Temporal regulation of renewable supply for electrolytic hydrogen

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Abstract

Electrolytic hydrogen produced using renewable electricity can help lower carbon dioxide emissions in sectors where feedstocks, reducing agents, dense fuels or high temperatures are required. This study investigates the implications of various standards being proposed to certify that the grid electricity used is renewable. The standards vary in how strictly they match the renewable generation to the electrolyser demand in time and space. Using an energy system model, we compare electricity procurement strategies to meet a constant hydrogen demand for selected European countries in 2025 and 2030. We compare cases where no additional renewable generators are procured with cases where the electrolyser demand is matched to additional supply from local renewable generators on an annual, monthly or hourly basis. We show that local additionality is required to guarantee low emissions. For the annually and monthly matched case, we demonstrate that baseload operation of the electrolysis leads to using fossil-fuelled generation from the grid for some hours, resulting in higher emissions than the case without hydrogen demand. In the hourly matched case, hydrogen production does not increase system-level emissions, but baseload operation results in high costs for providing constant supply if only wind, solar and short-term battery storage are available. Flexible operation or buffering hydrogen with storage, either in steel tanks or underground caverns, reduces the cost penalty of hourly versus annual matching to 7–8%. Hydrogen production with monthly matching can reduce system emissions if the electrolysers operate flexibly or the renewable generation share is large. The largest emission reduction is achieved with hourly matching when surplus electricity generation can be sold to the grid. We conclude that flexible operation of the electrolysis should be supported to guarantee low emissions and low hydrogen production costs.

Keywords: decarbonisation, electrolysis, green hydrogen, power purchase agreement, regulation

1. Introduction

Governments worldwide are seeking to scale up the production of green hydrogen to reduce emissions from sectors of the economy where direct electrification is challenging. In its 2022 REPowerEU strategy [1], the European Commission raised its target for domestic renewable hydrogen production in 2030 to 10 million tonnes per year, with an additional 10 million tonnes per year to be imported. India announced a target in 2022 to produce 5 million tonnes of hydrogen per year by 2030 [2]. The 2022 Inflation Reduction Act in the United States established a production tax credit (PTC) of up to 3 $\$/\mathrm{kg}_{\mathrm{H}_2}$ for clean hydrogen. in July 2023, the German government published its update of the national hydrogen strategy [3], which aims to produce 28–53 $\mathrm{TWh}_{\mathrm{H}_2}$ green hydrogen per year in Germany and import further 45–90 $\mathrm{TWh}_{\mathrm{H}_2}$ per year.

To qualify hydrogen for subsidies, to meet quota requirements and to maintain consumer confidence, a transparent system is required to certify that hydrogen is 'green', i.e. produced from renewable electricity. Several definitions for green hydrogen have been suggested. The strictest would be to require that only electricity from newly-built renewable generators directly connected to the electrolyser can be used to produce hydrogen. While this definition is unambiguous, it forces hydrogen production to be located at the site of generation, which may be far from hydrogen demand, and it prevents flexible operation of the assets from adapting to electricity market prices. The definition of green hydrogen could be relaxed in three ways: through (i) relaxing additionality, i.e. allowing generation from existing sources; by (ii) easing location requirements, permitting spatial separation within the same region, electricity market bidding zone, or continent; and by allowing (iii) relaxing temporal matching requirement, i.e., allowing for renewable generation and electricity demand for hydrogen production to match on sub-hourly, monthly or an annual basis.

While requiring additionality and locational matching within the same bidding zone are less controversial, there has been discussion about the need to require temporal matching. Hourly matching ensures that electricity is from renewable sources but can be technically hard to enforce and costly when renewable sources are scarce. In contrast, annual matching is technically easier. However, it implies that electrolysis operator relies on the local market electricity mix at times with low renewable feed-in, which may contain some share of the fossil-fuelled electricity. This can result in higher emissions for electrolytic hydrogen compared to alternatives like 'blue' hydrogen.

In February 2023, the European Commission published a regulation for green hydrogen production in the *Delegated Act for the regulation on Union methodology for renewable fuels of non-biological origin* (DA) [4]. These rules mandate geographical correlation and additionality, with hourly matching phased in by 2030 and monthly matching in the transition phase. While the industry appreciates the clarity this regulation provides, manufacturers warn that the strict rules may hinder the rapid scaling of hydrogen infrastructure [5] and indicate that continuous supply needs and the lack of hydrogen storage in most industrial sectors [6] could lead to high costs with hourly matching. While the rules for green hydrogen production in the EU have been decided, there is an ongoing debate in the US and other jurisdictions about the right regulatory approach.

Several papers have considered temporal regulation in the literature. Ricks et al. [7] examined procurement strategies in the US, assuming different offtake prices incentivised by the PTC introduced in the 2022 Inflation Reduction Act [8]. They find that hourly matching adds minimal costs while lowering emissions unless competing for limited high-quality renewable resources. In Brauer et al. [9], various additionality, location and temporal requirements were studied assuming a constant hydrogen demand in Germany for the year 2030. Similar to the US study [7], the authors found that hourly matching has a small cost premium but lowers emissions, both from the perspective of emissions attributed to the electricity consumption and from the impact on system emissions of the hydrogen production. The study by Brauer et al. [9], however, relied on low-cost hydrogen storage from liquid organic hydrogen carriers (LOHC) and did not examine the effect of different electrolysis operation modes or different background grid systems, which can substantially impact the results. Ruhnau et al. [10] also considered hourly versus annual matching for a baseload hydrogen demand in Germany but focused on the impact on the existing power system using historical marginal emission factors. They found significantly higher hourly matching costs, which is likely because only hydrogen storage in steel tanks was modelled. In their study, annual matching slightly reduced system emissions because of the freedom to have renewables feed in when prices and emissions are high. Due to the reliance on historical marginal data, the authors were unable to evaluate the effect of a larger hydrogen volume or future cost developments.

This study adds to the literature by considering a much wider range of background systems (different countries, points in time and cost assumptions) and varying the available hydrogen storage technologies to understand fully how temporal regulation affects emissions. We contrast the case of running an electrolyser of a given capacity using grid electricity only (i.e. no additional procurement of renewable resources) versus additional procurement of wind, utility-scale solar and batteries whose supply is matched on either an annual, monthly or hourly basis. We assume that the hydrogen demand is constant following the requirement of European industry [6] but examine several options for hydrogen storage to buffer the hydrogen production, including scenarios with no storage, (rather expensive) steel tanks, (relatively low-cost) underground cavern storage and zero-cost storage. The case of zero-cost storage is equivalent to having a time-flexible hydrogen demand. The German system in 2025 is taken as a base scenario. In a sensitivity analysis, we explore a case of a less clean grid than our benchmark scenario (the Netherlands in 2025, renewable generation share of 49%) and a case of a cleaner grid (Germany in 2030, renewable generation share of 80%). The Appendix provides further examples for Poland, the Czech Republic, Portugal and Spain (see Section 4.8.1).

2. Methods

2.1. Model structure

This study uses the European power system model PyPSA-Eur [11]. Total annualised system costs in a given year are minimised by optimising power generation and storage capacities under relevant engineering (such as linearised unit commitment following the formulation of Bowen et al. [12]) and policy constraints (such as National energy and climate plans (NECPs)).

The geographical scope of the model is set to Germany or Netherlands and its neighbouring countries. We model the ENTSO-E 220 kV and 380 kV transmission infrastructure clustered to the individual bidding zones [13]. We focus on the medium-term planning horizon, modelling two individual years, 2025 or 2030, with an hourly resolution. The years differ in technology cost assumptions, the existing fleet of legacy power plants, CO_2 prices and NECP additions.

The modelling is performed in two optimisation steps. In the first step, the capacities and dispatch of power plants and storage facilities in the power sector are optimised without any hydrogen production. In the second step, the optimised capacities of step one are exogenously fixed, and the hydrogen demand and production site are added. The optimisation is rerun, allowing capacity expansion of wind, utility-scale solar and battery storage at

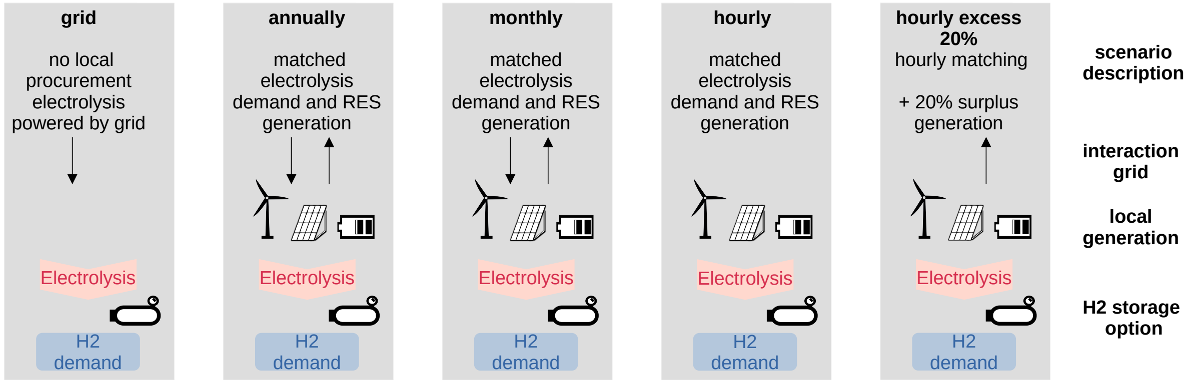

Figure 1: Five different regulatory scenarios are modelled. A (i) grid scenario without any additional renewable generation requirement in which electrolysis is powered by the grid as well as scenarios in which additional renewable energy sources (RES) have to match the electrolysis consumption on an (ii) annual, (iii) monthly or hourly basis (iv) without and (v) with allowed excess generation of 20%.

the hydrogen production site only, and any hydrogen storage allowed in the scenario. Since Cybulsky et al. [14] find a significant impact on emissions of different temporal matching regulations depending on how additionality is modelled, we conduct a co-optimisation of the electricity background system and the hydrogen production as well, which is discussed in the Appendix (see Section 4.7).

2.2. Scenarios

We analyse five regulatory scenarios of hydrogen production (see Figure 1):

(i) On-grid production (**grid**), where the electrolysis is powered by grid electricity without any additional procurement.

(ii) Additional renewable capacities in the local bidding zone, whose generation has to match the electrolysis consumption annually (**annually**). Grid electricity purchases and sales are allowed if this constraint is fulfilled.

(iii) Additional renewable capacities in the local bidding zone, whose generation must match the monthly electrolysis consumption (**monthly**). Grid electricity purchases and sales are allowed if this constraint is fulfilled.

(iv) Additional renewable capacities in the local bidding zone, whose generation has to match the electrolysis consumption hourly (**hourly**).

(v) Additional renewable capacities in the local bidding zone, whose generation has to match the electrolysis consumption hourly, while excess generation of 20% of yearly electrolysis demand can be sold to the grid (**hourly excess 20%**). An advantage of surplus generation is that it provides a hedge against inter-annual variability in renewable feed-in. For example, in a year with low winds, the renewable production would be sufficient to cover the electrolysis demand. In other years, the surplus electricity can be sold.

An additional reference scenario without hydrogen production and associated electricity demand is also computed, and its results are used as a benchmark for our analysis. In order to account for the electricity trade, we model all neighbouring countries in addition to the selected one. In all the modelled countries, renewable generation must meet the political targets as defined in the NECPs or by more recent national policy targets (such as the Easter package in Germany), see Table 1.

In all scenarios, we assume a fixed hydrogen demand of 28 $\mathrm{TWh}_{\mathrm{H_2}}$/a (0.84 million tonnes produced hydrogen per year) in the selected country. This demand corresponds to the minimum target of domestic green hydrogen production targets for 2030 ranging from 28–53 $\mathrm{TWh}_{\mathrm{H_2}}$ in Germany. The demand for hydrogen is continuous throughout the year, following the needs of European industry [6]. In a sensitivity analysis, we examine the effects of a higher hydrogen production of 53 $\mathrm{TWh}_{\mathrm{H_2}}$. The same demand is used in the Netherlands to allow results to be compared. The price of carbon dioxide emission certificates is set to 80 €/$\mathrm{t}_{\mathrm{CO_2}}$in 2025 and 130 €/$\mathrm{t}_{\mathrm{CO_2}}$in 2030.

We implement five variations of hydrogen storage for each policy scenario to represent different degrees of flexibility for hydrogen:

(a) zero-cost storage (**flexibledemand**), corresponding to a time-flexible hydrogen demand.

(b) storage in underground salt caverns (**underground**), low-cost storage, could be accessible via hydrogen pipeline network,

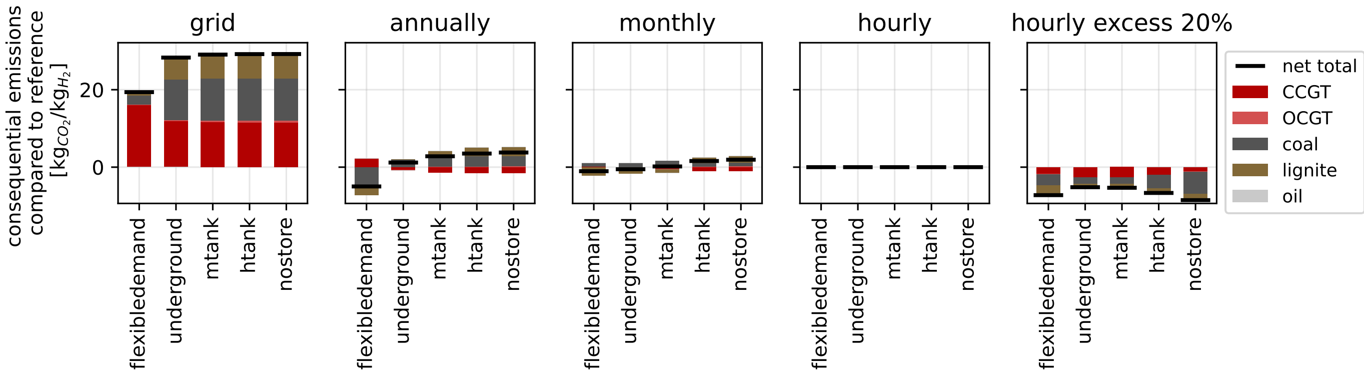

Figure 2: Consequential emissions of hydrogen production in Germany 2025, calculated as the difference in total system emissions per produced kg_{H_2} compared to a reference scenario without any hydrogen production.

(c) storage in medium pressure steel tanks (**mtank**), medium-cost storage,

(d) storage in high pressure steel tanks (**htank**), relatively expensive storage,

(e) no storage (**nostore**), inflexible hydrogen demand.

3. Results

In the following, we address two aspects of hydrogen production for the different regulatory scenarios. We first highlight the system impacts by analysing the carbon dioxide emissions from hydrogen production for each scenario based on the consequential emissions (Section 3.1). Second, we look at the costs (Section 3.2) of hydrogen production. In a further analysis, we consider the impact of the degree of decarbonisation of the background system (Section 3.3).

3.1. Consequential emissions

Consequence emissions reflect the total system emissions associated with hydrogen production. They are calculated as the difference between total system emissions and the reference scenario without hydrogen production.

The results show that additionality is required to prevent increased emissions. Consequential emissions are up to nearly three times the CO_2 intensity of grey hydrogen produced via steam methane reforming (10 kg_{CO_2}/kg_{H_2}) in the grid scenario. They are greatly reduced in annual, monthly and hourly matching scenarios due to additional procurement. Emissions decrease through annual and monthly matching in case of flexible demand and through hourly matching in all scenarios where surplus generation sales are permitted (see Figure 2).

Producers can buffer low renewable feed-ins and optimise electrolysis operation by shifting the production to times of low electricity prices due to affordable hydrogen storage or elastic demand. With inflexible demand, electrolysis operates continuously at full capacity (see Figure 5 in Appendix). In this case, without the additionality requirement, up to 29 kg_{CO_2} are emitted per produced kg_{H_2}. The emissions are particularly high because the electricity system cannot adapt to the new hydrogen demand according to the study design.

The effects of annual and monthly matching on emissions are nuanced. Annual and monthly matching increases demand in some hours when the electrolyser is running and RES are scarce, while it decreases demand for conventional generation in hours with plentiful RES. If the increase in demand is met with coal while gas is displaced at other times, emissions increase. On the other hand, if the increase is met by nuclear and otherwise curtailed renewable generation while coal is displaced, emissions sink. The precise impact depends on the background system mix and the electrolyser operation mode.

With inflexible hydrogen demand and continuous full-load electrolysis operation, annual matching can yield emissions up to 4 kg_{CO_2}/kg_{H_2}. In absolute numbers, this leads to an increase in emissions from the German power sector of 3.2 million tonnes of CO_2, corresponding to about 1.5% of power sector emissions in Germany in 2021. Compared with annual matching, monthly matching results in lower CO_2 emissions, up to 2 kg_{CO_2}/kg_{H_2}if hydrogen storage is expensive; this yields 1.6 million tonnes of additional carbon dioxide emissions in the absolute terms. However, if cheaper storage is available, emissions decrease, enabling annual and monthly matching to reduce total system emissions by -5 $kg_{CO_2}/kg_{H_2}$and -2 kg_{CO_2}/kg_{H_2}, respectively, with flexible demand (see left columns on annual and monthly panels in Figure 2). This is because having flexible electrolyser demand and variable generation, only constrained by the annual matching, provides

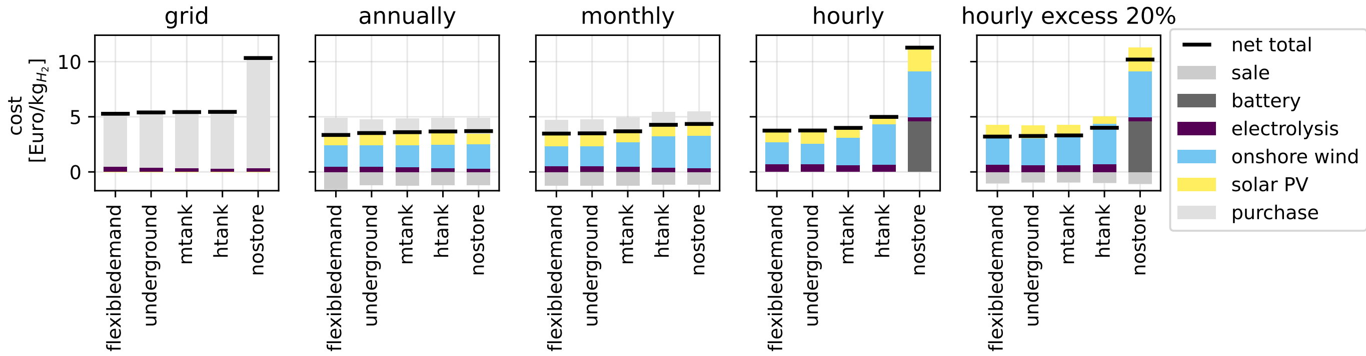

Figure 3: Cost of hydrogen production in Germany 2025.

many degrees of freedom. Capacity factors range with flexible demand between 62–68% for monthly and annual matching.

Electrolysers can use both procured and excess renewable electricity from the grid. The procured renewable energy can also be fed into the grid when electricity prices and emission intensities are high. Costly storage scenarios limit these flexibilities. In these cases, mean capacity factors of the electrolysis increase to at least 79%. The constant demand for electrolysis is met by additional fossil generation, which increases emissions.

In hourly matching scenarios without surplus electricity sales, total emissions remain unaffected by the additional electricity demand for hydrogen production because renewable generation meets the electrolysis demand every hour. Electrolysis capacity factors range between 45–52% if any hydrogen storage is available. The most substantial reduction in total system emissions of up to -9 kg_{CO_2}/kg_{H_2}occurs in hourly matching scenarios with a possible sale of surplus generation. This corresponds to a total reduction in system emissions of 7.2 million tonnes CO_2. In this case, the additional renewable generation sold to the grid reduces the operation of coal-fired plants and decreases system emissions. Unlike annual matching, hourly matching with allowed excess sales consistently reduces emissions in every hydrogen storage scenario.

3.2. Hydrogen production costs

The costs for the production of hydrogen are lowest independently of the storage options in the case of annual matching followed by monthly matching, with costs ranging between 3.35-3.70 €/kg_{H_2} and 3.48-4.35 €/kg_{H_2} respectively (see Figure 3). They are below the costs of the grid scenario because additional renewable capacity is built, which lowers the electricity prices. The costs for hourly matching compared to monthly matching are only 7–8% higher if demand is flexible or low-cost storage in the form of salt caverns is available. In the case of inflexible demand, hydrogen production costs with hourly matching are 11.27 €/kg_{H_2} and, therefore, 2.6 times higher than the production costs with monthly matching. These high costs result from transforming variable renewable electricity generation profiles into constant electrolyser output. This transformation is partly provided by battery storage (41% of production costs) and partly by overbuilding renewable capacities, which are then partially curtailed (see Figure 12 in Appendix). This underscores the importance of supporting low-cost storage or demand flexibility when implementing hourly matching regulations to prevent elevated production costs.

The cost of hourly matching with allowed excess is 3.20 €/kg_{H_2}, which is 4-8% below the cost of annual or monthly matching in the case of flexible demand. This is caused by the additional profit that can be made by selling electricity in hours of high feed-in of renewable generation.

3.3. Degree of decarbonisation of the power system

Hydrogen production emissions and costs are influenced by how countries generate electricity. To investigate the impact of power generation mix on our results, we set up an example of a dirtier grid, i.e., a grid with a higher share of fossil fuels (Netherlands 2025) and an example of a cleaner grid (Germany 2030 with coal power plants being phased out) compared to our Germany 2025 scenario. The country-specific shares of renewable generation are applied for the respective years (see Table 1 in the Appendix). An overview of the shares of the individual technologies in electricity generation for the respective year and country of the reference scenario is in the Appendix (see Figure 23). Hydrogen demand is assumed constant at 28 TWh_{H_2}/a to keep the results comparable.

Progress in the decarbonisation of the power sector significantly impacts hydrogen production emissions for the grid, annual and monthly scenarios. Since hourly matching has zero or negative emissions in the case of allowed excess,

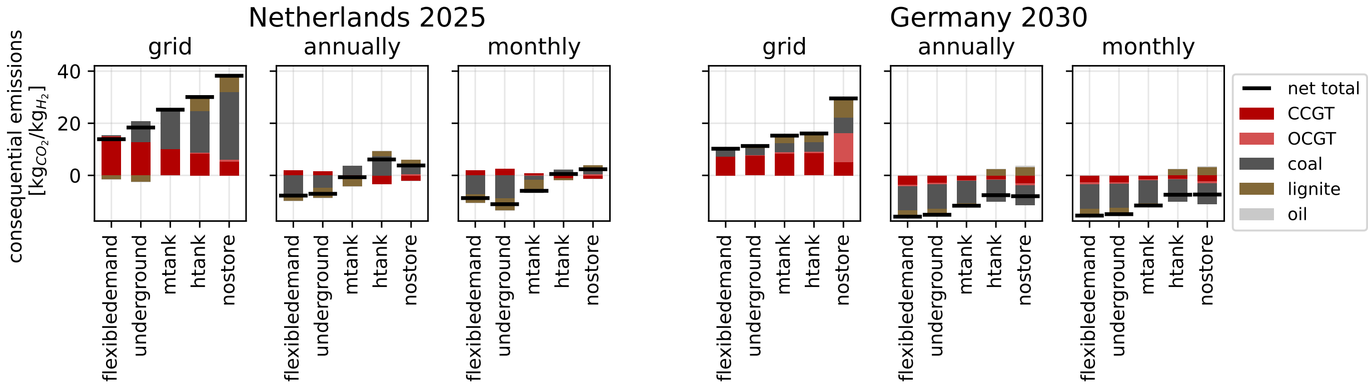

Figure 4: Consequential emissions for two selected cases representing a less clean system, Netherlands 2025 (*left*), and a cleaner system, Germany 2030 (*right*), than the reference case of Germany 2025.

we discuss only grid, annual, and monthly matching scenarios below. Suppose the renewable share in the overall electricity mix is lower, as in the case of the Netherlands in 2025, with a share of 49%. In that case, the consequential emissions of hydrogen production in the grid scenario can increase to 38 kg_{CO_2}/kg_{H_2} (see Figure 4), nearly more than four times the carbon intensity of grey hydrogen production (10 kg_{CO_2}/kg_{H_2}). Annually and monthly matching reduces emissions in scenarios with low-cost storage or flexible demand since local procurement sales reduce the coal power plant generation. In case of costly storage or inflexible demand, emissions increase by up to 6 kg_{CO_2}/kg_{H_2} and 2 kg_{CO_2}/kg_{H_2}, respectively, since electrolysis runs at hours with a higher share of coal generation.

We find that scenarios without additional local procurement increase system emissions even when there is a higher share of renewable generation and coal power plants are phased out, as in our scenarios for Germany 2030. The consequential emissions are negative with annual and monthly matching for every storage type, i.e., hydrogen production further reduces total system emissions. The reduction in emissions results from the fact that the purchased grid electricity has only a small share of fossil energy sources, and the sold electricity contributes more to the decarbonisation of the grid. Coal power plants in Germany are decommissioned, but additional emissions are reduced from coal generation in Poland for annual and monthly matching. A share of 80% renewable is below the set threshold of 90% in the DA [4]. However, our results show that even with inflexible demand, total emissions decrease with annual and monthly matching. Overall, the scenario with a cleaner grid illustrates that strict regulation of temporal matching hydrogen production with renewable electricity plays a minor role with increasing decarbonisation.

3.4. Further analysis

In the Appendix, we discuss the results, the limitations of this study and compare our findings to existing literature more extensive. In addition, we explore a variety of sensitivity scenarios in order to generalize our findings above the specific model assumptions. In particular, we drop the assumption that the background system cannot adapt to the new hydrogen demand, increase the hydrogen demand volume, analyse hydrogen production in four other European countries, alter the volume of excess electricity sales, alter the price of natural gas, and alter the share of renewable electricity in the background systems. All sensitivity analyses show that a flexible operation of the electrolysis reduces consequential emissions and that the generation mix in the background system has a large influence on the emissions of hydrogen production.

4. Conclusion

Many countries have set targets for clean hydrogen production to reduce fossil fuel dependence and decarbonise hard-to-electrify sectors. Regulations are needed to make sure that hydrogen production contributes to decarbonisation and does not increase greenhouse gas emissions.

In this work, we investigated different ways of regulating green hydrogen production. We analysed scenarios where the electrolysis operates directly with grid electricity without additional renewable generation and with additional local procurement. The local procurement matches the demand for electrolysis annually, monthly or hourly.

Our results reveal three low-emission and low-cost options for hydrogen production. Additional local renewable generation is necessary in all three cases to avoid increased emissions from hydrogen production. The first option is hourly matching with flexible demand or low-cost storage, which smooths out the variable feed-in of renewable generation. Flexible demand might be possible for some initial consumers like ammonia producers, who can switch easily between green and grey hydrogen. The second option is annual or monthly matching either with flexible demand such that electrolysis capacity factors are limited to around 70% or an upper limit on the electricity price when the electrolyser is allowed to operate. The third option is annual or monthly matching if the grid already has a high share of renewable generation and coal is phased out. In our scenarios, a share of 80% of renewable generation is sufficient for negative consequential emissions with annual matching. All three options are already provided in some form by the legislation from the European Union [4]. However, the order of implementation of monthly matching (transitional phase) and hourly matching (up to 2027) in the proposed legislation is inconsistent with our results. In order to limit emissions impacts, our results suggest a stricter regime in the short term that relaxes once system targets are met. For example, one could impose hourly matching or upper limits on electrolysis capacity factors until country-wide renewable targets are met and coal is phased out. Alternatively, one could relax the rules in the short term for the scale-up while volumes are small and then impose them in the medium term until targets are reached.

Compared to annual matching, hourly matching offers several benefits. Hourly matching has significantly lower attributional emissions based on the average grid mix when electricity is consumed for electrolysis. Hourly matching is the only case that provides incentives for demand flexibility and storage, which are typically cost-optimal in deep decarbonisation scenarios. If renewable electricity targets are not met, hourly matching provides a valuable hedge by guaranteeing low emissions, even in this case. Policy support mechanisms to boost green hydrogen production should be designed to promote flexible electrolysis operations to avoid increased emissions and system-friendly operation.

The regulation of green hydrogen production is often described as a trade-off between strict rules with higher costs or looser rules with potentially higher emissions. This work shows that regulations with low emissions and a small cost premium are possible.

Credit Author Statement

Elisabeth Zeyen: Methodology, Software, Validation, Formal analysis, Investigation, Data Curation, Writing - Original Draft, Visualization

Iegor Riepin: Conceptualization, Writing- Review & Editing

Tom Brown: Conceptualization, Methodology, Software, Resources, Writing- Review & Editing, Supervision

Conflict of Interest Statement

The authors declare no competing interests.

Data Availability Statement

The modelling workflow and data behind this study are open. The entire project is available in a public repository under MIT license [28]. The repository also contains a summary of output data for all scenarios. The code is available in a Github repository [29].

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Acronyms

CAPEX Capital expenditures

CfD Contract for Difference

DA Delegated Act for the regulation on Union methodology for renewable fuels of non-biological origin

ENTSO-E European network for transmission system operators electricity

ETS Emissions Trading System

EU European Union

FOM Fixed operation and maintenance costs

LOHC Liquid organic hydrogen carriers

NECP National energy climate plan

PPA Power Purchase Agreement

PTC Production Tax Credit

RES Renewable energy sources

VOM Variable operation and maintenance costs

Appendix

The Appendix is structured as follows:

1. We first provide a more detailed description of the model and the underlying assumptions (see Section 4.1.1 for modelling of the temporal matching , Section 4.1.2 for calculation of costs of hydrogen production, Table 1 shows an overview of the renewable targets, technology assumptions are summarised in Table 2, unit commitment parameter in Table 3 and fuel prices in Table 4).
2. We analyse the presented results in further detail (see Section 4.1.4 for a discussion of the results, Section 4.1.5 for a comparison to other literature and Section 4.1.6 for limitation).
3. Additional graphs on our main results in the manuscript are given in Section 4.2. In this section we show
    (a) for scenarios in Germany 2025 with two step optimisation the capacity factors of the electrolysis (Figure 5), electricity prices (Figure 6), attributional emissions (Figure 7), electricity generation mix when the electrolysis is running (see Figure 8), the installed capacities at the industrial site (renewable capacities Figure 9, electrolysis capacities Figure 10, storage capacities Figure 11), the curtailment of the renewable generation (Figure 12), the amount of sold and purchased electricity (Figure 13), electricity prices (Figure 14), one example week in March for monthly and hourly matching with flexible demand and without any storage options (Figures 15, 16, 17, 18), the installed capacities and electricity generation in Germany 2025 and 2030 (Figure 19 and Figure 20).
    (b) consequential and attributional emissions with a higher hydrogen demand in Germany 2025 of 53 TWh_{H_2} are shown in Figure 21 and 22 respectively
    (c) The generation mix for all considered countries without the additional hydrogen demand is given in Figure 23, capacity factors of electrolysis in Netherlands 2025 (Figure 24) and Germany 2030 (Figure 25), hydrogen production cost in Netherlands 2025 (Figure 26) and Germany 2030 (Figure 27).
4. We explore further sensitivity analyses in the last section. In these, we
    (a) The study's initial results are based on the assumption that the electricity background system cannot adjust to increased hydrogen demand, reflecting potential delays in infrastructure expansion despite the quick scaling of hydrogen production by 2030. To assess the impact of this assumption, a new scenario is modelled where both the background system and hydrogen production are optimised simultaneously in one step with a combined renewable generation target. We show the main findings of this one step optimisation such as the attributional emissions (Figure 30), the capacity factors of the electrolysis (Figure 31), the cost of hydrogen production (Figure 32) and the generation mix when the electrolysis is running (Figure 33),
    (b) explore hydrogen production in four further countries for the year 2025, namely Czech Republic (consequential emissions Figure 34, hydrogen production costs Figure 35), Poland (consequential emissions Figure 36, hydrogen production costs Figure 37), Spain (consequential emissions Figure 38, hydrogen production costs Figure 39) and Portugal (consequential emissions Figure 40, hydrogen production costs Figure 41),
    (c) vary the share of allowed excess sales with annual matching (see Figure 42).
    (d) vary the share of allowed excess sales with hourly matching (see Figure 43)
    (e) vary the fuel costs of natural gas between 20–50 Eur/MWh_{th} (consequential emissions for annual and monthly matching in Figure 44 and 45).
    (f) We vary the share of renewable generation in the background system in Germany to analyse the effect if political targets are not fulfilled or higher renewable generation shares are achieved (Section 4.8.5). Low generation of coal power plants and high feed-in of renewable generation are required to avoid increases in total system emissions with monthly matching.

Country	Renewable Constraint 2025 Share of renewable generation from total load	Renewable Constraint 2030 Share of renewable generation from total load
Germany	55.0% [1]	80.0% [30]
Denmark	85.0% [1]	117.0% [31]
Netherlands	49.0% [1]	73.0% [32]
Ireland	47.0% [1]	70.0% [32]
Austria	90.0% [1]	100.0% [33]
Belgium	32.3% [1]	37.0% [32]
Czech Republic	14.0% [1]	17.0% [32]
France	32.0% [1]	40.0% [32]
Great Britain	53.5% [1]	65.0% [34]
Poland	24.5% [1]	32.0% [32]
Spain	58.8% [1]	74.0% [32]
Portugal	69.0% [32]	80.0% [32]
Others	200% capacity increase compared to 2021	400% capacity increase compared to 2021

[1]Linear interpolated from 2020 renewable generation share to 2030 target.

Table 1: Renewable generation target by country for 2025 and 2030. Since most countries do not have a target for 2025, a linear increase from renewable generation in 2020 to 2030 target is assumed.

4.1. Further details of the used model

The modelling workflow and data behind this study are open. The entire project is available in a public repository under MIT license [28]. The repository also contains a summary of output data for all scenarios. The code is also available in a Github repository [29].

4.1.1. Temporal matching

Hydrogen production is co-optimised with the operation of the electricity system. In addition to purchasing grid electricity, the hydrogen producer can procure new renewable generators, batteries and hydrogen storage in the local market zone to meet any imposed policy requirement on temporal matching. The optimisation finds a cost-optimal portfolio of onshore wind, utility solar PV, electrolysis, battery and hydrogen storage to produce hydrogen.

Annual and monthly matching: In scenarios with annual or monthly matching requirements, the sum of all dispatch $g_{r,t}$ of contracted renewable generators $r \in R$ in hour t over a time span T is equal to the sum of the electricity demand d_t of the electrolysis in this period

$$\sum_{r \in R, t \in T} g_{r,t} = \sum_{t \in T} d_t. \tag{1}$$

Depending on the temporal regulation, T corresponds to a year or a month. The contracted renewable generators must be new (i.e. additional to the system) and sited in the local market zone. Purchases from the grid can cover electrolysis demand when renewable generation is low, as long as it is matched with sales to the grid when procured renewable resources exceed hourly electrolysis demand. The hourly price in the local market is derived from the dual variable of each zone's energy balance constraint.

Hourly matching: The hourly matching requirement is modelled with a constraint (2), enforcing the hydrogen producer to match electricity consumption with clean electricity on an hourly basis. Clean electricity can come from procured renewables or battery storage charged with procured renewables. No grid electricity is allowed to serve the electrolysis demand or procured storage.

Thus, the hourly generation from the procured renewable resources $r \in R$ and the discharge and charge from the procured battery storage $s \in S$, minus hourly sales to the grid ex_t must be equal to the hourly electricity demand of electrolysis:

Technology	Year	CAPEX (overnight cost)	FOM [%/year]	VOM [Eur/MWh]	Efficiency [per unit]	Lifetime [years]
utility solar PV	2025	612 €/kW	1.7	-	-	37.5
	2030	492 €/kW	2.0	-	-	40.0
onshore wind	2025	1077 €/kW	1.2	-	-	28.5
	2030	1035 €/kW	1.2	-	-	30
battery storage	2025	187 €/kWh	-	-	-	22.5
	2030	142 €/kWh	-	-	-	25
battery inverter	2025	215 €/kW	0.3	-	0.96	10
	2030	160 €/kW	0.3	-	0.96	10
hydrogen storage	2025	2.5 €/kWh$_{H_2}$	-	-	-	100
salt cavern	2030	2 €/kWh$_{H_2}$	-	-	-	100
hydrogen storage	2025	13.8[2] €/kWh$_{H_2}$	1.08	-	-	27.5
medium pressure tank[1]	2030	12.1[2] €/kWh$_{H_2}$	1.11	-	-	30
hydrogen storage	2025	51 €/kWh$_{H_2}$	1.08	-	-	27.5
high pressure tank[1]	2030	44.9 €/kWh$_{H_2}$	1.11	-	-	30
electrolysis	2025	550 €/kW$_{el}$	2.0	-	0.67	27.5
	2030	450 €/kW$_{el}$	2.0	-	0.68	30

[1] including compressor cost
[2] own assumption

Table 2: Technology costs assumptions for 2025 and 2030. Data is originally retrieved from the Danish Energy Agency's catalogues of technology data for energy technologies [35].

Technology	OCGT	CCGT	coal	lignite	oil	nuclear	biomass
start up costs [Eur/MW]	24 [36]	144 [36]	108[2]	58[2]	1[2]	50 [36]	78[2]
ramp up limit [p.u./h]	1 [37]	1[37]	1 [37]	1 [37]	1[2]	0.3[2]	1[2]
ramp limit startup [p.u./h]	0.2[2]	0.45[2]	0.38[2]	0.4[2]	0.2[2]	0.5[2]	0.38[2]
ramp limit shut down [p.u./h]	0.2[2]	0.45[2]	0.38[2]	0.4[2]	0.2[2]	0.5[2]	0.38[2]
min. up time [h]	0[38]	3[1] [37]	5[1] [37]	7[1] [37]	0[2]	6[1] [37]	2[2]
min. down time [h]	0[38]	2 [36]	6 [36]	6 [36]	0[2]	10 [36]	2[2]
p min [p.u.]	0[2]	0.45 [38]	0.325 [36]	0.325 [36]	0.2[2]	0.5 [36]	0.38[2]

[1] mean of cold start-up time of commonly used power plants
[2] own assumption based on average values from [36–38]

Table 3: Unit committent parameter.

	gas	coal	lignite	oil	nuclear	biomass
Fuel price [Eur/MWh$_{th}$]	35	8.9	6.5	50	2.6	7

Table 4: Fuel prices.

$$\sum_{r\in R} g_{r,t} + \sum_{s\in S}\left(\bar{g}_{s,t} - \underline{g}_{s,t}\right) - ex_t = d_t \tag{2}$$

The excess hourly generation from the procured renewable resources can be sold to the grid or curtailed. Note that for the base scenarios discussed in the main part of the manuscript, the excess (after the curtailment) is set to zero in the hourly scenarios or 20% in the hourly scenarios with allowed excess generation.

4.1.2. Cost of hydrogen production

The cost of hydrogen production [Eur/kg$_{H_2}$] presented in Figure 3 is defined as a sum of annualised capital costs C_a and variable operating costs $O_{a,t}$ of all new assets A contracted by the hydrogen producer, plus costs of electricity purchases from the grid, minus revenue from selling the excess electricity to the grid (if allowed by scenario) per MWh$_{H_2}$ of hydrogen demand d_{H_2}:

$$C_{H_2} = \frac{\sum_{a\in A} C_a + \sum_{a,t} O_{a,t} + \sum_t P_t \cdot (im_t - ex_t)}{d_{H_2}} \tag{3}$$

Electricity price P_t for every timesep t is estimated based on the marginal price of the local zone, as discussed above.

4.1.3. Carbon intensity of blue hydrogen

The results compare the carbon intensity of electrolytic hydrogen and blue hydrogen. The carbon intensity of blue hydrogen depends on the carbon capture rate and ranges between 1–5 kg$_{CO_2e}$/kg$_{H_2}$[9, 15]. We assume the lowest value of 1 kg$_{CO_2e}$/kg$_{H_2}$as a comparison to the carbon intensity of the electrolytic hydrogen to provide a conservative estimate, giving blue hydrogen the best possible conditions. This approach ensures that our results are robust if electrolytic hydrogen still appears favourable under these assumptions. The same assumption was made by Brauer et al. [9], making our study consistent with previous works and allowing for direct comparability.

4.1.4. Discussion

The rules for green hydrogen must balance the impact of production on carbon emissions with the additional cost burden on producers. Additional costs for producers may hinder the scale-up of hydrogen production necessary to meet long-term climate targets. Our results indicate that flexible operation is key in systems which do not have a high share of renewable generation ($>80\%$). In the case of a non-clean background system, electrolysers have cost-optimal capacity factors in the range of 45–68% to adapt to hours of high wind and solar production. This flexibility is made possible by flexible hydrogen demand or low-cost hydrogen storage in underground caverns to buffer the variable hydrogen production. We show that electrolysis production running at high capacity factors either causes high emissions (in the case of annual or monthly matching) or low emissions but high costs (in the case of hourly matching).

Examples where flexible hydrogen demand is possible in industry include ammonia production via the Haber–Bosch process or methane production via the Sabatier process. Both of these processes can be flexible with must-run part loads down to 30–50% [16–18].

Low-cost hydrogen storage in salt caverns relies on the availability of suitable geological salt deposits. Fortunately, there are abundant salt layers and domes in Europe [19]. These salt deposits are mainly concentrated around the North Sea, where abundant wind power resources are available. Hydrogen storage in steel tanks is feasible outside these locations, but this has a significant cost penalty on the hydrogen. Storing the hydrogen in liquid organic carriers (LOHC) may alleviate this cost penalty [9]. Our results show that in the case of inflexible hydrogen demand, hydrogen production systems will instead be run with steel tank storage than without any storage. Steel tanks can easily be deployed at hydrogen production or industrial sites, resulting in lower average production costs than no storage. A hydrogen pipeline network could also make underground storage accessible to a broader area.

Hourly matching is the only matching scheme that provides strong incentives for demand flexibility and storage since the cost differences between constant and flexible electrolyser operations are so high. For annual matching, the differences are much more minor. Incentives for flexible electrolyser operations are desirable since the flexible operation is seen in top-down system cost optimising studies [20]. The difference between the emissions of annually, monthly and hourly matched green hydrogen reduces with a cleaner background electricity system (see the change in German emissions from 2025 to 2030 in Figures 7, 28). However, hourly matching always results in low emissions, regardless of the background system, and provides a hedge against the case where ambitious targets for expanding renewable electricity are not met.

It is sometimes asked why strict rules are applied to hydrogen but not other new electricity consumers such as electric vehicles or heat pumps. One reason is that rules are required only for certification for producers seeking to get the label 'green' and associated subsidies. Another reason is that it is easier to regulate hydrogen production because it is done centrally at a large scale. This study shows a third reason: if hydrogen is produced without additionality or temporal matching, its carbon emissions impact can be worse than that of grey hydrogen. Numerous studies have shown that electric vehicles and heat pumps reduce emissions compared to fossil-based alternatives even with today's electricity mix [21–24].

It has also been argued that additionality requirements cannot affect system emissions in a system like Europe, where an emissions cap applies in the form of an Emissions Trading System (ETS) [25]. We argue that the large volume of planned hydrogen production in Europe by 2030, 10 million tonnes of hydrogen per year, means that additionality is a valuable precaution to ensure that renewable production keeps pace with electrolysis demand. Without this safeguard, emission certificate prices could rise to politically unsustainable levels and endanger the entire ETS. It would also lead to higher electricity prices, affecting all consumers.

The European Commission is considering competitive tendering as a support mechanism for hydrogen uptake and switching from natural gas-based to renewable hydrogen production for industrial processes [26]. Financial subsidies received through such competitive tendering (e.g., via Contracts-for-Difference (CfDs)) can enable hydrogen producers to stabilise their electricity procurement cost at a certain level (*the Strike Price*) for the duration of the contract. These subsidies will naturally affect green hydrogen production profiles and, consequently, the energy system impacts of hydrogen production. The impacts will largely depend on the design of tendering procedures and contracts. For example, an essential feature of the CfDs is the *Reference Price*. In the absence of a functioning market for hydrogen, different indexation options are being considered, such as the electricity price, grey hydrogen cost, and available commercial cost indexes, among others [27]. If the hourly electricity price is used as a reference point of a CfD, this would incentivise baseload operation of hydrogen producers by providing compensation against high electricity prices. In the context of our analysis, this would imply high attributional emissions (unless an hourly matching requirement is imposed). If a CfD is based on a time-fixed index, the subsidy will function like an offtake price. The latter can also facilitate a constant operation if the subsidy level is high compared to the market electricity prices. Taken together, the envisaged support for hydrogen projects makes the baseload operation scenario in our study even more relevant. Implementing a CAPEX subsidy for electrolysers could address some challenges and promote more economically viable operations. The subsidy should only be available for electrolysis with capacity factors below 70%. However, it is important to note that our investigation does not explore the impact of a capacity factor limitation.

4.1.5. Comparison to other studies

We now compare our results to other studies in the literature. In [7], annual and hourly matching rules were compared in the United States. This study used a setup with a high offtake price and a fixed electrolyser capacity without a predefined hydrogen delivery profile to the customer. In the annually matched case, the high offtake price incentivises running the electrolyser even when electricity prices are high, leading the electrolyser to run when fossil generators are dispatched. This scenario results in high capacity factors and high emissions. This finding and the lower emissions impact of hourly matching agree with our study. However, our study only sees a slight cost premium for hourly matching in [7], even with storage. This difference arises because, in [7], the model does not need to provide a constant stream of hydrogen and can choose to turn off the electrolyser if the cost of production in that hour is higher than the offtake price. Hydrogen storage is not considered in [7]. While Ricks et al. present a scenario where local renewable expansion competes for resources with system-wide renewable expansion, our primary results assume no such competition, attributed to our two-step optimisation approach. The impacts of these different methodologies are analysed in great detail in [14], which compares the methodology of a preprint of our study [28] with the study from Ricks [7]. The study points out how these distinct methodologies, specifically the compete versus non-compete approaches, yield varying results concerning consequential emissions. However, in a sensitivity analysis, we consider the impact of competition and the possible adjustment of the background system (see Section 4.7). Our results show that emissions from annual and monthly matching can be lowered with flexible electrolysis operation in scenarios using a one-step optimisation within a competitive framework. We see other factors besides the modelling of the competition as crucial, causing the differences in the results. The European energy system differs from that in the US in terms of CO_2 prices, renewable targets agreed in the NECPs and generally a higher share of renewables in the electricity mix compared to the US, which has an impact on the effect of the respective regulation.

The study design in Brauer et al. [9] is similar to ours in that they model a baseload hydrogen demand rather than using a fixed offtake price like [7]. Brauer et al. also see a small cost premium for hourly versus annual matching because the model uses hydrogen storage in the form of liquid organic hydrogen carriers (LOHC), which have a low cost for energy storage similar to the underground cavern storage in our study. We complement the study of [9] by exploring the availability of different storage options in the case that LOHC or cavern storage is unavailable. We also explore the impact of the electrolysis capacity factors, varying hydrogen demand volumes and different background grids with varying levels of cleanness. In contrast to the study of Brauer et al., we show that annual matching reduces system emissions if the background grid is largely decarbonised or capacity factors of electrolysis are below 60%.

Ruhnau et al. [10] investigated the impacts of hourly versus annual matching in Germany in the existing power system using historical marginal emission factors. The hydrogen demand profile was continuous, and hydrogen storage was available in steel tanks. They found similar costs for hourly and annually matched hydrogen to our study in 2025 with steel tanks. Like our study, they found that system emissions are slightly lowered by annual matching when electrolysis operates flexibly and more pronounced by hourly matching when excess electricity can be sold to the grid. In contrast to our study, they assess the emissions impact using marginal emissions factors. They, therefore, cannot see the non-linear effects of a large volume of hydrogen demand (such as higher-emission power plants being required in some hours for large volumes than are historically on the margin). They are also restricted to a historical system, whereas we expect the grid to be considerably cleaner in 2030 and, therefore, see more considerable emission reduction for annual matching. There are other differences in that [10] only considers wind power, no solar PV nor additional batteries for local procurement, and other hydrogen storage options were not explored.

4.1.6. Limitations of the modelling assumptions

Our study has several limitations that should be highlighted. We have limited the suite of procured technologies to utility photovoltaics, onshore wind and lithium-ion batteries as these are the technologies commonly considered for green hydrogen. Broadening the generators to include new hydroelectric or geothermal plants could reduce costs, particularly for hourly matching with expensive hydrogen storage. Allowing long-duration electricity storage, however, is unlikely to provide any additional benefit given that we have already made hydrogen storage available to the system.

As mentioned in the Discussion section, not all regions have suitable salt deposits available for underground hydrogen storage. In these cases, hydrogen producers are forced to use steel tanks or explore other options with more expensive conversion, such as liquid hydrogen storage.

We have not included that hydrogen could be considered green if electrolysis runs when electricity prices are low. This would reduce the cost of hourly matching. This is regulated in the DA[4] with a price threshold of 20 €/MWh or 36% of the EU carbon price (which currently corresponds to a price of 27 €/MWh with 75 €/t_{CO_2}[39]). Based on our results, prices are not low enough for enough of the year to make a substantial impact on our results.

There may be additional costs in wear-and-tear as well as efficiency losses from operating the electrolysers at low capacity factors. We have not considered these effects because we assume they are small compared to other costs in the system.

When we calculate the average emissions of the electricity system, we do not subtract renewable electricity procured with power purchase agreements (PPAs). The guarantees of origin for this electricity may already have been cancelled. Ideally, therefore, renewable energy from power purchase agreements should not also be used for green hydrogen. Using the residual mix, after subtraction of PPAs, would increase the attributional emissions of annually matched and grid electricity. However, since the volume of PPAs in Europe is currently low, this impact is expected to be small.

Competition for high-quality renewable sites between renewable projects built under subsidy schemes for regular electricity demand and renewables built for hydrogen production with electrolysis has not been modelled. In our model, all renewable generators see the same quality resources. Competition could lead to a higher impact of green hydrogen production, since it could use up good sites that would otherwise be used for decarbonising the electricity sector [7].

We have only matched renewable supply to electrolysis demand within each bidding zone. For large bidding zones like Germany there could be congestion inside the bidding zone that prevents the transport of the electricity. For example, if wind generation is procured in North Germany for electrolysers in South Germany, grid bottlenecks in Central Germany may prevent the transfer of electricity. Redispatch measures, whereby conventional generators are fired up to compensate missing production in South Germany, could worsen the emissions balance in this case.

4.2. Further plots of the main results

4.3. Capacity factor

The capacity factors are the actual hydrogen output divided by its maximal capacity. The capacity factors increase with higher hydrogen storage costs (see Figure 5). Low costs of hydrogen storage or an elastic demand allow the producer to buffer periods of low variable feed-in of the renewable generation, leading to lower capacity factors of the electrolysis since they only operate when electricity prices are low. If the demand is inflexible, electrolysis runs at full capacity around the clock to meet the demand. Running the electrolysis at full capacity every hour leads to increased emissions in the case of annual and monthly matching or to high hydrogen production costs in the case of hourly matching.

The grid, annual and monthly matching scenarios have higher capacity factors since, in these cases, there is flexibility to purchase grid electricity when directly procured generation is not available. In the case of monthly matching, electrolysis with purchased grid electricity can run at a higher capacity factor of, e.g. 62% with flexible demand compared to 45% with hourly matching, even low feed-in from the additional renewable generation.

4.4. Electricity prices

The electricity prices are a result of the optimisation. They are derived from each region's dual variables of the nodal balance constraint. An infinitely small relaxation of the constraint, i.e., one unit of load less to be met, returns the marginal costs of providing that unit, which can be used as the electricity price indicator in a competitive market. It should be noted that the capacities of conventional generators are fixed in the first optimisation step (without hydrogen demand) and, therefore, cannot adapt to the new additional demand for hydrogen. If power plant capacities could adjust to the higher electricity demand, prices would be lower. Assuming no adjustment represents the situation that permitting procedures and construction of additional power plants require longer periods than hydrogen production uptake.

Electricity prices increase in the grid, annual and monthly matching scenario if storage options are expensive or unavailable, and hydrogen demand is high (53 TWh_{H_2}). The hourly matching does not affect electricity prices. In the grid scenario with no additional local procurement, demand cannot be met every hour without hydrogen storage which is reflected by the higher average system prices. In annual and monthly matching scenarios, electricity prices increase by 14% if the electrolysis is operated inflexibly. The price increase is because hours with low feed-in from renewable generation are not bridged with storage, but electricity is purchased from the grid. This additional demand causes more coal-fired power plants to run, leading to a price rise.

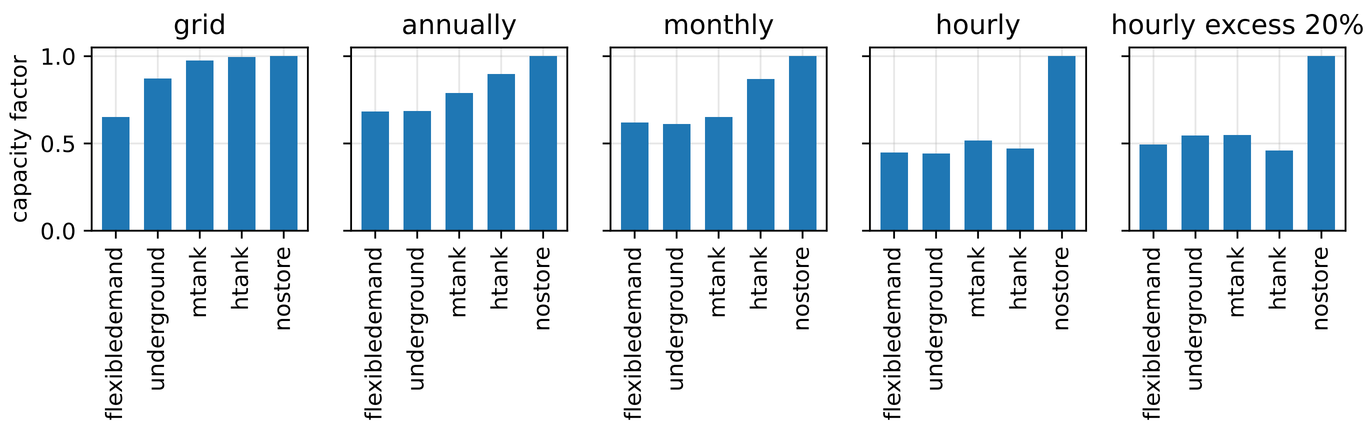


Figure 5: Capacity factors of electrolysis for local production in Germany 2025 with a hydrogen demand of 28 TWh_{H_2}.

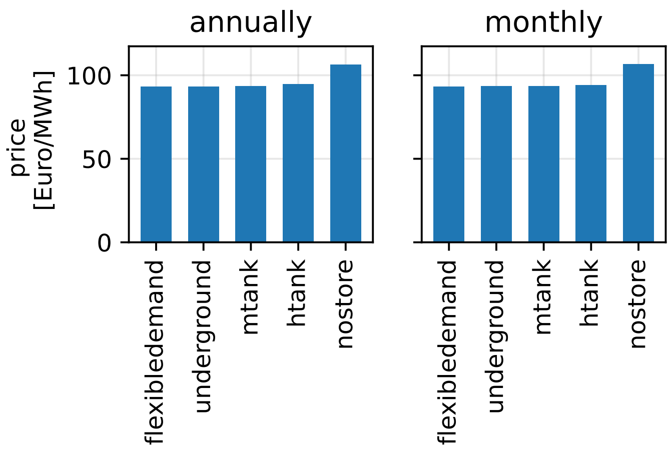


Figure 6: Electricity prices of annually and monthly matching for Germany 2025 with an annual hydrogen demand of 53 TWh_{H_2}.

4.5. Attributional emissions

Attributional emissions reflect the greenhouse gas emissions associated with the electricity use for hydrogen production. They are calculated based on the average emissions when the electrolysis uses grid electricity, considering imports and exports to the country. Attributional emissions are only guaranteed to be zero with hourly matching since every hour, the electrolysis demand must be met by additional renewable generation. The carbon intensity of hydrogen is highest in the case where the electrolysis is directly connected to the grid without any additionality requirement (**grid**), followed by the annual matching (see Figure 7 in Appendix). These attributional emissions are caused by the fact that electrolysis also runs during hours when fossil fuels contribute to the generation.

The carbon intensity rises as the cost of hydrogen storage increases. If hydrogen demand is flexible or low-cost storage is available, electrolysis can run when the feed-in of renewable generation is high, and electricity prices are low. If no hydrogen or only expensive storage is available, the variable feed-in of renewable generation cannot be bridged. In this case, the electrolysis is powered with a higher proportion of electricity from coal generation, which causes higher attributional emissions (see the generation mixes in Figure 8 in the Appendix).

In the grid scenario, in which the electrolysis is directly connected to the grid without additional renewable generation, the attributional emissions range between 5.4–7.8 kg_{CO_2}/kg_{H_2}, which is above the EU limit for low-carbon hydrogen of 3 kg_{CO_2e}/kg_{H_2}[40]. The attributional emissions of electrolytic hydrogen are even higher than those from the production of grey hydrogen from methane via steam methane reforming (10 kg_{CO_2e}/kg_{H_2}) if the grid is less clean (see carbon intensity in the Netherlands 2025 in Figure 28).

Annual and monthly matching have emissions below the EU threshold for every storage option but above the emissions of blue hydrogen (1 kg_{CO_2}/kg_{H_2}) ranging between 1.8–3.0 kg_{CO_2}/kg_{H_2}. Emissions increase if hydrogen storage is expensive or the demand is not flexible. Since attributional emissions depends on the cleanness of the background electricity grid, the value will be higher in countries with higher share of fossil-driven generators (see Figure 28).

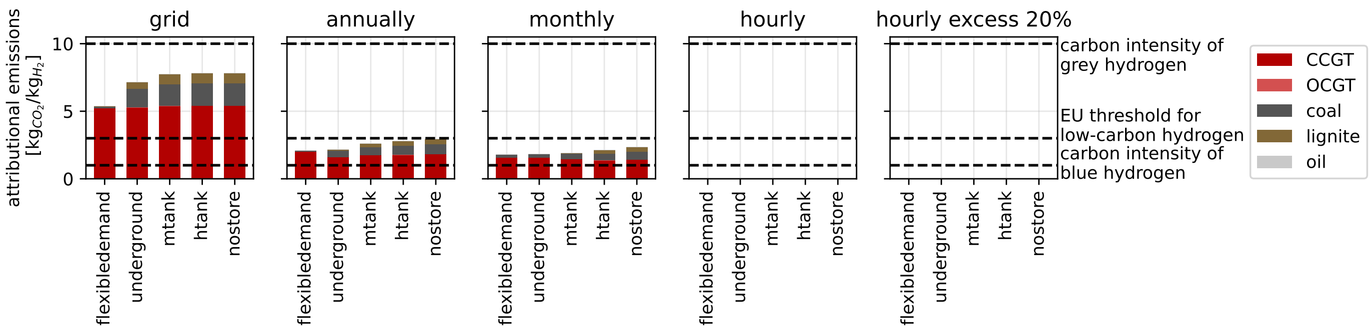


Figure 7: Attributional emissions of hydrogen for local production in Germany 2025 with a hydrogen demand of 28 TWh_{H_2}.

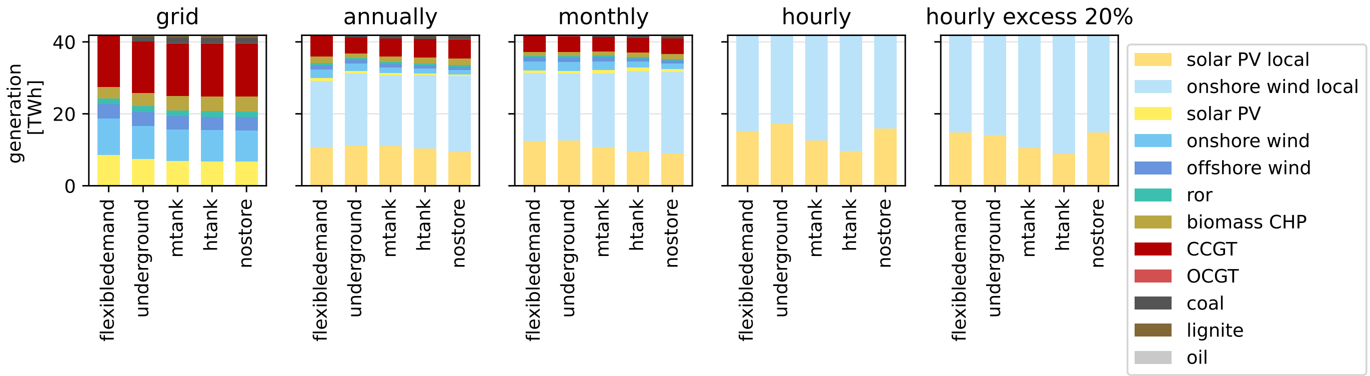


Figure 8: Mix of electricity generation in Germany 2025 when electrolysis is running with a hydrogen demand of 28 TWh_{H_2}..

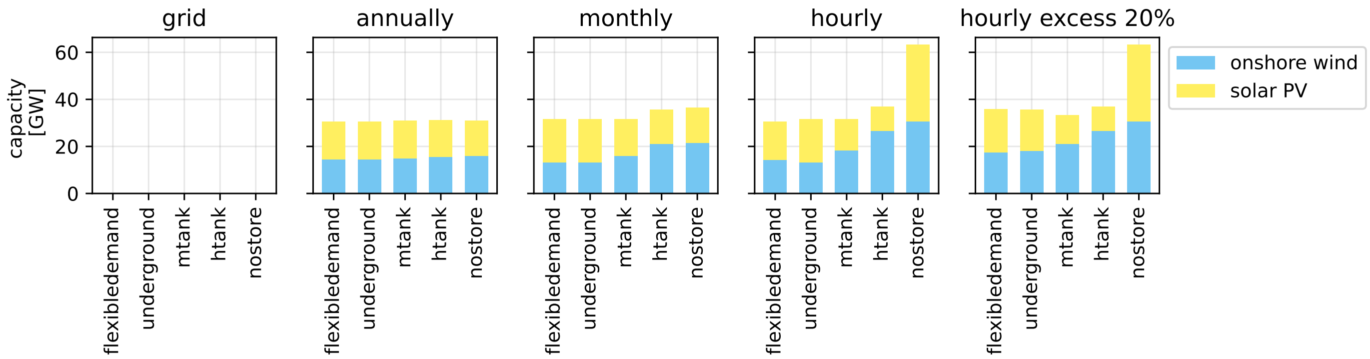


Figure 9: Installed renewable capacities at industrial node for Germany 2025. With annual matching solar is favoured. With hourly matching solar and onshore wind are built.

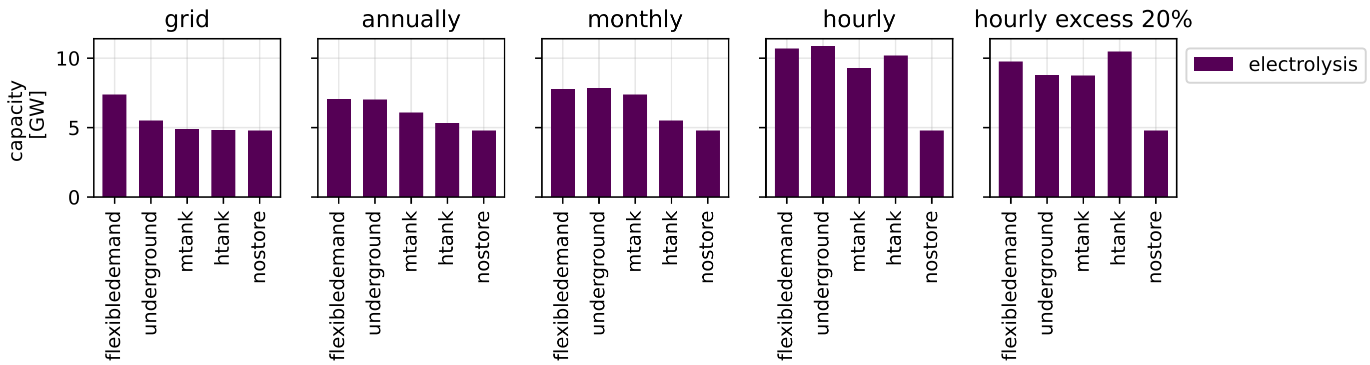


Figure 10: Installed electrolysis capacities at industrial node for Germany 2025.

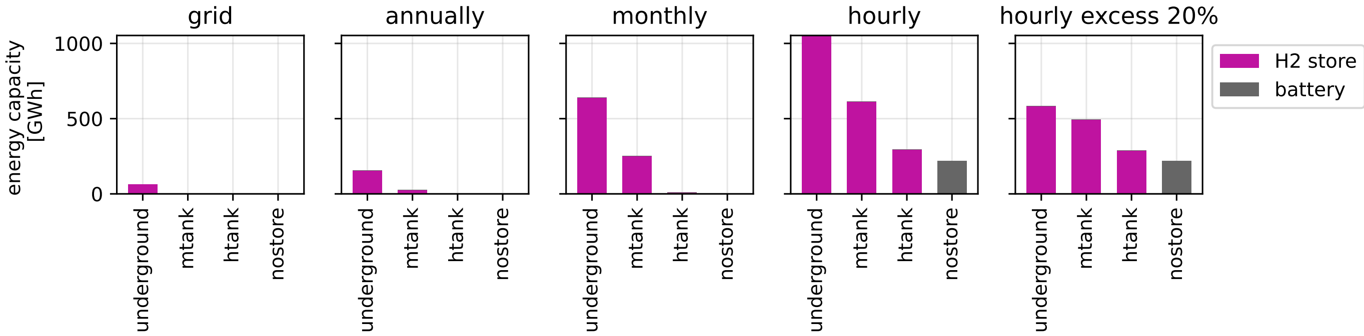
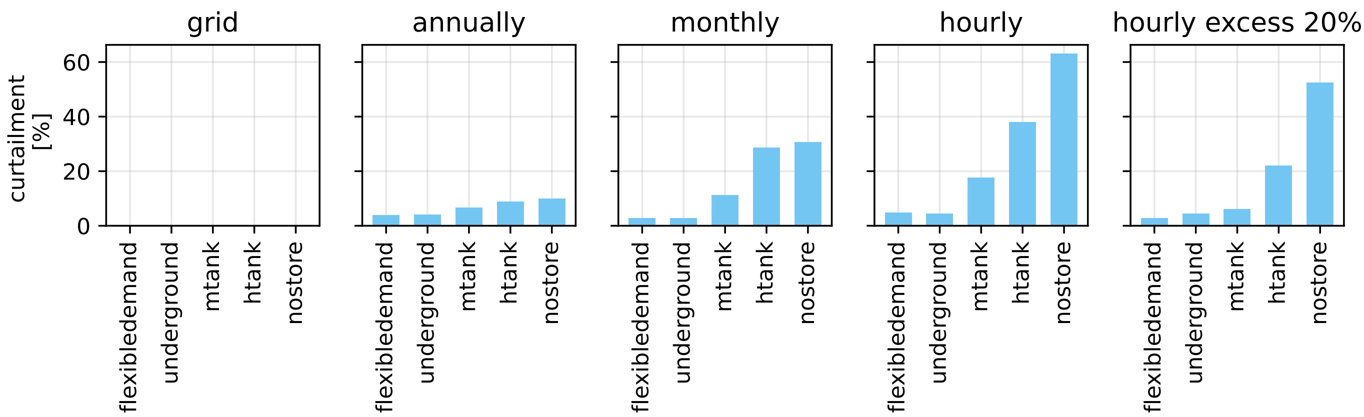
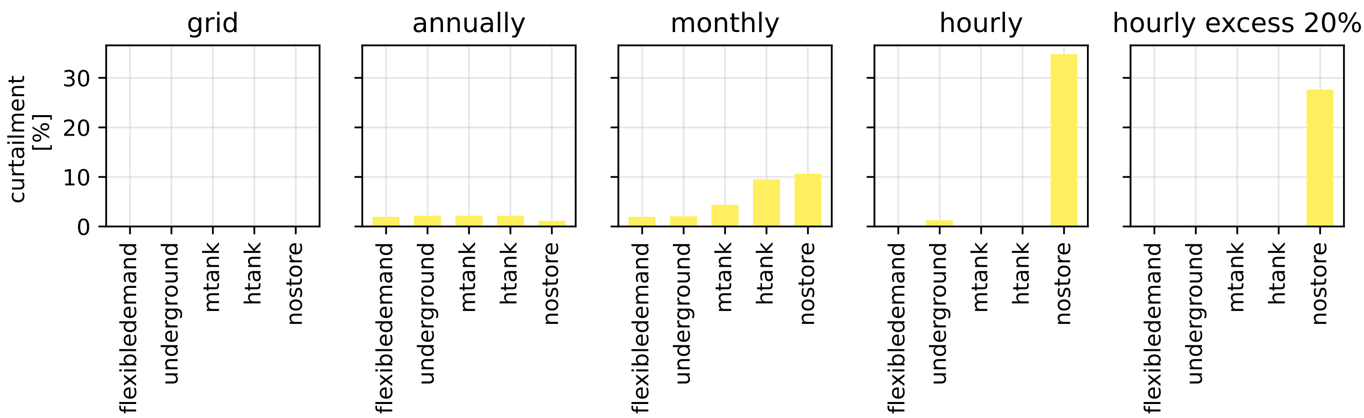


Figure 11: Energy storage capacities for Germany 2025.



(a) Curtailment local onshore wind



(b) Curtailment local solar PV

Figure 12: Curtailment of renewable generation at local node for Germany 2025.

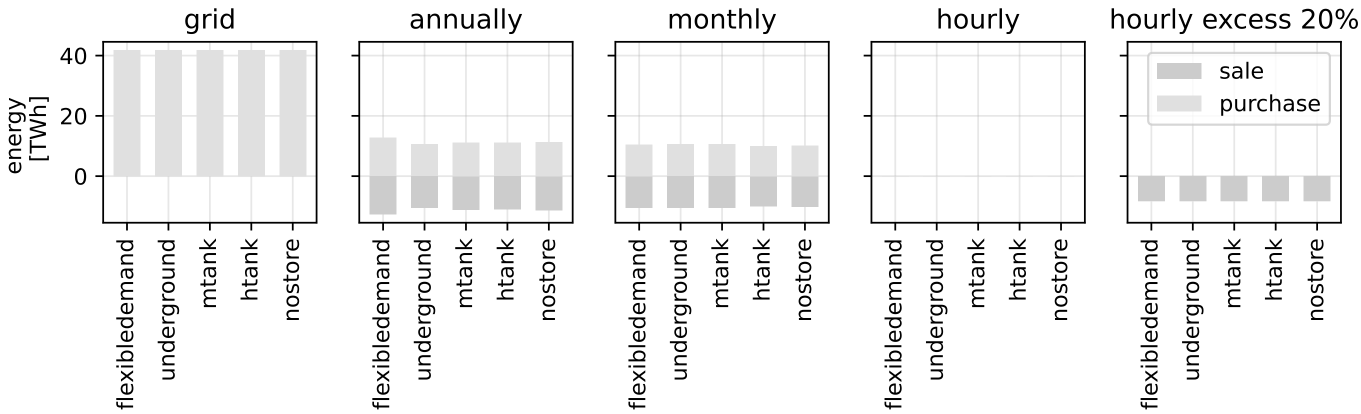


Figure 13: Sale and purchase from the local production to the background grid for Germany 2025.

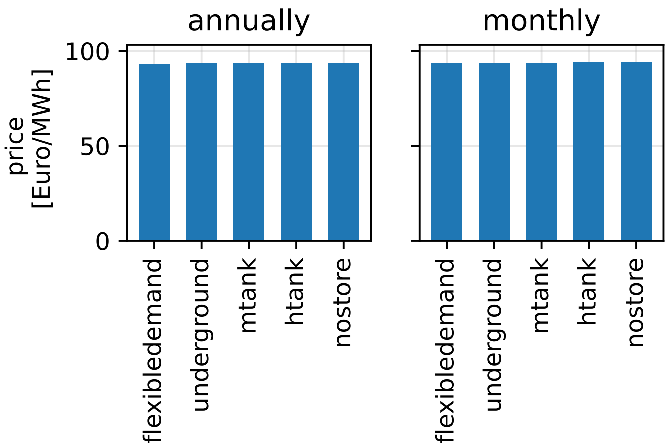


Figure 14: Electricity prices of annually and monthly matching for Germany 2025 with an annual hydrogen demand of 28 TWh_{H_2}. Electricity prices do not increase in contrast to a higher hydrogen demand of 53 TWh_{H_2} (see Figure 6).

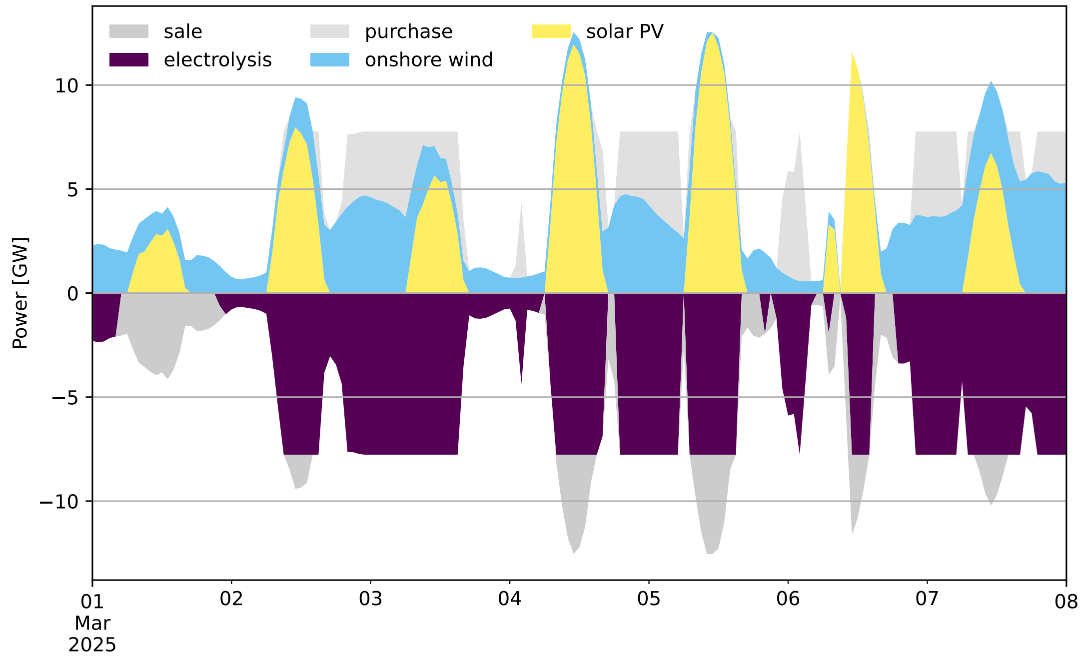


Figure 15: Representative week for monthly matching and flexible demand in Germany 2025. Electrolysis runs flexibly depending on price for purchasing electricity and local renewable generation. At hours with high feed-in of local renewable generation electricity is sold to the grid.

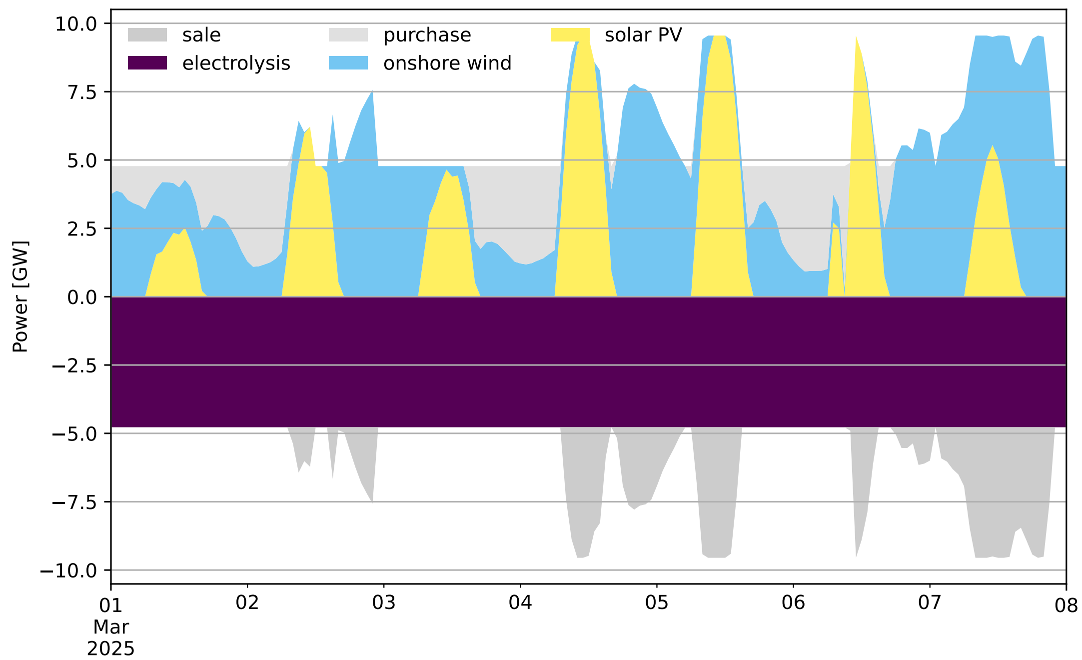


Figure 16: Representative week for monthly matching and no hydrogen storage options in Germany 2025. Electrolysis runs constantly. Hours with low feed-in of renewable generation are bridged with battery storage and purchase of electricity.

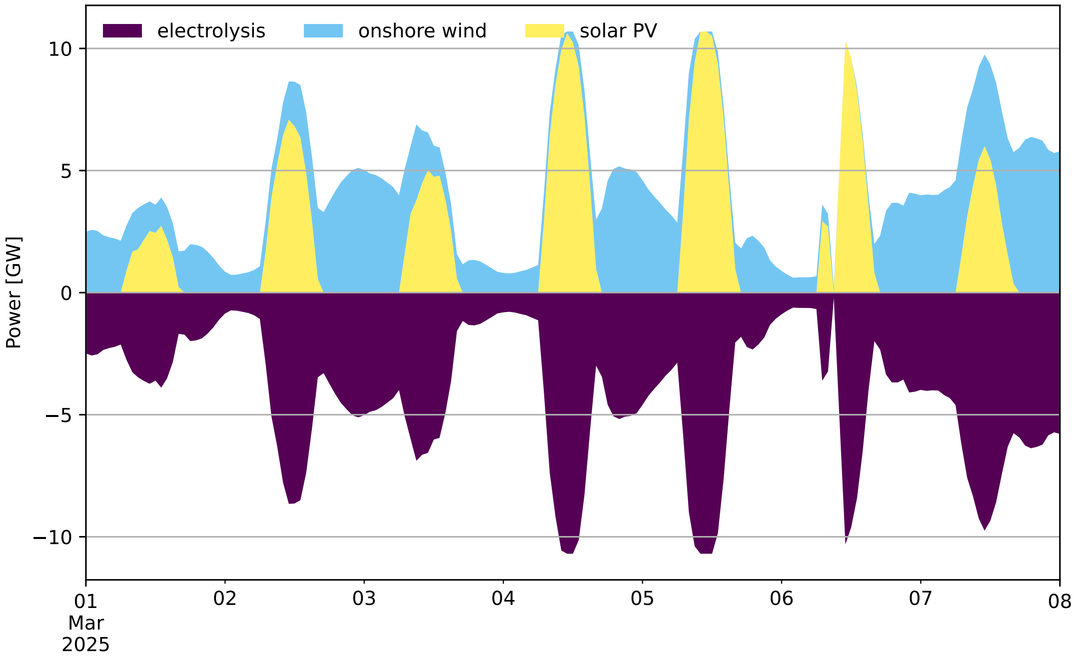


Figure 17: Representative week for hourly matching and flexible demand in Germany 2025. Electrolysis operation follows the feed-in of the local generation.

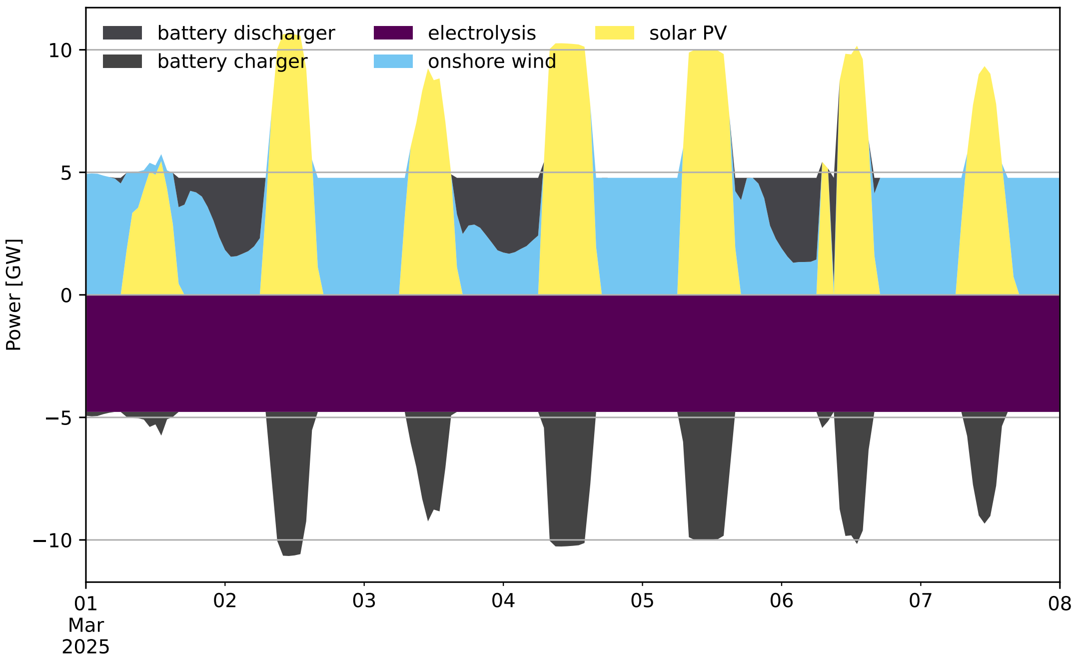


Figure 18: Representative week for hourly matching and no hydrogen storage options in Germany 2025. Electrolysis runs constantly. Hours with low feed-in of renewable generation are bridged with battery storage.

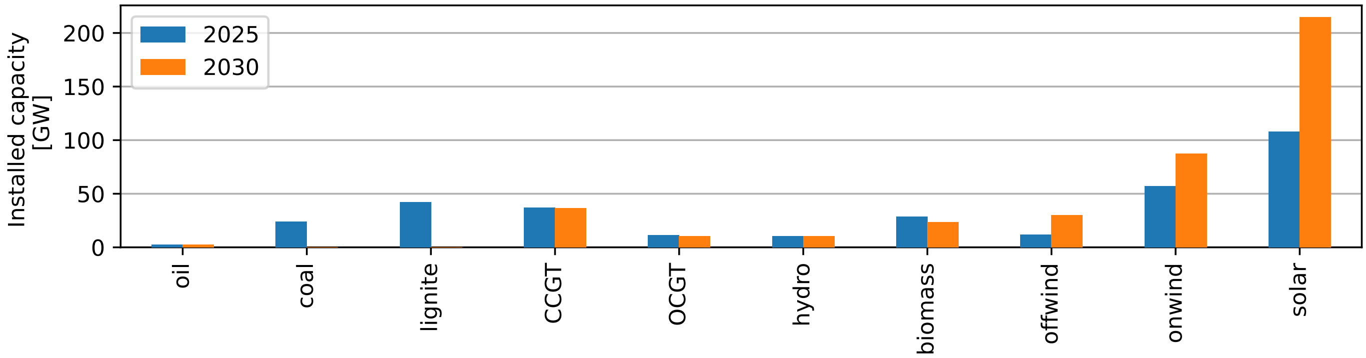


Figure 19: Installed capacities in Germany in 2025 and 2030 in the background system.

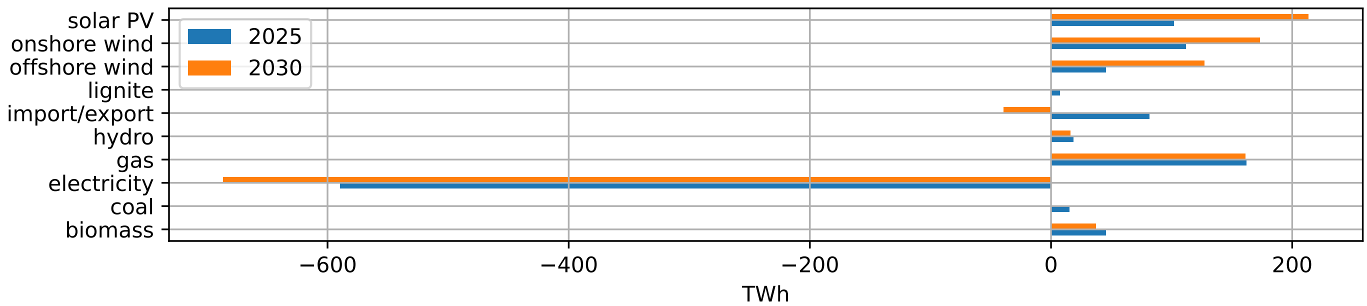


Figure 20: Electricity generation and demand in Germany 2025 and 2030 in the reference scenario without a hydrogen demand.

4.6. Larger Hydrogen demand of 53 TWh_{H_2}

The size of hydrogen demand has little impact on consequential and attributional emissions. For example, the consequential emissions for annual matching are about 4 kg_{CO_2}/kg_{H_2} in both cases, with a low demand of 28 TWh_{H_2} and a higher demand of 53 TWh_{H_2} (see Figure 2 and Figure 21). However, since a larger volume of hydrogen is produced, the overall increase in emissions is significantly higher compared to the lower demand. For example, there are additional emissions from hydrogen production of 5.8 million tonnes of CO_2 in the case of high demand and annual matching with the inflexible operation of electrolysis. In addition, electricity prices can increase by up to 14% due to the additional electricity demand in the case of large production volumes of green hydrogen for annual and monthly matching if the background system cannot adapt to the rapidly growing demand.

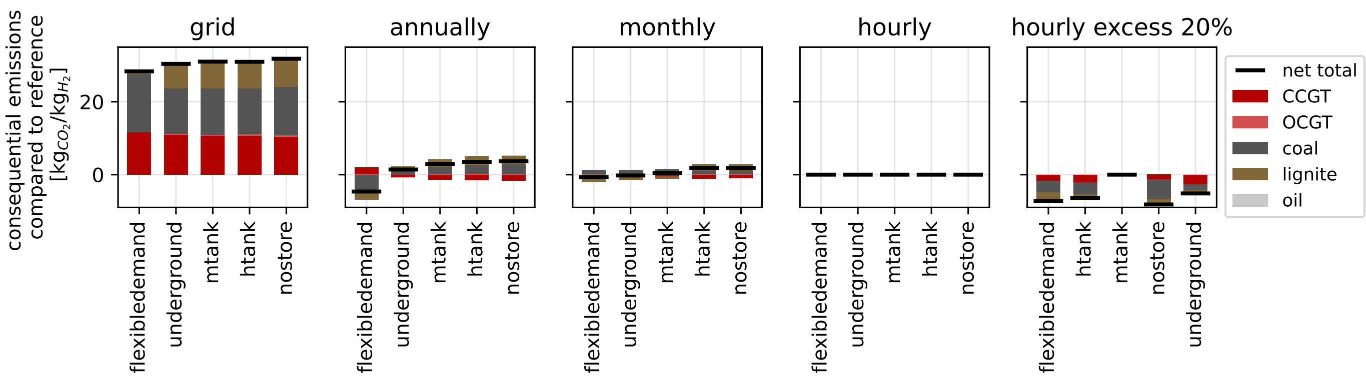


Figure 21: Consequential emissions in Germany 2025 with a larger hydrogen demand of 53 TWh_{H_2}.

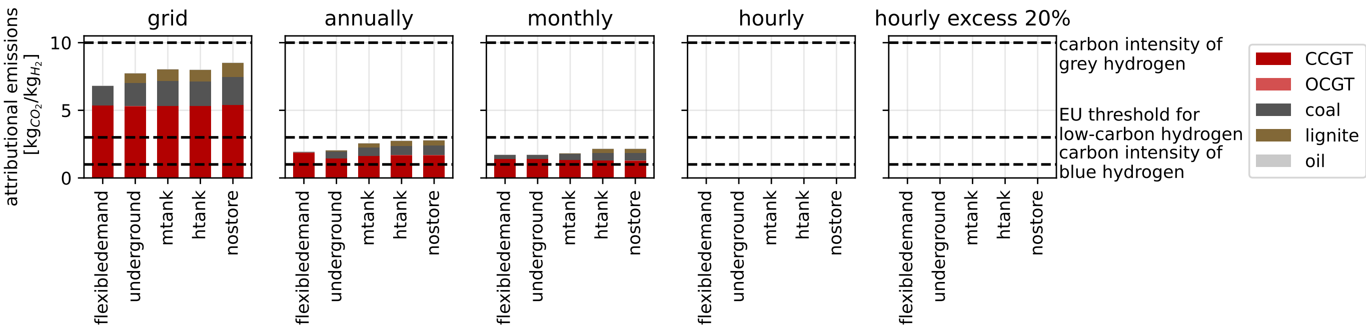


Figure 22: Attributional emissions of hydrogen for local production in Germany 2025 with a larger hydrogen demand of 53 TWh_{H_2}.

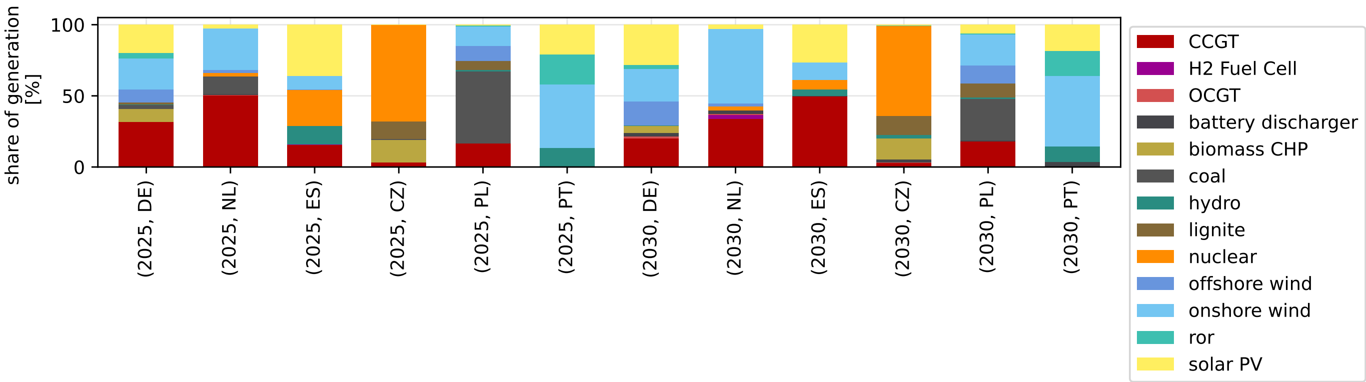


Figure 23: Electricity generation share of different countries and years split by carrier without the hydrogen demand.

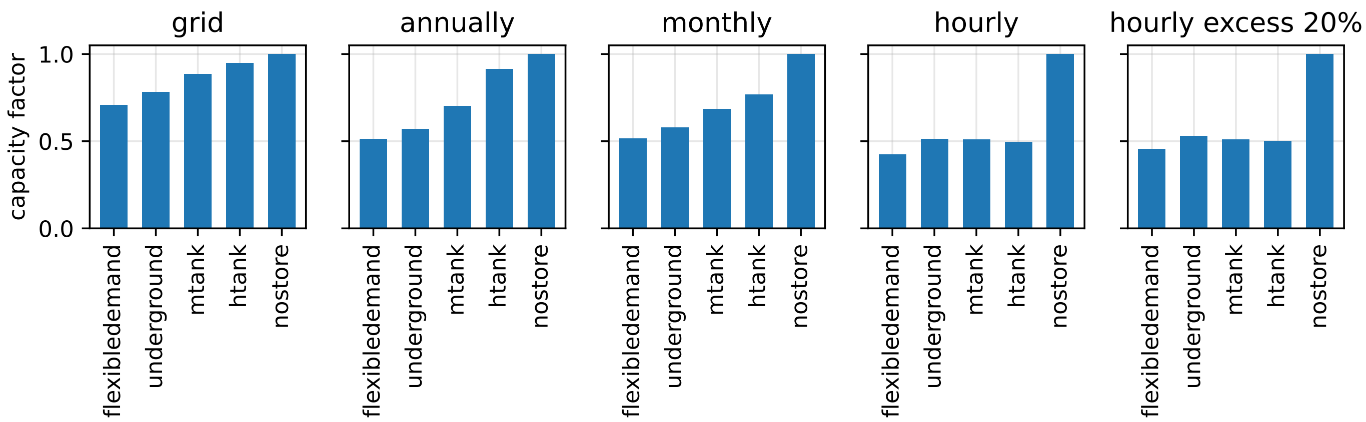


Figure 24: Capacity factors of electrolysis for local production in Netherlands 2025.

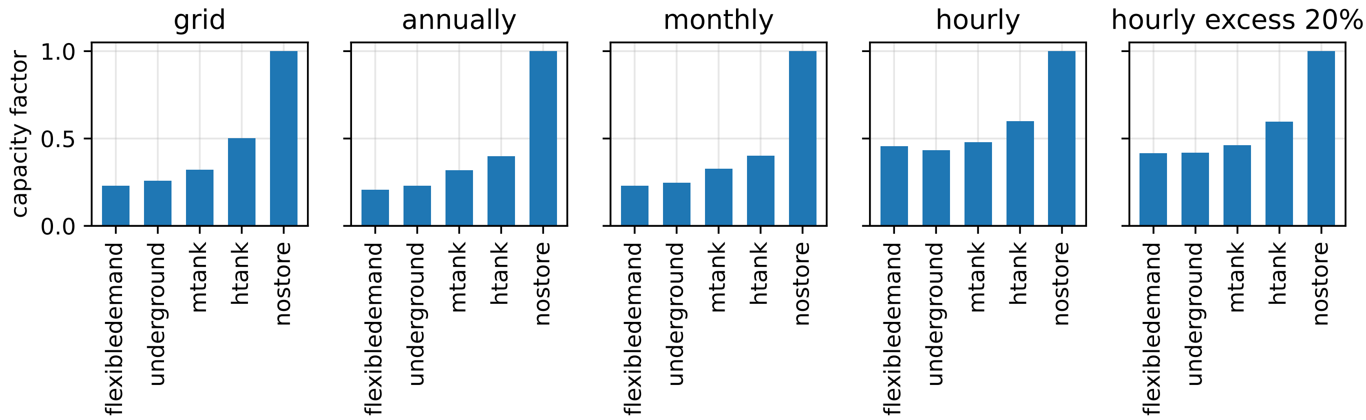


Figure 25: Capacity factors of electrolysis for local production in Germany 2030.

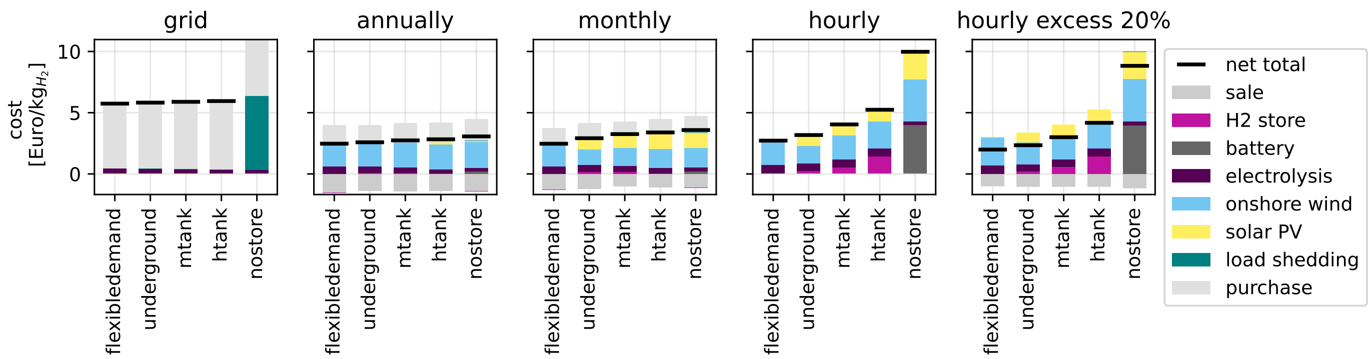


Figure 26: Cost breakdown of hydrogen production Netherlands 2025. In the grid scenario no additional generation capacity can be built. Without any hydrogen storage there are hours in which the hydrogen demand cannot be met.

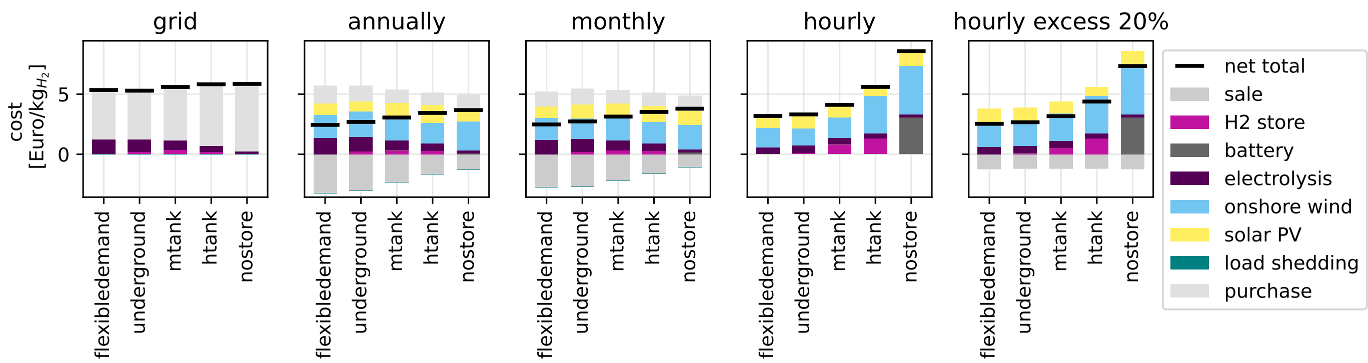


Figure 27: Cost breakdown of hydrogen production Germany 2030. In the grid scenario no additional generation capacity can be built. Without any hydrogen storage there are hours in which the hydrogen demand cannot be met.

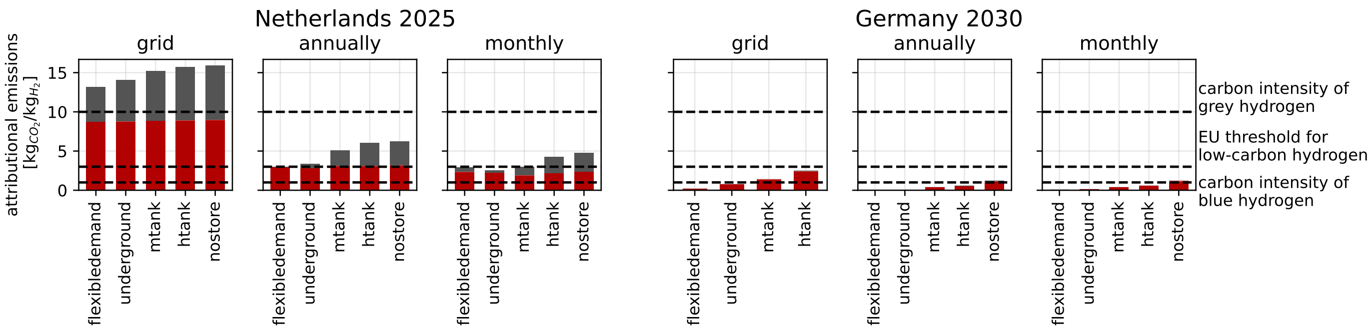


Figure 28: Attributional emissions for two selected cases representing a less clean system, Netherlands 2025 (*left*), and a cleaner system, Germany 2030 (*right*), than the reference case of Germany 2025.

4.7. Modelling impacts of unchanging infrastructure on new hydrogen demand

We assume in the previously presented results that the electricity background system cannot adapt its infrastructure to the additional hydrogen demand. Assuming no adjustment represents the situation that permitting procedures and construction of additional power plants require longer periods than the rapid scale-up of hydrogen production envisaged by 2030. This was implemented in a two-step process where we optimised the background system without the hydrogen demand and then fixed the background capacities to optimise the hydrogen procurement. In addition, we enforce in the two-step optimisation the renewable electricity targets only on the background system, and they can be overshoot in the second step with the locally procured renewable generation.

To evaluate the impacts of the assumption that the background system cannot adapt and renewable targets can be overshoot, we model another scenario by optimising the background system and hydrogen production simultaneously with a joint renewable generation target. Optimisation in one step has the advantage that the infrastructure of the background system can adapt to the additional hydrogen demand and that local renewable generations compete with renewable system generation. However, it has the disadvantage that it is no longer possible to determine whether the procured renewable generation is truly additional since the country's renewable electricity target is met either by the system or locally procured renewable generation. This highlights a problem with the definition of additionality. In reality, it is difficult to determine whether the locally procured renewables are truly additional or would not be built in any case in the background system in light of the political goals of decarbonisation.

In our one-step optimisation, we assume that the policy targets for the renewable generation share are met by local generation or in the background system. In this case, similar to the two-step optimisation, system emissions increase in the case of the grid, annually and monthly matching scenarios compared to the hourly matching scenario if hydrogen demand is not flexible. However, in contrast to the two-step optimisation, there are no increased emissions in the grid scenario compared to the annual or monthly matching, as the renewables are built either in the background system or at the local production (see Figure 29). This implies that the additionality requirement does not affect the total emissions if the policy targets are met. In the one-step optimisation, consequential emissions increase by a minimum of 7% (16 $\mathrm{Mt}_{\mathrm{CO_2}}$) compared to the reference scenario without hydrogen demand across all policy scenarios when locally procured renewable generation is not truly additional and counts towards the national target. This underlines the need to exclude local renewable generation for hydrogen production from national targets or increase the targets to avoid a total emission rise. The additionality requirement provides only insurance that emissions do not increase in the event of a strong rise in green hydrogen production and policy targets that are not adjusted to the new demand or are not met if the locally procured renewable generation is truly additional.

The attributional emissions increase in comparison to the two-step optimisation (see Figure 30). The attributional emissions of annual matching are above the EU limit for low-carbon hydrogen, except in the case of flexible demand. The higher attributional emissions result from the fact that the expansion of local renewables competes with an expansion in the system, which leads to an overall higher share of fossil generators in electricity generation.

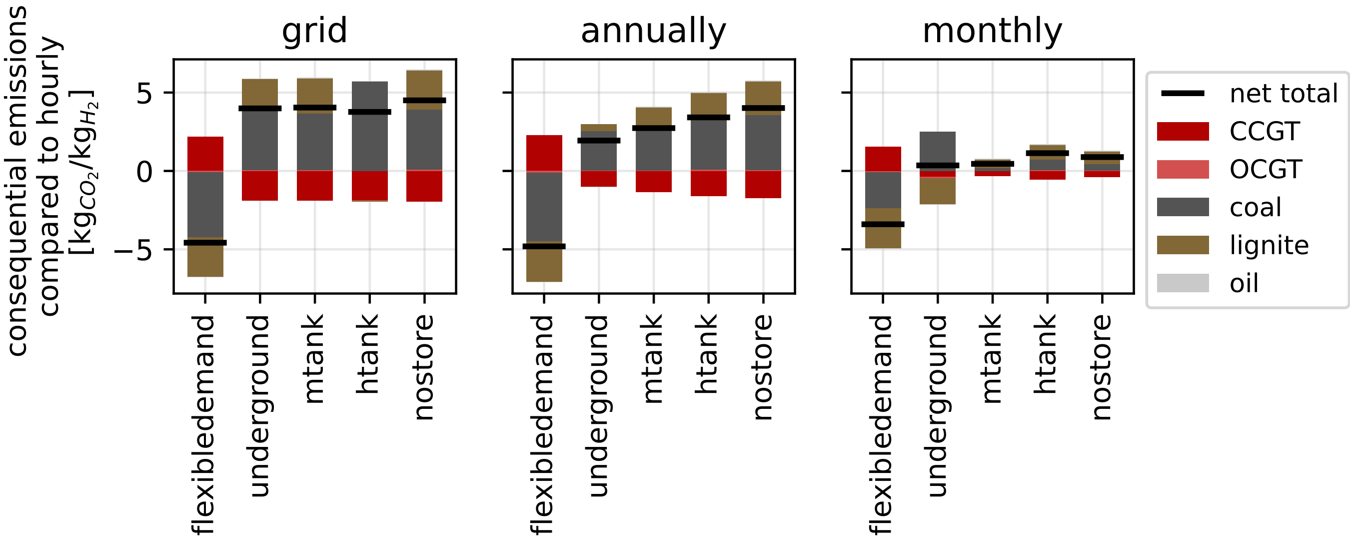


Figure 29: Consequential emissions in Germany 2025 with one step optimisation which allows the background electricity system to adapt to the new hydrogen demand.

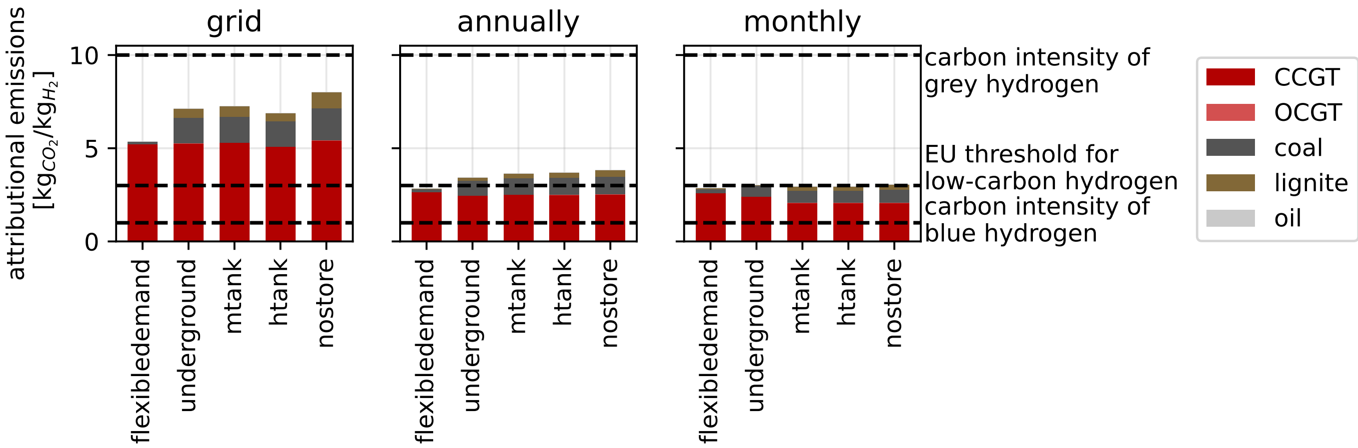


Figure 30: Attributional emissions of hydrogen, based on the mix of used electricity for Germany 2025 with the one step optimisation. The one step optimisation results in higher attributional emissions compared to the two step optimisation since the renewable generation share is overall lower. This is caused by the fact that the built renewables at the local hydrogen production are not truly additional (they are built either in the background system or at the local production node).

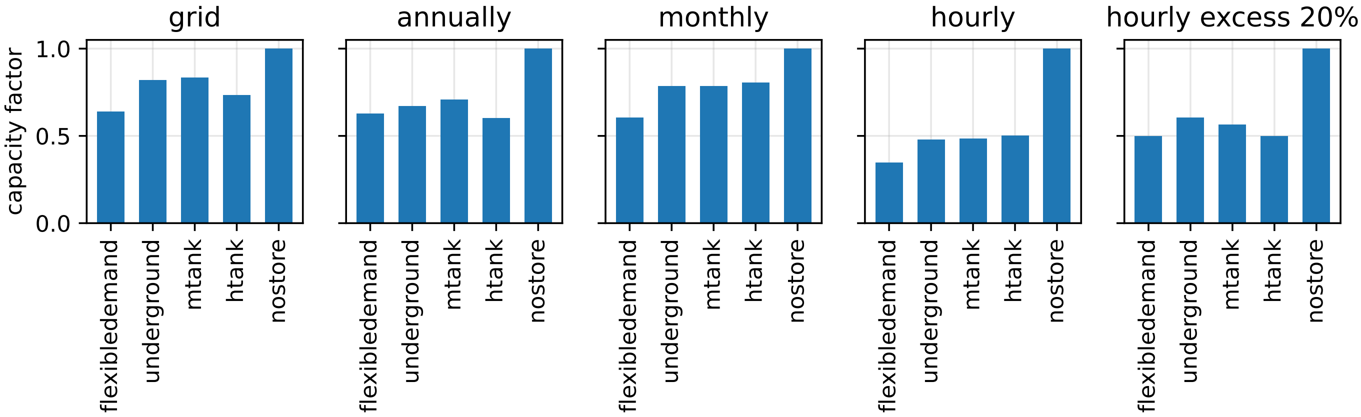


Figure 31: Capacity factors of electrolysis for different policies and different storage types in Germany 2025 with one step optimisation. Analogous to the two step optimisation, higher capacity factors are associated with higher costs for hydrogen storage. With completely inflexible demand, electrolysis runs at full capacity for all hours. This results in either higher emissions in case of the grid, annually and monthly scenarios or in high costs in case of the hourly matching.

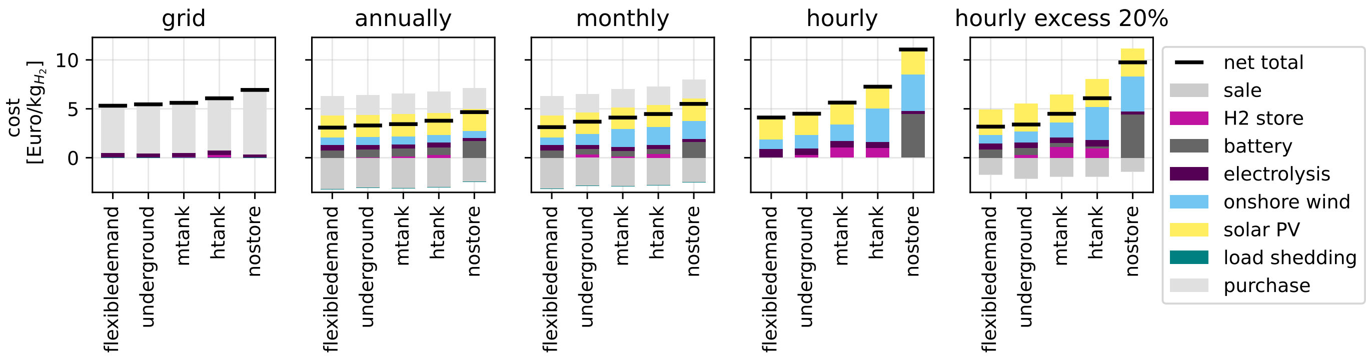


Figure 32: Cost of hydrogen production in Germany 2025 with one step optimisation.

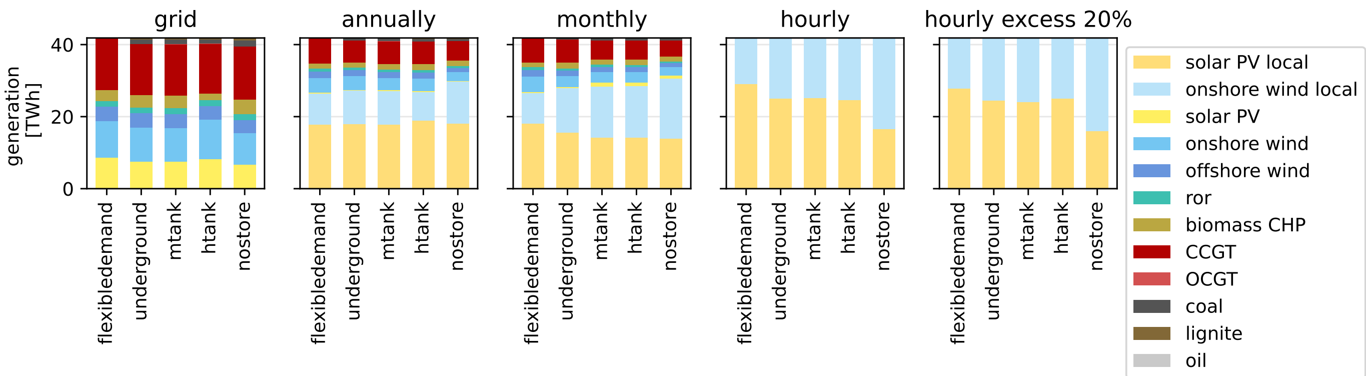


Figure 33: Mix of electricity generation in Germany 2025 when electrolysis is running for the one step optimisation.

4.8. Further sensitivities

4.8.1. Further countries: Czech Republic, Poland, Spain, Portugal

In the following we show the results for local hydrogen production of 28 $\mathrm{TWh}_{\mathrm{H}_2}$ in four additional countries (two countries with a higher share of conventional generation Czech Republic, Poland, and two countries with higher solar potential Spain and Portugal) in 2025.

In general, we observe a similar pattern regarding consequential emissions compared to Germany and the Netherlands. Flexible operation of electrolysis generally leads to lower emissions than constant operation. Consequential emissions are above those of grey hydrogen in all countries without additional renewable generators (grid scenario). In Poland (see Figure 36), the consequent emissions reach almost six times the value of grey hydrogen production (60 $\mathrm{kg}_{\mathrm{CO}_2}/\mathrm{kg}_{\mathrm{H}_2}$). Annual and monthly matching only lead to a very small increase in emissions. In the case of Czech Republic and Poland (see Figure 34 and 36), lignite production increases slightly in the case of inflexible electrolysis operation. In Portugal and Spain (see Figure 36 and 38), emissions increase by 2 $\mathrm{kg}_{\mathrm{CO}_2}/\mathrm{kg}_{\mathrm{H}_2}$in the case of inflexible operation with annual matching, while emissions decrease with monthly matching in all cases. Hourly matching has no influence on emissions and with allowed excess sales emissions decrease in all cases.

The cost premium for hourly matching in case of inflexible operation of electrolysis differs by country. While in Czech Republic and Poland (see Figure 35 and 37) the premium for hourly matching in case of flexible demand is above that in Germany at 8–9% higher costs, the premium in countries without coal generation and higher solar feed-in such as Portugal and Spain (see Figure 41 and 39) is lower at around 5%.

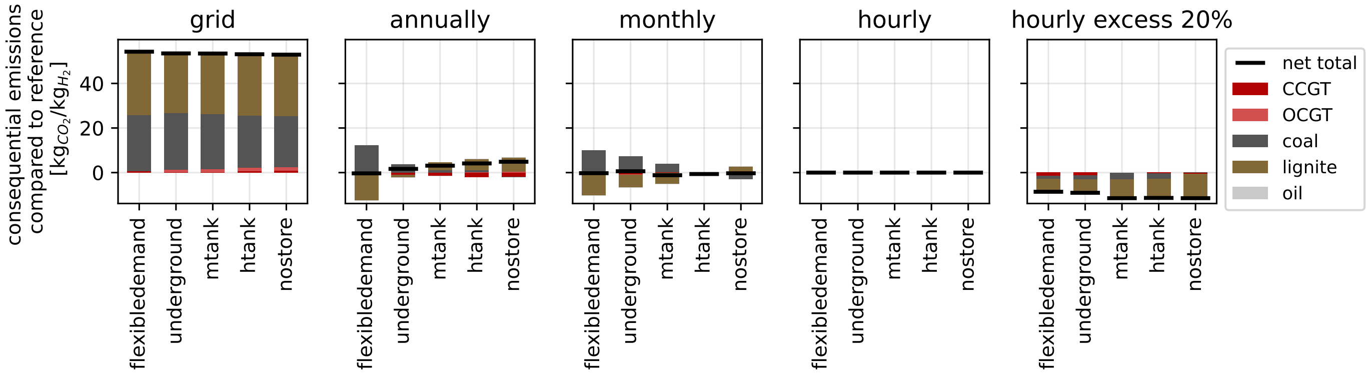


Figure 34: Consequential emissions for local hydrogen production in Czech Republic in 2025.

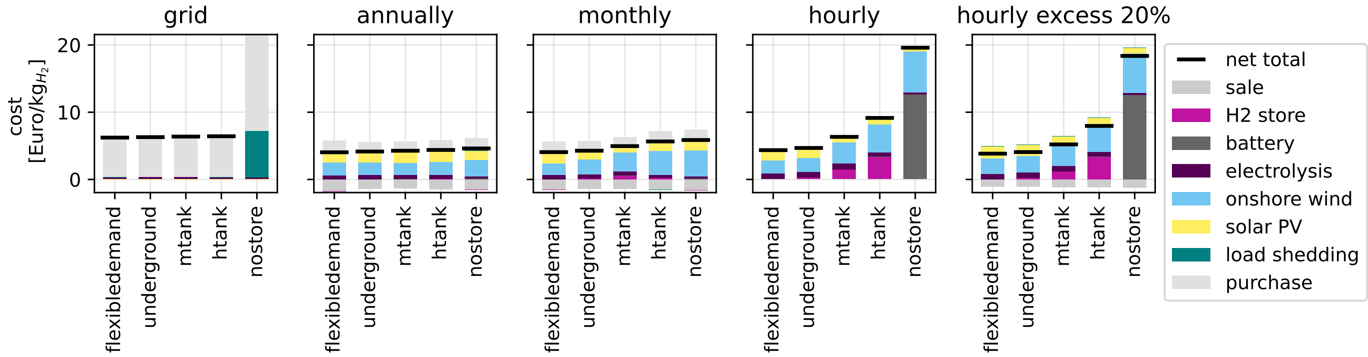


Figure 35: Hydrogen production costs in Czech Republic in 2025.

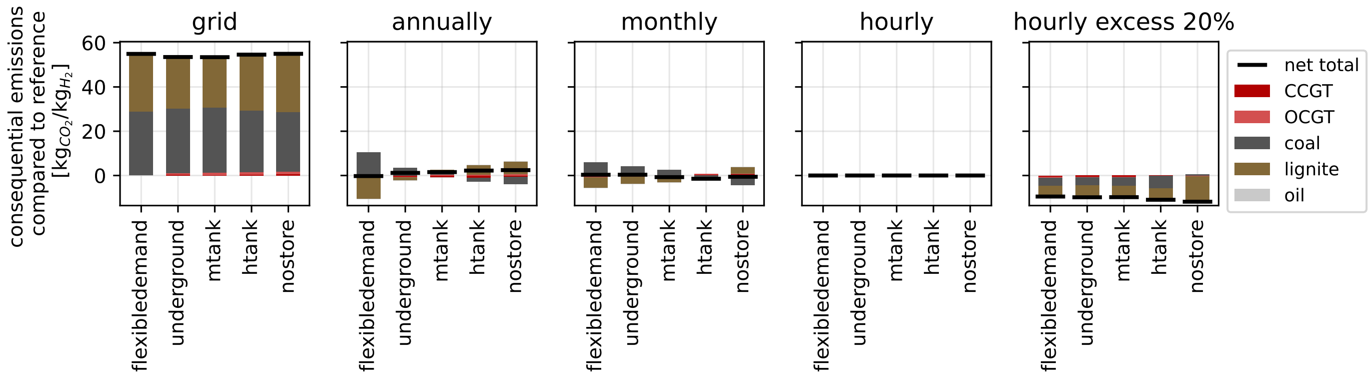


Figure 36: Consequential emissions for local hydrogen production in Poland in 2025.

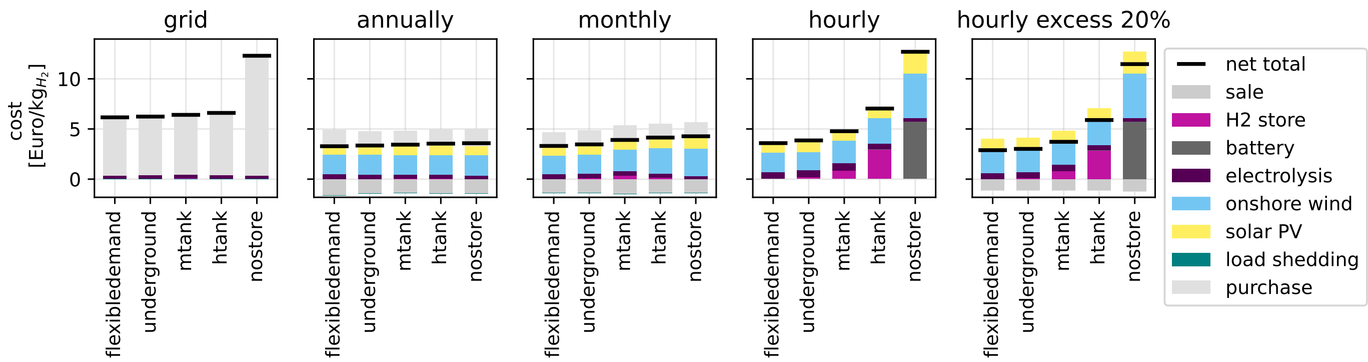


Figure 37: Hydrogen production costs in Poland in 2025.

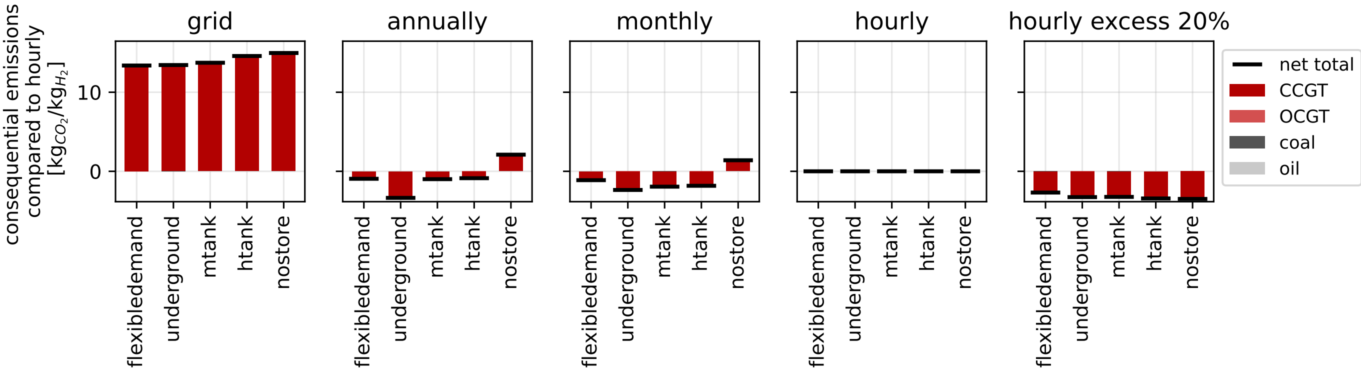


Figure 38: Consequential emissions for local hydrogen production in Spain in 2025.

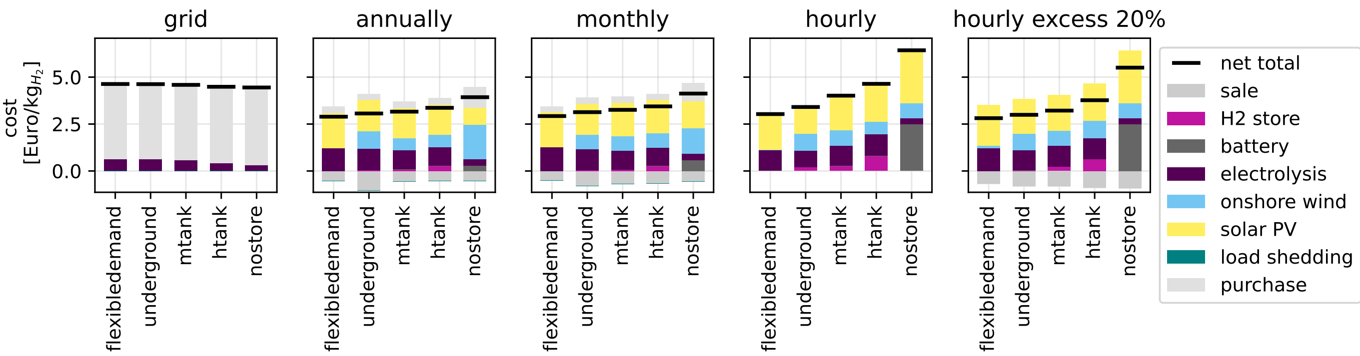


Figure 39: Hydrogen production costs in Spain in 2025.

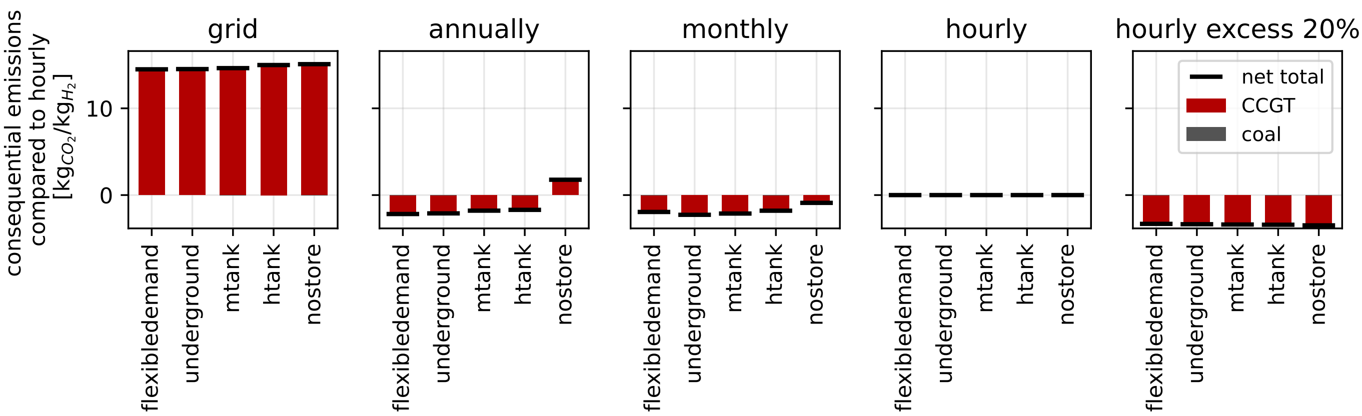


Figure 40: Consequential emissions for local hydrogen production in Portugal in 2025.

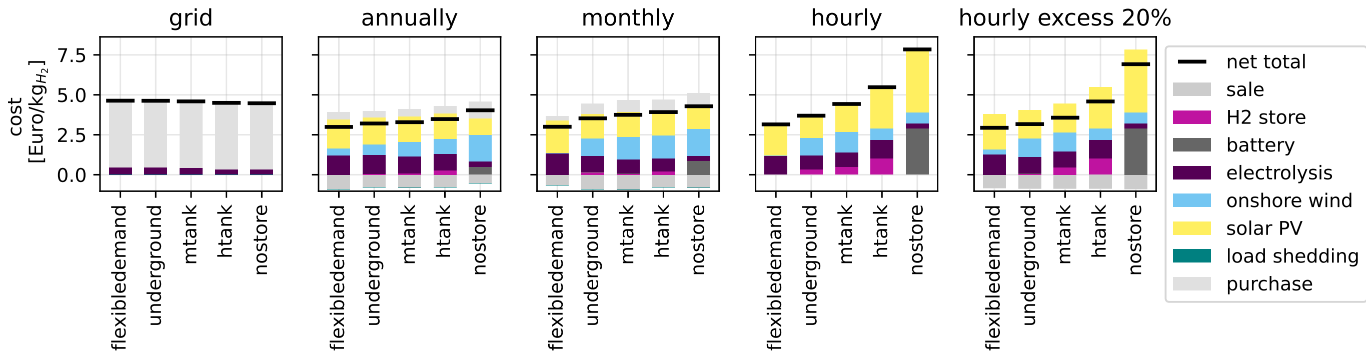


Figure 41: Hydrogen production costs in Portugal in 2025.

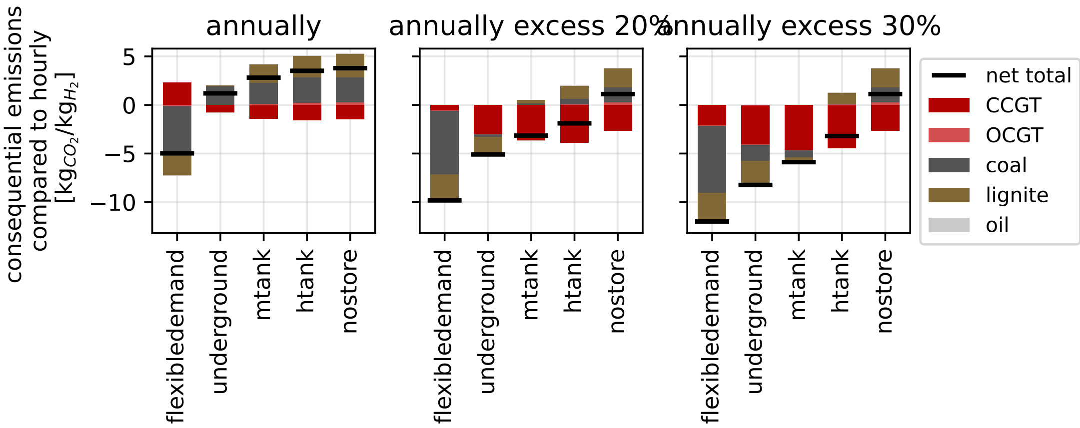
4.8.2. Allowing excess for annual matching

In the main results, in the annual matching scenario, the generation of local renewables equals the electricity demand of electrolysis summed over the year. In the following, we examine the impact of allowing additional local renewable production of up to 30%, which can be sold to the background grid.

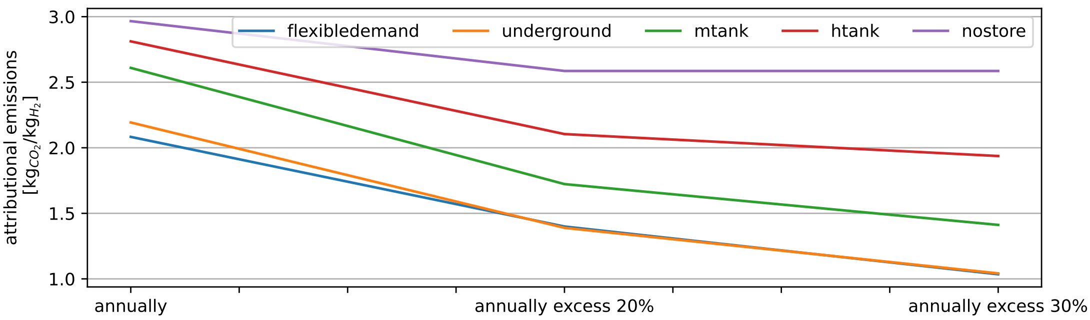
The consequential emissions decrease due to the higher share of renewable generation with increasing allowed excess sales (see Figure 42a). However, even with excess production of 30%, overall emissions increase in the case of inflexible demand.

Attributional emissions decrease with increasing excess sales. The decrease is more substantial in the case of flexible electrolysis operation, e.g. emissions decrease by 50% in flexible demand. In contrast, inflexible electrolysis operation leads to a decrease of 13% (see Figure 42b). In all annual matching scenarios in Germany 2025, however, they are still above the emissions of blue hydrogen and below the EU threshold for low-carbon hydrogen.

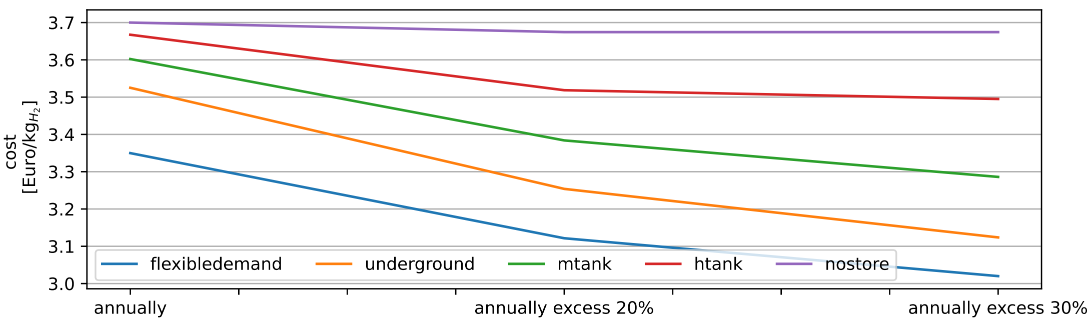
The costs of hydrogen production decrease by up to 10% in case of flexible demand due to the larger profits from excess sales (see Figure 42c). If no hydrogen storage is available and demand is inflexible, costs decrease only slightly by 1%



(a) Consequential emissions for annual matching with different allowed excess rates for Germany 2025.



(b) Attributional emissions for annual matching with different allowed excess rates for Germany 2025.



(c) Hydrogen production cost for annual matching with different allowed excess rates for Germany 2025.

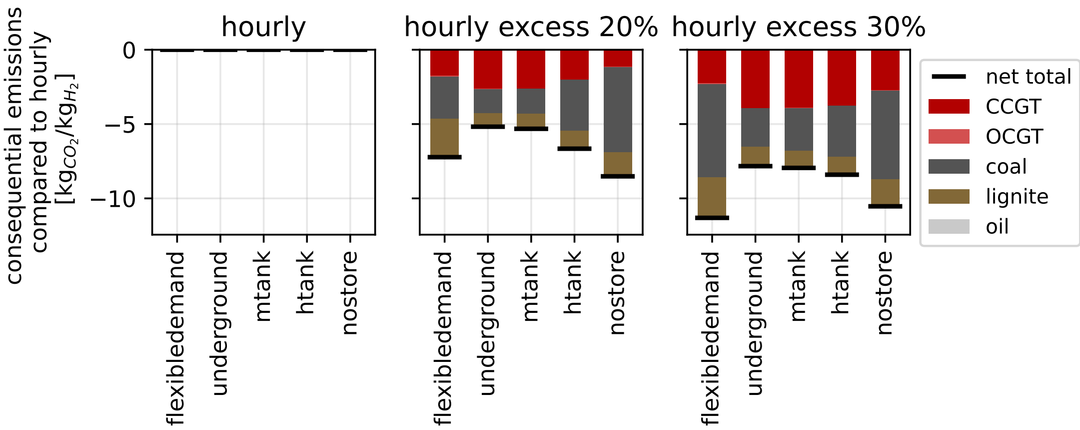
Figure 42: Scenarios with annual matching and different allowed excess to the grid for Germany 2025.

4.8.3. Allowing excess for hourly matching

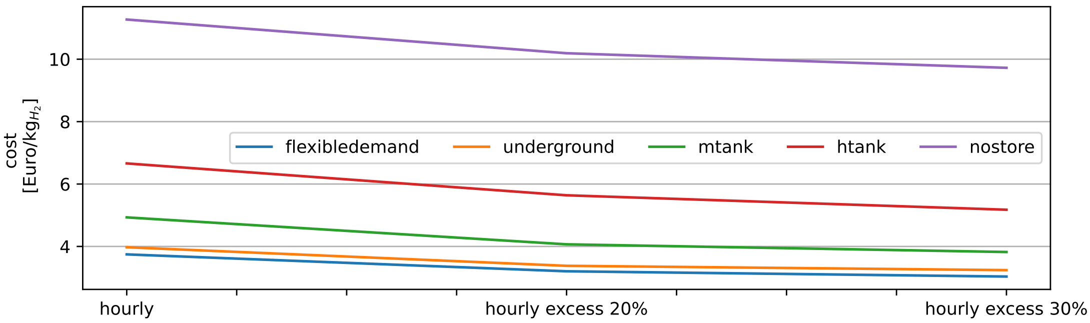
In the main results, we show one scenario with hourly matching and one with additional excess sales of 20%. In this sensitivity analysis, we allow for an even higher excess sale of 30% and consider the impact on consequential emissions and hydrogen production costs.

Consequential emissions reduce with increasing excess sales to a maximum -11 $kg_{CO_2}/kg_{H_2}$with 30% excess sale (see Figure 43a).

The cost of hydrogen production decreases on average by 19% with 30% excess sales compared to the hourly scenario (see Figure 43b). With flexible demand or cheap hydrogen storage, the costs with 30% excess sales are 3.04-3.24 €/kg_{H_2}. The costs for solar and wind increase slightly with rising excess sales, but greater profits in electricity sales lead to an overall reduction in costs.



(a) Consequential emissions.



(b) Cost breakdown for different allowed volumes of electricity sales to the grid with hourly matching for Germany 2025.

Figure 43: Scenarios with hourly matching and different allowed excess to the grid Germany 2025.

4.8.4. Sensitivity towards assumed gas prices

There is great uncertainty about future natural gas prices due to the Russian attack on Ukraine. A different merit order can arise depending on the gas price. The influence of this effect on our results is considered below. For this purpose, we vary the gas price between 20-50 Eur/MWh_{th} and consider the effects on the consequential emissions.

For gas prices between 20–40 Eur/MWh_{th} the general pattern of consequential emissions for annual and monthly matching remains the same. In the case of flexible demand, the emissions decrease. In the absence of low-cost storage, emissions increase. The more expensive the gas prices, the lower the consequential emissions from medium pressure tank hydrogen storage. In the case of a very high gas price of 50 Eur/MWh_{th}, the consequential emissions for each storage

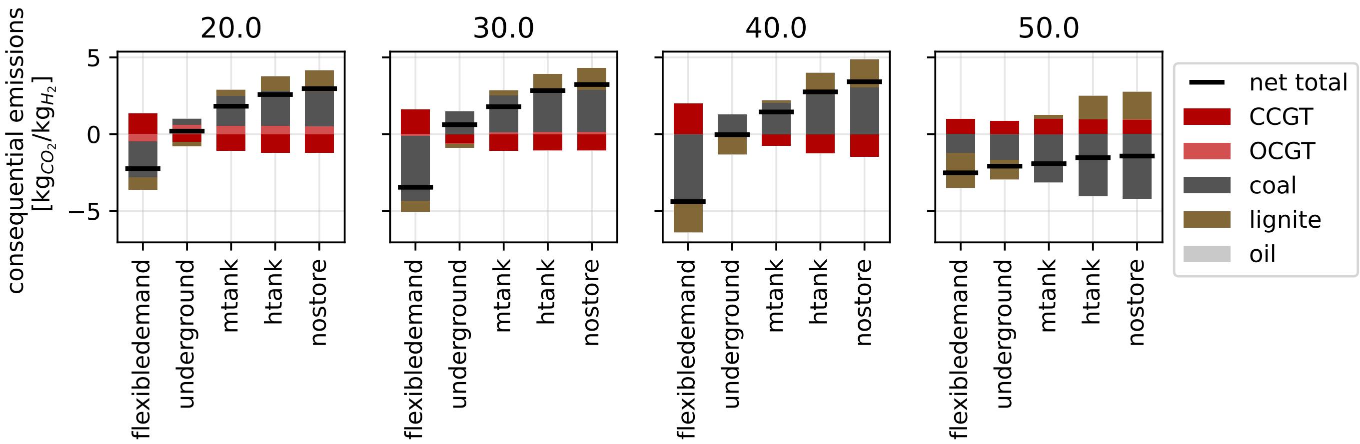


Figure 44: Consequential emissions for Germany 2025 for **annual matching** with varying natural gas prices between 20–50 Eur/MWh$_{\mathrm{th}}$ (default assumption is 35 Eur/MWh$_{\mathrm{th}}$).

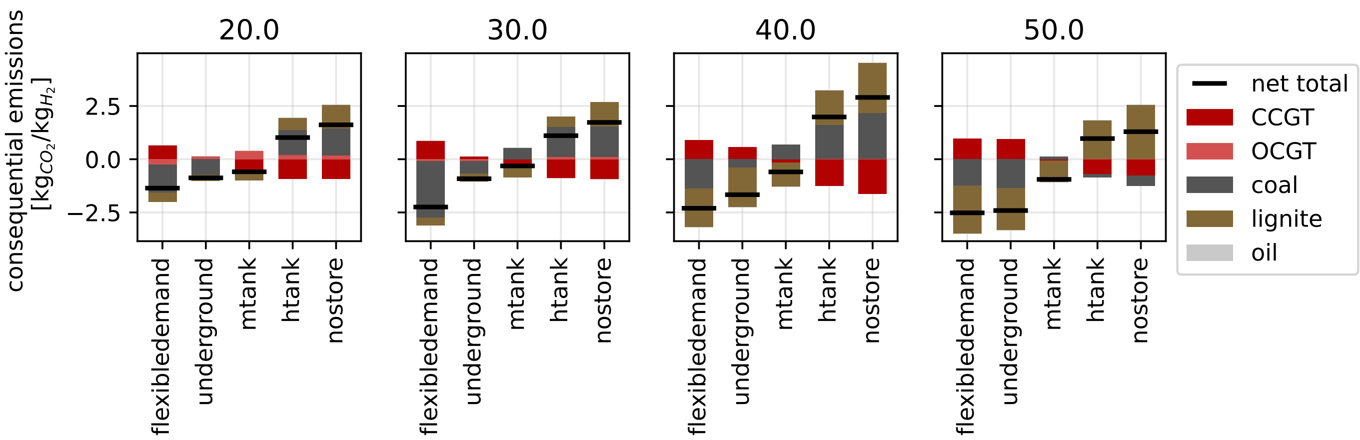


Figure 45: Consequential emissions for Germany 2025 for **monthly matching** with varying natural gas prices between 20–50 Eur/MWh$_{\mathrm{th}}$ (default assumption is 35 Eur/MWh$_{\mathrm{th}}$).

form decrease in the case of annual matching and increase in the case of monthly matching only in the case of expensive storage options.

4.8.5. Share of renewable generation

In the following, we consider the impact of the share of renewable generation on (i) consequential emissions, (ii) capacity factors of the electrolysis and (iii) costs of hydrogen production. We vary the renewable generation share in Germany between 40% (roughly 2021 share) to 100% (base assumptions is 55%). The renewable generation share in the neighbouring countries is kept on the 2025 target. The renewable generation share is defined as share from total electricity demand. The constraint is only applied in the first optimisation step when the electricity background system is optimised. Therefore, even with a share of 100% renewable generation in the first optimisation step, the additional hydrogen demand which is added in the second optimisation run may result in the use of conventional power plants with associated emissions.

Since only the grid, annually and monthly matching scenarios can purchase electricity from the rest of the system, only these regulatory options for hydrogen production are considered. Overall, consequential emissions decrease with a higher share of renewable (see Figure 46, Figure 47, Figure 48). But even in a system with 100% renewable without hydrogen demand, emissions increase in the case of inflexible operation of electrolysis for annual and monthly matching. This is due to the additional use of coal-fired power plants to provide electricity for the inflexible additional demand of

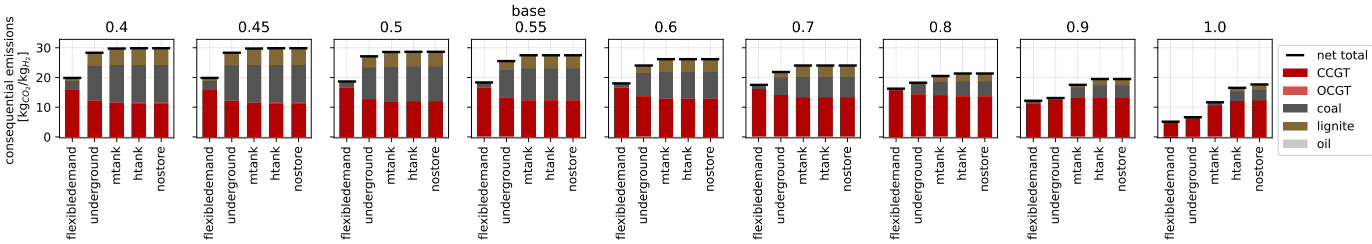


Figure 46: Consequential emissions for the **grid** scenario in Germany 2025 with increasing share of renewable generation from 40% to 100% renewable generation. Our base assumptions are 55% renewable gernation share in 2025. The renewable targets of the neighbouring countries are fixed to 2025. Coal power plants are still part of the generation mix in Germany. Since the renewable generation constraint only applies to the electricity demand before the hydrogen production and generation from coal power plants in neighbouring countries is increasing there can be consequential emissions even with a 100% renewable generation.

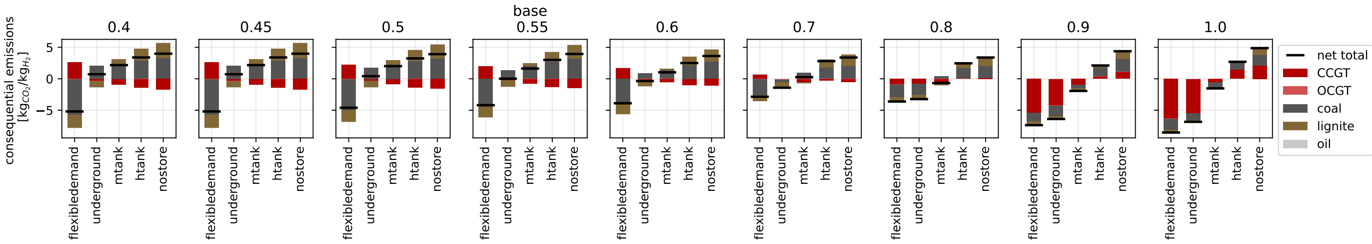


Figure 47: Consequential emissions for the **annually** scenario in Germany 2025 with increasing share of renewable generation from 40% to 100% renewable generation. Our base assumptions are 55% renewable gernation share in 2025. The renewable targets of the neighbouring countries are fixed to 2025. Coal power plants are still part of the generation mix in Germany.

electrolysis. As shown in our scenarios for Germany 2030, in the case of a phase-out of coal-fired power plants and a higher CO_2 price, no increased emissions are observed for annual or monthly matching with a renewable share of 80%. The capacity factors of electrolysis decrease with increasing renewable share due to the higher share of flexible electricity generation (see Figure 49 and Figure 50). In the grid scenario, the costs drop from 5.40 €/kg_{H_2} to as low as 3.99 €/kg_{H_2} as the share of renewables increases (see Figure 51). The costs decrease because the high share of renewable energy lowers the electricity prices and higher renewable energy feed-in can be used for hydrogen production. For monthly matching, the costs of hydrogen production for cheap forms of storage are down to 3.11 €/kg_{H_2} (see Figure 52). In the case of expensive storage, the costs increase from a renewable share of 80% to up to 4.49 €/kg_{H_2}. Since larger capacities of electrolysis are cost-optimal with a larger share of renewables, the share of electrolysis in the total costs of hydrogen production increases.

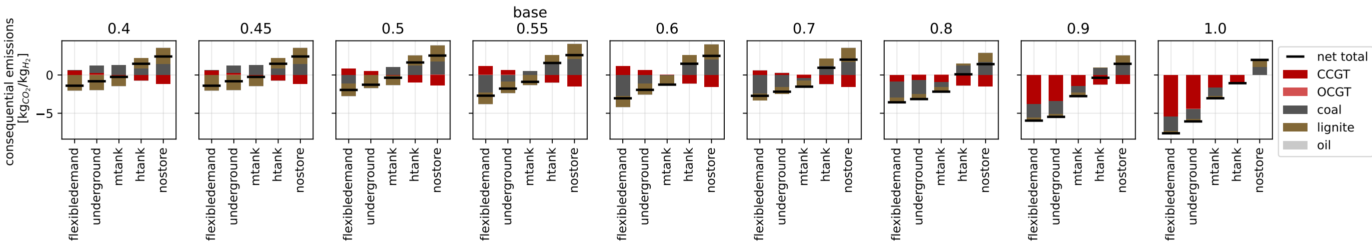


Figure 48: Consequential emissions for the **monthly** scenario in Germany 2025 with increasing share of renewable generation from 40% to 100% renewable generation. Our base assumptions are 55% renewable gernation share in 2025. The renewable targets of the neighbouring countries are fixed to 2025. Coal power plants are still part of the generation mix in Germany.

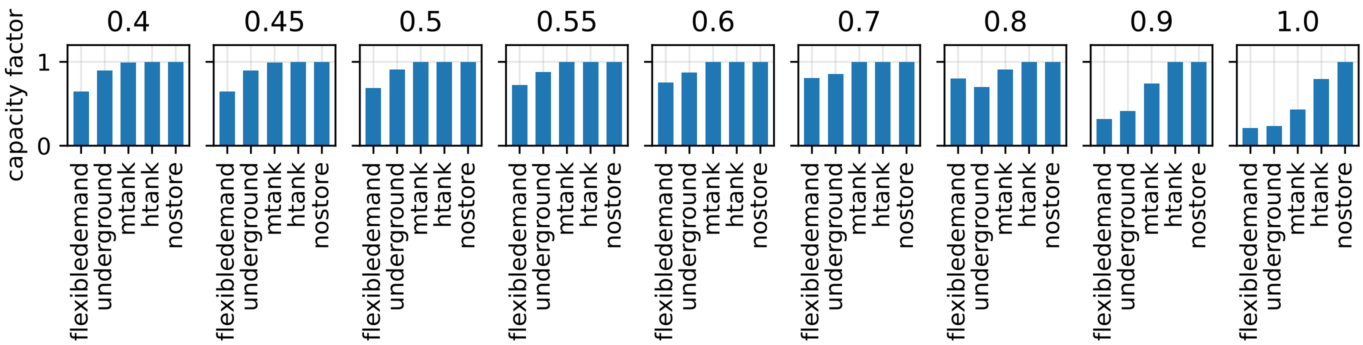


Figure 49: Capacity factors of the electrolysis for the **grid** scenario in Germany 2025 with increasing share of renewable generation from 40% to 100% renewable generation. With an increasing share of renewable generation the capacity factors are decreasing.

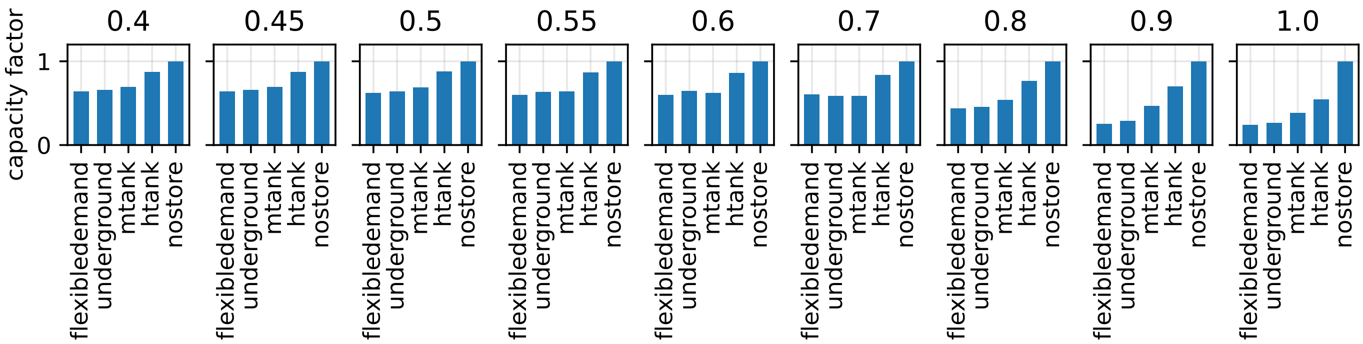


Figure 50: Capacity factors of the electrolysis for the **monthly** matching scenario in Germany 2025 with increasing share of renewable generation from 40% to 100% renewable generation. With an increasing share of renewable generation the capacity factors are decreasing.

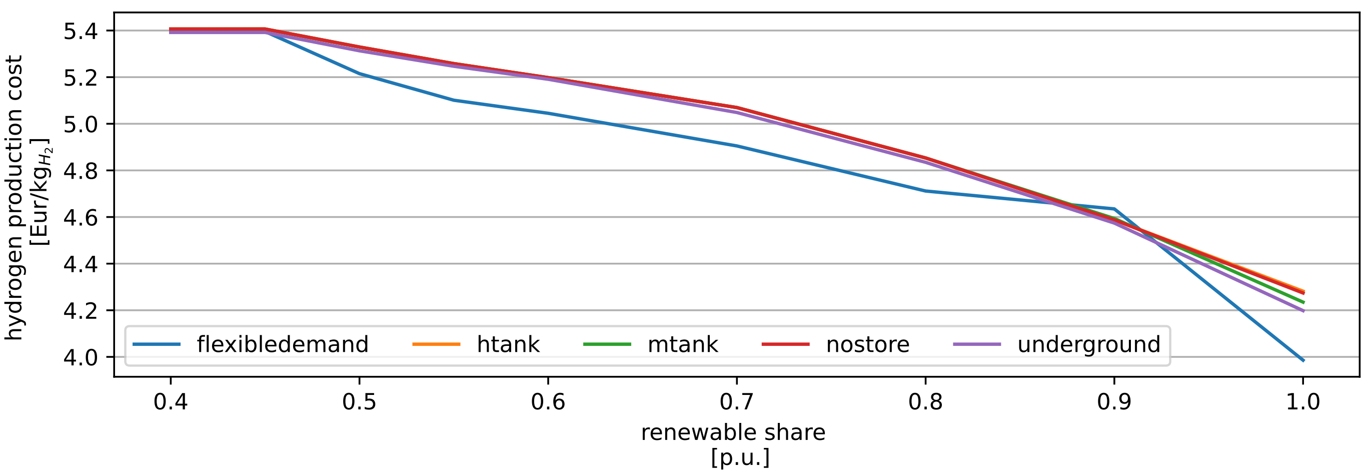


Figure 51: Cost of hydrogen production for the **grid** scenario in Germany with increasing share of renewable generation from 40% to 100% renewable generation.

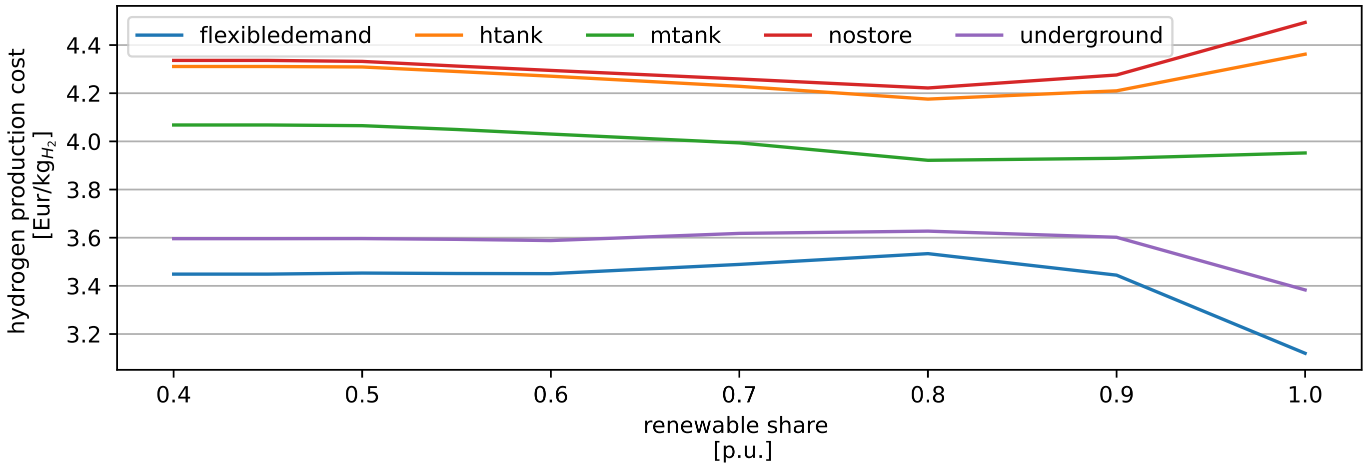


Figure 52: Cost of hydrogen production for the **monthly** matching scenario in Germany with increasing share of renewable generation from 40% to 100% renewable generation.

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