December 2nd, 2022

Douglas O'Donnell, Commissioner
Internal Revenue Service

Janet Yellen, Secreatary
Department of the Treasury

Re: Notice 2022-58, Request for Comments on Credits for Clean Hydrogen and Clean Fuel Production

Dear Commissioner O'Donnell and Secretary Yellen,

Thank you fo the opportunity comment on the Clean Hydrogen Production provisions of the Inflation Reduction Act.

I am writing on behalf of Mote, Inc, a company that turn woody waste biomass into carbon-negative hydrogen. We use gasification and geologic storage of carbon dioxide to achieve the dual aims of producing clean hydrogen and removing carbon dioxide from the air.

Mote is a spinout of the work that I did with my former colleagues at Lawrence Livermore National Laboratory on the report, *Getting to Neutral: Options for Negative Carbon Emissions in California.* In that report, we assessed methods of carbon removal to meet California's climate targets, as well as options to manage waste biomass, including agricultural residues and forest residues from fire management. We found that gasifying biomass to make hydrogen, while capturing and storing CO_2 for geologic storage, was the best option for the bulk of California's carbon removal needs.

This technology has great potential to scale nationally, solving multiple problems in climate, clean energy, and waste management.

We have reviewed the above-referenced Request for Comments and responded where our expertise in carbon accounting and energy systems could be of value. See responses to individual questions enclosed.

Sincerely,

Dr. Joshuah Stolaroff
Chief Technology Officer
Mote, Inc.
444 South Flower St., 14th Floor
Los Angeles, CA 90071
josh@motehydrogen.com

(1) a) Section 45V defines "lifecycle greenhouse gas emissions" to "only include emissions through the point of production (well-to-gate)."3 Which specific steps and emissions should be included within the well-to-gate system boundary for clean hydrogen production from various resources?

In general, Mote agrees that the well-to-gate life cycle analysis is the correct approach. This should include:

- Emissions from the from the facility itself
- Embodied emissions, including emissions from production and transport, of the fuels and materials used in the plant, including:
    - electricity
    - fossil fuels
    - water
    - feedstocks
    - chemicals
- Emissions from transport and disposal of wastes

Another major category is emissions from the construction of the facility and embodied emissions of the equipment and materials used to construct the facility. This category is more complex to estimate. However, embodied emissions may be important for electrolyzers. We suggest that the IRS perform a sensitivity analysis on embodied emissions from construction and determine whether this category is important to include. In particular, a type of project that is being widely proposed now is an electrolytic hydrogen facility that operates opportunistically on intermittent renewable electricity. In this case, the electrolyzers (and other equipment) are overbuilt by a large factor (3–5). If the production of those extra electrolyzers result in embodied emissions that push the carbon intensity of the hydrogen above the legislative threshold, then those emissions are important to include.

Accuracy of the of the greenhouse gas value is important. However, transparency, simplicity, and consistency of the calculation are also important. A threshold approach for some materials flows is appropriate. For example, materials and chemicals streams that comprise <2% of the mass flow of the facility in aggregate could be excluded.

Standard and benchmark values would also helpful for some factors. For example, embodied emissions for water and fuels and assumptions about materials transport could be standardized. If emissions from facility construction are included, many aspects of that calculation could be standardized as well.

(b)(i) How should lifecycle greenhouse gas emissions be allocated to co-products from the clean hydrogen production process? For example, a clean hydrogen producer may valorize steam, electricity, elemental carbon, or oxygen produced alongside clean hydrogen.

ii) How should emissions be allocated to the co-products (for example, system expansion, energy-based approach, mass-based approach)?
(iii) What considerations support the recommended approaches to these issues?

In general, common LCA approaches for co-product approaches are by economic value, mass, and embodied energy. We recommend that economic value is the best measure for this case. It is a fair measure of the motivation for running a facility, Facilities that generate the majority of the value from hydrogen production should allocate the majority of their emissions to hydrogen. The inverse is also true. Moreover, the IRS has the means to obtain and audit a facility's revenue steams more easily than its mass flows or energy flows.

We recommend that the 45V credit itself be included in the value calculation. For facilities that use the hydrogen rather than sell it, a stand-in market value of hydrogen should be used.

For Mote and other Biomass Carbon Removal (BiCRS) projects, a value-based allocation will tend to allocate most emissions to the hydrogen product, although this depends on the project location and specific customers.

(c)(i) How should lifecycle greenhouse gas emissions be allocated to clean hydrogen that is a by-product of industrial processes, such as in chlor-alkali production or petrochemical cracking?

Allocation should be by economic value. See response to (b) above.

(d) If a facility is producing qualified clean hydrogen during part of the taxable year, and also produces hydrogen that is not qualified clean hydrogen during other parts of the taxable year (for example, due to an emissions rate of greater than 4 kilograms of CO2-e per kilogram of hydrogen), should the facility be eligible to claim the § 45V credit only for the qualified clean hydrogen it produces, or should it be restricted from claiming the § 45V credit entirely for that taxable year?

In general, emissions rates should be calculated on an annual-average basis. If a facility were able to pick and choose periods for clean hydrogen production, there would be too much potential for gaming. For example, an SMR operating on fossil methane might claim a portion of clean hydrogen by purchasing a small portion of biogas without otherwise changing its operations. Or an electrolysis project operating on grid electricity might claim a portion of clean hydrogen for when the grid mix has lower carbon intensity, without actually investing in renewable electricity supply. Neither of these projects is making a meaningful investment into technology that can produce clean hydrogen in the long run, which is the intent of the IRA.

At the same time, a facility should not be punished for periods of higher instantaneous emissions if the annual average qualifies.

For both reasons, an annual average basis is appropriate. An exception should be if new equipment is put into operation in the middle of the year. For example, if carbon capture equipment gets added that drops the carbon intensity and then stays in operation permanently thereafter, a partial-year allocation of clean hydrogen credits is appropriate.

(e) How should qualified clean hydrogen production processes be required to verify the delivery of energy inputs that would be required to meet the estimated lifecycle greenhouse gas emissions rate as determined using the GREET model or other tools if used to supplement GREET?

> (i) How might clean hydrogen production facilities verify the production of qualified clean hydrogen using other specific energy sources?
> (ii) What granularity of time matching (that is, annual, hourly, or other) of energy inputs used in the qualified clean hydrogen production process should be required?

The allocation of electricity emissions is important for many clean hydrogen production pathways, and crucially important for electrolytic approaches. Large amounts of new renewable electricity will be required to achieve the qualifying carbon intensity targets in the IRA. The IRS should be cautious of the externalities associated with adding large amounts of intermittent renewables to electricity grids, especially when matched to continuous-load projects.

Facilities should be able to verify their use of renewable electricity through purchase agreements and payments. In general, these agreements should be for new (post-IRA) generating capacity on the same grid in which the facility draws power. However, this is not enough. A facility should also be able to verify purchase of energy storage and transmission services consistent with the renewable fraction or carbon intensity of the electricity that they claim.

Ignoring intermittency and using an annual net matching method for electricity would allow clean hydrogen projects to externalize intermittency and reliability problems onto ratepayers while reaping federal subsidies. An hourly time of use matching methodology would avoid this. However, hourly time matching could be unnecessarily burdensome and drive up the cost of clean hydrogen to consumers. We recommend that the IRS consult with grid operators to identify the degree of energy storage and transmission services required for marginal addition of renewable sources to increase supply without increasing the carbon intensity of the rest of the grid. In simplified terms, how many batteries are needed to avoid dispatching more fossil generation? The true answer will be regionally specific and change over time. However, the IRS could create standard requirements that solve most of the problem at reasonable cost.

We suggest that the IRS can find a middle ground that requires facility operators to verify some degree of purchased storage and transmission services, but does not go as far as hourly time matching. This will require development. Hourly time matching is a conservative fallback approach in the meantime.

(3) Provisional Emissions Rate. For hydrogen production processes for which a lifecycle greenhouse gas emissions rate has not been determined for purposes of § 45V, a taxpayer may file a petition with the Secretary for determination of the lifecycle greenhouse gas emissions rate of the hydrogen the taxpayer produces.

> (a) At what stage in the production process should a taxpayer be able to file such a petition for a provisional emissions rate?
> (b) What criteria should be considered by the Secretary in making a determination regarding the provisional emissions rate?

Clean hydrogen projects involve new technology and large capital outlays, which makes them generally difficult to finance. A provisional emissions rate determination would be important for moving projects through development, even at the challenging phase of Front End Engineering Design (FEED) or FEL-3. We recommend that taxpayers be allowed to seek a determination when projects have completed the pre-FEED, FEL-2, or equivalent phase of study, or otherwise obtained that level of specificity for material balance, process flow, utility demands, and other parameters used in the Determination.

(6) Coordinating Rules. (c) Coordination with § 45Q. Are there any circumstances in which a single facility with multiple unrelated process trains could qualify for both the § 45V credit and the § 45Q credit notwithstanding the prohibition in § 45V(d)(2) preventing any § 45V credit with respect to any qualified clean hydrogen produced at a facility that includes carbon capture equipment for which a § 45Q credit has been allowed to any taxpayer?

Carbon Removal facilities should be an exception to the 45Q exclusion.

The intent of the 45Q exclusion is essentially to prevent over-incentivizing certain hydrogen production pathways, specifically fossil hydrogen production with carbon capture and storage ("blue hydrogen"), which is by far the best-known type of facility that could otherwise qualify for both 45V and 45Q credits. In this case, a fossil hydrogen producer can add carbon capture and storage and receive 45Q credits as an incentive for that additional expense. The owner of such a facility can also add carbon capture and storage to lower the carbon intensity of the hydrogen and receive 45V credits to offset that additional expense. If the owner were to be paid by both programs, they would essentially be paid twice for the carbon capture and storage operation. The 45Q exclusion here makes sense; otherwise the fossil hydrogen facility would be unfairly compensated compared to other hydrogen technologies (such as electrolysis) and other carbon capture applications (such as fossil power plants).

Mote's technology, which can be categorized as a form of Biomass Carbon Removal and Storage (BiCRS), is categorically different. Mote produces two distinct value streams: low-carbon hydrogen and carbon removal. These can be separately valued and sold to different customers (though they are sometimes bundled together as carbon-negative hydrogen). A BiCRS facility like Mote's, that produces hydrogen by gasification of waste biomass, can already achieve carbon intensities lower than 4 kg CO_2e per kg H_2 *without* carbon capture, as noted in the Department of Energy's Clean Hydrogen Production Standard Draft Guidance. The 45Q incentive for carbon storage is *not* redundant in this case because it is still needed to support the addition of carbon capture and storage equipment.

Carbon removal at a BiCRS plant is fundamentally different from carbon capture at traditional fossil hydrogen plants, which avoid emissions rather than remove them from the air. **The carbon capture and storage equipment, even if collocated at, for example, a biomass gasification plant, should be considered a wholly separate facility in terms of the 45Q exclusion**, especially if the equipment is owned by a separate tax-paying entity.

If carbon capture and storage equipment collocated with a hydrogen BiCRS plant were excluded from 45Q, the net effect of the Inflation Reduction Act would be to disadvantage carbon removal compared to other hydrogen production pathways. In this case, both electrolytic hydrogen and BiCRS hydrogen would receive the 45V credit. In Mote's case, the 45V credit is about twice as valuable as the 45Q credit, so we would choose 45V. Without IRS guidance on this question, BiCRS hydrogen could then be precluded from claiming 45Q credits. Prior to the Inflation Reduction Act (IRA), BiCRS hydrogen had the added incentive of 45Q compared to water electrolysis hydrogen, which gave the extra revenue stream needed to justify capturing CO_2 rather than venting it.

It was never the intent of the IRA to restrict deployment of carbon removal. Carbon removal facilities should be treated separately with respect to 45Q exclusion.

As a means of separating carbon removal incentives from clean hydrogen incentives, we suggest counting only tons of CO_2 stored that drop the carbon intensity of the combined system below zero as qualified for 45Q credits. This would be sure to incentivize carbon removal without over-subsidizing fossil hydrogen pathways. We further suggest excluding avoided methane emissions from book-and-claim biogas from this calculation, because that is not carbon removal. Carbon removal is a distinct product with a distinct market value compared to avoided emissions from captured CO_2. Discouraging combined low-carbon 45V-qualifying hydrogen production facilities and 45Q-qualifiying carbon removal facilities was not the intent of the IRA.

Another case where the carbon removal distinction applies is a Direct Air Capture (DAC) facility with co-located hydrogen production. The co-location is advantageous if the DAC owner is using hydrogen for energy storage to overcome the intermittency of renewable power, or if the DAC owner is utilizing the CO_2 and hydrogen together to make chemicals. Here again in this example the hydrogen produced by water electrolysis and renewable electricity could qualify for 45V credits without the DAC facility. To apply the exclusion in this case would disadvantage this plant compared to one where the DAC and H_2 were physically separated. Such a separation for the purposes of the tax qualification would be needlessly costly.

Therefore, DAC facilities are another case where carbon removal should be considered exempt from 45Q exclusion.