February 26, 2024

Internal Revenue Service
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Room 5203
P.O. Box 7604
Ben Franklin Station, Washington, DC 20044

RE: Section 45V Credit for Production of Clean Hydrogen; Section 48(a)(15) Election to Treat Clean Hydrogen Production Facilities as Energy Property

Submitted via Regulations.gov

The American Clean Power Association[1] appreciates the opportunity to comment on the notice of proposed rulemaking (Proposed Rule), *Section 45V Credit for Production of Clean Hydrogen; Section 48(a)(15) Election to Treat Clean Hydrogen Production Facilities as Energy Property,* issued by IRS and Treasury (collectively, Treasury) on December 26, 2023.[2]

Treasury's Proposed Rule will simply not achieve the Administration's goals of utilizing green hydrogen to decarbonize sectors of our economy that have no alternative option to reduce their greenhouse gas (GHG) emissions. The proposal will deter investment in the industry by driving up the already high costs of producing green hydrogen – even with the use of the tax credit – causing it to remain uncompetitive with existing higher emitting fuels and feedstocks it must replace. This lack of investment will deter equally necessary supply chain investments in the equipment and infrastructure needed to reduce the costs of green hydrogen production: electrolyzers, new renewables, and storage infrastructure. Without the near-term opportunity to

[1] ACP is the leading voice of today's multi-tech clean energy industry, representing over 800 energy storage, wind, utility-scale solar, green hydrogen, and transmission companies. ACP is committed to meeting America's national security, economic and climate goals with fast-growing, low-cost, and reliable domestic power, including green hydrogen.
[2] Internal Revenue Service, *Section 45V Credit for Production of Clean Hydrogen; Section 48(a)(15) Election To Treat Clean Hydrogen Production Facilities as Energy Property*, available at: https://www.federalregister.gov/documents/2023/12/26/2023-28359/section-45V-credit-for-production-of-clean-hydrogen-section-48a15-election-to-treat-clean-hydrogen.

drive down costs through deployment, green hydrogen will not become a meaningful part of the climate solution.

In enacting the clean hydrogen tax credit, Congress intended to provide a robust incentive to catalyze and quickly scale a domestic green hydrogen economy that can affordably and meaningfully lower emissions in hard to decarbonize sectors. The tax credit holds the promise to provide an unprecedented level of support for the scaling of green hydrogen production—showing a strong congressional commitment to grow green hydrogen's share of the U.S. clean energy portfolio and to create a meaningful opportunity to boost domestic energy production, lower emissions, drive demand for new renewable energy, and expand domestic jobs in the clean energy sector.[3] However, the success of this incentive is contingent on flexible Section 45V guidance, and the Proposed Rule comes up short in this respect.

While ACP supports much of the Proposed Rule, unfortunately, it has one glaring flaw: an overly stringent near-term time-matching requirement that will prevent green hydrogen production from scaling up. Though ACP supports more exacting time-matching standards over time, it is critical that Treasury not phase in these standards too soon. ACP commissioned Wood Mackenzie Consulting to provide an independent, detailed report (WoodMac Report) describing how the Proposed Rule's time-matching standard will impact commercial deployment of green hydrogen. The report, which is attached to these comments, along with many other studies detailed herein, support ACP's position that Treasury's current time-matching proposal would severely limit the role green hydrogen will play in the economy of tomorrow.

As Treasury completes its work, it should strive to strike the right balance in the final rule by adopting stringent incrementality and deliverability requirements, while providing necessary

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[3] IEA, *Global Hydrogen Review* at 19. Available at https://iea.blob.core.windows.net/assets/5bd46d7b-906a-4429-abda-e9c507a62341/GlobalHydrogenReview2021.pdf (An estimated 90-million-ton reduction in carbon emissions each year by 2030.). These large emissions reductions are due to the fact that green hydrogen is essential for decarbonizing key sectors of the U.S. economy that are difficult to abate through direct electricity usage—including heavy duty manufacturing, chemical production, and heavy-duty transportation. Energy Innovation, Smart Design Of 45V Hydrogen Production Tax Credit Will Reduce Emissions and Grow the Industry at 9-10 (discussing the numerous industrial applications for green hydrogen in otherwise difficult to decarbonize sectors).

flexibility on time matching, thereby fulfilling congressional intent to unlock the decarbonization potential of this breakthrough technology.

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I. Executive Summary

Green hydrogen is key to unlocking deep emissions abatement because it can not only help decarbonize the market for conventional hydrogen, but also industries and manufacturing processes that cannot easily be powered by clean electricity (e.g., long-distance transportation and high-temperature industrial processes).[4] WoodMac estimates that the U.S. requires 50-80 million metric tons per annum of low carbon hydrogen adoption by 2050 to reach our net zero goals, which is approximately 1.6 times more low carbon hydrogen than DOE has projected the U.S. will need to meet its decarbonization targets.[5] According to DOE's National Clean Hydrogen Strategy and Roadmap, if the U.S. is to achieve even DOE's conservative decarbonization targets, green hydrogen use must increase from near-zero today to 10 million metric tons (MMT) by 2030, 20 MMT by 2040, and 50 MMT by 2050.[6] This necessary increase will not happen absent a sufficient glide path that allows green hydrogen to achieve scale and become cost competitive with conventional forms of hydrogen produced using fossil fuels.[7] In recognition of this fact, Congress designed the Section 45V tax credit to give green hydrogen an opportunity to compete with its more carbon-intensive counterparts in the hydrogen industry.

As the WoodMac analysis and other studies confirm, the green hydrogen industry currently faces a number of obstacles that prevent it from achieving large-scale deployment. For one, green hydrogen is a capital-intensive industry, and uncertainty around Section 45V eligibility creates a high-risk profile, limiting investor interest and capability. Second, industrial electrolyzers are a relatively new and underdeveloped technology, and steep capital expenses and learning curves presently stand in the way of advancements in green hydrogen production technologies. Third, there is limited infrastructure to connect green hydrogen to demand centers.

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[4] Hannah Murdock, et al., *Pathways to Commercial Liftoff: Clean Hydrogen*, DOE (March 2023), available at https://liftoff.energy.gov/clean-hydrogen/ ("Hydrogen can play a role in decarbonizing up to 25% of global energy-related CO2 emissions, particularly in industrial/chemicals uses and heavy-duty transportation sectors.").

[5] *Implications of 45V Guidance for the Future of the Green Hydrogen Industry*, Wood Mackenzie Report Prepared For ACP, (Feb. 2024), attached *infra* as Ex. A

[6] *U.S. National Clean Hydrogen Strategy and Roadmap,* DOE (June 2023), https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/us-national-clean-hydrogen-strategy-roadmap.pdf.

[7] *Id.*

Fourth, it is difficult to source low-cost renewable feedstocks that can support sustained and continuous commercial operations. Because of these challenges, green hydrogen is presently not cost-competitive with blue hydrogen and conventional fossil fuels, and these cost disparities inhibit green hydrogen producers from securing long-term production contracts with potential offtakers. Consequently, very little of the announced 70 billion dollars of investment in U.S. green hydrogen production is actually moving to the final investment and construction phases.

Unless policies help drive down costs and facilitate the deployment of green hydrogen technology, end-users will not have an incentive to switch to this technology on a widescale basis. While the Section 45V credits hold the promise of closing the cost gap, if Treasury prematurely imposes overly restrictive and costly hourly time-matching requirements, which preclude green hydrogen facilities from operating their electrolyzers when renewable energy is unavailable, it will reduce capacity factors, exacerbate high production costs, and make green hydrogen uncompetitive with alternative fuels. This, in turn, will cause early investors to perceive green hydrogen as an uneconomical venture – even with the generous clean hydrogen tax credits – and prevent necessary production capacity build-out, ultimately jeopardizing the growth of this industry and its ability to achieve economies of scale that can drive even further emissions reductions. In short, the weight of evidence confirms that if green hydrogen is to fully realize its decarbonization potential, Treasury must adopt a time-matching strategy that ensures the industry can overcome the current obstacles that make green hydrogen more expensive to produce and transport than its fossil-based competitors.

In 2023, ACP proposed a Green Hydrogen Framework (Framework) based on the "three pillars" for green hydrogen (temporality, incrementality, and deliverability), which was supported by our "big tent" diverse membership, based on the shared goal of supporting the development of the new green hydrogen industry in the U.S., while at the same time providing robust guardrails to ensure that it meets the IRA's thresholds for well-to-gate net emissions. The Framework offered a roadmap for effectively balancing the dual priorities of supporting early-market development of green hydrogen with maintaining a rigorous and robust standard for ensuring clean green hydrogen production. It was the result of considerable deliberation, analysis, and interaction with leading member companies in the clean power and green hydrogen industries, environmental organizations, and other stakeholders.

The Framework presented a path to encourage first movers in commercializing this new technology – while also ensuring near- and long-term emissions reductions – allowing the industry to reach economies of scale to lock in its long-term decarbonization goals.[8] Similar to the Proposed Rule, the Framework proposed "strict" incrementality and deliverability requirements. Namely, that green hydrogen incentives should be limited to facilities that can both demonstrate they are relying on "new" sources of clean power and are sourced from within relatively close-knit and interconnected geographic boundaries. However, ACP's support of strict incrementality and deliverability requirements in the Framework was based on a more flexible time-matching approach that allowed for a longer phase-in from annual to hourly matching, combined with exempting first-mover hydrogen projects from hourly time-matching requirements to ensure that the green industry has a realistic path to get out of the starting blocks.

The Proposed Rule runs contrary to ACP's proposal in two fundamental ways. First, it requires a transition from annual time matching to hourly time matching by January 1, 2028. This simply does not give green hydrogen developers enough time to take advantage of an annual time matching allowance and help them reach economies of scale before the transition. Second and equally important, the Proposed Rule does not exempt first-mover green hydrogen projects from hourly reporting requirements for the life of the tax credit. Without this exemption, it is unlikely that green hydrogen developers will be able to take advantage of initial annual time matching, whether it be the date currently proposed, or a later date (as suggested by ACP), due to financing and operational realities of changing time-matching regimes midstream. Once a green hydrogen project is financed and begins construction, it is exceedingly difficult to later change electrolyzer and plant design to accommodate the need to perform hourly time matching. Consequently, the Proposed Rule effectively creates an hourly time-matching requirement from

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[8] *ACP Green Hydrogen Framework Proposal on the "Three Pillars" for Building a Green H2 Industry & Ensuring Climate Benefits Under the Clean Hydrogen Tax Credits*, American Clean Power Association, (June 2023), available at https://cleanpower.org/wp-content/uploads/2023/06/ACP_GreenHydrogenFramework_Explanation.pdf.

the outset that will prove cost-prohibitive for this nascent, capital-intensive industry.[9] It is therefore critical that Treasury select an appropriate glide path in the final rule from annual to hourly time matching, lest it completely subvert congressional intent in enacting Section 45V to ensure a robust green hydrogen industry.

Given the aforementioned issues with the Proposed Rule, which are explained further below, the final rule should, above all, extend the phase-in date for hourly time matching to 2032 and exempt early adopters from an hourly regime. Specifically, ACP recommends that change and the following to the final rule to ensure the Section 45V credit fulfills its promise:

- **Time Matching**
    - Provide a longer glide path for the transition date to hourly time matching; 2028 will not provide the green hydrogen industry sufficient time to develop.
        - Allow projects to stay under annual time-matching so long as such projects begin construction by January 1, 2028; projects that begin construction in 2029 and beyond should be subject to the hourly time-matching requirement from the onset.
    - Exempt first-mover projects (i.e., those that are placed in service under annual matching) from transitioning to hourly time matching.
        - If Treasury does not support a full exemption from the hourly requirement for early movers (even though that would be the most effective and administrable solution to scale the industry), consider adopting a formulaic approach in which first movers only need to meet a certain percentage of hourly matching for the tenure of the tax credit, such as 85% hourly matching for projects placed in service before 2032.
    - Issue a public report outlining the status of the coverage of hourly tracking systems across the nation at least one year before any transition date; if the report finds that any region, structure, and/or market is not sufficiently developed to

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[9] Even studies that endorse hourly matching concede that hourly matching would result in lower utilization rates for electrolyzers and an increase in the LCOH for hydrogen produced. *See, infra* pp. 25 (discussing Princeton ZERO Lab article).

facilitate hourly tracking, implementation of an hourly time matching requirement should be delayed by at least one year to allow for the tracking system(s) to come online.
    - Clarify that stored electricity has a time stamp that correlates to the time such electricity is used in the production of clean hydrogen rather than when the electricity was generated or stored.
- **Incrementality**
    - Consider expanding the three-year incrementality window to at least one year after the hydrogen plant comes online to appropriately account for delays in the development process for renewables and align with the continuity requirements for onshore renewables.
    - Clarify that green hydrogen produced from repowered renewable facilities that meet the 80/20 Rule will be treated as "new" if the repower happens within the above window.
    - Exceptions to the incrementality requirement:
        - Increase the formulaic approach percentage threshold from a presumptive level of 10% to more appropriately address congestion and curtailment realities.
        - In addition to the formulaic approach, allow the formulaic level to be exceeded, on a case-by-case basis, for taxpayers providing evidence of historical congestion and curtailment.
    - Exempt qualified clean hydrogen facilities that are placed in service in states/regions with 100% zero-emissions, carbon-free, or renewable energy goals and the region/state has achieved 90% clean energy on the grid.
- **Deliverability**
    - Clarify that a hydrogen facility with firm transmission service between the hydrogen facility in one region and of clean energy source in another meets the deliverability requirement.
- **Energy Attribute Certificates (EAC)**
    - Clarify: (1) electricity from generating facilities that are directly connected to the hydrogen production facility may be taken into account for purposes of

determining the lifecycle GHG emissions rate regardless of whether such electricity generation creates an energy attribute credit that is retired; and (2) the 4.9% Line Loss Assumption does not apply to electricity generating facilities that are directly connected to a hydrogen production facility.

- **Carbon Matching**
  - Issue a supplement notice, prior to the finalization of the rule, requesting comment on the merit of including an annual carbon matching pathway as a potential alternative compliance option in the final rule.
- **45VH2-GREET Model**
  - Allow a facility to input in the 45VH2-GREET model the volume of hydrogen for which it is requesting Section 45V tax credits, rather than relying on total hydrogen production.
  - Clarify that power from a sub-regional grid (a subset of one of the nine regional grids identified in the Department of Energy (DOE) Transmission Needs Study be considered a potential "feedstock" for which a taxpayer can file a petition for a provisional emissions rate.
  - Allow a taxpayer to rely on the version of the 45VH2-GREET model in effect when the project begins construction, or on the first day of the taxable year in which the clean hydrogen is placed in service for the duration of the project.

II. Background

a. The current landscape of green hydrogen production costs.

The current levelized cost of green hydrogen (LCOH) production is up to nine USD per kilogram (kg).[10] Therefore, green hydrogen is two to six times more expensive to produce than hydrogen generated by non-renewable sources and up to ten times more expensive than traditional fossil fuels.[11] The cost of producing green hydrogen from renewables will need to fall by over 50% by 2030 to make it a viable competitor with conventional hydrogen and fossil fuels.[12] As the 2024 WoodMac analysis notes, green hydrogen economics must fall within $1-2/kg, on a delivered to customer basis, to encourage demand sectors to adopt green hydrogen at scale.[13]

The current cost of green hydrogen is primarily driven by ability to achieve high capacity factors—the higher such factors are, the more cost competitive relative to other sources of hydrogen. The ability to achieve high capacity factors in the green hydrogen industry under an hourly regime is presently limited by: (1) high electrolyzer system costs and supply chain issues; and (2) the cost and availability of renewable electricity and energy storage.[14]

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[10] *See infra* Ex. A (2024 WoodMac Analysis); *Levelized Production Costs of Green & Blue Hydrogen*, GEP, (Jan. 2023), available at https://www.gep.com/blog/strategy/Green-and-blue-hydrogen-current-levelized-cost-of-production-and-outlook#:~:text=The%20current%20levelized%20cost%20of,procurement%20cost%20of%20renewable%20electricity.

[11] *See* Daniel Moore, *Hydrogen's Power Grid Demands Under Scrutiny in Tax Credit,* Bloomberg (Apr. 6, 2023), available at: https://news.bloomberglaw.com/environment-and-energy/hydrogen-1; *supra* GEP (2023); Dolf Gielen, et al., *Unleashing the power of hydrogen for the clean energy transition*, World Bank, (July 11, 2023), available at https://blogs.worldbank.org/energy/unleashing-power-hydrogen-clean-energy-transition#:~:text=Green%20hydrogen%20is%20currently%20considerably,carbon%20capture%20and%20storage%E2%80%94production; https://womblebonddickinson.com/us/insights/alerts/hydrogen-near-term-challenges-long-term-opportunities; Wood Mac Study (finding that electrolytic hydrogen projects are still developing more slowly than natural gas reformation projects).

[12] *See,* S&P Global, *Green hydrogen costs need to all over 50% to be viable* (2020), available at: https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/electric-power/112020-green-hydrogen-costs-need-to-fall-over-50-to-be-viable-sampp-global-ratings

[13] *See infra* Ex. A (2024 WoodMac Analysis).

[14] Matthias Deutsch et al., *Making renewable hydrogen cost competitive,* Agora Energiewende (2021), available at https://static.agora-energiewende.de/fileadmin/Projekte/2020/2020_11_EU_H2-Instruments/A-EW_223_H2-Instruments_WEB.pdf.

1. Electrolyzer costs and supply chain issues

The current costs associated with electrolyzer systems for hydrogen production are notably high, which serves as an impediment to investment in the technology. There are four main kinds of commercial electrolzyers: alkaline electrolyzer; anion exchange electrolyzer (AEM); proton exchange membrane electrolyzer (PEM); and solid oxide electrolyzer (SOEC).

Alkaline electrolyzers are inexpensive but are not well suited to ramp up and down to match renewable electricity availability.[15] Prices range from $500 to $1,100 per kilowatt (kW), although these costs are anticipated to drop to between $344 and $850 by 2030 and further to between $200 and $700 by 2050.[16] AEM electrolyzers could be cost competitive with alkaline electrolyzers, but may come with a shorter lifespan and are at a lower level of technology and commercial readiness compared to the other forms of electrolzyers. They are currently priced at over $931 per kW.[17] PEM electrolyzers are ideal for quick ramping up with renewables but have high material costs. They currently cost between $667 to $1,800 per kW and are expected to have a projected decrease to $650 to $810 by 2030 and then to $200 to $510 by 2050.[18] SOEC electrolyzers can achieve higher temperatures and access an external source of process heat, making them more energy efficient than their counterparts; they are well-suited for integration in hard-to-abate industrial processes, including ammonia, chemical, and steel production, as well as oil refining.[19] SOECs are less durable and currently have a shorter operating life than other electrolyze alternatives.[20] These electrolyzers top the chart with the steepest costs, ranging from $1,410 to more than $5,600 per kW, but these are expected to lower to around $800 by 2030 and could fall as low as $300 by 2050.

Advancements in electrolysis technology are necessary to enhance efficiency and reduce costs. There are two key components to an electrolysis system: (1) the electrolyzer's stack or

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[15] Anne-Sophie Corbeau & Ann-Kathrin Merz, *Demystifying Electrolyzer Production Costs*, Columbia SIPA (July 11, 2023), available at: https://www.energypolicy.columbia.edu/demystifying-electrolyzer-production-costs/.
[16] *Id.*
[17] *Id.*
[18] *Id.*
[19] Gniewomir Flis, *Solid Oxide Electrolysis: A Technology Status Assessment*, Clean Air Task Force (2023), available at: https://cdn.catf.us/wp-content/uploads/2023/11/15092028/solid-oxide-electrolysis-report.pdf.
[20] *Id; see supra* Corbeau (2023).

"module"—where the hydrogen production takes place; and (2) the balance of plant, "which refers to the miscellaneous equipment surrounding the stack, including for cooling, compression, purification, power electronics, and water treatment."[21] Future reductions in the cost of electrolyzer technology hinge on the ability to scale up production, both in terms of producing larger electrolyzer modules and green hydrogen manufacturing facilities.[22] Today, electrolysis plants are typically very small, with the average size being around 1 to 1.37 megawatts (MW).[23] Experts surmise that the size of electrolysis plants will need to increase from 1 MW (typical today) to 100 MW or higher in a future hydrogen economy that will utilize large amounts of cheap electricity.[24]

Although there is a notable increase in the projected electrolyzer production capacity, now ranging between 9 and 13 gigawatts, actual manufacturing has lagged, with just around 200 MW installed over 2021 and 2022.[25] The electrolyzer supply chain will need to expand at an unprecedented pace to meet anticipated demand associated with the projected surge in electrolytic hydrogen production.[26] If this is to happen, policymakers will need to incentivize investments that help standardize design and supply chains and promote development of economies of scales.[27] The manufacturing of 1 GW of capacity per year – a 50 to 100 fold increase in production – would unleash considerable economies of scale, and several companies have announced plans to help achieve this objective. The pace of advancement will depend on whether Section 45V's tax credits can reduce costs enough to generate demand and promote the

[21] *Id.*
[22] *Id.*
[23] Emanuele Taibi, et al., Green Hydrogen Cost Reduction: Scaling Up Electrolysers to Meet the 1.5° Climate Goal, IRENA (2020), available at: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Dec/IRENA_Green_hydrogen_cost_2020.pdf; Polly Martin, *Barely 1GW of green hydrogen capacity would be installed in Europe by 2030 at current rate*, Hydrogen Europe (Nov. 2023), available at https://www.hydrogeninsight.com/production/barely-1gw-of-green-hydrogen-capacity-would-be-installed-in-europe-by-2030-at-current-rate-hydrogen-europe/2-1-1558335.
[24] Gas Turbine World, *Needed: Electrolyzers Producing Cheap, Green, Hydrogen* (2022), available at https://gasturbineworld.com/electrolyzers-green-hydrogen/; *supra* Agora (2021).
[25] *See supra* Corbeua (2023).
[26] *Id.*
[27] *See supra* IRENA (2020).

development an offtake market for green hydrogen before prospective consumers opt for more carbon-intensive alternatives.[28]

2. *Renewable energy prices and availability*

The other primary cost factor for green hydrogen is the current expense of renewable electricity, which is dropping significantly due to cheaper solar and onshore wind energy. According to a report by RMI, advancements in technology are anticipated to reduce the costs of renewable energy generation significantly by 2030—by up to 25% for wind and 50% for solar.[29] Data from the National Renewable Energy Laboratory (NREL) shows an 82% cost reduction in utility-scale photovoltaic (PV) systems since 2010, a trend largely attributed to increased investments in renewable energy.[30] As a result of these declining renewable costs, the economic feasibility of green hydrogen production is expected to improve, making it more competitive with conventional energy sources.[31] This cost-effectiveness is crucial for the widespread adoption of green hydrogen, which stands to play a pivotal role in the transition to a sustainable energy economy. However, it is important to allow enough time for these costs to go down. While increased investments in renewable energy are certainly helping, there has been a sustained upward pressure on renewable energy prices over the past several years because of demand and supply chain issues. There are also widespread challenges in getting projects through the interconnection que.

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[28] Deloitte, *Actualizing the Green Hydrogen Economy* (2023), available at: https://www2.deloitte.com/content/dam/Deloitte/de/Documents/sustainability/Deloitte_Actualizing-green-hydrogen-economy.pdf.

[29] Kingsmill Bon et al., *X-Change: Electricity 2023 Report*, RMI (2023), available at: https://rmi.org/insight/x-change-electricity/?__hstc=213470795.545d58c145c36f98ae523d8bd9eadf24.1707421056974.1707421056974.1707421056974.1&__hssc=213470795.1.1707421056974&__hsfp=3297838879.

[30] David Feldman et al., *U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2020*, National Renewable Energy Laboratory (2020), available at: https://www.nrel.gov/docs/fy21osti/77324.pdf.

[31] Qusay Hassan et al., *Green hydrogen: A pathway to a sustainable energy future*, International Journal of Hydrogen Energy (Jan. 2024), available at: https://www.sciencedirect.com/science/article/abs/pii/S0360319923045056.

3. Battery storage prices and availability

The final major contributing factor to the elevated costs of green hydrogen production is the expense associated with energy storage. Adequate storage capacity is crucial for balancing energy availability with the demands of power generation and electrolyzer operation. In 2022, utility-scale lithium-ion batteries cost $482 per kilowatt-hour (kWh).[32] NREL predicts these costs will fall to $255 per kWh by 2030 and $159 by 2050, representing a 47% and 67% reduction from 2022 costs, respectively.[33] As storage becomes cheaper, and if the credit allows for timestamp shifting of EACs, green hydrogen will be more affordable for and more attractive to developers. However, these cost decreases are well in the future, long after the start of construction for first movers. If the green hydrogen industry is to succeed, we cannot wait for these long-term decreases in cost, but instead must act now.

Moreover, the capacity for battery storage is rapidly increasing. In 2010, the U.S. had less than 1 gigawatt (GW) of battery storage;[34] however, by the end of 2023, U.S. utility-scale battery capacity totaled around 16 GW.[35] According to the U.S. Energy Information Administration (EIA), developers plan to add another 15 GW in 2024 and around 9 GW in 2025, which will bring the total to over 30 GW by the end of 2024 and roughly 40 GW by the end of 2025.[36] This expansion in storage capacity not only aligns with the increasing demand for renewable energy, but also enables a more resilient grid, capable of integrating larger shares of intermittent renewable sources like solar and wind, thereby facilitating a broader adoption and deployment of green hydrogen solutions.

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[32] Wesley Cole & Akash Karmakar, *Cost Projections for Utility-Scale Battery Storage: 2023 Update*, National Renewable Energy Laboratory (2023), available at: https://www.nrel.gov/docs/fy23osti/85332.pdf.
[33] *Id.*
[34] Suparna Ray*U.S. battery storage capacity will increase significantly by 2025*, , U.S. Energy Information Administration (Dec. 2022), available at: https://www.eia.gov/todayinenergy/detail.php?id=54939.
[35] Katherine Antonio & Alex Mey*, U.S. battery storage capacity expected to nearly double in 2024*, U.S. Energy Information Administration (Jan. 2023), available at: https://www.eia.gov/todayinenergy/detail.php?id=61202#:~:text=Planned%20and%20currently%20operational%20U.S.,Preliminary%20Monthly%20Electric%20Generator%20Inventory.&text=Battery%20storage%20projects%20are%20getting%20larger%20in%20the%20United%20States.
[36] *Id.*

III. Temporal Matching

While ACP appreciates the Proposed Rule's inclusion of a transition date from annual to hourly time matching, for the reasons discussed below, we have serious concerns that the chosen date (i.e., January 1, 2028) does not provide sufficient time for the green hydrogen industry to develop under the annual time-matching phase, for hourly REC standards and tracking systems to be widely and consistently deployed, or for a liquid market to emerge across the nation for the trading of energy attribute credits (EACs) to support that transition.[37] Absent a sufficient transition period, along with a provision excluding first movers from the requirement to move to hourly time matching, projects will be unable to account for the change in economics and project design that result from the shift – resulting in the entire project being financed as if it were under hourly requirements for the duration of the project and negating any benefit of annual time matching. For the foreseeable future, it is not possible, under an hourly regime, to scale the green hydrogen industry due to increased costs associated with such a regime and the technical challenges of getting an hourly tracking system up and running to help lower those costs. Consequently, implementing an hourly time-matching regime too early will result in the green hydrogen industry being kneecapped before it can walk.

ACP recommends that hourly time matching not be phased in until at least 2032 to give the green hydrogen industry time to become cost competitive with its more carbon intensive counterparts. Additionally, given that it is commercially infeasible for green hydrogen production facilities, once constructed, to transition from annual to hourly time-matching technology, ACP recommends that Treasury exempt first-mover projects that are placed in service before January 1, 2032, from forthcoming hourly time-matching requirements.

Finally, prior to the transition occurring, Treasury should issue a public report outlining the status of a nationwide EAC tracking system (including associated markets and structures) and its ability to successfully track at an hourly scale at least one year before any transition date. If the report finds that any region, structure, and/or market is not sufficiently developed to

[37] Proposed Rule at 89232-33.

facilitate the required hourly tracking, implementation of the EAC hourly time-matching requirement should be delayed by at least one year to allow for the market or markets to come online.

In support of these recommendations, we provide: (1) an overview of the studies analyzing the respective costs associated with annual and hourly time matching; (2) an overview of the available research on the emissions implications of adopting an annual versus hourly time-matching requirement this decade; (3) a discussion of how hourly time matching might affect the hydrogen hubs; (4) an explanation for why hourly EAC structures will not be available in certain parts of the U.S. by the 2028 transition date; (5) an articulation of the need to exempt first movers from hourly time matching for the duration of the life of the tax credit; (6) an explanation of why the final rule should adopt a start of construction date metric; (7) a request that the final rule clarify the impact of electricity storage on temporal matching; and (8) an explanation for why 2032 represents the appropriate transition date to annual time matching.

a. Studies show hourly time matching increases costs and will make green hydrogen production uneconomic if required this decade.

Green hydrogen is a capital-intensive industry. If green hydrogen facilities are to establish economies of scale with levelized production, energy, and electrolyzer costs, green hydrogen facilities will need to operate their electrolyzers at near full capacity over the course of the next decade.[38] However, there is often limited availability of renewable production at certain times of the day (i.e., when the sun is not shining and the wind is not blowing). Consequently, hourly time matching, which largely precludes hydrogen facilities from using alternative power from the grid when renewables are not available, will generally only allow an electrolyzer to run at approximately 46-72% capacity.[39] This curtailment of production means that costs are

[38] *See supra* Agora (2023).
[39] Leigh Collins, *US green hydrogen definition | 'Annual, rather than hourly matching could cut H2 costs by up to 175% and still be net zero',* Hydrogen Insight (Mar. 13, 2023), available at: https://www.hydrogeninsight.com/policy/us-green-hydrogen-definition-annual-rather-than-hourly-matching-could-cut-h2-costs-by-up-to-175-and-still-be-net-zero/2-1-1417840.

distributed over a smaller amount of hydrogen produced and could increase the LCOH up to 175%.[40]

Because of limited power availability, the only two options available to aid developers in increasing their capacity factors under an hourly regime are to oversize the electrolyzer and/or over procure renewables or storage. As noted above, both battery and hydrogen storage are currently expensive and often have limited operational capabilities depending on a project. So, this option will only marginally increase the capacity factors and will come at considerable costs. Even without over-procuring, assembling an hourly-matched portfolio requires combining both solar and wind supply — and a much more significant amount of the latter, exacerbating renewable supply issues considering interconnection queues are generally backlogged and the renewables mix therein is heavily skewed towards solar resources. Certain regions with poor wind resource potential (such as the Delta region in southern part of the Midwest System Operator) will struggle to accommodate hourly matched green hydrogen at all and miss out on green hydrogen deployment.

To the extent that a green hydrogen facility could afford to over-purchase renewables under an hourly-time matching system and still turn a profit in the near term, such a facility would only be able to do so in certain regions of the country, like West Texas, that already have high penetrations of both wind and solar (as well as accompanying transmission congestion). Thus, the imposition of near-term hourly time matching would encourage the development of extremely localized green hydrogen production in areas of the country that already struggle with renewable energy congestion and curtailment, not the nationwide green hydrogen deployment that Congress envisioned when passing Section 45V. In short, if an hourly time-matching system is imposed too soon, a green hydrogen developer will often be faced with the only feasible

[40] Melanie Vargas et al., *Green hydrogen: what the Inflation Reduction Act means for production economics and carbon intensity,* Wood Macenzie (Mar. 14, 2023), available at: https://www.woodmac.com/news/opinion/green-hydrogen-IRA-production-economics/ .

choice: limited production due to low capacity factors, assuming they can even finance a project under those realities.[41]

Not only does this situation make the operation of a green hydrogen plant uneconomic, but it also raises the question of whether end-use customers, which often require firm hydrogen supply, will be willing to contract for due to its low-capacity hydrogen supply from its "lumpy" hourly matched power. Downstream sectors needing a continuous source of hydrogen energy to run effectively (e.g., fuels and plastics) will likely not embrace green hydrogen.[42] Adding hydrogen storage or electricity storage to deliver a steadier flow will further increase costs. This makes it nearly impossible for green hydrogen projects to be competitive on a wide-scale basis under an hourly regime at the outset.

Researchers agree that hourly time-matching regimes increase green hydrogen production costs. The vast majority concur that if green hydrogen is to become cost-competitive under Section 45V, hourly requirements cannot be imposed while the green hydrogen industry is still in its infancy. These researchers also agree that once the green hydrogen industry reaches an economy of scale, an hourly time-matching system can be imposed.

For example, the ACP-commissioned WoodMac Report explains that the LCOH can be as high as 9.00/kgH2 (when qualifying and receiving the full value of the Section 45V tax credit) and that this cost must fall to $1.00-2.00/kgH2 before end-users in the power iron, steel, biofuels, and ammonia industries will adopt green hydrogen as a feedstock for their operations.[43] The LCOH is calculated by dividing the production volume costs by the amount of hydrogen produced. This means LCOH will be lower for electrolyzers operating at higher capacity factors

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[41] *Hydrogen Companies Urge Annual, Not Hourly, Matching for Credit,* Taxnotes (Apr. 12, 2023), available at: https://www.taxnotes.com/research/federal/other-documents/treasury-tax-correspondence/hydrogen-companies-urge-annual-not-hourly-matching-for-credit/7grp1.

[42] *Pathways to Commercial Liftoff: Clean Hydrogen* (hereinafter *Pathways*) at 12, U.S. Dept. of Energy (Mar. 2023), available at: https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-Clean-H2-vPUB.pdf; *See also Pathways* at 35, "When evaluating best-in-class projects, the PTC pulls forward breakeven for clean hydrogen versus traditional, fossil alternatives to within 3-5 years for many end uses (Figure 15). However, these breakeven points are sensitive to future fossil fuel prices and the levelized cost and *capacity factors of clean power sources* [emphasis added]."

[43] *See infra,* Ex. A.

(producing more hydrogen) and higher for those electrolyzers operating at lower capacity factors (producing less hydrogen). In other words, the study confirms that electrolyzers need to be operated at near full capacity to decrease production costs, make green hydrogen attractive to prospective buyers and competitive with alternative fuels, and to encourage widespread deployment and growth of the green hydrogen industry.[44]

Critically, the study concludes that capacity factors are higher under annual time-matching regimes than hourly regimes.[45] The data analyzed showed that under an hourly time-matching regime, electrolyzers can generally operate at less than 50% capacity factor, compared to 90%-100% under an annual time-matching regime.[46] Reducing the capacity factor has significant cost implications. The study finds that, under Treasury's hourly time-matching proposal, the 2032 LCOH is 20% and 27% higher in ERCOT and CAISO, respectively, than under ACP's annual time-matching proposal.[47] Specifically, in CAISO, a region with limited wind capacity, imposition of an annual-time matching system would result in a LCOH of \$5.37/kgH2, but under an hourly system the LCOH jumps to \$7.40/kgH2.[48] Given that green hydrogen production facilities can achieve lower production costs under an annual time-matching system, WoodMac found that extending the time frame for annual match eligibility to 2032 could drive a 44% increase in electrolytic hydrogen production over hourly time matching in 2028, and a 53% increase over hourly matching in 2032.[49] In sum, the study concludes that if green hydrogen producers are required to engage in hourly time matching, they will be less productive and cost competitive than they would be under an annual time-matching regime.[50]

Other studies support WoodMac's general conclusions as well. For example, in April 2023 and September 2023, MIT Energy Initiative Working Papers modeled case studies of the Texas (ERCOT) and Florida (FRCC) grids to assess the relative costs and emissions associated

[44] *Id.*
[45] *Id.*
[46] *Id.*
[47] *Id.*
[48] *Id.*
[49] *Id.*
[50] *Id.*

with annual and hourly time-matching regimes.[51] The modeling showed that "in nearly all cases" the LCOH is higher under hourly versus annual time-matching requirements because "[s]ignificantly higher capacities of renewables need to be installed under the hourly matching requirements and thus more capital and land is required."[52] The working group found that, based on May 2023 data, the LCOH is $0.25 to $2.49/kg higher under hourly than annual.[53]

Both studies explain that, under the hourly time-matching requirement and baseline electrolyzer operation mode, the LCOH, even *after* including the PTC, is still greater than $1/kg and thus not competitive with alternatives, such as grey hydrogen.[54] If policymakers want to scale up green hydrogen production and "support long-term economy-wide decarbonization goals by stimulating new demand for [hydrogen]" in sectors dominated by fossil fuels, green hydrogen must be given an opportunity to "achiev[e] electrolyzer [hydrogen] sales price that are lower than grey [hydrogen] prices (~$1/kg) and possibly even lower than natural gas reforming with CCS (including eligible [hydrogen] PTC for that process)."[55] The studies reiterate that this cannot be done if an hourly time-matching accounting system is imposed at the outset. Thus, the studies conclude "requiring hourly time matching in this decade may work against the policy objectives of the PTC to scale green [hydrogen] production" and cautions Treasury not to consider transitioning to hourly time matching until "2030 onwards."[56] The researchers subsequently reaffirmed the need for a phased approach in a January 2024 report.[57]

In March 2023, Wood Mackenzie analyzed electrolyzer capacity factors under an hourly versus an annual time-matching scenario using ERCOT South (Texas) and WECC (Arizona) as

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[51] Anna Cybulsky, et al., *Producing hydrogen from electricity: How modeling additionality drives the emissions impact of time-matching requirements* (Apr. 2023), available at: https://energy.mit.edu/wp-content/uploads/2023/04/MITEI-WP-2023-02.pdf.
[52] *Id.*
[53] Michael Giovanniello, et al., *Clean electricity procurement for procurement for electrolytic hydrogen: electrolytic hydrogen: An MIT Energy Initiative Working Paper* (Apr. 2023, Revised Sept. 2023), available at: https://energy.mit.edu/wp-content/uploads/2023/04/NE_Revised_Paper_September2023_124.pdf.
[54] *See supra* Cybulsky (MIT April 2023); Giovanniello (MIT Sept. 2023).
[55] *Id.*
[56] *Id.*
[57] Michael A. Giovanniello et al., *The influence of additionality and time-matching requirements on the emissions from grid-connected hydrogen production*, Nature Energy (2024), available at: https://www.nature.com/articles/s41560-023-01435-0.

case studies.[58] This study likewise concluded that hourly time matching "could result in unfavorable economics for green hydrogen adoption, by limiting operating hours to those when renewable resources are available, ultimately reducing the electrolyzer capacity factor."[59] The study explained that, in the WECC Arizona market, in the annual time-matching scenario, the LCOH was about $2/kg in 2025 and $1.50/kg in 2030, but in the hourly time-matching scenario, the LCOH was $4-5/kg. The study explained that "[t]his degree of cost increase could delay the ability to produce green hydrogen at cost parity to lower-cost, blue or grey hydrogen, ultimately hindering the economic competitiveness and adoption of both grid-connected and 100% renewable green hydrogen as a low-carbon fuel."[60]

Similarly, an April 2023 E3 study found that across all scenarios, the cost of producing hydrogen was significantly higher when an hourly time-matching requirement was used compared to an annual time-matching approach.[61] For instance, in the ERCOT market, the cost of hydrogen produced under an hourly time-matching requirement could be up to 102% higher than that produced under an annual time-matching requirement.[62] Likewise, in the Midcontinent Independent System Operator North, the production costs could increase by as much as 108% with an hourly- matching requirement and in the PJM market, the increase in production costs could be up to 61%, and in Southwest Power Pool (SPP), up to 66% higher with an hourly matching requirement.[63] A March 2023 Boston Consulting Group study likewise found that early hourly time-matching requirements more than double the cost of green hydrogen, making it uneconomical for most applications before 2030.[64] However, after 2030, hourly matching would

[58] Melany Vargas, et al, *Green hydrogen: what the Inflation Reduction Act means for production economics and carbon intensity*, Wood Mackenzie, (March 2023), available at: https://www.woodmac.com/news/opinion/green-hydrogen-IRA-production-economics/.
[59] *Id.*
[60] *Id.*
[61] Arne Olson, et al. *Analysis of Hourly & Annual GHG Emissions*, ACORE and E3 Study, (April 2023), available at: https://acore.org/wp-content/uploads/2023/04/ACORE-and-E3-Analysis-of-Hourly-and-Annual-GHG-Emissions-Accounting-for-Hydrogen-Production.pdf.
[62] *Id.*
[63] *Id.*
[64] Wilhelm Schmundt et al., *Building the Green Hydrogen Economy*, BCG (Mar. 2023), https://web-assets.bcg.com/bc/82/a99c71144a60aa435736f574cffe/bcg-infrastructure-strategy-2023-building-the-green-hydrogen-economy-mar-2023-r.pdf

result in a cost of green hydrogen that is competitive with other forms of hydrogen (grey and blue).[65]

As RMI noted in a 2023 analysis, “[t]o establish early offtake contracts, many industrial end users will require 24/7 hydrogen supply.”[66] Industrial processes like “[s]teel making, ammonia production, chemicals synthesis, or refining — are operated under high pressures at high temperatures” and “cannot be fully shut down without incurring a high cost.”[67] These “[o]ff-takers need assurance” that hydrogen will be reliably available before they will begin to consider hydrogen to be “a viable alternative to incumbent fossil fuels.” The analysis explains that achieving the requisite consistency under an hourly time-matching regime “will result in added system costs and complexity.”[68] Relying on a study produced by TU Berlin, found that “[i]f hydrogen needs to be supplied consistently” and low cost underground storage is not available . . . costs of hourly matched hydrogen can be 1.5 times that of annual matched systems if more expensive hydrogen storage is used, or over 2 times greater if no hydrogen storage is available.”[69] “They found that an hourly matched system could require up to twice the electrolyzer capacity than an annual matched system, and potentially 5 times the amount of hydrogen storage capacity, all to produce the same amount of hydrogen and deliver it with the same consistency as an annually matched system.”[70] Consequently, they conclude that “[m]andating hourly matched electrolysis immediately may delay project deployment” and preclude green hydrogen from “compet[ing] against natural gas-based hydrogen alternatives.”[71] These researchers advocate for a transition from monthly or annual time matching to hourly time matching in 2028 primarily because they contend “electrolysis technologies will become cheaper.” According to both the studies discussed above and a Wood Mackenzie study commissioned by ACP, this transition date is overly optimistic.

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[65] *Id.*
[66] Tessa Weiss, et al., *Calibrating US Tax Credits for Grid-Connected Hydrogen Production: A Recommendation, a Flexibility, and a Red Line*, RMI (2023), available at: https://rmi.org/insight/calibrating-us-tax-credits-for-grid-connected-hydrogen-production/.
[67] *Id.*
[68] *Id.*
[69] *Id.*
[70] *Id.*
[71] *Id.*

While the overwhelming evidence above indicates that the LCOH of green hydrogen under an hourly time-matching regime in the near-term is too high to be cost competitive, a study from Princeton University's ZERO Lab stands in stark contrast to these other studies. Though the researchers at Princeton University agree that the LCOH is higher under hourly versus annual time matching, they contend that, assuming the full 45V PTC subsidy is granted, by 2030 green hydrogen producers "would *likely* break even or make a profit on their investments as long as electrolyzer costs continue to decline," even under an hourly regime.[72] There are several flaws in the Princeton ZERO Lab analysis that give rise reason to question their results.

For one, the Princeton researchers cite the cost of electrolyzers to be between $300-$1200/kW.[73] As discussed above, electrolyzers that are compatible with high-temperature industrial processes presently cost from $1,410 to more than $5,600 per kW. This is nearly five times more than the range the Princeton researchers estimated. Proton exchange membrane electrolzyer costs are also higher than the Princeton cite, ranging between 1,200 per kW to $2,000 per kW.[74] Second, the Princeton researchers fail to recognize that flexible hydrogen production in response to fluctuating availability of renewables would still need to meet a consistent industrial demand profile.[75] Industrial users of green hydrogen require it constantly, not only during specific renewable generating windows. The only way to meet such a demand profile while renewable energy is not available is to store green hydrogen in large quantities. Procuring such storage facilities requires large capital expenditures. As such, the Princeton ZERO lab study grossly underestimates the costs of producing green hydrogen under an hourly accounting system.

In sum, the weight of evidence demonstrates that, if an hourly time-matching regime is imposed this decade, the associated costs will prevent the U.S. green hydrogen industry from

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[72] Wilson Ricks, et al., *Minimizing emissions from grid-based hydrogen production in the United States*, Environmental Research Letters, Princeton University's Zero Lab (Jan. 2023), https://iopscience.iop.org/article/10.1088/1748-9326/acacb5.
[73] *Id.*
[74] EY Parthenon, *Shortage of electrolyzers for green hydrogen* (February 2023), available at: https://assets.ey.com/content/dam/ey-sites/ey-com/en_in/topics/energy/2023/02/ey-shortage-of-electrolyzers-for-green-hydrogen-v2.pdf?download.
[75] *See supra* Princeton ZERO Lab Study (2023).

scaling up and establishing itself as a contender in the global hydrogen market. As such, Treasury should allow the industry to employ annual time-matching systems while it is in its infancy. We note however that, once the price of electrolyzers, renewable energy, and storage come down, an hourly time-matching regime can be imposed.

b. Studies have shown that annual time matching can meet the Section 45V well-to-gate emissions thresholds and enable commercial deployment of green hydrogen leading to long-term emissions reductions.

Because of the above-described cost increases associated with hourly time matching, studies have found that if a restrictive hourly time-matching system is imposed too early, the green hydrogen industry will never reach cost-competitiveness and, in turn, achieve scale. If green hydrogen facilities do not achieve scale in the near-term, industries that could have relied on green hydrogen to decarbonize (such as steel, concrete, chemical, and long-distance transportation industries) will likely turn to more carbon-intensive options.[76] Once these industries look to these other options to meet their needs, they will be unlikely to turn back to green hydrogen as they will have locked in long-term contracts with these other forms of hydrogen.[77] Consequently, the data shows that if Treasury requires hourly time matching without first giving the green hydrogen industry an opportunity to become cost-competitive, it will result in a loss of long-term emission reduction potential and aggregate emissions increases over time. The studies that call for a shorter glide path from annual to hourly time matching are based on both overly optimistic scenarios for near-term commercial deployment of green hydrogen, under any time-matching regime, and on the cherry-picking of one or two regions that result in overly inflated emission impacts.

For example, researchers at MIT considered the relative emissions benefits of annual and hourly time matching in ERCOT and FRCC, which represent the high and low end of renewables

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[76] *See* Giovanniellio (MIT 2023) ("Realizing low prices for green H2 would support long-term economy-wide decarbonization goals by potentially displacing fossil-fuel-based H2 in industrial applications and stimulating new demand for H2 in end uses that are currently dominated by fossil fuels (for example, heavy-duty transport").

[77] *See, e.g.*, Ben King, *Hydrogen in a post-IRA World,* Rhodium Group, (March 2023), available at: https://rhg.com/research/scaling-clean-hydrogen-ira/; Giovanniellio (MIT 2023) ("In addition, under hourly matching, the likelihood of substitution of green H2 with blue H2 is higher than under annual matching, again leading to potentially increased overall system wide.").

deployment, in three separate publications.[78] They determined that the emissions benefits associated with hourly time matching are far more pronounced when green hydrogen and non-hydrogen related electricity demand "compete" for "new renewable entering the power grid."[79] These researchers argue that because the demand for green hydrogen is still relatively small compared to the total additions of renewable energy, today's context more closely resembles a "non-compete" framework and, thus, "a low consequential emissions impact with annual time-matching is likely" in most regions.[80]

As the researchers explain, "in the near-term, demand for green [hydrogen] is likely to originate from sectors where [hydrogen] is already used today (e.g., ammonia production) and thus, be relatively small compared to the scale of electricity demand. . . . For example, if 10% of U.S. [hydrogen] consumption in 2021 (around 1 MT/year) were to immediately shift to consume electrolytic [hydrogen], it would amount to around 54 TWh electricity consumption or ~1% of US electricity consumption as of 2021."[81] The researchers note that, at the same time, given that the IRA incentivizes clean energy deployment, there will be additional available renewable power on the grid in the near future. Thus, "researchers expect significant non-[hydrogen] production related renewables to enter before seeing significantly large volumes of electrolytic [hydrogen] to be produced."[82] However, as demand for green hydrogen grows, the researchers believe that green hydrogen will begin to compete with power sector resources that would be deployed for non-hydrogen related projects.

Once the transition to a "compete" world begins (i.e., the industry is at scale), the researchers find that shifting to hourly time-matching requirements as green hydrogen demand grows may be necessary "to avoid the risk of high consequential emissions impacts from annual time-matching."[83] Consequently, the researchers advise Treasury to adopt annual time-matching

[78] *See supra* Cybulsky (MIT April 2023 Study); Giovanniello (MIT Sept. 2023 Study); Giovanniello (MIT Jan. 2024 Study).
[79] *Id.*
[80] *Id.*
[81] *Id.*
[82] *Id.*
[83] *Id.*

in the near term, and then transition to an hourly time-matching system once green hydrogen truly begins to "compete" with other renewable energy consumers. They explain that:

> [I]n the near-term, achieving low electrolyzer [hydrogen] sales prices under annual matching would encourage the deployment of electrolyzers, allowing for technology scale up and associated reductions in capital costs. Realizing such low prices for green [hydrogen] would support long-term economy-wide decarbonization goals by stimulating new demand for [hydrogen] in end uses that are currently dominated by fossil fuels (e.g., heavy-duty transport), as well as potentially displacing fossil fuel based [hydrogen] in existing industrial applications."[84]

Finally, the researchers note that "under hourly matching, the likelihood of substitution of green [hydrogen] with blue [hydrogen] is higher than under annual matching, again leading to potentially increased overall system-wide emissions" and as such, conclude that "[r]equiring hourly time matching in this decade may work against the policy objectives of the [Section 45V tax credit] to scale green [hydrogen] production."[85]

Similarly, the April 2023 Boston Consulting Group study evaluates annual as compared hourly matching requirements.[86] The study assesses hourly and annual time-matching approaches in the context of carbon emission limits, industry growth, cost implications, and the simplicity of qualifying for the PTC.[87] The research explains that "achieving long-term decarbonization will ultimately require hourly matching," but also found that, in the near term, "[o]n an aggregate annual basis, decarbonization potential under annual matching with and without conditions is likely larger than hourly given the lower cost and thus creates more economically viable demand to generate realized downstream decarbonization."[88] Similarly, a Rhodium Group study explains that "[d]elays in installing electrolyzers in the near term will result in a slower overall scale-up of electrolyzer capacity and, therefore, fewer emissions

[84] *Id.*
[85] *Id.*
[86] *See supra* BCG Study (March 2023).
[87] *Id.* The analysis assumed that under an annual matching approach, there would be a 10-year project lifespan consistent with the duration of the PTC. It also assumed a 2030 commercial operation date, the addition of a 500 MW electrolyzer capacity per region, and the support of this electrolyzer load with 100% solar capacity.
[88] *Id.*

benefits in the long run."[89] In other words, the study concludes that "[a]dhering to restrictive rules to claim the credit in the near term may hamper the ability of this industry to grow, reducing the range of clean hydrogen opportunities down the road."[90]

An April 2023 study by E3 examined simulated electricity market operations for four markets: ERCOT, MISO-North, the PJM, and SPP.[91] The researchers found that annual matching results in lower carbon emissions in 25 out of 40 scenarios between now and 2030, and that hourly time matching results in lower carbon emissions in 15 out of 40 scenarios between now and 2030.[92] The study provides that, most of the year, emissions rates are stable, and both matching methods yield similar carbon reductions; however, during hours with zero emissions, annual time matching proves more effective, allowing hydrogen production without increasing emissions, while hourly time-matching increases costs without significant emissions benefits.[93] The study explains that "modest changes in the renewable generation portfolio . . . can entirely eliminate incremental emissions observed under annual matching for those few scenarios where emissions are higher."[94] The study only focuses on the near- to medium-term and does not assess long-term emissions implications associated with increasing the costs of hydrogen production now.

In June of 2023, Resources for the Future conducted a comparison of the net emissions effects of hourly and annual crediting approaches in relation to electrolyzer load and renewable generation, focusing on the PJM region.[95] The study notes that, under the hourly approach, the electrolyzer load matches renewable generation on an hourly basis throughout the year, whereas under the annual approach, the electrolyzer load remains constant annually, equating to the total renewable generation.[96] The results reveal that an hourly time-matching approach alone may not

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[89] *See, e.g.*, Rhodium Group Study (March 2023).
[90] *Id.*
[91] ACORE and E3 Study (April 2023).
[92] *Id.*
[93] *Id.*
[94] *Id.*
[95] Aaron Bergman, et al., *Emissions Effects of Differing 45V Crediting Approaches,* Resources for the Future (June 2023), available at https://www.rff.org/publications/reports/emissions-effects-of-differing-45V-crediting-approaches/.
[96] *Id.*

mitigate the dispatch effect (i.e., the impact on the grid and emissions due to additional load), as previously thought in certain regions.[97] This is due to significant variability in Local Marginal Emissions (LMEs) across various grid nodes at any given hour, indicating that the benefits of hourly time matching in reducing emissions are not guaranteed unless the consumption and generation of energy are collocated at the same physical location.[98] More strikingly, the study found that in certain scenarios, particularly those involving PV generation, the annual time-matching approach had a lower dispatch effect than the hourly time-matching approach.[99] In these cases, the reduction in emissions due to PV generation outweighed any increases caused by the electrolyzer, leading to a net decrease in emissions.[100] The paper does not take a position on which proposed time-matching approach should be adopted, but does note that "Treasury will have to determine the appropriate balance, within the law, between the goals of driving electrolytic hydrogen deployment and not increasing emissions as that hydrogen capacity is deployed."[101]

The ACP-commissioned WoodMac report confirms that requiring adherence to an hourly matching requirement in the near term will prove cost-prohibitive for the green hydrogen industry and prevent it from achieving economies of scale and parity with alternative fuels in the next decade.[102] Though there may be marginal near-term emissions associated with allowing a limited number of early entrants to the green hydrogen market to engage in annual time matching, the study demonstrates that these emissions are offset by ensuring the deployment of green hydrogen in the long term.[103] If time-matching requirements are not sufficiently flexible to support rapid green hydrogen deployment, then other more carbon intensive options that currently have had more time to reach greater scale and maturity and, in turn, lower costs, will step in to fill the market share that green hydrogen could have otherwise occupied.[104] If first-wave projects in the green hydrogen industry are never given an opportunity to scale up

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[97] *Id.*
[98] *Id.*
[99] *Id.*
[100] *Id.*
[101] *Id.*
[102] *See infra* Ex. A.
[103] *Id.*
[104] *Id.*

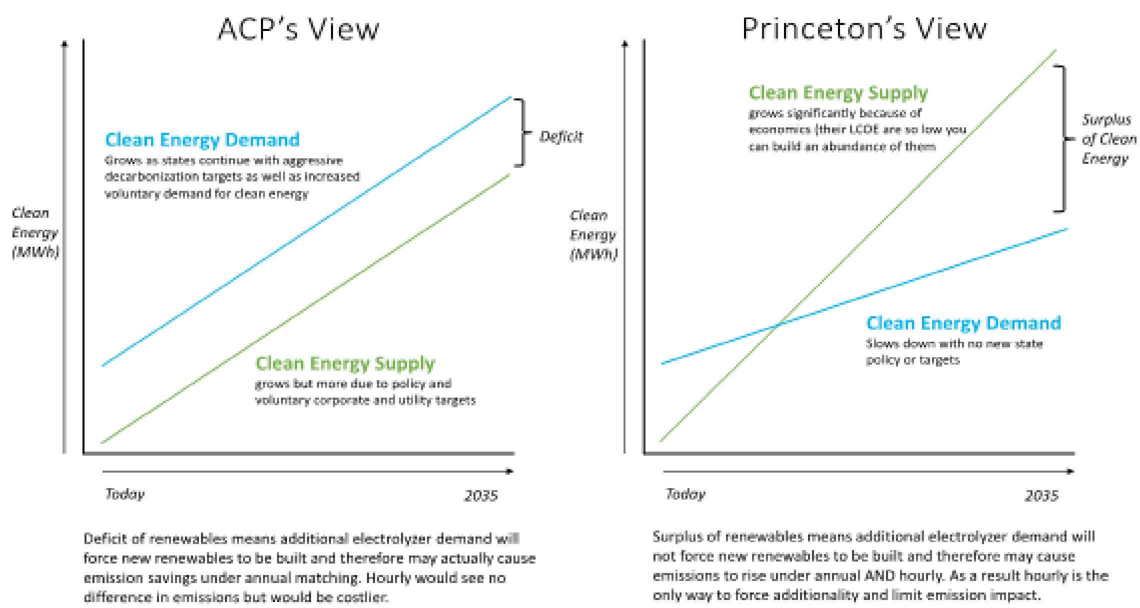
production and reach cost parities with alternatives, second and third wave green hydrogen producers will never be able to help the U.S. economy achieve deep decarbonization, especially since the Section 45V credit has a limited shelf life.

Finally, ACP's analytics team modeled ERCOT's electricity generation for 2023 to assess the impact of adding additional electrolyzer load on emissions.[105] The research explains that any new load will increase emissions while any new clean energy delivered to the grid will reduce emissions during hours in which clean energy is not already on the margin. For example, assuming a 500 MW electrolyzer is operating every hour in 2023 with a 70% efficiency (i.e., the amount of hydrogen produced is 70% of the energy required), the research finds that the electrolyzer would add 4,380 MW of annual load to ERCOT's system and produce 91.25 M kg of hydrogen. Meeting this load at 4% overbuild at most would require the build out of 1,589 MW to 2,290 MW of additional renewable capacity (depending on whether wind, solar, or a combination of both is dispatched to meet additional demand). Because ERCOT is still a fossil-heavy system, the additional wind and solar used to meet that new load would displace demand that would have otherwise been met by coal and natural gas. As a result, the emissions rate of the hydrogen production is below the 0.45 kg CO_2/kg H_2 required to meet Section 45V credit. That results in an electricity sector emissions decrease relative to the baseline scenario with the new wind and solar. In sum, the ACP research concludes that of the new electrolyzer load added in

[105] ACP's model assumes that additional wind and solar is built to meet the electrolyzer demand. The model determines the net demand (total electricity demand minus utility-scale solar and wind generation) every hour. The model then dispatches coal and gas resources (tranched by heat rate) to meet the remaining load. The model assumes that dispatch occurs by short-run marginal cost (SRMC), which is inclusive of fuel price, meaning that the model calculates the new system demand net of electrolyzer load and additional wind and solar generation at lowest cost and assumes that coal and natural gas is dispatched at lowest cost. Because the model assumes that coal and gas is dispatched at the lowest cost and does not account for operational constraints, such as min up/down time, ramping, and minimum capacity, less coal is dispatched in this model than was actually dispatched in 2023, while more natural gas is dispatched in this model than was dispatched in 2023. This means that the model takes a conservative approach to emissions savings associated with green hydrogen-related additional renewables generation. The model calculates the emissions associated with use of any one generator in any given hour by multiplying the amount of energy produced by the generator by the emissions rate of its fuel. Total emissions from hydrogen production is then calculated as a change in total emissions with and without the electrolyzer load, divided by the amount of hydrogen produced.

Texas, total annual emissions remain below the 0.45 kfCO2/kg H2—as long incremental renewables are built to meet that load.

In contrast, the Princeton Zero Lab study assessed the impact of grid-connected electrolysis on the evolution of the power sector in the western U.S. through 2030 and recommended the immediate adoption of an hourly time-matching system.[106] This study assumes that "the market for state-level policy compliance EACs is fully saturated, so simply adding demand for clean electricity attributes does not provide any economic incentive to increase supply."[107] In other words, the Princeton Zero Lab model assumes that, at some point in the near future, renewable energy production will become so inexpensive that renewable energy supply will outpace policy-driven demand for renewable electricity. In this context, green hydrogen facilities will add to the overall grid's load and "compete" with all other consumers on the grid for a limited supply of renewable energy that will not continue to grow absent additional policy incentives.



[106] *See supra* Princeton ZERO Lab Study (2023).
[107] *Id.*

Thus, the study finds that annual time matching is less effective at bringing about emissions reductions.[108]

As is noted above, other studies have concluded that the study's underlying assumptions regarding competition are not based on market dynamics we see today, nor on ones expected in the near-term (5-10 years).[109] Non-hydrogen related state and local decarbonization policies, as well as corporate commitments to decarbonize, are expected to cause demand for renewable energy to outpace renewable energy supply over the course of the next decade. Thus, stringent hourly time-matching polices that help to artificially generate renewable energy demand are not needed from an emissions reduction standpoint at this juncture. Additionally, the Princeton ZERO Lab researchers chose a region with some of the lowest electric grid emissions and highest renewable penetration within the country, which caused them to underestimate the emissions reduction potential of annual matching on a nationwide scale. They also caution that real world conditions like grid congestions would result in different outcomes.[110] Thus, the Princeton ZERO Lab study's conclusions regarding the relative carbon emissions difference between an annual and hourly system in the near term (i.e., between now and 2030) are inherently insufficient.

Additionally, the study by Princeton Net Zero Lab researchers concludes, based on faulty assumptions relating to costs, discussed above, that the green hydrogen industry will "likely" be able to reach cost competitiveness and scale up under an hourly time-matching system.[111] Therefore, these researchers did not account for the long-term loss of emissions reduction potential that will occur if the premature imposition of an hourly time-matching regime inhibits the green hydrogen industry from scaling up in the near-term. But even these researchers acknowledge that "[a]dditional near-term emissions may be considered a necessary cost of encouraging early electrolyzer deployment in order to address concerns regarding the feasibility of scaling up clean hydrogen supply to meet future goals. By ensuring that clean hydrogen is cost-effective and available at scale for various decarbonizing applications in the 2030s and

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[108] *Id.*
[109] *See supra* pp. 26-28.
[110] *Id.*, pg.10.
[111] *See supra* pp. 25.

beyond, early electrolysis deployments could potentially improve long-run climate outcomes even if they increase emissions in the near term."[112]

c. The hydrogen hubs have signaled the need for a longer glide path for annual to support green hydrogen.

The Proposed Rule could hinder the success of DOE's Hydrogen Hubs. In October of 2023, the agency announced a $7 billion investment to launch seven Regional Clean Hydrogen Hubs across the nation and to "accelerate the commercial-scale deployment of low-cost, clean hydrogen."[113] According to DOE, the seven hubs will "kickstart a national network of clean hydrogen producers, consumers, and connective infrastructure while supporting the production, storage, delivery, and end-use of clean hydrogen" with the ultimate goal of reducing 25 million metric tons of carbon emissions from end-uses each year.[114] However, according to DOE's proposed hub phased timeline, the earliest date a hub would begin project operations is 2031. This date is not in alignment with the January 1, 2028, date upon which Treasury would require hourly matching.

Success of the hub program relies on a dramatic reduction in the cost of producing clean hydrogen,[115] alongside sufficient long-term demand resulting in steady offtake and corresponding hydrogen price reductions.[116] Therefore, stringent hourly requirements for the 45V tax credit that increase green hydrogen costs, and prevent the scaling of the industry, will thwart the program's success and its goal to accelerate the deployment of low-carbon hydrogen. Instead, an annual time-matching regime that transitions to hourly when green hydrogen costs are more cost competitive, combined with an exemption for first movers, is necessary for the success of the hydrogen hubs that incorporate that technology.

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112 Princeton ZERO Lab Study (2023).
113 *See Biden-Harris Administration Announces $7 Billion For America's First Clean Hydrogen Hubs, Driving Clean Manufacturing and Delivering New Economic Opportunities Nationwide*, U.S. Department of Energy (October 13, 2023), available at: https://www.energy.gov/articles/biden-harris-administration-announces-7-billion-americas-first-clean-hydrogen-hubs-driving.
114 *Id.*
115 Resources for the Future, *Hydrogen Hubs: Helping Ensure Their Success* (2022), https://www.resources.org/common-resources/hydrogen-hubs-helping-ensure-their-success/
116 *See,* ARCHES, Re: Notice 2022-58-- Response to Request for Comments on Credits for Clean Hydrogen (H2) and Clean Fuel Production (2023), politico.com/f/?id=0000018a-6cd6-dd5e-abfe-efd6906c0000.

The Alliance for Renewable Clean Hydrogen Energy Systems (ARCHES) Hub in California and the Pacific Northwest Hydrogen Hub (PNWH2) in Washington provide clear examples of the need for flexibility on time matching. ARCHES was launched in California to accelerate the hydrogen market and is tasked with establishing a hydrogen ecosystem that drives down the cost of renewable hydrogen, while increasing renewable energy penetration and achieving California's net zero and carbon goals on an accelerated schedule.[117] To achieve these goals, ARCHES will utilize local renewable resources to produce hydrogen. The PNWH2 aims to integrate hydrogen into the clean energy portfolios of Washington, Oregon, and Montana with the goal of helping to eliminate fossil fuels from the region's transportation and electricity generation portfolio by 2045 and help achieve net-zero GHG emissions by 2050.[118] The hub will rely exclusively on renewable electricity and non-stressed water sources to produce electrolyctic hydrogen. Success of the hub will result in approximately 1.5 million metric tons per year of carbon emissions through a transition to clean hydrogen across hard to decarbonize areas.[119]

As ARCHES noted in comments to DOE, success of thee hubs "hinges on getting market signals right, enabling a level playing field among low-and zero carbon technologies and working from the perspective of operating a multi-level multi sectoral energy system."[120] As they further state, a regional and national network of hubs with sufficient demand to establish a hydrogen requires, among other things, "timely and consistent clean hydrogen production. . . [and]. . .competitive pricing."[121] Specifically, the comments note: "Time Matching needs to align with similarly situated technologies. Like other renewable portfolio standards, hydrogen should be allowed to use annual matching—the industry standard—vs. hourly tracking."[122] Furthermore, such standards should be designed in such a way as to apply consistently across other, similar technologies (e.g., batteries, pumped hydro, etc.). As ACP has fully detailed in the

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[117] Arches H2 – Alliance for Renewable Clean Hydrogen Energy Systems (ARCHES)
[118] Pacific Northwest Hydrogen Association, *Our work,* available at: https://pnwh2.com/pnwh2-hub#:~:text=The%20hub's%20efforts%20would%20help,greenhouse%20gas%20emissions%20by%202050.
[119] Department of Energy, *Regional Clean Hydrogen Hubs Selection for Awar Negotiations*, https://www.energy.gov/oced/regional-clean-hydrogen-hubs-selections-award-negotiations.
[120] Available at https://www.politico.com/f/?id=0000018a-6cd6-dd5e-abfe-efd6906c0000 .
[121] *Id.*
[122] *Id.*

comments above, timely and consistent production and competitive pricing will require an initial annual time-matching regime and will require an exemption for first mover projects. Absent these provisions, clean hydrogen hubs will be unlikely to successfully scale to create a marketable green hydrogen network.

d. The 2028 transition date will not provide sufficient time for the development of hourly EAC structures in certain regions of the country.

The 2028 transition date does not provide sufficient time for the national development of EAC systems tracked under an hourly regime. Citing a recent DOE report, the Proposed Rule explains that EACs are an "established means of verifying and documenting the generation and purchase of electricity" and are therefore a reasonable and appropriate method for determining eligibility for the 45V production tax credit.[123] However, the vast majority of EAC systems are not tracked hourly; rather, these systems use either annual or monthly tracking. Changing the granularity of these EAC systems therefore represents a major shift in the application and implementation of this credit system, as the former requires exponentially more granular data.

As the Proposed Rule itself acknowledges "hourly tracking systems for EACs are not yet broadly available across the county. . . . [T]he tracking systems and related contractual structures for hourly matching will take some time to develop to an appropriate level of maturity."[124] In fact, a 2023 Center for Resource Solutions (CRS) report found that of nine existing tracking services, only *two* were already tracking on an hourly basis, and details issues with respect to their implementation.[125] Notably, the Proposed Rule also explains that "software functionality in these two systems remains limited."[126] Furthermore, as of 2023, twelve states lack any tracking system, hourly or otherwise.[127]

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[123] DOE, *Assessing Lifecycle Greenhouse Gas Emissions Associated with Electricity Use for the Section 45V Clean Hydrogen Production Tax Credit* (2023), available at www.energy.gov/45Vresources.
[124] Proposed Rule at 89233.
[125] Center for Resource Solutions, *Readiness for Hourly: U.S. Renewable Energy Tracking Systems* (June 15, 2023), available at: https://resource-solutions.org/wp-content/uploads/2023/06/Readiness-for-Hourly-U.S.-Renewable-Energy-Tracking-Systems.pdf (hereinafter "CRS Report").
[126] Proposed Rule at 89233.
[127] CRS Report at 12.

As the CRS Report explains, future implementation of an hourly tracking system poses additional challenges for system administrators, including cost and data availability (identified as issues in all single state systems), particularly in WREGIS.[128] Regulatory oversight may pose additional challenges. In particular, since the primary purpose of single state tracking systems is state renewable portfolio system (RPS) compliance, the report cites concerns regarding how to move forward should a state not accept an hourly tracking system for compliance if accepted in a multi-state system.[129] Another notable implementation issue is the significant shift in data collection that must occur to account for hourly, rather than monthly, tracking—data points will increase from 12 to 8,760 per year.[130] In addition, moving from monthly to hourly systems, for example, will require the design and implementation of fractional units of less than 1 Mw/h (the current smallest unit of measurement under existing monthly systems).[131] The Environmental Management Account (EMA) would need to be updated for hourly tracking to accommodate those systems currently using the EMA to manage their portfolios.[132] Finally, while the regions cited in the CRS Report noted that the technological upgrades required to transition from monthly to hourly could take less than a year, stakeholder engagement and outreach is expected to take significantly longer (9 – 21 months).[133] In addition, WREGIS (the California region, discussed in more detail below), has indicated that full, functioning implementation of an hourly tracking system could take up to five years.[134]

The implementation history of the ten tracking systems currently in place throughout the country further supports the need for a more flexible transition timeline.[135] Many of these systems were created in the early 2000s and there was noticeable variation regarding their implementation timelines. For instance, PJM (the Mid-Atlantic) began discussion with stakeholders regarding a tracking system in early 2002 and the system was not finalized until

[128] *Id.* at 33 – 34.
[129] *Id.*at 34.
[130] *Id.* at 37.
[131] *Id.*
[132] *Id.* at 39.
[133] *Id.* at 41.
[134] *Id.* at 44.
[135] *Id.* at 12.

2005.[136] WREGIS began discussion of a tracking system in fall 2003,[137] while the system was projected to be finalized in 2005, it was not fully functional until 2007.

Additionally, the increased granularity increases the technological requirements and potential complications. For example, WREGIS, which had been successfully operating under a monthly tracking system, switched tracking platforms in late 2022. This switch created additional, unforeseen technological difficulties, which the region is still working to fully resolve. Much of the functionality in the old system was not immediately transferable to the new system; in addition, technological errors (or bugs) developed that resulted in significant problems with creating and issuing RECs in the new system. As a result, while the new system was anticipated to be released in the third quarter of 2022 (i.e., by the end of September), implementation was delayed until November 3 of that year due to system problems.[138] Furthermore, in preparation for the transition, all user accounts were frozen from October 19 to the launch deadline.[139] Even after the launch date, problems continued. In September 2023, the CEC Executive Director found good cause to extend the 2022 annual reporting requirements from July 30 to September 30.[140] Once it became clear that the system issues would still not be resolved by then, the deadline was again extended to "30 calendar days after WREGIS ha[d] fully resolved the system issue."[141]

In an updated email sent to system users on October 25, 2023, the WREGIS Administration outlined the continuing system issues, including: certain generators issuing too many or no certificates due to calculation errors, resulting in the inability to complete fuel and meter reallocations; user inability to transferring certain credits; and failure of the new system to account for pending generation data while processing previous data (e.g., fuel splits, renewable energy credit creation).[142] Due to these and other errors, a complete system freeze was

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[136] *Id.* at 11.
[137] *Id.* at 12.
[138] Coon, Andrea. "Software Release Delay." Received by Hope Fasching, Nov. 2, 2023.
[139] Coon, Andrea. "WREGIS Software Launch and Blackout Schedule Announcement." Received by Hope Fasching, Oct. 7, 2023.
[140] RPS Staff. "2022 Renewables Portfolio Standard Annual Reporting Deadline Extended for all Load-Serving Entities." Received by Hope Fasching, Sept. 29, 2023.
[141] *Id.*
[142] WREGIS Administration. "WREGIS—Update." Received by Hope Fasching, Oct. 25, 2023.

implemented on December 1, 2023, to give WREGIS time to fully address the problems.[143] Notably, as of January 26 of this year, this problem is still affecting the system's issuance capabilities – users and other affected stakeholders have urged the WREGIS Administration to resolve the issues as soon as possible.[144] Thus, while strictly speaking, WREGIS has implemented a more granular (monthly) tracking system, technological problems and resulting delays have caused major issues, many of which continue more than a year after the software transition. Without standardized and reliable hourly EAC systems in place, green hydrogen producers and customers may face outright failure for a factor wholly out of their control even if they take the necessary steps to sign hourly matching optimized VPPA portfolios, meet hydrogen facility start of construction and COD criteria, and check the boxes on incrementality and regionality.

Despite the above realities of transitioning to a more granular tracking system (notably, one that is still *less* granular than hourly), which will be especially true for regions that don't currently have a tracking system at all, the Proposed Rule opines that the 2028 transition date—a short four years from now—will "provide sufficient time for the implementation of the hourly EAC system."[145] Given the absence of hourly tracking systems across much of the country, and the lack of any form of tracking system in certain regions, the four-year timeline leaves little to no flexibility should implementation issues (technological or otherwise) or delays arise and renders the chosen date unworkable from a technological standpoint. Indeed, the Proposed Rule itself states: "The Treasury Department and the IRS acknowledge uncertainty in the timing of implementing an hourly matching requirement. . . ."[146] Furthermore, as discussed above, implementation challenges have, and continue to, affect the regions that have already transitioned to a more granular tracking. As the CRS Report notes, the existing tracking systems have similar functionality and operate under a common framework;[147] consequently, it is quite possible that other regions will face similar issues to those suffered by WREGIS during their transition.

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[143] WREGIS Administration. "WREGIS—Update." Received by Hope Fasching, Dec. 1, 2023.
[144] WREGIS Administration. "WREGIS—Update." Received by Hope Fasching, Jan. 26, 2024.
[145] *Id.*
[146] Proposed Rule at 89233.
[147] CRS Report at 13.

Finally, we emphasize that the 45V credit is a federal tax incentive and is therefore intended to be implemented nationally. This means that all regions in the country must have hourly tracking capabilities for the credit to be successfully and consistently implemented. Specifically, if a region is unable to implement hourly tracking, the development of hourly EAC markets will be delayed as well. Absent such markets and for the foreseeable future clean hydrogen producers will be forced instead to directly purchase RECs through a virtual power purchase agreement (vPPA) with wind and solar energy producers until the tracking systems create a platform for such purchases. It is unlikely that a producer would be able to purchase enough RECs to meet the hourly requirement to achieve high enough capacity factors. This creates both a financing and operational challenge, as it would require hydrogen producers to enter into vPPAs with the uncertainty that RECs would be produced during all required hours - which would simply not be the case. To combat this risk, clean hydrogen producers would be forced to over procure wind and solar to ensure a higher capacity factor for their electrolyzers. While this could increase certainty for project financiers, it would also significantly increase the cost and risk to the clean hydrogen producers. Finally, these producers would likely be required to use some form of storage (i.e., hydrogen or BESS) in addition to RECs to compensate for the remaining gaps in renewable energy production - especially to supply sufficient energy to customers in energy intensive industries such as ammonia and steel.

To combat the aforementioned challenges and to ensure that the 45V credit can be successfully implemented nationally, Treasury should issue a public report outlining the status of a nationwide EAC tracking system (including associated markets and structures) and its ability to successfully track at an hourly scale at least one year before any transition date. ACP emphasizes again that this transition date should be 2032 at the earliest to allow for sufficient time for these markets to develop. Should the report find that any region, structure, and/or market is not sufficiently developed to facilitate the required hourly tracking, implementation of the EAC hourly time-matching requirement should be delayed by at least one year to allow for the market or markets to come online. In this way, Treasury can be sure that the hourly time-matching requirement will be successfully and consistently implemented on a national basis. Finally, as outlined above, we stress that the current 2028 transition date does not comport with the operational dates of the clean hydrogen hubs.

e. The final rule should exempt first-mover projects from an hourly time-matching regime.

It is also crucial that the final rule exempt first-mover projects (i.e., those projects placed in service before 2032) from the transition requirement.[148] As outlined in more detail below, projects designed for hourly versus annual time-matching requirements will face drastically different economic and technological realities. An hourly time-matching requirement creates additional hurdles to project development (namely, electrolyzer and plant design) because projects must be designed to accommodate for the nuances associated with the increased graduality. These designs are essentially "set" at the onset of project construction and cannot be changed easily, if at all. In addition, EACs from incremental wind and solar projects will need to be sourced under contracts (VPPA/PPA) for the foreseeable future. Those VPPA/PPA contracts likely will have a longer tenor than the annual match transition period contemplated in the current guidance. The optimal EAC sourcing approach – EAC volume and mix of renewable sources – is different under annual match than hourly match. It will prove difficult if not impossible to structure the renewable supply contracts to change EAC volume and resource mix mid-stream, leading to the assumption of hourly EAC requirements from the onset. Without a provision excluding first-mover projects from the transition requirement, projects will need to be designed at the outset to serve the end hourly time-matching requirement, negating most of the benefit early-mover projects would receive from annual time-matching requirements - while still burdening these projects with the high cost of electrolyzers that have yet to realize manufacturing scale efficiencies.

Project financing can account for a modicum of change midstream in long-term agreements; however, this flexibility is not limitless and does not extend to significant and fundamental changes in the terms and conditions of such agreements. Given the ten-year life of the clean hydrogen tax credit, the absence of a legacy approach in the Proposed Rule will create

[148] Proposed Rule at 89232-33.

a significant and fundamental economic "cliff" for financing agreements that straddle the two accounting systems—significantly adding to the cost of the project.

As the following two subsections detail, this cliff is due to the vast disparities in two factors: (1) the price of green hydrogen under an annual versus an hourly accounting scheme; and (2) a similarly stark difference in the production capacity of green hydrogen facilities under the two factors. In other words, under an hourly accounting system as opposed to annual, the amount of green hydrogen produced will dramatically decrease while the cost to produce it will increase exponentially. Because of these realities, absent an exemption for first-mover projects, investors have indicated that they will just finance a green hydrogen production agreement subject to the cliff as if it were hourly the whole time, regardless of the initial framework.[149] By using the endpoint of hourly time matching for the life of these agreements, investors will give themselves certainty but, at the same time, will wipe out the purpose of starting with an annual time-matching approach at all—negating any potential benefit from allowing any period other than an hourly accounting system. This will make contracting for first-mover green hydrogen projects much more expensive at a critical juncture when they need to be cost-competitive for the industry to successfully mature.

Treasury should exempt first-mover projects from the transition requirement in the final rule. This will ensure that production costs for these initial projects is competitive enough to drive demand for green hydrogen, until the cost curve declines for green hydrogen with the maturity of the industry.[150]

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[149] Deloitte, *Green Hydrogen: Energizing the path to net zero*, (June 2023), available at: https://www2.deloitte.com/content/dam/Deloitte/at/Documents/presse/at-deloitte-wasserstoffstudie-2023.pdf.
[150] Rhodium Group Study (2023) ("To reap the potential benefits of green hydrogen, the US needs to develop an industry to build and install electrolyzers—something unlikely to happen if restrictive regulations constrain near-term electrolyzer deployment ... the US risks missing a key clean energy manufacturing opportunity absent supportive policies and robust domestic demand.").

1. ***Exempting first movers is necessary to economically price green hydrogen agreements in the near term.***

Exempting early green hydrogen producers from hourly time matching provides a critical economic incentive for project financiers by removing the aforementioned cliff that would be created by changing the time-matching requirements midstream and the significant increase in the price and the lower capacity factor that would result therefrom. As outlined in the sections above, green hydrogen is not yet economically competitive with other forms (two to six times more expensive)—thus, exempting these projects under an annual time-matching requirement is necessary to ensure that they will be able to compete with the other hydrogen forms on the market. Indeed, it is well understood that adopting an hourly time-matching requirement too early would exacerbate this price hurdle by resulting in uneconomic over procurement of renewable energy and storage and the underutilization of electrolyzers, ultimately raising prices and stifling adoption.

Without this exemption and the certainty it would provide, the simple reality is that green hydrogen producers will be required to build and finance projects on an hourly basis from day one, which is not economic in the near-term and, in turn, does not support the industry's ability to scale. This is because under an hourly accounting system as opposed to annual, the amount of green hydrogen produced will dramatically decrease while the cost to produce it will increase exponentially. Logically, such a drastic increase will, of course, also result in a significant reduction in customer interest in clean hydrogen and inhibit the adoption of this crucial industry.

In addition, green hydrogen producers may be required to sign long-term power purchase agreements with renewable energy generators to meet 45V requirements. A change from annual to hourly time matching without an early mover exemption (and the associated resulting cliff) will likely require assuming hourly matching from the onset in such power purchase agreements, leading to higher hydrogen costs from the onset. Most renewable generators will want a contract longer in tenor than the annual match period and most will be averse to contracts that change in volume and shape part way through the term at the hourly matching phase-in date. If they are even offered, shorter tenor contracts are likely to come at a significant price premium. Similarly, green hydrogen producers will be unable to finance projects that plan to rely on future procurement of supplemental renewables under new contracts to meet any forthcoming hourly requirements because of: (1) the uncertainty of future renewable supply cost and availability; (2) the need to develop and contract the hydrogen project based on a size, output, utilization, and power supply requirements that are consistent through the term of the contract; and (3) the potential to have excess renewable energy procured (i.e., commodity risk) at the onset of hourly time-matching when initial power purchase agreements are structured for annual time matching are still in place, but producing more than needed at certain times of day.

Having too short a period during which annual time matching applies risks incentivizing offtakers to only sign contracts for or after the switch to hourly occurs, to avoid the uncertainty created by the switch occurring in the middle of a contract. Should this happen, green hydrogen industry development will be delayed, and blue hydrogen will entrench itself with early adopters, potentially excluding green hydrogen out of the market. Therefore, aligning the timelines of green hydrogen project development, credit 45V applicability, and the transition from annual to hourly time-matching with the exemption early movers is vital for making green hydrogen a viable alternative to blue.

2. *Exempting first movers is necessary to ensure sufficient capacity factors are achieved in the near term.*

Hourly time matching will require procuring renewable electricity at all hours of operation or operating electrolyzers at lower capacity factors. As outlined in previous sections, due to the limited availability of renewable production at certain times, hourly time-matching would result in significantly lower capacity factors than under annual time-matching. If capacity factors cannot be met on a highly consistent and cost-effective basis, downstream sectors needing a continuous hydrogen stream to run effectively (e.g., fuels and plastics) will likely not embrace green hydrogen. Hourly matching will require enormous amounts of high-cost storage, for ratable delivery of hydrogen into downstream processes and will increase the price of green hydrogen. This is a disadvantage compared to fossil-based hydrogen production of hydrogen, which operates continuously and, in turn, does not require an extra expense for storage.

In contrast, the flexibility provided by initial annual time-matching, with a phased-in hourly accounting system as the cost curve declines for green hydrogen upon greater scale and maturity, will allow for higher, more economic capacity factors. Because annual time-matching would allow green hydrogen producers to reach greater capacity factors, downstream sectors will naturally be more willing to adopt it when it is closer in cost to fossil-based sources of hydrogen production. Thus, exempting first-mover green hydrogen projects from hourly time-matching will increase the capacity factor of such projects, ultimately reducing the price of green hydrogen and allowing it to become a viable option for users.

3. At a minimum, a percentage allowance of annual for the life of the tax credit should be allowed for first movers.

While ACP believes the best way to bring green hydrogen to scale, in the quickest time frame, is to provide a 100% annual matching for first-mover projects for the life of the tax credit, to the extent Treasury does not adopt this recommendation, we encourage it to consider, at a minimum, exempting a percentage of the capacity of the consumption of early mover hydrogen facilities from having to meet hourly requirements for the life of the tax credit. This pathway is consistent with the formulaic approach proposed for incrementality—creating a limited exception in light of compliance administrability issues.

For reasons discussed, it will be extremely difficult for first-mover green hydrogen projects to reliably meet hourly matching requirements in all hours of the day, resulting in capacity factors that will make these projects uneconomic. In addition, green hydrogen facilities run the risk of missing a few hourly matched hours making them ineligible for the highest tier of the tax credit. In order to incentivize early movers and ensure that they can effectively meet an hourly requirement (due to more limited availability of renewables, as well as higher costs for storage, until next decade), a certain percentage of annual matching should be permitted for the life of the tax credit for such projects.

Specifically, we recommend that Treasury consider at least 15% of the hourly generation from minimal-emitting electricity generators (for example, wind, solar, nuclear, and hydropower facilities) as satisfying the time-matching requirements for the life of the tax credit for hydrogen projects that start construction before January 1, 2028, and are placed in service before January 1, 2032, if they are annually matched after the transition to hourly. Under this approach, in assessing the emissions impacts of electricity used in the production of first-mover hydrogen producers for purposes of the Section 45V credit, at least 15%, as applied to the total amount of hydrogen consumed by a facility in a year, may be annually matched. In other words, a green hydrogen facility would be able to match 15% of its hydrogen consumption on an annual basis but would have to match 85% of its remaining capacity on an hourly basis. This would at least provide first movers the certainty of having a percentage of annual time matching for the life of the tax credit and would make it more cost-effective and administrable to meet an hourly requirement for these early movers.

While we appreciate that Treasury is mindful of the risk that such an allowance could result in hydrogen production facilities receiving credits for which they should not be eligible given their induced emissions rates, as demonstrated by the WoodMac Report and other studies, the level of commercial deployment in the near term will be minimal and, in turn, so will associated emissions. Moreover, to the extent there are nominal risks of any induced GHG emissions from such an approach, this nominal allowance would produce even lower emission levels than those associated with the proposed formulaic approach. Some degree of flexibility and certainty on time matching is crucial to bring the nascent clean hydrogen industry to scale, and we urge Treasury to spur this investment.

f. The final rule should adopt a start of construction date.

The Proposed Rule requires all projects to transition to hourly time-matching after January 1, 2028.[151] To exempt first movers and in recognition of permitting delays, Treasury should allow projects to start the development process under annual time-matching so long as such projects begin construction by January 1, 2028. On the other hand, projects that begin construction in 2029 and beyond should be subject to the hourly time-matching requirement from the onset.

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[151] Proposed Rule at 89232-33.

Treasury has applied the start of construction date when determining eligibility for other tax credits under the IRA.[152] The existing physical work test and safe harbor tests associated with a start of construction metric provide a clear framework for developers to work within and the flexibility to meet project permitting timelines.[153] Specifically, the continuous construction test under the safe harbor rules provides a holistic analysis of the facts and circumstances of a particular project, providing increased flexibility for projects in case of unforeseen delays, permitting or otherwise.[154] Furthermore, in addition to providing developers much needed certainty, using the start of construction date (as determined by the tests described above) could provide sufficient time for early-mover projects to secure funding under annual time-matching regime, thus helping to alleviate the financing cliff associated with the lack of a provision exempting first-mover projects from an hourly requirement.

g. The final rule should clarify impact of electricity storage on temporal matching.

ACP requests that a final rule clarify that stored electricity has a time stamp that correlates to the time such electricity is used in the production of clean hydrogen and not to the time the electricity was generated or stored. The Proposed Rule does not address the treatment of electricity storage for purposes of applying the temporal matching requirement. Furthermore, the preamble provides that "[a]mong the issues that require resolution as EAC tracking systems move to hourly resolution is the treatment of electricity storage."[155] ACP recommends that the Proposed Rule clarify that stored electricity has a time stamp that correlates to the time such electricity is used in the production of clean hydrogen and not to the time electricity was generated or stored. In an hourly time-matching regime, electricity storage will be critical to

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[152] IRS, Notice 2013-29, available at: https://www.irs.gov/pub/irs-drop/n-13-29.pdf.
[153] *Id.* at section 4.01, available at: https://www.irs.gov/pub/irs-drop/n-13-29.pdf ("Construction of a qualified facility begins when physical work of a significant nature begins. . . . Whether a taxpayer has begun construction of a facility before [the statutory deadline] will depend on the relevant facts and circumstances. The Internal Revenue Service will closely scrutinize a facility and may determine that construction has not begun on a facility before [the statutory deadline] if a taxpayer does not maintain a continuous program of construction as determined under section 4.06.").
[154] *Id.* at section 4.06(1) ("A continuous program of construction involves continuing physical work of a significant nature (as described in section 4.02). Whether a taxpayer maintains a continuous program of construction will be determined by the relevant facts and circumstances.").
[155] 88 Fed. Reg. at 89233.

ensure that zero-emissions renewable electricity can be used to power the electrolyzer in an efficient manner. Grid-tied electrolyzers are typically most economic when operating as close to 100 percent capacity as possible, which means that to meet a true green standard, they typically need to procure power as a block around the clock from wind, solar, and storage resources—allowing the electrolyzers to run at high-capacity factors. However, this only works if the electricity taken from a storage device is treated as produced in the same time period that such electricity is used by the hydrogen production facility. Otherwise, the storage device serves no benefit for the purpose of allowing the electrolzyer to run at full capacity.

h. 2032 represents a reasonable transition date.

The WoodMac study finds that, even under ACP's proposal, the 45V tax credits do not reduce the costs of green hydrogen enough to compete with blue hydrogen, grey hydrogen, diesel, or natural gas by 2032.[156] Thus, the study concludes that, because early imposition of hourly time matching pushes up the cost of green hydrogen beyond what most offtakers are willing to pay, the industry will not be ready for hourly matching by 2032, and indeed may not be ready until well into the 2030s.[157]

The WoodMac findings, along with those of the studies discussed above, highlight the critical need to both: (1) extend the hourly time-matching transition date until at least 2032; and (2) exempt first-mover projects that are placed in service before January 1, 2032, from any forthcoming hourly time matching for the duration of the life of the ten-year Section 45V tax credit. If early movants are allowed to employ an annual time-matching system through the 2030s, WooodMac's analysis confirms that they will have sufficient time to engage in cost learning and reach cost-competitiveness with alternative fuels, and, in turn, are more likely to entice offtakers to enter into long-term contracts with these facilities in the near term.[158] Locking in ten-year annual time-matching flexibility for those early movers who commence operations by the end of 2031 will ensure that their operations can achieve commercial viability over the

[156] *See infra* Ex. A (2024 WoodMac Analysis).
[157] *Id.*
[158] *Id.*

course of the life of their production contracts. Exempting first movers from this requirement is reasonable and will not give them an undue competitive advantage over their successors, because early movers are going to encounter higher upfront electrolyzer costs, lower capacity factors, and more expensive renewable energy prices than those that follow them into the green hydrogen market.

IV. Incrementality

Subject to the modifications discussed below, ACP is generally supportive of the Proposed Rule's concept of an incrementality (also known as "additionality") requirement in a final rule. As proposed, "an EAC meets the incrementality requirement if the electricity generating facility that produced the unit of electricity to which the EAC relates has a [commercial operations date (COD)] . . . that is no more than 36 months before the hydrogen production facility for which the EAC is retired was placed in service."[159] The COD is defined as the date on which a facility that generates electricity begins commercial operations.[160] An incrementality requirement is necessary to decarbonize the grid and to spur the new deployment of zero-emission resources. It is important to recognize that incrementality only is effective if there is adequate transmission.[161] The stricter the time requirement, the more likely the plant will be built in the easiest and quickest areas to build. Thus, ACP recommends several changes to the proposed structure for this requirement, as described further below.

If hydrogen facilities are allowed to draw from too many existing sources of existing zero-emission energy, the risk of an increase in overall GHG emissions is high. This is because purchasing non-incremental zero-emission energy does not always reduce or avoid emissions, as the energy would have been produced regardless. In other words, if electrolyzer loads are not paired with new zero-emission energy, the grid will often respond by ramping up fossil generators to serve the new load. The effective GHG impact of fossil generators would make the

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[159] Proposed Rule at 89229.
[160] Proposed Rule at §1.45V- 4(d)(2)(i).
[161] Building additional plants in areas of congestion will only increase the congestion resulting in a reduced value and emissions reductions from the existing plants.

facility in question ineligible for the Section 45V tax credit. Indeed, studies have shown that, absent a strict incrementality requirement, emissions increases may be in the tens to hundreds of millions of tonnes by the early 2030s.[162] Furthermore, a reasonably strict incrementality requirement will drive the production of new zero-emission energy. Absent such a requirement, hydrogen producers would be able—and arguably, incentivized—to draw from existing zero-emission energy sources, removing this energy from the grid without spurring additional clean energy sources to meet this new load.

While ACP supports strict incrementality requirements, the final rule should consider expanding the proposed three-year time incrementality window to *at least* one year after the hydrogen facility comes online to account for siting and permitting timelines. Site selection, permitting, interconnection, and construction timelines for renewable energy projects are typically longer than three years, as recognized by the Treasury's four-year window for the continuity requirements for most onshore renewables (and even longer for renewables on public lands and waters), from the beginning of the planning process to the commercial operations date (COD).

For example, a study by the Energy Transitions Commission found that site selection alone can span from four months to two years and that complying with the National Environmental Policy Act may require one to three years.[163] Effective stakeholder engagement typically demands a minimum of nine months, often requiring additional time beyond that due to multiple rounds of consultation. The acquisition of permits may extend for four years, as up to ten permits may be required for solar, and up to 20 for wind. Grid interconnection queues can range from one and half to four years, with potential further delays in cases involving significant grid constraints or queue backlogs. Construction timelines vary based on project type, with utility-scale solar projects typically completed in approximately six months, onshore wind farms taking up to two years, and offshore wind farms requiring three years.

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[162] *See, e.g.*, Rhodium Group Study (2023).
[163] Energy Transitions Commission, *Streamlining planning and permitting to accelerate wind and solar deployment* (Jan. 2023), available at: https://www.energy-transitions.org/publications/planning-and-permitting/.

The need to extend the deadline bears even greater significance in the context of green hydrogen facilities that are co-located with renewable energy installations. In such cases, it is likely that the green hydrogen facility will have a significantly earlier COD than its co-located renewable counterpart, due to the aforementioned delays in the renewable project development process. For instance, if a clean hydrogen facility becomes operational several years before the renewable energy component, the co-located component would not meet the Proposed Rule's criteria, ultimately disincentivizing such development. Thus, extending the development timeline becomes even more crucial in these cases, as it provides additional possibilities for synchronized renewable energy project deployment, optimizing resource utilization, and enhancing overall project efficiency. Accordingly, we recommend the extension of the project development timeline from three to at least four years before facility COD, recognizing the complexity inherent in the development of renewable energy projects.

a. The final rule should consider additional output from energy storage added to existing renewable facilities to be uprates.

The Proposed Rule provides an alternative test for establishing incrementality for electricity generating facilities that undergo an uprate.[164] Under the Proposed Rule, an EAC satisfies incrementality requirements "if the electricity represented by the EAC is produced by an electricity generating facility that had an uprate no more than 36 months before the hydrogen production facility with respect to which the EAC is retired was placed in service and such electricity is part of such electricity generating facility's uprated production."[165] This test could be helpful spur the addition of utility-scale battery energy storage capacity to existing renewable energy facilities. Under such circumstances, the additional output from the energy storage unit (which may provide clean energy at times when the original generation resource cannot, particularly if the storage resource is charged behind the meter) should be considered an uprate. The resulting amount of incremental capacity should be eligible for powering a green hydrogen facility provided that the 36-month rule (or 48-month, as suggested above) is satisfied.

[164] Proposed Rule at § 1.45V–4(d)(3)(i)(B)
[165] *Id.*

b. The final rule should clarify that energy generated from repowered renewable energy facilities meets the incrementality requirements.

The Proposed Rule does not address whether energy generated from repowered facilities meets the incrementality requirements. The final rule should include the clarification that it does. Treasury has long relied on the 80/20 Rule in recognition of the fact that repowered facilities should be treated as newly built because they have a similar useful life as compared to a newly built facility, and because they have a similar capacity and production profile to match the state of current technology.[166] Under the 80/20 Rule, a repowered facility may qualify as originally placed in service, even though it contains some used property, provided that the fair market value of the used property is not more than 20 percent of the facility's total value after repower. Treasury should apply this rule to the incrementality requirement.[167] To do so, and for consistency with prior Treasury guidance, the final rule should rely on a repowered facility's placed in service date, rather than its COD.[168] Additionally, the final rule should clarify that repowered facilities that have a new placed in service date under the 80/20 Rule will be considered to have satisfied the incrementality requirement.[169]

Furthermore, the final rule should clarify that the entire repowered facility is considered originally placed in service (and not just the portion of the facility that was repowered). This is consistent with long standing Treasury guidance that does not limit the amount of credit available to a repowered facility based on the percentage of new property as compared to used property. Rather, under the guidance, a repowered facility that meets the 80/20 Rule is eligible for the entirety of the available PTC.[170]

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166 *Id.*
167 Notice 2016–31, available at: https://www.irs.gov/pub/irs-drop/n-16-31.pdf.
168 *Id.*
169 *See* Revenue Ruling 94–31, Notice 2008–60, 2008–2 C.B. 178, (a qualified facility may qualify as originally placed in service even though it contains some used property, provided the fair market value of the used property is not more than 20 percent of the qualified facility's total value (that is, the cost of the new property plus the value of the used property)); Proposed 1.48-14(a).
170 *Id.*

c. Exceptions to the incrementality requirement

ACP appreciates the Proposed Rule's inclusion of certain situations in which it would be appropriate to apply an exception to the incrementality requirements:

> Such circumstances may include generation from minimal-emitting power plants (i) that would retire absent the ability to sell electricity for qualified clean hydrogen production, (ii) during periods in which minimal-emitting generation would have otherwise been curtailed, if marginal emissions rates are minimal, or (iii) in locations where grid-electricity is 100 percent generated by minimal-emitting generators or where increases in load do not increase grid emissions.[171]

The following section of the comments discusses each of the situations outlined above.

1. ACP supports the formulaic approach to curtailment

ACP supports the concept underlying the Proposed Rule's formulaic approach, which would deem "five percent of the hourly generation from minimal-emitting electricity generators (for example, wind, solar, nuclear, and hydropower facilities) placed in service before January 1, 2023, as satisfying the incrementality requirement."[172] ACP offers two improvements to this approach: first, Treasury should increase the default allowance to 10% or higher in areas experiencing high levels of congestion. Second, in the final rule, this default level should be an operating presumption, and Treasury should allow taxpayers to demonstrate, on a case-by-case basis, that a higher proportion of energy from existing clean resources would be subject to congestion.

The formulaic approach should apply to each generator or hydrogen facility and not be implemented on a facility-wide basis (i.e., each existing generator can use 10% of its hourly generation to produce hydrogen). Treasury should consider offering the option that the

[171] Proposed Rule at 89230.
[172] *Id.* at 89231.

percentage be applied to the production facility rather than the generator. However, the formulaic approach should apply to each generator or hydrogen facility and not be implemented on a fleetwide basis for each resource; such an approach would allow certain existing generators to essentially use their entire capacity to run hydrogen production, which could significantly reduce the demand for new clean energy sources and, in turn, could pose increased emission impact issues. Finally, should Treasury not adopt a default allowance, the taxpayer should still be able to demonstrate congestion and curtailment on a case-by-case basis to enable energy from existing resources to be deemed new, clean supply.

a) The final rule should increase the proposed allowance

ACP agrees with the Proposed Rule's rationale for adopting a default allowance—that in certain situations, calculating incremental generation may be unduly burdensome for minimally-emitting projects that would not materially contribute to overall grid emissions rates, particularly because estimating the impact of hydrogen production on curtailment requires inherently uncertain assumptions about a counterfactual scenario.[173] We appreciate the importance of creating an approach that sufficiently balances the need for administrative feasibility with the burden of accurately identifying circumstances that have a low risk of increased induced emissions. We also agree with the Proposed Rule that periods of low or negative wholesale electricity prices that reflect non-emitting resources operating "on the margin" in economic generation dispatch are the best indicator of when increased load is unlikely to significantly increase induced grid emissions.

For determining time periods when increased load is unlikely to significantly increase induced grid emissions, the percentage of hours with low or negative wholesale electricity prices

[173] *Id.* ("This pathway may be appropriate because some circumstances (including periods of curtailment or times when generation from minimal-emitting electricity generation is on the margin) may make the resulting incremental generation difficult to anticipate or identify, or because the process for identifying the circumstances (such as avoided retirement risk or modeling of minimal-emissions) may be overly burdensome to evaluate for specific electricity generators or require data that is not available.").

is a better metric than the percentage of renewable generation that is curtailed. The percentage of renewable energy that is curtailed is much smaller than the percentage of hours when renewables are on the margin. This is because typically only a small share of renewable output is actually curtailed when congestion is binding, but all of the renewable generation behind the point of congestion is on the margin and receives the same low or negative Locational Marginal Price (LMP). The percentage of hours when renewables are on the margin directly reflects how much of the time increased load (such as an electrolyzer) is unlikely to significantly increase induced grid emissions. By contrast, the percentage of curtailed renewable generation does not provide comparable data.

A close review of power system data supports increasing the default allowance from 5% to 10% of generation from existing non-emitting resources. First, we concur with the Proposed Rule that nationally, power prices were negative in "6.3 percent of hours in 2022, 5.8 percent in 2021, 4.8 percent in 2020, 3.3 percent in 2019, and 2.3% in 2018."[174] The 6.3% observed in 2022 is significantly greater than the Proposed Rule's default exception of 5%. Moreover, hours with negative prices consistently increased by one percentage point on average per year between 2018 and 2022, indicating that the growth of renewable energy is outpacing the expansion of transmission infrastructure needed to deliver that energy. This trend is expected to continue or accelerate for the foreseeable future, with growth in the need for transmission[175] significantly outpacing its recent construction,[176] and with nearly all regions continuing to lack effective policies to plan and pay for transmission.[177] As further indicators of this trend, transmission

[174] Proposed Rule at 89232 ("The DOE reports that wind curtailment in 2022 averaged 5.3 percent of total wind generation nationwide (data are only available for Independent System Operator (ISO) regions), and Lawrence Berkeley National Laboratory reports curtailment rates for solar photovoltaics at over 10 percent of solar generation in ERCOT and over 3 percent in California Independent System Operator (CAISO).").
[174] *Id.* at 89232.
[175] U.S. Department of Energy, *National Transmission Needs Study* (Oct. 2023), available at: https://www.energy.gov/sites/default/files/2023-12/National%20Transmission%20Needs%20Study%20-%20Final_2023.12.1.pdf, at viii
[176] *Id.*, at 24
[177] Americans for a Clean Energy Grid, *Transmission Planning and Development Regional Report Card* (June 2023), available at: https://www.cleanenergygrid.org/wp-content/uploads/2023/06/ACEG_Transmission_Planning_and_Development_Report_Card.pdf

congestion costs have more than tripled since 2016.[178] Curtailment of renewable energy has also increased,[179] and is expected to continue increasing in the near future.[180] In reviewing the Lawrence Berkeley National Laboratory (LBNL) study[181] used for the 5% estimate, the study warned that it was "backwards looking . . . and ignored the ability to access new, lower-cost generation resources." Further, the extension and expansion of federal renewable tax credits in the Inflation Reduction Act is further accelerating renewable deployment over the next decade.[182] Even if occurrences of negative prices continue their recent trend of increasing by one percentage point per year, they will exceed 10% by 2026.

Second, the 6.3% figure is a simple average across all hours and is not weighted by renewable generation in each hour. Given that the Proposed Rule proposes to multiply the default allowance percentage by the amount of renewable generation, the 6.3% figure needs to be significantly increased to account for the fact that renewable generation tends to be significantly above average during hours with low or negative prices because of the causal linkage between renewable generation and low power prices. This conclusion is supported by The LBNL Renewables and Wholesale Electricity Prices Tool data showing that wind's hourly profile and congestion reduce its market value by more than half.[183] More detailed analysis could calculate the share of renewable generation that occurred during periods with low or negative wholesale electricity prices.

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[178] Grid Strategies, *Transmission Congestion Costs Rise Again in U.S. RTOs,* (Jul. 2023), https://gridstrategiesllc.com/wp-content/uploads/2023/07/GS_Transmission-Congestion-Costs-in-the-U.S.-RTOs1.pdf

[179] Proposed Rule at 89232 ("The DOE reports that wind curtailment in 2022 averaged 5.3 percent of total wind generation nationwide (data are only available for Independent System Operator (ISO) regions), and Lawrence Berkeley National Laboratory reports curtailment rates for solar photovoltaics at over 10 percent of solar generation in ERCOT and over 3 percent in California Independent System Operator (CAISO).").

[180] *See* EIA, *Solar and wind power curtailments are rising in California* (Oct. 30, 2023), https://www.eia.gov/todayinenergy/detail.php?id=60822; EIA, *As Texas wind and solar capacity increase, energy curtailments are also likely to rise,* (Jul. 13, 2023), https://www.eia.gov/todayinenergy/detail.php?id=57100.

[181] Lawrence Berkeley National Laboratory (Millstein et al. 2022b), available at: https://emp.lbl.gov/publications/empirical-estimates-transmission; *See* fact sheet pg. 5 for limitations of the study.

[182] For example, see DOE noting that "The average wind deployment forecast for 2026 among analysts is 18 GW, a significant increase from the 11 GW 2026 forecast from a year ago (before the Inflation Reduction Act)." https://emp.lbl.gov/wind-technologies-market-report

[183] Ryan Wiser et al., *Land Based Wind Market Report,* Lawrence Berkley National Laboratory (Aug. 2023), available at: https://emp.lbl.gov/sites/default/files/emp-files/2023_land_based_wind_market_report_final_public.xlsx, tab "Value Relative to Flat Profile," showing a reduction from $67.7/MWh to $33.6/MWh.

Separately, the Proposed Rule argues that "the Treasury Department and the IRS believe that a broadly available allowance that is not tailored to specific geographic or other conditions should not be greater than the national average rate of the occurrence of the above circumstances," because the default allowance percentage is applied to the amount of renewable generation, and the 6.3% figure from 2022 is a simple average across "over 50,000 wholesale pricing nodes across the nation."[184] However, ACP submits that this figure should be weighted upward to account for that fact that nodes with renewable generation have significantly higher rates of low or negative electricity prices. LBNL data cited by the Proposed Rule indicates that wholesale power prices are negative 20% to more than 30% of the time in many locations with large amounts of wind generation.

Third, the 6.3% figure for 2022 only accounts for periods of negative wholesale electricity prices. These periods may not capture hours when wind or solar projects that bid into electricity markets at $0/MWh or at low positive prices, because they are not receiving the federal Production Tax Credit, are on the margin. Only solar projects placed in service following implementation of the IRA are eligible for the PTC, and many operating wind projects have either rolled off of their 10 years of PTC eligibility or have elected to receive a non-production-based incentive. These projects may bid into electricity markets at $0/MWh, or even low positive prices to reflect some variable operations and maintenance cost. As a result, tallying occurrences of power prices below $1/MWh (or a similarly low but positive threshold) would likely better capture periods when non-emitting resources are on the margin, and result in a higher default allowance than the 5% included in the Proposed Rule.

To that end, Treasury should adopt the higher 10% alternative default allowance suggested in the Proposed Rule, rather than the 5% allowance. A 10% default best reflects the share of time that increased load is unlikely to significantly increase induced grid emissions because existing non-emitting resources are operating on the margin.

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[184] Proposed Rule at 89231.

b) Taxpayers should be able to provide, on a case-by-case basis, evidence to exceed the default allowance for supply from existing clean generation.

In addition to the default presumption discussed above, the taxpayer should be able to provide evidence, on a case-by-case basis, to increase the applicable allowance. This could be done by (1) using historical wholesale electricity market prices to indicate periods when non-emitting resources are being dispatched on the margin at the location of the non-emitting energy supply, providing a sufficiently accurate and granular framework for measuring emissions, or (2) by using locational marginal emissions. As noted in the preceding section, we agree with the Proposed Rule that periods of low or negative wholesale electricity prices that reflect non-emitting resources operating "on the margin" in economic generation dispatch are the best indicator of when increased load is unlikely to significantly increase induced grid emissions. Specifically, this could be measured by the following:

- On an ex-ante basis, the share of generation (over the three most recent calendar years for which data is publicly available) from an existing non-emitting resource that occurred during time periods when the realized LMP at the nearest wholesale market price node is less than $1/MWh (or a similar threshold) should be deemed incremental non-emitting generation.
    - If the LMP is not available for a generator (i.e., if the generator is not located in a FERC-regulated Regional Transmission Organization or Energy Imbalance Market), then use of a proxy node should be allowed, such as the nearest interface with such a market. If a suitably proximate market pricing proxy node is not available, curtailment information, dispatch instructions, or system lambda data issued by the grid operator can be used in the alternative.
    - Under this approach, the offtaker should be located at the same location as the energy source, or at a location with higher percentage of LMPs below $1/MWh to ensure that the incremental generation does not result in increased emissions.

2. *Absent a default allowance, Treasury should adopt a case-specific approach to congestion and curtailment .*

Should Treasury decline to adopt a default allowance for existing clean supply, it should still adopt a case-specific approach to congestion and curtailment, using the ex-ante approach discussed above . Specifically, on a case-by-case basis taxpayers would be able to provide congestion, curtailment, and/or locational marginal price information to support the use of existing generation for EACs.

3. *If Treasury provides for an avoided retirements exception, the economic viability of an electric generating facility should be the metric for assessing retirement risk*

For circumstances in which a taxpayer could benefit from the avoided retirements provisions, Treasury should evaluate the economic viability of the electricity generating facilities (EGF) to assess retirement risk. An evaluation and review of EGF's historical financial performance showing that revenues did not cover costs in two out of the three calendar years prior to the operation of a hydrogen facility, then Treasury should determine that retirement risk exists. The EGF's revenues should include the EGF's settlement with the independent system operator, the EGF's settlement with its power purchasing agreement counterparties, and the receipt from the sales of renewable energy certificates. Tax benefits, such as PTCs, that the EGF has sold to tax equity investors for financing purposes should not be included in the EGF revenues, because the cash flows of the tax benefits will go to investors, not the EGF. Costs to be included in the assessment should include operating and maintenance costs, finance costs, lease costs, and all other costs that are essential for the EGF operations.

4. *The clean energy threshold approach should include certain exemptions for states with 100% zero emissions, carbon free, or renewable energy goals.*

In the preamble, Treasury notes that an exemption from the incrementality requirements may be reasonable in a region where "all generation-including imported generation comes from minimal emitting electricity generators."[185] In addition, ACP recommends that qualified clean hydrogen facilities that are placed in service in states with 100% zero-emissions, carbon-free, or renewable energy goals should be exempted from the incrementality rule if the region achieves 90% clean energy on the grid.

For instance, in 12 states (and the District of Colombia), the requirement is for 100% clean electricity by 2050 or earlier.[186] Presently, no state or region of the U.S. meets the 90% threshold, but this exemption could prove critical to the burgeoning green hydrogen industry as states or regions continue to adopt or strengthen these programs.[187] The incrementality pillar could add unnecessary administrative, duplicative, and costly burden to qualified clean hydrogen facilities in these states/regions. Moreover, in these areas, these goals will already ensure that new clean energy comes online to drive green hydrogen production.

In these states/regions, it should be up to the taxpayer (i.e., the owner of the green hydrogen facility) to claim the credit and provide the necessary evidentiary support where needed. On a yearly basis, Treasury could certify which states have surpassed that threshold and have the necessary enforceable laws and regulations in place that will continue the trajectory to 100%.

We also note that the European Union's (EU) newly enacted rules on renewable hydrogen provide an instructive example of such a clean energy threshold approach. They exempt hydrogen facilities from the incrementality requirement if such facilities are located in a bidding zone where the grid's renewable electricity share exceeded 90% in the previous year, provided that the hydrogen plant's annual production hours do not surpass the hours of available green electricity.[188] ACP believes that the EU's approach can serve as a helpful model and

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[185] Proposed Rule 89231.

acknowledges that this exemption may actually facilitate further investments in renewable power.[189]

V. Deliverability

The Proposed Rule defines the term "region" to mean a U.S. region derived from the National Transmission Needs Study (Needs Study), which was released by the DOE on October 30, 2023.[190] Each balancing authority is assigned to a specific region, and electricity is presumed to be deliverable between a generator and electrolyzer within a region. For example, 13 separate balancing authorities comprise the "Northwest" region, and the Proposed Rule's approach would deem electricity deliverable within that footprint.

ACP agrees that use of the DOE Needs Study regions is generally reasonable as a default presumption, as DOE's detailed study accounted for transmission constraints within and between regions. However, in the final rule, Treasury should account for several circumstances in which these regional boundaries might be overly restrictive, and not reflective of actual deliverability. Furthermore, ACP provides additional detail on the Proposed Rule's request for comment on whether there are "circumstances indicating that electricity is actually deliverable from an electricity generating facility to a hydrogen production facility, even if the two are not located in the same region or if the clean electricity generator is located outside of the U.S..".[191]

a. The taxpayer should be able to claim EACs from generation a facility in a geographic different region if such facility has firm transmission rights.

In circumstances where a generation facility is physically located in a different region from the hydrogen electrolyzer, the taxpayer should still be able to claim the EACs from that generation if the taxpayer or another party has procured firm transmission service with a rollover right – conditional or otherwise – between the generator and electrolyzer. For example, if a green

[190] Proposed Rule at 89228.
[191] Proposed Rule at 89233.

hydrogen facility obtains firm transmission service between its region and the region of its source of clean electricity, the final rule should plainly allow for transfers across regional boundaries. FERC's *pro forma* Open Access Transmission Tariff allows for procurement of firm transmission service.[192] Accordingly, the final rule should clarify that, where the taxpayer or another party procures firm transmission service between the regions where a generator and an electrolyzer are respectively located, the taxpayer should be eligible to claim EACs from that generator. Similarly, if a given generator is a network resource (and/or if an electrolyzer is a network load), procurement of network integration transmission service *within* the region – coupled with any necessary transmission rights to enable *interregional* transfers – should allow a taxpayer to utilize the EACs.

b. The final rule should accurately account for market expansion.

The regional boundaries of DOE's Needs Study accurately reflect current market (and transmission service) boundaries. However, the final rule should expressly account for market boundaries. At present, regions of the country without an independent grid operator (principally the non-California WECC region) utilize imbalance markets, which typically use transmission from member balancing authorities on an as-available basis. Extant energy markets include CAISO's Energy Imbalance Market, SPP's Western Energy Imbalance Service Market, and the Southeast Energy Exchange Market, none of which incorporate firm transmission. Should balancing authorities currently in a non-RTO region join an RTO, the final rule should allow those balancing authorities to be treated as internal to the RTO as of the participation date; this would allow appropriate flexibility in the regional boundaries when the regions themselves change.

[192] *See generally*, FERC *Pro Forma* OATT at II, p. 41, https://www.ferc.gov/sites/default/files/2020-04/pro-forma-open-access.pdf.

c. The final rule should allow for pre-qualification of generation and load

ACP recommends that a final rule allow for “pre-qualification” of clean energy supply and a hydrogen electrolyzer sink. Taxpayers should be able to demonstrate that the clean energy resource is deliverable if they can confirm the source of EACs, the sink, and a viable transmission pathway (comprised of NITS or point-to-point service) and can reflect this information on the NERC E-Tag for a transaction. This could provide benefits in terms of ensuring that deliverability requirements are administrable in practice, as E-Tags would offer a standardized format enabling generators, electrolyzer owners, transmission providers, and Treasury to readily confirm the source, sink, and pathway for delivery.

VI. Energy Attribute Certificate Clarifications

a. The final rule should provide clarifications for facilities that are directly connected to a hydrogen production facility.

The final rule should clarify that: (1) electricity from generating facilities that are directly connected to the hydrogen production facility may be taken into account for purposes of determining the lifecycle GHG emissions rate regardless of whether such electricity generation creates an EAC that is retired; and (2) the 4.9% Line Loss Assumption (defined below) does not apply to electricity generating facilities that are directly connected to a hydrogen production facility. The Proposed Rule provides that if a taxpayer determines a lifecycle GHG emissions rate for hydrogen produced using the most recent GREET model or a provisional emissions rate (PER), then the taxpayer may reflect in GREET or include in a PER the hydrogen production facility’s use of electricity as being from a specific electricity generating facility rather than from the regional electricity grid if the taxpayer acquires and retires a qualifying EAC for each unit of electricity that the taxpayer claims from such source.[193] To satisfy this requirement, a taxpayer’s acquisition and retirement of qualifying EACs must be recorded in a qualified EAC registry or accounting system so that the acquisition and retirement of such EACs may be verified by a

[193] Prop. Reg. § 1.45V-4(d)(1).

qualified verifier.[194] The Proposed Rule further state that these requirements apply regardless of whether the electricity generating facility is grid connected, directly connected, or co-located with the hydrogen production facility.[195]

The Proposed Rule adopts the 45VH2-GREET model for the purposes of calculating well-to-gate emissions of hydrogen production facilities. The 45VH2-GREET model includes estimates of the emissions associated with the generation of electricity from various power sources. In determining the emissions associated with the consumption of electricity from specific power sources, 45VH2-GREET assumes that 4.9% of generated electricity produced is lost in transmission and distribution prior to consumption (the "4.9% Line Loss Assumption").[196] It appears that the 4.9% Line Loss Assumption is solely for purposes of calculating the emissions rate and does not impact the number of EACs that must be retired under the time-matching requirement.[197]

The Proposed Rule should clarify that electricity from generating facilities that are directly connected to the hydrogen production facility (Behind-the-Meter or BTM) is taken into account for purposes of determining the lifecycle GHG emissions rate without the need to retire an EAC if none is created. Treasury should require the taxpayer to certify that no renewable energy certificate was created with respect to the BTM configuration and the IRS could confirm the taxpayer's representation with the renewable energy certificate market. This provides BTM projects certainty that they will be able to generate a Section 45V irrespective of whether hourly tracking will be available nationwide by 2028. The preamble to the Proposed Rule suggests that the qualified EAC retirement requirements were adopted because the Treasury are concerned

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[194] *Id.*
[195] *Id.*
[196] U.S. Dept. of Energy, Guidelines to Determine Well-to-Gate Greenhouse Gas (GHG) Emissions of Hydrogen Production Pathways using 45VH2-GREET 2023 (Dec. 2023) ("DOE 45VH2-GREET Guidelines"), §§ 2.4.1 (Emissions of Electricity Generation) and 3.2 (Accounting for Electricity in 45VH2-GREET 2023).
[197] *See* DOE 45VH2-GREET Guidelines, § 3.2 ("To account for transmission and distribution losses, 45VH2-GREET 2023 will then automatically assume that an addition ~4.9% of electricity was actually produced by each generator type chosen."); Prop. Reg. § 1.454(d)(1) ("one megawatt-hour of electricity use to produce hydrogen would need to be matched with one megawatt-hour of qualifying EACs").

with the potential double counting of EACs.[198] However, in circumstances where directly connected electricity generating facilities do not create tradable EACs that can be retired, there is no potential for double counting because there is no EAC to be traded in the first instance. Furthermore, it would be nonsensical to treat a BTM configuration differently than a grid-connected facility for purposes of determining lifecycle GHG emissions, especially where the electricity of the BTM configuration can be easily traced to the hydrogen production facility. ACP supports including safeguards to address Treasury's double-counting concerns, but requests that future guidance clarify that electricity generated by a BTM configuration be counted in determining the lifecycle GHG emissions rate even if an EAC is not created or separately retired.

Furthermore, Treasury should confirm that the 4.9% Line Loss Assumption does not apply to electricity generating facilities that are directly connected to hydrogen production facilities. The 4.9% Line Loss Assumption is based on 2018 estimates from the EIA regarding nationwide electricity losses relative to electricity disposition.[199] This assumption is not applicable to BTM configurations because the generated electricity is travelling a short distance to the hydrogen production facility and not subject to significant line loss. Accordingly, it does not make sense to burden a directly connected electricity generating facility with an assumed line loss as the quantity produced by the BTM renewables will be the same as the quantity delivered to and consumed by the electrolyzer.

b. ACP supports the proposed 1:1 ratio of megawatt-hour to qualifying EAC.

The Proposed Rule provides that "one megawatt hour of electricity used to produce hydrogen would need to be matched with one-megawatt hour of qualifying EACs."[200] The Proposed Rule seeks comment on whether a different treatment would be more appropriate to account for transmission and distribution ("T & D") line losses. ACP supports the 1:1 ratio this ratio should not be adjusted for T & D line losses. Because estimating T & D losses is a highly

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[198] *See* 88 Fed. Reg. at 89,227 ("Uniformly requiring claims of using electricity generated from specific sources to be evidenced by EACs that meet the requirements of proposed § 1.45V-4(d)(1) would mitigate the risk of double counting.").

[199] DOE 45VH2-GREET Guidelines, § 2.4.1 (Emissions of Electricity Generation) ft. nt. 18.

[200] Proposed rule at 89227.

complicated process that requires a significant amount of modeling, assumptions, and calculations, it would be impossible to develop a method to estimate losses that is simple and accurate. Every project will experience different losses, depending on a variety of factors including the location of the hydrogen production facility relative to the source of EACs, and the time of day. Ultimately, there is no accurate way to take into account losses , and as such, doing so would only lower the value of the produced hydrogen.

c. The one-megawatt-hour of electricity should apply only to electricity used to directly produce hydrogen.

As stated above, the Proposed Rule provides that "one megawatt hour of electricity used to produce hydrogen would need to be matched with one-megawatt hour of qualifying EACs."[201] The regulations do not clarify the scope of electricity at the hydrogen production facility that must be matched to EACs. Within a facility, the electrolyzer stack is the component that directly produces hydrogen, and is the primary load (90+%). The electrolyzer stack is also the component best suited for hourly EAC matching as its load can vary with the actual amount of hydrogen produced. Beyond the electrolyzer stack, hydrogen production facilities will also have multiple auxiliary loads, some of which are less variable. For example, some power conditioning and water treatment equipment will stay online in a hot standby mode, when the facility is not producing hydrogen. The final rule should clarify that the only electricity included in the scope of the matching requirement is the electricity used to directly produce hydrogen in the electrolyzer or electrolyzer stack unit. At the very least, energy not related to producing hydrogen, such as that hot standby, should be omitted from the calculation or covered in the formulaic approach.

VII. Carbon Matching

ACP supports the consideration of annual carbon matching as a potential alternative path for compliance. To that end, we encourage Treasury to issue a Supplemental Notice of Proposed Rulemaking seeking comment on the merits of incorporating a carbon matching pathway in the

[201] *Id.* at 89227.

final rule. The notice should request comments on providing carbon matching as an optional approach, in addition to the current three pillar compliance pathway. If added to the current proposal, taxpayers would have the option of either relying on the three pillars or on carbon matching. In order to develop a robust record on this, we encourage Treasury to issue such a notice as soon as possible.

Rather than aligning energy consumption with production on an hourly or yearly basis (with energy serving as a proxy measure for carbon emissions in both instances), a carbon matching approach directly measures the total induced carbon emissions resulting from the operations of energy consumption from the grid and total clean energy production. This approach holds the promise of better aligning with the legislative requirements of lifecycle emissions. It reflects the impacts of transmission congestion by using (LME) data to measure actual emissions from both the electrolyzer and the renewable energy source, and as a result could provide a more realistic assessment of a project's actual impact on carbon emissions. This approach is not only potentially more granular from an emissions perspective but also arguably better aligns with the goal of creating a scalable green hydrogen industry by accurately reflecting the emissions reduction potential of hydrogen projects.

The proposed deliverability criteria currently divides the country into roughly 15 large areas to evaluate emissions from clean hydrogen production. This approach does not take advantage of the detailed data from over 50,000 specific locations that show the true emissions based on actual electricity prices and pollution levels. A carbon matching proposal could make it possible to relax the requirement for co-locating renewable energy within the same grid as a clean hydrogen facility. This method could enable the development of electrolyzers in regions where new renewable development is physically or economically challenged. Further, this method could further promote the deployment of electrolyzers in regions with clean grids (as a result of high existing penetration of renewables) and the procurement of renewable energy in less clean grids (as a result of low existing renewable penetration).

Under the proposed time-matching requirement renewable power must be matched hour-by-hour to electrolyzer usage after a grace period (annual matching is permitted until January

2028). As discussed, this requirement will greatly increase the cost per metric ton of emissions reduced. Further, because the focus of hourly matching is on an individual plant's output, rather than on the reduction of emissions write-large, this requirement emphasizes the individual user over the entire grid... Carbon matching could serve as an alternative to the current time-matching requirement. While a system incorporating carbon matching could theoretically be effectuated without an incrementality requirement, any consideration of carbon matching should include an incrementality rule to ensure that the credit effectively incentivizes the development of new clean energy sources.

For all these reasons, we encourage Treasury to issue a supplemental notice seeking comment on whether to include a carbon matching alternative pathway in a final rule. As there has not been a lot of analysis or thought given to carbon matching, such a notice would allow stakeholders more time to deliberate on this issue and provide a robust record for Treasury on the merits of including a carbon matching option in the final rule.

VIII. 45VH2-GREET Model

ACP has three recommendations related to the use of the GREET model for determining lifecycle GHG emission rates.

a. A facility should be able to input "requested hydrogen production" in the 45VH2-GREET model.

The Proposed Rule provides that the lifecycle 45VH2-GREET emission rate of hydrogen is determined based on the taxable years "total hydrogen production" at a hydrogen production facility. Instead of relying on "total hydrogen production" a facility should be able to input into the 45VH2-GREET model the volume of hydrogen for which it is requesting section 45V production tax credits, or the "requested hydrogen volume." The "requested hydrogen volume" would be defined as the quantity of qualified clean hydrogen across all hours of the year for which the taxpayer is requesting a PTC.

The "requested hydrogen volume" approach is justified for three reasons. First, renewable generation is variable and as a result it is extremely challenging to accurately predict wind and solar generation moment to moment. Inevitably there will be inaccuracies and margins of error when making this calculation. Allowing a facility to input "requested hydrogen volume" would help account for this variability. Second, many of the highest potential use cases of clean hydrogen have downstream processes that require a steady and consistent stream of hydrogen. Currently, electrolytic hydrogen facilities connected to renewable energy generation may not be able to meet this steady supply requirement. If these facilities are to meet the downstream needs, they will have to at times rely on grid power. Allowing a hydrogen facility to input the "requested hydrogen volume" will help incentivize use of renewables for these downstream processes. In contrast, disqualifying a facility for utilizing grid power when necessary, will disincentivize the use of green hydrogen by these downstream offtakers, who will likely instead turn to more carbon intensive hydrogen counterparts. Third, today many electrolyzer technologies are not capable of operating at lower capacity utilizations. For example, an electrolyzer may have a minimum operation load of 40%. A facility relying on this equipment would be required to produce hydrogen at this minimum load even if EACs were not available. As a result, the facility would need to power the electrolyzer with grid electricity to fill the gap between EACs and the minimum operating load, thereby risking disqualification from PTC. While technologies are improving, allowing operators to input "requested hydrogen volume" would allow facilities to account for these existing technical limitations.

b. Treasury should include sub-regional grid power as a feedstock option eligible for DOE emissions rate and 45VH2-GREET provisional emissions rate (PER).

The current 45VH2-GREET model provides carbon intensity values for nine regional grids across the U.S. and eight production pathways. A taxpayer may file a petition with the Secretary for a DOE emissions value and a PER if a lifecycle GHG emission rate has not been determined under the most recent 45VH2-GREET model for the hydrogen produced by the taxpayer at a hydrogen production facility.[202] The proposed rule further provides that the life

[202] Proposed Rule § 1.45V–4(c)(2)(i)

cycle GHG emission rate has not been determined if a facility's feedstock or its hydrogen production technology is not included in the most recent Greet Model.[203] The rule should clarify that power from a sub-regional grid (a subset of one of the nine regional grids identified in the DOE Transmission Needs Study) be considered a potential "feedstock" for which a taxpayer can file a petition for a PER. To establish a PER for sub-regional grid power as a new feedstock, the taxpayer would follow the same process already established in § 1.45V—4(c)(3) *Process for filing a PER petition*, and § 1.45V—4(c)(5) *Department of Energy (DOE) emissions value request process*.

c. The final rule should provide taxpayers with the flexibility to use the 45VH2-GREET model that is available at the project's start of construction date for the entirety of the project's lifetime.

The regulations should allow a taxpayer to rely on the version of the 45VH2-GREET model in effect when the project begins construction, or on the first day of the taxable year in which the clean hydrogen is placed in service, for the 10 years of the PTC. To finance early-stage clean energy hydrogen projects investors and project developers need certainty as to the level of carbon intensity that will be assigned to a project for the duration of the PTC. This certainty is only possible if project developers can apply the same carbon intensity level, i.e., the same version of the 45VH2-GREET model, during the entirety of the ten -year credit window. Absent this certainty, developers may not be able to secure financing.

IX. Conclusion

ACP appreciates the opportunity to comment on the Proposed Rule. We share the goal of supporting the nascent green hydrogen industry in the U.S. while at the same time providing robust guardrails to ensure that it is both clean and green. We encourage Treasury to consider implementing the recommendations presented herein in the final rule to ensure the green hydrogen industry can scale up to meet its potential to help decarbonize the economy, drive demand for new renewable energy, and expand domestic jobs in the clean energy sector.

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[203] *Id.*

Implications of 45V Guidance to the Green Hydrogen Industry

Prepared for American Clean Power

February 2024

Table of Contents

Wood Mackenzie

Key takeaways

1

Green hydrogen is key to decarbonization

- To reach net-zero emission target by 2050, the US requires 50-80 mmtpa of low-carbon H_2 deployment, of which over 50% will be sourced from green H_2
- The lower carbon intensity of green H_2 is key to driving a lower CI H_2 supply mix in support of net-zero ambitions

2

Market context is already challenging for green hydrogen

- Scalability of green H_2 industry is necessary to lower costs and improve its competitiveness
- However, green H_2 projects face a significant number of challenges across the project lifecycle, limiting progress for green H_2 project commercialization and potentially leading to delays in low-carbon H_2 deployment

3

45V has the potential to make a big impact in accelerating green hydrogen deployment

- 45V's PTC can catalyze the H_2 industry by reducing the LCOH of green H_2 and bringing it to parity with blue H_2 and other fuels
- However, requiring hourly 45V CI matching in 2028 impacts green H_2 CF and LCOH, at a critical time for innovation and growth

4

UST Guidelines make economics, adoption and deployment challenging for green hydrogen

- LCOH is estimated to be orders of magnitude above the price range for adoption at scale, driven largely by the complexity the UST guidelines drive in H_2 power procurement
- UST guidelines will likely lead to greater blue H_2 deployment, limited scaling of green H_2, and ultimately a higher CI for H_2 supply

5

ACP's proposal would enable greater green hydrogen deployment, enabling the industry to get closer to key DOE Targets for the industry which are needed to support wider decarbonization goals

Executive Summary

Wood Mackenzie was engaged by ACP to provide independent analysis on 45V and its implications for the green hydrogen industry

We explored implications of two scenarios for how the 45V PTC guidelines could be defined and implemented

***45V Objective:** Enable the low-carbon hydrogen industry to scale and contribute to US decarbonization goals*

US Treasury Guidance

In December 2023, the **US Treasury** issued three pillars outlining how the 45V Production Tax Credit (PTC) will be implemented:

Temporality: Annual matching through 2027, with hourly matching starting in 2028 for all facilities, regardless of construction start or in-service date

Incrementality: Power must be sourced from generators coming online no earlier than 3 years of H_2 facilities' COD

Deliverability: Power supply from same DOE energy region

ACP Proposal

In the Summer of 2023, **ACP** prepared a different proposal with two key recommendations to change the US Treasury guidelines:

Temporality: Annual matching for the first 10 years of operations for plants beginning construction before 2029 and in service before 2033. Hourly matching for plants starting operations post-2032 or beginning construction post-2028

Incrementality: No proposed changes

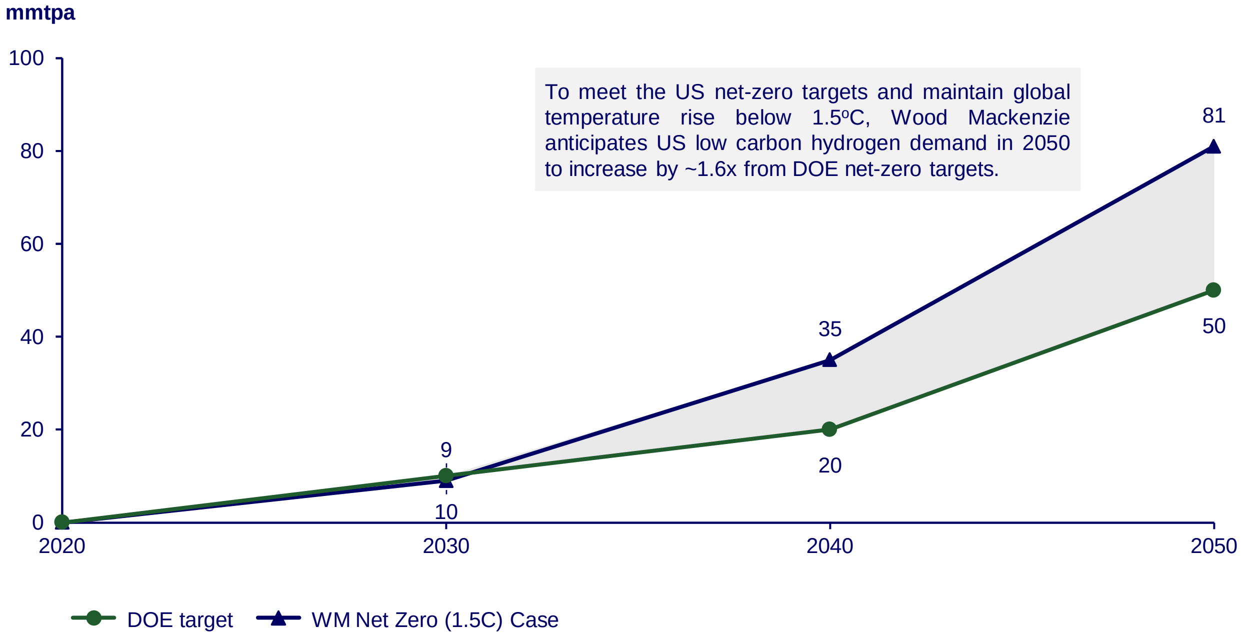
Deliverability: No proposed changes

		Key Metric	Type of Analysis
Our analysis focuses primarily on the **Temporality** dimension, in order to understand the implications of the US Treasury Guidance and the ACP proposal to achieve the objective of 45V	A	LCOH of Green H_2	LCOH estimation in ERCOT and CAISO by Scenario
	B	Deployment of Low CI H_2 Projects	Demand & supply of low-carbon H_2 projects by Scenario
	C	Emissions	Emissions associated with project deployment by Scenario

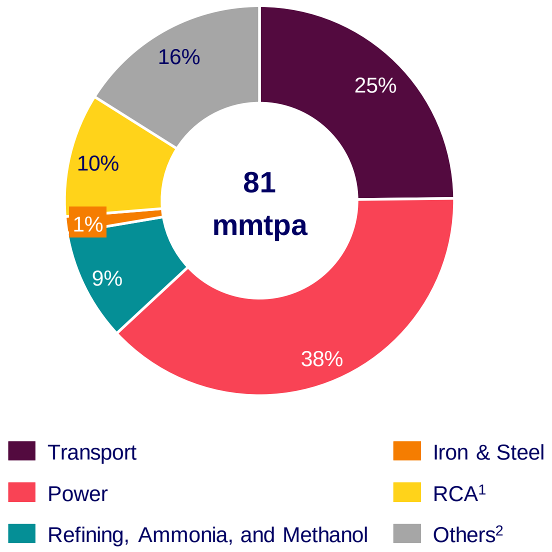
To reach net-zero, the US requires 50-80 mmtpa of low-carbon H_2 adoption by 2050

Domestic low-carbon hydrogen adoption is expected to occur most quickly in existing applications; long-term growth is driven by power, mobility, and high-heat applications

Wood Mackenzie US hydrogen demand outlook (net-zero case) vs DOE target



2050 WM net-zero hydrogen demand by sector



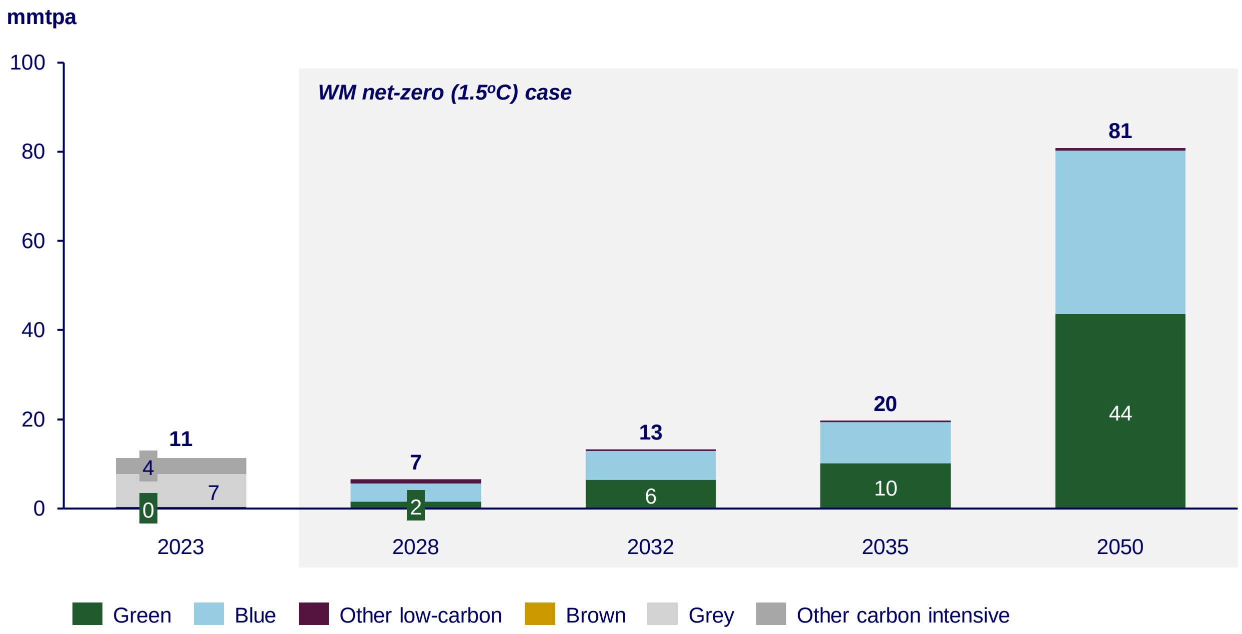
1. RCA: residential, commercial, and agriculture; 2. Others include cement, glass, ceramics, semiconductors, polysilicon, food hydrogenation, and various applications, as well as losses and gains during transportation process

Source: Wood Mackenzie Energy Transition Service

Green hydrogen must be deployed at scale to achieve net-zero ambitions

New energy markets have typically taken 30-50 years to scale, action is needed today to support the industry

Wood Mackenzie US low carbon hydrogen production[1] by type



- Wood Mackenzie's net-zero (1.5ºC warming) case estimates that roughly 80 mmtpa of low-carbon hydrogen will be needed in the U.S. to meet 2050 net-zero target
- To get to 80 mmtpa of low-carbon hydrogen by 2050, ~20 mmtpa must be deployed by 2035
- Current investment trends are not enough to achieve net-zero. There are 134 announced projects trying to achieve commercial operation date (COD), reflecting 17.2 mmtpa of capacity and an estimated investment of US$70 billion.
- Green hydrogen plays a key role in the US decarbonization journey, reflecting ~55% (44 mmtpa) of low-carbon hydrogen supply by 2050
- Meaningful policy intervention is needed to scale the market from virtually zero

1. Hydrogen production only includes domestic production catered for domestic consumption and excludes supply for exports.
Note: Wood Mackenzie's net zero case outlook considers only low carbon hydrogen supply will meet the incremental demand from the rapid decarbonization effort
Source: Wood Mackenzie Lens Hydrogen, Energy Transition Service

The low-carbon H_2 industry is nascent and needs to overcome challenges to scale

Project Development Challenges

Feedstock Sourcing
Complex sourcing strategies are needed to source reliable, low CI, and low-cost renewables or natural gas for sustaining continuous commercial operations at a competitive cost

Policy / Regulatory Guidance
Despite the momentum of 45V PTC and BIL, stringent regulatory requirements may deter first movers from scale-up operations, impeding growth potential and keeping costs higher for longer

EPC / Supply Chain / Technology
Clean hydrogen production technology and supply chain have yet to achieve commercial maturity to fully achieve large-scale production

Project Bankability / Financing Progress
High capital costs, uncertain future revenue streams, technical risk, and uncertainty around 45V eligibility create a high-risk profile, limiting investor interest and capability

Market Access and Delivery
Lack of existing and emerging demand markets, as well as limited infrastructure for connecting production to demand centers

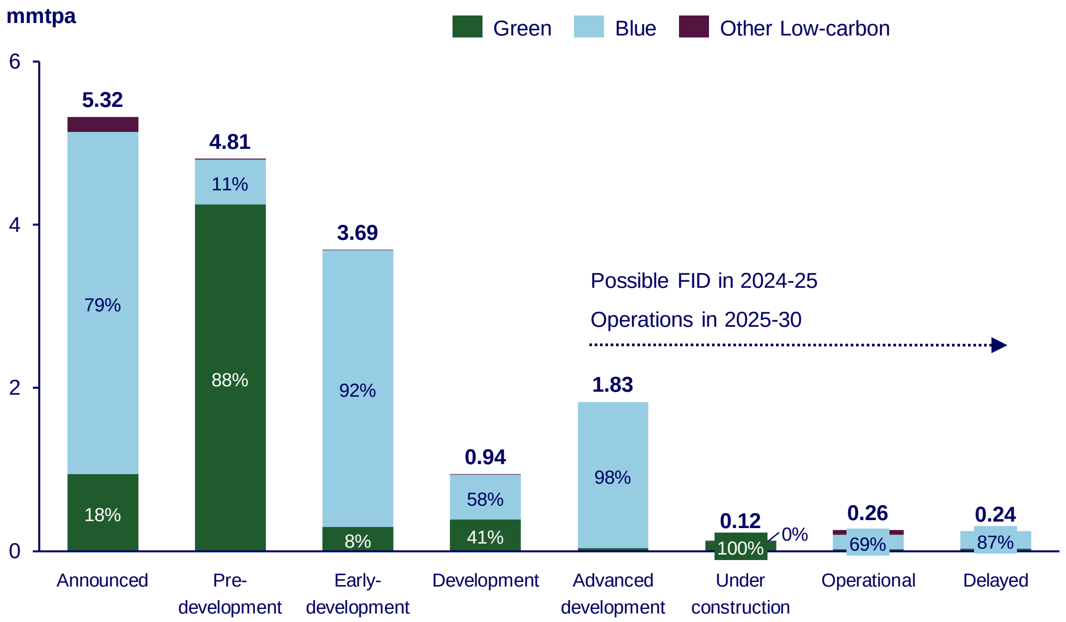
Marketing Progress (Offtakers & Revenues)
Hydrogen producers face challenges securing offtakers with sufficient demand who are willing to sign long-term contracts for costly low-carbon hydrogen

Source: Wood Mackenzie

Lack of cost competitiveness limits green H_2 commercialization and deployment…

Only 5% of projects likely to take FID in the next 2 years will be green hydrogen projects

US low carbon hydrogen project announcements by status



Over 95% of low-carbon hydrogen project capacities have yet to achieve commercial operations

- 27 projects are currently operational and contribute 0.26 mmtpa of capacity
- 9 projects are under construction and will potentially come online before 2028, but only account for 0.12 mmtpa of capacity
- 80+ projects are still progressing to achieve FID, reflecting 15.75 mmtpa capacity
- 4 projects are delayed or cancelled, totaling 0.24 mmtpa capacity

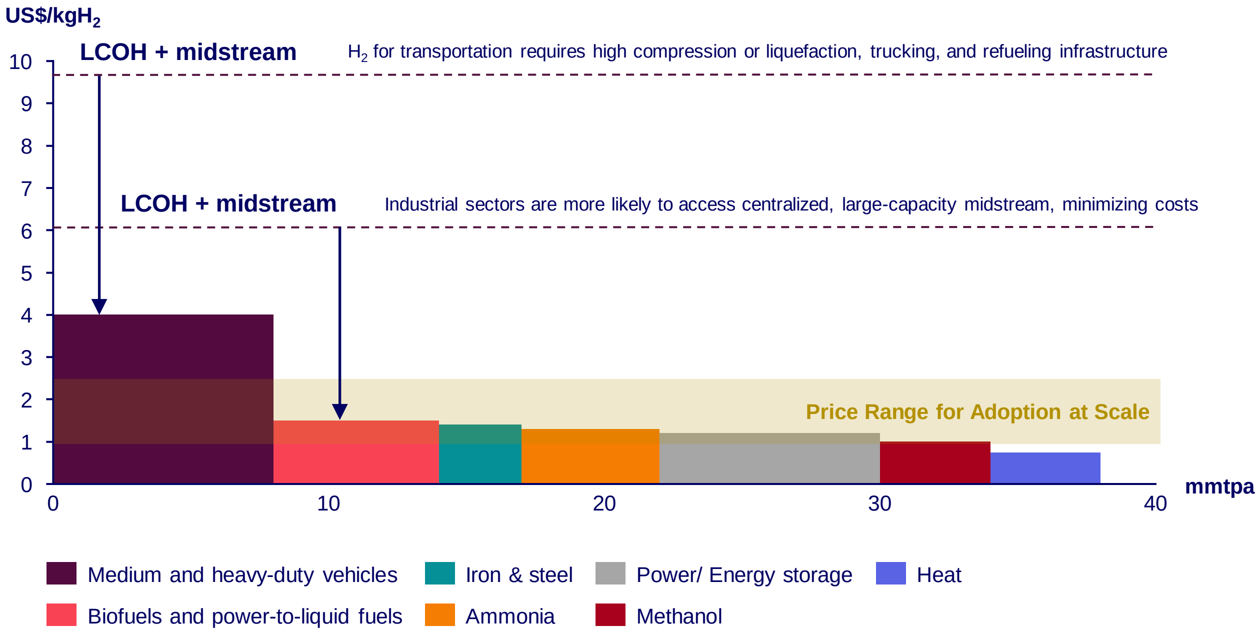
Blue hydrogen projects are advancing faster than green hydrogen projects

- Green hydrogen projects face major barriers to completion due to strict PTC guidance, alongside persistent challenges related to EPC, offtake agreements and financing
- Meanwhile, blue hydrogen projects leverage declining gas prices and supportive policies to enhance economic viability and progress

…which in turn limits economies of scale required to reduce costs and drive adoption

Green H_2 economics must fall within $1-2/kg, on a delivered to customer basis, to encourage adoption at scale

Potential low-carbon H_2 demand sectors and corresponding price range for adoption at scale



- H_2 price range of adoption at scale for each demand sector represents the price at which end-users are willing to adopt hydrogen in their operations
- Green H_2 production costs could be competitive in the medium and heavy-duty vehicle sectors compared to other competing fuels, such as electricity and petroleum derivatives. However, it becomes less competitive when factoring in the costs of compression/liquefaction and trucking to the end user
- Other sectors, including biofuels, ammonia, and power, currently consume cheap fossil feedstocks, so green H_2 must be low cost to be competitive. Large-scale consumers benefit from the ability to access feedstock supplies via lower cost high-capacity delivery infrastructure
- The 45V incentive could bring green H_2 cost closer to the Hydrogen Shot's goal and boost green H_2 demand creation, yet strict guidelines may prolong high costs, risking adoption and future deployment

Wood Mackenzie Source: Department of Energy, Wood Mackenzie

CONCEPTUAL

The 45V PTC aims to catalyze the nascent low-carbon hydrogen industry

In this report, we analyze the implications of capping the duration of annual matching to 2028

Motivation for a LCI H_2 45V Production Tax Credit

CO_2

US Decarbonization Need

- H_2 is required for US to reach net-zero by 2050
- Green H_2 supply is necessary as blue supply will be insufficient

$

Current Obstacle – Current Costs & Competition

- Without government support, there will be limited progression of green H_2 projects given costs are currently higher than competing fuels

Proposed Solution

- 45V Production Tax Credit (PTC) introduced by the Inflation Reduction Act (IRA) in 2022

Implementation challenges

$

Treasury-issued Guidelines – Awaiting Comments

- Proposed 45V implementation includes three main pillars:

Rule	Description	Challenge
Temporality	Annual matching allowed initially, but all projects must shift to **hourly matching starting in 2028**	Hourly matching typically results in electrolyzers running at low load factors, resulting in higher LCOH
Incrementality	Clean power must be sourced from generators coming online no earlier than 3 years of H_2 facilities' COD	Potential H_2 project delays due to bottlenecks (e.g. interconnection queue, supply chain issue, costs, etc.) in developing renewables assets linked to the project
Deliverability	H_2 producers must source power from within 1 of the 15 regions in the DOE's National Transmission Needs	Potential H_2 project delays due to having to ensure interregional transfers when there is physical delivery between them

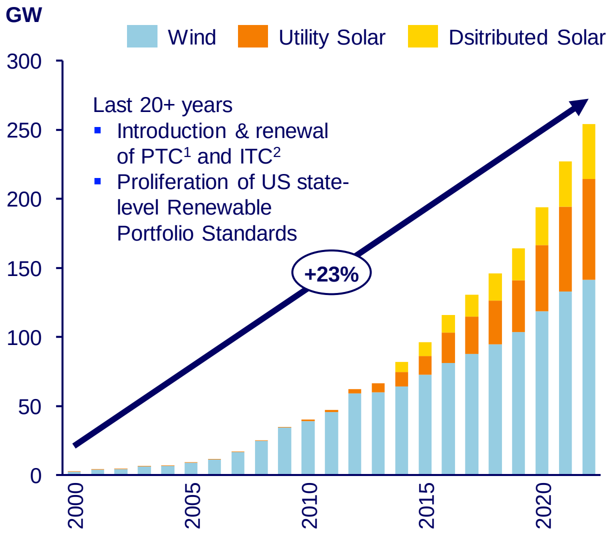
Note: The 45V production tax credit (PTC) generates a tax credit for each kilogram of clean hydrogen produced after 2022 for ten years starting at the commercial operations date (COD); it can amount to up to $3.00/kg for qualified clean hydrogen production

Source: Wood Mackenzie, US Treasury

Energy markets take decades to develop, which is why implementing 45V with a long-term view is critical…

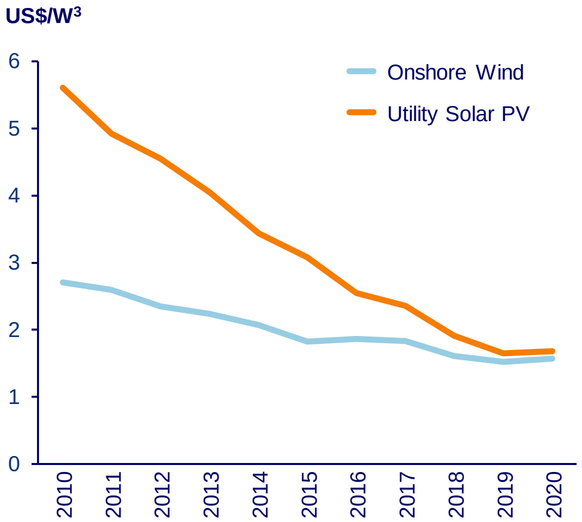
The renewables industry is an example of how the successful development of a new industry can take 20+ years

US Wind & Solar Installed Capacity



With a CAGR of 23% in 2000-2022, wind and solar have gone from being a new technology to acquiring a pivotal role in the US energy matrix

Unit Capex for Wind & Solar PV (2010-2020)



Only after at least two decades of continued support, costs are becoming more competitive, allowing the industry to reach record investment levels

- Developing an industry takes several decades
- Scaling it is only possible by lowering its costs
- The case of hydrogen is more complex than the case of renewables because most of the associated midstream and downstream infrastructure needs to be developed

1. PTC = Production Tax Credit; 2. ITC = Investment Tax Credit; 3. 2021 real US$ median values as reported by NREL; excludes labor and overhead
Source: EIA, NREL, Wood Mackenzie

CONCEPTUAL

…however, the currently defined 45V pillars impact capacity factor and costs

The lower the CF, the higher the cost of hydrogen on a levelized basis due to a lower volume of production

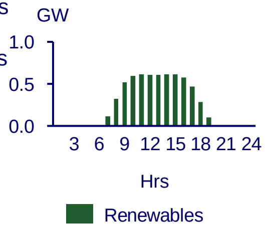
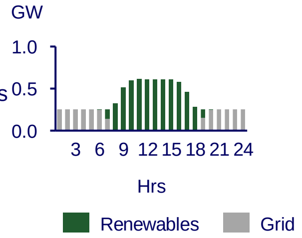
What is LCOH?

- Levelized cost of hydrogen (LCOH) is the preferred industry metric to compare a project's hydrogen production economics (US$/kg) across the different color production pathways

$$LCOH = \frac{PV\ (Costs)}{PV(Production)}$$

- The biggest driver of ***Costs*** are power price and capex
- The biggest driver of ***Production*** is the Capacity Factor (CF) since less operating time simply translates into less production
- The 45V Production Tax Credit (PTC) aims to make low-carbon hydrogen competitive vs. carbon-intensive hydrogen by reducing the costs and resulting LCOH of low-carbon hydrogen, driving H_2 producers to adopt the least carbon intensive technologies

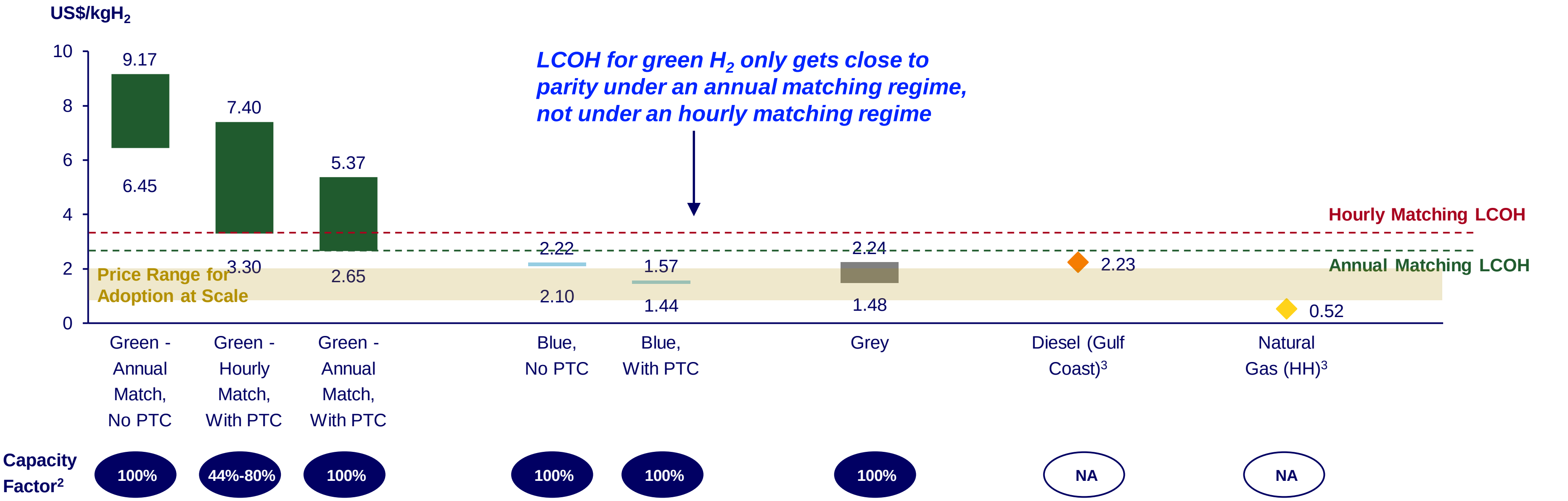
How does temporality affect the capacity factor and LCOH?

	Description	Typical power configuration	Capacity Factor (CF)	LCOH impact
1 Hourly Matching	▪ Electrolyzer demand matches the availability of renewable generation on an hourly basis ▪ H_2 is produced only at times when renewable generation occurs		Power Supply CF 20-40% Electrolyzer CF <50%	Lower H_2 production from low CF results in high LCOH
2 Annual Matching	▪ Electrolyzer demand is met annually by renewables but needs grid power supply to sustain continuous operations ▪ RECs from excess renewables generation in peak generation hours are used to verify renewable attributes of grid supplied power		Power Supply CF 100% Electrolyzer CF 90-100%	High H_2 production from high CF results in lower LCOH

A longer annual match eligibility period supports a higher capacity factor (CF) and lower LCOH during a critical period for growth and innovation

Hourly match requires load following of renewables, limiting project CFs and challenging green H_2 economics

Estimated LCOH range by temporality, fiscal regime and technology[1] (2032 COD)



1. Green LCOH range is based on the electricity cost ranges between ERCOT (low range) and CAISO (high range). Green H_2 refers to solar and wind-based electrolytic H_2, while blue H_2 refers to natural gas-based H_2 with CCS technology; 2. These capacity factors reflect the renewables uptime; 3. kg energy-equivalent of H_2

Note: detailed assumptions for LCOH calculation can be found in the Appendix

Source: Wood Mackenzie

ACP proposed an alternative to US Treasury Guidelines, which delays the hourly matching requirement, supporting the emergence of new green H_2 projects

ACP proposed changes to the three pillars of the US Treasury Guidelines to 45V

Pillars		US Treasury Guidelines (**UST Scenario**)		ACP Proposal **(ACP Scenario)**	
TEMPORALITY	**Annual Matching**	**Timing:**	Through 2027	**Timing:**	1st 10 years of operation
		Eligibility:	All H_2 facilities	**Eligibility:**	Construction start before 2029, COD before 2033
	Hourly Matching	**Timing:**	2028 & beyond	**Timing:**	2033 & beyond
		Eligibility:	All H_2 facilities	**Eligibility:**	All H_2 facilities except those eligible for annual matching
INCREMENTALITY		Clean power must be sourced from generators coming online no earlier than 3 years of H_2 facilities' COD			
DELIVERABILITY		Electrolyzers and power generation facilities must be in the **same DOE energy region – defined by markets**			

We have focused on the **TEMPORALITY** proposed changes since they have the most material impact on project viability

Source: US Treasury, American Clean Power, Wood Mackenzie

The impact of each proposal was evaluated in California and Texas power markets

These markets are located in major US H_2 hubs and reflect over 60% of announced low-carbon H_2 projects

Key assumptions for green H_2 and renewable energy projects in CAISO and ERCOT power markets

California

Power market	CAISO
Zone	SP15
Electrolyzer type and size	PEM | 200 MW

Renewables source

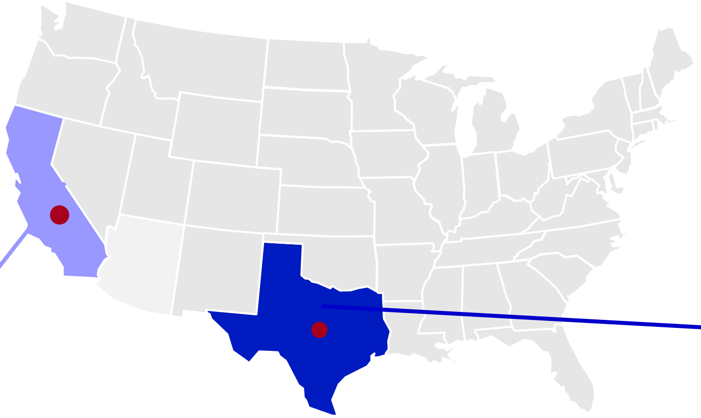
	Solar
Size	810 MW
Overbuild	4.1x
Capacity factor	25%

Power costs (US$/MWh)

	Hourly matching	Annual matching
2028	99.20	136.51
2032	84.35	124.44

Electrolyzer capacity factor (%)

Hourly matching	44%
Annual matching	100%



Texas

Power market	ERCOT
Zone	South
Electrolyzer type and size	PEM | 200 MW

Renewable sources

	Solar	Wind
Size	340 MW	340MW
Overbuild	1.7x	1.7x
Capacity factor	23%	40%

Power costs (US$/MWh)

	Hourly matching	Annual matching
2028	59.47	63.85
2032	60.15	66.78

Electrolyzer capacity factor (%)

Hourly matching	80%
Annual matching	100%

Wood Mackenzie assumptions

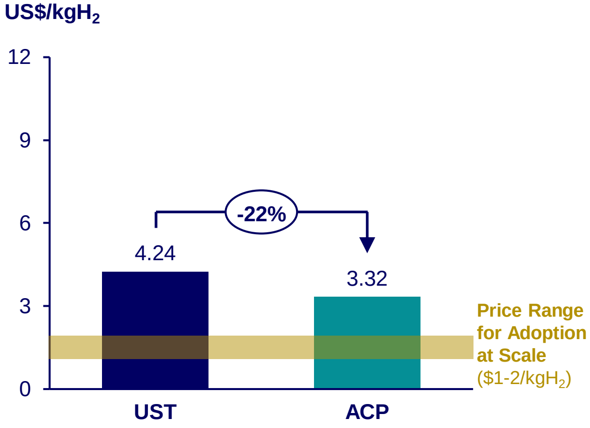
Wood Mackenzie's hourly renewables profiles and renewables capacity overbuild factor were optimized to achieve the highest H_2 capacity factor (CF) in the hourly matching scenario. H_2 producers may deploy different procurement strategies based on commercial decisions, such as choosing a smaller overbuild factor, to balance costs and production, resulting in lower H_2 CF

Source: Wood Mackenzie

In 2028, H_2 production costs are still too high to drive adoption in most sectors; annual matching reduces the cost to consumers by 20-30%

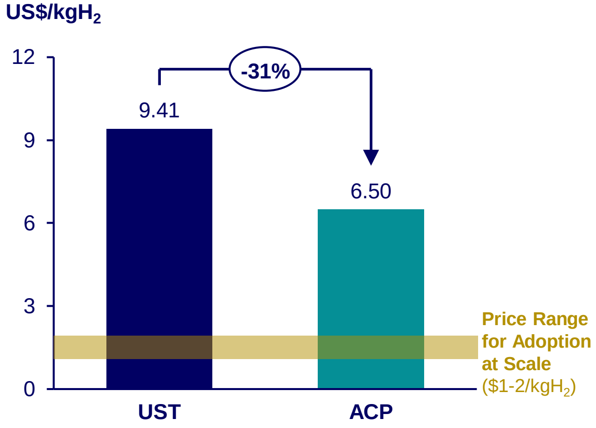
Regions with high quality wind are economically advantaged, but not enough to meet DOE H_2 shot goals

2028 ERCOT LCOH under UST vs ACP scenario (post 45V tax credit)



RE overbuild	3.4	3.4
Power config.	Hourly matching	Annual matching
Power cost (US$/MWh)	59.47	63.85
H_2 CF (%)	80%	100%

2028 CAISO LCOH under UST vs ACP scenario (post 45V tax credit)



RE overbuild	4.1	4.1
Power config.	Hourly matching	Annual matching
Power cost (US$/MWh)	99.20	136.51
H_2 CF (%)	44%	100%

- In ERCOT, high-quality solar and wind resources and overbuild capacity yield 80% H_2 capacity factor (CF) in the UST scenario, narrowing the gap between proposals. This highlights that hourly matching has the least negative consequences only in regions with robust solar and wind resources to support sufficient H_2 production
- In CAISO, higher power costs and lower H_2 CF drive a significantly higher LCOH compared to the ERCOT LCOH
- Despite substantial LCOH reduction from ACP proposals, the resulting LCOH is 3-6x higher than the DOE's H_2 Shot goal of US$1/kg and significantly above the price range for adoption at scale for end-use customers, potentially impeding green H_2 adoption

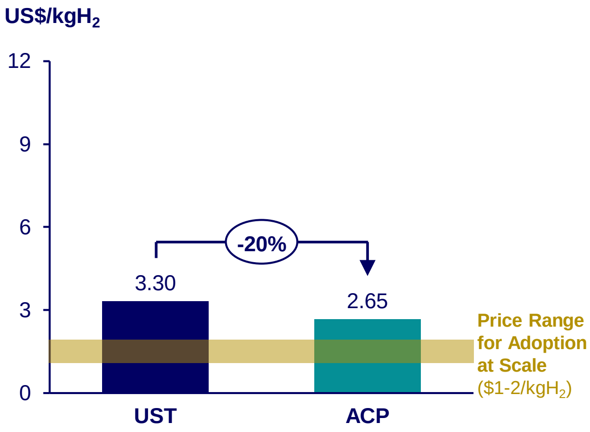
Wood Mackenzie

Note: All green H2 analysis in this study assumes green H2 production to receive the full 45V tax credits ($3/kgH2) by having <0.45kgCO2/kgH2 of carbon intensity. Detailed assumptions for LCOH calculation can be found in the Appendix
Source: Wood Mackenzie

In 2032, renewable & electrolyzer CapEx reductions lessen the impact of a lower capacity factor; ACP's proposal brings LCOH closer to the price for adoption at scale

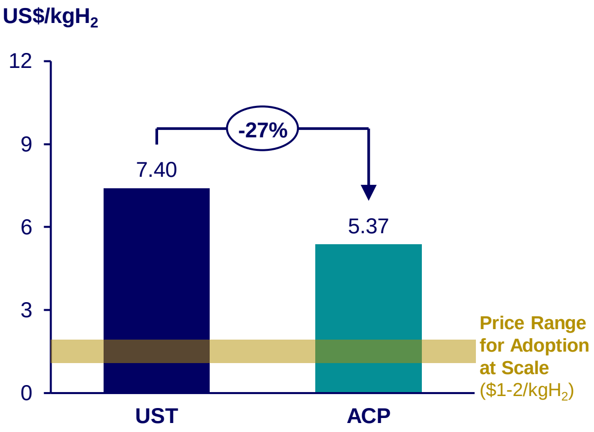
Still, even advantaged renewable resource regions like ERCOT are not able to fall in the $1-2/kg range

2032 ERCOT LCOH under UST vs ACP scenario (post 45V tax credit)



	UST	ACP
RE overbuild	3.4	3.4
Power config.	Hourly matching	Annual matching
Power cost (US$/MWh)	60.15	66.78
H_2 CF (%)	80%	100%

2032 CAISO LCOH under UST vs ACP scenario (post 45V tax credit)



	UST	ACP
RE overbuild	4.1	4.1
Power config.	Hourly matching	Annual matching
Power cost (US$/MWh)	84.35	124.44
H_2 CF	44%	100%

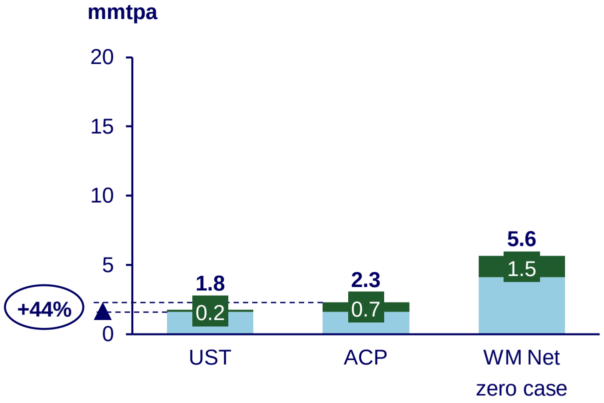
- LCOH under the UST hourly match regime has fallen by ~20% in both regions relative to 2028, signaling significant progress
- However, cost reductions are not enough to get into a price range for adoption at scale of US$1-2/kg$H_2$ by 2032 in either scenario, which reflects an inflection point for large-scale green hydrogen adoption
- Annual matching supports lower costs, but the current market context drives a starting point for green H_2 LCOH that may require more time or additional support beyond the 45V to achieve production costs needed to drive adoption at-scale

Note: All green H2 analysis in this study assumes green H2 production to receive the full 45V tax credits ($3/kgH2) by having <0.45kgCO2/kgH2 of carbon intensity. Detailed assumptions for LCOH calculation can be found in the Appendix
Source: Wood Mackenzie

Lower LCOH under ACP's proposal drives higher low-carbon H_2 deployment long-term, accelerating the deployment required to approach net-zero ambitions

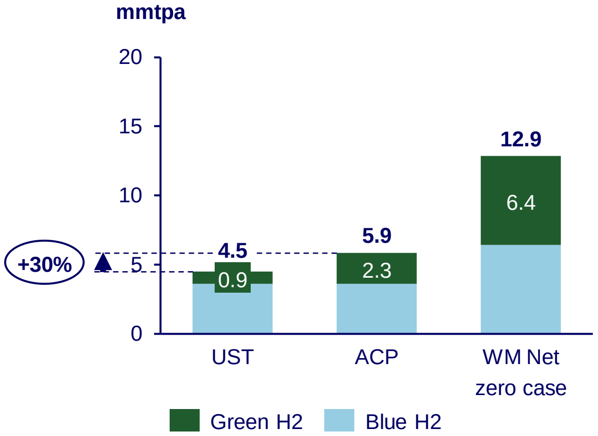
The deployment of blue H_2 increases under the UST guidelines to fill in for lost green H_2

2028 US low-carbon H_2 supply by type under ACP vs UST scenarios



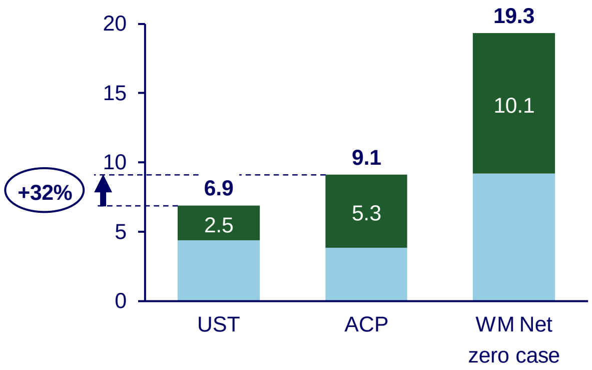
Extending the timeframe for annual match eligibility could drive a 44% increase in green hydrogen in 2028 (0.7 mmtpa vs. 0.2 mmtpa)

2032 US low-carbon H_2 supply by type under ACP vs UST scenarios



In 2032, an annual match regime could drive 2.3 mmtpa of green hydrogen as opposed to 0.9 mmtpa

2035 US low-carbon H_2 supply by type under ACP vs UST scenarios



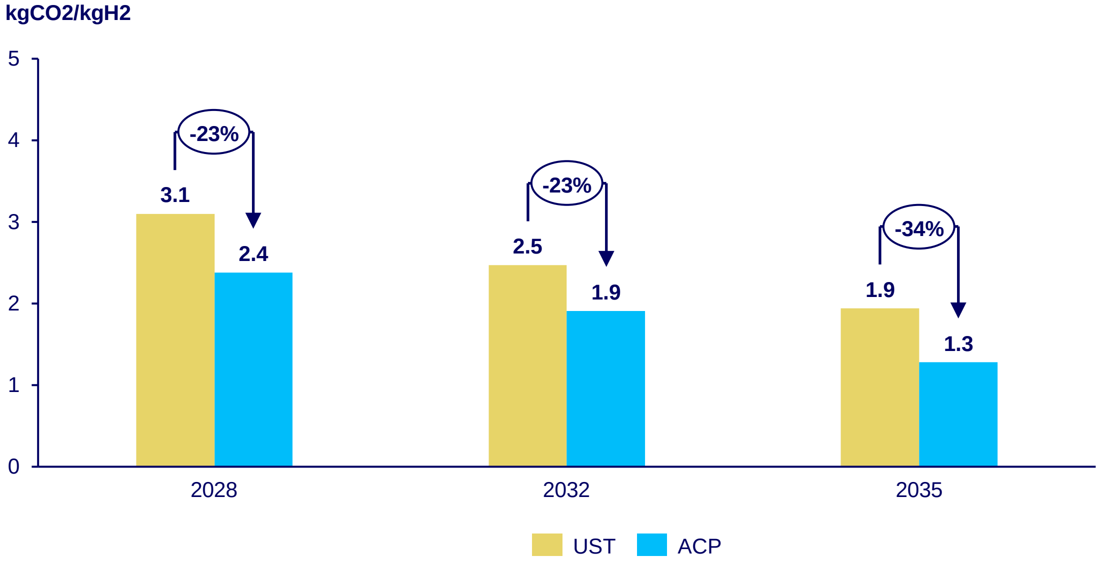
- Under the ACP proposal, green H_2 surpasses 5 mmtpa
- In the UST scenario, green H_2 costs stay higher for longer, stagnating deployment and widening the gap. Blue H_2 supply, on the other hand, resumes deployment growth in the mid-2030s to fill the demand gap from the subdued green H_2 deployment

Note: The "green H_2" mentioned in this slide refers to all electrolytic hydrogen (both green and pink H_2), whereas "blue H_2" refers to both blue and turquoise H2

Source: Wood Mackenzie

Higher green H_2 development under the ACP scenario, results in a lower CI of low-carbon H_2 supply

Carbon intensity of US low-carbon H_2 supply under UST vs ACP scenario



- Wood Mackenzie's low-carbon H_2 carbon intensity (CI) analysis focuses on how the green vs. blue H_2 evolution will impact decarbonization. The analysis is done by evaluating the average of green and blue H_2 CI, weighted by their respective deployment levels
- Blue H_2 CI is estimated based on a lifecycle emissions analysis of the natural gas value chain inclusive of CO_2 and CH_4, while green H_2 CI has zero CI:
  - For UST scenario, H_2 production results in zero CI
  - For ACP scenario, H_2 production uses annual RECs from dedicated renewables assets (incrementality pillar) to match grid power requirements, where the grid CI is above zero[1]
- The ACP scenario anticipates higher green H_2 deployment, which contributes to the 20-35% CI reduction in the ACP scenario compared to the UST scenario, and the gap widens in the later years

1. Although the current policy guidance lacks detail on this mechanism, developing a demand-agnostic carbon matching scheme is critical to ensure new electricity loads are served by renewable energy, supporting a broader decarbonization strategy

Note: The "green H_2" mentioned in this slide refers to all electrolytic hydrogen (both green and pink H_2), whereas "blue H_2" refers to both blue and turquoise H2. All green H_2 analysis in this study assumes green H_2 production to receive the full 45V tax credits (\$3/kgH_2) by having <0.45kgCO2/kgH2 of carbon intensity.

Source: Wood Mackenzie

Key conclusions

Market Takeaways

- Green H_2 is critical to meeting **US decarbonization goals**
- However, as a new energy market, getting it off the ground is challenging. Historically, new energy markets have taken **30-50 years** to develop and decades of policy support
- **The IRA 45V production tax credit** incentivizes **low-carbon hydrogen development** (low CI H_2) and potentially **enables the green H_2 industry to scale**
- However, the **US Treasury guidelines** for 45V implementation **create hurdles for the growth of the green H_2 industry**

US Treasury Guidance

- US Treasury guidance **does not provide adequate support** to help green H_2 move towards its tipping point
- Having **an hourly matching market mechanism** starting in 2028 leads to **low capacity factors**, which results in:
  - **Higher unit costs** due to less production to amortize the costs on
  - **Stagnation of deployment** caused by higher costs, creating barriers for many new entrants
  - **Increased carbon intensity**, resulting from greater blue H_2 supply filling in for lost green H_2

ACP Proposal

- **ACP proposed an alternative** to US Treasury Guidelines, which **delays the hourly matching requirement** to support green H_2 as the market is activated
- Based on Wood Mackenzie analysis in ERCOT and CAISO, extending annual matching has the following benefits:
  - **20-30% Cost reduction** to end-use consumers
  - **Viability** for many green H_2 projects, **doubling green H_2 supply** by 2035
  - **Lower carbon intensity** of low-carbon H_2, with over 30% CI reduction vs UST scenario less by 2035

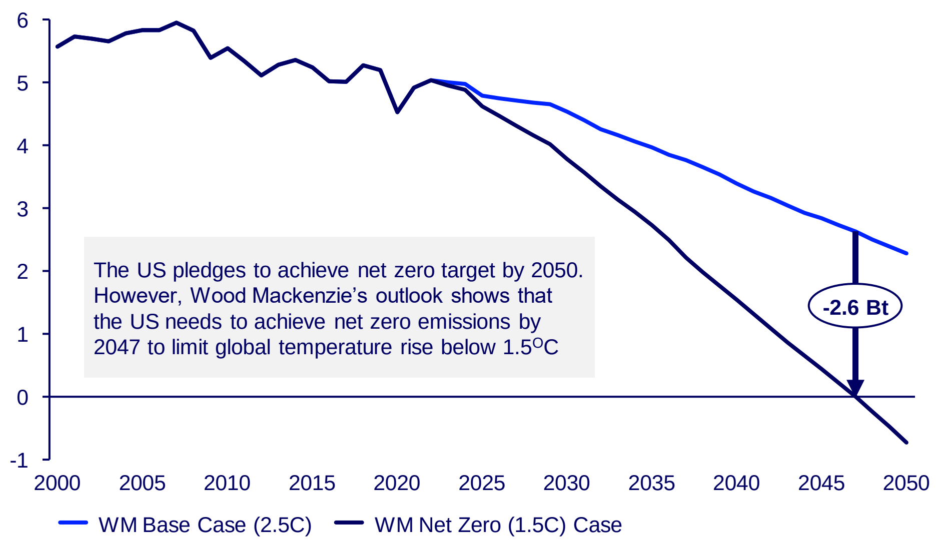
Section 2

Hydrogen's role in supporting US net zero ambitions

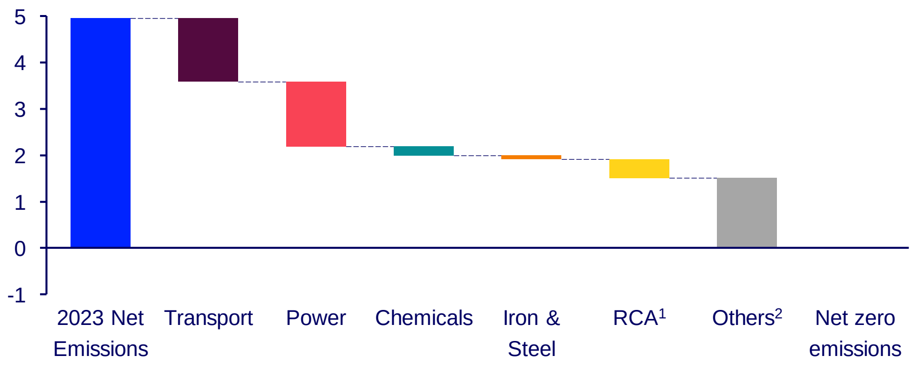
The US must accelerate decarbonization to meet targets for a 1.5ºC warming trajectory

Low-carbon hydrogen will play an important role by targeting hard-to-decarbonize sectors and sub-sectors

Wood Mackenzie CO_2 emissions outlook



Wood Mackenzie US carbon emissions by sector and H_2 role in decarbonizing US economy



	Transport	Power	Chemicals	Iron & Steel	RCA[1]	Others[2]
H_2 use case	Potential clean fuel for heavy-duty transports, such as marine and aviation	Potential use in dispatchable power plants (co-fire with gas/coal) and energy storage	Ammonia and methanol feedstocks, as well as reactant in refining process	Coke replacement in the blast furnace and heat source for producing direct reduced iron	Potential hydrogen boilers for district heating	Potential heat source for high-heating manufacturing, such as cement, ceramics, and glass

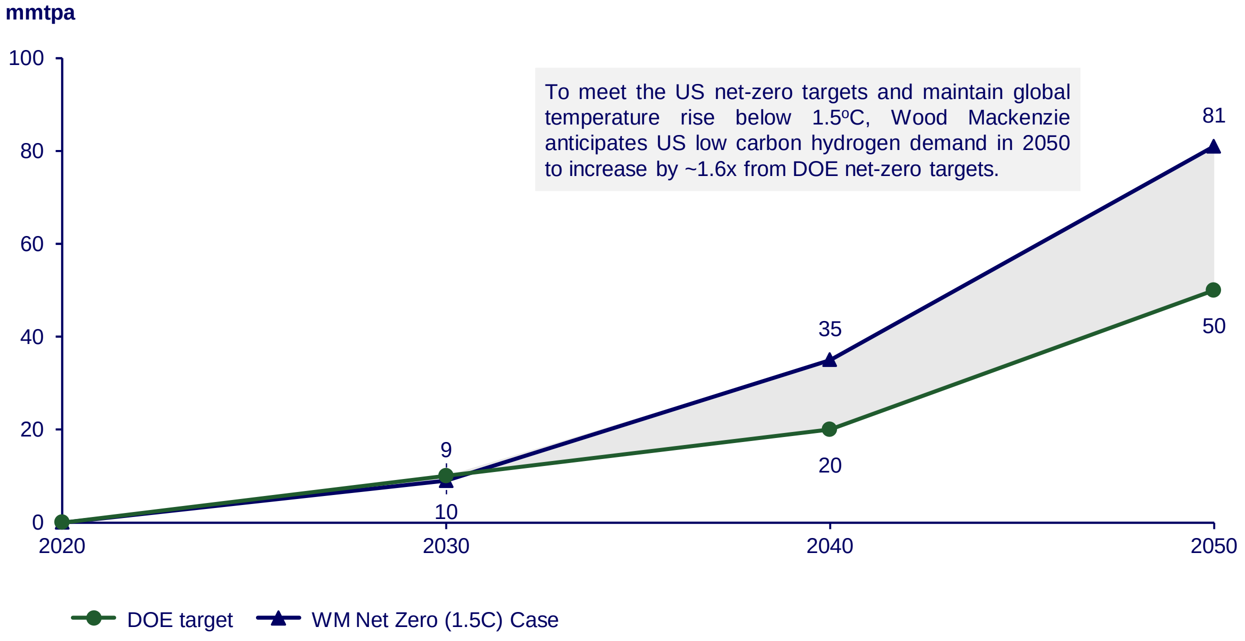
Note: 1. Others include cement, glass, ceramics, semiconductors, polysilicon, food hydrogenation, and various applications, as well as emissions from energy losses and gains during the transportation process; 2. RCA: residential, commercial, and agriculture
Low-carbon hydrogen primarily considers green and blue hydrogen, but includes other innovative technologies
Source: Wood Mackenzie Energy Transition Service

Wood Mackenzie

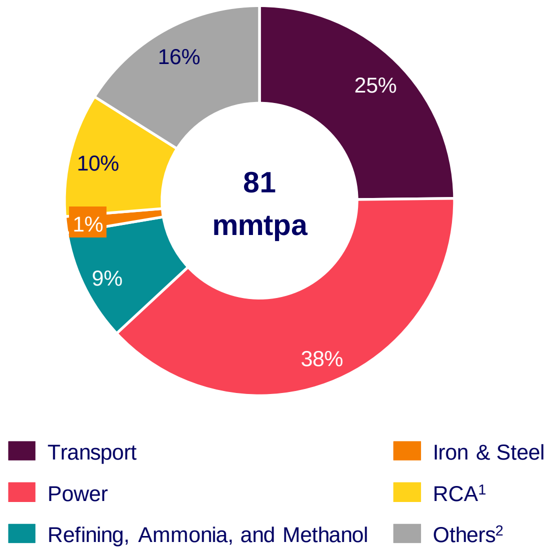
To reach net-zero, the US requires 50-80 mmtpa of low-carbon H_2 adoption by 2050

Domestic low-carbon hydrogen adoption is expected to occur most quickly in existing applications; long-term growth is driven by power, mobility, and high-heat applications

Wood Mackenzie US hydrogen demand outlook (net-zero case) vs DOE target



2050 WM net-zero hydrogen demand by sector

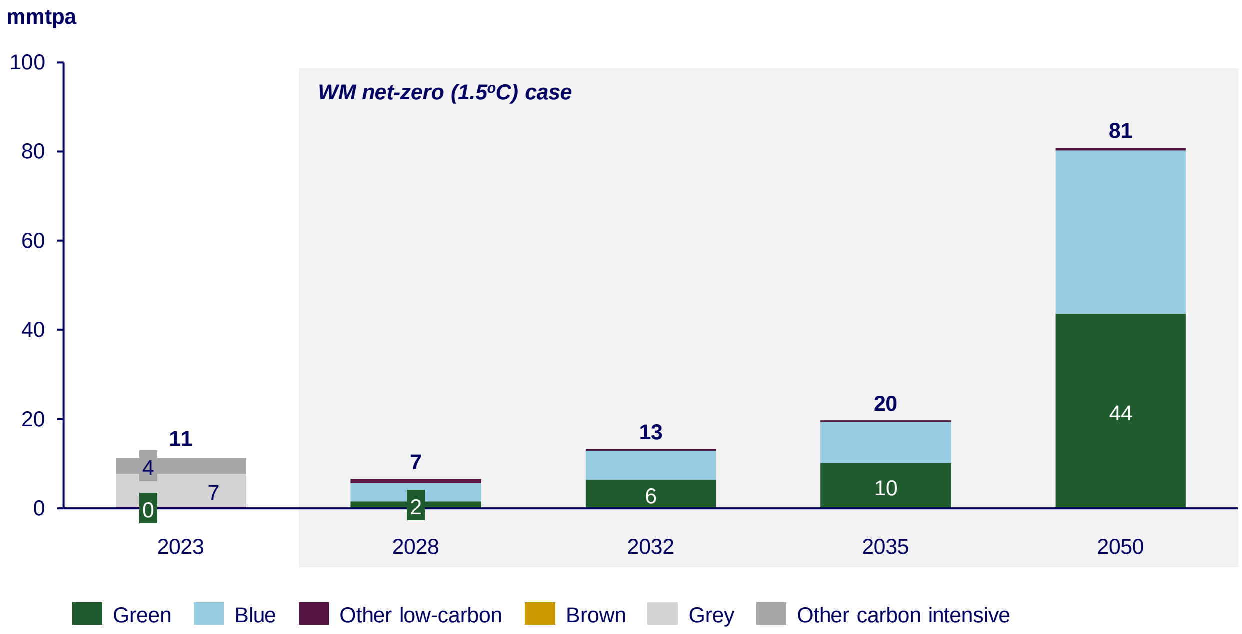


1. RCA: residential, commercial, and agriculture; 2. Others include cement, glass, ceramics, semiconductors, polysilicon, food hydrogenation, and various applications, as well as losses and gains during transportation process
Source: Wood Mackenzie Energy Transition Service

Green hydrogen must be deployed at scale to achieve net-zero ambitions

New energy markets have typically taken 30-50 years to scale, action is needed today to support the industry

Wood Mackenzie US low carbon hydrogen production[1] by type



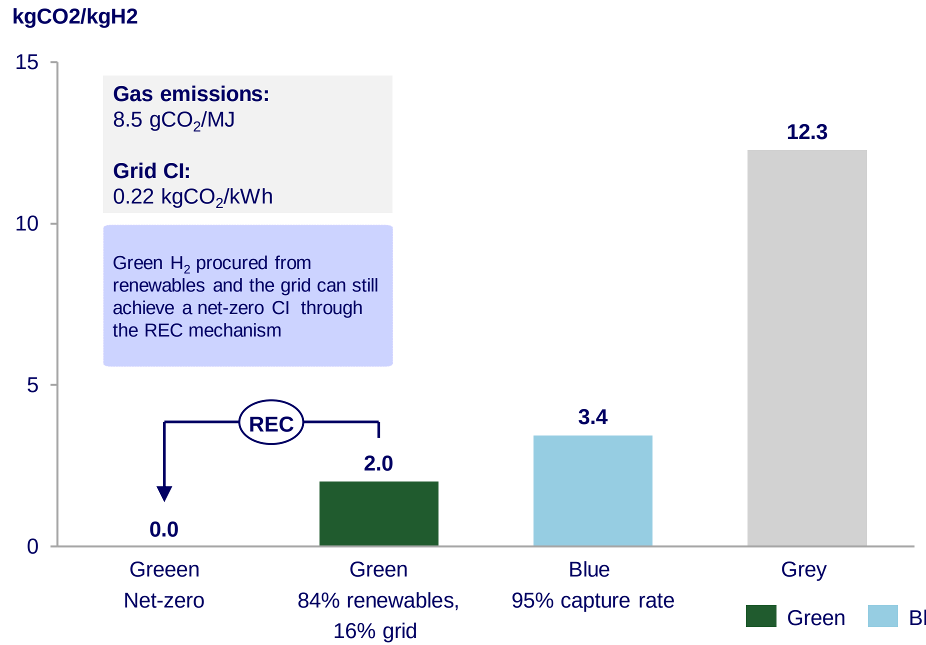
- Wood Mackenzie's net-zero (1.5ºC warming) case estimates that roughly 80 mmtpa of low-carbon hydrogen will be needed in the U.S. to meet 2050 net-zero target
- To get to 80 mmtpa of low-carbon hydrogen by 2050, ~20 mmtpa must be deployed by 2035
- Current investment trends are not enough to achieve net-zero. There are 134 announced projects trying to achieve commercial operation date (COD), reflecting 17.2 mmtpa of capacity and an estimated investment of US$70 billion.
- Green hydrogen plays a key role in the U.S. decarbonization journey, reflecting ~55% (44 mmtpa) of low-carbon hydrogen supply by 2050
- Meaningful policy intervention is needed to scale the market from virtually zero

1. Hydrogen production only includes domestic production catered for domestic consumption and excludes supply for exports.
Note: Wood Mackenzie's net zero case outlook considers only low carbon hydrogen supply will meet the incremental demand from the rapid decarbonization effort
Source: Wood Mackenzie Lens Hydrogen, Energy Transition Service

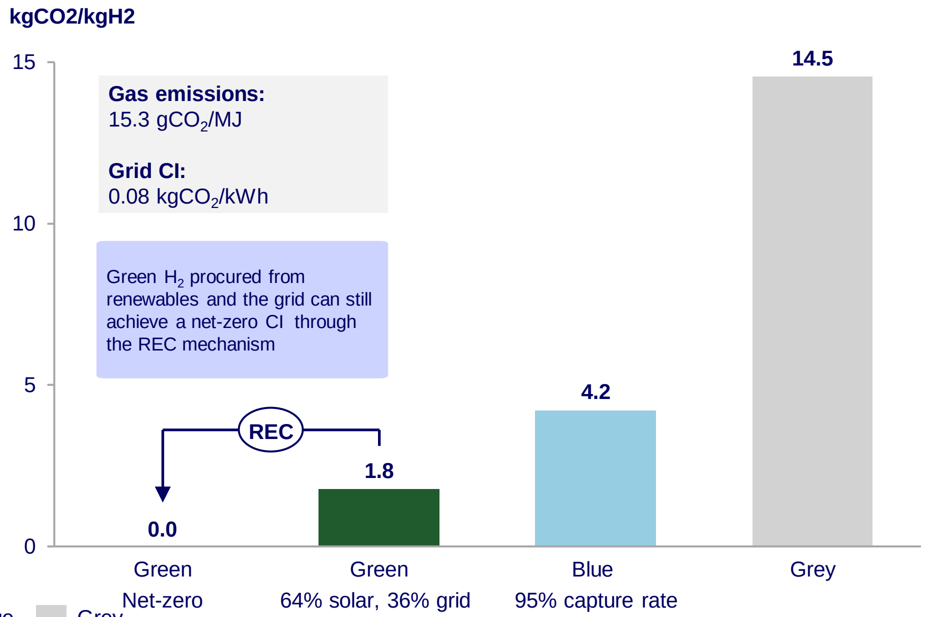
The lower carbon intensity of green hydrogen will support a lower CI hydrogen supply mix in support of net-zero ambitions

Green H_2 power procurement strategy is crucial to ensure effective emission reduction impact

Texas hydrogen carbon intensity profile in 2030



California hydrogen carbon intensity profile in 2030



Note: carbon intensity profile is estimated based on PEM electrolyser for green hydrogen and ATR (with 1% methane leakage) for blue and grey hydrogen.
REC: Renewable Electricity Credit
Source: Wood Mackenzie Hydrogen Service, Wood Mackenzie Power Service

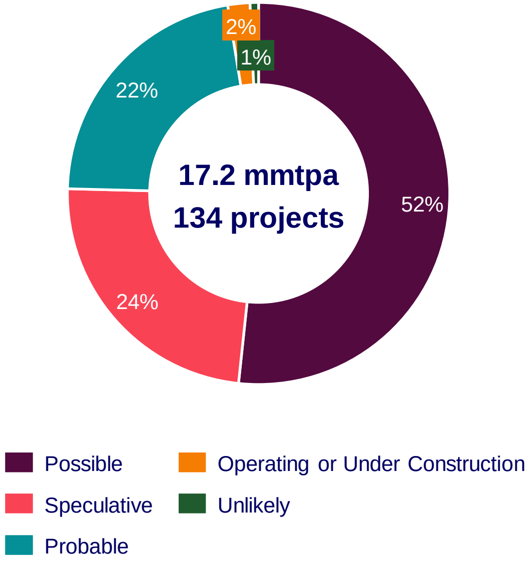
Section 3

Low carbon hydrogen market context and key challenges

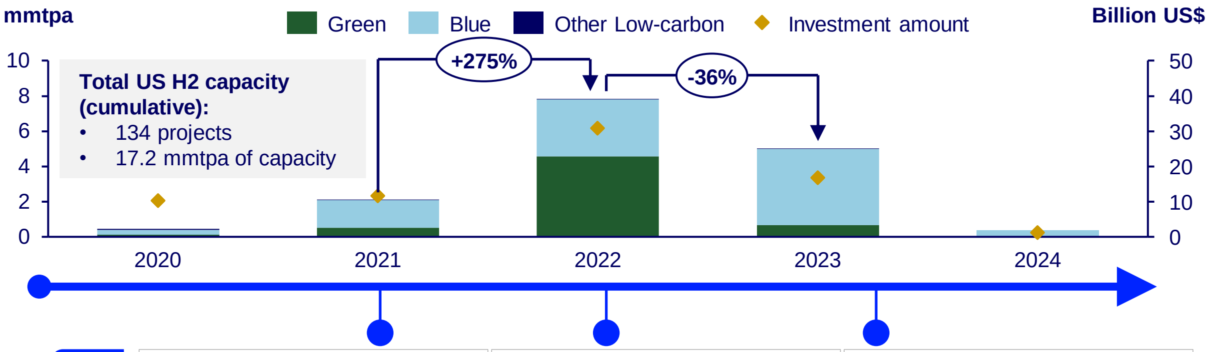
Post-IRA, the U.S. has positioned itself as a leader in terms of project announcements

>17.2 mmtpa of low-carbon hydrogen projects in the US have been announced, totaling ~US$70B in investment

US low-carbon hydrogen project announcements by WM likelihood



US low-carbon project announcements by announcement year

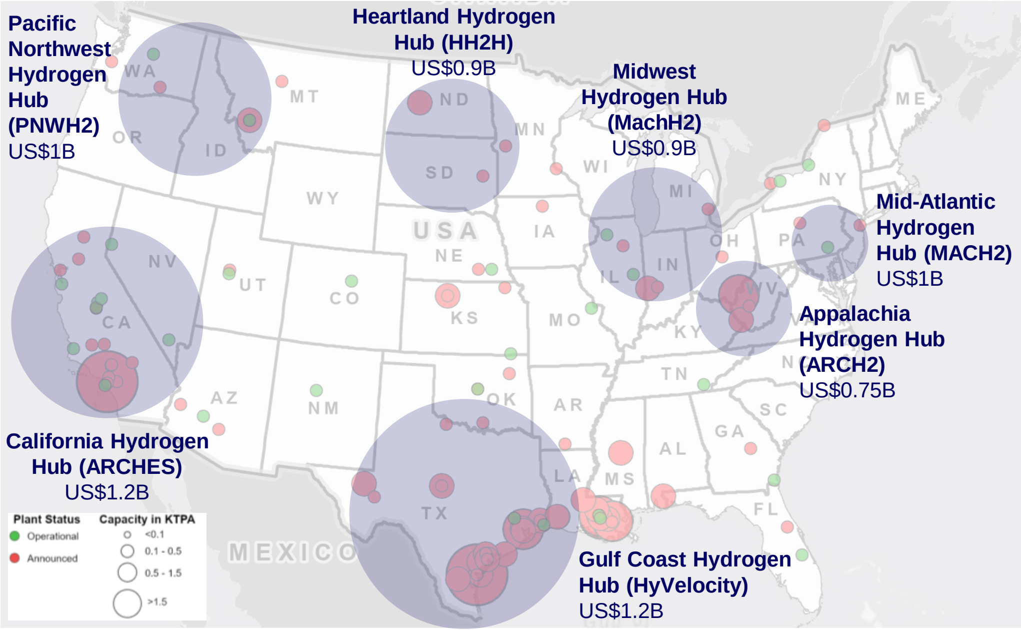


	2021	2022	2023
Key reforms	June 2021: **DOE's Hydrogen Shot** launched October 2021: Build Back Better Act (BBB) introduced and includes a Clean Hydrogen Tax Credit, but turned down by Senate in Dec 2021 November 2021: **Bipartisan Infrastructure Law** (BIL) passed	August 2022: Inflation Reduction Act (IRA) introduced to Senate as an amendment to the BBB August 2022: IRA signed, implementing the Clean Hydrogen Production Tax Credit 45V (PTC)	December 2023: **IRA guidance** released, imposing hourly matching rules on hydrogen projects in 2028
Impact	**BIL** and anticipation of a BBB amendment in 2022 spurred tremendous green hydrogen project announcements in Q1 2022, 3.8 mmtpa capacity was announced	Major IOCs announced substantial blue hydrogen projects to capitalize on IRA 45V and 45Q opportunities	Green hydrogen projects experience significant challenges, as doubt surrounds the 45V guidance

DOE Hydrogen Hub funding could further accelerate low-carbon hydrogen deployment

Cost sharing ranging from $0.75-1.2 billion provides additional support for larger scale project deployment

Map of hydrogen hubs and DOE funding



Key drivers for scaling low-carbon hydrogen deployment

Feedstock Resourcing	Access to a reliable and cost-effective feedstock for hydrogen production, such as renewables, natural gas, and water.
Infrastructure Access	Availability and suitability of facilities to support the production, storage, transportation, and distribution of low-carbon hydrogen.
Policy and Regulations	State-level policies or planned guidelines that support the growth and implementation of low-carbon hydrogen.
Demand Market Access	Availability and potential access to existing and emerging hydrogen demand markets.

The low-carbon H_2 industry is nascent and needs to overcome challenges to scale

Project Development Challenges

Feedstock Sourcing
Complex sourcing strategies are needed to source reliable, low CI, and low-cost renewables or natural gas for sustaining continuous commercial operations at a competitive cost

Policy / Regulatory Guidance
Despite the momentum of 45V PTC and BIL, stringent regulatory requirements may deter first movers from scale-up operations, impeding growth potential and keeping costs higher for longer

EPC / Supply Chain / Technology
Clean hydrogen production technology and supply chain have yet to achieve commercial maturity to fully achieve large-scale production

Project Bankability / Financing Progress
High capital costs, uncertain future revenue streams, technical risk, and uncertainty around 45V eligibility create a high-risk profile, limiting investor interest and capability

Market Access and Delivery
Lack of existing and emerging demand markets, as well as limited infrastructure for connecting production to demand centers

Marketing Progress (Offtakers & Revenues)
Hydrogen producers face challenges securing offtakers with sufficient demand who are willing to sign long-term contracts for costly low-carbon hydrogen

Wood Mackenzie Source: Wood Mackenzie

Those challenges are significantly heightened for green hydrogen projects

Which must reflect > 50% of U.S. hydrogen supply by 2050 to achieve decarbonization targets

	Key challenges for Green Hydrogen	Key challenges for Blue Hydrogen
Feedstock Sourcing	▪ Developers encounter challenges securing reliable green electricity to run electrolyzers at high-capacity factors. ▪ Green H_2 projects may be exposed to higher industrial power prices and incur additional network and REC costs when procuring from the grid	▪ Developers need to adopt new bilateral sourcing strategies with gas producers, as opposed to regular grid gas purchases, to secure low-carbon gas procurement and maximize 45V tax credit benefits
EPC/ Technology	▪ Limited electrolyzer manufacturing capacity in the US and globally ▪ Only a few EPCs can develop large-scale facilities, and the costs are considerably higher than initially predicted ▪ Electrolyzer vendors are hesitant to guarantee performance	▪ Supply chain more optimized for both ATR and SMR technology ▪ Uncertainty around how high capture rates (90%+) can be guaranteed in large-scale facilities
Market Access and Delivery	▪ Substantial infrastructure development is required to connect renewable resources and hydrogen facilities, from facilities to demand centers ▪ Demand markets depend on hydrogen vectors dominating global trade	▪ Benefit from access to gas pipelines near demand hubs, reducing the need for midstream infrastructure to access demand markets ▪ Projects will require access to CO_2 transmission pipelines and storage
Marketing	▪ Lack of credible offtakers to agree on firm, long-term commitment due to pricing uncertainty	▪ Minimum constraints to secure industrial offtakers via integrated or merchant models due to ability to achieve economics at parity with grey hydrogen ▪ Uncertain export market potential due to varying low-carbon hydrogen requirements in other markets
Financing	▪ High project risk profiles limit financing interest and availability ▪ Limited opportunities for vertical-integration to lower project risks ▪ Project bankability is compromised by the lack of firm offtake commitments for 60-70% of capacity	▪ More complex financing when projects involved nascent CCS technologies with high capture rates ▪ Export projects able to come to market faster and before more stringent regulations are applied
Policy/ Regulatory	▪ 45V guidelines uncertainty impedes developers from setting feedstock sourcing strategies and attracting offtakers	▪ 45V guidance on carbon intensity measurements enables developers to certify lower emissions or offset with renewable natural gas ▪ 45Q also offers significant support, with no CI restrictions and with a longer timeline compared to 45V

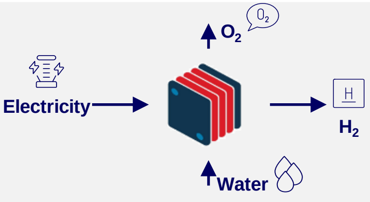
Source: Wood Mackenzie

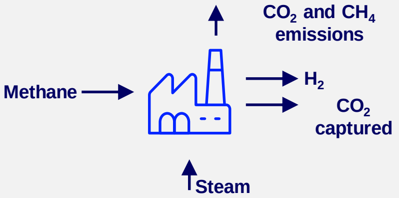
Impact to project completion: *Low* *Moderate* *High*

Scalability of green H_2 projects is key to meeting ambitious deployment requirements

But green project scale requires more innovation and time to compete with blue projects

	Green hydrogen	Blue hydrogen
Technology description	**Rediscovery of an old technology** The process splits water into H_2 and O_2 by using electricity. Chlor-alkali electrolysis has been the leading commercial technology, but new technologies (PEM, ALK, and SOEC) have recently emerged as more efficient alternatives	**Mature carbon intensive technologies** Steam-methane reforming (SMR) or autothermal reforming (ATR) generates H_2 from natural gas, employing carbon capture and storage (CCS) technology to cut CO_2 emissions. Current blue H_2 units capture less than 50% CO_2. Even with a 90% CO_2 capture rate, blue H_2 still emits 1.2-3.9kgCO_2/ kgH_2
(*)2030 US deployment	At current individual project size and H_2 capacity factor of **65- 100%** → **80-300 projects** → **1.1-3.5 mmtpa**	At current individual project size and H_2 capacity factor of **100%** → **14-18 projects** → **3-4 mmtpa**
World Scale Individual project size	**Current:** 100 MW, 26-40 tpd, **0.01 mmtpa** → **Long term:** 5 GW, 1300-2000 tpd, **0.5-0.7mmtpa**	**Current:** 250 MMscfd, 600 tpd, **0.2 mmtpa** → **Long term:** 750 MMscfd, 1800 tpd, **0.6 mmtpa**
Midstream	100-500 miles To access low-cost renewables 20-25% production To provide consistent supply	<50 miles Developed proximate to demand hubs Little storage is needed due to scale and capacity factor





Key findings

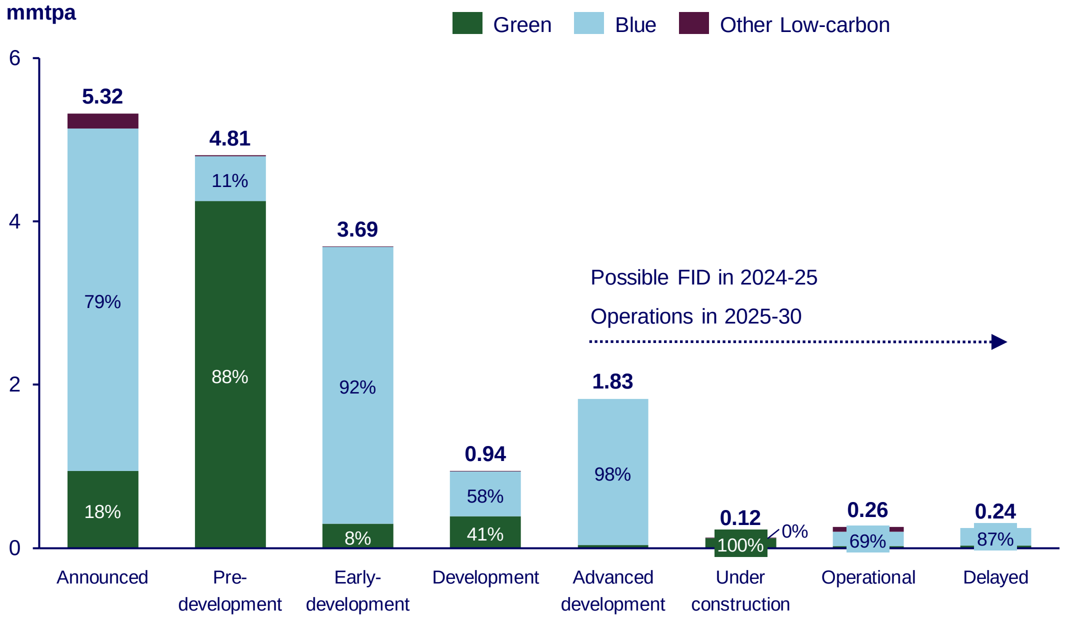
- Green hydrogen projects are starting at a much smaller scale of supply, requiring more innovation and time to achieve economies of scale
- More storage and pipeline development is needed for green hydrogen to connect low-cost supply to demand
- Blue hydrogen utilizes mature technology, but the development of CCS equipment with high capture rates is still at an early stage
- Blue hydrogen individual projects are significantly larger from the outset, leading to rapid economies of scale

Note: (*) US deployment is assuming 2030 WM Base Case and Net-Zero (1.5ºC) Case
Source Wood Mackenzie

Lack of cost competitiveness limits green H_2 commercialization and deployment…

Only 5% of projects likely to take FID in the next 2 years will be green hydrogen projects

US low carbon hydrogen project announcements by status



Over 95% of low-carbon hydrogen project capacities have yet to achieve commercial operations

- 27 projects are currently operational and contribute 0.26 mmtpa of capacity
- 9 projects are under construction and will potentially come online before 2028, but only account for 0.12 mmtpa of capacity
- 80+ projects are still progressing to achieve FID, reflecting 15.75 mmtpa capacity
- 4 projects are delayed or cancelled, totaling 0.24 mmtpa capacity

Blue hydrogen projects are advancing faster than green hydrogen projects

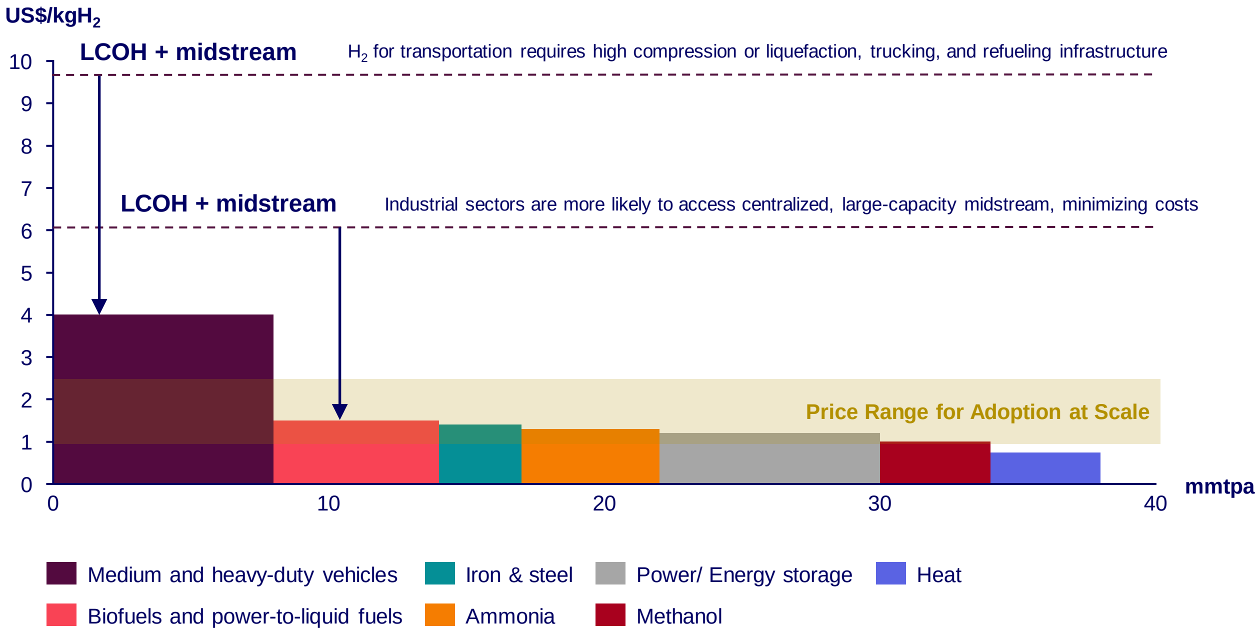
- Green hydrogen projects face major barriers to completion due to strict PTC guidance, alongside persistent challenges related to EPC, offtake agreements and financing
- Meanwhile, blue hydrogen projects leverage declining gas prices and supportive policies to enhance economic viability and progress

Source: Wood Mackenzie Lens Hydrogen

…which in turn limits economies of scale required to reduce costs and drive adoption

Green H_2 economics must fall within $1-2/kg, on a delivered to customer basis, to encourage adoption at scale

Potential low-carbon H_2 demand sectors and corresponding price range for adoption at scale



- H_2 price range of adoption at scale for each demand sector represents the price at which end-users are willing to adopt hydrogen in their operations
- Green H_2 production costs could be competitive in the medium and heavy-duty vehicle sectors compared to other competing fuels, such as electricity and petroleum derivatives. However, it becomes less competitive when factoring in the costs of compression/liquefaction and trucking to the end user
- Other sectors, including biofuels, ammonia, and power, currently consume cheap fossil feedstocks, so green H_2 must be low cost to be competitive. Large-scale consumers benefit from the ability to access feedstock supplies via lower cost high-capacity delivery infrastructure
- The 45V incentive could bring green H_2 cost closer to the Hydrogen Shot's goal and boost green H_2 demand creation, yet strict guidelines may prolong high costs, risking adoption and future deployment

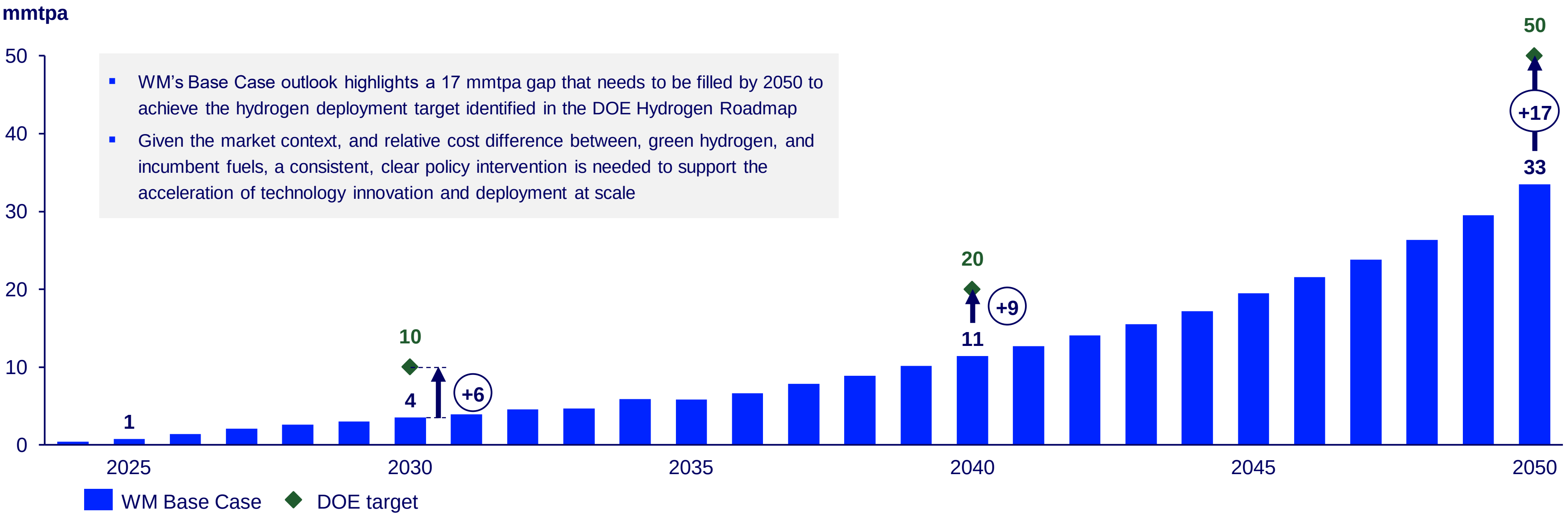
Source: Department of Energy, Wood Mackenzie

Without near-term support low-carbon hydrogen deployment will be delayed long-term

Despite momentum, US LCI H_2 adoption is falling short of DOE targets, strict guidelines will impede further deployment

US low-carbon hydrogen supply outlook vs DOE H2 roadmap

- WM's Base Case outlook highlights a 17 mmtpa gap that needs to be filled by 2050 to achieve the hydrogen deployment target identified in the DOE Hydrogen Roadmap
- Given the market context, and relative cost difference between, green hydrogen, and incumbent fuels, a consistent, clear policy intervention is needed to support the acceleration of technology innovation and deployment at scale



Source: Wood Mackenzie Lens Hydrogen, Department of Energy

Section 4

IRA 45V tax credit potential to catalyze hydrogen industry

The 45V PTC aims to catalyze the nascent low-carbon hydrogen industry

The objective of the 45V is to enable the nascent green H_2 industry to scale in support of wider decarbonization

IRA Low-carbon Hydrogen Production Tax Credit (45V)

Key Questions	Answer
What is the 45V?	▪ The 45V production tax credit (PTC) generates a tax credit for each kilogram of clean hydrogen produced after 2022 for ten years starting at the commercial operations date (COD)
How does it work?	▪ A two-tiered tax credit system is applied to 45V: – Up to $3.00/kg of production tax credits (PTC) for qualified clean hydrogen production, assuming producers satisfy applicable wage and apprenticeship requirements – Credit value for each facility is adjusted by the lifecycle GHG emissions as determined by the GREET model[1]
Who will benefit from 45V?	▪ Clean hydrogen developers and producers benefit from the PTC, which makes their low-carbon supply competitive against traditional, carbon-intensive hydrogen derived from fossil fuels and incumbent fossil fuel energy sources
Which H_2 assets are qualified for 45V?	▪ All hydrogen facilities that meet the following criteria: (1) located in the US, and; (2) owned by US taxpayer entity
When does the 45V end?	▪ January 1st, 2033: New projects will be eligible to receive the 10-year PTC if construction starts before December 31st, 2032 (i.e. PTC ends after December 31st, 2042)

Why is it important for the H_2 industry?

- The 45V is expected **to improve low-carbon hydrogen production economics** and drive investment to scale up clean hydrogen supply, which is currently deployed at a negligible scale and is less economically competitive than carbon-intensive hydrogen production and fossil fuel energy sources.
- Green hydrogen supply, incentivized by 45V, is expected to increasingly carve **decarbonization pathways for hard-to-decarbonize sectors**, such as refinery chemicals, high-heat energy-intensive industries, and transportation.

Wood Mackenzie

1. Greenhouse Gases, Regulated Emissions, and Energy use in Transportation model developed by the Argonne National Laboratory; the PTC can range from $0.60/kg to $3.00/kg, depending on the level of lifecycle emissions; a level of 0.45 $kgCO_2/kgH_2$ is required for the $3.00/kg PTC that we are assuming

Source: Wood Mackenzie, IRA

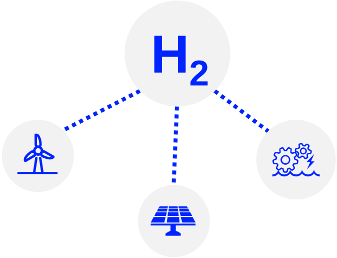
However, proposed guidelines create hurdles for green H_2 economics & deployment

The transition to hourly match in 2028 likely comes before challenges for green H_2 can be overcome

Treasury-issued Guidelines – *Awaiting Comments*

Rationale

Ensuring green H_2 projects source electricity from renewables projects built for them



Pillar	Description	Key Challenge for H_2
Temporality	Annual matching is initially allowed, but all projects must shift to **hourly matching starting in 2028**	Hourly matching typically results in electrolyzers running at low capacity factors, resulting in higher LCOH
Incrementality	Clean power must be sourced from generators coming online no earlier than 3 years of H_2 facilities' COD	Potential H_2 project delays due to bottlenecks (e.g. interconnection queue, supply chain issue, costs, etc.) in developing renewables assets linked to the project
Deliverability	H_2 producers must source power from within 1 of the 15 regions in the DOE's National Transmission Needs	Potential H2 project delays due to having to ensure interregional transfers when there is physical delivery between them

Expected Outcomes

- LCOH is expected to increase ↑
- Green hydrogen deployment and adoption is expected to fall below DOE targets ↓
- Carbon intensity of hydrogen supply is expected to increase ↑

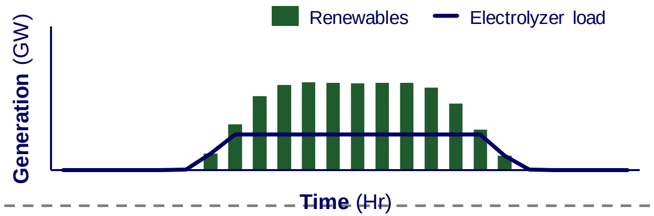
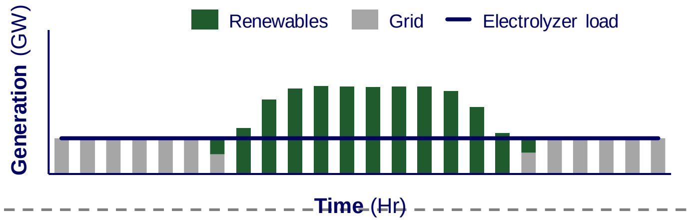
Note: The 45V production tax credit (PTC) generates a tax credit for each kilogram of clean hydrogen produced after 2022 for ten years starting at the commercial operations date (COD); it can amount to up to $3.00/kg for qualified clean hydrogen production

Source: Wood Mackenzie, US Treasury

Hourly match ensures zero CI H_2, but impacts capacity factors (CF) of green H_2 plants

The lower the CF, the higher the cost of hydrogen on a levelized basis due a lower volume of production

H_2 power procurement options to meet 45V CI eligibility (<0.45 $kgCO_2/kgH_2$)

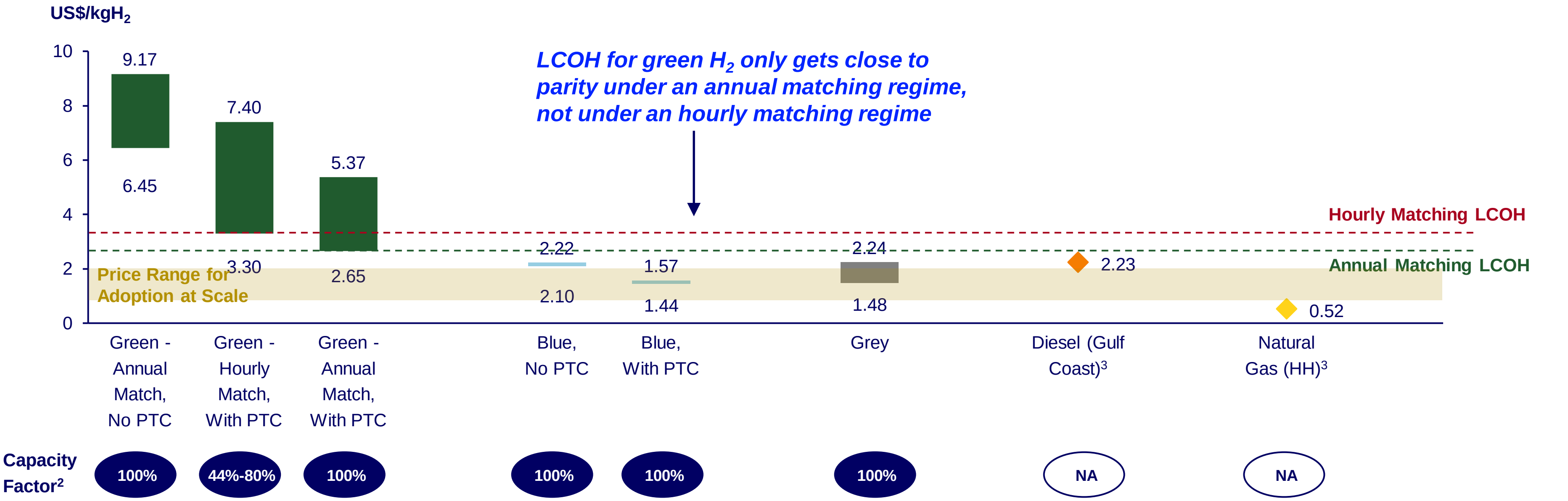
	1 Hourly matching	2 Annual matching
Description	▪ Electrolyzer demand matches the availability of renewable generation on an hourly basis. ▪ H_2 is produced only at times when renewable generation occurs ▪ Today, a Behind-the-meter configuration is the only procurement option available, since an hourly REC mechanism does not yet exist and is unlikely to emerge within this analysis timeframe	▪ Electrolyzer demand is met annually by renewables but needs grid supply to sustain continuous operations ▪ RECs from excess renewables generation account for additional clean MWh to displace grid power requirements in the hours when renewable generation is unavailable
Typical power configuration		
Capacity factor (CF)	**Power supply CF:** 20 – 40% **Electrolyzer CF:** <50%	**Power supply CF:** 100% **Electrolyzer CF:** 90 – 100%
LCOH impact	▪ Lower H_2 production from low CF spurs high LCOH	▪ High H_2 production from high CF helps H_2 producers reduce capital costs, thereby lowering LCOH

Source: Wood Mackenzie

A longer annual match eligibility period supports a higher capacity factor (CF) and lower LCOH during a critical period for growth and innovation

Hourly match requires load following of renewables, limiting project CFs and challenging green H_2 economics

Estimated LCOH range by temporality, fiscal regime and technology[1] (2032 COD)



1. Green LCOH range is based on the electricity cost ranges between ERCOT (low range) and CAISO (high range). Green H_2 refers to solar and wind-based electrolytic H_2, while blue H_2 refers to natural gas-based H_2 with CCS technology; 2. These capacity factors reflect the renewables uptime; 3. kg energy-equivalent of H_2

Note: detailed assumptions for LCOH calculation can be found in the Appendix

Source: Wood Mackenzie

Section 5

ACP and UST proposals and implications

Wood Mackenzie

ACP proposed an alternative to US Treasury Guidelines, which delays the hourly matching requirement, supporting the emergence of new green H_2 projects

ACP proposed changes to the three pillars of the US Treasury Guidelines to 45V

Pillars		US Treasury Guidelines (**UST Scenario**)		ACP Proposal **(ACP Scenario)**	
TEMPORALITY	**Annual Matching**	**Timing:**	Through 2027	**Timing:**	1st 10 years of operation
		Eligibility:	All H_2 facilities	**Eligibility:**	Construction start before 2029, COD before 2033
	Hourly Matching	**Timing:**	2028 & beyond	**Timing:**	2033 & beyond
		Eligibility:	All H_2 facilities	**Eligibility:**	All H_2 facilities except those eligible for annual matching
INCREMENTALITY		Clean power must be sourced from generators coming online no earlier than 3 years of H_2 facilities' COD			
DELIVERABILITY		Electrolyzers and power generation facilities must be in the **same DOE energy region – defined by markets**			

We have focused on the **TEMPORALITY** proposed changes since they have the most material impact on project viability

Source: US Treasury, American Clean Power, Wood Mackenzie

Wood Mackenzie was engaged by ACP to provide independent analysis on 45V and its implications for the green hydrogen industry

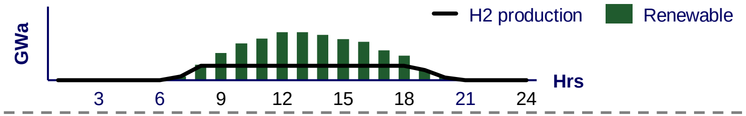
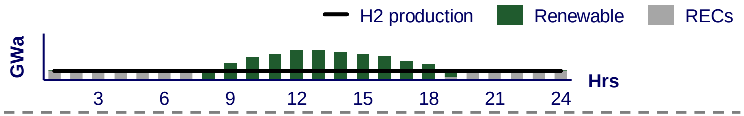
Wood Mackenzie explored the impact of two scenarios on low-carbon H_2 economic, deployment, and emissions

Wood Mackenzie's approach to evaluate UST vs ACP proposals

	Economic	Deployment	Emissions
What did we look at?	Levelized cost of hydrogen (LCOH), which represents breakeven price of a hydrogen production project	The low-carbon H_2 supply mix, which is influenced by demand market exposure, incumbent fuel economics, and competitive positioning of green H_2	Emission impact of the H_2 deployment in proportion to the green and blue contribution to the supply mix
Why it matters?	Provides a view of the H_2 project commercial viability and competitiveness over the project lifetime	Measures potential low-carbon H_2 industry growth	Assesses low-carbon H_2 production's role in meeting US net-zero target
How to understand it?	A lower LCOH is more appealing and attractive to potential investors and end-users	Lower LCOH drives higher deployment, which signals maturity of low-carbon H_2 industry and alignment with DOE target	Lower CI of low-carbon H2 supply supports US decarbonization pathways
Relevant metrics	**LCOH** (US$/kg$H_2$)	**H_2 supply outlook by type** (mmtpa)	**H_2 supply CI** (kgCO_2/kgH_2)

US Treasury's hourly matching rule complicates green H_2 power procurement decisions

Current lack of hourly matching market mechanisms leads to low capacity factors (CF) hurting green H_2 economies, while high CF solutions are yet to emerge

	Hourly Matching Power Procurement		Annual Matching Power Procurement
Example configuration			
Key challenges/ opportunities	▪ Green H_2 production will follow intermittent renewables generation, resulting in a **low capacity factor** leading to **higher LCOH** ▪ Market mechanisms to support hourly matched operations at higher capacity factors **do not yet exist** and face **significant development challenges**		▪ Green H_2 production is sustained at a **high capacity factor** to **reduce LCOH**, allowing green H_2 to achieve economies of scale faster and maximize deployment ▪ Market mechanisms **are in place** to support annual matching

Power sourcing options	**2028 – 2030:**
	▪ **Dedicated renewables assets** through PPAs and adjust green H_2 production to **match renewable profile(s)**
		Post-2030:
		▪ **Dedicated renewable assets** through PPAs
		▪ More sophisticated options to complement renewables procurement could include:
		  ▪ battery storage
		  ▪ grid power + hourly RECs[2] (assume hourly RECs market has been fully developed)
			2028 – 2032:
			▪ **Dedicated renewables assets** through PPAs, complemented with **grid power and annual RECs[1]**

Typical power costs	**Annual average of hourly renewable PPA price:** renewables LCOE[3] + network costs + annual REC	**Annual average of hourly renewable PPA price** and **additional costs** associated with more sophisticated options, which potentially create more complexity in pricing mechanism	**Annual weighted average of grid power and renewable PPA prices:** ▪ **Grid power price**: Wholesale price + network costs *(RECs are bundled into renewable PPA)* ▪ **Renewable PPA price**: Renewables LCOE[3] + network costs + annual REC

1. Annual-matching green H_2 production uses annual RECs from dedicated renewables assets (incrementality pillar) to match grid power requirements, where the grid CI is above zero. Although the current policy guidance lacks detail on this mechanism, developing a demand-agnostic carbon matching scheme is critical to ensure new electricity loads are served by renewable energy, supporting a broader decarbonization strategy; 2. An hourly REC mechanism, which certifies clean energy production for a specific hour, has not yet been developed and would face hurdles, such as limited renewables supply in critical hours due to intermittent generations and the need to implement complex monitoring and tracking systems. In our view, the establishment of a bankable hourly REC market within the timeframe of this analysis would be optimistic. The development of an hourly REC mechanism could be accelerated should sufficient demand from commercial and industrial sectors emerge for hourly mechanisms, likely to be driven by policy support,; 3. LCOE is adjusted with a premium to reflect the lost value of the excess generation.

Note: All green H_2 analysis in this study assumes green H_2 production to receive the full 45V tax credits ($3/kg$H_2$) by having <0.45kg$CO_2$/kg$H_2$ of carbon intensity.

Source: Wood Mackenzie

Wood Mackenzie

The impact of each proposal was evaluated in California and Texas power markets

These markets are located in major US H_2 hubs and reflect over 60% of announced low-carbon H_2 projects

Key assumptions for green H_2 and renewable energy projects in CAISO and ERCOT power markets

California

Power market	CAISO
Zone	SP15
Electrolyzer type and size	PEM | 200 MW

Renewables source

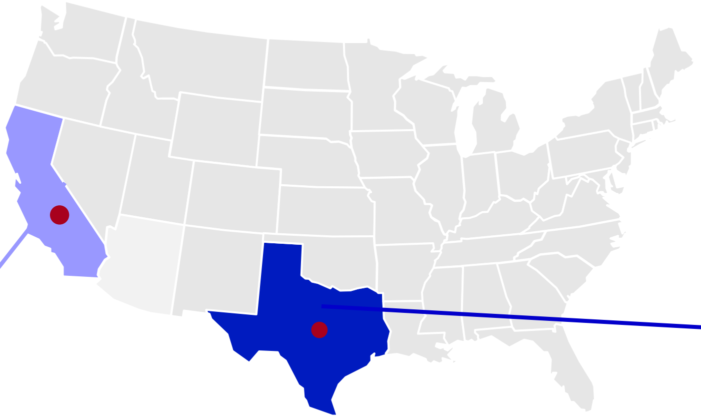
	Solar
Size	810 MW
Overbuild	4.1x
Capacity factor	25%

Power costs (US$/MWh)

	Hourly matching	Annual matching
2028	99.20	136.51
2032	84.35	124.44

Electrolyzer capacity factor (%)

Hourly matching	44%
Annual matching	100%



Wood Mackenzie assumptions

Wood Mackenzie's hourly renewables profiles and renewables capacity overbuild factor were optimized to achieve the highest H_2 capacity factor (CF) in the hourly matching scenario. H_2 producers may deploy different procurement strategies based on commercial decisions, such as choosing a smaller overbuild factor, to balance costs and production, resulting in lower H_2 CF

Texas

Power market	ERCOT
Zone	South
Electrolyzer type and size	PEM | 200 MW

Renewable sources

	Solar	Wind
Size	340 MW	340MW
Overbuild	1.7x	1.7x
Capacity factor	23%	40%

Power costs (US$/MWh)

	Hourly matching	Annual matching
2028	59.47	63.85
2032	60.15	66.78

Electrolyzer capacity factor (%)

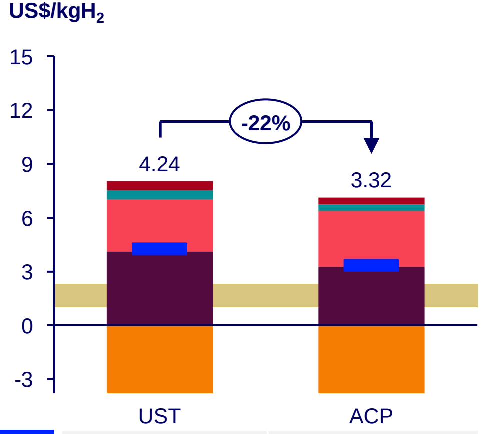
Hourly matching	80%
Annual matching	100%

Source: Wood Mackenzie

In 2028, H2 production costs are still too high to drive adoption in most sectors; annual matching reduces the cost to consumers by 20-30%

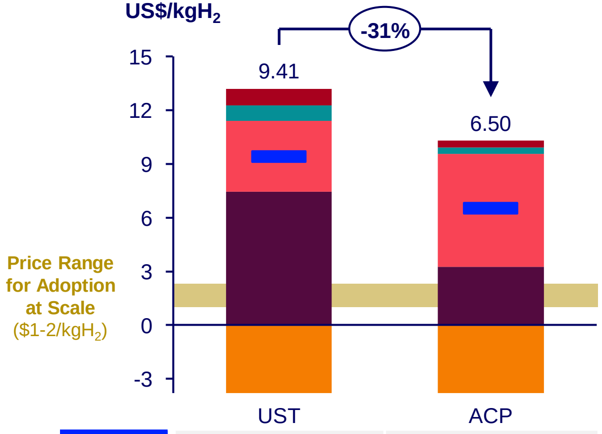
Regions with high quality wind are economically advantaged, but not enough to meet DOE H2 shot goals

2028 ERCOT LCOH under UST vs ACP scenario (post 45V tax credit)



RE overbuild	3.4	3.4
Power config.	Hourly matching	Annual matching
Power cost (US$/MWh)	59.47	63.85
H_2 CF (%)	80%	100%

2028 CAISO LCOH under UST vs ACP scenario (post 45V tax credit)



RE overbuild	4.1	4.1
Power config.	Hourly matching	Annual matching
Power cost (US$/MWh)	99.20	136.51
H_2 CF (%)	44%	100%

CapEx | Electricity Cost | Fixed and Variable OpEx | Financing | Tax Credit | Net LCOH

- In ERCOT, high-quality solar and wind resources and overbuild capacity yield 80% H2 capacity factor (CF) in the UST scenario, narrowing the gap between proposals. This highlights that hourly matching has the least negative consequences only in regions with robust solar and wind resources to support sufficient H2 production
- In CAISO, higher power costs and lower H2 CF drive a significantly higher LCOH compared to the ERCOT LCOH
- Despite substantial LCOH reduction from ACP proposals, the resulting LCOH is 3-6x higher than the DOE's H2 Shot goal of US$1/kg and significantly above the price range for adoption at scale for end-use customers, potentially impeding green H2 adoption

Wood Mackenzie

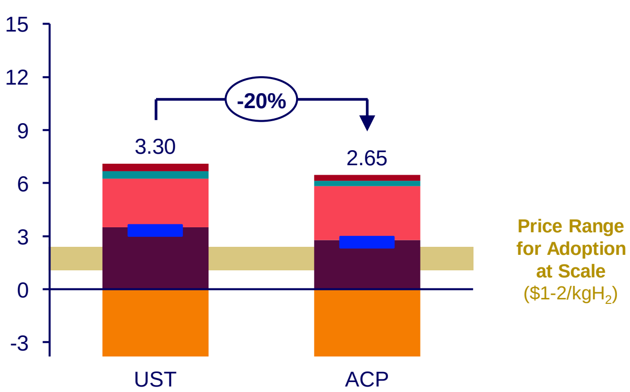
Note: All green H_2 analysis in this study assumes green H_2 production to receive the full 45V tax credits ($3/kgH$_2$) by having <0.45kgCO$_2$/kgH$_2$ of carbon intensity. Detailed assumptions for LCOH calculation can be found in the Appendix

Source: Wood Mackenzie

In 2032, renewable & electrolyzer CapEx reductions lessen the impact of a lower capacity factor; ACP's proposal brings LCOH closer to the price for adoption at scale

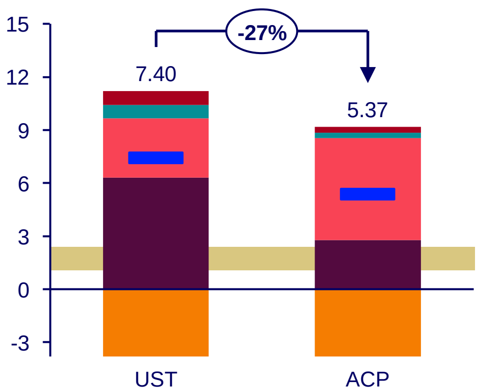
Still, even advantaged renewable resource regions like ERCOT are not able to fall in the $1-2/kg range

2032 ERCOT LCOH under UST vs ACP scenario (post 45V tax credit)



	UST	ACP
RE overbuild	3.4	3.4
Power config.	Hourly matching	Annual matching
Power cost (US$/MWh)	60.15	66.78
H_2 CF (%)	80%	100%

2032 CAISO LCOH under UST vs ACP scenario (post 45V tax credit)



	UST	ACP
RE overbuild	4.1	4.1
Power config.	Hourly matching	Annual matching
Power cost (US$/MWh)	84.35	124.44
H_2 CF	44%	100%

CapEx | Electricity Cost | Fixed and Variable OpEx | Financing | Tax Credit | Net LCOH

- LCOH under the UST hourly match regime has fallen by ~20% in both regions relative to 2028, signaling significant progress
- However, cost reductions are not enough to get into a price range for adoption at scale of US$1-2/kgH2 by 2032 in either scenario, which reflects an inflection point for large-scale green hydrogen adoption
- Annual matching supports lower costs, but the current market context drives a starting point for green H2 LCOH that may require more time or additional support beyond the 45V to achieve production costs needed to drive adoption at-scale

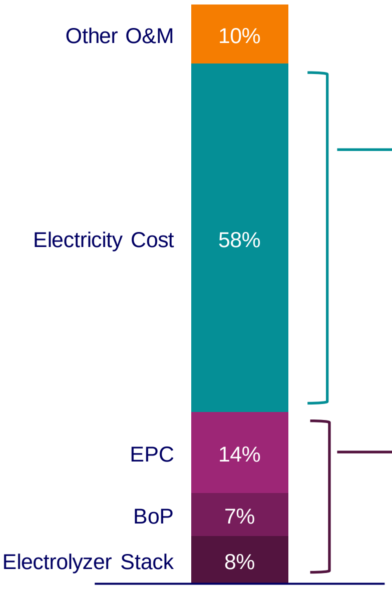
Note: All green H_2 analysis in this study assumes green H_2 production to receive the full 45V tax credits ($3/kg$H_2$) by having <0.45kg$CO_2$/kg$H_2$ of carbon intensity. Detailed assumptions for LCOH calculation can be found in the Appendix
Source: Wood Mackenzie

Renewable power and electrolyzer cost reductions will drive a tipping point for green hydrogen economics in the mid 2030s; ACP's proposal supports this transition

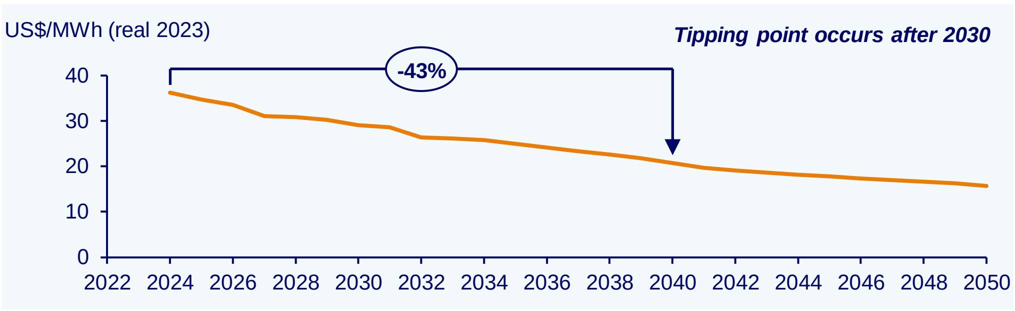
Learning curves, experience curves, and economies of scale will all contribute as markets develops

- LCOH will decline due to lower electricity costs and lower total installed cost (TIC) of electrolyzers
- These cost reductions will continue to be steep during the 2030's

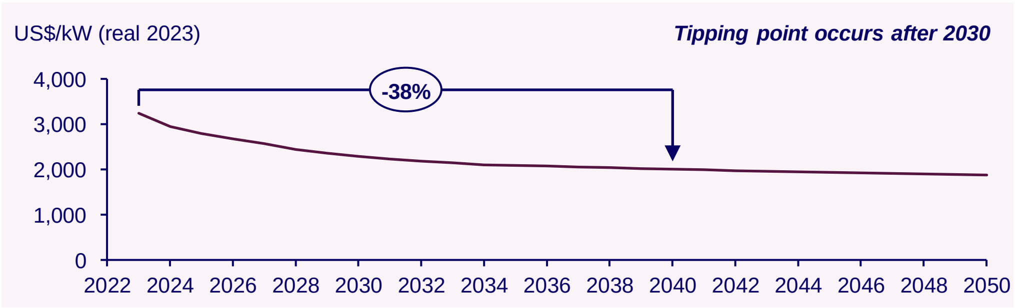
Illustrative LCOH Components (% Share)



Levelized Cost of Electricity (LCOE)[2] for Utility Solar – CA & TX



Projected Total Installed Cost for PEM Electrolyzers



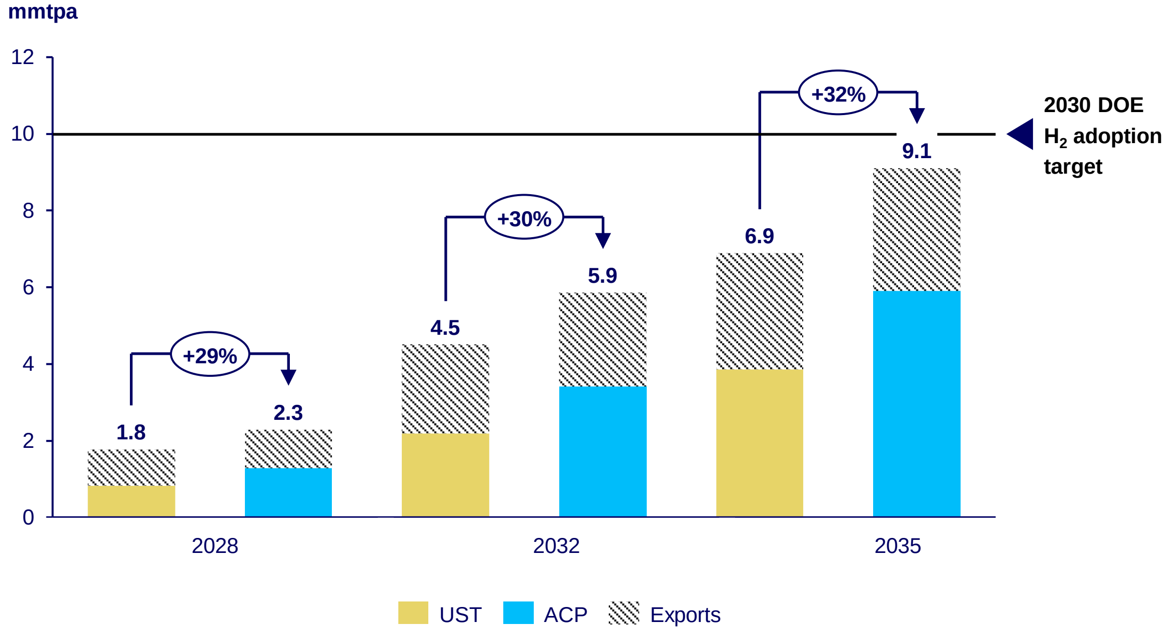
Wood Mackenzie

1.Other components of Capex are EPC, Balance of Plant and Other Capital; 2. LCOE is the levelized cost of energy including fixed and variable costs and tax benefits over the lifetime of a resource; only California and Texas considered; 3. Assumes a 150 MW solar farm
Source: Wood Mackenzie, WM North American Power Service February 2023

Lower LCOH under ACP's proposal drives higher low-carbon H_2 deployment long-term

A more supportive regime through 2032 accelerates deployment required to get closer to net-zero ambitions

US domestic low-carbon H_2 deployment outlook under UST vs ACP scenario



Approach to Deployment Analysis

- Wood Mackenzie evaluated the LCOH impact on low-carbon H_2 demand for 11 end-use applications, by considering the gap to parity with alternative feedstock/energy, alternative decarbonization options, and state and federal decarbonization pressures
- The analysis also considered the risks of higher LCOH on regional project and hub announcements, by evaluating regional energy resource potential and target end-use markets

Findings

- Under current market structures, low-carbon H_2 deployment depends almost entirely on consumers' willingness to adopt H_2 as a lower-carbon feedstock or energy alternative
- Although ACP scenario almost meets the DOE H_2 adoption target, low-carbon H_2 adoption in both scenarios fall short of the 2030 DOE target of 10 mmtpa, as LCOH remains higher than what most end-users are willing to pay
- Domestic adoption is supported by significant export potential in both scenarios, as potential international buyers of U.S. low-carbon hydrogen seek global portfolios that allow them to balance energy security (diversification of supply), with decarbonization pressures, and economics

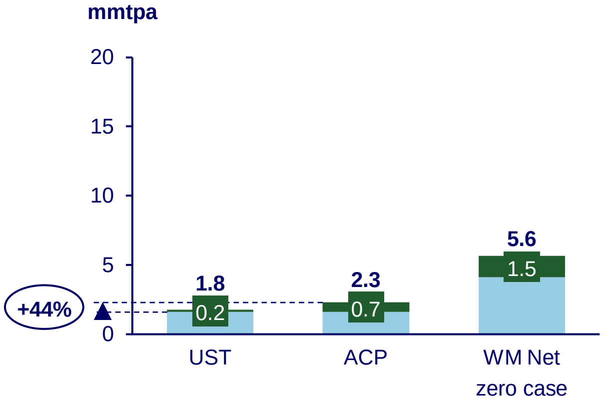
Wood Mackenzie

Source: Wood Mackenzie

Lower LCOH under ACP's proposal drives higher low-carbon H_2 deployment long-term, accelerating the deployment required to approach net-zero ambitions

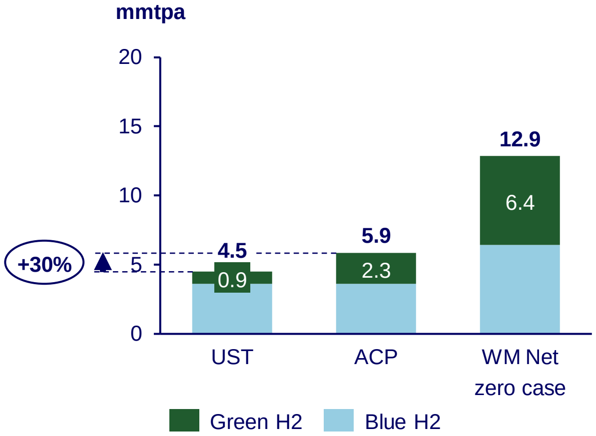
The deployment of blue H_2 increases under the UST guidelines to fill in for lost green H_2

2028 US low-carbon H_2 supply by type under ACP vs UST scenarios



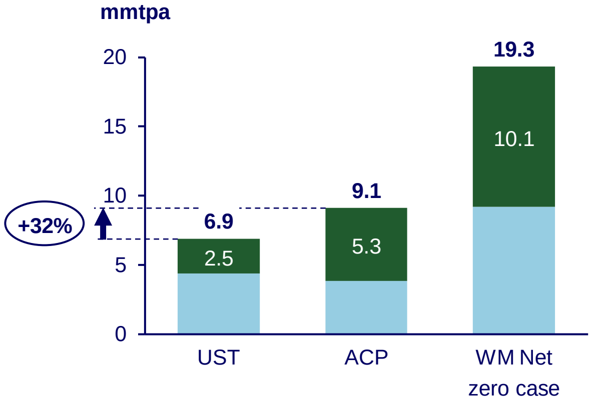
Extending the timeframe for annual match eligibility could drive a 44% increase in green hydrogen in 2028 (0.7 mmtpa vs. 0.2 mmtpa)

2032 US low-carbon H_2 supply by type under ACP vs UST scenarios



In 2032, an annual match regime could drive 2.3 mmtpa of green hydrogen as opposed to 0.9 mmtpa

2035 US low-carbon H_2 supply by type under ACP vs UST scenarios

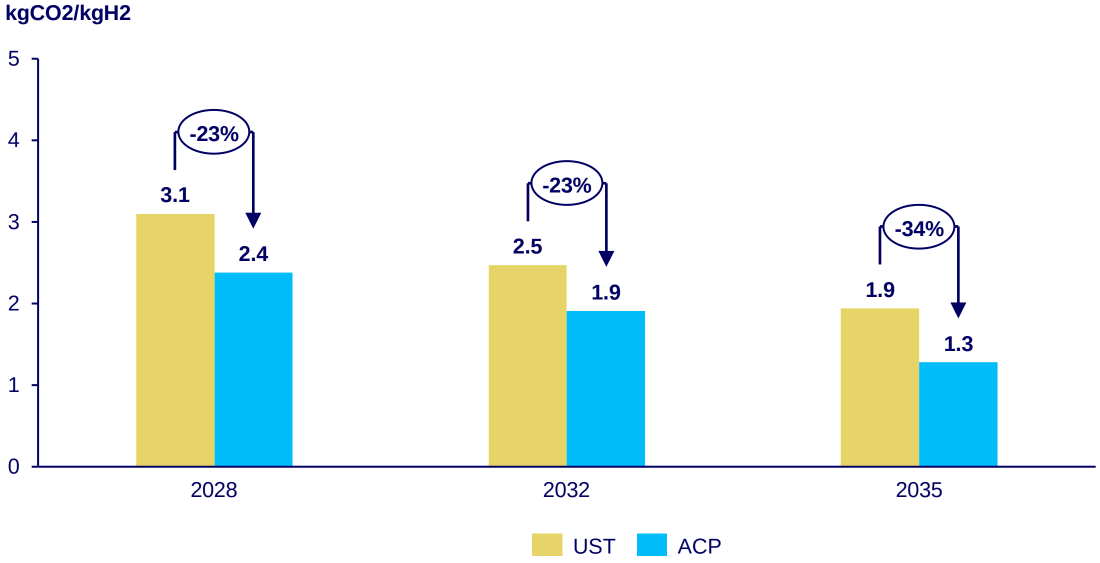


- Under the ACP proposal, green H_2 surpasses 5 mmtpa
- In the UST scenario, green H_2 costs stay higher for longer, stagnating deployment and widening the gap. Blue H_2 supply, on the other hand, resumes deployment growth in the mid-2030s to fill the demand gap from the subdued green H_2 deployment

Note: The "green H2" mentioned in this slide refers to all electrolytic hydrogen (both green and pink H2), whereas "blue H2" refers to both blue and turquoise H2
Source: Wood Mackenzie

Higher green H_2 development under the ACP scenario, results in a lower CI of low-carbon H_2 supply

Carbon intensity of US low-carbon H_2 supply under UST vs ACP scenario



- Wood Mackenzie's low-carbon H_2 carbon intensity (CI) analysis focuses on how the green vs. blue H_2 evolution will impact decarbonization. The analysis is done by evaluating the average of green and blue H_2 CI, weighted by their respective deployment levels
- Blue H_2 CI is estimated based on a lifecycle emissions analysis of the natural gas value chain inclusive of CO_2 and CH_4, while green H_2 CI has zero CI:
  - For UST scenario, H_2 production results in zero CI
  - For ACP scenario, H_2 production uses annual RECs from dedicated renewables assets (incrementality pillar) to match grid power requirements, where the grid CI is above zero[1]
- The ACP scenario anticipates higher green H_2 deployment, which contributes to the 20-35% CI reduction in the ACP scenario compared to the UST scenario, and the gap widens in the later years

1. Although the current policy guidance lacks detail on this mechanism, developing a demand-agnostic carbon matching scheme is critical to ensure new electricity loads are served by renewable energy, supporting a broader decarbonization strategy
Note: The "green H2" mentioned in this slide refers to all electrolytic hydrogen (both green and pink H2), whereas "blue H2" refers to both blue and turquoise H2. All green H2 analysis in this study assumes green H2 production to receive the full 45V tax credits (\$3/kgH2) by having <0.45kgCO2/kgH2 of carbon intensity.
Source: Wood Mackenzie

Key conclusions

Market Takeaways

- Green H_2 is critical to meeting **US decarbonization goals**
- However, as a new energy market, getting it off the ground is challenging. Historically, new energy markets have taken **30-50 years** to develop and decades of policy support
- **The IRA 45V production tax credit** incentivizes **low-carbon hydrogen development** (low CI H_2) and potentially **enables the green H_2 industry to scale**
- However, the **US Treasury guidelines** for 45V implementation **create hurdles for the growth of the green H_2 industry**

US Treasury Guidance

- US Treasury guidance **does not provide adequate support** to help green H_2 move towards its tipping point
- Having **an hourly matching market mechanism** starting in 2028 leads to **low capacity factors**, which results in:
  - **Higher unit costs** due to less production to amortize the costs on
  - **Stagnation of deployment** caused by higher costs, creating barriers for many new entrants
  - **Increased carbon intensity**, resulting from greater blue H_2 supply filling in for lost green H_2

ACP Proposal

- **ACP proposed an alternative** to US Treasury Guidelines, which **delays the hourly matching requirement** to support green H_2 as the market is activated
- Based on Wood Mackenzie analysis in ERCOT and CAISO, extending annual matching has the following benefits:
  - **20-30% Cost reduction** to end-use consumers
  - **Viability** for many green H_2 projects, **doubling green H_2 supply** by 2035
  - **Lower carbon intensity** of low-carbon H_2, with over 30% CI reduction vs UST scenario less by 2035

Appendix

Appendix content

Glossary

ACP: American Clean Power

ATR: Autothermal reformer

BIL: Bipartisan Infrastructure Law

CAGR: Compound annual growth rate

CAISO: California ISO

CapEx: Capital Expenditure

CCS: Carbon capture and storage

CF: capacity factor

CI: Carbon intensity

CO_2: Carbon dioxide

COD: Commercial Operation Date

DOE: Department of Energy

EPC: Engineering, Procurement, and Construction

ERCOT: Electric Reliability Council of Texas

FID: Financial Investment Decision

GW: Gigawatt

H_2: Hydrogen

IRA: Inflation Reduction Act

IRS: Internal Revenue Service

ITC: Investment Tax Credit

LCOE: Levelized Cost of Energy

LCOH: Levelized Cost of Hydrogen

LCI Hydrogen: Low-carbon intensity hydrogen (< 4 kg CO_2/4 kg H_2) – inclusive of blue and green hydrogen

MMTPA: Million metric ton per annum

MW: Megawatt

MWh: Megawatt-hour

OpEx: Operational Expense

PEM: Proton Exchange Membrane

PPA: Power Purchase Agreement

PTC: Production Tax Credit

PV: (1) Photovoltaic; (2) Present Value

RCA: Residential, Commercial, and Agriculture

RE: Renewable energy

REC: Renewable energy credits

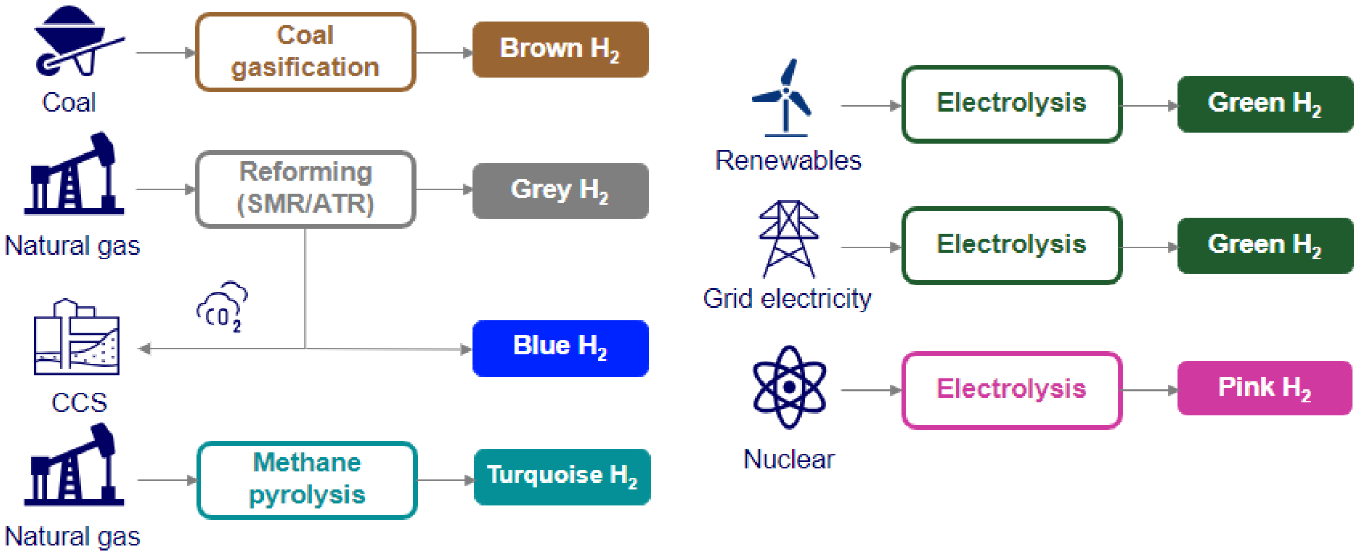
SMR: Steam methane reformer

TIC: Total Installed Cost

UST: US Treasury

WM: Wood Mackenzie

Hydrogen color wheel



Source: Wood Mackenzie

Appendix content

Power Costs Assumptions

Power Cost for this Analysis

- Represents a fundamentals-based approximation of the actual costs an H_2 electrolyzer will pay for power and RECs, considering the blend of power (renewables and grid) and REC sourcing needed to enable producers to qualify for the 45V credit.
- For renewables, we use LCOE as a proxy for PPA price, as it represents the revenue required for a project to achieve a desired rate of return. This is an imperfect but reasonable approximation of actual PPA prices, which can be influenced by other factors (PPA tenor, other revenue streams available to the project, etc.). We add network costs to reflect a physically delivered contract, and we assume RECs are bundled but priced into the PPA at an additional cost (using WM forecast of REC prices).
- For grid power, we use wholesale prices + an adder for network costs to approximate the delivered cost of electricity to an industrial user. RECs to offset the grid power are sourced from a combination of renewable project(s)

Market Standard PPA Contract

- Bilateral agreement between a customer and IPP for a long-term contract. Can be structured in multiple ways depending on the nature of wholesale and retail electricity regulation where the customer is located, and the customer's risk appetite.
- "Virtual" PPA prices (commonly quoted in market research, e.g., LevelTen) are not representative of a physical cost of power supply, as they represent the strike price in a fixed-for-floating, financially-settled wholesale energy contract. They are analogous to the LCOEs we use for the energy-only portion of renewable power cost.
- "Direct", "Behind the Meter", or "Retail Sleeved" PPAs cover a variety of structures for physical delivery of the renewable power, and all will include some amount of network costs in addition to the LCOE-driven portion for the generation itself.
- RECs are often bundled with PPAs but pricing can vary depending on the nature of the market.

Wholesale Power Market Price

- If not physically connected behind the meter, renewable projects typically sell power into the wholesale market, where real-time and day-ahead bidding is cleared at the price of the marginal generating unit in each period (hour or 15-minute increment).
- Industrial customers (like electrolyzers) generally cannot buy power directly from the wholesale market but purchase power from behind-the-meter assets or from their local LSE (utility or retailer). Delivered power cost to an industrial customer, therefore, includes both the wholesale price of electricity as well as the "poles and wires" cost of the grid. This can be structured in many ways depending on the nature of utility tariffs and/or retail contracts but will always fundamentally include both a wholesale electricity cost and a network cost.

LCOH Assumptions

Assumption	Description	Rationale
Size	200MW	Based on size of commercial scale projects announced and expected to come online in the 2028-2032 time period
Technology	PEM	Based on the need for the electrolyzer to run flexibly
Location	ERCOT (South) CAISO (SP15)	Locations chosen based on where we have seen the strongest pipeline of green H2 development activity
Capex	$3100/KW in 2028, falling to $2800/KW in 2032	Reflects Total Installed Cost (Stack, BoP, EPC and Owner costs) – based on real project quotes and discussions with vendors and EPC
Capacity Factor	Driven by scenario	For high-capacity cases – electrolyzer is running at 97% For low-capacity cases – Running at 97% of renewable resource availability
Storage	Storage is excluded from our analysis	LCOH is defined as a production only metric and is the primary driver of cost
Renewable Technology	Choice of renewable resource (e.g. Solar vs. wind vs. blend)	Selected based on most commercially attractive option in region and provides highest capacity factor
Overbuild	Size of renewable capacity vs. electrolyzer capacity	Size of renewable capacity is designed to match annual power and REC requirements of electrolyzer
Grid Power Requirement	Balance of grid power needed vs. dedicated renewable power	Grid power will be required to keep the electrolyzer operating at a high capacity when there isn't enough renewable energy generation available
Financing assumptions	▪ Discount rate - unlevered 10% ▪ 70% debt at 3.5% interest	

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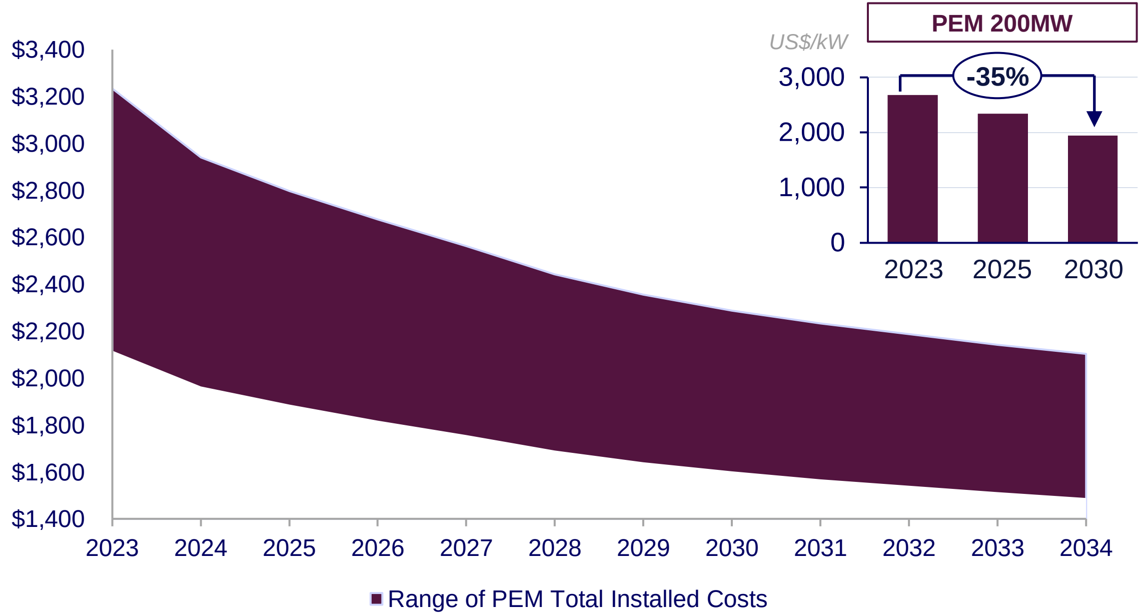
Starting CAPEX assumptions should reflect the current state of the market

Electrolysis projects have faced CapEx headwinds in recent years, yet will see cost declines before 2030

Projected Total Installed Cost (TIC) for Electrolysis Systems



- **Owner costs** high in coming years with lack of EPC experience in electrolysis projects
- **Performance guarantees** are required for project financing, but sharing technology risk between owner and OEM comes at a price
- **Labor and supply chain** constraints can be expected in coming years
- Large-scale projects today **have not yet realized economies of scale** due to nascency of projects and sector

Appendix content

Wood Mackenzie ran additional sensitivity analysis to investigate the impact of alternative approaches to the US Treasury guidance and ACP proposal

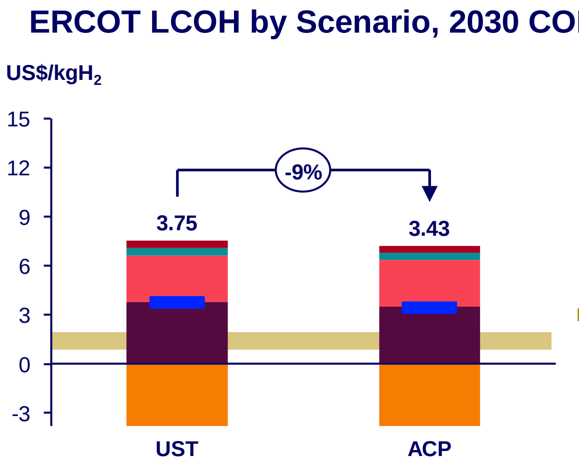
	Alternative Proposal	Alternative Procurement Strategy
	In service date	**Hourly Match High Capacity Factor[1]**
Sensitivity	▪ Adjust in-service date requirement from COD in 2028 to begin construction in 2028, with a 4-year safe harbor period to achieve COD before 2033 ▪ Eligible facilities qualify for annual match until 2032	▪ If hourly REC markets were to develop, hydrogen developers could implement projects with higher capacity factors and ensure compliance with hourly matching requirements
Reasons why this sensitivity is important	▪ Incentivizes first movers ▪ Allows more time for cost reductions ▪ Considers potential construction delays for first of a kind facilities	▪ Hourly REC markets would most likely develop in response to sufficient demand for an hourly mechanism from commercial and industrial load, which we believe is most likely to develop in the case of policy-driven demand ▪ Consistent, high capacity factor operations align with market demand and will improve project economics
Expected outcome	▪ Developers have more time to benefit from power and electrolyzer cost reductions before hourly match requirements kick-in ▪ LCOH increases when switching to hourly match will be slightly reduced	▪ Higher power costs due to the need to purchase costly hourly REC ▪ Higher capacity factors mitigate higher power costs and drive an LCOH that is marginally better than the low capacity factor hourly match case

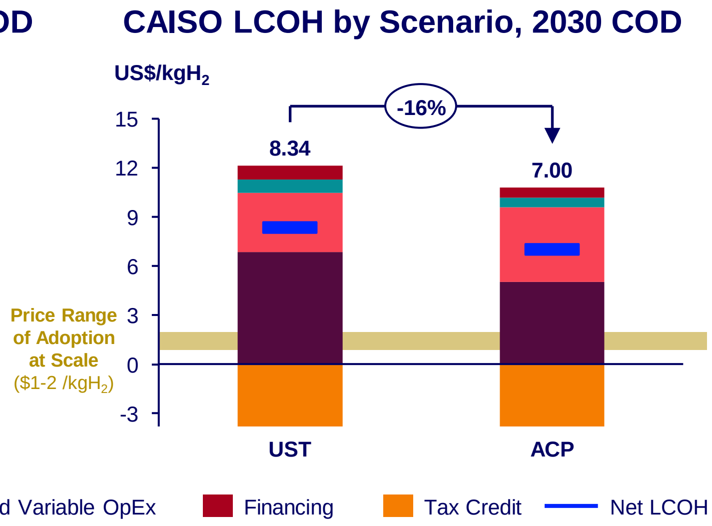
1. Hourly match low capacity factor is currently the only procurement option since an hourly REC mechanism does not exist and is unlikely to emerge within this analysis timeframe

Shifting out the UST in-service date has a marginal cost benefit

The primary benefit is allowing developers some buffer in managing development delays

		US Treasury Guidelines (**UST Scenario**)	Adjustment to UST In-Service Date
Annual Matching	**Timing**	Through 2027	
	Eligibility	All H_2 facilities	Construction start before 2029, COD before 2033
Hourly Matching	**Timing**	2028 & beyond	2032 & beyond
	Eligibility	All H_2 facilities	





- Regions of the US that cannot capitalize on high-capacity factors from combined wind and solar, like CAISO, will benefit more from a delayed in-service date due to the greater impact that capital cost has on LCOH when projects operate at lower capacity factors

Source: Wood Mackenzie

If an hourly REC market emerged, marginal cost benefits could be achieved

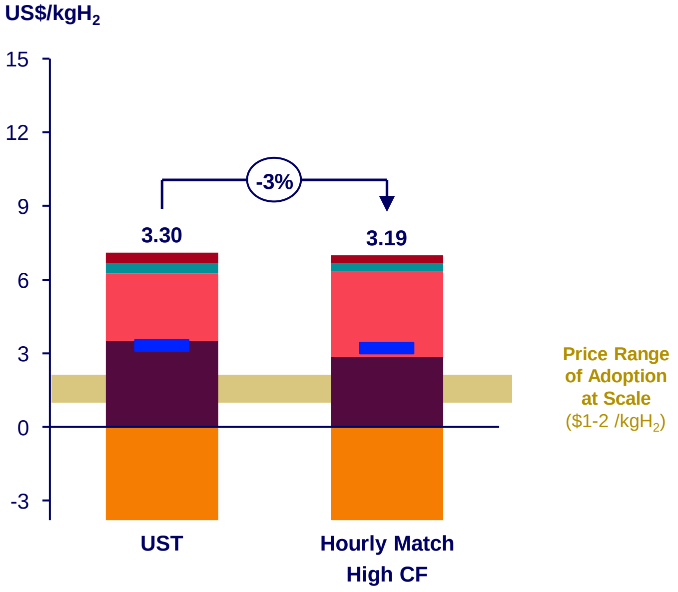
Hourly RECs would allow producers to operate at higher capacity factors

Hourly Match High Capacity Factor (CF) Sensitivity Analysis

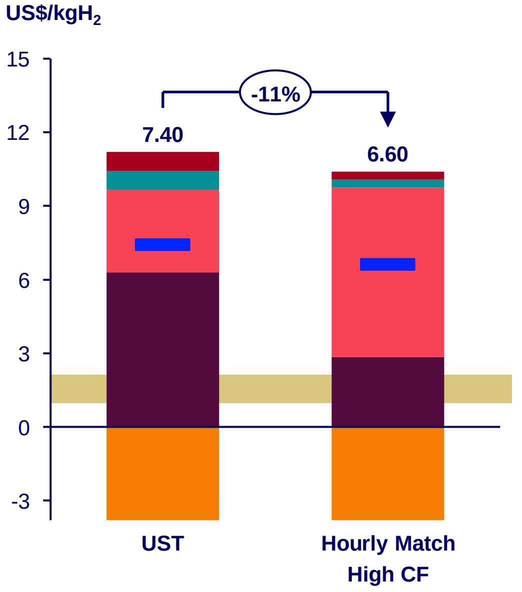
- One potential way to achieve a high capacity factor under an hourly matching regime is to leverage an **hourly REC mechanism** to displace grid power requirements in low renewable hours. The mechanism itself, which certifies clean energy production for a specific hour, does not currently exist and would take time to fully develop
- It is important to note that this alternative is highly speculative, hard to develop due to incrementality and regional constraints and would be hard to incorporate into financial modeling for project financing purposes
- Wood Mackenzie has developed a fundamentals-based approach to estimate the hypothetical hourly REC prices in order to assess the impact of using the hourly RECs mechanism on the LCOH of green hydrogen

		UST scenario	Hourly Match with High CF
H_2 Capacity factor (%)	ERCOT	80%	100%
	CAISO	44%	100%
2032 Power costs ($/kWh)	ERCOT	60.15	75.01
	CAISO	84.35	147.09

2032 ERCOT LCOH by Scenario



2032 CAISO LCOH by Scenario



Source: Wood Mackenzie

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