DEPARTMENT OF THE TREASURY

Internal Revenue Service

Section 45V Credit for Production of Clean Hydrogen; Section 48(a)(15) Election to Treat Clean Hydrogen Production Facilities as Energy Property. 88 Fed. Reg. 89220 (Dec. 26, 2023)

Docket No. REG-117631-23

Via Regulations.gov

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COMMENTS OF CLEAN AIR TASK FORCE

Clean Air Task Force ("CATF") is pleased to respond to the Department of the Treasury ("Treasury") and the Internal Revenue Service ("IRS") on their request for comments on Section 45V Credit for Production of Clean Hydrogen; Section 48(a)(15) Election to Treat Clean Hydrogen Production Facilities as Energy Property, 88 Fed. Reg. 89220 (Dec. 26, 2023). CATF is a global nonprofit organization working to safeguard against the worst impacts of climate change by catalyzing the rapid development and deployment of low-carbon energy and other climate-protecting technologies. With over 25 years of internationally recognized expertise on climate policy and a fierce commitment to exploring all potential solutions, CATF is a pragmatic, non-ideological advocacy group with the bold ideas needed to address climate change. CATF has offices in Boston, Washington D.C., and Brussels, with staff working remotely around the world.

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I. INTRODUCTION

Congress passed the Inflation Reduction Act ("IRA") to reduce greenhouse gas ("GHG") emissions by subsidizing clean energy deployment.[1] The clean hydrogen production tax credit, section 45V (hereinafter "section 45V" or "45V"), aims to promote clean hydrogen production technology development and enable a truly clean hydrogen market to take hold. Low-emissions hydrogen will be a critical decarbonization tool to combat climate change and will play a role in achieving full, economy-wide decarbonization. Given its properties as both a fuel and a feedstock, hydrogen can provide a decarbonization option to sectors that may be hard-to-abate, particularly where electrification may be either technically infeasible or prohibitively expensive.

But most hydrogen produced today is extremely carbon intensive. In enacting section 45V, Congress could have promoted *all* hydrogen production without regard for its lifecycle GHG emissions.[2] But it did not. The text and legislative history of section 45V and the IRA more generally demonstrate that Congress passed the law to reduce nationwide greenhouse gas emissions by subsidizing clean energy deployment. Congress did not want to promote the hydrogen industry for its own sake. It wanted to promote low-carbon hydrogen that would reduce overall greenhouse gas emissions.

Section 45V appropriately bases the tax credit amount on the carbon intensity of the hydrogen, with four tiers that increase in dollar amount as the carbon intensity decreases. The structure of the tiers of credits in section 45V shows that the cleaner the hydrogen is, the more highly Congress valued it. For a lifecycle greenhouse gas emissions rate below 0.45 kilograms ("kg") carbon dioxide-equivalent ("CO_2e") per kg of hydrogen ("H_2"), the full potential credit amount is $3 per kg of hydrogen.[3] If the lifecycle emissions rate is between 0.45 and 1.5 kg CO_2e per kg H_2, then the credit drops by two-thirds to $1 per kg of hydrogen.[4] The steep step-down from $3 to $1 (and then to $0) shows that Congress put a thumb on the scale in favor of the cleanest hydrogen production. As there are multiple ways to produce hydrogen that can minimize GHG emissions, and each of those production pathways includes emissions both at and upstream of the point-of-production, it is essential that the methodologies and assumptions behind the carbon intensity requirements are rigorous. Treasury must issue final regulations that lead to real-world decreases in systemwide lifecycle GHG emissions related to clean hydrogen production.[5]

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[1] *See* 168 Cong. Rec. S4210, 4211 (Aug. 6, 2022) (statement of Sen. Ben Cardin) ("The IRA makes investments to accelerate clean energy deployment, help achieve our climate goals, and create millions of jobs over the next decade."); *see also* 168 Cong. Rec. H7577, 7664 (Aug. 12, 2022) (statement of then-Chairman Neal) (emphasizing that the statute's clean energy tax credits—including section 45V—"were drafted with the goal of unleashing clean energy deployment, in line with President Biden's pledge of a 50-52 percent reduction from 2005 levels in economy-wide net greenhouse gas pollution in 2030.")

[2] *See* Changes to Renewable Fuel Standard Program, 75 Fed. Reg. 14670, 14766 (Mar. 26, 2010) (noting the context of the Renewable Fuel Standard that "[i]f Congress had sought to promote *all* biofuel production without regard to GHG emissions related to the full lifecycle of those fuels, it would not have specified GHG reduction thresholds for each category of renewable fuel for which volume targets are specified in the Act.") (emphasis added).

[3] 26 U.S.C. § 45V(b).

[4] *Id*.

[5] *See* 26 U.S.C. § 45V(f) (directing Treasury to "issue regulations or other guidance to carry out the purposes of this section.").

Treasury's proposal is an excellent first step toward ensuring that hydrogen that qualifies for 45V credits is truly clean. This comment outlines some of the key issues in ensuring rigorous guidance that appropriately rewards truly clean hydrogen and responds to some of the specific requests for comment outlined by Treasury and IRS.

Section II discusses the legal basis for electrolytic hydrogen requirements. Section 45V explicitly requires Treasury to account for "significant indirect emissions" associated with hydrogen production. Treasury's inclusion of the three pillars—incrementality, hourly matching, and deliverability—is critical to ensuring that electrolytic hydrogen does not actually increase systemwide GHG emissions. For an electrolytic hydrogen producer who claims that their electricity is from a specific generating facility rather than the regional grid, Treasury's proposal appropriately requires that they must purchase Energy Attribute Credits ("EACs") that comply with the three pillars. This is the best methodology for ensuring and verifying that the electricity used to produce hydrogen is clean.[6] These pillars are described further below.

Pillar	Description
Incrementality	Also known as "additionality", this pillar requires that projects draw on new clean power that is not already serving the electricity grid's existing energy demand.
Hourly Matching	This pillar requires that the hours of electricity used for hydrogen production must be matched with the hours of new clean electricity production.
Deliverability	Also known as "regional matching", this pillar requires that the hydrogen production facility be in the same region as the electricity it is claiming to use; or in other words, it must be physically feasible to deliver power from the electricity generator to the hydrogen producer.

Given the tremendous amount of electricity needed to produce electrolytic hydrogen, requiring the three pillars is the best way to ensure that hydrogen producers do not induce significant indirect emissions by diverting clean electricity from the grid, which would likely be replaced with higher-emitting electricity produced from fossil resources.

Section III delves into how to implement incrementality in certain cases. Specifically, we outline when Treasury can make exceptions to incrementality without allowing hydrogen producers to induce significant indirect emissions and how Treasury should administer those exceptions. First, Treasury should not apply a formulaic 5% exemption to incrementality for all existing minimal-emitting facilities. Such an exemption is too broad and is not a sufficient proxy for avoiding significant indirect emissions. Instead, we outline a more narrowly tailored test that

[6] Clean Air Task Force, *New Treasury tax credit guidance for clean hydrogen production includes necessary requirements to promote growth of truly clean hydrogen market* (Dec. 22, 2023), https://www.catf.us/2023/12/new-treasury-tax-credit-guidance-clean-hydrogen-production-includes-necessary-requirements-promote-growth-truly-clean-hydrogen-market/.

Treasury should use to determine whether receiving the 45V credit would allow facilities to avoid retirement, such that the electricity they generate for hydrogen production would effectively be "incremental." We also answer Treasury's requests for comment on other potential exceptions to incrementality, including curtailed electricity, clean grids and regions with emission caps, and uprates.

Section IV discusses other considerations for implementing the three pillars, including deliverability, hourly matching, and how to calculate the carbon intensity of different types of carbon-based electricity generation. In particular, we urge Treasury to collaborate with the Department of Energy ("DOE") and the Environmental Protection Agency ("EPA") to study whether electricity from fossil-based facilities that retrofit with carbon capture and sequestration ("CCS") equipment should be considered "incremental." Specifically, Treasury should model (1) whether emissions that would fill the gap left by the facility would be partially or entirely filled with higher-emitting generation; (2) whether there could be indirect emissions associated with the CCS retrofit; and (3) whether the capacity factor of the electricity production facility could increase after the addition of CCS equipment.

Section V addresses hydrogen produced from carbon-based pathways. In addition to ensuring electrolytic hydrogen is truly clean, Treasury must make several changes to its proposal with respect to fossil-based hydrogen. First, Treasury must shift methane leak rates from background data to foreground data in 45VH2-GREET. Treasury's proposed fixed national leak rate of 0.9% is both over- and under-inclusive of true upstream emissions. On the one hand, this "one-size-fits-none" approach fails to allow operators who can and want to prove they have lower leak rates to do so. On the other hand, it allows operators with leak rates far exceeding 0.9% to claim a rate that does not reflect conditions on the ground. We urge Treasury to require that operators provide verifiable, project-specific data to establish their methane leak rates as foreground data using the information they submit as part of subpart W, a subpart of the EPA-administered Greenhouse Gas Reporting Program ("GHGRP"). This simultaneously encourages operators to clean up methane leaks while also barring truly dirty operators from benefiting from the tax credit. Following this logic, we also urge Treasury to require upstream carbon dioxide ("CO_2") emissions to be calculated based on emissions reported under GHGRP subparts C and W, and to shift upstream CO_2 from the natural gas supply chain associated with extracting, processing, and transporting the natural gas to foreground data.

We also urge Treasury to adopt strict guidelines around hydrogen production pathways that use biomethane (both from landfills and from digesters) and fugitive methane. Treasury should not allow hydrogen producers to offset direct hydrogen facility emissions using "negative" emission rates from biomethane. Allowing such a practice goes against the text and intent of section 45V and would undercut truly clean hydrogen production methods that the tax credit is meant to promote. Similarly, Treasury should not allow fugitive methane sources to receive negative emission rates, because they capture methane that would have otherwise been leaked or flared. This would give oil and gas producers a windfall, particularly given that several state and federal regulations currently (or will soon) require emissions reductions to "fugitive methane." Section 45V is not meant to reward dirty oil and gas operators for doing the bare minimum.

Section VI addresses other considerations for calculating the production tax credit. We suggest that Treasury clarify that section 45V credits are determined based on an analysis of kilograms of clean hydrogen produced in a given tax year, evaluated on an hourly basis. Treasury's proposed annual averaging approach is unnecessarily restrictive for the nascent clean hydrogen industry because producers only need to use grid electricity for 1-3% of the year to exceed a 0.45 kg CO_2e/kgH_2 threshold. Thus, instead of an annual average, the tax credit should be awarded using a two-step approach: first, a hydrogen producer must meet an annual average of no more than 4 kg $CO_2e/kg\ H_2$ for all hydrogen produced in the given tax year to align with the definition of a clean hydrogen production facility; and second, the producer should then determine the carbon intensity of the hydrogen based on the kilograms of clean hydrogen produced, evaluated on an hourly basis. This section also cautions Treasury against allowing the use of EACs to offset emissions from fuels.

Section VII addresses the 45VH2-GREET tool. First, when there are significant changes made to 45VH2-GREET, including major changes to background data, switching information from background data to foreground data, or adding new hydrogen production pathways, there should be notice and comment on those changes. Additionally, when 45VH2-GREET is updated, producers who have already qualified for a carbon intensity score under a previous version of 45VH2-GREET should be allowed to grandfather their score. This will ensure predictability and minimize uncertainty and risk for producers when forecasting their 45V credits once they have qualified.

We also urge Treasury to increase accessibility and transparency of the 45VH2-GREET tool. In its current format, the tool is a "black box" where formulas and background data are locked behind passwords, making it arbitrarily difficult to understand how inputs translate into final carbon intensities. While DOE has published a user manual and established a help desk to increase accessibility, neither are a substitute for a transparent and accessible tool where the user can understand how various inputs and background data are used to calculate the final carbon intensity. To increase accessibility, Treasury should collaborate with DOE to publish a transparent tool where calculations are not locked behind passwords, update the user manual to be comprehensive of all background data, and increase the response rate of the DOE help desk.

II. LEGAL BASIS FOR ELECTROLYTIC HYDROGEN REQUIREMENTS

A. The plain text of section 45V requires Treasury to account for systemwide greenhouse gas emissions impacts from hydrogen production, and the three pillars best implement this requirement.

Electrolytic hydrogen is made by using electricity to split water into hydrogen and oxygen. The direct facility emissions of an electrolyzer are zero—that is, no GHGs are directly emitted at the point of hydrogen production from an electrolyzer. But because electrolysis requires significant amounts of electricity as a feedstock, the source of that electricity has the potential to add significant indirect emissions. In the same way that increasing production of biofuels can induce indirect emissions from land use change, increasing production of electrolytic hydrogen can lead to indirect emissions from *electricity* use change, as hydrogen producers either pull electricity directly from the grid or divert clean electricity otherwise headed to the grid. Treasury recognizes in its proposal that requiring electrolytic hydrogen producers to purchase qualifying EACs that are incremental, hourly matched, and deliverable is the best way to account for indirect grid emissions. Treasury's proposal follows the plain text of section 45V and ensures that clean hydrogen does not paradoxically lead to greater systemwide GHG emissions.

i. <u>Section 45V incorporates the Clean Air Act's expansive definition of "lifecycle greenhouse gas emissions."</u>

Section 45V provides that hydrogen producers may receive tax credits equal to the kilograms of qualified clean hydrogen produced during a taxable year, multiplied by the "applicable amount."[7] The applicable amount is equal to the "applicable percentage" of $0.60 (or of $3.00, once a multiplier is added if certain labor and prevailing wage requirements are met).[8] From here, four different tiers determine the applicable percentage of $0.60 that a hydrogen producer receives per kilogram of hydrogen produced. The four tiers are based on different lifecycle emissions rates; the lower the lifecycle emissions, the higher the percentage.[9]

Section 45V in turn defines "lifecycle greenhouse gas emissions" by explicit reference to the Clean Air Act ("CAA"), providing that, "[s]ubject to subparagraph (B), the term 'lifecycle greenhouse gas emissions' has the same meaning given such term under subparagraph (H) of section 211(o)(1) of the Clean Air Act."[10] CAA section 211(o)(1)(H) provides that "lifecycle greenhouse gas emissions" means:

> the aggregate quantity of greenhouse gas emissions (including direct emissions and significant indirect emissions such as significant emissions from land use changes), as determined by the Administrator, related to the full fuel lifecycle, including all stages of fuel and feedstock production and distribution, from feedstock generation or extraction through the distribution and delivery and use of the finished fuel to the ultimate consumer, where the mass values for all greenhouse gases are adjusted to account for their relative global warming potential.[11]

Section 45V only limits its adoption of the definition in CAA section 211(o)(1)(H) in one respect: it is "subject to subparagraph (B)", which provides that the "term 'lifecycle greenhouse gas emissions' shall only include emissions through the point of production (well-to-gate)."[12] Importing these limitations from section 45V to the definition in CAA section 211(o)(1)(H), the definition of "lifecycle greenhouse gas emissions" for the purpose of section 45V credits is:

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[7] 26 U.S.C. § 45V(a).
[8] *Id.* § 45V(b)(1); *id* § 45V(e) (The applicable amount of $0.60 can be multiplied by 5 if the hydrogen production facility meets certain requirements).
[9] *Id.* § 45V(b)(2).
[10] 26 U.S.C. § 45V(c)(1).
[11] 42 U.S.C. § 7545(o)(1)(H).
[12] 26 U.S.C. § 45V(c)(1).

> the aggregate quantity of greenhouse gas emissions (including direct emissions and significant indirect emissions such as significant emissions from land use changes), as determined by the Administrator, related to the ~~full~~ fuel lifecycle, including all stages of fuel and feedstock production and distribution, from feedstock generation or extraction through [**the point of production**] ~~the distribution and delivery and use of the finished fuel to the ultimate consumer~~, where the mass values for all greenhouse gases are adjusted to account for their relative global warming potential.[13]

Thus, the definition of "lifecycle greenhouse gas emissions" for purposes of section 45V is the same as the definition in section 211(o)(1)(H) except that the lifecycle for the tax credit extends only through the point of production. This means that Treasury's lifecycle accounting regulations must include pre-production emissions (i.e., those generated to produce power for electrolyzers), but not post-production emissions (i.e., those stemming from subsequent hydrogen distribution and consumption). Outside of this limitation, the rest of the definition remains the same as it does in the context of CAA section 211(o)(1)(H).[14]

ii. The definition of "lifecycle greenhouse gas emissions" includes "significant indirect emissions" related to the lifecycle.

Importantly, section 45V adopts in its entirety section 211(o)'s definition of "lifecycle greenhouse gas emissions" as it relates to "all stages of fuel and feedstock production"—which includes both "direct" GHG emissions and "significant indirect emissions."[15] In the context of hydrogen production, direct emissions are the greenhouse gases emitted directly by the hydrogen production facility. "Significant indirect emissions" are GHGs other than those directly emitted from the hydrogen facility that are nonetheless related to the hydrogen production.[16] The EPA has adopted a broad interpretation of indirect emissions under section 211(o)(1)(H), and Congress was aware of this interpretation when incorporating that section's definition of "lifecycle greenhouse gas emissions" into section 45V.[17]

CAA section 211(o)(1)(H) defines "lifecycle greenhouse gas emissions" for purposes of the renewable fuel standard ("RFS") program, which requires transportation fuels imported or

[13] 42 U.S.C. § 7545(o)(1)(H).
[14] *TRW Inc. v. Andrews*, 534 U.S. 19, 28 (2001) ("Where Congress explicitly enumerates certain exceptions . . . additional exceptions are not to be implied, in the absence of evidence of a contrary legislative intent.").
[15] 26 U.S.C. § 45V(c)(1) (incorporating 42 U.S.C. § 7545(o)(1)(H)).
[16] *See, e.g.*, EPA Center for Corporate Climate Leadership, Greenhouse Gas Inventory Guidance, Indirect Emissions from Purchased Electricity 1 (Dec. 2023), https://www.epa.gov/sites/default/files/2020-12/documents/electricityemissions.pdf ("Indirect emissions are those that result from an organization's activities but are actually emitted from sources owned by other entities.")
[17] *See Lamar, Archer & Cofrin, LLP v. Appling*, 138 S. Ct. 1752, 1762 (2018) (quoting *Lorillard v. Pons*, 434 U. S. 575, 580 (1978)) ("Congress is presumed to be aware of an administrative or judicial interpretation of a statute and to adopt that interpretation when it re-enacts a statute without change"); *Bragdon v. Abbott*, 524 U. S. 624, 645 (1998) ("When administrative and judicial interpretations have settled the meaning of an existing statutory provision, repetition of the same language in a new statute indicates, as a general matter, the intent to incorporate its administrative and judicial interpretations as well").

sold in the United States to contain certain amounts of renewable biofuels each year.[18] The RFS aims to reduce lifecycle greenhouse gas emissions associated with transportation fuel by providing that renewable biofuels meet certain GHG reduction thresholds.[19]

The text of section 211(o)(1)(H) provides an example of "significant indirect emissions": "significant emissions from land use changes."[20] In the context of the RFS, "significant emissions from land use changes" refers to a situation where, for example, a farm that previously supplied corn for human consumption switches to supplying its corn to ethanol producers because of increased demand for biofuels. Because of the switch, other farms will expand production to fill in the gaps in demand for corn for human consumption and thus will deforest more land to provide this corn. Conversion of forest to cropland to fill the gap in corn for food results in increased systemwide GHG emissions. Section 211(o)(1)(H) explicitly recognizes that these indirect impacts of increased demand for biofuel "relate[] to the . . . fuel lifecycle,"[21] and it requires EPA to measure how biofuel production causes systemwide changes in land use-related emissions. The analysis does not focus exclusively on project-specific emissions clearly tied to one biofuel producer.

Indeed, EPA's standing interpretation of section 211(o)(1)(H) is extremely broad. EPA interpreted "significant indirect emissions" in a 2010 rulemaking ("RFS2 Rule") that established the regulatory framework for the updated RFS program.[22] EPA took a "consequential" approach to GHG emissions accounting, meaning that in conducting lifecycle analyses, EPA accounted for GHGs emitted "directly or indirectly, as a consequence of changes in demand for the product."[23] Using this approach, EPA determined that GHG emissions from *international* indirect land use change induced by increased biofuel production were "significant indirect emissions" under section 211(o)(1)(H).[24]

Congress knew about EPA's interpretation of section 211(o)(1)(H) when it drafted the IRA.[25] By incorporating section 211(o)(1)(H) into the IRA, Congress validated EPA's interpretation of that provision and directed Treasury to apply EPA's logic to hydrogen

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[18] *See Growth Energy v. EPA*, 5 F.4th 1, 7 (D.C. Cir. 2021).
[19] *See, e.g.*, 42 U.S.C. § 7545(o)(1)(B) (defining "advanced biofuel" as renewable fuel with a lifecycle emissions rate of "at least 50 percent less than baseline lifecycle greenhouse gas emissions"); *id.* § 7545(o)(1)(E) (defining "cellulosic biofuel" as having a lifecycle emissions rate of "at least 60 percent less than the baseline lifecycle greenhouse gas emissions").
[20] The modifier, "such as" in reference to "significant emissions from land use changes" makes clear that "significant emissions from land use changes" is *one example* of significant indirect emissions, not the only type of significant indirect emissions. *See* 42 U.S.C. § 7545(o)(1)(H).
[21] 42 U.S.C. § 7545(o)(1)(H).
[22] *See* 75 Fed. Reg. at 14670.
[23] RFS2 Regulatory Impact Analysis, EPA-420-R-10-006, 298-310, at 299 (Feb. 2010), see excerpt attached.
[24] 75 Fed. Reg. at 14765.
[25] *See Lamar, Archer & Cofrin*, 138 S. Ct. at 1762; *Bragdon*, 524 U. S. at 645.

production. As explained below, Treasury's interpretation of section 211(o)(1)(H) aligns with the plain text of the statute and with EPA interpretation of the provision.[26]

iii. "Significant emissions from land use change" can be analogized to a systemwide accounting scheme of indirect emissions from hydrogen production.

The "indirect power use changes" resulting from hydrogen production are directly analogous to "indirect land use changes" resulting from the production of biofuels. Consider a grid-connected hydrogen producer that draws grid electricity as a feedstock for hydrogen production. This drives up overall grid demand, and therefore the need for additional electricity supply to "bridge [at least some of] the gap."[27] If most of the gap-filling electricity to meet electricity demand from the grid draws on unabated fossil fuels (which is the most likely type of electricity production to fill the gap, per the current United States ("U.S.") generation mix),[28] then there will be a net increase in system wide emissions.

Similar logic applies to a behind-the-meter hydrogen producer. A producer that draws on existing clean electricity resources will divert that electricity from the grid or from supplying other existing electricity demand. This diversion will likely increase the overall carbon intensity of the electricity production mix, as increased capacity from fossil fuel sources is likely to fill the gap. The hydrogen producer will likely increase systemwide grid emissions, even if it does not directly draw grid power. Failure to account for these emissions would result in an inaccurate lifecycle analysis that does not account for real world emissions impacts.[29] Thus, just as EPA must consider the systemwide land use emissions impacts stemming from production of a biofuel feedstock (e.g., corn), Treasury must consider systemwide power grid emissions impacts stemming from production of a hydrogen feedstock (e.g., electrons).[30]

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[26] *See* Letter from EPA Deputy Admin. Janet G. McCabe to Assistant Secretary Lily Batchelder at 2 (Dec. 20, 2023), https://home.treasury.gov/system/files/136/45V-NPRM-EPA-letter.pdf (It is "reasonable and consistent with [EPA's] precedent for Treasury to determine that induced grid emissions are an anticipated real-world result of electrolytic hydrogen production that must be considered" and "[s]uch interpretation would be consistent with the EPA's long-standing interpretation and application of CAA section 211(o)(1)(H) in the context of the RFS program.").

[27] Rachel Fakhry, Nat. Res. Def. Council, *Success of IRA Hydrogen Tax Credit Hinges on IRS and DOE* (Dec. 8, 2022), see attached.

[28] *See* Energy Information Admin., *Short-Term Energy Outlook* at 2 (Feb. 2024), https://www.eia.gov/outlooks/steo/pdf/steo_full.pdf (fossil fuels accounted for 59% of national electricity generation in 2023, compared to 22% for renewables and 19% for nuclear).

[29] *See* 75 Fed. Reg. at 14766 ("the alternative of ignoring such emissions would result in grossly inaccurate assessments").

[30] Section 45V also provides that lifecycle GHG emissions through the point of production are "determined under the most recent Greenhouse gases, Regulated Emissions, and Energy use in Transportation model [("GREET")] developed by Argonne National Laboratory, or a successor model (as determined by the Secretary)." 26 U.S.C. § 45V(c)(1)(B). As a general matter, GREET is updated annually to reflect new information and data. US Department of Energy, Guidelines to Determine Well-to-Gate Greenhouse Gas (GHG) Emissions of Hydrogen Production

iv. <u>Indirect grid emissions from hydrogen production are "significant" and are "related to" the fuel lifecycle.</u>

Not only are changes in grid emissions resulting from electricity use by hydrogen production facilities "indirect" emissions under section 211(o)(1)(H), but they are also a "significant" source of indirect emissions for hydrogen electrolysis. The term "significant" is not defined in section 45V or section 211(o)(1)(H), and section 211 instead specifies that the quantity of emissions is "determined by the Administrator."[31] It is a "fundamental canon of statutory construction that, unless otherwise defined, words will be interpreted as taking their ordinary, contemporary, common meaning."[32]

Black's Law Dictionary defines "significant" as "[e]mbodying or bearing some meaning; having or expressing a sense . . . [o]f special importance; momentous, as distinguished from insignificant."[33] Merriam Webster defines "significant" as "having or likely to have influence or effect: important" and "of a noticeably or measurably large amount."[34] Courts interpreting the meaning of the word "significant" have relied on similar definitions.[35] Each of these definitions indicates that, for emissions to be "significant," they must be noticeably large. But what counts as "noticeably large" is context-dependent; otherwise, we would not refer to "jumbo shrimp."

Pathways using 45VH2-GREET 2023, at 25 (Dec. 2023), https://www.energy.gov/sites/default/files/2023-12/greet-manual_2023-12-20.pdf [hereinafter 45VH2-GREET Manual]. Several commenters in response to Treasury's initial request for information argued that the version of GREET in existence at the time Congress passed the IRA did not account for consequential or indirect emissions and that as a result, Treasury should not include such emissions in its lifecycle GHG emissions accounting. As we have explained in prior letters, if Congress intended for Treasury to use the GREET model as it was at the time IRA was passed, Congress would not have (1) referred to section 211(o), which includes significant indirect emissions (i.e., consequential emissions) and (2) included the possibility of a "successor model." *See NLRB v. SW Gen., Inc.*, 580 U.S. 288, 304 (2017) ("It is . . . a cardinal principle of statutory construction that we must give effect, if possible, to every clause and word of a statute."). Section 45V therefore contemplated that Treasury would update GREET (or create a successor model) to incorporate certain required elements of 45V, such as the ability of grid-connected hydrogen producers to purchase renewable energy credits to offset their electricity consumption). To this end, Treasury properly updated GREET and published the 45V-specific version, "45VH2-GREET." 88 Fed. Reg. 89220, 89223 [hereinafter "Proposal"].

[31] While CAA section 211(o)(1)(H) refers to the Administrator of the EPA, it follows that the decision of determining the aggregate quantity of greenhouse gas emissions when imported into section 45V would be left to the relevant agency (here, the Treasury).

[32] *Sandifer v. U.S. Steel Corp.*, 571 U.S. 220, 227 (2014) (cleaned up) (quoting *Perrin v. United States*, 444 U.S. 37, 42 (1979)); *see also Wis. Cent. Ltd. v. United States*, 138 S. Ct. 2067, 2074 (2018) ("words generally should be interpreted as taking their ordinary, contemporary, common meaning at the time Congress enacted the statute") (cleaned up) (quoting *Perrin*, 444 U.S., at 42).

[33] SIGNIFICANT, Black's Law Dictionary (11th ed. 2019).

[34] Merriam-Webster Online Dictionary, *significant (adjective),* https://www.merriam-webster.com/dictionary/significant (last visited Feb. 21, 2024).

[35] *See Benko v. Quality Loan Serv. Corp.*, 789 F.3d 1111, 1118, (9th Cir. 2015) ("Several dictionaries offer complementary definitions of 'significant,' with each suggesting that the word essentially means 'important' or 'characterized by a large amount or quantity.'"); *VIP of Berlin, LLC v. Town of Berlin*, 593 F.3d 179, 187 (2nd Cir. 2010) ("one common definition of the term 'significant' is 'of a noticeably or measurably large amount."); *id.* (citing Webster's Third New Int'l Dictionary 2116 (1993) (defining significant as "important, weighty, notable"); *Kaufman v. Allstate N.J. Ins. Co.*, 561 F.3d 144, 157 (3rd Cir. 2009) ("The word 'significant' is defined as 'important, notable.'") (citing *Oxford English Dictionary* (2d ed. 1989)); *accord Woods v. Std. Ins. Co.*, 771 F.3d 1257, 1266 (10th Cir. 2014).

Accordingly, EPA has defined "significance" of emissions under section 211(o)(1)(H) "in terms of their relationship to total GHG emissions for given fuel pathways."[36] The same approach should follow for section 45V, which also has GHG emissions requirements and thresholds. Specifically, the "significance" of indirect emissions should be measured in terms of their relationship with the emissions thresholds in section 45V.

Applying this logic, indirect grid emissions resulting from hydrogen production are clearly significant. Research has found that hydrogen produced from electricity—whether that electricity is directly connected behind-the-meter or grid-connected with Power Purchase Agreements ("PPAs") or EACs—has the potential to *increase* economy-wide emissions. The carbon intensity of input electricity is currently the largest driver of electrolysis-related emissions.[37] Induced indirect emissions from grid-based electrolysis are magnitudes higher than the statutory tiers, particularly compared to the highest credit tier.[38] They are undoubtedly significant in relation to the statutory GHG thresholds.

And it makes sense that electricity used to produce hydrogen—and therefore the emissions from replacing that electricity—would be significant; electrolytic hydrogen requires a tremendous amount of electricity. For example, an electrolysis plant making around 10,000 kilograms per hour of hydrogen consumes the same amount of electricity in that time as 440,000 U.S. homes.[39] Given the immense amount of electricity used to produce clean hydrogen, it makes sense that displacing existing clean electricity to produce that hydrogen would create a "significant" gap in the grid that would be filled with dirty electricity. By incorporating the definition of "lifecycle greenhouse gas emissions" from CAA section 211(o)(1)(H) into section 45V, Congress sought to address the risk that hydrogen production might cause increased systemwide GHG emissions.

Finally, systemwide grid emissions are "related . . . to the fuel lifecycle" of hydrogen production. The term "'relating to' . . . is a broad one – 'to stand in some relation; to have bearing or concern; to pertain; refer; to bring into association with or connection with.'"[40] Thus, section 211(o)(1)(H), in referring to emissions *relating to* the lifecycle of making a fuel, casts a broad net around "significant indirect emissions". EPA has taken a similarly broad read of

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[36] 75 Fed. Reg. at 14766.

[37] *See* Amgad Elgowainy, et al, *Hydrogen Life-Cycle Analysis in Support of Clean Hydrogen Production* 7, Argonne Nat'l Lab'y. (Oct. 2022) https://publications.anl.gov/anlpubs/2022/10/179090.pdf ("The most important factor for the [well-to-gate carbon intensity] of [hydrogen] production via water electrolysis is the [carbon intensity] of the supplied power.").

[38] *See* Wilson Ricks et al., *Minimizing emissions from grid-based hydrogen production in the United States* 2, Env't. Rsch. Letters 18 (2023), see attached ("Using the current average U.S. generation mix, embodied emissions from grid-connected electrolysis would be far too high to meet statutory requirements for even the minimum PTC."); *id.* at 5 (noting that—without an additionality requirement for grid-connected electrolyzers—attributional emission intensities for hydrogen production could reach 20 kg CO_2e per kilogram of hydrogen, compared to the section 45V threshold of 4 kg CO_2e per kilogram of hydrogen).

[39] Clean Air Task Force, *Hydrogen Production Calculator*, https://www.catf.us/hydrogen-converter/ (last visited Feb. 6, 2024).

[40] *Morales v. TWA*, 504 U.S. 374, 383 (1992) (quoting Black's Law Dictionary 1158 (5th ed. 1979)); *accord Dan's City Used Cars, Inc. v. Pelkey*, 569 U.S. 251, 260 (2013).

"related to" in interpreting section 211(o)(1)(H).[41] In the RFS2 Rule, EPA predicted through modeling that "increased demand for feedstocks to produce renewable fuel that satisfies [the RFS] *will likely result in* international land use change" and "[s]uch change is, then, 'related to'; the full fuel lifecycle of these fuels."[42] Indeed, EPA noted that the statute did not require EPA to "wait until these effects occur to establish the required linkage, but instead believes that it [was] authorized to use predictive models to demonstrate likely results."[43]

Under these metrics, systemwide grid emissions are related to the hydrogen fuel lifecycle. The following analyses and models demonstrate that drawing clean electricity from the grid "will likely result in" increased systemwide GHG emissions, described in more depth below:

- **Princeton ZERO Lab**[44], **Energy Innovation**[45], and **MIT Energy Initiative**[46] all evaluated emissions on a project-level basis and found that if hydrogen projects are not required to comply with all three pillars, emissions could increase up to 5 times compared to today's gas-based hydrogen.

- **The Rhodium Group** found that annual (as opposed to hourly) matching could increase total GHG emissions by 34 to 58 million metric tons ("MMT") of CO_2e in 2030 and a cumulative 56 to 97 MMT from 2023 to 2030. They also found that without an incrementality requirement, emissions estimates increase by 73 MMT in 2030.[47]

- **Evolved Energy Research** found that requiring the three pillars improved emissions impacts significantly in all of their modeling scenarios. For example, they found that in comparison to limited requirements, the three pillars would avoid 47 to 109 MMT CO_2 in 2030 and cumulatively would avoid 247 to 643 MMT CO_2 through 2032.[48]

- **Electric Power Research Institute ("EPRI") and GTI Energy** found that when considering the net economy-wide effect, the change in cumulative emissions ranged from a *reduction* of 670 MMT of CO_2 with a three pillars requirement, to an *increase* of 340 MMT without the three pillars requirement (relative to a no hydrogen credit case). When comparing the three pillars to requirements with only one or two of the pillars, the three pillars scenario was the *only* scenario that decreased net CO_2 emissions.[49]

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[41] *See* 75 Fed. Reg. at 14767.
[42] *Id.* (emphasis added).
[43] *Id*.
[44] *See* Ricks et al., *supra* note 38.
[45] Dan Esposito, et al., *Smart Design of 45V Hydrogen Production Tax Credit Will Reduce Emissions*, Energy Innovation Policy & Technology LLC (2023), see attached.
[46] Anna Cybulsky et al., *Producing hydrogen from electricity*, MIT Energy Initiative (April 2023) (working paper), see attached.
[47] Ben King et al., *How Clean Will US Hydrogen Get?,* Rhodium Group (Jan. 4, 2024), see attached.
[48] Ben Haley & Jeremy Hargreaves, *45V Tax Credit Analysis: Three Pillars Impact Analysis,* Evolved Energy Research (last updated Jun 23, 2023), see attached.
[49] Elec. Power Rsch. Inst. & GTI Energy, *Impacts of IRA's 45V Clean Hydrogen Production Tax Credit* [whitepaper] (Nov. 2023), see attached.

- **Environmental Resources Management ("ERM")** conducted a detailed literature review of approximately 30 reports on this topic and concluded that these reports find that the three pillars framework will protect against emissions increases while still allowing for long-term growth of the clean hydrogen industry.[50]

These analyses are more than enough to meet the statutory requirement of significance.

v. The goal of section 45V and the IRA is to reduce GHG emissions and address climate change.

Finally, the intent of section 45V is to promote truly clean hydrogen and combat climate change by reducing GHG emissions. Congress passed the IRA to "make[] investments to accelerate clean energy deployment, help achieve our climate goals, and create millions of jobs over the next decade."[51] Additionally, the clean energy tax credits, including section 45V, "were drafted with the goal of unleashing clean energy deployment, in line with President Biden's pledge of a 50-52 percent reduction from 2005 levels in economy-wide net greenhouse gas pollution in 2030."[52] The goal of section 45V is to incentivize *truly clean* hydrogen that can help address climate change; not to incentivize hydrogen for its own sake. Failing to account for grid-induced emissions would have the opposite effect: it would promote hydrogen production that leads to *greater* GHG emissions. Congress could not have wanted this.

The structure of section 45V further bears this out. The tiers of credits in section 45V demonstrate that the cleaner the hydrogen is, the more highly Congress valued it. In particular, the steep step-down from $3 to $1 (and then to $0) shows that the legislature put a thumb on the scale in favor of the cleanest hydrogen production. Awarding lucrative tax credits to hydrogen producers that induce significant GHG emissions flies in the face of the goals of section 45V. Treasury must issue final regulations that lead to the GHG emissions reductions section 45V is intended to achieve.[53]

B. Treasury's proposal correctly considers how hydrogen production increases systemwide emissions of the electricity grid by implementing the three pillars approach.

To account for significant indirect emissions from hydrogen production, Treasury proposes that when a taxpayer determines a lifecycle GHG emissions rate using 45VH2-GREET, the taxpayer may "treat such hydrogen production facility's use of electricity as being from a specific electricity generating facility rather than being from the regional electricity grid . . . only if the taxpayer acquires and retires qualifying EACs . . . for each unit of electricity that the

[50] Angelina Bellino et al., *Assessment of Grid-Connected Hydrogen Impacts,* Env't Res. Mgmt. (Feb. 9, 2024), see attached.
[51] 168 Cong Rec S 4210, 4211 (Aug. 6, 2022).
[52] 168 Cong Rec H 7577, 7664 (Aug. 12, 2022).
[53] *See* 26 U.S.C. § 45V(f) (directing Treasury to "issue regulations or other guidance to carry out the purposes of this section.").

taxpayer claims from such source."[54] "Qualifying EACs" are those that meet three pillars: (1) incrementality, (2) temporal matching, and (3) deliverability.[55] As Treasury explains, the "use of EACs with attributes that meet [the three pillars] is an appropriate way for the Treasury Department and the IRS to document electricity inputs to electrolytic hydrogen production."[56] Perhaps most importantly, EACs that are incremental (new clean electricity) "serve as a reasonable methodological proxy for quantifying certain indirect emissions associated with electricity."[57] In other words, without a new clean electricity requirement, hydrogen producers *cannot prove* that they avoided significant indirect emissions. Purchasing incremental EACs proves that the electrolyzer was powered by only clean energy. The three pillars effectuate section 45V's emissions thresholds and account for real, systemwide emissions increases related to hydrogen production.[58]

Treasury's proposed guidance takes a reasonable approach to implementing these three pillars and includes immediate start-dates of the requirements for incrementality and deliverability, and a 2028 start date for hourly matching. To maintain the rigor of the 45V methodologies and meet the required carbon intensity tiers, the start dates and requirements for the three pillars cannot be further loosened from the proposed guidance.

Finally, some stakeholders have raised concerns that implementing the three pillars could inadvertently stymie hydrogen production from projects such as DOE's Regional Clean Hydrogen Hubs. As stated above, Congress did not intend to incentivize the hydrogen industry for its own sake, but to advance clean hydrogen production, which is attainable with the three pillars approach, including the purchase of EACs that meet the three pillars. We expect that the Regional Clean Hydrogen Hubs will likely be able to move forward with projects either by meeting the 3 pillar requirements or by utilizing alternative funding sources. For example, other funding sources that can be "stacked" with the Regional Clean Hydrogen Hubs funding include other DOE grants, such as carbon capture and storage and direct air capture hubs or industrial decarbonization demonstrations; and state policy incentives, such as in Pennsylvania and Colorado.[59] Other options for hydrogen hubs to move forward include potential scale-down of projects to maximize the impact of DOE funding, reprioritization to projects that can meet the 45V requirements, and purchasing of EACs as a compliance mechanism to enable them to receive 45V credits. The availability of qualifying EACs is not expected to be a limiting factor for hydrogen projects to meet the 3 pillar requirements.[60]

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[54] Proposal at 89248 (proposed regulation at § 1.45V-4(d)(1)).
[55] Proposal at 89249.
[56] Proposal at 89227.
[57] *Id*.
[58] *Cf.* 75 Fed. Reg. 14766 (Explaining that in the context of assessing the LCA of biofuels under the RFS, "[i]gnoring international emissions, a large part of the GHG emission associated with the different fuels, would result in a GHG analysis that bears no relationship to the real world emissions impact of transportation fuels.").
[59] *See e.g.,* Alternate Fuels Data Center, *Hydrogen Laws and Incentives in Pennsylvania,* Dep't of Energy, Off. of Energy Efficiency & Renewable Energy, https://afdc.energy.gov/fuels/laws/HY?state=PA (last accessed Feb. 22, 2024); Alternate Fuels Data Center, *Hydrogen Laws and Incentives in Colorado,* Dep't of Energy, Off. of Energy Efficiency & Renewable Energy, https://afdc.energy.gov/fuels/laws/HY?state=co (last accessed Feb. 22, 2024).
[60] Elec. Power Rsch. Inst. & GTI Energy, *supra* note 49.

III. IMPLEMENTING INCREMENTALITY FOR ELECTROLYTIC HYDROGEN

To meet the incrementality pillar, Treasury's proposal requires electric generating units ("EGUs") to be placed in service no more than 36 months before the hydrogen production facility that is retiring the EAC is placed in service.[61] As explained above, this requirement is necessary to limit significant indirect emissions, because diverting existing clean electricity production on the grid from meeting pre-existing electricity demand will likely result in the gap being filled with higher-emitting electricity production. But as Treasury recognizes, there may be certain specific circumstances where the diversion of existing minimal emissions power generating resources to hydrogen production would be unlikely to result in significant induced GHG emissions.[62] These circumstances include "generation from minimal-emitting power plants

(i) that would retire absent the ability to sell electricity for qualified clean hydrogen production,
(ii) during periods in which minimal-emitting generation would have otherwise been curtailed, if marginal emissions rates are minimal, or
(iii) in locations where grid electricity is 100 percent generated by minimal-emitting generators, or where increases in load do not increase grid emissions."[63]

This section explains how Treasury should administer such exceptions in a way that provides flexibility to the growing clean hydrogen industry without leading to significant indirect emissions.

A. Treasury should not apply an overbroad 5% exemption to incrementality.

Treasury proposes a "formulaic approach" to addressing incrementality for existing clean generators that would "deem five percent of the hourly generation from minimal-emitting electricity generators . . . placed in service before January 1, 2023, as satisfying . . . incrementality."[64] Treasury reasons that 5% could be a proxy for both curtailments and avoided retirements given that it matches historical and projected trends for both. For curtailments, Treasury notes that Lawrence Berkeley National Laboratory predicts that negative wholesale prices, which is likely when curtailments would occur, occurred during "roughly five percent of hours over the last several years."[65] For avoided retirements, Treasury notes that the Energy Information Administration predicts that about "five percent of the nuclear fleet" is at risk of retirement such that the 5% exemption could "also serve as a proxy for avoided retirements."[66]

A broad 5% exemption, however, only crudely addresses both options. Indeed, Treasury recognizes why this approach does not meet the requirements of section 45V by acknowledging that such an exemption "without further temporal, spatial, and circumstantial precision results in

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[61] Proposal at 89249 (proposed regulation § 1.45–4(d)(3)(i)(A))
[62] *Id.* at 89230–32.
[63] *Id.* at 89230.
[64] *Id.* at 89231.
[65] *Id.* at 89232.
[66] *Id.*

hydrogen production facilities receiving credits for which they should not be eligible *given their induced emissions rates*."[67] And these induced emissions are significant: analysis from the Rhodium Group found that a 5% exemption for all existing clean generation could result in 1.5 billion metric tons of increased emissions cumulatively through 2035.[68] Additionally, new analysis of existing clean generators in California observes a "consequential emissions intensity of roughly 20 kg CO_2e/kg H_2 for any hydrogen produced by electrolyzers taking advantage of this [5-10%] incrementality exemption."[69] This far exceeds the statutory thresholds, therefore constituting significant indirect emissions.

For curtailments, a 5% exemption to incrementality across all regions at any time is too broad to accurately target the circumstances when curtailments occur. Curtailments usually occur when there is a systemwide oversupply of energy compared to the demand on the system, or when local transmission constraints inhibit exporting power outside of a region. These are specific circumstances and can vary depending on the time of day and the hydrogen producer's geographic location. Treasury acknowledges this geographic variation by referencing data from Lawrence Berkeley National Lab on how curtailment rates for "solar photovoltaics [were] over 10 percent . . . in [Electricity Reliability Council of Texas (ERCOT)] and over 3 percent in California Independent System Operator (CAISO)."[70] For time variation, analysis by Energy Innovation found that nearly a quarter of the total wind and solar energy wasted in CAISO in 2023 occurred in just 1% of hours, and nearly 80% of that waste happened in 10% of hours.[71] Providing a 5% exemption for a facility's generation without geographic and temporal restrictions allows circumstances where more existing clean generation will be exempted than necessary, resulting in a gap in generation that will likely be partially or entirely filled by high-emitting generation. As a result, instead of utilizing wasted clean generation as intended, the broad 5% exemption will induce significant indirect emissions as disallowed under the statute.

For avoided retirements, a broad 5% exemption for incrementality to all existing minimal-emitting generation is arbitrary and divorced from the facility-level determination necessary to accurately determine economic distress. Avoided retirement can be a proxy for incrementality, because if the facility were to shut down, it would no longer be producing electricity. If instead, a hydrogen producer contracted that electricity (or consumed it, if they were owned by the same entity) and in doing so contributed to a decision to keep the nuclear facility operating, then the electricity produced from that nuclear facility would be an incremental increase compared to a situation where the facility retired. The hydrogen producer—with the support of the 45V credit—would have helped to enable the facility to continue operating, and the gap in electricity production for the grid would not be made any greater because of the hydrogen production.

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[67] *Id.* at 89231 (emphasis added).
[68] King et al., *supra* note 47.
[69] Wilson Ricks and Jesse D. Jenkins, Research Addendum Examination of Proposed Exemptions to Incrementality Requirements for Section 45V, at 1, Princeton University Zero Lab (Feb. 22, 2024), see attached.
[70] Proposal at 89232.
[71] Dan Esposito et al., 45V Exemptions Need Strong Guardrails to Protect Climate, Grow Hydrogen Industry, Energy Innovation Pol'y & Tech. (Feb. 2024), see attached.

CATF agrees that the continued operation of minimal-emitting generation will be vital to decarbonizing our grid. But a 5% exemption for *all* generators allows both financially healthy and financially stressed facilities to divert electricity toward hydrogen production. Carving out exemptions for financially healthy facilities that do not need additional revenues from sales to hydrogen producers will only result in significant indirect emissions. This is because healthy facilities would have otherwise supplied that 5% of clean electricity to the grid; pulling the 5% of clean electricity from the grid creates a gap that will likely be filled by high-emitting generation (hence the estimated 1.5 billion metric tons of increased emissions cumulatively through 2035[72]). To determine if additional revenues from sales to hydrogen producers would allow a minimal emitting facility to avoid retirement, Treasury must take a more targeted approach. Section III.B sets out a potential pathway for demonstrating avoided retirements for nuclear facilities.

Finally, Treasury must ensure that a 5% exemption or any other incrementality exemption, if implemented, is aligned with hourly matching. Allowing facilities to allocate their 5% exemption to any hours within a month or a year would cause facilities to optimize their allocation based on when their EACs are the most valuable. Unfortunately, this would likely be when the grid is also the dirtiest due to the lack of competing EACs from variable low-carbon generation like solar and wind. Should there be an influx of exempt EACs during these hours, there is a risk that the electrolyzer demand would be partially or entirely met with high-emitting, fossil-based generation.

B. Avoided Retirements Approach for Nuclear Facilities

CATF has previously advocated for allowing an exemption to the incrementality requirement where the qualified clean hydrogen production extends the lifetime of the minimal-emitting power plant.[73] To accurately determine whether the power plant needed the revenue from the hydrogen project to continue operating, facilities must demonstrate that they are under sufficient financial duress and are at risk of shutting down. This section details a potential means of demonstrating avoided retirement for nuclear facilities that does not lead to significant indirect emissions that are impermissible by statute. Importantly, creating an incrementality carveout that is not based on facility-specific considerations would risk inducing significant indirect emissions in violation of section 45V.[74] As a result, Treasury should consult with DOE on creating similar criteria for other generating sources.

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[72] King et al., *supra* note 47.

[73] Clean Air Task Force & Nat. Res. Def. Council, RE: Notice 2022-49 Request for Comments on Certain Energy Generation Initiatives–Hydrogen (Apr. 10, 2023), see attached [hereinafter "CATF & NRDC Comments"].

[74] The nuclear industry has argued that it should be exempted from incrementality because there have only been two new facilities in the U.S–Vogtle 3 and 4–in over 30 years. *See* Nick Ferris, *Why a new era for US nuclear looks unlikely,* Energy Monitor (May 26, 2023), https://www.energymonitor.ai/sectors/power/why-a-new-era-for-us-nuclear-looks-unlikely/?cf-view. We recognize that there are numerous advantages to pairing nuclear to electrolysis and that constructing new nuclear is difficult. Nuclear energy is also particularly well suited for pairing with electrolysis given that hydrogen is already consumed at nuclear power plants to mitigate stress corrosion cracking in

i. Summary of the Avoided Retirements Approach

Rather than a blanket 5% exemption, a more targeted solution for avoided retirements would be to apply a 5% exemption specifically to facilities that can demonstrate that the hydrogen revenue would help the facility avoid retirement. To demonstrate this, facilities must pass an economic test to show that they are in economic duress and would benefit from additional revenues (i.e., that the 45V credit is helping them avoid retirement). For nuclear facilities, an economic test based on eligibility for the section 45U nuclear production tax credit is a suitable proxy to measure whether a nuclear facility has sufficient revenues to match the generating costs for the facility. As an alternative to the 45U proxy, facilities could also demonstrate economic duress by qualifying to receive Civil Nuclear Credit Program ("CNCP") funding. Facilities should be required to submit to Treasury either: (1) a form demonstrating eligibility for 45U for two out of the three previous years from when the facility aims to produce hydrogen; or (2) a DOE determination of eligibility for CNCP at any point in the previous three years.

In addition to an economic test using 45U or CNCP, only existing facilities in wholesale markets should qualify to demonstrate avoided retirements, given their greater exposure to market risk. Facilities in "cost-of-service" states should not qualify to demonstrate avoided retirements because of the regulations in place in those states that guarantee nuclear facilities recover a reasonable rate of return on top of their generating costs.

Finally, if the facility does not satisfy the economic test, the facility can still procure replacement EACs for the facility's EACs to meet the incrementality pillar. Otherwise, Treasury must claw back any 45V credits claimed using the facility's EACs.

ii. Nuclear facilities must pass an economic test to be considered incremental.

To demonstrate that a hydrogen project is meaningfully supporting the economics of a nuclear plant and helping to prevent the nuclear facility from retiring, the nuclear operator must first demonstrate that the facility is under financial risk. The most accurate means of doing so is a rigorous open-book process similar to what is required under the CNCP. As part of the CNCP, facilities submit calculations of projected average annual operating loss for continuing to operate, justify the key assumptions used in these calculations, and compare them to historical financial trends. However, we recognize that the added administrative burden associated with implementing this process for all generation sources seeking to access 45V may complicate business development opportunities.

Instead, CATF proposes a simplified proxy approach, such that a nuclear facility may pass one of the following two economic tests to be considered incremental:

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boiling water reactors, the excess waste heat from nuclear power can be used to increase efficiencies of solid oxide electrolyzers, and the high-capacity factors of nuclear power plants lead to better utilization of the capital investment spent on expensive electrolyzers. *See generally* Mike Fowler et al., Bridging the Gap: How Nuclear-Derived Zero-Carbon Fuels Can Help Decarbonize Marine Shipping, Clean Air Task Force (Aug. 2021), https://cdn.catf.us/wp-content/uploads/2021/08/21092159/NuclearZCFMarineShipping.pdf.

1) For two out of the three years prior to the Commercial Operations Date (see definition below), a plant must have qualified for a nonzero payment under the formula for determining the 45U zero-emission nuclear power production credit as passed in the 2022 Inflation Reduction Act. The formula in the statute should be used to determine whether a plant would qualify for a nonzero payment *rather* than relying on tax records. This is because hydrogen producers may still seek to claim 45V using nuclear EACs even after the 45U credit expires on December 31, 2032.

2) A facility is qualified for the CNCP, as determined by the DOE, at any point within 36 months prior to the Commercial Operations Date. Note that the facility does not need to *receive* any funding from the CNCP; it only needs to *qualify* for the CNCP using that program's methodology.

The following analysis outlines the justification for these two options.

The 45U credit provides up to $15/megawatt hour ("MWh") toward existing nuclear plants and decreases proportionally as a facility's revenue rises above $25/MWh (in 2022 financial terms), reaching zero when market revenues increase above $43.75/MWh. Credits received from other local, state, and federal zero emission credit programs are also considered market revenues such that receiving these credits effectively decreases the amount of 45U credit the facility can claim. As shown in Figure 1, the 45U tax credit keeps facility revenues around $40/MWh when market revenues are above $25/MWh.
For illustration purposes, the criteria for payment under 45U is listed here as well:

If ($0.003/kWh)(e) - (0.16)(g - ($0.025/kWh)(e)) > 0, there is a nonzero payment under 45U

Where *e* equals the kilowatt hour ("kWh") of electricity produced by the taxpayer at a nuclear power facility and sold by the taxpayer to an unrelated person during the taxable year, and where *g* equals the gross receipts in dollars from any electricity produced by such a facility excluding credits received from other federal, state, and local zero-emission credit programs. Actual calculations should use inflation adjusted amounts for the $0.003/kWh and $0.025/kWh amount as detailed in the statute.

Simplifying gross receipts *g* as the average electricity revenue per MWh of electricity generated *p* multiplied by the amount of electricity produced by the taxpayer *e*, the formula simplifies down to:

If p < $43.75 / MWh, there is a nonzero payment under 45U

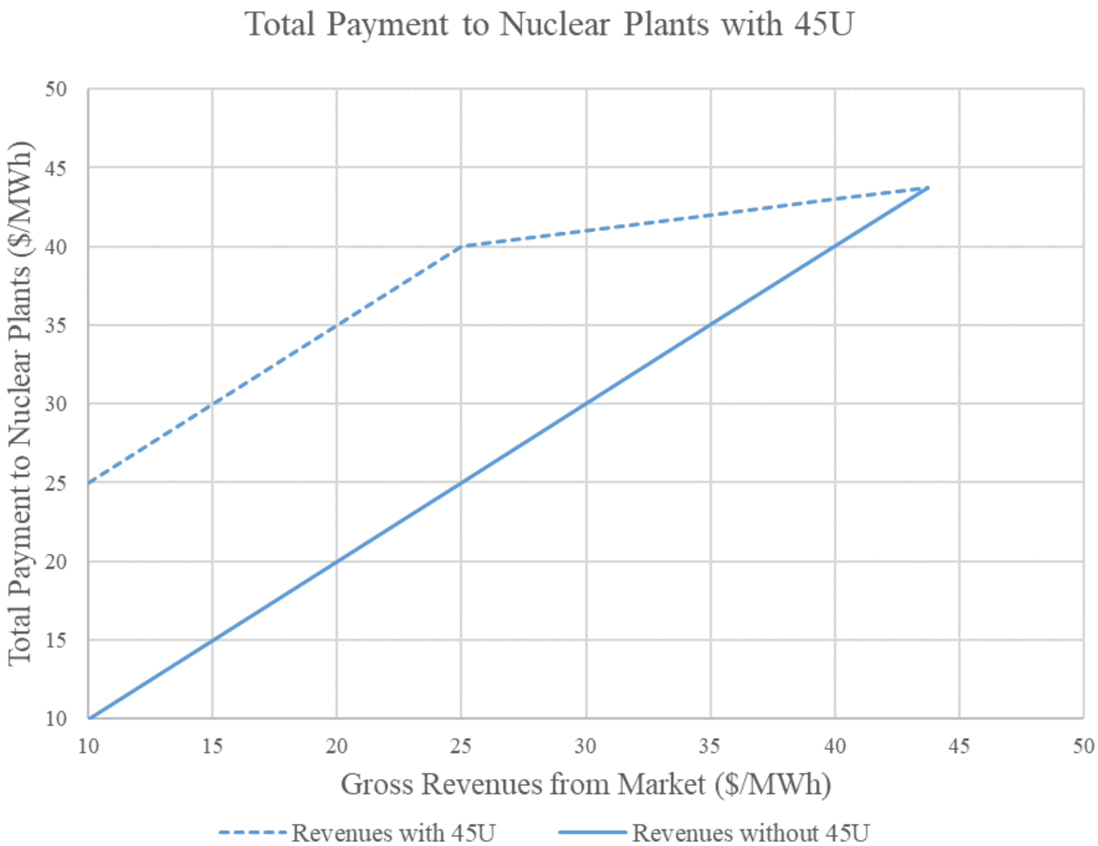

Figure 1. Total revenue to nuclear plants with and without the 45U nuclear PTC (dollar thresholds are in 2022 dollars)

The $43.75/MWh threshold is within the range of historical generating costs for nuclear facilities, which according to the Nuclear Energy Institute ("NEI") have been as high as $51.22/MWh in 2012 and as low as $28.64/MWh in 2022.[75] While there is a significant margin between $43.75/MWh and the latest generating costs, this margin may help mitigate the financial risks from owning and operating a nuclear facility, such as fluctuations in fuel prices, changes in regulatory requirements, and unplanned maintenance, which have not been included in these reported generating costs from NEI.

Given that multiunit facilities require approximately $40/MWh to stay financially healthy and the credit is designed to keep revenues within that range, the 45U tax credit can serve as a proxy for determining when a facility is under financial duress and could benefit from additional revenue from hydrogen sales to continue operations. Economic tests that do not have a similar formulated approach as 45U to prevent excess profits, such as qualification for other local, state, or federal subsidies, should not be used as a metric to demonstrate economic duress. Doing so would risk misallocating federal funding to facilities that increase economy-wide emissions.

[75] Nuclear Energy Institute, Nuclear Costs in Context, at 2–3 (Dec. 2023), see attached.

To provide additional flexibility and help insulate a facility's eligibility as incremental from fluctuations in electricity markets, facilities should only be required to qualify for two of the previous three years. If necessary, Treasury could also establish a longer qualification period to provide more certainty to nuclear developers (for example, by requiring facilities to qualify for four out of the previous six years).

iii. Facilities must submit a form to Treasury to demonstrate 45U eligibility.

Facilities must submit an avoided retirement form to the Treasury department demonstrating 45U eligibility for two out of three of the previous years or a determination of CNCP eligibility by DOE at any point within the last 36 months. The date that the facility files the form to Treasury is considered the facility's Commercial Operations Date (COD). Hydrogen producers procuring EACs from the nuclear facility must abide by the same 36-month vintage requirements as procuring EACs from other facilities. After filing to demonstrate 45U eligibility, the COD cannot be changed for avoided retirement considerations.

iv. Only facilities in wholesale electricity markets should be allowed to demonstrate avoided retirement.

EGUs owned by utilities subject to cost-of-service regulations experience reduced economic pressure, as state regulators set retail electricity prices at a rate sufficient to cover generation costs and provide a reasonable return on investment.[76] As a result, nuclear facilities owned by utilities subject to cost-of-service regulations should not be allowed to demonstrate avoided retirement through the aforementioned tests as a means of qualifying for the 45V credit.

Instead, qualification should be limited to nuclear facilities in wholesale electricity markets where there is less insulation from market forces. Prior to 2021, wholesale electricity prices decreased significantly due to a combination of low natural gas prices, increased deployment of wind and solar, and weak demand growth for electricity.[77] If the wholesale market price is consistently lower than the nuclear plant's operating costs, the owner of the plant may decide to retire the facility rather than continue to endure losses. These decreased prices have been cited by plant owners as major factors in the closure of at least eight out of the twelve reactors that have shut down since 2013.[78]

But exposure to market fluctuations is not always detrimental to nuclear facilities. The rise in wholesale prices in 2021 provided sufficient revenue for nuclear facilities in the New York Independent System Operator ("NYISO") and Pennsylvania-New Jersey-Maryland Interconnection ("PJM").[79] Given that market fluctuations can be both beneficial and detrimental

[76] Cong. Rsch. Serv., U.S. Nuclear Plant Shutdowns, State Interventions, and Policy Concerns (updated Feb. 7, 2022), see attached [hereinafter CRS, *U.S. Nuclear Plant Shutdown*].
[77] Andrew Mills et al., *The impact of wind, solar, and other factors,* 283 Applied Energy (Feb. 1, 2021), available at https://www.sciencedirect.com/science/article/pii/S0306261920316561.
[78] Cong. Rsch. Serv., *supra* note 76.
[79] Muhammad Maladoh Bah, *State and federal nuclear support schemes in dynamic electricity market conditions: Insights from NYISO and PJM*, 182 Energy Policy (Aug. 4, 2023), see attached.

to the financial health of a nuclear facility, access to wholesale electricity markets should not be the sole criteria to demonstrate economic duress.

v. Facilities that pass the economic test can consider 5% of their net summer capacity as incremental.

As outlined above, the goal of implementing an economic test is to ensure that only existing facilities that would have otherwise retired are receiving 45V credit. Ideally, an economic test for existing facilities would accurately measure if the facility is truly under financial duress *after* receiving other sources of public funding from federal, state, or local programs (i.e., CNCP or the 45U credit). But determining whether a facility still needs the hydrogen production tax credit for economic viability *after* receiving it may be difficult to administer. Doing so would require evaluating the facility annually using the 45U formula or the CNCP criteria to best assess if it is under economic duress without the hydrogen-related revenues. This would factor in changing market conditions or government support that may also be working in tandem to increase the financial health of a facility. As noted above, generating costs for dual-unit nuclear facilities have also been on a decline from a high of $51.22/MWh in 2012 to the current low of $28.64/MWh in 2022.[80] An annual assessment, however, would complicate project development, considering that facilities could receive and lose eligibility year by year.

Given that the economic tests listed above merely demonstrate whether the facility was under financial duress *before* receiving revenues from the tax credit and that it does not factor in changing economic conditions *after* receiving the credit, there will likely still be facilities who pass the economic test but do not actually need the 45V credit to avoid retirement. As a result, we urge Treasury to adopt a final safeguard in addition to the economic test outlined above. Specifically, if a facility qualifies as incremental under the economic tests outlined above, then only 5% of their net summer capacity from existing facilities should be considered incremental.

This layered approach—economic test plus a 5% cap—will help ensure that existing facilities do not cause induced emissions by shifting too much of their clean electricity from the grid to hydrogen production. The 5% cap recognizes that the hydrogen tax credit will not be the sole solution to keep a facility running but rather will be one option in a portfolio of options. For nuclear facilities, a 5% cap of the total generation is also in line with conversations with nuclear operators, where hydrogen is seen as a solution within a portfolio of options but is not the sole solution to keeping facilities operating. Treasury should also create similar economic tests for other generation sources to ensure only facilities that are truly at risk of retirement without additional revenues from hydrogen production can qualify as incremental.

vi. The 5% exemption for facilities should be applied on an hourly basis.

To align with the principle of hourly matching, the 5% exemption should be applied to a facility's generation at every hour after January 1, 2028. Prior to January 1, 2028, facilities can

[80] Nuclear Energy Institute*, supra* note 75.

allocate their exemption annually. Allowing nuclear facilities to allocate their 5% exemption to any hours within a month or a year would cause facilities to optimize their allocation based on when their EACs are the most valuable. Unfortunately, this would likely be when the grid is also the dirtiest due to the lack of competing EACs from variable low-carbon generation like solar and wind. Should there be an influx of qualified nuclear-based EACs during these hours, there is a risk that the electrolyzer demand would be partially or entirely met with high-emitting, fossil-based generation. The transition timeline for this hourly-based exemption for incrementality should be aligned with the transition period for the broader hourly matching requirement from Treasury.

A 5% hourly exemption is also easier to implement compared to a monthly or annual based one. To implement a monthly or annual option, generators without the ability to use an Application Programming Interface ("API") would need to manually designate the hours at which the exemption would apply. The EAC registry would then need to verify the 5% exemption is not exceeded. For more details on this issue, please see M-RETS' response to Treasury's request for comments on Section 45V Credit for Production of Clean Hydrogen; Section 48(a)(15) Election to Treat Clean Hydrogen Production Facilities as Energy Property, 88 Fed. Reg. 89220 (Dec. 26, 2023).

C. Curtailed Electricity

For circumstance (ii)—where minimal-emitting generation would have otherwise been curtailed—Treasury has proposed a broad 5% exemption to incrementality for all electricity generation. Treasury noted that this figure coincides with historical curtailment values across different generation sources and projected retirement for nuclear facilities. As explained, this broad exemption would allow facilities to divert electricity towards hydrogen production during hours that are the dirtiest.

Instead, a more targeted solution would be to exempt facilities from the incrementality requirement only when hydrogen producers procure EACs for electricity that would have been curtailed. This can be shown by establishing a price floor (in dollars per MWh) for the locational marginal pricing at the node applicable to the hydrogen project. Prices below this floor would likely result in facilities curtailing electricity generation. This method has more precision and rigor than an overarching percentage exemption, because it directly targets the hours where electricity has a high chance of being curtailed. A remaining challenge, however, is that developers could have difficulty understanding when these hours would be and likewise could struggle to take advantage of them. Some regions such as the Pacific Northwest may have a better understanding than others of their expected curtailment hours, if their curtailment is most likely due to seasonal-level variations (rather than daily, weather-based variations).

Another viable option is for DOE to conduct backwards-looking analyses at a fixed frequency to determine capacity and timing of curtailment in each deliverability region. This option could be the basis for a fixed percentage exemption that is limited to specific hours of the day, and while similar to Treasury's proposal, it should have additional stipulations on when the exemption would apply. Should Treasury pursue this approach, there should be a fixed lifetime for how long these curtailment EACs are available on the market that aligns with the issuance of the DOE study. This allows for adaptation to the changing occurrence of curtailment as the grid changes. While this option provides more certainty for developers, it does potentially allow for more indirect emissions since historical data may not align with reality. This is especially true for regions with policies that call for increased adoption of intermittent renewable generation that could both increase the magnitude of curtailments and shift their occurrence periods.

D. Clean Grids and Regions with Emission Caps

For circumstance (iii) where "increases in load do not increase grid emissions", CATF agrees that facilities sourcing hourly matched electricity from the same deliverability region that satisfy this requirement could be exempt from the incrementality requirement. The requirement to use incremental electricity that is both hourly matched to demand and deliverable is intended to prevent significant indirect emissions. Specifically, the incrementality requirement is necessary because diverting existing minimal-emitting generation from meeting pre-existing demand could result in the electricity production gap being partially or entirely filled with high-emitting electricity production. If instead, the diversion does not induce significant indirect emissions, then there is likewise no need for the electricity used for hydrogen production to be incremental.

Proponents of this exemption have argued that certain state policies may be sufficient to ensure that marginal demand will not result in significant indirect emissions.[81] CATF recommends that Treasury work with DOE to evaluate the following considerations when developing an exemption from incrementality based on state policies:

1. **Regions should have a cap-and-trade system; exemption to incrementality should not be based solely on the current emissions intensity of or the percentage of minimal-emitting generation within the deliverability zone.** The carbon intensity of the electricity grid can be influenced by policies and incentives designed to increase the use of minimal-emitting generation, such as Clean Electricity Standards ("CES") and Renewable Portfolio Standards ("RPS"). However, the emissions intensity and the percentage of minimal-emitting generation within the deliverability zone do not prevent marginal demand increases to be partially or entirely met with high-emitting electricity production. Treasury's proposal for circumstance (iii) lists "locations where grid electricity is 100% generated by minimal-emitting generators" as an example of when developers can be exempt from incrementality.[82] But without proper guardrails against consequential emissions, developers can still build or ramp up high-emitting electricity generating resources to meet the marginal demand from hydrogen production. While the EU has established exemptions to incrementality based on the carbon intensity of the grid or the percentage of minimal-emitting generation,[83] the EU also has an Emissions

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[81] *See e.g.*, Washington State Department of Commerce, Re: Notice 2022-58 Credits for Clean Hydrogen and Clean Fuel Production (July 14, 2023), https://deptofcommerce.app.box.com/s/tv8091970uthjqiekdtc1i2bo30rp525.
[82] Proposal at 89230.
[83] *See* Commission Regulation 2018/2001, art. 4, 2023 O.J. (EU), accessed at https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=PI_COM%3AC%282023%291087.

Trading System ("ETS") that caps the consequential emissions that could result from this exemption.[84] Regions pursuing the same exemption in the U.S. should, at minimum, have similar requirements to cap the increase in consequential emissions. For example, a region without a formal cap-and-trade system but with a CES or RPS could implement a guardrail to ensure that increased hydrogen production does not lead to significant induced grid emissions, such as: (1) an overall cap on CO_2 emissions from its grid, or (2) a cap on the emissions intensity of new generation.

2. **Cap-and-trade systems should account for import and export power flows to minimize emissions leakage.** Given that facilities in a state with a cap-and-trade program may procure EACs from EGUs outside of the state but within the same deliverability region, careful consideration is required to minimize emissions leakage to states without the same strict emission caps. The Northwest deliverability region is a prime example of the risk of this concern given that Washington, which has a cap-and-trade program,[85] is within the same deliverability zone as Idaho, which does not.

3. **Penalties for exceeding emissions caps should be evaluated against the value of the 45V PTC.** According to CATF analysis, the most lucrative tier of 45V could allow certain producers in regions with cheap, plentiful, zero-carbon electricity to produce hydrogen almost for free as electrolyzer capital costs decrease.[86] Given the value of the PTC, Treasury should also evaluate the enforcement mechanisms for the relevant cap and trade programs. Should the punitive measures of these programs be insufficient, developers may choose to exceed emission caps while remaining profitable due to the value of the PTC. To mitigate this concern, Treasury should require states to submit implementation plans and should collaborate with DOE to assess progress. Should the state policy prove ineffective, Treasury should also consider claw back provisions for the 45V credits issued to project developers who qualified under this exemption but exceeded emission caps.

4. **States must submit modeling to demonstrate that the incrementality exemption does not result in consequential emissions.** CATF recommends that Treasury request submissions from states on capacity expansion modeling that examines the consequential emissions impact of hydrogen projects pursuing the 45V credit. The modeling should be based on long-run electricity system-level impacts, be compared with a baseline without

[84] European Commission, *EU Emissions Trading System (EU ETS)*, https://climate.ec.europa.eu/eu-action/eu-emissions-trading-system-eu-ets_en, (last visited Feb. 22, 2024).
[85] *See* State of Washington Department of Ecology, *Washington's cap and invest program* https://ecology.wa.gov/air-climate/climate-commitment-act/cap-and-invest (last visited Feb. 22, 2024).
[86] Based on Internal CATF Analysis. A combination of technologies and electricity costs can reach this threshold; electricity from wind at 35% capacity factor and around $20/MWh, geothermal at 70% capacity factors and around $40/MWh, or at 35%, or nuclear at 90% capacity factors and around $45/MWh all can reach this target. Assumes total investment costs reach the estimates outlined in the 2022 *A One-Gigawatt Green-Hydrogen Plant* ISPT Report. The 2030 would shift depending on how quickly capital costs for electrolyzers come down. *See* Hans van Noordende & Peter Ripson, A One-GigaWatt Green-Hydrogen Plant, Institute for Sustainable Process Technology, Hydrogen Hub Innovation Program (2022), https://ispt.eu/media/Public-report-gigawatt-advanced-green-electrolyser-design.pdf.

these projects, account for emissions leakage across regions, and span the ten-year timeframe of 45V. Treasury should consult with DOE to develop guidelines on the input assumptions that states use in the modeling.

E. Uprates

Treasury's guidance also recognizes that an alternative test for establishing incrementality for an EGU is if the facility undergoes an uprate. The uprated portion of that facility's generation, or the "incremental generation capacity", is then considered incremental on an hourly or annual basis as in line with the broader hourly matching phase in. CATF concurs with this alternative test and has previously advocated for uprates as a credible exemption to incrementality.[87] By producing additional, minimal-emissions generation above the previous facility baseline, an uprate has the same effect as bringing online minimal-emissions generation from a new facility. As a result, procuring electricity from the facility's incremental generation capacity would not induce significant indirect emissions.

IV. OTHER CONSIDERATIONS FOR IMPLEMENTING THE THREE PILLARS

A. Interregional Deliverability

CATF supports the deliverability requirements outlined by Treasury in the proposed guidance. However, it is important to note that if the deliverability regions change over time, hydrogen producers should have the option to grandfather their region from previous qualification for 45V to avoid year-to-year uncertainty of which generating resources might meet deliverability requirements. As transmission and infrastructure develops nationally, if an updated formulation of the deliverability regions is beneficial to a hydrogen producer, they should also be allowed to elect to use the newest version of the deliverability requirements.

B. Registries are able to provide the systems needed for hourly matching.

For comments on the feasibility of hourly matching, please see comments from EnergyTag on section 45V Credit for Production of Clean Hydrogen; Section 48(a)(15) Election to Treat Clean Hydrogen Production Facilities as Energy Property, 88 Fed. Reg. 89220 (Dec. 26, 2023).

C. Carbon Intensity of Different Types of Electricity Generation

i. <u>Biomass should not be considered categorically a carbon-neutral energy source.</u>

Biomass, as a firm energy source, has the potential to complement intermittent renewables in supplying energy for hydrogen production. However, biomass used for electricity should not be considered categorically a carbon-neutral energy source. A comprehensive

[87] CATF & NRDC Comments.

lifecycle assessment must be conducted to determine the emissions impact of electricity derived from biomass. In particular, the treatment of all forms of forest biomass harvested from "managed forests" as carbon-neutral would be unfounded and contrary to scientific findings. Power plants that burn biomass or a combination of biomass and coal can emit more CO_2 per kWh of electricity generated than otherwise identical power plants that burn just coal. A shift to using biomass to produce electricity does not automatically reduce or limit the amount of CO_2 emitted from a source, and in many scenarios, it can increase the CO_2 emissions.[88] Thus, any hydrogen producer using biomass-produced electricity must be required to conduct a comprehensive, full lifecycle assessment to determine the real emissions impact of the electricity derived from biomass. Without such a comprehensive review, biomass-produced electricity would be inappropriately accounted for in 45V qualification.

ii. Fossil based electricity.

Treasury requests comment on whether electricity from fossil-based facilities that retrofit CCS should be considered incremental and whether using electricity from these facilities for hydrogen production would result in indirect GHG emissions.[89] CATF recommends Treasury collaborate with DOE and EPA to conduct modeling given that the indirect emissions impacts may vary and may be significant. When retrofitting a fossil-based facility, the developer is removing high-emitting generation from the grid and adding new clean generation at the same time. In some cases, after adding CCS equipment, the capacity factor could increase, and the facility could provide more electricity to the grid than it did prior to adding the CCS equipment. However, in the case that there is no net increase in electricity production to correspond with the net increase in demand from hydrogen production, there is still a gap in electricity generation that could be partially or entirely filled with high-emitting generation. Should the gap be filled with generation that is higher emitting than the non-retrofitted facility, the indirect emissions associated with the retrofit may be significant; even if the gap is filled with generation that is cleaner or just as emitting as the non-retrofitted facility, there could be indirect emissions associated with the retrofit. Given the uncertainty in the indirect emissions impact, CATF highly encourages Treasury to conduct further analysis and modeling on this issue in collaboration with DOE and EPA to better understand the potential emissions impacts.

Should the fossil-based electricity be considered incremental, Treasury requests comments on how to verify the emissions associated with the electricity used in hydrogen production given that emissions can be "highly variable or uncertain."[90] CATF agrees that, compared to other sources of minimal-emitting electricity generation like solar, wind, and nuclear, the carbon intensity of fossil-based electricity with carbon capture and storage can be highly variable. As shown below in Table 1, variations in carbon capture rate and upstream emissions associated with feedstock procurement could significantly change the resulting carbon intensity of the electricity. Across the four cases examined, which use an illustrative CCS rate of 90%, the carbon intensity of the electricity ranges from 0.44 to 0.081 kg CO_2e/kWh. The

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[88] Comments of Clean Air Task Force et al., Docket ID No. EPA-HQ-OAR-2017-0355 (Oct. 31, 2018), https://cdn.catf.us/wp-content/uploads/2017/06/21094001/ACE_Joint_NGO_Comments_Biomass.pdf.
[89] Proposal at 89229.
[90] Proposal at 89229.

unabated case, using the fixed methane leak rate currently in 45VH2-GREET of 0.9% and upstream CO_2 emissions of 5.04 g CO_2e/MJ NG (please see section (V)(A) below for more information on how upstream emissions associated with natural gas procurement impact the carbon intensity of fossil-based hydrogen production) yields the highest electricity carbon intensity. Case 1 demonstrates that adding CCS lowers the electricity carbon intensity, and Cases 2 and 3 demonstrate that reducing upstream methane and CO_2 emissions respectively can further decrease the electricity carbon intensity. Finally, while a 90% carbon capture rate is used to illustrate the examples below, greater than 90% capture rates are achievable.[91]

	Unabated	**Case 1**	**Case 2**	**Case 3**
CCS Rate (%)	0%	90%	90%	90%
Upstream Methane Emissions (%)	0.9%	0.9%	0.3%	0.3%
Upstream CO_2 (g CO_2e/MJ NG)	5.04	5.04	5.04	3.84
Electricity Carbon Intensity (kg CO_2/kWh)	0.44	0.10	0.081	0.073

Table 1. Calculated electricity carbon intensities for a sample natural gas combined cycle plant with and without carbon capture for different upstream methane and upstream CO_2 assumptions.[92]

Given the variations in carbon intensity for fossil-based electricity, CATF recommends Treasury apply the same rigorous requirements used for verifying the lifecycle emissions of hydrogen facilities claiming 45V to fossil-based electricity producers seeking to supply EACs for 45V. In other words, fossil-based EGUs must conduct an annual lifecycle analysis attestation that is verified by a third party without conflict of interest. This attestation must then be submitted to Treasury by the taxpayer claiming 45V credits.

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[91] Sources come from the first table in this CATF blog, *see* Jay Duffy & John Thompson, *The time is now*: *The Biden administration must adopt strict CO2 emissions standards for the power sector,* Clean Air Task Force (Feb. 7, 2023) https://www.catf.us/2023/02/time-now-biden-administration-must-adopt-strict-co2-emission-standards-power-sector/. (citing Quail Run Energy Center, Chapter 313 Application to Ector County ISD (Apr. 20, 2022), https://assets.comptroller.texas.gov/ch313/1701/1701-ector-quail-appamend1.pdf; Deer Creek Energy Center, *Funding Opportunity Announcement 2515*, Office of Fossil Energy and Carbon Management (Oct. 6, 2021), https://www.energy.gov/fecm/articles/funding-opportunity-announcement-2515-carbon-capture-rd-natural-gas-and-industrial.(announcing selected projects); Baytown Energy Center, *Our CCUS Projects,* Calpine Carbon Capture, https://calpinecarboncapture.com/ (last accessed Feb. 26, 2024). Plant Barry, *DOE Backs Carbon Capture Development,* Power Magazine (Sep. 1, 2022), https://www.powermag.com/doe-backs-carbon-capture-development-at-two-major-gas-fired-power-plants/.

[92] Internal CATF calculations. Assumes facility emissions from a sample natural gas combined cycle plant with CCS is 39 kg CO_2/kWh. *See* Nat. Energy Tech. Lab'y, Cost and Performance Baseline for Fossil Fuel Plants Volume 1 Case B31B, Exhibit 5-25, Mission Execution and Strategic Analysis (Sept. 24, 2019). https://www.osti.gov/servlets/purl/1569246; Upstream methane emissions are from GREET default and a low upstream methane rate of 0.3% is assumed based on emissions from the Appalachian basin. *See infra* note 98; Upstream CO_2 emissions were calculated by using CO_2 emissions reported by operators in the oil and gas production, gathering and boosting, and processing segments nationwide (reporting year 2018) to GHGRP subparts W and C. Total emissions are divided by gas delivered to customers.

V. CARBON BASED PATHWAYS

A. Adoption of fixed national upstream methane and CO_2 emissions rates provides an inadequate and indefensible basis for determining the correct tier of 45V.

The use of fixed, national upstream methane and CO_2 emissions rates undercuts a powerful incentive for continuous improvement in methane and CO_2 mitigation from the supply chain that provides natural gas to hydrogen producers seeking the 45V credit. Parties claiming the credit should have the ability to demonstrate lower upstream methane and CO_2 leak rates in their supply chain based on verifiable, project-specific measurement data from the GHGRP.

Section 45V provides that lifecycle greenhouse gas emissions include emissions at "all stages of fuel and feedstock production and distribution, from feedstock generation or extraction" through the point of production of hydrogen.[93] Hydrogen derived from carbon-based pathways can include the use of natural gas as a feedstock, and as a result, the 45V lifecycle analysis must include GHG emissions from extraction, production, and distribution of that natural gas. Methane and CO_2 emissions from oil and gas production, processing, and transmission are highly variable between operators, and the total amounts can be substantial.[94]

Treasury and the IRS must, therefore, adopt a lifecycle methodology that accurately captures upstream methane and CO_2 emissions. Specifically, we urge Treasury to shift methane leak rates and CO_2 emissions from background data to foreground data in 45VH2-GREET by requiring all methane leak rates and upstream CO_2 emissions to be calculated using the methodologies prescribed by subparts W and C of the GHGRP, regardless of whether the oil and gas operators are required to report their leak emissions under that program.[95] Under the current version of 45VH2-GREET, the upstream methane leak rate is treated as a fixed nationwide rate of 0.9%, and the upstream CO_2 emissions is similarly fixed. A fixed leak rate fails to accurately represent emissions from actual sites or operators. For example, a hydrogen project with an actual methane leak rate of 0.3% would qualify for the same tier as a project with an actual leak rate of 3%. The inability to differentiate between high-emitting and low-emitting sources and operators fails to incentivize natural gas facilities to reduce lifecycle methane and CO_2 emissions associated with hydrogen production, as intended by Congress in passing 45V. But most importantly, a fixed leak rate creates an inaccurate lifecycle analysis that "bears no relationship to the real world emissions impact" of the hydrogen produced.[96] This is both because a fixed rate will allow hydrogen producers utilizing natural gas with actual upstream leak rates higher than

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[93] 26 U.S.C. § 45V(c)(1)(A)(incorporating 42 U.S.C. § 7545(o)(1)(H)).

[94] *See* Hellgren et al., Benchmarking Methane and Other GHG Emissions of Oil & Natural Gas Production in the United States, Clean Air Task Force & Ceres (May 2023), https://cdn.catf.us/wp-content/uploads/2022/07/14094726/oilandgas_benchmarkingreport2022.pdf (Updated analysis from Ceres and Clean Air Task Force benchmarks the relative emissions intensity and total reported methane, carbon dioxide, and nitrous oxide emissions of more than 300 U.S. oil and gas producers and finds dramatic variations between companies and basins. This third annual report analyzes the production-based emissions of the largest oil and gas producers in the U.S. and highlights dramatic variation among producers and basins.) [hereinafter "CATF & Ceres Report"].

[95] 40 C.F.R § 98.231-2.

[96] *See* 75 Fed. Reg. at 14766.

0.9% to qualify for 45V, and because it will prevent operators that secure gas produced, processed, and transported with lower emissions from qualifying for anything more favorable than the bottom tier of 45V. Treasury must not allow a methodology that mischaracterizes lifecycle emissions so drastically.

To illustrate the importance of these factors, CATF performed an analysis to demonstrate the combined impacts that the methane leak rate and upstream CO_2 emissions have on the 45V tier under which an operator may qualify. In this analysis, summarized in the table below, CATF compared four different scenarios against the 45VH2-GREET base case scenario, which includes the fixed 0.9% methane leak rate as well as the CO_2 value incorporated into 45VH2-GREET using zero-carbon electricity. In all cases, CATF assumed a high fixed carbon capture rate of 98% on the autothermal reforming ("ATR") equipment. In Case 1, CATF used the current version of 45VH2-GREET, using the current 0.9% fixed leak rate and a national average of 5.04g CO_2e/MJ natural gas.[97] In Case 2, CATF looked at the results of maintaining the national average CO_2 rate but lowered the leak rate to 0.3% to show what impacts a lower leak rate has on the 45V credit tier. CATF used 0.3% as a demonstration of a reasonable low leak rate. This is based on 0.4% leak rates that have been measured in gas-producing areas in Northeast Pennsylvania,[98] with an additional estimated reduction due to implementation of EPA methane rules. To demonstrate how lower upstream CO_2 emissions can influence the 45V credit tier, Case 3 includes the fixed 0.9% leak rate but adjusts the upstream CO_2 number downward to 3.84g CO_2e/MJ natural gas, which reflects CO_2 emissions in the Appalachian basin.[99] Finally, CATF used Case 4 to show the impacts to the 45V tier when both lower methane leak rates and lower upstream CO_2 emissions can be used.

[97] 5.04 CO_2/MJ was calculated by using CO_2 emissions reported by operators in the oil and gas production, gathering and boosting, and processing segments nationwide (reporting year 2018) to GHGRP subparts W and C. Total emissions are divided by gas delivered to customers.

[98] Barkley, et al., *Quantifying methane emissions from natural gas production in north-eastern Pennsylvania*, 17 Atmospheric Chemistry & Physics, 13941–13966 (Nov. 2017), see attached.

[99] 3.84g CO_2/MJ is calculated using CO_2 emissions reported by operators in the oil and gas production, gathering and boosting, and processing segments in the Appalachian basin (reporting year 2018) to GHGRP subparts W and C. Total emissions are divided by gas delivered to customers from that basin in that year. CATF & Ceres Report, *supra* note 94.

	GREET Case	Case 1	Case 2	Case 3	Case 4
Upstream Methane Leak	0.9% (fixed, known rate)	0.9%	0.3%	0.9%	0.3%
Upstream CO_2 Emissions (g CO_2e/MJ NG)	Unknown (fixed background data)	5.04	5.04	3.84	3.84
CCS Rate	98%	98%	98%	98%	98%
H_2 Carbon Intensity (kg CO_2e/kg H_2)	2.66	1.83	1.27	1.65	1.09
IRA 45V Tier ($/kg of H_2)	Tier 4 - $0.60	Tier 3 - $0.75	Tier 2 - $1.00	Tier 3 - $0.75	Tier 2 - $1.00

Table 2. Carbon intensity calculations for fossil-based hydrogen with CCS using different upstream methane leak rates, upstream CO_2 rates, and carbon capture rates. Calculations were conducted using CATF's lifecycle analysis model.[100]

This analysis shows that maintaining the methane leak rate and upstream CO_2 emissions as background data limits the credit's applicability to deserving hydrogen producers while failing to provide a powerful incentive for continuous improvement in upstream emissions. 45VH2-GREET as it currently stands results in fossil gas hydrogen producers qualifying for the lowest tier (Tier 4) of 45V. If methane and CO_2 emissions are shifted to foreground data, some producers may be able to achieve a higher tier, and others may not qualify at all. Instead, Treasury's proposal to categorize upstream methane and CO_2 as background data undermines the economics of hydrogen production projects, particularly for fossil-based projects in Regional Clean Hydrogen Hubs. Limiting developers to Tier 4 could push developers to claim credits under section 45Q (the federal carbon capture tax credit) instead. Section 45Q does not involve the same rigorous lifecycle analysis as 45V because it does not account for upstream emissions. Thus, use of the 45Q credit instead of 45V would further disincentivize producers from cleaning up upstream emissions.[101] Additionally, a fixed leak rate would allow the dirtiest operators represented in the CATF-Ceres "Benchmarking Report" to hide behind the work others undertake to reduce greenhouse gas emissions. On the other hand, allowing the foreground use of methane could have important impacts, as leak rates by producer can vary substantially, even within basins.[102] By shifting both methane leak rates and upstream CO_2 emissions to verifiable, project-specific foreground data, Treasury can ensure that hydrogen producers earning credits truly reach the GHG lifecycle emissions thresholds set out in 45V.

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[100] *See* Clean Air Task Force, Hydrogen Delivered Lifecycle Analysis Tool, https://www.catf.us/hydrogen-lifecycle-analysis-tool/ (lasted visited Feb. 26, 2024).
[101] Internal CATF analysis shows the 45Q tax credit is equivalent to around $0.8 per kilogram of hydrogen produced. This is more lucrative than Tier 4 of 45V, which provides $0.6 per kilogram of hydrogen produced.
[102] CATF & Ceres Report*, supra* note 94.

A potential rationale for Treasury to have chosen a fixed leak rate is administrative ease. But to implement methane leak rates and upstream CO_2 emissions as foreground data, Treasury can simply use the methodologies set out in subparts W and C of the GHGRP, which are signed and certified under penalty of law and submitted to the EPA. As part of the Methane Emission Reduction Program within IRA, Congress directed the EPA to update subpart W—which focuses on oil and gas operations—of the EPA-administered GHGRP to "accurately reflect total emissions" from oil and natural gas reporting facilities.[103] EPA has proposed a revision which, once finalized, will apply to emissions reported in 2025 and beyond and will provide a more accurate quantification method for methane loss rates for natural gas feedstocks than a fixed leak rate. The GHGRP requires natural gas facilities to report their annual methane and CO_2 emissions, with specific rules about which facilities must report emissions, which emissions sources to include, and how to calculate emissions. The data from the program, which is publicly available, is granular for many emissions sources, including leaks. Because facilities are already submitting this data and EPA has successfully collected, curated, and published it, it can readily serve as an operational source of information for calculating emissions for 45VH2-GREET. Operators should be required to provide verifiable, project-specific data supporting their methane leak rates and CO_2 emissions as foreground data using the data they submit for subparts W and C or, if their operations or facilities are too small to be required to report under subparts W and C, using the same methodologies required by those subparts to calculate their emissions and leak rate.

The veracity of project-specific methane leak rates based on subpart W data is bolstered by the use of that data to calculate the Waste Emissions Charge ("WEC"), which was also enacted under the IRA.[104] In the WEC context, EPA plans to utilize subpart W reporting to determine whether annual emissions from any given applicable facility exceed a threshold based on a percentage of the natural gas throughput or sales for the site. In the recent WEC proposal, EPA allows for third-party audits of reports in addition to the verification processes built into subpart W, and the forms are signed and certified under penalty of law and submitted to EPA.[105] Together, these measures are meant to ensure the accuracy of the submitted data, and thus the accuracy of the associated emissions charge. In the context of a foreground leak rate based on subpart W, the potential audit, combined with the pre- and post-submittal digital verification processes already built-in to the EPA's GHGRP, would provide an additional layer of oversight on the integrity of the reported leak rate.

Finally, in the alternative, if Treasury maintains a fixed national methane leak rate, it is critical that such leak rate includes all wells from which the hydrogen producer could procure natural gas. As proposed, it appears as if the 0.9% leak rate does not include co-producing wells – wells that produce both oil and natural gas. As such, the fixed 0.9% leak rate underestimates

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[103] 42 U.S.C. 7436(h). While an update to subpart C is not required by IRA, EPA can update and improve those reporting requirements independently of IRA. We note that the concerns about the accuracy of Subpart W that led Congress to mandate the update to subpart W do not generally apply to subpart C, and that EPA has recently proposed revisions to subpart C. *See also* Revisions under GHG Reporting Rule, 87 Fed. Reg. 36920, 36940 (Jun. 21, 2022).
[104] Waste Emissions Charge for Petroleum and Natural Gas Systems, 89 Fed. Reg. 5318 (Jan. 26, 2024).
[105] *See id.* at 5352-53.

the true leak rate for natural gas, since natural gas from oil wells makes up a significant portion of overall U.S. gas production. It is imperative that any fixed national methane leak rate is based on emissions from both natural gas wells and wells that co-produce oil and natural gas.

B. Guardrails for biomethane

i. Treasury should finalize the First Productive Use rule for biomethane and methane originating from coal mines.

Treasury recognized in its proposal that, like the three pillars, guardrails around the biomethane to hydrogen pathways are necessary to "reflect the ways in which additional [biomethane] . . . can impact lifecycle GHG emissions."[106] Like the three pillars for electrolytic hydrogen, proper guardrails around biomethane are important to ensure that section 45V does not *increase* systemwide GHG emissions. Treasury took an important first step in proposing the "First Productive Use" rule, which provides that to earn credits under section 45V, the biomethane used to produce hydrogen must be the first productive use of that methane.[107] As Treasury explains, the goal of this rule is to "limit emissions associated with the diversion of biogas or [renewable natural gas] from other pre-existing productive uses."[108] The First Productive Use rule will help direct biomethane that is otherwise vented (or, in some cases, flared) to hydrogen production rather than creating an additional demand for gas by taking from other sources that may meet that demand through dirtier sources. This is important to avoid significant indirect emissions associated with hydrogen produced from biomethane.[109] And this is especially important for agricultural methane emissions, which have risen over the last few decades despite overall declines in national methane emissions.[110] Because that methane is not being used, hydrogen producers would be able to use agricultural methane under the First Productive Use rule, thereby reducing that sector's methane emissions without creating additional emissions.

ii. Biomethane from landfills or anaerobic digesters should not receive negative emission rates.

To fulfill the intent of section 45V—to promote truly clean hydrogen production through technologies that may require more funding to enter the market—Treasury must not allow

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[106] Proposal at 89238.
[107] The First Productive Use rule is also critical for fossil methane that comes from coal mines for the same reasons as biomethane. However, separating captured "fugitive" emissions from the oil and gas sector from the rest of the natural gas in a pipeline is inappropriate because nationally applicable rules recently finalized by EPA limit, and in some cases prohibit, fugitive and vented emissions. We urge Treasury to clarify that, when it discusses "other fugitive sources of methane," it is not including fugitive methane emissions from the oil and natural gas sector.
[108] Proposal at 89239.
[109] *See supra* section (II)(A) (outlining the requirement in 45V to avoid significant indirect emissions).
[110] Ben Lilliston, *New EPA data confirms role of factory farms in rising agriculture emissions*, Institute for Agriculture & Trade Policy (Mar. 3, 2022), https://www.iatp.org/new-epa-data-confirms-role-factory-farms-rising-agriculture-emissions.

negative emission rates from biogenically sourced methane.[111] Currently, over 95% of hydrogen produced is made using steam methane reforming ("SMR") without carbon capture, an extremely carbon-intensive method of hydrogen production.[112] Congress passed section 45V in this context. Allowing a negative emission rate from biomethane could allow SMR developers to claim a lower carbon intensity for hydrogen production without actually investing in any of the technology Congress intended to promote by enacting section 45V.

For example, consider the possibility of blending feedstocks like fossil natural gas and biomethane. Using 25% or less biomethane—depending on the negative carbon intensity—blended with fossil natural gas could result in hydrogen producers that use polluting SMR methods with *no carbon capture and storage* to qualify for the highest 45V tier.[113] Under the California Low Carbon Fuel Standard ("LCFS"), the carbon intensity for current fuel pathways for dairy and swine manure used as feedstock ranges from –92.22 to -790.41 g CO_2e/MJ biomethane, with the average being -302.75 g CO_2e/MJ biomethane.[114] Using a conservative estimated carbon intensity of -150 g CO_2e/MJ biomethane, a fossil hydrogen producer with 90% CO_2 abatement could earn the top tier of the tax credit by offsetting only 4% (or less) of its fuel use.[115] More negative carbon intensities would allow hydrogen producers to qualify for the highest tax credit tier with an even smaller portion of biomethane.

While capturing biomethane is environmentally beneficial, collecting this pollution from landfills and anaerobic digesters is a very mature technology, not the type of nascent technology that Congress intended to advance through 45V. The results discussed above show how blending a small amount (4% or less) of biomethane into a producers' feedstock could radically change the amount of subsidy an operator can receive if Treasury allows hydrogen producers to use negative emissions intensities for a feedstock or a portion of it when calculating their lifecycle emissions intensity. These radical changes from small portions of biomethane would also lead to undesirable market distortions, such as highly disparate prices between biomethane from operations that begin capture in response to 45V compared to those with existing biomethane capture, as well as incentives to increase biomethane production from digesters by addition of other materials to the digester.

We understand that, at present, there is not a pathway in 45VH2-GREET to utilize biomethane and receive negative credits for prevention of emissions. It is critical that Treasury maintains this bar to ensure that no biomethane will be allowed to have a negative emissions intensity in the 45VH2-GREET model.

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[111] As explained *supra* section (I), the differentiation in the tax credit tiers (in particular, the steep step-down from $3 to $1, and then to $0) shows that Congress put a thumb on the scale in favor of the cleanest hydrogen production.
[112] A. Basile et al., Membrane reactors for methane steam reforming (MSR), Woodhead Publishing Series in Energy, https://www.sciencedirect.com/topics/engineering/methane-steam-reforming.
[113] Emily Grubert et al., *The New Hydrogen Rules Risk opening the Door to Methane Offsets*, Heatmap (Feb. 9, 2024), see attached.
[114] California Air Resources Board, LCFS Pathway Certified Carbon Intensities, https://ww2.arb.ca.gov/resources/documents/lcfs-pathway-certified-carbon-intensities (last visited Feb. 23, 2024).
[115] Grubert et al., *supra* note 113.

C. Fugitive methane sources should not receive negative emissions rates because they capture methane they claim would otherwise have been leaked or flared.

Treasury requests comment on lifecycle analysis considerations associated with fugitive methane.[116] Treasury defines "fugitive methane" as the "release of methane through, for example, equipment *leaks*, or *venting* during the extraction, processing, transformation, and delivery of fossil fuels to the point of final use, such as coal mine methane or coal bed methane."[117] This definition creates the distorted baseline assumption that methane would have been leaked or vented, such that the captured methane could receive a negative lifecycle emissions rate.

Treasury should not give oil and gas producers a windfall by allowing them to set a counterfactual that the methane would have otherwise been leaked or vented. Leaking natural gas is not good practice; it not only harms the climate, but it can also harm the health of workers and people who live near oil and gas facilities. And it wastes natural resources and, in some cases, causes safety problems. If Treasury were to allow credits for capture of currently fugitive methane, it would create a situation where the sloppiest, most polluting operators reaped the highest rewards. This is especially true considering a number of state and federal agencies have regulations that do, or will soon, require emissions reductions to "fugitive methane," including EPA's recently finalized methane and volatile organic compounds standards.[118] Oil and gas operators should not get financial credit under 45V for complying with other regulations they are legally required to follow; this does not actually reduce lifecycle greenhouse gas emissions. Thus, coal, oil, and gas producers should not be able to capture methane and claim a negative emissions value because they claim it would otherwise have been vented or leaked during the process of extraction processing, transportation, and delivery. Instead, leaks and venting from fossil gas should be part of the regular treatment of SMR or ATR fossil gas pathways in 45VH2-GREET such that capturing this gas cannot lead to negative emissions rates. Anything reflected in 45VH2-GREET's upstream accounting should not be claimed as a fugitive methane *credit*.

D. Bioenergy and Biomass gasification

Harvesting corn stover and logging residues can decrease soil organic carbon levels and increase GHG emissions.[119] Given this potential impact, 45VH2-GREET modeling assumptions

[116] Proposal at 89239.
[117] Proposal at 89238 (emphasis added).
[118] *See* Standards of Performance for New, Constructed, Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, EPA-HQ-OAR-2021-0317 (unofficial) (final version of rule forthcoming), https://www.epa.gov/system/files/documents/2023-12/eo12866_oil-and-gas-nsps-eg-climate-review-2060-av16-final-rule-20231130.pdf.
[119] Hui Xu et al., *A global meta-analysis of soil organic carbon response to corn stover removal*, 11 GCB Energy 10 (May 26, 2019) https://doi.org/10.1111/gcbb.12631; Marcio Nunes et al., *Science-based maize stover removal can be sustainable*, 11 Agronomy Journal 4 (Jun. 29, 2020) https://www.osti.gov/servlets/purl/1836085; Kai Lan et al., *Soil organic carbon change can reduce the climate benefits of biofuel produced from forest residues*, 8 Joule 2 (2024), https://www.cell.com/action/showPdf?pii=S2542-4351%2823%2900537-8; Jason James et al., *Effects of forest harvesting and biomass removal on soil carbon and nitrogen: Two complementary meta-analyses*, 485 Forest Ecology and Management (2021), https://doi.org/10.1016/j.foreco.2021.118935.

should be updated based on quantitative data to reflect the potential effects of harvesting residues on soil emissions. More quantitative data may be needed to inform updated modeling assumptions, and modeling assumptions may need to be periodically updated to reflect the state of the science.

Additionally, we appreciate GHG emissions associated with increased use of fertilizer that may be required with corn stover removal are included in the model assumptions. We also appreciate that the guidance recognizes that the assumption of carbon neutrality and zero land use change emissions is not necessarily appropriate when hydrogen is produced from other (non-residue) forms of biomass and look forward to reviewing any developments in this space in 45VH2-GREET.

Finally, comprehensive lifecycle analyses of hydrogen supply chains should be used to determine which tier biomass gasification (with and without CCS) qualifies for. Biogenic emissions should be included in lifecycle analyses.

VI. OTHER CONSIDERATIONS FOR CALCULATING THE PRODUCTION TAX CREDIT

A. Treasury should clarify that section 45V credits are determined based on an analysis of kilograms of clean hydrogen produced in a given tax year, evaluated on an hourly basis.

Treasury's proposed regulation provides at § 1.45V-4(a) that the amount of section 45V credit is determined "according to the lifecycle GHG emissions rate of all hydrogen produced at a hydrogen production facility during the taxable year."[120] The preamble confirms that the credit determination "must include all hydrogen production from the year."[121] Instead of this approach, we urge Treasury to adopt a two-step means of determining lifecycle emissions: first, a hydrogen producer must meet an annual average of no more than 4 kg CO_2e/kg H_2 for all hydrogen produced. Second, if the producer's annual average meets this threshold, they should then calculate their lifecycle emissions rates on an hourly basis, which is the most feasible measurement proxy for a kilogram-by-kilogram approach.

i. Legal basis for two-step approach.

Step one. The basis for the annual average cap of 4 kg CO_2e/kg H_2 is set out plainly in the statute. Section 45V provides credits based on the "kilograms of qualified clean hydrogen produced by the taxpayer during such taxable year at a qualified clean hydrogen production facility."[122] To earn any credits, therefore, hydrogen must be produced at a qualified clean hydrogen production facility. A "qualified clean hydrogen production facility" is defined as one that "produces qualified clean hydrogen."[123] The statute in turn defines "qualified clean

[120] Proposal at 89247 (emphasis added).
[121] Proposal at 89224–89225.
[122] 26 U.S.C. § 45V(a)
[123] *Id*. § 45V(c)(3).

hydrogen" as "hydrogen which is produced through a process that results in a lifecycle greenhouse gas emissions rate of not greater than 4 kilograms of CO_2e per kilogram of hydrogen."[124] Because hydrogen must be produced at a qualified clean hydrogen production facility to earn the credit, and such a facility must produce hydrogen with a lifecycle emissions rate of less than 4 kg CO_2e/kg H_2, a facility seeking the 45V tax credit must meet an annual lifecycle emissions rate average of no more than 4 kg CO_2e/kg H_2.

Step two. Once a facility meets that average and is a "qualified clean hydrogen production facility," section 45V requires a "kilogram-by-kilogram approach," where projects receive credit for each kilogram of clean hydrogen they produce, evaluated on an hourly basis. This is because the "amount of credit" is determined by multiplying the "kilograms of qualified clean hydrogen" by the applicable amount, which is determined by the lifecycle emissions rate.[125] Kilograms of hydrogen may have different emissions rates at different hours, so projects should receive credit for each kilogram of clean hydrogen they produce evaluated on an hourly basis.

In addition to reflecting the text of section 45V, a kilogram-by-kilogram approach aligns with the other requirements in section 45V. Most notably, hydrogen producers must account for "significant indirect emissions" in their lifecycle GHG analyses. As discussed in detail above, the three pillars approach best quantifies significant indirect grid emissions that result from electrolytic hydrogen production. Using a kilogram-by-kilogram approach fits well with the three pillars by recognizing the reality that there may be portions of the year when renewables or other clean electricity are unavailable to electrolytic hydrogen producers. When this occurs, section 45V does not mandate that the resulting unqualified hydrogen be detrimental to the producer by reducing their credit for clean hydrogen. Thus, so long as the producer meets the annual cap, evaluating lifecycle emissions rates on an hourly basis aligns with and complements the three pillars.

ii. Implementing the two-step approach.

To implement this, CATF recommends Treasury use the following approach:

1. Calculate the total annual average of a facility's hydrogen production, and check whether that average falls under the 4 kg CO_2e/kg H_2 cap.

2. If the annual average falls below the cap, calculate and credit each hour of hydrogen production from a facility separately. Producers would track and report the carbon intensity of the hydrogen produced over the course of each hour and receive credit for their carbon intensity from each individual hour.

If a facility produces hydrogen with differing carbon intensities in the course of one hour, they can calculate the average carbon intensity for that hour. For example, if a facility produces

[124] *Id*. § 45V(c)(2)(A).
[125] *Id*. § 45V(a); *id*. § 45V(b).

hydrogen at 0.00 kg $CO_2e/kg\ H_2$ during the first half of the hour and produces hydrogen at 4.00 kg $CO_2e/kg\ H_2$ during the latter half of the hour, the producer would be credited for hydrogen at 2.00 kg $CO_2e/kg\ H_2$ for the whole hour.

iii. Impacts of the two-step approach compared to annual averaging.

Crediting producers via a kilogram-by-kilogram approach would increase financial certainty compared to the annual averaging approach by providing flexibility for unplanned and planned maintenance. Traditional hydrogen offtakers such as refineries and chemical plants require a reliable, round-the-clock supply of hydrogen to maintain operations. As a result, hydrogen supply contracts for these offtakers usually include penalties based on how often the hydrogen producer is onstream. To prevent shutting down customer operations from insufficient hydrogen supply, hydrogen producers may be obliged to supply hydrogen even when there are insufficient EACs or inoperable carbon capture to ensure that the operation is clean. For electrolytic hydrogen producers, developers will likely be installing electricity and hydrogen storage to manage variability in both electricity supply and hydrogen demand. However, unplanned maintenance or higher-than-average customer demands, which could occur due to planned or unplanned maintenance for the customer's other hydrogen suppliers, may deplete these reserves and cause production of dirtier hydrogen.

Under Treasury's proposed annual averaging approach, developers must factor in both the potential contractual penalties and the chance of dropping to the next 45V tier for *all* the hydrogen produced during the year. As shown in the table below, it only takes using grid electricity for 1% to 3% of the year to exceed the 0.45 kg $CO_2e/kg\ H_2$ threshold, should the producer make hydrogen at 0 kg $CO_2e/kg\ H_2$ for the remainder of the year. The range varies due to the different carbon intensities of the different deliverability regions. This added uncertainty from annual averaging significantly increases project risks, especially when producers may still be learning how to operate reliably and safely given the nascence of the electrolytic hydrogen industry.[126]

[126] The annual averaging approach is less impactful to fossil-based hydrogen facilities, as further explained below.

		Time it takes to exceed 0.45 kg $CO_2e/kg\ H_2$		
Region	**Carbon intensity of grid based H_2 (kg $CO_2e/kg\ H_2$)**	**Hours**	**Days**	**% of the Year**
NPCC	15	263	11.0	3.0%
WECC	18	219	9.1	2.5%
TRE	21	188	7.8	2.1%
RFC	23	171	7.1	2.0%
SPP	23	171	7.1	2.0%
SERC	25	158	6.6	1.8%
FRCC	26	152	6.3	1.7%
ASCC	32	123	5.1	1.4%
MRO	32	123	5.1	1.4%
HICC	46	86	3.6	1.0%

Table 3. Demonstrates the time required for hydrogen producers to exceed 0.45 kg $CO_2e/kg\ H_2$ when using grid electricity from different deliverability regions should the producer make hydrogen at 0 kg $CO_2e/kg\ H_2$ for the remainder of the year. Carbon intensity values are from 45VH2-GREET and are rounded to the nearest integer.

The annual averaging approach is less impactful to fossil-based hydrogen facilities given that producers are unlikely to reach the most lucrative tier of 0.45 kg $CO_2e/kg\ H_2$ and that unabated fossil-based hydrogen is less carbon intensive, at around 14 kg $CO_2e/kg\ H_2$ for ATR, compared to grid-based hydrogen.[127] To drop from 1.51 kg $CO_2e/kg\ H_2$ in the third tier to 2.51 kg $CO_2e/kg\ H_2$ in the fourth tier, facilities would have to be producing unabated hydrogen for 26 days, or around 7.1% of the year, according to CATF calculations. Should fossil-based facilities reach the most lucrative tier, it would only take 11.7 days, or around 3.2% of the year, to increase the annual carbon intensity above 0.45 kg $CO_2e/kg\ H_2$ and drop them from the most lucrative tier to the second tier.

B. Fuels crediting

EACs should not be allowed to offset emissions from fuels (i.e., purchasing renewable energy credits ("RECs") should not outweigh emissions from natural gas feedstocks), because emissions from fuels should first be avoided if possible. EACs cannot substitute for methodologies and technologies that would have prevented emissions in the first place, and hydrogen producers should not have avenues to receiving the hydrogen tax credit without making every effort to minimize the GHG intensity of that hydrogen. CATF strongly advocates that section 45V credits should only be allowed for truly clean hydrogen, as intended by the requirements of the tax credit. Fossil-based hydrogen production processes should instead be encouraged to use high rates of CCS to bring down their hydrogen's GHG intensity.

[127] Assuming 1821 MMBTU, 12000 kWh, and no coproduct steam for 10000 kg of hydrogen, 45VH2-GREET returns a carbon intensity of 14 kg $CO_2e/kg\ H_2$ for ATR based hydrogen without CCS.

VII. 45VH2-GREET

A. Notice-and-comment should be provided for significant changes to 45VH2-GREET.

Treasury's proposal clearly contemplates that 45VH2-GREET will be updated in the future. It notes with respect to provisional emissions rates, for example, that "for the taxable year in which the hydrogen production pathway the taxpayer uses to produce hydrogen at a qualified clean hydrogen production facility is first included in an updated version of 45VH2-GREET, the updated version of 45VH2-GREET will be considered the most recent GREET model."[128] And the 45VH2-GREET manual explains that "[f]uture versions of the model may also include additional hydrogen production pathways," such as reformation of biomethane, reformation of coal mine methane, gasification of other types of biomass, and others.[129] The manual further states that GREET tools will be updated annually to "include new technologies and more recent estimates of background data" and that 45VH2-GREET will likely be updated accordingly.[130]

CATF supports regular updates to 45VH2-GREET to reflect new information about hydrogen production technology and background data. Currently, the GREET tool is updated roughly annually without input from the public. But certain updates to 45VH2-GREET could have major impacts on implementation of the credit, as well as the real world GHG emissions impacts resulting from the issuance of the credit. Thus, the public should be provided notice, and there should be an opportunity to comment, when there are significant changes in methodology and/or assumptions in 45VH2-GREET, including but not limited to the following instances:

(1) major changes to background data;
(2) switching information from background data to foreground data; or
(3) adding new hydrogen production pathways.

Of course, if any of the above updates are made to 45VH2-GREET, there need only be a comment period with respect to that particular update.[131] Failure to provide notice-and-comment in these situations could violate the Administrative Procedure Act ("APA").[132]

The APA sets out procedures federal agencies must use for rulemaking. The APA defines "rulemaking" as an agency process for "formulating, *amending*, or repealing a rule."[133] The APA defines "rule" as "the whole or *a part of* an agency statement of general or particular applicability and future effect designed to implement, interpret, or prescribe law or policy."[134]

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[128] Proposal, at 89246.
[129] 45VH2-GREET Manual at 25.
[130] *Id.*
[131] *See West Virginia v. EPA*, 362 F.3d 861, 872, (D.C. Cir. 2004) (the reopening rule "is not a license for bootstrap procedures by which petitioners can comment on matters other than those actually at issue, goad an agency into a reply, and then sue on the grounds that the agency has re-opened the issue") (cleaned up).
[132] *Cf. Owner-Operator Indep. Drivers Ass'n v. Fed. Motor Carrier Safety Admin.*, 494 F.3d 188, 193, (D.C. Cir. 2007) (holding agency violated the APA where it failed to give interested parties opportunity to comment on the methodology of a model the agency used to justify its regulations).
[133] 5 U.S.C. § 551(5) (emphasis added).
[134] 5 U.S.C. § 551(4) (emphasis added).

When an agency formulates, amends, or repeals a rule, the agency must (1) issue a "general notice of proposed rule making," ordinarily by publication in the Federal Register;[135] (2) give interested persons the opportunity to submit "written data, views, or arguments" and consider and respond to significant comments submitted[136]; and (3) include a "concise general statement" of the rule's basis and purpose in the final rule.[137]

Critically, the APA "makes no distinction . . . between initial agency action and subsequent agency action undoing or revising that action."[138] That is, an agency "may not alter" a legislative rule without notice and comment.[139] This is equally true when the agency incorporates a tool or model by reference into its rule. Here, 45VH2-GREET is incorporated by reference into Treasury's proposed 45V regulation; it is not a part of the actual regulation. But 45VH2-GREET performs the critical function of calculating lifecycle greenhouse gas emissions for purposes of section 45V, an integral part of the statute. As a result, substantial changes to 45VH2-GREET could alter the nature of the 45V regulation.

This principle is illustrated in rules about incorporating publications or consensus standards into regulations. "Incorporation by reference" refers to the practice of "codifying material published elsewhere by simply referring to it in the text of a regulation."[140] While this practice usually refers to incorporating technical standards developed by private sector organizations into government regulations, the rules around the practice can also apply to incorporation of Argonne's tool into the 45V regulations. For example, the Office of the Federal Register's regulations provide that "[i]ncorporation by reference of a publication is limited to the edition of the publication *that is approved*. Future amendments or revisions of the publication are not included."[141] The reason to limit incorporation to the current version is straightforward: incorporating future versions of a tool or publication deprives the public of the opportunity to provide input on those future versions.[142]

These principles apply to future updates to 45VH2-GREET. 45VH2-GREET is integral to the implementation of section 45V, such that changes to the tool substantively impact the way section 45V applies to taxpayers. And 45VH2-GREET must reflect the parameters set out for

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135 5 U.S.C. § 553(b).
136 5 U.S.C. § 553(c); *Perez v. Mortg. Bankers Ass'n*, 575 U.S. 92, 95 (2015).
137 5 U.S.C. § 553(c).
138 *FCC v. Fox TV Stations, Inc.*, 556 U.S. 502, 515 (2009); *see also Perez v. Mortg. Bankers Ass'n*, 575 U.S. 92, 101 (2015) ("[T]he D.C. Circuit correctly read § 2 of the APA to mandate that agencies use the same procedures when they amend or repeal a rule as they used to issue the rule in the first instance.")
139 *Clean Air Council v. Pruitt*, 862 F.3d 1, 9 (D.C. Cir. 2017) (quoting *Nat'l Family Planning & Reprod. Health Ass'n v. Sullivan*, 979 F.2d 227, 234 (D.C. Cir. 1992)).
140 Emily S. Bremer, *Incorporation by Reference in an Open-Government Age*, 36 Harv. J.L. & Pub. Pol'y 131, 132 (2013).
141 1 C.F.R. § 51.1(f) (2012) (emphasis added). *See also* Circular No. A-119 Revised (Feb. 10, 1998) ("In regulations, the reference [to voluntary consensus standards] must include the date of issuance"). *Contrast* Alaska Stat. § 44.62.245(a) (state regulation explicitly *allowing* incorporation of future versions of a document).
142 *See, e.g.*, Standards Improvement Project-Phase III, 76 Fed. Reg. 33590, 33593 (June 8, 2011) (OSHA regulations observing that OSHA "cannot incorporate by reference the latest editions of consensus standards without undertaking new rulemaking because such action would . . . deprive the public of the notice-and-comment period required by law").

lifecycle greenhouse gas emissions in the text of section 45V. If 45VH2-GREET is updated in a manner that ignores "significant indirect emissions" from hydrogen production in violation of section 45V,[143] for example, the public must have an opportunity to comment on these updates.

Providing a notice-and-comment period for substantial updates to 45VH2-GREET will not be burdensome to the implementation of section 45V. Indeed, agencies regularly solicit public comment in response to updates in their tools and models. For example, EPA recently opened a public comment period for an updated version of its Waste Reduction Model ("WARM"), an Excel-based tool that "estimates the potential greenhouse gas emissions, energy savings and economic impacts of baseline and alternative waste management practices of materials."[144] Like GREET, WARM undergoes regular external peer review and data quality assessments, but EPA still opens new versions to public comment. As another example, the U.S. Department of Agriculture periodically updates its technical report, "*Quantifying Greenhouse Gas Fluxes in Agriculture and Forestry: Methods for Entity-Scale Inventory*" based on newly available data and methodologies, and when it does, it solicits public comment.[145] And EPA periodically requests public comment for new 1-100 ENERGY STAR scores for different types of buildings.[146] These are just a few examples of how 45VH2-GREET could be updated in a manner that is both efficient and responsive to public input.

B. Producers may use carbon intensity scores from older 45VH2-GREET versions if results differ when using new versions.

To conduct appropriate project planning and financing, clean hydrogen producers will require a level of certainty in the amount of 45V credit that they will be able to receive during their project's operation. While there will need to be some level of risk appetite for changes to 45V amounts if their project details change over time, forcing changes to carbon intensity calculations during a project's lifespan (without any change to the project) could create undue risk and uncertainty. To mitigate this concern, once a producer has qualified for a carbon intensity score from 45VH2-GREET, they should be grandfathered with that score (assuming their project details remain the same) for their ten-year credit period. Whether they use a new 45VH2-GREET version during their ten-year credit period could be optional for producers if it would impact their score. This method would allow for the most up-to-date, rigorous carbon intensity analysis to be used when a project first comes online but would minimize the risk of 45V changes that would be outside the producer's control.

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[143] 26 U.S.C. § 45V(c)(1)(A) (incorporating 42 U.S.C. § 7545(o)(1)(H)).
[144] Waste Reduction Model (WARM) Version 16, 88 Fed. Reg. 88913 (Dec. 26, 2023).
[145] *See* Updates to Technical Guidelines for Quantifying GHG, 85 Fed. Reg. 12760 (Mar. 4, 2020) (request for comment on updated report in 2020); Updates to Technical Guidelines for Quantifying GHG, 88 Fed. Reg. 37846 (June 9, 2023) (requesting comment again in 2023).
[146] Energy Star, Updates to ENERGY STAR Scores, https://www.energystar.gov/buildings/benchmark/understand_metrics/score_updates#Details (last visited Feb. 5, 2024).

C. Provisional Emissions Rates.

CATF supports Treasury's proposal that provisional emissions rates ("PER") "must be consistent with the lifecycle GHG emissions framework provided in the section 45V regulations."[147] It is critical that DOE's determinations tack as closely as possible to Treasury's guidelines and to existing pathways in 45VH2-GREET. To this end, CATF also supports Treasury's proposal that "if applicable, background data parameters in 45VH2-GREET will also be treated as background data . . . in the emissions value request process," and "[t]reatment of EACs and other proposals outlined in the regulations in this part under section 45V will be consistently applied in the emissions value request process."[148] Treasury must review the PER petition to ensure that the emissions assessment and rate provided by DOE is fully consistent with its regulations.

Finally, to maintain transparency, Treasury and/or DOE should publicize DOE's analytical assessment of lifecycle GHG emissions and the emissions rate itself once DOE has provided the PER applicant with the assessment.

D. 45VH2-GREET must be accessible.

The current 45VH2-GREET is inaccessible, as it is difficult to understand how the model calculates carbon intensities. The 45VH2-GREET excel package from DOE's website contains two files: a 45VH2-GREET excel file and a GREET1_2023 Excel file. Taxpayers use the former to calculate the carbon intensity of their hydrogen. The latter launches simultaneously when opening 45VH2-GREET and presumably serves as background data for the former model. Within 45VH2-GREET, there are no formulas to trace for the user to understand how the inputs translate into carbon intensities. All calculations appear to be done through excel macros that are locked behind a password and are therefore inaccessible to the user. Although the data and formulas in GREET1_2023 are accessible and are not locked behind passwords, they are difficult to trace, and it is impossible to determine what is being used by 45VH2-GREET without access to the macros.

It is understandable that DOE restricts the background data and calculations that users can change to limit fraud. But the current tool is a "black box" where it is arbitrarily difficult to understand how inputs translate into final carbon intensities. Although DOE has provided a 45VH2-GREET user manual to increase accessibility, the manual is not comprehensive.[149] For example, it does not list key information like the assumptions for the CO_2 emissions associated with extracting, processing, transporting, and distributing methane to the hydrogen production facility.

Beyond the inaccessible calculations, 45VH2-GREET is only compatible with Windows operating systems. Future updates should include greater compatibility across different operating

[147] Proposal at 89248 (§ 1.45V-4(c)(3) of proposed regulations).
[148] *Id*. (§ 1.45V-4(c)(5) of proposed regulations).
[149] *See* 45VH2-GREET Manual.

systems to improve accessibility. A priority should be compatibility with the Mac operating system, given that around 23% of U.S. enterprises (organizations with 1000+ employees) use that system.[150]

Treasury must make 45VH2-GREET accessible and transparent.[151] CATF encourages Treasury to collaborate with DOE to do so. The easiest means of increasing accessibility is to provide users with the macro password for 45VH2-GREET. To prevent fraud, Treasury could build an identical spreadsheet with a different password (unknown to taxpayers) that taxpayers must submit when claiming 45V credits. DOE should also publish a detailed, comprehensive manual explaining the calculations and assumptions for each production pathway. This will work in tandem with transparent macros to help users understand how their inputs translate into carbon intensities.

To assist with accessibility, DOE must also be responsive to questions surrounding the tool. CATF emailed DOE's help desk on Tuesday February 6, 2024, for clarity on the upstream CO_2 emissions assumptions used in fossil-based pathways and on how GREET treats carbon monoxide if it is a coproduct of hydrogen production rather than an impurity. However, as of February 23, 2024, CATF has not received a response. Given the lack of transparency with the current tool, a responsive help desk is even more vital.

VIII. CONCLUSION

CATF appreciates the opportunity to comment on Treasury's proposed 45V guidance. Treasury's proposal is an excellent first step toward ensuring section 45V fosters the growth of a truly clean hydrogen market that is needed to combat climate change. This comment provides suggestions to strengthen guardrails around hydrogen lifecycle analyses to avoid induced GHG emissions from hydrogen—which would negate the purpose of the credit—while also emphasizing flexibility and the need to create certainty for hydrogen producers. Both principles are critical to getting this lucrative credit right. Adopting CATF's recommendations would result in a tax credit that both promotes a clean hydrogen market and protects our climate.

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[150] Johnny Evans, *Macs reach 23% share in US enterprises, IDC confirms*, Computerworld (Jan. 27, 2021), https://www.computerworld.com/article/3604601/macs-reach-23-share-in-us-enterprises-idc-confirms.html.

[151] *See GPA Midstream Ass'n v. United States DOT*, 67 F.4th 1188, 1197 (D.C. Cir. 2023) ("We have long held that, in order to provide the public with a meaningful chance of participating in the rulemaking process, as required by the APA, *see* 5 U.S.C. § 553(c), an agency must disclose critical information justifying the proposal in time for public comment.")

Respectfully submitted,

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