Spatial Incentives for Power-to-hydrogen through Market Splitting

HEMF Working Paper No. 03/2022

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July 2022

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Highlights

- Impact of market split on investments and operation of electrolyzers in Germany
- Application of Benders decomposition and a specific PtH_2 modelling approach
- Market splitting supports efficient integration of PtH_2 into electricity markets
- Missing spatial incentives prevent tapping the potential for market-based PtH_2 ramp-up
- Electrolyzers' location support renewable energy integration of low-carbon hydrogen

Abstract

In the context of the energy transition and ambitious decarbonization goals, hydrogen is becoming essential both as a storage option for renewable energy surplus and as a green fuel for multiple usages. The European Commission already foresees 40 GW of electrolyzer capacity by 2030, yet their locations will strongly affect the European transmission system. With a view to the ramp-up of power-to-hydrogen, zonal electricity markets with large market zones may fail to provide efficient locational investment incentives. Existing research has already discussed potential market splits as a mid-term solution to improve congestion management, recognizing that the first-best solution of nodal prices is controversial. Using the example of Germany, this study combines the two research streams by investigating the impacts of market splitting on the operation and investment in electrolyzers. The optimization approach includes endogenous investment decisions linked to a detailed scheduling model. The results reveal that market splitting supports the efficient integration of electrolyzers into electricity markets, reducing internal congestion and renewable curtailment. Missing spatial incentives hence imply a considerable unused potential for the market ramp-up of electrolyzers. From a political perspective, market splitting benefits the system regarding (integration) costs and reduces subsidy requirements for reaching 2030 targets. Yet under strict additionality criteria, the incentives for electrolyzer investments become again insufficient.

Keywords: Hydrogen, German Energy Transition, Electricity Market, Operations Research, Market Split

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1 Introduction

The major aim of the energy transition is to decarbonize the energy sector by replacing fossil fuels with low-carbon energy sources. In Germany and many other European countries, this transformation involves covering energy demand in the future primarily with renewable energy from wind and solar power. This form of energy supply also contributes to reducing energy import dependencies. Due to topological and meteorological conditions, wind farms have mainly been built at the periphery of European countries. However, wind infeed far from the load centers requires sufficient transmission capacities. Delays in grid expansion imply that European Transmission System Operators (TSOs) currently face grid congestions on an almost daily basis. These challenges underscore the increasing importance of congestion management and raise questions regarding the delimitation of bidding zones.

The above mentioned challenges take on a new dimension as the ramp-up of the hydrogen economy has gained momentum in recent years with various national and international hydrogen strategies (Federal Ministry for Economic Affairs and Energy 2020; Secretary of State for Business, Energy & Industrial Strategy 2021; EU Commission 2022). In the medium term, the Europe-wide and national targets up to 2030 are quite moderate. The focus of hydrogen strategies at this stage is on the ramp-up or expansion of hydrogen supply based on fixed target values and less on the associated market changes. In addition, the EU is in the process of introducing mandatory evaluation criteria for green hydrogen (EU Commission 2023).

Hydrogen is expected to play various roles in the future; in addition to serve decarbonization in various applications, it can contribute substantial flexibility to relieve bottlenecks in the power grid. Yet it is unclear whether the current market design supports this use of hydrogen in renewable integration. Our work contributes to the ongoing debate on the delimitation of bidding zones in European electricity markets by investigating the impact on local investments in electrolyzers stemming from changed bidding zone delimitations. We analyze to what extent a market split mitigates existing distortions and modifies the investment incentives – creating benefits for the system as a whole. The focus of our case study is on Germany yet the insights gained are applicable in general to zonal markets involving large market zones. These tend to neglect locational incentives for a system-friendly integration of renewables and electrolyzers. One example is Great Britain with a similar north-south divide in terms of wind generation in the north and load centers in the south (Alexander, James, and Richardson 2015; Frysztacki et al. 2021).[1]

Research has addressed various aspects of grid congestion and possible solutions. Economists generally agree that nodal pricing is the first-best solution for pricing scarce transmission capacity (Schweppe et al. 1988; Hogan 1992; Ehrenmann and Smeers 2005; Bjørndal and Jörnsten 2007; Deilen et al. 2019). As Eicke and Schittekatte (2022) point out in their review, the advantages of nodal pricing outweigh the benefits of zonal pricing yet there is a strong reluctance among practitioners in Europe against implementing the nodal system. On the other hand, a regular review of bidding zones is foreseen in the European Union (EU) to guarantee efficient pricing of inter-zonal congestion. The basis is therefore laid in the guideline on Capacity Allocation and Congestion Management (CACM) (cf. Commission Regulation (EU) 2015/1222 2015). The (optimal) delimitation of such bidding zones has been subject of several academic papers. For example, Felling and Weber (2018) develop a hierarchical cluster algorithm to identify possible new price zone configurations. Other papers devoted to the computation of appropriate price zone configurations based on cluster algorithms include (Burstedde 2012; Kang et al. 2013; Breuer and Moser 2014; Klos et al. 2014). While small bidding zones might lead to strong price variations across locations, the impact of larger bidding zones has repeatedly been found to be limited—at least regarding average prices. Thereby repeatedly exogenously given bidding zones have been investigated (e.g. Trepper et al. 2015; Egerer et al. 2016; Blume-Werry et al. 2017). For instance, Egerer et al. (2016) apply a North-South split and show that prices increase in the

[1] Note that a PtH2 component in grid tariffs would neither entirely solve the problem. It would provide siting incentives yet the operation of the electrolyzers would still be based on country-wide power prices. Therefore we do not investigate such an approach further.

southern zone and, at the same time, decrease in the northern zone for Germany in 2012 and especially 2015. What they do not investigate, but where we tie in, are the investment incentives resulting from these price differences. Other studies have moreover shown the substantial effects on congestion management and have reported more frequent zero and negative prices in the more peripherical northern areas of Germany. The discussion on bidding zone configuration and congestion management is furthermore not limited to Germany as cases from Italy (Colella et al. 2020; Bovo et al. 2021), Scandinavia (Bems et al. 2016; Herre et al. 2019) or Central-Western Europe (Felling et al. 2023) show.

Despite the extensive number of studies on bidding zone configurations and their impacts, their interplay with the emerging power-to-hydrogen (PtH_2) infrastructure has not yet been considered. Most previous hydrogen system studies have focused on the interdependencies between hydrogen supply chains and electricity systems. Vom Scheidt et al. (2022) combine an electrolytic hydrogen supply chain model with an electricity system dispatch model for a cross-sectoral case study of Germany. They consider nodal electricity prices and hydrogen infrastructure investments. However, the authors do not point out how the electrolyzers, as a new flexibility provider, can be integrated in a system-oriented way since they assume an exogenously defined electricity demand by the electrolyzers. Furthermore, they simplify the geographical scope of the electricity system by neglecting neighboring countries and other EU members in 2030. Hence, potential effects resulting from electricity exchanges with neighboring countries are not analyzed. The authors recommend a broader geographic scope for further research. With respect to the impacts on the electricity system, Runge et al. (2019) focus on optimizing supply chains for hydrogen stored in liquid organic hydrogen carriers under the influence of electricity prices resulting from different electricity market designs. They state that it is economically attractive to transport fuels from northern to southern Germany in case of nodal pricing. The authors call for further analysis of the impacts on the electricity system. Another study considers the effects of the electrolyzers for redispatch but does not consider the perspective of day-ahead electricity wholesale markets (Xiong et al. 2021). Furthermore, the authors use data from 2015; thus, the study's findings do not reflect future developments, especially regarding electricity grids. Further research on PtH_2 has focused on flexible electrolyzer operation (Bødal et al. 2020; Zhang et al. 2020), impacts on grid congestion (Lieberwirth and Hobbie 2022), storage options (Kirchem and Schill 2022) and the interrelationships between electricity markets and hydrogen supply for trucks (Rose and Neumann 2020). The discussed aspects are not limited to Germany as studies from Denmark (Berg et al. 2021), the US (Koleva et al. 2021) and the Netherlands (Schrotenboer et al. 2022) show.

This literature review reveals a lack of investigation of the interplay between the electrolyzer operation and market design in the context of a connected European energy system with a common (zonal) market framework. For example Pearson et al. (2022), support our hypothesis that with the higher shares of renewable generation in 2030, congestion on transmission grids will increase dramatically. Although they do not explicitly consider hydrogen or a modified market design, our findings fit their results in that we can reduce congestion and thus redispatch costs by adding distributed flexibility. Against this background, we investigate the question to what extent a market split incentivizes the build-up of PtH_2 capacities. We consider the impacts of scarce transmission capacity and a potential split of the German market zone on investments in electrolyzers. To answer the research questions, we apply a detailed electricity market model which includes capacity adjustments for electrolyzers based on a flexible Benders decomposition approach. We expect two effects. On the one hand, we assume there will be an effect from market split on the production of H_2. On the other hand, we expect changes depending on the level of the market value of the produced hydrogen, which is reflected in the so-called use value defined later.

The remainder of this paper is organized as follows. In Section 2, we explain the methodology regarding the Benders decomposition approach which includes the electricity and heat market model WILMAR Joint Market Model (JMM) as a subproblem, embedding it in an investment model, labelled Iterative Optimization of (Dis-)Investment in Large Energy Systems (IDILES), as a master problem. Furthermore, we briefly explain the concept for modelling PtH_2 technologies. Section 3 presents the data description and scenario framework. Section 4 discusses the results, focusing on the impacts on spatial investment incentives, impacts on the utilization of electrolyzers, the system costs effects, and the impacts on congestion, emissions and renewable integration. We conclude by providing policy implications.

2 Methodology

To study the integration of PtH_2, we apply a detailed energy market model including a Benders decomposition approach (Benders 1962). This approach combines an upper level (master problem) including investment decisions and a lower level of operational decision making (subproblem, cf. Figure 1). The overall framework aims at minimizing total system costs and includes the IDILES module (Leisen et al. 2022) at the upper level to handle investment (and disinvestment) decisions. It is used here to investigate the sizing and siting of electrolyzer investments. At the lower level, the widely used WILMAR Joint Market model (JMM, cf. e.g., Weber et al. (2009), Meibom et al. (2011) and Trepper et al. (2015)) is applied to solve the subproblem of determining the optimal operation (dispatch) of electrolyzers, power plants, storages and other flexible units. Figure 1 illustrates the overall framework and the interplay between the upper and lower levels.

The approach provides a consistent extension of the very detailed JMM, which has been designed to investigate the impact of variable renewable energy sources on the operation of future electricity systems. The JMM takes the installed capacities as given, but with the help of the IDILES module (Leisen et al. 2022), capacities may be iteratively adjusted depending on the profitability of the candidate technologies in the operational subproblem. Iterations are stopped if an economic equilibrium is reached (up to a given tolerance level).

In equilibrium, a zero-profit condition holds for any technology selected for investment (cf. also Böcker and Weber 2020). I. e., the revenues of the marginal unit obtained during operations (computed based on the shadow prices) are just sufficient to cover the sum of all capital and operational costs. Using the Benders decomposition approach, IDILES thus optimizes long-term investment and disinvestment decisions while the JMM optimizes the dispatch. The effects of the investment and disinvestment decisions on market prices (and all associated decisions) and system costs are hence considered consistently. A more detailed model description can be found in Leisen et al. (2022). Other applications of Benders decomposition to energy systems can be found in Bloom (1983), McCusker et al. (2002), Shahidehopour and Yong Fu (2005) and Montoya-Bueno et al. (2020). The following subsections provide more detail on both levels of the overall problem.

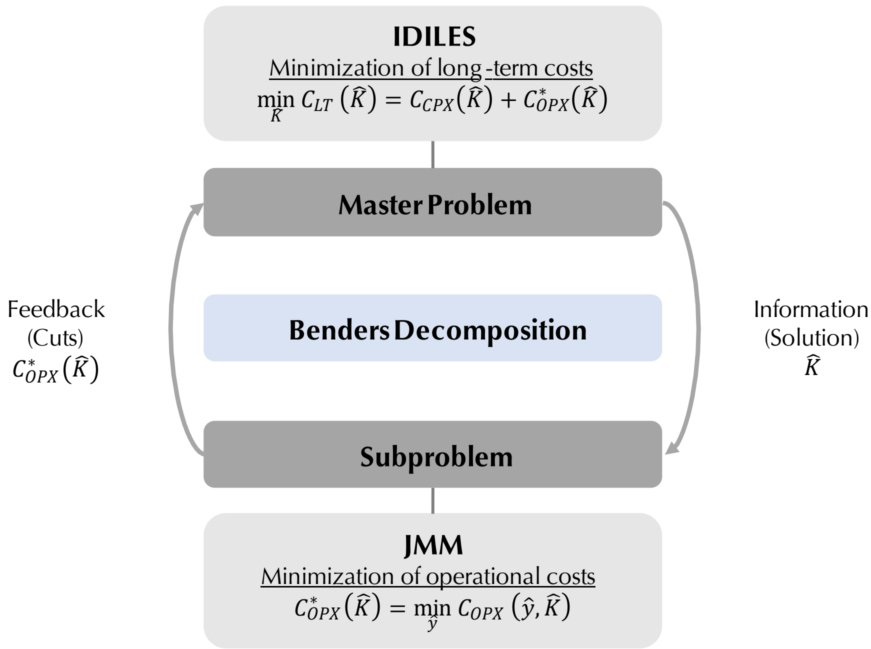

Figure 1: Benders decomposition framework

2.1 Iterative Optimization of (Dis-)Investment in Large Energy Systems (IDILES)

Subsequently, we explain the model framework beginning with the general Benders decomposition approach of which the IDILES module handles the upper-level problem. We then continue by describing the iterative updating process leading to the equilibrium capacities in IDILES, postponing the more detailed description of the lower-level operational problem to Section 2.2.

Following the notation of Leisen et al. 2022), Eq. (1) to (4) summarize the formulation of the overall optimization problem including both operational decisions (modelled in the JMM) and investments (dealt with in IDILES):

$$\min_{\widehat{K}} C_{LT}(\widehat{K}) \tag{1}$$

$$C_{LT}(\widehat{K}) = C_{CPX}(\widehat{K}) + C^*_{OPX}(\widehat{K}) \tag{2}$$

$$C^*_{OPX}(\widehat{K}) = \min_{\hat{y}} C_{OPX}(\hat{y}, \widehat{K}) \tag{3}$$

$$A\hat{y} + B\widehat{K} \geq d \,. \tag{4}$$

Accordingly, the overall objective is to minimize long-term system costs C_{LT}, which may be split into the minimum operational costs C^*_{OPX} at given capacities $\widehat{K}$ and capacity-related costs C_{CPX}. Capacity-related costs thereby include investment costs and fixed costs. The vector of decision variables $\widehat{K}$ handled in IDILES corresponds to the installed capacities of a subset of technologies considered for investment (in occurrence electrolyzers). The dispatch decision variables (included in the JMM) are summarized in the vector $\hat{y}$ and the corresponding multiple constraints for the operational problem are represented by equation (4). Details of these operational constraints are discussed in Section 2.2 below. There are no specific constraints at the upper level in the IDILES module, i.e., in the investigated setting, we do not impose any limitations on investments. But in the iterative Benders approach, additional constraints derived from the operational problem (so-called cuts or cutting planes) are incorporated successively in the upper-level problem, cf. Figure 1 and the detailed explanation below. Although the problem formulated in Eq. (1) to (4) might also be solved in a closed optimization without decomposition, the decomposition approach has two key advantages (Leisen et al. 2022): First, a closed optimization would necessitate high computing capacities and second, a closed optimization comes along with the assumption of perfect foresight (at least) at the operational level, which does not reflect the actual market situation.

The optimal operational costs $C^*_{OPX}(\hat{K})$ are a convex function of the capacities $\hat{K}$ (cf. Conejo (2006), p. 112). Correspondingly, the hyperplane defined by a first-order Taylor series expansion of $C^*_{OPX}(\hat{K})$ around any reference capacity vector $\hat{K}^{(i)}$ provides a lower bound to the optimal operational costs for given capacities $\hat{K}$:

$$C^*_{OPX}(\hat{K}) \geq C^*_{OPX}(\hat{K}^{(i)}) + \left(\hat{K} - \hat{K}^{(i)}\right)^{\mathrm{T}} \cdot \nabla C^*_{OPX}(\hat{K}^{(i)}) \,. \tag{5}$$

Thereby $\nabla C^*_{OPX}(\hat{K}^{(i)})$ describes the gradient of operational costs with respect to capacities, i.e. the marginal change of the objective function when capacities are changing. These changes may be computed from the solutions of the dual problem of the lower-level problem, i.e. the shadow prices $\hat{\lambda}^{(i)}$ of the constraints (4) (cf. Leisen et al. 2022) using the relationship:

$$\nabla C^*_{OPX}(\hat{K}^{(i)}) = B^T \hat{\lambda}^{(i)} \,. \tag{6}$$

The economic interpretation of the gradient is that $-\nabla C^*_{OPX}$ corresponds to the contribution margins that are earned by a marginal capacity addition at a given capacity level $\hat{K}^{(i)}$.

For any capacity addition in a long-term equilibrium, these contribution margins should equal the sum of (annualized) investment costs plus fixed costs (zero-profit condition):

$$-\nabla C^*_{OPX}(\hat{K}^{(i)}) = c^{inv} + c^{fix} \,. \tag{7}$$

We thereby treat the considered year as a representative year and do not perform an intertemporal optimization across multiple years – this is equivalent to using myopic expectations regarding future years.

Characteristic for the Benders decomposition is then that it uses a series of cuts as described in Eq. (5) to iteratively narrow the search space for the optimal capacities in the master problem. The master problem is thus given by the equations:

$$\min_{\hat{K}^{(j)}} C_{CPX}\left(\hat{K}^{(k)}\right) + \theta \tag{8}$$

$$\theta \geq C^*_{OPX}\left(\hat{K}^{(i)}\right) + \left(\hat{K}^{(k)} - \hat{K}^{(i)}\right)^{\mathrm{T}} \cdot \nabla C^*_{OPX}\left(\hat{K}^{(k)}\right) \forall i \in \{1, \dots, k-1\}\,. \tag{9}$$

The variable θ thus represents a lower bound to the operational costs in the upper-level problem and this bound is tightened with each iteration k by the inclusion of an additional inequality constraint (Eq. (9)) derived from the previous iteration $k-1$. This is also depicted in Figure 1, where the master problem receives with each iteration an additional constraint (cut) as feedback from the operational problem. Benders decomposition is known to converge to the optimal solution of the integrated problem described by Eq. (1) to (4), yet in practice the iterations are ended if the gap between the upper and the lower bound to the objective function value drops below a predefined threshold.

When using the JMM to describe the subproblems of operational optimization, the (implicit) assumption of perfect foresight at the operational level that underlies Eq. (3) and (4) is abandoned as the JMM uses a rolling planning approach (cf. Section 2.2). This comes along with the more realistic assumption of limited operational foresight and with improved computational performance (Kallabis 2020). But at the same time, the standard result for Benders decomposition of convergence to the global optimum does not always apply. Leisen et al. (2022) indicate sufficient conditions for a convergence to the global optimum. If these are not met, the iterative algorithm yet still converges to a local optimum.

In our application we only consider capacity adjustments for the electrolyzers. All other capacities are treated as fixed parameters. This is done both to avoid unrealistic system configurations (cf. Section 3) and to limit computation time (cf. Section 4). Correspondingly, the relevant constraints in the subproblem are the limits imposed by the installed capacities on the electricity use of electrolyzers, cf. Eq. (13) in Section 2.2. The sum of the corresponding shadow prices then corresponds to the contribution margin $-\nabla C^*_{OPX}$ of the electrolyzers. As long as this cost gradient exceeds the investment and fixed costs, investments in the electrolyzers lead to excess profits (or in a system perspective: to a decrease in overall system costs) – hence their capacities will increase until the contribution margins just recover the investment and fixed costs (cf. eq. (13)).

2.2 Operational Optimization: Joint Market Model (JMM)

For the operational level in the subproblem, we use the JMM. The JMM is a linear optimization model that covers the European power system. It determines the dispatch of power plants and storages subject to techno-economic constraints. Therefore, this section gives an overview on the dispatch decision variables and the corresponding set of constraints for the operational problem. The JMM uses a rolling planning approach which allows for considering sequential market clearing and reduces computation time. A more detailed model description can be found in Weber et al. (2009), Meibom et al. (2011) and Trepper et al. (2015). To illustrate the high level of detail of the JMM, it is worth mentioning the consideration of regional heat markets, control reserve markets, and further technical restrictions, such as part-load efficiencies, minimum and maximum generation, minimum operation and down times, and start-up times. Here, we focus on the day-ahead market which is cleared with limited foresight until the end of the market time horizon. We neglect information updates, such as forecasts of volatile renewables during intraday to limit the modelling complexity albeit it would be worth addressing the implications of forecast updates on electrolyzer operations and contribution margins in future work.

Given that this paper focuses on PtH_2 and market splitting, we further concentrate on equations relevant to both and on the impact of changes in capacity due to disinvestment and investment decisions.

Relevant indices are the time steps t, the technologies j, and the areas a as a subset of the regions r, which reflect the bidding zones. The objective function minimizes the total operational system costs over the optimization period. Here, the costs of fuel $c_{a,t}^{fuel}$, CO_2 certificates $c_{a,t}^{CO2}$, operation and maintenance $c_{a,j}^{O\&M}$ as well as start-up $c_{a,j}^{STARTUP}$ are considered. In the rolling planning approach, a shadow price $Sp_{a,j}^{STORAGE}$ is assigned to the content of the storages $V_{a,j,T}^{STORAGE}$ at the last time step T of the planning horizon to reflect the future value of the energy collected in hydro, pumped, and battery storages. This reduces the overall operational costs. To reflect the value of the produced hydrogen, we further reduce the system costs by the revenues obtained from selling the produced hydrogen $P_{a,j,t}^{PtH2}$ at a price $\xi_{a,j,t}^{PtH2}$. To improve readability, we omit additional variable costs in Equation (10), e.g., for heat production or taxes:

$$\begin{aligned} \min C_{OPX}; C_{OPX} = & \sum_{j\in J^{DISPATCH}} \sum_{a\in A} \sum_{t\in T} \left(\frac{c_{a,t}^{fuel} + f_{fuel}^{CO2-factor} \cdot c_{a,t}^{CO2}}{\eta_j} + c_{a,j}^{O\&M} \right) \cdot P_{a,j,t}^{SPOT} \\ & + \sum_{j\in J^{ONLINE}} \sum_{a\in A} \sum_{t\in T} c_{a,j}^{STARTUP} \cdot P_{a,j,t}^{STARTUP} \\ & - \sum_{j\in J^{STORAGE}} \sum_{a\in A} Sp_{a,j}^{STORAGE} \cdot V_{a,j,T}^{STORAGE} - \sum_{j\in J^{PtH2}} \sum_{a\in A} \sum_{t\in T} \xi_{a,j,t}^{PtH2} \cdot P_{a,j,t}^{PtH2} \end{aligned} \tag{10}$$

Equation (11) provides a reduced representation of the balance equation for electricity sold on the day-ahead market, including transmission and curtailment variables.

$$\begin{aligned} & \sum_{j\in J_{a(r)}^{DISPATCH}} P_{a,j,t}^{SPOT} + P_{r,t}^{RES} - P_{r,t}^{RES_{CURT},SPOT} + \sum_{(\bar{r},r)\in RR} \left(1-\delta_{\bar{r},r}\right) \cdot P_{\bar{r},r,t}^{TRANS,SPOT} \\ & = D_{r,t}^{ELEC} + \sum_{j\in J_{a(r)}^{StORAGE}} W_{a,j,t}^{SPOT} + \sum_{j\in J_{a(r)}^{PtH2}} W_{a,j,t}^{SPOT} + \sum_{(r,\bar{r})\in RR} P_{r,\bar{r},t}^{TRANS,SPOT} \\ & \qquad \forall t \in T^{SPOT}, \forall r \in R \end{aligned} \tag{11}$$

The balance equation ensures that supply meets demand for every hour of the year. The right side of the equation describes total demand, which consists of electricity demand from end users $D_{r,t}^{ELEC}$, charging of storages, and electrolyzers' consumption $W_{a,j,t}^{SPOT}$ and exports $P_{r,\bar{r},t}^{TRANS,SPOT}$. The left side of the equation corresponds to total supply, including the production from hydro and thermal power plants as well as storages $P_{a,j,t}^{SPOT}$, infeed from volatile renewable energy sources, such as wind and solar $P_{r,t}^{RES}$, and imports $P_{\bar{r},r,t}^{TRANS,SPOT}$ from neighboring regions (with transmission losses $\delta_{\bar{r}r}$). Furthermore, the renewable infeed may be reduced by curtailments $P_{a,j,t}^{RES_{CURT},SPOT}$. Since we assume that there are no payments for excess renewable energy in 2030 due to full market integration, there is no penalty term in the objective function associated with curtailments. As curtailment comes at no cost it is cheaper than to continue renewable production at negative power prices and consequently no negative prices will occur in the model.

The cross-border electricity trading is modelled in a simplified manner using the net transfer capacity (NTC) approach. The corresponding transmission restrictions apply to all electricity transfers between bidding zones. Hence, a market splitting for Germany is also reflected by a constraint on the electricity exchange between northern and southern Germany. The general form of these constraints is given in Equation (12):

$$P_{r,\bar{r},t}^{TRANS,SPOT} + P_{r,\bar{r},t}^{TRANS,ANC,+} \leq l_{r,\bar{r}}^{TRANS,MAX} \tag{12}$$

$$\forall\, r, \bar{r} \in R, \forall t \in T$$

The exogenously fixed transmission capacity $l_{r,\bar{r}}^{TRANS,MAX}$ provides an upper limit to the sum of electricity exports $P_{r,\bar{r},t}^{TRANS,SPOT}$ and the possible export of ancillary services (positive reserves) $P_{r,\bar{r},t}^{TRANS,ANC,+}$.

Regarding the relevant restriction for determining the contribution margins, the maximum capacity for electricity procurement in the electricity markets is given in Equation (13). In each timestep, the sum of electricity purchased on the day-ahead market $W_{a,j,t}^{SPOT}$ cannot exceed the maximum loading capacity of the electrolyzers $K_{a,j}$.

$$W_{a,j,t}^{SPOT} \leq K_{a,j} \quad \forall a \in A, \forall t \in T^{SPOT}, \forall j \in J^{PtH2} \tag{13}$$

Similar, to Durakovic et al. (2023), we do not assume further flexibility and ramping constraints for electrolyzers. This limitation might lead to an overestimation of the provided flexibility in case of specific technologies like alkaline electrolyzers (Bertuccioli et al. 2014) or solid oxide electrolyzers (Buttler and Spliethoff 2018). We assume only proton exchange membrane (PEM)[2] electrolyzers in our work as ramp-up times might be in the range of a few seconds, depending on the technological specifications (Ulleberg et al. 2010; Eichman et al. 2014; Tuinema et al.

[2] The abbreviation PEM also stands for polymer electrolyte membrane.

2020; Varela et al. 2021; Wang et al. 2022). Since this paper focuses on operating and investment incentives through market design, the neglect of this aspect does not bias the overall implications.

2.3 Modelling of Power-to-hydrogen

When modelling the integration of PtH_2 in energy market models, it is common to utilize a market-clearing mechanism to match supply and demand (Bødal et al. 2020; vom Scheidt et al. 2022). Demand is typically specified as an exogenous parameter in such cases, and the price is obtained endogenously from the market-clearing mechanism. As Bucksteeg et al. (2021) demonstrate, there is another way to model PtH_2 in electricity market models. Based on the results by Böcker and Weber (2015), they argue that the value of hydrogen is equal to the opportunity costs of hydrogen consumers, which corresponds to the cost of purchasing hydrogen from other sources, such as steam reforming or import (Bucksteeg et al. 2021).

In the first case, the natural gas price c_t^{gas} and the costs for CO_2 compensation c_t^{CO2}, i.e., CO_2 certificates, mainly determine the use value ξ_t^{PtH2} of the electricity used in the electrolyzers, as indicated in Equation (14):

$$\xi_{a,j,t}^{PtH2} = \left(c_t^{gas} + f_{gas}^{CO2-factor} \cdot c_t^{CO2}\right) \cdot \eta_{PtH2} \tag{14}$$

Here, $f_{gas}^{CO2-factor}$ is the emission factor of the natural gas used in steam reformation and η_{PtH2} is the conversion rate of the electrolyzers. This approach builds on the assumption that gas consumers, e.g., industry, can choose between electrolytic and fossil hydrogen. Since we assume domestic steam reforming as most competitive alternative here, we refer to the scenarios using the use value from Equation (14) as "domestic Steam Methane Reformation" (short: *SMRdom*) in the following.

Yet the EU obviously focuses the development of green hydrogen by 2030, especially under the RePowerEU Plan (EU Commission 2022) although hydrogen production based on natural gas with carbon capture, utilization and storage (CCUS) might still be a competitive alternative regarding the avoidance of CO_2 emissions. According to (IEA 2018), CCUS would add about 0.5

EUR/kgH_2 to the hydrogen production costs and could support a rapid scaling up of low-carbon hydrogen production (IEA 2020a). But even if the European focus remains on green hydrogen, the hydrogen strategies of countries like Germany and of the EU as a whole suggest that not only hydrogen from domestic sources will be used in the future.

Therefore, we consider a second alternative formulation of the use value. In this case, the international price for green hydrogen sets the opportunity costs for domestically produced hydrogen and the use value for domestic electrolyzers corresponds to the hydrogen import price $p_t^{H2,imp}$ multiplied by the electrolyzer efficiency η_{PtH2}. Implicitly, we assume here that steam reforming is no (longer a) competitive alternative, most likely due to some kind of regulatory intervention. As domestic electrolytic hydrogen is likely to be not available in sufficient quantities, the price on the hydrogen market is basically set by green H_2 imports (Agora 2021a; 2022). In this case, labeled *GreenImp* for short, the use value is hence given by the following eq. 15:

$$\xi_{a,j,t}^{PtH2} = p_t^{H2,imp} \cdot \eta_{PtH2} \tag{15}$$

Regardless of whether the use value is determined in the case *SMRdom* via eq. 14 or in the case *GreenImp* via eq. 15, the basic rule of market-oriented operation of domestic electrolyzers then is: the electrolyzers operate whenever the electricity price is less than or equal to the use value ξ_t^{PtH2} — this may also be derived formally from the Lagrangian based on the objective function (10) and the balance eq. (11). Under this condition, the variable procurement costs of hydrogen from domestic electrolysis are lower than or equal to those of alternative production routes. If the electricity price is strictly smaller than the use value, the difference corresponds to the contribution margin earned by the electrolyzers. If electricity prices exceed the use value, the electrolyzers will not run. In summary, electrolyzers have an incentive for utilization whenever the marginal generation costs of the price-setting technology are less than or equal to the use value.

Like Bucksteeg et al. (2021), the proposed approach does not explicitly consider any re-conversion of hydrogen to electricity. This is plausible for the time horizon considered in the case study, namely the year 2030. However, such an approach is even justifiable and useful in the presence of power plants using hydrogen as fuel. The exogenously given use value for hydrogen corresponds to the fuel price these units pay. In this perspective, the market price of hydrogen is independent of the supply and demand or storage potentials in the regional electricity system; instead, it is determined by alternative technology routes (e.g., steam reforming) and/or international supply. For a more detailed description of the chosen approach, e.g., regarding the integration into reserve markets or the negligible role of maximum storage capacity, see Bucksteeg et al. (2021).

The advantage of the chosen approach lies in the analysis of purely market-based incentives in a system-cost-minimizing framework. Since we focus on the effects of market splitting on the integration of PtH_2 in Germany, modeling an exogenous hydrogen demand would moreover require allocating the demand to the respective market zones. In contrast, endogenous hydrogen demand allows for assessing the allocation of the necessary electrolyzer capacity (in the upper-level investment problem). As a result, production volumes are endogenously determined, while prices for H_2 are known. Whether hydrogen from electrolysis is competitive is then dependent on the implemented market design – or put differently: in this setting, market design choices made by policy makers have a direct impact on the system integration of domestic PtH_2.

3 Data and Scenarios

We investigate the impact of market splitting on the deployment of electrolyzers in scenarios focusing on the mid-term future, represented by the year 2030. Below, we explain our key assumptions and data for the investigated case and then discuss the investigated scenarios and sensitivities.

3.1 Data and market split

Data for power plant portfolios, demand time series, NTCs, and fuel prices (except for natural gas)[3] are based on the Ten-Year Network Development Plan (TYNDP)-scenario, “Distributed Energy 2030”, from ENTSO-E (2020). In order to reflect the planned coal phase-out in Germany, the remaining lignite and hard coal capacities are replaced by gas-fired power plants. For renewable infeed profiles, we use data from Open Power System (2020) based on weather information from 2016 and we scale it as described in Pöstges et al. (2022). Assumptions on CO_2 prices are based on data from World Energy Outlook (WEO) (IEA 2020b; 2021). Here, we use the WEO 2021 “Net Zero Emissions by 2050 Scenario” as a reasonable assumption for a possible CO_2 price development path to 2030. Assumptions on the investment costs and technical parameters of electrolyzers are based on an extensive literature review and our assumptions (Williams et al. 2007; Agora 2018; 2021; Dagdougui et al. 2018; Gorre et al. 2019; IEA 2019; Prognos 2020; Ausfelder and Dura 2021; Hydrogen Council 2021). Following the discussion in Pitschak et al. (2017) and Wang et al. (2022), we further assume that by 2030 PEM electrolyzers will be the dominant technology due to their high flexibility and despite the technological opportunities offered by solid oxide electrolyzer cells (SOECs).

Regarding the current electrolyzer capacities in Germany, we use information from DVGW (2022) and TÜV Süd (2019). Accordingly, we end up with existing capacities below 100 MW for electrolyzers in Germany by the end of 2021. A summary of the key data assumptions is given in Table 1. The Use Value for the *SMRdom* case is based on H_2 production costs from steam reformation from IEA (2019) and Katebah 2022), where we have adjusted gas prices to our scenario setting. The Use Value for the *GreenImp* case is an average price for imported green H_2 from (Prognos 2020; Merten et al. 2020; Agora 2021b; 2022).

[3] Due to the Ukrainian conflict with impacts on gas prices, we configured gas prices based on available future quotes from eex.com taking the average price quotes in the first quarter of 2023 as basis.

Table 1: Key input data

Case		*SMRdom*	*GreenImp*
CO_2 Price	EUR/t CO_2	114	
Fuel Prices			
Natural Gas	EUR/MWh_{th}	45.30	
Coal	EUR/MWh_{th}	15.48	
Oil	EUR/MWh_{th}	73.80	
PtH_2			
Use Value	EUR/MWh_{el}	61.74	83.68
Investment Costs	EUR/kW	638.72	
Fixed costs	EUR/kW	19.16	
Conversion Rate	%	73	

According to TSOs, Germany faces regional differences in electricity generation and demand, which lead to grid bottlenecks from northern to southern Germany (Rippel et al. 2018). To investigate this issue with our model, we split the German market into two bidding zones: A north zone and a south zone (Figure 2). Our chosen split corresponds to the first proposal of possible alternative bidding zone configurations by the European Union Agency for the Cooperation of Energy Regulators (ACER) to be considered in the bidding zone review process. The market split is based on the most satisfying split for two bidding zones in Germany regarding improvements in price dispersion and further indicators compared to the status quo (ACER 2022).

Here, we use the grid data information obtained from ENTSO-E (2020). Nodal prices from the Osmose research project[4] serve as indicators to divide Germany into north and south zones along federal state borders (Figure 2). This simplified market split captures key features of the north and the south zones, as illustrated by the duration curves for residual loads shown in Figure 2. Correspondingly, we expect this approach to reveal the key interdependencies in our analysis.

[4] OSMOSE (https://www.osmose-h2020.eu/).

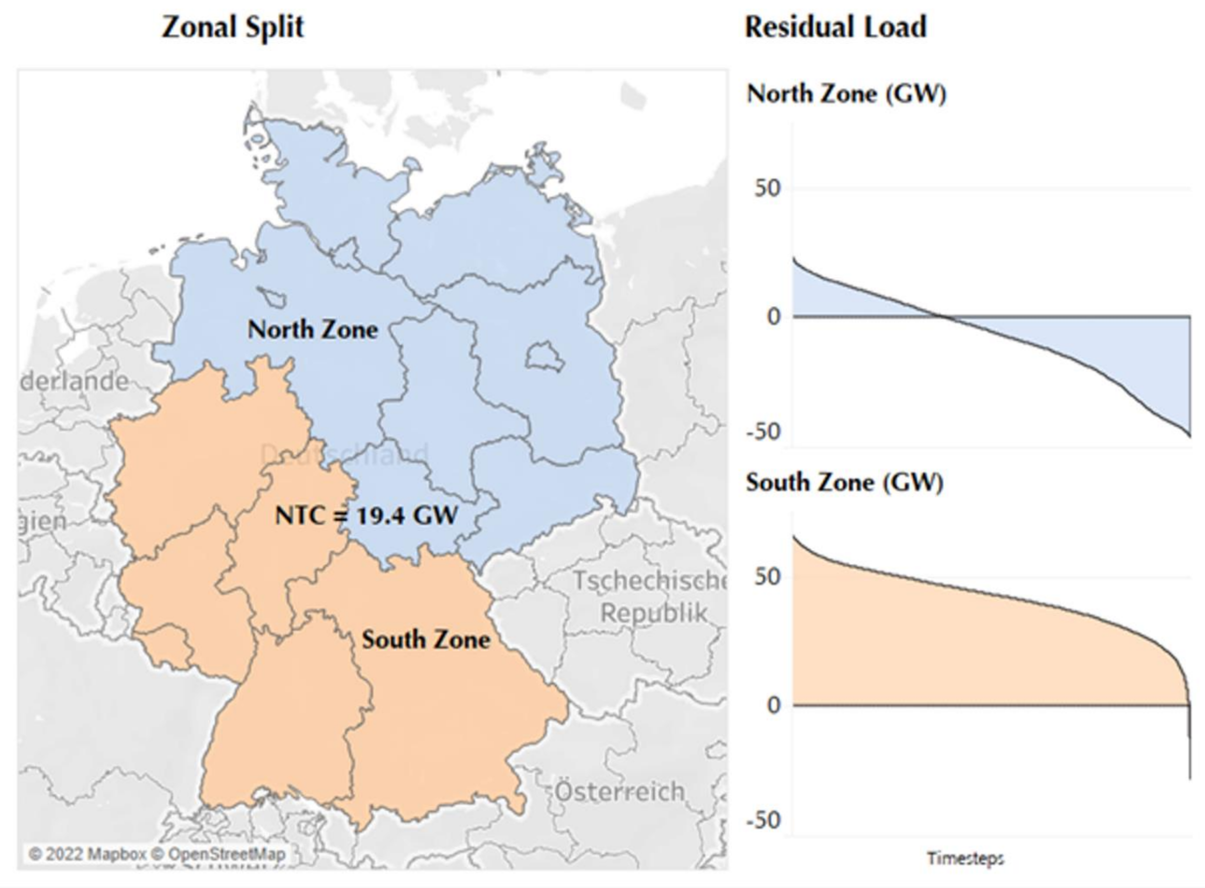

Figure 2: Considered market split of the German bidding zone

The thermal transmission capacity is aggregated to the level of interzonal borders, which results in a net transfer capacity of about 19.4 GW across the north-south zonal market split in Germany. We specify the distribution of generation capacities exogenously and allocate them to the north and south zones. To allocate the controllable generation capacities, we base our distribution on data from BNetzA (2021). The distribution of the regional renewable energy source infeed and the demand time series is done using an internal tool that allows for creating a time series at the county level (NUTS-3)[5] and scaling of the data to match aggregate TYNDP time series. The time series of counties in the south and north zones are added to obtain the zonal time series.

Figure 3 shows the German power plant portfolio in 2030. For the scenarios without market split, the portfolio *DE* is used; the scenarios with two bidding zones use the portfolios *DE_North* in the

[5] In Germany, the NUTS3 regions correspond to counties ("Landkreise") and independent cities. In other EU countries, the regions have similar areas and populations.

north zone and *DE_South* in the south zone. Installed capacities in Germany are mainly based on gas-fired power plants (36.4 GW), solar (109.9 GW), onshore (95.5 GW) and offshore wind (17.3 GW). Other non-renewables (15.8 GW) are smaller scale combined heat and power (CHP)-plants based on oil and gas. Other renewables (6.6 GW) are mainly biomass and municipal waste plants. Flexibilities include battery storages (5.1 GW), pump storages (8.4 GW), and electrolyzers, which are determined endogenously. The electrolyzer capacities differ between scenarios and correspond to the IDILES results described in Section 4. The German base load in 2030 is about 688.8 TWh. Further information on the data can be found in the Appendix.

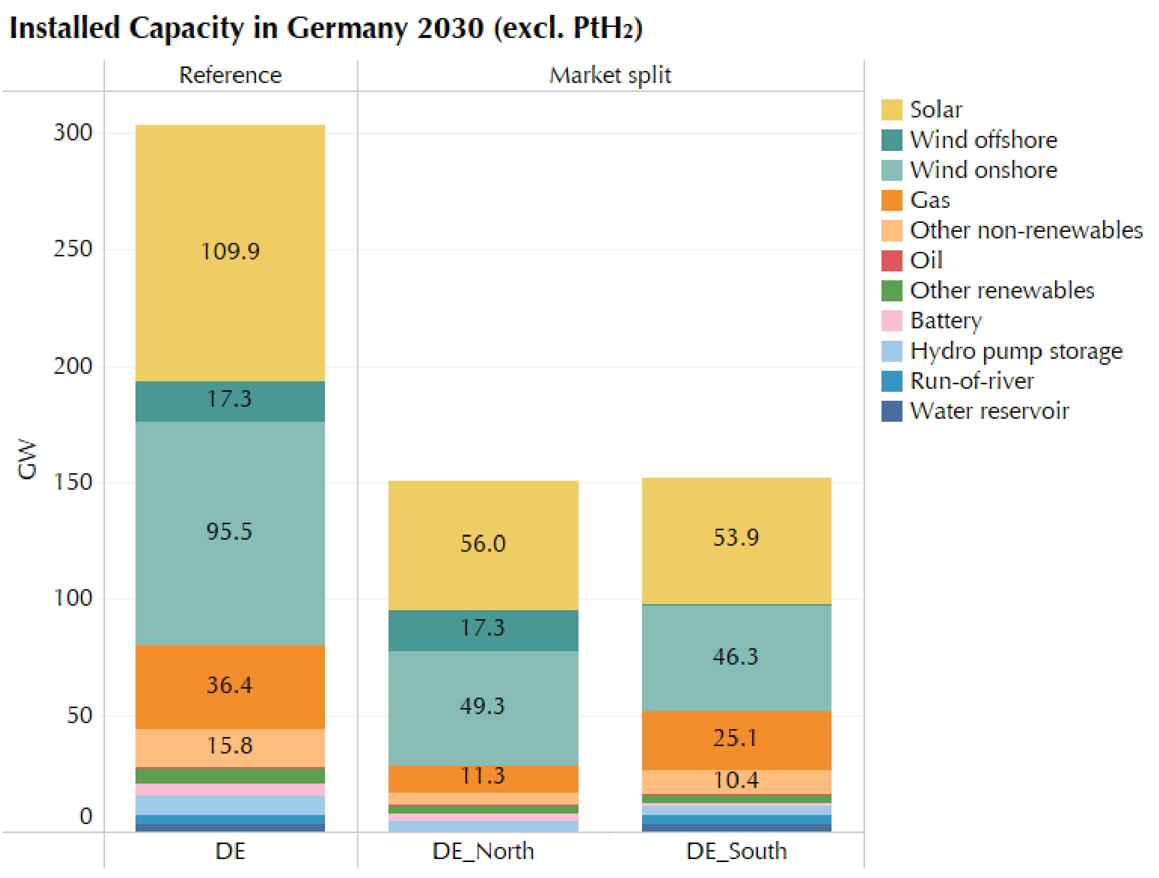

Figure 3: Installed capacities in Germany in 2030 (excl. PtH_2) for all scenarios

3.2 Scenarios and sensitivities

In order to investigate the potential impact of market splitting on investments in PtH_2 capacities, we examine four scenarios plus two reference runs (cf. Table 2). On the one hand, we consider the two cases defined above regarding the relevant drivers for the use value of electricity consumed in electrolyzers, i.e. the cases *SMRdom* and *GreenImp*. While the first one is more reflective of an early transition stage where PtH_2 may penetrate the market by partly substituting conventional hydrogen obtained via steam reforming, the second one focuses on the build-up of a "pure play" green hydrogen infrastructure, where business cases building on domestic and imported green hydrogen are in competition. In the reference runs, which correspond to the initial iteration in our iterative Benders decomposition approach, we take the existing electrolyzer capacities as starting point and we investigate, whether the market prices provide sufficient incentives to induce a market-driven investment in electrolyzers based on the achievable contribution margins. If this is not the case, there is no business case for market-driven PtH_2 investments – and iterations immediately stop. Otherwise, the Benders cuts enable an iterative adjustment of capacities until electrolyzer capacities in equilibrium do not earn any excess profits but recover their CAPEX and fixed cost.

The other dimension of scenario construction reflects the move from Germany being a single bidding zone towards a situation with a market split. By comparing the model results for both bidding zone configurations, we therefore are capable to assess whether and to what extent a market split provides incentives for a market-driven investment in electrolyzers and how the investments depend on the relevant competitor on the hydrogen market.

Table 2: Scenario description

Driver for use value → / **Bidding zone configuration** ↓		**Steam reforming**	**Green hydrogen imports**
	Reference run	*SMRdom*	*GreenImp*
Status quo *SQ*	*SQ_0*	*SQ_SMRdom*	*SQ_GreenImp*
Market split *MS*	*MS_0*	*MS_ SMRdom*	*MS_ GreenImp*

Obviously, the corresponding market outcomes depend both on the competitive situation in other parts of Europe and on the regulations in place. For northern Germany, where excess wind energy may drive electrolyzer investments (cf. Figure 2), potentially competing investments in neighboring Denmark are of particular relevance. Therefore, we investigate in a sensitivity run, whether the consideration of PtH_2 investment options abroad modify the business case for German electrolyzers – limiting the computational effort by solely including investment options in Denmark where high wind capacities also provide a potentially favorable context for electrolyzer investments.

In a second sensitivity, we investigate the interplay between regulatory settings and the market incentives for PtH_2 investments against the background that EU policy emphasizes the importance of "additionality" when it comes to green hydrogen production (cf. EU Commission 2020). This concept has been detailed recently in the proposed delegated regulation regarding green hydrogen for transport fuels (EU Commission 2023) and has been subject to a number of recent scientific analyses (Ruhnau and Schiele 2022; Schlund and Theile 2022; Villavicencio et al. 2022). In the delegated regulation as of February 2023, it is stated that all installed electrolyzers built after 2027 must be connected with a renewable electricity producing source not older than 36 months compared to the construction date of the corresponding electrolyzer. Electrolyzers constructed before 2028 are excepted from this requirement until 2038. In our context of general PtH_2 investment, a corresponding regulation without loopholes would imply that domestic electrolyzers can only compete with green hydrogen imports if they are directly associated with an additional renewable investment which does not benefit of any subsidies. By considering such a requirement in a sensitivity analysis, we shed light on the interplay between the regulations regarding green hydrogen and the electricity market design.

The geographical scope of our scenario analysis includes the entire EU (except Cyprus and Malta) as well as neighboring countries like Norway, UK, Switzerland and the Balkans. Thus, the scenario outcomes reflect the impact of the European internal market for electricity. Regarding the investment decisions, we focus on investments in electrolyzers in Germany (except for the sensitivity analysis) to highlight the interplay between PtH_2 capacity changes and the bidding zone configuration; hence, in all scenarios we consider the same initial situation regarding the remaining European countries. This reflects that the European internal market for electricity and the EU strategies for decarbonization are not translating into homogenous national energy policies, rather the prospective energy systems are shaped by national specificities in terms of geography (e.g., hydro potentials) and energy policy (e.g. nuclear policy and renewable support mechanisms). These impact the national technology mix and especially in a mid-term perspective, the interplay of national regulations and Europe-wide market mechanisms is difficult to capture in detail. Therefore we prefer to stick to an established European reference scenario taken from the TYNDP established by the European TSOs (ENTSO-E 2020) which has the ambition to describe a realistic Pan-European transition path to 2030. To our knowledge, the TYNDP scenarios serve as basis for cost-benefit analysis for projects of common interest and thus reflect European climate targets in energy markets. Focusing on electrolyzer capacity adjustments in Germany moreover has the additional benefit of limiting calculation time. Given that the JMM is considering reserve power markets and power plants characteristics like start-up costs in detail, endogenous capacity adjustments across Europe through IDILES, would induce a substantial increase in computation times. One may argue that neglecting indirect effects of PtH_2 investments related to capacity adjustments (for electrolyzers or other technologies like renewables) in other parts of the European electricity system may bias some of the results. Yet as these are second-order effects, we believe that they have limited impacts in the medium term – and that on the other hand the focus on sole electrolyzer investments in Germany makes it easier to understand the interplay of market dynamics and regulatory settings. Adjusting all generation capacities also tends to lead to system configurations that are not reflecting real-world decision-making constraints, even if they are optimized with respect to the specified objective function.

4 Results and Discussion

The runs for the four investigated scenarios achieve convergence to equilibrium electrolyzer capacities after up to 12 iterations. The computation time is on average 12:31 h per iteration on a high-performance desktop computer[6]. Correspondingly the computation takes around 6 days for scenarios with investment incentives.

4.1 Impacts on Spatial Investment Incentives

The results for the four scenarios show that market-driven investments in electrolyzer capacities in Germany are strongly dependent both on the bidding zone configuration and the use value level (cf. Figure 4).

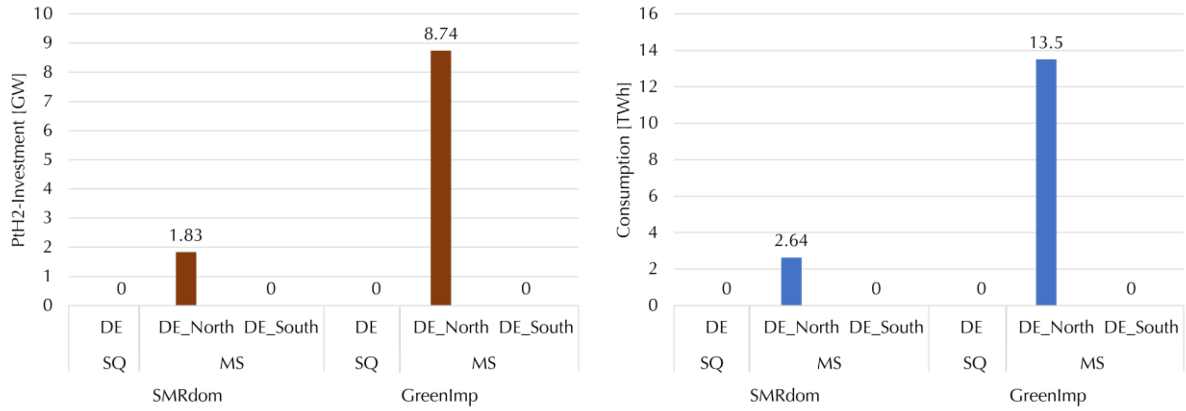

Figure 4: Electrolyzer investments and corresponding electricity consumption

For both use values investigated, investments in electrolyzers only occur in the case of a market split and are then limited to the DE_North zone. Compared to the status quo, no change, and thus no investment, happens in the south zone (cf. also the key scenario results summarized in Table A.4 in the Appendix). This "corner solution" is a consequence of different price distributions in the different market zones (cf. Figure 5). Zero prices and prices below 10 €/MWh are much more frequent in the northern German bidding zone than in the south or in a single bidding zone. This is because the share of renewables is higher in the north, while demand is higher in the south (cf. Figure 2) and because of the limited NTC between both market zones. Thus, the supply curves differ in the north and in the south.

[6] We used a Intel® Core™ i9-9900K CPU with 3.60GHz.

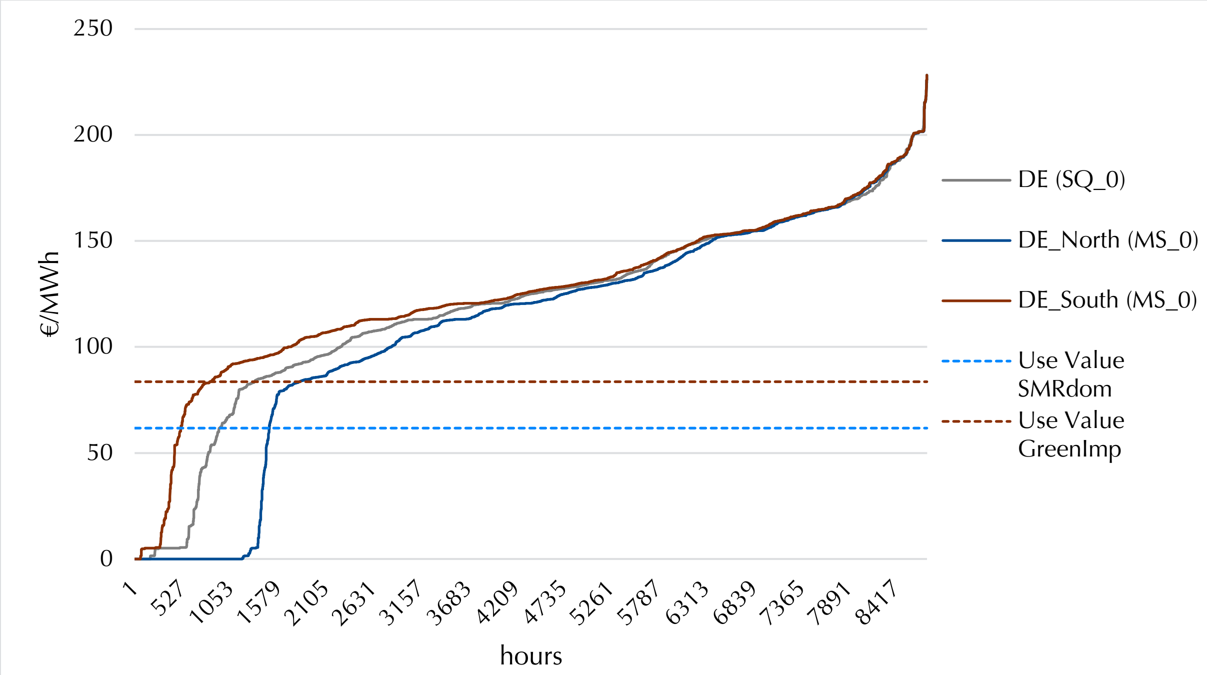

Figure 5: (Inverted) price duration curves in the reference runs *SQ_0* and *MS_0* and relevant use values

Figure 6 shows an excerpt of the corresponding PDCs for the reference run *MS_0* along with the cumulative contribution margins and the CAPEX (sum of investment and fixed cost). If the cumulative contribution margins in the reference run exceed the (annualized) CAPEX, there exists an incentive to invest. Yet according to Figure 6, the total contribution margin in the south is smaller than the annualized CAPEX even at the initial electrolyzer capacities of 30 MW. Hence, there is no incentive to invest in the south and similar results are obtained for the status quo of a single bidding zone. In the north zone, incentives for investments yet exist as the cumulated contribution margins exceed the CAPEX.

Even with the market split, the installed capacities however fall below the government's target of 10 GW by 2030 regardless of the assumed use value. But these are investments solely driven by market incentives and without any subsidies. The results underscore hence the potential impact of market splitting on electrolyzer investments, and they also point at the decisive role of the actual use value.

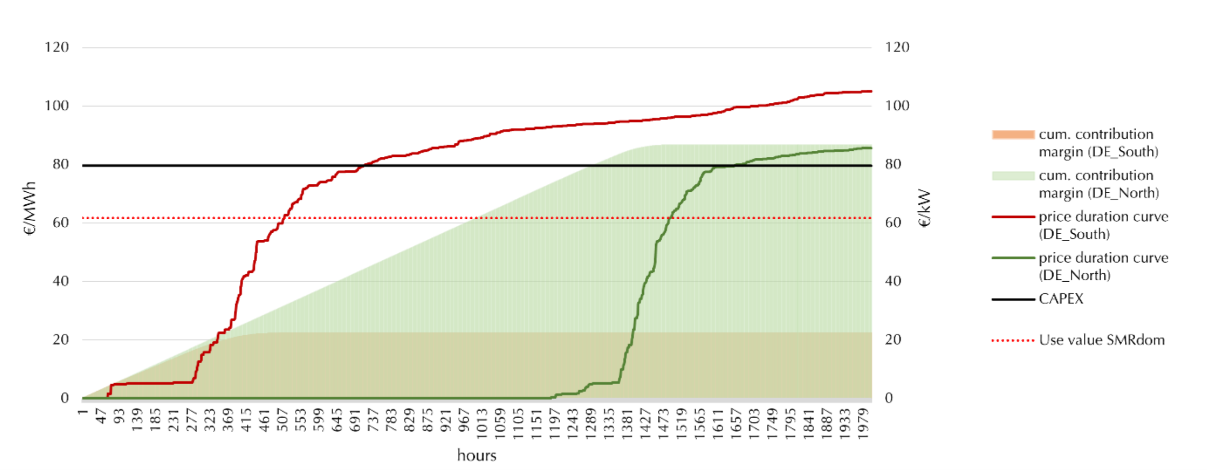

Figure 6: Details of the price duration curves and profitability of electrolyzers in DE_North and DE_South in the scenario *MS_SMRdom* for the initial run *MS_0*.

The increased value of hydrogen in the *MS_GreenImp* scenario compared to the *MS_SMRdom* scenario leads to a higher profitability of electrolyzers in the initial run. In the final market equilibrium, this translates into higher investments in electrolyzers (Figure 4), while full cost recovery is achieved for electrolyzers in both scenarios as illustrated in Figure 7.

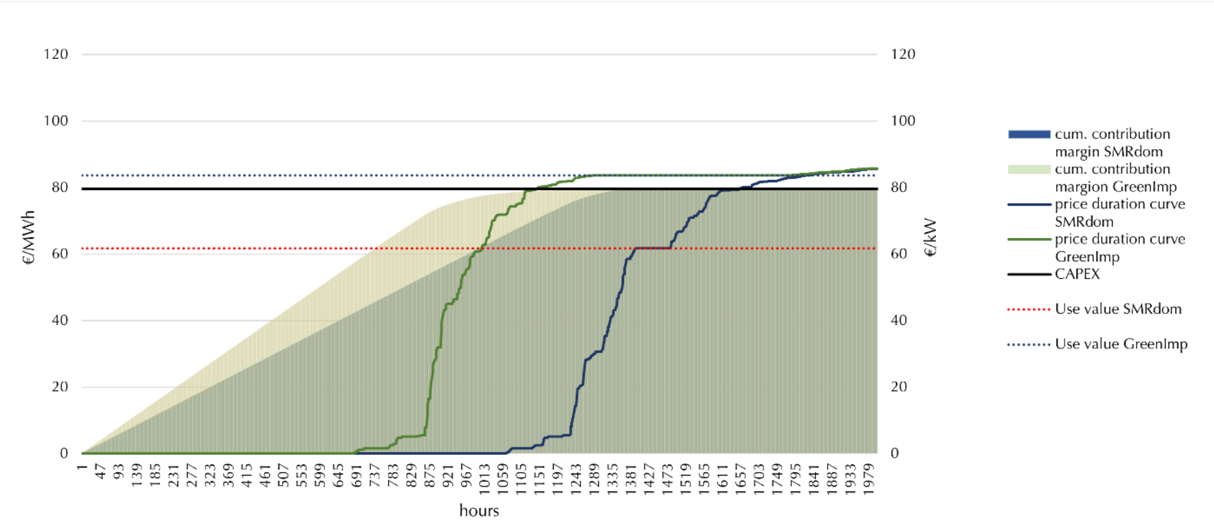

Figure 77: Details of the price duration curves and profitability of electrolyzers in DE_North in the scenarios *MS_SMRdom* and *MS_GreenImp*.

As the contribution margin per hour is larger in the *MS_GreenImp* scenario due to the higher use value, less low price hours are needed to recover CAPEX. The price duration curve in equilibrium is hence more shifted to the left (cf. Figure 7) and utilization hours of electrolyzers are lower than in the scenario *MS_SMRdom* (cf. Table A.4)– or put differently, the higher installed electrolyzer capacity under this scenario absorbs more excess renewable energy and thus modifies the dispatch of plants and pushes up the inverted price duration curve.

Along with the variations of electrolyzer capacity, the amount of electricity consumed by the electrolyzers also differs among the scenarios (cf. Figure 4). While the electrolyzers in the north consume 2.64 TWh in the scenario *MS_SMRdom* and 13.50 TWh in the *GreenImp* scenario, the amount in the south zone is close to zero in both cases as no investment incentives arise there.[7]

The *GreenImp* scenario hence show much higher incentives both for investment in domestic electrolysis and for the corresponding production. With higher demand by electrolyzers, there is also some increase in the use of technologies with non-zero variable costs. These are partly based on fossil fuels and given the corresponding operational constraints such as minimum operation time and minimum downtime, this also impacts CO_2 emissions (cf. Section 4.3).

4.2 System Cost Effects

Figure 8 illustrates the changes in total cost for the entire European electricity system related to the electrolyzer investments occurring in the market split scenarios. The savings correspond to the difference in system costs between the reference run with almost no electrolyzer capacity and the final equilibrium with optimized electrolyzer capacities. Savings are only shown for the market split scenarios as the incentives to invest in electrolyzers are insufficient under the status quo of a single bidding zone. Comparing the reference runs *SQ_0* with *MS_0* (cf. Table A.4 in the Appendix), it should be noted that the system costs increase due to the market split. This is mostly related to the fact that redispatch cost are neglected in our market-centered perspective. A well-designed market split contributes to reducing redispatch quantities and redispatch costs

[7] Note that the electrolyzer consumption in the north zone in the MS scenarios is of the same order of magnitude than the flexibility provided by load shifting in the analyses by Pearson et al. (2022), which sums up to 6 to 9 TWh Yet this comparison should not be overstressed as both studies have different focal points and use different methodologies even though both investigate the situation in 2030.

by imposing a market-based dispatch which already (at least partly) reflects grid constraints (cf. e.g. Trepper et al. 2015; Felling et al. 2023) – but comes at some extra cost.

In the two relevant scenarios *MS_SMRdom* and *MS_GreenImp*, the optimal exploitation of the PtH_2 potential is beneficial. Whereas the benefits are only in the order of 10 M€ in the scenario *MS_SMRdom*, the cost savings increase to 190 M€ in the scenario *MS_GreenImp*, i.e. about 25,000 € per year for each installed MW of electrolyzer capacity.

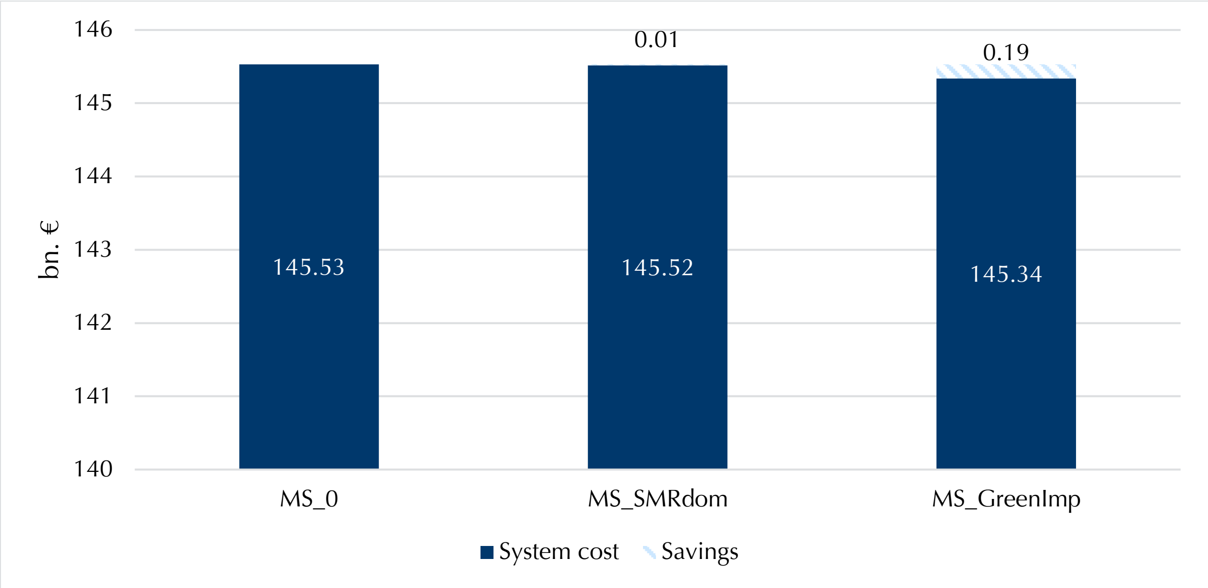

Figure 8: System cost and benefits relative to the initial market split run in bn. €

4.3 Impacts on Congestion, Emissions and Renewable Integration

Besides affecting system costs, the investment in electrolyzers in Germany may also affect other aspects of the integrated European electricity market. One key indicator are thereby the cross-border energy exchanges. Figure 9 therefore summarizes the aggregate annual electricity exchanges between Germany and its neighboring countries in the market split scenarios. The results suggest that the installation of electrolyzers in Germany has only limited impacts on the cross-border energy exchanges – at least at the annual scale. The largest single change is observed when comparing imports from Denmark in the scenario *MS_GreenImp* to the outcomes in the reference run *MS_0*. Imports increase in that case by about 1.5 TWh. Also the flows inside Germany which are predominantly running from north to south are not massively impacted by the electrolyzer installations. The annual balance is again decreased by about 1.5 TWh, which corresponds to about 1 % of the total annual quantity.

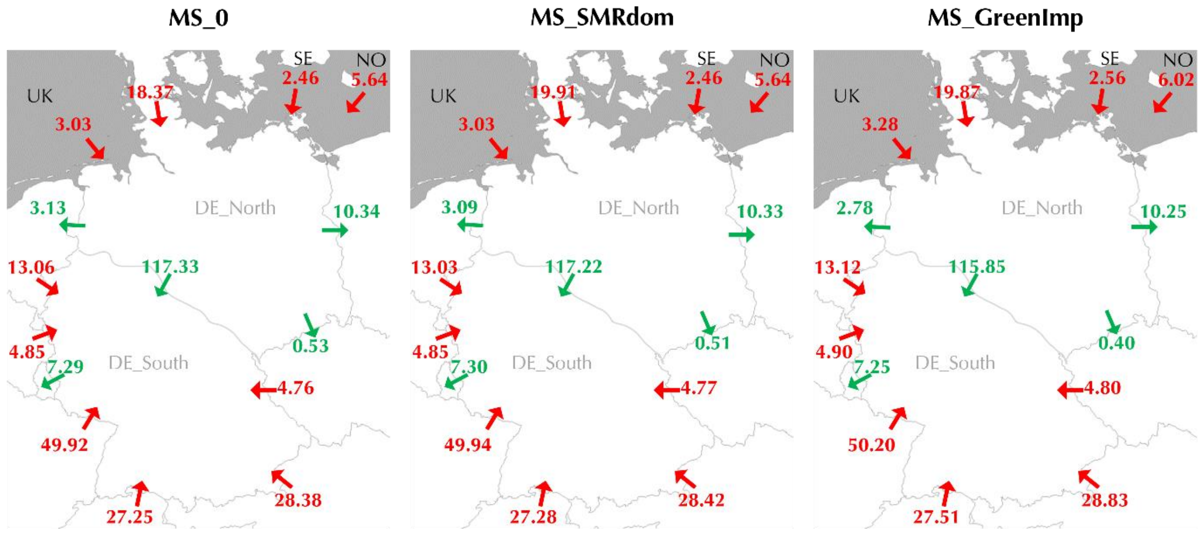

Figure 9: Germany's annual electricity exchange with neighboring countries

One major benefit expected from PtH_2 installations is the reduction of renewable curtailment. Figure 10 therefore shows the renewable curtailment for the different market split scenarios. Across all scenarios, the curtailment in northern Germany is most important and may be traced back to high renewable production along with low demand and substantial transfer capacity restrictions. Comparing the reference run to the optimized scenarios with additional electrolyzer capacities in the market split case, the curtailment decreases due to the provision of flexibility by the electrolyzers. In the scenario *MS_GreenImp* with about 8.74 GW of installed electrolyzer capacity consuming about 13.5 TWh of electricity per year, 8.4 TWh of renewable curtailment is avoided in the overall system compared to the baseline case. This is almost entirely a consequence of reduced curtailment in northern Germany. Overall, this implies that 62 % of the electricity consumed in the electrolyzers in this scenario is renewable electricity that would otherwise be curtailed. In total, the changes in imports and exports indicated in Figure 9 contribute another 31 % to the electricity consumption of the electrolyzers, hence only a small share of the electrolyzer electricity is produced by local conventional plants in northern Germany.

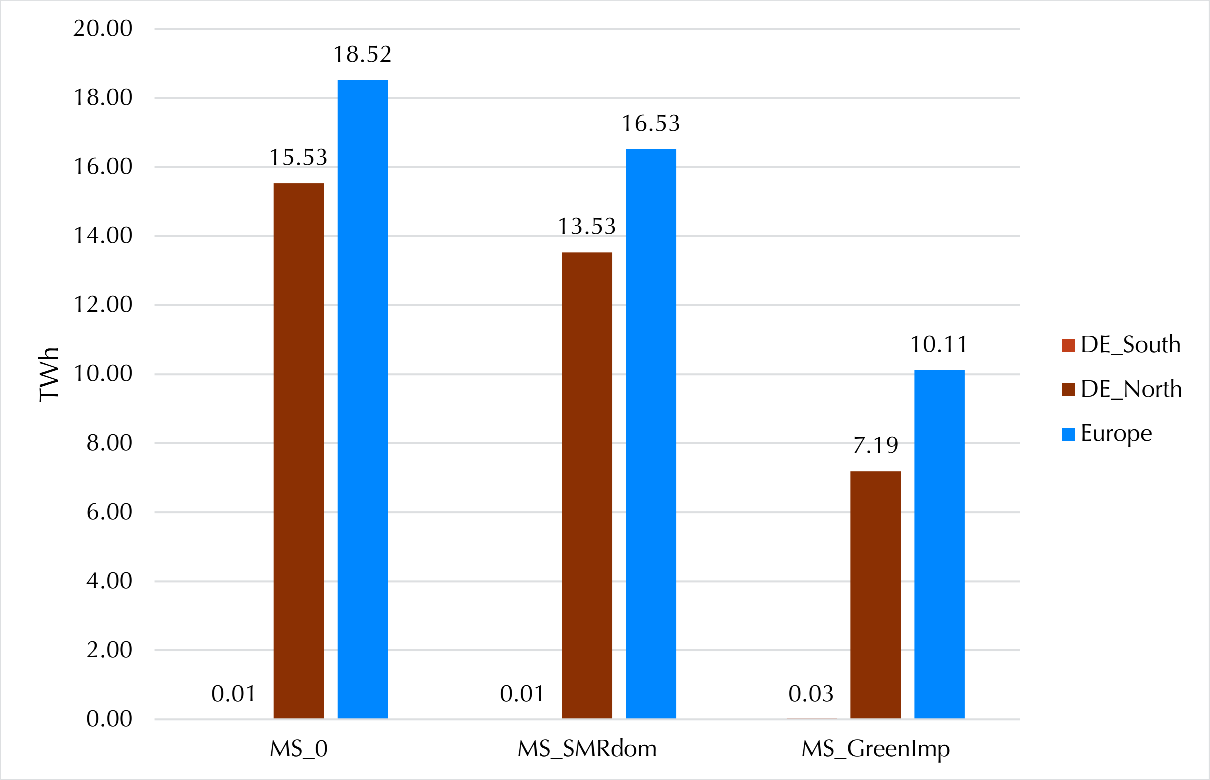

Figure 10: Renewable curtailment

This has obvious implications for another key system indicator, namely the CO_2 emissions. Figure 11 shows the emissions in northern Germany for the three market split scenarios, whereas Figure 12 indicates the corresponding emissions for the entire European system.[8] Obviously the change in emissions in northern Germany is very limited and also at the European scale, extension of the *MS_SMRdom* scenario has emissions are almost at the level of *MS_0*. With the higher electrolyzer capacities in the scenario *MS_GreenImp*, the electricity production mix changes and there is a somewhat more pronounced increase in emissions from fossil generation.[9]

[8] It should be noted that emissions increase in our market-based modelling when the market split is introduced (cf. Table A.4 in the Appendix). This is again related mostly to the fact that redispatch is neglected in our modelling and that redispatch in the status quo scenario is larger than in the market split scenarios – implying that additional fossil energy is used at this stage which contributes additional emissions not accounted here.

[9] That emissions exceed the initial level is possible here because we assume a fixed CO_2 price and not a fixed emissions budget with a variable price as in the EU ETS. As emission certificates in the EU ETS may be transferred between years, the annual budget in the ETS is in fact also not fixed and using a constant CO_2 price is a valid assumption.

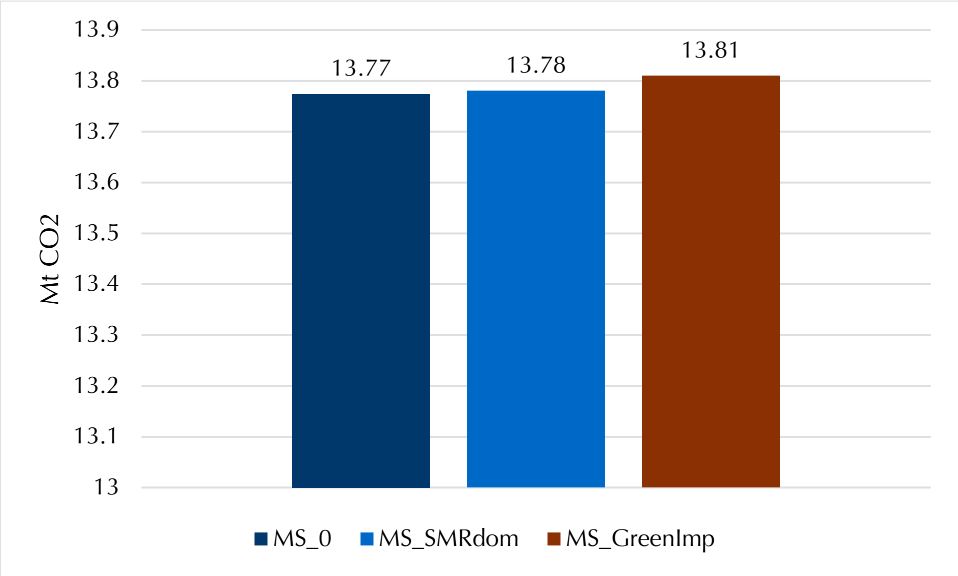

Figure 11: Total CO_2-emissions in DE_North in the market split scenarios

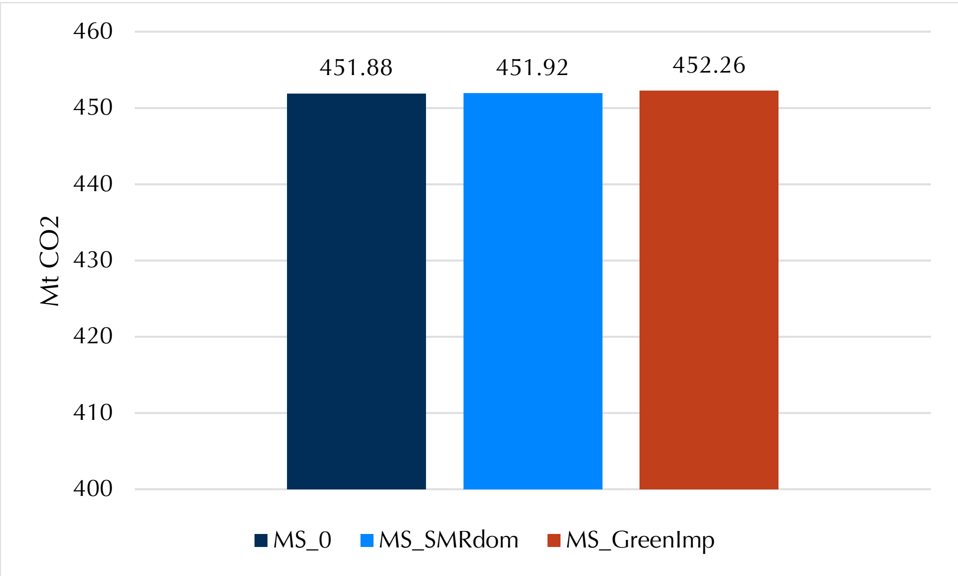

Figure 12: Total CO_2-emissions in Europe in the market split scenarios

This temporary effect of an increase in emissions in principle contradicts the goal of decarbonization. Yet when computing the CO_2 intensity per produced unit of hydrogen based on the change in CO_2 emissions between *MS_0* and *MS_SMRdom* respectively *MS_GreenImp* it becomes obvious that the marginal carbon intensity attributable to the hydrogen produced is rather small (cf. Figure 13). When considering only the emission changes in northern Germany, the emission intensity is below 0.005 t_{CO2}/MWH_{H2} in both scenarios. And even when taking into consideration the entire emission effect in the European system, the emissions only increase by by 0.02 t_{CO2}/MWH_{H2} in the scenario *MS_SMRdom* and by 0.04 t_{CO2}/MWH_{H2} in the scenario *MS_GreenImp*. This is far lower than the emission intensity of steam reforming which induces CO_2 emissions in the range of 7.5 to 12 tons of CO_2 per ton of hydrogen, i.e. 0.22-0.36 tCO2/MWh (Katebah et al. 2022). Consequently, the substitution of H_2 from steam reformation in the scenario *MS_SMRdom* clearly leads to a net emission reduction. In the scenario *MS_GreenImp* this is not true – as long as the imported green hydrogen is effectively emission-free. Yet this requires that the EU is capable of both imposing and enforcing its strong additionality criteria regarding green hydrogen also in foreign countries.

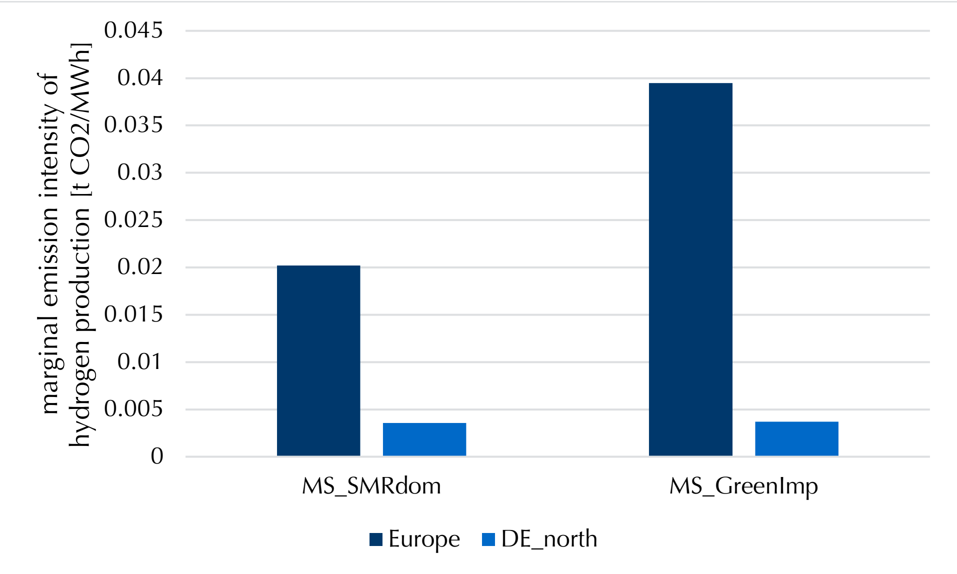

Figure 13: CO_2 intensity per unit of H_2 produced

4.4 Sensitivities regarding investments abroad and additionality requirements

The results shown in the previous sections are obtained under two major assumptions: on the one hand that investment opportunities in other EU countries do not substantially affect the viability of electrolyzer investments inside Germany. And on the other hand, that no explicit additionality criterion is imposed which would require that any electrolyzer investment has to be accompanied by a corresponding renewable generation investment in order to compete with green hydrogen imports. As discussed in Section 3.2, we therefore subsequently investigate two major sensitivities to assess the impact of these assumptions.

First, we do not restrict the investment options to Germany alone, but also allow for investments in electrolyzers in neighboring countries, here Denmark. We focus on Denmark to limit computational efforts and as to our understanding investments in Denmark are particularly prone to compete with those in northern Germany given the geographic proximity and the similarities in the generation mix. We implement this sensitivity within the scenario *MS_GreenImp*, as this scenario provides larger investment incentives compared to *MS_SMRdom*.

In the initial iteration, we find that contribution margins for electrolyzers in Denmark exceed the corresponding CAPEX yet these are positive albeit smaller compared to those in DE_North (cf. Table 3). In the final equilibrium, investments only occur in DE_North as the contribution margins in Denmark do not cover CAPEX when capacities in DE_North increase to minimize system costs. This indicates that our main results regarding investments in Germany are rather robust and that at the same time the potentially congested Danish-German border does not provide sufficient incentives to place electrolyzers directly in Denmark. Rather the more ample interconnections between Denmark and the hydro-dominated Nordic countries Norway and Sweden make investments in Danish electrolyzers less attractive as they compete with the flexibility of the Nordic hydro reservoirs.

In a second sensitivity calculation, we consider the effects of the additionality principle as proposed by the EU Commission. We test this again within the settings of the scenario *MS_GreenImp*, as this scenario fosters on competition between green hydrogen production inland and abroad. To reflect the key idea of the additionality principle, we investigate investments in a combined technology consisting of a wind onshore turbine and an electrolyzer which is then exclusively used for producing green hydrogen. We assume additional investment costs of 1000 EUR/kW and fixed cost of 30 €/kW for the onshore wind capacities on top of the electrolyzer costs (ENTSOG and ENTSO-E 2022) as well as a strict temporal coupling of wind energy production and electrolyzer operation. With the annual full load hours for a typical onshore wind site in northern Germany (2088 h), the annual contribution margin is higher than for a market-based operation of the electrolyzer. Yet it is not sufficient to cover the higher CAPEX of the combined installations (cf. Table 3).

Table 3: Results of sensitivity calculations for the scenario *MS_GreenImp*

		Scenario *MS_GreenImp*	**Sensitivity 1 + Invest DK**	**Sensitivity 2 Additionality**
DE_North	**annual contribution margin** - first iteration (€/kW)	120.98	120.98	174.24
	- after optimization (€/kW)	79.61	79.61	174.24
	CAPEX (€/kW)	79.61	79.61	204.24
	additional electrolyzer capacity after optimization (MW)	8736	8736	0
DK	**annual contribution margin** - first iteration (€/kW)	-	99.93	-
	- after optimization (€/kW)	-	70.77	-
	CAPEX (€/kW)	-	79.61	-
	additional electrolyzer capacity after optimization (MW)	-	0	-

For a weaker version of the additionality principle as considered by Ruhnau and Schiele (2022), the situation is different. They consider a relaxation of the additionality criterion by imposing a matching of the electrolyzer electricity consumption with additional wind energy production on a yearly basis. This implies that the dispatch of the electrolyzer may be again optimized against market prices and the wind production is also valued at market prices. The capacity of the wind turbine investment must yet be such that the annual additional volume of grid feed-in must at least cover the consumption from the grid. Such a "temporally relaxed" additionality criterion provides sufficient incentives for investments in the reference run. In fact, these are identical to the sum of the contribution margins for stand-alone electrolyzer capacities and an appropriately sized wind park.

5 Conclusion and Policy Implications

Our analyses indicate that a rather simple split of the German market zone induces in the mid-term until 2030 already sufficient incentives for market-driven electrolyzer investments. Whereas no PtH_2 investments occur under the status quo of a single German bidding zone, the market splitting leads to substantial investments in electrolyzers in northern Germany enabling an improved usage of the high renewable generation in that region. In contrast, electrolyzer investments in southern Germany are discouraged and congestion of scarce transmission capacities is somewhat relieved. The level of investments depends strongly on the relevant competition situation on the hydrogen market: in case that the substitution of domestic steam reforming is in the focus, investments in electrolyzers are much less attractive than in a situation where domestic PtH_2 competes with green hydrogen imports. Taking into account the interplay in the European electricity market, we find that additional emissions induced by the energy consumption of the electrolyzers are far lower than those of conventional hydrogen production routes. Therefore, a classification of this hydrogen as "low carbon" seems justified even if no strict additionality requirement is imposed on the hydrogen project. Strict additionality requirements by contrast turn out to raise prohibitive barriers for electrolyzer investments even in a market split scenario.

The market-based approach to PtH_2 investments also implies that a system-friendly operation of electrolyzers utilization is incentivized in the market split scenario. The electrolyzers then act as a flexibility provider. While the results show high volumes of curtailed renewable energy in the status quo, curtailment is reduced due to PtH_2 operation in the optimized cases. Hence, the integration of renewables is also supported by PtH_2.

A limiting aspect of our analysis is the neglect of service provision by electrolyzers to further markets like ancillary services that may enable additional revenues for electrolyzers and could thus potentially alter investment decisions and levels. Since the focus of this paper is on operating and investment incentives arising from bidding zone configurations, neglecting other markets does not fundamentally alter the overall implications. Future analyses that consider these aspects would yet be beneficial. Also, the present analysis only partially answers the question of the role of hydrogen in a cross-sectoral view. Correspondingly, the impact of hydrogen demand on additional electricity capacities (Durakovic et al. 2023) is not at the heart of the present analysis. Our approach does not include an integrated energy system model which enables the analysis of a broader set of interactions. But the approach chosen here also avoids some of the drawbacks of an integrated approach – not only in terms of computational complexity. Notably integrated energy system models determine the optimal outcome from the perspective of an omni-scient system planner. This provides valuable insights into the optimal (long-term) strategies. But it does not necessarily reflect what will happen in reality where numerous existing regulations and practices (e.g. regarding electricity tariffs) apply.

Already with our approach with a reduced set of capacity adjustments, we can show that the integration of PtH_2 is beneficial for decreasing overall system costs in the market split case. A higher provision of flexibility by larger electrolyzer capacities leads also to increased system costs savings.

Considerations regarding (partial) system transformation must also consider developments towards a decarbonized system. Our analysis shows that a market split might be beneficial for incentivizing investments into electrolyzers but temporally leads to a slight increase of CO_2 emissions in the European electricity system (in 2030). Putting this increase in relation to the produced quantity of hydrogen yet shows that the emission intensity is about a factor 10 lower than for grey hydrogen obtained through steam reforming. One limiting aspect of our analysis is the neglection of the detailed topology of the electricity grid. Through a consideration of detailed grid constraints already in the electricity market (through nodal pricing), more granular spatial incentives could be obtained – yet such a fundamental change in market design is unlikely to be achieved in the next years.

Regarding our research focus on the interplay between market design, policy instruments and the deployment of electrolyzers, we hence conclude that already a rather simple split of Germany in two bidding zones substantially improves the prospect for market-driven investments in electrolyzers which in turn are instrumental to reduce renewable curtailment in a context of persisting grid bottlenecks. Yet the strength of the incentives depends on the prevalent competition in the hydrogen market. Incentives are much stronger if domestic PtH_2 is allowed to compete with imported green hydrogen and no excessive additionality requirements are imposed. In conclusion, we point out the following key results:

- Market splitting leads to more efficient deployment of PtH_2 as prices indicate scarcity and lead to location-dependent investment incentives.
- Market incentives are sufficient for inducing PtH_2 investments; thus, the need for subsidies is strongly reduced in such a scenario.
- The locational signals for deployment and operation of the electrolyzers induce benefits for the system regarding costs as well as curtailment of renewables.
- The choice of the location of electrolyzers in the nearer term affects the necessary grid expansion in the longer term.
- Electrolyzer operation only induces very limited increases in CO_2 emissions and the produced hydrogen qualifies as "low carbon" hydrogen.
- Missing spatial incentives imply that a considerable potential for the market ramp-up of electrolyzers remains unused.

Given these results, we identify the following policy implications: in the ongoing debate on bidding zone configurations in Europe, the impact of bidding zones on investment incentives – especially regarding electrolyzers - should play a major role. As an adequate split of bidding zones strengthens investment incentives, this also leads to a reduction of uncertainty among investors. Policy makers should hence take into account that a decision to split existing bidding zones will reduce distorting incentives for flexibility provision and correspondingly the system transformation may speed up. Such a market split may thus substitute administrative policy measures and subsidies designed to accelerate the introduction of green hydrogen production.

At the same time this will reduce renewable curtailment and thus enable a more effective use of renewable resources. These positive system effects become even more important in scenarios with higher renewable shares in Europe – so, the market splitting increases the substitution of emissions in downstream processes (H_2 production by electrolysis instead of steam reformation) of the overall energy system directly.

The results shown in this paper reflect the used input data and the methodology applied. Thus, we refer to the observed effects rather than absolute results. Notably our methodology does not reflect all indirect effects related to increased sector coupling through electrolysis. Aspects that can be investigated in the future include electricity system feedback effects in the form of investments in electricity generation and electricity storage systems as well as hydrogen system feedbacks like the impact of potentially lowered hydrogen prices. Also the inclusion of detailed electricity grids and combining the electrolyzer infrastructure with the existing gas transport infrastructure and other transport routes might provide further insights. Although our analysis focuses on Germany, our results also contain valuable insights for other countries where hydrogen will play an important role. The insights are notably relevant for countries with a large or growing share of renewable energy sources and, at the same time, an uneven spatial distribution of demand and generation capacities like UK.

Acknowledgement

We thank Hannes Hobbie, Dana Kirchem, Martin Lieberwirth, Wolf-Peter Schill and the participants of the online workshop “Power sector implications of green hydrogen in Germany” on 7 April 2022 for valuable comments on earlier drafts and two anonymous reviewers and the editor for detailed feedback on the manuscript. We gratefully acknowledge funding by the German Federal Ministry for Economic Affairs and Climate Action (BMWK) via the research project MODEZEEN, Fkz 03EI1019C.

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Appendix

Nomenclature

Indices and Sets:

a, A	Area
i, I	Iteration, where $\forall i \in \{1, \dots, k-1\}$
j, J	Unit group / Technologies
k	Current iteration
r, R	Region
t, T	Time step

Parameters:

A	Coefficient matrix of operational variables
B	Coefficient matrix of investment variables
c_t^{gas}	Natural gas price
$c_{a,t}^{fuel}$	Fuel costs
$c_{a,t}^{CO2}$	Costs of CO_2 certificates
$c_{a,j}^{O\&M}$	Costs of operation and maintenance
$c_{a,j}^{STARTUP}$	Start-up costs
d	Vector of right-hand side parameters in operational constraints
$D_{r,t}^{ELEC}$	Electricity demand
$f_{gas}^{CO2-factor}$	Emission factor of the natural gas

$K_{a,j}$	Installed capacity, in occurrence maximum loading capacity of the electrolyzers
$l_{r,\bar{r}}^{TRANS,MAX}$	Exogenously fixed transmission capacity
$\delta_{\bar{r}r}$	Transmission losses
η_{PtH2}	Conversion rate of the electrolyzers

Variables:

C_{OPX}	Operational costs
C_{LT}	Long-term system costs
C_{OPX}^{*}	Minimum operational costs
C_{CPX}	Capacity-related costs
$\nabla\hat{C}_{LT}^{(i)}$	Gradient of the long-term costs in iteration i
$\nabla\hat{C}_{OPX}^{*(i)}$	Gradient of the operational costs
$\widehat{K}$	Vector of capacities in the upper-level problem
$P_{a,j,t}^{PtH2}$	Produced hydrogen
$P_{r,\bar{r},t}^{TRANS,SPOT}$	Im- and exports
$P_{r,t}^{RES}$	Infeed from volatile renewable energy sources
$P_{a,j,t}^{RES_{CURT},SPOT}$	Curtailment
$P_{r,\bar{r},s,t}^{TRANS,ANC,+}$	Ancillary services (positive reserves)
$Sp_{a,j}^{STORAGE}$	Marginal value of terminal storage content
$V_{a,j,T}^{STORAGE}$	Storage content

$W_{a,j,t}^{ANC,-}$	Provision of negative spinning reverse
$W_{a,j,t}^{SPOT}$	Electrolyzers' consumption
$W_{a,j,t}^{NONSP\_ANC,-}$	Provision of non-spinning reverse
$\hat{y}$	Vector of dispatch decision variables
$\hat{\lambda}_t$	Shadow price
$\xi_{a,j,t}^{PtH2}$	Use value of the electricity used in the electrolyzers

Additional Information on the used Data

Table A.1: Overview of data sources for key assumptions regarding CO_2 prices, fuel prices and hydrogen.

Scenario		**SMRdom**	**GreenImp**	
CO_2 Price	EUR/t CO_2	114		WEO 2020, 2021
Fuel Prices				
Natural Gas	EUR/MWh_{th}	45.30		TYNDP 2020
Coal	EUR/MWh_{th}	15.48		TYNDP 2020
Oil	EUR/MWh_{th}	73.80		TYNDP 2020
PtH_2				
Use Value	EUR/MWh_{el}	61.74	83.68	Williams et al. 2007 Agora 2018, 2021
Investment Costs	EUR/kW	638.72		Dagdougui et al. 2018 Gorre et al. 2019
Fixed costs	EUR/kW	19.16		IEA 2019 Prognos 2020
Conversion Rate	%	73		Ausfelder and Dura 2021 Hydrogen Council 2021

Table A.2: Installed Capacities in Germany in 2030 (exogenously given).

Capacities [GW]	DE	DE_North	DE_South
Technology			
Solar	109.9	56.0	53.9
Wind Onshore	95.5	49.3	46.2
Wind Offshore	17.3	17.3	0.0
Gas	36.4	11.3	25.1
Other Non-Renewables	15.8	5.4	10.4
Other Renewables	6.6	3.2	3.4
Hydro Pump Storage	8.4	4.4	4.0
Run-of-River	4.0	0.0	4.0
Waterreservoir	2.9	0.0	2.9
Battery	5.1	3.5	1.6
Oil	0.8	0.6	0.2

Table A.3: Overview of the used data sources of IDILES and JMM.

Data	Source	Comment
Power plant portfolio	TYNDP 2020	Scenario Distributed Energy (Climate Year 1984)
Demand time series	TYNDP 2020	Scenario Distributed Energy (Climate Year 1984)
Net transfer capacities	TYNDP 2020	Scenario Distributed Energy (Climate Year 1984)
Renewable infeed	Open Power System 2020	Weather Infromation 2016
CO2 Prices	WEO 2020, 2021	WEO 2020 Sustainable Development Scenario, WEO 2021 Net Zero Emissions by 2050 Scenario
Hydrogen Data	Williams et al. 2007 Agora 2018, 2021 Dagdougui et al. 2018 Gorre et al. 2019 IEA 2019 Prognos 2020 Ausfelder and Dura 2021 Hydrogen Council 2021	The sources allow for defining expenditures and costs, conversion rates and the value of hydrogen
Distribution of German power plants in North and South	BnetzA 2021	Geographic Information

Overview on scenario results

Table A.4: Summary of key scenario results for Germany

		SQ_0	*MS_0*		*MS_SMRdom*		*MS_GreenImp*	
		DE	**DE_North**	**DE_South**	**DE_North**	**DE_South**	**DE_North**	**DE_South**
Capacity	**MW**	55	25	30	1835	30	8741	30
Hydrogen production	**TWh**	0.073	0.05	0.03	2.64	0,01	13.40	0,02
Utilization hours of electrolyzers	**h**	1330*	1818*	835*	1477	499	1748	679
Net position (imports)	**TWh**	-128	102	-238	101	-238	98	-238
CO2-emissions	**Mt**	55	13.8	43.7	13.8	43.7	13.8	43.7
Average prices	**EUR/MWh**	119.27	110.09	125.45	110.88	125.59	114.85	126.5
Curtailment	**TWh**	1.77	15.53	0.01	13.53	0.01	7.19	0.03
System costs (Europe)	**bn. EUR**	144.74	145.53		145.52		145.34	

*For SQ_0 and MS_0 we show the values for the case *GreenImp*. The utilization hours of electrolyzers in case *SMRdom* can be seen in Figure 5.

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