United States Department of Energy
Office of Energy Efficiency & Renewable Energy
1000 Independence Avenue, SW
Washington, DC 20585
Cleanh2standard@ee.doe.gov

Proposed Clean Hydrogen Production Standard:
Comments and Feedback from Bakken Energy

To Whom It May Concern:
On behalf of Bakken Energy, I respectfully submit the following comments to the Department of Energy's Office of Energy Efficiency & Renewable Energy in response to the Department of Energy's (DOE's) initial proposal for a Clean Hydrogen Production Standard (CHPS), developed to meet the requirements of the Infrastructure Investment and Jobs Act of 2021, also known as the Bipartisan Infrastructure Law (BIL), Section 40315.

Bakken Energy is a commercial scale hydrogen production company built with a focus on decarbonizing heavy-duty transportation in the upper Midwest and across the country. We appreciate the opportunity to respond to the DOE's request for feedback pertaining to the proposed CHPS.

We would welcome the opportunity to participate in any stakeholder engagement as the DOE further crafts this important guidance. Thank you for your time and your consideration.

Sincerely,

Chris B. Tillotson
Chief Projects Officer

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.

See Attached spreadsheet

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?

While well suited for many use cases, the GREET model needs to evolve to better support low-carbon intensity natural gas-based hydrogen production methods including ATR. As currently constituted, the model does not support the level of granularity needed to account for project specific factors, such as the utilization of low-carbon intensity cogenerated power and steam sources, and avoided emissions from use of responsibly-sourced natural gas feedstock. This is discussed further in response to question 2(a) below.

2) Methodology

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?

Bakken Energy supports the inclusion of a CHPS LCA framework, as such a framework allows for carbon intensity to be measured consistently across the various clean hydrogen projects and the taxpayers that support them. Still, we are concerned that if DOE does not modify GREET to better account for project specific traits with granularity up and down the supply chain and/or account for project characteristics that have a net positive environmental impact (i.e., avoided emissions), the credit will not properly incent the responsible hydrogen production it's drafters intended.

We are supportive of carbon accounting methods that incorporate accounting for 'avoided emissions' and the GHG emissions impact of clean hydrogen production relative to the situation (or baseline) where clean hydrogen production does not currently exist. Specifically, this would apply to the use of flare gas in the production of clean hydrogen where the avoided GHG emissions in the form of methane emissions and increased CO2 emissions from the flare stack would be accounted for and applied to LCA calculations. These avoided emissions have been referred to as Scope 4 – Avoided Emissions. Avoided emissions would also apply to brownfield scenarios whereby an existing higher GHG emitting facility is redeveloped into clean hydrogen production facility with greatly reduced GHG emissions.

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?
The taxpayer should determine how GHG emissions should be allocated to co-products, considering what co-products are being produced and the pathway being used in the production of the hydrogen. The taxpayer's proposed approach should have a technical basis and be subject to approval by the DOE. A one-size fits all approach will almost certainly run into unforeseen circumstances where a particular co-product (e.g., oxygen as co-product using an energy-based approach would be allocated zero emissions because oxygen has no heat value, and the approach would breakdown in this case) would not be accounted for.

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)?

Please see the answer to question 2(c).

3) Implementation

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

We have no current plans to retrofit existing grey SMR hydrogen facilities to clean hydrogen production facilities. Attempting to do so would pose several techno-economic challenges, including:

- the economic limit of CO_2 capture for syngas is approximately 98%;
- the economic limit of CO_2 capture of SMR flue gas is approximately 90% (due to the low partial pressure of CO_2 – both from a mole % and operating pressure perspective), and flue gas carbon capture processes are much more expensive than syngas;
- depending on the design of the SMR and the water shift reactors, the amount of CO and CH_4 slip can be relatively high and can represent 30-40% of the total carbon in the syngas, which will ultimately become Scope 1 emissions as this waste stream is typical used as fuel (assuming no carbon capture on the equipment utilizing this fuel) – even with carbon capture, the economic limit would be 90% due to the low partial pressure of CO_2 in these applications; and
- SMR carbon capture requires two carbon capture units – one for the syngas and a unit for the SMR flue gas resulting in additional cost and complexity of the retrofit.

These observations were modeled in GREET1 using the H2 User Interface and GREET's default SMR values (Well-to-Gate) in the most optimistic scenario. Even such, using our pathway, the output barely achieves the proposed clean hydrogen production standard of 4.0 kgCO_2e/kgH_2 and would require a more in-depth analysis using process simulations and licensor carbon capture proprietary information to confirm feasibility of achieving the proposed specification.

There may also be other physical constraints (e.g., insufficient space around the SMR for the carbon capture units) that may make retrofitting these existing units impractical or uneconomic.