Division of Energy and Innovation
UNIVERSITY OF HOUSTON

Comments on Notice of Proposed Rulemaking – Credit for Production of Clean Hydrogen, Election to Treat Clean Hydrogen Production Facilities as Energy Property

IRS 2023-0066-0001

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Background

The University of Houston (UH) and UH Energy is thankful for the opportunity to submit comments in response to the U.S. Internal Revenue Service's Notice of Proposed Rulemaking released on December 25, 2023. UH Energy is part of the University of Houston's Division of Energy and Innovation and is dedicated to collaborative research amongst diverse faculty from nine colleges addressing sustainability and decarbonization in energy. UH Energy provides educational opportunities for professionals and students and collaborates with industry partners to advance the energy workforce, leadership, research and development, and innovation.

Comments

(1) The Treasury Department and the IRS seek comment on the readiness of verification mechanisms that could be utilized for certain background data in 45VH2–GREET if it were reverted to foreground data in future releases. For example, the upstream methane loss rate is background data in 45VH2–GREET, and the Treasury Department and the IRS seek comment on conditions, if any, under which the methane loss rate may in future releases become foreground data (such as certificates that verifiably demonstrate different methane loss rates for natural gas feedstocks, sometimes described as responsibly sourced natural gas).

Emissions from feedstock and energy production should undoubtedly be included in the calculation of well-to-gate emissions. However, not all producers, operators, and transporters are the same. Certainly, hydrogen producers interested in utilizing 45V and natural gas or other fossil fuels as a feedstock are cognizant of upstream emissions and the trouble those emissions pose to their ability to utilize 45V. Treating the feedstock as background information which is not malleable discounts the ability and innovation of producers to address upstream emissions with individual operators.

Today upstream emissions accounting is possible and contracting mechanisms – along with certificates – exist to verify different methane loss rates for natural gas feedstocks originating from individual fields, producers, and transporters. Allowing for methane emissions rates to become foreground data not only increases the number of feasible projects utilizing fossil fuels as a feedstock, but also will place pressure on operators and transporters to responsibly produce and deliver feedstocks that meet the needs of hydrogen producers, decreasing overall methane emissions and placing market pressure on producers and transporters to address methane emissions.

Required conditions under which methane loss rates can become foreground data should include evidence of contractual terms requiring methane loss rates be minimized, a certificate from producers and/or transporters verifying the contract has been met with a quantified emissions rate, and a report showing emissions data and any steps taken in a given year to reduce methane losses.

(2) While the Treasury Department and the IRS are soliciting comment on the type of information that hydrogen producers must provide in order to document and verify the direct and indirect GHG emissions associated with purchased electricity generally, we are also seeking input on two specific types of electricity generation for which GHG emissions can be highly variable or uncertain: fossil fuel-powered electricity generation with CCS and biomass-powered electricity generation. With regard to non-minimally emitting electricity generation, and fossil fuel-powered generation and biomass powered generation with or without CCS in particular, the Treasury Department and the IRS request comment on mechanisms to verify accurately real-world emissions related to hydrogen production. This includes mechanisms for, among other things, verification of the origin of the feedstock, rate of carbon capture, and other parameters that are relevant to accurate lifecycle analysis, as well as the ability of EAC instruments to represent accurately such attributes. … The Treasury Department and the IRS also request comment on the extent and manner in which incrementality, temporal matching, and deliverability should be applied in accounting for existing or new electricity generation from biomass or fossil feedstock. These comments may inform future versions of 45VH2–GREET.

In the same way that EAC can be sold or traded from renewable power producers to hydrogen producers, so to can EACs be sold or traded from minimally emitting resources and fossil fuel and biomass powered generation with or without CCS (or CCUS). As mentioned in the above comment, for fossil fuel generators, this should include a verification of methane losses from upstream production and transportation which can be verified to fall below the background assumptions contained in versions of 45VH2-GREET. For biomass electric generation similar certificates should be a component of verifying upstream emissions for feedstock. Secondarily, the electric generator can reliably monitor and verify process emissions in the production of electricity which may be adjusted accordingly due to process innovations and utilization of CCS (or CCUS). Technology and solutions exist to monitor these emissions and accordingly, EACs should be readily produced verifying emissions not only from feedstock but also from electric generation.

Regarding the extent and manner in which incrementality, temporal matching, and deliverability should be applied to new or existing generation from fossil feedstock it seems prudent and aligned with the goals of the Inflation Reduction Act and other federal policy to treat this generation differently. Specifically, it would significantly further the goals of decarbonizing the electric generation sector to not require fossil fuel or biomass generation come from newly built facilities. Instead, encouraging the rapid implementation of CCS (or CCUS) and emissions reductions would best be achieved by allowing fossil generators to elect to retrofit existing facilities. By not requiring incremental plants be built, but instead allowing retrofits, the proposed rule place significant pressure on existing producers to reduce emissions through retrofits which are less costly than constructing new facilities. Further, allowing retrofits rather than requiring new facilities disincentivizes the construction of additional facilities utilizing fossil fuels, which may unintentionally increase nationwide emissions as any incremental facility

equipped with CCS (or CCUS) capabilities will still produce some emissions. Finally, timing and cost objectives are best achieved by allowing retrofits and not requiring incremental fossil fuel generation. Newly built facilities are in most cases more expensive to construct and take more time to permit and construct than retrofits. Accordingly, allowing retrofits controls costs passed to end users and allows for faster low carbon fossil fuel generation interconnection.
Regarding deliverability, it makes sense to require that generation from fossil feedstock meet the same general conditions as generation from renewable sources – meaning that they should be located in the same RTO or transmission system. However, to the extent that such rules would apply to the feedstock itself, it makes little sense to require that fossil fuel feedstock be produced for the generator in the same RTO or transmission area. To illustrate this example, consider a hydrogen producer utilizing natural gas generation equipped with CCS (or CCUS) in Washington, Oregon, Minnesota, Wisconsin, North Carolina, South Carolina, Georgia, or in the Northeast where oil and gas production are de minimis or completely absent. Such states may have a reliable supply of natural gas, even renewable natural gas, or responsibly sourced natural gas. However, all or a portion of that supply may come from outside of the RTO or transmission area operating in that state. In such situations, it would be counterintuitive and undermine the purpose of the enabling statutory language to require that all feedstocks be sourced from the immediate area where the hydrogen is being produced.
Regarding temporal matching, it is prudent to require that in scenarios where CCS (or CCUS) is only in operation during certain times, that hydrogen producers only utilize that energy or account for that low carbon energy when the generator is utilizing its CCS (or CCUS) equipment.

(3) The Treasury Department and the IRS seek comments on whether and how to provide alternative approaches to identifying circumstances in which there is minimal risk of significant induced grid emissions for certain existing electricity generating facilities.
The Treasury Department and the IRS seek comments on whether to recognize an avoided retirements approach that would treat EACs from an existing electricity generating facility as satisfying the incrementality requirement if the facility is likely to avoid retirement because of its relationship with a hydrogen production facility.

With respect to processes that may be used to implement this approach, the Treasury Department and the IRS request comments on whether such approach should allow existing minimal-emitting generators that wish to provide EACs to hydrogen producers to demonstrate incrementality through submission to the IRS or another Federal agency, such as the DOE, specific information that supports a conclusion that the electricity generator is at risk of retirement that may be mitigated by sales to hydrogen producers, and, if so, what information and information submission process should be required.

Minimally emitting generators at risk of retirement should be considered incremental generators for hydrogen producers. *Comments on specific questions are contained below.*

(i) the appropriate criteria that should be considered to assess retirement risk.

The criteria for assessing retirement risk are often a company specific decision dictated by a host of factors including environmental risks, marketplace pressures, and contracts for sale of power retiring. Any criteria for assessing retirement risk should be as flexible as possible and rely on the power plant operator for assessing those risks. For example, a wind generation plant *may be operating in a non-integrated marketplace. Those facilities PPA or Energy Sales Agreement may be nearing the end of its 20–25-year term. The decision on whether to negotiate a new sales agreement with the incumbent utility or to retire the facility may often be a complicated issue involving pressures for further transmission system upgrades, changed terms from the time the original contract was entered, an unfriendly regulatory body, and other concerns. Such a facility should not be forced to retire or negotiate with the utility if onerous criteria prevent that facility from contracting to sell the power to hydrogen producers. There are innumerable scenarios in which a retirement decision is detail specific and therefore any such criteria should be flexible. This is not to say that a generator should be able to simply state that they are planning to retire a plant and therefore should qualify as incremental for hydrogen production. Instead, factors such as showing that a PPA is ending or that without a sale to a hydrogen producer the plant would otherwise be retired should be shown. However, strict scrutiny over these decisions is not necessary and oversight is often already provided by utility commissions, utilities, and transmission operators. Further, the nature of the industry is one in which sales to a utility or RTO are often preferable over sales to a single end user which may or may not survive over the depreciation schedule of the invested capital needed for generation projects.*

(ii) the extent to which demonstration of financial loss, projected or actual local electricity market conditions, presence of out-of-market financial support (which could potentially include financial support driven by Federal or State policy, bilateral contracts for EACs or above-market electricity sales, or revenue provided by cost-of-service regulation), or upcoming relicensing decisions, in combination, are appropriate criteria to assess risk;

Such considerations, while important to the power producer and hydrogen producer, should not be limiting factors on whether such facilities are eligible as incremental facilities.

(iii) industry best practices for estimating financial loss and the documentation necessary to support those estimates.

No comment but refer to above comment.

(iv) the appropriate criteria that should be taken into account to assess the likelihood that an electricity generator's relationship with a hydrogen production facility avoids retirement of the generator (for example, size of electrolyzer, co-location, contract length, or otherwise).

The criteria that should be taken into account to assess the likelihood that a generators relationship with a hydrogen producer or producers avoids retirement should be in simplistic terms that the electric generator was affirmed through the operator that it was scheduled to be retired and that the facility is now delivering low carbon electricity to a hydrogen producer or producers and a contract exists between the parties. Again, a number of scenarios can be imagined whereby overly restrictive criteria severely limit the ability of these parties to contract with one another. Any such criteria should not limit the capacity of the plant dedicated to hydrogen production nor should it impose inflexible contractual lengths on parties. Take again, the example of the wind farm coming to the end of a PPA with a utility who does not want to renew a contract. That wind farm may have 10, 12, or even 20 years of operational life left without significant investment to repower turbines. However, if 15- or 20-year agreements were mandated, that asset would not be available to provide clean electricity for hydrogen production.

The same could be said of a nuclear plant nearing a relicensing decision. There are technical and regulatory uncertainties that may make each case unique and therefore stringent criteria should be avoided.

(v) the appropriate criteria that should be taken into account to ensure that only electricity generation supplying the minimum hydrogen production necessary to avoid retirement is counted as incremental, and, in particular, whether there should be a cap on the amount of generation from a given facility that qualifies as incremental and how such a cap should be determined;

There should be no cap on the amount of generation from a given facility that qualifies as incremental and therefore there is no need to determine how such a cap should be calculated. If a facility is set to retire and produces low carbon electricity, that electricity should be put to use whether it is on the grid or for hydrogen production.

(vi) the period during which any determination of incrementality of existing electricity generators would be maintained before a new showing would be required.

The period during which any determination of incrementality for existing generators should be presumed accurate after an initial showing and the presumption should stay intact with a renewed showing every ten (10) years. Ten years allows time for parties to rely on the presumption and find alternatives if market conditions have changed.

(vii) the process by which eligibility for this approach should be determined and any related administrability considerations; and

Eligibility for this approach should be determined through a sworn statement from the operator stating that the generation plant would otherwise be retired but for the designation. This sworn statement should be supported by documents showing for example that a PPA has come to its end and steps are being taken to plan for decommissioning, or that the financials of the plant for three of the last five years show that operating the plant without such designation is uneconomical and that steps to retire the plant are being taken. Operators should be required to provide notice that they are seeking such designation to either the counterparty utility or RTO, or state utility commission and such party should have the opportunity to object to such submission within 45 days of receiving notice. If the designation is objected to, the IRS should make a determination based on the record and any hearing required by law.

(viii) what role, if any, EAC tracking systems should play in the verification or tracking of eligible EACs from such electricity generators.

No comment.

(4) The Treasury Department and the IRS seek comments on whether to provide an opportunity to demonstrate zero or minimal induced grid emissions through modeling or other evidence under specific circumstances. A demonstrated or modeled minimal-emission approach could treat electricity produced by certain existing electricity generating facilities under certain circumstances as satisfying the incrementality requirement if it is demonstrated that such sources and circumstances would not give rise to significant induced grid emissions. Such a showing

could be based on modeling or potentially be deemed to be made in certain circumstances based on regional grid characteristics, state policy, or facility history.

The Treasury Department and the IRS request comments on this demonstrated or modeled minimal-emission approach, including: (i) the circumstances in which it should be available and the criteria that are appropriate to evaluate and determine whether those circumstances occur; (ii) who should apply under this approach, the electricity generation facility, the hydrogen producer, or both; (iii) what data or modeling should be submitted; (iv) best practices for making such demonstrations, including for ensuring the impartiality and replicability of calculation approaches; (v) how an administrator of such a program would validate the accuracy of applicant submissions; (vi) under what circumstances, if any, it would be appropriate to deem generation to satisfy the incrementality requirement without modeling, and what documentation should be provided in these cases; (vii) the process by which eligibility for this approach should be determined and any related administrability considerations; (viii) the period during which any determination of incrementality would be maintained before a new showing would be required; and (ix) the circumstances and capability of EACs and tracking systems to track and verify energy attributes from such sources.

The approach to allow modeling to demonstrate incrementality should be implemented both as a standalone approach and to verify and show that incrementality is being achieved through a certain percentage of generation that would otherwise be curtailed. The circumstances in which it should be available should include anytime in which the generator is able to produce minimally emitting electricity but cannot otherwise be sold under existing contracts – i.e., lack of demand, curtailments, transmission constraints, etc. Under this approach, the hydrogen producer should apply with documentation from the generation facility affirming such modeling is correct. The data submitted need only show that minimally emitting electricity was produced and sold to the hydrogen producer and that such electricity could not otherwise be sold into the market for any reason other than that the price was not favorable during a given period of time. The administrator should presume such results are accurate but there should be a process by which to challenge such assertions by counterparties who would otherwise have received the electricity under contract but for the sale to the hydrogen producer.

(5) The Treasury Department and the IRS seek comments on this five percent-allowance approach, including the merits of this approach compared to the targeted pathways described, particularly with respect to balancing administrative feasibility and burden with accuracy of identifying circumstances with a low risk of induced grid emissions. The Treasury Department and the IRS also seek comments on whether 5 percent is the appropriate magnitude for an allowance. In particular, as noted earlier, data show that curtailment rates have increased in recent years, and NREL's Cambium model predicts additional increases going forward. In light of these data and projections, the Treasury Department and the IRS seek comments on whether a higher amount, such as up to 10 percent, would be appropriate, either in general or in certain cases or circumstances. The Treasury Department and the IRS also seek comments on: (i) how a five-percent allowance should be tracked, allocated, and administered and how feasible it is for EAC tracking systems to incorporate data on such an allowance; (ii) whether the five percent should apply to all existing minimal-emitting electricity generators in all locations or a subset and for what reasons; (iii) whether such an allowance should be assessed at the individual plant level or across an operator's fleet within the same deliverability region; and (iv) any other

administrability considerations. The Treasury Department and the IRS seek comments specifically on whether and how the "averaging" approach of a proxy appropriately captures the circumstances in which generation is incremental or does not generate induced grid emissions. The Treasury Department and the IRS also seek comments on how and whether the targeted alternative approaches or the other proxy approaches described subsequently in this part V.C.2.a.iii of this Explanation of Provisions might replace the five-percent allowance or might be coordinated with the allowance.

The # percent allowance approach is appropriate and should be implemented. The approach should be adopted in a form that does not set specific numeric limits on the percentage that is to be considered incremental, but instead relies on market conditions to dictate the percentage on an annualized basis. For example, in circumstances, like those present in Western and Central Kansas, wind generation is frequently curtailed due to supply exceeding demand, transmission constraints, or other factors. This amount of curtailment varies but consistently occurs. Such curtailments should be tracked by individual generators and confirmed by utilities, cooperatives, or transmission operators. It may be appropriate to institute a minimum percentage – i.e., 5 percent – but allow for this percentage to be increased if shown that curtailments exceed 5 percent in a given year.

We also suggest that such matching be based on carbon-intensity of the energy primary energy at the point of use.