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.

Need to see the excel file to provide comments.

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?

The estimates from GREET are fairly accurate on a regional basis. However, issues can be encountered when looking at micro geographies. A micro geography carbon emissions can be significantly altered by the simply start of a solar or wind electricity production facility or worsen by a new natural gas power plant.

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.

The efficiencies associated with electricity transportation and distribution appear to be missing from figure 1. The EIA estimates that 5% of the US electricity production is loss in transmission and distribution (https://www.eia.gov/tools/faqs/faq.php?id=105&t=3), resulting in higher GHG emissions at the point of consumption.

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?

Monitoring and measuring the CO2 volume at the point of injection in the CCS site is ultimately the most accurate way of determining the actual reduction. Furthermore, measurements of upstream feedstock like natural gas in a steam methane reforming facility allows for the calculation of the CO2 emissions (CO2 produced from natural gas in the SMR minus captured and sequester CO_2 = emitted CO_2). These calculated CO_2 emissions would include the so called CO_2 leakage.

e) Atmospheric modeling simulations have estimated hydrogen's indirect climate warming impact (for example, see Paulot 2021).[19] 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?

If hydrogen is used as a feedstock to produce other products, the indirect impact can be calculated via the difference between the hydrogen produced (i.e. from natural gas via SMR) and the hydrogen still present in the downstream product (i.e. ammonia). This can provide a fairly accurate value of the hydrogen unintentionally released. If hydrogen is used a fuel in either direct combustion or a fuel cell, then estimating the indirect impact becomes more difficult to achieve.

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?

All CO_2 released has an equal negative impact to the environment, however not all released CO_2 is equal. One can produce hydrogen from natural gas via steam methane reforming and release the CO_2 at the production site, or the CO_2 could be captured and used to make a useful product like dry ice (used in the food and beverage industry), urea (made by reacting ammonia with CO_2 and used as fertilizer) before is released. Both CO_2 molecules ended up being released to the atmosphere, but one can argue that the CO_2 used to make other products had a more useful life on earth than the CO_2 released directly from the SMR. At a minimum, CHPS should be consistent with the IRA definition for the $\leq$2 $kgCO_2e/kgH_2$ at the site of production which does not include the CO_2 quantities that leave the facility as a product (dry ice, urea, etc.).

2) Methodology

This is exactly the type oof questions we are trying to answer by engaging with Hinicio. I do not think we are able to answer them yet. Perhaps Hinicio could provide input on this?

a) The IPHE HPTF Working Paper (https://www.iphe.net/iphe-working-paper-methodology-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?

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?

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 by-product hydrogen from these processes typically handled (e.g., venting, flaring, burning onsite for heat and power)?

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?

Hydrogen producers would have to provide some level of detail data about their operations, like source of natural gas, natural gas consumption, hydrogen production, quantities of CO_2 permanently sequester, etc.

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?

This can be done if gas deliveries can be tracked from source to end user via the multiple traders that may or may not be involved. Not an easy task…

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, RECs (Renewable Energy Credits), VPPAs (Virtual Power Purchase Agreements) and other structures should be allowed to characterize the carbon intensity emissions for hydrogen production. Here are the requirements to be able to do so:

- The RECs should be retired on behalf of the entity producing the hydrogen so that it can be traceable
- For new hydrogen producing facilities, that require incremental power demand, the RECs or VPPAs should come from new renewable energy producing facilities only. The new incremental demand requires new incremental supply, and this must not come from a carbon source
- For retrofits of existing facilities that do not require incremental power demand, the RECs or VPPAs can come from any renewable energy producing facilities (new or existing)

The one con with this approach is the intermittency of renewable power supply and the continuous power demand of hydrogen production, which as the US grid becomes greener then incremental continuous demand might need incremental carbon based power. This, however, isn't a concern yet given that the US grid is at 20% renewable (https://www.eia.gov/tools/faqs/faq.php?id=427&t=3).

d) What is the economic impact on current hydrogen production operations to meet the proposed standard (4.0 $kgCO_2e/kgH_2$)?

Most hydrogen produced in the US is via steam methane reforming (SMR) of natural gas. An SMR without carbon capture and sequestration emits ~10-12 $kgCO_2e/kgH_2$, about 60% of these emissions come from the process side, the CO_2 produced when removing hydrogen from methane, and the remainder 40% come from the combustion of natural gas to generate the heat required to operate the reformer. The 60% process side emissions typically consist of high purity CO_2, 94-96% with the balance being water, and can be captured, dehydrated, and compressed to be permanently sequestered. The 40% combustion emissions are typically flue gas with 8-12% CO_2 in nitrogen and other compounds. This low concentration CO_2 is very costly to capture as it requires ammine absorption processing and glycol dehydration before the CO_2 can be compressed for permanent sequestration, the current 45Q tax credit of $85 per metric ton of CO_2 does not make flue gas capture economically feasible. Furthermore, the cost of this processing is dependent on the scale. The only flue gas CO_2 capture facility in operation in the US is the Petra Nova coal fire power plant facility that captures 1.4 million metric tons of CO_2 annually (https://www.energy.gov/fecm/petra-nova-wa-parish-project). Most hydrogen producing facilities do not have the quantity of flue gas CO_2 emissions necessary to reach a project scale like the Petra Nova facility.

4) Additional Information

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

One point of consideration is the fact that the IRA does not allow a single facility to receive both a 45Q tax credit and a 45V tax credit. This is clearly intended to prevent facilities from capturing CO_2 and getting double credits on the hydrogen, which is understandable. This issue I have is in relation to 45Q(c) which is the $60/MT tax credit that a facility can receive from using captured CO_2 to make environmentally friendly products like chemicals or fuels. I argue that 45V credits and 45Q(c) credits should be allowed in the same facility, for example:

Renewable power > hydrogen via electrolysis > green ammonia + CO_2 > urea

Taking renewable power to make green hydrogen and then green ammonia, then capturing CO_2 to reacted with the green ammonia to make carbon neutral urea. In this example, the facility should be able to claim 45V for the clean hydrogen and 45Q(c) for the CO_2 used to make carbon neutral urea. These credits are for two separate products and should be allowed.

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