WHITE PAPER

Impacts of IRA's 45V Clean Hydrogen Production Tax Credit

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THE LOW-CARBON RESOURCES INITIATIVE

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EXECUTIVE SUMMARY

Hydrogen and low-carbon fuels could play important roles in reaching economy-wide net-zero emissions, especially for applications in industry, transport, and energy storage. The Inflation Reduction Act (IRA) contains novel production tax credits for clean hydrogen (45V), which depend on the life-cycle emissions intensity of hydrogen production. This complexity raises questions about impacts of 45V tax credits on hydrogen production and emissions, which also depend on the assumed cost and performance of hydrogen production technologies, power sector responses, and hydrogen demand.

Our analysis uses EPRI's US-REGEN model to understand potential impacts of the 45V subsidy on hydrogen supply and demand, emissions, electricity generation, and fiscal costs under scenarios that vary qualification criteria and the scope of the demand response for hydrogen. Scenarios varying the criteria for qualified generation used for electrolytic hydrogen production are based on three "pillars," which refer to requirements for hourly temporal matching, additionality or use of new resources, and local deliverability. We expand the literature on 45V impacts by using a full energy systems model—encompassing fuel production, transport, storage, and use—to capture hydrogen demand feedbacks outside of the power sector as well as the dispatch dynamics of grid-connected electrolysis.

Impacts on Hydrogen Production: **The analysis indicates that 45V credits could lead to significant deployment of electrolytic hydrogen, even with more stringent qualification criteria including hourly matching of zero-carbon electricity generation and electrolysis production.**

- 45V tax credits could cover around 90% of electrolytic hydrogen production costs in the most favorable cases (e.g., high-quality wind resource regions with lower electrolysis capital costs), and around 40% of production costs in the most expensive configurations.

- 45V subsidies could lead to significant deployment of new hydrogen production from electrolysis, ranging from 13–24 MtH$_2$ annually by 2035 (compared with about 10 MtH$_2$ of production today, which is largely from conventional steam methane reforming). Scenarios with less stringent certification criteria generally have greater hydrogen deployment and tax credit uptake.

- Based on scenarios that include only current state and federal policies and incentives, electrolytic hydrogen production peaks in 2035 and declines thereafter, given the expiration of the tax credits and return to unsubsidized price levels. Production in the post-subsidy period depends on the future policy environment and company goals, as net-zero targets could create additional incentives for low-carbon hydrogen.

- 45V-induced hydrogen demand is largely for electric generation and blending into existing natural gas pipelines, which are flexible demands that can be reversed if incentives change after tax credits expire. Converting electricity to hydrogen and back to electricity incurs roundtrip losses of around 65%, which has impacts on clean electricity demand and emissions.

Emissions Implications of Qualification Rules: **Net effects of 45V on economy-wide emissions depend on qualification criteria.**

- Depending on the qualification criteria for input generation, 45V can lead to a net decrease or a net increase in economy-wide CO$_2$ emissions during the subsidy period, relative to a scenario without 45V credits (Figure ES-1).

- All three qualification pillars—hourly temporal matching, use of new generation resources, and local deliverability—are required to ensure net economy-wide CO$_2$ reductions from 45V across all scenarios during the subsidy period. Scenarios with only annual matching can lead to similar or slightly lower emissions than without 45V, depending on assumptions about hydrogen demand. When the qualification criteria allow existing zero-carbon resources, emissions increase relative to the No 45V case, and increase further when deliverability is not required. With less stringent criteria, emissions from additional electricity generation to power electrolysis are larger than emissions reductions from displaced conventional hydrogen production and end-use fossil fuel consumption.
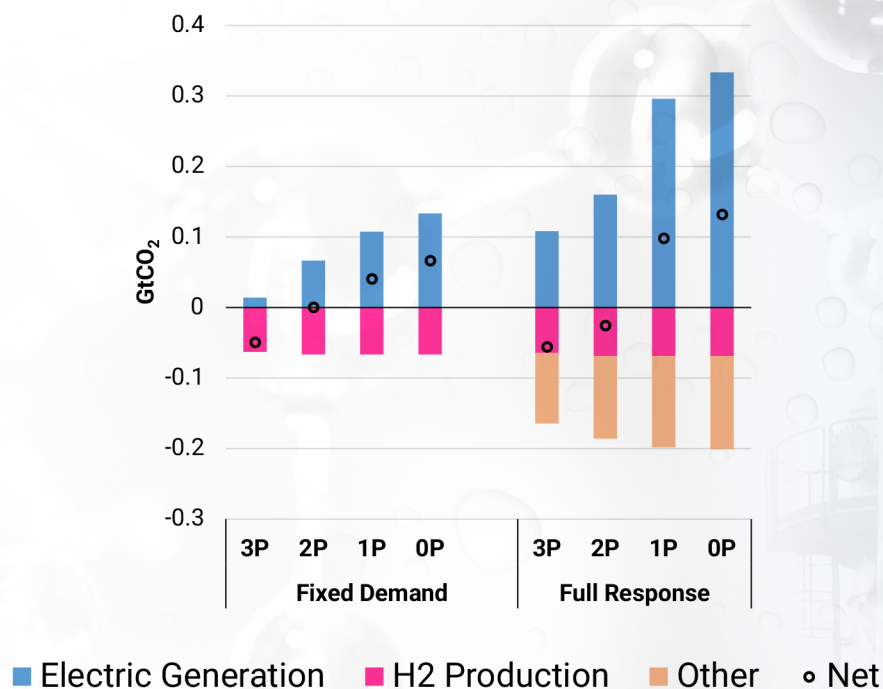
Figure ES-1. *Change in 2035 CO_2 emissions in hydrogen demand scenarios vs. No 45V Case, assuming different qualification criteria. 3P includes requirements for hourly matching, new clean generation, and deliverability; 2P removes hourly matching; 1P removes hourly matching and new generation requirements; and 0P removes all three pillars. Fixed Demand assumes no incremental non-electric hydrogen demand, while Full Response includes non-electric demand feedbacks.*

- Scenario differences in the net emissions impact are due to the gap between the actual change in generation (or "consequential") and attributed generation nominally designated for qualification, which becomes larger as qualification criteria are relaxed. Less stringent criteria lead to more natural gas-fired generation despite all nominally attributed generation coming from zero-carbon resources. Even with the most stringent "three pillar" criteria (including requirements for hourly matching, new clean generation, and deliverability), the emissions intensity of incremental electricity generation is greater than zero, though these increases in electric sector CO_2 are more than offset by reductions in CO_2 from hydrogen production.

- After the subsidy period, CO_2 emissions are slightly lower than in the baseline without 45V in all cases, because some remaining electrolysis continues to displace non-electric production, and because the induced build-out of wind and solar during the 45V subsidy period leads to slightly greater installed capacity levels afterwards.

Fiscal Expenditures and Abatement Costs: 45V credits could entail cumulative fiscal costs of $385-756 billion and $750/t-CO₂ reduced.

- 45V credits may have cumulative fiscal costs of $386 to $756 billion (in real 2022 dollar terms), although only 13–25% of this cost occurs during the 10-year budget period ending in 2032.

- The net increase in uptake of other IRA incentives as a result of 45V could add cumulative fiscal costs of $90 to 176 billion.

- These high fiscal costs and modest emissions reductions under the three pillars scenarios indicate very high fiscal outlays per tonne of CO_2 reduced for IRA's 45V hydrogen tax credits, which can exceed $750/t-CO₂. These costs are approximately an order-of-magnitude higher than the implied abatement costs of other IRA credits.

- Tax credits are aimed not only at reducing emissions but also at encouraging technological change and providing operational experience for hydrogen production, transport, storage, and use. Such experience can contribute to buying down learning curves so that low-emitting hydrogen is ready to deploy when needed as the economy approaches net-zero levels, as illustrated in EPRI's Net-Zero 2050 report (Blanford, et al., 2022).

Several factors beyond 45V tax credits could influence future hydrogen and use:

- **Hydrogen hubs:** $7 billion for the Regional Clean Hydrogen Hubs program as part of the Bipartisan Infrastructure Law (the seven selected projects across the country were announced in October 2023).

- **Company targets:** Company net-zero targets may mean that purchasers have a greater willingness-to-pay for hydrogen that meets stringent certification criteria, perhaps going further than qualification criteria for 45V. This research indicates that the cost premium of hourly matched hydrogen production is relatively small ($0.1-0.2/kgH$_2$) for good wind and solar resource locations.

LIST OF ABBREVIATIONS

0P	Scenario that relaxes qualification criteria for the $3/kgH$_2$ 45V credit, allowing annual-matched, existing/new zero-carbon resources anywhere in the U.S.
1P	Scenario that allows both annual matching and existing zero-carbon resources, enforcing only the deliverability pillar
2P	Scenario where additionality and deliverability pillars are enforced, but only annual matching is required
3P	Scenario where all three pillars for 45V credits are enforced (temporal matching, additionality, and deliverability)
45Q	Inflation Reduction Act tax credit for captured CO_2
45V	Inflation Reduction Act clean hydrogen production tax credit
45Y	Inflation Reduction Act clean electricity production tax credit
48E	Inflation Reduction Act clean electricity investment tax credit
111	Section 111 of the Clean Air Act new and existing source performance standards
CCS	carbon capture and storage
CO_2	carbon dioxide
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
GHG	greenhouse gas
GW	gigawatt
H2	hydrogen
IRA	Inflation Reduction Act of 2022
ITC	investment tax credit
kg	kilogram
kW-e	kilowatt-electric
LHV	lower heating value
MISO	Midcontinent Independent System Operator
MMBtu	one million British thermal units
Mt	million metric tonnes
NPV	net present value
PJM	PJM Interconnection
PTC	production tax credit
SMR	steam methane reforming
SPP	Southwest Power Pool
US-REGEN	U.S. Regional Economy, GHG, and Energy
ZERC	zero-emissions resource credits

INTRODUCTION

Hydrogen and low-carbon fuels could play important roles in reaching economy-wide net-zero emissions, especially for applications in industry, transport, and energy storage where other low-emitting options are more limited or costly. For instance, modeling of economy-wide net-zero CO_2 pathways in the U.S. by 2050 concluded that, "Hydrogen's use as a low-carbon fuel is projected to increase, whether through fuel cell vehicles, blending with the natural gas supply to support needs in buildings, or through direct use for process heating in industries" (Blanford, et al., 2022). Deployment of hydrogen and hydrogen-derived fuels are larger when carbon removal and carbon capture are limited, which increases electrolytic hydrogen production, fuels synthesis from hydrogen and biogenic carbon, and direct use for medium- and heavy-duty vehicles and high-temperature process heat.

The Inflation Reduction Act (IRA) signed into law in August 2022 includes many subsidies for deployment of a wide range of clean energy technologies, as well as incentives for development of domestic supply chains and investment in under-served communities. It is projected to have significant impacts on both emissions and fiscal expenditures (Bistline, et al., 2023; Bistline, Mehrotra, Wolfram, 2023). Among the key measures are expanded and increased tax credits for wind and solar power generation, nuclear energy, battery storage, carbon capture, electric vehicle adoption, domestic clean energy manufacturing, and building efficiency and electrification.

One of the most complex elements of the IRA is the 45V production tax credit for clean hydrogen. This incentive is substantively different than most other IRA incentives in several important ways:

- It is entirely new. While many other IRA incentives build upon existing subsidies and programs, there has been no previous federal policy support in the U.S. for hydrogen production.
- The magnitude of the 45V credit depends on a life-cycle greenhouse gas (GHG) emissions assessment. Most other IRA incentives are directly tied to a specified activity, such as investment in a qualified technology, which is more straightforward to define and verify. For 45V, the level of subsidy depends on the GHG intensity of its supply chain, which introduces definitional ambiguity and enforcement challenges.

- The magnitude of the 45V subsidy relative to production costs is potentially much larger than for any other IRA incentive. In particular, the highest tier of $3 per kgH_2, which is likely available only for electrolytic hydrogen (i.e., produced using electricity and water as inputs), could cover up to 90% of levelized production costs in some cases, while credits for solar and wind, for example, could offset 30% of levelized costs. Moreover, the electrolytic production pathway is also the most complex to assess from a life-cycle GHG perspective and raises broader questions about emissions attribution from interventions that alter grid operations and investments.
- The significant electricity consumption of electrolytic hydrogen production could—depending upon how the program is implemented—potentially lead to emissions increases relative to a counterfactual without hydrogen tax credits.

As with other IRA tax credits, there is no budgetary limit on 45V uptake, implying that fiscal costs are uncapped under the law. For all of these reasons, the introduction of 45V has generated a flurry of commercial interest, analysis, and public scrutiny of the details.[1] Implementation guidance from the Treasury Department has been delayed until at least October 2023, extending the debate and the window of opportunity for further clarification of the issues. These questions extend beyond 45V tax credits, given how guidelines related to these credits could influence state emissions standards, EPA rules (e.g., the proposed power plant regulations under Section 111 of the Clean Air Act), trade policy, and other areas where low-emitting hydrogen plays a role. Beyond hydrogen, guidelines for these tax credits raise broader questions about emissions attribution from interventions that alter grid operations and investments, including end-use electrification, energy efficiency, direct air capture, and electricity-derived fuels.

In this paper, we present a quantitative analysis of the potential impacts of the 45V subsidy under alternative implementation scenarios. We first review the literature of other studies examining 45V impacts. We then provide an overview of the structure of the 45V incentive as specified in the IRA and illustrate the implications for non-electric hydrogen production technologies (e.g., conventional production from natural gas and the potential for carbon capture).

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1   Summaries of existing analysis are found in the literature review section.

Next, we discuss the electrolytic hydrogen production pathway and highlight the key uncertainties and difficulties associated with estimating its cost and life-cycle emissions. Model results are first presented for a simple bounding case with dedicated zero-carbon electric generation for electrolytic hydrogen production. These results are expanded to integrated modeling scenarios with grid-connected electrolysis under various specifications of the qualification criteria. Finally, we discuss implications of 45V production incentives for hydrogen demand across the economy. We conclude with overall implications for hydrogen production volumes, emissions, and costs from 45V-induced investments.

LITERATURE REVIEW

Several recent modeling studies that investigate potential effects of hydrogen tax credits on emissions, cost, hydrogen production, and the power sector mix are summarized in Table 1. These studies vary in their geographic focus, sectoral scope, and scenario design. Our study is unique in several respects:

- **Regional variation:** Instead of focusing on a few regions, our analysis examines implications of 45V credits under 16 different regional circumstances. This breadth illustrates potential heterogeneity in regional resources, wind and solar resource potential, existing infrastructure, state policies, and other factors that may be important in understanding the economics of hydrogen supply and demand.

- **Economy-wide energy system modeling:** Most existing studies focus on the power sector and do not explicitly represent hydrogen demand endogenously. Such feedback between hydrogen demand and the power sector may be important for emissions effects of 45V credits.

- **Endogenous electrolyzer investment:** Unlike most other studies that assume fixed levels of electrolysis deployment, our analysis allows electrolyzer deployment to vary on a region- and scenario-specific basis and has endogenous sizing and dispatch of electrolyzers.

Discussions about requirements for hydrogen production to minimize emissions impacts often focus on three "pillars:"

- **Temporal matching:** Electrolytic H_2 production and qualifying electricity generation can be matched across different timeframes, including hourly and annually.

- **Additionality:** Electrolysis must have clean electricity supplied by new resources.[2]

- **Deliverability:** Electrolytic H_2 production occurs nearby qualifying electricity generation. Such geographical correlation or localization requirements also could help minimize grid congestion from these new loads.

Several research groups, companies, and environmental organizations wrote a letter to the Department of the Treasury in February 2023 and stated that, "Additionality, deliverability, and hourly matching are necessary to guard against negative consequences" (link). Recent studies in Table 1 investigate potential impacts of these requirements on emissions, costs, and other outcomes.

These studies provide conflicting guidance on the emissions implications of hourly matching requirements. Studies like Ricks, et al. (2023) indicate that, "requiring grid-based hydrogen producers to match 100% of their electricity consumption on an hourly basis with physically deliverable, 'additional' clean generation" can provide emissions rates "equivalent to electrolysis exclusively supplied by behind-the-meter carbon-free generation." In contrast, Olson, et al. (2023) find that CO_2 emissions can be lower with annual matching than with hourly matching for many regions and scenarios. Cybulsky, et al. (2023) illustrate how this discrepancy could be caused by modeling differences in additionality requirements. Their analysis distinguishes between "compete" frameworks—where H_2 and non-H_2 demand compete for new clean electricity generation—and "non-compete" ones—a more stringent definition of additionality that only considers low-emitting supply additional if it would not be deployed in a counterfactual without electrolysis. Cybulsky, et al. (2023) find in their Texas and Florida case studies that the consequential emissions effects under annual matching are significantly lower in the "non-compete" framework, which they argue is closer to "today's context" for many markets. Zeyen, et al. (2022) conclude that emissions differences decrease between annual and hourly matching requirements when the background electricity system has more low-emitting resources.

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2   There are additional questions about whether all new clean supply would qualify as "additional" or just new resources that would not have been added without electrolytic hydrogen demand, about the eligibility of otherwise-curtailed generation from existing clean resources, and about whether generation from clean facilities that would have otherwise retired would be eligible. For this analysis, we define additional as new clean capacity.

One important limitation of the studies above is that many do not model hydrogen demand explicitly or capture emissions effects associated with reductions in fuels that hydrogen displaces. These effects could be important for comparing emissions under hourly matching vis-à-vis annual matching, especially if annual matching lowers production costs and consequently increases hydrogen demand relative to its applications with unsubsidized pricing.

Table 1. Summary of recent modeling studies of hydrogen subsidies

|	THIS ANALYSIS	CYBULSKY, ET AL. (2023)	HH (2023)	OLSON, ET AL. (2023)	RICKS, ET AL. (2023)	ZEYEN, ET AL. (2022)
Region	16 U.S. regions	ERCOT, FRCC	27 U.S. regions	ERCOT, MISO, SPP, PJM	Western U.S.	Germany and neighbor countries
Time Horizon	2025 through 2050	2021	2024 through 2032	2025/2030	2030	2025/2030
Model Scope	Full energy supply and demand	Power sector and H_2 supply	Full energy supply and demand	Power sector and H_2 supply	Power sector and H_2 supply	Power sector and H_2 supply
Electrolyzer Investment	Endogenous	Exogenous	Endogenous	Exogenous	Exogenous	Exogenous
H_2 Demand	Endogenous, hourly demand	Constant hourly demand	Endogenous; exogenous sensitivity	Constant hourly demand[3]	No demand enforced	Constant hourly demand
H_2 Storage	Yes	Yes	Yes	No	No	Yes
Electric Sector Investments	Endogenous	Endogenous	Endogenous	Exogenous	Endogenous	Endogenous
Temporal Matching	HM with excess sales; AM	HM with excess sales; AM	HM without excess sales; AM	HM and AM with energy and emissions match	HM with and without excess sales; WM; AM	HM without excess sales and with 20%; MM; AM
Additionality Definition	Compete	Compete; non-compete	Compete	Non-compete	Compete	Non-compete
Deliverability	With/without requirements	With requirements	With requirements	With requirements	With requirements	With requirements

HM = hourly matching; WM = weekly matching; MM = monthly matching; AM = annual matching; HH = Haley and Hargreaves (2023)

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3   Electrolysis load is assumed constant "except the top 10% highest priced hours" (Olson, et al., 2023).

45V STRUCTURE

The 45V incentive (§13204 in the IRA) is a production tax credit valued at $0.60/kgH_2 for life-cycle intensity of 2.5–4 kgCO_2-e/kgH_2, increasing on a sliding scale up to $3/kgH_2 for intensity below 0.45 kgCO_2-e/kgH_2 (Figure 1). Similar to other IRA incentives, these levels are conditional on prevailing wage and apprenticeship requirements; the credit values are 80% lower if these labor bonus criteria are not met. The credit values are also indexed to inflation, with the specified nominal values expressed in year 2022 dollars. The life-cycle GHG intensity of production is to be determined by [ANL's GREET model](#), although guidance on the details of the assessment has not been released. Credits apply for projects that have commenced construction by the end of 2032 and continue for 10 years from project start. 45V clean hydrogen production credits can be combined with 45Y clean electricity production and 48E clean electricity investment credits, but cannot be combined with 45Q credits for carbon capture.
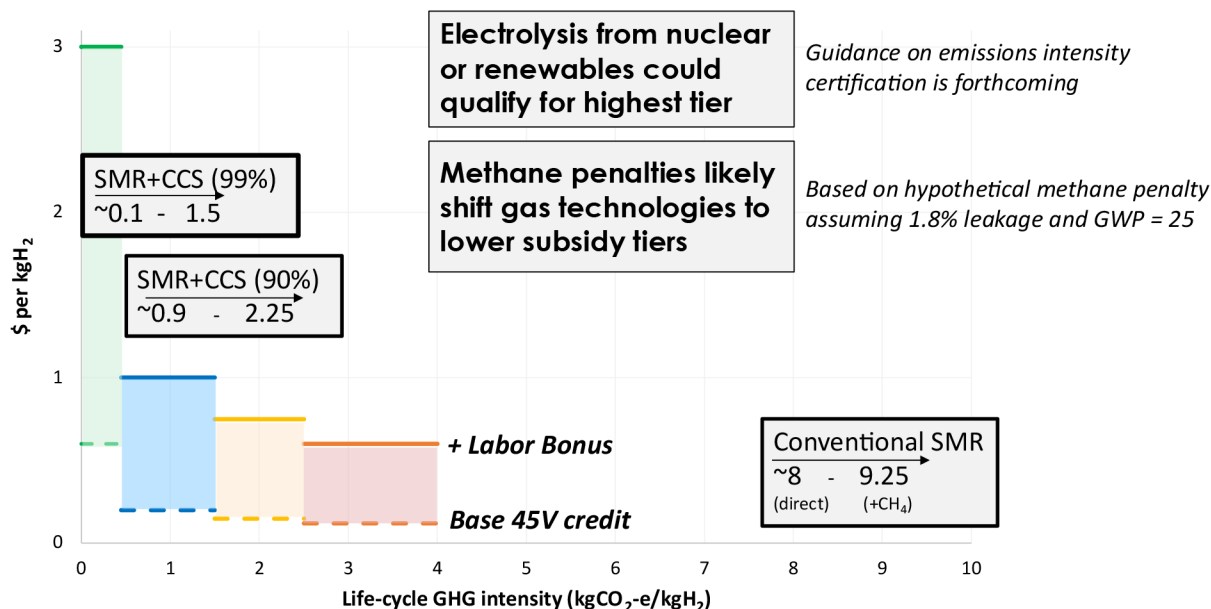
Figure 1. *Summary of IRA 45V Hydrogen Production Tax Credit.*

NON-ELECTRIC HYDROGEN PRODUCTION

The U.S. currently produces around 10 million metric tonnes (Mt) per year of hydrogen for non-energy uses in various industries, particularly as a feedstock for ammonia and fertilizer production and as a reactant to reduce sulfur in petroleum refining. Essentially all current domestic production uses a conventional steam methane reforming (SMR) process, where natural gas provides heat and feedstock hydrogen (along with water). The direct carbon emissions intensity from SMR hydrogen production is around 8 $kgCO_2/kgH_2$,[4] or roughly twice the threshold to qualify for the minimum 45V incentive. However, any life-cycle GHG intensity would likely include an accounting for methane emissions from upstream natural gas production, processing, and distribution. There is significant uncertainty and variation in estimates of gas-related methane emissions, as well as ambiguity of attribution in specific applications and translation to CO_2 equivalence. Using current median estimates of relevant parameters, upstream methane from SMR hydrogen production could account for an additional 1.25 $kgCO_2$-e/kgH_2.[5]

One option for low-carbon hydrogen is SMR production with carbon capture and storage (CCS). Based on input assumptions for EPRI's US-REGEN model, SMR+CCS production would have a direct CO_2 intensity of around 0.9 $kgCO_2/kgH_2$ with 90% capture and as low as 0.1 $kgCO_2/kgH_2$ with higher capture rates. Similarly, pyrolysis technologies convert methane to hydrogen using very high heat and produce a solid carbon waste stream with very low or zero direct CO_2 emissions. Still, any hydrogen production technology using natural gas would presumably be subject to upstream methane accounting, and the resulting adder (even if lower than current estimates due to future reductions in methane leakage rates) would likely preclude qualification for the lowest GHG intensity tier (below 0.45 $kgCO_2$-e/kgH_2). Thus SMR+CCS or pyrolysis technologies would likely only be eligible for the $0.75 or $1/$kgH_2$ subsidy tiers. This subsidy would be available for the first 10 years of project operation. Assuming a 40-year project lifetime, the actual reduction to the levelized hydrogen production cost, using 45V credits, would be lower at around $0.41 to $0.55/$kgH_2$.[6]

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4   Based on US-REGEN input assumptions, the natural gas input to SMR is ~0.15 MMBtu per kgH_2, which based on 54 $kgCO_2$/MMBtu for the direct carbon content of natural gas translates to ~8 $kgCO_2/kgH_2$.

5   Assuming 1.8% for system-wide leakage rate of delivered gas and a 100-year global warming potential of 25.

6   Based on an assumed project life of 40 years and a discount rate of 7%, the discounted net present value (NPV) of the first 10 years of production represents roughly 55% of total project NPV.

Note that hydrogen production with SMR+CCS could alternatively claim the 45Q subsidy for captured carbon of $85/tCO_2$, which translates to around $0.69 to $0.76/kgH_2.[7] The 45Q credit can be claimed for 12 years instead of 10 for 45V, resulting in a levelized reduction of $0.42 to $0.46/kgH_2 using this subsidy pathway. Thus, the 45Q and 45V incentives are roughly equivalent in magnitude for natural gas-based hydrogen production. Moreover, the value of either IRA incentive for SMR+CCS or pyrolysis is similar in magnitude to the cost premium for these technologies over conventional SMR production. Based on assumed costs for new capacity in US-REGEN, the estimated levelized hydrogen production cost for conventional SMR is around $1.07/kgH_2 and around $1.55/kgH_2 for SMR+CCS (both assuming a gas price of $3/MMBtu), suggesting a levelized cost premium of around $0.48/kgH_2.

The upshot of these observations is that the value of IRA incentives for SMR+CCS (and potentially pyrolysis) is similar in magnitude to the cost premium for these technologies over conventional SMR production. Hence, they could potentially motivate investments in carbon capture retrofits of existing plants or new capacity using CCS or pyrolysis, reducing the carbon footprint of the hydrogen production industry. However, this subsidy pathway would be unlikely to result in materially lower hydrogen production costs and thus unlikely to motivate additional investment in new applications using hydrogen to replace existing energy carriers (e.g., hydrogen fuel cell vehicles or hydrogen replacing natural gas for process heat or electric generation). At current fuel prices, and absent a carbon price or other policy-based adder on fossil fuel use, hydrogen as an energy carrier is generally not competitive.

45V can create an incentive for expanded deployment of hydrogen technologies, especially when it reduces the production cost of hydrogen lower than the cost from conventional SMR. One possible scenario for this to occur is through electrolytic hydrogen via zero-carbon electric generation, which would qualify for the highest 45V subsidy tier of $3/kgH_2.[8] This pathway is discussed in the subsequent section. In addition, company net-zero targets may mean that purchasers have a greater willingness-to-pay for low-carbon hydrogen, especially for companies with more limited or costly decarbonization options. 45V tax credits can help to reduce the magnitude of this cost premium, potentially encouraging greater investments.

ELECTROLYTIC HYDROGEN PRODUCTION

The production of hydrogen with electrolysis uses electric energy to separate hydrogen from water. In current market conditions, the electrolytic hydrogen pathway is for most applications much more expensive than conventional SMR. Although some electrolytic hydrogen production exists today, it operates at very small scales in the U.S., and the technologies are at an early stage of commercialization. There is significant promise for improvements in electrolysis capital cost with scale and learning, which translates to a broad range of uncertainty around cost projections for the near- and medium-term (Bedilion, et al., 2023). Complicating the picture further is the relationship between the source of the electric input and its cost. A simplistic representation might assume that an electrolytic hydrogen producer operated its capacity at a full constant load and paid a flat industrial price for electricity. While this setting might describe small-scale electrolysis activities today, it likely would not hold for a future market in which electrolysis is used for bulk hydrogen production. Even in today's market conditions, a producer could likely achieve lower costs by optimally dispatching the electrolyzer against a real-time wholesale price of electricity, absorbing a lower capacity factor but concentrating production in hours with lower electricity prices. This flexible operational model will only become more compelling as shares of variable renewable generation increase and will be especially salient in the context of aligning with qualified zero-carbon generation. On the other hand, opportunistic dispatch requires both operational flexibility, which may be limited with some electrolysis technologies (Motealleh et al., 2023), and hydrogen storage (Chiaramonte, 2023), whose costs and availability vary significantly by region.

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7   A 90% capture rate implies roughly 8.1 kgCO_2 captured per kgH_2 produced. Up to 8.9 kgCO_2/kgH_2 could be captured with a 99% capture rate. These calculations are based on assumed LHV efficiency of 68% for SMR+CCS.

8   It may also be possible for hydrogen production from a biomass feedstock with carbon capture to qualify for the highest subsidy tier, depending on how biogenic carbon is treated in the life-cycle assessment. For this analysis we assume that the bio-hydrogen pathway does not qualify for the 45V incentive (Chiaramonte, 2023).
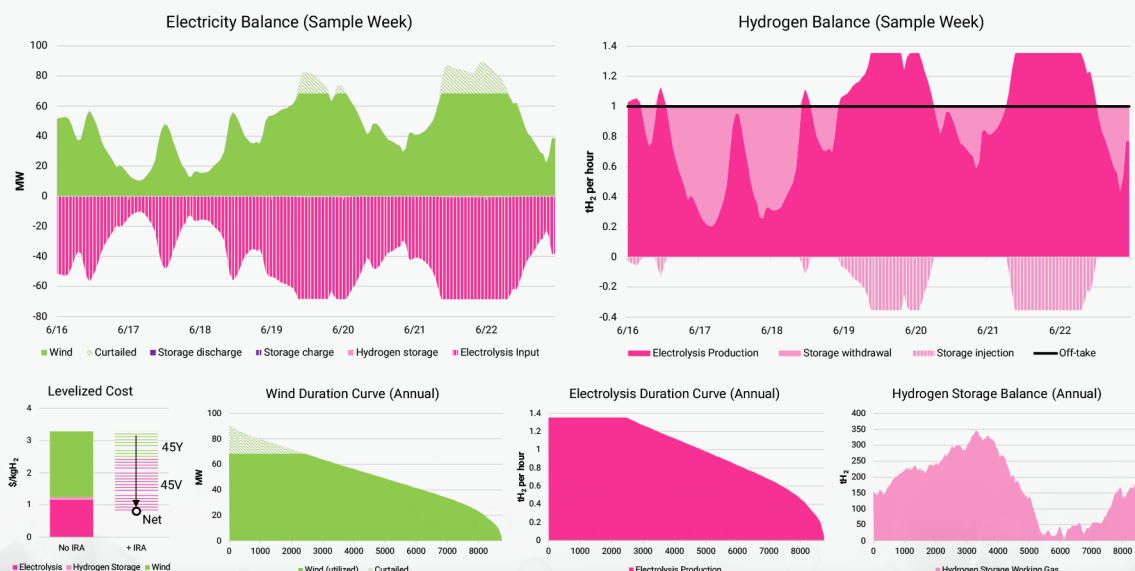
ELECTROLYSIS WITH DEDICATED GENERATION

To understand the costs of supplying electrolytic hydrogen production powered exclusively by zero-carbon generation, one approach is to model production with dedicated electric generation, i.e., not grid-connected. This configuration both ensures the life-cycle emissions qualification criteria for the 45V subsidy are met without ambiguity and is relatively straightforward to calculate based on assumptions for capital costs and resource profiles for a given location. In the context of variable generation from wind or solar, the calculation does require an optimization of the relative sizing of electrol-

ysis, renewable generation capacity, batteries, and hydrogen storage. Analysis of this trade-off (see sidebar) shows that it is not optimal simply to set nominal electrolysis capacity equal to nominal renewable capacity and align hydrogen production exactly with renewable output. Instead, a lower average cost can be achieved by over-sizing renewable capacity relative to electrolysis capacity, causing some generation to be curtailed during periods of high output but increasing the capacity factor of the electrolyzer over the course of the year. In the case of solar generation, it is economic to include battery storage in the configuration as well. In all cases using variable renewable resources, some level of seasonal hydrogen storage is required to enable a constant delivery profile.

MODELING ELECTROLYTIC HYDROGEN PRODUCTION WITH DEDICATED ZERO-CARBON GENERATION

Optimal configuration of generation, storage, and electrolysis was calculated for each zero-carbon resource type (wind, solar, nuclear) in each of 16 U.S. regions with the objective of delivering a constant off-take profile for produced hydrogen. Assumptions for hourly regional resource shapes and technology cost and performance are based on US-REGEN inputs. Scenarios included a range of assumptions for electrolysis capital costs, with the high end at $2,800/kW-e corresponding to the results of a recent EPRI study (Kern and Mancuso, 2022) on current engineering-based estimates for total capital requirement for a central-scale PEM electrolysis plant. The default and lower costs of $1,400/kW-e and $700 kW-e correspond to projected cost declines from scale and learning over the 45V subsidy period.

This figure illustrates results for electrolysis production from dedicated wind generation in the Southwest Power Pool (SPP) region assuming default electrolysis capital costs and a nominal constant off-take of 1 tH$_2$ per hour. In the optimal configuration, nominal wind capacity is estimated to be 42% larger than the nominal electrolysis capacity, resulting in a 66% capacity factor for the electrolyzer and curtailment of 5% of wind. The levelized cost of hydrogen is $3.29/kgH$_2$ before accounting for IRA incentives, falling to around $0.80/kgH$_2$ including 45Y and 45V. 45Y offsets around 30% of the wind generation cost, while 45V more than offsets the electrolysis capital and non-electric operating costs. These costs for SPP wind represent the most favorable economics over all region/technology combinations in the U.S.

Modeling of hydrogen production with dedicated generation from wind, solar, and nuclear across regions of the U.S. indicates that without IRA incentives, the cost of electrolytic hydrogen production ranges from under $3 to around $7 per kgH_2. This range includes variation in the capital cost for electrolysis as well as regional renewable resources. The lowest production costs for zero-carbon resources obtain in Midwest regions using wind generation. Note that when the same modeling experiment is conducted with natural gas included as a generation option (again, without IRA production and investment incentives), a gas-fired combined cycle power plant is the lowest cost pathway overall for electrolytic hydrogen, at a cost of around $2.50 per kgH_2 (assuming a gas price of $3/MMBtu). However, this pathway is more costly and much less efficient than conventional SMR for producing hydrogen from natural gas. Accordingly, the direct carbon intensity of electrolysis from gas-fired combined cycle is approximately 16.9 $kgCO_2/kgH_2$, or roughly twice that of conventional SMR.[9]

Using these results as a benchmark, the same approach can be used to illustrate the impact of IRA incentives on the costs of electrolytic hydrogen production. **One key feature of the 45V hydrogen production subsidy is that it can be combined or "stacked" with the 45Y clean electricity production credit for zero-carbon generation, and with the 48E investment tax credit for storage and other zero-carbon technologies.** Examining first the impacts of 45Y and 48E alone (shown as "No 45V" in Figure 2), the dedicated generation model shows production costs for zero-carbon electrolytic hydrogen in the range of $1.84 to $5.63 per kgH_2. Moreover, the low end of the range, again corresponding to high-quality wind resource regions in the Midwest with low electrolysis costs, is below the cost of production using gas-fired combined cycle as the generation source (again assuming a $3/MMBtu gas price), or roughly equivalent with reference electrolysis costs. The implication is that an adoption subsidy for electrolytic hydrogen (such as 45V) could poten-

tially translate to increased renewable deployment based on 45Y and 48E incentives even without any explicit stipulations on the generation source. However, as the analysis in the subsequent section shows, the more likely outcome is some combination of wind and gas or other fossil, which might not result in a significant improvement below conventional SMR in terms of emissions intensity.

Finally, applying the dedicated generation model with 45V included alongside the other IRA incentives illustrates the potentially large relative magnitude of the subsidy. The range across regions, resources, and electrolysis capital cost uncertainty for the subsidized production cost of zero-carbon electrolytic hydrogen is $0.20 to around $4 per kgH_2. In other words, value of the subsidy (which translates to around $1.64 per kgH_2 in levelized terms, accounting for a project investment life that exceeds the subsidy period of 10 years) **covers around 90% of production costs in the most favorable cases (high-quality wind resource regions with lower electrolysis capital costs), and around 40% of production costs even in the most expensive configurations.**

The dedicated generation scenario represents in a sense the most restrictive interpretation of the qualification criteria for the highest tier of the 45V subsidy. Even in such a setting, the results show that the subsidized costs of production could be significantly lower than conventional SMR, suggesting a potentially large impact on hydrogen deployment. Nonetheless, it is unlikely that physically separate production will be required to qualify electrolytic hydrogen as low- or zero-carbon. When the analysis is extended to consider the more plausible case of grid-connected electrolysis, the questions of how the qualification criteria are defined and implications for costs, emissions, and adoption become more complex. Additionally, an integrated economy-wide analysis is needed to assess the potential scale of incremental hydrogen demand resulting from 45V-subsidized production. The next section describes an analysis with the US-REGEN model of alternative 45V implementation scenarios.

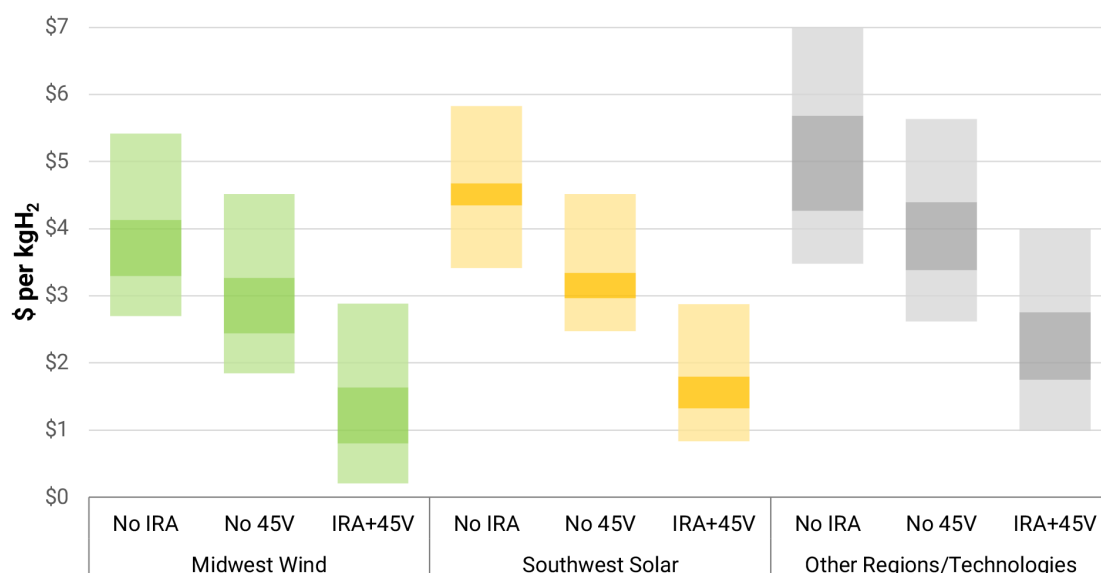9   Based on a heat rate of 6.26 MMBtu per MWh and 50 kWh per kgH_2.

Figure 2. *Levelized Cost of Hydrogen Production based on dedicated generation. Ranges are separated by region/technology category and IRA scenario. Midwest Wind refers to high quality wind resources in SPP, Texas, MISO, and parts of the Rocky Mountains. Southwest Solar refers to high quality solar resources in California, Arizona, Nevada, New Mexico, Texas, and parts of the Southern Plains. Other Regions/ Technologies includes solar and wind in the Southeast, Northwest, and Northeast as well as nuclear. The "No 45V" ranges include IRA incentives for generation and storage but not for hydrogen production. The darker middle part of each range reflects only within-category variation across region/technology for default electrolysis capital costs of $1400/kW-e. The full range reflects high and low electrolysis capital costs of $2800/kW-e and $700/kW-e, respectively. All costs shown in $2022.*

INTEGRATED ANALYSIS OF GRID-CONNECTED ELECTROLYSIS

When a producer of electrolytic hydrogen uses electricity supplied by the grid, its dispatch decisions and the dispatch of other grid-connected assets, as well as capacity additions (and potentially retirements), all become endogenous variables relevant to the determination of both the costs and the emissions intensity of production. As such, these metrics are conditional on the system characteristics and scenario assumptions for its future evolution and must be modeled in an integrated setting. In the context of a fixed-term subsidy such as 45V, the intertemporal dynamics of investment and dispatch also become important, since the expiration of the subsidy's term (10 years from the start of the project in the case of 45V) fundamentally changes dispatch incentives and thus consequential impacts. Note that such effects are not reflected in the levelized cost analysis for the dedicated (non-grid-connected) generation configuration described in the previous section, which implicitly assumes an unchanging operational pattern over the project's lifetime. The key difference is that in the grid-connected context, dispatch of the electrolyzer considers the opportunity cost of allowing power to flow to other customers on the grid instead.

The analysis presented here uses EPRI's US-REGEN modeling framework, an integrated economy-wide energy system model with a detailed representation of both electric generation and hydrogen production. The model also represents technology trade-offs in the end-use sectors and includes a range of fuel supply pathways and carbon management options. It has 16 regions, with more detailed spatial resolution for renewable resources and climate zones. Resource and load profiles are based on gridded, hourly data. US-REGEN is framed as an intertemporal optimization of both investment and dispatch of energy supply and demand technologies through 2050. It reflects existing state and federal policies and can be used to analyze the impacts of potential future policy and technology developments. The full model documentation is available here. See the Appendix for additional information on the key input assumptions for this study, including cost and performance for hydrogen technologies and the representation of IRA incentives.

In addition to modeling the potential generation and emissions impacts of electrolytic hydrogen supply, analysis with US-REGEN can assess the potential scale of demand for hydrogen, including existing industrial uses as well as potential new demands in both the electric and non-elec-

tric sectors in response to the 45V incentive. Modeled new demands include:

- Electric generation (which is assumed to require new hydrogen-ready combustion turbine or combined cycle capacity)
- Blending with natural gas in existing pipelines to meet non-electric gas demands (up to 20% by volume or around 7% on an energy basis)
- Direct use of hydrogen for commercial and industrial heating, and hydrogen fuel cell vehicles for both on-road and non-road applications

An important consideration for any new hydrogen application is the distribution cost to deliver hydrogen from the production location to the end-user, which in many cases can be significantly larger than the production costs (particularly for vehicle applications which incur high costs for dispensing to pressurized on-board tanks). Hydrogen distribution costs are modeled in US-REGEN as a levelized cost adder to delivered hydrogen that varies by sector and application (see assumptions here). One key assumption is what level of distribution costs to assume for hydrogen delivered to electric generators. For this analysis, we have assumed a levelized distribution cost of $6/MMBtu (or roughly $0.68/kgH_2), similar to other large industrial users (and lower than other sectors and applications). The implications of this assumption are discussed further below.

SCENARIOS

The analysis in this paper considers four scenarios for defining the qualification criteria for zero-carbon generation to qualify electrolytic hydrogen for the $3/kgH_2 45V production subsidy. These scenarios, summarized in Table 2, follow the three so-called "pillars" described above: temporal matching, additionality, and deliverability. In the first scenario, labeled 45V_3P, all three pillars are enforced. In the 45V_2P scenario, the additionality and deliverability pillars are enforced, but only annual matching is required. The 45V_1P scenario allows both annual matching and existing zero-carbon resources, enforcing only the deliverability pillar. The 45V_0P scenario further relaxes the criteria to allow annual-matched, existing or new zero-carbon resources anywhere in the U.S. to qualify. In each scenario, the criteria are implemented via a compliance obligation for zero-emissions resource credits (ZERCs) equal to the amount of generation used for qualifying hydrogen production. When hourly matching is enforced, ZERCs include a time stamp which must coincide with production. To ensure additionality, only new vintage technologies earn ZERCs, and deliverability requires that ZERCs come from the same model region. As a baseline for comparison to these alternatives, a fifth scenario includes all IRA incentives except for 45V, labeled No_45V.

The analysis also considers two scenarios for hydrogen demand. In the first, all end-use fuel demands are fixed to their values in the No_45V case. This "Fixed Demand" scenario excludes potential incremental non-electric hydrogen demand in response to lowered hydrogen prices resulting from the 45V incentive. Any new electrolytic production can be used only to offset non-electric production (excluding production integrated with ammonia synthesis) for baseline end-use demands or within the electric sector as a generation fuel. This comparison allows a cleaner hypothetical calculation of the consequential generation and emissions impacts of 45V-subsidized electrolytic production before accounting for non-electric demand feedbacks. The second scenario considers the full equilibrium response to the alternative 45V scenarios, incorporating a broader range of effects. This scenario is labeled "Full Response."

Table 2. *Scenario descriptions for alternate assumptions about IRA hydrogen tax credit (45V) qualification criteria.*

	TEMPORAL MATCHING: Zero-carbon generation must coincide with electrolysis production on an hourly basis	ADDITIONALITY: Zero-carbon resources must be new capacity	DELIVERABILITY: Zero-carbon resources must reside in the same region as electrolysis production
Three Pillars (45V_3P)	✓	✓	✓
Two Pillars (45V_2P) (only annual matching required)		✓	✓
One Pillar (45V_1P) (annual matching with existing resources allowed)			✓
No Requirements (45V_0P) (any zero-carbon generation in the U.S. qualifies)			

RESULTS: FIXED HYDROGEN DEMAND SCENARIO

As suggested in the preceding sections, the **introduction of the 45V subsidy could lead to significant deployment of new hydrogen production from electrolysis**. In general, the effect of relaxing the certification criteria (i.e., moving from 45V_3P to 45V_0P) is to increase the amount of hydrogen deployment and subsidy uptake. However, it could also increase economy-wide CO_2 emissions. Starting with the hydrogen demand scenario without non-electric demand feedbacks, the top row of Figure 3 shows hydrogen production over time across the five 45V scenarios. The model operates in five-year time-steps and assumes that new additions in the 2030 and 2035 time-steps are eligible to receive the 45V production subsidy in the current and subsequent time-steps.[10] During the subsidy period, electrolytic production increases rapidly, displacing conventional non-electric production and expanding to produce additional hydrogen that is consumed for electric generation.

In all scenario variations for the qualification criteria, the **45V production subsidy leads to operation of electrolysis at a high capacity factor** (80–90%), with production curtailed only during periods of very high electricity prices. At the same time, the subsidized price of hydrogen encourages dispatch of hydrogen-fired electric generation at a capacity factor of around 30–40%, most of which coincides temporally with electrolytic production. Thus, the 45V subsidy creates a large enough incentive to compete with natural gas for power generation, despite roundtrip losses of around 65% from converting electricity to hydrogen and back again.[11] By the 2045 time-step, the subsidy has expired for all vintages, at which point some electrolysis capacity added during the subsidy period is retired, although some remains, operating at a lower capacity factor. In the post-subsidy period, it is no longer economic to use hydrogen for electric generation.

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10   The IRA stipulates that projects commencing construction by the end of 2032 are eligible for the subsidy.

11   Assuming 70% efficiency for electrolysis and 50% efficiency of a combined cycle turbine, the roundtrip efficiency would be 35%, implying 65% losses. For hydrogen generation with a less efficient simple cycle turbine, roundtrip losses would be greater.
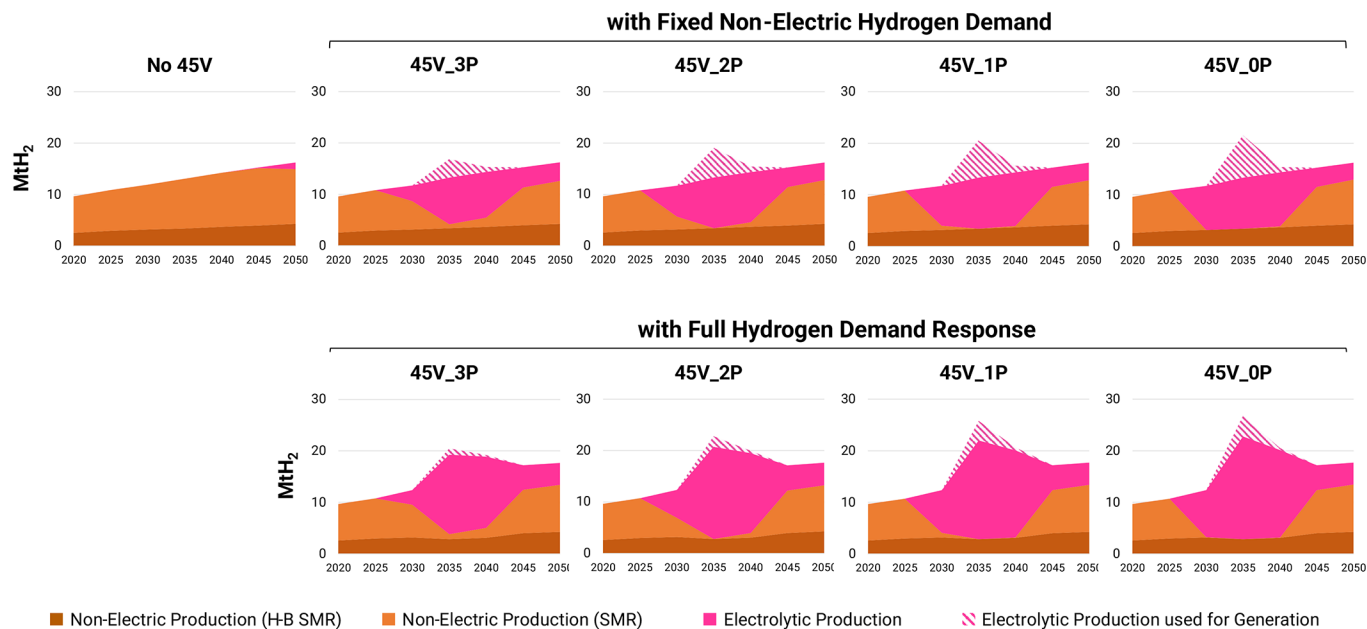

Figure 3. *Hydrogen Production and Disposition of Electrolysis across qualification criteria scenarios and hydrogen demand scenarios (see Table 2 for scenario definitions). Total orange area (light plus dark) reflects total non-electric hydrogen production. Darker orange area refers to production from SMR integrated with ammonia synthesis in the Haber-Bosch (H-B) process. Total pink area (solid plus hatched) reflects total electrolytic hydrogen production. Hatched pink area refers to the subset of electrolytic production that is directed back to electric generation. The "Full Hydrogen Demand Response" is discussed in the next section. Current production of around 10 MtH₂ corresponds to roughly 1.1 quad Btu in energy terms based on LHV.*
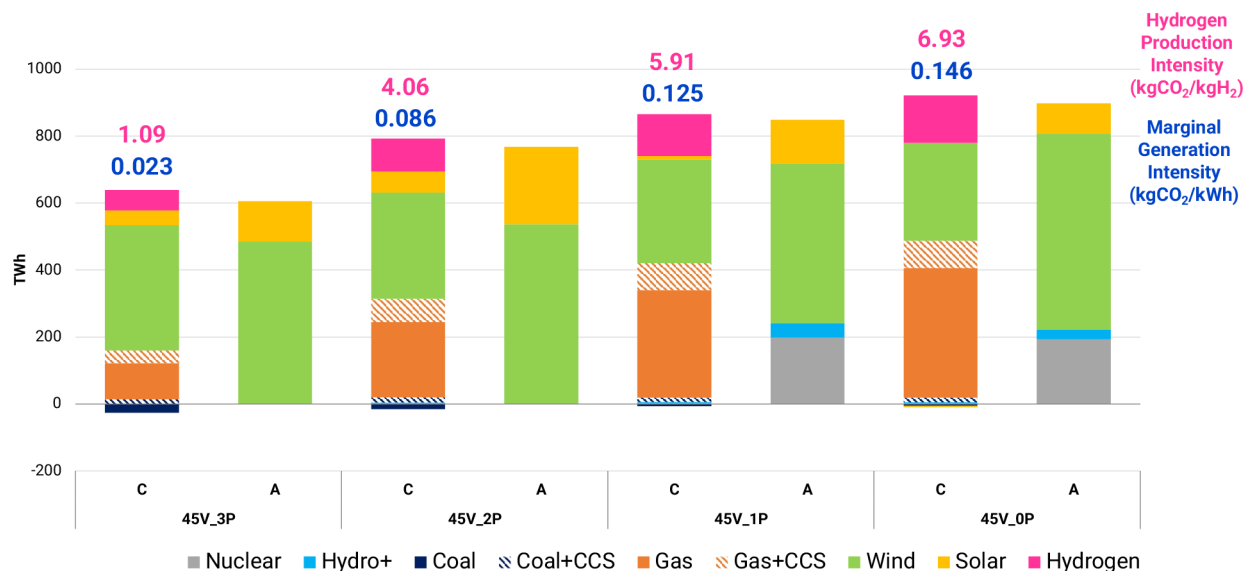
Figure 4. *2035 Change in Generation vs. No 45V Case (C) compared to Attributed Generation to 45V Hydrogen Production (A) for Fixed Demand scenario (see Table 2 for scenario definitions). Consequential generation (C) is the actual change in generation, whereas attributed generation (A) is the nominal generation providing ZERCs for qualification. Marginal generation intensity and hydrogen production intensity metrics are based on consequential change in emissions divided by incremental generation and hydrogen production, respectively.*

The key result for understanding the implications of the alternative scenarios for qualification criteria is the modeled change in generation to supply expanded electrolytic production. In each scenario, electricity consumed for 45V-qualified electrolysis must be matched by a corresponding amount of ZERCs, whose definition varies by scenario. The generation providing ZERCs for qualification is referred to as "attributed generation," and its associated "attributed emissions" are by definition zero. However, because of endogenous responses to both dispatch and capacity in the power system, the actual change in generation, or "consequential generation," may not be the same as attributed generation, and its associated "consequential emissions" may not be zero (Figure 4). This analysis demonstrates that **as the qualification criteria are relaxed, the difference between consequential and attributed generation becomes larger**, and that even with the most stringent "three pillar" criteria, the consequential marginal intensity of generation is greater than zero, though these increases in electric sector CO_2 are offset by reductions in CO_2 from hydrogen production (Figure 5).

Figure 4 shows consequential versus attributed generation in 2035 for each criteria scenario (again for the case with no incremental non-electric hydrogen demand). As noted previously, production and hence generation increase for scenarios with more relaxed criteria. But incremental gen-

eration from fossil, particularly combined cycle natural gas, also increases, making up larger fraction of total consequential generation as the criteria relax. This is particularly true for the scenarios with deliverability only or no requirements (45V_1P and 45V_0P cases), which allow existing zero-carbon resources such as nuclear and hydro to provide qualifying ZERCs as part of the attributed generation mix. Because these resources are not additional, allowing them to be used for attribution effectively puts no constraints on the consequential generation used to meet the incremental electrolysis load. In fact, in the 45V_0P case in which there is only one national, annual ZERC market for which both existing and new zero-emissions resources qualify, the price in that market is zero, implying that the qualification criteria are non-binding. Thus, this scenario coincides with a case where all electrolytic hydrogen production is eligible for the highest tier of the 45V subsidy regardless of the attributed generation source.

In the 45V_3P case, which enforces hourly matching, additionality, and local deliverability, the consequential generation mix is closest to the attributed mix, but even in this case there is a certain amount of "leakage" whereby incremental electrolytic load leads to increases in generation from non-qualified sources. To illustrate how this can happen, consider that a certain amount of high-quality
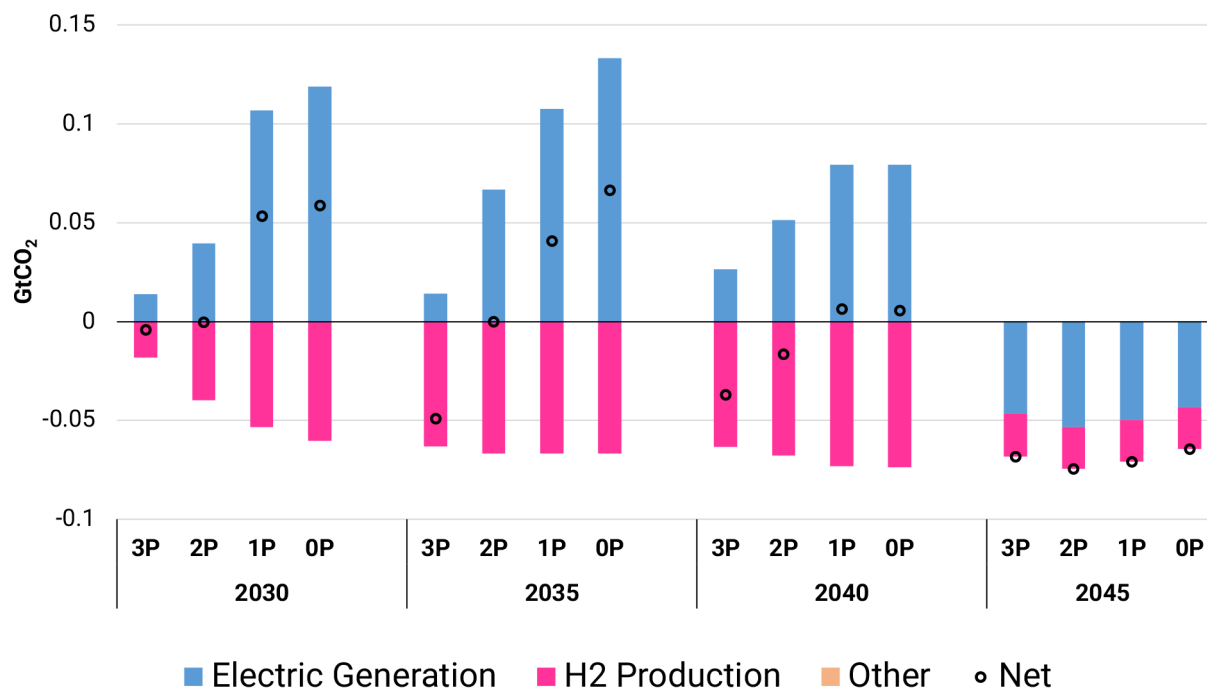
Figure 5. *Change in CO₂ emissions in 45V scenarios versus the No 45V Case over time (see Table 2 for scenario definitions, assumes fixed non-electric hydrogen demand). Changes illustrate increasing emissions for less stringent qualification criteria.*

renewable resources (e.g., Midwest Wind or Southwest Solar) are added in the baseline scenario, i.e. they are economic even without the 45V subsidy. When the 45V subsidy is introduced, these resources now qualify for ZERCs which can be used to offset incremental generation from other sources (such as gas or possibly gas with CCS depending on 45Q or other policy incentives). **From an enforcement perspective, it can be difficult to distinguish whether a resource is additional relative to a hypothetical baseline, thus it is assumed that all new qualifying sources are considered eligible, creating the potential for this type of leakage.**

In the 45V_2P case, hourly matching is relaxed to require only annual matching (while still enforcing the other two pillars). The result is more attributed generation from wind and solar but less actual (i.e., consequential) incremental zero-carbon generation compared to the more stringent 45V_3P case. In both scenarios, the 45V production subsidy encourages near-constant operation of electrolysis, but the relaxed matching requirement affords more flexibility for incremental dispatch from fossil resources to meet electrolytic load. In all scenarios, some incremental generation comes from gas and coal with CCS, even though these technologies are not included as qualified zero-carbon

sources, and in fact deployment of CCS increases as incremental generation increases with less stringent criteria. The implication is that the 45Q incentive for captured carbon, along with state policies in some cases, act to moderate the leakage effects of relaxing the 45V qualification criteria.

Figure 4 also indicates the corresponding consequential emissions intensity of both generation and hydrogen production in each case. Note that in the 45V_3P and 45V_2P cases, emissions from incremental gas-fired generation are partially offset by decreased dispatch of existing coal. Apart from this effect, the marginal emissions intensity essentially reflects the share of gas versus zero-carbon resources in the incremental mix, which reaches around 40% in the least binding 45V_0P case. In all cases, the consequential intensity of hydrogen production (direct CO₂ emissions only) is greater than the 0.45 kgCO₂-e/kgH₂ threshold for qualification for the \$3/kg subsidy, despite an attributional intensity of zero. Although the consequential intensity remains below the direct CO₂ intensity of conventional production (around 8 kgCO₂/kgH₂, as noted above), only a portion of electrolytic production goes toward offsetting non-electric production, with as much 46% absorbed by expansion of hydrogen use into the electric sector in 45V_0P case (Figure 3).
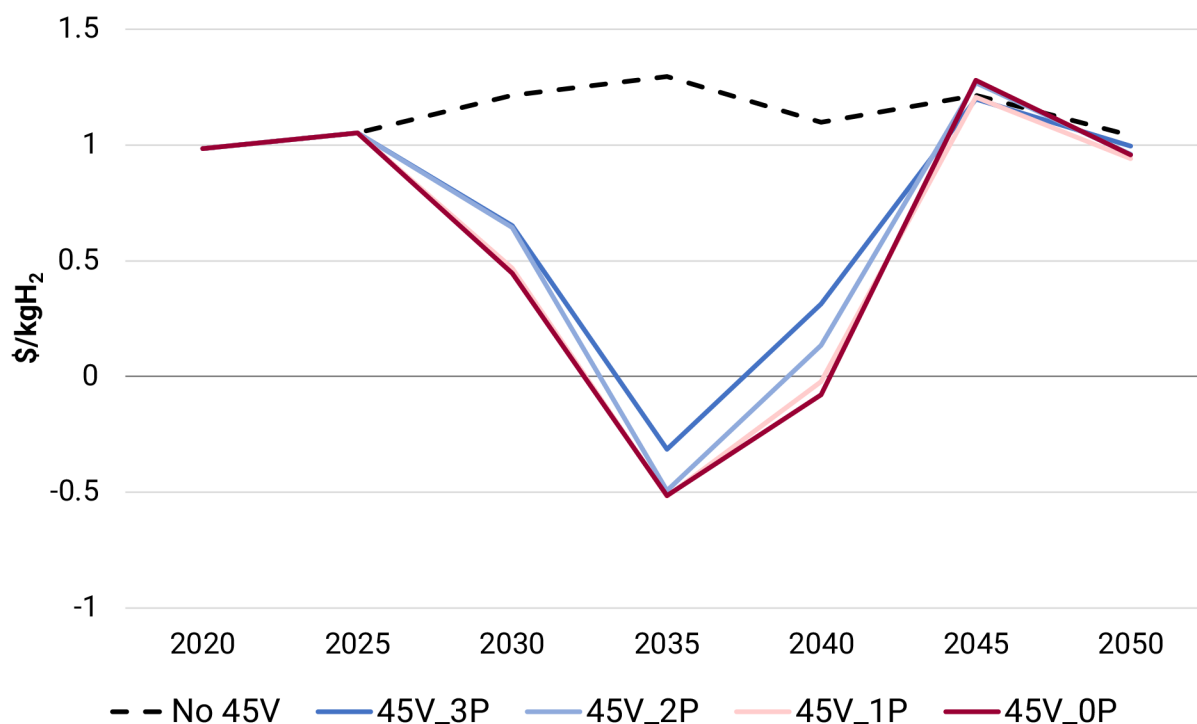
Figure 6. U.S. average hydrogen production price (excludes storage and delivery costs) in $2022 across qualification scenarios for fixed demand case (see Table 2 for scenario definitions).

The net effect on total CO_2 emissions depends on the balance between increased emissions from electric generation and decreased emissions from displaced conventional SMR production, shown in Figure 5. **Only in the 45V_3P case does the 45V subsidy decrease net CO_2 emissions during the subsidy period**. The net effect is roughly zero in the 45V_2P case and clearly positive in the less stringent criteria cases. That is, **with less stringent qualification criteria for input generation, subsidizing electrolysis leads to greater emissions from incremental generation than it offsets from displaced conventional hydrogen production**. After the subsidy period, CO_2 emissions are slightly lower than in the No 45V baseline in all cases, because some remaining electrolysis continues to offset non-electric production, and because the induced build-out of wind and solar during the 45V subsidy period leads to slightly greater installed capacity levels afterwards.

During the period of eligibility for the 45V subsidy there is a strong impact on the realized production price of hydrogen, shown in Figure 6. In 2035, the production price (national average weighted by regional production) falls below zero because the value of the subsidy exceeds the variable costs of production. Because electrolysis is deployed preferen-

tially in regions with favorable economics (especially the Midwest), the national average price during the subsidy period mainly reflects costs in those regions. Production prices are slightly lower with less stringent qualification criteria. However, these comparisons illustrate how adding more stringent certification criteria to lower the emissions intensity of hydrogen production is relatively low cost, adding $0.1-0.2/kgH_2 to meet all three pillars. Note that in the No 45V case, conventional SMR production is setting the price. After the subsidy period, prices return to roughly this level, although some electrolytic production remains.

RESULTS: FULL FEEDBACKS ON NON-ELECTRIC HYDROGEN DEMAND

For scenarios that allow full feedbacks on non-electric hydrogen demand, lower production prices lead to increases in hydrogen demand and production from electrolysis across all qualification scenarios (second row of Figure 3). Increased hydrogen demand is greatest in the scenarios with less stringent qualification criteria. **Some of these demand increases are temporary, peaking in 2035 and declining thereafter, given the expiration of the tax credits and return to unsubsidized price levels** (Figure 6). The

short-term demand increase comes mostly from blending into existing natural gas infrastructure, which can be reversed after the subsidy period at low costs, as well as some uptake for ammonia production (displacing a small amount of conventional Haber-Bosch production using SMR with natural gas), fuel cell vehicles, and other applications in more limited quantities. Increased competition for hydrogen leads to less demand in the electric sector when non-electric demand responses are incorporated but higher demand economy-wide. Consequently, equilibrium prices are slightly higher in the "Full Response" scenario.

Net CO_2 emissions across the qualification cases in 2035 are shown in Figure 7 for both hydrogen demand scenarios. As in the "Fixed Demand" case discussed earlier, overall emissions increase for the one- and zero-pillar cases relative to the case without 45V credits in the "Full Response" case, with larger emissions increases due to the more extensive scale of electrolytic hydrogen production and associated CO_2 from electricity generation. However, hydrogen displaces fossil fuel consumption in these "Full Response" cases (e.g., from blending with natural gas), which partially offsets incremental CO_2 from electric generation and leads to net emissions declines in the two-pillar case, unlike the Fixed Demand case that leads to roughly zero change. **Overall, these scenario results suggest that, with less stringent qualification criteria for input generation, 45V credits increase net CO_2 emissions during the subsidy period.**

Generation to supply new electrolytic production in the 45V_3P case is largely concentrated in the Midwest region, and a large share of both consequential and attributed generation comes from wind power (Figure 8). This result mirrors earlier findings both in the case of electrolysis with dedicated generation (Figure 2) and the grid-connected mix with fixed non-electric hydrogen demand (Figure 4). Even with enforcing the three pillars, incremental electrolytic load can lead to increases in generation from emitting sources, as shown in the higher gas-fired generation in the East. The large influx of variable renewable energy leads to changes in dispatch and power flow patterns across model regions, as illustrated by the shifts in gas dispatch in the South and East regions.
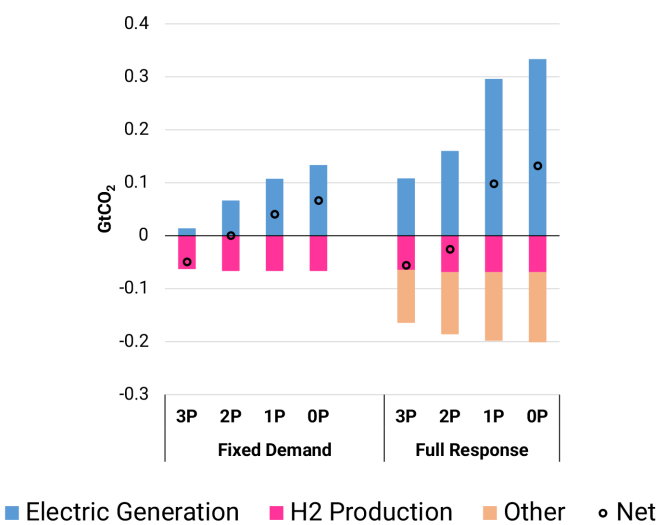

Figure 7. *Change in 2035 CO_2 emissions in hydrogen demand scenarios vs. No 45V Case, assuming different qualification criteria (see Table 2 for scenario definitions).*

Table 3 provides a summary of the scale of hydrogen deployment and associated fiscal outlay on the 45V production tax credit. Total installed electrolysis capacity peaks in 2035, reaching 94 to 164 GW-e across scenarios (and declining to 52–74 GW by 2050). Cumulative electrolytic hydrogen production over the model time horizon ranges from 166 to 297 MtH$_2$, as compared to only around 10 MtH$_2$ in the No 45V scenario, with most production occurring during the subsidy period. **The range of total cumulative undiscounted fiscal outlay for 45V in $2022 is $385 to $756 billion, plus an additional $90 to $176 billion on outlay for other IRA incentives induced by 45V uptake**. In the 45V_1P and 45V_0P scenarios, fiscal outlay is highest, while cumulative emissions increase. Because 45V subsidy uptake peaks in 2035 and continues at high levels through 2040 before declining, only 13–25% of cumulative fiscal costs are incurred during the current 10-year budget period ending in 2032. This range depends on the extent of deployment in the 2030 timeframe, which is more sensitive to the qualification criteria and subject to uncertainty about electrolysis capital costs and other factors.
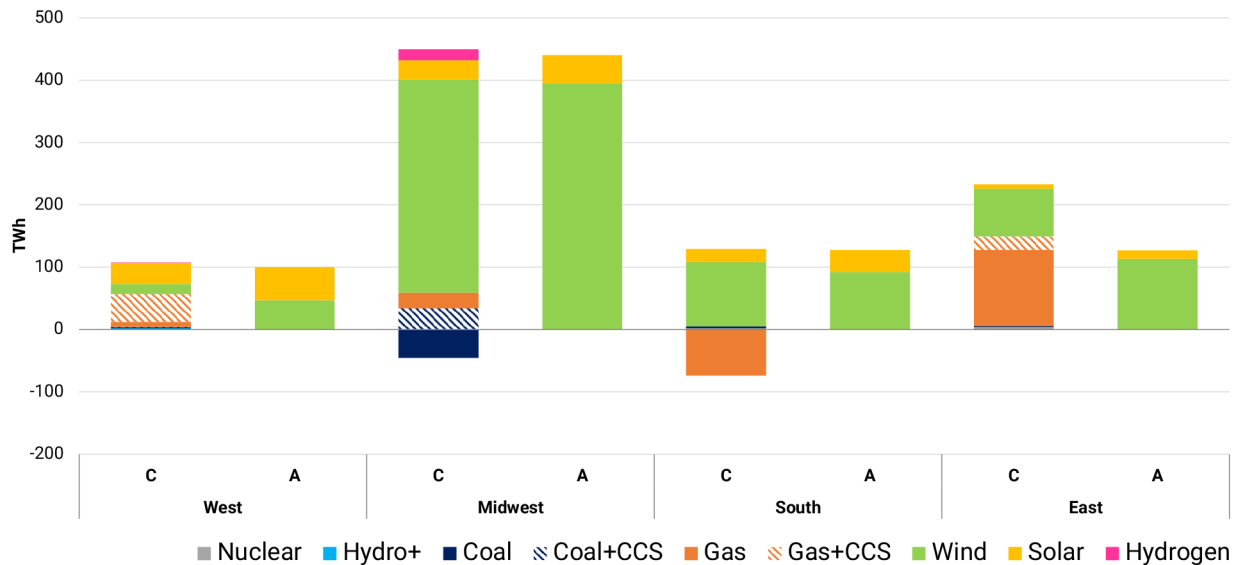
Figure 8. *2035 Change in generation vs. No 45V Case (C) compared to attributed generation to 45V hydrogen production (A) by region for the 45V_3P scenario with full hydrogen demand response. Consequential generation (C) is the actual change in generation, whereas attributed generation (A) is the generation providing ZERCs for qualification. Regional definitions are shown in the Appendix.*

Table 3. *Summary of 45V impacts on electrolytic hydrogen deployment and fiscal outlay*

	"Fixed Demand" hydrogen demand scenario			
	45V_3P	45V_2P	45V_1P	45V_0P
Electrolysis Capacity in 2035 (GW-e)	94	105	121	125
Cumulative H$_2$ Production 2025-2050 (MtH$_2$)	166	199	219	227
Subsidized H$_2$ Production (MtH$_2$)	128	163	183	191
Total Fiscal Outlay for 45V ($2022 B)	385	488	548	574
Increase in Other IRA Outlay vs. No 45V ($2022 B) *(includes 45Y, 48E, and 45Q)*	90	98	107	108

	"Full Response" hydrogen demand scenario			
	45V_3P	45V_2P	45V_1P	45V_0P
Electrolysis Capacity in 2035 (GW-e)	121	134	160	164
Cumulative H$_2$ Production 2025-2050 (MtH$_2$)	213	253	289	297
Subsidized H$_2$ Production (MtH$_2$)	168	207	244	252
Total Fiscal Outlay for 45V ($2022 B)	504	621	731	756
Net Change in Other IRA Fiscal Outlay ($2022 B) *(includes 45Y, 48E, and 45Q)*	162	176	174	173

DISCUSSION

This analysis explored potential impacts of IRA's 45V hydrogen tax credits under a range of implementation scenarios. We expand the literature by using a full energy systems model—encompassing fuel production, transport, storage, and use—unlike the majority of 45V assessments that do not capture feedbacks outside of the power sector (Table 1). However, similar to most power-sector-focused studies, we find that economy-wide CO_2 emissions generally increase with IRA's hydrogen tax credits unless all three pillars—hourly temporal matching, additionality, and deliverability—are included. After the subsidy period ends, our analysis indicates an emissions decline across all implementation scenarios relative to a counterfactual without 45V credits due to continued (although diminished) displacement of fossil-based hydrogen production with electrolysis as well as increased deployment of wind and solar, though these effects are small relative to the increases through 2040. Even with all three pillars, we show that some emissions leakage exists, which increases power sector emissions with 45V relative to the case without these credits. Change in total cumulative economy-wide emissions ranges from a reduction of 0.67 $GtCO_2$ in the 45V_3P case to an increase of 0.34 $GtCO_2$ in the 45V_0P case.

Our comprehensive scope and endogenous investment allow us to provide the first estimate of fiscal costs and abatement costs of 45V credits. Cumulative fiscal costs through 2040 are $504–756 billion in real 2022 dollar terms, which is similar in magnitude to projected outlays on power sector production and investment tax credits under the IRA (Bistline, et al., 2023). These high fiscal costs and modest emissions reductions under the three pillars scenarios indicate very high fiscal outlay per tonne of IRA's 45V hydrogen tax credits, which can exceed $750/t-$CO_2$. These costs are approximately an order-of-magnitude higher than the implied abatement costs of other IRA credits (Bistline, et al., 2023) and greater than recent social cost of CO_2 estimates (Rennert, *et al.*, 2022). In scenarios with limited pillar requirements, economy-wide CO_2 emissions can increase from 45V credits, despite billions of cumulative associated fiscal costs.

The national coverage of our analysis allows us to show the regional variation in electrolyzer deployment and power sector responses, with Midwest wind accounting for the bulk of electrolytic hydrogen production due to its lower

costs than other geographies and resources. This result indicates that earlier studies focusing on specific geographies with ex-ante assumptions about electrolyzer deployment and/or generation mixes to support such hydrogen production may not adequately track economic drivers for adoption. Note that the analysis does not include the $7 billion from the Regional Clean Hydrogen Hubs program that is funded through the Bipartisan Infrastructure Law, which includes seven hubs across the country with a range of hydrogen production approaches.

These results raise several additional questions:

- **Blending in power sector and impacts of EPA's proposed power plant performance standards:** The scenarios in this analysis consider the ability to blend hydrogen into existing natural gas pipelines for non-electric end-uses up to 20% by volume (7% on an energy basis). Blending hydrogen for existing gas-fired electricity generation also may provide an off-taker for subsidized hydrogen. One possible motivation for blending at existing gas turbines and combined-cycle plants is EPA's proposed power plant performance standards under Section 111 of the Clean Air Act, which were proposed in May 2023 and have compliance pathways that entail hydrogen blending. While this analysis assumes 20% blending by volume is broadly feasible, there are many uncertainties in cost and performance impacts and important operational characteristics that have not been demonstrated at commercial scale (EPRI, 2023).

- **Impacts of long-run climate policies replacing IRA:** This analysis includes on-the-books federal and state policies, including IRA tax credits and their expirations. However, the policy landscape may shift over time and entail emissions policies that offer different incentives for hydrogen production and consumption. Many states and companies have pledged to reduce their carbon emissions to net-zero levels, and policies that assist energy systems to achieve these goals may have different roles for hydrogen than the tax credits provided by IRA. For instance, in EPRI's Net-Zero 2050 report (Blanford, et al., 2022), hydrogen demand in economy-wide net-zero CO_2 scenarios ranges from 4–10 Quad Btus in 2050, which is higher than 2050 demand in the IRA-only scenarios in this paper. However, hydrogen production for a cost-minimizing net-zero target is primarily through SMR with CCS and bioenergy with CCS instead of the electrolytic hydrogen production that dominates the IRA scenarios in this analysis.

A key point is that the expiration of the 10-year production subsidy fundamentally changes dispatch incentives for electrolysis. For instance, the uptake for blending and dual-fuel power generation could disappear once hydrogen production does not receive these substantial credits. The degree to which the tax credit expiration lowers capacity factors of electrolyzers also depends on the evolving policy context, including potential economy-wide net-zero policies. Such paradigm shifts in electrolyzer use, hydrogen cost, and hydrogen demand may be true regardless of whether new vintage eligibility is extended for hydrogen tax credits.

- **Potential hydrogen demand from export markets:** This analysis focus solely on impacts of 45V credits on domestic hydrogen demand. However, IRA's incentives for low-emitting hydrogen production and carbon capture may alter the economics of export markets for low-emitting fuels. For instance, methane derived from CO_2 and low-emitting hydrogen—referred to as e-gas or e-methane—may provide a low-emitting alternative to fossil-based natural gas, especially for countries with higher conventional fuel costs (Venkatesh, Blanford, and Molar-Cruz, 2023).

- **Effects on technological change:** Tax credits are aimed not only at reducing emissions but also at encouraging technological change and providing operational experience for hydrogen production, transport, storage, and use. Such experience can contribute to buying down learning curves so that low-emitting hydrogen is ready to deploy when needed as the economy approaches net-zero levels. However, the impacts of these tax credits on future technological cost and performance depend on several uncertain factors, including spillovers from actions in other countries, the relative drivers of cost reductions (e.g., learning-by-doing, economies of scale, research and development), as well as changes in materials and labor costs.

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APPENDIX: US-REGEN MODELING FRAMEWORK

EPRI's U.S. Regional Economy, Greenhouse Gas, and Energy (REGEN) model represents 16 distinct regions of the continental U.S. (Figure A1).

The US-REGEN energy-economy system model features detailed representations of electric sector capacity and dispatch, end-use sector activities and technologies, and non-electric fuel supply, including an expanded set of fuel pathways including hydrogen and hydrogen-derived fuels. For the power sector and hydrogen production, the model determines generation capacity investments, generation dispatch, energy storage investment and operations, hydrogen production, transmission and CO_2 pipeline investments, and other parameters to minimize the net present value of system costs to meet demand in every hour subject to policy, market, and technology constraints.
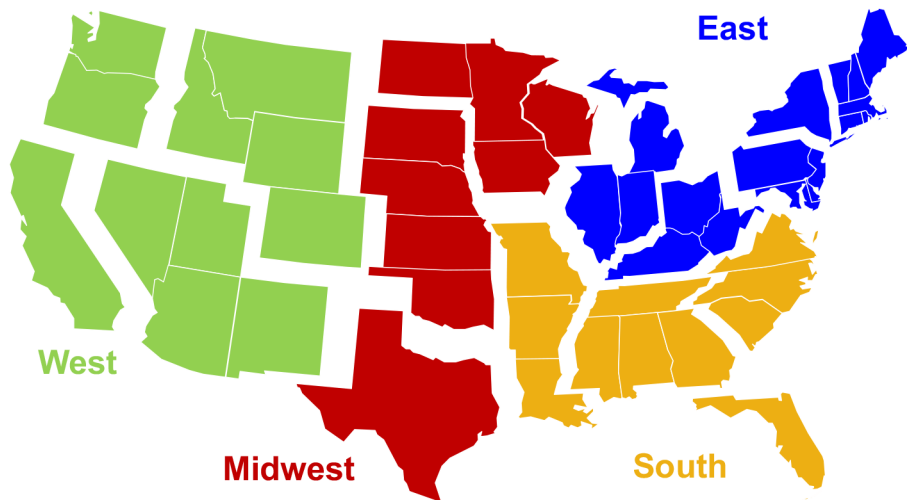

Figure A1. *US-REGEN regional aggregation for this analysis. 16 state-based model regions are shown with the four aggregate reporting regions.*
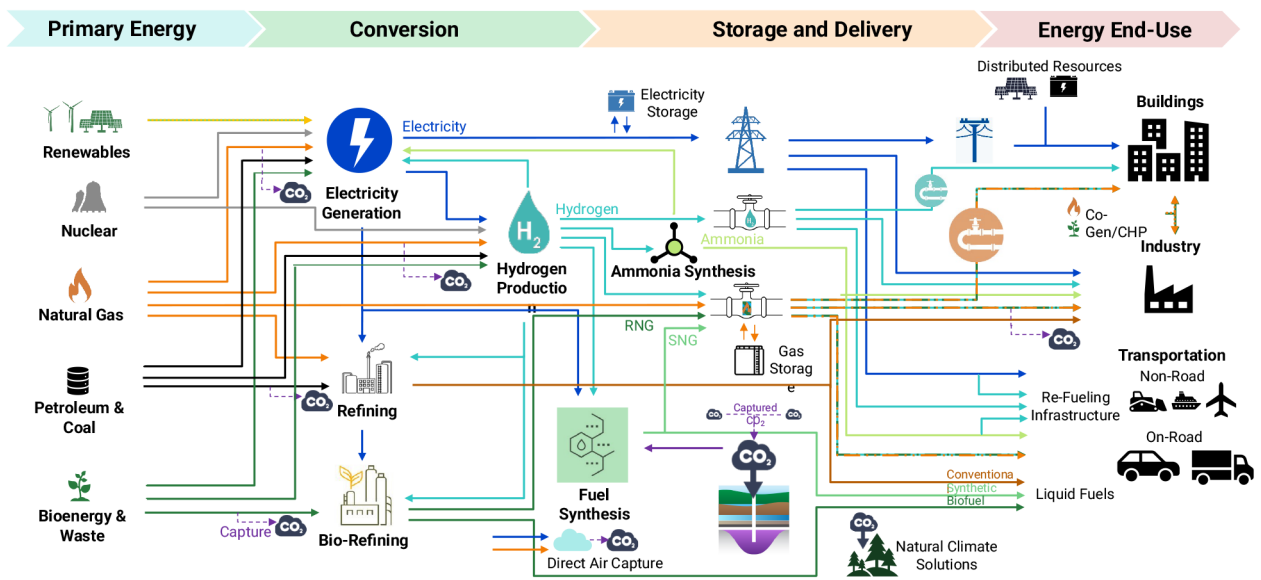

Figure A2. *Economy-wide low-carbon energy pathways modeled in US-REGEN.*
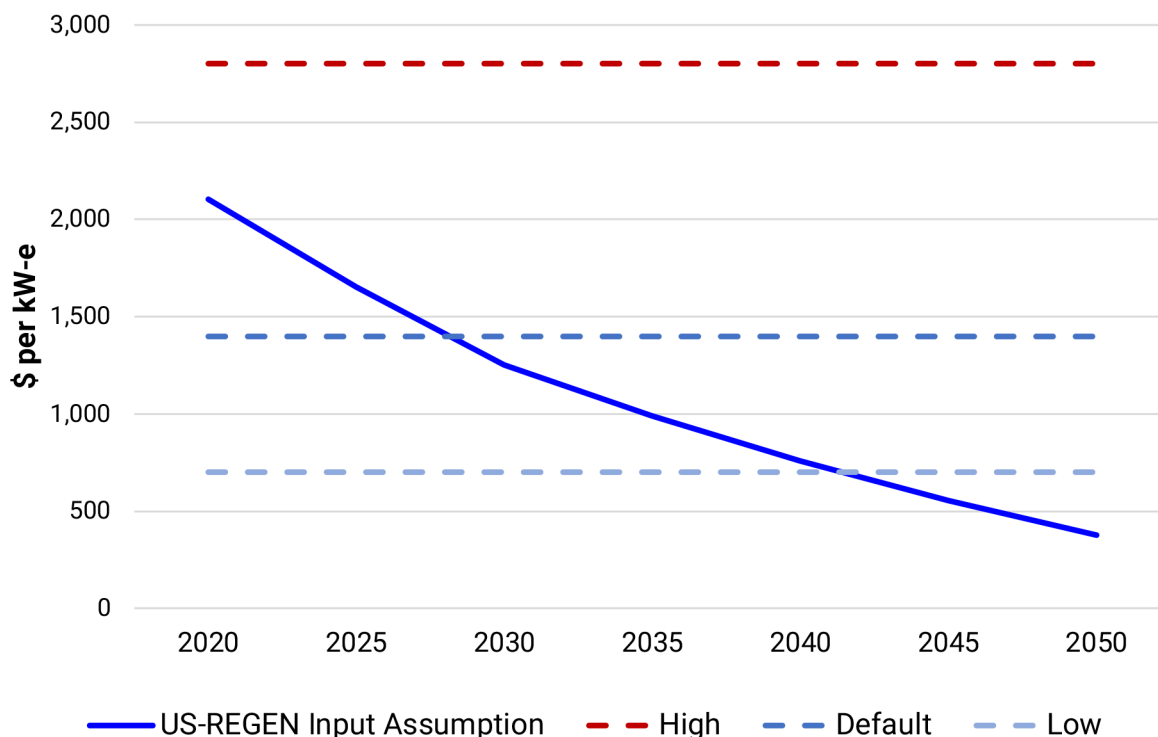
Figure A3. *Electrolysis Capital Cost Assumptions (total capital requirement in $2022). Default, High, and Low levels correspond to the sensitivity range used in the dedicated generation analysis. The US-REGEN cost curve reflects the model's exogenous assumption for new vintage investment costs in each model time-step.*

Technology cost and performance estimates are based on EPRI's Technology Assessment Guide (TAG) framework, which provides detailed engineering-based studies, including the expanded array of low-carbon technologies for the Net-Zero 2050 report (Blanford, et al., 2022): https://lcri-netzero.epri.com/en/description-model.html

Electrolysis capital cost assumptions over time are shown in Figure A3, including higher and lower sensitivity assumptions for the dedicated generation analysis.

Scenarios in this analysis assume on-the-books federal and state policies and incentives. Inflation Reduction Act (IRA) tax credits related to this analysis include not only the 45V hydrogen credits, described in earlier sections, but also:

• **Clean Electricity Production Tax Credit (PTC, 45Y):** The PTC becomes technology-neutral in 2025 for zero-emitting generation options. Credits are $27.50/MWh with the labor bonus with 10% bonuses for domestic content and energy communities. This credit remains in place at its full value until the latter of 2032 or when the power sector reaches 25% of its 2022 levels.

• **Clean Electricity Investment Tax Credit (ITC, 48E):** The ITC is 30% with the labor bonus with 10 percentage point bonuses for domestic content and energy communities. Like the PTC, the ITC can extend until power sector emissions reach 25% of their 2022 levels.

• **CO_2 Capture Credits (45Q):** 45Q credits award up to $85/t-$CO_2$ for stored CO_2. There is a 12-year project eligibility, and facilities must commence construction by 2032 to be eligible.

Fuel costs are endogenously determined in US-REGEN on a region- and scenario-specific basis.

Detailed US-REGEN documentation as well as recent reports and peer-reviewed journal articles can be found at https://esca.epri.com/models.html.

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GTI Energy is a leading research and training organization. Our trusted team works to scale impactful solutions that shape energy transitions by leveraging gases, liquids, infrastructure, and efficiency. We embrace systems thinking, open learning, and collaboration to develop, scale, and deploy the technologies needed for low-carbon, low-cost energy systems.

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