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Abstract. Many administrations, including the EU and the US, have introduced substantial support policies for electrolytic hydrogen. However, interactions of such policies with existing climate policies remain poorly understood. Here, we combine an analytical and a numerical model to investigate the combination of emissions trading, renewable electricity subsidies, and electrolytic hydrogen support. We find that supporting hydrogen reduces renewable subsidies, while emissions prices increase unless the operation of hydrogen electrolysis flexibly responds to electricity prices. Even without explicit regulations on electricity sourcing, the increase in electricity demand for hydrogen production is almost entirely covered by additional renewable electricity generation. If subsidized hydrogen is explicitly required to be matched with additional renewable electricity ("green hydrogen"), the amounts of emissions and renewable electricity remain constant, but the prices of emissions and electricity decline, and support costs for renewable electricity and hydrogen increase. Overall, matching requirements inflate the hydrogen-policy-related system costs by 2–7%. We conclude that promoting the price-responsiveness of hydrogen electrolysis offers greater potential for synergies with emissions trading and renewable electricity subsidies than enforcing strict matching requirements.

Keywords: Environmental policy, electrolytic hydrogen, emissions trading, renewable energy, energy markets, welfare and redistribution, demand-side flexibility.

JEL classifications: C61, D47, Q21, Q28, Q41, Q48.

1 Introduction

Role of hydrogen. Electrolytic hydrogen is expected to play a crucial role in future net-zero emissions energy systems. A recent global net-zero energy scenario assumes that the volume of hydrogen and its derivatives will increase by more than five times, with 60% of this production expected to come from electrolysis (International Energy Agency, 2021). This is because wind and solar energy are expected to drive the decarbonization of the power sector, and electrolytic hydrogen can make decarbonized electricity accessible to end uses that cannot easily be directly electrified, such as long-distance transport and heavy industry (Ueckerdt et al., 2021). Additionally, electrolytic hydrogen could flexibly utilize renewable electricity when available, thereby supporting the market integration of renewable electricity (Ruhnau, 2022). Finally, electrolytic hydrogen could provide a solution for long-term power storage and long-distance energy transmission in highly renewable electricity systems (Ruhnau & Qvist, 2022; Neumann et al., 2023).

Hydrogen subsidies. If the climate externality were the only market failure, emission pricing would be sufficient to promote the efficient adoption of abatement technologies, such as hydrogen. There are, however, two reasons to implement additional subsidies for hydrogen in the real world. First, if efficiently high emission prices are politically unfeasible, deployment subsidies for abatement technologies may be a second-best solution. This topic has been frequently discussed in the context of renewable energy sources (Kalkuhl et al., 2013; Jenkins, 2014; Dimanchev & Knittel, 2023), and more recently, it has been extended to hydrogen technologies (Fell et al., 2023). A second rationale for hydrogen subsidies is related to learning externalities due to knowledge spillovers. This argument has also been frequently advanced regarding renewable energy sources (Katsoulacos & Xepapadeas, 1996; Jaffe et al., 2005; Fischer & Newell, 2008; Lehmann & Söderholm, 2018) and may likewise apply to electrolytic hydrogen as an immature technology.[1]

Hydrogen regulation. While the existing literature has shown that subsidies for renewable energy sources simultaneously address learning and climate externalities, supporting electric hydrogen may entail a dilemma. In current energy systems, which are not yet fully decarbonized, the subsidized deployment of hydrogen electrolysis can—under certain conditions—lead to higher utilization of fossil power plants and, therefore, increase power sector emissions (Ricks et al., 2023; Giovanniello et al., 2024; Zeyen et al., 2024). To support the hydrogen ramp-up without risking higher power sector emissions, recent regulations in the EU[2] and the US[3] define requirements for electrolytic hydrogen to qualify as "green", or "renewable", and hence be eligible for subsidies. These requirements entail that green hydrogen production must be geographically and temporally matched with "additional" renewable electricity production.

Temporal matching. A vigorous debate has emerged regarding the strictness of the above requirements, particularly the temporal granularity of matching. Previous studies agree that rigorous temporal matching at an hourly scale would always avoid additional power sector emissions but also increase the costs of green hydrogen (Schlund & Theile, 2022; Villavicencio et al., 2022; Ricks et al., 2023; Ruhnau & Schiele, 2023; Giovanniello et al., 2024; Zeyen et al., 2024). However, some studies

[1] In addition to subsidies, the low liquidity of long-term energy markets may justify state-backed derisking instruments for decarbonization investments (Dimanchev et al., 2024). We further discuss this aspect in Section 4.
[2] In the EU, this regulation was established by the Renewables Energy Directive II (European Parliament & European Council, 2018) and detailed by the Delegated Act for Renewable Fuels of Non-Biologic Origin (RFNBO) (European Commission, 2023).
[3] In the US, this regulation was established by the Inflation Reduction Act (US Congress, 2022) and detailed by the Section 45V Credit for Production of Clean Hydrogen (US Department of Treasury, 2023).

find that a more relaxed temporal matching can be sufficient to limit emissions, particularly when hydrogen electrolysis is flexibly responding to electricity market prices or the market share of renewable generation is large (Ruhnau & Schiele, 2023; Zeyen et al., 2024). Notably, these studies overlook the interactions between such matching requirements and emissions trading, as existent in the EU.

Interactions with emissions trading. Studies on the interactions between a hydrogen policy and emissions trading remain limited. Qualitatively, Bruninx et al. (2022) argue that complementary hydrogen support may not alter overall emissions but could impact the resulting emission price and cost-effectiveness of abatement. Quantitatively, Roach and Meeus (2023) find that increasing emissions prices may lead to higher required subsidies to reach electrolytic hydrogen targets due to higher electricity prices. More recently, Hoogsteyn et al. (2025) find that hydrogen policy may reduce emissions prices. However, these studies did not consider hydrogen matching requirements and offer a limited view on electrolyzer flexibility[4]—two aspects we demonstrate to be crucial for policy interaction. Moreover, they do not examine the implications of overlapping climate policies for total system costs or welfare.

Aim and setting. This article aims to integrate the previously disconnected literature on temporal matching and overlapping climate policies. To this end, we employ both an analytical and a numerical model to assess the implications of introducing hydrogen support in the context of existing climate policies, specifically a cap on emissions and production targets for renewable electricity. Both models are partial equilibrium models of the power sector, with different assumptions regarding hydrogen matching requirements and the flexibility of hydrogen electrolysis. Here, we define flexibility as the ability to temporally adjust the operation of hydrogen electrolysis while meeting the same hydrogen demand, possibly by utilizing hydrogen storage. This flexibility comes at the cost of increasing the installed electrolyzer capacity and building hydrogen storage. Meanwhile, it generates the benefit of shifting hydrogen production to times of low electricity prices, while complying with potential matching requirements.

Models. The analytical model enables us to identify the qualitative interaction effects between hydrogen support and overlapping climate policies under various assumptions regarding hydrogen matching requirements and electrolyzer flexibility. The numerical model provides quantitative insights and captures a significantly higher level of technical detail. More precisely, the numerical model is a capacity expansion model that simultaneously optimizes both brownfield capacity expansion and the hourly dispatch of power plants. This high temporal resolution enables us to accurately capture the effects of temporal matching, the temporal availability of renewable energy sources, and the temporal flexibility of hydrogen electrolyzers. The model is calibrated for a 2030 scenario, focusing on a subset of the European electricity market, including Germany and 13 connected bidding zones that cover two-thirds of the European electricity demand. For simplicity, we assume price-inelastic electricity demand and a price-inelastic annual cap on power sector emissions within the geographical scope of our model.[5] Furthermore, our model takes the currently implemented country-specific policy targets for renewable electricity and electrolytic hydrogen as a given.

Findings. The analytical and numerical models consistently yield three main findings. The findings depend on whether renewable electricity targets are binding, i.e., whether subsidies are necessary to

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[4] Short-term hydrogen storage is free, and long-term hydrogen storage is absent.

[5] We hence abstract from the price-elastic response in electricity demand and from emissions by other countries and sectors under the EU emissions trading scheme, as well as from the banking of emissions certificates and the market stability reserve, the implications of which we discuss in Section 4.

meet the targets.[6] First, introducing hydrogen support without a matching requirement increases the prices of emissions and electricity and reduces renewable electricity subsidies if renewable targets are binding. If renewable targets are non-binding, the electricity demand from hydrogen electrolysis triggers substantial additional investment in renewable electricity—even without matching requirements. If cheap hydrogen storage supports flexible electrolyzer operation, this additional renewable generation can displace fossil-fueled generation in times when the hydrogen electrolysis is not running and even lead to a decrease in the prices of emissions and electricity. Second, we find that matching requirements do not affect market outcomes if renewable electricity targets are non-binding. This is because, without binding renewable electricity targets, hydrogen producers can be matched with renewable electricity generation that would have been built on a market basis anyway. Third, if renewable electricity targets are binding, matching requirements reduce the prices of emissions and electricity relative to the case without matching. The lower electricity prices cause renewable electricity subsidies to increase. Meanwhile, hydrogen prices rise due to the costs of matching, and welfare decreases primarily because matching distorts the renewable electricity mix away from the cost optimum. Temporally more granular matching requirements amplify these effects.

Contributions. Our analysis is the first to examine hydrogen policies with matching requirements in the context of emissions trading. With that, we contribute to the longer-standing economic analysis of overlapping climate policy instruments. In particular, specific support for renewable electricity generation has been frequently found to undermine the cost-effectiveness of emissions trading in mitigating climate change (e.g., Amundsen & Mortensen, 2001; Jensen & Skytte, 2003; Linares et al., 2008; De Jonghe et al., 2009; Böhringer & Rosendahl, 2010; Fankhauser et al., 2010)—but may also induce additional emission reductions under certain conditions (Jarke & Perino, 2017). To our knowledge, interactions between emissions trading and hydrogen policies have been assessed by only a few studies, and an assessment of matching requirements and electrolyzer flexibility has been lacking in this context (Bruninx et al., 2022; Roach & Meeus, 2023; Hoogsteyn et al., 2025). On the other hand, we contribute to the more recent but growing literature on matching requirements by more comprehensively considering interactions with overlapping climate policies (e.g., Ruhnau & Schiele, 2023; Giovanniello et al., 2024; Zeyen et al., 2024). More precisely, we are the first to analyze interactions between hydrogen policy with different matching requirements, emissions trading, and renewable electricity subsidies.

Outline. The remainder of this paper is structured as follows. Section 2 introduces the model and input data, Section 3 presents the results, Section 4 discusses the findings and limitations, and Section 5 concludes.

[6] Our numerical model suggests that renewable electricity targets are binding in a subset of the considered countries.

2 Analytical model

Overview. We first employ an analytical partial equilibrium model of the electricity sector to examine the interactions among hydrogen support, emissions trading, and renewable electricity policy. We are particularly interested in understanding how introducing a policy target for electrolytic hydrogen affects the electricity generation mix, market prices, subsidy levels, and total system cost. In this context, we shed light on the effect of hydrogen electrolysis flexibility and the requirements to match hydrogen production with renewable electricity. Subsection 2.1 introduces the analytical model, and Subsections 2.2 and 2.3 present the results for inflexible and flexible electrolysis, respectively.

2.1 Model formulation

General setup. Our analysis represents the partial equilibrium of the electricity and hydrogen market from the perspective of a social planner aiming to minimize the total system cost, denoted as K, which is the sum of annual electricity and electrolytic hydrogen production costs. We assume perfect markets and exogenously defined demand quantities and policy targets. To capture intra-annual variation in electricity production and consumption, we introduce two periods, $t = \{1,2\}$. In each period, electricity can be generated from coal-fired, gas-fired, and renewable power plants.

Electricity generation. Regarding the electricity generation, we assume that coal- and gas-fired power plants have only variable production costs, $K_C(x_{C,t}) = \frac{k_C}{2} x_{C,t}^2$ and $K_G(x_{G,t}) = \frac{k_G}{2} x_{G,t}^2$, which depend on their time-varying electricity generation, $x_{C,t}$ and $x_{G,t}$, respectively. For the evaluation, we define the annual coal- and gas-fired electricity generation as $x_C = \sum_t x_{C,t}$ and $x_G = \sum_t x_{G,t}$, respectively. By contrast, we assume that renewable power plants exhibit only fixed costs, $K_R(\hat{x}_R) = \frac{k_R}{2} \hat{x}_R^2$, which depend on their installed capacity, $\hat{x}_R$. Renewable electricity generation is subject to a temporal availability profile, a_t, and the intra-annual renewable electricity generation, $a_t \hat{x}_R$, is variable but deterministic and known ex ante. Without loss of generality, we assume that $a_1 > a_2$ and $a_1 + a_2 = 1$ such that the annual renewable electricity generation is $x_R = \sum_t a_t \hat{x}_R = \hat{x}_R$.

Hydrogen production. Hydrogen electrolyzers are also assumed to involve only fixed production costs, $K_H(\hat{x}_H) = \frac{k_H}{2} \hat{x}_H^2$, which depend on their installed hydrogen production capacity, $\hat{x}_H$. The electrolyzers are assumed to run with a temporal production profile, b_t. The corresponding electricity consumption of the electrolyzers is $b_t h \hat{x}_H$, where $h > 1$ represents the electricity intensity of hydrogen production. Without loss of generality, we assume $b_1 + b_2 = 1$ such that the annual hydrogen production is $x_H = \sum_t b_t \hat{x}_H = \hat{x}_H$. We consider two extreme cases for the flexibility of hydrogen electrolysis. First, we assume that the electrolysis runs inflexibly (baseload), with $b_1 = b_2 = \frac{1}{2}$. Second, we assume that the electrolysis runs flexibly, producing only in period $t = 1$, when the availability of renewable electricity is high, i.e., $b_1 = 1$ and $b_2 = 0$. In fact, the optimal level of flexibility of electrolysis emerges from the trade-off between the investment costs of electrolyzers and hydrogen storage as well as the volatility of electricity prices—something we will explicitly represent in our numerical model (Section 3).

Optimization problem. The social planner minimizes the total system cost

$$\min_{x_{C,t}, x_{G,t}, \hat{x}_R, \hat{x}_H} K = \sum_t \left(K_C(x_{C,t}) + K_G(x_{G,t}) \right) + K_R(\hat{x}_R) + K_H(\hat{x}_H) \tag{1}$$

subject to

$$x_{C,t} + x_{G,t} + a_t \hat{x}_R \geq \overline{D}_t + b_t h \hat{x}_H \quad \forall t \tag{2}$$

$$\sum_t \left(e_C x_{C,t} + e_G x_{G,t} \right) \leq \bar{E} \tag{3}$$

$$\hat{x}_R \geq \bar{R} + mh\hat{x}_H \tag{4}$$

$$\hat{x}_H \geq \overline{H} \tag{5}$$

Electricity balance. The first constraint (Eq. (2)) represents the electricity balance. It ensures that the electricity supply from all available power plants satisfies the electricity demand in each period. The electricity demand consists of electricity for hydrogen production, $b_t h \hat{x}_H$, and all other electricity demand, $\overline{D}_t$, which is an exogenous input to our model.

Emissions cap. The second constraint (Eq. (3)) enforces an exogenous annual carbon emissions cap $\bar{E}$. Carbon emissions arise with coal- and gas-fired generation and are given as $e_C x_{C,t}$ and $e_G x_{G,t}$. e_C and e_G are the technology-specific emissions factors, and coal-fired generation is assumed to be more emission-intensive than gas-fired generation, i.e., $e_C > e_G$. This emissions cap implies by definition that hydrogen production cannot lead to an overall increase in emissions.

Renewable electricity target. The third constraint (Eq. (4)) defines a lower bound for renewable electricity. This lower bound consists of a hydrogen-independent renewable electricity target, $\bar{R}$, and may be increased by $mh\hat{x}_H$ due to hydrogen matching, where m corresponds to the matching rate with

$$m = \begin{cases} 0, & \text{no matching} \\ 1, & \text{annual matching} \\ \dfrac{1}{2a_2}, & \text{intra-annual matching with inflexible electrolysis} \\ \dfrac{1}{a_1}, & \text{intra-annual matching with flexible electrolysis} \end{cases}$$

For annual matching, this condition implies that the operators of hydrogen electrolysis need to build or contract a capacity of renewable power plants $\hat{x}_{R\to H}$ that satisfies the annual electricity demand from electrolysis, i.e., $\hat{x}_{R\to H} \geq h\hat{x}_H$. The effect of intra-annual matching depends on the flexibility of the electrolysis. For inflexible operation, the matched renewable power plants must satisfy electricity demand from electrolysis in the period with low availability of renewable electricity, i.e., $a_2 \hat{x}_{R\to H} \geq b_2 h \hat{x}_H$ or $\hat{x}_{R\to H} \geq \frac{1}{2a_2} h\hat{x}_H$. For flexible operation, the matched renewable power plants must satisfy electricity demand from electrolysis in the period with high availability of renewable electricity, i.e., $a_1 \hat{x}_{R\to H} \geq b_1 h \hat{x}_H$ or $\hat{x}_{R\to H} \geq \frac{1}{a_1} h\hat{x}_H$. These conditions can be merged into the expression above. We assume that only renewable capacity not contracted by electrolysis counts toward the non-hydrogen renewable electricity target.

Hydrogen target. The fourth constraint (Eq. (5)) encodes an exogenous hydrogen target. It requires that the annual hydrogen production, $\sum_t b_t \hat{x}_H = \hat{x}_H$, must meet the annual production target, $\overline{H}$.

Lagrangian and shadow prices. The Lagrangian corresponding to the social planner's optimization problem is:

$$L = K_R(\hat{x}_R) + K_H(\hat{x}_H) + \textstyle\sum_t \left(K_C(x_{C,t}) + K_G(x_{G,t}) \right) + \sum_t \lambda_{D,t} \left(\overline{D}_t + b_t h \hat{x}_H - x_{C,t} - x_{G,t} - a_t \hat{x}_R \right) + \lambda_E \left(\sum_t \left(e_C x_{C,t} + e_G x_{G,t} \right) - \bar{E} \right) + \lambda_R (\bar{R} - \hat{x}_R + mh\hat{x}_H) + \lambda_H (\overline{H} - \hat{x}_H) \tag{6}$$

The Lagrange multipliers can be interpreted as the shadow prices of the optimization constraints and implicit expressions of the electricity price ($\lambda_{D,t}$), the emissions price (λ_E), the renewable electricity subsidy (λ_R), and the hydrogen price (λ_H). We define two aggregate electricity price metrics: the electricity base price as an unweighted average, i.e., $\lambda_B = \frac{1}{2}\sum_t \lambda_{D,t}$, and the market value of renewable electricity as an average weighted by renewable generation, i.e., $\lambda_{MV} = \sum_t a_t \lambda_{D,t}$.

Solution. We first solve the optimization problem under the assumption that all constraints are binding (i.e., $\lambda_{D,t}, \lambda_E, \lambda_R, \lambda_H > 0$). In addition, we find it helpful to investigate the case of a non-binding renewable electricity target (i.e., $\lambda_R = 0$). This would represent an electricity system in which renewable power plants are deployed on a market basis and no longer require subsidies. The corresponding Karush-Kuhn-Tucker conditions are provided in Appendix A.

2.2 Analytical results for inflexible electrolysis

Overview. Table 1 summarizes the marginal effects of implementing a hydrogen target with inflexible electrolysis. It distinguishes between a binding renewable electricity target (upper part) and a non-binding renewable electricity target (lower part), as well as between different matching requirements (columns).

Binding renewables target without matching. For a binding renewable electricity target without matching ($m = 0$), the hydrogen policy does not alter renewable electricity generation. Hence, hydrogen production is entirely based on additional fossil-fueled electricity generation. Due to the emissions constraint, higher fossil-fueled generation is only possible through a decrease in coal-fired generation and an overproportional increase in gas-fired generation. The increase in electricity demand and fossil-fueled generation leads to rising prices of emissions and electricity. The hydrogen price also increases with the hydrogen target due to the pass-through of higher electricity prices and the increasing marginal cost of electrolysis capacity. Meanwhile, higher electricity prices imply a lower required subsidy for renewable electricity. In our simplified model, the additional baseload demand from inflexible electrolysis raises electricity prices equally in both periods, and the market value of renewable electricity and the base electricity price increase at the same rate. Increasing the hydrogen target naturally increases the total system cost. The marginal increase in the total system cost corresponds to the hydrogen price, which equals the sum of the marginal electrolyzer costs and power-to-hydrogen conversion efficiency times the electricity price.

Binding renewables target with annual matching. For a binding renewable electricity target with annual matching ($m = 1$), the additional renewable electricity generation equals the increase in electricity demand from hydrogen production on an annual basis. As a result, fossil-fueled electricity generation, the electricity base price, and the emissions price remain at the levels they were before the introduction of the hydrogen target. Compared to no matching, however, annual matching increases coal-fired generation and decreases gas-fired generation. This can be viewed as a variant of the green-promotes-the-dirtiest hypothesis, which has been discussed in the context of interacting renewable subsidies and emissions trading (Böhringer & Rosendahl, 2010). While the electricity base price and emissions price remain constant with annual matching, renewable subsidies increase. This is due to the increasing marginal costs of renewable electricity and their declining market value.[7]

[7] The decline in the market value increases with the difference in the availability of renewable electricity between the two periods, i.e., the variability in the renewable electricity. The electricity price decreases in the period with high availability of renewable electricity and increases proportionately in the other period. As a result, the marginal value of renewable electricity decreases while the electricity base price remains constant.

Change in		**Without matching ($\boldsymbol{m=0}$)**	**Annual matching ($\boldsymbol{m=1}$)**	**Intra-annual matching ($\boldsymbol{m=\frac{1}{2a_2}>1}$)**
Binding renewable electricity target ($\boldsymbol{\lambda_R>0}$)				
Coal-fired generation	$\frac{\partial x_C^*}{\partial \bar{H}}=-\frac{e_G}{e_C-e_G}h(1-m)$	Decreases	No change	Increases
Gas-fired generation	$\frac{\partial x_G^*}{\partial \bar{H}}=\frac{e_C}{e_C-e_G}h(1-m)$	Increases	No change	Decreases
Renewable generation	$\frac{\partial x_R^*}{\partial \bar{H}}=hm$	No change	Increases	Increases more
Emissions price	$\frac{\partial \lambda_E^*}{\partial \bar{H}}=\frac{e_Gk_C+e_Ck_G}{(e_C-e_G)^2}\frac{h}{2}(1-m)$	Increases	No change	Decreases
Electricity base price	$\frac{\partial \lambda_B^*}{\partial \bar{H}}=\frac{e_G^2k_C+e_C^2k_G}{(e_C-e_G)^2}\frac{h}{2}(1-m)$	Increases	No change	Decreases
Renewable market value	$\frac{\partial \lambda_{MV}^*}{\partial \bar{H}}= \begin{cases} \frac{e_G^2k_C+e_C^2k_G}{(e_C-e_G)^2}\frac{h}{2}, & m=0 \\ -\frac{(a_1-a_2)^2k_Ck_G}{k_C+k_G}\frac{h}{2}, & m=1 \\ \frac{1}{2a_2}\frac{h}{2}\left(-\frac{(a_1-a_2)^2k_Ck_G}{k_C+k_G}-\frac{(a_1-a_2)(e_G^2k_C+e_C^2k_G)}{(e_C-e_G)^2}\right), & m=\frac{1}{2a_2} \end{cases}$	Increases	Decreases	Decreases more
Renewable subsidy	$\frac{\partial \lambda_R^*}{\partial \bar{H}}=hmk_R-\frac{\partial \lambda_{MV}^*}{\partial \bar{H}}= \begin{cases} -\frac{\partial \lambda_{MV}^*}{\partial \bar{H}}, & m=0 \\ hk_R-\frac{\partial \lambda_{MV}^*}{\partial \bar{H}}, & m=1 \\ \frac{1}{2a_2}hk_R-\frac{\partial \lambda_{MV}^*}{\partial \bar{H}}, & m=\frac{1}{2a_2} \end{cases}$	Decreases (with the increase in the marginal value of renewables)	Increases (with the increase in the marginal cost and the decrease in the marginal value of renewables)	Increases more (with the larger increase in the marginal cost and the larger decrease in the marginal value of renewables)
Hydrogen price	$\frac{\partial \lambda_H^*}{\partial \bar{H}}=k_H+h\left(\frac{\partial \lambda_B^*}{\partial \bar{H}}+m\frac{\partial \lambda_R^*}{\partial \bar{H}}\right)= \begin{cases} k_H+h\frac{\partial \lambda_B^*}{\partial \bar{H}}, & m=0 \\ k_H+h\frac{\partial \lambda_R^*}{\partial \bar{H}} & m=1 \\ k_H+h\left(\frac{\partial \lambda_B^*}{\partial \bar{H}}+\frac{1}{2a_2}\frac{\partial \lambda_R^*}{\partial \bar{H}}\right), & m=\frac{1}{2a_2} \end{cases}$	Increases (with the increase in the marginal electrolyzer cost and the electricity base price)	Increases (with the increase in the marginal electrolyzer cost and the renewable electricity subsidy)	Increases more (with the increase in the marginal electrolyzer cost and the larger increase in the renewable electricity subsidy minus the decrease in the electricity base price)
Total system cost	$\frac{\partial K^*}{\partial \bar{H}}=\lambda_H^*=k_H\bar{H}+h(\lambda_B^*+m\lambda_R^*)$	Increases	Increases more	Increases even more
Non-binding renewable electricity target ($\boldsymbol{\lambda_R=0}$)				
Coal-fired generation	$\frac{\partial x_C^*}{\partial \bar{H}}=-\frac{(e_C-e_G)e_G\left((a_1-a_2)^2k_Ck_G+2(k_C+k_G)k_R\right)}{\mathrm{A}}h$	Decreases		
Gas-fired generation	$\frac{\partial x_G^*}{\partial \bar{H}}=\frac{(e_C-e_G)e_C\left((a_1-a_2)^2k_Ck_G+2(k_C+k_G)k_R\right)}{\mathrm{A}}h$	Increases		
Renewable generation	$\frac{\partial x_R^*}{\partial \bar{H}}=\frac{(e_G^2k_C+e_C^2k_G)(k_C+k_G)}{\mathrm{A}}h$	Increases		
Emissions price	$\frac{\partial \lambda_E^*}{\partial \bar{H}}=\frac{(e_Gk_C+e_Ck_G)\left((a_1-a_2)^2k_Ck_G+2(k_C+k_G)k_R\right)}{\mathrm{A}}\frac{h}{2}$	Increases		
Electricity base price	$\frac{\partial \lambda_B^*}{\partial \bar{H}}=\frac{(e_G^2k_C+e_C^2k_G)\left((a_1-a_2)^2k_Ck_G+2(k_C+k_G)k_R\right)}{\mathrm{A}}\frac{h}{2}$	Increases		
Renewable market value	$\frac{\partial \lambda_{MV}^*}{\partial \bar{H}}=k_R\frac{\partial x_R^*}{\partial \bar{H}}$	Increases		
Renewable subsidy	$\frac{\partial \lambda_R^*}{\partial \bar{H}}=0$	No change		
Hydrogen price	$\frac{\partial \lambda_H^*}{\partial \bar{H}}=k_H+h\frac{\partial \lambda_B^*}{\partial \bar{H}}$	Increases (with the increase in the marginal cost of electrolyzers and the electricity base price)		
Total system cost	$\frac{\partial K^*}{\partial \bar{H}}=\lambda_H^*=k_H\bar{H}+h\lambda_B^*$	Increases		

Table 1: Marginal impacts of an increasing hydrogen target with inflexible electrolysis. Note that $A>0$ (see Appendix B).

The hydrogen price also increases as it now needs to cover the renewable subsidy in addition to the marginal costs of electrolyzers and the electricity base price. Consequently, the total system cost of attaining a hydrogen target also increases by the subsidy paid for the additional renewable electricity generation multiplied by the power-to-hydrogen conversion efficiency. As electricity demand, hydrogen demand, and emissions are independent of the matching requirements, the matching-induced increase in total system costs can be interpreted as a welfare loss.

Binding renewables target with intra-annual matching. For a binding renewable electricity target with intra-annual matching ($m = \frac{1}{2a_2}$), the additional renewable electricity generation exceeds the increase in electricity demand from hydrogen production on an annual basis. This is because more renewable capacity must be contracted for hydrogen production, as the matching requirement must also be met during the period of low renewable electricity generation availability (a_2 in our model). As a result, fossil-fueled electricity generation, the electricity base price, and the emissions price decrease to levels below those before the introduction of the hydrogen target. Relative to annual matching, intra-annual matching amplifies the substitution of coal-fired for gas-fired electricity generation and the increase in renewable electricity subsidies. The hydrogen price and the total system costs also increase, as more renewable electricity generators must be built, and the cost of building these increases with the renewable electricity subsidy.

Non-binding renewables target without matching. If the renewable electricity target is non-binding, i.e., if the deployment of renewable electricity generation is purely market-driven, renewable generation will also rise with an increasing hydrogen target. Hence, hydrogen production is at least partly based on renewable electricity, even without a political matching requirement. As our numerical simulations will show below, the increase in renewable electricity generation induced by hydrogen support can already be substantial in the absence of matching (Subsection 3.3). Still, the fossil-fueled electricity production in the analytical model also increases, as a result of a decrease in coal-fired generation and an overproportional increase in gas-fired generation. However, this substitution effect is less pronounced than with a binding renewable electricity target. The renewable electricity subsidy remains zero and is unaffected by marginal changes in hydrogen production.[8] As with a binding renewable electricity target, the hydrogen price increases with the rising marginal cost of electrolyzers and the rising electricity base price, and the increase in total system cost equals the hydrogen price.

Non-binding renewables target with matching. If the renewable electricity target is not binding, matching does not alter how a hydrogen target affects our considered output variables. This is because, in this case, hydrogen producers can be matched with renewable electricity generation that would have been built on a market basis anyway. Matching only implies a swap of renewable and fossil generation between electricity demand for hydrogen and other applications, without further implications. For intra-annual matching, this finding is conditional on the availability of renewable electricity always being larger than the electricity consumption of the inflexibly operated electrolyzer, $a_2 \hat{x}_R \geq \frac{h}{2} \hat{x}_H$.

2.3 Analytical results for flexible electrolysis

Overview. Table 2 summarizes the marginal effects of implementing a hydrogen target with flexible electrolysis, in the same format as the previous summary for the inflexible case.

[8] Increasing costs of renewable electricity generation also imply that matching may induce a switch from a setting with a non-binding renewables target (i.e., zero subsidy) to a setting with a binding renewables target (i.e., a positive renewable electricity subsidy), everything else equal.

Binding renewables target. For a binding renewable electricity target, the results for the generation mix, emissions price, and electricity base price remain unchanged compared to those with inflexible electrolysis. By contrast, the market value of renewable electricity is positively affected by flexibility: without matching, flexibility amplifies the increase in market value; with annual matching, flexibility causes market values to increase instead of decrease; and with intra-annual matching, flexibility reduces the decrease in market value. As a result, subsidies for renewable electricity are smaller than with inflexible electrolysis. The hydrogen price now depends on the electricity price in the first period, which must be lower than the base price to make flexibility economical.[9] As expected, the total system cost increases with the hydrogen price as the hydrogen target is increased.

Non-binding renewables target. For a non-binding renewable electricity target, flexible hydrogen electrolysis increases the equilibrium quantity of renewable electricity more substantially than inflexible electrolysis. As the quantity of renewable electricity changes, the residual generation mix also changes. Interestingly, the sign of the changes in coal and gas generation is ambiguous, depending on the sign of $\Gamma = 2\big((k_C + k_G)k_R - a_2(a_1 - a_2)k_C k_G\big)$: if $\Gamma > 0$, coal decreases less and gas increases less than with inflexible electrolysis;[10] if $\Gamma < 0$, coal increases and gas decreases. The results for the emissions and electricity base price are also ambiguous: they increase if $\Gamma > 0$ and decrease otherwise. As with the binding renewable electricity target, the hydrogen price and the total system cost with flexible electrolysis depend on the electricity price in the first period.

Condition for decreasing prices. To better understand the conditions for such a counterintuitive result, namely that the electricity base price and the emissions price can decrease with additional flexible electricity demand, we examine the sign of $\Gamma = 2\, k_C k_G \left(\frac{k_R}{k_C} + \frac{k_R}{k_G} - a_2(a_1 - a_2)\right)$. For $\Gamma < 0$, the positive term $\frac{k_R}{k_C} + \frac{k_R}{k_G}$ needs to be small, which is the case if the slope in the cost of renewable electricity is relatively small compared to the slope in the cost of fossil fueled electricity, i.e., $k_R \ll k_C, k_G$. Second, the negative term $a_2(a_1 - a_2)$ needs to be large, which is the case for $a_1 \to \frac{3}{4}, a_2 \to \frac{1}{4}$. This implies that a significant portion of renewable electricity production occurs in the first period, benefiting from the hydrogen-driven price increase during that period, which drives the expansion of renewable electricity. Meanwhile, a smaller but still substantial part of renewable electricity production occurs in the second period, substituting for fossil-fueled electricity generation. We refer to this as "renewable spillover effect": flexible electrolysis consumes electricity when the availability of renewable electricity is high, thereby pulling more renewable generators into the market; these additional generators also produce electricity when electrolysis is not running, substituting for fossil-fueled electricity generation. If this renewable spillover effect is strong, electricity base prices and emissions prices may decrease as flexible electricity demand increases.

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[9] To be precise, if flexibility is costly, i.e., $k_{H,flexible} > k_{H,inflexible}$, the difference between the electricity price in the first period and the base price should be large enough to compensate for the cost of flexibility, i.e., $\lambda_B^* - \lambda_{D1}^* > \left(k_{H,flex} - k_{H,inflex}\right)\frac{\bar{H}}{h}$. In the case of intra-annual matching, this inequality expands to $\lambda_B^* - \lambda_{D1}^* > \left(k_{H,flex} - k_{H,inflex}\right)\frac{\bar{H}}{h} + \left(\frac{1}{a_1} - \frac{1}{2a_2}\right)\lambda_R^*$, with $\frac{1}{a_1} - \frac{1}{2a_2} < 0$ for $a_1 > 2a_2$. This implies that flexibility becomes more economical if renewable electricity is highly volatile, because it allows the hydrogen electrolysis to be matched with less renewable electricity.

[10] To see that the increase is smaller than with inflexible electrolysis, we compare 2Γ to its equivalent in Table 1. This yields $-2a_2(a_1 - a_2)k_C k_G + 2(k_C + k_G)k_R < (a_1 - a_2)^2 k_C k_G + 2(k_C + k_G)k_R$, which is equivalent to $a_1 > a_2$, which is true by assumption.

Change in		**Without matching ($m = 0$)**	**Annual matching ($m = 1$)**	**Intra-annual matching ($m = \frac{1}{a_1} > 1$)**
Binding renewable electricity target ($\lambda_R > 0$)				
Coal-fired generation	$\frac{\partial x_C^*}{\partial \bar{H}} = -\frac{e_G}{e_C - e_G} h(1-m)$	Decreases (as with inflexible electrolysis)	No change (as with inflexible electrolysis)	Increases (as with inflexible electrolysis)
Gas-fired generation	$\frac{\partial x_G^*}{\partial \bar{H}} = \frac{e_C}{e_C - e_G} h(1-m)$	Increases (as with inflexible electrolysis)	No change (as with inflexible electrolysis)	Decreases (as with inflexible electrolysis)
Renewable generation	$\frac{\partial x_R^*}{\partial \bar{H}} = hm$	No change (as with inflexible electrolysis)	Increases (as with inflexible electrolysis)	Increases more (as with inflexible electrolysis)
Emissions price	$\frac{\partial \lambda_E^*}{\partial \bar{H}} = \frac{e_G k_C + e_C k_G}{(e_C - e_G)^2} \frac{h}{2}(1-m)$	Increases (as with inflexible electrolysis)	No change (as with inflexible electrolysis)	Decreases (as with inflexible electrolysis)
Electricity base price	$\frac{\partial \lambda_B^*}{\partial \bar{H}} = \frac{e_G^2 k_C + e_C^2 k_G}{(e_C - e_G)^2} \frac{h}{2}(1-m)$	Increases (as with inflexible electrolysis)	No change (as with inflexible electrolysis)	Decreases (as with inflexible electrolysis)
Renewable market value	$\frac{\partial \lambda_{MV}^*}{\partial \bar{\mathrm{H}}} = \begin{cases} \frac{h}{2}\left(\frac{e_G^2 k_C + e_C^2 k_G}{(e_C - e_G)^2} + \frac{(a_1 - a_2) k_C k_G}{k_C + k_G}\right), & m = 0 \\ \frac{h}{2} \frac{\left((a_1 - a_2) - (a_1 - a_2)^2\right) k_C k_G}{k_C + k_G}, & m = 1 \\ \frac{a_2}{a_1} \frac{h}{2}\left(-\frac{(a_1 - a_2) k_C^2}{k_C + k_G} - \frac{\mathrm{B}}{(e_C - e_G)^2}\right), & m = \frac{1}{a_1} \end{cases}$	Increases (more than with inflexible electrolysis)	Increases (as opposed to inflexible electrolysis)	Decreases (less than with inflexible electrolysis under plausible assumptions, see Appendix B)
Renewable subsidy	$\frac{\partial \lambda_R^*}{\partial \bar{H}} = hmk_R - \frac{\partial \lambda_{MV}^*}{\partial \bar{H}}$	Decreases (more than with inflexible electrolysis)	Decreases (as opposed to inflexible electrolysis)	Increases (less than with inflexible electrolysis)
Hydrogen price	$\frac{\partial \lambda_H^*}{\partial \bar{H}} = k_H + h\left(\frac{\partial \lambda_{D1}^*}{\partial \bar{H}} + m\frac{\partial \lambda_R^*}{\partial \bar{H}}\right) = \begin{cases} k_H + h\frac{\partial \lambda_{D1}^*}{\partial \bar{H}}, & m = 0 \\ k_H + h\left(\frac{\partial \lambda_{D1}^*}{\partial \bar{H}} + \frac{\partial \lambda_R^*}{\partial \bar{H}}\right) & m = 1 \\ k_H + h\left(\frac{\partial \lambda_{D1}^*}{\partial \bar{H}} + \frac{1}{a_1}\frac{\partial \lambda_R^*}{\partial \bar{H}}\right), & m = \frac{1}{a_1} \end{cases}$	Increases (with the increase in the marginal electrolyzer cost and the electricity price in period 1)	Increases less (with the inc. in the marginal electrolyzer cost and the difference between the inc. in the electricity price in period 1 and the dec. in the renewable subsidy)	Increases more (with the increase in the marginal electrolyzer cost, the electricity price in period 1, and the renewable electricity subsidy)
Total system cost	$\frac{\partial K^*}{\partial \bar{H}} = \lambda_H^* = k_H \bar{H} + h(\lambda_{D1}^* + m\lambda_R^*)$	Increases	Increases more	Increases even more
Non-binding renewable electricity target ($\lambda_R = 0$)				
Coal-fired generation	$\frac{\partial x_C^*}{\partial \bar{H}} = -\frac{(e_C - e_G) e_G \Gamma}{\mathrm{A}} h$	Ambiguous (decreases less than with inflexible electrolysis or increases)		
Gas-fired generation	$\frac{\partial x_G^*}{\partial \bar{H}} = \frac{(e_C - e_G) e_C \Gamma}{\mathrm{A}} h$	Ambiguous (increases less than with inflexible electrolysis or decreases)		
Renewable generation	$\frac{\partial x_R^*}{\partial \bar{H}} = \frac{(e_G^2 k_C + e_C^2 k_G)(k_C + k_G) + (2a_1 - 1)(e_C - e_G)^2 k_C k_G}{\mathrm{A}} h$	Increases (more than with inflexible electrolysis)		
Emissions price	$\frac{\partial \lambda_E^*}{\partial \bar{H}} = \frac{(e_G k_C + e_C k_G)\, \Gamma}{\mathrm{A}} \frac{h}{2}$	Ambiguous (increases less than with inflexible electrolysis or decreases)		
Electricity base price	$\frac{\partial \lambda_B^*}{\partial \bar{H}} = \frac{(e_G^2 k_C + e_C^2 k_G)\, \Gamma}{\mathrm{A}} \frac{h}{2}$	Ambiguous (increases less than with inflexible electrolysis or decreases)		
Renewable market value	$\frac{\partial \lambda_{MV}^*}{\partial \bar{\mathrm{H}}} = k_R \frac{\partial x_R^*}{\partial \bar{H}}$	Increases (more than with inflexible electrolysis)		
Renewable subsidy	$\frac{\partial \lambda_R^*}{\partial \bar{H}} = 0$	No change		
Hydrogen price	$\frac{\partial \lambda_H^*}{\partial \bar{H}} = k_H + h\frac{\partial \lambda_{D1}^*}{\partial \bar{H}}$	Increases (with the increase in the marginal cost of electrolyzers and the electricity price in period 1)		
Total system cost	$\frac{\partial K^*}{\partial \bar{H}} = \lambda_H^* = k_H \bar{H} + h\lambda_{D1}^*$	Increases		

Table 2: Marginal impacts of an increasing hydrogen target with flexible electrolysis. Note that $A > 0$, $B > 0$ under plausible assumptions, and $\Gamma \in \mathbb{R}$ (see Appendix B).

3 Numerical model

Motivation. We complement the preceding analytical considerations with a numerical model that captures a broader range of aspects of real-world electricity markets. On this basis, the numerical model can indicate whether renewable electricity targets are binding and how flexibly hydrogen electrolysis is operated, depending on the cost of hydrogen storage. Furthermore, it resolves the analytical ambiguities linked to effect directions in the case of flexible electrolysis and non-binding renewable electricity targets. Finally, it enables us to estimate effect sizes.

Overview. Like the analytical model, the numerical model represents the partial equilibrium of the electricity sector, subject to emissions trading, renewable electricity policies, and hydrogen support schemes with varying matching requirements. We calibrate the model for a subset of the European electricity market, including Germany and all connected bidding zones, and investigate a scenario for the year 2030. We select this horizon, as political hydrogen production targets are already substantial, but the remaining power sector emissions are not yet negligible for this horizon.[11] Subsection 3.1 introduces the numerical model, Subsection 3.2 outlines our parametrization, and Subsections 3.3 and 3.4 present the results for our main scenario and alternative flexibility cost assumptions, respectively.

3.1 Model formulation

Power market modeling. As for the analytical model, the numerical model represents the partial equilibrium of the electricity market by minimizing the total system cost, assuming perfectly inelastic electricity demand. The model simultaneously optimizes capacity expansion and dispatch of electricity generation, hydrogen electrolysis, and storage of both electricity and hydrogen. Investment decisions are based on the annualized fixed cost of new assets. The dispatch of all assets, as well as trade between bidding zones, is optimized for one year in an hourly resolution, accounting for capacity constraints and variable costs. Such a high temporal resolution is deemed critical for our analysis of a power sector with a high share of variable renewable electricity generation and potential hourly hydrogen matching requirements. The geographical scope includes Germany and the thirteen connected bidding zones.[12] Every zone is modeled as a single node, and trade between zones is subject to the expected future interconnector capacity. The model is based on the open-source power system model *PyPSA-Eur*, more precisely on a version of the model developed by Zeyen et al. (2024).[13]

Power plant capacities. Existing power plants are considered if their expected lifetime exceeds 2030 and if they are not affected by currently implemented coal phase-out policies. Regarding new capacity, the model can invest in three types of renewable generators, namely solar photovoltaics (PV), onshore wind energy, and offshore wind energy. The model can also invest in open-cycle and combined-cycle (natural) gas turbines, battery storage, and long-duration electricity storage, which consists of hydrogen electrolyzers, hydrogen storage, and combined-cycle hydrogen turbines. Onshore wind is modeled with

[11] This is in line with Giovanniello et al. (2024) arguing that hourly matching of hydrogen may only be required in the medium term, but neither in the short-term when hydrogen volumes are still negligible nor in the long-term when the power grid is already largely decarbonized.

[12] Which are the bidding zones of Austria (AT), Belgium (BE), Switzerland (CH), Czeck Republic (CZ), Denmark (DK1 and DK2), France (FR), Great Britain (GB0), Luxembourg (LU), Netherlands (NL), Southern Norway (NO2), Poland (PL), and Southern Sweden (SE2). Luxembourg and Germany share one bidding zone but are modeled separately for an easier parametrization with national statistics. The connection between Great Britain and Germany (NeuConnect) is planned to go online in 2028.

[13] We use the one-step optimization setup from Zeyen et al. (2024) to allow for a market equilibrium interpretation of our results.

distinct resource classes per bidding zone. Each resource class has an individual hourly availability profile and renewable capacity potential. In essence, the resource classes are a stepwise representation of upward-sloping long-run marginal supply curves. We do not model hydrogen trade across nodes in our model, as we anticipate that the necessary infrastructure will not yet be developed by 2030.

Emission policy. For the emissions policy, we implement a price-inelastic cap on power sector emissions across the model region. The choice of a super-national quantity-based instrument reflects the set-up of the EU emissions trading scheme, but we abstract from some real-world complexities. We do not model changes in emissions beyond the power sector and the model region. In this way, we isolate the effect that hydrogen policies have on emissions prices via the power sector. The parameterization of our modeled emission cap is detailed in Subsection 3.2, and the implications of hydrogen policies beyond the power sector are discussed in Section 4. Furthermore, we fix emissions for the year 2030 and neglect banking and borrowing (Rubin, 1996; Salant, 2016), the market stability reserve, and potential endogenous certificate cancellations (Perino & Willner, 2016; Rosendahl, 2019; Bruninx et al., 2020; Schmidt, 2020). The latter is justified by the expectation that cancellation effects in the EU emissions trading scheme diminish toward 2030 (Schmidt, 2020; Perino et al., 2025).

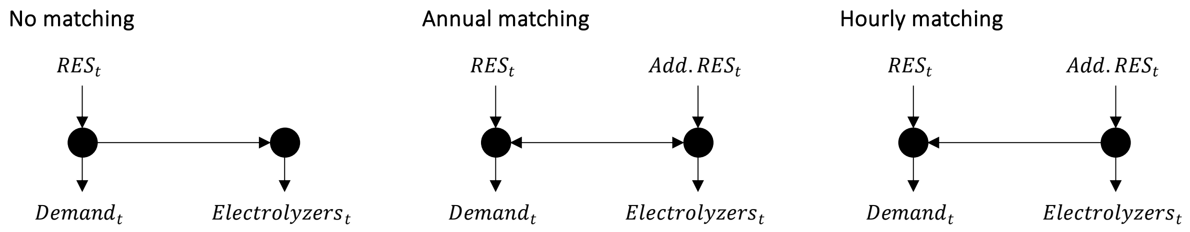
Renewable policy. For the renewable policy, we model national deployment targets, reflecting the political status quo in Europe. For all countries, we model a minimum share of renewable electricity, which is defined as the annual electricity generation from renewable energy sources divided by the annual final electricity consumption. The electricity consumption of hydrogen electrolysis is not included in the final electricity consumption. Hence, hydrogen policy does not affect the national renewable electricity targets but may need to be matched with "additional" renewable electricity production, which does not count toward the national renewable electricity target, as detailed below. We abstract from technology-specific renewable electricity targets.

Hydrogen policy. For the hydrogen policy, we consider national hydrogen production targets in line with national hydrogen strategies and varying hydrogen matching requirements. We model a hydrogen balance at an hourly resolution and require hydrogen to be supplied constantly ("baseload"), reflecting the conservative assumption that downstream hydrogen consumption processes have low flexibility (e.g., industry). The model can oversize the electrolyzer capacity and invest in hydrogen storage to enable flexible operation.[14] Acknowledging that the "flexibility costs" of hydrogen electrolysis are uncertain, we vary the cost of hydrogen storage. Figure 1 illustrates our implementation of matching requirements. Without matching, hydrogen electrolysis can buy "general" electricity from the grid (renewable or not). Under the annual matching requirement, the electricity consumed for hydrogen production must be matched with dedicated "additional" renewable generation on an annual basis. Intra-annually, additional renewable electricity can be sold to the grid, and electrolysis can buy general electricity from the grid as needed. Under hourly matching, matching with additional renewable electricity is required on an hourly basis. The additional electricity can still be sold to the grid, but electrolysis can never consume general electricity from the grid. Dedicated batteries can be built to support hourly matching, and surplus can be used to supply final electricity demand.

Market interpretation. The model can be interpreted as a stylized brownfield partial equilibrium model of a perfectly functioning electricity market. Most importantly, the model abstracts from uncertainty, transaction costs, and market power (cf. Section 4). With these simplifications in mind, hourly electricity prices for each represented bidding zone can be read from the shadow variables of the electricity balance constraint. The model-wide and time-invariant emissions price can be read from the

[14] We refrain from modeling ramping constraints of hydrogen electrolysis, as these seem to be negligible at an hourly temporal resolution for both alkaline and proton exchange membrane electrolyzers (Lange et al., 2023).

shadow variable of the emission constraint. Required subsidies for renewables and hydrogen prices can be read from the constraints representing renewable and hydrogen targets, respectively.



No matching: $$\frac{\sum_t RES_t}{\sum_t Demand_t} \geq share_{RES}$$

Annual matching: $$\frac{\sum_t RES_t}{\sum_t Demand_t} \geq share_{RES}$$ $$\sum_t Add.RES_t \geq \sum_t Electrolyzers_t$$

Hourly matching: $$\frac{\sum_t RES_t}{\sum_t Demand_t} \geq share_{RES}$$ $$Add.RES_t \geq Electrolyzers_t \; \forall t$$

Figure 1: Schematic illustration of the implemented hydrogen matching requirements. The national renewable electricity target (share$_{RES}$) is defined as the share of renewable electricity (RES) and final electricity consumption (Demand). Depending on the matching requirement, additional renewable electricity (Add. RES) must exceed electricity consumption from the electrolyzers (Electrolyzers) in annual or hourly terms.

3.2 Model parameterization

Overview. We calibrate the model for a subset of the European electricity market, including Germany and all connected bidding zones, and a scenario for the year 2030. For each bidding zone, we define final electricity consumption time series, renewable electricity generation potentials and availability time series, and capacities of existing electricity generators. Furthermore, we define assumptions for fuel and investment costs, which are geographically uniform but vary across scenarios. Particular attention is devoted to accurate time series for final consumption and renewable generation, as these are critical for our analysis of a power sector with high shares of renewable electricity and hydrogen matching requirements at a potentially hourly resolution.

Final electricity consumption. For the final electricity consumption, we rely on hourly time series from the European Resource Adequacy Assessment (ENTSO-E, 2022). These simulated time series account for the expected electrification of heat and transport but exclude electricity consumption from electrolyzers, which we model endogenously (as detailed below). We select the time series for the horizon 2030 and the weather patterns from 2013. Across our model scope, the annual electricity consumption amounts to approximately 2,750 TWh, which is about two-thirds of the entire European consumption.[15]

Renewable electricity generation. For the renewable electricity generation, we derive capacity potentials and availability profiles from weather data using the *Python* package *atlite* (Hofmann et al., 2021). More precisely, capacity potentials are derived from the Corine Land Cover dataset, and availability profiles are derived from the SARAH2 and ERA5 weather reanalysis datasets for the year 2013. For onshore wind, the available land in each bidding zone is clustered based on wind speed into 15 distinct resource classes. Offshore wind is distinguished by distance from shore into two classes, and solar is not distinguished within bidding zones due to relatively homogeneous solar radiation. The

[15] EU plus Great Britain, Switzerland, and Norway.

distinct resource qualities translate into varying levelized costs of electricity, which can be represented as stepwise upward-sloping cost-potential curves (see Figure 2 for onshore wind in Germany).[16]

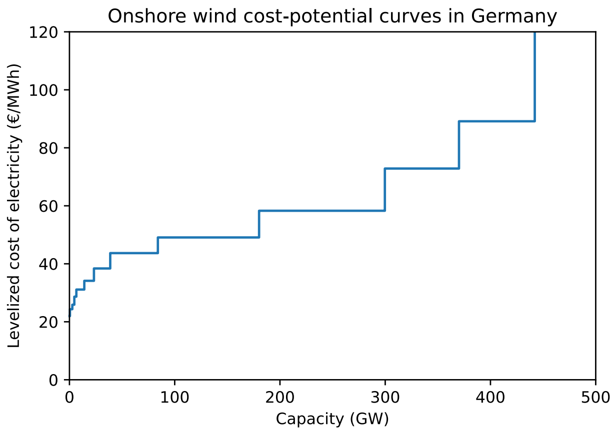


Figure 2: Renewable cost-potential curves for the example of Germany. Note that the axes are truncated to focus on the relevant part of the cost-potential curves.

Existing capacities and fuel costs. For exogenous asset capacities and investment cost assumptions in 2030, we primarily use the default assumptions from *PyPSA-Eur*[17] and focus on discussing deviations here. Exogenous capacity assumptions pertain to the legacy capacity of power plants, based on their remaining lifetime. Here, we include agreed-upon national plans for phasing out coal and nuclear energy.[18] Furthermore, interconnector capacity is considered according to European network development plans. Fuel costs are set at 6.5 €/MWh for lignite, 8.5 €/MWh for hard coal, and 23 €/MWh for natural gas, based on the latest World Energy Outlook (IEA, 2024), futures commodity prices, and own transport cost assumptions.

Investment costs. Most investment cost assumptions are based on data from the Danish Energy Agency (DEA, 2025). For renewable electricity generators, we observe that the techno-economic cost assumptions from the Danish Energy Agency imply a considerably lower levelized cost of electricity than current bids in renewable electricity support schemes. We hypothesize that some of this cost difference is due to land scarcity, resulting from planning restrictions, bottlenecks in permitting, and, more generally, local land-use conflicts and disamenity costs (e.g., Lehmann & Tafarte, 2024; Ruhnau et al., 2024; McKenna et al., 2025). To approximate the effect of such potential land scarcity, we increase investment costs by 15% for solar PV and 30% for onshore and offshore wind energy, relative to data from the Danish Energy Agency.[19] For hydrogen electrolyzers, we assume investment costs of 1,100 €/kW_{el}, reflecting recent estimates by the International Energy Agency for both alkaline and proton exchange membrane technology (IEA, 2024). For hydrogen storage, we assume investment costs of 45 €/kWh_{H2} in our *main* scenario, which represents relatively expensive high-pressure tanks.

[16] Note that such regionally aggregated availability profiles are smoother than the availability profiles of individual plants, which may underestimate the costs of hourly matching (Casas Ferrús et al., 2024).
[17] Github repository: https://github.com/pypsa/pypsa-eur
[18] For the example of German, we reduce the capacity of coal- and lignite-fired power plants to 8 and 6 GW, respectively, according to phase-out plans on the national and North-Rhine-Westphalian state level.
[19] This yields investment costs of 442 €/kW_{el} for solar PV, 1,425 €/kW_{el} for onshore wind, and 2,192 €/kW_{el} for offshore wind (plus connection costs as a function of shore distance). In fact, higher land rents would increase fixed operational costs (€/kW/a) and lower resource quality reduces the specific output (kWh/kW). Hence, increasing specific investment costs (€/kW) is only an approximation of the general effect that land scarcity increases the levelized costs of renewable electricity (€/kWh).

In the *cheap flex* scenario, we reduce the investment cost of hydrogen storage to 1.5 €/kWh_{H2}, which represents much cheaper underground salt caverns. We also add hydrogen-fired combined cycle gas turbines to the pre-configured technology set, at 5% higher investment costs than natural-gas-fired plants of the same type. Those turbines can only run on hydrogen produced within the model scope (i.e., no hydrogen imports). The hydrogen used in power plants does not count toward the defined hydrogen target (see below), and no matching requirements apply. All investment costs are annualized using a 7% weighted average cost of capital.

Emission cap. We parametrize the cap on emissions within our model scope based on a reference run with exogenous emission prices. While the number of emission certificates released annually under the EU Emissions Trading Scheme until 2030 is politically defined, actual emissions within our model scope in 2030 are highly uncertain for two reasons. First, the total emissions in 2030 are unclear due to the inter-temporal optimization of market actors and automatic cancellations by the market stability reserve (see Bruninx et al., 2022). Second, it is unclear how emissions in 2030 will be endogenously distributed across sectors and countries. To exclude this complexity from the present analysis, we determine an emission cap for our model based on a reference model run without hydrogen, setting an exogenous emissions price to 100 €/t_{CO2} in 2030, according to the latest price projections by the German Environmental Agency (UBA, 2025). This yields an emission cap of about 148 Mt_{CO2}, which is fixed for all other model runs.

Renewable electricity and hydrogen targets. For renewable electricity and hydrogen, we apply national minimum production targets as summarized in Table 3. For renewable electricity generation, we multiply the nationally defined minimum shares by the final electricity consumption resulting from the aggregated time series described above. For hydrogen, we apply minimum production targets rather than capacity targets to ensure comparability of our scenarios in terms of hydrogen output, while also allowing the model to determine the economically optimal level of electrolyzer capacity endogenously.

Table 3: National policy targets for renewables and hydrogen in 2030.

Country	Renewable share (%)	Electrolyzer capacity (GW_{el})	Electrolyzer consumption (TWh_{el})	Hydrogen production (TWh_{H2})
DE	80%	10	40	25
AT	100%	1	4	2
BE	37%	1.5	6	4
CH	0%	0	0	0
CZ	17%	0	0	0
DK	117%	5	20	12
FR	40%	6.5	26	16
GB	65%	8.1	29	20
LU	0%	0	0	0
NL	73%	8	32	20
NO	0%	0	0	0
PL	32%	1.6	6	4
SE	0%	1	4	2
Total		**42.7**	**171**	**106**

Sources: National Energy and Climate Plans, National Hydrogen Strategies. For Belgium, in the absence of a political hydrogen target, we use the planned electrolyzer capacity as reported by Hydrogen Europe (2022).

Meanwhile, national hydrogen strategies often define hydrogen targets in terms of installed electrical capacity. We therefore convert these targets into production volumes, assuming 4,000 full-load hours and a power-to-hydrogen conversion efficiency of 62%. For the example of Germany, this yields 25 TWh of hydrogen production, which is slightly below the targeted production range in the German National Hydrogen Strategy.[20]

3.3 Numerical results for the main scenario

Overview. The numerical results for our *main* scenario are qualitatively in line with the analytical results for inflexible electrolysis (Figure 3). Without matching, the load-weighted hydrogen price across the model scope is approximately 134 €/MWh$_{H2}$ (4.4 €/kg$_{H2}$). Meanwhile, adding demand for electrolytic hydrogen raises the emissions price by about 22% and the load-weighted average electricity price by 5%. The effect of annual matching is relatively minor, increasing the hydrogen price by 1% and reducing the prices of emissions and electricity by 2–4%. Hourly matching leads to a substantial amplification of these effects, increasing the hydrogen price by 9% and reducing the prices of emissions and electricity by 14% and 6%, respectively. If hydrogen requires policy support, annual and hourly matching results in increased hydrogen subsidy payments of 0.1 and 1.3 billion €/a, respectively.[21] The model-wide average capacity factor of the hydrogen electrolysis is 0.82 without matching and decreases to 0.75 with hourly matching requirements. The total system costs increase by 14 billion €/a when introducing hydrogen without matching and by an additional 0.2 and 1.1 billion €/a when requiring annual and hourly matching, respectively. Put differently, matching inflates the hydrogen-policy-related system costs by 2–8%.[22] As the electricity supply, hydrogen supply, and emissions are independent of matching requirements, these matching-related cost increases can be interpreted as welfare losses.

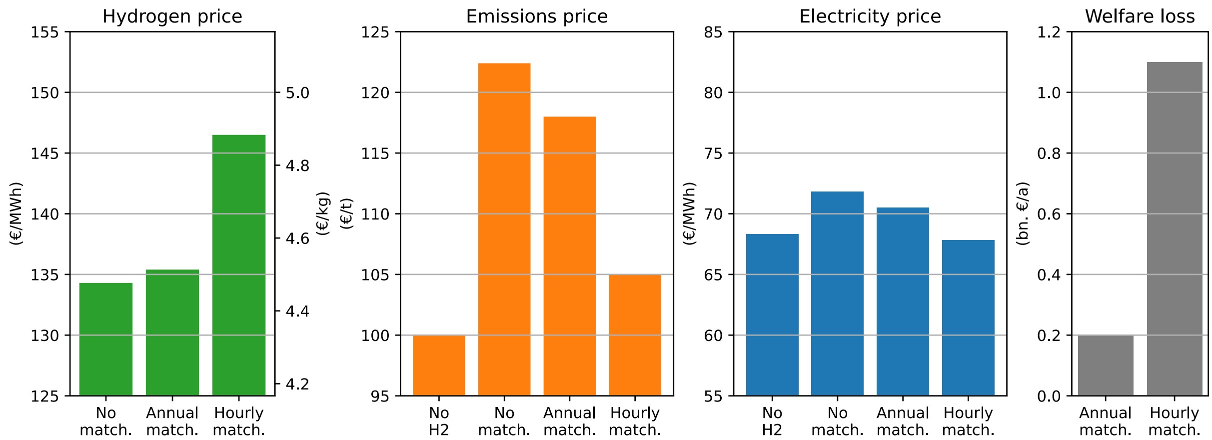


Figure 3: Prices of hydrogen, emissions, and electricity, as well as matching-related welfare losses in our main scenario. Emissions prices are the shadow variable of the model-wide emissions constraint, electricity and hydrogen prices are the dual variables of the hourly and regional electricity and hydrogen balances, and the load-weighted averages are displayed.

[20] The strategy assumes 95–130 TWh of hydrogen demand and 30–50% domestic share in hydrogen supply. Multiplying 95 TWh with 30% yields 28.5 TWh of domestic hydrogen production.

[21] Because the national hydrogen targets sum up to approximately 100 TWh/a, a 1 €/MWh increase in the hydrogen price leads to an increase in hydrogen support cost of about 0.1 billion €/a.

[22] Without hydrogen targets, the model could build hydrogen electrolysis and hydrogen-fired gas turbines for long-term electricity storage, but this option is found to be uneconomical across all considered scenarios.

RES subsidies. Regarding renewable electricity subsidies, the numerical model reveals a heterogeneous situation across countries with renewable electricity targets. Independent of the implemented hydrogen policy, subsidies are found to be zero in the Czech Republic, France, Great Britain, and Poland, implying that the renewable electricity targets are non-binding. For countries with non-zero subsidies, subsidy levels are displayed in Figure 4 (left). The changes in subsidy levels are qualitatively in line with the analytical model, with the addition that hydrogen policy can also lead to switches between binding and non-binding renewable electricity targets. In Germany and Denmark, renewable electricity subsidies are about 6 €/MWh without hydrogen, are reduced to 0–2 €/MWh when hydrogen is introduced without matching, and increase to 10–19 €/MWh with hourly matching requirements. In Austria and Belgium, subsidies become non-zero only when hourly matching is required. To put these marginal subsidy levels into perspective, we approximate changes in absolute renewable electricity subsidies (Figure 4, right). Across all countries, hydrogen without matching reduces renewable electricity subsidy payments by 2.4 billion €/a, while annual and hourly matching increase subsidy payments by 0.8 and 4.4 billion €/a, respectively (relative to the reference scenario without hydrogen).

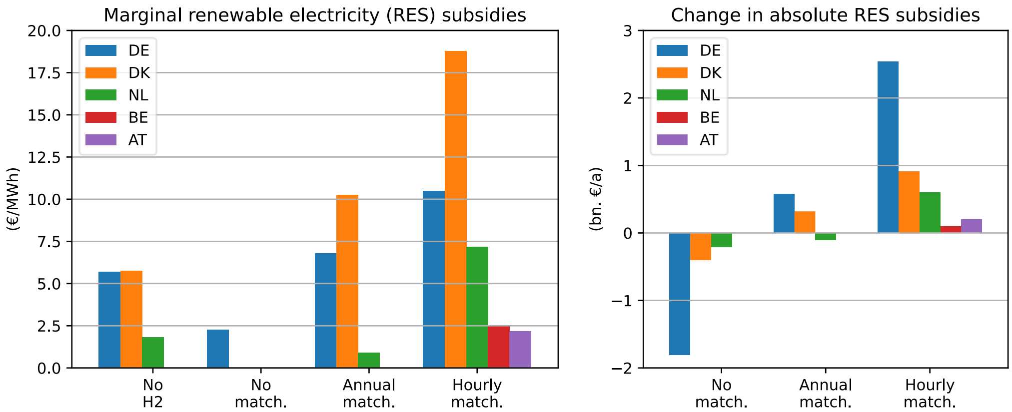


Figure 4: Marginal subsidies and changes in absolute subsidies for renewable electricity in our main scenario. Marginal subsidies are the shadow variables of the national renewable electricity constraints, and the change in absolute subsidies is approximated by multiplying the change in marginal subsidies by the national renewable electricity targets.

Electricity generation mix. An investigation of the electricity generation mixes in the numerical model reveals that renewable electricity generation is most strongly affected by hydrogen policies (Figure 5). Interestingly, the results suggest that even without a matching requirement, almost all additional electricity generation for producing electrolytic hydrogen originates from renewable energy sources, with similar contributions from solar photovoltaics, onshore wind, and offshore wind. By contrast, the changes in fossil and nuclear electricity generation are negligible. Matching affects mostly the renewable electricity generation mix, substituting onshore wind for offshore wind with annual matching and solar PV for onshore wind with hourly matching. Furthermore, with hourly matching, natural-gas-fired electricity generation increases, and nuclear and coal-fired generation increase. The latter aligns with the green-promotes-the-dirtiest hypothesis, previously discussed in the context of the analytical model (Subsection 2.2). Notably, this substitution occurs across countries. For instance, with annual matching, onshore wind energy is increasing in Germany and Denmark to fulfill national matching requirements and is substituting for offshore wind energy in the Netherlands. As increasing renewable electricity generation in Germany and Denmark is relatively expensive (cf. Figure 4), this matching-induced substitution contributes to the observed welfare losses. In essence, matching requirements hardly alter the overall amount of renewable electricity generation but increase the related cost.

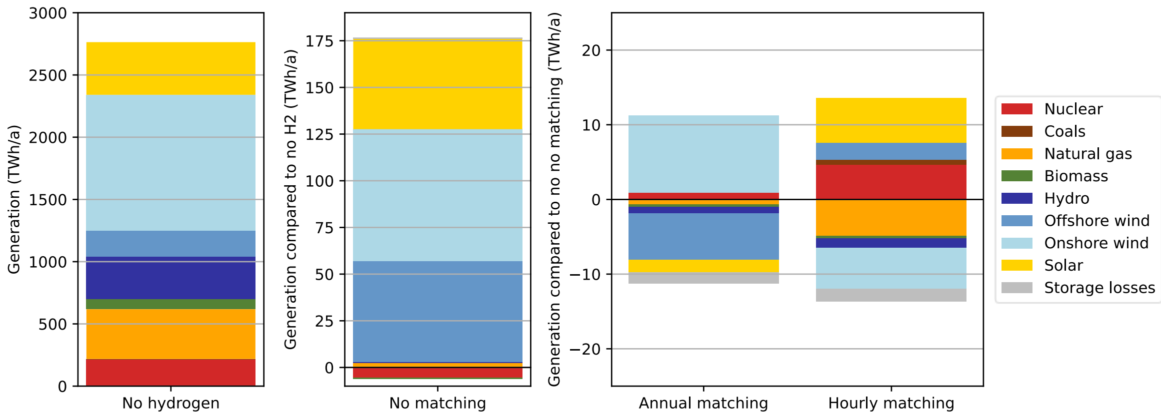


Figure 5: Electricity generation mix without hydrogen (left), changes in the generation mix when introducing hydrogen without matching relative to no hydrogen (center), and changes in the generation mix when introducing annual and hourly matching requirements relative to no matching (right) in our main scenario.

3.4 Numerical results for cheap flexibility

Cheap flex without matching. When reducing the costs of hydrogen storage in the *cheap flex* scenario, the numerical results change both quantitatively and qualitatively (Figure 6). As expected, cheap flexibility reduces the hydrogen price without matching requirements. The corresponding hydrogen support costs are also reduced by approximately 1.7 billion €/a. The model-wide average capacity factor of the hydrogen electrolysis decreases from 0.75–0.82 to 0.53–0.55 for various matching requirements, which is a direct result of the more flexible electrolyzer operation. Interestingly, introducing hydrogen without matching hardly affects the electricity price and substantially reduces the emissions price. This resolves the ambiguity in the results of the analytical model with flexible electrolysis and non-binding renewables targets and can be explained by a renewable spillover effect: cheap hydrogen storage enables hydrogen electrolysis to shift consumption to hours with low prices, which increases the market value of renewable electricity generators who produce disproportionately when prices are low. In countries with non-binding renewables targets, increased market values trigger additional investment in renewable electricity generators, and these generators also produce some electricity when the electrolyzers are not operating (due to high electricity market prices), displacing some fossil-fueled electricity generation. This is confirmed by Figure C1 in Appendix C, which also reveals that more flexible electrolysis shifts renewable electricity generation from offshore to onshore wind energy, as the latter is cheaper but more volatile, and increases the utilization of existing nuclear power plants with low operational cost.

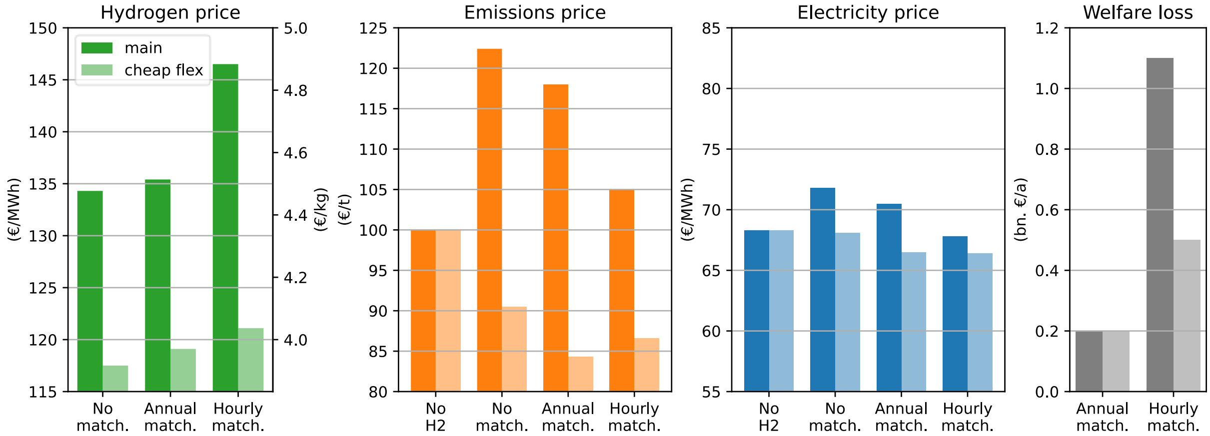


Figure 6: Prices of hydrogen, emissions, and electricity, as well as matching-related welfare losses in the cheap flex scenario (light colors), compared to the results of the main scenario (dark colors).

Cheap flex with matching. Cheap flexibility does not significantly alter the simulated effects of annual matching on hydrogen, emissions, and electricity prices relative to the main scenario. With hourly matching, however, cheap flexibility attenuates the increase in hydrogen prices and reduces welfare losses. This makes sense as cheap flexibility now makes it easier (i.e., less costly) to fulfill more granular matching requirements. Interestingly, hourly matching results in a slight *increase* in the emissions price compared to annual matching. This is because hourly matching restricts the flexibility of hydrogen electrolyzers: they can now only respond to the availability of matched renewable electricity, but not the overall system balance. As a result, electricity generation from open-cycle gas turbines slightly increases, while that from the less emission-intensive combined-cycle gas turbines slightly decreases.[23] The negative effect of restricted electrolyzer flexibility slightly overcompensates the positive effect of the additional renewable electricity generation triggered by hourly matching. Still, hourly matching slightly reduces the load-weighted electricity prices. As in the main scenario, both annual and hourly matching increase subsidies for renewable electricity, as shown in Figure C2 in Appendix C.

[23] These changes partially net out in Figure C1 in Appendix C.

4 Discussion

Summary of findings. Our analysis of introducing electrolytic hydrogen in a system with an emissions cap and renewable electricity targets yields three main findings: First, hydrogen support without matching may increase the prices of emissions and electricity, and reduce potential renewable electricity subsidies. However, if renewable electricity targets are non-binding, i.e., renewable electricity does not need subsidies to meet the targets, and if hydrogen flexibility is cheap, hydrogen support without matching may reduce the prices of emissions and electricity. This is due to additional investment in renewable electricity, which is triggered by flexible hydrogen production during periods of low electricity prices, and which spills over to periods of high electricity prices when hydrogen electrolysis is not operational. In any case, even without matching requirements, additional electricity demand for hydrogen production is almost entirely covered by renewable electricity generation. Second, mandating hydrogen to be "green" by matching requirements has no effect if renewable electricity targets are non-binding. This is because electrolytic hydrogen is matched with renewable electricity that would have been built on a market basis anyway. Third, if renewable electricity targets are binding, matching requirements decrease the prices of emissions and electricity, increase hydrogen prices and renewable subsidies, and cause welfare losses. These effects increase with the temporal granularity of matching requirements. In contrast, the flexible operation of electrolysis may mitigate welfare losses and price effects of a hydrogen policy.

Literature comparison. Our study provides the first comprehensive analysis of how hydrogen policies with matching requirements interact with emissions trading. Previous studies on matching requirements have established that the stringency of these requirements drives hydrogen prices and reduces emissions (Schlund & Theile, 2022; Villavicencio et al., 2022; Ricks et al., 2023; Ruhnau & Schiele, 2023; Giovanniello et al., 2024; Zeyen et al., 2024). In our model with an inelastic cap on emissions, their finding of reduced emissions translates to lower emission prices. In this sense, our finding that cheap hydrogen-related flexibility reduces CO_2 prices aligns with previous research that has shown that cheap flexibility tends to reduce emissions (Zeyen et al., 2024).

Welfare losses. Moreover, we contribute to the literature on hydrogen regulation by quantifying the welfare losses arising from hydrogen matching requirements. With an inelastic emissions cap and inelastic demand for electricity and hydrogen, matching requirements increase the total system cost, while the system output, including externalities, remains unaffected. Across all scenarios, we estimate welfare losses of 0.2 to 1.1 billion €/a in our numerical model. The model covers two-thirds of European electricity demand. A linear extrapolation suggests welfare losses of up to 1.7 billion €/a for the entire European market (including Norway, Switzerland, and the United Kingdom).

Policy implications: welfare. Overall, our analysis suggests that an explicit "green hydrogen" policy hardly contributes to the EU's policy objectives of reducing emissions and increasing renewable energy. Overall, emissions remain unaffected by matching requirements due to the cap in the emissions trading scheme. Moreover, matching only slightly increases the use of renewable electricity generation. In fact, even without matching, the increasing electricity demand for hydrogen production is primarily satisfied by additional electricity generation from renewable energy sources. At the same time, matching requirements lead to substantial welfare losses. Note that our analysis does not include the administrative costs of monitoring and enforcing matching requirements, which may further reduce welfare relative to our estimates. These considerations suggest that policymakers should refrain from imposing hydrogen matching requirements to increase welfare.

Policy implications: redistribution. Our analysis also reveals that matching requirements have distributional implications, which may affect the political economy of the climate policy mix. We demonstrate that, for a given hydrogen target, implementing matching requirements yields an advantage for electricity consumers and buyers in the emissions trading scheme, who benefit from lower prices for both emissions and electricity. In turn, burdens increase for those actors who must pay for the then-higher subsidies for hydrogen and renewable electricity—often taxpayers if subsidies are funded from public budgets. This redistribution may be politically appealing if opposition towards climate and hydrogen policies primarily results from potentially unacceptable increases in emissions prices driven by hydrogen support. Matching may be considered part of a "second-best" policy mix to reach emissions targets with politically constrained emissions prices. This extends the argument by Fell et al. (2023) that too low emissions prices can be a reason for supporting hydrogen, independent of matching. However, the question remains open as to whether augmenting hydrogen support with matching requirements is more efficient than directly supporting renewable electricity in reaching climate targets within politically constrained emissions prices (see, e.g., Kalkuhl et al., 2013; Gawel et al., 2014).

Policy implications: flexibility. Finally, our analysis points to electrolyzer flexibility as a potential solution to reconcile welfare and distributional policy objectives. If hydrogen storage were cheap, the operation of hydrogen electrolysis would strongly respond to electricity market prices and, as a result, increase welfare and mitigate the potential adverse effects of hydrogen policy on prices of emissions and electricity. While the feasibility of this solution depends on the costs of hydrogen storage, which cannot directly be affected by policymakers, we can think of three policy options to support the flexible operation of hydrogen electrolyzers. First, safeguarding (or establishing) the pass-through of hourly electricity prices seems key to a flexible operation of electrolysis. Notably, grid fees should be designed in a way that does not impede flexibility incentives. Second, policymakers may support the building of low-cost underground storage. Given the nascent nature of this technology, policy support may help overcome learning externalities. Finally, low-cost underground hydrogen storage will likely be centralized, and policymakers may support the buildout of hydrogen transmission infrastructure to grant decentralized electrolyzer projects access to the low-cost storage.

Imperfect electricity markets. It is also worthwhile to reflect on how matching affects the operation of imperfect electricity markets and the market integration of renewable electricity. Our model calculates deterministic market equilibria. In the real world, with uncertainty and low long-term market liquidity, market-based investments in renewable electricity producers are expected to fall short of our model results. One argument in favor of matching requirements could be that they support the liquidity of long-term electricity markets, as hydrogen producers would be forced to act as counterparties for renewables. However, the reduced risk of renewable electricity investments may come at the expense of an increased risk of hydrogen investments. Meanwhile, matching reduces the possibilities for hydrogen projects to hedge their electricity consumption to renewable counterparties. Furthermore, we demonstrate that matching requirements reduce the market value of renewable electricity, thereby impairing market-based investments. In fact, our numerical model illustrates that renewable electricity subsidies may become necessary in the presence of matching requirements in several European countries, where optimal investments in renewable generation capacities would have occurred purely market-driven otherwise.

Imperfect matching markets. Markets for matching renewable electricity with hydrogen will also be imperfect. Notably, our model overlooks the transaction costs associated with matching. Especially with co-existing subsidies for renewable electricity, transaction costs may be high due to limited market liquidity for renewable power purchase agreements. Related to this, our model assumes that hydrogen producers can match with a portfolio of all renewable generators within a bidding zone. Transaction costs in imperfect markets may limit portfolio sizes, which increases the volatility of renewable electricity availability and, therefore, the costs of intra-annual matching (Casas Ferrús et al., 2024).

Price-inelastic emissions cap and electricity demand. Beyond assuming perfect markets, our model is limited to a regional subset of the European power sector, for which we assume a price-inelastic cap on emissions. In the real world, however, the changes in emissions prices that we find in our model may be partially mitigated by a price-elastic emission reduction in other sectors and countries under the EU emissions trading scheme. Furthermore, if electrolytic hydrogen substitutes for fossil fuels in other sectors covered by the EU emissions trading scheme, this will further reduce the price of emissions. Hence, the present study can be considered conservative regarding potential increases in emissions prices. We also neglect the potential cancellation of EU emission certificates by the market stability reserve, which could attenuate price changes but cause hydrogen to actually have an impact on emissions (Bruninx et al., 2022). Similarly, price elasticity in electricity and hydrogen demand may attenuate our quantitative findings. Nevertheless, we expect that our qualitative results will remain applicable.

Transferability to other jurisdictions and hydrogen imports. Our research focuses on domestic hydrogen production in Europe, where a policy mix including an emissions cap and renewable energy targets is already in place. This raises questions about its applicability to other jurisdictions and to imported hydrogen. Interestingly, the US clean hydrogen regulation applies less stringent matching requirements[24] in states with renewable electricity targets and robust emissions caps, such as California and Washington State—but it does not fully remove matching requirements, which our results suggest would be welfare-enhancing. In some countries, including other states in the US, an emissions trading scheme or an exogenous increase in emissions prices or renewable support may be politically unattainable. In this case, policymakers may need to resort to matching requirements as a second-best solution to ensure that climate targets are met. Similarly, the EU may consider matching requirements as a second-best solution for imported hydrogen from countries without an emissions cap (Schumm et al., 2025). Certainly, broader dynamics of such trade restrictions need to be scrutinized (Antweiler & Schlund, 2024). By contrast, our research suggests that matching requirements may be waived for hydrogen imports from countries with a stringent emissions cap. This could provide an incentive for hydrogen-exporting countries to introduce or intensify emissions policies, similar to the argument brought forward by Schmidt et al. (2024) and the more general discussion on international climate policy cooperation in the context of carbon border adjustment mechanisms (Nordhaus, 2015; Böhringer et al., 2016; Overland & Sadaqat Huda, 2022).

[24] More precisely, hydrogen projects in states with renewable electricity targets and robust emissions caps are exempt from the incrementality requirement, i.e., they do not need to match with newly built renewable generators but can match with any renewable generator (US Department of Treasury, 2023).

5 Conclusions

Context and contribution. In Europe, support policies for electrolytic hydrogen complement existing climate policies, most notably emissions trading and national targets for expanding renewable energy. As an important design feature, EU hydrogen policies involve matching regulations that require electrolytic hydrogen to be produced from dedicated, additional renewable electricity generators to be labeled "green hydrogen" and, hence, be eligible for subsidies. We provide the first analytical and numerical assessment of market and policy interactions arising from this policy mix.

Hydrogen policy without matching. We show that, without matching, the interactions depend on the flexibility of hydrogen electrolysis. With inflexible electrolysis, politically induced hydrogen demand increases the prices of emissions and electricity. By contrast, the additional electricity demand from flexible electrolysis can reduce prices for emissions and electricity. Hydrogen prices and system costs associated with hydrogen policy are also lower with more flexible electrolysis. In any case, subsidies for renewable electricity are decreasing. Increased prices of emissions and electricity could impair the political acceptance of hydrogen and climate policy. In turn, supporting the price responsiveness of hydrogen electrolysis could be one option to enhance political acceptance.

Hydrogen matching requirements. Furthermore, we find that matching requirements only have effects when renewable energy targets are binding. In this case, policymakers may face a trade-off. On the one hand, matching increases the hydrogen-policy-related system costs without inducing additional emission reductions. These costs primarily materialize in the form of higher subsidies necessary for hydrogen production and renewable electricity generation. On the other hand, matching mitigates increases in the prices of emissions and electricity, which would otherwise arise with the implementation of the hydrogen policy. Hence, matching requirements may facilitate the political acceptance of hydrogen policies but come at the cost of welfare losses.

Acknowledgements

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Appendix A: Karush-Kuhn-Tucker conditions

The corresponding Karush-Kuhn-Tucker conditions for the Lagrangian derived in Subsection 2.1 are:

(A) $\frac{\partial L}{\partial x_{C,t}} = k_C x_{C,t} - \lambda_{D,t} + \lambda_E e_C \geq 0 \quad \forall t$

(B) $\frac{\partial L}{\partial x_{G,t}} = k_G x_{G,t} - \lambda_{D,t} + \lambda_E e_G \geq 0 \quad \forall t$

(C) $\frac{\partial L}{\partial \hat{x}_R} = k_R \hat{x}_R - \sum_t \lambda_{D,t} a_t - \lambda_R \geq 0$

(D) $\frac{\partial L}{\partial \hat{x}_H} = k_H \hat{x}_H + \sum_t \lambda_{D,t} b_t h + \lambda_R mh - \lambda_H \geq 0$

(E) $\frac{\partial L}{\partial \lambda_{D,t}} = \overline{D}_t + b_t \hat{x}_H - x_{C,t} - x_{G,t} - a_{R,t}\hat{x}_R \leq 0 \quad \forall t$

(F) $\frac{\partial L}{\partial \lambda_E} = \sum_t \left(e_C x_{C,t} + e_G x_{G,t}\right) - \bar{E} \leq 0$

(G) $\frac{\partial L}{\partial \lambda_R} = \bar{R} - \hat{x}_R + mh\hat{x}_H \leq 0$

(H) $\frac{\partial L}{\partial \lambda_H} = \bar{H} - \hat{x}_H \leq 0$

(N) $x_{C,t}, x_{G,t}, \hat{x}_R, \hat{x}_H, \lambda_{D,t}, \lambda_E, \lambda_R, \lambda_H \geq 0$

(I) $x_{C,t} \frac{\partial L}{\partial x_{C,t}} = x_C \left(k_C x_{C,t} - \lambda_{D,t} + \lambda_E e_C\right) = 0 \quad \forall t$

(II) $x_{G,t} \frac{\partial L}{\partial x_G} = x_G \left(k_G x_{G,t} - \lambda_{D,t} + \lambda_E e_G\right) = 0 \quad \forall t$

(III) $\hat{x}_R \frac{\partial L}{\partial \hat{x}_R} = \hat{x}_R \left(k_R \hat{x}_R - \sum_t \lambda_{D,t} a_t - \lambda_R\right) = 0$

(IV) $\hat{x}_H \frac{\partial L}{\partial \hat{x}_H} = \hat{x}_H \left(k_H \hat{x}_H + \sum_t \lambda_{D,t} b_t h + \lambda_R mh - \lambda_H\right) = 0$

(V) $\lambda_{D,t} \frac{\partial L}{\partial \lambda_{D,t}} = \lambda_{D,t} \left(\overline{D}_t + b_t \hat{x}_H - x_{C,t} - x_{G,t} - a_{R,t}\hat{x}_R\right) = 0 \quad \forall t$

(VI) $\lambda_E \frac{\partial L}{\partial \lambda_E} = \lambda_E \left(\sum_t \left(e_C x_{C,t} + e_G x_{G,t}\right) - \bar{E}\right) = 0$

(VII) $\lambda_R \frac{\partial L}{\partial \lambda_R} = \lambda_R (\bar{R} - \hat{x}_R + mh\hat{x}_H) = 0$

(VIII) $\lambda_H \frac{\partial L}{\partial \lambda_H} = \lambda_H (\bar{H} - \hat{x}_H) = 0$

Appendix B: Details on the analytical solutions

Parameter A. We introduced A as a placeholder for the denominators in Table 1 and Table 2 for the non-binding renewables target. This placeholder is defined as

$$A = e_G^2 \left(k_C^2 + 2k_G k_R + 2k_C\big((1 - 2a_1 a_2)k_G + k_R\big)\right) \\ + e_C^2 \left(k_G^2 + 2k_G k_R + 2k_C\big((1 - 2a_1 a_2)k_G + k_R\big)\right) \\ - 2(a_1 - a_2)^2 e_C e_G k_C k_G - 4e_C e_G (k_C + k_G)k_R.$$

Because $a_1 > a_2 > 0$ and $a_1 + a_2 = 1$, $a_1 - a_2 < 1$ and $a_1 a_2 < \frac{1}{4}$, such that $1 - 2a_1 a_2 > 0$. This allows us to define a lower bound for A:

$$A > e_G^2(k_C^2 + 2k_G k_R + 2k_C k_R) + e_C^2(k_G^2 + 2k_G k_R + 2k_C k_R) - 2e_C e_G k_C k_G - 4e_C e_G (k_C + k_G)k_R$$

This can be simplified to

$$A > (e_G k_C - e_C k_G)^2 + 2(e_C - e_G)^2 (k_C + k_G)k_R > 0.$$

We can hence conclude that $A > 0$.

Parameter B. We further introduced B as a placeholder in Table 2.

This placeholder is defined as

$$B = 2a_2(e_G^2 k_C + e_C^2 k_G) + (a_1 - a_2)e_C(e_C k_G + (2e_G - e_C)k_C).$$

The specific carbon emissions of a hard-coal-fired power plant are approximately 800 g/kWh, while those of a gas-fired power plant are around 400 g/kWh (Ruhnau et al., 2022). Hence, we can approximate $e_C \approx 2e_G$ and

$$B \approx 2a_2(e_G^2 k_C + e_C^2 k_G) + (a_1 - a_2)e_C^2 k_G > 0.$$

Comparison of market value declines. We hypothesize that the renewable market value with intra-annual matching declines less if the electrolyzer is operated flexibly compared to baseload operation:

$$\frac{a_2}{a_1}\frac{h}{2}\left(-\frac{(a_1 - a_2)k_C^2}{k_C + k_G} - \frac{B}{(e_C - e_G)^2}\right) > \frac{1}{2a_2}\frac{h}{2}\left(-\frac{(a_1 - a_2)^2 k_C k_G}{k_C + k_G} - (a_1 - a_2)\frac{(e_G^2 k_C + e_C^2 k_G)}{(e_C - e_G)^2}\right)$$

Inserting parameter B, substituting $a_2 = 1 - a_1$, using the approximation $e_C \approx 2e_G$, and assuming $k_C \approx k_G$ yields

$$\frac{a_1(39 - 2(7 - 4a_1)a_1) - 22}{8a_1(1 - a_1)} h k_G > 0.$$

This inequality holds for $a_1 > 0.662$, i.e., if the renewable electricity production is sufficiently volatile.

Appendix C: Details on the numerical solutions

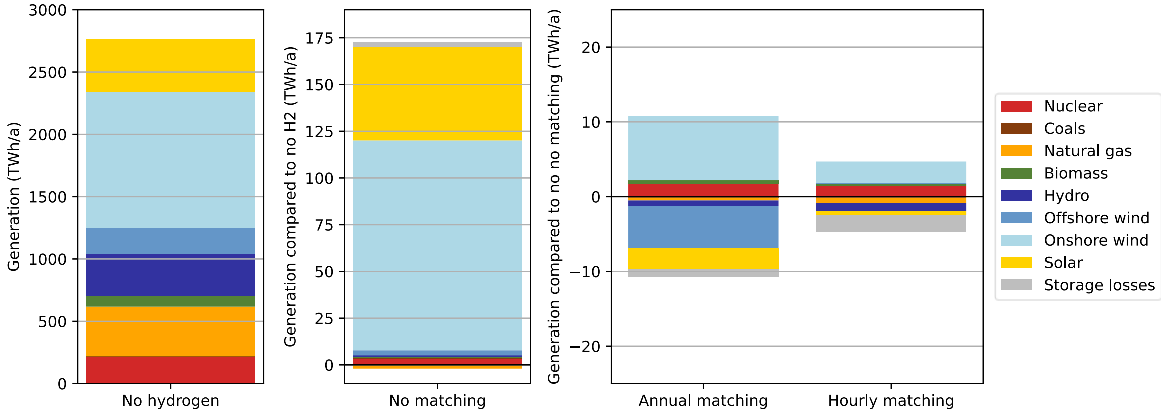

Figure C1: Electricity generation mix without hydrogen (left), changes in the generation mix when introducing hydrogen without matching relative to no hydrogen (center), and changes in the generation mix when introducing annual and hourly matching requirements relative to no matching (right) in the cheap flex scenario.

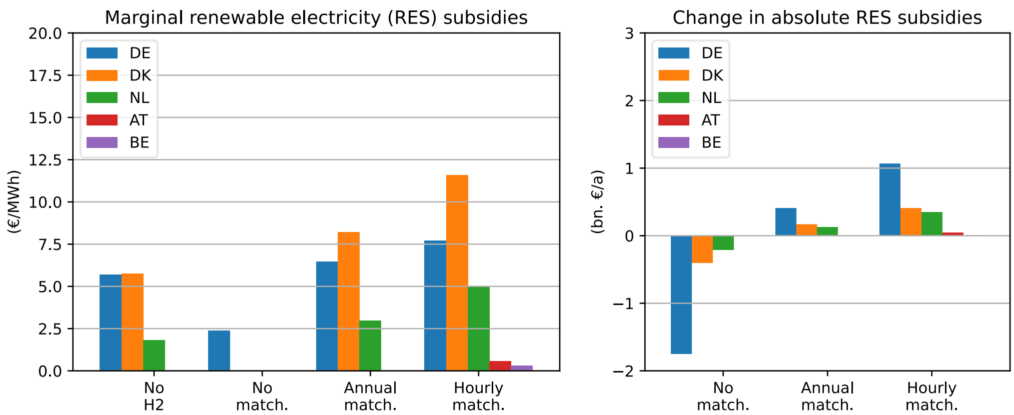

Figure C2: Marginal subsidies and changes in absolute subsidies for renewable electricity in the cheap flex scenario. Marginal subsidies are the shadow variables of the national renewable electricity constraints, and the change in absolute subsidies is approximated by multiplying the change in marginal subsidies by the national renewable electricity targets.

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