Bloomenergy™

November 14, 2022

Via E-mail: cleanh2standard@ee.doe.gov
U.S. Department of Energy
James V. Forrestal Building
1000 Independence Avenue Southwest
Washington, D.C. 20585

Re: Comments on the U.S. Department of Energy Clean Hydrogen Production Standard (CHPS) Draft Guidance

Bloom Energy appreciates the opportunity to submit its comments in support of the Clean Hydrogen Production Standard (CHPS) Draft Guidance issued by the Department of Energy's ("DOE" or "Department").[1]

Bloom Energy applauds Secretary Granholm and the Department for their efforts to advance the production of clean hydrogen, which will be key to a clean, equitable, reliable and affordable energy transition. Bloom Energy appreciates the opportunity to respond to the draft CHPS guidance and looks forward to working with the DOE on deploying both hydrogen electrolyzers and hydrogen fuel cells to contribute to that transition.

Founded in 2001, Bloom Energy's mission is to make clean, reliable, and affordable energy for everyone in the world. Bloom's Energy Server Platform is a technology for producing clean and sustainable energy, whether in the form of our Solid Oxide Electrolyzer Cell (SOEC), which has won numerous accolades for industry-leading efficiency in electrolytic hydrogen production, or our solid oxide fuel cell (SOFC), which delivers highly reliable and resilient, 'Always On' electric power, and can be powered by hydrogen, ammonia, methane (whether biogas, renewable natural gas or natural gas), or blends of them. The Bloom Energy SOEC and SOFC are designed in California and are manufactured in California and in Delaware. Bloom Energy recently announced its first dedicated production line for hydrogen electrolyzers.[2]

Bloom Energy systems power everything from hospitals to data centers to grocery stores with 24/7/365 on-site, uninterruptable power. At Bloom Energy, we help create sustainable communities by reducing carbon emissions and criteria air pollutants, including the particulate emissions that disproportionately burden disadvantaged communities. In 2020, our systems reduced CO2e, NOx, and SO2 emissions for our customers by 636,266 Metric Tons, 2,467,309 lbs and 550,651 lbs respectively. Bloom Energy's solid oxide electrolyzer (SOEC) recently demonstrated its potential for pairing with zero-carbon energy production through its partnership with the DOE's Idaho National Laboratory (INL), which found that the Bloom Energy

[1] 87 Fed. Reg. 58,776 (Sep. 28, 2022).
[2] Owens, "Bloom Energy Opens First Electrolyzer Production Line" (Delaware Business Times, Nov. 1, 2022), *available at* Bloom Energy opens first electrolyzer production line - DBT (delawarebusinesstimes.com).

solid oxide electrolyzer was the most efficient tested to date. As INL Director John Wagner stated,

> "The Bloom electrolyzer is, without a doubt, the most efficient electrolyzer we have tested to-date at INL," said John Wagner, director, Idaho National Labs. "When hydrogen is produced from a clean, 24/7 source, like nuclear, it can help us address some of the significant challenges we face around decarbonization. Pairing the research and development capabilities of a national laboratory with innovative and forward-thinking organizations like Bloom Energy is how we make rapidly reducing the costs of clean hydrogen a reality and a real step toward changing the world's energy future."[3]

Bloom Energy's SOEC is exceptionally efficient in any application, but particularly excels when paired with clean power and an exothermic heat source, such as steam from nuclear generation or heat from industrial applications.

Responses to Requests for Stakeholder Feedback

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.***

Response:

Bloom Energy does not have subject-matter expert opinions on future values of lifecycle emission parameters for hydrogen production. However, we can provide feedback on the assumptions made regarding key parameters with high variability that are described in the Hydrogen Production Pathway Assumptions spreadsheet provided by the Department.

Fugitive methane emissions:

An emerging certified gas marketplace in the U.S. allows value chain leak rates to be certified through standards designed by organizations such as MiQ, Equitable Origin, Xpansiv, and Project Canary. MiQ, for example, has developed a methane emissions certification standard with regulation through a not-for-profit and independently audited certification standard. The MiQ

[3] EnergyTech Staff, "Idaho National Lab Hydrogen Demonstration: Bloom Electrolyzer highly efficient at nearly 38 kWh per KG" (Energy Tech Aug. 11, 2022), available at https://www.energytech.com/energy-efficiency/article/21248571/idaho-national-lab-hydrogen-demonstration-bloom-electrolyzer-highly-efficient-at-nearly-38-kwh-per-kg

Standard is an independent framework for assessing methane emissions from the production of natural gas, along with the policies and practices of the producers making it. MiQ Certificates, which are held on MiQ's Digital Registry, contain the certified methane intensity for each facility, from production to boosting and gathering, processing, transmission and storage, liquefaction, LNG shipping and regasification. Each certified facility is audited and is given a methane intensity grade that feeds into an overall grade and methane intensity for the aggregation of each stage of the supply chain. Certificates can be retired on the MiQ Digital Registry by (or on behalf of) end users. Statements setting out the details of the certificates retired can then be used as evidence in lifecycle assessments and greenhouse gas reporting and lifecycle assessments, creating more precise emission estimates for methane fugitive methane leakage during hydrogen production. Bloom suggests that the Standard allows companies to use their MiQ certified leak rates to demonstrate leak rate performance in their lifecycle assessments for hydrogen production.

As a part of their work, MiQ is in the process of modeling basin-specific natural gas supply chain leak rates for over 600 basins globally. This opensource tool can be used to provide leak rates for lifecycle assessments of hydrogen production and will be more accurate than assuming ~1% methane leakage for the national average. Bloom suggests that the CHP Standard includes language to allow companies to use basin-specific leak rates in their lifecycle assessments for hydrogen production.

Rate of carbon capture:

Bloom agrees with the proposed 95% carbon capture at natural gas reforming facilities and gasification plants but does not have any estimates for future achievable regional or national average values.

Share of clean energy within electricity consumption:

Bloom agrees with the use of predominantly clean energy in electrolysis to enable achievement of lifecycle targets proposed in this draft guidance. However, the technical and economic feasibility of access to 85% clean power is completely dependent upon the guidance permitting use of market-based mechanisms for acquiring clean power. Please see Bloom's response below to Question 3.C. for our feedback on why clean energy procurement should include market-based solutions for hydrogen production.

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?

Response:

The GREET model uses eGRID emission factors to determine the carbon intensity of regional grids. The World Resource Institute's (WRI) Greenhouse Gas Protocol (GHG) Scope 2 Guidance[4] lists location-based emission factor hierarchies and lists the eGRID total output emission rates as an indicative emission factor to use. Published eGRID subregional rates are the most accurate, standardized, and transparent method for reporting emissions from purchased electricity. The eGRID subregion emission rates most accurately represent the actual electricity used by consumers by limiting the import and export of electricity within an aggregated area.

The subregions were defined by the U.S. Environmental Protection Agency (EPA) as a compromise between NERC regions (which EPA felt were too big) and balancing authorities (which EPA felt were generally too small). These emission rates are heavily utilized for voluntary greenhouse gas reporting and are expected to be adopted by the SEC, as stated in the Proposed Rule to Enhance and Standardize Climate-Related Disclosures for Investors. The SEC ruling would require companies to disclose Scope 1 and 2 greenhouse gas emissions, along with an abundance of additional ESG metrics. Aligning the calculation requirements of the carbon intensity of regional grids with the GHG Protocol Scope 2 Guidance and SEC Proposed Rule on Climate-Related Disclosures will provide a standard approach for companies while allowing them to reference pre-existing guidance documents for their lifecycle analyses.

Bloom suggests that the CHPS recommends that companies use the most recent version of eGRID total output emission rates to represent the carbon intensity of regional grids and that the GREET model updates their grid emission rates annually to reflect the most recent eGRID emission rate releases.

> ***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.***

Response:

Bloom Energy supports a CHPS definition that is fully consistent with the definition of "qualified clean hydrogen" under 26 U.S.C. Section 45V, promulgated in Section 13204 of the 2022 Inflation Reduction Act ("IRA"). DOE should continue to coordinate closely with Treasury to ensure that there are no differences that could, by creating confusion in the market and thereby chilling financing, undermine the joint intent of the IRA and the IIJA to stimulate a robust clean hydrogen economy.

We note that the statutory definitions of the Clean Hydrogen Production Standard and of qualified clean hydrogen both focus on emissions up to production, with CHPS referring to emissions "produced at the site of production" and the tax credit referring to emissions to the

[4] https://www.wri.org/research/ghg-protocol-scope-2-guidance

"point of production"; cf. 42 U.S.C. § 822(b)(1)(B) & 26 U.S.C. § 45V(c)(1)(B). While the GREET lifecycle analyses through to the point of production are specifically identified for use in determining the 45V hydrogen production tax credit, and consistent with the requirements for the Clean Hydrogen Production Standard, consideration of downstream emissions after the point at which the hydrogen is produced is clearly precluded by both statutory provisions. Policy concerns and regulatory requirements regarding any downstream emissions associated with hydrogen distribution may well be appropriate for other authorities, but they must be addressed pursuant to those authorities, and are not permissible for either the Clean Hydrogen Production Standard or the 45V hydrogen tax credits. Emissions associated with the distribution of hydrogen after the point of production are not only well beyond the statutory authority, but are generally beyond the control of the entities producing hydrogen (unlike upstream emissions, which hydrogen producers have some control over through their energy and feedstock choices). Downstream emissions beyond the point of production should be addressed through policy and regulatory mechanisms focused on the entities responsible for distribution and utilization of hydrogen beyond the point of production.

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?

Response:

Bloom Energy reserves any comment on this question at this time.

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?

Response:

While indirect climate warming impacts of hydrogen are currently under study, the state of science remains nascent, and is based on relatively scant data. The leaks and releases associated with hydrogen production are almost certainly de minimis relative to concerns that have been raised with respect to hydrogen distribution. Since the statute does not allow for consideration of downstream emissions in determining the CHPS, as discussed above, the sole focus of the CHPS should be on ensuring that reasonable steps to minimize emissions are incorporated in hydrogen production.

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

Response:

Bloom Energy reserves any comment on this question at this time.

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?

Response:

Bloom Energy supports the use of WRI's GHG Protocol for guidance on determining Scope 1, Scope 2, and partial Scope 3 emissions for companies' lifecycle analyses. The GHG Protocol is the basis for most GHG accounting frameworks, such as the CDP Climate Change Report and the U.S. Securities and Exchange Commission's proposed rule on climate-related disclosures.[5] Once the SEC Proposed Rule is promulgated, most companies will be required to report their Scope 1, Scope 2, and possibly Scope 3 emissions using the GHG Protocol.

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?

Response:

Bloom Energy reserves any comment on this question at this time.

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

[5] "The Enhancement and Standardization of Climate-Related Disclosures for Investors," 87 Fed. Reg. 21334 (Apr. 11, 2022).

allocated to the co-products (e.g., system expansion, energy-based approach, mass-based approach), and what is the basis for your recommendation?

Response:

Bloom Energy reserves any comment on this question at this time.

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)?

Response:

Bloom Energy reserves any comment on this question at this time.

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?

Response:

We recommend a third-party verification standard be established, similar to those present in the project development environment of most environmental attribute certificate (EAC) standards. The best practice is for new standards to align with ISO 14064-3:2019 "Greenhouse Gases — Part 3: Specification with Guidance for the Validation and Verification of Greenhouse Gas Assertions."[6] We recommend both validation of future claims and verification of past activity by a competent, independent, International Organization for Standardization (ISO) 14065-accredited third party. Annual time intervals for desk audits with limited assurance, and every 5 years for field validation with reasonable assurance, would be appropriate.

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?

Response:

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[6] https://www.iso.org/standard/66455.html

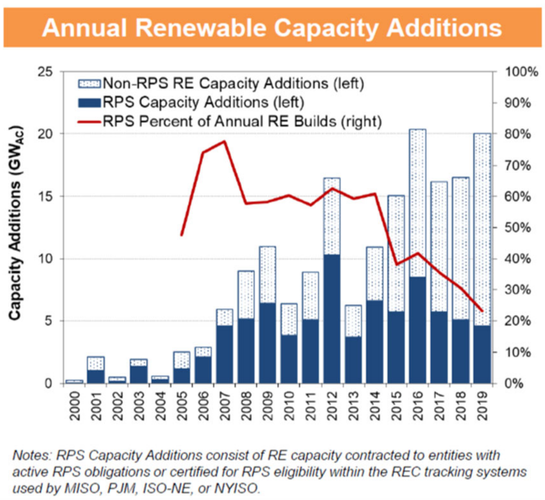
Generally, developers cannot definitively ascertain the basin of origin of any natural gas traveling through interstate pipelines, so we recommend that EPA-issued upstream average leak rate estimates be used as a default. Alternatively, there is an emerging certified gas marketplace in the U.S. that allows value chain leak rates to be certified through standards designed by organizations such as MiQ, Equitable Origin, Xpansiv, and Project Canary. Gas certified under these standards can be transacted with the underlying physical gas or its provenance and associated leak rate attributes unbundled from the underlying material and applied to gas delivered downstream. The mechanics and claims enabled by these transactions are similar to those present in the unbundled renewable energy credit marketplace. We recommend that DOE permit leak rates carried through certificated gas transactions replace default average leak rates otherwise published by EPA.

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?

Response:

Yes, renewable energy credits, power purchase agreements and other voluntary market structures, which have proven to be a significant driver for deploying clean energy and achieving the Department's SunShot Initiative, should be an allowable means of assessing electricity emissions for the power used in grid-connected electrolytic hydrogen projects. Numerous state, regional and voluntary programs have been developed, deployed and have had demonstrated success in contributing to the build-out of a greenhouse-gas reducing electricity system, using increasingly sophisticated market mechanisms. The use of these mechanisms is essential to achieving the goals of both the BIL and the IRA, including the development of a clean hydrogen production industry, and of the Department's own Hydrogen Shot initiative. By relying on established, broadly accepted voluntary market structures that meet reasonable threshold standards, the Department can take advantage of the momentum and achievements in deploying renewable and clean energy that has resulted from their use. As these standards are improved to reflect the dynamically-changing energy system, through the jurisdictions and complex stakeholder processes that established them and have created their success, it would be appropriate to subsequently apply those improved standards to new hydrogen production facilities.

There is no need or justification for the Department to create a voluntary market structure, or separate EAC standard, solely for electrolyzers. The production of hydrogen, from an electric system perspective, is no different than any other customer demand (or "load," as it is referred to in the power sector)—and the results of voluntary market structures on transforming the energy sector are nothing short of extraordinary. The EAC mechanisms that most voluntarily green power markets and state renewable portfolio standards and clean energy standards (collectively, "RPS"[7]) alike depend on for compliance with state law, regional market rules, voluntary standards and individual corporate or organizational commitments have developed in the United States over the last 25 years. From 2000 through 2019, voluntary green power markets have grown to produce approximately 150 TWh/year of renewable power, nearly 80% of the additional 189 TWh/year required by RPSs. There can be no question that these markets have significantly contributed to greening the electric power supply; as the U. S. DOE's Lawrence Berkeley National Labs has shown, the growth of those markets which form the bulk of non-RPS procurement has increasingly outpaced the minimum thresholds for state clean and renewable energy requirements, with the share of new renewable energy capacity attributable to legally-required RPS mechanisms shrinking to 23% in 2019.[8]



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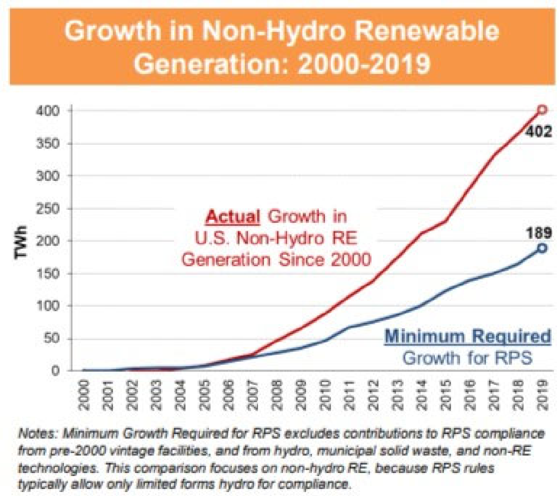

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Voluntary market mechanisms, including EAC standards, share many things in common, including the intent to reduce greenhouse gas emissions from energy production as well as other environmental, economic, and social benefits. Existing, widely deployed and accepted regional, state and voluntary market systems all resulted from complex, multi-stakeholder processes that required balancing myriad concerns and considerations. EAC systems generally start from the premise that a credit represents energy that otherwise would have been generated by non-qualifying resources, and therefore produces greenhouse gas benefits at a minimum (since generally speaking, electricity delivered to the grid must be constantly balanced with energy consumed,[11] and as greenhouse gas has global impacts, rather than local or regional impacts, the location of the reduction is immaterial with respect to global warming). There is no doubt that

[7] For purposes of these comments, we use the term RPS to include legally-required demonstration of the use of clean energy through RECs, zero emission credits (ZECs) and other mechanisms.

[8] Barbose, "U.S. Renewables Portfolio Standards 2021 Status Update: Early Release" (Feb. 2, 2021), *available at* https://emp.lbl.gov/publications/us-renewables-portfolio-standards-3

[9] *Id.* At 18

[10] *Id.*

[11] With the exception of storage, which is increasing at a rapid rate but remains a small percentage of overall grid capacity.

the varying EAC systems could be improved to achieve their underlying objectives, including more optimally driving carbon emissions from energy generation than can be accomplished through simple annual displacement by qualifying energy. Many EAC and RPS systems have developed significant restrictions over time to better align their use with the state, regional and corporate objectives of their underlying program, such as limiting qualifying generation to that "deliverable" to the end user. Concern has been raised by some parties that the energy need for electrolyzers may not match the generation provided by wind and solar, and could cause increased emissions- at least in some hours, and at least when electrolyzer load increases to a significant proportion of grid energy usage; these parties are likely to argue for EACs that have been "time-stamped" to match production and consumption. It is notable, however, that no broadly-accepted EAC system, either in the United States or elsewhere, has yet to match the time at which energy is used to the time at which it was generated- in part, perhaps, due to the complexity of storage which can shift that time, adding complexity that has not yet been evaluated through stakeholder processes underpinning EAC systems in broad use. The bodies responsible for developing, implementing and operating EAC systems, whether pursuant to state law, regional agreements, or voluntary understandings, are best situated to work with their stakeholders to enhance them, balancing the cost, complexity, environmental, social and market fluidity, credibility and administration considerations that have gone into establishing them. Since electrolyzers will comprise a very small percentage of the overall EAC-qualifying energy produced for many years to come, there is ample time for those state, regional and voluntary bodies to work through their stakeholder processes and make any changes to needed to adjust those systems so as to avoid unintended outcomes.

While a national EAC system as part of a national RPS or clean energy standard might well have many economic and environmental benefits, no such system has yet been authorized under federal law, and the Department has not been authorized to adopt one. In the meantime, and at least until much higher proportions of clean energy have been achieved than exists in even the cleanest energy systems operating in the nation to date, it cannot reasonably be disputed that EAC systems and voluntary green power markets in broad use are substantially reducing overall climate emissions from the power sector. We note that the legislative history of the IRA clearly indicates Congressional intent to allow the use of Renewable Energy Credits and other forms of EACs, for purposes of IRA compliance;[12] it is not credible to read into this exchange a reference to EAC systems that do not yet exist. An attempt to impose more stringent requirements on hydrogen production than prevails in existing electricity markets has no support in the IIJA or its legislative history. The regulation and standards associated with electric system emissions have been in existence and undergoing evolution for many years and are subject to the jurisdiction of many state and regional jurisdictions, as well as industry standards organizations. Inserting the CHPS program into that body of law and into the voluntary mechanisms have grown alongside them (and, as noted above, are increasingly exceeding them) would give the appearance of bootstrapping, inserting the Department into the regulation of climate emissions from the energy

[12] Colloquy between Sens. Carper & Wyden with respect to "H.R. 5376 – 117th Congress (2021-2022): Inflation Reduction Act of 2022" (Aug. 6, 2022), *available at* https://www.congress.gov/congressional-record/volume-168/issue-133/senate-section/article/S4165-3

sector in a fashion that has never been authorized in federal law, and risking the appearance of unwelcome intrusion by DOE into the jurisdictions and ongoing work of those other governmental and industry bodies.

In contrast, there is immediate and serious reason to be concerned that failing to recognize existing EAC systems that meet reasonable threshold standards could frustrate the intent of the BIL and the IRA to stimulate a new clean hydrogen economy, and the Department's "Hydrogen Shot" goal of driving clean hydrogen production costs to $1/kg by 2031.[13] Hydrogen production projects, including electrolyzers and their associated balance of plant, are capital-intensive; in addition, as is a well-known result of production tax credits such as the new 45V, their financing will depend on assurance of production outcome to provide a reasonably certain revenue stream from that credit. Consequently, hydrogen production facilities can be expected to operate the projects at a high capacity factor. Even those projects co-located with utility-scale solar or wind will still require electricity from the grid to operate when the renewable generation is not producing, to assure recovery of investment and capture of tax credit revenue. Grid power will be required to carry those projects through extended bad weather, even for those production facilities paired with co-located batteries as well as solar or wind, due to limited battery capacity (currently, co-located storage is most often deployed for two-to-four hour durations). One promising exception for co-location with clean energy generation for which grid power may not be necessary, and for which Bloom Energy is an acknowledged global leader, will be electrolyzers paired with nuclear generation. Geothermal offers another baseload clean energy exception. The charter for Department of Energy to advance clean hydrogen production through the CHPS, as well as through other provisions of the BIL and the IRA, certainly did not envision limiting its efforts to nuclear- or geothermal-paired electrolyzers, however.

Further, the nation has invested and is continuing to invest significant money into the modernization of the electric grid to enable the transmission of renewable power over longer distances. Cutting hydrogen production off from the grid will result in less efficient utilization of total available resources at two levels. First, the hydrogen production facility would overbuild renewables plus storage to maintain operations in a downside solar/wind case, underutilizing the renewable resource. Second, certain regions already experience significant curtailments (15-20%).[14] Hydrogen production facilities integrated into the grid can leverage existing "stranded" renewable generation as flexible load (within operating limits) to balance that generation. As an aside, it is important to note that EACs cannot be created from curtailed energy, only from energy actually delivered to the grid. A failure to allow use of existing, broadly-accepted EACs meeting threshold standards would also constrain hydrogen production to those limited locations in which renewable power is most reliable and least expensive, potentially further from hydrogen demand, exacerbating inefficiencies due to hydrogen transport that may not have been

[13] https://www.energy.gov/eere/fuelcells/hydrogen-shot

[14] *See* Seel et al, "Plentiful Electricity Turns Wholesale Prices Negative," Fig. 1 (Advances in Applied Energy, Nov. 2021), *available at* https://www.sciencedirect.com/science/article/pii/S2666792421000652?via%3Dihub

required if the electrons could be directed to a production facility closer to demand—and inconsistent with the Department's Hydrogen Hub initiatives.

Overall, in addition to increasing costs, failing to have access to developed EAC markets offers the worst combination of outcomes for the nation's energy infrastructure. Such an approach would: (i) lower demand (i. e. prices) in those EAC markets, dis-incentivizing new clean generation; (ii) limit the ability to leverage/balance excess renewables; and (iii) potentially force hydrogen production to the edges of the system. Given the track record of voluntary green power market mechanisms, the Department's charge to incentivize the development of green hydrogen production in this country, and the Department's limited authority with respect to imposing or altering the existing state, regional, or voluntary EAC systems on which billions of dollars of investments already rely, it is both reasonable and appropriate for the Department to rely on those systems, providing that they meet minimum standards to assure continued reduction of greenhouse gas emissions. This course of action is also consistent with federal precedent, which often relies on state or regional programs that meet threshold federal requirements, and as a matter of comity, particularly in light of continued development of EAC programs through complex stakeholder processes.

The appropriate standard for any hydrogen electrolyzer project is that which applies in the jurisdiction in which it is located, again presuming that standard meets minimum thresholds. If there is no such standard in the jurisdiction in which the electrolyzer is located or if the standard fails to meet threshold requirements (such as requirements to prevent double-counting the EAC for an RPS or any other purpose, or that qualifying generation contributes to supplying electricity to relevant load by injecting power into the same regional interconnect), then the use of voluntary standards such as the well-established and regarded Green-e certification program provided by the Center for Resource Solutions would be reasonable.

To ensure the steady and confident investment needed to launch an industry, the most critical issue is that the standards in place at the time of financial close of the project remain applicable to that project. New standards that enhance climate and other policy outcomes would be appropriate for new projects and will help ensure that green hydrogen production, as it grows to become a significant proportion of overall electric power demand, continues to achieve the Department's objectives. In considering threshold standards for EAC systems that may be used to comply with the CHPS, we recommend considering the criteria currently in use by the Green-e program administered by the Center for Resource Solutions, the leading standard in the domestic voluntary market.

In summary, the intent of the CHPS is to stimulate the development of the nation's clean hydrogen production. The CHPS should recognize state-approved or widely accepted commercially available means of characterizing carbon intensity of electricity emissions that meet reasonable threshold standards and that reflect the best practices currently in broad use today. As EAC standards evolve, new projects should adhere to them and be required to follow those standards in place in the jurisdiction in which they are located as of the date of their financial close. As discussed above, harmonization with the 45V tax credit is key to the successful launch of the clean hydrogen economy in this country, and to the success of the CHPS program.

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

Response:

Please see the answer to question 3.c.

4. Additional Information

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

Response:

Bloom Energy reserves any further comment at this time.

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