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Abstract

Governments worldwide have recently launched policy support programs for hydrogen, where the level of support is to be tied to the carbon intensity of the hydrogen produced. Here we analyze the impact of alternative accounting rules for assessing the carbon intensity of electrolytic hydrogen on the financial and emission performance of Power-to-Gas (PtG) systems. We initially calibrate our model to reference plants eligible for the production tax credit specified under the Inflation Reduction Act in the United States. Contrary to common beliefs, we find that more stringent accounting rules provide investors with sufficient incentives to invest in PtG systems today. Yet, they can still lead to life-cycle average carbon intensity levels close to those for hydrogen produced from natural gas with carbon capture. Less stringent rules generally entail higher investment incentives but also significantly higher emissions. Overall, our findings reflect the incentives for investors to utilize capacity by procuring additional, carbon-intensive electricity from the general grid.

Keywords: hydrogen, carbon accounting, climate policy, life-cycle costing, capacity investments

JEL Codes: M41, M48, Q56, Q58

1 Introduction

Governments around the world have recently launched support policies for electrolytic and other low-carbon hydrogen production technologies[1–5]. These policies aim to accelerate the transition to a decarbonized economy, particularly in hard-to-abate sectors such as steel, chemicals, and heavy transportation[6–11]. Since the abatement potential of electrolytic hydrogen hinges on the emissions embodied in the electricity converted via Power-to-Gas (PtG) processes, governments in the United States (US), the European Union, and other regions have tied the level of policy support to the carbon intensity of the hydrogen produced. Yet, it remains a topic of intense debate how to assess this carbon intensity and thereby determine the level of support[12–15].

This paper examines the impact of alternative accounting rules for assessing the carbon intensity of electrolytic hydrogen and thus the level of policy support for PtG systems. In the debate on this topic, the common belief is that more stringent rules incentivize electrolytic hydrogen production during periods of abundant renewable energy and thus result in lower emissions than hydrogen production from natural gas[12;13]. Yet, more stringent rules might also starve PtG systems as long as abundant renewable energy remains infrequent, thereby limiting incentives for initial investments[16;17]. Our analysis shows how alternative rules shape the trade-off between the profitability of PtG systems and the average carbon intensity of the hydrogen produced over the life cycle of these systems.

In alignment with Europe, US regulators during the Biden administration have recently announced plans to base the assessment on multiple pillars that increase in stringency over time[18]. Accordingly, any renewable electricity that investors seek to credit to the produced hydrogen is to be deliverable to PtG plants and incremental to the existing renewable energy supply in the market. For hydrogen produced before 2030, the temporal matching of electricity generation and hydrogen production is to be assessed on an annual basis, as is the carbon intensity of the produced hydrogen. For hydrogen produced after that, the electricity matching is to switch to an hourly basis. Investors can further choose to assess the carbon intensity of hydrogen on either an annual basis or an hourly basis, provided that the corresponding annual average does not exceed a certain threshold. As of this writing, the US Congress has voted for a significant reduction in the duration of the policy support for hydrogen and other clean energy technologies. In particular, the policy support for hydrogen is now set to be available for investment projects, the construction of which begins before

January 1, 2028. The envisioned pillars for assessing the carbon intensity of the hydrogen produced, however, appear to have remained unchanged.

We initially calibrate our economic model to reference plants eligible for the production tax credit specified in the Inflation Reduction Act in the current economic context of the US. Contrary to common expectations, we find that the hourly carbon accounting rules provide investors with sufficient incentives to invest in PtG systems today, with internal rates of return between 8.6–14.7% for hydrogen sales prices between \$1.0–3.5 per kilogram (kg). Yet, they also result in life-cycle average carbon intensity levels between 0.1–8.7 kg of carbon dioxide equivalents per kg of hydrogen (kg CO_2e/kg H_2). These estimates are lower than those for conventional "grey" hydrogen but, for hydrogen prices above \$1.5/kg, comparable to those for "blue" hydrogen produced from natural gas with carbon capture[19–22]. The surprisingly wide range of estimates emerging from our analysis reflects the incentives for investors to utilize capacity by procuring increasing amounts of carbon-intensive electricity from the general grid as hydrogen prices rise. This effect becomes particularly pronounced once the tax credit eligibility expires after the first ten years of an investment.

We further find that the annual carbon accounting rules lead to significantly higher profitability of PtG systems, with internal rates of return between 10.4–22.5% for hydrogen prices between \$1.0–3.5/kg. These upper estimates lie substantially above the typical range of investment returns available for renewable energy infrastructure[23–26], which speaks to the frequently voiced concern that tax credits of up to \$3.0/kg could lead to excessive returns for investors[27]. Our calculations also project significantly higher life-cycle average carbon intensity levels between 6.0–12.5 kg CO_2e/kg H_2. The lower end of this range falls right in the middle of estimates for blue hydrogen[19;20], while the upper end is comparable to lower estimates for grey hydrogen[22]. The higher estimates for both profitability and carbon intensity now reflect the incentives for investors to convert substantially more carbon-intensive electricity from the general grid, both during and after the tax credit period.

Our paper contributes to the emerging literature on the role of carbon accounting in determining the effectiveness of climate policies[28–31]. In particular, most recent studies on the policy support for electrolytic hydrogen consider a (central) planner seeking to minimize the total cost of an energy system subject to meeting given demands for electricity and hydrogen[12–15]. These studies then assess changes in the total cost and emissions of the system depending on whether the hydrogen demand is met by converting (non-)incremental renewable energy on different temporal intervals. In contrast, our analysis takes the perspective of a representative investor seeking to maximize the net present value of investments in PtG systems in response to policy support for electrolytic hydrogen. This approach enables us to examine how the financial and emission performance of PtG systems is shaped by alternative accounting rules. Such an analysis has been missing in the literature, as a recent review highlights[15].

More broadly, our analysis relates to recent work on the role of product carbon footprints in decarbonizing supply chains[32]. Reliable product carbon footprints are increasingly demanded by corporate customers seeking to decarbonize their supplier network[33]. Similarly, the Carbon Border Adjustment Mechanism by the European Union, set to take effect in 2026, requires an assessment of the emissions embodied in certain goods imported to the bloc[34]. In this context, our paper provides an initial analysis of how alternative rules for allocating overhead emissions to products affect the investment decisions when policymakers seek to incentivize lower carbon production.

2 Economic Model

Consider an investor seeking to maximize the net present value of an investment in a PtG system converting electricity to hydrogen (Figure 1). This investment initially includes renewable energy sources (wind, solar, or both) for the renewable electricity converted to hydrogen to be incremental to the existing renewable energy supply in the market. Our analysis would be analogous if the investor were to procure renewable electricity from a third party, possibly via a power purchasing agreement. The renewables and the PtG plant (electrolyzer, piping, and compressor) may be located in different places. Yet, they are connected to the same grid so that, in principle, the generated renewable energy can be delivered to the PtG plant.

To maximize the investment value, the investor seeks to optimally size the relative capacity of the renewables and the PtG plant and to optimally use the installed capacity (see Methods for details). At any given point in time, the generated renewable electricity can be sold into the grid at the current market price, or it can be contractually dedicated to the PtG plant for hydrogen production. This dedication can be captured, for instance, through Energy Attribute Certificates (EACs) for renewable energy, as recent regulatory guidance envisions[18]. The PtG plant can procure additional electricity from the general pool to use any spare capacity. Yet, this electricity may be generated from fossil fuels and entail carbon emissions. Each kg of hydrogen produced can be sold to customers at a fixed price and may qualify for a particular level of policy support, depending on its assessed carbon intensity.

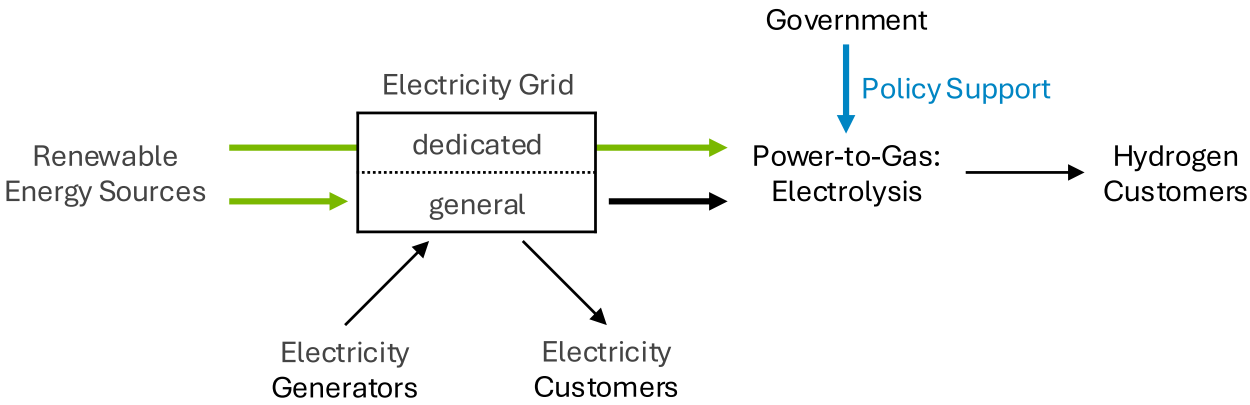

Figure 1. Setting. This figure illustrates the techno-economic setting of the PtG system considered in our analysis.

Our analysis considers alternative carbon accounting rules for assessing the carbon intensity of hydrogen and thus the level of policy support for PtG systems. Each rule determines how much electricity the PtG plant can utilize at any given time to keep the emissions attributed to the hydrogen produced below a certain threshold in order to qualify the hydrogen for a certain level of policy support. The hydrogen produced and the level of policy support received, in turn, drive the cash flows for a given initial investment.

To examine the impact of alternative rules, we assess the profitability of PtG systems and, thus, the financial incentives for investors to deploy them. We measure profitability as the cost of capital at which the maximized net present value of the PtG system would be equal to zero. This cost of capital can be interpreted as the internal rate of return of the investment and allows us to compare PtG systems with different capacity sizes.

We also assess the average carbon intensity of the hydrogen produced over the life cycle of PtG systems. We measure this carbon intensity as the total emissions embodied in the electricity from the general pool converted to hydrogen over the life cycle of a system divided by the total hydrogen produced over that time. This metric can be interpreted as the expected well-to-gate carbon footprint of electrolytic hydrogen, excluding any emissions embodied in the installed equipment.

To describe alternative carbon accounting rules precisely, let $v_{1i}(t|A)$ denote the optimized kilowatt-hours (kWh) of renewable electricity sold to the general grid in hour t of year i, given accounting rule A, where $t = 1, \ldots, m$ for $m = 8760$ hours, and $i = 1, \ldots, T$ for T useful years of the investment. Let $v_{2i}(t|A)$ further denote the optimized kWh of dedicated renewable electricity converted to hydrogen and $v_{3i}(t|A)$ the optimized kWh of general grid electricity converted to hydrogen in hour t of year i, holding fixed accounting rule A. We further denote by $CI_{ei}(t)$ the capacity-weighted average carbon intensity of general grid electricity in hour t of year i (in kg CO_2e/kWh) and by η the average conversion efficiency of the PtG plant (in kg H_2/kWh). Our measure for the average carbon intensity of the hydrogen produced over the life cycle of the PtG system (in kg CO_2e/kg H_2), given accounting rule A, is then:

$$CI_h(A) \equiv \frac{\sum_{i=1}^{T} \sum_{t=1}^{m} CI_{ei}(t) \cdot v_{3i}(t|A)}{\sum_{i=1}^{T} \sum_{t=1}^{m} q_i(t|A)}, \tag{1}$$

where $q_i(t|A) = \eta \cdot [v_{2i}(t|A) + v_{3i}(t|A)]$ denotes the optimized kg of hydrogen produced in hour t of year i, given rule A.

Consistent with recent regulatory guidance[18], our measure in (1) initially adopts a *market-based* approach that assesses the emissions embodied in electrolytic hydrogen based on contractual arrangements for renewable energy supply. Yet, we also examine the impact of a *location-based* approach, where any electricity procured from the grid is assigned the average carbon intensity of the local grid (see the Discussion).

We initially calibrate our model to reference plants eligible for the production tax credit specified in the Inflation Reduction Act in the context of the US state of Texas. The Inflation Reduction Act[1] provides a tax credit of up to \$3.0/kg for hydrogen with a carbon intensity of up to 0.45 kg CO_2e/kg H_2. Texas has experienced significant growth in wind and solar energy capacity in recent years. It is also home to several industries that require hydrogen as a production input[35] and to large-scale hydrogen production projects supported by the Inflation Reduction Act[36]. Our data inputs come from multiple sources, including journal articles, technical reports, industry databases, and interviews with industry experts (see Methods for details).

3 Carbon Intensity of Electricity: Hourly Matching

Since renewable energy generation is intermittent, a key point of debate is the time interval for matching electricity generation and hydrogen production. Analysts have argued that hourly matching incentivizes electrolytic hydrogen production during periods of abundant renewable energy and thus at lower emissions than hydrogen production from natural gas [12;13]. Companies have contended that this could starve PtG systems if abundant renewable energy remains relatively infrequent, thereby limiting the investment incentives [16;17].

In recent guidance, US regulators have announced plans to require hourly electricity matching for hydrogen produced from 2030 onward [18]. Yet, investors can choose to assess the carbon intensity of hydrogen on either an annual basis or an hourly basis, provided that the corresponding annual average does not exceed 4.0 kg CO_2e/kg H_2. This flexibility, the regulators have argued, provides investors with "additional investment certainty" if they cannot procure renewable energy for a limited number of hours during the year.

We first examine two carbon accounting rules that are both consistent with this guidance. The first rule, denoted by A, amounts to an hourly calculation of tax credits. Specifically, the carbon intensity of hydrogen in hour t of year i is assessed as:

$$CI_{hi}(t|A) \equiv \frac{CI_{ei}(t) \cdot v_{3i}(t|A)}{q_i(t|A)}. \tag{2}$$

Further, the annual tax credit for the PtG system in year i is given by multiplying the *hourly* amount of hydrogen produced by the production tax credit corresponding to the assessed carbon intensity of hydrogen in that *hour* and taking the sum over all hours of the year. Thus:

$$PTC_{hi}(A) \equiv \sum_{t=1}^{m} f\big(CI_{hi}(t|A)\big) \cdot q_i(t|A), \tag{3}$$

where $f(\cdot)$ identifies the tax credit (in \$/kg H_2) corresponding to a given carbon intensity of hydrogen (in kg CO_2e/kg H_2), as specified in the Inflation Reduction Act [1]. If PtG systems satisfy the prevailing wage and apprenticeship requirements, $f(\cdot)$ can be expressed as:

$$f(x) \equiv \begin{cases} 3.0 & \text{if } x \leq 0.45, \\ 1.0 & \text{if } x \in (0.45, 1.5], \\ 0.75 & \text{if } x \in (1.5, 2.5], \\ 0.6 & \text{if } x \in (2.5, 4.0], \\ 0.0 & \text{if } x > 4.0. \end{cases} \tag{4}$$

The second accounting rule, denoted by B, amounts to an annual calculation of tax credits. The carbon intensity of hydrogen is then assessed on an annual basis such that:

$$CI_{hi}(B) \equiv \frac{\sum_{t=1}^{m} CI_{ei}(t) \cdot v_{3i}(t|B)}{\sum_{t=1}^{m} q_i(t|B)}. \tag{5}$$

The annual tax credit for the PtG system in year i is then given by multiplying the *annual* amount of hydrogen produced by the production tax credit corresponding to the assessed carbon intensity of hydrogen in that *year*. Thus:

$$PTC_{hi}(B) \equiv f\big(CI_{hi}(B)\big) \cdot \sum_{t=1}^{m} q_i(t|j). \tag{6}$$

A direct comparison of equations (3) and (6) shows the operational flexibility investors gain under accounting rule A in comparison to B. Under this rule, investors can forgo tax credits in some hours and fully utilize the PtG plant with general grid electricity without compromising tax credit eligibility in other hours.

Figures 2 and 3 display our estimates for the impact of the two carbon accounting rules. Figure 2 shows the life-cycle performance of PtG systems across hydrogen prices ranging from \$1.0/kg to \$3.5/kg, due to computational complexity in steps of \$0.5/kg. These prices reflect the range of transaction prices observed for industrial-scale hydrogen supply today and are often cited as critical benchmarks for the widespread adoption of low-carbon hydrogen[37;38]. Figure 3 shows our estimates at hydrogen prices of \$1.5/kg and \$2.5/kg, split between the two life stages of PtG systems: the first ten years, when they are eligible for the tax credit, and their remaining lifetime.

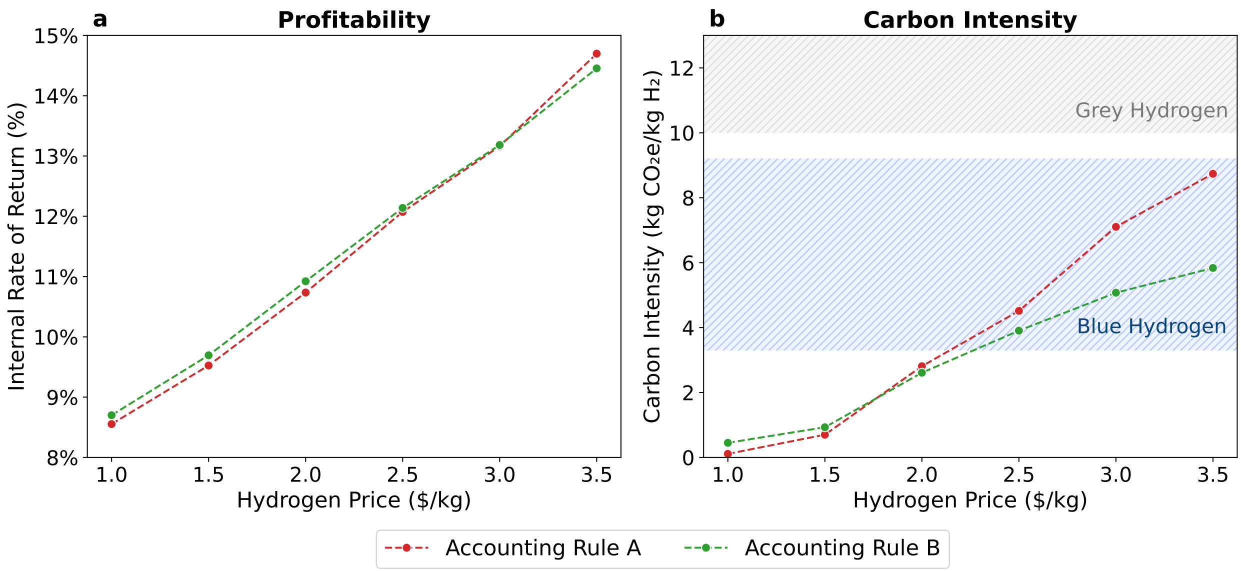

Figure 2. Life-cycle performance under hourly carbon accounting. This figure shows the impact of accounting rules A (hourly tax credits) and B (annual tax credits) on (**a**) the profitability of PtG systems, and (**b**) the life-cycle average carbon intensity of hydrogen, given hydrogen prices between \$1.0/kg and \$3.5/kg. The dots show our point estimates at specific hydrogen prices, while the dashed lines interpolate between them for illustration.

Contrary to commonly voiced concerns, we find that both accounting rules induce sufficient profitability of PtG systems already today (Figure 2a). In particular, our calculations project that the internal rate of return of PtG systems increases almost linearly from 8.6% to 14.7% as hydrogen prices rise from \$1.0/kg to \$3.5/kg and the PtG systems produce more hydrogen, especially after the tax credit (Figure 3a and c). These returns are close to the typical range of 8.5–12.5% that have been observed for early investments in renewable energy infrastructure[23–26].

We also find that the profitability of investments is similar under both accounting rules. In other words, the operational flexibility under accounting rule A (hourly tax credits) does not translate into additional investment incentives due to higher profitability. The nearly identical profitability arises because, at lower hydrogen prices, PtG systems operate in similar ways under both rules (Figure 3a and c). Given rule A, rising hydrogen prices imply that PtG systems are incentivized to forgo the tax credit in more hours and produce more hydrogen from general grid electricity. Yet, this financial benefit in some hours is effectively offset by PtG systems qualifying all hydrogen produced for the tax credit under rule B.

As for emissions, we find that both accounting rules result in a lower life-cycle average

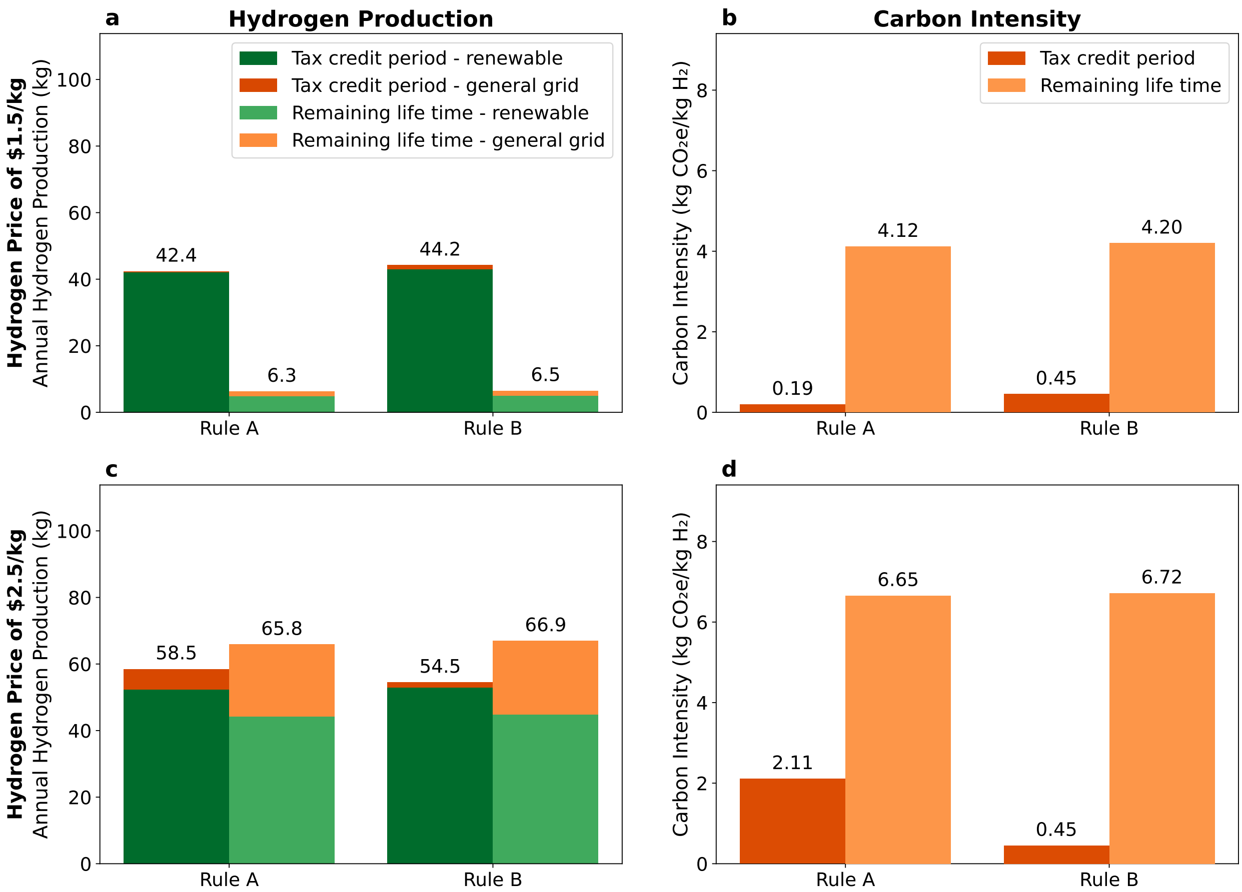

Figure 3. Life-stage performance under hourly carbon accounting. This figure shows the impact of accounting rules A (hourly tax credits) and B (annual tax credits) on (**a** and **c**) the annual hydrogen production and (**b** and **d**) the annual carbon intensity of hydrogen, given hydrogen prices of \$1.5/kg and \$2.5/kg. Annual hydrogen production is calculated based on a renewable power generation capacity of 1.0 kilowatt peak (see Methods for details).

carbon intensity than conventional hydrogen production, but not necessarily much lower (Figure 2b). For hydrogen prices up to \$1.5/kg, our calculations project a carbon intensity between 0.1–0.9 kg CO_2e/kg H_2 under both accounting rules. For prices above \$1.5/kg, we obtain a carbon intensity between 2.8–8.7 kg CO_2e/kg H_2 under rule A and 2.6–5.8 kg CO_2e/kg H_2 under rule B. These estimates are lower than those for conventional (grey) hydrogen but comparable to those for (blue) hydrogen produced from natural gas with carbon capture[19;20;22]. The increase in the life-cycle average carbon intensity arises because PtG systems produce more hydrogen from general grid electricity once the tax credit eligibility expires (Figure 3a and c), which increases the carbon intensity of hydrogen during that period (Figure 3b and d). PtG systems also boost hydrogen output when prices rise, especially after the tax credit (Figure 3a and c), which increases the weight of that period in the life-cycle average. Such projections must, of course, be qualified by their reference to the current carbon intensity of general grid electricity (see the Discussion).

Our calculations also show that, for hydrogen prices above \$1.5/kg, the carbon intensity of hydrogen increases more sharply with hourly tax credits (rule A) than annual tax credits (rule B). This reflects that PtG systems under rule A are incentivized to forgo the tax credit more often in favor of a higher conversion of general grid power. Nevertheless, the annual carbon intensity of hydrogen remains well below 4.0 kg CO_2e/kg H_2 for the hydrogen prices considered (Figure 3b and d). The constraint on the hourly assessment of the carbon intensity of hydrogen thus remains non-binding. Under rule B, the carbon intensity of hydrogen during the tax credit period is always exactly equal to 0.45 kg CO_2e/kg H_2, the threshold for the highest tax credit (see equation (4)).

4 Carbon Intensity of Electricity: Annual Matching

In response to concerns about hourly matching, US regulators[18] have indicated their willingness to assess both the temporal matching of electricity and the carbon intensity of hydrogen on an *annual* basis for hydrogen produced through 2030. This accounting rule, denoted by C, effectively allows investors to offset renewable energy sold to the general grid in some hours against electricity procured from that grid in other hours. With $CI_{ei} = \frac{1}{m}\sum_{t=1}^{m} CI_{ei}(t)$ representing the annual average carbon intensity of grid electricity, the average carbon intensity of hydrogen produced in year i becomes:

$$CI_{hi}(C) \equiv \frac{CI_{ei} \cdot \sum_{t=1}^{m} \big(v_{3i}(t|C) - v_{1i}(t|C)\big)}{\sum_{t=1}^{m} q_i(t|C)}. \tag{7}$$

Tax credits are again calculated on an annual basis, as described in equation (6). Since we seek to examine the impact of alternative carbon accounting rules, our analysis initially assumes that a rule applies for the entire life of a PtG system.

Following recent regulatory guidance[18], our analysis so far has required investors to install incremental renewable energy capacity. Since this requirement remains controversial[13], we now consider an accounting rule, denoted by D, that does not mandate co-investment in renewables. Instead, investors can choose whether to co-invest in renewables. In addition, they can procure EACs for renewable energy from non-incremental sources (also often referred to as Renewable Energy Certificates) on the open market to offset electricity procured from the general grid. Since most of such EACs traded today are not time-specific, we denote by v_{ri} the optimized amount of EACs (in kWh) procured in year i. The average carbon intensity of hydrogen produced in year i then becomes:

$$CI_{hi}(D) \equiv \frac{CI_{ei} \cdot \left[\sum_{t=1}^{m} \big(v_{3i}(t|D) - v_{1i}(t|D) \big) - v_{ri} \right]}{\sum_{t=1}^{m} q_i(t|D)}. \tag{8}$$

The annual tax credit for the PtG system is again calculated as described in equation (6).

Figures 4 and 5 illustrate the impact of the two hydrogen carbon intensity rules C and D. Both rules lead to substantially higher profitability of PtG systems than the two hourly carbon accounting rules (Figure 4a). In particular, our calculations project that the internal rate of return of PtG systems increases from 10.4% under both rules to 18.6% under rule C and 22.5% under rule D as hydrogen prices rise from \$1.0/kg to \$3.5/kg (Figure 5a and c). These upper estimates lie substantially above the typical range of 8.5–12.5% observable for early investments in renewable energy infrastructure[23–26]. This speaks to the frequently voiced concern that tax credits of up to \$3.0/kg might be excessive, leading to abnormal investment returns[27].

Our analysis also shows that, as hydrogen prices rise, the profitability of PtG systems grows more sharply if non-incremental renewable energy is permitted (rule D) than if it is not (rule C). Investors can then exploit the effective price arbitrage between EACs and tax credits. In particular, investors are incentivized to build larger PtG plants and produce more hydrogen under rule D than under rule C (Figure 5a and c). For hydrogen prices up to \$2.0/kg, higher revenues and capital costs under rule D roughly offset each other, resulting in similar internal rates of return as under rule C. Above \$2.0/kg, revenue growth outpaces increases in capital costs more under rule D. Overall, we find that investors are incentivized to always co-invest in renewables under rule D as renewables are economically viable on their own.

Regarding emissions, we find that both annual carbon accounting rules result in life-cycle average carbon intensities consistently in the range of hydrogen production from natural

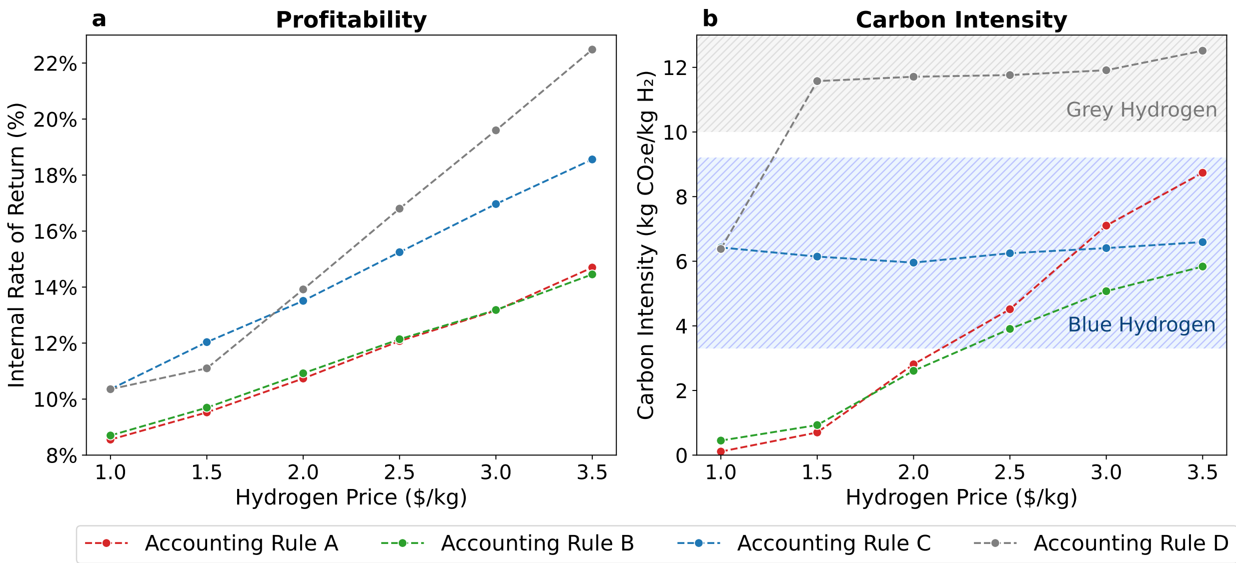

Figure 4. Life-cycle performance under annual carbon accounting. This figure shows the impact of accounting rules C (incremental renewable energy) and D (non-incremental renewable energy) on (**a**) the profitability of PtG systems, and (**b**) the life-cycle average carbon intensity of hydrogen, given hydrogen prices between \$1.0/kg and \$3.5/kg. The dots show our point estimates at specific hydrogen prices, while the dashed lines interpolate between them for illustration. The impact of accounting rules A and B is shown for reference.

gas (Figure 4b). Under rule C, our calculations result in a carbon intensity of about 6 kg CO_2e/kg H_2 across the hydrogen prices considered. This value falls right in the middle of estimates for blue hydrogen[19;20]. Under rule D, we obtain a carbon intensity of about 12 kg CO_2e/kg H_2 for hydrogen prices above \$1.0/kg, which is comparable to lower estimates for grey hydrogen[22]. The higher value under rule D reflects the incentives for investors to build larger PtG systems, produce more hydrogen, and convert significantly more grid electricity both during the tax credit period and thereafter (Figure 5). Note that, at a hydrogen price of \$1.0/kg, our calculations also yield a carbon intensity of about 6 kg CO_2e/kg H_2 under rule D because, at that price, it is economically unattractive for investors to procure any EACs for renewable energy on the open market.

Our calculations also project that the life-cycle average carbon intensities under both annual carbon accounting rules remain fairly stable across hydrogen prices above \$1.0/kg. Under rule C, this stability mainly reflects the natural limit imposed by the amount of self-generated renewable energy (Figure 5a and c). Under rule D, the PtG plant is incentivized to also procure a similar share of electricity from the general grid across hydrogen prices

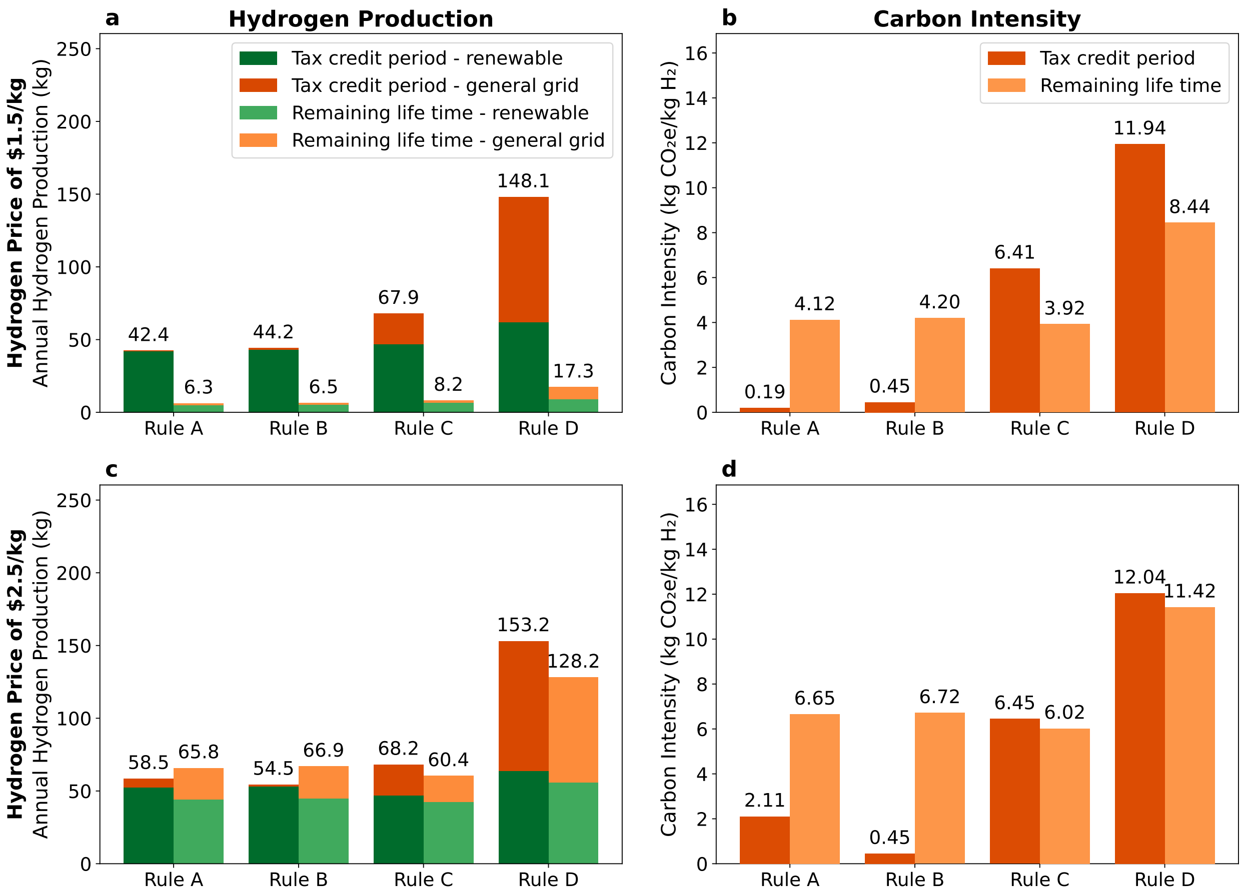

Figure 5. Life-stage performance under annual carbon accounting. This figure shows the impact of accounting rules C (incremental renewable energy) and D (non-incremental renewable energy) on (**a** and **c**) the annual hydrogen production and (**b** and **d**) the annual carbon intensity of hydrogen, given hydrogen prices of \$1.5/kg and \$2.5/kg. The impact of accounting rules A and B is shown for reference. Annual hydrogen production is calculated based on a renewable power generation capacity of 1.0 kilowatt peak (see Methods for details).

and produce at full capacity. We further note that the carbon intensity of hydrogen under accounting rule C reflects an upper bound on the carbon intensity under rule B, where the difference between them shows the impact of annual versus hourly matching of electricity generation and hydrogen production.

5 Discussion

Governments often evaluate the impact of a policy relative to its costs. We now examine the impact of alternative carbon accounting rules on the capacity of the policy support to incentivize electrolytic hydrogen production. We measure this policy impact as the total hydrogen produced over the life cycle of the PtG system divided by the discounted value of the annual tax credits awarded to the PtG system. With r as the weighted average cost of capital, the policy impact (in kg H_2/\$) under, say, accounting rule A is then:

$$PI(A) \equiv \frac{\sum_{i=1}^{T} \sum_{t=1}^{m} q_i(t|A)}{\sum_{i=1}^{T} PTC_{hi}(A) \cdot (1+r)^{-i}}. \tag{9}$$

Figure 6 shows that a tax credit of \$3.0 per kg induces the production of more than 1.0 kg of hydrogen for all hydrogen prices and all four carbon accounting rules considered in this analysis. This is mainly due to PtG systems continuing to produce hydrogen after the tax credit period. We also find that, for hydrogen prices up to \$1.5/kg, the policy impact of all four rules is nearly identical. For prices above \$1.5/kg, the policy impact increases in a concave form under most rules and increases more sharply under the two hourly carbon accounting rules, especially under rule A (hourly tax credits). The concavity reflects the financial incentive to convert more electricity to hydrogen as hydrogen prices rise, yet at a decreasing rate as PtG plants reach their capacity limit more often. The sharp increase under rule A occurs mainly because PtG systems are incentivized to forgo the tax credit more often and convert more general grid electricity. Nevertheless, PtG systems produce nearly the same amount of hydrogen over their life cycle as under rule B (annual tax credits, Figure 5a and c). The lower increase under the annual carbon accounting rules (C and D) mainly occurs because the total tax credit received by PtG systems remains fairly stable across hydrogen prices, and the life-cycle amount of hydrogen produced increases less strongly in relative terms than under the hourly rules (A and B).

According to recent regulatory guidance[18], investors are to obtain and retire EACs to verify that a kWh of energy has been generated from renewables. Most EACs available today are traded separately from the underlying electricity[28]. That is, renewable electricity can be sold to one customer and the corresponding EACs to another. Analysts have argued that such unbundled trading undermines incentives for renewable energy deployment and that EACs should be tied (or bundled) to the electricity they certify[28]. While the regulatory guidance remains silent on this issue, the hourly accounting rules (A and B) effectively reflect

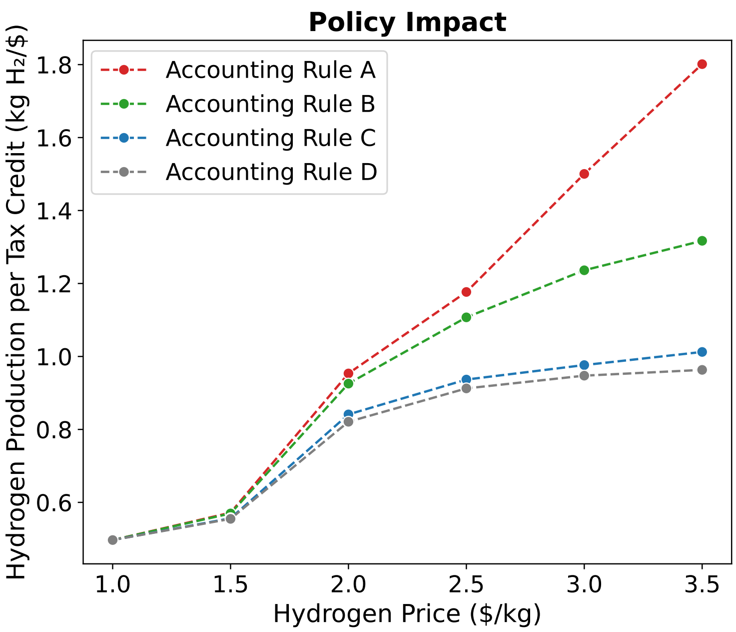

Figure 6. Policy impact of alternative carbon accounting rules. This figure shows the impact of alternative carbon accounting rules on the capacity of the policy support to incentivize electrolytic hydrogen production, given hydrogen prices between \$1.0/kg and \$3.5/kg. The dots show our point estimates at specific hydrogen prices, while the dashed lines interpolate between them for illustration.

bundled EACs, whereas the annual accounting rules (C and D) reflect *unbundled* EACs.

Following recent regulatory guidance[18], our approach has allowed investors to assess the emissions embodied in the electricity they consume based on contractual arrangements with energy suppliers. Critics often argue, however, that such *market-based* methods can also enable firms to misrepresent the actual emissions embodied in their electricity consumption[28]. Some further advocate for using *location-based* methods instead, where any electricity procured from the grid is assigned the average carbon intensity of the local grid[39]. Such methods effectively compel investors to co-locate renewables with the PtG plant and connect them with dedicated transmission lines. Without such co-location, any renewable electricity produced would have to flow through the local grid and would incur grid fees. In addition, the PtG plant would only be credited with a fraction of this renewable supply, while investors would bear the full cost of developing the renewable capacity.

To examine the impact of location-based methods, we initially assume that investors can co-locate renewables with the PtG plant and find the same wind and solar resources as before. Yet, we note that areas near hydrogen customers may often have less space or weaker wind and solar irradiation. Our analysis, detailed in Supplementary Note 1, focuses on accounting rules A, B, and C, since rule D reflects market-based methods by construction. We find that the performance of PtG systems under each of these three rules is largely parallel to the corresponding one shown in Figure 4. In particular, we find that the profitability of PtG systems is slightly higher, the life-cycle average carbon intensity of hydrogen is roughly equivalent, and the policy impact is slightly higher, in particular for lower hydrogen prices. These differences are primarily due to the avoidance of grid charges on generated renewable energy under location-based methods. As a result, investors build relatively more renewable energy capacity, a larger PtG component, and convert relatively more renewable energy, especially after the tax credit period. We also note that if investors were not able to co-locate the PtG plant with renewables, they would not invest in the PtG plant at all under location-based methods. Yet, this conclusion must be qualified by the current carbon intensity of grid electricity in Texas.

Finally, we assess the generalizability of our findings by examining changes in input parameters. In particular, we examine the impact of lower tax credits to capture potential policy shifts. We also examine lower future carbon intensity levels of the general grid and changes in the average and variance of electricity prices to reflect temporal and regional differences in the share of renewable power generation. As detailed in Supplementary Notes 2–4, our analysis delivers a consistent assessment of the implications of alternative carbon accounting rules. Specifically, our finding that the profitability of PtG systems ranges between 8.0–15.0% under hourly carbon accounting rules and is significantly higher under annual accounting rules emerges in most variations. This finding mainly reflects that if investors were to achieve lower net present values, for example, due to lower tax credits, they would also build smaller PtG plants and thus obtain similar internal rates of return. Furthermore, across most variations, our estimates of the life-cycle average carbon intensity of electrolytic hydrogen are comparable to those for blue hydrogen under accounting rules A, B, and C for hydrogen prices above \$1.5/kg and close to lower estimates for grey hydrogen under rule D. Lower future carbon intensity levels of the general grid would lead to substantially lower estimates, while lower average electricity prices would have the opposite effect.

6 Conclusion

Governments worldwide have recently launched policy programs for hydrogen, where the level of support is to be tied to the carbon intensity of the hydrogen produced. This paper has examined how alternative carbon accounting rules for assessing the carbon intensity of electrolytic hydrogen shape the financial and emission performance of PtG systems. We initially calibrate our model to reference plants eligible for the production tax credit specified in the Inflation Reduction Act in the economic context of the US. Contrary to common expectations, we find that more stringent accounting rules provide investors with sufficient incentives to invest in PtG systems today. Yet, they can also lead to life-cycle average carbon intensity levels close to those for hydrogen produced from natural gas with carbon capture. Less stringent accounting rules generally yield higher incentives but also significantly higher emissions. Overall, our findings reflect the strong incentives for investors to utilize capacity by procuring additional, carbon-intensive electricity from the general grid.

Future research in this line of work could explore the implications of additional carbon accounting rules. Our analysis has focused on those widely discussed and described in regulatory guidance, but other approaches are readily conceivable as well. Future work could also adapt our model to other jurisdictions with policy support for electrolytic hydrogen. In the European Union, for example, support levels depend not only on the carbon intensity of hydrogen but also on the outcomes of competitive auctions[2]. Finally, it would be instructive to build on our approach and prior studies[12–15] to develop a (partial) market equilibrium model that maximizes total welfare for given price elasticities of electricity and hydrogen demand. Such a model would enable the analysis of how alternative carbon accounting rules for assessing the carbon intensity of hydrogen drive the total emissions resulting from electricity and hydrogen production, as well as the total tax credit payouts and their impact on a government's budget.

Methods

Economic Model

As described, our model considers an investor seeking to maximize the net present value of an investment in a PtG system. The long-term optimization of this investment problem chooses the capacity configuration in terms of the joint capacity size of the renewables, the share of this capacity constituted by wind energy, and the capacity size of the PtG plant. Given the long-term capacity configuration, the inner optimization seeks to maximize the annual contribution margin by optimizing the real-time use of the installed capacity. Here, the decision variables include the kWh of renewable energy sold to the general grid, the kWh of renewable energy contractually dedicated to the PtG plant, and the kWh of electricity procured from the general grid. The subsequent derivations initially focus on accounting rule A for illustration.

To describe the inner optimization, let $v_{1i}^{\circ}(t|A)$ denote the kWh of renewable electricity sold to the general grid and $v_{2i}^{\circ}(t|A)$ the kWh of dedicated renewable electricity converted to hydrogen in hour t of year i, given rule A. We also denote by $k_e \in [0,1]$ the joint peak capacity of the renewables and by $s \in [0,1]$ the share of this peak capacity constituted by wind energy. For the purpose of the economic model, we normalize the capacity investment in renewables to 1 kilowatt (kW) of joint peak electricity generation. To be sure, our numerical analysis calibrates the costs and revenues of renewables and PtG plants in accordance with the system sizes that have been built in recent years. We further respectively denote by $CF_{wi}(t), CF_{si}(t) \in [0,1]$ the capacity factors, that is, the shares of the maximum wind and solar power generation in hour t of year i. The actual amount of renewable power generated in hour t of year i is then given by $CF_i(t|s) \cdot k_e \cdot 1$ hour, where $CF_i(t|s) = s \cdot CF_{wi}(t) + (1 - s) \cdot CF_{si}(t)$.

Let $p_{si}(t)$ denote the price per kWh at which renewable energy can be sold on the open market in hour t of year i. Wind and solar power in the US are both eligible for production tax credits in the after-tax amount of PTC_{ei} per kWh of power generated in year i. Since the production tax credits are only available for the first ten years of the investment, $PTC_{ei} = 0$ for the remaining lifetime. To account for the impact of corporate income taxes, we denote the investor's effective income tax rate by $\alpha \in (0,1)$. The pre-tax contribution margin from renewable power generation of the PtG system in year i can then be expressed as:

$$CM_{ei}(A) \equiv \sum_{t=1}^{m} \big(p_{si}(t) + \frac{PTC_{ei}}{1-\alpha}\big) \cdot \big(v_{1i}^{\circ}(t|A) + v_{2i}^{\circ}(t|A)\big), \tag{10}$$

where the amounts of renewable energy sold to the general grid and converted to hydrogen can be chosen such that they jointly do not exceed the amount generated at any given time. Formally,

$$v_{1i}^{\circ}(t|A) + v_{2i}^{\circ}(t|A) \leq CF_i(t|s) \cdot k_e \cdot 1 \text{ hour}, \text{ for all } t = 1, \ldots, m.$$

In addition to converting renewable energy, the PtG plant can procure grid electricity up to its capacity limit. Let $v_{3i}^{\circ}(t|A)$ denote the kWh of general grid electricity converted to hydrogen in hour t of year i, given rule A. Let $p_{bi}(t)$ further denote the price per kWh at which general grid electricity can be bought on the market in hour t of year i. To produce hydrogen, the PtG plant also incurs a variable cost of δ_e for every kWh of renewable energy transmitted to the PtG plant via the grid. This cost markup includes grid surcharges and other retail charges for large-scale industrial customers. The PtG plant further incurs a variable cost of w_h per kg of hydrogen produced for consumable inputs, such as water and reactants for deionizing the water.

Every kg of hydrogen produced can then be sold to customers at a fixed price of p_h and may qualify for a particular production tax credit, depending on its assessed carbon intensity. We denote by $PTC_{hi}^{\circ}(A)$ the after-tax amount of the annual tax credit for the PtG system in year i and calculate it in direct analogy to equation (3). Since this tax credit is also available only for the first ten years of the investment, $PTC_{hi}(A) = 0$ for the remaining lifetime. With k_h denoting the kW of peak power absorption of the PtG plant, the pre-tax contribution margin from hydrogen production in year i can then be expressed as:

$$\begin{aligned} CM_{hi}(A) \equiv \frac{PTC_{hi}^{\circ}(A)}{1-\alpha} &+ \sum_{t=1}^{m} \big(p_h - w_h\big) \cdot \eta \cdot \big(v_{2i}^{\circ}(t|A) + v_{3i}^{\circ}(t|A)\big) \\ &- \big(p_{si}(t) + \delta_e\big) \cdot v_{2i}^{\circ}(t|A) - p_{bi}(t) \cdot v_{3i}^{\circ}(t|A), \end{aligned} \tag{11}$$

where the amounts of dedicated renewable and general grid electricity can be chosen such that they jointly do not exceed the peak capacity of the PtG plant at any given time. Formally,

$$v_{2i}^{\circ}(t|A) + v_{3i}^{\circ}(t|A) \leq k_h \cdot 1 \text{ hour}, \text{ for all } t = 1, \ldots, m.$$

We note in passing that both $v^\circ_{2i}(t|A)$ and $v^\circ_{3i}(t|A)$ can be chosen flexibly for each hour of the year, since the PtG technology considered in the numerical analysis can be ramped up and down rapidly[40].

Aggregating the components in equations (10) and (11) gives the total annual pre-tax contribution margin of the PtG system in year i. The inner optimization problem can then be expressed as:

$$CM_i(s, k_e, k_h|A) \equiv \max_{v^\circ_{1i}(t|A),\, v^\circ_{2i}(t|A),\, v^\circ_{3i}(t|A)} \left\{ CM_{ei}(A) + CM_{hi}(A) \right\} \tag{12}$$

subject to the constraints:

$$v^\circ_{1i}(t|A) + v^\circ_{2i}(t|A) \leq CF_i(t|s) \cdot k_e \cdot 1 \text{ hour}, \text{ for all } t = 1, \ldots, m, \tag{13}$$

$$v^\circ_{2i}(t|A) + v^\circ_{3i}(t|A) \leq k_h \cdot 1 \text{ hour}, \text{ for all } t = 1, \ldots, m. \tag{14}$$

To describe the outer optimization, let SP_w and SP_s represent the system prices per kW of peak wind and solar energy, respectively. The system price of the combined renewable capacity is then $SP_e(s) = s \cdot SP_w + (1 - s) \cdot SP_s$. We further denote by SP_h the system price per kW of peak power absorption of the PtG plant. In addition to investment costs, the PtG system incurs annual fixed costs, such as insurance and maintenance expenditures. Let F_{wi} and F_{si} represent the fixed operating costs per kW of wind and solar capacity in year i. The combined fixed costs are then $F_{ei}(s) = s \cdot F_{wi} + (1 - s) \cdot F_{si}$. We further denote by F_{hi} the fixed operating costs per kW of the PtG plant in year i.

Investment returns are affected by corporate income taxes through the corporate tax rate and the allowable tax shields for debt and depreciation. Let $\gamma = (1 + r)^{-1}$ represent the discount factor with r as the applicable cost of capital. The parameter r can be interpreted as the weighted average cost of capital, provided the cost of debt is incorporated on an after-tax basis to reflect the debt tax shield[41]. To capture the impact of corporate income taxes, we denote by $d_i \geq 0$ the percentage of the initial capital expenditure that can be deducted as a depreciation charge in year i from revenues in the calculation of taxable income. By construction, $\sum_{i=0}^{T} d_i = 1$. In case the productive capacity of the renewables and the PtG plant degrades over time, we denote by x_i the effective share of the initial capacity of the overall system that is still productive in year i.

Incorporating the inner optimization in equation (12), the outer optimization problem can then be expressed as:

$$
\begin{aligned}
NPV(A) \equiv \max_{s,\, k_e,\, k_h} \Bigg\{ &(1-\alpha) \cdot \sum_{i=1}^{T} x_i \cdot \gamma^i \cdot CM_i(s, k_e, k_h|A) - \gamma^i \cdot \big(F_{ei}(s) \cdot k_e + F_{hi} \cdot k_h\big) \\
&- \big(1 - \alpha \cdot \sum_{i=0}^{T} d_i \cdot \gamma^i\big) \cdot \big(SP_e(s) \cdot k_e + SP_h \cdot k_h\big) \Bigg\}.
\end{aligned} \tag{15}
$$

Following recent regulatory guidance, our analysis initially assumes that the investment in a PtG system includes renewables for the renewable electricity converted to hydrogen to be incremental to the existing renewable energy supply in the market. Thus, $k_e = 1$ if $k_h > 0$. Overall, the investor would invest in a PtG system if and only if $NPV(A) \geq 0$. This condition becomes binding when an investment in renewables alone is not economically viable, and the addition of a PtG plant increases the overall net present value but not enough to make it non-negative[42].

The preceding derivations are directly analogous under accounting rules B and C. Under rule D, investors can choose whether to co-invest in renewables. That is, they can freely choose k_e on the interval $[0, 1]$ for the outer optimization. In addition, they can procure EACs for renewable energy from non-incremental sources on the open market. Since most EACs traded today are not time-specific, we denote by v_{ri}° the amount of EACs (in kWh) procured in year i and by p_{ri} the price per kWh at which EACs can be bought on the market in year i. The total cost of EACs procured in year i is thus $p_{ri} \cdot v_{ri}^{\circ}$. If this term is subtracted from, say, the pre-tax contribution margin of hydrogen production $CM_{hi}(\cdot)$ in equation (11), then the remaining derivations can proceed as described above.

Model Calibration

We initially calibrate our model to reference plants eligible for the production tax credit available under the Inflation Reduction Act in the current economic context of Texas in the US. Our data inputs come from multiple sources, including journal articles, technical reports, industry databases, and interviews with industry experts. All data inputs are provided in an Excel file available as part of the Supplementary Data.

Our analysis considers a PtG plant with a Polymer Electrolyte Membrane (PEM) electrolyzer. The corresponding system price is based on recent industry data[43;44] and includes acquisition, project development, and installation costs. System prices for wind and solar energy are calculated as the arithmetic averages of the median values provided in recent reports for utility-scale onshore wind by Lazard[45] and the Lawrence Berkeley National Laboratory[46], as well as recent reports for utility-scale solar photovoltaic by the National Renewable Energy Laboratory[47] and the Lawrence Berkeley National Laboratory[48;49]. All system prices are expressed in 2024 $US and were adjusted to the price level in Texas using regional price parities from the US Bureau of Economic Analysis[50].

Hourly capacity factors for wind energy are calculated using the Pluswind dataset[51]. In particular, we selected a location in the MERRA-2 model[52] that reflects the median value of annual average capacity factors across locations in Texas and across the MERRA-2, HRRR, and ERA-5 data models[52]. Hourly capacity factors for solar energy are calculated using the PySAM package[53]. Similar to our procedure for wind energy, we selected a location in the dataset that reflects the median value of annual average capacity factors across Texas. To generate capacity factors in PySAM, we used the PVWatts v8 module based on typical meteorological year weather data, with key parameters set to 1000 kW_{dc} system capacity, fixed tilt of south-facing (180° azimuth), and 1.2 DC-to-AC ratio. Solar and meteorological data were sourced from the National Solar Radiation Database[54], specifically the Physical Solar Model v3.2.2 TMY dataset.

Hourly sales prices for electricity on the wholesale market are calculated based on ERCOT day-ahead prices obtained from Hitachi Energy's Velocity Suite[55]. To construct a reference year, we calculate a simple price vector where each hourly price is equal to the average across the day-ahead prices observed in Texas between the years 2015–2024 for the corresponding hour:

$$p_s(t) = \frac{1}{10} \sum_{i=2015}^{2024} p_{si}(t).$$

The resulting price vector reflects a deregulated electricity market with a substantial share of renewable power generation. Based on this vector of hourly sales prices for electricity, we calculate a vector of hourly buying prices for electricity by adding a cost markup for grid surcharges and other retail charges for large-scale industrial customers according to the pricing structure outlined by providers such as Griddy[56]. We set this cost markup 1.0% higher than the cost markup δ_e incurred for converting dedicated renewable energy to ensure that the optimization algorithm prioritizes the conversion of renewable energy over the conversion of carbon-intensive electricity from the general grid. This adjustment has a negligible effect on the profitability of PtG systems.

Hourly carbon intensity values for general grid electricity are calculated based on the EIA-930 dataset by the Energy Information Administration[57], using the CO2i_ERCO_D time series available from 2019–2023. Similar to our procedure for hourly electricity sales prices, we calculate a reference vector where each hourly carbon intensity is equal to the average across the carbon intensity levels observed in Texas between the years 2019–2023 for the corresponding hour:

$$CI_e(t) = \frac{1}{5}\sum_{i=2019}^{2023} CI_{ei}(t).$$

Like for electricity prices, the resulting carbon intensity vector reflects a deregulated electricity market with a substantial share of renewable power generation.

We implement the economic model in Python using optimization packages from Gurobi[58] and SciPy[59]. In particular, we use a Mixed-Integer Linear Programming approach from Gurobi for the inner optimization to capture the stepwise granting of the hydrogen production tax credit in equation (4). We then use a differential evolution algorithm from SciPy for the outer optimization. To mitigate computational costs, our numerical optimization initially assumes that the hourly distribution of electricity prices, capacity factors, and carbon intensity levels of general grid electricity remains constant over the lifetime of a PtG system. Since production tax credits are only available for the first ten years of the investment, we run the inner optimization for two representative years: the first year of operation with tax credits and the eleventh year of operation without tax credits.

Since each sensitivity analysis reported in Supplementary Notes 1–4 requires several runs of the optimization program, we run the inner optimization in these calculations for 1,000 randomly selected hours instead of a full year. This significantly shortens the run time of the optimization. Differences between the results for 1,000 hours and a full year are negligible.

Data availability

The data used in this study are referenced in the main body of the paper and the Supplementary Information. Data that generated the plots in the paper are provided in an Excel file available as part of the Supplementary Data. Additional information is available upon request to the corresponding author.

Code availability

Computational code is available upon request to the corresponding authors.

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Author Contributions

The authors jointly developed the research question and economic model. P.H. led the literature review, data collection, and numerical calibration. All authors contributed to the analysis of the numerical findings and the writing of the paper.

Ethics Declarations

The authors declare no competing financial or non-financial interests.

Supplementary Information:

Policy Support for Electrolytic Hydrogen: Impact of Alternative Carbon Accounting Rules

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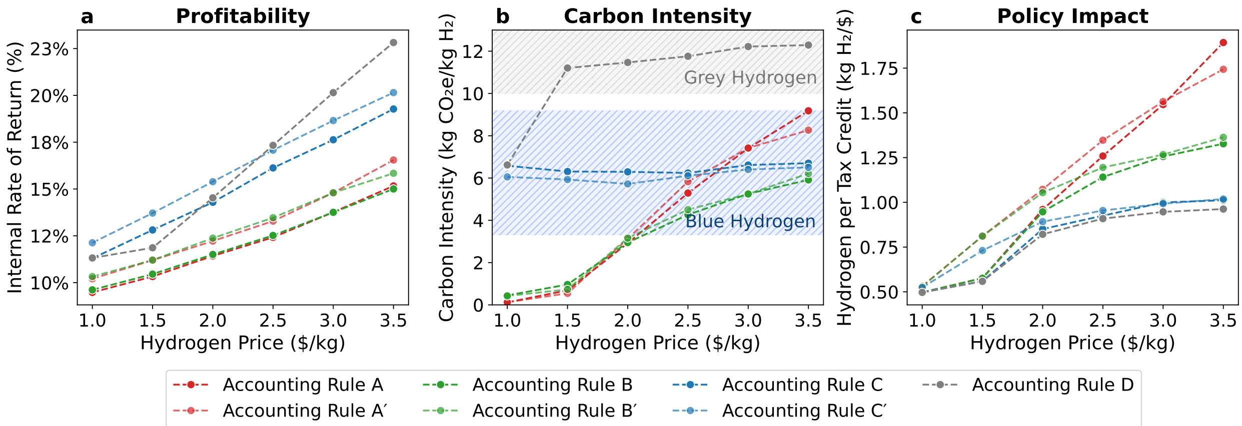
1 Location-Based Methods

To examine the impact of location-based methods, we initially assume that investors can co-locate renewables with the PtG plant and find the same wind and solar resources as before. Yet, we note that areas near hydrogen customers may often have less space or weaker wind and solar irradiation. Due to the co-location, PtG plants now incur no cost markup for grid surcharges and other retail charges for renewable energy converted to hydrogen (i.e., $\delta_e = 0$). Our analysis focuses on accounting rules A, B, and C, since rule D reflects market-based methods by construction. We denote the location-based variants of these rules by A', B', and C'.



Supplementary Figure 1. Life-cycle performance under location-based methods. This figure shows the impact of location-based methods on (**a**) the profitability of PtG systems, (**b**) the life-cycle average carbon intensity of hydrogen, and (**c**) the policy impact of the production tax credit, given hydrogen prices between \$1.0/kg and \$3.5/kg. The dots show our point estimates at specific hydrogen prices, while the dashed lines are used for illustration to interpolate between them.

Figure 1 shows our estimates for the implications of location-based methods. We find that the performance of PtG systems under these methods is largely parallel to the corresponding one shown in Figure 4. In particular, we find that the profitability of PtG systems is slightly higher, the life-cycle average carbon intensity of hydrogen is slightly lower, and the policy impact is slightly higher. These differences are primarily due to the avoidance of grid charges on generated renewable energy under location-based methods. As a result, investors build relatively more renewable energy capacity and convert relatively more renewable energy, especially after the tax credit period.

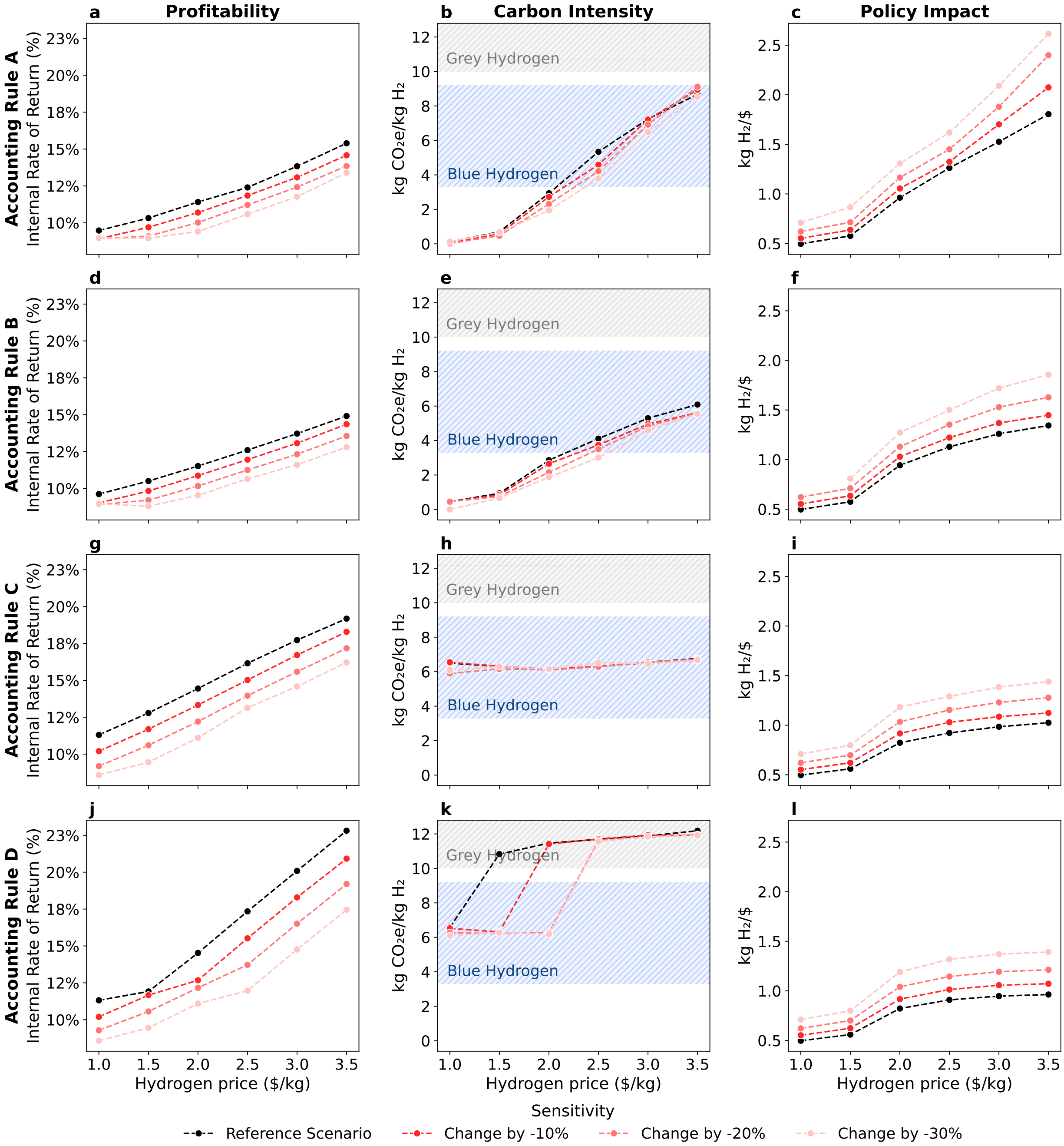
2 Reduced Production Tax Credits

To examine the effect of reduced production tax credits, we multiply by the function $f(\cdot)$ specified in equation (4) by the scalar λ and repeat our analysis for $\lambda = \{0.9, 0.8, 0.7\}$. These values reflect a reduction of the tax credits by 10, 20, and 30%.

Figure 1 shows our estimates for the implications of reduced production tax credits. As one might expect, we find that the profitability of PtG systems declines as production tax credits decline. The reduction of internal rates of return, however, is mitigated by the fact that investors are incentivized to build smaller PtG plants. As a result, the profitability of PtG system still ranges between 8.0–15.0% under hourly accounting rules and is significantly higher under annual accounting rules in most variations.

As for emissions, we find that the life-cycle average carbon intensity of hydrogen is fairly insensitive to the changes in production tax credits. One exception is that, under accounting rule D, the jump in the life-cycle average carbon intensity now occurs at higher hydrogen prices. This reflects that, below a certain hydrogen price, it is economically unattractive for investors to procure any EACs for renewable energy on the open market.

We further find that the policy impact of the tax credits increases as the tax credits are reduced. In other words, the policy program becomes more effective in incentivizing electrolytic hydrogen production. This finding reflects that investors would build smaller PtG plants and produce less hydrogen. Yet, this reduction is outweighed by the reduction in tax credits paid.

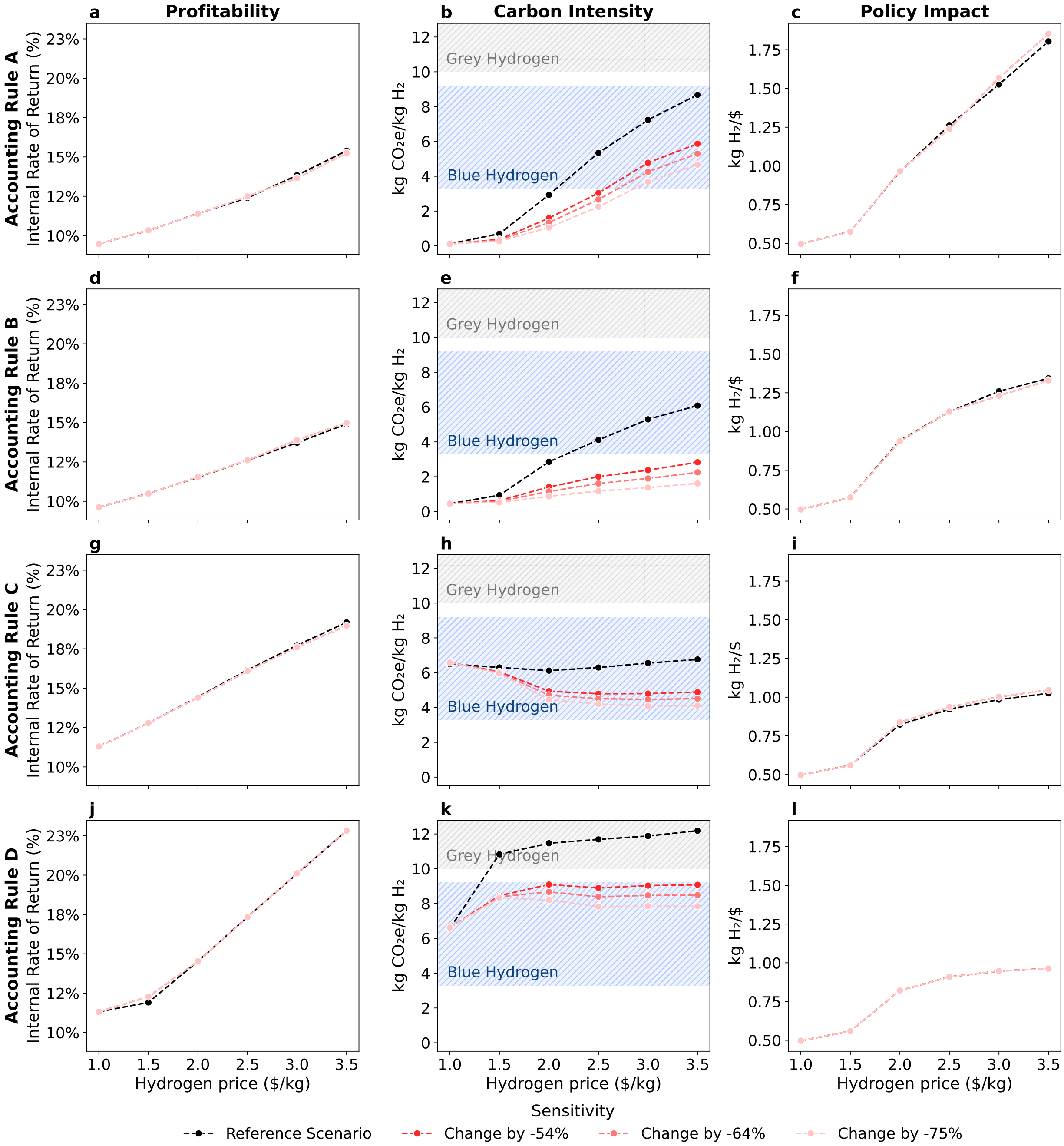


Supplementary Figure 2. Life-cycle performance under reduced production tax credits. This figure shows the impact of reduced production tax credits on (**a, d, g, j**) the profitability of PtG systems, (**b, e, h, k**) the life-cycle average carbon intensity of hydrogen, and (**c, f, i, l**) the policy impact of the production tax credit, given hydrogen prices between \$1.0/kg and \$3.5/kg. The dots show our point estimates at specific hydrogen prices, while the dashed lines are used for illustration to interpolate between them.

3 Carbon Intensity of Grid Electricity

This section examines the impact of lower future carbon intensity levels of general grid electricity to reflect higher shares of renewable power generation in the future. Recall from Methods that, to mitigate computational costs, our numerical calibration runs the inner optimization for two representative years: the first year of operation with tax credits and the eleventh year of operation without tax credits. To examine the impact of lower future carbon intensity levels, we therefore multiply the reference vector for the hourly carbon intensity of general grid electricity by a reduction factor and use this adjusted vector only for the second inner optimization (i.e., the eleventh year of operation). Our analysis considers three alternative projections for the carbon intensity of general grid electricity, as provided by the National Renewable Energy Laboratory[60]. The central scenario projects a reduction of 64% by 2035, while the lower and upper scenarios project reductions of 54% and 75%.

Figure 3 shows our estimates for the implications of lower future carbon intensity levels of general grid electricity. As one might expect, we find that the profitability of PtG systems and the policy impact of the tax credits remain unchanged. This is because the reduction in carbon intensity levels only applies for the period after the tax credits. In terms of emissions, however, we find that the life-cycle average carbon intensity of hydrogen declines significantly as general grid electricity becomes less carbon-intensive. In particular, we find that the life-cycle average carbon intensity levels under accounting rule B are now below those for blue hydrogen at all hydrogen prices considered. Under rule D, they are now below those for grey hydrogen and close to upper estimates for blue hydrogen at all hydrogen prices considered.



Supplementary Figure 3. Life-cycle performance under lower future carbon intensity levels of general grid electricity. This figure shows the impact of lower future carbon intensity levels of general grid electricity on (**a, d, g, j**) the profitability of PtG systems, (**b, e, h, k**) the life-cycle average carbon intensity of hydrogen, and (**c, f, i, l**) the policy impact of the production tax credit, given hydrogen prices between \$1.0/kg and \$3.5/kg. The dots show our point estimates at specific hydrogen prices, while the dashed lines are used for illustration to interpolate between them.

4 Changes in Electricity Prices

In this section, we examine the implications of changes in the average and variance of electricity prices to reflect temporal and regional differences in the share of renewable power generation. To that end, let $\mu(t)$ denote the multiplicative deviation factor of electricity selling prices given by:

$$p_s(t) \equiv \mu(t) \cdot \frac{1}{m} \sum_{t=1}^{m} p_s(t).$$

By construction,

$$\sum_{t=1}^{m} \mu(t) = 1.$$

Furthermore, let α denote the relative change in the annual average of electricity prices and β the relative change in the hourly variation of electricity prices during hours where prices are above average. In addition, we calculate the corresponding change in the hourly variation of electricity prices during hours where prices are below average, denoted by $\hat{\beta}$, such that the adjusted annual average remains unchanged. Thus, the adjusted electricity price in a particular hour is given by:

$$\hat{p}_s(t) = \begin{cases} \beta \cdot \mu(t) \cdot \alpha \cdot \frac{1}{m} \sum_{t=1}^{m} p_s(t) & \text{for } t \text{, where } \mu(t) \geq 1, \\ \hat{\beta} \cdot \mu(t) \cdot \alpha \cdot \frac{1}{m} \sum_{t=1}^{m} p_s(t) & \text{for } t \text{, where } \mu(t) < 1, \end{cases}$$

where $\hat{\beta}$ is calculated such that

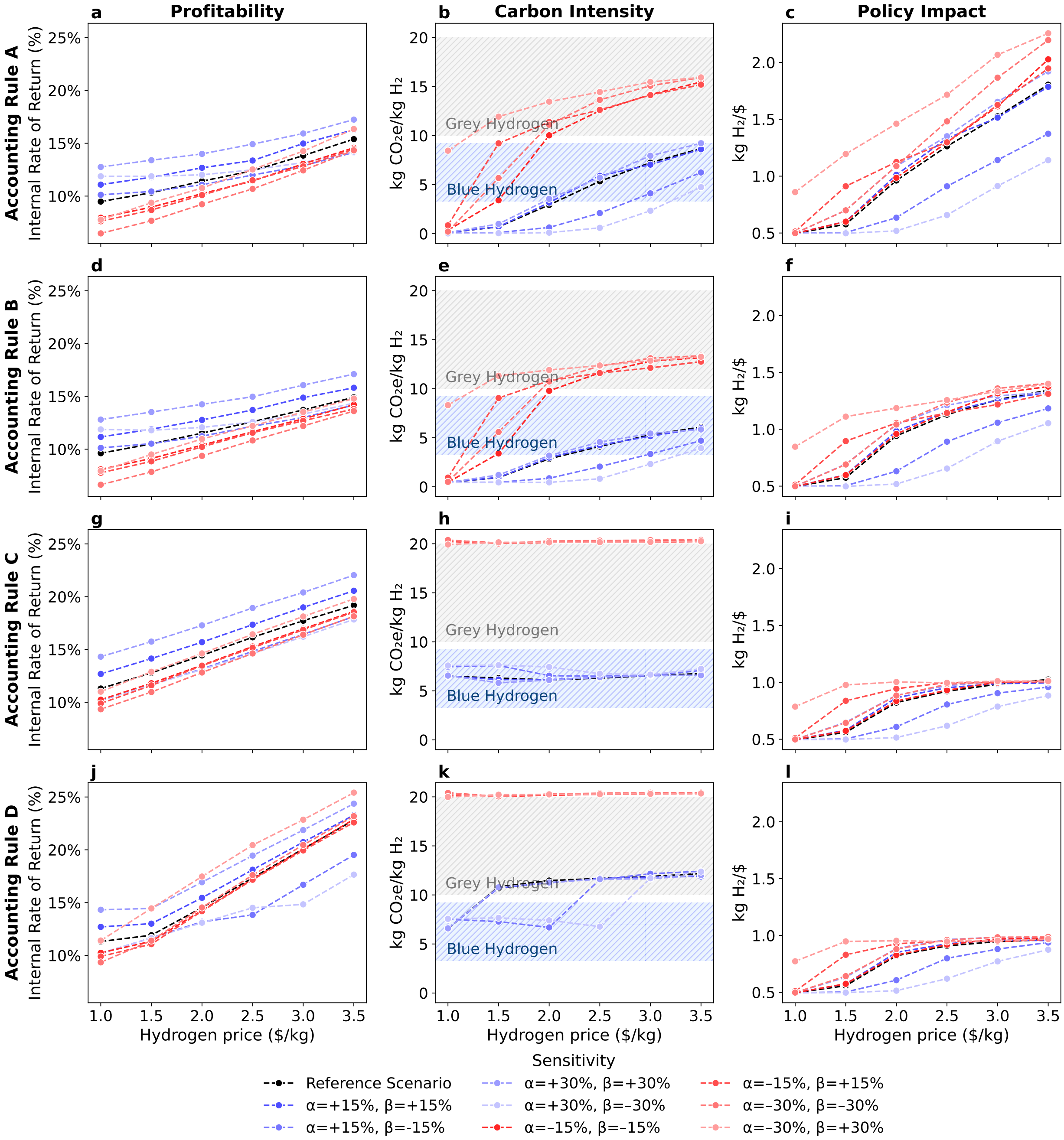
$$\frac{1}{m} \sum_{t=1}^{m} \hat{p}_s(t) = \alpha \cdot \frac{1}{m} \sum_{t=1}^{m} p_s(t).$$

The vector for hourly electricity buying prices, $p_b(t)$, is adjusted in direct analogy to that. We note that our sensitivity analysis does not aim to develop a new model for future electricity prices. Instead, we examine the impact of different electricity price distributions on the financial and emission performance of PtG systems, given accounting rules A through D. In particular, we examine permutations of simultaneous changes for α and β up to $\pm 30\%$, due to computational cost in steps of 15%.

Figure 4 shows our estimates for the implications of changes in electricity prices. We find that, under accounting rules A through C, the profitability of PtG systems increases (decreases) as the average of electricity prices increases (decreases), whereas decreases (increases) in the variance of electricity prices mitigate this effect. This mainly reflects that the generated renewable energy can be sold at higher (lower) market prices. Under rule D, the profitability of PtG systems appears to increase as the average of electricity prices either increases or decreases. We attribute this effect to the following observation: When the average of electricity prices declines, the generated renewable energy can be sold at higher market prices. When the average of electricity prices rises, however, PtG systems can buy the significant amounts of general grid electricity they procure at lower market prices.

Regarding emissions, we find that, under the hourly carbon accounting rules, the life-cycle average carbon intensity of hydrogen tends to decline (strongly increase) as the average of electricity prices increases (decreases). This reflects that PtG systems convert less (significantly more) general grid electricity. Under the hourly carbon accounting rules, life-cycle average carbon intensity levels of hydrogen remain almost unaffected when the average of electricity prices increases. This is mainly due to the natural limit on the amount of general grid electricity that can be converted, imposed by the generated renewable energy. Yet, the life-cycle average carbon intensity levels of hydrogen increase significantly when average prices decline. PtG systems, at all changes in the average of electricity prices considered, now produce at almost full capacity, resulting in relatively high and constant life-cycle average carbon intensity levels.

As for the policy impact, we generally find that lower averages and higher variances in electricity prices lead to a greater policy impact. While the scenarios with smaller changes in both parameters remain close to our reference scenario, the scenarios with higher changes have a significant impact on the life-cycle production of hydrogen per $ of tax credit. We observe the largest impact of the differences in the average and variance of electricity prices under accounting rule A. This is due to the operational flexibility investors have under this rule. For rules B through D, we observe some convergence of the policy impact with increasing hydrogen prices.



Supplementary Figure 4. Life-cycle performance under changes in electricity prices. This figure shows the impact of simultaneous changes in the average and variance of electricity prices on (**a, d, g, j**) the profitability of PtG systems, (**b, e, h, k**) the life-cycle average carbon intensity of hydrogen, and (**c, f, i, l**) the policy impact of the production tax credit, given hydrogen prices between \$1.0/kg and \$3.5/kg. The dots show our point estimates at specific hydrogen prices, while the dashed lines are used for illustration to interpolate between them.

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