Response to Clean Hydrogen Production Standard Draft Guidance

November 14, 2022

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Thank you for the opportunity to comment on the Clean Hydrogen Production Standard draft guidance. Our detailed comments are below. Key takeaways from these comments include:

- The CHPS should be employed in a way that identifies scalable implementations of clean hydrogen technologies that have high long-term decarbonization value, and excusing projects from meeting the standard should only occur when clear justification can be made and a plan for meeting or surpassing the standard in the near term (within five years) is proposed.
- The GREET model should include additional pathways to continue to broaden its applicability in assessing all modes of hydrogen production. Data should be collected from projects that are held to the CHPS in order to test the assumptions made in setting it and to refine it going forward.
- Creating a production standard that makes it complex for developers to complete LCA accounting, or that require additionality or a significant reduction in scope 3 emissions too soon could place undue burden on hydrogen projects and increase project costs and limit scale up of clean hydrogen production. This runs counter to the goal of adhering to the CHPS without limiting economic feasibility. At the same time, ensuring accurate assessment of carbon intensity is paramount to ensuring the CHPS supports truly clean hydrogen projects (those that can truly achieve near-zero carbon intensities over time).

As a final note, the clean hydrogen production standard, on its own, does not ensure that clean hydrogen is used as an effective tool for decarbonizing hard-to-abate sectors of the economy. Wherever possible, full lifecycle accounting, from cradle to grave, should be used to assess the emissions impacts of hydrogen projects instead of or in addition to the CHPS.

Detailed 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.*

Please see the attached spreadsheet for input on the assumptions made about key parameters. Further details on each are provided here.

Fugitive methane emissions:

At present, leakage of methane between the point of natural gas drilling and the point of use is likely to be higher than 1% on average.

Field measurements in North America have found that official inventories likely underestimate methane emissions. [1,2,3,4] Recent work by Argonne National Laboratory to update GREET also acknowledged this finding.[5] For example, Alvarez et al. (2018) reported a national production-averaged methane emission rate of 2.3% across the US oil and gas supply chain in a meta-analysis of measurement data.

However, numerous cost-effective methane abatement measures using currently available technology exist[6,7], and some estimates have suggested that such measures could reduce methane leakage in US oil and gas systems by as much as 65% by 2025.[8] Companies that procure low-leakage natural gas should be able to get credit for reducing lifecycle carbon intensity under the CHPS, but guidance on best practices for leakage certification will be important.

Additionally, a large oil and gas industry group representing 20%+ of the US natural gas value chain has reported successfully reducing methane emissions to less than 0.5% in 2021.[9] A separate group of global oil and gas companies, the Oil and Gas Climate Initiative, is now targeting an upstream methane emissions intensity target of less than 0.20% by 2025.[10]

This suggests that target methane leakage rates below 1% across the upstream supply chain are technologically and economically feasible. It will be important for companies to have clear guidance on how they can demonstrate that they are procuring low-leakage natural gas, or blending renewable natural gas, and should have the option to ascribe lower than average upstream leakage rates to their projects if they provide evidence (ideally leakage certification would be based on a standardized approach using verifiable, direct measurement data rather than mass-balance/equipment-based estimates). Including this guidance would encourage increased monitoring and verification of upstream methane emission intensity and promote purchasing of low emission methane.

Rate of carbon capture:

Currently operating, first-of-a-kind CO2 capture operations at hydrogen production facilities remove only 50-60% of CO2 emissions.[11] However, numerous new natural gas-based hydrogen production

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[1] https://www.science.org/doi/10.1126/science.aar7204
[2] https://doi.org/10.1021/acs.est.0c04117
[3] https://doi.org/10.1038/s41467-020-20314-w
[4] https://doi.org/10.1088/1748-9326/abef33
[5] https://greet.es.anl.gov/publication-update_ng_2021
[6] https://www.mckinsey.com/capabilities/sustainability/our-insights/curbing-methane-emissions-how-five-industries-can-counter-a-major-climate-threat
[7] https://iea.blob.core.windows.net/assets/465cb813-5bf0-46e5-a267-3be0ccf332c4/Driving_Down_Methane_Leaks_from_the_Oil_and_Gas_Industry.pdf
[8] https://www.catf.us/2022/07/epa-still-clear-pathway-significantly-reduce-methane-emissions-oil-gas/
[9] https://onefuture.us/
[10] https://www.ogci.com/action-and-engagement/reducing-methane-emissions/#methane-target
[11] https://www.pembina.org/pub/carbon-intensity-blue-hydrogen-production

facilities with carbon capture have been proposed with capture rates of 90-95%[12,13], demonstrating that high capture rates are technically feasible. In contrast, carbon capture retrofits at existing natural gas-based hydrogen production facilities may be limited to lower capture rates—potentially in the range of 60-70%.

Given the purpose of the CHPS is to create the most aggressive standard that is technically and economically feasible, we agree that a higher assumed capture rate reflected in newer plant designs is an appropriate benchmark to use.

However, if methane leakage of procured gas exceeds ~0.5%, retrofits with lower capture rates (e.g., 60-70%), may not be able to meet the proposed emissions intensity threshold under the CHPS. But if they are able to procure low leakage gas while also achieving capture rates on the higher end of what is expected to be feasible for retrofits and using clean electricity, it may still be possible to qualify. The chart below shows how capture rates and upstream methane leakage can balance to realize CI below 4 kgCO2/kgH2.

H2 CI (kg CO2e / kg H2) assuming different leakage and capture rates
(green shading indicates that CI is below the least stringent PTC threshold of 4kg CO2e / kg H2)

Upstream Methane Emissions Rate (% of extracted methane)	Capture rate: 50%	51%	52%	53%	54%	55%	56%	57%	58%	59%	60%	61%	62%	63%	64%	65%	66%	67%	68%	69%	70%	71%	72%	73%	74%	75%
0.0%	5.00	4.90	4.80	4.70	4.60	4.50	4.40	4.30	4.20	4.10	4.00	3.90	3.80	3.70	3.60	3.50	3.40	3.30	3.20	3.10	3.00	2.90	2.80	2.70	2.60	2.50
0.1%	5.13	5.03	4.93	4.83	4.73	4.63	4.53	4.43	4.33	4.23	4.13	4.03	3.93	3.83	3.73	3.63	3.53	3.43	3.33	3.23	3.13	3.03	2.93	2.83	2.73	2.63
0.2%	5.26	5.16	5.06	4.96	4.86	4.76	4.66	4.56	4.46	4.36	4.26	4.16	4.06	3.96	3.86	3.76	3.66	3.56	3.46	3.36	3.26	3.16	3.06	2.96	2.86	2.76
0.3%	5.39	5.29	5.19	5.09	4.99	4.89	4.79	4.69	4.59	4.49	4.39	4.29	4.19	4.09	3.99	3.89	3.79	3.69	3.59	3.49	3.39	3.29	3.19	3.09	2.99	2.89
0.4%	5.53	5.43	5.33	5.23	5.13	5.03	4.93	4.83	4.73	4.63	4.53	4.43	4.33	4.23	4.13	4.03	3.93	3.83	3.73	3.63	3.53	3.43	3.33	3.23	3.13	3.03
0.5%	5.66	5.56	5.46	5.36	5.26	5.16	5.06	4.96	4.86	4.76	4.66	4.56	4.46	4.36	4.26	4.16	4.06	3.96	3.86	3.76	3.66	3.56	3.46	3.36	3.26	3.16
0.6%	5.79	5.69	5.59	5.49	5.39	5.29	5.19	5.09	4.99	4.89	4.79	4.69	4.59	4.49	4.39	4.29	4.19	4.09	3.99	3.89	3.79	3.69	3.59	3.49	3.39	3.29
0.7%	5.92	5.82	5.72	5.62	5.52	5.42	5.32	5.22	5.12	5.02	4.92	4.82	4.72	4.62	4.52	4.42	4.32	4.22	4.12	4.02	3.92	3.82	3.72	3.62	3.52	3.42
0.8%	6.06	5.96	5.86	5.76	5.66	5.56	5.46	5.36	5.26	5.16	5.06	4.96	4.86	4.76	4.66	4.56	4.46	4.36	4.26	4.16	4.06	3.96	3.86	3.76	3.66	3.56
0.9%	6.19	6.09	5.99	5.89	5.79	5.69	5.59	5.49	5.39	5.29	5.19	5.09	4.99	4.89	4.79	4.69	4.59	4.49	4.39	4.29	4.19	4.09	3.99	3.89	3.79	3.69
1.0%	6.32	6.22	6.12	6.02	5.92	5.82	5.72	5.62	5.52	5.42	5.32	5.22	5.12	5.02	4.92	4.82	4.72	4.62	4.52	4.42	4.32	4.22	4.12	4.02	3.92	3.82
1.1%	6.46	6.36	6.26	6.16	6.06	5.96	5.86	5.76	5.66	5.56	5.46	5.36	5.26	5.16	5.06	4.96	4.86	4.76	4.66	4.56	4.46	4.36	4.26	4.16	4.06	3.96
1.2%	6.59	6.49	6.39	6.29	6.19	6.09	5.99	5.89	5.79	5.69	5.59	5.49	5.39	5.29	5.19	5.09	4.99	4.89	4.79	4.69	4.59	4.49	4.39	4.29	4.19	4.09
1.3%	6.72	6.62	6.52	6.42	6.32	6.22	6.12	6.02	5.92	5.82	5.72	5.62	5.52	5.42	5.32	5.22	5.12	5.02	4.92	4.82	4.72	4.62	4.52	4.42	4.32	4.22
1.4%	6.86	6.76	6.66	6.56	6.46	6.36	6.26	6.16	6.06	5.96	5.86	5.76	5.66	5.56	5.46	5.36	5.26	5.16	5.06	4.96	4.86	4.76	4.66	4.56	4.46	4.36
1.5%	6.99	6.89	6.79	6.69	6.59	6.49	6.39	6.29	6.19	6.09	5.99	5.89	5.79	5.69	5.59	5.49	5.39	5.29	5.19	5.09	4.99	4.89	4.79	4.69	4.59	4.49
1.6%	7.13	7.03	6.93	6.83	6.73	6.63	6.53	6.43	6.33	6.23	6.13	6.03	5.93	5.83	5.73	5.63	5.53	5.43	5.33	5.23	5.13	5.03	4.93	4.83	4.73	4.63
1.7%	7.26	7.16	7.06	6.96	6.86	6.76	6.66	6.56	6.46	6.36	6.26	6.16	6.06	5.96	5.86	5.76	5.66	5.56	5.46	5.36	5.26	5.16	5.06	4.96	4.86	4.76
1.8%	7.40	7.30	7.20	7.10	7.00	6.90	6.80	6.70	6.60	6.50	6.40	6.30	6.20	6.10	6.00	5.90	5.80	5.70	5.60	5.50	5.40	5.30	5.20	5.10	5.00	4.90
1.9%	7.54	7.44	7.34	7.24	7.14	7.04	6.94	6.84	6.74	6.64	6.54	6.44	6.34	6.24	6.14	6.04	5.94	5.84	5.74	5.64	5.54	5.44	5.34	5.24	5.14	5.04
2.0%	7.67	7.57	7.47	7.37	7.27	7.17	7.07	6.97	6.87	6.77	6.67	6.57	6.47	6.37	6.27	6.17	6.07	5.97	5.87	5.77	5.67	5.57	5.47	5.37	5.27	5.17
2.1%	7.81	7.71	7.61	7.51	7.41	7.31	7.21	7.11	7.01	6.91	6.81	6.71	6.61	6.51	6.41	6.31	6.21	6.11	6.01	5.91	5.81	5.71	5.61	5.51	5.41	5.31
2.2%	7.94	7.84	7.74	7.64	7.54	7.44	7.34	7.24	7.14	7.04	6.94	6.84	6.74	6.64	6.54	6.44	6.34	6.24	6.14	6.04	5.94	5.84	5.74	5.64	5.54	5.44
2.3%	8.08	7.98	7.88	7.78	7.68	7.58	7.48	7.38	7.28	7.18	7.08	6.98	6.88	6.78	6.68	6.58	6.48	6.38	6.28	6.18	6.08	5.98	5.88	5.78	5.68	5.58
2.4%	8.22	8.12	8.02	7.92	7.82	7.72	7.62	7.52	7.42	7.32	7.22	7.12	7.02	6.92	6.82	6.72	6.62	6.52	6.42	6.32	6.22	6.12	6.02	5.92	5.82	5.72
2.5%	8.36	8.26	8.16	8.06	7.96	7.86	7.76	7.66	7.56	7.46	7.36	7.26	7.16	7.06	6.96	6.86	6.76	6.66	6.56	6.46	6.36	6.26	6.16	6.06	5.96	5.86

Target Leakage Range (0.0%–1.0%)

Likely retrofit capture rates based on expert consultation (60%–70%)

Figure 1. SMR units are assumed to produce 10 kg CO2e / kg H2 without carbon capture, based on assumptions used by Gorski et al. (2021). It is assumed that clean electricity is used for any power needs of the SMR+CCS, so emissions from electricity are assumed to be zero—total H2 CI in the figure is only a function of upstream leakage and process CO2 emissions.

Other (e.g., pressure and purity conditions at output of hydrogen production facilities): The CHPS should address H2 purity in a way that accounts for a more realistic array of conditions. Specifically, pressure levels and purity levels will need to cover a much broader range depending on the application. Pressures can vary widely depending upon where the hydrogen is in the production pathway: pipeline injection (~80 bar), mobility (400-900 bar for HRS and 350 to 700 bar for vehicles), etc. Purity required varies widely depending upon the end use: mobility (grade 5.0, or 99.999%), for power (99%-99.9%), etc. It is also possible for certain production methods to result in a mix of gases that could reduce the overall purity of H2 but that would not materially impact its usage in applications. Mixtures of H2 that contain some level of inert or gases with no GWP (e.g., helium) should be treated as a possible product from the outlet of the system.

[12] https://www.airproducts.com/news-center/2021/06/0609-air-products-net-zero-hydrogen-energy-complex-in-edmonton-alberta-canada#/

[13] https://www.suncor.com/en-ca/newsroom/news-releases/2226977)

Additionally, the CHPS should include guidance on how to account for, and limit, H2 emissions from production plants that may result either from venting due to operational requirements or unwanted leaks. While H2 emissions don't cause direct warming, they have an indirect warming impact over short time frames that should be reflected in the CHPS CI calculation. As DOE continues to study H2 emissions impact, the CHPS should be updated to reflect a more accurate understanding as it evolves. Finally, the environmental impact and permanence of all other wastes / byproducts of the process under analysis (e.g., solid C from pyrolysis, slugs from W2H, sulfur, and other materials) should be validated and included if disposal incurs additional emissions.

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?

No comment.

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.

Figure 1 is missing emissions related to converting H2 to other vectors (e.g., LOHC, ammonia, methanol) that are used to deliver the hydrogen to the point of use. It also doesn't seem to account for transportation methods beyond pipeline transport. This seems incompatible with the approach described in the draft guidance, which states the "lifecycle target corresponds to a system boundary that terminates at the point at which hydrogen is delivered for end use". Given that the CHPS will be used to assess the hydrogen hubs, it will be important to understand how both upstream and downstream emissions, up to the point of delivery for end use, influence the carbon intensity of the H2. That said, we recognize that the hubs will be assessed both by the carbon intensity of their H2 production against the CHPS, as well as by the carbon intensity of the full life cycle against the incumbent pathway that clean hydrogen's use will be displacing. The CHPS guidance should be updated to ensure the system boundary shown in Figure 1 and the description in the document are aligned.

d) Mitigating emissions downstream of the site of hydrogen production will require close monitoring of potential CO2 leakage. What are best practices and technological gaps associated with long-term monitoring of CO2 emissions from pipelines and storage facilities? What are the economic impacts of closer monitoring?

The current long-term monitoring programs for storage and transportation are robust, effective, and safe. Storage has seen no leaks, out of any storage medium, with over 400 million tons of CO2, stored since the 1990s, globally including tens of million in the United States. This is due to the pre-operational, operational and closure best practices including: wells logs, wellhead and formation pressure, injection and production testing, seismic surveys, micro-seismicity baselines, baselines atmospheric monitoring, surface CO2 sensors and more.

The need for all of these monitoring technologies will be highly site-dependent, underlying the need for total, quality site characterization.

Monitoring and sensing for CO2 pipelines include pipeline flow assurances, field sensors, corrosion monitoring, as well as aerial drone footage shot over varying time spans. The CO2 pipeline record is also outstanding with one major incident, caused by an incredibly unlikely sinkhole event and a contaminated CO2 stream.

The economic impacts of the increased monitoring are non-linear and highly dependent on the monitoring technique used. For storage, seismic is disproportionately more expensive than the other techniques and requiring more would drastically increase the cost of storage projects. The economic costs of pipelines are driven by active field visits though this could be mitigated through drone implementation.

The DOE should consider zero to negligible leakage rates from both storage and transportation unless site-specific criteria necessitate a different evaluation.

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

While more research should be done to assess rates of hydrogen leakage, the general view is that the climate impacts of H2 leakage are likely to be small and shorter term relative to the climate impacts of methane leakage; furthermore, the climate impacts of methane leakage from fossil fuel-based hydrogen production with high rates of carbon capture are in turn likely to be smaller and shorter term than the climate impacts of unabated direct combustion of fossil fuel-based methane.[13]

A key issue in characterizing the indirect climate warming impact of hydrogen is choosing the appropriate metrics to use. The convention has been to use the 100-year GWP metric applied to emissions of 1 kg of different gases to assess warming impacts. While this metric is imperfect, it is preferable to other metrics that have recently been proposed and we believe this metric should be the basis for accounting for hydrogen leakage in the CHPS.

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

As shown in Figure 1, the life cycle system boundary proposed for the CHPS assumes that CO2 captured in the production of hydrogen is permanently sequestered. If instead, the CO2 is utilized in such a way that it is eventually emitted into the atmosphere (e.g., utilized in clean fuels), the climate benefit of the CO2 capture would be reduced. The CHPS should avoid crediting sequestered and utilized CO2 equally.

As this question demonstrates, a hydrogen production standard is not a sufficient approach for assessing the reduction in carbon emissions that is realized by making and using clean hydrogen to displace incumbent processes. Any robust assessment of carbon intensity should be performed from cradle to grave.

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?

Questions around the additionality associated with inputs into hydrogen production processes are challenging to address. Including an assessment of Scope 2 and partial Scope 3 emissions in the GHG accounting of lifecycle emissions is important in understanding the role that clean hydrogen's production, movement and use will play in reducing greenhouse gas emissions relative to an incumbent process. However, since the CHPS proposed here does not cover the entire lifecycle of hydrogen, and cannot be used to assess the relative GHG emissions reductions associated with the use of clean hydrogen, it may not be necessary to include assessments of Scope 3 emissions at least in the first version of the CHPS.

While existing frameworks for Scope 2 and 3 accounting do have drawbacks, it is not clear that introduction of a new framework would be helpful. Additionality of green hydrogen, and how to prove it, is currently the subject of intense debate in Europe; this includes the question of how to account for the temporal correlation between "additional" renewable electricity production and its consumption in the electrolyzer, and on the geographic correlation between where the renewable capacity is physically located and whether the receiving electrolyzer is in that market.[14]

Given the Department of Energy's ability to revise the CHPS within a five-year window, the agency could consider electing to use existing LCA methodology in the near term, and subsequently assess the accuracy of this tool in estimating the emissions intensity of projects, and the state of the clean hydrogen market at the end of a two- or three-year period. At this time, DOE could use this information to determine if new criteria or a more thorough consideration of end-use in LCA accounting is necessary and valuable to ensure hydrogen production and end-use are yielding emissions reductions, and not increases. This would balance the need to speed up deployment of nascent clean hydrogen production pathways with the desire to prioritize high integrity, low-emission projects.

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

No comment.

[14] https://www.rechargenews.com/energy-transition/scrapped-eus-controversial-additionality-rules-for-green-hydrogen-are-history-after-european-parliament-vote/2-1-1299195

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?

No comment.

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)?

No comment.

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?

Monitoring and validation should be done according to standards on a regular basis (where standards don't exist, they should be created). Some approaches that should be used to verify emissions from commercial-scale projects include site audits during operations (where applicable), carbon intensity or green certificates (for feedstocks like NG, power, and water), mass balance calculations, and verification through operational data. The approach taken will depend on the part of the value chain that is being assessed: an assessment for a pipeline will be different from the approach taken to assess an H2 plant and different from a CCS storage site. While there is already experience on how to assess, measure, and certify leaks from pipelines and CO2 wells, more work may be required to standardize an approach for H2 manufacturing plants. Plant operators like Shell, who have already implemented a process, should be consulted for insights.

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?*

No comment.

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?

Renewable energy credits, power purchase agreements, or other market structures should be allowable, but with restrictions that prevent these tools from simply pushing the carbon impact of electricity on a regional grid to other users. However, guardrails should also be designed to avoid unnecessary obstacles to clean hydrogen production. Some examples of these restrictions include:

(1) RECs for renewable power should be temporally correlated with their usage in electrolysis. However, to avoid increasing production costs and limiting volumes, the EU's approach of correlating on a monthly basis could be used at first. Switching to a more granular temporal correlation should be gradual, subject to the actual deployment of renewables and actual feasibility for project developers to deliver on a more stringent requirement.

(2) Eventually, RECs should be available only on the basis of "additionality", but requirements around additionality in the near-term should phase in over time to give the clean hydrogen market a chance to ramp up. Otherwise, permitting and construction timelines, and the resultant delays, could greatly hamper the feasibility of hydrogen production.

(3) RECs should only be available within the same power grid; for example, wind power added in Wyoming should not be available for use by an electrolyzer in Florida. A similar approach is taken in the EU; there, an electrolyzer should be in the same 'bidding zone' as the renewable generation. A bidding zone is the largest geographical area within which market participants are able to exchange energy without capacity allocation.

It is also important to note that recent analyses suggest the deployment of electrolytic hydrogen will not be as fast or aggressive as cost modeling might lead us to believe, given challenges associated with supply chain build out, other economic factors, and technology limitations. For these reasons, there may be value in being more lenient in near-term accounting, and increasing requirements on electricity additionality over time.

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

To the extent that meeting the standard in the near-term requires use of mostly clean (>85% clean electricity), meeting the standard may be challenging for first mover projects. To address this, flexibility in phasing in any additionality requirements is crucial to account for long permitting procedures of renewable projects. Before additionality requirements kick in, a transitional period is needed for the market to ramp-up. In the EU, industry associations[15] are asking for a transitional period up until 2028, and a ten-year grandfathering period for early projects starting at the end of the transitional period (equivalent to the length of a standard power purchasing agreement) so that first mover projects comply with additionality rules in the second half of their lifetime.

4) Additional Information

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

Adherence to the CHPS

While the CHPS will not categorically exclude projects that cannot meet the threshold carbon intensity for clean hydrogen or the more encompassing carbon intensity described in the CHPS so long as they "demonstrably aid the achievement of the CHPS", caution should be exercised when substantiating

[15] https://renewableh2.eu/wp-content/uploads/2022.10.6_Industry-letter-on-RFNBO-DA.pdf (Renewable Hydrogen Coalition (supported by BE) and Hydrogen Europe

decisions to select such projects, and transparent and detailed justification should be required of the applicant and made available by DOE in such cases.

There are in fact three goals of the hydrogen hubs program in the BIL, which are:

1. Demonstrably aid in achievement of the CHPS;
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.**

To achieve this last goal in particular, hydrogen hubs should demonstrate technologies that are scalable decarbonization tools.

Overall, a 4kgCO2/kgH2 threshold might make sense in the short term for an applicant for federal hubs funding, but in order to meet all three of the goals of the hydrogen hubs, any project that is selected as a hub should be able to demonstrate, in a detailed and credible manner, a pathway for reaching a target of <2kgCO2/kgH2 with a specific target timeline for doing so. Any technology or project that cannot make improvement to reduce the carbon intensity of production below 4kgCO2/kgH2 by 2030, or at least within the decade, should not be prioritized as a scalable solution for decarbonization.

GREET

In addition to the comments made above, the GREET model should be updated regularly to ensure that inputs to the tool reflect the latest understanding about the assumptions made and incorporate novel processes to produce hydrogen. Additionally, as a means of refining the CHPS in next iterations, an effort should be made to gather data from real projects to inform the assumptions used to set the standard, with the goal of continuing to lower the standard over time to the greatest extent that is economically and technically possible. This data should also be made publicly available in some format. Finally, additional pathways should be incorporated into the model to improve its applicability across all modes of clean hydrogen production.