UNITED STATES DEPARTMENT OF ENERGY
Hydrogen and Fuel Cells Technologies Office

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In the Matter of:	)
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Clean Hydrogen Production Standard	)
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COMMENTS OF EDF RENEWABLES, INC.

Pursuant to the Department of Energy's ("DOE") September 22, 2022 Clean Hydrogen Production Standard ("CHPS") Draft Guidance,[1] EDF Renewables, Inc. ("EDFR," formerly known as EDF Renewable Energy, Inc.) hereby submits these comments on the CHPS implementing the requirements of the Infrastructure Investment and Jobs Act.[2] EDFR agrees with DOE that "[h]ydrogen plays a critical role in a comprehensive energy portfolio for the United States, and the use of hydrogen resources promotes energy security and resilience as well as provides economic value and environmental benefits for diverse applications across multiple sectors in the economy."[3] EDFR supports DOE's efforts to promote the production of green hydrogen and hopes that in doing so DOE takes into consideration the impacts of green hydrogen's production on the electric grid. Sound policy will support grid reliability and lower carbon intensity; poor policy will do the converse. EDFR welcomes this opportunity to share its views with DOE on the right policy solutions for green hydrogen and the grid.

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1 U.S. Department of Energy, Clean Hydrogen Production Standard (CHPS) Draft Guidance (Sept. 22, 2022) (hereinafter "CHPS Draft Guidance"), https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-production-standard.pdf.

2 *See* Infrastructure Investment and Jobs Act, Pub. L. No. 117-58, § 40315, 135 Stat. 429, 1015 (2021).

3 CHPS Draft Guidance at 1.

I. INTRODUCTION

As one of the leading renewables developers in the United States over the past 40 years, EDFR has developed more than 20 GW of renewables projects in North America and has 34 GW of projects in its development pipeline. It has built projects across the United States in RTO/ISO and bilateral markets under various offtake structures, ranging from 25-year busbar utility power purchase agreements ("PPA") to virtual power purchase agreements ("VPPA") for commercial and industrial buyers, and long-term and short-term Renewable Energy Credit ("REC") sales. EDFR delivers grid-scale power (onshore and offshore wind, solar photovoltaic, storage, and hydrogen), distributed solutions such as solar, storage, demand response, and electric vehicle charging, and asset optimization services. EDFR and its broader corporate family (collectively, the "EDF Group") have deep experience and expertise with hydrogen technologies and projects.

The EDF Group has over 20 years of history in hydrogen technologies and projects, with competencies spanning project development, engineering and plant design, hydrogen technology and electrolysis, and research and development. Today, the EDF Group has hydrogen projects in various phases of development in 12 countries across five continents, including multiple operational research facilities in Europe, a commercial facility serving the French hydrogen mobility market, and a UK project pairing offshore wind with electrolysis that is about to begin construction. This latter project will enter operations with 10 MW of electrolysis and will grow to over 500 MW.

As the green hydrogen market has matured, the EDF Group has structured its business accordingly. Beginning in research and development, the EDF Group, together with the Karlsruhe Institute for Technology, formed the European Institute for Energy Research in 2002, which has dedicated laboratories and a large research team focused on low-carbon hydrogen. In

2018, the EDF Group made a strategic investment in McPhy, a provider of alkaline electrolyzers. In 2019, the market had matured sufficiently that the EDF Group established a new business entity to develop green hydrogen projects in Europe (Hynamics), as well as a dedicated team in the United States within EDFR.

EDFR has a multi-GW green hydrogen pipeline, including a first award through Atlantic Shores Offshore Wind for a 10 MW electrolysis facility. It is active in several regional green hydrogen hubs and looks forward to the DOE review of regional hydrogen hub proposals. EDFR anticipates being able to announce several partnerships for multi-hundred MW and GW-scale hydrogen production facilities in the United States.

In establishing the CHPS, EDFR believes that DOE should consider the energy landscape holistically and in a pragmatic, balanced way that supports a nascent clean hydrogen industry, while recognizing current constraints in the electricity markets. CHPS policy should encourage renewable electricity procurement for new electrolyzer load which supports, or at a minimum does not harm, grid reliability and grid stability, without limiting the near-term growth of green hydrogen production. In the near- to medium-term, to operate at utilization rates above 80% to 90% and to minimize the cost of electrolysis-derived hydrogen, this requires that hydrogen producers have the option to use a combination of onsite renewable and grid power ultimately sourced from renewable resources.

It is critical to the success of the clean hydrogen industry that producers be allowed to benefit from the diverse renewable resources available on the grid and not be artificially or contractually linked to specific renewable facilities. Requiring a hydrogen producer to execute a PPA or VPPA tied to specific generating assets (or new assets if other constraints related to additionality were imposed) would expose the producer to outsized power trading risk and price volatility. For instance, if such a PPA or VPPA standard were to be imposed, to meet its annual power requirements, given the capacity factor of renewables, a hydrogen producer would need to sign contracts with projects with nameplate energy capacity 2.5 to 3.5 times the nameplate capacity of its own load. While this would balance the number of RECs with the producer's load on an annual basis, this mismatch between power procurement and power consumption in any interval could be a multiple of consumption (up to 3.5 times), which would subject the hydrogen producer to energy market price volatility and financial risk. This outsized risk would serve as a significant obstacle to investment in green hydrogen.

If hydrogen producers are to benefit from the existing and continually expanding diversified renewable energy generation on the grid, they need the flexibly to use a combination of onsite renewables (when feasible) coupled with grid power ultimately sourced from verified green sources paired with RECs. Given procurement/load mismatch and the resulting financial risks, PPAs and VPPAs should be an option for hydrogen asset owners to consider, but it would not be prudent to require such contracts as part of the green power supply solution. Instead, RECs provide the most straightforward method to link grid power consumption at the electrolyzer's site to verified renewable energy supply, provided that certain standards are met with respect to the regionality and timestamping of the REC supply.

II. CHPS SHOULD BE BALANCED AND REASONABLE, RELYING ON RECS, REGIONALITY, AND AN HOURLY TIME OF USE STANDARD

EDFR's comments focus on the methodology and implementation of clean hydrogen production qualifications. DOE should consider various parameters when crafting the CHPS standard on an electrolyzer's electricity source, including (1) the location of the electric resource or RECs used by the electrolyzer, (2) the time of electricity production relative to the time of the electrolyzer's electricity use, (3) the carbon emission intensity of the grid in which the electrolyzer is located, and (4) the additional nature of the electric resource. The requirements for such considerations should increase over time, with requirements phased-in over discrete, agreed-upon intervals through end-of-year 2035. EDFR supports the use of RECs, with regionality and an hourly Time of Use Standard. EDFR does not support a requirement for additionality, or the inclusion of carbon emission intensity of the grid, for the reasons described below.

A. Regionality

Including a regionality requirement for REC procurement more directly links hydrogen electrolyzer load to verified renewable energy. A beneficial consequence of this locational load matching is that it incentivizes a more balanced build out of new green infrastructure, promoting grid stability and reduced market volatility. The Balancing Authority ("BA") or RTO/ISO market is an ideal boundary in which the purchase of renewable energy or RECs would be required and in which the hourly carbon emission intensity would be calculated. However, since some BAs are smaller than others, the appropriate boundary should include electrically connected, adjacent BAs, and resources that are directly delivered or dynamically scheduled into the host BA or electrically connected, adjacent BAs. For example, new electrolyzer load located in the Los Angeles Department of Water and Power ("LADWP") BA could utilize RECs generated in, or from renewable resources delivered or dynamically scheduled into, the California ISO or the LADWP BA.

B. Time of Use Standard

The Time of Use Standard matches an electrolyzer's use of electricity with renewable energy, as established by a timestamped REC. EDFR does not recommend linking compliance with a specific REC tied to each of the 8760 hours in a year (365 days/year x 24 hours/day), as this standard is substantially harder to achieve than a standard based on the average month-hour. Instead, EDFR suggests that compliance accounting utilize the existing 12 months/year x 24 hours/day structure prevalent in energy trading ("12 x 24 matrix"). This results in 288 hour-long periods ("Month Hours").[4] While not a perfect time of use methodology, it is widespread in industry and would provide material contributions to grid stability by incentivizing the development of renewables across all hours of the day and all seasons.

In contrast, a standard based on annual volume matching is too lax and inefficient. It disregards the relationship between electrolyzer load and generation and exacerbates the over-generation of renewables in some regions, causing negative pricing and increasing carbon emissions. EDFR opposes annual volume matching. Under such an approach, a REC could be generated at any time of the day or year and still count for CHPS purposes. In divorcing electrolysis load from generation, an annual methodology does not incentivize a mix of renewable generation that can cover all 24 hours of the day. Instead, it incentivizes the lowest cost type of renewable and could lead to over-generation and negative pricing in some regional markets, while increasing carbon emissions. Indeed, an annual approach is so lax that it may expose DOE and the clean hydrogen industry to allegations of greenwashing.

A Time of Use Standard based on Month Hours, as further described below, creates a more efficient match between electrolyzer load and generation, promotes the development of the proper mix of renewables that can generate electricity during all hours of the year (including intra-day and seasonal), and reduces carbon emissions. It may not be possible to meet a higher

[4] As an example, the hour from noon to 1 p.m. in November 2022 would be assigned a single time period (a Month Hour). Under a 365 days/year x 24 hours/day approach, there would be 30 discrete time periods, as each hour-long period from noon to 1:00 p.m. in November is counted separately.

Time of Use Standard solely with solar generation, but this approach links an electrolyzer with the diversified, balanced green resource mix that it would require.

To provide flexibility for a nascent industry, DOE should increase requirements over time. In practice, this means that not all RECs procured would be subject to the standard in the near- to medium-term, though the requirements would increase over time as the industry developed and as renewable resources became more widely available. The standard will create the foundation for the accounting techniques used to track time of use, and implementation of more stringent requirements in the medium- to longer-term will incentivize: (1) electrolyzers to run when renewable energy is abundant, and (2) the deployment of renewable generation with a diverse generating profile and energy storage -- both of which support long-term grid stability.

Calculations for EDFR's Proposed Time of Use Standard. Time of use should be calculated on an annual look-back basis based upon the following formula using a 12 x 24 matrix:

- For each Month Hour in the prior year calculate *a*/*b*, where *a* and *b* are as follows:

  a) RECs (purchased and retired by the Project Company LLC) in each Month Hour

  b) MWh of load consumed in each Month Hour

  If *a*/*b* is over 1, use 1 as the value. 1 represents 100%, meaning that in any hour, the Time of Use Factor cannot be greater than 100%.[5] This is a conservative approach that prevents over crediting of RECs during certain Month Hours and encourages the procurement of RECs covering a greater number of Month Hours.

- To incentivize co-location of renewable generation with electrolyzers and recognize the grid benefits provided, any RECs generated by onsite or behind-the-meter

[5] By way of example, if in June at noon:

a) RECs purchased by Electrolyzer LLC = 150 MWh

b) Electrolyzer Load = 100 MWh

(a) / (b) = 1.5 or 150%, however, the Time of Use Factor cannot exceed 1 or 100%

renewable generation would be subject to a 1.2X multiplier. Any bonus RECs may apply to any period for compliance purposes.

- The addition of co-located storage would also provide a bonus by allowing the shifting of excess RECs procured beyond load in any Month Hour. For every MWh discharged by the battery, 1 REC may be moved from one period to any other period and would be subject to a 1.5X multiplier. The accounting for the REC would not need to match the actual time of discharge of the battery with the rationale being that energy should be shifted to maximize benefit for the overall grid, providing the greatest value for ratepayers.

- Determine the average Time of Use Score of each Month Hour (over the 288 Month Hours accounted for in the 12x24 matrix). The result is the Electrolyzer's Time of Use Score.

EDFR suggests that CHPS require a Time of Use Standard of no less than:

- 50% in years 1 through 5 of operation or until 2030; this lower standard would be in place for a specific number of years, phasing higher in years after it is deemed that the market has achieved scale;

- 75% in years 5+ of operation or after 2030; and

- If economically and technologically feasible, the standard would be higher in later years, to be phased in and determined during subsequent rulemakings.[6]

This Time of Use Standard, as proposed, would exist alongside, and not replace, a requirement for hydrogen producers to procure annual RECs, with regionality provisions as advocated above, for any MWh to be deemed generated by renewable energy. This use of annual RECs would gradually be replaced by the Time of Use methodology as the compliance standard tightens.

The data and mechanisms to attach timestamps to RECs exist. While not all electronic REC trading platforms are currently configured with this detail, they could be, given the existence of the underlying data. The prevalent and historic use of attestations from renewable

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6 Annual RECs would cover the balance of an electrolyzer's regulatory requirement. For example, in years 1 through 5, the Time of Use Standard would be 50%, so timestamped RECs would cover half the requirement and annual RECs (not timestamped) could cover the rest. Similarly, when the Time of Use Standard is 75%, annual RECs would cover the remaining 25%.

energy generators would adequately fill this gap until trading platforms establish adequate electronic compliance tracking.

C. Carbon Emission Intensity of the Grid

While the carbon emission intensity of the BA or RTO/ISO market is in many ways relevant to the quantification of clean energy used to produce hydrogen, for CHPS compliance purposes, where at all possible, the procurement of RECs should be considered the compliance standard. To prevent double counting of green attributes, any grid electricity consumed but not backstopped by REC procurement should not be considered green or even partially green. The renewables facility that generated the power has presumably sold its associated RECs. As a result, grid electricity should be deemed to have the average carbon emission intensity of the relevant BA or RTO/ISO market with any green attribute removed from the calculation (as the entities that procured RECs would have been deemed to consume the green portion of that power).

Special considerations may exist in markets where RECs are not used and attestations from renewable generators are unavailable. A utility with a green tariff, for instance, could provide comparable compliance documentation since it couples RECs with the power, so long as it meets substantially similar requirements relating to the supply of renewable power to the hydrogen producer.

Finally, absent clear DOE-defined rules and transparent data, it is not feasible for hydrogen producers to measure or calculate the grid's carbon intensity for the purpose of understanding the thresholds needed to meet compliance standards. DOE should clearly define, in advance of any compliance period, the appropriate assumption for the grid's carbon intensity, as well as the threshold percentage of green power needed across all markets to achieve any minimum green hydrogen standard.

III. REQUIRING CO-LOCATION IS NOT FEASIBLE

Ideally, onsite renewable energy resources would directly power hydrogen electrolyzers. In the near- to medium-term, however, this goal is not practical for several reasons. First, requiring co-located utility-scale renewable resources would create serious timing issues if the resources were interconnected into the grid. Grid interconnection would be optimal from a commercial, market, and reliability perspective,[7] but, unfortunately, interconnection queues are backlogged across the United States. At the end of 2021, there were over 8,100 active interconnection requests in interconnection queues, representing more than 1,000 GW of generation and 400 GW of battery storage.[8] A temporal mismatch between the electrolyzer and the renewables generator would occur because an electrolyzer could be constructed long before the generator would be interconnected and reach commercial operation date.

Second, a co-location requirement would also present siting issues. A large renewables facility utilizes hundreds of acres of land. For example, a utility-scale solar plant may require five to 10 acres of land per MW of generating capacity. The nameplate capacity of the renewables plant would have to be 2.5 to 3.5 times the nameplate electrolysis load. The optimal location for siting an electrolyzer and ancillary infrastructure (e.g., liquefaction or ammonia production facilities) is often not adjacent to sufficient available land to site utility-scale renewables.

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7 Being interconnected to the grid would allow the renewables facility to inject power during times of peak load. This might be commercially advantageous, would add supply to the market (which supports competition and reduces prices), and enhances reliability.

8 *Improvements to Generator Interconnection Procedures and Agreements*, Notice of Proposed Rulemaking, 179 FERC ¶ 61,194, at P 18 (2022).

Third, capital costs would be excessive if a green hydrogen developer had to build utility-scale renewables in addition to an electrolyzer and other ancillary capital-intensive infrastructure (e.g., liquefaction or ammonia production facilities). The ancillary infrastructure does not have the flexibility to operate on an intermittent basis and would require further costly infrastructure buildout, including battery energy storage and/or hydrogen storage capacity. Similarly, hydrogen consumers often require consistent, reliable supply. In the absence of a hydrogen pipeline that serves the consumers, the production facility would again have to add storage infrastructure.

Instead of requiring co-location, EDFR suggests that DOE provide an incentive to facilities that have co-located renewables generation. To reward co-location, any RECs generated by onsite or behind-the-meter renewable generation would receive a 1.2X multiplier. Any bonus RECs may apply to any period for compliance purposes under the Time of Use Standard.

IV. ADDITIONALITY SHOULD NOT BE REQUIRED

DOE should not impose an additionality requirement. Doing so would be counterproductive and impede the development of a clean hydrogen industry in the United States. Notably, after having studied the issue and received stakeholder comments, the European Parliament moved to reject an additionality requirement.[9] For several reasons, the Time of Use Standard is better suited to supporting the adoption of green hydrogen than additionality.

First, PPAs and VPPAs are unsuitable for powering electrolyzers. An additionality requirement would logically require two things: a contractual link to a specific renewable asset and a contractual tenor consistent with the Production Tax Credit time horizon. As noted

[9] *See* Sam Bartlett, *Green Hydrogen: From Additionality to Sustainability* (Sept. 26, 2022), https://gh2.org/blog/green-hydrogen-additionality-sustainability.

previously, if such a PPA or VPPA standard were to be imposed, to meet its annual power requirements, a hydrogen producer would need to sign contracts with renewables facilities with nameplate energy capacity 2.5 to 3.5 times the nameplate capacity of its own consumption. While this would balance the number of RECs with the hydrogen producer's load, the mismatch between power procurement and power consumption, when for any interval contracted generation could be a multiple of consumption (up to 3.5 times), would subject the producer to energy market price volatility and financial risk. This outsized risk would serve as a significant obstacle to investment in hydrogen. In addition to this largely uncovered power price risk exposure, the tenor of contract would need to match the tax credit tenor to maintain the link to additionality. This limits the electrolyzer's flexibility on power procurement and its ability to optimize operations over time as the grid changes.

Second, additionality requirements are inconsistent with the Time of Use Standard. The Time of Use Standard both better supports decarbonization goals and encourages balanced green energy deployments matched with load, offering the grid more long-run stability. Additionality and the Time of Use Standard, however, are not easily paired as requirements. Additionality links to specific assets. In contrast, modeling indicates that diverse renewable assets supplying power would be required to meet the Time of Use Standard. Buying timestamped RECs from a diverse set of assets or structured power products with REC backing from intermediaries would best meet time of use requirements while not requiring hydrogen producers to over procure power and take power price risk.

Third, new renewables development would create a temporal mismatch with the electrolyzer facility. New utility-scale renewables can take six years or longer to develop, construct, and interconnect. Requiring hydrogen producers to wait for new utility-scale renewables would slow hydrogen deployment as the current renewable footprint is not optimized for hydrogen production. Additionality requirements combine the development risk of new renewables with the development of new hydrogen, creating project-on-project risk for hydrogen deployment. Furthermore, the expected life of an electrolyzer is approximately half that of a traditional renewable energy project, leading to increased project-on-project risk, reduced investment, and a slowdown in green hydrogen deployment.

Fourth, additionality is unnecessary for the deployment of renewable energy and green hydrogen production. The Inflation Reduction Act incentivizes renewable energy projects independently from green hydrogen production.[10] Unduly burdening green hydrogen with additionality provisions makes the United States less competitive internationally, incentivizes investment to move to other global geographies, and would make the United States an outlier among other nations, including those within the European Union, which recently moved to remove additionality requirements in its Renewable Energy Directive II and European Delegation Act.

Finally, the value of additionality should not be oversimplified or overstated. While additionality of new renewable projects can directly reduce the carbon emissions on the electric grid when new projects generate electricity in hours with high carbon intensity, absent consideration of the interplay between time of generation and the local grid's hourly carbon intensity, adding new renewables with similar generation profiles to those that already exist in high volumes, has only marginal value, and in some cases leads to curtailment, congestion, and negative pricing.

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[10] Inflation Reduction Act of 2022, Pub. L. No. 117-169, 136 Stat. 1818 (August 16, 2022).

V. CONCLUSION

For the foregoing reasons, EDFR respectfully submits these comments and requests that DOE consider them as it develops and issues the CHPS.

Respectfully submitted,

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