

The influence of additionality and time-matching requirements on the emissions from grid-connected hydrogen production

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The literature provides conflicting guidance about the appropriate time-matching requirement between electricity consumption by electrolyzers and contracted variable renewable energy (VRE) for qualifying hydrogen (H₂) as ‘low carbon’. Here we show that these findings are highly influenced by different interpretations of additionality. Substantially lower consequential emissions are achievable under annual time matching when presuming that VRE for non-H₂ electricity demand does not compete with VRE contracted for H₂, as opposed to when assuming that all VRE resources are in direct competition. Further analysis considering four energy system-relevant policies suggests that the latter interpretation of additionality is likely to overestimate the emissions impacts of annual matching and underestimate those of hourly matching. We argue for starting with annual time matching in the near term for the attribution of the H₂ US production tax credits, where conditions resemble the ‘non-compete’ framework, followed by phase-in and subsequent phase-out of hourly time-matching requirements as the grid is deeply decarbonized.

Policies aimed at economy-wide decarbonization, such as the Inflation Reduction Act (IRA) in the United States, emphasize electrifying end uses while decarbonizing the growing electric power supply. In that context, an important question arises: what are the carbon dioxide (CO₂) emissions induced by specific loads (existing or new) connected to the grid that also contractually procure electricity from specific, often low-carbon, resources? This question is especially relevant for hydrogen (H₂) production via grid-connected electrolyzers, which is receiving increased policy attention—for instance, the IRA provides production tax credits (PTC) for ‘low-carbon’ H₂ that are tied to specific emissions thresholds, reaching a maximum of US\$3 per kg of H₂¹. Simply using grid-connected electricity to power electrolyzers, even in relatively high variable renewable energy (VRE) grids in the United States in 2021, such as California’s, would result in greater emissions

than H₂ produced from natural gas (NG) steam methane reforming (SMR) without carbon capture and storage (CCS)².

Modelling the emissions induced by a specific grid-connected load that contracts with a specific grid-connected generation resource is complex because instantaneous power flows from a particular producer cannot be directly associated with a particular user. However, modelling exercises to characterize emissions impacts of individual loads, as performed in this paper, are critical for informing the policy-making process. They guide policymakers to draft qualifying requirements that third parties (for example, a H₂ producer or a corporation) need to fulfil for their activities or products to be ‘certified’ as low carbon and to reap financial and/or reputational benefits. Consequently, these qualifying requirements have billion-dollar ramifications as they will directly impact investments in the energy sector.

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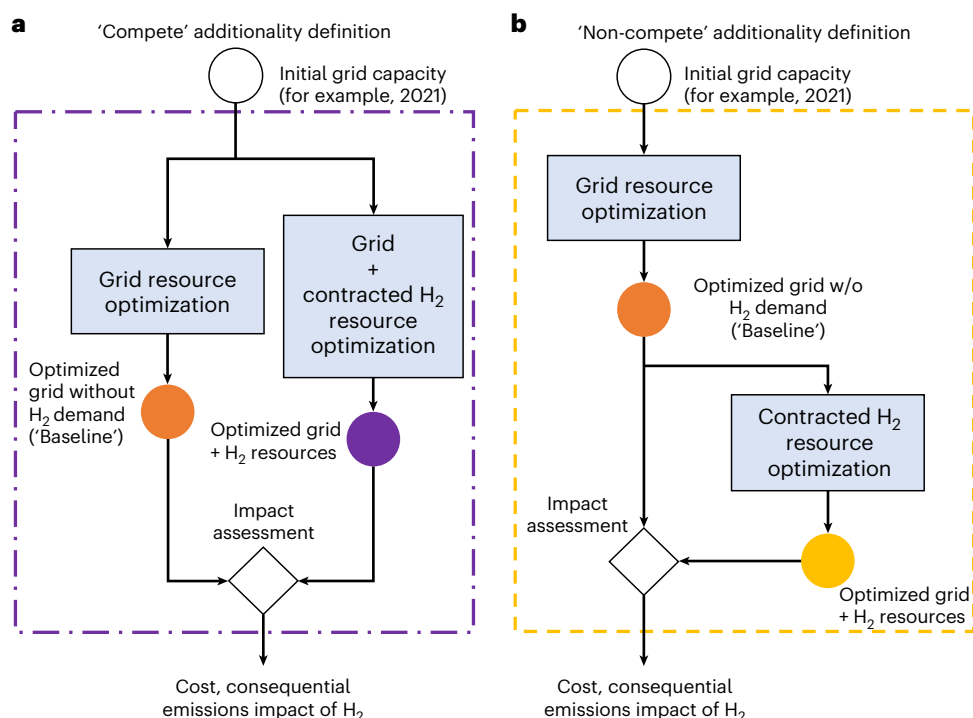


Fig. 1 | Modelling emissions and cost impacts of additionality. Approaches for evaluating the cost and consequential emissions impact of electrolytic H₂ production based on the two alternative definitions of additionality. **a**, The 'compete' definition (purple dotted box) mirrors the approach of Ricks et al.³ and allows for competition among investment in resources contracted for H₂ production and other grid resource investments. **b**, The 'non-compete' definition of additionality (yellow dotted box) follows the approach of Zeyen et al.⁴ where

contracted H₂ resources are optimized after investments in non-H₂ related grid resources. Here contracted H₂ resources refer to battery storage, wind, solar generation, electrolyzers and H₂ storage resources to meet H₂ demand and satisfy the specified time-matching requirement. Note that the baseline grid in both additionality frameworks is the same, whereas the optimized grid with H₂ resources is different (as indicated by the different colours of the circles).

This Article's contribution to the field of electricity emissions accounting is grounded in an analysis of the H₂ PTC, which has spurred a vigorous debate in the academic and policy spheres. The debate has largely focused on qualifying time-matching requirements for low-carbon, grid-connected H₂ production, with recent research papers by Ricks et al.³ and Zeyen et al.⁴ supporting different requirements. The time-matching requirement defines the timescale over which the volume of contracted low-carbon electricity generation (in MWh) needs to equal the volume of electricity consumed for H₂ production (for example, hourly, annual or other). Zeyen et al. find that annual matching generally leads to limited associated emissions, whereas hourly matching typically raises the cost of H₂ production compared with annual matching. In contrast, Ricks et al. find that under annual matching, the emissions associated with the H₂ production are substantially higher than acceptable thresholds and hourly matching is needed. These two conflicting results present a conundrum for policymakers tasked with making imminent decisions about how to implement H₂ PTC policies.

Besides temporal matching, a second important qualifying requirement is additionality. The additionality requirement establishes a causal relationship between the procured low-electricity generation and H₂ production—a truly additional generation resource is one that would not have been built had the load that contracts its electricity not been built. The aim of an additionality requirement is to avoid double-counting low-carbon electricity deployed for other objectives (for example, grid decarbonization). A third key qualifying requirement is spatial matching, that is, the extent to which the electrical path between the procured low-carbon electricity supply and the electrolyser is physically congested over the lifetime of the supply contract.

Here we use an open-source energy system model⁵ to quantify the interaction of alternative interpretations of the additionality (which we label 'compete' and 'non-compete') and time-matching requirements (annual and hourly) in terms of consequential emissions and the levelized cost of electrolytic H₂ production (LCOH). We find that the emissions impact of a time-matching requirement is conditional upon the applied additionality modelling framework, and this observation partly explains the divergent findings of the above-mentioned papers. Furthermore, through modelling of different contextual policies, we demonstrate that the standard 'compete' additionality framework in many contexts is likely to overestimate of the emissions impact of annual matching and/or underestimate those for hourly matching. In general, this study highlights that one cannot generalize emissions impacts of a selected time-matching requirement in isolation from how other qualification requirements are defined and other existing energy system-related policies that are in place.

Modelling additionality and relevant energy policies

At one extreme, any generation resource that is not operating in the system before installation of the electrolyser can be considered 'additional'. This additionality definition, used in ref. 3, can be modelled via two parallel runs with cost-optimal brownfield grid expansion under the same set of assumptions, including 'initial grid' conditions (Fig. 1a). The only difference between both runs is that one run excludes H₂ load ('baseline grid') whereas the other includes H₂ load that is constrained to meet certain temporal and/or spatial matching requirements ('counterfactual grid'). The consequential emissions from electrolytic H₂ production can be calculated as the difference in emissions between both grids. Under this modelling framework,

Table 1 | Summary of the four policy scenarios evaluated to quantify their impact on emissions and cost associated with alternative time-matching and additionality requirements related to electrolytic H₂ production

	Standard case	Policy scenario
Limiting the electrolyser's annual capacity factor	Baseload and unconstrained flexible operation	Range of maximum annual capacity factors (20–80%)
Minimum annual VRE generation requirement, RPS	None	60 and 80% VRE target for non-H ₂ electricity demand (Supplementary Methods equation (6))
VRE + battery storage capacity buildout limit	Unconstrained	15 GW (Supplementary Methods equation (7))
Use of NG-based H₂ to meet H₂ demand	Only electrolytic H ₂	Competition for H ₂ production between electrolysis and NG-based H ₂ with CCS

in the counterfactual grid, the more low-carbon resources that are built out to satisfy H₂ demand, the fewer low-carbon resources might be built out merely because of their cost effectiveness (due to the self-cannibalization effect of renewables). In that sense, H₂ demand 'competes' with the decarbonization of other electrifying sectors without strict matching requirements (for example, transport or heating).

At the other extreme, only generation resources that would not have been deployed in the absence of electricity demand for H₂ production can be considered additional. This additionality definition, applied in ref. 4, involves evaluating model outcomes in series rather than in parallel (Fig. 1b). First, we solve the cost-optimal grid brownfield expansion excluding H₂ load to yield the 'baseline grid'. Subsequently, the counterfactual grid is obtained by running the cost-effective grid expansion to satisfy H₂ demand *with the expanded baseline grid as a starting point*. As H₂ demand for low-carbon resources is only satisfied after low-carbon resource needs for non-H₂ demand or any other decarbonization policy is fulfilled, H₂ load does not compete with other drivers for investment in low-carbon electricity. This so-called 'non-compete' framework implies a stricter definition for additionality, whereas the additionality definition according to the 'compete' framework is easier to enforce in practice (Supplementary Note 1 provides further details).

Besides analysing alternative additionality frameworks, we also evaluate the impact of four policies on the system impacts of time-matching requirements under the 'compete' additionality framework, where such policy interactions are relevant (Table 1). The first policy constrains the maximum annual capacity factor of the electrolyser so as to incentivize a producer meeting a fixed H₂ demand under annual time matching to forgo production during periods of high electricity prices. This policy would also reduce emissions impact of H₂ production in a fossil-fuel-dominant power system, where periods of high electricity prices are correlated with periods of high marginal grid emissions intensity.

Second, to analyse the impact of the initial grid on the emissions and LCOH of alternative qualifying requirements, we evaluate scenarios where we impose minimum annual VRE generation requirements (60% and 80% of the non-H₂ electricity demand). Such an annual VRE generation requirement can be realized by two approaches in isolation or in combination: via renewable portfolio standard (RPS) policies⁶, as is in place in 29 US states as of June 2023⁷ or via decentralized procurement of VRE supply by several end-use customers, for example, by the numerous pledges of corporates to become climate neutral⁸. When including a minimum VRE requirement under the 'compete' framework, VRE for

non-H₂ load is prioritized. This prioritization, by definition, is inherent in the 'non-compete' framework.

Third, many grids are facing substantial delays in connecting new generation to the transmission grid^{9,10}, which was not considered in prior studies. We model this policy failure by adding a constraint that limits the capacity of VRE and battery storage that can be built out (Methods).

Fourth, whereas most studies on qualifying requirements focus exclusively on electrolytic H₂, other H₂ pathways like NG-based H₂ production with CCS (so-called blue H₂) are also receiving policy support. To understand how qualifying requirements impact competition between green and blue H₂, we evaluate scenarios with the option to also invest in blue H₂.

Impact of different interpretations of additionality

Figure 2 shows that the contracted resource mix for H₂ production under annual time-matching requirements is more sensitive to the additionality definition than under hourly requirements. In general, wind plays a greater role under an hourly time-matching requirement than under an annual requirement for both additionality frameworks in the Electric Reliability Council of Texas (ERCOT) case study. Under the 'compete' framework, solar generation is preferred to meet annual time-matching requirements, whereas under the 'non-compete' framework, wind generation plays a greater role to meet the contractual requirement. This is a consequence of which generation resources are built out in the baseline grid expansion. Because baseline grid expansion in the ERCOT case study solely results in solar additions (Supplementary Fig. 4), use of solar to serve H₂ load under the 'non-compete' framework has diminished economic value as compared with the 'compete' framework.

Compared with annual time matching, hourly time matching leads to higher capacities of contracted resources for H₂ production under both additionality modelling frameworks. Consequently, hourly matching generally leads to reductions in carbon-based generation, especially NG, compared with the baseline grid scenario for both ERCOT (Fig. 2c,d) and the grid managed by the Florida Reliability Coordinating Council (FRCC) (Supplementary Fig. 19). The increased capacity deployment is necessary to ensure that the VRE generation plus net discharge of battery storage from contracted resources is at least equal to hourly electrolyser power consumption (Supplementary Methods equation (3)). Extensive deployment also implies that these contracted resources will generate in excess of electrolyser power demand at certain times. As such, more expensive generation on the margin is displaced (Extended Data Fig. 1a,b). The displaced generation includes VRE resources that would have been deployed in the baseline grid and NG and, to a limited extent, coal generation. Hourly time matching generally leads to low or negative emissions under both additionality modelling frameworks. In the 'compete' framework, competition with non-contracted grid resources results in less negative, or even positive, consequential emissions (Fig. 3).

In the annual time-matching cases and the 'compete' framework, additional gas generation is needed to meet electricity demand for H₂ production during times of low solar availability (Extended Data Fig. 1c). In contrast, under the 'non-compete' framework, increases in gas generation during low VRE availability hours are largely offset by decreases in gas and coal generation during hours with high solar availability (Extended Data Fig. 1d). This is explained by more VRE investment for non-H₂ electricity demand under the 'non-compete' framework, which is the main driver of the diverging consequential emissions under annual matching when comparing both additionality frameworks (Fig. 3). In the 'compete' framework and annual time matching, the emissions under baseload operation are greater than the emissions of H₂ production from NG without CCS¹¹. Flexible operation

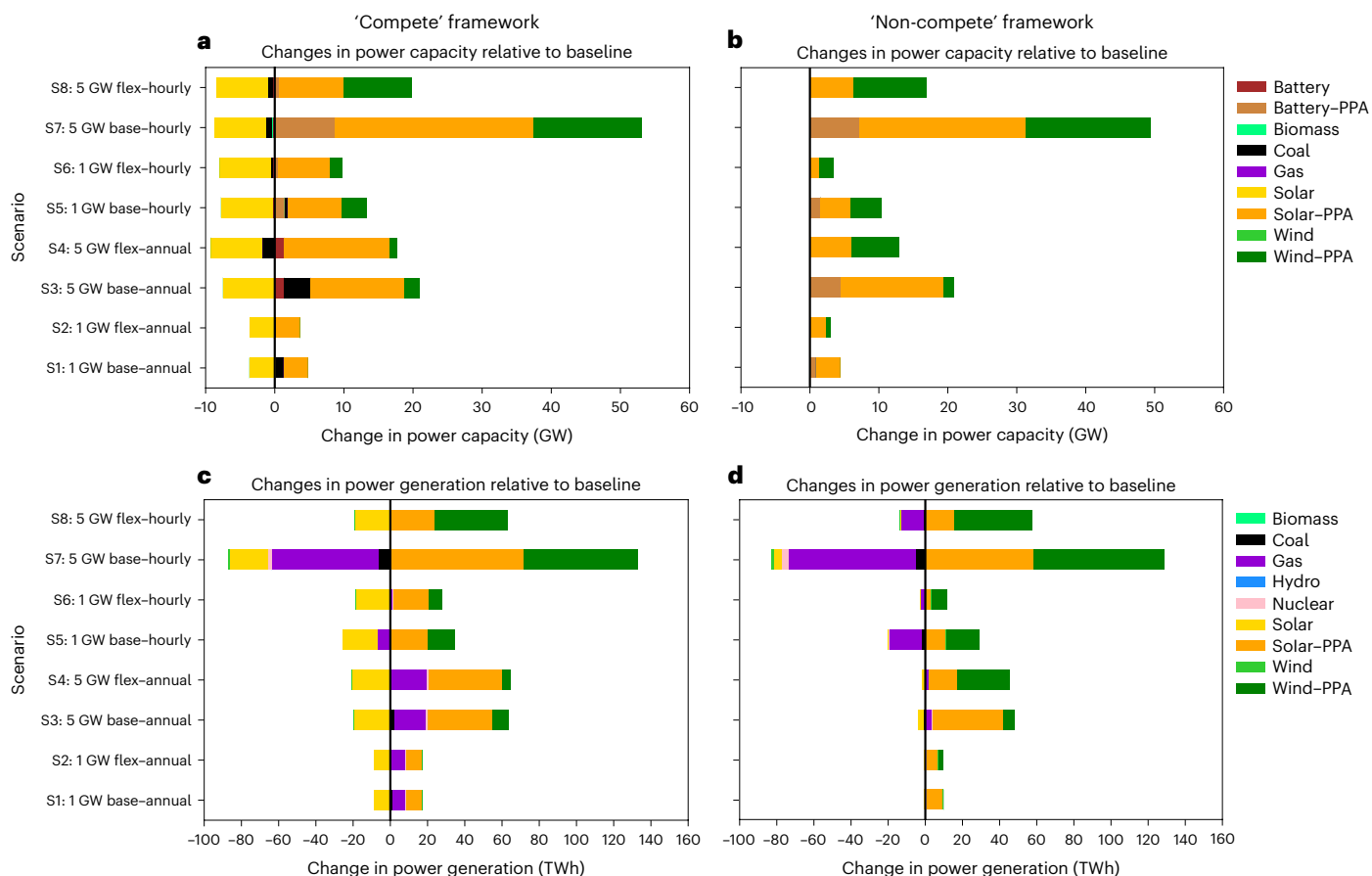


Fig. 2 | Power sector resource changes due to H₂ production. a–d, Change in power generation and storage capacity (a,b) and annual power generation (c,d) resulting from electrolytic H₂ production under alternative H₂ demand scenarios, time-matching requirements and additionality frameworks. Results correspond

to the case study based on the grid managed by ERCOT and are reported relative to the baseline scenario involving grid resource expansion without any H₂ demand. Power purchase agreement (PPA) refers to resources added specifically to meet time-matching requirements for H₂ production.

slightly mitigates this effect by limiting NG generation versus the baseline grid.

Flexible electrolyser operation results in lower capacity deployment for both annual and hourly time-matching requirements under both additionality modelling frameworks (Fig. 2). This is because flexible operation enables the shifting of electricity consumption for H₂ production to better match the availability of contracted VRE resources, whereas relying on relatively low-cost H₂ storage (Supplementary Table 2) to meet H₂ demand. It also avoids the need for expensive battery storage deployment to meet hourly time-matching requirements, instead deploying H₂ storage capacity (Supplementary Figs. 7 and 8). As a consequence, under flexible operation, the volume of excess electricity sales reduces (Supplementary Figs. 5 and 6), and less negative consequential emissions are observed with hourly time matching (Fig. 3). Interestingly, in the 1 GW H₂ demand scenario with hourly time matching under the 'compete' framework, the combined effect of flexible operation and competition with other grid resources results in positive consequential emissions in both ERCOT (Fig. 3) and FRCC (Supplementary Fig. 24). This is due to a greater reliance on solar compared with the corresponding baseload operation scenario and the lack of any contracted battery storage that results in greater reliance on NG to meet net load requirements (Supplementary Figs. 5 and 6). Higher H₂ demand levels result in wind accounting for a greater share of contracted VRE capacity towards H₂ production, which decreases consequential emissions intensity.

In nearly all cases for ERCOT (and FRCC; Supplementary Fig. 25), the LCOH is greater under hourly versus annual time-matching

requirements when disregarding the attribution of a PTC (Fig. 4). Under the hourly time-matching requirement with baseload electrolyser operation, the LCOH after including the PTC remains greater than US\$1 kg⁻¹ in all cases and thus not competitive with NG H₂ without CCS¹¹. Flexible electrolyser operation reduces the LCOH compared with the corresponding baseload operation scenario when disregarding the PTC (Fig. 4), most notably under an hourly time-matching requirement. This is because the reduction in contracted power sector resources more than offsets increases in the fixed cost of the electrolyser and H₂ storage. This result reaffirms other studies that note the importance of electrolyser flexibility to minimize the cost of H₂ production and support grid decarbonization efforts¹².

LCOH without PTC attribution is generally greater under the 'non-compete' framework than the 'compete' framework. This is because the value of excess electricity sales, defined as the difference between absolute value of elec-sales and elec-purchases in Fig. 4, is generally smaller in the 'non-compete' versus 'compete' framework (Supplementary Tables 7 and 8). This is due to two effects. First, in the 'compete' framework, H₂ is inherently prioritized and contracts the most valuable VRE portfolio relative to resources built out for non-H₂ load. Second, wholesale electricity prices under the 'non-compete' framework are more depressed due to greater amounts of VRE generation in the baseline grid. However, when attributing the PTC that corresponds to the consequential emissions found in our modelling, the 'non-compete' cases generally have much lower LCOH than the 'compete' cases, especially under annual time matching.

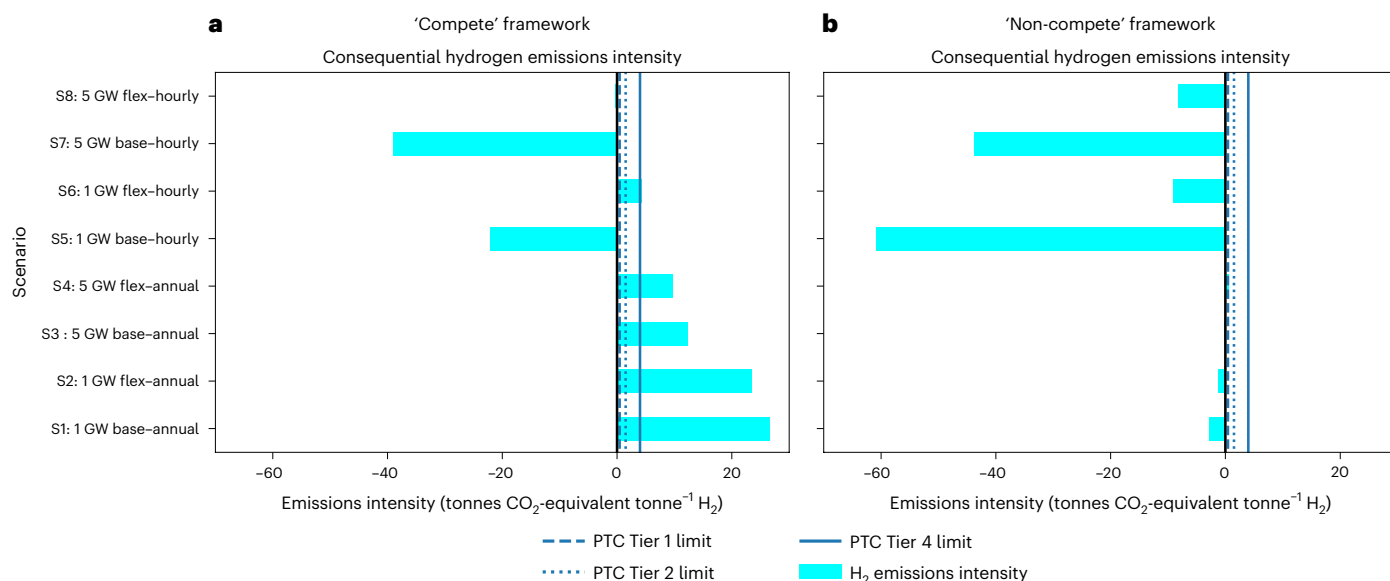


Fig. 3 | Emissions impacts under alternative additionality frameworks.

Consequential emissions intensity of H₂ production for alternative H₂ demand scenarios, electrolyser operation modes and time-matching requirements under the 'compete' (a) and 'non-compete' (b) frameworks of additionality. Results correspond to the ERCOT case study and are reported relative to the baseline

grid. Also shown are threshold emissions intensity values for the H₂ PTC in the IRA. H₂ that meets the Tier 1 limit is eligible for a credit of US\$3 kg⁻¹, whereas H₂ that meets the Tier 2 or Tier 4 limits are eligible for credits of US\$1.0 kg⁻¹ and US\$0.6 kg⁻¹, respectively.

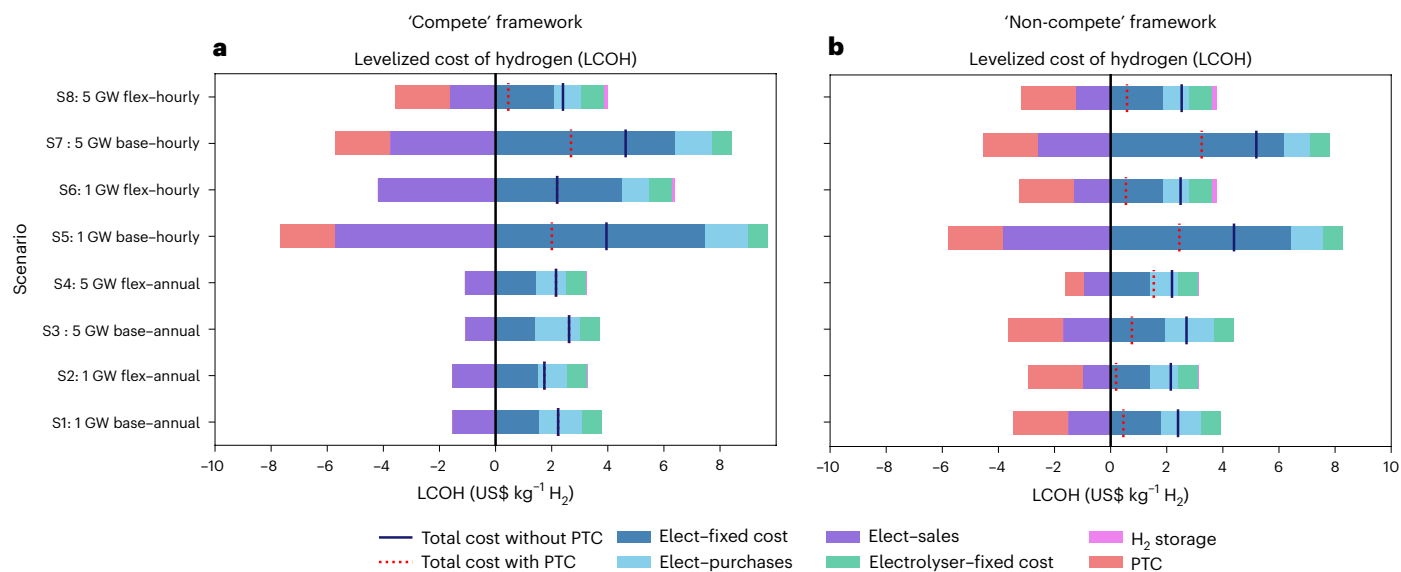


Fig. 4 | LCOH impacts under alternative additionality frameworks.

a,b, Levelized cost of H₂ (LCOH) for the ERCOT case study under scenario with different H₂ demands, time-matching requirements, additionality frameworks and electrolyser operation modes. Levelized cost calculated per description provided in Methods. Elec-sales, revenues earned from selling excess electricity to the grid using contracted power sector resources; elec-purchases, cost of grid electricity purchased to operate the electrolyser; electrolyser-fixed cost,

annualized capital and fixed operating and maintenance (FOM) cost of the electrolyser; elec-fixed cost, annualized capital and FOM cost of contracted power sector resources, after accounting for investment tax credit (30%); H₂ storage, capital and FOM cost of gaseous H₂ storage system, which includes the capital cost of the compressor and tank. The total cost with PTC shows the LCOH after accounting for PTC based on consequential emissions for each case.

Impact of relevant energy policies

To assess the robustness of the results, we present the results of two relevant energy-policy scenarios: a minimum annual VRE requirement (for example, a RPS) and the lack of an adequate interconnection policy for VRE deployment. In Supplementary Notes 2 and 3, we present the results of the two other scenarios: competition with blue H₂

(Supplementary Fig. 28) and an operating constraint on electrolyzers (Supplementary Fig. 29).

Figure 5 highlights the emissions and cost impact of an annual VRE requirement in serving non-H₂ load that is above the optimal level (vis-à-vis the objective function). This policy scenario is most relevant under annual time matching and the 'compete' additionality framework

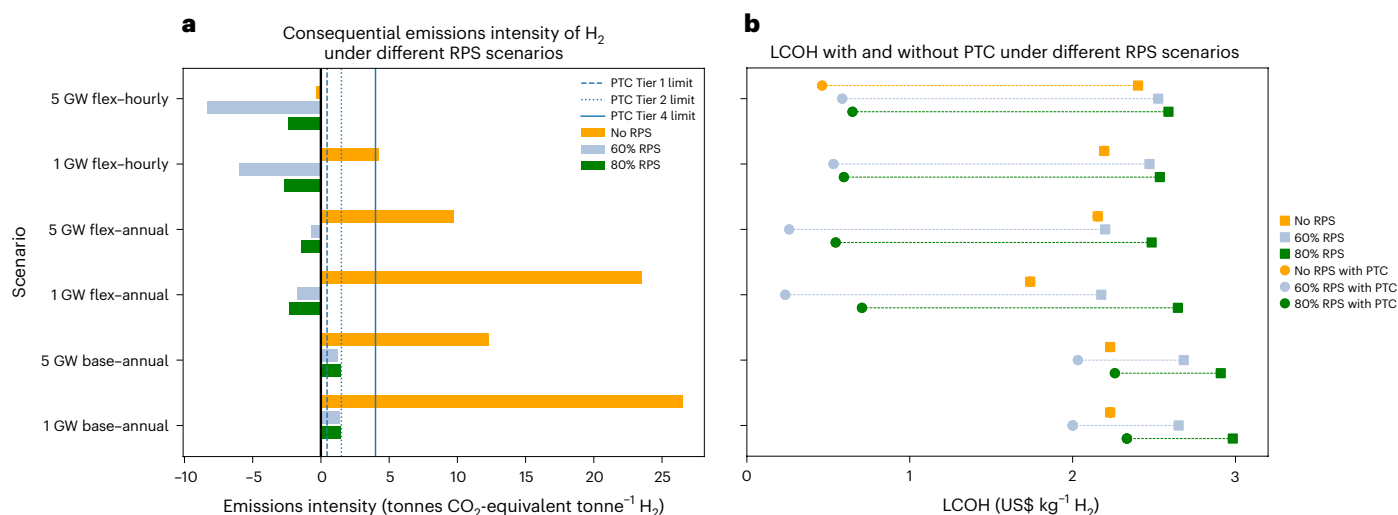


Fig. 5 | Emissions and cost under binding renewable electricity targets.

a,b, Consequential emissions intensity of H₂ production (a) and levelized cost of H₂ with and without the PTC (b) under VRE requirements (no RPS, 60% RPS and 80% RPS) for scenarios with different H₂ demand levels, time-matching requirements and electrolyser operation modes under the 'compete'

additionality framework. Results correspond to the ERCOT case study. For the levelized cost of H₂, the awarded PTC subsidy is based on the consequential emissions intensity of H₂ for each scenario. Additional results for the annual VRE requirement scenarios are reported in Supplementary Figs. 12–14.

because of the high consequential emissions intensity of H₂ production in our earlier results (Fig. 3).

The key finding (Fig. 5a) is that enforcing a minimum VRE requirement of 60% under the 'compete' framework is sufficient to reduce the consequential emissions associated with both annual and hourly time matching below the most stringent PTC threshold, when flexible operation is considered. In short, the consequential emissions under the 'compete' framework with the RPS mirror those under the 'non-compete' framework without RPS (Fig. 3). This is because the RPS effectively reduces competition between the VREs built for non-H₂ load and those contracted for H₂ production, thereby making the latter 'strictly additional'.

Under an hourly time-matching requirement, a RPS of 80% results in less negative consequential emissions than the 60% RPS due to the declining value of excess electricity sales from the VRE resources available for H₂ production. Moreover, under an 80% RPS, the emissions intensity associated with H₂ production under hourly or annual time-matching requirements becomes relatively similar. This finding suggests that in very high VRE grids, at least with regards to consequential emissions, the choice of an hourly or annual time-matching requirement has limited impact.

Figure 5b shows that a RPS increases LCOH, not accounting for PTC attribution, similarly to the trend seen under the 'non-compete' framework as compared with the 'compete' framework in Fig. 4. The competition between VRE deployments for H₂ production and the RPS results in a lower value of electricity sales to the grid and thus a higher LCOH. The impact is smaller for hourly matching, which may be due to the increased availability of energy storage (Supplementary Fig. 14) that enables electrolyzers to reduce their electricity purchase costs. Nevertheless, the relatively larger LCOH increases for annual time matching with a RPS policy are more than offset by the eligible PTC under this scenario.

The next scenario, with a limit on the buildout of VRE and battery storage representing interconnection challenges, will lead to equal or lower-than-cost-optimal VRE capacity levels. Figure 6 highlights that this effect is most impactful under hourly time matching under which higher VRE capacity is deployed to serve H₂ load. Such a buildout limit results in substantially greater consequential emissions associated with hourly matching under the 'compete' additionality

framework (Fig. 6a). For 5 GW H₂ demand, a 15 GW deployment limit causes emissions to rise from being negative to being greater than 6 tonnes CO₂-equivalent tonne⁻¹ H₂, exceeding the least-stringent PTC threshold. This occurs because overbuilding VRE capacity relative to electrolyser demand is not feasible under the buildout limit, which increases fossil fuel generation as compared with the baseline grid case (Fig. 6d).

The LCOH without PTC attribution does not change substantially due to the VRE plus storage buildout limit (Fig. 6b). The portfolio of VRE contracted with H₂ demand now favours relatively more wind over solar (Fig. 6c), which improves VRE capacity utilization and results in lower electricity-related fixed costs (Fig. 6b). In addition, to further improve capacity utilization and minimize VRE curtailment, the capacity of electrolyser and H₂ storage are increased (Fig. 6b), which raises their fixed costs and offsets the reduction in electricity sector fixed costs. Because consequential emissions intensity increases, substantially higher LCOH is seen when considering the PTC attribution.

Implementation of the buildout limit with the same H₂ demand is not feasible under the 'non-compete' framework. The H₂ demand cannot be fulfilled anymore because a large share of the grid-connected capacity has been utilized by VRE built out in the baseline run to cost optimally serve non-H₂ load. Thus, a possible implication of VRE and storage deployment constraints under an hourly time-matching requirement is fewer deployments of electrolyser projects in favour of other low-carbon H₂ production technologies.

Policy interpretation

Two key results summarize our findings from the standard cases (Figs. 2–4) across the two considered regions (ERCOT and FRCC). First, the consequential emissions of electrolytic H₂ are conditional upon how the additionality requirement is modelled. Under the 'compete' framework, an hourly time-matching requirement is the only way to reach consequential emissions that are under the threshold needed to receive the highest PTC. In contrast, under the 'non-compete' framework, an annual time-matching requirement is sufficient in all cases to meet the threshold needed to receive the highest PTC (US\$3 kg⁻¹). The second key result is that independent of the additionality modelling framework, hourly time-matching requirements lead to a higher LCOH relative to annual requirements, excluding

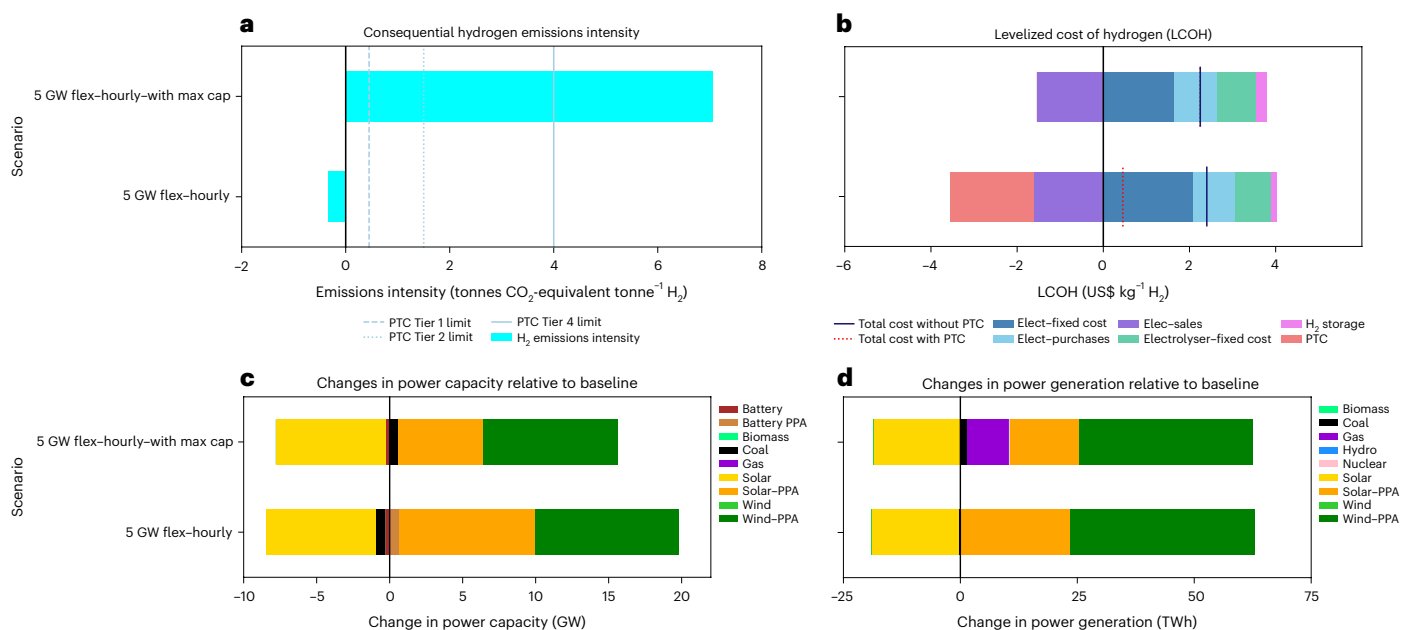


Fig. 6 | Impact of renewables plus storage capacity deployment limits. **a–d**, Consequential emissions intensity of H₂ production (**a**), levelized cost of H₂ (**b**), power system capacity change (**c**) and power system generation change (**d**) under an hourly time-matching requirement with 5 GW of hydrogen demand and flexible electrolyser operation with unconstrained VRE plus storage capacity deployment and a 15 GW limit under the ‘compete’ modelling framework. Note that 15 GW VRE plus storage deployment limit is not binding

for the 1 GW electrolyser demand. Results correspond to the ERCOT case study and are reported relative to the baseline grid involving grid resource expansion without any H₂ demand. See the caption of Fig. 3 for details on the consequential emissions subplot (**a**) and the caption of Fig. 4 for details on the LCOH subplot (**b**). Additional results for the VRE deployment scenarios are reported in Supplementary Figs. 17 and 18. An explanation for the 15 GW VRE and storage limit is provided in Methods, max cap, maximum capacity limit.

the attribution of a PTC, but this disparity can be largely reduced via flexible electrolyser operation. Considering both electrolyser operation modes, we find that the increase in LCOH from annual to hourly is US\$0.25–\$2.49 kg⁻¹, which is a greater range than the US\$0–1 kg⁻¹ increase between hourly time-matching and no time-matching requirements reported by ref. 3 (Supplementary Note 4 provides an overview of all results).

Further, we investigated how four policy scenarios impact our results, with a focus on the results in the ‘compete’ additionality framework where the impacts of time-matching requirements are the most striking.

In the first two policy scenarios in Table 2, the consequential emissions under annual matching are reduced relative to the standard case. In the other two policy scenarios, the consequential emissions under hourly time-matching increase relative to the standard case in some implementations. In summary, the results of these policy scenarios show that the standard runs under the ‘compete’ additionality framework in many contexts may in practice overestimate emissions for annual matching and underestimate emissions for hourly matching. These results also suggest that the difference in the LCOH under annual and hourly matching will probably be smaller relative to the standard case (Table 2).

Our results provide robust evidence for our original thesis: one cannot generalize emissions impacts of a specific time-matching requirement in isolation from how other qualification requirements are defined and other existing policies. However, it leaves open an important question for policymakers: which time-matching requirement is the most appropriate to consider when determining eligibility for the PTC in the United States?

It can be argued that the near-term context, in which the relative demand for renewable electricity for electrolytic H₂ is small compared with the total additions of VREs, more closely resembles the ‘non-compete’ additionality framework; we expect substantial non-H₂

load related VREs to enter before seeing high volumes of electrolytic H₂. As of May 2023, installed electrolyser capacity in the United States amounted to 67 MW (579 MW under construction)¹³, implying that 1 GW and 5 GW electricity-equivalent H₂ demand would represent roughly a 2× and 10× installed and under-construction capacity. Moreover, in the near term, demand for green H₂ is likely to originate from sectors where H₂ is already used today (for example, ammonia production) and thus be relatively small compared with the scale of electricity demand. For example, if 10% of US H₂ consumption in 2021 (around 1 MT per year) were to immediately shift to consume electrolytic H₂, it would amount to around ~1% of US electricity consumption as of 2021. At the same time, VRE deployments on the grid are likely to grow rapidly in the near term, as evident from their dominance in the existing interconnection queue in many US regions⁹ and due to dedicated VRE incentives, for example, PTCs or investment tax credits in the IRA, state RPSS⁷ and corporate procurements⁸.

The above interpretation would imply that less stringent annual time-matching requirements may be reasonable in the near term to ensure minimal consequential emissions (Fig. 3) while leading to lower LCOH outcomes (Fig. 4). Requiring hourly time matching in this decade may work against the policy objectives of the PTC to scale green H₂ production. While hourly time matching with flexible operation can also achieve low consequential emissions and LCOH outcomes under the ‘non-compete’ framework, its implementation would require much larger land area, onsite H₂ storage and capital investments than under annual time matching that may serve as additional barriers. In the case that electrolytic H₂ would manage to secure the scarcely available connection capacity, we have shown that the consequential emissions of H₂ production under hourly matching can greatly exceed the lowest PTC tier (Fig. 6). In addition, under hourly matching, the likelihood of substitution of green H₂ with blue H₂ is higher than under annual matching, again leading to potentially increased overall system wide (Supplementary Fig. 28).

Table 2 | Summary of results of the four policy scenarios relative to the results under the standard ‘compete’ additionality framework

	Time-matching requirement	Consequential emissions	LCOH
Limiting annual electrolyser capacity factor		Decrease	Increase
Minimum annual VRE generation requirement, RPS	Annual matching	Substantial decrease across all cases	Increase under annual requirements
VRE + battery storage capacity buildout limit		Substantial increase when limit is binding	Negligible impact
Use of SMR-CCS to meet H ₂ demand	Hourly matching	Increase under hourly requirements with baseload operation; flexible operation cases unchanged	Decrease under hourly requirements with baseload operation; flexible operation cases unchanged

In contrast, in the near term, lower implementation barriers and electrolyser H₂ sales prices under annual matching would encourage the deployment of electrolysers, allowing for technology scale-up and associated reductions in capital costs. Realizing low prices for green H₂ would support long-term economy-wide decarbonization goals by potentially displacing fossil-fuel-based H₂ in industrial applications and stimulating new demand for H₂ in end uses that are currently dominated by fossil fuels (for example, heavy-duty transport). In the case of the new H₂ demand, additional investments will be needed to facilitate H₂ use (for example, refuelling infrastructure, new equipment), and having cheap H₂ in the short-term incentivizes its use. To mitigate risk of competition for VREs during peak periods, the introduction of an annual capacity factor limit for the electrolyser can be a pragmatic policy to complement annual time-matching requirements. Slight decreases in the capacity factor (for example, capacity factor $\leq 80\%$) lead to important decreases in emissions at the expense of only a limited increase in the LCOH (Supplementary Fig. 29).

However, as demand for green H₂ grows, it is likely that the magnitude of VRE resources contracted for H₂ production will grow and increasingly compete with VRE resources that would be deployed for other reasons. In this case, the ‘compete’ framework for additionality is more suitable to evaluate the consequential emissions impact of H₂ production. Therefore, in the medium term (from 2030 onwards), shifting to hourly time-matching requirements may be necessary to avoid the risk of high consequential emissions impacts. Moreover, a phased approach for implementing more stringent hourly time matching may also benefit from capital cost declines for power sector resources (VRE, battery storage) and electrolysers that would make the LCOH outcomes for hourly time matching more compelling than values estimated here.

Finally, in the longer run, when grids are highly decarbonized (for example, over 60% of non-H₂ load covered by low-carbon generation including VREs, nuclear, hydro), an hourly time-matching requirement may no longer be necessary. Annual matching under flexible operation can achieve negative consequential emissions and similar LCOH outcomes as hourly time matching, without incurring additional VRE and storage investment (Fig. 6). Collectively, these factors indicate that a phased approach on defining the qualifying requirements for the H₂ PTC may be the most pragmatic approach to minimize barriers to grid

decarbonization whereas at the same time stimulating electrolytic H₂ use in difficult-to-decarbonize applications through the availability of low-cost H₂ supply.

Conclusions

Our systematic analysis of time-matching and additionality requirements in the context of electrolytic H₂ production highlights that one cannot generalize emissions impacts of a particular time-matching requirement in isolation from how other qualification requirements are defined and what other regionally differentiated energy policies are in place. Through two case studies, the ERCOT and FRCC grids, we confirm that the consequential emissions from producing electrolytic H₂ are conditional upon how the additionality requirement is modelled. Furthermore, an analysis of critical policy scenarios shows that the standard runs (that is, with these policies) under the ‘compete’ additionality framework are likely to overestimate consequential emissions for annual matching and/or underestimate them for hourly matching. These results give policymakers insight into the effectiveness of time-matching requirements in limiting consequential emissions in different regional contexts. Finally, our findings are not only relevant for the attribution of PTCs for low-carbon H₂ production but also broadly applicable for characterizing electricity-related emissions accounting in different contexts.

With regards to PTC implementation in the US context, we argue for a ‘phased approach’ in defining time-matching requirements for the attribution of the PTC: annual matching in the near term to kick off electrolytic H₂ production followed by transition to hourly time matching. Further modelling is needed to understand the timing of and the duration over which such a stringent time-matching requirement might be necessary (Supplementary Note 5). The modelling analysis to inform the phase-in and phase-out of hourly time-matching requirements should consider different levels of non-H₂ VRE deployment, H₂ demand and competition between green vs blue H₂, among other factors for various regions.

Methods

Model overview

This study uses the Decision Optimization of Low-carbon Power and Hydrogen Networks model⁵, an open-source energy systems capacity expansion model that co-optimizes investment and operation of electrical power and H₂ sectors while considering their spatially and temporally resolved interactions. The model minimizes the total system cost associated with bulk infrastructure of both commodities (electricity and H₂). This includes annualized capital costs for new capacity and fixed and variable operating costs for both existing and new generation, storage and transmission capacity and any costs for load shedding. The cost minimization is carried out subject to many system and technology-level constraints, including: ramping limits and temporally dependent resource availability limits for VRE generation and system-level constraints, which includes hourly energy supply–demand balance for H₂ and electricity at each location, and case-specific or hourly/annual time matching and energy share requirements. Further details of the model formulation and set-up can be found in ref. 5. Key modifications and additions to the model that were implemented for this analysis are reported in Supplementary Methods equation (1)–(7).

Region and time horizon of interest

Our analysis is based on two regional US grids that are representative of low and high end of VRE generation share in the United States as of 2021: grids managed by the ERCOT and the FRCC. The contributions of grid-connected VRE generation in ERCOT and FRCC grids as of 2021 were 26.5% (3.1% solar, 23.4% wind) and 3.0% (3.0% solar, 0% wind), respectively. Low VRE penetration grids are a common occurrence in the United States as of 2021—for example, Mid-Atlantic (2.4%), New

England (6.1%) and East South Central (0.4%)¹⁴. Full results for FRCC are reported in Supplementary Figs. 19–27.

Power sector modelling assumptions

The data inputs and sources used to define the 2021 system for both ERCOT and FRCC studies are provided in the Supplementary Information. Unless otherwise stated, all costs have been converted to 2021 US dollars. Relevant technology cost and performance assumptions are reported in Supplementary Tables 1 and 2. Across all scenarios, we allow the model to alter the power capacity mix via investment in solar, wind and Li-ion battery storage, both for non-H₂ and H₂ electricity demand and retirement of existing fossil fuel generation resources. In our analysis, we do not allow for retirements of existing nuclear plants, based on the assumption that it would be economically viable to continue running these plants based on the available credits for nuclear in the IRA. The parametrization of battery storage also considers a self-discharge rate of 0.002% per hour (ref. 15). The model can independently vary the installed energy capacity and power capacity for Li-ion storage so long as the ratio of energy capacity to power capacity (that is, duration) is between 0.15 and 12 h.

Aggregated power generation capacity for all resources for ERCOT and FRCC are reported in Supplementary Table 5. Annual demand and generation information is reported in Supplementary Table 6. The electricity demand data was obtained from PowerGenome¹⁶ and corresponds to demand for 2021 for the two regions.

Hourly resource availability data for onshore wind and solar photovoltaics for each region was generated by averaging hourly resource availability profiles for weather year 2012 from multiple sites, available from a previous study¹⁷. The site-level data for photovoltaics were simulated using site-level irradiation data from the National Solar Radiation Database in conjunction with the open-source model PVLIB. In the case of wind, the site-level resource data were simulated using site-level wind speed data from the National Renewable Energy Laboratory Wind Integration National Dataset Toolkit and power curve data based on the Gamesa G26/2500 wind turbine. Further details about the site-level data calculation are provided in the supporting information of a previous publication¹⁷. Supplementary Fig. 3 shows the geographic areas used to compute average capacity factors for wind and solar generation in FRCC and ERCOT. The regional-level wind and solar availability profiles for FRCC were generated by averaging resource availability profiles over the entire FRCC service territory. In the case of ERCOT, we considered only sites in West Texas and the Panhandle, to account for the fact that this region has the highest quality renewable resources and, thus, is likely to dominate new resource deployment (and already dominates existing resource deployment). As a simplification, we do not impose additional constraints or costs on VRE deployment and thus do not capture the increasing marginal cost of adding wind and solar resources into the system used by other grid studies³.

Supplementary Fig. 1 visualizes the hourly demand profile and VRE resource profile for FRCC, which highlights how wind availability tends to be low during summer months when electricity demand is relatively high. Supplementary Fig. 2 visualizes the VRE resource and demand data for ERCOT, with wind exhibiting less seasonal variation than in FRCC.

Fuel cost assumptions

The model runs were based on fuel price assumptions based on 2019 rather than 2021, as summarized in Supplementary Table 4, so as to not consider the short-term distortion in fuel prices resulting from exceptional events (COVID-19 pandemic, EU energy crisis and so on). Whereas the spot prices of natural gas through 2021 were much higher than 2019 values (as high as US\$6 per one million British thermal units (MMBtu⁻¹)), it is interesting to note that prices in 2023 have come down to levels seen in 2019. For example, according to the data from the US Energy Information Administration¹⁸, the average Henry hub

spot price in January and February 2023 were US\$3.27 MMBtu⁻¹ and US\$2.38 MMBtu⁻¹, respectively.

We use modified fuel costs for natural gas technologies using CCS for H₂ production to implicitly account for the cost of CO₂ transportation and storage. The incremental CCS cost added to the fuel cost is computed by multiplying the captured CO₂ per MMBtu of NG (Supplementary Table 3) with the assumed CO₂ transportation and storage cost, equal to US\$11.6 tonne⁻¹ per the assumption used by the National Energy Technology Laboratory in their techno-economic analysis of natural gas H₂ production technologies¹¹.

H₂ demand characterization and electrolyser capacity modelling

Under both baseload and flexible electrolyser operation in our analysis, electrolyser capacity is sized to meet exogenous H₂ demand, such that at any hour, only 95% of the installed capacity is available for generation. This is to account for planned outages related to maintenance. We evaluated the system outcomes for varying levels of hourly H₂ demand of 18.4 to 92.1 tonnes of H₂ per hour (0.16 to 0.81 MT per year), which for typical electrolyser specific power consumption (54.3 MWh tonne⁻¹) ranges from 1 to 5 GW of hourly electric power consumption. For simplicity, when discussing results, we use labels such as '1 GW' to indicate an hourly H₂ demand level of 18.4 tonnes of H₂ per hour. Because the total amount of H₂ produced is fixed, the available PTC does not impact the operational behaviour of the electrolyser and therefore we do not consider it in the model but rather include it when estimating the levelized cost of H₂. Supplementary Table 2 summarizes cost assumptions for electrolysers and H₂ storage and natural gas H₂ production with CCS. The latter is only considered in the policy scenario evaluating competition between green and blue H₂ pathways.

Time-matching requirements

As in refs. 3,4, we model two time-matching requirements—hourly and annual. However, here we compare the results for these time-matching requirements under two alternative frameworks for additionality, as defined earlier.

Annual time matching is implemented via a constraint that requires that the annual generation output from contracted wind and solar resources must equal the annual electricity consumption of the electrolyser (Supplementary Methods equation (2)). In contrast, the hourly time-matching requirement is modelled by implementing a constraint that requires the net hourly output of contracted resources (VRE generation and battery storage net discharge) to be at least equal to the hourly electricity consumption of the electrolyser; Supplementary Methods equation (3)). To ensure battery storage charges from eligible VRE generation resources, we allow only the contracted battery, if deployed, to charge in each hour up to the available generation from contracted VRE resources (Supplementary Methods equation (4)). In this implementation, the hourly time-matching requirement allows for the contracted resources to sell any excess electricity in a given hour (for example, an hour with high solar or wind availability) to the grid and earn revenues that can partly offset the capital cost associated with the contracted resources and thereby reduce the cost of H₂ production. The option to sell electricity to the grid when economical is also available in the annual time-matching requirement case, so long as the sum of annual generation matches that of the electricity consumption of the electrolyser.

Metrics of interest

The emissions impact of H₂ production is evaluated using the consequential emissions intensity, defined as the difference in power system emissions with and without H₂ demand divided by the annual quantity of H₂ produced. As noted by others^{3,4}, this is an appropriate metric for assessing emissions intensity in modelling exercises; however, alternative metrics are needed for real world accounting, because the

‘counterfactual grid’ used to calculate consequential emissions cannot be observed. Although the PTC focuses on life-cycle greenhouse gas emissions, as a simplification, our analysis considers only CO₂ emissions related to fossil fuel combustion for electricity generation because these will dominate overall emissions.

Aside from consequential emissions intensity, we evaluate the levelized cost of H₂ (LCOH), which approximates the cost to the H₂ producer who invests in the electrolyser and H₂ storage and the additional low-carbon electricity generation that is required for the H₂ to be eligible for the PTC under alternative time-matching and additionality requirements. The LCOH can also be thought of as a proxy for the minimum H₂ selling price that would lead to a zero profit for the H₂ producer over the lifetime of the investment in the electrolyser. In practice, the H₂ producer may not directly invest in the VRE plus battery storage assets but could choose to sign a power purchase agreement (PPA) that pays another developer who has invested in these assets. Here we are trying to approximate the cost of the PPA by accounting for the difference between the cost of electricity grid consumption incurred by the hydrogen producer and the revenues from sales of electricity from the VRE plus battery storage assets.

The LCOH includes: the capital cost of added VRE and battery storage (after the 30% investment tax credit under the IRAs), the cost of electricity purchases from the grid for H₂ production, revenue from electricity sales to the grid from the procured renewables (accounting for battery charging/discharging) and electrolyser and H₂ storage fixed costs. Revenues and costs for electricity purchases and sales to the grid are accounted for based on the shadow price of electricity supply–demand balance constraint enforced for each hour of the year in the model. In each case, we report the LCOH with and without including the applicable H₂ PTC.

Additional details on the VRE deployment limit policy scenario

In cases where the VRE capacity deployment constraint is modelled, we have set this limit at 15 GW for illustrative reasons. Average VRE additions in ERCOT for the ten-year period 2012–2021 was 2.7 GW per year. Thus, 15 GW is roughly what might be expected to be installed in ERCOT over five years. Note that ERCOT has been one of the power systems where the interconnection queue issue has so far been relatively modest compared with other US power systems (due to a proactive buildout of transmission).

Calculation of the 45 V and 45Q tax credit impacts on annualized LCOH

The 45 V production tax credit for producing low-carbon H₂ using electrolyzers is only available for the first ten years of project operation, and the 45Q tax credit for sequestering CO₂ captured from SMR with CCS pathway is available only for the first 12 years of operation. H₂ production plants will probably be in operation longer than the window for receiving their respective tax credit—we assume 20 years for electrolyzers and 25 years for SMR facilities (Supplementary Table 2). The annualized impact of the tax credit on LCOH must account for the fact that the credit is available only for a portion of the project’s full lifetime, that is, the full US\$3 kg^{−1} PTC will not reduce LCOH by US\$3 kg^{−1}. We conducted an annualized cost calculation in which the respective credit is awarded for the eligible number of years then not awarded in the remaining years of operation. We assume a 4% discount rate and 2% inflation rate for these calculations. The net result is a PTC credit, and resulting reduction in LCOH, of US\$1.95 kg^{−1} and 45Q credit of US\$56.5 tonne^{−1} CO₂ sequestered.

Data availability

The input data for the various scenarios evaluated along with the outputs are available at <https://zenodo.org/records/10198811>.

Code availability

The model source code used for this study is available at <https://github.com/macroenergy/Dolphyn.jl/tree/main>.

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Author contributions

M.A.G. gathered data for the model, performed research, participated in the writing and framework development and generated figures.

A.N.C. and D.S.M. performed the model runs, analysed the output, generated figures and contributed to the writing. D.S.M. developed the framework for the study. T.S. performed analysis and contributed to the framework and to the writing.

Competing interests

The authors declare no competing interests.

Additional information

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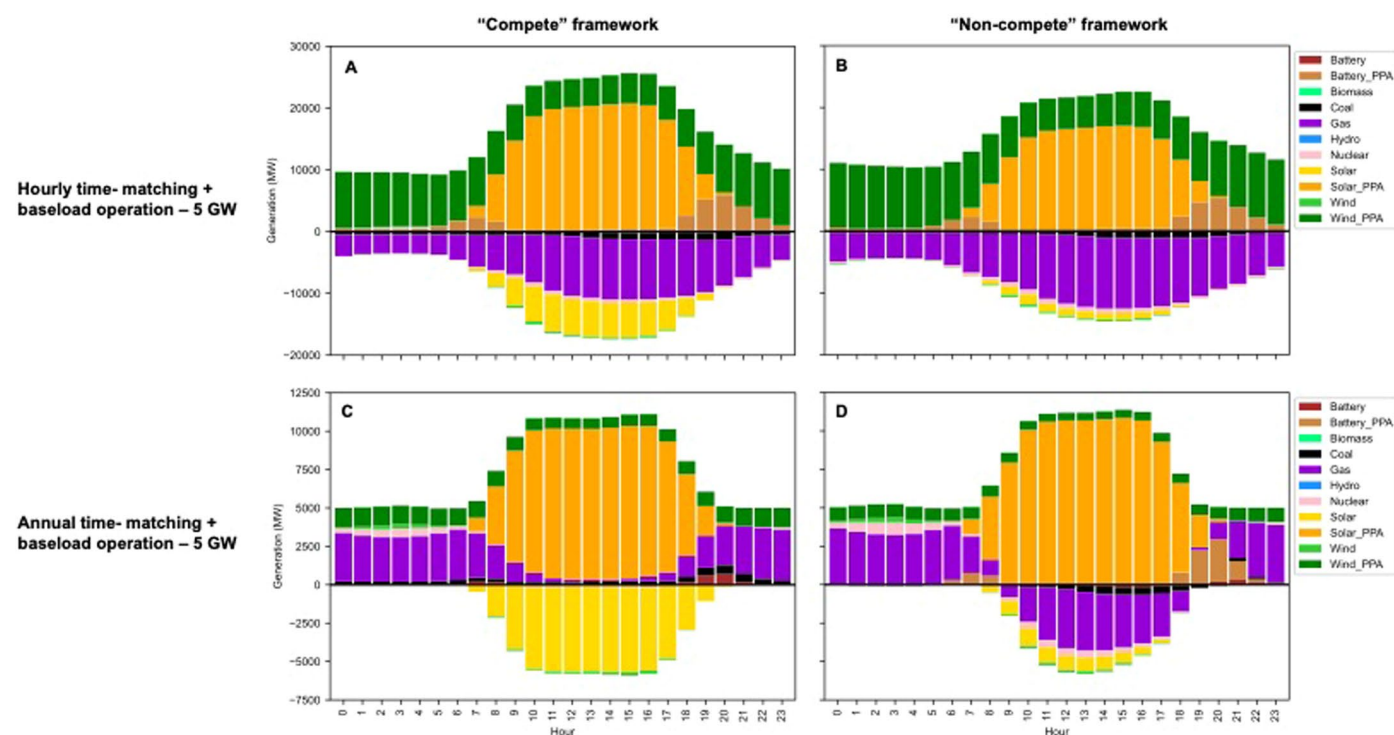
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Extended Data Fig. 1 | Grid dispatch impacts with different qualifying requirements. Difference in average hourly dispatch in ERCOT between counterfactual and baseline grid under the 'compete' (1st column) and 'non-compete' definitions (2nd column) of additionality and annual (top row) and hourly time-matching requirements (bottom row): A and B: 5 GW of H₂

production with baseload electrolyzer operation and annual time-matching requirements. C and D: 5 GW of H₂ production with baseload electrolyzer operation and hourly time-matching requirements. Resources with suffix '_PPA' refer to resources added specifically to meet time-matching requirements for H₂ production.