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Via email to Cleanh2standard@ee.doe.gov

Karen Dandrige
Hydrogen and Fuel Cell Technologies Office
U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy
Re: Notice of Availability of Draft Guidance on Hydrogen and Fuel Cell Program: Guidance for the Clean Hydrogen Production Qualifications; 87 FR 58776

Dear Ms. Dandridge:

The American Petroleum Institute (API) appreciates the opportunity to comment on the Department of Energy's (DOE's) draft guidance for the Clean Hydrogen Production Standard (CHPS), 87 Fed. Reg. 58776, September 28, 2022. API recognizes this effort as DOE's first attempt to incorporate input from industry and other stakeholders in the development of a CHPS, as required by the Bipartisan Infrastructure Las (BIL), also known as the Infrastructure Investment and Jobs Act (IIJA).[1] As an established supplier of feedstock for hydrogen production, consumer of hydrogen, and leader in CO_2 management, and expected producer, transporter, and consumer of low-carbon hydrogen, the oil and natural gas industry has a significant role to play and interest in the establishment of a well-developed clean hydrogen production standard. The oil and natural gas industry is central to the collection and proper allocation of upstream greenhouse gas emission data that are associated with the production and transportation of natural gas. This data, as expressed in the draft guidance, is of critical importance to ensuring that the CHPS represents an accurate lifecycle accounting of greenhouse gas emissions for hydrogen produced by both thermal and electrolytic pathways. As the industry looks to engage in the development of a low-carbon hydrogen economy, it is in the industry's best interest to ensure that it is built on a solid foundation of robust data and analysis.

This letter raises concerns regarding the deficiencies of the current and updated GREET model to meet the needs of the CHPS, the scope of the CHPS being discussed by DOE beyond production, the ability of applicants to credibly include improvements in operations that are not included in the GREET model, the allocation of emissions among coproducts, uncertainty with respect to global warming potentials that will be applied, the ability to treat the verification of emissions associated with all feedstocks used to produce clean hydrogen equitably, and the approach that DOE is taking to meet the legal requirements and qualification of the standard as a guidance or a regulatory standard.

[1] Public Law 117-58 (November 15, 2021) 135 Stat. 1015

1. *API is concerned by the development of the Clean Hydrogen Production Standard as a non-regulatory standard.*

DOE has stated that the CHPS is not a regulatory standard; however, this approach does not recognize the manner in which this standard will likely be used. While DOE insists that the CHPS is not a regulatory standard and will be used "only to guide the DOE's hydrogen programs in EPAct 2005,"[2] this claim is directly in conflict with orientation of the CHPS to align with the 45V tax credit. DOE notes that the CHPS "uses the same lifecycle analysis system boundary as the IRA *and targets the emissions rate where the operators can begin to qualify for credits,*" (emphasis added).[3] Therefore, the standard appears to impose requirements in the same way that a regulation does. In drafting the CHPS to align with the IRA 45V tax credit requirements, despite being under no obligation to do so and with no lifecycle requirements included in the BIL for DOE's Regional Hydrogen Hub program, it is clear that DOE has drafted the CHPS to become the standard for the 45V tax credit. If DOE intends the standard to have the same effect as a regulation does, the standard must be issued as a proposed regulation that follows proper notice and comment rulemaking procedures under the Administrative Procedure Act (APA).

Issuing the standard as a proposed regulation, following notice and comment procedures under the APA, would provide greater insight and certainty for stakeholders regarding DOE's next steps for the CHPS. At this point, it is unclear if DOE will provide additional opportunities for stakeholder engagement in the near future and beyond. Further, DOE has noted in the draft guidance that the BIL requires that the production standard be reviewed within 5 years of its development, yet the guidance provides no indication of how or when that review will be initiated.

The IRA requires that the DOE use the GREET model, "or a successor model as determined by the Secretary". Building on the uncertainty associated with DOE's path forward for the CHPS, it is unclear how the Secretary will determine or select when or how to adopt a successor model. While the IRA is referring to the Secretary of Treasury, the GREET model, as a product of Argonne National Laboratory, is the responsibility of the Department of Energy, enabling DOE to address this concern within the structure of the CHPS. As the CHPS is also reliant on the GREET model (and any successor version), this draft guidance may represent the only opportunity for stakeholders to raise concerns over the design of the model or its ability to address the needs of the BIL and the IRA. Full adherence to the APA would allow for a more complete opportunity to engage in the improvement of the GREET model. Stakeholders could be given a greater opportunity to provide additional data that may assist in the development of the model, or an opportunity to indicate which areas in the model should be prioritized for improvement.

Finally, adherence to APA processes, including the establishment of a formal docket, would allow for stakeholders to review comments submitted by other interested parties. This information sharing can help to address and alleviate concerns simply by enabling stakeholders to review and consider different points of view or solutions to commonly-voiced problems as proposed by others. The latter element could also help DOE find an acceptable path forward on any such problems by allowing stakeholders to show alignment behind a specific approach. In contrast to the opacity of the legislative process, this sort of "daylight" can help stakeholders better understand agency decision-making regarding which

[2] USDOE, "Clean Hydrogen Production Standard (CHPS) Draft Guidance," p3. September 22, 2022.
[3] *Id*., p4.

arguments the agency may find the most compelling and to which comments the agency may apply greater value.

2. *The modeling and data used to determine the carbon intensity of hydrogen production is of paramount importance and must reflect the best available approaches.*

> *1) b) Lifecycle analysis to develop the targets in this draft CHPS were developed using GREET. GREET contains default estimates of carbon intensity parameters that are not likely to vary widely by deployments in the same region of the country (e.g., carbon intensity of regional grids, net emissions for biomass growth and production, avoided emissions from the use of waste-stream materials). In your experience, how accurate are these estimates, what are other reasonable values for these estimates and what is your justification, and/or what are the uncertainty ranges associated with these estimates?*

As reflected in many of DOE's questions and the inclusion of the "Hydrogen Production Pathway Assumptions" spreadsheet, DOE recognizes that the current and updated versions of the GREET model are not yet fully developed to provide a lifecycle assessment of hydrogen production for the purpose of the 45V tax credit provided by the Inflation Reduction Act of 2022 (IRA). API has commissioned an expert review of the GREET model to contribute to this comment package and to guide necessary improvements to the model. This review is enclosed, titled "Evaluation of Argonne National Laboratory's GREET Model for Use in the Clean Hydrogen Production Standard (CHPS)," prepared by Philip Heirigs, P.E. of P Heirigs Consulting LLC. It is clear from the review that the model is not sufficiently developed at this time to capture an accurate representation of upstream methane emissions nor is it sufficiently developed to recognize the range of thermal production pathways that may be pursued by hydrogen producers.

The GREET model does not provide a pathway for the production of clean hydrogen at refineries or other existing industrial facilities that have on-site hydrogen production capabilities. As noted in DOE's draft National Clean Hydrogen Strategy and Roadmap, the refining sector accounted for 55% of all hydrogen consumption in the US in 2021.[4] Further, in the context of DOE's strategy to target "Strategic, High-Impact Uses of Hydrogen,"[5] DOE has cited petroleum refining as a "near-term" opportunity to reduce emissions by displacing conventional hydrogen. For a significant portion of the refining sector, employing such a strategy would mean producing clean hydrogen at the refinery. EIA estimated in 2014 that roughly one-third of hydrogen used in refineries was produced on-site rather than being supplied by merchant producers.[6] In its current iteration, the GREET model allows only for a central plant.

> *1) a) Many parameters that can influence the lifecycle emissions of hydrogen production may vary in real-world deployments. Assumptions that were made regarding key parameters with high variability have been described in footnotes in this document and are also itemized in the*

[4] U.S. Department of Energy, "DOE National Clean Hydrogen Strategy and Roadmap (Draft)." Sept. 2022. https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-strategy-roadmap.pdf
[5] Id., p 41
[6] https://www.eia.gov/todayinenergy/detail.php?id=24612

attached spreadsheet "Hydrogen Production Pathway Assumptions." Given your experience, please use the attached spreadsheet to provide your estimate for values these parameters could achieve in the next 5-10 years, along with justification.

As recently noted by the National Academies of Sciences, Engineering, and Medicine (NAS), "LCAs [Lifecycle Analyses] are subject to considerable uncertainty and variability," further, NAS states that "LCA methods need to appropriately characterize uncertainty and variability to aid LCA stakeholders' interpretation of LCA results."[7] The NAS report explicitly recommends that uncertainties should be considered for policy outcomes that are driven by LCA results.

The expert review includes additional discussion of the significant uncertainty regarding the carbon intensity of both natural gas production and thermal production of hydrogen. While API has not provided projections of future values for these estimates, it is important to note that the application of point estimates within the GREET model ignores these uncertainties and may result in the disqualification of otherwise admissible production pathways. Specifically, the expert review cites NETL reports from 2019 and 2022 on the emissions uncertainty associated with natural gas production and hydrogen, respectively. When specific facility and value-chain data is not available, rather than providing a point estimate GREET should provide a range of the potential carbon intensity for applicants. Individual facilities could likely include values for these parameters based on emission profiles reported to the EPA's Greenhouse Gas Reporting Program (GHGRP).[8]

Additionally, the expert review has revealed that the GREET model applies an adjustment to the methane leakage and venting associated with production and transmission of natural gas, as estimated in the EPA's national GHG inventory ("Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2020"), of roughly 45%. Such an adjustment is inappropriate and will drive further inaccuracy in the estimated carbon intensity of thermal clean hydrogen production pathways.

The GREET model uses EPA's 2022 "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2020," as the base estimate for fugitive and vented methane emissions from natural gas production.[9] It is worth noting that even this information is available with some regional disaggregation in the supporting documentation. However, adjusting this data with a factor based on "top-down" emissions estimation studies is inappropriate. First, the data from the Inventory has already been adjusted. While the GHGRP forms a portion of the basis for the Inventory's "bottom-up" emissions estimation approach, it also relies on published studies as referenced in the Inventory's Methodology discussion in Section 3.7 Natural Gas Systems.[10] Second, the adjustment made to value-chain emissions based on data from the range of "top-down" estimates that is cited has not been incorporated or evaluated by any other government body, nor has it been presented for public comment for use in a standard. The EPA's GHG Inventory is designed to meet the agreed upon methodologies of the international scientific community. The

[7] National Academies of Sciences, Engineering, and Medicine. 2022. *Current Methods for Life-Cycle Analyses of Low-Carbon Transportation Fuels in the United States*. Washington, DC: The National Academies Press. https://doi.org/10.17226/26402
[8] 40 CFR part 98
[9] EPA (2022) Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2020. U.S. Environmental Protection Agency, EPA 430-R-22-003. https://www.epa.gov/ghgemissions/draft-inventory-us-greenhouse-gas-emissions-and-sinks-1990-2020.
[10] Id., p. 3-94

adjustment applied in the GREET model is not. Using such an adjustment without a thorough evaluation of the validity of the data and its proper application to develop an appropriate adjustment factor is a significant fault of the GREET model. There is no indication or ability to review the adjustment methodology to ensure that the adjustments made are based on sound science and universally accepted methodologies. The GREET model should rely upon the emission factors included in the GHG Inventory or derived from the GHGRP, without adjustment at least until a credible adjustment methodology can be determined.

3) b) DOE-funded analyses routinely estimate regional fugitive emission rates from natural gas recovery and delivery. However, to utilize regional data, stakeholders would need to know the source of natural gas

While the GREET model accounts for significant variability in regional electricity generation carbon intensities, it does not consider or allow for regional variability in regional natural gas production and transport. DOE's question 1)b) (above) clearly references regional variability in electricity, biomass and waste inputs, yet omits the regional variability of natural gas production. Regional variability of natural gas production must be similarly enabled in the GREET model – especially in the near term as producers may seek to locate hydrogen production facilities near lower carbon intensity natural gas production. Such data can be collected from the EPA's GHGRP, subpart W.[11] Subpart W has been a trusted source of emission information from facilities through the full natural gas value chain since 2016, with portions of the value chain reporting since 2011. Data provided by facility operators must follow prescribed methodologies and is verified by the EPA annually. Additionally, because this data is facility specific, it provides a clear regional picture and more accurate average of the GHG intensity of the natural gas value chain. Whether taking a "bottom-up" or "top-down" approach to estimating the GHG intensity of natural gas systems, it is important to recognize that both methodologies represent estimates and are reliant on averaging of emission volumes. Reflecting this, EPA has recently proposed revisions to Subpart W to improve the accuracy of facility emission estimates, including allowing for the use of new methodologies in certain applications.

3) a) How should the GHG emissions of hydrogen commercial-scale deployments be verified in practice? What data and/or analysis tools should be used to assess whether a deployment demonstrably aids achievement of the CHPS?

As noted below, use of data from the EPA's GHGRP can provide both DOE and the operator of a hydrogen production facility with EPA verified data regarding the upstream emissions of the production facility. This is true of both grid electricity and natural gas. To assess or verify the GHG emissions of the hydrogen production facility itself, a mass balance approach should be sufficient to account for any hydrogen leaks. Any CO_2 captured and sent for geologic storage will also be verified by EPA in the GHGRP.

[11] 40 CFR §98.230

1) d) Mitigating emissions downstream of the site of hydrogen production will require close monitoring of potential CO_2 leakage. What are best practices and technological gaps associated with long-term monitoring of CO_2 emissions from pipelines and storage facilities? What are the economic impacts of closer monitoring?

The monitoring of long-term sequestration of captured CO_2 is already well established by EPA under the GHGRP, subpart RR. Subpart RR requires project developers to submit for approval a detail monitoring, reporting, and verification (MRV) plan in order to meet the EPA requirements for injection of CO_2. The CHPS should rely upon this EPA established approach.

Technological gaps may exist regarding pathways that utilize or permanently store CO_2 in other substances or forms. DOE should consult with EPA on the best potential methodologies for accounting for these volumes of CO_2. In applying such an approach, DOE and EPA should be consistent with the methodologies and guidance set forth by the IRS as related to qualifying for the 45Q tax credit.

3. *The IRA and DOE both clearly articulate a "well-to-gate" boundary for the CHPS. This must be maintained with certainty and should not include any emissions considered to be downstream from the point of production.*

While the inclusion of upstream emissions associated with the production and transport of methane is necessary, the analysis provided in Appendix A and provided above, shows that these lifecycle emissions are not yet properly included in the GREET model. The impact of this data is not limited to thermal production pathways, as electrolytic pathways may still depend in part or whole on grid electricity. Upstream of the point of hydrogen production, regardless of pathway, the modeling must have an accurate representation of emissions.

API is concerned that DOE is considering downstream emissions associated with the delivery or use of hydrogen. The statutory language of the IRA for the 45V tax credits indicate that the lifecycle emission profile should be limited to "well-to-gate" emissions, where gate is understood as the point at which the hydrogen leaves the production facility.[12] This stands in direct conflict with the statement by DOE in footnote 11 that within the CHPS Draft Guidance, "the lifecycle target corresponds to a system boundary that terminates at the point at which hydrogen is delivered for end use." While the definition of "Lifecycle Greenhouse Gas Emissions" provided in the IRA would include delivery and end-use if applied strictly by the definition in 42 USC 7545(o)(1)(H), the IRA makes explicitly clear "The term 'lifecycle greenhouse gas emissions' shall only include emissions through the point of production (well-to-gate)."[13]

Multiple questions from DOE's CHPS Draft Guidance reference emissions that may be occurring downstream of production.[14] As a "production standard" and under the statutory language provided in the IRA, the definition of "qualified clean hydrogen" and the supporting standard do not include emissions related to the delivery or use of hydrogen.

[12] Inflation Reduction Act of 2022, Sec. 45V.(c)(B).
[13] Inflation Reduction Act of 2022, Sec. 45V.(c)(B).
[14] USDOE, "Clean Hydrogen Production Standard (CHPS) Draft Guidance," September 22, 2022. For example, questions 1)e) and 1)f).

2) a) The IPHE HPTF Working Paper (https://www.ihpe.net/iphe-working-paper-methodology-doc-oct-2021) identifies various generally accepted ISO frameworks for LCA (14067, 14040, 14044, 14064, and 14064 [sic]) and recommends inclusion of Scope 1, Scope 2 and partial Scope 3 emissions for GHG accounting of lifecycle emissions. What are the benefits and drawbacks to using these recommended frameworks in support of the CHPS? What other frameworks or accounting methods may prove useful?

API generally supports the use of ISO frameworks for lifecycle assessments. The IPHE HPTF Working Paper serves as a source of potential methodologies that could be applied by DOE. DOE's choices, however, may be constrained by the selection of the GREET model and the choices already made within that approach. Similarly, it is not clear what utility these ISO frameworks will provide when DOE and Congress have already determined both the scope of the lifecycle assessment for this production standard (well-to-gate, as noted above) and the model with which this assessment should be completed (GREET or a successor model). Regardless, API objects to the inclusion of Scope 3 emissions as these are outside of the "well-to-gate" boundary established by legislation and are not representative of a "production standard".

API does agree that a "materiality threshold" should be established for verification purposes to allow for potential variation. The threshold commonly applied in ISO approaches is 5% of total system emissions.

1) e) Atmospheric modeling simulations have estimated hydrogen's indirect climate warming impact (for example, see Paulot 2021).[19] The estimating methods used are still in development, and efforts to improve data collection and better characterize leaks, releases, and mitigation options are ongoing. What types of data, modeling or verification methods could be employed to improve effective management of this indirect impact?

As noted in the question, these methods are still under development. No such "indirect impacts" of hydrogen leaks should be included in the production standard until estimation methods have been well-established. Additionally, such leaks are not likely to have a more significant negative climate impact that would consume the beneficial climate impacts of the development of a robust clean hydrogen economy, as noted by RMI in direct response to *Paulot (2021)* and other similar studies.[15] As noted by RMI, "the climate benefit from a well-regulated clean hydrogen economy outweighs the impact of any emissions that hydrogen would add to our energy system," where the regulation of the clean hydrogen economy cannot be effectively driven by a production standard.

In the event that DOE in the future determines that leaked hydrogen should be included as an input to a lifecycle production standard, once estimation methodologies are well-established, such leaks should only be included from the production facility. As noted above, the production standard's lifecycle

[15] T.K. Blank, et al., "Hydrogen Reality Check #1: Hydrogen Is Not a Significant Warming Risk." RMI, May 9, 2022. https://rmi.org/hydrogen-reality-check-1-hydrogen-is-not-a-significant-warming-risk/

boundary terminates at the gate and should not include delivery or end-use. This is confirmed by the IPHE HPTF working paper, where emissions past the production gate are not considered.[16]

4. DOE must provide a pathway for the LCA approach, using the GREET model or other methods, to be kept up-to-date with science and data, and should allow for the certification of individual pathways.

As producers invest in new methods to produce feedstocks and to produce clean hydrogen, it is essential that the CHPS be sufficiently flexible to allow for frequent updates and the inclusion or adoption of specific validated pathways. As recommended by the NAS, "Regulatory agencies should formulate a strategy to keep LCAs up to date, which may involve periodic reviews of key inputs to assess whether sufficient changes have taken place to warrant a re-analysis, and agencies should be aware that substantial changes to LCAs on timescales of less than a decade can occur."[17] Currently, the GREET model is updated on a roughly annual basis - and as shown above is already in need of further update. DOE should allow for specific pathways to be introduced and validated as needed without causing unreasonable delays. Additionally, DOE should invest in more frequent updates to the GREET model as data is made available, to ensure that the model is representative of the emissions associated with feedstocks and production pathways as they occur. While the IRA does not provide a specific cadence for making improvements or incorporating new data, the annual basis on which the model is currently revised is not likely to be sufficient. Similarly, the 5-year maximum period under which the Secretary is required to consider updates to the production standard does not represent a reasonable frequency at this time.

5. Where possible, the CHPS should rely on system expansion, or displacement, as the primary method to allocate emissions by co-product.

> *2) c) How should GHG emissions be allocated to co-products from the hydrogen production process? For example, if a hydrogen producer valorizes steam, electricity, elemental carbon, or oxygen co-produced alongside hydrogen, how should emissions be allocated to the co-products (e.g., system expansion, energy-based approach, mass-based approach), and what is the basis for your recommendation?*

GHG emissions from coproducts should be properly allocated to those coproducts, as directed by ISO approaches to lifecycle assessments. Similarly, if a coproduct of the hydrogen production pathway is displacing emissions that would be generated by the product being produced independently, those avoided emissions should be credited to the hydrogen production pathway. The GREET model includes some of these allocations, for example for steam produced as a byproduct of hydrogen production.

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[16] IPHE 2021, Methodology for Determining the Greenhouse Gas Emissions Associated With the Production of Hydrogen, A Working Paper Prepared by the IPHE Hydrogen Production Analysis Task Force, Available online: https://www.iphe.net/iphe-working-paper-methodology-doc-oct-2021

[17] National Academies of Sciences, Engineering, and Medicine. 2022. *Current Methods for Life-Cycle Analyses of Low-Carbon Transportation Fuels in the United States*. Washington, DC: The National Academies Press. https://doi.org/10.17226/26402

Credit for export steam is appropriately treated with a displacement approach, as noted in Appendix A to this comment letter.

6. DOE must allow for the use of market-based mechanisms to prove the carbon-intensity of the upstream value-chain, where possible, with appropriate limitations to curtail potential abuses.

> *3) c) Should renewable energy credits, power purchase agreements, or other market structures be allowable in characterizing the intensity of electricity emissions for hydrogen production? Should any requirements be placed on these instruments if they are allowed to be accounted for as a source of clean electricity (e.g., restrictions on time of generation, time of use, or regional considerations)? What are the pros and cons of allowing different schemes? How should these instruments be structured (e.g., time of generation, time of use, or regional considerations) if they are allowed for use?*

Renewable energy credits, power purchase agreements, or other market structures representing "indirect book accounting" approaches should be allowed to characterize the intensity of both electricity generation emissions and natural gas production emissions. This is clearly reflected in the legislative intent of the Inflation Reduction Act of 2022. Senators Carper and Wyden indicated that "indirect book accounting factors," including but not limited to "renewable energy credits, renewable thermal credits, renewable identification number, or biogas credits," should be recognized and incorporated in the lifecycle analysis of hydrogen production.[18]

In the context of Sen. Carper's reference to such "indirect book accounting factors" not being limited to those used for electricity generation, DOE must provide for a similar treatment of natural gas production. Similar structures have been developed in the form of certificates and emission tags, and are continuing to evolve and be developed. Allowing such market structures to characterize the intensity of electricity production but not natural gas production would present a significant deviation between the treatment of the inputs to hydrogen production and would run contrary to the intent of the law.

When evaluating renewable energy credits (RECs), power purchase agreements (PPAs), or other market structures, DOE should consider the time and date of generation and the location of generation.

While the ability to generate and market time and location specific RECs is in its infancy, such market instruments are likely to develop over time, especially given the recent IRA provisions. DOE should consider integrating more detailed products as they develop and become more available, which include indication of time or date and especially location of generation, when they become sufficiently robust. This will help to ensure that producers using such an approach are not taking credit for zero emission electricity while relying on sources that are less expensive or that have higher potential GHG emissions than the electricity actually used in hydrogen production.

> *4) a) Please provide any other information that DOE should consider related to this BIL provision if not already covered above.*

[18] 168 Cong. Rec. S4166 (daily ed. Aug. 6, 2022) (statement of Sen. Tom Carper).

7. DOE must maintain consistency with other US government and international standards that rely on 100-year global warming potentials for non-CO_2 GHG emissions.

As written, none of the BIL, IRA or Draft Guidance from DOE clearly state the appropriate global warming potentials that should be applied to convert other greenhouse gases to their CO_2 equivalent. The GREET model applies the 100-year global warming potential from IPCC AR6 as its default. However, to ensure that investors and operators have a consistent and certain approach, DOE should include in its final guidance clear direction that the 100-year global warming potential should always be applied for all greenhouse gases. The values from the IPCC AR4 report would be more consistent with other Federal Government applications (such as the EPA's annual greenhouse gas inventory and the greenhouse gas reporting rule). This would conform generally with the IPHE HPTF Working Paper, though the Working Paper cites IPCC 2018, not AR4.[19]

8. DOE's use of a lifecycle analysis to determine the "well-to-gate" emissions associated with hydrogen production may reveal the standard required by the BIL, but clearly deviates from and goes beyond the established requirement.

DOE has properly cited that the BIL requires that the DOE develop a clean hydrogen production standard that supports multiple production sources and defines the term "clean hydrogen" in section 822(b) as "hydrogen produced with a carbon intensity of equal to or less than 2 kilograms of carbon dioxide-equivalent produced at the site of production per kilogram of hydrogen produced."[20] However, while DOE notes that the definition of clean hydrogen is "not the sole component of the CHPS" it is the primary factor that DOE was directed to define in the task assigned by the BIL. The statute did not direct DOE to provide a lifecycle analysis of "qualified clean hydrogen" for the purpose of the 45V tax credit contained in the IRA. The assertion that the lifecycle assessment should be included in the effort to define "clean hydrogen" for the purpose of the BIL is without merit.

Further, the Clean Hydrogen Research and Development Program directs DOE to establish "a series of technology cost goals oriented toward achieving the standard of clean hydrogen production developed under section 822(a);"[21] it does not direct DOE to orient the program to DOE's self-defined CHPS. The purpose of the Clean Hydrogen Research and Development Program would be accurately understood as directing DOE to support efforts to reduce the carbon intensity of hydrogen production from a variety of sources at the point of production, not across the lifecycle value chain. To that extent, while DOE is correct that the purpose of the Regional Hydrogen Hubs program is to "demonstrably aid the achievement of the clean hydrogen production standard developed under section 822(a),"[22] this should be viewed in the context of the definition of "clean hydrogen" as a 2 kilogram production site standard,

[19] IPHE 2021, Methodology for Determining the Greenhouse Gas Emissions Associated With the Production of Hydrogen, A Working Paper Prepared by the IPHE Hydrogen Production Analysis Task Force, Available online: https://www.iphe.net/iphe-working-paper-methodology-doc-oct-2021
[20] Public Law 117-58 (November 15, 2021) 135 Stat. 1015
[21] Public Law 117-58 (November 15, 2021) 135 Stat. 1007. DOE's Draft Guidance for the CHPS inaccurately cites the Inflation Reduction Act of 2020 for this passage.
[22] Public Law 117-58 (November 15, 2021) 135 Stat. 1009

not a lifecycle emissions standard. Therefore, applicants to the Regional Hydrogen Hubs program should not be expected by DOE to "reduce emissions across the supply chain as aggressively as technologically and economically feasible."[23] DOE first suggested using a lifecycle approach to evaluate the GHG intensity of hydrogen production in the Notice of Intent to issue Funding Opportunity Announcement No. : DE-FOA-002779.[24] However, DOE was not accepting comments in response to the NOI. It is only because DOE has added this criteria into the Funding Opportunity Announcement for the Regional Hydrogen Hubs program that such a lifecycle approach is necessary.[25]

It is clear from the statutory language that the CHPS does not follow the direction of the BIL, overextending the definition of "clean hydrogen" to encompass lifecycle value chain emissions that were not intended to be included in the definition for the purpose of the Regional Hydrogen Hubs program. DOE's continued assertion that the approach in the CHPS meets the requirements of the BIL is inaccurate. Further, DOE's assertion that the lifecycle target established by the IRA is "likely achievable by facilities that achieve the BIL's definition of 'clean hydrogen' as [less than or equal to] 2 kgCO2e/kgH2 at the site of production" is baseless. Value chain lifecycle emissions, which are relevant to the 45V tax credit, are not necessarily within the control of the hydrogen production facility owner or operator. Therefore, there is no way to establish that meeting the production site standard set by the BIL for "clean hydrogen" will enable an owner or operator to meet the 45V lifecycle requirements. Those emissions that occur upstream of the facility may cause the lifecycle emissions to exceed the 4kgCO2e/kgH2 requirement regardless of the emission profile of the hydrogen production facility.

While API does not necessarily accept the lifecycle approach established by DOE in the CHPS as a means of establishing the definition of "clean hydrogen", these comments seek to address and improve the deficiencies of the approach provided by DOE in the CHPS to ensure that the estimation of the lifecycle emissions of "qualified clean hydrogen" is representative of the best possible data and is as accurate as possible.

9. The development of a robust low-carbon or clean hydrogen economy has significant potential impacts for the US, for US industries, and specifically for the US oil and natural gas industry. Such an economy must be built on sound science and analysis that enables the production of low-carbon or clean hydrogen from multiple technologies and feedstocks.

As noted above, the oil and natural gas industry has significant interest in the development of a robust low-carbon or clean hydrogen economy. The establishment of such an economy will be driven in the near-term by the Regional Hydrogen Hubs program of the BIL, the 45V tax credit from the IRA, and private investment. Both government programs will likely rely on standards set forth by DOE, either by

[23] USDOE, "Clean Hydrogen Production Standard (CHPS) Draft Guidance," September 22, 2022.
[24] USDOE, Office of Clean Energy Demonstrations, "Notice of Intent No.: DE-FOA-0002768," June 2, 2022. At page 5, "While all projects will be required to meet the minimum clean hydrogen production standard, DOE intends to also evaluate full lifecycle emissions for each application and will give preference to applications that reduce GHG emissions across the full project lifecycle, inclusive of hydrogen production, compared to current industry standards."
[25] USDOE, Office of Clean Energy Demonstrations, "Bipartisan Infrastructure Law: Additional Clean Hydrogen Programs (Section 40314): Regional Clean Hydrogen Hubs Funding Opportunity Announcement." September 22, 2022, page 44.

statute or by default. It is essential, therefore, that the standard set by DOE is based on sound-science and methodologies, and solid legal footing. Any failure to meet the requirements of the standard as set forth under the BIL or to meet the requirements and goals of the 45V tax credit will likely delay the expansion of this important source of greenhouse gas reductions.

Sincerely,

Marcus J Koblitz

Marcus Koblitz
Senior Policy Advisor, Climate & ESG

Encl: Philip Heirigs, P.E., "Evaluation of Argonne National Laboratory's GREET Model for Use in the Clean Hydrogen Production Standard (CHPS)," November 11, 2022

CC: Alejandro Moreno, Assistant Secretary for the Office of Energy Efficiency & Renewable Energy (EERE), DOE
Brad Crabtree, Assistant Secretary for the Office of Fossil Energy and Carbon Management (FECM), DOE
Dr. Sunita Satyapal, Director for Hydrogen and Fuel Cell Technologies Office, EERE, DOE
Sam Thomas, Director for Hydrogen and Carbon Management, FECM, DOE

FINAL REPORT

EVALUATION OF ARGONNE NATIONAL LABORATORY'S GREET MODEL FOR USE IN THE CLEAN HYDROGEN PRODUCTION STANDARD (CHPS)

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November 11, 2022

FINAL REPORT

EVALUATION OF ARGONNE NATIONAL LABORATORY'S GREET MODEL FOR USE IN THE CLEAN HYDROGEN PRODUCTION STANDARD (CHPS)

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<u>List of Acronyms</u>

API – American Petroleum Institute

ATR – Auto-thermal reforming, a hydrogen production technology

BIL – Bipartisan Infrastructure Law

BTU – British thermal unit

BU – bottom up

CHPS – Clean Hydrogen Production Standard

CH4 – methane

CO2 – carbon dioxide

CO2e – carbon dioxide equivalents, a measure of GHG emissions

DOE – U.S. Department of Energy

EIA – U.S. Energy Information Administration

EPA – U.S. Environmental Protection Agency

GHG – Greenhouse gases

GHGRP – Greenhouse Gas Reporting Program implemented by EPA

GREET – Greenhouse gases, Regulated Emissions, and Energy use in Technologies, a lifecycle emissions model developed by Argonne National Laboratory

H2 - hydrogen

IRA – Inflation Reduction Act

kgCO2e/kgH2 – kilograms of CO2e per kilogram hydrogen produced

kWh – kilowatt-hour

LWR – nuclear light water reactor

MMBTU – million BTU

MMSCFD – million standard cubic feet per day

NETL – National Energy Technology Laboratory

NG – natural gas

N2O – nitrous oxide

PEM – proton exchange membrane, a type of water electrolysis technology

SMR – steam ethane reforming, a hydrogen production technology

SOEC – solid oxide electrolysis cell, a type of water electrolysis technology

TD – top down

WTG – well-to-gate

1. EXECUTIVE SUMMARY

The U.S. Department of Energy (DOE) recently released draft guidance on its Clean Hydrogen Production Standard (CHPS)[1] that was developed to meet the requirements of the Infrastructure and Jobs Act of 2021, which is also known as the Bipartisan Infrastructure Law (BIL). DOE has proposed an initial target for the CHPS of 4.0 kgCO2e/kgH2 based on a lifecycle accounting of greenhouse gas emissions associated with hydrogen production. In its evaluation of various options that could meet the proposed CHPS, DOE relied heavily on Argonne National Laboratory's Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET) lifecycle emissions model.

This project, performed under the sponsorship of the American Petroleum Institute (API), evaluated the GREET model as it relates to hydrogen production.[2] The project is intended to evaluate the GREET model's ability to accurately assess the "well-to-gate" lifecycle GHG emissions associated with hydrogen production, with a particular focus on hydrogen produced from natural gas with carbon capture. The project analyzed the natural gas-based production methods included in the model, as well as upstream emissions associated with the production and transport of natural gas. The project also evaluated hydrogen production via electrolysis, including an assessment of emissions associated with electricity production and transport.

Based on the analyses presented below, the following recommendations are being made with respect to the development of the Clean Hydrogen Production Standard:

1. If only being applied as guidance for DOE funding opportunities, the Clean Hydrogen Production Standard should distinguish between new facilities and retrofits of existing facilities for natural gas-based hydrogen production:
    - For new facilities, a CHPS of 4.0 kgCO2e/kgH2 is too stringent and could potentially exclude natural gas autothermal reforming (ATR) plants with carbon capture based on work performed by the National Energy Technology Laboratory (NETL) on advanced fossil-based hydrogen plants. It would also exclude hydrogen production via Proton Exchange Membrane (PEM) electrolysis using geothermal electricity. A more appropriate target is in the range of 5.0 to 6.0 kgCO2e/kgH2.
    - For existing facilities, a numeric kgCO2e/kgH2 standard is not appropriate. Instead, DOE should establish a CO2 reduction target for individual facilities based on a percent reduction (e.g., 90%) of the ***process gas stream*** as that has a higher CO2 concentration and does not carry a significant nitrogen load from combustion air, making CO2 capture more efficient.

[1] See https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-production-standard.pdf#:~:text=DOE%E2%80%99s%20Proposed%20Clean%20Hydrogen%20Production%20Standard%20Considering%20statutory,with%20the%20IRA%E2%80%99s%20definition%20of%20%E2%80%9Cqualified%20clean%20hydrogen.%E2%80%9D

[2] The GREET1_2022.xlsm spreadsheet model was used as the basis for this review (released and accessed on October 11, 2022).

2. Petroleum refineries produce a significant amount of hydrogen on-site. Any programs implementing the CHPS should allow a pathway for refinery participation.
3. The GREET model accounts for the significant variability in regional electricity generation but does not consider regional variability in natural gas production and transport. That issue should be addressed in the development of a Clean Hydrogen Production Standard.

2. INTRODUCTION AND BACKGROUND

The U.S. Department of Energy (DOE) recently released draft guidance on its Clean Hydrogen Production Standard (CHPS)[3] that was developed to meet the requirements of the Infrastructure and Jobs Act of 2021, which is also known as the Bipartisan Infrastructure Law (BIL). DOE has proposed an initial target for the CHPS of 4.0 kgCO2e/kgH2 based on a lifecycle accounting of greenhouse gas emissions associated with hydrogen production. The BIL defines "clean hydrogen" as hydrogen produced with a carbon intensity less than or equal to 2.0 kgCO2e per kg of H2 produced at the site (i.e., only direct emissions are considered). DOE is proposing 4.0 kgCO2e/kgH2 on a lifecycle basis, arguing that this is likely achievable by facilities that meet the definition of "clean hydrogen" under the BIL. Additionally, the proposed lifecycle-based CHPS aligns with the definition of "qualified clean hydrogen" needed to be eligible for 45V tax credits under the 2022 Inflation Reduction Act (IRA). In its evaluation of various options that could meet the proposed CHPS, DOE relied heavily on Argonne National Laboratory's Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET) lifecycle emissions model.

At the request of the American Petroleum Institute (API), P Heirigs Consulting LLC has performed an evaluation of the GREET model as it relates to hydrogen production.[4] This project is intended to evaluate the ability of the GREET model to accurately assess the "well-to-gate" (WTG) lifecycle GHG emissions associated with hydrogen production, with a particular focus on hydrogen produced from natural gas with carbon capture (often referred to as "blue hydrogen"). The project analyzed the natural gas-based production methods included in the model, as well as upstream emissions associated with the production and transport of natural gas. The project also evaluated hydrogen production via electrolysis, including an assessment of upstream emissions associated with electricity production and transport.

Specific deliverables under this project included a critical evaluation of the GREET model as it relates to the following:

- Natural gas-based hydrogen production methodologies;

[3] See https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-production-standard.pdf#:~:text=DOE%E2%80%99s%20Proposed%20Clean%20Hydrogen%20Production%20Standard%20Considering%20statutory,with%20the%20IRA%E2%80%99s%20definition%20of%20%E2%80%9Cqualified%20clean%20hydrogen.%E2%80%9D

[4] The GREET1_2022.xlsm spreadsheet model was used as the basis for this review (released and accessed on October 11, 2022). See https://greet.es.anl.gov/greet_excel_model.models

- The level of disaggregation of midstream and upstream GHG emissions associated with natural gas production and transport;
- The variability of GHG emissions associated with natural gas production and transport as well as GHG emissions associated with SMR-based hydrogen production; and
- Data sources associated with electrolysis production methods, generation of electricity, and emissions associated with upstream production and transport of generation fuels.

In addition to the above, questions posed in DOE's CHPS draft guidance of particular interest to API were also addressed.

Results of the above analyses are summarized in the following sections of this report.

3. NATURAL GAS STEAM METHANE REFORMING

Steam methane reforming (SMR) is the primary means of hydrogen production in the U.S., currently accounting for 95% of hydrogen production.[5] Natural gas is the typical feedstock for SMR, but fuel gas from refining operations can also be used as feed to SMR facilities that are co-located with or within a refinery.[6] Combustion of natural gas also supplies the heat needed to support the various reactions that convert the feedstock (primarily methane in the case of natural gas) to hydrogen. CO2 is produced both from the feed and the fuel streams, with the feed stream typically accounting for 55% to 70% of total CO2 emissions, depending on facility. Waste heat generated in the process is captured in the form of steam, which is typically exported and is assigned a credit in the GREET model.

While GREET does not explicitly model GHG emissions from hydrogen production in a refinery setting, it is important to recognize that refinery-based hydrogen production via SMR is very common. For example, of the 140 refineries that reported emissions to EPA's GHG Reporting Program (see EPA's "flight" tool[7]), 40% reported emissions under Subpart P, reflecting hydrogen production not related to a byproduct of other refining operations (e.g., catalytic reforming). This is reasonably consistent with EIA's 2014 estimate that about one-third of hydrogen used in refineries was produced on-site, with the remainder being supplied by

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[5] See: https://www.energy.gov/eere/fuelcells/hydrogen-production-natural-gas-reforming

[6] Fuel gas is a byproduct of petroleum refining and typically consists of light hydrocarbons (methane, ethane, propane) and hydrogen. The composition of fuel gas will vary depending upon which process unit produces the gas. SMR for hydrogen production at a refinery may use fuel gas in addition to natural gas.

[7] See: https://ghgdata.epa.gov/ghgp/main.do#/listFacility/?q=Find%20a%20Facility%20or%20Location&st=&bs=&et=&fid=&sf=11001100&lowE=-20000&highE=23000000&g1=1&g2=1&g3=1&g4=1&g5=1&g6=0&g7=1&g8=1&g9=1&g10=1&g11=1&g12=1&s1=0&s2=0&s3=0&s4=0&s5=1&s6=0&s7=0&s8=0&s9=0&s10=0&s201=0&s202=0&s203=0&s204=0&s301=0&s302=0&s303=0&s304=0&s305=0&s306=0&s307=0&s401=0&s402=0&s403=0&s404=0&s405=0&s601=0&s602=0&s701=0&s702=0&s703=0&s704=0&s705=0&s706=0&s707=0&s708=0&s709=0&s710=0&s711=0&s801=0&s802=0&s803=0&s804=0&s805=0&s806=0&s807=0&s808=0&s809=0&s810=0&s901=0&s902=0&s903=0&s904=0&s905=0&s906=0&s907=0&s908=0&s909=0&s910=0&s911=0&si=&ss=&so=0&ds=E&yr=2020&tr=current&cyr=2020&ol=0&sl=0&rs=ALL

industrial plants.[8] While the EIA estimates showed an increasing fraction of off-site hydrogen production over time, the volume produced on-site was relatively constant at 1.4 billion cubic feet per day over the 2012 to 2014 timeframe (there was a decrease in 2009-2011, likely a result of demand destruction caused by the recession). Given the large quantity of hydrogen produced on-site at refineries, the CHPS should provide a pathway for refineries to participate in the programs under which the CHPS is implemented.

The following covers modeling of SMR in GREET and related issues. Details on the specific reactions and equipment related to SMR are not covered here, but good primers on hydrogen production via SMR are available elsewhere[9] and would be useful for understanding some of the discussion that follows.

GREET Modeling of Hydrogen Production via SMR

The only natural gas-based hydrogen pathway in the GREET model is via steam methane reforming, either at a central plant or distributed. As this evaluation also investigated model inputs and results for carbon capture, a central plant was assumed for this analysis. Production of gaseous hydrogen was also assumed (rather than liquid hydrogen). Only well-to-gate (WTG) emissions were included in this analysis, so pipeline transport of hydrogen and energy required for compression for automotive use were not assessed. GHG emissions from conversion of natural gas to hydrogen via autothermal reforming (ATR) are not modeled by GREET, but lifecycle GHG emissions for this pathway from a recently published report by the National Energy Technology Laboratory (NETL) are discussed below following the GREET results.[10]

Natural Gas SMR without Carbon Capture – The NETL report cited above was used by Argonne to update modeling of SMR hydrogen for GREET1_2022. Those inputs are summarized in the simple block flow diagram shown in Figure 1, where the basis is 1 MMBTU of hydrogen produced (lower heating value), which translates to 8.793 kgH2 based on the hydrogen fuel specifications in GREET (290 BTU/ft^3 and 2.55 g/ft^3 at 32°F and 1 atm pressure).

The energy inputs summarized in Figure 1 were combined with the appropriate emission factors from GREET1_2022 to arrive at the GHG emissions shown in Table 1. Note that these estimates include upstream emissions associated with natural gas recovery, processing, and transmission, assuming 25.3% North American conventional gas and 74.7% North American shale gas, which is the model default for a 2021 analysis year used as the basis for analysis in this report. Natural

[8] See: https://www.eia.gov/todayinenergy/detail.php?id=24612
[9] See, for example, "Analysis of CO2 Emissions, Reductions, and Capture for Large-Scale Hydrogen Production Plants," Dante Bonaquist, Praxair, October 2010. https://www.linde.com/-/media/linde/merger/documents/sustainable-development/praxair-co2-emissions-reduction-capture-white-paper-w-disclaimer-r1.pdf?la=en
[10] "Comparison of Commercial, State-of-the-Art, Fossil-Based Hydrogen Production Technologies, Eric Lewis, et al., National Energy Technology Laboratory, April 12, 2022. https://www.netl.doe.gov/projects/files/ComparisonofCommercialStateofArtFossilBasedHydrogenProductionTechnologies_041222.pdf

Figure 1. Baseline GREET Inputs for Natural Gas SMR Hydrogen Production – No Carbon Capture.

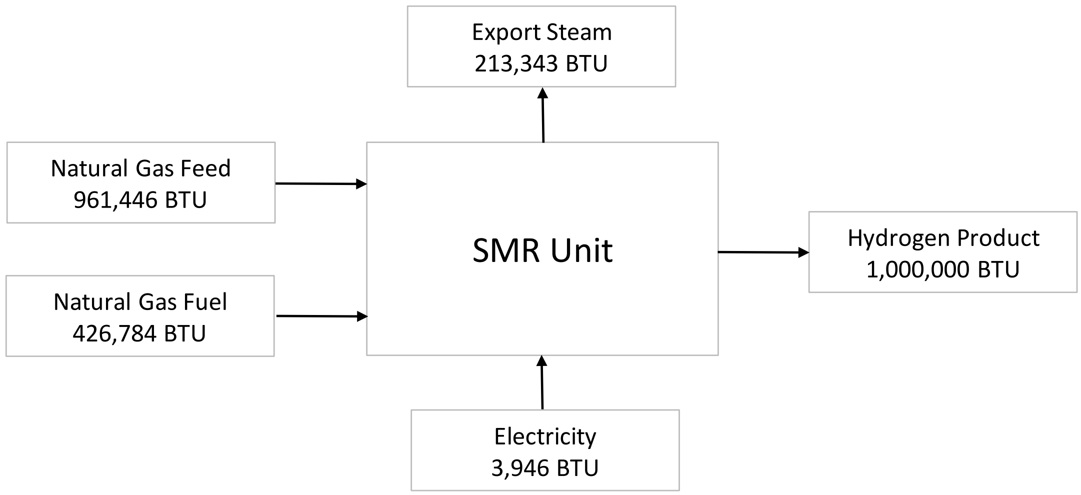


Table 1. Default GREET1_2022 Lifecycle GHG Emissions for Natural Gas SMR without Carbon Capture (per MMBTU of Hydrogen Produced)

LCA Component	Feed	Fuel	Electricity*	Steam**	Total
Natural gas energy (BTU)	961,446	426,784	3,946	-266,679	1,125,497
Direct emissions (gCO2e)	57,347	25,456	483	-15,843	67,442
Gas recovery (gCO2e)	5,902	2,620	56	-1,637	6,942
Gas processing (gCO2e)	2,672	1,186		-741	3,117
Gas transmission (gCO2e)	4,611	2,047		-1,279	5,379
Total GHG (gCO2e)	70,532	31,309	539	-19,501	82,880 (9.4 kgCO2e/kgH2)

* Electricity shown here is U.S. average. Direct emissions reflect generation and transport; the 56 gCO2e in the "Gas recovery" row is upstream electricity feedstock emissions.
** Steam credit based on 213,343 BTU divided by estimated boiler efficiency of 0.8.

gas transport from the field to a hydrogen central plant is assumed to be 680 miles, with a leakage/venting emission rate of 0.0994 gCH4/mmBTU per mile (more detail on natural gas emissions is discussed below). Credit for export steam is treated with a displacement approach, assuming it would have displaced steam produced by natural gas in an industrial boiler with an efficiency of 80%. 100-year global warming potentials of 29.8 for CH4 and 273 for N2O were used to convert these compounds to CO2e, based on the 6th Assessment Report of the IPCC.[11]

[11] These were updated from AR5 values in GREET_2021.

Overall, the 82,880 gCO_2e per 1 MMBTU hydrogen shown in Table 1 translates to 9.4 $kgCO_2e/kgH_2$.[12]

Of note in Table 1 is that upstream emissions associated with natural gas recovery, processing, and transmission as well as upstream electricity emissions account for almost 20% of total lifecycle emissions, with methane leakage alone contributing 8% of the total (0.7 $kgCO_2e/kgH_2$).

Natural Gas SMR with Carbon Capture – This scenario was also updated in GREET1_2022 based on the NETL report. Primary inputs to the carbon capture scenario include:

1. CO_2 capture efficiency is assumed to be 96.2%.
2. If CO_2 capture is implemented, there will be no export steam credit as that energy would be applied to CO_2 removal.
3. Additional processing energy and electricity are included in the energy balance.

The CO_2 available for capture is assumed to be both the feedstock carbon and the fuel carbon, and CO_2 emissions are determined from the fuel specifications for natural gas in the GREET model as follows (0.724 is carbon fraction of natural gas and 44/12 is the ratio of CO_2/C molecular weights):

(22.0 gNG/ft3) / (983 BTU/ft3) * 10^6 = 22,380 gNG/MMBTU NG

22,380 gNG/MMBTU NG * 0.724 * 44/12 = 59,413 gCO_2/MMBTU NG

Applying the above emission factor to both the feed and fuel streams with a capture efficiency of 96.2% results in a CO_2 capture rate of 84,354 gCO_2/MMBTU H_2 produced. This value is applied as a credit to the SMR lifecycle emissions shown in Table 2. This reduced the lifecycle GHG emissions from natural gas based SMR to 3.4 $kgCO_2e/kgH_2$. If the capture efficiency was reduced to 90% with all other inputs constant, the resulting GHG emission rate would be 4.0 $kgCO_2e/kgH_2$.

[12] Note that some of the emissions values in Tables 1 and 2 do not align exactly with the GREET spreadsheet model. That is because the GREET model does not explicitly break out upstream natural gas emissions for both the feed and the fuel streams. However, the overall results in the tables do match quite well with the reported GREET results (within 0.3% to 0.7%).

Table 2. Default GREET1_2022 Lifecycle GHG Emissions for Natural Gas SMR with Carbon Capture (per MMBTU of Hydrogen Produced)

LCA Component	Feed	Fuel	Electricity*	CO2 Capture**	Total
Natural gas energy (BTU)	987,709	488,626	45,202		1,521,537
Direct emissions (gCO2e)	58,913	29,145	5,534	-84,354	9,238
Gas recovery (gCO2e)	6,064	3,000	646		9,710
Gas processing (gCO2e)	2,745	1,358			4,103
Gas transmission (gCO2e)	4,737	2,343			7,080
Total GHG (gCO2e)	72,459	35,846	6,180	-84,354	30,131 (3.4 kgCO2e/kgH2)

* * Electricity shown here is U.S. average. Direct emissions reflect generation and transport; the 646 gCO2e in the "Gas recovery" row is upstream electricity feedstock emissions.
**Based on 96.2% capture efficiency.

GREET Assumptions Related to Natural Gas Production and Transport

Upstream GHG emissions from natural gas recovery, processing, and transmission account for almost 20% of total emissions for natural gas SMR hydrogen production without carbon capture (Table 1) and about two-thirds of total emissions for natural gas SMR hydrogen production with carbon capture (Table 2). Because the inputs for upstream natural gas calculations can be variable and can have a substantial impact on the overall results, a more thorough investigation of the baseline inputs was conducted. Of particular interest is the methane leak rate, which Argonne has estimated to result in an approximate 2 kgCO2e/kgH2 difference between a 0.7% leak rate and a 3% leak rate.[13] At a 3% leak rate, Argonne has estimated natural gas SMR hydrogen production with carbon capture to be over 5.0 kgCO2e/kgH2. The baseline leak rate in GREET1_2022 is estimated to be 1.0%.[14]

The methodology Argonne used to estimate methane emissions from natural gas pathways in GREET1_2022 is described in a recently released technical report.[15] The primary source of emissions data for methane leakage and venting emissions is from EPA's 2022 report, "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2020,"[16] which includes data reported as part of EPA's Greenhouse Gas Reporting Program (GHGRP) as an input. The GHGRP requires reporting for over 8,000 sources or suppliers, and reporting is at the facility level. As a result, detailed data are available on GHG emissions associated with natural gas

[13] "GREET Model for Hydrogen Lifecycle GHG Emissions," Amgad Elowainy, Presentation at H2IQ Webinar, June 15, 2022. https://www.energy.gov/sites/default/files/2022-06/hfto-june-h2iqhour-2022-argonne.pdf
[14] As discussed below, Argonne has estimated upstream methane leakage emissions to be 188 gCH4/MMBTU NG. At 82% NG methane content (25% conventional/75% shale), this translates to 229 g NG/MMBTU NG, which, in turn, translates to 10,200 BTU NG per MMBTU NG, or 1.0%.
[15] "Updated Natural Gas Pathways in GREET 2022," A. Burnham, Argonne National Laboratory, October 2022. https://greet.es.anl.gov/publication-update_ng_2022.
[16] See https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks and associated material.

production and transmission. Natural gas throughput data from the Energy Information Administration (EIA) were used by Argonne to develop emission factors on a gCH4 per MMBTU natural gas basis.

Because of concerns that the "bottom-up" (BU) emissions data reported as part of the GHGRP may under-estimate real-world emissions, Argonne implemented a hybrid calculation approach in which the EPA BU data were adjusted with "top-down" (TD) data developed previously by other researchers.[17] The results for both methods are summarized in Table 3, which shows that the BU/TD adjustment increased total upstream natural gas methane leakage and venting emission rates by about 45%.

Table 3. Methane Leakage and Venting Emissions Estimates in GREET1_2022 (Units: grams Methane per MMBTU Natural Gas)

Process	Argonne BU/TD Hybrid*		EPA 2022	
	Conventional	**Shale gas**	**Conventional**	**Shale gas**
Recovery - CH4 Leakage and Venting	***113.3***	***114.2***	**76.5**	**77.5**
Recovery - Completion CH4 Venting	0.6	1.4	0.5	1.3
Recovery - Workover CH4 Venting	0.0	0.1	0.0	0.3
Recovery - Liquid Unloading CH4 Venting	4.8	4.8	3.3	3.3
Well Equipment - CH4 Venting and Leakage	76.7	76.7	45.1	45.1
Gathering and Boosting - CH4 Venting & Leakage	31.2	31.2	27.6	27.6
Processing - CH4 Venting & Leakage	***6.0***	***6.0***	**3.8**	**3.8**
Transmission and Storage - CH4 Venting & Leakage**	***67.6***	***67.6***	**48.8**	**48.8**
Distribution - CH4 Venting and Leakage***	19.6	19.6	19.6	19.6
Total CH4 Venting and Leakage	***187.0***	***187.8***	**129.1**	**130.1**

* Shaded cells are the model baseline inputs for natural gas to central hydrogen plant pathway.

** Per 680 miles; assumed pipeline distance to central hydrogen plants is 680 miles.

*** This category represents transport to distributed H2 facilities and is not included in WTG emissions for the central hydrogen plant pathway evaluated in this report.

Variability in Natural Gas Production and Distribution GHG Emissions

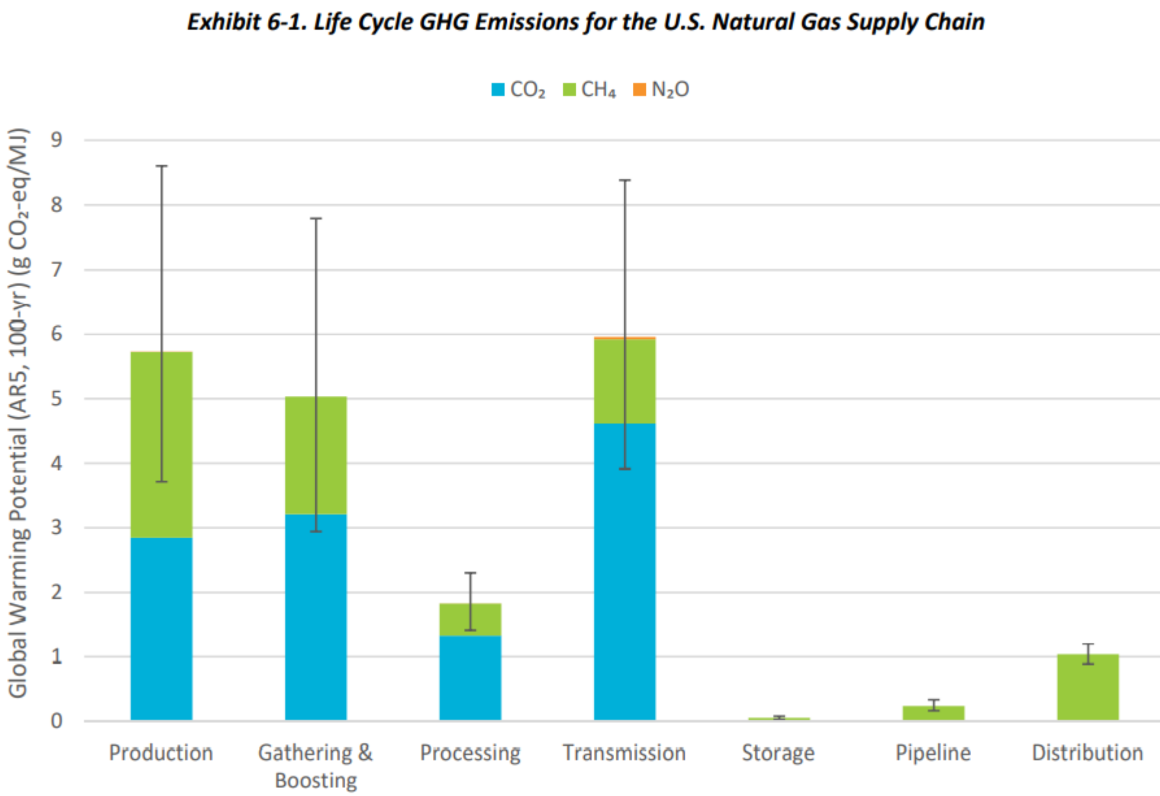
The tight time constraint associated with this project did not allow for an independent assessment of the variability in natural gas production and distribution GHG emissions. However, a 2019 study sponsored by NETL investigated upstream emissions associated with natural gas production in the U.S.[18] That study included an assessment of 30 different scenarios representing 14 onshore production basins, split out by production technology (conventional, shale, and tight gas), for a total of 27 onshore scenarios. There were two offshore scenarios and one associated

[17] See: (1) Alvarez, R., et al., 2018, Assessment of methane emissions from the U.S. oil and gas supply chain, Science, DOI: 10.1126/science.aar7204; and (2) Rutherford, J. S., et al. 2021. Closing the methane gap in US oil and natural gas production emissions inventories. Nature Communications, 12(1), 1–12.

[18] "Life Cycle Analysis of Natural Gas Extraction and Power Generation," James Littlefield et al., KeyLogic Systems, LLC and National Energy Technology Laboratory, April 19, 2019. https://www.netl.doe.gov/energy-analysis/details?id=7C7809C2-49AC-4CE0-AC72-3C8F8A4D87AD

gas scenario. The study estimated mean GHG emissions for the U.S. natural gas supply based on these scenarios, and results were presented along with uncertainty estimates (95% confidence intervals). Figure 2 below, extracted from the report, shows estimated GHG emissions for the U.S. natural gas supply. As observed in the figure, there is significant variability in GHG emissions across the U.S. natural gas supply. Exhibit E-31 of the report lists mean GHG emissions for the 30 scenarios studied, which range from a low of 14.2 gCO2e/MJ (Gulf of Mexico and Alaska Offshore) to a high of 31.2 gCO2e/MJ (Gulf - Shale) relative to a U.S. average of 19.9 gCO2e/MJ. DOE should consider this variability in the development of the CHPS as there are likely to be regional differences in upstream GHG emissions from natural gas-based hydrogen production.

Figure 2. Variability in Lifecycle GHG Emissions for the U.S. Natural Gas Supply (Replicated from NETL, 2019)



Variability in Natural Gas SMR Hydrogen Production GHG Emissions

The development of the inputs for hydrogen production via SMR in the previous version of GREET (GREET1_2021) can be found in a 2019 report from Argonne National Laboratory,[19]

[19] "Updates of Hydrogen Production from SMR Process in GREET 2019," Pingping Sun and Amgad Elgowainy, Argonne National Laboratory, October 2019. https://greet.es.anl.gov/publication-smr_h2_2019

which, in turn, was based on a technical paper also published in 2019[20] and a 2010 Praxair whitepaper on hydrogen production via SMR.[21] While baseline GREET inputs and resulting GHG emissions are generally intended to represent a "median" hydrogen plant in the U.S., the technical paper that supported Argonne's inputs for GREET1_2021 presented a range of estimates for GHG emissions from specific hydrogen plants. CO2 emissions for individual plants were available through the National Emissions Inventory (NEI) and the Greenhouse Gas Reporting Program (GHGRP) databases, but hydrogen production volumes are generally considered CBI and were not widely available. As a result, the authors estimated hydrogen production using several different methods described in the report. The bottom line, however, is that there was significant variability in CO2 emissions per unit of hydrogen produced across facilities. For example, Table S4 of the Supporting Materials[22] listed results for the four different methodologies used in that analysis as summarized below in Table 4. As seen in the table, there is substantial variability in GHG emissions per unit of hydrogen production across the SMR plants in the U.S. While the minimum and maximum estimates are likely outliers because of data entry errors in the databases used by the authors, the differences in the 1st and 3rd quartiles still show substantial variability. This underscores the fact that all production units are different, and a one-size fits all approach to establishing a Clean Hydrogen Production Standard is not appropriate.

Table 4. Variability in Estimated On-Site CO2 Emissions (kgCO2/kgH2) for SMR Plants in the U.S. (Values Converted from gCO2/MJ H2 to kgCO2/kgH2)

Parameter*	Method 1	Method 2	Method 3	Method 4
Facilities	6	36	40	42
Minimum	9.4	2.1	--**	2.1
1st Quartile	10.1	7.6	--**	7.9
Median	11.8	9.1	9.0	9.3
3rd Quartile	12.6	10.7	--**	11.1
Maximum	48.1	26.2	--**	48.1

* Note that the minimum and maximum values appear to be outliers.

** Method 3 assumed 9 kgCO2/kgH2 to determine hydrogen production for all facilities; thus, all plants were assigned this value.

[20] "Criteria Air Pollutants and Greenhouse Gas Emissions from Hydrogen Production in U.S. Steam Methane Reforming Facilities," Pingping Sun, Ben Young, Amgad Elgowainy, Zifeng Lu, Michael Wang, Ben Morelli, and Troy Hawkins Environmental Science & Technology 2019 53 (12), 7103-7113. DOI: 10.1021/acs.est.8b06197

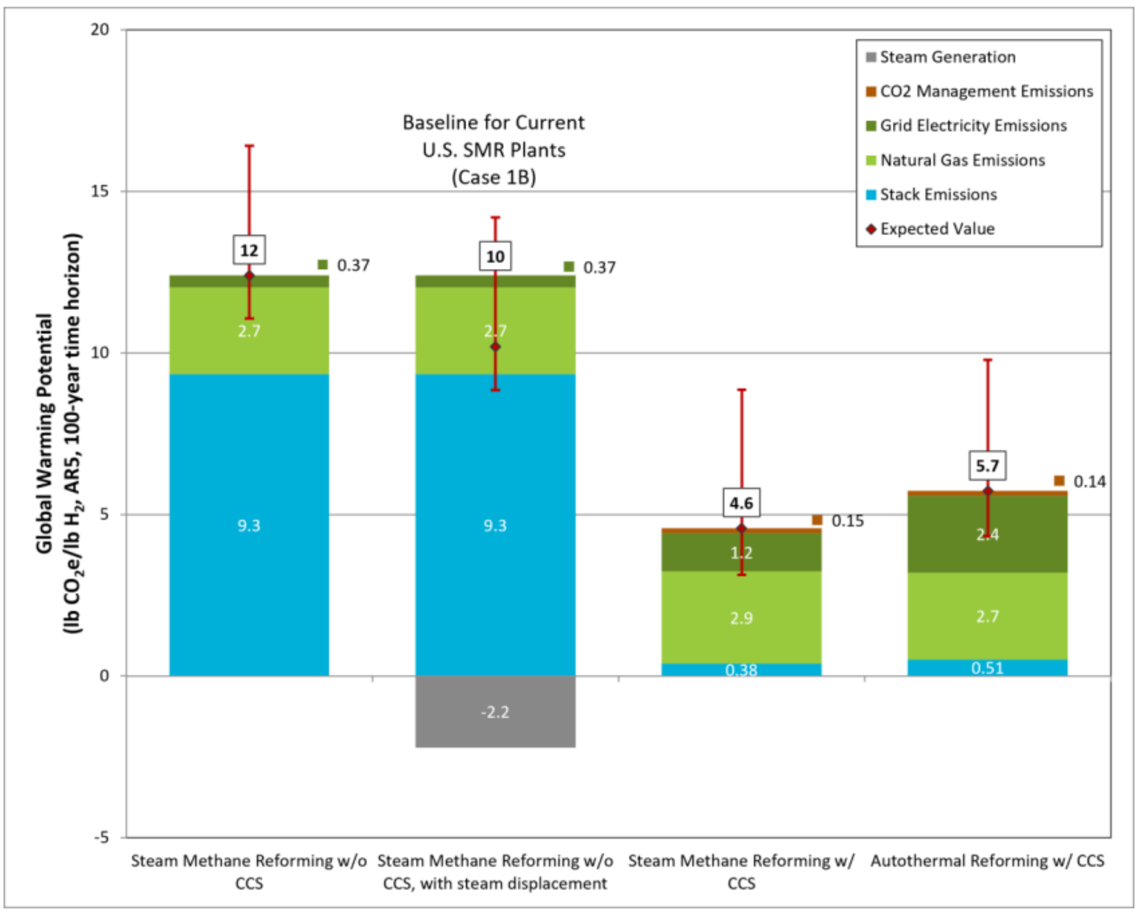
[21] "Analysis of CO2 Emissions, Reductions, and Capture for Large-Scale Hydrogen Production Plants," Dante Bonaquist, Praxair, October 2010. https://www.linde.com/-/media/linde/merger/documents/sustainable-development/praxair-co2-emissions-reduction-capture-white-paper-w-disclaimer-r1.pdf?la=en

[22] Available for download at: https://pubs.acs.org/doi/abs/10.1021/acs.est.8b06197.

The NETL report that served as the basis for the SMR inputs for GREET1_2022 also reported lifecycle GHG emissions for four natural gas-based hydrogen production scenarios: (1) SMR, no carbon capture, no steam export; (2) SMR, no carbon capture, with steam export; (3) SMR, with carbon capture; and (4) ATR, with carbon capture. Results of this analysis are presented in Exhibit 3-52 of the report, which is replicated below as Figure 3. While the results shown in the figure are relatively consistent with the GREET1_2022 results,[23] two items are of particular importance: (1) the confidence intervals shown on the figure are fairly large; and (2) the difference between SMR with carbon capture and ATR with carbon capture is 1.1 kgCO2e/kgH2. Taking this last point a step further, assuming GREET would assign about a 1 kgCO2e/kgH2 difference between the technologies, ATR with carbon capture would not meet the 4.0 kgCO2e/kgH2 standard being proposed by DOE.

Figure 3. Lifecycle GHG Emissions for Natural Gas Based Hydrogen Production (Replicated from NETL, 2022)

Exhibit 3-52. CO_2e life cycle emissions for all reforming cases



[23] The higher estimates in the NETL report relative to GREET1_2022 are likely a result of differing emission factors between GREET1_2022 and the NETL analysis.

Optimizing Carbon Capture in SMR by Focusing on the Process Gas Stream in Retrofit Applications

In developing a Clean Hydrogen Production Standard, DOE should distinguish between new facilities and existing facilities that add carbon capture as a retrofit application. A good example of this is the NETL-Air Products demonstration of CO2 capture and sequestration at Air Products' SMR facility located within the Valero refinery in Port Arthur, Texas.[24] In that demonstration project, CO2 capture was added between the SMR unit and the pressure swing absorption (PSA) unit,[25] which has successfully captured CO2 emissions from the process gas stream for use in enhance oil recovery (EOR) applications.

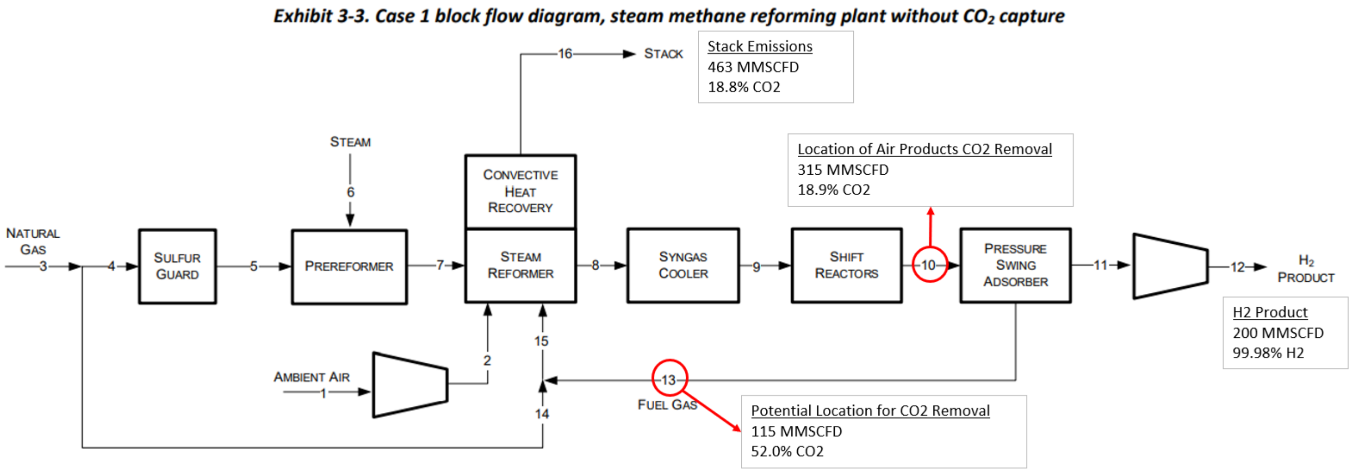
As noted by NETL in a review of CO2 capture from industrial processes,[26]

> *Since CO2 capture from flue gas is considerably more expensive and complex (low CO2 partial pressure, N2/O2 impurities) than from syngas, it is more economical to capture the CO2 from the syngas stream prior to entering the PSA unit in an ATR plant.*

While this discussion was related to an ATR plant, the same can be said about an SMR plant. Based on the material balance presented in the 2022 NETL report used for inputs to the GREET1_2022 model, nearly 70% of total CO2 emissions from natural gas SMR are contained in the process gas stream. This is seen in Figure 4 below, which was replicated from the NETL report, with mass balance information added to the figure. Given the relatively high CO2 concentrations and lower volumetric flows associated with the process gas stream, it is likely to be more efficient and cost-effective to focus CO2 removal on the process gas stream rather than also including combustion CO2 in the capture process. For example, CO2 removal focused at stream number 13 in Figure 4 would target 69% of CO2 emissions while processing 25% of the volumetric flow from the entire process.

[24] See: https://www.netl.doe.gov/sites/default/files/netl-file/FE0002381.pdf
[25] PSA units are very efficient at separating the final hydrogen product from other components in the process gas stream, typically achieving hydrogen concentrations of greater than 99% by volume.
[26] See: https://www.netl.doe.gov/carbon-capture/industrial#hydrogen

Figure 4. SMR Diagram (No Carbon Capture) from NETL (2022) with Volumetric Flows and CO2 Concentrations Identified for Select Streams



4. ELECTROLYSIS OF WATER

Electrolysis of water to produce hydrogen is an existing pathway in GREET1_2022. Generally speaking, modeling electrolysis hydrogen pathways in GREET is relatively simple. An energy efficiency factor (BTUs of electricity needed to produce a BTU of hydrogen) is coupled with the carbon intensity of the electricity source (e.g., gCO2e/MMBTU electricity) used for the conversion of water to hydrogen and oxygen. The most important factor for estimating lifecycle GHG emissions from hydrogen production from water electrolysis is the CI of the electricity source.[27] That is followed by the efficiency of the process. Argonne noted that alkaline technology is the most mature technology, followed by proton exchange membrane (PEM) technology. High-temperature solid oxide electrolysis cell (SOEC) technology is furthest from commercial application, but it is the most efficient technology.

GREET Modeling of Hydrogen Production via Electrolysis for Central Plants

For GREET1_2022, Argonne relied on the DOE Hydrogen and Fuel Cells Program Record No. 19009[28] for efficiency estimates for PEM electrolysis technologies. The current state of performance for central hydrogen production is estimated to be 60.1% (or 55.5 kWh/kg H2), while future performance is estimated to be 65% (or 51.3 kWh/kg H2), which is based on a hydrogen production capacity of 50,000 kg/day.[29] The DOE Hydrogen and Fuel Cells Program

[27] "Hydrogen Life-Cycle Analysis in Support of Clean Hydrogen Production," Amgad Elgowainy, et al., Argonne National Laboratory, October 2022. https://greet.es.anl.gov/publication-hydrogenreport2022
[28] "Hydrogen Production Cost from PEM Electrolysis," David Peterson, et al., Department of Energy, February 3, 2020. https://www.hydrogen.energy.gov/pdfs/19009_h2_production_cost_pem_electrolysis_2019.pdf
[29] Note that this is at the lower end of the capacity criterion for funding under the H2Hub program, which specifies the following under "Technical Merit and Impact": *The ability of the proposed H2Hub to produce at least 50-100MT of clean hydrogen per day.* See: https://oced-exchange.energy.gov/FileContent.aspx?FileID=e159ff1f-5572-437e-b02d-b68acb461893

Record No. 20006[30] was used for efficiency estimates for SOEC technology. It is envisioned that this pathway would be integrated with a nuclear light water reactor (LWR), and the steam drawn from the reactor would supply thermal and electrical energy to the SOEC process. The electrolysis efficiency of this integrated system is estimated to be 79% (or 42 kWh/kg H2).[31]

The calculation of lifecycle GHG emissions for current state PEM technology for a central plant is shown in Table 5 assuming 2021 U.S.-average electricity mix. Lifecycle GHG emissions are 25.9 kgCO2e/kgH2, or about 2.5-times greater than natural gas SMR hydrogen *without* carbon capture. Also shown in the Table 5 calculations is an estimate assuming 85% renewable electricity, which was an option identified in DOE's draft CHPS guidance as meeting the 4.0 kgCO2e/kgH2 target. The calculations in Table 5 show a result of 3.9 kgCO2e/kg H2. However, unless renewable generation capacity is installed at the production site or a specific contracting arrangement is made with a producer, it is unclear if that could be achieved. If renewable electricity is obtained from an existing generation facility, it is possible that there would be no net decrease in GHG emissions as the electricity taken off-line to fuel the electrolysis plant may need to be made up for with other sources – likely to be grid-average electricity. This is simply shuffling of emissions.[32]

The GREET model also allows the user to take a displacement credit for oxygen produced in the electrolysis process, which is not included in the Table 5 estimates. However, it is a relatively small credit, amounting to approximately 0.3 kgCO2e/kgH2.

[30] "Hydrogen Production Cost from High Temperature Electrolysis – 2020," David Peterson, et al., Department of Energy, September 29, 2020. https://www.hydrogen.energy.gov/pdfs/20006-production-cost-high-temperature-electrolysis.pdf

[31] There is a small carbon footprint from nuclear electricity in GREET related to mining, transportation, and enrichment of the uranium supply, so efficiency does factor into the lifecycle analysis for this pathway.

[32] This issue was recognized in the recent National Academies report on lifecycle analysis of low-carbon transportation fuels in the U.S. (see https://nap.nationalacademies.org/catalog/26402/current-methods-for-life-cycle-analyses-of-low-carbon-transportation-fuels-in-the-united-states). As noted in the National Academies report: *In the absence of additionality requirements or measures to ensure that renewable electricity is used to produce green hydrogen, the upstream GHG emissions attributable to fossil fuels in the grid would be attributed to the hydrogen and can therefore greatly increase its assessed emissions.* As discussed later in this report, upstream GHG emissions from electricity generation are highly regionally specific and depend on the mix of generation sources (natural gas, coal, hydro, wind, solar, etc.) in an area. While it may be possible to use the current Renewable Energy Certificate program as an accounting framework for green hydrogen production, appropriate safeguards would need to be put in place to ensure that the additionality requirements recommended in the National Academies report are met.

Table 5. Sample Calculation of PEM Electrolysis GHG Emissions Based on GREET1_2022 (U.S. Average Electricity Mix)

Parameter	Value	Source
Electrolysis Efficiency:	60.1%	DOE Record No. 19009
BTU Electricity/MMBTU H2:	1,663,894	=10^6/0.601
Electricity gCO2e/MMBTU	136,717	U.S. average from GREET
gCO2e per MMBTU H2:	227,483	=1,663,894*136,717/10^6
Lifecycle GHG (kgCO2e/kgH2):	25.9	= 227,483/8.793/1000
% Solar/Wind/Hydro:	85%	Fraction from CHPS Guidance
Lifecycle GHG (kgCO2e/kgH2):	3.9	=25.9*(1 - 0.85)

GREET Modeling of Electricity Generation

As noted above, the carbon intensity of the electricity source is the most important component of the lifecycle GHG emissions associated with hydrogen production via electrolysis. As a result, this section of the report investigates electricity generation in GREET1_2022 in more detail.

GREET includes estimates for electricity generation for a number of different feedstocks and technologies, including natural gas, coal, residual oil, biomass, nuclear power, geothermal, hydroelectric, solar, and wind. GHG emissions associated with hydroelectric, solar, and wind are assumed to be zero.

The model calculates emissions of feedstocks (upstream emissions) separately from direct emissions at the generation site. In addition, an adjustment for transmission losses in included in the on-site emissions estimates. Table 6 presents lifecycle GHG emissions calculated by GREET1_2022 for the 2021 U.S. average generation mix and for natural gas, coal, residual oil, nuclear, and geothermal. There is a small carbon footprint associated with nuclear power generation from extraction and refining of uranium, while emissions from geothermal production are associated with fugitive CO2 emissions from geofluid. Coal-based electricity has the highest GHG footprint, whereas natural gas is about half that of coal. Residual oil, which is used sparingly except in Hawaii and Alaska, has a GHG footprint similar to that of coal. The U.S.-based electricity generation mix is 0.3% residual oil, 36.5% natural gas, 23.8% coal, 19.6% nuclear, 0.3% biomass, and 19.5% "other" (solar, wind, hydro).

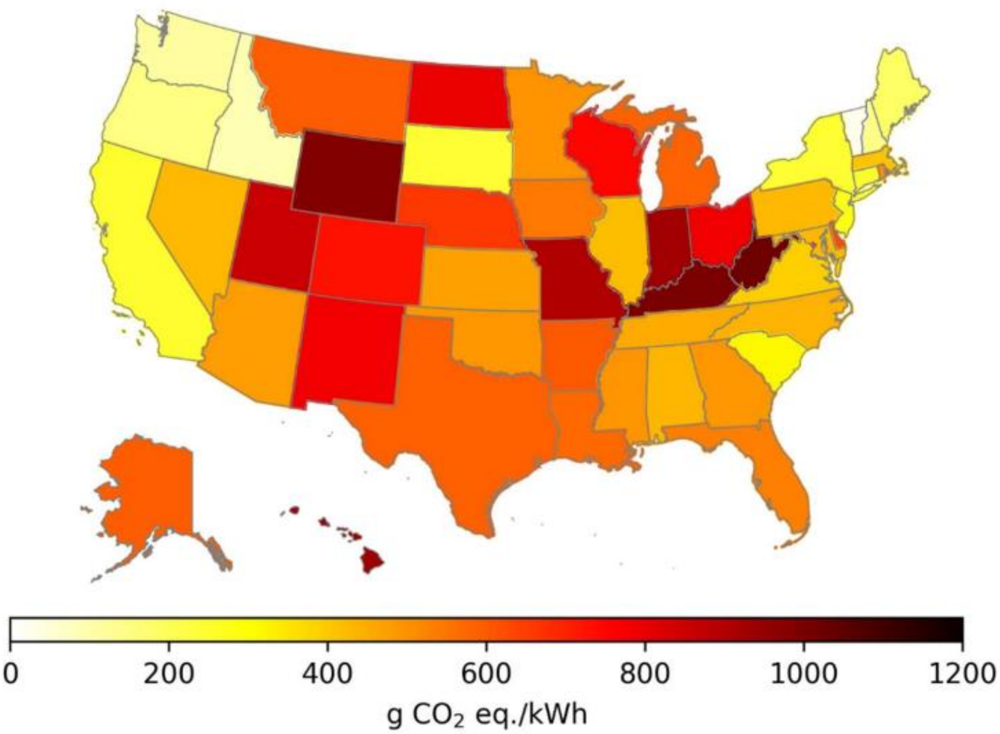
Because the mix of electricity generation sources varies widely across the U.S., state-level and regional-level GHG emissions also vary significantly. This is observed in Figure 5, which shows Argonne's estimated state-level electricity GHG emissions intensity from 2020. In areas that have a high fraction of coal, GHG emissions are high. In areas with a high fraction of renewables and nuclear, GHG emissions are much lower.

Table 6. Lifecycle GHG Emissions Associated with Electricity Generation (Based on GREET1_2022)

Electricity Mix	Feedstock (gCO2e/MMBTU)	Fuel (On-Site)* (gCO2e/MMBTU)	Total (gCO2e/MMBTU)	Total (gCO2e/kWh)
U.S. Average Mix	14,297	122,421	136,717	466
100% Natural Gas	25,703	132,133	157,836	539
100% Coal	18,440	307,629	326,069	1,113
100% Residual Oil	43,055	278,401	321,456	1,097
100% Nuclear	1,923	0	1,923	7
100% Geothermal	0	28,033	28,033	96

* Includes transmission losses.

Figure 5. State-Level Electricity GHG Emissions Intensity (Replicated from Argonne, 2020)[33]

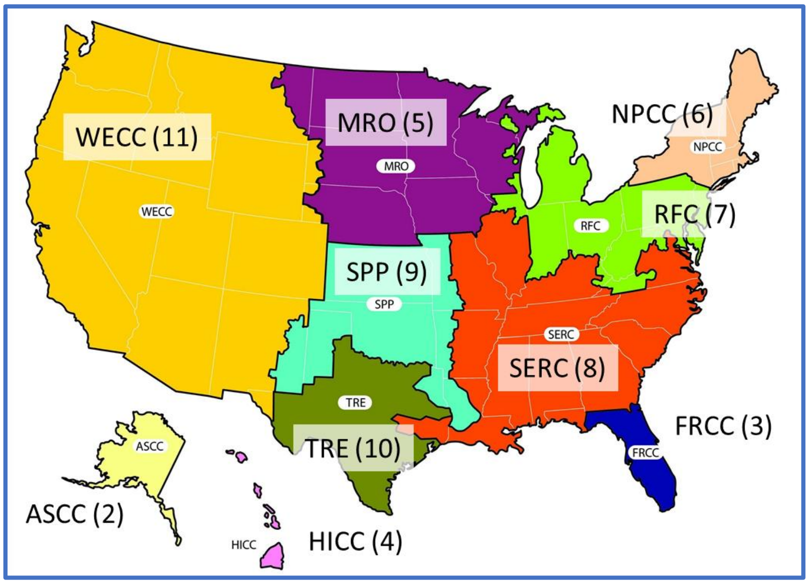


GREET1_2022 was used to estimate the PEM electrolysis hydrogen GHG footprint for the different electricity regions included in the model. As shown in Figure 6, there is significant regional variation in lifecycle GHG emissions associated with hydrogen production via

[33] "Update of Emission Factors of Greenhouse Gases and Criteria Air Pollutants, and Generation Efficiencies of the U.S. Electricity Generation Sector," Longwen Ou and Hao Cai, Argonne National Laboratory, August 2020. https://greet.es.anl.gov/publication-ele_2020

hydrolysis. Details on the electricity generation mix for each of the regions shown in Figure 6 are summarized in Appendix A.

Figure 6. Variation in PEM Electrolysis Hydrogen GHG Footprint by Region Based on GREET1_2022*



Region	H2 CI (kgCO2e/kgH2)
U.S. Mix	25.9
ASCC Mix	33.6
FRCC Mix	27.5
HICC Mix	49.3
MRO Mix	34.5
NPCC Mix	15.4
RFC Mix	26.3
SERC Mix	27.7
SPP Mix	26.3
TRE Mix	24.6
WECC Mix	20.4
CA Mix	16.3

* Does not include co-product oxygen credit, which amounts to approximately 0.3 kgCO2e/kgH2. Estimates prepared with GREET1_2022; figure replicated from GREET1_2022.

5. QUESTIONS POSED UNDER THE CHPS DRAFT GUIDANCE

There were a number of questions posed under the CHPS draft guidance for which DOE requested comment. This section of the report addresses those questions relevant to the lifecycle modeling.

Methane Leak Rates (1% Model Default) – Methane leak rate is a substantial contributor to upstream natural gas GHG emissions. It is important to get this right. To the extent possible, this should be based on actual field data, and variability across regions should be considered.

Lifecycle Boundary – The lifecycle boundary presented in the draft guidance looks complete; we have nothing to add on that issue.

Management of Indirect Climate Warming Impact of H2 – Given the considerable uncertainty in climate impacts of well-studied compounds, this should be neglected.

Downstream Utilization of CO2 – This is not relevant to the lifecycle WTG GHG emissions of hydrogen production.

Biogenic Feedstocks (e.g., RNG) – More work on the lifecycle GHG impacts of biogenic feedstocks is needed. Additionally, flexibility in crediting biogenic feedstocks for hydrogen production would be useful (e.g., “book-and-claim” without the requirement for physical tracking of molecules).

Co-product Credit Methodology – Co-products should be credited with a displacement approach. Other approaches (e.g., energy allocation, mass allocation) should be considered only if there is not an obvious displaced product.

6. RECOMMENDATIONS

Based on the analyses presented above, the following recommendations are being made with respect to the development of the Clean Hydrogen Production Standard:

1. If only applied as a guidance for DOE funding opportunities, the Clean Hydrogen Production Standard should distinguish between new facilities and retrofits of existing facilities for natural gas based hydrogen production:
   - For new facilities, a CHPS of 4.0 kgCO2e/kgH2 is too stringent and could potentially exclude natural gas autothermal reforming (ATR) plants with carbon capture based on the NETL work on advanced fossil-based hydrogen plants. It would also exclude hydrogen production via PEM electrolysis using geothermal electricity. A more appropriate target is in the range of 5.0 to 6.0 kgCO2e/kgH2.
   - For existing facilities, a numeric kgCO2e/kgH2 standard is not appropriate. Instead, DOE should establish a CO2 reduction target for individual facilities based on a percent reduction (e.g., 90%) of the ***process gas stream*** as that has a higher CO2 concentration and does not carry a significant nitrogen load from combustion air, making CO2 capture more efficient.
2. Petroleum refineries produce a significant amount of hydrogen on-site. Any programs implementing the CHPS should allow a pathway for refinery participation.
3. The GREET model accounts for the significant variability in regional electricity generation but does not consider regional variability in natural gas production and transport. That issue should be addressed in the development of a Clean Hydrogen Production Standard.

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Appendix A

Electricity Mix and PEM Electrolysis Hydrogen GHG Footprint by Region and Generation Technology (GREET1_2022)

Table A1. Electricity Mix and PEM Electrolysis GHG Footprint by Region

Fuel Type and H2 GHG Emissions	Region											
	U.S. Mix	ASCC Mix	FRCC Mix	HICC Mix	MRO Mix	NPCC Mix	RFC Mix	SERC Mix	SPP Mix	TRE Mix	WECC Mix	CA Mix
Residual oil	0.3%	15.7%	0.1%	67.7%	0.2%	0.2%	0.1%	0.2%	0.1%	0.1%	0.1%	0.0%
Natural gas	36.5%	42.1%	68.7%	0.0%	28.2%	47.3%	38.2%	32.5%	26.0%	44.6%	32.3%	45.1%
Coal	23.8%	11.5%	12.4%	12.8%	40.2%	1.2%	23.7%	28.9%	29.3%	17.8%	16.7%	4.0%
Nuclear power	19.6%	0.0%	13.4%	0.0%	15.0%	27.0%	31.9%	31.4%	5.8%	10.6%	8.1%	8.6%
Biomass	0.3%	0.6%	0.2%	2.8%	0.3%	1.4%	0.1%	0.4%	0.0%	0.0%	0.5%	1.1%
Others	19.5%	30.1%	5.1%	16.6%	16.2%	23.0%	6.0%	6.5%	38.8%	26.9%	42.2%	41.1%
H2 (kgCO2e/kgH2)	25.9	33.6	27.5	49.3	34.5	15.4	26.3	27.7	26.3	24.6	20.4	16.3
H2 (kgCO2e/kgH2) with co-product credit	25.6	33.3	27.2	49.0	34.2	15.1	26.0	27.4	26.1	24.4	20.2	16.0

Table A2. Electricity Mix and PEM Electrolysis GHG Footprint by Generation Technology

Fuel Type and H2 GHG Emissions	Technology Type					
	NG Power Plants	Coal Power Plants	Nuclear Power Plants	Hydro Power Plants	NGCC Turbine	Geothermal
Residual oil	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Natural gas	100.0%	0.0%	0.0%	0.0%	100.0%	0.0%
Coal	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
Nuclear power	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%
Biomass	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Others	0.0%	0.0%	0.0%	100.0%	0.0%	100.0%
H2 (kgCO2e/kgH2)	29.9	61.7	0.4	0.0	27.4	5.3
H2 (kgCO2e/kgH2) with co-product credit	29.6	61.5	0.1	-0.3	27.1	5.0