Clean electricity procurement for electrolytic hydrogen:

A framework for determining time-matching requirements

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Abstract

The degree of time matching between electricity consumption by water electrolyzers and contracted variable renewable energy (VRE) required to qualify as "low-carbon" hydrogen (H_2) has spurred a vigorous debate with billion-dollar ramifications. We show that conflicting literature results about the appropriate time-matching requirement are explained by two different interpretations of "additionality" of the contracted VRE. Significantly lower consequential emissions are achievable under annual time-matching in the additionality framework that presumes VRE for non-H_2 electricity demand does not compete with VRE for H_2 ("non-compete" framework), as opposed to the framework where all VRE resources are in direct competition ("compete"). We further investigate the interaction of time-matching requirements for H_2 production with four energy system-relevant policies, which suggests that the "compete" additionality framework without regard for the policy context is likely to overestimate the emissions impact of annual matching and underestimate those of hourly matching. We argue for a "phased approach" in defining time-matching requirements for the attribution of the H_2 production tax credits in the U.S. context - start with annual time-matching in the near-term, 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. The findings are broadly applicable to design low-carbon emissions accounting standards for any grid-connected load.

1. Introduction

Policies aimed at economy-wide decarbonization, such as the Inflation Reduction Act (IRA) in the United States (US) and the European Green Deal in the European Union (EU), emphasize electrifying end-use devices across sectors while decarbonizing the growing electric power supply. In that context, an important question arises: What are the carbon dioxide (CO_2) emissions induced by specific loads (existing or new) connected to the grid that also contractually procure electricity from specific, often low-carbon, resources? For end-uses like residential heating and passenger transport, this question is relatively less important since electrification of these end-uses substantially reduces carbon emissions compared to incumbent fossil fuel-based technologies, even when considering today's grids [1], [2]. In contrast, emissions accounting is arguably more important for grid-connected water electrolyzers since their use for hydrogen (H_2) production may not necessarily result in lower emissions than currently deployed fossil fuel pathways. For instance, simply using existing grid-connected electricity to power water electrolyzers, even in relatively high variable renewable energy (VRE) grids in the United States in 2021, such as California's, would lead to emissions from H_2 production that are greater than emissions from natural gas (NG) steam methane reforming (SMR) without carbon capture and storage (CCS) Other examples where modeling emissions impact of end-use electricity loads is relevant include a) corporate and regional procurement of renewable energy credits (RECs) to meet emissions goals (e.g., net-zero by 2050), b) electricity suppliers selling "green" electricity to retail consumers, and c) carbon removal credits for direct air capture.

Modeling emissions induced by a specific grid-connected load contracting with a specific grid-connected generation resource is highly complex because instantaneous power flows from generators cannot be associated with a particular electricity load. This is due to the temporal and spatial dynamics of grid operations. However, modeling exercises to characterize emissions impacts of individual loads, as performed in this paper, have a very high policy relevance. They guide policy makers to draft pragmatic qualifying requirements, which are the criteria that third parties (e.g., a H_2-producer, a big corporate, a "green" retailer) need to fulfill for their activities or products to be "certified" as low-carbon. Being certified as low-carbon implies access to certain incentives or reaping reputational benefits. Hence, these qualifying requirements shape the capital investments undertaken by these market parties, with significant energy system implications. This is especially true for electrolytic H_2 production in the U.S. context, where the IRA provides generous production tax credits (PTC) for "low-carbon" H_2, with the PTC amount tied to specific emissions thresholds, reaching a maximum of \$3 per kg of H_2 [3].

This paper's contribution to the field of electricity emissions accounting is grounded in an analysis of the H_2 PTC, which has been the subject of conflicting guidance in the academic literature and intense debate in the policy sphere. Debate has been particularly active around qualifying time-matching requirements for low carbon grid-connected H_2 production, with recent research papers by Ricks et al. [4] and Zeyen et al. [5] supporting different policies. 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 H_2 production (e.g., hourly, annual, or other). Zeyen et al. find that annual matching works well in certain contexts and implementations, whereas hourly matching raises the cost of H_2 production compared to annual matching in certain contexts. In contrast, Ricks et al. find that annual matching fails — the incentivized H_2 production results in significantly higher emissions — and hourly matching is needed. The conflicting results of the two papers are a puzzle, and they present a conundrum for policy makers tasked with making imminent decisions about how to implement H_2 PTC policies. The public debate has also almost entirely narrowed down polemic discussions around the time-matching requirement for electrolytic H_2 production [6]. The main contribution of our paper is to highlight that one cannot generalize emission impacts of a selected time-matching requirement in isolation from how other qualification requirements are defined and what other existing energy system-related policies that are in place.

Besides temporal matching, a second important qualifying requirement is spatial matching. Spatial matching is concerned with the extent to which the electrical path between the procured low-carbon electricity supply and the electrolyzer is physically congested over the lifetime of the supply contract. In this paper, we do not focus on spatial matching. Rather, we focus on the third key qualifying requirement, which is additionality. The additionality requirement establishes a causal relationship between the procured low-electricity generation and H_2 production. The aim of an additionality requirement is to avoid double-counting low-carbon electricity deployed for other objectives (e.g., grid decarbonization). Deeper analysis of the methodologies applied in Ricks et al. and Zeyen et al., presented in Section 2.1, reveals that the divergence in their findings can be explained by their interpretation of the additionality requirement.

Here, we quantify the interaction of alternative interpretations of the additionality (which we label "compete" as in Ricks et al. and "non-compete" as in Zeyen et al.) and time-matching requirements (annual and hourly) in terms of consequential emissions and the levelized cost of electrolytic H_2 production (LCOH). We use an open-source energy system model [7] to conduct a regional case study of the Texas (ERCOT) and Florida (FRCC) grids, where the initial power grid is defined per 2021 conditions. Our regional case studies and focus on near-term technology cost assumptions allow us to understand the near-term impacts of H_2 production via electrolyzers in relatively low-VRE penetration power systems. In our results, we confirm that indeed the emissions impact of a time-matching requirement is conditional upon the applied additionality modeling framework. In particular, under the loosest interpretation of additionality (the "compete" framework), the consequential emissions associated with annual time-matching are much larger than the H_2 PTC emissions limits, while a stricter interpretation of additionality (the "non-compete" framework) results in near-zero consequential emissions under annual matching for both case studies.

In addition to the crucial importance of how additionality is interpreted in the modeling, we run a range of scenarios covering relevant policies that also impact the answer to the "billion-dollar question": what time-matching requirements are appropriate to qualify as low-carbon H_2 production and, hence, have the right to receive PTC credits in the U.S. context? These scenarios include:

1. Limits on the annual capacity factors of electrolyzers
2. Requirements for minimum annual VRE generation supplying non-H_2 load
3. Constraints on VRE + battery storage capacity deployment
4. Competition with NG-based H_2 production with CCS with eligible IRA tax credits

Our case studies illustrate the sensitivity of the emissions impacts under different time-matching requirements to these four relevant policy scenarios. The results demonstrate that the standard "compete" additionality framework in many contexts is likely to provide a too pessimistic estimate of the emissions impact of annual matching and/or a too optimistic estimate for hourly matching.

The remainder of the paper is structured as follows. In Section 2, we explain in depth the different interpretations of modeling additionality, our high-level modeling choices, and the rationale behind the four policy scenarios. In Section 3, we discuss the results using the case study of ERCOT (FRCC results are shown in the SI as a robustness check), which is followed by a discussion (Section 4), where we provide policy recommendations and a conclusion. A brief description of methods is provided in the main text, with further details provided in the supporting information (SI).

2. Context: important drivers of emissions impacts of electrolytic H_2 other than the time-matching requirement

This section is divided into three parts. First, we explain in detail the different interpretations of additionality in Ricks et al. and Zeyen et al. and their specific impact on the modeling formulation. Second, we briefly highlight the other salient features of the two closely related literature studies and how these inform our modeling approach. Third, we elaborate on our constructed policy scenarios.

2.1 Different interpretations of the additionality requirement

At one extreme, any generation resource that is not operating in the system prior to installation of the electrolyzer can be considered "additional". This is the definition applied in Ricks et al. From a modeling perspective, this implies doing two parallel runs with cost-optimal brownfield grid expansion under a set of assumptions and using an "initial grid" as the starting point. One run excludes any H_2 load ("baseline grid") and another run includes a certain H_2 load complying with certain temporal and/or spatial matching requirements ("counterfactual grid"). The consequential emissions from electrolytic H_2 production can be calculated as the difference in emissions between both grids. With regards to the counterfactual grid run, low-carbon resources are built out (or kept online, e.g., the avoidance of the shutdown of a nuclear power plant) to satisfy H_2 demand, to comply with other grid-decarbonization policies (e.g., emissions targets or alike), or just because of their cost effectiveness. Under such modeling framework, the more low-carbon resources are built out to satisfy H_2 demand, the less low-carbon resources might be built out merely because of their cost-effectiveness (due to the self-cannibalization effect of renewables). In that sense, H_2 demand "competes" with the decarbonization of other electrifying sectors without strict matching requirements (e.g., transport or heating). Hence, we refer to this modeling setup as the "compete" framework.

At the other extreme, only generation resources that would not have been deployed in the absence of electricity demand for H_2 production can be considered additional. This is the definition of additionality applied by Zeyen et al. In contrast to the "compete" framework, in this case, the model runs are not done in parallel, but in series. First, using the initial grid as a starting point, the baseline grid is obtained by doing a cost-optimal grid brownfield expansion under a set of assumptions but excluding any H_2 load. Subsequentially, the counterfactual grid is obtained by running the cost-effective grid expansion to satisfy H_2 demand *with the baseline grid as a starting point*. As H_2 demand for low-carbon resources is only satisfied after low-carbon resource needs for non-H_2 demand or any other decarbonization policy is fulfilled, H_2 load does not compete with other loads willing to contract low-carbon electricity. Hence, we refer to this modeling setup as the "non-compete" framework. The "non-compete" framework implies a stricter definition for additionality, while the additionality definition according to the "compete" framework is easier to enforce in practice. Figure 1 provides a schematic overview of both additionality frameworks.

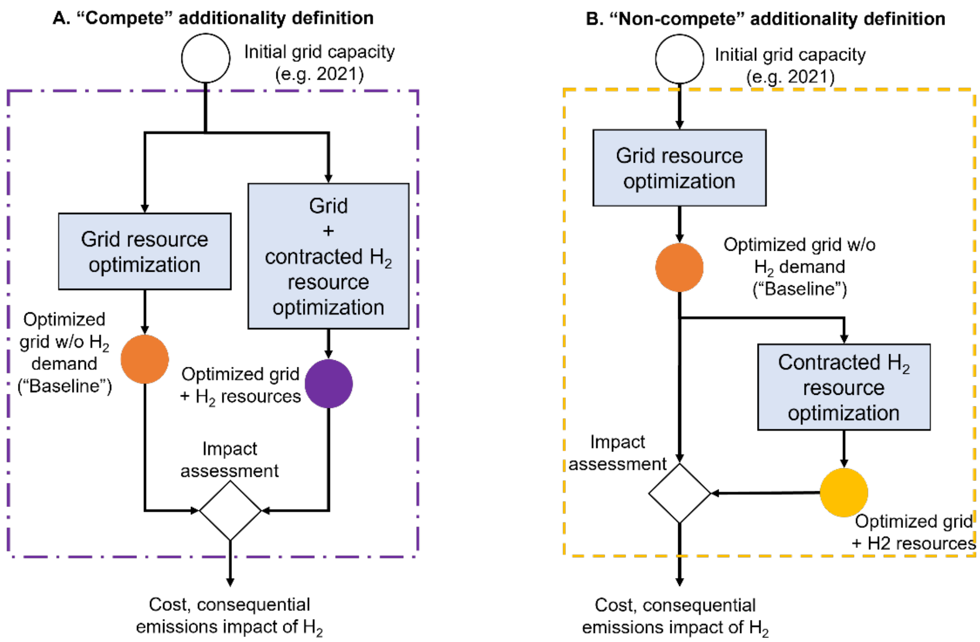

Figure 1: Approaches for evaluating the cost and consequential emissions impact of electrolytic H_2 production based on the two alternative definitions of additionality. The "compete" definition (purple dotted box, part A), mirrors the approach of Ricks et al. [6] and allows for competition among investment in resources contracted for H_2 production and other grid resource investments. The "non-compete" definition of additionality (yellow dotted box, part B) follows the approach of Zeyen et al. [7] where contracted H_2 resources are optimized after fixing investment in non-H_2 related grid resources. Here, contracted H_2 resources refer to battery storage, wind, solar generation, electrolyzer, and H_2 storage resources to meet H_2 demand and satisfy the specified time-matching requirement. Note that the baseline grid in both additionality frameworks is the same, while the optimized grid with H_2 resources is different (as indicated by the different colors of the circles).

In a nutshell, the major reason behind the different results presented in the aforementioned two papers is that in the Ricks et al.'s modeling, low-carbon generation built in the baseline grid (orange circle in Figure 1A) to serve the non-H_2 load can be "shifted" in the counterfactual grid (purple circle in Figure 1A) to serve the H_2 power demand. Also, under this modeling approach, it can happen that higher-carbon generation that is present in the initial grid (white circle in 1A) is retired in the baseline grid but retained in the counterfactual grid to serve the non-H_2 load. Such dynamics, i.e., renewables being "shifted" from serving non-H_2 load to H_2 load and potentially less retirement of high-carbon generation in the counterfactual versus the baseline grid, play a much larger role under annual time-matching than under hourly matching. In Zeyen et al. this shifting is proscribed, so that the annual time matching largely succeeds in driving the desired additionality vis-à-vis the baseline grid and thus does not lead to high levels of consequential emissions.

2.2 Our modeling approach is informed by the two closely related literature studies

Table 1 provides a high-level overview of the key assumptions in this study and two other recent papers with significant overlap on the research questions of interest. Since our focus is on the different interpretations of additionality and its interaction with time-matching requirements, as a simplification, we do not consider transmission constraints and spatial matching requirements. In what follows, we briefly discuss the other elements of our modeling approach and contrast it against the two literature studies, with further details in the methods section and SI.

Table 1. Comparison of key assumptions and context between this study and two other recent papers with a significant overlap on the research questions of interest.[a] The authors in [5] assume a fixed H_2 demand of 28 TWh of H_2 per annum. [b] Our model is starts with an initial grid resembling generation mix in 2021 and uses 2022 technology cost and performance assumptions to evaluate near-term evolution of the grid mix in both regions (See Table S1).

	Ricks et al. [4]	Zeyen et al. [5]	This work
Additionality definition evaluated?	"compete"	"non-compete"	"compete" and "non-compete'
Inter-regional transmission constraints?	Yes	Yes	No
Region and time horizon of interest	Western U.S. — 2030	Germany, Netherlands — 2025/2030	Texas (ERCOT), Florida (FRCC) — 2025-2030[b]
Exogeneous H_2 demand characterization	No demand enforced, both in quantity and profile	Constant hourly H_2 demand (3.2 GW[a])	Constant hourly H_2 demand 1 and 5 GW
Energy storage options evaluated	Li-ion	Li-ion, tank-based gaseous H_2 storage and other lower cost forms of H_2 storage	Li-ion, tank-based gaseous H_2 storage
Operation of the electrolyzer	Flexible	Flexible	Baseload and flexible
Time-matching requirements analyzed	• Annual matching • Hourly matching without excess sales • Hourly matching with excess sales • Weekly matching	• Annual matching • Hourly matching without excess sales • Hourly matching with 20% excess sales	• Annual matching • Hourly matching with excess sales

Our analysis is based on two case studies that are representatives of low and high end of VRE generation share in the U.S. as of 2021: ERCOT and 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 U.S. as of 2021 - for example, Mid-Atlantic (2.4%), New England (6.1%), and East South Central (0.4%) [8].[1]

Table 1 highlights that our assumptions for exogeneous H_2 demand and energy storage options are aligned with Zeyen et al. but differ from the assumptions of Ricks et al. For instance, we assume a constant hourly H_2 demand, which is what would be expected from typical industrial applications that are likely to be major consumers of electrolysis-based H_2 [9]. This implies that irrespective of electrolyzer operating mode, the combination of electrolyzer output plus net discharge of H_2 storage, where available, must meet a constant H_2 load for each hour of the year. We model cases with and without H_2 storage investments, corresponding to scenarios with *baseload* and *flexible* electrolyzer operation, respectively. Baseload operation may be appealing to maximize capital utilization and minimize degradation.[2] Under *flexible operation*, exogenous, time-invariant H_2 demand must be met, as in the baseload case, but electrolyzer size and operation, along

[1] The regions are defined as follows (as per EIA reference): Mid Atlantic: New Jersey, New York, Pennsylvania. New England: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont. East South Central: Alabama, Kentucky, Mississippi, Tennessee.
[2] Such operation is also incentivized by having a PTC in place rather than a non-distortive ITC. However, this discussion goes beyond the scope of the paper.

with the size of H_2 storage, are decision variables (see Eq. S1 in SI). In contrast, Ricks et al. do not enforce an exogeneous H_2 demand, nor in quantity or in profile and also do not model investment in H_2 storage. As the H_2 demand is not fixed exogenously in their model, the electrolyzer can operate flexibly depending on relative difference between marginal cost and exogeneous H_2 revenue. Finally, even though Ricks et al. and Zeyen et al. model additional time-matching requirement options, for clarity, we model only the two most debated options– hourly and annual time-matching requirements – described in Methods and SI.

2.3 Relevant policy scenarios impacting emissions under time-matching requirements

Table 2: 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 H_2 production.

	Base case	Policy scenario
Limiting the electrolyzer's annual capacity factor	Baseload and unconstrained flexible operation	Range of max. annual capacity factors (20%-80%)
Minimum annual VRE generation requirement ("RPS")	None - relatively low VRE systems	60 and 80% VRE target for non-H_2 electricity demand (Eq. S6)
VRE + battery storage capacity installation limit	Unconstrained	15 GW (Eq. S7)
Use of NG-based H_2 to meet H_2 demand	Only electrolytic H_2	Competition for H_2 production between electrolysis and NG-based H_2 with and without CCS

Table 2 provides an overview of the four policy scenarios evaluated. First, we model a policy that constrains the maximum annual capacity factor of the electrolyzer. Such policy effectively translates into a minimum capacity deployment constraint for an exogeneous annual H_2 demand to be met. The rationale behind this policy, previously suggested by Zeyen et al., is that a producer needing to meet a fixed H_2 demand under annual time matching will be incentivized to forgo production during periods of high electricity prices, which (often) correlate with periods of high marginal grid emissions intensity in a fossil-fuel dominant power system (i.e., in most systems coal-fired power generation is the marginal generation technology). The trade-off that this policy faces is a higher LCOH compared to unconstrained operation as the investment costs of the electrolyzer need to be recouped in fewer hours of utilization.

Second, both Ricks et al. and Zeyen et al. evaluate systems with higher VRE generation grids compared to FRCC and ERCOT as of 2021. To analyze the impact of the initial grid on the emissions and costs of alternative qualifying requirements, we evaluated scenarios where we impose minimum annual VRE generation requirements for the ERCOT grid (60% and 80% of the non-H_2 electricity demand). Such an annual VRE generation requirement can be interpreted as a renewable portfolio standard (RPS) as is in place in many states in the US [10], [11].[3] Similarly, rather than a more centralized RPS policy, high generation shares of VRE can also be attained in a decentralized way, e.g., by the numerous pledges of big corporates to become climate neutral [12]. Our hypothesis is that when imposing a minimum annual VRE generation, the results under the "compete" additionality framework will converge towards the results of the "non-compete" framework. The reason being that when including a minimum VRE requirement under the "compete" framework, VRE for non-H_2 load is prioritized. This prioritization is inherent in the "non-compete" framework due to the modeling formulation.

[3] Note that Texas has an RPS but that this RPS has not been binding. The reason being that the VRE growth has far outpaced RPS needs in Texas, mostly driven by the attractive business case of wind. The point of our analysis here is to understand the overall dynamics of such policy rather than mimicking ERCOT.

Third, the prior work did not consider the impact of interconnection queues on emissions and LCOH under different time-matching requirements. Currently, many US power systems are facing significant delays in connecting new generation to the transmission grid.[4] In other words, the difficulty in connecting VRE represents a policy failure in synchronizing VRE and grid expansion. We model this policy failure by adding a constraint that limits the capacity of VRE + battery storage that can be built out. We have set this constraint at 15 GW for illustrative reasons.[5] Our hypothesis is that this constraint will reduce investment in VRE resources not contracted to H_2 production in favor of those contracted for H_2 production under the hourly matching and "compete" framework, and thereby increase consequential emissions associated with H_2 production.

Fourth, while studies on qualifying requirements focus exclusively on electrolytic H_2, other H_2 pathways like NG-based H_2 production with CCS (so-called blue H_2) are also relevant and are receiving policy support. To understand how qualifying requirements impact competition between green and blue H_2, we evaluate scenarios with the option to invest in NG based H_2 without CCS (grey H_2) and blue H_2 that avails the IRA 45Q tax credit ($85/tonne CO_2 sequestered – see Table S2 and Table S3). In these modeling runs, we assume green H_2 receives the full PTC of $3/kg under different time-matching requirements to meet the exogeneous H_2 demand.

3. Results

The results section is split into two parts. In the first part, we provide a discussion of the ERCOT base case study (see

Table 1), with a recognition of its similarity with findings from the FRCC case study (described in SI). In the second part, we discuss the impact of the four policy scenarios on the results in the context of the ERCOT case study (see Table 2).

3.1 Base case study: power sector impacts, consequential emissions and LCOH

This section is split up into three subsections. First, we discuss how the resource mix is impacted under different assumptions. Second, we report the consequential emissions. Third, we discuss the impact of additionality modeling frameworks on the LCOH. For the equations behind the consequential emissions and LCOH calculation, see Methods.

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[4] Rand et al. [13] report that over 2,000 GW of total generation and storage capacity was seeking connection to the grid in 2022 (over 95% of which is for zero-carbon resources like solar, wind, and battery storage). This is also an issue in Europe [14].

[5] Average VRE additions in ERCOT for the 10-year period 2012-2021 was 2.7 GW/year. Thus, 15 GW is roughly what might be expected to be installed in ERCOT over 5 years. Note that ERCOT has been one of the power systems where the interconnection queue issue has so far been relatively modest compared to other US power systems (due to a proactive buildout of transmission).

3.1.1 Power sector resource impacts: installed capacity and generation

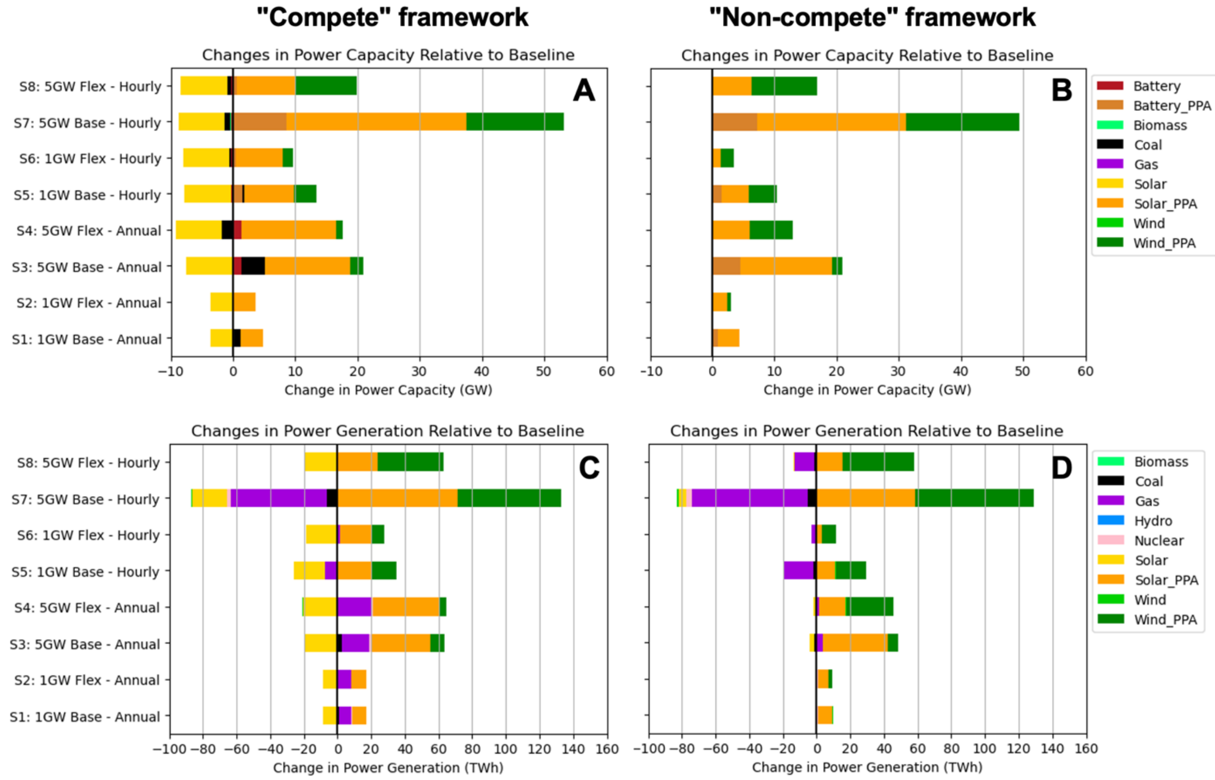

Figure 2. Change in power generation and storage capacity (top row, A-B) and annual power generation (bottom row, C-D) resulting from electrolytic H_2 production under alternative H_2 demand scenarios, time-matching requirements, and additionality frameworks. Results correspond to the ERCOT case study and are reported relative to the baseline scenario involving grid resource expansion without any H_2 demand, as defined in Figure 1. Resources with suffix "_PPA" refer to resources added specifically to meet time-matching requirements for H_2 production.

We make three observations from the results in Figure 2. The first observation is that the contracted resource mix for H_2 production under annual time-matching requirements is more sensitive to the additionality definition than resources contracted under hourly time-matching requirements. This is also true for FRCC (see Figure S19). Solar generation is preferred to meet annual time-matching requirements under the "compete" framework. Wind generation plays a greater role in the "non-compete" framework for annual cases with flexible electrolyzer operation and solar is preferred in cases with baseload operation, whereas FRCC exhibits the opposite trends (see Figure S19). These results are a consequence of the generation resources built out in the baseline grid expansion. For example, the baseline grid expansion in ERCOT solely results in solar additions —with solar generation share increasing to 14.2% (see Figure S4). As a consequence, under the "non-compete" framework and annual matching, when adding VRE to serve H_2 load on top of the baseline grid, there is a diminished economic value of solar additions. Instead, wind is built. In contrast, under the "compete" framework, where initial solar generation share begins at 2021 levels (7.8%), contracting solar PV to meet annual time-matching requirements is cost-effective and outcompetes deployment of non-contracted solar PV resources that would have been deployed without H_2 demand – for example, see results for 5 GW + baseload - annual scenario in Figure 2 A/C. At the same time, as shown in Figure 3C, due to the diurnal availability of solar resources, there is a need for additional gas generation to meet incremental electricity demand for H_2 production during times of low solar availability. In contrast, under the "non-compete" framework, increases in gas generation under annual time-matching requirements are largely offset by decreases in both gas and coal generation during hours with high solar availability (see Figure 3D). Thus, although the dispatch of fossil-based generators is also altered in annual cases under the "non-compete" framework compared to the baseline grid, large changes in fossil-based generation are not observed as the total volume of fossil-based generation remains more or less similar as in the baseline grid.

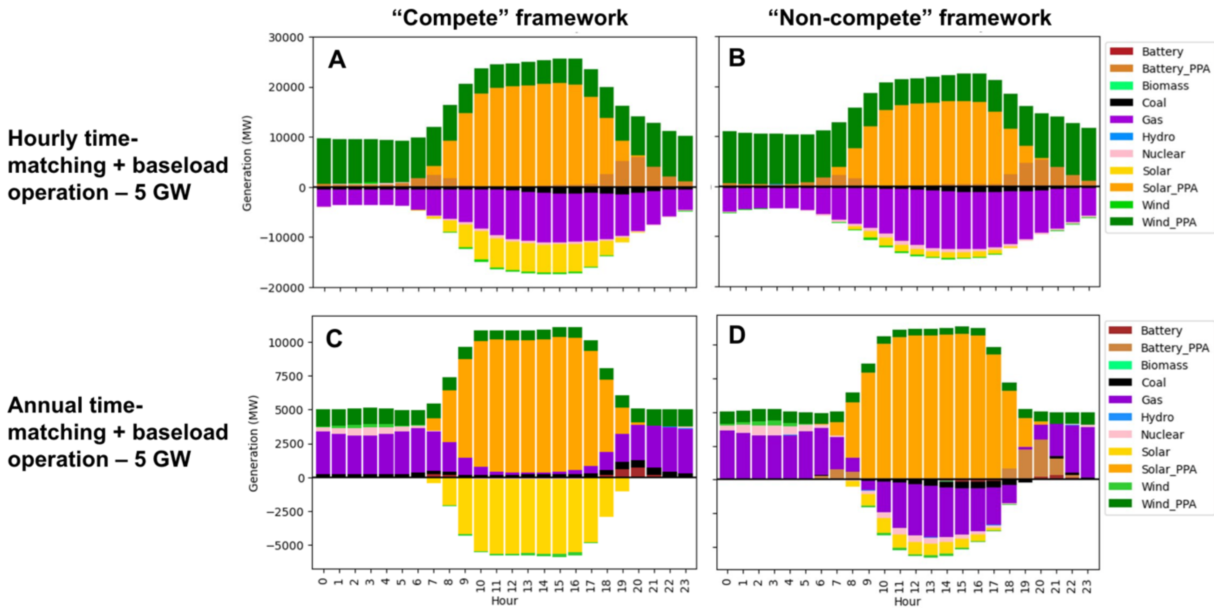

*Figure 3. Difference in average hourly dispatch in ERCOT between counterfactual and baseline grid under the "compete" (1st column) and "non-compete" definitions (2nd column) of additionality and annual (top row) and hourly time-matching requirements (bottom row): **A and B**: 5 GW of H_2 production with baseload electrolyzer operation and annual time-matching requirements. **C and D**: 5 GW of H_2 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 H_2 production.*

A second observation is that compared to annual time-matching requirements, hourly time-matching leads to higher capacities of contracted resources for H_2 production under both additionality modeling frameworks. Consequently, hourly matching generally leads to reductions in carbon-based generation, especially natural gas, compared to the baseline grid scenario for both ERCOT (Figure 2C/D) and FRCC (see Figure S19). The increased capacity deployment is necessary to compensate for the intermittency of VRE generation while simultaneously ensuring that generation plus net-discharge of battery storage from contracted resources is at least equal to hourly electrolyzer power consumption (see Eq. S3). The increased capacity deployment also implies that these contracted resources will generate in excess of electrolyzer power demand at certain times that can be dispatched to meet non-H_2 electricity demand and displace more expensive generation on the margin (Figure 3A/B). The displaced generation includes VRE resources that would have been deployed in the baseline grid as well as natural gas and, to a limited extent, coal generation.

Finally, the third observation is that allowing for flexible electrolyzer operation results in lower capacity deployment for both annual and hourly time-matching requirements under both additionality modeling frameworks, for both ERCOT (Figure 2) and FRCC (Figure S19). This is because flexible operation enables shifting electricity consumption for H_2 production to better match the availability of contracted VRE resources, while relying on relatively low-cost H_2 storage (modeled based on cost of above-ground tank storage, see Table S2) to meet H_2 demand. Notably, flexible electrolyzer operation avoids the need for expensive battery storage deployment to meet hourly time-matching requirements, instead deploying H_2 storage capacity equal to 2-6 hours of H_2 demand for the annual time-matching requirement and 25-38 hours of H_2 demand for the hourly time-matching requirement scenarios for ERCOT Figure S7-Figure S8). In the case of annual time-matching requirements and the "compete" framework for additionality, flexible electrolyzer operation also results in smaller increase of natural gas generation compared to the baseload operation scenario (Figure S6).

3.1.2 Consequential emissions

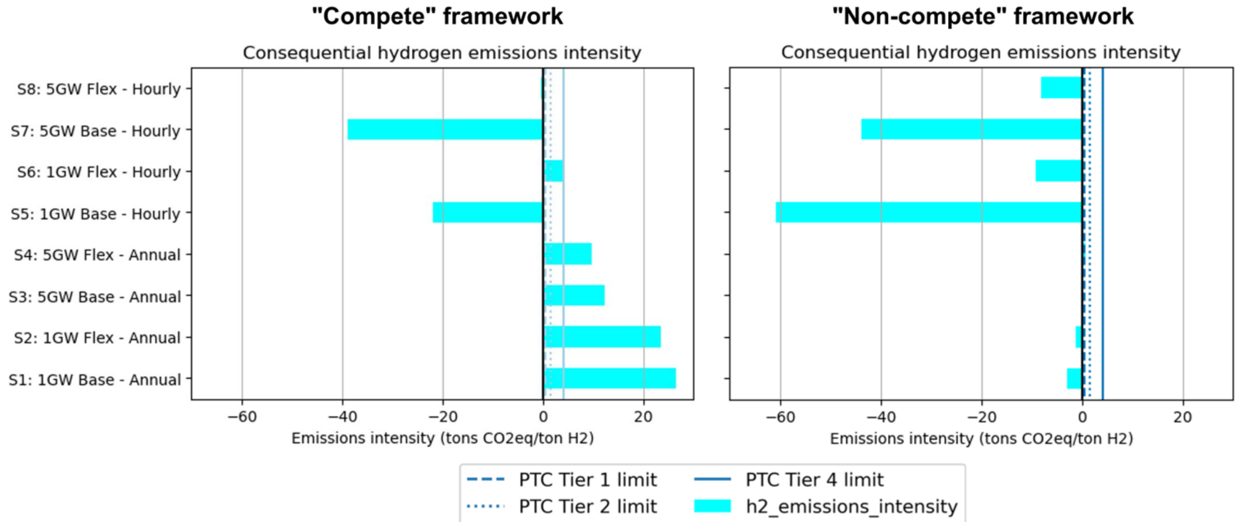

Figure 4. Consequential emissions intensity of H_2 production for alternative exogeneous H_2 demand levels, electrolyzer operation modes, and time-matching requirements under the "compete" and "non-compete" frameworks of additionality described earlier and highlighted in Figure 1. Results correspond to the ERCOT case study and are reported relative to the baseline grid, as defined in Figure 1. Also shown are threshold emissions intensity values for H_2 PTC in the IRA, with the production meeting the Tier 1 limit eligible for up to \$3/kg PTC while those meeting Tier 2 and Tier 4 limits are eligible for PTC in the amount of \$1.0/kg and \$0.6/kg, respectively.

We make two observations from the consequential emissions results in Figure 4. The first observation is that annual time-matching requirements generally lead to either near-zero emissions in the "non-compete" framework (because the total volume of natural gas generation vs. the baseline grid remains virtually unchanged) or highly positive emissions in the "compete" framework. In the latter case, the consequential emissions of the H_2 production under baseload operation are higher than the emissions intensity of H_2 production from NG without CCS (see Table S3) [15]. Although flexible operation mitigates this effect by limiting natural gas generation versus the baseline grid under annual time-matching in the "compete" framework, the levels of flexibility investigated are insufficient to make the produced H_2 eligible for even the highest PTC threshold of 4 $kgCO_{2eq}/kg\ H_2$. Consequential emissions results for FRCC are highly consistent with those of ERCOT (see Figure S24).[6]

The second observation is that hourly time-matching requirements generally lead to low or negative consequential emissions under both additionality modeling frameworks. However, in the "compete" framework, we can still see the effect of competition with non-contracted grid resources resulting in less negative, or even positive, consequential emissions (Figure 4). Flexible operation reduces the capacity deployment of contracted resources (Figure 2), which reduces the volume of excess electricity sales, illustrated in Figure S5, and consequently results in less negative consequential emissions compared to the corresponding baseload grid. Interestingly, in the 1 GW H_2 demand scenario under hourly time matching

[6] We notice one interesting difference between ERCOT and FRCC. Namely, for ERCOT, the consequential emissions intensity decreases as H_2 demand increases under baseload electrolyzer operation with an annual time-matching requirement in the "compete" framework, whereas it increases for FRCC. This difference can be explained by the slightly differing interactions of VRE generation with the fossil-based generation in the initial grid per system.

for the "compete" framework, the combined effect of flexible operation and competition with other grid resources results in a positive consequential emissions in both ERCOT (Figure 4) and FRCC (Figure S24). Here, there is a greater reliance on solar to meet hourly time-matching requirements compared to the corresponding baseload operation scenario. At the same time, the lack of any contracted battery storage implies a greater reliance on natural gas to meet net load requirements (Figure S5) that ultimately results in positive consequential emissions. Higher levels of H_2 demand result in wind accounting for a greater share of contracted VRE capacity towards H_2 production, even in the flexible operation case, and thus result in negative consequential emissions intensity.

3.1.3 Levelized cost of H_2 (LCOH)

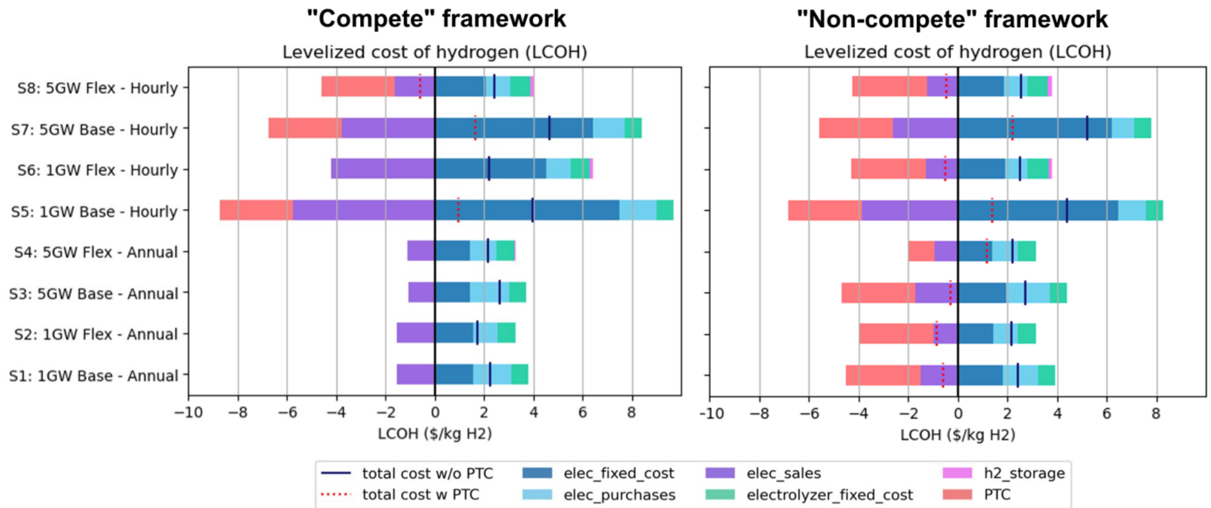

Figure 5. Levelized cost of H_2 for the ERCOT case study under scenario with different H_2 demand (1, 5 GW equivalent power consumption), time-matching requirements (annual vs. hourly), additionality frameworks ("compete" vs "non-compete") and electrolyzer operation modes (Baseload vs. flexible). Levelized cost calculated per description provided in Section 6.5. 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 electrolyzer; electrolyzer_fixed_cost = annualized capital and fixed operating and maintenance (FOM) cost of the electrolyzer; elec_fixed_cost = annualized capital and FOM cost of contracted power sector resources, after accounting for investment tax credit (30%); h_2_storage= capital and FOM cost of gaseous H_2 storage system, which includes the capital cost of the compressor and tank. The total cost with PTC (total cost w PTC) shows the LCOH after accounting for PTC based on consequential emissions for each case.

We make three observations from the LCOH results in Figure 5. The first observation is that the LCOH results are consistent with the existing literature on the relative cost of hourly vs. annual time-matching. In nearly all cases for ERCOT and FRCC (see Figure S25), the LCOH is higher under hourly versus annual time-matching requirements when disregarding the attribution of a PTC. This finding correlates with Figure 2, which shows that significantly more resources need to be built to meet hourly versus annual time-matching requirements, irrespective of the additionality modeling framework. Under the hourly time-matching requirement with baseload electrolyzer operation, the LCOH after including the PTC is still generally greater than \$1/kg and thus not competitive with today's grey H_2. In all other cases, electrolytic H_2 production is cost competitive if a \$3/kg PTC were awarded, and even reaches negative levels. In general, although absolute levels of power prices are often slightly higher in FRCC, likely due to relatively lower VRE resource quality (see Table S6), LCOH dynamics in FRCC (Figure S25) closely mirror those in ERCOT.

A second observation from Figure 5 is that flexible electrolyzer operation reduces the LCOH compared to the corresponding baseload operation scenario under hourly time-matching when disregarding the PTC.

The reduction in contracted power sector resources more than offsets any increases in the fixed cost of electrolyzer and H_2 storage. This result is again consistent with other studies modeling electricity-H_2 sector interactions that note the importance of electrolyzer flexibility to minimize the cost of H_2 production and support grid decarbonization efforts [16].

A third observation from Figure 5 is that the LCOH without PTC attribution is generally greater in the "non-compete" framework as compared to the "compete" framework. The driver behind this result is the value of excess electricity sales, defined as the difference between absolute value of elec_sales and elec_purchases in Figure 5. Excess electricity sales are generally higher in the "compete" vs "non-compete" framework (see Table S7 and Table S8), due to two effects. First, in the "compete" framework, H2 is inherently prioritized and contracts the most valuable VRE portfolio relative to VRE portfolio built out for non-H_2 load. Second, the wholesale electricity prices under the "non-compete" framework are more depressed due to greater amounts of VRE generation in the baseline grid. Consequently, higher fractions of the electricity fixed costs are allocated to the LCOH in the "non-compete" framework – for example, under annual matching in the 1 GW + flexible electrolyzer operation scenario, the net electricity cost allocated to the cost of H_2, defined as electicity_fixed_cost – excess_elec_sales in Figure 5 and reported in Table S7 and Table S8, is \$1.42/kg in the "non-compete" framework vs. \$1.01/kg in the "compete" framework. As H_2 demand increases from 1 to 5 GW in the same scenario, the net electricity cost allocated to cost of H_2 increases in both the "compete" framework and "non-compete" framework. Finally, when considering the LCOH with the corresponding PTC for the consequential emissions found in our modeling, the "non-compete" cases generally have much lower LCOH than the "compete" cases, especially under annual time-matching where the PTC is never awarded in "compete" cases.

3.2 Impact of the four policy scenarios on the base case study

In this subsection we cover the results of our four policy scenarios. For clarity, we focus on the most relevant modeling runs, rather than discussing all results under alternative H_2 demand scenarios, time-matching requirements, and additionality frameworks.

3.2.1 Limiting the electrolyzer's annual capacity factor

In this policy scenario, we gradually reduce the maximum annual capacity factor of the electrolyzer below levels that are optimal with regards to the objective function (i.e., overall system cost minimization). This policy scenario is most relevant under annual time-matching and the "compete" additionality framework as the capacity factor of the electrolyzer and consequential emissions from H_2 production were relatively high in the base case at 95-96% (see Figure S7 and Figure S8).

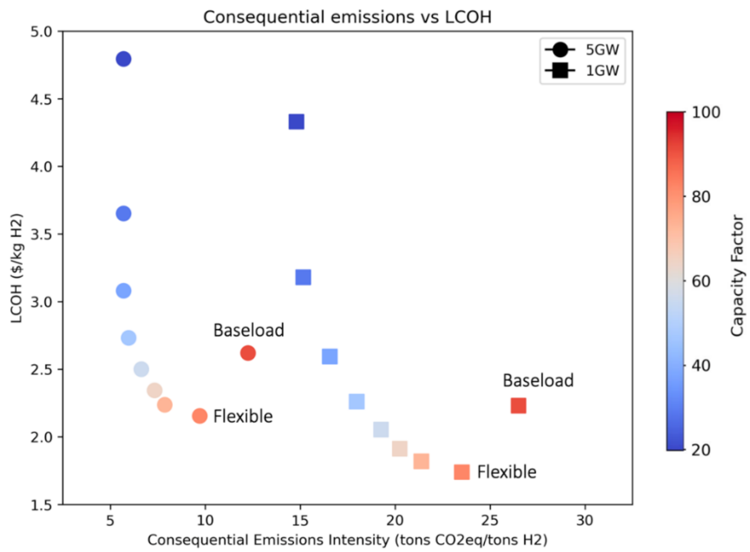

Figure 6. Consequential emissions intensity vs the levelized cost of H_2 (LCOH) under baseload operation, flexible operation, and scenarios with different upper limits on annual electrolyzer capacity factor (20%, 30%, 40%, 50%, 60%, 70%, and 80%) under the "compete" framework and annual time-matching requirement. Capacity factor refers to the number of hours in a year that the electrolyzer is in operation. The color of each marker indicates the capacity factor at which the electrolyzer operates. The "Flexible" label indicates the scenarios with flexible electrolyzer operation and no capacity factor limit. The "Baseload" indicates the scenarios with baseload electrolyzer operation. Additional results for the electrolyzer capacity factor limit analysis are reported in Figure S9 - Figure S11.

Figure 6 illustrates a trade-off in the results: constraining the electrolyzer capacity factor results in lower emissions under an annual time-matching requirement in the "compete" additionality framework, however, this reduction comes at the expense of increasing LCOH. As discussed in Section 3.1.2, none of the scenarios with annual time-matching under the "compete" modeling framework achieve even the least stringent PTC emissions threshold. This remains true even at the lowest capacity factor limits modeled here (20%). It must be noted that imposing modest capacity factor limits, for instance 80% or 70%, lead to relevant reductions in emissions at only a modest increase in the LCOH (compared to the scenario where no capacity factor limit is in place (labeled "Flexible")). Reducing the capacity factor limit further conversely leads to very low reductions in emissions at significant increases in the LCOH.

3.2.2 Imposing an annual VRE requirement

Here we introduce a minimum annual VRE requirement in serving non-H_2 load that is above the level that is optimal with regards to the objective function. Such a requirement can be interpreted as an RPS policy or an aggregation of voluntary VRE procurement commitments of grid users. This policy scenario is most relevant under annual time matching and the "compete" additionality framework because of the high consequential emissions intensity of H_2 production in the base case (Figure 4).

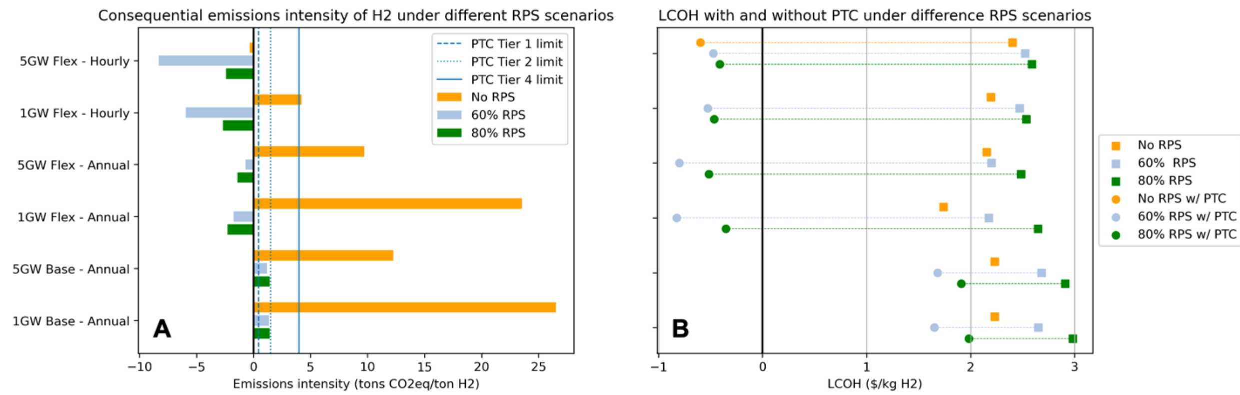

Figure 7. Consequential emissions intensity of H_2 production (A) and levelized cost of H_2 with and without the PTC (B) under VRE requirements (no RPS, 60% RPS, and 80% RPS) for scenarios with different H_2 demand levels (1GW and 5GW) and time-matching requirements (annual and hourly) all with flexible electrolyzer operation under the "compete" modeling framework. For the levelized cost of H_2, the awarded PTC subsidy is based on the consequential emissions intensity of H_2 for each scenario. Additional results for the annual VRE requirement scenarios are reported in Figure S12 - Figure S14.

The key finding from the results in Figure 7A is that enforcing a minimum VRE requirement (i.e., RPS) of 60% under the "compete" framework is sufficient to reduce the consequential emissions associated with both annual and hourly time matching to below the most stringent PTC threshold, when flexible operation is considered. Compared to the "No RPS" scenario, RPS scenarios have lower emissions under annual time-matching — below 1.5 tonnesCO_2eq/tonneH_2 with baseload operation and negative emissions with flexible operation — and result in negative emissions under all hourly time-matching scenarios. In short, the consequential emissions under the "compete" framework with the RPS mirror those under the "non-compete" framework without RPS (Figure 4), as we anticipated in Section 2.1. This is because the RPS effectively reduces competition between the VREs built for non-H_2 load and those contracted for H_2 production — here, 60% or 80% of non-H_2 electricity demand must be met via VREs regardless of H_2 demand. This implies that the VREs contracted for H_2 production are much more likely to be "strictly additional," i.e., they would not have been built without the H_2 demand. This dynamic is especially impactful under an annual time-matching requirement, in which VREs contracted for H_2 production "compete" directly with the grid for the highest-quality VRE resources without an RPS.

Under an hourly time-matching requirement, an 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 H_2 production with an increasing RPS. Moreover, under an 80% RPS, the emission intensity associated with H_2 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.

The key finding from Figure 7B is that an RPS increases LCOH, not accounting for PTC attribution. This finding is aligned with the increased LCOH (without PTC attribution) seen under the "non-compete" framework as compared to the "compete" framework in Figure 5. The competition between VRE deployments for H_2 production with VRE deployments to meet the RPS results in lower value of electricity sales to the grid and thus a higher LCOH. Across the scenarios, the increase in LCOH (without PTC attribution) with RPS is generally greater for annual (0.04 – 0.91 $/kg) rather than hourly (0.12- 0.33 $/kg) time-matching requirements. A plausible explanation for the lower LCOH impact under hourly time-matching is the increased availability of energy storage (Figure S14), in the form of batteries and H_2 storage, that enables electrolyzers to reduce their electricity purchase costs compared to the cases with annual time-matching.[7] Regardless, the relatively larger LCOH increases for annual time-matching with an RPS policy are more than offset by the eligible PTC amounts under this scenario, so as to effectively reduce the LCOH as seen by a prospective H_2 buyer. Overall, Figure 7 highlights how under an RPS, annual matching under flexible operation can achieve negative consequential emissions and similar LCOH outcomes as hourly time matching, without incurring additional VRE + storage investment and associated implementation barriers (see next section).

3.2.3 Introducing a constraint on the VRE + battery storage buildout

In this policy scenario, we introduce a constraint on the maximum buildout of VRE + battery storage which will lead to equal or lower than optimal VRE capacity levels with regards to the objective function. This policy scenario is most relevant under hourly time-matching under which larger VRE capacities are deployed to serve H_2 load compared to annual time matching. In Figure 8 we show the results for the "compete" framework and relatively high H_2 demand (5 GW) that can be served by operating the electrolyzer flexibly. Under a 1 GW H_2 demand and flexible electrolyzer operation, the VRE capacity constraint is not binding and hence not shown.

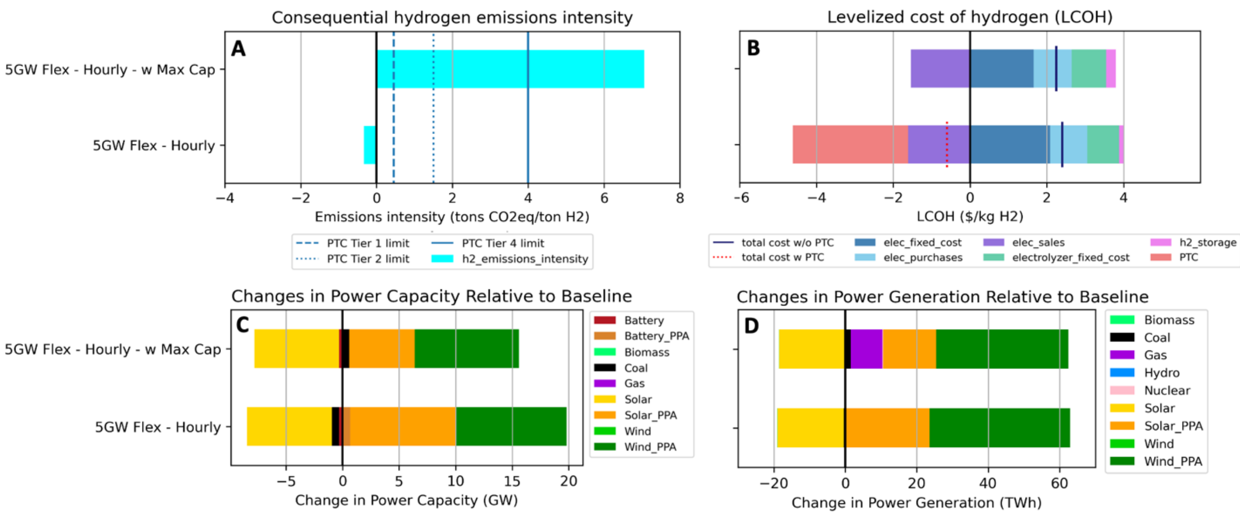

Figure 8. Consequential emissions intensity of H_2 production (A), Levelized Cost of H_2 (B), power system capacity change (C) and power system generation change (D) under hourly time-matching requirement with 5GW of electrolyzer demand for with unconstrained VRE + storage capacity deployment and a 15GW limit under the "compete" modeling framework. Results correspond to the ERCOT case study and are reported relative to the baseline grid involving grid resource expansion without any H_2 demand, as defined in Figure 1. See Figure 4 for details on the consequential emissions graph (left) and Figure 5 for details on the LCOH graph (right). Additional results for the VRE deployment scenarios are reported in Figure S17 - Figure S18.

Figure 8A shows how a binding limit on new VRE + battery storage capacity deployment can significantly increase the consequential emissions associated with hourly matching under the "compete" additionality framework. For 5 GW H_2 demand under an hourly time-matching requirement, a 15 GW VRE + storage deployment limit causes emissions to rise from negative to >6 tonnesCO_2eq/tonneH_2, exceeding the least stringent PTC threshold. The main reason is that overbuilding VRE capacity relative to electrolyzer demand is disincentivized or not feasible under the VRE + storage deployment limit, which increases fossil fuel generation as compared to the baseline grid case (Figure 8D).

[7] Note that the objective function of the model is to minimize total system cost. The optimal way to produce electrolytic H_2 from a system perspective is not necessarily equivalent to being optimal from the perspective of a project developer (who wants to minimize the LCOH).

Surprisingly, Figure 8B shows that the introduced constraint has limited impact on LCOH when not considering attribution of the PTC, even though the objective function (system cost) increases approximately 1.5%. When VRE + storage capacity additions are limited, the VRE mix deployed to contract with H_2 demand favors wind over solar (Figure 8C) to improve capacity utilization which results in lower electricity-related fixed costs seen in Figure 8. In addition, to further improve capacity utilization and minimize VRE curtailment, the capacity of electrolyzer and H_2 storage are increased (duration increases from 33 to 61 hours), which increases their fixed costs and offsets the reduction in electricity-related fixed costs. However, because consequential emissions intensity increases with a VRE + storage cap in place, substantially higher LCOH is seen when considering the PTC attribution.

Finally, it is worth noting that modeling the above VRE + storage deployment constraint with the same H_2 demand is not feasible under the "non-compete" framework. The H_2 demand cannot be fulfilled anymore, as insufficient VRE capacity is available to be built out. A large share of the grid-connected capacity has been utilized by VRE built out in the baseline run to cost-optimally serve non-H_2 load. A possible implication of this result is that under VRE + storage deployment constraints, an hourly time-matching requirement might lead to fewer deployments of electrolyzer projects in favor of other low-carbon H_2 production technologies like NG based routes with CCS (see next section).

3.2.4. Competition with NG-based H_2 production

In this policy scenario, we introduce competition between green and NG-based H_2 production to satisfy the H_2 demand under different scenarios in the "compete" additionality framework.

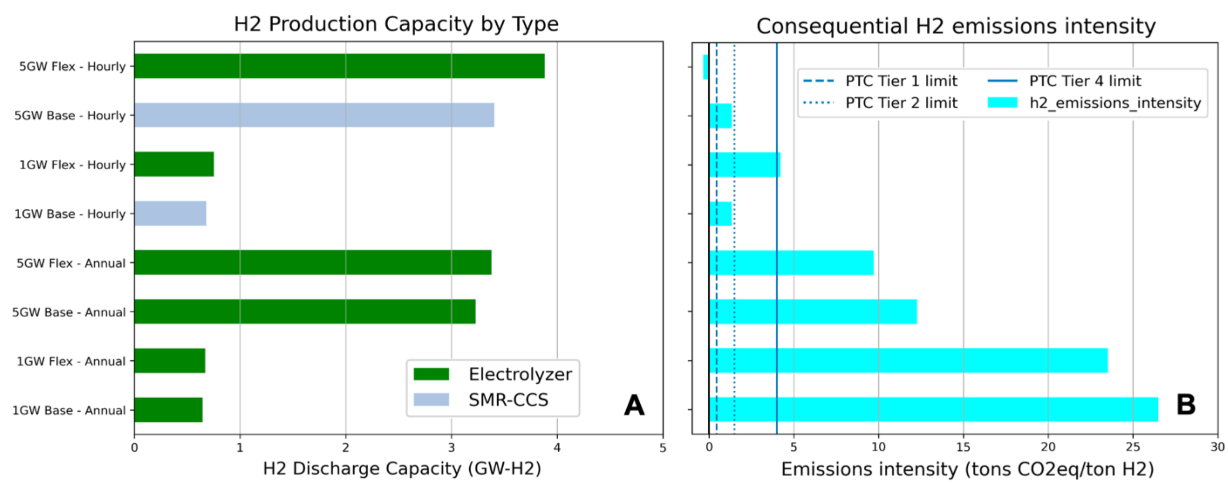

Figure 9. H_2 production capacity by resources type (available resources are electrolyzer, SMR, SMR with CCS, and ATR with CCS) (A) and consequential emissions (B) under different scenarios of time-matching requirements, exogeneous H2 demand and electrolyzer operation modes. Results correspond to "compete" additionality framework runs for the ERCOT system SMR = Steam Methane Reforming. CCS = Carbon Capture and Storage. ATR = Autothermal Reforming. Consequential emissions results correspond to the ERCOT case study and are reported relative to the baseline grid involving grid resource expansion without any H_2 demand, as defined in Figure 1. Additional results for changes in power capacity and generation, absolute power and generation capacity, and electrolyzer capacity factors, and battery and H_2 storage are reported in Figure S15 –Figure S16.

Figure 9A shows that substitution of electrolyzers with SMR with CCS (blue H_2) only occurs in scenarios with an hourly time-matching requirement and when baseload electrolyzer operation is enforced. This reflects the LCOH results reported in Section 3.1.3, which shows that compared to the other scenarios, hourly time-matching with baseload electrolyzer operations leads to significantly higher LCOH (Figure 5). An important implication of these results is that, with the PTC, electrolytic H_2 is competitive with NG-based H_2 production with CCS, even under the more stringent hourly time-matching requirement, assuming that flexible electrolyzer operation is feasible.[8] However, in a range of scenarios, green H_2 can be substituted by blue H_2, and this is most likely under hourly time-matching. Such scenarios include the cases when flexible operation is not optimal or feasible (e.g., more expensive H_2 storage, or higher than anticipated investment cost of electrolyzers) or when contracting VRE is more expensive than anticipated. The latter could also include the scenario when VRE + battery storage deployment is constrained due to supply chain or interconnection issues, as highlighted above in Figure 8. Future analysis is required to better understand under what conditions overall higher energy system-wide emissions would result when green H_2 would be substituted by blue H_2 due to the additional financing and/or grid connection capacity needs that hourly matching introduces.

4. Discussion

Two key results summarize our findings from the base case study. First, the consequential emissions from producing electrolytic H_2 are conditional upon how the additionality requirement is modeled. Under the "compete" framework, in which we co-optimize the grid with the resources needed to fulfill H_2 demand, an hourly time-matching requirement is the only possible way to reach consequential emissions that are under the threshold needed to receive the highest PTC (and this is not even guaranteed in all hourly time-matching cases). In contrast, under the "non-compete" framework, in which we first optimize the grid and sequentially optimize the resources needed to satisfy the H_2 load, an annual time-matching requirement is sufficient in all cases to meet the threshold needed to receive the highest PTC ($3/kg). The second key result is that independent of the additionality modeling framework, hourly matching requirements lead to a higher LCOH relative to annual matching requirements excluding the attribution of a PTC. However, we find that the increase in LCOH is $0.25- $2.49/kg, which is a greater range than the $0-1/kg increase between hourly time-matching and no time-matching requirements reported by Ricks et al.[9] Significantly higher capacities of VRE and storage need to be installed under the hourly time-matching requirements. Optimal flexible operation of the electrolyzer, whether it is under hourly or annual time-matching requirements, reduces the LCOH. Under the annual matching requirement, flexible operation tends to lower consequential emissions versus baseload operation, while the opposite is true under hourly matching.

We summarize both key findings in Figure 10 , which shows LCOH results for ERCOT and FRCC, considering a $3/kg PTC, and notes where the PTC would be correctly or incorrectly provided based on the modeled consequential emissions. Generally, the LCOH is lower in ERCOT compared to FRCC for every run due to higher quality VRE resource availability (especially wind).

[8] In this regard it is important to repeat that the way to produce H_2 that is optimal from the perspective of a system planner might not coincide with the lowest-cost H_2 production strategy of a project developer. In addition, the lower cost of green H_2 vs. blue H_2 is partly an outcome of VRE + battery storage resources contracted with H_2 production receiving the investment tax credit (30% reduction in capital cost) as per the IRA. So, in effect, green H_2 receives two subsidies: PTC for H_2 and ITC for electricity producing resources. Such "subsidy stacking" has been explicitly ruled out in the European legislation for clean hydrogen [17].

[9] Ricks et al compare hourly to no requirement, whereas we compare hourly to annual. Since cost of an annual time-matching requirement should be at least as expensive as no time-matching requirement, we can assume that the cost increases reported by Ricks et al. would only be smaller if they compared annual and hourly, whereas our reported cost increases would likely be larger if we compared hourly to no requirement.

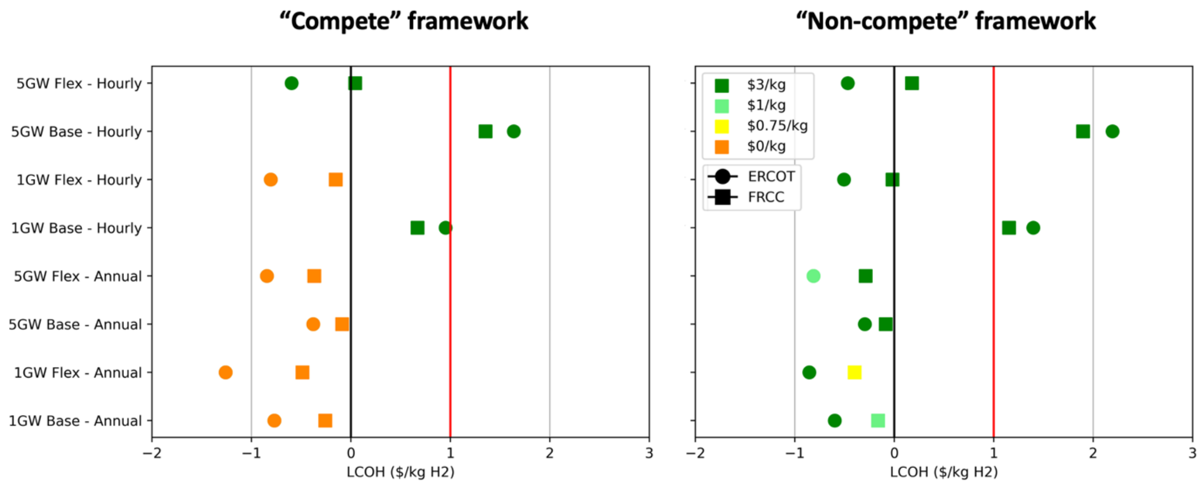

Figure 10. LCOH and compliance with the PTC emissions threshold under different scenarios for both additionality frameworks. Since consequential emissions cannot be assessed in practice, the $3/kg H_2 was applied to LCOH in all cases. The color of the data point indicates which PTC level would have been awarded based on the modeled consequential emissions. Dark green indicates that the consequential emissions associated with a case were correctly applied (i.e., below the emissions threshold to receive the $3/kg H_2 subsidy); light green and yellow indicate that the case met an intermediary PTC emissions threshold ($1 and $0.75, respectively); orange indicates that the PTC was incorrectly applied to a case that did not exceed even the least stringent PTC emissions threshold. ERCOT and FRCC LCOH markers are represented by circles and squares, respectively.

Further, we have investigated how four policy scenarios would 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 (Figure 10). Table 3 summarizes these results.

*Table 3: Summary of results of the four policy scenarios relative to the base case "compete" additionality framework. Up/down arrows indicate the trend in the respective category under the policy scenario, with more arrows indicating a greater magnitude of change. Arrows with * indicate potential impacts. i.e., result only holds in some cases.*

	Time-matching requirement	**Consequential emissions**	**LCOH**
Limiting annual electrolyzer capacity factor	Annual matching	↓	↑
Minimum annual VRE generation requirement		↓ ↓	↑
VRE +battery storage capacity installation limit	Hourly matching	↑ ↑	↓
Use of SMR-CCS to meet H_2 demand		↑*	↓*

Under the first two policy scenarios, a capacity factor limitation and a minimum VRE requirement, the consequential emissions under annual matching are reduced relative to the base case. Under the other two policy scenarios, a VRE capacity installation limit and competition between green and blue H_2, the consequential emissions under hourly time matching increase relative to the base case in some cases. In summary, the results of these policy scenarios show that the base case runs under the "compete" additionality framework in many contexts are likely to provide a too pessimistic estimate for annual matching and/or a too optimistic estimate for hourly matching with regards to the magnitude of consequential emissions from electrolytic H_2 production. Further, these results also suggest that the difference in the LCOH under annual and hourly matching will likely be smaller relative to the base case (indicated by arrows in Table 3).

The presented analysis reconciles the findings of the two papers [4], [5] that consider alternative additionality modeling frameworks and further extends this research with additional policy scenarios. Our results provide robust evidence for our original thesis: one cannot generalize emission impacts of a specific choice for the time-matching requirement in isolation from how other qualification requirements are defined and other existing policies that are enacted in the energy system. However, it leaves open an important question for policy makers: **which time-matching requirement is the most appropriate to consider when determining eligibility for the PTC in the U.S.?** In other words, which "additionality" framework best resembles the relevant context and what policy scenarios should be taken into consideration?

To address this question, it is useful to keep in mind the scale of electrolytic H_2 deployment and the broader scale of H_2 use in the economy today. As of May 2023, installed electrolyzer capacity in the United States amounted to 67 MW (579 MW under construction) [18], implying that 1 GW and 5 GW electricity-equivalent H_2 demand would represent roughly a 2X and 10X of national installed + under-construction capacity. Moreover, in the near-term, demand for green H_2 is likely to originate from sectors where H_2 is already used today (e.g., ammonia production) and thus, be relatively small compared to the scale of electricity demand. For example, if 10% of U.S. H_2 consumption in 2021 (around 1 MT/year) were to immediately shift to consume electrolytic H_2, it would amount to around 54 TWh electricity consumption or ~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 U.S. regions [13], as well as due to dedicated VRE incentives, e.g., PTCs or investment tax credits (ITCs) in the IRA. Thus, it may be reasonable to assume that the total VRE generation capacity to be added to the grid for non-H_2 related causes[10] is likely to be much larger than the VRE generation capacity to be contracted for H_2 production in the near term, independent of the time-matching requirement.

It can be argued that this near-term context, in which the relative demand for renewable electricity for electrolytic H_2 is small compared to the total additions of VREs, more closely resembles the "non-compete" additionality modeling framework; we expect significant non-H_2 load related VREs to enter before seeing significantly large volumes of electrolytic H_2 to be produced. However, as demand for green H_2 grows, driven in part by demand stimulation from other policies (e.g., the H_2 Hubs proposal in the IRA) as well as availability of low-cost H_2 (post PTC), it is likely that power sector resources contracted for H_2 production will grow in magnitude and increasingly compete with power sector resources that would be deployed for non-H_2 related causes. In this case, the "compete" framework for additionality will be more suitable to evaluate the consequential emissions impact of H_2 production.

The above interpretation would imply that less stringent annual time-matching requirements may be reasonable in the near term to ensure minimal consequential emissions (Figure 4) while leading to lower LCOH outcomes (Figure 5). 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 H_2 storage, and capital investments than under annual time matching. These requirements may constitute additional barriers for practical implementation.[11] One particular difficulty is the need to connect VRE + storage to the grid. The many VRE projects being

[10] Other sources of VRE deployment include grid decarbonization policy goals and bilateral power purchase power agreements signed by existing large consumers of electricity. For example, according to Bloomberg [12], corporate clean energy procurements stood at 20.3 GW in 2021 in the U.S. as compared to 9.1 GW in 2018.

[11] Flexible operation, which is more valuable for hourly time-matching vs. annual time-matching, requires oversizing electrolyzer capacity vs. average H_2 demand and thus could increase emissions from other life cycle stages and also increase use of already constrained critical materials [19].

developed to serve non-H_2 load are competing for the scarce connection capacity available in most regions in the U.S. In the case that electrolytic H_2 would manage to secure the scarcely available connection capacity, we have shown that the consequential emissions of H_2 production under hourly matching can significantly increase and exceed the lowest PTC tier (Figure 8). In addition, under hourly matching, the likelihood of substitution of green H_2 with blue H_2 is higher than under annual matching, again leading to potentially increased overall system-wide emissions. Note that the qualification requirements for PTCs are set at the federal level, while the energy system context could be different across states owing to differentiated state-level policies. For example, in some states the interconnection queue might be more severe, in other states (without a large interconnection queue) an ambitious RPS may be enforced, leading to a massive deployment of VREs for non-H_2 purposes, while in yet another state natural gas prices can be very low, making competition with blue H_2 more intense.

In summary, requiring hourly time-matching in this decade may work against the policy objectives of the PTC to scale green H_2 production. In particular, in the near-term, achieving low electrolyzer H_2 sales prices[12] under annual matching would encourage the deployment of electrolyzers, allowing for technology scale up and associated reductions in capital costs. Realizing such low prices for green H_2 would support long-term economy-wide decarbonization goals by stimulating new demand for H_2 in end uses that are currently dominated by fossil fuels (e.g., heavy-duty transport), as well as potentially displacing fossil fuel based H_2 in existing industrial applications.[13] In the case of the new consumers of H_2, additional investments will be needed to facilitate H_2 use (e.g., refueling infrastructure, higher CAPEX equipment), and having very cheap H_2 in the short-term could create an added incentive for its use. In contexts where it is deemed that the risk is high that annual matching would lead to high emissions, i.e., VREs contracted for H_2 production outcompete VRE projects serving non-H_2 loads (such as where no RPS or other commitments are in place to enforce VRE deployment for non-H_2 loads), the introduction of an annual capacity factor limit for the electrolyzer can be a pragmatic policy. We have shown that slight decreases in the capacity factor (e.g., limiting the capacity factor to 80%) lead to important decreases in emissions at the expense of only a limited increase in the LCOH (Figure 6).

In the medium-term (from 2030 onwards), as VRE resources for H_2 production compete with VRE resources for grid decarbonization, shifting to hourly time-matching requirements as green H_2 demand grows may be necessary to avoid the risk of high consequential emissions impacts from annual time-matching. 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 electrolyzers that would make the LCOH outcomes for hourly time-matching more compelling than values estimated in this study. Also, the interconnection queue issue might become less severe with reformed interconnection processes.

Finally, in the longer run, we have shown that when grids are highly decarbonized (e.g., 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 + storage investment and the associated implementation barriers (Figure 7). Collectively, these factors

[12] The actual selling price of the electrolytic H_2 will be higher than LCOH to account for producer return on investment and additional taxes, both of which were not considered here.

[13] For displacing fossil-based H_2 in existing applications, the LCOH of electrolytic H_2 has to match or be lower than the marginal cost of natural gas reforming based H_2 since many of those facilities may have fully paid off their capital costs.

indicate that a phased approach on defining the qualifying requirements for the H_2 PTC may be the most pragmatic approach to minimize barriers to grid decarbonization while at the same time stimulating electrolytic H_2 use in difficult-to-decarbonize applications through the availability of low cost H_2 supply.

5. Conclusion

Which time-matching requirement, i.e., annual or hourly, shall be demanded from H_2 developers to receive the H_2 PTC in the U.S. context has been at the center of the public and academic debate. Beyond uncovering the assumptions that drive the difference in results between relevant academic papers, we have also investigated the effect of four relevant policy scenarios on the estimated consequential emissions under the different time-matching requirements. Our main conclusion is that one cannot generalize emission impacts of a selected time-matching requirement in isolation from how other qualification requirements are defined and what other regionally-differentiated energy system policies are in place. Our findings are not only relevant for the attribution of PTCs for low-carbon H_2 production but also broadly applicable for characterizing electricity-related emissions accounting in different contexts.

We have contrasted two proposed additionality modeling frameworks via two case studies, ERCOT and FRCC grids, and confirm that the consequential emissions from producing electrolytic H_2 are conditional upon how the additionality requirement is modeled. Furthermore, independent of the additionality modeling framework, an hourly time-matching requirement leads to higher levelized cost of H_2 (LCOH) compared to annual time-matching requirements (excluding the attribution of a PTC). Significantly higher capacities of renewables need to be installed under the hourly time-matching requirement, and thus more capital and land is required and possibly more H_2 storage (for flexible operation).

Further, we modeled four policy scenarios to demonstrate their impact on consequential emissions from H_2 production and the LCOH under different requirements, specifically in the "compete" additionality modeling framework. The results of these policy scenarios show that the base case runs under the "compete" additionality framework in many contexts are likely to provide an overly pessimistic estimate for annual matching and/or an overly optimistic estimate for hourly matching with regards to the magnitude of consequential emissions from electrolytic H_2 production. Further, these results also show that the difference in the LCOH under annual and hourly matching will likely be smaller relative to the base case. Effectively, these scenarios represent a checklist for policy makers to understand the effectiveness of different time-matching requirements in limiting consequential emissions in different regional contexts.

With regards to PTC implementation in the U.S. context, we argue for a "phased approach" in defining time-matching requirements for the attribution of the PTC: a) annual matching in the near term to kick-off electrolytic H_2 production and b) and a deeper evaluation based on further modeling to understand the timing of transition to hourly time matching and the duration over which such a stringent time-matching requirement might be necessary. The modeling analysis to inform the phase-in and phase-out of hourly time-matching requirements should consider different levels of non-H_2 VRE deployment, H_2 demand and competition between green vs. blue H_2, among other factors for various regions.

While our modeling is based on perfect knowledge of hourly VRE availability over the year, uncertainty and inter-annual fluctuations in VRE availability will need to be accounted for in practice, which could increase the LCOH differences between more stringent hourly time-matching vs. annual time-matching requirements – this would be an important area to investigate further. Moreover, we also assumed all electrolyzers to belong to one portfolio and all wind and solar resources to have homogeneous production profiles. The analysis can be further refined by integrating more granular project-specific economics of H_2

production, such as in [20] into a system-wide model, where the ability to use other clean generation resources like nuclear could also be considered. Finally, in this paper we did not cover spatial matching requirements. Independent of hourly or annual time-matching requirements, it is important that congestion between the electrolyzer and the contracted renewables is limited. This topic may be explored in more depth in future work.

6. Methods

6.1 Model overview

This study uses the Decision Optimization of Low-carbon Power and Hydrogen Networks (DOLPHYN) model [7], an open-source energy systems capacity expansion model that co-optimizes investment and operation of electrical power and H_2 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 H_2). This includes annualized capital costs for new capacity and fixed and variable operating costs for both existing and new generation, storage, and transmission capacity, as well as any costs for load-shedding. The cost minimization is carried out subject to many system and technology-level constraints, including a) ramping limits and temporally dependent resource availability limits for VRE generation, and b) system-level constraints, including hourly energy supply-demand balance for H_2 and electricity at each location, as well as case-specific or hourly/annual time matching and energy share requirements. Further details of the model formulation and setup can be found in [7].

6.2 Region and time horizon of interest

The data inputs and sources used to define the 2021 system for both ERCOT and FRCC studies are provided in the SI. Relevant technology cost and performance assumptions are reported in Table S1 and Table S2, and fuel costs are reported in Table S4. Power generation capacity for all resources for ERCOT and FRCC are reported in Table S5. Annual demand and generation information is reported in Table S6. Hourly VRE capacity factors and hourly demand profiles for ERCOT and FRCC are visualized in Figure S1 and Figure S2, with VRE profiles generated by averaging data from subregions of ERCOT and FRCC, as visualized in Figure S3. 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 studies[4]. In our case studies, we do not allow for retirements of existing nuclear plants, based on the assumption that it would be economically viable based on the available credits for nuclear in the IRA. Full results for FRCC are reported in Figure S19Figure S27.

6.3 Exogeneous H2 demand characterization and electrolyzer capacity modeling

Under both baseload and flexible electrolyzer operation in our analysis, electrolyzer capacity is sized to meet exogeneous 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 H_2 demand of 18.4 to 92.1 tonnes of H_2 per hour (0.16 to 0.81 MT/year), that for typical electrolyzer specific power consumption (54.3 MWh/tonne), ranges from 1 to 5 GW of hourly electric power consumption. For simplicity, when discussing results, we use labels of like “1 GW” to indicate an hourly H_2 demand level of 18.4 tonnes of H_2 per hour. Because the total amount of H_2 produced is fixed, the available PTC does not impact the operational behavior of the electrolyzer and therefore we do not consider it in the model, but rather include it when estimating the levelized cost of H_2.

6.4 Time-matching requirements

Like in Ricks et al. and Zeyen et al., 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 electrolyzer (see Eq. S2 in SI). In contrast, the *hourly time-matching requirement* is modeled 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 electrolyzer (see Eq. S3 in SI). To ensure battery storage charges from eligible VRE generation resources, we only allow the contracted battery, if deployed, to charge in each hour up to the available generation from contracted VRE resources (see Eq. S4 in SI). In this implementation, the hourly time-matching requirement allows for the contracted resources to sell any excess electricity in a given hour (e.g., 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 H_2 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 electrolyzer.

6.5 Metrics of interest

The emissions impact of H_2 production is evaluated using the *consequential emissions intensity*, defined as *the difference in power system emissions with and without* H_2 *demand divided by the annual quantity of H_2 produced.* As noted by others [4], [5], this is an appropriate metric for assessing emissions intensity in modeling exercises; however, alternative metrics are needed for real world accounting, since the "counterfactual grid"" used to calculate consequential emissions cannot be observed. Although the PTC focuses on lifecycle GHG emissions, as a simplification, our analysis only considers CO_2 emissions related to fossil fuel combustion for electricity generation since these will dominate overall emissions.[14]

Aside from consequential emissions intensity, we evaluate *the levelized cost of H_2 (LCOH),* which approximates the cost to the H_2 producer who invests in the electrolyzer and H_2 storage, as well as the additional low-carbon electricity generation that is required for the H_2 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 H_2 selling price that would lead to a zero profit for the H_2 producer over the lifetime of the investment in the electrolyzer. The LCOH includes: a) the capital cost of added VRE and battery storage (after the 30% ITC under the IRA[15]), b) the cost of electricity purchases from the grid for H_2 production, c) revenue from electricity sales to the grid from the procured renewables (accounting for battery charging/discharging), and d) electrolyzer and H_2 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

[14] While emissions from other lifecycle stages will impact the absolute lifecycle GHG emissions of H_2 production, the impact of matching requirements will primarily affect electricity consumption–related emissions as compared to emissions from other stages (e.g., electrolyzer manufacturing).

[15] The IRA allows for an eligible VRE and storage facility to either receive the credit as a ITC or PTC—as a simplification we restricted our analysis to the case when the VRE and battery storage owner only relies on the ITC, which may be the economical choice when capital costs of these assets are still high and/or resource quality is average to low [21].

balance constraint enforced for each hour of the year in the model.[16] In each case, we report the LCOH with and without including the applicable H_2 PTC.

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Supporting Information (SI)

S1. Modeling data inputs

This section summarizes the major data inputs used in the modeling. Unless otherwise stated, all costs have been converted to 2021 USD. Table S1 summarizes the cost assumptions for VRE and Li-ion battery storage resources. The parametrization of battery storage also considers a self-discharge rate of 0.002% per hour [22]. 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 (i.e., duration) is between 0.15-12 hours. Table S2 summarizes cost assumptions for electrolyzers and H_2 storage.

S1.1 Cost and performance assumptions

Table S1. Generation technology cost and performance parameters. A discount rate of 4% is used to annualize investment costs. Reported annualized cost account for the investment tax credit (ITC) for wind, solar and battery storage deployments, which as per the IRA is set to be 30%. Data corresponds to 2022 costs reported by the NREL Annual Technology Baseline 2022 edition [23].

Technology	Lifetime (years)	Investment cost – power ($/MW)		Annualized CAPEX w/ ITC – Power ($/MW/year)	Investment cost – energy ($/MWh)		Annualized CAPEX w/ ITC– Energy ($/MWh/year)	Fixed operation and maintenance cost		Variable operating cost ($/MWh)
		W/o ITC	W ITC		W/o ITC	W/o ITC		Power ($/MW/year)	Energy ($/MWh/year)	
Solar PV	30	1176,000	823,200	52,105	-	-	52,105	22,721	-	0
Onshore wind	30	1428,000	999,600	56,185	-	-	56,185	17,781	-	0
Li-ion battery storage	15	255,150	178,605	16,064	296,100	207,270	18,642	6379	7403	1[17]

Table S2. H_2 production and storage technology cost and performance parameters. A discount rate of 4% is used to annualize investment costs. Data sourced from NREL H2A analysis and other literature [24] [25]. Cost and performance assumptions for natural gas reforming technologies sourced from NETL techno-economic analysis study [15]. The cost of feedwater for electrolyzer is relatively small compared to the cost of energy and thus is ignored in the analysis. SMR = Steam Methane Reforming. CCS = Carbon Capture and Storage. ATR = Autothermal reforming. Cost units of $/MWH$_2$ are based on converting per tonne capital costs using H_2 lower heating value. In runs where we model competition between electrolyzer and NG reforming pathways, the VOM costs for electrolyzer is set to $-3,000/tonne to account for PTC credit. In these runs, the VOM for NG reforming is adjusted to account for IRA 45Q tax credit ($85/tonne CO2 sequestered). The credit is calculated based on a NG fuel emissions factor of 0.05306 tCO2/MMBtu.

Technology	Lifetime	Investment cost		Annualized investment cost		Fixed operation and maintenance (FOM) cost -H_2 production rate ($/MWH$_2$/year)	Variable operating and maintenance cost (VOM) ($/t H_2)	Electrical power use (MWh/t H_2)	Natural gas (NG) use (MMBtu/t H_2)
		H2 production rate ($/MWH$_2$)	Energy ($/t H_2)	H_2 Production rate ($/MWH$_2$/y)	Energy ($/t H_2/y)				
Electrolyzer	20	1937,791	-	142,586	-	28,604	0	54.3	0
H_2 storage (tank)	30	-	587,000	-	33,929	-	0	-	0

[17] To avoid instances of battery charging and discharging simultaneously, which is possible in a capacity expansion model formulated as linear program (LP), we penalize battery charging and discharging with a small but non-zero variable operating cost.

H_2 storage compressor	15	2451,496	-	220,490	-	-	0	0.71	0
SMR	25	544,423	-	34,849	-	16,804	86.9	-	174.8
SMR-CCS	-	1324,505	-	84,784	-	36,872	241.99	-	185.9
ATR-CCS	-	1046,855	-	67,011	-	28,599	357.6	-	174.7

Table S3. Summary of process CO_2 emissions, CO_2 capture and available credits from the U.S. IRA for different H_2 technologies. SMR = Steam Methane Reforming. CCS = Carbon Capture and Storage. In runs where we model competition between electrolyzer and NG reforming pathways, the VOM costs for electrolyzer is set to \$-3,000/tonne to account for PTC credit from Inflation Reduction Act (IRA). In these runs, the VOM for NG reforming is adjusted to account for IRA 45Q tax credit (\$85/tonne CO_2 sequestered). The credit is calculated based on a NG fuel emissions factor of 0.05306 tCO_2/MMBtu.

Technology	Process fuel combustion emissions (tCO_2/tH_2)	CO_2 capture rate (%)	CO_2 captured (tCO_2/tH_2)	Credit available from IRA (\$/tH_2)
Electrolyzer	-	-	-	
SMR	9.27	0	0	0.0
SMR-CCS	0.37	96.2	9.49	806.5
ATR-CCS	0.51	94.5	8.76	744.6

The model runs were based on fuel price assumptions based on 2019 rather than 2022, as summarized in Table S4, so as to not consider the short-term distortion in fuel prices resulting from the Russian invasion of Ukraine. While the spot prices of natural gas through 2021 were much higher than 2019 values (as high as \$6/MMBtu), it is interesting to note that prices in 2023 have come down to levels seen in 2019.[18] Table S5 summarizes power capacity in GW by resource type for FRCC and ERCOT in 2021.

We use modified fuel costs for natural gas technologies using CCS for H_2 production, to implicitly account for the cost of CO_2 transportation and storage. The incremental CCS cost adder to the fuel cost is computed by multiplying the captured CO_2 per MMBtu of natural gas with the assumed CO_2 transportation and storage cost, equal to 11.6 \$/tonne per the assumption used by NETL in their techno-economic analysis of natural gas H_2 production technologies [15].

Table S4. Fuel price assumptions for FRCC and ERCOT case studies. Data sourced from EIA Annual Energy Outlook 2022 [26] for 2021 prices. Natural gas and coal modeled with combustion CO2 emissions factors of 0.05306 tCO2/MMBtu and 0.09552 tCO2/MMBtu, respectively. The natural gas cost for CCS technologies applies to both SMR-CCS and ATR-CCS technologies summarized in Table S2

Fuel	FRCC	ERCOT
Natural gas	4.15	2.03
Natural gas cost for CCS technologies	-	2.62
Coal	3.37	2.47
Uranium (for nuclear)	0.71	0.70

Table S5. Existing power capacity in GW as of 2021 for ERCOT and FRCC. Generators clusters and technical characteristics (e.g., heat rate) were adapted from 2019 data sourced from PowerGenome [27] to match the 2021 capacity as reported by EIA [26]. Diurnal battery storage is assumed to have an energy capacity corresponding to a rated duration of 4 hours.

	FRCC	ERCOT
Coal	5.4	14.4
Natural gas combined cycle	31.1	35.1
Natural gas combustion turbine	10.2	7.0
Nuclear	3.7	5.0
NG steam turbine	4.1	10.8
Biomass	0.3	0.1
Hydro	0.04	0.5
Solar	4.8	9.1
Wind (onshore)	0.0	34.1
Diurnal battery storage	0.45	0.7

S1.2. Load and generation resource characterization

Table S6 summarizes the key assumptions for characterizing electricity power demand and electricity resources for the two regional case studies. The electricity demand data was obtained from PowerGenome [27] and corresponds to demand for 2021 for the two regions. Figure S1 visualizes the hourly demand profile and VRE resource profile for FRCC, which highlights how wind availability tends to be low during

[18] For example, according to the data from the U.S. Energy Information Administration (https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm), the average Henry hub spot price in Jan and Feb 2023 were 3.27\$/MMBtu and \$2.38/MMBtu, respectively.

summer months when electricity demand is relatively high. Figure S2 visualizes the VRE resource and demand data for ERCOT, with wind exhibiting less seasonal variation than in FRCC.

Table S6. Characterization of electricity demand, variable renewable energy (VRE) resource availability and availability factors for other resources in the system. Availability factors refers to the fraction of nameplate capacity of the resource that can be utilized in each hour. For VRE resources, the availability factor, also known as capacity factor, varies from one hour to the next depending on weather conditions. In our modeling for we assume constant availability factors for other resources, although these resources may also have unforced outages that could impact their hourly availability in practice. Power demand data was generated by multiplying each hour of a 2019 demand profile generated by PowerGenome [27] by a scalar, so that total annual power demand equaled the annual demand reported in the 2022 EIA AEO report.

	FRCC	ERCOT
Peak power demand (GW)	48.3	75.7
Annual power demand (TWh)	245.9	388.9
Annual average capacity factor: onshore wind:	30.6%	46.3%
Annual average capacity factor: solar PV	26.6%	29.4%
Hourly maximum availability factor for various resources		
Coal, natural gas, and biomass	90%	
Nuclear	95%	
Battery	100%	
Electrolyzers	95%	

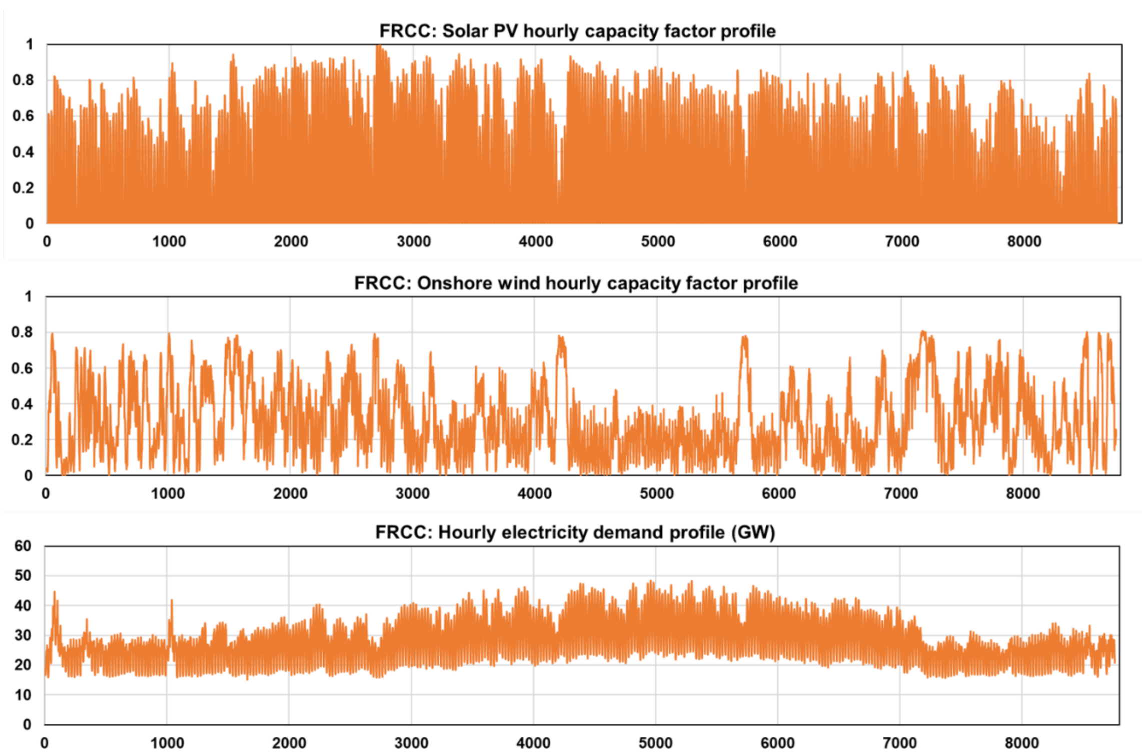

Figure S1. Hourly resource availability profiles solar PV (top row) and onshore wind (middle row) as well as hourly electricity demand profile (bottom row) for FRCC case study. Details about the data inputs discussed in Section S1.2

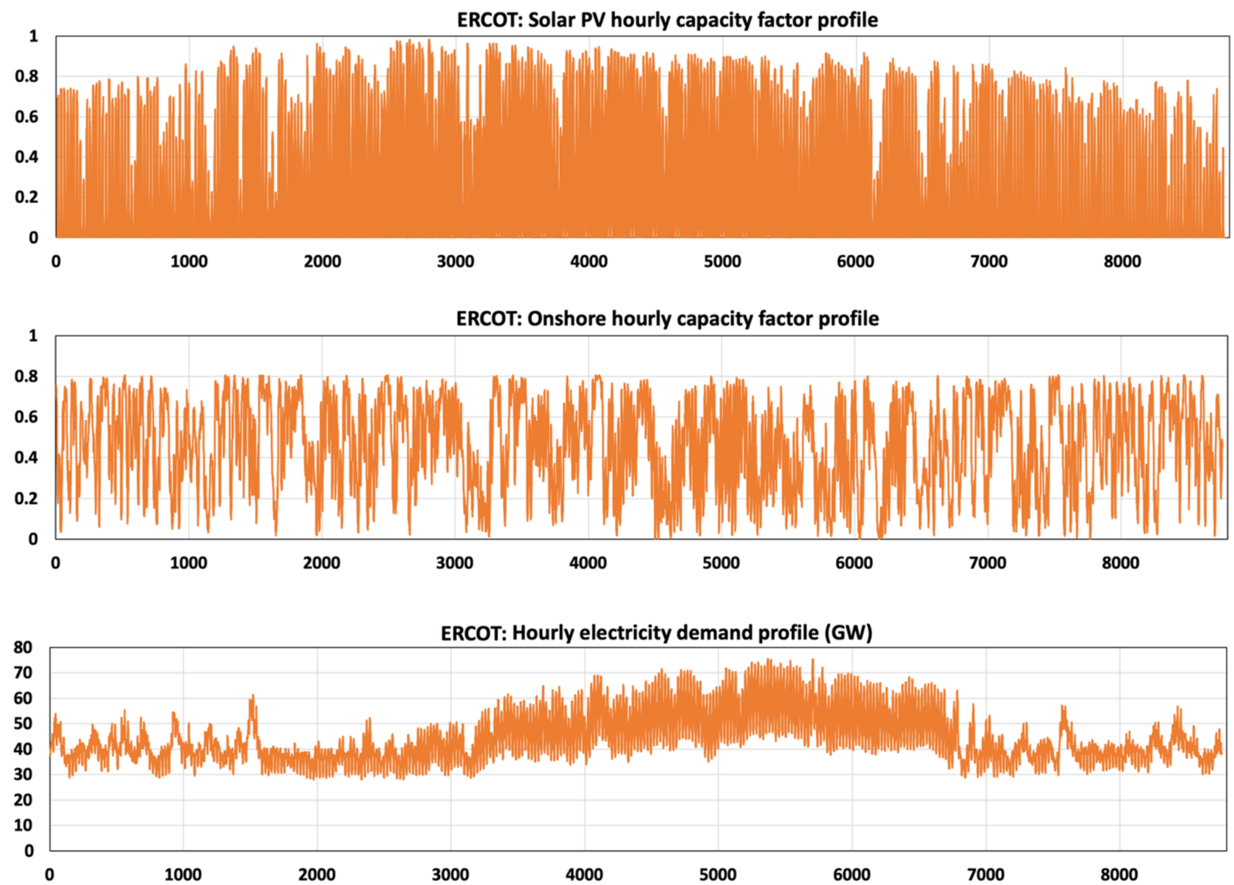

Figure S2. Hourly resource availability profiles for solar PV (top row) and onshore wind (middle row), as well as hourly electricity demand profile (bottom row) for ERCOT case study. Details about the data inputs discussed in Section S1.2

Hourly resource availability data for onshore wind and solar PV for each region was generated by averaging hourly resource availability profiles for weather year 2012 from multiple sites, available from a previous study [28]. The site-level data for PV was simulated using site-level irradiation data from the National Solar Radiation Database in conjunction with the open-source PVLIB. In the case of wind, the site-level resource data was simulated using site-level wind speed data from the NREL Wind Integration National Dataset Toolkit and a 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 publication [28]. Figure S3Figure S3 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 only considered 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).

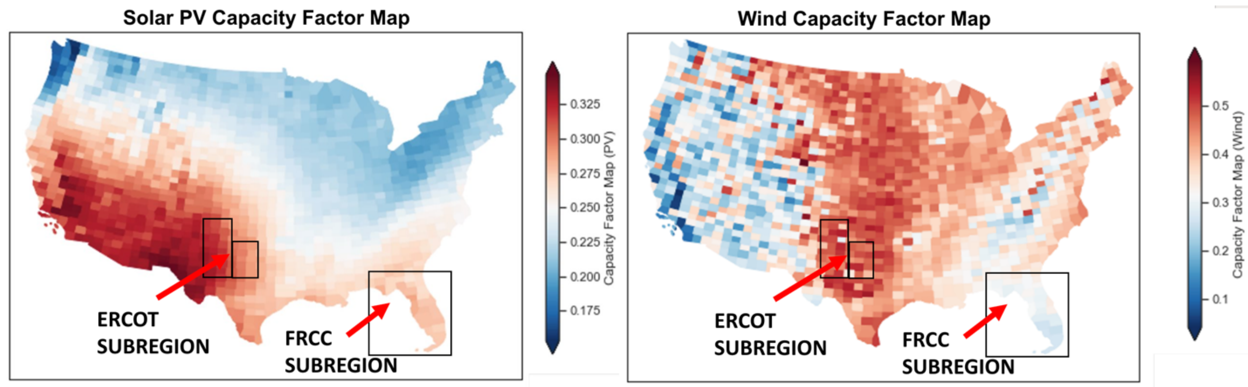

Figure S3. Sub-regions for computing hourly capacity factors for solar and wind resources in ERCOT and FRCC. This figure is an adaptation of Figure S2 from [28], which shows average annual capacity factors computed according to 2012 weather data. To compute hourly capacity factors for this paper, we average hourly capacity factors for the coordinate blocks in the highlighted regions.

S2 Key model constraints

Hourly H_2 supply-demand balance

Equation S1 enforces that sum of electrolytic H_2 production (gen_t^{Ely}) plus production from natural gas reforming technologies, if available ($\sum_{g\in G} gen_{g,t}^{NG}$) plus net discharge of H_2 storage ($dischg_t^{H2} - chg_t^{H2}$), if available, must equal the exogeneous hourly H_2 demand (δ_t^{H2}) for all hours of the year.

$$gen_t^{Ely} + \sum_{h\in H_{NG}} gen_{h,t}^{NG} + dischg_t^{H2} - chg_t^{H2} = \delta_t^{H2} \qquad \forall t \in T \qquad \text{(S1)}$$

Annual time-matching requirement

Equation S2 states that sum of contracted VRE generation ($gen_{g,t}^{VRE}$) from eligible set of renewable resources (TMR_g) throughout the year must be equal to annual electrolyzer electricity consumption. The latter is calculated as a product of the annual H_2 demand and power consumption per unit of H_2 produced (λ^{Ely}).

$$\sum_{g\in TMR_g} \sum_{t\in T} gen_{g,t}^{VRE} = \lambda^{Ely} \sum_{t\ in\ T} \delta_t^{H2} \qquad \text{(S2)}$$

Hourly time-matching requirement

The hourly time-matching requirement constraint enforces that for every hour of the year, the electrolyzer power consumption, equal to product of its generation times the specific power consumption (λ^{Ely}), must be less than or equal to generation from the contracted set of VRE generation (TMR_g) + net injection from set of eligible battery storage (TMR_b). This ensures that new electrolyzer demand is accounted for by these additional resources at each hour. If there is no storage or natural gas reforming technologies, then electrolyzer will be operating in baseload conditions resulting in $gen_t^{Ely} = \delta_t^{H2}$ by equation S1.

$$\sum_{g\in TMR_g} gen_{g,t}^{VRE} + \sum_{k\in TMR_b}\left(dischg_{k,t}^{bat} - chg_{k,t}^{bat}\right) \geq gen_t^{Ely} \lambda^{Ely}\ for\ all\ t \in T \qquad \text{(S3)}$$

At each time step, the amount charged by the new battery resource (part of set TMR_b) cannot exceed maximum available generation from set of eligible renewable resources (part of set TMR_g), defined as the sum of the hourly capacity factor ($\alpha_{g,t}^{VRE}$) times the installed capacity (Cap_g^{VRE}). This ensures that the battery is charging only when procured renewable energy is available.

$$chg_{k,t}^{bat} \leq \sum_{g\in TMR_g} \alpha_{g,t}^{VRE} \times Cap_g^{VRE} \ \forall\ t \in T\ , k \in TMR_b \qquad \text{(S4)}$$

Electrolyzer maximum annual capacity factor

When modeling the policy scenario with a maximum annual capacity factor limit ($\alpha^{Ely,Max}$), we include Equation S5 in the model. The constraint effectively translates into a minimum electrolyzer capacity deployment constraint for an exogeneous annual H_2 demand. β^{ELY} in Equation S5 refers to the availability factor for the electrolyzer, which denotes the fraction of installed capacity that is available for production in any hour.

$$\frac{1}{8760}\sum_{t\ in\ T}\delta_t^{H2} \leq \alpha^{Ely,Max} \times \beta^{ELY} \times Cap^{Ely} \qquad \text{(S5)}$$

Minimum annual VRE generation requirement

The minimum annual VRE generation requirement, summarized in equation S6, enforces that annual generation from non-PPA resources must be at least equal to a pre-specified fraction (κ) of annual sum of hourly electricity demand (δ_t^{elec}). Note that electricity demand does not include electricity consumed for H_2 production. In addition, generation from PPA VRE resources (i.e., belonging to set TMR_g) are not counted towards meeting this constraint. Allowing excess electricity sales from PPA VRE resources to be counted towards meeting the annual VRE generation requirement results in VRE capacity deployment that is much in excess of H_2 production needs. This means that electricity rather than H_2 is the primary product of these contracted VRE resources. Since our focus was on H_2 production, we chose to disallow contracted VRE resources to participate in meeting the system-wide annual VRE generation requirement constraint. As the relative magnitude of "excess sales" (PPA VRE resources not used for H_2 production – "excess sales") is small relative to the total amount of VRE production in the system, we argue that this simplification does not have a substantial impact on the results.

$$\sum_{g \in VRE \setminus TMR_g}\sum_{t \in T} egen_g^{VRE} \geq \kappa \times \sum_{t \in T}\delta_t^{elec} \qquad \text{(S6)}$$

Maximum VRE + storage deployment constraint

The maximum VRE+ storage deployment constraint enforces that the total power capacity investments in VRE resources and battery storage, both to meet contractual requirements for H_2 production and to serve non-H_2 demand must be less than or equal to an exogenously specified value (Max_{Cap}). TMR_g and TMR_b refer to VRE and battery resources for H_2 production, respectively, and $Grid_g$ and $Grid_b$ refer to VRE and battery resources for non-H_2 demand. This constraint is meant to mimic the implicit limits on new resource investment owing to delays in grid interconnection and supply chain limits.

$$\sum_{g \in TMR_g} Cap_g^{VRE} + \sum_{g \in Grid} Cap_g^{VRE} + \sum_{k \in TMR_b} Cap_k^{bat} + \sum_{k \in Grid_b} Cap_k^{bat} \leq Max_{Cap} \qquad \text{(S7)}$$

S3 Additional results for ERCOT

S3.1 Base case scenarios

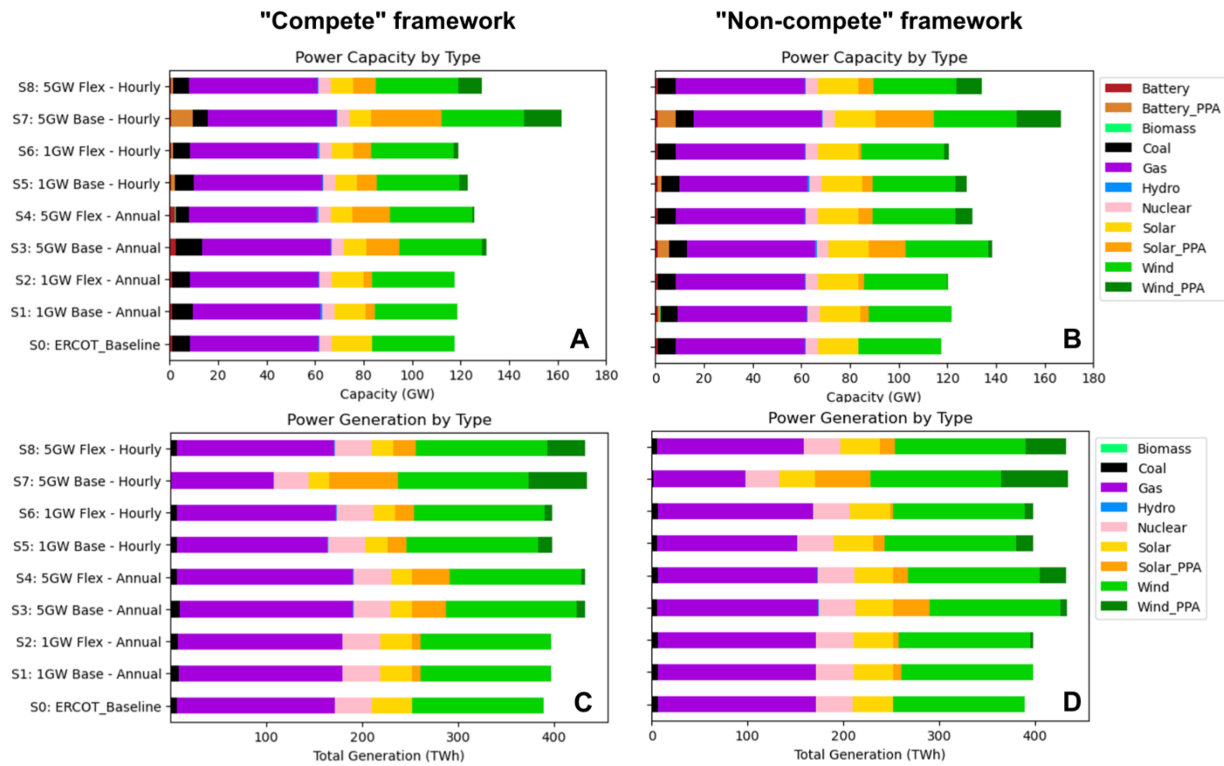

Figure S4. Power generation and storage capacity (top row, A-B) and annual power generation (bottom row, C-D) resulting from electrolytic H_2 production under alternative H_2 demand scenarios, time-matching requirements, and additionality frameworks. Results correspond to ERCOT case study. Also shown are the results for the baseline grid scenario involving grid resource expansion without any H_2 demand, as defined in Figure 1.

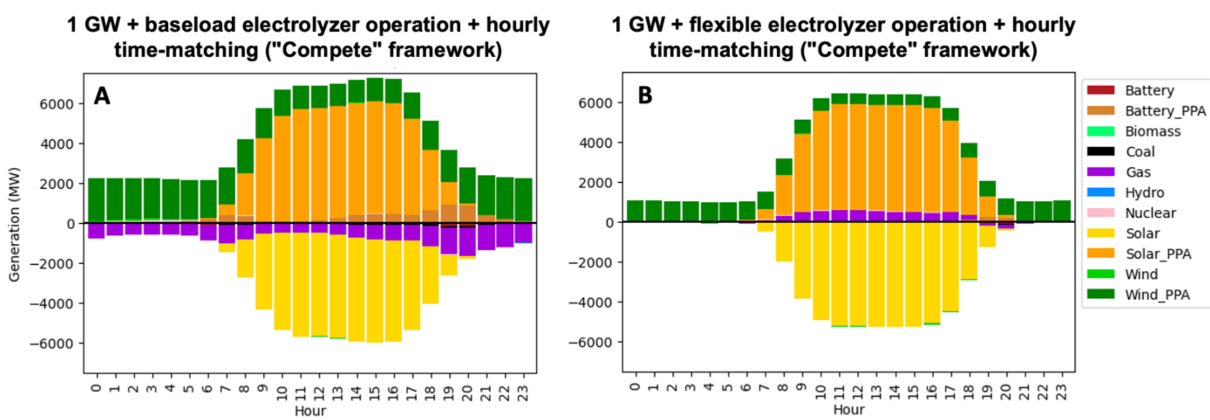

Figure S5. Average hourly change in power system dispatch between cases with H_2 production vs. baseline grid in ERCOT for the scenarios with 1 GW H_2 demand, hourly time-matching requirements, "compete" additionality framework, and baseload electrolyzer operation (A) or flexible electrolyzer operation (B).

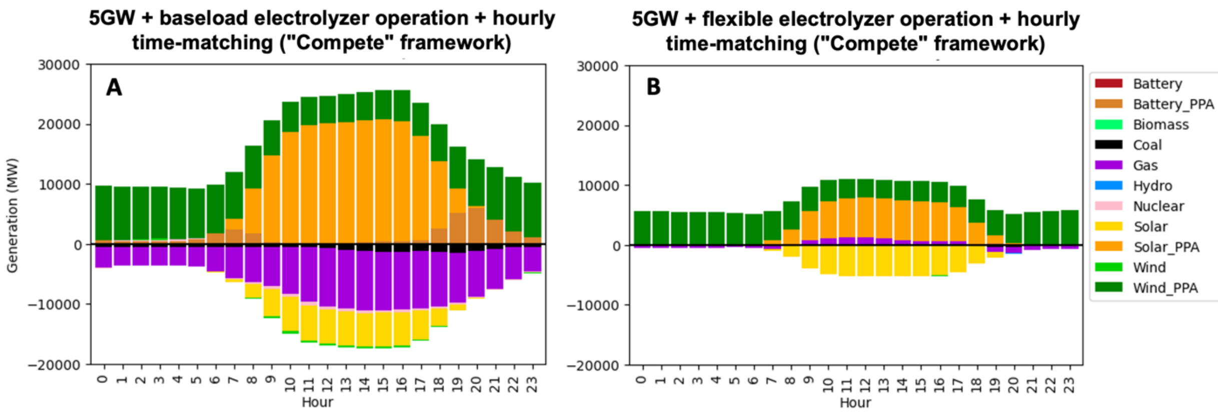

Figure S6. Average hourly change in power system dispatch between cases with H_2 production vs. baseline in ERCOT for the scenarios with 5 GW H_2 demand, annual time-matching requirements, "compete" additionality framework, and baseload electrolyzer operation (A) or flexible electrolyzer operation (B).

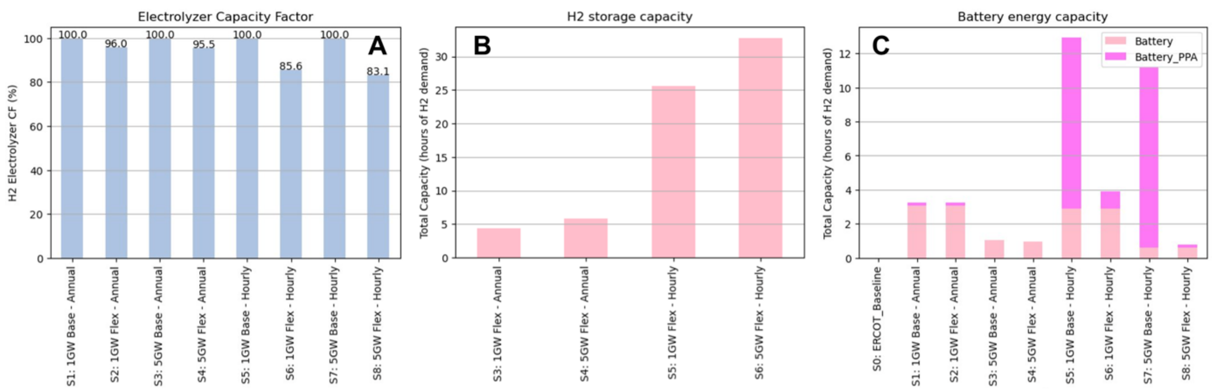

Figure S7. Electrolyzer capacity factor (A), H_2 storage capacity (B) and battery energy capacity (C) for alternative H_2 demand scenarios, time-matching requirements under the "compete" additionality framework. Results correspond to ERCOT case study. H_2 and battery storage capacity reported in terms of hours of exogeneous H_2 demand that can be met with the available storage capacity when full. Electrolyzer capacity factor calculated based on available capacity in each hour, which is 95% of the installed capacity.

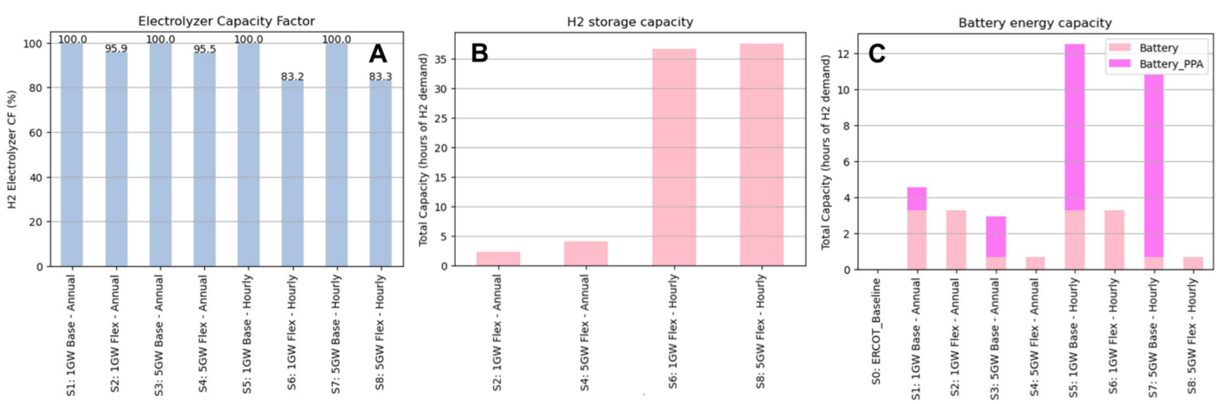

Figure S8. Electrolyzer capacity factor (A), H_2 storage capacity (B), and battery energy capacity (C) for alternative H_2 demand scenarios, time-matching requirements under the "non-compete" additionality framework. Results correspond to ERCOT case study. H_2 and battery storage capacity reported in terms of hours of exogeneous H_2 demand that can be met with the available storage capacity when full. Electrolyzer capacity factor calculated based on available capacity in each hour, which is 95% of the installed capacity.

S3.2 Maximum electrolyzer capacity factor scenarios

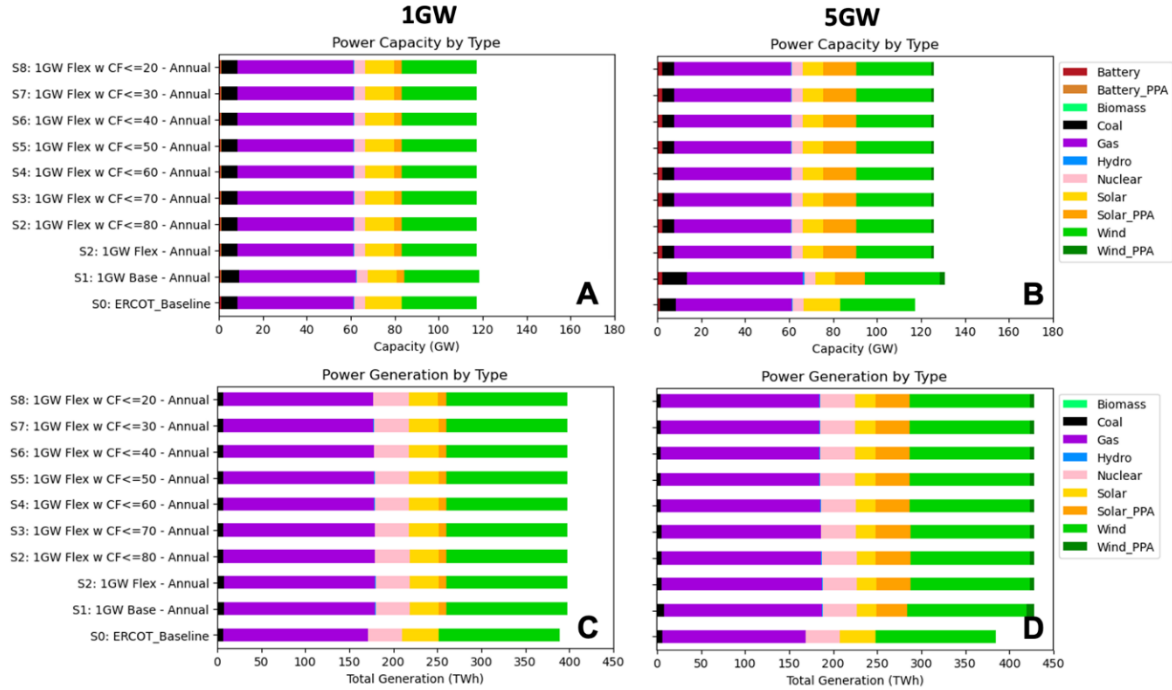

Figure S9. Power generation and storage capacity (top row, A-B) and annual power generation (bottom row, C-D) resulting from electrolytic H_2 for scenarios with 1GW (1st column) and 5GW (2nd column) of electrolyzer demand under an annual time-matching requirement with baseload operation, flexible operation, and different upper limits on annual electrolyzer capacity factor (20%, 30%, 40%, 50%, 60%, 70%, and 80%). Results correspond to the ERCOT case study under the "compete" additionality framework. Also shown are the results for the baseline grid scenario involving grid resource expansion without any H_2 demand, as defined in Figure 1.

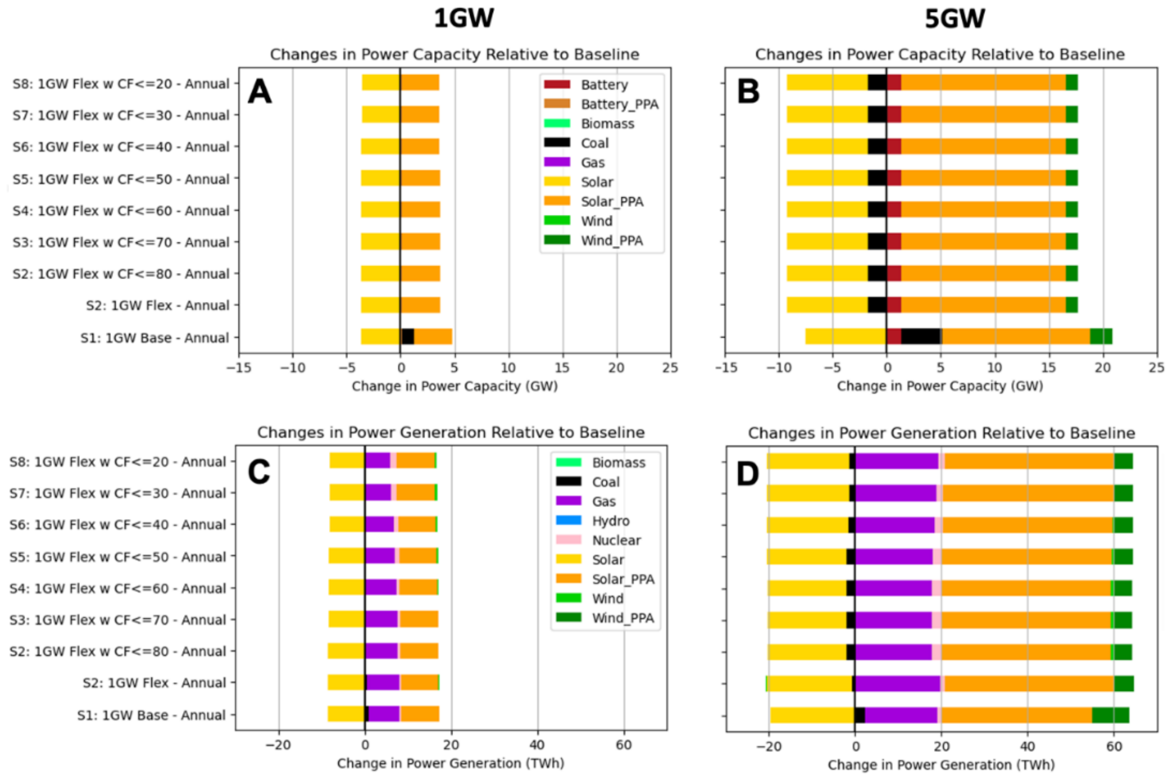

Figure S10. Change in power generation and storage capacity (A, B) and annual power generation (C, D) resulting from electrolytic H_2 for scenarios with 1GW (1st column) and 5GW (2nd column) of electrolyzer demand under an annual time-matching requirement with baseload operation, flexible operation, and different upper limits on annual electrolyzer capacity factor (20%, 30%, 40%, 50%, 60%, 70%, and 80%). Results correspond to the ERCOT case study under the "compete" additionality framework and are reported relative to the baseline grid scenario involving grid resource expansion without any H_2 demand, as defined in Figure 1.

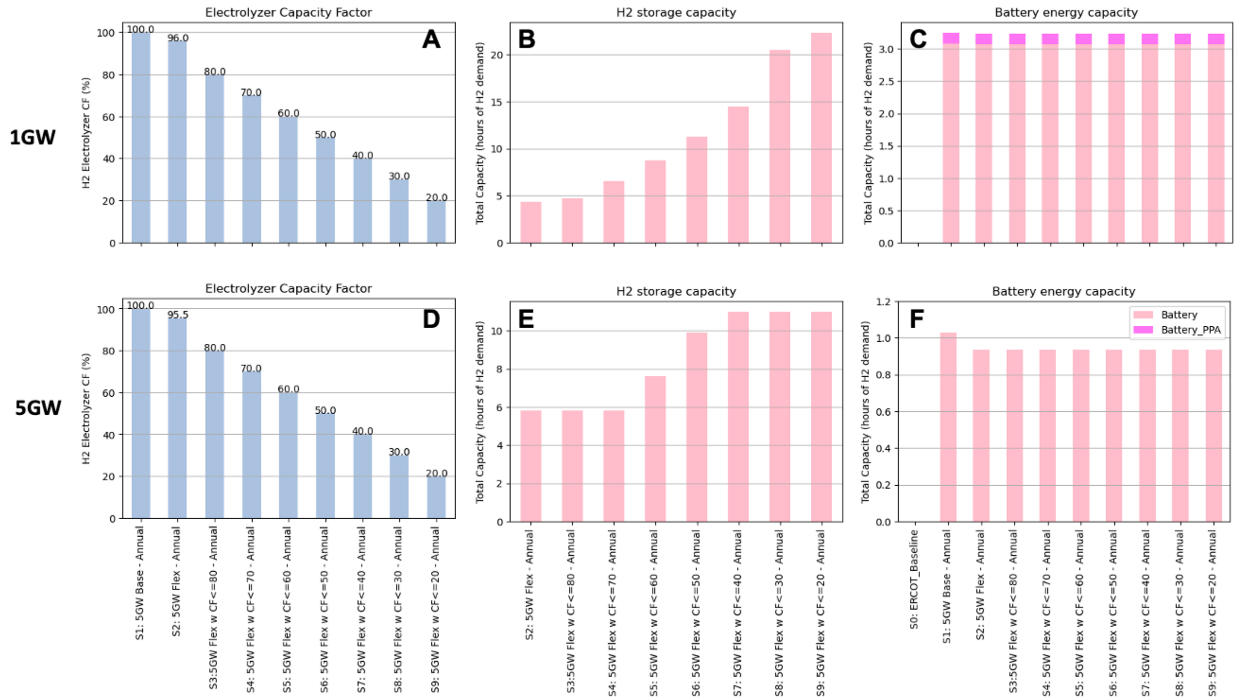

Figure S11. Electrolyzer capacity factor (A, D), H_2 storage capacity (B, E) and Battery energy capacity (C, F) under baseload operation, flexible operation, and scenarios with different upper limits on annual electrolyzer capacity factor (20%, 30%, 40%, 50%, 60%, 70%, and 80%) with an annual time-matching requirement. Results correspond to the ERCOT case study under the "compete" additionality framework. H_2 and battery storage capacity reported in terms of hours of exogeneous H_2 demand that can be met with the available storage capacity when full. Electrolyzer capacity factor calculated based on available capacity in each hour, which is 95% of the installed capacity.

Table S7. Component values for the levelized cost of H_2 in \$/kg H_2 for the "compete" additionality framework for the ERCOT case study under scenario with different H_2 demand (1, 5 GW equivalent power consumption), time-matching requirements (annual vs. hourly), and electrolyzer operation modes (Baseload vs. flexible). Levelized cost calculated per the description provided in Section 6.5. 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 electrolyzer; electrolyzer_fixed_cost = annualized capital and fixed operating and maintenance (FOM) cost of the electrolyzer; 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 H_2 storage system, which includes the capital cost of the compressor and tank. Excess electricity sales, as described in Section 3.1.3, is calculated as elec_sales - elec_purchases. Net electricity cost for H_2 production, as described in Section 3.1.3, is calculated as electicity_fixed_cost – excess_elec_sales. The values reported are plotted in the left panel of Figure 5

	elec_sales	**elec_purchases**	**elec_fixed_cost**	**electrolyzer_fixed_cost**	**h2_storage**	**Excess electricity sales**	**Net electricity cost for H_2 production**
S1: 1GW Base - Annual	-1.55	1.56	1.54	0.69	0	0	1.54
S2: 1GW Flex - Annual	-1.55	1.02	1.54	0.71	0.02	0.53	1.01
S3: 5GW Base - Annual	-1.08	1.58	1.43	0.69	0	-0.51	1.93
S4: 5GW Flex - Annual	-1.1	1.08	1.44	0.72	0.02	0.02	1.41

S5: 1GW Base - Hourly	-5.74	1.53	7.47	0.69	0	4.21	3.27
S6: 1GW Flex - Hourly	-4.2	0.97	4.52	0.8	0.11	3.23	1.29
S7: 5GW Base - Hourly	-3.76	1.32	6.39	0.69	0	2.44	3.95
S8: 5GW Flex - Hourly	-1.62	0.98	2.08	0.82	0.13	0.64	1.44

Table S8. Component values for the levelized cost of H_2 in \$/kg H_2 for the "non-compete" additionality framework for the ERCOT case study under scenario with different H_2 demand (1, 5 GW equivalent power consumption), time-matching requirements (annual vs. hourly), and electrolyzer operation modes (Baseload vs. flexible). See description of Table S7 for details. The values reported are plotted in the right panel of Figure 5.

	elec_sales	**elec_purchases**	**elec_fixed_cost**	**electrolyzer_fixed_cost**	**h2_storage**	**Excess electricity sales**	**Net electricity cost for H_2 production**
S1: 1GW Base - Annual	-1.51	1.44	1.79	0.69	0	0.08	1.72
S2: 1GW Flex - Annual	-0.99	0.99	1.42	0.71	0.01	0	1.42
S3: 5GW Base - Annual	-1.7	1.77	1.95	0.69	0	-0.07	2.02
S4: 5GW Flex - Annual	-0.96	1.02	1.39	0.72	0.02	-0.06	1.45
S5: 1GW Base - Hourly	-3.86	1.13	6.44	0.69	0	2.73	3.71
S6: 1GW Flex - Hourly	-1.3	0.93	1.89	0.82	0.15	0.37	1.52
S7: 5GW Base - Hourly	-2.61	0.93	6.18	0.69	0	1.68	4.51
S8: 5GW Flex - Hourly	-1.24	0.92	1.87	0.82	0.15	0.32	1.55

S3.3 RPS scenarios

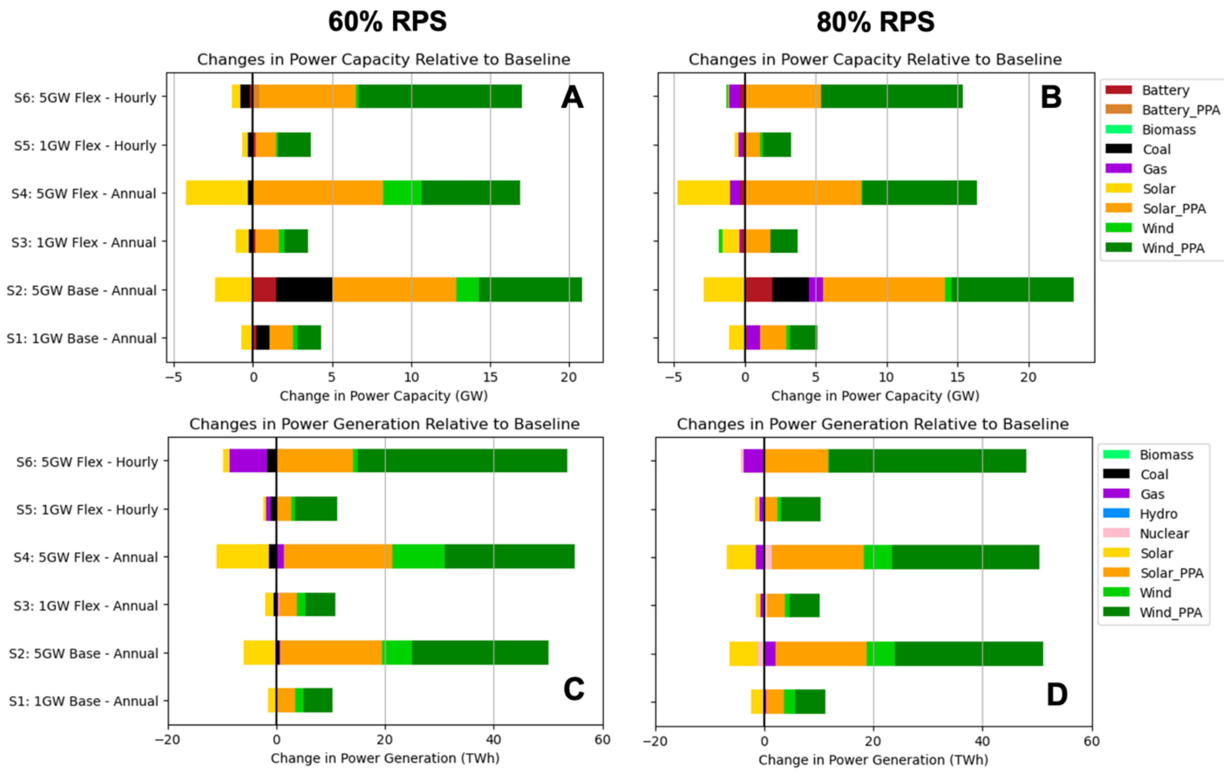

Figure S12. Change in power generation and storage capacity (top row, A-B) and annual power generation (bottom row, C-D) resulting from electrolytic H_2 production under alternative H_2 demand scenarios, time-matching requirements, and electrolyzer operation modes under a 60% RPS (1st column) and an 80% RPS (2nd column). Results correspond to the ERCOT case study under "compete" additionality framework and are reported relative to the baseline grid scenario involving grid resource expansion with the relevant RPS and without any H_2 demand. Resources with suffix "_PPA" refer to resources added specifically to meet time-matching requirements for H_2 production.

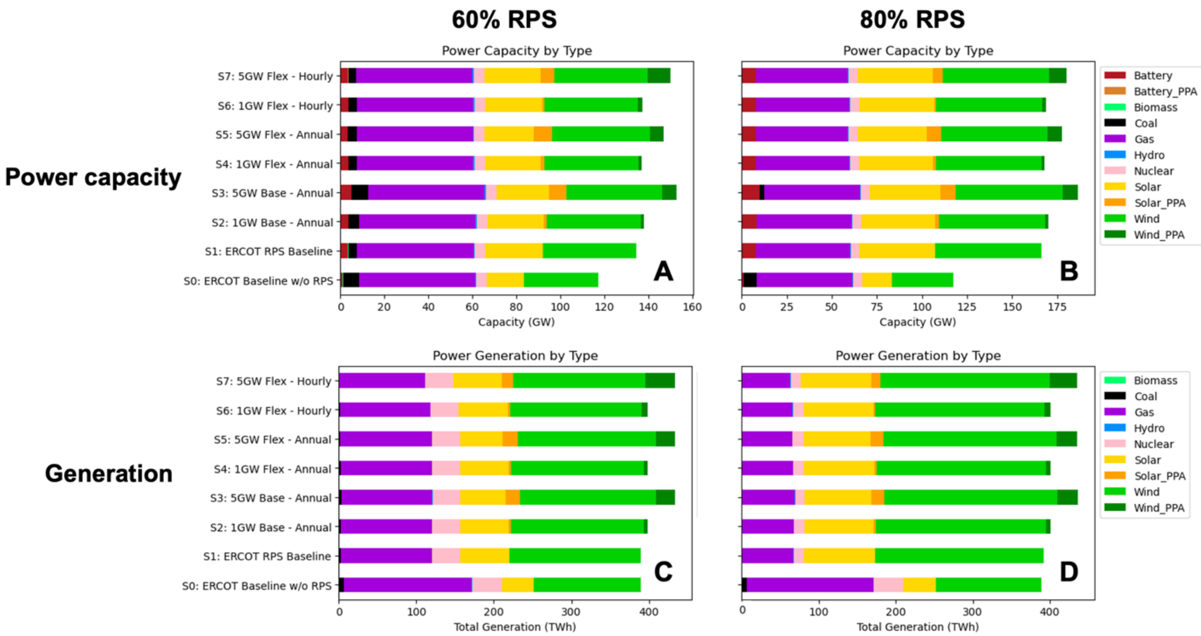

Figure S13. Power generation and storage capacity (top row, A-B) and annual power generation (bottom row, C-D) resulting from electrolytic H_2 production under alternative H_2 demand scenarios, time-matching requirements, electrolyzer operation modes with a 60% RPS (1st column) and 80% RPS (2nd column). Results correspond to the ERCOT case study under the "compete" additionality framework. Also shown are the results for the baseline grid scenario involving grid resource expansion without any H_2 demand, as defined in Figure 1.

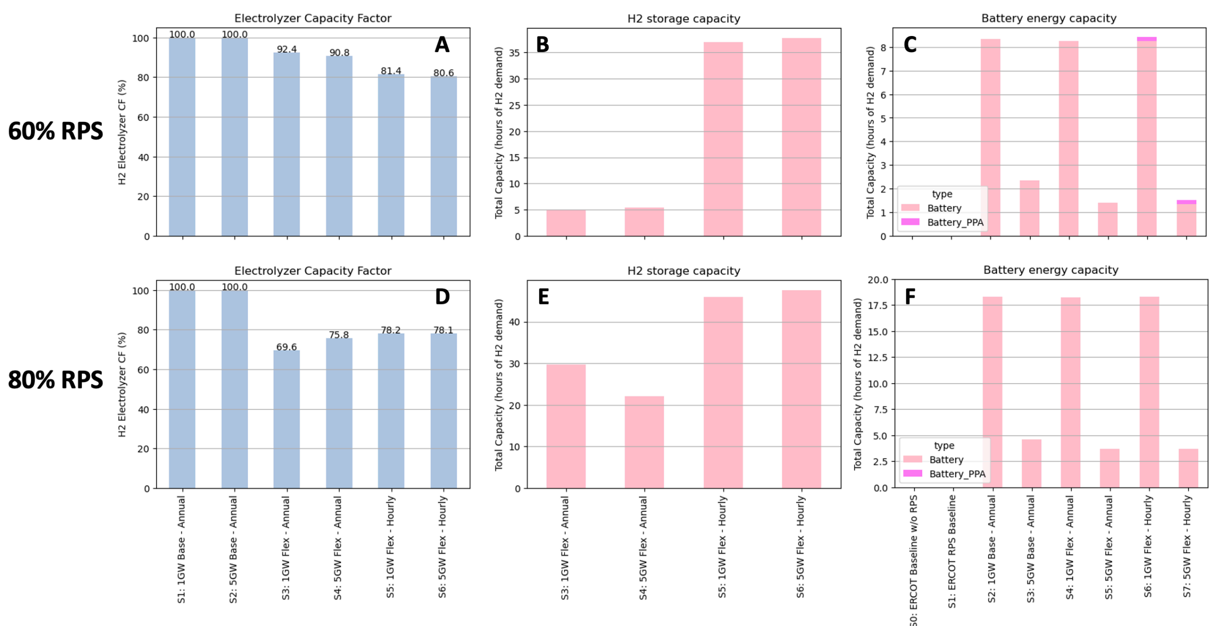

Figure S14. Electrolyzer capacity factor (A, D), H_2 storage capacity (B, E) and battery energy capacity (C, F) for alternative H_2 demand scenarios, time-matching requirements under the "compete" additionality framework with a 60% RPS (top row) or 80% RPS (bottom row). Results correspond to the ERCOT case study under the "compete" additionality framework. H_2 and battery storage capacity are reported in terms of hours of exogeneous H_2 demand that can be met with the available storage capacity when full. Electrolyzer capacity factor is calculated based on available capacity in each hour, which is 95% of the installed capacity.

S3.4 Competition with NG-based H_2 production scenarios

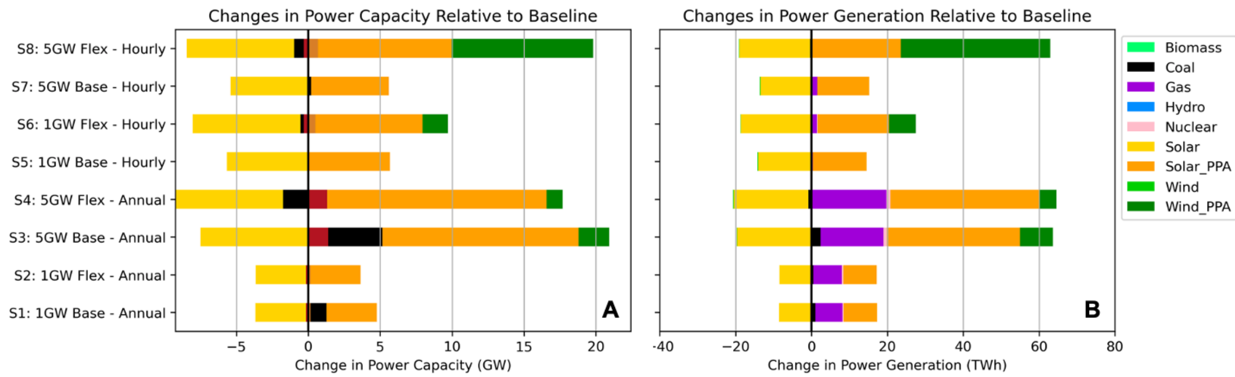

Figure S15. Change in power generation and storage capacity (A) and annual power generation (B) resulting from electrolytic H_2 production under alternative H_2 demand scenarios, time-matching requirements, and electrolyzer operation modes under scenarios where NG-based H_2 production can compete with electrolysis for serving the H_2 demand. Results correspond to the ERCOT case study under the "compete" additionality framework and are reported relative to the baseline grid scenario involving grid resource expansion without any H_2 demand, as defined in Figure 1.

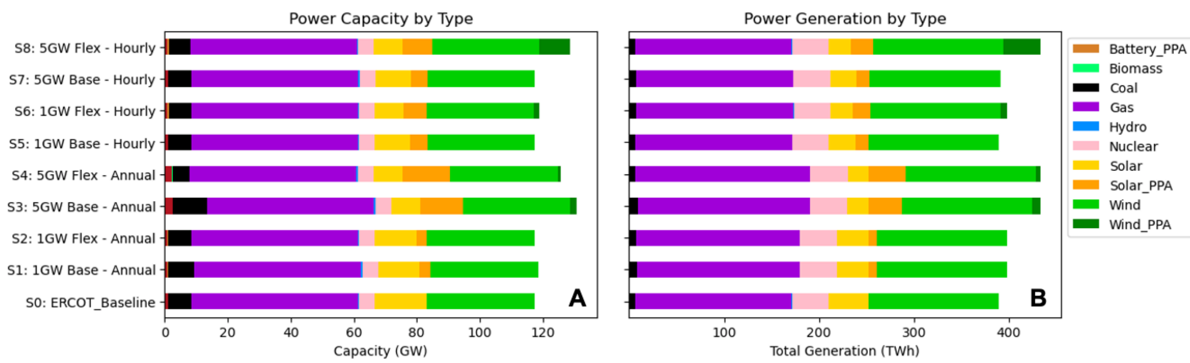

Figure S16. Power generation and storage capacity (A) and annual power generation (B) resulting from electrolytic H_2 production under alternative H_2 demand scenarios, time-matching requirements, and electrolyzer operation modes under scenarios where NG-based H_2 production can compete with electrolysis. Results correspond to the ERCOT case study under the "compete" additionality framework. Also shown are the results for the baseline grid scenario involving grid resource expansion without any H_2 demand, as defined in Figure 1.

S3.5 Limit on VRE deployment capacity scenarios

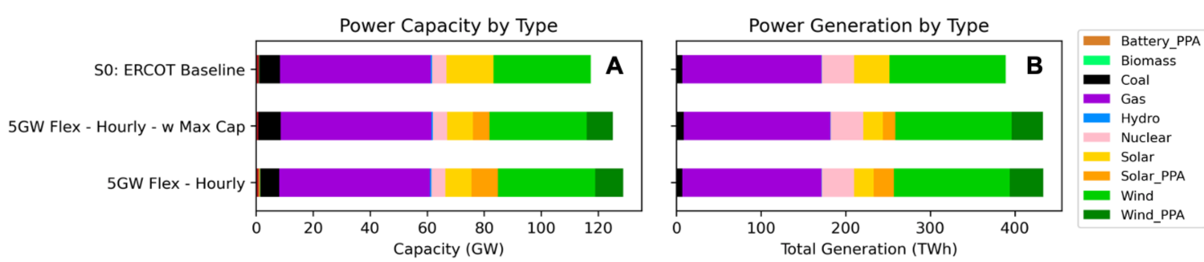

Figure S17. Power generation and storage capacity (A) and annual power generation (B) resulting from electrolytic H_2 production in scenarios with and without a cap of 15GW on VRE deployment capacity with 5GW of electrolyzer demand, hourly time matching, and flexible electrolyzer operation under the "compete" additionality framework. Results correspond to the ERCOT case study. Also shown are the results for the baseline grid scenario involving grid resource expansion without any H_2 demand, as defined in Figure 1.

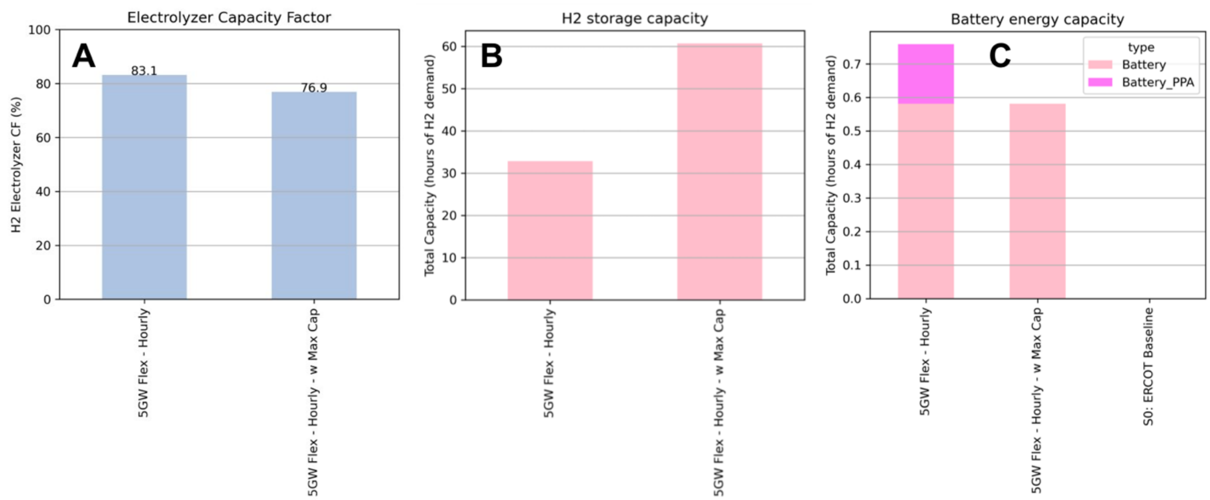

Figure S18. Electrolyzer capacity factor (A), H_2 storage capacity (B), and battery energy capacity (C) for scenarios with and without a cap of 15GW on VRE deployment capacity with 5GW of electrolyzer demand, hourly time-matching, and flexible electrolyzer operation under the "compete" additionality framework. Results correspond to the ERCOT case study. H_2 and battery storage capacity reported in terms of hours of exogeneous H_2 demand that can be met with the available storage capacity when full. Electrolyzer capacity factor calculated based on available capacity in each hour, which is 95% of the installed capacity.

S4 Additional results for FRCC

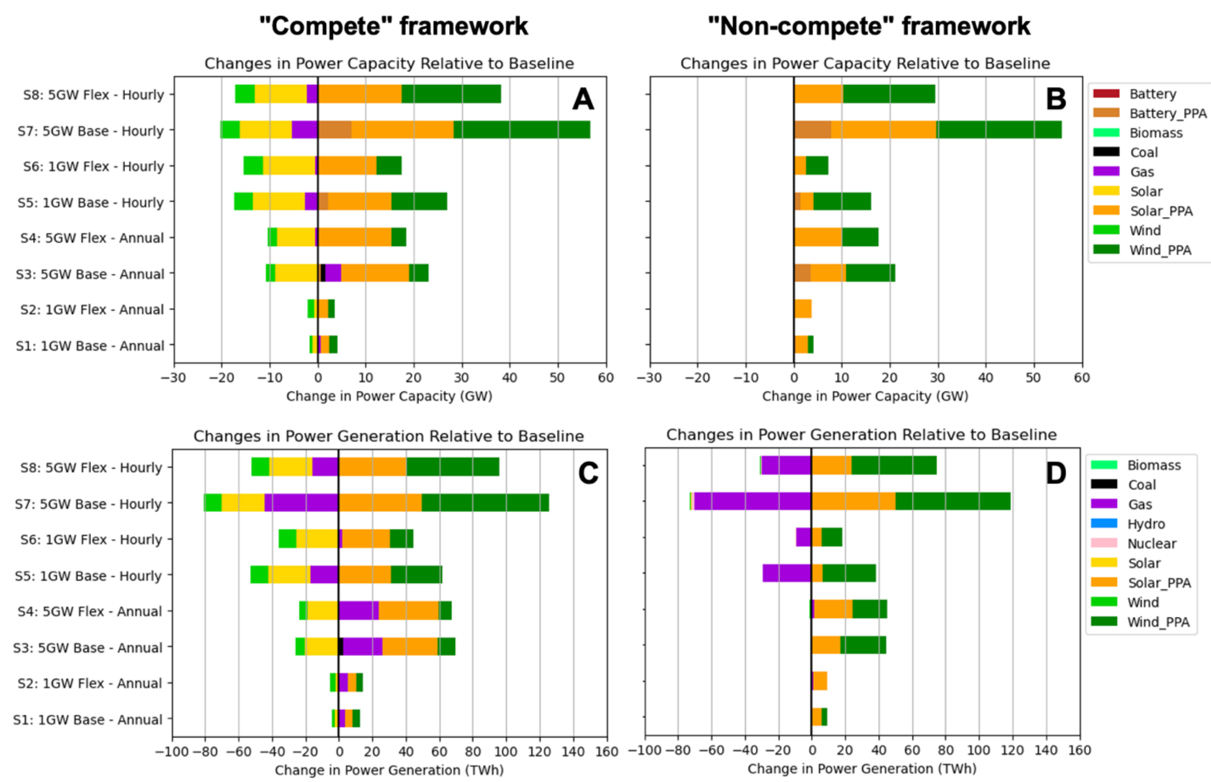

Figure S19. Change in power generation and storage capacity (top row, A-B) and annual power generation (bottom row, C-D) resulting from electrolytic H_2 production under alternative H_2 demand scenarios, time-matching requirements, and additionality definitions. Results correspond to FRCC case study and are reported relative to the baseline grid scenario involving grid resource expansion without any H_2 demand, as defined in Figure 1.

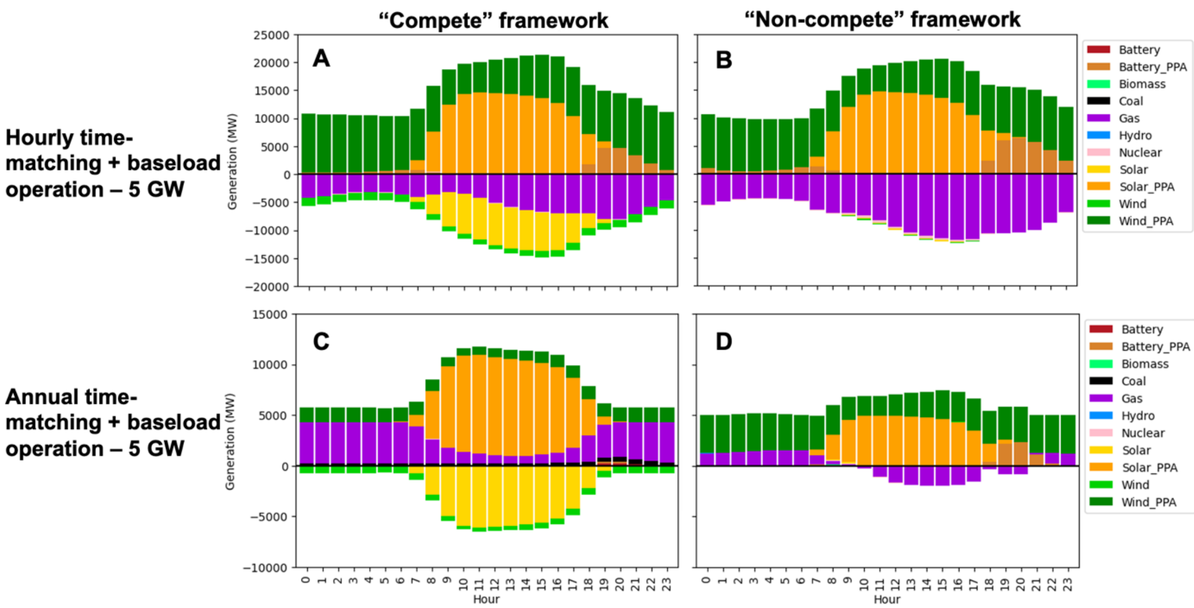

Figure S20 Average hourly change in dispatch in FRCC between cases with H_2 production vs. baseline grid for the following scenarios under the "compete" (1st column) and "non-compete" definitions (2nd column) of additionality and annual (top row) and hourly time-matching requirements (bottom row): A and B: 5 GW of H_2 production with baseload electrolyzer operation and annual time-matching requirements. C and D: 5 GW of H_2 production with baseload electrolyzer operation and hourly time-matching requirements.

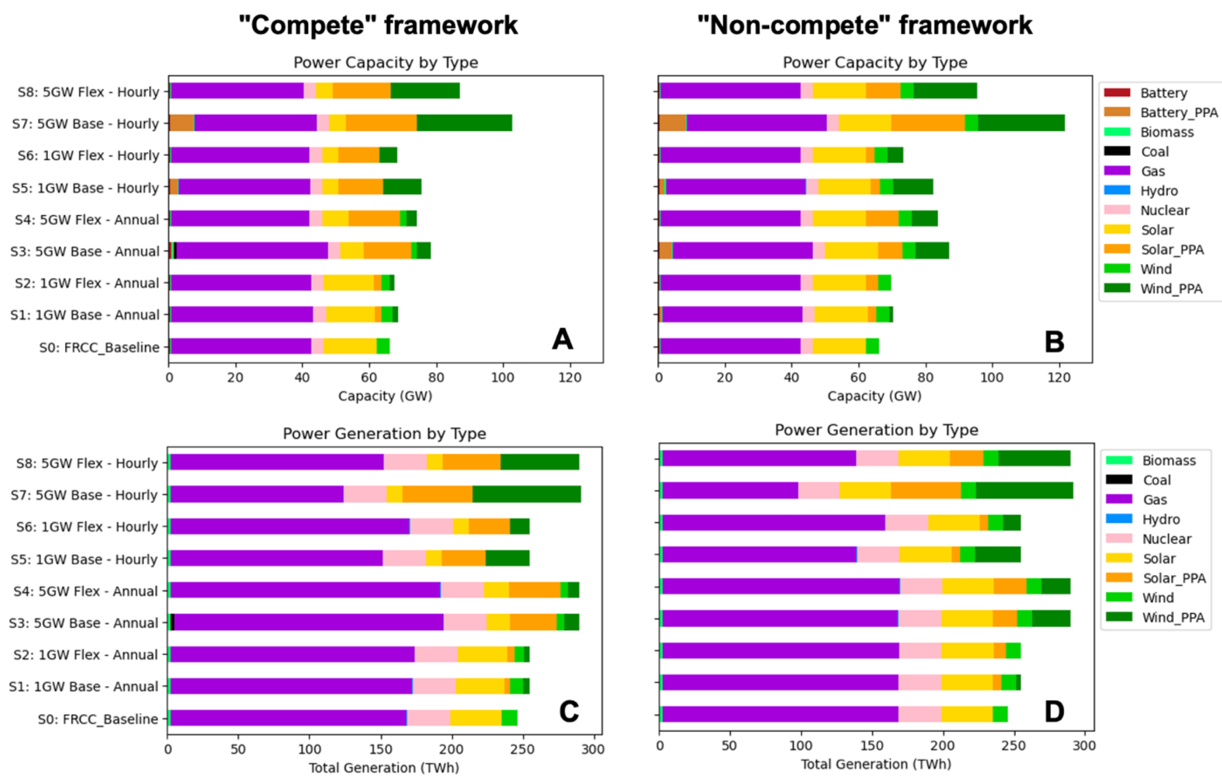

Figure S21. Power generation and storage capacity (top row, A-B) and annual power generation (bottom row, C-D) resulting from electrolytic H_2 production under alternative H_2 demand scenarios, time-matching requirements, and additionality definitions. Results correspond to FRCC case study. Also shown are the results for the baseline scenario involving grid resource expansion without any H_2 demand, as defined in Figure 1.

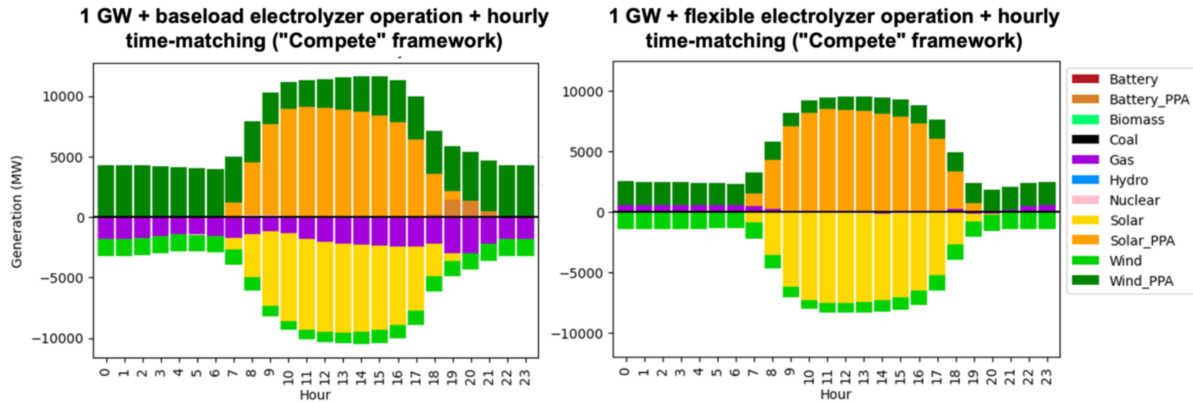

Figure S22. Average hourly change in power system dispatch between cases with H_2 production vs. baseline in FRCC for the scenarios with 1 GW H_2 demand and hourly time-matching requirements, "compete" additionality framework and baseload electrolyzer operation (1st column) or flexible electrolyzer operation (2nd column).

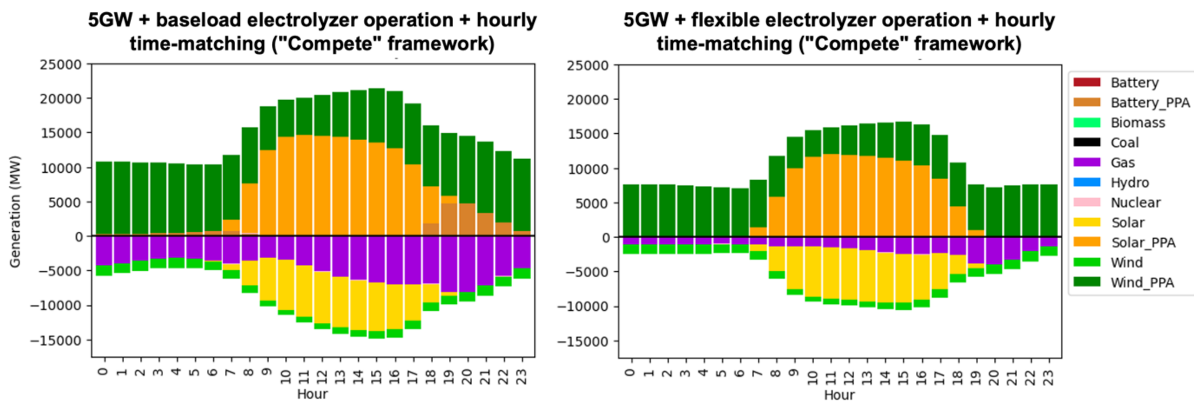

Figure S23. Average hourly change in power system dispatch between cases with H_2 production vs. baseline in FRCC for the scenarios with 5 GW H_2 demand, annual time-matching requirements, "compete" additionality framework and baseload electrolyzer operation (1st column) or flexible electrolyzer operation (2nd column).

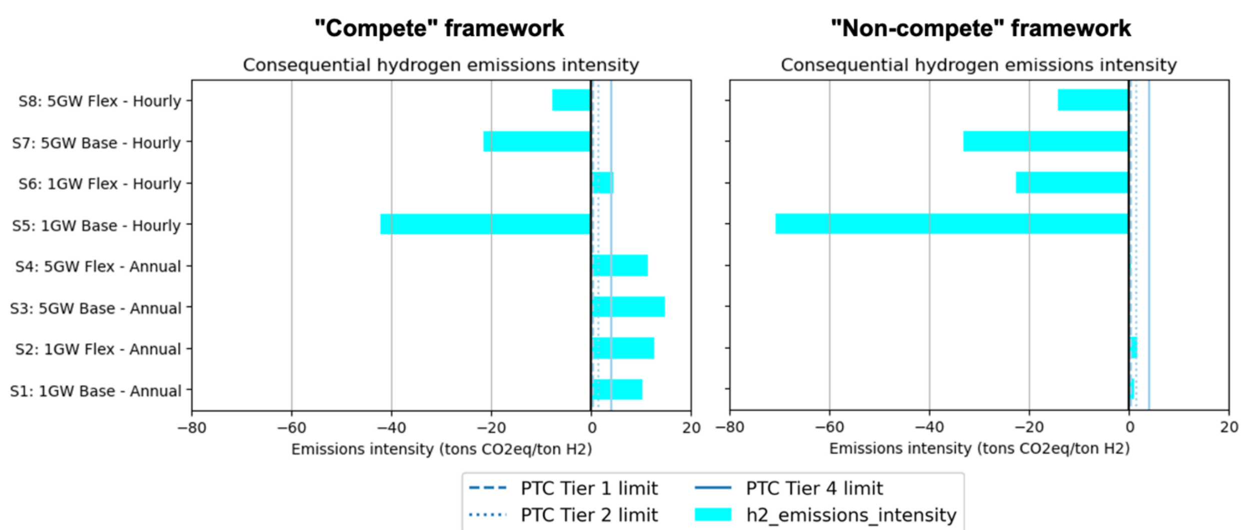

Figure S24. Consequential emissions intensity of H_2 production for alternative exogeneous H_2 demand levels, electrolyzer operation modes, and time-matching requirement under the "compete" and "non-compete" frameworks of additionality described earlier and highlighted in Figure 1. Results correspond to the FRCC case study and are reported relative to the baseline grid scenario involving grid resource expansion without any H_2 demand, as defined in Figure 1. Also shown are threshold emissions *intensity values for H_2 PTC in the IRA, with the production meeting the Tier 1 limit eligible for up to \$3/kg PTC while those meeting Tier 2 and Tier 4 limits are eligible for PTC in the amount of \$1.0/kg and \$0.6/kg, respectively.*

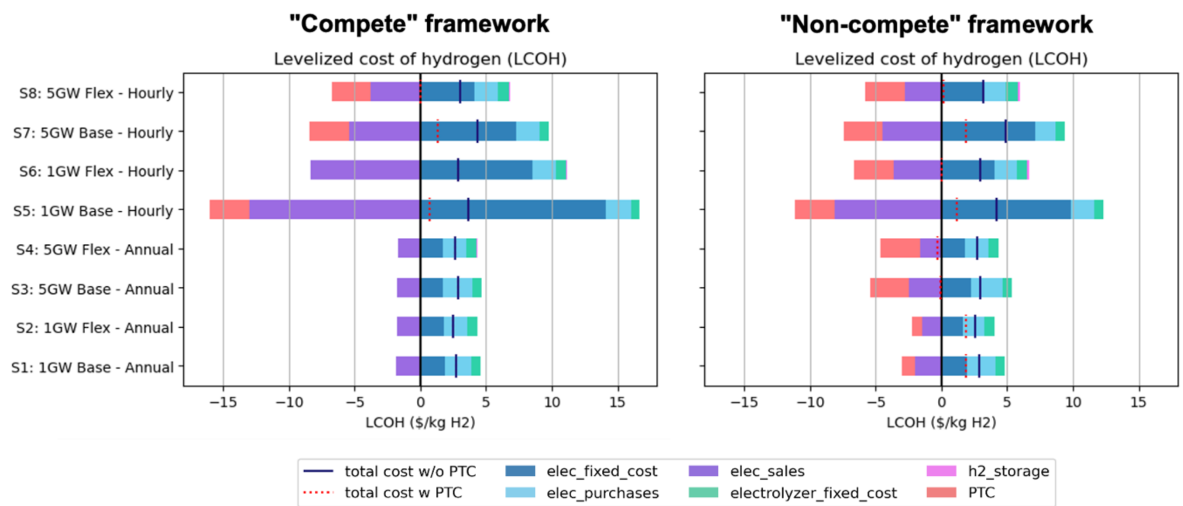

Figure S25. Levelized cost of H_2 for the FRCC case study under scenario with different H_2 demand (1, 5 GW equivalent power consumption), time-matching requirements (annual vs. hourly), additionality frameworks ("compete" vs "non-compete") and electrolyzer operation modes (Baseload vs. flexible). Levelized cost calculated per description provided in Section 6.5. 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 electrolyzer; electrolyzer_fixed_cost = annualized capital and fixed operating and maintenance (FOM) cost of the electrolyzer; elec_fixed_cost = annualized capital and FOM cost of contracted power sector resources, after accounting for investment tax credit (30%); h_2_storage= capital and FOM cost of gaseous H_2 storage system, which includes the capital cost of the compressor and tank. The total cost with PTC (total cost w PTC) shows the LCOH after accounting for PTC based on consequential emissions for each case.

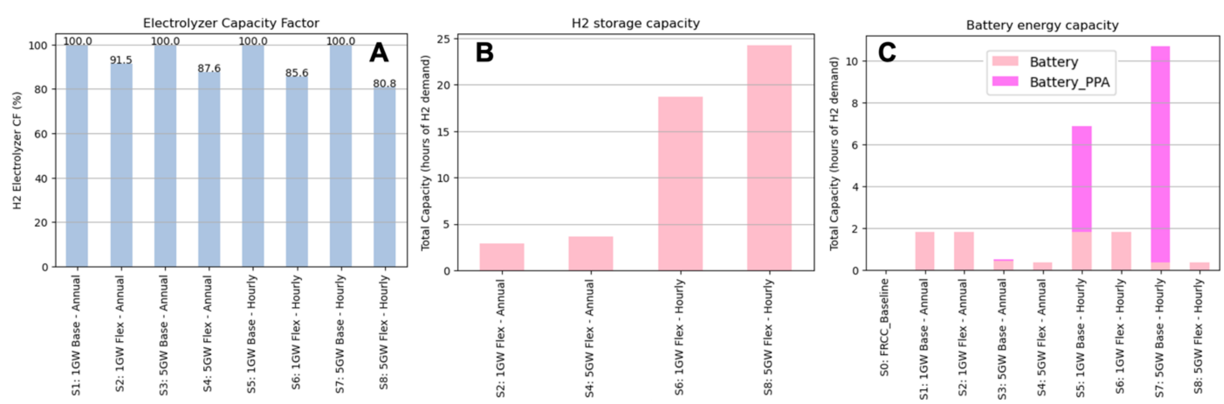

Figure S26. Electrolyzer capacity factor (A), H_2 storage capacity (B) and battery energy capacity (C) for alternative H_2 demand scenarios, time-matching requirements under the "compete" additionality framework. Results correspond to FRCC case study. H_2 and battery storage capacity reported in terms of hours of exogeneous H_2 demand that can be met with the available storage capacity when full. Electrolyzer capacity factor calculated based on available capacity in each hour, which is 95% of the installed capacity.

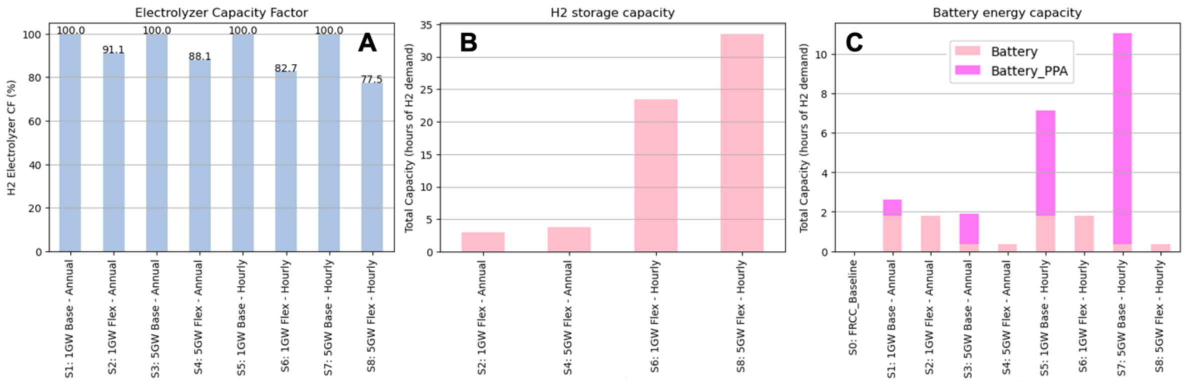

Figure S27. Electrolyzer capacity factor (A), H_2 storage capacity (B) and battery energy capacity (C) for alternative H_2 demand scenarios, time-matching requirements under the "non-compete" additionality framework. Results correspond to FRCC case study. H_2 and battery storage capacity reported in terms of hours of exogeneous H_2 demand that can be met with the available storage capacity when full. Electrolyzer capacity factor calculated based on available capacity in each hour, which is 95% of the installed capacity.