proposal includes support for MRV requirements and frequent leak detection and repair (LDAR) surveys.[7]

Guidance on Scope 3 emissions associated with green, or electrolytic, hydrogen production includes documentation on low-CI electricity required under the California LCFS.[8] To verify the source of electricity generation, CARB requires book-and-claim accounting for renewable electricity with the use of renewable energy certificate (REC) retirements. There is also some prevention of policy overlap under the LCFS where retired RECs must not be used toward state-level Renewable Portfolio Standard (RPS) requirements. CARB is considering stronger safeguards around the source of electrolytic hydrogen generation to prevent grid imbalances and unintended emissions impacts from added electricity demand. These same safeguards are critical for projects supported under the CHPS, as described in response 3c.

b) Use of some biogenic resources in hydrogen production, including waste products that would otherwise have been disposed of (e.g., municipal solid waste, animal waste), may under certain circumstances be calculated as having net zero or negative CO2 emissions, especially given scenarios wherein biogenic waste stream-derived materials and/or processes would have likely resulted in large GHG emissions if not used for hydrogen production. What frameworks, analytic tools, or data sources can be used to

---

[6] Yuanrong Zhou et al., "Life-Cycle Greenhouse Gas Emissions of Biomethane and Hydrogen Pathways in the European Union" (Washington, D.C.: International Council on Clean Transportation, October 10, 2021), https://theicct.org/publication/life-cycle-greenhouse-gas-emissions-of-biomethane-and-hydrogen-pathways-in-the-european-union/.

[7] European Commission, "Proposal for a Regulation of the European Parliament and of the Council on Methane Emissions Reduction in the Energy Sector and Amending Regulation (EU) 2019/942," December 15, 2021, https://eur-lex.europa.eu/resource.html?uri=cellar:06d0c90a-5d91-11ec-9c6c-01aa75ed71a1.0001.02/DOC_1&format=PDF.

[8] CARB, "Book-and-Claim Accounting for Low-CI Electricity," April 2019, https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/guidance/lcfsguidance_19-01.pdf.

quantify emissions and sequestration associated with these resources in a way that is consistent with the lifecycle definition in the IRA?

The Environmental Protection Agency (EPA) has included guidance on calculating emissions associated with wastes, residues, and byproducts in its Regulatory Impact Assessment of biofuels. This document was published upon promulgation of the Renewable Fuel Standard in 2010. When assessing emissions from these products, it is important to consider the baseline or "counterfactual" case representing the standard end-use for waste products in the absence of alternative fuel demand.

CARB has revisited the counterfactual case for biomethane derived from dairy manure in its updates to the 2022 Climate Scoping Plan.[9] These considerations may significantly alter the CI and associated credit value of biogenic natural gas from one that is negative to one that has substantial GHG emissions. For facilities within jurisdictions such as California that have implemented methane capture requirements independently of clean fuel regulations,[10] crediting avoided methane emissions is not reflective of baseline conditions. For facilities outside these jurisdictions, emissions can be certified at the project level. However, it is important that the inconsistent treatment be phased out within a reasonable timeframe to avoid perverse incentives for non-localized biomethane production.

c) How should GHG emissions be allocated to co-products from the hydrogen production process? For example, if a hydrogen producer valorizes steam, electricity, elemental carbon, or oxygen co-produced alongside hydrogen, how should emissions be allocated to the co-products (e.g., system expansion, energy-based approach, mass-based approach), and what is the basis for your recommendation? d) How should GHG emissions be allocated to hydrogen that is a by-product, such as in chlor-alkali production, petrochemical cracking, or other industrial processes? How is byproduct hydrogen from these processes typically handled (e.g., venting, flaring, burning onsite for heat and power)?

We recommend that emissions from hydrogen co-products such as steam and electricity be allocated on an energy basis while emissions for co-products with significant economic value be allocated using a market-based approach. For co-products that are recycled back within the process stream (e.g., heat, electricity), we recommend the use of a system expansion LCA approach to offset emissions from

---

[9] California Air Resources Board, "Low Carbon Fuel Standard Public Workshop: Concepts and Tools for Compliance Target Modeling," November 9, 2022, https://ww2.arb.ca.gov/sites/default/files/2022-11/LCFSPresentation.pdf.

[10] California Legislature, "SB-1383 Short-Lived Climate Pollutants: Methane Emissions: Dairy and Livestock: Organic Waste: Landfills." (2016), https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160SB1383.

primary fuel production. This co-product allocation methodology is largely consistent with EPA's RIA rulemaking.[11]

3) Implementation

a) How should the GHG emissions of hydrogen commercial-scale deployments be verified in practice? What data and/or analysis tools should be used to assess whether a deployment demonstrably aids achievement of the CHPS?

b) DOE-funded analyses routinely estimate regional fugitive emission rates from natural gas recovery and delivery. However, to utilize regional data, stakeholders would need to know the source of natural gas (i.e., region of the country) being used for each specific commercial-scale deployment. How can developers access information regarding the sources of natural gas being utilized in their deployments, to ascertain fugitive emission rates specific to their commercial-scale deployment?

c) Should renewable energy credits, power purchase agreements, or other market structures be allowable in characterizing the intensity of electricity emissions for hydrogen production? Should any requirements be placed on these instruments if they are allowed to be accounted for as a source of clean electricity (e.g. restrictions on time of generation, time of use, or regional considerations)? What are the pros and cons of allowing different schemes? How should these instruments be structured (e.g. time of generation, time of use, or regional considerations) if they are allowed for use?

Yes, it is critical that the source of electricity used as an input fuel for hydrogen is verified before being quantified within a lifecycle GHG assessment. Electrolysis is a highly electricity intensive process and can result in GHG emissions higher than conventional fossil fuels, even when only a fraction of grid-based electricity is utilized.[12]

Proposals to verify the source of electricity include, at a minimum, a newbuild power-purchase agreement (PPA) to establish a direct link between a renewable electricity generator and a hydrogen producer. Thus, we advise against the use of unbundled renewable electricity certificates (RECs) as a verification method unless phased out within a strict timeframe (e.g., three years to accommodate for plant construction and scaleup).

---

[11] US EPA, "Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis," February 2010.

[12] Wilson Ricks, Qingyu Xu, and Jesse D. Jenkins, "Enabling Grid-Based Hydrogen Production with Low Embodied Emissions in the United States" (Zenodo, October 10, 2022), https://doi.org/10.5281/zenodo.7183516.

We support the use of geographic and temporal correlation to promote grid stability and traceability. These methods were proposed under the EU Delegated Act on H_2 Additionality; regional requirements were adopted by Parliament in the fall 2022 version.[13] Temporal matching has been argued to be overly burdensome by industry stakeholders. However, time-of-use attribute electricity certificates are available and can be readily matched with generation sources. Ricks et al. used an electricity systems capacity expansion model to estimate that economic impact of hourly vs. annual temporal matching and found a negligible increase in the levelized cost of hydrogen if an hourly system was employed. Authors find that relative to a regulatory scheme where no requirements were placed on electricity generation, this would increase the cost of hydrogen by a maximum of $1/kg. The GHG benefits of employing hourly matching requirements were significant and could lead to more than 20kgCO2e/kg H_2 in emission savings.

Though a temporal matching requirement could deter some developers from scaling up capacity, this tradeoff is more than justifiable to ensure that hydrogen investment is leading to real and verifiable GHG emission reductions.

d) What is the economic impact on current hydrogen production operations to meet the proposed standard (4.0 kgCO2e/kgH2)?

4) Additional Information

a) Please provide any other information that DOE should consider related to this BIL provision if not already covered above.

[13] Allen & Overy LLP, "Hydrogen Latest EU Policy Updates," 2022.