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Clean Hydrogen Future Coalition

The Department of Energy ("DOE" or "Department") proposes to adopt a Clean Hydrogen Production Standard ("CHPS") incorporates the definition of clean hydrogen provided in the Bipartisan Infrastructure Law (BIL) and supports diverse feedstocks. The CHFC's approach is resource and technology agnostic in the production of clean hydrogen. All methods of production are necessary to produce the quantities of clean hydrogen, build out the infrastructure, and stimulate end-use demand to create a clean hydrogen industry.

DOE's proposed lifecycle GHG emissions target (CHPS) is a secondary evaluation tool. DOE must also require a regional hydrogen hub applicant to meet the statutory definition of clean hydrogen to determine whether an applicant is eligible and in compliance with the statute (P.L. 117-58). Clean hydrogen production using renewable or certified natural gas, for example, can be deemed zero CO_2 emitting for purposes of meeting or exceeding the 2 kg CO_2e per kg H_2 definition of clean hydrogen.

In the proposal on page 6, DOE states that the BIL provisions governing Regional Clean Hydrogen Hubs make clear that DOE can select projects that exceed the emissions threshold for "clean hydrogen" or the lifecycle target set by the CHPS – "DOE can select projects that do not meet the CHPS so long as the selected projects "demonstrably aid the achievement" of the CHPS". This statement does not actually reflect what is required by the statute. The BIL states that "The Secretary shall establish a program to support the development of at least 4 regional clean hydrogen hubs that—

1) demonstrably aid the achievement of the clean hydrogen production standard developed under section 16166(a) of this title;
2) demonstrate the production, processing, delivery, storage, and end-use of clean hydrogen; and
3) can be developed into a national clean hydrogen network to facilitate a clean hydrogen economy."[1]

Further, section 16166(a), states "the Secretary, shall develop an initial standard for the carbon intensity of clean hydrogen production that shall apply to activities carried out under this subchapter. This is followed by section 16166(b) which states "the standard developed under subsection (a) shall define the term "clean hydrogen" to mean hydrogen produced with a carbon intensity equal to or less than 2 kilograms of carbon dioxide-equivalent produced at the site of production per kilogram of hydrogen produced"[2]. The emissions "produced at the site of production" means the carbon intensity would be calculated using scope 1 (direct) emissions only.

DOE's program to support the development of at least 4 regional clean hydrogen hubs shall demonstrably aid the achievement of the clean hydrogen production standard. Additionally, DOE is required to develop its CHPS to demonstrate the production of "clean hydrogen" and "clean hydrogen" means hydrogen produced with a carbon intensity equal to or less than 2 kilograms of carbon dioxide-equivalent produced at the site of production per kilogram of hydrogen produced.

DOE proposes to establish a lifecycle greenhouse gas emissions target for its CHPS. Although DOE states that the lifecycle target proposed in the draft aligns with Section 13204 of the 2022 Inflation Reduction Act (IRA), this is not accurate. The IRA requires that qualified clean hydrogen must be produced "through a process that results in a lifecycle greenhouse gas emission rate of not greater

[1] 42 U.S.C. 16161a(b)(1) through (3)
[2] 42 U.S.C. 16166(a) and 16166(b)(1)(B)

than 4 kilograms of CO_2e per kilogram of hydrogen”[3]. However, the IRA defines lifecycle greenhouse gas emissions to include “significant indirect emissions” by reference to 42 U.S.C. 23 7545(o)(1)[4]. The statute further states that “the term ‘lifecycle greenhouse gas emissions’ shall only include emissions through the point of production (well-to-gate), as determined under the most recent Greenhouse gases, Regulated Emissions, and Energy use in Transportation model (commonly referred to as the ‘GREET model’) developed by Argonne National Laboratory, or a successor model (as determined by the Secretary).”[5]

The draft guidance for the proposed CPHS indicates on page 4 that the “lifecycle target aligns with the new clean hydrogen policy drivers established in the IRA 45V Credit provisions described above. The proposed CHPS established under the BIL uses the same lifecycle analysis system boundary as the IRA and targets the emissions rate where the operators can begin to qualify for credits, thus creating alignment between the two statutory provisions.”

DOE’s proposed CHPS does not use the same lifecycle analysis system boundary (well-to-gate) as the IRA requires for 45V. DOE’s proposed CHPS uses a system boundary for hydrogen production that goes beyond the “well-to-gate” boundary required by the statute for production methods that utilize fossil fuel by including emissions from CO_2 compression, transport, and storage; to the extent those emissions occur outside the hydrogen production facility, they are scope 3 indirect emissions. DOE must define its CHPS using consistent boundaries and emission scopes for all production methods. Further, the CHPS has no analysis or consideration of “significant indirect” emissions for all production methods as required by 45V. Therefore, the proposed CHPS does not align with 45V.

On page 5, DOE notes that its proposed CHPS is aligned with 45V provisions in the IRA and is aligned with international best practices. DOE elaborates that the International Partnership for Hydrogen in the Economy’s H2PA Task Force and CertifHy both agree that the most appropriate boundary conditions for hydrogen emissions analysis should include both upstream and downstream emissions. The fact that the proposed CHPS includes downstream emissions means it cannot be aligned with the IRA’s 45V as the lifecycle analysis is required to be well-to-gate. DOE is required to develop a CHPS to aid in the evaluation of reginal clean hydrogen hubs and other hydrogen programs created in the Bipartisan Infrastructure Law, but its proposed CHPS is **not** aligned with the statutory requirements in 45V.

The CHFC recommends that whatever boundary and scope conditions DOE utilizes to develop its CHPS, those boundary and scope conditions must be consistent across all production methods. The CHFC appreciates the opportunity to submit comments on the CHPS.

Sincerely,

Shannon Angielski

Shannon Angielski
President

[3] Inflation Reduction Act of 2022, Section 13204 (c)(1)(A)

[4] 42 U.S.C. 23 7545(o)(1): The term “lifecycle greenhouse gas emissions” means the aggregate quantity of greenhouse gas emissions (including direct emissions and significant indirect emissions such as significant emissions from land use changes), as determined by the Administrator, related to the full fuel lifecycle, including all stages of fuel and feedstock production and distribution, from feedstock generation or extraction through the distribution and delivery and use of the finished fuel to the ultimate consumer, where the mass values for all greenhouse gases are adjusted to account for their relative global warming potential.

[5] Inflation Reduction Act of 2022, Section 13204 (c)(1)(B)

CHFC Responses to CHPS Questions

1) 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?

CHFC encourages DOE to allow applicants to substitute more granular data for factors like the carbon intensity of regional grids, where available. Grid carbon intensity can vary significantly within NERC regions, which are utilized in the GREET model. The Edison Electric Institute (EEI) developed a database that provides carbon dioxide emission intensity rates and resource mix information, accounting for renewable energy certificates, for delivered electricity by electric distribution company, which will provide more detailed emissions data within regions:

https://www.eei.org/en/issues-and-policy/national-corporate-customers/co2-emission

It is important to consider that the fraction of electricity that a project can source from the grid while meeting the proposed 4.0 $kgCO_2e/kgH_2$ lifecycle emissions standard depends significantly on the greenhouse gas intensity of the grid. As noted, projects should be able to utilize local grid carbon intensity data, where available, to make this demonstration.

1) 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?

As discussed above, the statute does not require consideration of downstream indirect emissions for the CHPS, but CHFC notes that the Environmental Protection Agency has a rigorous CO_2 storage permitting program that requires monitoring and verification of emissions from CO_2 storage facilities under the Safe Drinking Water Act's Underground Injection Control, Class VI permit program.

1) f) How should the lifecycle standard within the CHPS be adapted to accommodate systems that utilize CO_2, such as synthetic fuels or other uses?

The Section 45Q carbon oxide sequestration credits have a CO_2 utilization lifecycle analysis requirement to be eligible and have established a program to accommodate systems that utilize CO_2. CHFC recommends following the same methodology.

2) 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 CO_2 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 quantify emissions and sequestration associated with these resources in a way that is consistent with the lifecycle definition in the IRA?

Use of waste products that would otherwise have been disposed of should be counted as having a net zero emission.

2) 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?

Emissions should be allocated using system expansion to the largest degree possible. The GREET model utilizes system expansion and its principles are well accepted.

3) 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?

The IPHE allows for the use of renewable energy credits (RECs), power purchase agreements, and market structures to be allowed in calculating the electricity emissions for hydrogen production. Following the IPHE guidelines should be required if they are allowed to be accounted for as a source of clean electricity. The accounting system should allow for the use of electricity generated by nuclear resources to be treated the same way as electricity generated by renewables. The accounting should be done on an annual basis with reasonable restrictions, considering data availability, on time of generation, time of use, or regional considerations. The use of behind-the-meter RECs should also be allowed if they are third-party verified.

Similarly, the use of thermal energy credits (for renewable natural gas) or other market-based structures should also be allowed.