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# Flexible green hydrogen: Economic benefits without increasing power sector emissions

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## Abstract

Electrolytic hydrogen complements renewable energy in many net-zero energy scenarios. In these long-term scenarios with full decarbonization, the “greenness” of hydrogen is without question. In current energy systems, however, the ramp-up of hydrogen production may cause additional emissions. To avoid this potential adverse effect, recently proposed EU regulation defines strict requirements for electrolytic hydrogen to qualify as green: electrolyzers must run on *additional* renewable generation, which is produced in a temporally and geographically congruent manner. Focusing on the temporal dimension, this paper argues in favor of a more flexible definition of green hydrogen, which keeps the additionality criterion on a yearly basis but allows for dispatch optimization on a market basis within that period. We develop a model that optimizes dispatch and investment of a wind-hydrogen system—including wind turbines, hydrogen electrolysis, and hydrogen storage—and apply the model to a German case study based on data from 2017-2021. Contrasting different regulatory conditions, we show that a flexible definition of green hydrogen can reduce costs without additional power sector emissions. By contrast, requiring simultaneity implies that a rational investor would build a much larger wind turbine, hydrogen electrolyzer, and hydrogen storage than needed. This leads to additional costs, underutilized resources, and a potential slow-down of green hydrogen deployment. We discuss that current trends in the energy transition are likely to amplify the economic and environmental benefits of a flexible definition of green hydrogen and recommend this as the way forward for a sustainable hydrogen policy.

## Acknowledgements

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# 1 Introduction

**Hydrogen as a climate solution.** The Paris Agreement defines the goal of limiting global warming well below 2 °C, aiming for 1.5 °C. To fulfill this goal, an increasing number of countries has set net-zero emission targets. One frequently discussed component for reaching net-zero emissions is low-carbon hydrogen, in particular “green” hydrogen produced from renewable electricity (Blanco et al., 2018; Parra et al., 2019). This is because green hydrogen as well as derived synthetic fuels have the potential to decarbonize energy end-use sectors for which cheaper options like direct electrification are not available or not economical (Ruhnau et al., 2019; Ueckerdt et al., 2021). For the example of the EU, the European Commission estimates hydrogen needs of around 13-14%% of the energy mix by mid-century (EC, 2020).

**Hydrogen as a source of flexibility.** In addition to decarbonizing hard-to-abate sectors, electrolytic hydrogen may be an important source of flexibility for the power sector. On the one hand, hydrogen can serve as a long-term storage solution (Victoria et al., 2019; Dowling et al., 2020; Ruhnau and Qvist, 2022). On the other hand, hydrogen for other sectors could be produced in hours when wind and solar energy is abundant, helping the system integration of these variable renewable energy sources and stabilizing their market values (Stöckl et al., 2021; Ruhnau, 2022). Along these lines, studies on net-zero energy systems normally assume that, apart from off-grid installations at locations with very good resources, hydrogen electrolyzers are fully integrated in the electricity system and optimizing their operation based on market prices (Capros et al., 2019; International Energy Agency, 2021; Lugovoy et al., 2021).

**Need to define green hydrogen.** While there will be no question about the “color” of electrolytic hydrogen in a future net-zero energy system, it is essential to define green hydrogen in a system that is not yet fully decarbonized. Without a clear definition of green hydrogen, the near-term ramp-up of electrolytic hydrogen may cause additional electricity demand that is supplied by fossil fuels and, hence, increase emissions in the power sector. As a result, electrolytic hydrogen would not necessarily reduce emissions compared to hydrogen produced from natural gas via (unabated) steam methane reforming. More generally, the ramp-up may not even materialize because electrolytic hydrogen could not compete against fossil hydrogen. By contrast, based on a legal definition and a corresponding certification, some end-consumers may have a higher willingness to pay for green hydrogen, the state may subsidize it, and it could be considered in renewable energy or sectoral decarbonization targets.

**RED II sustainability criteria.** Against this background, the European Commission lays out three preconditions for hydrogen to qualify as renewable within the Renewables Energy Directive II (RED II) and the associated “Delegated Act on the methodology to determine the renewability of electricity used in the production of renewable liquid and gaseous fuels of non-biological origin” (RFNBOs)<sup>1</sup>. First, it must be produced based on additional renewable electricity, that is, electricity from newly built renewable generators that do not receive any other subsidy (additionality criterion). Second, green

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<sup>1</sup> <https://ec.europa.eu/info/law/better-regulation/have-your-say/initiatives/7046068-Methodology-on-share-of-renewable-electricity-in-the-production-of-renewable-transport-fuels-of-non-biological-origin> (accessed 2022-05-23)

hydrogen shall be produced at the same time as the additional renewable energy generation occurs (simultaneity criterion). Third, the electrolyzer and the additional renewable generators should not be too distant from each other (proximity criterion). By regulating the additional supply of renewable electricity, these criteria are meant to prevent an increase in fossil electricity generation and related emissions due to the ramp-up of electrolyzers.<sup>2</sup>

**Argument.** In this paper, we argue in favor of a more flexible, system-friendly definition of green hydrogen, which keeps the additionality criterion but allows for temporal optimization based on wholesale market prices. This would mean that additional electricity could be fed into the grid when prices are high and taken out when prices are low—as long as the overall (annual) volume of grid feed-in is equal or larger than take-out. Because renewables depress market prices whenever they are available, there is an incentive for electrolyzers to follow the system-wide availability of renewables (instead of following the individual asset). Allowing electrolyzers to produce whenever market prices are low would reduce the cost of hydrogen (for investors or for the state in terms of subsidies). In addition, if carbon prices are high enough, power prices will reflect marginal emissions, and a market-based optimization of electrolyzers will reduce the emissions of the power system.

**Method & case study.** To support this argument, we model optimized investment and hourly dispatch decisions for a wind-hydrogen system under different regulatory frameworks. The wind-hydrogen system comprises wind turbines, hydrogen electrolysis, and hydrogen storage. Hydrogen storage is considered to balance between a varying hydrogen production and an assumed baseload hydrogen offtake, e.g., by an industrial consumer. We contrast three regulatory scenarios: first, an isolated wind-hydrogen system without market interaction (“island system”); second, a grid-connected system in which the electrolyzer can use the additional wind generation only during the hour where it is produced (this reflects the simultaneity requirement in the current draft of the RED II regulation); and third, a grid-connected system in which the additionality restriction is enforced only on a yearly basis (relaxing the simultaneity criterion). In addition to the optimal investment and dispatch decisions, we analyze the resulting levelized cost of hydrogen (LCOH) and the related emissions based on marginal power sector emission factors (using an enhanced version of a method developed by Fleschutz et al. (2021)). We apply our model to a German case study, using observed wholesale electricity prices and the generation profile of an exemplary wind farm. We first focus on the years 2017 to 2020 before exploring the impact of the emerging energy crisis in 2021 on our results. Investment decisions are calibrated with 2020 cost assumptions from the EU asset project.

**Previous literature on simultaneity.** This paper adds to previous studies on the implications of the simultaneity requirement for green hydrogen. Pototschnig (2021) argues that the annual nature of EU renewable energy targets would only require temporal congruency of additional renewables and hydrogen production on an annual basis. In addition, Frontier Economics (2021a, 2021b) show that a temporally flexible hydrogen production substantially reduces the levelized cost of green hydrogen compared to inflexible operation, while the implications for the power sector are ambiguous. Similarly,

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<sup>2</sup> Note that additional renewable generation in the sense of RED II can be associated with hydrogen production through a private physical connection or through power purchase agreements when electricity is transmitted via the public grid.

Schlund and Theile (2022) find an increased contribution margin from relaxing the simultaneity criterion, but they conclude that this will always lead to increased emissions. The present paper extends the scope of these previous studies in three important dimensions. First, this paper estimates the effect that regulation has not only on the dispatch of but also the investment into green hydrogen. In particular, we are estimating the optimal relative size of hydrogen electrolyzers and dedicated “additional” wind turbines. Second, we are the first to include hydrogen storage in our optimization, which poses realistic costs and limitations to the flexible operation of hydrogen electrolyzers. Finally, our analysis is based on observed historical electricity prices, while Frontier Economics (2021a, 2021b) and Schlund and Theile (2022) use synthetic electricity prices from a fundamental market model and a regression model, respectively. We furthermore consider observed fuel and carbon prices in a high temporal resolution to characterize the role of these prices in producing green hydrogen, not least exploring the implications of the emerging energy crisis in 2021.

**Findings.** We find that a flexible definition of green hydrogen leads to a significant reduction of the cost of hydrogen, while avoiding additional emissions in the power sector. Across the years 2017-2020, the average levelized cost of green hydrogen are reduced from 200 €/MWh<sub>H2</sub> in the island case and 150 €/MWh<sub>H2</sub> in the simultaneity case to 100 €/MWh<sub>H2</sub> in the flexible case, and power sector emissions are reduced by -0.005 to -0.027 t/MWh<sub>H2</sub> compared to producing green hydrogen in an island system or not at all. While reduced costs of a flexible green hydrogen production is qualitatively in line with previous studies, we demonstrate that the cost reduction arises not only from a more efficient dispatch of the electrolysis but also from a reduced size of all components of the wind-hydrogen system (wind turbines, hydrogen electrolysis, and hydrogen storage). According to our model results, the rational response to relaxing the simultaneity criterion is an increase in the utilization of the electrolyzer while keeping some flexibility to adjust to both dedicated renewable production and market prices.

**Conclusion.** We conclude that an annual additionality requirement without strict simultaneity is economically beneficial and at the same time sufficient to address the environmental concern of increasing power sector emissions. The economic benefits materialize as lower costs of green hydrogen, which can reduce the need for subsidies and increase the speed for a hydrogen ramp-up. Furthermore, relaxing the simultaneity criterium enables hydrogen electrolysis to provide flexibility to the electricity market, which can reduce overall system costs. As we discuss in the end of this paper, current trends in the energy transition are likely to amplify the benefits of a flexible definition of green hydrogen and hence pave the way for market-based hydrogen without need for subsidies.

**Outline.** The remainder of this paper is structured as follows. Section 2 introduces our model, regulatory scenarios, and input data. Section 3 presents the results in terms of optimal dispatch and investment of a wind-hydrogen system across the years 2017-2021. Section 3 provides a discussion of the results, and Section 4 draws conclusions.

## 2 Method

### 2.1 Cost optimization model

**Idea.** We use a model to determine the cost-optimal configuration and operation of a co-located wind-hydrogen system that supplies a fixed amount of hydrogen to a local base-load consumer. This setting reflects one frequently discussed scenario for the initial ramp-up of green hydrogen before integrated hydrogen grids and hence liquid markets are created. The model optimizes investment and dispatch decisions from the investor’s perspective with perfect foresight—given different regulatory scenarios (Subsection 2.2). The investment decisions include the wind generation capacity, the hydrogen electrolyzer capacity, and the hydrogen vessels storage capacity. Dispatch is optimized for the hydrogen electrolyzer and the hydrogen storage. Furthermore, depending on the regulatory framework, the model accounts for the option to exchange electricity with the grid and trade related volumes on wholesale electricity markets. The optimization problem is normalized to 1 MWh of hydrogen per year, and all decision variables are linear, reflecting that the modular nature of wind turbines, electrolyzer stacks, and hydrogen vessels allows for flexibility with sizing and operating actual projects.

**Objective function.** The model minimizes the LCOH, which is the sum of investment costs, variable costs, and the net costs of trading (Eq. 1).<sup>3</sup> The investment costs are calculated as the product of installed capacities  $CAPA_{tec}$  and annualized fixed costs  $afc_{tec}$ , where  $tec$  is the set of technologies, including wind generation,  $wind$ , hydrogen electrolysis,  $PtG$ , and hydrogen storage,  $sto$ . Furthermore, we consider variable costs,  $cost_{tec}^{var}$ , depending on the electricity generation of the wind turbine,  $GENE_{t,wind}$ , and the electricity consumption of the electrolyzer,  $CONS_{t,PtG}$ , in every hour,  $t$ . Trading increases costs when buying electricity,  $BUY_t$ , at time-varying buy prices,  $p_t^{buy}$ , and reduces costs when selling electricity,  $SELL_t$ , at time-varying sell prices,  $p_t^{sell}$ . As discussed below, we use wholesale electricity prices as sell prices, while the buy prices include a fixed mark-up for taxes and grid fees on top of the wholesale prices.

$$LCOH = \sum_{tec} CAPA_{tec} cost_{tec}^{fix} + \sum_t GENE_{t,wind} cost_{wind}^{var} + CONS_{t,PtG} cost_{PtG}^{var} + \sum_t BUY_t p_t^{buy} - SELL_t p_t^{sell} \quad (1)$$

**Energy balances.** The two main constraints of the model are the electricity balance and the hydrogen balance, respectively. The electricity balance (Eq. 2) states that the consumption of the electrolyzer must be met by wind generation plus buy and minus sell volumes from trading in every hour. The hydrogen balance ensures an annual supply of 1 MWh hydrogen at a constant rate, that is, 1/8760 MWh of hydrogen supply per hour (Eq. 3). This supply requirement must match on an hourly basis with the operation of the electrolyzer (accounting for the power-to-hydrogen conversion efficiency  $\eta_{PtG}$ ) plus discharging of the hydrogen storage,  $OUT_{t,sto}$ , minus charging of the hydrogen storage,  $IN_{t,sto}$ .

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<sup>3</sup> As a general rule, we denote decision variables with capital letters, and parameters with non-capitalized letters.

$$CONS_{t,PtG} = GENE_{t,wind} + BUY_t - SELL_t \quad \forall t \quad (2)$$

$$\frac{1}{8760} = CONS_{t,PtG} \eta_{PtG} + OUT_{t,sto} - IN_{t,sto} \quad \forall t \quad (3)$$

**Capacity constraints.** Further constraints relate the dispatch to the investment variables. The sum of the hourly wind generation and curtailment,  $CURTAIL_t$ , equals the installed wind turbine capacity times the hourly capacity factors,  $profile_{t,wind}$  (Eq. 4). The electrolyzer can consume electricity up to its installed capacity (Eq. 5), and the hydrogen storage level,  $LEVEL_{t,sto}$ , cannot exceed the installed storage capacity. For a sensitivity analysis, we also constrain the grid availability such that selling electricity is impossible in hours when the grid is congested (see Subsection 3.4).

$$GENE_{t,wind} + CURTAIL_t = CAPA_{wind} profile_{t,wind} \quad \forall t \quad (4)$$

$$CONS_{t,PtG} \leq CAPA_{PtG} \quad \forall t \quad (5)$$

$$LEVEL_{t,sto} \leq CAPA_{sto} \quad \forall t \quad (6)$$

**Hydrogen storage level.** Another constraint links the storage level at the end of hour  $t$  to the storage level at the end of the previous hour  $t - 1$ , accounting for storage charging and discharging during hour  $t$ :

$$LEVEL_{t,sto} = LEVEL_{t-1,sto} + IN_{t,sto} - OUT_{t,sto} \quad \forall t \quad (7)$$

**Additionality.** The final constraint represents the additionality criterion. In case trading is allowed, the amount of electricity that is sold to the market must be greater than or equal to the amount of electricity that is bought from the market on an annual basis (Eq. 8). Note that this is equivalent to the requirement that the annual electricity generation of the wind turbine must be greater or equal to the annual electricity consumption of the electrolyzer.

$$\sum_t SELL_t \geq \sum_t BUY_t \quad (8)$$

## 2.2 Regulatory scenarios

**Scenarios.** We run the model for three scenarios: an island system, market interaction with simultaneity requirement, and a market interaction without simultaneity requirement.

**Island system.** For the island scenario, there is no option to exchange electricity with the wholesale market (Eq. 9). This scenario matches the (implicit) assumption in many studies on the cost of green hydrogen (IEA, 2019; IRENA, 2020). While such a setup may be an economically attractive option at locations with very high renewable resource potentials, we show below that it would be very expensive to build such a system in Germany. Nevertheless, we use the island system as a reference for demonstrating the value of market interaction with and without a simultaneity requirement. Note that we are not requiring that the utilization of the electrolyzer is equal to the utilization of the wind turbine. By contrast, the relative size of the wind turbine and the electrolyzer are optimized, trading-

off the costs of renewable curtailment, low utilization of the electrolyzer, and the cost of storing hydrogen to smoothen the supply of hydrogen to the end consumer.

$$SELL_t = BUY_t = 0 \quad \forall t \quad (9)$$

**Market interaction with simultaneity.** In the second scenario, we allow for market interaction but with an hourly simultaneity requirement.<sup>4</sup> This means that selling electricity to the market is allowed, but electricity purchases are prohibited (Eq. 10). This scenario has been proposed and analyzed before by Frontier Economics (2021a, 2021b) and Schlund and Theile (2022), but without optimizing the relative capacity of the wind turbine and the hydrogen electrolyzer. Similarly, Glenk and Reichelstein (2019) analyze a wind-hydrogen system with the option to sell electricity to the market, including capacity optimization. However, they did not consider the cost of hydrogen storage, which is a gap we aim to fill with the present study.

$$\begin{aligned} SELL_t &\geq 0 & \forall t \\ BUY_t &= 0 & \forall t \end{aligned} \quad (10)$$

**Market interaction without simultaneity.** Finally, we consider a scenario with market interaction without a simultaneity requirement. Hence, both electricity sales and purchases are possible (Eq. 11). Note that  $p_t^{buy} > p_t^{sell}$  to account for taxes and grid fees and that the additionality criterion needs to be fulfilled on an annual basis (Eq. 8). While this scenario is also included in Frontier Economics (2021a, 2021b) and Schlund and Theile (2022), we additionally consider the implications for capacity optimization and the role of hydrogen storage.

$$SELL_t, BUY_t \geq 0 \quad \forall t \quad (11)$$

**Subsidies.** For additional sensitivity analyses, we consider subsidies on the operational and investment cost of the electrolyzer (see Subsection 3.4).

## 2.3 Input data

**Cost assumptions.** Our cost assumptions are summarized in Table 1. The assumptions for the wind turbine is based on the “medium” estimate for 2020 from the EU ASSET project (De Vita et al., 2018). The assumptions for the hydrogen technologies are based on a more detailed analysis by Element Energy (Walker et al., 2018). For all components, a weighted average cost of capital of 5% is assumed. Furthermore, a conversion efficiency of 75% is assumed for the hydrogen electrolyzer (IEA, 2019).<sup>5</sup>

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<sup>4</sup> Note that the current draft of the relevant EU regulation entails two exceptions to the rule of simultaneity: monthly balancing is allowed during a transitional period of 5 years and grid purchases are allowed when prices are below a certain threshold. However, this paper abstract from these detailed rules and focuses on the effect of an “ideal” simultaneity criterion.

<sup>5</sup> This conversion efficiency as well as all references to the energy content of hydrogen throughout this document refer to the lower heating value of hydrogen (33.3 kWh<sub>H2</sub>/kg<sub>H2</sub>).



Table 1: Cost assumptions

Technology		Wind onshore	Hydrogen electrolyzer	Hydrogen storage
Unit		€/kW <sub>el</sub>	€/kW <sub>el</sub>	€/kWh <sub>H2</sub>
Investment cost	unit	1,295	750	10
Lifetime	a	25	20	20
Fixed O&M	unit p.a.	14	20	0.3
Annualized fixed cost	unit p.a.			
Variable cost	€/MWh <sub>el</sub>	0.00018	0.002	-

**Electricity prices.** For the hourly wholesale electricity prices, we use historical data from the German day-ahead market, retrieved via the SMARD data platform.<sup>6</sup> These prices are used directly as sell prices. For buying electricity, we assume a mark-up of 27.5 €/MWh<sub>el</sub>. This includes 20.5 €/MWh<sub>el</sub> taxes and 7 €/MWh<sub>el</sub> grid fees but excludes the renewables levies, which the German government decided to remove by mid-2022.<sup>7</sup>

**Wind profile.** The hourly capacity factors of the wind farm are based on an exemplary project in the North-East of Germany (Brandenburg). The project was commissioned in September 2017 with 3.6 MW wind turbines from Nordex (N117/3600). For 2018-2021, we obtained measured data in a ten-minutes resolution, which we aggregated to an hourly time series. We complemented this measured data with synthetic profiles for the years 2017-2019 from Aurora Energy Research. Note that the measured data are affected by grid-related curtailment, while the simulated profiles are not. We therefore use synthetic profiles whenever possible.

**Grid unavailability.** For the years 2018 and 2019 we use measured wind generation and wind speed data to construct an hourly time series of grid unavailability. This data is used for a sensitivity analysis in Subsection 3.4. More precisely, we identify hours when the wind turbine was not producing despite wind speeds exceeding 5 m/s. We assume all such downtime was due to an unavailability of the grid, that is, the wind turbine was not able to feed into the grid because of grid congestion. In fact, there may also be other reasons for downtime, such as outages and maintenance of the wind turbine, such that our estimate is an upper boundary of grid unavailability. Overall, we identify 459 hours of grid unavailability in 2018 and 380 hours in 2019. Multiplying this unavailability time series with the synthetic wind generation profiles yields an estimated curtailment of 3–5 % of the potential wind generation.

**Marginal emission factors.** We estimate the impact of green hydrogen on power sector emissions based on hourly marginal emission factors. These marginal emission factors represent the marginal increase (or decrease) in emissions for an increase (or decrease) in electricity consumption. In general, marginal emission factors cannot be observed but need to be estimated. For this, we use the *elmada* model, which estimates marginal emissions based on the observed hourly residual load and the merit order model (Fleschutz et al., 2021; Fleschutz and Murphy, 2021). While the original model uses

<sup>6</sup> <https://www.smard.de/home/downloadcenter/download-marktdaten>

<sup>7</sup> <https://www.bundesregierung.de/breg-de/service/publikationen/massnahmenpaket-des-bundes-zum-umgang-mit-den-hohen-energiekosten-2020522>

historic annual fuel prices, we develop it further to run based on daily spot prices for natural gas, hard coal, and carbon emissions. Although power plants often have long-term contracts, they face the opportunity cost of not (re-)selling fuels and emission certificates at current spot prices. By recalculating the merit order curve for every day based on spot prices, we think that we better account for the real-world behavior of power plants. Nevertheless, the merit order model comes with limitations, such as neglecting the intertemporal ramping costs and constraints of power plants.

**Fuel and carbon prices.** As an input to the *elmada* model, we use the price for coal delivered into the Amsterdam, Rotterdam, and Antwerp (ARA) region and gas traded at the Title Transfer Facility (TTF) in the Netherlands, both retrieved via Investing.com.<sup>8</sup> Missing gas price data in the beginning of 2017 are backward filled with the first available data point from our source. For carbon, we use prices from the EU Emission Trading Scheme, retrieved via ember-climate.org.<sup>9</sup> Figure 1 displays the used daily fuel and carbon prices. While carbon prices rose in 2018 and natural gas prices fell in 2019, the most significant observation is the rapid increase of all prices in 2021. Therefore, we treat 2021 separately in our analysis (Subsection 3.3).



Figure 1: Daily fuel and carbon prices.

<sup>8</sup> [https://www.investing.com/commodities/coal-\(api2\)-cif-ara-futures-historical-data](https://www.investing.com/commodities/coal-(api2)-cif-ara-futures-historical-data) and <https://www.investing.com/commodities/dutch-ttf-gas-c1-futures-historical-data>  
<sup>9</sup> <https://ember-climate.org/data/carbon-price-viewer/>

## 3 Results

**Overview.** This section presents results for the years 2017-2021. Among these years, 2021 sticks out because of the European energy crisis—gas prices and, therefore, electricity prices were exceptionally high. Among the other years, the results for 2017 are most representative. Therefore, we first discuss 2017 in detail (Subsection 3.1), before analyzing variations between 2017-2020 (Subsection 3.2). Finally, we discuss the implications of the energy crisis based on data for 2021.

### 3.1 Optimal investment and dispatch in 2017

#### 3.1.1 *Island system*

**Investment.** As a benchmark, we first discuss our results for the benchmark case of an island system. In such a system, the cost-optimal capacities of the wind turbine and the electrolyzer are 1.14 kW/MWh<sub>H2</sub> and 0.42 kW/MWh<sub>H2</sub>, respectively. The wind turbine is built larger than the electrolyzer to increase the utilization of the electrolyzer to about 3,200 h/a, compared to 2,200 h/a of the wind turbine. In fact, the cost optimization model solves the trade-off between minimizing wind curtailment and maximizing the electrolyzer's utilization. The size of the hydrogen storage is 23 kWh/MWh<sub>H2</sub>. This storage size is large enough to smoothen the hydrogen supply to the assumed 1/8760 MWh per hour baseload offtake (Eq. 3).

**Dispatch.** The hourly dispatch behavior of the island system is straight-forward, as depicted in Figure 2. During roughly 1,500 h/a, the electrolyzer produces at full load and the surplus wind generation is curtailed (Section A in the figure). Most of the remaining time of the year, the electrolyzer consumes the available wind energy generation (Section B), producing at part load. Otherwise, wind energy is curtailed even though the electrolyzer does not run at full capacity (Section C), or wind energy and hence hydrogen production are zero (Section D). Curtailment despite the electrolyzer not running at full load occurs because the potential hydrogen generation exceeds hydrogen demand, and the hydrogen storage is already full. Overall, almost half of the potential wind energy generation is curtailed (1.2 of 2.5 MWh/MWh<sub>H2</sub>).

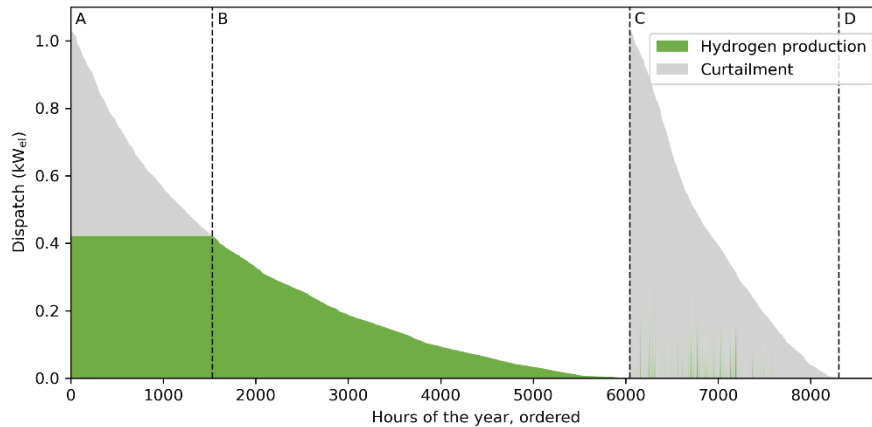


Figure 2: Hourly dispatch decisions of an island system. Hours sorted by potential wind generation within each section in descending order. Note that the electrolyzer produces at part load during some hours in section C.

**Costs and emissions.** For a cost-optimal island system, the LCOH is 183 €/MWh<sub>H<sub>2</sub></sub> (6.1 €/kg<sub>H<sub>2</sub></sub>).<sup>10</sup> Two thirds of this are the investment cost for the wind turbine (121 €/MWh<sub>H<sub>2</sub></sub>), and the remainder accounts for the investment cost of the electrolyzer (36 €/MWh<sub>H<sub>2</sub></sub>) and that of the hydrogen storage (26 €/MWh<sub>H<sub>2</sub></sub>).

### 3.1.2 Market interaction with simultaneity requirement

**Investment.** When allowing for feed-in, the cost-optimal capacity of the electrolyzer decreases to 0.36 kW/MWh<sub>H<sub>2</sub></sub>, while the capacity of the wind farm increases to 1.22 kW/MWh<sub>H<sub>2</sub></sub>. The storage size decreases slightly to 22 kWh/MWh<sub>H<sub>2</sub></sub>. These results can be explained by the option to sell surplus electricity to the market, which makes building a larger wind turbine more attractive. It should be noted, however, that the average sales revenues are only 33 €/MWh<sub>el</sub>, which is much lower than the levelized cost of wind energy of 49 €/MWh<sub>el</sub>. As a direct implication of the smaller electrolyzer, the utilization of the electrolyzer increases to 3,700 h/a.

**Dispatch.** The dispatch decision of the electrolyzer now becomes slightly more complex (Figure 3). When the electrolyzer is running at full load, surplus wind energy is now curtailed only when electricity prices are negative (Section A) and sold to the market otherwise (Section B). For most of the remaining hours of the year, the electrolyzer just consumes the available wind energy (Section C). Otherwise, wind energy may be sold to the market even though the electrolyzer does not run at full capacity (Section D) or no wind energy is available (Section E).

<sup>10</sup> 100 €/MWh<sub>H<sub>2</sub></sub> equals to 3.3 €/kg<sub>H<sub>2</sub></sub>.

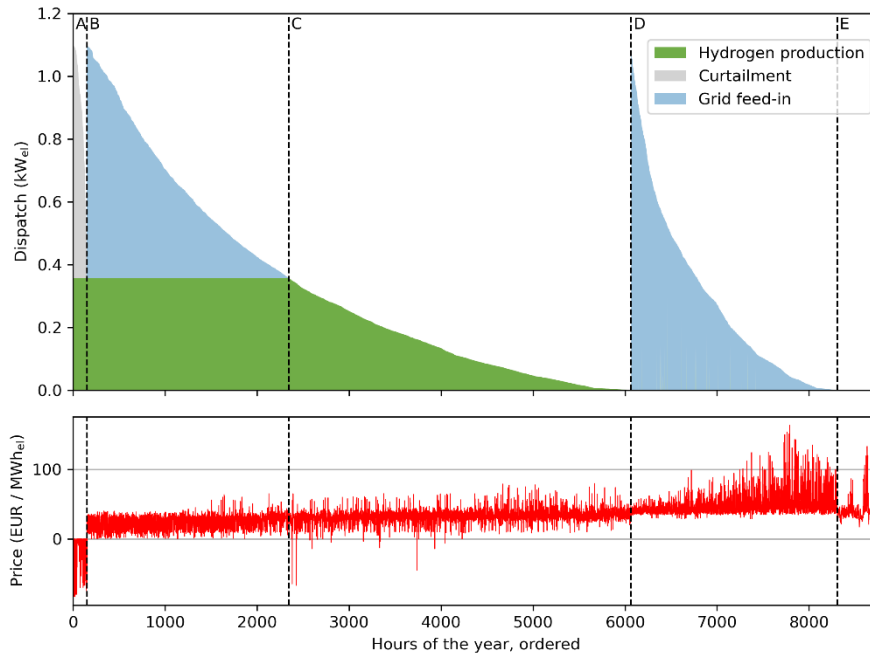


Figure 3: Hourly dispatch decisions of a system with the option to sell to the electricity market (strict temporal congruency). Hours sorted by potential wind generation in descending order. Note that the electrolyzer produces at part load during some hours in section D.

**Dispatch (cont'd).** Feed-in despite the electrolyzer not running at full load (Section D in Figure 3) can happen for two reasons: first when the potential hydrogen generation exceeds hydrogen demand, and the hydrogen storage is already full; and second when electricity prices are so high that it is economical to rather sell electricity than filling up the hydrogen storage. Against this background, it is interesting to observe that the prices in Section D tend to be higher than the prices in Sections B and C, which means that feed-in beyond the surplus is substantially price responsive (on average 49 €/MWh<sub>el</sub> vs. 24 and 33 €/MWh<sub>el</sub>, respectively). As a result, feed-in happens disproportionately when prices are high, supporting the system when electricity is scarce. Overall, the wind turbine has a production potential of 2.7 MWh<sub>el</sub>/MWh<sub>el</sub>, of which 49% are used in the electrolyzer, 48% are fed into the grid, and 3% are curtailed.

**Costs and emissions.** Compared to the island case, the LCOH decreases by more than 20% to 143 €/MWh<sub>H2</sub> (4.8 €/kg<sub>H2</sub>). Most of this reduction can be traced back to the revenues from selling electricity instead of curtailment (42 €/MWh<sub>H2</sub>). Furthermore, the investment costs for the electrolyzer decrease (by 5 €/MWh<sub>H2</sub>), but this is over-compensated by an increase in the investment costs for the wind turbine (by 8 €/MWh<sub>H2</sub>). Environmentally, we estimate that the grid feed-in reduce emissions by 1.1 t<sub>CO2</sub>/MWh<sub>H2</sub> (36 g<sub>CO2</sub>/kg<sub>H2</sub>). Hence, requiring additionality and temporal congruency means that every MWh of green hydrogen produced reduces emissions in the electricity system because the optimal size of the wind turbine is inflated. Put differently, every MWh of green hydrogen would not only reduce emissions when consumed instead of fossil fuels, but also would it reduce emissions in the power sector because it comes with more additional green electricity than actually needed for hydrogen production.

### 3.1.3 Market interaction without simultaneity requirement

**Investment.** When relaxing the requirement of temporal congruency, the cost-optimal capacity of the electrolyzer decreases further to 0.20 kW/MWh<sub>H<sub>2</sub></sub>, which results in an electrolyzer utilization of 6,800 h/a. Furthermore, the capacity of the wind turbine and of the hydrogen storage decrease to 0.61 kW/MWh<sub>H<sub>2</sub></sub> and to 1.7 kWh/MWh<sub>H<sub>2</sub></sub>, respectively. Hence, the hydrogen storage can now cover only up to 15 hours of hydrogen demand.

**Dispatch.** The dispatch behavior is illustrated in Figure 4. For extremely negative prices (below -43 €/MWh<sub>el</sub>), all wind production is curtailed and the electrolyzer runs at full load based on electricity from the grid (Section A), helping to absorb the surplus of renewable energy in the grid. For more moderate negative prices (between -15 and -41 €/MWh<sub>el</sub>), the electrolyzer runs at full load based on wind energy, and only the surplus is curtailed (Section B). Above -14 €/MWh<sub>el</sub>, surplus is fed into the grid (Section C). The feed-in at negative prices may seem counter-intuitive, but it can be explained by the fact that the amount of electricity fed into the grid defines what can be bought back at another time. Hence, feeding in an additional MWh<sub>el</sub> at -14 €/MWh<sub>el</sub> enables buying an additional MWh<sub>el</sub> from the grid at another hour without violating the yearly additionality constraint. Apparently, the cost of feeding in electricity at -14 €/MWh<sub>el</sub> are lower than the value of buying it back at another time (and lower than increasing the capacity of the wind turbine).

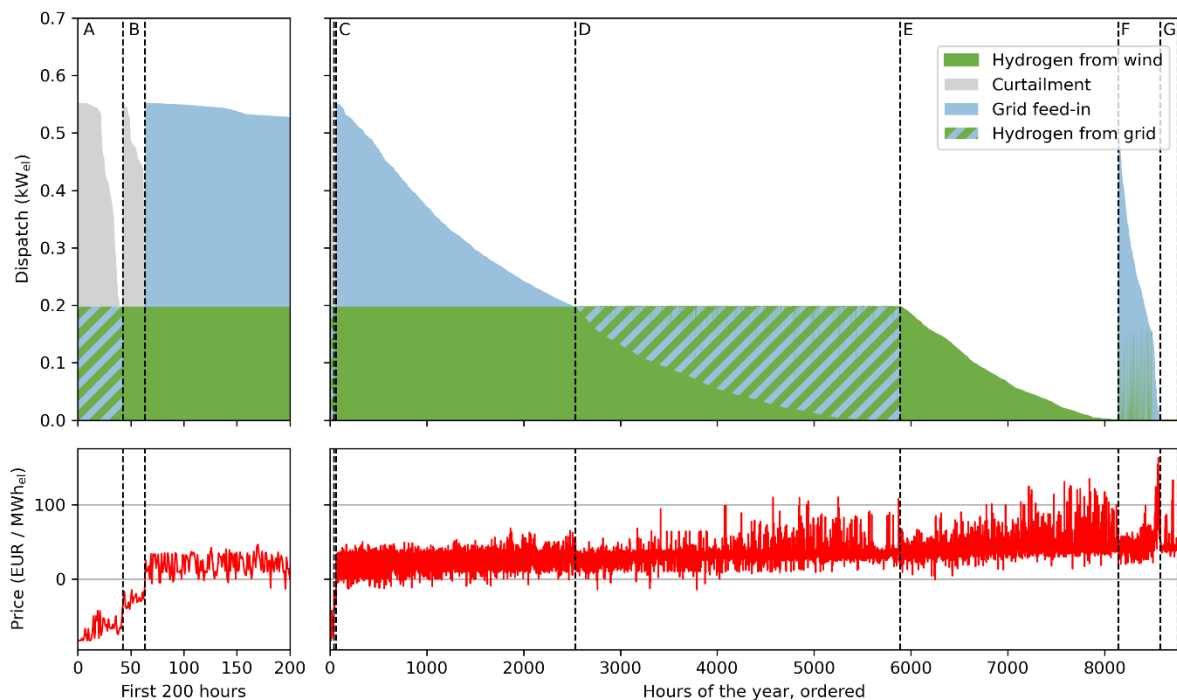


Figure 4: Hourly dispatch decisions of a system with the option to sell to and buy back from the electricity market (no temporal congruency). Hours sorted by potential wind generation in descending order.

**Dispatch (cont'd).** During most of the remaining hours of the year, the electrolyzer runs on a mix of wind energy and grid electricity, including some hours where it runs fully on grid electricity (Section D). Otherwise, the electrolyzer just consumes the available electricity (Section E), electricity is fed into

the grid even though the electrolyzer is not running at full load (Section F), or no hydrogen is produced during hours when no wind energy is available (Section G). Again, it is interesting to note that prices tend to be high for when feed-in exceeds the surplus of wind energy (Section F: 51 €/MWh<sub>el</sub> on average). On the other hand, prices tend to be low when electricity is purchased from the market (Section D: 31 €/MWh<sub>el</sub>), and prices tend to be medium when neither feed-in beyond surplus nor purchase occur (Section E: 44 €/MWh<sub>el</sub>). Hence, although the hydrogen storage is relatively small, the electrolyzer dispatch responds significantly to electricity market prices and hence the system-wide scarcity of electricity. Overall, of the 1.36 MWh<sub>el</sub>/MWh<sub>H<sub>2</sub></sub> producible wind energy, 64% is directly used for hydrogen production, 34% is sold to the market and bought back at another time for hydrogen production, and 2% is curtailed.

**Costs and emissions.** Compared to the sell-only case, relaxing the requirement of temporal congruency reduces the LCOH by 30% to 100 €/MWh<sub>H<sub>2</sub></sub> (3.3 €/kg<sub>H<sub>2</sub></sub>). This is the result of two opposing effects: on the one hand, the overall investment costs decrease by 100 €/MWh<sub>H<sub>2</sub></sub>; on the one hand, the commercial balance from trading reverses from revenues of 42 €/MWh<sub>H<sub>2</sub></sub> to costs of 27 €/MWh<sub>H<sub>2</sub></sub>. Because the overall grid feed-in equals grid take-out, net costs from trading mean that the weighted average price of electricity feed-in (Sections C and F) is lower than the weighted average price of electricity take-out (Sections A and D). Based on marginal emission factors, we estimate that the electricity feed-in reduces emissions in the grid by 0.40 t/MWh<sub>H<sub>2</sub></sub>, and the electricity take-out increases emissions by 0.38 t/MWh<sub>H<sub>2</sub></sub>. Hence, producing 1 MWh<sub>H<sub>2</sub></sub> while allowing for temporal flexibility reduces grid emissions by 0.02 t/MWh<sub>H<sub>2</sub></sub> (0.7 g<sub>CO<sub>2</sub></sub>/kg<sub>H<sub>2</sub></sub>).

## 3.2 Comparing the years 2017-2020

**Intro.** This section provides an overview of the aggregated results for the years 2017-2020.

**Investment.** The investment decisions for the wind turbine, the electrolyzer, and the hydrogen storage are summarized in Figure 5. It becomes clear that the cost-optimal configuration of all components very much depends on the regulatory framework. Comparing the first two scenarios, the scenario with simultaneity sees larger wind capacity but lower storage than the island system, highlighting an incentive to overbuild on the wind turbine because surplus power can be sold to the market, whereas in the island system even the large storage cannot avoid significant curtailment. In the third scenario, the cost-optimal size of the wind turbine and of the electrolyzer decreases by a factor of two for all years, and the reduction in size of the hydrogen storage is even more pronounced. This is because, in the first two scenarios, preventing the electrolyzer to run on electricity from the grid means that the local hydrogen storage must be large enough to cover longer periods without simultaneous production from the dedicated wind plant. While centralized hydrogen storage in salt caverns is a promising option for long-term storage in highly renewable energy systems, it seems implausible to put this (implicit) requirement on single projects during the phase of a ramp-up of green hydrogen.

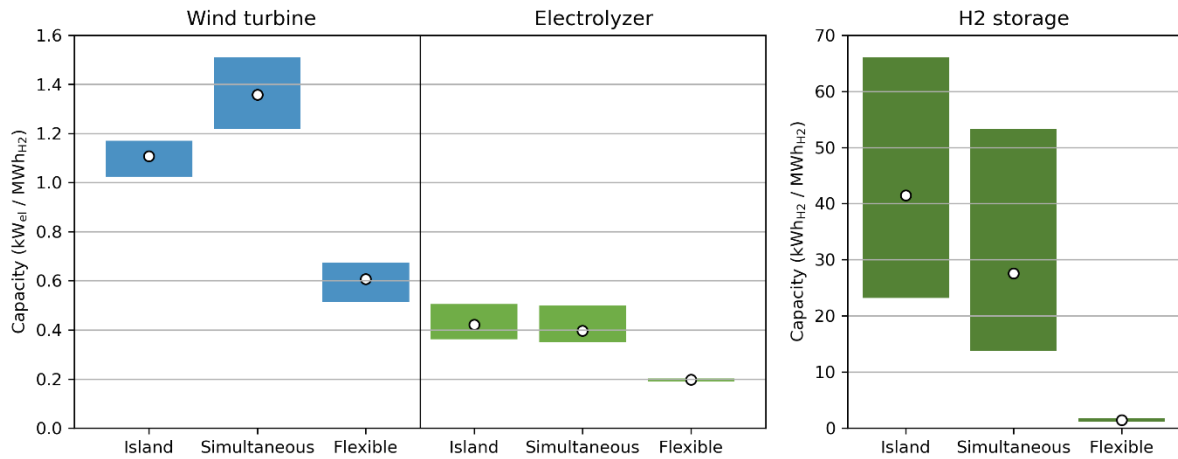


Figure 5: Cost optimal capacity of the wind turbine, the electrolyzer, and the hydrogen storage for the different regulatory scenarios. The graph displays the ranges as well as the mean across the yearly results for 2017-2020.

**Inter-annual variation.** It is noteworthy that the optimal sizes of the electrolyzer and, even more so, of the hydrogen storage vary widely between years for the island and for the simultaneity case. This means that any system configuration that is cost-optimal for one year will not be cost-optimal (or not even capable of supplying the same amount of hydrogen) for another year. This will lead to additional cost for a system optimization across the years compared to our optimization based on individual years. In the flexible case, the variation in the cost-optimal size of the electrolyzer and of the hydrogen storage are substantially reduced. This means that one system configuration is (almost) cost-optimal for all years, which reduces additional costs related to inter-annual variability. Only the optimal size of the wind turbine still varies proportionately to the inter-annual variation of the wind yield.

**Curtailement and grid feed-in.** The left-most plot in Figure 6 summarizes annual curtailment and grid feed-in. While the option to feed-in electricity to the grid naturally reduces curtailment, the relaxation of the simultaneity criterion leads to a substantial further reduction. This can partially be explained by the smaller size of the wind turbine, which also leads to a reduction in grid feed-in in the flexible case compared to the simultaneous case. The other part of the explanation for the reduced curtailment in the flexible case is that electricity is sold to the market at negative prices for the possibility of buying it back later (see Subsection 3.1). While the additional feed-in at negative prices may lead to curtailment of renewables elsewhere in the grid, it may as well incentivize additional consumption or the ramp down of remaining fossil fuel generators.<sup>11</sup>

<sup>11</sup> Some fossil fueled power plants produce at negative prices because their costs of ramping down are higher than paying a negative price for feeding electricity into the grid.



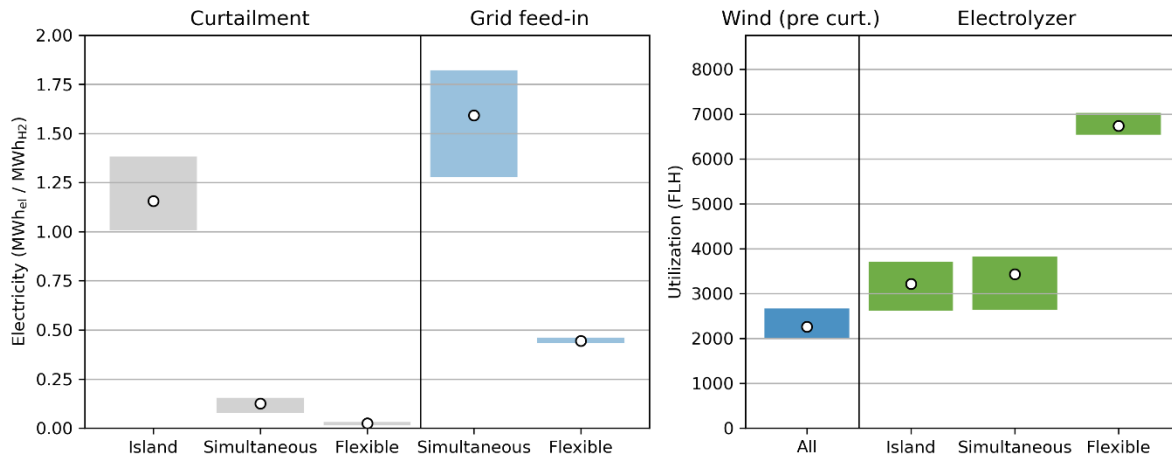


Figure 6: Annual curtailment and grid feed-in as well as utilization of the wind turbine and the electrolyzer for the different regulatory scenarios. Note that gross grid feed-in is displayed and that, in the flexible scenario, an equal amount of electricity is bought back from the grid. The graph displays the ranges as well as the mean across the yearly results for 2017-2020.

**Utilization.** The utilization of the electrolyzer is generally higher than that of the wind turbine (right plot in Figure 6). In the island system, this is because the wind turbine is built larger than the electrolyzer, trading off the cost of curtailing wind energy with the cost of a low utilization of the electrolyzer. In the simultaneity scenario, the utilization of the electrolyzer increases slightly because the option to sell electricity to the market reduces the cost of overbuilding the wind turbine. Relaxing simultaneity increases the utilization of the electrolyzer by a factor of roughly two (to 6,500-7,000 h/a). This reflects the value of a higher utilization of the electrolyzer which can be achieved based on trading electricity. Nevertheless, the utilization is significantly lower than 8760 full load hours, which means that there is also a value in flexibility.

**LCOH.** Figure 7 summarizes the LCOH as well as the cost and emissions from trading for the different regulatory scenarios. The LCOH decreases drastically when market interaction is permitted, from 200 €/MWh<sub>H2</sub> in the island case and 150 €/MWh<sub>H2</sub> in the simultaneity case to 100 €/MWh<sub>H2</sub> in the flexible case.<sup>12</sup> Compared to an island system, the cost in the simultaneity case decreases mainly due to revenues from selling surplus electricity to the market. When also allowing the electrolyzer to buy back electricity from the market, costs decrease further because the size of all components can be reduced (cf. Figure 5). The revenues from grid feed-in decrease and are overcompensated by the cost for buying back, leading to a net positive cost of trading.<sup>13</sup>

**Emissions.** In terms of power sector emissions, the island system does not lead to any changes by definition. Because of the considerable feed-in, the simultaneity case reduces power sector emissions by more than 1 t/MWh<sub>H2</sub>. For the flexible case, we estimate that the emission reductions from feed-in are slightly higher than the additional emissions from buying back. As a result, a flexibly operated

<sup>12</sup> In terms of €/kg<sub>H2</sub>, this means a reduction from 6.6 €/kg<sub>H2</sub> in the island case and 5 €/kg<sub>H2</sub> in the simultaneity case to 3.3 €/kg<sub>H2</sub> in the flexible case.

<sup>13</sup> The average sell price is 29.6 €/MWh<sub>el</sub> and the average buy price is 61.7 €/MWh<sub>el</sub>, including 34.2 €/MWh<sub>el</sub> for wholesale prices and 27.5 €/MWh for taxes and grid fees.

electrolyzer leads to a slight reduction in power sector emissions (-0.005 to -0.027 t/MWh<sub>H2</sub>) compared to not operating the electrolyzer (or not interacting with the market in the island case). The hourly simultaneity criterion leads to a substantial reduction in power sector emissions, but this comes at a 50% increase in LCOH. Hence, the criterion would force producers of green hydrogen to make a substantial financial contribution to additional renewable generation well beyond the amount needed to avoid creating additional emissions. This would increase the already high cost for the ramp up of hydrogen technologies, slowing down the ramp up or inflating the need for green hydrogen subsidies. Meanwhile, green hydrogen could be carbon-neutral (or even negative) at a much lower cost, with a more flexible additionality criterion that does not require hourly simultaneity.

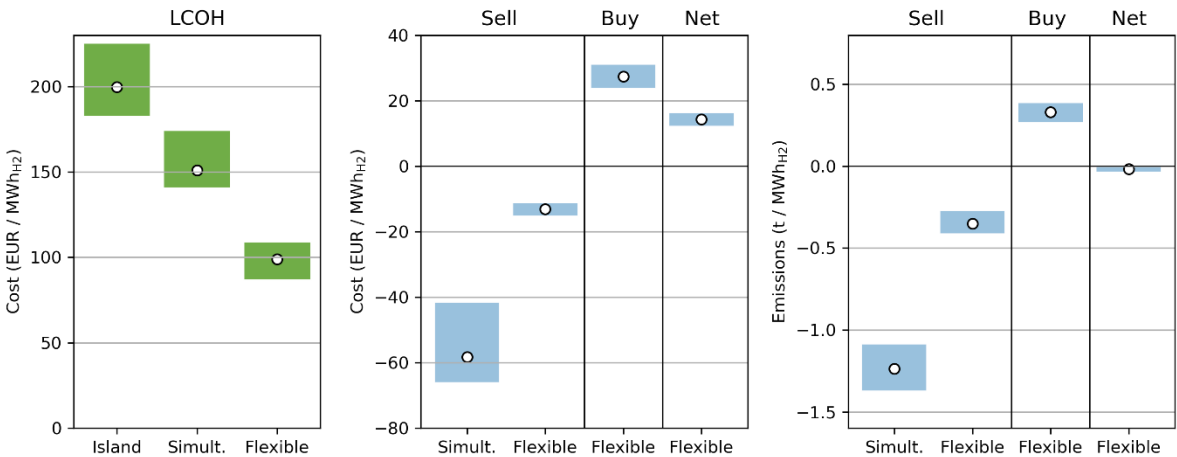


Figure 7: Levelized cost of hydrogen (LCOH) as well as cost and emissions resulting from trade for the different regulatory scenarios. Negative costs are revenues, and negative emissions are avoided emissions in the electricity system. The graph displays the ranges as well as the mean across the yearly results for 2017-2020.

### 3.3 Year 2021

**Setting.** The year 2021 was very different from the years 2017-2020 because of exceptionally high fuel and carbon prices (see Figure 1). Repeated years like 2021 would have major implications for the cost-optimal system configuration. In fact, the electricity market revenues of the wind farm in 2021 were larger than its cost, leading to zero cost of additionality (and an unbound optimization problem). However, it seems implausible that investors tailor their investment decisions to an exceptional year like 2021. Therefore, we refrain from investment optimization in 2021. Instead, we fix the capacities of the wind turbine, the electrolyzer, and the hydrogen storage to the average optimal values from 2017-2020. Put differently, we are analyzing how a system that was designed based on historical observations would have responded to the unanticipated price shock in 2021. Of course, long-term market prices may not return to 2017-2020 levels and, hence, alter the cost-optimal investment decision. While modeling future prices is beyond the scope of the present paper, Section 4 provides a qualitative discussion of how trends in energy transition can be expected to affect our results.

**Results.** Focusing on the flexible scenario without the simultaneity requirement, Figure 8 summarizes the model results for 2021 (displayed as bars) and contrasts them to the mean of 2017-2020 (displayed as points). In 2021, the wind turbine produces slightly above the average the years 2017-2020 (left plot

in Figure 8). Because the hydrogen production is fixed to 1 MWh/a, the project is selling more electricity than it is buying in 2021, while the net sales were always zero (as a result of cost optimization) in the preceding years. However, not only the (net) sales but also the purchases increase, which means that the electrolyzer does exchange more electricity with the market. This can be explained by the much higher volatility of electricity prices in 2021. This means a higher value of flexibility, which the electrolyzer captures by a more flexible and market-oriented operation. This also becomes apparent in the commercial trade balance (center plot in Figure 8). The revenues from selling electricity to the market triple, and the cost from buying electricity back double. As a result, the net cost of trading electricity in 2021 are half of the average cost in 2017-2020 (7 vs. 14 €/MWh<sub>H2</sub>).

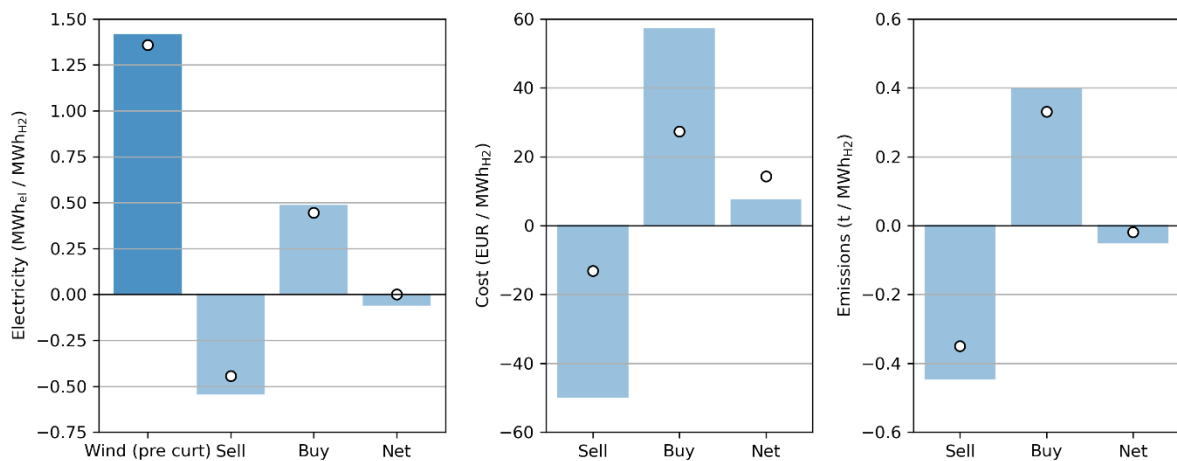


Figure 8: Electricity volumes, costs, and emissions for the flexible regulatory scenario (market interaction with additionality but without simultaneity). The bars depict the results for 2021 and the points are the mean across the yearly results for 2017-2020.

**LCOH and opportunity cost.** Adding up investment cost, variable cost, and the reduced cost of trading, the LCOH in 2021 decreases to 92 €/MWh<sub>H2</sub> (compared to an average of 99 €/MWh<sub>H2</sub> across 2017-2020). However, the high electricity prices in 2021 drive up the opportunity cost of not selling electricity on the wholesale market. Considering this increased opportunity cost in the cost calculation, the LCOH in 2021 amounts to 150 €/MWh<sub>H2</sub> (5 €/kg<sub>H2</sub>). Note that this cost metric refers to a baseload hydrogen supply. Although we would argue that baseload operation is an appropriate assumption to design a wind-hydrogen system for the years 2017-2020, it may be beneficial to deviate from the baseload supply by adjusting the downstream industrial process during some hours in 2021. In fact, we have seen some industrial consumers across the EU adjusting their natural gas and electricity consumption in response to the price shock in 2021 (Stiewe et al., 2022).

**Emissions.** In terms of trading-related power sector emissions, the net emissions remain negative even without simultaneity requirement, and the magnitude of the emission reduction increases (-0.049 t/MWh<sub>H2</sub> in 2021 vs. -0.02 t/MWh<sub>H2</sub> in 2017-2020). Most of this reduction can be attributed to the net feed-in of electricity. To disentangle the effect of the additional feed-in from the effect of relaxing the simultaneity criterion, we estimate that the average emission reduction of electricity feed-in is -0.823 t/MWh<sub>el</sub>. Multiplying this with the 0.57 MWh<sub>el</sub>/MWh<sub>H2</sub> increase in electricity feed-in results in a power sector emission reduction of -0.047 t/MWh<sub>H2</sub>, which is slightly below the overall reduction

of  $-0.049 \text{ t/MWh}_{\text{H}_2}$ . Put differently, the per-MWh<sub>el</sub> reduction in emissions due to grid feed-in is larger than the per-MWh<sub>el</sub> increase in emissions due to grid take-out.<sup>14</sup> Hence, we conclude that a flexibly operated electrolyzer can reduce power sector emissions also in times of a price shock as observed in 2021. If hydrogen production was reduced because of the price shock, the contribution to decarbonizing the electricity system would be even larger.

### 3.4 Sensitivity analyses

**Overview.** This section presents the results of sensitivity analyses regarding grid unavailability, operational subsidies, and investment subsidies, respectively. For all sensitivity analyses, a flexible operation of the electrolyzer is considered.

**Grid unavailability.** For the years 2018 and 2019 we use hourly time series to prohibit the wind-hydrogen system to sell electricity when the grid is congested. In both years, we observe a reduction in electricity trades and an increase in curtailment. To compensate for the additional curtailment, the size of the wind turbine is increased. Meanwhile, the electrolyzer and the hydrogen storage are also increased in size to enable a more flexible use of electricity in times of grid unavailability. As a result, the LCOH rises and the power sector emissions are further reduced, but most effects are very small (about 1% change compared to the main scenarios).

**Operational subsidies.** Regarding operational subsidies, we implemented a time-invariant premium per MWh of hydrogen produced. While this reduces the LCOH, optimal investment and dispatch decisions remain unaffected. This can be explained by the fact that the overall hydrogen production is normalized to 1 MWh (Eq. 3) and, therefore, a time-invariant operational subsidy effectively means subtracting a constant from the objective function (Eq. 1), which should generally not change the optimal value of decision variables in an optimization problem. Put differently, it is the absolute difference between the hourly electricity prices that incentivizes the investment in a larger electrolyzer, the investment in hydrogen storage, and the flexible operation of the system. Operational subsidies that maintain the decision makers' exposure to these absolute differences do not alter the system's optimal degree of flexibility.<sup>15</sup>

**Investment subsidies.** Because the investment subsidy changes the *relative* cost of the different elements of the electrolyzer-storage-wind system it alters the investment decision, and the subsequent dispatch behavior. More precisely, the capacities of the hydrogen electrolyzer and storage increase, and the utilization of the electrolyzer decreases. This is as expected because the lower net investment cost of the electrolyzer make it more economically more attractive to build a larger capacity and capture more revenue from spot price variation and from increasing the share of directly used wind energy. Electricity trading is reduced and, therefore, the effect on power sector emissions decreases while remaining negative (i.e., emissions are still reduced). Naturally, the LCOH decreases.

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<sup>14</sup> We also conducted a sensitivity with a slightly smaller wind turbine capacity to compensate for the above-average wind availability in 2021. This sensitivity analysis also yielded a reduction in power system emissions for the flexible electrolyzer.

<sup>15</sup> By contrast, operational subsidies that reduce the absolute differences between the hourly electricity prices, such as contracts for differences based on hourly electricity prices, will reduce the optimal degree of flexibility.

## 4 Discussion

**Summary.** We demonstrate that different regulatory frameworks have a significant effect not only on the optimal dispatch but also on the optimal investment decisions of a wind-hydrogen project. Our main finding is that increasing the degrees of freedom for market interaction of the project reduces the levelized cost of green hydrogen—from 200 €/MWh<sub>H2</sub> for the island case over 150 €/MWh<sub>H2</sub> for the simultaneity case to 100 €/MWh<sub>H2</sub> for the flexible case (years 2017-2020). In the case of flexible market interaction, a rational investor trades off the costs of building a larger electrolyzer and local hydrogen storage with the benefits of using local renewable electricity when available or grid electricity when market prices are low. While the capacities of the electrolyzer and of the hydrogen storage in the flexible case are significantly reduced compared to the simultaneous case, a rational investor would still choose to build a larger-than-necessary electrolyzer and some hydrogen storage to benefit from flexibility. We further show that an annual additionality requirement is sufficient to avoid an increase in power system emissions in all considered cases.

**System benefits of flexibility.** Allowing for a flexible operation of hydrogen electrolysis can have positive implications beyond reducing the LCOH and (slightly) reducing the power system emissions. In general, flexibility can reduce the overall cost of the electricity system. It stabilizes renewable capture prices by increasing the power market price in hours with high overall renewables generation in the system (but potentially lesser or no generation by the "electrolyzer-coupled" wind turbine). The flexible case therefore indirectly improves the economics of existing variable renewables, in line with previous research (Böttger and Härtel, 2021; Ruhнау, 2022). Hence, a flexible definition of green hydrogen can help the profitability of renewables across the system and incentivize the market-based investment in renewables beyond the additionality requirement. By contrast, the simultaneity requirement may lead to inefficiencies such as overinvestment in hydrogen storage in steel vessels to balance renewable variability on a project-level instead of using large-scale underground storage for balancing the residual variability of renewables after regional smoothing.

**Literature comparison: economics.** Our general finding that relaxing the simultaneity requirement improves the economics of green hydrogen is in line with previous studies on that topic. While the contribution margins reported by Schlund and Theile (2022) are not directly comparable, the LCOH reported by Frontier Economics (2021a) offer an interesting point of reference. Their estimated LCOH for a new-built system with an annual additionality requirement is 120 €/MWh<sub>H2</sub>, which is somewhat higher than our estimate of 100 €/MWh<sub>H2</sub>, which is likely caused by their more conservative assumptions on the investment cost and the conversion efficiency of hydrogen electrolysis. When imposing a simultaneity requirement, however, their estimated LCOH increase by only 30 €/MWh<sub>H2</sub>, instead of 50 €/MWh<sub>H2</sub> in our case. This could be because Frontier Economics (2021a) neglects storage costs, which we find to be considerable in a case with simultaneity (as well as in the island case).

**Literature comparison: emissions.** Previous studies came to ambiguous conclusions regarding the impact of simultaneity on power sector emissions. Schlund and Theile (2022) find that emissions in the flexible case increase compared to a simultaneity case. While we make the same observation, we argue that this is because the simultaneity case leads to an over-fulfillment of the additionality criterion and

hence contributes to the decarbonization of the electricity system beyond what is necessary to produce the green hydrogen. Compared to not producing green hydrogen at all—which we find to be the relevant reference scenario, given hardly any green hydrogen generation exists today—, we find that an annual additionality requirement is sufficient to avoid an increase in power sector emissions, and even slightly reduce them. Frontier Economics (2021b) find that the impact of flexible green hydrogen on power sector emissions depends on the utilization of the electrolyzer, which is an input to their model. Our study adds to this discussion showing that the cost-optimal utilization of the electrolyzer, as chosen by a rational investor, would lead to a decrease in power sector emissions in all the cases that we have considered.

**Outlook.** Our main results are based on the years 2017-2020, and we also discuss the impact of the price shock observed in 2021. Beyond this, there are several foreseeable trends that may impact the results of our study, including an increasing share of renewables in the overall electricity system, increasing carbon prices, decreasing investment costs of the electrolyzer, and a liquid hydrogen market. The implications of these trends for the main results of these study are qualitatively discussed in Table 2. Overall, we come the conclusion that the benefits from a flexible definition of green hydrogen would only increase, that is, the LCOH and power sector emissions would be reduced further.

*Table 2: Trends in the energy transition and implications for the main results of this study*

<b>Trend</b>	<b>LCOH of flexible green hydrogen is likely to...</b>	<b>Power sector emissions of flexible green hydrogen are likely to...</b>
<b>Increasing share of renewables in the overall electricity system</b>	... <b>decrease</b> , as the electrolyzer will run more often on low prices induced by renewables	... <b>decrease</b> , as the electrolyzer will run more often on system-wide surplus of renewables
<b>Increasing carbon prices</b>	... <b>decrease</b> , as the project benefits from high prices when feeding in electricity	... <b>decrease</b> , as the incentive increases to feed in (take out) electricity when marginal emissions are high (low)
<b>Decreasing investment cost of the electrolyzer</b>	... <b>decrease</b> as a direct result	... <b>decrease</b> , as the trade-off between a utilization and flexibility of the electrolyzer tilts toward flexibility (which is likely to reduce emissions because of the above trends)
<b>Liquid hydrogen market (backbone)</b>	... <b>decrease</b> , as large-scale salt caverns will become available for cheap hydrogen storage	

**Limitations.** There are some limitations to this study, which may be addressed in future research. First, we assumed that the wind farm and the electrolyzer are co-located, but there may also be the case of a virtual assignment of an electrolyzer to a distant portfolio of renewables via power purchase agreements. In this case, it would be necessary to consider grid congestion and to apply (some) taxes, levies, and grid fees not only to market purchases but also to consumption from the dedicated additional wind farm. Second, we calibrated our model to the example of Germany, but we did not capture all details of the German regulation. On the one hand, further research may account for more details of the German regulation, e.g., capacity-based grid fees. On the other hand, our model may be

applied to other countries with different market prices, renewable profiles, and regulation on taxes, levies, and grid fees. Third, a lower LCOH may be achieved by including solar photovoltaics in the optimization system. Furthermore, batteries may be an attractive complement to hydrogen storage for balancing more short-term variations in the dedicated renewable production. Fourth, our model makes the simplified assumption of perfect foresight. In reality, renewable generation and market prices are uncertain and may not perfectly be anticipated, which may increase the cost for the wind-hydrogen system. On the other hand, the flexibility of the electrolyzer may generate additional value through trading in the intraday market or through balancing forecast errors of the dedicated wind farm in real-time, further supporting the system integration of renewables. Finally, it should be recalled that the estimation of marginal emission factors is inherently uncertain (see Subsection 2.3).

## 5 Conclusions and policy implications

**Economic benefits of flexible green hydrogen.** We conclude that relaxing the simultaneity requirement has several benefits. First, the levelized cost are reduced substantially, from 150 €/MWh<sub>H2</sub> to 100 €/MWh<sub>H2</sub>, a finding that is robust across different years and qualitatively consistent with the existing literature. Assuming that the initial ramp-up of hydrogen needs to be subsidized, relaxing the simultaneity requirement means that less subsidies would be needed to incentivize the same amount of green hydrogen. Second, relaxing the simultaneity requirement would enable the electrolyzer to provide valuable flexibility to the electricity market. If markets are well designed, the electrolyzer would (at least partially) respond to the system-wide availability of renewables better than the production pattern of an individual asset. For example, the electrolyzer could run when prices are low due to abundant solar generation when the dedicated wind farm is not producing. Ultimately, the market-wide price signal, not the individual asset production pattern should indicate scarcity. Third, a flexible definition of green hydrogen would reduce the capacities of all components of the wind-hydrogen system—wind turbines, hydrogen electrolysis, and hydrogen storage—for the same amount of green hydrogen output. Beyond economic efficiency, this would reduce the environmental impact of the wind hydrogen system, including embedded emissions.

**No evidence for increasing power sector emissions.** Meanwhile, we find no evidence that relaxing the simultaneity requirement would increase power sector emissions. By contrast, we find a slight reduction in power sector emissions across all considered cases. While we cannot exclude the possibility that other cases exist, we discuss that current trends in the energy transition are likely to amplify the positive implications of a flexible green hydrogen definition not only in terms of economics but also in terms of power sector emissions. This analysis of course only includes emissions from the *production* of hydrogen. Should a green hydrogen economy get off the ground, the benefits of the *application* of green hydrogen in various hard-to-decarbonize sectors such as industry would be large emissions reductions that remain unquantified here. These potential emissions reductions are the main reason to produce green hydrogen in the first place.

**Policy recommendation.** On this basis, we recommend a flexible definition of green hydrogen, with an annual additionality criterion and no strict hourly simultaneity requirement. As a result, it would be up to the investor and operator of a green hydrogen project to solve the complex trade-off between

responding to the availability of the dedicated renewable production, responding to market prices (and hence the system-wide availability of renewable production), and increasing the electrolyzers' utilization, while matching the temporal patterns of hydrogen demand. Meanwhile policy makers could focus providing the right price signals based on which investors and operators would decide. For example, high carbon prices would align economic and environmental incentives for the flexible production of green hydrogen.

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