February 26, 2024

To: **The Honorable Lily Batchelder, Assistant Secretary for Tax Policy**
Re: **Docket IRS-2023-0066, Section 45V Credit for Production of Clean Hydrogen**

U.S. Department of the Treasury, Internal Revenue Service
Office of Tax Policy
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Washington, DC 20044
Submitted directly to www.regulations.gov; IRS-2023-0066

Assistant Administrator Batchelder:

Environmental Defense Fund (EDF) appreciates the opportunity to comment on Treasury's proposed regulations for *Section 45V Credit for Production of Clean Hydrogen*, established by the Inflation Reduction Act of 2022.[1] EDF is a global non-profit, non-governmental, and non-partisan environmental organization, with staff, offices, and millions of members across the world who are carrying out the organization's mission to build a vital earth for everyone. Our key priorities are to stabilize the climate and strengthen people's ability to thrive in a changing climate, which includes universally upholding the fundamental human rights of all people to breathe clean air, drink clean water, have access to sustainable food, grow in vibrant communities, and live in a clean and healthful environment in balance with flourishing biodiversity. We do this by using science, economics, law, and uncommon partnerships to find practical and lasting solutions to the most serious environmental problems.

We would be glad to clarify or elaborate on any of the points made in the comments below. If there are any questions, please contact Morgan Rote, Director, U.S. Climate Policy (mrote@edf.org).

Section 45V provides generous funding for clean hydrogen production, which stands to play a significant role in the evolution of the hydrogen economy. Clean hydrogen has the potential to solve pressing energy challenges for the 'hard to abate' sectors such as industrial production and global transport, which have few readily available alternatives to fossil fuel energy sources and feedstocks. However, 45V does not include any guardrails on how much hydrogen is produced and for what it is used. If 45V provides incentives for hydrogen production that is not delivering actual climate benefit, it directly undermines the intention of the 45V tax credit and has the potential to lock in unsustainable processes and infrastructure, promoting the greenwashing of status quo processes at taxpayers' expense and setting up the industry for future disruptions. Such an outcome would also undermine public trust in hydrogen as a climate tool and likely place already vulnerable communities at risk of exposure to increased emissions and pollution.

Accurately assessing the GHG intensity of hydrogen production is critical when determining eligibility for incentives such as 45V. These impacts can vary greatly depending on many factors, including from where

[1] 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 (proposed Dec. 26, 2023).

electricity is sourced, the rates of carbon capture, the levels of hydrogen and methane emissions, and the timescale considered. However, several of these factors are often inadequately accounted for in analytical frameworks, with material implications. For instance, a new EDF study suggests that for blue hydrogen (i.e., natural gas reforming with carbon capture) pathways, high rates of hydrogen emissions (10%) and upper end methane leakage (5.4%) – both factors rarely included in climate impact assessments of hydrogen production – can lead to an *increase* in warming in the near term by up to 50% compared to the fossil fuel applications they are replacing. Meanwhile, if those emissions are low (i.e., 1% for hydrogen, 0.01% for methane), warming impacts could *decrease* by over 70%. Carbon capture rates are also significant, as a rate of 60% can reduce the climate benefits relative to a 98% capture rate by 15-50% in the near-term and 20-60% in the long-term.[2] It is important to note here that many communities have expressed their deep concerns around the utilization of carbon capture technology, and EDF has published separate material sharing key guidelines that the Department of Energy (DOE) should consider during the funding of related CCS projects.[3]

For green (i.e., renewable-based electrolysis) hydrogen pathways, high levels of hydrogen emissions (10%) alone can reduce the anticipated climate benefits from replacing fossil fuel systems in the near-term by up to 25%. Moreover, if the renewable electricity used for green hydrogen is not additional (or 'incremental') to what is needed for the electric grid, then there may be more warming than the fossil fuel systems the hydrogen is replacing, over all timescales.[4]

There is also a need to overcome known weaknesses in standard metrics.[5] For example, it is critical to calculate and consider the impact of both near- and long-term climate warming. The standard metrics employed for assessing climate impacts (GWP with a 100-year time horizon) do not convey warming effects in the near term and assumes an unrealistic one-time pulse of emissions rather than the more realistic case of continuous emissions over time. This is especially relevant to hydrogen and methane's climate impacts given that both are short-lived climate pollutants that have stronger near-term warming power than over the long term. Climate change and its devastating impact is happening today, and research suggests that faster rates of warming in the coming decades can lead to more record-shattering heat extremes.[6] Relying solely on long-term climate metrics that mask near-term warming effects will not result in the best climate outcomes for the wellbeing of this and the next generations.[7]

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[2] Sun, T, et al, Climate impacts of hydrogen and methane emissions can considerably reduce the climate benefits across key hydrogen use cases and time scales, Environ. Sci. Technol. 2024, https://pubs.acs.org/doi/10.1021/acs.est.3c09030

[3] Environmental Defense Fund, n.d., Effective CO2 management, BetterHubs, https://betterhubs.edf.org/core-objectives/effective-co2-management/

[4] Sun, T, et al, Climate impacts of hydrogen and methane emissions can considerably reduce the climate benefits across key hydrogen use cases and time scales, Environ. Sci. Technol. 2024, https://pubs.acs.org/doi/10.1021/acs.est.3c09030

[5] Ocko I.B., et al. Unmask temporal trade-offs in climate policy debates. Science 2017. 356, 492-493. https://www.science.org/doi/10.1126/science.aaj2350

[6] Fischer, E M, et al. Increasing probability of record-shattering climate extremes. Nature Climate Change 2021. 11, 689-95. https://www.nature.com/articles/s41558-021-01092-9

[7] Sun T, et al. Path to net zero is critical to climate outcome. Sci Rep. 2021 Nov 12;11(1):22173. https://www.nature.com/articles/s41598-021-01639-y

We are on the precipice of creating the largest incentive for hydrogen production in the world, and it is Treasury's responsibility to ensure that this tax credit does not incentivize nonoptimal – or worse, counterproductive – hydrogen production projects, or those which are financially unsustainable once the tax credit expires – and achieves maximum climate benefits with taxpayer dollars. Specifically, we call on Treasury to address the following points:

Electrolytic Hydrogen

- Uphold the 3-pillar framework for electrolytic hydrogen in its final rule;
- Consider targeted flexibilities under the incrementality requirement that can meet stakeholder needs while upholding the overall emissions integrity of the framework – this could include exemptions for repowering, effective state emissions caps, avoided nuclear retirements, curtailed resources, or very clean grids;
- Uphold hourly matching, reflecting a Scope 2 attribute-based approach for temporal matching and including a small amount of operational flexibility (e.g., through a limited buffer volume of non-hourly matched credits);
- Include small adjustments to deliverability bounds to account for actual transmission constraints (e.g., line losses) and opportunities (e.g., wheeling between regions); and
- Establish a centralized certificate tracking system to coordinate across regions and avoid double-counting.

Methane and Carbon Emissions from Fossil-Based Hydrogen

- Kick-start a joint agency process to update the methane leakage estimates annually in GREET and support a move to basin-specific leak rates based on reliable, recent, and imminent measurement data;
- Ensure that the nationwide average methane leak rate is similarly updated and accounts for emissions from co-producing wells;
- Incorporate dual time horizons for climate impact assessment calculations (GWP with both 20- and 100-year time horizons);
- Prohibit users from inputting company-specific gas values, given the challenges of relying on existing differentiated gas certification schemes in regulatory contexts; and
- Preserve the draft methodology of calculating CCS rate based on actual volumes of carbon sequestered (and not utilized), which should be reported on an annual basis.

Biomethane and Fugitive Methane Pathways

- Limit eligibility of landfill methane to only that generated from food waste already in landfills as of Inflation Reduction Act of 2022 (IRA) passage;
- Allow biomethane from livestock farms to be an eligible pathway, subject to strong climate protections;
- Disallow the use of book-and-claim systems for biomethane feedstocks at this stage and first convene a joint agency group to evaluate an appropriate standard for such systems; in the meantime, biomethane used for hydrogen production should be "direct use" through a direct, exclusive pipeline connection;

- Prohibit carbon-negative biomethane or fugitive methane scores from being used to offset the positive emissions associated with hydrogen production;
- Require net methane leakage from 45V-eligible livestock biomethane to be measured using monitoring sensors and factored into GREET climate impact assessments with dual GWP time horizons (20 and 100-year);
- Require livestock farms seeking 45V eligibility to adopt nutrient management plans and other best practices to reduce ammonia losses and other environmental impacts from land application and digested manure storage or treatment;
- Require landfills seeking 45V eligibility to meet minimum gas collection efficiency requirements and other best practices to limit fugitive methane emissions;
- Require verification of available productive use for biomethane through on-site, third-party inspections; and
- Prohibit fugitive methane pathways until a robust techno-economic study has been conducted.

Hydrogen Emissions

- Require hydrogen emissions to be factored into 45VH2–GREET and treated as climate-warming emissions by applying dual GWP values (20 and 100-year) from the IPCC and recent multi-model assessments[8] to already-included or observable loss rates,[9] and develop a process to incorporate measured hydrogen emissions rates as reliable data becomes available;
- Preclude all detectable levels of H2 emissions (i.e., not just those from venting or flaring) from receiving the tax credit, as these volumes of hydrogen are not 'sold or used;'
- Stipulate that all levels of fugitive hydrogen emissions will eventually be excluded from receiving the tax credit once high-precision sensors are widely available; and
- Require hydrogen producers to adopt hydrogen emissions management plans, including a commitment to incorporate best available sensor technology (once commercially available and accessible) and other operational best practices to mitigate leakage.

Other

- Reserve decisions on provisional emissions rates for geologic hydrogen until a later rulemaking process can be undertaken based on robust climate and environmental data; and
- Establish additional backstops to prevent abuse of the tax credit, defining "wasteful" uses as those which do not reduce systemwide GHG emissions.

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[8] IPCC AR5 and AR6 include hydrogen's GWP100 values, and the multi-model study by Sand et al. (2023) includes a GWP20 value; IPCC Fourth Assessment Report (AR4), Working Group I, Chapter 2, 2.10.3.6 Hydrogen (2007); IPCC AR6 Working Group III, Chapter 6, 6.4.5.1 Hydrogen: Low-carbon Energy Fuel, pg. 657 (2022); Sand, M et al. (2023), "A multi-model assessment of the global warming potential of hydrogen," Communications Earth & Env 4, 203, https://www.nature.com/articles/s43247-023-00857-8

[9] The R&D version of GREET does include loss rates throughout the value chain. Moreover, hydrogen producers are often able to conduct a mass balance calculation of what they expect to produce versus what they actually produce.

Contents

I. Statutory Background

a. Treasury Is Responsible for Assessing Lifecycle Greenhouse Gas Emissions under Section 45V in Accordance with the Incorporated Clean Air Act Definition

Section 45V provides a tax credit for the production of “qualified clean hydrogen.”[10] The credit for any taxable year is an amount equal to the product of (i) the kilograms of qualified clean hydrogen produced by the taxpayer during such taxable year at a qualified clean hydrogen production facility, and (ii) the applicable amount as determined under section 45V(b) with respect to such hydrogen. Section 45V(c)(2)(A) provides that “qualified clean hydrogen” is hydrogen which is produced through a process that results in a lifecycle greenhouse gas emissions rate of not greater than 4 kilograms (kg) of carbon dioxide equivalent (CO_2e) per kg of hydrogen. The percentage of the tax credit (of $3/kg) that can be claimed depends on the lifecycle greenhouse gas emissions (i.e., lifecycle carbon intensity) of the production process:

- 20% for 2.5 to 4 kg of CO_2e per kg of hydrogen;
- 25% for 1.5 to 2.5 kg of CO_2e per kg of hydrogen;
- 33.4% for 0.45 to 1.5 kg of CO_2e per kg of hydrogen; and
- 100% for less than 0.45 kg of CO_2e per kg of hydrogen.

Section 45V(f) directs Treasury to “issue regulations or other guidance to carry out the purposes of this section, including regulations or other guidance for determining lifecycle greenhouse gas emissions.” Congress directed Treasury to institute these standards by August 2023—“[n]ot later than 1 year after the date of enactment of this section,” which occurred in August 2022.[11]

The term “lifecycle greenhouse gas emissions” is defined in section 45V(c)(1) through a two-part definition. First, “[i]n general” and subject the second part of the definition, “lifecycle greenhouse gas emissions” is given the same meaning established under section 211(o)(1) of the Clean Air Act, a statute administered by the U.S. Environmental Protection Agency (EPA).[12] Second, “lifecycle greenhouse gas emissions” only includes emissions “through the point of production (well-to-gate),” as determined under the most recent GREET model, “or a successor model (*as determined by the Secretary*).”[13] Treasury is therefore responsible for issuing regulations or guidance for determining lifecycle greenhouse gas emissions through the point of production, in accordance with the Clean Air Act definition, using GREET or a successor model that Treasury finds appropriate.

The Clean Air Act definition, found in section 211(o)(1)(H), defines “lifecycle greenhouse gas emissions” as:

> 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 [of the EPA], related to the full fuel lifecycle, *including*

[10] 26 U.S.C. § 45V(c)(2).

[11] 26 U.S.C. § 45V(f).

[12] 26 U.S.C. § 45V(c)(1)(A) (cross referencing 42 U.S.C. § 7545(o)(1)(H)).

[13] 26 U.S.C. § 45V(c)(1)(B) (emphasis added).

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[.][14]

Section 45V, through incorporation of Clean Air Act section 211(o)(1)(H), requires Treasury to account for aggregate greenhouse gas emissions related to the full fuel (hydrogen) lifecycle through the point of production. Treasury is required to account for direct emissions and significant indirect emissions related to all stages of hydrogen production and hydrogen feedstock production.

In the context of hydrogen production, there are direct emissions from hydrogen production facilities, as well as significant emissions from electricity and feedstock production. While direct emissions from the production facility can have an important impact on hydrogen's lifecycle emissions profile, emissions from electricity and feedstock production often make up the majority of hydrogen's total lifecycle emissions.[15] Because emissions from electricity and feedstock production greatly influence and may dominate hydrogen's lifecycle emissions profile, they are "significant" emissions under the statutory definition.[16] Emissions from electricity and feedstock production are likewise "related to" hydrogen production because both are connected to or result from producing hydrogen.[17]

The inclusion of emissions from electricity and feedstock production in Treasury's lifecycle assessment is likewise consistent with EPA's practice under section 211. Under section 211, EPA administers the Renewable Fuel Standard (RFS). As part of the RFS, EPA analyzes the lifecycle emissions of fuels, applying section 211(o)(1)(H)'s definition. After section 211(o) was added to the Clean Air Act, EPA adopted regulations to implement the RFS (known as "RFS2"), "consider[ing] the full lifecycle emission impacts of fuel production from both direct and indirect emissions, including significant emissions from land use changes."[18] In this initial assessment, EPA "recognize[d] that lifecycle GHG assessment of biofuels is an evolving discipline" and stated it would "continue to revisit [its] lifecycle analyses in the future as new information becomes available."[19] In explaining why it considered emissions from international land use change, in addition to direct emissions, EPA explained that the statutory requirement to consider "significant indirect emissions" meant that it was appropriate to consider emissions that are "'significant' in terms of their relationship to total GHG emissions for given fuel pathways" based on EPA's

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[14] 42 U.S.C. § 7545(o)(1)(H) (emphasis added).

[15] *See, e.g.*, Argonne National Laboratory, Hydrogen Life-Cycle Analysis in Support of Clean Hydrogen Production at 12 (2022), https://publications.anl.gov/anlpubs/2022/10/179090.pdf (showing lifecycle emissions of hydrogen made with methane feedstocks being dominated by emissions from natural gas (methane) production); *see also id.* at 7 ("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.").

[16] "Significant" is defined as "having or likely to have influence or effect: important" and "of a noticeably or measurably large amount." Merriam-Webster Online Dictionary, https://www.merriam-webster.com/dictionary/significant.

[17] *See Morales v. TWA*, 504 U.S. 374, 383 (1992) ("The ordinary meaning of [the words '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[.]'" (quoting Black's Law Dictionary 1158 (5th ed. 1979)).

[18] U.S. EPA, Final Rule: Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program, 75 Fed. Reg. 14670 (Mar. 26, 2010).

[19] *Id.*

assessments and modeling.[20] EPA routinely updates its lifecycle analyses under the RFS to reflect the best available data and most recent scientific methods.

Section 45V, by incorporating Clean Air Act section 211(o)(1)(H), thus requires Treasury to consider direct emissions and significant indirect emissions, from well-to-gate, associated with hydrogen production. Treasury's inclusion of induced grid emissions from electricity used for hydrogen production and its inclusion of emissions associated with feedstock production is required by the plain text of the statute. Both categories of emissions are "significant," often dominating hydrogen's lifecycle emissions profile, and directly "related to" hydrogen's well-to-gate lifecycle, attributable to production processes and feedstocks. Consistent with EPA's assessments in the RFS context, "significant indirect emissions" includes induced grid emissions and emissions from feedstock production, like upstream methane emissions from oil and gas production, which both greatly influence the overall emissions profile of hydrogen production. When considering and assessing these emissions, as required by the statute, Treasury must rely on the best available methods and scientific data.

b. 45V's Lifecycle Greenhouse Gas Emissions Definition Requires Consideration of Emissions from Electricity Generation and Use

Increased electricity demand caused by producing hydrogen through electrolysis can result in significant emissions from electricity generation. Indeed, the lifecycle emissions of hydrogen produced with grid-connected electrolyzers are dominated by emissions from electricity generation. Hydrogen produced using electricity from the U.S. average grid is estimated to have a carbon intensity of 21 kg of CO_2/kg H2, many times higher than the statutory thresholds and roughly double the emissions of uncontrolled steam methane reforming (SMR).[21] Induced grid emissions or systemwide grid emissions caused by hydrogen production must be considered because they are significant, dominating the overall emission profile of hydrogen made with grid-connected electrolyzers, and result from using electricity to produce hydrogen.[22]

Treasury has rightly considered induced grid emissions as required by section 45V, and has rightly determined, based on the best available science and data, that the use of Energy Attribute Certificates (EACs) or Renewable Energy Certificates (RECs) are the best available method for verifying these emissions. In its accompanying memo, EPA likewise confirms that the proposed methods and requirements are an "appropriate way of verifying" zero-carbon power and serve as a "reasonable methodological proxy" for assessing induced grid emissions from hydrogen production.[23] This is also consistent with congressional intent, as the legislators that drafted section 45V expressly stated that

[20] *Id.* at 14766.

[21] Thomas Koch Blank and Patrick Molly. *Hydrogen Decarbonization Impact for Industry: Near-term challenges and long-term potential*. 2020. RMI, https://rmi.org/wp-content/uploads/2020/01/hydrogen_insight_brief.pdf.

[22] Hydrogen made with fossil-generated electricity, even if behind-the-meter and paired with CCS, entails significant upstream emissions associated with oil, gas, and coal extraction, processing, and transportation. These emissions are distinct from embodied emissions in materials (e.g., cement used to construct a power plant) because they are ongoing, and the result of fuel production used to generate electricity.

[23] Letter from Janet McCabe, Deputy Administrator, U.S. EPA, to Lily Batchelder, Assistant Secretary for Tax Policy, U.S. Dept. of Treasury (Dec. 20, 2023), https://home.treasury.gov/system/files/136/45V-NPRM-EPA-letter.pdf.

"lifecycle greenhouse gas emissions" should include "indirect book accounting factors" like CEAs or RECs for grid emissions.[24]

c. 45V's Lifecycle Greenhouse Gas Emissions Definition Requires Consideration of Emissions from Oil and Natural Gas Production, Processing, Transmission, Storage, and Distribution

Under 45V, lifecycle greenhouse gas emissions include emissions through the point of production, including emissions from "all stages of fuel and feedstock production and distribution, from feedstock generation or extraction through the distribution and delivery and use . . . ."[25] In the case of hydrogen produced with natural gas as a feedstock, the lifecycle definition requires consideration of emissions from extraction, production, and transportation of the feedstock—natural gas.[26] Methane emissions occurring during oil and gas production, processing, transmission, storage, and distribution dominate the overall emissions profile of hydrogen produced with natural gas as a feedstock and must therefore be accurately accounted for using the best available methods.

Natural gas is extracted from underground reserves that commonly consist of commingled and unprocessed oil, natural gas, and other hydrocarbons. Depending on the reserve and extraction processes, crude oil, raw gas, and/or natural gas liquids may be produced at a single site. Natural gas wells, along with crude oil wells that produce associated natural gas, send raw natural gas into the gathering pipeline system which is then processed and fed into the transmission and distribution system for delivery to users, like hydrogen producers. Transmission and distribution pipelines thus contain natural gas that has been extracted from a variety of oil and gas wells.

Because those using natural gas as a feedstock—in this case, the hydrogen producer—may receive natural gas that is extracted from natural gas wells, crude oil wells that co-produce natural gas, or both, emissions occurring from both types of extraction processes must be considered. Both types of wells produce the feedstock that is commingled in the gas system and may be used in hydrogen production. When a hydrogen producer sources natural gas from a primarily oil producing region where natural gas is a co-product, like the Permian Basin, emissions from wells that co-produce oil and gas must be accounted for. For example, in 2022, natural gas production in the Permian Basin hit an annual high, averaging 21.0 billion cubic feet per day (Bcf/d), coming primarily from oil-directed drilling producing

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[24] *See* 168 Cong. Rec. at S4165-6 (Aug. 6, 2022) (colloquy between Senators Wyden and Carper: "It is also my understanding of the intent of section 13204, is that in determining 'lifecycle greenhouse gas emissions' for this section, the Secretary shall recognize and incorporate indirect book accounting factors, also known as a book and claim system, that reduce effective greenhouse gas emissions[.]"). CEAs or RECs allow a producer to offset their emissions by supporting clean energy somewhere else, and therefore are necessary for grid-connected electrolyzers to satisfy section 45V's requirements. This strongly suggests that Congress intended for grid-connected electrolyzers that met the IRA's emissions thresholds to also access the section 45V credit.

[25] 26 U.S.C. § 45V(c)(1)(A) ("Subject 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[.]").

[26] *See, e.g.*, CRS, *Calculation of Lifecycle Greenhouse Gas Emissions for the Renewable Fuel Standard (RFS)* (March 12, 2010), https://crsreports.congress.gov/product/pdf/R/R40460/9 ("For petroleum fuels, potential lifecycle emissions include the following sources: process emissions from exploration and extraction of crude oil; electricity generation for use in exploration and extraction of crude oil; transportation of crude oil to refineries; refinery process emissions; electricity generation and use at refineries; upstream natural gas and coal emissions (e.g., extraction and mining); distribution of finished product; end-use combustion of the fuel.").

associated gas.[27] This gas, like gas co-produced from oil wells in other regions, could readily be used as a feedstock to produce hydrogen, and failure to account for emissions during its production would arbitrarily exclude significant emissions related to the hydrogen production process that must be considered under the lifecycle greenhouse gas emissions definition of section 45V. Emissions from co-producing wells can readily be attributed between oil production and gas production using well-established lifecycle assessment methods.

There are likewise significant regional differences in methane emissions from oil and gas production across basins, and these differences can be an order of magnitude in many instances. The large variation is driven by geologic characteristics and modes of production. Because of this variation, scientists have been working over the past decade to characterize emissions at the basin or sub-basin level. Many basins and sub-basins in the U.S. now have credibly measured emissions rates associated with oil and gas production. Readily available, peer-reviewed methods are commonly used to generate basin-level methane estimates. Using available methods to generate basin-level leak rates for purposes of 45VH2-GREET would result in significantly more accurate lifecycle emissions estimates than the current default leak rate. In light of the large variation in methane emissions across oil and gas operations and basins, Treasury should use basin level methane estimates. Any default leak rate used in 45VH2-GREET should be set conservatively to protect taxpayer dollars and ensure positive environmental outcomes.[28]

II. Emissions Accounting for Electrolytic Hydrogen

a. The 3-pillar Framework for Electrolytic Hydrogen Will Ensure Emissions Reductions and Establish a Sustainable, Durable Hydrogen Industry; Treasury Must Uphold this Framework in the Final Rule

EDF applauds the 3-pillar framework that has been laid out in the draft guidance. It reflects the consensus that has emerged from many studies regarding the importance of the 3 pillars in mitigating emissions increases, as well as the framework's ability to establish a sustainable, durable hydrogen economy. For example, studies from Princeton University, Energy Innovation, and Evolved Energy Research find that without the 3 pillars, 45V could add hundreds of millions of tons of pollution per year

[27] U.S. Energy Information Administration, *Two counties in New Mexico account for 29% of Permian Basin crude oil production* (July 6, 2023), https://www.eia.gov/todayinenergy/detail.php?id=57020#:~:text=In%202022%2C%20natural%20gas%20production,produced%20from%20oil%2Ddirected%20drilling.

[28] For example, prior GREET publications have evaluated a range of methane leakage assumptions from 0.7%-3%. *See, e.g.*, Argonne National Laboratory, GREET MODEL FOR HYDROGEN LIFE CYCLE GHG EMISSIONS at 8, https://www.energy.gov/sites/default/files/2022-06/hfto-june-h2iqhour-2022-argonne.pdf. It would be appropriate for 45VH2-GREET to employ a high-end estimate given the significant amount of the tax credit and the risk of taxpayers subsidizing dirty fossil hydrogen production.

relative to partial or no implementation of the pillars.[29, 30, 31] EDF recently released a report from Environmental Resources Management (ERM) that summarized key findings from approximately 30 reports on the 3 pillars and outlined key areas of consensus and explained differences in assumptions; as well as explored different policy design options.[32] Many of the comments in this section represent direct excerpts from that report.

In addition to helping protect against emissions increases, the 3 pillars will enable robust low-carbon value chains that endure past the tax credit's expiration. Specifically, the 3 pillars will incentivize domestic market solutions to complement variable renewables (e.g., long-duration storage, batteries and transmission lines), the build-out of hydrogen storage, and the deployment of more flexible electrolyzers capable of producing competitively priced hydrogen after the tax credit expires. Strong requirements will also support global value chains, including by aligning with or exceeding international market requirements such as those in the EU. Moreover, the guidelines for 45V will serve as an important precedent for future low-carbon tax credits, policies or regulations – both hydrogen-related and beyond.[33]

b. Treasury Should Consider Targeted Flexibilities Under the Incrementality Requirement that Can Uphold the Emissions Integrity of the Framework

B1. Fossil Fuel Electricity

Treasury should not allow CCS installations to count as 'incremental' sources of supply for fossil fuel generators. The incrementality requirement is designed to prevent emissions increases and ensure that new investments in *clean* energy supply are being incentivized. Adding CCS to an existing generator does not change the overall supply of electricity on the grid and should therefore not be considered incremental, nor does it represent clean energy supply. If an existing generator with CCS were to quality for 45V, the hydrogen demand would still need to be met by new load, which would have an indirect impact on emissions.

Moreover, there is no justification for offering an exemption for fossil generation with CCS under an 'avoided retirement' scenario, as CCS for existing facilities is already covered by 45Q, and 45V is not needed to justify those investments.

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[29] Ricks, W., Xu, Q., & Jenkins, J. D. (2023). Minimizing emissions from grid-based hydrogen production in the United States. Environmental Research Letters, 18(1), 014025. https://doi.org/10.1088/1748-9326/acacb5

[30] Energy Innovation Policy & Technology LLC®. (2023, April). Smart Design of 45V Hydrogen Production Tax Credit Will Reduce Emissions and Grow The Industry. https://energyinnovation.org/wp-content/uploads/2023/04/Smart-Design-Of-45V-Hydrogen-Production-Tax-Credit-Will-Reduce-Emissions-And-Grow-The-Industry.pdf

[31] New analysis: The 3 pillars will support large hydrogen deployment. (2023, June 20). https://www.nrdc.org/bio/rachel-fakhry/new-analysis-3-pillars-will-support-large-hydrogen-deployment

[32] Assessment of Grid-Connected hydrogen production impacts. (2024). ERM. https://www.erm.com/assessment-of-grid-connected-hydrogen-production-impacts/

[33] *Id.*

If Treasury were to extend this exception, they would at a minimum need to account for the upstream emissions associated with fuel extraction, processing and transport.

B2. Facility Repowering

Treasury has proposed to provide an alternative test for establishing incrementality for facilities that undergo an uprate (§1.45V-4(d)(3)(i)(B)). EDF supports this inclusion and recommends that repowered facilities should also be included. Repowering could be defined by the 80/20 rule, which has previously been used by the IRS to determine if a repower is significant enough to qualify as a new asset eligible for prior generation production and investment tax credit incentives. As explained in our recent report with ERM, "This rule compares the magnitude of the fair market value (FMV) of the remaining assets with the cost of the new assets and dictates that the FMV of remaining assets must be less than or equal to 20 percent of the sum of the FMV of the remaining assets plus the cost of new assets. The rule can also be understood as the cost of new assets needing to be greater than or equal to 80 percent of the sum of the FMV of the remaining assets plus the cost of new assets."[34]

B3. Avoided Facility Retirements

Treasury asks about whether to make eligible capacity from electricity generation facilities that would otherwise be retired. As ERM explains in a recent report: "Baseload zero-carbon electricity will play an important role in the continued decarbonization of the electricity grid."[35] This type of generation provides a unique value; therefore, if a facility is able to provide safe, secure, and clean energy generation, there may be broader interest in its continued economic viability and in avoiding early retirements.

As the draft rule acknowledged, since 2013, 13 commercial nuclear reactors have closed early because of shifting energy markets and economic factors.[36] State-driven financial incentives and the Civil Nuclear Credit Program introduced in the Bipartisan Infrastructure Law have since helped to extend the life of several reactors.

There are now 11 reactors with 10.1 GW of total capacity with licenses set to expire by 2030, as shown in Figure 1 below.[37] An alternative view of summer capacity is shown below in Figure 2, where the average remaining life of reactors drops dramatically from around 15 years in 2023 to less than 10 years in 2035. These license expirations showcase an opportunity to prolong the contribution of existing nuclear in their respective markets. Federal funding through the Civil Nuclear Credit Program can help extend these licenses, although its next application cycle will not require a publicly announced.[38] This change in

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[34] Assessment of Grid-Connected hydrogen production impacts. 2024. ERM. https://www.erm.com/assessment-of-grid-connected-hydrogen-production-impacts/

[35] *Id.*

[36] DOE (U.S. Department of Energy). 2022. "Biden-Harris Administration Announces Major Investment to Preserve America's Clean Nuclear Energy Infrastructure." https://www.energy.gov/articles/biden-harris-administrationannounces-major-investment-preserve-americas-clean-nuclear

[37] Nuclear Energy Institute. 2023. U.S. Nuclear Plant License Information. https://www.nei.org/resources/statistics/us-nuclear-plant-license-information

[38] DOE (U.S. Department of Energy). 2023. "Civil Nuclear Credit Award Cycle 2." https://www.energy.gov/gdo/civilnuclear-credit-award-cycle-2

eligibility will be beneficial for reactors that are not publicly sharing their economic situation. If sufficient, subsidy programs such as the Civil Nuclear Credit Program, and other incentives provided within the IRA specifically for existing nuclear generation, should be the first revenue support option for existing nuclear, particularly in the near term. Supplying hydrogen tax credit eligible generation could offer a potential revenue stream further into the next decade where that generation remains critically important for achieving U.S. decarbonization goals.

Participation in clean hydrogen value chains could provide new financial opportunities for nuclear generators, either reducing their risk for early retirement or providing necessary support for operating license extensions. From a net impact perspective, preventing a resource from retiring and retaining that zero-emission electricity in the grid supply is no different from a new project entering the market. However, if a nuclear plant that was not at risk of retirement is made eligible, then the resource is simply diverted from existing demand to new hydrogen demand, and in could enable a potential equivalent net increased dispatch of fossil generation. For example, a recent report by Rhodium estimates that shifting all existing nuclear generation to hydrogen production results in increased net cumulative emissions by 1.3-4.7 billion metric tons through 2035.[39]

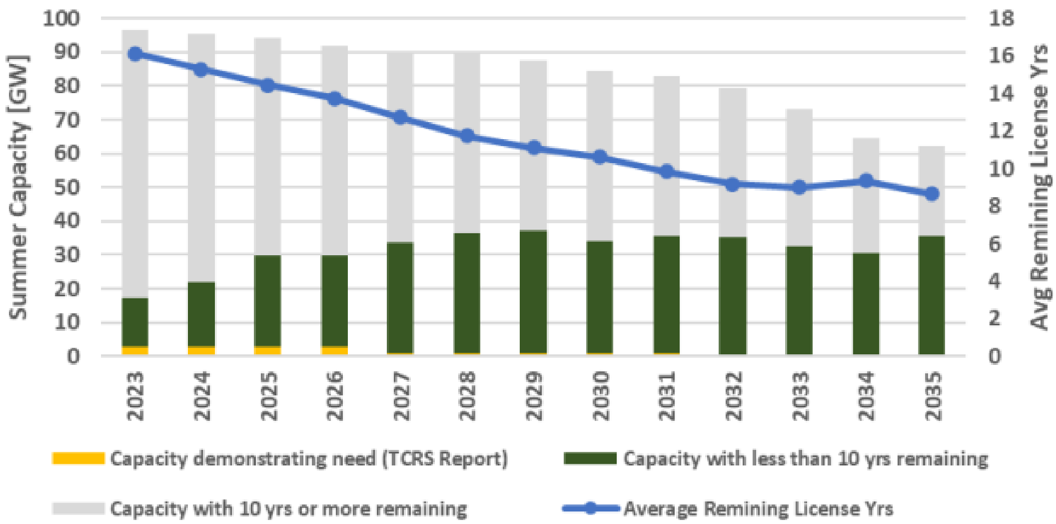
Figure 1. Nuclear Reactor Licenses Expiring by 2030[40]

	Reactor Licenses Expiring By 2030		
Reactor Name	**Generation Capacity (GW)**	**State**	**Expiration Date**
Diablo Canyon 1	1.1	CA	11/2/2024
Diablo Canyon 2	1.1	CA	10/26/2025
Clinton	1.1	IL	9/29/2026
Perry 1	1.3	OH	11/7/2026
Nine Mile Point 1	0.6	NY	8/22/2029
Ginna	0.6	NY	9/18/2029
Dresden 2	0.9	IL	12/22/2029
Commanche Peak 1	1.3	TX	2/8/2030
H.B. Robinson 2	0.8	SC	7/31/2030
Monticello	0.7	MN	9/8/2030
Point Beach 1	0.6	WI	10/5/2030
Total	**10.1**	**8 States**	

GW = gigawatts

[39] Rhodium Group. 2024. "How Clean Will US Hydrogen Get? Unpacking Treasury's Proposed 45V Tax Credit Guidance." https://rhg.com/research/clean-hydrogen-45v-tax-guidance/
[40] Assessment of Grid-Connected hydrogen production impacts. (2024). ERM. https://www.erm.com/assessment-of-grid-connected-hydrogen-production-impacts/

Figure 2. U.S. Nuclear Fleet Capacity by License Duration and TCRS Demonstrated Need[41]



To maximize emission reductions, the ideal solution is to identify and limit eligibility to those plants that are truly at risk of retiring without 45V support -- recognizing that proving a counterfactual can be challenging. Given this difficulty, Treasury has solicited input on a rigorous demonstration of need for financial support above and beyond other federal and state subsidies. Implementation of this type of demonstration should be aligned, where possible, with other existing state or federal programs for both consistency in methodology and efficiency.

One example is the Civil Nuclear Credit Program, which will distribute $6 billion in funding to help preserve the existing nuclear fleet in the U.S.[42] Eligible nuclear reactors are primarily those which are expected to close due to economic reasons and the closure will result in an increase in air pollution (due to fossil fuel generators fully or partially offsetting the supply). It may be that such a program serves only as a mechanism to establish eligibility but is not needed to dictate eligibility duration, as that could introduce additional project risk for 45V. Eligible reactors may also qualify for the Zero Emission Nuclear PTC under 45U, which provides a base credit of 0.3 ¢/kWh up to a maximum 1.5 ¢/kWh of electricity produced from a qualified facility and sold to an unrelated party between 2024 through 2032. Treasury is expected to issue a final rule this year which will provide further guidance to existing nuclear plants seeking to prevent premature closure. Treasury should consider aligning 45U and 45V guidance to allow a common framework for demonstrated need.

Another potential option for existing low-carbon baseload generator eligibility for 45V could be to require a binding long-term financial agreement between the hydrogen producer and generator that's seeking a license extension. This financial agreement could take the form of a long-term bundled PPA or be sleeved with a similar structure option in regulated markets, providing stronger incrementality

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[41] *Id.*

[42] DOE (U.S. Department of Energy). 2023. "Civil Nuclear Credit Program." https://www.energy.gov/gdo/civilnuclear-credit-program

connection than the use of unbundled certificates. A minimum term length (triggering a license extension) could be required of these PPAs on the order of 10 to 15 years to ensure sufficient additional capacity is created, in addition to a maximum share of capacity that could go toward hydrogen production. In the case of existing nuclear, many plants in the U.S. nuclear fleet would require a license extension to fulfill these term obligations for PPAs executed closer to 2030.

If hydrogen producers could help avoid the retirement of those plants and make it economical to keep this low-carbon electricity generation on the grid, hydrogen producers could make an even stronger case for incrementality impacts. Even one nuclear facility that shuts down prematurely will have a significant impact on U.S. emissions in the electric power sector. However, the easier it is for a plant to claim 45V eligibility, the greater the risk of both diverting a zero-carbon resource from supporting existing demand to new hydrogen demand, as well as a deadweight loss of subsidy funds. It's important to strike a balance, and Treasury will have to weigh these relative risks when crafting the final rule.

B4. Curtailment

Treasury also requests comments on whether to provide an opportunity to demonstrate zero or minimal induced grid emissions through modeling or other evidence, including curtailment. EDF agrees that identifying and procuring curtailed resources would have limited or no induced grid emissions. This is also consistent with the EU's Delegated Act, which allows resources that would have been curtailed as demonstrated by downward dispatch or prices reflective of renewables as the marginal generator.[43]

In the U.S., this curtailment option will likely not provide a material amount of electricity to support hydrogen production under 45V until much higher levels of renewable penetration are reached. But as wind and solar generation increase as a percentage of the overall grid mix, demand-side management to balance the grid will increase in importance and opportunity. Electrolyzers which can quickly ramp up or down to follow these non-dispatchable resources can become a demand-side resource for grid balancing. However, this would require their base operations to be at lower utilization factors for them to have spare capacity in reserve to enable them to ramp up and create demand to consume excess renewables. Declines over time in electrolyzer capital costs along with potential new capacity ancillary services as another revenue source (i.e., a demand response program in reverse) will further enable operating with a level of base spare capacity. The additional benefit of stronger temporality requirements is the market signal for which types of supply and grid solutions are most beneficial to optimize the system and investments, including renewables generation.

Even in markets considered to be high renewable such as California, curtailment volumes are relatively minimal relative to total volumes of generation[44] – but they may nonetheless provide enough power to support an electrolyzer load and thus play an important role for certain projects. Grid and weather forecasts can predict when curtailment is most likely to occur, but there are many real-time variables. Validation of the use of curtailed volumes will depend upon it being economic or grid mandated.

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[43] European Commission. 2023. "Delegated Regulation on Union Methodology for RFNBOs." February 2023. https://energy.ec.europa.eu/system/files/2023-02/C_2023_1087_1_EN_ACT_part1_v8.pdf

[44] Energy Innovation Policy & Technology LLC. 2023. "Smart Design of 45V Hydrogen Production Tax Credit Will Reduce Emissions and Grow the Industry.: April 2023. https://energyinnovation.org/publication/smart-design-of45v-hydrogen-production-tax-credit-will-reduce-emissions-and-grow-the-industry/

Economic curtailment would be theoretical, based on a formula of price signals which would determine when the effective net price to the generator in the hour is negative (inclusive of an energy PTC) and mechanical potential output based on weather data which would determine the theoretical generation amount curtailed. Apart from demand response program participation, the most viable option for curtailment as an expanded option for incrementality will likely be to apply it on a geographic basis versus project-specific, similar to electricity prices in a pricing zone reflecting the marginal generation (i.e., locational marginal prices, or LMPs).

For example, a project could be exempt from the incrementality requirement if it procures EACs from clean energy projects generated during times when LMPs at the electrolyzer do not exceed $10/MWh.

B5. State Emissions Caps

The incrementality requirement is a reasonable methodological proxy for determining that generation being used for hydrogen electrolysis is additional, i.e., that it would not have otherwise existed. It is not a perfect proxy, as it cannot ensure that future clean generating capacity that would have otherwise served other grid-connected end-uses is not diverted to hydrogen electrolysis. However, in the absence of declining emissions constraints on power sector emissions, incrementality and the three pillars as a whole are likely to be the only nationally deployable policy framework that can provide a check on emissions increases from hydrogen production.

Treasury also acknowledges that state or local policies, or certain regional grid makeups may help to prevent emissions increases. Indeed, EDF believes that the role of the three pillars becomes less critical to avoiding increased emissions from hydrogen production in states or regions with effective, high-integrity caps on economy-wide or power sector emissions. In their analysis of 45V crediting approaches RFF have argued the same.[45, 46]

To date, economy-wide GHG emission reduction targets have been established in nearly half of the states nationwide through either state legislation or executive action.[47] States have also adopted various climate policies, some focusing on technology-forcing policies, while others have adopted regulations to directly limit GHG emissions from particular sources and sectors, including cap and trade programs designed to limit the overall quantity of greenhouse gas pollution from covered sources.

Emissions caps, in particular, have strong potential to be a viable substitute to incrementality requirements, as technology-forcing policies such as clean energy standards that fall short of requiring 100% clean electricity in the near-term do not provide the certainty on an upper limit on GHG pollution that a well-designed cap can.

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[45] Emissions effects of differing 45V crediting approaches. (n.d.). Resources for the Future. https://www.rff.org/publications/reports/emissions-effects-of-differing-45v-crediting-approaches/

[46] Unpacking the proposed guidance on the 45V tax credit for clean hydrogen. (n.d.). Resources for the Future. https://www.resources.org/common-resources/unpacking-the-proposed-guidance-on-the-45v-tax-credit-for-clean-hydrogen/

[47] Environmental Defense Fund. 2023. "U.S. States with Binding Economy-wide Climate Targets." https://blogs.edf.org/climate411/wp-content/blogs.dir/7/files/2023/02/US-States-with-Binding-Economy-WideTargets.pdf

States that have finalized emissions cap and trade regulations include California, Washington, and the current 11 state members of RGGI. California and Washington have adopted economy-wide programs, covering roughly 80% of statewide emissions, including emissions associated with all in-state power generation and electricity imports, whereas the RGGI program covers electric power generation in participating states.[48,49] In addition, Colorado and Oregon have both adopted statutes requiring emissions from electricity sales to decline by at least 80% below 2005 levels by 2030, although neither provide an upper limit on cumulative emissions through that time period.

A well-designed high integrity emission cap program will prevent emissions increases across the capped sources resulting from increases in electricity demand, whether it is for hydrogen electrolysis or any other end-use. This backstop against increases in indirect GHG emissions as a result of increased demand is the intent of the incrementality pillar.

Some administrability challenges may exist in translating emissions caps into fulfillment of incrementality requirements, including the need for strong enforcement, for the capped area to become the new geographical boundary for the deliverability pillar, and for change-of-law guidance in the event of changes to an emissions cap policy. The risk of emissions being moved to other jurisdictions to avoid the state caps (typically referred to as "emissions leakage") should also be mitigated as much as possible. Even if state caps cover electricity imports, policies may do an inadequate job of pricing those imports and accounting for the full marginal emissions impact. There is also a risk that some capped states export less clean generation as a result of increased demand for in-state hydrogen production.

However, any risks of leakage from a capped region should be weighed against the fact that incrementality is an imperfect proxy for additionality and could still lead to higher emissions than under BAU – in order words, it does not guarantee that the "new" clean generation used for electrolysis would not have otherwise been used to serve other gird-connected end-uses. In addition, under current proposals, full implementation of the three pillars (i.e., with hourly matching) will not begin until 2028. Allowing state caps to substitute for incrementality requirements could result in a higher proportion of these earlier projects being sited in capped states where their potential to drive emissions increases relative to BAU is much more effectively mitigated.

The decision of whether to provide an incrementality exception to capped states should be carefully considered. Under this pathway, potentially eligible states should submit an application to Treasury and DOE, which includes a description of the state policies and any necessary adjustments to capture as close to the full emissions impact of imports and exports as possible and a statement of the updated deliverability bounds. Based on this information, NREL should conduct modeling to confirm that the state cap would indeed be effective at preventing significant emissions increases, compared with the alternative emissions expected under the default incrementality approach.

B6. Low-Carbon Electricity Grids

[48] California Air Resources Board. 2023. Cap-and-Trade Program. https://ww2.arb.ca.gov/our-work/programs/capand-trade-program/about

[49] Regional Greenhouse Gas Initiative. 2023. Elements of RGGI. https://www.rggi.org/program-overview-anddesign/elements

The emissions impact of the incrementality requirement may stand to diminish once the grid reaches sufficiently high levels of decarbonization. Highly decarbonized grids (i.e., those with around 90-95% clean power) will be at lower risk for increasing emissions from marginal resources because the overall grid has a lower carbon intensity. For this reason, the EU in their Delegated Act on the methodology for renewable fuels of non-biological origin has allowed for an exception to incrementality for low emission intensity grids (defined as less than 18 grams carbon dioxide per megajoule [gCO2/MJ] or less than 143 pounds carbon dioxide per megawatt hour [lb CO2/MWh] inclusive of all generation) as well as for a high percentage of renewables (defined as greater than 90%) in the grid mix. Once either of these grid conditions are met over a calendar year, they shall be continued to be considered met only for the subsequent five calendar years (i.e., the incrementality exception is not guaranteed in perpetuity). Also under this exception, hydrogen producers are still required to meet temporality and deliverability requirements along with securing supply through a PPA.[50]

As of 2021, eGRID data represented below on Figure 19 shows there are currently no U.S. regions which have met either of the EU threshold requirements, with nuclear and hydro being key contributors in many regions with the lowest intensities.[51] However, based on Cambium data, there are a few regions with notable projected growth in the next decade, which, if projections are actualized, might become relevant for demonstrating minimal emissions effects by 2035. These include SPP South and the Rocky Mountain Power Authority. See Figures 20 and 21 in ERM's report for forecasted regional renewable penetration rates and grid emissions intensities.[52]

Accounting for the intensity of the remaining grid, including nuclear, increases the regions which may reach EU exemption thresholds if considering a grid intensity versus just a renewables percentage mix. In addition to the regions which may reach 90% renewables, California, ERCOT, New York, and Arizona/New Mexico also have the potential to reach the EU grid intensity threshold under certain scenarios.

B7. Formulaic Approaches

Treasury also asks about formulaic approaches to address incrementality, such as deeming 5% of the hourly generation from existing generators as satisfying the requirement. This approach would not meet the broader objective of reducing indirect emissions. For example, the Rhodium Group estimates that a blanket exemption like this, without mechanisms to guarantee existing generation is only diverted during periods with low marginal emissions rates, could cause a systemwide increase in emissions of up to 1.5 billion metric tons through 2035.[53]

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[50] European Commission. 2023. Delegated regulation on Union methodology for RFNBOs. https://energy.ec.europa.eu/system/files/2023-02/C_2023_1087_1_EN_ACT_part1_v8.pdf

[51] USEPA (U.S. Environmental Protection Agency). 2023. Emissions & Generation Resource Integrated Database (eGRID). https://www.epa.gov/egrid

[52] ERM, 2024, Assessment of Grid Connected Hydrogen Electrolysis Impact, Part II, https://www.erm.com/globalassets/documents/publications/assessment-of-grid/assessment-of-grid-connected-h2-electrolysis-impact_part-ii_implementation_final.pdf

[53] Rhodium Group. 2024. "How Clean Will US Hydrogen Get? Unpacking Treasury's Proposed 45V Tax Credit Guidance." https://rhg.com/research/clean-hydrogen-45v-tax-guidance/

If a formulaic approach is taken, at a minimum it should be paired with an analysis of local grid intensity or renewables penetration, as discussed in the section above.

c. Treasury Should Uphold Hourly Matching, Reflecting a Scope 2 Attribute-Based Approach and Including a Reasonable Level of Operational Flexibility

C1. Feasibility of Hourly Matching

EDF supports the time-matching requirement in the Proposed Rule and believes that a phase-in from annual to hourly matching starting in 2028 is both prudent and feasible. We support the comments that have been drafted by EnergyTag and other organizations regarding the feasibility of transitioning to hourly matching by 2028. As described in the comments, Treasury should:

- Consider requiring a standard for the EAC registries to follow. This would help prevent fraud, enhance auditability and help registry interoperability.
- Maintain the 2028 phase-in for hourly matching. Once one registry has hourly EAC capability, it should be able to cover any regions that do not yet have capability.
- Allow a provisional pathway to hourly matching that uses hourly meter data and annual or monthly EACs to demonstrate hourly matching where hourly EACs are not available.
- Provide guidance describing in detail how standalone storage may be used to time-shift hourly EACs in a robust way that accounts for losses and uses a consistent and transparent allocation methodology.

C2. Scope 2 Attribute-Based Approach

Treasury seeks comments on modeling as an alternative approach to demonstrating zero or minimal induced grid emissions. While marginal emissions are a very useful tool for modeling and monitoring both supply and demand impacts, there are challenges with data availability for marginal emissions that will be discussed in a subsequent section. More importantly, a Scope 2 approach is more consistent with specific end-user accountability for what is within their control to manage related to electricity supply.

The Scope 2 approach, specifically referencing the GHG Protocol's market-based methodology, is based on the attributes of the electricity supply, accounting for the conveyance of those attributes via market-based mechanisms such as EACs. This attribute-based approach is the most reflective of electricity procurement activities by hydrogen producers. The current version of the Greenhouse gases, Regulated Emissions, and Energy Use in Transportation (GREET) model – 45VH2-GREET – references the GHG Protocol's location-based methodology, which is reflective of the average grid intensity and does not account for conveyance of market-based mechanisms. The GREET model will need to be updated to account for the attributes of specific electricity supply sources versus the average grid mix.

C3. Operational Flexibility

Treasury should consider options for providing some degree of operational flexibility in meeting an hourly temporal requirement while maintaining the framework's overall integrity. This might be necessary to mitigate short term disruptions, supply variability, or to accommodate lags in data sets. For example, some data references (including average grid factor, location based, residual or even some supplier/utility-based factors) are currently only available as an annualized number or factor and may be referencing generation from the prior year due to the validation process of those factors. Use of eGRID factors directly or indirectly, such as Green-e® residual factors, could even be upwards of two years delayed as the U.S. Environmental Protection Agency's (EPA's) traditional posting is every other year with a 1- year lag.

Providing operational flexibility could take different approaches, including allowing a limited percentage of the annual electricity supply volume under the Scope 2 approach to be exempt from any hourly temporality requirement. This "exempted" volume can be accounted for by using average grid intensities, supplier-specific intensities or, if those values are too carbon-intensive, by utilizing unbundled EACs. In the event that Treasury provides mechanisms for limited volume buffers, it will be important to provide guidance on which of these intensities should be used, as assumptions of intensities will have material impacts on lifecycle emissions, as highlighted in a recent ERM report (Part II) on pgs. 35-38.[54]

d. Deliverability Bounds Should Include Small Adjustments to Account for Actual Transmission Constraints and Opportunities

D1. Regional Bounds

As a potential alternative to the Transmission Needs Study regions, the U.S. Environmental Protection Agency's (EPA's) eGrid sub-regions are a notable viable alternative to ISOs, as they are designed to reflect limitations on transmission exchanges between regions.

D2. Wheeling Between Regions

Flexibility could be incorporated by extending eligibility to wheeling or importing of electricity along with the EACs from a neighboring deliverability region, leveraging Green-e's approach within their electricity standard.[55] Green-e does not stipulate how that wheeling is to be demonstrated; however, there are a few options depending on the neighboring regions.

One option for demonstrating the wheeling of the electricity is through direct transmission capacity rights. If not held directly, there would need to be sufficient "on behalf of" designation. This would be an effective requirement for cross-regional grid transmission operation boundaries. A second option is referencing the relationship of LMPs between neighboring grids. This option would currently be limited to ISO regions due to data availability issues, which will be discussed in a subsequent Section. The use of LMP differentials would also only be appropriate for demonstrating wheeling between deliverability areas within the same ISO as they become less indicative of power flows the farther apart the price points are geographically.

D3. Transmission Line Losses

Electricity lost when transmitted from one point to another, also known as transmission line loss, should be accurately accounted for based on established grid factors and whether the hydrogen production

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[54] ERM, 2024. Assessment of Grid Connected Hydrogen Production Impact Part II Implementation Considerations. https://www.erm.com/globalassets/documents/publications/assessment-of-grid/assessment-of-grid-connected-h2-electrolysis-impact_part-ii_implementation_final.pdf

[55] Green-e, 2023. Renewable Energy Standard for Canada and United States. https://www.greene.org/docs/energy/Green-e%20Standard%20US.pdf

facility is connected at the transmission or distribution level of the grid. Line losses can be easily corrected by procuring additional clean energy instead of supplementing energy lost with fossil fuel-fired electric generating units.[56] Line loss factors are published by utilities and/or ISOs for their service regions and are generally included in electricity invoices. The Energy Information Administration (EIA) also estimates line loss factors. Accounting for line loss factors should be required because they are a component of lifecycle emissions.

e. A Centralized Certificate Tracking System Will Be Needed to Coordinate Across Regions and Avoid Double Counting

E1. Double Counting

Given the range of certificate systems and state/local policies in place, there can be a risk of double counting, where multiple entities substantiate a claim with the same megawatt hour (MWh) of generation, particularly with regards to certificates used for compliance. For this reason, RE100 includes a requirement in its technical criteria for attribute aggregations, or "ownership of all environmental and social attributes associated with generation, and that none of these attributes have been sold off, transferred, or claimed elsewhere."[57] Green-e® has also outlined what they consider to be specific potential double counting risks and justifications for positions they have taken within their standards on eligibility for their product programs, including applicable requirements.[58] These risks are particularly high in the case of certificates being retired on behalf of the customer (either specifically in their name, as the result of participation in a specific program such as a voluntary green tariff, or as a part of a broader customer base), rather than certificates being transferred to and retired directly by a consumer.

Treasury should offer additional clarity in the final rule addressing potential double counting risks, specifically with regard to claim rights in the context of RPS and carbon programs.

E2. Data Management

The variety of tracking systems for certificates throughout the U.S. presents another factor to incorporate in an implementation framework. Development of a centralized governance and management system could provide the necessary incentives to update tracking systems to enable broader imports/exports between systems, particularly between tracking systems which cover areas within the same ISO or balancing area. The larger impact would come from centralized data collection of claimed attributes, which would enable development of comprehensive residual intensity factors that would be used to strengthen Scope 2 emissions reporting more broadly.

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[56] Energy Innovation Policy & Technology LLC, "Smart Design of 45V Hydrogen Production Tax Credit Will Reduce Emissions and Grow the Industry," April 2023, https://energyinnovation.org/publication/smart-design-of-45vhydrogen-production-tax-credit-will-reduce-emissions-and-grow-the-industry/

[57] RE 100 Climate Group & CDP. 2022. RE100 Technical Criteria. https://www.there100.org/sites/re100/files/2022-12/Dec%2012%20-%20RE100%20technical%20criteria%20%2B%20appendices.pdf

[58] Green-e ® Energy. 2023. Green-e ® Renewable Energy Standard for Canada and the United States. https://www.green-e.org/docs/energy/Green-e Standard US.pdf

III. Methane Emissions from Fossil-Based Hydrogen

a. Methane Leakage Poses a Serious Climate Challenge for Fossil-Based Hydrogen Production

Methane emissions from the oil and natural gas supply chain are relevant to hydrogen systems because producing hydrogen using natural gas with carbon capture technologies (known widely as "blue" hydrogen) is a widely proposed strategy to produce low-carbon hydrogen. Natural gas is composed primarily of methane, a potent greenhouse gas with an especially strong warming impact over shorter time periods.

Methane is both a direct and indirect greenhouse gas in that it absorbs infrared radiation but also affects atmospheric chemistry in ways that increase other greenhouse gases (mostly tropospheric ozone and stratospheric water vapor). Compared with carbon dioxide emissions of equal mass, fossil fuel methane's warming potential is 83 times higher over a 20-year period and 30 times higher over a 100-year period.[59] Human-caused methane emissions are responsible for around 30% of today's warming; this translates to half a degree Celsius of warming above preindustrial levels, which is around half of today's net warming when you consider how humans are influencing both warming and cooling of Earth.[60] Human activities have considerably increased the amount of methane in the atmosphere. Atmospheric methane concentrations are now 2.5 times higher than preindustrial levels.[61] Furthermore, methane levels have accelerated since the mid-2000s.[62]

Large-scale buildout of hydrogen production facilities using methane feedstocks is already projected in the US. As shown in Figure 3, EDF analysis of Rystad Energy data suggests that thermochemical (i.e., ATR, SMR and gasification) production methods with fossil fuel feedstocks could make up the majority of new capacity additions in the U.S. over the next decade.[63,64] And more than half of the DOE Regional Clean Hydrogen Hubs that were selected plan to produce hydrogen using natural gas. Protective guardrails under 45V are needed to ensure that these new facilities can only access the tax credit if they are truly achieving low carbon intensities using low-emitting feedstocks and production methods.

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[59] IPCC, WG 1, The Physical Science Basis, at 7-125; https://www.ipcc.ch/report/ar6/wg1/

[60] IPCC AR6, Summary for Policymakers (2021), at pg. 13. https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_SPM.pdf

[61] NASA. (n.d.). Methane | Vital Signs – Climate change: Vital signs of the planet. Climate Change: Vital Signs of the Planet. https://climate.nasa.gov/vital-signs/methane/

[62] NASA. (n.d.). Methane | Vital Signs – Climate change: Vital signs of the planet. Climate Change: Vital Signs of the Planet. https://climate.nasa.gov/vital-signs/methane/

[63] EDF analyzed information on proposed U.S. hydrogen production projects from Rystad Energy's proprietary HydrogenCube database to identify proposed projects and anticipated production capacity by technology type. Capacity was totaled for all current U.S. project proposals in the database, including those at the conceptual, application, final investment decision and under construction stages, and including projects of commercial, demonstration, pilot, or unknown scale. Data provided in Appendix C.

[64] Thermochemical processes include natural gas reforming, biomass gasification, biomass-derived liquid reforming, and solar thermochemical hydrogen. DOE Hydrogen and Fuel Cell Technologies Office, n.d. "Hydrogen Production Processes." https://www.energy.gov/eere/fuelcells/hydrogen-production-processes

Figure 3. Technology breakdown of announced U.S. hydrogen production projects slated to come online between 2020 and 2035[65]

New U.S. Hydrogen Capacity by 2035							
	ATR w/ CCS	Gasification w/ CCS	SMR w/ CCS	Electrolysis	Waste	SMR	Total
Capacity (thousand tonnes per year)	4220	319	4029	4477	268	1280	14592
Percentage	29%	2%	28%	31%	2%	9%	100%

The oil and gas supply chain—upstream production, to transportation, to local distribution—is responsible for nearly half of the nation's methane emissions from human activities,[66] and one quarter of human-caused methane emissions globally.[67, 68] For blue hydrogen systems, feedstock methane emissions are often the largest contributor to lifecycle greenhouse gas emissions, and studies show that high methane leakage rates (combined with hydrogen leakage) can make blue hydrogen applications worse for the climate in the near-term than fossil fuel alternatives.[69] Therefore, it is critical to accurately account for methane emissions associated with hydrogen production.

b. GREET's Default Methane Leak Rate Must Be Updated, Including by Incorporating Basin-Specific Estimates

As proposed, the methane leak rate associated with oil and gas production is considered "background data" within GREET—meaning it cannot be modified by the user. The current 45VH2-GREET model version, which is used to determine tax credit eligibility, assumes a 0.9% national average leak rate of methane, which is not representative of actual emissions.

GREET's nationwide default rate currently excludes emissions from wells that produce and market both oil and gas (i.e., "co-producing wells"), which produce gas that is fed into the natural gas supply chain that hydrogen producers will use as a feedstock. It also scales top-down emissions measurement data to EPA's Greenhouse Gas Inventory (GHGI) for natural gas systems, which shows emissions decreasing over

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[65] Data extracted by EDF in July 2023 from Rystad Hydrogen Cube Browser version 2.6.14.

[66] U.S. EPA. Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2018 (2020) replacing EPA's oil and gas methane emissions data with Alvarez et al. 2018 data.

[67] Ocko, IB et al., Acting rapidly to deploy readily available methane mitigation measures by sector can immediately slow global warming, Environ. Res. Lett., 16, 054042 (2021), https://iopscience.iop.org/article/10.1088/1748-9326/abf9c8

[68] Alvarez et al., Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain, 361 Science 186 (2018), https://doi.org/10.1126/science.aar7204

[69] Sun, T, et al, Climate Impacts of Hydrogen and Methane Emissions Can Considerably Reduce the Climate Benefits across Key Hydrogen Use Cases and Time Scales, Environ. Sci. Technol. (2024), https://pubs.acs.org/doi/10.1021/acs.est.3c09030; and Bauer et al., On the Climate Impacts of Blue Hydrogen Production, Sustainable Energy & Fuels (2022), https://pubs.rsc.org/en/content/articlelanding/2022/se/d1se01508g

time, especially for the production segment – whereas measurement data have not shown such a decline;[70] and it does not include recent data showing that distribution emissions are significantly higher than EPA estimates.[71] Appendix A explains these methodological concerns in more detail.

In the same way that emissions from electricity generation vary by grid region, methane emissions from oil and gas production vary substantially by basin. This variation in leak rates strongly affects the actual lifecycle emissions from hydrogen production using natural gas as a feedstock. For example, the total methane leakage rates for the Permian basin and the Uinta basin have been measured at around 3-4% and 6-8%, respectively.[72,73,74,75]A hydrogen producer sourcing natural gas from one of these basins would therefore have a far higher lifecycle emissions intensity than would be reflected by using the 0.9% default leak rate in 45VH2-GREET, even when adjusting for oil v gas wells. Reliance on a single nationwide default methane leak rate obscures these large differences between basins and prevents full and accurate accounting of greenhouse gas emissions burdens of downstream uses. In fact, in a 2022 presentation on the GREET model for hydrogen life cycle GHG emissions, Argonne assumed a 0.7-3.0% methane leak rate, which is more reflective of the range of measured data from across production basins.[76] See Appendix B for more information on developing basin-specific values.

To accurately capture the climate impact of blue hydrogen production and ensure 45V drives clean hydrogen production as intended, it is critical that GREET include basin- (or sub-basin-) specific upstream methane values based on measured data. Numerous publicly available studies have measured methane leak rates in basins across the U.S. using ground-based measurements, aircraft measurements, or satellite data. Using measurement-informed, basin-specific leak rates is the most scientifically rigorous and accurate way of accounting for upstream methane emissions in a lifecycle model like GREET. For example, MethaneSAT is an upcoming satellite capable of both broad coverage, high spatial resolution and high precision. As such, data from the satellite will soon deliver a greater understanding of how

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[70] Lu, X., et al. (2023). Observation-derived 2010-2019 trends in methane emissions and intensities from US oil and gas fields tied to activity metrics. Proceedings of the National Academy of Sciences of the United States of America, 120(17). https://doi.org/10.1073/pnas.2217900120

[71] Weller, Z. D., Hamburg, S. P., & Von Fischer, J. C. (2020). A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems. Environmental Science & Technology, 54(14), 8958–8967. https://doi.org/10.1021/acs.est.0c00437

[72] Lu, X., et al. (2023b). Observation-derived 2010-2019 trends in methane emissions and intensities from US oil and gas fields tied to activity metrics. Proceedings of the National Academy of Sciences of the United States of America, 120(17). https://doi.org/10.1073/pnas.2217900120

[73] Zhang, Y., et al. (2020). Quantifying methane emissions from the largest oil-producing basin in the United States from space. Science Advances, 6(17). https://doi.org/10.1126/sciadv.aaz5120

[74] Lin, J. C., et al. (2021). Declining methane emissions and steady, high leakage rates observed over multiple years in a western US oil/gas production basin. Scientific Reports, 11(1). https://doi.org/10.1038/s41598-021-01721-5

[75] Note that for basins that produce oil as well as gas (e.g., Permian, Uinta), these leakage rates are not directly comparable to the 0.9% leakage rate currently used in GREET since the total leakage rate in each basin must be allocated between oil, gas, and co-producing wells.

[76] Argonne National Laboratory. (2022, June). Greet® Model For Hydrogen Life Cycle GHG Emissions. Retrieved February 19, 2024, from https://www.energy.gov/sites/default/files/2022-06/hfto-june-h2iqhour-2022-argonne.pdf

emissions are characterized across oil & gas production basins/sub basins, allowing for determination of leak rates at various spatial and temporal scales.

Treasury should kick-start a joint agency process to update the model annually and support a move to basin-specific leak rates that are based on recent and reliable measurement data. Treasury should also ensure that any nationwide average leak rate is similarly updated annually and accounts for emissions from co-producing wells (which are currently not included in the nationwide 0.9% leak rate)**.**

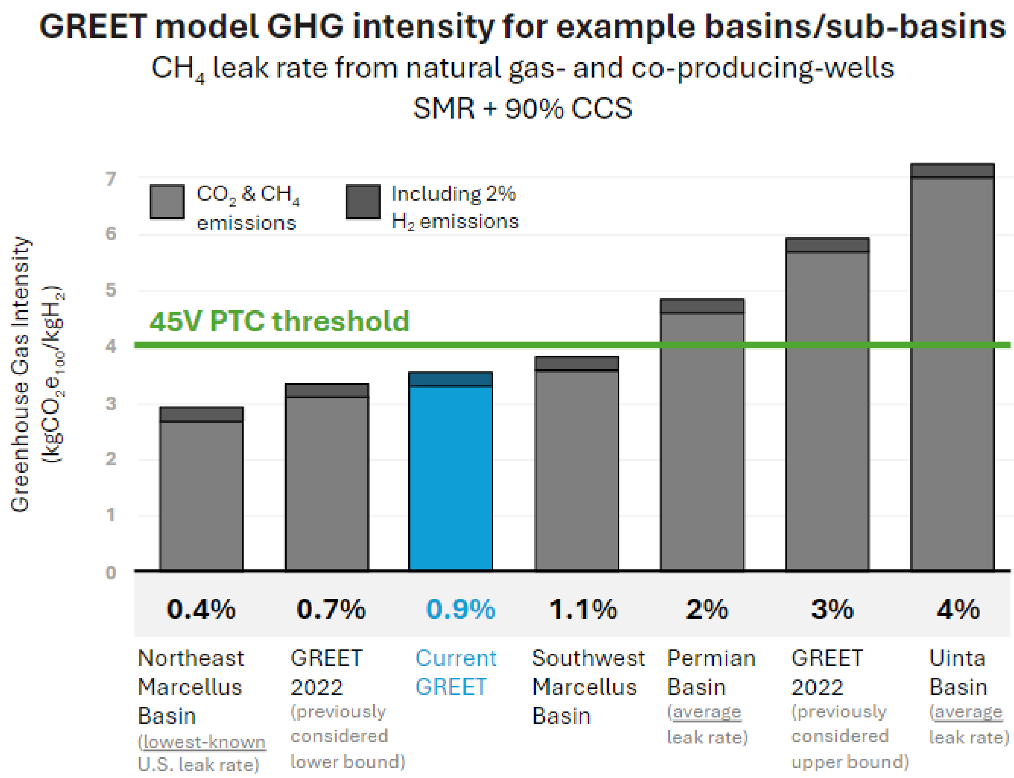
Ultimately, 45VH2-GREET should require the use of basin-specific leak rates, relying on a nationwide average only in cases where basin-specific leak rates are infeasible. Treasury, as the agency responsible for determining the appropriate version of GREET under 45V[77] and for ensuring 45V is accurately implemented based on lifecycle greenhouse gas emissions, must ensure GREET's methane assumptions are updated each year to reflect the best available methods and data.

c. Methane Leakage Assumptions Have a Significant Effect on 45V Eligibility and Overall Climate Impact

To show the significance of the choice of methane leakage rate, we modified the background methane leak rate within 45VH2-GREET in order to calculate lifecycle GHG emissions (carbon dioxide and methane) associated with hydrogen production from a standard SMR facility, assuming 90 or 95% carbon dioxide is captured and using the metric in GREET with a 100-year time horizon (GWP100). The methane leakage rate considerably affects the emissions per unit of hydrogen produced as well as the eligibility for the tax credit, as shown in Figures 4a and 4b.

[77] Section 13204 (45V) of the Inflation Reduction Act, which falls under the Committee on Finance, states that "the Secretary [of Treasury]" has jurisdiction over a successor model to GREET: "*The term "lifecycle greenhouse gas emissions" shall only include emissions through the point of production (well-to-gate), as determined under the most recent GREET model developed by Argonne National Laboratory, or a successor model (as determined by the Secretary)."*

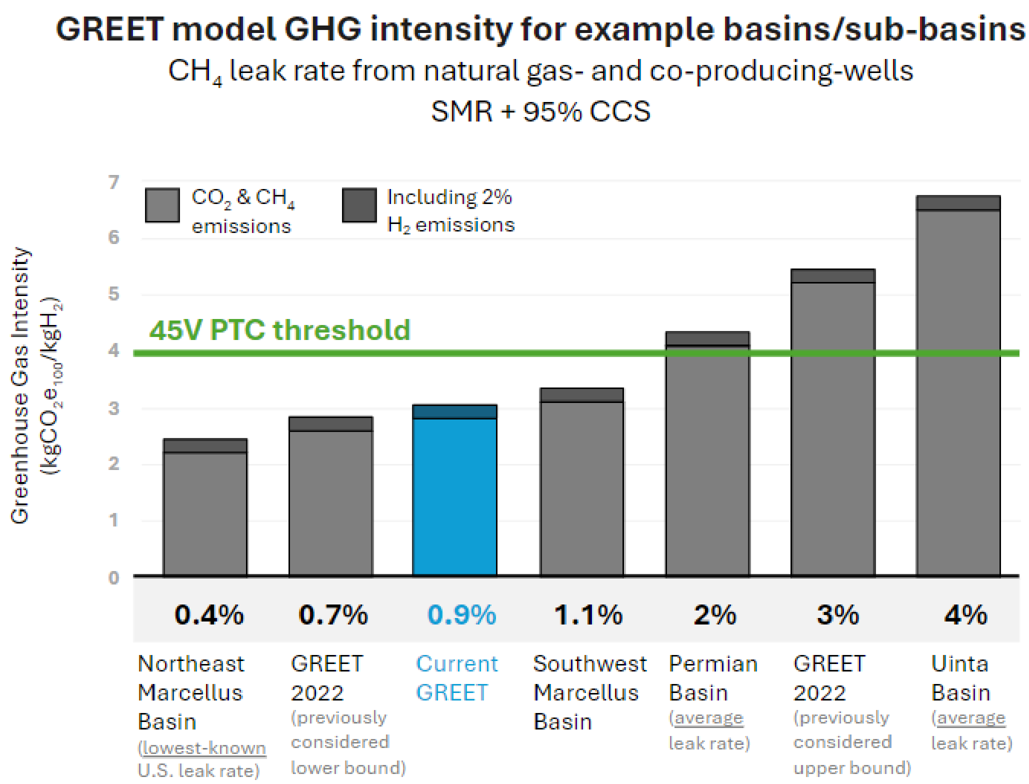
Figure 4a. GREET Model GHG Intensity for Example Basins/Sub-Basins – 90% CCS. Note that average basin emissions are shown for the Permian and Uinta basins, and it is likely that sub-basins will have a higher value.[78,79]



[78] Methane leakage rates are illustrative to demonstrate the extent of geographic variability. Calculations use 45VH2-GREET 2023 and GWP100 values; using GWP20 would significantly increase the emissions intensity of all data points. CCS is assumed to be powered by zero-emissions renewable electricity.

[79] 0.4% for NE Marcellus from Barkley et al. 2023 (0.3% for production through transmission plus 0.1% distribution); 0.7% and 0.3% from Argonne 2022; 2.0% for average Permian Basin from EDF calculations of Zhang et al. 2020 data (1.9% for production through transmission and 0.1% distribution), including allocated emissions from co-producing wells based on energy content of natural gas vs. oil production; 1.1% for SW Marcellus from Ren et al. 2019; 4% for average Uinta Basin from EDF calculations of Lin et al. 2021, including allocated emissions from co-producing wells based on energy content of natural gas vs. oil production.

Figure 4b. GREET Model GHG Intensity for Example Basins/Sub-Basins – 95% CCS. Note that average basin emissions are shown for the Permian and Uinta basins, and it is likely that sub-basins will have a higher value. [80, 81]



Relying on the default national average can easily undercount a project's emissions by 40% or more. This is particularly problematic for hydrogen produced with gas sourced from the Permian and similar high-emitting basins due to the high leakage rate, where projects could appear eligible for tax credits even though they should not be. For example, assuming a 90% CC rate, GWP100 values, zero-emissions electricity, and no hydrogen emissions, using GREET's default national average yields a GHG intensity of 3.3 $kgCO_2e/kgH_2$, which would be eligible for a \$0.60 tax credit. Using a more realistic, yet still conservative estimate of 2% for the Permian basin natural gas methane emissions yields a GHG intensity

[80] Calculations use 45VH2-GREET 2023 and GWP100 values; Using GWP20 would significantly increase the emissions intensity of all data points given that methane's GWP20 value is three times higher than its GWP100 value. CCS is assumed to be powered by zero-emissions renewable electricity.

[81] 0.4% for NE Marcellus from Barkley et al. 2023 (0.3% for production through transmission plus 0.1% distribution); 0.7% and 0.3% from Argonne 2022; 2.0% for average Permian Basin from EDF calculations of Zhang et al. 2020 data (1.9% for production through transmission and 0.1% distribution), including allocated emissions from co-producing wells based on energy content of natural gas vs. oil production; 1.1% for SW Marcellus from Ren et al. 2019; 4% for average Uinta Basin from EDF calculations of Lin et al. 2021, including allocated emissions from co-producing wells based on energy content of natural gas vs. oil production.

of 4.6 $kgCO_2e/kgH_2$, which would be ineligible.[82] At a project level, the Gulf Coast (also known as HyVelocity) H2 Hub, which is projected to produce 0.712 million tons of H_2 by 2030, could emit nearly 800,000 tons of GHG emissions per year (based on GWP100) that would go largely unrecognized by the lifecycle calculation – the equivalent of more than 170,000 cars on the road.[83]

This is particularly important when combined with potential biomethane accounting provisions. As discussed in section V, if carbon-negative biomethane offsets are allowed, this could easily make dirty forms of blue hydrogen eligible for the top $3 tax credit tier.

d. Basin and Sub-Basin Methane Leak Rates Should Be Presented as Fixed Drop-Down Assumptions within GREET that Cannot be Replaced with Bespoke Inputs like Differentiated Gas Certifications

As proposed, the methane leak rate associated with oil and gas production is considered "background data" within 45VH2-GREET—meaning it cannot be modified by the user for the purposes of qualifying for 45V tax credits. As discussed above, we recommend that the national average methane leak rate be updated to reflect the best available and most recent data, and that Treasury move toward basin-specific leak rates that would automatically populate within 45VH2-GREET based on the basin from which the user sources gas.[84]

Treasury seeks comment on the "conditions, if any, under which the methane loss rate may in future releases become foreground data (such as certificates that verifiably demonstrate different methane loss rates for natural gas feedstocks, sometimes described as responsibly sourced natural gas)." Treasury specifically seeks comment on the "readiness of verification mechanisms that could be utilized for certain background data in 45VH2-GREET if it were reverted to foreground data in future releases."

We agree with Treasury that there are currently insufficient verification mechanisms for the methane loss rate to become foreground data and allow the use of bespoke inputs based on differentiated gas certifications (sometimes referred to as "responsibly sourced gas"). We therefore strongly support Treasury's proposal to retain the methane loss rate as background data, subject to our recommendations above to require use of basin-specific loss rates (i.e., as a drop-down menu of basins, similar to how electricity grids can be selected). Below, we first explain why Treasury cannot accurately allow the option to choose bespoke inputs or a default leak rate, and second, why certification schemes cannot currently be relied upon under 45V.

[82] Calculated using 45VH2-GREET model; assumes no hydrogen emissions.
[83] Assumes a typical passenger vehicle emits 4.6 metric tons of CO2e per year. EPA, n.d. "Greenhouse gas emissions from a typical passenger vehicle," https://www.epa.gov/greenvehicles/greenhouse-gas-emissions-typical-passenger-vehicle#:~:text=typical%20passenger%20vehicle%3F-,A%20typical%20passenger%20vehicle%20emits%20about%204.6%20metric%20tons%20of,around%2011%2C500%20miles%20per%20year.
[84] *See, e.g.*, Department of Energy, *Guidelines to Determine Well-to-Gate Greenhouse Gas (GHG) Emissions of Hydrogen Production Pathways using 45VH2-GREET 2023* at 22 (December 2023), https://www.energy.gov/sites/default/files/2023-12/greet-manual_2023-12-20.pdf.

e. Treasury Cannot Provide Optionality for Users to Choose between Bespoke Methane Leak Rates or Background Methane Leak Rates

An option to choose bespoke inputs as an alternative to a default, nationwide average leak rate (or basin-specific drop-down rates) would lead to inaccuracies in methane emission estimates. Because 45VH2-GREET relies on one average nationwide methane loss rate (or, ideally, basin-specific loss rates as we recommend), allowing an option to include a bespoke methane loss rate as a substitute (i.e., an option to supply foreground data) would make the default methane loss rate inaccurate for all other users. Put another way, the default methane loss rate in GREET is an average that covers all methane emissions from the U.S. natural gas supply chain, including those falling under differentiated gas certification schemes. If some users rely on their own bespoke methane loss rates, the average loss rate (or basin-specific loss rate) would need to be adjusted for all other users to account for the subtraction of those emissions in order to maintain accuracy (sometimes called "conservation of mass").

To address this and maintain accuracy within GREET would lead to significant complexities. For example, if the average nationwide loss rate were 1%, but half of users in 45VH2-GREET supplied bespoke inputs of 0.5% based on differentiated gas certifications, the 1% default assumption would no longer be accurate. The 1% default would need to be recalculated, subtracting out the portion of production and emissions covered by the bespoke inputs. If the default loss rate were not adjusted, it would result in an inaccurate downward ratcheting of the total methane emissions. Constant reassessing of the default would be required, and this task would become even more complex with a move toward basin-specific defaults.[85]

In addition to the scientific complexities, there are strong policy reasons to not permit this type of optionality. If users could choose between a default or a bespoke input, only those with emissions below the average default would use bespoke inputs, while others, even if they had data or certifications showing their emissions are higher, would simply opt for the default. A claimant might even seek to use bespoke inputs for only the portion of their gas where a certification showed emissions lower than the default, discarding certifications showing higher emissions for another portion of their gas and instead relying on the default. As a result of inaccurate accounting of upstream methane emissions, taxpayers would subsidize hydrogen produced with actual carbon intensities higher than reflected in 45VH2-GREET.

f. Treasury Should Not Change the Methane Loss Rate to Foreground Data because Existing Differentiated Gas Certification Schemes Have Limited Coverage and Verification Mechanisms

Natural gas certification schemes vary widely in coverage, participation, integrity, and verification and monitoring requirements. Certified or differentiated natural gas is purported to have been produced and transported via methods that meet certain environmental, social, and methane emission best practices, and according to the supplier, has undergone assessment by an independent third party to determine that the gas is produced under specified best practices. Because there are no established criteria for differentiated gas, there is considerable uncertainty around the credibility of purported "certification" of

[85] This issue would exist even if the bespoke inputs are not based on differentiated gas certifications--for example if users could rely on operator-specific emissions reported to EPA's GHGRP.

the methane intensity of gas.[86] There is significant variability between existing certifiers on the critical issues set forth below. As of now, none of the existing certification regimes are sufficiently robust to be included in a regulatory framework.[87]

The three primary issues with relying on existing certification schemes in regulatory contexts are explained below.

- **Lack of measurement, reporting and verification (MRV) standards:** Peer-reviewed studies using direct methane measurements continue to demonstrate that actual emissions are significantly higher than self-reported estimates contained in official inventories.[88] Without comprehensive direct measurement and independent verification (MRV) and transparency around intensity calculations, there is no way for natural gas producers, certifiers or customers to know what the actual emissions intensity of the certified gas production is and whether it actually meets the differentiated gas certification standards. However, some certifiers currently certify gas as having a low methane intensity based largely on emission factors that are not based on direct methane measurements. Others rely heavily on continuous methane monitors, which, according to recent studies, are of questionable utility when it comes to quantifying emissions.

- **Limited participation:** High-integrity certification could incentivize some operators to reduce emissions. However, participation in voluntary certification schemes is up to individual industry actors. There is therefore a high risk that only a few already low-emitting operators would choose to participate. This would imply limited additional emission reductions from certification programs.

- **Cherry-picking within company portfolios:** The potential for emissions reductions is further diminished by limited coverage of participating companies. This is because many certification schemes allow participating operators to choose to only certify gas from facilities that already have good emissions performance. Often, different production facilities have significantly different emissions levels based on geology and other factors outside of the operator's control, as well as other extraneous factors such as state or local regulations or facility age. Since certification is voluntary, companies are more likely to choose to certify facilities that are already

[86] *See* Lackner & Mohlin, Certification of Natural Gas With Low Methane Emissions: Criteria for Credible Certification Programs, EDF (May 2022), https://blogs.edf.org/energyexchange/wp-content/blogs.dir/38/files/2022/05/EDF_Certification_White-Paper.pdf.

[87] Efforts are ongoing to update methane emissions reporting under subpart W of EPA's Greenhouse Gas Reporting Program (GHGRP), but existing reporting requirements have been shown to significantly underestimate actual emissions. The GHGRP is also limited in coverage, applying only to larger facilities, and lacks monitoring and verification requirements. It would therefore be inappropriate at this point to allow the use of bespoke inputs based on emissions reported to subpart W.

[88] *See, e.g.*, Rutherford et al., *Closing the methane gap in US oil and natural gas production emissions inventories,* 12 Nature Comms. 4715 (2021), https://www.nature.com/articles/s41467-021-25017-4 ("In the United States, recent synthesis studies of field measurements of CH_4 emissions at different spatial scales are ~1.5–2× greater compared to official greenhouse gas inventory (GHGI) estimates, with the production-segment as the dominant contributor to this divergence.")

low-emitting due to such factors. This would imply minimal or even zero additional emission reductions from certification programs.

In the context of 45V and 45VH2-GREET, these problems are amplified. First, given the amount of the tax credit, allowing differentiated gas certifications to be used to reduce the lifecycle emissions of a hydrogen production pathway would exacerbate manipulation of these schemes through tactics like cherry-picking. Second, with the multitude of certification programs emerging, it would be difficult or impossible for Treasury to vet each and determine its suitability. Treasury does not have the resources to engage in this task, which would result in questionable certifications being used to support claiming the tax credit, at the expense of the American taxpayer. Third, regulatory requirements, such as EPA's recently finalized methane standards for the oil and gas sector and the IRA's waste emissions charge will drive uniform, nationwide methane reductions, and operators should not be able to profit from these required reductions through differentiated gas certifications.

For the reasons described above, we support Treasury's proposal to disallow differentiated gas certifications as foreground data within 45VH2-GREET. Such certifications are not sufficiently verifiable and lack the coverage that would be necessary to replace average default leak rates. Importantly, allowing these certifications as an alternative to default methane loss rates within 45VH2-GREET would make the default average methane loss rate inaccurate by removing lower emitting gas that is otherwise accounted for in the average loss rate. Treasury therefore cannot provide users with the option to use default methane loss rates or bespoke inputs based on differentiated gas certifications without undertaking complex and ongoing updates to the default loss rates.

g. *Greenhouse Gas (GHG) Intensities Should Be Reported for Both Near- and Long-Term Time Horizons*

Both methane and hydrogen (discussed in Section VII) emissions impact the climate mostly over the first couple of decades after they are emitted.[89, 90, 91] Their short atmospheric residence times (a decade and a few years on average, respectively) combined with effects on atmospheric chemistry that influence other greenhouse gases with short residence times, yield warming effects that are short-lived. This means that emissions of hydrogen and methane primarily affect near-term warming, but do not commit to considerable warming in the long-term unless the emissions continue.

However, the GREET model uses a metric that weights emissions of non-carbon dioxide (CO_2) gases based on the long-term impacts of a one-time pulse of their emissions relative to that from CO_2 (CO_2e

[89] Forster, P. et al.: The Earth's Energy Budget, Climate Feedbacks, and Climate Sensitivity. In Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, and B. Zhou (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 923–1054, doi: 10.1017/9781009157896.009

[90] Sand, M. et al. A multi-model assessment of the Global Warming Potential of hydrogen. Commun Earth Environ 4, 203 (2023). https://doi.org/10.1038/s43247-023-00857-8

[91] Warwick, N. J. et al.: Atmospheric composition and climate impacts of a future hydrogen economy, Atmos. Chem. Phys., 23, 13451–13467, https://doi.org/10.5194/acp-23-13451-2023

with 100-year time horizon). For hydrogen and methane, this means accounting for decades of time where their pulse of emissions is no longer influencing the atmosphere. The result is that their warming effects during the time periods that they are affecting the climate are masked.

In order for deployment of hydrogen systems to be an effective decarbonization strategy, it is important to consider climate impacts of specific hydrogen initiatives in both the near- and long-term. Both methane and hydrogen's warming potency relative to carbon dioxide is around three times higher over a 20-year period than a 100-year period.[92, 93, 94] Focusing only on the long-term will mask the strong near-term impacts of hydrogen and methane emissions, which can lead to suboptimal climate outcomes and even perverse outcomes in the coming decades.[95,96,97]

Given that GREET already uses the GWP metric in its calculations of overall GHG intensity, it is relatively straightforward to include multiple time horizons in the GWP calculations by using a different value for weighting non-CO_2 emissions. We recommend the GREET model should be updated to allow for calculation of CO_2e in both 20 and 100-year time horizons given existing science that suggests it adequately captures both near- and long-term climate impacts.[98,99] To align with congressional understanding when passing 45V, GWP100 should be used to determine eligibility, but GWP20 values (and methane leakage rates themselves) should also be reported to Treasury for informational purposes so producers and policymakers can understand the hydrogen project's full climate impact.

IV. Carbon Capture and Sequestration

EDF supports the approach taken in 45VH2-GREET to account for carbon capture and sequestration rates from SMR and ATR facilities. By requiring users to input actual volumes of carbon sequestered,

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[92] Forster, P. et al.: The Earth's Energy Budget, Climate Feedbacks, and Climate Sensitivity. In Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, and B. Zhou (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 923–1054, doi: 10.1017/9781009157896.009.

[93] Sand, M. et al. A multi-model assessment of the Global Warming Potential of hydrogen. Commun Earth Environ 4, 203 (2023). https://doi.org/10.1038/s43247-023-00857-8

[94] Warwick, N. J. et al.: Atmospheric composition and climate impacts of a future hydrogen economy, Atmos. Chem. Phys., 23, 13451–13467 (2023), https://doi.org/10.5194/acp-23-13451-2023

[95] Sun, T, et al, Climate impacts of hydrogen and methane emissions can considerably reduce the climate benefits across key hydrogen use cases and time scales, Environ. Sci. Technol. (2024), https://pubs.acs.org/doi/10.1021/acs.est.3c09030

[96] Sun T, et al. Path to net zero is critical to climate outcome. Sci Rep. 11, 22173 (2021), https://www.nature.com/articles/s41598-021-01639-y

[97] Ocko, I. B. and Hamburg, S. P.: Climate consequences of hydrogen emissions, Atmos. Chem. Phys., 22, 9349–9368 (2022), https://doi.org/10.5194/acp-22-9349-2022

[98] Ilissa B. Ocko et al., Unmask temporal trade-offs in climate policy debates. Science 356, 492-493 (2017). DOI:10.1126/science.aaj2350

[99] Cohen-Shields et al., Distortion of sectoral roles in climate change threatens climate goals, Front. Clim. 5 (2023), https://www.frontiersin.org/articles/10.3389/fclim.2023.1163557/full

consistent with the amounts reported to the GHGRP, the model is able to reflect actual capture rates. It would be inappropriate to rely on percentage capture rates given that facilities often capture at rates lower than their nameplate efficiencies, don't run their CCS technologies constantly, and/or don't control emissions from all processes at a facility.[100, 101] Treasury should preserve this methodology of calculating CCS rate. It should ensure that these volumes are fully sequestered rather than utilized and reported on an annual basis.

V. Biomethane

Treasury has stated that it intends to provide rules addressing hydrogen production pathways using biomethane, sometimes referred to as renewable natural gas (RNG). Biomethane can be produced from many different sources, including landfills, wastewater treatment plants, and livestock. Some sources of biomethane capture preexisting sources of methane emissions for productive use, but biomethane can also be produced from new organic source materials that would otherwise not produce methane (e.g., purpose-grown crops, waste wood).[102] In these cases, methane released during production, processing, and end-use applications would result in a net increase in climate pollution.[103] In addition, SMR with landfill gas and potential CCS is already included as an eligible pathway in 45V, and biomethane from livestock farms is under consideration, including via book-and-claim systems. Livestock biomethane is also seen by some hydrogen producers as a potential offsetting mechanism for dirtier fossil methane feedstocks, given that this type of biomethane can receive very low and even negative emissions-intensity scores in certain models (e.g., California's LCFS).

In general, many of the beneficial uses of biomethane—hard-to-electrify sectors of the economy such as heavy industry that needs combustion fuel—are also the most beneficial uses of hydrogen.[104] Biomethane may be more efficiently used directly for hard-to-electrify applications, rather than to produce hydrogen for those same uses. Thus, Treasury should exercise caution when identifying pathways for the use of biomethane under 45V.

Specifically, Treasury should:

- Limit eligibility of landfill biomethane to only that generated from waste already in landfills as of IRA passage to avoid incentivizing additional landfilling of organic waste;

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[100] Bauer, C., et al. (2022). On the climate impacts of blue hydrogen production. Sustainable Energy and Fuels, 6(1), 66–75. https://doi.org/10.1039/d1se01508g

[101] Pembina Institute. (2021, August). Carbon intensity of blue hydrogen production. Retrieved February 19, 2024, from https://www.pembina.org/reports/carbon-intensity-of-blue-hydrogen-revised.pdf

[102] *See* Joe Rudek & Stefan Schwietzke, *Not all biogas is created equal*, EDF Energy Exchange (Apr. 15, 2019), available at https://blogs.edf.org/energyexchange/2019/04/15/not-all-biogas-is-created-equal/.

[103] *See* Mark Omara & Joe Rudek, *Careful accounting is critical to assessing the climate benefits of biomethane*, EDF Energy Exchange (Mar. 24, 2021), available at https://blogs.edf.org/energyexchange/2021/03/24/careful-accounting-is-critical-to-assessing-the-climate-benefits-of-biomethane/.

[104] *See, e.g.*, Samantha Gross, The Challenge of Decarbonizing Heavy Industry at p16-17, Brookings Institute (June 2021), https://www.brookings.edu/wp-content/uploads/2021/06/FP_20210623_industrial_gross_v2.pdf.

- Allow for biomethane from livestock farms to be an eligible 45V pathway, subject to strong climate protections;
- Disallow the use of book-and-claim systems for biomethane feedstocks at this stage and first convene a joint agency group to evaluate an appropriate standard for such systems; in the meantime, biomethane used for hydrogen production should only be "direct use" through a direct, exclusive pipeline connection;
- Prohibit carbon-negative biomethane scores from being used to offset the positive emissions associated with hydrogen production (e.g., by setting the lowest allowable biomethane GHG intensity scores at zero);
- Require net methane leakage from livestock biomethane to be measured using monitoring sensors and factored into GREET climate impact assessments with dual GWP time horizons (20 and 100 years);
- Require livestock farms to adopt nutrient management plans and other best practices to reduce ammonia losses and other environmental impacts from land application and digested manure storage or treatment;
- Require landfills to meet minimum gas collection efficiency requirements and other best management practices to limit fugitive methane emissions;
- Adopt best practices for feedstock eligibility and emissions accounting; and
- Require verification of available productive use for biomethane through on-site, third-party inspections.

a. Biomethane Relevance for 45V

A1. Methane Emissions from Landfills Represent a Major Climate and Public Health Challenge Which Is Best Dealt with through Diversion, Composting, and Best Practices for Gas Collection

More than 70% of current biomethane production comes from municipal solid waste (MSW) landfills.[105] However, landfills only capture some of the methane that they generate. These fugitive emissions from landfills are significant and avoidable: by (1) preventing disposal of organic waste in landfills through waste prevention and organics recycling programs and (2) implementing best management practices to boost gas collection efficiency at the landfill. Incentivizing energy production at landfills puts more sustainable waste management pathways at a relative disadvantage and provides no guardrails to minimize methane leakage.

[105] Department of Energy, *FOTW #1242, June 13, 2022: Production Capacity of Renewable Natural Gas Projects was 574 million Diesel-Gallon Equivalents in 2021* (June 13, 2022), https://www.energy.gov/eere/vehicles/articles/fotw-1242-june-13-2022-production-capacity-renewable-natural-gas-projects.

As noted earlier in these comments, methane is a potent greenhouse gas that traps heat in the atmosphere at more than 80 times the rate of CO_2 on a 20-year scale.[106] Around 30% of today's warming is driven by methane emissions from human activities.[107]

In the United States, municipal solid waste (MSW) landfills are the third-largest source of human-related methane emissions, accounting for 14% of the total.[108] In 2021, U.S. MSW landfills emitted an estimated 3.7 million metric tons of methane according to EPA's inventories, or about 295 million metric tons of carbon dioxide equivalent (MMT CO_2e) on a 20-year time horizon. That's equivalent to the annual greenhouse gas pollution from 66 million gas-powered passenger vehicles or 79 coal-fired power plants.[109]

Food waste is the single most landfilled material, responsible for an estimated 58% of fugitive methane emissions from U.S. MSW landfills.[110] Diverting food waste to anaerobic digesters can better capture biogas and produce biomethane for productive uses. As the organic fraction of this waste – which includes food waste, yard waste, and paper – decomposes without oxygen in the landfill, it generates methane.

Data reported voluntarily to EPA's Landfill Methane Outreach Program (LMOP) shows that 47% of reporting landfills (1,229 of 2,636) have a gas collection system in place to capture a portion of their methane emissions and route it to a flare for destruction or to a beneficial use project. Per LMOP, 487 of these landfills have energy projects as of July 2023, utilizing captured methane to generate electricity or upgrading it to biomethane for pipeline injection or transportation fuel.[111] Importantly, collection and control systems cannot capture all generated methane, as they are not installed in all areas of the landfill, experience downtime, and can malfunction. Large amounts of methane escape from landfills into the atmosphere, diffusely through the landfill surface and in more concentrated hot spots, often due to cracks or gaps in the landfill cover, leaking gas wells, or the exposed working face. Landfill gas collection efficiency can vary widely by site, due in part to design and operational factors. While landfill

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[106] Forster, P., et al. 2007: Changes in Atmospheric Constituents and in Radiative Forcing. In: Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change [Solomon, S., et al]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. https://www.ipcc.ch/site/assets/uploads/2018/02/ar4-wg1-chapter2-1.pdf

[107] Methane: A crucial opportunity in the climate fight. (n.d.). Environmental Defense Fund. https://www.edf.org/climate/methane-crucial-opportunity-climate-fight

[108] "Basic Information about Landfill Gas," U.S. Environmental Protection Agency, August 2023, https://www.epa.gov/lmop/basic-information-about-landfill-gas.

[109] Preet Bains et al., *Trashing the Climate: Methane from Municipal Landfills*, Environmental Integrity Project, May 2023, https://environmentalintegrity.org/reports/trashing-the-climate/.

[110] Max Krause et al., *Quantifying Methane Emissions from Landfilled Food Waste,* U.S. Environmental Protection Agency Office of Research and Development, October 2023, https://www.epa.gov/system/files/documents/2023-10/food-waste-landfill-methane-10-8-23-final_508-compliant.pdf.

[111] "LMOP Landfill and Project Database," U.S. Environmental Protection Agency, August 2023, https://www.epa.gov/lmop/lmop-landfill-and-project-database.

emissions models often assume a default collection efficiency of 75%, studies show instances where collection efficiency can be much lower.[112, 113]

Furthermore, recent airborne methane surveys suggest that landfill emissions may be higher and more persistent than previously expected.[114] Since 2016, airborne surveys conducted by Carbon Mapper and partners have detected high-emitting methane plumes at more than 200 U.S. landfills across 29 states.[115] In California, Carbon Mapper's flyovers found that a subset of landfills were the state's largest methane emitters (41%), with higher observed emission rates than the oil and gas or agriculture sectors.[116] Detectable methane plumes at California landfills often reached 1,000 kg/hr, ten times what EPA considers to be a "super-emitter" in the oil and gas sector.[117]

A study under review in *Atmospheric Chemistry and Physics* uses observations from the TROPOMI satellite instrument to quantify methane emissions from 70 landfills reporting to GHGRP across the contiguous United States. The authors find a median 77% increase in observed emissions (13 Gg/a), compared to reported emissions (7.2 Gg/a).[118] The authors attribute the discrepancy to two main factors: 1) over-estimated recovery efficiencies at facilities with gas collection systems and 2) under-accounting of site-specific operational changes across facilities.[119]

Landfill emissions also threaten nearby communities. Beyond climate-warming methane emissions, landfills release harmful co-pollutants that adversely impact the health and well-being of nearby communities. Landfill gas contains hazardous air pollutants, precursors to ozone and particulate matter, and odor nuisance compounds. These pollutants contribute to urban smog and impact human health

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[112] James Hanson and Nazil Yesiller, *Estimation and Comparison of Methane, Nitrous Oxide, and Trace Volatile Organic Compound Emissions and Gas Collection System Efficiencies in California Landfills Final Report*, Prepared for: The California Air Resources Board and The California Department of Resources Recycling and Recovery, March 25, 2020, https://ww2.arb.ca.gov/resources/documents/landfill-gas-research.

[113] Nickolas J. Themelis and A.C. (Thanos) Bourtsalas, "Methane Generation and Capture of U.S. Landfills," *Journal of Environmental Science and Engineering A* 10 (2021): 199-206. https://www.davidpublisher.com/Public/uploads/Contribute/61ad830cee8a6.pdf.

[114] *National Strategy to Advance an Integrated U.S. Greenhouse Gas Measurement, Monitoring, and Information System*, The Greenhouse Gas Monitoring and Measurement Working Group & The White House, November 2023, https://www.whitehouse.gov/wp-content/uploads/2023/11/NationalGHGMMISStrategy-2023.pdf.

[115] "Carbon Mapper Data Portal," Carbon Mapper, January 2024, https://carbonmapper.org/data/.

[116] Riley Duren et al., "California's methane super-emitters," *Nature* 575 (2019): 180-184, https://pubmed.ncbi.nlm.nih.gov/31695210/.

[117] Jason Schroeder, "Landfill Methane Research Workshop: Methane Remote Sensing for Leak Identification and Mitigation," California Air Resources Board, December 5, 2022, https://ww2.arb.ca.gov/sites/default/files/2022-12/Methane%20Remote%20Sensing.pdf.

[118] Hannah Nesser at al., "High-resolution U.S. methane emissions inferred from an inversion of 2019 TROPOMI satellite data: contributions from individual states, urban areas, and landfills," *EGUsphere* [preprint] (2023), https://egusphere.copernicus.org/preprints/2023/egusphere-2023-946/.

[119] Docket No. EPA-HQ-OAR-2019-0424, "Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule," Hannah Nesser, July 27, 2023, https://www.regulations.gov/comment/EPA-HQ-OAR-2019-0424-0306.

and the environment.[120] In addition, the leachate from landfills can contaminate nearby soil and groundwater. Landfills are often sited near vulnerable communities. Analysis using the EPA's Environmental Justice Screening and Mapping Tool shows that 54% of MSW landfills reporting to the GHGRP have communities located within one mile that exceed the national average for either percent low-income or percent people of color.[121]

A2. Landfill Biomethane as a 45V Pathway Creates Many Climate Risks that Must Be Addressed, including by Limiting Eligibility to that Generated from Existing Food Waste

Incorporating landfill biomethane into 45V creates many climate risks. For one, incentivizing landfill biomethane generation for hydrogen production can put more sustainable waste management alternatives, such as waste prevention or composting, at a relative disadvantage. It risks creating an economic incentive to continue landfilling methane-generating organic waste, when diverting that waste from landfills is the better climate solution.

Incentivizing landfill energy production is also dangerous without robust standards in place to capture methane and co-pollutants from the landfill. As discussed above, landfill gas collection efficiency can vary widely, including at landfills with energy projects. At biomethane-producing landfills, operators may optimize their wellfield for landfill gas *quality* rather than the *quantity*, which in some cases can lead to more fugitive emissions than at a landfill with an electricity project or a flare.

Treasury should limit eligibility of landfill methane to only that generated from food waste already in landfills as of IRA passage to avoid incentivizing additional landfilling of organic waste.

A3. Methane from Livestock Farms also Poses a Climate Challenge, though There Are Fewer Existing Mitigation Programs

In 2021, livestock manure management contributed 2.4 million tons, or 9.1%, of the United States' anthropogenic methane emissions.[122] Reducing methane emissions from livestock manure is crucial to offset global temperature increases due to methane's short lifetime and higher greenhouse gas potency than CO2.

Anaerobic digesters are an integrated manure management tool used by farmers on livestock farms as part of an approach to reduce methane emissions from manure lagoons and storage ponds, minimize odors and air quality concerns, generate products for use on the farm, and reduce solids content.[123]

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[120] *Understanding and Control of Municipal Solid Waste Landfill Air Emissions Request for Applications (RFA)*, U.S. Environmental Protection Agency, October 2022, https://www.epa.gov/research-grants/understanding-and-control-municipal-solid-waste-landfill-air-emissions-request.

[121] Preet Bains et al., *Trashing the Climate: Methane from Municipal Landfills*, Environmental Integrity Project, May 2023, https://environmentalintegrity.org/reports/trashing-the-climate/.

[122] EPA (2024) Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2022. U.S. Environmental Protection 9 Agency, EPA 430-D-24-001. https://www.epa.gov/system/files/documents/2024-02/us-ghg-inventory-2024-main-text.pdf

[123] The Benefits of Anaerobic Digestion | US EPA. (n.d.). US EPA. https://www.epa.gov/agstar/benefits-anaerobic-digestion

Manure is fed into a digester, which is a gas-tight container, where microorganisms break down organic material into biogas and other compounds. This biogas can be a source of energy for several uses, including generation of electricity on-farm or processing into biomethane and injecting into pipelines. This allows farmers to sell their generated electricity or produced biomethane to help offset the cost of installing, operating, and maintaining the digester and in the case of large operations, make a profit. Without a digester, methane emitted from manure in lagoons or other open storage systems would otherwise be released into the atmosphere.

Most livestock farms in the US are not currently required to capture biogas or other gaseous emissions. For many operations, especially medium and small operations, it is often not economical for them to install a digestor.[124] While more widespread installation of manure management practices would be beneficial for climate mitigation, programs to incentivize such activities are currently limited. Those that do exist include California's Alternative Manure Management Program, which provides financial assistance for the implementation of non-digester manure management practices, which will result in reduced greenhouse gas emissions,[125] and the USDA Natural Resources Conservation Service's provision of financial and technical assistance for some alternative manure management practices.[126]

A4. Biomethane from Livestock Farms Can Be an Eligible 45V Pathway with Strong Protections in Place

Under narrow circumstances, biomethane from livestock farms can provide a small-scale low-emissions hydrogen pathway by capturing waste biogas methane that would otherwise escape to the atmosphere. For example, using biogas methane to generate 45V-eligible clean electricity using a generator or small-scale methane fuel cell at a livestock farm facility could enable the installation of an anaerobic digestor to capture methane that otherwise would have been vented.[127] Biomethane from livestock farms should be an eligible pathway for 45V, through both SMR and electrolysis, with many protections around feedstock eligibility, book-and-claim accounting, and the use of offsets.[128] The clearest pathway for biomethane from livestock farms to be an eligible 45V pathway is through direct use of biomethane to

[124] E3A, n.d. Anaerobic Digester Applications for the Farm or Ranch, https://extension.missouri.edu/media/wysiwyg/Extensiondata/Pub/pdf/energymgmt/em0703.pdf

[125] California Department of Food and Agriculture, 2024, Alternative Manure Management Program, https://www.cdfa.ca.gov/oefi/AMMP/

[126] USDA, Natural Resources Conservation Service, 2021, Conservation Practice Standard: Waste Separation Facility, https://www.nrcs.usda.gov/sites/default/files/2022-10/Waste_Separation_Facility_632_NHCP_CPS_2019.pdf

[127] USDA, 2010, "USDA grant helps Vermont dary turn manure into power," https://www.usda.gov/media/blog/2010/10/22/usda-grant-helps-vermont-dairy-turn-manure-power; *see also* Bloom Energy, Biogas Energy, (last accessed Feb. 16, 2024).https://www.bloomenergy.com/biogas-energy/ (last accessed Feb. 16, 2024).

[128] Kumar et al 2022. Overview of hydrogen production from biogas reforming: Technological advancement. International Journal of Hydrogen Energy. Vol 47, Issue 82, https://www.sciencedirect.com/science/article/abs/pii/S0360319922035327

produce hydrogen. However, livestock biomethane also introduces risks around methane leakage and management of anaerobic digester effluent, as discussed later in this section, that must be addressed.[129]

b. Book and Claim Systems

The use of biomethane for hydrogen production brings several challenges. The benefits of capturing and using biomethane strongly depend on how the biomethane is produced and sourced and the infrastructure used to process and deliver it – and as discussed later in this section, the leakage of methane during capture and transport has the potential to seriously erode its climate benefits. When biomethane is sold on the market into a common carrier pipeline through a "book-and-claim" system, it is particularly difficult to track and verify its emissions impact.

As interest and policy mandates for clean energy have expanded, systems have developed to verify, issue, and track environmental attributes associated with certain fuels and energy types. Book-and-claim systems allow entities to "book" or record an environmental attribute in a registry, and other entities may "claim" an attribute, such as by purchasing an environmental attribute credit generated by a booking entity.[130]

In the Proposed Rule, Treasury states that it "intend[s] to provide rules addressing hydrogen production pathways that use renewable natural gas (RNG) ... for purposes of the section 45V credit," and that "hydrogen producers using RNG or fugitive methane would be required to acquire and retire corresponding attribute certificates through a book-and-claim system that can verify in an electronic tracking system that all applicable requirements are met."[131] However, Treasury also acknowledges there are many open questions around the use of book-and-claim systems,[132] and it does not yet provide such a pathway for the current pathway of landfill gas. As discussed herein, existing book-and-claim tracking systems for biomethane are nascent and not yet reliable enough to be used for purposes of the 45V credit.

B1. Existing Book-and-Claim Systems for Biomethane Are Not Sufficiently Mature for Incorporation into 45V

Book-and-claim systems for the environmental attributes associated with biomethane are complex, cross-jurisdictional, and less mature than RECs in the clean electric power context. The M-RETs credit tracking system just launched in 2020 for renewable fuel credits, while M-RETs has been tracking clean energy generation credits for many more years. The Center for Resource Solutions just launched a voluntary third-party certification program for biomethane in 2021, while its equivalent certification for clean energy generation has been available since 1997. And continued challenges with the

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[129] *See* Mark Omara & Joe Rudek, *Careful accounting is critical to assessing the climate benefits of biomethane*, EDF Energy Exchange (Mar. 24, 2021), available at https://blogs.edf.org/energyexchange/2021/03/24/careful-accounting-is-critical-to-assessing-the-climate-benefits-of-biomethane/.

[130] *See generally* Blank et al., *Clean Energy 101: Book & Claim*, RMI (May 30, 2023), https://rmi.org/clean-energy-101-book-and-claim/.

[131] Proposed Rule at 89238, 89239.

[132] *See id.* at 82940.

administration of U.S. EPA's Renewable Fuel Standard demonstrate (1) the need to strengthen the regulatory program's oversight of the RIN market and (2) the importance of external checks on the validity of biomethane environmental attributes beyond the existing regulatory compliance framework.

In light of these limitations, caution is needed. Before permitting any book-and-claim accounting, Treasury should first convene with other agencies and stakeholders, including U.S. EPA and prominent third-party certification entities, to evaluate an appropriate standard for when book-and-claim environmental attributes for biomethane may be appropriate in the context of hydrogen production under 45V.

In the meantime, biomethane used during the hydrogen production process should be "direct use," through a direct, exclusive pipeline connection (or other dedicated transport system) between the hydrogen production facility and the source of the gas that is procured. Relative to a book-and-claim system, the direct connection between a gas supplier and a hydrogen production facility can reduce the uncertainty of pipeline leakage, tracking, and verification. Given the lack of standardized and reliable book-and-claim systems for biomethane, a direct and exclusive pipeline connection is the only way to reliably verify the origins of the biomethane being used for hydrogen production.

If book-and-claim systems are utilized in the future, they should include the following protections:

- Verification of first productive use and environmental attributes through both GHGRP reporting and on-site, third party inspections;
- Measurement, reporting and verification of actual GHG emissions associated with biomethane production and transport to a hydrogen facility;
- Fugitive methane leakage estimates based on measured data;
- Verification of digestate management and adoption of nutrient management plans to limit ammonia emissions; and
- A national third-party certification system to audit credits and ensure no double-counting.

B2. The Environmental Attributes of Biomethane Can Be Traded and Tracked Through Nascent Markets

In the United States, environmental attributes associated with biomethane are tracked through a few book-and-claim programs, with attributes referred to as Renewable Fuel Credits or Renewable Thermal Certificates ("RFCs" or "RTCs"). The primary mechanisms that underpin procurement of environmental attributes associated with biomethane are tracking systems, which issue tradable commodities in the form of certificates that may be used and accepted for compliance with regulatory standards or to fulfill voluntary commitments. The most common regulatory programs for which RFCs are traded on tracking systems are the U.S. EPA Renewable Fuel Standard and the California Low Carbon Fuel Standard, each discussed below. A secondary mechanism underpinning environmental attribute markets for biomethane is third-party certification programs, which are used in addition to tracking systems to provide an added layer of credibility and quality assurance for the environmental attributes.

The primary verification and tracking system for biomethane credits in the U.S. is the M-RETS platform for renewable thermal tracking, a relatively new program that launched in 2020.[133] The M-RETS tracking system issues one "Renewable Thermal Certificate" for each dekatherm (Dth) of "renewable thermal" generation, including biomethane.

The certificate includes the environmental attributes and can include optional verified GHG intensity data and track full or partial carbon lifecycles. For carbon intensities, M-RETS supports the use of the GREET model, Canada's GHGenius model, or the LCFS lifecycle pathway.[134] To our knowledge, the system does not yet include details regarding counterfactual / first productive use, methane leakage, or ammonia impacts.

M-RETS also operates a leading renewable electricity credit ("REC") tracking system and explains that "[r]enewable thermal markets are currently in a state comparable to nascent REC markets. M-RETS can help build these markets just like early REC tracking systems helped build and sustain emerging renewable electricity markets."[135]

B3. One of the Primary Regulatory Programs Allowing Book-And-Claim for Biomethane, the U.S. EPA Renewable Fuel Standard, Reveals the Challenges in Fuel Crediting Systems

Environmental attribute credits for biomethane are used to comply with a small number of state and federal regulatory programs. The U.S. EPA Renewable Fuel Standard ("RFS"), created by the Energy Policy Act of 2005 and expanded by the Energy Independence and Security Act of 2007, specifies annual volumetric mandates for renewable transportation fuels.[136] Refiners and importers of petroleum fuels are the obligated parties that must demonstrate deployment of a minimum volume of renewable transportation fuels each year. Biomethane can qualify for credits in the RFS, though it makes up a small proportion of the overall RFS program.[137]

The compliance system for the RFS program is tracked using Renewable Identification Numbers ("RINs"), electronic certificates associated with qualified biofuels. Obligated entities demonstrate compliance by retiring a sufficient number of RINs to satisfy their annual renewable volume obligation.[138]

Qualifying biofuel producers, including biomethane producers, can generate and sell RINs to the obligated parties.[139] To generate RIN credits, biomethane producers must register with EPA and undergo

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[133] M-RETS. (n.d.-b). M-RETS Renewable Thermal Tracking. Retrieved February 21, 2024, from https://www.mrets.org/m-rets-renewable-thermal-tracking-system/

[134] *Id.*

[135] *Id.*

[136] Jiao, H. (2023, May 19). Overview of the U.S. renewable fuel Standard. Farmdoc Daily. https://farmdocdaily.illinois.edu/2023/05/overview-of-the-us-renewable-fuel-standard.html

[137] *See* U.S. EPA, Final Rule: *Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program*, 75 Fed. Reg. 14670, 14673 (Mar. 26, 2010).

[138] *See* 40 C.F.R. § 80.1434(a)(1).

[139] *See generally* Gerveni, M., T. Hubbs and S. Irwin. "Overview of the RIN Compliance System and Pricing of RINs for the U.S. Renewable Fuel Standard." farmdoc daily (13):95, Department of Agricultural and Consumer

an independent third-party engineering review upon initial registration and once every three years.[140] EPA permits RINs to be generated for biomethane if the generator and purchaser of the RIN credits are connected by a commercial distribution system, which may include a physically connected pipeline.[141]

Starting in 2010, EPA required "that each of these mandated volumes of renewable fuels achieve certain minimum thresholds of GHG emission performance."[142] "To qualify as a renewable fuel under the RFS program, a fuel must be produced from approved feedstocks and have lifecycle GHG emissions that are at least 20 percent less than the baseline petroleum-based gasoline and diesel fuels" (or 60% less for cellulosic biofuel).[143] However, the program does not require measurement, reporting, or verification of actual GHG emissions associated with the production, transport, and use of the renewable fuels.

There is a history of fraud in the RFS program, and a recent EPA Office of Inspector General report identified several weaknesses in the current program.[144] The documented RIN fraud includes:

- From 2013 to 2021, EPA brought 16 enforcement actions against 15 companies; most of the actions were for the generation and sale of fraudulent RINs.[145]
- 13 companies transacted nearly 339 million invalid RINs and collected approximately $87 million in proceeds.
- 68 companies purchased a total of over 168 million fraudulent RINs and paid about $8.1 million in civil penalties.[146]

The EPA Office of Inspector General made the following findings regarding the current RFS program:

- "The EPA has not implemented controls to prevent a producer from entering more RINs than the producer is able to generate based on its registered capacity.
- "The EPA also allows firms that provide RIN verification services to provide other services for producers, which may reduce the audit provider's independence. As a result, the EPA does not

Economics, University of Illinois at Urbana-Champaign, May 24, 2023, https://farmdocdaily.illinois.edu/2023/05/overview-of-the-rin-compliance-system-and-pricing-of-rins-for-the-us-renewable-fuel-standard.html.

140 40 C.F.R. § 80.1450(b)(2).

141 *See* 40 C.F.R. § 80.1426; 40 C.F.R. § 80.125; U.S. EPA, Final Rule: *Renewable Fuel Standard (RFS) Program: Standards for 2023-2025 and Other Changes*, 88 Fed. Reg. 44468, 44524 (July 12, 2023).

142 U.S. EPA, Final Rule: *Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program*, 75 Fed. Reg. 14670, 14674 (Mar. 26, 2010).

143 U.S. EPA, Final Rule: *Renewable Fuel Standard (RFS) Program: Standards for 2023-2025 and Other Changes*, 88 Fed. Reg. 44468, 44500 (July 12, 2023).

144 U.S. EPA Office of Inspector General, *The EPA Must Improve Controls and Integrate Its Information System to Manage Fraud Potential in the Renewable Fuel Standard Program*, Report No. 23-P-0032 (Sept. 19, 2023), https://www.epaoig.gov/sites/default/files/reports/2023-09/_epaoig_20230919-23-p-0032.pdf [hereinafter EPA OIG, RFS Report].

145 *Id.* at 4; *see also* U.S. EPA, Civil Enforcement of the Renewable Fuel Standard Program, https://www.epa.gov/enforcement/civil-enforcement-renewable-fuel-standard-program (last updated Oct. 18, 2023).

146 EPA OIG, RFS Report at 4.

have reasonable assurance that the program is achieving its goals of reducing greenhouse gas emissions and expanding the nation's renewable fuels sector.

- "[T]he EPA's system for tracking and overseeing RIN reporting has not been integrated with other RIN-related systems, including the system used to track RIN transactions. Integration has been slowed by limited program resources, security, and confidentiality concerns, and ever-expanding RFS program data needs. This lack of integration places a significant burden on staff to address information requests and has caused data-quality problems, including missing or incomplete reports, that must be addressed to improve RFS program implementation."[147]
- The EPA allows companies to submit RIN transactions to the EMTS after the regulatory deadlines. In an analysis of 2021 transactions, while most transactions were timely submitted, there were hundreds of late submissions that "involved the trading of 97,752,959 RINs with an approximate market value of $133 million."[148]
- In addition, a prior EPA OIG report issued in 2016 "concluded that the EPA was not meeting the congressional requirements established by the Energy Independence and Security Act of 2007 to provide objective analysis on the environmental impacts of the RFS program to inform science-based decision-making on biofuel policy." As of September 2023, EPA had not yet completed two of the four corrective actions; they are due to be completed in 2024.[149]

B4. The Other Primary Regulatory Programs Allowing Book-And-Claim for Biomethane, California's LCFS, Offers Lessons around Verification and Enforcement

California's Low Carbon Fuel Standard ("LCFS") establishes an annual, declining carbon intensity target for transportation fuels used in California. Entities with high carbon fuels generate deficits and must purchase credits annually to comply with the target; while clean fuels, including biomethane, generate credits.[150, 151] The LCFS is administered by the California Air Resources Board ("CARB") and was first approved in 2009.[152] States such as Oregon and Washington have adopted similar programs.[153]

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[147] *Id.* at At a Glance.

[148] *Id.* at 10.

[149] *Id.* at 7 (citing U.S. EPA Office of Inspector General, *EPA Has Not Met Certain Statutory Requirements to Identify Environmental Impacts of Renewable Fuel Standard*, Report #16-P-0275 (Aug. 18, 2016), https://www.epaoig.gov/sites/default/files/2016-08/documents/_epaoig_20160818-16-p-0275.pdf).

[150] FAQ: The Standardized Regulatory Impact Assessment for the Low Carbon Fuel Standard | California Air Resources Board. (n.d.). https://ww2.arb.ca.gov/resources/documents/faq-standardized-regulatory-impact-assessment-low-carbon-fuel-standard

[151] *See* State of California Air Resources Board. (2023, September 8). Low Carbon Fuel Standard 2023 Amendments Standardized Regulatory Impact Assessment (SRIA). https://ww2.arb.ca.gov/sites/default/files/2023-09/lcfs_sria_2023_0.pdf *at 1-2*

[152] *See* State of California Air Resources Board. (2023, September 8). Low Carbon Fuel Standard 2023 Amendments Standardized Regulatory Impact Assessment (SRIA). https://ww2.arb.ca.gov/sites/default/files/2023-09/lcfs_sria_2023_0.pdf *at 1*.

[153] Department of Environmental Quality : Clean Fuels Program : Oregon Clean Fuels Program : State of Oregon. (n.d.). Clean Fuels Program : Department of Environmental Quality. Retrieved February 21, 2024, from https://www.oregon.gov/deq/ghgp/cfp/Pages/default.aspx

To generate credits, clean fuel sources must undergo evaluation by CARB staff and verification by a third party. CARB added the third-party verification requirements in 2018 to ensure data completeness, accuracy, and conformance with the regulation, and verification services must be performed by qualified verifiers.[154] An independent reviewer must perform a final check on the verification team's work. The independent reviewer must agree with the verification findings before the validation or verification statement is issued.

CARB staff perform onsite inspections, including out-of-state inspections for facilities that sell credits in California. Such inspections have resulted in enforcement actions for improper crediting under LCFS.[155] It is not clear how regularly or widely such inspections are conducted. Reporting requirements vary depending on the level of program participation. Holders of certified Tier 1 or Tier 2 fuel pathways certified under CA-GREET3.0 are required to update site-specific CI data on an annual basis. Some entities must do annual reporting and verification, while others must do quarterly. However, the program does not require measurement, reporting, or verification of actual GHG emissions associated with the production, transport, and use of the renewable fuels.

CARB has identified violations of the LCFS program standards and pursued enforcement actions, recording 14 settlement agreements since 2017.[156] For example, a 2022 settlement involved the retirement of over 20,000 credits that had been improperly generated and sold for compliance with the California LCFS program.[157]

Biomethane has historically made up a relatively small fraction of the alternative fuels tracked through the LCFS program. The program currently allows for indirect accounting for biomethane "injected into the North American natural gas pipeline without requirements that this fuel be demonstrated to have been physically delivered into California."[158] However, CARB proposed in 2023 "to align the deliverability requirements for biomethane with the requirements applicable to other fuels, which must be physically consumed in California or, in the case of low-CI electricity, meet specific deliverability requirements."[159]

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[154] LCFS verification | California Air Resources Board. (n.d.). Retrieved February 21, 2024, from https://ww2.arb.ca.gov/lcfs-verification

[155] *See*, e.g., California Air Resources Board. (n.d.). Diamond Green Diesel LLC Settlement. Retrieved February 21, 2024, from https://ww2.arb.ca.gov/diamond-green-diesel-llc-settlement

[156] California Air Resources Board, LCFS Enforcement Activities, https://ww2.arb.ca.gov/resources/documents/lcfs-enforcement (last accessed Feb. 24, 2024).

[157] Diamond Green Diesel LLC Settlement Agreement, between CARB and Diamond Green Diesel LLC, Notice of Violation: F101618-DGDR-RPT (July 2022), https://ww2.arb.ca.gov/sites/default/files/2022-07/diamond_green_diesel_llc_sa.pdf.

[158] *See* Low Carbon Fuel Standard 2023 Amendments Standardized Regulatory Impact Assessment (SRIA). (2023, September 8). State of California Air Resources Board. https://ww2.arb.ca.gov/sites/default/files/2023-09/lcfs_sria_2023_0.pdf *at 9.*

[159] *See* Low Carbon Fuel Standard 2023 Amendments Standardized Regulatory Impact Assessment (SRIA). (2023, September 8). State of California Air Resources Board. https://ww2.arb.ca.gov/sites/default/files/2023-09/lcfs_sria_2023_0.pdf at 8.

CARB proposes to institute deliverability requirements starting in 2041.[160] The final rules package, issued December 2023, is up for a vote at CARB in March 2024.[161]

B5. Third-Party Certification for Biomethane Environmental Attributes Is an Important Component to Offer Credibility and Ensure No Double-Counting

In addition to credit tracking systems and regulatory compliance reporting, another relevant mechanism for book-and-claim systems for environmental attributes of biomethane is the availability of third-party certification. The nonprofit Center for Resource Solutions ("CRS") approved a Green-e Renewable Fuels Standard in September 2021 for biomethane. Green-e has existed since 1997 as a certification for renewable electric power[162] and launched more recently for biomethane and other fuels. This third-party certification is supplemental to a credit tracking system, and acts like an auditor to assess renewable fuel eligibility, offer credibility, and ensure a quality standard for biomethane.[163]

The Green-e Renewable Fuels Standard is a voluntary product, but it can help credit buyers ensure there is no double counting by ensuring that no RINs or LCFS credits can be used for the same dekatherm of biomethane. Green-e "does not certify renewable fuel or RFC production, usage, and/or transactions that result in double counting, including double counting between compliance and voluntary markets," such as "one party claiming the renewable fuel for their own voluntary use and another party claiming it toward compliance with the Low Carbon Fuel Standard (LCFS), Renewable Fuels Standard (RFS), or other state compliance quotas."[164]

Together, these programs offer proof that book-and-claim systems for biomethane are not sufficiently mature for incorporation into 45V. Existing weaknesses in terms of fraud, data management, emissions measurement, and enforcement must be corrected – and a nationwide system of certification and verification established – before systems can be considered reliable for the purposes of 45V.

c. Carbon-Negative Offsets of Biomethane

Biomethane is seen by some hydrogen producers as a potential offsetting mechanism for dirtier fossil methane feedstocks, given that certain types of biomethane can receive very low and even negative emissions-intensity scores in certain models (e.g., California's LCFS). Offsetting could take place under

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[160] At p31, Public Hearing to Consider the Proposed Amendments to the Low Carbon Fuel Standard Staff Report: Initial Statement of Reasons. (2023, December 19). California Air Resources Board. https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/isor.pdf

[161] *See* Low Carbon Fuel Standard | California Air Resources Board. (2024, February 14). https://ww2.arb.ca.gov/rulemaking/2024/lcfs2024

[162] Green-E® Energy | Green-E. (n.d.). Retrieved February 21, 2024, from https://www.green-e.org/programs/energy

[163] *See* CRS Webinar Slides 25-26 (Oct. 4, 2023), https://speakerdeck.com/resourcesolutions/making-an-impact-with-renewable-fuels-purchases?slide=25.

[164] Center for Resource Solutions, Green-e Renewable Fuels Standard Version 1.0 at 15 (Sept. 16, 2021), https://www.green-e.org/docs/rf/Green-e%20Renewable%20Fuels%20Standard.pdf.

either a book-and-claim system or through direct connection (e.g., a hydrogen producer procuring both biomethane and fossil-based methane).

The practice of offsetting would allow a high-emitting blue hydrogen facility to artificially reduce its GHG intensity score – and thus claim eligibility for 45V – by purchasing a small share of biomethane credits, while doing nothing to change the underlying production technologies or processes. This could enable a blue hydrogen (or even grey hydrogen) producer to claim eligibility for the top $3 tax credit by blending just livestock biomethane totaling just 6% (and 13%, respectively) of feedstock volumes.[165]

When hydrogen is produced through a combination of fossil natural gas and biomethane—obtained via direct pipeline connection or book-and-claim credits—the producer should not be able to use carbon-negative scores to offset positive emissions from fossil fuels. Doing so could inappropriately permit hydrogen producers to earn generous tax credits through 45V for producing hydrogen with heavily polluting fossil natural gas.

C1. Offsets Are Not Justified Under 45V

Offsets are often used in carbon markets to reduce net system emissions when mitigation actions are otherwise too expensive to be undertaken in a particular sector in the near term. However, the practice of assessing and ensuring the quality of offsets is challenging, even in the most optimal circumstances. One major challenge is that of assessing the additionality of offsets (i.e., that a mitigation activity would not have taken place in the absence of the added incentive created by the offsets) and establishing crediting baselines (i.e., the emissions level against which reductions are quantified). Treasury has acknowledged this challenge in its draft rule in its attempt to define hydrogen production as a "first productive use."

These challenges are compounded by the fact that 45V is not a carbon market or subject to an overarching cap on emissions. It is an unbounded incentive program that provides highly generous tax credits to hydrogen production, regardless of the climate impact that results from its eventual use. For example, it would be energy inefficient, a waste of taxpayer resources, and potentially worse for the climate were 45V to be used to purchase biomethane to produce blue hydrogen to then be injected back into the gas pipeline system for industrial decarbonization—when instead, biomethane could be used directly for industrial decarbonization.

Moreover, 45V is designed to stand up a whole new industry which does not yet exist. The investments being made will last for many decades and should be designed with long-term climate and community impacts in mind. The tax credit values are high enough that offsetting could result in methane-based hydrogen becoming the dominant mode of production in the coming decades and taking away market share from green electrolysis – which is the most effective hydrogen production method for eliminating both climate and health-harming pollution.

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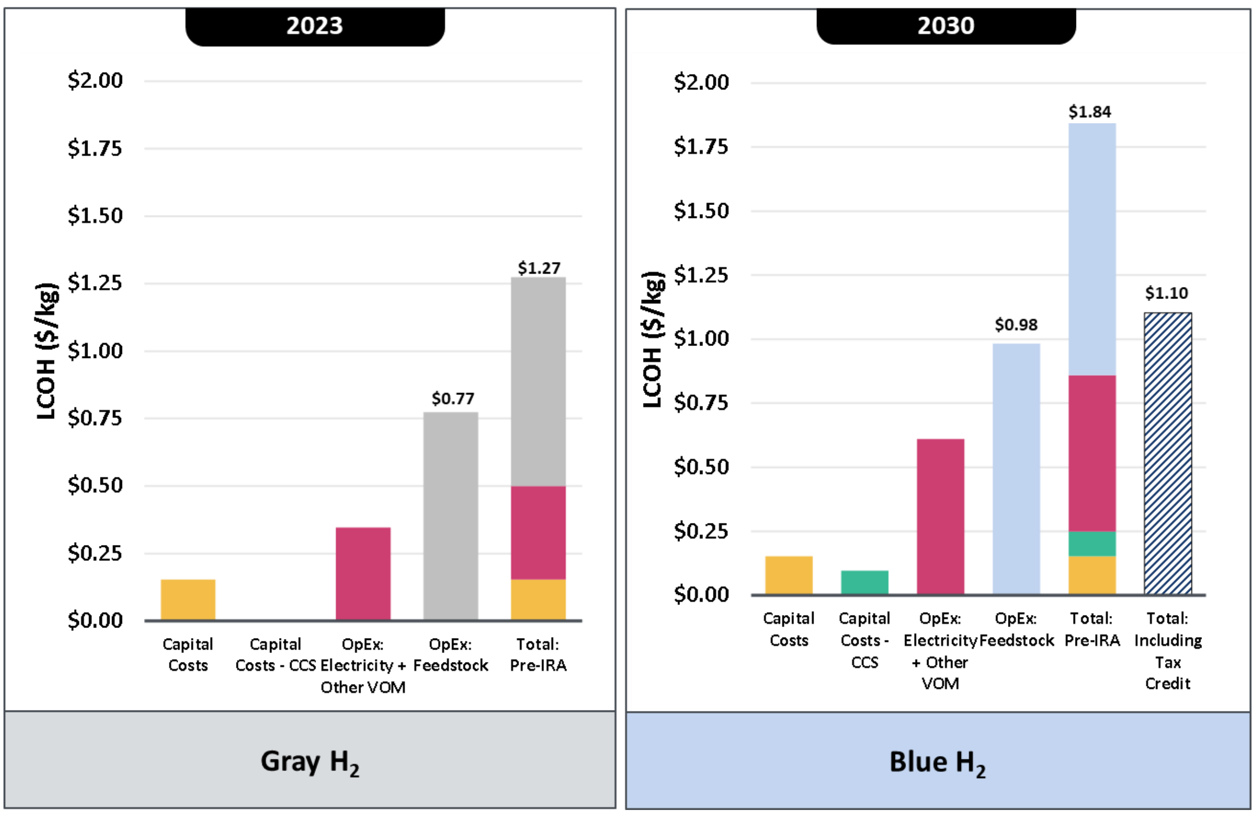
[165] EDF calculations; assumes GHG intensities of –372 gCO_2e/MJ (or –61.3 $kgCO_2e/kgH_2$) for livestock biomethane, 4.6 $kgCO_2e/kgH_2$ for blue hydrogen, and 10 $kgCO_2e/kgH_2$ for grey hydrogen. GHG intensity of livestock biomethane from EPA, 2020, "An overview of renewable natural gas from biogas," Table 2

This outcome would undermine IRA intent. The tax credit tiers were carefully designed to drive cost reductions for multiple pathways as needed to achieve cost competitiveness with grey hydrogen. The maximum credit tier was established at 0-0.45 $kgCO_2e/kgH_2$, suggesting negative-emissions pathways were not to be considered eligible. Moreover, analysis from the Brattle Group suggests that blue hydrogen costs are already projected to be around $1.80 by 2030 without any tax credits (including 45Q, which brings costs down further), shown in Figure 5.[166] This confirms that an effective $3/kg tax credit was not deemed necessary to support the buildout of the blue hydrogen economy. Allowing steam methane reforming projects to receive such a credit would bring their per unit costs down into negative territory.

Figure 5. Projected Costs of Blue Hydrogen in 2030[167]



Furthermore, offsets are not justified under the tiered tax credit system. Under this system, emissions reductions of 60%, 70%, and even 85% are worth just $0.60-$1.00, whereas the final 95% are worth three times that. This suggests that emissions reductions are not fungible, and one cannot apply an even weighted average approach to carbon-negative scores.

Lastly, offsets would violate the climate intent of the IRA, which was to achieve net-zero emissions. Climate net-zero requires carbon/GHG removal to mitigate any unabated emissions. The IPCC has

[166] The Brattle Group, 2024, "The economics of hydrogen production and delivery," https://www.brattle.com/wp-content/uploads/2024/02/Emerging-Economics-of-Hydrogen-Production-and-Delivery_2024-1.pdf

[167] *Id*.

recognized that carbon dioxide removal will be necessary to address residual emissions – in addition to, and not instead of – rapid emissions cuts.[168] Because livestock biomethane constitutes avoided methane, not removed methane, they do not justify enabling new positive emissions to be generated from dirty hydrogen production.

C2. Offsets under 45V would Incentivize the Buildout of Fossil-Based Hydrogen, which Has Higher Levels of GHG and Air Pollution and Negatively Impacts Local Communities

45V offers a significant amount of funding, on the order of the revenues that California's LCFS program provides. We estimate it equates to \$0.91 per kg CH_4, compared to current LCFS prices of \$0.67 per kg CH_4.)[169,170] Given how deeply negative the GHG intensity scores for dairy farms can be (up to -372 gCO_2e/MJ, or -61.3 $kgCO_2e/kgH_2$), a blend of only 6% of biomethane would be enough to make a blue hydrogen facility eligible for the top \$3 tax credit.[171]

Given the ease of achieving the top tax credit, offsets would directly incentivize the build-out of hydrogen from methane feedstocks, which are inherently polluting and lock in harms caused by the fossil fuel and petrochemical industries. Some existing SMR facilities release hundreds of tons of nitrogen oxides that contribute to ozone and particulate pollution, along with volatile organic compounds, sulfur dioxide, and direct particulates. This pollution contributes to harmful health effects, including cardiovascular and respiratory ailments, cancer, and premature death.[172]

As shown below, existing facilities are overwhelmingly sited in EJ communities and petrochemical corridors heavily burdened by pollution.[173] New thermochemical (i.e., ATR, SMR and gasification) plants are disproportionately proposed for the Gulf Coast areas of Texas and Louisiana, areas that are heavily overburdened already due to an existing concentration of refineries, chemical production, and other heavy industry.[174]

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[168] IPCC, Climate Change 2022: Mitigation of Climate Change Summary for Policymakers at 36 (2022), https://www.ipcc.ch/report/ar6/wg3/downloads/report/IPCC_AR6_WGIII_SummaryForPolicymakers.pdf

[169] Calculation assumes 3.295 kgCH4/kgH2; \$65/MT CO2e LCFS credit price; 207 gCO2e/MJ; and 50 MJ/kgCH4; See Saur, G and Milbrandt, A (2014) "Renewable hydrogen potential from biogas in the United States," NREL, https://www.nrel.gov/docs/fy14osti/60283.pdf

[170] Note that these numbers are not directly comparable because the 45V incentive would be divided in some way between the hydrogen producer and the feedstock supplier.

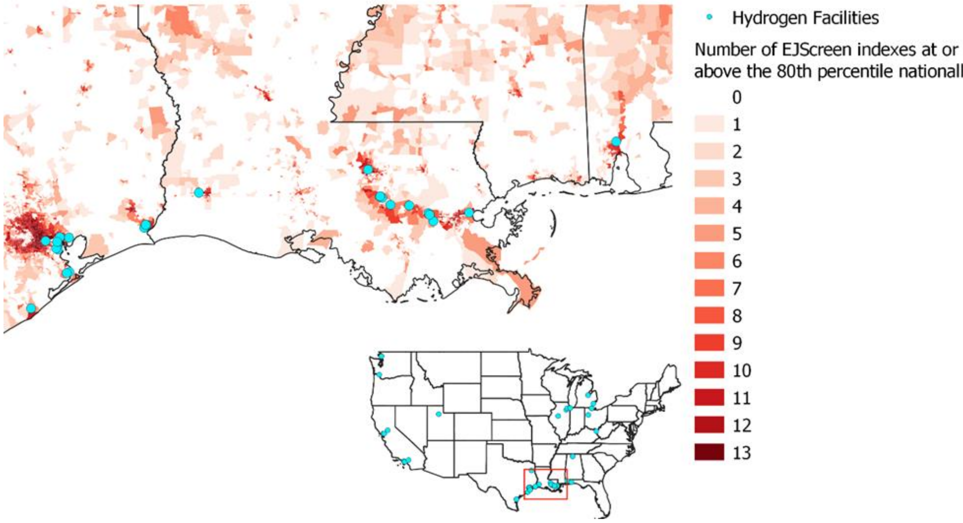
[171] Assumes GHG intensities of –372 gCO2e/MJ (or –61.3 kgCO2e/kgH2) for livestock biomethane and 4.6 kgCO2e/kgH2 for blue hydrogen; EPA, 2020, "An Overview of Renewable Natural Gas from Biogas," https://www.epa.gov/sites/default/files/2020-07/documents/lmop_rng_document.pdf

[172] Environmental Defense Fund, et al., Petition for Rulemaking to List and Establish National Emission Standards for Hydrogen Production Facilities under Clean Air Act Sections 111 and 112 at 2 (Sept. 15, 2023), https://www.edf.org/sites/default/files/2023-09/Petition%20for%20Rulemaking%20-%20Hydrogen%20Production%20Facilities%20-%20CAA%20111%20and%20112%20-%20EDF%20et%20al.pdf.

[173] *Id.*

[174] U.S. Department of Energy, Pathways to Commercial Liftoff: Clean Hydrogen at 23, Figure 8 (March 2023), https://liftoff.energy.gov/wp-content/uploads/2023/05/20230523-Pathways-to-Commercial-Liftoff-Clean-Hydrogen.pdf [hereinafter "Liftoff"].

Figure 6: Gulf Region Hydrogen Production Facilities Overlaid with EJ Screen Indices[175]



Carbon-negative offsetting of 45V would drive even greater buildout of these polluting facilities, which are currently largely unregulated, worsening local air pollution problems at the expense of frontline communities.[176]

It is even possible that offsetting would incentivize more build-out of unabated "grey" (i.e., steam methane reforming without carbon capture) hydrogen facilities, which are significantly cheaper to build without carbon capture equipment and would still be eligible for the top tax credit with just a 13% biomethane blend.[177] This would grant 45V funds to technologies and processes that 45V is explicitly designed to replace – and could leave us with a set of unabated facilities post-45V expiration running on the cheapest fossil feedstocks they can locate.

Biomethane offsetting is not just a risk for thermochemical pathways – it also poses a serious problem in the context of electrolytic hydrogen production. If biomethane offsets were to be allowed as an electricity source, this would enable large volumes of dirty electricity to be procured alongside it – ramping up fossil fuel generation and accompanying GHG and air pollution.

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[175] Existing merchant hydrogen plants were identified based on facilities reporting to the GHGRP under Subpart P. Community information on EPA environmental justice indices and neighborhood demographic profile data were available through EPA's Enforcement and Compliance History Online (ECHO) website. Facilities shown are a regional subset of the national data, and the color gradients represent the number of EJ screen indices exceeding the 80th percentile (white means no indices exceed the 80th percentile, while the darkest red indicates that all 13 indices exceed the 80th percentile). U.S. EPA, EJ Screen: Environmental Justice Screening and Mapping Tool, https://www.epa.gov/ejscreen

[176] EDF, Allies Ask EPA to Protect People from Fossil Fuel-Based Hydrogen Production Pollution. (2023, September 15). Environmental Defense Fund. https://www.edf.org/media/edf-allies-ask-epa-protect-people-fossil-fuel-based-hydrogen-production-pollution

[177] Assumes GHG intensities of –372 gCO_2e/MJ (or –61.3 $kgCO_2e/kgH_2$) for livestock biomethane and 10 $kgCO_2e/kgH_2$ for grey hydrogen

Under no circumstances should a carbon-negative score of biomethane be used to offset the positive emissions associated with hydrogen production.

C3. There Are Several Potential Ways to Prevent Carbon-Negative Offsetting

There are several potential ways to implement this. For example:

- Recognizing the potential for perverse climate impacts in the context of 45V, Treasury could disallow application of carbon-negative scores solely for the purposes of the 45V credit. This would effectively grant biomethane a score of zero for calculations of blended feedstocks (post-capture). For example, if a SMR facility utilizes 15% negative-emissions biomethane and 85% positive-emissions fossil gas, limiting biomethane to a score of zero would yield an average emissions intensity of 3.91 $kgCO_2e/kgH_2$ and make it eligible for a $0.60 tax credit, rather than a score of -5.2 $kgCO_2e/kgH_2$ and $3 credit under carbon-negative accounting.[178] This option has the benefit of consistency with the treatment of electrolytic hydrogen – it acknowledges different feedstocks but averages emissions on a facility basis.
- Treasury could define a 'production process' explicitly in terms of feedstock origin, acknowledging that gas is more capable of differentiating feedstocks than electricity. SMR with biomethane would be deemed a distinct production process from SMR with fossil gas and be evaluated for 45V eligibility separately, even if both feedstocks are used in the same facility. Even if one process has negative emissions, these are irrelevant for the other process's calculation. For the same example facility, the 15% biomethane portion would be evaluated as a zero- or negative-emissions process and potentially receive the top credit, but the 85% fossil gas would average 4.6 $kgCO_2e/kg$ and receive no credit.
- Treasury could uphold the current structure that disallows the use of blended feedstocks within the same facility. This would reflect the reality that blending occurs well before the feedstock reaches the premises, and the facility has no way to verify the GHG intensity of the biomethane portion. This would only allow for a facility to use either full biomethane (directly piped or trucked to the facility) to receive the top $3 tax credit, or full fossil gas with its true GHG intensity score (4.6 $kgCO_2e/kgH_2$).

d. Methane Leakage and Environmental Impacts

D1. Methane Leakage from Biogas Production Is Common and Can Be Significant

Methane leakage from biogas production and upgrading facilities is common with estimated leakage rates in the 2 – 4% range up to as much as 15%. When the organic material digested would otherwise

[178] Assumes an emissions intensity of -61.3 $kgCO_2e/kgH_2$ for biomethane and 4.6 $kgCO_2e/kgH_2$ for fossil gas

not produce methane, or if the methane is being diverted from a flare, methane loss rates as low as 2.5% are likely to negate the benefits of offsetting fossil fuels.[179]

If biomethane is to be used as a feedstock for the production of hydrogen, leakage from the capture and processing of the biogas as well as transportation to the H_2 facility,[180] needs to be included as an input into GREET.

D2. Methane Leakage from Livestock Biomethane Needs to Be Properly Managed and Factored into GREET

When livestock biomethane is used for hydrogen production, the leakage of methane and the resulting net methane emissions relative to the counterfactual must be considered and factored into GREET climate impact assessments. EPA acknowledges in its RNG Operations Guide that "fugitive emissions of methane, depending upon their magnitude, can negate the climate and environmental benefits of RNG projects."

One of the largest leakage points in digester biomethane production comes from improper digestate management. Digestate is the effluent that comes out of the digester, which contains nutrients that can fertilize crops. It is common in the United States for digestate to be held in open storage pits or lagoons. Although the manure has been digested, and most of the biogas has been captured in the digester, digestate still produces some methane which is emitted if the digestate is stored in an open lagoon or storage tank. Residual methane emissions from the digestate are estimated to be between 0.2-5.9% of that captured in the digester.[181]

Covering digester effluent storage captures this residual methane, which can be flared or added to the digester biogas, enhancing the carbon market value when it is used for energy. An impermeable cover on the digestate can reduce residual methane emissions by 90%.[182] There are also developing technologies which can capture the ammonia and concentrate, and potentially be sold to generate additional revenue.[183, 184]

Another large leakage point is from the biogas process – that is, the process by which biogas is captured in a digester and "cleaned" to produce renewable natural gas to meet natural gas pipeline standards.

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179 Grubert, E. (2020). At scale, renewable natural gas systems could be climate intensive: the influence of methane feedstock and leakage rates. Environmental Research Letters, 15(8), 084041. https://doi.org/10.1088/1748-9326/ab9335

180 Methane leakage from transportation should be included for both biomethane and fossil-based methane.

181 Cornell College of Agriculture and Life Sciences. (2023, January 10). Covers for digestate effluent storage from anaerobic digestion. https://ecommons.cornell.edu/server/api/core/bitstreams/a725208d-82ba-4b17-aab4-b1305191c377/content

182 Id.

183 Pandey, B. K., & Chen, L. (2021). Technologies to recover nitrogen from livestock manure - A review. Science of the Total Environment, 784, 147098. https://doi.org/10.1016/j.scitotenv.2021.147098

184 Abbà, A., et al (2023). Ammonia Recovery from Livestock Manure Digestate through an Air-Bubble Stripping Reactor: Evaluation of Performance and Energy Balance. Energies, 16(4), 1643. https://doi.org/10.3390/en16041643

Methane leakage from the processing of biogas is estimated to be in the 2 – 4% range, or up to as much as 15%.[185] Methane leakage in the transmission and distribution of natural gas has been estimated to be in the range of 0.4 - 0.9%.[186]

If biomethane is to be used as a feedstock to produce hydrogen, leakage from the capture and processing of the biogas must be measured and included as an input to the GREET model using both 20- and 100-year time horizons. Methane leaks can be detected and measured using monitoring sensors at the anaerobic digester and during the processing of biogas to biomethane.[187]

D3. Landfill Biomethane Projects Can Have Significant Fugitive Emissions, which Must Be Controlled as a Requirement for 45V Eligibility

EPA acknowledges in its RNG Operations Guide that "fugitive emissions of methane, depending upon their magnitude, can negate the climate and environmental benefits of RNG projects." While a well-run anaerobic digester is estimated to collect 95% to 98% of the methane generated, the default collection efficiency for landfills is about 75%, and can vary widely based on design and operational practices. In 2021, MSW landfills with biomethane projects reported the release of more than 490,000 tons of methane emissions under GHGRP. In addition, Carbon Mapper has quantified super-emitting methane plumes at 35 MSW landfill sites with biomethane projects. At the Fort Bend Regional Landfill in Needville, Texas and the Roosevelt Regional Landfill in Roosevelt, WA, for example, Carbon Mapper detected plumes emanating from the biomethane upgrading facilities and across the landfill surface. Just because a site has an energy project does not mean the site is maximizing methane capture and minimizing fugitive emissions at the landfill.

Solutions are available to better control emissions from landfilled waste *and* prevent future landfill methane generation. To maximize climate and community benefits, we must do both. Fortunately, there are a number of technically feasible, readily available strategies to reduce landfill emissions today, at modest cost.[188] Modernizing landfill operations – through comprehensive leak detection and repair, expanded gas collection system coverage, and enhanced cover practices – can cut methane immediately from waste-in-place, while protecting nearby communities from co-pollutants. At the same time, scaling up efforts that keep organic waste out of landfills – through strategies like edible food donation and composting – will avoid future landfill methane generation and ensure organic materials are put to their highest and best use in the circular economy.

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[185] Grubert, E. (2020b). At scale, renewable natural gas systems could be climate intensive: the influence of methane feedstock and leakage rates. Environmental Research Letters, 15(8), 084041. https://doi.org/10.1088/1748-9326/ab9335

[186] Gasper, R. (2018, April 25). The production and use of Waste-Derived renewable natural gas as a climate strategy in the United States. World Resources Institute. https://www.wri.org/research/production-and-use-waste-derived-renewable-natural-gas-climate-strategy-united-states

[187] Hong, T., et al (2020). State-of-the-art of methane sensing materials: A review and perspectives. TrAC Trends in Analytical Chemistry, 125, 115820. https://doi.org/10.1016/j.trac.2020.115820

[188] Heijo Scharff et al., "The impact of landfill management approaches on methane emissions," *Waste Management & Research: The Journal for a Sustainable Circular Economy* (2023), https://journals.sagepub.com/doi/10.1177/0734242X231200742

State and federal regulations exist to control and reduce landfill methane emissions. Several states, including California, Maryland, and Oregon have landfill methane control measures more protective than the baseline federal rules. Strengthened federal rules from EPA are needed to drive greater and uniform reductions nationwide. EPA should issue nationwide rules that are at least as protective as the strongest state standards, including comprehensive monitoring standards which would help track and ensure landfill methane emissions are reduced and not worsened if for landfill biomethane generation were to increase as a result of 45V.

Importantly, the GREET model does not currently include fugitive emissions at the landfill in its lifecycle analysis, even though fugitive emissions of methane, depending upon their magnitude, can negate the climate and environmental benefits of biomethane projects. These "upstream" emissions are considered outside the system boundary of the analysis, since flaring is used as a counterfactual scenario. This effectively means that a landfill biomethane project collecting 90% of its methane would receive the same GHG intensity score as a landfill collecting only 20% of its methane – and releasing the rest into the atmosphere. In both cases, hydrogen produced from the landfill biomethane could be eligible for the highest tax credit value. To address this concern, Treasury should require landfills producing biomethane eligible under 45V adopt best management practices to limit fugitive methane.

D4. Local Air Quality Impacts of Ammonia from Anaerobic Digestion Must Be Addressed

One of the most significant air pollutants of concern locally surrounding biogas systems is ammonia. Approximately 80% of ammonia emissions in the United States, encompassing emissions from both natural sources and human activities, are from agricultural sources. Notably, around 60% of these national emissions stem from livestock manure.[189] Ammonia is a health concern, as it has the potential to form fine particulate matter (PM2.5), which can lead to respiratory and pulmonary issues in nearby communities.[190] The ammonia emissions also present an environmental risk contributing to soil acidification and/or eutrophication in downwind ecosystems.[191] Furthermore, ammonia oxidation in the atmosphere may increase atmospheric levels of nitrous oxide, a powerful greenhouse gas with a GWP100 of 273.[192, 193]

During anaerobic treatment or storage, manure organics decompose in an oxygen-free environment and produce methane, ammonia, and other gases. In open-system manure storage or treatment lagoons, as the manure undergoes anerobic decomposition, most of these compounds are lost to the atmosphere. If the anerobic decomposition takes place in an enclosed environment (such as a covered lagoon or anaerobic digester), the methane degases from the liquid phase and is captured under the cover where

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[189] US EPA 2017 NEI

[190] Brook, R. D., et al (2010). Particulate matter air pollution and cardiovascular disease. Circulation, 121(21), 2331–2378. https://doi.org/10.1161/cir.0b013e3181dbece1

[191] Wyer, K. E., et al (2022). Ammonia emissions from agriculture and their contribution to fine particulate matter: A review of implications for human health. Journal of Environmental Management, 323, 116285. https://doi.org/10.1016/j.jenvman.2022.116285

[192] Pai et al, Exploring the Global Importance of Atmospheric Ammonia Oxidation, ACS Earth Space Chem. 2021, 5, 7, 1674-1685, https://pubs.acs.org/doi/10.1021/acsearthspacechem.1c00021

[193] IPCC AR6 WGI Chapter 7 2021

it can be collected and flared or used as a fuel. However, the ammonia stays in solution and hence the dissolved ammonia gets very concentrated inside the anaerobic digester relative to that remaining dissolved in an open lagoon.

Once the digestate from the anaerobic digester or covered lagoon is discharged from beneath the cover into an open lagoon or storage tank, the ammonia is lost to the atmosphere in the same quantity or perhaps somewhat higher quantities, relative to that lost in an open lagoon, presenting a serious health risk to downwind communities.

Any 45V tax credit generated from biogas created from manure in covered lagoons or anaerobic digesters for hydrogen production should be predicated upon management of the digestate to greatly reduce ammonia losses. Keeping the digestate in an enclosed system would greatly reduce the loss of ammonia from the digestate as well as allowing for the capture of the residual methane in the digestate. The residual methane could be added to the digester biogas and used as fuel. An impermeable cover on the digestate reduces ammonia losses by 55-100% and residual methane emissions by 90%, while a permeable cover is estimated to reduce ammonia by 40-80%.[194, 195]

D5. Treasury Should Require Livestock Farms to Adopt Nutrient Management Plans and Best Practices to Reduce Local Environmental Impacts

Farm systems can have a negative impact on local communities, specifically around air pollutants, odors, and other downwind ecosystem and water concerns. Producers of biomethane from digesters should have a robust system in place, preferably a third-party vetted Nutrient Management Plan (NMP) and a Comprehensive Nutrient Management Plan (CNMP), to prevent methane leaks and ammonia emissions to participate in 45V. For farmers using digesters, compliance with relevant USDA NRCS standards, including both USDA NRCS Nutrient Management (Code 590) to ensure digestate nutrients are well-managed, and USDA NRCS Anaerobic Digester Conservation Practice Standard (CPS) for Anaerobic Digesters (Code 366) is paramount.[196, 197] This guidance outlines standard practices to improve air quality by reducing greenhouse gas emissions and objectionable odors from manure or agricultural waste, and/or to reduce transport of pathogens to surface water.[198] These practices apply where biogas production and capture are components of a waste management system plan or a comprehensive nutrient management plan, and sufficient and suitable organic feedstocks are readily available. This

[194] Cornell College of Agriculture and Life Sciences. (2023, January 10). Covers for digestate effluent storage from anaerobic digestion. https://ecommons.cornell.edu/server/api/core/bitstreams/a725208d-82ba-4b17-aab4-b1305191c377/content

[195] Colorado State University Extension. (2022, September 23). Best Management Practices for reducing ammonia emissions: Lagoon Covers – 1.631B - extension. Extension. https://extension.colostate.edu/topic-areas/agriculture/best-management-practices-for-reducing-ammonia-emissions-lagoon-covers-1-631b/#:~:text=Covering%20stored%20liquid%20manure%20slows,thus%20increasing%20its%20fertilizer%20value

[196] United States Department of Agriculture. (2015, December). Conservation Practice Standard Nutrient Management Code 590 (Ac.). https://datcp.wi.gov/Documents/NM590Standard2015.pdf

[197] United States Department of Agriculture. (2023, February). Conservation Practice Standard Anaerobic Digestor Code 366 (no). https://www.nrcs.usda.gov/sites/default/files/2023-04/366-NHCP-CPS-Anaerobic-Digester-2023.pdf

[198] *Id.*

practice standard outlines system design, cover, etc., as well as gas collection, transfer, control, and utilization, and monitoring/safety requirements, including criteria for maintenance of air quality, but does notably leave out the control of ammonia emissions, which should be addressed per earlier information.

Without these guardrails, programs like 45V could encourage the build out of additional digesters with no oversight into how they are managed – potentially leading to harmful methane leaks and other air pollutants (particularly ammonia) which can negatively affect local air, soil, and water quality and in turn, harm local communities.

D6. Treasury Should Set Guidelines to Ensure Landfill Biomethane Projects Are Following Best Management Practices

Treasury should set guidelines to promote best management practices for biomethane projects eligible for 45V. For landfills, Treasury should consider setting a minimum gas collection efficiency requirement, which qualifying projects would need to maintain and verify through gas collection system data and monitoring surveys. Treasury should also require qualifying landfills to follow best management practices around gas collection, cover, and monitoring that maximize methane recovery and minimize fugitive emissions.

In November 2023, the state of Michigan took a similar step in its clean electricity standard by requiring the operator of a qualifying landfill gas recovery and electricity generation facility to employ “best practices for methane gas collection and control and emissions monitoring."[199]

These recommended best practices come at modest cost, especially compared to the potential value of the 45V credit. While the party overseeing landfill operations may differ from the party developing the biomethane project, the two can work together to ensure best practices and high collection efficiency are maintained.

e. Feedstock Eligibility & Emissions Accounting

To the extent to which biomethane (from either landfills or other sources) is allowed as a hydrogen pathway (i.e., through direct use, or even if book-and-claim accounting is allowed), the following provisions for feedstock eligibility and best practices for emissions accounting should be followed.

Counterfactuals (Q11): Treasury asks whether venting is an appropriate counterfactual assumption for some biomethane pathways. EDF believes this is an appropriate assumption for *livestock farms* only on a case-by-case basis. It is true that many, if not most, livestock farms are not currently required to capture and flare their gas, and it is not economical for them to install a digestor. In these cases, the venting counterfactual appropriately credits the gas with avoided methane emissions. However, this should not translate into a carbon-negative score that can be used to offset dirtier hydrogen production (see section C). And if, instead, a farm is already capturing and/or selling their gas (e.g., into the LCFS), this farm’s “counterfactual” is no longer venting, and the emissions intensity score should no longer reflect that.

[199] Michigan House Fiscal Agency, Senate Bill 271 (S-3), 2023, https://www.legislature.mi.gov/documents/2023-2024/billanalysis/House/pdf/2023-HLA-0271-43C8EB2C.pdf

Moreover, if a change is made to a policy or regulatory framework that the digestor is subject to, the baseline counterfactual should re-set. For example, if New York were to establish a regulation requiring livestock farms to capture and flare their methane, this would require changing the counterfactual to flaring for NY livestock farms.

For *landfill biomethane*, the appropriate counterfactual is flaring at a 95-98% destruction efficiency. Many U.S. landfills already have gas capture and collection systems installed to meet regulatory requirements, and many are already required to flare at high destruction efficiencies. Landfills supplying biomethane to hydrogen producers are likely to be currently regulated or regulated in the future and subject to gas collection and destruction requirements. It would therefore be inappropriate to include a venting counterfactual.

First Productive Use (Q4): EDF strongly supports Treasury's proposal to require biomethane receiving the credit to originate from the "first productive use" of the methane, and to prevent eligibility in instances where biomethane was already being productively used or captured. This helps to ensure an additional climate benefit is achieved and protects against the waste of taxpayer dollars. Specifically, biomethane that has previously been put to productive uses (e.g., being burned for energy or heat or used as a feedstock) and/or received a revenue stream (e.g., through a LCFS or RFS) should not be credited for delivering additional emissions reductions in the context of 45V. Credited methane should only be from true waste streams and/or gas that would otherwise be vented to the atmosphere.

Date of Eligibility (Q8): We agree with Treasury's proposal to define the "first productive use" as the time when a producer of that gas first begins using or selling it for productive use in the same taxable year (or after) the relevant hydrogen production facility was placed in service. This baseline date may be reconsidered in the event of a major policy or regulatory change that affects the opportunity for pre-existing productive use (e.g., if LCFS eligibility expires).

Changes to Waste Capacity (Q8): The draft rule states that for existing biogas sources that typically vent a portion of their gas, that vented portion may be eligible for 45V if the venting volume can be adequately demonstrated and verified. For landfill gas, only the methane generation potential of waste-already-in-place at the time of IRA passage should be eligible for the credit. To calculate this, Treasury can use the waste-in-place value reported to the GHGRP in 2022 to estimate the methane generation potential of the degradable organic carbon in that buried waste. Only this quantity of gas, with a standard collection efficiency assumption applied, should be eligible as a feedstock under 45V. Alternatively, Treasury could set a time bound, such as 3-5 years from IRA passage, a period by which most organic materials in the landfill as of 2022 would have decayed, and landfill methane would only be an eligible feedstock in that window. This approach is important to avoid diversion from lower-emitting disposal methods to landfills.

If livestock biogas sources become more efficient at capturing methane, thus lowering the vented portion and increasing the volume of potential productive gas, that increased volume should also be eligible for the credit. In any case, this eligibility should not translate into a carbon-negative score that can be used for offsetting dirty hydrogen production.

Verification (Q4): Even in the case of direct use (i.e., not book-and-claim), verification of available productive use (or in other words, vented volumes and lack of pre-existing productive use) should take place through both data reported to the Greenhouse Gas Reporting Program and through on-site, third-party verification.

VI. Fugitive Methane

Treasury also seeks comment on potential eligibility of coal mine methane and other fugitive sources of methane. Fugitive methane from coal mines is a climate challenge, given the lack of regulations and policy incentives to encourage mitigation and the cost of deep reductions.

However, as is the case for biomethane, crediting these sources with GHG intensity scores introduces a series of risks, including the challenge of accurately accounting for GHG emissions (which is foundational to a robust and effective credit system), the risk of perpetuating fossil fuel activities, and the risk of enabling investments in dirty hydrogen production facilities. In the event that fugitive methane emissions are permitted, the same restrictions on carbon-negative offsetting should apply to fugitive methane emissions as well as biomethane, under the same logic explained in Section 5c.

In addition to that restriction, any use of fugitive methane should be delayed until achievement of the following principles can be demonstrated:

- Comprehensive: Fugitive methane should only be considered as a potential feedstock after conducting a lifecycle accounting based on measured data of the full hydrogen value chain (including likely end use), compared to the potential avoided emissions impact.
- Additional: The use of fugitive methane should offer an additional climate benefit over what the existing regulatory and policy framework would have achieved. Double counting should not be allowed with any other incentive programs, such as state emissions caps.[200]
- Directly Attributable: The use or procurement of fugitive methane should not be allowed to offset the positive emissions from other feedstocks.
- Measurable: Any use of fugitive methane must rely on scientific, peer-reviewed, measurement data rather than reported GHGRP data.
- Verifiable: The emissions associated with fugitive methane must be verified by a third party, and any use of book-and-claim would require a certificate tracking system to be first stood up and overseen by Treasury.
- Prudent: Negative externalities and the potential for perverse incentives, such as the creation of new methane markets, should be examined and mitigated. For example, the use of fugitive methane emissions should not prolong the lifetime of coal mining operations or enable the short-term build-out of hydrogen infrastructure that does not align with long-term climate objectives.
- Equitable: Guardrails must be in place to ensure that greenhouse gas emissions and health-harming co-pollutants are not increased or prolonged where facilities are proximate to or impacting disadvantaged communities. Limits on eligibility should be placed on the basis of

[200] Treasury should also make clear that under no circumstances can methane from oil and gas operations be eligible for treatment as "fugitive methane" under 45V. Fugitive methane (i.e. natural gas) from oil and gas operations is a valuable commodity that results from intentional production of a hydrogen feedstock and is already accounted for under 45V and GREET.

whether facilities contribute to the cumulative pollution burden of affected proximate communities.

- Targeted: Fugitive methane sources should be considered individually. Each has different methane leakage rates associated, as well as different preferred abatement alternatives – for example, incentives would be more appropriate for metallurgic coal, which currently has fewer substitutions for steelmaking, rather than thermal coal, which has viable replacement for power generation. Similarly, orphaned coal mines may have fewer opportunities for abatement than abandoned coal mines, which are often subject to lasting operator liability.

Given the significant uncertainties around each of the above principles, Treasury is not yet in a place to allow fugitive methane pathways for hydrogen production. Before considering eligibility, Treasury, in partnership with DOE and EPA, should first conduct a techno-economic study on fugitive methane impacts. This should include:

- A rigorous accounting of the lifecycle emissions for the full hydrogen value chain, including upstream methane emissions from different pathways and methane losses during capture and transport;
- An assessment of MRV systems and their accuracy;
- An analysis of the economics of blending, policy options for ensuring additionality, and abatement costs versus subsidy levels; and
- An assessment of the implications for different sectors, including how 45V eligibility might prolong fossil fuel activities and/or affect environmental and community outcomes.

VII. Hydrogen Emissions

a. *Hydrogen Has Significant Short-Term Warming Potential*

Hydrogen is a short-lived, indirect greenhouse gas (GHG) that causes warming by increasing the concentrations of GHGs in the atmosphere.[201, 202, 203, 204] Around 30% of molecular hydrogen emitted into the atmosphere chemically reacts with the naturally occurring hydroxyl radical after a few years. This reaction ultimately increases the amounts of short-lived greenhouse gases including methane, tropospheric ozone, and stratospheric water vapor.

The latest science suggests that hydrogen emissions are 30-40 times more powerful at trapping heat over the following 20 years than carbon dioxide for equal mass, and 8-12 times more powerful over a

[201] Warwick, N. J., et al (2023). Atmospheric composition and climate impacts of a future hydrogen economy. Atmospheric Chemistry and Physics, 23(20), 13451–13467. https://doi.org/10.5194/acp-23-13451-2023

[202] Sand, M. et al. A multi-model assessment of the Global Warming Potential of hydrogen. Commun Earth Environ 4, 203 (2023). https://doi.org/10.1038/s43247-023-00857-8

[203] Derwent, R. (2023). Global warming potential (GWP) for hydrogen: Sensitivities, uncertainties and meta-analysis. International Journal of Hydrogen Energy, 48(22), 8328–8341. https://doi.org/10.1016/j.ijhydene.2022.11.219

[204] Hauglustaine, D., Paulot, F., Collins, W., Derwent, R. G., Sand, M., & Boucher, O. (2022). Climate benefit of a future hydrogen economy. Communications Earth & Environment, 3(1). https://doi.org/10.1038/s43247-022-00626-z

100-year period.[205, 206, 207, 208] A recent multi-model assessment asserted high confidence in the quantification of hydrogen's warming effects and explicitly stated that the science is robust enough to be included in policy decisions and tools.[209]

Four IPCC assessment reports (TAR, AR4, AR5, AR6) mention hydrogen's warming effects. The IPCC Third Assessment Report (TAR) cautions that "in a possible fuel-cell economy, future emissions may need to be considered as a potential climate perturbation."[210] Hydrogen's GWP100 values (based on its tropospheric effects only) are reported in the Fourth Assessment Report[211] and Fifth Assessment Report.[212] The Sixth Assessment Report identifies hydrogen leakage as a challenge that the industry must overcome.[213]

b. Hydrogen Is Known to Enter the Atmosphere through Operational Releases and Leakage

Hydrogen is emitted from both natural and human systems. However, there are virtually no empirical measurements of hydrogen emissions from the current hydrogen industry. Hydrogen is notoriously hard to hold onto given its small molecular size, and it is emitted throughout the value chain from both operational releases and leakage. A current concern is that hydrogen emissions may considerably increase as the hydrogen energy industry is scaled up. In the absence of direct measurements, several studies have estimated emissions from venting, purging, and leakage at various stages of the value chain and in total, finding a wide range in emissions anywhere from <1% to 20%.[214] Advanced sensor equipment capable of measuring hydrogen emissions down to the parts per billion level at a fast

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205 Warwick, N. J., et al (2023). Atmospheric composition and climate impacts of a future hydrogen economy. Atmospheric Chemistry and Physics, 23(20), 13451–13467. https://doi.org/10.5194/acp-23-13451-2023

206 Sand, M. et al. A multi-model assessment of the Global Warming Potential of hydrogen. Commun Earth Environ 4, 203 (2023). https://doi.org/10.1038/s43247-023-00857-8

207 Derwent, R. (2023). Global warming potential (GWP) for hydrogen: Sensitivities, uncertainties and meta-analysis. International Journal of Hydrogen Energy, 48(22), 8328–8341. https://doi.org/10.1016/j.ijhydene.2022.11.219

208 Hauglustaine, D., Paulot, F., Collins, W., Derwent, R. G., Sand, M., & Boucher, O. (2022). Climate benefit of a future hydrogen economy. Communications Earth & Environment, 3(1). https://doi.org/10.1038/s43247-022-00626-z

209 Sand, M. et al. A multi-model assessment of the Global Warming Potential of hydrogen. Commun Earth Environ 4, 203 (2023). https://doi.org/10.1038/s43247-023-00857-8

210 IPCC Third Assessment Report (TAR), Working Group I, Chapter 4, 4.2.3 Reactive Gases , pg. 256 (2001)

211 IPCC Fourth Assessment Report (AR4), Working Group I, Chapter 2, 2.10.3.6 Hydrogen (2007)

212 IPCC Fifth Assessment Report (AR5), Working Group I, Chapter 8 Supplemental Material, 8.SM.14 Metric Values for Other Near-Term Climate Forcers to Support Section 8.7.2, pg. 23 (2013)

213 IPCC AR6 Working Group III, Chapter 6, 6.4.5.1 Hydrogen: Low-carbon Energy Fuel, pg. 657 (2022)

214 Esquivel-Elizondo, S., Mejia, A. H., Sun, T., Shrestha, E., Hamburg, S., & Ocko, I. B. (2023). Wide range in estimates of hydrogen emissions from infrastructure. Frontiers in Energy Research. https://doi.org/10.31219/osf.io/unzrm

response time was recently developed[215] (with several more instruments under development[216]), and will enable empirical measurements of hydrogen emissions from existing infrastructure in the near future. For example, EDF has been partnering with Aerodyne Research – developers of a highly advanced hydrogen sensor that detects hydrogen with a 5ppb precision – to test and measure hydrogen emissions from infrastructure. And in 2023, DOE invested more than $8 million in high-precision sensor development.[217]

Hydrogen emissions can significantly undermine the climate benefits of hydrogen use. For example, a study published by EDF in 2022 shows that under high rates of methane and hydrogen emissions, blue hydrogen can be worse for the climate in the near term than the fossil fuels it is replacing.[218] EDF also recently published a study that reanalyzed a previously published lifecycle assessment as an illustrative example to show how the climate impacts of hydrogen deployment can be far greater than expected when including the warming effects of hydrogen emissions, observed methane emissions intensities, and near-term timescales. The study considers eight well-to-use hydrogen pathways in the industry, transport, and power sectors compared to the fossil fuel alternatives they intend to replace. The authors found that for blue hydrogen pathways, high hydrogen and methane emissions can yield an increase in warming in the near-term by up to 50%, whereas low emissions decrease warming impacts by at least 70%. For green hydrogen pathways, upper-end hydrogen emissions can reduce the climate benefits in the near-term by up to 25%.[219]

c. Hydrogen Emissions Should Be Factored Into 45VH2-GREET and Submitted to Treasury Using Multiple Time Horizons

Due to the warming potential of hydrogen, hydrogen emissions associated with production must be factored into lifecycle assessments through the 45VH2-GREET model. Failure to do so would compromise the emission reduction potential of the 45V tax credit. We understand that Argonne has already been exploring the inclusion of hydrogen emissions into the GREET model. While the GREET model currently does not include hydrogen's warming effects, the R&D version does include loss rates throughout the value chain. Moreover, hydrogen producers are often able to conduct a mass balance calculation of what

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[215] Environmental Defense Fund, 2023, "Hydrogen emissions measurement study," https://www.edf.org/sites/default/files/documents/hydrogen-emissions-measurement-study-2023.pdf

[216] Department of Energy. (n.d.). Selections for funding opportunity in support of the hydrogen Shot and a university research consortium on grid resilience. energy.gov. Retrieved February 26, 2024, from https://www.energy.gov/eere/fuelcells/selections-funding-opportunity-support-hydrogen-shot-and-university-research

[217] Highlights from 2023—a Big Year for Clean Hydrogen. (2024, January 11). Energy.gov. https://www.energy.gov/eere/fuelcells/articles/highlights-2023-big-year-clean-hydrogen#:~:text=Sixteen%20projects%20were%20selected%20to,%248%20million%20for%20hydrogen%20sensors

[218] Ocko, I. B. and Hamburg, S. P.: Climate consequences of hydrogen emissions, Atmos. Chem. Phys., 22, 9349–9368, https://doi.org/10.5194/acp-22-9349-2022

[219] Sun, T. et al (2024). Climate Impacts of Hydrogen and Methane Emissions Can Considerably Reduce the Climate Benefits across Key Hydrogen Use Cases and Time Scales. Environmental Science & Technology. https://pubs.acs.org/doi/10.1021/acs.est.3c09030

they expect to produce versus what they actually produce. We recommend that hydrogen's GWPs be applied to one of these two current forms of loss rates (by using GWP values of 37 for GWP20 and 12 for GWP100),[220] and then as empirical measurements became available, the loss rates should be updated annually to reflect best available data.

Similar to our comments on methane leakage, we understand that GWP100 values will be used to determine eligibility. Even these values can make or break eligibility; for example, in figure 4b, hydrogen emissions of just 2% renders Permian basin-derived hydrogen ineligible for the tax credit. In addition, GWP20 values (along with the hydrogen loss rates themselves) should also be reported to Treasury for informational purposes so producers and policymakers can understand the hydrogen's full climate impact.

*d. Treasury Has Taken the Right First Step by Excluding Wasted Hydrogen from Receiving the Tax Credit; All Detectable Emissions Should Be Similarly Exclude*d

We welcome Treasury's draft rule in taking a first step of excluding "wasted" gas (i.e., vented and flared) from being able to claim the 45V tax credit. This would not only be a waste of taxpayer resources and defy the statute of the IRA calling for subsidized hydrogen to be "for sale or use," but it would also result in directly incentivizing climate-warming emissions. The final rule should be amended to also specify "purged" hydrogen as being excluded alongside other wasted forms, as well as levels of unintentional emissions that are detectable (e.g., by comparing the mass balances and/or known inputs with the calculated outputs of hydrogen energy to be sold). These loss rates should be reported to Treasury alongside the claimed volumes to improve the data collection around hydrogen emissions.

e. As Sensor Technology Progresses, Smaller Levels of Fugitive Emissions Should Also Be Excluded from Receiving the Tax Credit

As high precision sensors become commercially available, it will become increasingly possible for hydrogen producers to measure their fugitive emissions along with their calculated lost volumes. Sensors are already nearing this point, with some high-precision, high-frequency sensors already undergoing field tests (as described in section B above). Treasury should thus stipulate that all levels of fugitive emissions will eventually be excluded from receiving the tax credit once high-precision hydrogen sensors are commercially available and accessible.

f. Treasury Should Require Hydrogen Producers to Adopt Emission Management Plans

To both verify the amount of wasted hydrogen gas and as an incentive to control hydrogen emissions, producers should be required to submit hydrogen emission management plans to Treasury each year. These should include a commitment to using the best available sensor technology to detect leaks (once commercially available and accessible), as well as operational best practices to mitigate leakage – such as adequately insulating pipes, installing vapor recovery units to capture boil-off, recovering vented

[220] Sand, M. et al. A multi-model assessment of the Global Warming Potential of hydrogen. Commun Earth Environ 4, 203 (2023). https://doi.org/10.1038/s43247-023-00857-8

hydrogen, and installing control devices on storage tanks.[221] Management plans should also disclose whether producers are using venting, flaring, and purging practices and state how a facility is verifying final volumes to ensure tax credit compliance.

VIII. Embodied Emissions

Treasury should proceed with caution around calls for including embodied emissions for 45V eligibility. While all lifecycle emissions should be fully measured and calculated, including embodied emissions in eligibility would require an adjustment to the GHG intensity thresholds. Congressional colloquy makes clear that the current GHG intensity thresholds were set under the assumption that embodied emissions would not be included. Neither IPHE,[222] IEA,[223] nor DOE[224] currently include embodied emissions in their LCA methodologies, under the rationale that these emissions are projected to decline substantially to the point of immateriality. Any future inclusion of embodied emissions should be applied to both electrolytic and SMR pathways, with a careful accounting of equipment timelines, production allocation, the full set of associated technologies, and regional variability of emissions.

IX. Geologic Hydrogen

While the formation of geologic, or natural, hydrogen is well understood, and exploration efforts are underway in many countries, only one reservoir is currently being commercially exploited. Geologic hydrogen can offer positive benefits over fossil fuels and blue/green hydrogen, though there are some uncertainties around its climate impact.

Geologic hydrogen can co-occur with methane. Therefore, drilling to extract it can lead to both new hydrogen and methane emissions, which must be prevented or mitigated if we want this form of hydrogen to be climate beneficial.

One study estimates that if the methane content of the gas reservoir is less than 1.5%, the LCA GHG emissions could be lower than those from green hydrogen, assuming all processes rely on clean electricity fuels and fugitive hydrogen emissions are less than 1%.[225] However, the methane content of

[221] Environmental Defense Fund. (2023, May 8). Preventing and mitigating hydrogen emissions from infrastructure. Retrieved February 21, 2024, from https://www.edf.org/sites/default/files/documents/H2%20Emissions%20Mitigation%20Factsheet_08MAY2023.pdf

[222] *See* IPHE Hydrogen Production Analysis Task Force. (2023, July). Methodology for Determining the Greenhouse Gas Emissions Associated With the Production of Hydrogen. https://www.iphe.net/_files/ugd/45185a_8f9608847cbe46c88c319a75bb85f436.pdf *pg 42*

[223] International Energy Agency. (n.d.). Towards hydrogen definitions based on their emissions intensity. Retrieved February 21, 2024, from https://iea.blob.core.windows.net/assets/acc7a642-e42b-4972-8893-2f03bf0bfa03/Towardshydrogendefinitionsbasedontheiremissionsintensity.pdf

[224] U.S. Department of Energy. (n.d.). U.S. Department of Energy Clean Hydrogen Production Standard (CHPS) Guidance. Retrieved February 21, 2024, from https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/clean-hydrogen-production-standard-guidance.pdf

[225] Brandt, A. R. (2023). Greenhouse gas intensity of natural hydrogen produced from subsurface geologic accumulations. Joule, 7(8), 1818–1831. https://doi.org/10.1016/j.joule.2023.07.001

geologic hydrogen reservoirs vary and could be as high as 30% or more.[226, 227] This methane content has an even greater impact when considering the near-term time horizon (GWP20).

Given the significant uncertainties associated with climate impact, the community concerns and air quality risks that would arise around drilling activities, and the lack of basis for cost estimates and subsidy needs, Treasury should reserve decisions on provisional emission rates for geologic hydrogen until a later rulemaking process can be undertaken based on robust climate and environmental data.

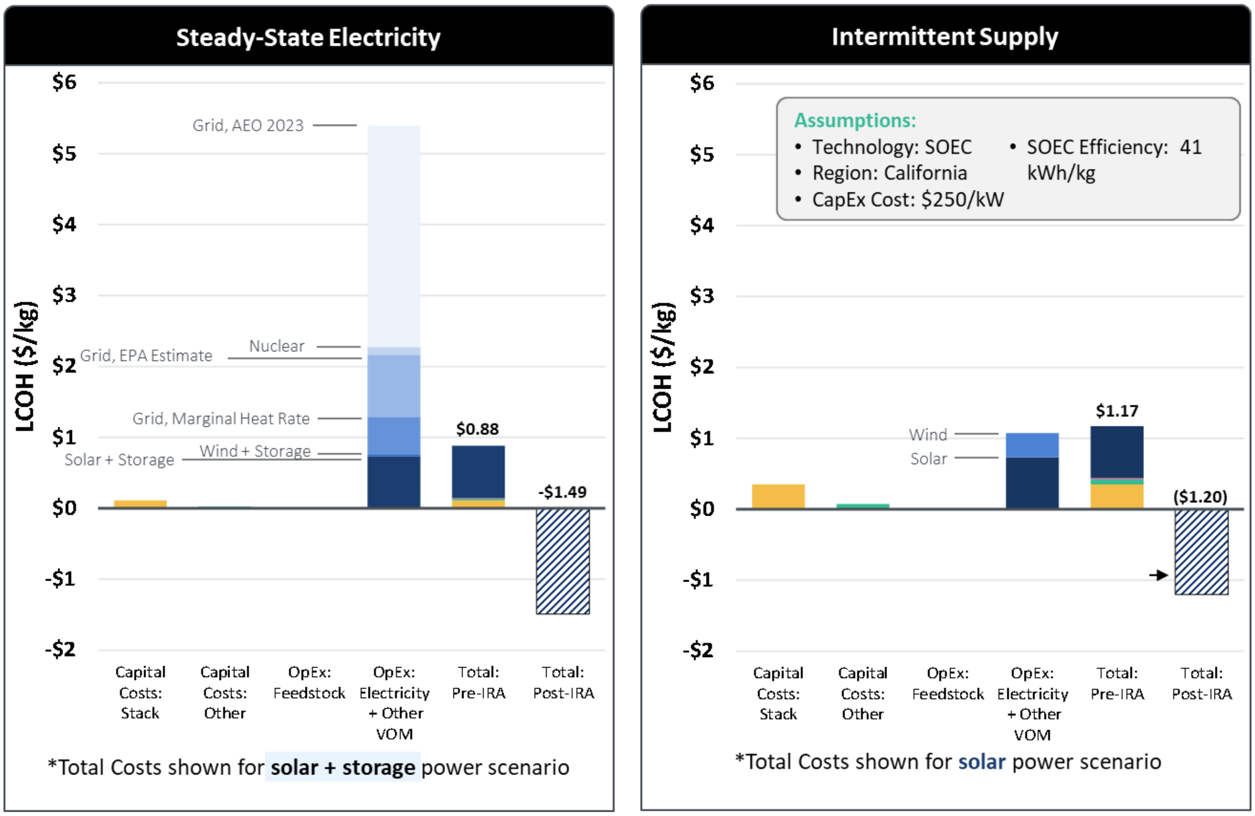
X. Potential for Abuse

There is a high risk of abuse of 45V, including through stacking with other tax credits, and having money flow toward non-optimal uses of hydrogen. For example, a synthetic methane company could combine IRA tax credits for renewable electricity, hydrogen, and CCS, along with subsidies from California's LCFS, totaling more than $60/MMBtu to produce a commodity worth just $3/MMBtu (the Henry Hub price) -- a clear waste of taxpayer dollars.[228]

Moreover, the hydrogen from 45V doesn't even need to be turned into an energy commodity to be eligible for (and circumvent the intent of) the tax credit. While there are specific protections against wasteful venting or flaring, the hydrogen could nonetheless be turned into electricity and used to power blockchain mining or run through a combustion turbine at times when it provides no value to the grid.[229] This is even more likely of a scenario in later years of the tax credit, when hydrogen production costs come down close to or below $3/kg. As shown in Figure 7, the Brattle Group projects green hydrogen production costs in California to reach $0.88/kg for steady-state electricity and $1.17/kg for intermittent supply by 2030.[230] Coupling that with 45V yields negative costs, or free production.

[226] EDF assessment of Zgonnik 2020, "The occurrence and geoscience of natural hydrogen: A comprehensive review," Earth-Science Reviews 203, https://doi.org/10.1016/j.earscirev.2020.103140
[227] Natural Hydrogen Energy LLC. (n.d.). Natural Hydrogen Energy LLC. https://nh2e.com/
[228] Examples provided by Michael Liebreich and Jesse Jenkins during Canary Media webinar, Clean energy experts break down hydrogen hype and hope. (2024, February 1). Canary Media. https://www.canarymedia.com/articles/hydrogen/clean-energy-experts-break-down-hydrogen-hype-and-hope
[229] *Id.*
[230] The Brattle Group, 2024, "The economics of hydrogen production and delivery," https://www.brattle.com/wp-content/uploads/2024/02/Emerging-Economics-of-Hydrogen-Production-and-Delivery_2024-1.pdf

Figure 7. Potential Electrolytic Hydrogen Production Costs in California in 2030[231]



This phenomenon of supply overshoot occurred in Spain in 2008 through their short-lived policy of uncapped, unlimited solar tariffs. Even with a revenue reduction trajectory (which 45V notably does not have), the proliferation of projects and tax credit liability was so great that it nearly bankrupted the country. Spain was forced to end the subsidy retroactively that paralyzed the market for nearly a decade.[232]

Treasury must establish backstops to prevent this type of abuse. It must expand on its proposed §1.45V-2(b)(1) provision to define what classifies as "wasteful" beyond being "vented, flared, or used to produce hydrogen." It should prohibit purposes that do not reduce system-wide GHG emissions.

[231] The Brattle Group, 2024, "Emerging economics of hydrogen production and delivery," https://www.brattle.com/wp-content/uploads/2024/02/Emerging-Economics-of-Hydrogen-Production-and-Delivery_2024-1.pdf

[232] Deign, J. (2019, August 15). Spain moves to prevent a second solar bubble. Wood Mackenzie. https://www.greentechmedia.com/articles/read/spain-tightens-rules-for-solar-as-second-bubble-looms

XI. Appendices

Appendix A. Technical Memo Regarding the Nationwide Methane Leakage Rate in 45VH2-GREET 2023

The 45VH2-GREET 2023 model used to calculate lifecycle greenhouse gas emissions of hydrogen production estimates that methane leakage during the natural gas recovery, processing, and transmission processes sums to ~0.9% of natural gas consumed by the reformer.[233] (This 0.9% leak rate is not inclusive of combustion methane emissions, which are treated separately in GREET. For better visibility into the overall methane burden of natural gas in GREET, we recommend that a leak rate inclusive of combustion emissions is also published.) As Appendix B states, enhancing the GREET model to incorporate basin-specific emissions data would lead to more accurate accounting of greenhouse gas emissions associated with specific hydrogen production facilities. However, in basins where current emissions data is unavailable, a default leak rate based on average, nationwide emissions may still need to be used. Here, we identify several areas of improvement for calculating this nationwide leakage rate.

1. GREET's nationwide, default leakage rate currently excludes emissions from wells that produce and market both oil and gas. Commonly referred to as "co-producing wells" or "oil wells producing associated gas," these wells produce gas that is fed into the natural gas supply chain that hydrogen producers will use as a feedstock. The "natural gas pathway" in GREET uses the same division that EPA uses between the Natural Gas Greenhouse Gas Inventory (GHGI) and the Petroleum GHGI.[234] This division is based on gas-to-oil ratios: wells with GOR>100 mcf/bbl are defined as gas wells, and well with GOR<100 mcf/bbl are defined as oil wells.[235] (Note that the particular GOR threshold can vary between agencies: EIA defines gas wells based on a GOR>6 mcf/bbl, and oil wells based on a GOR<6 mcf/bbl.[236] This difference highlights that relying on the EPA GHGI distinction may be inaccurate). However, wells classified as "oil wells" under any definition can and often do produce and market some amount of natural gas, which may ultimately be purchased by hydrogen producers. Excluding emissions from oil wells means that these emissions are not properly accounted for.

    a. EDF Recommendation: Leak rates in GREET should include emissions from co-producing wells. Typical LCA protocols require allocating emissions among different co-products coming from the same unit process or product system.[237] Various life cycle assessments models have used different ways to split emissions from oil and gas production, though a

[233] https://www.energy.gov/sites/default/files/2023-12/greet-manual_2023-12-20.pdf

[234] Burnham, A. (2023). Updated Natural Gas Pathways in GREET 2023. Argonne National Lab (anl.gov)

[235] United States Environmental Protection Agency. (2015, April). Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2013: Revision to Well Counts Data. https://www.epa.gov/sites/default/files/2015-12/documents/revision-data-source-well-counts-4-10-2015.pdf

[236] US oil and gas wells by production rate - U.S. Energy Information Administration (EIA). (n.d.). https://www.eia.gov/petroleum/wells/#:~:text=We%20designate%20wells%20as%20either,well%20as%20an%20oil%20well

[237] International Organization for Standardization. ISO 14040:2006, Environmental management — Life cycle assessment — Principles and framework. (2006).

common method is to use relative energy production.[238,239] We recommend that GREET use a similar method in order to account for emissions from oil wells that also produce and market natural gas.

2. GREET's nationwide default leakage rate incorporates certain top-down emissions measurement data but scales it to the natural gas GHGI. The natural gas GHGI shows emissions decreasing with time, especially for the production segment, the biggest contributor to overall supply chain emissions. Measurement data have not shown such a decrease over time,[240] so scaling the measurement-based emissions data based on the GHGI trend may yield a low-bias in the national leakage rate.

    a. EDF Recommendation: Rather than scaling the measurement-based emissions data with the GHGI for each year, the best and most currently available measurement-based estimates of total national (and/or basin-specific) methane emissions should be used to determine average GREET methane leakage rates.

3. GREET's nationwide, default leakage rate does not include recent data showing that distribution emissions are significantly higher than EPA estimates: Weller et al.[241] found that nationally, emissions from distribution mains pipelines were roughly five times higher than estimated by EPA.

    a. EDF Recommendation: The GREET model should incorporate this new data and revise their emissions estimate for pathways involving distribution pipelines to align with that found by Weller et al.

[238] Allen, D. T., Chen, Q., & Dunn, J. B. (2021). Consistent Metrics Needed for Quantifying Methane Emissions from Upstream Oil and Gas Operations. Environmental Science and Technology Letters, 8(4), 345–349. https://doi.org/10.1021/acs.estlett.0c00907

[239] Alvarez, R. A., et al (2012). Greater focus needed on methane leakage from natural gas infrastructure. Proceedings of the National Academy of Sciences of the United States of America, 109(17), 6435–6440. https://doi.org/10.1073/pnas.1202407109

[240] Lu, X., et al (2023). Observation-derived 2010-2019 trends in methane emissions and intensities from US oil and gas fields tied to activity metrics. Proceedings of the National Academy of Sciences of the United States of America, 120(17). https://doi.org/10.1073/pnas.2217900120

[241] Weller, Z. D., Hamburg, S. P., & Von Fischer, J. C. (2020). A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems. Environmental Science & Technology, 54(14), 8958–8967. https://doi.org/10.1021/acs.est.0c00437

Appendix B. Technical Memo Regarding the Need for Basin-Specific Methane Leakage Rates in 45VH2-GREET 2023

The 45VH2-GREET 2023 model used to calculate lifecycle greenhouse gas emissions of hydrogen production estimates that methane leakage during the natural gas recovery, processing, and transmission processes sums to ~0.9% of natural gas consumed by the reformer.[242] This leakage rate is intended to capture only a nationwide average. However, methane emissions and methane leakage rates are known to vary significantly across basins. For example, many studies find the total methane leakage rate from oil and gas production in the Permian to be between 3% and 4%,[243,244,245,246] in subbasins of the Marcellus to range from 0.4%[247] to 1.1%[248] to even higher[249] and in the Uinta to be between 6% and 8%.[250,251] Reliance on a single nationwide average leakage rate obscures these large differences between basins and prevents a full accounting of greenhouse gas emissions burdens of downstream uses.

In order to properly assign methane emissions to hydrogen production projects -- to reflect the actual emissions associated with the natural gas being used as feedstock -- regionally specific leakage rates should be incorporated into GREET. In the same way that emissions from electricity generation vary by grid region, methane emissions from oil and gas production vary by basin, and this should be accounted for in 45VH2-GREET. To do this, we recommend an approach similar to that demonstrated in the recent

[242] U.S. Department of Energy. (2023, December). Guidelines to Determine Well-to-Gate Greenhouse Gas (GHG) Emissions of Hydrogen Production Pathways using 45VH2-GREET 2023. https://www.energy.gov/sites/default/files/2023-12/greet-manual_2023-12-20.pdf

[243] Zhang, Y., et al (2020). Quantifying methane emissions from the largest oil-producing basin in the United States from space. Science Advances, 6(17). https://doi.org/10.1126/sciadv.aaz5120

[244] Lu, X., et al (2023b). Observation-derived 2010-2019 trends in methane emissions and intensities from US oil and gas fields tied to activity metrics. Proceedings of the National Academy of Sciences of the United States of America, 120(17). https://doi.org/10.1073/pnas.2217900120

[245] Barkley, Z., et al (2022).: Quantification of oil and gas methane emissions in the Delaware and Marcellus basins using a network of continuous tower-based measurements, Atmos. Chem. Phys. https://acp.copernicus.org/preprints/acp-2022-709/acp-2022-709.pdf

[246] Varon, D. J., et al (2023). Continuous weekly monitoring of methane emissions from the Permian Basin by inversion of TROPOMI satellite observations. Atmospheric Chemistry and Physics, 23(13), 7503–7520. https://doi.org/10.5194/acp-23-7503-2023

[247] Barkley, Z., et al (2023). Quantification of oil and gas methane emissions in the Delaware and Marcellus basins using a network of continuous tower-based measurements. Atmospheric Chemistry and Physics, 23(11), 6127–6144. https://doi.org/10.5194/acp-23-6127-2023

[248] Ren, X, et al (2019). Methane Emissions from the Marcellus Shale in Southwestern Pennsylvania and Northern West Virginia Based on Airborne Measurements. Journal of Geophysical Research: Atmospheres, 124(3), 1862–1878. https://doi.org/10.1029/2018jd029690

[249] Omara, M., et al (2016). Methane Emissions from Conventional and Unconventional Natural Gas Production Sites in the Marcellus Shale Basin. Environmental Science & Technology, 50(4), 2099–2107. https://doi.org/10.1021/acs.est.5b05503

[250] Lin, J. C., et al (2021). Declining methane emissions and steady, high leakage rates observed over multiple years in a western US oil/gas production basin. Scientific Reports, 11(1). https://doi.org/10.1038/s41598-021-01721-5

[251] Note that for basins that produce substantial amounts of oil as well as gas (Permian, Uinta), these leakage rates are not directly comparable to the 0.9% leakage rate currently estimated in GREET since the total basin-level leakage rates have not been apportioned between oil and gas production.

preprint by Vallejo et al.[252]: they calculate a total methane leakage rate from oil and gas production for two illustrative basins using recent, measurement-based data. They then allocate emissions in each basin for different stages between oil, gas, and natural gas liquids using an energy-based allocation method (using publicly available production data) and derive emissions for that basin's natural gas pathway.

We lay out our recommended approach below:

1. Determine the optimal scale for spatial differentiation of methane leak rates (e.g., basin or sub-basin) depending on the availability of emissions data and the specificity with which end users of natural gas can determine its production origin. For simplicity within this memo, we reference basins or sub-basins as a natural boundary for spatial differentiation, but larger regions may equally be used within GREET depending on data availability.
2. For each basin or sub-basin, gather and synthesize the best available measurement-based emissions data into an integrated basin leakage rate. This synthesis of measurement data should be updated regularly (e.g., yearly or every 2-3 years) to incorporate new data, including aircraft, satellite, and ground-based data.
3. Use measurement data or inventory approaches to split emissions between stages: production, processing, transmission, and distribution.
4. Use publicly available production data in order to allocate emissions between various co-products at each stage of production.
5. Derive a leakage rate for the natural gas pathway (which includes natural gas-allocated emissions from co-producing wells) in each basin (or sub-basin) and assign it within GREET to natural gas sourced from that basin.

As an example to show both the range of natural gas leakage rates between regions, and the process by which that variation could be incorporated into methane leakage rates within GREET, we rely on the total methane leak rates from Ren et al.[253] for the Southwestern Marcellus (1.1% leakage rate) and Zhang et al.[254] for the Permian (3.7% leakage rate) as representative of recent, available data for that sub-basin and basin, respectively. We then use both the emissions breakout by stage (production vs. processing vs. transmission) and the oil and gas production data presented in Vallejo et al.[255] to derive leakage rates for the natural gas produced from both the Permian and the Southwestern Marcellus, shown in Table 1 below.

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[252] Vallejo, V., Nguyen, Q. P., & Ravikumar, A. (2023, November 20). Geospatial Variation in Carbon Accounting of Low-Carbon Hydrogen Production Pathways: Implications for the Inflation Reduction Act. https://eartharxiv.org/repository/view/6278/

[253] Ren, X., et al (2019c). Methane Emissions from the Marcellus Shale in Southwestern Pennsylvania and Northern West Virginia Based on Airborne Measurements. Journal of Geophysical Research: Atmospheres, 124(3), 1862–1878. https://doi.org/10.1029/2018jd029690

[254] Vallejo, V., Nguyen, Q. P., & Ravikumar, A. (2023, November 20). Geospatial Variation in Carbon Accounting of Low-Carbon Hydrogen Production Pathways: Implications for the Inflation Reduction Act. https://eartharxiv.org/repository/view/6278/

[255] Vallejo, V., Nguyen, Q. P., & Ravikumar, A. (2023, November 20). Geospatial Variation in Carbon Accounting of Low-Carbon Hydrogen Production Pathways: Implications for the Inflation Reduction Act. https://eartharxiv.org/repository/view/6278/

Region	Natural Gas-Allocated Methane Leakage Rate[256]
Permian	2.0%
SW Marcellus	1.1%

Due to the low relative production of natural gas liquids compared to natural gas in the SW Marcellus, the natural gas pathway leakage rate ends up being nearly identical to the overall SW Marcellus sub-basin leakage rate at ~1.1%. In the Permian, due to the significant oil production, the leakage rate allocated to natural gas production (including from co-producing wells) ends up being slightly more than half of the overall basin leakage rate. (Note that the difference between these two regions in this analysis is less than that found in Vallejo et al.; that study also included a study in the Permian that we do not consider due to its smaller study domain, high detection threshold of measurements, and assumption of persistence of emissions).

[256] Includes emissions from production, gathering, processing, transmission, and distribution.

Attachment C. EDF Analysis of Rystad Data on U.S. Hydrogen Production Projects

See attachment

Attachment D. New EDF Hydrogen Lifecycle Analysis

See attachment or Sun et al, Climate Impacts of Hydrogen and Methane Emissions Can Considerably Reduce the Climate Benefits across Key Hydrogen Use Cases and Time Scales, Environ. Sci. Technol. 2024, https://pubs.acs.org/doi/10.1021/acs.est.3c09030

Attachment E. ERM Assessment of Grid-Connected Hydrogen Production Impacts – Part I

See attachment or https://www.erm.com/assessment-of-grid-connected-hydrogen-production-impacts/

Attachment F. ERM Assessment of Grid-Connected Hydrogen Production Impacts – Part II

See attachment or https://www.erm.com/assessment-of-grid-connected-hydrogen-production-impacts/